A NEW APPROACH TO REDUCE THE FORMATION FLUID INVASION DURING WELL CONTROL OPERATIONS

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

GAZEL TEKDAL

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

AUGUST 2019

Approval of the thesis:

A NEW APPROACH TO REDUCE THE FORMATION FLUID INVASION DURING WELL CONTROL OPERATIONS

submitted by **GAZEL TEKDAL** in partial fulfillment of the requirements for the degree of **Master of Science in Petroleum and Natural Gas Engineering Department, Middle East Technical University** by,

Prof. Dr. Halil Kalıpçılar
Dean, Graduate School of **Natural and Applied Sciences** _______________

Assoc. Prof. Dr. Çağlar Sınayuç
Head of Department, **Petroleum and Natural Gas Eng.** _______________

Prof. Dr. Mahmut Parlaktuna
Supervisor, **Petroleum and Natural Gas Eng., METU** _______________

Examining Committee Members:

Assoc. Prof. Dr. Çağlar Sınayuç
Petroleum and Natural Gas Engineering Dept., METU _______________

Prof. Dr. Mahmut Parlaktuna
Petroleum and Natural Gas Eng., METU _______________

Assist. Prof. Dr. Ali Ettehadi
Petroleum and Natural Gas Engineering Dept., IKCU _______________

Date: 19.08.2019

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Surname: Gazel Tekdal

Signature:

ABSTRACT

A NEW APPROACH TO REDUCE THE FORMATION FLUID INVASION DURING WELL CONTROL OPERATIONS

Tekdal, Gazel
Master of Science, Petroleum and Natural Gas Engineering
Supervisor: Prof. Dr. Mahmut Parlaktuna

August 2019, 114 pages

Well control technique is particularly important in oil and gas operations such as drilling, well work over, and well completions because of higher drilling costs, waste of natural resources, and the possible loss of lives of rig personnel.

It is known very well that the larger the volume of influx, the more difficult to bring the well under control.

The aim of this study is to lessen volume of influx from the formation by shut-in the well with a new well control approach. This approach is based on decreasing the difference between the formation pressure and the bottom-hole pressure by pumping drilling mud after shut-in. A multiphase dynamic well control simulator has been used to demonstrate results of study.

It was observed that when this new approach was applied, the volume of formation fluid invasion and stabilization time decrease.

Keywords: Well Control, Influx, Simulation, Well Shut-In

ÖZ

KUYU KONTROL OPERASYONLARINDA FORMASYON AKIŞKAN GİRİŞİNİ AZALTMAK İÇİN YENİ BİR YAKLAŞIM

Tekdal, Gazel
Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği
Tez Danışmanı: Prof. Dr. Mahmut Parlaktuna

Ağustos 2019, 114 sayfa

Kuyu kontrol tekniği özellikle sondaj ve kuyu tamamlama gibi petrol ve doğal gaz operasyonlarında yüksek sondaj maliyetleri, doğal kaynak israfı ve kule personelinin can kaybı olasılığı nedeniyle önemlidir. Formasyondan kuyuya giren akışkan hacmi ne kadar fazla ise, kuyunun tekrar kontrol altına alınmasının daha zor olduğu çok iyi bilinmektedir.Bu çalışmanın amacı kuyunun kapatılmasından sonra formasyon akışkan girişinin yeni bir kuyu kontrol yaklaşımı ile azaltılmasıdır.

Bu yaklaşım kapama işleminden sonra kuyu içine sondaj çamuru pompalayarak formasyon basıncı ile kuyudibi basıncı arasındaki farkı azaltmaya dayanır. Çalışmanın sonuçlarını göstermek için çok fazlı dinamik bir kuyu kontrol simülatörü kullanılmıştır.

Bu yeni yaklaşım uygulandığında, toplam giren akışkan hacminin ve stabilizasyon süresinin azaldığı gözlenmiştir.

Anahtar Kelimeler: Kuyu Kontrolü, Formasyon Akışkan girişi, Simülasyon, Kuyu Kapama

To My Family,

ACKNOWLEDGEMENTS

I would like to express my sincere gratitude to my supervisor Prof. Dr. Mahmut Parlaktuna for his helpful guidance and encouragement throughout my graduate study.

I would like to thank Ayşe Filiz Şahin and Tevhide Tuğba Uyar for their encouragement.

I would like to thank my colleagues and friends Ayşenur Mazlum Üstün and Saniye Günal for their encouragement.

It is a pleasure to thank my colleagues, Muzaffer Görkem Gökdemir, İlker Yücel Öğrenmiş and Gökçe Güven in TPAO Well Control Center for supporting me and for their understanding. I would like to thank Clive Battisby from Drilling System for his valuable feedback.

I want to thank the Turkish Petroleum Corporation for permission for using simulator.

I wish to express my deepest gratitude to my family for their love, support and encouragement.

Finally, I would like to state my sincere thanks to my dearest husband, Mazlum Tekdal for his support, encouragement, understanding and patience and to our sweet daughter, Piraye for her presence in our life.

TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

CHAPTER 1

INTRODUCTION

A Well control is the technique used in oil and gas operations. During conventional drilling, the general application is maintaining hydrostatic pressure higher than formation pressure but not exceeding the fracture pressure. If the hydrostatic pressure is lower than the formation pore pressure, there is a possible risk of kick. “Kick is the uncontrolled flow of formation fluid into the wellbore and occurs when primary well control is lost” [1].

The larger kick volume cause high surface pressure and makes it difficult controlling the kick. Also higher kick volume can lead to uncontrolled blowout which increases the possibility of injury and potential loss of life, a failure of surface equipment, higher drilling costs and waste of natural resources.

When a kick occurs, the well must be shut-in instantly to stop the influx of formation fluid into the wellbore. When the well is shut-in to prevent any further fluid, pressure rises at the surface because of formation fluid entry into the annulus, as well as because of the difference between the bottom-hole pressure and the formation pressure.

In this study, the aim is to lessen volume of influx from the formation after shut-in the well with a new well control approach. A new well control approach is based on decreasing the difference between the formation pressure and the bottom-hole pressure by pumping drilling mud after shut-in. This methodology provides us reducing the volume of influx that enter the wellbore.

A multiphase dynamic well control simulator has been used to demonstrate how influx volumes can be reduced. The inspired paper when the determining the topic of this study is *“Method of Rapid Stabilizing Shut-In Drill Pipe Pressures for Blowout Wells*” by Xiangfang, Tao and Xiuxiang (2000).

According to Darcy's Law, several parameters like permeability, viscosity, and length of section open to wellbore, radius of wellbore and pressure of formation affect the severity of a kick. In this study, only the effect of permeability was demonstrated. In order to evaluate the effect of permeability in details, four scenarios for different formation permeability values have been used in simulation. Selected permeability values for this study are 10, 50, 100 and 300 md.

The shut-in procedure includes one more step in this approach unlike the conventional method. When the positive kick indicator is observed by a driller, the well must be shut –in immediately. After shut-in, started immediately pumping current mud into well at 5 spm pumps speed. The volume of pumping mud is followed by the stroke counter. The pumps are stopped after the desired volume (±0.1 bbl) has been pumped into the well. The interest of volume pumped for this study are 2, 4, 6, 8, 10 and 12 strokes.

After running several simulations the essential values like drill pipe pressure, bottom-hole pressure, casing shoe pressures and total influx volume from formation are compared.

CHAPTER 2

THEORY

2.1. Well Control

The primary well control is defined as the prevention of formation fluid flow into the wellbore by maintaining the hydrostatic pressure of drilling fluid equal to or higher than formation fluid pressure. An example of primary well control conditions is shown in Figure 2.1

If primary well control has failed, secondary well control is provided by using special equipment called blow out preventer (BOP) system.

The main idea behind the usage of secondary well control is to stop the flow of formation fluids into the wellbore and enable the flow to the surface and safely discharged, while preventing further influx downhole. In order to control kicks and prevent blowouts;

- Firstly, to prevent the entry of additional formation fluids into the well, the annulus is closed at surface, with the BOP valves.

- Then, heavy mud is circulated (kill mud) down the drill string and up the annulus by using one of well control methods like Driller's and Wait & Weight Method .

- Hereby, the well will be back under primary control [2].

Failure in the secondary well control causes a catastrophic situation, blowout (Figure 2.2).

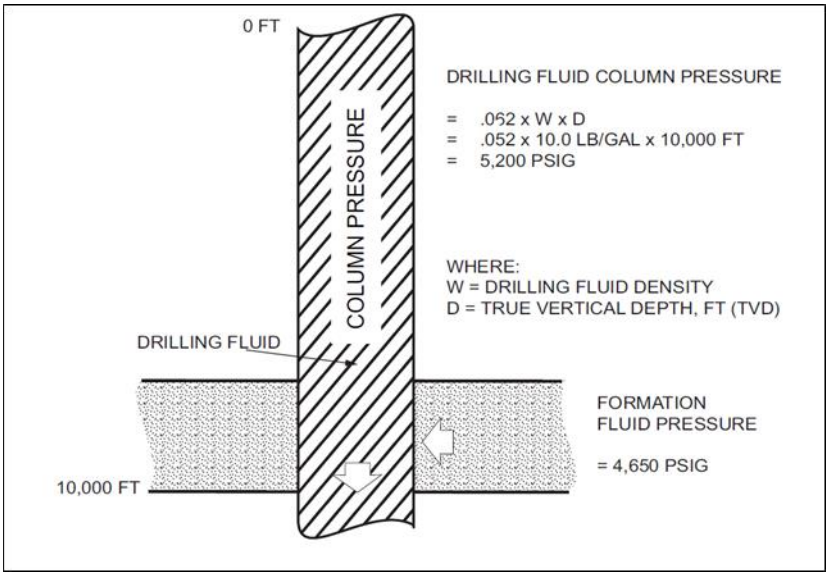

Figure 2.1. Example of Primary Well Control Conditions [3]

Figure 2.2. Blowout in the Gulf of Mexico [4]

2.2. Causes of Kicks

Necessary conditions for a kick to occur:

1. Higher formation pressure than well bore pressure.
2. Sufficient formation permeability for fluid flow into the wellbore.

The main reasons of kicks are;

1. Insufficient mud weight,
2. Not keeping the hole full of mud,
3. Swabbing, abnormal formation pressure
4. Lost circulation.

2.2.1. Insufficient Mud Weight

The weight of the mud is the primary means of preventing kicks. If the mud weight is low, cannot provide sufficient hydrostatic pressure and causes a kick. The mud weight can be insufficient if pore pressure is higher than expected. Also mud weight can be reduced because of various reasons; mud contamination by solids or chemicals, high temperature, rheological problems, mud centrifuges and etc.

2.2.2. Not Keeping the Hole Full of Mud

When the drill string is pulled from hole, the fluid level decreases because of volume of pulled drill string. As we know from hydrostatic pressure formula, if vertical depth is changed, hydrostatic pressure change also. So, to keep the hole full, a volume of mud equal to the volume of drill string which has been removed, must be added to the hole. To be sure keeping the hole full, trip tank and trip sheet must be used during tripping. A trip tank is a small calibrated mud tank with a small capacity about with 1 bbl or 0.5 bbl divisions that is used to monitor the well. A trip sheet is used to record the volume of mud put into the well or displaced from the well.

2.2.3. Swabbing

The swabbing is the temporary pressure reduction in the well when pulling the drill pipe out of the well. Swabbing is generally considered detrimental in drilling operations, because it can lead to kicks and wellbore stability problems. Swabbing is increased by high pulling speeds, mud properties with high viscosity and high gels, tight annulus (BHA/hole clearance) or restricted annulus clearance and having a balled up bit or BHA (Figure 2.3). Most of the swabbing effect occurs when the bit is first moved off bottom [5].

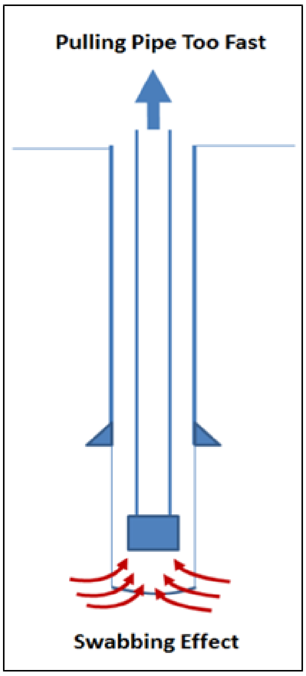

Figure 2.3. Swabbing Effect [6]

2.2.4. Abnormal Formation Pressure

An underbalanced wellbore pressure occurs when an abnormally pressured formation is encountered. The normal formation fluid pressure gradient for most areas is generally between 0.433 psi/ft for fresh water and 0.465 psi/ft for salt water [7]. Any pressure that deviates from this normal pressure gradient is named as abnormal formation pressure (Figure 2.4).

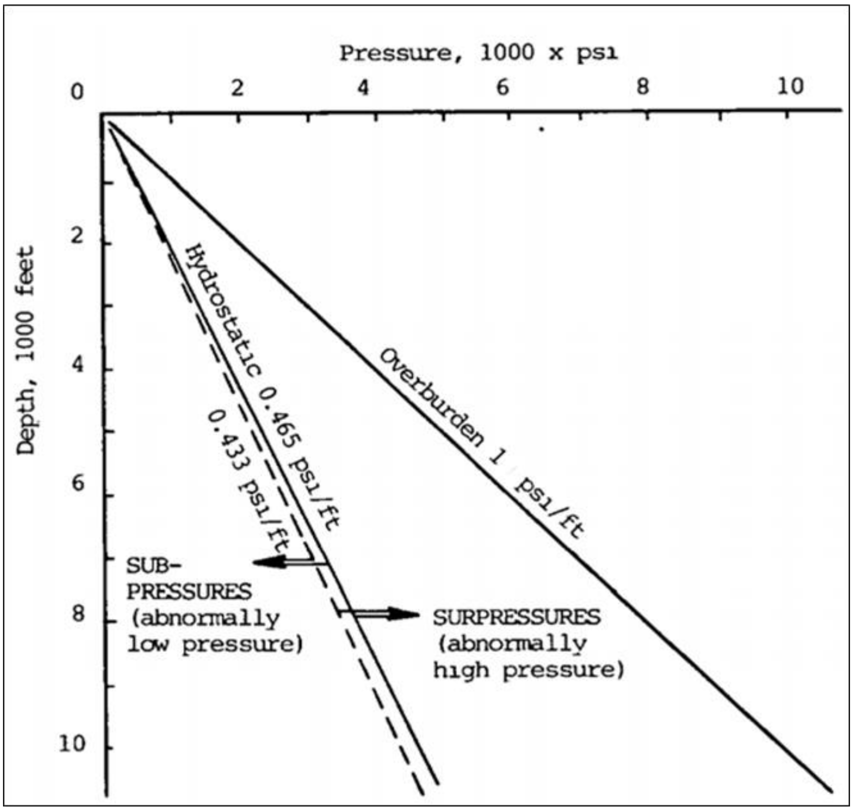

Figure 2.4. Subsurface Pressure Concepts [7]

Abnormal pore pressure is caused by various mechanisms like compaction effect, diagenetic effect (or chemical alteration of rock minerals by geologic processes), density differential effects, and fluid migration effects and etc. [8].

Abnormal pressure zones can be predicted by methods such as well logging and measurement-while-drilling (MWD) techniques, which are capable of measuring shale compaction, or density [5].

While drilling, when drilled into abnormally high pressured gas zone, if the drilling fluid weight used is not high enough, the gas will enter the wellbore rapidly and resulting in gas kick.

2.2.5. Lost Circulation

Lost circulation is the uncontrolled flow of drilling fluid into the formation that causes the level of mud drop in the hole. Because of this drop, reduction of hydrostatic pressure occurs. Loss of circulation can occur to cavernous or vugular formations; naturally fractured, pressure depleted or sub-normally pressured zones; fractures induced by excessive pipe running speeds; annulus plugging due to BHA balling or sloughing shales; excessively high annular friction losses; or excessive circulation breaking pressures when mud gel strength is high [9]. When lost circulation occurs, annulus should be filled with low density fluid or water as a first action to do.

2.3. Kick Indicators

There are many parameters which may indicate an occurrence of kick. Warning signs and possible kick indicators can be observed at the surface. Each rig personnel have the responsibility to recognize and interpret these signs and take the correct action. Kick indicators can be categorized into positive indicators and possible indicators.

2.3.1. Positive Kick Indicators

Positive indicators are virtually certain signs that the well has kicked in early stage. Those are;

While Drilling

- Increase in return flow
- Increase in pit levels

While Tripping

- Hole not taking the correct amount of fluid (either running in or pulling out)

2.3.2. Possible Kick Indicators

Possible indicators may appear before the formation pressure becomes high enough to cause kick .The most common possible indicators are;

- Increase in Drilling Rate (Drilling Break)
- Change in Pump Pressure or Pump Stroke
- Increase in Gas Levels
- Increase in Torque and Drag measurements
- Change in Cuttings Size and Shape
- Change in Mud Properties
- Increase in Mud Temperature

2.4. Kick Behavior

An influx of formation fluid can be oil, gas, water or various combination of these. If the density of formation influx is lower than the density of drilling mud, hydrostatic pressure of mud column reduces below the formation pressure. Thus, an influx flows into the wellbore at an increasing rate until well is shut-in.

The rate of formation fluid depends on permeability of the formation, the differences between hydrostatic pressure of mud column and the pressure of formation and the length of drilled formation [5].

Gas kicks are the most difficult to deal with compared with liquid because of its properties which are low density and high compressibility.

Because the gases are usually lighter than the mud, they have a tendency to float or migrate up the hole toward to surface. As long as the well remains closed-in and there is not any formation fracture, the gas remains at a constant pressure if not allowed to expand while comes to the surface. But the migrating gas exerts pressure higher up the closed well.

When gas rises to top, the volume of the gas must be allowed to expand to decrease the initial gas pressure. In addition, the annulus pressure or the casing pressure increases if the bubble rises.

On the contrary, because the total hydrostatic pressure of mud column in the annulus remains constant, a rise in casing pressure must cause a rise of bottom-hole pressure. As a result, the increase in wellbore pressure may cause to break down the formation and resulting possible underground blowout.

The behavior of gas is understood by analyzing the real gas behavior. The real gas law is given in equation 2.1. [10]

$$PV = z\, n\, R\, T \qquad (2.1)$$

Where:

P = Pressure (psia)

V = Volume, ft3

z = Compressibility factor

n = Number of moles, lb-mole

R = Universal gas constant, $ft^3 \cdot psia/°R \cdot lb.mol$

T = Temperature, °Rankine

The compressibility factor of hydrocarbon gases generally determined experimentally, and formation temperatures are not always available. Hereby, the following shortened equation for gas expansion is used for calculations by some well-control operations [5].

$$P_1.V_1 = P_2.V_2 \tag{2.2}$$

P1= Formation Pressure, psi

P2= Hydrostatic pressure at any depth in the well bore, psi

V1= Initial Gas Volume, bbl

V2= Gas Volume at surface, bbl

2.5. Shut-In Procedures and Shut-In Pressures

When a kick occurs (any of the positive indications of a kick observed) the well can be shut in instantly to stop the influx of formation fluid into the wellbore (Figure 2.5). The safest precaution is to shut-in the well and control pressures if we are not sure whether or not the well is flowing. The shut-in procedures change according to types of rigs, types of drilling operations and company policy.

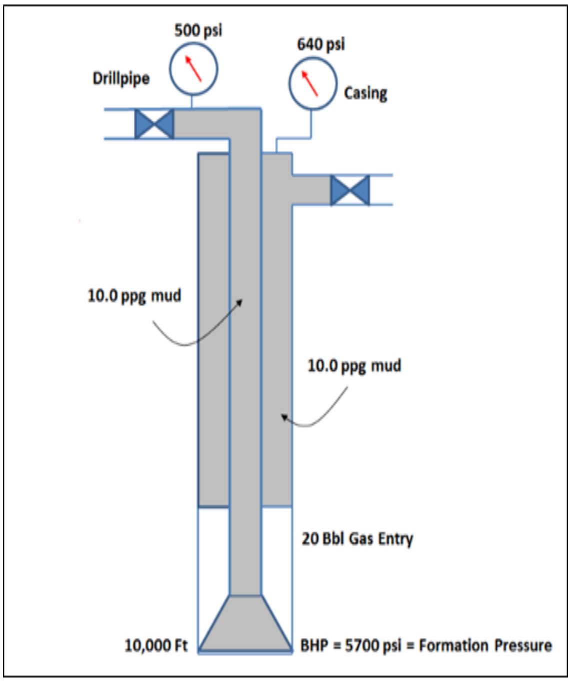

Figure 2.5. Well Shut-In on a Kick [6]

Blowout preventer stack is located on the sea floor for floating rigs, so specific procedures like hang-off are needed to shut-in the well. Another case to consider that when it is occurred; while drilling, tripping, running casing, cementing or logging operations.

There are two control points which are choke (hydraulically actuated or manually actuated) and high closing ratio valve (HCR) / hydraulically actuated gate valve are shown in Figure 2.6.

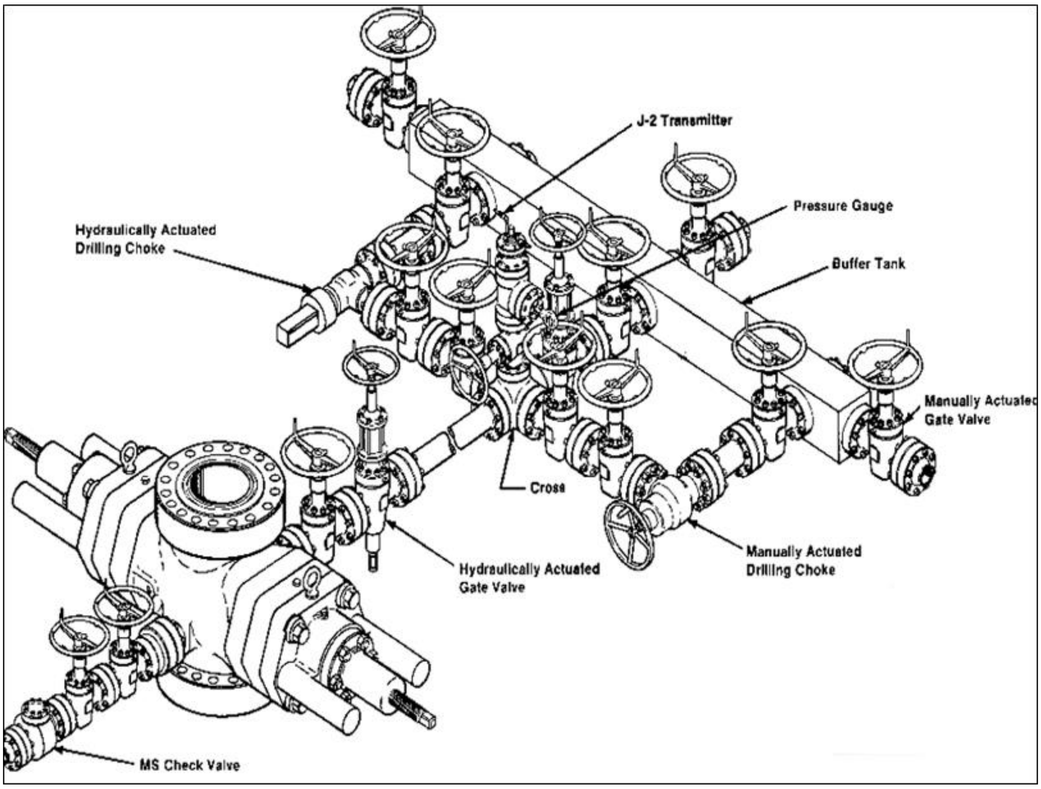

Figure 2.6. The Position of the HCR Valve and Chokes [10]

There are two types of shut-in methods which are Hard Shut-in and Soft Shut-in.

2.5.1. Hard Shut-In

In hard shut-in procedure, choke and high closing ratio valve (HCR) / hydraulically actuated gate valve are in closed position while drilling.

When the well control situation is occurred while drilling, the following procedure may be used.

- Stop rotating
- Raise the drill string until spaced out (ensure that any tool joint is not in a ram BOP)

- Stop mud pumps
- Check for flow
- Close annular or pipe rams
- Open HCR
- Notify supervisor
- Record Shut-in drill pipe and casing pressures (SIDPP & SICP), pit gain and total depth.

The advantages of hard shut-in method are faster procedure, smaller kick size and easy to remember.

2.5.2. Soft Shut-In

In soft shut-in procedure, the choke is in an opened position while drilling. When a kick occurs while drilling, the following procedure may be used.

- Stop rotating
- Raise the drill string until spaced out (ensure that any tool joint is not in a ram BOP)
- Stop mud pumps
- Check for flow
- Open HCR
- Close annular preventer
- Close choke
- Notify supervisor

- Record Shut-in drill pipe and casing pressures (SIDPP & SICP), pit gain and total depth.

The advantages of soft shut-in method are more sensitive control of annular pressure buildup during closure and less intense pressure fluctuations in the wellbore.

2.6. Shut-In Drill Pipe Pressure (SIDPP) & Shut-In Casing Pressure (SICP)

Fluids flow from the formation into the wellbore throughout a kick. When the well is closed to avoid any further fluid flow or a blowout, pressure rises at the surface because of formation fluid entry into the annulus, as well as because of the difference between the mud hydrostatic pressure and the formation pressure [11].

Once the well is shut-in, the drill pipe and casing pressures will be in balance with time (Figure 2.7). These stabilized pressures are called shut-in pressures. The rate of pressure buildup and time required for stabilization depend upon the formation fluid type, formation properties, initial differential pressure and drilling fluid properties [12].

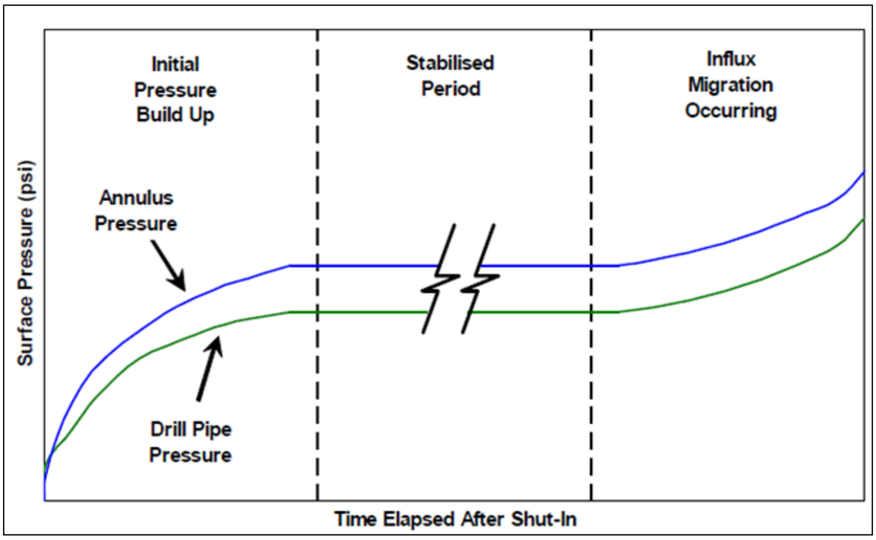

Figure 2.7. Surface Pressures after Shut-In [13]

SIDPP and SICP represent bottom-hole pressure conditions. Because of kick fluids in the annulus, SIDPP is usually lower than SICP [5]. The type of kick fluids (gas, oil or salt water) or phase (single or multi-phase) determine difference between SIDPP and SICP. SICP will be the highest when the kick is gas because of its lowest density according to other kick fluids.

When the influx is gas, the gas will migrate up the hole because of its lighter density. During migration of gas, surfaces pressures (SIDPP, SICP) and bottom-hole pressure (BHP) are both increase. Thus, increased pressures may break down the formation and cause lost circulation if the well is in a shut-in condition for a long time.

Since SIDPP pressure is essential to well control to calculate formation pressure and the kill mud weight, it should be obtained accurately. As stated before, because of influx migration after stabilization, increasing SIDPP does not reflect the actual pressure. Therefore, before calculations, it must be checked to ensure pressure increment is due to trapped pressure or not.

Formation pressure and kill mud weight can be determined by using SIDPP correctly, on the condition that only single phase, incompressible, cutting free and homogeneous density drilling fluid is in the drill string. The formation pressure can be determined using equation 2.3.

$$FP = HP + SIDPP \tag{2.3}$$

Where FP is formation pressure (psi), HP is hydrostatic pressure (psi) and SIDPP is shut-in drill pipe pressure (psi).

Once SIDPP is obtained accurately, the kill mud weight can be determined using equation 2.4.

$$KMW = CMW + [SIDPP / (TVD \times 0.052)] \tag{2.4}$$

Where KMW is kill mud weight (ppg), CMW is current mud weight in drill string (ppg) and TVD is true vertical depth (ft).

2.7. Maximum Allowable Annular Surface Pressure (MAASP)

"MAASP is defined as the surface pressure which, when added to the hydrostatic pressure of the existing mud column, results in formation breakdown at the weakest point in the well [13]".

Excessive pressure may cause mechanical failure and formation breakdown during first closure or throughout the circulation. Mechanical failure of well control equipment is one of the reasons of loss of well control. A formation breakdown can cause loss of circulation and an underground blowout. Maximum allowable pressure must be determined to avoid these problems [3].

In order to determine MAASP, a leak-off test pressure data is needed.

A Leak-off test is conducted to determine the fracture pressure of the formation. It is usually conducted after drilling a short distance below the casing shoe. When conducting the Leak-off test, the well is closed-in and drilling fluid is pumped into well bore gradually. The pressure in the well will increase because of increasing volume pumped in closed well until a formation break occurs. The pressure increase for each volume pumped will be the same. When the pressure increases a smaller amount for a volume pumped, it is the surface leak-off pressure (Figure 2.8). At that point, the pump should be stopped immediately for further irreversible deformation on the formation. The sum of Leak-off pressure and the hydrostatic pressure of the drilling fluid is calculated as the formation fracture pressure [3].

The formation fracture pressure can be determined using equation 2.5.

"Formation Fracture Pressure (psi) = Leak-off Pressure (psi) +

"Hydrostatic Pressure at Shoe (psi)" (2.5)

The MAASP is can be determined using equation 2.6.

"MAASP (psi)= Formation Fracture Pressure (psi) –

"Hydrostatic Pressure at Shoe (psi)" (2.6)

In terms of mud weight the formula can be re-written by using equation 2.7.

"MAASP (psi) = [Maximum Allowable Mud Density (ppg) –

"Current Mud Density (ppg)] × 0.052 × Shoe TVD (ft) " (2.7)

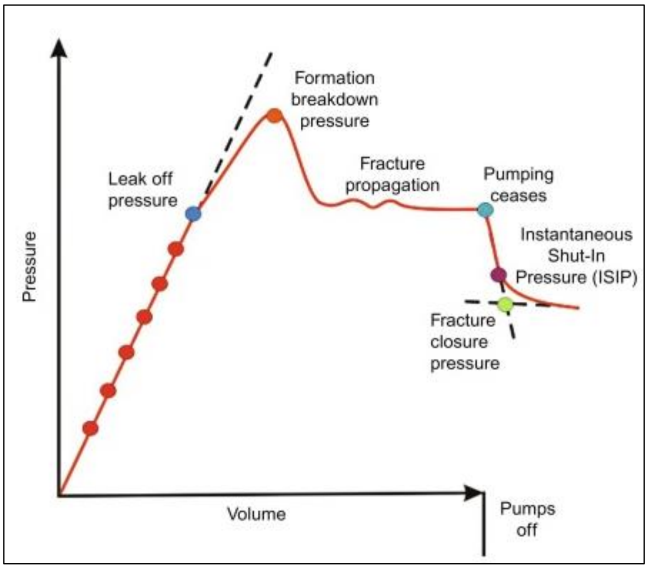

Figure 2.8. A Sample Graph for Leak-Off Test (LOT) [14]

MAASP value depends on mud density, when mud density changes, the value changes, too. Hence, MAASP value must be re-calculated.

2.8. Well Control Methods

When a kick occurs and the well is shut-in, an appropriate kill procedure is to be started. Killing a well refers to removal of influx fluids from the wellbore, and fill the hole with mud of sufficient weight to bring the well under control. When circulation can be established, there are two common methods of circulating out kicks [3]:

1. Driller's Method
2. Wait and Weight Method

Although there are differences between the methods, the basic principle is to keep the bottom-hole pressure constant during the well control operation by adjusting choke, while holding kill rate constant.

2.8.1. Driller's Method

There are two circulations in Driller's method. The aim of first circulation is to remove the influx out of the well by using current mud and the aim of second circulation is to kill the well with a heavier mud which is called kill mud.

When starting to bring pumps up to speed, casing pressure must be held constant until kill rate is reached. After reaching kill rate speed, the drill pipe gauge shows ICP (Initial Circulating Pressure). ICP will be held constant until influx is removed from annulus. The ICP is defined as:

$$ICP = SIDPP + SCP \tag{2.8}$$

ICP = Initial circulating pressure, psi

SIDPP = Shut-in drill pipe pressure, psi

SCP = Slow circulating pressure, psi

After the kick is totally removed from the well, when the well is shut-in, drill pipe and casing pressure will be the same value. If not, it means that there is influx still left in the wellbore.

Second circulation starts with bringing pumps to kill rate by holding casing pressure constant. While circulating with the kill mud, casing pressure must be held constant until kill mud reaches the bit. After that, drill pipe pressure must be constant at the FCP (Final Circulating Pressure) until kill mud reaches at surface.

The FCP is defined as [5]:

$$FCP = SCP \times (KMW \div CMW) \tag{2.9}$$

FCP = Final circulating pressure, psi

SCP = Slow circulating pressure, psi

KMW = Kill mud weight, ppg

CMW = Current mud weight, ppg

After the entire well is displaced to kill mud, pumping operation is stopped and drill pipe and casing pressure is observed. If the well is successfully killed, both drill pipe and casing pressure will be zero. If not, it is understood that there is some influx still in the well.

2.8.2. Wait and Weight Method

There is one circulation in Wait and Weight Method. While the kill mud is pumped in, the current mud and influx are removed from the well through the choke.

When starting to method bring pumps up to speed, casing pressure must be held constant until kill rate is reached. When the pump is up to kill rate, the drill pipe gauge shows ICP. Drill pipe pressure will decrease as kill mud will go down in the drill string and when kill mud reaches the bit, the drill pipe gauge shows FCP. Drill pipe schedule must be followed until kill mud reaches to the bit. After that, drill pipe pressure must be constant at the FCP until kill mud reaches at surface. When kill mud reaches the surface pumping operation is stopped and drill pipe and casing pressure is observed. If the well is successfully killed, both drill pipe and casing pressure will be zero.

2.9. Permeability

According to Darcy's Law, several parameters affect the severity of a kick. One of these parameters is permeability.

"Permeability is a measure of how easy a fluid will through the rock and depends upon the number, size and degree of interconnection between the pore spaces [13]." The permeability is an essential property of reservoir rocks that controls the how much and how quickly a kick will enter the well.

The units of permeability are the Darcy (D) and m^2. For geological applications millidarcy (mD) is used. [15].

From Darcy’s Law, the equation can be used for the flow rate of gas into the wellbore [5];

$$Q = \frac{0.007.k.\ \Delta P.h}{\mu.\ Ln\ (R_e / R_w)\ 1440} \tag{2.10}$$

Q = flow rate (bbl/min)

k= permeability (md)

ΔP= pressure differential (psi)

h= length of section open to wellbore (ft)

μ= viscosity of intruding gas (cP)

R_e= radius of drainage (ft)

R_w= radius of wellbore (ft)

In order to evaluate the effect of permeability in details, different permeability values have been used in this study.

2.10. Compressibility

During a kick, fluids flow from the formation into the wellbore. When the well is closed to prevent any further fluid flow or a blowout, pressure rises at the surface because of gas upward migration and gas compressibility.

All of the currently existing pressure analysis models are based on gas upward migration approach. On the other hand gas compressibility also play an important role in the pressure build-up. The initial total annular volume filled by the gas is reduced because of the compressibility of gas phase in annular fluid system [16].

After gas kicks occurs, there are drilling mud and formation fluid in the annulus. When the formation fluid is gas, the compressibility must be considered.

2.11. Pascal's Principle

"Pascal's law states that a pressure applied to a fluid in a closed container is transmitted equally to every point of the fluid and to the walls of the container" [17]. Under static condition pressure at any point inside the well-bore will be the hydro-static pressure due to mud weight but during our method well bore pressure (or pressure at any point) will be the sum of surface pressure and hydrostatic pressure. Surface pressure is due to pumping drilling fluid into the well while the BOP is shut and this surface pressure is transmitted equally to bottom-hole pressure.

2.12. Description of New Approach

A new well control approach is based on decreasing the difference between the formation pressure and the bottom-hole pressure by pumping drilling mud after shut-in. This methodology provides us reducing the volume of influx that enter the wellbore. Hence the permeability, viscosity and pressure of formation cannot be changed, only bottom-hole pressure is increased by pumping drilling fluid into the closed well.

The shut-in procedure includes one more step in this approach unlike the conventional method. When the positive kick indicator is observed by a driller, the well must be shut –in immediately. In this study hard shut-in is applied. As it was mentioned before, in hard shut-in procedure the steps are as follows;

- Stop rotating the string
- Raise the drill string until spaced out
- Stop the mud pumps
- Check for fluid flow
- Close the annular preventer or pipe rams
- Open the HCR
- Notify the supervisor
- Record the Shut-in drill pipe and casing pressures (SIDPP & SICP), pit gain and total true vertical depth of the well.

After closing the annular preventer or pipe ram and opening the HCR, started immediately pumping current mud into well at 5 spm pumps speed. The volume of pumping mud is followed by the stroke counter. The pumps are stopped after the desired volume (±0.1 bbl) has been pumped into the well. The interest of volume pumped for this study are 2, 4, 6, 8, 10 and 12 strokes. The pump displacement is 0.1 bbl/stk. Thus, the values of transmitted mud volume into the well are 0.2, 0.4, 0.6, 0.8, 1 and 1.2 bbl.

According to Darcy’s Law, several parameters affect the severity of a kick. One of these parameters is permeability. In order to evaluate the effect of permeability in detail, four scenarios for different permeability values have been used in simulation. Selected permeability values for this study are 10, 50, 100 and 300 md.

2.13. Modeling Consideration

The following assumptions are made for this study;

- Drilling fluid (water base mud) is slightly compressible using a constant compressibility of 2.944E-06 (1/psi)

- Isothermal non penetrating drilling fluid

- Ideal gas law is used to calculate the gas expansion.

- The rock is considered incompressible

- Expansion of casing string, and fluid leakage are not considered, the system boundary is rigid and fixed.

- Darcy flow equation is used in the reservoir formation flow calculation

2.14. The physics of New Approach

The physics of this study and physics of the Leak-off test and Bull heading operation, are similar. Therefore, the Leak-off test (LOT) and Bull heading operation have been evaluated for this study.

As it was mentioned in earlier, A Leak-off test (LOT) is conducted to determine the fracture pressure of the formation. It is usually conducted after drilling a short distance below the casing shoe. When conducting the Leak-off test, the well is closed-in and drilling fluid is pumped into well bore gradually. The pressure in the well will increase because of increasing volume pumped in closed well until a formation break occurs. So, as it is done for LOT, material balance concept could be given to analyze this study, too.

For LOT, the summation of the four component volumes at any time throughout the test must be equal to the volume pumped in. The compressible system is decomposed [18];

1) Compression of drilling fluid

2) Expansion of casing string
3) Open hole expansion
4) Fluid leakage

In our study expansion of casing string, open-hole expansion and fluid leakage are not considered, the system boundary is rigid and fixed. But there is a compression of influx in addition to these components. Therefore, the material balance equation can be written in the form;

$$\text{Volume Pumped}=\text{Volume to Mud Compression} + \text{Volume to Influx Compression} \quad (2.11)$$

The pressure change is acquired by pumping the drilling fluid into the system steadily. This situation contains only drilling-fluid compression in the well. The fluid compressibility is calculated from the well-known compressibility equation in differential form [18],

$$c=-\frac{1}{V_o}\left(\frac{\partial V}{\partial P}\right)_T \quad (2.12)$$

Injection of mud into the well cause contraction of original fluid in the well resulting with increase in pressure. The minus sign indicates that a negative change in volume results in an increase in pressure. The minus sign in the equation is cancelled out because the decrease in fluid volume due to compression is equal to the volume pumped [18]. Because temperature is assumed to be constant, the equation can be rewritten as;

$$cP = \ln\left(1+\frac{V}{V_o}\right) \tag{2.13}$$

$$V=V_o(e^{cP}-1) \tag{2.14}$$

$$\ln(1+x)=x-\frac{x^2}{2}+\frac{x^3}{3}-\frac{x^4}{4}+-\ldots(|x|<1) \tag{2.15}$$

$$cP=\frac{V}{V_o}-\left(\frac{V}{V_o}\right)^2+\left(\frac{V}{V_o}\right)^3-\left(\frac{V}{V_o}\right)^4\pm\ldots \tag{2.16}$$

Because V/V_o are small, their squared terms will be even smaller. Therefore, the similar solution is written by keeping the first term [18],

$$V=cV_oP \tag{2.17}$$

V= Volume pumped, bbl

c = Compressibility, 1/psi

V_o= System volume, bbl

P= Pressure, psi

When drilling mud compressibility is assumed to be low, because of the highly compressible gaseous phase, the system is considered slightly compressible. For slightly compressible fluid system, the standard compressibility expression under isothermal condition can be expressed as follow [16].

$$c_g = \frac{1}{\rho_g} \frac{d\rho_g}{dP_{bh}} \tag{2.18}$$

c_g= Gas compressibility, 1/psi

ρ_g = Gas density, lb/ft^3

P_{bh} = Bottom hole pressure, psi

The other operation which have been evaluated for this study is Bull heading which is one of the well control methods when gas kick occurs.

By pumping kill fluid into wellbore makes the wellbore gas compressed so that bottom-hole pressure exceeds formation pressure and gas leaks off to the formation. Bull heading operation is divided into three stages, including gas compression stage, gas seepage stage and gas-liquid seepage stage [19].

Bull heading is not a conventional well control method. It is performed when normal circulation cannot possible and to prevent the toxic gas like hydrogen sulfide gas from reaching the surface.

The first stage of bull heading operation, gas compression stage, is similar with this study, so only this stage have taken considered. Conditions for both methods are the same.

During bull heading process, in the gas compression stage, when drilling fluid pumped into wellbore, the gas will be exposed to compression. Therefore the total volume of gas decreases and the pressure rises constantly. It can be said that gas compressibility play an important role in pressure build up. As a result taking advantage of the gas compressibility, the difference between the formation pressure and the bottom-hole pressure can be reduced.

2.15. Similar Study

The inspired paper when the determining the topic of this study is *"Method of Rapid Stabilizing Shut-In Drill Pipe Pressures for Blowout Wells*" by Xiangfang, Tao and Xiuxiang (2000).

The aim of the study is to shorten the drill pipe pressure stabilized time after shut-in. Intermittently, a certain amount of drilling mud is pumped into well at a small flowing rate, resulting in the desired initial shut-in drill pipe pressure. To shorten the drill pipe pressure stabilized time, the difference between the formation pressure and the flowing bottom-hole pressure have to be reduced because the other parameter like porosity, permeability and formation pressure cannot changed.

The pressure buildup after the first batch of drilling mud, the next pumping time and mud volume to be pumped are determined by a computer model. According the trend of drill pipe pressure build up, the one of these two options is applied; mud is pumping into well again or discharging mud through choke.

The method is fit for the reservoir, which has high pressure and medium or low porosity. Although the aim of the study is to shorten the drill pipe pressure stabilized time after shut-in, the volume of influx entering into well can be decreased, too [20].

Both studies have many similarities and differences.

Similarities are;

- Drilling fluid pumped into wellbore after shut-in during stabilization time
- Shortened stabilization time
- Reduced influx volume
- In the similar study, according the trend of drill pipe pressure build up, pumping or discharging mud is determined. Because of assuming that the SIDPP is known, this method is not exactly fit for wild cat well, exploration well and development well.

  In our study, it is assumed that the SIDPP is not known as in real applications. It is determined according to trend of drill pipe pressure. If drill pipe pressure continues to increase after pumping desired volume of mud, it is understood that the SIDPP is not reached yet. But if drill pipe pressure remains constant, it is understood that the SIDPP is exceeded. In such a case the pressure trapped in the well will occur and a suitable method can be applied to bleed trapped pressure.

Differences are;

- In the Xiangfang et al.'s study heavier mud weight is used and to calculate the mud weight, pumping time and mud volume to be pumped are determined by the computer model.

  On the other hand, in our study current mud is pumped after shut-in. The pumps are stopped after the desired volume of mud has been pumped into the well. There is no need to use another pump and heavier mud. Therefore, no waste of time and no calculation.

- In our study the effect of permeability was evaluated instead of porosity.
- In our study, as well as the Darcy's Law, the compressibility equation together with the material balance concept is given to examine the behavior of influx and drilling mud in closed system.

CHAPTER 3

STATEMENT OF PROBLEM

Well control is one of the most important aspects of oil and gas operations such as drilling, well work over, and well completions. The aim of well control is to prevent influx of formation fluids into the wellbore, to stop the flow and enable the flow safely discharged while preventing further influx.

It is known very well that the larger volume of influx, the more difficult to bring the well under control. If the amount of volume of influx that enters the borehole can be reduced, the maximum pressure that occurs in the well can be reduced, stress levels on equipment and personnel can be reduced, thus lowering the risk of adverse consequences.

The aim of this study is to lessen volume of influx from the formation after shut-in the well with a new well control approach. A commercial multiphase dynamic well control simulator (DrillSIM 5000) has been used to demonstrate how influx volumes can be reduced at different formation permeability values.

In the study, as well as the Darcy's Law, the compressibility equation together with the material balance concept is given to examine the behavior of influx and drilling mud in closed system.

In order to evaluate the effect of permeability in details, scenarios for different permeability values have been used in simulation.

CHAPTER 4

METHODOLOGY

4.1. Well Control Simulator

A commercial multiphase dynamic well control simulator, DrillSIM 5000, was used to conduct the simulations in this study (Figure 4.1). It meets IWCF (International Well Control Forum) & IADC (International Association of Drilling Contractors) training criteria or standards for industry accreditation.

Figure 4.1. Well Control Simulator, DrillSIM 5000Enter the Figure Caption here

The DrillSIM system computer utilizes a mathematical model. The operation of rig equipment and downhole characteristics encountered in “real world” conditions are simulated by this mathematical model. The Simulation software is completely integrated package that is designed to interact with the Trainees actions. The simulator software enables the Trainee to observe the results of his/her actions just as similarly as they would happen in the real field condition [15].

Basic and advanced training like drilling, tripping, circulating, running and cementing casing, well control operations and downhole well control and equipment problems can be given by the DrillSIM.

4.2. New Approach and Data Acquisition Methodology

In this study formation properties, hole sizes and depths, casing size and setting depths, drill string component properties, bit size, nozzle area, drilling fluid properties, and wellbore temperatures are utilized as input data to simulate the real scenarios. Input data utilized in this study is given in the Table 4.1.

Table 4.1. Well Input Data

<table>
<tr><td colspan="5">Hole Data</td></tr>
<tr><td>Hole Size:</td><td colspan="4">8-1/2 inch</td></tr>
<tr><td>Well Depth:</td><td colspan="4">5602 feet; TVD = MD</td></tr>
<tr><td colspan="5">Casing & Shoe Data</td></tr>
<tr><td>Casing Size:</td><td colspan="4">9-5/8 inch;</td></tr>
<tr><td>Casing Depth:</td><td colspan="4">3900 feet TVD = MD</td></tr>
<tr><td colspan="5">Drill String Data:</td></tr>
<tr><td>Component</td><td>Diameter</td><td>Weight (lb/ft)</td><td>Length (ft)</td><td>Inside Capacity (bbl/ft)</td></tr>
<tr><td>Drill Pipe</td><td>5 inch</td><td>22.60</td><td>5002</td><td>0.0177</td></tr>
<tr><td>Drill Collar</td><td>6-1/4 inch</td><td>83.16</td><td>600</td><td>0.0077</td></tr>
<tr><td colspan="5">Bit Data:</td></tr>
<tr><td colspan="2">Bit Type:</td><td colspan="3">Tricone (IADC 134)</td></tr>
<tr><td colspan="2">Bit Size:</td><td colspan="3">8-1/2 inch</td></tr>
<tr><td colspan="2">Bit Nozzles Size:</td><td colspan="3">11/32 inch</td></tr>
<tr><td colspan="5">Drilling Fluid & Pump Data:</td></tr>
<tr><td colspan="2">Mud Density:</td><td colspan="3">10.5 ppg (Water base mud)</td></tr>
<tr><td colspan="2">Plastic Viscosity:</td><td colspan="3">12.01 cP</td></tr>
<tr><td colspan="2">Yield Point:</td><td colspan="3">18.00 lb /100 ft^2</td></tr>
<tr><td colspan="2">Rheology Type:</td><td colspan="3">Non-Newtonian; Fann tables</td></tr>
</table>

Pump Displacement:	0.1 bbl/stk
Slow Pump Pressure:	750 psi @ 50 stk/min
Pump Rate while Drilling	90 spm
Reservoir Data:	
Reservoir Pressure:	3600 psi
Reservoir Temperature:	253 °F
Reservoir Fluid Data:	
Influx Type:	Gas
Influx Density:	1.92 ppg
Formation Strength Data:	
Leak-Off Pressure @ Casing Shoe	3354 psi
Fracture Pressure @ Casing Shoe	4368 psi
MAASP:	1232 psi
Loss Zone Data:	
Depth at Top of Formation:	5590 ft
Formation Pressure Gradient:	0.54 psi/ft

The well provided for this study is a vertical well drilled from surface to the target reservoir located at approximately 5600 ft TVD.

The kick is arranged to start at 5600 ft. After 2 ft of drilling in reservoir section, the hard shut-in procedure is applied to shut the well. In hard shut-in method, annular or pipe ram can be used to shut-in the well, in these cases pipe ram is preferred due to shorter closure time. After shutting the well the data acquisition is started. All scenarios are started from this point and recorded snapshot is used to make accurate comparisons of results.

A new well control approach is based on decreasing the difference between the formation pressure and the bottom-hole pressure by pumping drilling mud after shut-in.

Different volumes of drilling fluid are pumped into the well during stabilization period of pressures to increase the bottom-hole pressure. After closing the annular preventer or pipe ram and opening the HCR, started immediately pumping current mud into well at 5 spm pump speed. The volume of pumping mud is followed by the stroke counter. The pumps are stopped after the desired volume (±0.1 bbl) has been pumped into the well. The interest of volume pumped for this study are 2, 4, 6, 8, 10 and 12 strokes. As it is mentioned in well data table, pump displacement is 0.1 bbl/stk. Thus, the values of transmitted mud volumes into the well are 0.2, 0.4, 0.6, 0.8, 1 and 1.2 bbl.

In order to evaluate the effect of permeability in details, 4 scenarios for different permeability values have been used in simulation. Selected permeability values for this study are 10, 50, 100 and 300 md, shown in the Table 4.2. The maximum volume of mud pumped into well differs in each scenarios because of different permeability values. Therefore, the number of cases for all scenario are different.

Table 4.2. Number of Cases for Scenarios

Scenarios	**Permeability**	**Number of Cases**
Scenario 1	10 md	7
Scenario 2	50 md	6
Scenario 3	100 md	6
Scenario 4	300 md	5

4.3. Data Display of Simulator

Some drilling parameters and progress of any influxes can be displayed on the simulator screen and this screen display is shown in this study for every case.

An example screen display can be seen in Figure 4.2. The screen divided into 3 sections. The first section of the screen display contains the data of hole depth, shoe depth and bit depth as both true vertical depth (T.V. D) and measured depth (M.D).

There are some pressures and volume data in the second section of screen display, listed below:

- Under /over balance
- Bottom hole pressure
- kh (permeability milli darcy x exposed reservoir height)
- Influx rate
- Total kick volume
- Total influx from formation
- **Differential pressure to bull heading reservoir;** the over pressure required to force formation fluids into the kick zone formation.
- **Differential pressure to initiating leak-off at casing shoe;** the over pressure required to initiate leak-off at casing shoe.
- **Differential pressure to initiating fracture at casing shoe;** the over pressure required to initiate fracture at casing shoe.
- **Differential pressure to initiating losses at loss zone;** the over pressure required to initiate loss at loss zone.

Finally, the third section of the screen display contains drill pipe pressure, casing pressure, annular pressure at casing shoe, leak-off pressure at casing shoe, annular pressure at loss zone, leak-off pressure at loss zone, bottom-hole pressure and formation pressure. In addition, as it is seen from the example screen display there is a well schematic in the third section. There are 3 yellow lines in the annulus which representing separated influx volumes. As the influx volume increases, the line gets thicker.

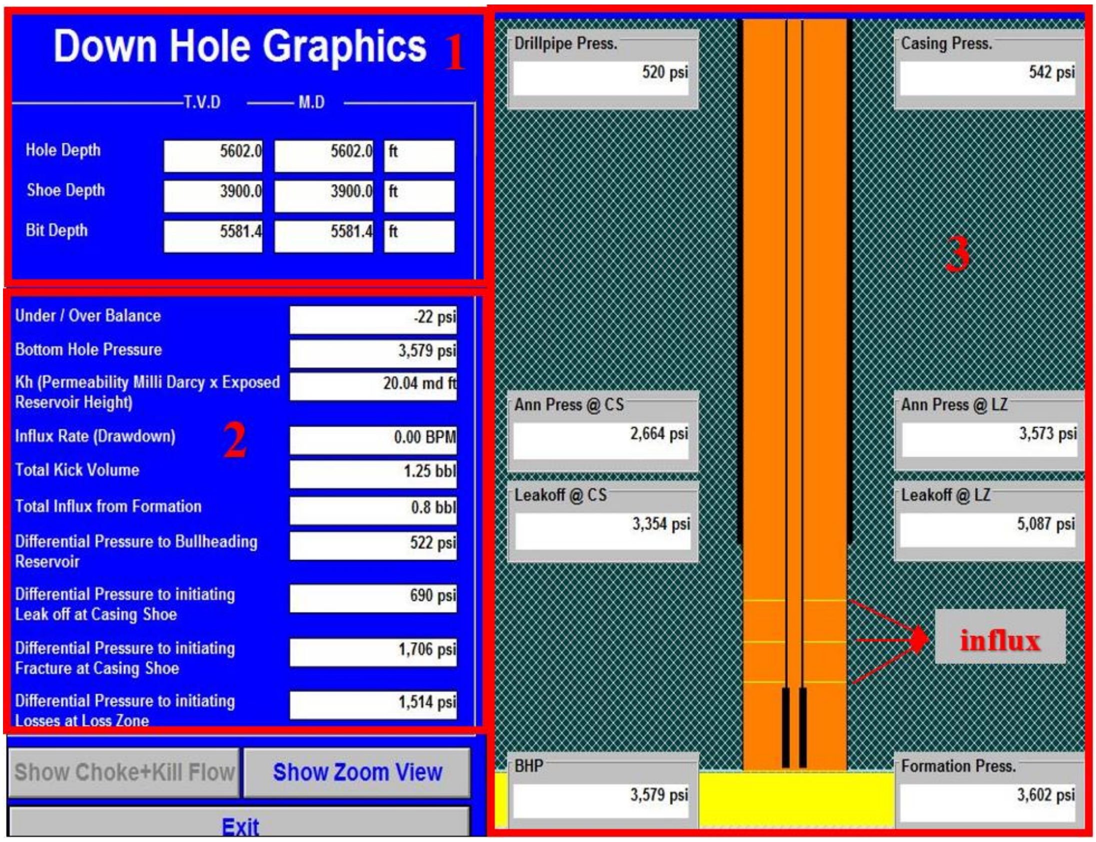

Figure 4.2. The Screen Display of Simulator

CHAPTER 5

RESULTS AND DISCUSSIONS

5.1. General Results and Discussions

Different volumes of drilling fluid are pumped into well during stabilization period of pressures to increase the bottom-hole pressure. The maximum volume of mud pumped into well differs in each scenarios because of different permeability values. Therefore, the number of cases for all scenario are different. The maximum volume of mud is determined according to observed SIDPP. If the observed SIDPP after stabilization is 50 psi higher than the calculated SIDPP, the trial is stopped at this stage.

After running several simulations with different volumes of drilling fluid at different formation permeability, the results are then transferred to excel sheets, and the essential values like drill pipe pressure, bottom-hole pressure, casing shoe pressures and total influx volume from formation is presented as a table for comparison of results. In addition to the tabulated results, drill pipe pressures, bottom-hole pressures and casing shoe pressures versus stabilization time charts and comparisons of the total influx from formation and total kick volume charts are demonstrated.

It is observed that when the new approach is applied, there are decreases in different rates in total influx volume at different formation permeability values.

5.2. Scenarios

5.2.1. Scenario 1 (10 md)

In Scenario 1, the permeability of reservoir is selected as 10 md. There are seven cases. Cases are started with conventional method and followed by unconventional approach.

5.2.1.1. Case 1: Conventional Method

In the first case, when gas kick has been observed, the well is shut-in according to the conventional method of shut-in procedures (Figure 5.1). The total influx from formation was observed 0.1 bbl until the well is completely closed. Hence the permeability of reservoir is too low, drill pipe pressure rises slowly instead of stabilizing the steady value.

The other reason of rising in pressure slowly is due to gas percolating up the hole. It is not easy to understand the difference between percolating gas and a low permeability formation until the influx has been circulated out of the hole.

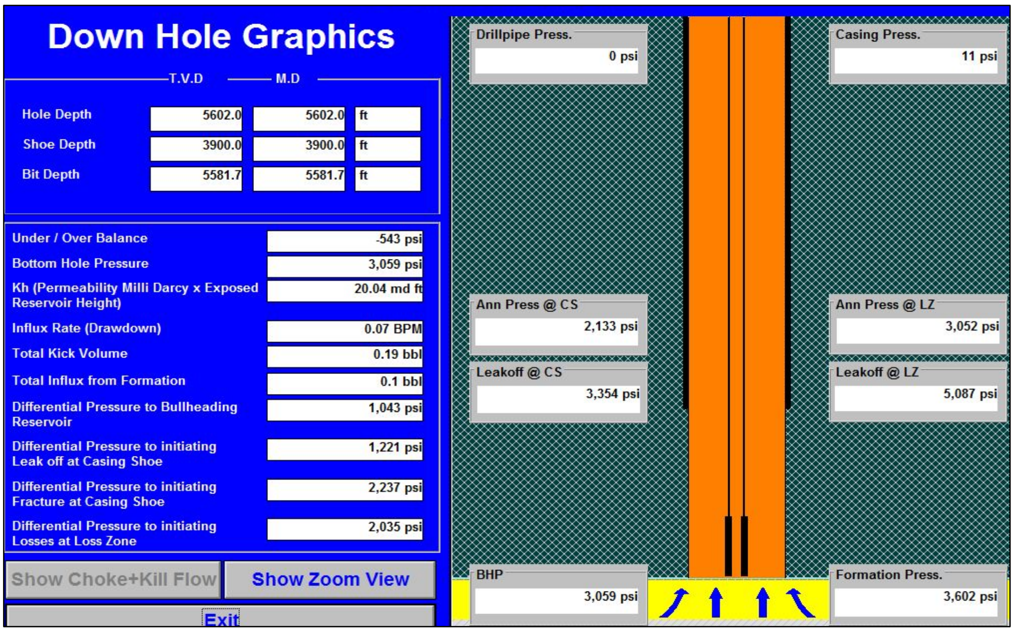

Figure 5.1. Well Schematics & Well Data after Stabilization for Conventional Method (10 md)

Since the difference between low permeability and migration of gas is not clear, it is assumed that any pressure rise after the first hour of shut-in is because of migrated gas phase [5].

In the case 1, pressure rise is allowed for one hour and it is observed that pressure cannot be stabilized because of low permeability. The drill pipe pressure after an hour is attained as an SIDPP and found that the SIDPP is 24 psi lower than the calculated SIDPP.

There are three separated influx volumes in the annulus and total influx from formation was observed as a volume of 0.8 bbl after one hour which is accepted as the stabilization period (Figure 5.2).

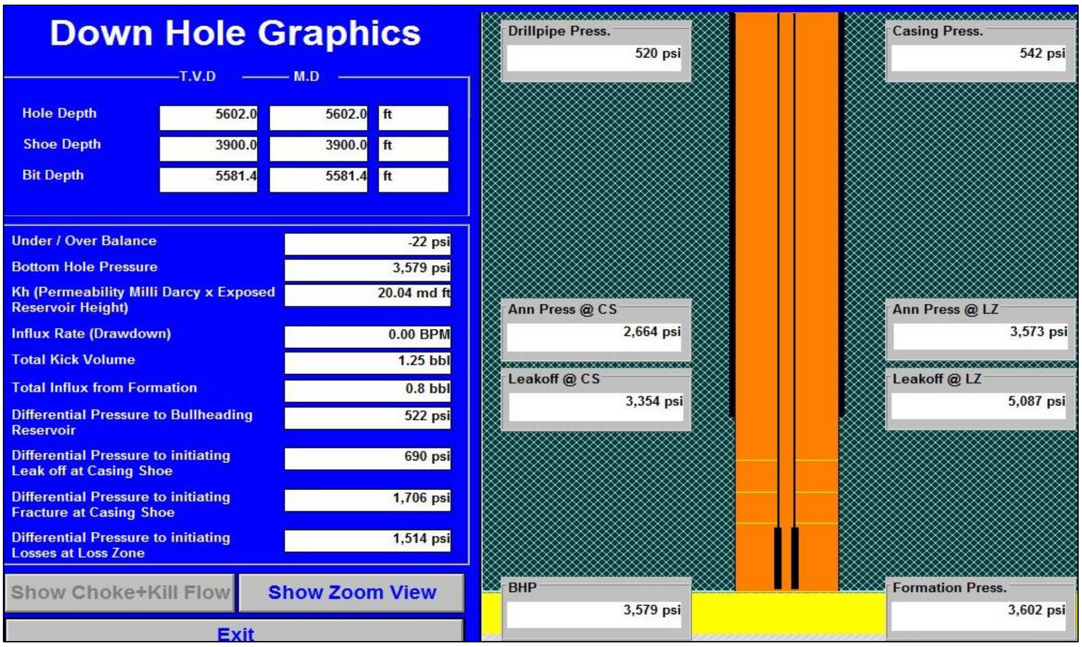

Figure 5.2. Well Schematics & Well Data after Stabilization for Conventional Method (10 md)

When drill pipe pressure increase period is observed (Figure 5.3), it is seen that there are two times slope changes until the drill pipe pressure reaches equilibrium and it is known that the volume of influx increases during this time. The reasons of these changes in the pressure increase rate is additional influx volumes.

The first separated influx volume enters the well before the well is completely closed. This section does not appear in the chart because the chart (Figure 5.3) shows the time after the shut-in.

The second separated influx volume enters during the time between 230 – 300 seconds that is marked with circle 1 and the third separated influx volume enters during the time between 1260 – 1360 seconds that is marked with circle 2 in Figure 5.3.

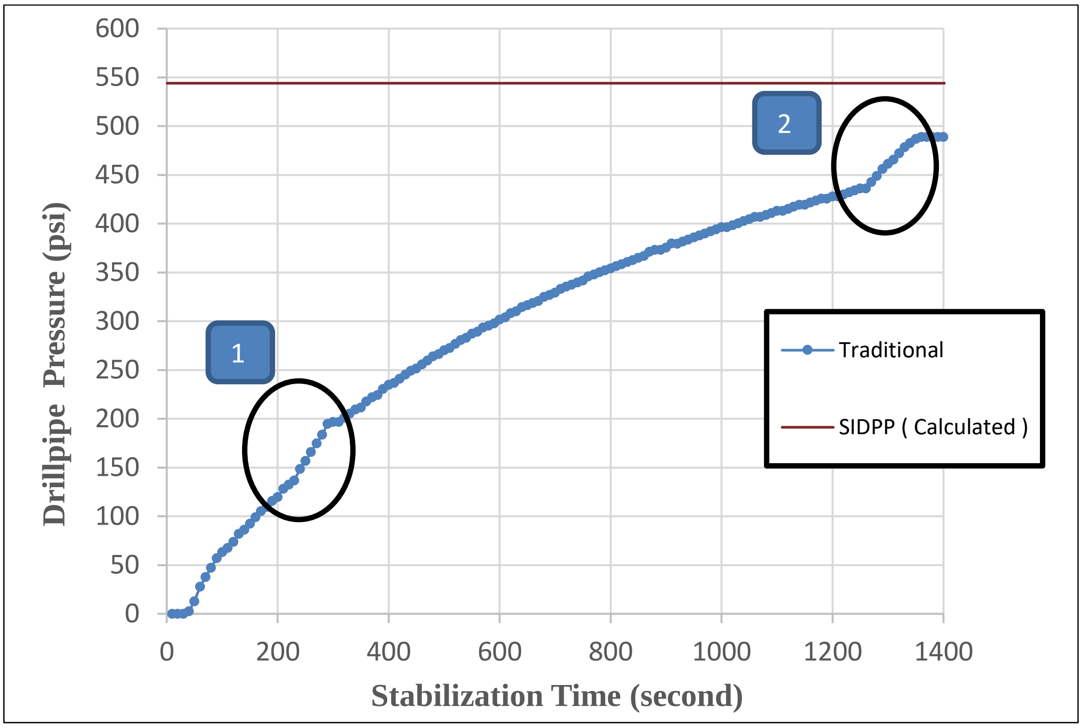

Figure 5.3. Detailed SIDPP vs. Stabilization Time for Conventional Method (10 md)

5.2.1.2. Case 2: 2 Stroke

In case 2, 2 stroke (0.2 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after one hour is determined as an SIDPP value and it is observed that the SIDPP is 6 psi lower than the calculated SIDPP (Figure 5.4).

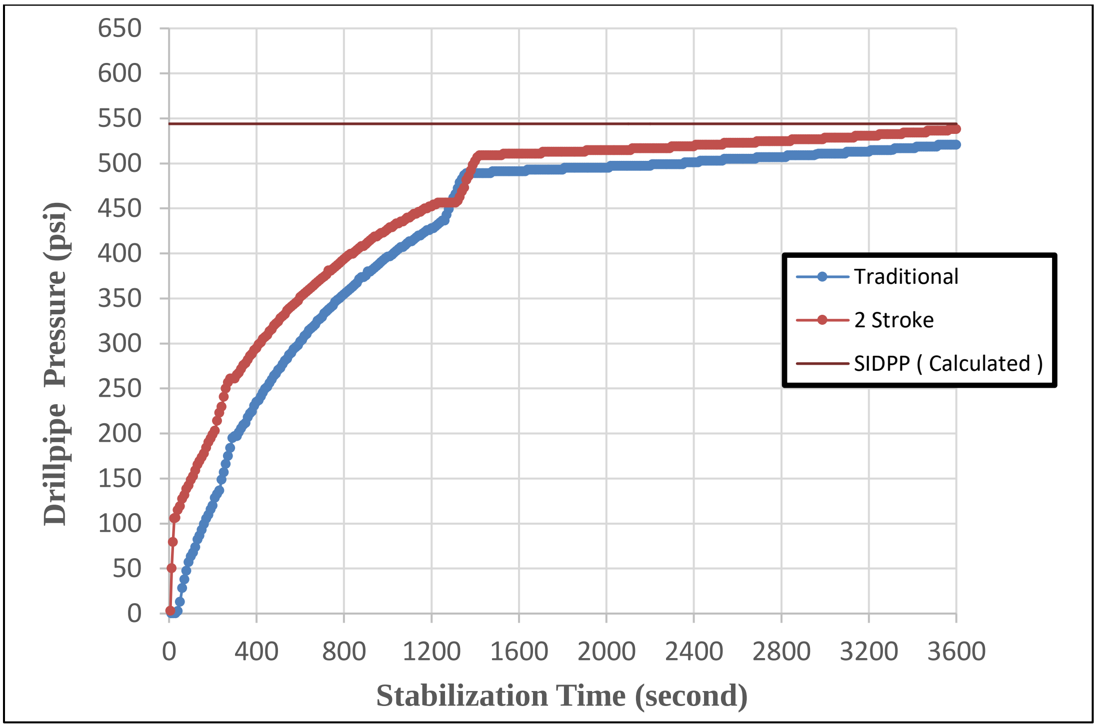

Figure 5.4. SIDPP vs. Stabilization Time for 2 Stroke (10 md)

There are three separated influx volumes in the annulus and total influx volume from formation was observed 0.7 bbl after one hour which is admitted as a stabilization time (Figure 5.5).

It is seen that pumping 0.2 bbl mud volume into the well during stabilization period provides 0.1 bbl less influx volume from formation.

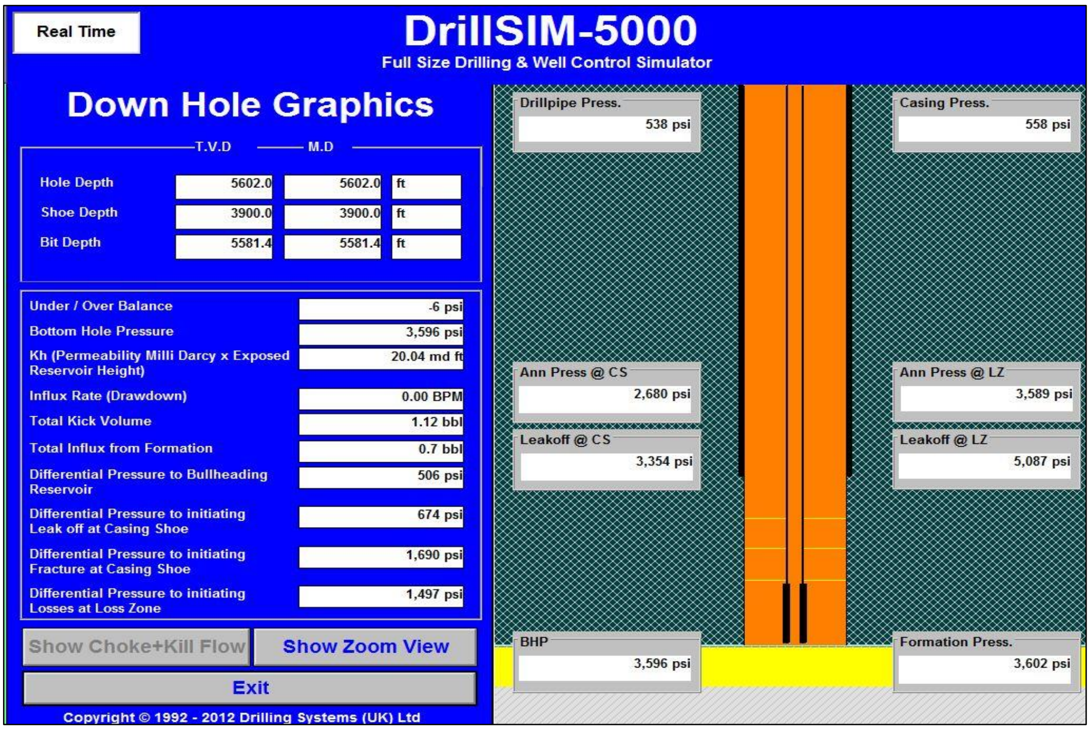

Figure 5.5. Well Schematics & Well Data after Stabilization for 2 Stroke (10 md)

When drill pipe pressure increase period is observed (Figure 5.6), it is seen that there are three times slope changes until the drill pipe pressure reaches equilibrium,

Unlike conventional method, the reason of the first slope that is marked with circle 1 is because of pumping mud into well during the time between 0 – 30 seconds (Figure 5.6).

There are three separated influx volumes in the annulus when drill pipe pressure reaches equilibrium.

The first separated influx volume enters the well before the well is completely closed. This section does not appear in the chart because the chart (Figure 5.6) shows the time after the shut-in.

The second separated influx volume enters during the time between 200 – 280 seconds that is marked with circle 2 and the third separated influx volume enters during the time between 1320 – 1420 seconds that is marked with circle 3 in Figure 5.6.

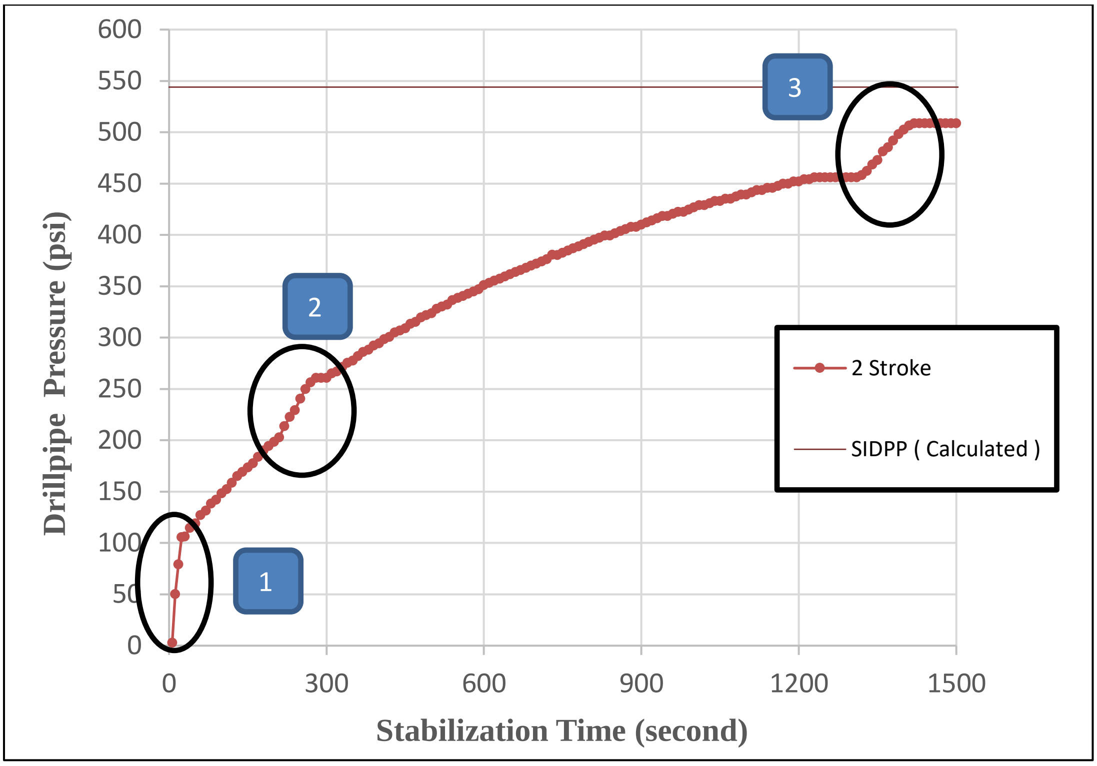

Figure 5.6. Detailed SIDPP vs. Stabilization Time for 2 Stroke (10 md)

5.2.1.3. Case 3: 4 Stroke

In this case 4 stroke (0.4 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after an hour is determined as an SIDPP and it is seen that the SIDPP is 59 psi lower than the calculated SIDPP (Figure 5.7).

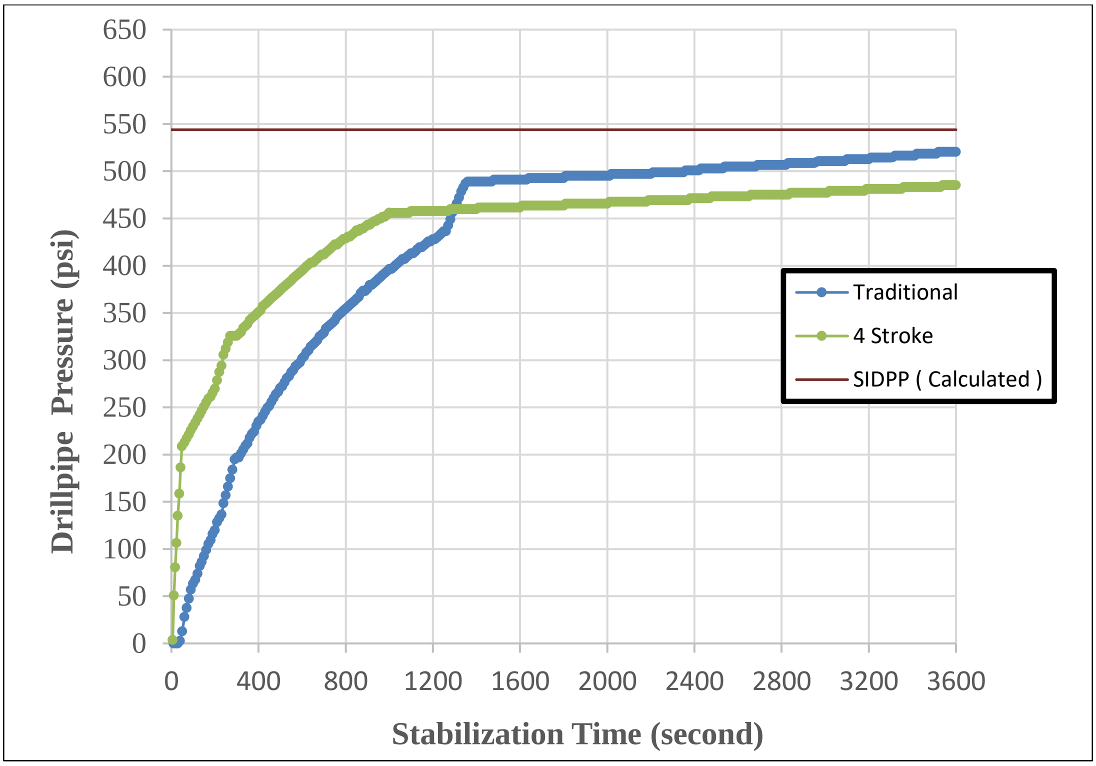

Figure 5.7. SIDPP vs. Stabilization Time for 4 Stroke (10 md)

There are two separated influx volumes in the annulus and total influx from formation was observed 0.5 bbl after one hour which is admitted as a stabilization time (Figure 5.8).

It is seen that pumping 0.4 bbl mud volume into the well during stabilization period provides 0.3 bbl less influx volume from formation.

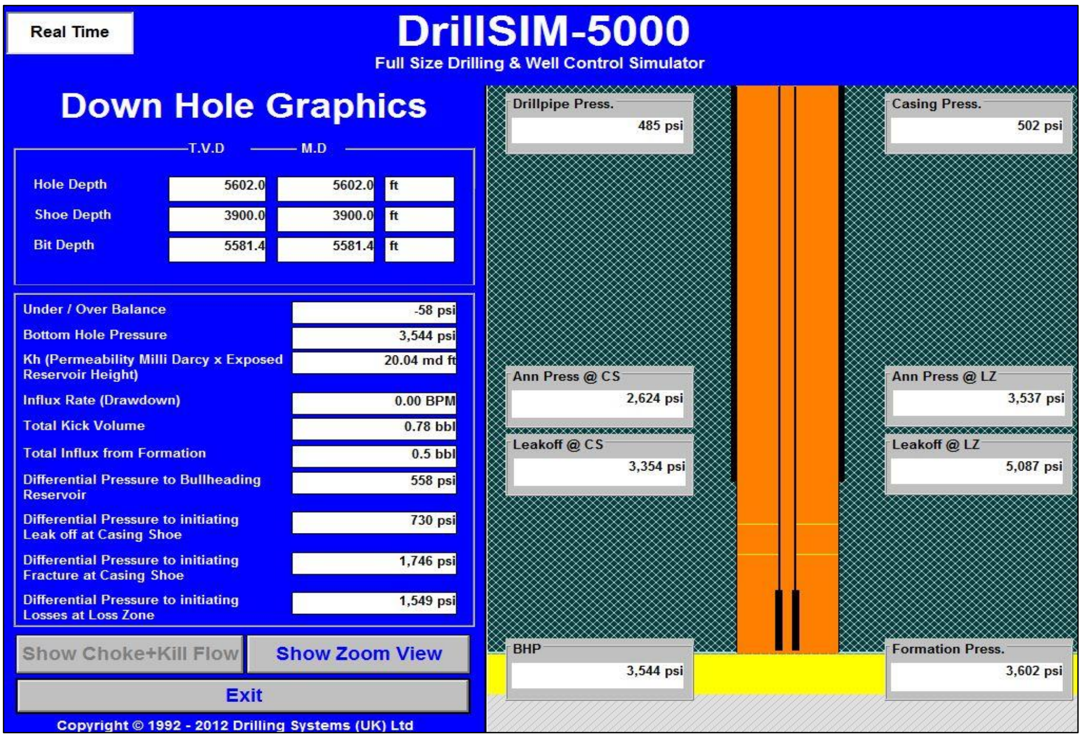

Figure 5.8. Well Schematics & Well Data after Stabilization 4 Stroke (10 md)

5.2.1.4. Case 4: 6 Stroke

In this case 6 stroke (0.6 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after an hour is determined as an SIDPP and it is seen that the SIDPP is 62 psi lower than the calculated SIDPP (Figure 5.9).

There are two separated influx volumes in the annulus and total influx from formation was observed 0.4 bbl after one hour which is admitted as a stabilization time (Figure 5.10).

It is seen that pumping 0.6 bbl mud volume into the well during stabilization period provides 0.4 bbl less influx volume from formation.

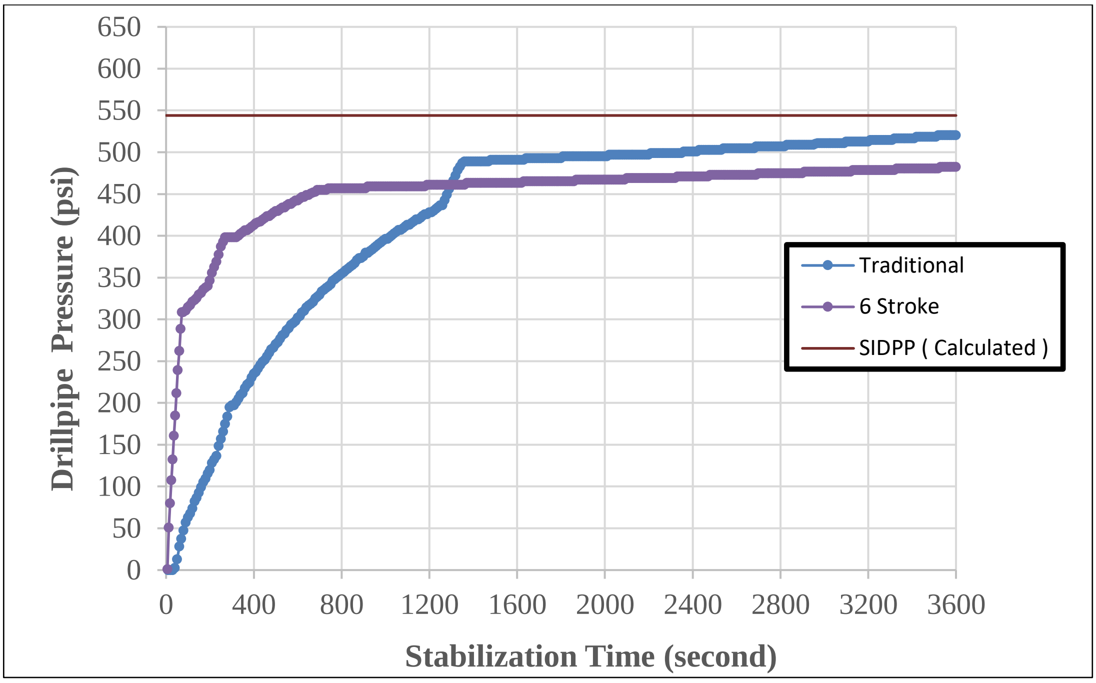

Figure 5.9. SIDPP vs. Stabilization Time for 6 Stroke (10 md)

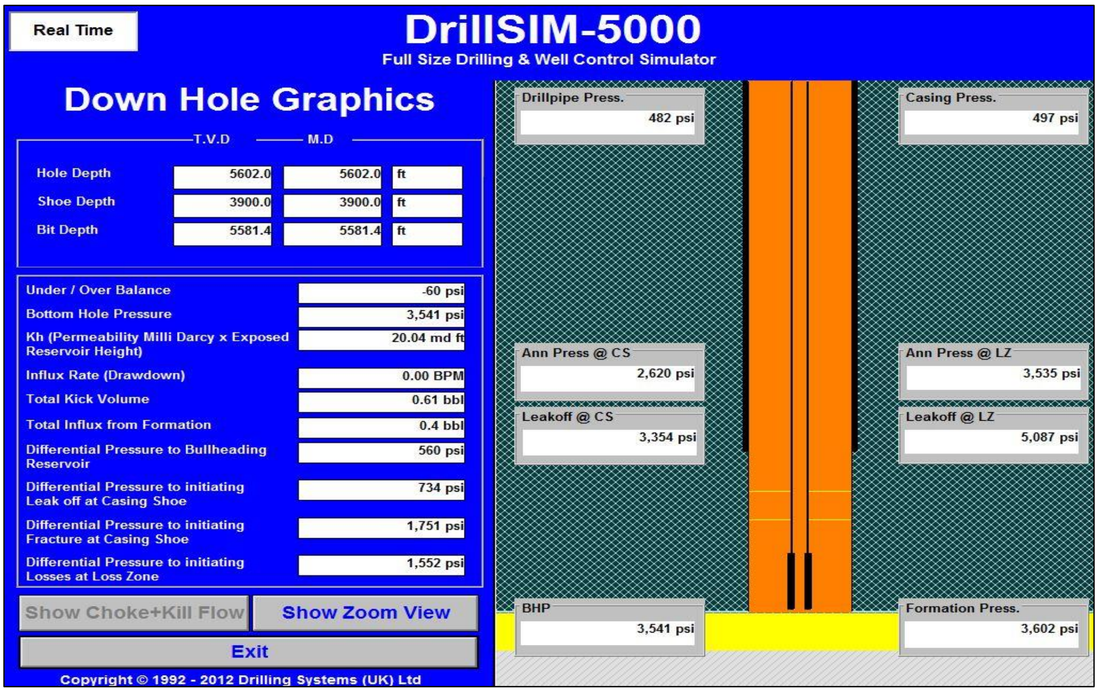

Figure 5.10. Well Schematics & Well Data after Stabilization 6 Stroke (10 md)

5.2.1.5. Case 5: 8 Stroke

In this case 8 stroke (0.8 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after an hour is determined as an SIDPP and it is seen that the SIDPP is 57 psi lower than the calculated SIDPP (Figure 5.11).

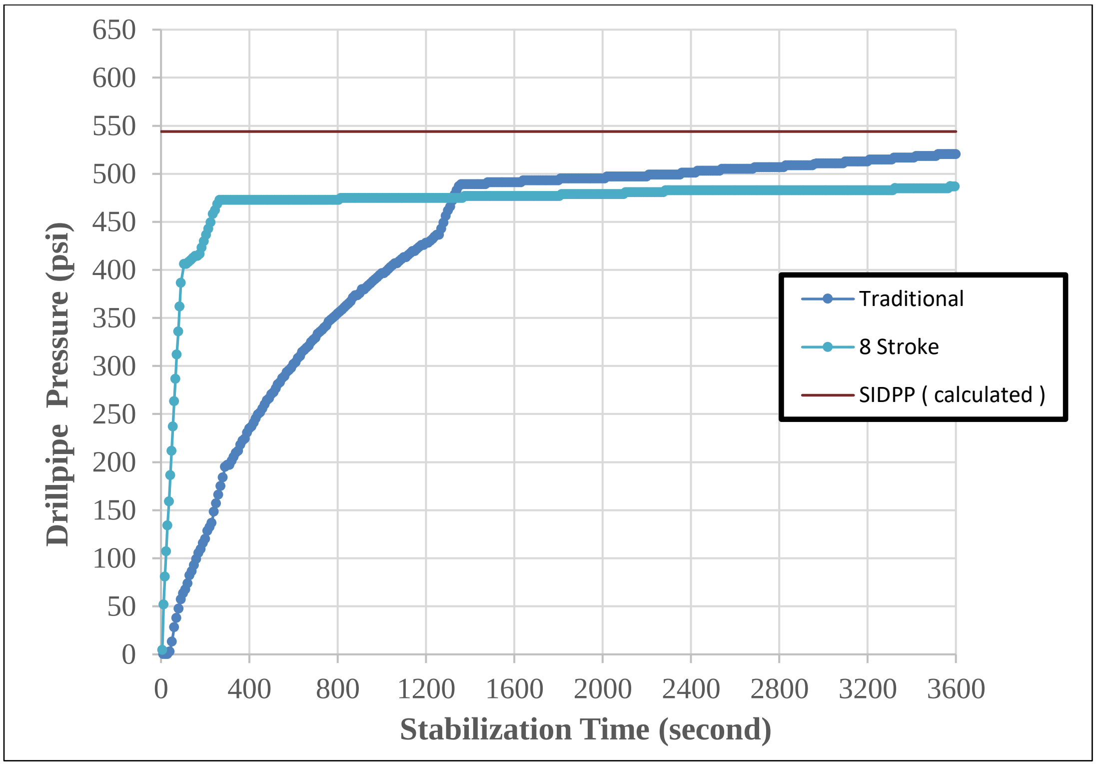

Figure 5.11. SIDPP vs. Stabilization Time for 8 Stroke (10 md)

There are two separated influx volumes in the annulus and total influx from formation was observed 0.2 bbl after one hour which is admitted as a stabilization time (Figure 5.12).

It is seen that pumping 0.8 bbl mud volume into the well during stabilization period provides 0.6 bbl less influx volume from formation.

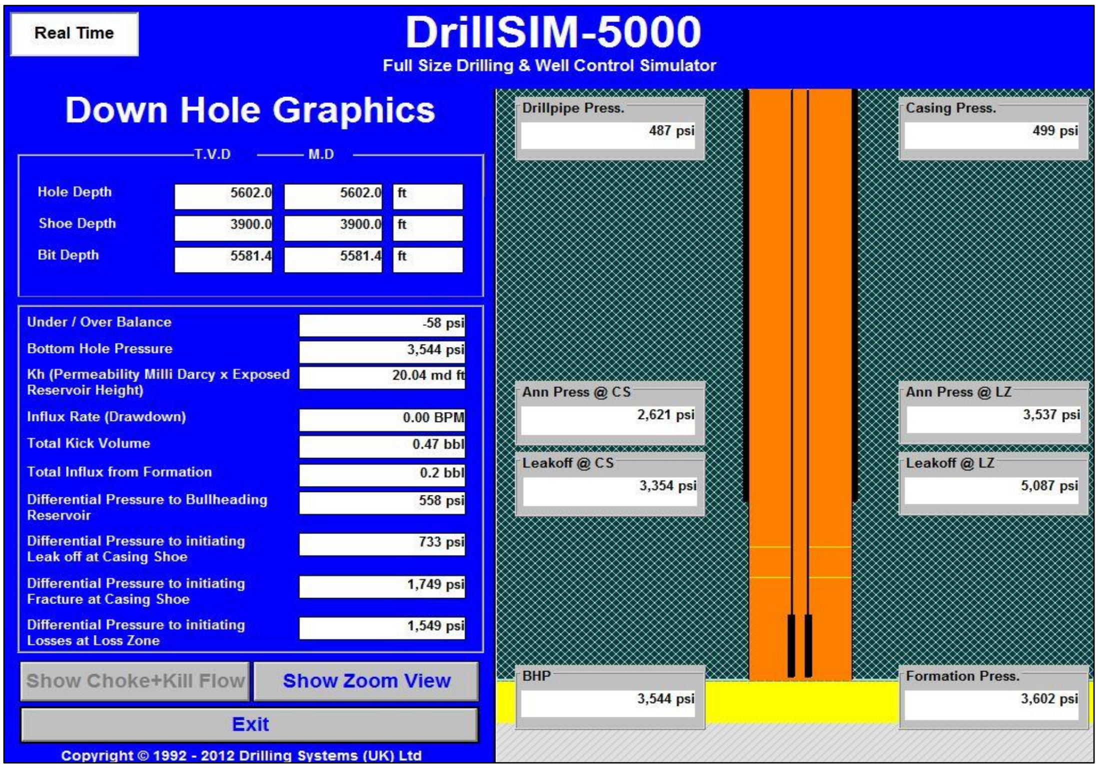

Figure 5.12. Well Schematics & Well Data after Stabilization 8 Stroke (10 md)

5.2.1.6. Case 6: 10 Stroke

In this case 10 stroke (1 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after an hour is determined as an SIDPP and it is seen that the SIDPP is 35 psi lower than the calculated SIDPP (Figure 5.13).

There are one separated influx volume in the annulus and total influx from formation was observed 0.2 bbl after one hour which is admitted as a stabilization time (Figure 5.14).

It is seen that pumping 1 bbl mud volume into the well during stabilization period provides 0.6 bbl less influx volume from formation.

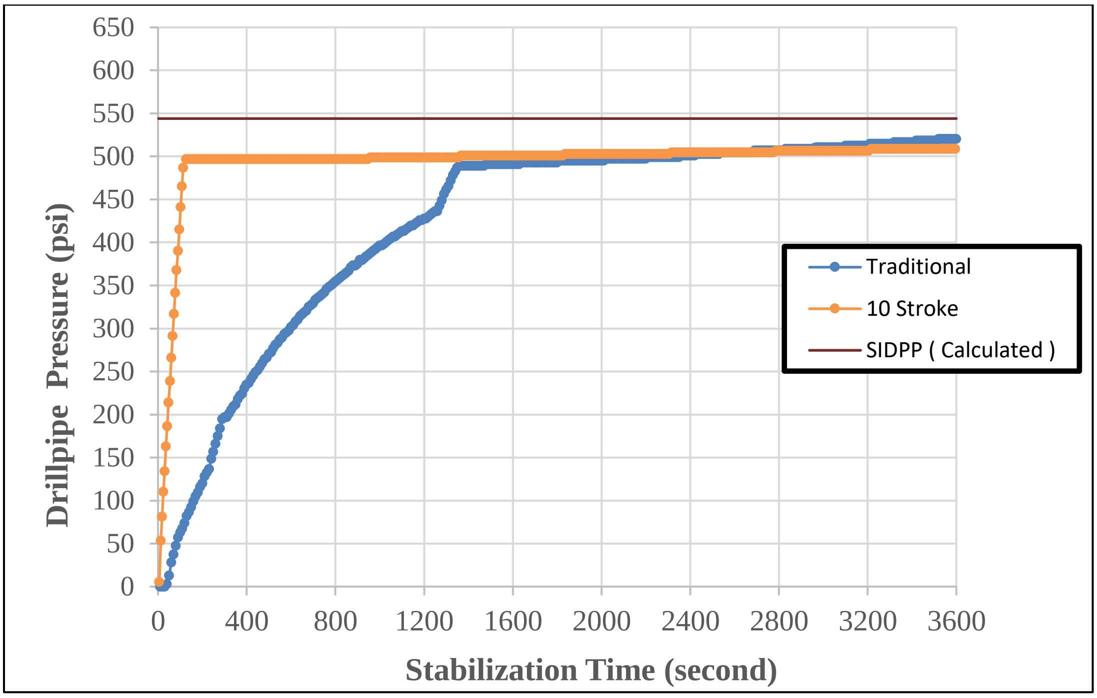

Figure 5.13. SIDPP vs. Stabilization Time for 10 Stroke (10 md)

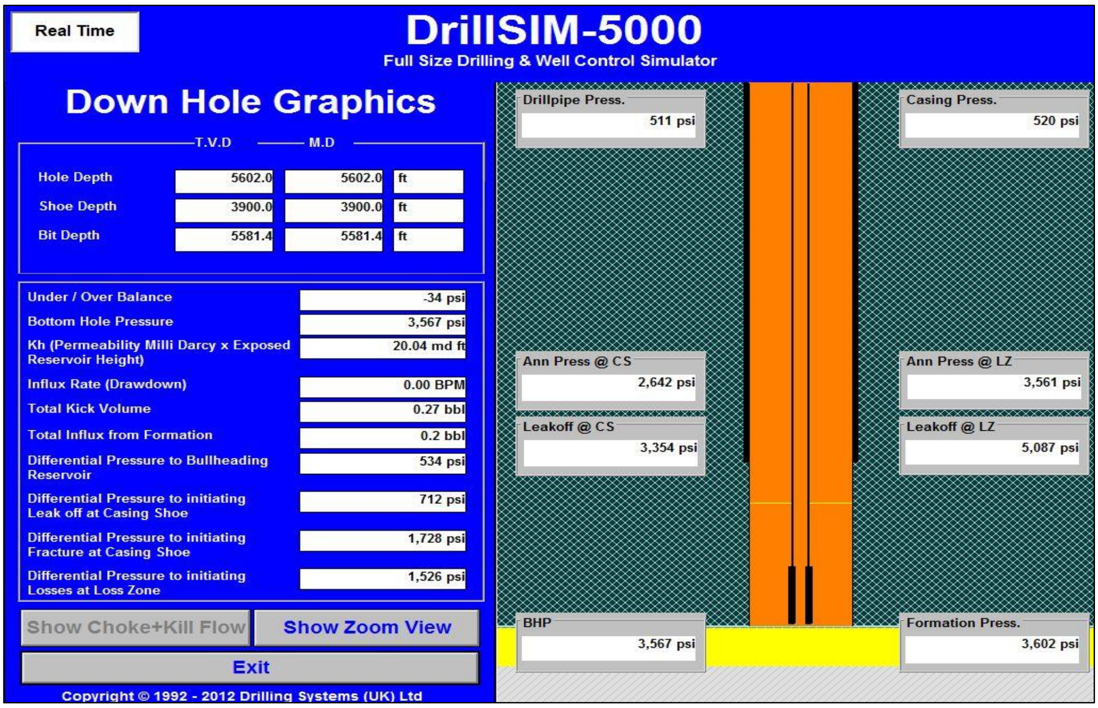

Figure 5.14. Well Schematics & Well Data after Stabilization 10 Stroke (10 md)

5.2.1.7. Case 7: 12 Stroke

In this case 12 stroke (1.2 bbl) volume of mud is pumped into the closed well after shut-in. The drill pipe pressure after an hour is determined as an SIDPP and it is seen that the SIDPP is 61 psi higher than the calculated SIDPP (Figure 5.15). Because of higher SIDPP than calculated SIDPP (544 psi), we can conclude these trials at this stage.

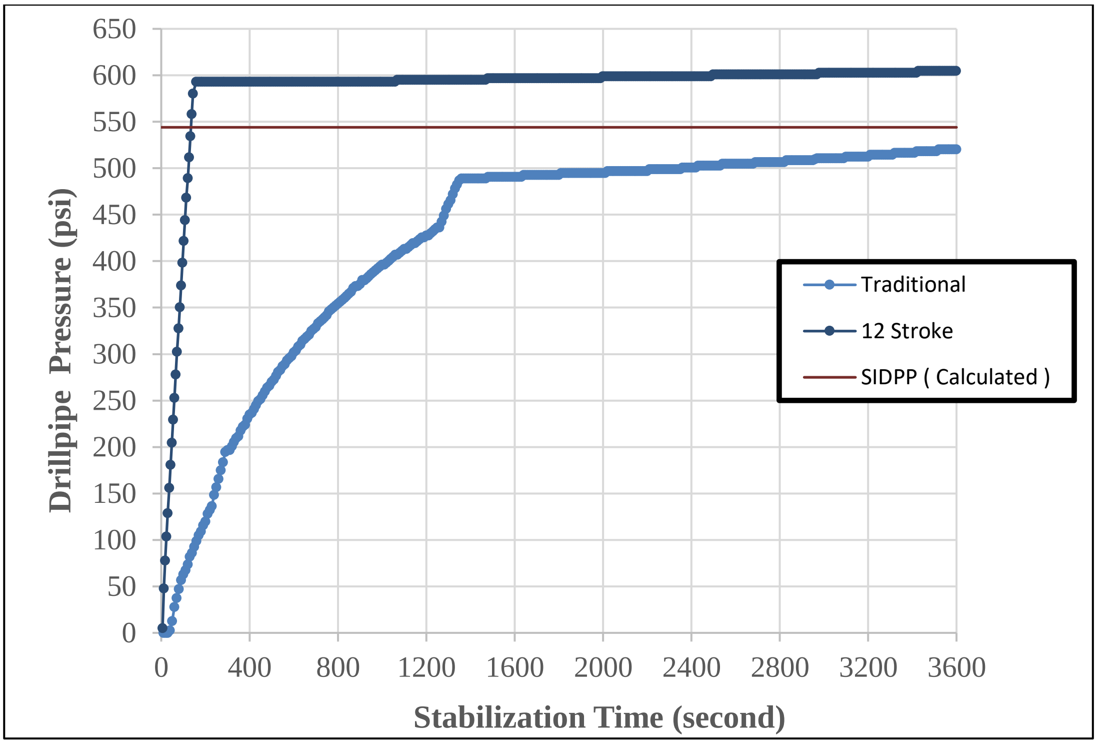

Figure 5.15. SIDPP vs. Stabilization Time for 12 Stroke (10 md)

There are one separated influx volumes in the annulus and Total influx from formation was observed 0.2 bbl after one hour which is admitted as a stabilization time (Figure 5.16).

It is seen that pumping 1.2 bbl mud volume into the well during stabilization period provides 0.6 bbl less influx volume from formation.

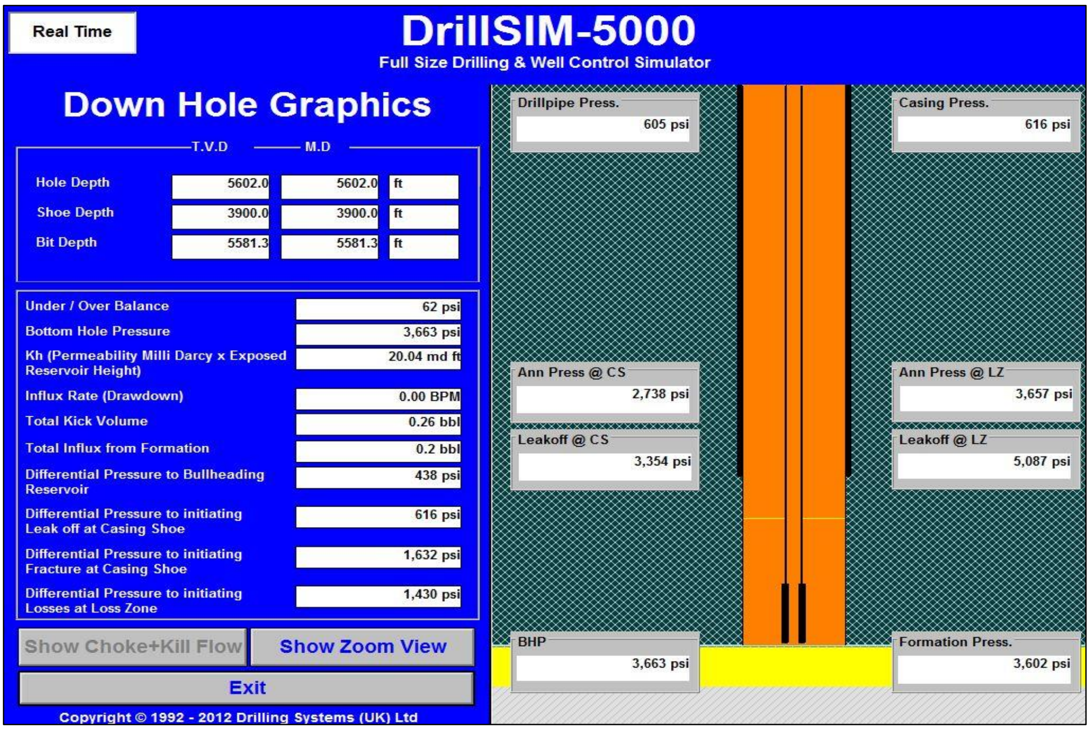

Figure 5.16. Well Schematics & Well Data after Stabilization 12 Stroke (10 md)

5.2.1.8. Comparison of Results for Scenario 1

In Scenario 1, the results of seven cases are compared and evaluated. SIDPPs, BHPs and Casing shoe pressures versus stabilization time for all cases for the formation which has the permeability is 10 md are shown in the graphics.

As it is seen, even in the conventional method, pressure cannot be stabilized and continues to rise slowly because of low permeability. Therefore the drill pipe pressure after an hour is attained as an SIDPP. It is seen that SIDPP is 24 psi lower than the calculated SIDPP.

In the case 2, pressure difference is observed 6 psi which is the closest value to the calculated SIDPP. Conversely, the farthest SIDPP value to the calculated SIDPP is observed in the case 4 in which pressure differential is 62 psi. It is observed that pressure differentials are independent from the pumped volume of mud to the wellbore for the cases in scenario 1.

Bottom-hole pressure is one of the values that is studied and compared. The comparison of results are shown in Figure 5.19. Bottom-hole pressure is increased by pumping drilling fluid into the closed well. As it is seen from the graphic, the behavior of bottom-hole pressure build up is almost the same to the behavior of SIDPP build up.

Casing shoe is one of the critical zones. As it was mentioned before excessive pressure may cause mechanical failure and formation breakdown during first closure or throughout the circulation. A Formation breakdown can cause loss of circulation and an underground blowout. Maximum allowable pressure must be determined to avoid these problems. Therefore casing shoe pressure is studied and compared, too. As it is seen from the Figure 5.20, casing shoe pressure for all cases below the formation fracture pressure at casing shoe which is 4368 psi.

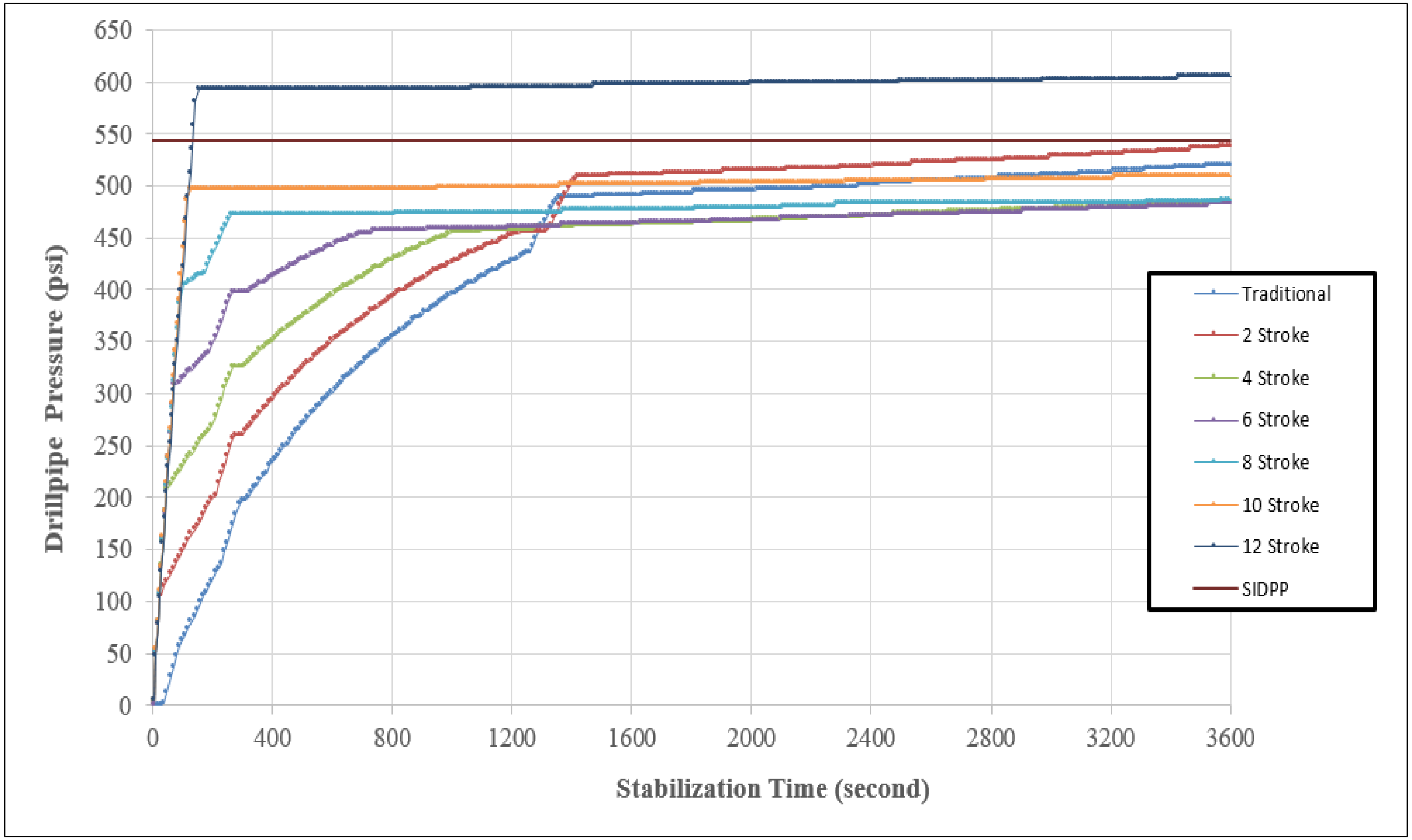

Figure 5.17 Comparison of the SIDPP vs. Stabilization Time for the Cases for 10 md Permeability

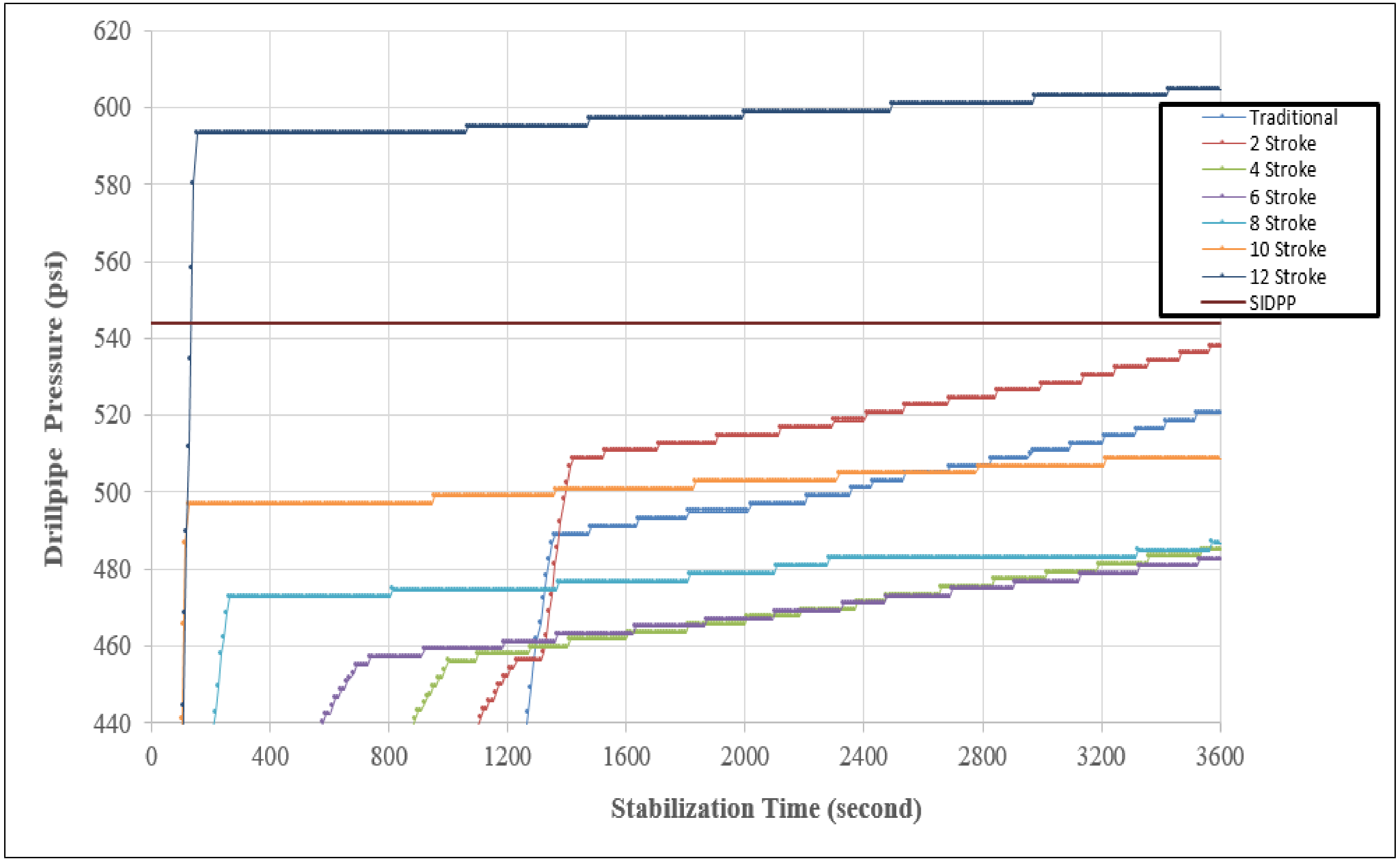

Figure 5.18 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 10 md Permeability (Detail Scale)

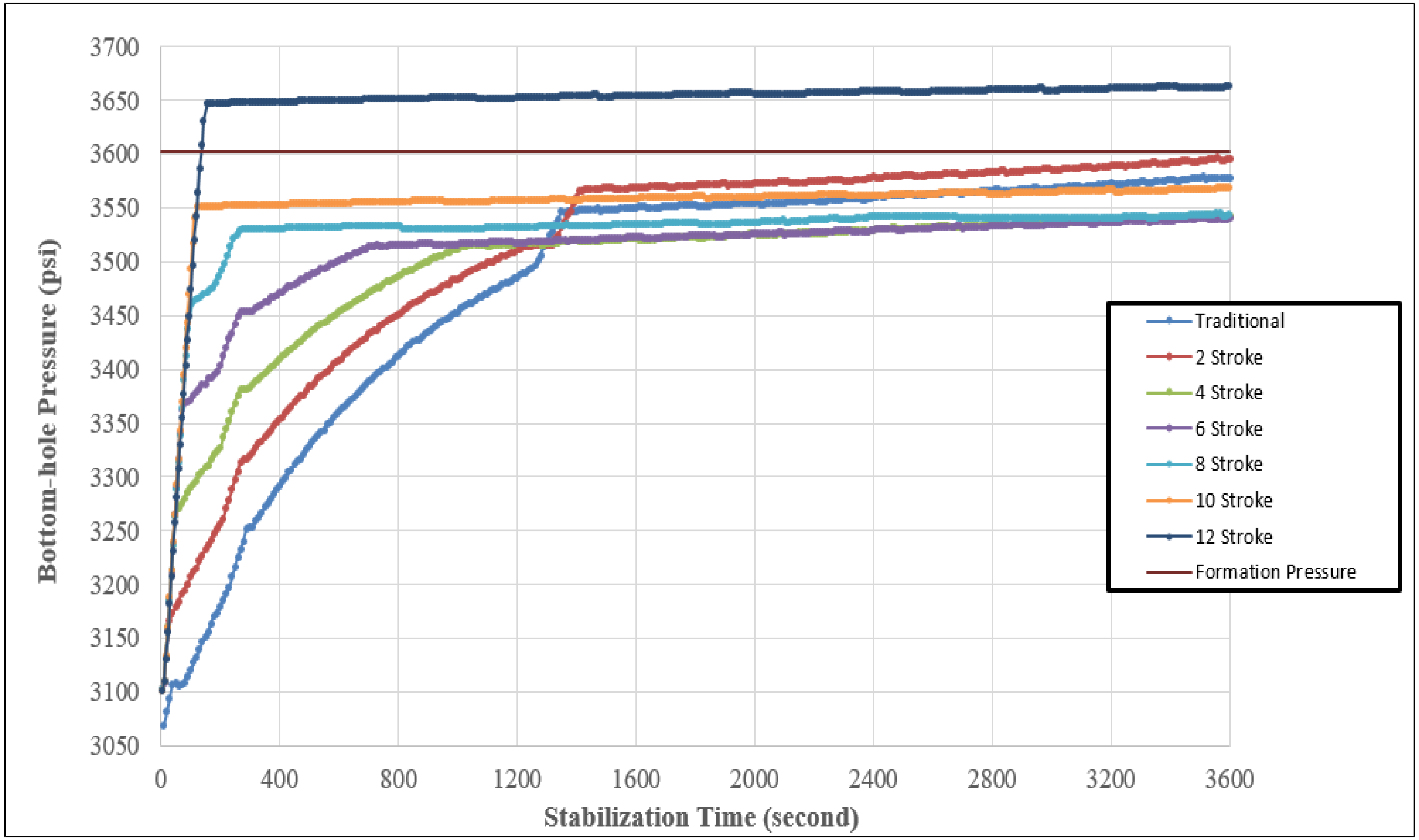

Figure 5.19 Comparison of the BHP vs. Stabilization Time for the Cases for 10 md Permeability

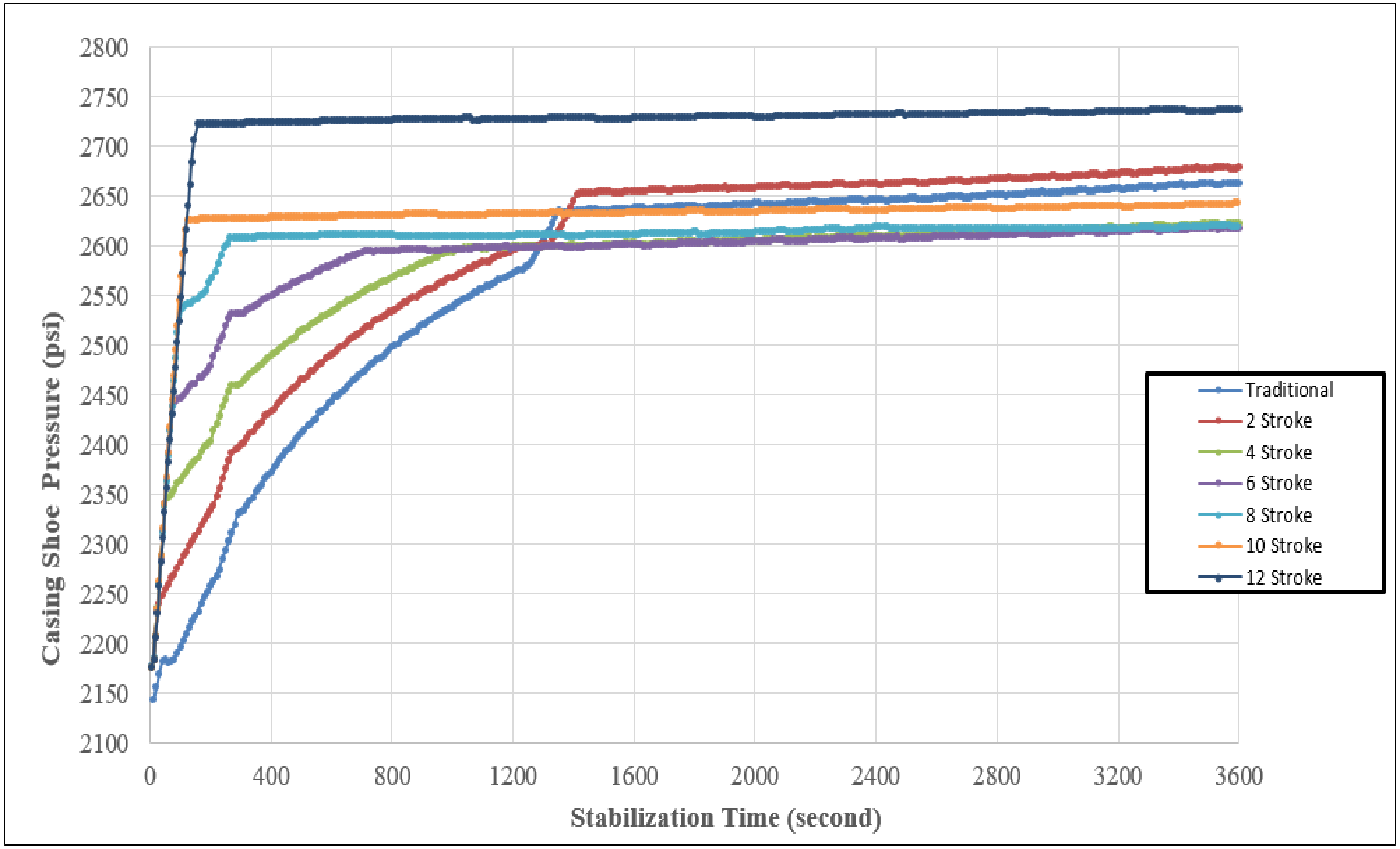

Figure 5.20 Comparison of the Casing Shoe Pressure vs. Stabilization Time for the Cases for 10 md Permeability

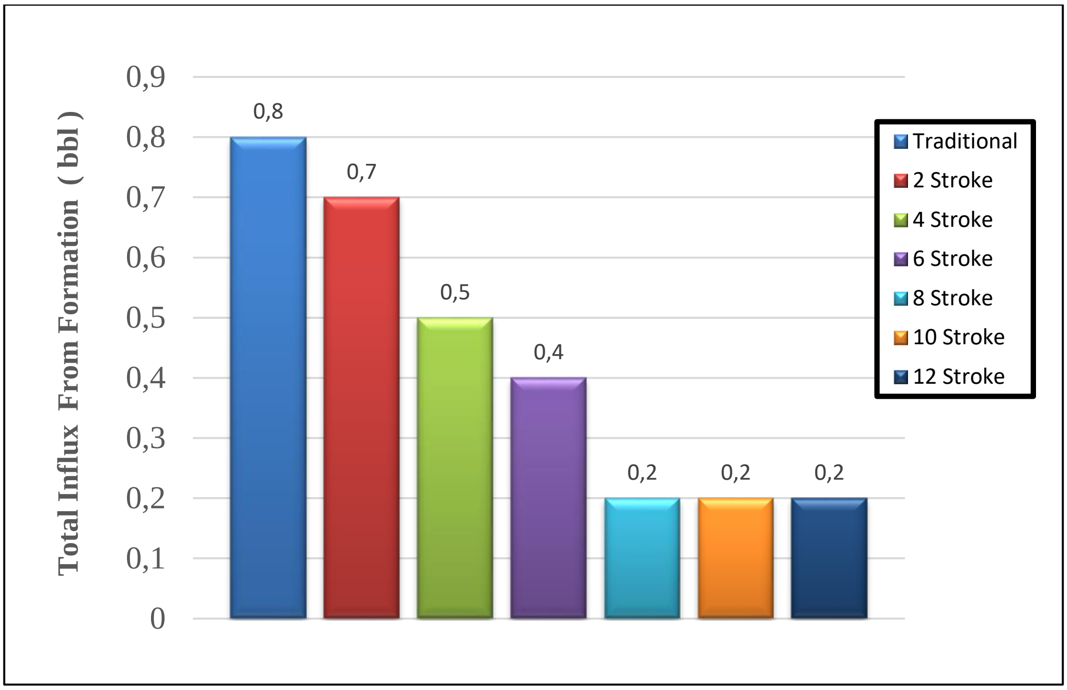

Figure 5.21. Comparisons of the Total Influx from Formation for the Cases for 10 md Permeability

The main aim of this study is to lessen volume of influx from the formation after shut-in the well with a new well control approach. Figure 5.21 illustrates the comparisons of the total influx volume from formation for the cases for 10 md permeability. It can be seen an advantages of the new well control approach over conventional method.

In conventional method, total influx volume from formation is 0.8 bbl which is the maximum value in Scenario 1. When the new well control approach is applied, gradual decrease is seen until Case 6 and remains unchanged From Case 5 to Case 7. Although volume of mud pumped into wellbore changes From Case 5 to Case 7, the total influx is constant for these cases, because this influx volume is taken during the time until well shut-in completely.

It is known that shut-in period allows additional inflow of gas bubbles into annulus because the gas bubbles in annulus are capable of further compression [16]. Figure

5.22 illustrates the comparisons of the total influx volume from formation and total kick volume for the cases for 10 md permeability.

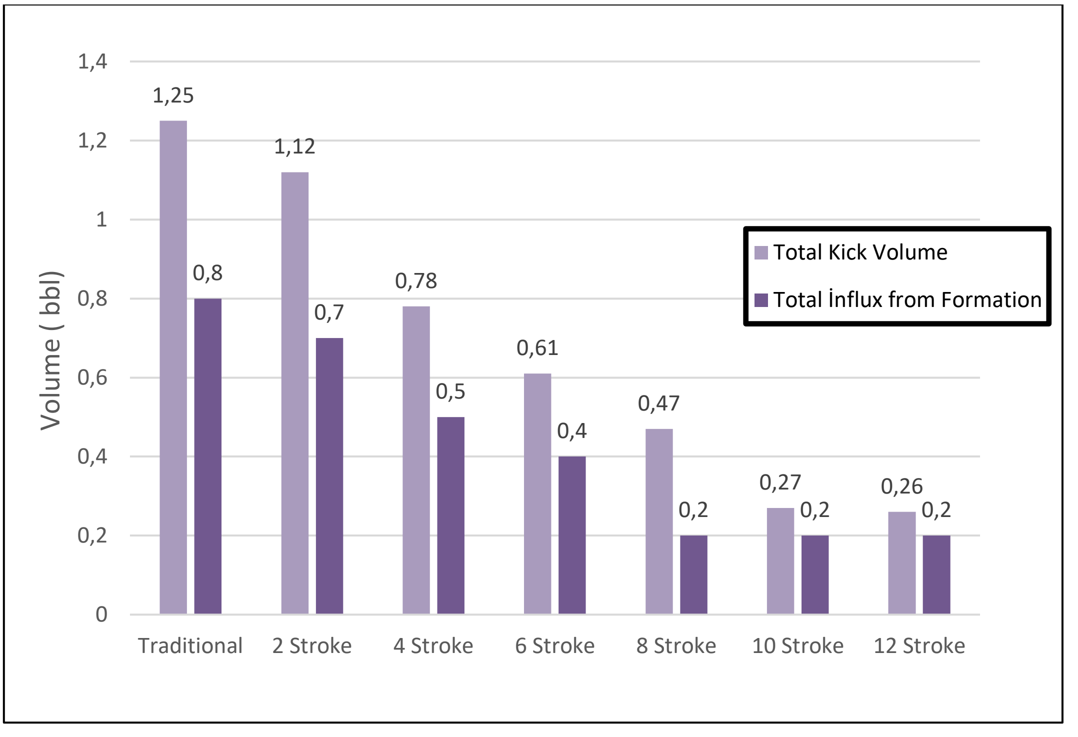

Figure 5.22. Comparisons of the Total Influx from Formation and Total Kick Volume for the Cases for 10 md

As it is seen from the Figure 5.22, when the new well control approach is applied, since the compressibility of gas, the total volume of mud pumped into well does not allow the same volume of influx to be reduced. For instance, the volume of total influx from formation for traditional method is 0.8 bbl. When 6 stroke (0.6 bbl.) volume of mud pumped into well bore after shut-in, the influx volume becomes 0.4 bbl.

Although volume of mud pumped into well changes From Case 5 to Case 7, the total influx is constant for these cases and it is understood that pumping mud into well does not reduce influx volume further except the compression of gas.

Table 5.1. Comparison of the Results for the Cases for 10 md Permeability

Total Stroke	Real Stroke	Stabilization Time	% Time	Total Influx fr.Fm	% Total Influx fr.Fm	Max. Shoe Pressure	SIDPP	Pressure Differential
0	0.0	3600	100	0.8	100	2664	520	-24
2	2.1	3600	100	0.7	88	2679	538	-6
4	4.0	3600	100	0.5	63	2623	485	-59
6	5.9	3600	100	0.4	50	2619	482	-62
8	8.1	3600	100	0.2	25	2620	487	-57
10	10.1	3600	100	0.2	25	2644	509	-35
12	12.1	3600	100	0.2	25	2738	605	61

The data in the table 5.1 is used to compare and evaluate the results of all cases for 10 md permeability. As shown in the Table 5.3, the maximum decrease in total influx volume is 75 percent. It seems that this new approach is successful when all the results are taken into consideration.

5.2.2. Scenario 2 (50 md)

In Scenario 2, the permeability of reservoir is selected 50 md. There are six cases. Cases are started with conventional method and followed by unconventional approach.

5.2.2.1. Case 1: Conventional Method

In the first case, when gas kick has been observed, the well is shut-in according to the conventional method of shut-in procedures. Hence the permeability of reservoir is low, drill pipe pressure rises slowly instead of stabilizing the steady value. There are two separated influx volumes in the annulus and total influx from formation was observed as a volume of 1.5 bbl after 1536 seconds (about 26 minutes) which is accepted as a stabilization time (Figure 5.23).

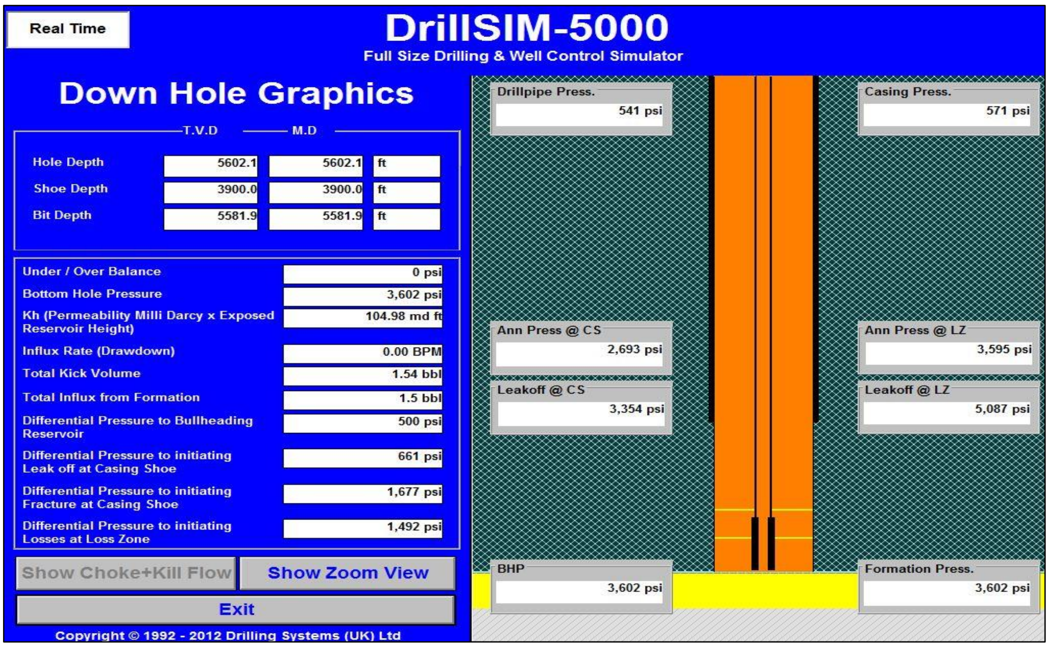

Figure 5.23. Well Schematics & Well Data after Stabilization for Conventional Method (50 md)

5.2.2.2. Case 2: 2 Stroke

In case 2, 2 stroke (0.2 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 544 psi and it is observed that the SIDPP is equal to the calculated SIDPP (Figure 5.24).

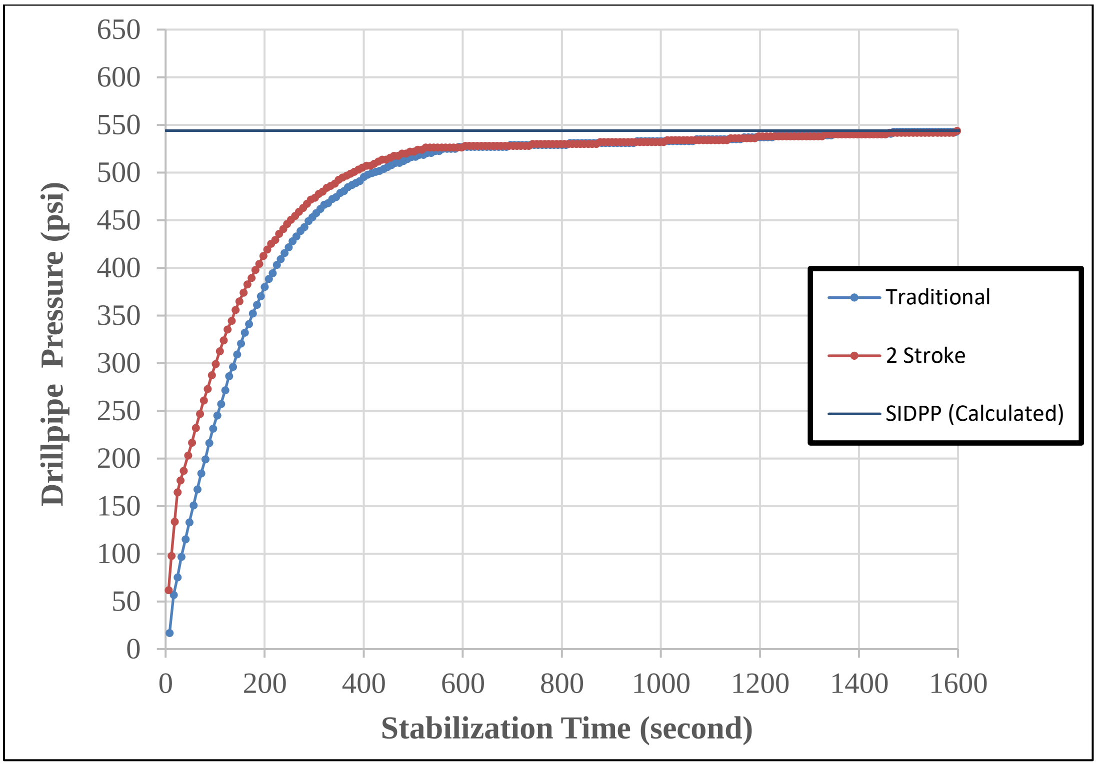

Figure 5.24. SIDPP vs. Stabilization time for 2 Stroke (50 md)

There are two separated influx volumes in the annulus and total influx from formation was observed 1.3 bbl after 1622 seconds (about 27 minutes) which is accepted as a stabilization time (Figure 5.25).

It is seen that pumping 0.2 bbl mud volume into the well during stabilization period provides 0.2 bbl less influx volume from formation.

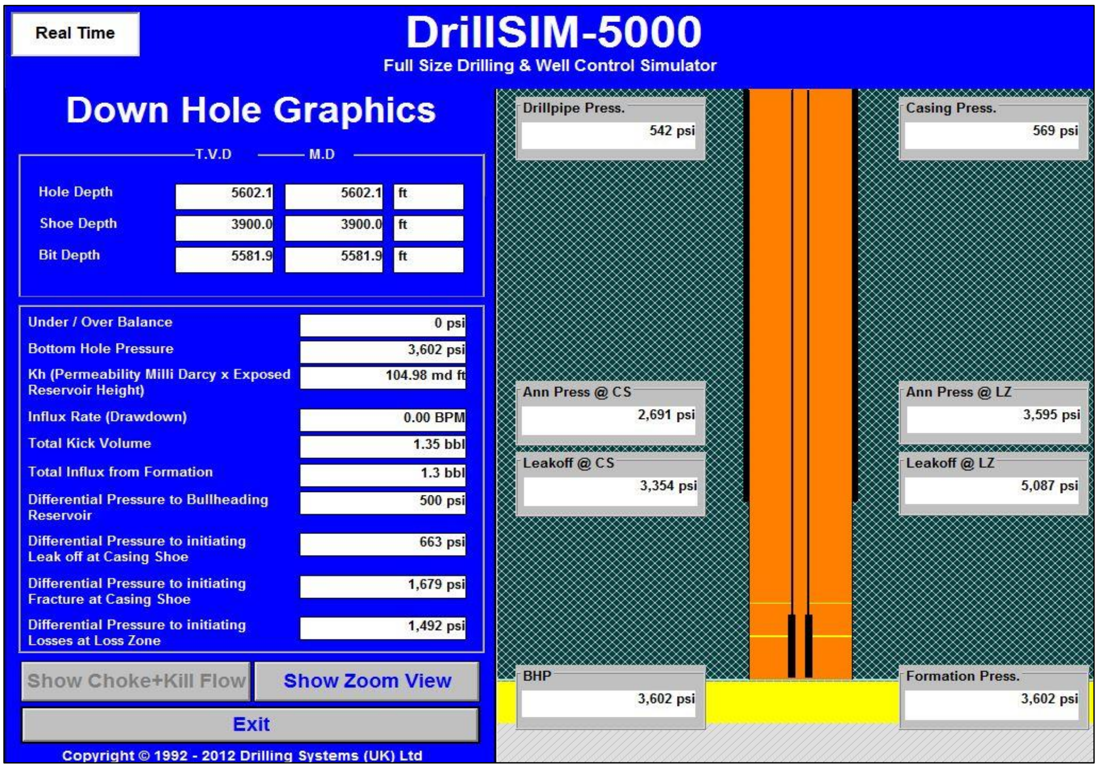

Figure 5.25. Well Schematics & Well Data after Stabilization for 2 Stroke (50 md)

5.2.2.3. Case 3: 4 Stroke

In this case 4 stroke (0.4 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 543 psi and it is observed that the SIDPP is 1 psi lower than the calculated SIDPP (Figure 5.26).

There are two separated influx volumes in the annulus and total influx from formation was observed 1.1 bbl after 1610 seconds (about 27 minutes) which is accepted as a stabilization time (Figure 5.27).

It is seen that pumping 0.4 bbl mud volume into the well during stabilization period provides 0.4 bbl less influx volume from formation.

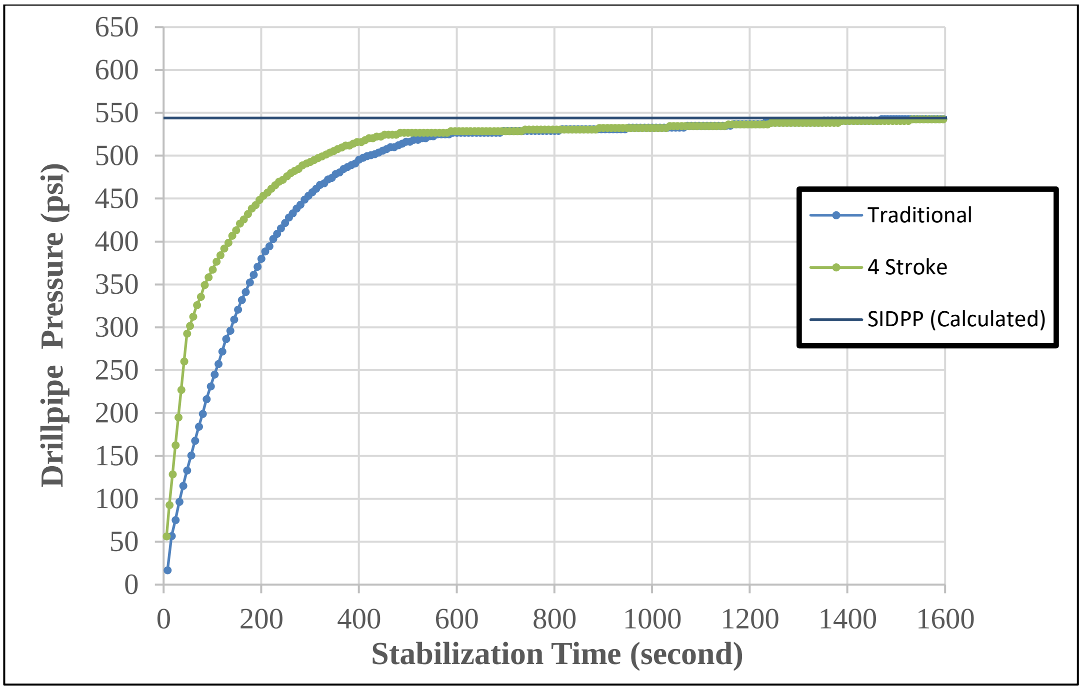

Figure 5.26. SIDPP vs. Stabilization Time for 4 Stroke (50 md)

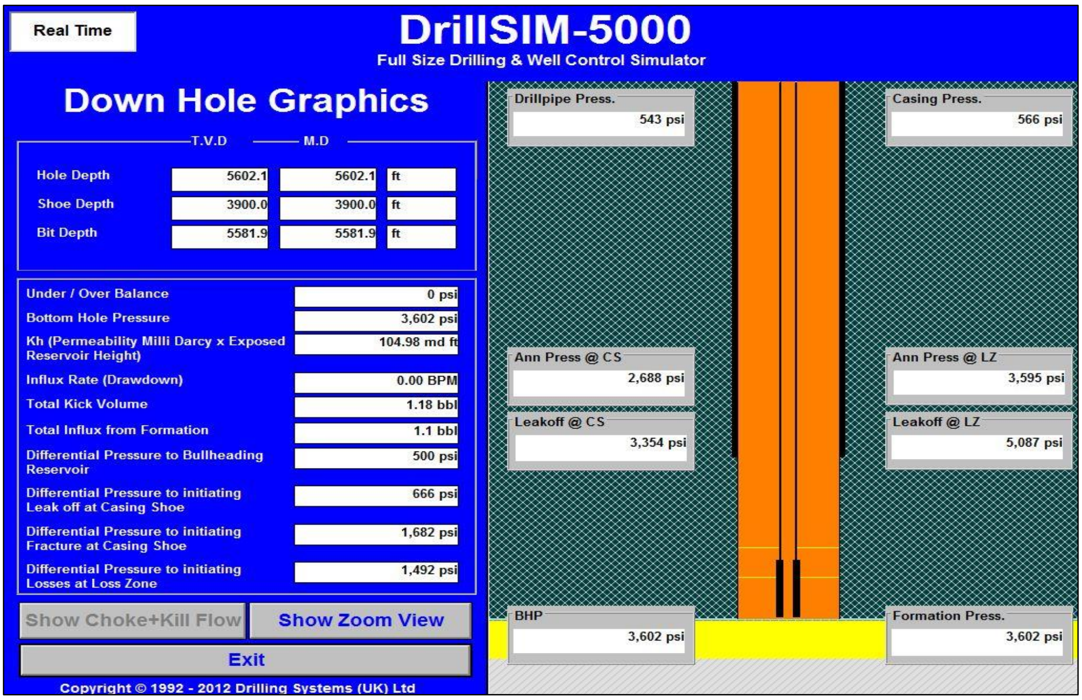

Figure 5.27. Well Schematics & Well Data after Stabilization for 4 Stroke (50 md)

5.2.2.4. Case 4: 6 Stroke

In this case 6 stroke (0.6 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 543 psi and it is observed that the SIDPP is 1 psi lower than the calculated SIDPP (Figure 5.28).

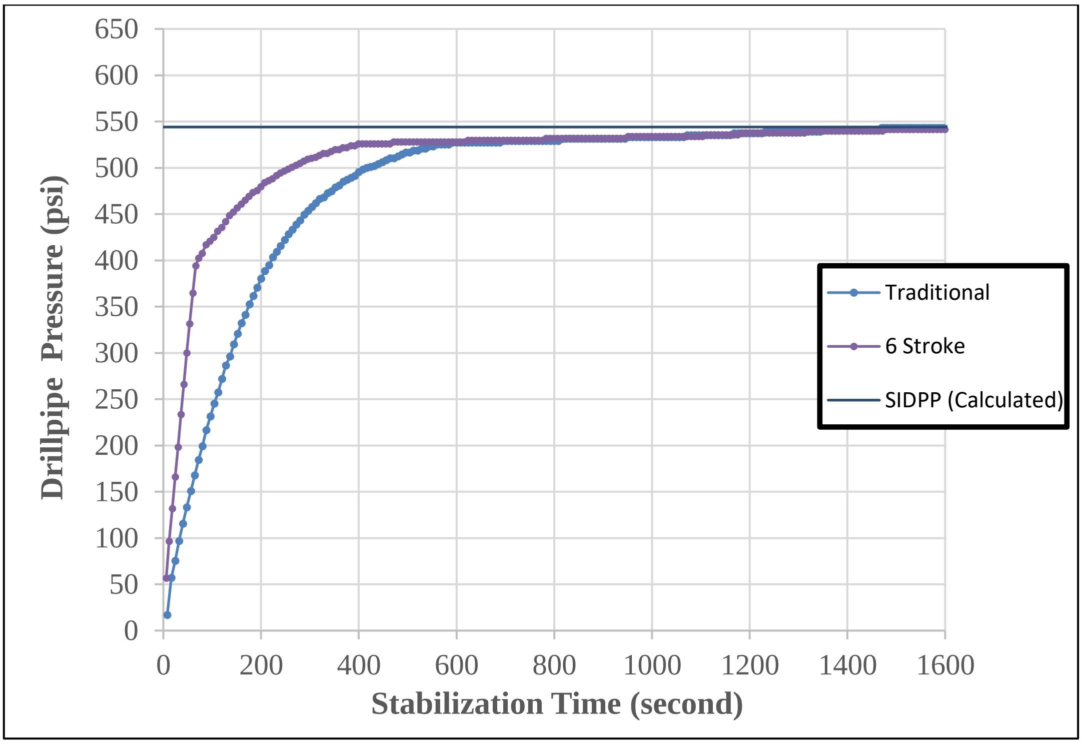

Figure 5.28. SIDPP vs. Stabilization Time for 6 Stroke (50 md)

There are two separated influx volumes in the annulus and total influx from formation was observed 1.0 bbl after 1676 seconds (about 28 minutes) which is accepted as a stabilization time (Figure 5.29).

It is seen that pumping 0.6 bbl mud volume into the well during stabilization period provides 0.5 bbl less influx volume from formation.

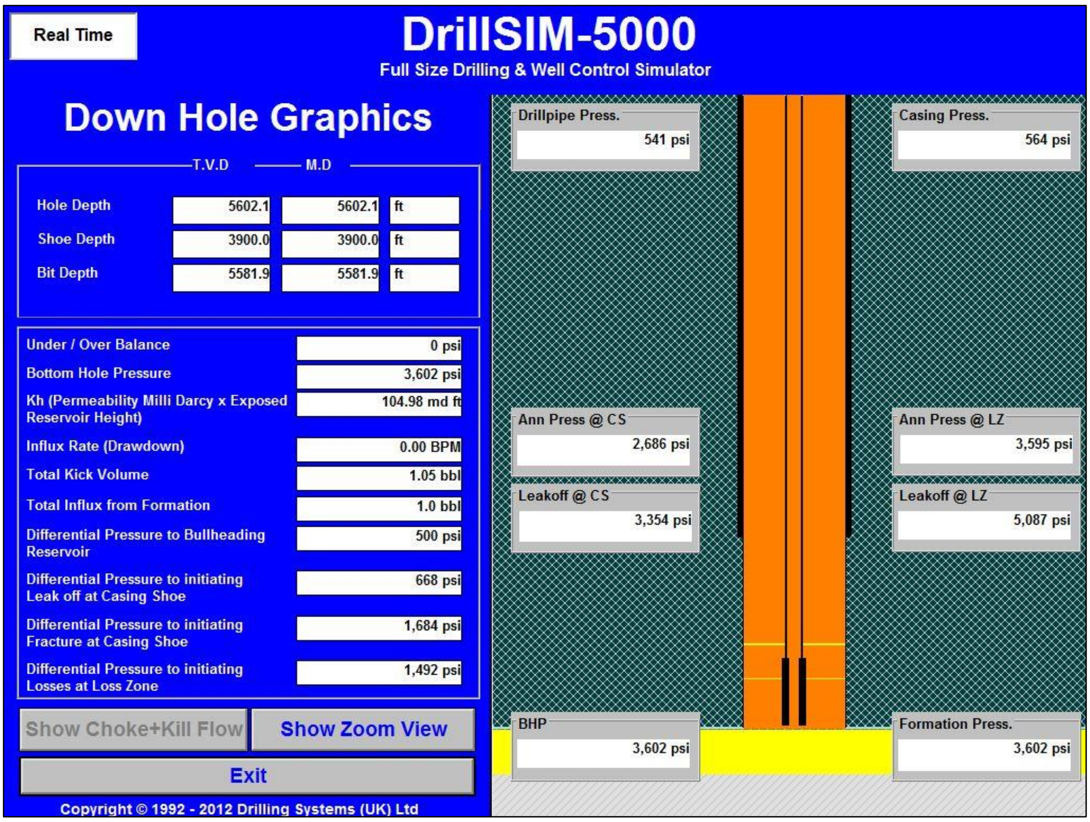

Figure 5.29. Well Schematics & Well Data after Stabilization for 6 Stroke (50 md)

5.2.2.5. Case 5: 8 Stroke

In this case 8 stroke (0.8 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 541 psi and it is observed that the SIDPP is 3 psi lower than the calculated SIDPP (Figure 5.30).

There are two separated influx volumes in the annulus and total influx from formation was observed 0.8 bbl 1550 seconds (about 26 minutes) which is accepted as a stabilization time (Figure 5.31).

It is seen that pumping 0.8 bbl mud volume into the well during stabilization period provides 0.7 bbl less influx volume from formation.

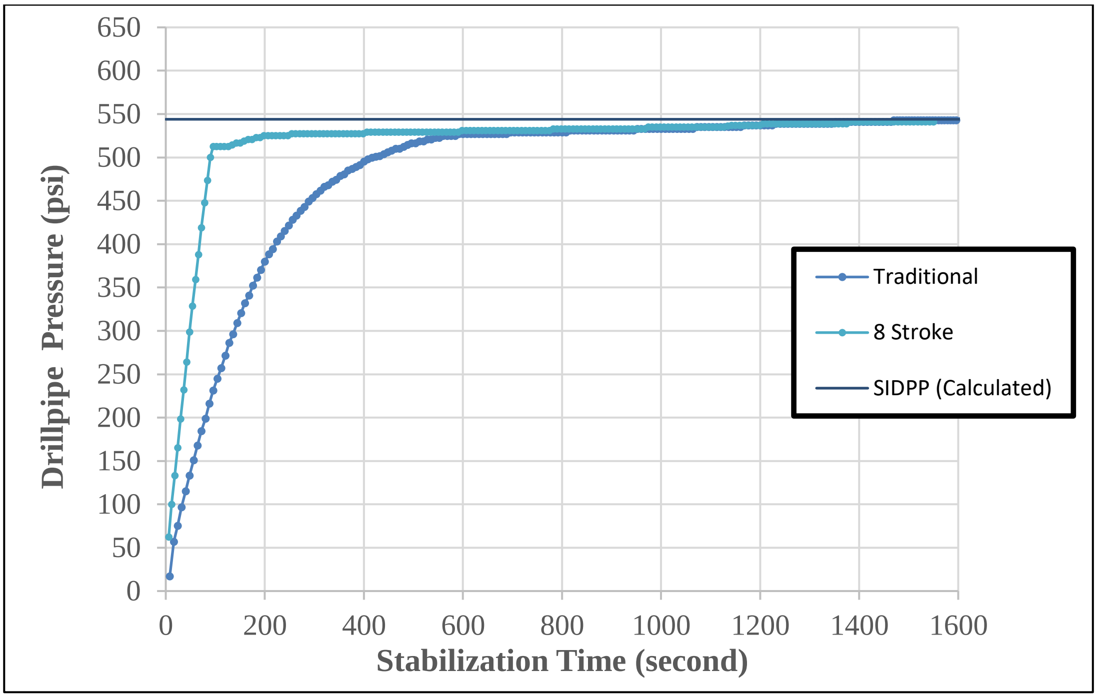

Figure 5.30. SIDPP vs. Stabilization Time for 8 Stroke (50 md)

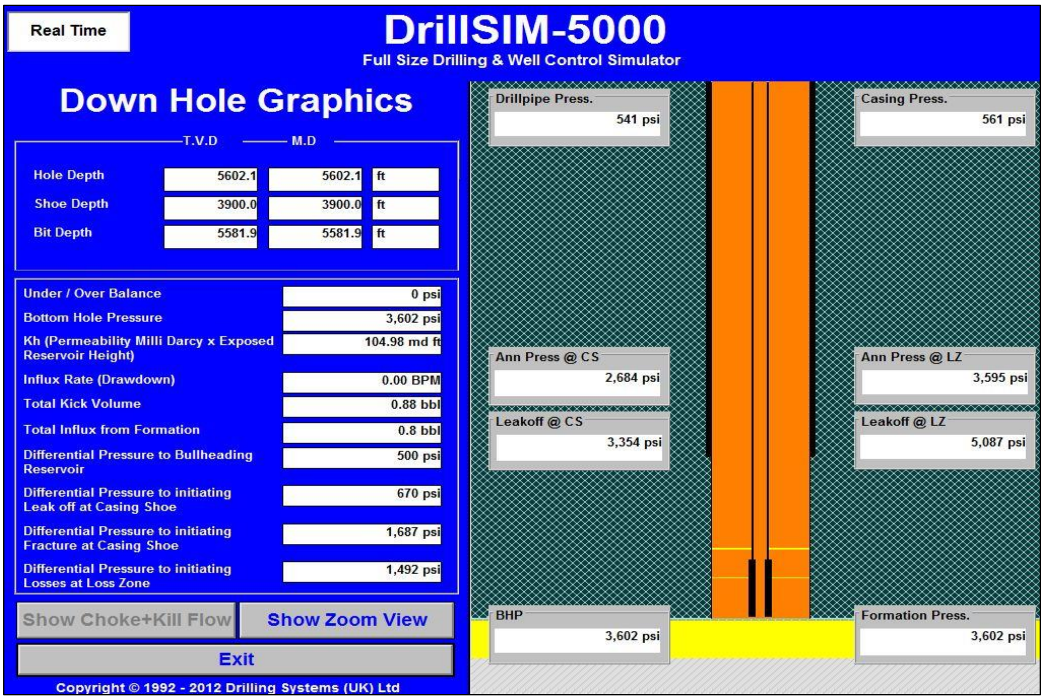

Figure 5.31. Well Schematics & Well data after Stabilization for 8 Stroke (50 md)

5.2.2.6. Case 6: 10 Stroke

In this case 10 stroke (1 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 607 psi and it is observed that the SIDPP is 63 psi higher than the calculated SIDPP (Figure 5.32). Because of higher SIDPP than calculated SIDPP (544 psi), we can conclude these trials at this stage.

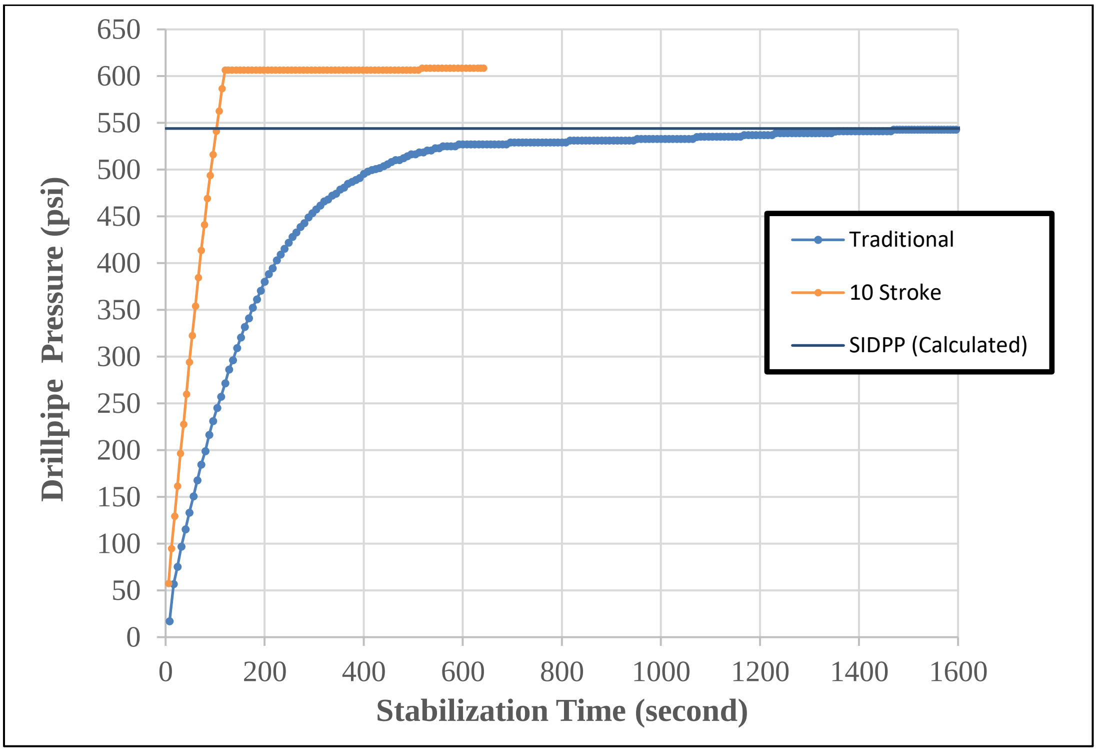

Figure 5.32. SIDPP vs. Stabilization Time for 10 Stroke (50 md)

There are two separated influx volumes in the annulus and total influx from formation was observed 0.8 bbl after 2 minutes that is the stabilization time (Figure 5.33).

It is seen that pumping 1 bbl mud volume into the well during stabilization period provides 0.7 bbl less influx volume from formation.

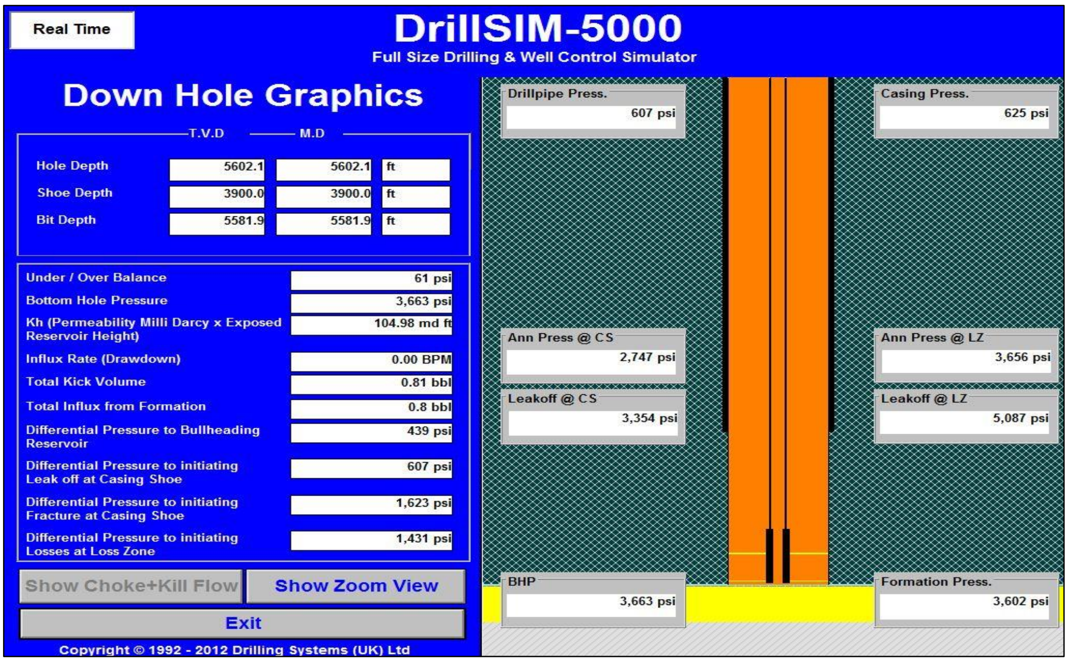

Figure 5.33. Well schematics & Well Data after Stabilization for 10 Stroke (50 md)

5.2.2.7. Comparison of Results for Scenario 2

In scenario 2, the results of six cases are compared and evaluated. SIDPPs, BHPs and Casing shoe pressures versus stabilization time for all cases for the formation which has the permeability is 50 md are shown in the graphics. In all cases except Case 6, pressure differences is observed 1 or 2 psi which means SIDPPs are almost the same as the calculated SIDPP (Figure 5.34).

The comparison of bottom-hole pressures are shown in Figure 5.36. As it is seen from the graphic, the behavior of bottom-hole pressure build up is almost the same to the behavior of SIDPP build up.

Casing shoe pressures is studied and compared, too. As it is seen from the Figure 5.37, Casing shoe pressure for all cases below the formation fracture pressure at casing shoe which is 4368 psi.

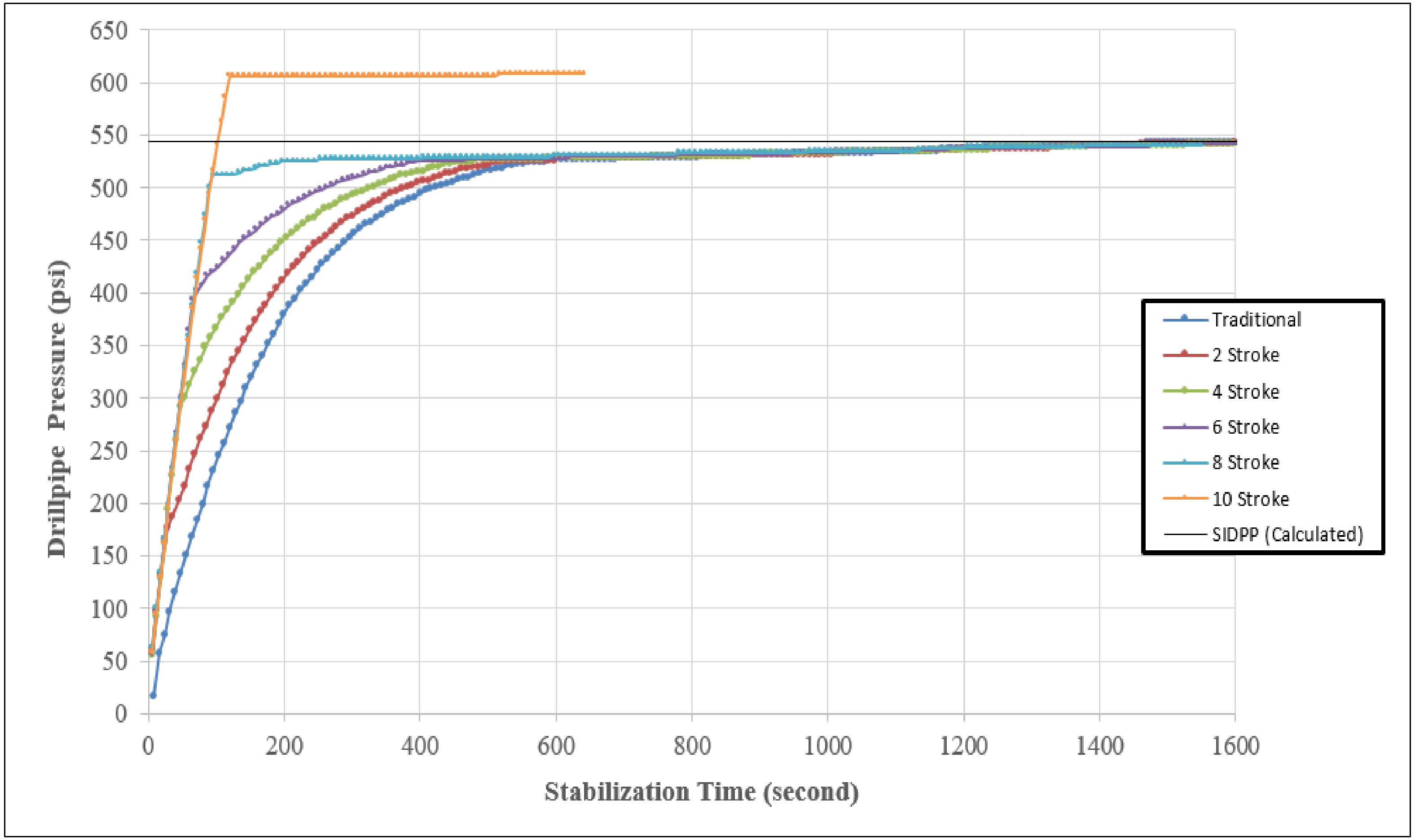

Figure 5.34 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 50 md Permeability

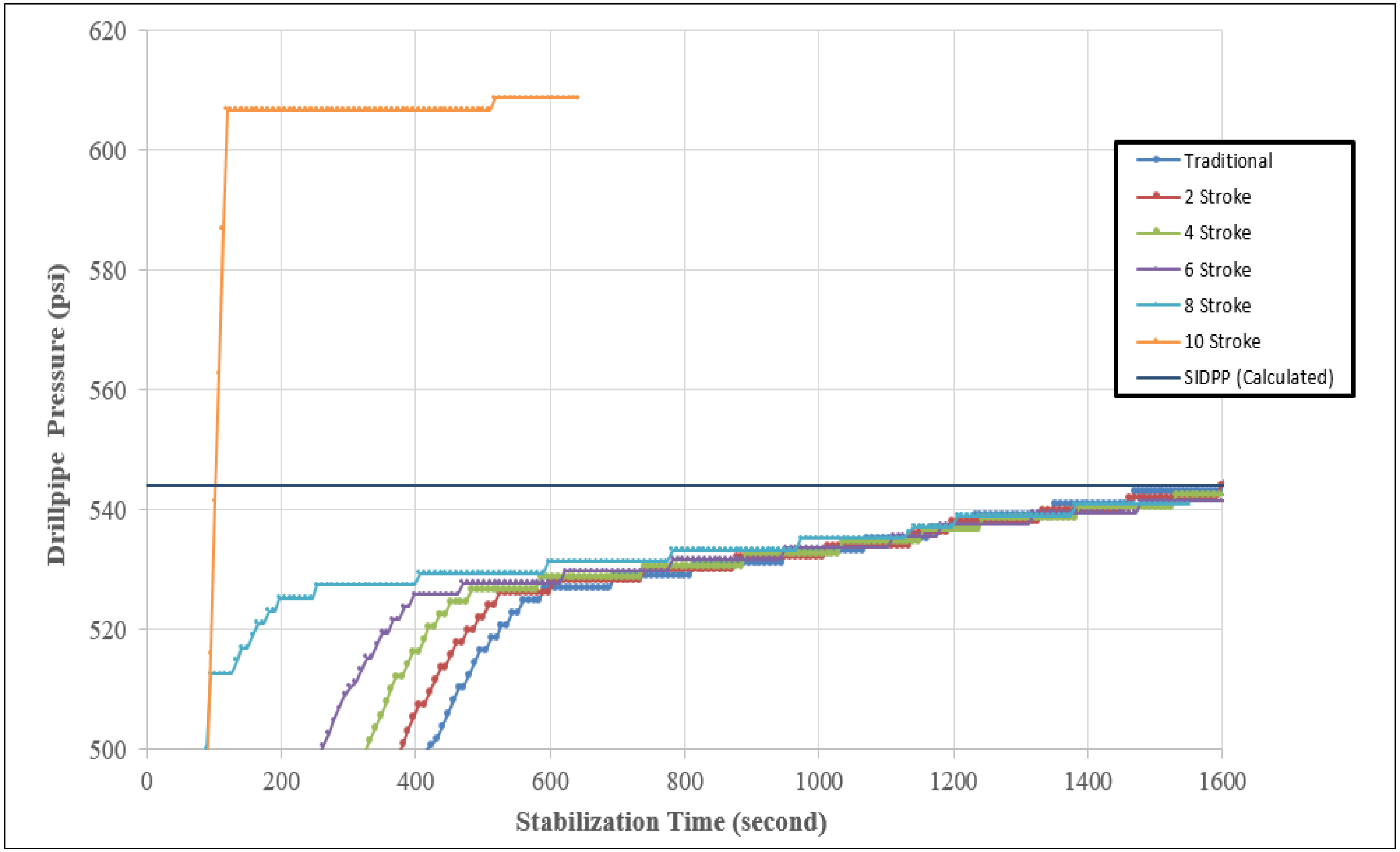

Figure 5.35 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 50 md Permeability (Detail Scale)

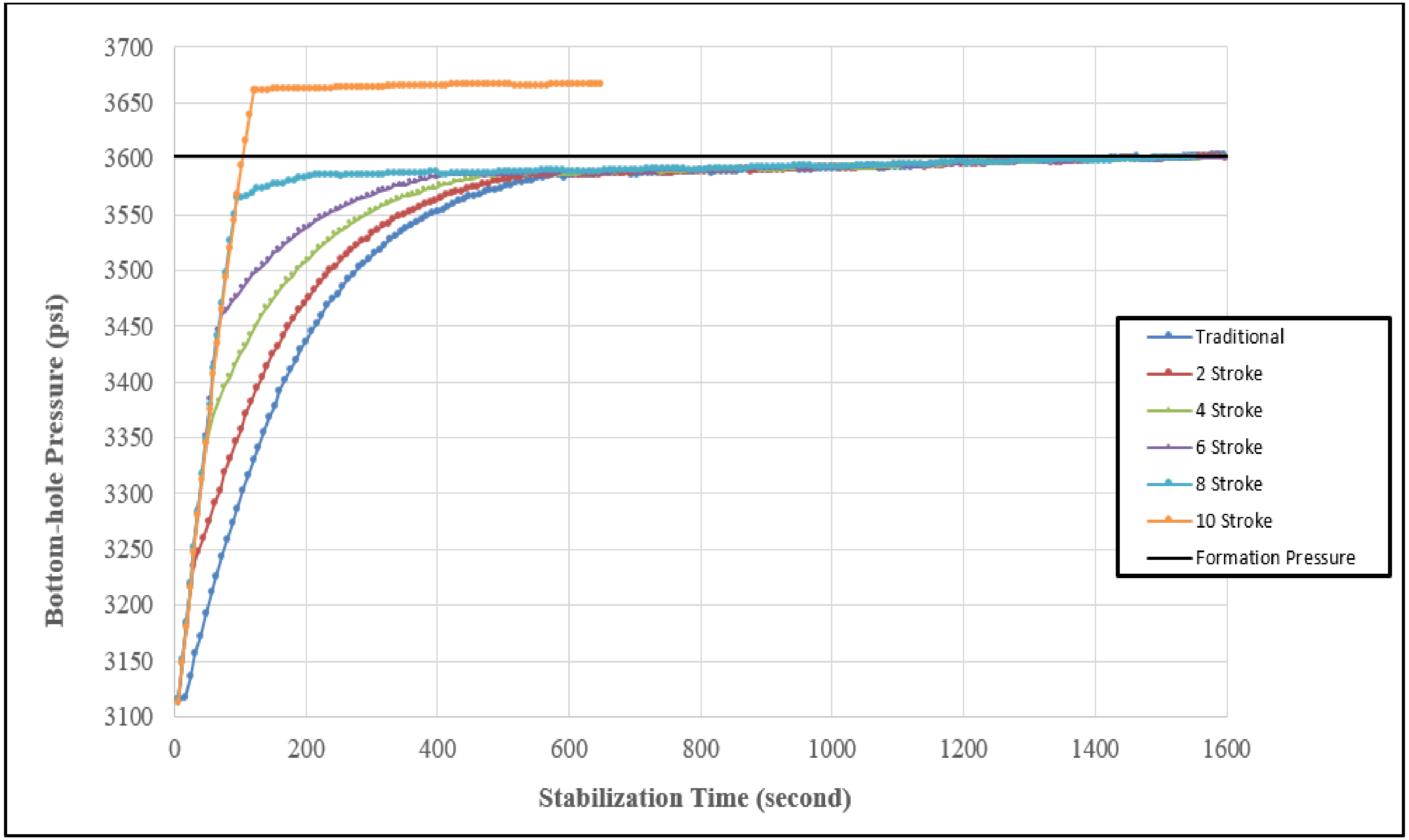

Figure 5.36 Comparison of the BHP vs. Stabilization Time for the Cases for 50 md Permeability

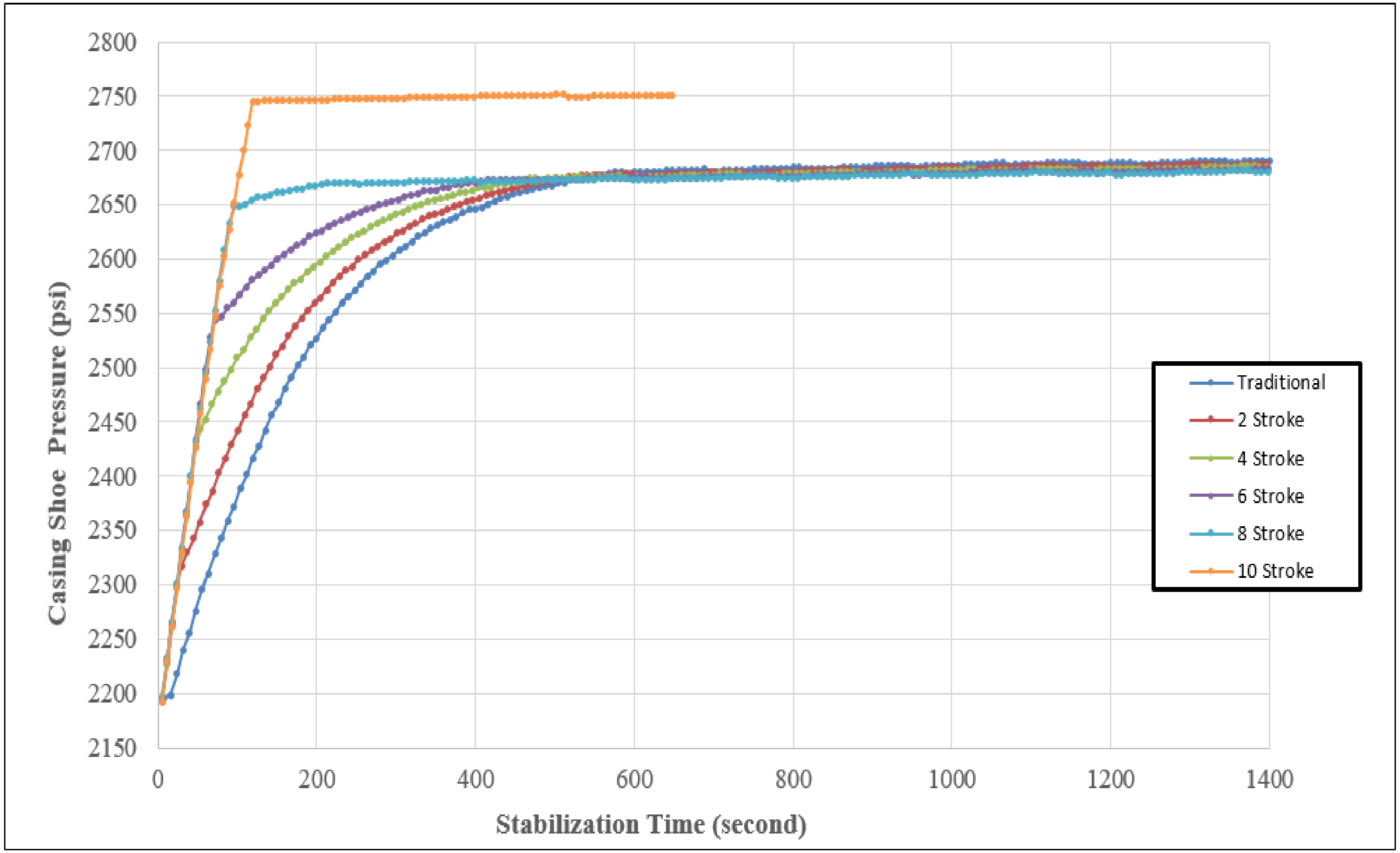

Figure 5.37 Comparison of the Casing Shoe Pressure vs. Stabilization Time for the Cases for 50 md Permeability

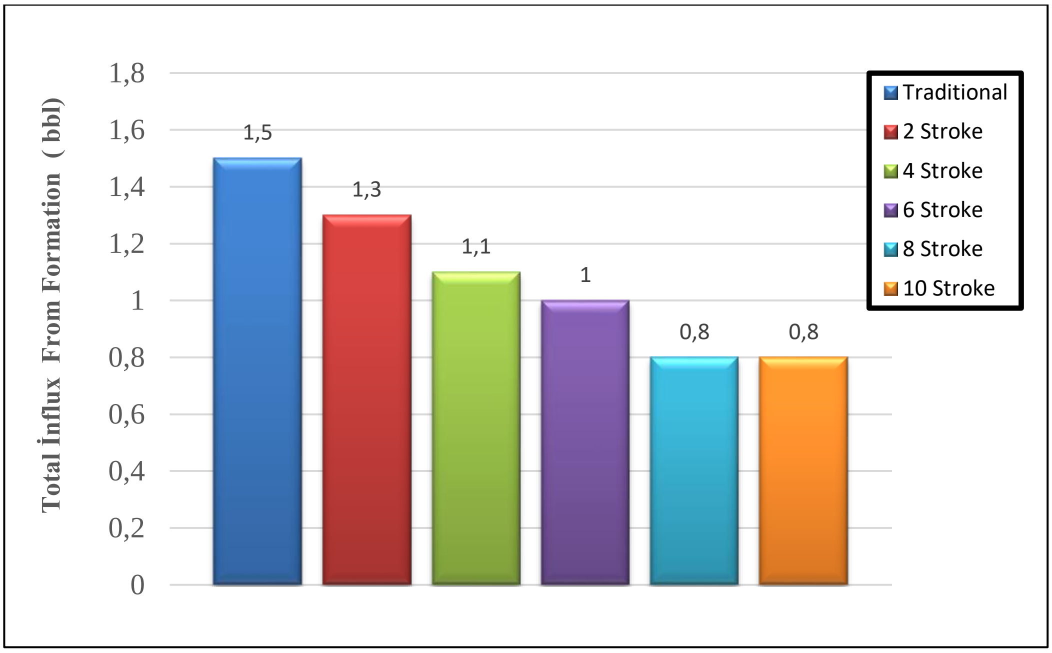

Figure 5.38. Comparisons of The Total Influx from Formation for the Cases for 50 md

Figure 5.38 illustrates the comparisons of the total influx volume from formation for the cases for 50 md permeability.

In conventional method, total influx volume from formation is 1.5 bbl which is the maximum value in Scenario 2. When the new well control approach is applied, gradual decrease is seen until Case 5 and remains unchanged From Case 5 to Case 6. Although volume of mud pumped into well changes From Case 5 to Case 6, the total influx is constant.

As it is seen from the Figure 5.39, when the new well control approach is applied, since the compressibility of gas, the total volume of mud pumped into well does not allow the same volume of influx to be reduced. Although volume of mud pumped into well is different for Case 5 and Case 6, the total influx is constant for these cases the total influx is constant for these cases, because this influx volume is taken during the time until well shut-in completely. It is understood that pumping mud into well does not reduce influx volume further after one point except the compression of gas.

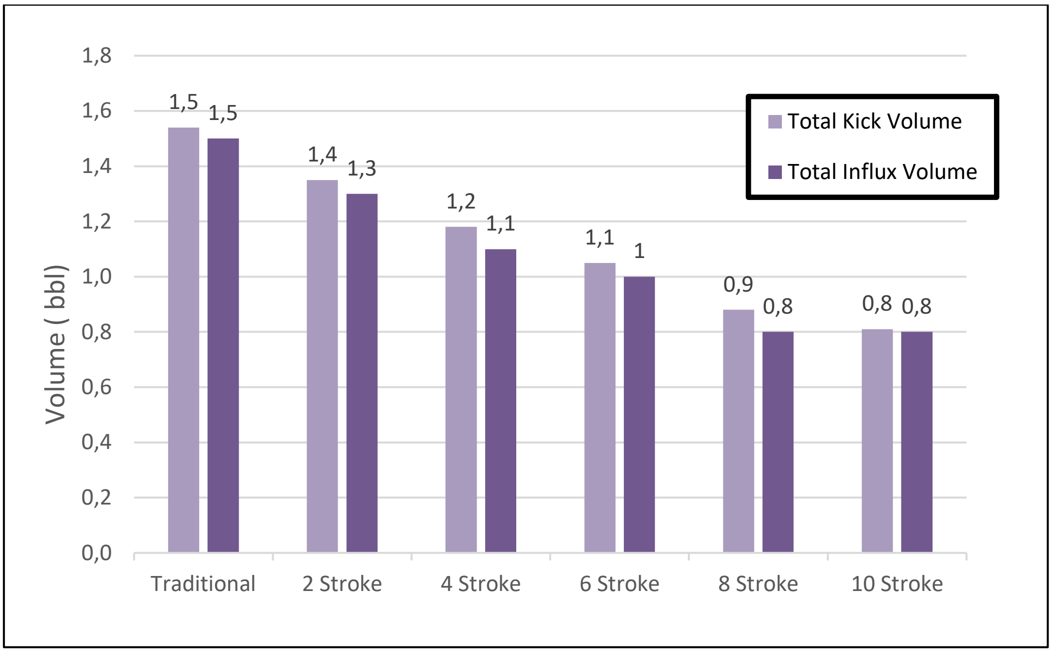

Figure 5.39. Comparisons of the Total Influx from Formation and Total Kick Volume for the Cases for 50 md Permeability

The data in the table 5.2 is used to compare and evaluate the results of all cases for 50 md permeability. As shown in the Table 5.2, stabilization times for the unconventional cases are almost the same to stabilization time of conventional method. The maximum decrease in total influx volume is 47 percent.

Table 5.2. Comparison of the Results for the Cases for 50 md Permeability

Total Stroke	Real Stroke	Stabilization Time	% Time	Total Influx fr.Fm	% Total Influx fr.Fm	Max.Shoe Pressure	SIDPP	Pressure Differential
0	0	1536	100	1.5	100	2693	543	-1
2	2.1	1622	106	1.3	87	2691	544	0
4	4.1	1610	105	1.1	73	2688	543	-1
6	6.0	1676	109	1.0	66	2686	543	-1
8	8.0	1550	100	0.8	53	2684	541	-3
10	10.1	120	8	0.8	53	2746	607	63

5.2.3. Scenario 3 (100 md)

In Scenario 3, the permeability of reservoir is selected 100 md. There are six cases. Cases are started with conventional method and followed by unconventional approach.

5.2.3.1. Case 1: Conventional Method

In the first case, when gas kick has been observed, the well is shut-in according to the conventional method of shut-in procedures. Because of high permeability of reservoir, drill pipe pressure rises fast. There is one separated influx volume in the annulus and total influx from formation was observed as a volume of 1.9 bbl after 307 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.40).

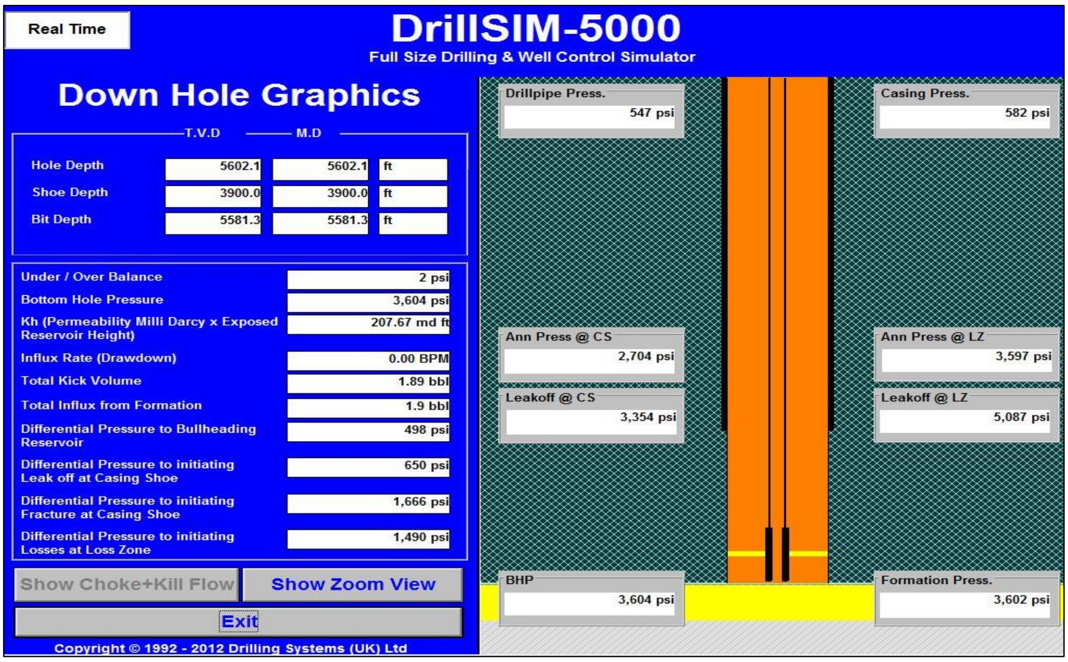

Figure 5.40. Well Schematics & Well Data after Stabilization for Conventional Method (100 md)

5.2.3.2. Case 2: 2 Stroke

In case 2, 2 stroke (0.2 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 553 psi and it is observed that the SIDPP is 9 psi higher than the calculated SIDPP (Figure 5.41).

There is one separated influx volume in the annulus and total influx from formation was observed 1.7 bbl after 305 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.42).

It is seen that pumping 0.2 bbl mud volume into the well during stabilization period provides 0.2 bbl less influx volume from formation.

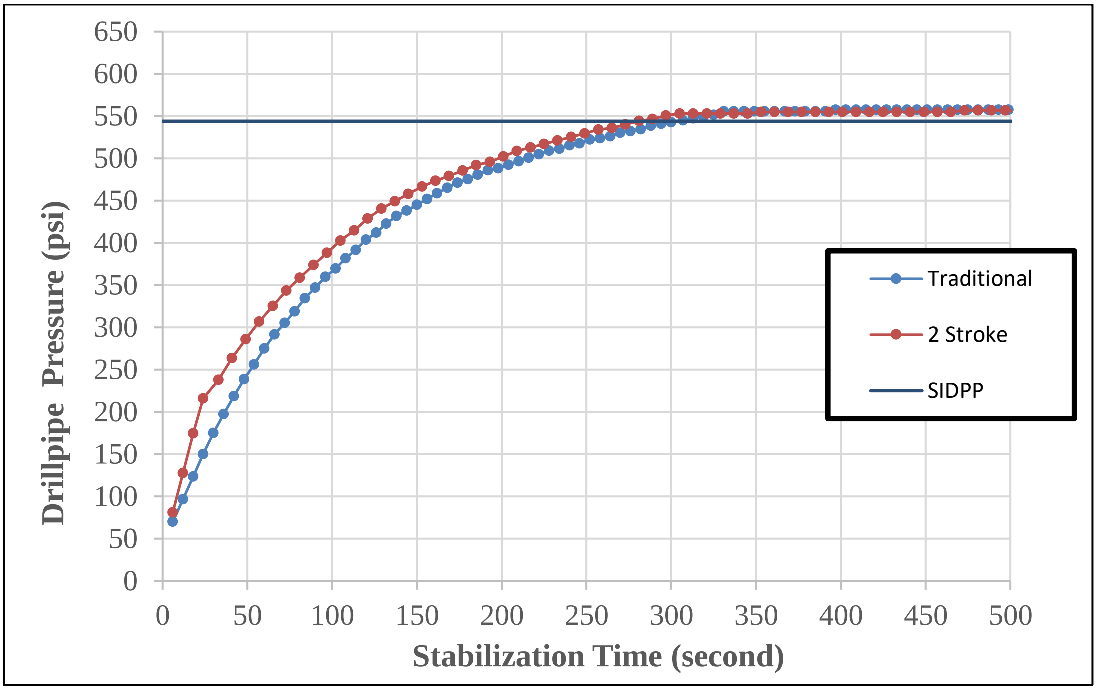

Figure 5.41. SIDPP vs. Stabilization Time for 2 Stroke (100 md)

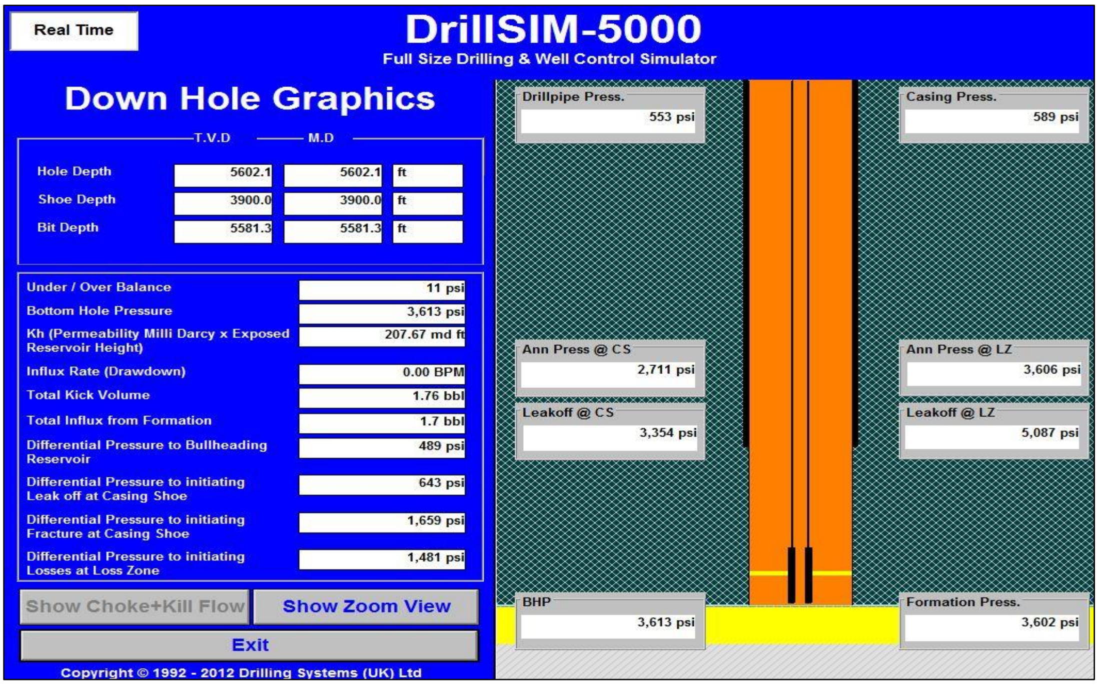

Figure 5.42. Well Schematics & Well Data after Stabilization for 2 Stroke (100 md)

5.2.3.3. Case 3: 4 Stroke

In this case 4 stroke (0.4 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 557 psi and it is observed that the SIDPP is 13 psi higher than the calculated SIDPP (Figure 5.43).

There is one separated influx volume in the annulus and total influx from formation was observed 1.6 bbl after 274 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.44).

It is seen that pumping 0.4 bbl mud volume into the well during stabilization period provides 0.3 bbl less influx volume from formation.

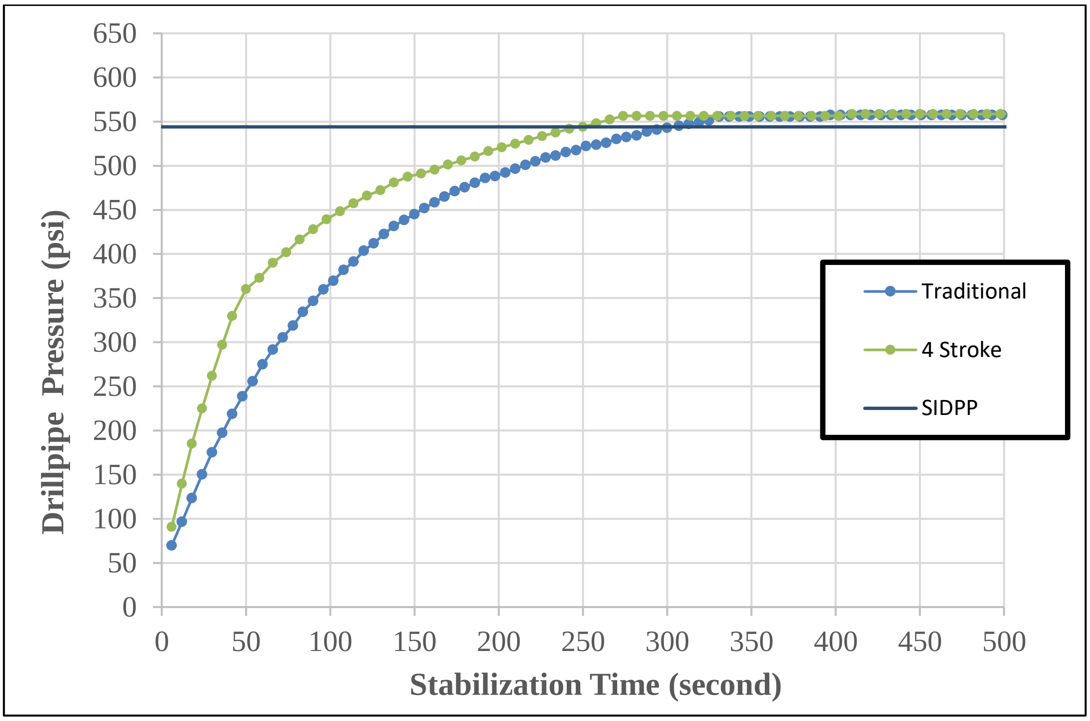

Figure 5.43. SIDPP vs. Stabilization Time for 4 Stroke (100 md)

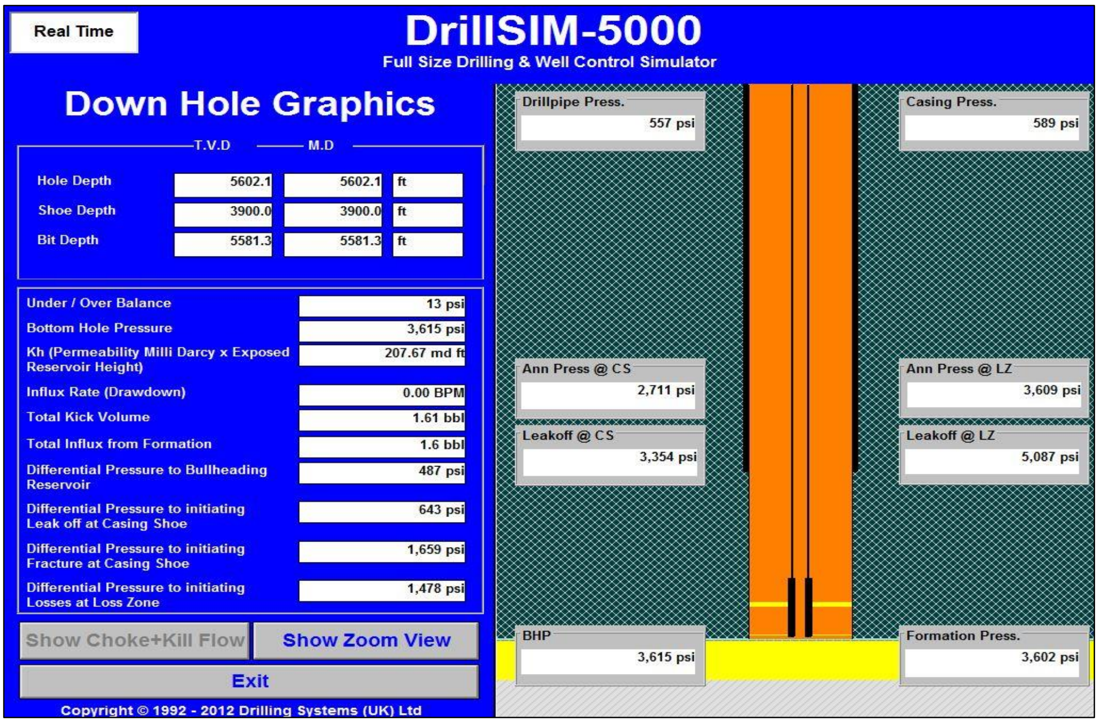

Figure 5.44. Well Schematics & Well Data after Stabilization 4 Stroke (100 md)

5.2.3.4. Case 4: 6 Stroke

In this case 6 stroke (0.6 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 568 psi and it is observed that the SIDPP is 24 psi higher than the calculated SIDPP (Figure 5.45).

There is one separated influx volume in the annulus and total influx from formation was observed 1.4 bbl after 250 seconds (about 4 minutes) which is accepted as a stabilization time (Figure 5.46).

It is seen that pumping 0.6 bbl mud volume into the well during stabilization period provides 0.5 bbl less influx volume from formation.

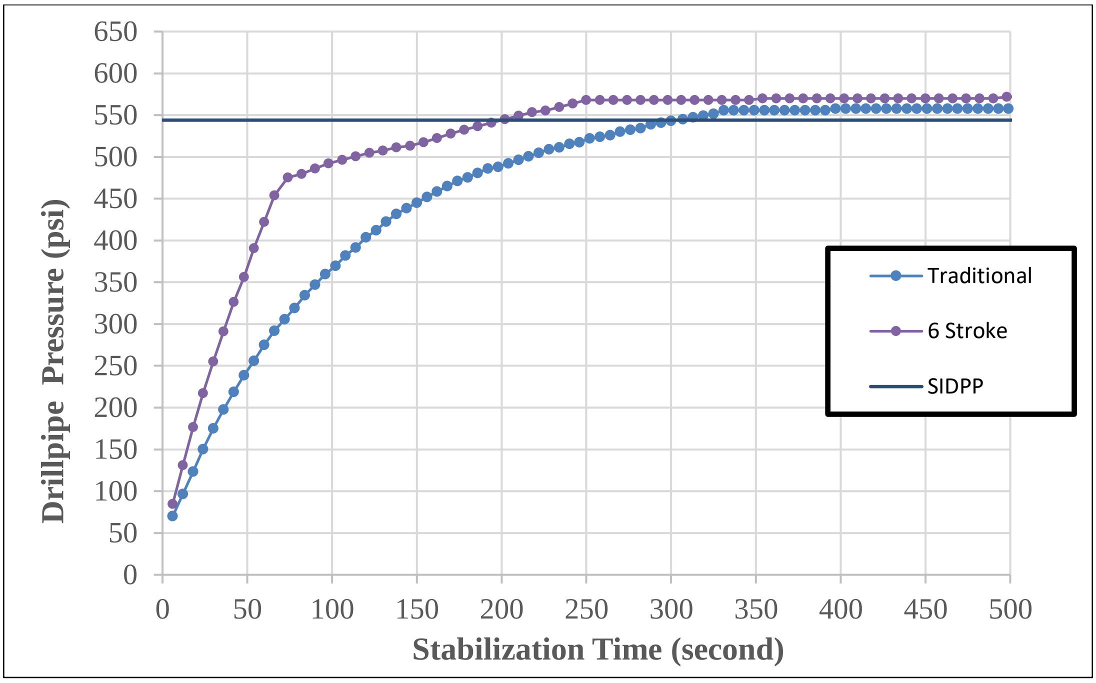

Figure 5.45. SIDPP vs. Stabilization Time for 6 Stroke (100 md)

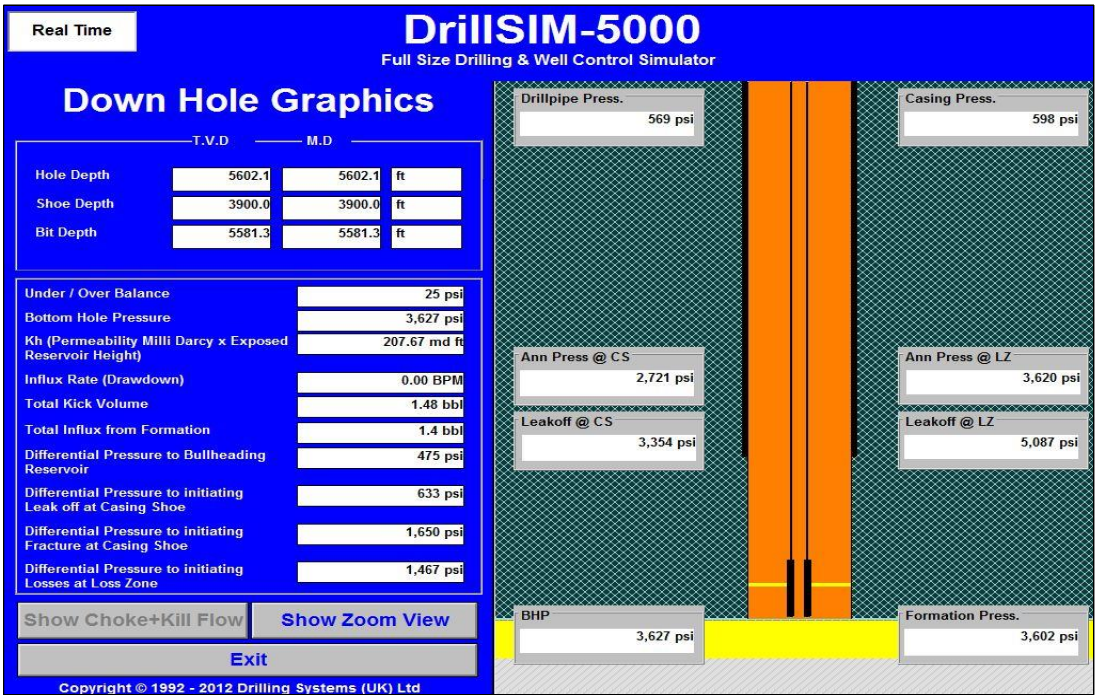

Figure 5.46. Well Schematics & Well Data after Stabilization 6 Stroke (100 md)

5.2.3.5. Case 5: 8 Stroke

In this case 8 stroke (0.8 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 571 psi and it is observed that the SIDPP is 27 psi higher than the calculated SIDPP (Figure5.47).

There is one separated influx volume in the annulus and total influx from formation was observed 1.3 bbl after 99 seconds (about 1.5 minutes) which is accepted as a stabilization time (Figure 5.48).

It is seen that pumping 0.8 bbl mud volume into the well during stabilization period provides 0.6 bbl less influx volume from formation.

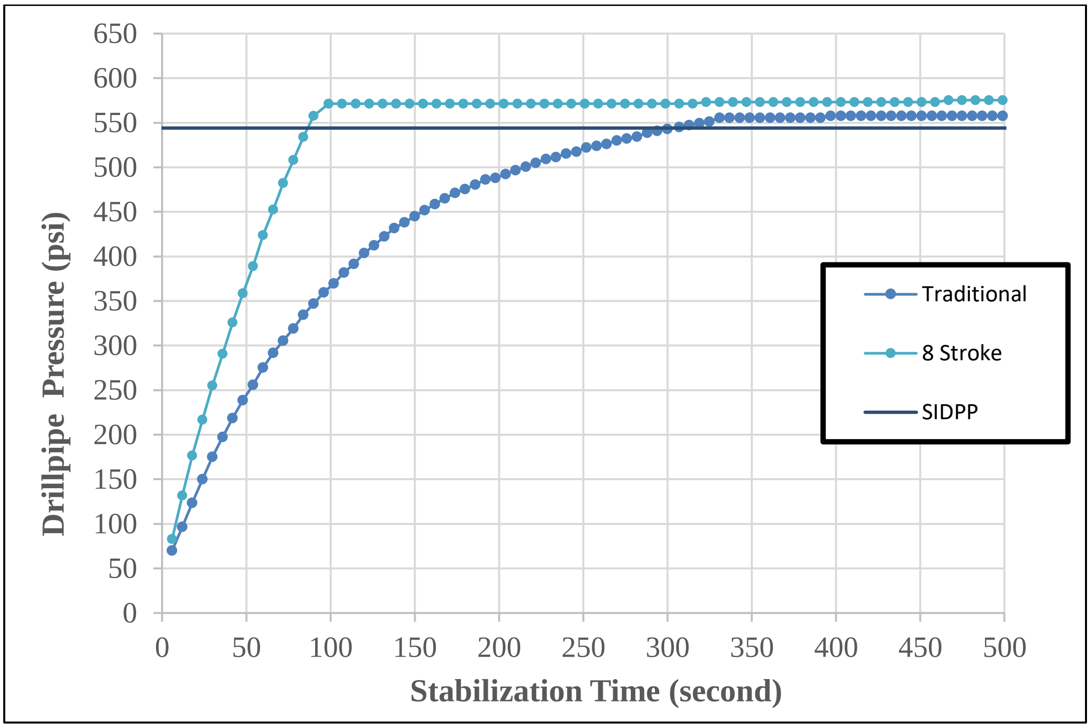

Figure 5.47. SIDPP vs. Stabilization Time for 8 Stroke (100 md)

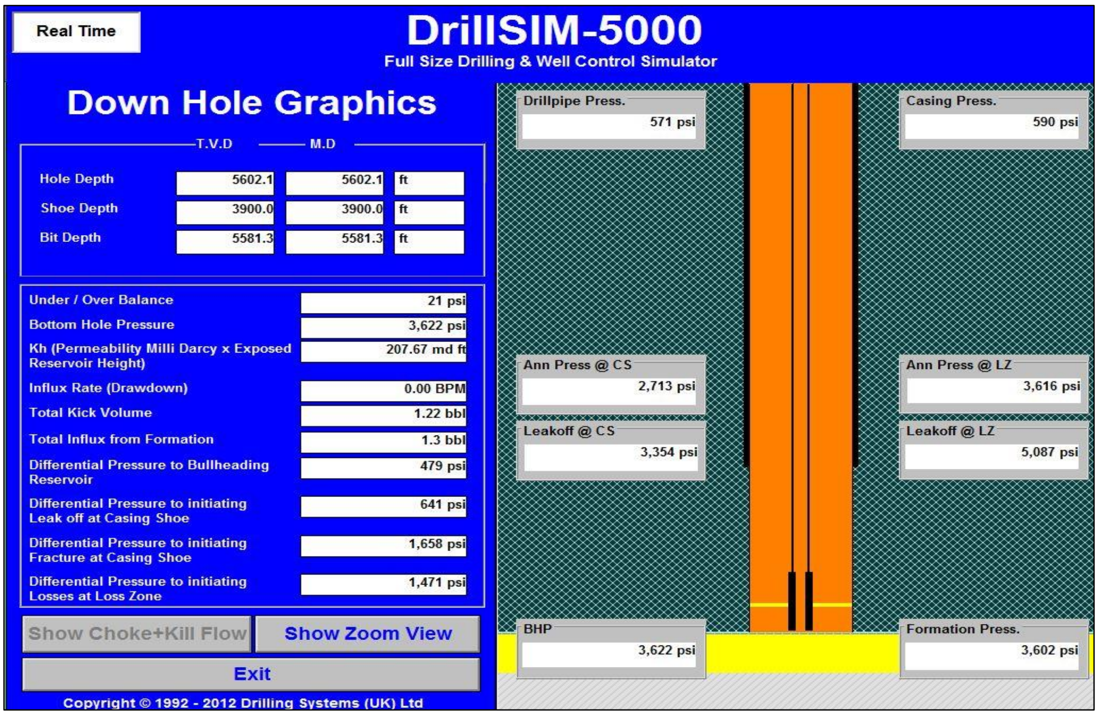

Figure 5.48. Well Schematics and Well Data after Stabilization 8 Stroke (100 md)

5.2.3.6. Case 6: 10 Stroke

In this case 10 stroke (1 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 663 psi and it is observed that the SIDPP is 119 psi higher than the calculated SIDPP (Figure 5.49). Because of higher SIDPP than calculated SIDPP (544 psi), we can conclude these trials at this stage.

There is one separated influx volume in the annulus and total influx from formation was observed 1.3 bbl after 122 seconds (about 2 minutes) that is the stabilization time (Figure 5.50).

It is seen that pumping 1 bbl mud volume into the well during stabilization period provides 0.6 bbl less influx volume from formation.

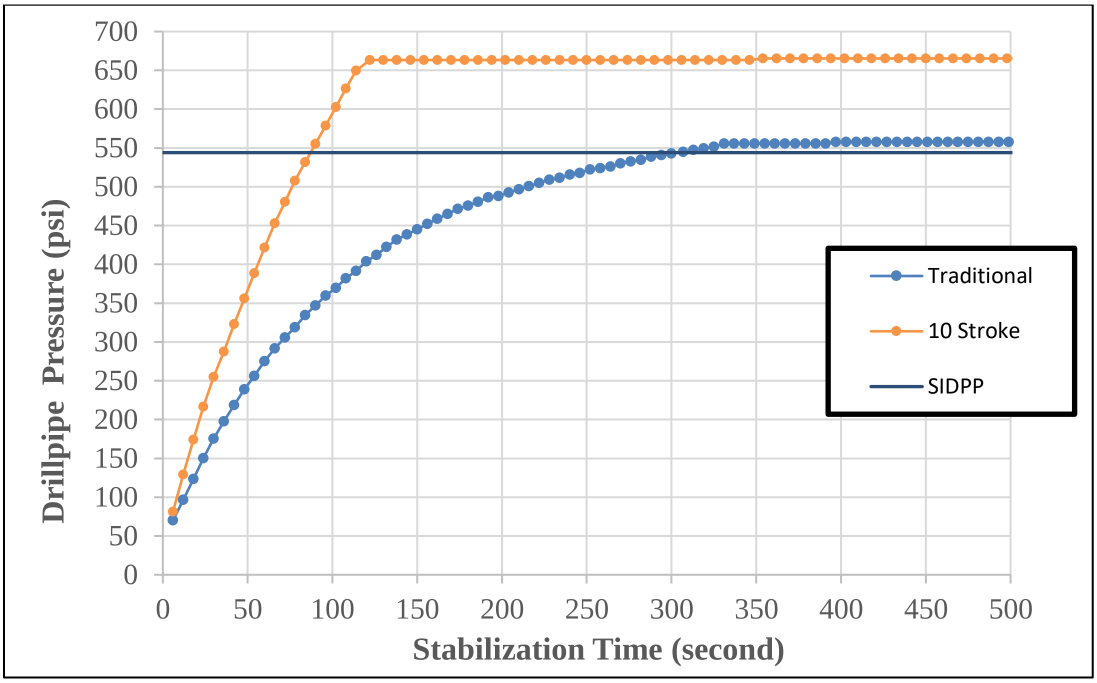

Figure 5.49. SIDPP vs. Stabilization Time for 10 Stroke (100 md)

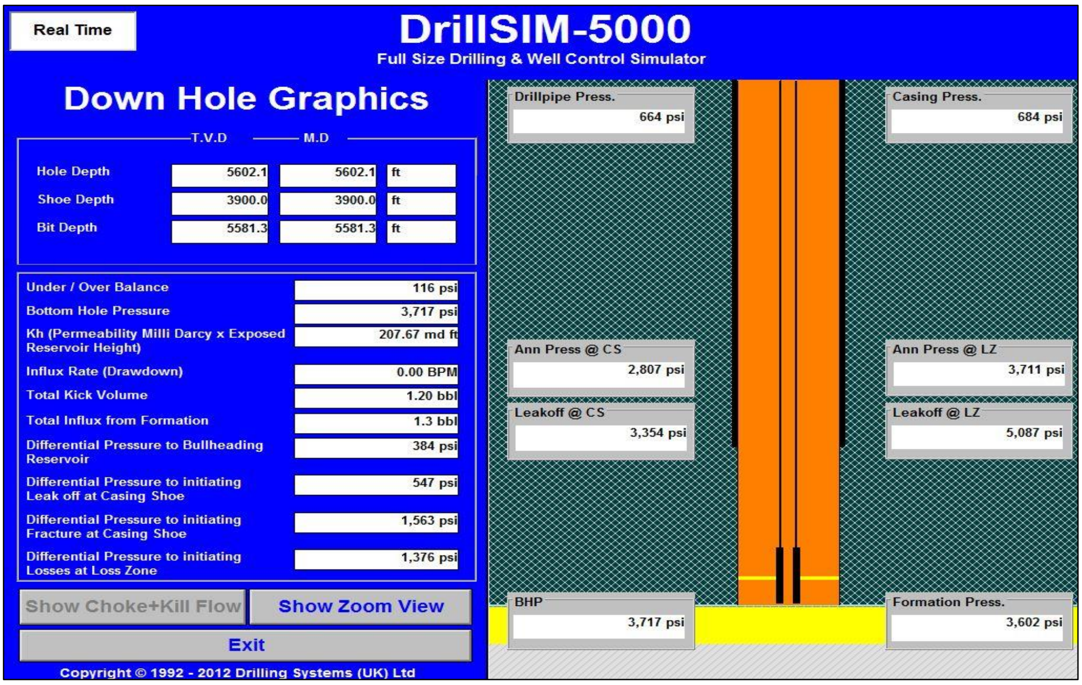

Figure 5.50. Well Schematics & Well Data after Stabilization 10 Stroke (100 md)

5.2.3.7. Comparison of Results for Scenario 3

In scenario 3, the results of six cases are compared and evaluated. SIDPPs, BHPs and Casing shoe pressures versus stabilization time for all cases for the formation which has the permeability is 100 md are shown in the graphics. In all cases except Case 6, pressure differences is observed between 1 and 27 psi which means SIDPPs are slightly higher than the calculated SIDPP (Figure 5.51).

The comparison of bottom-hole pressures are shown in Figure 5.53. As it is seen from the graphic, the behavior of bottom-hole pressure build up is almost the same to the behavior of SIDPP build up.

Casing shoe pressures is studied and compared, too. As it is seen from the Figure 5.54, Casing shoe pressure for all cases below the formation fracture pressure at casing shoe which is 4368 psi.

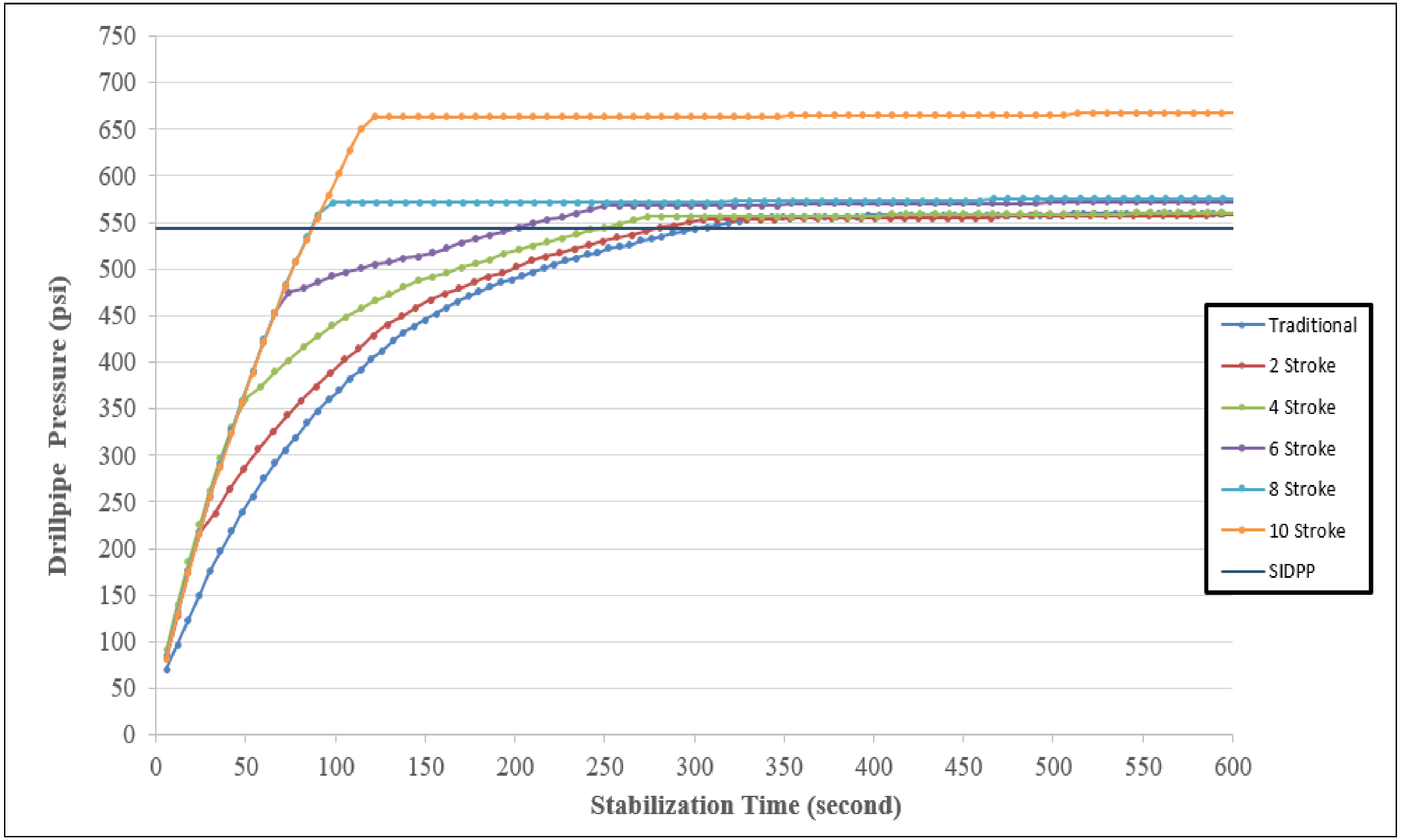

Figure 5.51 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 100 md Permeability

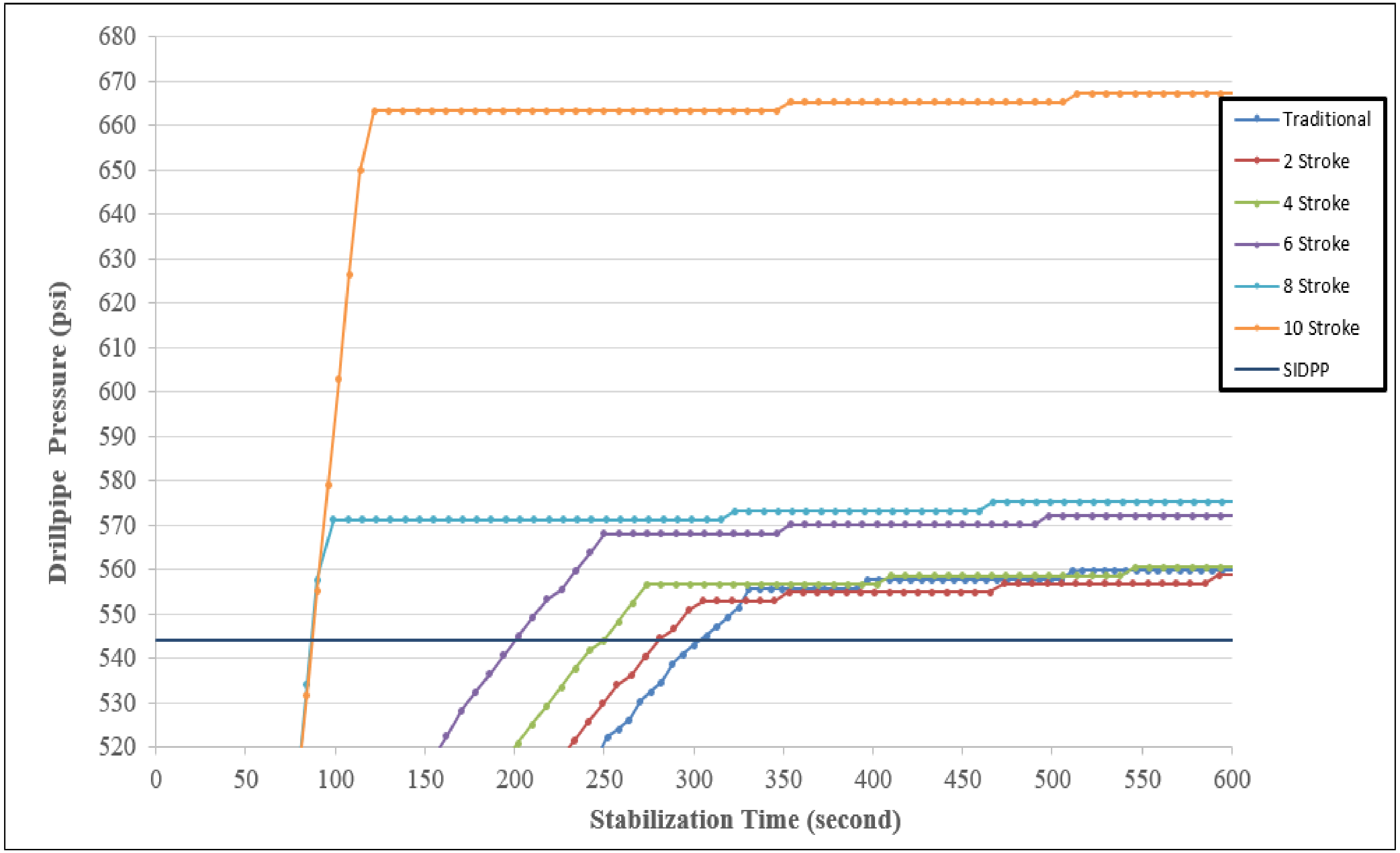

Figure 5.52 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 100 md Permeability (Detail Scale)

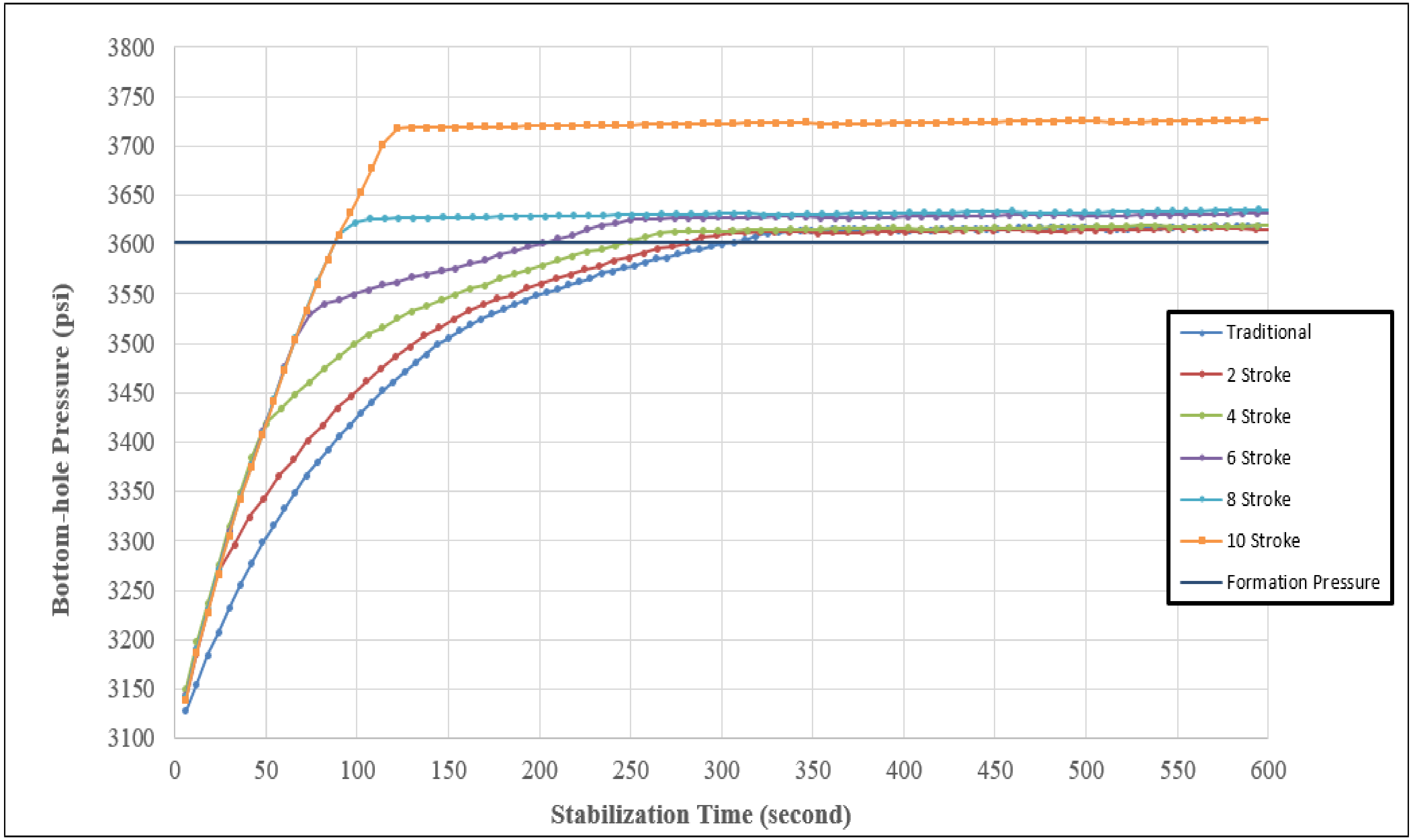

Figure 5.53 Comparison of the BHP vs. Stabilization Time for the Cases for 100 md Permeability

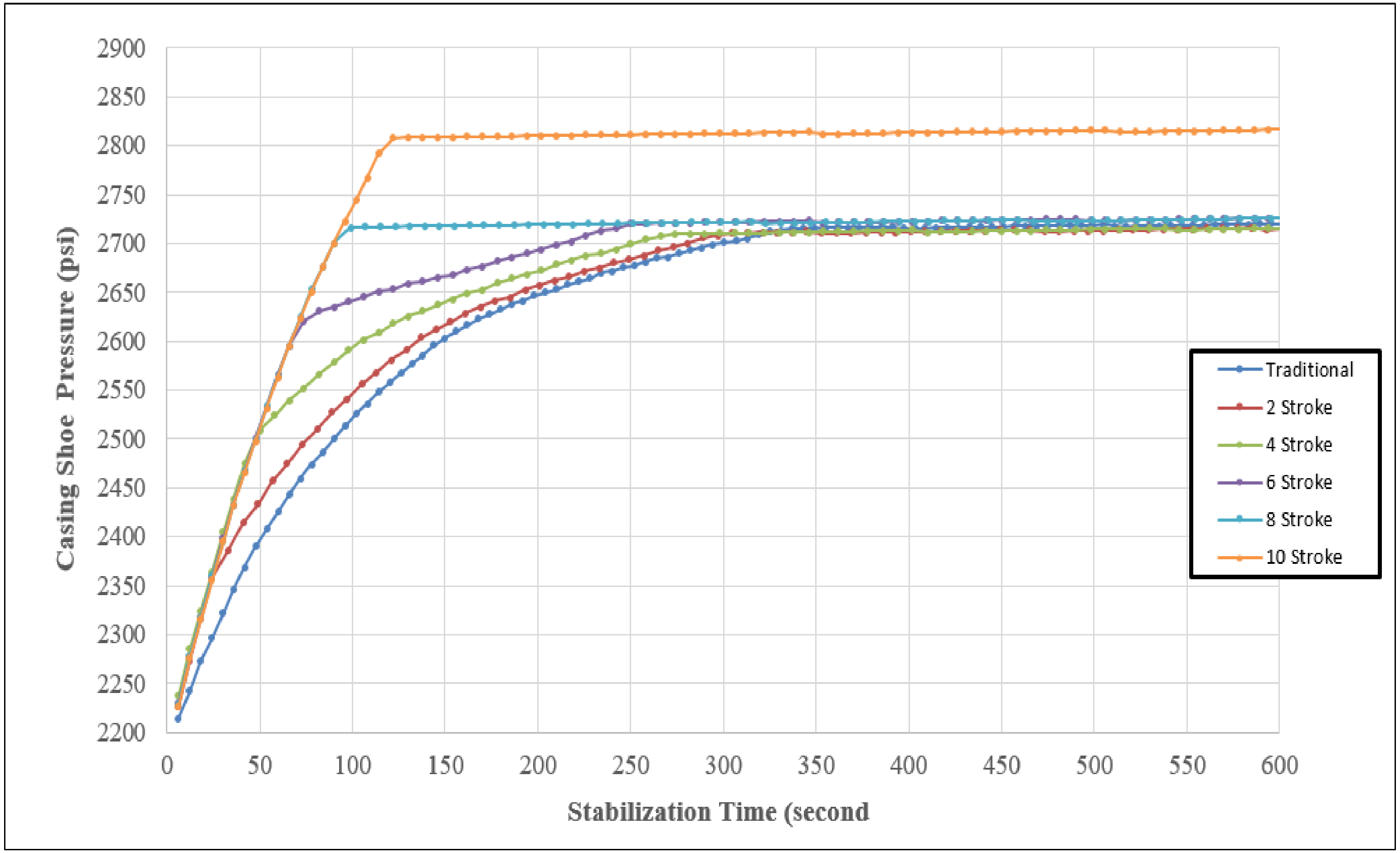

Figure 5.54 Comparison of the Casing Shoe Pressure vs. Stabilization Time for the Cases for 100 md Permeability

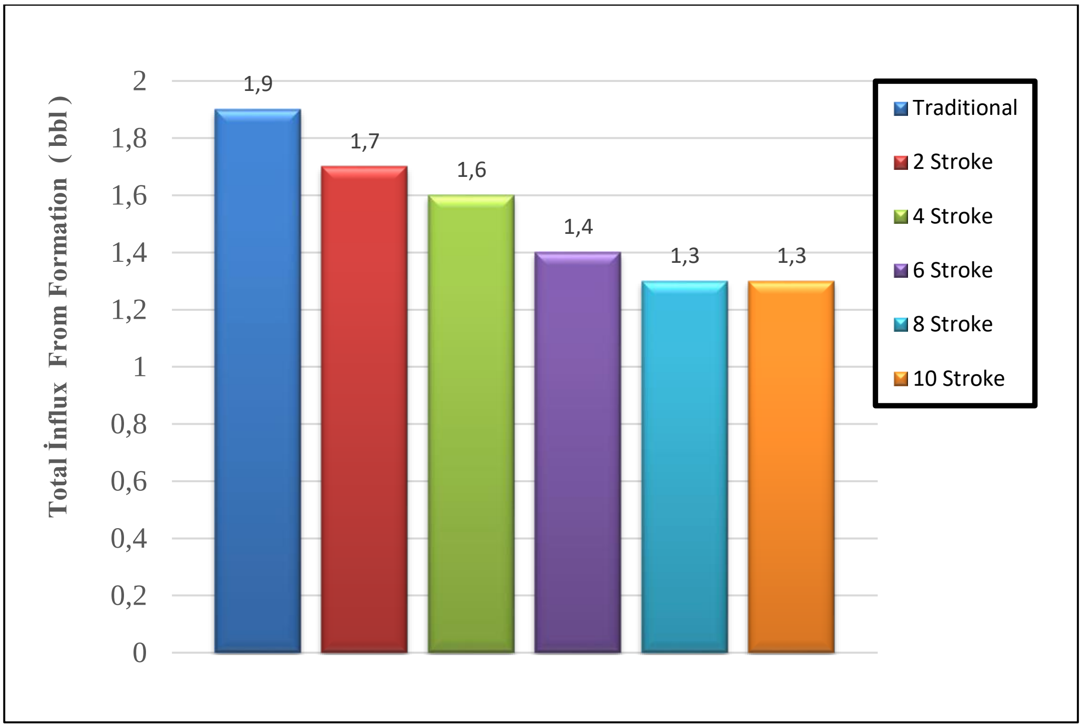

Figure 5.55. Comparisons of the Total Influx from Formation for the Cases for 100 md

Figure 5.55 illustrates the comparisons of the total influx volume from formation for the cases for 100 md permeability. It can be seen an advantages of the new well control approach over conventional method for high permeable reservoirs.

In conventional method, total influx volume from formation is 1.9 bbl which is the maximum value in Scenario 3. When the new well control approach is applied, gradual decrease is seen until Case 5 and remains unchanged From Case 5 to Case 6.

As it is seen from the Figure 5.56, when the new well control approach is applied, since the compressibility of gas, the total volume of mud pumped into well does not allow the same volume of influx to be reduced. Although volume of mud pumped into well is different for Case 5 and Case 6, the total influx is constant for these cases, because this influx volume is taken during the time until well shut-in completely. It is understood that pumping mud into well does not reduce influx volume further after one point except the compression of gas.

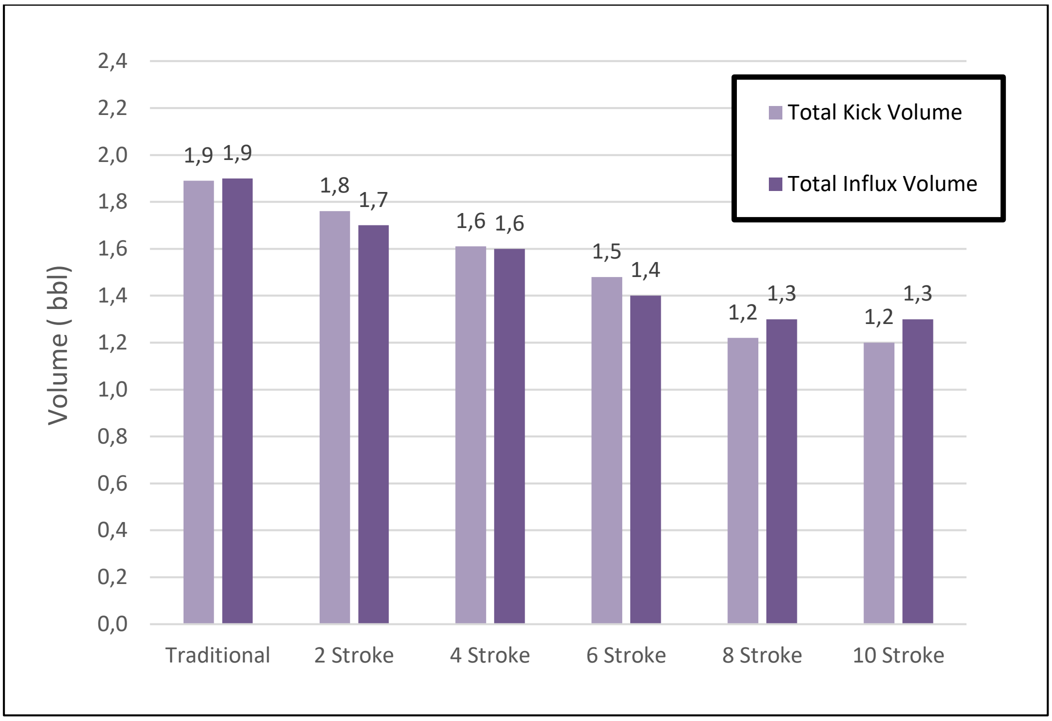

Figure 5.56. Comparisons of the Total Influx from Formation and Total Kick Volume for the Cases for 100 md Permeability.

As shown in the Table 5.3, stabilization times for the unconventional cases decreases gradually and the maximum decrease in stabilization time is 68 percent. The maximum decrease in total influx volume is 32 percent. It seems that this new approach is successful when all the results are taken into consideration.

Table 5.3. Comparison of the Results for the Cases for 100 md Permeability

Total Stroke	Real Total Stroke	Stabilization Time	% Time	Total Influx fr.Fm	% Total Influx fr.Fm	Max.Shoe Pressure	SIDPP	Pressure Differential
0	0,0	307	100	1,9	100	2702	545	1
2	2,0	305	99	1,7	89	2711	553	9
4	4,0	274	89	1,6	84	2709	557	13
6	6,0	250	81	1,4	74	2719	568	24
8	8,0	99	32	1,3	68	2716	571	27
10	10,0	122	39	1,3	68	2808	663	119

5.2.4. Scenario 4 (300 md)

In Scenario 4, the permeability of reservoir is selected 300 md. There are five cases. Cases are started with conventional method and followed by unconventional approach.

5.2.4.1. Case 1: Conventional Method

In the first case, when gas kick has been observed, the well is shut-in according to the conventional method of shut-in procedures. Because of high permeability of reservoir, drill pipe pressure rises very fast. There is one separated influx volume in the annulus and total influx from formation was observed as a volume of 3.7 bbl after 312 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.57).

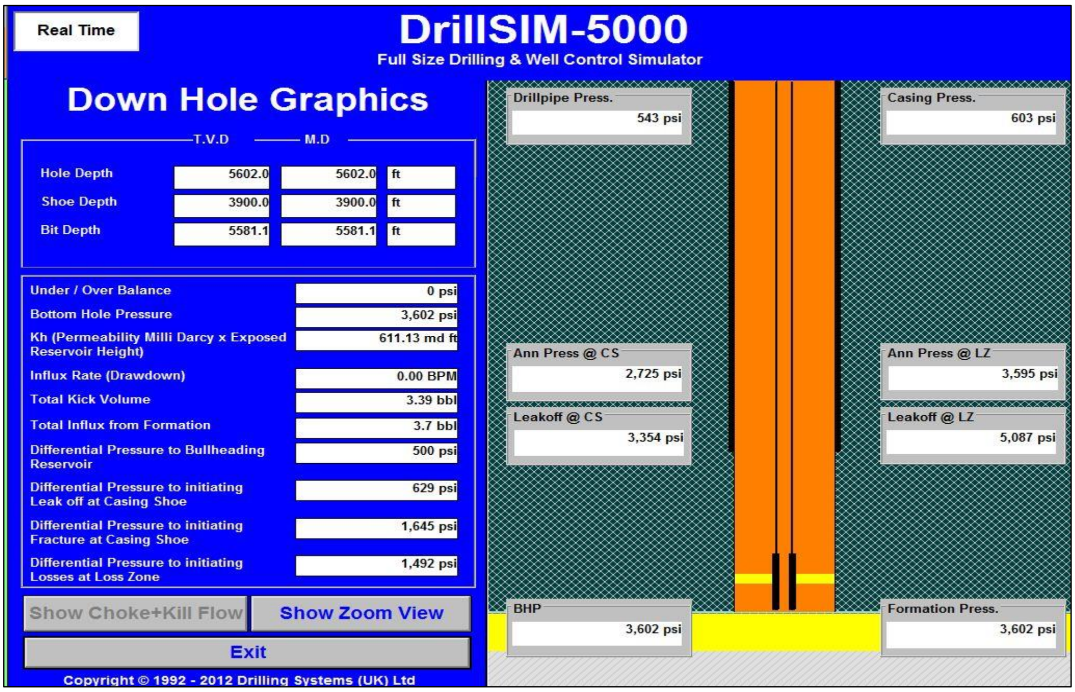

Figure 5.57. Well Schematics & Well Data after Stabilization for Conventional Method (300 md)

5.2.4.2. Case 2: 2 Stroke

In case 2, 2 stroke (0.2 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 543 psi and it is observed that the SIDPP is 1 psi lower than the calculated SIDPP (Figure 5.58).

There is one separated influx volume in the annulus and total influx from formation was observed 3.4 bbl after 295 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.59).

It is seen that pumping 0.2 bbl mud volume into the well during stabilization period provides 0.3 bbl less influx volume from formation.

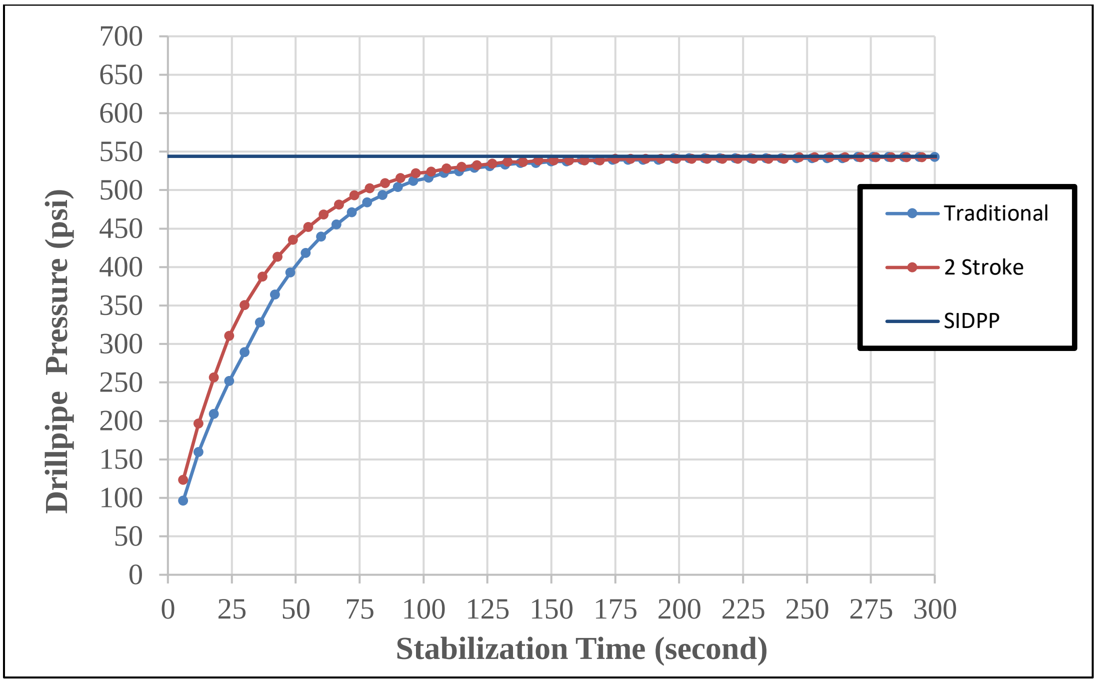

Figure 5.58. SIDPP vs. Stabilization Time for 2 Stroke (300 md)

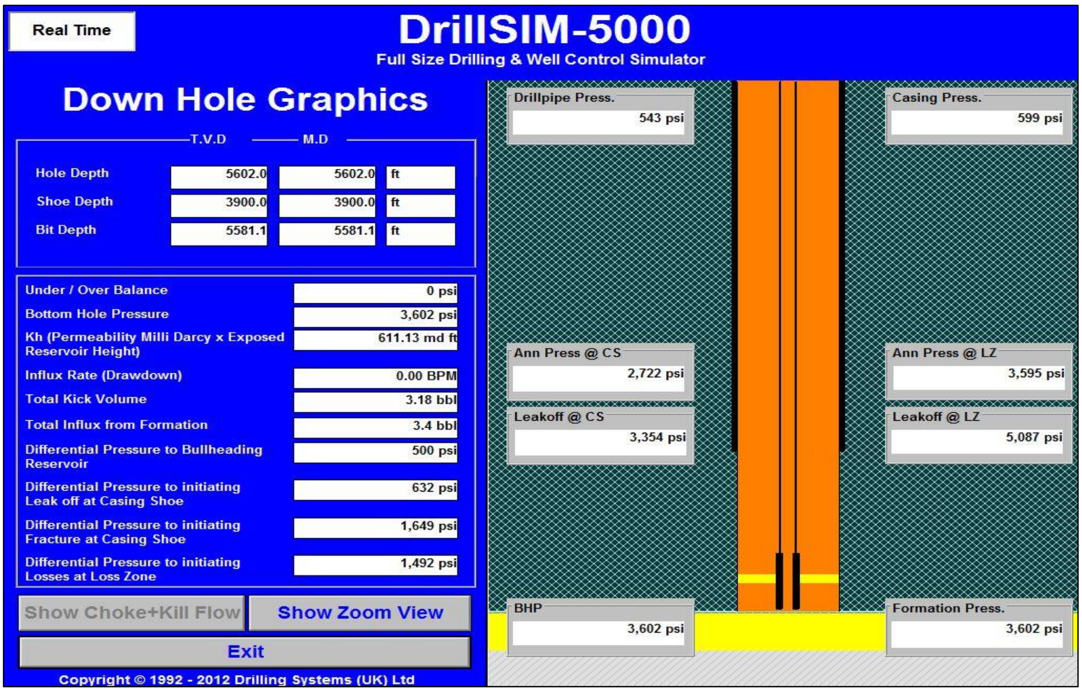

Figure 5.59. Well Schematics & Well Data after Stabilization for 2 Stroke (300 md)

5.2.4.3. Case 3: 4 Stroke

In this case 4 stroke (0.4 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 544 psi and it is observed that the SIDPP is equal to the calculated SIDPP (Figure 5.60).

There is one separated influx volume in the annulus and total influx from formation was observed 3.3 bbl after 290 seconds (about 5 minutes) which is accepted as a stabilization time (Figure 5.61).

It is seen that pumping 0.4 bbl mud volume into the well during stabilization period provides 0.4 bbl less influx volume from formation.

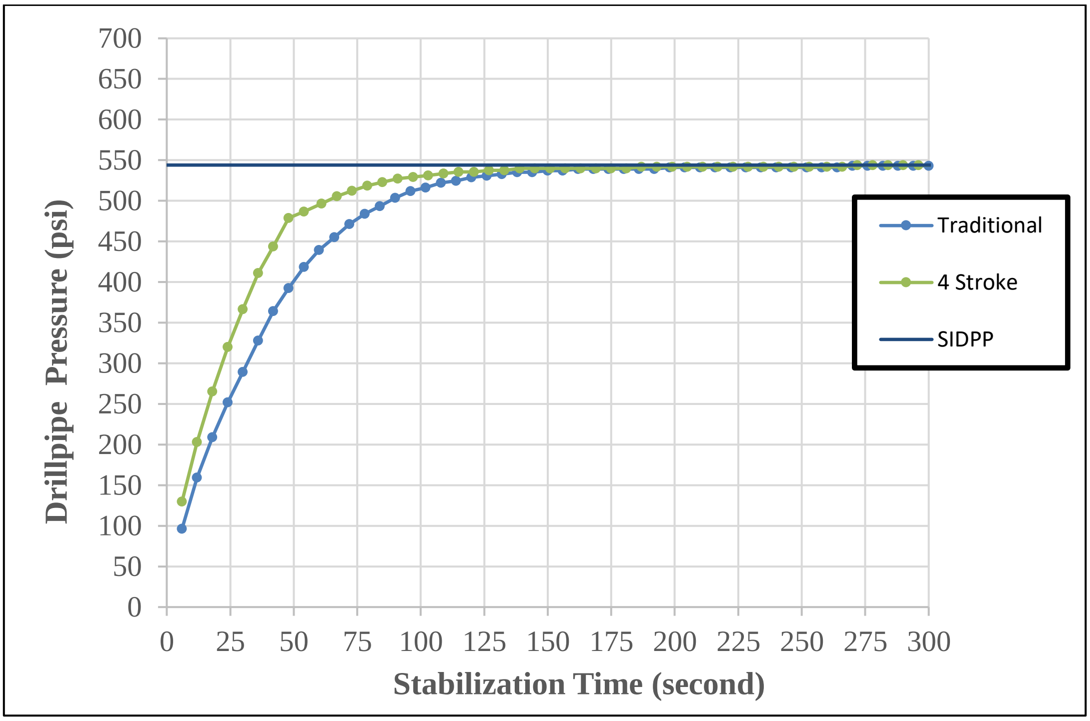

Figure 5.60. SIDPP vs. Stabilization Time for 4 Stroke (300 md)

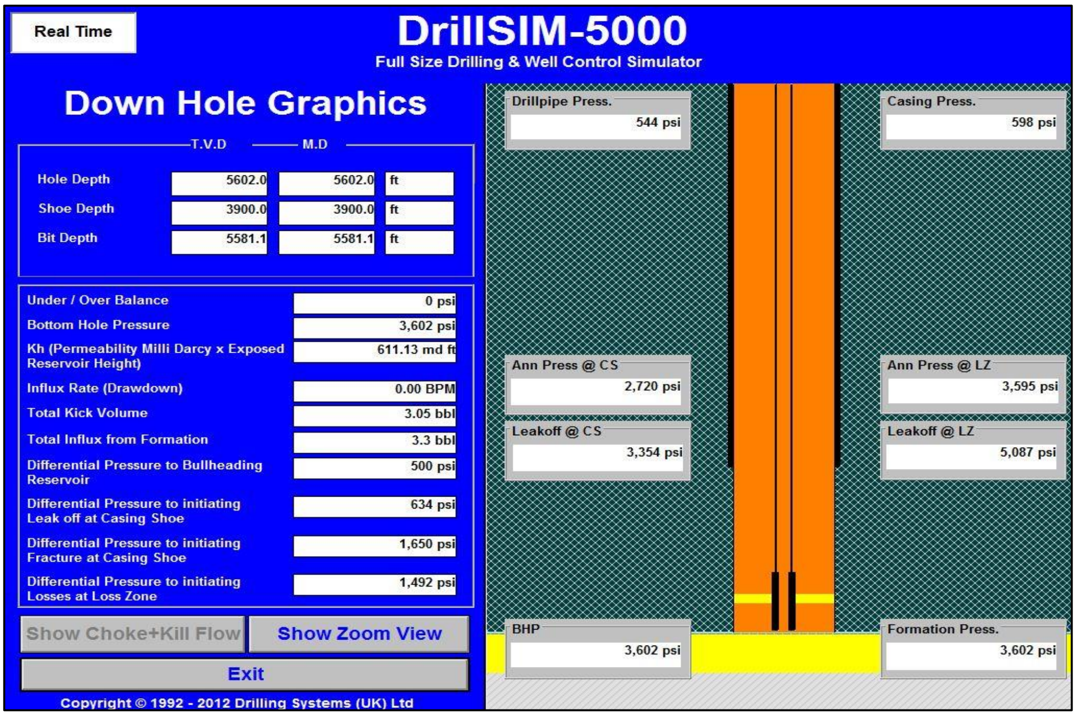

Figure 5.61. Well Schematics & Well data after Stabilization for 4 Stroke (300 md)

5.2.4.4. Case 4: 6 Stroke

In this case 6 stroke (0.6 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 578 psi and it is observed that the SIDPP is 34 psi higher than the calculated SIDPP (Figure 5.62).

There is one separated influx volume in the annulus and total influx from formation was observed 3.2 bbl after 73 seconds (about 1 minute) which is accepted as a stabilization time (Figure 5.63).

It is seen that pumping 0.6 bbl mud volume into the well during stabilization period provides 0.5 bbl less influx volume from formation.

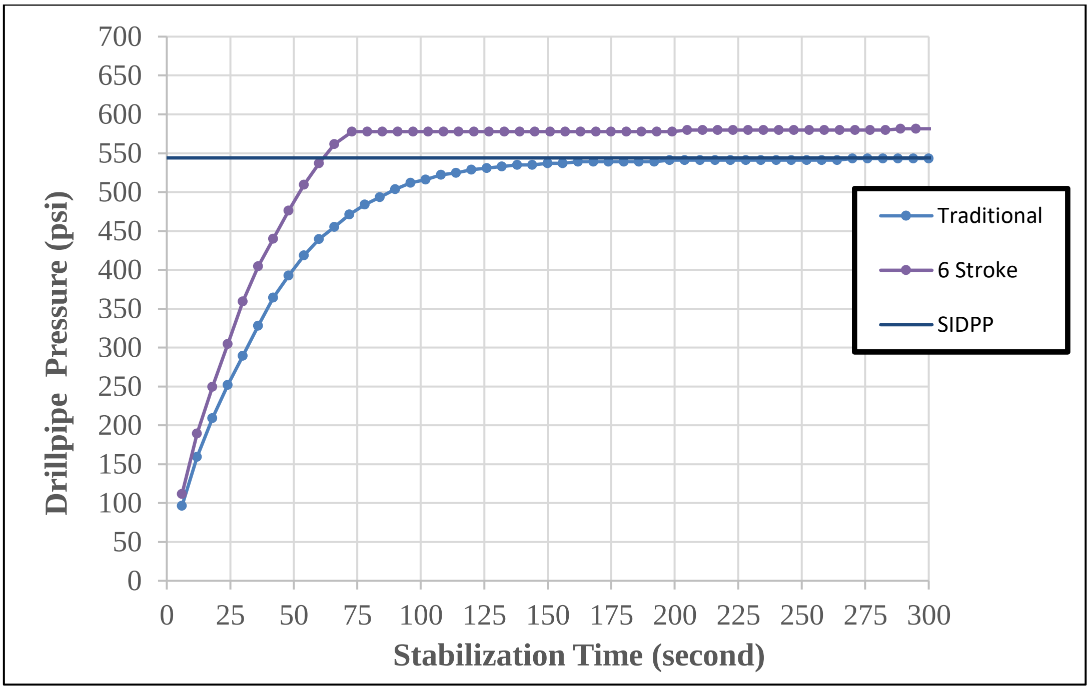

Figure 5.62. SIDPP vs. Stabilization Time for 6 Stroke (300 md)

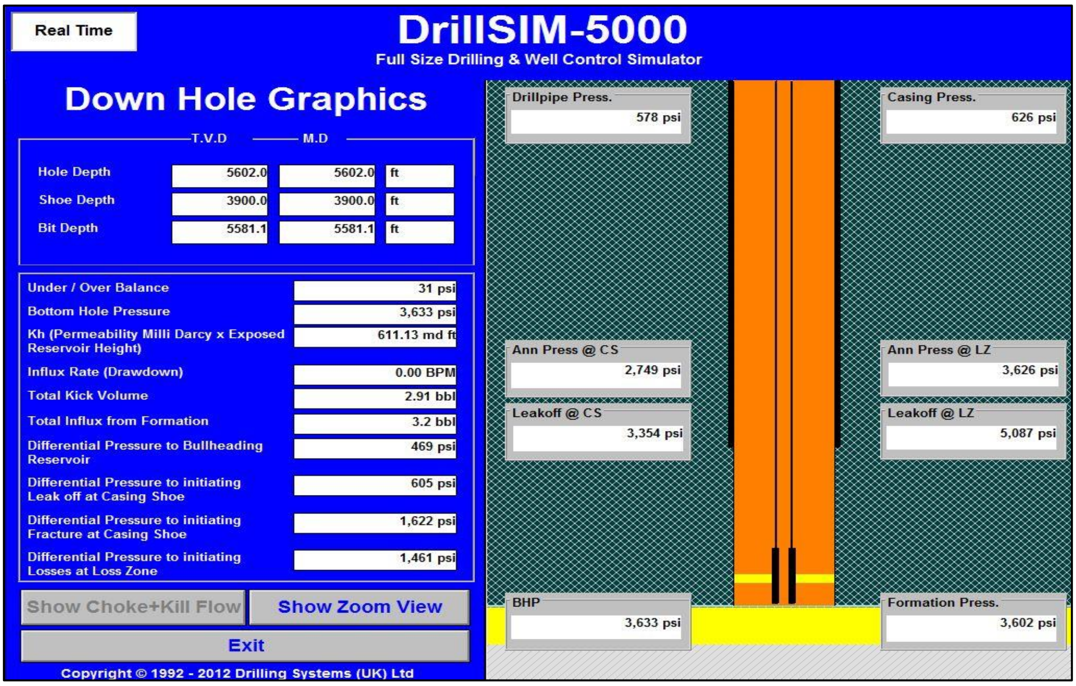

Figure 5.63. Well Schematics & Well data after Stabilization for 6 Stroke (300 md)

5.2.4.5. Case 5: 8 Stroke

In this case 8 stroke (0.8 bbl) volume of mud is pumped into the closed well after shut-in. The SIDPP is 672 psi and it is observed that the SIDPP is128 psi higher than the calculated SIDPP (Figure 5.64). Because of higher SIDPP than calculated SIDPP (544 psi), we can conclude these trials at this stage.

There is one separated influx volume in the annulus and total influx from formation was observed 3.2 bbl after 96 seconds (about 1.5 minutes) which is accepted as a stabilization time (Figure 5.65).

It is seen that pumping 0.8 bbl mud volume into the well during stabilization period provides 0.5 bbl less influx volume from formation.

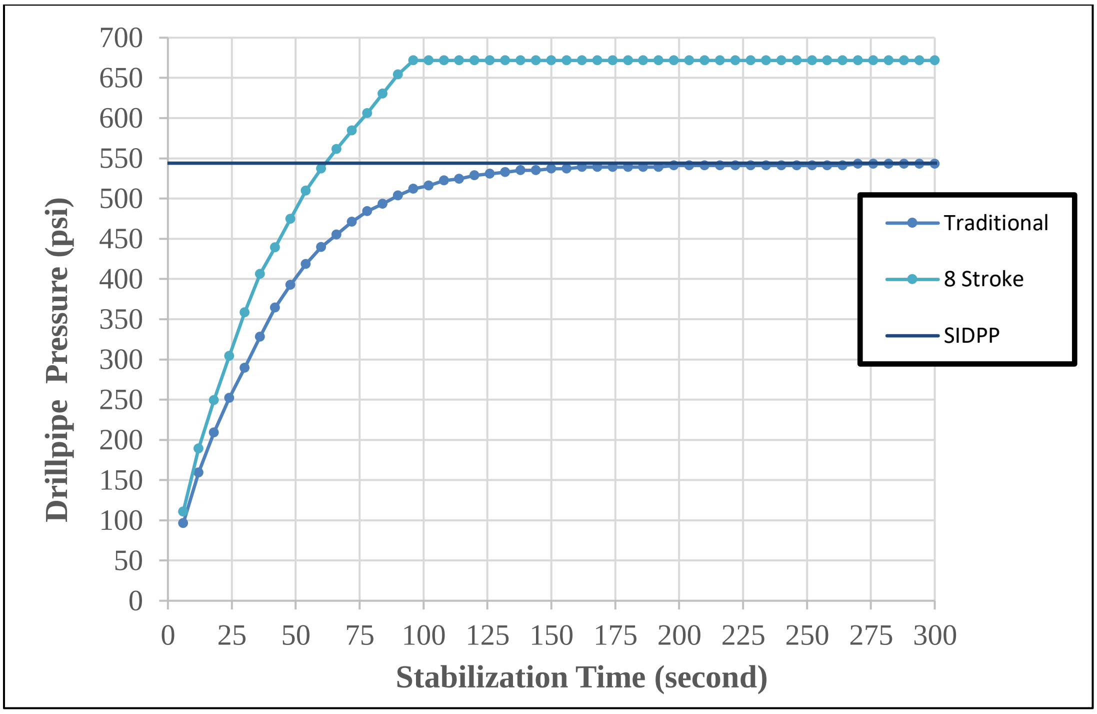

Figure 5.64. SIDPP vs. Stabilization Time for 8 Stroke (300 md)

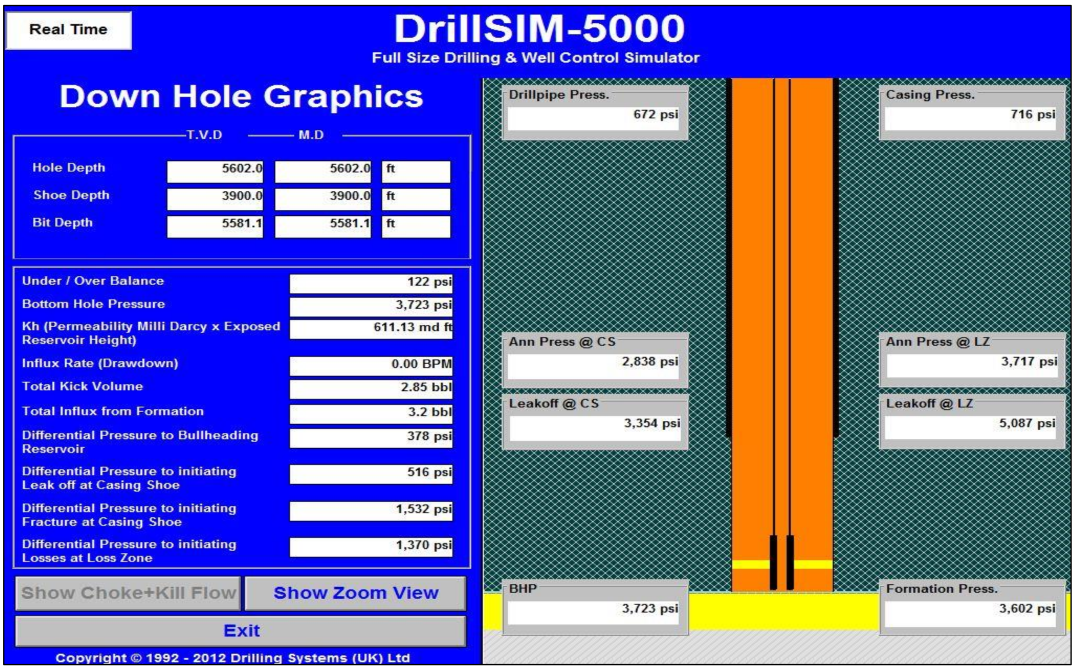

Figure 5.65. Well Schematics & Well Data after Stabilization for 8 Stroke (300 md)

5.2.4.6. Comparison of Results for Scenario 4

In scenario 4, the results of six cases are compared and evaluated. SIDPPs, BHPs and Casing shoe pressures versus stabilization time for all cases for the formation which has the permeability is 300 md are shown in the graphics. In all cases except Case 5, pressure differences is observed between 1 and 37 psi which means SIDPPs are slightly higher than the calculated SIDPP (Figure 5.66 and Figure 5.67).

The comparison of bottom-hole pressures are shown in Figure 5.68. As it is seen from the graphic, the behavior of bottom-hole pressure build up is almost the same to the behavior of SIDPP build up.

Casing shoe pressures is studied and compared, too. As it is seen from the Figure 3.70, Casing shoe pressure for all cases below the formation fracture pressure at casing shoe which is 4368 psi.

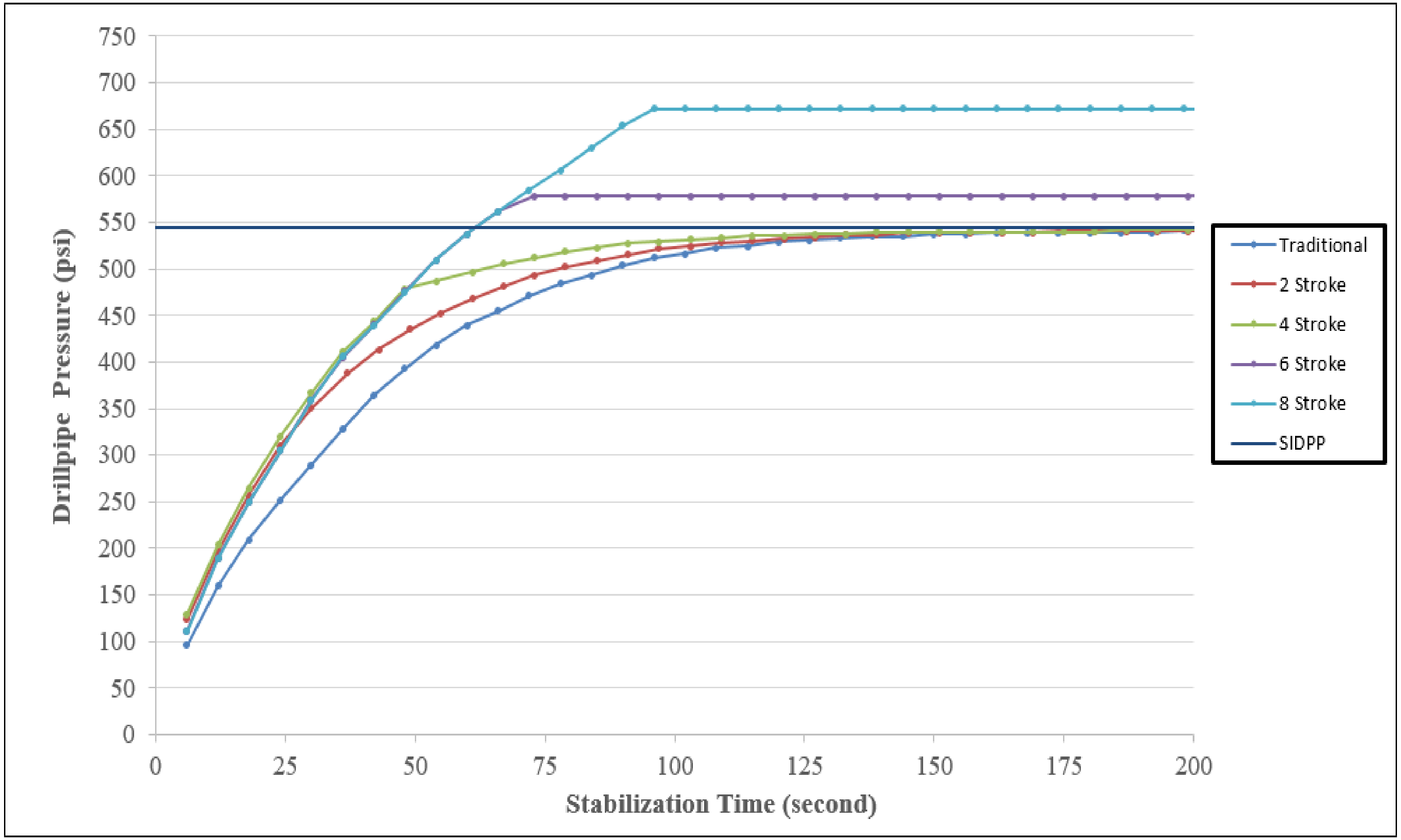

Figure 5.66 Comparisons of the SIDPP vs. Stabilization Time for the Cases for 300 md Permeability

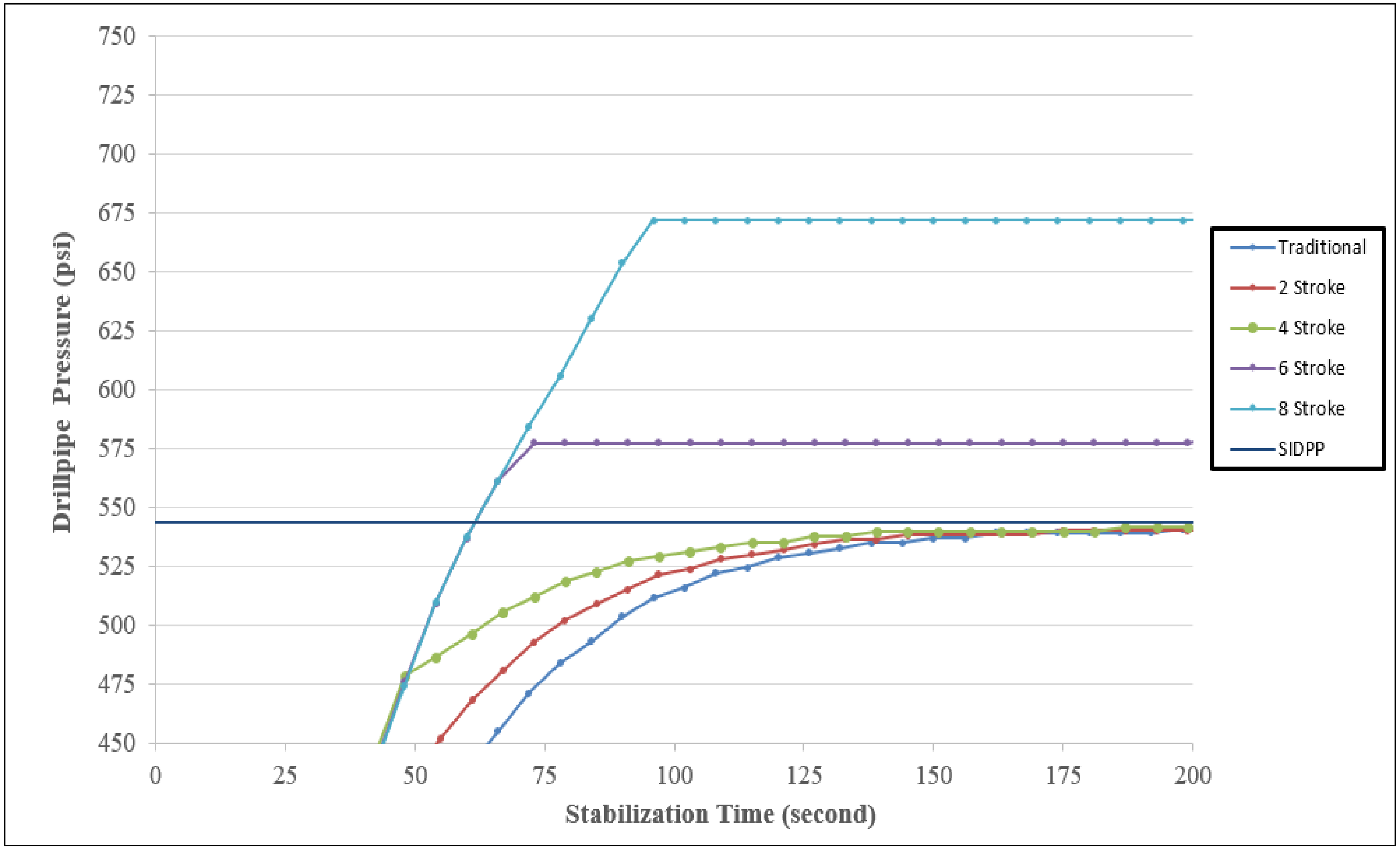

Figure 5.67. Comparisons of the SIDPP vs. Stabilization Time for the Cases for 300 md Permeability (Detail Scale)

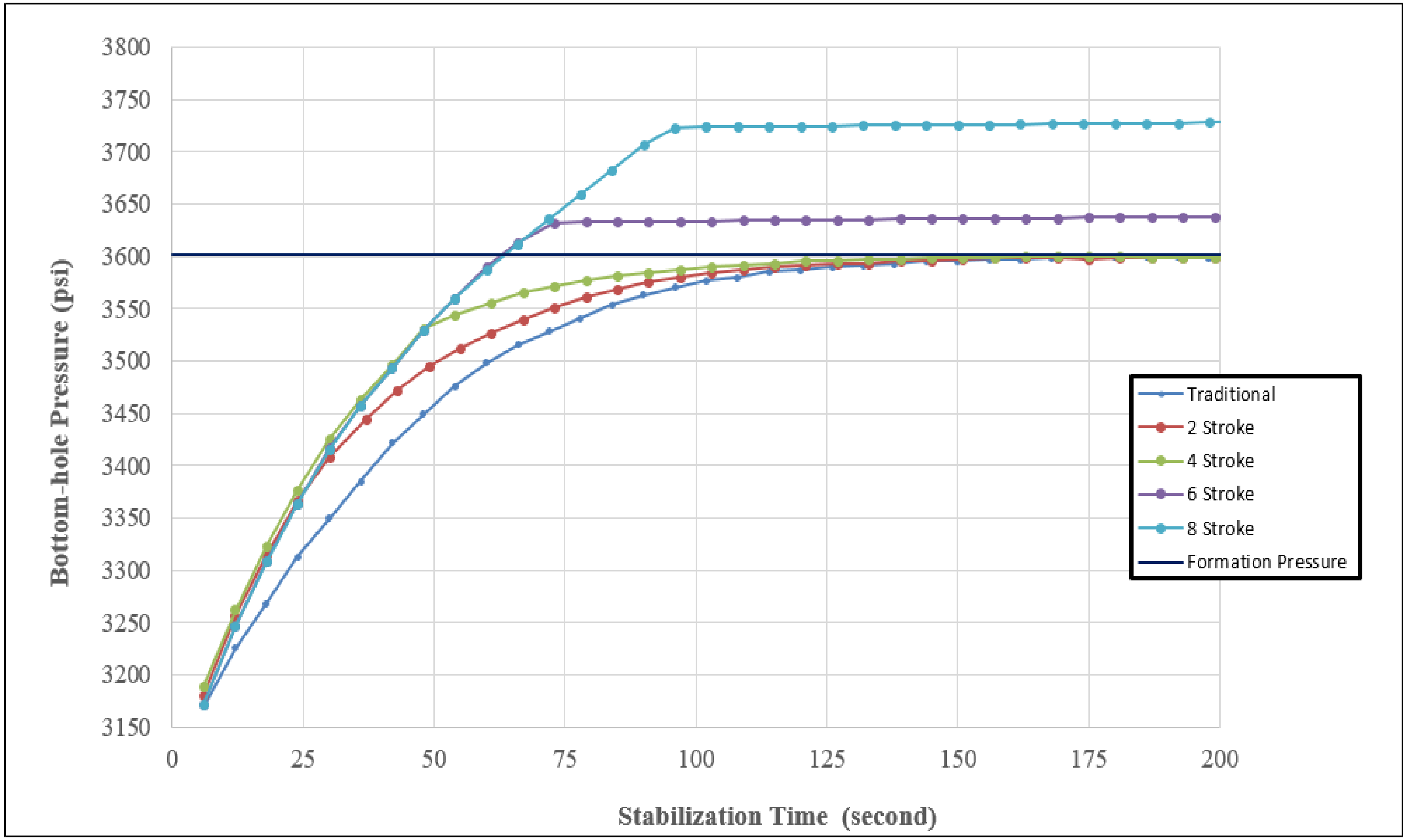

Figure 5.68. Comparison of the BHP vs. Stabilization Time for the Cases for 300 md Permeability

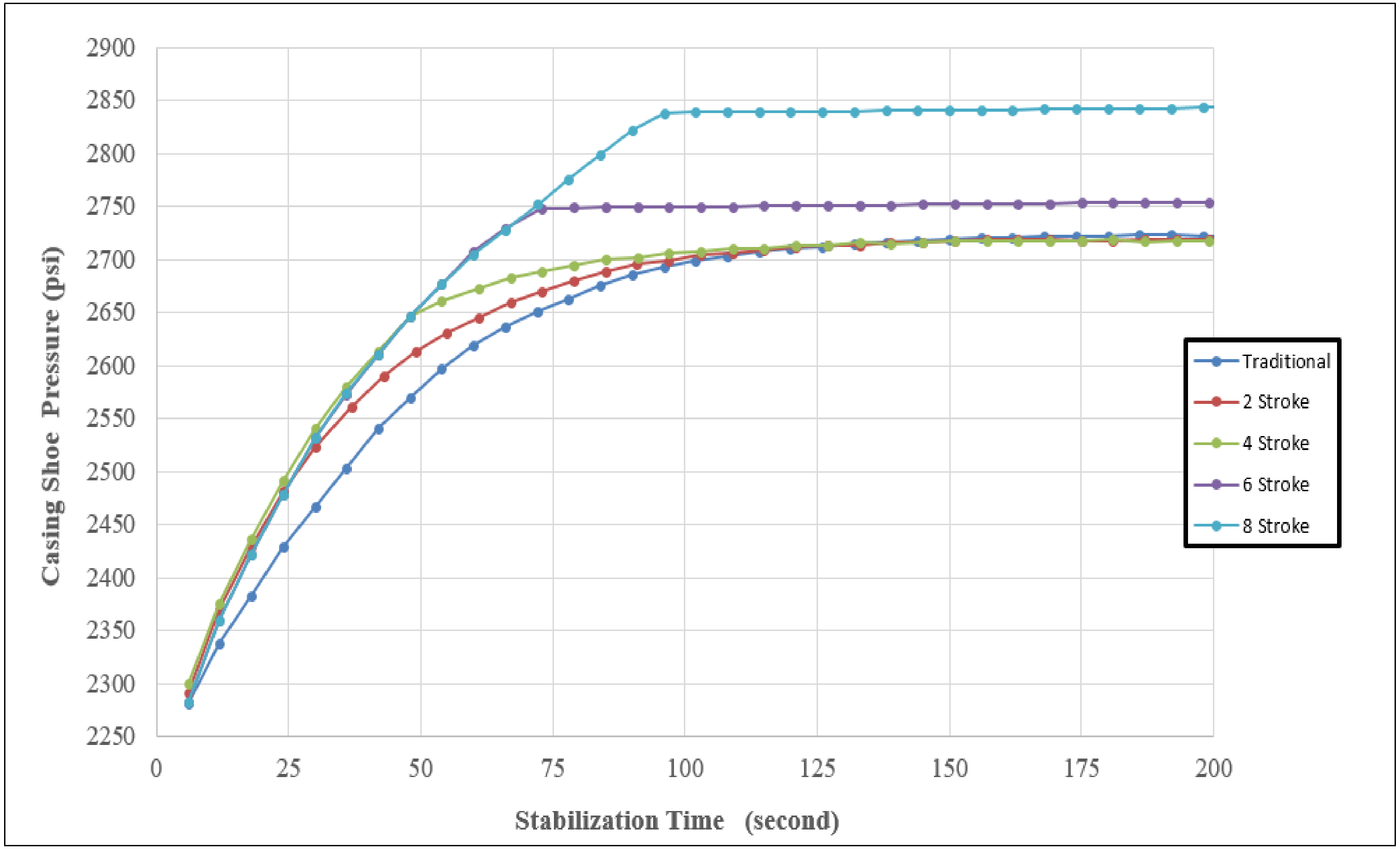

Figure 5.69. Comparison of the Casing Shoe Pressure vs. Stabilization Time for the Cases for 300 md Permeability

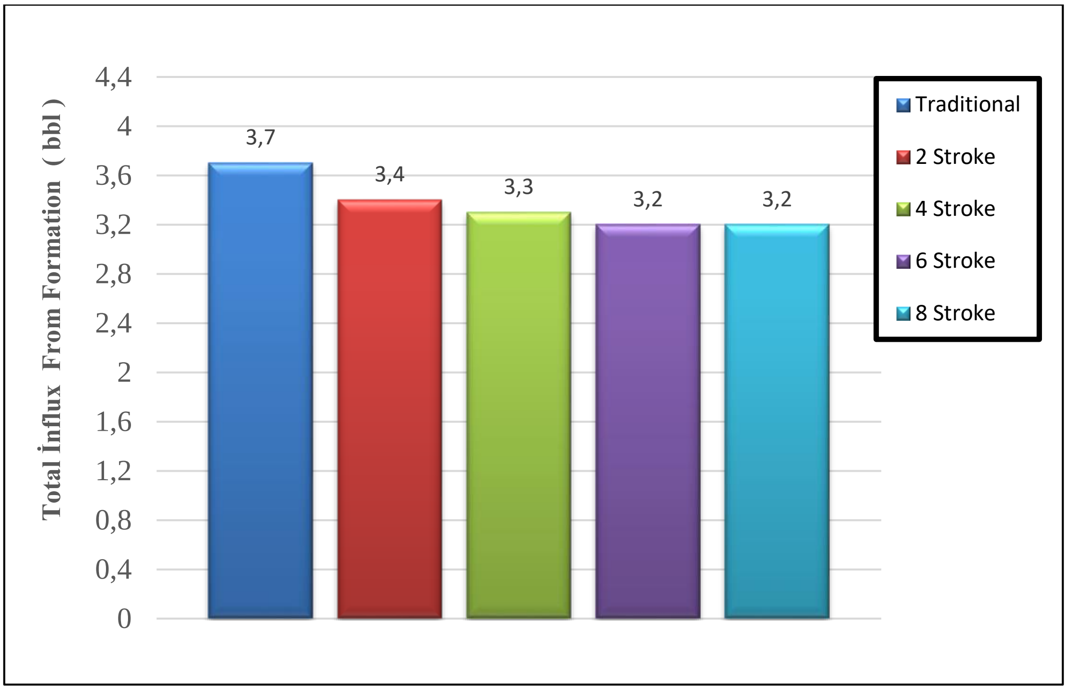

Figure 5.70. Comparisons of the Total Influx from Formation for the Cases for 300 md

Figure 5.70 illustrates the comparisons of the total influx volume from formation for the cases for 300 md permeability.

In conventional method, total influx volume from formation is 3.7 bbl which is the maximum value in Scenario 4. When the new well control approach is applied, gradual decrease is seen until Case 4 and remains unchanged From Case 4 to Case 5. Although volume of mud pumped into well changes From Case 4 to Case 5, the total influx is constant.

As it is seen from the Figure 5.71, when the new well control approach is applied, since the compressibility of gas, the total volume of mud pumped into well does not allow the same volume of influx to be reduced. Although volume of mud pumped into well is different for Case 4 and Case 5, the total influx is constant for these cases because this influx volume is taken during the time until well shut-in completely.

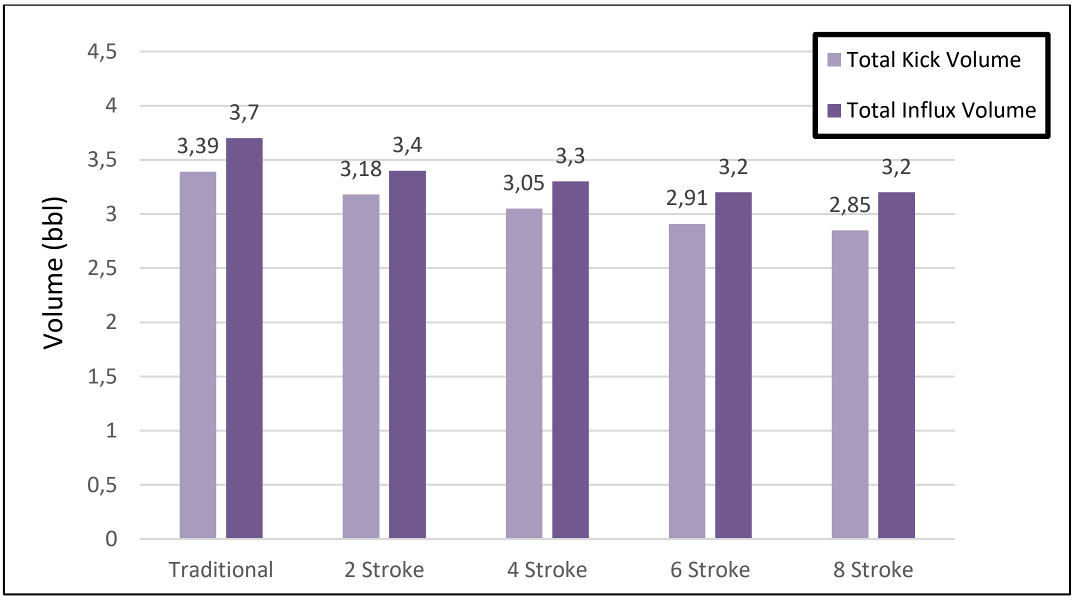

Figure 5.71. Comparisons of the Total Influx from Formation and Total Kick Volume for the Cases for 300 md Permeability

As shown in the Table 5.4, stabilization times for the unconventional cases decreases gradually and the maximum decrease in stabilization time is 77 percent which is the highest value in all scenarios. The maximum decrease in total influx volume is 14 percent.

Table 5.4. Comparison of the Results for the Cases for 300 md Permeability

Total Stroke	Real Total Stroke	Stabilization Time	% Time	Total Influx fr.Fm	% Total Influx fr.Fm	Max.Shoe Pressure	SIDPP	Pressure Differential
0	0,0	312	100	3.7	100	2726	543	-1
2	2,1	295	95	3.4	92	2722	543	-1
4	4,1	290	93	3.3	89	2720	544	0
6	6,0	73	23	3.2	86	2748	578	34
8	8,1	96	31	3.2	86	2838	672	128

5.3. Comparison of Scenarios Results

Permeability is a one of parameters affects the severity of a kick. In order to evaluate the effect of permeability in details, the results of reductions in the total influx volumes for four scenarios with the permeability values of 10, 50,100 and 300 md have been compared and shown in the Figure 5.72 and Figure 5.73

As it is seen from the Figure 5.72 and Figure 5.73, when the new well control approach is applied, the maximum reduction (75 %) in the total influx volumes is seen at 10 md that is the lowest permeability value in this study. On the other hand, the least reduction (14 %) in the total influx volumes is seen at 300 md that is the highest permeability value in this study.

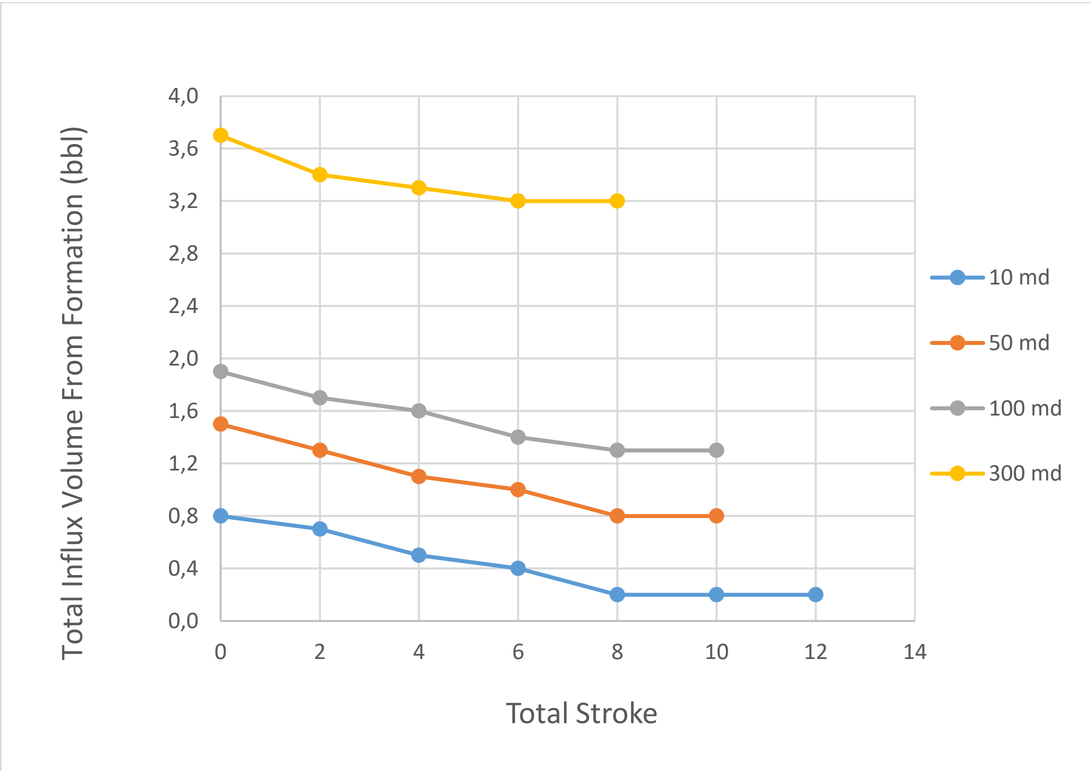

Figure 5.72. Comparisons of reductions in the total influx volumes for the four scenarios (bbl)

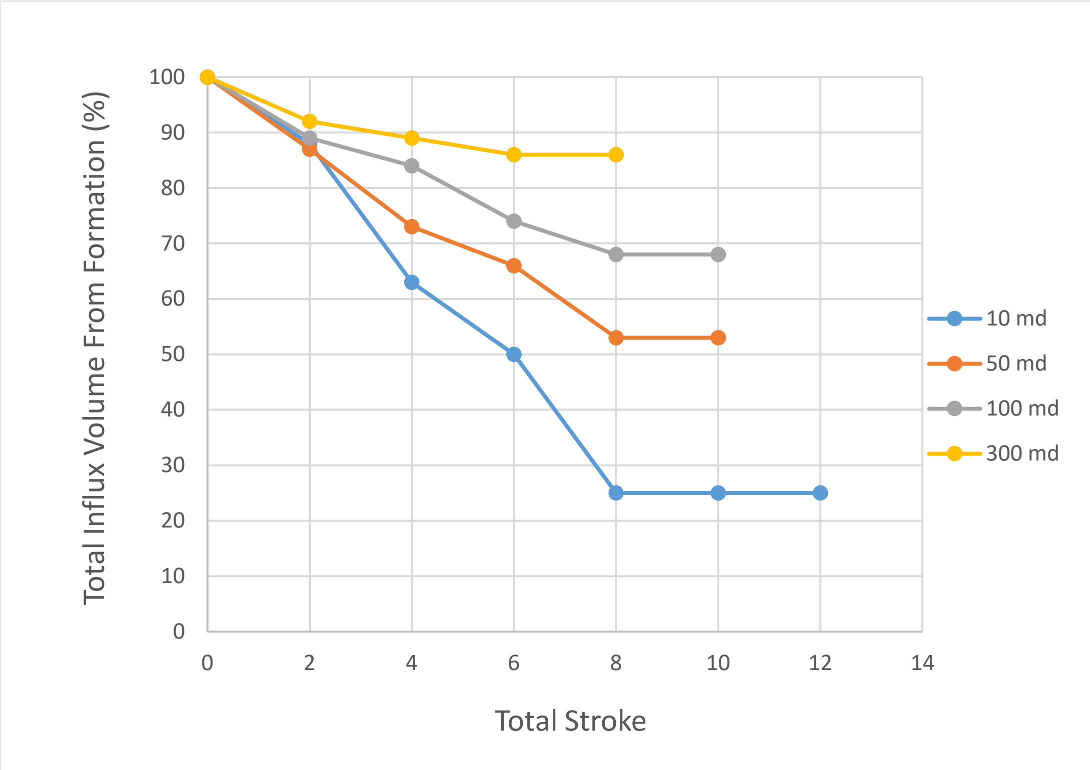

Figure 5.73. Comparisons of reductions in the total influx volumes for the four scenarios (%)

It is known that from Darcy's Law, flow rate of formation fluid increases as permeability increases. In this study, the mud is pumped at the same flow rate (5 spm) for all scenarios, but flow rate of formation fluid increases with increasing permeability. Therefore, the highest influx volume and the least reduction in the total influx volumes are seen at 300 md.

CHAPTER 6

CONCLUSIONS

The objective of this study was to lessen volume of influx from the formation after shut-in the well with a new well control approach. The new well control approach is based on decreasing the difference between the formation pressure and the bottom-hole pressure by pumping drilling mud after shut-in. The DrillSIM 5000 has been used to demonstrate how the volume of influx that enter the wellbore can be reduced.

In order to evaluate the effect of permeability in details, four scenarios with different permeability values have been used in simulation. Selected permeability values for this study were 10, 50, 100 and 300 md. The following conclusions are acquired from the overall simulation runs and analysis.

1. For high pressure reservoirs with low permeability (scenario 1 - 10 md), the maximum decrease in total influx volume was 75 percent that is a really very serious decline. In all cases of Scenario was the stabilization time exceeded the 1-hour limit due to low permeability. Therefore, actual stabilization times were not reported but the simulations were stopped within one hour after mud injection.

2. For high pressure reservoirs with a permeability of 50 md (scenario 2), the maximum decrease in total influx volume was 47 percent that is a considerable decline. Stabilization times for the unconventional cases are almost the same for all the cases, around 26 minutes.

3. For high pressure reservoirs with a permeability of 100 md (scenario 3), the maximum decrease in total influx volume was 32 percent that is a good decline. Stabilization times for the unconventional cases decreases gradually and the maximum decrease in stabilization time is 68 percent compared to conventional stabilization time.

4. For high pressure reservoirs with a permeability of 300 md (scenario 4), the maximum decrease in total influx volume was 14 percent that is not a significant decline. On the other hand, there was a significant decline in stabilization time as high as 77 percent.

5. It was found that, the casing shoe pressure, in all cases, never exceeded the formation fracture pressure at casing shoe which is 4368 psi.

6. It was observed that percent decrease in total influx volume decreases but the percent decrease in stabilization time increases with an increase in formation permeability.

7. It was concluded that, the initial total kick volume is reduced in higher permeability cases because of the compressibility of gas phase in annular fluid system.

Finally, it can be said that this new approach is reliable and can be used for the wells that have high pressure and low and high permeable formations, when formation fracture pressure and MAASP values are known. In addition, for this approach to be effective, pumping mud into well should started as soon as the shut-in the well.

REFERENCES

[1] Omosebi AO, Osisanya SO, Chukwu GA and Egbon FO "Annular Pressure Prediction During Well Control" paper SPE 163015, presented at the Nigeria Annual International Conference and Exhibition, Abuja, Nigeria, August 6-8, 2012.

[2] Oil & Gas Drilling Engineering, http://oilngasdrilling.com/secondary-well-control.html, last visited on May 2018.

[3] API RP 59, Recommended Practice for Well Control Operations, Second Edition, May 2006.

[4] Popular Mechanics, https://www.popularmechanics.com/science/energy/a6065/how-the-bp-oil-rig-blowout-happened/, last visited on May 2018.

[5] Baker, R.: "Practical Well Control", 1998, 4.

[6] Drilling Handbook, http://www.drillinghandbook.com/category/well-control/, last visited May 2018.

[7] Fertl, W.H.: "Abnormal Formation Pressure" (1976).

[8] Well Control Manual, Petroleum Engineering Research and Technology Transfer Laboratory, Louisiana State University, undated.

[9] TPAO Araştırma Merkezi Well Control Manual, Third Edition, 2014.

[10] TPAO Araştırma Merkezi Well Control Course Presentations.

[11] Mitchell, R. F.(ed.):"Petroleum Engineering Handbook,Volume II: Drilling Engineering", 2006, page II-194

[12] Standard Handbook of Petroleum and Natural Gas Engineering, Third Edition page 4-401.

[13] Transoceon Well Control Handbook, July 2011.

[14] ScienceDirect, https://www.sciencedirect.com/topics/engineering/fracture-gradient last visited May 2019.

[15] Petrophysics MSc Course Notes – Dr. Paul Glover – page 22.

[16] Shihui, S., Tie, Y., Xueliang, B., Xun, C. And Nan, Z., "Wellbore Flow Analysis of a Gas Kick Well During Shut-In". The Open Fuels & Energy Science Journal (2015, 8): 63-67.

[17] TeachEngineering, https://www.teachengineering.org/lessons/view/uoh_fluidmechanics_lesson01 last visited December 2018.

[18] Altun, G., Langlinais, J., Buorgoyne, A. T., "Application of A New Model To Analyze Leak-Off Tests", SPE Drilling & Completion, (June 2001): 108-116

[19] Sun, X.Kelin, W., Yan, T., Yanze, W., Luan, S. And Shao, S., "Study on Applicable Conditions and Mathematic Models of Bullheading", The Open Petroleum Engineering Journal (2017): 10-15.

[20] Xiangfang Li, Tao Gang and Xiuxiang Sui "Method of Rapid Stabilizing Shut-In Drill pipe Pressures for Blowout Wells" paper IADC/SPE 59262, presented at the IADC/SPE Drilling Conference, New Orleans, Louisiana, February 23-25, 2000.