SUBSEA KICK DETECTION ON FLOATING VESSELS: A PARAMETRIC STUDY

A Thesis

by

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ABSTRACT

Well control in drilling operations is priority to personnel safety. Detection of kicks, or the unscheduled entry of formation fluids into the wellbore, is vital to well control. It has been determined that return flow rate is the parameter most sensitive to detecting kicks and lost circulation. One kick detection method associated with this parameter is delta flow early kick detection or simply the delta flow method. This method has limitations on floating vessels. Inaccurate readings can occur due to the heave motion of a vessel. This is a result of the sensor being downstream of the compensatory slip joint. Expansion and compression of this joint can result in return flow readings that are not representative of the actual value. Inaccurate readings could create situations in which a false kick or false lost circulation is detected. Other inaccurate readings could result in an actual kick or lost circulation situation not being detected. In the past, work has been done to address this by developing a sensor that adjusts for heave. This work supports a project aimed at removing the need for motion compensation by relocating the sensor to a location independent of this motion.

A company is currently developing a delta flow early kick detection sensor to be placed at or near the seafloor. The stationary location of this sensor aims to remove the inaccuracy caused by slip joint compensation of vessel movement. This work will consist of a parametric study on the relationship of various drilling system and kick parameters at the seafloor using a well control simulator. The goal is to understand these relationships and determine the delta flow accuracy required based on a given kick size.

As a result, this study found that a sensor capable of detecting a 10 barrel kick would require an accuracy of 2.4% and a 20 barrel kick would require a 4.6% accuracy for detection. This case was a shallow water, low kick intensity scenario. This accuracy and the others reported for the drilling and kick parameter ranges provide the boundaries for a well control sensor to be placed at the seafloor.

DEDICATION

This work is dedicated to my parents for always supporting me in whatever dream I pursue.

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Thanks go to the Texas A&M Petroleum Engineering Department for giving me this incredible opportunity to pursue research and a career in such an important and exciting industry. I am especially grateful to Dr. Schubert for being patient with my constant requests for a project, and then giving me a project more interesting and important than I could have thought up. I am also thankful to General Electric for this project and for funding me. Thanks go to Dr. Teodoriu and Dr. Aubeny for being willing to join my committee. Finally, I thank my friends and family for their support.

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1. INTRODUCTION

Well Control and its methods have been discussed in great length (Choe et al. 2005; Santos 1991; Schubert et al. 2006; Watson 2003). Conditions that require well control include an unscheduled entry of formation fluids into the wellbore, which defines a kick (Watson 2003), and lost circulation, defined as the loss of drilling fluid or slurry to formation (Howard and Jr. 1951). Kicks and lost circulation can cause blowouts, loss of a well, damage to equipment, and result in both human and financial loss (Schubert 1995). The principle reasons for taking a kick include the following (Watson 2003):

- Insufficient Wellbore Fluid Density:
  - Low Drilling or Completion Fluid Density
  - Increased Gas Cut in Drilling Fluid
- Reduction in Annulus Head:
  - Fluid Losses from Lost Circulation
  - Swabbing in the Kick
  - Tripping without Filling
- Friction Pressure from Pipe Movement
- Collision of Two or More Wellbores
- Cement Hydration

In the instance of a kick or lost circulation, early detection is vital to successful well control procedures and avoidance of the dangers previously mentioned. Different methods of kick detection exist and are used in operations. Some common kick identifiers include (Watson 2003):

- Drilling Breaks
- Pump Pressure Changes
- Mud Return Rate Increase
- Pit Gain
- Loss of Drillstring Weight
- Gas Cutting or Salinity Changes
- Flow with Pumps Off

Although all these identifiers can detect a kick or lost circulation, some are more reliable than others and all are limited in offshore floating drilling operations. The limited capability of existing kick detection methods in offshore drilling operations provides the basis for this work.

An outside party wishes to develop a kick detection sensor for offshore floating drilling operations. The first step is to perform a parametric study of various drilling and kick variables to understand their effects on upstream annular flow and pressure distribution at different time steps during a kick event. In doing so, this study aims to determine:

1. The effect of different kick sizes
2. The effect of gas entrainment in the kick influx and the gas volume increase as it rises upstream
3. The effect of drilling system parameters

Ultimately it is desired to identify the accuracy required for the delta flow early kick detection method based on a given kick size. Discussion of the delta flow early kick detection method and other kick identifiers is found in subsequent sections along with a discussion of their limitations in floating offshore drilling.

1.1 Method Selection Process

The kick detection method used in this study was analyzed based on its ability to quickly and accurately identify a kick. Although the placement of a sensor at the seafloor does not change this requirement, increased sensitivities are expected, making time and accuracy of great importance. Initial identifiers of focus include the pressure and fluid velocity distributions at or near the seafloor. These have been previously identified as being timely and accurate identifiers in all drilling including floating drilling vessels (Maus et al. 1978). A kick detection method associated with fluid velocity distribution is the delta flow method. The delta flow method has long been used as an identifier for offshore floating drilling (Jardine et al. 1991; Maus et al. 1978; Speers and Gehrig 1987) and is discussed in the subsequent section.

1.2 Delta Flow Method

The delta flow method for kick detection is based on the closed loop drilling fluid circulation system where flow into the system (Q_i) is equal to flow out (Q_o) of the system. This can be used to detect kicks and lost circulation in a closed loop drilling system. If $Q_i > Q_o$, drilling fluid is lost to formation, indicating lost circulation. For $Q_o > Q_i$, an influx has occurred, indicating a kick. The general delta flow equation can be represented by

$$Q_o - Q_i = \Delta Q \quad \text{.......} (1)$$

Where the inequality

$$Q_i > Q_o \quad \text{.......} (2)$$

represents lost circulation and

$$Q_i < Q_o \quad \text{.......} (3)$$

indicates a kick has been taken.

Delta flow requires a technique to record inlet flow rate and outlet flow rate with accuracy. Previous methods (Doria and Morooka 1997) to get these measurements have included calculation of pump strokes, pump capacity and efficiency to calculate Q_i. A paddle flow meter can be used to detect Q_o. The accuracies reported with this Q_i and Q_o

detection are 10% and 20% respectively (Doria and Morooka 1997).A schematic of the Doria and Morooka method for MODU's is seen below in **Fig. 1**.

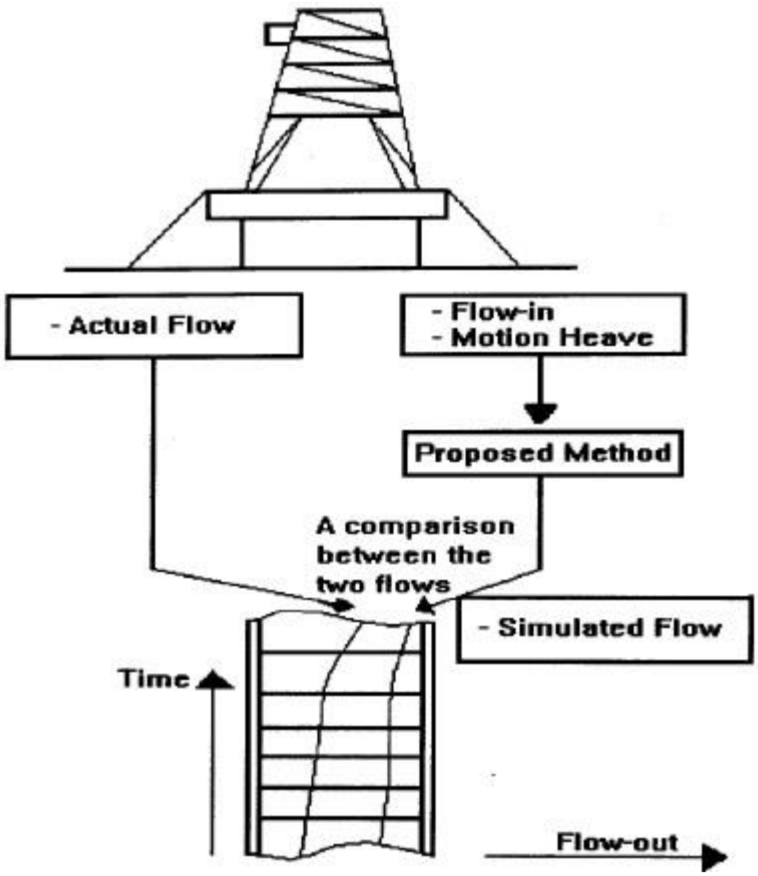

Fig. 1 - Offshore Heave Compensation (Doria and Morooka 1997)

Another approach uses magnetic flow meters for both entry and return lines (Speers and Gehrig 1987). According to the investigators, this method allows for accurate flow observation in undesirable conditions such as particle-laden drilling fluid.

A disadvantage to delta flow is vessel heave effect or the up and down motion of the floating vessel. This is caused by wave motion. Exit flow rate measured above the telescopic joint on the riser unit is subjected to movements that can make these measurements inaccurate.

Fig. 2 - Telescopic Joint (GE 2013)

The slip joint can act as a pump in that it causes variations in return flow as it moves up and down (Westerheim 1979). An example is represented in **Fig. 2** The result of this inaccuracy could cause a false alarm or not being able to detect an abnormal event. It has been reported that a six foot vessel motion with a period of 15 seconds can cause a 1,200 gallon per minute amplitude oscillating pumping action given a telescopic joint with a 20 in. diameter (Barton 1978). Based on this information, a kick detector downstream of the telescopic joint could falsely detect a 30 bbl kick or lost circulation event for a 1,200 gpm pumping action. In another scenario, if the telescopic joint is emptied, a 10 bbl kick over a minute of influx for a 420 gpm oscillation could not be detected, resulting in serious consequences to rig and crew safety. Efforts have been made to combat this effect and develop heave compensators that enhance return flow measurement accuracy (Speers and Gehrig 1987; Westerheim 1979). This is still undesirable as additional equipment and potential inaccuracies exist.

1.3 Pit Gain

Pit gain is another warning indicator of an abnormal event. Pit gain is a measurement of the volume displaced by the influx (Schubert 1995). In some cases, the influx volume is directly related to the volume of pit gain. If the influx is soluble in the drilling fluid (DF) this volume relationship is not direct and must be accounted for using PVT relationships. An example of this is a gas influx in oil-based mud (OBM). This situation is relevant to this study as many deep water wells are drilled with OBM’s, and the case of solubility needs to be studied. It is further complicated due to study limitations which are discussed in a subsequent section. In some situations pit gain shows intentional addition of DF materials at surface and is not an indication of a kick.

1.4 Current State of Floating Drilling Well Control

Floating drilling vessels include drillships and semi-submersible vessels and are often referred to as mobile offshore drilling units or MOBU's. In this report, both are considered as "floaters". Floaters use the same indicators for kick detection as fixed structure offshore drilling or onshore drilling (Watson 2003). Additional equipment is of course required. Discussion of the equipment and hydraulic differences is out of the scope of this study and will not be discussed here. Although the same indicators are used, kick detection with these methods can be difficult and inaccurate.

The source of difficulty in kick detection for floating vessels is the heave motion that occurs from tidal motion. Heave motion describes the up and down movement or movement about the z axis, with the x-y plane being the water surface plane. **Fig. 3** demonstrates this movement on a drillship.

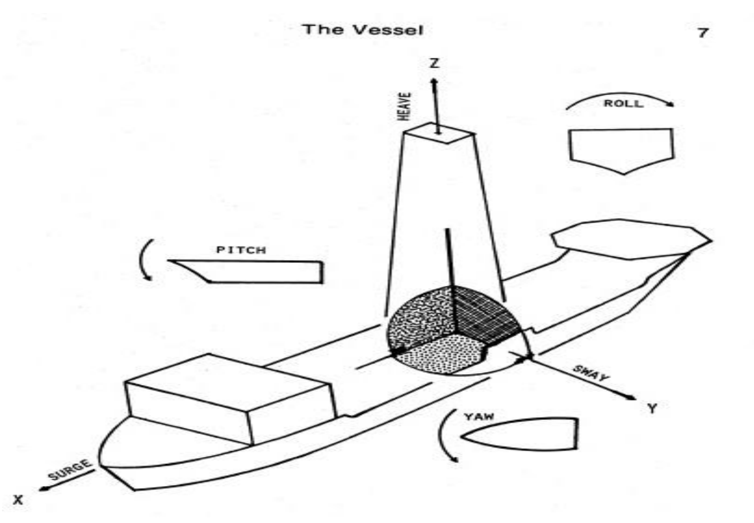

Fig. 3 - Floating Vessel Movements (Sheffield 1980)

Heave motion is compensated for with a slip joint to allow for riser movement relative to the ship. The riser serves to provide an annulus from the seafloor to the vessel for returned drilling fluid and cuttings. Storage and release of returned drilling fluid in the telescoping joint from heave can cause variations in flow rate that do not represent the actual value, which in turn lead to inaccuracy in kick detection. Kick detection that relies on measurement of return flow rate (i.e. delta flow kick detection) will be affected by this movement as seen in **Fig. 4**.

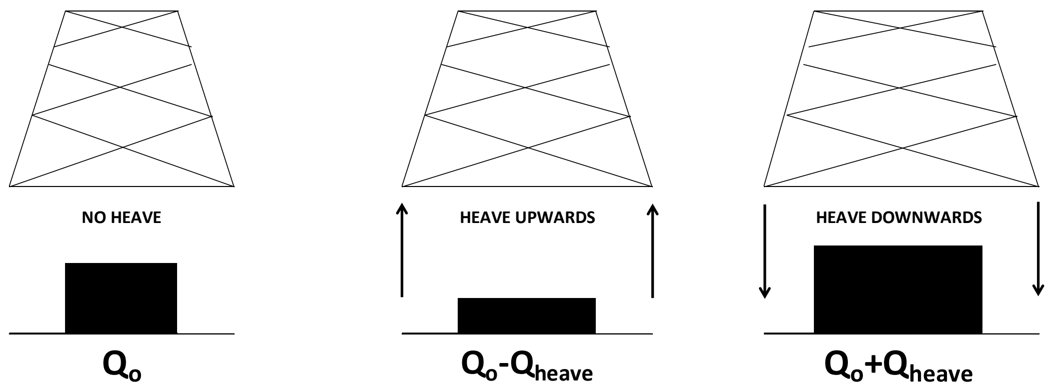

Fig. 4 - Heave Effect on Flow Detection

Developments in reducing heave effect include heave compensated kick and lost circulation detectors (Jardine et al. 1991; Watson 2003; Westerheim 1979). One method accounts for heave motion with electronic sensors that filter out the spikes in readings from heave. Another method makes heave adjustments based on a calculation of heave distance and riser diameter (Watson 2003). These methods do not entirely remove heave impact on kick detection and another solution below the compensatory joint that fully eliminates this inaccuracy is more desirable.

Measurement of pit gain as a form of kick detection is also subject to inaccuracies because of vessel motion (Watson 2003). Vessel movement will directly affect fluid levels and cause incorrect readings. Intentions to minimize fluid level fluctuation include installing baffles and adding more floats to mud pits. According to Schuh, the principle motions impacting floating vessel pit gain measurement are pitch and roll motions (Schuh 1979). This effect is demonstrated in **Fig. 5**. The authors reported a range from 20 to 60 bbls in pit variation measurement with an approximately 50 bbl range for pitch and roll motions of 3°. The proposed solution to the floating vessel pit gain measurement problem was to locate two equally spaced sensors along the mud surface centroid to eliminate pit gain variation due to vessel movement. As in the case of heave compensated kick detection, this method requires additional precautions and does not entirely remove the effect of vessel motion. Another method is desirable, which gives rise to this study.

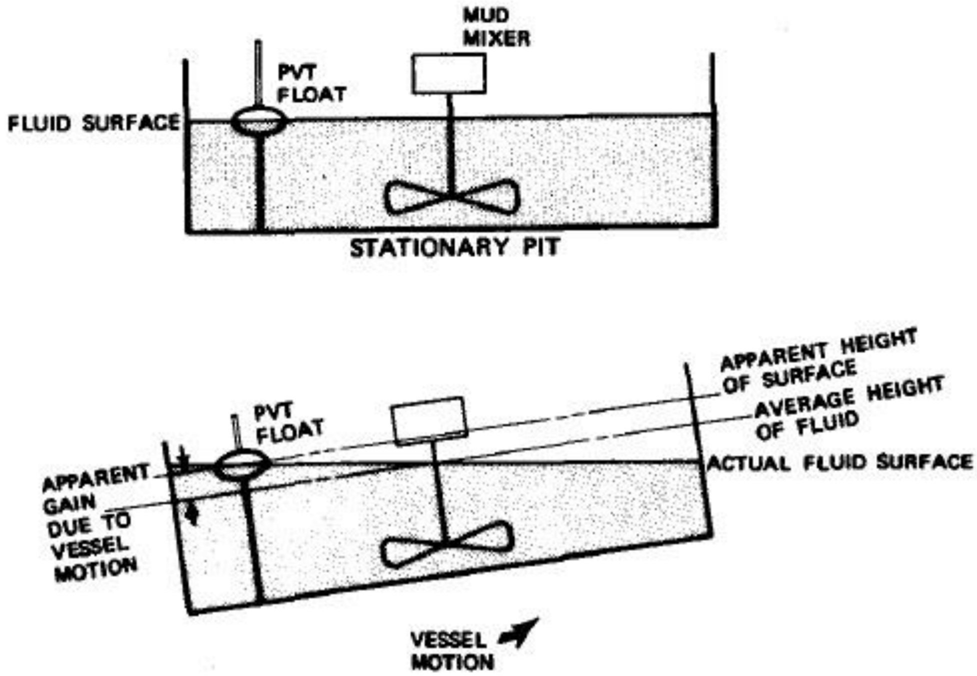

Fig. 5 - Vessel Motion Effect on Pit Gain Measurement (Schuh 1979)

1.5 Offshore Well Control Events and Statistics

A good understanding of real-life offshore well control events is important to provide those concerned with comparison to the work in this study. A major offshore contractor has published a report compiling statistics on all wells drilled from 2005 to 2009. The contractor drlled over 6,500 wells in this period (Foster 2009). It is important to understand the fraction of the rigs that were offshore floaters as this is the focus of this study. For the period stated, the active floating rig count averaged 60 rigs as compared to 43 for bottom-supported rigs.

Wells are described as either being development, exploration, or workover/abandonment ("other") wells. For a description of well type, refer to (Mitchell and Miska 2011). Within this time, 3,155 wells were for development, 1,386 exploration, and 425 were other. In that time, 556 well control events occurred (Mitchell and Miska 2011). A summary of the well control events is found in **Table 1**:

Table 1 - Well Event General Statistics

Event	Quantity	Well Classification
Kick	329	All
Ballooning	142	All
All	306	Exploration
All	242	Development

Based on the rig count in 2009, the kick frequency per rig was 0.6. That is, for every 5 rigs, 3 kicks occurred. This highlights how common offshore kicks are, and based on the reported floater rig count, one can infer that for 329 kicks, 60%, or about 192 of those kicks occurred on floating vessels.

Also of importance to this study are data that highlight the severity of kicks that occurred, how the contractor was able to manage different kick sizes, what should be expected of a sensor designed to detect kicks on floating vessels, and finally what kick size the contractor was able to comfortably manage and what kick sizes caused serious complications. According to the contractor, kick severity can be described by the volume and the density in ppg above the original mud weight. **Table 2** summarizes the results by severity for the time period of consideration.

Table 2 - 2005 to 2009 Well Control Events by Severity

Severity Type	Description	Value	Unit
Volume	Kicks Detected Under 20 bbls	84%	N/A
Volume	Kicks Exceeding 20 bbls	14%	N/A
Both	Unloaded Drilling Riser	6	Rigs
Kick Intensity	Kicks Above 0.5 ppg	44%	N/A
Kick Intensity	Kicks Above 1 ppg	25%	N/A

The contractor reported that capturing a kick in less than 20 bbls of influx as reasonable. For a floating vessel, this was considered optimum. These statistics confirm ranges for kick parameters defined in this study. Based on this report, it could be gathered that the ability to detect kicks on floating vessels of well under 20 bbls would be very attractive from the viewpoint of this major drilling contractor. Of the kicks that exceeded 20 bbls, labeled "red zone" kicks by the driller, several approached 150 or more bbls. A table that summarizes this information is found in **Fig. 6**.

Year	Division	Rig	Client	Hole size, in	Volume, bbl	Intensity, ppg	Time, hrs
2009	FEA	[redacted]	[redacted]	8.5	97.0	1.80	82.50
2009	NRS	[redacted]	[redacted]	6	95.3	0.65	20
2009	SAM	[redacted]	[redacted]	12.25	60.0	1.18	165.50
2009	GGA	[redacted]	[redacted]	12.25	36.0	0.15	29.25
2009	SAM	[redacted]	[redacted]	12.25	30.0	0.69	383
2009	FEA	[redacted]	[redacted]	6	30.0	0.81	8.00
2009	NAM	[redacted]	[redacted]	12.25	25.0	0.26	96.00
2009	NAM	[redacted]	[redacted]	12.25	22.9	0.00	45.50
2009	NAM	[redacted]	[redacted]	17.5	22.0	0.48	192.00
2009	NAM	[redacted]	[redacted]	8.5	20.0	0.74	20.00
2008	MED	[redacted]	[redacted]	6	200	1.68	8.5
2008	FEA	[redacted]	[redacted]	6	93	0.51	137.5
2008	WAS	[redacted]	[redacted]	8.5	78	1.8	31.5
2008	IME	[redacted]	[redacted]	12.25	53.6	1.11	27.75
2008	WAS	[redacted]	[redacted]	17.5	37	0.37	9
2008	MED	[redacted]	[redacted]	8.5	30	1.16	16.75
2008	FEA	[redacted]	[redacted]	6	28	0	24
2008	NAM	[redacted]	[redacted]	12.25	27	0.06	2
2008	NRS	[redacted]	[redacted]	8.5	26	2.5	26.5
2008	NAM	[redacted]	[redacted]	12.25	21	0.3	44
2007	FEA	[redacted]	[redacted]	8.5	60	1.58	15
2007	GGA	[redacted]	[redacted]	8.5	45	0.38	252.5
2007	GGA	[redacted]	[redacted]	6	34	0.89	14
2007	NAM	[redacted]	[redacted]	12.25	30	0.75	75
2007	NAM	[redacted]	[redacted]	8.5	29.5	1.2	16.5
2007	IME	[redacted]	[redacted]	17.5	21	0.52	78.75
2006	IME	[redacted]	[redacted]	17.5	102	0.7	37.5
2006	NAM	[redacted]	[redacted]	17.5	33	0.15	27
2006	IME	[redacted]	[redacted]	12.25	30	0.69	14.5
2006	GGA	[redacted]	[redacted]	8.5	24	2.27	22.5
2006	FEA	[redacted]	[redacted]	8.5	23.4	0.76	8.75
2006	IME	[redacted]	[redacted]	8.5	23	2	35
2005	IME	[redacted]	[redacted]	6	140	0.46	41.25
2005	IME	[redacted]	[redacted]	8.5	100	1.47	20.25
2005	FEA	[redacted]	[redacted]	8.5	80	No data	13.25
2005	FEA	[redacted]	[redacted]	6	30	No data	4.5
2005	IME	[redacted]	[redacted]	6	28	0.07	17.5
2005	IME	[redacted]	[redacted]	6	25	No data	21.75

Fig. 6 - Kick Records of More Than 20 Barrels

Also of interest is the fact that unloading of the drilling riser occurred six times in the course of four years, or more than once a year. This was reported to be of major concern to the contractor. Suggestions for improvement included better performing fundamental well control, treating every positive indicator as a kick, and quickly shutting in and using the choke for returns whenever there is doubt (Foster 2009). Another issue of concern was misidentification of ballooning which resulted in not quickly detecting the kick.

Mud type and kill circulation method should also be considered for comparison to this study. Calculations are done for every run for oil-based mud. Results of kick statistics by drilling fluid type are listed in the following **Table 3**:

Table 3 - Kicks by Mud Type

	Mud Type	
Year	O/SBM	WBM
2009	9	1
2008	8	2
2007	5	1
2006	4	2
2005	4	2
Totals	30	8

It is most common to take a kick in oil-based or synthetic based mud. This is due to the preference of operators to use these drilling fluids, especially in expensive offshore wells (Veil 1995). For the sake of this study it is important to understand the worst-case scenario for kick detection. In the case of drilling fluid, OBM's will pose the greatest problem due to gas kick solubility.

Finally, the results of circulation method are presented. For this study, the Driller's Method was selected for each simulation.

WCE Kill Method	2005	2006	2007	2008	2009	Method total
Drillers	57	33	35	33	35	193
Circulate	23	22	24	41	43	143
Wait & Weight	10	19	17	25	31	102
Bullhead	14	15	6	12	8	55
Bleed Off	13	3	6		1	23
Pump kill mud (pilot)		1	3		5	9
Dynamic kill			1	1	2	4
Volumetric	1	1		1	2	5
Stripping	5			1	2	6
Hot tap		1				1
Mudcap WC method						1
Off-bottom kill				1		1
Lubricate					1	1
Inadequate info	5	4			1	12
Yearly Totals	**128**	**100**	**92**	**115**	**121**	**556**

Fig. 7 - Kick Circulation Method Statistics from 2005 – 2009 (Foster 2009)

The driller's method is the most commonly used method for this contractor as shown in **Fig. 7**. The method was selected over a third of the time a kill was required. This agrees with the selection used in this study. The results published in this section serve to justify the parameter ranges and methods used in this study. The next section discusses the objectives and procedures used in this work.

2. OBJECTIVES AND PROCEDURES

The purpose of the study is to aid in development of a sensor to be placed near the seafloor to improve kick detection during floating drilling operations. Placement of the sensor near the seafloor will improve kick detection by removing the heave effect that requires compensation in current operations. The intended detection method is delta flow. It is necessary to examine the effect of a kick on pressure and fluid velocity of drilling fluids in the annulus at or near the seafloor where the sensor is to be located. This study intends to be able to determine the accuracy required for the delta flow early kick detection method based on a given kick size.

2.1 Parameters of Study

In order to determine the accuracy required for the delta flow method, a study must be done to determine the relationships and sensitivities of various drilling and kick parameters. These parameters were identified before beginning the study and are defined in **Table 4** and **Table 5**. Each parameter was assigned a realistic range of conditions that may exist operationally.

2.1.1 Kick Parameters

The kick parameters of study include kick size, kick intensity (KI) and gas volume fraction (GVF). The kick intensity is defined as the formation pressure increment above the mud weight in use (Wessel and Tarr 1991). For example, a well being drilled with 15 ppg mud with a 1 ppg kick intensity will be killed with a 16 ppg mud.

$$KI(ppg) = P_f(ppg) - MW(ppg) \tag{4}$$

Given a DF density, kick intensity can be obtained by **Equation 4**.

Table 4- Kick Parameters and Ranges

Kick Parameters	Nickname	Ranges (min - max)
Kick Size	VKICK	10 - 200 bbl
Kick Intensity	KI	0.5 - 2.5 ppg
Gas Volume Fraction	GVF	0%, 50%, 100%

2.1.2 Drilling Parameters

Drilling system parameters include water depth, well depth, drilling fluid density and drilling fluid flow rate. The drilling ranges replicate scenarios that will be observed in operations. Some situations have been identified as critical to early kick detection (Watson 2003). A kick gone undetected at shallow depth situations can quickly escalate in immediate danger to the crew. The low pressure level of a shallow hole can result in quick gas expansion (Schoffmann and Economides 1991). In deeper holes, it is expected that greater pressures will impact gas expansion and migration. Detection sensitivity is potentially a lesser requirement in this case for a similar sized kick. On the other hand, a deep HP/HT well being drilled with OBM taking a gas kick will require a different sensitivity. The differing compressibility of diesel based (or synthetic based) muds as compared to WBM, together with gas solubility, will change kick characteristics (Ng 2009) and are important to this study. From these examples it can be seen that the importance of identifying relationships and sensitivities in all the proposed ranges is critical for proper sensor design.

Table 5 - Drilling System Parameters and Ranges

Drilling System Parameters	Nickname	Ranges (min - max)
Water Depth	DWATER	0 – 15,000 ft
Well Depth	DWELL	5,000 – 30,000 ft
Drilling Fluid Density	PPG	9 - 16 ppg
Drilling Fluid Flow Rate	GPM	400 - 1000 ppg

As part of the parametric study it is necessary to adjust each parameter individually and examine its effect on the return flow rate near the seafloor. To meet objective terms, each parameter must also be considered on a kick size basis. It is desired to know what delta flow rate detection will be required based on the kick size for all of the outlined drilling and kick parameters. Determination of parameters most sensitive to delta flow will provide comparison for experimental work being done and ultimately aid in sensor design and establishing sensitivity feasibility. In order to do this, a tool that can examine these many cases required in a timely fashion was identified for use and is discussed in the subsequent section.

2.2 The Well Control Simulator

The Well Control Simulator was developed by Dr. Jonggeun Choe as a two-phase model that can be applied to simple drilling scenarios as well as more complicated offshore multilateral and ERD cases. It was selected for its ease of use for a parametric study that requires many simulations for comparison. The simulator has the ability to replicate a well control event at accelerated time steps, making it ideal for the many simulations required. Flexibility exists in the circulation method that can be selected, including the Driller's and Engineer's Methods.

2.2.1 Simulator Assumptions

The Simulator was developed with several assumptions(Choe and Juvkam-Wold 1997). These assumptions are:

1. Unsteady-state two-phase flow
2. One-dimensional flow along a flow path
3. Water-based mud; gas solubility negligible
4. Incompressible mud
5. Constant temperature gradient (input)

6. Kick occurs at bottom of well while drilling

The two-phase model incorporates pressure, temperature, gas and liquid fractions, densities and velocities (Choe and Juvkam-Wold 1997). The reader is directed to Dr. Choe's 1997 paper in the references section for derivations and boundary conditions. Flow phase is simulated as alternating gas-mud layers (GML) with no slippage between the layers. Simple mixture properties with gas slip velocity are applied and the GML's are simulated as one slug with an effective gas fraction (Choe and Juvkam-Wold 1997). When a kick influx occurs, the simulator assumes the reservoir is infinite-acting, is homogeneous and has skin. Parameters are calculated at the middle point of the two-phase region and the effective flow rate is the gas inflow rate added to the mud circulation rate.

2.2.2 Well Control Simulator Inputs

The Well Control Simulator has input variables controlling drilling system and kick and formation parameters. These can be adjusted by the user for the conditions desired. The user is responsible for setting these conditions before the simulation is run.

Table 6 - Well Control Simulator User Inputs

Parameter	Variable	Value
Well Definition	Well Location	Onshore
		Offshore
	# of Well Trajectories	Single
		Multilateral
	Mud Rheology	API RP 13D
		Power-law
	Mud Compressibility	
	Gas Deviation Factor	
Casing and Offshore Data	Conductor Casing Data	
	Offshore Data	Water Depth
		Temperature Gradient
		Riser Dimensions
		Choke Dimensions
		Kill Line Dimensions
Fluid and Bit Data	Mud Input Type	Shear Stress Reading
		PV and Yield Stress
	Gas Kick Data	Specific Gravity
		Mole Fraction of CO_2
		Mole Fraction of H_2S
Well Geometry	Trajectory Type	Deviated
		Vertical
		Horizontal
	Well and Drill String Data	TVD
		Pipe Dimensions
		Lateral Dimensions
Pore and Fracture Pressure	Pore and Fracture Method	Eaton
		Barker
		User Determined
Choke and Formation Data	Pump Circulation Rates	While Drilling
		During Kill Operation
	Shut-In Data	Kick Intensity
		Pit Gain Warning
	Formation Properties	Permeability
		Porosity
		Skin Factor
		ROP
Pump Data	Pump Type	Duplex
		Triplex
		Pump Dimensions

Table 6 lists user inputs that can be modified. The parametric study was done with a given base case. Variables are modified based on the parameter being considered.

Table 7 Lists the base case scenario for all runs. In some circumstances, the base case was changed in order to meet certain needs. For example, deep wells being drilled with a high flow rate required greater kick intensity than one ppg. In this case, a higher KI was required to overcome the large ECD caused by the high flow rate and large TVD. All deviations from the base case are listed discussed during the report of their results, and also in the excel spreadsheets where the simulation run outputs are recorded.

Table 7 - Base Case Scenario

Parameter	Variable	Value
Water Depth	10,000	ft.
Well Depth	20,000	ft.
Mud Weight	16	lb/gal.
Drilling Fluid PV	40	cp
Drilling Fluid YP	18	lb/100 sq. ft.
Drillpipe ID	5	in.
Nozzle Sizes	16/32	in.
Well Depth	20,000	.
$g_{T\,(water)}$	-1	°F/100 ft.
g_T	1	°F/100 ft.
ID_{riser}	19	in.
Well Trajectory	Vertical/Single Well	
Circulation Metho	Driller's Method	
Fluid Model	Power-Law	
Pump	Triplex	
Flow Rate	300	GPM
Kick Intensity	1	PPG
Permeability	250	md
Porosity	0	

Further assumptions include the well being a single vertical well. In all cases, conductor and surface casing are set along with an intermediate string. For depths BML greater than 2,500 ft., the intermediate string is usually 2,500 ft. shallower than the overpressure formation and drill bit. Specific modifications and assumptions are all made in the appendix of this work.

2.3 Simulator Procedure

The simulator functions also as a training module that is intended for student petroleum engineers (Choe and Juvkam-Wold 1997). It functions to imitate the actual process that occurs when drilling and taking a kick in the field. Upon setting inputs, the process follows (Choe and Juvkam-Wold 1997):

1. Start simulation and begin pumping;
2. Drill to target depth;

   The bit is automatically set 2.5 ft. away from the zone where the kick is expected to occur. In the case where a flow check is done, pumps are shut off and drilling stops upon reaching the target depth. In the case where no flow check is done, drilling and circulation occur through the target depth.

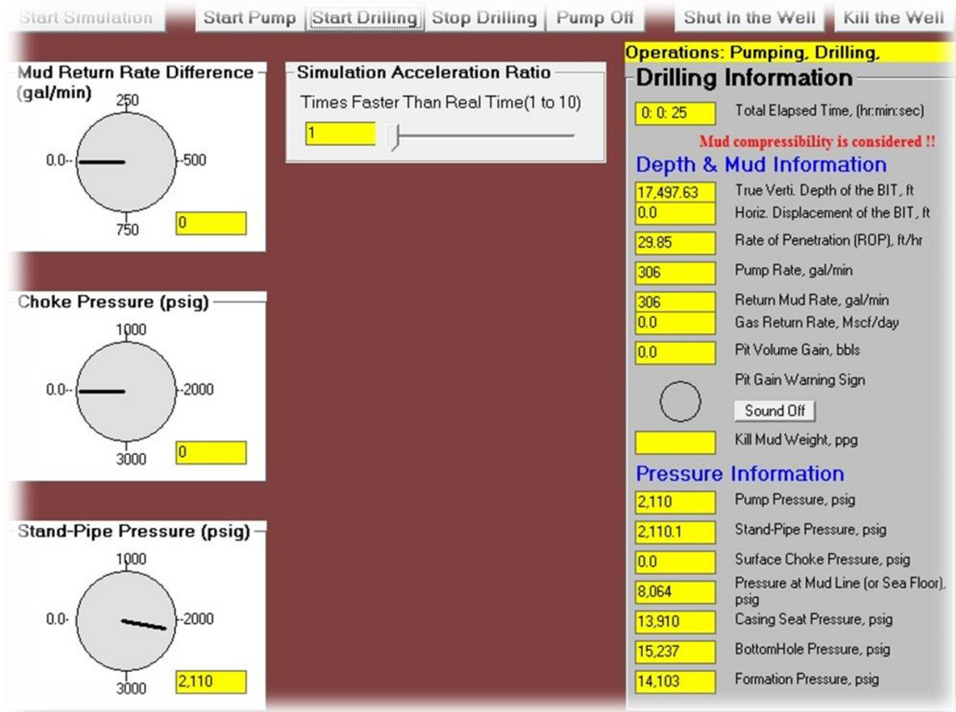

Fig. 8 - Drilling Interface: Pumping, Drilling Ahead

Fig. 8 shows the drilling interface screen as seen by the user. Gages to the left indicate mud return rate difference, choke pressure and stand-pipe pressure (SPP). As mentioned in section one, these are potential indicators that a kick is being taken. To the right of the screen is the drilling information panel showing current operations and readings that will be output with the end results and are also listed in Table 9. The pit volume gain reading in the panel is what the user watches to obtain the desired kick influx volume. The Simulator Acceleration ratio panel located at the center and top of the screen is where the acceleration from real-time is controlled.

3. Take a kick;

The kick warning indicator is set prior to beginning simulation and will warn the user when the desired kick volume has been reached. For example, if a 10 bbl kick is set, the warning indicator will signal an alarm when this has been reached. In the majority of cases a range from 0-40 bbl kicks was desired for each parameter. In other cases, for reasons of solubility calculation in OBM, a larger kick in WBM was required. Calculation performed to get a kick volume in OBM is discussed in a later section.

4. Detect the kick from warning indicator and pit volume indicator;
5. Shut-in well;
6. Well stabilization;

   Once the well is shut in, choke and SPP must stabilize before kick circulation can begin. The choke and SPP gages on the left panel of the drilling interface screen are observed until there is little (<5 psi change per time interval) to no change in pressure. Once this requirement is met, the well can be killed.

7. Kill well;

   Once the user selects 'Kill the Well' from the drilling interface screen, another screen is shown and the previously selected circulation method is performed.

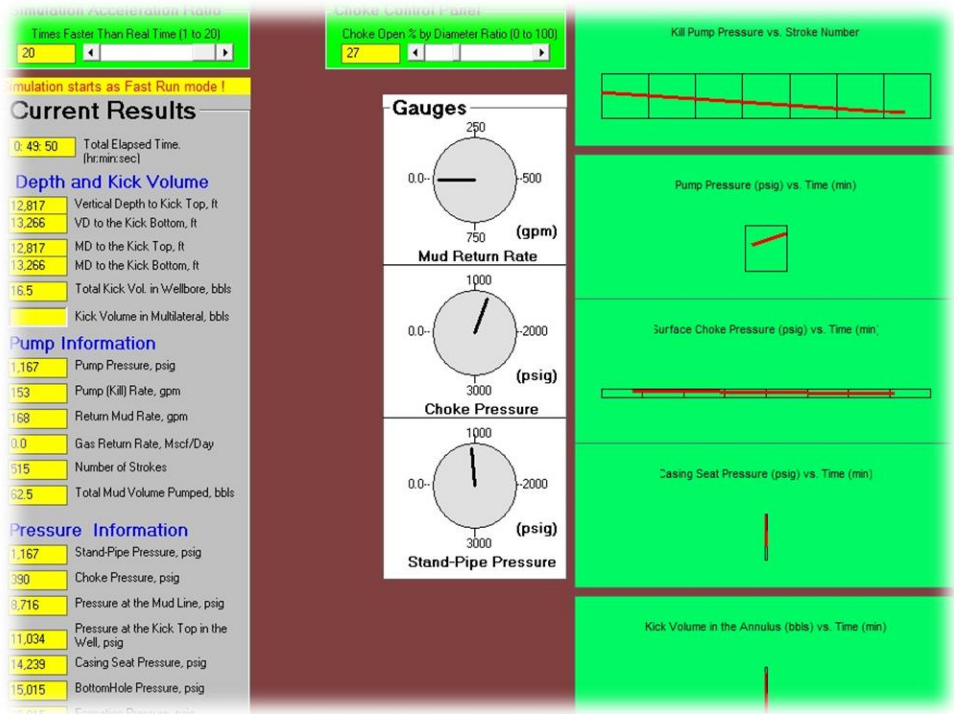

Fig. 9 - Kick Circulation Screen

The same readings as the drilling interface are provided to the left of the screen in **Fig. 9**. This allows the user to see exactly when the kick surfaces, when it is fully circulated out and also to observe the expansion characteristics by observing the increase in total kick volume as the kick migrates up-hole. A wellbore viewing option allows the user to visually observe the kick expansion and migration.

The kick circulation process can be accelerated similar to the drilling process. It can also be further accelerated with a ‘Fast Run’ option as circulations can take upwards of several hours. If ‘Fast Run’ is selected, the user is unable to use the annulus viewing option. An automated option for circulation is the automatic or ‘perfect’ circulation where the simulator controls the choke throughout. This is selected in the Driller’s screen when the well has been shut-in. Although not ideal for using the simulator as a teaching tool, for the purpose of running many simulations this perfect circulation option was always selected in this work.

8. Output results to Excel for analysis;

This process is repeated for each parameter and for each step within the study. The parametric study was performed by analyzing each in steps. Steps were determined to allow enough data points to see relationships in the analysis. The steps for each parameter are listed below in **Table 8**.

Table 8 - Parameter Steps for Simulation Runs

PARAMETER	ABBREVIATION*	STEPS
Well Depth (TVD)	DWELL	Every 2,500 ft.
Water Depth	DWATER	1, 5, and 10,000 ft.
DF Density	RHO	9, 11, 13 and 16 PPG
Circulation Rate	GPM	400, 600, 800 and 1000 GPM
Kick Intensity	KI	Every 0.5 PPG
Kick Volume	VKICK	10, 50, 100, 150 and 200 bbl kicks
Gas Volume Fraction	N/A	N/A
*For use and reference in Excel analysis		

Simulations were done for each parameter step in two different ways. The first simulations were done to imitate drilling into formation and turning off pumps to check for flow. The other method was done to replicate inadvertently drilling into a kicking formation. It is important to do both as they can both be experienced in practice. The flow-check scenario is performed in practice when any kick indicator is observed (Schubert 1995). Drilling ahead through formation simulates unknowingly entering the kicking formation. The delta flow observance is expected to vary in these two situations and thus needs to be recorded.

2.4 Data Acquisition

The simulator interface allows for export of each simulation run. Once circulation is completed, files are directly exported into Excel. This is the final process with the simulator before analysis. Information from each time step from the run is delivered to an empty spreadsheet where calculations can be made. This is the raw information that is used to see pressure and flow relationships for each parameter.

Table 9 - Simulator Output to Excel

Output	Unit
Time	minutes
Pump Pressure	psig
Standpipe Pressure	psig
Choke Pressure	psig
Casing Shoe Pressure	psig
BHP	psig
Pressure at Mudline	psig
Kick Top	ft
Kick Bottom	ft
Kick Pressure	psig
Pit Volume	bbls
Kick Density	ppg
Pump Stroke	#
Circulation Volume	bbls
Choke Open Diameter	%
Kick Influx Rate	Mcf/Day
Mud Return Rate	gpm
Gas Return Rate	Mcf/D

A sample of simulator output in Excel format produces the results in **Fig. 10**.

Date:	Tuesday,February 12, 2013																
Time:	11:02 PM																
Input File Name	C:\Users\Owner\Documents\TAMU\THESIS\SOFTWARE_INFO_FILES\CASES_DAT\DWELL_VKICK\GE_DWELL_27500_VKICK10.dat																
		Well Control Simulation Results															
Time	Pump P.	Standpipe P.	Choke P.	Casing Shoe P.	BHP	P.@mudline	Kick Top	Kick Bottom	Kick P	Pit Volume	Kick Density	Pump Stroke	Circ. Volume	Choke Open Dia	Kick Influx	Mud Retu
minutes	psig	psig	psig	psig	psig	psig	ft	ft	psig	bbls	ppg	#	bbls	%	Mcf/Day	gpm
0	0	0	0	13702	22163	8060	0	0	0	0	0	0	0	100	0	
0	0	0	0	13702	22163	8060	0	0	0	0	3.34	0	0	100	0	
0	0	0	0	13702	22163	8060	0	0	0	0	3.34	0	0	100	0	
0.83	2724.4	2724.4	0	13875.8	23592.8	8064.5	0	0	0	0	3.34	0	0	100	0	30
1.67	2726.1	2726.1	0	13875.8	23594.6	8064.5	0	0	0	0	3.34	0	0	100	0	30
2.5	2727.9	2727.9	0	13875.8	23596.3	8064.5	0	0	0	0	3.34	0	0	100	0	30
3.33	2729.6	2729.6	0	13875.8	23598.1	8064.5	0	0	0	0	3.34	0	0	100	0	30
4.17	2731.4	2731.4	0	13875.8	23599.8	8064.5	0	0	0	0	3.34	0	0	100	0	30
5	2733.1	2733.1	0	13875.8	23601.6	8064.5	27500	27500	23601.6	0	3.34	0	0	100	0	30
5.83	2446.9	2446.9	0	13875.8	23315.4	8064.5	27088	27501	22342.8	0	3.32	0	0	100	0	30
6.67	2689.6	2689.6	0	13886.9	23558.1	8064.8	26822	27502	22136.5	1.05	3.31	0	0	100	5123.7	33
7.5	2660.4	2660.4	0	13884.7	23528.8	8064.7	26593	27503	21924.6	1.25	3.31	0	0	100	990.3	32
8.33	2646.7	2646.7	0	13885	23515.1	8064.7	26352	27503	21709.1	1.73	3.31	0	0	100	2330.4	32
9.17	2638.5	2638.5	0	13886.2	23506.9	8064.7	26143	27504	21529.6	2.44	3.31	0	0	100	3473.2	33
10	2633	2633	0	13887.8	23501.4	8064.8	25967	27505	21386.2	3.37	3.31	0	0	100	4547.9	33
10.83	2625.7	2625.7	0	13889.6	23494.1	8064.8	25784	27506	21237.9	4.52	3.3	0	0	100	5587	33
11.67	2616.2	2616.2	0	13891.6	23484.7	8064.9	25594	27507	21083.8	5.91	3.3	0	0	100	6831.8	3
12.5	2604.1	2604.1	0	13893.8	23472.6	8064.9	25395	27508	20922.6	7.62	3.3	0	0	100	8351.6	34
13.33	2589	2589	0	13896.4	23457.4	8065	25185	27508	20752.6	9.72	3.3	0	0	100	10232.9	35
14.17	2569.9	2569.9	0	13899.5	23438.4	8065.1	24960	27509	20571.5	12.3	3.3	0	0	100	12586.1	36
15	2546.1	2546.1	0	13903	23414.6	8065.2	24718	27510	20376.3	15.48	3.3	0	0	100	15555.5	37
15.83	2476	2476	0	13907.3	23344.4	8065.3	24453	27511	20163.3	19.44	3.3	0	0	100	19328.2	38
16.67	2366.1	2366.1	0	13913.7	23234.5	8065.4	24131	27512	19906.7	25.34	3.29	0	0	100	28793.5	3
17.5	2210.5	2210.5	0	13923.4	23078.9	8065.7	23715	27513	19578.2	34.39	3.29	15	0	100	44234	42
18.33	1993.4	1993.4	0	13937.7	22861.9	8066.1	23161	27513	19139.9	48.19	3.28	65	0	100	67361.1	45
19.17	1905.3	1905.3	0	14064.4	22773.8	8066.6	22401	27514	18748.5	68.96	3.28	115	0	100	101453.2	51
20	1628.1	1628.1	0	14130.1	22496.5	8067.1	21530	27515	18109.4	93.53	3.28	165	0	100	119993.2	56
20.17	1554	1554	0	14149	22422.5	8067.3	21301	27515	17941.5	100.29	3.27	215	0	100	168017.5	58
20.17	0	1554	0	14149	22422.5	8067.3	21301	27515	17941.5	100.29	3.27	15	0	100	168017.5	58
20.17	0	1554	0	14149	22422.5	8067.3	21301	27515	17941.5	100.29	3.27	65	0	0	168017.5	58
21	0	1430	1945.1	15647.1	23595	10005.1	21301	27515	19114.1	100.29	3.34	115	0	0	0	
21.5	1772.1	1772.1	2500.5	16531.6	23595	13198.8	20969	27500	20633.1	134.79	3.4	15	1.82	34.1	0	68
23.17	2366.6	2366.6	0	16912.2	24189.6	10103.7	20241	26315	19251.6	135.83	3.37	65	7.89	100	0	68
24.83	2316.3	2316.3	0	16912.2	24139.3	9292.4	19513	25563	18641	135.98	3.37	115	13.96	100	0	54
26.5	1772.1	1772.1	673.5	16544	23595	9923.8	18926	24978	18226.2	136.06	3.37	165	20.03	37	0	42
28.17	1772.1	1772.1	1547.5	16657.1	23595	10524	18452	24507	17880.6	136.14	3.37	215	26.1	27.9	0	36
29.83	1772.1	1772.1	1886.8	16697.9	23595	10707.4	18040	24096	17569.5	136.2	3.37	265	32.17	25.1	0	32

Fig. 10 - Simulator Raw Data Output to Excel

The simulator run from Fig. 10 is for a comparison of the DWELL and VKICK parameters for a TVD of 27,500 ft. and kick volume of 100 bbls. This sample shows time steps from 0 to 29.83 minutes. The raw data can be used to obtain many values such as kick duration, delta flow, effect on mudline pressure, among others.

2.5 Simulator Limitations

There are two limitations of the well control simulator for this study. Gas volume fraction, a kick parameter of the study, cannot be modified in Choe's simulator. Second, the simulator drilling fluid is WBM. The simulator itself does not demonstrate the effect of solubility, a critical consideration in design of a well control sensor. Each of these limitations have been addressed and are discussed subsequently.

2.5.1 Gas Volume Fraction Limitation

Different fluids can enter the wellbore in kick form (Choe and Juvkam-Wold 1997). These fluids include gases, liquids, hydrocarbons, formation water or any combination. Gas volume fraction is one of the kick parameters selected for study. Modification of GVF allows for inclusion of these non-gas fluids for the parametric study. It has been determined previously (Choe and Juvkam-Wold 1997) that a gas kick is the most troublesome in well control because of compressibility and density characteristics. The high compressibility (expansion) and low density of gas provide the most critical case for kick consideration. Any kick mixture composed of other non-gas components will be less compressible (expandable) and will pose a lesser problem in well control.

The well control simulator cannot modify the GVF of the kick influx. It can adjust the CO_2 and H_2S fractions, which were both left as none in this study. A GVF less than one and containing liquid would reduce the effect of solubility and compressibility, making kick identification and well control more manageable. It was determined that the simulator GVF of one (all gas) was suitable for this study as it treats the worst-case well control event scenario.

2.5.2 Gas Solubility in OBMs from Simulator PVT Data

As mentioned in the well control simulator assumptions section, a WBM is assumed where gas solubility is negligible (Choe and Juvkam-Wold 1997). This study focuses on offshore floating drilling where deep water and HP/HT conditions are expected. In these drilling operations OBM and SBM are often used. In environmentally sensitive areas, SBM is used in place of OBMs (Monteiro et al. 2010). Gas solubility is a concern in either DF because of solubility and must be considered in this study. To account for this case, additional calculation is necessary to obtain an equivalent influx volume in OBM from the PVT information available in the simulator output. This method and its assumptions are detailed in **Table 10**:

Table 10 - Solubility Assumptions

PARAMETER	VALUE	UNIT
Drilling Fluid	#2 Diesel	N/A
SG_{DF}	0.85	N/A
ρ_{DF}	297.5	lb/bbl
Gas	Methane	N/A
MW_{gas}	16	lb/lb-mol
SG_{gas}	0.5517	N/A
ρ_{water}	350	lbm/bbl
$z_{bht,p}$	After SPE 26668	N/A
z_{surf}	1	N/A
P_{surf}	14.65	psia
T_f	60	°F
P_f	Given	ft
T_f	Given	°F
Flow Rate	Given	bbl/min
Influx Volume	Given	bbl

2.5.2.1 Calculation of Kick Influx in OBM

Given the PVT conditions and kick volume from the well control simulator, an equivalent kick volume in OBM can be obtained in the following manner.

Surface GOR;

$$\frac{p_{bht,p}\dfrac{V_{gas}}{V_{DF}}}{z_{bht,p}T_{bht,p}} = \frac{p_{surf}GOR}{z_{surf}T_{surf}} \Rightarrow GOR_{surf} = \frac{p_{bht,p}\dfrac{V_{gas}}{V_{DF}}z_{surf}T_{surf}}{z_{bht,p}T_{bht,p}p_{surf}}, SCF/bbl \quad \text{.............................}(4)$$

Calculating moles of mixture;

$$mol_m = mol_{DF} + mol_{gas} \quad \text{..}(5)$$

where

$$mol_{DF} = \frac{WT_{DF}}{MW_{DF}} \quad \text{..........} (6)$$

$$mol_{gas} = \frac{GOR}{380.7(scf\ /\ lbmol)} \quad \text{..........} (7)$$

Mixture Molecular Weight;

$$MW_m = x + y \quad \text{..........} (8)$$

where

$$y = \frac{mol_{gas}}{mol_m} \quad \text{..........} (9)$$

$$x = \frac{mol_{DF}}{mol_m} \quad \text{..........} (10)$$

Mixture Weight (McCain 1990)

$$MW = \frac{42.43\gamma_o}{1.008 - \gamma_o} \quad \text{..........} (11)$$

$$lb_{mix} = lb_{DF} + lb_{gas} = lb_{DF} + \frac{lb_{gas}}{bbl_{DF}} * MW_{gas} \quad \text{..........} (12)$$

Volume of Mixture per bbl of DF

$$\frac{V_{mix}}{bbl_{DF}} = \frac{m_w}{\rho_w} = \frac{\frac{m_m}{\gamma_o}}{\rho_w} \quad \text{..........} (13)$$

Kick Volume Equivalent in OBM DF

$$V_{kick \to OBM} = \frac{V_{mix}}{V_{DF}} - V_{k,WBM} \quad \text{..........} (14)$$

This process was applied to each simulator run to get delta flow to kick volume relationships in OBM and was added to the original analysis done for the WBM assumptions. Compressibility factors for the OBM kick volume analysis were determined using an Excel VBA program that utilizes the correlations from SPE 26668 (McCain 1990). The range of pressure and temperature data for these z factor correlations is seen below with associated statistical data.

Table 11 - Gas Compressibility Correlation P, T Ranges after McCain, 1990

VARIABLE	UNIT	MEAN	MINIMUM	MAX
T	°F	243.800	78.0	326.0
p	psia	3758.6	514.0	12814
z	N/A	0.989	0.689	2.099

The range of pressure, temperature and gas compressibility for this study are observed below.

Table 12 - Study P, T Ranges

VARIABLE	UNIT	MINIMUM	MAX
T	°F	60.0	300.0
p	psia	14.7	20000
z	N/A	0.98	2.05

A comparison of **Table 11** and **Table 12** demonstrates the difference in the tested pressure range between the gas compressibility after McCain and those of the study. This difference may lead to inaccuracies between actual compressibility factors at the high pressures of the study and those obtained using SPE 26668 correlations and is discussed in the results section of this paper.

3. RESULTS OF PARAMETRIC STUDY

3.1 General Analysis of Raw Output Data

To do a parametric study of the various drilling and kick parameters it is important to first understand the raw output data from the simulator and the story it tells through the well control event time cycle. Raw output data can tell the user when a kick is occurring and what happens to the pressure profile at different locations as the kick progresses through the well. It can also demonstrate the effects on flow rate that occur during a well control event. Furthermore, a good understanding of the pressure and flow relationships can benefit the user in identifying potential abnormal events in the simulation run, where applicable.

3.1.1 Mudline Pressure during a Well Control Event

Pressure in the annulus at the seafloor can be used as a potential kick identification parameter. The mudline pressure changes with certain processes that occur during a well control event. Drilling with pumps on, well shut-in, well kill, and kick circulation all impact the mudline pressure.

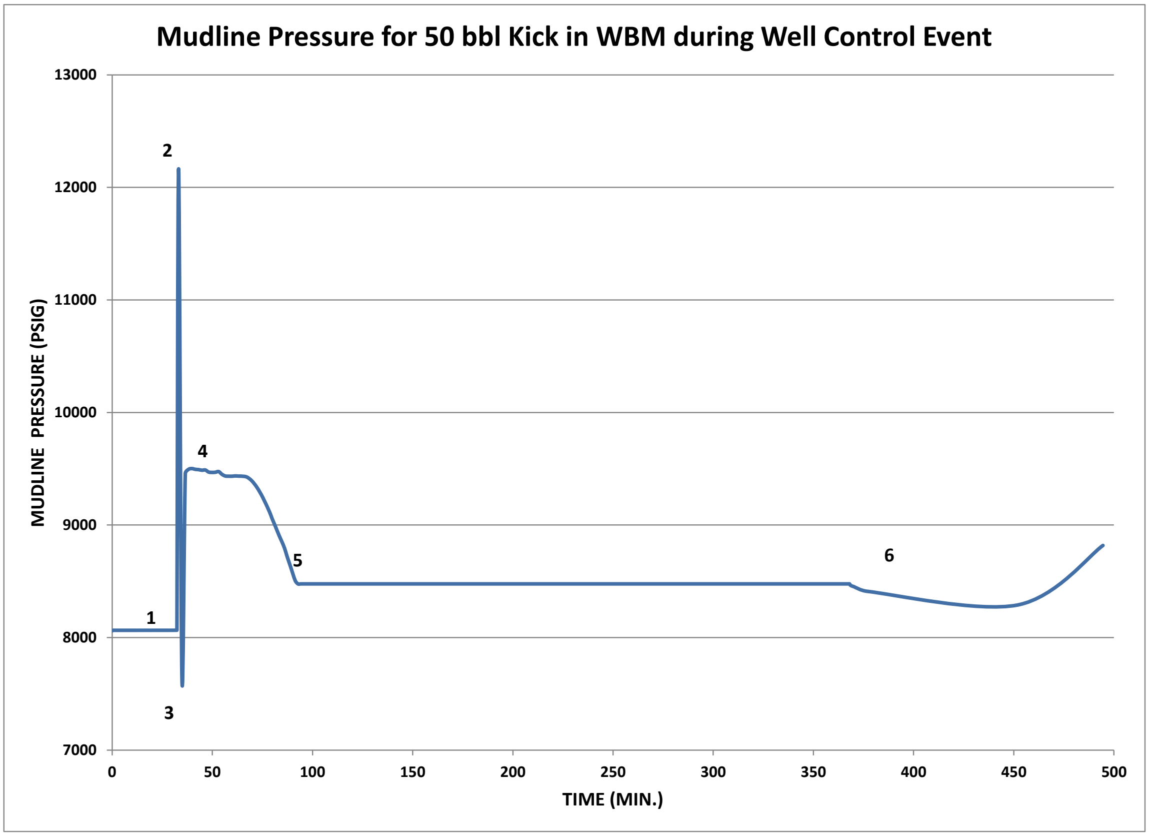

Fig. 11 - Mudline Pressure during Well Control Event

Fig. 11 represents the mudline pressure through a well control event where a kick was taken and then circulated out. The conditions for this simulation are listed in **Table 13**. The numbers in **Fig. 11** identify the following events:

1. Drilling ahead with pumps on until well shut-in;

   During this time the overpressured formation is drilled into and a kick is taken until detected by the pit gain warning alarm. Once the kick is detected the well is shut-in, marking the end of the first straight line segment.

2. Mudline Pressure spike;

Circulation begins and the kick starts to migrate up the wellbore. The kick bottom is no longer at the bottom of the hole. The choke is restricted to about 40% in this time step.

3. The choke is opened 100% and there is a sharp pressure drop;
4. The choke is once again restricted back below 40% and the pressure spikes upwards;

   At this point the choke is manipulated to maintain a steady initial circulating pressure (ICP) on the drillpipe gauge as per the Driller's Method. In the case of this and all simulations, choke manipulation was automatically done by the program.
5. The kick bottom has risen above the mudline and is entirely above the seafloor, resulting in a constant pressure reading;
6. The choke is opened back up to 100% and the well is once again shut-in.

Table 13 - Assumptions for Fig. 11

Parameter	Variable	Value
Water Depth	10,000	ft.
Well Depth	17,500	ft.
Mud Weight	15.5	lb/gal.
Flow Rate	300	GPM
Kick Intensity	1	PPG

3.1.2 Drilling Fluid Return Rate during Well Control Event

Delta flow rate has also been identified as a potential kick identification parameter. Understanding the effect of a well control event on return flow rate (and thus delta flow rate) is also important in order to begin analysis of delta flow rate in this study.

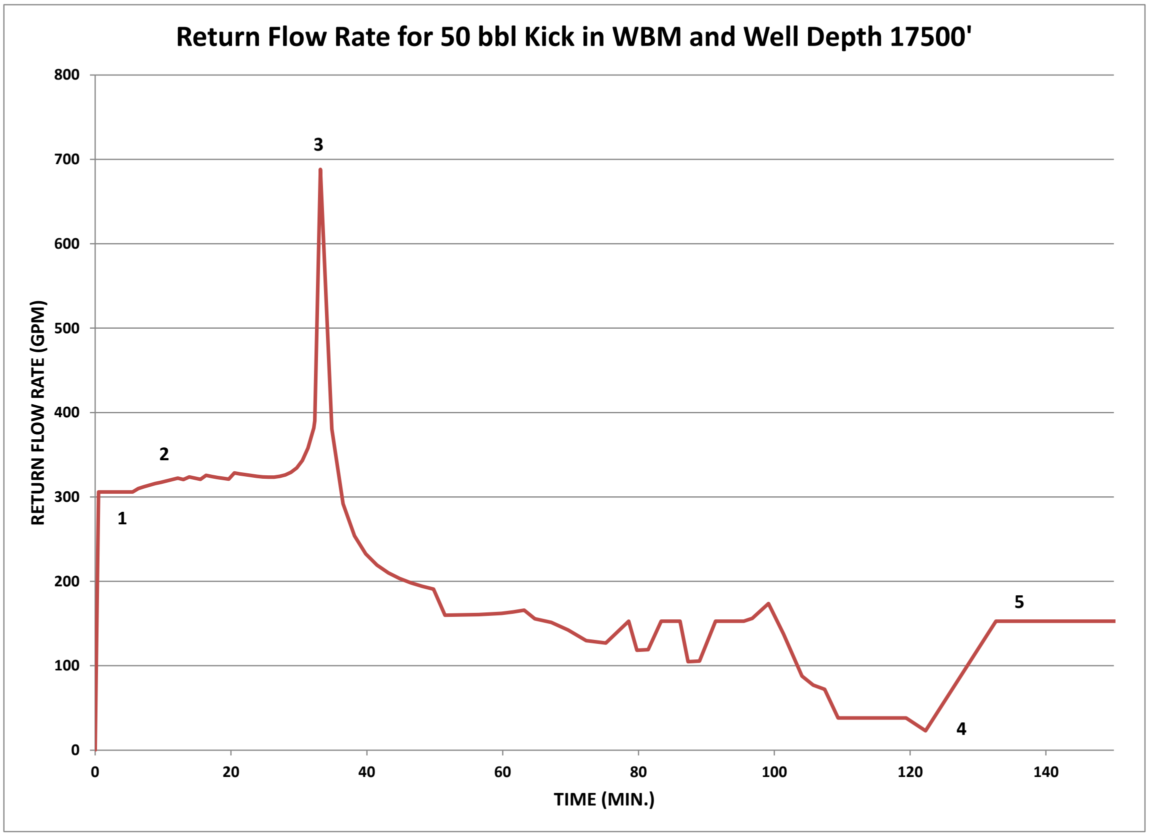

Fig. 12 - Return Flow Rate during Well Control Event

Fig. 12 represents the return flow rate through a well control event where a kick was taken and then circulated. The conditions for this simulation are the same as in the mudline pressure example and are listed in **Table 13**. The numbers in **Fig. 11** identify the following events:

1. Pumps are turned on and the flow rate is brought up to 300 gpm. Drilling commences;
2. Kick influx is marked by the increase in flow rate;

   Flow rate increases nonlinearly until it reaches the peak immediately before the next process (3).
3. Return flow rate reaches a peak, coinciding with the maximum kick influx rate;

   The return flow rate begins to decline as the well is shut-in and kick circulation begins. The return flow rate is affected by manipulation of the choke and gas expansion. The fluctuation of return flow rate from points 3 to 4 demonstrates these processes.
4. Return flow rate reaches a minimum;

   The flow rate minimum coincides with the bottom of the kick being circulated out of the well.
5. Return flow rate is maintained constant.

   Once the kick has been completely circulated, flow rate is maintained constant. The choke is held constant. There is no longer any effect of gas expansion and migration on return flow rate.

Although the focus of this study is to identify relationships and sensitivities up to and including the point when a kick has been identified, it is important to understand how mudline pressure and delta flow rate are affected through the entire event.

3.2 Kick Volume

It is desired to know the effect of different kick sizes on the mudline pressure and return flow rate in this study. All other parameters being held constant, one should expect an increase in detected kick size to produce a greater delta flow and also an increase in pressure at the seafloor. For example, a 10 bbl kick will produce a lesser delta flow than a 40 bbl kick. This is due not only to more expansion with increased size but also the Darcy pseudosteady-state equation that governs kick influx rate:

$$q = \frac{703 k_g h (p_e{}^2 - p_{wf}{}^2)}{\mu_g T z (\ln \frac{r_e}{r_w} - 0.75)} \quad \text{.......} \quad (15)$$

As h increases, or the drill bit penetrates further into the overpressured formation, kick influx rate, q, will increase. The higher influx rate and resultant increasing volume expansion rate causes the delta flow value to increase. Further, P_{wf} is dropped by the hydrostatic column density reduction caused by the low density gas displacing higher density drilling fluid out of the hole, causing a larger pressure drop and therefore influx drive.

The effect of kick volume is expected to be similar in relationship to mudline pressure as it is to delta flow. Pressure, measured at the seafloor, should increase due to the effect of increased return flow rate (friction pressure) as previously mentioned. In the case of a sensor to be placed at the seafloor, the pressure would be recorded downstream from its location (i.e. riser and vessel movement equipment). While the kick is below the ML, the flow rate in the annulus above the sensor experiences the increase in return flow rate previously mentioned from increasing kick influx rate.

This work assumes a power law drilling fluid hydraulic model. Assuming turbulent flow in the annulus ahead of the kick, the equation is as follows (API 2010):

$$\left(\frac{dp}{dL}\right) = \frac{f_a {v_a}^2 \rho}{25.81(D_2 - D_1)} \quad \text{(16)}$$

Substituting velocity for flow rate we have

$$v_a = \frac{q_a}{A} = \frac{q_a}{\frac{\pi(D_2 - D_1)^2}{4}} \Rightarrow \left(\frac{dp}{dL}\right) = \frac{f_a {q_a}^2 \rho}{15.92(D_2 - D_1)^5} \quad \text{(17)}$$

And thus the total pressure drop across the annulus length is

$$\Delta p = \left(\frac{dp}{dL}\right)\Delta L \quad \text{(18)}$$

Pressure drop is a function of the square of flow rate. For positive circulation, or circulation of drilling fluid down drillpipe and back up through the annulus, the increase in flow rate from kick influx will increase the pressure in the annulus, and this will be observed by the sensor. Just as the kick volume vs. delta flow relationship, pressure at seafloor and kick volume should interact similarly. With an understanding of these relationships, the results of the parametric study for VKICK and drilling parameters are reported in the following sections.

3.2.1 Kick Volume and Well Depth

It was determined through use of the two-phase simulator that for any given well depth, larger kick influx will result in an increased delta flow to detection in both WBMs and OBMs. This agrees with the indications from previous sections. Although OBM results will differ in value from WBM, the parameter relationships will be the same and results from this point on will be reported in general fashion without differentiation between OBMs and WBMs unless noted.

3.2.1.1 Kick Volume and Well Depth Drilling into Formation

The effect of kick volume for a well TVD of 20,000 ft. is reported below.

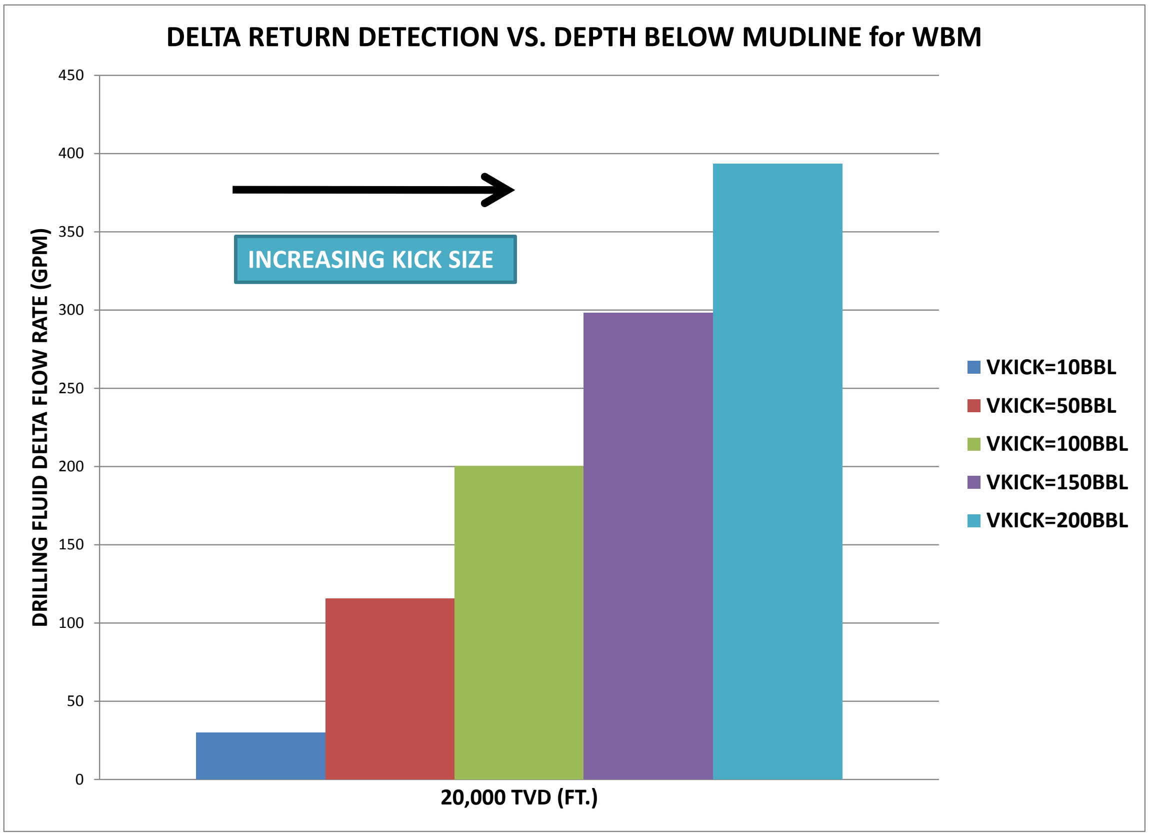

Fig. 13 - Effect of Kick Size on Delta Flow Detection for 20,000 TVD Well

For a 10 bbl kick at 20,000 ft. TVD in WBM, the simulator recorded a delta flow rate of 29.8 gpm as seen in **Fig. 13**. Circulating flow rate in this case was 305.9 gpm and the circulating rate at the time of the 10 bbl kick was 335.7 gpm. A 100 bbl kick under the same conditions caused a delta flow observance of 200 gpm. For a delta flow evaluated as a percent of the initial circulating rate, the 10 bbl kick resulted in a 9.7% change in flow rate where

$$\Delta Q(\%) = \frac{Q_o - Q_i}{Q_i} * 100 \quad (19)$$

The 100 bbl kick caused a 65% change in flow rate. As with all comparisons, all parameters hold true to the base case apart from those being compared. For example, if considering a 30,000 TVD well, all drilling and kick parameters are held constant apart from the TVD which is changed from the 20,000 ft. base case to 30,000 ft. For reference to the base case, the reader is referred to the table outlining the simulation base case. The effect of increasing well depth on delta flow detection can be seen in the following figure:

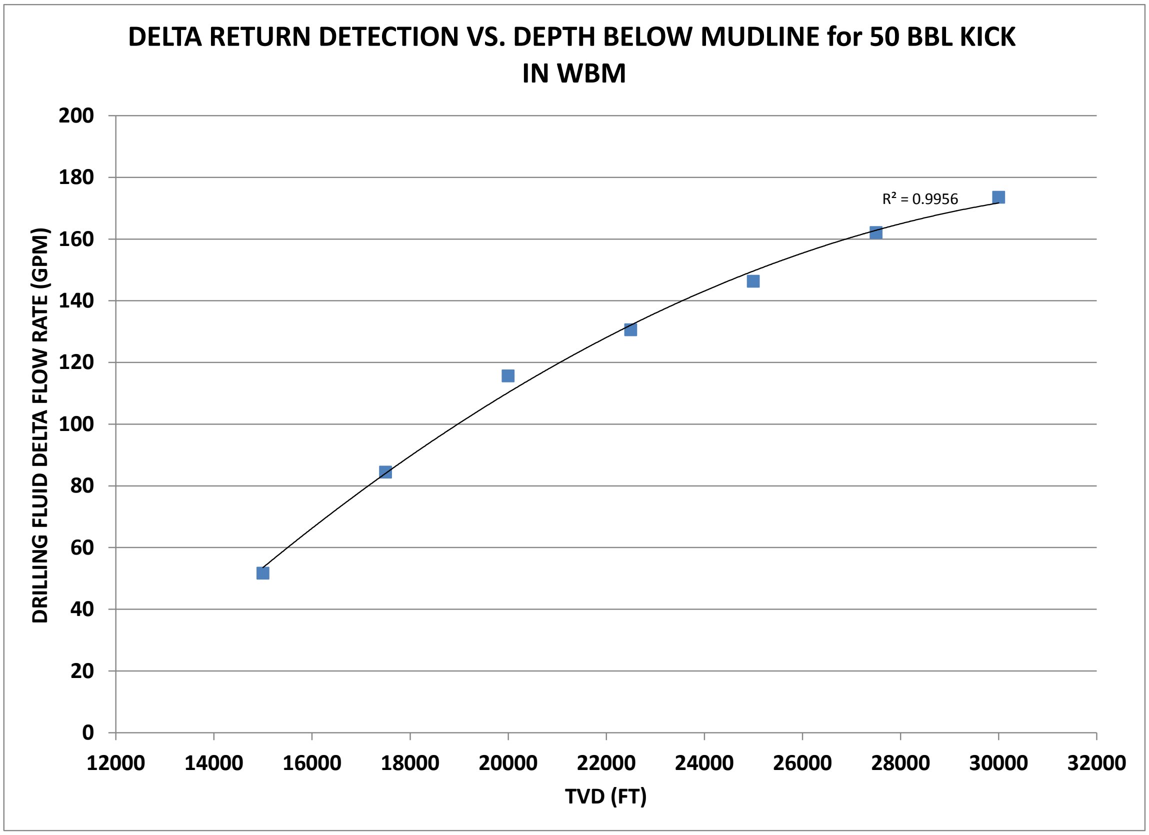

Fig. 14 - Effect of Well Depth on Delta Flow Detection

Fig. 14 indicates that, for increasing well depth, the delta flow to detect a given kick size increases. In this case, a 50 bbl kick in WBM at 15,000 ft. TVD produced a 51.7 gpm (17%) ΔQ, while the delta flow for the same kick size at 30,000 ft. TVD was observed to be a 56% change or 173.5 gpm.

3.2.1.2 Flow Check Scenario and Sensitivity to Circulation

It is common well control practice to drill into a new formation and check for flow. In this scenario drilling is stopped and pumps are shut off to check for flow upon reaching a new formation (Schubert 1995). In each simulator run, the new formation flow check occurs upon drilling into the overpressured formation. This scenario was imitated and the results are reported along with the inadvertent drilling case.

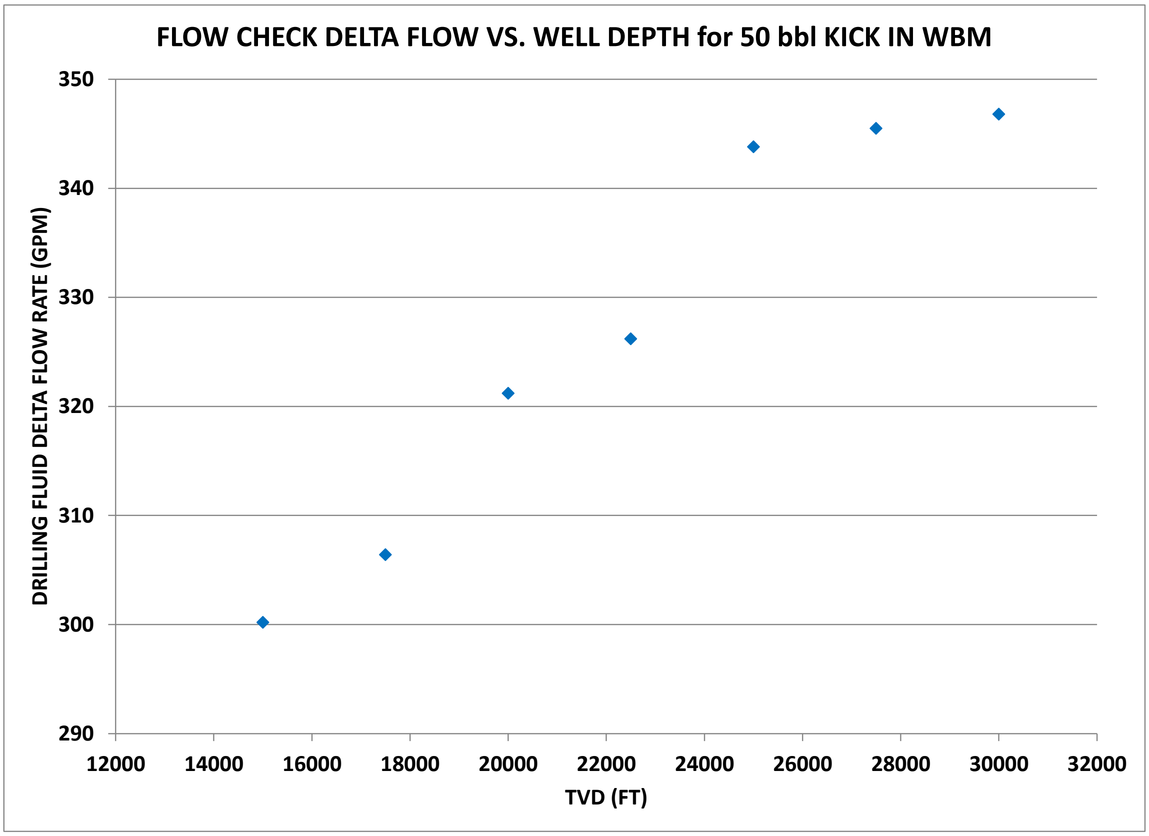

Fig. 15 - Well Depth Effect on Delta Flow for Flow Check Scenario

Fig. 15 confirms the relationship demonstrated for the inadvertent case where delta flow to detection increases with increasing well depth for a given kick size. For the flow check case, a 50 bbl kick in WBM at 15,000 ft. TVD produced a 300 gpm ΔQ, while the delta flow for the same kick size at 30,000 ft. TVD was observed to be approximately

345 gpm. For all flow check cases, there is no flow in and the increase in return flow is produced directly from the kick influx.

It is valuable to compare delta flow in a flow check situation against that which occurs during inadvertent drilling. If delta flow does demonstrates indifference to or is more sensitive to the flow check scenario, the flow check scenario will always be the most sensitive to delta flow versus inadvertent drilling for each parameter and must be reported. On the other hand, if a relationship can be established determining an increased sensitivity of delta flow to circulation (inadvertent drilling scenario), it will not be necessary to report the flow check scenario for each parameter as it would not produce a most-sensitive delta flow case.

A comparison of delta flow values for inadvertent drilling and flow check scenarios is seen in the following figure.

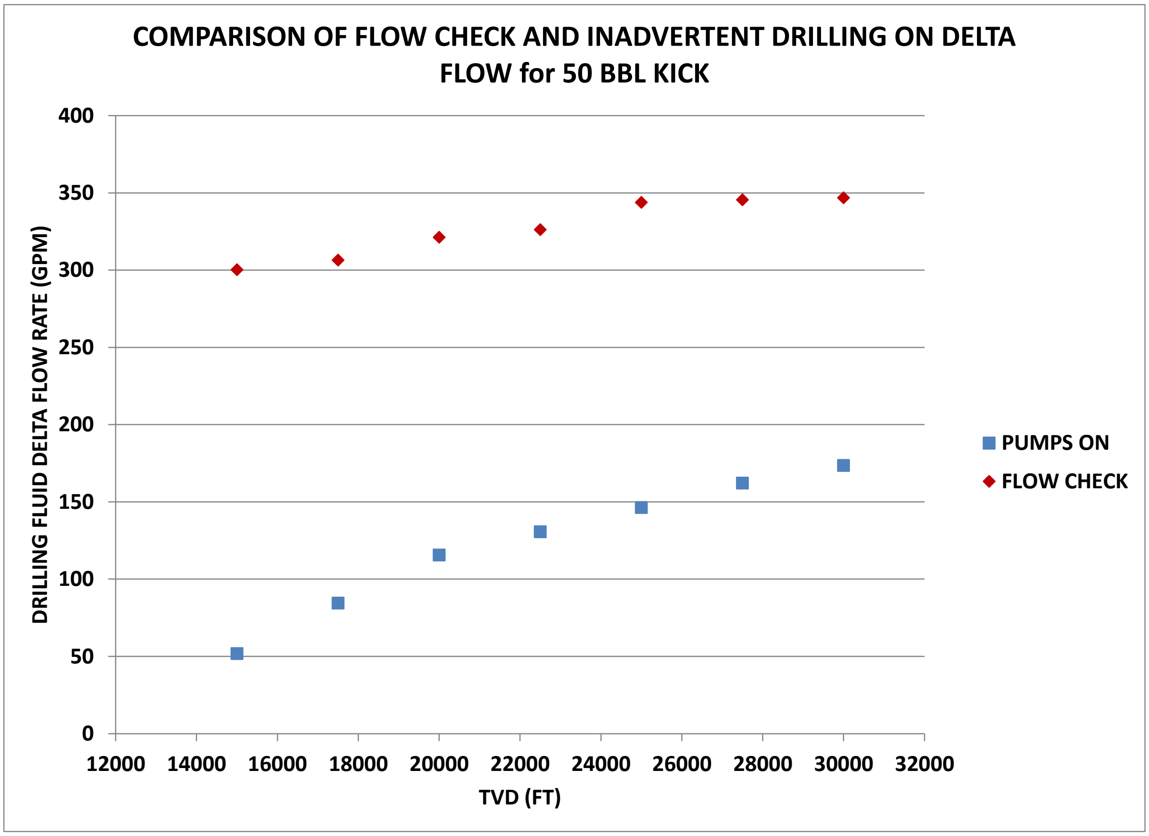

Fig. 16 - Delta Flow Comparison: Flow Check and Inadvertent Drilling Scenarios

Fig. 16 demonstrates the effect of not circulating while taking a kick. The scenario of drilling into formation and taking a kick is more sensitive than the flow check scenario to delta flow. The percent increases in delta flow to detection for flow check vs. pumps on at 20,000 ft. and 30,000 ft. are about175% and 100%, respectively. This comparison, along with visual analysis of **Fig. 16** demonstrates that delta flow difference for circulation and no circulation decreases with increasing depth.

The sensitivity of delta flow to circulation is demonstrated by the comparison of the two scenarios. All other parameters held constant, delta flow to detection is lesser in a circulating scenario than a no circulation scenario. Based on this analysis, it is expected that the decreased sensitivity of the flow check scenario will hold true for all other drilling and kick parameters reviewed in this study. To confirm this, the equations that govern delta flow should be checked.

According to (Maus et al. 1978), in the early stages of a kick (principal concern for early kick detection), increase in return flow rate can be defined by the following equation:

$$q = At \quad \text{.......} \quad (20)$$

where q is the return flow rate, A is a rate constant and t is time. According to Maus et al., the rate constant is dependent on ROP, reservoir permeability, mud underbalance and bit size. In this study, these are all held constant. Rate of penetration can slightly change once the drill bit has entered the overpressured formation due to circulation rate and this was observed during simulation runs. This is not expected to largely affect the flow check/drilling delta flow sensitivity relationship, however, and the no flow delta flow results will not be reported beyond this section because of this. Comparison of the effect of circulation rate on delta flow in a later section will further demonstrate the decreased sensitivity relationship as circulating rate approaches zero.

3.2.2 Kick Volume and Well Depth in Oil-Based Mud

A comparison of the effect of well depth on oil-based muds holds true as it does in water-based mud. In this study, all but one of the delta flow sensitivity relationships hold the same for oil-based mud and water-based mud. The difference between the two is the scale of sensitivity to delta flow. This section compares the data based on well depth. Based on the preliminary calculations for pit gain and delta flow, delta flow is generally more sensitive in oil-based mud. There are certain cases where calculations show this not holding true, and these are discussed.

As with water-based mud, the depth relationships hold true for the oil-based mud comparison. The results of delta flow detection for a given kick size at various well depths in oil-based mud are given on the following page in **Fig. 17**:

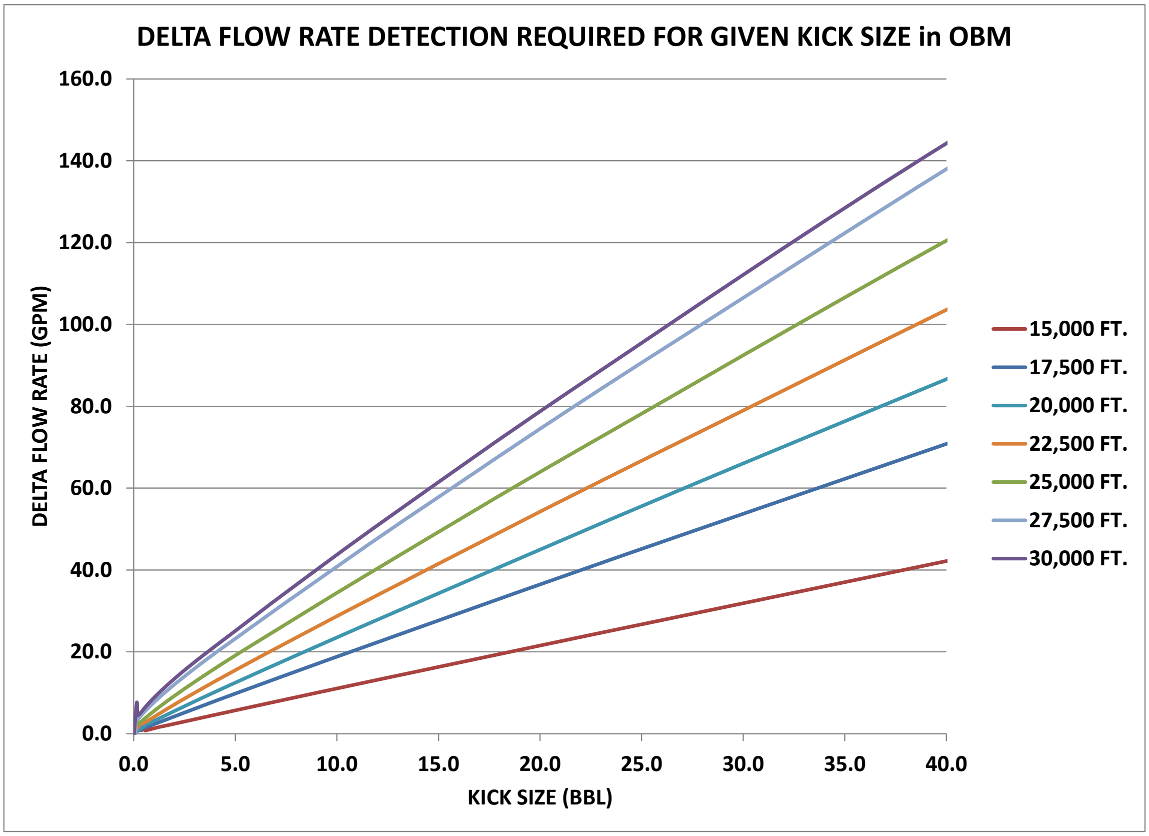

Fig. 17 - Effect of Well Depth on Delta Flow for Given Kick Size in OBM

A comparison of delta flow for different well depths of OBM and WBM will indicate which is more sensitive for a given kick size.

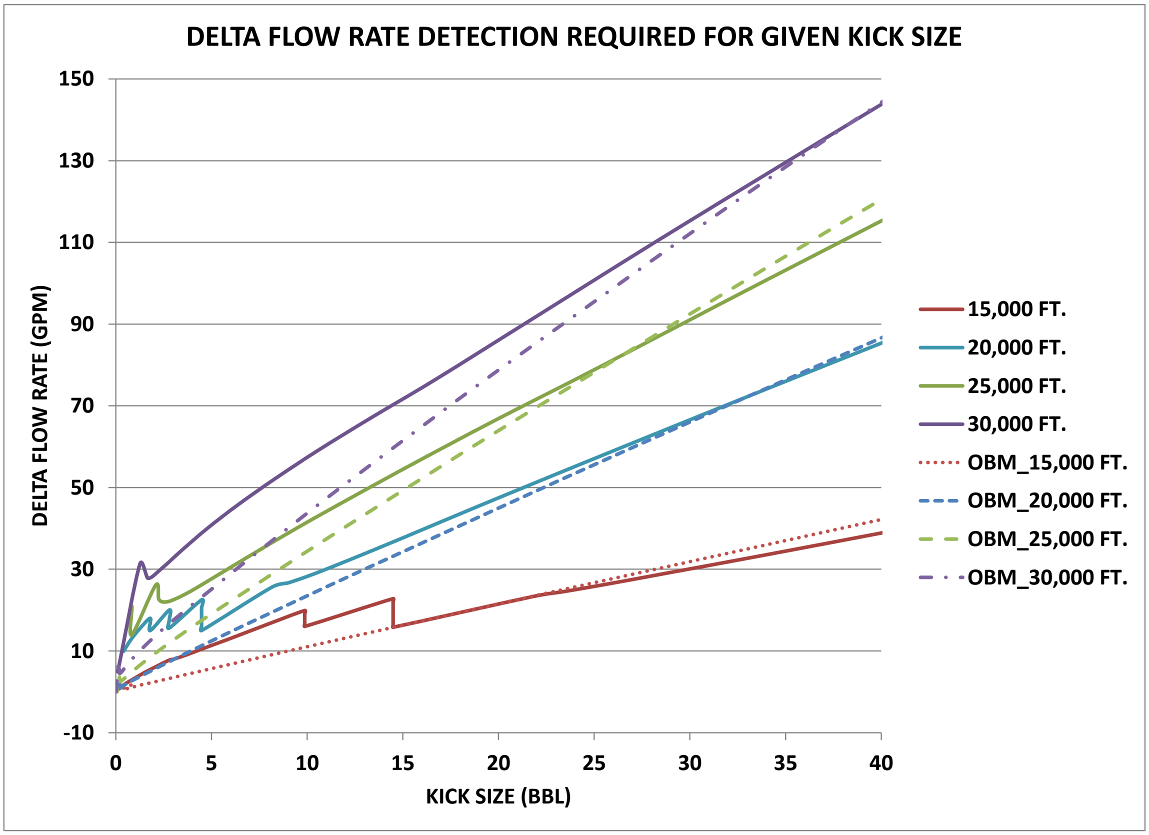

Fig. 18 - Comparison of Mud Type Delta Flow Sensitivity for Different Depths

It is seen that for kick sizes of less than 20 bbls, the delta flow to detection for a given kick size is less in OBM than WBM for all depths of study. As the kick size grows, the delta flow for OBM begins to approach and exceed the value observed in WBM. If a kick volume of 10 bbls is to be detected, the delta flow is more sensitive for all depths in OBM. The most sensitive case, as seen in **Fig. 18**, is the shallow well case. A 10 bbl kick is detected at a delta flow of about 13 gpm in OBM, versus about 17 gpm in WBM. For a 300 gpm circulation rate, the percent delta flow change is 4% and about 5.5% for OBM and WBM, respectively. A larger differential develops for greater depths between the two drilling fluid types. At 30,000 ft. TVD the delta flows to detect a 10 bbl kick are

40 gpm and 60 gpm for OBM and WBM respectively, or 13% and 20% change in flow rate.

3.3 Drilling Fluid Circulation Rate

Adjustment of the drilling fluid circulation rate changes the equivalent circulating density (ECD) and requires adjustment for comparison across the required range of 400 to 1000 gpm rates against a constant overpressured formation pressure. The equivalent circulating density can be described by the following equation (Mi-SWACO 2006):

$$ECD = \rho + \frac{P_a}{0.052TVD}(lb/gal) \quad \text{.......} \quad (21)$$

As previously mentioned, formation pressure must overcome the BHP in order for a kick to occur. When circulating, the BHP exerted is the ECD that includes the P_a term, or the annulus interval pressure loss. The equation that describes P_a will depend on the rheological model. To observe the relationships in annular pressure loss, another equation is presented (Mi-SWACO 2006):

$$P_a = \frac{f_a V_a{}^2 \rho}{92{,}916(D_2 - D_1)} L_m \quad \text{.......} \quad (22)$$

This term is similar to the frictional pressure loss term in the Power Law fluid model described in **Equation 16** and is in fact also a frictional pressure loss term. The V_a term, or annular velocity, is a description of the effect of flow rate on ECD. An increase in flow rate will increase the ECD as can be seen in **Equation 20**.

The effect of ECD in this study results in the need for adjustment of KI across the flow rate range to experience kicks in all situations. For this reason it is not possible to compare the entire range against a constant overpressured formation KI for flow rate while circulating. To compare the flow rates against a constant overpressure-ECD difference, the following process was applied to each flow rate step for a base case of 400 gpm flow rate and kick intensity of two pounds per gallon:

1) Define base case: Q = 400 gpm; KI = 2 ppg
2) Determine ECD from Simulator for given flow rate (600, 800, 1000 gpm)
3) Calculate ΔECD based on ECD of 400 gpm case
4) Add the ΔECD (ppg) to the base case KI (ppg)

For example, upon commencing drilling at 600 gpm the simulator shows a BHP (ECD) of 17,238 psi compared to the BHP_{400GPM} of 15950 psi, translating to a difference of one ppg. This one ppg difference is added to the initial KI of two ppg to obtain the required kick intensity for the 600 gpm case, resulting in an equivalent three ppg KI. This process is applied to all cases and a summary is seen below in **Table 14**.

Table 14 - Kick Intensities for Rate Parameter

Q	ECD	ΔECD	ΔKI	KI
GPM	PSI	PSI	PPG	PPG
400	15950		N/A	2
600	17238.0	1288.0	1.0	3.0
800	19210.0	3260.0	2.5	4.5
1000	21306.0	5356.0	4.1	6.1

The equations described are defined by the following:

$$\Delta ECD = ECD_n - ECD_{400}(PSI); \quad (23)$$

$$\Delta KI = \frac{\Delta ECD}{0.052 TVD}(PPG); \quad (24)$$

$$KI_n = KI_{400} + \Delta KI \quad (25)$$

Simulations for circulating rate comparison were done with the kick intensities from **Table 14**. Performing this calculation incorporates the effect of ECD on the change in KI required to the same point of reference overpressure.

3.3.1 Circulation Rate in Water-Based Mud

The circulation rate scenario was performed at 25,000 ft. TVD and 10,000 ft. of water. This differs from the base case of 20,000 ft. TVD and 10,000 ft. of water. The effect of circulation rate on delta flow can be seen in **Fig. 19**.

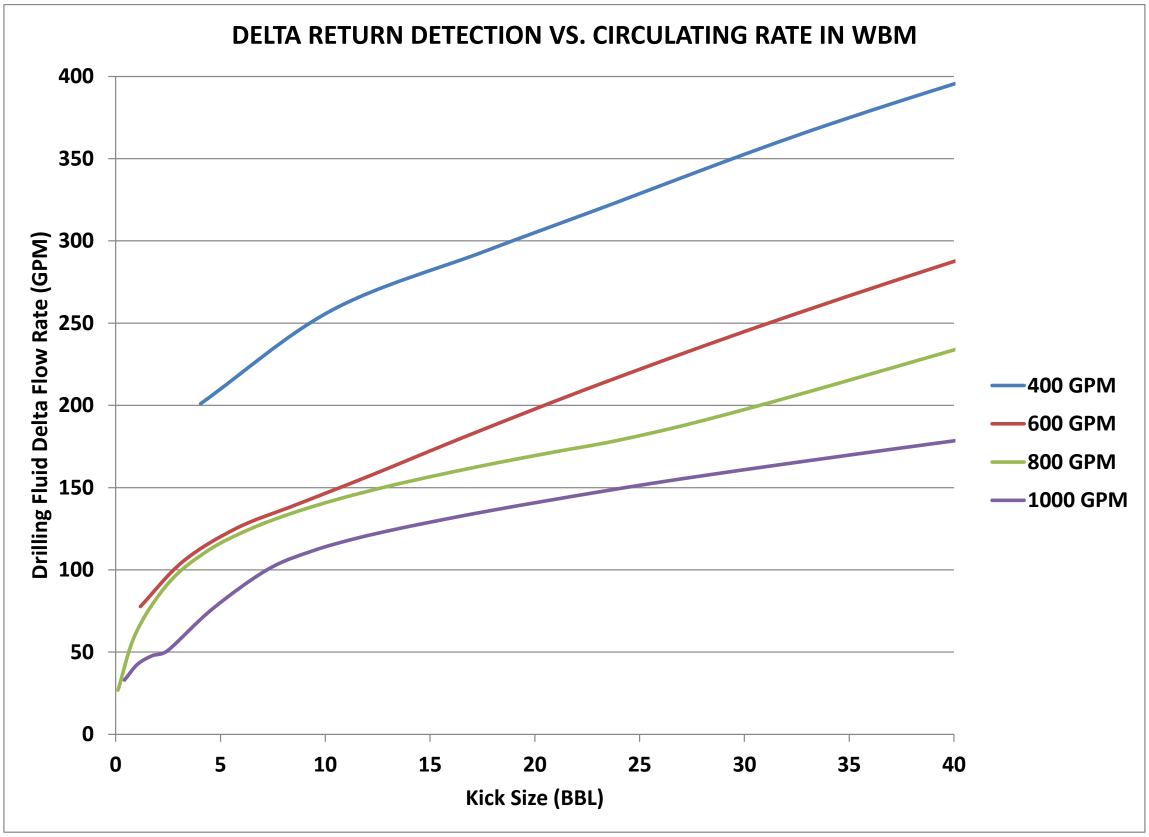

Fig. 19 - Effect of Circulation Rate on Delta Flow Detection

The delta flow rate to detection decreases with increasing flow rate. Delta flow detection will be more sensitive to a higher circulating rate than a lower rate. For the circulation rate range used in this study, the 1000 gpm rate is the most sensitive to delta flow. A nine bbl kick in these conditions reflects an 11% change in flow rate or delta flow to detection of 113 gpm. A 43 bbl kick is detected by a change in flow of 195 gpm, or 20% change in flow. In the case of the least sensitive scenario of 400 gpm circulating rate, a 10 bbl kick is detected by a 250 gpm delta flow or 64% change in flow rate. A 30 bbl kick in these conditions is detected by a 370 gpm delta flow and a 47 bbl kick a 420 gpm delta flow, suggesting that for a 40 bbl kick the delta flow to detection is somewhere between 90 and 105%.

3.3.3 Circulation Rate in Oil-Based Mud

The results for delta kick to detection at different circulation rates are seen below in **Fig. 20**.

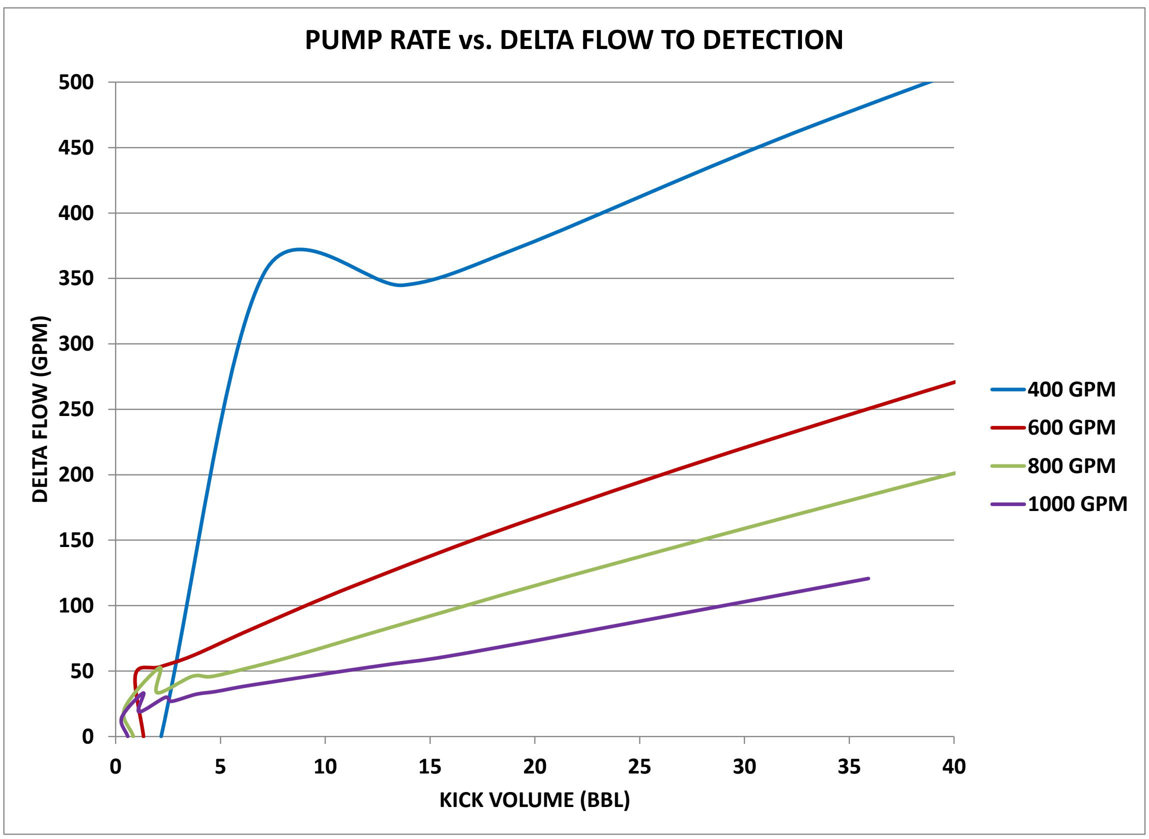

Fig. 20 - Effect of Flow Rate on Delta Flow for OBM

Visual check shows an irregularity in the 400 gpm case. The overall pattern follows suit with WBM, delta flow to detection will decrease with increased flow rate. There is a large step in delta flow from 400 to the next larger circulating rate. For the OBM case, a 10 bbl kick is detected by a delta flow of 106, 69, and 48 gpm for the 600, 800 and 1000 gpm circulation rates, respectively. This accounts for delta flow differences of 18%, 9%, and 5% respectively. The 1000 gpm circulation rate is the most sensitive to delta flow and it approaches a delta flow difference under 5% to detect a 10 bbl kick.

3.4 Water Depth

The simulations for water depth were performed maintaining a fixed TVD and adjusting water depth per the previously mentioned steps. The TVD was held constant at 20,000 ft. Adjusting the water column length will adjust riser length. A comparison of the effects of delta flow to detection for a given kick size with varying water depth is performed in the following sections. Simulations were done for water depth looking at a low circulation rate (400 gpm) and a higher end circulation rate of 1000 gpm. The reported results for the water depth study are for the 400 gpm rate case. Also for this case, the kick intensity was increased to 2 ppg, as was done for the circulating rate study. This, as mentioned previously, differs from the 300 gpm case and the cause is ECD.

3.4.1 Water Depth Using Water-Based Mud

The results of study of the effect of water depth on delta flow rate to kick detection indicate that the smallest delta flow occurs at shallow depth. This can be seen by **Fig. 21**.

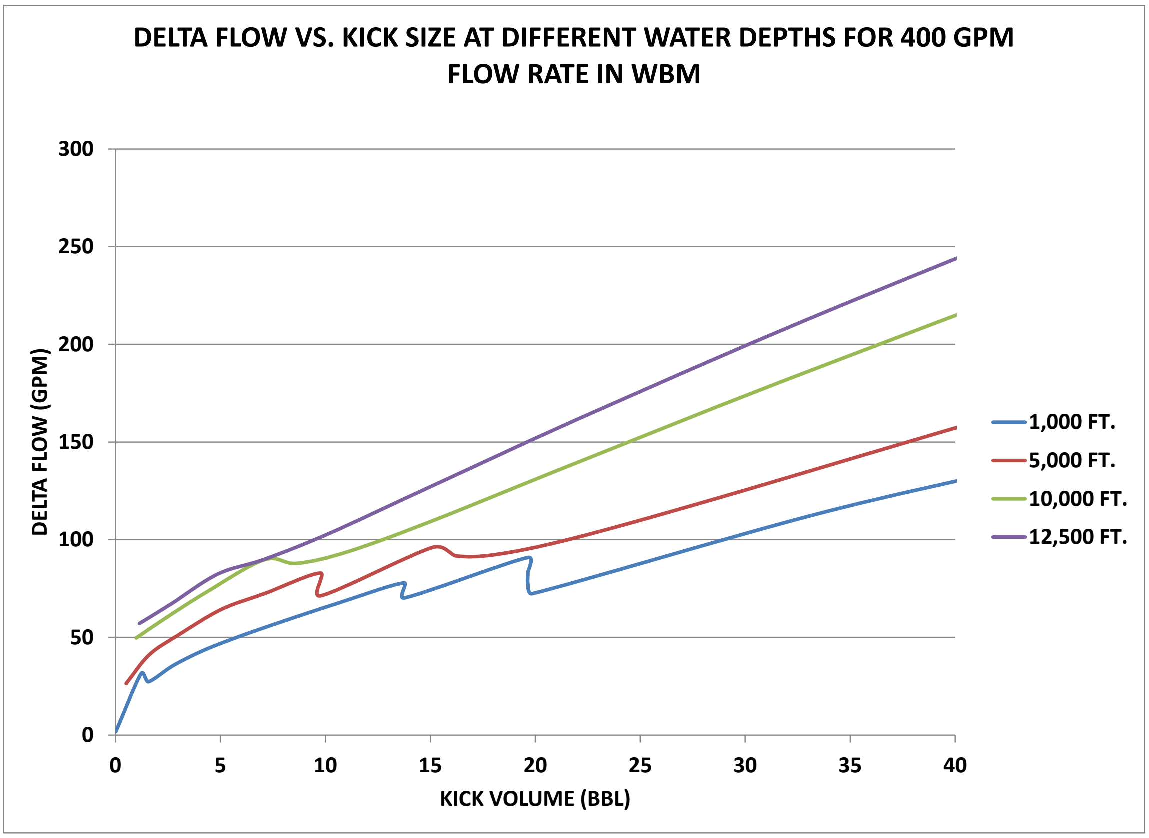

Fig. 21 - Effect of Water Depth on Delta Flow Detection (After Shanghai Study)

For detection of a 10 bbl kick in 1,000 ft. of water, a 58 gpm change in rate (15% change in rate at 400 gpm circulating rate) is the delta flow to detection. A 40 bbl kick would be detected by a 129 gpm, or 32%, delta flow. In 12,500 ft. of water, a 10 bbl kick is detected by a 102 gpm or 25% delta flow and a 40 bbl kick is detected by a 243 gpm or 61% delta flow.

3.4.2 Water Depth Using Oil-Based Mud

The result of water depth and its effect on delta flow in oil-based mud is seen in the following figure.

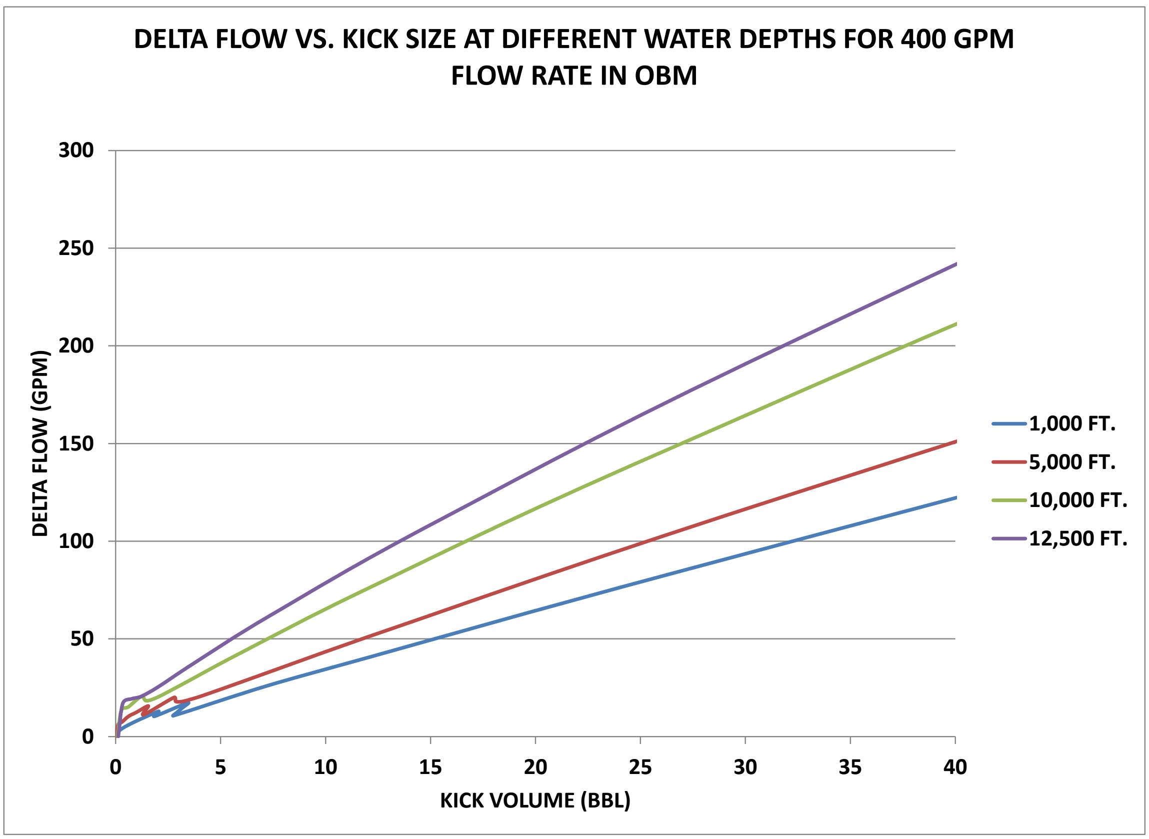

Fig. 22 - Effect of Water Depth on Delta Flow in OBM

In 1,000 ft. of water, a delta flow detection of 34 gpm (8.5% based on a 400 gpm flow rate) is required to detect a 10 bbl kick. A 40 bbl kick would be detected by a 122 gpm (31%) change in flow rate. In 10,000 ft. of water a delta flow detection of 65 gpm (16%) and 210 gpm (53%) flow rate is observed for 10 and 40 bbl kicks, respectively. These results are observes in **Fig. 22**.

Comparison of delta flow and water depth for WBM and OBM demonstrates the increased sensitivity in OBM, as observed in the other parameters studies. **Fig. 23** demonstrates this sensitivity.

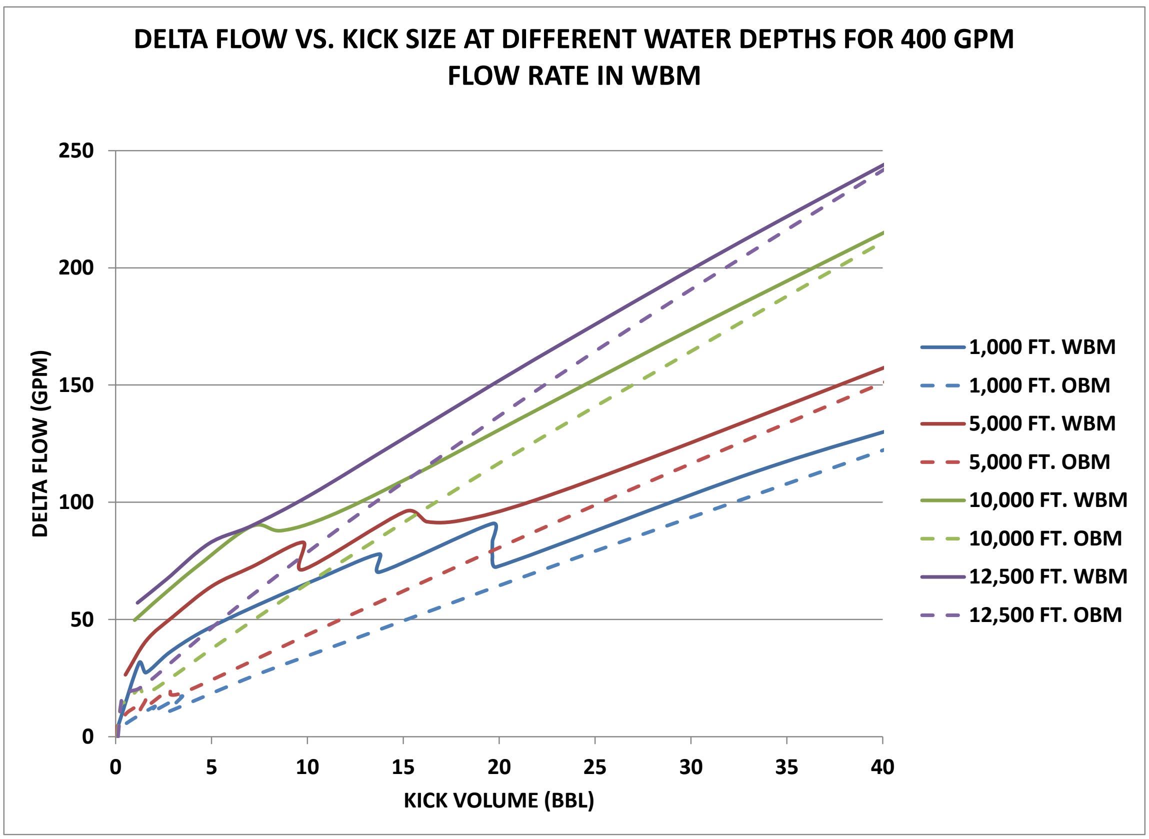

Fig. 23 - Comparison of Water Depth Effect on Delta Flow for WBM and OBM

Fig. 23 shows that the difference between delta flow sensitivity increases with decreasing water depth early in the kick occurrence. It is expected that in a real-life scenario, the delta flow fluctuations in OBM would be similar to those seen in WBM. This could indicate that the early difference between the WBM and OBM case would be lesser than that observed above. Analysis of the water depth parameter shows that the most sensitive delta flow for a given kick size should be expected at shallow depths in OBM.

3.5 Drilling Fluid Density

Drilling fluid density was compared using the density ranges proposed of 9 to 16 ppg. The circulation rate was the same as the base case of 300 gpm. It was observed that delta flow sensitivity increased with increasing drilling fluid density. The OBM case was once again more sensitive than the WBM cases. The results of the drilling fluid density parametric study are reported in the following sections.

3.5.1 Drilling Fluid Density in Water-Based Mud

The results of delta flow sensitivity based on a given kick size in WBM are seen in **Fig. 24**. The 9 ppg drilling fluid showed the least sensitivity to delta flow while the 16 ppg DF was the most sensitive for a given kick size.

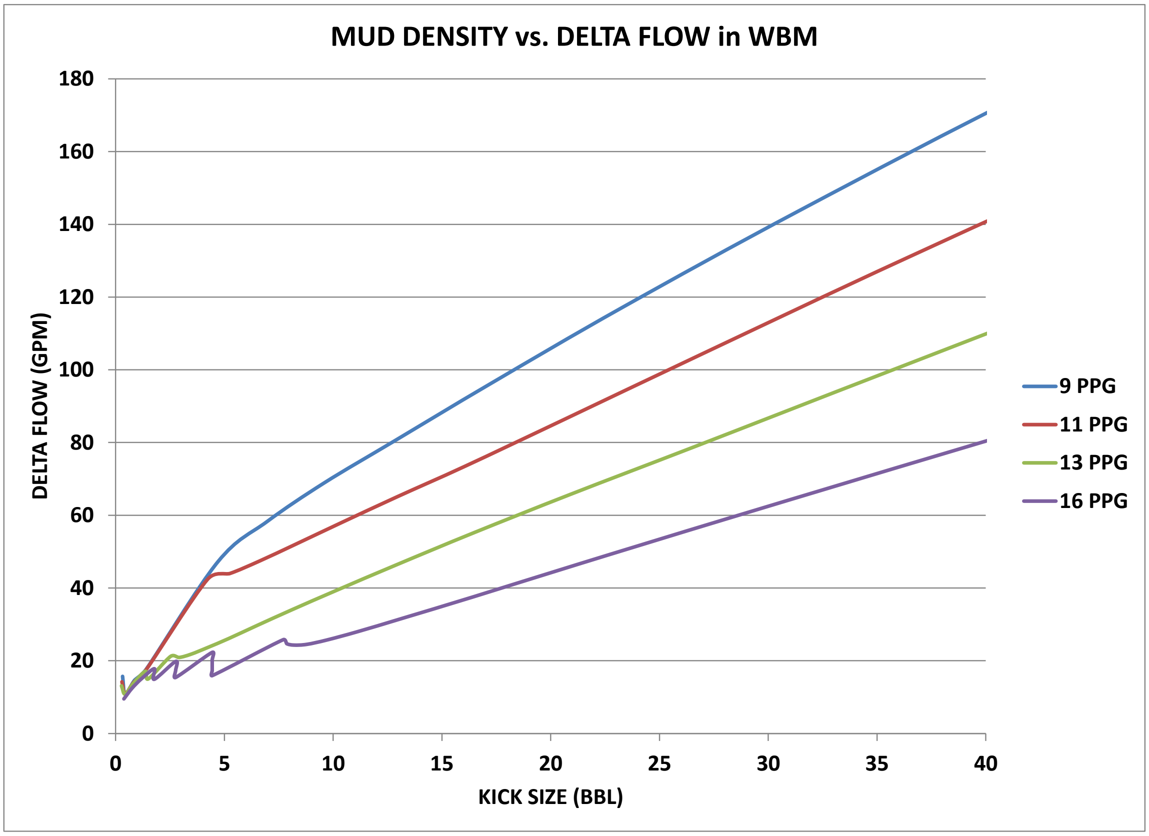

Fig. 24 - Effect of Drilling Fluid Density on Delta Flow Kick Detection

In the case of a 9 ppg mud, a 10 bbl kick is detected by a delta flow of 70 gpm or 23%. A 40 bbl kick is detected by a delta flow of 170 gpm or over 50%. For the 16 ppg case, kicks of 10 and 40 bbl are detected by delta flow rates of 26 gpm (8.7%) and 80 gpm (27%), respectively.

3.5.2 Drilling Fluid Density in Oil-Based Mud

The results of delta flow sensitivity to oil-based drilling fluid indicate the most sensitive case for this parameter. The following demonstrates the results of the OBM DF study:

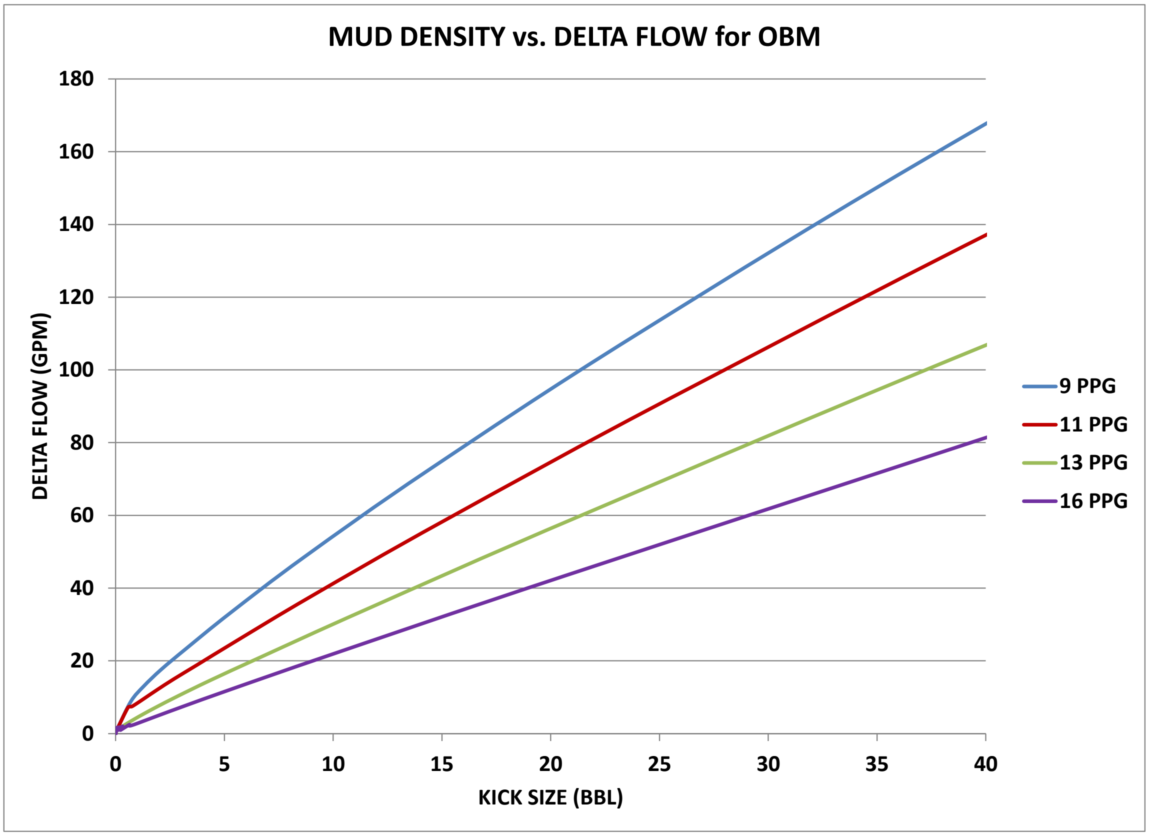

Fig. 25 - Effect of Drilling Fluid Density on Delta Flow in OBM

As seen in **Fig. 25**, For the 9 ppg density, a 10 bbl kick is detected by a delta flow of 54 gpm or 18%. A 40 bbl kick is detected by a delta flow of 167 gpm or 56%. For the 16 ppg case, kicks of 10 and 40 bbl are detected by delta flow rates of 21 gpm (7%) and 81 gpm (27%), respectively.

Comparison of WBM and OBM cases is shown in **Fig. 26**:

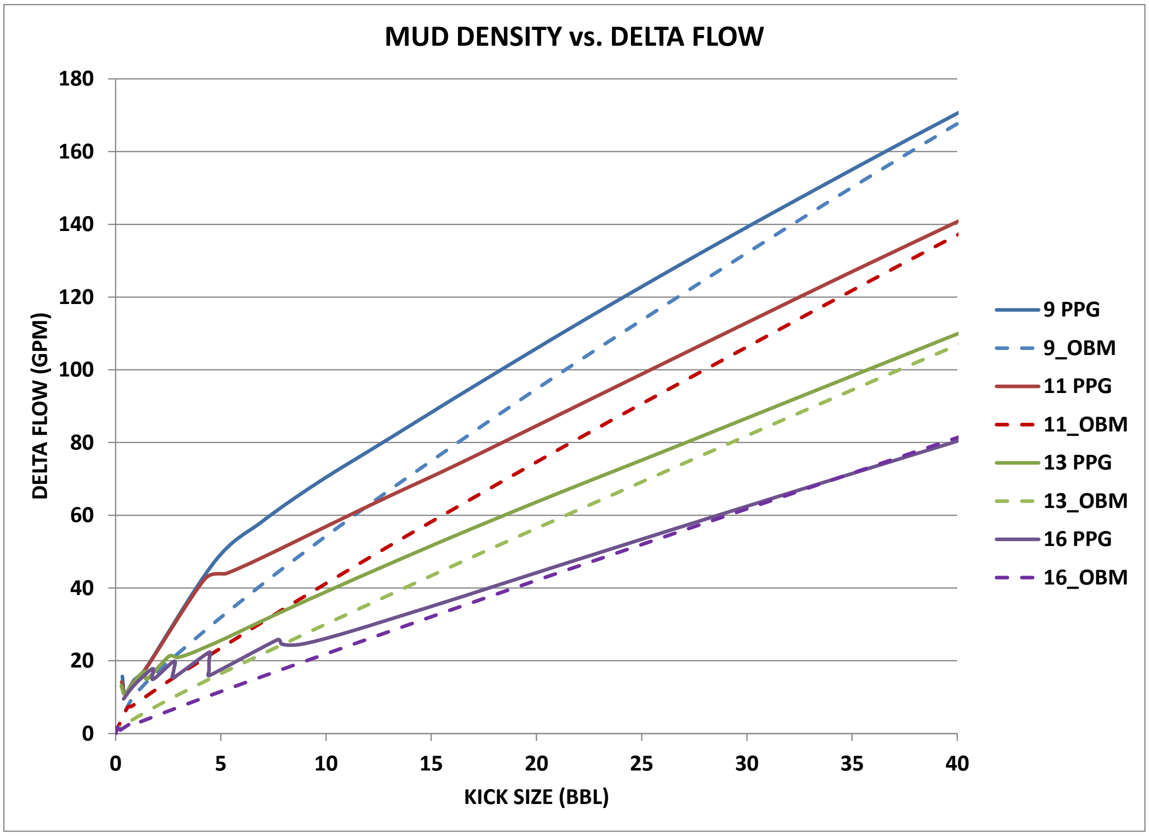

Fig. 26 - Comparison of Mud Density Effect on Delta Flow for WBM and OBM

Based on the results, it appears that there will be a larger delta flow in OBM than WBM for the 16 ppg case. This should not occur in real-life conditions and the result is believed influenced by the inconsistency of OBM kick calculations for large volumes. Comparison at more reasonable, smaller (more desired from a well control standpoint) volumes holds the trend of increased sensitivity in OBM due to solubility.

3.6 Kick Intensity

The second kick parameter of study is kick intensity. Kick intensity was compared against all drilling parameters in the same manner done in the above sections. Based on the relationships established comparing kick volume to all drilling parameters, the most sensitive scenarios can be more efficiently compared. For example, it is known that for depth the most sensitive scenario is in shallow water and/or TVD. It is thus expected that once an understanding of kick intensity sensitivity is determined, it can be coupled with the known drilling parameter sensitivities to obtain the highest level of accuracy (sensitivity) that will be required of the sensor.

The boundaries of study for kick intensity were original 0.5- 2.5 ppg. In the majority of cases, a 0.5 or 1 ppg KI would not produce a kick while circulating. This is due to the ECD of circulating and the effect on BHP. Many scenarios were attempted to be able to "see" a kick at these low intensities with lowered densities and lowered circulation rates. Some scenarios showed kicks but of negligible influx rate for a well control issue. In these cases, often times the circulation rates and mud densities are unreasonable in a real-life condition. Thus, the majority of reported results for kick intensity are within a range of 1.5 – 2.5 ppg, unless a lower KI was feasible.

Flow check scenarios with no ECD allow observance of kicks with low intensities. Although it has been previously revealed the effect of flow checking on delta flow detection, a case will be shown so as to be able to see the relationship at the low range of intensities. The following sections report the results of the KI study.

3.6.1 Kick Intensity for Shallow TVD Scenario

This study was done while circulating and ranges of kick intensity were obtained between 1.5 to 2.5 ppg. This scenario was chosen because of the known sensitivity of delta flow detection and shallow depths. In this scenario, there is 2,500 ft. of hole in 10,000 ft. of water. Results show that delta flow to detection increases in sensitivity as kick intensity decreases. This is reasonable and can be best explained by the darcy equation which defines the flow from the reservoir into the annulus:

$$q = \frac{703 k_g h (p_e^{\ 2} - p_{wf}^{\ 2})}{\mu_g T z (\ln \frac{r_e}{r_w} - 0.75)} \qquad (15)$$

Kick intensity can be seen in the term of (pe^2 - pwf^2). Recall that p_e is reservoir pressure and for this study p_{wf} would be the bottomhole ECD. Increasing kick intensity will make this term larger and increase q, or flow into the annulus, and cause a greater rate of increase of return flow rate. A larger rate of increase in return flow rate will develop a larger delta flow for a given kick size. Thus, knowing smaller kick intensity will cause the pressure drop term to reduce, one can conclude it will cause a smaller rate of increase in return flow rate for a given kick size.

The results of the scenario described above can be seen in **Fig. 27**:

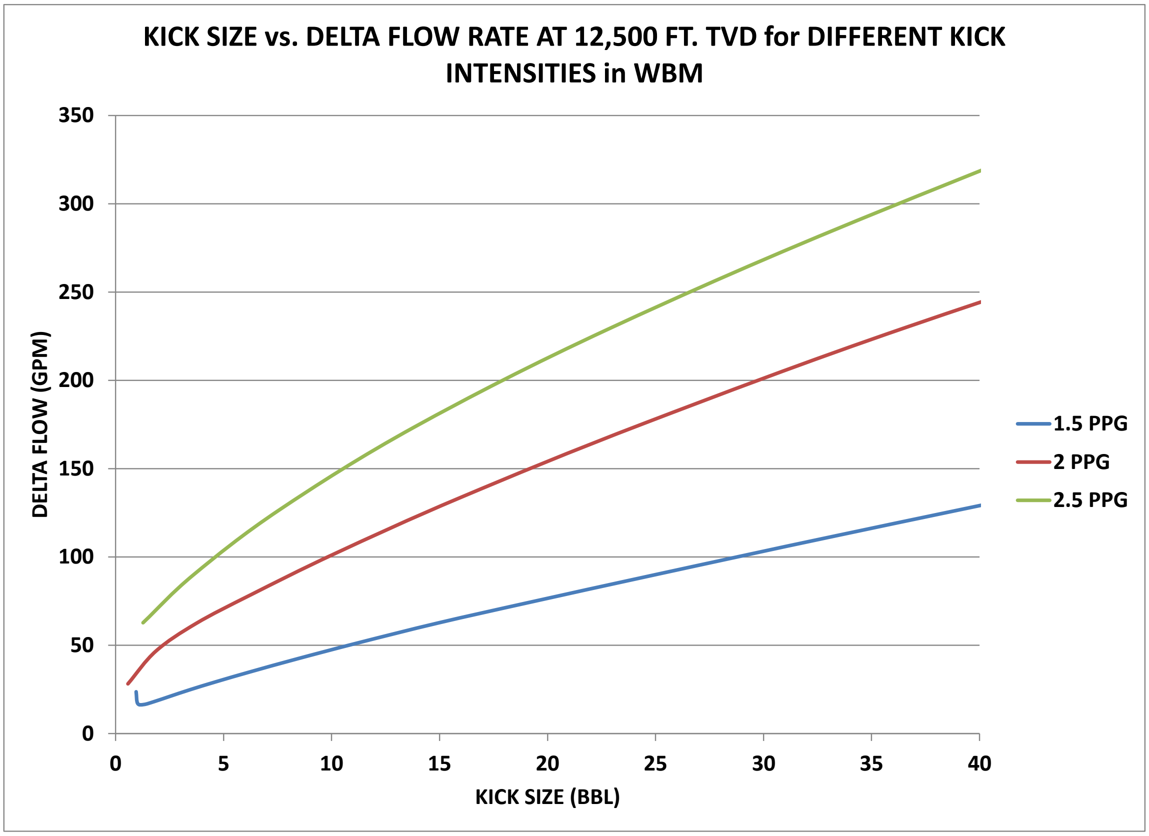

Fig. 27 - Effect of Kick Intensity on Delta Flow Detection for Given Kick Size

It is seen from **Fig. 27** that the lesser KI produces the highest sensitivity. For a KI of 1.5 ppg, a 10 bbl kick is detected by a delta flow of 47 gpm or 16%. A 40 bbl kick can be detected by a delta flow of 128 gpm or 43%. For the 2.5 ppg case, a 10 bbl kick can be detected by a 144 gpm, or 48% delta flow accuracy.

3.6.2 Kick Intensity for Shallow TVD Scenario in OBM

The results for the OBM case are in the following figure:

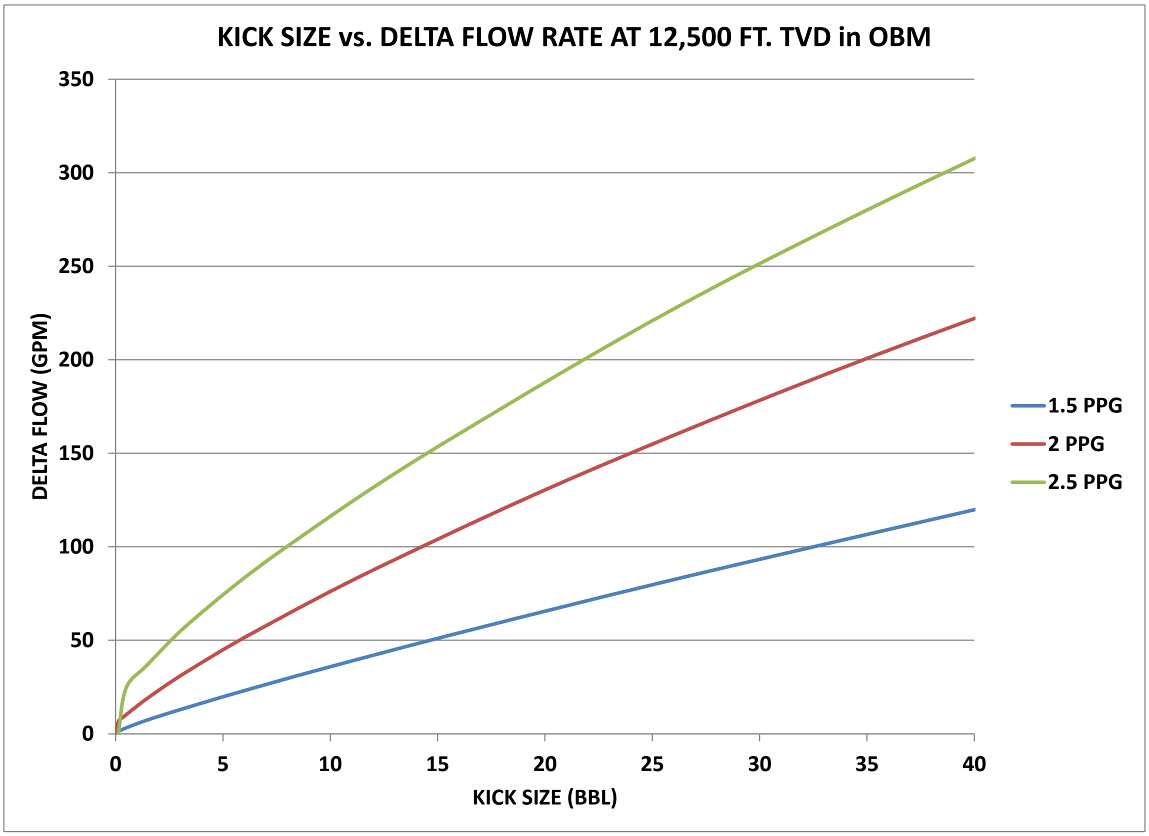

Fig. 28 - Effect of Kick Intensity on Delta Flow for OBM Case

Fig. 28 shows that for a kick intensity of 1.5 ppg, a 10 bbl kick can be detected by a 36 gpm or 12% delta flow accuracy. A 40 bbl kick can be detected by a 120 gpm or 40% delta flow accuracy. A comparison of the WBM and OBM cases is seen in **Fig. 29**:

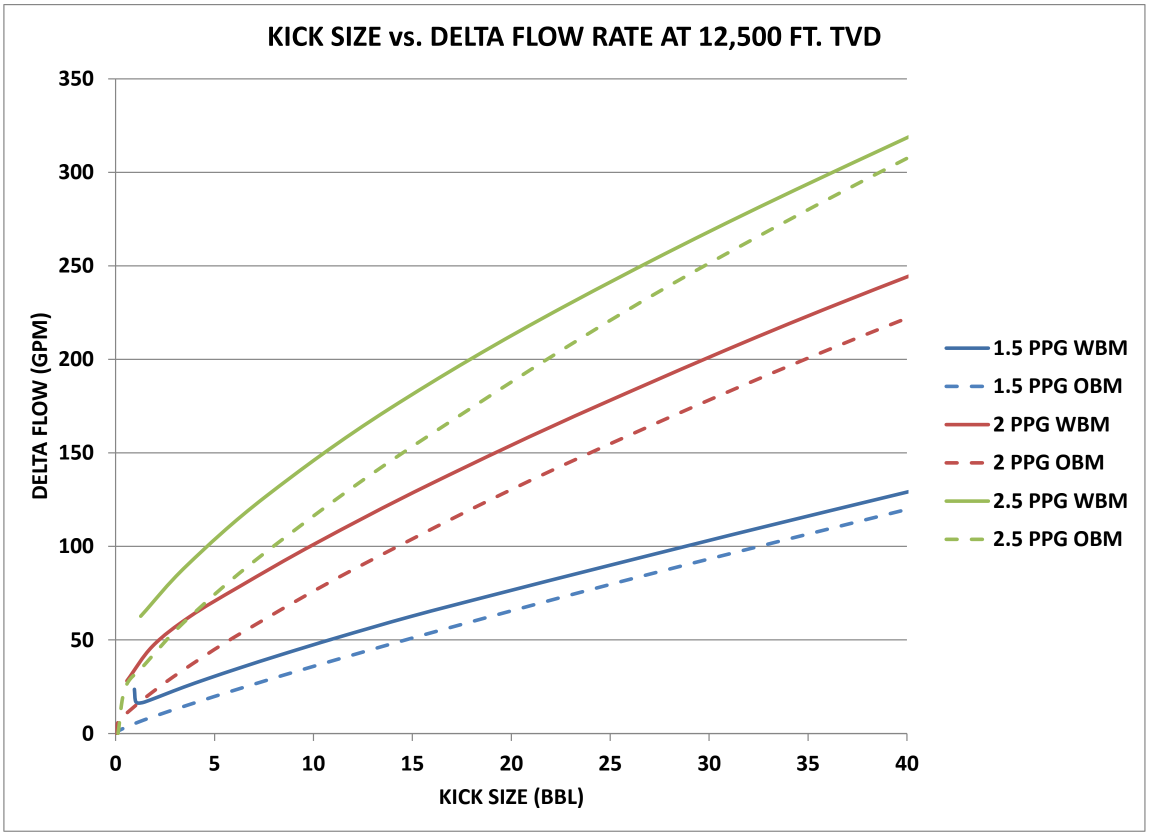

Fig. 29 - Comparison of WBM and OBM Cases for Kick Intensity

3.6.3 Full Range Kick Intensities for Flow Check Scenario

So as to show the effect of the entire range of kick intensities (0.5 – 2.5), the flow check simulation scenarios are reported in this section. It is important to note that for this scenario, drilling is stopped at the overpressured formation and pumps are shut off. The well is hydrostatic. Thus, circulation flow rate is irrelevant to the flow check scenario as no circulation is occurring. Nevertheless, the flow rate used to get to the overpressured depth was 400 gpm for these runs. For WBM, a comparison of the effect of kick intensity on delta flow is seen in **Fig. 30**.

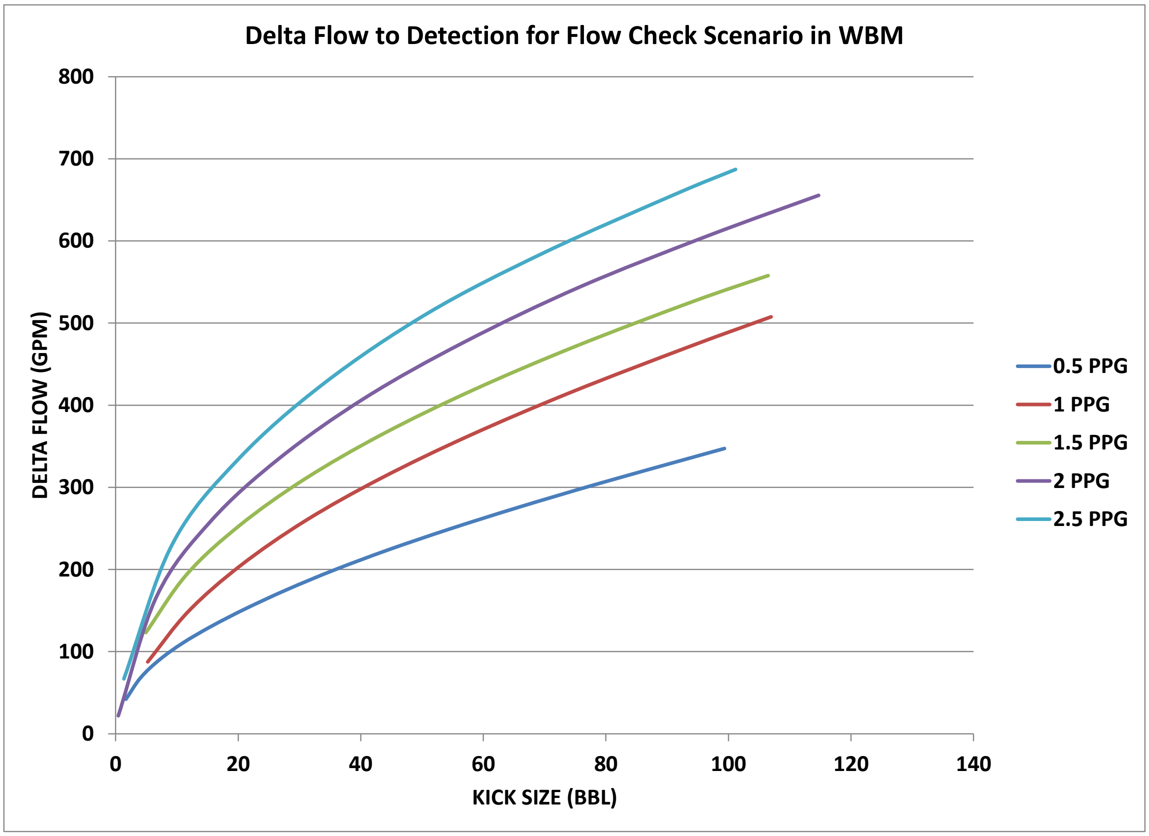

Fig. 30 - Effect of Kick Intensity on Delta Flow for Hydrostatic Well Conditions

As in the dynamic scenario, delta flow will be most sensitive to a small kick intensity scenario. A 10 bbl kick caused by an overpressure of 0.5 ppg will be detected by a delta flow of 105 gpm. A 10 bbl kick in caused by an overpressure of 1 ppg will be detected by a delta flow of 238 gpm.

This example demonstrates the effect of a 0.5 ppg overpressure on delta flow. It has been explained that this overpressure will not cause a kick while circulating for the ranges of study. It has been demonstrated that for the kick intensity parameter, for all scenarios considered, a smaller kick intensity will cause the greatest sensitivity in delta flow. However, this example shows that the greatest sensitivity will occur in circulating conditions, even though the kick intensity for circulating conditions may be higher than static conditions. This, again, is due to the effect of annular friction while circulating.

3.7 Kick Intensity and Water Depth

The results of delta flow sensitivity for the extreme cases of water depth, 1,000 and 10,000 ft., were determined. The TVD for these wells is 20,000 ft. at 300 gpm circulating rate. It is known from the previous study of water depth that the shallow situation will pose the greatest delta flow sensitivity. A comparison of the two extreme cases is done to demonstrate the scale of magnitude of sensitivity. It was determined that a shallow water depth combined with a low kick intensity will provide one of the most sensitive scenarios of the study, which will be discussed further later in this work.

3.7.1 Kick Intensity and Water Depth in WBM

The results for the 1,000 ft. water depth case are provided in **Fig. 31**:

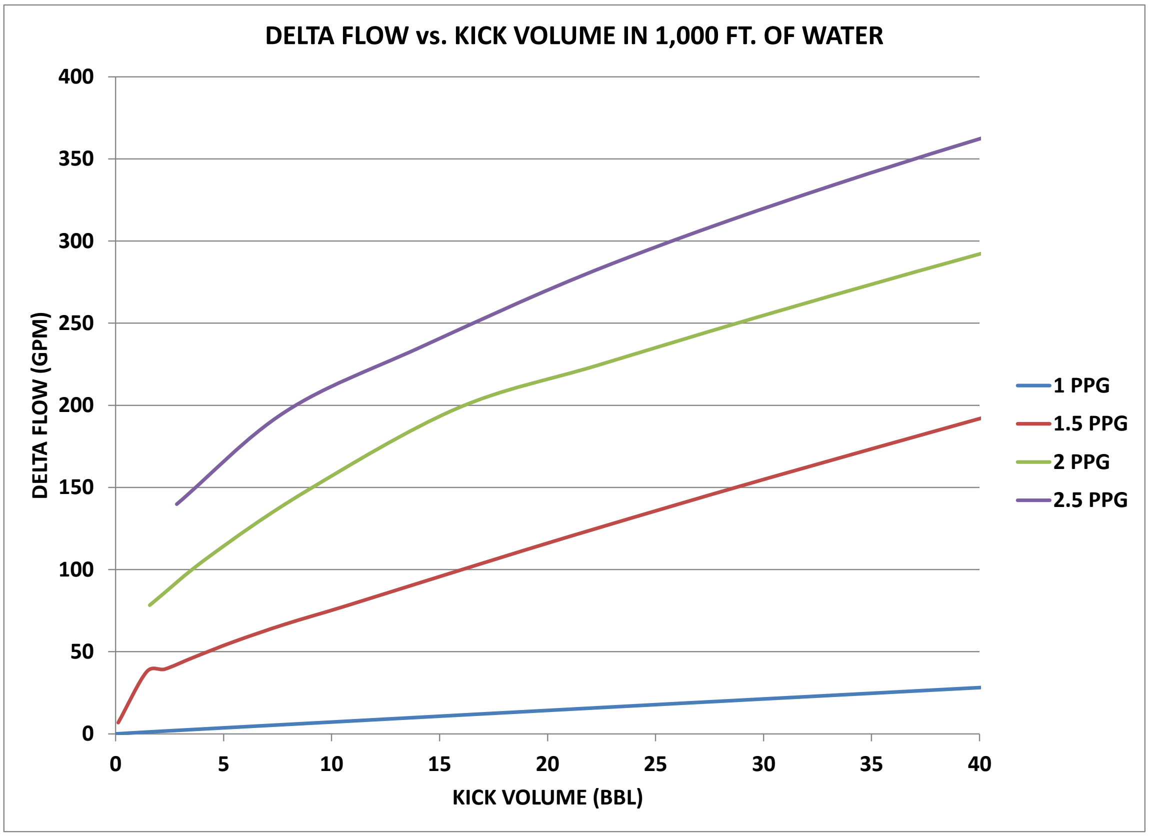

Fig. 31 - Effect of Kick Intensity in 1,000 Feet of Water

Delta flow will be most sensitive in a 1 ppg overpressure scenario. The delta flow to detection for a 10 bbl kick at 1 ppg KI will be 7 gpm, or only slightly greater than two percent. Four percent accuracy could detect a kick size of 17 bbl in this scenario. Five percent accuracy could detect a kick size of 21 bbl. A 40 bbl kick would be detected by a delta flow of 28 gpm or 10% accuracy. A 10 bbl kick for a 2.5 ppg KI would be detected by a delta flow of 210 gpm or 70%.

The results for kick intensity in 10,000 feet of water are reported in **Fig. 32**.

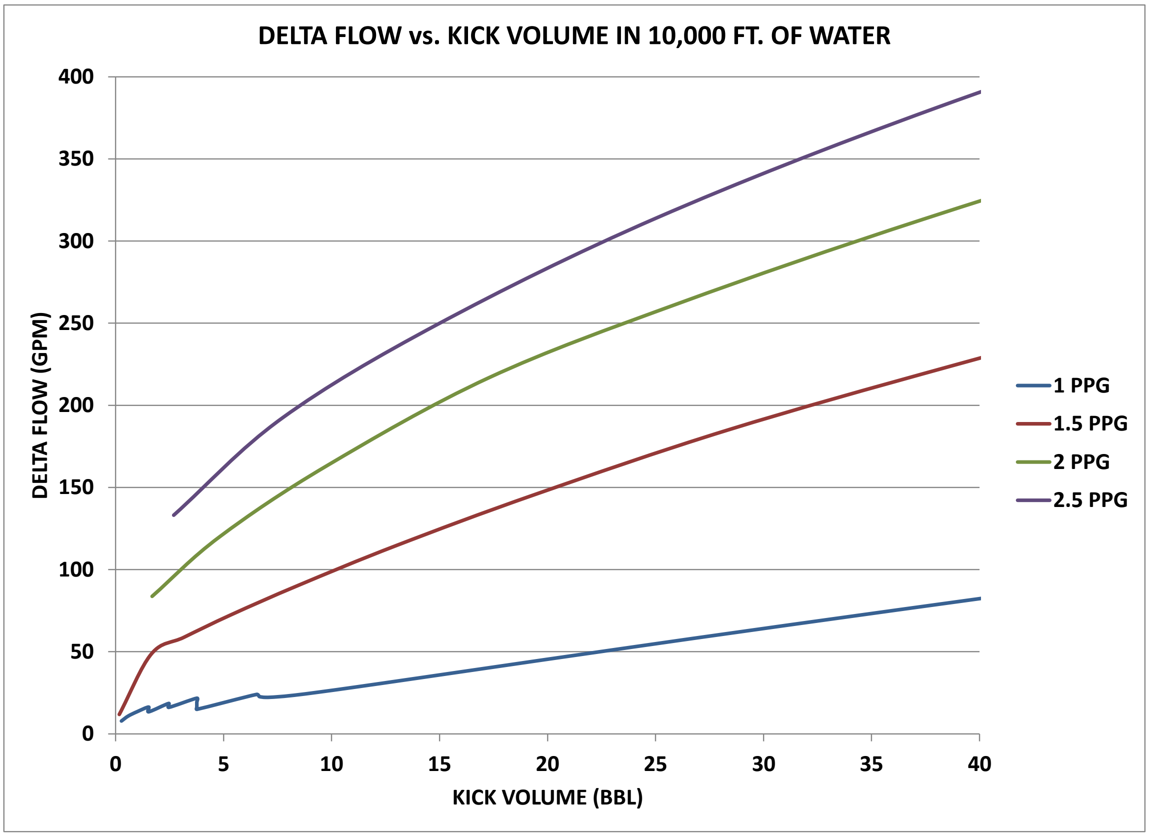

Fig. 32 - Effect of Kick Intensity on Delta Flow in 10,000 ft. of Water in WBM

A delta flow of 26 gpm or 9% accuracy will detect a 10 bbl kick for a 1 ppg overpressure in 10,000 ft. of water. A 10 bbl kick for 2.5 ppg overpressure can be detected by a delta flow of 210 gpm or 70% change in flow.

The results for OBM for kick intensities greater than 1.5 ppg experience the same inconsistency as was observed for 1,000 ft. of water with a small KI. The OBM volume for the same delta flow as WBM is greater, and is not reported. The sensitive case of 1 ppg overpressure produces a delta flow of 7% or 22 gpm for a 10 bbl kick. There is little difference between sensitivities for OBM and WBM for this case.

3.7.2 Kick Intensity and Water Depth in OBM

The results for OBM for one pound per gallon kick intensity did not agree with previously established results and relationships. This effect is believed to be due to limitations from the HP/HT effects (19,000 PSI) on gas compressibility correlations used and also the sensitivity of bottomhole pressure as the equivalent circulating density approaches the overpressure. The results for 1.5, 2, and 2.5 pound per gallon kick intensities are reported in **Fig. 33**.

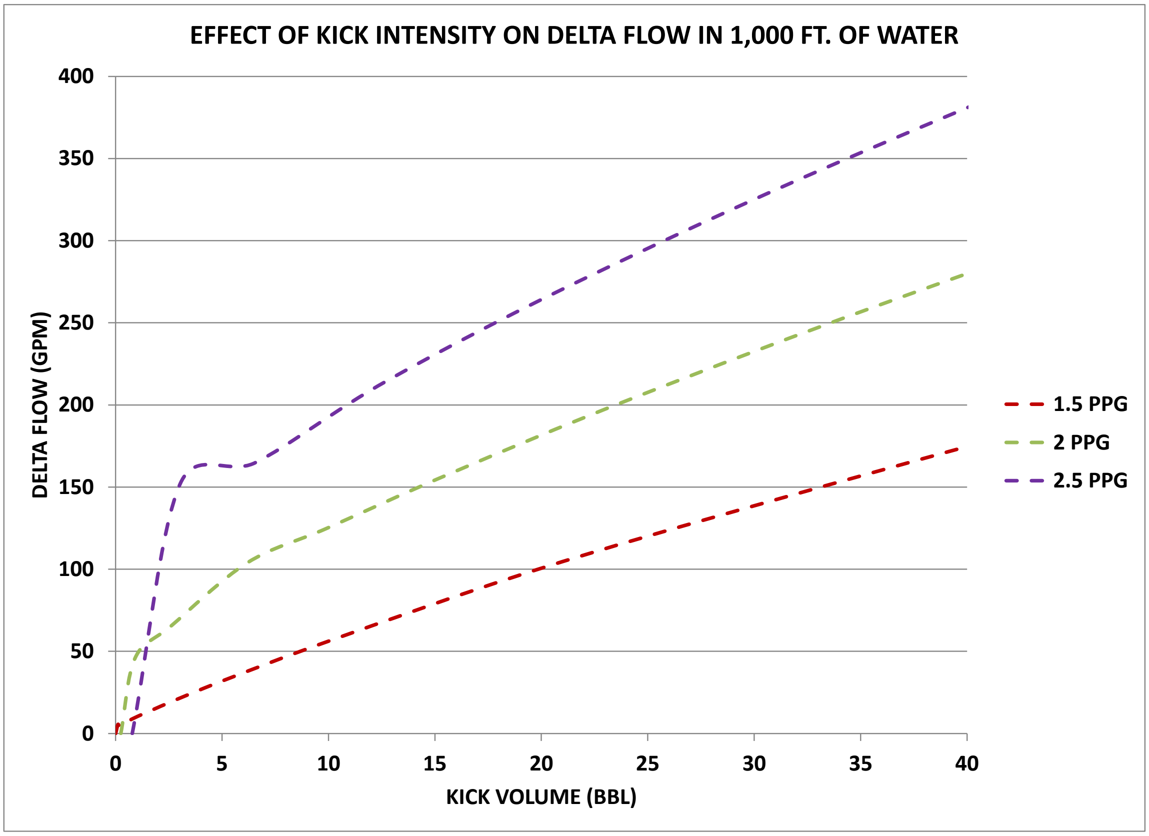

Fig. 33 - Effect of Kick Intensity on Delta Flow in 1,000 ft. of Water in OBM

A 10 bbl kick can be detected by 19% accuracy or 56 gpm delta flow given a 1.5 ppg KI. In the 2.5 ppg overpressured scenario, a 10 bbl kick will be detected by a 193 gpm delta flow or over 60% accuracy. Comparison of OBM to WBM is seen in **Fig. 34**:

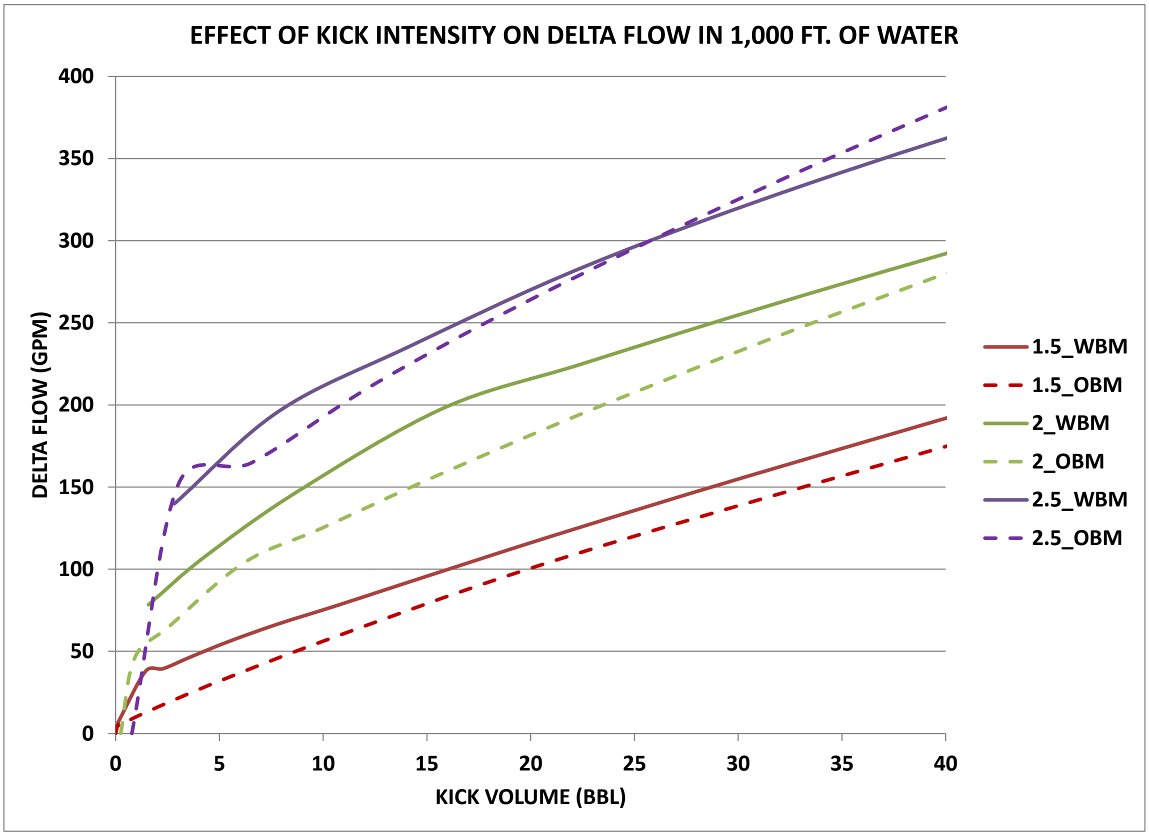

Fig. 34 - Comparison of Kick Intensity and Delta Flow for WBM and OBM

The 2.5 ppg overpressure shows the delta flow increasing more for OBM than WBM for a kick volume approximately greater than 25 bbl. This is believed to be affected by the limitation of OBM calculations for large kick sizes. This plot further demonstrates the increased sensitivity for OBM drilling.

3.8 Kick Intensity and Density

It has been determined that delta flow sensitivity increases with increasing drilling fluid density. For the range studied, the 16 ppg DF was determined as being most sensitive to delta flow. Sensitivity further increases when coupled with decreasing kick intensity. The results of the kick intensity and density study are reported in the following sections.

3.8.1 Kick Intensity and Density in WBM

The one ppg kick intensity has been determined as most sensitive in this scenario that will still give an underbalanced situation for the base conditions. A one ppg kick intensity together with the highest mud weight of study should produce the most sensitive situation. The results of the study in WBM are observed in **Fig. 35** and verify this hypothesis.

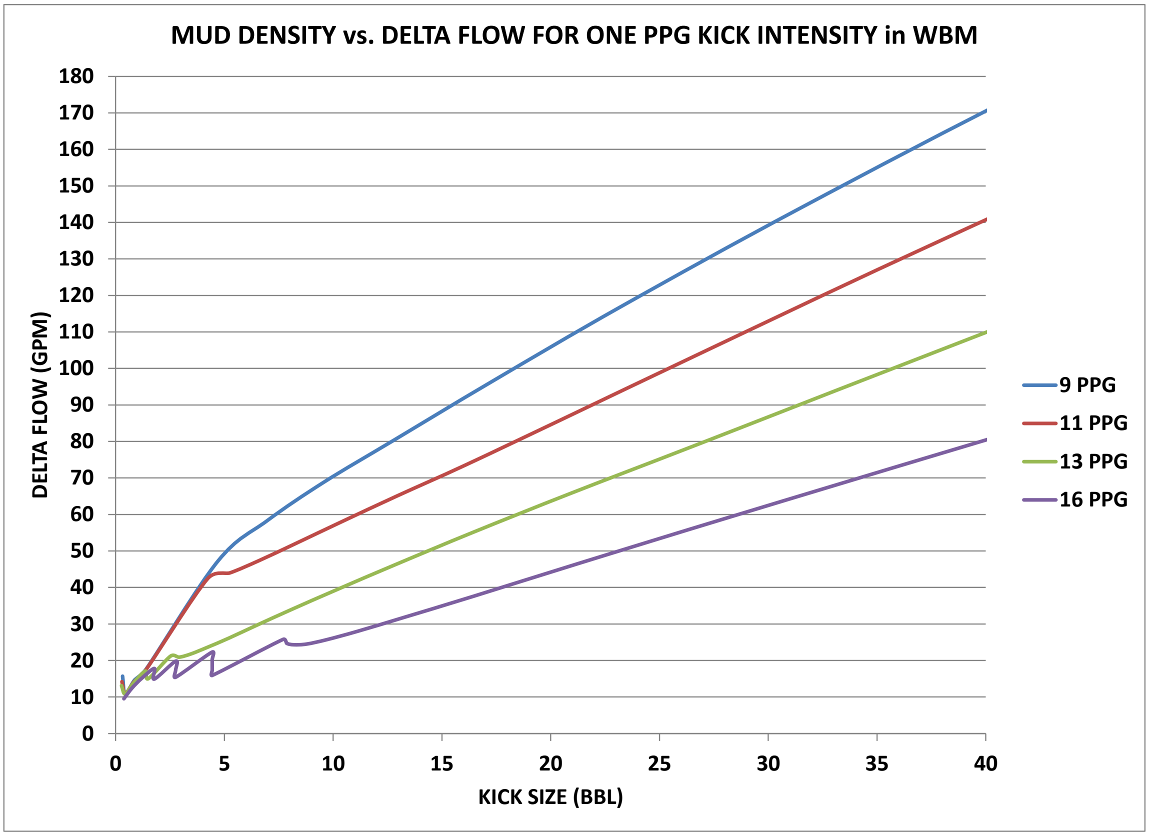

Fig. 35 - Effect of Kick Intensity and Drilling Fluid Density on Delta Flow in WBM

The 16 ppg density, one ppg overpressure scenario does prove to provide the most sensitive delta flow. A 10 bbl kick is detected by a 26 gpm or 9% delta flow. For a nine ppg drilling fluid, a delta flow of 70 gpm or 23% will detect a 10 bbl kick as shown in **Fig. 35**.

3.8.2 Kick Intensity and Density in OBM

The results for the study in oil-based mud are reported in **Fig. 36**:

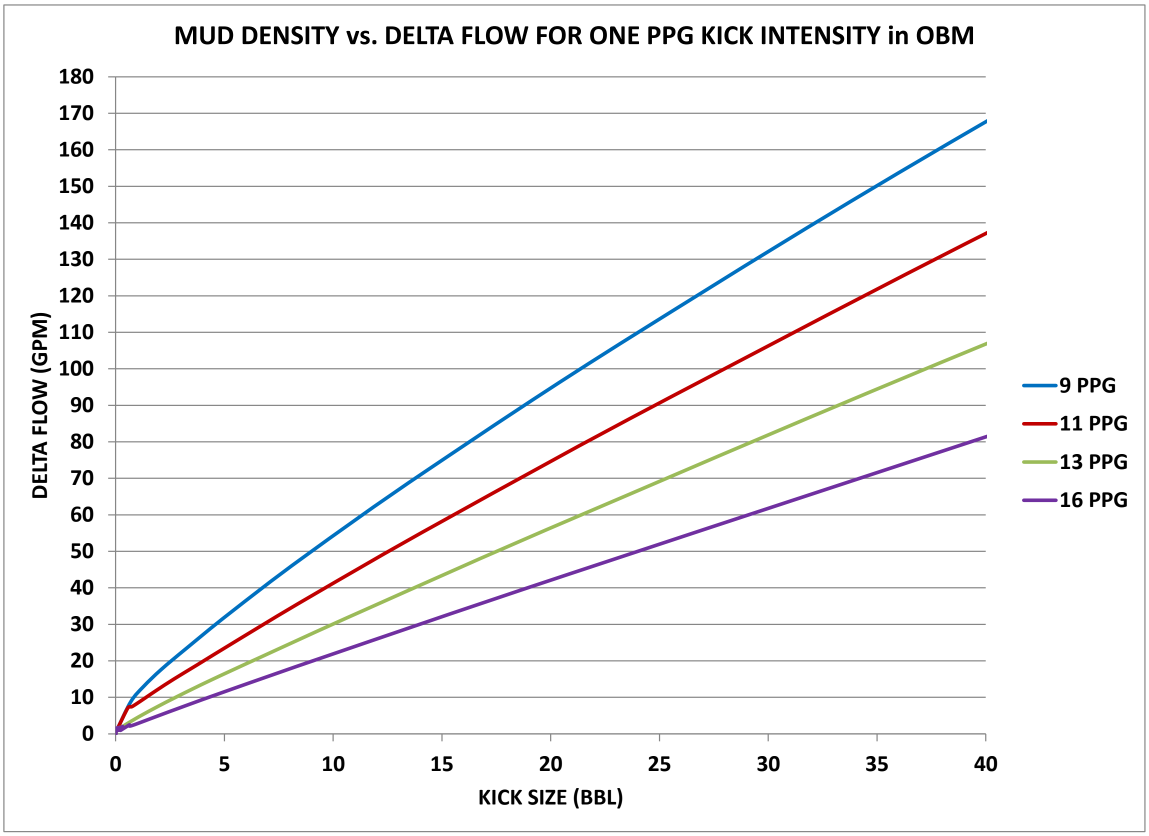

Fig. 36 - Effect of Kick Intensity and Drilling Fluid Density on Delta Flow in OBM

A 10 bbl kick in 16 ppg OBM is detected by a delta flow of 22 gpm or 7% accuracy. The same kick in 9 ppg OBM is detected by a delta flow of 54 gpm or 18% accuracy.

Comparison of the scenario for both WBM and OBM is reported in **Fig. 37**:

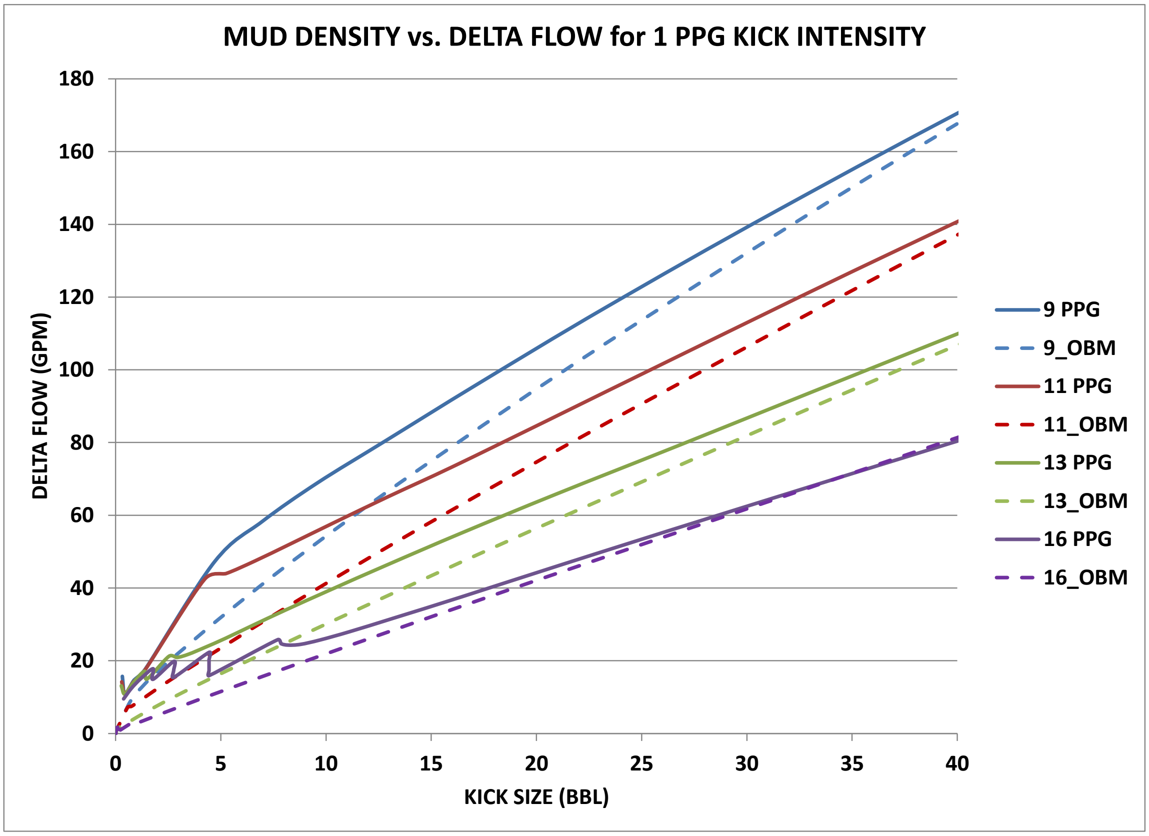

Fig. 37 - Mud Density and Kick Intensity Effect on Delta Flow for WBM and OBM

Once again, the increased sensitivity of OBM to WBM is observed. The most sensitive scenario for this comparison was a 7% accuracy (22 gpm) delta flow in the case of a 10 bbl kick for the a drilling fluid density and kick intensity of 16 ppg and 1 ppg, respectively.

4. DISCUSSION OF GAS SOLUBILITY IN OIL-BASED DRILLING FLUID

Several OBM calculations showed limitations in OBM delta flow calculations. As kick size approached large volumes, ranging from greater than 20 or greater than 40 or 50 barrels depending on the parameter, the OBM kick volume could be seen approaching or even exceeding the volume observed in WBM. For large kick intensities, this trend is also observed for volumes exceeding 20 barrels. It is theorized that some of the effect is caused by gas compressibility correlations not meeting the PT ranges studied (recall Calculation of Kick Influx in OBM), which has already been discussed. To determine the validity of the detection ranges, this section identifies previous work done in the area of gas solubility in drilling fluid and the effect it has on pit gain measurement.

4.1 Gas Kick in Synthetic-Based Mud

Calculation of gas solubility in synthetic drilling fluid has been previously investigated (Lima et al. 1999; Monteiro et al. 2010; O'Bryan et al. 1988; Thomas et al. 1984). Lima et al. performed a calculation for determination of kick detection in a riserless drilling configuration. They assumed a synthetic-based mud (SBM) with a certain oil phase fraction. Mud compressibility was not considered. The calculation uses heat transfer principles, a Power Law hydraulic model, and the Soave-Redlich-Kwong equation of state (EOS), and assumes a methane gas kick. The volume of fraction of oil, or fluid in which a methane gas kick is soluble, was 0.58. The scenario is observed in **Table 15**.

Based on these assumptions, the authors determined that for a 10 bbl kick at bottomhole conditions, an 8.5 bbl kick would be observed at the surface. The results can be observed in **Fig. 38**:

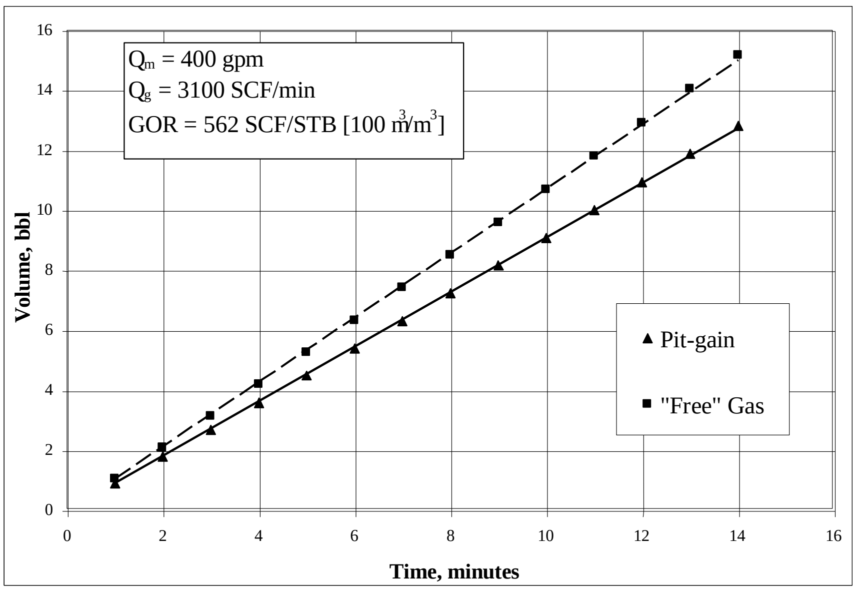

Fig. 38 - Lima et al. SBM Kick Pit Gain Comparison

A conclusion drawn from the study was that the pit gain versus volume of free gas followed a semi-linear trend on a pit gain-time scale, as observed in **Fig. 38**. In this study, the pit gain in OBM was observed to be somewhat linear to that of WBM compared against delta flow.

A similar run was done by the simulator as that performed by Lima et al. The conditions are found in **Table 15**:

Table 15 - Lima et al., Simulator Run Comparison

Parameter	Lima et al.	Choe Simulator	Unit
TVD	20,000	20,000	ft.
Hole Diameter	8.5	8.5	in.
Water Depth	10,000	10,000	ft.
Influx Rate	3,100	*Varies*	SCF/min
Circulating Rate	400	400	GPM
f	0.58	1.00	
VKICK	10	10	BBL
GOR	562	*Varies*	SCF/STB

Before comparison is done, note three main differences. The Lima et al. example performs calculation with a constant influx rate. The simulator more realistically mimics the increasing influx that will occur as the annular drilling fluid column is displaced by more and more gas, decreasing the BHP and further increasing influx rate. The second major difference is the drilling fluid assumption used by Lima et al. They assume a SBM with an oil (fraction gas is potentially soluble in) fraction of 0.58. The calculation done for this study assumes a 100% oil (diesel) phase, providing more volume per unit volume for a gas kick to become soluble in. Finally, GOR cannot be adjusted with the simulator and will be a function of influx rate and circulation rate and thus the volume of drilling fluid contacted by the influx. Doing a conceptual comparison of the two scenarios, one would expect that the simulator kick volume seen would be less than Lima et al. for the same conditions.

It is difficult to compare these scenarios for kick volume and time. As mentioned, the influx rate is not constant for the simulator, so it is not possible to compare kick volume and time for both scenarios. The kick volume will be increasing exponentially while kick volume increases linearly for Lima et al. Thus, for the simulator scenario, kick volumes are compared against a fixed delta flow. That is to say, compare the volume of OBM versus a 10 bbl kick in WBM for a fixed flow value.

The plot of the simulator run for this scenario is seen in **Fig. 39**:

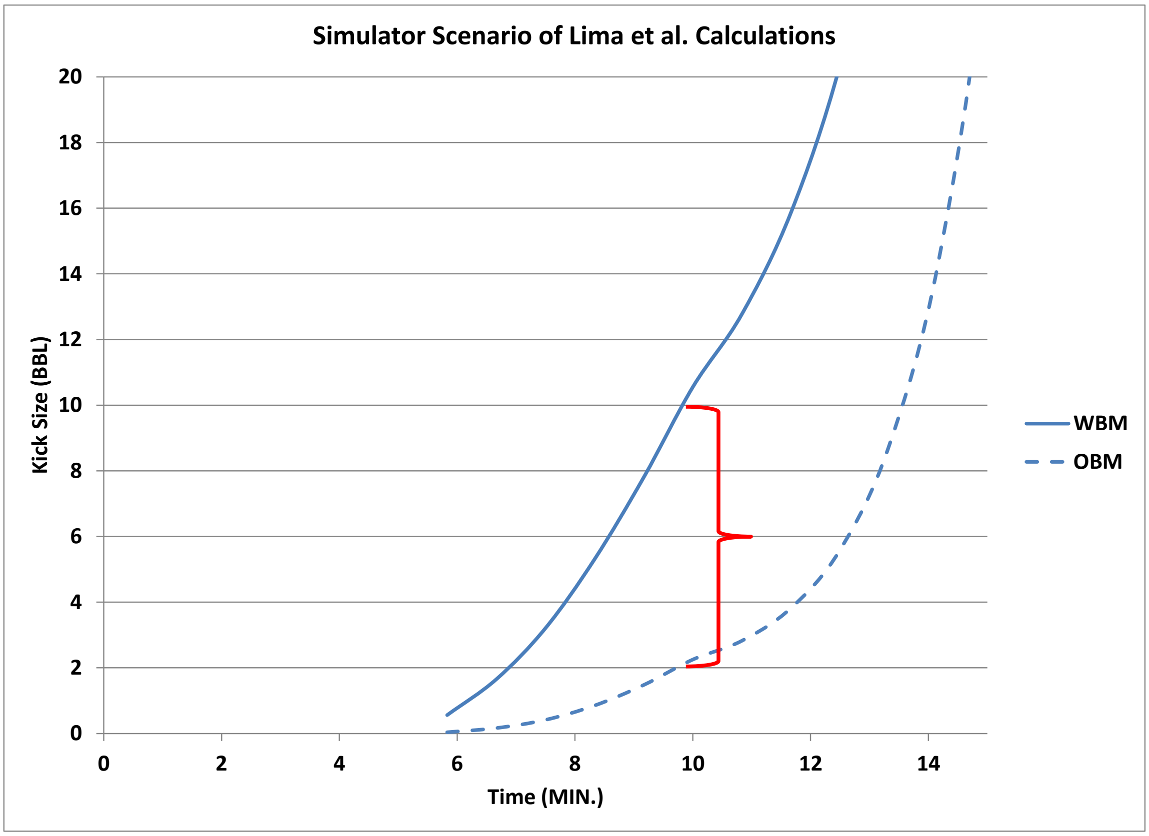

Fig. 39 - Simulator Approximation for Lima et al. Kick in SBM Scenario

For a 10 bbl kick in WBM, a 2 bbl kick is seen in OBM. The GOR at this moment in the simulator was calculated to be 490 SCF/BBL. The difference between the Lima et al. case and the simulator approximation is over 300%.

It is not possible to correct GOR to a constant value or to get it to match the Lima et al. case. A correction to get the OBM calculation to better match the SBM calculation may be possible, however, by adjusting the OBM calculations where the GOR equation:

$$\frac{p_{bht,p}\dfrac{V_{gas}}{V_{DF}}}{z_{bht,p}T_{bht,p}} = \frac{p_{surf}GOR}{z_{surf}T_{surf}} \Rightarrow GOR_{surf} = \frac{p_{bht,p}\dfrac{V_{gas}}{V_{DF}}z_{surf}T_{surf}}{z_{bht,p}T_{bht,p}\,p_{surf}}, SCF/bbl \quad \text{.............................} \quad (4)$$

is modified by a multiplier of the desired oil fraction, in this case 0.58. The pit gain is then the mixture volume resultant from this fraction plus the volume of free gas not soluble in the “SBM” of the simulator. The result shows some similarities in the OBM-WBM relationships as time progresses, however there exists still the fundamental difference caused by the GOR issue. A comparison of these results is shown in **Fig. 40**:

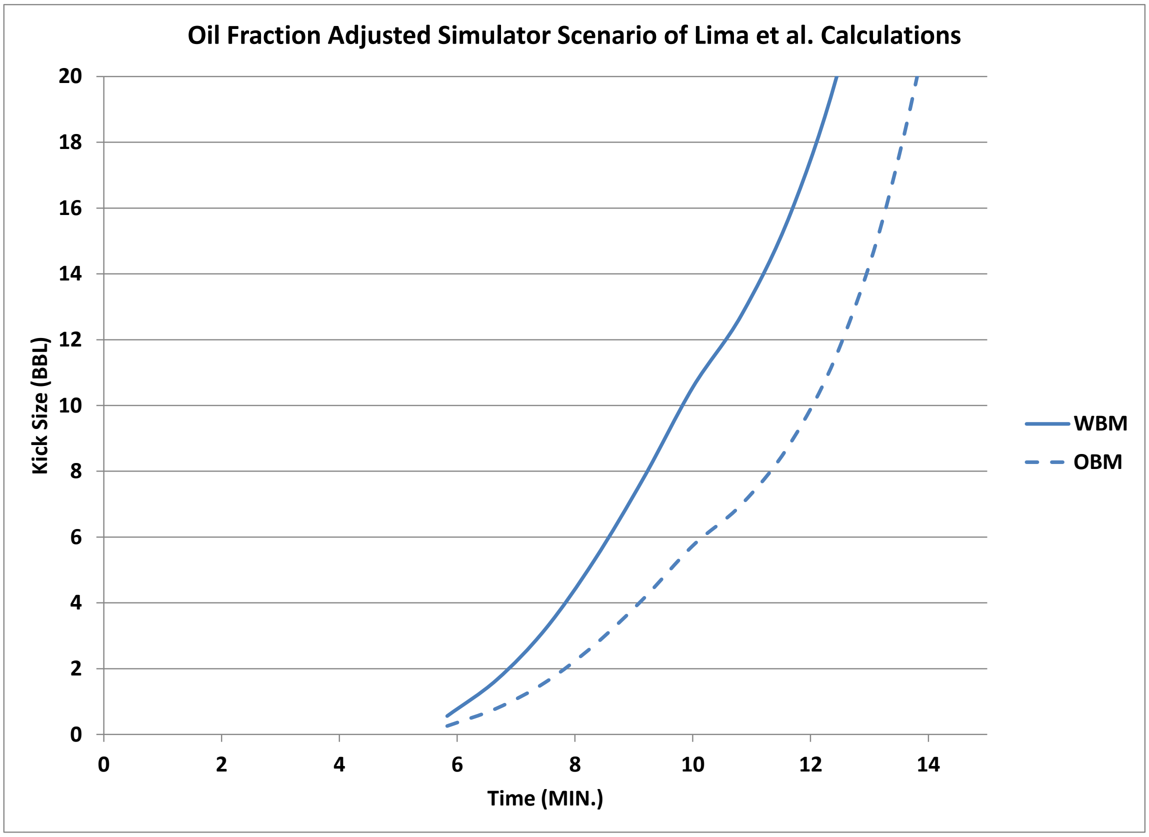

Fig. 40 - Oil Fraction Modified SBM Mud Scenario

In this case, the pit gain seen in OBM is 5.5 bbls, or a 55% difference between the Lima et al. calculation based on a 10 bbl kick. There is still a difference seen, with the simulator OBM calculations being on the conservative end. It can be seen, however, that the volumes move away from each other as in the Lima et al. study with time, but again that the curve is not linear as represented in that study.

4.2 Oil-Based Mud and Gas Solubility in the Literature

Previous studies have calculated the difference between pit gain in OBM versus WBM can be as much as 80% (O'Bryan et al. 1988). The case comparing Lima et al. and the simulator approximation saw an 80% difference for a 10 bbl kick between the two drilling fluids. Another study was done to determine the effect of gas solubility in oil-based drilling fluids and their effect on kick detection (Thomas et al. 1984). Thomas et al. determined that, because of dissolution, pit gain and annular flow rate are more difficult to detect in an OBM than a WBM and will not change as rapidly as in water-based mud. Although more difficult to detect, the study determined that a kick in OBM will be easier to control due to the lesser pressure rise as compared to that seen in WBM. Thomas et al. also reported that a very large kick will be similar in both oil-based and water-based muds, which confirms the effect seen in this study where, as pit gain increases, the volumes and annular delta flows begin to approach a similar value.

4.2.1 Gas Solubility Comparison to JPT 11115

Thomas et al. did a calculation to compare pit gain for a WBM and OBM for the given conditions shown in **Table 16**:

Table 16 - Thomas et al. Versus Simulator Run Parameters

Parameter	Thomas et al.	Choe Simulator	Unit
TVD	15,000	20,000	ft.
Hole Diameter	8.875	8.875	in.
Water Depth	N/A	N/A	ft.
Formation Pressure	8,600	8,600	psi
Porosity	0.15	0.15	
Permeability	10	10	md
Water-Based MW	10	10	ppg
Oil-Based MW	9.95	N/A	ppg
Kick Intensity	0.46	0.46	ppg
Circulating Rate	210	210	gpm
f	1.00	1.00	

A comparison of pit gain for WBM and OBM for both cases is seen in the following **Fig. 41**:

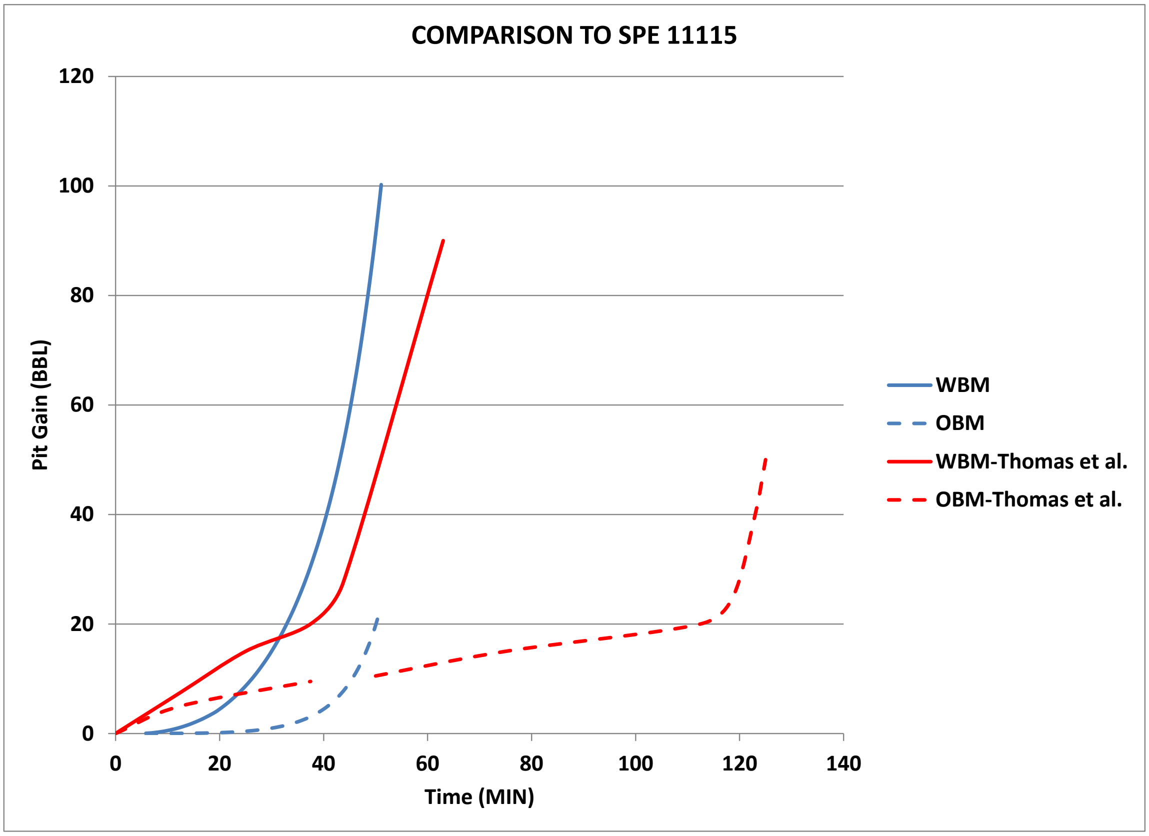

Fig. 41 - OBM vs. WBM Pit Gain Comparison to Thomas et al.

A comparison of kicks in WBM for Thomas et al. and the simulator demonstrates similar tendency. The pit gain increases with time to a point at which it grows at a greater rate. The OBM comparisons also demonstrate similar characteristics. There is a steady increase and at some point in time the rate of pit gain also increases as seen in WBM. The OBM calculation used in this study shows the increasing rate component of the curve occurring much earlier in time than the Thomas et al. case. The Thomas case used GOR and B_o correlations based on Standing (Standing 1947). It is unknown if the GOR is held constant as in the Lima et al. study or if it changes with time as occurs in the simulator due to increasing influx rate. For early time (time of concern for kick detection), the simulator WBM and OBM pit gain calculations will provide a more conservative pit gain. It is expected that this would result in a lesser, or more sensitive, delta flow determined in this study. Based on these comparisons, this study will lead to a more conservative sensor design.

4.2.2 Gas Solubility Comparison to SPE 16676

SPE 16676 performed a simple calculation for methane in diesel #2, or a situation very similar to that used in this study. The authors, O'Bryan and Bourgoyne, determined solution volumes for different concentrations of methane in #2 diesel. These volume ratios are a solution gas-oil ratio (r_{so}), volume factor without gas (B_{ong}), and a volume factor with gas (B_{og}) (O'Bryan et al. 1988). Based on these experimentally determined values, a given GOR, a downhole gas oil ratio (r'_{so}) can be calculated and eventually a pit gain in OBM. The equations are outlined in the following:

$$r'_{so} = \frac{GOR * P_a * z * T_{bh}}{T_{surf} * P_{bh} * 5.615 \frac{ft^3}{bbl}} \quad (26)$$

$$G = (B_{og} - B_{ong}) * \left(\frac{V_{influx}}{r'_{so}} \right) \quad (27)$$

where G is the observed pit gain. The O'Bryan and Bourgoyne method was applied to one simulator scenario for comparison. The scenario used was the DWELL_VKICK scenario at 15,000 ft. TVD.

Six individual calculations were made using SPE 16676 based on the gas-oil ratio determined by the simulator at bottomhole conditions. With this determined, volume factors were selected based on the O'Bryan and Bourgoyne SPE 16676 figures for volume factor based on pressure and the gas-oil ratio. These calculations were made at the simulator recorded kick values in water-based mud of one, 9.87, 25.6, 42.18, 72.88, 72.88, and 100.29 barrels. Delta flow was calculated based on the pit gain calculated (G) and the time step information. The results from the simulator and SPE 16676 were agreeable and this provides confidence for the OBM calculations performed in the thesis. These results of the comparisons can be seen in **Fig. 42**.

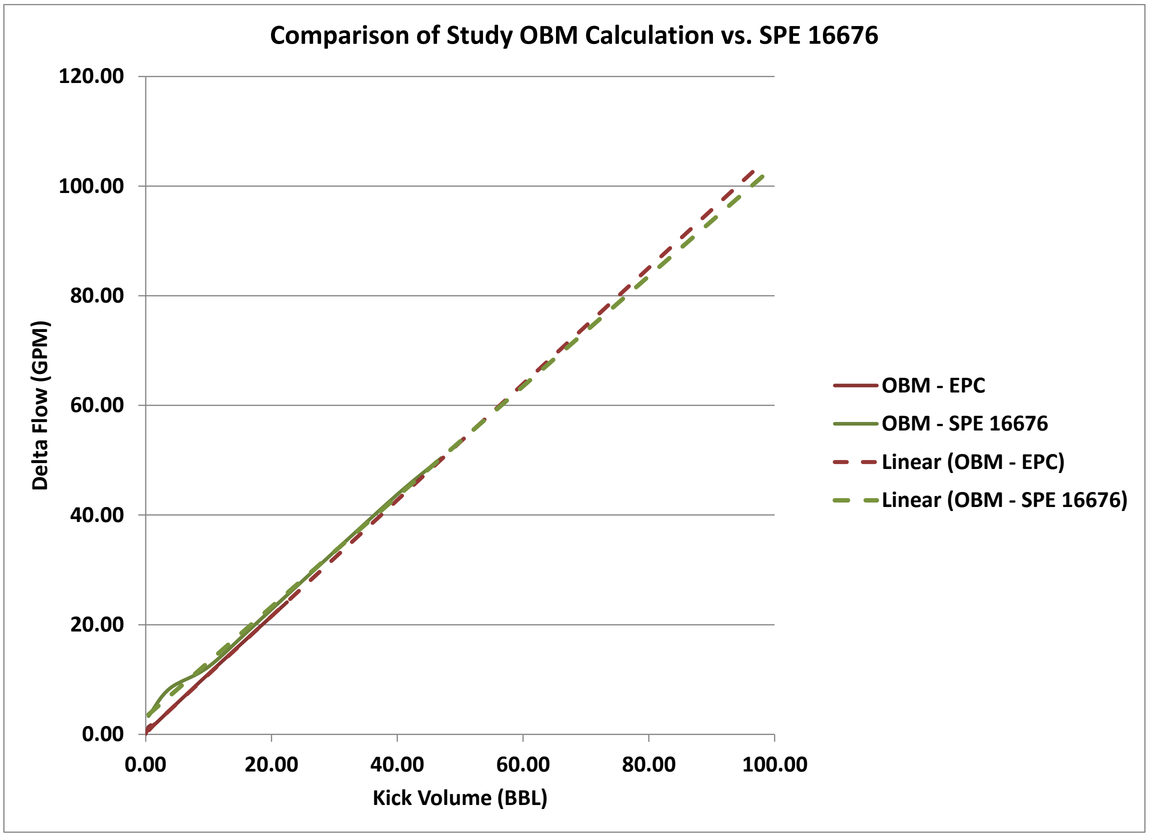

Fig. 42 - Comparison of Study OBM Calculations vs. O'Bryan and Bourgoyne

The maroon line represents the calculations done in the study while the olive colored line those of the O'Bryan and Bourgoyne calculation. For a given pit gain, the study calculations will predict a smaller delta flow versus O'Bryan. For larger pit gains (>60 bbls or so), the method used in the study tends to predict a larger delta flow for a given pit gain. For volumes of concern (<40 bbl kick detection), the calculations used in the study appear once again on the conservative end. For a pit volume range of 10 to 50 bbls, the percent error is 5.1% based on O'Bryan and Bourgoyne's method. This leads to the conclusion that the calculations for gas solubility in this study are suitable for application.

5. CONCLUSION AND RECOMMENDATIONS

Sensitivity patterns were determined for all kick and drilling parameters. Sensitivity is described by a given kick size providing the smallest delta flow as a percent of circulating rate. Low kick intensity, coupled with any drilling parameter, will always provide the most sensitive delta flow scenario. The order of sensitivity of drilling parameters for the ranges studied, from most to least, are 1) water depth, 2) depth below mudline, 3) density and 4) circulating flow rate.

Within each drilling parameter is a trend of high to low sensitivity. For water depth, delta flow for a given kick size is smallest at shallow depths. This is also true for depth below mudline, where a shallow depth will provide the most sensitive scenario. A high density will be greater in sensitivity to a low density drilling fluid. Finally, higher circulating rate will be more sensitive to delta flow than a low circulating rate.

It was determined that the smallest delta flow for a given kick size will occur at shallow water depths. For this scenario, a sensor capable of detecting a 2.4% change in flow would be required to detect a 10 bbl kick. A sensor capable of detecting a 4.6% change in flow would be required to detect a 20 bbl kick. A summary of the results is tabulated in **Table 17**:

Table 17 - Results of Delta Flow for Given Kick Size

ΔQ AS % OF CIRCULATING FLOW RATE		10 BBL KICK		20 BBL KICK	
PARAMETER	KEY VALUES	ΔQ (%) WBM	ΔQ (%) OBM	ΔQ (%) WBM	ΔQ (%) OBM
DWATER_KI	1,000 FT. WATER, KI=1, 300 GPM	2.4	2.4	4.6	4.6
DWELL_VKICK	15,000 TVD, 300 GPM	5.3	3.6	7.0	7.0
GPM_VKICK	1000 GPM	11.9	4.2	15.2	6.6
DENSITY_KI	16 PPG, KI=1, 300 GPM	8.6	7.2	14.4	13.7

For shallow depths below mudline, a 3.6% delta flow was recorded for a 10 bbl kick and a 7% delta flow for a 20 bbl kick. The last two cases of density and flow rate are different for water-based mud and oil-based mud. Oil-based mud is more sensitive at high flow rates than high density. Water-based mud is more sensitive to density than flow rate. In the case of high flow rate for oil-based mud, 10 and 20 bbl kicks will result in 4.8% and 7.3% delta flows. This difference is caused by the circulating rate alteration of GOR, especially at the highest flow rate case of 1000 gpm. Increasing flow rate will result in decreasing GOR which will affect pit gain and delta flow as demonstrated in a previous section.

5.1 Conclusion

Kick detection in offshore floating vessels is complicated by vessel movement. This difficulty has resulted in the development of compensatory instruments that aim to remove the resultant detection inaccuracy. An optimum detection method is one that would eliminate entirely this effect. This study supports that goal, in which a sensor would be placed at or near the seafloor, by determining what kick and drilling parameters will be most sensitive to the delta flow early detection method for a given kick size.

The following was determined based on the parameter ranges established in this study:

1. A sensor must be capable of observing a two and three percent delta flow in order to detect a 10 barrel kick and between four and five percent for a 20 barrel kick;
2. Low kick intensity coupled with any drilling parameter will always produce the smallest delta flow for a given kick size;
3. Oil-based drilling fluids require increased delta flow sensitivity in the majority of cases for a given kick size due to solubility;
4. Drilling parameters given in order from most to least sensitive to delta flow for a given kick size are:
    - Water depth
    - Well depth
    - Drilling fluid density
    - Circulating Rate

5.2 Recommendations

An experimental study was undergoing at the time this paper was written. The study involves doing scaled tests of these scenarios using a coriolis flow meter in one or more labs. The next natural step is to combine and compare these results for a more precise and accurate determination of the needs of a subsea kick sensor. Finally, a prototype is expected to be installed in a floating offshore environment where the equipment can be streamlined with existing equipment and then field tested. Data should be gathered for actual well control events to measure against those determined in the lab and theoretically. Once calibrated, the product will be ready for commercial application.

Although it was determined that delta flow accuracy is not as delicate in deep water and depths below mudline, a study must be done to correlate gas compressibility factors to the pressures and temperatures currently being reached by industry and those used in this study. It is becoming more common to work in over 350°F and 20,000 psi. The gas compressibility factors in this study have not been tested to these conditions. Although it cannot be proven that modification of the gas compressibility factors will establish new sensitivities in this study, it may affect the boundaries expected, which must be known absolutely in work that involves the safety of human lives.

NOMENCLATURE

Abbreviations

bbl	Barrel of Oil
CO_2	Carbon Dioxide
DWELL	Well Depth (TVD) (ft) Parameter
DWATER	Water Depth Parameter
ECD	Equivalent Circulating Density
ERD	Extended Reach Drilling
f	Soluble Fraction of Synthetic-Based Mud
Floater	Floating Drilling Vessel: Drillships and Semi-Submersibles
GOR	Gas-oil Ratio
gpm	Gallons per Minute/Flow Rate (Parameter)
GVF	Gas Volume Fraction Parameter
H	Permeable thickness
H_2S	Hydrogen Sulfide
HP/HT	High Pressure/High Temperature
k_g	Permeability to gas
KI	Kick Intensity (Parameter)
Mcf/d	Thousand Cubic Feet per Day
ML	Mudline
MODU	Mobile Offshore Drilling Unit
MW	Mud Weight

n	nth Term
RHO	Drilling Fluid Density
P_a	Annulus Interval Pressure Loss
p_e	Reservoir Pressure
p_f	Formation Pressure
ppg	Pound per Gallon
PSIG	Pounds per square inch gage pressure
PV	Plastic Viscosity
PVT	Pressure-Volume-Temperature
p_{wf}	Flowing Wellbore Pressure
Q_i	Flow In
Q_o	Flow Out
ΔQ	Change in Flow
r_e	Reservoir Radius
r_w	Wellbore Radius
ROP	Rate of Penetration
SBM	Synthetic-Based Mud
SPP	Stand
TVD	Total Vertical Depth
VKICK	Kick Volume Parameter
YP	Yield Stress
$z_{surf(bht,p)}$	Gas Compressibility of Surface, Bottomhole Conditions

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APPENDIX A

<u>Gas Kick in Oil-Based Mud Calculation:</u>

Parameters:

(Base Case Well Design) Apart From:

Circulation Rate	400 gpm
Well Depth	25,000 ft. TVD
Water Depth	15,000 ft.
BHT	245°F

Time Step of First Kick Detection:

Influx Flow Rate	200 gpm

$$\frac{V_g}{V_d} = \frac{200}{400} = 0.5 \Rightarrow GOR = \frac{p_{bht,p} \dfrac{V_{gas}}{V_{DF}} z_{surf} T_{surf}}{z_{bht,p} T_{bht,p} p_{surf}} = 1232 SCF / bbl = 3.24 lbg / Bd$$

$$\Rightarrow mol_m = 1.305 + mol_{gas} = 4.54 mol.$$

$$y = \frac{3.24}{4.54} * 16 = 11.4 \ldots x = \frac{1.305}{4.54} * 228 = 65.53 \Rightarrow MW = 76.93$$

$$MixWT = 16GOR + WT_d = 16(3.24) + 297.5 = 349.3 lb$$

$$\frac{V_{mix}}{V_d} = 1.54 \Rightarrow V_{kick} = V_{mix} - V_d = 2.17 bbl$$

Where

Surface GOR;

$$\frac{p_{bht,p} \dfrac{V_{gas}}{V_{DF}}}{z_{bht,p} T_{bht,p}} = \frac{p_{surf} GOR}{z_{surf} T_{surf}} \Rightarrow GOR_{surf} = \frac{p_{bht,p} \dfrac{V_{gas}}{V_{DF}} z_{surf} T_{surf}}{z_{bht,p} T_{bht,p} p_{surf}}, SCF / bbl \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

Calculating moles of mixture;

$$mol_m = mol_{DF} + mol_{gas} \quad (5)$$

Where

$$mol_{DF} = \frac{WT_{DF}}{MW_{DF}} \quad (6)$$

$$mol_{gas} = \frac{GOR}{380.7(scf / lbmol)} \quad (7)$$

Mixture Molecular Weight;

$$MW_m = x + y \quad (8)$$

Where

$$y = \frac{mol_{gas}}{mol_m} \quad (9)$$

$$x = \frac{mol_{DF}}{mol_m} \quad (10)$$

Mixture Weight (McCain 1990)

$$MW = \frac{42.43\gamma_o}{1.008 - \gamma_o} \quad (11)$$

$$lb_{mix} = lb_{DF} + lb_{gas} = lb_{DF} + \frac{lb_{gas}}{bbl_{DF}} * MW_{gas} \quad (12)$$

Volume of Mixture per bbl of DF

$$\frac{V_{mix}}{bbl_{DF}} = \frac{m_w}{\rho_w} = \frac{\frac{m_m}{\gamma_o}}{\rho_w} \quad (13)$$

Kick Volume Equivalent in OBM DF

$$V_{kick \rightarrow OBM} = \frac{V_{mix}}{V_{DF}} - V_{k,WBM} \quad (14)$$