CONSIDERATION OF COMPRESSIBILITY EFFECTS FOR APPLIED-BACK-PRESSURE DYNAMIC WELL CONTROL RESPONSE TO A GAS KICK IN MANAGED PRESSURE DRILLING OPERATIONS

by

WILLIAM A. BACON

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ABSTRACT

CONSIDERATION OF COMPRESSIBILITY EFFECTS FOR APPLIED-BACK-PRESSURE DYNAMIC WELL CONTROL RESPONSE TO A GAS KICK IN MANAGED PRESSURE DRILLING OPERATIONS

William Alexander Bacon, M.S.

The University of Texas at Arlington, 2011

Supervising Professor: Albert Tong

Managed Pressure Drilling (MPD) operations offer the ability to control a relatively small gas kick dynamically, without shutting in the well using blowout preventers. One currently employed method of dynamic well control uses applied-back-pressure to force flow exiting the wellbore to equal flow entering the drill-pipe, which is taken as an indication that the influx has stopped. However, for flow out equals flow in to imply influx cessation, the assumption of incompressibility of fluid in the wellbore is necessary. When fluid compressibility is appreciable, solely ensuring flow rate continuity does not necessarily imply influx cessation.

The period of “dynamic well control” in an MPD operation- from the moment an influx is identified until the moment the influx is believed to have ceased- is examined in this work. A control volume mass balance with compressibility is used to analyze the system. This approach enables inclusion in flow calculations of the expansion or compression of in-situ influx gas within the wellbore.

Since cessation of influx is the primary goal of dynamic well control, this work examines the transient, multiphase flow behavior in the annulus to explore limitations of the existing applied-back-pressure, dynamic, well control technique. It is shown that with the existing method, influx cessation does not always occur once flow out is constrained to equal flow in. It is also shown that in some situations where influx cessation is indeed achieved when flow out equals flow in, the back pressure applied at surface is higher than required to achieve influx cessation- i.e., influx ceases before the moment when flow out equals flow in. These outcomes are the consequence of the compressibility of the in-situ gas, and make the existing method unreliable in some critical situations of influx.

A new applied-back-pressure, dynamic well control technique has been proposed, and a transient, multiphase flow analysis is used to identify pressure-based indicators of influx cessation. It is shown that time derivatives of pressure and pressure transfer carry the signature of well response for the given control strategy, and can be used to infer cessation of influx. It is argued that, taken together, these are more reliable indicators of influx cessation (and hence successful well control) than solely ensuring flow out equals flow in.

Numerous transient, multiphase flow simulations have been conducted to support the key conclusions of this work.

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NOMENCLATURE

Abbreviations:

ABP - Applied Back Pressure

BHP - Bottomhole Pressure

CBHP - Constant Bottomhole Pressure

GOM - Gulf of Mexico

IADC - International Association of Drilling Contractors

LSU - Louisiana State University

MMS - Minerals Management Service

MPD - Managed Pressure Drilling

NTL - Notice to Lessees

OCS - Outer Continental Shelf

PI - Productivity Index

RCD - Rotating Control Device

SPE - Society of Petroleum Engineers

SPP - Standpipe Pressure

UBD - Underbalanced Drilling

WHP - Wellhead Pressure

Other Nomenclature:

$BHP_{initial}$ = Initial Bottomhole Pressure

BHP(t) = Transient Bottomhole Pressure

$BHP_{conventional}$ = Bottomhole Pressure for conventional drilling operations

BHP_{MPD} = bottomhole pressure for a managed pressure drilling operation

C1 = Aggressive control response

C2 = Relaxed control response

ΔBHP = BHP when Q_{out} = Q_{in} was achieved minus reservoir pressure

ΔP = (BHP – P_{res}) when Q_{out} = Q_{in} was achieved

$\Delta P_{acceleration}$ = pressure change due to acceleration

$\Delta P_{friction}$ = pressure change due to friction

$\Delta P_{hydrostatic}$ = pressure change due to annular fluid density

$\Delta P_{energy.}$ = pressure change as a result of another device

$\overline{\mathrm{P}}$ = Non-dimensional pressure transfer parameter

P_{ref} = Value of (BHP – WHP) at steady-state, before influx fluid entered the wellbore

P_{res} = Reservoir pressure

PTP = Non-dimensional pressure transfer parameter

Q_{in} = Volumetric flow rate of drilling fluid entering the drillpipe

Q_{out} = Volumetric flow rate of fluid exiting the annulus

Q_{exp} = Rate of change of in-situ volume of influx fluid within the annulus

Q_{influx} = Volumetric flow rate of influx fluid entering the wellbore

Δt = Time from influx cessation to Q_{out} = Q_{in}

ρ_{in} = Density of fluid pumped into drillpipe

ρ_{out} = Density of fluid exiting the wellbore

CHAPTER 1

INTRODUCTION

1.1 The Drilling System

The conventional drilling process is depicted in Figure 1-1. The drillbit is conveyed to the bottom of the hole on hollow drill pipe, which is rotated at surface. During drilling, a fluid is circulated to the drill bit via the drill pipe. This fluid serves the function of cooling the drill bit and cleaning the drill bit face of drilling cuttings. The fluid properties are engineered to facilitate carrying of drill solids back to surface.

An important function of the drilling fluid is to provide pressure support to the wellbore wall. This support is required for two reasons:

1) Provide support to the borehole wall and prevent borehole collapse (borehole stability)
2) To maintain the wellbore at a pressure higher than that of any formation fluids (well control).

The second purpose, well control, is the basic theme for this thesis. The rock formation that is drilled through has some form of porosity filled with formation fluids. These fluids can be water, or in the case of a reservoir, hydrocarbons. The pressure in these fluids is referred to as the “pore” pressure. If the pore spaces are connected, these formations will also have permeability – that is, fluids can flow through them in response to a pressure gradient. The aim of conventional well control is to operate such that fluid pressure in the wellbore is always higher than the pore pressure, thus preventing the flow of formation fluids into the wellbore. The pressure in the wellbore is controlled by varying the density, and thereby the hydrostatic pressure of the drilling fluid column within the wellbore. At the same time, the pressure exerted by the fluid should not exceed the failure limit of the formation rock- for if it does, the exposed formation will fracture and allow loss of drilling fluids into the formation. This limiting strength of the rock is referred to as its "fracture pressure", and the aim in drilling is thus to maintain the flowing pressure in the wellbore between the two limits of pore pressure and fracture pressure.

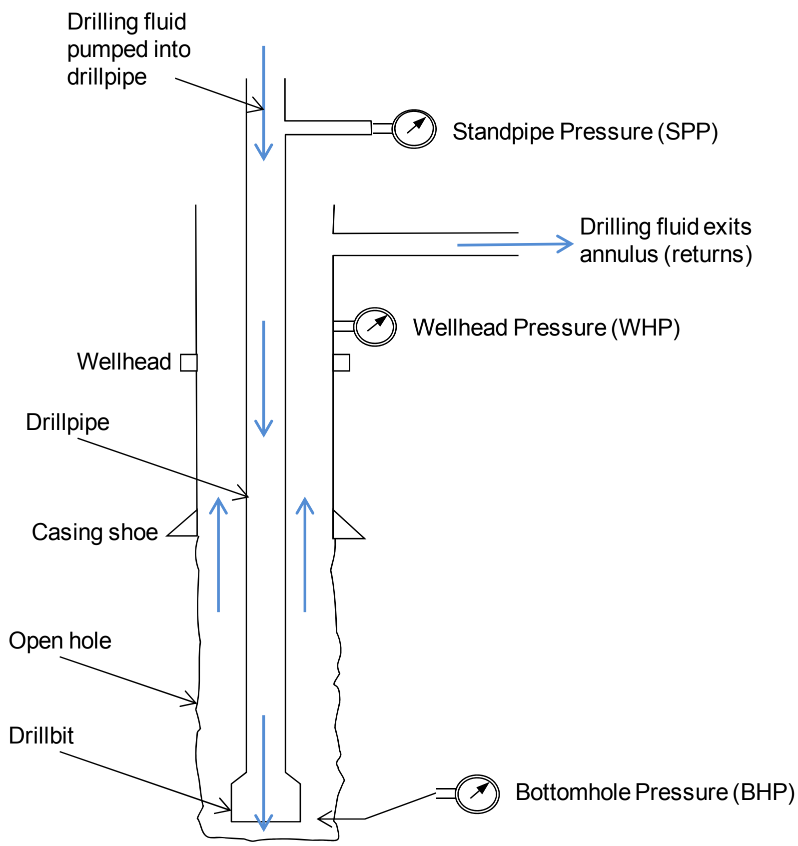

Figure 1-1 Conventional drilling system while drilling ahead

The drilling system described is a closed system. Fluid is pumped from surface storage, down the drill pipe. Returns from the wellbore annulus travel back through surface processing, where drilling solids are removed, to surface storage. The total volume of drilling fluid within the system remains nearly constant[1]. Hence, if a high pressure, permeable formation is penetrated and an influx occurs, it can easily be detected as an increase in system volume. Therefore, if a

[1] Some fluid loss is expected due to cuttings being wetted, evaporation, etc.

formation influx occurs, the volumetric rate leaving the annulus (returns) will exceed that being pumped into the drillpipe, thus resulting in a net gain in the system volume. Detection of such system gains is the front line of well control.

1.2 Conventional Well Control

A critical element of oil and gas well engineering and operations lies with the control of enormous amounts of energy within the wellbore. Over geological time, energy in the form of pressurized fluids has built up within the reservoir formation. The key to successful well design and implementation is tapping into this energy with a wellbore, providing a conduit for the controlled flow of hydrocarbons to surface. When control over this wellbore is lost, an uncontrolled release known as a blowout can occur. Blowouts are an uncontrolled escape of formation fluids from the well, and can cause catastrophic effects such as loss of life and devastating economic and environmental damage.

In conventional drilling, as noted earlier, wellbore pressure is maintained at a value between formation pore pressure and fracture pressure. Formation pressure is the naturally occurring pressure of fluids within a formation, while fracture pressure is the maximum wellbore pressure a formation can resist without fracture. The wellbore pressure is maintained within the formation pore pressure/fracture pressure window by utilizing drilling fluid, or mud, at an appropriate density to create hydrostatic pressure which will overcome formation pressure at a particular depth. Figure 1-2 illustrates the relationship between formation pressure, mud hydrostatic and fracture pressure. If not properly controlled, an unwanted formation influx, or kick, can develop into a blowout - a continuous uncontrolled release to surface.

1.2.1 Causes of Kicks

A kick may occur at any time wellbore pressure falls below formation pore pressure while in a permeable and porous zone containing fluids. The main reasons for this pressure differential are either an unexpected rise in formation pressure, or a decrease in mud hydrostatic pressure.

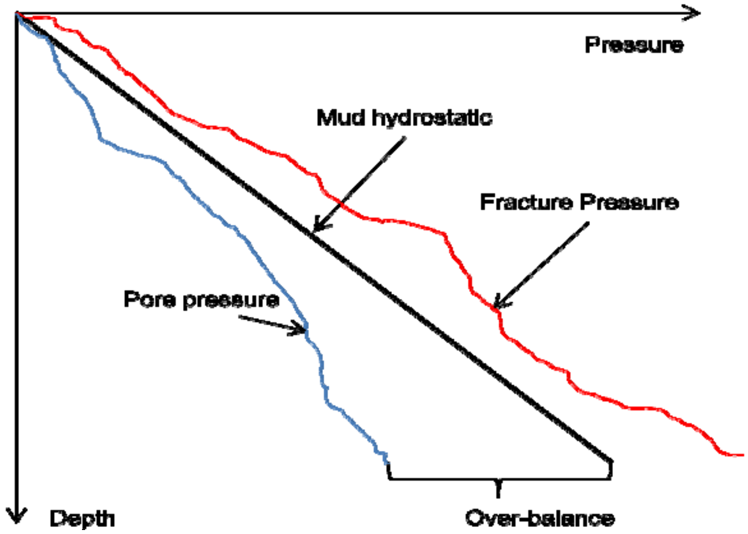

Figure 1-2 Relationship between Formation Pressure, Mud (drilling fluid) Hydrostatic and Fracture Pressure

A rise in formation pressure can be due to geological processes that have occurred in the region being drilled. Wells are drilled in regions where oil and gas are trapped, and the same processes that create the hydrocarbons can also produce large pressures. It is therefore not uncommon to come across regions of abnormally high formation pressure while drilling.

Mud hydrostatic can decrease due to any event that causes the mud column in the hole to drop, such as lost circulation or tripping out (pulling the drilling assembly out of the hole) while not filling the hole to adequately compensate for the volume of the removed drilling assembly.

1.2.2 Conventional Shut-In

The goal of the driller on detecting a kick, is of course to control it (i.e., return to a condition of wellbore pressure exceeding pore pressure) as quickly as possible, while safely removing the influx already in the wellbore (which is referred to as "circulating the kick out"). When a kick is detected during conventional drilling, the well is shut-in. That is, the blowout preventers (equivalent to a pressure control valve system at surface) are closed and circulation stopped. A conventional shut-in is illustrated by Figure 1-3. Shutting-in will cause wellbore pressure to increase until a state of pressure equilibrium between wellbore and formation is reached, which causes the influx to stop. While pressure increases throughout the entire wellbore, an increase in standpipe pressure (SPP) and wellhead pressure (WHP) will be noticed (see Figure 1-3). When pressure in the well is increased to the point that an influx is stopped, this is known as ‘controlling the well’. Once the well has been controlled, the influx is circulated out at very low pump rates while maintaining constant bottomhole pressure (BHP).

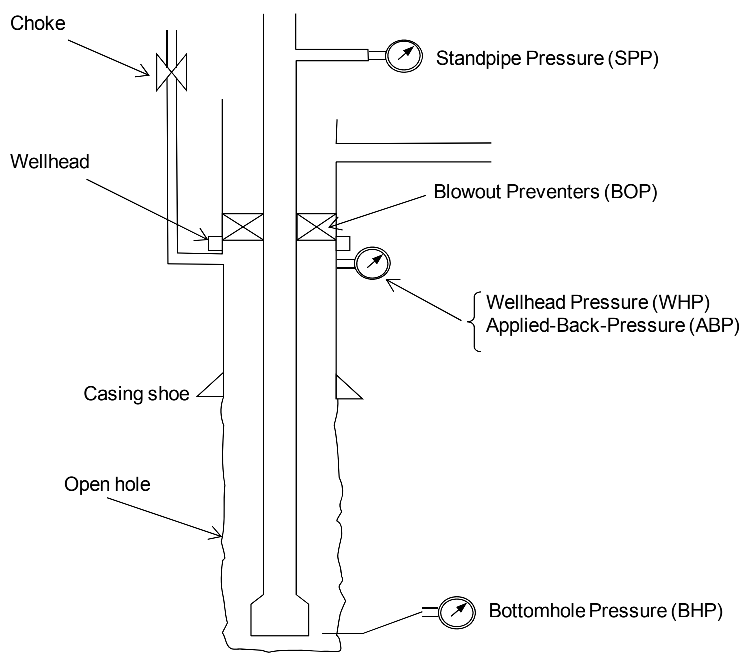

Figure 1-3 Conventional Shut-In

Maintaining constant BHP automatically allows any in-situ influx gas within the wellbore to expand an appropriate amount as it is circulated along the annulus. Controlled expansion of circulating gas kicks is vital. Uncontrolled expansion will result in enormous volumes of gas displacing mud out of the hole (and hence loss of hydrostatic pressure in the wellbore). In contrast, not allowing any expansion will result in large pressure increase throughout the entire wellbore, potentially leading to formation breakdown at a weaker zone and mud losses.

1.2.3 The Driller's Method

One of the most common methods of circulating out a kick is the driller's method. This technique involves circulating a kick out of the well using the same drilling mud as was being used before the kick was detected.

Before circulation commences, the drillpipe contains only static, single-phase, drilling mud. Therefore, maintaining constant SPP automatically maintains constant BHP while the kick is being circulated out.

Once the kick has been removed from the well, new mud with higher density calculated to provide a hydrostatic pressure slightly greater than the new formation pressure is circulated through the well while maintaining constant BHP.

The driller's method is convenient due to its effectiveness and simplicity, allowing personnel to easily understand and monitor the process of circulating out a kick.

1.2.4 Gas Migration

Due to density difference between drilling mud and influx gas, buoyancy force causes gas bubbles in the annulus to rise, or migrate. Therefore, gas in the system will always have a relative upwards velocity (in a vertical or inclined well) compared to the drilling mud. For this reason, even after the influx has ceased, pressure throughout the entire wellbore will continue to increase as gas migrates and is prevented from expanding.

By considering an influx as ideal gas and allowing the gas to migrate to surface without allowing expansion, one would expect BHP to be nearly double its initial value (assuming reasonably small initial WHP) and the new WHP would be greater than the original BHP. This, of course, must be avoided to reduce risk of fracturing a section of open hole, or causing surface equipment to fail.

1.3 <u>Managed Pressure Drilling</u>

Managed Pressure Drilling (MPD) is a class of techniques that allows control of bottom hole pressure through a combination of controlling the density, flow rate and well head pressure (or back pressure). It was developed to allow drilling operations proceed where conventional drilling is considered uneconomical, high risk, or even impossible. Two of the greatest advantages of MPD are the ability to reduce non-productive time and drill where extremely narrow pore/fracture pressure windows exist.

MPD's ability to reduce non-productive time comes from the reduction of operational problems, such as stuck pipe and differential sticking, and also from the ability to perform dynamic well control, which forms the basis for this research. The ability to drill through narrow formation/fracture pressure windows stems from dynamic and precise annular pressure control which is not available in conventional drilling.

1.3.1 MPD Well Control

Concepts required to understand MPD well control are essentially the same as for conventional well control. In conventional drilling, mud density is selected to impose hydrostatic pressure greater than formation pressure for any section of open hole. Also, unless shut-in, conventional systems are open to atmosphere at the surface. So for conventional systems the mud hydrostatic pressure alone is considered the primary barrier for well control. In MPD, however, the system is closed to atmosphere and the capacity to apply back-pressure on the annulus is added. For this reason, in MPD, the primary barrier for well control is often considered the combination of mud hydrostatic pressure, rotating control device and flow control choke (equipment is discussed in section 1.3.5). Therefore, in MPD operations, a combination of drilling fluid density, friction and applied-back-pressure (ABP) are used to balance formation pressure. A simple MPD system is illustrated by Figure 1-4.

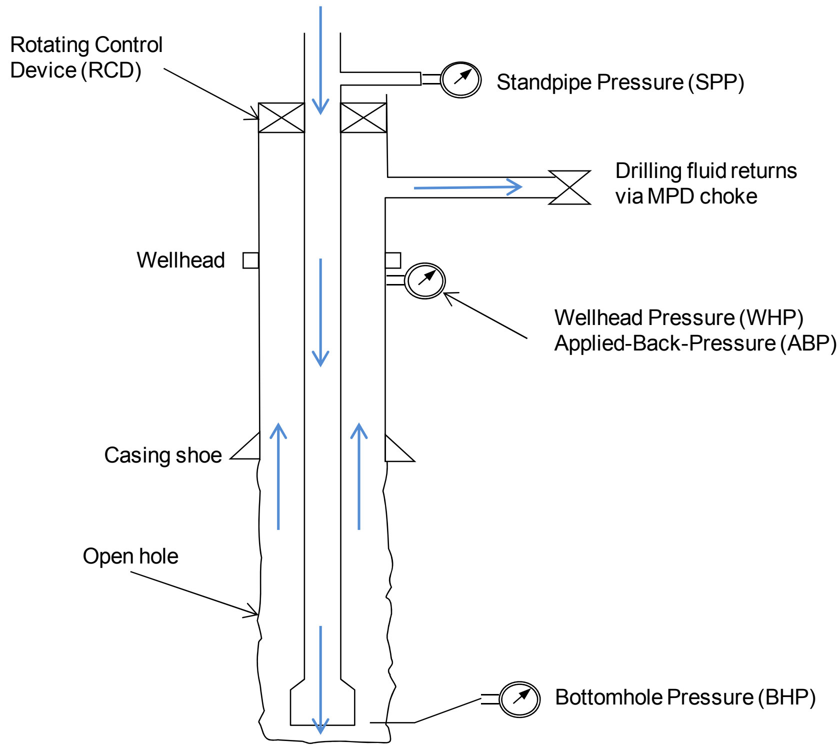

Figure 1-4 A simple MPD system

Equation (1.1) and (1.2) compare how BHP is controlled for conventional and managed pressure drilling operations, respectively.

$$BHP_{conventional} = \Delta P_{hydrostatic} + \Delta P_{friction} \tag{1.1}$$

$$BHP_{MPD} = ABP + \Delta P_{hydrostatic} + \Delta P_{friction} + \Delta P_{energy} + \Delta P_{acceleration} \tag{1.2}$$

Where: $BHP_{conventional}$ = bottomhole pressure for conventional drilling operations

$\Delta P_{hydrostatic}$ = pressure change due to annular fluid density

$\Delta P_{friction}$ = pressure change due to friction

BHP_{MPD} = bottomhole pressure for a managed pressure drilling operation

ABP = applied-back-pressure

$\Delta P_{energy.}$ = pressure change as a result of another (energy) device, and

$\Delta P_{acceleration}$ = pressure change due to acceleration

Pressure change due to acceleration is usually considered negligible. Also, for the purposes of this research, no equipment components, such as a sea floor pump, are included that would contribute to ΔP_{energy}. Therefore, for the remainder of this work, Equation (1.2) simplifies to Equation (1.3).

$$BHP_{MPD} = ABP + \Delta P_{hyd.} + \Delta P_{friction} \qquad (1.3)$$

1.3.2 Dynamic, MPD Well Control

When well control is performed without stopping circulation and shutting-in conventionally, it may be referred to as *dynamic well control.* Unlike conventionally shutting-in and getting an accurate indication of reservoir pressure from standpipe pressure, however, dynamic well control contains more inherent risk of under or over estimating the required BHP to control the well. However, it allows more rapid control of the kick, if feasible.

1.3.3 Applied-Back-Pressure, Dynamic, Well Control

Dynamic well control responses to a gas influx can include two principal methods to increase BHP; Increase applied-back-pressure or increase pump rate. Increasing pump rate, increases the friction loss (third term in Equation (1.3) above) and hence the BHP. However, this approach has limited application due to pump limits, and reduced impact in large wellbores (as discussed in Chapter 2). Therefore, increasing applied back pressure is the most common approach for dynamic well control, and is the focus of this work.

For this method, the primary indicator of a well control event is an increase in flow out of the system. That is, $Q_{out} > Q_{in}$. If the influx volume taken is sufficiently small (as defined by the well control matrix discussed in section 1.3.4), then the decision to apply a dynamic well control response will be made. Hence, we will further define dynamic well control as maintaining drilling pump rate and using MPD equipment to provide an applied-back-pressure response to force $Q_{out} = Q_{in}$. After this balance is achieved, any desired overkill can be applied and the kick circulated out while maintaining constant standpipe pressure.

This dynamic well control method is one currently used in industry and has been tested in research such as Das (Das, et al., 2008) and Davoudi (Davoudi, et al., 2010). For this dynamic well control method to work successfully, the following assumptions are required:

- It is assumed that any influx gas within the well is very small compared to the total annular volume. Therefore, the fluid in the annulus may be assumed incompressible, and the instantaneous condition of $Q_{out} = Q_{in}$ will imply influx cessation.
- It is assumed that no lost circulation exists. Lost circulation will mask $Q_{out} = Q_{in}$ indicating influx cessation.

Another important requirement for this method of well control to work successfully, is to employ accurate flow metering by using equipment such as a Coriolis meter, described in Section 1.3.5.3. Without this ability, even if positive identification of an influx is possible through monitoring pit gains, control of the influx by forcing $Q_{out} = Q_{in}$ will not be achievable.

1.3.4 Decision to Shut-In Conventionally

When an influx is positively identified during a MPD operation, the decision whether to apply conventional or dynamic well control techniques must be made. For this decision to be made responsibly, numerous factors such as influx volume, influx intensity, influx rate, and anticipated maximum surface pressures and flow rates must be considered. If made without reasonable justification, it can significantly increase the time to achieve complete control of the well, thus exposing equipment and personnel to greater risk. If not made when justified, it can lead to increased influx and unmanageable pressures or rates at surface, leading to potentially risky situations which can ultimately result in a blowout. It is therefore one of the more crucial decisions made during an MPD operation. Indeed, an important motivation for this work is the desire to provide a rigorous and quantitative basis for this decision, which, at present, is lacking in the regulation.

An MPD Operations Matrix is required by the Minerals Management Service[2] (MMS, 2008), when applying for a Permit to Drill for an MPD operation in the Gulf Of Mexico (GOM) region. An MPD Operations Matrix, illustrated in Figure 2-3, assists with operational decisions regarding whether conventional or dynamic well control techniques should be employed once an influx is observed. Yellow and orange zones indicate conditions where various dynamic well control procedures may be used to bring conditions back into a green zone. Red Zones indicate conditions where conventional well control techniques should be employed. The MPD Operations Matrix is discussed further in CHAPTER 2.

1.3.5 MPD Equipment

MPD operations can require the addition of various kinds of equipment, depending on the type of MPD operation employed. The equipment used is essentially similar to that which is used for underbalanced drilling operations. Two of the most important pieces of equipment required specifically for MPD operations are the Rotating Control Device and MPD Choke Manifold, and they are briefly discussed below. Although often used in conventional drilling operations, the Coriolis meter is also discussed here, due to its important role in applied-back-pressure, dynamic, MPD well control.

1.3.5.1 Rotating Control Device

The foremost piece of equipment differentiating MPD from conventional drilling operations is a Rotating Control Device (RCD). The RCD provides the seal between atmosphere and wellbore, while allowing pipe movement and diverting returns flow. In conjunction with the flow control choke, the RCD provides the ability to apply back-pressure on the annulus during an MPD operation.

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[2] Since 2010, MMS has been superseded by Bureau of Ocean Energy Management, Regulation and Enforcement; see www.boemre.gov.

1.3.5.2 MPD Choke Manifold

The MPD choke manifold provides an adjustable choke system which is used to dynamically control the required BHP by means of applying surface back-pressure. It also provides a controlled flow path for returns fluid.

1.3.5.3 Coriolis Meter

A Coriolis meter is used to accurately measure the mass flow rate of fluid exiting the annulus. The ability to measure return flow accurately is essential for the applied-back-pressure, dynamic well control procedures discussed in this research. Although mass flow rate is measured, commonly used equipment in MPD operations converts this to volumetric flow rate, which is output to the operator. Typical outputs during a dynamic well control scenario are shown in Figure 2-1.

1.4 Under-Balanced Drilling

Under balanced drilling refers to a modern drilling technique where the pressure within the wellbore is deliberately maintained *below* reservoir pressure. While underbalanced, permeability within the rock will cause fluids to flow from the reservoir to the wellbore. This is in contrast to conventional (and managed pressure) drilling where the wellbore is maintained overbalanced. The overbalanced state can cause movement of fluid into the formation, causing both particulates and fluid to be carried into the near wellbore area and damaging formation permeability and the resulting well productivity.

Formation invasion is somewhat mitigated in overbalanced drilling operations through the buildup of an impermeable “filter cake” layer on the wellbore surface. This filter cake is a layer of sized solids that are big enough that they do not penetrate the pore throats, but bridge over them impeding fluid flow from the wellbore to the formation. However, the process of filtercake build up requires that some formation fluid be lost to the wellbore area. No matter how good the fluid system, some near wellbore invasion will occur.

To overcome the damaging effects of overbalanced drilling techniques the industry moved to underbalanced drilling. This technique is much the same as managed pressure drilling, except that no filter cake is built up, and the surface handling equipment must be capable of handling production while drilling through a permeable fluid bearing zone.

In underbalanced drilling the hydrostatic pressure of the fluid, being deliberately held below pore pressure, is by definition inadequate to provide well control. Hence, as with MPD, the primary well control barrier is often considered drilling fluid hydrostatic in combination with the RCD and choke. This is in contrast to conventional well control, where fluid hydrostatic pressure alone is considered the primary barrier and must be maintained at a reasonable margin above pore pressure.

It is interesting to note that industry experience has revealed that simply reducing the margin of overbalance, through MPD, can reduce the formation invasion and resulting damage that occurs in conventional drilling.

CHAPTER 2

LITERATURE REVIEW

The subject of dynamic well control in a managed pressure drilling (MPD) operations has received much attention in the recent past. It should be recalled that the goal in dynamic well control is to control the influx and circulate the kick out without shutting the well in. As such, most workers have focused on different strategies of pressure (or flow) management that achieve control in the most effective manner.

Das (Das A. K., 2007) has investigated alternative initial responses to kicks for various well scenarios during managed pressure drilling operations. The objective was to determine the most effective response for a given situation. An interactive, transient, multiphase flow simulator was used to simulate three methods of initial response; Shut-in the well conventionally, apply back pressure, and increase mud pump rate.

The 'apply back pressure' response involved increasing back pressure until flow-out equal to flow-in was achieved, which is taken to imply that influx has ceased for an intact wellbore. However, flow-out equal to flow-in indicating influx cessation appears to be true only if the fluid in the annulus is assumed incompressible. Removing this assumption will form an essential part of this thesis.

Effectiveness of the initial responses were judged based on ability to minimize casing pressure, stop formation influx with minimal additional gain, verify formation influx was controlled and identify lost returns. No single response was identified as the most effective for all scenarios tested in this research. Some tentative conclusions were:

- When effective, the 'increase mud flow rate' response results in the lowest casing and shoe pressure and, therefore, minimize risk of lost returns or surface equipment pressure ratings being exceeded.

- The ‘apply back pressure’ has a comparable but less significant advantage over the ‘shut-in’ response. However, reliable ways of identifying lost circulation were not identified.
- The ‘shut-in’ response generally results in highest casing and casing shoe pressures, causing the most chance of lost circulation. However, this response is the least likely to allow unintentional formation fluid flow to surface.

Maintaining flow-out equal to flow-in during applied-back-pressure response to a gas kick in a non-intact wellbore was also studied, and it was found that uncontrolled flow of gas at surface may result.

Das (Das, Smith, & Frink, 2008) has continued to describe results from the simulation study described above (Das, 2007). Some of the most important considerations discussed are the ability to minimize risk of lost returns by continuing to circulate while responding to a kick, and the difficulty of determining if formation influx is being offset by lost circulation during an applied-back-pressure response. The need for a practical technique to determine if lost returns are present during an initial response is emphasized.

This work also discussed the effect of maintaining flow-out equal to flow-in while simulating a gas kick in a non-intact well. It suggested that for an intact wellbore, this method would typically cause excessive wellbore pressure and, therefore, will increase risk of lost returns. Also suggested, was that this method is not considered a correct approach for conventional well control, although is still sometimes considered as a means of preventing additional gain.

Davoudi (Davoudi, Smith, Patel, & Chirinos, 2010) has further investigated alternative initial responses to kicks taken during managed pressure drilling operations. This work completed the evaluation of alternative initial responses to kicks in managed pressure drilling operations for an industry-supported research project.

Three alternative responses were concluded to be appropriate for general application; Increase casing pressure until flow-out is equal to flow-in, shut-in the well, and adapting an MPD pump shut-down schedule to detect and shut-in low rate kicks. Increasing pump rate was also concluded to be effective, but has very limited application. It was concluded that increasing back pressure until flow-in is equal to flow-out, while maintaining constant pump rate, is the most effective response that avoids the disadvantages of conventionally shutting in the well. However, accurate flow metering and special interpretation of Q_{out} to confirm influx cessation is required.

Guner (Guner, 2009) performed a simulation study to determine the most appropriate initial response to kicks arising due to MPD specific complications causing BHP fluctuations. Surface equipment failures and unintentional equivalent circulating density reductions are typical MPD specific complications because managed pressure drilling wells are usually statically underbalanced. Being statically overbalanced, these complications would, therefore, not occur in conventional drilling operations.

A number of different initial responses, including increasing surface back-pressure, were simulated on a transient drilling simulator for cases where various MPD specific complications were present. Increasing back-pressure was found to be the most effective response if adequate flow metering was used and surface equipment condition allowed.

As with previously mentioned research, for the increase back-pressure method, once back-pressure has been increased to the point where flow-out is equal to flow-in, the influx is concluded to have stopped.

Carlsen (Carlsen, Nygaard, Gravdal, Nikolaou, & Schubert, 2008) compared a conventional shut-in procedure to an introduced ‘dynamic shut-in’ procedure for an operation adopting automatic control of the MPD choke and annulus pump. Using a computer model to compare the two methods in a kick scenario, this work concluded that the dynamic shut-in procedure resulted in a smaller kick volume than conventionally shutting-in. This was because of annular friction pressure loss due to shutting the pumps down during the conventional method.

Vieira (Vieira P. , Arnone, Torres, & Barragan, 2009) describes the benefits of MPD equipment with regard to kick detection and well control, and the associated reduction in Non-Productive Time, and hence costs. The requirement for more accurate kick detection equipment for MPD rather than conventional drilling is discussed, particularly with regard to the use of Coriolis type flow meters for return flow monitoring. Early kick detection and accurate measurement of return flow from the annular side is emphasized.

This work shows an example of a kick being detected by monitoring deviations in return flow from flow into the drillpipe. Figure 2-1 depicts a scenario where a data acquisition system has detected and controlled a kick using automated MPD equipment. In this case the kick is controlled within two minutes, allowing a volume gain of only 1.1 bbl.

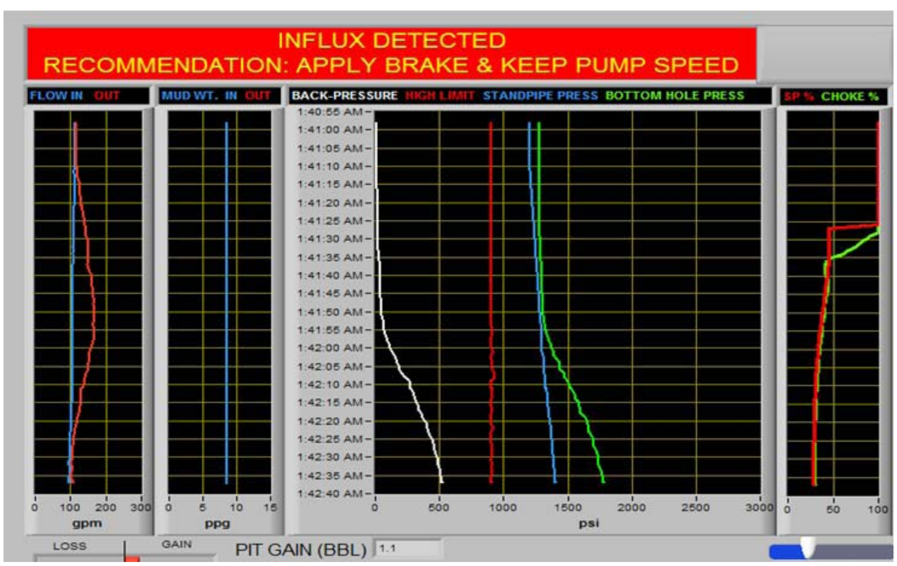

Figure 2-1 Early Kick Detection (Vieira, et al., 2009)

Saponja (Saponja, Adeleye, & Hucik, 2005) has given a general overview of managed pressure drilling. With a major focus on the value added by using MPD due to the reduction of

Non-Productive Time (NPT), this work also covers well control aspects that come into play in the case of over-pressured High Pressure Low Volume (HPLV) nuisance gas zones. The concept of dynamically controlling the well after a gas kick is discussed, and a Flow Control Matrix (FCM) is introduced, which is proposed to bridge the gap between dynamic well control using MPD and conventional well control.

Used as an operational tool, the FCM provides guidelines on how to proceed with well control in clear operational envelopes which have taken into account equipment limitations and operational safety hazards. Figure 2-2 shows a FCM, which provides well control decisions as a function of return gas rate and flowing Wellhead Pressure (WHP). The yellow zones indicate a risk level where certain MPD actions may be taken to reduce the level of risk to a green zone. The red zones indicate a high level of risk indicating that the well is required to be shut-in and conventional well control processes are to be used.

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

Figure 2-2 Flow Control Matrix (Saponja, et al., 2005)

The Minerals Management Service (MMS, 2008) have provided a Notice to Lessees (NTL) and Operators of Federal Oil, Gas, and Sulphur Leases in the Outer Continental Shelf, Gulf of Mexico OCS Region conducting MPD for wells with surface blowout preventers. The

MMS Gulf of Mexico OCS Region developed this NTL with the input and cooperation of the International Association of Drilling Contractors (IADC) Committee for Underbalanced Operations and Managed Pressure Drilling.

An appendix to the NTL contains a Managed Pressure Drilling Operations Matrix. This matrix is required as part of an Application for Permit to Drill, and is similar in nature to the Flow Control Matrix described by Saponja. It communicates when to proceed to various corrective actions to bring an unexpected influx under control. Figure 2-3 shows the Managed Pressure Drilling Operations Matrix, illustrating the risk-based well control actions to be a function of influx indicator and surface pressure indicator. The influx indicator can be given by any or a combination of influx state, influx rate, influx duration and volume gain

The NTL provides descriptions and examples of the MPD Operations Matrix inputs. However, these examples are by no means comprehensive and details regarding procedures to determine these limits are not included.

MPD Drilling Matrix		Surface Pressure Indicator (See Chart 2 Below)			
		At Planned Drilling Back Pressure	At Planned Connection Back Pressure	> Planned Back Pressure & < Back Pressure Limit	≥ Back pressure Limit
Influx Indicator (See Chart 1 Below)	No Influx	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	Operating Limit	Increase back pressure, pump rate, mud weight, or a combination of all	Increase back pressure, pump rate, mud weight, or a combination of all	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	< Planned Limit	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action
	≥ Planned Limit	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action

Figure 2-3 Managed Pressure Drilling Operations Matrix (MMS, 2008)

Vieira (Vieira P. , Arnone, Torres, & Barragan, 2009) cites the MPD Operations Matrix described in the NTL (MMS, 2008) and a method to determine the maximum tolerable influx is discussed. Here, the influx indicator is based on the consideration of annular pressure at the casing shoe not exceeding fracture pressure, and annular pressure at surface not exceeding the RCD rating.

Other works by Vieira (Vieira, et al., 2008) and Tellez (Tellez, et al., 2009) have also referred to the use of a Flow Control Matrix for well control events in managed pressure drilling operations.

Santos (Santos, Leuchtenberg, & Shayegi, SPE 81183 Micro-Flux Control: The Next Generation in Drilling Pocess, 2003) presented Micro-Flux Control, which is the monitoring and adjustment of return flow to control fluid loss or gain during drilling operations. The requirement that the well be drilled closed, with return flow passing through a choke to control pressure, suggested that this type of operation would now be considered MPD. Micro-Flux Control was intended to utilize an automated choke system.

Van Riet (Van Riet, Reitsma, & Vandecraen, 2003) described the development and full scale testing of a fully automated system designed to maintain constant BHP during drilling operations. This system also included a pump in the back-pressure system which allows pressure control even when no flow is being produced from the main pumps. As with the work presented by Santos (Santos, Leuchtenberg, & Shayegi, SPE 81183 Micro-Flux Control: The Next Generation in Drilling Pocess, 2003), this work described what is essentially a MPD system with fully automated pressure control.

Santos (Santos, Reid, Jones, & McCaskill, 2005) described very positive results from the application of the Micro-Flux Control method at a test well facility. Influxes were detected and controlled using an automated system, with pit gains being limited to less than 1 bbl.

Santos (Santos, Catak, Kinder, Franco, Lage, & Sonnemann, 2007) presented results from the first MPD field applications of the Micro-Flux Control equipment. Overall, the ability of real-time influx detection observed from the test well applications were confirmed for these field applications.

Fredericks (Fredericks, et al., 2008) has described a system developed out of necessity to provide the ability to explore shallow gas potential where fast kick detection and accurate pressure control were essential for avoiding lost returns. This system involved the integration of automated pressure control technology, pressure while drilling (PWD) and drill string telemetry. Testing and drilling operations confirmed the integrated system's ability to maintain near constant BHP and provide fast and accurate kick detection.

Vieira (Vieira P. , et al., 2008) presented a field example where constant bottomhole pressure MPD was applied to mitigate variations in equivalent circulating density when circulation was disrupted. An offset well with similar casing design was drilled conventionally and a comparison was made between the MPD and conventional drilling operations. Total drilling days for each section were 65 for the conventionally drilled section and 40 for the MPD section. Non-productive time was 7.6 days for the conventionally drilled section and 1.1 days for the MPD section. These figures show a significant improvement by using MPD for this field application.

Tellez (Tellez, et al., 2009) described the successful application of MPD to a HP/HT well to avoid formation influx, lost circulation, formation damage and differential sticking and also to increase operation safety.

CHAPTER 3

STATEMENT OF PROBLEM

Dynamic well control procedures are currently employed in industry, yet the behavior of a gas influx during these processes is not fully understood. This work aims to gain further understanding into the applied-back-pressure, dynamic, MPD well control response to a gas kick and, therefore, to propose improvements to the procedure.

Before defining the research objectives, two points must be briefly discussed; Compressibility effects during dynamic well control, and MPD limits used to determine whether conventional or dynamic well control methods will be used to control an influx.

3.1 Compressibility Effects during Dynamic Well Control

The applied-back-pressure, dynamic, MPD well control response (described in section 1.3.3) often used in industry relies on the assumption that if a gas kick is sufficiently small, the fluid within the annulus is effectively incompressible. Hence, obtaining $Q_{out} = Q_{in}$ is considered to imply that no influx can be flowing into the wellbore (assuming no lost circulation). Thus, controlling the applied back pressure until $Q_{out} = Q_{in}$ is achieved has become the classical approach to dynamic well control. In reality, however, with a gas influx, the fluid in the annulus is no longer incompressible. Depending on the transient pressure profile within the annulus, compression or expansion of in-situ influx gas within the wellbore may occur. At a time instant, any rate of compression or expansion of in-situ influx gas will contribute to flow exiting the annulus. Therefore, $Q_{out} = Q_{in}$ in this case will not necessarily imply influx cessation. This concept is explained in detail and developed further in Chapter 4.

3.2 MPD Limits to Determine Conventional or Dynamic Well Control

Within the current literature, there are considerable gaps with respect to how influx limits are determined for use in the MPD Operations Matrix, as defined by the MMS (MMS, 2008).

Some literature does either reference the MPD Operations Matrix directly, or reference a similar approach, such as Saponja (Saponja, Adeleye, & Hucik, 2005), who introduces the Flow Control Matrix for managed pressure drilling operations. However, as mentioned in CHAPTER 2, methods to determine influx limits in each case are not explained. In order to set these limits, it is of great importance to have a thorough understanding of the system under consideration.

The extent of compressibility effects on the currently employed applied-back-pressure, dynamic, MPD well control procedure is currently unknown. However, the effects may be significant enough that accounting for them when calculating operating and planned limits for the MPD Operations Matrix will significantly reduce risks and/or improve the safe operating window of MPD dynamic well control techniques. Even in the event that compressibility effects are negligible, understanding the effects will contribute to increasing confidence in the quantification of well control risk in MPD operations.

3.3 Research Objective

Current procedures for applied-back-pressure, dynamic, MPD well control responses to a kick assume incompressible fluids within the annulus. This is clearly inappropriate for a case where compressible influx gas has entered the annulus. Although it may be argued that the assumption is reasonable for a sufficiently small gas influx, current understanding does not allow the determination of whether this assumption is reasonable. This research aims to consider the effect of compressibility on dynamic well control such that either compressibility can be confidently disregarded from dynamic well control, or, where appropriate, current procedures can be improved to account for compressibility.

By analyzing a control volume with mass flow rate balance, a set of claims are developed. These claims are tested by simulating applied-back-pressure, dynamic, MPD well control responses using an industry accepted, transient, multiphase flow simulator.

It is shown that for the current industry kick response (ensuring $Q_{out} = Q_{in}$), if the in-situ influx gas within the wellbore is being compressed at the instant when $Q_{out} = Q_{in}$ is achieved, then $Q_{out} = Q_{in}$ is not by itself an adequate basis to assume that formation flow has ceased. Furthermore, without sufficient deliberate or accidental overkill, there is a risk of assuming the well has been controlled, when in fact, formation fluid is still entering the wellbore. It is also shown that if significant volume expansion of the in-situ influx fluid within the wellbore has occurred during the currently employed response, then applied-back-pressure during the response will be excessive, exerting undue pressure on the formation and entire system.

On the basis of these findings, an improved applied-back-pressure, dynamic, MPD well control response will be proposed. As part of the development of the proposed procedure, a set of conditions forming a signature implying influx cessation is formulated and tested.

With regard to setting influx limits for the MPD Operations Matrix for a particular system, this research allows better understanding of the effect of influx compressibility during dynamic, MPD well control. At the least, these findings increase understanding and thereby reduce risk associated with setting influx limits. In the best case, limits may be increased due to procedures allowing dynamic responses for larger influx volumes. Such a case, for example, may be reducing risk of applying excessive applied-back-pressure by following the new applied-back-pressure, dynamic response proposed in this research. This reduction in pressure exerted on the system will carry through for the entire process of circulating out the kick and, therefore, reduce peak values of wellhead pressure, casing shoe pressure and surface flow rate, all of which are beneficial in a drilling operation.

With future enhancement, this research may assist a drilling engineer to calculate a more suitable operating envelope than is currently used in the field. Such an envelope will account for compressibility effects which may cause excessive back-pressure, or the possibility of the influx not being controlled after $Q_{out} = Q_{in}$ has been achieved.

Future enhancement may also allow the development of a real-time simulator for operational use, which employs varying data such as volume gain, pump rate, applied back-pressure, flow in, flow out, etc, and is able to recognize a signature indicating influx cessation.

Or, in the case where significant volume expansion may have occurred, the simulator will be able to calculate the excessive back-pressure applied during the well control process, based on readily obtainable parameters. The engineering team can then communicate this pressure difference to the choke operator (or have it relayed to the automated choke control system) and the back-pressure on the annulus can be reduced and thereby unnecessary pressure on the formation removed.

CHAPTER 4

APPROACH AND METHODS

Broadly, the research plan was to consider the system from an analytical standpoint, with the objective of developing a set of claims that indicate influx cessation. Various computer simulations were then performed which demonstrated the validity of the claims.

All computer simulations were performed with UbitTS™; a transient, multiphase flow simulator. These simulations modeled scenarios of drilling into high pressure, permeable formation with insufficient circulating bottomhole pressure, and hence taking a gas kick. Various applied-back-pressure responses to control the well were executed, which illustrate the compressibility effects of the system.

4.1 Control Volume Analysis

Consider a typical MPD operation with drilling fluid being circulated down the drill pipe and returning through the annulus (Figure 4-1). Assume that an influx occurs. Assume further that there are no fluid losses within the wellbore. Our interest is from the moment that it is determined an influx has occurred, until the moment that it is concluded no further influx is occurring, and a standard kick circulation procedure is adopted. More specifically, we are interested in the control actions taken during this period, which constitutes the "dynamic well control" of an MPD kick.

Considering the control volume encompassing the wellbore, as shown in Figure 4-1, a mass flow rate balance of fluid entering and exiting the control volume was performed, as shown in Equation (4.1). Here, we have added the various components that contribute to the flow exiting the annulus; namely, pumped drilling mud, influx into the wellbore and expansion within the wellbore.

$$Q_{out}\rho_{out} = Q_{in}\rho_{in} + Q_{influx}\rho_{out} + Q_{exp}\rho_{out} \tag{4.1}$$

Where, Q_{out} = volumetric flow rate of fluid exiting the wellbore

ρ_{out} = density of fluid exiting the wellbore

Q_{in} = volumetric flow rate of fluid being pumped into the drillpipe

ρ_{in} = density of fluid being pumped into the drillpipe

Q_{influx} = volumetric flow rate of influx fluid entering the wellbore

Q_{exp} = rate of change of in-situ volume of influx fluid within the annulus due to expansion or compression

In Equation (4.1), it is assumed that any volume of influx fluid entering the wellbore displaces the same volume of fluid at the surface. Similarly, it is assumed that any volume increase or decrease of in-situ influx gas within the wellbore displaces the same volume of fluid at the surface. With these two assumptions, the density of fluid exiting the annulus, ρ_{out}, has been associated with the influx and expansion terms in Equation (4.1).

In general, the density of the fluid entering the wellbore is slightly different from that exiting the wellbore, due to differences in temperature and pressure. However, without loss of generality, it can be assumed that the densities of fluid entering and exiting the wellbore are equal. Then, the mass flow rate balance reduces to a volumetric flow rate balance, as shown by Equation (4.2).

$$Q_{out} = Q_{in} + Q_{influx} + Q_{exp} \tag{4.2}$$

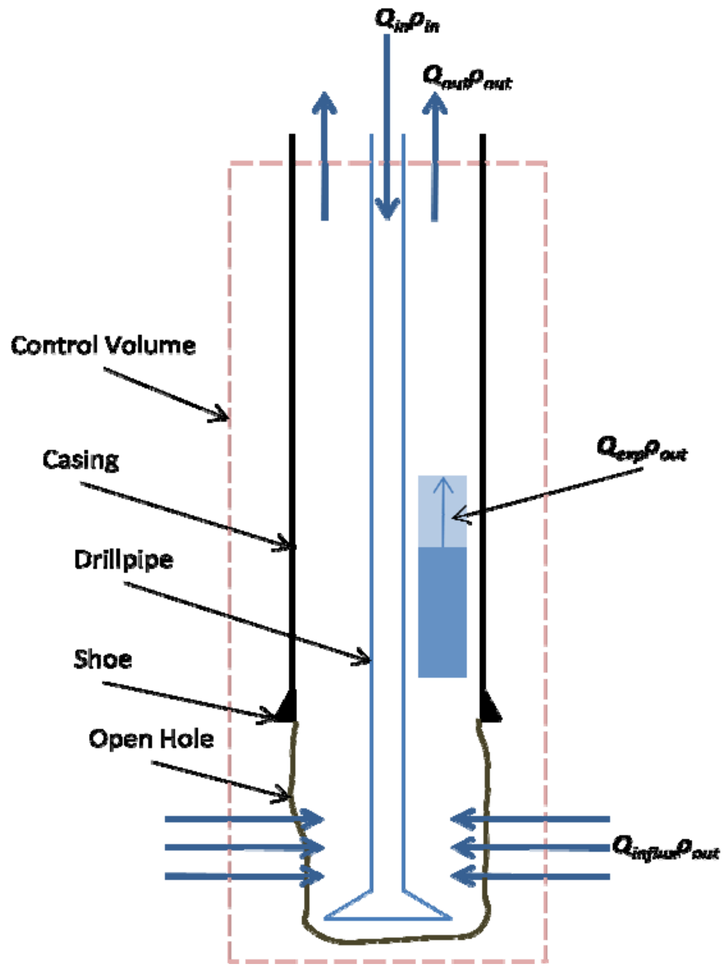

Figure 4-1 Control Volume for Mass Flow Rate Balance

As noted earlier, even under steady-state conditions of normal drilling without an influx, the density of the fluid entering the annulus is not the same as that exiting it, due to differences in temperature and pressure. Typically, pressure of the fluid being pumped in is greater than that of the fluid exiting the wellbore, and the temperature of the fluid exiting the wellbore is higher than that of the fluid entering, so that we have $Q_{out} > Q_{in}$. In practice, the difference between these rates is taken into account as an additive correction factor, so that $Q_{out} = Q_{in}$ within an additive constant. That is, for the condition where no influx has occurred and there is no in-situ influx fluid within the wellbore (or at least no expansion or compression of any in-situ influx fluid within the wellbore), the condition $Q_{out} = Q_{in}$ is assumed to exist (within an additive correction factor, which is assumed to be applied). The main benefit of this assumption is that it allows for the commonly used flow-rate based approach for well control.

The desire to use a volumetric flow rate balance for the analysis rather than a mass flow rate balance has stemmed from operational constraints. Although the Coriolis meter measures mass flow rate, current equipment used in MPD operations converts this into a volumetric flow rate by using an assumed density. This volumetric flow rate is then used as the primary indicator that a kick is occurring ($Q_{out} > Q_{in}$), or has been controlled ($Q_{out} = Q_{in}$). It is noted that although the key conclusions of this work hold whether this assumption is made or not, we make this assumption here to stay within the framework of MPD well control as it is applied in the field today.

4.2 Thesis Statements

Based on the volumetric flow rate balance, Equation (4.2), and analytical reasoning, a set of thesis statements are developed. The first is an argument against the currently used applied-back-pressure, dynamic MPD well control method described in Section 1.3.3. The second statement allows further understanding of problems with the currently used method. The third, is based on understanding developed from the first two, and consideration of MPD well control objectives, and proposes an improved applied-back-pressure, dynamic MPD well control procedure.

4.2.1 Thesis Statement 1

Simply observing Equation (4.2) and having considered the case where some compressible influx fluid may have entered the wellbore, the first thesis statement can be expressed as:

For a compressible system, $Q_{out} = Q_{in}$ is not an adequate basis to conclude that influx has ceased.

Consider the case where $Q_{out} = Q_{in}$ and $Q_{exp} < 0$. The statement $Q_{exp} < 0$ implies that the rate of change of in-situ volume of influx fluid within the wellbore at a particular time instant is less than zero. In other words, the influx fluid volume is contracting while being compressed. Now, considering these conditions in conjunction with Equation (4.2), this must imply influx is still occurring, as illustrated by Equations (4.3).

$$\begin{aligned} &Q_{out} = Q_{in} \\ &and\ Q_{exp} < 0 \\ &\Rightarrow Q_{influx} > 0 \end{aligned} \tag{4.3}$$

4.2.2 Thesis Statement 2

For the development of thesis statement 2, consider the condition $Q_{exp} > 0$. The condition $Q_{exp} > 0$ implies that the rate of change of in-situ volume of influx fluid within the wellbore at a particular time instant is greater than zero. In other words, the in-situ influx gas is expanding as it travels along the annulus (and is exposed to progressively lower pressure). Considering Equation (4.2) in conjunction with the fact that Q_{influx} cannot be negative (assuming no lost circulation), $Q_{exp} > 0$ must imply $Q_{out} > Q_{in}$. This means that we cannot have the condition of $Q_{out} = Q_{in}$ at any time the fluid in the annulus is expanding (although influx may have already ceased). By the same token, at any time instant at which $Q_{out} = Q_{in}$, in-situ influx fluid cannot be expanding within the annulus.

The above points lead to an important observation: If a case where $Q_{exp} > 0$ exists when cessation of the influx occurs (at which time $Q_{out} > Q_{in}$), then by the time applied-back-pressure is increased to the point where $Q_{out} = Q_{in}$, applied-back-pressure will have been excessive. By this we mean that additional back pressure has been applied solely to ensure $Q_{out} = Q_{in}$, although it was not needed to stop the influx itself.

Based on the above arguments, and consideration of the first thesis statement, the second thesis statement can be expressed as follows:

For Q_{out} = Q_{in} to imply influx cessation, the rate of change of in-situ volume of influx fluid within the wellbore must be zero. Additionally, if Q_{out} = Q_{in}, then the rate of change of in-situ volume of influx fluid within the wellbore cannot be positive.

An important point to note regarding any value of the rate of change of in-situ influx fluid volume within the wellbore is that we are referring to the net rate of change of the total influx volume within the wellbore, not the local changes in influx volume. For instance, at a given time, in locations where the influx gas is locally exposed to higher pressure, it may be contracting, and conversely, elsewhere in the wellbore, influx gas may be expanding as it is exposed to lower pressure over time. However, even in this case, the net rate of change of in-situ influx fluid volume within the wellbore may be zero, negative, or positive, depending on the dominant factors affecting all of the influx fluid's pressure in the wellbore.

4.2.3 Thesis Statement 3

This statement is a logical consequence of thesis statements 1 and 2, the results obtained from simulations designed to test these statements, and MPD well control objectives.

As discussed in detail in Chapter 5, simulations designed to test thesis statement 1 indeed validate the statement that solely by ensuring Q_{out} = Q_{in}, we cannot assume influx cessation has occurred. Several examples are shown (in Chapter 5) illustrating that the condition Q_{out} = Q_{in} can be reached both before and after influx ceases.

Although thesis statement 2 is analytically based, it was also supported by these simulations. Cases where Q_{out} = Q_{in} was reached after influx cessation did indeed apply an excessive back-pressure, as expected. As implied by thesis statement 2, this excessive applied-back-pressure was due to the suppression of expansion of in-situ influx fluid within the wellbore.

Now, while keeping in mind the first two thesis statements, the primary objectives of MPD well control should be considered. These objectives can be summarized as follows:

1. Minimize peak wellhead pressure and surface flow rates,

2. Manage wellbore pressures tightly within the pore pressure / fracture pressure window,
3. Maximize the chance of a successful kill, and,
4. Reduce non-productive time.

The overarching goal underlying the above objectives is simply the *minimization of total influx size*. Particularly when considering a gas kick, a large volume of influx gas makes achieving the above objectives difficult or even impossible.

The above considerations lead to the development of the third thesis statement, which is a proposal for a modified dynamic well control technique for gas kicks in MPD operations. The statement follows:

> *An optimal response during dynamic well control is to aggressively increase applied-back-pressure to force $Q_{out} = Q_{in}$, and then maintain $Q_{out} = Q_{in}$ until the rate of change of in-situ volume of influx fluid within the wellbore is zero. The "Overkill" magnitude is proportional to the time $Q_{out} = Q_{in}$ is maintained beyond time of influx cessation.*

An aggressive applied-back-pressure response achieves two main purposes:

1. Reduction of total influx volume, and
2. Increase of the chance $Q_{exp} < 0$ at the time when $Q_{out} = Q_{in}$ is first achieved.

The reason for reduction of total influx volume is described above in terms of the primary MPD well control objectives. Increasing the chance $Q_{exp} < 0$ at the time when $Q_{out} = Q_{in}$ is first achieved reduces and possibly eliminates the likelihood of exerting excessive applied-back-pressure during the well control procedure. If $Q_{exp} < 0$ at the time when $Q_{out} = Q_{in}$ is first achieved, then in view of the volumetric flow rate balance, there must still be influx fluid entering the wellbore, as illustrated by Equations (4.3). Bottomhole pressure will then rise as long as $Q_{out} = Q_{in}$ is maintained, due to the reservoir pumping up the wellbore in an effort to self-equilibrate, and also due to suppressing expansion of in-situ influx gas within the wellbore. This has led to the concept of a dynamic shut-in, which is described in further detail in Section 4.3.1.

4.3 Signature to Determine Influx Cessation

In view of the proposed dynamic MPD well control method described by the third thesis statement, an important question remaining is, at what point can it be determined that influx cessation has occurred? If $Q_{exp} < 0$ at the time when $Q_{out} = Q_{in}$ was achieved, it is known that if $Q_{out} = Q_{in}$ is maintained, at some point bottomhole pressure will increase to the point where influx cessation occurs. However, a method to recognize the moment of influx cessation has not yet been defined. This is clearly of value in optimizing the well control procedure.

In this section, a set of signature conditions suggesting influx cessation are proposed. Along with the condition that $Q_{out} = Q_{in}$, if these signature conditions are met, influx cessation is implied.

4.3.1 Dynamic Shut-In

An interesting perspective on the proposed applied-back-pressure, dynamic, MPD well control method described by the third thesis statement is to view the process as a *dynamic* shut-in. To illustrate this concept, consider hypothetical conventional and dynamic shut-in scenarios, as illustrated in Figure 4-2 and Figure 4-3, respectively. Assume for simplicity, that the elastic response of the wellbore to changes in pressure is negligible.

As with the dynamic shut-in, the conventional shut-in process, described in Section 1.2.2, also aggressively forces $Q_{out} = Q_{in}$ by applying back-pressure. The main differences here are that a) $Q_{out} = Q_{in} = 0$ for the conventional shut-in, and b) back-pressure is applied with blowout preventers and conventional choke, rather than a rotating control device and MPD choke.

In order to compare the two methods, we zoom into the time period between when $Q_{out} = Q_{in}$ is first achieved and shortly after influx cessation, but before commencing constant BHP circulation. That is, $Q_{out} = Q_{in}$ is maintained throughout the entire time of comparison for the two methods.

BHP in the conventional shut-in process decreases due to a loss of friction pressure in the annulus when the pumps are shut down. Therefore, the conventional shut-in process starts from a higher differential pressure between bottomhole and reservoir than when fluid in the system was circulating. This can be seen by the friction pressure difference shown in Figure 4-2.

For the conventional shut-in method, two processes contribute to the rise in BHP once the pumps have been shut down and the well shut-in; 1) Differential pressure between reservoir and bottomhole causing influx fluid to flow into the wellbore, acting to ‘pump up’ the annulus, and 2) Suppression of expansion of in-situ influx fluid within the wellbore.

The rate of formation flow into the wellbore is proportional to differential pressure between reservoir and bottomhole. Therefore, influx rate is highest at the start of the well control processes shown in Figure 4-2 and Figure 4-3. As BHP approaches reservoir pressure, differential pressure decreases and hence the rate of change of BHP due to differential pressure decreases. Once BHP reaches reservoir pressure, differential pressure vanishes and no further formation flow enters the wellbore. Hence, the rate of change of BHP due to differential pressure is zero.

Suppression of expansion of in-situ influx gas within the wellbore causes BHP to increase as influx fluid travels along the annulus. Once influx cessation occurs, it is expected that the rate of change of BHP due to suppression of expansion is approximately constant, as is explained in Section 4.3.3.

For the conventional shut-in, an increase in differential pressure from loss of friction when the pumps are shut down causes an increase in influx rate, acting to ‘pump up’ the well faster than before the friction pressure drop occurred. For the dynamic shut-in, this friction pressure drop does not occur, and hence it may be expected that a conventional shut-in will result in a larger kick. This is indeed what was found in previous work by Carlsen (Carlsen, Nygaard, Gravdal, Nikolaou, & Schubert, 2008) and Das (Das A. K., 2007). It is also expected that a dynamic shut-in would result in influx cessation sooner than a conventional shut-in due to less differential pressure to begin with. Of course, for these comparisons to be made it is assumed that initial kick volume and initial circulating BHP were the same for the two different procedures.

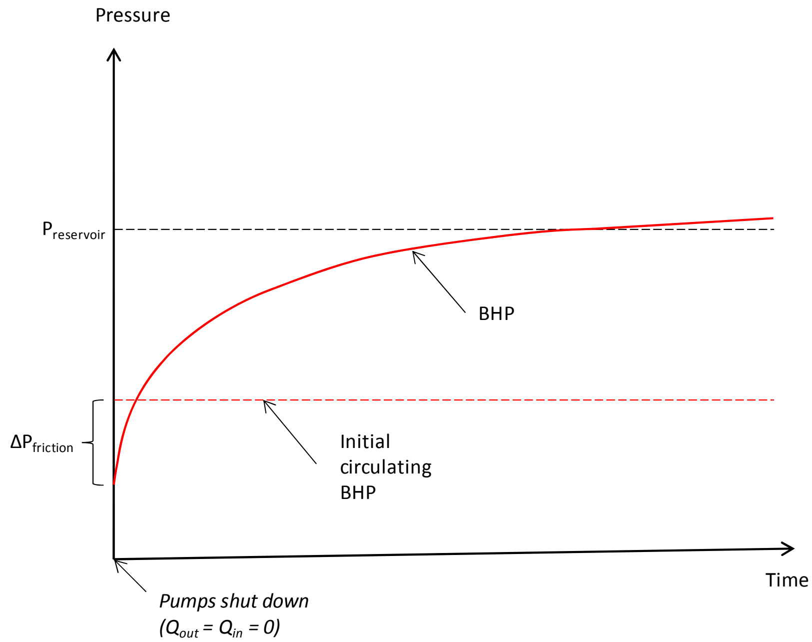

Figure 4-2 BHP Profile for a Hypothetical Conventional Shut-In Scenario

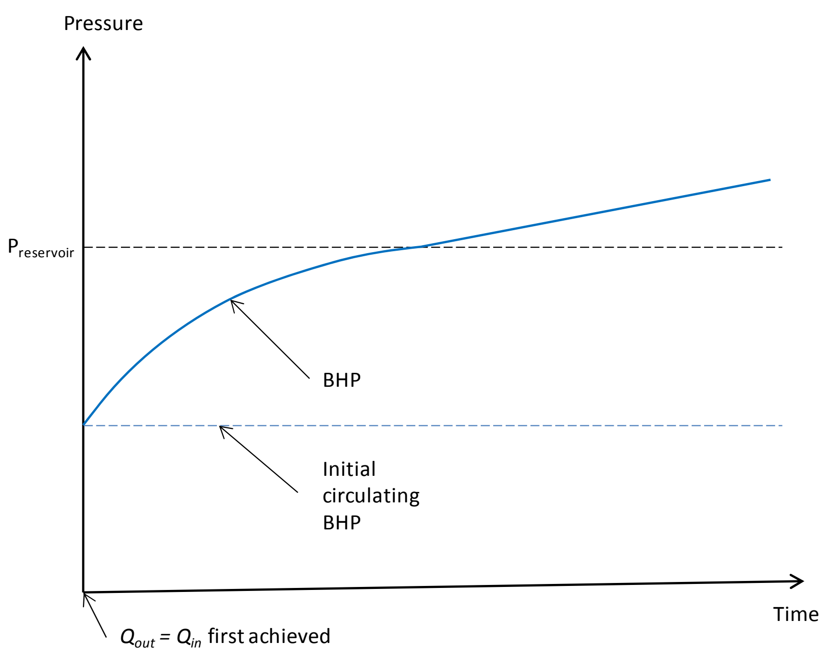

Figure 4-3 BHP Profile for a Hypothetical Dynamic Shut-In Scenario

An argument could be presented that the dynamic shut-in procedure is more efficient than the conventional shut-in procedure by virtue of the factors described above. However, for a dynamic shut-in for a scenario in which influx gas covers a significant vertical displacement due to high circulation rate being maintained, bottomhole pressure increase due to suppression of expansion may be significant to the point that it masks the nature of BHP profile expected in a conventional shut-in case.

The analogy between BHP profile for the conventional and dynamic shut-in cases are, however, plain to see. The comparison of these two methods plays a role in the signature expected to indicate influx cessation during the proposed dynamic well control process.

4.3.2 Signature 1

Taking into account the moment when BHP reaches reservoir pressure and influx cessation occurs, the factors contributing to further change in BHP are considered. Given that when Q_{out} = Q_{in}, expansion of in-situ influx gas within the wellbore is not being allowed, a rate of pressure increase due to suppression of expansion will exist. Since differential pressure between the reservoir and wellbore has vanished, suppression of expansion is the only factor contributing to BHP change, and this rate of change must be a positive. Therefore, the first signature indicating cessation of influx is expressed by Equations (4.4):

$$\begin{gathered} When\ Q_{out} = Q_{in} \\ and\ Q_{influx} = 0, \\ \frac{\partial(BHP)}{\partial t} > 0 \end{gathered} \tag{4.4}$$

Equations (4.4) state that after influx cessation, while Q_{out} = Q_{in}, the first derivative of BHP with respect to time must be positive. Note that by itself, Equations (4.4) are a necessary, but not sufficient condition. That is, Q_{out} = Q_{in} in conjunction with influx cessation implies Equations (4.4), however Q_{out} = Q_{in} in conjunction with Equations (4.4) do not imply influx cessation. Additional conditions must be sought to ensure this.

4.3.3 Signature 2

Consider an average gas bubble travelling along the annulus under conditions such that it is not expanding or contracting- i.e., it is subject to pressure that is not changing. An average gas bubble is one that represents the average conditions of pressure in the column of in-situ gas in the annulus. Making the following simple assumptions, we can estimate the expected profile for the rate of increase of BHP when suppression of expansion of a rising gas bubble is the only factor contributing to BHP change.

1. It is assumed that the effect on BHP from the average gas bubble considered above is approximately representative of the entire in-situ volume of influx fluid within the wellbore. Since Q_{exp} refers to the rate of change of total influx volume in the wellbore, $Q_{exp} = 0$ implies that the net rate of expansion is zero. Therefore, by assuming the average gas bubble is representative of all in-situ influx fluid, it is assumed that the BHP profile due to suppression of all influx fluid expansion is similar in nature to the BHP profile due to suppression of expansion of the average gas bubble.
2. Next, it is assumed that the acceleration of the average gas bubble is negligible. By this assumption it is proposed that the average gas bubble reaches terminal velocity relatively quickly.
3. Finally, it is assumed that the trajectory of the bubble does not change. That is, distance travelled and vertical displacement covered by the bubble are assumed to be linearly proportional.

Now, the effect on BHP as the average gas bubble travels along the annulus while being exposed to zero pressure change is considered. As the bubble moves ahead, drilling mud is displaced behind. The bubble, therefore, loses friction pressure and hydrostatic pressure (due to vertical upward displacement). However, since the bubble being considered is exposed to constant pressure, the transient BHP is expressed by Equation (4.5).

$$BHP(t) = BHP_{initial} + \Delta P_{hydrostatic} + \Delta P_{friction} \tag{4.5}$$

Friction pressure decrease is approximately linearly proportional to distance the bubble travels. Hydrostatic pressure decrease is approximately linearly proportional to vertical displacement, which is assumed to be linearly proportional to the distance travelled. Since constant velocity has been assumed, the accumulation of friction and hydrostatic pressure changes are approximately linearly proportional to time. Therefore, since BHP is increased by the accumulation of friction and hydrostatic pressure changes, it is expected to increase approximately linearly with time. Therefore, differentiating Equation (4.5) with respect to time, it follows that the first and second derivatives of BHP with respect to time are constant and zero, respectively, as expressed by Equations (4.6)

$$\begin{gathered}\frac{\partial(BHP)}{\partial t} \cong constant \\ \Rightarrow \frac{\partial^2(BHP)}{\partial t^2} \cong 0\end{gathered} \tag{4.6}$$

Based on the above, the second signature indicating influx cessation can be expressed as shown in Equations (4.7).

$$\begin{gathered}When\ Q_{out} = Q_{in} \\ and\ Q_{influx} = 0, \\ \frac{\partial^2(BHP)}{\partial t^2} \cong 0\end{gathered} \tag{4.7}$$

Equations (4.7) state that after influx cessation occurs, while $Q_{out} = Q_{in}$, the second derivative of BHP with respect to time must be approximately equal to zero. Note that as with Equations (4.4), Equations (4.7) are necessary, but not sufficient, to imply influx cessation.

4.3.4 Signature 3

For the development of the third influx cessation signature, a new term labeled the non-dimensional pressure transfer parameter (PTP) is defined by Equation (4.8).

$$\bar{P} = \frac{(BHP - WHP) - p_{ref}}{p_{ref}} \tag{4.8}$$

Where, p_{ref} = value of *(BHP – WHP)* before influx fluid entered the wellbore.

The PTP represents a comparison of pressure gradient within the annulus at a particular time, to the pressure gradient within the annulus at steady state conditions before an influx was taken. It takes into account all factors that vary the pressure gradient within the annulus, while discarding factors that contribute to approximately constant pressure changes. Such factors varying the pressure gradient within the annulus include friction pressure gradient change due to change in flow rate, hydrostatic pressure gradient change due to different density formation fluid entering the wellbore, and pressure waves in the annulus due to changes in WHP or BHP. Factors contributing to constant pressure changes include wellhead pressure change (after the pressure wave has reached bottomhole and stabilized) and friction through surface equipment downstream from the choke. Therefore, the PTP can be viewed as an indicator of transient pressure gradient within the wellbore.

When $Q_{out} = Q_{in}$, influx cessation has occurred and a certain amount of influx fluid is within the wellbore, we would expect the PTP to be less than, or equal to zero. The reasons for this are 1) there is less hydrostatic pressure gradient (assuming influx fluid density lower than drilling mud density) and 2) there cannot be more friction (assuming influx fluid viscosity less than drilling mud viscosity), since $Q_{out} = Q_{in}$. Hence, the third influx cessation signature component has been expressed by Equations (4.9).

$$\begin{gathered} When\ Q_{out} = Q_{in} \\ and\ Q_{influx} = 0, \\ \bar{P} \leq 0 \end{gathered} \tag{4.9}$$

Once again, as with the first two components of the influx cessation signature, Equations (4.9) are necessary, but not sufficient to imply influx cessation.

4.3.5 Signature 4

The PTP and the first derivative of the PTP with respect to time were considered for the development of the fourth influx cessation signature component. Once an influx has been detected ($Q_{out} > Q_{in}$) and WHP is aggressively increased, a significant decrease in the PTP would be expected, regardless of its value before the WHP increase. This is because WHP increases much faster than BHP due to time taken for the pressure wave created by the WHP change to reach bottomhole. Since the difference between BHP and WHP decreases during the process of aggressively increasing WHP, the PTP must also decrease. Given that the PTP is decreasing during this process, the first derivative of the PTP with respect to time must be negative.

Once $Q_{out} = Q_{in}$ has been achieved, the choke is controlled to maintain $Q_{out} = Q_{in}$. At this point WHP is no longer being aggressively increased and the transient effects of the aggressive response are removed. As such, the rate of change of the difference between BHP and WHP reduces, and leveling out of the PTP at a value less than or equal to zero (as described in Section 4.3.4) is expected. This corresponds to an increase in first derivative of the PTP with respect to time.

As influx cessation approaches, the rate of increase of BHP and WHP reduces, and hence the rate of change of the PTP becomes less. Once influx cessation occurs, a relatively small, approximately linear, increase in WHP and BHP should be present due to suppression of expansion being the only factor contributing to their increase. Since $Q_{out} = Q_{in}$ is being maintained, expansion is being suppressed, and the hydrostatic pressure difference between wellhead and bottomhole does not change. Therefore, the PTP should remain at an approximately constant value. Correspondingly, the first derivative of the PTP when influx cessation occurs should be approximately equal to zero.

In summary, the fourth signature component indicating influx cessation comprises a set of values leading up to influx cessation and when influx cessation occurs. The signature component is expressed by the following:

1. First and second derivatives of the PTP with respect to time are negative, corresponding to aggressive WHP pressure increase,
2. First derivative of the PTP with respect to time increases, but remains negative, corresponding to $Q_{out} = Q_{in}$ being achieved and maintained, and
3. First derivative of the PTP with respect to time is approximately equal to zero when influx cessation occurs, and approximately constant thereafter.

4.3.6 Influx Cessation Signature Summary

The expected signature indicating influx cessation has been summarized by Table 4-1. Equations in the middle two columns represent expected profiles while the proposed dynamic well control method is being executed, *before* influx cessation has occurred. Equations in the column on the right represent various signature components expected while $Q_{out} = Q_{in}$ is continuing to be maintained, *after* influx cessation has occurred. While individual signature components represented in Table 4-1 may represent insufficient conditions to imply influx cessation, it is expected that if all of these signature components are met, a necessary and sufficient condition to imply influx cessation has been expressed.

Table 4-1 Influx Cessation Signature Summary

Time Period During Response	WHP aggressively being increased to reduce Q_{out}	Q_{out} = Q_{in} being maintained *before* influx cessation	Q_{out} = Q_{in} being maintained *after* influx cessation
Signature	$\frac{\partial \bar{P}}{\partial t} < 0$ $\frac{\partial^2 \bar{P}}{\partial t^2} < 0$	$\frac{\partial \bar{P}}{\partial t} < 0$ $\frac{\partial^2 \bar{P}}{\partial t^2} > 0$	$\frac{\partial (BHP)}{\partial t} \geq 0$ $\frac{\partial^2 (BHP)}{\partial t^2} \cong$ $\bar{P} \leq 0$ $\frac{\partial \bar{P}}{\partial t} \cong 0$ $\frac{\partial^2 \bar{P}}{\partial t^2} \cong 0$

4.4 Simulations

Simulations designed to test the various statements and signature components presented previously in this chapter were executed. The first four sets of simulations were based on testing thesis statements 1 and 2. They were, therefore, founded on the premise suggested by some current dynamic, MPD well control procedures, that when Q_{out} = Q_{in}, influx cessation is implied. For this reason, the procedure for the first four sets involved achieving the instantaneous condition of Q_{out} = Q_{in}, followed by setting up for constant bottomhole circulation of the kick. The fifth set of simulations was designed to test the third thesis statement, a proposed new dynamic, MPD well control method. The procedure included achieving Q_{out} = Q_{in} and then maintaining Q_{out} = Q_{in} to analyze the subsequent increase in BHP and well control effectiveness.

4.4.1 UbitTS™

UbitTS™ (Under-Balanced Interactive Transient Training Simulator) was developed by Scandpower Petroleum Technology, with Blade Energy Partners as a co-developer. It was developed, as its name would suggest, primarily as a transient training simulator for under-balanced drilling operations

With an OLGA engine for mechanistic multiphase transient flow modeling, UbitTS™ is able to model complex under-balanced drilling operations with interactive real-time user control.

UbitTS™ can model under-balanced drilling surface equipment, such as rotating control head and drilling choke, and it can also simulate drillpipe injection, annular gas injection, kicks, lost circulation, and various operational problems.

Of great importance to this research is the ability of UbitTS™ to model gas kicks and allow real-time well control measures to be simulated by the user. The equipment used for MPD is very similar in some respects to the equipment used for UBD, so UbitTS™ is a valid tool for use in MPD well control research.

Figure 4-4 shows the main execution window in UbitTS™, which provides the user with real-time updating of all important parameters and the ability to interactively manage the various controls that would be available in a real operation.

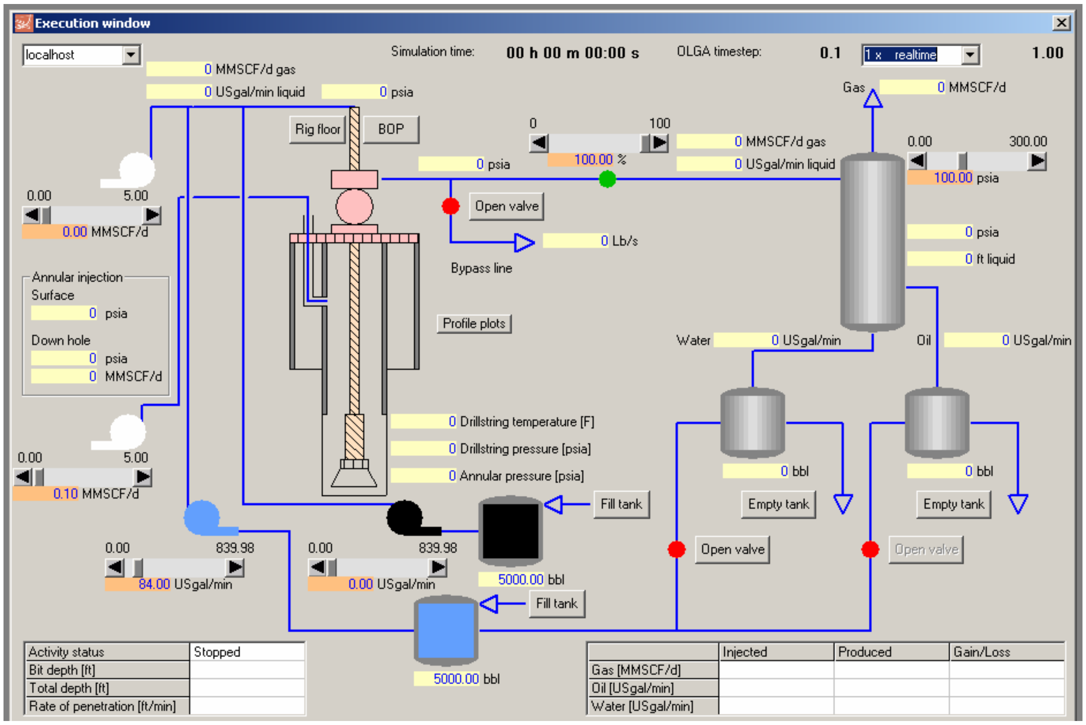

Figure 4-4 UbitTS™ Main Execution Window

4.4.2 Assumptions in UbitTS™

During any over-balanced drilling operation, such as conventional and managed pressure drilling), drilling fluid contains additives that create a filtercake in the open hole section of the wellbore. Filtercake is required to prevent fluid loss in any over-balanced situation. As a result of these additives, drilling mud for conventional and MPD operations will be characterized by non-Newtonian fluid behavior. That is, shear stress is not linearly proportional to the shear strain (where the constant of proportionality is the dynamic viscosity). In under-balanced drilling operations, however, one of the primary goals is to reduce the risk of formation damage. For this reason, filtercake is undesirable, and so drilling fluid used in under-balanced operations is usually characterized by Newtonian behavior. UbitTS™, therefore, does employ the assumption of Newtonian viscosity for fluids.

Another assumption made by UbitTS™ is the real gas law for gas types.

4.4.3 Validation of UbitTS™

An OLGA engine is used by UbitTS™ for the transient multiphase flow modeling, and was used in research by Stanislawek (Stanislawek & Smith, 2005). This research, titled 'Evaluation of Alternative Well Control Strategies for Dual Density Deepwater Drilling' was presented at the IADC/SPE Managed Pressure Drilling Conference & Exhibition in San Antonio in 2005. The research included validating OLGA against a full scale experiment executed by Lopes at LSU. BHP was measured during the experiment involving unsteady, multiphase flow in the annulus. A good correlation between the experimental and simulation data was found, with a maximum discrepancy of 2.5%.

In research performed by Mykytiw (Mykytiw, Davidson, & Frink, 2003), UbitTS™ was used as an aid in design optimization by simulating concentric casing injection where pressure instability and slugging tendency may be present. Although validation data was not given, the research concluded that a good correlation existed between the UbitTS™ predictions and real well data.

In validation checks performed by Das in his master's thesis for LSU (Das A. K., 2007), annular friction pressures were found to be consistently low when compared to manual calculations carried out at LSU.

4.4.4 Simulation Set-Up

The scenario depicted in the simulations was not based on any particular existing well, but rather a general theoretical case. Well geometry and configuration the same for all simulations, as illustrated in Figure 4-5. That is, for all simulations the well was vertical with a 6.1" (ID) liner run from the 10,000 ft shoe back to surface. The drillstring consisted of a 6" bit, 330 ft of 4.75" (OD) bottomhole assembly, with the remaining drillpipe at 3.5" (OD).

Reservoir conditions did vary between different simulations. However, in all cases 20 ft of open hole was drilled before encountering a permeable, high-pressure zone containing methane.

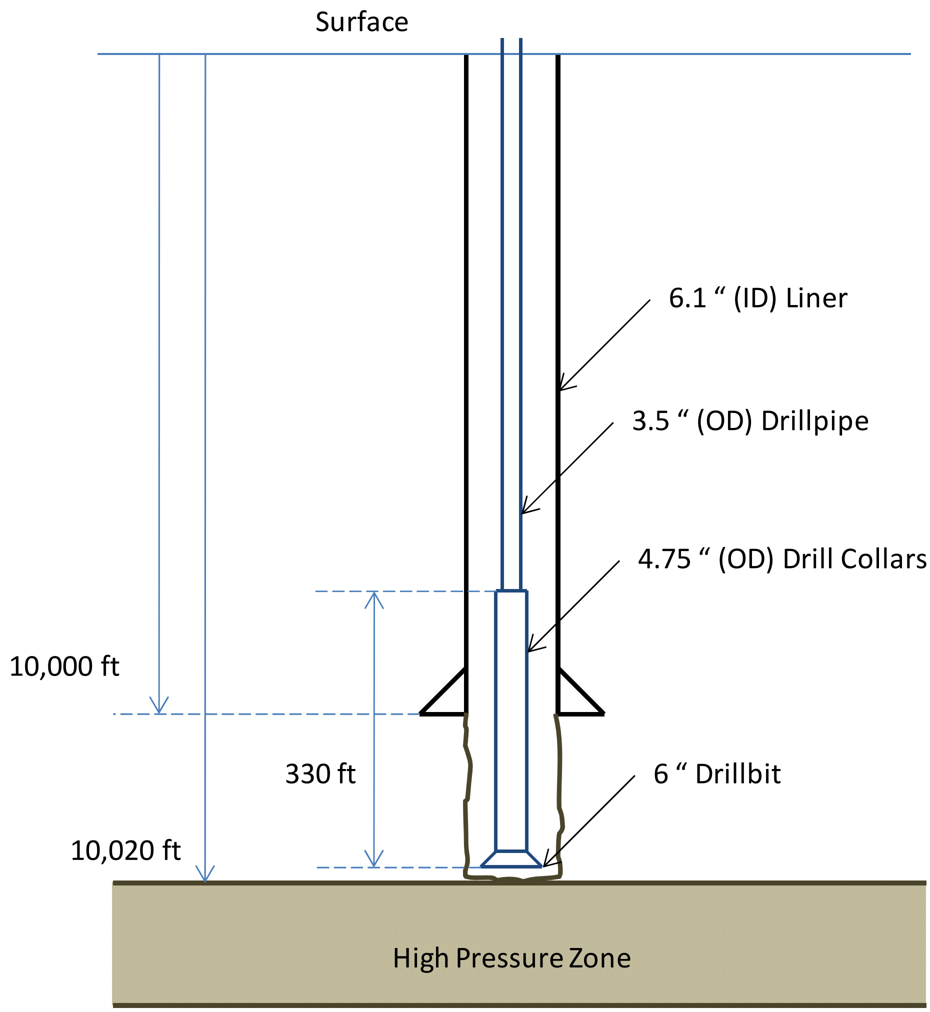

Figure 4-5 Simulation Geometry

4.4.5 Simulation Procedures

In all cases, the procedure was to simulate an applied-back-pressure, dynamic, MPD well control response to taking a kick after drilling into a permeable, high-pressure zone containing methane gas. Back-pressure was applied with varying degrees of intensity, and varying detection times. Detection time was defined as the time from the start of formation flow to the time an applied-back-pressure response was commenced.

For all simulations, a restart file was set-up in UbitTS™ such that the well had been drilled to approximately 10019.9 ft, drilling had been stopped, and the well circulated to ensure steady

–state conditions existed (stable pressures and flow rates, with no gas in the system). For each simulation involving different pump rate, mud weight, or reservoir conditions, a new restart file was created allowing each well control scenario to be commenced from the corresponding steady-state conditions.

4.4.5.1 General Procedure for Simulation Sets 1-4

For simulation sets 1-4, the following procedure was executed:

1. Restart file was loaded and drilling commenced.
2. BHP, SPP, WHP, separator liquid inflow (Q_{out}), separator gas inflow and formation flow was monitored.
3. At pre-determined detection time, drilling was ceased and first increment of choke reduction was applied (applied-back-pressure).
4. While closely monitoring separator inflow, applied-back-pressure was varied (varying response for different simulations) until separator liquid inflow returned to its initial value ($Q_{out} = Q_{in}$).
5. As soon as possible after separator liquid inflow returned to its initial value, choke was adjusted to required level such that BHP stabilized (set-up for constant BHP circulation).

As mentioned previously, simulation sets 1-4 were designed to test a currently used dynamic, MPD well control method against thesis statement 1 & 2. As such, for these tests $Q_{out} = Q_{in}$ was achieved only for a moment before the applied-back-pressure response was relaxed to create stabilized BHP as soon as possible. It should be noted that no deliberate level of overkill was applied. The reason for this was to gain an understanding of the amount BHP would increase once the applied-back-pressure response was relaxed. In practice, MPD operators would deliberately apply a slight excess of back-pressure to increase BHP a predetermined amount above its value when $Q_{out} = Q_{in}$ was achieved. The amount of back-pressure to apply to achieve this desired overkill would be based on fingerprinting performed previously for the well.

Another point to note regarding this procedure was that the initial, steady-state value of Q_{out} was used to represent Q_{in}. This comes from the previously mentioned assumption that the density of the fluid entering the drillpipe is the same as the density of the fluid exiting the annulus. This assumption can be made by taking the steady-state difference between flow pumped into the drillpipe and flow exiting the annulus into account.

4.4.5.2 Simulation Set 1

Simulation set 1 was an initial set of essentially random experiments designed to simulate an applied-back-pressure, dynamic, MPD well control response. Parameters such as reservoir pressure, productivity index, mud weight, pump rate, detection time, and applied-back-pressure response were varied between simulations.

4.4.5.3 Simulation Sets 2 and 3

Simulation sets 2 and 3 each contained eight different simulations. Within the eight simulations there was a low and high PI, low and high detection time, and aggressive and relaxed applied-back-pressure response. Set-up of the eight simulations performed in simulation sets 2 and 3 is illustrated in Table 4-2.

In each set, the first four simulations were designed to have approximately the same initial volume of kick, where the initial volume was the amount of influx taken at detection time. The low and high detection times then represented two different initial spreads for the same influx volume. The same initial volume for the two cases was achieved by numerical integration of the formation mass flow rate data up to the low detection time for the high PI case. The low PI case was then run for long enough that numerical integration of formation mass flow rate data yielded the same influx mass as for the high PI case. The time at which this occurred was set as the high detection time. Influx mass data was then roughly approximated as volume by assuming ideal gas at reservoir pressure and temperature of 63 ^{0}C. This calculation was only intended to provide an approximate influx volume, and therefore a high level of accuracy was not required.

Table 4-2 Design for Simulation Sets 2 and 3

Simulation	Productivity Index	Detection Time	Control Response
1	High	Low	1
2	High	Low	2
3	Low	High	1
4	Low	High	2
5	Low	Low	1
6	Low	Low	2
7	High	High	1
8	High	High	2

Control response 1 was more aggressive than control response 2, with the aim of observing different expansion or compression effects on the system for the same initial influx volume.

4.4.5.4 Simulation Set 4

Simulation set 4 was designed to gain a greater understanding of the applied-back-pressure response alone. Therefore, the same conditions up to detection time were used for all eight simulations. Various applied-back-pressure responses varying from extremely aggressive to quite relaxed were executed.

4.4.5.5 Simulation Set 5

Simulation set 5 was constructed to test the new dynamic, MPD well control response proposed in thesis statement 3. As such, the following procedure was executed:

1. Restart file was loaded and drilling commenced.
2. BHP, SPP, WHP, separator liquid inflow (Q_{out}), separator gas inflow and formation flow was monitored.
3. At pre-determined detection time, drilling was ceased and first increment of choke reduction was applied (applied-back-pressure).

4. While closely monitoring separator inflow, applied-back-pressure was varied (varying response for different simulations) until separator liquid inflow returned to its initial value (Q_{out} = Q_{in}).
5. Choke was manipulated to maintain Q_{out} = Q_{in}.
6. Q_{out} = Q_{in} was maintained indefinitely after BHP reached reservoir pressure.

It should be noted that the proposed new dynamic, MPD well control procedure would not involve maintaining Q_{out} = Q_{in} indefinitely after BHP has reached reservoir pressure. The amount of overkill desired is an operational concern, and is not suggested by this research. As such, Q_{out} = Q_{in} was maintained indefinitely for simulation set 5, with the intent of monitoring the BHP profile after BHP had reached reservoir pressure while Q_{out} = Q_{in} was being maintained. This implied that BHP increase was due to suppression of expansion alone, allowing testing of the signature expressed by Table 4-1.

4.5 Data Analysis

After each simulation was executed, a data file was dumped into Excel for further analysis. Contained within each data file are all relevant parameters associated with the system at each time increment the data was calculated. A print screen showing plots of BHP, WHP, SPP, Q_{out}, formation flow, and separator gas inflow (for long simulations) was also created at the termination of each simulation.

Within each data file corresponding to a simulation, the following calculations were performed:

- Cumulative influx mass.
- First and second derivatives of BHP with respect to time.
- First and second derivatives of SPP with respect to time.
- Non-dimensional pressure transfer parameter (defined in section 4.3.4).
- First and second derivatives of non-dimensional pressure transfer parameter.

Formation mass flow rate was numerically integrated using the Trapezoidal rule to provide cumulative influx mass. All derivatives were calculated numerically using a forward difference scheme.

Within each data file corresponding to a simulation from set 5, the following parameters were plotted against time:

- First and second derivatives of BHP with respect to time.
- First and second derivatives of SPP with respect to time.
- Non-dimensional pressure transfer parameter.
- First and second derivatives of non-dimensional pressure transfer parameter with respect to time.

From each data file corresponding to a simulation, the following data was recorded to a simulation summary worksheet:

- Time at which influx started.
- Time at which first choke response was executed.
- Time at which $Q_{out} = Q_{in}$ was first achieved.
- Time at which influx cessation occurred.
- Time at which BHP reached reservoir pressure.
- Cumulative mass of influx at detection time.
- Total cumulative mass of influx (if influx cessation did not occur, cumulative mass of influx at time when $Q_{out} = Q_{in}$ was first achieved was recorded).
- BHP, WHP and SPP at time of influx cessation (if influx cessation did not occur, no value was recorded).
- BHP, WHP and SPP at time at time when $Q_{out} = Q_{in}$ was first achieved.

Within each simulation summary worksheet for simulations sets 1-4, calculations for the following values were performed:

- Additional mass gain (amount of influx mass gained from detection time to time when $Q_{out} = Q_{in}$ was achieved).
- Influx density (approximate value based on ideal gas at reservoir pressure and temperature of 63 ^{0}C).
- Initial, total and additional volume gains (volume gains based on approximate density).
- Control time 1 (time taken from detection time to influx cessation - if influx cessation did not occur, no value was calculated).
- Control time 2 (time taken from detection time to time when $Q_{out} = Q_{in}$ was achieved)
- ΔBHP (BHP when $Q_{out} = Q_{in}$ was achieved minus reservoir pressure).
- δBHP (BHP when $Q_{out} = Q_{in}$ was achieved minus BHP at influx cessation - if influx cessation did not occur, no value was calculated).
- δWHP (WHP when $Q_{out} = Q_{in}$ was achieved minus WHP at influx cessation - if influx cessation did not occur, no value was calculated).
- δSPP (SPP when $Q_{out} = Q_{in}$ was achieved minus SPP at influx cessation - if influx cessation did not occur, no value was calculated).
- Overshot (amount BHP increased from time when $Q_{out} = Q_{in}$ to time BHP stabilized).

Within each simulation summary worksheet for simulations set 5, calculations for the following values were performed:

- Additional mass gain (amount of influx mass gained from detection time to time of influx cessation).
- Influx density (approximate value based on ideal gas at reservoir pressure and temperature of 63 ^{0}C).
- Initial, total and additional volume gains (corresponding volume gains based on approximate density).
- Control time 1 (time taken from detection time to influx cessation).

- Control time 2 (time $Q_{out} = Q_{in}$ was maintained until influx cessation).

4.6 Relevant Time Scale

The relevant time scale for this research was primarily between detection time and influx cessation. Although simulations have included the time leading up to detection time and an amount of time following influx cessation, this was necessary to simulate dynamic well control scenarios, and also to gain understanding of the phenomenon being investigated.

This research does not propose appropriate detection times, nor does it propose appropriate values of BHP above pore pressure to serve as a safety net (overkill) during a dynamic well control process. Detection times can vary for many reasons including equipment accuracy and procedures, while desired overkill must be determined by the operator depending on a particular operation and the associated risks.

CHAPTER 5

RESULTS AND DISCUSSION

5.1 Results from Simulation Sets 1-4

Results from simulation sets 1-4 showed many cases illustrating the concepts proposed in thesis statements 1 and 2.

In most cases simulations showed that $Q_{out} = Q_{in}$ was achieved before influx cessation occurred. In a number of these cases, BHP was still below reservoir pressure at the time $Q_{out} = Q_{in}$ was achieved, to the point that influx cessation never occurred (even after an inherent overshoot of BHP before stabilization was achieved). As implied by the volumetric flow rate balance shown by Equation (4.2) and thesis statement 1, these cases suggested that in-situ influx fluid within the wellbore was contracting at the time when $Q_{out} = Q_{in}$ was achieved.

Some simulations showed cases where influx cessation occurred before the time at which $Q_{out} = Q_{in}$ was achieved. By considering Equation (4.2), since $Q_{out} > Q_{in}$ when $Q_{influx} = 0$, in-situ influx fluid within the wellbore must have been expanding at that time. Therefore, as expected, an excessive applied-back-pressure was applied by the time $Q_{out} = Q_{in}$ was achieved.

Simulation set 4 showed a large variation of results illustrating concepts introduced by this research, even though initial conditions up to detection time were the same for each simulation. Implied from these results was that, within this research, WHP response was the primary factor influencing whether or not in-situ influx gas was expanding or contracting at the time $Q_{out} = Q_{in}$ was achieved. Therefore, within this section, results and discussion pertaining to simulation sets 1-4 have generally regarded simulation set 4 only. Simulation sets 1-3 are presented in Appendix A and will not be discussed in this section.

5.1.1 Illustrative Examples

Examples of simulations showing both insufficient and excessive applied-back-pressure, as described above, are shown by the figures in this section.

5.1.1.1 Insufficient Applied-Back-Pressure

Figure 5-1 and Figure 5-2 show an example of when insufficient back-pressure was applied; hence influx cessation had not occurred by the time Q_{out} = Q_{in} was achieved. These figures show screen shots of excecution plots which were output by UbitTS™.

It can be seen that BHP, shown by the ‘Drillbit: Annular pressure’ plot in Figure 5-1, at the start of the simulation was approximately 4400 psi. Shortly after drilling commenced, a high pressure (4600 psi), permeable formation zone with a productivity index of 0.5 MMscf/day was encountered. As soon as this high pressure zone was penetrated, formation fluid began to flow into the wellbore, as shown by the ‘Formation: Total flow’ plot in Figure 5-1. Due to the relatively incompressible drilling fluid within the wellbore, Q_{out}, as shown by the ‘Separator: Inlet liquid flow’ plot in Figure 5-1, began to increase at approximately the same time as formation flow started. Also during this time, it is interesting to note that BHP began to rise even though no choke adjustment had been executed yet. Although gas was replacing drilling mud in the annulus, thereby reducing hydrostatic pressure within the wellbore, the increase in BHP can be explained by an increase in friction pressure in the annulus due to increase in flow rate. In this case the friction pressure increase dominated the hydrostatic pressure decrease, and hence an overall increase in BHP was seen.

Approximately 40 seconds after formation flow began, the influx was detected, drilling was stopped, and the first choke adjustment was executed, as shown by the ‘Return choke; Opening’ plot in Figure 5-2. Within a few seconds of this choke area reduction, a pronounced increase in the rate of change of WHP, shown by the ‘Return choke: Upstream pressure’ plot in Figure 5-1, followed by an increase in the rate of change of BHP was observed. As soon as WHP began to rise, Q_{out} began to decrease, as expected, due to the particularly aggressive choke response. Also, since drilling had ceased and BHP was rising quickly, formation flow rate began to decrease.

At approximately 78 seconds, the condition Q_{out} = Q_{in} was achieved. At this point, the choke opening was increased in an effort to stabilize BHP as soon as possible. As can be seen, once the choke adjustment had taken affect, Q_{out} began to increase, while BHP and formation flow rate began to stabilize. BHP was stabilized after a further increase of approximately 50 psi.

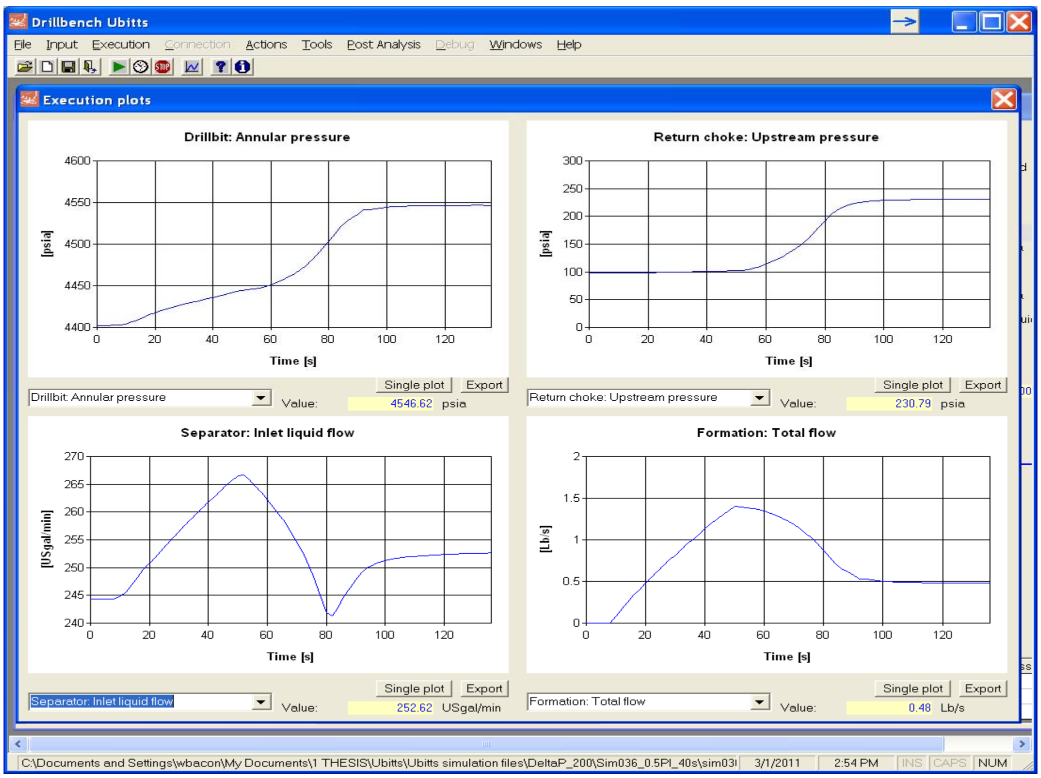

Figure 5-1 Example of insufficient ABP

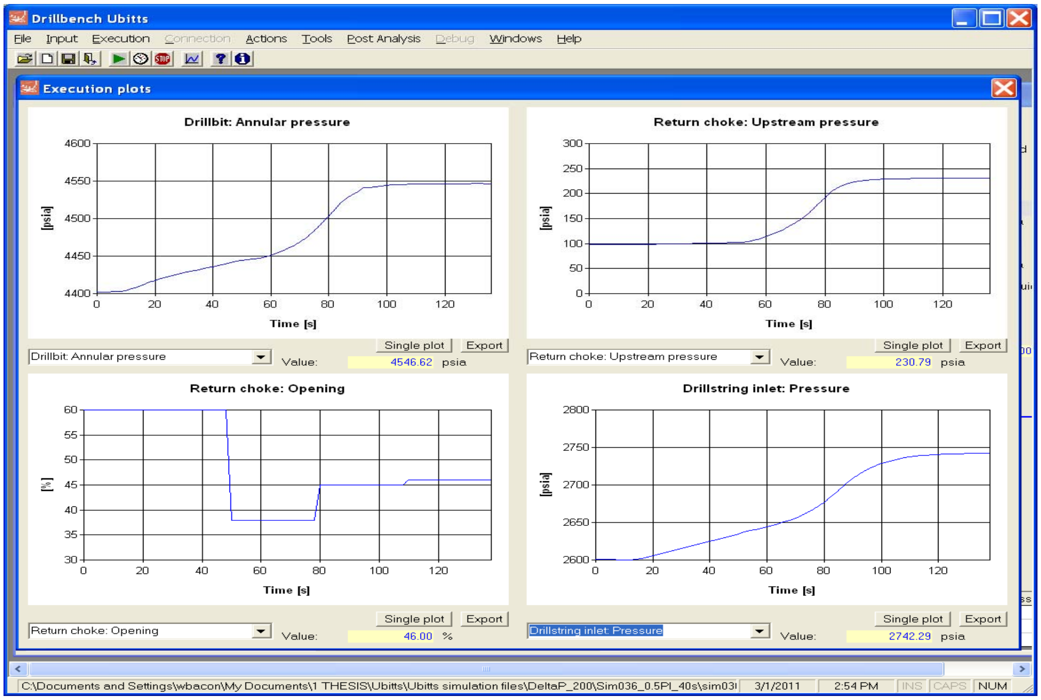

Figure 5-2 Example of insufficient ABP (cont....)

After stabilization BHP was still approximately 50 psi below formation pressure. Hence, as expected, formation flow rate was still non-zero as influx gas continued to enter the wellbore.

Two interesting general remarks which aid understanding of some basic concepts discussed in earlier sections are; 1) SPP, shown by the 'Drillstring inlet: Pressure' plot in Figure 5-2, follows a very similar profile to BHP, although with a slight delay, during the entire simulation. This is due to the drillstring being maintained full of fluid at constant density and flow rate, hence any change in BHP is reflected by SPP. Operationally, this is very important, as SPP is frequently used to guage BHP since SPP is a readily obtainable reading. The delay is accounted for by the time it takes for a pressure wave to travel from bottomhole to standpipe. 2) Once BHP has been stabilized and is being maintained roughly constant, it can be seen that Q_{out} is slightly increasing. This is to be expected, since in-situ influx gas within the wellbore is being allowed to expand as it travels along the annulus and is exposed to proggressively lower pressures. Consideration of Equation (4.2) helps to illustrate this concept. Since Q_{in} *and* Q_{influx}

are both constant near the end of this simulation, the concept of positive rate of change of in-situ influx fluid volume can ge expressed by Equations (5).

$$Q_{out} = Q_{exp} + constant$$

$$and\ \frac{\partial Q_{out}}{\partial t} > 0 \qquad (5.1)$$

$$\therefore \frac{\partial Q_{exp}}{\partial t} > 0$$

5.1.1.2 Excessive Applied-Back-Pressure

Figure 5-3 and Figure 5-4 show an example of when excessive back-pressure was applied due to suppression of expansion at the time when Q_{out} = Q_{in} was achieved. Reservoir set-up and all other conditions up to detection time were the same as for the insufficient applied-back-pressure example described in section 5.1.1.1.

For this simulation, the same initial choke reduction was used for the previous expample. However, the increase in applied-back-pressure was relaxed before the condition of Q_{out} = Q_{in} was achieved, in an effort to facilitate slower convergence of Q_{out} to Q_{in}. The reason for the same aggressive, initial choke adjustment as for the previous example was to achieve fast initial reduction of Q_{out}, thereby reducing the total quantity of influx fluid during the well control process. This can be illustrated by considering integration of the Q_{out} curve. To perform the dynamic well control process in this manner, this simulation required a more complicated choke control procedure than for the previous example, as can be seen from the choke opening plot in Figure 5-4.

A relatively slow convergence of Q_{out} to Q_{in}, with an aggressive initial reduction of Q_{out}, was achieved as desired. The condition of Q_{out} = Q_{in} was achieved at approximately 380 seconds. However, influx cessation occurred at approximately 310 seconds. This resulted in forcing Q_{out} = Q_{in} 72 seconds after influx cessation had occurred. As can be seen by the BHP plot in Figure 5-3, at the 380 second mark, BHP is 11 psi above reservoir pressure with a positive first derivative with respect to time. As described by thesis statement 2 in section 4.2.2, and demonstrated by Equations (5.2), at any time instant where Q_{out} = Q_{in} exists, expansion of in-situ influx gas within the wellbore is being suppressed. Therefore, suppression of expansion alone was acting to increase BHP when Q_{out} = Q_{in} was achieved.

$$Q_{out} = Q_{in}$$
$$and\ Q_{influx} = 0 \qquad (5.2)$$
$$\therefore Q_{exp} = 0$$

As soon as Q_{out} = Q_{in} was achieved, the choke was relaxed in an effort to stabilize BHP. Equations (5), as in the previous example, explain the observed changes in BHP and Q_{out}. In this example, however, Q_{influx} = *constant* = *0, and* there was only a 3 psi increase in BHP after a stabilization attempt was made. A correspondingly small Q_{out} increase was observed. It should be noted that stabilization occurred extremely quickly, and due to the large time scale for this example, it is difficult to see the specific effect by only viewing the execution plots.

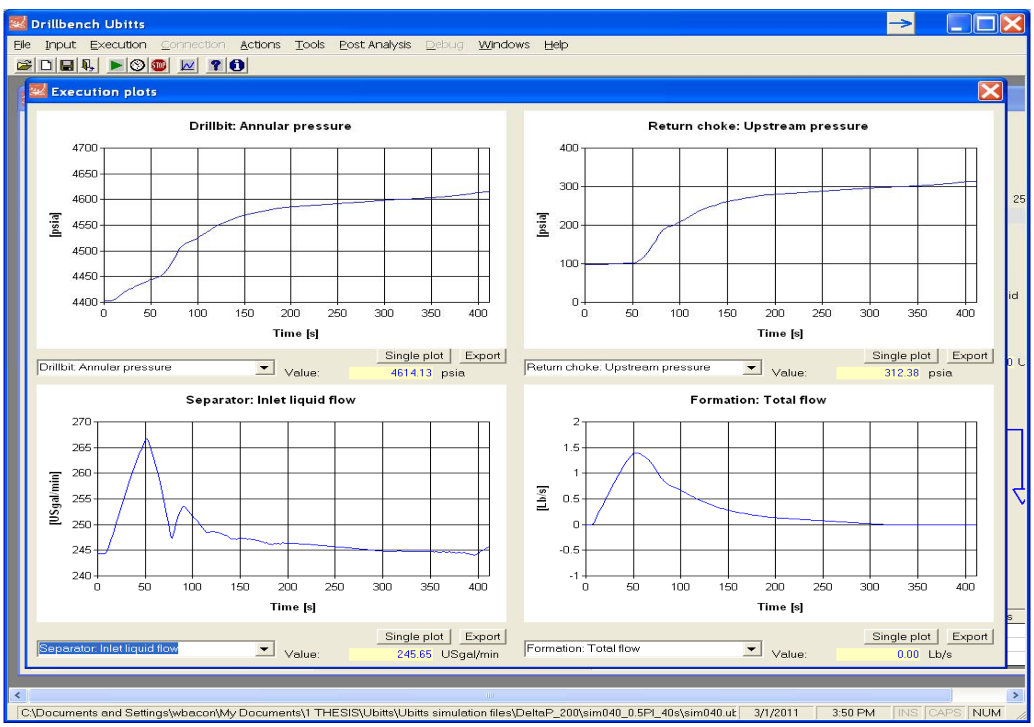

Figure 5-3 Example of Excessive ABP

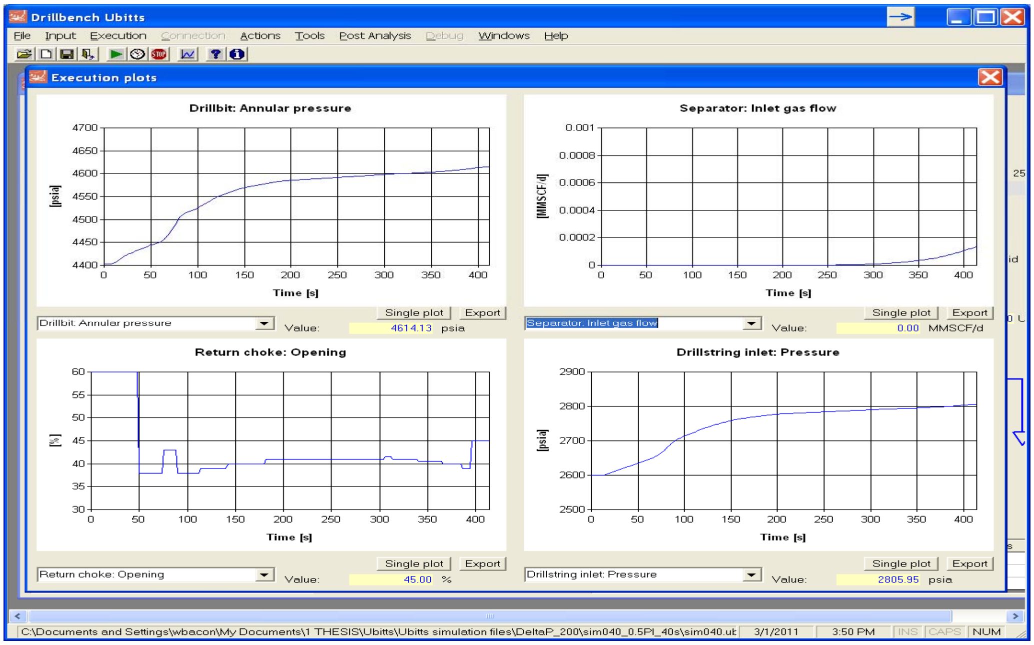

Figure 5-4 Example of Excessive ABP (cont...)

Another point to note for this example is that due to the large time scale, gas to surface, as shown in the 'Separator: Inlet gas flow' plot in Figure 5-4 was observed before termination of the simulation. This amount of gas flow (approximately 200 scf/day), however, is insignificant, as explained in Section 5.4.4.

5.1.2 Simulation Set 4 Summary

Table 5-1 shows summarized results from simulation set 4. Simulations 33-39 all showed cases where in-situ influx fluid was contracting when $Q_{out} = Q_{in}$ was achieved. Simulations 33-36 show this to the point that influx cessation never occurred, even after an inherent overshoot while trying to stabilize BHP. Simulation 40, however, showed a case of expansion when $Q_{out} = Q_{in}$ was achieved, and was discussed in detail in Section 5.1.1.2.

Table 5-1 Simulation Set 4 – Summary of Results

Simulation Set 4				
P_{res} (psi)	PI (MMscf/day)	ρ_{mud} (ppg)	Pump Rate (gpm)	ΔP (psi)
4600	0.5	8	240	-200

Sim. #	Times			Influx Volumes			BHP			Stopped Influx?
	Detection (s)	Control (s)	Δt (s)	Initial (bbl)	Total (bbl)	Add. (bbl)	$Q_{out} = Q_{in}$ (psi)	ΔP (psi)	+P (psi)	
33	40	216	-	0.5	3.2	2.7	4586	-14	7	N
34	42	108	-	0.5	2.1	1.6	4566	-34	14	N
35	42	6	-	0.5	1.2	0.7	4508	-92	44	N
36	42	30	-	0.5	1.1	0.6	4503	-97	44	N
37	42	344	-4	0.5	3.8	3.3	4598	-2	6	Y
38	42	408	-8	0.5	5.7	5.2	4595	-5	9	Y
39	42	264	-4	0.5	2.5	2.0	4599	-1	3	Y
40	42	340	72	0.5	1.9	1.4	4611	11	3	Y

5.2 Results from Simulation Set 5

Simulation set 5 was designed to test the new dynamic well control method proposed by thesis statement 3, and also the signature components suggested in Section 4.3. The essential difference between simulation set 5 and all previous simulations was that once $Q_{out} = Q_{in}$ was achieved, it was maintained. Also, the initial choke adjustments were always aggressive in an attempt to minimize total influx volume and have a negative rate of change of in-situ influx fluid volume within the wellbore at the time $Q_{out} = Q_{in}$ was first achieved.

In all cases from simulation set 5, the rate of change of in-situ influx fluid volume within the wellbore was negative at the time $Q_{out} = Q_{in}$ was first achieved. This supported the theory behind the new dynamic well control method proposed by thesis statement 3. By having $Q_{exp} < 0$ when $Q_{out} = Q_{in}$ was first achieved, we have ensured that $Q_{influx} > 0$ at that time, thereby reducing the chance of applying excessive back-pressure during the procedure.

In each simulation, the concept of the 'dynamic shut-in', described in Section 4.3.1, was illustrated clearly. Once $Q_{out} = Q_{in}$ was being maintained, BHP increased with reducing first derivative with respect to time as the reservoir 'pumped up' the wellbore in an effort to reach pressure equilibrium between reservoir and wellbore.

Results from simulation set 5 are summarized in Table 5-2, and various signature components discussed in detail in Section 5.3. UbitTS execution plots, graphs of first and second derivatives of BHP, the non-dimensional pressure transfer parameter and its first and second derivatives are included in Appendix B.

5.2.1 Illustrative Examples

Results from a selection of dynamic well control scenarios in simulation set 5 are shown in the following figures. These simulations have been referred to as ideal responses. However, it should be noted that in real operations an ideal response would terminate when desired overkill has been applied following influx cessation. These simulations continue to maintain $Q_{out} = Q_{in}$

for an indefinite amount of time following influx cessation, in an attempt to study the behavior of the system.

5.2.1.1 Simulations 41 - 44

Figure 5-5 shows the first scenario (simulation 41) in simulation set 5. A very short detection time (42 s) and hence small initial kick (0.5 bbl) was followed by aggressively achieving and then maintaining $Q_{out} = Q_{in}$ for an indefinite period of time following influx cessation. BHP reached reservoir pressure (4600 psi) and hence influx cessation occurred at 176 seconds. The total influx volume was approximately 1.4 bbl.

The ‘dynamic shut-in’ concept can be plainly seen by examining Figure 5-5. BHP began to stabilize as it approached reservoir pressure. We can see that although BHP stabilized to some extent, a positive gradient was maintained at all times, including after influx cessation occurred. As previously discussed, this positive BHP gradient is due to the suppression of expansion and can be expressed by Equations (5.2).

Interestingly, we may expect that the magnitude of the positive BHP gradient following influx cessation to be proportional to the distance travelled by the influx gas to which expansion is being suppressed. This is, indeed, what was observed from simulations 41 – 44. Detection time for these simulations was progressively increased, with all other set-up parameters constant, which resulted in progressively larger influx travel times. Kick volumes also progressively increased during these simulations. However it would be expected that the distance travelled by influx gas being suppressed has far more influence over rising BHP than influx volume itself. Of course, all other parameters being equal (differential pressure and productivity index), a larger spread of influx gas will correspond to a larger total influx volume.

Figure 5-6 shows a much longer detection time (approximately 300 s) corresponding to simulation 44, and hence a very large initial kick (14.1 bbl). BHP reached reservoir pressure (4600 psi) and hence influx cessation occurred at 353 seconds. The total influx volume was 16.1 bbl, which is realistically too large for a dynamic well control procedure to be performed. If this event occurred in real operations, the well would most likely be shut-in conventionally to ensure surface equipment pressures and flow rates are not exceeded.

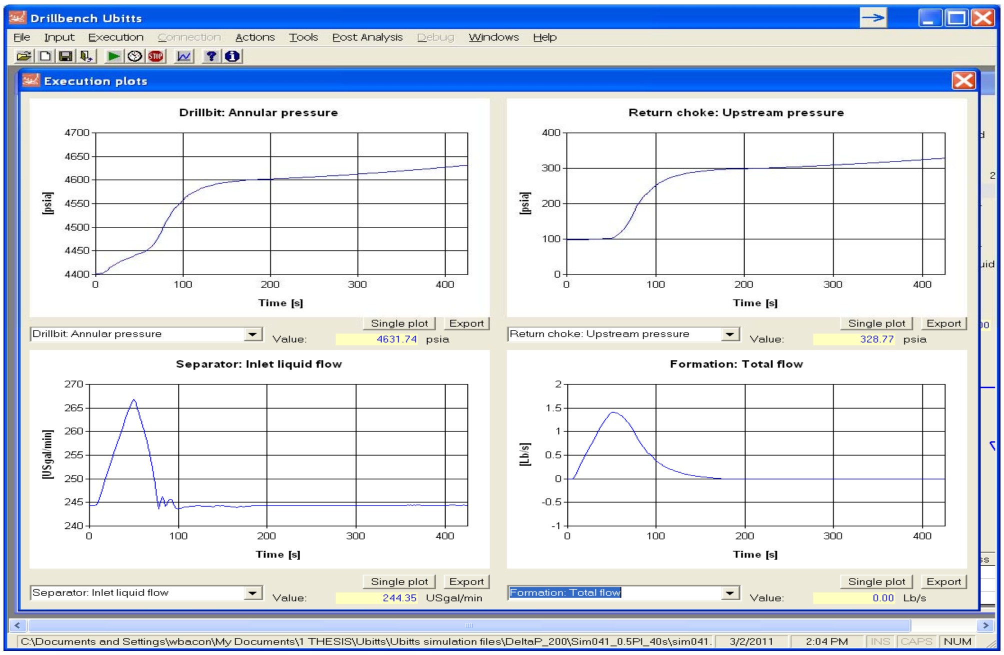

Figure 5-5 Example of Ideal Response – Simulation 41

Although there is such a large influx volume, the 'dynamic shut-in' concept for simulation 44 is recognizable by examining Figure 5-6. BHP stabilized to some extent as it approached reservoir pressure, but the magnitude of the positive gradient after influx cessation occurred was far larger than for simulation 41, shown in Figure 5-5. As previously discussed, this positive BHP gradient is due to the suppression of expansion and appears to be proportional to the distance travelled by gas for which expansion is being suppressed. Indeed, simulations 42 and 43 had results which fell agreeably in between simulations 41 and 44, as expected.

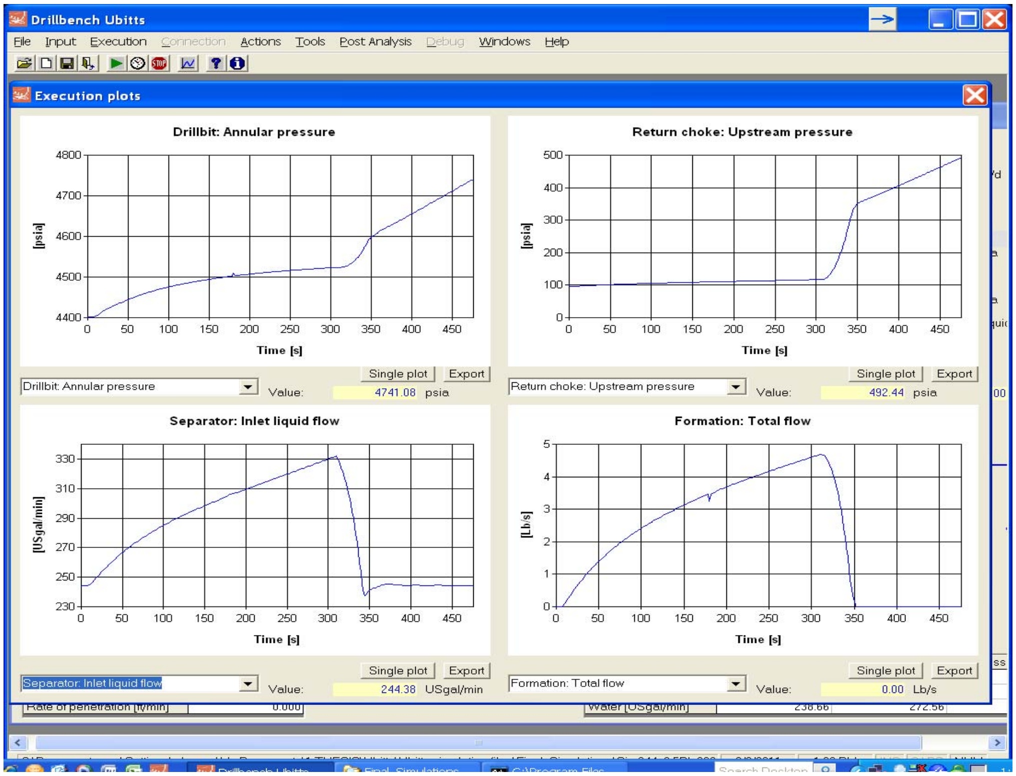

Figure 5-6 Example of Ideal Response – Simulation 44

At some point, for a very large influx times and volumes, we may expect BHP increase due to suppression of expansion to mask any recognition of reservoir and wellbore equilibrating with one another. However, simulation 44 shows positive results, since the dynamic shut-in concept is recognizable, and the influx volume was most likely greater than would be applicable for any dynamic well control procedure. Also, detection time was large, indicating that influx gas would have travelled significant distances along the wellbore.

Another important correlation observed from simulations 41 – 44 is the reduction of time maintaining Q_{out} = Q_{in} required to cause influx cessation, compared with increasing influx volumes. In each case influx volume was increased, the time from when Q_{out} = Q_{in} was first achieved to the time influx cessation occurred, decreased. This is expected, once again due to increase in BHP due to suppression of expansion. A larger rate of BHP increase is expected from suppression of gas expansion a larger influx gas volume which has spread over a larger distance. In this case, an average gas bubble, such as that described in Section 4.3.3 will have been further along the wellbore than for a smaller kick with less spread. Therefore, this BHP increase due to suppression of expansion contributes more towards controlling the influx than for a case with lower in-situ influx gas volume and spread.

Table 5-2 Simulation Set 5 - Summary of Results

						Influx			Times				
Sim. #	**PI** (MMscf/Day)	**Pres** (psi)	**ΔP** (psi)	**ρ_m** (ppg)	**Pump** (gpm)	**Initial** (bbl)	**Total** (bbl)	**Add.** (bbl)	**Detection** (s)	**Control 1** (s)	**Q_{influx}=0** (s)	**Q_{out}=Q_{in}** (s)	**Control 2** (s)
41	0.5	4600	-200	8	240	0.5	1.4	0.9	42	126	168	69	99
42	0.5	4600	-200	8	240	2.4	3.7	1.3	102	69	171	135	36
43	0.5	4600	-200	8	240	7.5	9.3	1.8	202	54	256	238	18
44	0.5	4600	-200	8	240	14.1	16.1	2.0	302	44	345	335	11
45	0.05	4800	-400	8	240	0.1	1.4	1.2	40	596	635	55	581
46	0.5	4800	-400	8	240	1.1	3.4	2.3	40	123	163	101	62
47	0.5	4800	-400	8	240	15.7	20.2	4.5	200	66	266	245	21
48	0.5	6900	-240	12	260	1.4	2.4	1.0	62	57	119	92	27

5.3 Signature Results

In this section simulation set 5 results are further explored as they relate to the proposed signature components described in Section 4.3. That is, the first and second derivatives of BHP with respect to time, and the non-dimensional pressure transfer parameter, or PTP (described in Section 4.3.4), and its first and second derivatives with respect to time have been analyzed.

5.3.1 Illustrative Example

Figures contained in this section show an illustrative example of the various signature parameters that resulted from simulation set 5. Simulation 42 was analyzed, since it had typically identifiable signature components and a relatively small kick volume of 3.7 bbl, which is a realistic situation for dynamic well control to be applied. For the reasons described in Section 4.6, the primary focus of the analysis for this section was between times of influx detection and cessation.

As can be seen by examining the UbitTS execution plots in Figure 5-7, the dynamic shut-in concept is clearly visible and similar in nature to the simulations discussed in Section 5.2.1.1. Figure 5-8 and Figure 5-9 show the first and second derivatives of BHP with respect to time, respectively. At detection time, when the first choke adjustment was applied, the first derivative of BHP increased significantly. During this time a corresponding positive value of the second derivative of BHP was seen. This is expected, since the choke area reduction increased WHP which in turn increased BHP. And, due to an aggressive choke response, increase in BHP pressure due to choke adjustment was expected to be more significant than increase in BHP due to either suppression of expansion or the drive for reservoir and bottomhole to self-equilibrate.

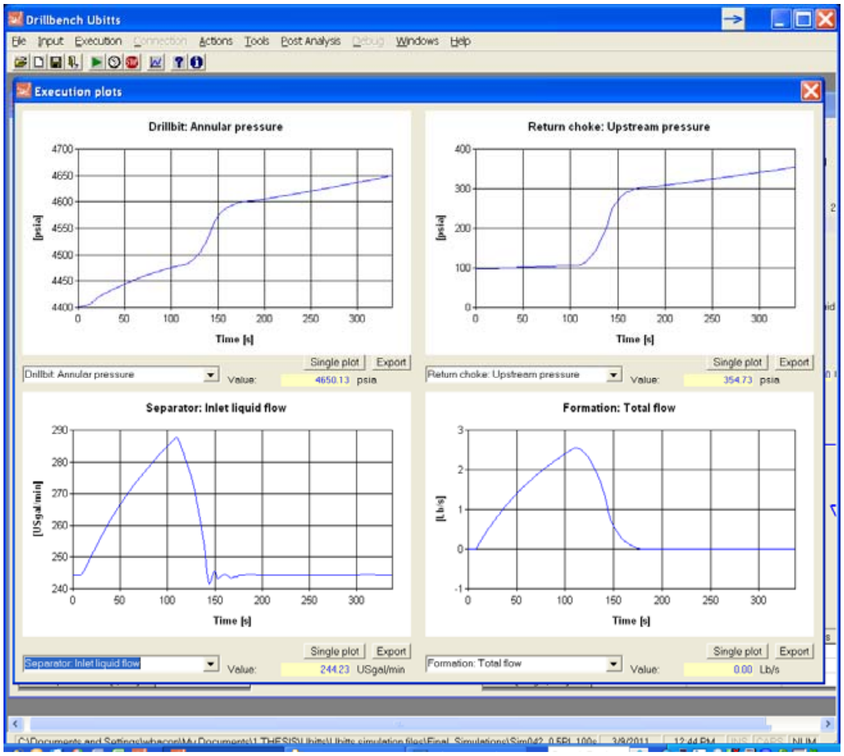

Figure 5-7 UbitTS Execution Plots for Simulation 42

Once $Q_{out} = Q_{in}$ was achieved, a sharp drop in the first derivative of BHP was observed, as shown in Figure 5-8. A corresponding change in the second derivative of BHP was seen, as shown in Figure 5-9. Although erratic, the second derivative did show an important general trend. Once $Q_{out} = Q_{in}$ was achieved the second derivative of BHP switched from generally positive, to generally negative. This can be explained by the elimination of increase in BHP due to aggressive choke area reduction. The only factors influencing the increase in BHP after $Q_{out} = Q_{in}$ was achieved were suppression of expansion and the drive for reservoir and bottomhole to self-equilibrate. Assuming that differential pressure between reservoir and wellbore was more significant than suppression of expansion, this would imply a negative second derivative of BHP with respect to time.

Some of the erratic results for second derivative of BHP with respect to time may be attributed to the following reasons: $Q_{out} = Q_{in}$ is difficult to achieve, resulting in a kind of damped oscillatory response for the convergence of Q_{out} to Q_{in}, and the first and second derivatives are calculated using a numerical, forward-difference approach, which may contain significant error at particular time instants.

Therefore, in accordance with the first two proposed signature components described in Sections 4.3.2 and 4.3.3, it was seen that when influx cessation occurred, the first derivative of BHP remained positive and the second derivative became approximately equal to zero.

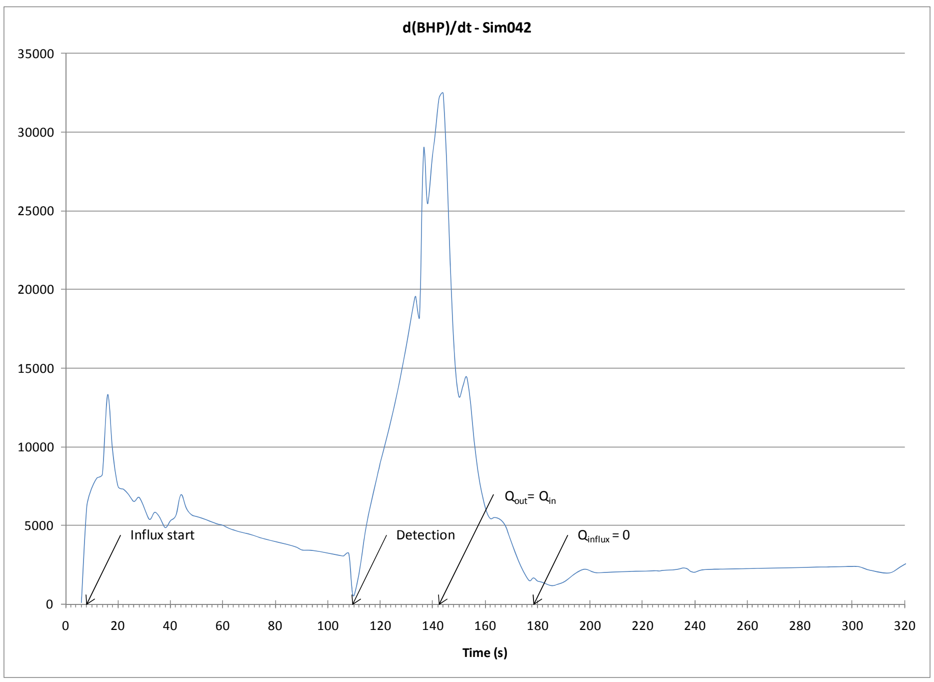

Figure 5-8 First Derivative of BHP for Simulation 42

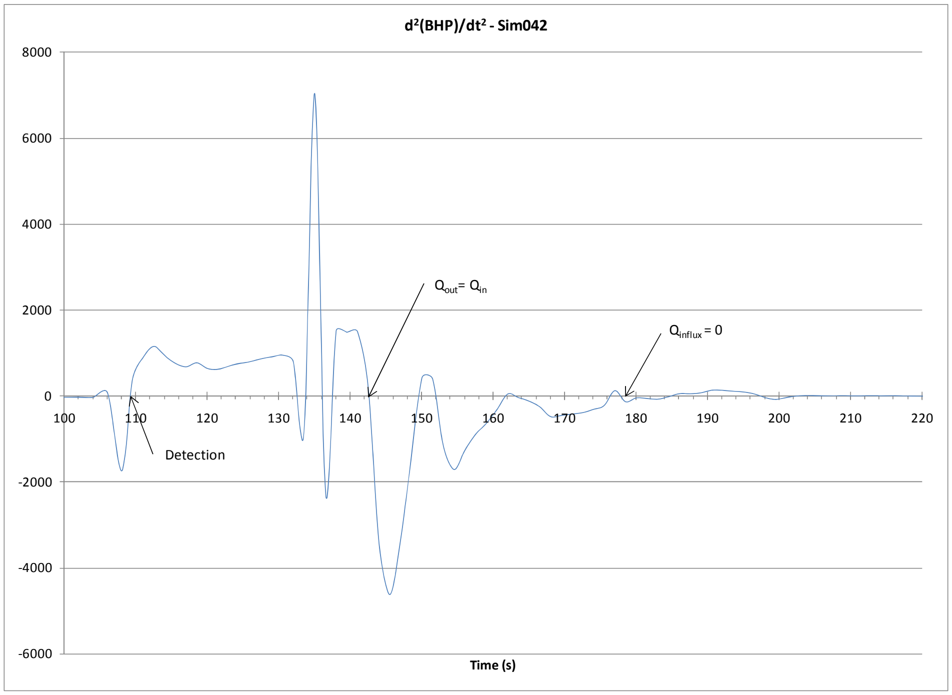

Figure 5-9 Second Derivative of BHP for Simulation 42

Next, the non-dimensional pressure transfer parameter, or PTP, shown in Figure 5-10, was considered. This parameter was defined in Section 4.3.4, and represents the difference between BHP and WHP at a particular time, compared to the difference between BHP and WHP of the relatively incompressible system before an influx occurred. Therefore, the PTP can be used to indicate variations of pressure gradient within the annulus, compared to initial annular pressure gradient.

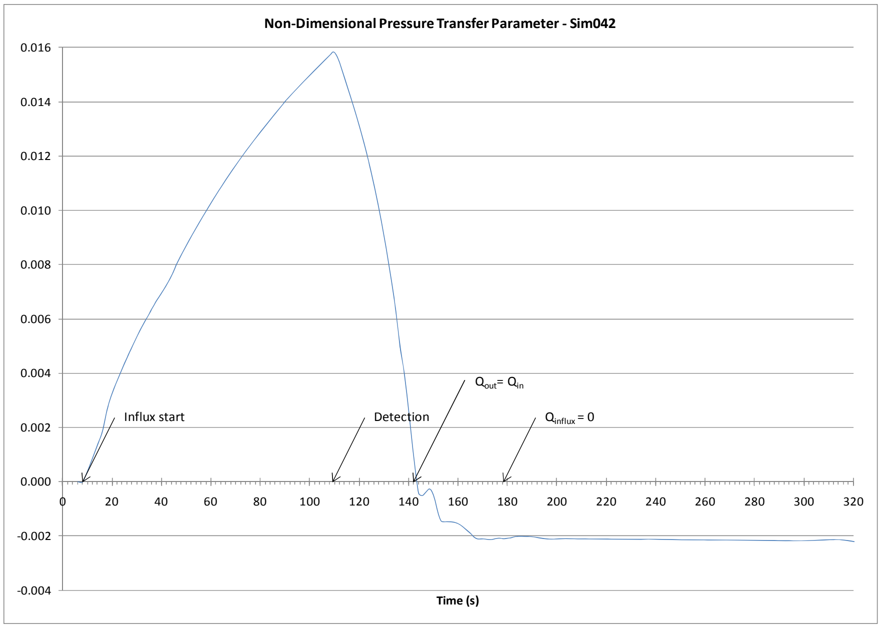

Figure 5-10 Non-Dimensional Pressure Transfer Parameter for Simulation 42

As shown in Figure 5-7, as influx gas began to enter the wellbore, BHP increased and WHP remained relatively constant. Since the difference between BHP and WHP became greater, this corresponded to an increase in the PTP, shown in Figure 5-10. At detection time, an aggressive choke adjustment was applied, and WHP began to increase sharply. This resulted in rapid decrease of the PTP, as expected. Once $Q_{out} = Q_{in}$ had been achieved, the PTP became negative since the annulus now contained gas and, therefore, had a reduced hydrostatic pressure gradient. At this stage no aggressive WHP changes were being applied and there could not be a greater friction pressure gradient than for the initial steady-state conditions (assuming that influx gas viscosity was less than drilling fluid viscosity), as described in Section 4.3.4. Therefore, in accordance with the third proposed signature component indicating influx cessation, the non-dimensional pressure transfer parameter was less than, or equal to zero when influx cessation occurred.

The first and second derivatives of the PTP with respect to time are shown in Figure 5-11. At detection time, a significant decrease in the first derivative of the PTP occurred. This corresponded to the decrease observed in the PTP itself, which was due to the aggressive increase of applied-back-pressure. Corresponding to the decrease in first derivative of the PTP was a negative spike in the second derivative of the PTP. Although this spike was recognizable in this instance, its magnitude was smaller than some of the noise observed during the simulation.

Once Q_{out} = Q_{in} had been achieved and the choke response relaxed, the first derivative of the PTP rapidly increased as the PTP began to level out. Corresponding to the rapid increase of the first derivative was a significant positive spike in the second derivative of the PTP.

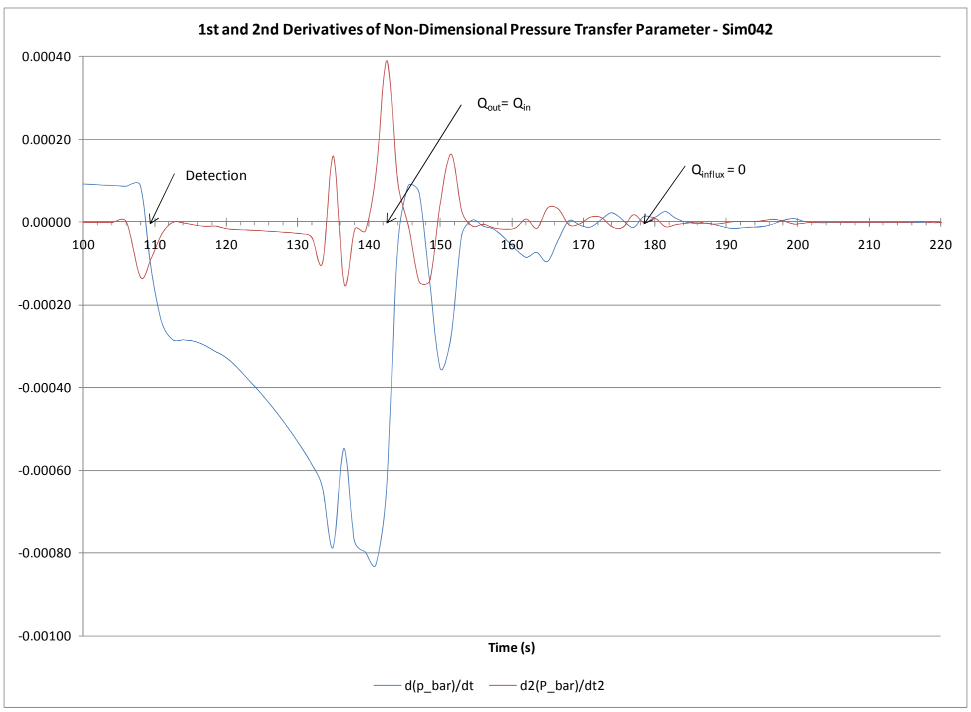

Figure 5-11 First and Second Derivatives of Non-Dimensional Pressure Transfer Parameter for Simulation 42

As BHP approached reservoir pressure and the PTP began to level out, the first derivative of the PTP approached zero and the second derivative fluctuated around zero. In accordance with proposed signature component 4, once influx cessation occurred and Q_{out} = Q_{in} was maintained, the PTP remained approximately constant, with its first and second derivatives approximately equal to zero. This was expected since no new formation flow was entering, and expansion was being suppressed. Therefore, there was no appreciable change in pressure difference between bottomhole and surface.

5.3.2 General Signature Results

The results observed from simulation 42, discussed in Section 5.3.1, were generally typical of the results from simulation set 5. All signature components proposed in Section 4.3 were observed in all scenarios from simulation set 5, with only a few exceptions. In each case, these exceptions could be explained by factors such as high noise in the data due to very low kick size, or excessive gas to surface. These cases are discussed in Section 5.3.3.

Maintenance of $Q_{out} = Q_{in}$ was required for longer to cause influx cessation in cases where the kick volume was lower. This is explained by a greater rate of BHP increase due to the suppression of influx gas expansion for a larger kick. As previously mentioned, this rate of pressure increase due to suppression of expansion contributes to the speed at which BHP approaches reservoir pressure and, therefore, controls the influx.

With most of the simulations the second derivative of the PTP was quite erratic at various times. However, an important observation was the positive spike associated with the increase in the first derivative of the PTP around the time that $Q_{out} = Q_{in}$ was achieved. This spike was clearly recognizable in all of the simulations. Therefore, the positive spike in the second derivative of the PTP, in conjunction with achieving $Q_{out} = Q_{in}$, should be considered with the signature components.

5.3.3 Signature Violations

No exceptions to the signature components proposed in Section 4.3 were shown in any simulations. However, one exception appeared to be shown by simulation 45 until further insight was obtained. Also, in cases where the influx volume was very low, the noise levels in the obtained data were quite high, obscuring the signature components in some cases. These cases are discussed below.

5.3.3.1 Gas to Surface

One very clear exception to the proposed signature components appeared to be shown by simulation 45, which was a very low permeability reservoir zone (productivity index of 0.05 MMscf/day), with a low detection time (approximately 40 s). These two factors resulted in a very low total influx volume (1.4 bbl) and a very long simulation time (635 s to control the influx). The reason for the long simulation time can be explained by the dynamic shut-in concept. Since the reservoir had such a low permeability, the flow rate caused by differential pressure between reservoir and wellbore was low. Hence, the action of the reservoir pumping up the wellbore was slow. Coupled with this was the small initial influx volume (0.1 bbl), resulting in a very slow pressure increase due to suppression of expansion once $Q_{out} = Q_{in}$ was achieved.

Execution plots from UbitTS for simulation 45 are shown in Figure 5-12 and Figure 5-13. It can be seen that gas flow to surface, shown by the 'Separator: Inlet gas flow' plot in Figure 5-13, became increasingly large towards the end of the simulation. A large spike in Q_{out} near the end of the simulation can also be seen, as shown in Figure 5-12. Clearly, the magnitude of gas flow to surface had become significant, affecting the results of the simulation. Importantly, $Q_{out} = Q_{in}$ was not being maintained at this point, due to the additional gas flow to surface. Therefore, the proposed signature components cannot be applied to indicate influx cessation for simulation 45. Indeed, Figure 5-14 shows that the non-dimensional pressure transfer parameter was positive at the time of influx cessation, which would have been in violation of the third signature component had the condition $Q_{out} = Q_{in}$ been applicable at that time.

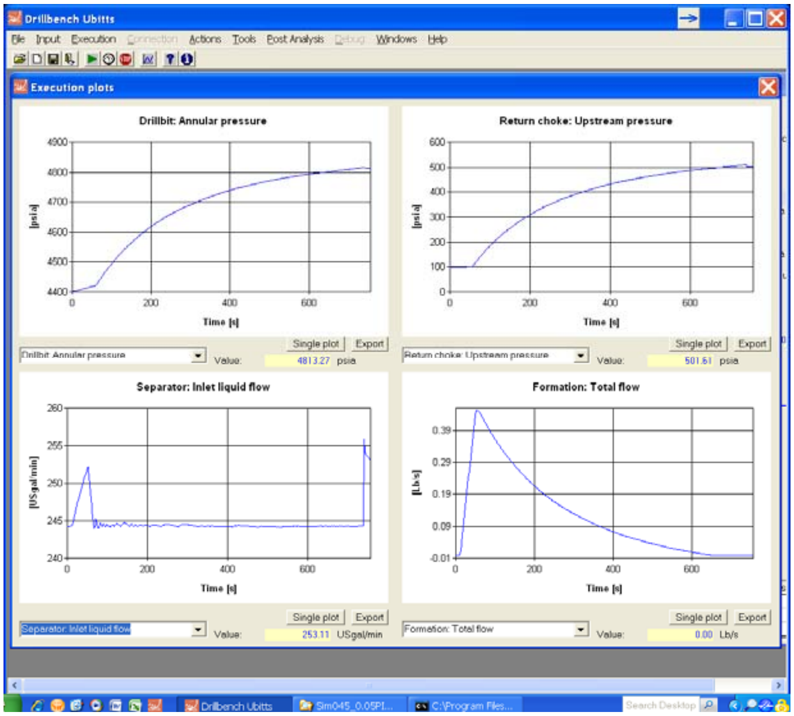

Figure 5-12 UbitTS Execution Plots for Simulation 45

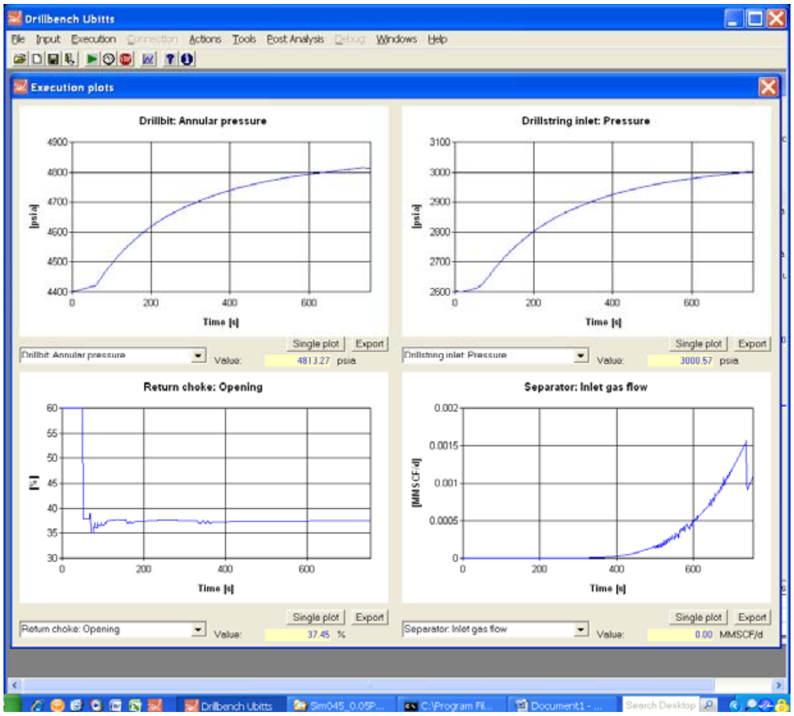

Figure 5-13 UbitTS Execution Plots for Simulation 45 (cont…)

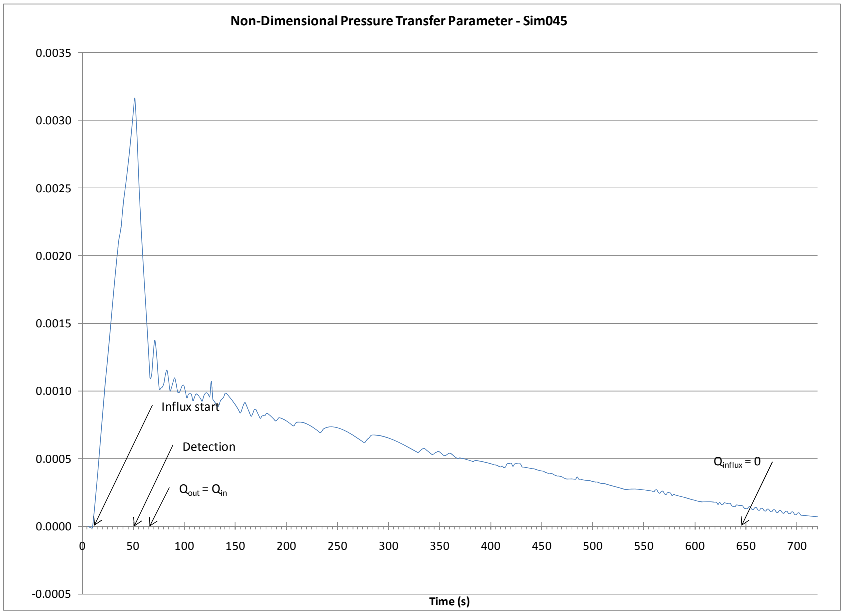

Figure 5-14 Example of Exception to Signature – Simulation 45

5.3.3.2 Small Influx Volumes

Another important scenario where difficulty to recognize signature components existed was for very low kick volumes. Simulation 41 was a good example of low kick volume (approximately 1.4 bbl) and relatively high data noise levels. Simulation 45, discussed in Section 5.3.3.1, was also an example of a small kick volume where a lot of data noise existed. In fact, simulation 45 contained the most noise out of all simulations in simulation set 5. However simulation 45 had a number of varying parameters such as productivity index, differential pressure and significant gas to surface, etc. Therefore, simulation 41 was chosen to illustrate the effect of increased noise with small kick volume due to its relative comparability to other cases in simulation set 5.

Figure 5-15 shows the first and second derivatives of the PTP for simulation 41. It can be seen that the previously discussed signature components were generally visible. However, after the condition Q_{out} = Q_{in} was achieved, a large amount of movement in both the first and second derivatives was evident. Figure 5-16 shows the same parameters for simulation 44, which created a much larger kick (16.1 bbl). Simulation 44 had the same set-up parameters as simulation 41, with only the detection time being increased from 42 s to approximately 300 s. Clearly, the signature components are more identifiable for simulation 44 than simulation 41; with much less noise at the time the maintenance of Q_{out} = Q_{in} was being attempted.

Of course, the condition Q_{out} = Q_{in} can never be achieved exactly. Also, in attempting to achieve Q_{out} = Q_{in}, an oscillatory response occurs at first, due to overshooting the desired value. The reason for the increased data noise for smaller kick volumes during the attempt to maintain Q_{out} = Q_{in} was probably due to the relative magnitude of instability in the Q_{out} curve to the magnitude of the signature components themselves. That is, the inability to maintain Q_{out} = Q_{in} exactly was very significant when compared to various system values that indicate signature components.

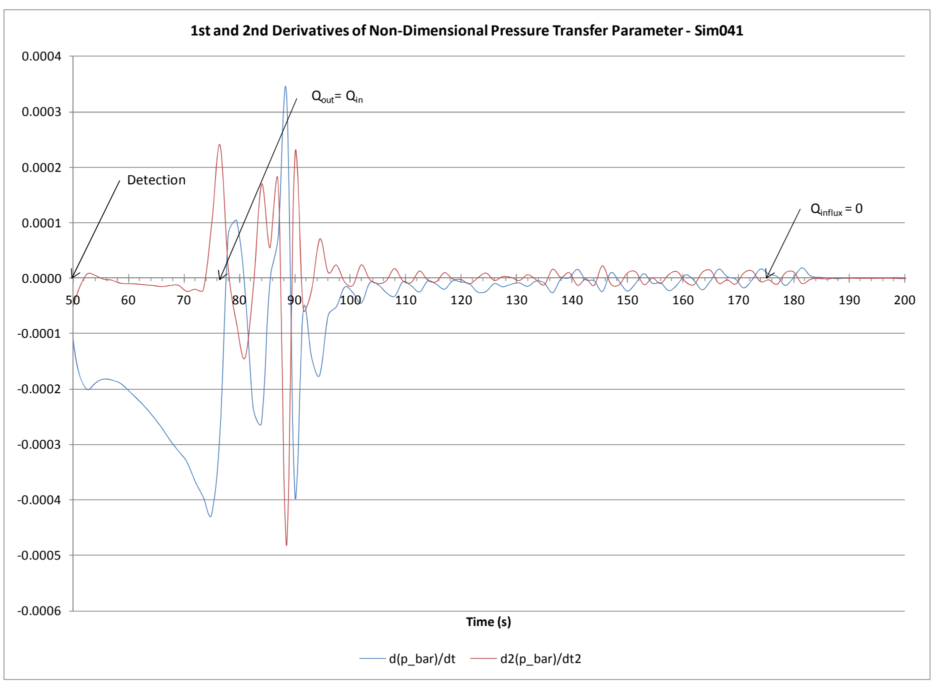

Figure 5-15 First and Second Derivatives of Non-Dimensional Pressure Transfer Parameter for Simulation 41

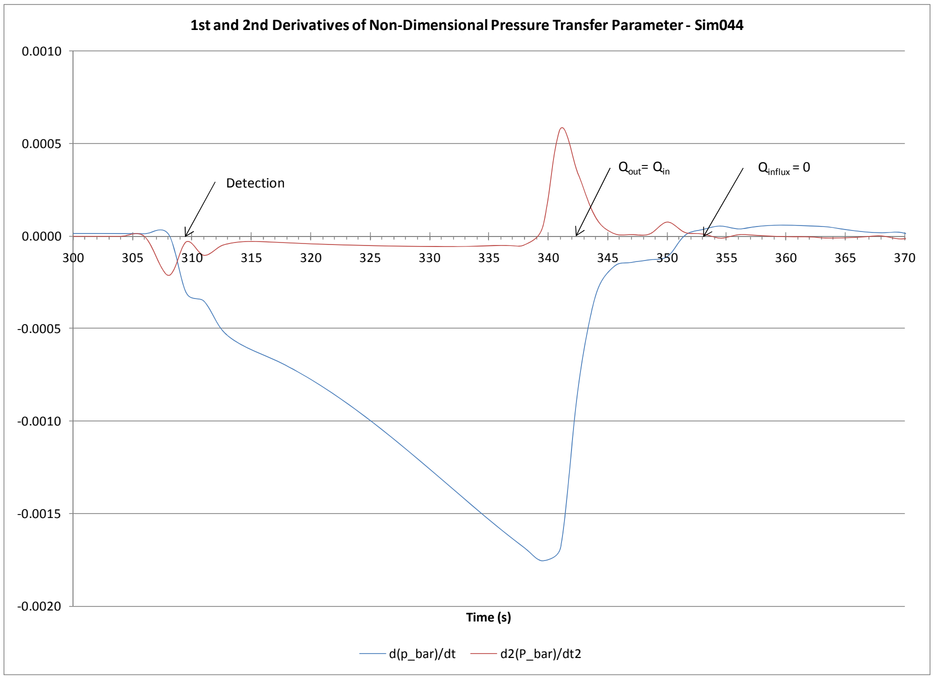

Figure 5-16 First and Second Derivatives of Non-Dimensional Pressure Transfer Parameter for Simulation 44

Increased noise with smaller kick volumes may be no cause for alarm, since the influx volumes are small. Naturally, if the signature is misinterpreted and constant BHP circulation is commenced before influx cessation has occurred, the amount of formation flow will either be negligible, or allow a slightly larger kick which will be recognized and controlled effectively.

5.4 General Discussion Points

5.4.1 Simulation Set 1

One consistent factor within simulation set 1 was that all of the kicks taken were large. In terms of approximate volume in barrels, the total kick volumes varied from 10 bbl to 43 bbl. Due to the size of these influx volumes, a dynamic, well control procedure would probably not be applicable to all or most of these scenarios.

Due to the lengthy simulations in this set, significant amounts of gas flow to surface were seen. Most of these cases showed that influx cessation occurred before $Q_{out} = Q_{in}$ was achieved and, therefore, excessive back-pressure was applied. However, gas to surface caused a moment of instability in all of these simulations. Therefore, the results from these simulations could not be interpreted with confidence.

Therefore, due to gas flow to surface implying questionable credibility to simulation set 1, and kick volumes generally larger than realistic for this procedure, little time was spent discussing or presenting simulation set 1.

5.4.2 Transient WHP Response

A very important point that significantly affected the approach for this research was the method of applying back-pressure within UbitTS™. Because UbitTS™ was designed as a training simulator, application of back-pressure was executed via real-time adjustment of choke. This created a very complex process for which the response could never be repeated in exactly the same way. Therefore, due to the inconsistency of the WHP response, a parametric study was impossible. Accordingly, an analytical approach was taken for this research, followed by some simulations designed to test analytical findings, rather than a rigorous parametric study designed to form specific correlations between important parameters.

5.4.3 Dynamic Shut-In versus Conventional Shut-in

One disadvantage of the dynamic shut-in process is the fast circulation rate carrying influx fluid further along the annulus in a given period of time, thereby increasing the rate of pressure increase due to suppression of expansion. This effect may be found to mask the stabilization of BHP at reservoir pressure and increases the chance of applying excessive back-pressure. This same effect also occurs in a conventional shut-in, particularly for low permeability reservoirs which take a long time to pump up the annulus. The increase in pressure due to suppression of expansion in the conventional shut-in case is due purely to gas migration alone, and therefore occurs more slowly than in a dynamic shut-in process.

5.4.4 Gas to surface

UbitTS produced gas to surface in unrealistically short time frames. Initial separator gas inflow values were of the order 10exp-11 MMscf/day, and could occur as soon as 50 seconds after influx gas entered a slim-hole well at 10,000ft. These values steadily increased until separator liquid inflow values were significantly affected, causing some instability in the results, as described in Section 5.4.1. The gas inflow values were of the order 0.001 MMscf/day when instability began to occur.

It is reasonable to assume that simulated gas flow rates to surface were becoming realistic at the point where instability began to occur, due to high slip velocities that occur in multiphase flow. It is also a realistic phenomenon that when significant amounts of gas arrive at surface, the function of the Coriolis meter is impeded, causing instability.

CHAPTER 6

CONCLUSIONS

The work presented in this thesis has demonstrated that compressibility effects of a gas influx can be significant during applied-back-pressure, dynamic, MPD well control scenarios. An analytical approach was used to gain understanding of gas influx behavior during the response and its effect on the system. The analytical findings were then tested by utilizing an interactive, transient, multiphase flow simulator to replicate various applied-back-pressure, dynamic, MPD well control responses to gas influxes in a vertical, slim-line well geometry.

Within the scope of this research, it has been shown that achieving the condition $Q_{out} = Q_{in}$ during an applied-back-pressure, dynamic, MPD well control response to a gas influx is no cause to assume influx cessation has occurred. Indeed, many simulations showed that at the time $Q_{out} = Q_{in}$ was achieved during a response, BHP remained below reservoir pressure and formation flow was continuing to enter the wellbore.

Analysis of mass flow rate through a control volume surrounding the wellbore resulted in the development of two thesis statements suggesting various effects caused by compressibility of a gas influx during an applied-back-pressure, dynamic, MPD well control response. These two thesis statements have been expressed as:

1. *For a compressible system,* $Q_{out} = Q_{in}$*, is not an adequate basis to conclude that influx has ceased, and*
2. *For* $Q_{out} = Q_{in}$ *to imply influx cessation, the rate of change of in-situ volume of influx fluid within the wellbore must be zero. Additionally, if* $Q_{out} = Q_{in}$*, then the rate of change of in-situ volume of influx fluid within the wellbore cannot be positive.*

Further analysis of mass flow rate through the control volume, and consideration of MPD, well control objectives resulted in the development of a third thesis statement. This statement is a proposed new applied-back-pressure, dynamic, MPD well control response, and has been expressed as:

3. *An optimal response during dynamic well control is to aggressively increase applied-back-pressure to force* $Q_{out} = Q_{in}$, *and then maintain* $Q_{out} = Q_{in}$ *until the rate of change of in-situ volume of influx fluid within the wellbore is zero. The "Overkill" magnitude is proportional to the time* $Q_{out} = Q_{in}$ *is maintained beyond time of influx cessation.*

Following the proposed new applied-back-pressure, dynamic, MPD well control response expressed by thesis statement 3, a set of signature components developed to recognize influx cessation during the response was introduced. A summary of the influx cessation signature components is expressed in Table 6-1.

For the development of the influx cessation signature, a new parameter, termed the 'non-dimensional pressure transfer parameter', was introduced and defined as,

$$\bar{P} = \frac{(BHP - WHP) - p_{ref}}{p_{ref}}$$

where p_{ref} = value of *(BHP – WHP)* before influx fluid entered the wellbore.

Overall, the proposed response, expressed by thesis statement 3, showed very positive results within the scope of simulations performed for this research. The influx signature was clearly visible for most of the simulations, with no simulations violating the proposed rules.

Situations where a number of signature components were less clearly visible included for very small kicks, and for very low reservoir productivity index. This was most likely due to the magnitude of the noise in the data being comparable to the magnitude of the signature components themselves. The positive view of this result may be that if a signature is misinterpreted, and additional influx gas is allowed into the wellbore, the well control response can be repeated, with the signature being recognizable.

Table 6-1 Influx Cessation Signature Summary

Time Period During Response	WHP aggressively being increased to reduce Q_{out}	$Q_{out} = Q_{in}$ being maintained *before* influx cessation	$Q_{out} = Q_{in}$ being maintained *after* influx cessation
Signature	$\frac{\partial \bar{P}}{\partial t} < 0$ $\frac{\partial^2 \bar{P}}{\partial t^2} < 0$	$\frac{\partial \bar{P}}{\partial t} < 0$ $\frac{\partial^2 \bar{P}}{\partial t^2} > 0$	$\frac{\partial (BHP)}{\partial t} \geq 0$ $\frac{\partial^2 (BHP)}{\partial t^2} \cong$ $\bar{P} \leq 0$ $\frac{\partial \bar{P}}{\partial t} \cong$ $\frac{\partial^2 \bar{P}}{\partial t^2} \cong 0$

This research has provided some initial insight into compressibility effects of a gas influx during applied-back-pressure, dynamic, MPD well control responses. However, the simulation program used to test analytical conclusions did not form a rigorous parametric study. Further research is required to test the analytical conclusions more thoroughly for a range of well geometries, mud densities and types, influx densities, pump rates, etc.

APPENDIX A

SUMMARY OF RESULTS FOR SIMULATION SETS 2 AND 3

Table A-1 Summary of results for simulation set 2

P_{res} (psi)	ρ_{mud} (ppg)	Pump Rate (gpm)	ΔP (psi)
4800	8	240	400

			Times			Influx Volumes			BHP		
Sim.	PI (MMscf/day)	Response	Detection (s)	Control (s)	Δt (s)	Initial (bbl)	Total (bbl)	Add. (bbl)	$Q_{out} = Q_{in}$ (psi)	ΔP (psi)	Stop Influx?
17	0.5	C1	62	204	-16	2.3	11.4	9.0	4772	-28	Y
18	0.5	C2	62	650	110	2.3	18.3	16.0	4888	88	Y
19	0.05	C1	166	238	-	2.2	6.3	4.1	4714	-86	N
20	0.05	C2	166	508	-32	2.2	9.0	6.7	4772	-28	Y
21	0.05	C1	60	224	-	0.3	2.0	1.7	4627	-173	N
22	0.05	C2	60	356	-	0.3	2.6	2.3	4685	-115	N
23	0.5	C1	166	-	-	-	-	-	-	-	NA
24	0.5	C2	166	-	-	-	-	-	-	-	NA

Table A-2 Summary of results for simulation set 3

P_{res} (psi)	ρ_{mud} (ppg)	Pump Rate (gpm)	ΔP (psi)
4600	8	240	200

			Times			Influx Volumes			BHP		
Sim.	PI (MMscf/day)	Response	Detection (s)	Control (s)	Δt (s)	Initial (bbl)	Total (bbl)	Add. (bbl)	$Q_{out} = Q_{in}$ (psi)	ΔP (psi)	Stop Influx?
25	0.5	C1	42	104	-	0.5	1.8	1.3	4569	-31	N
26	0.5	C2	42	290	-18	0.5	2.8	2.3	4598	-2	Y
27	0.05	C1	122	160	-	0.5	1.4	0.9	4511	-89	N
28	0.05	C2	122	388	-	0.5	2.0	1.5	4569	-31	N
29	0.05	C1	40	68	-	0.1	0.2	0.2	4424	-176	N
30	0.05	C2	40	310	-	0.1	0.7	0.7	4490	-110	N
31	0.5	C1	122	90	-4	3.4	5.6	2.2	4598	-2	Y
32	0.5	C2	122	222	86	3.4	5.7	2.3	4627	27	Y

APPENDIX B

RESULTS FOR SIMULATION SET 5

Appendix B includes the following graphs shown for each simulation in set 5:

1. UbitTS execution plots,
2. First and second derivatives of BHP,
3. Non-dimensional pressure transfer parameter, and
4. First and second derivatives of the non-dimensional pressure transfer parameter.

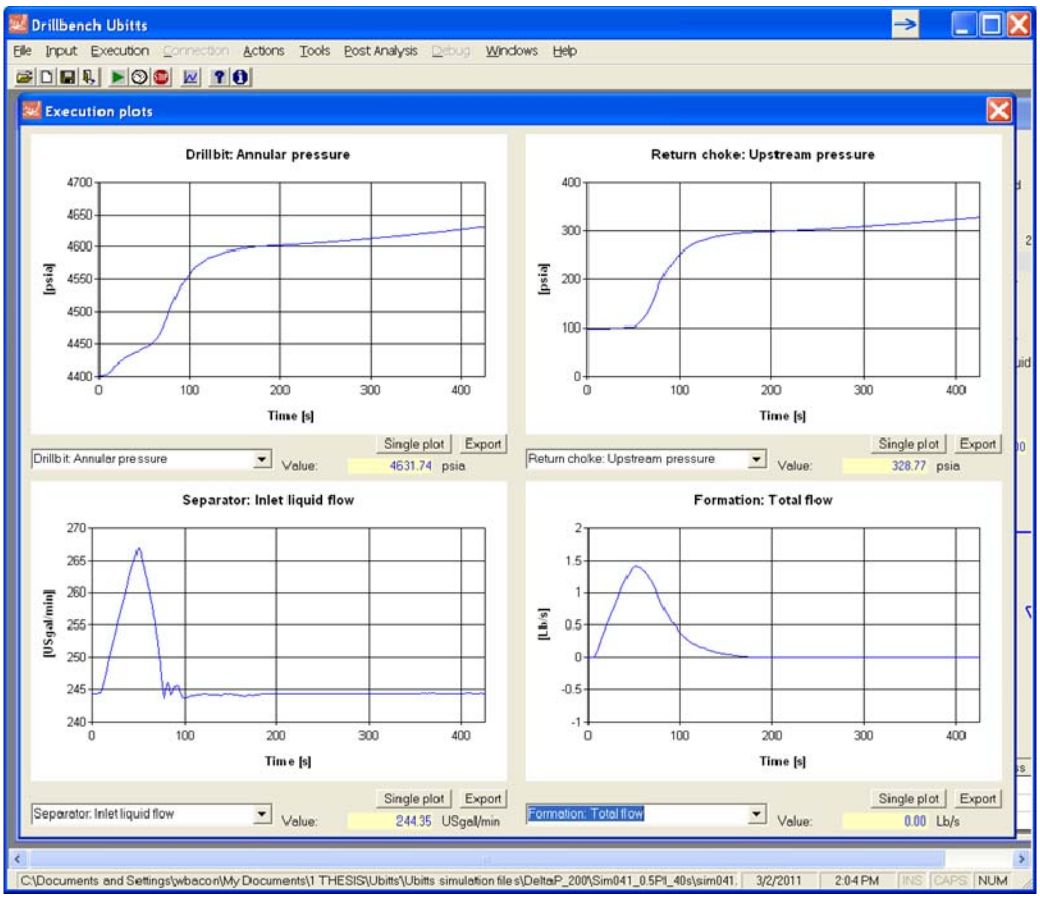

Figure B-1 UbitTS execution plots for simulation 41

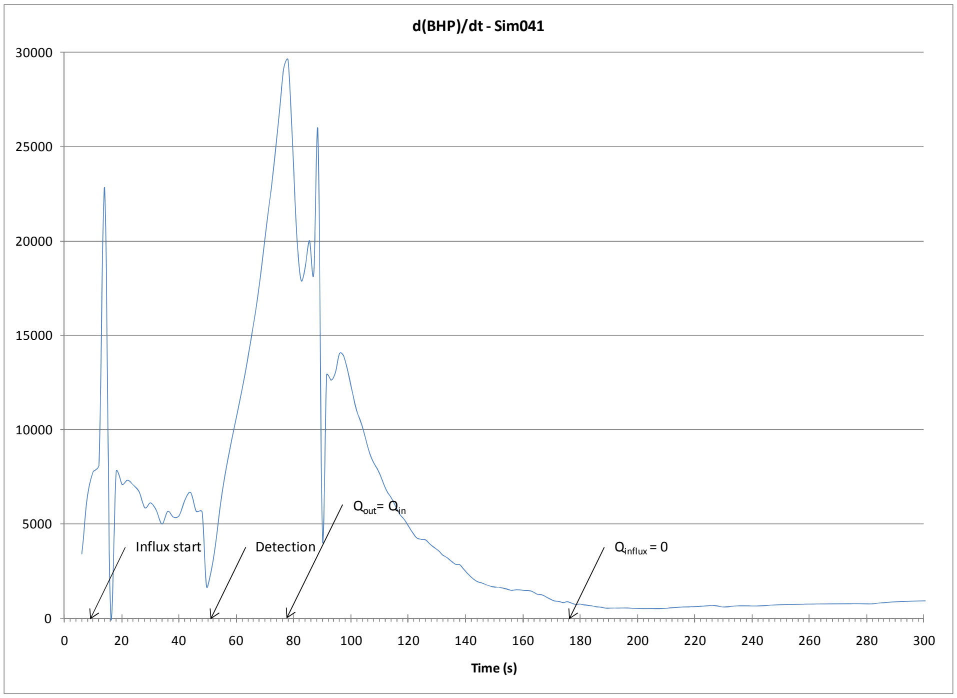

Figure B-2 First derivative of BHP for simulation 41

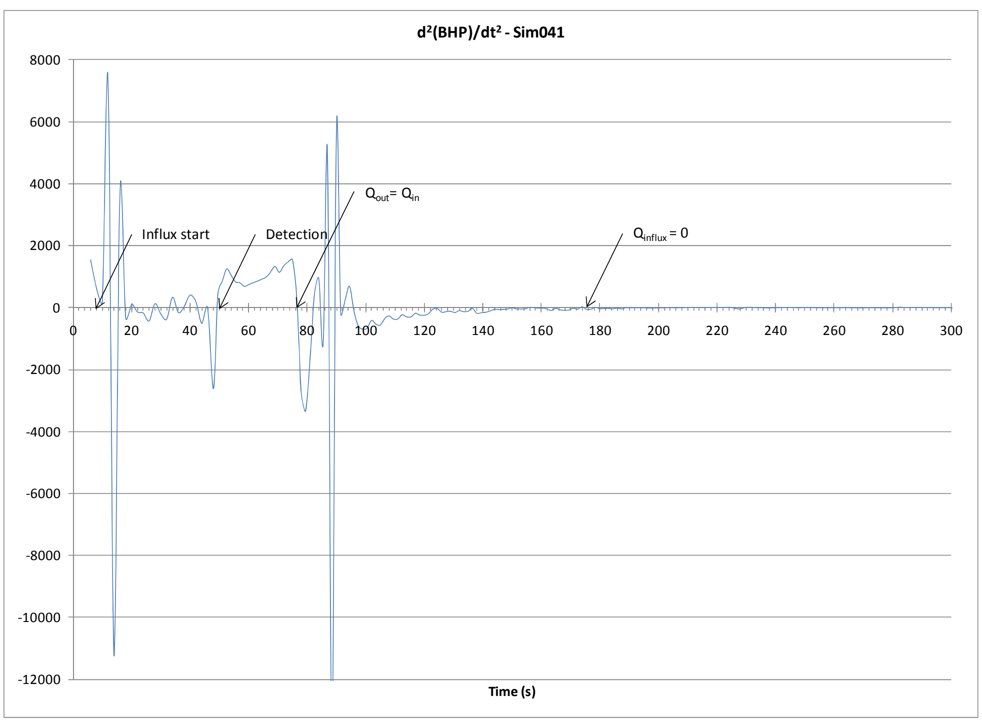

Figure B-3 Second derivative of BHP for simulation 41

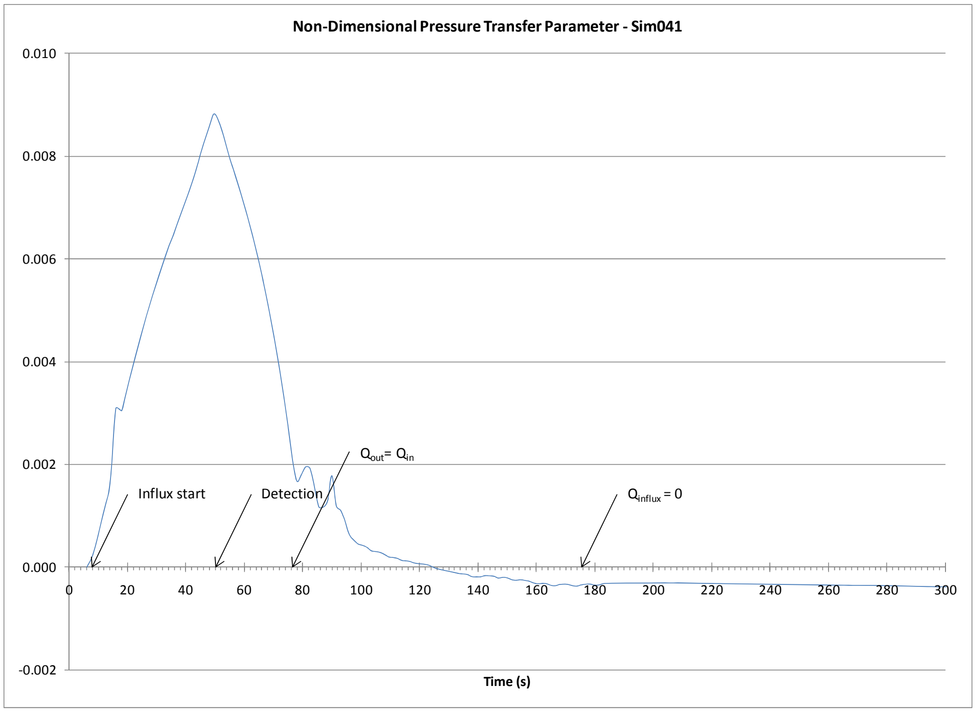

Figure B-4 Non-dimensional pressure transfer parameter for simulation 41

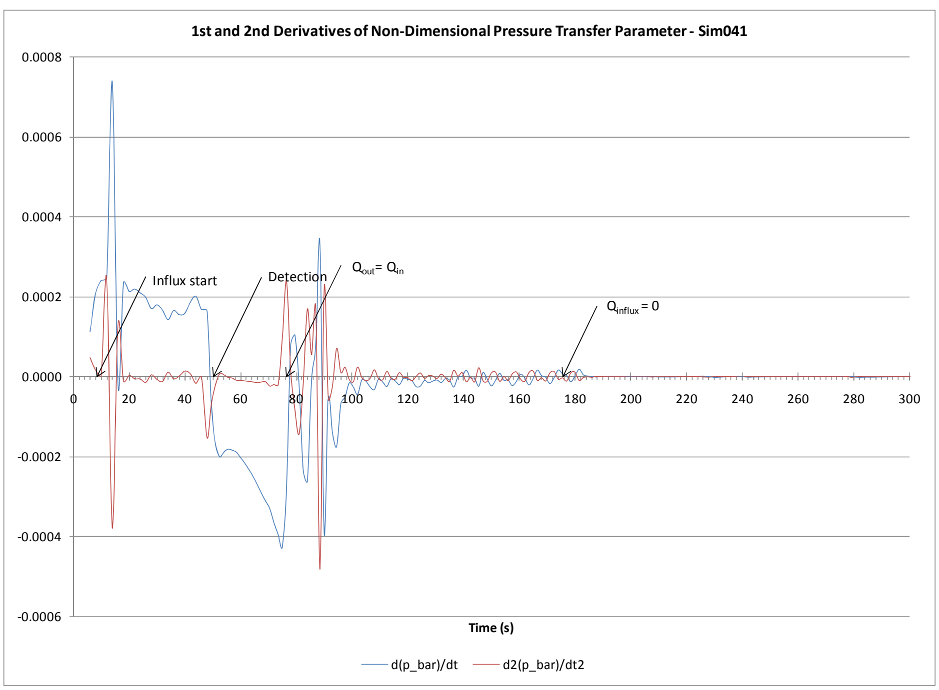

Figure B-5 First and second derivatives of non-dimensional pressure transfer parameter for simulation 41

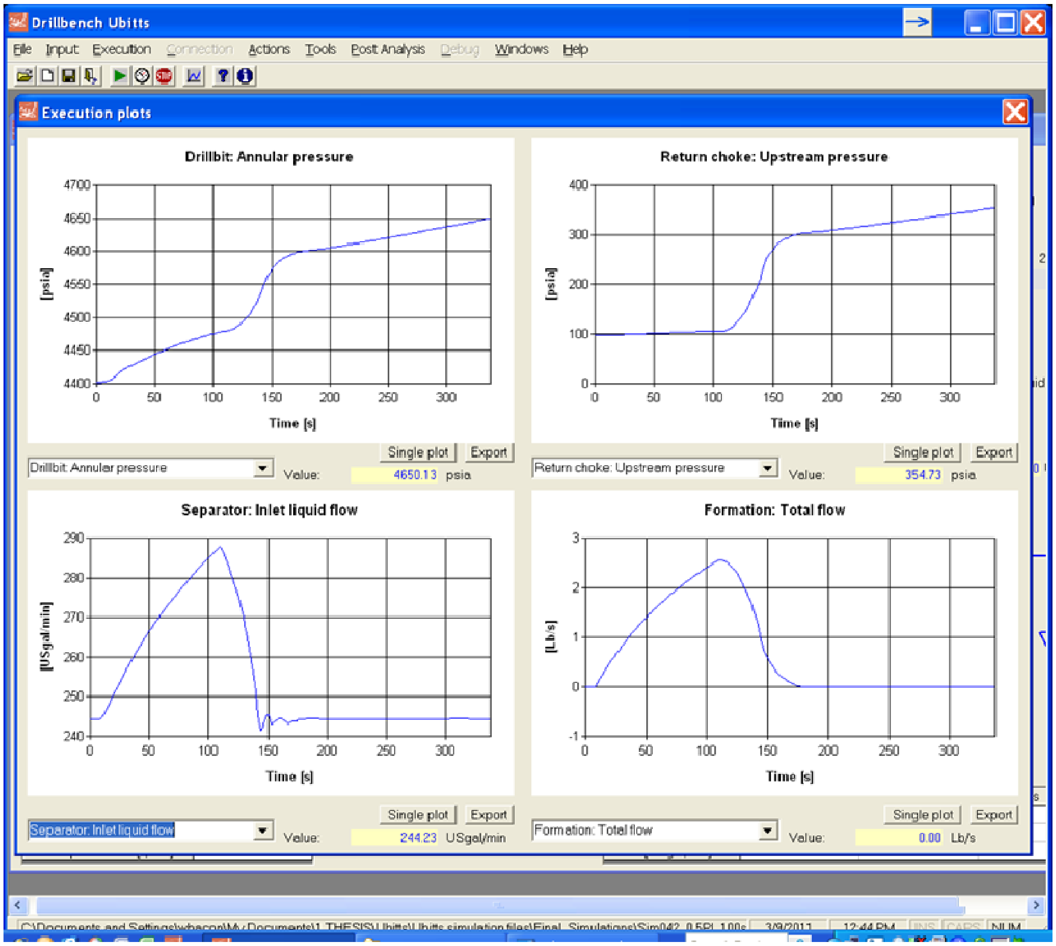

Figure B-6 UbitTS execution plots for simulation 42

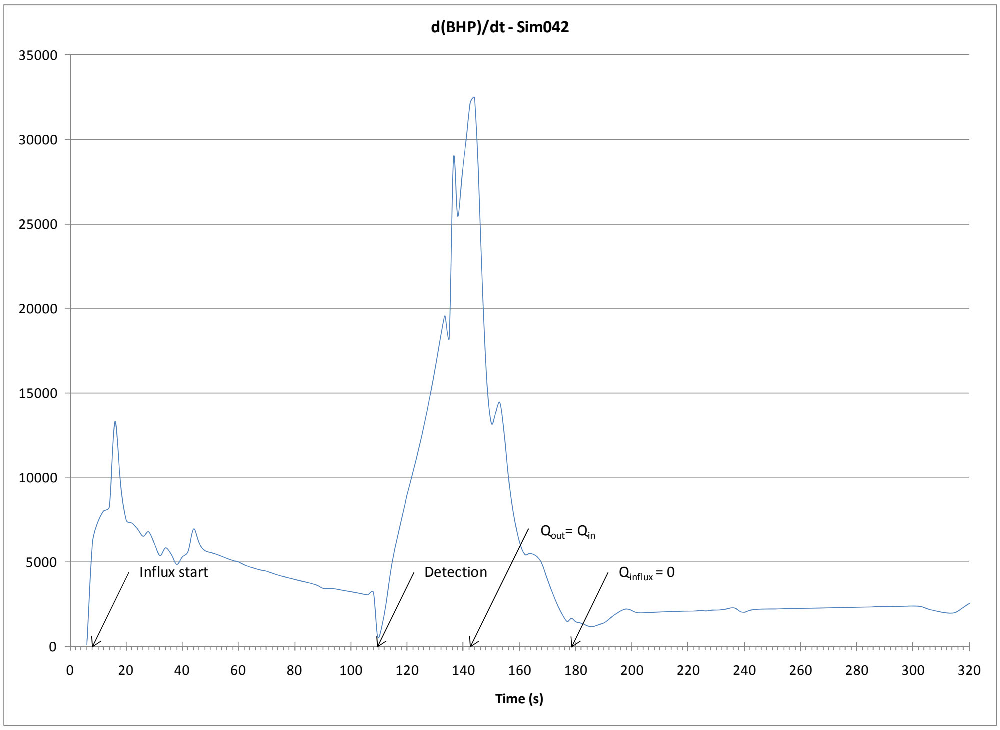

Figure B-7 First derivative of BHP for simulation 42

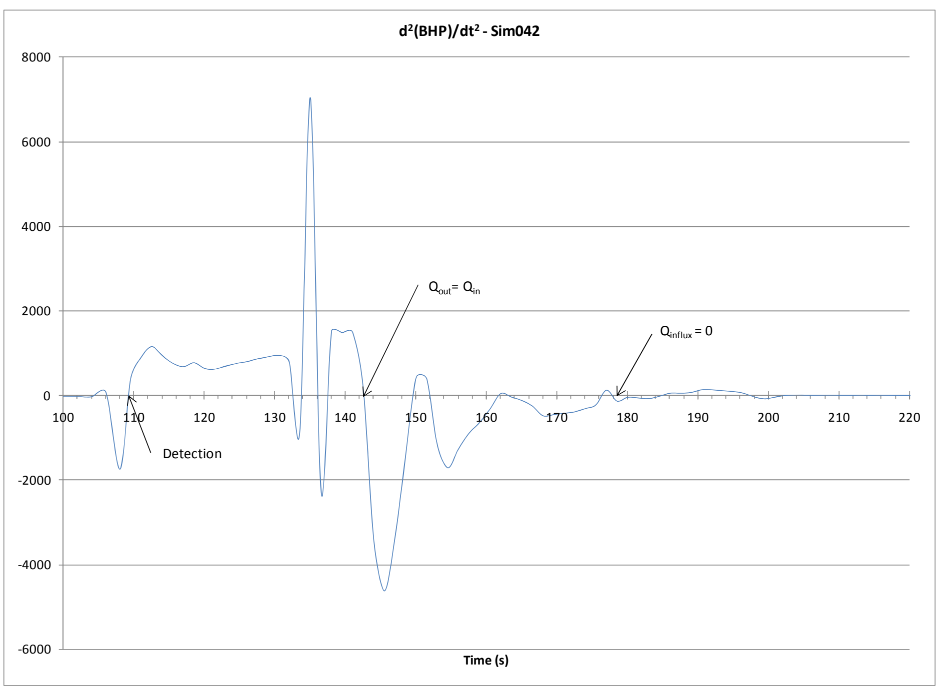

Figure B-8 Second derivative of BHP for simulation 42

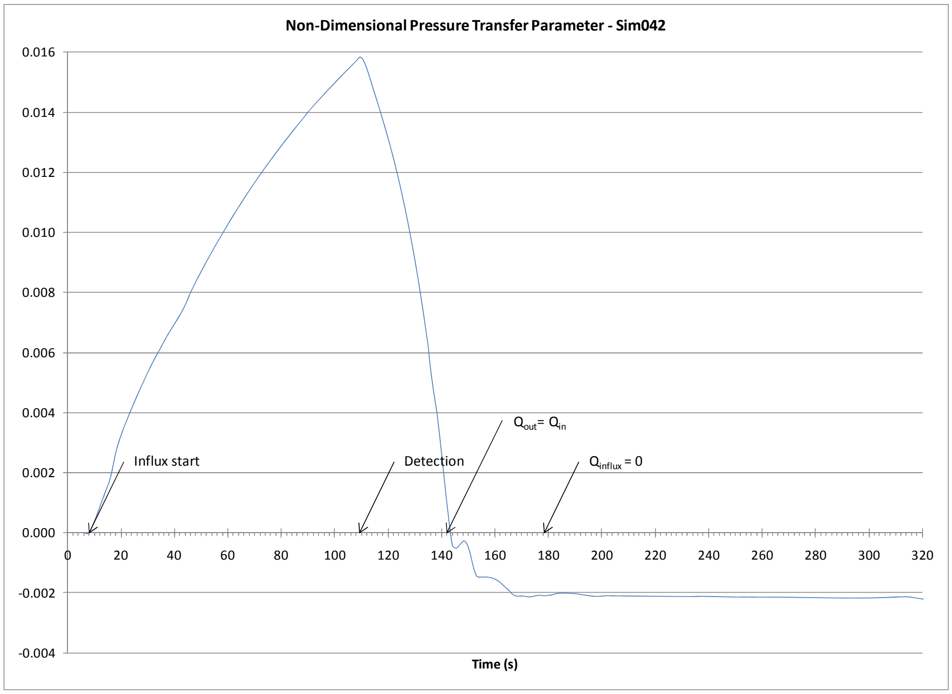

Figure B-9 Non-dimensional pressure transfer parameter for simulation 42

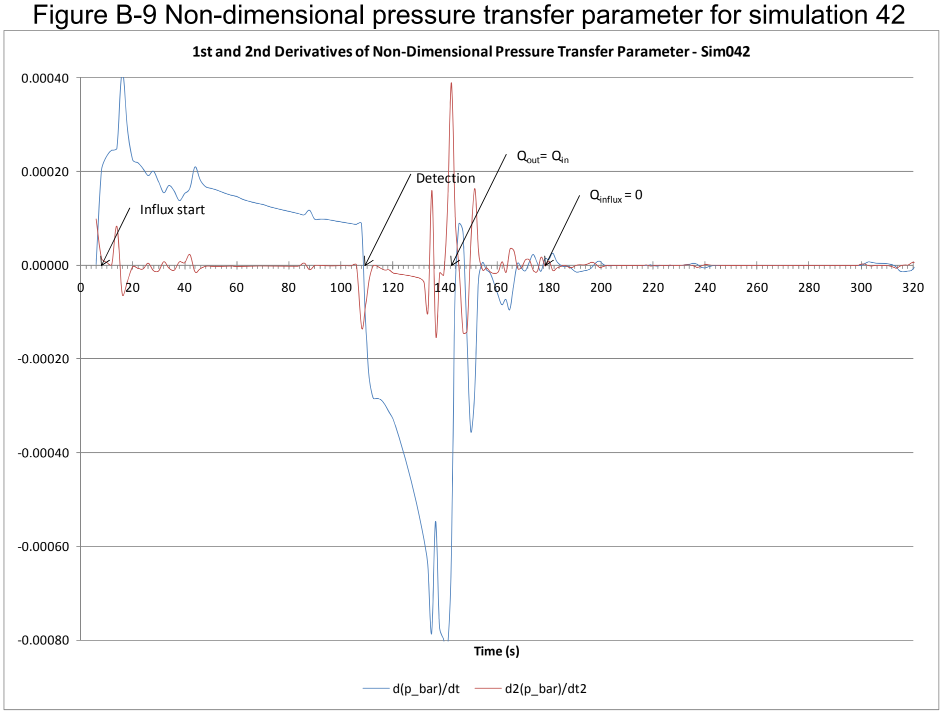

Figure B-10 First and second derivatives of non-dimensional pressure transfer parameter for simulation 42

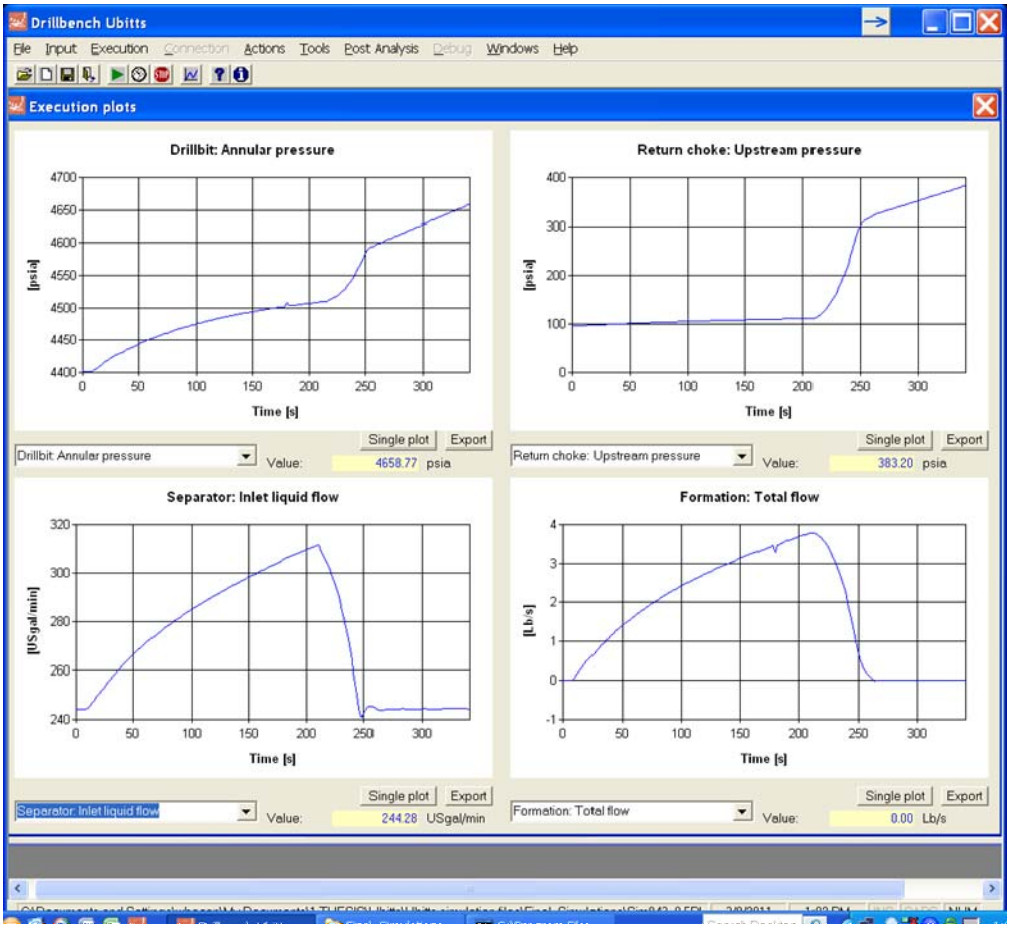

Figure B-11 UbitTS execution plots for simulation 43

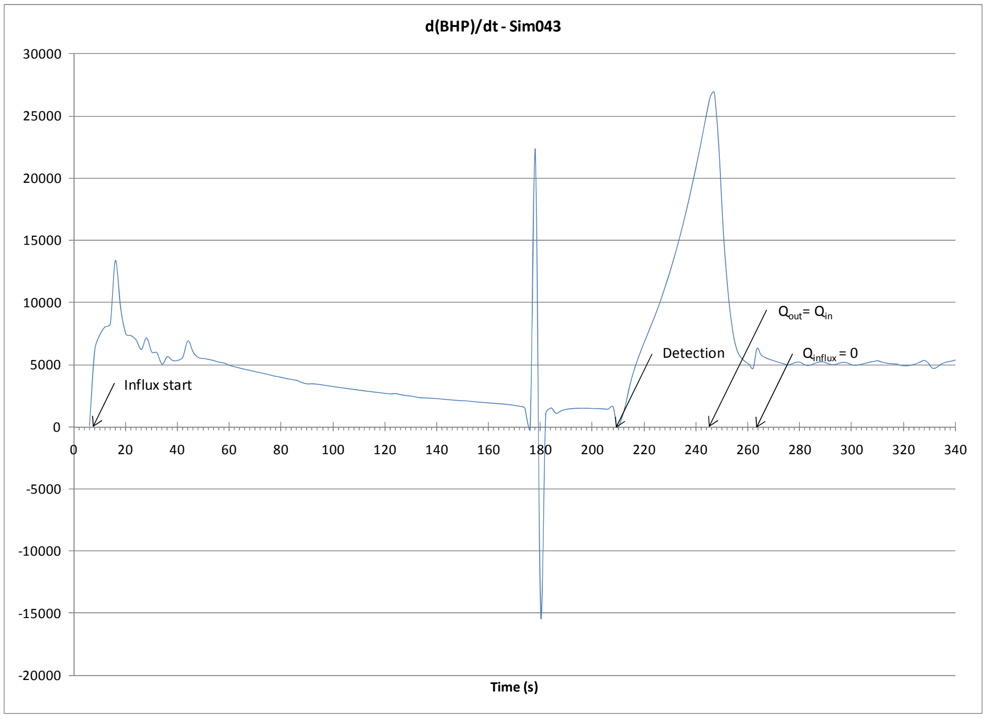

Figure B-12 First derivative of BHP for simulation 43

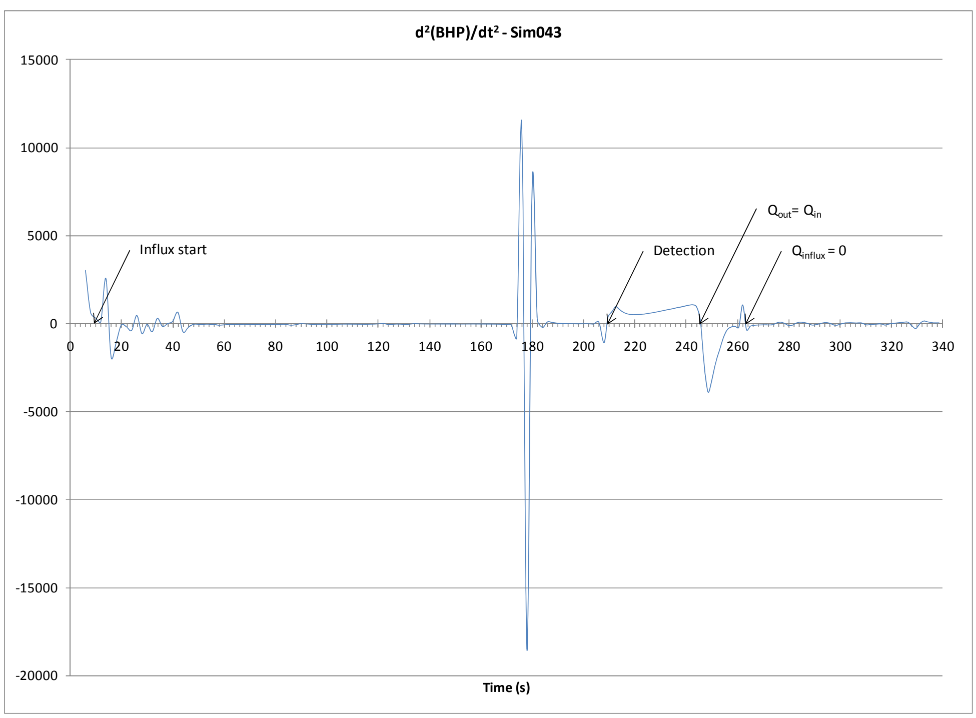

Figure B-13 Second derivative of BHP for simulation 43

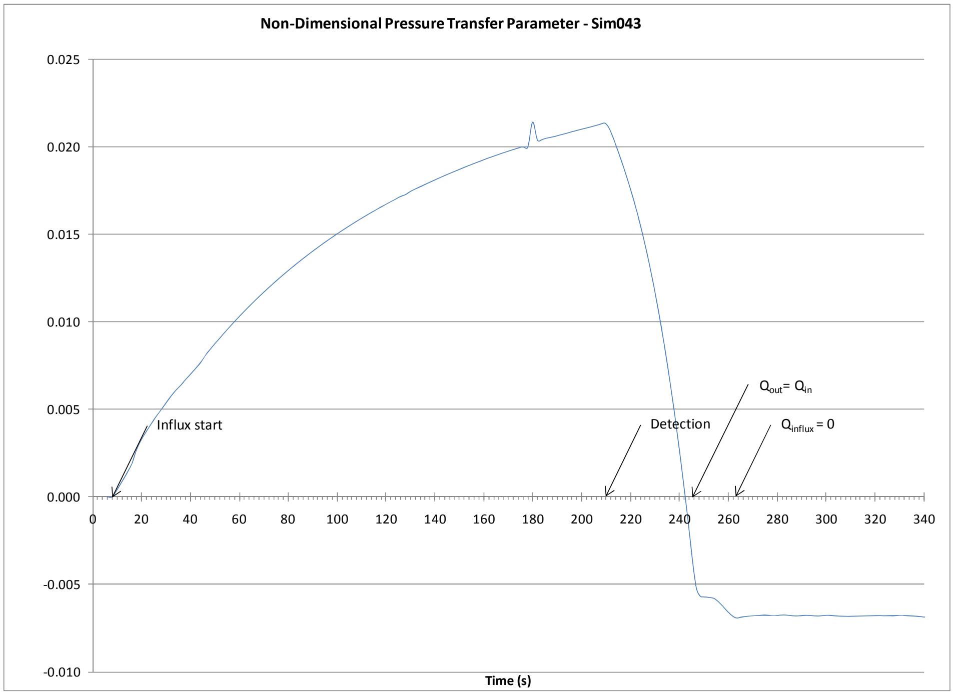

Figure B-14 Non-dimensional pressure transfer parameter for simulation 43

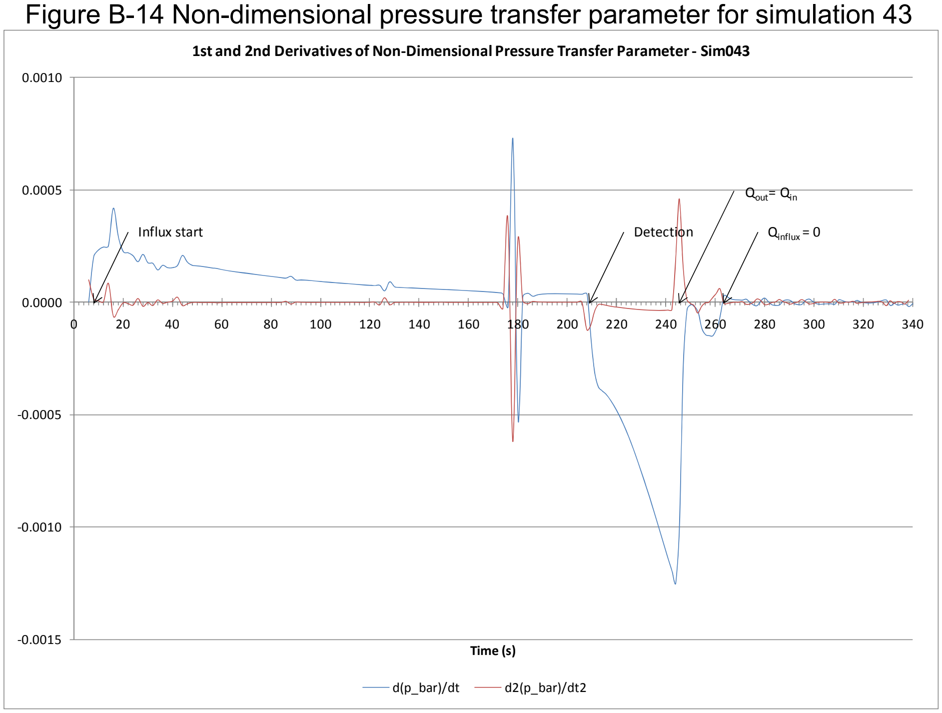

Figure B-15 First and second derivatives of non-dimensional pressure transfer parameter for simulation 43

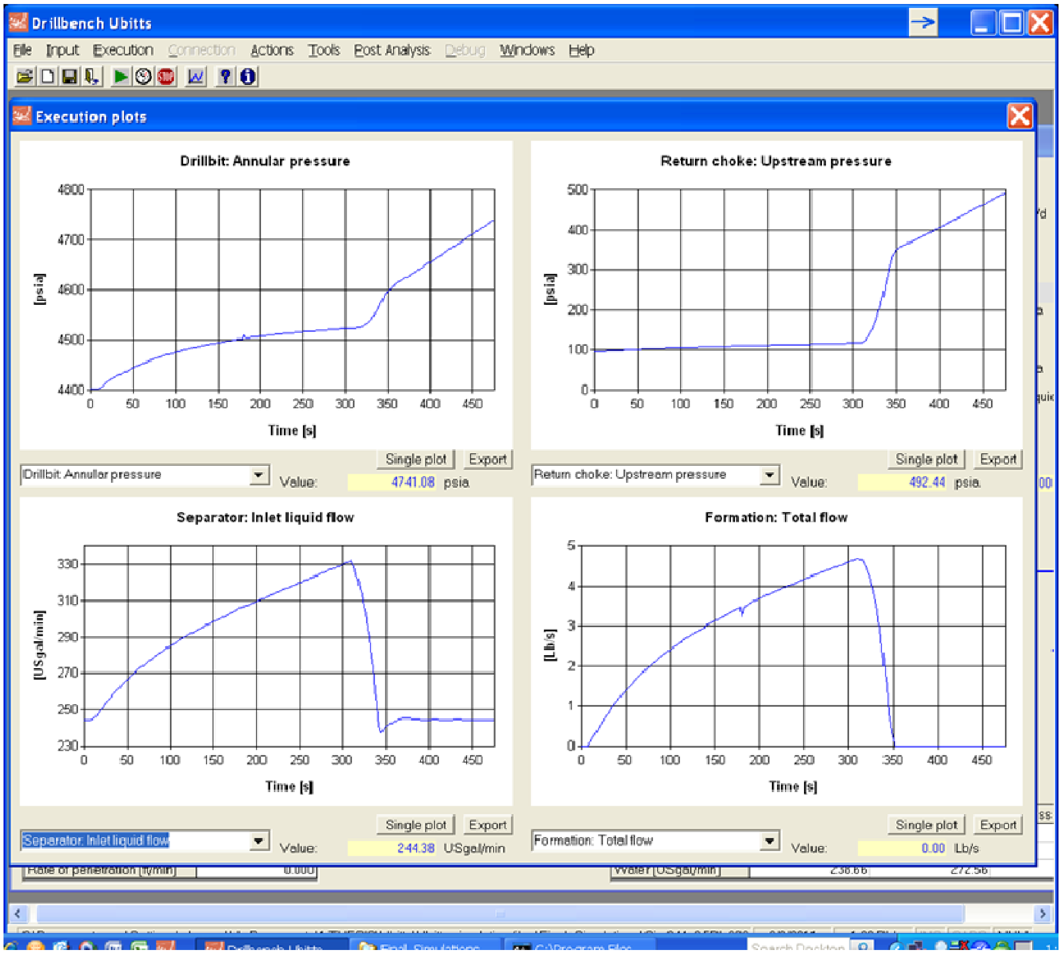

Figure B-16 UbitTS execution plots for simulation 44

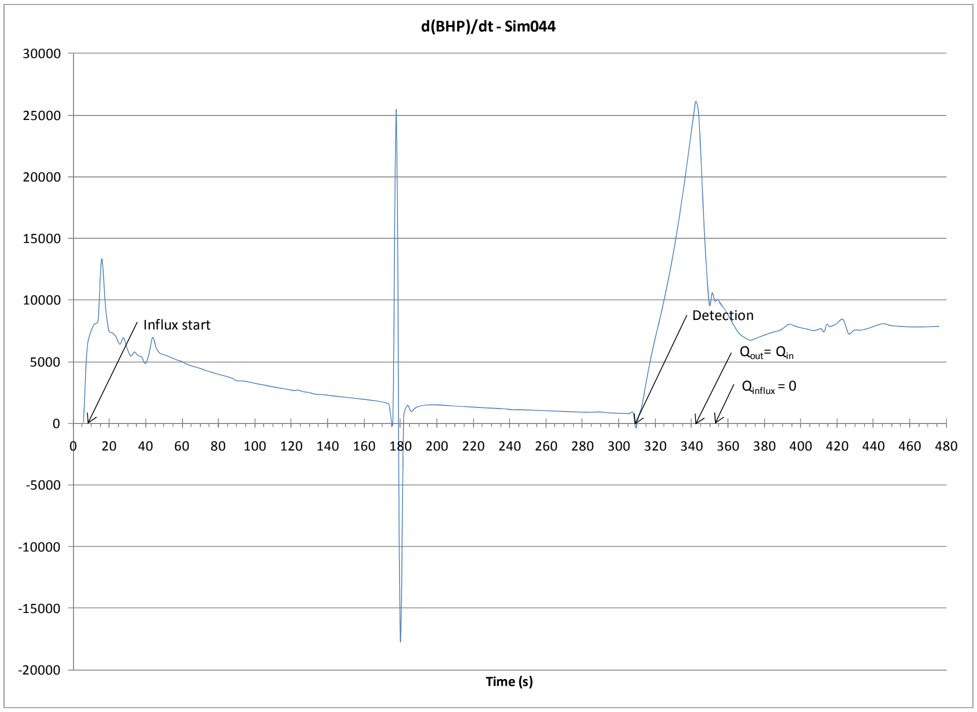

Figure B-17 First derivative of BHP for simulation 44

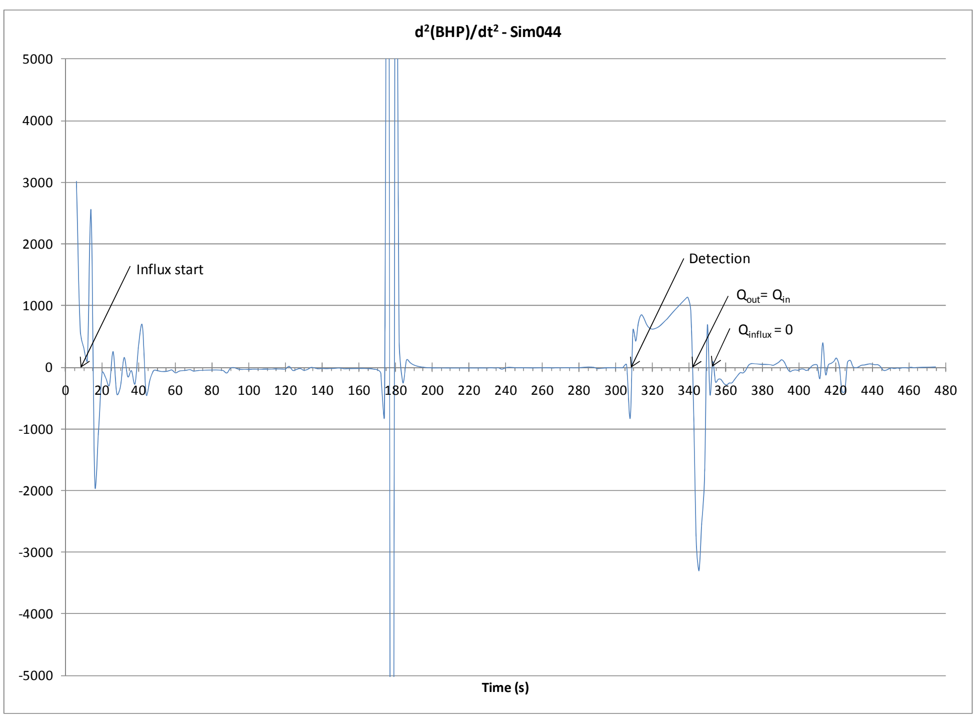

Figure B-18 Second derivative of BHP for simulation 44

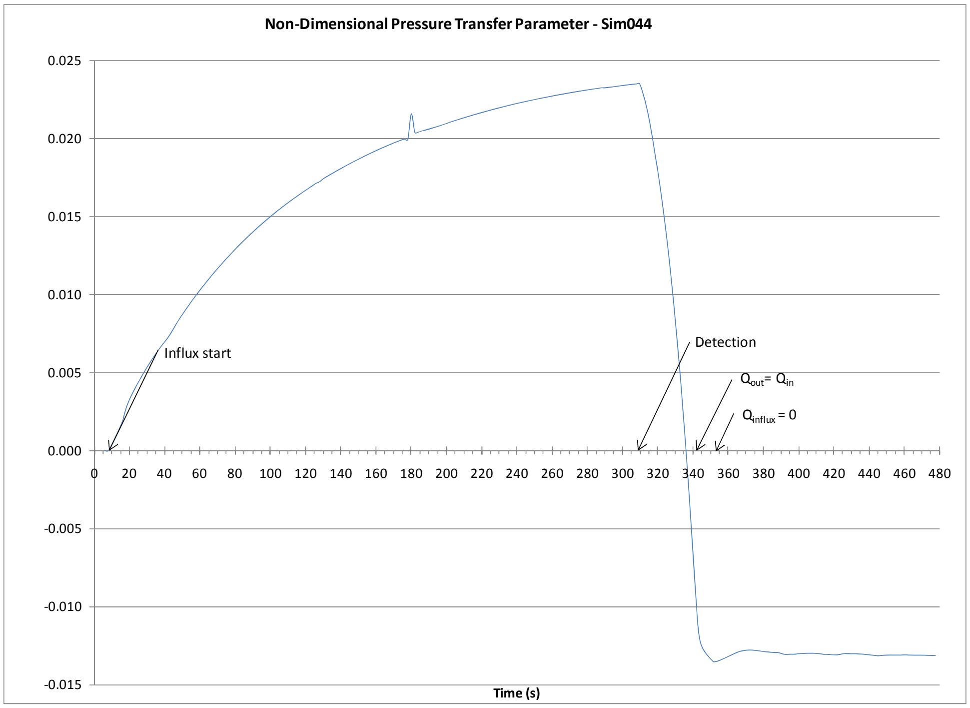

Figure B-19 Non-dimensional pressure transfer parameter for simulation 44

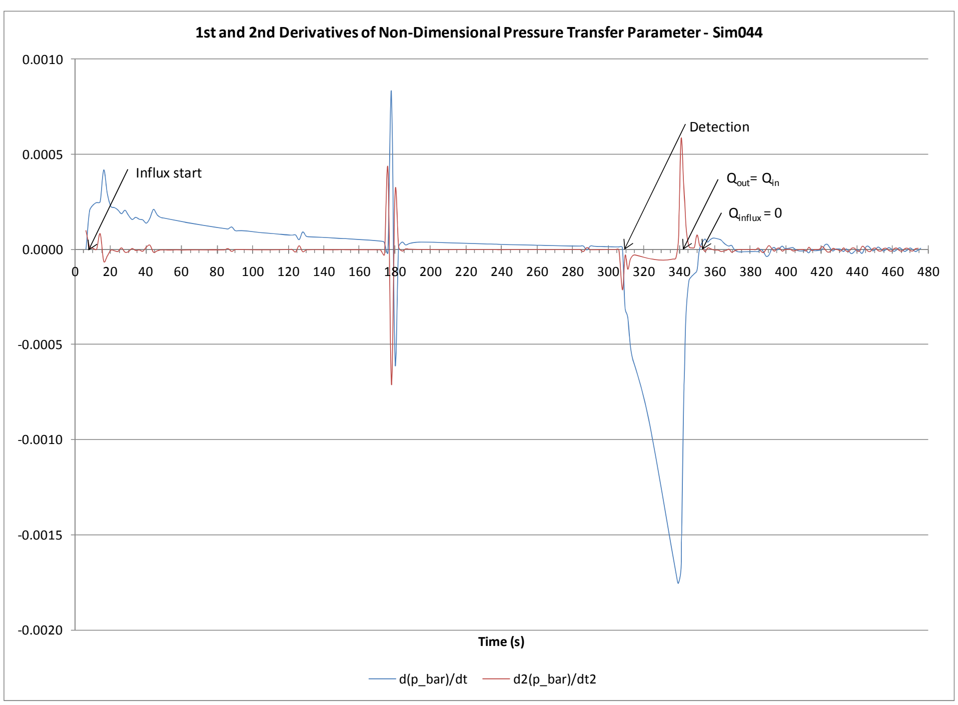

Figure B-20 First and second derivatives of non-dimensional pressure transfer parameter for simulation 44

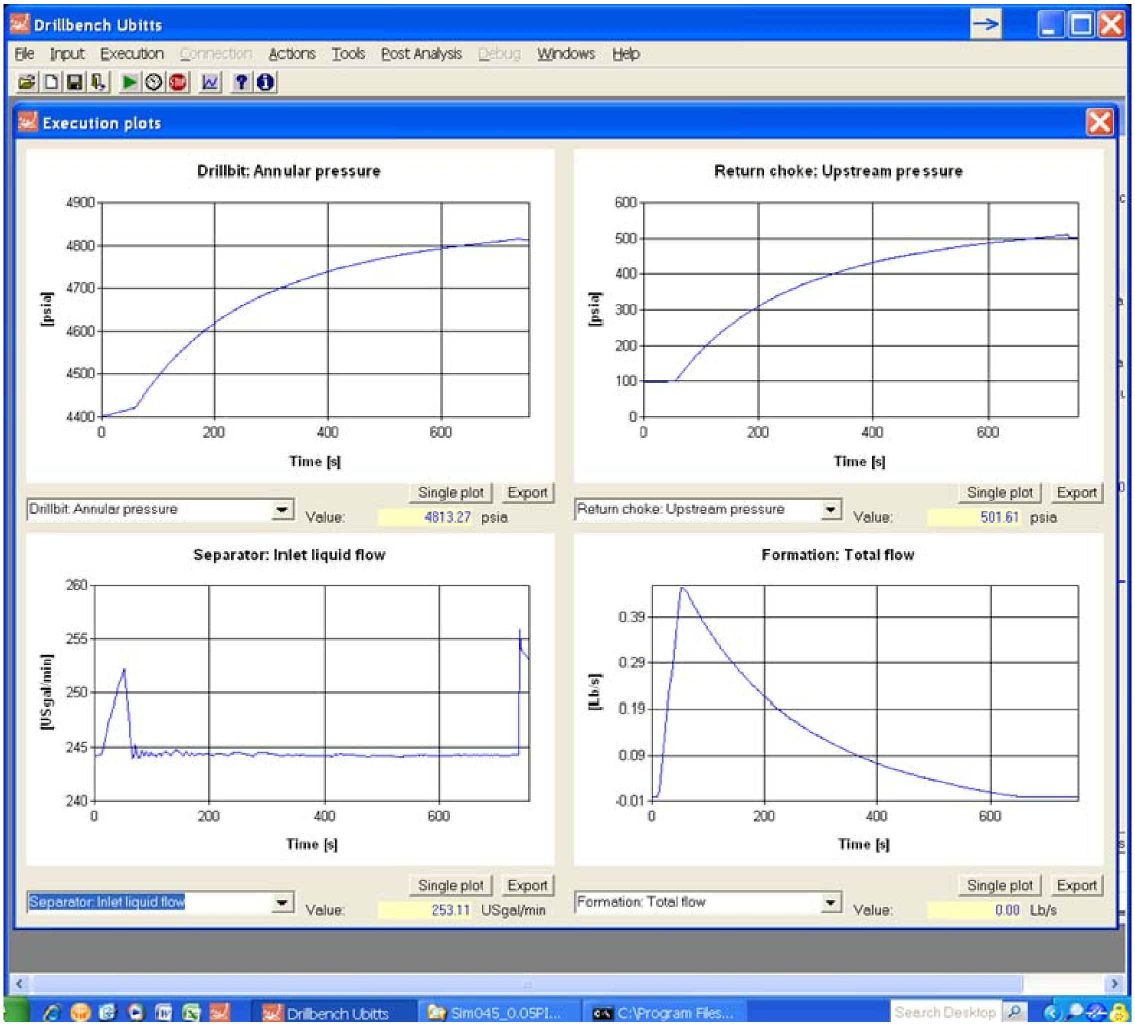

Figure B-21 UbitTS execution plots for simulation 45

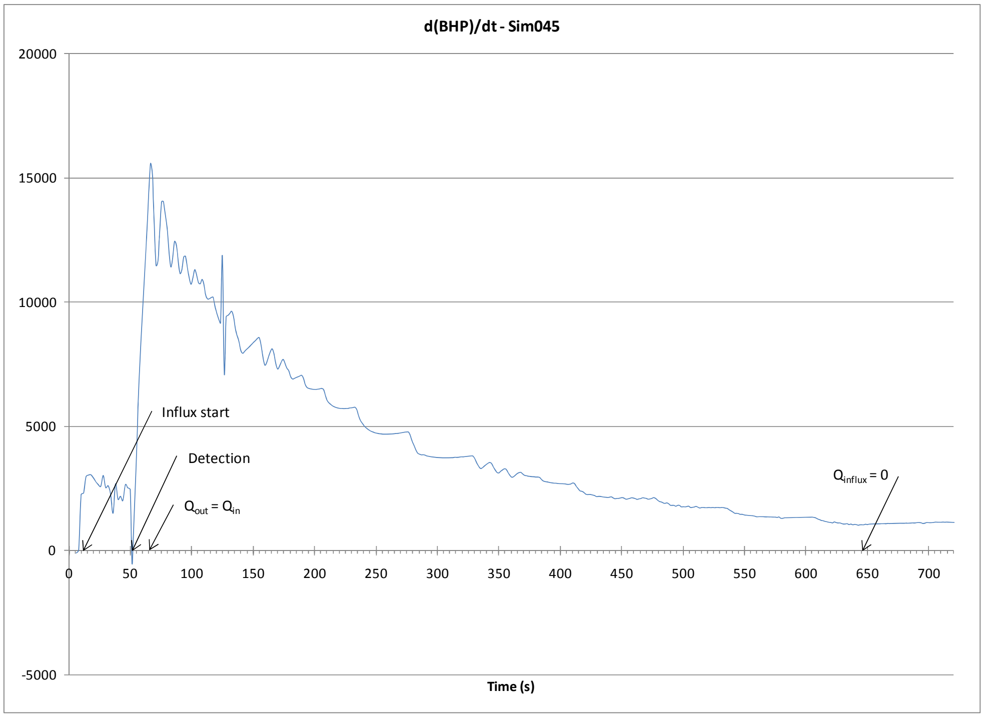

Figure B-22 First derivative of BHP for simulation 45

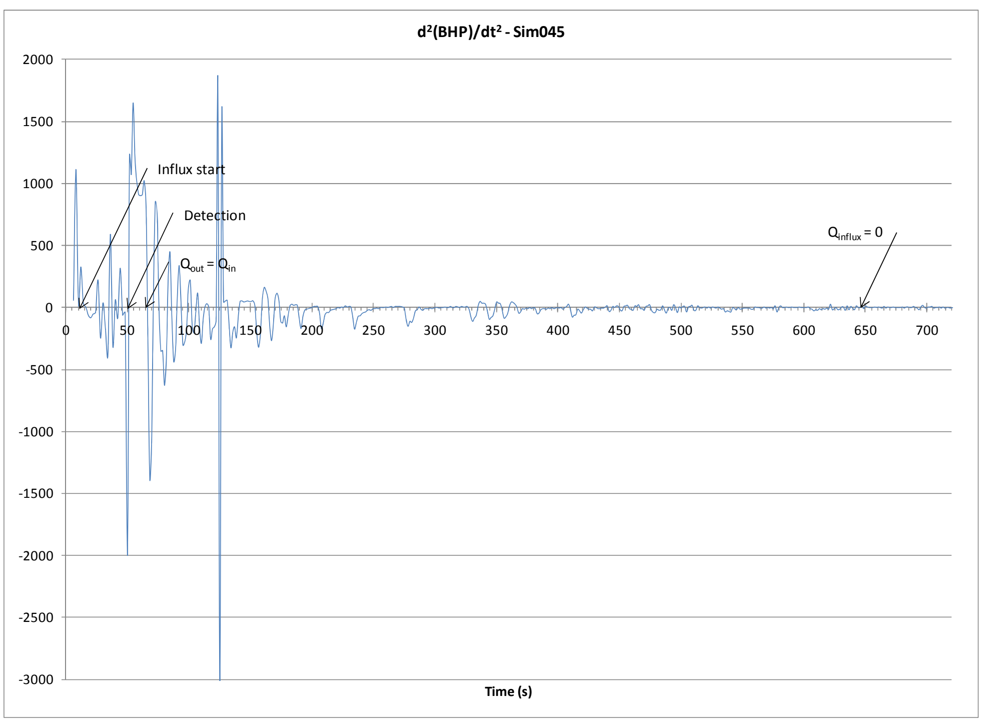

Figure B-23 Second derivative of BHP for simulation 45

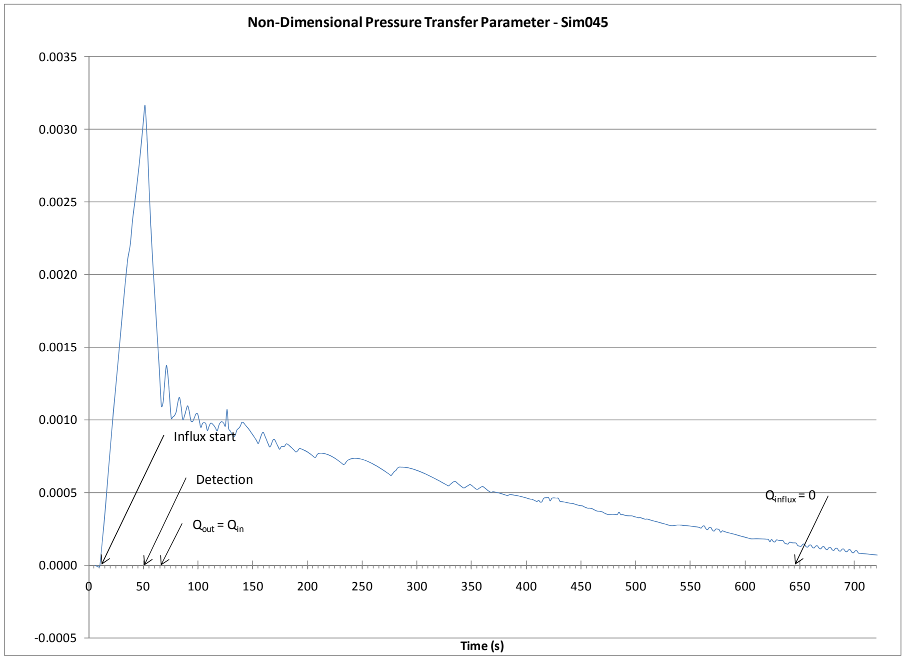

Figure B-24 Non-dimensional pressure transfer parameter for simulation 45

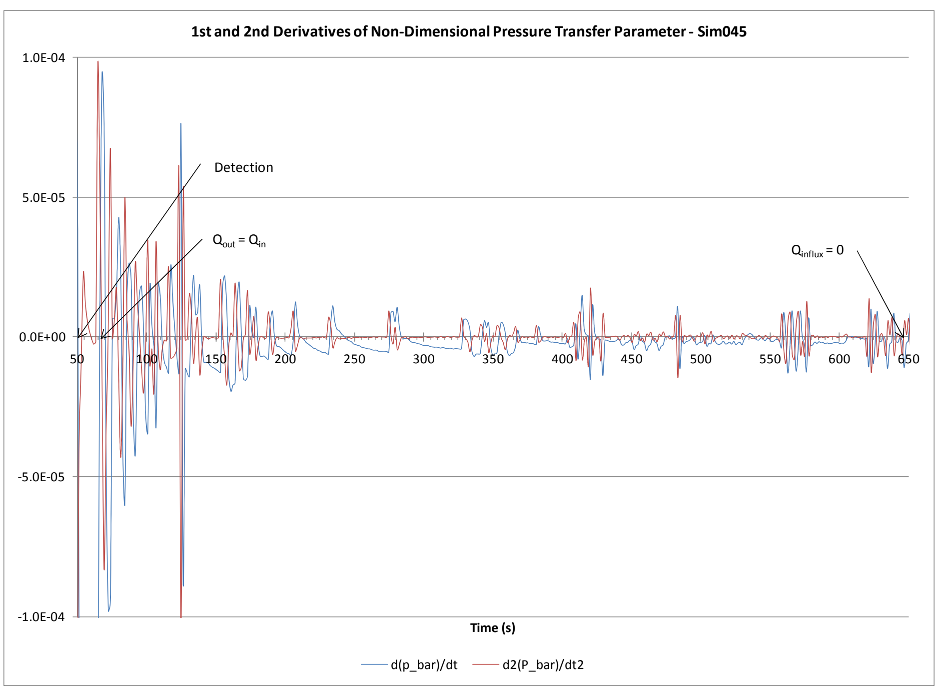

Figure B-25 First and second derivatives of non-dimensional pressure transfer parameter for simulation 45

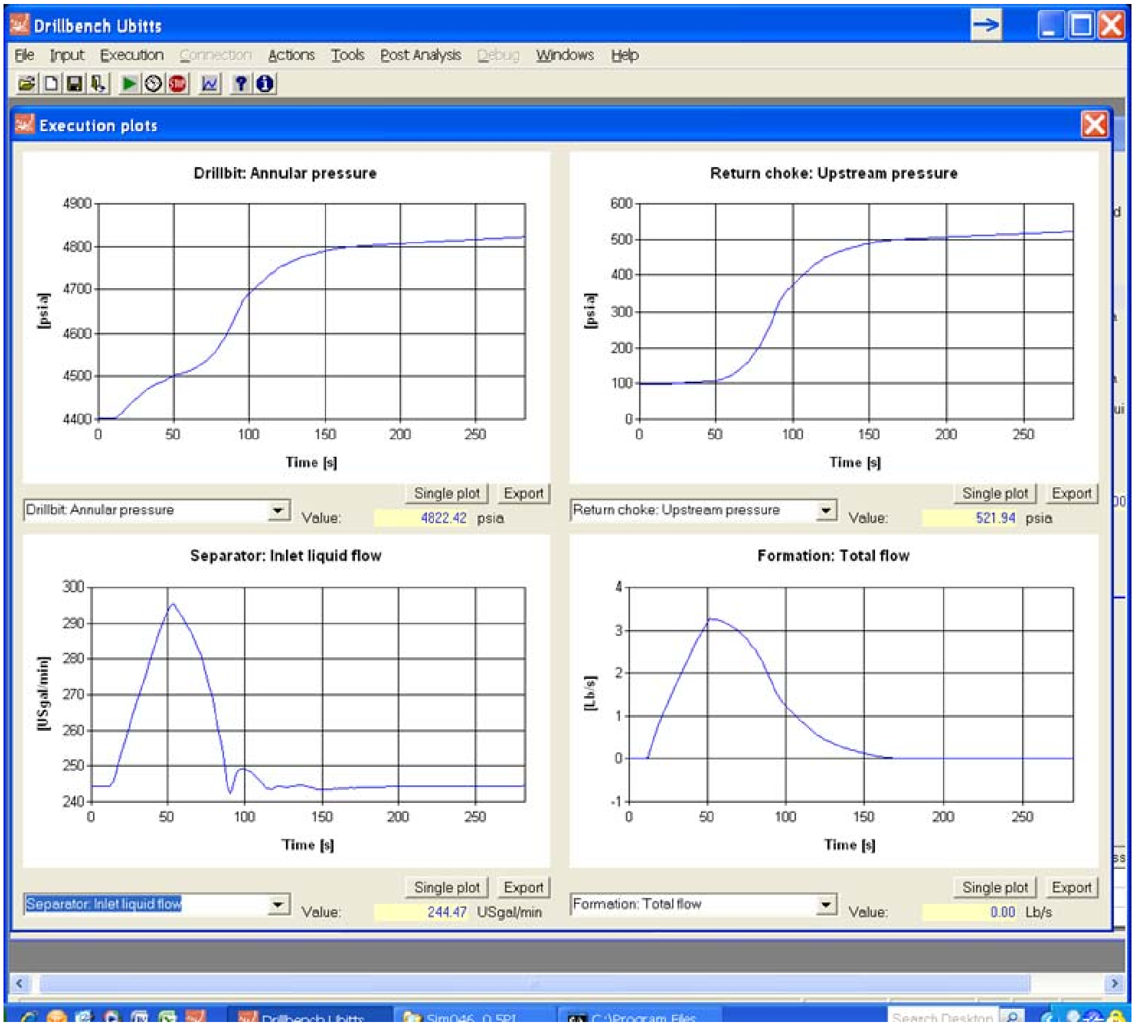

Figure B-26 UbitTS execution plots for simulation 46

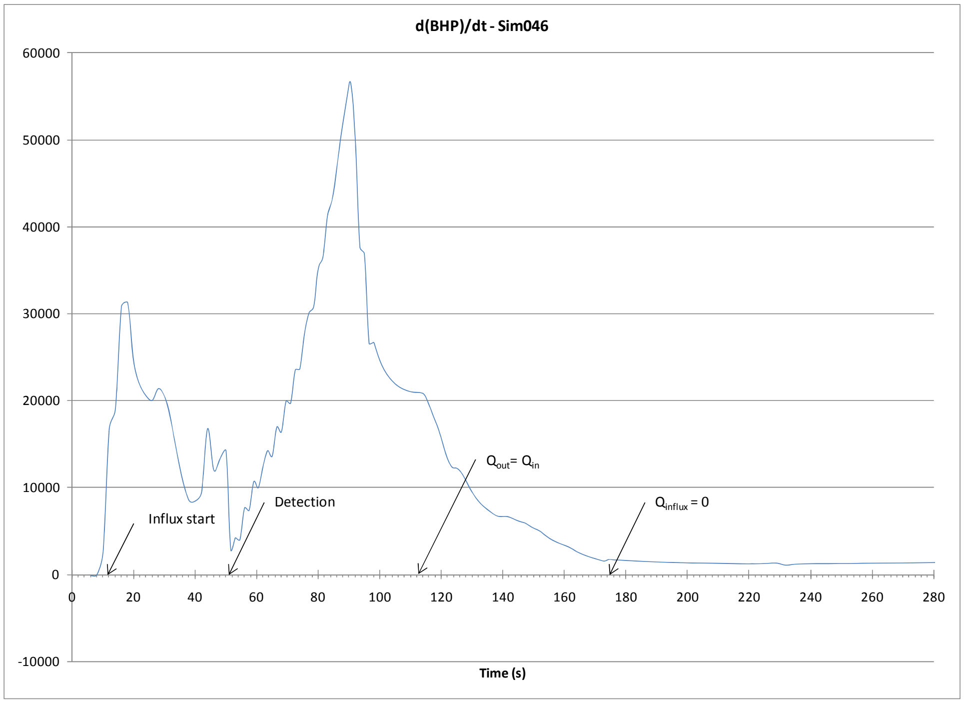

Figure B-27 First derivative of BHP for simulation 46

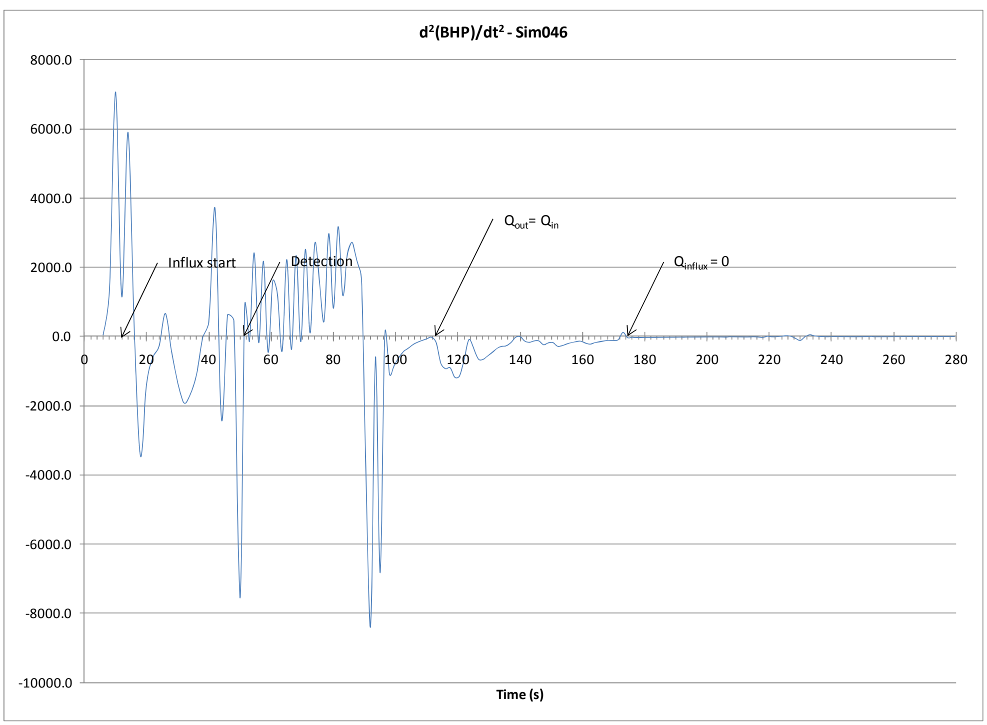

Figure B-28 Second derivative of BHP for simulation 46

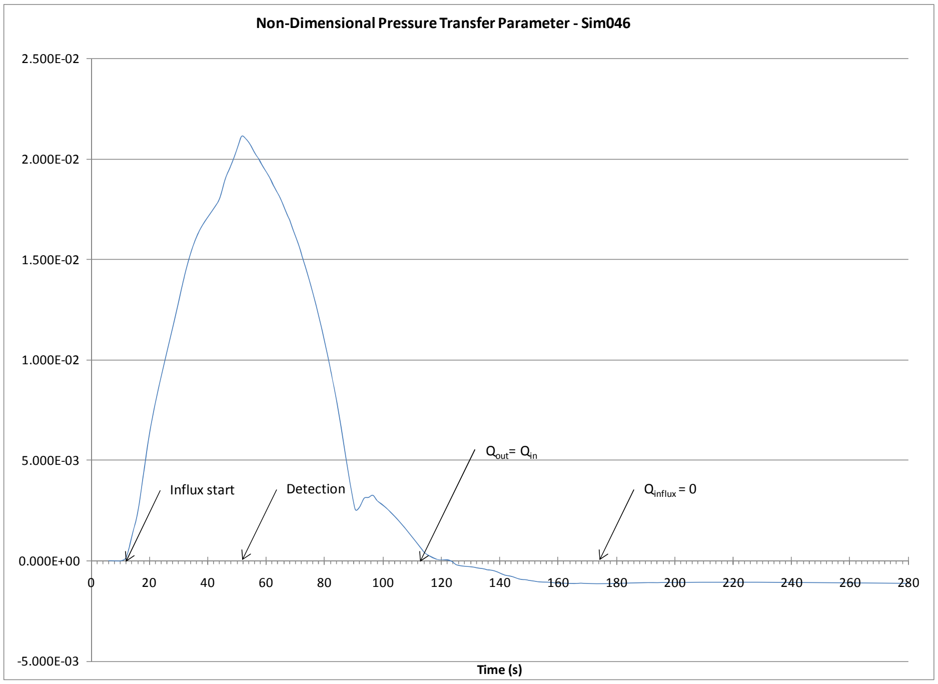

Figure B-29 Non-dimensional pressure transfer parameter for simulation 46

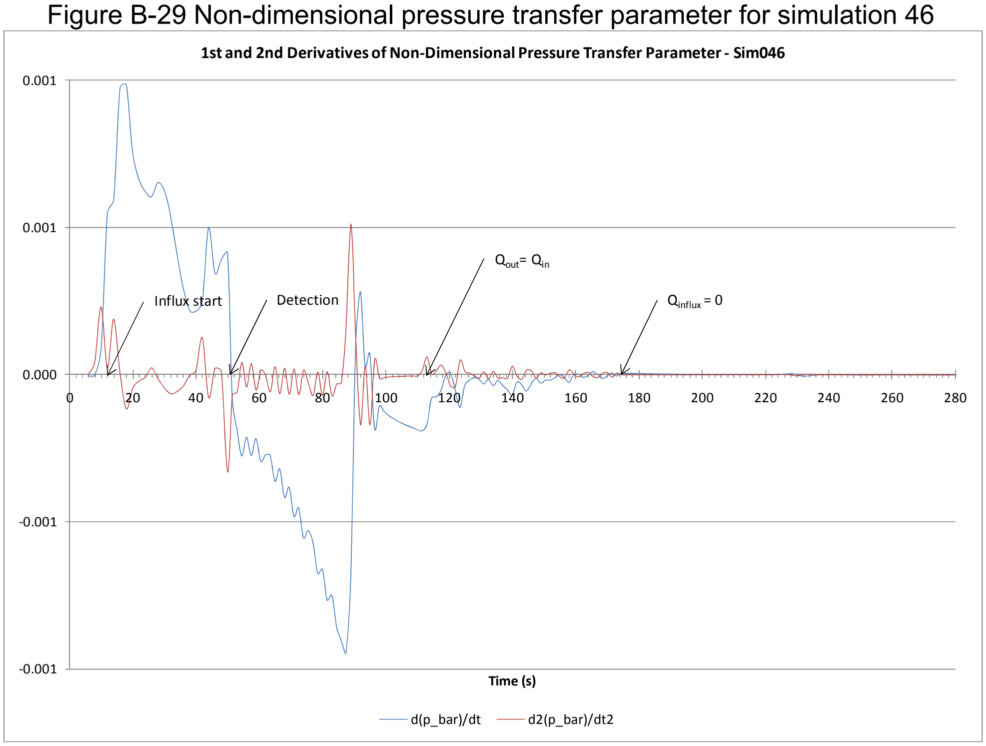

Figure B-30 First and second derivatives of non-dimensional pressure transfer parameter for simulation 46

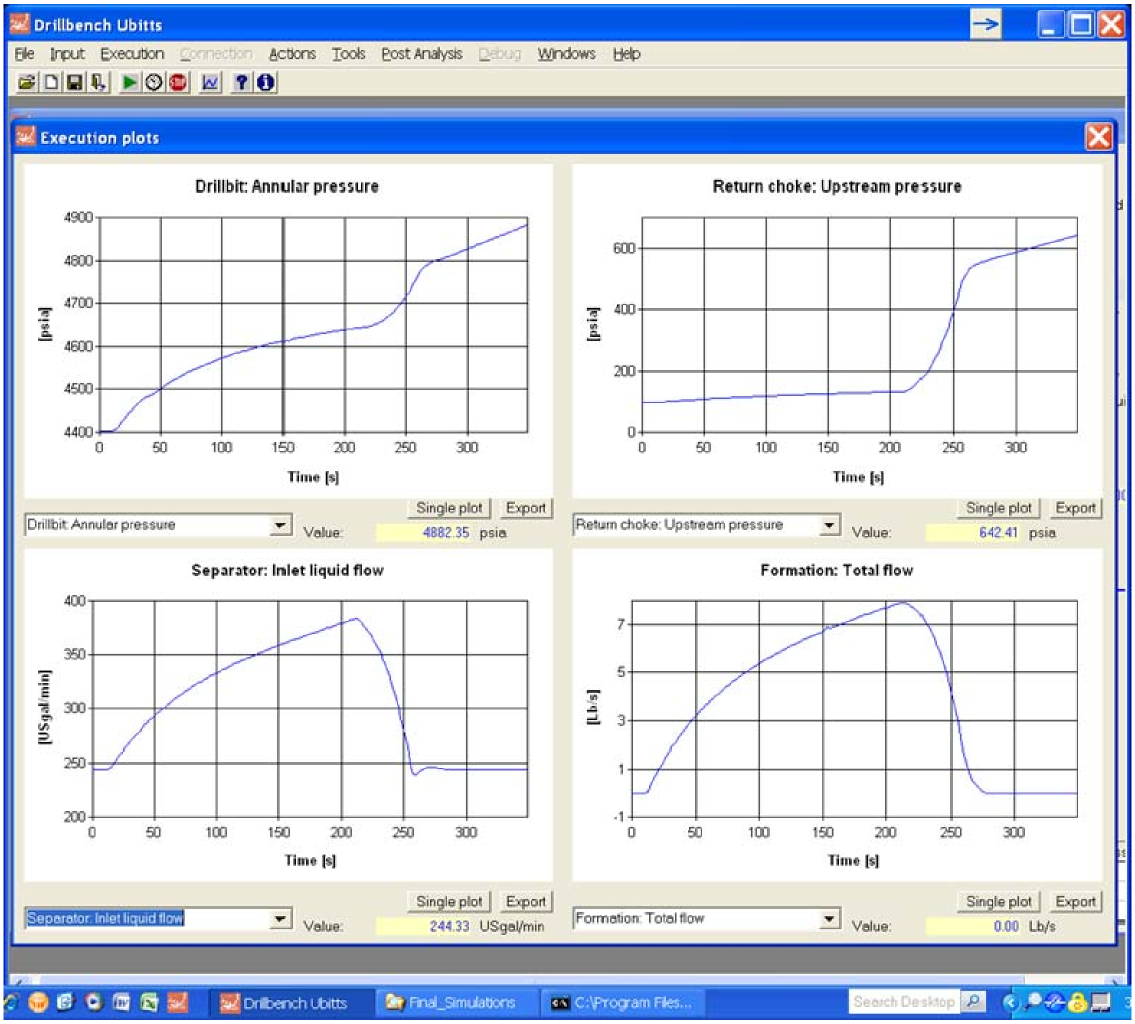

Figure B-31 UbitTS execution plots for simulation 47

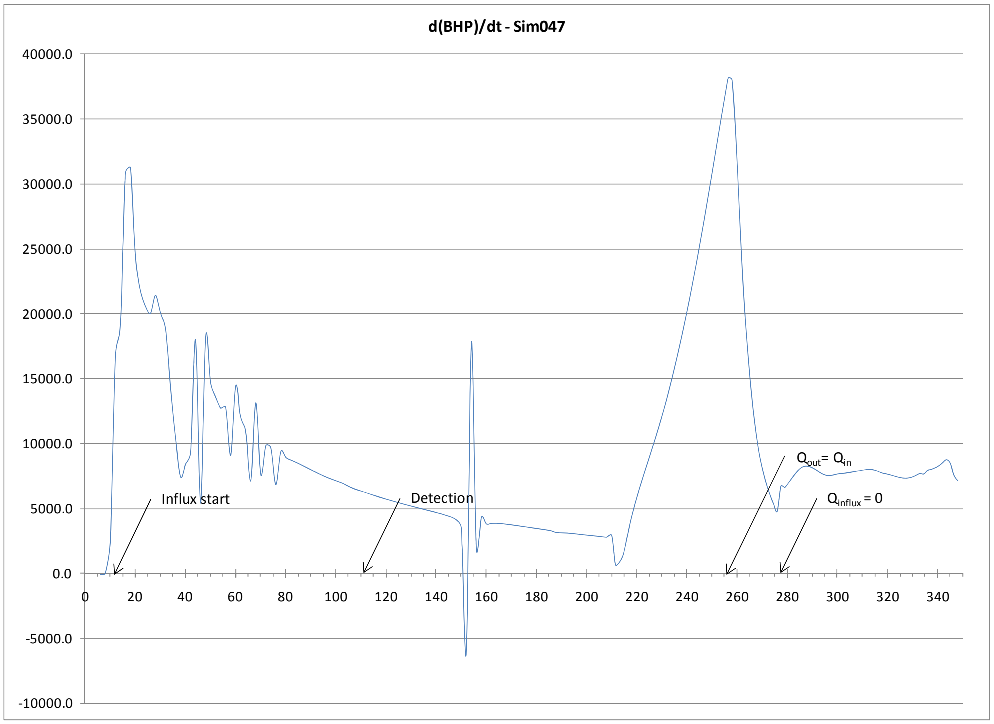

Figure B-32 First derivative of BHP for simulation 47

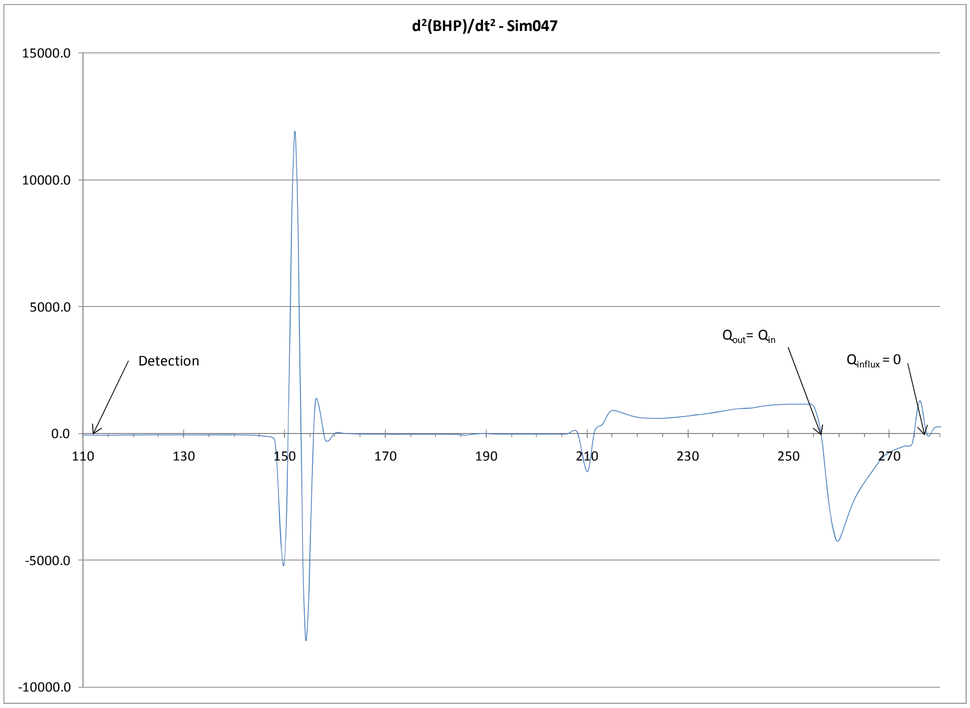

Figure B-33 Second derivative of BHP for simulation 47

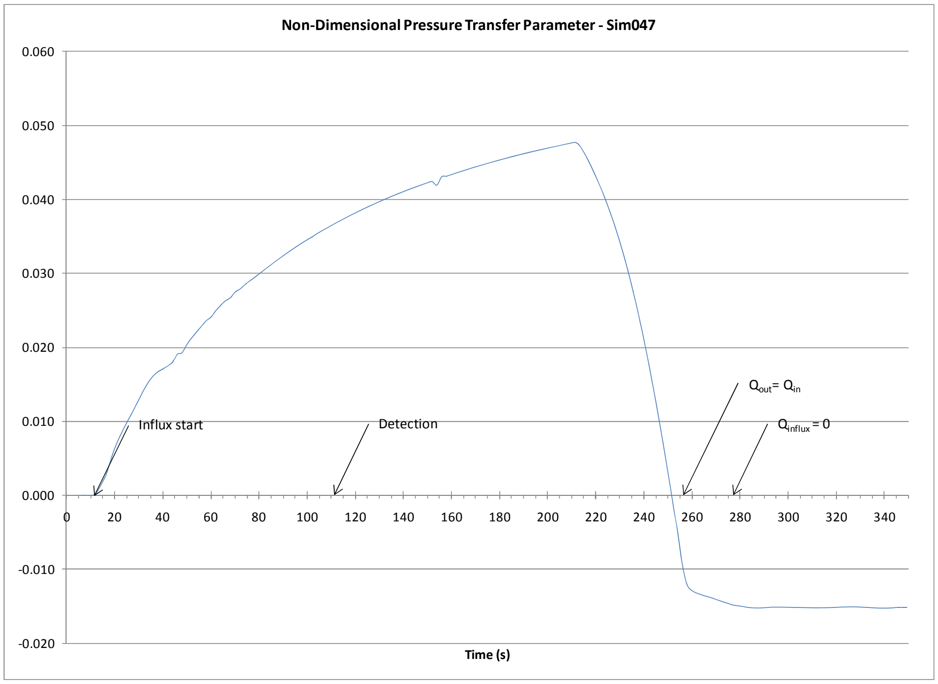

Figure B-34 Non-dimensional pressure transfer parameter for simulation 47

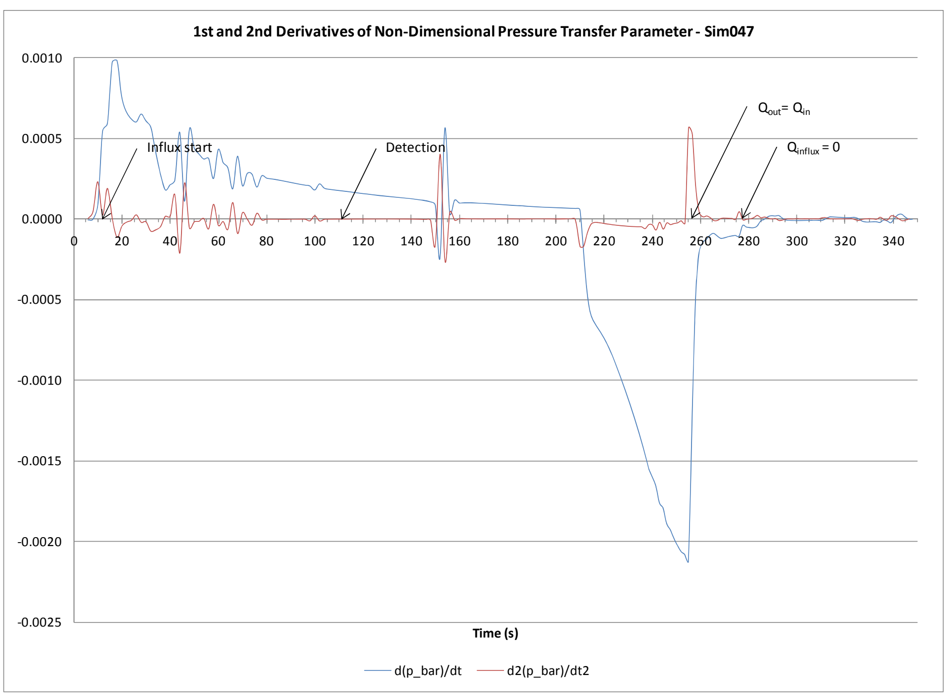

Figure B-35 First and second derivatives of non-dimensional pressure transfer parameter for simulation 47

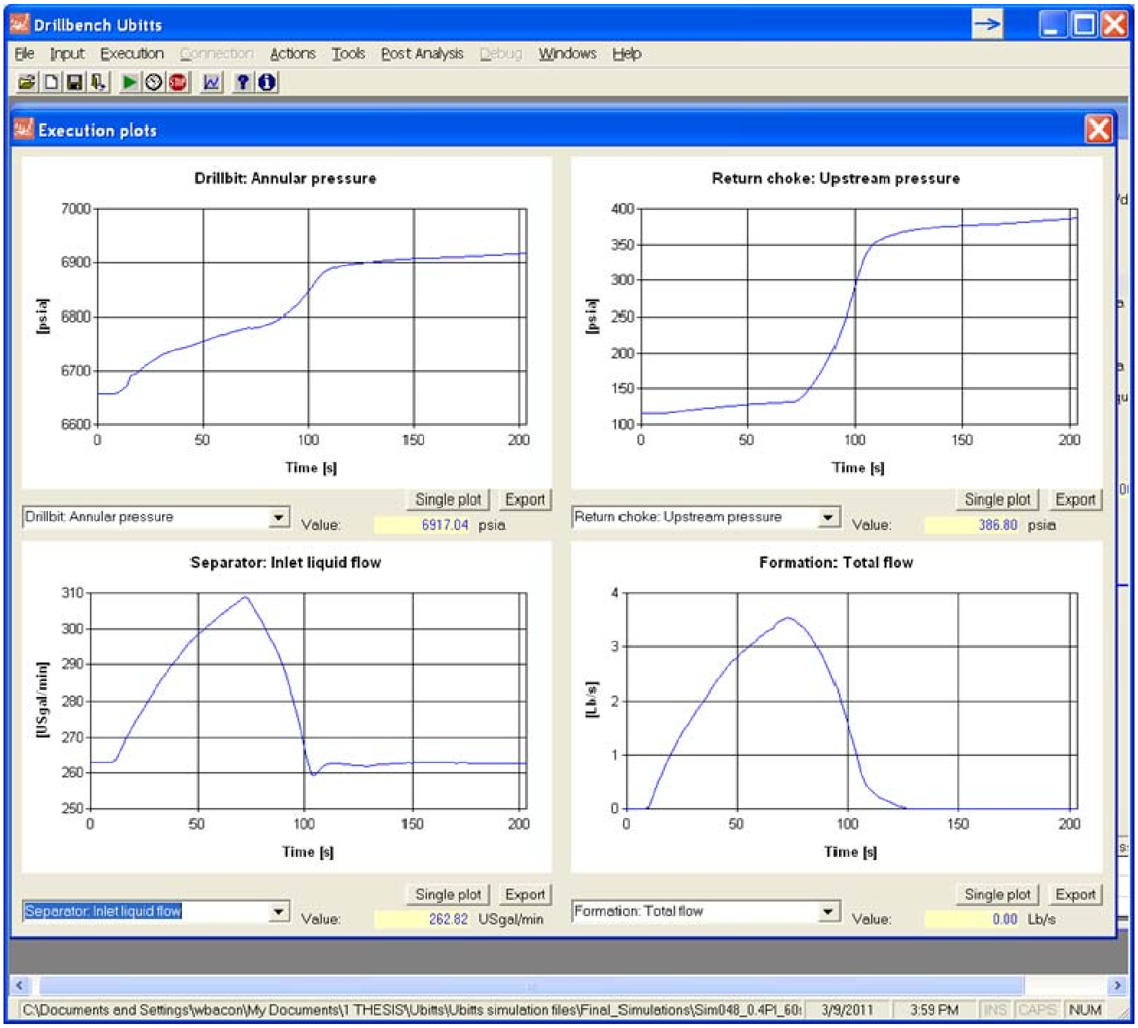

Figure B-36 UbitTS execution plots for simulation 48

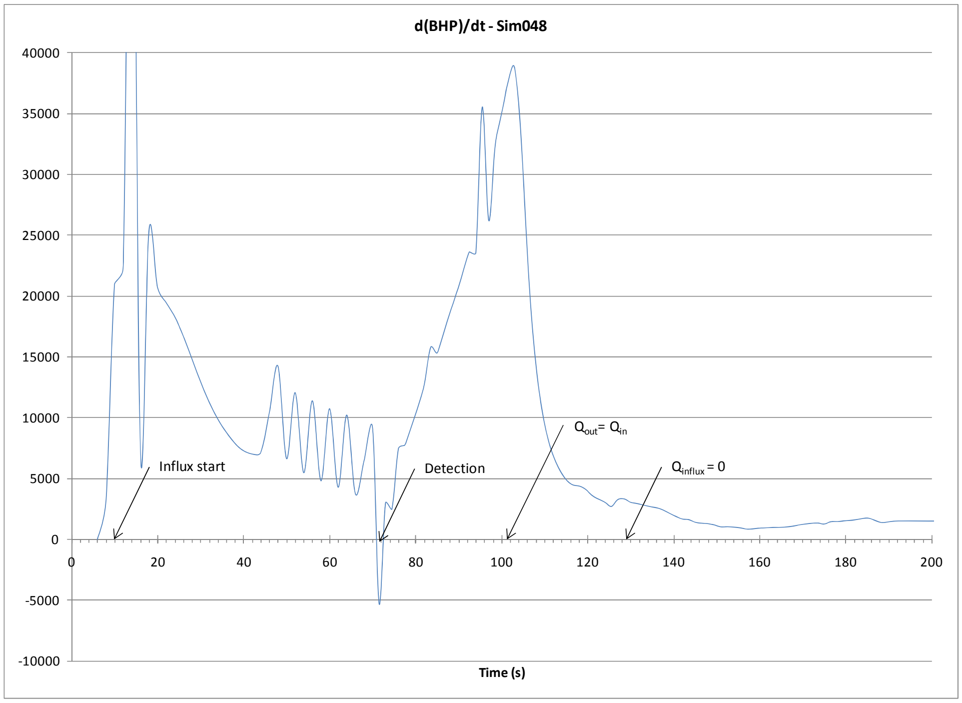

Figure B-37 First derivative of BHP for simulation 48

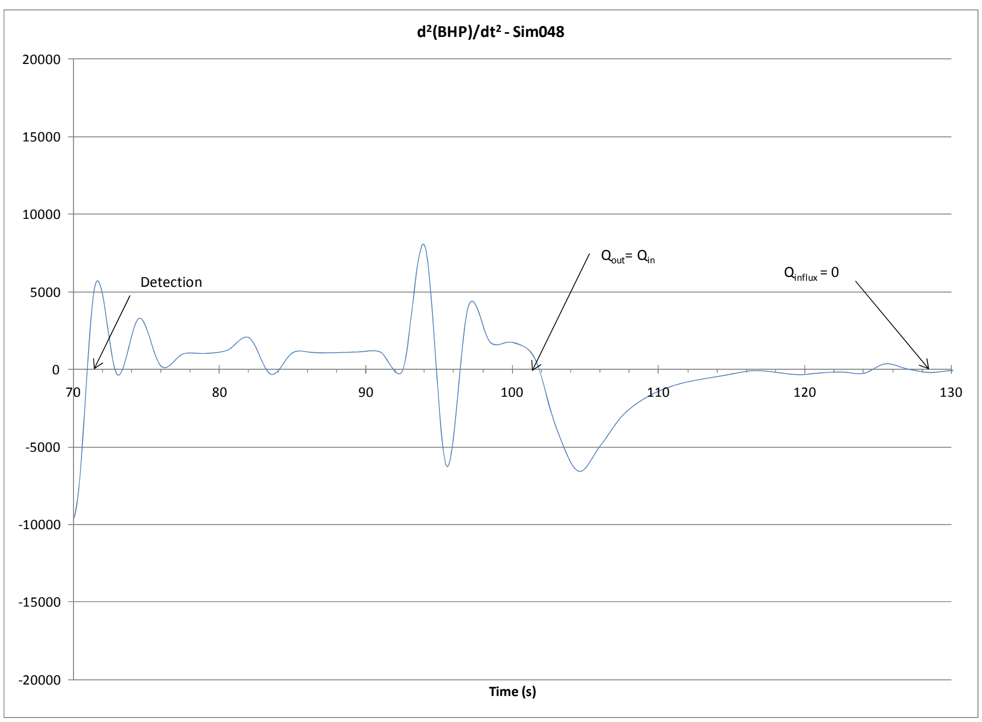

Figure B-38 Second derivative of BHP for simulation 48

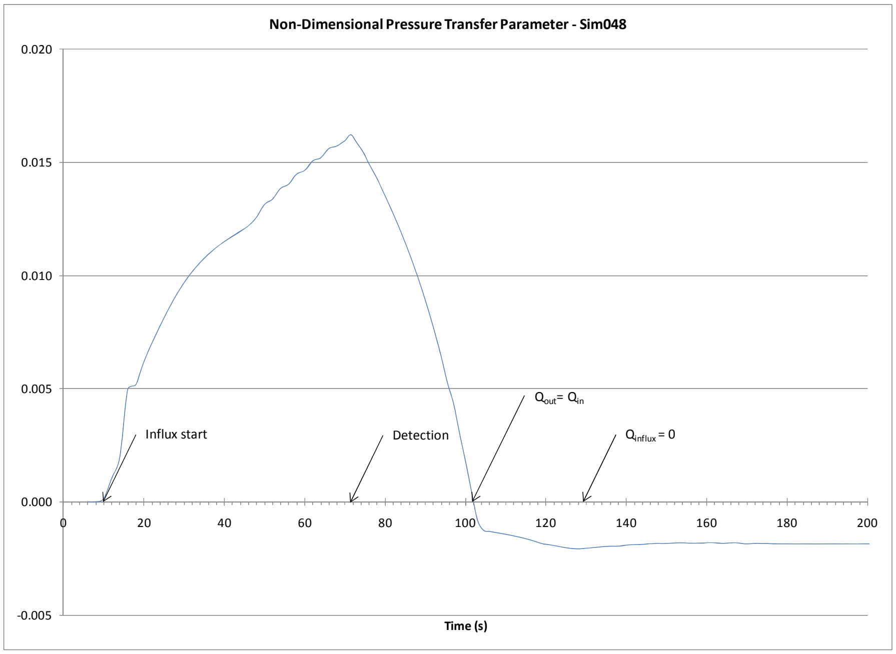

Figure B-39 Non-dimensional pressure transfer parameter for simulation 48

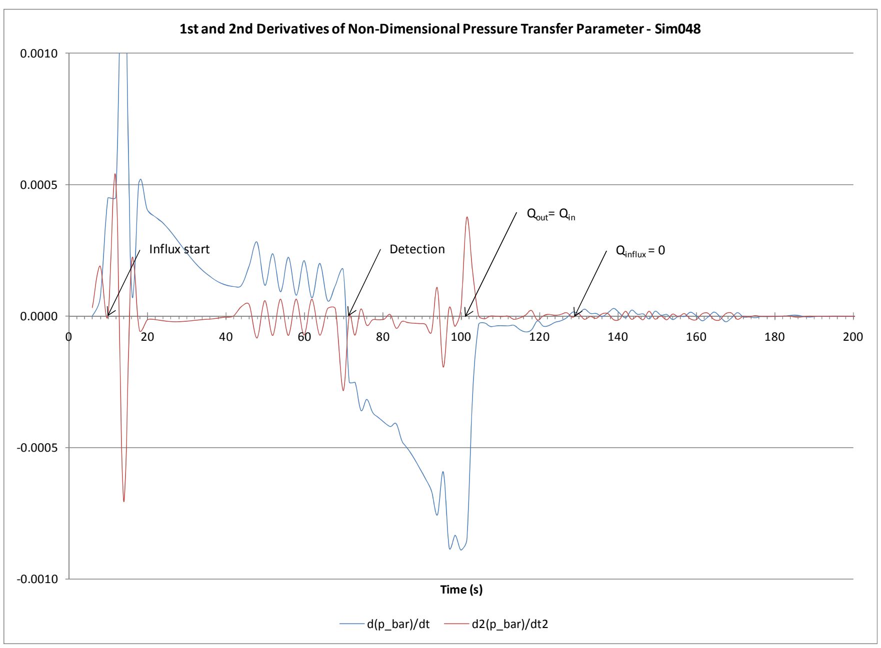

Figure B-40 First and second derivatives of non-dimensional pressure transfer parameter for simulation 48

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BIOGRAPHICAL INFORMATION

William is an Australian national, completing his undergraduate degree in Mechanical Engineering from the University of Tasmania in 2004. He commenced his career as a project engineer at Sunrice's Deniliquin rice mill in outback New South Wales. From there he moved to Bradken Resources' steel foundry in Perth, where he oversaw several capital upgrades to the plant. This work was demanding in terms of operations and project management but provided limited technical challenges. During this time in Perth, he was exposed via the engineering community to the oil and gas industry and well engineering. Already searching for more technical engineering work than he had previously experienced, this sparked a deep interest. On moving to Dallas Texas for family reasons, William took the opportunity to work with Blade Energy Partners, an industry leader in well engineering, and completed a Master of Science in Mechanical Engineering at the University of Texas at Arlington.