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Simulation study of emerging well control methods for influxes caused by bottomhole pressure fluctuations during managed pressure drilling

Hakan Guner
Louisiana State University and Agricultural and Mechanical College, hguner1@lsu.edu

SIMULATION STUDY OF EMERGING WELL CONTROL METHODS FOR INFLUXES CAUSED BY BOTTOMHOLE PRESSURE FLUCTUATIONS DURING MANAGED PRESSURE DRILLING

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ABSTRACT

Managed Pressure Drilling (MPD) is an emerging drilling technology that utilizes mud weight, surface backpressure and annular frictional pressure loss (AFP) to precisely control the wellbore pressure.

The goal of this project is to identify the most appropriate initial response and kick circulation method for the kicks that result from complications specific to MPD. These complications that can cause a reduction in bottomhole pressure were classified as surface equipment failures and unintended equivalent circulating density (ECD) reductions. Rotating control device (RCD) and pump failures are the examples of surface equipment failures. Pump efficiency loss and BHA position change represent the unintended ECD reductions.

Shut-in (SI), MPD pump shut down, increasing surface backpressure, increasing pump rate, starting a new pump with surface backpressure and increasing pump rate with surface backpressure responses were simulated on a transient drilling simulator for kicks taken due to the pump efficiency loss, and the simulation results were evaluated. Shut-in and starting a new pump with a surface backpressure were simulated for a pump failure, which led to a loss of total AFP, and the simulation results were evaluated. A shut-in response was simulated for surface pressure loss (RCD failure), and its results were evaluated. Shut-in, MPD pump shut down, increasing surface backpressure pressure, increasing pump rate and increasing pump rate with surface backpressure responses were simulated, and the simulation results were evaluated for the kick taken due to BHA position change.

Kick circulation was also simulated after the influx was stopped by the initial responses. The kicks were circulated using driller's method at normal, half, and increased circulating rates depending on the initial response. The results of circulating simulations were also evaluated.

SI was concluded to be applicable for all kicks caused by bottomhole pressure fluctuations. However, increasing casing pressure is the most effective response if it is practical given the surface equipment and its condition. Normal rate circulation following these responses is generally better than using an increased or slow pump rate for these kinds of kicks. It reduces the surface backpressure and non productive time (NPT) required versus slower pump rates.

1. INTRODUCTION

1.1 Managed Pressure Drilling Concept

The international Association of Drilling Contractors (IADC)[1] defines managed pressure drilling (MPD) as follows:

"MPD is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore." IADC further states that "The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process. "

The purpose of managed pressure drilling is to create a pressure profile in the annulus within the operating window guided by pore and fracture pressures[2]. Pressure control in the annulus is achieved by employing the following techniques: adjusting fluid density, frictional pressure losses and the surface backpressure by using a combination inclusive of a rotating control device (RCD), choke, pump, and the design of well bore and drillstring configuration[3]. MPD uses some of the same equipment used in underbalanced drilling (UBD). However, in contrast to the UBD operations, MPD operations are intended to prevent formation fluid from flowing into wellbore[4]. Hydrostatic pressure, or the equivalent static density (ESD) of the fluid in the annulus, is to be maintained lower than pore pressure during UBD. It can be equal, higher, or less than the pore pressure in MPD. However, the wellbore pressure, whether static or dynamic, is always expected to be equal or higher than the pore pressure during MPD. There are several variations of MPD including Constant Bottom Hole Pressure Method (CBHP), Pressurized Mud

Cap Drilling (PMCD), dual gradient (DG), health, safety, and environment (HSE), which is also referred to as returns flow control[5]. Figure 1 shows these MPD variations and their benefits as described by Hannagen[6]. The CBHP method of MPD has a wider application area and many benefits compared to the other MPD variations. This research focuses on the CBHP method of MPD application as explained in the following sections.

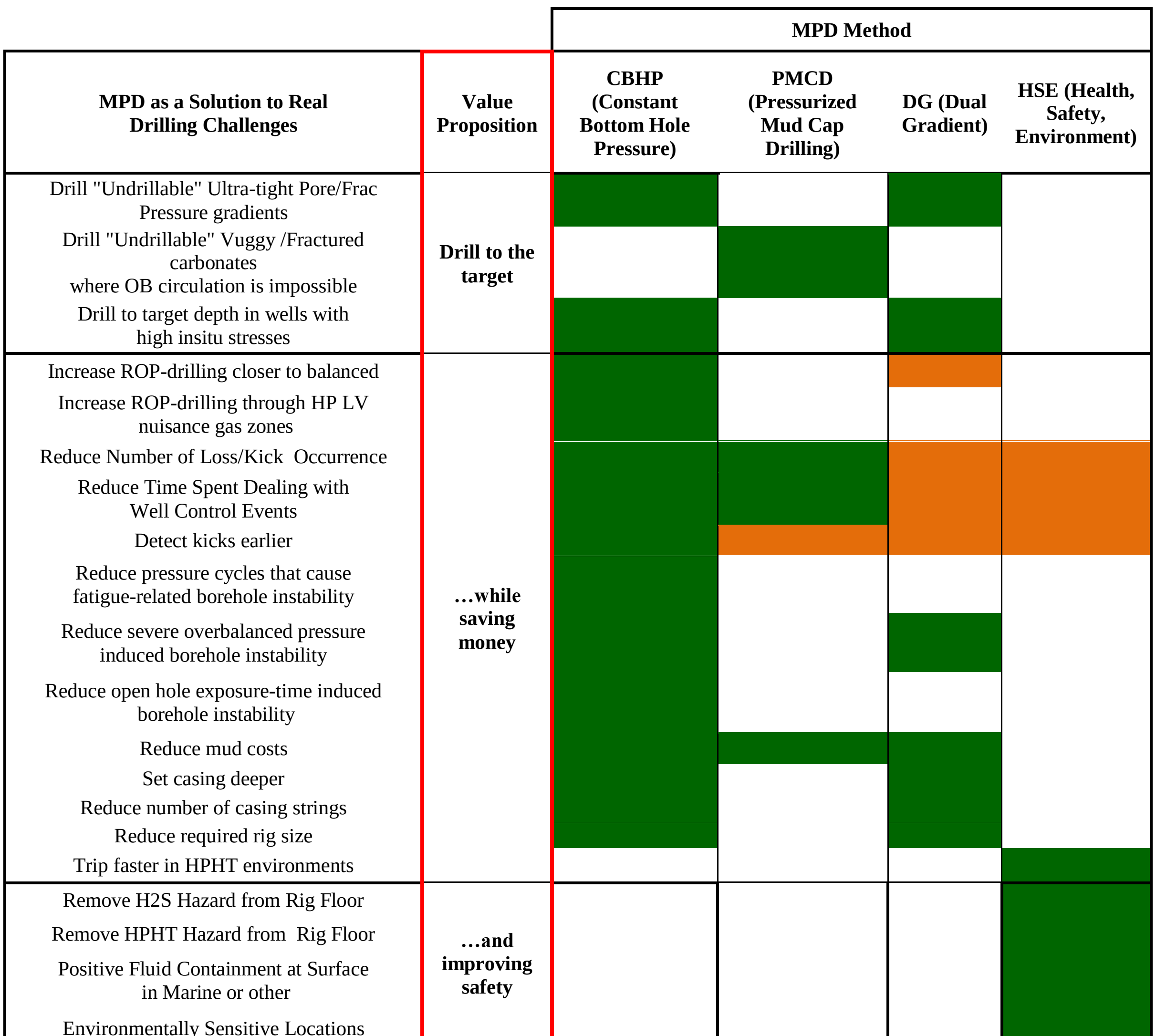


Figure 1: MPD variations and Properties[6]

1.2 Motivations for Managed Pressure Drilling

The efforts behind the development of new drilling technologies are often to reduce the non-productive time (NPT) due to drilling problems. Table 1 shows the drilling problems occurring during offshore gas well drilling in the Gulf of Mexico from 1993 to 2002, and more than 36% of the drilling problems occur due to the pressure issues. Stuck pipe, lost returns, and kicks are all related to the pressure problems and compose the important portion of the NPT.

Table 1: Drilling problems in Gulf of Mexico from the final report of MMS Joint Industry Project DEA 155 (data from James K. Dodson Company)[7]

Water Depth	<600 ft	<600 ft
TVD	<15,000 ft	>15,000 ft
Wells	549	102
Average TVD	11,668 ft	17,982 ft
Differentially Stuck Pipe	11.60%	11.10%
Lost Circulation	12.70%	12.80%
Well Instability	4.30%	2.50%
Kick	8.20%	9.70%
Trouble Subtotal	36.80%	36.10%

Saponja et al.[8] explained, based on Dodson's data, that drilling NPT generates 25% of a standard well's cost. In addition, Kozicz[3] stated in his paper that approximately 50% of the drilling NPT comes as a result of pressure issues. Lost circulation and stuck pipe problems may be reduced by minimizing wellbore pressure opposite the zones causing these problems. On the other hand, kicks, shallow water flows, and wellbore instability require a wellbore pressure high enough to control these problems. Deep wells often encounter problems of both kinds, with tight margins between the minimum and maximum operable, practical wellbore pressures. The precise control possible with MPD can help to reduce or eliminate such problems. Quitzau et al.[9]

proposed a concept for extending casing points by managing the ECD. In his concept, a large diameter liner is run as part of drillstring in the high pressure formation, whereas a small diameter liner is used in the shallower sections of the hole. The mud weight is then reduced to provide a higher ECD within the pore and fracture pressures window at the bottom and a lower ECD and thus a lower pressure in the shallower sections. Saponja et al.[8] supported MPD as a cost-effective method that drills through high pressure zones without increasing mud weight. Drilling with a lower overbalanced pressure improves ROP. In addition, the risk of needing an additional intermediate casing string is reduced by managing the wellbore pressure and by avoiding formation influx and loss returns[8].

Saponja et al.[8] suggested that MPD enables the process of drilling "economically unattainable[1]" formations by means of conventional drilling together with improved ROP and reduced NPT. Fossil et al.[2] mentioned that one of the repeated drilling problems, which also increases the NPT, is the loss of circulation in high-temperature high-pressure (HTHP) deepwater wells. In his paper, Coker[10] stated that around 70% of the offshore hydrocarbon reservoirs cannot be drilled by conventional drilling due to economic issues. He added that considerable hydrocarbon resources will be left in place unless MPD technology is utilized. May et al.[11] explained that Shell applied managed pressure drilling as an innovative technology to safely drill depleted reservoirs in the Gulf of Mexico. Further, he added that Shell used MPD technology and successfully completed drilling a well that was previously concluded as unsuccessful due to lost circulation and wellbore instability problems in the Gulf of Mexico.

MPD is required because it can help to reduce the drilling cost, mitigate the pressure related drilling hazards, and drill into formations otherwise inaccessible due to tight pore pressure and fracture pressure window, thus avoiding kick and lost returns risks.

1.3 Constant Bottom Hole Pressure Method of Managed Pressure Drilling

The constant bottom hole pressure (CBHP) method of MPD maintains a constant bottomhole pressure by manipulating backpressure and wellbore frictional pressure losses in a closed drilling system[12]. Vieira et al.[13] stated that turning the pumps on and off leads to bottomhole pressure fluctuations. This may bring drilling and wellbore stability incidents, which increases the NPT[13]. The CBHP method of MPD utilizes a closed loop circulating system and is intended to eliminate the bottomhole pressure fluctuations occurring during pump turn on/off.

Bottomhole pressure is a function of three factors: hydrostatic pressure of the drilling fluid, frictional pressure losses due to circulating drilling fluid in the annulus, and surface backpressure. The CBHP of MPD is achieved by the combination of these parameters in a specially equipped system. Figure 2 depicts the factors that manage the bottomhole pressure.

Figure 3 illustrates MPD drilling and its advantages over conventional drilling in the pore pressure fracture gradient window. In conventional drilling, equivalent static density (ESD) of the drilling fluid is maintained above the pore pressure gradient. This may create a risk of loss when the circulation is started and the ECD exceeds the fracture gradient as shown in Figure 3. On the contrary, ESD of the drilling fluid is typically kept less than or about equal to the formation pressure gradient during the CBHP method of MPD. In dynamic conditions, ECD increases the wellbore pressure to a level slightly above the formation pressure. Surface backpressure can be adjusted during drilling or static conditions to maintain a constant bottomhole pressure. Surface pressure can compensate for the lack of the ECD effect while the pumps are turned off for tripping or connections. Surface pressure is maintained with a special piece of equipment called a rotating control device (RCD). The main function of the RCD is to seal the annulus, contain the annulus pressure, and divert the wellbore flow to the choke manifold[13].

The CBHP method of MPD is especially applicable in the small hole sizes because of the higher ECD effect.

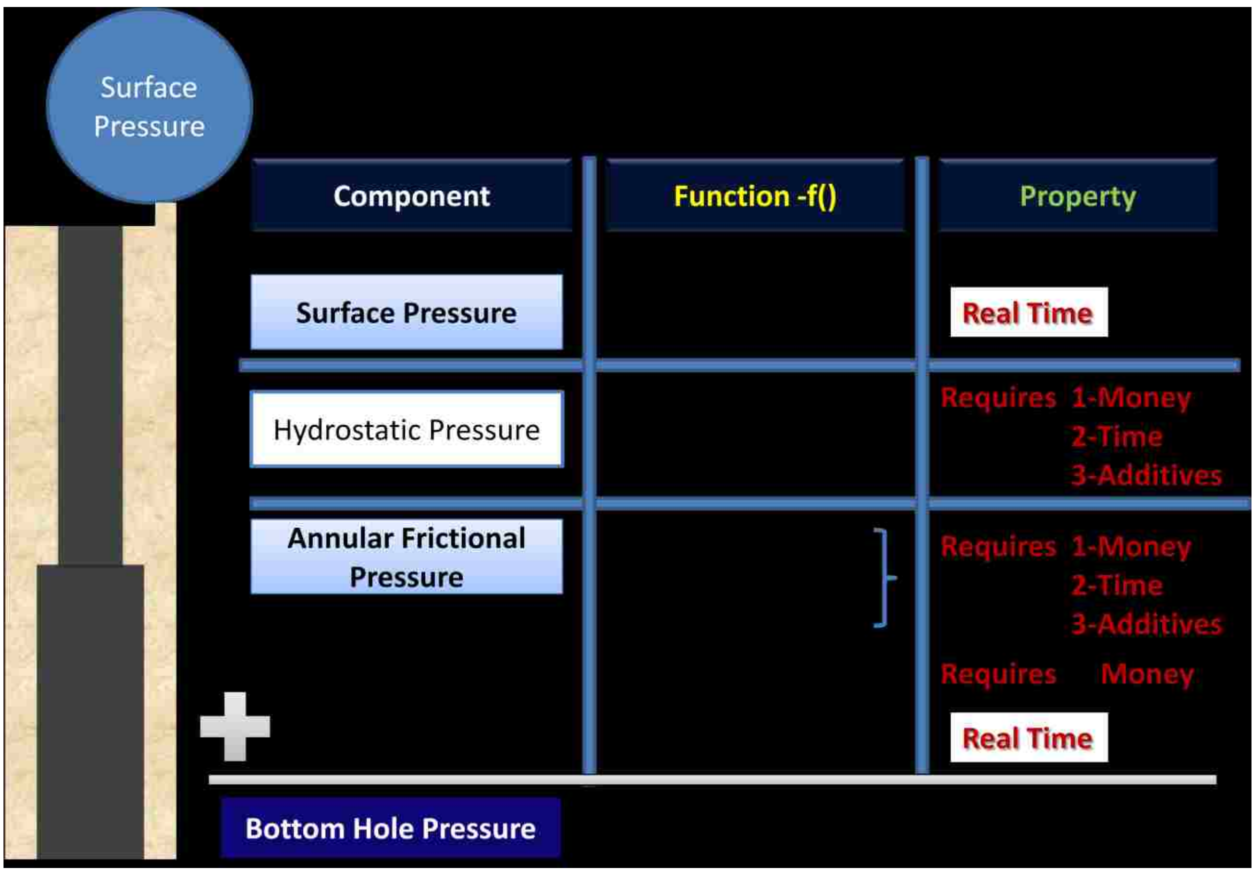


Figure 2: Bottomhole pressure parameters

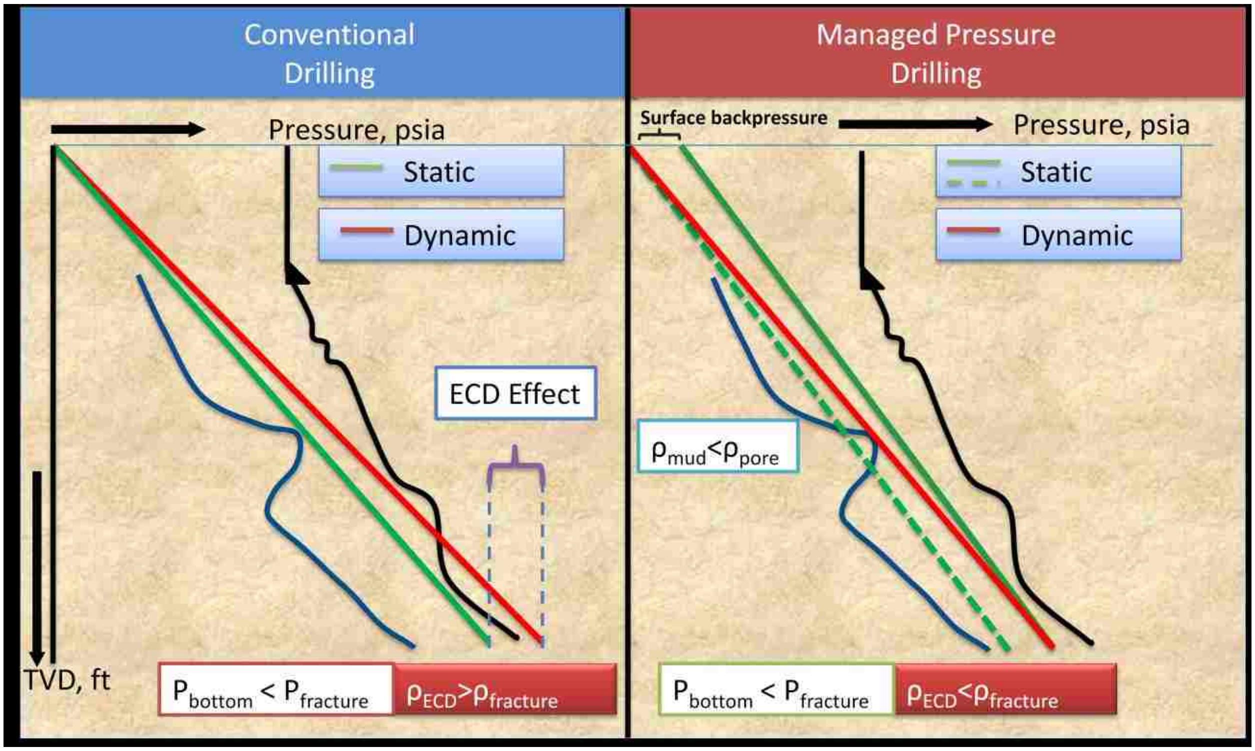


Figure 3: MPD and conventional drilling wellbore pressure profiles

1.4 Research Objectives

MPD employs special equipment and techniques that enable continuous dynamic well control; therefore, this feature allows alternative well control methods. The objective of this research is to identify reliable well control methods for the constant bottomhole pressure method of managed pressure drilling. Well control methods may include different initial responses to kicks and different kick circulation strategies when compared to conventional drilling.

This research focuses on alternative well control methods for formation influx caused by unintended bottom hole pressure fluctuations below the formation pressure. Unintended BHP fluctuations can be caused by surface equipment or downhole (e.g. washout) failures and control errors. Four specific kick scenarios were studied in this research: pump efficiency loss, pump failure, RCD failure, and ECD reduction due to BHA position change. These scenarios were selected to serve as models for the other causes of pressure fluctuations in the well.

Pump efficiency loss, which is a common mechanical occurrence during drilling, leads to partial loss of annular frictional pressure (AFP). While drilling close to the formation pressure, partial loss of AFP may result in formation influx into wellbore.

Pump failure is another of equipment problem, which leads to the total loss of AFP. Loss of AFP can then trigger the formation flow into the wellbore.

An RCD may fail due to a worn rubber-sealing element if servicing is not provided often enough. If an RCD fails in a static condition, the trapped pressure offsetting the AFP is lost, and a kick is gained. The RCD failure scenario represents a loss of surface pressure. Another cause is a choke wash out.

A reduction in ECD at a high pressure zone due to the BHA moving below the zone is the final scenario defined in the project. In such a case, wellbore pressure at the top of the high pressure zone decreases based on the reduction in drill collar length above the high pressure sand zone as the well is drilled deeper.

These scenarios were simulated on the Dynaflodrill simulator provided by SPT Group. The simulation results were evaluated to identify the most appropriate initial responses and circulation procedures for kicks taken under these various causes of kicks. This research was conducted as a part of a LSU-industry consortium project and supported by major operating and oil service companies.

1.5 Overview of Research

This research is described in this thesis in eight chapters.

Chapter 1 introduces managed pressure drilling and the constant bottom hole pressure variation of MPD, explains the purpose of the thesis, and introduces the scenarios that have been studied.

Chapter 2 reviews the MPD literature. It further explains the CBHP method of MPD concept and the required equipment. It also reviews the associated well control issues in the literature. Finally, this chapter summarizes published case histories for the CBHP method of MPD.

Chapter 3 describes the research plan and gives details about the methodology used to complete the research. This includes the description and features of the simulator used.

Chapter 4 defines the matrix of simulations performed for the initial response study and the prospective alternative initial responses to stop the formation influx.

Chapter 5 defines the potential kick circulation strategies.

Chapter 6 describes slim (Well X) and large hole (Well Y) well scenarios. Well X represents a typical offshore slim hole side track on which simulation studies were performed. Well Y represents a typical vertical large hole development drilling well on which simulation studies were performed. Further, kick scenarios are introduced in this section.

Chapter 7 presents the results of the simulated initial responses and circulation methods for defined kick scenarios. The results of the kick scenario simulations are then analyzed. The effectiveness of initial responses and circulation strategies are discussed with respect to effectiveness of stopping formation feed-in, the risk of lost returns, the risk of surface equipment failure, NPT, and the final pit gain (additional gain).

Chapter 8 derives conclusions for each kick scenario and for overall simulation runs. This section also presents recommendations for future studies.

2. LITERATURE REVIEW

The focus of this research is to investigate well control methods for influx taken due to unintentional fluctuations in bottomhole pressure during MPD operations. This subject has not been addressed in significant detail in industry publications or professional papers. Nevertheless, there is relevant published knowledge. This chapter summarizes the pertinent information found in a review of literature on well control and MPD operations. It includes an overview of the different MPD concepts; a review of the different approaches and equipment being used to implement the CBHP method of MPD; a description of a variety of well control considerations relating to MPD; and finally, a summary of relevant field experiences from published case histories.

2.1 General MPD Concepts

MPD is an advanced drilling technology that utilizes both a pressurizable fluid system and specialized equipment to more precisely control the annular pressure profile throughout the wellbore[13]. The aim is to maintain the annulus pressure within close tolerances and close to the boundary of formation pressure, wellbore stability, and fracture pressure[2]. The pressurizable closed circulation system of MPD allows better and more accurate control of the wellbore pressure profile by coordinating surface pressure with mud weight and pump rate adjustments[5]. MPD technology optimizes the drilling process by minimizing the NPT and avoiding drilling problems associated with pressure fluctuations[4]. Different from the underbalanced drilling (UBD), the objective of MPD is to avoid the formation fluid influx, and the drilling-related problems, thus enabling production from the economically undrillable prospects [4].

Malloy[14] stated that one MPD method is not enough to address these problems.

Hannegan[4] explained the several variations of MPD, such as CBHP method of MPD, pressurized mud cap drilling (PMCD), dual gradient drilling (DGD), HSE MPD, riserless MPD, and zero discharge riserless MPD.

Vieria et al[13] described the CBHP method of MPD as a technique that maintains a bottomhole pressure (BHP) constant during the entire drilling operation. The CBHP method utilizes appropriate levels of surface backpressure and AFP to maintain the BHP constant in a pressurizable fluid system by avoiding ECD changes. Hannegan[5] stated that CBHP fits well in tight pressure environments.

Terwogt[15] defined Pressurized Mud Cap Drilling (PMCD) as an advanced technique used to manage wells with drilling fluid losses. Upon losing the drilling fluid into formation, hydrostatic pressure in the annulus decreases. If it drops below the formation pore pressure of a permeable formation, the formation fluid begins to flow. The well is controlled by filling the annulus at a higher rate than the flowing gas. He named this method "mud cap drilling." If the wellbore pressure across the high pressure permeable zone is less than the formation pressure due to mud losses, the annulus is filled with a slightly lower mud weight than the reservoir pressure. This allows surface pressure to be maintained at the surface by closing the annulus with a RCD. This method uses a lower mud weight and closed pressure system and is called PMCD. Fossil et al.[2] explained that controlled mud cap (CMC) is another MPD variation that relies on a high pressure drilling riser with a BOP system to separate subsea and surface levels for deep water offshore application. A multiphase real-time simulator is required to calculate pressure profile in the wellbore. The simulator will control the mud lift pump power distribution system.

It will regulate the speed of the mud lift pump so that the required height of the mud column in the riser is maintained in controlling the BHP.

Schubert et al.[16] defined dual gradient drilling (DGD) as an unconventional method of drilling that utilizes a relatively small diameter return line to circulate the drilling fluid and cuttings from sea floor to surface. DGD allows wellbore pressure stay within the operating window limited by the formation pore and fracture pressure. A seafloor pump is utilized to lift the return fluids and cuttings from annulus to mud system. The riser is filled with seawater during DGD, and a rotating diverter separates the wellbore fluids from the seawater. A return line is used as a choke line in conventional riser drilling for well control.

Hannegan[5] summarized the HSE or returns flow control of MPD. It aims to enhance health, safety, and environmental issues by closing the mud returns on the rig floor. The annulus is isolated to prevent return fluids to expose to the atmosphere. Hannegan[4] further explained that riserless MPD is useful in controlling shallow geohazards. The subsea choke decrease increases BHP as if the drilling were performed with a marine raiser filled with drilling fluid and cuttings. He also defined zero discharge riserless MPD as a dual gradient riserless drilling.

2.2 Constant BHP Method and Systems

This section includes an overview of the different systems and equipment used to implement the CBHP method of MPD. This research focuses on the CBHP method. Hence, the existing service companies, in addition to equipment and technologies that support CBHP MPD, will also be summarized.

The objective of the CBHP method is to avoid kick and loss hazards by maintaining a constant BHP. This is typically achieved by drilling with a fluid that is lighter than the pore pressure so that the BHP is held constant by utilizing surface backpressure and AFP in a closed circulation system. It is applicable in environments with narrow pressure limits between pore or stability and fracture pressures. Drilling can continue in deeper sections with the same mud weight used in the shallower section as it can utilize AFP and surface backpressure. Thus, the CBHP of MPD allows lengthier open hole sections and reduces the required number of casing strings[17].

The CBHP method of MPD requires a closed circulation system and special equipment. The key components of a closed circulation system include a RCD and a non-return valve (NRV). A RCD seals the annulus and allows choke to control the wellbore pressure from the surface[18]. Cantu et al[18] stated that RCD has become standard drilling rig equipment and the key component of well control equipment during UBD and MPD operations. An NRV is a one-way valve that allows fluid to flow in one direction[19]. The NRV is a vital tool in preventing possible back flow from the bottom through the drill string, trapping the pressure in the annulus for safe tripping or connections[13]. Typically, at least two NRVs are required to be positioned in the BHA for safe drilling. The MPD choke manifold is another key component for controlling wellbore pressure to maintain a constant BHP. There are automated and manual chokes available in the industry. An automated system controls the choke manifold via a programmable logic controller, which is adjusted based on a hydraulic simulator. An automated choke should provide more precise control than a manual choke. During tripping operations, a downhole deployment valve[13] (DDV) may also be used to avoid snubbing and to trap the pressure for constant bottom hole pressure. It is run as a part of casing string and can be controlled from the surface. Aside from use of the DDV, the mud weight can also be increased and circulated to kill the well at a slow rate so that the heavy mud is placed across the open hole or in the casing[21]. Vieira et al.[13] also recommended a “MPD multiphase separator” be used for the wells that may encounter large volumes of formation influx.

There are also various systems developed by service and operating companies; these utilize different technologies and tools to implement the CBHP method of MPD. Dynamic annular pressure control system (DAPC), Secure Drilling, a continuous circulation system (CCS), an ECD reduction tool, and Sperry Drilling Services' GeoBalance™ Managed Pressure Drilling (MPD) are systems for applying the CBHP of MPD.

At Balance introduced a closed system called the DAPC system to control the BHP. The DAPC system provides an automated control of surface-applied annular backpressure to the annulus to maintain the BHP constant. DAPC components are listed as the choke manifold, backpressure pump, integrated pressure manager, real time hydraulics model, and coriolis flow meter[22]. A pressure while drilling (PWD) tool can be attached to the BHA in order to calibrate the hydraulic simulator.

Impact Solutions Group introduced the Secure Drilling™ system as a new MPD technology[23]. The Secure Drilling System utilizes “micro-flux control” technology for improving drilling in narrow margins, offshore and other challenging wells through automated kick detection[24]. Santos et al[25] stated that the micro-flux control concept can detect a kick as low as 0.25 bbl in some situations. The system uses a closed-loop circulation system managed by automated data acquisition and a computerized pressure control system. The system was tested with oil and water based mud at Louisiana State University in 2005[24].

The continuous circulating system (CCS)[26] is equipment that was developed by a joint industry project, managed by Maris International Ltd, and supported by Shell U.K., BP, Statoil, BG, Total, and Eni. Jenner et al.[26] defined CCS as a new technology that enables continuous circulation during the connection of drill pipes to drill string in CBHP. The idea behind CCS is to create a steady pressure regime and ECD[27]. CCS technology provides improved control of equivalent circulating density, eliminates pressure surges during connections, and removes the rig downtime to circulate the cuttings by providing continuous circulation. This reduces the stuck pipe problems, especially in the horizontal wells. In tight margins, it removes the pressure spikes during connections and reduces the risk of lost returns, wellbore breathing, or ballooning. However, CCS cannot handle a BHA that has an OD higher than “5-7/8”, and it is not used in the well control events[26].

Weatherford, cooperating with BP, developed an ECD reduction tool as an MPD application[28]. Bern et al[29] described the ECD reduction tool as a special tool to counteract wellbore pressure increase due to AFP annulus by effectively reducing the hydrostatic head. The ECD reduction tool is added in the drillstring by making a short trip and represents a low cost method to convert conventional drilling to MPD[29].

Finally, Halliburton introduced Sperry Drilling Services' GeoBalance™ Managed Pressure Drilling (MPD) Service to reduce the drilling days and improve economics[30].

2.3 Well Control Concepts

The focus of this research is to investigate a reliable well control method for the CBHP method of MPD. Well control for MPD has not been studied in detail. Existing information in the literature related to well control and MPD will be summarized after the conventional well control concept has been discussed. Thus, this section reviews the conventional well control issues.

One of the most important points in well control is the influx (kick) detection. Early kick detection is crucial to blow out prevention.[31]. The primary indications of a kick are a gain in the pit volume, an increase in return mud flow rate, a decrease in pump pressure, or an increase in pump strokes or drilling rate during conventional drilling. Jardine et al.[32] explained the importance of accurate flow measurements and the effect of heave motion in kick detection for floating rigs. Bryant et al.[33] evaluated the gas influx detection by using an MWD acoustic technique. The results showed that acoustic responses can indicate the existence of a gas bearing formation earlier than the conventional methods. Codazzi et al.[34] explained the acoustic method for gas influx detection. The technique can detect the kick earlier than conventional techniques.

Once the kick is detected based on the mentioned surface warning signals, the pump is shut down and the well is checked for flow[31]. Dupuis et al.[35] recommended avoiding flow check and closing the BOP quickly after a kick is detected in slim hole wells. If the well is flowing, then the formation fluid flows into the wellbore and the well is shut in as an initial response to stop the formation fluid influx during conventional procedure. The kick can be circulated with Driller's method or the Wait and Weight method or the Concurrent method[36].

Swab kick occurs because of hydrostatic pressure reduction in the annulus. Rudolf et al.[37] explained that swab kicks are caused by the upward movement of drillstring or casing in the hole. He added that the mud weight should be determined to compensate for the swab and temperature effects. Shaughnessy et al.[38] noted well control issues such as swabbing on trips, ballooning formations, low permeability kicks, liner top failure, flow after cementing, and casing wear during ultra high pressure, high temperature drilling.

2.4 Well Control for CBHP Method

This section reviews well control concepts, including initial reactions, circulation methods, and the causes of the kick during CBHP of MPD.

Das et al.[39] compared and evaluated the shut in the well, applying surface backpressure while continuing circulating and increasing pump rate as the possible and alternative initial responses for CBHP method MPD. He concluded that there is no single best reaction as the initial response results depend on the hole geometry and the location of the weak zones. Nevertheless, he added that increasing the choke pressure and pump rate may stop the influx with lower pit gain and lower surface choke pressure versus the shut in during MPD operations. He described that increasing the pump rate minimizes the need for surface backpressure. In addition to that, he defined increasing the casing pressure as the simplest alternative response, causing less risk of lost return at the casing shoe versus the shut in. This research evaluates the initial responses he studied along with the new responses for different kick and wellbore scenarios.

Chustz et al.[40] explained the advantage of the DAPC system of the CBHP method of MPD toward stopping the influx instantly. He mentioned that the DAPC system can increase BHP instantly upon gaining an influx up to the defined minimum allowable pressure before fracturing. He discussed increasing annular pressure while both circulating and ramping down the rig pumps before shutting in the well. He highlighted the elimination of additional influx prior to shut in compared to the conventional drilling operations.

Malloy[14] stated that MPD allows control of BHP from the surface within a "30-50 psi" range.

The Mineral Management Service (MMS)[41] described a matrix for controlling a kick during MPD operations. Figure 4 shows the matrix defined by the MMS. The possible initial responses include shutting in, increase of backpressure, pump rate and mud weight. If the hazard is severe and falls into the red-shaded area in Figure 4, shutting in the well is the only applicable response.

MPD Drilling Matrix	Surface Pressure Indicator			
	At Planned Drilling Back Pressure	**At Planned Connection Back Pressure**	**> Planned Back Pressure & < Back Pressure Limit**	**≥ Back Pressure Limit**
No influx	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
Operating Limit	Increase back pressure, pump rate, mud weight, or a combination of all	Increase back pressure, pump rate, mud weight, or a combination of all	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
< Planned Limit	Cease Drilling. Increase back pressure, pump rate, mud weight, or a combination of all	Cease Drilling. Increase back pressure, pump rate, mud weight, or a combination of all	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action
≥ Planned Limit	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action

Figure 4: Influx control matrix[41]

In addition, Saponja et al.[8] defined a similar Flow Control Matrix (FCM) as a primary well control step during underbalanced drilling operations, interfacing between MPD and well control as shown in Figure 5. The FCM[8] gathers all operational hazards and equipment limitations and provides a tangible response to the rig crew. The hazards and the responses are defined based on the wellhead flowing pressure and the return gas rate. Initial responses include changing the pump rate, surface backpressure, and shut-in.

		WELLHEAD FLOWING PRESSURE		
		0-3,447 kPa	**3,447-4,800 kPa**	**4,800+ kPa**
RETURN GAS RATE	**0-594 $10^3m^3/d$ (0-21 MMscfd)**	**Manageable**	**Adjust system to increase BHP: - Increase liquid injection rate - Decrease surface backpressure**	**Shut-in on rig's BOP**
	0-594 $10^3m^3/d$ (0-21 MMscfd)	**Adjust system to increase BHP: - Increase liquid injection rate - Increase surface backpressure**	**Adjust system to increase BHP: - Weight up drilling fluid**	**Shut-in on rig's BOP**
	892+$10^3m^3/d$ (31.5+MMscfd)	**Shut-in on rig's BOP**	**Shut-in on rig's BOP**	**Shut-in on rig's BOP**

Figure 5: Flow Control Matrix[8]

The MPD well control system requires special equipment along with the conventional equipment. A joint industry project, DEA155[7], written by Malloy[7] defined RCD as one of the main components of an MPD system. He also added that RCD is not expected to take the place of a blow out preventer as a primary well control device. He stated that an RCD can have “2500 psi” capability for land, jack up and barge drilling operations. This rate is altered to “5000 psi” in the static mode.

Saponja et al.[8] explained the minimum BOP stack configuration with RCD and primary/secondary flow lines that fits the Alberta Energy and Utilities Board (EUB)regulations as shown in Figure 6. An annular preventer is installed for primary isolation during RCD servicing. Blind rams are used to isolate the well when the drillstring is out of the well.

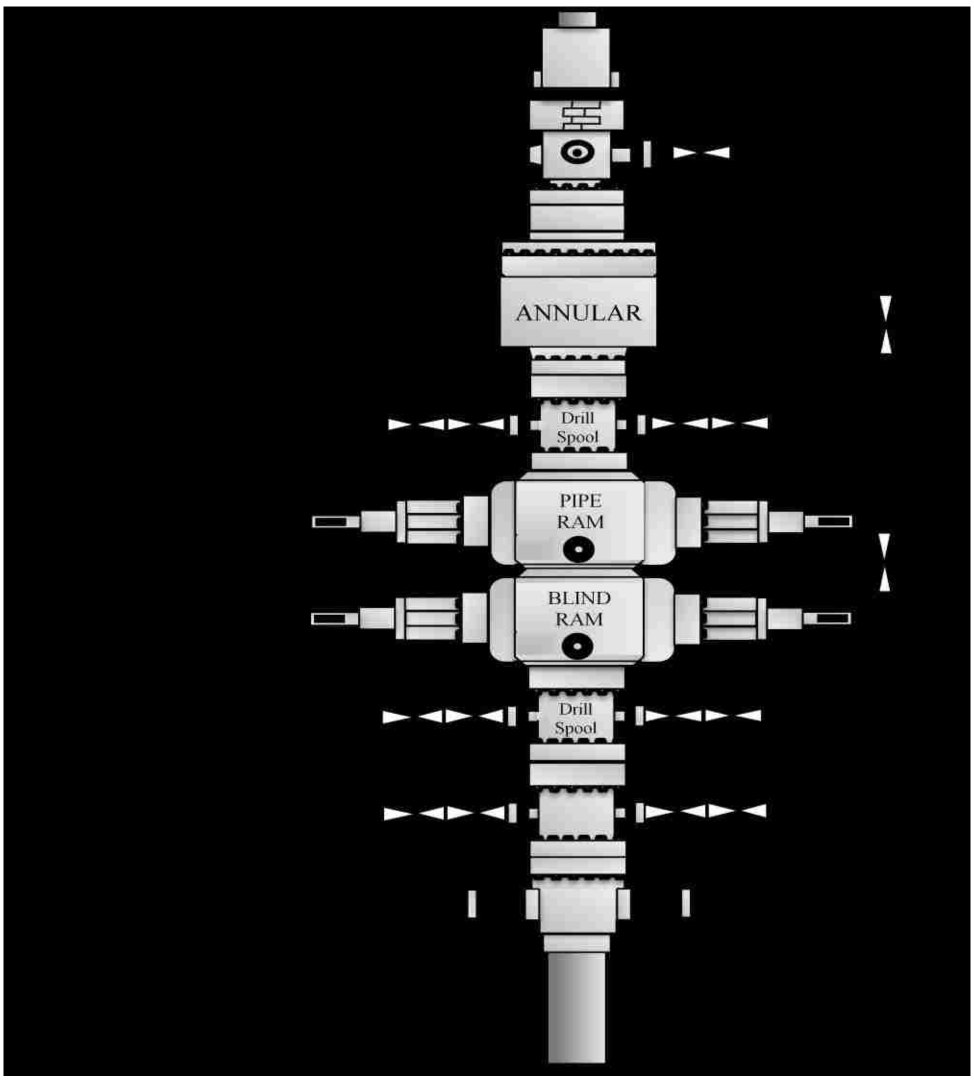


Figure 6: BOP stack arrangement for MPD[8]

Chutz et al.[40] emphasized the utility of PWD for CBHP: PWD provides real time BHP monitoring. Nevertheless, he added that the MWD signals are weak when circulating at reduced rates.

Fredericks et al[42] stated that DAPC can detect the kicks by monitoring and comparing flow in and out. A flow meter is installed downstream of the choke manifold to measure the flow out. The system also compares the real BHP and hydraulics model for an improved kick detection. If a kick is detected, the well can be shut in or the system can increase BHP and circulate the kick automatically by setting a new bottomhole pressure set point. The system was tested in the "Shell SIMWELL" test well to evaluate the control of a gas kick. A nitrogen gas bubble was injected while DAPC was controlling the backpressure. The system detected a reduction in the hydrostatic pressure and manipulated the backpressure automatically to maintain the BHP constant.

Santos et al.[43] explained well control issues for the Secure Drilling system. A micro influx indicates a kick, and the choke is automatically manipulated to increase the backpressure for flow in and flow out equality. He[43] added that after the backpressure is increased and the flow in is equal to the flow out, the system circulates the kick out by a driller's method of maintaining the BHP constant.

Bode et al.[44] discussed the well control issues on a slim-hole well and introduced the importance of frictional pressure losses in slim hole wells. A slim hole well brings new procedures and techniques to well control. He explained that based on his slim hole well data, more than 90% of the pump pressure is required for the pressure losses in the annulus, versus about 10% in conventional wells. This fact indicates a new procedure for well control operations.

He also explained that "Dynamic kill" is an effective well control method when the well can be killed by the significant ECD effect, because the dynamic kill method has an advantage over conventional circulation methods. BHP is controlled by the combination of hydrostatic pressure of the mud and the frictional pressure losses in the annulus during dynamic kill. On the other hand, the dynamic kill method depends on the surface capacity, open hole fracture pressure, and the anticipated formation pressure. In addition, Bode et al.[44] emphasized the importance of the early detection of kick when it was small enough not to harm the formation or shoe during well control operations. In conventional wells, a kick detection depends on the size of the mud tank and type of pit volume totalizer (PVT) equipment; however, due to the small capacity in the annulus, a kick should be detected smaller than 1 bbl in slim hole wells. Bode et al.[44] mentioned the significant advantage of electromagnetic flow meters over PVT to detect the kick while small.

2.5 Causes of Kicks

Formation fluid enters the wellbore when the wellbore pressure is below the formation pore pressure of a permeable formation. An underbalanced wellbore pressure occurs during failure to fill an annulus, the swabbing effect of pulling the pipe, loss circulation, drilling with insufficient density of drilling fluid, or when an abnormally pressured formation is encountered[31]. Abnormal pore pressure is caused by four mechanisms: compaction effect, diagenetic effect (or chemical alteration of rock minerals by geologic processes), density differential effects, and fluid migration effects[31].

A careless choke operation, control system failure, or RCD leak may also cause formation fluid influx into wellbore during the CBHP of MPD. Chustz et al.[40,45] pointed out that

BHP excursions is experienced during MPD operations due to unplanned events of surface equipment, such as the change of RCD element or top drive swivel packing.

Figure 7 is a sample of BHP, casing pressure, and ECD during connection and circulation. During connections, the ECD effect is lost: the expected pressure profile due to ECD change is drawn with a dashed line in Figure 7. Actual BHP is maintained constant by offsetting the AFP with surface backpressure. Figure 8 shows the procedure for maintaining the BHP constant during a MPD pump shut down. As the pump is ramped down and ECD decreases, appropriate levels of surface backpressure is applied to compensate for the reduction in the ECD

2.6 Schedule to Maintain BHP Constant During Pump Start Up or Shut Down

Medley et al.[47] explained the preparation for the dynamic to static transition during MPD. Hydraulic models are utilized to calculate a casing pressure schedule for the pump rate decrease. The well is not shut down. Instead, choke is partially closed. The idea is to impose pressure to the annulus at the surface by reducing the choke opening. ECD and bottom hole circulating pressure can be calculated by hydraulic models, which can also be validated by PWD data if available. A "surface back pressure versus pump rate" table is prepared as a schedule to follow during MPD pump shut down or start up. Before reducing the pump rate, the choke opening is reduced until the required surface pressure is read on the gauge. The pump rate is set to the next target on the schedule. This procedure is repeated until the pump is shut down. With this method, BHP is maintained above the pore pressure, and influxes are avoided.

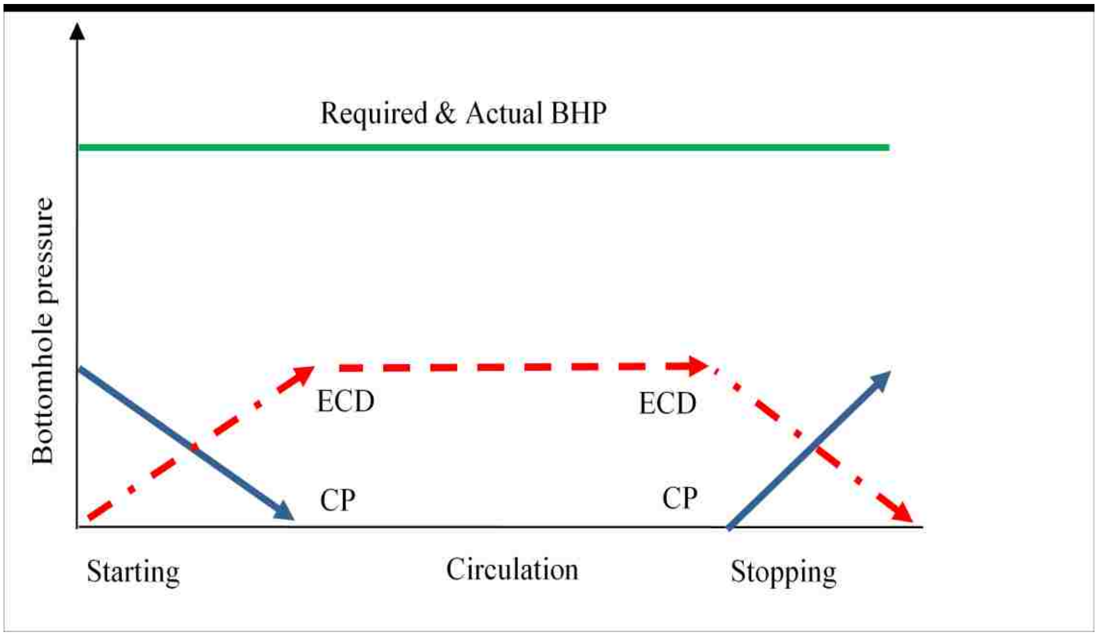


Figure 7: Bottomhole pressure during CBHP of MPD[8]

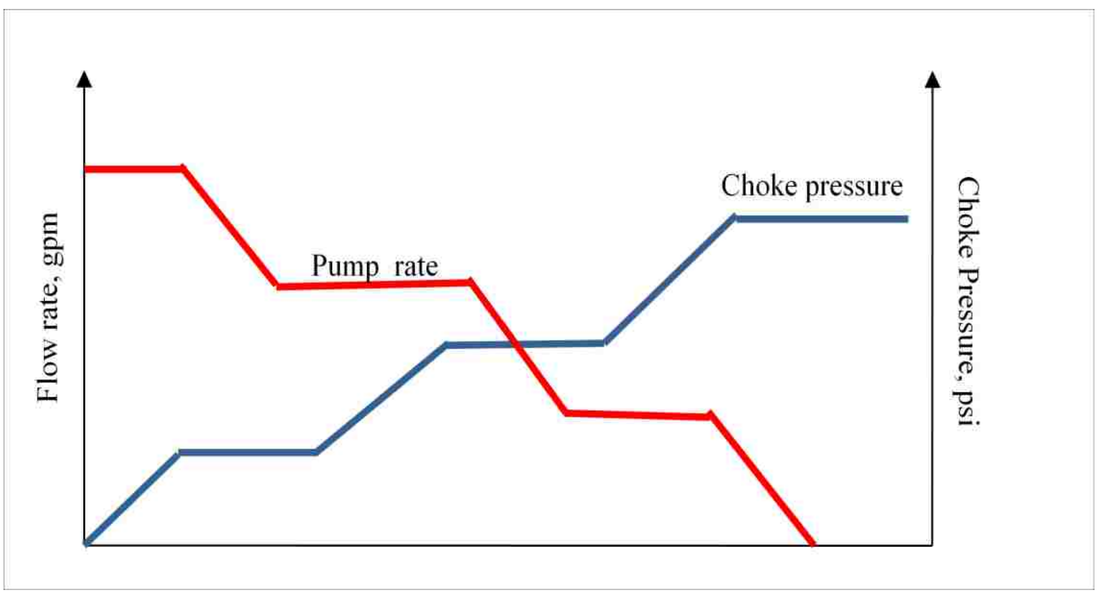


Figure 8: Choke pressure in connection during CBHP of MPD

2.7 Case Histories for CBHP Method

This section includes the drilling experiences achieved by a CBHP variation of MPD, its application, and related well control issues available in published case histories.

Chustz et al.[45] explained a case history of a drilled well by Shell Oil Company in the Gulf of Mexico. Shell deployed CBHP of MPD and DAPC technology for a redevelopment drilling in deep water fields that were previously inaccessible. The redevelopment well was drilled successfully, and BHP was kept relatively constant by the system. The depleted formation caused reductions in the formation fracture pressure in specific intervals. The high AFP, together with static mud weight designed for wellbore stability, threatened fracturing in the depleted intervals. The minimum equivalent mud weight (EMW) for wellbore stability was 14.3 ppg at TD. The fracture gradient at the depleted interval was 15.3 ppg. A safe operating drilling window was therefore 1 ppg. Conventional drilling would result in a dynamic mud weight that would exceed fracture gradient by 0.3 ppg. The automated DAPC system was used and allowed the mud weight to be reduced to 13.9 ppg, yielding 15.2 ppg ECD at the designated pump rate, rotary speed and penetration rate. During connections and with rig pumps off, surface backpressure was applied to compensate the loss of the ECD effect, and the EMW was maintained at 14.6 ppg. The trainees of drilling crew is crucial for MPD operations. BHP control within a tight operating window depends on a driller's performance in pump start up and turn off processes.

A Secure Drilling system[46] was successfully used to drill a well in the Santa Barbara field in Venezuela. The well was planned to be drilled with 11 to 14 ppg mud weight, but the Secure Drilling system drilled with 9.5 ppg. The system drilled the well with 200-300 psi overbalance, which would have been 2000 psi if the conventional drilling had been used. The well was drilled without stuck pipe, lost circulation, drag, H2S and other directional issues[46].

Caldorani et al.[27] gave an extensive case history of the CCS system of MPD in drilling a well in the Mediterranean. Numerous drilling problems had been encountered with conventional drilling due to a close operating window limited by pore and fracture pressures. CCS was used when the well was reentered, and plugs were drilled out in the 8-1/2" hole. ECD was maintained constant, while drilling from 4846 m to 4971 m. After that depth, gas influx was observed, and, at 4979 m, mud losses occurred. At 4991m, more severe losses were encountered, and a lost circulation material pill was pumped to stop the losses. After stopping the losses, a 7" liner was run and the well then was drilled with a 5-7/8" hole. This interval was also drilled with a CCS system, but, at 5130 m, the gas level in the annulus increased. Then the Hydril BOP was closed, and mud was bullheaded down the drillstring. Again, gas influx was encountered, followed by losses, while drilling from 5128 m to 5130 m. A rotating BOP was rigged up, and drilling resumed with the annulus pressure held between 500 to 800 psi. Attempts to complete the well with a 5" liner were unsuccessful. The well was secured with a cement plug. Petrobel drilled into the previously inaccessible reservoir by using CCS and MPD equipment. However, the failure to complete the well and the many well control challenges encounter reinforce the need for reliable well control procedures to handle influxes and loss problems in MPD operations.

Vieria et al.[13] described a case history of an exploratory well drilled with the CBHP Method of MPD in Saudia Arabia. From previously drilled wells, the formation pressures were estimated for the 8-3/8" and 5-7/8" hole sections. Many drilling and wellbore stability problems were encountered in the previous offset wells. One possible reason for the instability was the significant fluctuation in the BHP expected in conventional drilling during pump turn on/off due to ECD changes. The CBHP method of MPD was employed during the drilling of 8-3/8” and 5-7/8” hole sections as shown in Table 2, where ΔP referred to dynamic and static wellbore pressure differences that would have occurred using conventional methods.

Table 2: The reasons for use of MPD method[13]

Hole Section	Drilling problems	MPD technique applicable	Solution provided	ΔP (psi)
8 3/8"	Tight Hole, influx, salt water formation	CBHP	CBHP during connections and tripping procedures, avoiding hole sloughing and influx. Possible abnormal pressure.	715
5 7/8"	Gas influx		CBHP for manage the possible abnormal pressure.	780

The purpose of MPD here was to drill to the target depth with minimum drilling complications, thereby avoiding well control operations by maintaining BHP constant and properly managing the wellbore pressure. Bottomhole pressure was maintained constant during static and dynamic conditions with MPD. The well was successfully drilled, and it represented the first well employing the CBHP method with MPD in the Kingdom of Saudi Arabia.

3. RESEARCH METHOD

3.1 Introduction

The objective of this research is to establish a sound basis for determining the best initial responses and circulation methods to use for kicks taken due to unintentional pressure fluctuations. These can be caused by surface equipment failures (e.g. loss of surface pressure and pump failure) and unintended ECD reductions (e.g. pump efficiency loss and changing ECD due to a BHA position change) during CBHP drilling. The initial response is fundamental in stopping formation influx, and the circulation method is important for controlling and removing the kick in a safe manner.

Different initial responses, described in Chapter 4, and kick circulation methods, described in Chapter 5, were simulated for different kick and well conditions using a transient, multi-phase flow simulator. The simulator results were evaluated and compared for each kick and well scenario at critical zones such as at casing shoe, bottom and surface.

3.2 Research Plan

In order to achieve the project objective, the following work plan was completed.

1. Transient underbalanced drilling simulators were investigated to select the most suitable software for this project in July-August 2007.

2. A literature review about MPD and well control issues was conducted to define the project and to identify the surface equipment problems encountered during MPD, such as RCD failure.

3. Information on the characteristics of reservoirs and well representative of typical MPD applications were gathered from the project sponsors. The main reason for using MPD

technology in these applications was a tight operating window between pore pressure and fracture pressure.

Formation properties and the drilling description were input as data for the simulations of two well scenarios: Well X with a 6” hole size and Well Y with an 8.5” hole size.

4. Kick detection limits were categorized as low gain and high gain. Low gain was defined between 2 to 5 bbl, while high gain was defined between 15 to 20 bbl.

5. Potential causes for decreases in bottomhole pressure during MPD operations were identified by discussions in project consortium meetings and by the literature review in regard to the surface equipment problems encountered during MPD.

6. Simulations were conducted for the multiple alternative initial responses that are feasible for each cause of kick. Kicks were simulated for each well scenario and for the assumed detection limits.

7. The purpose of each initial response was to stop the influx from the formation, by increasing the wellbore pressure to equal or slightly higher than the reservoir pressure. At the end of each initial response, a simulation file screen was saved to allow consistent comparison of different kick circulation methods as the kick was circulated.

8. After the formation influx was stopped by the initial responses, a circulation test was run on the simulator. The driller’s method was applied as the primary circulation method, because the continuing mud weight was already known to be sufficient for the planned operation for most causes of the kicks. Three major circulating options were investigated: reduced, normal, and increased circulating rates.

9. The simulations were compared and evaluated in two parts: initial responses and kick circulation methods. The primary effectiveness measure of the initial response is the success in stopping formation influx. The secondary criteria are the risk of fracturing the formation and the final surface pressure required. An additional final criterion is the ease of the application of the initial response.

The primary effectiveness of kick circulation is the removal of the kick with a slightly overbalanced BHP held constant during circulation so as not to result in an additional influx. The secondary criterion is to maintain the integrity of the surface equipment and wellbore. The success of the kick circulation methods was evaluated based on the maximum bottom pressure, maximum surface pressure, wellbore pressure at the shoe casing, risk of lost returns, flow rate at surface, maximum pit gain and the kick circulation time as well as the practicality of the implementation of the method.

10. Complications and errors encountered during the simulations were recorded and reported to SPT Group, the supplier of the simulator.

General conclusions were explained for the initial responses and kick circulation methods. Specific conclusions for each kick scenarios were summarized by considering the initial responses and kick circulations together collectively.

3.3 Multiphase Flow Simulator

A transient, multiphase flow simulator, Dynaflodrill (DFD), was used to conduct the simulations in this research. DFD is part of the drillbench software marketed by SPT Group. Dynaflodrill[48] was created to investigate the UBD operations for steady state and dynamic conditions.

3.3.1 Features

DFD can simulate realistic scenarios in steady state or dynamic modes by utilizing multiphase flow models. Three aspects of DFD are discussed below: problem description and setup, operation and output.

3.3.2 Problem Description and Setup

DFD was designed to allow formation properties, depths and pressures, drill string component properties, bit size, nozzle area, drilling fluid properties, casing size and setting depths, wellbore temperatures, and well survey data to be utilized as input data to simulate real scenarios. Drill string and parasitic gas injection options are provided to conduct the special operations. Formation fluid types can be selected.

3.3.3 Operations

DFD is designed to simulate drilling, circulating, tripping, gas injection, and well control operations. DFD presents two execution options: batch mode and interactive. Batch mode uses input data to simulate a given scenario as a function of time. In interactive mode, an execution panel enables real-time control of pump rate, ROP, and surface backpressure. Figure 9 shows the interactive execution panel of DFD. Well control operations may be conducted upon gaining a kick, which can be detected from the increase in flow out, total influx, influx from the reservoir, free gas, and pump pressure plots. Surface casing pressure can be applied either as pressure values or as choke opening fraction. The surface casing pressure can be monitored with a real-time choke pressure plot. In addition, a number of real time plots like bit and well depth, bottom hole pressure, pressure at observation points, pump pressure, annulus pressure profile, frictional gradient, gas rate out, total influx, and flow in-flow out provide precise feedback on drilling and well control operations. Nevertheless, DFD does not report the pit gain, and fracture pressure is not defined or considered in DFD. Thus, mud losses cannot be calculated and simulated. Pit gain is calculated after exporting the flow in and flow out data to an Excel spreadsheet.

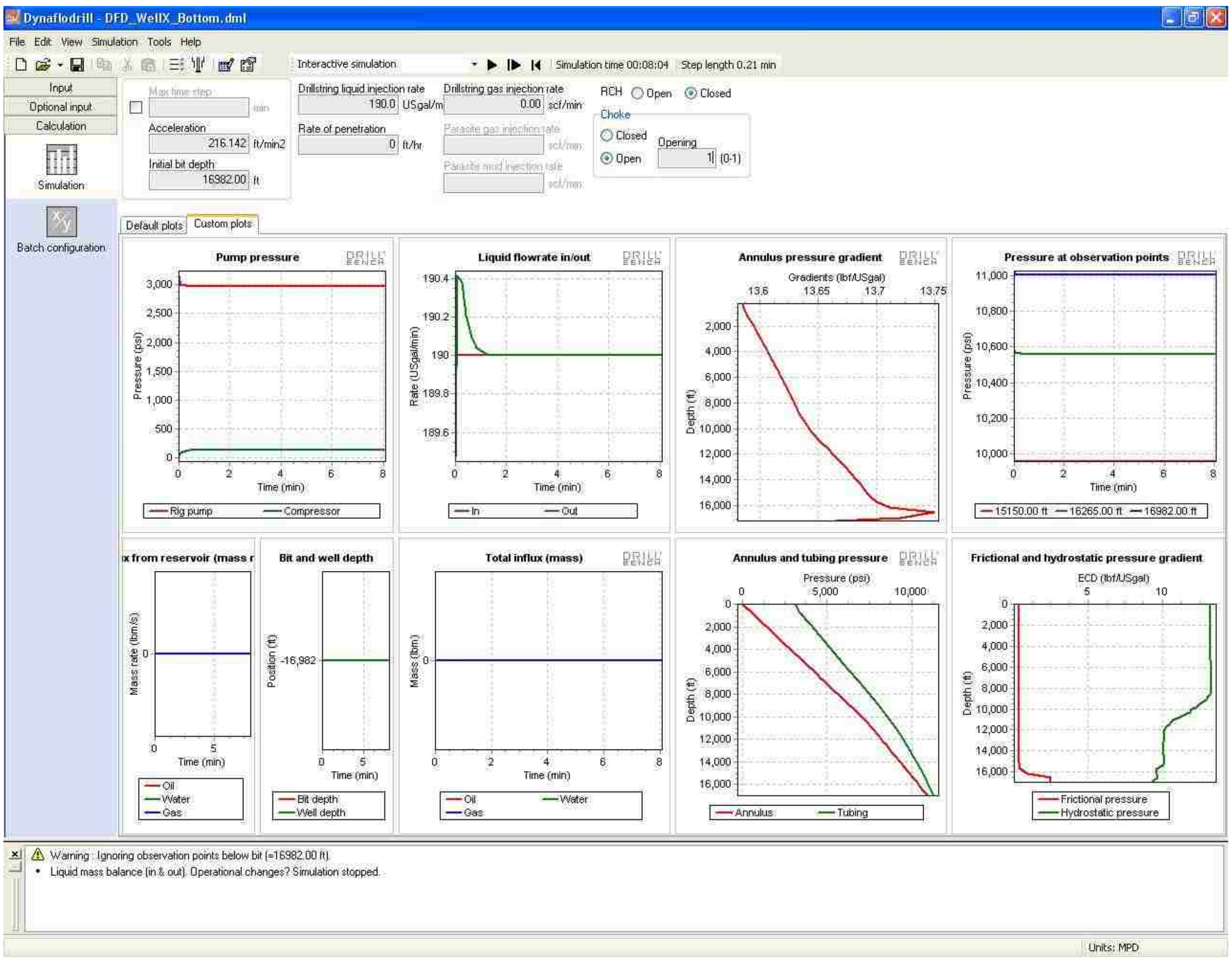


Figure 9: Execution panel of DFD

3.3.4 Output

Casing pressure, flow in and flow out, pump pressure, gas rate at the surface, wellbore pressures at bottom, casing shoe depth and high pressured formation were used as output for the evaluation of the initial responses and circulation methods simulation results.

3.3.5 Evaluation of Simulation Results

After all simulation results were obtained, the results were transferred to Excel sheets, and the necessary plots like casing pressures, bottom hole pressure etc. were prepared. Finally, the results of related scenarios were tabulated in one Excel sheet for comparison of initial responses and circulation methods. Along with the tabulated results, several plots were prepared. Flow out and pump pressure versus time were plotted after the kick was detected. At the end of initial responses, casing pressures, flow in and flow out were plotted versus time, and wellbore pressure profile plots were prepared. After the circulation of kick, casing pressures, flow out, pit gains, and gas rate out were plotted versus time. These plots and tabulated results were evaluated for a comprehensive conclusion about the success and practicality of the operations. The practicality of operations was evaluated based on the schedule or calculation requirement before the kick or during the kick gain. The practicality of the new responses was also evaluated based on the full-scale trials on Petroleum Engineering Research and Technology Transfer Laboratory (PERTT Lab).

3.3.6 Causes of BHP Reductions

There are several potential causes of BHP reductions during MPD operations. These reductions can fit into three categories: human carelessness, equipment failure, or formation failure. The carelessness of drilling crews may cause BHP reduction. Failure to fill the annulus during tripping, reducing pump rate during circulation, increasing the choke opening or reducing the surface backpressure by mistake can be classified as human carelessness. The second cause of the BHP reduction is equipment failure. Equipment failure occurs when the surface or drilling equipment fails. RCD failure, choke erosion, swivel packing leakage, leaking drillpipe, pump failure, power system failure, and pump efficiency loss are included as mechanical failures. An automated control system failure is also considered on equipment failure. BHP reduction due to formation failure occurs when the formation is fractured and mud is lost into the fractured zone. Mud can also be lost when a high permeable formation or natural fractures are encountered.

This research focuses on kicks taken due to equipment failures and on the effects of inadequate or incorrect design on the wellbore pressure reduction. Equipment failures that lead to BHP reductions affect two real time parameters: surface backpressure and ECD. For example, surface pressure loss is observed when a RCD failure or a choke erosion failure occurs. In this research, RCD failure was simulated to represent the loss of surface backpressure. An ECD reduction can occur due to equipment failures such as pump failure, pump efficiency loss, power system failure, or a leak in the drillpipe. In this research, an ECD reduction was studied by simulating pump failure, which also represents a power system failure, and pump efficiency loss.

Human carelessness in the hydraulic design, which can cause a reduction in wellbore pressure opposite a high pressure, permeable zone due to an ECD reduction, was also studied in this research. This effect resulted from an ignoring the wellbore geometry change in the hydraulics calculations due to the BHA progressing deeper as the well is drilled.

4. Initial Responses to Kicks

4.1 Introduction

The initial response to a kick is crucial in stopping a formation fluid influx as soon as possible. The initial response determines the success of the well control operations, since it is the first reaction of a well control operation. In a kick occurrence, the initial response is applied to stop the formation fluid intrusion in a way that that allows the wellbore pressure to be increased over the formation pore pressure. In conventional drilling, “shut-in” is the only generally accepted initial response that can be applied in a well control situation. However, the closed circulation system of MPD-CBHP allows for alternative initial response applications in addition to shut-in. The drilling fluid can be pressurized, since the annulus is sealed with an RCD, which isolates the annulus and diverts the return flow to the choke manifold. Application of surface backpressure and the management of AFP and their derivatives bring new initial response possibilities to well control operations. Alternative initial responses include making a MPD pump shut down by increasing surface backpressure per step (ending up with a closed choke), increasing surface backpressure at the current rate, increasing pump rate, starting a new pump with casing pressure, and increasing pump rate with surface backpressure, which is derived from surface pressure and AFP utilization. Table 3 presents a matrix showing which of these can be applied to each class of kick cause that was defined in Chapter 3. The remaining section describes each of these reactions in more detail.

4.2 Shut-In

Shut-in has proven to be an effective initial response in conventional drilling. Shut-in closes the well, enables pressure build up, and stops the formation fluid influx. Shut-in can be accomplished by using either an annular BOP or a ram BOP. Shut-in can be applied in two ways: hard shut-in and soft shut-in[31]. Soft shut-in takes longer and causes higher kick volumes. Hard shut-in stops the flow faster but can lead to a pressure surge from a water hammer effect[31].During the CBHP method of MPD, a well can be shut in either by closing BOPs or by fully closing the choke on the MPD choke manifold when the BOPs are open if an RCD is in use.

Shut-in enables calculation of the kill mud weight and formation pressure using the shut-in drill pipe pressure (SIDPP) and the mud density. However, non-return valves (NRV), which are essential in MPD for safe connections and tripping, prevents the shut-in pressure build up from being observed on the drill pipe pressure gauge. It requires bumping the float and interpreting SIDPP; such SIDPP is often difficult to interpret when bumping the float.

Table 3: Project matrix; kick scenarios and possible initial responses

	Causes of Bottom Hole Pressure Fluctuations			
Initial Responses	Loss of Pump Efficiency	Pump Failure	RCD Failure	ECD Reduction due to BHA Position Change
SI	✓	✓	✓	✓
MPD Pump Shut down	✓			✓
Incr. Surface Back Pressure	✓			✓
Incr. Pump Rate	✓			✓
Start up new pump with Pc	✓	✓		
Incr. Q with Pc	✓			✓

4.3 MPD Pump Shut Down

MPD pump shut down (MPD SD) is a method for turning off the pumps and increasing choke pressure, based on a schedule designed to provide a relatively constant bottomhole pressure. Frictional pressure losses in the annulus are calculated for several pump rates. Before reducing the pump rate, the difference in the frictional pressure between the current and next slower rate is added as backpressure using the choke. Then the pump rate is reduced to the next level, and this sequential process is repeated until the pump is turned off. Therefore, the reduction in the ECD effect as pump speed is reduced is compensated by the appropriate levels of backpressure. The pump rates in the schedule must be selected properly so that the added backpressure between steps is less than the pressure increase that would cause formation fracture. This method was applied as an initial response by closing the choke at the end of the pump shut down. MPD SD was simulated on a time-dependent schedule. Manual MPD SD takes six to ten minutes, while an automated MPD SD takes two to three minutes to turn off the pump, as per the test conducted at LSU Well Control Facility and discussion with consortium members.

4.4 Increasing Surface Backpressure

Casing pressure cannot be applied without closing the BOPs in conventional drilling. The closed system of MPD provided by the RCD enables casing pressure application without closing the BOP. Increasing casing pressure is a potentially fast initial response in that it can be applied to stop the formation flow while circulating in an MPD operation. The surface casing pressure is applied by reducing the choke opening. One common approach for implementing this method is to increase casing pressure until flow in and flow out are equalized. When the flow in and flow out are equal, the formation flow is concluded to have stopped, and the wellbore pressure and formation pressure balanced. After that time, pump pressure can be maintained constant for constant bottomhole pressure during kick circulation.

4.5 Increasing Pump Rate

Increasing the pump rate, which is essentially beginning a dynamic kill, is a response that does not require increasing the surface backpressure. The logic is that increasing frictional pressure losses in the annulus can increase bottomhole pressure to balance the formation pressure. It can be very effective in slim hole wells but is unlikely to be applicable in large hole wells. Once formation flow has been stopped, its verification can be difficult and typically relies on matching flow in and flow out. The pump pressure and rate must then be maintained constant and should be followed carefully. Application of this method is limited by the pressure and stroke ratings of the pumps.

4.6 Starting Up a New Pump with Casing Pressure

Starting up a new pump with casing pressure is used in two different implementations depending on the scenario.

This response provides a dynamic change between pumps (starting a new pump while turning off a failing pump) and continuous circulation. It also involves increasing the surface casing pressure to equal to the hydrostatic pressure loss, which can be estimated based on the assumed kick detection limit or a measured pit gain. At the same time, the backup pump is started and circulation continues by the old and new pump together. The key point is to keep the actual total pump rate at the original pump rate before the efficiency loss. Before reducing the old pump rate, the total pump rate is increased above the normal (original) rate by the initial rate with the new pump. Then, the pump rate of the failing pump is reduced by an equal amount. The total increased pump rate, which is equal to the sum of the rates from both pumps, should be chosen so as to avoid causing excessive shoe pressure. This method can be implemented with or without requiring a flow out meter downstream of the pump to be implemented to replace an inefficient pump.

This response can be altered and applied for the pump failure case and can also called as starting a new pump with a reduced choke opening. In such a case, the pump is started up while the choke opening is reduced. During the pump rate increase, the pump pressure and flow out are monitored. Until pump rate is brought to its original rate, flow out is forced to be close to the flow in. After pump rate is brought to the circulating rate, pump pressure is not allowed to increase above normal circulating pump pressure.

4.7 Increasing Pump Rate with Casing Pressure

Increasing the pump rate with increased casing pressure combines both responses in an attempt to optimize the pressure values in the well. This initial response also requires less surface pressure, and reduces the risk of lost returns at the casing shoe versus only increasing casing pressure.

The specific procedure used in this study to implement this concept is dependent upon the kick scenario. During a pump efficiency loss case, a flow in meter is assumed to be installed. Then, the pump rate is set to give an actual rate, original pump rate and the casing pressure is increased simultaneously, based on the hydrostatic loss calculated in advance from the kick detection limit. For a kick caused by BHA position change, the casing pressure is increased initially. The increased casing pressure reduces the flow out, and then the pump rate is increased to flow out rate. Hence, the wellbore pressure is increased by utilizing the surface backpressure and ECD. Formation flow stop is verified by comparing the pump rate and flow out rates. However, since the pump rate is high, flow stop verification must done rapidly and then pump pressure should be maintained constant. Otherwise rapid gas migration reduces the wellbore pressure and may result in kick gain.

5. KICK CIRCULATION METHODS

5.1 Introduction

A kick must be circulated out of the well, after the initial kick response and the formation flow is stopped, to allow routine operations to be resumed. The kick must be circulated to the surface while wellbore pressure is maintained constant to avoid additional kicks. In this research, the driller's method (DM) was applied because the existing mud weight was adequate to maintain control except when MPD operations were disrupted by an unanticipated reduction in wellbore pressure. Other common kick circulation methods are the wait and weight method and the concurrent method. These involve increasing the mud weight during the kick circulation. Therefore, they are not required, nor applicable, to most of the types of kicks studied in this project.

5.2 Driller's Method

The DM is a widely used kick circulation method. It requires almost no calculations, and that makes it practical for application during conventional drilling. Circulation starts as soon as the stabilized pressures are recorded. This avoids excessive pressure imposed on the casing shoe that results from gas migration. In addition, waiting in a static condition for the mud mixing may lead to stuck hazards[49]. The driller has no need to follow a drill pipe schedule, since the pump pressure is always held constant as the mud weight is changed. The DM more easily responds to nozzle plugging problems[49]. However, The DM has a higher risk of surface equipment failure, because a higher surface pressure is expected during DM[49]. Therefore, operating limits should be understood regarding surface equipment such as BOPs, RCD (unless the BOPs are open), flow return line, choke, and mud-gas separator, as to whether the equipment can handle expected pressures and flow rates exposure. DM circulates the kick by maintaining the bottomhole pressure constant, which is controlled based on the pump pressure. This is achieved by adjusting the choke opening. In this research, three derivatives of DM were used: reduced (half) circulating rate, full (normal) circulating rate (also includes the slightly reduced circulating rate after a pump efficiency loss), and increased circulating rate.

5.2.1 Reduced Rate Driller's Method

The driller's method is most frequently applied at a reduced circulating rate. This rate is typically about one-half of the normal circulating rate. The advantages of using a reduced rate are a lower peak gas flow rate and better control, as the kick is circulated slowly. However, the reduced circulating rate increases the NPT and requires a higher surface casing pressure, which leads to higher risk lost returns at the potential weak zones.

Pump pressures at normal and reduced rates are routinely recorded after making 500 ft of hole in conventional drilling[31]. This recorded pressure is used upon experiencing a kick. After the initial response is applied, the pump rate is set to kill rate, i.e., half the rate of the normal rate, and the kick is circulated. In addition, the reduced circulating rate allows for the assumption that frictional pressure losses in the annulus can be ignored. This assumption is important in conventional well control, because it allows safer circulation with the additional surface backpressure.

The approach for applying this method to MPD operations is slightly different. Pump pressure at a reduced circulating rate is recorded with the additional backpressure, since the wellbore pressure is kept slightly higher than the pore pressure with the ECD support. Unless additional surface backpressure is applied when the mud weight is lower than the pore pressure in permeable formations, a kick will occur.

5.2.2 Normal Rate Driller's Method

The driller's method can also be applied at a normal circulating rate. This rate is equal to the actual original rate (or a lower rate due to pump efficiency loss). The full circulating rate is evaluated as an alternative method to the circulation at the reduced rate. This approach utilizes the AFP to reduce the backpressure required during MPD. The advantages of using a normal circulating rate are the reduced NPT, surface casing pressure and pressure exposure at shoe by utilizing the AFP. The disadvantage of this method is the high gas flow rate at surface, which may create a risk for the handling capacity of the separator. In addition, fast circulation of the kick may cause difficulty in responding to complications.

5.2.3 Increased Rate Driller's Method

The driller's method can also be applied at an increased circulating rate. This approach utilizes the increased AFP to significantly reduce the backpressure requirement during MPD. The well is killed at higher pump rates than the initial rate. This method reduces the NPT, the surface casing pressure required and pressure across the casing shoe versus normal circulating rate. The disadvantages of this method are high return mud and gas rates at the surface, as well as difficulty in responding to dangerous situations. There are also some complications with the increased rate circulation, such as the BHP increase, which requires a method to reduce excessive BHP at the end of the circulation.

6. DESCRIPTION OF SCENARIOS

6.1 Wellbore Scenarios

Consortium members of this project provided two well descriptions that were appropriate for MPD applications.

6.1.1 Slim Hole Well X

The industry consortium supporting this research provided data for a well with a small-hole diameter, and this well has a similar configuration to that defined by Chustz et al[40]. This well, known as Well X, is an excellent candidate in the study of MPD.

Figure 10 shows the wellbore configuration for Well X. The major characteristics of the well include the following:

- The drillstring is composed of 3.5” drillpipe, 3.5” heavy drillpipe and 4.75” drill collars.
- The well is cased at 15150 ft MD/13979 ft TVD.
- A high pressure sand exists at 16265 ft MD/14800 ft TVD, and there are two potential loss zones both above and below the high pressure sand. These occur at 15150 ft MD/13979 ft TVD - at the casing shoe; and 16982 ft MD/15320 ft TVD - at the bottom section, which represents a depleted sand.
- The highest pore pressure gradient in the open hole is 13.7 ppg (10544 psi) at 16265 ft MD/14800 ft TVD.

Following a conventional well control design, a mud weight greater than 13.7 ppg is required to drill Well X. However, if this mud weight was used, that would have led to significant frictional pressure losses in the slim annulus and increased the risk of problems such as lost returns and pipe sticking. To overcome these complications, a 13.2 ppg mud weight should be utilized in a MPD drilling method. The pressure difference between the 13.7 ppge formation and 13.2 mud weight is compensated for by the 0.52 ppge of ECD. During tripping or connection, the 0.52 ppge ECD effect is balanced by the surface backpressure at the choke.

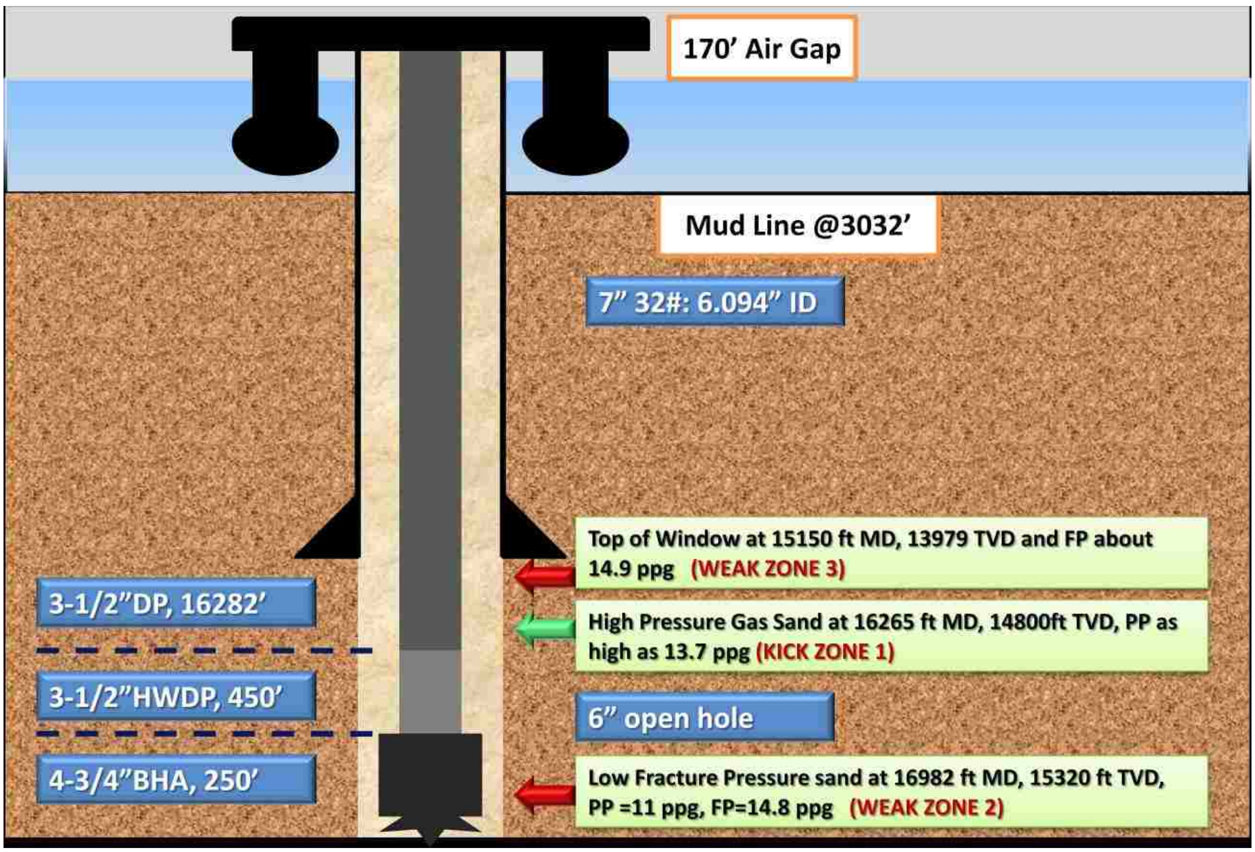


Figure 10: Schematics for Well X

Figure 11 presents the trajectory of Well X. The Well X is not a vertical well which means that the measured depth is different from the true vertical depth. True vertical depth is used to find the vertical length of the kick in order to calculate the hydrostatic pressure loss during the implementation of some initial responses.

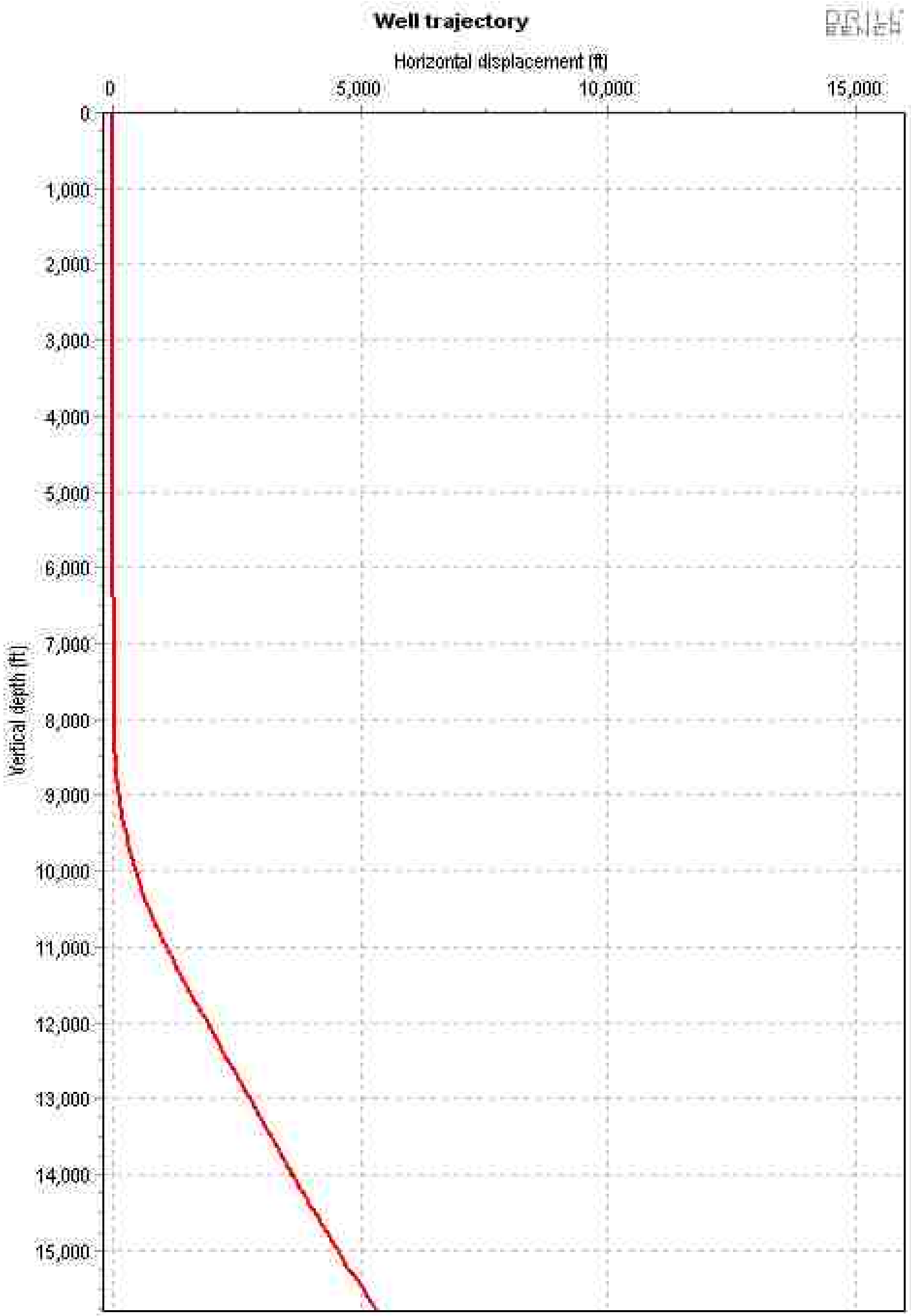


Figure 11: Well X trajectory from DFD

6.1.2 Large Hole Well Y

Well Y, which is a representation of MPD's larger hole application, was provided and defined by the industry consortium supporting this project. The 12.25" interval of Well Y was identified as a potential candidate for MPD because of the 1.0 ppge margin between the pore and fracture pressures. Figure 12 illustrates a summary of the wellbore configuration.

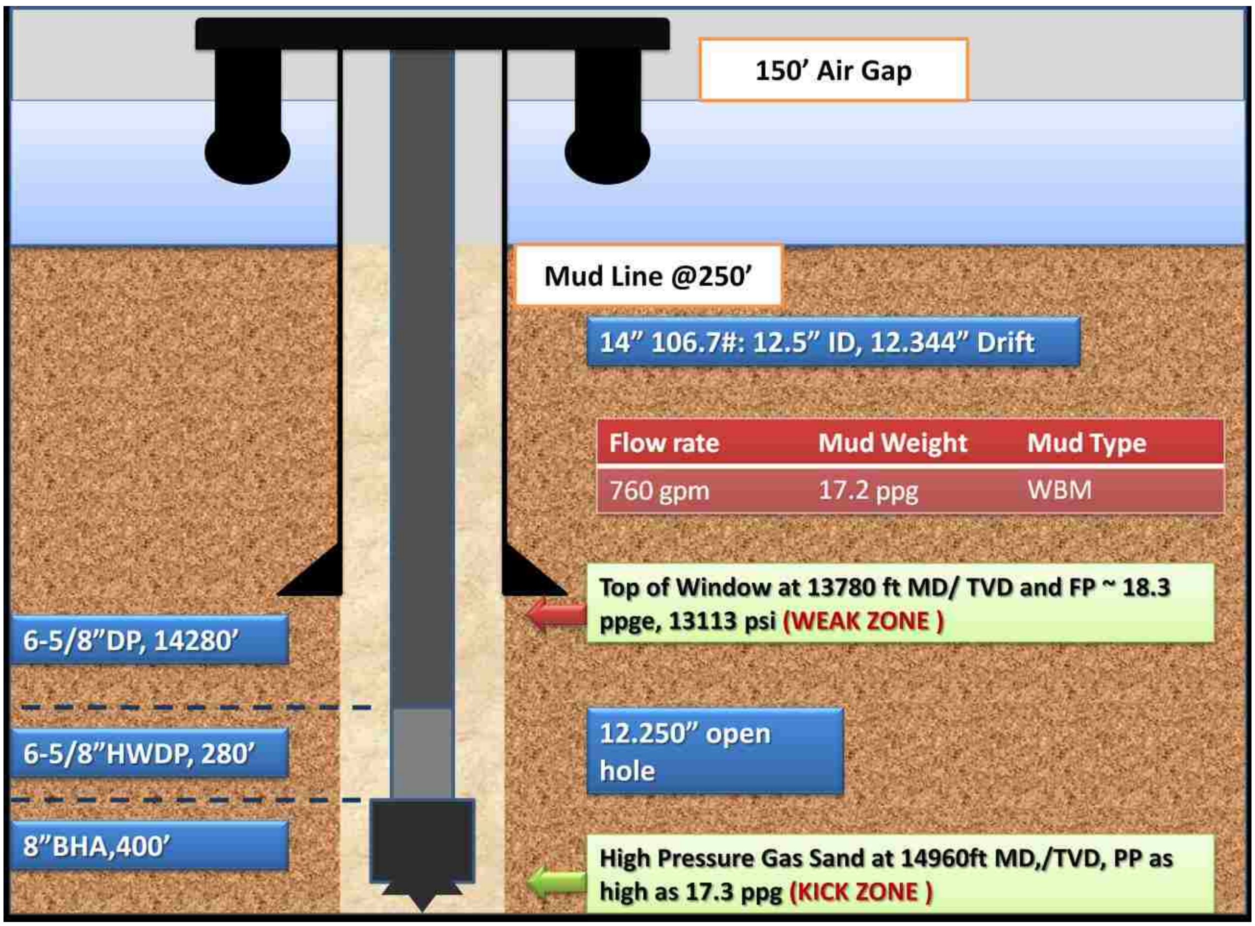


Figure 12: Wellbore Schematics for Well Y

The well is vertical from surface to the target depth. There is a potential loss zone around the casing shoe at 13780 ft MD/TVD and a high pressure zone at 14960 ft MD/TVD. A 17.2

ppg mud weight is used to drill 30 ft of a 12.25” hole into a 17.3 ppg high pressure zone. The pressure difference between the mud weight and formation pressure gradient is offset by the AFP at 760 gpm circulation rate. Fracture pressure gradient decreases with depth and reaches to17.9 ppg at the bottom while it is 18.3 ppg at the casing shoe. The highest risk of lost return takes place at the bottom of the hole.

6.2 Kick Scenarios

MPD offers a wellbore pressure profile close to the formation pore pressure. Any reduction in a bottomhole pressure component (as shown in Figure 2) may cause the (balanced or slightly overbalanced) wellbore pressure profile to shift below the formation pore pressure. Complications that could cause such reductions were categorized as surface equipment failure and unintended ECD reduction. Each kick scenario was simulated for small and large pit gains, which were defined as 2-5 and 15-20 bbl, respectively. Table 4 shows the simulated initial responses and circulation methods for defined kick scenarios described in the following sections.

6.2.1 Surface Equipment Failure

Wellbore pressure is controlled by the density of drilling fluid, surface casing pressure and ECD. The surface casing pressure and ECD are provided by the surface equipment. The surface casing pressure is maintained by utilizing the choke manifold and a RCD, whereas the ECD is generated by the rig pumps. Failures of RCD and pump pressure lead to the loss of surface casing pressure and ECD. Therefore, these failures cause pressure reduction in the entire wellbore. RCD and pump failures are discussed in the following section.

Table 4: Responses and circulation methods matrix for kick scenarios

Bottom Hole Pressure Fluctuations					
Initial Responses	**Circulation Methods**	**Loss of Pump Efficiency**	**Pump Failure**	**RCD Failure**	**ECD reduction due to BHA position change**
SI	DM Half Rate DM Full Rate	✓	✓	✓	✓
MPD Pump Shut Down	DM Half Rate DM Full Rate	✓			✓
Incr. Surface Back Pressure	DM Full rate	✓			✓
Incr. Pump Rate	DM New Rate	✓			✓
Start up new pump with Pc	DM Full Rate	✓	✓		
Incr Q with Pc	DM Full Rate or New Rate	✓			✓

6.2.1.1 RCD Failure (Loss of Surface Pressure)

Any loss of surface pressure with more generally pumps off would cause a kick. A RCD failure is an example of this cause. The rubber-sealing element of RCD wears out over time, and it must be replaced periodically. If the RCD maintenance is not performed regularly, the RCD can fail, causing the wellhead pressure to be lost, and the annulus to be exposed to atmospheric pressure. This leads to an underbalanced condition and a pit gain if the density of the drilling is less than the formation pressure gradient.

This case was simulated with the pumps off, and the overbalance pressure was provided by a surface backpressure. This case could also represent other surface equipment failures that could cause loss of surface well pressure, such as the choke line washout.

6.2.1.2 Pump Failure

A power or a mechanical failure may result in a pump failure. When a pump fails, circulation stops and the AFP is lost. This does not cause any well control problems for conventional drilling, but it could lead to a kick which would call for a well control response for MPD operations. In this case, the well was circulated at the original rate until the assumed pump failure occurred. Afterwards, ECD in the annulus was lost resulting in the formation influx.

6.2.2 Unintended ECD Reduction

An AFP reduction causes a decrease in the ECD, and therefore, leads to pressure drops in the wellbore. ECD reduction can occur as a result of a decreasing pump rate, a leaking drillstring, or a changing wellbore geometry. Pump efficiency loss and a changing wellbore geometry due to BHA movement were simulated as the causes of unintended ECD reductions representing the kick scenarios in this research.

6.2.2.1 Pump Efficiency Loss

Pump efficiency loss is a common pump problem observed in drilling operations. Continuous operation for an extended period causes a loss in pump efficiency which changes the flow rate pumped into drillstring. Ultimately, this process reduces the AFP in the wellbore. Partial loss of ECD does not cause any trouble in conventional drilling. However, a reduction in ECD while using a static mud weight less than the pore pressure gradient can result in formation fluid intrusion into the wellbore in MPD. In this research, the pump efficiency loss scenario was created based on a 10% loss in the volumetric efficiency. In other words, this case was simulated by reducing the original pump rate by 10%.

6.2.2.2 BHA Position Change

The wellbore pressure opposite a given formation decreases as the drill collars move through and pass the formation. This is because the annular frictional pressure losses are higher in the narrow annulus around the drill collars than they are in the annulus around the drillpipe. This reduction in wellbore pressure, or ECD, opposite a permeable formation can cause a kick if the wellbore pressure is less than the formation pressure. Figure 13 and Figure 14 illustrate the reduction in the ECD at the top of high pressure sand caused by a deep progression of BHA below the sand. This whole process can result in a kick.

The BHA is located across a high pressure sand as shown in Figure 13. In this situation, pressure at the top of the high pressure zone is equal to the sum of the choke pressure (if any), the hydrostatic pressure, and frictional pressure drops across the drill pipe and the length of drill collars above the sand. The pressure at the top of the sand is greater than the pore pressure, which permits safe drilling. However, as the drilling continues, the BHA progresses deeper, and the drill collars move below high pressure sand. This reduces the AFP at the top of the high pressure sand. The pressure at the top of the zone is then equal to the sum of the choke pressure, hydrostatic pressure and AFP around the drill pipe. Therefore, the higher ECD around the drill collars is replaced by the lower ECD around the drill pipe and the loss of the higher AFP gradient around the drill collar can lead to an underbalanced condition and a kick. This condition was simulated as one cause of unintended ECD reduction.

This case was simulated on Well X. The flow rate was adjusted to 160 gpm from 190 gpm because circulating at 190 gpm generated sufficient frictional pressure loss around the drillpipe to prevent a kick. The initial bit depth was set at 16500 ft with the top of the drill collars, above the top of the high pressure sand. Drilling progressed until a kick volume representing the assumed detection limit was gained. While drilling with 160 gpm, the drill collars moved down in the hole, and the total length of drill collars above the high pressure sand decreased. Then, the wellbore pressure dropped below the pore pressure. When a pit gain increase was detected, drilling was stopped and well control methods were applied.

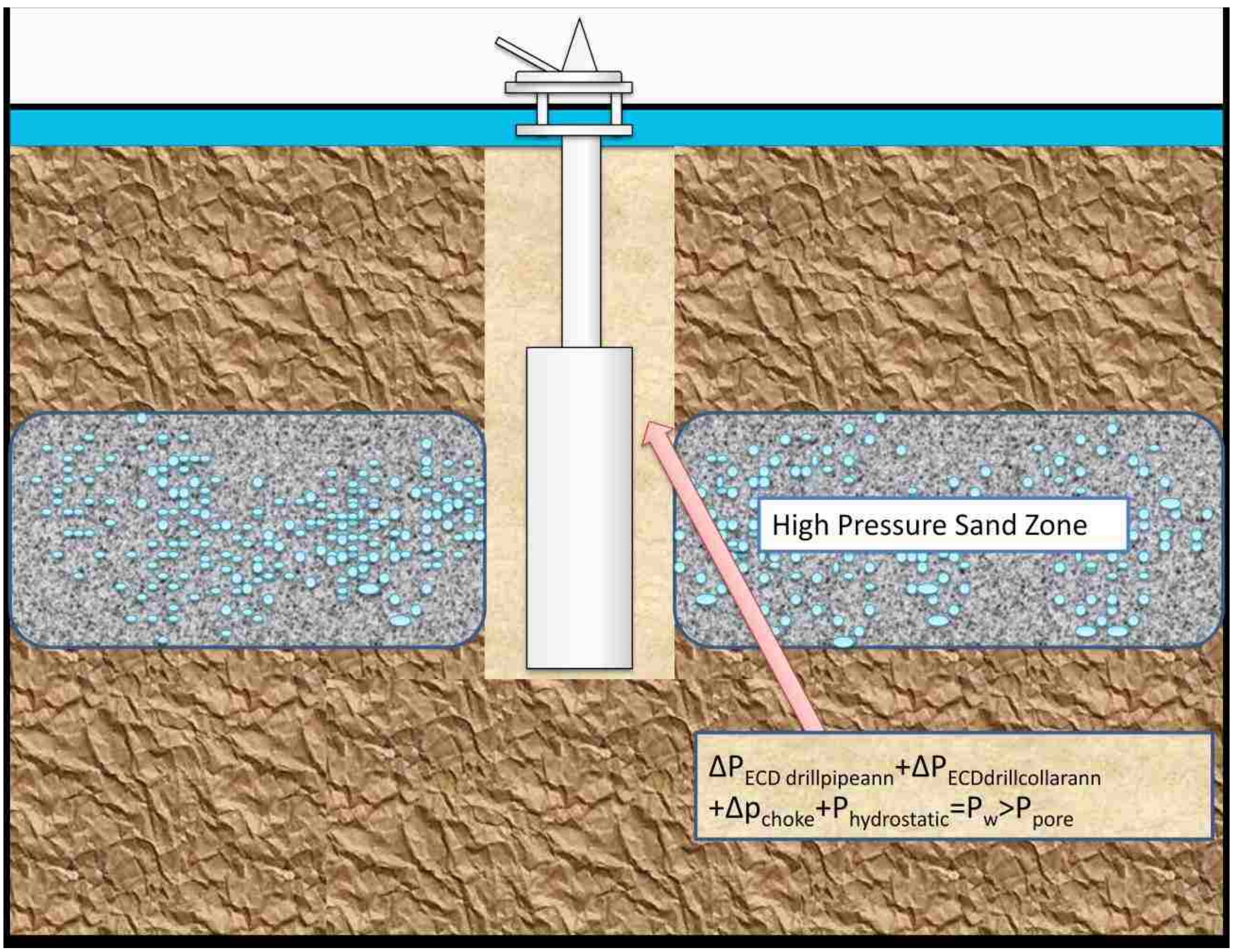


Figure 13: BHA position and overbalanced condition at high pressure zone

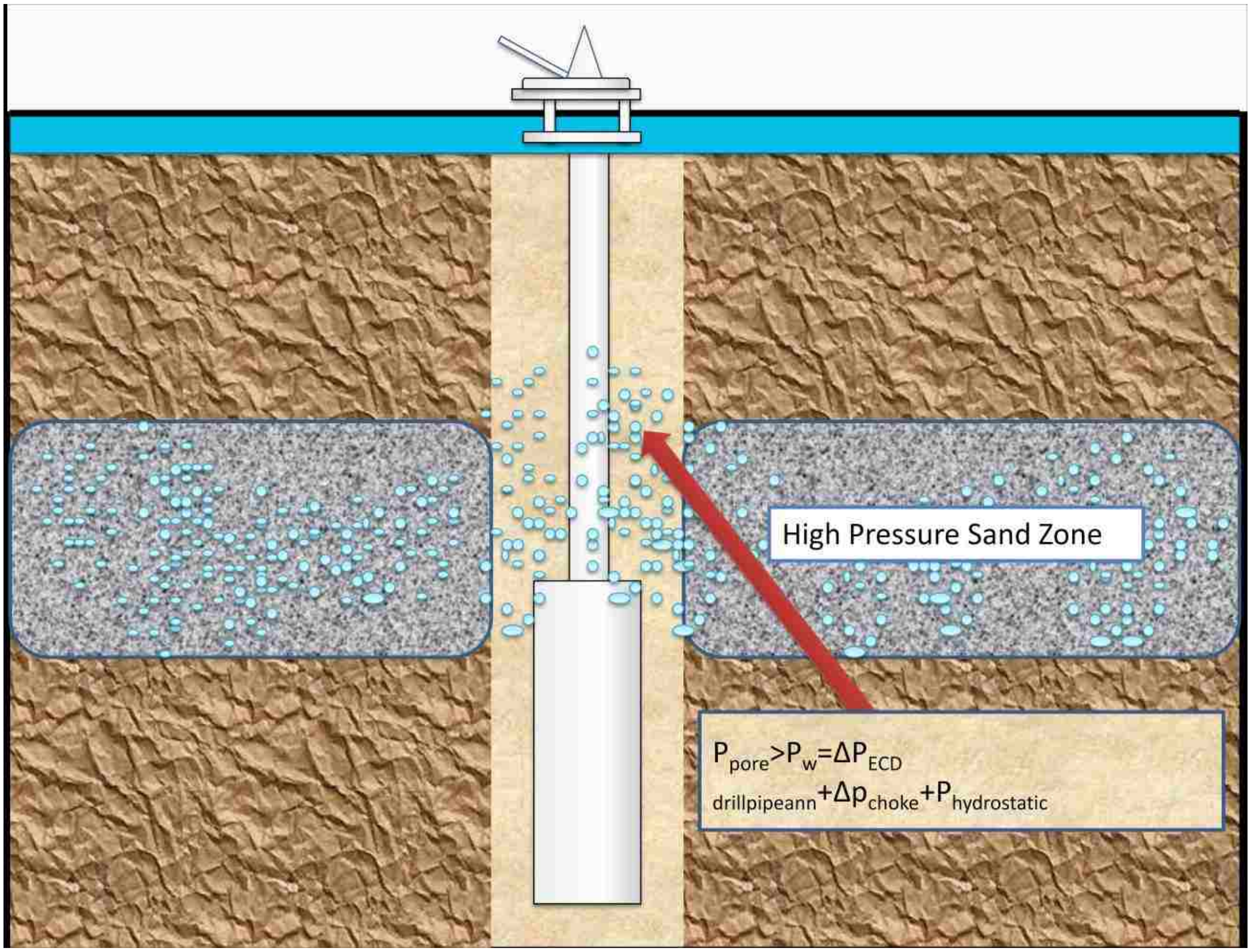


Figure 14: BHA position and underbalanced condition at high pressure zone

6.3 Summary

Alternative initial responses and circulation methods were simulated for surface equipment failures and unintended ECD reductions in small and large wellbore geometries for small and large pit gains. RCD and pump failures were simulated as the examples of surface equipment failures. Pump efficiency loss and BHA positions were simulated as the examples of unintended ECD reduction case. Each scenario was simulated for large and small kick detection limits. The following chapter will discuss the results of these kick scenarios.

7. RESULTS AND ANALYSIS

The DFD software is used to study different scenarios of formation fluid influx during drilling due to the two following failure categories:

- Surface equipment failure
- Unintended ECD reduction

For each of the above possible failure cases, two scenarios are studied. Scenarios studied for surface equipment failure are listed as:

- RCD failure (Loss of surface pressure)
- Pump failure

Similarly, scenarios studied for unintended ECD reduction are:

- Pump efficiency loss
- BHA position change

The above four scenarios are simulated for two different kick sizes, which are 2-5 bbl and 15-20 bbl for small and large kicks respectively.

In addition, each of the scenario sets mentioned above are studied for two different wells, namely Well X and Well Y, with different wellbore geometries as described in Chapter 6. BHA position change scenario is not simulated for Well Y due to insignificant ECD effect expected for wells that have relatively larger hole size diameter than Well X.

This chapter presents and discusses the simulation results of the different initial responses and the circulation methods simulated for these kick scenarios as given in Table 4.

7.1 Kicks Taken due to Surface Equipment Failure

The initial responses and circulation methods for kicks due to surface equipment failure are represented by two scenarios, namely RCD failure (representing the loss of the surface pressure) and pump failure (representing the loss of ECD).

7.1.1 RCD Failure (Surface Pressure Loss)

Failure of a RCD with the pumps off caused release of the trapped pressure required to maintain the wellbore pressure, and the formation fluid intruded into the wellbore.

Among all of the six initial response options, SI was the only applicable response because the surface backpressure could not be applied when there was no RCD, and pumping would not be feasible as the return flow would come to the rig floor. After the influx was stopped by the SI, the kick was circulated out with the driller's method at normal and half circulating rates. This scenario was repeated both for small and large pit gains in Well X and Well Y.

7.1.1.1 Results

Figure 15 shows the flow rate and surface casing pressure change for the entire well control process, which includes loss of surface casing pressure, SI, pump start up and kick circulation at normal circulating rate for large pit gain in Well X. In this figure, it can be seen that casing pressure was not maintained constant during the pump start up; instead, it was reduced as the pump rate was increased.

Conventional SI is implemented by turning the pumps off; however since in this scenario the pumps were already turned off, the well was shut in after the pit gain was increased to 21 bbl. This increased the casing pressure and increased the wellbore pressure. Tables 5 and 6 summarize the initial response and circulation results for large pit gain in Well X and Well Y, respectively. These tables include important parameters that allow the evaluation of the most appropriate initial response and circulation methods such as the maximum pressures (i.e. at the casing shoe, bottom and surface), the maximum return rates and NPT. The detailed simulation results for Well X and Well Y are given in the results section of appendix.

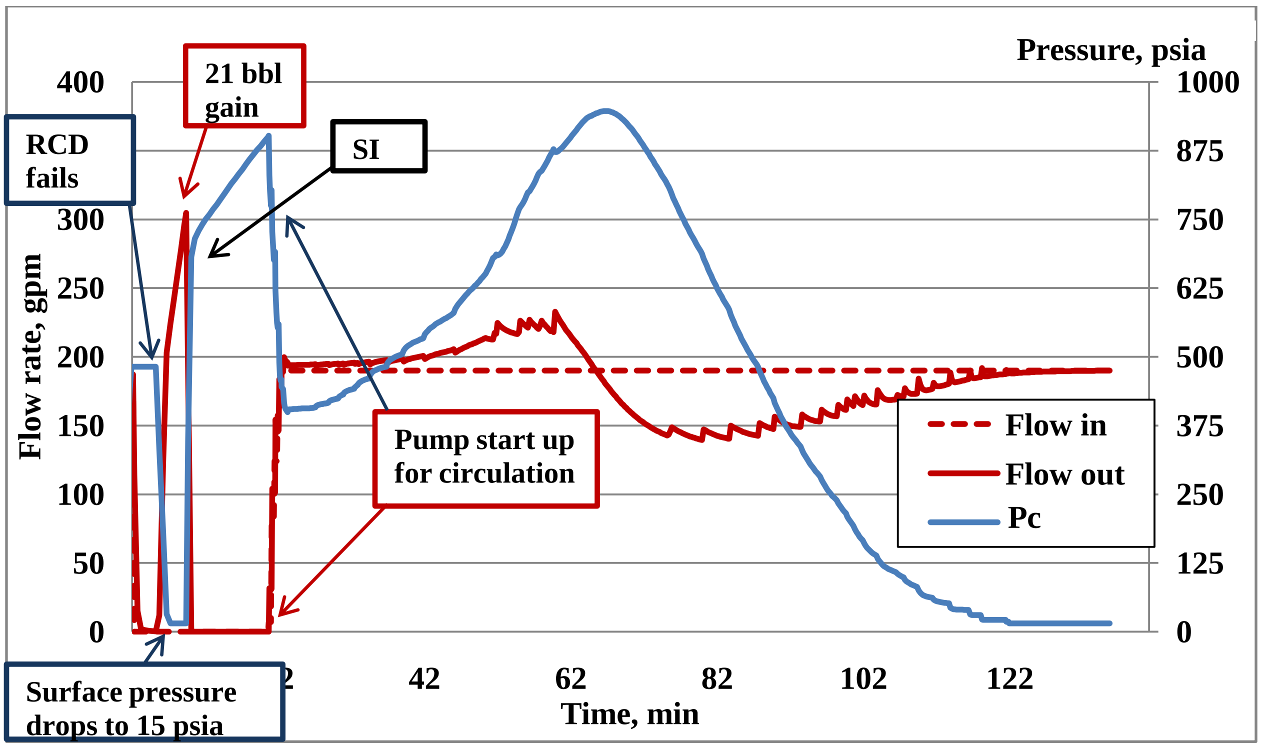


Figure 15: SI and further kick circulation after RCD failure, Well X

Table 5: Response and circulation results for RCD failure in Well X

Cause: RCD Failure											
gain: 21 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP, (max) psi	BHP variation (max) psi	NPT, (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10221	11072	10227	947	2860	11086	77	120	233
	Half rate			10227	1153	1182	11087	78	190	113

Table 6: Response and circulation results for RCD failure in Well Y

Cause: RCD Failure											
gain: 20 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12578	13517	12586	503	3667	13552	63	121	879
	Half rate			12586	568	1285	13553	64	190	450

7.1.1.2 Analysis

The results of the simulation showed that SI followed by normal circulation rate reduced the surface casing pressure and NPT versus the reduced circulation rate as seen in Figure 16. This was also true for Well Y (see Table 6, NPT column). However, normal circulating rate caused a higher return rate at the surface. Therefore, surface equipment should be able to handle the maximum return rate.

Tables 5 and 6 indicate that the maximum casing shoe and bottomhole pressures, and therefore the maximum risk of lost returns occurred during pump start up for circulation as seen in Figure 17. These are slightly greater than the maximum pressures observed during the initial responses.

The difference in the maximum surface pressures between normal and reduced circulating rates in Well X was higher than in Well Y (see Table 5and Table 6). However, the difference in the maximum surface casing pressures during kick circulation at normal and reduced rates were not significant in Well Y since it has a lower ECD effect due to the larger annulus.

SI must be applied for the kicks caused by a RCD failure, as it is the only applicable response. Circulating the kick at normal circulating rate is advantageous in reducing the surface pressure. In addition, the maximum risks of lost returns occur during pump start up.

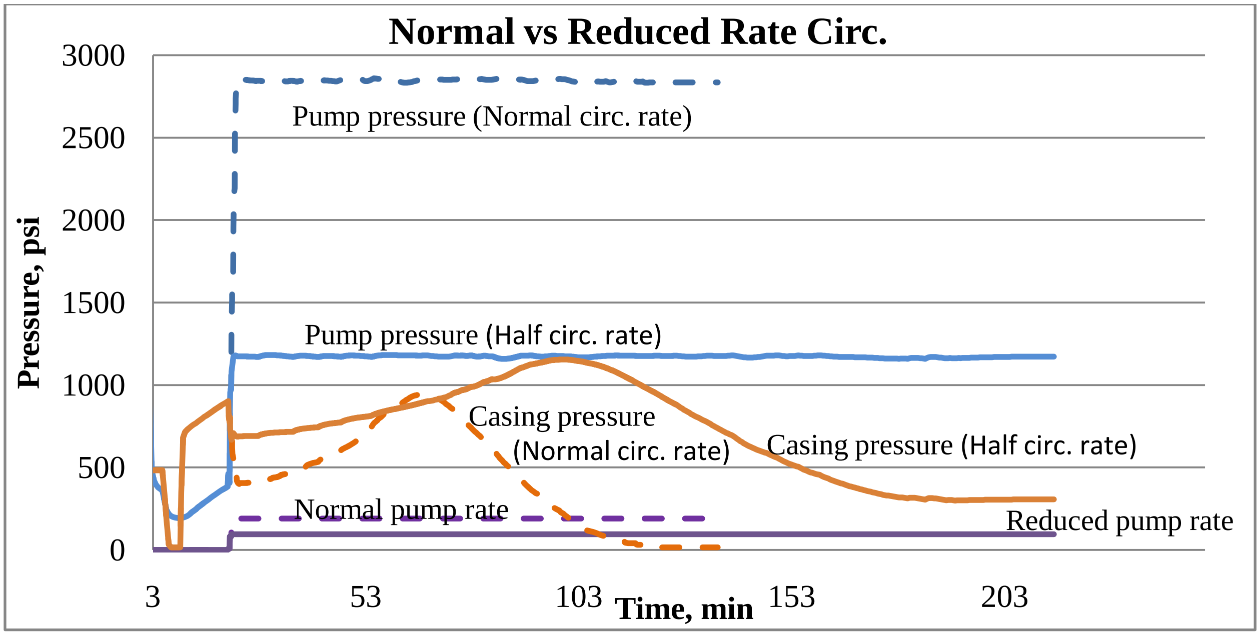


Figure 16: Normal and reduced circulating rates comparison

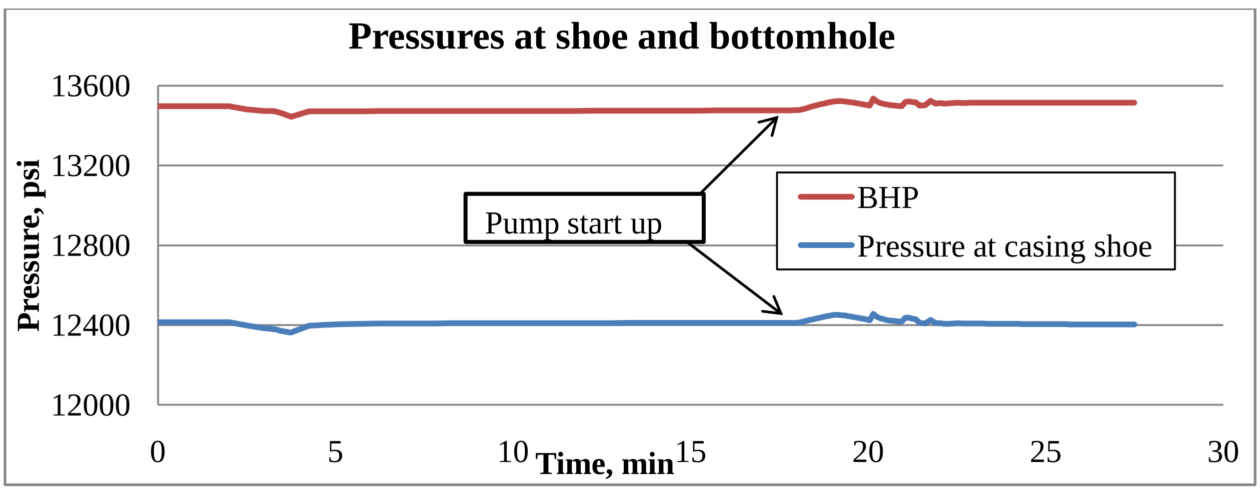


Figure 17: SI and further pump start up for full rate circulation, 2 bbl kick, Well Y

For the evaluation of half and full circulating rate methods, the simulation results showed no significant difference between small and large kick sizes.

7.1.2 Pump Failure

Only two applicable initial responses were indentified for kicks taken due to pump failure. The well could be shut-in or a new pump could be started without shutting the well in. Therefore, SI and starting a new pump with a reduced choke opening (SNP w/Pc) responses were simulated for the kicks taken due to a total loss of ECD caused by a pump failure. After the formation flow was stopped by SI response, the kick was circulated out with driller's method at full and half circulating rates. The SNP w/Pc response was simulated as an alternative response to SI. First, the influx was stopped by SNP w/Pc, and then the kick was circulated out with driller's method at a normal circulating rate. These responses were simulated for small and large pit gains in Well X and Well Y.

7.1.2.1 Results

This scenario was simulated for two initial responses: SI and SNP with a reduced choke opening.

The SI response resulted in approximately similar casing pressure and flow in/out profiles with RCD failure (as shown in Figure 15). They were both applied when the pump was not circulating. After the casing pressure was stabilized, both responses required a pump start up to circulate out the kick. The only difference is in the reality. In case of a pump failure, SI is applied by closing the choke in a pump failure case, however during a RCD failure the well is closed by closing BOPs.

Figures 18 and 19 show the results of SNP with a reduced choke opening response for large pit gain in Well Y. Figure 18 presents the BHP, casing shoe pressure, casing pressure and flow in/out. Figure 19 presents the choke opening and pump pressure change with time. Figure 18 (showing flow in and out trends) and Figure 19 (showing pump pressure trend) are important because these plots should be used to determine how the choke opening can be adjusted to make the flow in and flow out rates equal. This response is implemented by adjusting choke opening based on the pump pressure and flow out measurement. It stops the influx by utilizing the ECD and surface backpressure. The choke opening was defined to be initially reduced to 0.7 (Figure 19), while a new pump was brought up to the original pump rate. The choke opening was adjusted in small increments to match the flow in and flow out, and then (after pump rate reaches the original rate) to match the pump pressure to the original pump pressure since the normal circulating pressure was providing enough bottomhole pressure to control the wellbore until the pump failed (Figure 18).

Table 7 presents the important response results for SI and SNP with a reduced choke opening. Table summarizes the pressures at the potential weak zones and final gain, which are utilized to evaluated and compare the responses. Table 8 shows the simulated circulation results at the end of the initial response. The data in the tables was used to compare and evaluate the initial responses and circulation methods, by comparing the risk of loss returns at weak zones and the maximum observed surface pressure requirements.

Response and circulation results are similar for Well X and Well Y. Thus, the results (for large and small pit gains) for Well X are presented in the appendix section. Well Y results are analyzed in the following section.

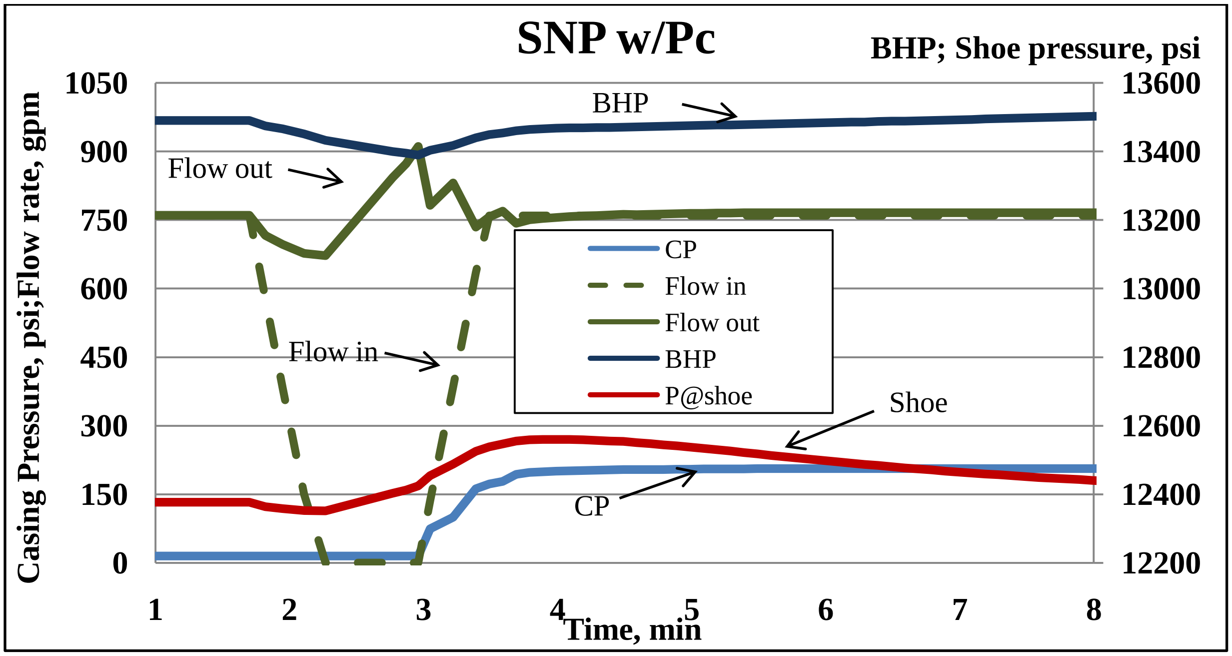


Figure 18: SNP w/Pc response for Well Y, large gain

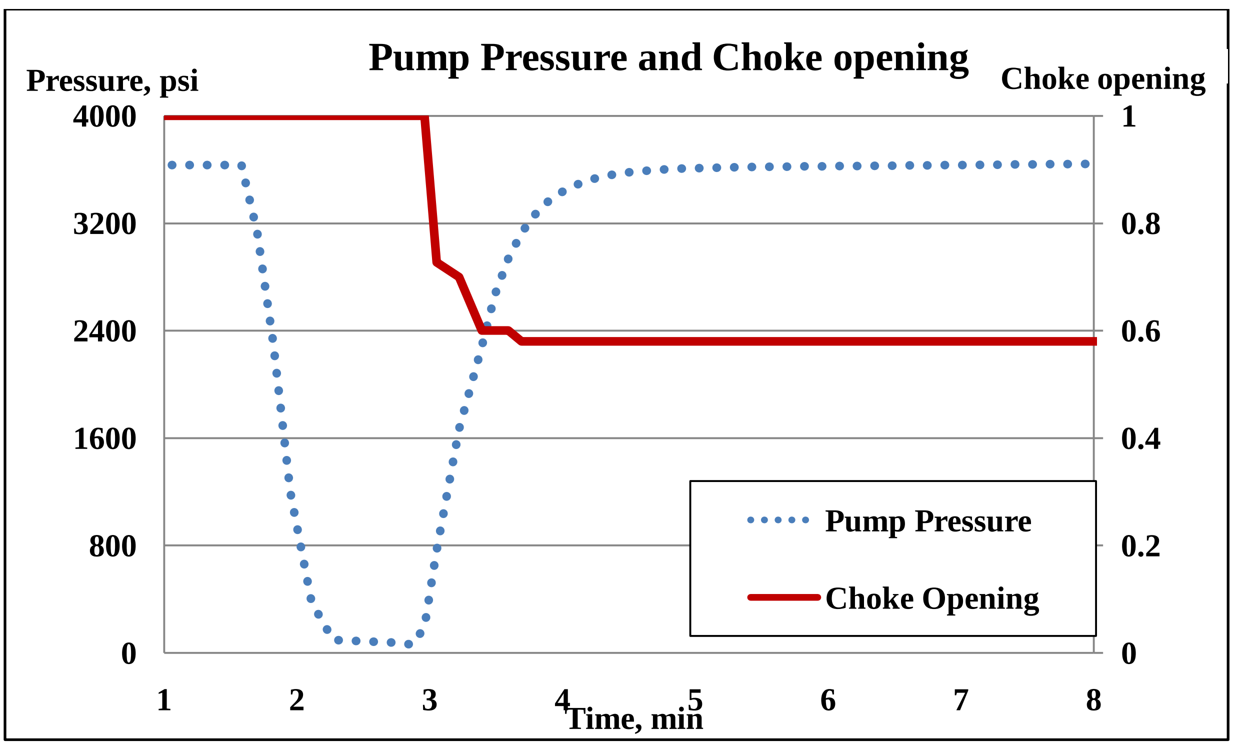


Figure 19: Choke opening and pump pressure during SNP w/Pc for Well Y

Table 7: Response results for pump failure in Well Y

Initial gain: 20 bbl	Cause: Pump Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12561	12562	358	388	22	13472	13502
Start up new pump with Pc	12548	12548	204	206	24	13473	13498
Normal Circ. @ 760 gpm	12376	12376	15	15	-	13473	13498
Shoe Fracture Pressure= 13113psi				Bottom Fracture Pressure= 14073psi			

Table 8: Response and circulation results for pump failure in Well Y

Cause: Pump Failure											
gain: 20 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12562	13502	12575	473	3666	13533	44	118	874
	Half rate			12575	531	1273	13533	44	188	443
SNP w/Pc	Full rate	12548	13498	12410	549	3665	13524	35	103	870

7.1.2.2 Analysis

The simulation results for the SI and SNP with a reduced choke opening responses are similar. Pump start up after SI required a slightly higher (less than 30 psi) pressure at the shoe than did SNP with reduced choke opening (Table 8). SNP with a reduced choke opening gave a higher maximum circulating surface casing pressure because a larger influx intruded into wellbore during the response application. It also had less NPT than SI since it did not require pressure stabilization.

Figure 20 illustrates the bottomhole pressures for SI and SNP w/Pc. It shows that this process stopped the formation flow with only minor bottomhole pressure fluctuations whereas there were significant pressure fluctuations during pump start up after SI.

SNP with a reduced choke opening requires adjustment of choke opening based on metering of flow out and pump pressure. Therefore, its application is complex and the success of this response depends on the application. On the contrary, SI is easy and straightforward to implement.

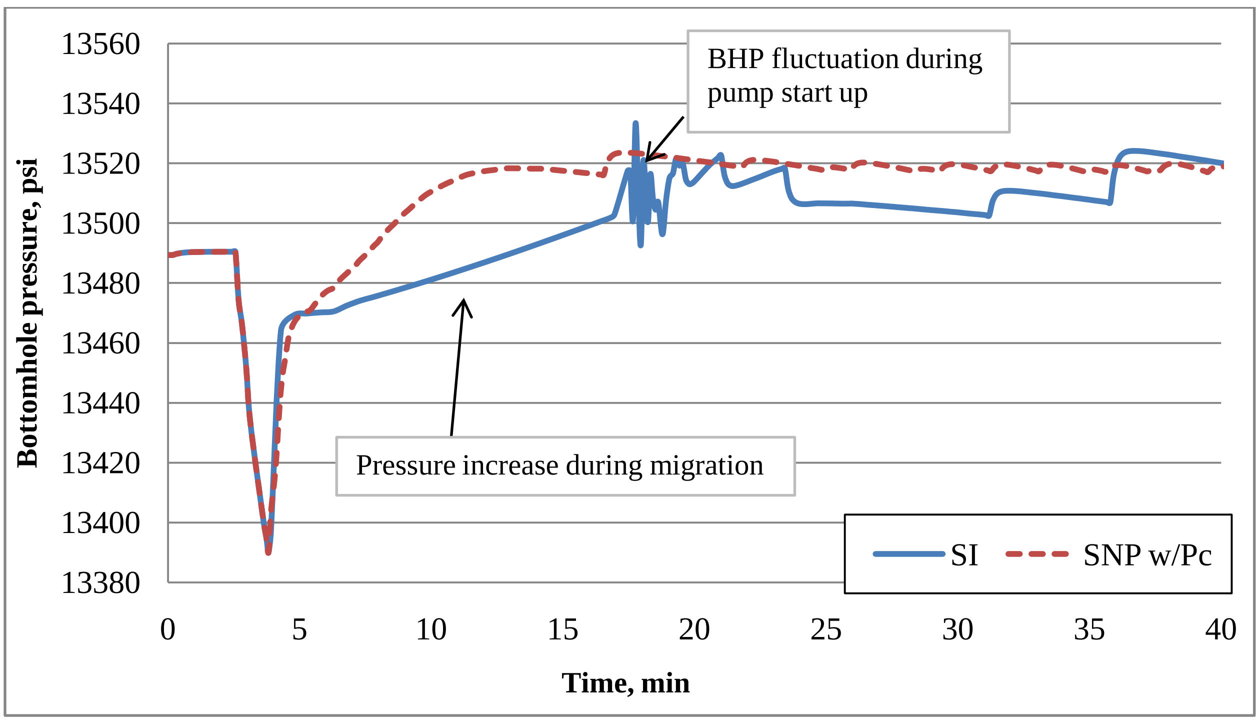


Figure 20: BHP fluctuations during SI and SNP w/Pc

The simulation results showed no significant difference between small and large kick sizes.

7.2 Kicks Taken due to Unintended ECD Reduction

Unintended ECD reductions are exemplified by pump efficiency loss and BHA position change in this research. For the pump efficiency loss scenario, the pump pressure to secure the wellbore is known. However, it is not known for BHA position change scenario.

7.2.1 Pump Efficiency Loss

A pump efficiency loss of 10% was used in this research. Initial responses were classified as non-circulating and circulating responses. Non-circulating responses do not benefit the ECD and only stop the formation flow by an increase in surface casing pressure. These responses are SI and MPD SD. Circulating responses utilize only ECD or both ECD and surface casing pressure to stop the influx. These are the increased casing pressure, increased pump rate, starting a new pump with casing pressure and increased pump rate with casing pressure responses.

7.2.1.1 Results

Pump efficiency loss scenario results were given as non-circulated and circulated responses. The below results were obtained from Well X for a 15 bbl kick. Simulation applications and results are approximately same for Well X and Well Y and for small pit gain case. The important differences observed for the large pit gain case are further discussed in the analyses section. The remaining results are shown in the appendix.

7.2.1.1.1 Non-Circulating Response Results

Non-circulating responses are the SI and MPD SD. Figure 21 illustrates a manual MPD SD in normal conditions. Flow in, out and casing pressure in Figure 21 show base line for initial response application. The flow out in this plot is used for early kick detection. Figures 22 and 23 show the results of the SI, manual MPD SD, automated MPD SD and the modified manual and automated MPD SDs. Figure 22 shows the flow in and flow out profiles which represents the effectiveness of the responses in stopping the influx (such as how fast the influx was stopped). Figure 23 compares the surface casing pressure required and thus the risk of lost returns at casing shoe and risk of surface equipment failure. These plots compare the non-circulating responses in terms of final gains and surface casing pressures, and this comparison was used to evaluate the most appropriate initial response method to be applied for this scenario. The most suitable response is the one, which leads to the lowest surface pressure and pit gain. SI response stopped the flow rapidly and ended up with the lowest surface casing pressure. Manual MPD SD had the largest influx and the maximum surface casing pressure as it caused a longer underbalanced condition compared to the others. Automated MPD SD response was relatively better than the manual MPD SD since the well was closed in a shorter time. MPD SD responses were improved by additional surface casing pressure. These new responses stopped the influx as fast as SI but these responses gave higher surface casing pressure. The most important results in these plots are that the lowest surface casing pressure was achieved by SI.

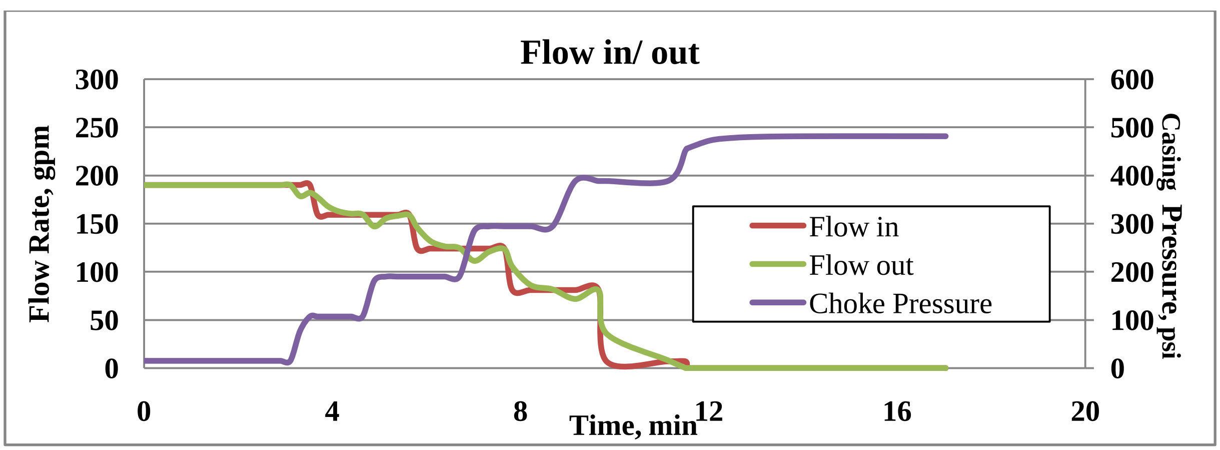


Figure 21: MPD SD under normal conditions

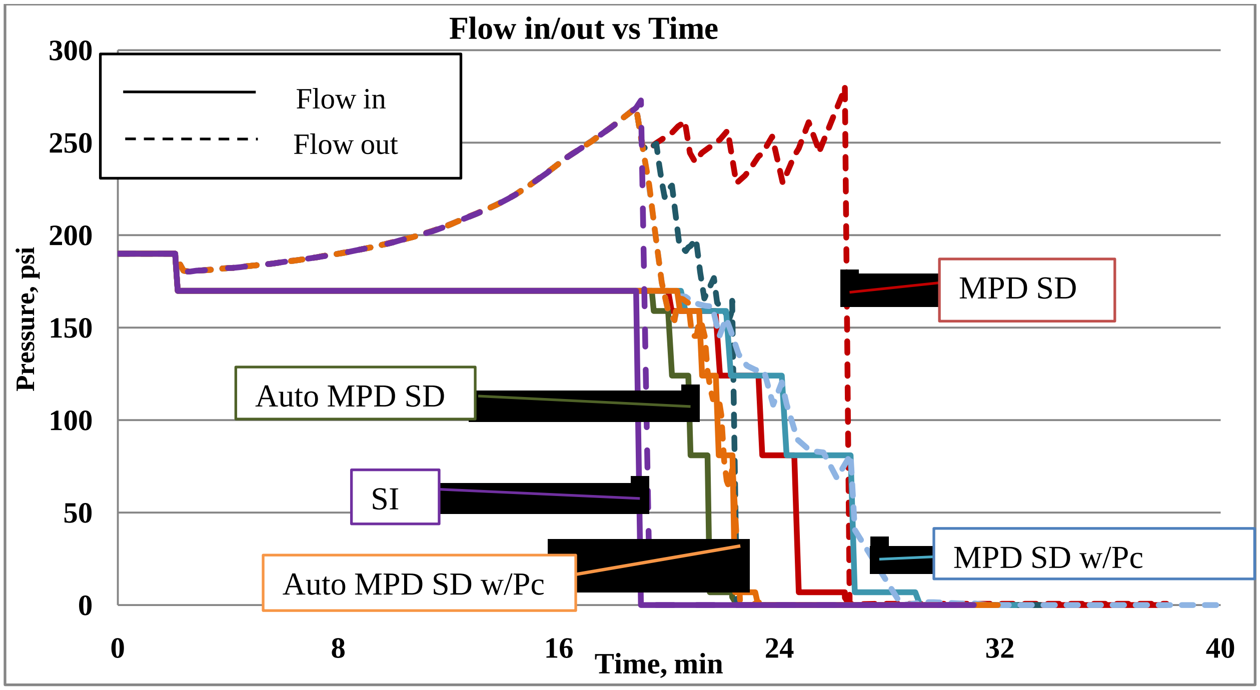


Figure 22: Flow in and out for SI, MPD SD responses

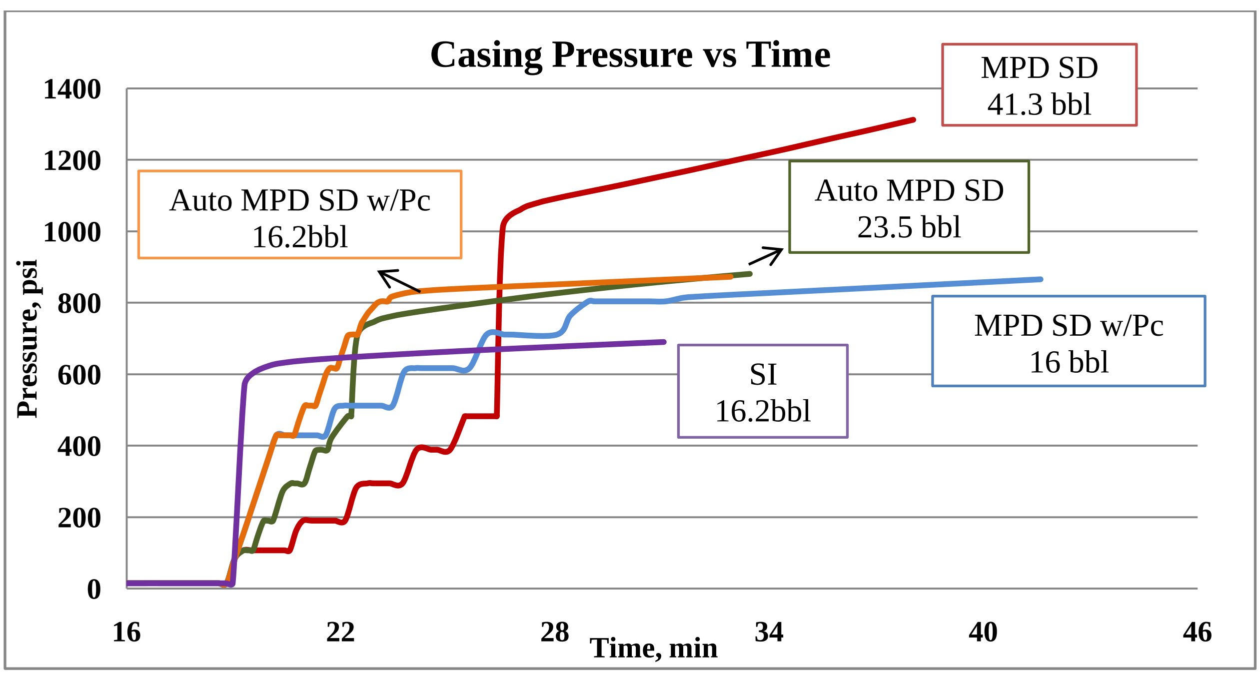


Figure 23: Casing pressures for SI and MPD SD responses

7.2.1.1.2 Circulating Response Analysis

7.2.1.1.2.1 Increasing surface casing pressure

The first simulated circulating response is the increased casing pressure. Three different choke pressure applications were proposed. Initially, the choke pressure was increased to the maximum casing pressure before fracturing with a pressure value that is a 100 psi (safety factor) less than the maximum choke pressure (MCPBF-SF). Secondly, a potentially improved response was executed by applying surface backpressure equal to the loss of hydrostatic pressure calculated from the pit gain. Finally, casing pressure was increased in steps of 200 psi until flow out got equal to flow in. The results of these responses are shown in Figures 24 and 25. These plots show the effectiveness of the responses in terms of flow in, flow out and surface casing pressure. In Figure 24, it can be observed that after 20th min, flow out and flow in were almost equal, hence the influx was stopped by all responses.

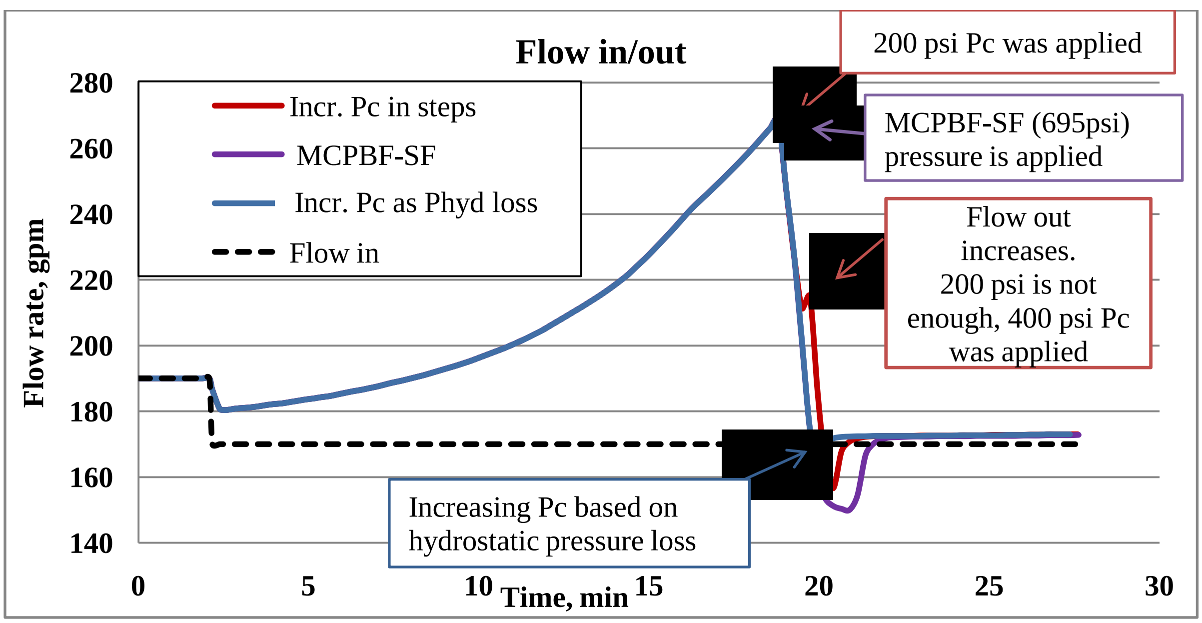


Figure 24: Flow in/out for increasing the casing pressure responses

Therefore, the response that gives low casing pressures in Figure 25 and high feasibility will be compared with other initial responses in the analysis section.

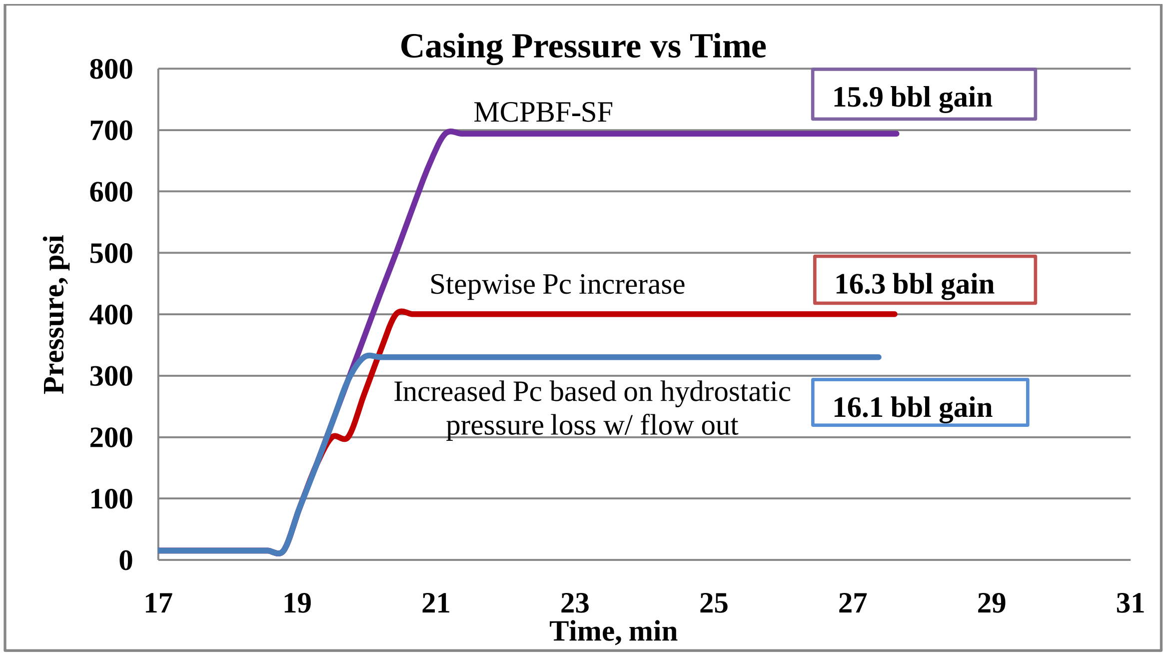


Figure 25: Casing pressures for increased casing pressure responses

7.2.1.1.2.2 Increasing Pump Rate

The second simulated circulating response is the increased pump rate. Figures 26 and 27 show the flow in, flow out, pump pressure and wellbore pressure profiles during increased pump rate response. These plots verify formation flow stoppage based on flow in and out and annular pressure gradient. They indicated that the influx was stopped successfully within the pump pressure rating. The underbalanced pressure gradient was increased above the formation pore pressure as shown in Figure 27. During the kick circulation, the annulus pressure was relatively maintained constant until choke was full opened and the pump rate was reduced (as shown in Figure 28). This response will be analyzed in detail in the analysis section.

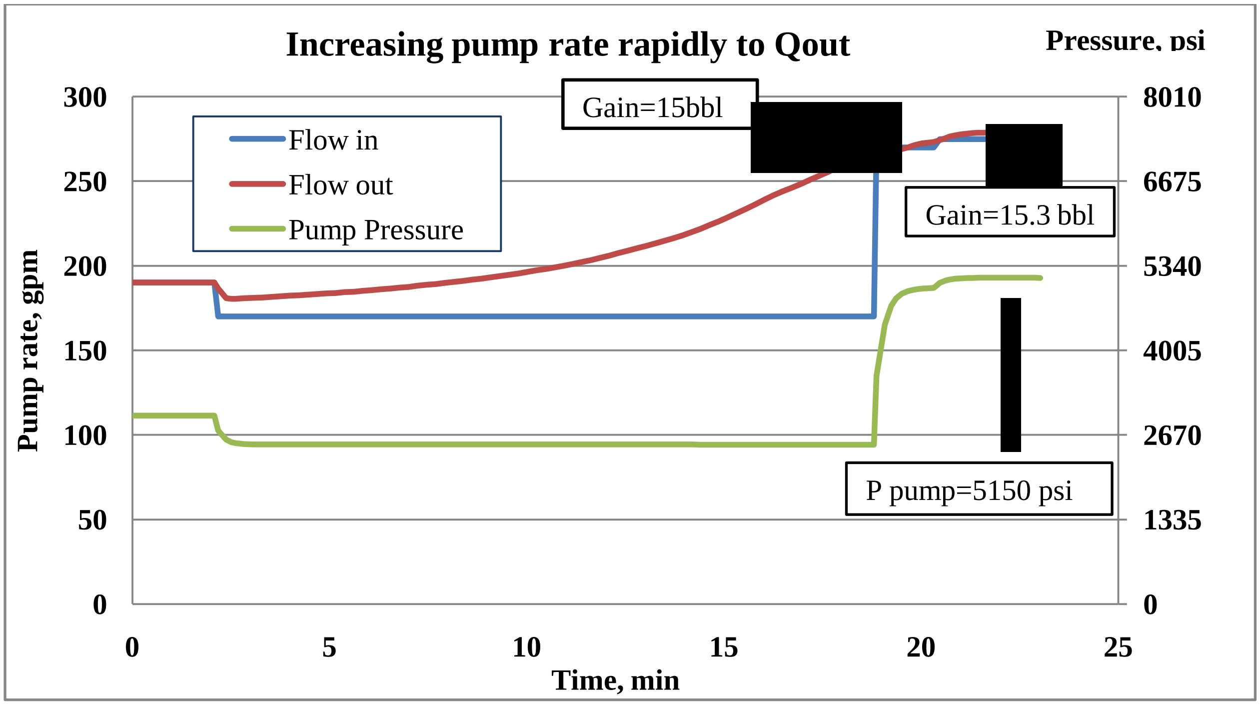


Figure 26: Increased pump rate response

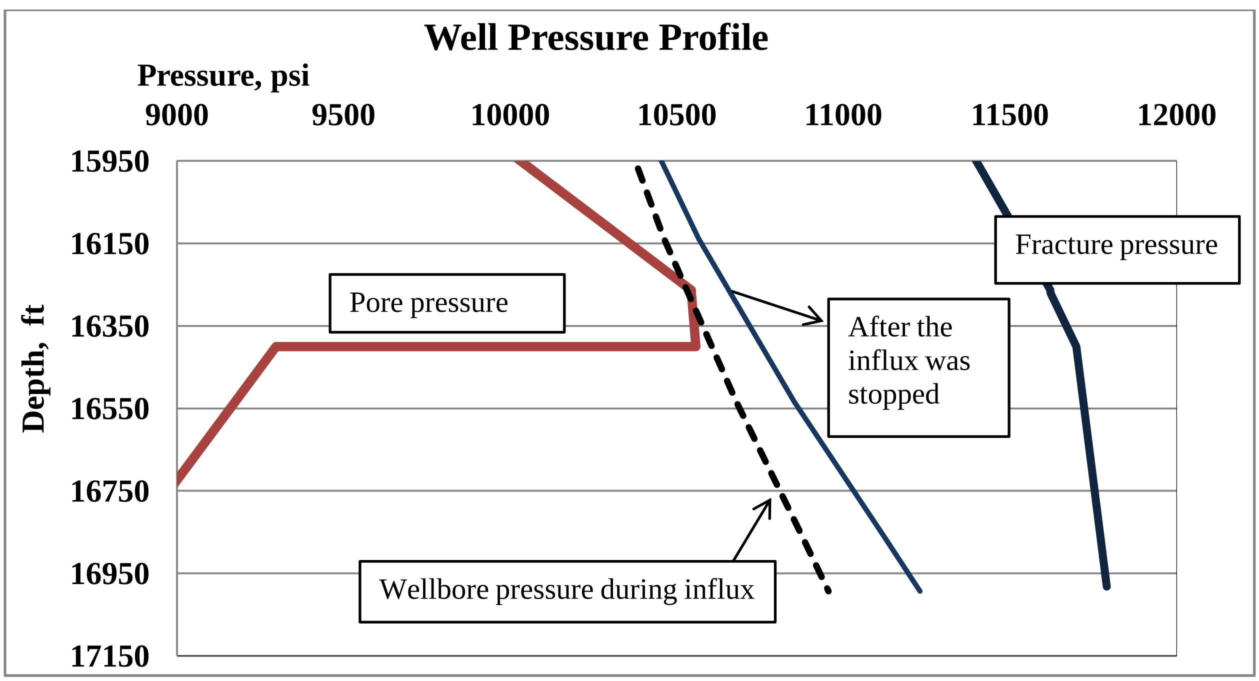


Figure 27: Annulus pressure profile after the increased pump rate

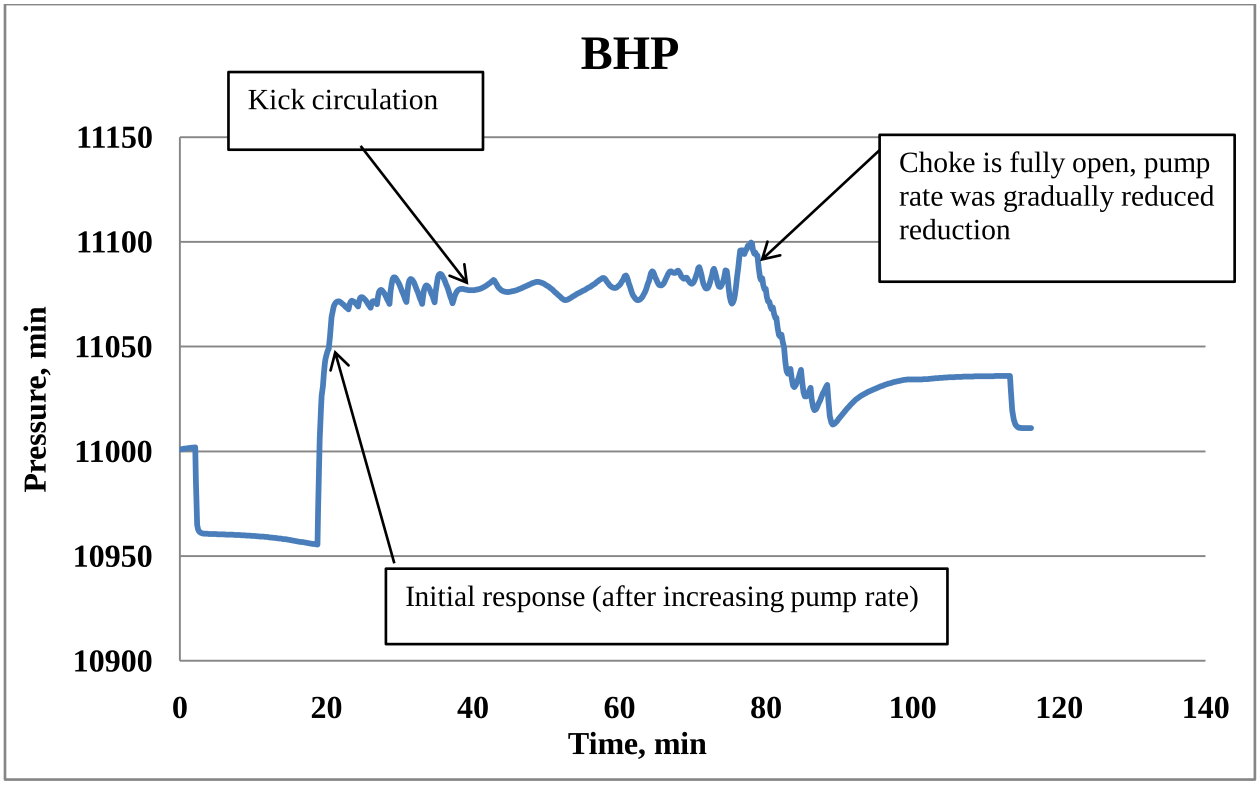


Figure 28: BHP during increasing pump rate and further kick circulation

7.2.1.1.2.3 Starting a New Pump with Additional Casing Pressure

Another circulating response is the starting a new pump with casing pressure (SNP w/Pc). Different from the one applied for pump failure, SNP w/Pc was applied while a failing pump was working. Surface casing pressure was added to offset the hydrostatic pressure loss. Then, a new pump was started as the inefficient pump was shut down. This response was applied in two variations depending on whether a flow-in meter is available. Figure 29 shows the bottomhole pressure, gain, flow in and out as well as the application of SNP w/Pc based on the pump schedule in Table 9 without a flow-in meter installed. This plot indicates that the influx was stopped with acceptable bottomhole pressures fluctuates (less than 70 psi) and final gain (16.8bbl).

The schedule in Table 9 was also used in a variation where casing pressure is increased only after the old pump was totally replaced by a new pump. Figure 30 shows starting a new pump and then increasing casing pressure response without a flow in meter installed based on the schedule in Table 9. The formation fluid influx was stopped but the final kick size (31.4 bbl) increased as the choke pressure was reacted after the new pump was set to the original rate as shown in Figure 30.

Finally, the same response was applied assuming a flow in meter installed as shown in This initial variation was also reinforced by applying surface casing pressure. The amount of the surface casing pressure was again determined based on the hydrostatic pressure loss in the wellbore obtained from the pit gain. It allowed rapid adjustments to be sure that flow out is equal to flow in. This reduced the total kick size (15.96 bbl). However, Figure 31 plot shows that bottomhole pressure increased about 90 psi.

7.2.1.1.2.4 Increased Casing Pressure with Corrected Pump Rate

The final circulating response simulated is the increased (corrected) pump rate with increased casing pressure. The pump rate was corrected to the original rate with casing pressure. Figure 32 illustrates the results of correcting pump rate response as casing pressure was increased to offset the loss of hydrostatic pressure. The plot includes the flow in, flow out and casing pressure change versus time. The results are very similar to the prior response. The plot also shows that influx was stopped with 16 bbl. The overbalance is verified when flow in and out are equal after 20th minute.

Table 9: Schedule for starting up a new pump

Old Pump, gpm		New Pump, gpm	Total, gpm	
Q_{in}, indicated	$Q_{out,}$ actual with 90 % Eff	Q	Q, ind.	Q, act.
190	170	0	190	170
190	170	15	205	185
175	157.5	15	190	172.5
175	157.5	30	205	187.5
160	144	30	190	174
160	144	45	205	189
145	130.5	45	190	175.5
145	130.5	60	205	190.5
130	117	60	190	177
130	117	75	205	192
115	103.5	75	190	178.5
115	103.5	90	205	193.5
100	90	90	190	180
100	90	105	205	195
85	76.5	105	190	181.5
85	76.5	120	205	196.5
70	63	120	190	183
70	63	135	205	198
55	49.5	135	190	184.5
55	49.5	150	205	199.5
40	36	150	190	186
40	36	165	205	201
25	22.5	165	190	187.5
25	22.5	180	205	202.5
10	9	180	190	189
10	9	190	200	199
0	0	190	190	190

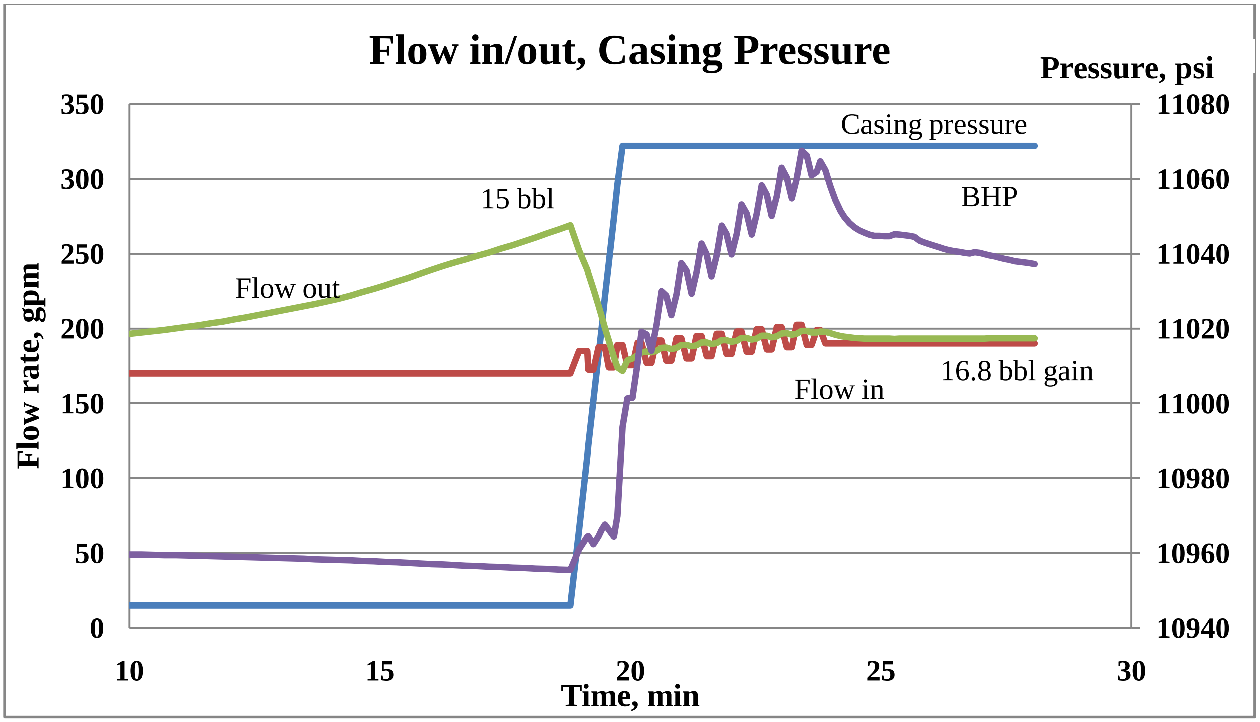


Figure 29: SNP w/Pc without a flow meter installed

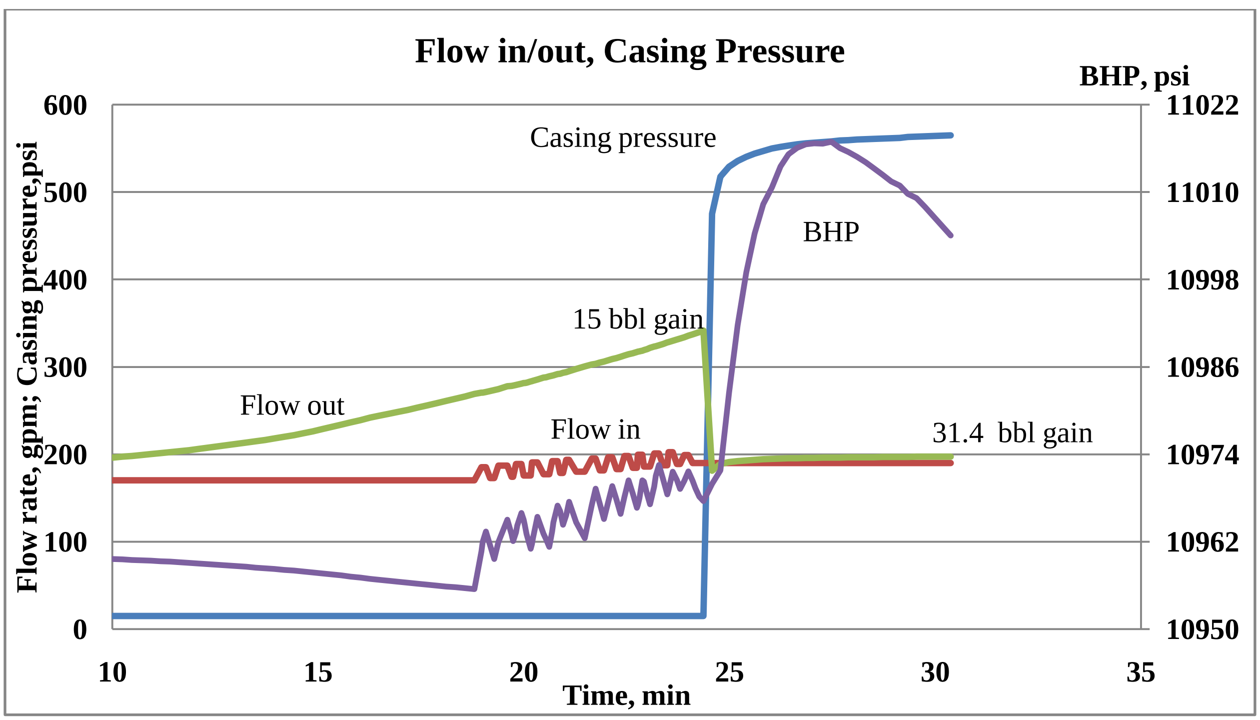


Figure 30: SNP then applying Pc without a flow meter installed

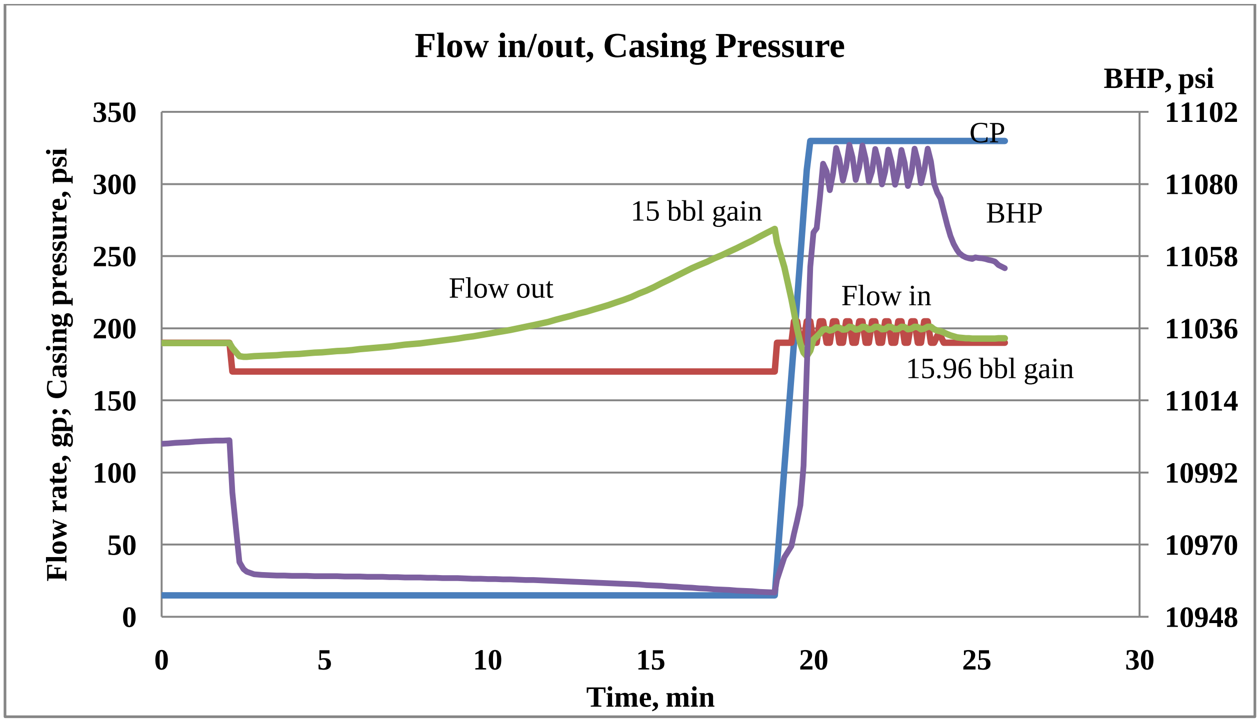


Figure 31: SNP w/Pc with a flow in meter installed

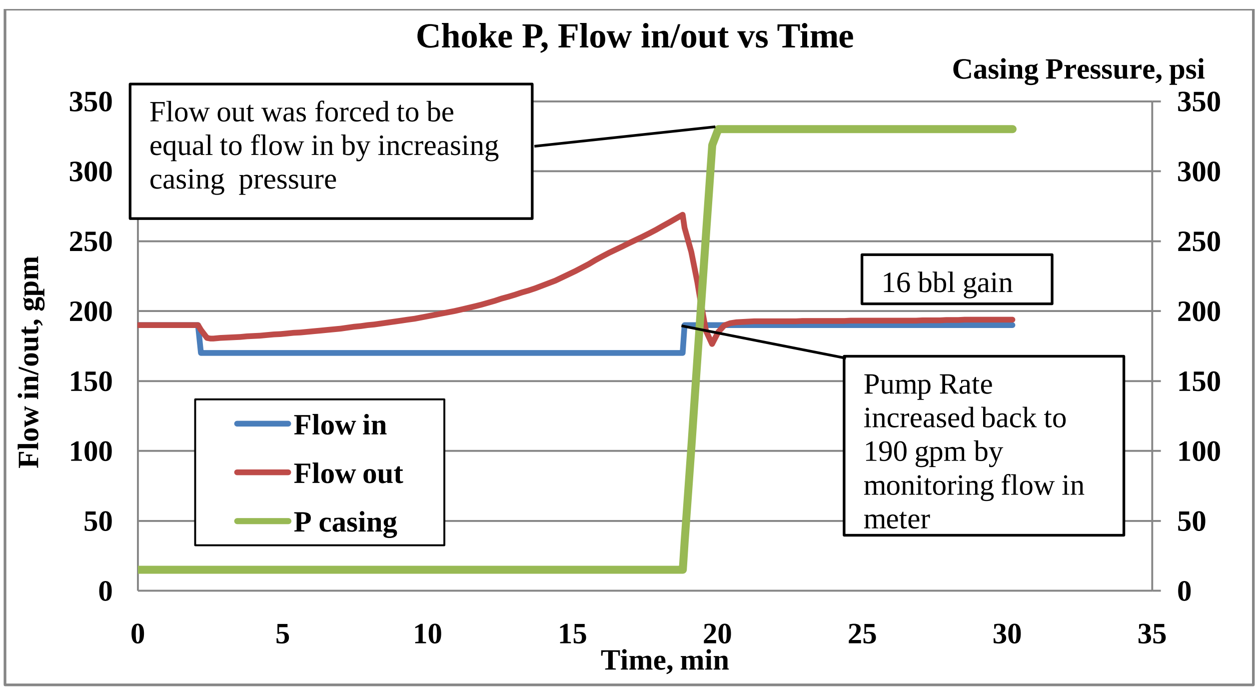


Figure 32: Increasing (correcting) pump rate with casing pressure

7.2.1.2 Analysis

7.2.1.2.1 Non-Circulating Responses

Non-circulating responses stop the flow without measuring flow in and flow out. There is also no need for formation flow verification. At the end of the non-circulating responses, choke is closed and the casing pressure builds up. This process increases the wellbore pressure and stops the flow.

Figures 22 and 23 compare the non-circulating responses. The shut in response is simple after the kick is detected. The pumps were turned off, and then the well was shut in by closing the choke. A MPD SD schedule was prepared so that the bottomhole pressure would not increase beyond 100 psi, and this rise was avoided when the pump was shut down. MPD SD was applied to stop the formation influx on a time schedule representing a manual procedure. This response was very slow and led to an additional kick gain. Thus, kick volume increased up to 41 bbl, as shown in Figure 23. An automated MPD SD was also simulated in order to compare with the manual MPD SD. The automated MPD SD was relatively more successful, but it also resulted in an additional 8 bbl kick. During a manual MPD SD, the wellbore was exposed to an underbalanced condition for a longer time. This explains the final gain differences between manual and automated MPD SD responses. SI stopped the flow with a lower final pit gain and a casing pressure versus MPD SD responses.

A potentially improved MPD SD method was also considered as an initial response. Additional casing pressure was added to the MPD SD schedule. The hydrostatic pressure loss for a 15 bbl gas kick (kick detection limit) was calculated and added to the surface pressure in the MPD SD schedule. This method was named “MPD SD with additional choke pressure” (MPD

SD w/Pc). MPD SD w/Pc was very effective in minimizing the additional gain. During this response, flow out was nearly equal to the flow in at all levels of pump rate as in Figure 22. A very small additional kick was gained during this response. An automated form of MPD SD w/Pc response was also performed to obtain results for a better comparison. Both automated and manual MPD SD w/Pc successfully stopped the formation flow with similar final casing pressures. The final gain and the shut in casing pressure was less than all other MPD SD. SI has a great advantage over manual and automated MPD SD. However, the improved manual and automated MPD SD gives the same final gain as SI.

7.2.1.2.2 Circulating Responses

Circulating responses for kicks caused by loss of pump efficiency generally require accurate flow in and flow out measurements. These responses involved various combinations of increasing choke pressure and pump rate. Formation flow stoppage was verified by comparing the accurate flow measurements. Once the flow in was higher than flow out and the following slope of flow out increase was reduced (as shown in Figures 24 and 26), the initial response was considered successful. Then, kick circulation was continued by maintaining started by maintaining the pump pressure rate and pump pressure constant. This approach was applied for both the increased casing pressure and increased pump rate responses.

7.2.1.2.2.1 Increased Surface Casing Pressure

Three variations of increased casing pressure response, as described in section 7.2.1.1.2.1, were simulated. All stopped the formation fluid influx.

MCPBF-SF was the only response that did not require flow in metering and resulted in about a 16 bbl gain. This response ended up with slightly less gain than the stepwise casing pressure increase response. The final surface choke pressure was 295 psi higher than necessary to stop the formation flow influx.

Increasing casing pressure to offset the hydrostatic pressure lost due to the kick fluids was also successful. However, increasing the casing pressure based on the hydrostatic pressure loss may not be sufficient since the pump rate was reduced and the overall AFP lowered. Therefore, it would generally require comparing measured flow in and out and adjusting casing pressure to stop the formation fluid flow.

The increased casing pressure response based on forcing flow out equal to flow in was also simulated. Initially, casing pressure was increased in a 200 psi step and the flow out versus flow in was measured. At the 20th minute, as shown in Figure 24, flow out was increasing. An additional 200 psi, totaling 400 psi surface backpressure, was applied, and the influx was stopped (Figure 25).

7.2.1.2.2.2 Increased Pump Rate

Increasing the pump rate, similar to a dynamic kill, whereby the AFP can be utilized to increase the BHP and to stop the formation influx is most likely to succeed in slim hole wells like Well X. After a 15 bbl kick was detected, increasing the pump rate was attempted as a means to stop the formation fluid influx. The pump rate was directly increased to equal the flow out value of 270 gpm as shown in Figure 26, and the well was killed by the increased AFP. The flow out rate was observed for a period before committing to a kick circulation rate. However, during that period, circulating at a high rate led to rapid gas migration and quick expansion of the kick volume. Therefore, pump rate was again increased to a value just above the flow out of 275 gpm. Figure 27 shows that the new pump rate increased the AFP and the wellbore pressure profile shifted above the formation pore pressure. A drillpipe pressure was measured at that rate, and the kick circulation was initiated at the 275 gpm pump rate. This response also requires accurate flow in and flow out metering.

7.2.1.2.2.3 Starting a New Pump with Additional Casing Pressure

Starting a new pump (SNP) with additional casing pressure is a method that can be applied with or without a flow meter installed to the downstream of the pump. This initial response can utilize the knowledge that there was no formation flow before the loss of pump efficiency as a basis for stopping the influx. Specifically, circulating with an efficient pump at the original pump pressure provides enough bottomhole pressure to secure the wellbore. This requires replacing the failing pump with an efficient pump. Control is achieved more quickly if surface backpressure is applied to offset the loss of hydrostatic due to the kick fluid. The failing pump can then be replaced with a new one by simultaneously changing the rate from each pump. It was applied in three different ways.

Initially, it was performed by assuming no flow in meter was installed. It began by applying surface casing pressure as shown in Figure 29 and then the new pump rate was increased gradually. When maximum pump rate was reached, the final gain ended up with 16.8 bbl.

The second response was simulated without initial application of additional casing pressure. Casing pressure was applied to increase the pump pressure to the original value after the new pump rate was increased to the original rate as shown in Figure 30. This response gave a 31 bbl kick; because the wellbore pressure was still below the formation pressure, and the influx continued, during the pump transition in the absence of the casing pressure.

Finally, a potentially improved response, SNP with additional surface casing pressure, was simulated. The simulation results are shown in Figure 31. The aim to use a flow in meter was to keep the actual pump rate above 190 gpm. During pump start up, the new pump rate was increased to keep the actual pump rate above 190 gpm. This was achieved by increasing new pump rate by 15 gpm, while the old pump rate was reduced by 15 gpm. The 15 gpm increment for the new pump was selected because it increased the total pump rate to 205 gpm, which caused 54 psi higher AFP than 190 gpm. Generally, a 54 psi addition is an allowable BHP increase, and it should not cause any wellbore stability risk. This response gave the minimum smallest final gain of 15.96 bbl.

7.2.1.2.2.4 Increased Casing Pressure with Corrected Pump Rate

Increasing (correcting) the pump rate of the inefficient pump to give an actual flow rate into the well equal to the intended rate with casing pressure response was applied by increasing surface backpressure. Hence, formation flow was stopped by the increased ECD and the surface backpressure as shown in Figure 32. The actual pump rate was increased to the original value, and the choke pressure was added to create a balanced or slightly overbalanced condition. This response is only applicable if there is a flow in meter installed so that the actual rate is known. Otherwise, this response cannot be applied. By the use of the flow in meter, the pump stroke rate was increased to an indicated 211 gpm for an actual flow rate in of 190 gpm. Casing pressure equal to the hydrostatic pressure loss was added simultaneously with the increased pump rate. After that, the pump rate was maintained constant and the choke pressure was adjusted to keep drillpipe pressure constant at the pre-recorded value before the pump lost efficiency. This response stopped the flow quickly.

7.2.1.2.3 Comparison of Responses

This section compares the results of different initial responses. Initial responses that have more than one application are presented by the response that gave the best result. Therefore, the results of six different initial responses are plotted and tabulated. Plots show and compare the pressure profiles at different sections of the wellbore. Tabulated results present and compare the pressures at shoe, bottomhole pressure, surface pressure and the final gains.

Figure 33 shows the entire wellbore pressure profiles for the SI, automated MPD SD w/Pc, stepwise increasing casing pressure by monitoring flow out, increasing pump rate, SNP w/Pc with flow in meter installed and increasing pump rate with casing pressure responses as well as the pressure profiles before and after taking the kick. It compares the surface casing pressure requirements of the initial responses. Surface casing pressures decrease from non-circulating responses to circulating responses. Automated MPD SD w/Pc caused the highest surface pressure, and it was followed by SI response. The surface pressures decrease as the use of AFP increases. The increased casing pressure, SNP w/Pc and the increased pump rate with increased casing pressure responses gave similar results as they had similar surface pressures. Finally, increased pump rate gave no surface pressure as it only utilized AFP to increase the wellbore pressure. Figure 34 shows the pressure profiles for these responses over the depth interval opposite the casing shoe. The pressure results at the casing shoe are examined in terms of risk of casing shoe failure or lost returns. Non-circulating responses (automated MPD SD w/Pc and SI respectively) had the highest risk. Other than the non-circulating responses, increasing casing pressure had the highest risk of casing shoe failure because it required a higher surface pressure than the other circulating responses. The minimum risk of lost returns resulted from increased pump rate response. Briefly, the casing shoe pressure increases depending on the surface pressure. Hence, circulating responses, which utilize AFP and reduce the need for surface pressure, end up with a lower risk of casing shoe failure.

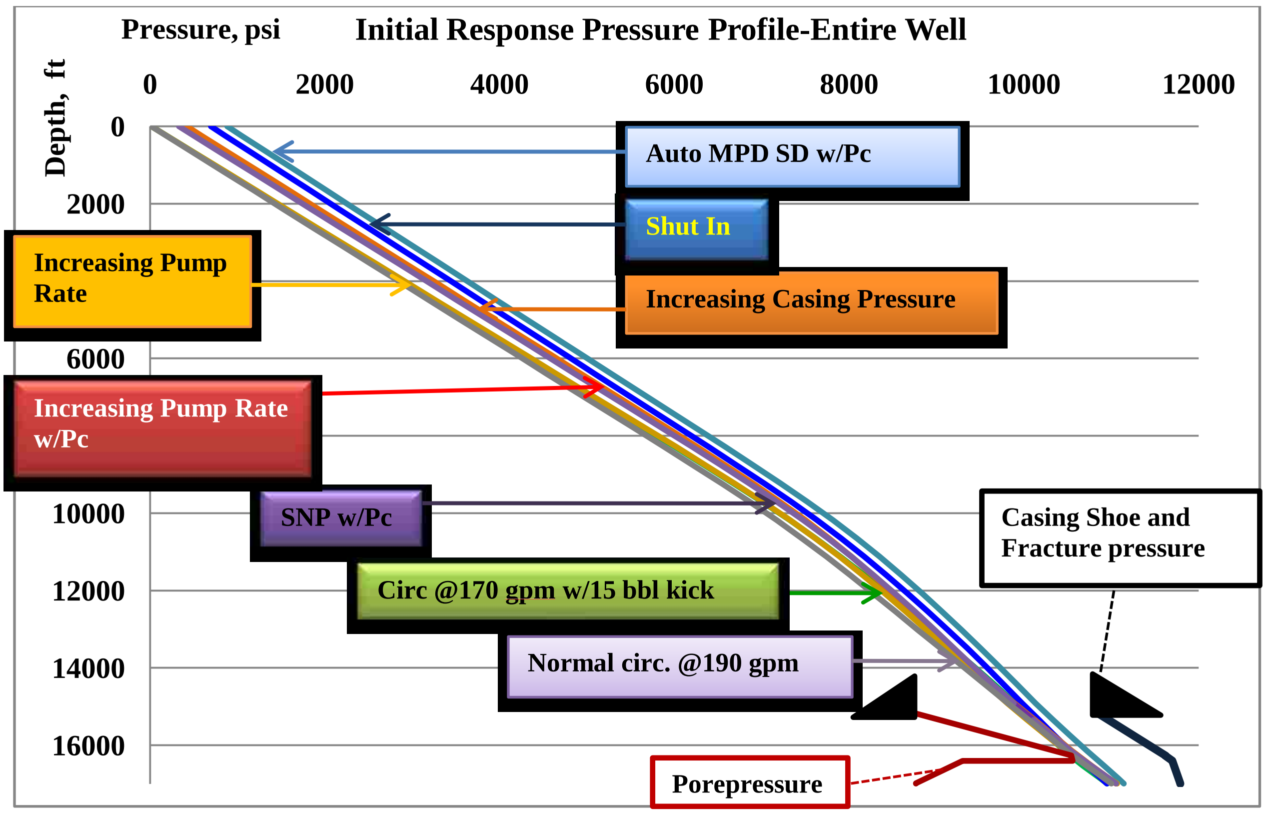


Figure 33: Final wellbore pressures in Well X

Figure 35 illustrates the pressures for six initial responses across the high pressure sand zone. All of the initial responses shifted the pressure profile into safe window and successfully stopped the formation fluid influx. The highest overbalance pressure was provided by automated MPD SD w/Pc because it had the highest surface pressure due to being designed to recover all of the overbalance used in normal operations. All of the other responses, except the increased pump rate, resulted in a similar pressure opposite the high pressure zone. The increased pump rate provided the lowest pressure at the high pressure zone because it had no surface pressure and utilized only the AFP.

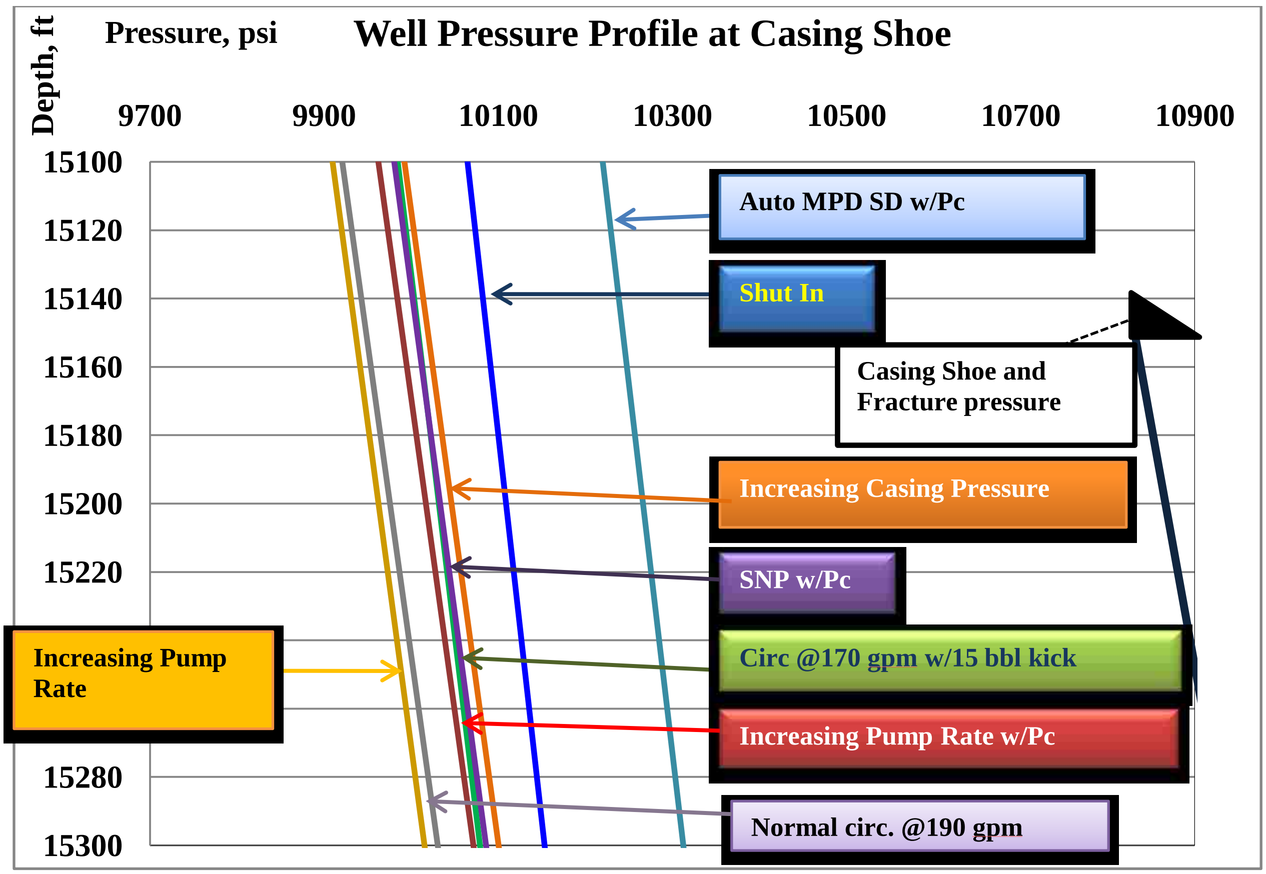


Figure 34: Final wellbore pressures across the casing shoe in Well X

The risk of lost returns was also evaluated at the bottom of the hole, since Well X had a formation below the high pressure zone that was depleted and had a lower fracture gradient than at the shoe. Figure 36 shows the wellbore pressures at the bottom for each initial response. Fracture pressure is not shown on the plot because it is 11790 psi and is off of the scale of the plot. Circulating reactions generally resulted in higher bottomhole pressures due to the high frictional pressure gradients around the drill collars, but the automated MPD SD w/Pc gave the highest BHP for the same reason as in the previous paragraph. The SI response gave the lowest BHP because it stopped the flow based on the formation pressure and imposed no additional AFP. Therefore, SI provided the lowest risk of lost returns below the kick zone.

Table 10 summarizes these wellbore pressures after high gain for eleven initial responses as well as the normal circulating wellbore pressures. The table is used to evaluate responses in terms of the highest pressures at casing shoe, bottom and surface, and final pit gain.

SI is the best non-circulating response because it gave the lowest pressures at every point, provided the smallest gain and is easy to apply.

Circulating responses generally caused lower pressures on surface equipment and at the casing shoe than non-circulating responses did, as they used AFP. However, they caused higher bottomhole pressures, which can be a problem if the greatest risk of lost returns is on the bottom. However, conditions are important for circulating responses because pressure values everywhere are affected by the wellbore and drillstring geometry. The increased pump rate response had the largest advantages and disadvantages in this regard. However, it had other disadvantages (pump pressure limitation, faster loss of pump efficiency, requires flow meter, schedule for pump rate reduction). Any circulating response with the inefficient pump may result in pump failure and well control failure. The most practical responses are probably SI and SNP w/Pc. They support switching to the use of an efficient pump. SNP w/Pc had advantage in maintaining stability and integrity, reducing NPT and providing continuous circulation over SI. Nevertheless, its application is more complex than SI.

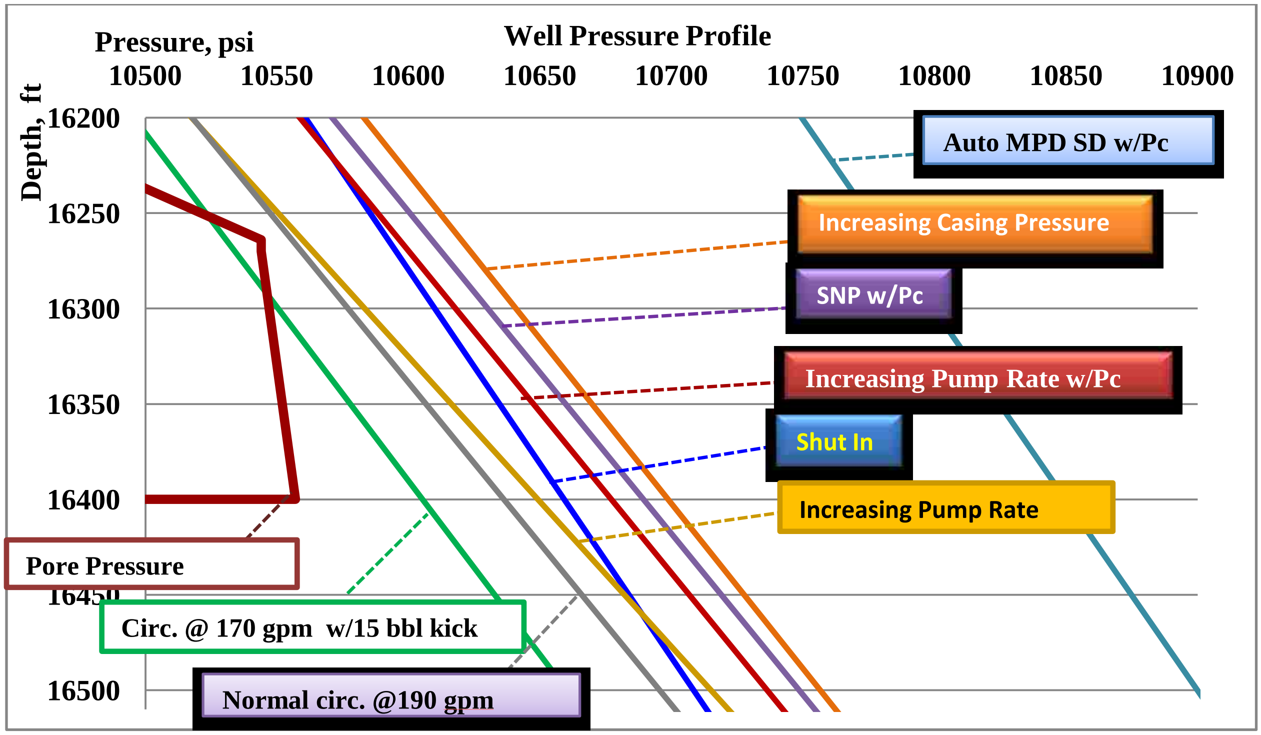


Figure 35: Final wellbore pressures across the high pressure zone in Well X

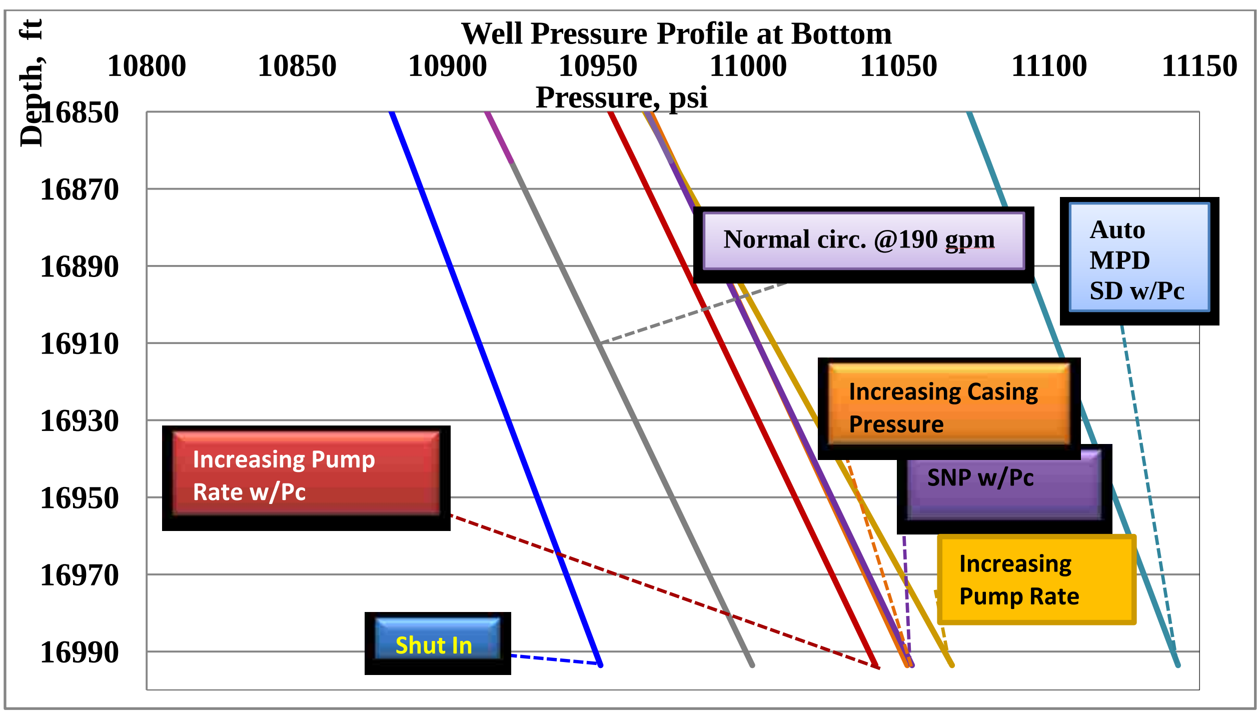


Figure 36: Final wellbore pressures at the bottomhole in Well X

Table 10: Initial response results for high gain kick due to pump efficiency loss, Well X

Initial gain: 15 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	Pcasing, flow stop	Pcasing, max	Gain, bbl	P bottom flow stop	P bottom, (max) psi
SI	10070	10083	633.8	690	16.2	10886	10941
Manual MPD SD	10187	10258	1092	1312	41.5	10903	11113
Auto. MPD SD	10101	10156	780	889	23.5	10903	11016
Manual MPD SD w/add Pc	10054	10197	821	871	16.2	10991	11122
Auto MPD SD w/add Pc	10140	10240	831	881	16	10991	11143
Incr. P casing stepwise	10086	10086	400	420	16.3	11040	11059
Incr. Pump Rate	9932	10006	15	15	15	11068	11072
Start up new pump with Pc	10036	10102	330	300	16	10994	11092
SNP w/o flow meter	10045	10045	536	565	31	10992	11017
SNP w/Pc, w/o flow meter	10046	10058	322	322	16.8	10994	11068
Corr. Pump Rate with Pc	10076	10080	330	330	16	11040	11061
Normal Circ.@ 190 gpm	9948	9948	15	15	0	11001	11001
Shoe Fracture Pres= 10832 psi					Bottom Fracture Pres= 11790 psi		

7.2.1.2.3.1 Initial Responses in Well Y

The same initial responses were also studied in a relatively larger hole, Well Y; where the ECD is less significant compared to Well X. The aim is to see the effectiveness of the initial responses in different wellbore sizes.

Non-circulating and circulating responses (except for the increased pump rate response) gave generally similar results in terms of risk of lost returns and final kick sizes as shown in Figure 37 and Table 11.

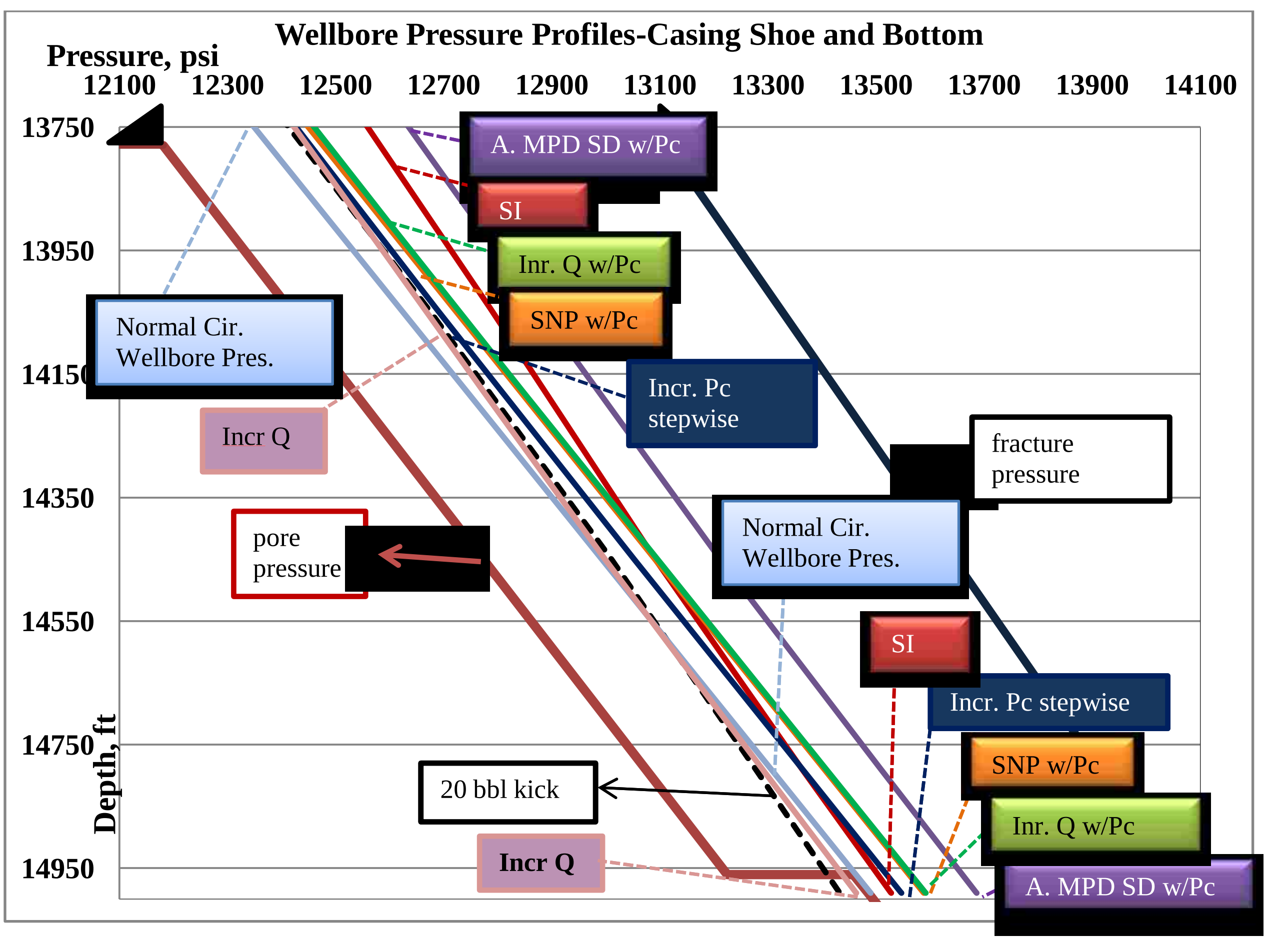


Figure 37: Final wellbore pressures at the bottomhole in Well Y

Table 11 gives the surface pressures, final gains, pressure at shoes and bottom. The order of the lost returns risk and surface equipment failure risk (due to surface casing pressure) are similar to Table 10 except for the increased pump rate response.

Table 11: Initial response results for high gain kick due to pump efficiency loss, Well Y

Initial gain: 20 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom flow stop	P bottom (max) psi
SI	12557	12591	423	473	30	13475	13528
Manual MPD SD	12872	13286	1614	2221	185	13514	14208
Auto. MPD SD	12685	12719	652	756	51.9	13656	13531
Manual MPD SD w/add. Pc	12580	12621	509	560	24	13629	13684
Auto. MPD SD w/add. Pc	12631	12651	508	550	24	13615	13662
Incr. P casing stepwise	12522	12533	250	250	23	13505	13547
Start up new pump with Pc	12517	12572	259	259	22	13480	13597
Corr. Q with Pc	12524	12578	259	259	22	13592	13592
Normal Circ @ 760 gpm	12376	12376	15	15	-	13489	13489
Shoe Fracture Pressure= 13113psi				Bottom Fracture Pressure= 14073psi			

Figure 37 shows the final pressure profiles of the initial responses. The plot compares the pressures at shoe and bottom with respect to pore pressure and fracture pressure. There is a significant difference when increasing the pump rate response was simulated in Well Y.

Different from Well X, the increased pump rate response could not stop influx because the wellbore pressure was less than the formation pressure as shown the Figure 37. Pump rate was increased to its maximum rating; but the developed AFP was inadequate to stop the formation influx. Therefore, it is concluded that the success of an increasing pump rate response depends on the well conditions and brings risks for large pit gain.

7.2.1.2.3.2 Kick Circulation

Circulation to remove kick fluids following the most relevant initial responses was also simulated. Circulations were simulated at both the normal drilling rate and at half that rate for the non-circulating responses. Circulation was also continued at a constant rate for the circulating responses. Pumps were started up for kick circulation at normal or half circulating rate after the formation influx was stopped by non-circulating responses. Figure 38 illustrates a complete well control process. It also shows the casing pressure, flow in/out, gas rate out and pit gain behavior during a full well control operation. In Figure 38, a kick was taken, and the well was shut in. After the pump was started, kick was circulated with Driller's method. Until point "1" in the figure, gas was being circulated to surface, and during that period gas expanded and flow out increased. At point "2," the pit gain was at a peak, and casing pressure was maximized to compensate for the gas expansion. After point "2," the flow out dropped below the flow in, AFP and annulus hydrostatic pressure increase, and the choke opening needs to be increased. At point "3," the gas rate at the surface peaked and flow out dropped to its minimum point because of gas hold up at the surface. After that point, mud offset the gas, and the casing pressure requirements decreased. Flow out started to increase and equalize with flow in as the gas content in the mud decreased.

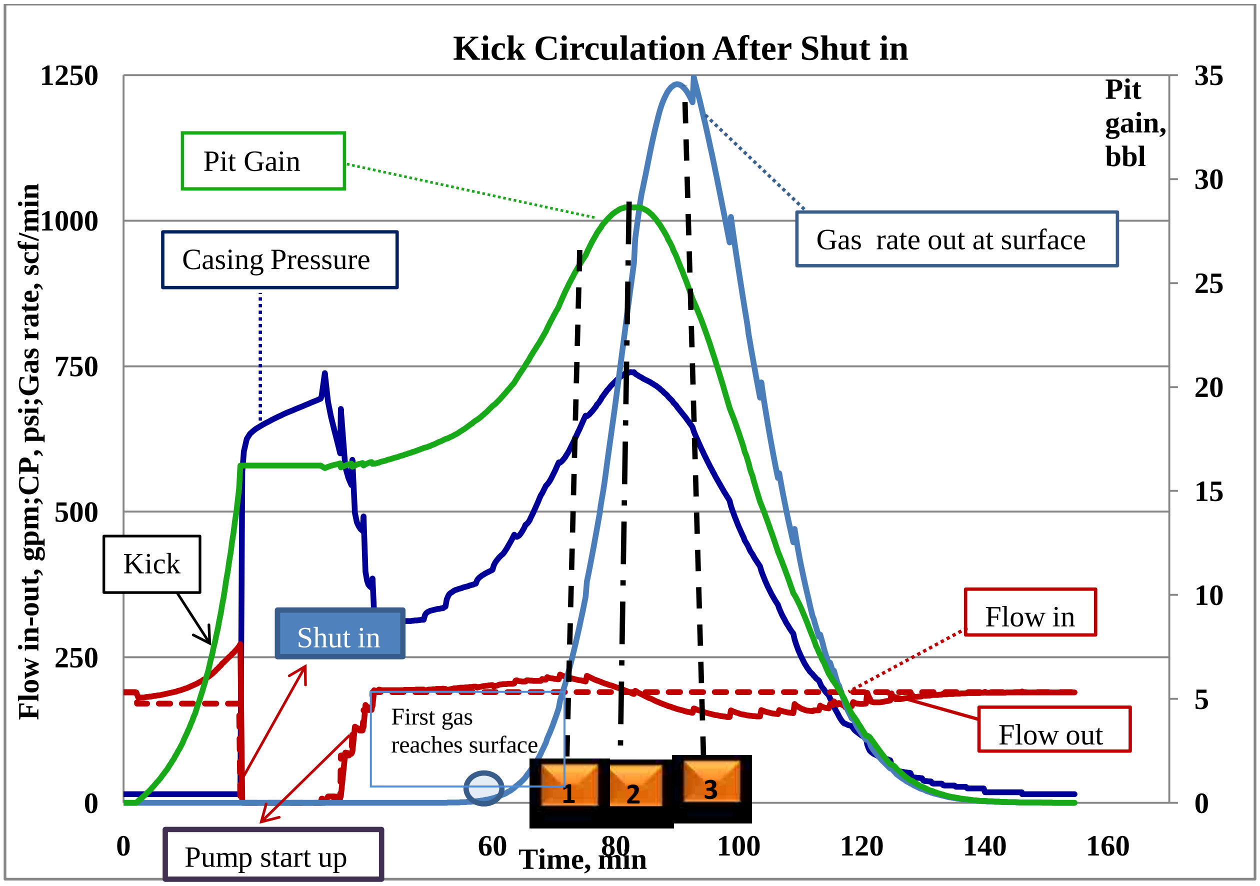


Figure 38: SI and normal rate kick circulation

Figure 39 represents the casing pressures resulting from each circulation. This plot shows that the surface pressure requirement decreases as the circulating pump rate increases. Reduced circulating rate required higher casing pressures to maintain bottomhole pressure above the formation pore pressure due to a lower AFP. Thus, the maximum casing pressures were observed during half circulating rate. Circulating casing pressures after SI and automated MPD SD w/Pc looked almost identical for specific circulating rates. Circulating following the increased casing pressure at the inefficient rate (170 gpm) required a lower casing pressure than reduced rate circulation but a higher pressure than the normal circulating rate. Finally, circulating at the increased rate, 275 gpm, resulted in the lowest surface pressure requirement as a result of the significant AFP.

Another benefit of circulating at increased or normal rates is the reduced NPT. The kick is circulated out in a shorter time at high circulation rates. Therefore, it was concluded that circulating at the full or higher rate demonstrated advantages over reduced rate circulation. Figures 40 and 41 show the gas rate and mud return rate at the surface, based on the circulation rate. These plots prove that the peak return flow rates are dependent on the circulating rates. Gas flow rate out decreases as the circulating pump rate decreases. Figures 40 and 41 show that circulating at an increased rate increased both the gas and mud rates at surface. Therefore, the surface equipment should be sized to handle these peak return flow rates during kick circulation for the kick circulation rate that is planned for use.

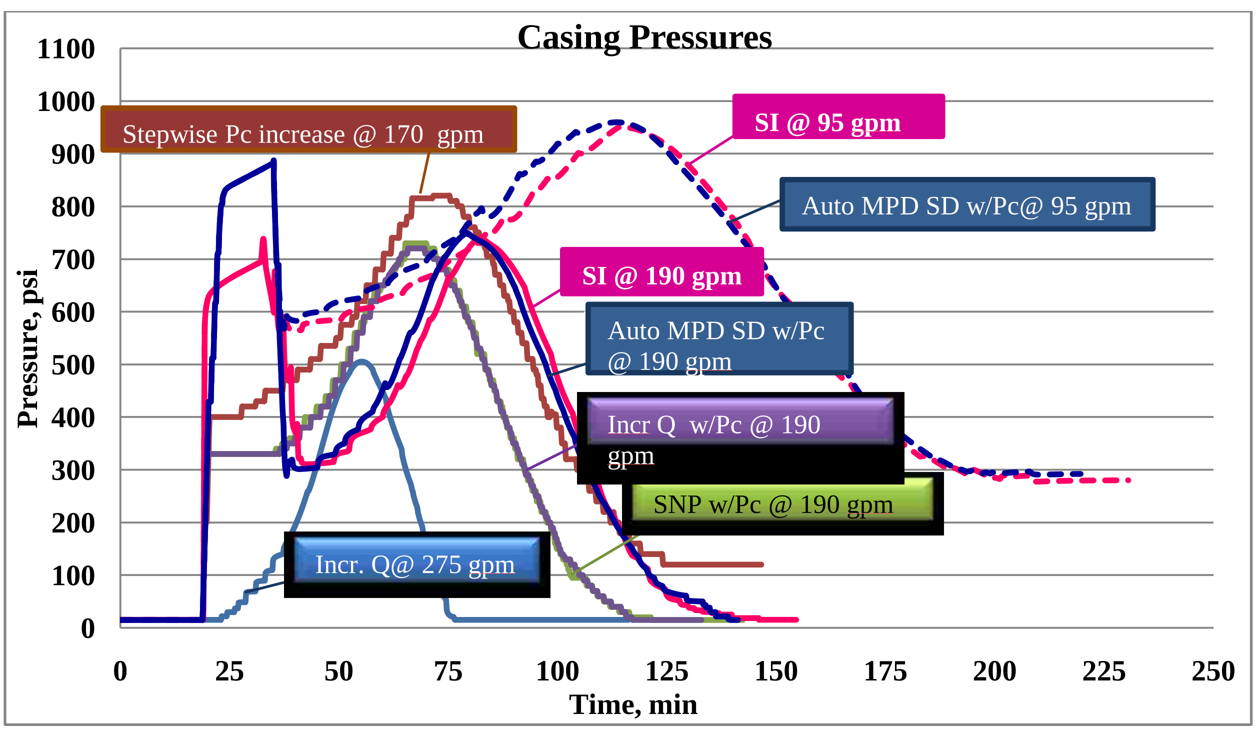


Figure 39: Casing pressures during circulation study

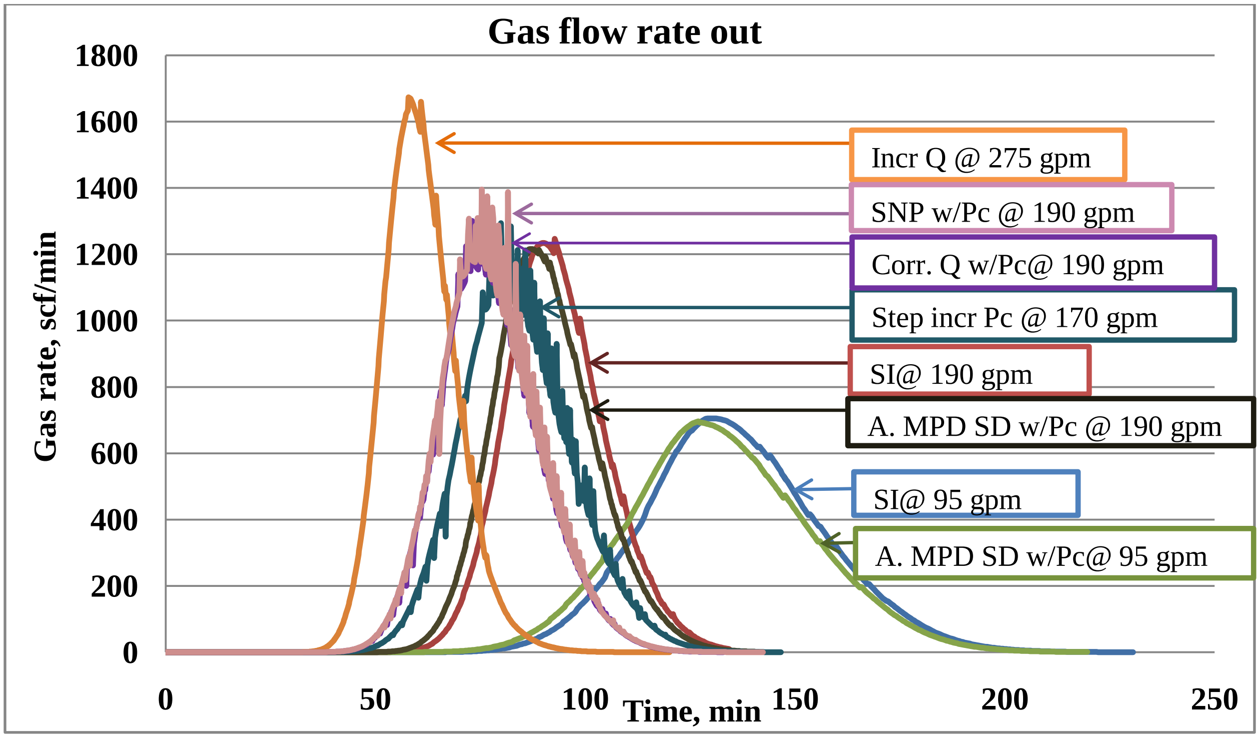


Figure 40: Gas return rates at the surface

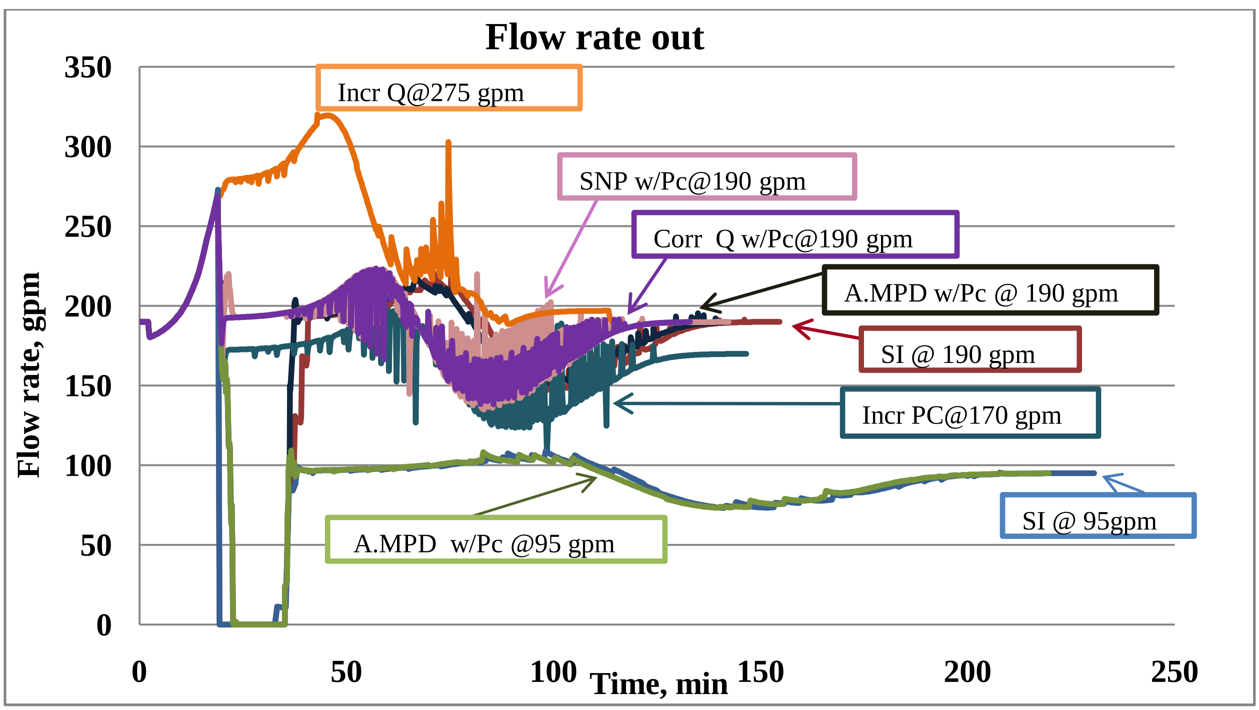


Figure 41: Mud return rates at the surface

A significant complication is that the increased rate response requires a schedule for reducing pump rate during kick circulation. This complication occurs because after the gas reaches the surface, bottomhole pressure increases as mud replaces the circulated gas. As the kick was removed, the choke opening was increased to maintain the pump pressure. Although the choke was fully opened (meaning that no backpressure was applied), the pump pressure began to increase. There was still about 9 bbl of gas in the well at the 76th minute, and as shown in Figure 42, the pump pressure begins increasing as the gas was removed. At this stage, there were three possible reactions: pump pressure (and bottomhole pressure) might be allowed to increase and circulation would continue, pump rate could be directly reduced to the original rate (190 gpm), or pump rate could be reduced gradually.

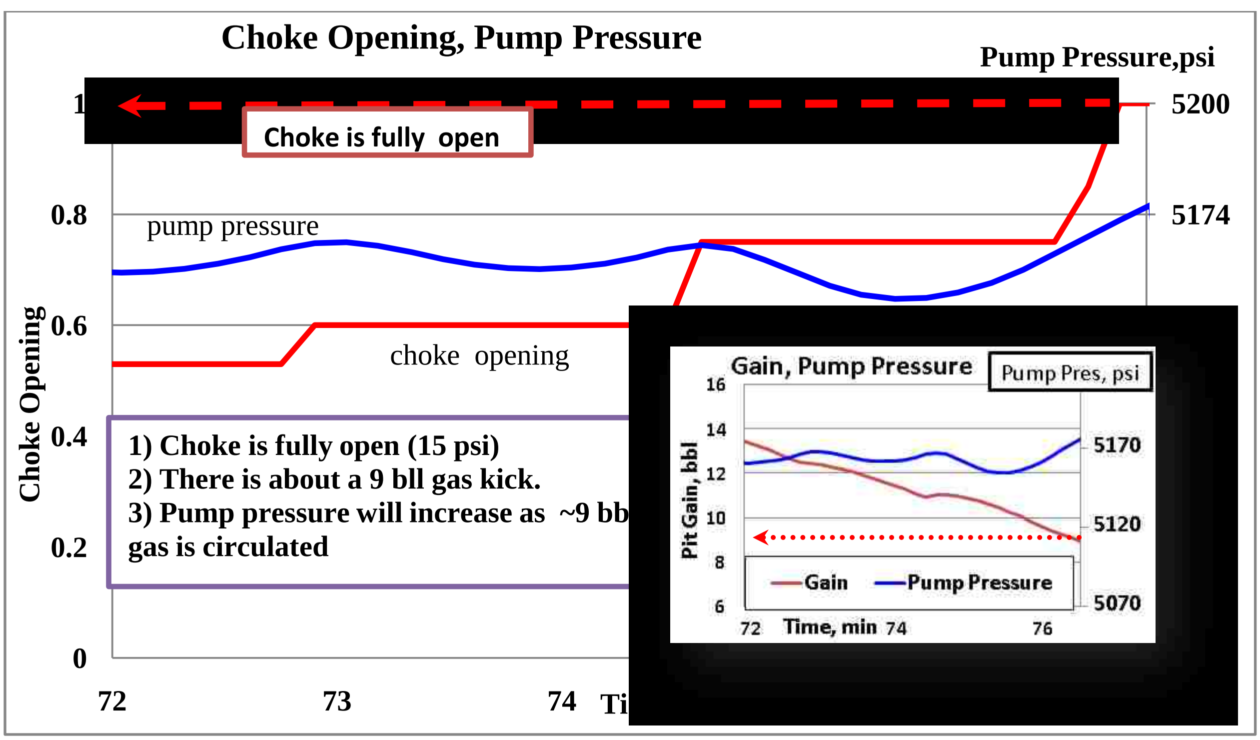


Figure 42: Pump pressure as gas reaches the surface during the increased pump rate

Figure 43 shows the final wellbore pressures for these possible three responses. Continued circulation at an increased rate increased the bottomhole pressure more than was necessary to stop the influx. There was no risk of lost returns for this well, but for tighter margins, such an increase may fracture the formation. In addition, the final BHP would be higher than seen in Figure 43, because the simulator crashed before the kick circulation was completed. Also, the pump pressure might increase more than was allowed. When the pump rate was directly reduced to the original value, another kick was gained because the presence of the 9 bbl kick resulted in the well's being underbalanced. However, if the pump rate was gradually reduced to the original rate based on a schedule, the BHP could be successfully maintained within a reasonable pressure window.

Figure 44 shows the gradual pump rate reduction, based on a schedule created with an Excel spreadsheet. In Figure 44, the plot to the right side of dashed line shows the simulation results for a gradual reduction of pump rate. As seen in the plot, kick was circulated successfully and the flow in and out became equal.

The overall kick circulation simulation results are summarized in Table 12. The table compares the maximum pressure values at casing shoe, bottomhole and surface, the maximum flow out rates and NPT of the circulation simulation results. The evaluation for circulation is conducted based on the circulation duration time, maximum pressure at the potential weak zones and the surface, maximum flow rates at surface, and the ease of application. The maximum pressure at the casing shoe, or risk of shoe failure, was observed during circulations after non-circulating (SI and automated MPD SD w/Pc) responses as shown in Figure 39 and summarized in Table 12. This was true for full rate and half rate circulations. The maximum observed pressures at the shoe after the responses that required a pump start up for kick circulation are at least 100 psi than those for circulating responses, independent from the circulation rate. This higher pressure at the shoe occurred during pump start up. Therefore, the evaluation of initial responses at the shoe should consider the initial response and the consequent kick circulation together. Similarly, the maximum observed BHP should also be evaluated while considering the initial response together with the circulation. It should be noted that the MPD SD w/Pc response caused the highest shoe and bottom pressures and therefore the highest risk of lost returns. All of the other responses gave lower and similar maximum bottomhole pressures. The circulating responses gave the maximum shoe pressures within a range of 96 psi and minimized the risk of lost returns at the shoe.

For the normal circulating rate responses, the maximum annulus surface pressure was observed either when the gas hold up was at maximum or during pump start up. The maximum surface pressure during circulation is minimized when the kick is circulated at an increased rate due to the increased AFP.

A shorter time was spent for total well control in circulating responses than for non-circulating responses. Circulating responses stopped formation flow relatively quickly, whereas non-circulating responses required pressure stabilization that increased the NPT time. Additionally, when circulating at a normal or increased rate, a well control operation was completed in a shorter time than at half rate circulation, and this significantly reduced the NPT. The increased circulating rate gave the shortest circulation time, which in turn reduced NPT and the cost. However, it required a schedule as discussed in this section when the gas reached surface.

The advantages of circulating responses include the lower cost of NPT, lower pressure on surface equipment and at casing shoe. However, it should be recalled that the circulating responses and their consequent kick circulations are performed with an inefficient pump (except for SNP w/o flow metering). This may cause pump failure and failure in well control. Therefore, a simple shut in followed with a kick circulation at normal circulating rate using an efficient pump and SNP w/Pc are the most appropriate reactions for these kinds of kicks. Among these, SNP w/o flow metering provides continuous circulation and reduces the NPT, whereas SI and full rate circulation requires no preliminary calculations or schedules and no flow in or out metering.

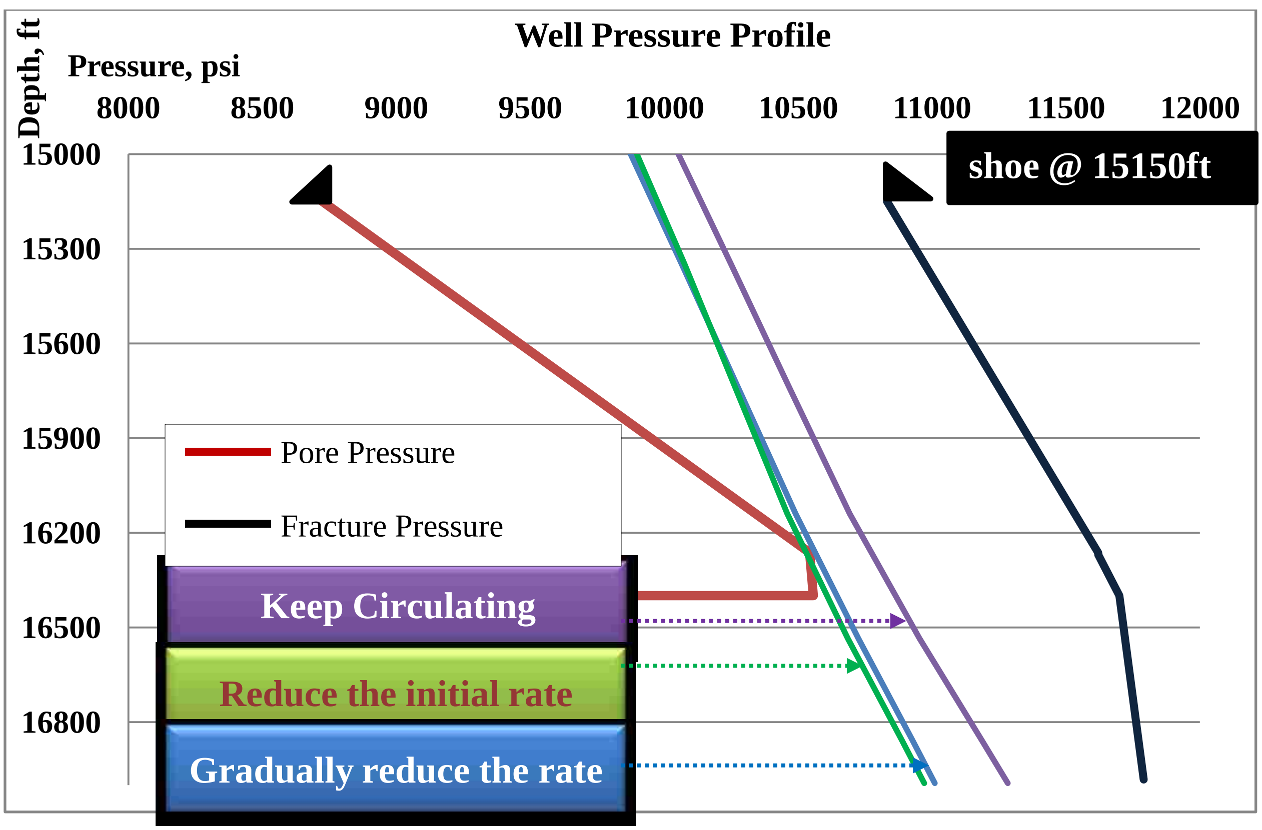


Figure 43: Wellbore pressures

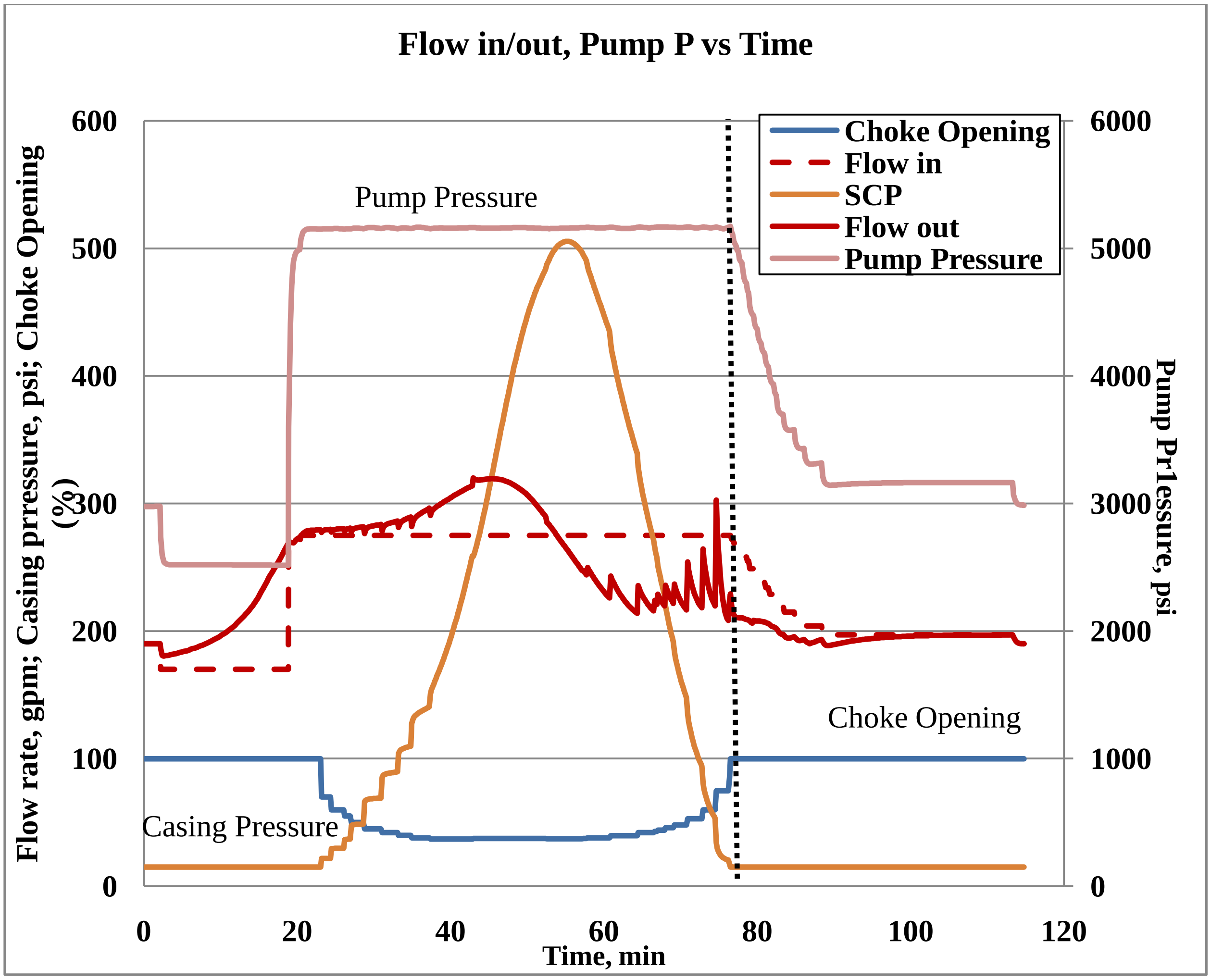


Figure 44: Gradually reduced pump rate

There is no significant difference between large gain and small gain cases. In small gain case, there is less risk of lost returns and all of the responses stop the influx with allowable pressures at potential weak zones. However, kick circulation with an efficient pump discussion is also valid for small pit gain. Circulation should be performed with an efficient pump, which is possible by SI and SNP w/Pc.

Table 12: Circulation results for high gain kick due to pump efficiency loss, Well X

Cause: Efficiency Loss										
gain: 20 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10083	10941	10152	740	3009	11054	92	118	204
	Half rate			10152	951	1293	11054	92	180.5	100
a. MPD SD w/Pc	Full rate	10240	11143	10256	886	3034	11170	167	122	219
	Half rate			10256	960	1348	11170	168	189	109
Incr. P casing	Full rate	10086	11059	10045	820	2635	11079	78	109	180
Incr. Pump Rate	Full rate	10006	11072	9976	506	5173	11099	98	95	320
SNP w/Pc	Full rate	10102	11092	9997	715	3001	11050	48	109	222
SNP w/Pc,w/o flow	Full rate	10058	11068	10015	742	3041	11068	67	109	223
Corr. Q with Pc	Full rate	10080	11061	9990	720	3018	11019	17	101	203

7.2.2 BHA Position Change

BHA position change led to a reduction in ECD across the high pressure zone in the wellbore. This reduced the wellbore pressure below the formation pore pressure. SI and MPD SD responses were applied as non-circulating responses. The increased casing pressure, increased pump rate and combination of these were applied as circulating responses. After the non-circulating responses, kick was circulated at normal and half circulating rates. The kick was circulated at the rates that the influx was stopped after circulating responses. This case was simulated for only Well X because ECD was not significant in Well Y (relatively larger well), for large and small pit gains.

7.2.2.1 Results and Analysis

BHA position change results were divided into non-circulating and circulating responses. The results below were obtained from Well X after gaining a 20 bbl kick. The tabulated results for small pit gain are shown in the appendix as large pit gain is more important and there is no significant difference between large and small pit gains.

7.2.2.1.1 Non-Circulating Responses

Non-circulating responses are SI and MPD SD. Figures 45 and 46 present a MPD SD for pre-kick conditions. Figure 45 shows that the bottomhole pressure is maintained relatively constant during a MPD SD, which means the aim of MPD SD is met under normal conditions. Figure 46 establishes a kick baseline or fingerprint which enables to detect the small kick. MPD SD schedule was simulated under kick conditions. The flow out in this figure can be used for early kick detection by checking whether the flow out trends match, since mismatch means a kick.

Figures 47 and 48 show the applications and the results of the SI, manual MPD SD and automated MPD SD applied after the kick was detected. Figure 47 compares the flow return rates during SI, manual MPD SD and automated MPD SD responses, which is used to evaluate the effectiveness of the responses in formation influx stoppage. A response is considered as effective if the flow out trend is equal to flow in, which is SI in this case. Figure 48 is used to compare the corresponding surface pressures of the responses. The lowest casing pressure reduces the lost returns risk and surface equipment failure risk, which is also for SI in this case.

The SI final casing pressure was less than 900 psi and the final gain was 21.9 bbl. The SI was rapid and stopped the formation fluid flow with the less final gain and casing pressure than the MPD SD responses as shown in Figure 47 and 48. Some additional gain occurred while turning off the pump for SI as shown in Figure 47. However, it was not significant.

The final surface casing pressures and gains for manual and automated MPD SD responses were about 1100 and 1600 psi, and 28 bbl and 49 bbl, respectively. Automated MPD SD ended up with a lower final gain and casing pressure compared to the manual MPD SD because the automated MPD SD was completed in a shorter time. However, these responses were not effective compared to SI.

Figures 49 and 50 compare SI and the improved (adding casing pressure equal to hydrostatic pressure loss to the pump shut down casing pressure schedule) manual and automated MPD SD responses. Figure 49 compares flow in and out values for SI and the improved MPD SD responses, similar to Figure 47. Figure 50 shows that the improved manual and automated MPD SD responses stopped the formation flow with about 870 psi surface casing pressures. The final gains for these responses were about 22 bbl.

The improved MPD SD responses stopped the influx effectively and gave almost the same final gain and casing pressure as SI (see Figures 49 and 50). However, there exist limitations for improved MPD SD responses. Pressure loss and the required overbalance pressure are not known precisely and are needed for the revised MPD SD schedule. This is not a huge disadvantage, unless the pressure loss is overestimated, because the needed pressure will build up after closing the choke.

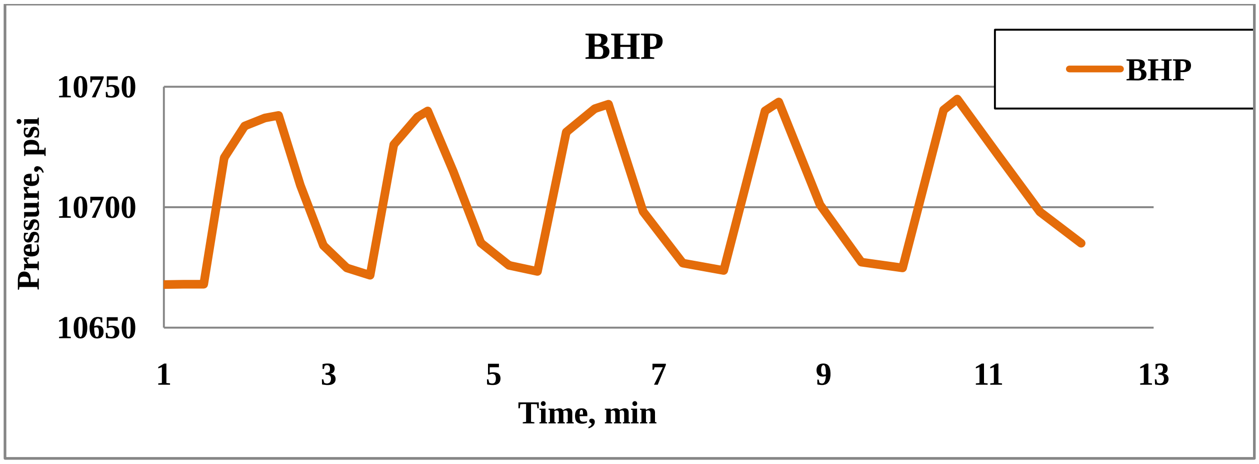
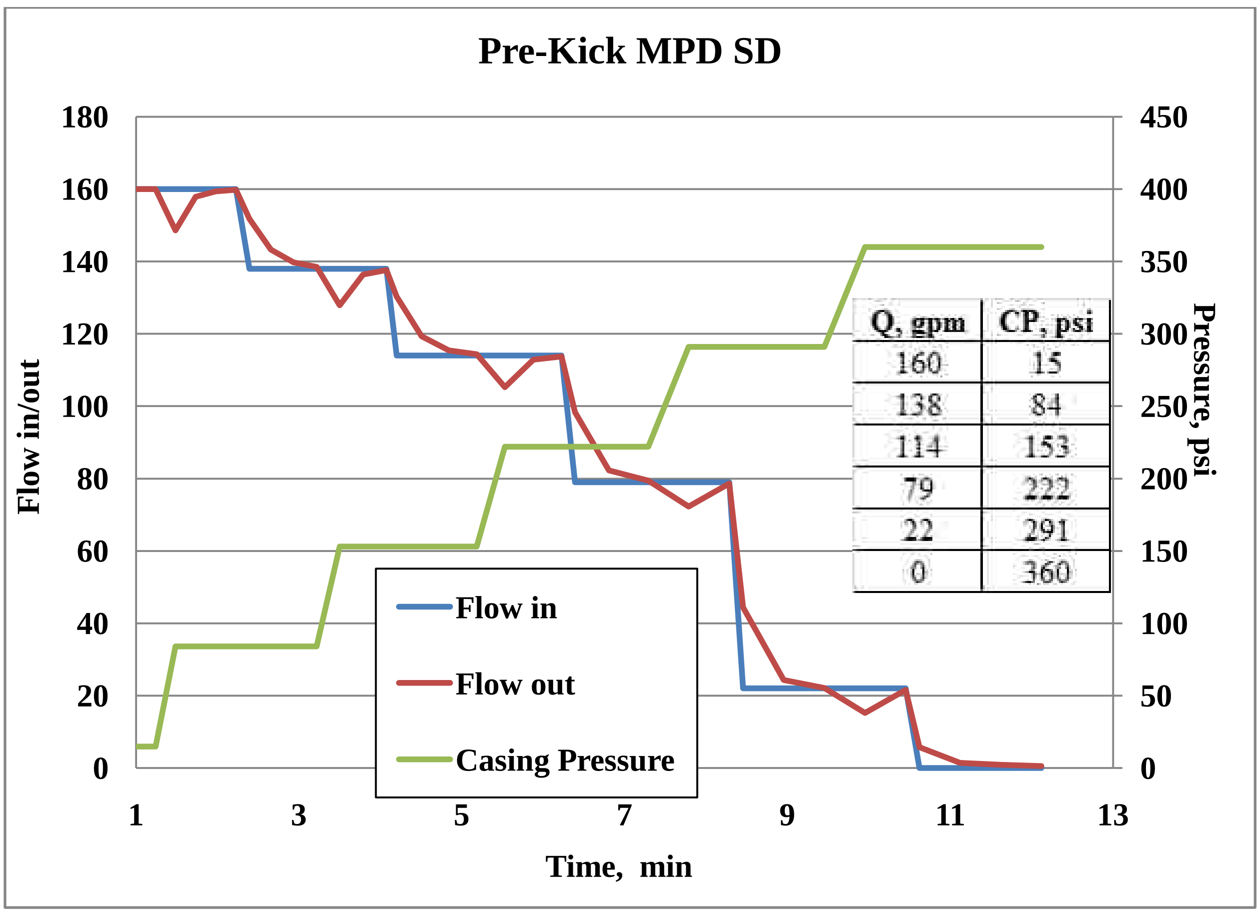


Figure 45: BHP during pre-kick MPD SD



Q, gpm	CP, psi
160	15
138	84
114	153
79	222
22	291
0	360

Figure 46: Pre-kick MPD SD

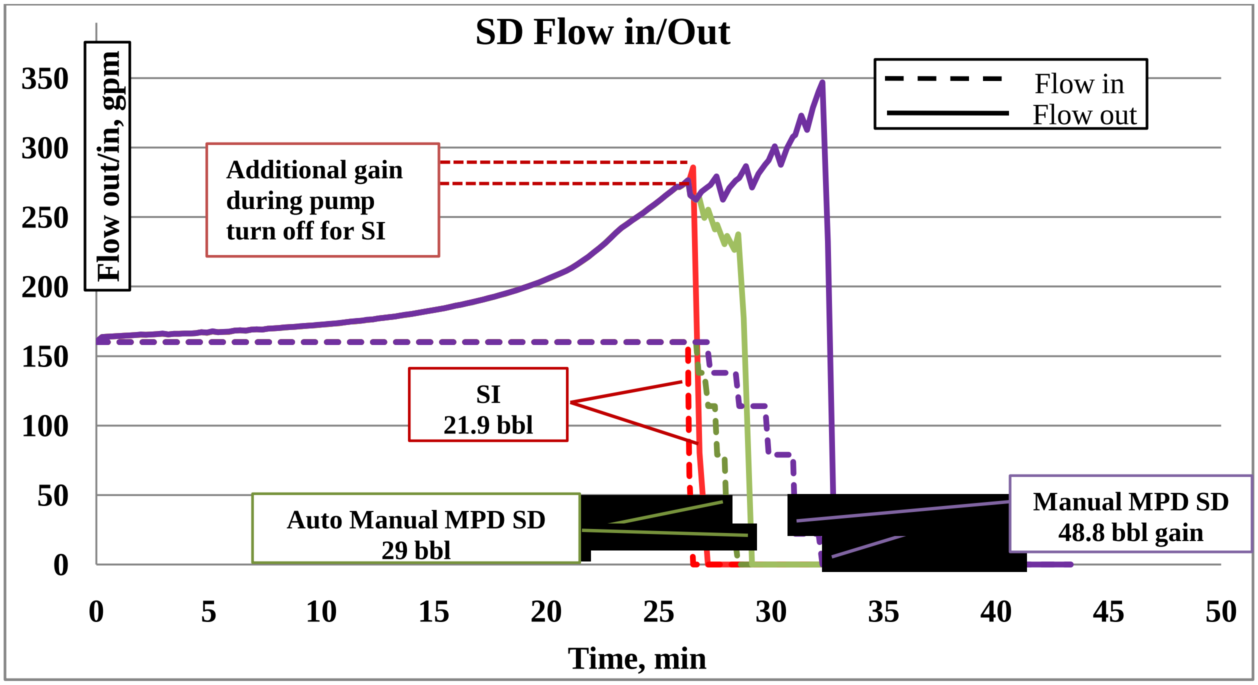


Figure 47: Flow in/out during SI, manual and automated MPD SD

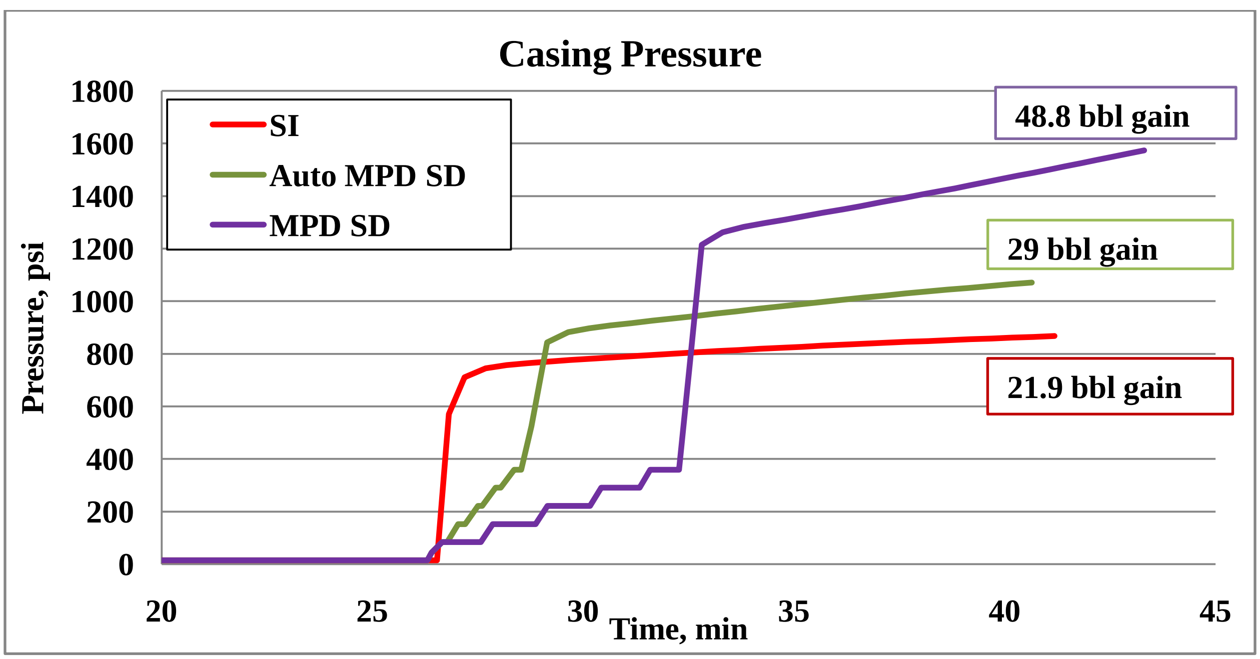


Figure 48: Casing pressures for SI, manual and automated MPD SD

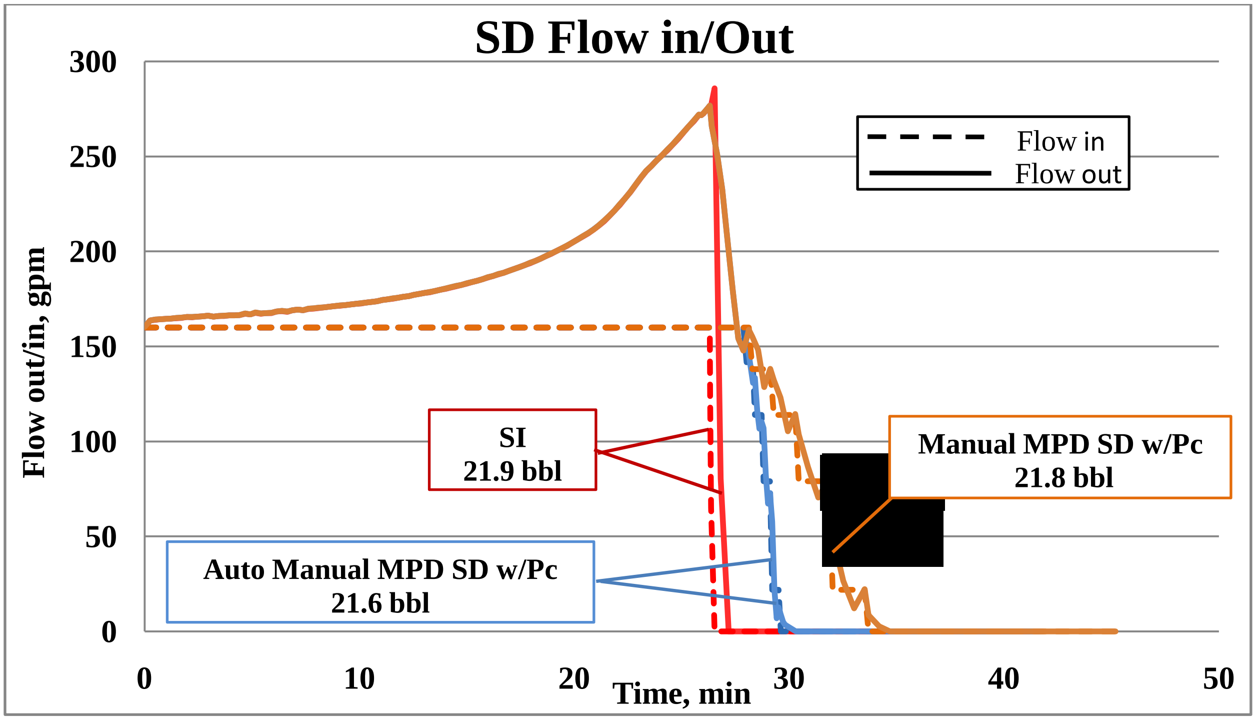


Figure 49: Flow in/out during SI, improved manual and automated MPD SD

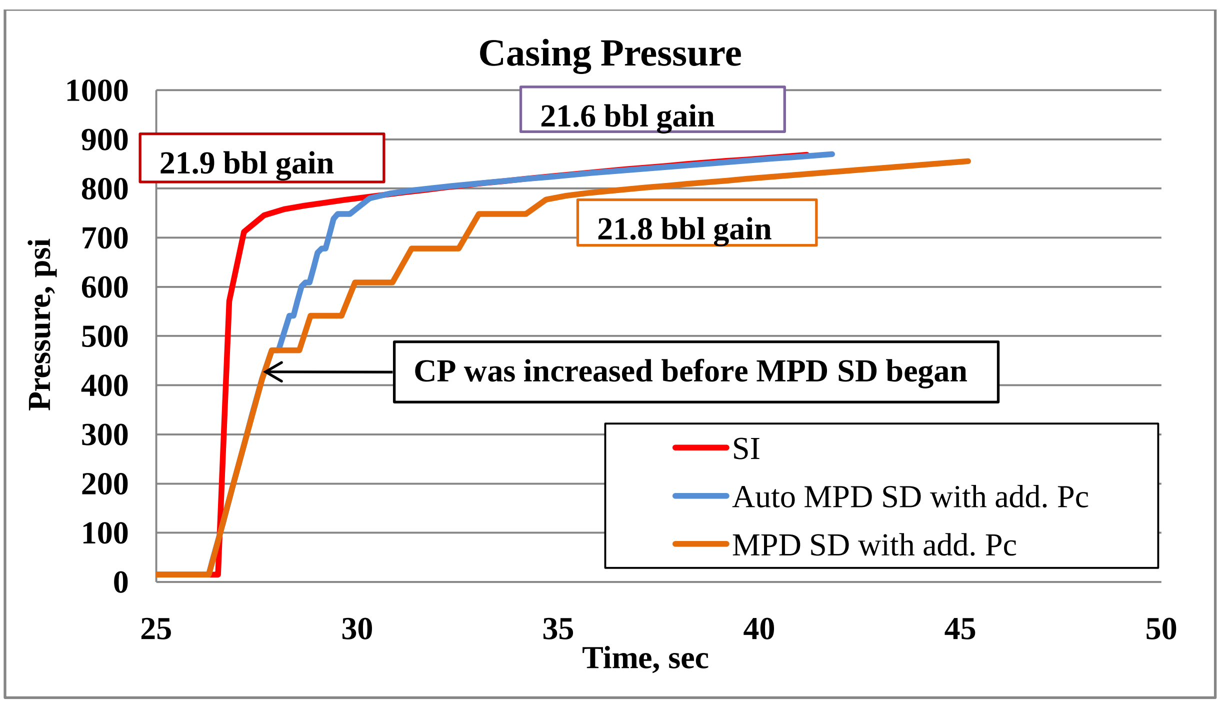


Figure 50: Casing pressures for SI, improved manual and automated MPD SD

7.2.2.1.2 Circulating Responses

Responses utilizing continued circulation for kicks caused by ECD reduction due to BHA position change were also applied to stop the influx. These responses include increasing surface backpressure, increasing pump rate, and increasing pump rate with surface backpressure.

7.2.2.1.2.1 Increasing Surface Backpressure

The technique of increasing surface backpressure while continuing to circulate was applied in three different ways. These are increasing casing pressure to MCPBF-SF, increasing the casing pressure equal to the hydrostatic pressure loss (calculated from pit gain) and stepwise increase of casing pressure. These responses are same as the increased casing pressures responses used in the pump efficiency loss case.

Figures 51 and 52 show the results of these responses. Figure 51 presents the surface casing pressures resulting from these initial responses and therefore the relative risk of equipment failures. The final surface casing pressure for MCPBF-SF, increasing the casing pressure equal to the hydrostatic pressure loss and stepwise increase of casing pressure responses are about 870, 475and 500 psi respectively. Figure 52 illustrates the flow in and flow out profiles. This plot is used to show that flow in and flow out is almost equal, which indicates that flow was stopped, at the end of the responses.

MCPBF-SF does not require flow measurement. It stopped the flow but caused excessive surface casing pressure.

Increasing the surface backpressure equal to the hydrostatic pressure loss requires flow measurement in this case. In theory, this response should not have stopped the influx since the normal wellbore pressure was inadequate to prevent formation influx. The added safety pressure to surface backpressure stopped the influx with a very low overbalance pressure.

Stepwise casing pressure increase was implemented by 200 psi increments. When the flow out increased, surface backpressure was increased by an additional 200 psi. This pressure increase forced the flow out be almost equal to flow in as shown in Figure 52. In the 28th minute of Figure 52, flow out started to increase again. However, only a 100 psi surface backpressure was applied because flow out was almost equal to the flow in and 200 psi surface backpressure increase would cause an unnecessarily high wellbore pressure.

The stepwise casing pressure increase stopped the flow with a similar final gain to the other circulating responses and it resulted in a lower casing pressure than the MCPBF-SF response as shown in Figure 51. Practically, this response is considered preferable to the increased casing pressure equal to the hydrostatic pressure loss because no prior calculations are required to define an initial casing pressure and it is more feasible.

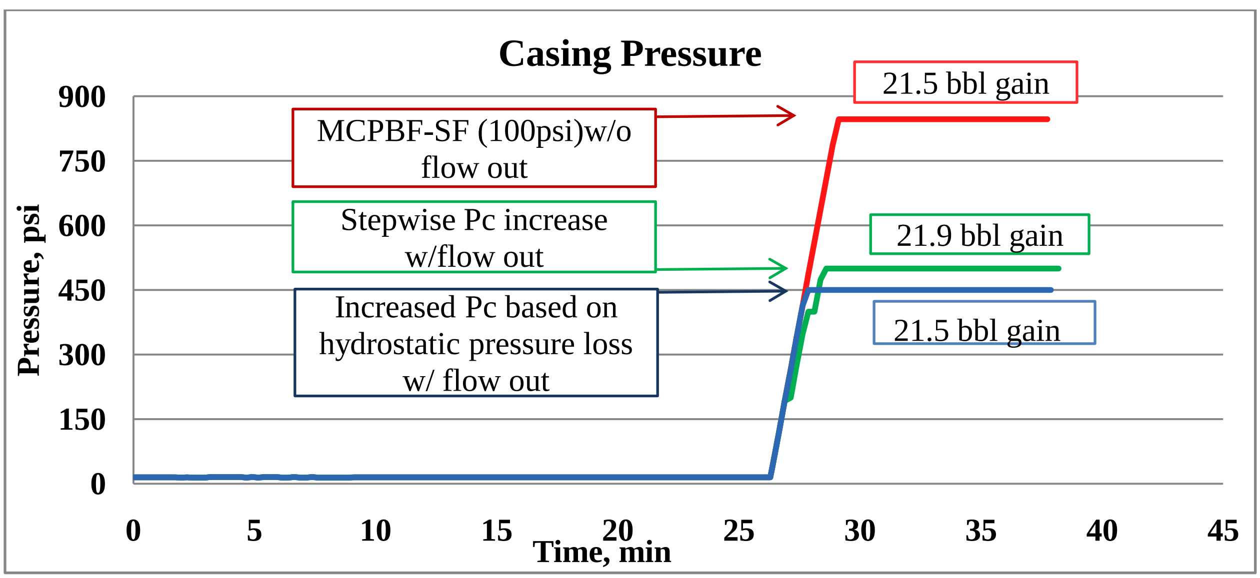


Figure 51: Casing pressure for three increasing surface backpressure responses

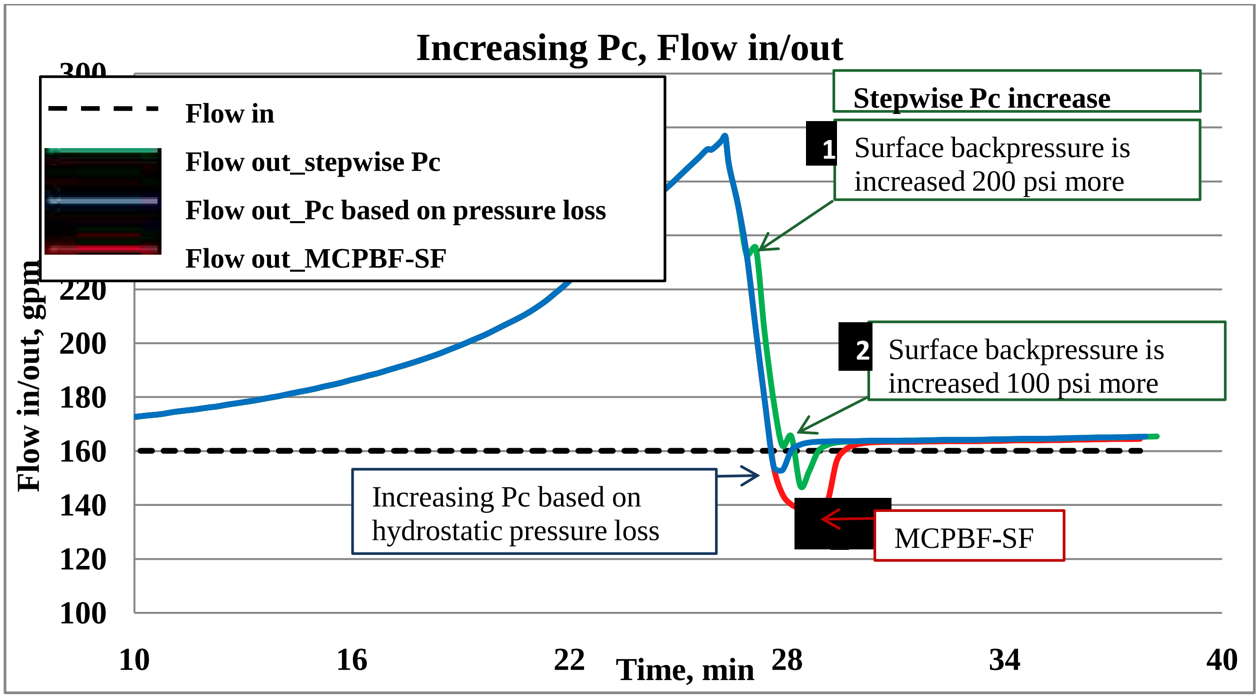


Figure 52: Flow in and out for three increasing surface backpressure responses

7.2.2.1.2.2 Increasing Pump Rate

Increasing the pump rate to stop the formation influx is another potential initial response. Figure 53 shows that the pump rate was increased to 280 gpm which was slightly above the return flow rate of 277 gpm. The flow out rate was then monitored to verify that the influx was stopped. Flow stoppage was verified when flow in was higher than flow out, and the flow out subsequently increased to a value only slightly higher than the flow in and was almost constant. The pump pressure was recorded as about 5114 psi at that point, and it was then maintained relatively constant by adjusting the choke pressure during the kick circulation. However, kick circulation after increasing the pump rate increased the bottomhole pressure when the gas reached surface and required a schedule to reduce the pump rate similar to the profile shown in Figure 44 so as to eliminate the bottomhole pressure increase.

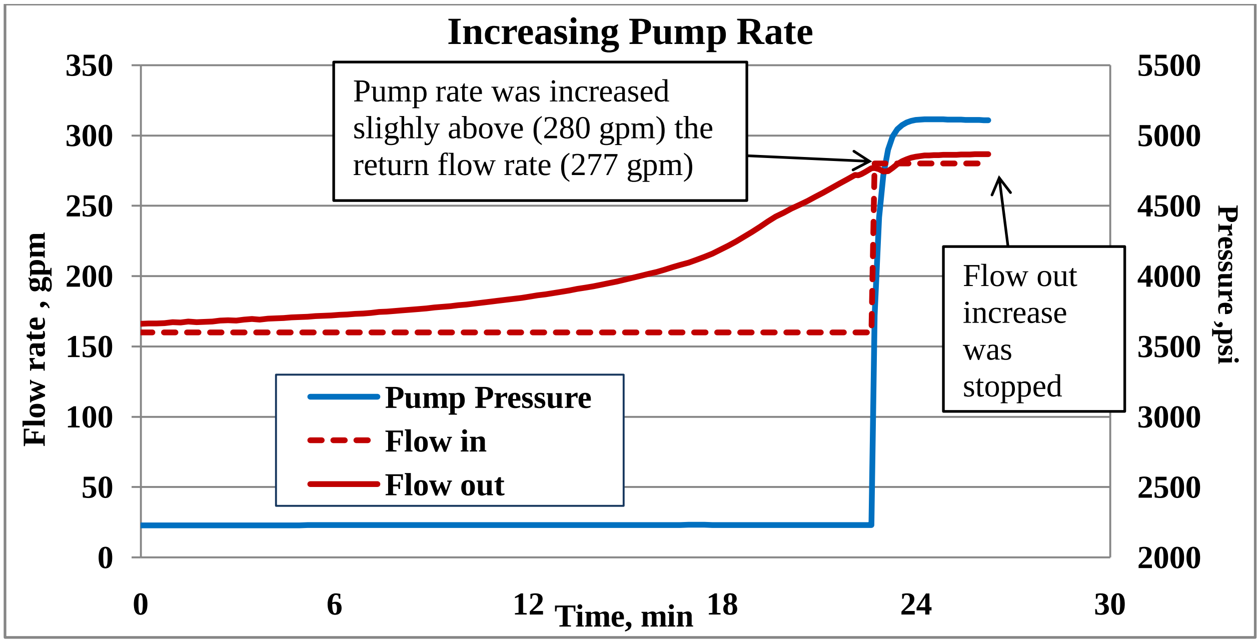


Figure 53: Increasing the pump rate response

7.2.2.1.2.3 Increasing Pump Rate with Casing Pressure

Increasing the pump rate with casing pressure was applied by utilizing increased surface backpressure prior to increasing the pump rate and ECD in the annulus.

A 200 psi casing pressure was applied initially, and then the pump rate was increased equal to the new return flow rate as shown in Figure 54. The 200 psi casing pressure was selected randomly but based on replacing about half of the 450 psi hydrostatic loss due to a kick equal to the kick detection limit. The remaining pressure (hydrostatic pressure loss and required overbalanced) needed was intended to be met by the AFP. The pump rate was increased to just more than the new return flow rate. Flow stoppage was verified when the flow in became higher than flow out, and then the flow out was only slightly greater than the flow in and was almost constant. The difference was a result of the fast expansion of the gas kick resulting from high circulating rate and low casing pressure. Once the flow is stopped, kick must be controlled by maintaining the new recorded pump pressure constant because fast gas expansion may lead the wellbore pressure to drop again. This response also required a pump rate reduction schedule as the gas kick was removed to avoid an excessive bottomhole pressure increase.

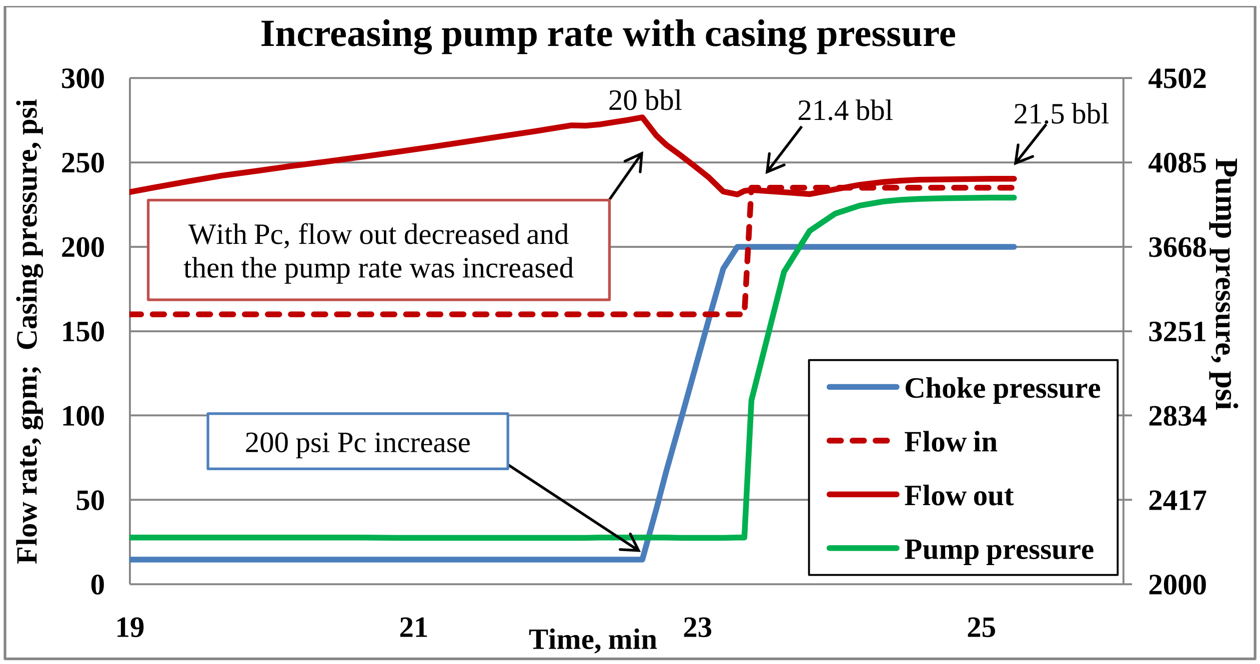


Figure 54: Increasing the pump rate with casing pressure

7.2.2.1.3 Comparison of Responses

This section compares the discussed initial responses. Five different initial response results were plotted and tabulated in this section. Only the five best of ten responses explained above are presented in these plots. These are SI, automated MPD SD w/Pc, stepwise increasing surfaceback pressure, increasing pump rate and increasing pump rate with casing pressure. Plots show and compare the pressure profiles at different sections of the wellbore. Tabulated results present and compare the pressures at shoe, bottomhole pressure, surface pressure and the final gains for each initial response.

Figure 55 shows the wellbore pressure profiles of representative examples of the initial responses. It compares the surface casing pressures results of the simulated responses. The automated MPD SD w/Pc and SI caused the maximum casing pressures because they did not have the benefit of AFP. For the circulating responses, the casing pressures experienced decreased progressively between the stepwise increasing surface backpressure, increasing the pump rate with casing pressure and increasing pump rate responses.

Figure 56 focuses on the pressure profiles opposite the casing shoe, high pressure sand zone and bottom. It shows the risk of lost returns at the potential loss zone. None of these initial responses caused any significant risk of lost returns in Well X as shown in Figure 56. However, initial responses can be ranked based on their risk of lost returns at the casing shoe. Automated MPD SD w/Pc and SI have the highest risk of lost returns. The increased casing pressure gave desired results at every critical point compared to circulating and non-circulating responses. It gave a lower casing shoe pressure than non-circulating responses and provided the highest overbalance at the high pressure zone.

Table 13 summarizes the simulated initial response results. It compares the tabulated pressure and gain size. It shows that the initial responses ended up with almost similar pit gains except that the standard MPD SD responses were worse. Circulating responses showed lower pressures at the casing shoe and therefore reduced the risk of lost returns at the shoe. The bottomhole pressure results of essentially all of the responses were close.

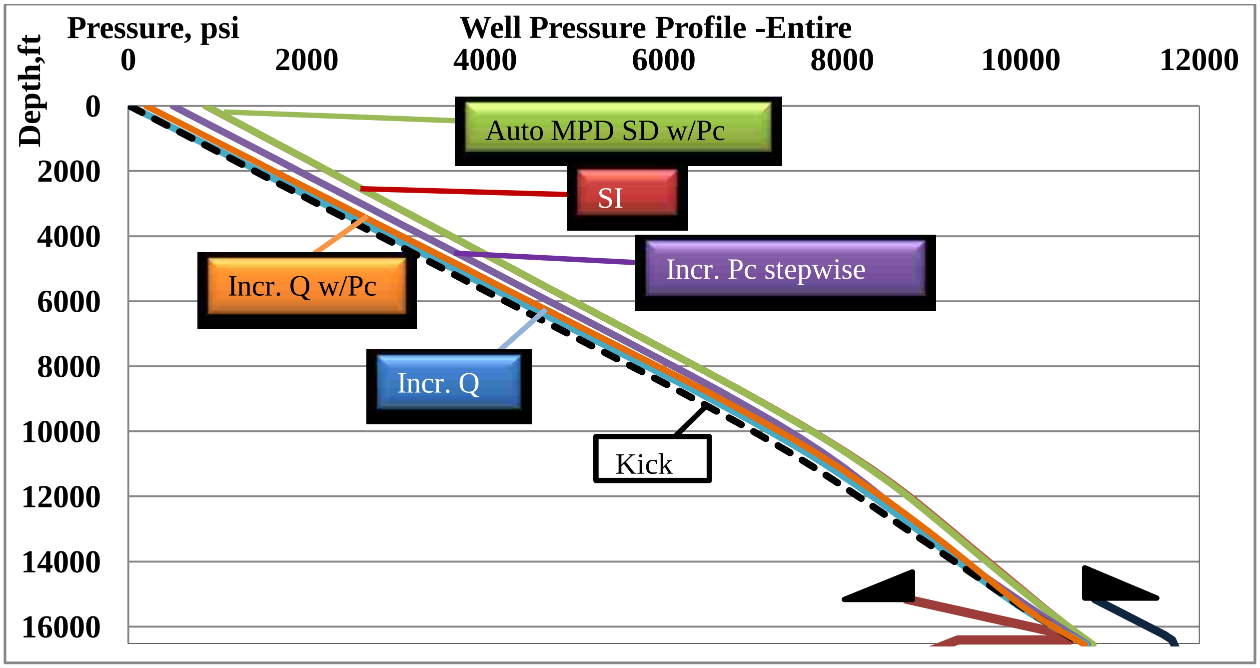


Figure 55: Wellbore pressure profiles

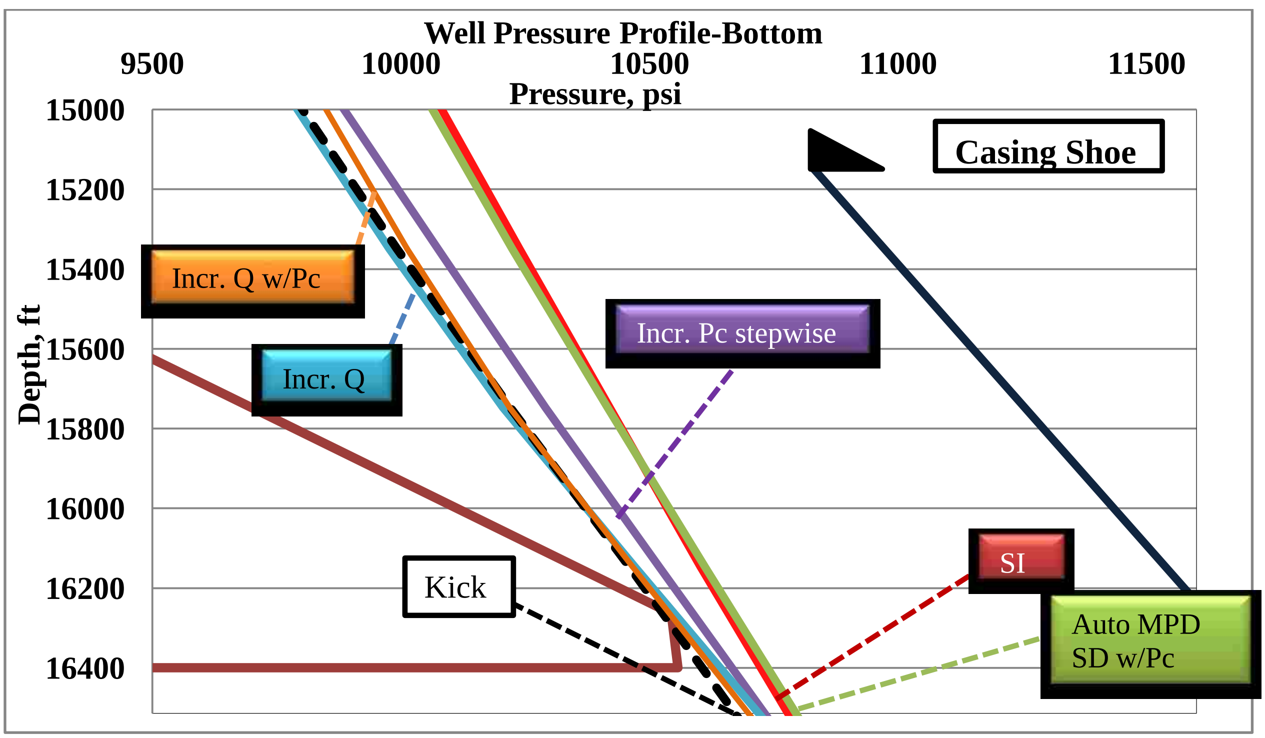


Figure 56: Pressure profile at shoe and high pressure zone

Table 13: Initial response results for BHA position change

Initial gain: 20 bbl	Cause: ECD reduction due to BHA position change						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10100	10149	792	868	21.9	10692	10778
Manual MPD Pump SD	10232	10366	1283	1575	48.8	10664	10975
Auto. MPD Pump SD	10138	10231	908	1071	29	10666	10849
MPD Pump Shut D w/Pc	10042	10097	796	868	21.8	10719	10783
Auto. MPD Pump SD w/ Pc	10087	10133	800	875	21.6	10729	10799
Incr. Casing Pressure	10016	10051	473	500	21.9	10702	10736
Incr. Pump Rate	9922	9943	15	15	20	10712	10730
Incr Q with Pc	9940	9974	200	200	21.5	10700	10701
Normal Circ. @160 gpm	9884	9884	15	15	-	10668	10668
Shoe Fracture Pres= 10832 psi					Bottom Fracture Pres= 11790 psi		

7.2.2.1.4 Comparison of Kick Circulation

Kick was circulated by driller's method at the end of the five initial responses mentioned above.

Figure 57 shows and compares the casing pressures during the kick circulation simulations after each initial response. The highest casing pressures during circulation were observed for the half circulating rate cases, due to the lower AFP. On the other hand, full circulating rate experienced a lower maximum casing pressure while circulating out the kick. The increased pump rate minimized the casing pressure imposed on the surface equipment, but it required much higher pump pressure and surface flow rate capacity due to large return rates.

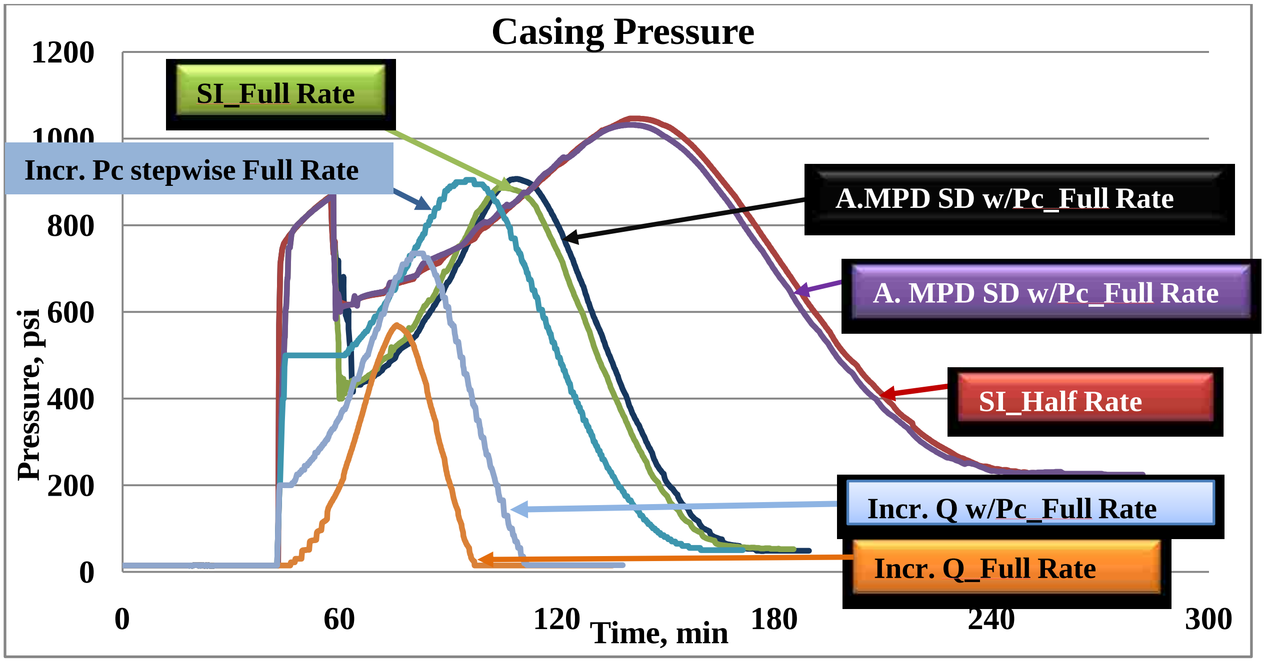


Figure 57: Casing pressures during circulation

Half circulating rate took a longer time to circulate the kick. This increased the NPT versus the normal and increased rate circulation. The increased pump rate response had a potential benefit in reducing NPT. However, the increased pump rate, as well as increasing pump rate with casing pressure, required a schedule to reduce the pump rate so as to eliminate the excessive AFP at the end of the kick circulation.

Table 14 summarizes the simulated circulation results. It evaluates the kick circulation results in terms of maximum pressure, flow rate out and NPT. The maximum bottomhole pressures were observed during pump startup after the non-circulating responses. Circulating responses eliminated these fluctuations, as they did not require pump start up. The increased pump rate response did not result in the highest pressure at the bottom, as it did in the pump efficiency loss case. This is because it had the lowest overbalance opposite the high pressure zone. However, it required a schedule to eliminate the bottomhole pressure increase during kick circulation. Increasing the pump rate with casing pressure had the same requirements as the increaed pump rate response.

Increasing the casing pressure stepwise was the most desirable initial response because since its application is not limited by the pump pressure for the kicks taken due to reduction in the ECD. The increased casing pressure response is the most practical for minimizing pressures and NPT without requiring any special procedures.

Table 14: Circulation results for BHA position change

Cause: ECD reduction due to BHA position change										
gain: 20 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP, (max) psi	BHP variation (max) psi	NPT, (I.R.+Cir.) min	Flow out, (max), gpm
SI	Full rate	10149	10778	10143	907	2260	10774	89	140	181
	Half rate			10143	1046	1020	10774	89	200	108
a. MPD SD w/Pc	Full rate	10133	10799	10078	889	2272	10764	96	136	186
	Half rate			10078	1032	1300	10794	96	212	110
Incr. P casing stepwi.	Full rate	10051	10736	9966	905	2303	10731	64	124.8	112.8
Incr. Pump Rate	Full rate	9943	10730	9947	570	5126	10753	85	84.5	324
Incr Q with Pc	Full rate	9974	10701	9939	735	3930	10727	59	95	276

8. CONCLUSION

This thesis investigated alternative initial responses and proper circulation methods for different kick scenarios resulting from the unintended bottomhole pressure fluctuations. This chapter presents the conclusions and some recommendations resulting from the analysis of the simulation runs made during the investigation. The following conclusions include the best well control methods for kicks taken due to surface equipment failures (e.g. RCD and pump failure) and unintended ECD reductions (e.g. pump efficiency loss, BHA position change).

8.1 Specific Kick Cause Conclusions

This section explains the best initial responses and circulation methods if the cause is known. RCD failure is an example of loss of surface pressure, and a pump failure represents a total loss of ECD. A pump efficiency loss is one example of an ECD reduction. A reduction in ECD due to BHA position change causing wellbore pressure drop opposite a given formation in the wellbore is another example of an ECD reduction.

8.1.1 RCD Failure

A SI response using the BOP, specifically followed by a pump start up schedule for normal circulating rate, is concluded to be the most appropriate well control method for kicks caused by loss of RCD failure. SI stops the formation flow successfully, and normal circulating rate reduces the NPT and surface pressure. However, the surface equipment must handle the maximum return rates that result from kick circulation at normal circulation rate and potential rapid gas migration. This response also applies to other causes of loss of surface pressure containment such as a choke wash out. In such a case, the BOP is closed and conventional SI is applied same as the RCD failure.

8.1.2 Pump Failure

A SI response by simply closing the choke, followed by a pump start up schedule for the normal circulating rate, is the most appropriate well control response to a pump failure. It stops the formation flow, and it is straightforward to apply. SI can also be applied when the cause of the inability to maintain the circulation is a failure in the power generating system.

Starting a new pump with a reduced choke opening is a new idea for an initial response that is concluded to be an opportunity as a well control option for kicks caused by pump failure. It minimizes the bottomhole pressure fluctuations and reduces the NPT relative to a SI response. It also reduces the period that the well stays static. However, the implementation procedure for this response requires further development. This response is not applicable if the cause of the pump failure is the power system failure.

8.1.3 Pump Efficiency Loss

A SI response by closing the choke, followed by a pump start up schedule for the normal circulating rate, is the most appropriate well control response to a pump efficiency loss. It also allows circulating the kick with a new pump, but the well is static during the pressure stabilization after SI. It has the same advantages and disadvantages as described in the previous section (8.1.2).

Starting a new pump with additional surface casing pressure is a new idea for an initial response that is concluded to be an opportunity as a well control option for kicks caused by pump efficiency loss. This response replaces a failing pump with a new one while providing continuous circulation. Along with continuous circulation, it reduces the pressure imposed on the surface equipment and casing shoe, reduces NPT and eliminates the period that the well stays static. However, it creates pressure fluctuations, and the operator must be able to control the failing and new pump at the same time.

8.1.4 BHA Position Change

Increasing the casing pressure until the measured flow out is equal to flow in is the most effective response for kicks caused by BHA position change. It provides continuous circulation and lower pressures versus the non-circulating responses. Although other circulating responses require schedules for reducing the pump rate to eliminate the bottomhole pressure increase after the kick reaches surface, the increased casing pressure response does not require any preliminary calculations. However, this response requires accurate flow out measurement.

A SI response followed by a pump start up schedule for normal circulating rate is concluded as a secondary well control option. It increases the final gain while the pump is being turned off. It has the same features as stated in 8.1.2.

8.2 Overall Conclusions

The following conclusions are derived from the overall simulation runs and analysis. These conclusions are related to kicks caused by bottomhole pressure reductions but they may also be effective for kicks caused by higher formation pressure.

1. SI is applicable for every kick scenario caused by bottomhole pressure reduction. It has several advantages. It is straightforward and the easiest initial response to implement. It does not require any flow measurement. It minimizes bottomhole pressure, which is desired if there is a weak zone at bottom. However, it typically gives higher pressure at casing shoe and at surface. It may result in significant pressure fluctuations during pump start up at casing shoe and at bottom.

It also requires turning the pumps off which accelerates the formation feed-in and may increase the kick size. It results in longer NPT than a typically circulating response.

2. Increasing the casing pressure is the most effective response if it is practical given the surface equipment and its condition. It minimizes the casing shoe and surface casing pressures and NPT relative to the SI response. It requires no preliminary calculation or schedule. Nevertheless, it requires metering of flow out (and flow in for pump efficiency loss). It also requires intact pressure containment equipment: RCD, choke.

3. Normal rate circulation following these responses is generally better than using an increased or slow pump rate for these kinds of kicks. It reduces the surface pressure and NPT versus slower pump rates. It does not require a pump rate reduction schedule like the increased rate circulation response does. The disadvantage relative to a slower pump rate is that the surface equipment must handle the high return rates. During kick circulation, drillpipe pressure should be maintained constant, and flow out should not be forced to be equal to flow in.

8.3 Conclusions Regarding Other Applicable Responses

1. An increased pump rate response can be advantageous depending on the conditions. It requires less surface casing pressure and reduces NPT relative to the other responses. It minimizes the risk of casing shoe failure. However, it does not necessarily stop the formation flow and can significantly increase risk during the attempt to stop the formation flow. Pump pressure and rate ratings limit its application in many situations. Surface equipment must handle the higher maximum return rate. It causes high bottomhole pressure depending on the location of the high pressure zone. It requires accurate flow out metering. It requires a schedule for pump rate reduction as kick is removed to maintain BHP.

2. MPD SD can be applied as an alternative to SI if the pit gain is very small when the kick is detected but has no advantage over SI. Its effectiveness depends on the overbalance tolerance of the bottomhole pressure that the MPD pump shut down is created with.

3. An automated MPD SD has advantage over manual MPD SD if the influx continues during the process because the automated MPD SD reduces the time that the well is underbalanced.

8.4 Recommendations

SNP w/Pc after a pump efficiency loss, starting a new pump with a reduced choke opening after a pump failure and the improved MPD SD responses are new ideas and their effectiveness and operational ease should be investigated. These responses should be demonstrated in a real well to observe and define general procedures. Bottomhole pressure fluctuations and operational practicality of the SNP w/Pc and SNP with a reduced choke opening should be investigated. The improved MPD SD that begins by increasing the casing pressure should be demonstrated to observe the pressure fluctuations in front of the casing shoe.

Two new related ideas were proposed by John Rogers Smith and Gerry Masterman in the LSU Petroleum Engineering department. The evaluation of these ideas is also recommended.

Smith suggested a method combining a normal shut-in reaction and a normal pump start up pressure schedule for responding to a pump failure. His method is as follows:

i. Begin closing the drilling choke to increase casing pressure as soon as a total pump failure is identified.

ii. Line up to circulate using a back-up pump as soon as practical.

iii. Engage the backup pump and begin circulating. Increase rate towards first rate in pump start up schedule.

iv. If CP is less than the first CP in the pump start up schedule, continue increasing the pump rate (and closing the choke if not fully closed). If CP is greater than the first CP in the schedule, open the choke more to reduce the CP to the target value.

v. Once pump rate and CP are adjusted to any step on the pump start up schedule, continue following the schedule.

vi. Once the pump rate has been returned to the normal circulating rate, expect DPP to stabilize at the target DPP. If not, kick volume may have reduced hydrostatic pressure in the annulus. If necessary, reduce choke opening to increase CP to force DPP at normal circulation rate to equal the target DPP.

vii. OPTION: If loss of hydrostatic is known (either from pit gain or from SICP being greater than the scheduled CP with pumps off), add the loss of hydrostatic to each CP on the pump start up schedule.

Gerry Masterman developed an idea for replacing a failing pump with a "new" pump while continuing circulation for the pump efficiency loss problem. His idea is as following:

i. Start 2nd pump and if necessary, increase rate until DPP = DPP circulating at full rate before pump problem

ii. As DPP increases above target DPP begin reducing rate on 1st pump

iii. As DPP decreases to near or below target DPP begin increasing rate on 2nd pump

iv. Repeat ii) and iii) until 1st pump is shut down and 2nd pump is at the original full circulating rate.

v. Expect DPP to stabilize at the target DPP. If not, kick volume may have reduced hydrostatic pressure in the annulus. If necessary, reduce choke opening to increase CP to force DPP at normal circulation rate to equal the target DPP.

Several upgrades to Dynaflodrill would be very advantageous. The numerical solution should be more stable. The version four of the software typically crashes when a large volume gas is at or near the surface. Inclusion of a formation fracture model to simulate loss scenarios is also recommended because any excessive surface casing pressure increase may break the formation and create lost returns, which increases the hydrostatic pressure loss. This effect cannot be studied with the version four of the software.

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APPENDIX A1: SIMULATOR INPUT DATA FOR WELL X

SURVEY

Survey section			
Md	**Inclination**	**Azimuth**	**Vertical depth**
[ft]	**[deg]**	**[deg]**	**[ft]**
0.00	0.0	0.0	0.00
88.00	0.0	0.0	88.00
170.00	0.0	0.0	170.00
2988.00	0.0	0.0	2988.00
3088.00	0.2	137.8	3088.00
3188.00	0.1	112.6	3188.00
3288.00	0.1	49.5	3288.00
3388.00	0.2	27.7	3388.00
3488.00	0.2	8.2	3488.00
3588.00	0.2	358.5	3588.00
3688.00	0.1	327.9	3688.00
3788.00	0.2	258.6	3788.00
3888.00	0.2	267.2	3888.00
3988.00	0.4	339.3	3988.00
4088.00	1.3	25.6	4087.99
4188.00	1.0	28.0	4187.97
4288.00	0.9	32.0	4287.95
4388.00	0.9	27.1	4387.94
4488.00	0.8	32.0	4487.93
4588.00	0.8	44.9	4587.92
4688.00	0.5	56.8	4687.91
4788.00	0.5	66.3	4787.91
4888.00	0.3	84.0	4887.91
4988.00	0.2	123.1	4987.90
5088.00	0.4	134.5	5087.90
5188.00	0.5	153.4	5187.90
5288.00	0.7	167.6	5287.90
5388.00	0.5	179.1	5387.89

5488.00	0.4	189.6	5487.89
5588.00	1.3	161.6	5587.88
5688.00	1.1	148.3	5687.85
5788.00	1.2	143.0	5787.83
5888.00	0.8	123.1	5887.82
5988.00	0.8	121.4	5987.81
6088.00	0.9	112.1	6087.80
6188.00	1.2	107.7	6187.78
6288.00	1.1	71.2	6287.76
6388.00	0.9	55.1	6387.75
6488.00	1.2	59.7	6487.73
6588.00	1.2	63.1	6587.71
6688.00	1.3	59.3	6687.68
6788.00	1.2	62.2	6787.66
6888.00	1.4	72.3	6887.63
6988.00	1.3	74.3	6987.61
7088.00	1.2	72.6	7087.58
7188.00	1.2	67.3	7187.56
7288.00	1.4	61.6	7287.53
7388.00	1.3	61.7	7387.51
8173.00	0.1	205.1	8172.45
8263.00	0.1	275.5	8262.45
8353.00	1.6	58.5	8352.43
8443.00	3.5	53.5	8442.34
8533.00	5.2	53.8	8532.08
8623.00	6.2	54.8	8621.63
8713.00	7.5	51.6	8710.99
8803.00	8.6	54.8	8800.10
8893.00	10.0	51.7	8888.92
8983.00	11.3	48.6	8977.37
9074.00	12.5	47.4	9066.41
9164.00	13.9	48.0	9154.03
9254.00	15.5	47.7	9241.08
9344.00	17.0	47.5	9327.48
9437.00	18.0	47.7	9416.18
9528.00	19.3	47.4	9502.40
9618.00	20.8	46.9	9586.94

9711.00	21.7	47.2	9673.61
9801.00	22.4	47.5	9757.03
9893.00	23.5	48.3	9841.75
9984.00	24.9	48.3	9924.75
10074.00	26.4	48.8	10005.88
10166.00	26.7	49.1	10088.18
10257.00	27.0	49.1	10169.36
10349.00	27.7	49.2	10251.08
10439.00	28.3	49.5	10330.55
10532.00	29.4	50.4	10412.00
10623.00	30.9	50.4	10490.69
10714.00	32.1	50.0	10568.28
10804.00	33.3	50.5	10644.01
10895.00	34.4	50.0	10719.59
10986.00	35.5	49.8	10794.17
11076.00	36.6	49.4	10866.94
11165.00	37.0	49.3	10938.20
11255.00	37.4	49.4	11009.89
11345.00	37.6	49.2	11081.29
11435.00	38.0	49.4	11152.41
11525.00	38.5	49.2	11223.08
11616.00	38.8	49.3	11294.15
11707.00	39.4	49.4	11364.77
11798.00	39.7	49.4	11434.94
11890.00	40.1	49.4	11505.52
11982.00	40.4	49.8	11575.74
12074.00	40.3	49.9	11645.85
12164.00	40.6	49.7	11714.34
12254.00	40.8	50.0	11782.57
12346.00	40.9	50.0	11852.16
12437.00	40.6	50.2	11921.10
12531.00	40.6	50.4	11992.47
12631.00	40.5	50.2	12068.45
12713.00	40.4	50.8	12130.85
12805.00	40.2	50.6	12201.02
12900.00	40.5	50.8	12273.42
12994.00	40.6	51.0	12344.84

13175.00	41.0	50.9	12481.86
13270.00	41.0	51.1	12553.56
13360.00	41.1	51.0	12621.43
13451.00	41.0	50.9	12690.06
13545.00	41.0	50.6	12761.00
13637.00	41.2	50.7	12830.33
13727.00	41.5	50.8	12897.89
13818.00	41.4	50.9	12966.10
13910.00	41.2	51.0	13035.21
14002.00	40.8	50.7	13104.65
14033.00	40.7	51.0	13128.13
14141.00	41.1	50.7	13209.76
14233.00	40.8	51.3	13279.25
14323.00	40.7	51.2	13347.43
14413.00	40.4	51.1	13415.82
14503.00	39.9	51.3	13484.61
14592.00	40.0	51.0	13552.84
14682.00	40.1	51.0	13621.73
14772.00	40.4	51.4	13690.42
14862.00	40.1	51.5	13759.11
14951.00	40.1	51.7	13827.19
15042.00	40.1	51.7	13896.80
15132.00	40.2	52.1	13965.59
15170.00	40.2	52.2	13994.62
15193.00	41.6	54.4	14012.01
15200.00	41.6	54.4	14017.24
15243.00	41.6	54.4	14049.37
15300.00	41.1	55.3	14092.16
15400.00	40.1	56.8	14168.12
15443.00	39.6	57.4	14201.13
15500.00	40.7	59.0	14244.70
15600.00	42.5	61.5	14319.49
15700.00	44.4	63.9	14392.08
15750.73	45.4	65.1	14428.01
15800.00	44.9	63.4	14462.76
15900.00	44.0	60.1	14534.12
16000.00	43.3	56.7	14606.49

16021.30	43.1	55.9	14622.02
16100.00	43.1	55.9	14679.49
16200.00	43.1	55.9	14752.50
16300.00	43.1	55.9	14825.52
16400.00	43.1	55.9	14898.54
16500.00	43.1	55.9	14971.55
16580.04	43.1	55.9	15029.99
16600.00	43.1	55.9	15044.57
16700.00	43.1	55.9	15117.58
16780.04	43.1	55.9	15176.03
16800.00	43.4	55.9	15190.56
16900.00	44.9	55.9	15262.31
16982.30	46.1	55.9	15319.98
17000.00	46.1	55.9	15332.25
17100.00	46.1	55.9	15401.55
17200.00	46.1	55.9	15470.85
17300.00	46.1	55.9	15540.16
17400.00	46.1	55.9	15609.46
17500.00	46.1	55.9	15678.76
17600.00	46.1	55.9	15748.06
17674.95	46.1	55.9	15800.01

WELLBORE GEOMETRY

Startup conditions		
Target depth	[ft]	17700.00

Casing program				
Name	**Hanger depth**	**Setting depth**	**Inner diameter**	**Outer diameter**
	[ft]	**[ft]**	**[in]**	**[in]**
7" T95 32.0 lbs/ft	0.00	15150.00	6.094	7.000

Open hole section	
Length	Diameter
[ft]	[in]
1832.00	6.000

STRING

Drillstring		
Drillstring type:		Drillpipe
Average stand length	[ft]	30.00

Component section				
Component	Type	Section length	Inner diameter	Outer diameter
		[ft]	[in]	[in]
DC 4 3/4" NC 35-37	DrillCollar	250.00	2.500	4.750
HWDP 3 1/2" NC38(3 1/2 IF)	Drillpipe	450.00	2.063	3.500
dp 3 1/2" S135 15.50 lb/ft	Drillpipe	16282.00	2.602	3.500

Bit: Bit 6"		
Name:		Bit 6"
Outer diameter	[in]	6.000
Flow area	[in2]	0.37

Bit nozzles
Diameter
[1/32 in]
11
11
11
11

SURFACE EQUIPMENT

Choke		
Inner diameter	[in]	3.000
Closure time	[min]	0.33
Choke control:		Opening
Working pressure	[psi]	14.7000

Pump		
Liquid rate change	[RateChange]	0.0015772545
Volumetric output	[PumpCapacity]	0

BOP		
Closure time	[min]	0.08

INJECTION SYSTEM

Injection system	
Check valve installed:	no

Drillstring injection	
Active:	yes

Gas		
Density	[gas gravity]	1.00
N2	[0-1]	0.75
CO2	[0-1]	0.25
Hydrocarbon	[0-1]	0.00
H2S	[0-1]	0.00

Annulus injection	
Active:	no

MUD

Fluid: LSU_WellX		
Name:		LSU_WellX
Base oil density	[lbm/USgal]	7.3022
Water density	[lbm/USgal]	8.3454
Solids density	[lbm/USgal]	35.0507
Density	[lbm/USgal]	13.20
Reference temperature	[Fahrenheit]	90.00
Fluid type:		Liquid
Oil water ratio:		0/100
Rheology type:		Non-Newtonian; Fann tables
Pvt model:		Black oil

Fann reading	
Shear rate	**Shear stress**
[rpm]	**[lbf/100ft2]**
600.0	47
300.0	26
200.0	17
100.0	11
6.0	3
3.0	2

RESERVOIR

Cuttings	
Hole cleaning criterion:	MaxConcentration
Max concentration	0.04

Lithology							
Name	**Top**	**Bottom**	**Reservoir type**	**Pressure**	**Temperature**	**Reservoir fluid**	**Flow model**
	[ft]	**[ft]**		**[psi]**	**[Fahrenheit]**		
Form 1	15150.00	16265.00	Matrix	8723.0000	145.00	Gas	Reservoir model
HP Sand	16265.00	16401.00	Matrix	10544.0000	155.81	Gas	Reservoir model
Form 2	16401.00	16982.30	Matrix	9297.0000	157.17	Gas	Reservoir model
LP Sand	16982.30	17101.00	Matrix	8763.0000	162.93	Gas	Reservoir model

Layer		
Density	[lbm/USgal]	0.01

Water		
Density	[lbm/USgal]	8.4289
Compressibility	[psi-1]	7.58E-08
Volume factor		1
Viscosity	[cp]	2.00

Oil		
Density	[lbm/USgal]	7.4691
Compressibility	[psi-1]	1.38E-06
Volume factor		1.1
Viscosity	[cp]	2.00

Gas		
Density	[gas gravity]	0.65
N2	[0-1]	0.00
CO2	[0-1]	0.00
Hydrocarbon	[0-1]	1.00
H2S	[0-1]	0.00

TEMPERATURE

Drillstring temperature	
Depth	Temperature
[ft]	[Fahrenheit]
0.00	85.00
17700.00	170.00

Annulus temperature	
Depth	Temperature
[ft]	[Fahrenheit]
0.00	90.00
17700.00	170.00

OPTIONAL INPUT

Operation	
Grid cell count	80

Well	
Open hole roughness	0.099996
Steel roughness	0.0018

Sub models	
Pressure loss model:	Semi-empirical
Gas density model:	Hall-Yarborough
Friction factor model:	Dodge-Metzner
Rheology model:	Robertson-Stiff

Surface equipment		
Working pressure	[psi]	14.7000

APPENDIX A2: SIMULATOR INPUT DATA FOR WELL Y

SURVEY

Survey section			
Md	Inclination	Azimuth	Vertical depth
[ft]	[deg]	[deg]	[ft]
0.00	0.0	0.0	0.00
14960.00	0.0	0.0	14960.00
15865.00	0.0	0.0	15865.00
16000.00	0.0	0.0	16000.00

WELLBORE GEOMETRY

Startup conditions		
Target depth	[ft]	16180.00

Casing program				
Name	Hanger depth	Setting depth	Inner diameter	Outer diameter
	[ft]	[ft]	[in]	[in]
14" 106.7lbs/ft	0.00	13780.00	12.500	14.000

Open hole section	
Length	Diameter
[ft]	[in]
1210.00	12.250

STRING

Drillstring		
Drillstring type:		Drillpipe
Average stand length	[ft]	90.00

Component section				
Component	**Type**	**Section length**	**Inner diameter**	**Outer diameter**
		[ft]	**[in]**	**[in]**
DC 8 "	DrillCollar	400.00	2.750	8.000
HWDP 6 5/8"	Drillpipe	280.00	4.000	6.625
dp 6 5/8" G105 27.70 lb/ft	Drillpipe	14310.00	5.902	6.626

Bit: Bit 12 1/4		
Name:		Bit 12 1/4
Outer diameter	[in]	12.250
Flow area	[in2]	0.97

Bit nozzles
Diameter
[1/32 in]
13
13
13

SURFACE EQUIPMENT

Pump		
Liquid rate change	[RateChange]	0.0015772545
Volumetric output	[PumpCapacity]	0.001

BOP		
Closure time	[min]	0.08

INJECTION SYSTEM

Injection system	
Check valve installed:	no

Drillstring injection	
Active:	yes

Gas		
Density	[gas gravity]	1.00
N2	[0-1]	0.75
CO2	[0-1]	0.25
Hydrocarbon	[0-1]	0.00
H2S	[0-1]	0.00

Annulus injection	
Active:	no

MUD

Fluid: Water Based Mud Well Y		
Name:		Water Based Mud Well Y
Base oil density	[lbm/USgal]	7.3022
Water density	[lbm/USgal]	8.3454
Solids density	[lbm/USgal]	35.0507
Density	[lbm/USgal]	17.20
Reference temperature	[Fahrenheit]	117.00
Fluid type:		Liquid
Oil water ratio:		0/100
Rheology type:		Non-Newtonian; Fann tables
Pvt model:		Black oil

Fann reading	
Shear rate	**Shear stress**
[rpm]	**[lbf/100ft2]**
600.0	124
300.0	72
200.0	52
100.0	33
6.0	11
3.0	10

RESERVOIR

Cuttings	
Hole cleaning criterion:	MaxConcentration
Max concentration	0.1

Lithology							
Name	**Top**	**Bottom**	**Reservoir type**	**Pressure**	**Temperature**	**Reservoir fluid**	**Flow model**
	[ft]	**[ft]**		**[psi]**	**[Fahrenheit]**		
Sand 1	14960.00	14991.00	Matrix	13458.0000	360.00	Gas	Reservoir model

Layer		
Density	[lbm/USgal]	35.00

Water		
Density	[lbm/USgal]	8.3454
Compressibility	[psi-1]	7.58E-08
Volume factor		1
Viscosity	[cp]	2.00

Oil		
Density	[lbm/USgal]	7.3022
Compressibility	[psi-1]	1.30E-08
Volume factor		1
Viscosity	[cp]	2.00

Gas		
Density	[gas gravity]	0.65
N2	[0-1]	0.00
CO2	[0-1]	0.00
Hydrocarbon	[0-1]	1.00
H2S	[0-1]	0.00

TEMPERATURE

Drillstring temperature	
Depth	**Temperature**
[ft]	**[Fahrenheit]**
0.00	113.00
1066.00	121.00
2049.00	127.00
3033.00	134.00
4016.00	140.00
5000.00	147.00
6066.00	154.00
7049.00	160.00
8033.00	166.00
9016.00	172.00
10000.00	177.00
11024.00	181.00
12048.00	185.00
13071.00	188.00
14030.00	191.00
14960.00	200.00

Annulus temperature	
Depth	Temperature
[ft]	[Fahrenheit]
0.00	146.00
1066.00	157.00
2049.00	166.00
3033.00	176.00
4016.00	184.00
5000.00	192.00
6066.00	199.00
7049.00	204.00
8033.00	208.00
9016.00	211.00
10000.00	212.00
11024.00	211.00
12048.00	210.00
13071.00	207.00
14030.00	204.00
14960.00	201.00

OPTIONAL INPUT

Operation	
Grid cell count	80

Well	
Open hole roughness	0.1
Steel roughness	0.01

Sub models	
Pressure loss model:	Semi-empirical
Gas density model:	Hall-Yarborough
Friction factor model:	Dodge-Metzner
Rheology model:	Robertson-Stiff

APPENDIX A3: SIMULATION RESULTS

Table 15: RCD failure, initial response results in Well X for 21 bbl kick

Initial gain: 21 bbl	Cause: RCD Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10206	10221	740	900	21.8	10900	11072
Normal Circ. @190 gpm	9958	9958	15	15	-	11001	11001

Table 16: RCD failure, circulation results in Well X for 21 bbl kick

Cause: RCD Failure											
gain: 21 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP, (max) psi	BHP variation (max) psi	NPT, (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10221	11072	10227	947	2860	11086	77	120	233
SI	Half rate	10221	11072	10227	1153	1182	11087	78	190	113

Table 17: RCD failure, initial response results in Well X for 4 bbl kick

Initial gain: 4 bbl	Cause: RCD Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10030	10030	409	422	4	10881	10897
Normal Circ. @190 gpm	9958	9958	15	15	-	11001	11001

Table 18: RCD failure, circulation results in Well X for 4 bbl kick

Cause: RCD Failure										
gain: 4 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10030	10897	10176	529	2860	11087	78	119.8	206
	Half rate			10176	529	1178	11087	78	184.5	103

Table 19: RCD failure, initial response results in Well Y for 20 bbl kick

Initial gain: 20 bbl	Cause: RCD Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12578	12578	382	415	20.7	13480	13517
Normal Circ. @760 gpm	12376	12376	15	15	-	13489	13489

Table 20: RCD failure, circulation results in Well Y for 20 bbl kick

Cause: RCD Failure										
gain: 20 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12578	13517	12586	503	3667	13552	63	121	879
	Half rate			12586	568	1285	13553	64	190	450

Table 21: RCD failure, initial response results in Well Y for 2 bbl kick

Initial gain: 2 bbl	Cause: RCD Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12408	12411	210	214	2.2	13472	13746
Normal Circ. @760 gpm	12376	12376	15	15	-	13489	13489

Table 22: RCD failure, circulation results in Well Y for 2 bbl kick

Cause: RCD Failure											
gain: 2 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12411	13476	12456	233	3660	13535	46	113	782
	Half rate			12456	233	1263	13535	46	176	401

Table 23: Pump failure, initial response results in Well X for 20.2 bbl kick

Initial gain: 20.2 bbl	Cause: Pump Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10205	10220	714	876	20.4	10897	11073
Start up new pump with Pc	10159	10213	384	397	21.5	10990	11028
Normal Circ. @ 190 gpm	9958	9958	15	15	-	11009	11009

Table 24: Pump failure, circulation results in Well X for 20.2 bbl kick

Cause: Pump Failure										
gain: 20.2 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10220	11073	10233	903	2860	11096	87	120	230
	Half rate			10233	1119	1182	11096	87	189	114
SNP w/Pc	Full rate	10213	11028	10024	957	2889	11065	56	107	231

Table 25: Pump failure, initial response results in Well X for 3.4 bbl kick

Initial gain: 3.4 bbl	Cause: Pump Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10017	10017	397	407	3.4	10881	10895
Start up new pump with Pc	10022	10042	96	104	3.9	10997	11050
Normal Circ. @ 190 gpm	9958	9958	15	15	-	11009	11009

Table 26: Pump failure, circulation results in Well X for 3.4 bbl kick

Cause: Pump Failure										
gain: 3.4 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10017	10895	10146	460	2849	11068	59	118	230
	Half rate			10146	493	1180	11063	54	181	114
SNP w/Pc	Full rate	10042	11050	10004	308	2881	11056	47	106	205

Table 27: Pump failure, initial response results in Well Y for 20 bbl kick

Initial gain: 20 bbl	Cause: Pump Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12561	12562	358	388	22	13472	13502
Start up new pump with Pc	12548	12548	204	206	24	13473	13498
Normal Circ. @ 760 gpm	12376	12376	15	15	-	13473	13498

Table 28: Pump failure, circulation results in Well Y for 20 bbl kick

Cause: Pump Failure											
gain: 20 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12562	13502	12575	473	3666	13533	44	118	874
	Half rate			12575	531	1273	13533	44	188	443
SNP w/Pc	Full rate	12548	13498	12410	549	3665	13524	35	103	870

Table 29: Pump failure, initial response results in Well Y for 3 bbl kick

Initial gain: 3 bbl	Cause: Pump Failure						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12408	12412	209	215	4.8	13473	13478
Start up new pump with Pc	12413	12447	71	85	3.6	13508	13550
Normal Circ. @ 760 gpm	12376	12376	15	15	-	13473	13498

Table 30: Pump failure, circulation results in Well Y for 3 bbl kick

Cause: Efficiency Loss											
gain: 3 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12412	13478	12427	218	3653	13511	22	111	782
	Half rate			12427	278	1252	13508	19	174	394
SNP w/Pc	Full rate	12447	13550	12436	124	3691	13550	61	98	780

Table 31: Pump efficiency loss, initial response results in Well X for 15 bbl kick

Initial gain: 15 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	Pcasing, flow stop	Pcasing, max	Gain, bbl	P bottom, psi	P bottom, (max) psi
SI	10070	10083	633.8	690	16.2	10886	10941
Manual MPD SD	10187	10258	1092	1312	41.5	10903	11113
Auto. MPD SD	10101	10156	780	889	23.5	10903	11016
Manual MPD SD w/add Pc	10054	10197	821	871	16.2	10991	11122
Auto MPD SD w/add Pc	10140	10240	831	881	16	10991	11143
Incr. P casing stepwise	10086	10086	400	420	16.3	11040	11059
Incr. Pump Rate	9932	10006	15	15	15	11068	11072
Start up new pump with Pc	10036	10102	330	300	16	10994	11092
SNP w/o flow meter	10045	10045	536	565	31	10992	11017
SNP w/Pc, w/o flow meter	10046	10058	322	322	16.8	10994	11068
Corr. Pump Rate with Pc	10076	10080	330	330	16	11040	11061
Normal Circ.@ 190 gpm	9948	9948	15	15	0	11001	11001

Table 32: Pump efficiency loss, circulation results in Well X for 15 bbl kick

Cause: Efficiency Loss										
gain: 15 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10083	10941	10152	740	3009	11054	92	118	204
	Half rate			10152	951	1293	11054	92	180.5	100
a. MPD SD w/Pc	Full rate	10240	11143	10256	886	3034	11170	167	122	219
	Half rate			10256	960	1348	11170	168	189	109
Incr. P casing	Full rate	10086	11059	10045	820	2635	11079	78	109	180
Incr. Pump Rate	Full rate	10006	11072	9976	506	5173	11099	98	95	320
SNP w/Pc	Full rate	10102	11092	9997	715	3001	11050	48	109	222
SNP w/Pc,w /o flow	Full rate	10058	11068	10015	742	3041	11068	67	109	223
Corr. Q with Pc	Full rate	10080	11061	9990	720	3018	11019	17	101	203

Table 33: Pump efficiency loss, initial response results in Well X for 2 bbl kick

Initial gain: 2 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	Pcasing, flow stop	Pcasing, max	Gain, bbl	P bottom, psi	P bottom, (max) psi
SI	9999	10000	401	411	2.95	10886	10900
Manual MPD Pump SD	10103	10110	524	533	2.12	11030	11038
Auto. MPD Pump SD	10107	10115	513	522	2	11022	11029
Incr. P casing	9969	9977	100	100	2	10978	10999
Incr. Pump Rate	9943	9950	15	15	2	10996	10996
SNP w/Pc w/o flow in meter	9953	9983	45	45	1.84	11000	11040
Corr. Q with Pc	9967	9976	50	50	1.91	10998	11019
Corr. Q then Pc	9967	9978	51	52	1.96	10972	11022
Normal Circ. @190 gpm	9948	9948	15	15	-	11001	11001

Table 34: Pump efficiency loss, circulation results in Well X for 2 bbl kick

Cause: Efficiency Loss											
gain: 2 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	10000	10900	10120	487	2999	11055	54	118	204
	Half rate			10120	487	1291	11055	54	180	108
Auto. MPD SD	Full rate	10115	11052	10130	527	2994	11074	73	113	224
	Half rate			10130	527	1300	11063	62	171	110
Incr. P casing	Full rate	9977	10999	9972	225	2566	11007	6	109	180
Incr. Pump Rate	Full rate	9950	10996	9969	159	3088	11025	23	99	207
SNP Pc w/o meter	Full rate	9983	11040	9969	170	2994	11019	18	101	203
Corr. Q with Pc	Full rate	9976	11019	9969	170	2995	11019	18	101	203
Corr. Q then Pc	Full rate	9978	11022	9970	184	2998	11024	23	101	201

Table 35: Pump efficiency loss, initial response results in Well Y for 20 bbl kick

Initial gain: 20 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	12557	12591	423	473	30	13475	13528
Manual MPD SD	12872	13286	1614	2221	185	13514	14208
Auto. MPD SD	12685	12719	652	756	51.9	13656	13531
Manual MPD SD w/add. Pc	12580	12621	509	560	24	13629	13684
Auto. MPD SD w/add. Pc	12631	12651	508	550	24	13615	13662
Incr. P casing stepwise	12522	12533	250	250	23	13505	13547
Start up new pump with Pc	12517	12572	259	259	22	13480	13597
Corr. Q with Pc	12524	12578	259	259	22	13592	13592
Normal Circ @ 760 gpm	12376	12376	15	15	-	13489	13489

Table 36: Pump efficiency loss, circulation results in Well Y for 20 bbl kick

Cause: Efficiency Loss											
gain: 20 bbl		Initial Response		Circulation							
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12591	13528	12591	538	3660	13540	51	128	852
	Half rate			12591	604	1265	13540	51	204	428
Incr. Pc stepwis	Full rate	12533	13547	12446	515	3098	13556	67	124	894
SNP w/Pc	Full rate	12572	13597	12478	498	3741	13589	100	107	922
Corr. Q with Pc	Full rate	12578	13592	12485	535	3732	13593	104	104	906

Table 37: Pump efficiency loss, initial response results in Well Y for 2.12 bbl kick

Initial gain: 2.12 bbl	Cause: Loss of Pump Efficiency						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing, psi	P casing, (max) psi	Gain, bbl	P bottom, psi	P bottom, (max) psi
SI	12437	12443	238	250	8.1	13472	13484
Manual MPD SD	12440	12446	247	252	4	13517	13533
Auto. MPD SD	12441	12446	243	249	4	13513	13535
Incr. P casing stepwise	12440	12440	100	100	1.9	13540	13542
Incr. Pump Rate	12370	12370	15	15	2.3	13473	13474
Start up new pump with Pc	12421	12431	67	67	1.5	13535	13544
Correcting Q with Pc	12426	12429	67	67	1.4	13535	13535
Normal Circ. @ 760 gpm	12376	12376	15	15	-	13489	13489

Table 38: Pump efficiency loss, circulation results in Well Y for 2.12 bbl kick

Cause: Efficiency Loss										
gain: 2.12 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP (max) psi	BHP variation (max) psi	NPT (I.R.+Cir.) min	Flow out (max) gpm
SI	Full rate	12443	13484	12451	252	3657	13527	38	114	804
	Half rate			12451	257	1255	13511	22	181	408
Incr. P casing	Full rate	12440	13541	12439	140	3092	13548	59	104	695
Incr. Pump Rate	Full rate	12370	13474	12399	94	3577	13512	65	98	774
SNP w/Pc	Full rate	12431	13544	12421	87	3676	13534	45	95	802
Corr. Q with Pc	Full rate	12429	13535	12426	87	3676	13535	46	96	812

Table 39: BHA position change, initial response results in Well X for 20 bbl kick

Initial gain: 20 bbl	Cause: ECD reduction due to BHA position change						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	10100	10149	792	868	21.9	10692	10778
Manual MPD Pump SD	10232	10366	1283	1575	48.8	10664	10975
Auto. MPD Pump SD	10138	10231	908	1071	29	10666	10849
MPD Pump Shut D w/Pc	10042	10097	796	868	21.8	10719	10783
Auto. MPD Pump SD w/ Pc	10087	10133	800	875	21.6	10729	10799
Incr. Casing Pressure	10016	10051	473	500	21.9	10702	10736
Incr. Pump Rate	9922	9943	15	15	20	10712	10730
Incr Q with Pc	9940	9974	200	200	21.5	10700	10701
Normal Circ. @160 gpm	9884	9884	15	15	-	10668	10668

Table 40: BHA position change, circulation results in Well X for 20 bbl kick

Cause: ECD reduction due to BHA position change										
gain: 20 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP, (max) psi	BHP variation (max) psi	NPT, (I.R.+Cir.) min	Flow out, (max), gpm
SI	Full rate	10149	10778	10143	907	2260	10774	89	140	181
	Half rate			10143	1046	1020	10774	89	200	108
a. MPD SD w/Pc	Full rate	10133	10799	10078	889	2272	10764	96	136	186
	Half rate			10078	1032	1300	10794	96	212	110
Incr. P casing stepwi.	Full rate	10051	10736	9966	905	2303	10731	64	124.8	112.8
Incr. Pump Rate	Full rate	9943	10730	9947	570	5126	10753	85	84.5	324
Incr Q with Pc	Full rate	9974	10701	9939	735	3930	10727	59	95	276

Table 41: BHA position change, initial response results in Well X for 2 bbl kick

Initial gain: 2 bbl	Cause: ECD reduction due to BHA position change						
Initial Responses	Pw @shoe flow stop	Pw@shoe (max) psi	P casing psi	P casing (max) psi	Gain bbl	P bottom psi	P bottom (max) psi
SI	9993	9995	395	406	2.7	10644	10659
Manual MPD Pump SD	9984	10010	401	412	2.6	10665	10706
Auto. MPD Pump SD	9993	10017	400	410	2.1	10673	10710
MPD Pump Shut D w/Pc	10036	10045	450	460	2.1	10725	10765
Auto. MPD Pump SD w/ Pc	10043	10067	450	460	2	10724	10763
Incr. Casing Pressure stepw	9946	9956	100	100	2	10692	10712
Incr. Pump Rate	9904	9906	15	15	2	10663	10675
Incr Q with Pc	9914	9916	50	50	2	10667	10676
Normal Circ. @160 gpm	9884	9884	15	15	-	10668	10668

Table 42: BHA position change, circulation results in Well X for 2 bbl kick

Cause: ECD reduction due to BHA position change										
gain: 2 bbl		Initial Response		Circulation						
Initial Response	Circulation study	Max Pres @shoe in response	Max Pres @BH in response	Pw @shoe (max)psi	Pcasing (max) psi	Pump P (max) psi	BHP, (max) psi	BHP variation (max) psi	NPT, (I.R.+Cir.) min	Flow out, (max), gpm
SI	Full rate	9995	10659	10028	409	2259	10706	38	115	170
	Half rate			10028	409	1000	10706	38	196	116
a. MPD SD w/Pc	Full rate	10067	10763	10064	459	2261	10764	96	123	184
	Half rate			10066	459	1005	10766	98	188	97
Incr. P casing stepw	Full rate	9956	10712	9949	195	2282	10712	44	111	170
Incr. Pump Rate	Full rate	9906	10675	9922	168	2560	10696	28	106	186
Incr Q with Pc	Full rate	9916	10676	9929	190	2361	10696	28	108	176

VITA

Hakan Guner was born in Izmir, Turkey, in March, 1983. He received his Bachelor of Science degree in Petroleum and Natural Gas Engineering Department in 2006 from Middle East Technical University, Ankara, Turkey. After graduated from Middle East Technical University, he was awarded a Master of Science scholarship by Turkish Petroleum Corporation. He then attended Louisiana State University in Baton Rouge, Louisiana, where he is currently pursuing his Master of Science in Petroleum Engineering. His research interests include drilling engineering, managed pressure drilling and well control.