University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Ind. Economics/ spez: drilling & contracts	Spring semester, 2011 Open
Writer: Ingrid Haugen	………………………………………… (Writer's signature)
Faculty supervisor: Kjell Kåre Fjelde External supervisor(s): Thor Paulsen	
Title of thesis: KILLING A HIGH RATE BLOWOUT WELL THROUGH A RELIEF WELL	
Credits (ECTS):	
Key words: Blowout Relief well Dynamic kill	Pages: ……81…………… + enclosure: ………… Stavanger, …14.06.2011…………….. Date/year

Foreword

The background for this thesis is the Macondo accident in Mexico 2010. I wanted to learn more about blowouts and how it is possible to kill it with a relief will. Therefore I would like to thank Thor Paulsen at Statoil for helping me designing the thesis, guiding me through the whole simulation and writing process and for all the feedback on my work. Thank you Thor.

I will also thank Kjell Kåre Fjelde at the University of Stavanger for excellent guiding and support during the process..

Summary

A kick can be defined as an unintended influx of formation fluids into a borehole.[1] If the kick can't be controlled it will evolve into a blowout. In this case a relief well would have to be drilled to stop the influx. To be able to kill the blowing well one need to increase the bottom hole pressure. When the bottom hole pressure in the well becomes greater than the reservoir pressure the influx is stopped.

The method used to increase the bottom hole pressure is called dynamic kill.[2] When drilling a relief well from a floater kill fluid is pumped from the relief well rig. The kill fluid goes down the kill and choke line through the BOP [Blow Out Preventer], into the annulus of the relief well, it continues further down the annulus to the intersect point and in to the blowing well. To be able to increase the BHP [Bottom Hole Pressure] one needs to deliver enough volume of mud at high enough pump rate. The blowing well will be stopped by pumping so fast that the pressure in the blowing well exceeds the formation pressure. When fluid is flowing in pipes it looses pressure; friction pressure. These friction pressure losses occurs in the pipes on the rig, in the kill and choke line and in annulus in both relief well and the blowing well. Different simulation tools has been used to run simulations to find out how the friction pressure is affected by water depth (length of kill and choke line), ID; [Internal Diameter] size on kill and choke line and mud-type used.   These results are represented graphically. The water depth varied from 100m-1200m, ID on kill and choke line from 3" to 4,5" and mud weights varied from 1,8sg to 2,2sg. The only ID on kill and choke-line that were able to deliver required rate for all water depths and all mud types, without exceeding the pressure limitation for the rig where 4,5". If the pressure exceeds the pressure limitations we need more than one relief well.

---

[1] Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080*

[2] SPE 115287 MS Dynamic Killing Parameters Design in Underground Blowout Well *Rudi Rubiandi R.S 2008*

Table of Content:

Figure list:

Table list:

Introduction:

The Macondo accident with the Deep Water Horizon oil spill in 2010 shows us the importance of well control. Most of the easy to find and produce hydrocarbons are depleted, which forces the oil and gas industry to move into new areas so that they can be able to continue supplying the world with hydrocarbons. Blowouts have been a problem for this industry since its inception.[3] With the advent of modern drilling equipment such as MWD [Measure While Drilling] the frequency of blowouts tends to decrease. Nevertheless unfortunate combinations of equipment failure, human error, geological uncertainty etc still give rise to incidents which may lead to loss of wells, equipment and even human lives[4].

Study objective

To be able to kill a high rate blowout, a relief well would have to be drilled and we need to obtain a high enough pump rate to increase the friction in the relief well such that the relief well pressure increases above the blowing formation pressure. When kill fluid is pumped down kill and choke lines and further down annulus pressure losses will occur. The objective was to evaluate how these losses were affected by water depths, size/ID on kill and choke line and the effect of different mud types. To find these effects several simulations were run. The simulation tools used are KICK (developed by the SPT group) and Quick Process (Statoil developed program.)

Structure of the thesis

This paper explains how blowout occurs and the different ways to control it. The main objective is relief well drilling and dynamic kill. The first chapter explains well control and the causes for kick which can develop into a blowout, followed by the different techniques to stop the influx. Since the main objective is on relief well drilling and dynamic kill this has been explained more detailed. The paper also explains the different tools used to intersect with a blowing well. The simulation tools in this paper are described and the results are presented graphically in the end.

---

[3] SPE/IADC 92626 Modelling Ultra-Deepwater Blowouts and Dynamic Kills and the resulting Blowout Control Best Practices Recommandations *Samuel F. Noyar, Jerome J. Schubert 2005*
[4] SPE 36485 Analysing of Surface and Wellbore Hydraulics Provides Key to efficient Blowout Control *P. Oudemann1996*

Blowouts and Kill Techniques

How does a blowout occur?

(The main content in this chapter is from Blowout and Well Control Handbook)

A kick can be defined as an unintentional influx of formation fluids into a borehole. If the flow is successfully controlled the kick has been killed. A blowout is the result of a kick that is not handled correctly or where equipment fails to operate as intended and the kick comes out of control. In this case, a certain kill procedure has to be initiated to kill the well. [5]

To prevent that inflow from the formation reaches surface, certain elements have to be in place. Well barriers are envelopes of one or several dependent well barriers elements. The hydrostatic pressure of the drilling fluid is the primary barrier. The second barriers are the Blow Out Preventer; BOP, casing, cement wellhead etc. (See Figure 1: Norsok standard D-10 Well barriers elements) If a kick occurs mud is used to kill and control the well. Drilling fluid density will therefore always be a prime concern.

The hydrostatic pressure is given by the formula:

$$P = \rho g h$$

P= pressure [bar]

ρ=density of mud [sg]

g=gravity [0,0981]

h= vertical height of mud [m]

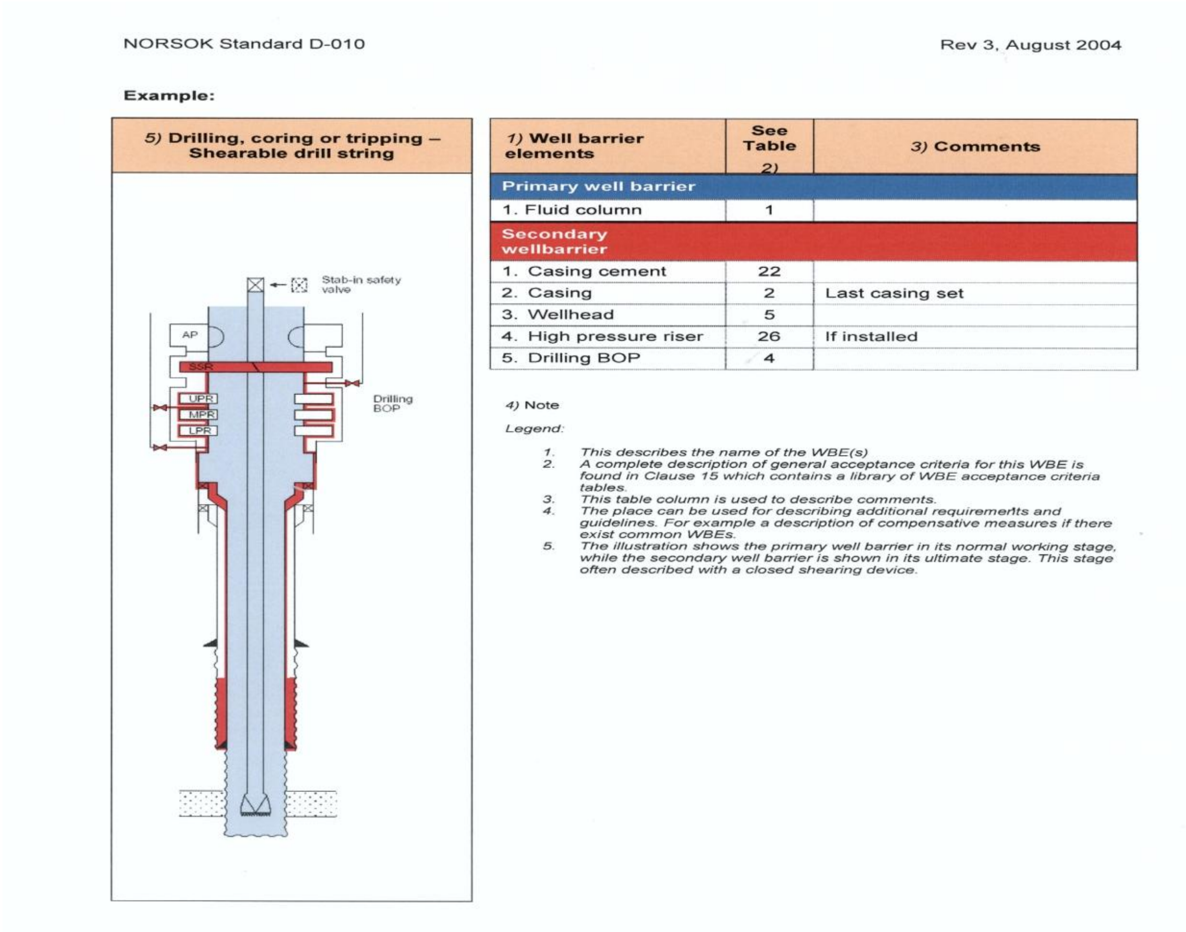
The hydrostatic pressure given by the mud should always be greater than the formation pressure, but less than the fracture pressure. When the hydrostatic pressure is greater than the fracture pressure it can lead to loss of circulation.

When the primary well control barrier have been lost it becomes necessary to seal the well to prevent the flow from flowing uncontrolled to the surface. These second barriers consist of several barrier elements, forming a barrier envelope. These barrier elements typically consist of cemented

---

[5] Blowout and Well Control Handbook *Robert D. Grace2003 ISBN; 9780750677080*

casing, wellhead, Blowout Preventer [BOP] and drill pipe Blowout Preventer. See Figure 1: Norsok standard D-10 Well barriers elements


NORSOK Standard D-010 Rev 3, August 2004

Example:

5) **Drilling, coring or tripping – Shearable drill string**

1) **Well barrier elements**	**See Table** *2)*	*3)* **Comments**
Primary well barrier		
1. Fluid column	1	
Secondary wellbarrier		
1. Casing cement	22	
2. Casing	2	Last casing set
3. Wellhead	5	
4. High pressure riser	26	If installed
5. Drilling BOP	4	

4) Note

Legend:

1. *This describes the name of the WBE(s)*
2. *A complete description of general acceptance criteria for this WBE is found in Clause 15 which contains a library of WBE acceptance criteria tables.*
3. *This table column is used to describe comments.*
4. *The place can be used for describing additional requirements and guidelines. For example a description of compensative measures if there exist common WBEs.*
5. *The illustration shows the primary well barrier in its normal working stage, while the secondary well barrier is shown in its ultimate stage. This stage often described with a closed shearing device.*

Figure 1: Norsok standard D-10 Well barriers elements[6]

There are many different types of Blow Out Preventers. This paper will focus on subsea BOP's. Figure 2: Minimum Subsea Stack Requirement shows a minimum subsea stack requirement. Sometimes a double annular preventer will be used with a connector in between. The connector allows for the top package to be pulled and the top annular preventer to be repaired. The lower annular preventer is used as a back up when the top annular preventer fails. Shear rams are a necessity in the event that conditions dictate that the drill string must be shared and the drilling vessel moved off location. The kill and choke line are connected to the BOP through side outlets of the BOP. These lines are used to pump kill fluid from the rig when the BOP is closed.

[6] Norsok D-10 http://www.npd.no/Global/Norsk/5%20-%20Regelverk/Skjema/Br%C3%B8nnregistrering/Norsok_standard_D-010.pdf

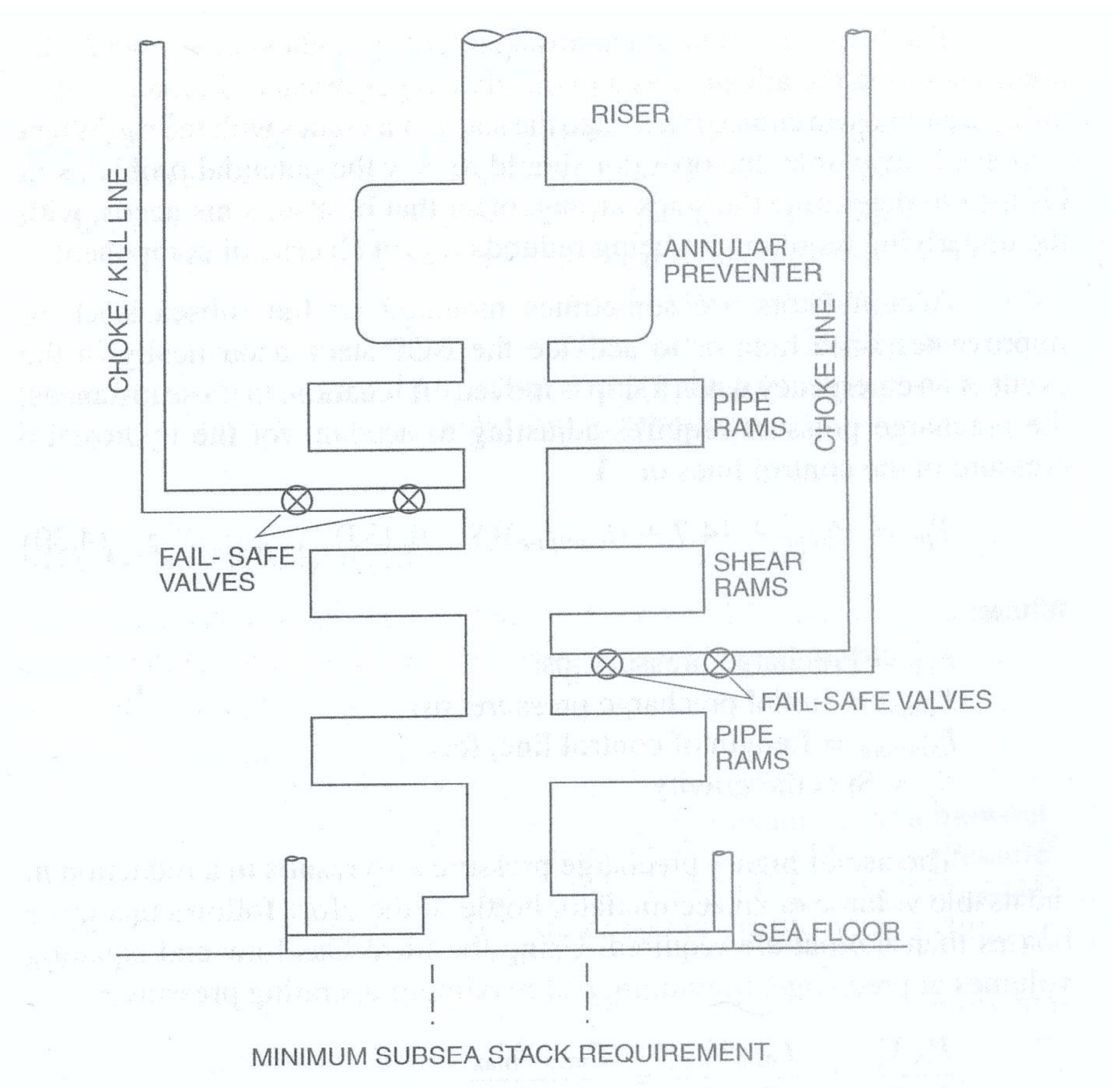


Figure 2: Minimum Subsea Stack Requirement[7]

The key causes for a kick are:

- *Insufficient mud weight (i.e. higher pore pressure in the formation than planned for)*
- *Improper hole fill-up on trips*
- *Swabbing*
- *Gas cut mud*
- *Lost circulation*

[7] Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080*

Insufficient mud weight is one of the most common causes for a kick. This can happen when a permeable zone is drilled while using a mud weight that exerts less pressure than the formation pressure within the zone. This can happen when drilling into formations with an unexpected high formation pressure. Especially in exploration wells, there is some uncertainty related to pore pressure predictions.

Improperly filling the hole during trips is another cause of kicks. As the drill pipe is pulled out of the hole, the mud level falls because the drill pipe steel volume is removed from the well. When pulling the pipe out of the hole the mud level decreases. It is necessary to fill the hole with mud periodically to avoid reducing the hydrostatic pressure and the risk for a kick to occur. There are different methods that can be used to fill the hole, but it is important that they are able to measure the precise amount of required mud. The two most common methods are a trip tank and pump stroke measurement. Another method is to fill the hole periodically with a positive displacement pump.

Swabbing; When pulling pipe, the pressure in the well will be lowered temporarily. If this pressure reduction lowers the effective hydrostatic pressure below the formation pressure, a potential kick can be taken. The pressure reduction caused by swabbing will depend on pipe pulling speed, mud properties, and hole configuration.

Gas Cut mud: Gas contaminated mud will occasionally cause a kick, although this is rare. The mud density reduction is usually caused by fluids from the volume cut and released into the system. As the gas is circulated out to surface it expands and reduces the overall hydrostatic pressure sufficient to allow a kick to occur.

Lost circulation can sometimes lead to a kick. The mud column is reduced and therefore the hydrostatic pressure will decrease. When a kick occurs due to lost circulation, the problem may become severe. A large volume of kick fluid may enter the hole before the rising mud level is observed at the surface.

The dominant causes are insufficient mud weight and improperly filling of the holes.

In case of a kick, different warning signs will occur. These will be described next.

Warning signs of kick:

- *Flow rate increase*
- *Pit volume increase*
- *Flowing well with pumps off*
- *Improper hole fill-up on trips*

- *Pump pressure decrease and pump stroke increase*
- *String weight change.*
- *Increase in ECD*

Primary indicators:

Flow rate increase. If the outlet rate is higher than the inlet rate, there can be a clear sign of an influx situation. The difference in inlet and outlet flow rates, indicates that influx is taken in the well.

Pit Volume increase: If the pit volume is not changed as a result of surface controlled actions, a pit increase indicates that a kick is occurring. Fluids entering the wellbore displace an equal volume of mud at the flow line and results in a pit gain.

Flowing well with pumps off: When the rig pumps are off, and there still is a continued flow from the well this indicates a kick in progress. An exception is when the mud in the drill pipe is considerably heavier than in the annulus as in the case of a slug.(used during connections to ensure “dry connections”.

Improper hole fill-up on trips: When the drill string is pulled out of hole, the mud level should decrease by a volume equivalent to the removed steel. If the hole doesn’t require the calculated volume of mud to bring the mud level back to the surface, it is assumed that a kick has entered the hole and filled the displacement volume of drill string.

Secondary indicators:

Pump pressure decrease and pump stroke increase. A pump change may indicate a kick. Initial fluid entry into the borehole may cause the mud to flocculate and temporarily increase the pump pressure. As the flow continues, the low density influx will displace heavier drilling fluids and pump pressure can begin to decrease. As the fluid in the annulus become less dense, the mud in the drill pipe fall.

String weight change: Drilling fluid provides a buoyant effect to the drill string and reduces the actual pipe weight supported by the derrick. Heavier mud has a greater buoyant force than less dense mud. When a kick occurs and low density formation fluids begin to enter the borehole, the buoyant force of the mud system is reduced. The string weight observed at the surface begin to increase.

Drilling Break: An abrupt increase in bit penetration rate, called a drilling break, is a warning sign of a possible kick. A gradual increase in penetration rate is an abnormal-pressure-detection indicator, and it should not be misinterpreted as an abrupt rate increase. It is not certain that a kick will occur although a drilling break have been observed, only that a new formation has been drilled that has kick potential.

Gas Cut Mud Weight: Reduced mud weight observed at the flow line has occasionally caused a kick to occur. Generally, gas cut mud only indicates that a formation has been drilled that contain gas. It does not mean that the mud weight must be increased.[8]

Increase in ECD: [Equivalent Circulating Density] When a kick is taken, the total flow in the annulus increases. This will in turn be seen as an increase in ECD in the early stage of a kick.

If an inflow is experienced it is important to shut down the well by shutting down the pumps, stop rotation and close the BOP. This inflow must be removed from the wellbore before the operation can continue. The operations to remove the influx and bring the well back to a safe condition is called a kill operation. There are several available options to kill a well. The most common methods involve circulating the influx safely from the bottom of the well up to the rig and out of the well. See

Kill fluid are introduced from surface directly into the well. In a well kill operation it will be necessary to circulate down the drillpipe and up annulus and through an exit at surface. To be able to do this there are two lines attached to the BOP. These lines are called choke-line and kill line. The choke line carries the mud and kick fluid from the BOP to the choke. The choke is used to regulate the flow, such that we maintain the bottom hole pressure constant above formation pressure during the well kill. The primary concern of a kill line is to serve as a back-up choke line and is also used for pressure monitoring, but in some kill operations like bullheading both the kill and the choke lines are used to pump mud directly in to the annulus.

If all barriers fails and control over the well is lost the kick will evoke into a blowout; an uncontrolled flow of formation fluids. There exist different types of a blowout; subsurface blowout, underground blowout, or uncontrolled flow to the surface. [9] A surface blowout is when the fluid flows from the reservoir to the rig floor. It can release large volumes of potentially dangerous formation fluids. In the case of toxic and combustible gases, the safety of human life becomes a serious and potentially

---

[8] Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080*

[9] Kicks and Blowout Control second edition *Neal Adams, Larry Kuhlman1994 ISBN 0-87814-419-6*

paramount consideration. Loss of hydrocarbons reserves is another problem. Drilling rig equipment can be destroyed. The primary concerns in a blowout s is the safety of human lives, the secondary is the environmental protection. The tertiary are the blowout cost factors can be large although they seldom are given primary consideration.

Underground blowouts are when fluids flow from one formation zone to another. It can use the wellbore as a flow path or it can flow from one formation to another with no signs of a blowout on the surface. Underground blowouts can escalate to sub-surface blowout some distance from the wellbore. [10]

Figure 3: Macondo Accident

Sub surface blowout is when the flow exits the well at seabed. Here are the exit conditions controlled by hydrostatic pressure and temperature of seawater. These factors have shown to have an important influence on the behavior of the flow. Large amount of gas in the sea can also reduce the buoyancy for the vessels in the area above. The Macondo Accident/blowout was a sub-surface blowout see Figure 3: Macondo Acc.

[10] Blowflow a Software Tool Developed by IRIS for risk based Evaluation of Blowout Scenarios. 2008 *Kjetil Aleksander Moe*

Consequences of a blowout

The consequences in a blowout-situation can be catastrophic; and do not only affect the rig personnel and oil-company. Therefore there are different concerns in a blowout situation that needs to be considered.[11] One of these concerns is the environmental protection. In the Macondo accident 510km shoreline were affected by oil spill pollution. This affected both the fishing - and the tourism industry.

The main concern is the safety of human lives. 11 people died in the Macondo accident. It is not only the personnel on the rig that are affected, health and safety of human is also important when the clean up starts. This needs to be considered from the blowout starts, until the well is killed and the cleanup is done.

The economic concerns are not given the main attention. There are great economic losses both for the operator and other companies. These losses are the loss of the rig and equipment, but also loss of reserves and the losses that come with the bad publicity. The Macondo accident led to a 6 months drilling moratorium in the Gulf of Mexico which affected all operators and contractors. Other factors are the loss of income for the fishing and tourism industry.

Fortunately blowouts are rare. There are several elements in place to prevent it, but the consequences can be severe. All blowouts are inherently different, never know what's going to happen which makes it impossible to cover all possibilities. A structured guideline is important to avoid overlooking critical steps. A blowout contingency plan should contain directives for handling most aspects of blowout management. The preparation that needs to be done would include ensuring the availability of a nearby rig for relief well drilling, sufficient stock of tubular goods to complete the relief well, and pump capacity to kill the blowing well. With these elements in place relief well drilling can be started quickly, thus reducing the time to regain control over the well. The plan should consider the possible modes of failure and the response to these failures to restore well integrity[12].

There are several different ways to kill a blowout which will be explained in the next chapter.

---

[11] IADCE/SPE 39354 Trends extracted from 800 Gulf Coast blowouts during 1960-1996 *Pål Skalle, Augusto L. Podio 1998*

[12] SPE/ IACD 105612 Hydraulic Conntrol Requirements for Big Bore and HP/HT Developments Validation With Field Experience *P.Oudemann2007*

Different Kill Techniques for Blowouts

Basically there are two options available two kill a blowout.[13] The first and preferred option is the inwell-kill. [14]This means that kill fluid is pumped down the drillpipe and up annulus of the original well, see Figure 4: Inwell Kill. When this can't be done because the blowing well is inaccessible, a relief well would have to be drilled.

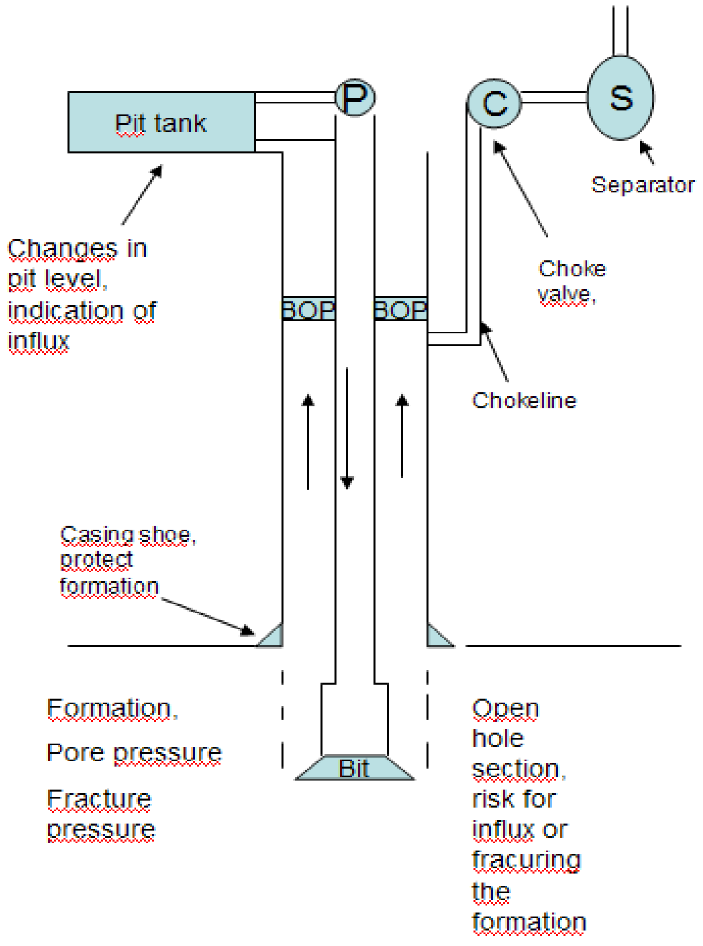


Figure 4: Inwell Kill[15]

The different methods to kill a blowing well are:

- Bridging
- Capping
- Bullheading

[13] SPE 16674 Conventional and Unconventional Kill Techniques for Wild Wells *ELY, J.W, S.AHolditch 1987*
[14] SPE 22559 – PA Advancement in Dynamic Kill Calculations for Blowout Wells G.E Kouba,G.R. MacDougall, B.W. Schumaker 1993
[15] Well Control Presentation; Kjell Kåre Fjelde

- Vertical intervention
- Depletion/flooding of reservoir
- Dynamic kill

Bridging: Many blowouts have been killed by well bridging. The formation around the blowout collapses and seals the flow path. Bridging usually occurs within 24 hours after the well blows. If the well does not bridge within 24 hours, it is likely to blow for an extended time or until the well is killed. Bridging is considered a passive technique, which means that it is subject to formation properties and generally is not influenced by kill attempts. Either the well bridge or it does not bridge, but one doesn't have much control over it.

Capping: In simple terms it means putting a cap on the blowing well. This involves clearing debris and removing parts of the old BOP stack and wellhead, installing a new capping stack and then closing the well. Several kill methods are commonly used for a capped well. Bullheading is the most common.

Bullheading: Bullheading the well is to displace influx fluids back down the well with mud. It involves pumping down the well into an exposed formation. High pressure on the casing may cause problems. Well pressure may approach the casing allowable working pressure. The original casing integrity may be reduced because of damage or wear. The bullheading pressure and mud hydrostatic pressure may exceed the formation fracture pressure at the casing seat or some other exposed formation. The formation will be fractured, and mud may be lost in to the formation. Mud may be pumped into the well with no returning. It is difficult to differentiate if the mud is going to the formation at the casing seat, into an exposed formation or through a hole in the casing.

Vertical intervention: A semi-submersible rig is moved directly over a live subsea blowout. Work is done on the blowout from the vertical position. [16]

When none of these methods don't work or can't be done a relief well would have to be drilled to intercept the blowout well from surface. [17] When the relief hits the blowing well and communication is established, the BOP (Blow Out Preventer) is closed and kill mud is pumped down the kill and choke line. There are different ways of killing a blowout with a relief well. Flooding/ Depletion and dynamic

---

[16] Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080*

[17] SPE 116274 Successful Relief Well Drilling Utilizing Gyroscopic MWD (GMWD) for Re Entry into an Existing Cased Hole *Juergen Maehs, Dough MacAfee, Steve Renne, Greg Cellos, Ananth Srinivasan2008*

kill. The most common method is the dynamic kill/ direct kill which will be explained in further details in the next chapter.

Relief Wells & Dynamic Kill

What is a relief well?

If a blowing well becomes inaccessible from the surface a relief well would have to be drilled to stop the well from flowing, see Figure 5: Relief Well The main difference between a relief well and another ordinary well is the target. The relief wells mission is to hit the blowing well, that's what makes it so difficult, (so simple and yet so difficult.) Drilling a relief well can be compared with looking after a needle in a haystack. If the relief well misses the target the kill operation can't be performed.

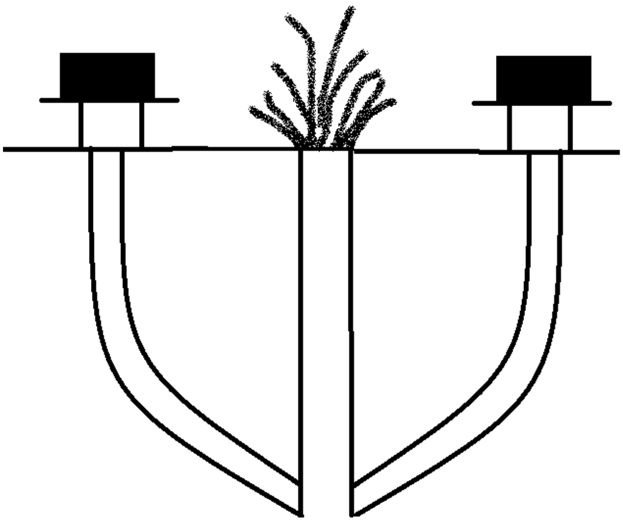
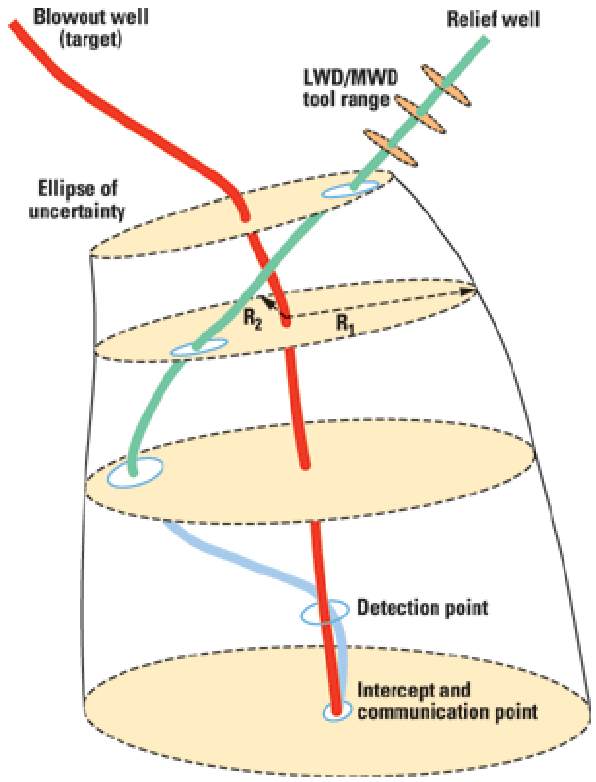


Figure 5: Relief Well

For a relief well to be able to hit the target it can be drilled as an S-shaped well. This is usually done for vertical blowout wells. An s-shaped well means that it is drilled vertical down to the planned KOP [Kick Off Point], and then deviated before turned vertical again to drop to the target. Normally two relief wells are drilled at the same time. Drilling takes time, and in case anything goes wrong with one well, one can still continue with the other without losing time. Time is also an important factor considering the consequences. Reducing time can reduce both the environmental consequences and the cost.

When drilling a relief well different tools are used to be able to hit the blowing well. These tools will be explained further in detail in the next chapter. These tools are depending on casing or steel in the blowing well to be able to hit it. The relief well will therefore intersect the blowing well at the lowest casing shoe. To be able to detect the blowing well, the relief well is drilled as shown in figure 6.

The aim is to align the wellbore at an incident angle of 3-4 degrees rather than aiming directly, (see figure 7). This approach gives the best chance for a first attempt intersect and allows steering of the bit for a repeated attempt instead of plug back and sidetrack.[18]



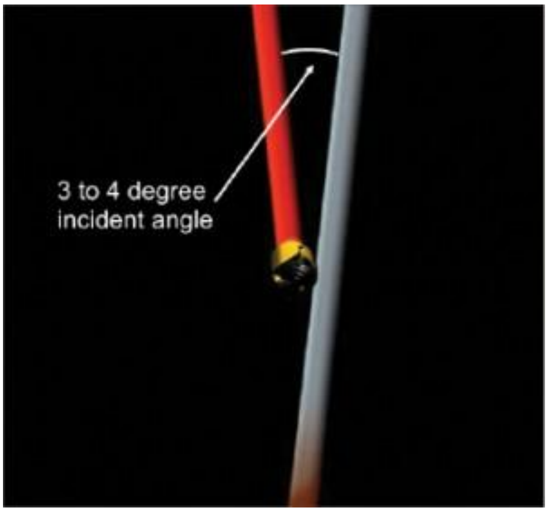


Figure 7: The aim is to align the wellbore at an incident angle of 3-4 degrees rather than aiming directly.[16]

Figur 6: Relief Well Trajectory

Feil! Fant ikke referansekilden. "Illustrates a trajectory that would be drilled to reduce a large ellipse of uncertainty. By planning an effective sweep pattern, the relief well and target survey uncertainties are combined and are relief well plan is designed to detect any target within a cylinder along the target survey path". [19]

The kill-operation is not finish when the relief well has hit the target. It's here the actual kill starts. To be able to kill the well the Bottom Hole Pressure (BHP) in the well needs to exceed the formation

[18] http://www.drillingcontractor.org/an-introduction-to-relief-well-planning-dynamic-kill-design-recognizing-the-common-limitations-7431
[19] http://208.88.129.54/January-2003-LWDMWD-proximity-techniques-offer-accelerated-relief-well-operations.html

pressure so that the influx from the formation will be stopped. The method used to increase the BHP is called dynamic kill.

The blowing well has a lower BHP than the relief well. When intersecting the relief well will experience massive losses. Therefore when the relief well hits the target the relief well BOP closes to avoid loosing all the mud in the riser and potentially experience a kick in the relief well. Kill fluid is pumped down the kill and choke line down the annulus of the relief well to the intersect point and up the blowing well.[20] See Figure 7 Pumping kill fluid

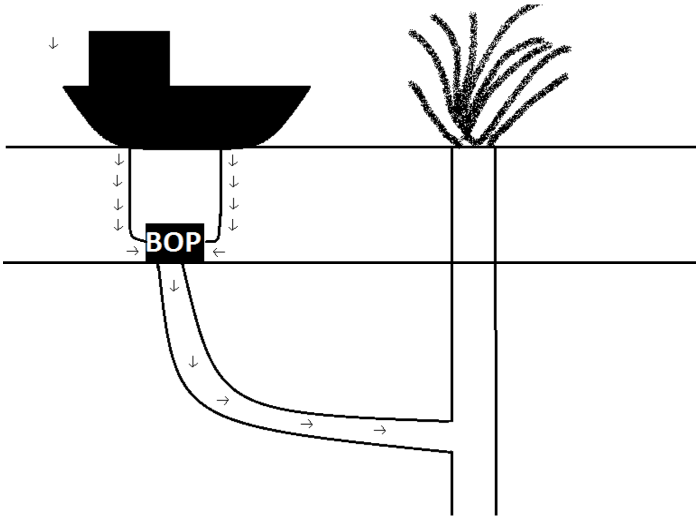


Figure 7 Pumping kill fluid

---

[20] Dual relief Well Intervention Feasibility Study- 2011 Statoil Internal

How is a dynamic kill performed and what is the principle behind the kill?

To kill a well dynamically is to use frictional pressure losses to control the flowing bottom hole pressure and ultimately the static bottom hole pressure of the blowout. Before explaining the dynamic kill process one need to know the difference between flowing bottomhole pressure and static bottomhole pressure. "Static bottom hole pressure; when the flow has been stopped and the pressure has built up, the pressure that exist when the fluids are not flowing will be the formation or reservoir pressure."[21] Flowing bottom hole pressure; is the pressure downhole when the well is flowing.[22]

Dynamic kill has been successful in controlling various high rate blowouts. It was developed in late 1970's and early 1980. In 1978, Mobil Oil had a 400 MMscfd gas blowout in Indonesia's Arun field. Instead of taking the expected one year to kill the blowout the blowout was controlled in 89 days.[23]

The dynamic kill relies on sufficiently heavy kill mud being injected into the blowout well at rates that are adequate to increase the bottom hole pressure and thereby stopping the inflow from the reservoir. The dynamic kill procedure requires that the combination of hydrostatic pressure from the mixture of formation fluids and kill mud plus the multiphase friction along the blowout well bore is sufficient to create the necessary BHP. [24]

In some cases seawater or brine is pumped down in beginning of the kill and replaced with mud to control the static bottom hole pressure in the end.

Bottom hole pressure is not only a result of hydrostatic pressure. When pumping kill fluid through the relief well and up the blowing well additional frictional pressure is created. The frictional pressure supplements the hydrostatic.

$$P_{BH} = P_{hyd} + P_{friction}$$

The engineering concepts behind a dynamic kill are best understood using the U-Tube model.

[21] www.glossary.oilfield.slb.com
[22] http://www.eng-tips.com/viewthread.cfm?qid=99325&page=7

[23] SPE/IADC 92626 Modelling Ultra-Deepwater Blowouts and Dynamic Kills ans the Resulting Blowout Control Best Practices Recommendations *Samuel F. Noyart, Jerome J. Schubert 2005*
[24] Dual Relief Well Intervention Feasibility Study 2011 Statoil Internal

U-tube effect:

In a U-tube manometer the height of one leg of fluid changed by altering the density of some of the fluid in the other leg. In a well with drill pipe in a hole, the string of drill pipe is one leg, and the annulus between the drill pipe and the wellbore is another. The U tube effect is then when the mud in the drill pipe flows into the annulus until the pressures equalizes between the annulus and the drill pipe.

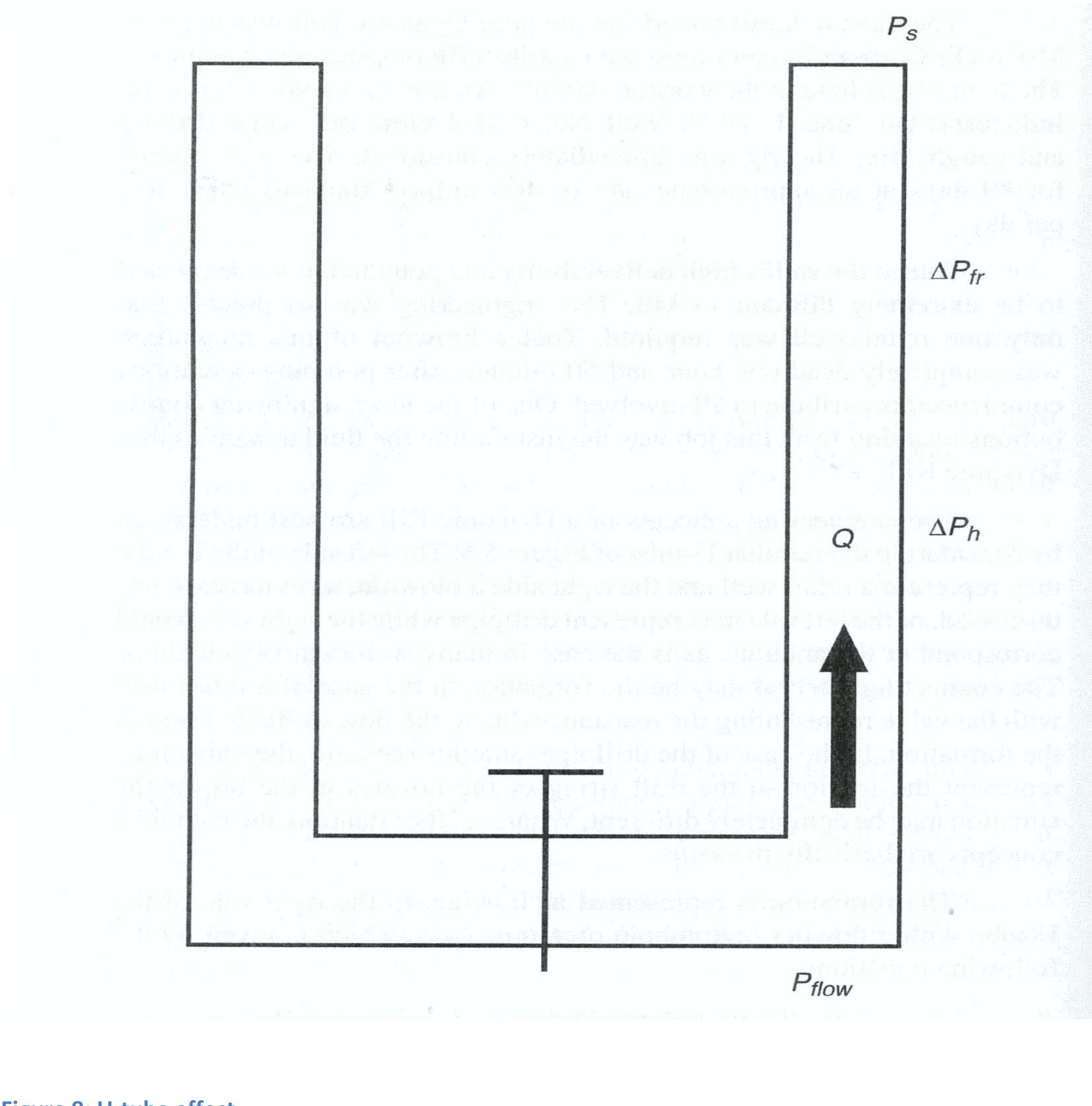


Figure 8: U-tube effect

In the relief well drilling case the left side of the u-tube represents a relief well, and the right side a blowout. The connecting interval may be the formation with the valve representing the resistance due to the flow of fluids through the formation. See Figure 8: U-tube effect.

The formation is represented as flowing up the right side of the U-tube with a flowing bottom hole pressure P_{flow} which is given by the following equation:

$$P_{flow} = P_s + \Delta P_{fr} + \Delta P_h$$

Where:

P_s = Surface pressure (psi)

ΔP_{fr} = Frictional pressure (psi)

ΔPh = Hydrostatic pressure (psi)

The most simple approach is to design a kill fluid and rate such that the frictional pressure loss plus the hydrostatic is greater than the shut-in bottom hole pressure Pb which is equal to the reservoir pressure. [25]

The multiphase frictional pressure loss initially required to control the well is not what will control the static reservoir pressure. The multiphase frictional loss required to control the well is that which control the flowing bottom hole pressure, The flowing bottom hole pressure may be much less than the static bottom hole pressure.

The process must be designed based on pore pressure and fracture pressure. It is not a process that involves pumping the heaviest mud at the highest possible rate. If the formation fracture we will have losses and not be able to kill the well, hence we need accurate monitoring of the BHP. In some cases two different mud weights are used to avoid fracturing.

During intersection with the blowing well mud loss will be experienced because of the different pressure in the BHP of the relief well and the FBHP (Flowing Bottom Hole Pressure) of the blowing well.
All available pumps will be used to keep the relief well full while the bit is raised to the casing shoe. (Prevention in case of open hole collapse.) Then the BOP will be closed and the dynamic kill will begin.

While monitoring BHP via APWD [Annular Pressure While Drilling] a quite high initial constant pump

---

[25] Blowout and Well Control Handbook *Robert D. Grace2003 ISBN; 9780750677080*

rate will be established and maintained until the BHP reaches the static reservoir pressure. (Monitoring the BHP can also be done by a drill string that is filled up with a known fluid density.)

Once the BHP has increased to the static reservoir pressure the pump rate will have to be reduced to avoid fluid losses due to induced fractures but still the BHP is kept above the static pressure. The bottom hole pressure is usually stabilized with a rate which is lower than the initial pump rate. After stabilization additional circulation will be done to ensure that all hydrocarbons have been removed. All hydrocarbons have to be thoroughly flushed or else there is a risk of resumption of flow from light fluids and migration gas.[26]

When all hydrocarbons are removed the pumps can be stopped. The dynamic kill process is now complete.

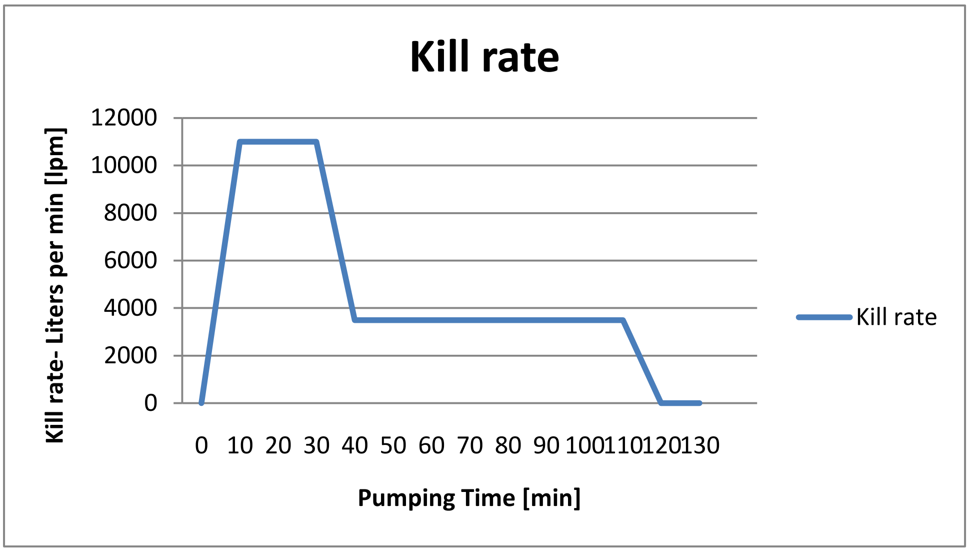


Figure 9; Killrate vs time

When intersecting the pumprate is quickly increased. The BHP will gradually increase as kill fluid is mixed with the blowout formation fluids in the blowing well. This high pumprate is usually maintained until the BHP is equal or slightly greater than the pore pressure. When the BHP is above pore pressure the pumprate is gradually reduced to maintain the BHP above the static pore pressure but below the fracture pressure. The initial high pumprate will only be required for a small portion of the kill-operation. See Figure 9; Killrate vs time

[26] Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080*

Important technology for reaching relief well target

When we are drilling a relief well there are different uncertainties that we need to deal with. One of the bigger problems is to ensure that the relief well hits the blowing well. It is difficult to know where the drill bit is at the exact time. There are many directional drilling tools to help us, but there are cumulative and systematic errors associated with the tools used. These systematic errors creates a cone or an ellipse relative to the specific location of the blowout well and the relief well. It is difficult to know where the blowing well is related to the drill bit. The deeper a well gets the larger the ellipse of uncertainties gets.[27] The key to successful intercepting a target is to overcome these uncertainties in the position of both the target well and the relief well. To reduce the ellipse of uncertainty, or maybe most of all the uncertainty in the relative distance between the target and the relief well one needs help from different tools.

These tools are so-called ranging tools; they help to identifying where the blowing well is located relative to the relief well. As mentioned, the deeper the well gets the larger the ellipse of uncertainty gets. Therefore the ranging has to be repeated in planned intervals. After a ranging run, then the necessary adjustments can be made before continuing drilling towards the target. Range is the distance the tool can measure

The homing is an iterative process of: (see Figure 10: Homing in)

1) Ranging run results in new target coordinates
2) Re-plan well to new target location
3) Plan next drilling ranging interval
4) Drill to next ranging depth target [28]

---

[27] Dual Relief Well Intervention Feasibility Study 2011 Statoil Internal
[28] http://www.vectormagnetics.com/oil-gas/applications/relief-wells

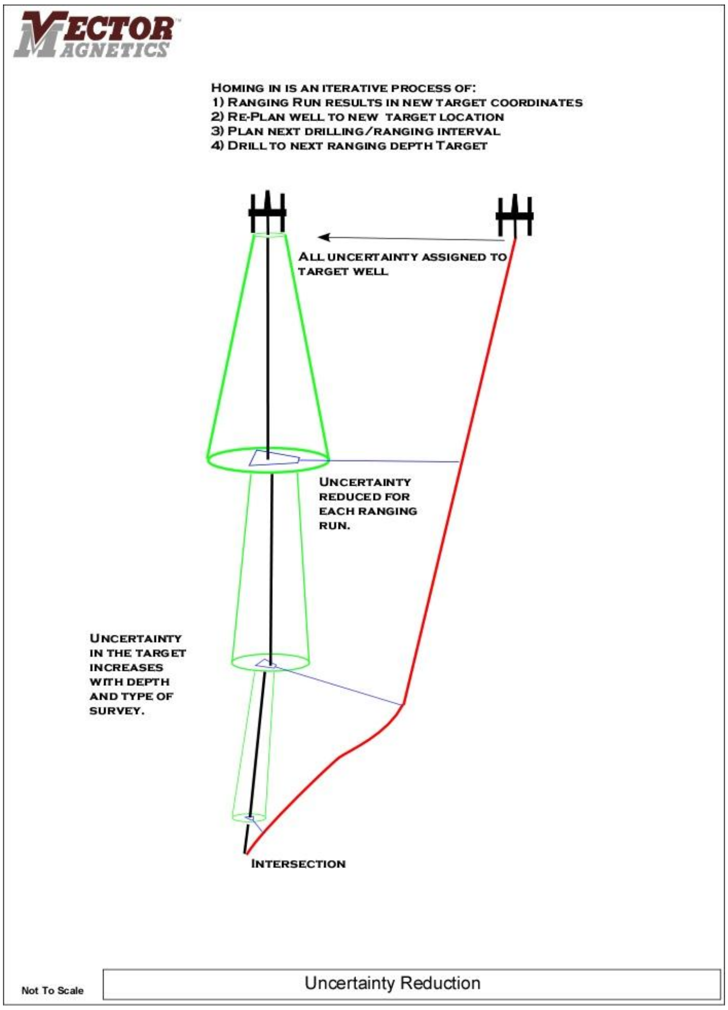


Figure 10: Homing in

To perform the ranging there exist different tools with different range. The technology has developed since the first relief wells were drilled. Higher range on the tools means fewer runs which again means less rig time. The tools are depending on casing or steel in the blowing well to be able to hit the target. If there is a long open hole section in the well, the lowest intersection point will be the lowest casing shoe. There exist both passive and active ranging tools. Active tools inject current in the formation which enhances the magnetic field from the casing in the blowing well. Passive ranging is not depending on another source.

The types of instruments available can be categorized as follows:
(The main content in the following is from Statoil Governing Document- Well Incident and Blowout Response Plan –Statoil Internal *2004)*

- Resistivity instrument and methods
- Magnetic instrument and methods

- Electromagnetic instrument and methods[29]

Resistivity Instruments where mostly run in the 1960-1970 before electromagnetic and magnetostatic techniques were defined

Magnetostatic Instruments utilize sensitive magnetometers to analyze either an induced or remnant magnetic pole from casing or drill string. The distance and direction data can be generated by these tools and the range of measurement is dependent upon the magnometer sensitivity, strength of the magnetic pole being measured and influence of adjacent magnetic dipoles. Experience indicates that useful data can be recorded at ranges up to 15 m and 20m or more at the casing shoe, depending on pole strength. *This means that the tool is able to "see" maximum 20 m ahead.*
Electromagnetic method has replaced the magnetostatic method for relief work because of the increased range, but it is still useful when the approach angle is high, at the end of casing shoes or drill string, or there only exist short pieces of pipe and parted casing fragments.

Electromagnetic Instruments use alternating current: AC magnetometers to measure a radial magnetic field around the target casing. The field is induced by injecting current into the formation from an electrode in the relief well. The currents collect on steel casing because it takes about 10 million times more voltage to drive current in the earth than in steel.
Alternating current running up and down the casing in turn creates an alternating radial magnetic field following Amperes law. The magnetometers in the instrument are turned to the injection frequency and measure the direction of the field, much in the same way as measuring the earth's magnetic field. Measured direction of the field will be perpendicular to the casing. Distance is determined by analyzing the signal intensity and incorporates a complex modeling program to fit the data to the circumstances. The systems range is approximately 60 m in water based drilling mud.[30]

The first application of electromagnetic ranging to achieve a down hole well intersection was performed on a blowout in the Gulf of Mexico in 1980. In 1982 the technology were modified with down hole current injection to demonstrate that casing could be detected in a blowout at a range of at least 200 ft. The technology showed great efficiency in locating tubulars for a direct intersection.

Vector Magnetics are the inventors and developers of the electromagnetic proximity measurements.

---

[29] Statoil Governing Document- Well Incident and Blowout Response Plan –Statoil Internal *2004*
[30] Statoil Governing Document- Well Incident and Blowout Response Plan –Statoil Internal *2004*

The Vector magnetic systems used in relief well drilling are:

- Active AC Magnetic Ranging (WellSpot and WellSpot At Bit explained next)
- Passive Magnetic Ranging (PMR)[31]

Active AC magnetic (Figure is the primary detection method today. Original they were run on wireline in the relief well. This is still done but there has also been developed a WellSpot at Bit tool (Figure) which allow for a bit measurement of distance and direction to the target tubular. This is both time and cost effective since one doesn't need to trip the drill pipe out of the hole. [32]

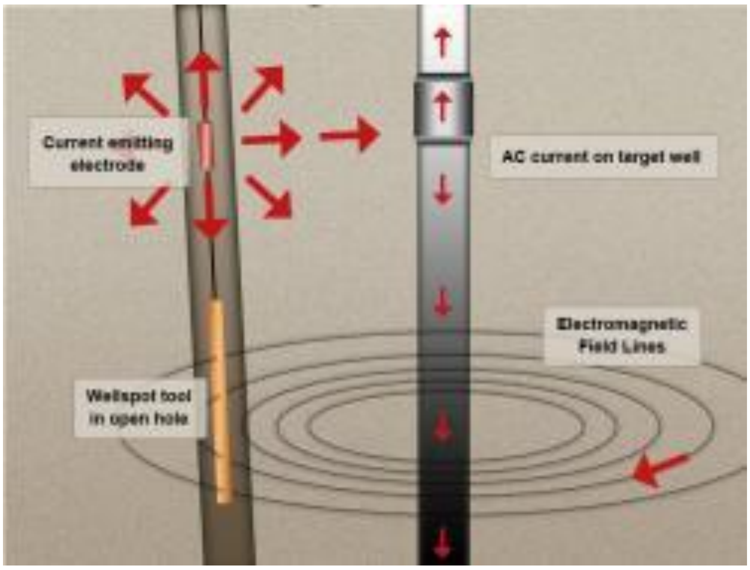


Figure 11: Active AC Magnetics

The standard Wellspot requires injection of alternating electric current to establish a magnetic field. This current is injected through an electrode that is deployed on wireline into the open hole in the relief well. The electrode is on the same tool string and is separated from the sensor package by a length of non-conducting bridle. [33]

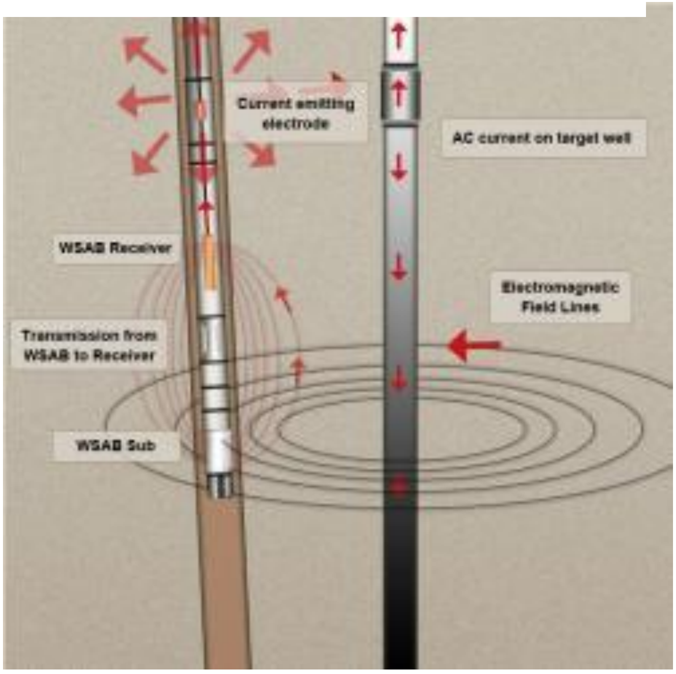


Figure 12: Wellspot at Bit

The casing or drill pipe of the target well concentrates the current and generates an electro-magnetic field. Sensors in the tool in a relief well detect the magnitude, direction, and radial gradients of the electro-magnetic and magnetostatic fields. A computer on the surface collects these measurements for computation of the distance and direction from hole high side and magnetic North to target.

[31] http://www.vectormagnetics.com/oil-gas/applications/relief-wells
[32] http://www.vectormagnetics.com/oil-gas/services/wellspot-and-gradient-tools
[33] http://www.vectormagnetics.com/oil-gas/services/wellspot-bit-wsab

WSAB [Wellspot At Bit] consist of a WSAB sub behind the drill bit. This is transmitting wireless to a receiver tool. In this case we do not need to trip out of the hole. The purpose is to minimize rig time and to give updated information to make the intersect easier:

Passive Magnetic ranging Figure 13: Passive Magnetic) is achieved by analyzing gravity and magnetic data over a range of measured depths to estimate the location and orientation of the target relative to the drilling well. The resolution depends on a number of factors, including the distribution of magnetization along the target. Sometimes it can be difficult to give an accurate estimate of range. The maximum detection range is 5-10 m, depending on total target well magnetization. [34]

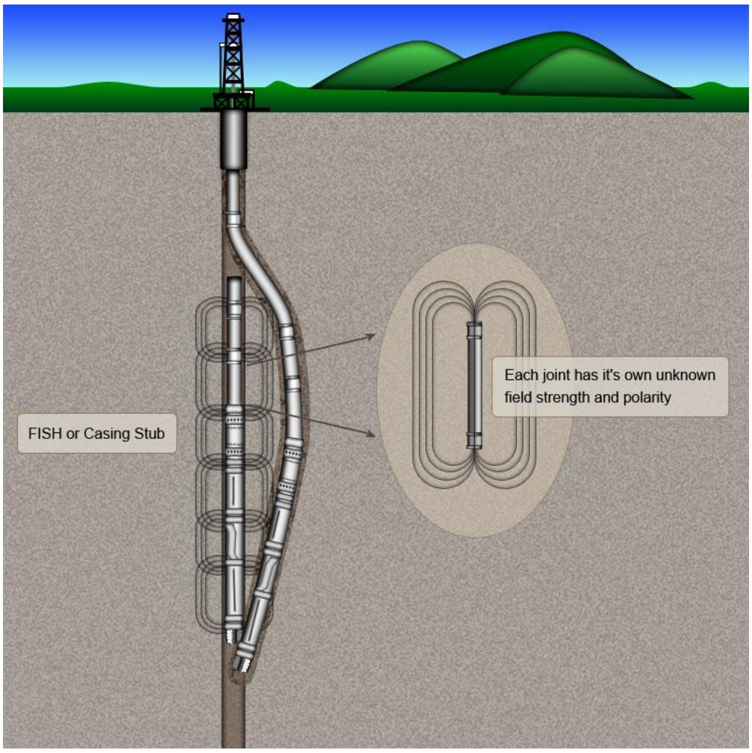


Figure 13: Passive Magnetic

[34] http://www.vectormagnetics.com/oil-gas/services/passive-magnetic-ranging

Important considerations when planning a relief well

Relief well planning in general

A theoretical relief well design can be developed for contingency planning, but the actual design usually has to be modified and established based on the conditions of the blowout as well as considerations of many factors. The factors that must be considered are surface location/site, trajectory and intercept strategy and limitations in magnetic ranging. [35] *It is a requirement on the Norwegian Continental Shelf [NCS] that a relief well plan with the relief well site is selected prior to start drilling the "blowing" well. (Shallow hazards.)*

Interception strategy

The first decision point in relief well planning is to evaluate the hydraulic kill point, placing the depth proximity, orientation and position tolerance of the relief well intersection with the blowout wellbore. This most critical step influences the entire relief well planning process and requires an iterative analysis of all variables involved. Once this point is chosen, two parallel planning paths must be evaluated. First one side considers a drilling design to place the relief well at the chosen point considering all constraints. The other is to design the kill hydraulics and associated pumping and special equipment to carry out the kill operation at the chosen point. If both planning targets cannot achieve their goal (with a reasonable degree of confidence), then the kill point must be re-evaluated.[36]

Relief well site selection

Site selection is normally done by an elimination process. It is simple but can be the most difficult aspect since no best solution exists. Often the site is selected hastily in order to start drilling as soon as possible. When selection the site a dozen factors must be considered. [37]

For an offshore operation, insurance carriers for the drilling contractor typically requires that rig location for the relief well has a specific minimum offset distance established between the relief well and blowout well. This distance is often at least 500 m from the surface location of the blowout. One

---

[35] http://www.drillingcontractor.org/an-introduction-to-relief-well-planning-dynamic-kill-design-recognizing-the-common-limitations-7431
[36] SPE 24578 Dynamic Two Phase Flow Simulator: A Powerful Tool for Blowout and Relief Well Kill Analysis *O.B Rygg, Pål Smestad J.W Wright 1992*
[37] Kicks and Blowout Control Second Edition *Neal Adams, Larry Kuhman1994 ISBN 0-87814-419-6*

of the primary considerations in selecting a site is the appropriate directional wellplan to be used: The blowout wellpath location must be known with some degree of certainty before a directional plan for relief can be developed.
Locations are often rig specific and can be affected by bathymetry profile, geotechnical properties of the sea bed, and presence of shallow hazards on the seabed in the affected area.[38]

Some of the factors that must be considered are wind which has both negative and positive effects on the rig site selection. Wind can carry towards the relief well rig or it can carry the gas away from the rig. Gases can be toxic (like H2S, COx).There are also explosions related to the flammable gas. The advantages of wind are that the gases are diluted and dissipated.[39]

Other factors are water currents, the concern here relates to possible movement of an oil slick towards the rig. Heat can also be a concern, but very few blowouts creates heat loading that would require the rig to move

Well Trajectory

Trajectories are developed with numerous design parameters in mind. They always strive to position the relief well in relation to the target well so that the effectiveness of the proximity ranging tools can be maximized. The initial search depth – the point where the proximity ranging tools will first be deployed - is determined based on such factors as survey uncertainty and casing setting depths but is often designed to be when the relief well is approximately 30 m from the target well and roughly 300 m above the planned interception point. The casing should be placed either considerably before or anytime after the first ranging point. Since the active ranging tool requires injection of electric current there must be sufficient open hole below the casing shoe for the electrode to come in contact with the formation in the open hole. The higher the separation is between the wells the more open hole is required. [40]

[38] http://www.drillingcontractor.org/an-introduction-to-relief-well-planning-dynamic-kill-design-recognizing-the-common-limitations-7431
[39] Kicks and Blowout Control Second Edition *Neal Adams, Larry Kuhman1994- ISBN 0-87814-419-6*
[40] Dual Relief Well Intervention Feasibility Study *2011 Statoil Internal*

Important Limitation – The main concern

To be able to kill the blowout with "dynamic kill" the rig surface equipment and the relief well geometry must allow for passage of the kill fluid at required rate within the pressure limitations. This paper concentrates on relief wells and how to obtain enough rate to kill a blowing well. Pumps on drilling rigs are positive displacement pumps. The delivering of positive displacement pumps is a function between pump rate and pump pressure. The higher pump pressure the lower rate and vice versa.

When fluid is flowing in a pipe it loses its energy, the energy is absorbed by "dissipation" in friction forces. This loss of energy is called pressure loss and is expressed by the difference in the pressure of the fluid between two points of the pipe. [41]

These losses are caused by:

- Internal friction due to fluid viscosity
- External friction due to pipe roughness

In a kill operation when kill fluid is pumped down kill and choke line and annulus of the relief well these pressure losses will occur in:

- Pipe system on the rig
- Kill and choke lines
- Annulus of the relief well

For the purpose of this study, the friction in the blowing well is not taken into account The initial high pump-rate will only be required the first minutes of the kill. See figure 10: Killrate

To be able to kill the well/ stop the inflow, the relief well has to deliver enough volume of mud at high enough rate. The rate must be sufficiently large to induce sufficient friction in the blowing well, but if the pump pressure is too high it will not be possible to provide a sufficient rate.

[41] DDH Drilling Data Handbook *Gilles Gabolde, Jean-Paul Nguyen Eight Edition*

No matter how high pump pressure we can obtain the friction pressure loss can make it impossible to deliver the kill rate needed. This makes the pipe system on the rig and the kill - and choke- lines the limiting factors.

There are several key parameters that will affect the frictional losses/pump pressure and the kill rate we can use.

- Water depth
- length of kill and choke line
- U-tube effect
- ID; Internal Diameter choke and kill line
- Geometry and measured depth of the relief well
- Fluid properties (especially viscosity)

The water depth can make it impossible to pass the required rate through the choke and kill lines. As the water depth increases the length of the kill and choke line and the frictional pressure loss in the choke line increase proportionally.

The parameters that are within control of the relief well are rig, geometry of the relief well and fluid properties.

This thesis concentrates on relief wells and how to obtain enough rate to kill a blowing well.

The main questions to be answered are:

- Can the well be killed with the pump rate one relief well is able to deliver.
- Where is the limit between for 1 relief?

To be able to answer these questions different simulations tools are used. The simulation tool used will be explained in the next chapter.

Simulation Tools

Tools used in this paper

Multiphase flow is very complex. Computer models are used to interpret the multiphase circulating system. [42] In this paper we are interested in pressure losses. There exist several different tools to help model different situations. OLGA is a tool used for pressure calculations in pipe. OLGA ABC [Advanced Blowout Control] was developed to be an "easier" version of OLGA to be used for blowout analysis. OLGA ABC[43] is suited for modeling typical operations related to wells which are blowing out and the planning of relief wells.

Obviously OLGA ABC would be the perfect tool for simulation of relief well and how to kill a blowout. But there is one important thing missing. OLGA ABC (has so far spring 2011) not included choke and kill lines in the relief well design. (Figure 15: Surface equipment OLGA ABC). In this thesis we are interested in how the length and internal diameter of the kill and choke lines affect the friction pressure losses. Hence, OLGA ABC could not be used for this study since the choke/kill lines were not included.

The kill and choke line can be the limiting factor in a kill operation. We are therefore interested in these specific losses to find out how much mud that can be delivered through one relief well.

No ideal program exists for this case, so we needed to figure out a way to solve the problem. The best way was found to be by using one of Drillbench applications. Both Drillbench and OLGA and OLGA ABC are developed by the SPT group for blowout applications. (SPT group is the world leader in dynamic modeling in the oil and gas industry.)

---

[42] PE 24578 Dynamic Two-Phase Flow simulator A Powerful Tool for Blowout and Relief Well Kill Analysis *O.B Rygg, Pål Smestad, J.W. Wright 1992*

[43] OLGA ABC: http://www.sptgroup.com/en/Products/olga/OLGA-ABC/

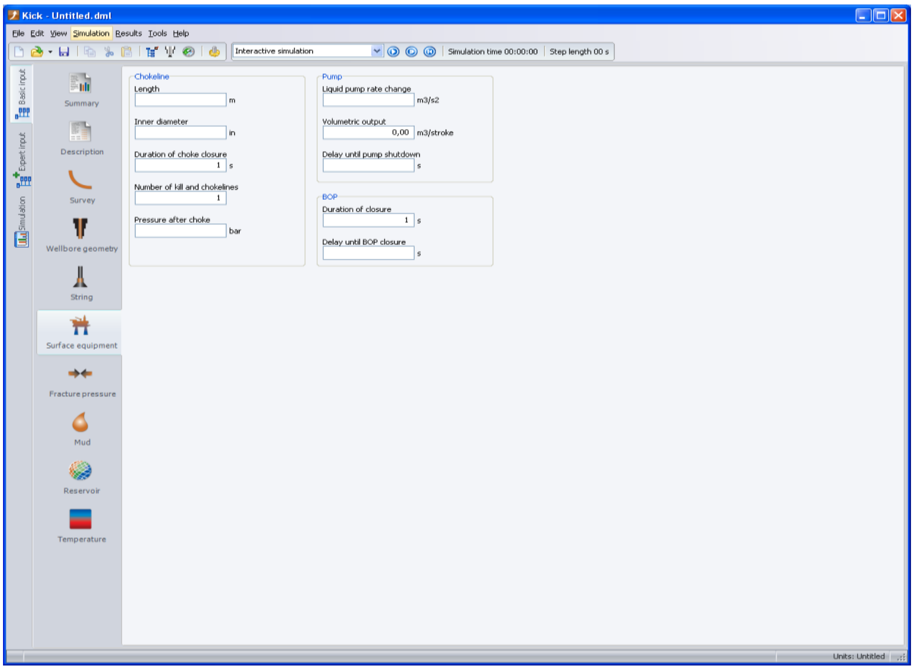


Figure 14: Surface equipment Drillbench Kick

The only application where it's possible to add information about kill and choke line is the dynamic well control modeling tool Kick. Here it's possible to choose number of choke lines and the size on them. Kick is designed to perform different kick tolerance calculations to ensure that reasonable kick volumes can be safely handled and circulated to surface. Kick calculates pressure conditions for the entire well, including necessary choke settings to maintain constant bottom hole pressure while circulating a influx out of the well. [44]Even if Kick is mainly used for conventional kick analysis, it can also be used for analyzing the pressure losses in kill and choke line.

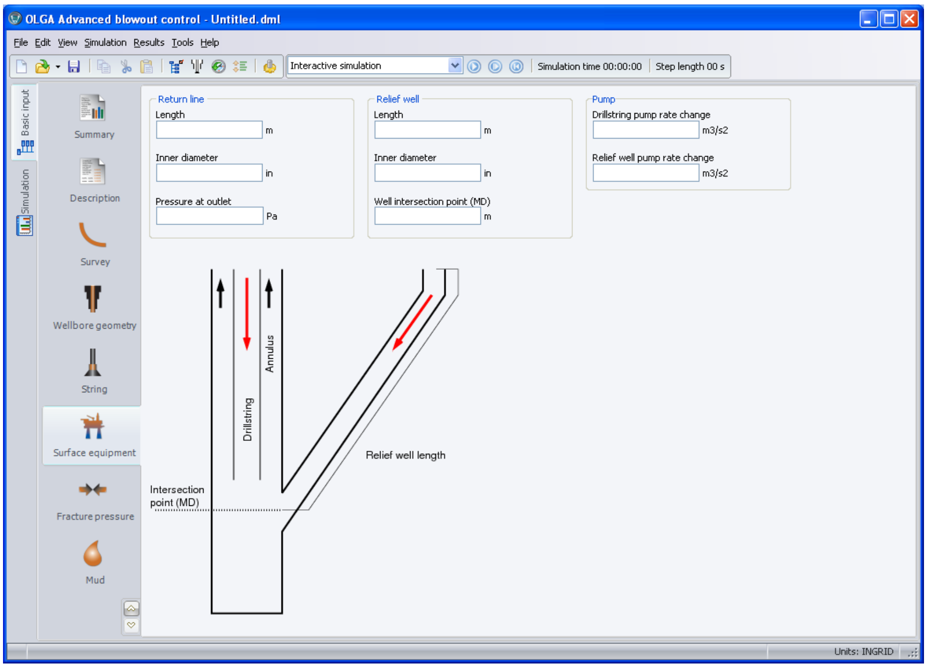


Figure 15: Surface equipment OLGA ABC

[44] Drillbench: http://www.sptgroup.com/en/Products/Drillbench/Advanced-drilling-engineering-and-operation/

Quick process

Quick Process is a Statoil developed pressure technical support program. It is made as an excel add-in. A spreadsheet including formulas has been made for calculation of pressure losses in piping and fittings. Input values are, length, diameter elevation, valves and bends. (Figure 16 Quick Process) The calculations are divided into different segments which can be connected. [45]

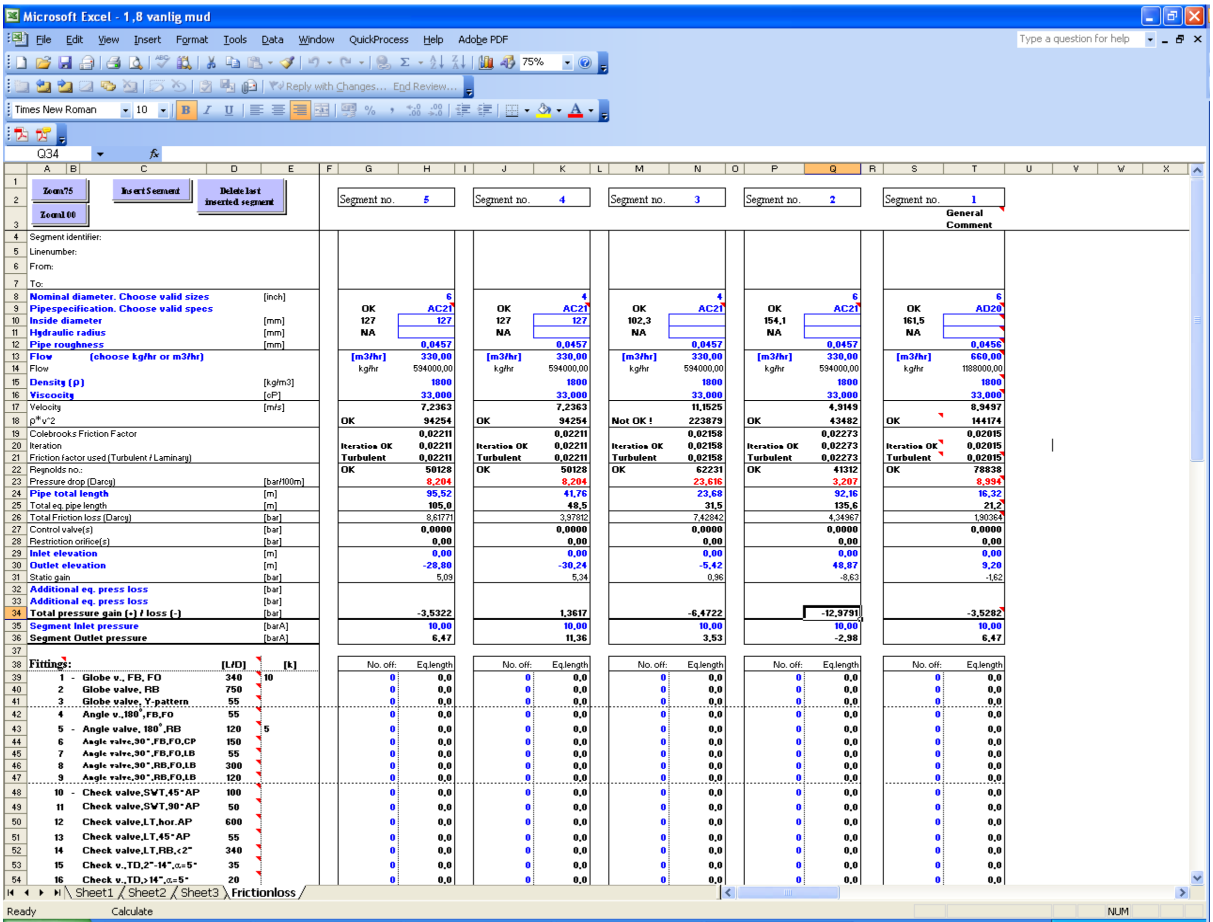


Figure 16 Quick Process

[45] User Guide Quick Process – Statoil Internal

Analysis

How was the simulations performed?

To find the total pressure loss/pump pressure the different simulation tools where used;

- Quick Process; Surface
- KICK; Kill and choke lines
- KICK; Annulus relief well

The results are summarized to get the total pressure.

Water depth and corresponding length of kill and choke line varied from 100 -1200m, the sizes on kill and choke lines varied from 3” to 3,5”. Five different types of heavy mud where used from 1,8 sag to 2,2sg.

For each size on kill and choke line all the different mud types were ran. This means that for each water depth 20 simulations were run. (With 15 different water depths; 300 simulations were run in Kick.)

For the simulations on the rig the only variable where the mud, this means that only five simulations were run in Quick Process.

Next the relief well input in Kick will be explained in further details. This is not relevant for the analysis but gives a better understanding of the simulation tools.

INPUT IN KICK

The data needed to run a simulation is divided into case specific data and more standard data. Standard data are defined in a so called library. The default installation of Drillbench contains a library with values for pipes and tubulars, tools, and fluids. Information can be added to library to define new items. Typical library entries are fluids, pipes and tools. The case specific data are: Well trajectory, geometry, operational conditions, and temperature. In this case standard pipes are used but new mud-types to be used in this analysis have been added.

Input:

- Summary

- Description
- Survey
- Wellbore geometry
- String
- Surface equipment
- Fracture pressure
- Mud
- Reservoir
- Temperature
- Model parameters: observation points measured depth. This one gives the opportunity to analyze pressure at different places in the well.

The summary window is an overview of the most important information entered in the case. (See Figure 17: Summary) The data for the summary window are added in description. The description window is used to describe the main purposes and key parameters of the current case.

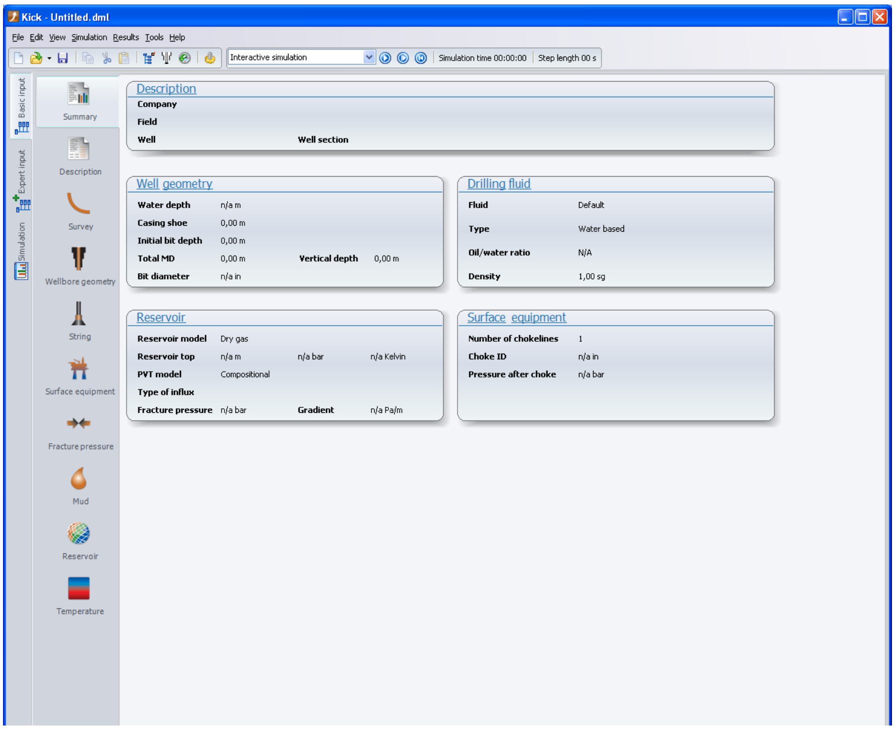


Figure 17: Summary

Survey: The input data for the Survey are Measured depth, Inclination and Azimuth. The simulator calculates the true vertical depth (TVD) by using the minimum curvature algorithm, The angle is given in deviation from the vertical. The survey data used in the simulations can be seen in the Figure 18: Survey)

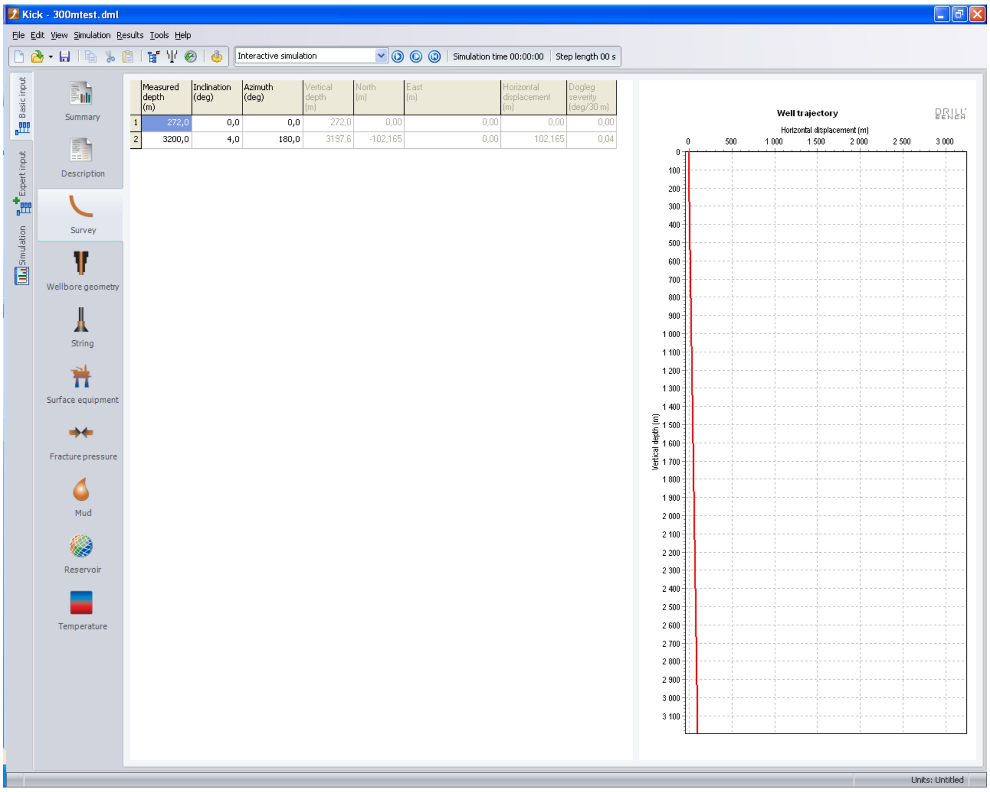


Figure 18: Survey

Wellbore geometry: The wellbore geometry section contains the specification of the actual hole. The wellbore is divided in two parts Riser and casing/liner. Hanger depth is the starting depth for the casing string. Setting depth is the casing shoe depth or depth for cross-over to another casing dimension. The Figure 19: Wellbore geometry shows the wellbore for our simulations

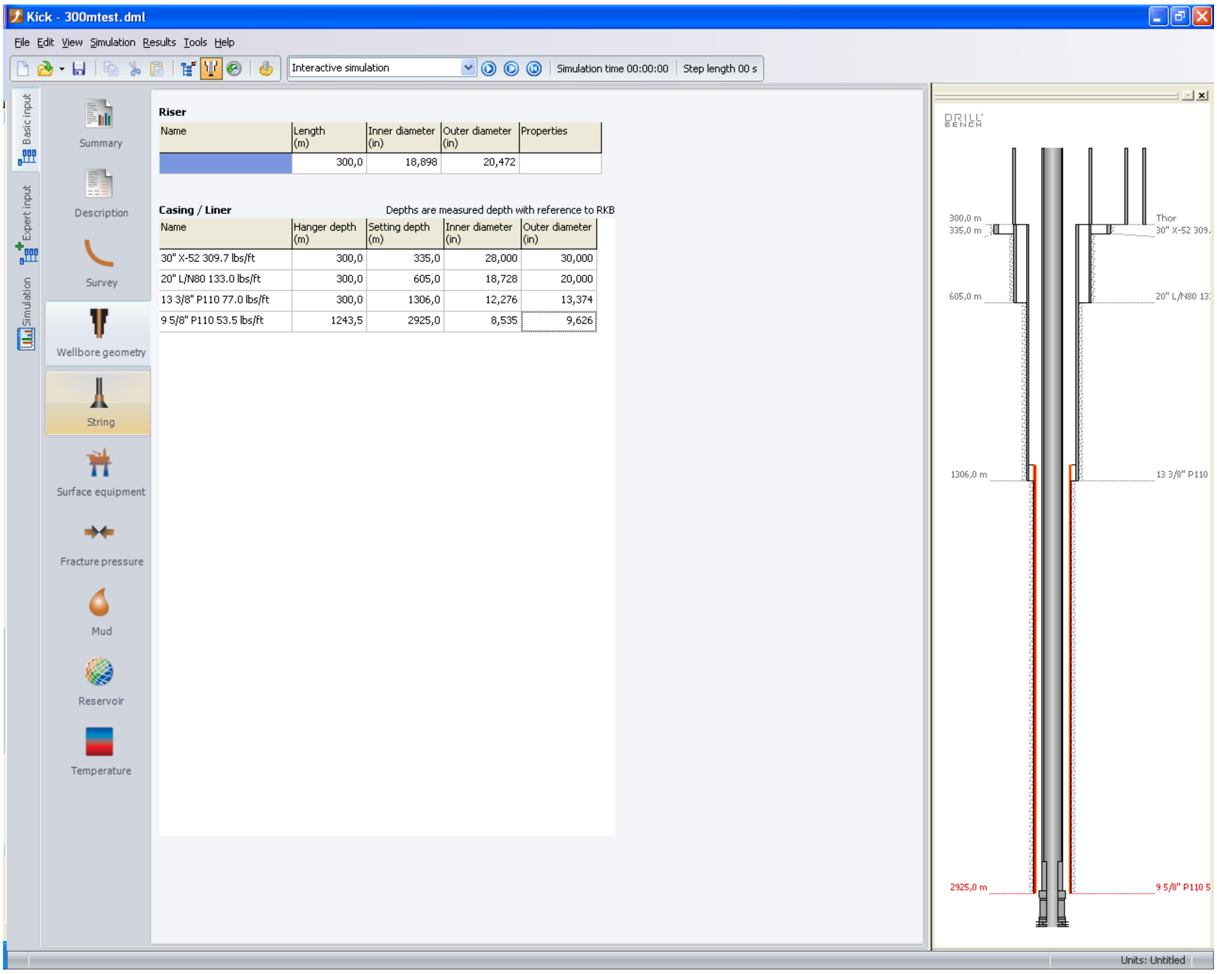


Figure 19: Wellbore geometry

String: The top row in the table is the component just above the bit. All components including the BHA are defined in the table starting just behind the bit and going up the string. The bit is defined separately. The flow area through the nozzles are defined. The Figure 20: String shows the drill string used in the simulations.

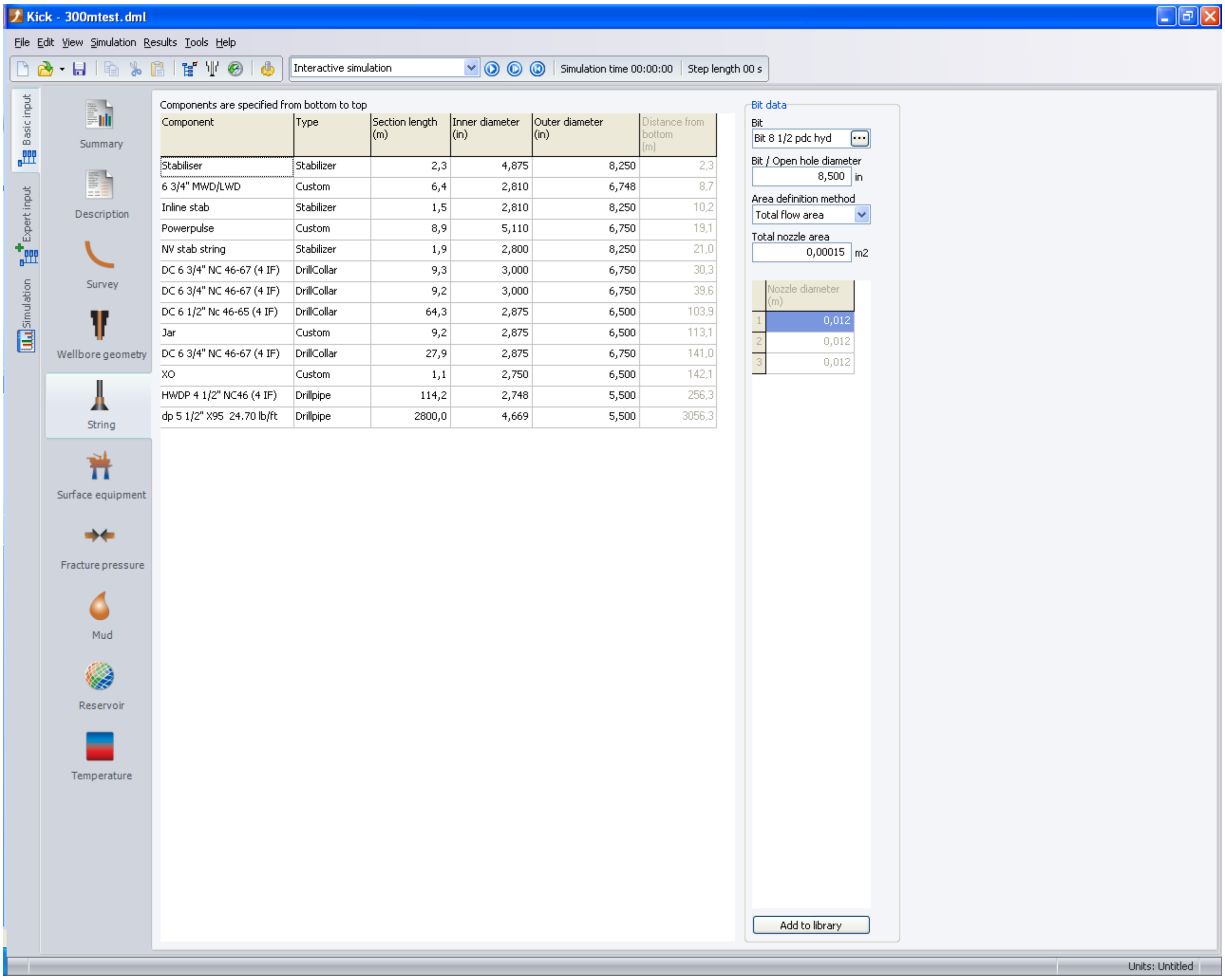


Figure 20: String

The surface equipment defines the rig equipment, see fig 21. It includes number of choke lines, size and length.

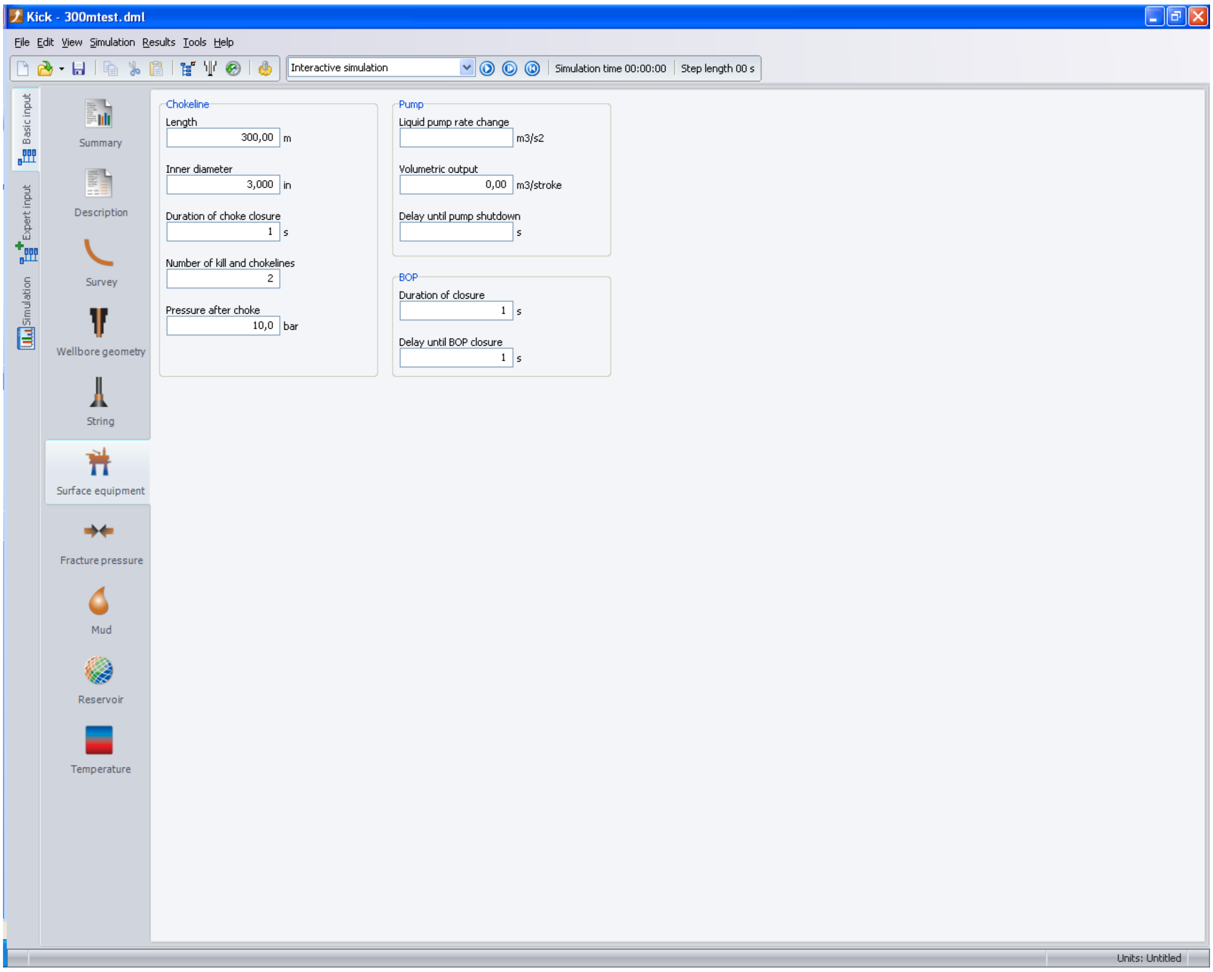


Figure 21: Surface Equipment

Fracture pressure: The fracture pressure can be specified for different depths and refers to formation strength. (Point of elastic deformation). See Figure 22: Fracture Pressure

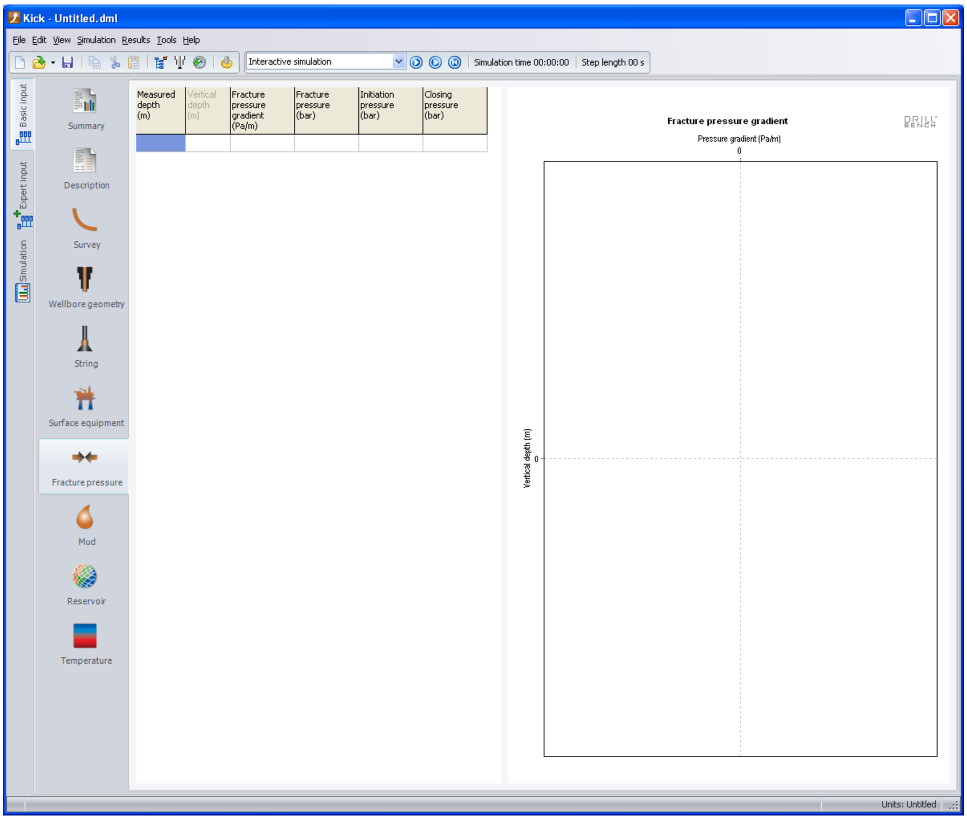


Figure 22: Fracture Pressure

Mud: Fluid can either be selected from the library or new fluid can be defined by entering relevant data. Relevant data:, Fann reading.

Mud types used:

- 1,8sg used in exploration drilling
- 2,0sg brine low viscosity used on Kvitebjørn
- 2,0sg used in exploration drilling
- 2,2 sg brine low viscosity (not used)
- 2,2sg (not used) theoretically

See fig 24-27 for rheology properties. Figure 24 also shows the input parameters for mud.

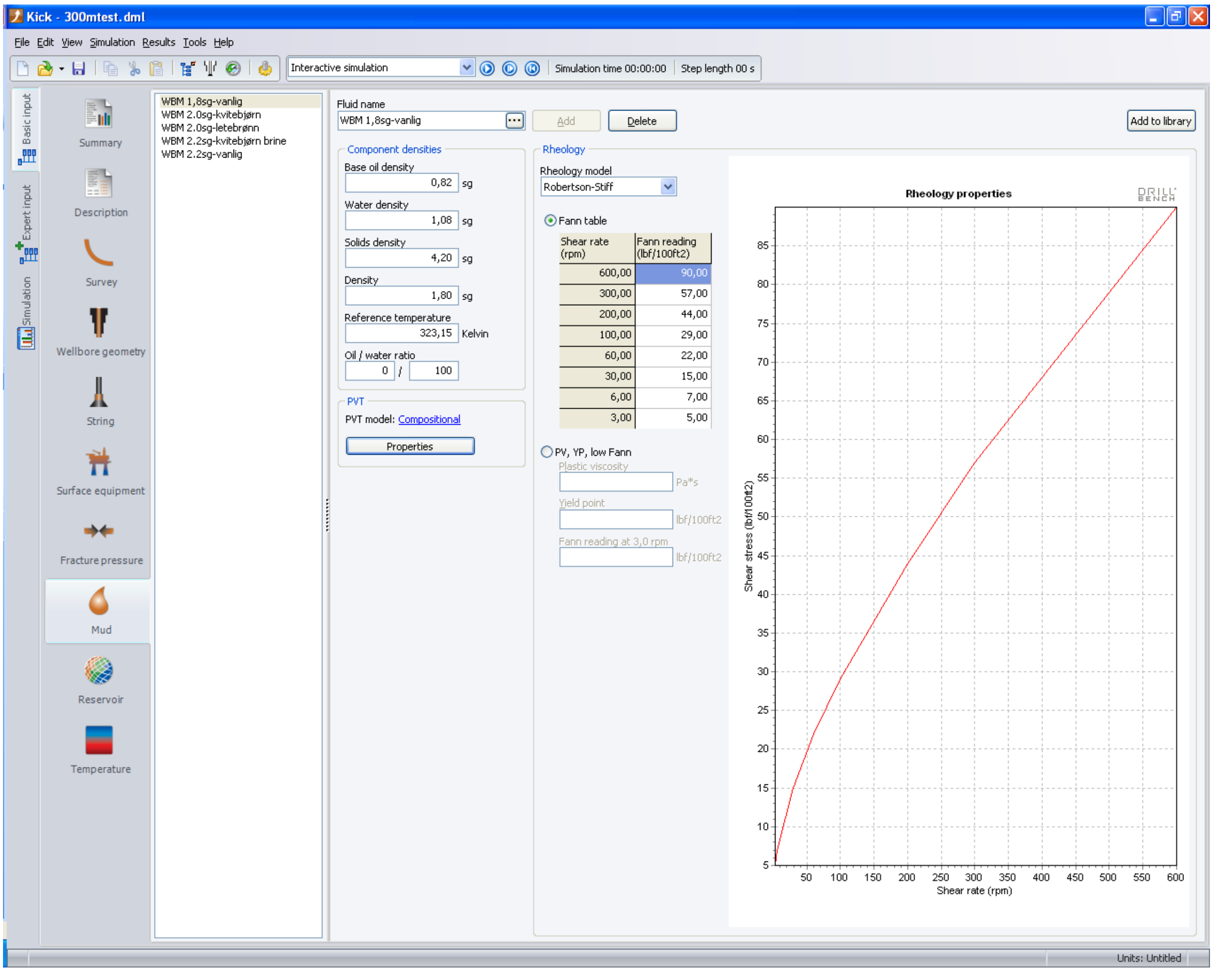


Figure 23: 1,8 sg Mud

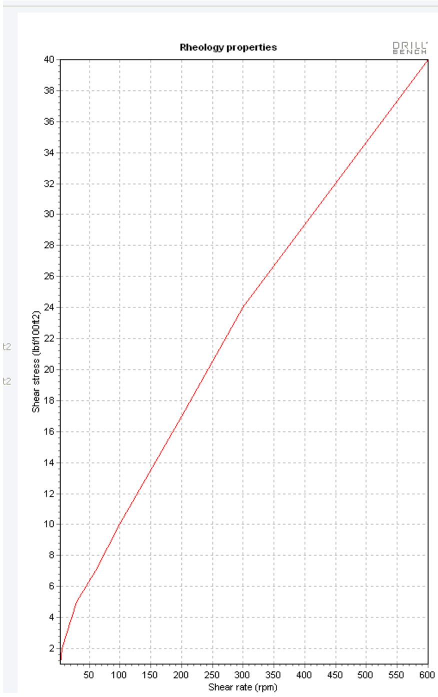
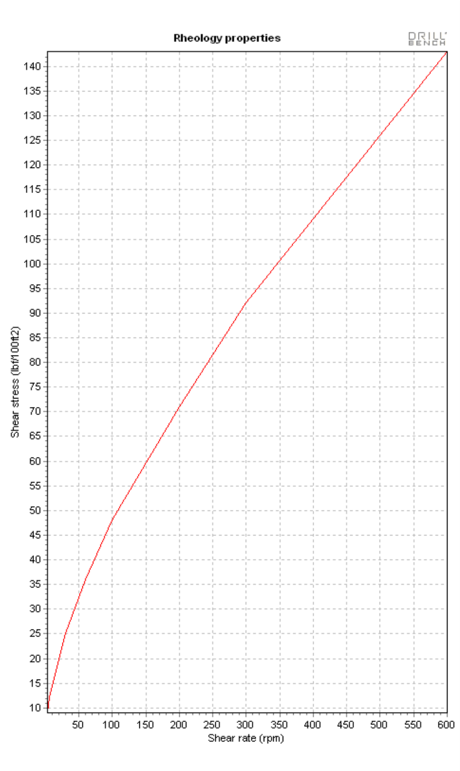


Figure 24: 2,0 sg brine Rheology properties



Figur 25: 2,0 sg Rheology properties

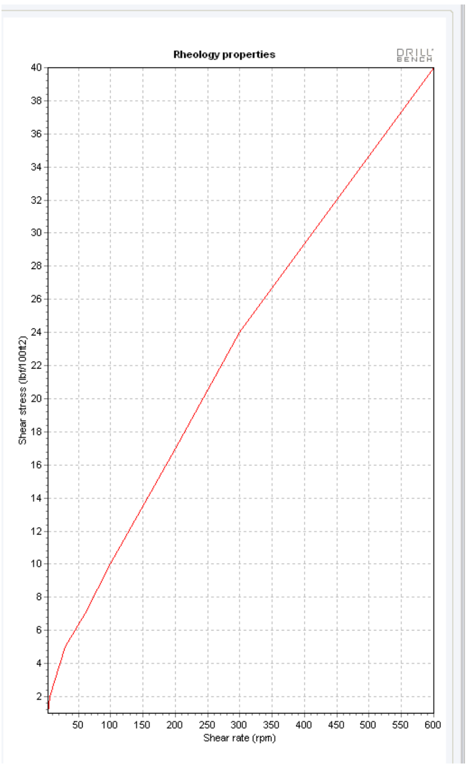


Figure 26: 2,2 sg brine Rheology properties

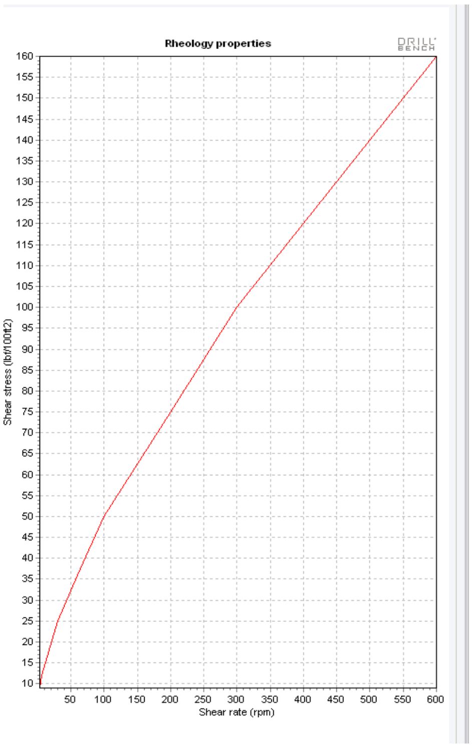


Figure 27: 2,2 sg brine Rheology properties

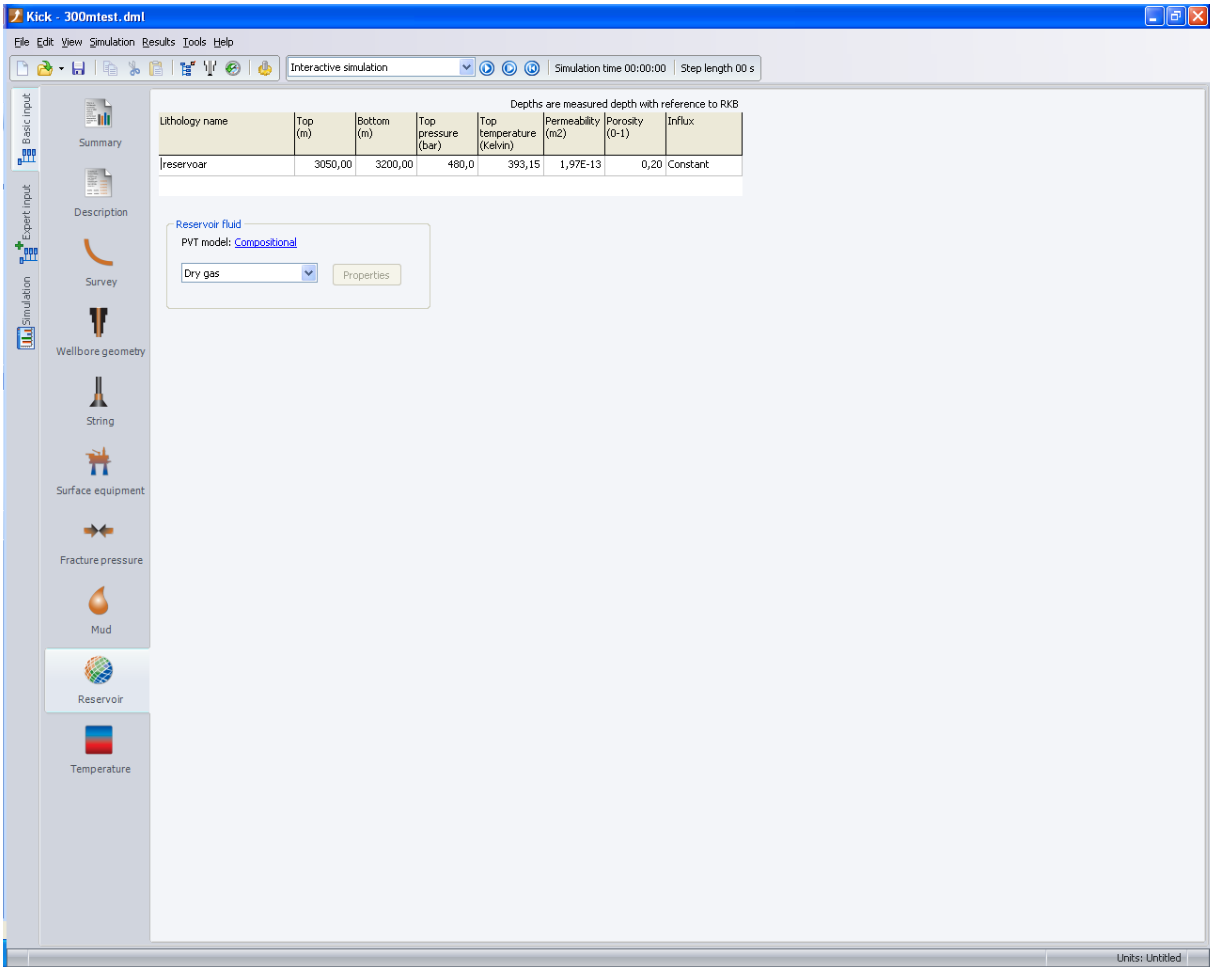


Figure 28; Reservoir

Reservoir: Type of influx fluid are selected from a dropdown list. The PVT properties of the reservoir influx are defined by a fluid properties file generated by PVT sim. (PVT sim is a thermodynamic simulation software package provided by Calsep.

Reservoir zone: Top and Bottom defines the upper and lower boundary of the reservoir zone and are given in measured depth from RKB. Top pressure and top temperature is the pressure and temperature at the top of the reservoir. See figure 29; Reservoir.

Temperature:

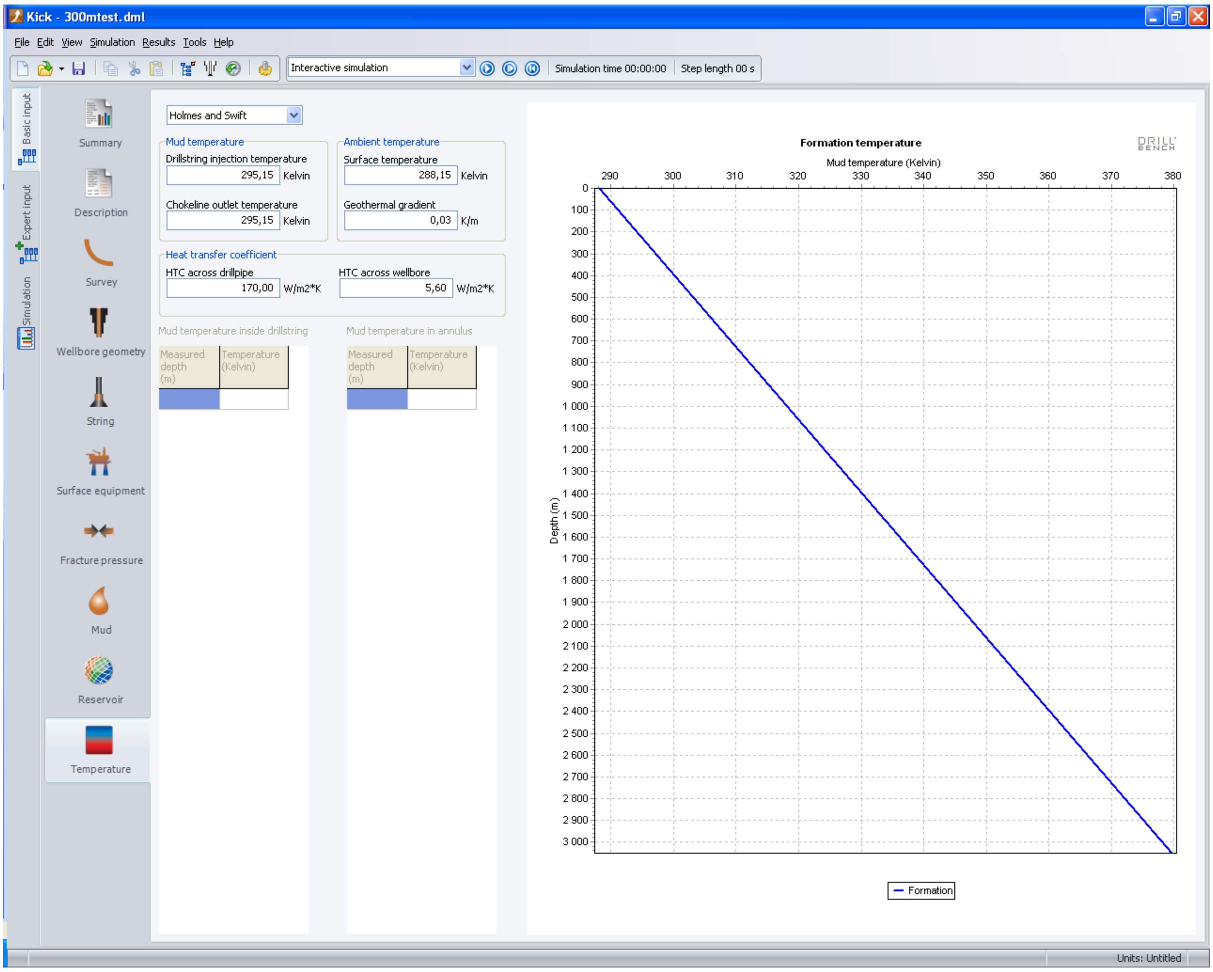


Figure 29: Temperature

Pressure at observation points. Seabed and length of well, are used to calculate friction pressure loss in annulus. (This will be explained in more details under; How simulations are performed.)

SIMULATION:

The simulation window is divided into two sections; (See Figure 30: Simulation window.)

- Simulation control; where different operational parameters can be varied.
- Simulation results presented in different plots.

The different plot windows can be used for showing the results as the simulation runs. (See fig. Figure 31: custom plots). It is possible to customize the plot view due to personal preferences and also add new custom plots window. We have customized plot so we can se the friction pressure losses in the kill and choke lines, and see the pressure at observation points. The observation points are chosen to bee at the seabed and at the bit so that we are able to calculate the friction pressure loss in annulus.

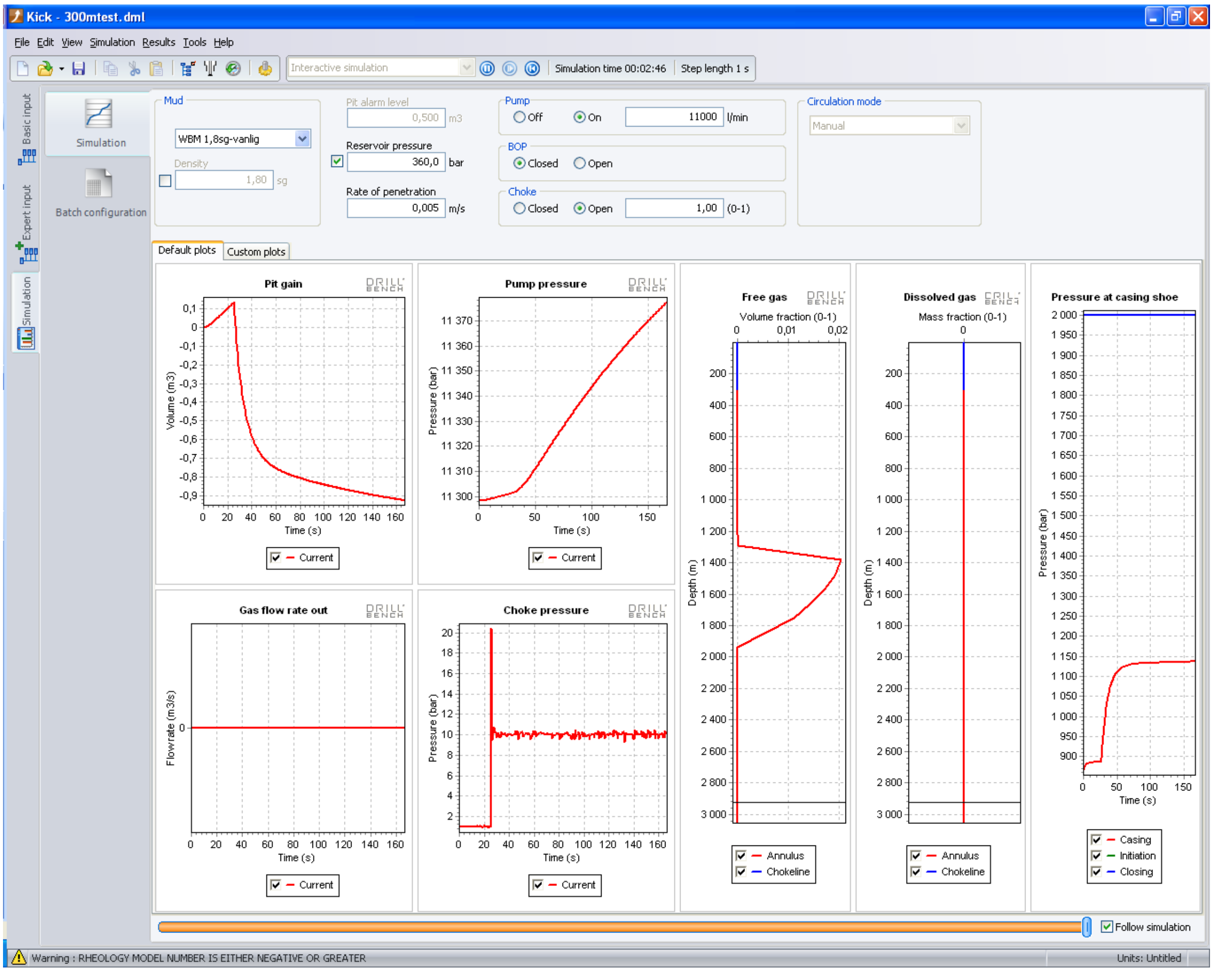


Figure 30: Simulation window

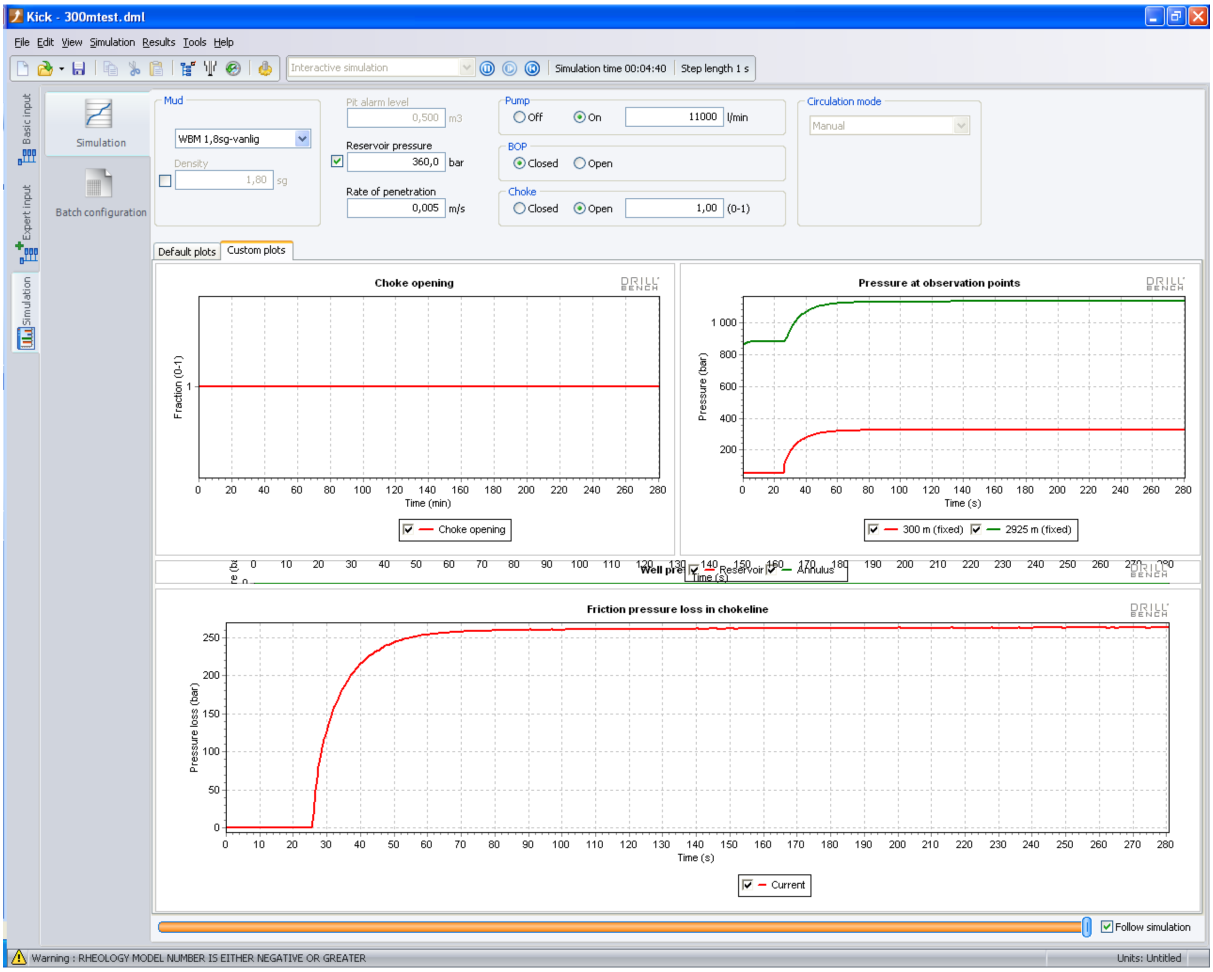


Figure 31: custom plots

Each simulation “run” result in a graphs like these. The data from the graph gives us the maximum point. The maximum point is then added to the simulation matrix which will be explained in the next chapter.

Quick Process:

The different parts are divided into segments. Flow rate, density, viscosity, length, bend and diameters are put in the tables for each segment. The program calculates the different pressure loss in each segment. The different segments are then added together which gives us the friction pressure loss on the rig. In this simulation a standard rig has been used, the base for the information needed is taken from Deep Sea Atlantic.

Simulation matrix and assumed flow parameters

20 simulations were run for each water depth. With 15 different water depths the simulation matrix becomes quite complex. All simulations are using the same well design. With increasing water depth, the length of annulus will decrease. The flow rate is assumed to be 11 000 l/min in all the simulations, which is a normal kill rate for high rate blowouts.

To be able to explain the simulation matrix, we take one part at the time. First the friction pressure loss in kill and choke lines is presented, then the friction pressure loss in annulus and then the for the rig. The matrix as one can be seen in the appendix. The total pressure loss is the sum of the 3 elements; losses on the rig, in kill and choke lines, and in annulus.

Kill and choke line

In the simulations two choke lines were specified in order to mimic that both the kill and choke line are used during a blowout kill. (The flow path is reversed in the simulations compared to a relief well scenario, but the pressure losses will be the same.)

To find the friction pressure loss the lowest graph; friction pressure losses in choke line inFigure 31: custom plots. is used.

Table 1 Friction pressure loss kill and choke line

Friction pressure losses *Pump 11000 l/min* **Water depth (m)**	**MW (sg)**	**Mud weight (sg)**	**kill & chokeline** *friction pressure losses [bar]* 3"	3,5"	4"	4,5"
100	1,80	1,8 sg	93	47	23	13
100	2,00	2,0sg brine	104	48	25	14
100	2,00	2,0sg	106	49	26	15
100	2,20	2,2sg brine	111	54	31	18
100	2,20	2,2sg	118	57	32	19
150	1,80	1,8 sg	137	66	38	21
150	2,00	2,0sg brine	151	72	38	21
150	2,00	2,0sg	154	73	39	22
150	2,20	2,2sg brine	162	77	44	23
150	2,20	2,2sg	173	84	46	26
200	1,80	1,8 sg	181	87	48	28
200	2,00	2,0sg brine	199	95	50	29

200	2,00	2,0sg	204	98	52	30
200	2,20	2,2sg brine	214	102	56	31
200	2,20	2,2sg	229	110	60	35
250	1,80	1,8 sg	224	108	58	36
250	2,00	2,0sg brine	243	116	66	37

(For the “full matrix” /table see appendix.)

Annulus

Here the “pressure at observation points” graphs are used. (upper right corner figure) figure The pressure at bottom of the well and at seabed is found in excel. The pressure at seabed is subtracted from the pressure at bottom and then the hydrostatic pressure is also subtracted which leaves us with the friction pressure losses.

$$P_{Bottom} = P_{seabed} + P_{Hydr,ann} + \Delta P_{fric,ann}$$

$$\Delta P_{fric,ann} = P_{Bottom} - P_{seabed} - P_{Hydr,ann}$$

P_{bottom}: pressure at bottom of the well; 2925,

P_{seabed}: pressure at seabed; seabed

$P_{hydr,ann}$: Hydrostatic pressure from mud in annulus; hydr.mud

$\Delta P_{fric, ann}$: Friction pressure loss in annulus; Total

Table 2 Friction pressure losses annulus

Friction pressure losses annulus
3"

	Pressure at observation points			Total:
well depth	*2925*	seabed	hydr.mud	
2825	968	120	499	349
2825	1057	131	554	371
2825	1097	135	554	408
2825	1153	141	610	402
2825	1224	149	610	466
2775	1011	173	490	348
2775	1103	187	544	371

2775	1152	194	544	414
2775	1204	205	599	401
2775	1280	216	599	465
2725	1054	226	481	348
2725	1149	246	535	368
2725	1194	253	535	406
2725	1255	268	588	399
2725	1335	283	588	464
2675	1097	278	472	347
2675	1194	302	525	367

The friction pressure loss in annulus were larger than expected, to control the answers the frictional pressure loss were calculated by using the pressure loss equations in DDH[46].

Analytical calculations annulus of relief well

Bingham fluid annulus

Turbulent flow

$$P = \frac{Ld^{0,8}Q^{1,8}{\mu_p}^{0,2}}{706,96(D_o - D_i)^{1,8}(D_o - D_i)^3}$$

P= [kPa]

L= Length [m]

d= Fluid specific gravity [kg/l]

Q= Fluid flow rate [l/min]

μ_p=Plastic viscosity [cp]

D_o= Annulus outside diameter [in]

D_i= Annulus inside diameter (outside string) [in]

Numbers used:

400m water depth:

L= 2525m

d= 1,8/2,0/2,2sg

[46] DDH Drilling Data Handbook Eight Edition *Gilles Gabolde, Jean-Paul Nguyen 2006*

Q=11000l/min

μ_p= 33/51/60

D_0=8,5”

D_i=5”

This gives:

1,8sg 33cP:

P= 46611kPa =466bar

2,0 sg 51 cP:

P=56165kPa = 562 bar

2,2 sg 60cP

P= 617 bar

From the simulation matrix:

1,8sg; 344 bar

2,0sg: 402 bar

2,2sg: 459 bar

The results from the simulations are lower then for the results calculated after the formula, which tells us that the there are great pressure losses in annulus.

Rig

Table 3 Friction pressure loss rig

Mud type	Friction pressure loss
1,8sg	38
2,0 sg brine	35
2,0 sg	42
2,2 sg brine	36
2,2 sg	47

The different segments in Quick process are added together one for each mud-type which gives us:

Results

To show the affect of the size on kill and choke line, the different sizes are shown in the following graphs, one for each mud type. As expected the pressure loss will increase with decreasing ID and increasing length.

As we had expected there were large/great friction pressure losses in the kill and choke lines

Kill and choke line

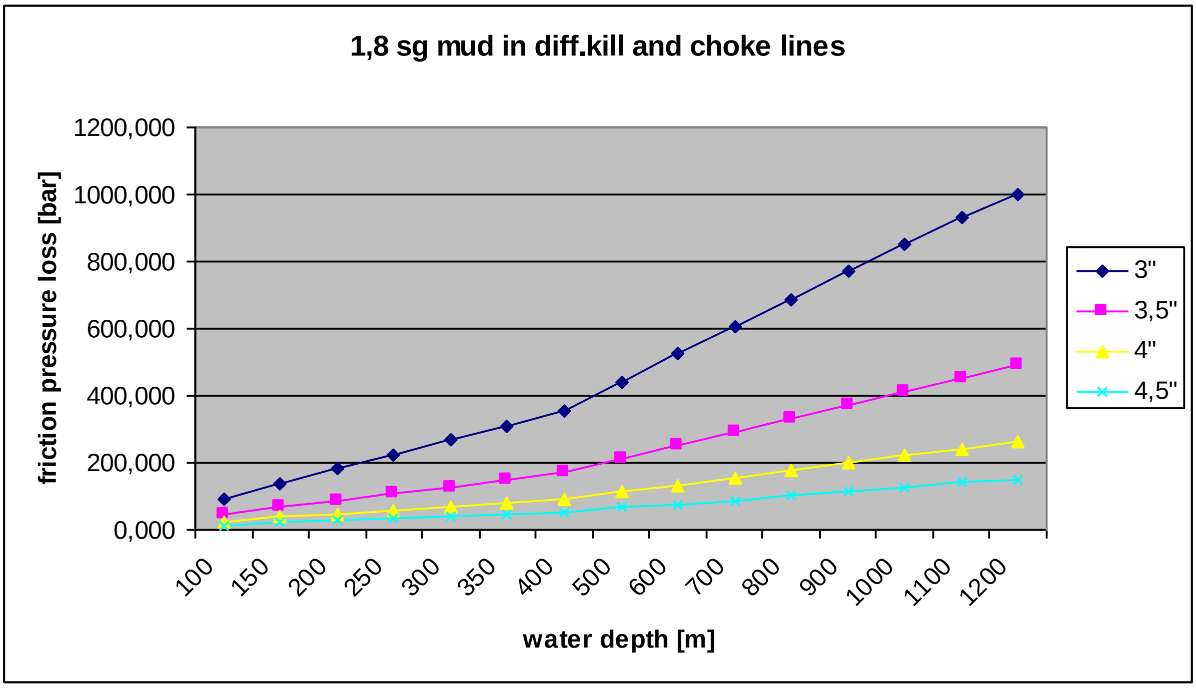


Figure 32: 1,8 sg kill and choke lines

Figure 33 demonstrates how the frictional pressure losses will depend on choke/kill line ID, water depth and rheology. In figure 33the I D and water depth is varied using one mud type. Another mud is used in figure 34-38, and we can see how this affects the pressure losses. (increasing with increased mud weight, viscosity)

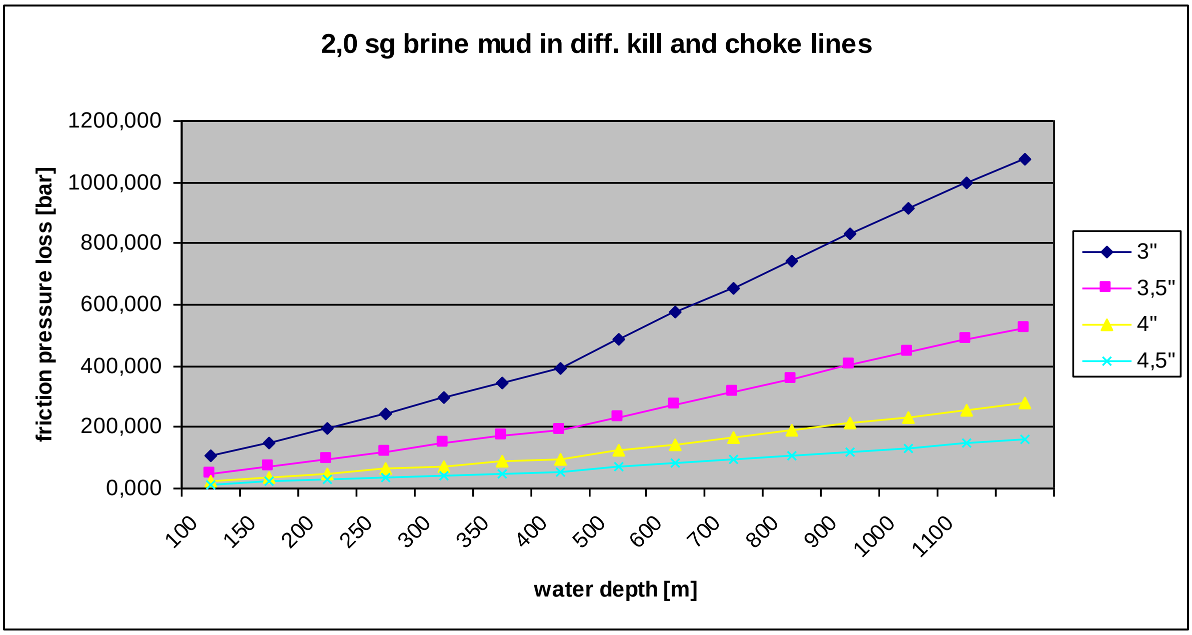


Figure 33: 2,0 sg brine kill and choke lines

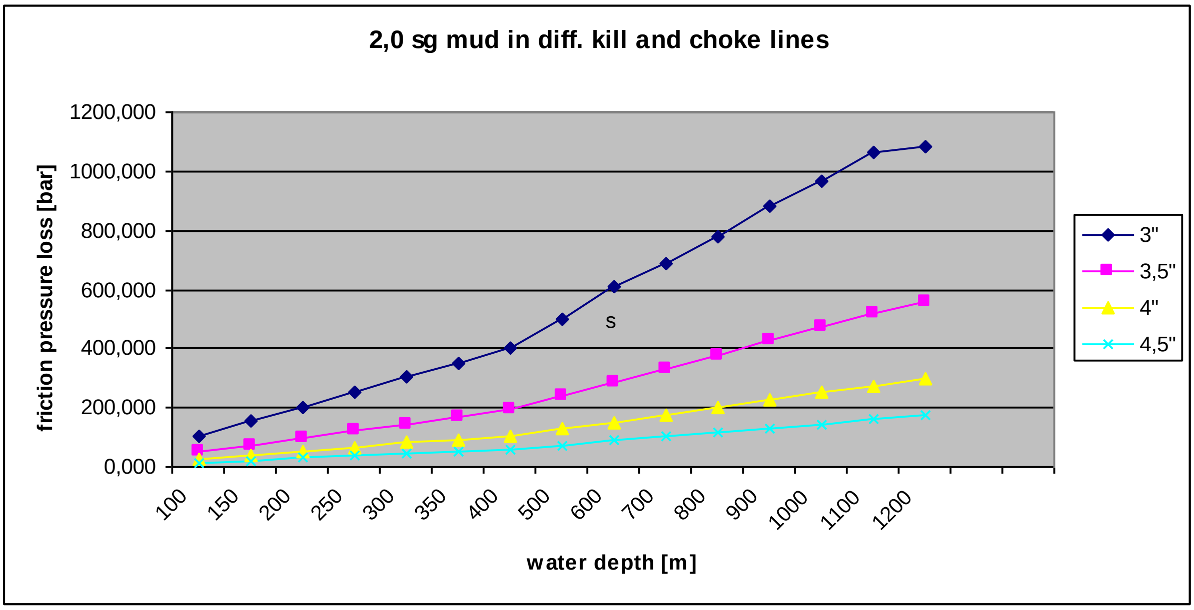


Figure 34: 2,0 sg kill and choke lines

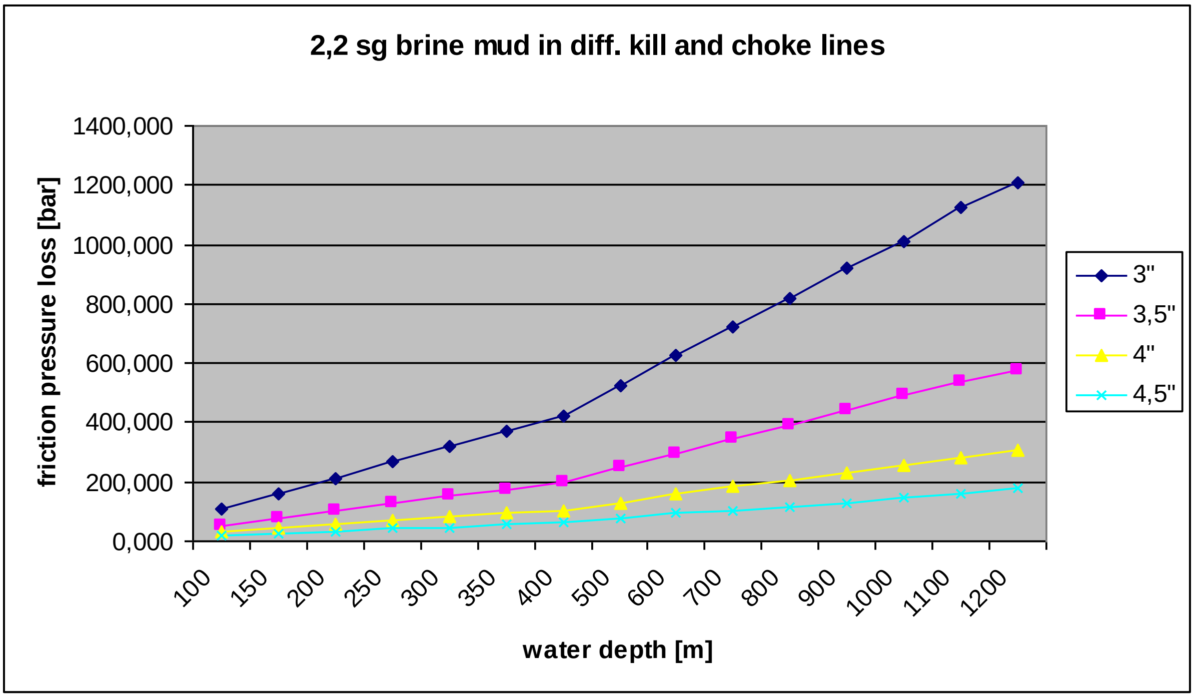


Figure 35: 2,2 sg brine kill and choke lines

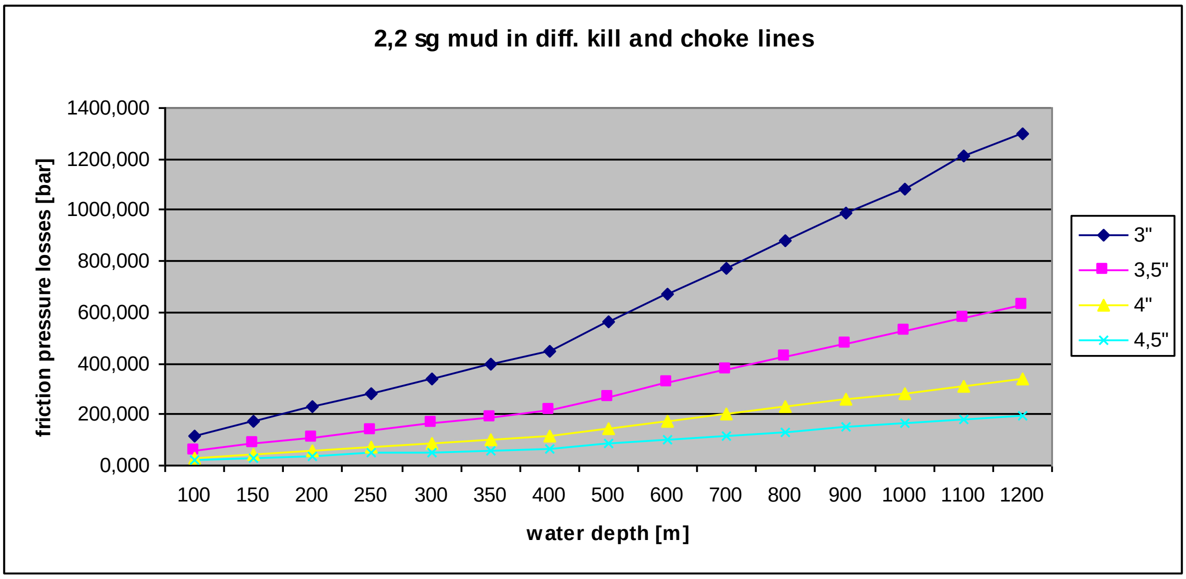


Figure 36: 2,2 sg kill and choke lines

To show the effect of the different mud types, the frictional pressure losses for all mud types for specific ID's are shown in figure 38-42,. all mud types are presented for each size of the kill and choke line. As the diagram/graph shows the lightest mud/lowest viscosity mud type has the lowest friction pressure loss, both for 3", 3,5", 4" and 4,5".

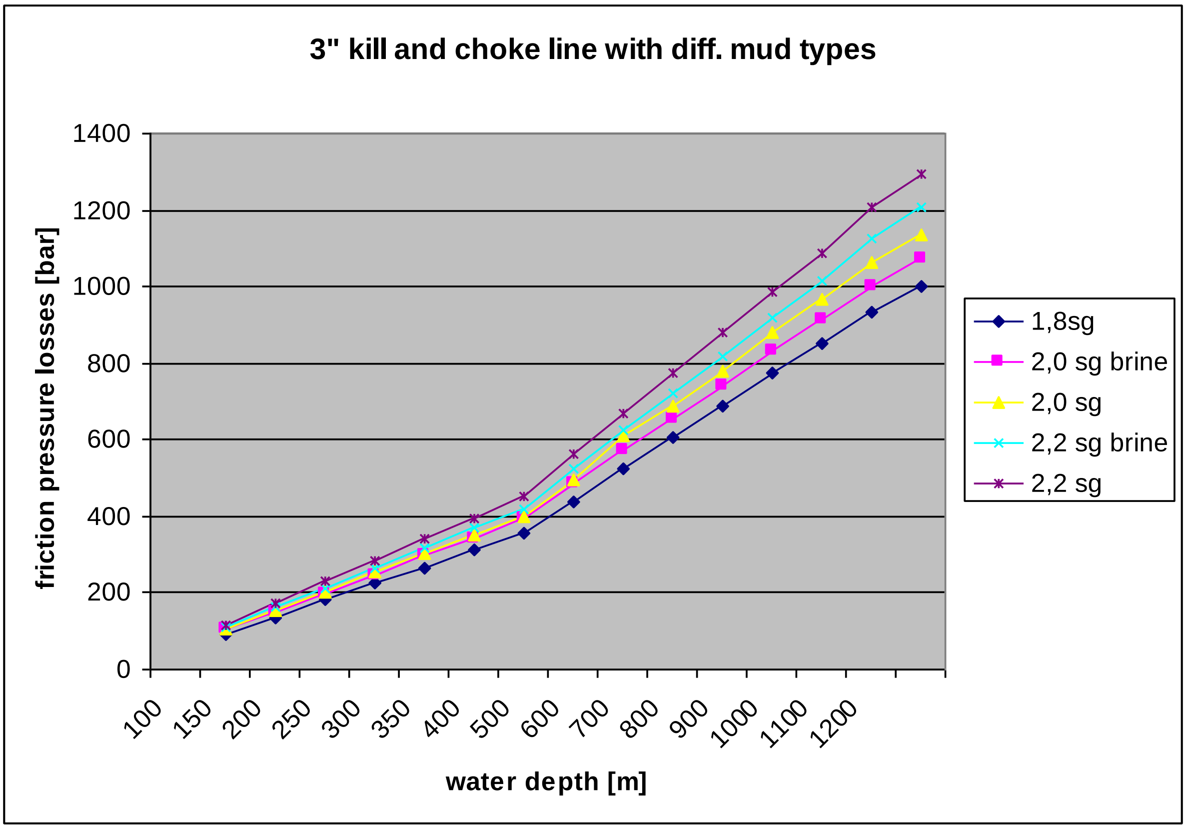


Figure 37: 3" kill and choke line, diff. mud types

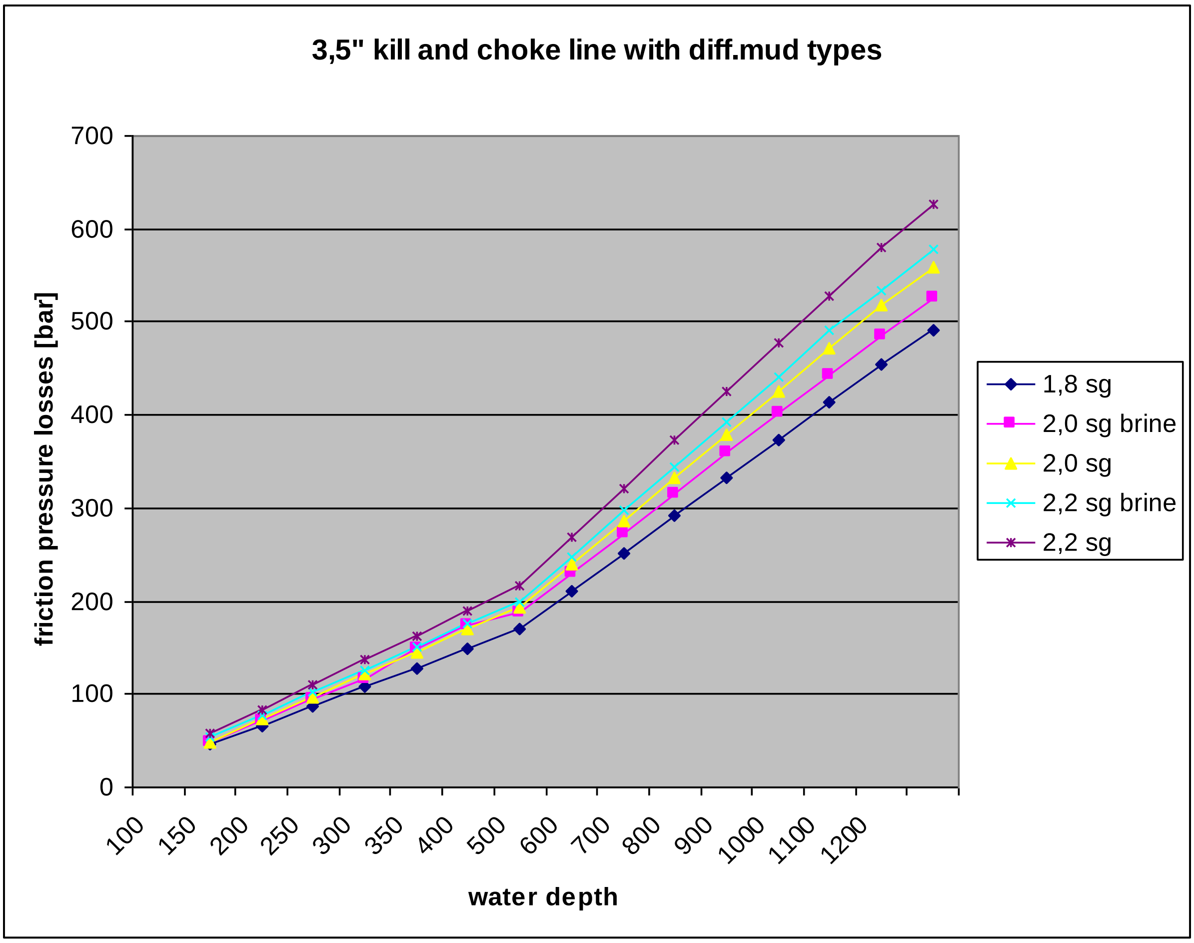


Figure 38: 3,5" kill and choke line, diff. mud types

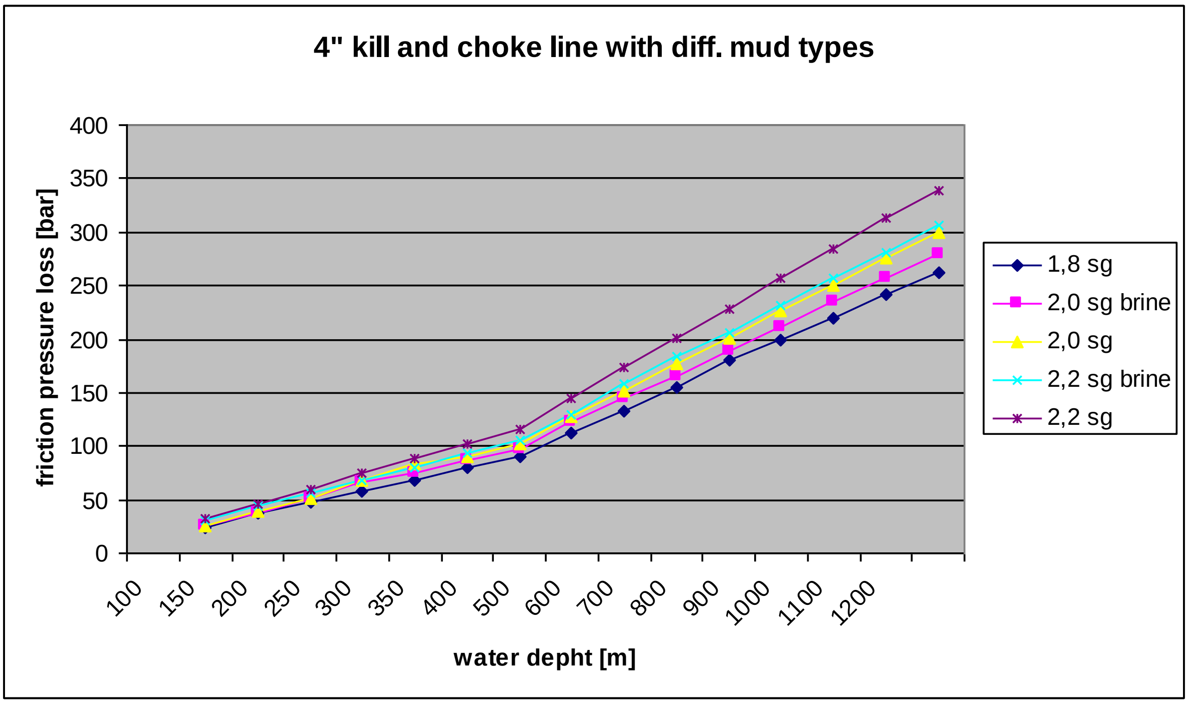


Figure 39: 4" kill and choke line, diff. mud types

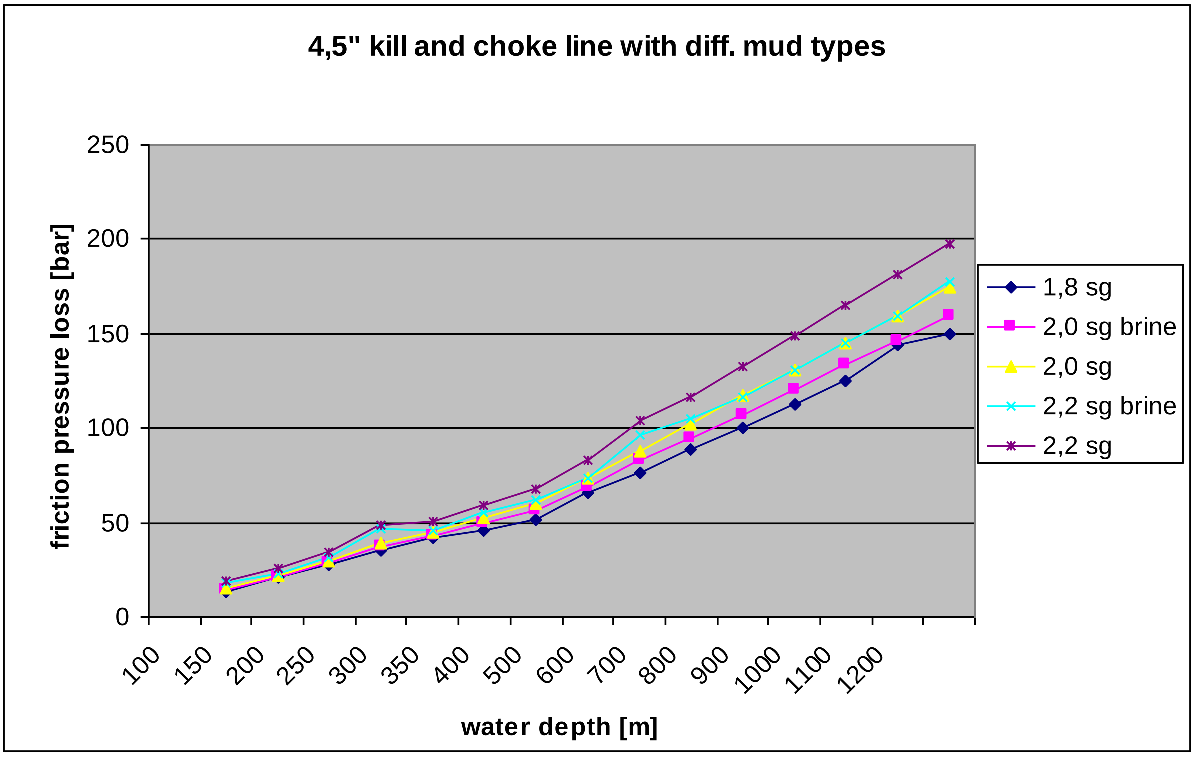


Figure 40: 4,5" kill and choke line, diff. mud types

Annulus

Is presented in the same way as the kill and choke lines. Figure 43-46 shows the friction pressure loss with varied mud-types.

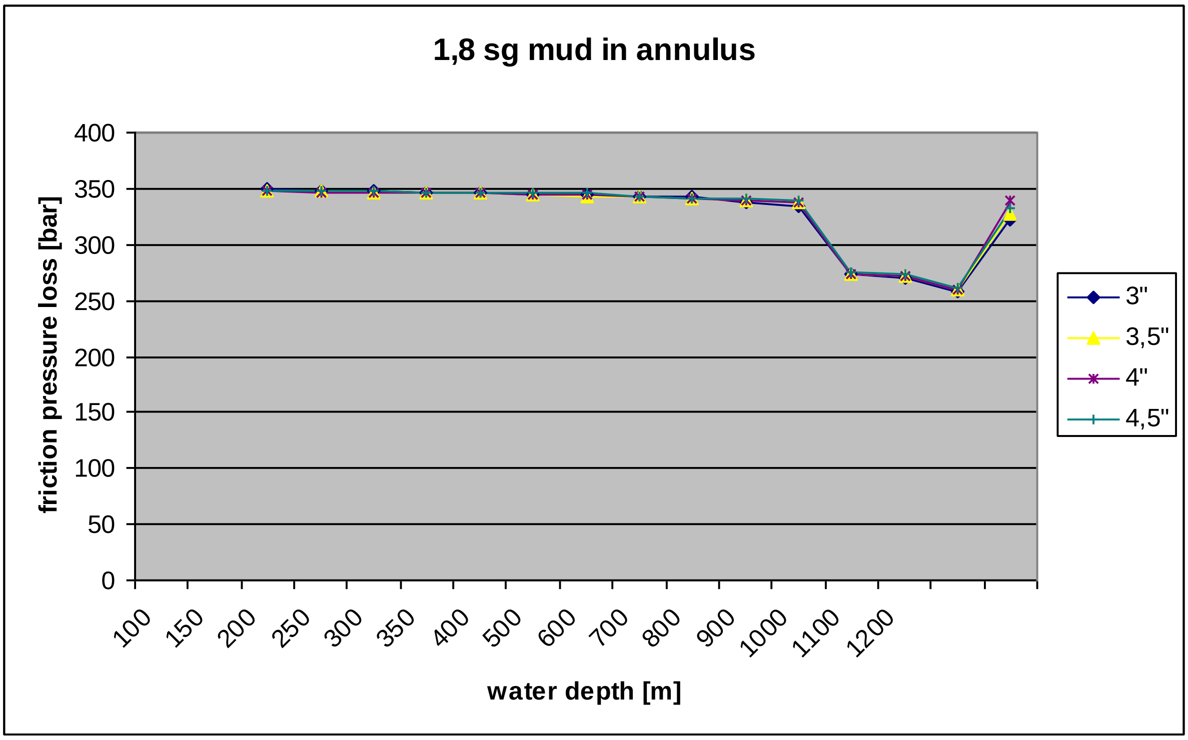


Figure 41: 1,8 sg annulus

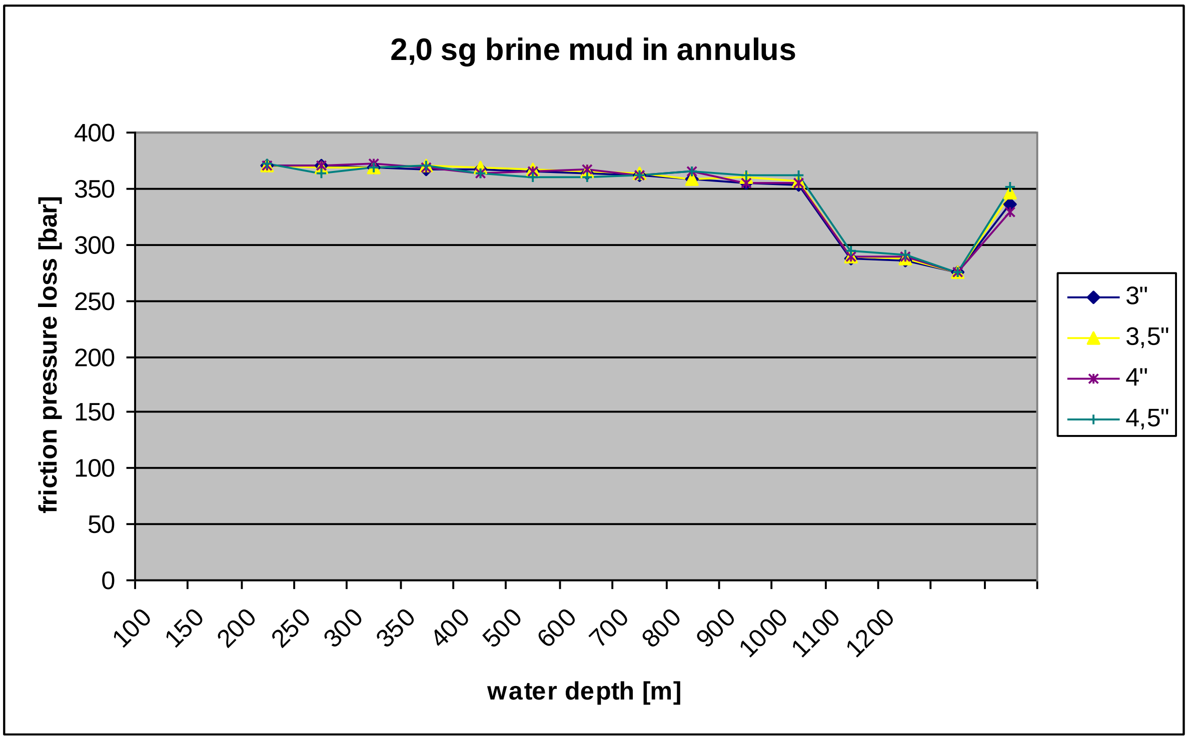


Figure 42: 2,0sg brine annulus

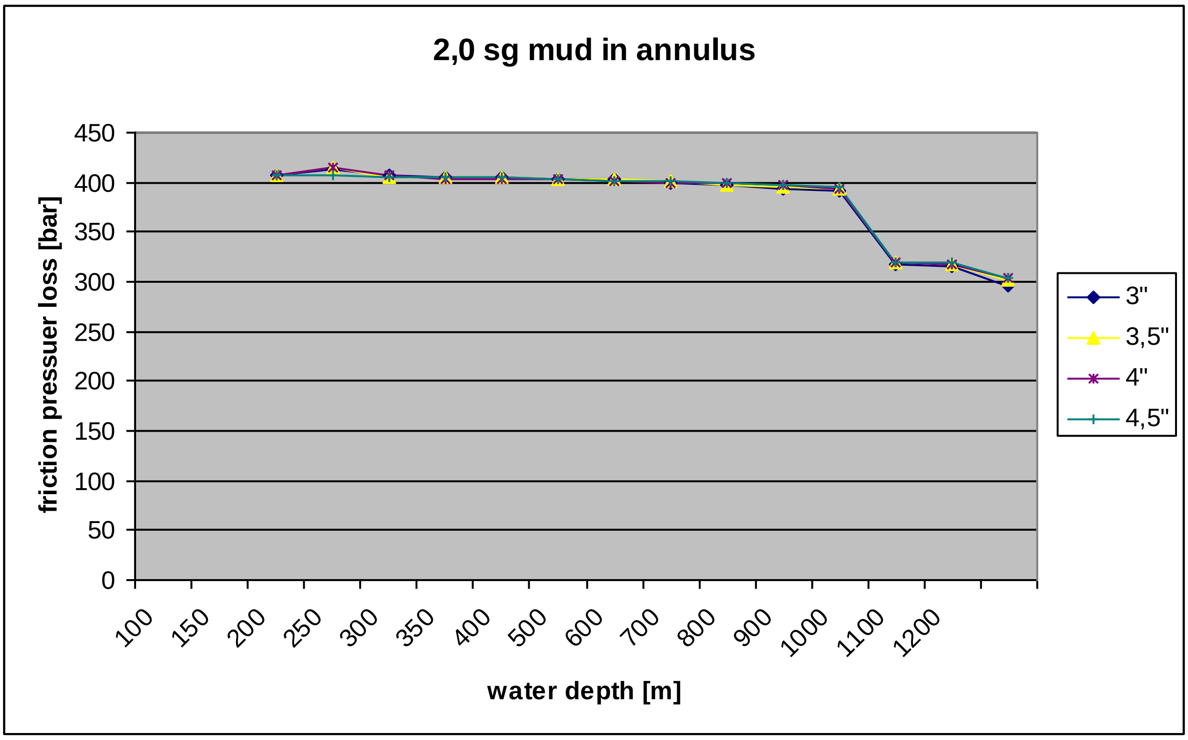


Figure 43 : 2,0 sg annulus

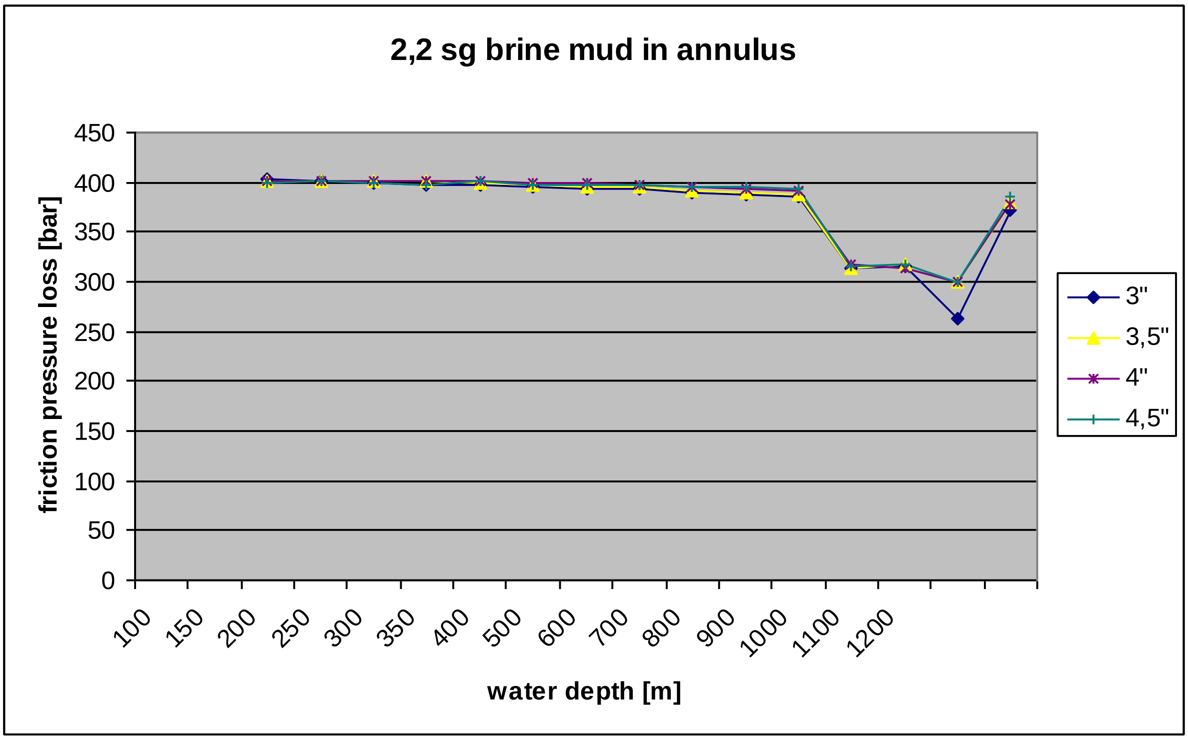


Figure 44 : 2,2sg brine annulus

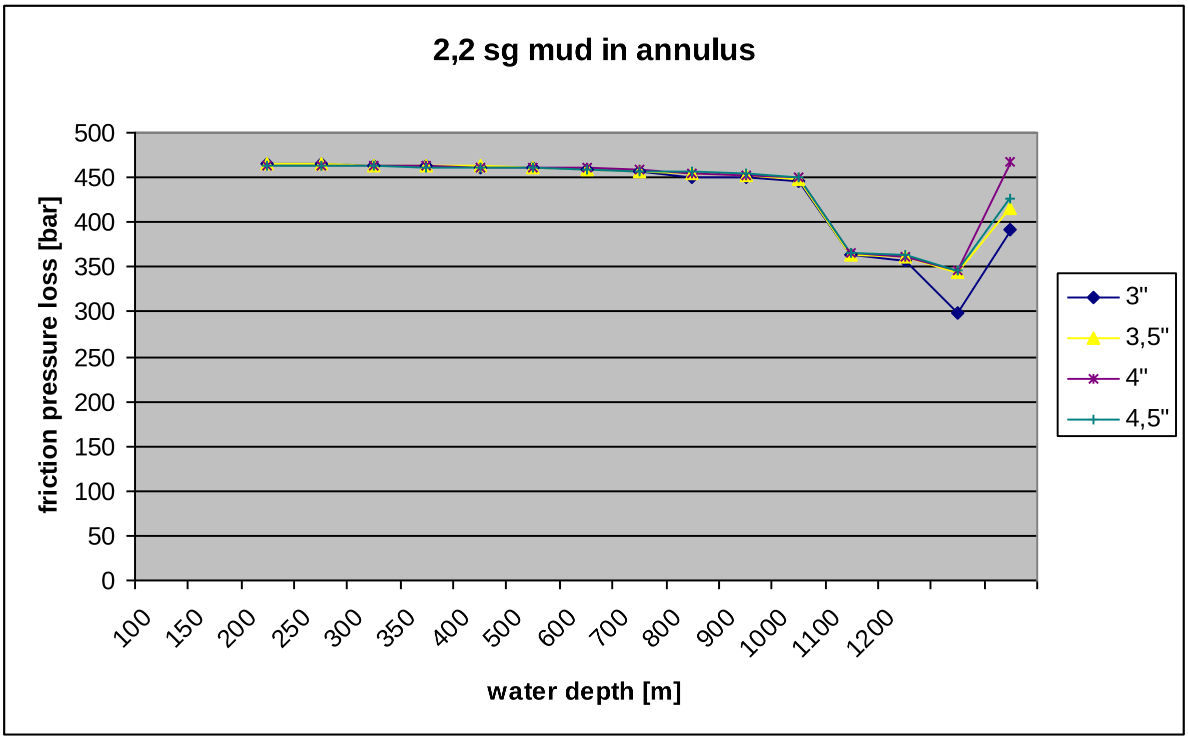


Figure 45: 2,2 sg annulus

The annulus frictional pressure loss is not affected by size on kill and choke lines To show this the effect of different mud are represented for 3” (figure 47) and 4,5” (figure 48). The results are approximately the same.

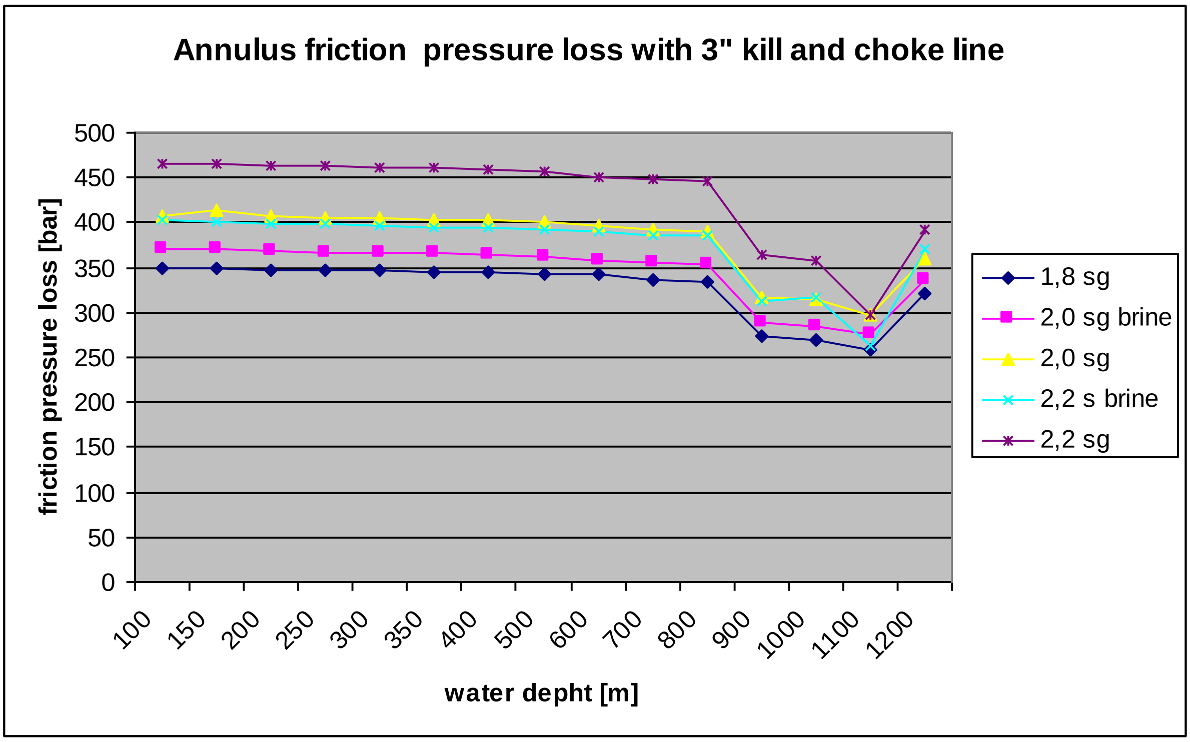


Figure 46: 3" annulus diff.mud

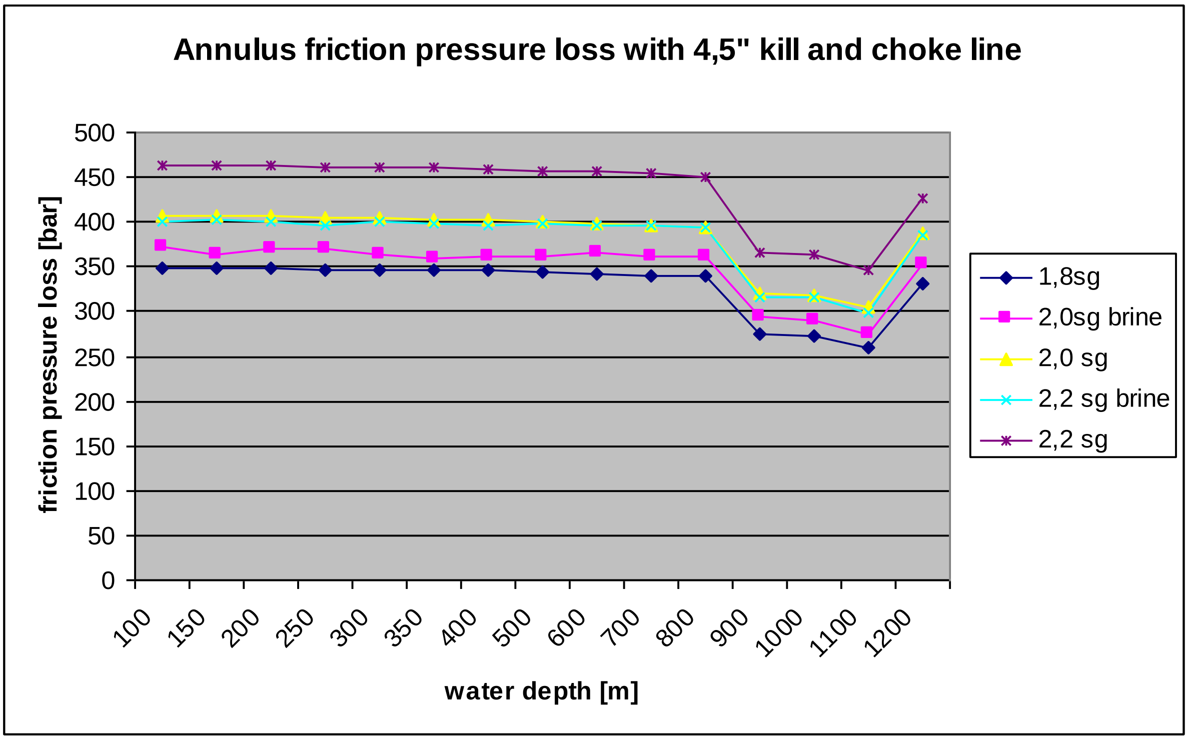


Figure 47: 4,5 " annulus diff. Mud

As figure 41-45 (different mud types in annulus) and 46-47 (different sizes on kill and choke line in annulus) shows there are some result that needs to be investigated further. The results for water depths; 900, 1000 and 1100 are significant lower than for the other water depths. The input data in Kick is the same so there is no obvious reason for the results to be different. One reason can be that Kick has trouble calculating the results for these high water depths, but then again the result for 1200 m is reasonable. The simulations have been run several times for 900, 1000 and 1100 but Kick gives the same result each time. To control the results the annular friction pressure loss is calculated by the pressure loss equations used earlier.

Analytical calculations annulus of relief well

Bingham fluid annulus

Turbulent flow: [47]

$$P = \frac{Ld^{0,8}Q^{1,8}{\mu_p}^{0,2}}{706,96(D_o - D_i)^{1,8}(D_o - D_i)^3}$$

P= [kPa]

L= Length [m]

d= Fluid specific gravity [kg/l]

Q= Fluid flow rate [l/min]

μ_p=Plastic viscosity [cp]

D_o= Annulus outside diameter [in]

D_i= Annulus inside diameter (outside string) [in]

Numbers used:

d= 1,8 , μ_p =33

Q=11000l/min

D_0=8,5”

D_i=5”

900m water depth; L= 2025m gives P=37280kPa = 373bar

[47] DDH Drilling Data Handbook Eight Edition *Gilles Gabolde, Jean-Paul Nguyen 2006*

1000m water depth; L=1925m gives P=35522kPa = 355bar

1100m water depth; L=1825m gives P = 33694= 337bar

When comparing this result with the results in figure 41; 1,8 sg in annulus, the results from the calculations are noticeably higher than the other results. If the calculated results are more precise, it may be more accurate to calculate the annular friction pressure by formula than to use the simulation tool.

Rig

The friction pressure losses for the rig are presented in table since it is not affected by any other variables than mud-type.

Table 4 Friction pressure loss rig

Mud type	Friction pressure loss
1,8sg	38
2,0 sg brine	35
2,0 sg	42
2,2 sg brine	36
2,2 sg	47

Total

Is presented in the same way as the kill and choke line and annulus. Figure 51-55 shows how the frictional pressure loss varies with different size on kill and choke-lines, one mud-type presented at the time.

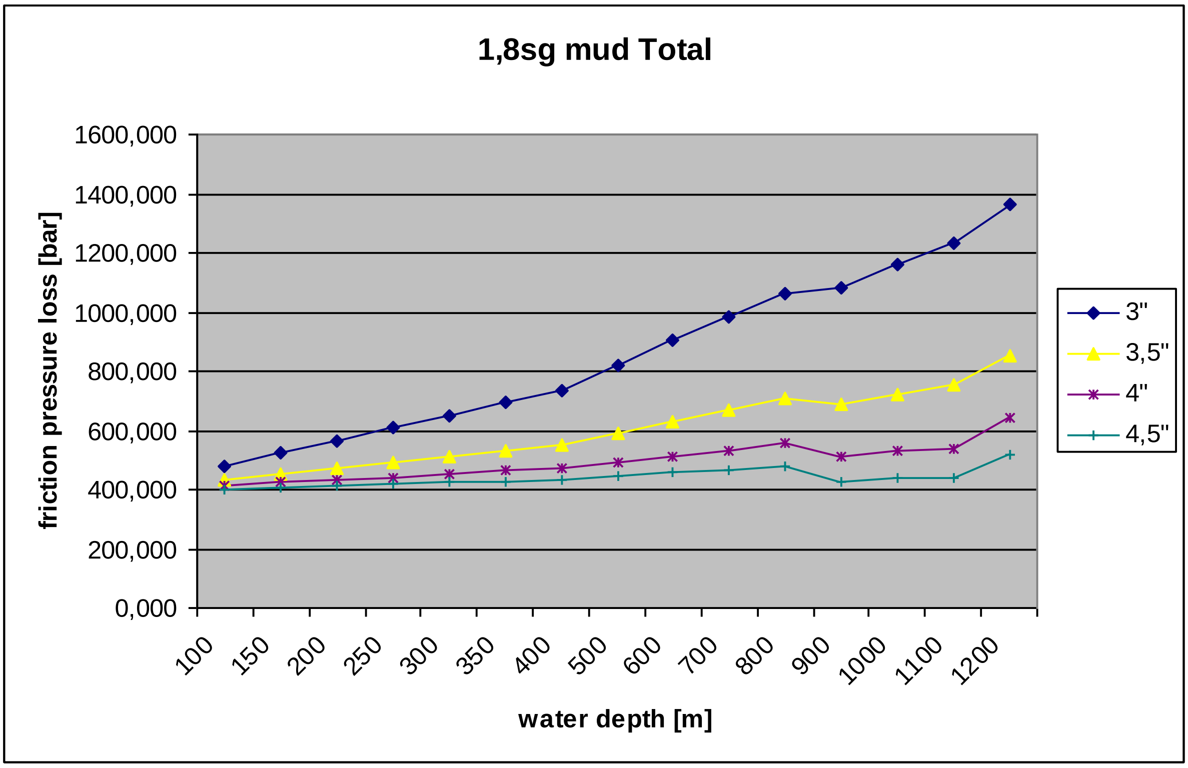


Figure 48: 1,8 sg Total

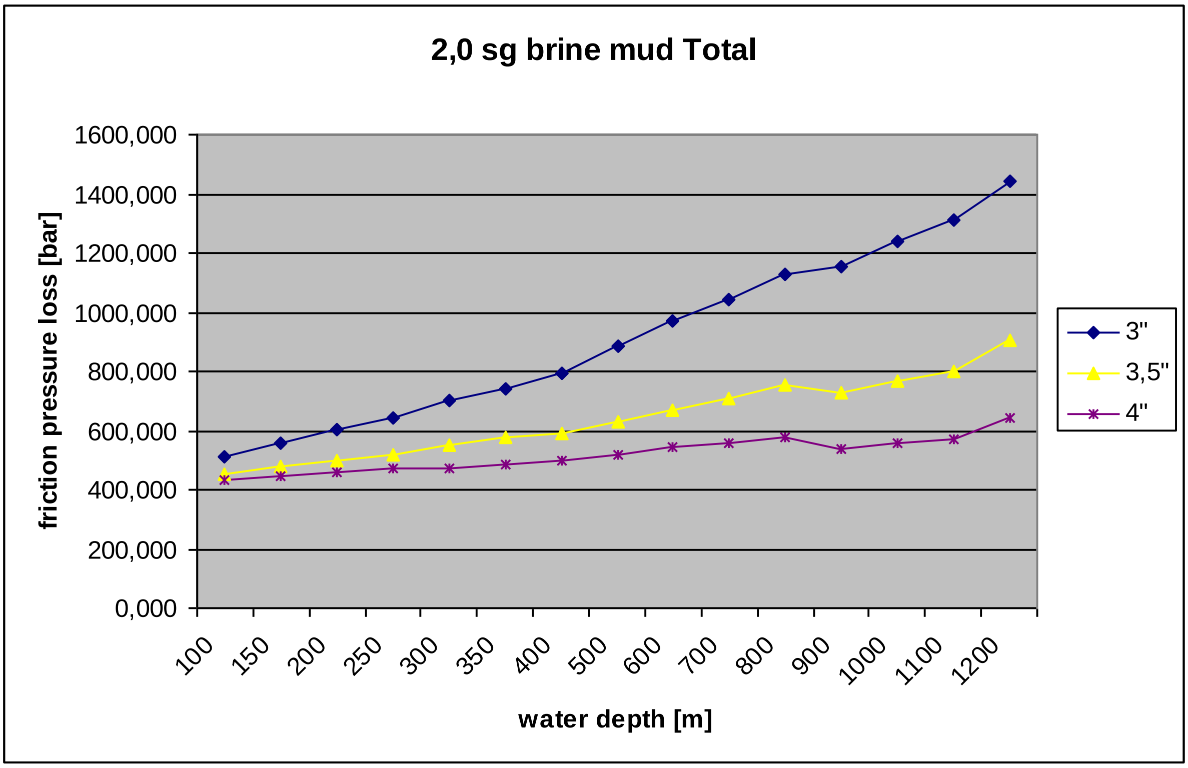


Figure 49: 2,0 sg brine Total

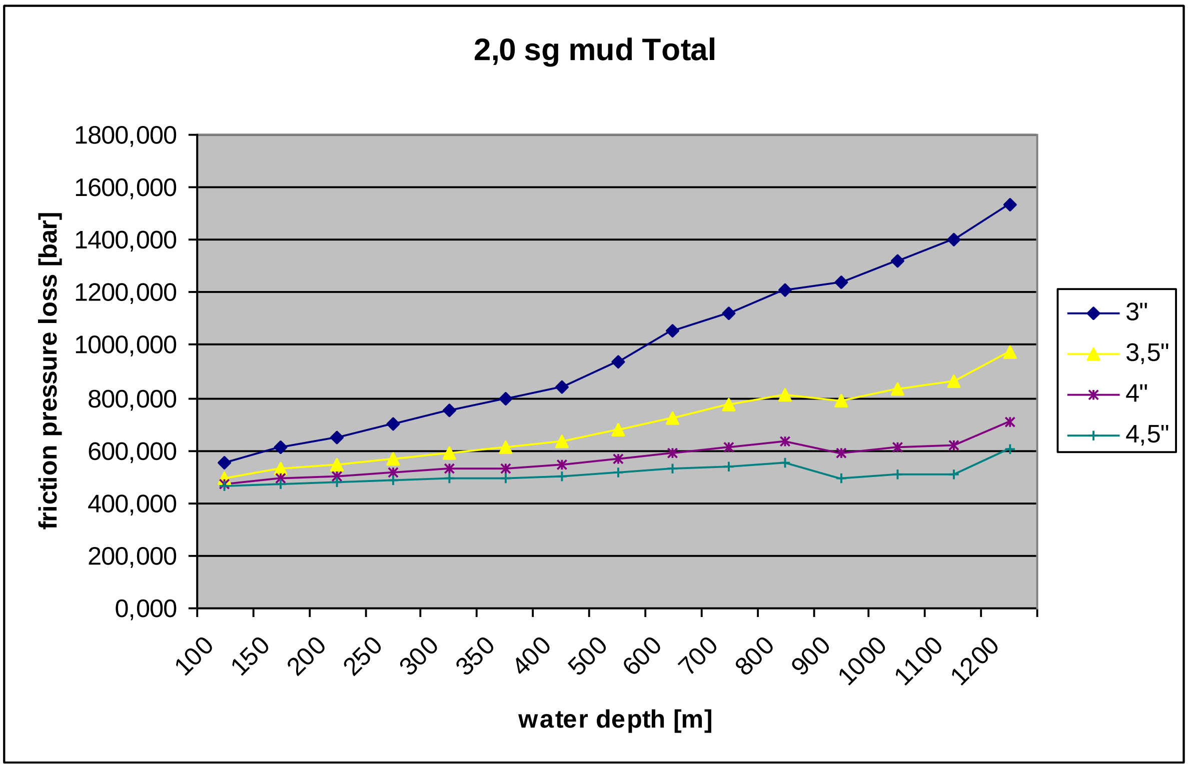
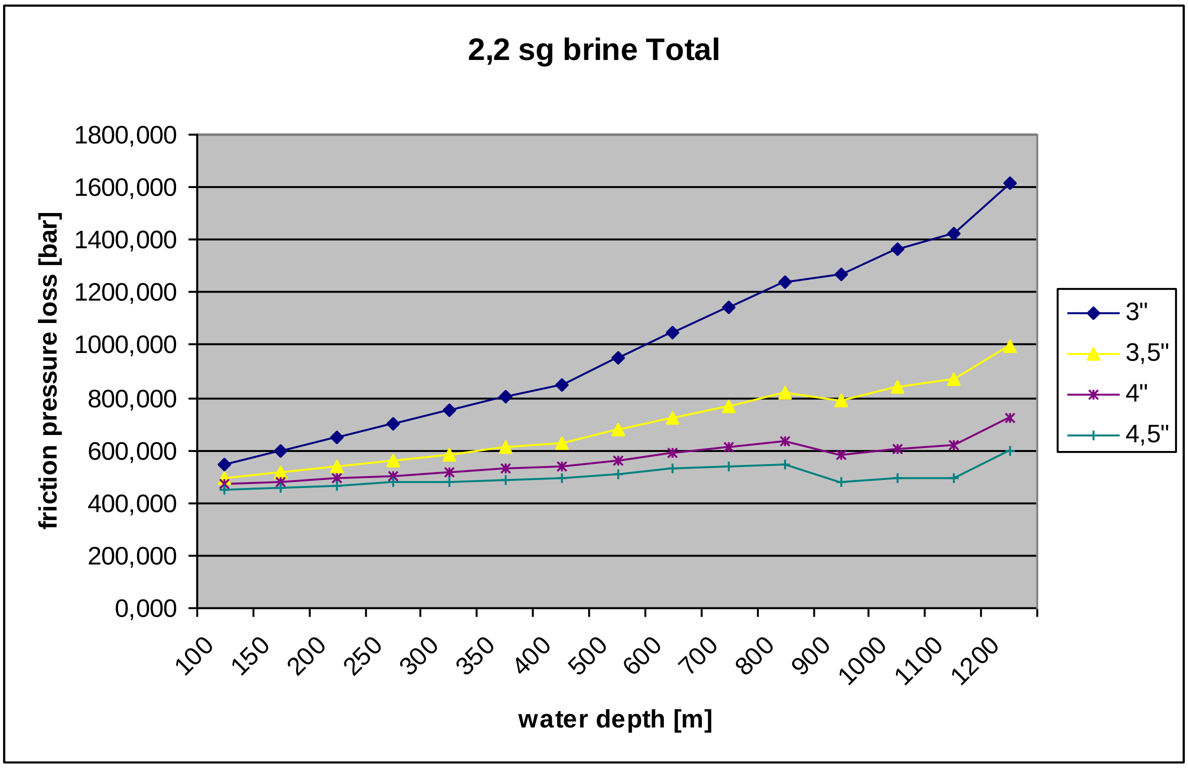


Figure 50: 2,0 sg Total



Figur 51: 2,2 sg brine Total

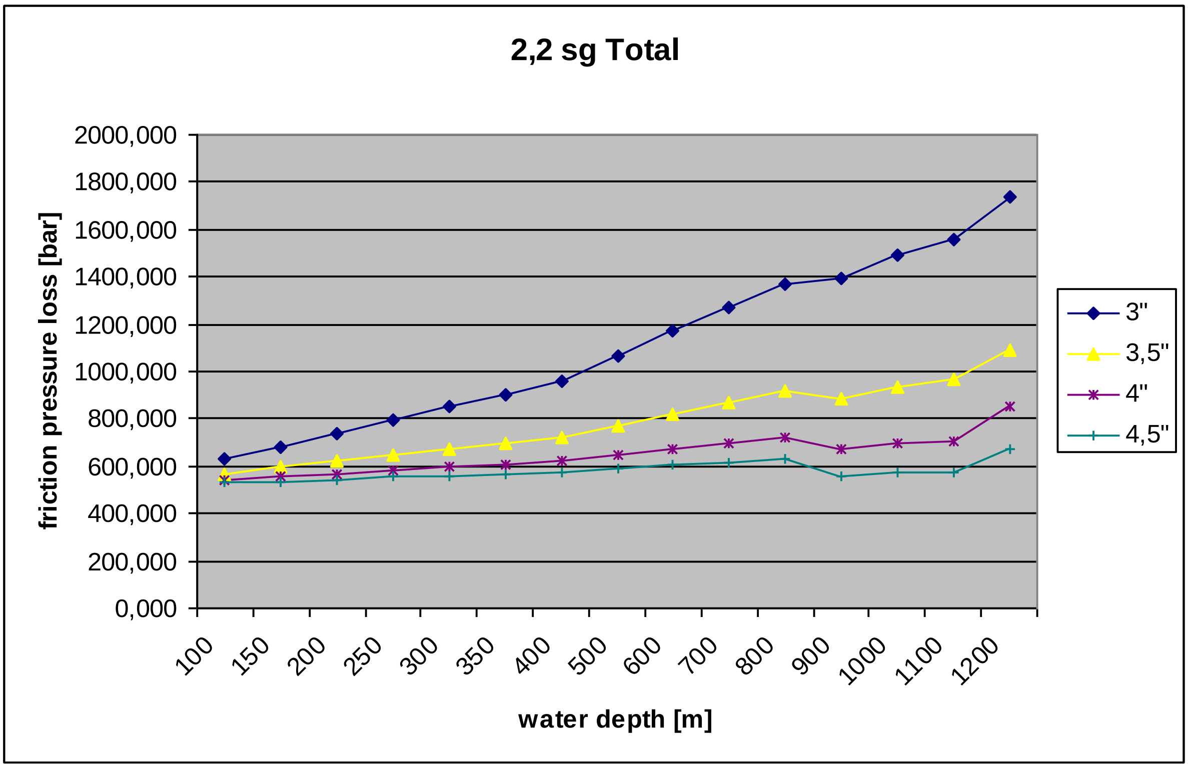
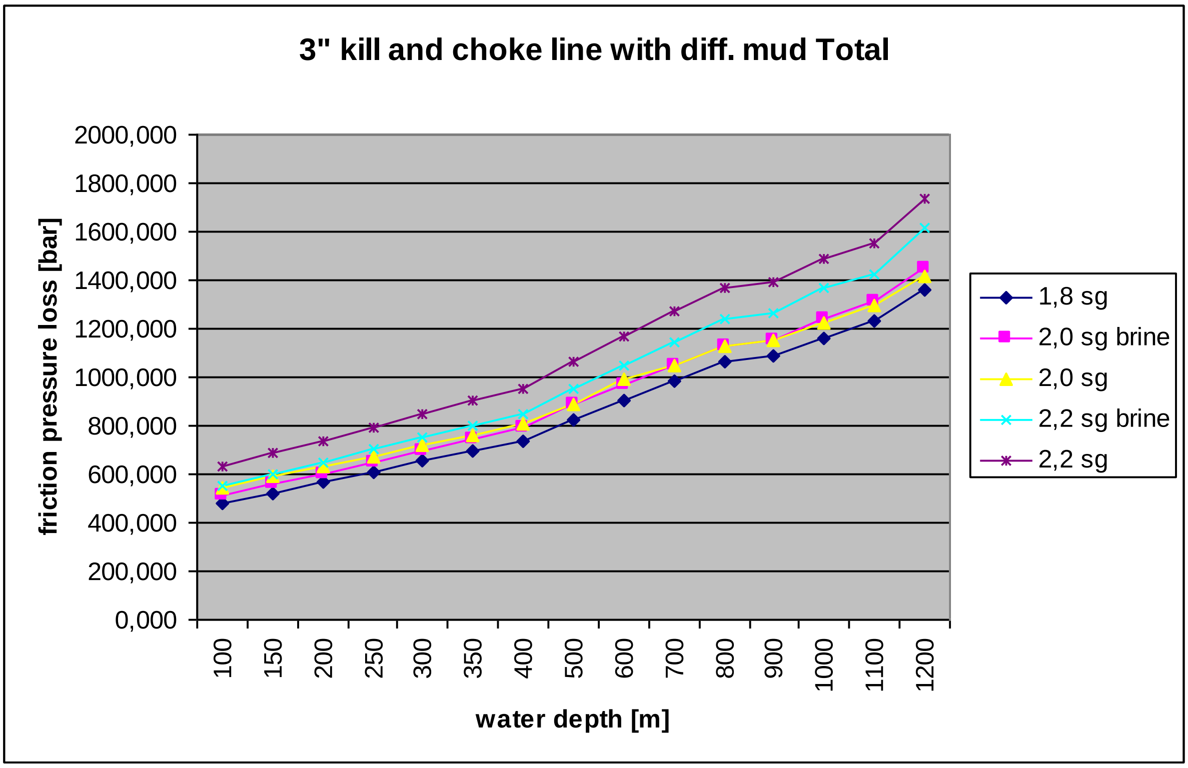
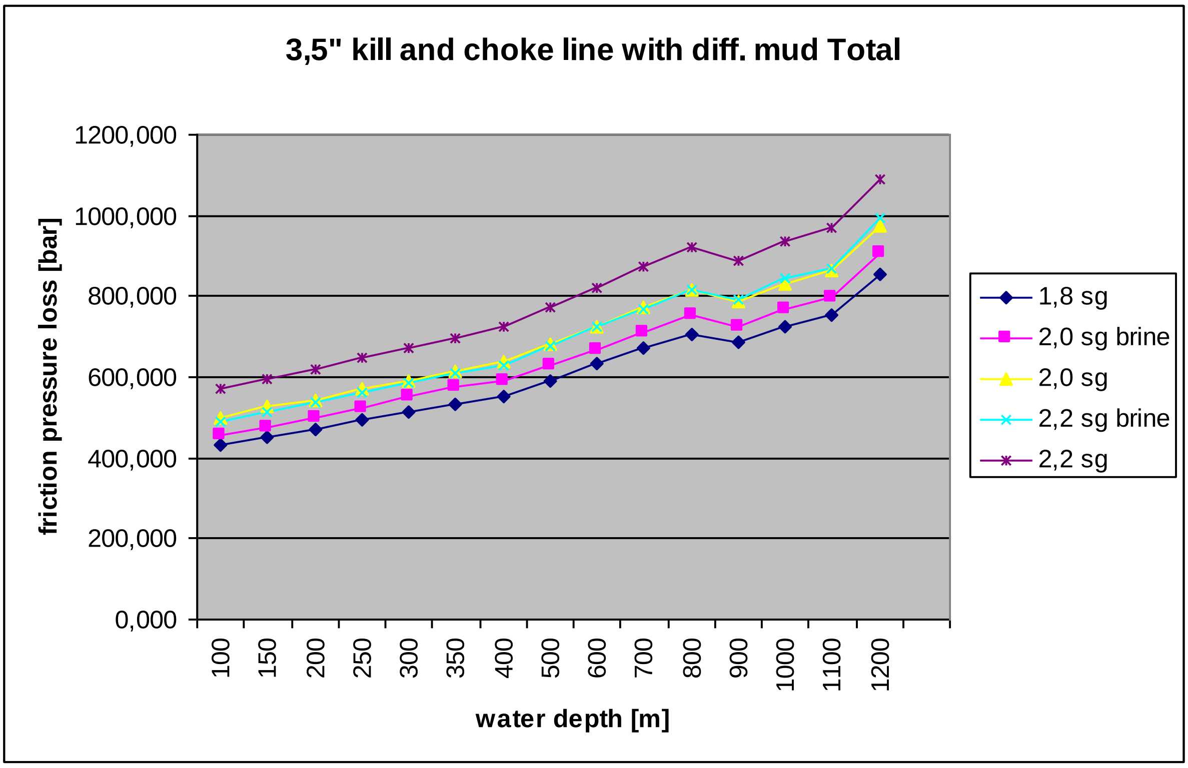


Figure 52: 2,2 sg Total

Figure 54-57 shows how the total frictional pressure varies with different mud types, presented for each size on kill and choke lines.



Figur 53: 3" diff. mud Total



Figur 54: 3,5" diff. mud Total

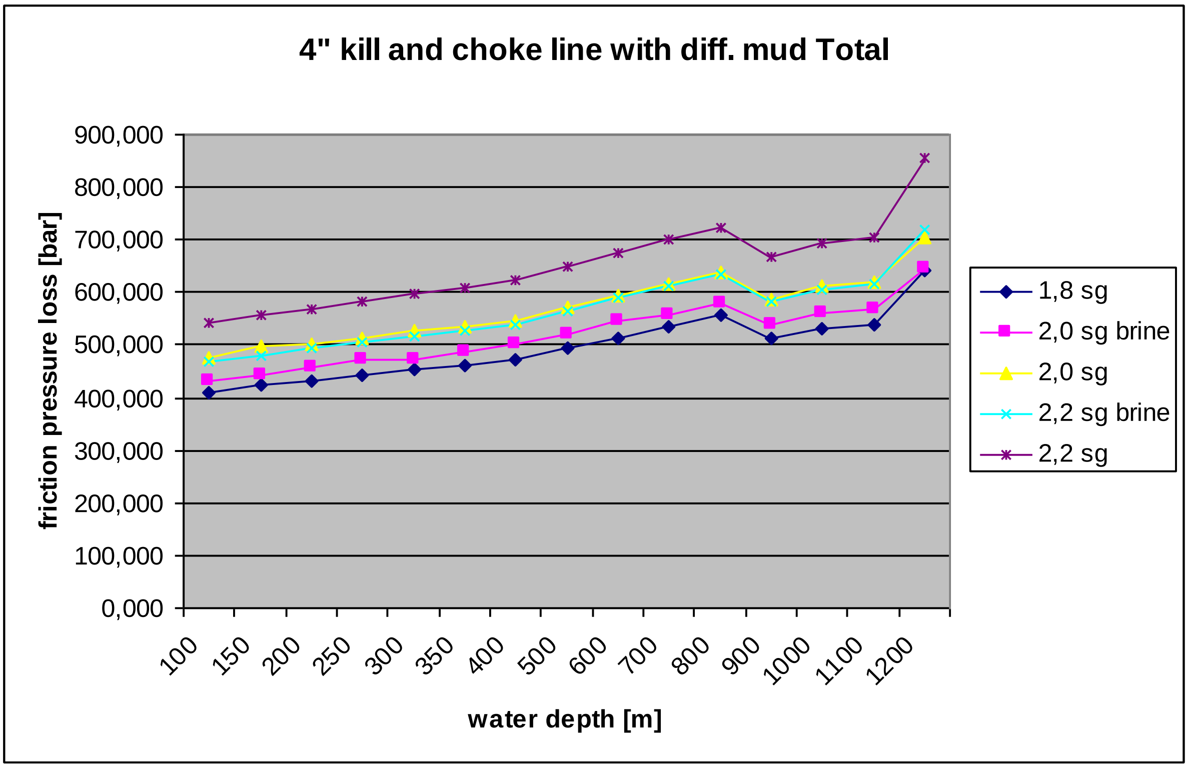


Figure 55: 4" diff. mud Total

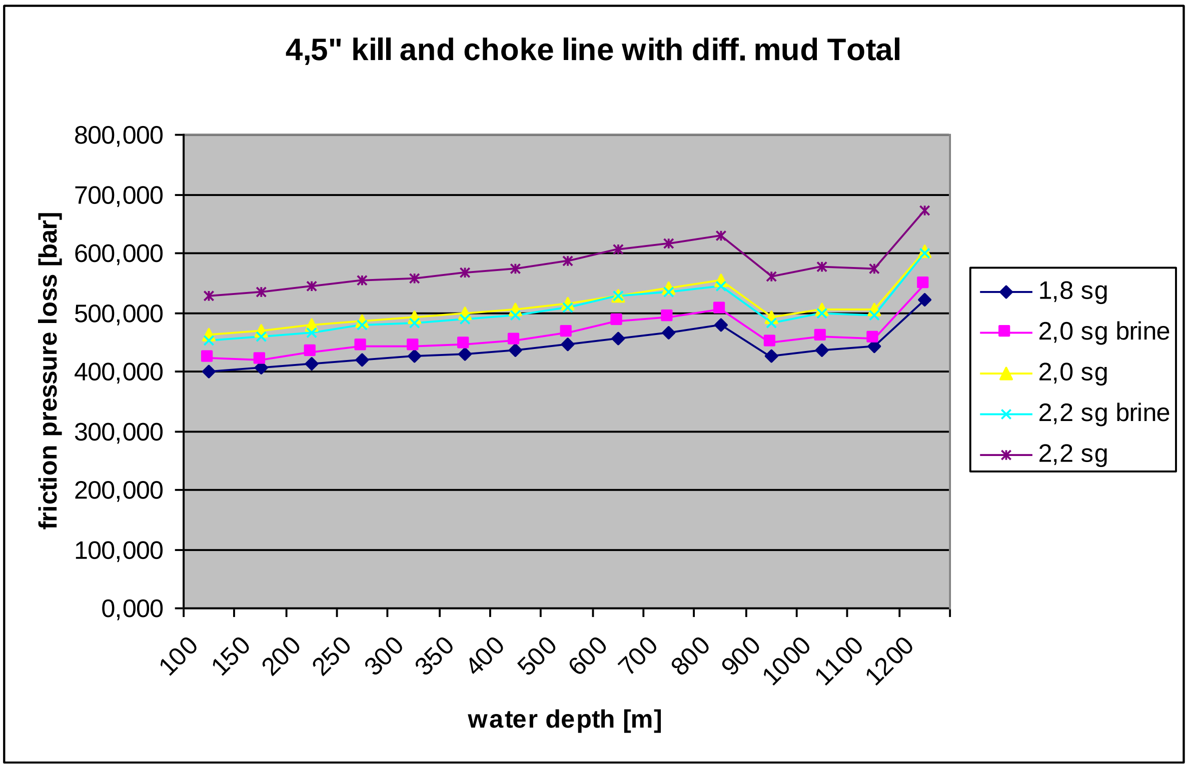


Figure 56: 4,5" diff. mud Total

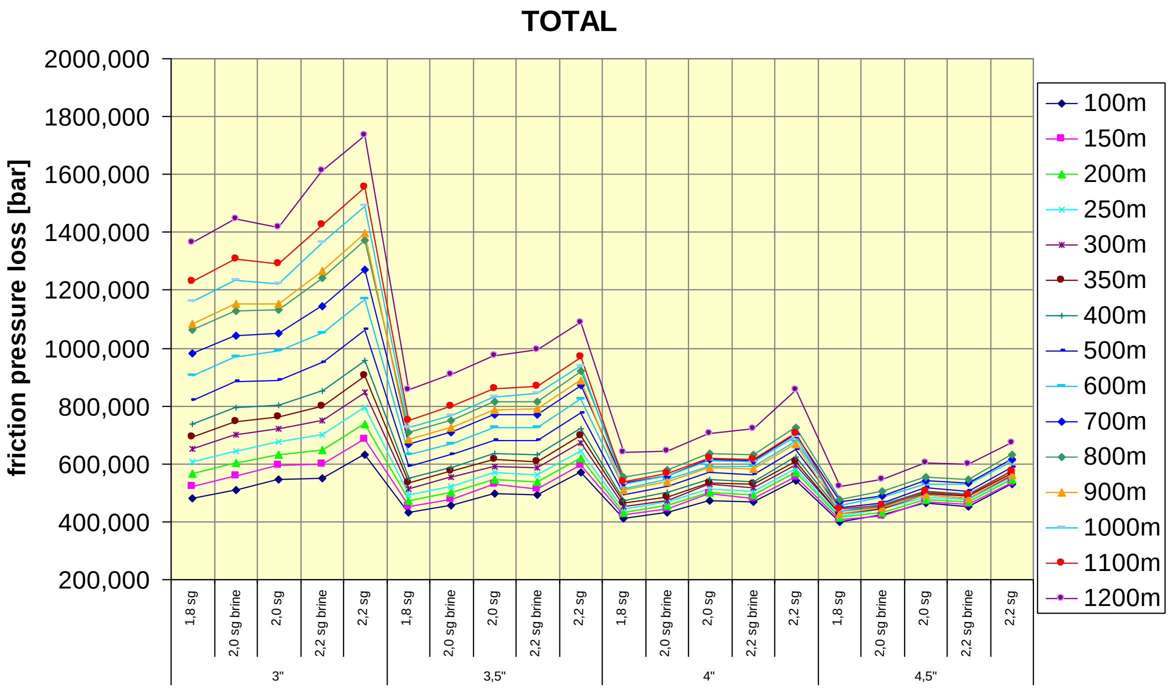


Figure 57: TOTAL

The x-axis in Figure 57: TOTAL shows the different sizes on the kill and choke- lines. For each size the different mud types is shown. The series represent the different water depths. In this graph it is easy to see how the friction pressure loss decrease with increasing size on kill and choke lines. (the graph is shown “full size in the appendix”. General pressure limitations for a 10K rig (10 000 phi) will be at 690bar shown as a straight line in the graph. See Figure 58: Total frictional pressure loss with pressure limitations.

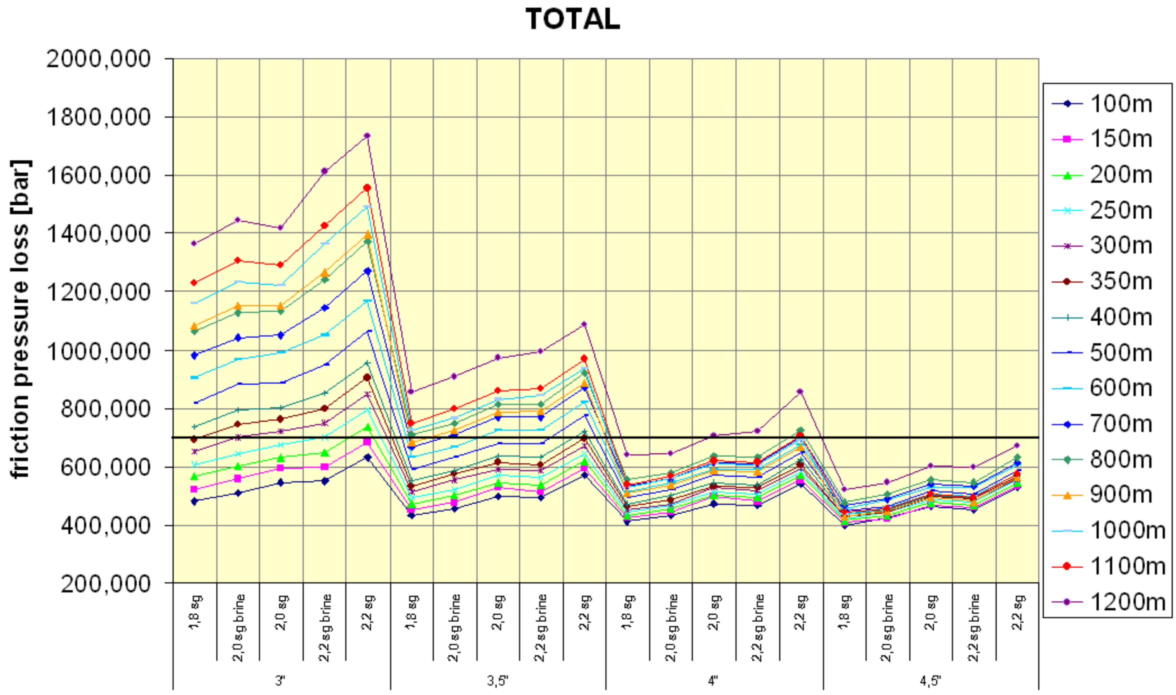


Figure 58: Total frictional pressure loss with pressure limitations

Recommendation and Conclusions

Different simulations are run to find the friction pressure losses when pumping kill fluid down a relief well to kill a well. We have analyzed both the friction pressure losses on the surface/ rig, the kill and choke line and the annulus of the relief well.

Kill and choke lines

As we had expected there were large/great friction pressure losses in the kill and choke lines. As the graphs shows; the friction pressure losses in kill and choke line is decreasing with increasing size.When the size on the lines increase with 0,5” the friction pressure loss decreases. This is the same for all mud types. The greatest “decrease” is between 3” and 3,5”.

Annulus

The friction pressure losses in annulus were larger than expected, but analytical calculations shows that the results are reasonable. This shows that when planning a relief well the relief well design has to be taken into account. Water depth doesn’t affect the friction pressure loss in annulus. The only affect here is the mud weight and viscosity and the length of annulus. As with the kill and choke lines the effect is the same; the higher mud weight the higher friction pressure loss. Instead of simulating the friction pressure losses, they can also be calculated.

The only effect on the rig is the mud weight and viscosity.

The brine based mud gives lower friction pressure losses than the other mud –types. This is important when choosing mud-type, but it is also important to know that the brine-based mud is a lot more expensive.

To summarize; friction pressure is increasing with increasing water depth and increased mud weight. Friction pressure loss is decreasing with increased internal diameter on kill- and choke line.

General rig pressure limitations for a 10K/10 000psi rig are 690 bar. For a 3” kill and choke lines, the rig and well can deliver 11 000 l/min to a water depth at 200 m. With the same pressure limitations but with 3,5” kill and choke line it can deliver up to 600 m water depth with mud types less than 2,2sg. If the lines are increased to 4” it can deliver to all water depths, except for 1200 m with 2,2 sg mud . With ID 4,5” on kill and choke lines it can deliver 11 000 l/min for all water depths.

References:

1. Blowout and Well Control Handbook *Robert D. Grace 2003 ISBN; 9780750677080* [1,5,7,8,17,26,27]

2. SPE 115287 MS Dynamic Killing Parameters Design in Underground Blowout Well *Rudi Rubiandi R.S 2008*[2]

3. SPE/IADC 92626 Modeling Ultra-Deepwater Blowouts and Dynamic Kills and the resulting Blowout Control Best Practices Recommendations *Samuel F. Noyar, Jerome J. Schubert 2005*[3,24]

4. SPE 36485 Analyzing of Surface and Wellbore Hydraulics Provides Key to efficient Blowout Control *P. Oudemann 1996*[4]

5. NORSOK d-10 http://www.npd.no/Global/Norsk/5%20-%20Regelverk/Skjema/Br%C3%B8nnregistrering/Norsok_standard_D-010.pdf

6. Kicks and Blowout Control second edition *Neal Adams, Larry Kuhlman 1994 ISBN 0-87814-419-6*[9,38,40]

7. Blowflow a Software Tool Developed by IRIS for risk based Evaluation of Blowout Scenarios. *Kjetil Aleksander Moe 2008(Bach. Thesis)*[10]

8. *http://en.wikipedia.org/wiki/Deepwater_Horizon_oil_spill..*[11]

9. IADCE/SPE 39354 Trends extracted from 800 Gulf Coast blowouts during 1960-1996 *Pål Skalle, Augusto L. Podio 1998*[12]

10. SPE/ IACD 105612 Hydraulic Control Requirements for Big Bore and HP/HT Developments Validation With Field Experience *P.Oudemann 2007*[13]

11. SPE 16674 Conventional and Unconventional Kill Techniques for Wild Wells *ELY, J.W, S.AHolditch 1987*[14]

12. SPE 22559 – PA Advancement in Dynamic Kill Calculations for Blowout Wells G.E Kouba,G.R. MacDougall, B.W. Schumaker 1993[15]

13. *Well Control Presentation* Kjell Kåre Fjelde[16]

14. SPE 116274 Successful Relief Well Drilling Utilizing Gyroscopic MWD (GMWD) for Re Entry into an Existing Cased Hole *Juergen Maehs, Dough MacAfee, Steve Renne, Greg Cellos, Ananth Srinivasan 2008*[18]

15. http://www.drillingcontractor.org/an-introduction-to-relief-well-planning-dynamic-kill-design-recognizing-the-common-limitations-7431[19]
16. http://208.88.129.54/January-2003-LWDMWD-proximity-techniques-offer-accelerated-relief-well-operations.html[20]

17. Dual relief well intervention feasibility study 2011 Statoil Internal[21,25,28,41]

18. www.glossary.oilfield.slb.com[22]

19. www.eng-tips.com/viewthread.cfm?qid=99325&page=7

20. http://www.vectormagnetics.com/oil-gas/applications/relief-wells[29,32]

21. Statoil Governing Document- Well Incident and Blowout Response Plan –Statoil Internal *2004*[30,31]

22. http://www.vectormagnetics.com/oil-gas/services/wellspot-and-gradient-tools[33]

23. http://www.vectormagnetics.com/oil-gas/services/wellspot-bit-wsab[34]

24. http://www.vectormagnetics.com/oil-gas/services/passive-magnetic-ranging[35]

25. http://www.drillingcontractor.org/an-introduction-to-relief-well-planning-dynamic-kill-design-recognizing-the-common-limitations-743136

26. SPE 24578 Dynamic Two Phase Flow Simulator: A Powerful Tool for Blowout and Relief Well Kill Analysis *O.B Rygg, Pål Smestad J.W Wright 1992*[38,39]

27. DDH Drilling Data Handbook Eight Edition *Gilles Gabolde, Jean-Paul Nguyen 2006*[42,46,47]

28. SPE 24578 Dynamic Two-Phase Flow simulator A Powerful Tool for Blowout and Relief Well Kill Analysis *O.B Rygg, Pål Smestad, J.W. Wright*[43]

29. SPT Group Hjemmeside[44]

30. Drillbench hjemmeside 45 http://www.sptgroup.com/en/Products/Drillbench/Advanced-drilling-engineering-and-operation/

31. User Guide Quick Process –Statoil Internal46

32. OlGA ABC. http://www.sptgroup.com/en/Products/olga/OLGA-ABC/

Nomenclature list:

BOP	Blow Out Preventer
BHP	Bottom Hole Pressure
ECD	Equivalent Circulating Density
FBHP	Flowing Bottom Hole Pressure
MWD	Measure While Drilling
ID	Internal Diameter
KOP	Kick Off Point
APWD	Annular Pressure While Drilling
AC	Alternating Current
NCS	Norwegian Continental Shelf
DDH.	Data Drilling Handbook
ABC	Advanced Blowout Control