TRABAJO ESPECIAL DE GRADO

DOWN HOLE BLOWOUT PREVENTER (DH-BOP): INNOVADOR EQUIPO DE SEGURIDAD PARA EL CONTROL DE INFLUJOS

Presentado ante la Ilustre
Universidad Central de Venezuela
Por el Br. Sanchez, D. Jessica, D.
Para optar al Título de
Ingeniero de Petróleo

Caracas, Noviembre de 2011

TRABAJO ESPECIAL DE GRADO

DOWN HOLE BLOWOUT PREVENTER (DH-BOP): INNOVADOR EQUIPO DE SEGURIDAD PARA EL CONTROL DE INFLUJOS

Tutores Académicos: Dr. Diego Giacca
Dr. Raffaele Romagnoli
Tutores Industriales: Ing. Paolo Ferrara
Ing. Amicosante Marco

Presentado ante la Ilustre
Universidad Central de Venezuela
Por el Br. Sanchez, D. Jessica, D.
Para optar al Título de
Ingeniero de Petróleo

Caracas, Noviembre de 2011

Sánchez, D. Jessica, D.

DOWN HOLE BLOWOUT PREVENTER (DH-BOP): INNOVADOR EQUIPO DE SEGURIDAD PARA EL CONTROL DE INFLUJOS

Tutores Académicos: Dr. Diego Giacca, Dr. Raffaele Romagnoli
Tutor Industrial: Ing. Paolo Ferrara, Ing. Amicosante Marco
Tesis. Caracas, U.C.V. Facultad de Ingeniería. Escuela de Ingeniería de Petróleo. Año 2011. Pg. 86.

Palabras Claves: Down Hole Blowout Preventer, reventon, influjo, análisis de riesgo, control de pozos.
Resumen: Un Reventón (Blowout) es el escape sin control de aceite, gas o agua de un pozo debido a la liberación de presión en un yacimiento o a la falla de los sistemas de contención.

Esta tesis fue desarrollada con la ayuda de ENI E&P y Baker Huge, el propósito original de este desarrollo fue:

- Mejorar el nivel de seguridad durante operaciones.
- Disminuir el riesgo ambiental.
- Mejorar los procedimientos de control de pozos.

El Capitulo 1 presento una explicación de los usos principales de un Blowout Preventer (BOP). Seguido de una definición de las causas naturales y operativas que conllevan a un influjo, luego se presentaron los métodos para el control de pozo usados por ENI e&p.

A continuación en el Capitulo 2, fueron presentados interpretaciones relacionadas con los más costosos y frecuentes reventones en la historia, peores reventones de acuerdo con el volumen de petróleo liberado, resumen de reventones de gas y principales y secundarias barreras que fallan en todas las fases de la operación.

En el Capitulo 3 se mostro una descripción de un Down Hole Blowout Preventer (DHBOP) el cual fue desarrollado con el propósito de separar la formación del resto del pozo en el caso de un influjo, esto es realizado inflando un packer. Con el fin de obtener factibles resultados se llevo a cabo una primera prueba de campo en Oklahoma, Enero, 2010, seguida de una segunda prueba de campo en Val d'Agri, Italy, Enero, 2011. En este capítulo se explicaron los procedimientos utilizados, resumen del test, descripción de la herramienta y resultados obtenidos.

Finalmente, un análisis de riesgo fue realizado para conocer la variación en la frecuencia de ocurrencia de un reventón e identificar la relación que existe entre dicha frecuencia y los diferentes elementos de riesgo identificados en el pozo. Para esto fue aplicado un enfoque cuantitativo con el uso de un análisis de árbol de fallas. Con dicho método fue evidente que la probabilidad de falla de un DHBOP en combinación con un BOP es casi despreciable. Igualmente fue comprobado que con el uso de la herramienta la probabilidad de ocurrencia de un

reventón disminuye en 1,6E8 veces, lo cual representa una gran contribución a la estimación del riesgo total en las instalaciones petroleras y gasíferas. Por estas razones se concluyo que el uso de la herramienta es técnicamente factible.

ACKNOWLEDGEMENTS

Firstly, I would like to thank God for giving me life.

Secondly, the “Universidad Central de Venezuela” for allowing me to begin this wonderful experience and additionally offering me the opportunity to continue and culminate it abroad.

Further on, I would like to thank the "Politecnico di Torino" for giving me the opportunity to study in Italy, and at the same time the Italian Ministry of External affairs for providing me the financial aid during this period.

Diego Giacca, Marco Amicosante, Paolo Ferrara, thank you for being my supervisors. I am also very grateful with Eni S.p.a for allowing me to develop my master thesis in their installations. Very special and warm thanks to Jenny Graterol for "adopting" me as her thesis student and for following thoroughly every single step of this work, and specially for being besides my supervisor, a wonderful friend without whom I wouldn't have been able to finish my work in such an outstanding manner. Thank you so for your guidance.

But speaking from the heart, I want dedicate my thesis and career culmination to the most important person in my life, my mother Xiomara Dubon, for being my role model, for all the sacrifices that she has done for me, for always guiding and supporting me during my education and just for being there for me every time I've needed her. Thanks to you, today I am a professional. You are a part of this success and hence, is it also yours. Thank you mum.

Without leaving beside my wonderful father and brother, Wilberto Sanchez and Adrian Sanchez, for being the best family that anyone can have or dream of, and for always supporting me and filling me with joy and happiness even when we were apart.

I would also like to thank a person that has helped me and provided me support in so many different ways, someone that I know that that I can always count on and that will always be there for me. Thank you Mrs. Isabel Fernandez.

Additionaly, I want to thank my lifetime friends, that are already a family for me and even though we don't see each other often, I remember all of you with so much love and beautiful memories: Teresita, Jonathan, Doribell, Adaireth, Maria, Hany, Carlos, Josi and Kevin. Guys, I miss you so.

Obviously I would not leave beside my friends from the University, those that even though did not intervene directly in this work, supported me during the first four years of my career: Mariana, Fernando, Eduardo, Sandy, Fanny, Diana, Nael, Barbara, Marielys, Wendy and Manuel. From all of you I learned so many things, both professionally and personally.

I also want to thank a person that influenced me positively in so many different ways, that gave me a valuable lesson of life and left with me so many beautiful memories. For the endless and sleepless nights of study, for teaching me how to believe in myself and giving me the right advice no matter the situation, Frank Fajardo. I thank you.

Once in Italy, I also met two marvelous persons that as for today represent an integral and important part of my life, Vanessa and Juliana, thank you for being my study buddies and my friends for ever. Girls, thank you so much for being with me, for everything that you did and keep on doing for me. You're the best!
Without forgetting my lovely flatmates: Carlos, Mari, Moni and Roro, for all the shared experiences and adventures, for standing up with me for a whole year and being the best flatmates in the whole world, I thank you.

And because the life never stops surprising you, when you never expect it beautiful people arrive in your life, and due to this, during my two years in Turin I made friendships that I will never forget, thanks to my venezuelan mates in Italy:

Adri, Emma, Clau, Alfon, Anni, Vivi, Luisa, Elka and Alex, and so many more that I would love to mention but if I did so I would never end. This was a journey, a path, an experience that thanks to you and many more turned out to be a wonderful one, that I would have never expected to turn out this way and for which I am very grateful for.

Jessica D, Sanchez Dubon

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

Blowouts occur for a variety of reasons, most common factors relate to human errors, equipment malfunctions and unexpected geology. The original scope of this thesis is to provide data useful in predicting the frequency of a blowout. Factors to be included are land, water depth, well depth. Further, this work presents an interpretation of how to decrease the blowout occurrence with the use of the eni e&p Down Hole Blowout Preventer (DHBOP).

The general goals pursued by eni e&p in developing the DHBOP were as follows:

- Improve operation safety levels
- Decrease environmental risks
- Improve well control procedures
- Reduce non-productive times (NPT)

This thesis (Chapter 1) starts with an explanation about the main uses and primary functions of the Down Hole Blowout Preventer; then a description of the standard equipment, including: Annular BOP, Ram BOP, high pressure equipment, low pressure equipment and auxiliary equipment is proposed. Further, this chapter presents some interpretations related to the most expensive and frequent blowouts in the history, the worst offshore blowouts according to the volume of oil released, a gas blowout statistical summary and most frequent primary and secondary barriers that failed in all phases.

This is followed by an explanation of the natural and operatives causes of a kick; also the controls normally used in a case of kick, known as primary and secondary control, are going to be explained. After, the methods used to control a kick are described; these are going to be introduced in the order of priority according to the best practices in force in eni e&p. These methods are: (1) the Wait and Weight Method; (2) the Driller's Method; (3) the Volumetric Method; (4) the Bullheading Method.

Chapter 2 will present some interpretations related to the most expensive and frequent blowouts in the history.

Moreover, the last chapter (Chapter 3) shows a description of the Down Hole Blowout Preventer (DHBOP), which has been developed to separate a formation from the rest of the borehole in a kick situation, by inflating a packer element and closing a valve within the string. In addition, this third chapter presents an explanation about the motivation to use a DHBOP, its main functions, the benefits in terms of safety, the operation modes, the operational procedure, followed by a description of the communication link between the packer, placed at the bottom of the well, and the surface.

This packer was tested twice: the first field test was carried out in Oklahoma, at the well BH-N-15 in January, 2010, while the second was performed in Val d'Agri, Italy, at the well ME10 or B in January 2011. This chapter will describe the system used, the test objectives and procedures and the results obtained.

Finally, Chapter 3 will present a risk analysis on the variation in frequency of a blowout, depending on the various risk elements identified in the well, on the platform and in the procedures of the Organization. In this analysis, a comparison of the occurrence of a blowout when a Blowout Preventer is used alone and together with the Down Hole Blowout Preventer is also discussed.

CHAPTER I

BLOWOUT PREVENTER

Before going on any further, we should familiarize with a Blowout, which is an uncontrolled flow of reservoir fluids into the wellbore, and sometimes to the surface. A blowout may consist of salt water, oil, gas or a mixture of these. A Blowout can occur in all the four phases of operations: exploration, drilling, production and workovers.

A blowout is not always evident at surface; it can happen, in fact, that a reservoir fluid flows within another formation without reaching the surface: this is known as an underground blowout. Normally, involve a significant downhole flow of formation fluids from a zone of higher pressure (the flowing zone) to one of lower pressure (the charged zone or loss zone). These two cases of blowout are important, but the underground blowout is considered the most expensive problem.

The primary functions of a blowout preventer system are to:

- confine formation fluids to the wellbore;
- provide means to add fluids to the wellbore;
- allow controlled volumes of fluid to be withdrawn from the wellbore.

Normally, they are operated more in function of testing, prior to spud or drilling out of a casing shoe, than for actual well control situations.

Additionally, blowout preventer systems are used to:

- regulate and monitor wellbore pressure;
- center and hang off the drill string in the wellbore;
- shut in the well (e.g. seal the annulus between drillpipe and casing);

- “kill” the well, preventing the flow of formation fluids from the reservoir into the wellbore
- seal the wellhead (close off the wellbore);
- cut the casing or drill pipe (in case of emergencies).

1.1 DESCRIPTION OF THE EQUIPMENT

The contents of this thesis cannot foresee all aspects of the BOP Equipment that may be encountered, instead, here a general explanation about operational principles is given.

At the first point, we should know that two categories of blowout preventers are generally used: ram and annular. BOP stacks frequently utilize both types, typically with at least one annular BOP stacked above several ram BOPs. Both Ram and Annular preventers were originally designed to shut-in a well and to contain high pressure fluids within the wellbore.

Conventional circulation of the mud and rotation of the drill pipe must stop, when the well is shut-in with the BOP’s. Vertical reciprocation of the pipe to avoid sticking and circulation of the kick fluids through the choke line may be resumed after shut-in of the well. Consequently, BOP’s are designed for secure, high-pressure containment of the wellbore for a low number of cycles.

The Well Control Equipment can be divided in the following parts:

a. Annular BOP
b. Ram BOP
c. High Pressure Equipment
d. Low-Pressure Equipment
e. Auxiliary Equipments.

a. Annular BOP

Generally, this is the first BOP to be closed when a kick occurs and is located at the top stack. An annular BOP can close around any tubing diameter and, in case of emergency, is able to perform total well closure.

The closing time according to API RP 53 recommended practice is:

- For 20” diameters or larger is less than 45 seconds
- For diameters smaller than 20” is less than 30 seconds

Annular BOPs are equipped with a closing piston which is hydraulically operated by applying pressure to closing and opening chambers. The main components are: body, head, piston, closing/opening chambers, packing unit, seals.

- Operational Principles

- Closure

When the BOP closing starts, the working fluid enters the closing chamber and pushes the piston upwards. As a consequence, the packing unit tightens more and more around the BOP centre, sealing it. [1]

- Opening

During opening, the working fluid enters the opening chamber and pushes the piston downwards (the closing chamber is emptied). The packing unit returns to its original position, opening the BOP. [1]

Annular BOP’s are also characterized by the opening/closure pressure that according to eni e&p practices vary according to BOP typology, though in most cases it ranges between 700-1500 psi (50-105 kg/cm^2). Another fact that has to be controlled is the Maximum Working Pressure (WP), that is defined as the maximum well pressure the BOP can bear and control in working conditions.

b. Ram BOP

This type of BOP´s works as here described. First, the rams extend around the center of the wellbore to stop the flow; the inner and top faces of the rams are fitted with packers that seal the space between each other, the wellbore and around the pipes, running through the wellbore, exerting pressure. Outlets at the sides of the BOP housing (body) are used for connection to choke and kill lines or valves.

They are useful in case of stripping operations, but cannot be used alone; instead, they are combined with an annular BOPs or with another ram BOP. An important characteristic is that they fit to a certain pipe diameter, which means that when the pipe diameter changes, also the Ram BOP must be changed.

Ram BOP closure ensures both upwards and downwards mechanical sealing. Upwards mechanical sealing prevents the drill string from being expelled, in case of high well pressure values or of insufficient pipe weight.

According to eni e&p practices, the main advantages of Ram BOPs compared with Annular BOPs are the following:

- better resistance to high pressure values;
- less control fluid volume required, which implies shorter closing time;
- they can support the drill string weight;
- they allow stripping, in case of very high pressure values;
- once they have been closed, they prevent the drill string from being expelled

- Operations

  Opening and closing working pressure is around 105 kg/cm^2, but this kind of BOP can achieve a maximum value of 210 kg/cm^2 in case of emergency. The closing time normally is less than 30 seconds.

  Moreover Ram BOP are equipped with a secondary sealing which is performed by a seal inserted around rams rod. This seal has been designed to work in static conditions; once it has been actuated, the rams should not be opened or closed to avoid damaging the ram shaft. This secondary seal should be used just in case the primary sealing is leaking

c. High Pressure Equipment

This equipment is made by the following parts:

- Casing
- Stack Equipment
- Choke and Kill Line Equipment
- Drillstem Control Equipment

- **Casing:** it is a large-diameter pipe lowered into an open hole and cemented in place. For an adequate characterization of a formation from a pressure regime standpoint and a correct positioning of the casing, the following parameters have to be determined:
    - Pore pressure
    - Overburden pressure
    - Fracture pressure

These pressures are strictly dependent one from the other. In fact, pore pressures and overburden pressures are related between them by the compaction pressure in accordance with the effective stress principle and together allow the calculation of fracture pressures.

After having roughly calculated the depths to which the various casings must be run, controls are then carried out to check that these depths are satisfactory.

Checking the accuracy of the casing setting points is based on determining the following five (5) basic factors, that is:

1. Maximum pressure available at the choke: it represents the maximum pressure that can be allowed to accumulate at the

wellhead in case a kick had to be controlled, without causing the fracturing of the formation below the shoe of the last casing run in hole. The minimum acceptable value can be not less than 10 kg/cm^2 for surface casings and 50 g/L difference between the fracture gradient below the casing shoe and the density of the mud in hole (or 40-50 kg/cm^2) for the others.

2. Maximum differential pressure: it is the difference between the pressure exerted by the mud at the maximum density foreseen in that given hole section (generally this is the value of the mud density at the end of each hole section) and the pore pressure as a function of depth.

3. Drilling balance: it is the difference between the pressure due to the drilling mud at its density and that of the formation, as a function of depth. This measure indicates how much the pressure exerted by the mud exceeds the pore pressure.

4. Kick tolerance: it represents the volume of maximum influx (kick) that, once entered into the wellbore, can be circulated out with a “constant bottomhole pressure” method without fracturing the formation below the shoe of the previous casing.

5. Expected drilling problems: When selecting the casing setting depths, other factors should be taken into consideration, especially for what regards the shallower casings, such as:
    - Shallow Gas
    - Hole Ageing (“time dependent” deformation of the rocks: Creep)
    - Unstable Formations
    - Seepages and Circulation Losses
    - Deviated or Horizontal Drilling

- Production Requirements: Open Hole vs Cased Hole
- Economics

- **Stack Equipment**: some of the basic functions of the stack equipment are the following:

  - Seal the well against the drillstring or open hole and contain well pressure.
  - Provide a full-bore opening to allow passage of drilling and testing tools.
  - Permit unrestricted flow of fluids to the choke line, while the preventers are closed.

  Operators should test and operate the components of the stack to be confident that they are functioning properly. In general, the stack components are very resistant and very reliable.

  Just a few things have to be taken into account once the BOP stack is set:

  - BOP working pressure rating
  - BOP internal diameter
  - Availability of adequate drillings spools.

- **Choke and Kill Line Equipment:** Many well control problems begin in the choke line or downstream of the choke line. It is unusual to find a rig without the potential for a serious problem between the blowout preventer (BOP) stack and the end of the flare lines. In order to appreciate how a choke line must be constructed, it is necessary to remember that, in a well control situation, solids-laden fluids are extremely abrasive.

Some of the basic functions of the choke and kill line equipment are the following:

- Provide a way to allow fluids to be pumped into the well below a closed preventer.
- Convey drilling fluid to the bell nipple and flowline.

A typical choke line is shown in **Figure 1.1** As illustrated, two valves are flanged to the drilling spool. There are outlets on the body of the blowout preventers; however, these outlets should not be used on a routine basis, since severe body wear and erosion may result.

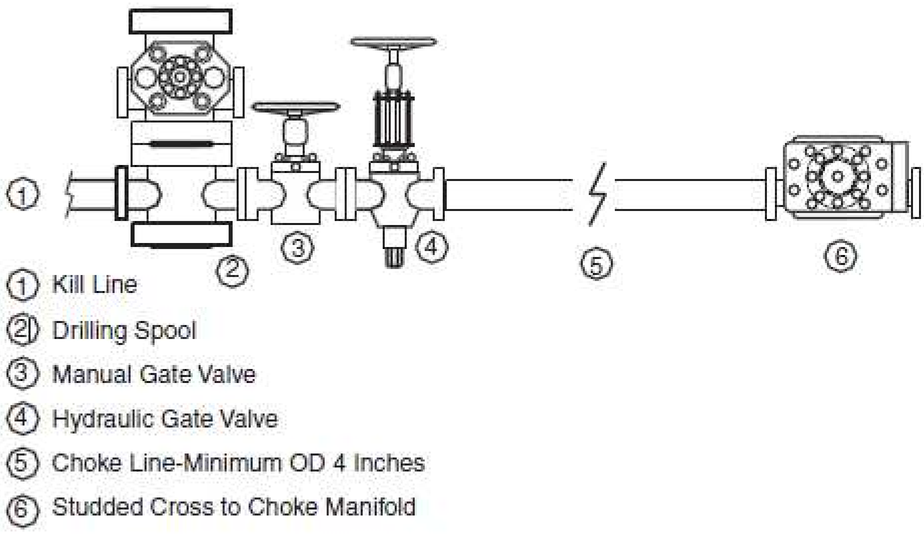

Figure 1.1 A typical choke line

Figure 1.1 also shows two valves: one valve is hydraulically operated, while the other one works like a backup of the first one in case of failure. Special attention should be given to the position of the hydraulic valve. Most often it is outboard with a safety valve next to the spool to be used, only if the hydraulic valve fails to operate properly. The outboard position for the hydraulic valve is the better choice under most circumstances, since the inboard valve is always the safety valve. If the hydraulic valve is outboard, it is important that the system be checked and flushed regularly to insure that the choke line is not obstructed with drill solids.

The kill line is a high-pressure pipe leading from an outlet on the BOP stack to the high-pressure rig pumps, usually extending approximately 30,5 to 46 meters from the wellhead. The main purpose of the kill line is to provide remote hydraulic access to the well; it should never be used for any purpose other than an emergency access. The kill line access should never be used as a fill-up line.

For instance, at one location, a fill-up line was connected to the kill line access. When a kick was taken and the well was shut in, the subsequent pressure ruptured the fill-up line; the fluid ignited and the rig was lost. At many locations, the kill line has provided the intended access to the wellbore and the well has been saved. The integrity of the kill line system can be assured by using the kill line only as intended.

Kill and choke line connections can be installed:

- Directly on the Ram BOP side outlets: this solution allows to reduce the connections number and the stack height, but it causes greater erosion inside the BOP during blowout control.
- By means of a drilling spool: this solution concentrates erosion inside the drilling spool, but it requires a higher number of connections and a higher stack. It also increases the distance between the BOP rams, thus facilitating stripping operations.

- **Drill Stem Control Equipment**

The accumulator: is a device used in a hydraulic system to store energy or, in some applications, dampen pressure fluctuations. Well pressure-control systems typically incorporate sufficient accumulator capacity to enable the blowout preventer to be operated with all other power shut down.

It is composed of:

- a tank containing hydraulic fluid (oil) at atmospheric pressure;

- one or more high-pressure pumping units to pressurize the fluid;
- nitrogen pre-charged bottles to store the pressurized fluid.

The oil is sent to a manifold and also to closing mechanisms through the control valves.

Operations: the pressure accumulator functioning is characterized by five stages.

- Pre-charge: the accumulator bottles are pre-charged with nitrogen at a pressure around 70,3 kg/cm^2.
- Charge: the control fluid is pumped from the tank by the pumps and sent to the bottle charging line. The process ends once the accumulator pressure reaches the desired value. The charging pressure is around 210,9 kg/cm^2.
- Discharge: once the control valves start, the pressurized control fluid stored in the bottles is sent to the working lines to set the connected mechanisms to opening or closure. Then, a decrease in the accumulator pressure takes place, due to the discharging operation and the pumps may be actuated, if the pressure values decrease below the defined limit.
- Pump control: adequate pressure automatic switches (hydro-electrical and hydro-pneumatic) allow the pump functioning.
- Regulation: the control fluid can be adjusted by adequate valves, which allow the pressure to be reduced and controlled.

Dimensional data: the accumulator is dimensioned depending on the fluid total volume required to carry out a given number of closing-opening operations and the usable fluid. The following values must be considered:

- Pre-charging pressure: as mentioned, this is the initial pressure of the bottles charged with nitrogen (70,3 kg/cm^2).

- Working pressure: it is the pressure achieved once the bottles are filled with the control fluid (210,9 kg/cm^2).
- Minimum working pressure: it is the minimum pressure which allows the accumulator to be used (14 kg/cm^2 above the pre-charging pressure).

Other components, like accumulator bottles, valves and pressure gauges, accumulator pumps, valve connections, closing valves, control fluid tank, working lines and remote control panels, should be included in the drill stem control equipment.

d. Low – Pressure Equipment

- Manifold Lines
- Mud-Gas Separator
- Degassers

Manifold Lines: they are typically located on the rig floor and provide flexible and variable flow control and well shut-in capability upstream of the process and measurement equipment during well test operations. The flow path, on one side of the manifold, has an adjustable choke, which is used during well cleanup or drawdown operations, until a stable flow condition has been reached.

Applications:

• Offshore and land operations

• Drill stem tests (DST)

• Well cleanups

• Production/well tests

• Well shut-in at surface

- **Mud/Gas Separator:** it is the first unit of solids control equipment arranged to treat mud. As such, they process all of the mud from the flowline before the mud reaches the primary shale shakers. The units have no moving parts and rely on the density difference between the gas and the mud for removal. The process is simple, yet very effective.

  In a separator, the lines are the parts which are normally problematic; this is due to the velocity of the drilling fluid, gas, barite and solids that are passing through it. Even very slight bends, which are barely noticeable, have been known to erode in a few minutes. Special attention has to be given to these lines, because they must be as straight as possible.

  Also, the separator itself could be a source of problems. The most common problems are due to size, inability to adequately control the liquid level and erosion of the body. Before installing a separator, the gas volume that is going to be used during the operation should be anticipated; this volume is a function of the physical size of the container, the maximum separator working pressure and the flare line size.

Normally, during offshore operations, the use of a separator is neglected because to the limitation of space; on the other hand, in land operations, this piece of equipment is not a source of problems.

As a rule, all separators used in well control operations should be big, the body should not be smaller than 1,2 m in diameter and 2,4 m in height. Generally, the operating pressure is approximately 8,8 kg/cm^2. However, this can vary according to the liquid level control mechanism. For making the system much more reliable it is recommended the use of a positive liquid level control.

Although the liquid level in the separator is controlled by a hydrostatic column of mud, in most cases the separator body is immersed a few feet into the mud pit. In other cases, a hydrostatic riser controls the liquid level. Therefore, if the pressure exceeds the hydrostatic pressure of the column controlling the liquid level, gas and reservoir fluids will pass out the bottom of the separator and will enter the mud pits. Such a scenario is common with separators designed as described and the results are unacceptably hazardous.

Another important consideration is how the fluid enters into the vessel. Some separators are designed to permit tangential entry, in the case that the fluids involved are only gas and liquid. If the fluid contains solids, a perpendicular entry is the best choice.

- **Degasser**: Degassers are used to remove the small entrained gas bubbles left in the mud by the mud/gas separator. These units are positioned downstream from mud/gas separators, gumbo removal equipment (if utilized), shale shakers and mud conditioners (if utilized), while hydrocyclones and centrifuges follow in the arrangement. The purpose of degassers is to remove the small bubbles of air or gas present in the mud system in order to insure that a mud with the required density is recirculated down the drill pipes. If the air or gas is not removed, the mud weight measured in the pits may be misleading giving values lower than the actual ones and could result in unnecessary additions of weighting materials, thereby giving true mud densities down the hole which are much higher with respect to what planned. Furthermore, as the mud rises to the surface, the dissolved gasses expand and evolve from the drilling fluid decreasing the hydrostatic pressure and causing the pumping operations to become erratic.

Two types of degassers are available:

- atmospheric;
- vacuum-type.

Atmospheric degassers process mud by accelerating fluid through a submerged pump impeller and impinging the fluid on stationary baffles to maximize surface area and thus enable gasses to escape to the atmosphere. As with all processing equipment the process rate is dependent upon solids content and fluid viscosity; processing rates are therefore dependent on mud properties.

Vacuum-type degassers utilize negative pressure to withdraw entrained gasses from the mud. In order for this to work, mud is pumped through a Venturi tube, which develops a negative pressure, thus sucking mud into the unit; the mud then flows over dispersion plates, arranged either horizontally or vertically, creating thin sheets of gas-cut mud. These dispersion plates bring entrained gases closer to the surface for easy removal by a stand-alone vacuum pump. Degassed drilling fluid is pumped through an "eductor" to remove drilling fluid from the vacuum chamber. Equalization between degasser suction and discharge compartments is through a high weir at the top of the tanks. Degasser suctions should be located at the bottom of the compartments. The choice between horizontally- or vertically-mounted units is based on the footprint requirements of the specific rig.

e. Auxiliary Equipment

This kind of equipment includes the following items:

- Safety valves and cocks.
- Instruments.

They also include working-condition control devices and instruments for kick monitoring and detection.

The most commonly used safety valves and cocks are:

- Upper Kelly cocks.
- Lower Kelly cocks.
- Safety valves for drill pipes.
- Inside BOP.

All sealing parts are characterized by a maximum working pressure value.

- Pressure tests: they should be performed with a pressure not lower than 70% of the drill pipes internal pressure, considering the degree and diameter of the drill string highest section and assuming the pipes as new.
- Testing pressure: it must not be higher than the BOP working pressure and in no case it can be higher than 10.000 psi.

- **Upper Kelly Cock: it** must be installed between the swivel and the Kelly and has the following functions:
  - Isolate the surface circuit from the well pressure.
  - Stop the flow and reduce the kick volume in case of blowout from the pipes.

- **Lower Kelly Cock**: it is used to prevent return flow from the pipes in case the upper cock is either out of service or not accessible. The working pressure should be proportional to the installed BOP pressure.

- **Safety valves for drill pipes:** must be installed before the inside BOP, if there is one. The safety valves must be kept at hand on the rig floor in the open position, with the provided key and with the necessary reductions to connect it to the drill pipes being used.

In case the back flow is particularly violent, a special valve called “fast shut-off valve” should be used, which, thanks to its particular bowl-shaped lower part and to its remarkable weight, allows installation in all conditions

- **Inside BOP’s**: they are check valves used to prevent blowouts from the pipes and to carry out stripping operations. Because of their function, they must be kept at hand on the rig floor, together with all the other emergency equipment.

Once the valve has been dropped and pumped to its seat, the insert is latched to the seat indented part by the jaws. When the circulation is interrupted, the well pressure and the spring action push the internal ball upwards.

A limited return flow, subsequently discharged to keep it under control, allows the insert to latch into the seat. From that moment on, both upwards and downwards stripping operations are allowed.

1.2 CAUSES OF KICK

In order for a blowout to occur, the formation pressure must be greater than the wellbore pressure; this condition is the result of different causes, such as:

- Natural Causes

  They may determine an abnormal and sudden increase in formation pressure.

  a) Abnormal pressure (overpressures)

- Operative Causes

  b) Insufficient mud weight

c) Swabbing
d) Failure to keep the well full during trips
e) Circulation losses
f) Drilling gas
g) Charged formation

More than 50% of blowout cases are a combination of causes b) and c).

a) Abnormal pressures (overpressures)

The formation pressure is considered normal when it is equivalent to the pressure of a column of saline water with a density D* between 1.03 - 1.07 kg/L; it is considered abnormal, if it is otherwise.

The main mechanisms responsible for abnormal pressures occurrences can be grouped in the following categories (Swarbrick, R.E. and Osborne M.J., 1996-1998):

- **stress-related mechanisms**, which cause the compression of the rocks with pore volume reduction, such as disequilibrium compaction (vertical loading stress) or tectonics (lateral/vertical compressive stress);

- **fluid volume increase mechanisms**, which determine an increase in volume of the fluids within the pores of a rock, transformed, then into pressure increase in case the volume increase is restricted. Examples are: temperature increase, water release due to mineralogical transformations of rocks (diagenesis), hydrocarbon generation, bitumen and oil cracking to gas;

- **fluid movements and buoyancy mechanisms**, which cause the movement of fluids from a formation to another with increase in pressures, if these extra volumes of fluids are not accommodated with an increase in volume of the receiving formations. Examples of these mechanisms are: osmosis, hydraulic or artesian pressure, buoyancy of hydrocarbons above water due to density contrasts;

- **redistribution of overpressured fluids**, originated by one of the mechanism categories mentioned above, from one formation to another. This occurrence, referred to as transference, though not a real mechanism in itself, may all the same exert a strong influence on many of the pore pressure profiles seen in the subsurface and may, sometimes, mask the recognition of the true mechanism which has originated the pressure anomaly.

If these zones, be chance, are drilled with an insufficient mud weight, a kick can occur, which, if not properly managed, can degenerate in a blowout.

b) Insufficient mud weight

The main tool to prevent a kick is to always have in the well the required column of mud at the right density; an insufficient mud weight can be experienced when:

- an abnormal pressure zone is entered unexpectedly;
- drilling deliberately in underbalance conditions.

c) Swabbing

The reduction in the bottom hole pressure when a string, wireline tools or rubber-cupped seals are pulled out of the well, depends on:

- Mud density and viscosity
- String pulling speed
- Clearance between drill collar and open hole diameters
- Presence of clay balls on the bit and stabilizers

It is possible to recognize if the formation fluid has entered the well during tripping out by observing the mud level in the pits. This influx of formation fluid creates an underbalanced situation at bottom hole. In order to minimize and prevent the swabbing effect, the following precautions should be taken:

- Decrease the trip velocity
- Condition the mud, carefully checking its rheological characteristics
- Pay the utmost attention in case of overpull during a trip
- Increase in mud density
- Run frequent short trips.

d) Failure to keep the well full on trips

This is one of the most frequent causes of a kick. If the volume of the steel removed during the tripping out is not replaced by an equal volume of mud, the hydrostatic pressure decreases along the entire well section. So, the hydrostatic pressure is lower than the formation pressure in the same layer, causing the fluid to enter the well.

e) Circulation losses

Losses of circulation indicate a flow of mud from the well towards the formation. Circulation losses can be caused by:

- Geological causes
    - Karstic formations
    - Fractured formations
    - Faults
- Operative conditions that can take place inside the well
    - Substantial friction losses in the annulus
    - Swabbing during tripping in (surge pressure)
    - Starting of circulation through holes of small diameter at great depth
    - Gumbo shale in the annulus

Some formations can be affected more frequently by lost circulation or abnormal absorption:

- Fractured or karstic limestone formations.
- Depleted levels
- Formations with fractures induced during drilling
- Pressure surges in the annulus

f) Drilling gas

When a gas bearing formation is drilled, the volume of gas contained in the drilled rock is released. The gas forms an emulsion with the mud which loses density. The gas released in the well is subject to the hydrostatic pressure exerted by the overlying mud column. As soon as the gas starts to flow upwards, the pressure over it decreases and the gas expands.

The decrease in mud density is minimal at the bottom and greater at the surface, with a slight decrease of the bottom hole pressure.

The quantity of gas released when a gas-bearing formation is drilled determines a continuous contamination of the mud, which depends on the following factors:

- Drilling rate
- Degree of porosity of the formation
- Hole diameter

g) Charged formation

When different formations having different pressures are drilled, formation fluid may flow from one formation to another before the casing is run in and cemented. This phenomenon is known as underground blow-out. In this way one formation may pressurize another formation due to differences in their pore pressure.

1.3 INDICATORS

It is very important to recognize a kick at the early stage, because less volume of fluid results contaminated, the higher is the probability to prevent a blowout.

The careful monitoring and evaluation of certain indicators help individuate the first signals of an abnormal situation. These kick indicator can be subdivided as follows:

1.3.1 Increase in Rate of Penetration (Drilling Breaks)

As we know the rate of penetration tends to decrease as the depth of the well increases, because of increasing hardness of the rocks. But a remarkable increase in the rate of penetration may indicate a change of formation or a reduction in differential pressure. Then when an unexpected higher pressured zone is drilled, the rate of penetration increases.

1.3.2 Increase in Circulating Mud Volumes

Any flow of formation fluid into a well determines an increase in the surface mud volume. This change in the return flow is the first signal of abnormal well pressure. In this case, it is necessary to stop operations and carry out a flow check.

A circulating mud volume increase may also depend on other causes, not related to the kick. Some of them are:

- Addition of materials to modify the mud characteristics.
- Leakage or incorrect use of mud system valves which can cause the accidental transfer of mud between the tanks.

1.3.3 Variation in Pump Pressure and Strokes

If we compare the formation fluids with the mud, we can say that they are characterized by a lower density. So, their influx into the well determines a decreases of the annulus hydrostatic pressure and a subsequent unbalance in the well. Therefore, this unbalance determines a decrease of the circulating pressure and possibly an increase of the pump strokes.

This situation may indicate that a kick is taking place and it is necessary to stop the operations and apply the recommended procedures.

However, it must be taken into consideration that the decrease of circulating pressure may also be due to other causes:

- Pump failure
- Unbalanced mud
- Wash-out of the drill string

1.3.4 Drilling Gas

As said, a drilling gas increase is an indication of an abnormally porous formation. Normally, it is an indication that an influx passes from the formation into the wellbore. The gas enters into the wellbore and slowly migrates up to the surface, where it expands producing a decrease in mud density.

1.3.5 Variation in Chloride Concentration

An increase in chlorides in the drilling mud indicates the entrance of native water. In fact, the salinity in water formation is usually greater than that in drilling mud.

Not just the chloride ions content is measured, also an increase or decrease in the resistivity and pH are related to bottom hole differential pressure.

1.3.6 Other Indicators of a Kick

- Decrease in the drill string weight and increase in the circulating pressure.
- Increase in torque and/or overpulls.

1.4 WELL CONTROL

1.4.1 Primary Control

Primary control mainly consists in maintaining the hydrostatic pressure at a value, which is sufficient to balance the maximum pore pressure of the formation. This pressure is provided by the drilling mud. In theory, the mud weight provides the minimum pressure to achieve the balance, but in practice to this weight is added a safety margin with respect to the pore gradient. In brief, primary well control mainly depends on the correct fluid weight use to maintain the formation fluid under control, as well as on the accuracy and control of the gathered data.

1.4.2 Detection of Abnormal Well Conditions

In the literature, there are available different methods, qualitative and quantitative, which have been developed for an accurate detection of any abnormal conditions occurring while drilling. Generally, these methods can be divided into the following groups [2]:

- Use of previous field history and drilling experiences (depth of flowing zones, pore and fracture gradients, types of fluids, permeability, mud losses and lost circulation intervals).

- Physical responses from the well (pit gains or losses, increases in drilling fluid return rates, changes in flowing temperatures, drilling breaks, variations in pump speeds and/or standpipe pressures, swabbing, reduction in mud densities, effects on gas shows and pit gains due to pipe connections, short and round trips, hole problems indicating underbalance).

- Chemical and other responses from the well (chloride changes in the drilling fluid, oil and gas shows, formation water, shale density, electrical logs, drilling parameters equations and MWD/LWD readings).

1.4.3 Flow Checks

- A minimum 10 minutes flow check will be made any time there is a drilling break while drilling.
- It could be not necessary to flow check drilling breaks in the interbedded sands of the reservoir, if these sands have a known regressive pore pressure gradient.
- Prior to making any flow check, pick-up pumping out so that the lower full opened safety valve is accessible at the rig floor.
- A flow check should be realized prior to pulling the BHA through the BOP.
- All flow checks will be conducted on the trip tank, with the trip tank pumps running.
- The trip tank is to be kept half full at all times and is to be flushed at the beginning of each shift.
- Rotate the pipe during the flow checks.
- While the trip tank is being emptied, the well needs to be checked with someone observing the flow line.

1.4.4 Kick Prevention

If primary control is not sufficient, a kick will be experienced; as mentioned in the first paragraphs, common causes of kicks are:

- Swabbing of formation fluids while tripping.
- Failure to check that the hole takes or gives up the correct volume of fluid when tripping.
- Encountering abnormal formation pressure.
- Insufficient mud weight.
- Loss of circulation leading to reduction in equivalent hydrostatic pressure.

Extreme care shall be taken to monitor: mud volumes, drilling breaks and gas cut mud.

1.4.5 Slow Circulating Rate Pressure (SCR Pressure)

In surface wellheads, the selected slow circulation rates should be in a range between ¼ and ½ of the planned circulation flow rate.

Awareness of these values is an important element in killing operations, in order to avoid formation breakdown.

This pressure should be measured in the choke control panel gauge or on the gauge which would be used during well control operations.

According to eni e&p practices in subsea wellheads, the selected slow circulation rates should not be less than ½ bbl/min and not greater than 4 bbl/min.

1.4.6 Maximum Allowable Annulus Surface Pressure (MAASP)

There is an absolute upper limit for the pressure in the annulus of an oil and gas well as measured at the wellhead. For each well's phase, the MAASP value depends on the following factors:

- Drilling/completion fluid density.
- Minimum formation fracture gradient below the casing shoe or perforations.

1.4.7 Secondary Control

If the hydrostatic pressure becomes lower than the formation pressure, the fluid (water, gas, oil etc.) contained in the formation would enter into the wellbore. This means that a kick has occurred already. The next step is preventing it from becoming a blowout. There are two main procedures that must be followed:

a) Shut- in

When any of the kick indicators are observed, the well must be shut in by closing the BOPs and choke valve; this procedure is followed to avoid any possible uncontrolled expansion of the fluid inside the wellbore.

b) Circulate out the fluid cushion that has entered the well

This procedure involves circulating a sufficient volume of mud through the adjustable choke valve to expel the kick and to exchange the entire gas cut mud volume with higher density mud. In order to balance the pressure inside the wellbore, a new hydrostatic pressure that has to exceeds the formation pore pressure is set. All this process must be done while keeping the expansion under control.

c) Increase mud weight

This procedure prevents any further influx of fluids into the well and, using the most suitable method, allows the displacement of the bottom hole cushion (kick). It also restores the hydrostatic balance between the formation pressure and the hydrostatic pressure exerted by the drilling fluid.

The success of this operation depends on prevention: this means the proper use of proper equipment and ad hoc testing and maintenance programs. Training plays a fundamental role; in fact, the success of this type of operation depends often on quick reaction from personnel, who must recognize the problem as it occurs and proceed with shut-in and well control procedures.

All the conventional methods used to bring the well under control are based on the "Constant Bottom Hole Pressure" concept; this determines the bottom hole pressure from the mud density and the shut-in drillpipe pressure and to keep the bottom hole pressure constant while the influx is displaced . It is established that the required constant bottom hole pressure should be slightly higher than the pore pressure to be maintained throughout the killing operation, in order to maintain the balance between the well and the formation.

According to eni e&p practices, the order of preference in the use of the Well Control Methods is the following: the Wait and Weight method is the first, but if this is not practical, the Driller's Method will be used; the last choice will be the

Volumetric Method. In any case, the use of these methods will always be influenced by the field knowledge of the drilling/completion team.

Before detailing these three methods it is necessary to introduce some theoretical considerations:

Theoretical Considerations

- **Gas Expansion**

In the late 1950s and early 1960s, the oil industry started to realize that no all the influxes are in a liquid state; they can be also in a gaseous state: In this case it must be taken into account that the gas has the property to expand as it approaches to the surface. The first mathematical relationship to be used is the well known law of real gases (Equation 1.1):

$$PV = ZnRT \tag{1.1}$$

where:

P = Pressure, psia
V = Volume, ft^3
Z = Compressibility factor
N = Number of moles
R = Gas constant
T = Temperature, °Rankine

By neglecting changes in temperature, T, and compressibility factor, Z, and under varying conditions, the Equation 1.1 can be simplified into Equation 1.2 as follows:

$$P_1V_1=P_2V_2 \tag{1.2}$$

where:

1= Denotes conditions at any point

2= Conditions at any point other than point 1

This establishes that the pressure of a gas multiplied by the volume of the gas is constant and in the case when the gas is not permitted to expand the pressure begins to be excessive.

Thereby, the main goal of the circulating method is to bring the gas to the surface, where it is allowed to expand to avoid rupturing the wellbore; it is also mandatory to keep the Bottom Hole Pressure constant in order to prevent additional influx of formation fluids.

- **The U-Tube Model**

The importan of this Model is that all classical displacement procedures are based on the U-Tube Model, illustrated in **Figure 1.2**. The left side of the U-Tube represents the drillpipe while the right side of the U-Tube represents the annulus. Therefore, the U-Tube Model describes a system where the bit is on bottom and it is possible to circulate from bottom. If it is not possible to circulate from bottom, classical well control concepts are meaningless and not applicable.

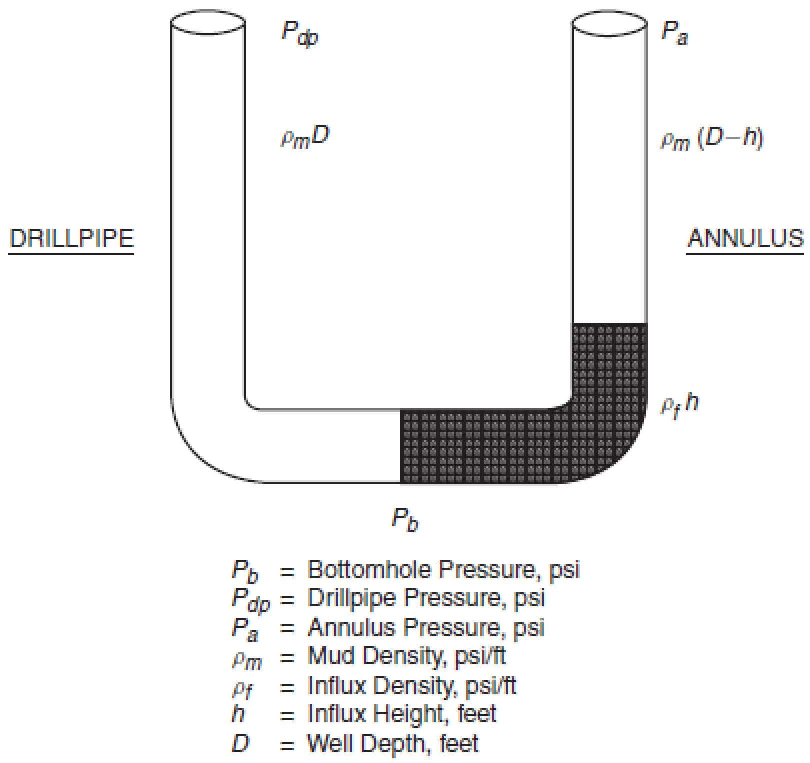

Figure 1.2 The U-Tube Model

As illustrated in **Figure 1.2**, there is an influx of formation fluid in the annulus. As primary control indicates, the well is shut in. Under these conditions, there is static pressure on the drillpipe, which is denoted by P_{dp}, and static pressure on the annulus, which is denoted by P_a. The formation fluid, ρ_f, in the annulus occupies a volume that can be defined by the area of the annulus by the height, *h*, of the influx.

The left side of the U-Tube represents the drillpipe and, in static conditions, the bottomhole pressure is determined utilizing Equation 1.3:

$$P_b = \rho_m D + P_{dp} \tag{1.3}$$

where:

P_b= Bottomhole pressure, [psi]

ρ_m= Mud gradient, [psi/ft]

D= Well depth, [feet]

P_{dp}= Shut-in drillpipe pressure, [psi]

Thereby, all classical models, that will be explained in this thesis, must keep the shut-in bottomhole pressure, P_b, constant in order to prevent additional influx of formation fluids while displacing the initial influx to the surface. In this method, all the variables are known and the drillpipe side is used to control the bottomhole pressure, P_b.

The Wait and Weight method

The W&W Method involves only one circulation. The influx is circulated out and the kill mud is pumped in one circulation. While pumping kill mud from surface to bit, a drill pipe pressure schedule has to be calculated and followed. The drill pipe pressure is held constant ,thereafter, until the kill mud is observed returning to the surface. [3]

The Wait and Weight Method is discussed in detail as follows [4]:

- Step 1: on each tour, read and record the standpipe pressure at several rates in strokes per minute (spm), including the anticipated kill rate for each pump.
- Step 2: prior to pumping, read and record the drillpipe and casing pressures. Determine the anticipated pump pressure at the kill rate using Equation 1.4:

$$Pc = Pks + Pdp \tag{1.4}$$

Where:

P_c = Circulating pressure during displacement, psi

P_{ks} = Recorded pump pressure at the kill rate, psi

P_{dp} = Shut-in drillpipe pressure, psi

- Step 3: Determine the density of the kill-weight mud, ρ_1, using Equation 1.5

$$\rho_1 = \frac{\rho_m * D + P_{dp}}{0.052 * D} \tag{1.5}$$

where:

ρ_1 = Density of the kill-weight mud, ppg

ρ_m = Gradient of the original mud, psi/ft

P_{dp} = Shut-in drillpipe pressure, psi

D =Well depth, feet

- Step 4: Determine the number of strokes to the bit by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Equation 1.6:

$$STB = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p} \tag{1.6}$$

where:

STB = Strokes to the bit, [strokes]

C_{dp} = Capacity of the drillpipe, [bbl/ft]

C_{hw} = Capacity of the heavy-weight drillpipe, [bbl/ft]

C_{dc} = Capacity of the drill collars, [bbl/ft]

l_{dp} = Length of the drillpipe, [feet]

l_{hw} = Length of the heavy-weight drillpipe, [feet]

l_{dc} = Length of the drill collars, [feet]

C_p = Pump capacity, [bbl/stroke]

- Step 5: Determine the new circulating pressure, P_{cn}, at the kill rate with the kill-weight mud at the bit, utilizing Equation 1.7:

$$P_{cn} = P_{dp} - 0.052 * (\rho_1 - \rho) * D + \left(\frac{\rho_1}{\rho}\right) * P_{ks} \tag{1.7}$$

where:

ρ_1 = Density of the kill-weight mud, ppg

ρ = Density of the original mud, ppg

P_{ks} = Original circulating pressure at kill rate, psi

P_{dp} = Shut-in drillpipe pressure, psi

D =Well depth, feet

- Step 6: For a complex drill string configuration, determine and graph the pumping schedule for reducing the initial circulating pressure, P_c, determined in Step 2, to the final circulating pressure, P_{cn}, determined in Step 5. Using Equations 1.8 and 1.9, calculate Table 1.1 and create the corresponding graph.

Table 1.1.- Pumping Schedule: Strokes vs Pressure

Strokes	Pressure
0	700
STKS 1	$P1$
STKS 2	$P2$
STKS 3	$P3$

. . . .	...
STB	*Pcn*

$$STKS\ 1 = \frac{C_{dp1} l_{dp1}}{C_p} \tag{1.8a}$$

$$STKS\ 2 = \frac{C_{dp1} l_{dp1} + C_{dp2} l_{dp2}}{C_p} \tag{1.8b}$$

$$STKS\ 3 = \frac{C_{dp1} l_{dp1} + C_{dp2} l_{dp2} + C_{dp3} l_{dp3}}{C_p} \tag{1.8c}$$

$$STB = \frac{C_{dp1} l_{dp1} + C_{dp2} l_{dp2} + C_{dp3} l_{dp3} + \cdots + C_{dc} l_{dc}}{C_p} \tag{1.8d}$$

$$P_1 = P_c - 0.052(\rho_1 - \rho)(l_{ds1}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{STKS1}{STB}\right) \tag{1.9a}$$

$$P_2 = P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{STKS2}{STB}\right) \tag{1.9b}$$

$$P_3 = P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2} + l_{ds3}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{STKS3}{STB}\right) \tag{1.9c}$$

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2} + l_{ds3} + \cdots + l_{dc}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right) \tag{1.9d}$$

where:

STKS 1 = Strokes to end of section 1 of drill string

STKS 2 = Strokes to end of section 2 of drill string

STKS 3 = Strokes to end of section 3 of drill string

STB = Strokes to the bit as determined in Step 4

ρ_1 = Density of kill-weight mud, [ppg]

ρ = Density of original mud, [ppg]

$l_{ds1,2,3}$ = Length of section of drill string, [feet]

$C_{ds1,2,3}$ = Capacity of section of drill string, [bbl/ft]

$P_{1,2,3}$ = Circulating pressure with kill-weight mud to the end of section 1,2,3, [psi]

P_{dp} = Shut-in drillpipe pressure, [psi]

P_{ks} = Circulating pressure at kill speed determined in Step 1, [psi]

C_p = Pump capacity, [bbl/stroke]

P_{cn} = New circulating pressure, [psi]

P_c = Initial displacement pressure determined in Step 2 using Equation 2.4, [psi]

For a drill string composed of only one weight of drillpipe and one string of heavy-weight drillpipe or drill collars, the pumping schedule can be determined using Equation 1.10:

$$\frac{STKS}{25\,psi} = \frac{25\,(STB)}{Pe-Pcn} \tag{1.10}$$

- Step 7: raise the density of the mud in the suction pit to the kill weight determined in Step 3.

- Step 8: bring the pump to a kill speed, keeping the casing pressure constant at the shut-in casing pressure. This step should require less than five minutes.
- Step 9: once the pump is at a satisfactory kill speed, read and record the drillpipe pressure. Adjust the pumping schedule accordingly. Verify the drillpipe pressure using the diagram established in Step 1. Displace the kill-weight mud to the bit pursuant to the pumping schedule established in Step 6 as revised in this step.
- Step 10: displace the kill-weight mud to the surface, keeping the drillpipe pressure constant.
- Step 11: shut in the well, keeping the casing pressure constant and observe that the drillpipe pressure and the casing pressure are 0 and the well is dead.
- Step 12: if the surface pressures are not 0 and the well is not dead, continue to circulate, keeping the drillpipe pressure constant.

- Step 13: once the well is dead, raise the mud weight in the suction pit to provide the desired trip margin.
- Step 14: Drill ahead.

Driller's Method

The Driller's Method requires two circulations to kill a well. During the first circulation, the influx is circulated out with the original mud weight. In order to maintain constant BHP, the circulation through the drill pipe is done at constant pressure. If the original mud weight is insufficient to balance the formation pressure, the well is killed by circulating a heavier mud (kill mud) in a second circulation.

To hold constant Bottom Hole Pressure (BHP) during the second circulation, one of two procedures is employed. The casing pressure is held constant while pumping kill mud from surface to bit and the drill pipe pressure is held constant thereafter, until the kill mud is observed returning to the surface. Alternately, during the second circulation, a drill pipe pressure schedule can be calculated and followed while pumping kill mud from surface to bit, and drill pipe pressure is held constant thereafter.

This Method can be further classified as a simple displacement which requires minimal calculations. The recommended procedure is as follows [5]:

- Step 1: on each tour, read and record the standpipe pressure at several rates in strokes per minute (spm), including the anticipated kill rate for each pump.
- Step 2: after a kick is taken and prior to pumping, read and record the drillpipe and casing pressures. Determine the anticipated pump pressure at the kill rate using Equation 1.11:

$$Pc = Pks + Pdp \tag{1.11}$$

- Step 3: bring the pump to a kill speed, keeping the casing pressure constant at the shut-in casing pressure. This step should require less than five minutes.
- Step 4: once the pump is at a satisfactory kill speed, read and record the drillpipe pressure. Displace the influx, keeping the recorded drillpipe pressure constant.
- Step 5: once the influx has been displaced, record the casing pressure and compare with the original shut-in drillpipe pressure recorded in Step 1. It is important to note that, if the influx has been completely displaced, the casing pressure should be equal to the original shut-in drillpipe pressure.
- Step 6: if the casing pressure is equal to the original shut-in drillpipe pressure recorded in Step 1, shut in the well by keeping the casing pressure constant while slowing the pumps. If the casing pressure is greater than the original shut-in drillpipe pressure, continue circulating for an additional circulation, keeping the drillpipe pressure constant, and then shut in the well, keeping the casing pressure constant while slowing the pumps.
- Step 7: read, record and compare the shut-in drillpipe and casing pressures. If the well has been properly displaced, the shut-in drillpipe pressure should be equal to the shut-in casing pressure.
- Step 8: if the shut-in casing pressure is greater than the shut-in drillpipe pressure, repeat Steps 2 through 7.
- Step 9: if the shut-in drillpipe pressure is equal to the shut-in casing pressure, determine the density of the kill-weight mud, $\rho 1$, using Equation 1.12:

$$\rho_1 = \frac{\rho_m * D + P_{dp}}{0.052 * D} \tag{1.12}$$

- Step 10: raise the mud weight in the suction pit to the density determined in Step 9.
- Step 11: determine the number of strokes to the bit by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Equation 1.13:

$$STB = \frac{C_{dp}l_{dp}+C_{hw}l_{hw}+C_{dc}l_{dc}}{C_p} \tag{1.13}$$

- Step 12: bring the pump to speed, keeping the casing pressure constant.
- Step 13: displace the kill-weight mud to the bit, keeping the casing pressure constant.

Warning: Once the pump rate has been established, no further adjustments to the choke should be required. The casing pressure should remain constant at the initial shut-in drillpipe pressure. If the casing pressure begins to rise, the procedure should be terminated and the well shut in.

- Step 14: after pumping the number of strokes required for the kill mud to reach the bit, read and record the drillpipe pressure.
- Step 15: displace the kill-weight mud to the surface, keeping the drillpipe pressure constant.
- Step 16: with kill-weight mud to the surface, shut in the well by keeping the casing pressure constant while slowing the pumps.
- Step 17: read and record the shut-in drillpipe pressure and the shut-in casing pressure. Both pressures should be zero.
- Step 18: open the well and check for flow.
- Step 19: if the well is flowing, repeat the procedure.
- Step 20: if no flow is observed, raise the mud weight to include the desired trip margin and circulate until the desired mud weight is attained throughout the system.

Volumetric Method

The volumetric method is normally used to control gas expansion, migrating up-hole, during the shut-in period.

The most common situations, where the volumetric method may be applicable, include the following:

- When the mud pumps are inoperable.

- The drill string is far off the bottom or out of the hole.
- There is a washout in the drill string.
- The bit is plugged.
- The drill string has parted and dropped.

In this method, the BHP is maintained relatively constant and slightly in excess of the pore pressure, whilst the gas is allowed to expand as it migrates up to the surface. The volumetric method mainly consists in the follow steps [6]:

- Step 1: a constant bottom hole pressure is maintained by bleeding off mud, with an equivalent hydrostatic head equal to the rise in pressure caused by the migrating gas. For instance, if the choke pressure rises by 7,03 kg/cm^2, a volume of mud equivalent to the hydrostatic pressure of 100 psi is slowly bled off, maintaining constant casing pressure.
- Step 2: bleed off in very small increments to allow the pressure to respond by using a manual adjustable choke and diverting the mud into the trip tank.
- Step 3: repeat this process until the influx has migrated up to the BOP.
- Step 4: when the gas is at the BOP stack, lubricate mud into the well. The lubrication procedure will replace the influx with mud, as the gas is bled off at the choke.
- Step 5: pump mud into the casing until pump pressure reaches the predetermined limit and stop the pump.
- Step 6: leave the well shut-in for a time to allow gas to migrate through the lubricated mud.
- Step 7: bleed gas from the well until the surface pressure is reduced by the exact amount equal to the hydrostatic pressure of the fluid volume lubricated into the well.
- Step 8: route returns via the mud gas separator and monitor. If a significant quantity of mud is returned, bleeding should be stopped and further time allowed for the gas to migrate through the lubricated mud.

- Step 9: it is unlikely that all the gas will rise to surface as a discrete bubble and it will be mixed through the mud; therefore, it will take a considerable length of time to be completed.
- Step 10: when using subsea BOP stacks, gas migration may occur in the choke line leading to a reduction in bottom hole pressure. In this case, a dynamic volumetric method is used for venting the gas from the subsea BOP, by circulating down the kill line and up the choke line. Control surface pressure and pit gain with the choke line. Use the kill line to monitor the bottom hole pressure.

Note: If the mud weight is insufficient to balance the formation pressure, it will be necessary to strip drill pipe into the well to implement a standard well kill method.

Bull heading

This method should be only used when normal methods for killing a well with conventional circulation are not possible or may result in a critical well conditions.
Bullheading is usually only considered when the following situations occur:

- A H2S influx cannot be handled safely by rig personnel and equipment.
- A kick is taken with the pipe far off bottom or even out of the hole.
- Circulating the kick out may result in excessive gas rates at surface.
- Kick calculations show that the MAASP will be greatly exceeded during conventional kill operations.
- Killing completed wells, i.e. actual producing wells or production well tests in cased wells.

Major factors that will be considered to determine the feasibility of bullheading are as follows:

- Characteristics of the open hole formations, including fracture gradients and estimated permeability.
- Rated pressures of casing, making allowance for wear and deterioration.
- Size, location and nature of the influx.
- Consequences of fracturing a section of open hole.

Bullheading procedures will be defined and decided at the rig site, in order to control a specific situation; it must be clear that the drilling/completion fluid and influx are squeezed back downhole into the weakest exposed open hole formation.

Kill Methods Considerations

According to eni e&p best practices, the explained methods should be used in the following situations[7]:

a) Use the Drillers method to kill the well if the influx is due to swabbing

- The bit shall be backed on bottom.
- It may be necessary to kill the well in stages, while working the pipe back to bottom.
- If the intermediate casing shoe is deep enough, a circulation at this point will probably kill the well; however, some influx will still be in the open hole.
- If it is not possible to get the pipe back to bottom, there may be difficulties in killing the well completely.

b) Killing the well by the Wait and Weight Method, the final circulating pressure should be reached when the killing fluid reaches the horizontal section vertical depth, not the bit position.

c) Volumetric Method may not be very effective in horizontal wells since the influx tends to be “by-passed” in the horizontal section and remains in the borehole. This method, however, should be considered, if the pipe cannot be stripped to bottom.

d) Bullheading Method. This method should be considered if:

- The pipe cannot be stripped to bottom.
- There is no pipe in the hole.
- A large influx has been taken.

1.4.8 Tertiary Control

If secondary control cannot be maintained due to equipment failure and consequent loss of well control, it is still possible to apply proper measures to avoid the complete loss of the well.

Although these measures may avoid the risk of a blow-out, they usually lead to partial loss of the well. The main remedies that can be adopted are:

- Barite plugs
- Cement plugs

Barite Plugs

This method consists in pumping into the well through the drill pipe a mixture of barite, water or oil. If conditions permit, the string is pulled above the plug itself.

As known, the barite is characterized by high density and fine particle grain size, which is fundamental to form an impermeable barrier in order to stops the well flowing out.

A barite plug offers the following advantages: it can be pumped through the bit; the string may be recovered; the material is available on site.

The plugs must be made-up from top quality barite and it must have the following properties:

- High density;

- High settling rate.

The biggest risk involved is that the string gets plugged, if circulation is interrupted before the plug is completely displaced. Barite plugs may be displaced with the rig pumps, but it is preferable to use a cementing unit to allow more accurate volume control. In order for the plug to get a good seal and to be accurately displaced, a plug length of at least 60 m is recommended.

Barite plugs can be made in two ways:

a) barite/water mixture;

b) barite/oil mixture.

Cement Plugs

Cement plugs may be used to stop bottom hole influxes, but this implies abandoning the well and loss of most of the drilling equipment.

The method mainly consists in pumping a cement slurry with accelerators into the annulus through the drill string. Quick setting cement reduces the chances of gas-cutting. The cement is usually pumped until pump and choke pressures show that a bridge has formed.

The use of cement plugs offers little possibility of recovering the string. The drill string may even become plugged after pumping the cement. This would preclude any further attempt to control the well, if the first attempt fails. Cement plugs must, therefore, be considered as the last solution.

CHAPTER II

HISTORICAL CASES

This report presents frequencies of blowouts and well releases based on data from the areas of US GoM OCS (US GoM) and North Sea. The frequency basis is the latest blowout statistics distributed by SINTEF, per December 2005, Ref. /1/. The time period of the research started from 01.01.84 to 31.12.03 to estimate the frequency of the events.

Also, this report will focus in documenting blowout and well release frequencies based on well operations of North Sea standards with respect to standards of practice and equipment. Another important issue that I will introduce is a mutual understanding of the data selected and use of the frequencies amongst oil companies and risk analysts.

Delimitation

- Descriptions of well control incidents are not included in this report.
- Only hydrocarbon releases are included in the frequency calculations, i.e. incidents where the released formation fluid is defined as water or incidents where the releases have been solely mud are disregarded.
- Blowouts caused by external loads (e.g. fire, storm) are not included except for the production phase, where it is mentioned explicitly.
- Underground blowouts with no release to the sea or platform are excluded

2.1 HISTORICAL CASES

Blowouts occur for a variety of reasons as it will be explained in the next chapter. Most factors relate to human errors, equipment malfunction and geology. Proper planning to handle this situation after the blowout requires an understanding of the technical basis of each scenario and some quantitative information on damage, frequency, etc. Often, planning and operational decisions relating to blowouts are based on insufficient data, failure to consult with blowout specialists or emotional factor.

Further, this thesis presents some interpretations related with the most expensive and frequent blowouts in the history. Literature searches from prior projects were beneficial in developing in the eni's Company blowout files. Also, Marintek's, BP, and Society of Petroleum Engineers (SPE) blowout database was used to provide insight into database elements and structure.

Blowout data reporting is improving in the industry, although, it has been poor historically. Emphasis is being given to data collection by various sources, including government agencies and insurance companies. Hopefully, developments in the future will lend themselves to data collection that will provide answers where voids currently exist.

Some data were generalized to fit in a manageable number of categories. If a sufficient number of categories had been created to better handle the data, the database structure would have been unmanageable and many categories would have few or no data points. The results should be considered as qualitative indicators rather than absolute quantitative measurements. The relatively small number of events and available data on each event required this approach.

2.2 DISCUSSION OF BLOWOUT DATA ANALYSIS

Figure 2.1 shows blowout occurrences by year for several areas. The composite data are segregated into the regions of Alberta, Canada; Texas, USA and South America. These data are based on the number of blowout jobs in past history. However, documented reports were not available for their entry into the database. [8]

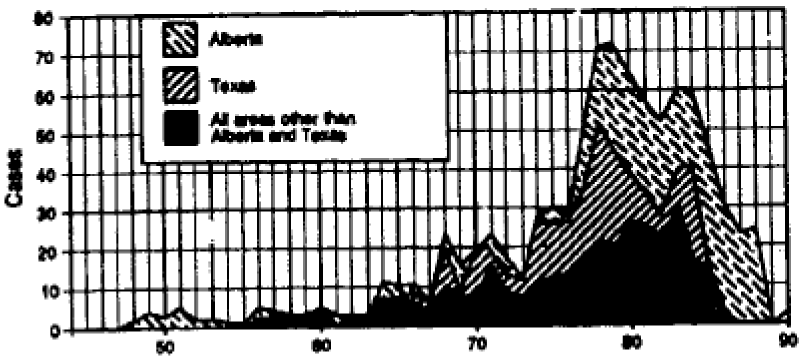

Figure 2.1 Blowout occurrence Vs Years

As we can notice the number of reported blowouts increased from the late 1960s and even more rapidly as the activity for oil was stimulated in 1973. The peak was in 1978. The trend has subsequently decreased in general accordance with the reduced drilling activity. Even you have to keep in mind that serious well-control incidents can occur any time, even when least expected.

Two recent incidents in the Gulf of Mexico remind us this fact. The first that will be mentioned is the BP Macondo blowout. in this case is notice that once the casing is installed and cement is pumped, the danger is not over. The second case that we would like to mention was a deepwater horizon oil spill, clearly an ecological disaster in Venezuela; this was the major blowout in the mentioned country.

The *Deepwater Horizon* oil spill, also referred to as the BP oil spill or the Macondo blowout, is an oil spill in the Gulf of Mexico which flowed for three months in 2010. It is the largest accidental marine oil spill in the history of the petroleum industry. The spill stemmed from a sea-floor oil gusher that resulted from the April 20, 2010, explosion of *Deepwater Horizon*, which drilled on the BP-operated Macondo Prospect. The explosion killed 11 men working on the platform and injured 17 others. On July 15, 2010, the leak was stopped by capping the gushing wellhead, after it had released about 4.9 million barrels (780,000 m^3) of crude oil. An estimated 53,000 barrels per day (8,400 m^3/d) escaped from the well just before it was capped. It is believed that the daily flow rate diminished over time, starting at about 62,000 barrels per day (9,900 m^3/d) and decreasing as the reservoir of hydrocarbons feeding the gusher was gradually depleted. On September 19, 2010, the relief well process was successfully completed, and the Federal Government declared the well "effectively dead". [9]

At approximately 9:45 p.m. CDT, on April 20, 2010, methane gas from the well, under high pressure, shot all the way up and out of the drill column, expanded onto the platform, and then ignited and exploded. Fire then engulfed the platform.[10][11] Most of the workers escaped the rig by lifeboat and were subsequently evacuated by boat or airlifted by helicopter for medical treatment;[12] however, eleven workers were never found despite a three-day Coast Guard search operation, and everything indicated that they have died in the explosion.[12] Efforts by multiple ships to douse the flames were unsuccessful. After burning for approximately 36 hours, the *Deepwater Horizon* sank on the morning of April 22, 2010.[13]

The second case was on April 20, 2010, the Deepwater Horizon, a mobile, semisubmersible deep-sea oil-drilling rig leased by British Petroleum (BP), was completing a newly drilled well forty-one miles off the Louisiana coastline in the Gulf of Mexico when it exploded and sank, killing eleven oil-rig workers, injuring seventeen, and triggering the largest offshore oil spill in U.S. territory in American history. It will likely be one of the top ten in world history if it is not stopped soon. The spill is clearly an ecological disaster, but overreaction to it could cause more environmental and economic harm than good. It should be viewed in perspective historically and environmentally, and policymakers should wait to make changes until the full effects of the spill can be understood.

The estimates of the amount of oil leaking from Deepwater Horizon have superseded the initial estimate of 5,000 barrels per day; according to the Department of the Interior, oil is leaking at a rate of 20,000 to 40,000 barrels per day, though some estimates run as high as 60,000 barrels per day.[14] Using a midpoint range of 30,000 barrels per day, by June 1 about 172,000 tons[15] had leaked from the well under Deepwater Horizon. By comparison, the *Exxon Valdez* spilled 37,000 tons, and the 1969 Santa Barbara platform spill released 12,000 tons.

Delimitation

- A specific description of well control incidents is not included in this thesis. It is included just an identification number of incidents, estimation of cost, frequency and quantity of oil released.
- Only hydrocarbon releases are included in the frequency calculations, i.e. incidents where the released formation fluid is defined was water or incidents where the releases have been solely mud are disregarded.
- Blowouts caused by external loads (i.e. fire, storm) are not included except for the production phase, where it is mentioned.

2.3 PHILOSOPHY AND METHOD

1.- Hierarchic Approach

A hierarchic approach was chosen for the calculation of blowout frequencies. This means that main classes were defined for the frequencies calculated. Subsequently, the main classes are divided into subclasses. Subclasses are defined as oil wells and gas wells, except for the main class shallow gas. The latter main class has been split into restricted and full releases and topside and subsea releases, due to some different definitions of the category well release compared to blowouts.

Sometimes, the data for the subclasses are scarce. Thus, in order to get a more reliable frequency, the data have been split so that each subclass may be evaluated on the basis of other information as well.

2.- Guidelines for Choosing Main Classes

The guidelines for choosing the main classes are as follows:

- Each main class should contain a number of incidents (preferably more than 3) to obtain a reasonable basis for calculating the main class frequency. Alternatively, available exposure data should be sufficient to assess a reliable frequency for the main class.
- To the largest extent possible, each main class should have common failure modes. Hence, common trends (change in risk over time) can be found.
- The main classes should have the same, or similar, consequences.

3.- Main Classes

The frequencies have been calculated for 4 different main classes:

- "shallow gas",
- "blowout",
- "well release" and
- “cost”

as presented below. The terminology "deep" is referring to well operations performed after the BOP is installed on the well and act as a blowout barrier.

Shallow Gas: this main class includes blowouts and well releases and is only defined for the operation drilling, where the release medium is reported as shallow gas. The allocation of blowouts and well releases into one main class is done since failure modes are the same.

The only difference between a shallow gas blowout and a shallow gas well release is that well releases are per definition successfully diverted.

Frequencies of shallow gas releases are split into full and restricted releases, but also topside and subsea releases.

Blowout: The blowout frequency in this main class is calculated separately for the operations regarding drilling, completion, production and well interventions.

Well Release

The well release frequency in this main class is calculated separately for the operations regarding drilling, completion, production and well interventions.

The difference of the failure modes of well releases compared to blowouts is that failures in the BOP system give a smaller contribution to hydrocarbon releases.

Cost

The method applied to estimate costs for a hypothetical spill is the EPA BOSCEM. It is an Oil Program with a methodology for estimating oil spill costs, including response costs and environmental and socioeconomic damages, for actual or hypothetical spills. The model can quantify relative damage and cost for different spill types for regulatory impact evaluation, contingency planning, and assessing the value of spill prevention and reduction measures.[16]

The following section gives the results of some of the analysis from the data mentioned. **Table 2.1** shows the locations of the six Worst Offshore Blowouts according to the volume of oil released.

Table 2.1 Six Worst Offshore Blowouts

	Volume Released (Barrels)
The **Deepwater Horizon oil spill** (also referred to as the **BP oil spill** or the **Macondo blowout**) It is an oil spill in the Gulf of Mexico, which flowed for three months in 2010. It is the largest accidental marine oil spill in the history of the petroleum industry	4.900.000
Sedco 135F and the IXTOC-1 Well In 1979, the IXTOC-1 blowout flowed uncontrollably in the Bahia de Campeche, Mexico, until it was capped 9 months later.[17]	3.500.000
Ekofisk Bravo Platform Phillips Petroleum's Ekofisk B platform experienced an 8-day oil and gas blowout in 1977, during a production well workover.[18]	202.381

Funiwa No.5 Well Oil from the 1980 Funiwa 5 blowout polluted the Niger Delta for 2 weeks, followed by fire and the eventual bridging of the well.	200.000
Hasbah Platform Well 6 Drilled in 1980 by the Ron Tappmeyer jack-up, exploratory well No. 6 blew out in the Persian Gulf for 8 days and cost the lives of 19 men.	100.000
Union Oil Platform Alpha Well A-21 The 1969 Union Oil Platform A blowout lasted 11 days but continued leaking oil into the Santa Barbara Channel for months afterwards.	80.000

Table 2.2 Other Notable Blowouts

Adriatic IV A blowout and fire in 2004 destroyed both the Adriatic IV jack-up and Temsah gas platform off the Egyptian coast.	
Al Baz Santa Fe's Al Baz jack-up burned and sank after a blowout in 1989 with the loss of 5 lives.	5 fatalities
Arabdrill 19 A leg punch-through in 2002 led to a blowout and fire which sank both the Arabdrill 19 and a production platform in Saudi's Khafji Field.	3 fatalities
Blake IV and Greenhill Petroleum Corp. Well 250 In 1992, Greenhill Petroleum's workover oil well blew out in Timbalier Bay, igniting after 2 days and taking 11 days to cap.	Major release
C.P. Baker Drilling Barge Built in 1962 using an uncommon catamaran design, the C. P. Baker drilling barge burned and sank after a shallow gas	22 fatalities

blowout.	
Enchova Central Petrobras' Enchova Platform suffered twice with blowouts and fire in both 1984 and 1988, ending with the loss of the platform in 1988.	42 fatalities
Ensco 51 A blowout and fire in 2001 in the Gulf of Mexico caused the collapse of the Ensco 51's derrick, resulting in extensive platform damage.	
Ocean Odyssey This 1988 North Sea blowout occurred whilst drilling an HPHT well on the Ocean Odyssey, resulting in the death of the radio operator.	1 fatality
Petromar V Drillship The Petormar V drillship sank in 1981 after a shallow gas blowout in the South China Sea.	
Sea Quest Whilst working off Nigeria, the Sea Quest suffered extensive fire damage after a blowout in 1980 and was then deliberately sunk.	
West Vanguard Another shallow gas blowout, the West Vanguard suffered explosion and fire in 1985 off Norway, with the loss of 1 life.	1 fatality

The following **Table 2.3** gives the results of some of the analysis of the ten most expensive accidents in the history.

Table 2.3 Most Expensive Accidents

Incident	Cost ($)
Piper Alpha Occidental's Piper Alpha platform was destroyed by explosion and fire in 1988. 167 workers were killed in the blaze.	1.270.000.000
Petrobras P36 In 2001, an explosion destabilized the P36 production rig in the Campos Basin, Brazil, eventually causing it to sink.	515.000.000
Enchova Central Petrobras' Enchova PCE-1 Platform suffered twice with blowouts and fire in both 1984 and 1988, ending with the loss of the platform in 1988	461.000.000
Sleipner A A design error resulted in the structural failure in 1991 of the gravity base unit of the original Sleipner A platform.	365.000.000
Mississippi Canyon 311 (Bourbon) In 1987, the Mississippi Canyon 311 A Bourbon platform in the Gulf of Mexico was tilted to one side by an extensive underground blowout.	274.000.000
Mighty Servant 2 The Mighty Servant 2 struck a rock and sank off Indonesia whilst carrying platform modules in 1999.	220.000.000
Mumbai (Bombay) High North A support vessel collided with Mumbai High North in 2005, rupturing a riser and causing a major fire which destroyed the platform.	195.000.000
Steelhead Platform A blowout in 1987 led to six months of trouble for the Steelhead Platform, resulting in fire and extensive platform damage.	171.000.000
Name not known 1993: Explosion and fire destroyed a platform control room and damaged adjacent platforms on Lake Maracaibo, Venezuela, with eleven fatalities.	122.000.000
Petronius A In 1998, a crane load line broke while lifting the south topside module of the Petronius platform, dropping the module into the Gulf of Mexico.	116.000.000

The next **Table 2.4** Gas Blowout Statistical Summary is based in the SL Ross Northstar study, from 1955 until 1993. The different blowouts are grouped according to the operations taking place when the blowout occurred and are compared with the number of total wells (both exploratory and development wells) drilled in the area of interest.

Table 2.4 Gas Blowout Statistical Summary

	Worldwide 1955-1980	Norwegian North Sea 1976-1980	UK North Sea 1955-1980	USGOM & North Sea combined, 1980-1992	North Sea-Norway & UK 1980-1993
Well Drilled	36633	11116	1559	15294	4704
Exploration Wells	11737	4175	838	5781	2315
Development Wells	24896	6941	721	9513	2389
Exploration Well Blowout incl. Shallow Gas Blowout	96	32	unknown	43	16
Development Well Blowout incl. S.G Blowout	66	14	unknown	25	4
Production/Workover Blowouts	52	unknown	unknown	43	4
Total Blowout incl. S.G & Production Blowouts	214	46	6	111	24
Shallow Gas Blowouts	54	unknown	0	46	unknown
Blowout Incidence: total exp&dev. Blowout/total drilled	One in 230	One in 249	One in 260	One in 230	One in 290
Blowout Incidence: Exploration Drilling	One in 120	One in 130	-	One in 130	One in 170
Blowout Incidence: Development Drilling	One in 380	One in 500	-	One in 380	One in 440

Table 2.5 gives an oil blowout summary for a range of well types.

Table 2.5 Oil Blowout Data Summary

Event	Historical Frequency	Experience
Gas Blowout during development drilling	2.5×10^{-3} /wells drilled	US OCS, 1964-1995
Gas Blowout during exploration drilling	5.4×10^{-3}/wells drilled	US OCS, 1964-1995
Blowout during production and workovers involving some oil discharge > 1 bbl	6.5×10^{-5}/well-years	US OCS, 1964-1995
Development drilling blowout with oil spill > 10.000 bbl	7.8×10^{-5}/wells drilled	Worlwide, 1970-2000
Exploration drilling blowout with oil spill > 10.000 bbl	1.5×10^{-4}/wells drilled	Worlwide, 1970-2000
Development drilling blowout with oil spill > 15.000 bbl	3.9×10^{-5}/wells drilled	Worlwide, 1970-2000
Exploration drilling blowout with oil spill > 15.000 bbl	5.5×10^{-5}/wells drilled	Worlwide, 1970-2000
Production/workover blowout with oil spill > 10.000 bbl	2.5×10^{-5}/well-year	Worlwide, 1970-2000
Production/workover blowout with oil spill > 15.000 bbl	1.5×10^{-5}/well-year	Worlwide, 1970-2000
PLATFORM SPILLS (Incl. Blowouts)		
Oil spill > 10.000 bbl	1.3×10^{-5}/well-year	US OCS, 1964-1995
Oil spill > 1.000 bbl	3.6×10^{-5}/well-year	US OCS, 1964-1995
Oil spill > 50 bbl	8.3×10^{-4}/well-year	US OCS, 1964-1995
Oil spill > 1-5 bbl	1.7×10^{-2}/well-year	US OCS, 1964-1995

As last main point, **Table 2.6** shows the most frequent primary and secondary barriers that failed in all phases in Louisiana, Texas OCS, in the period 1960-1996. It can be seen that more or less primary and secondary barriers fail in similar percentages, being 1206 and 1239, respectively.

Table 2.6. Most frequent primary and secondary barriers that failed in all phases (Louisiana, Texas OCS, 1960-1996)

Primary Barrier	BO	Secondary Barrier	BO
Swabbing	268	Failed to close BOP	171
Drilling break / unexpected high pressure	95	Rams not seated	21
Too low mud weight	74	Unloaded too quickly	59
Formation breakdown/lost circulation	71	DC/Kelly/TJ/WL in BOP	36
Gas cut mud	68	BOP failed after closure	98
Trapped/expanding gas	60	BOP not in place	80
Wellhead failure	44	Diverted/chocked- no problem	60
Xmas tree failure	31	Fracture at casing shoe	48
While cement setting	34	Failed to stab valve/kelly/TIW	50
Poor cement	20	Casing leakage	46
Tubing leak	18	Annular valve/choke	32
Improper fill up	24	String safety valve failed	25
Tubing burst	12	Formation breakdown/lost circulation	29
Tubing plug failure	13	Diverter failed after closure	17
Uncertain reservoir depth/pressure	20	String failure	17
Water cut mud	9	Casing valve failed	16
Flange leak	9	Wellhead seal failed	14
Annular losses	8	Xmas tree failed	16
Csg. Collapse	8	String safety valve not installed	8
Unknown	320	SCSSV/storm choke failed	9
		Unknown	357

CHAPTER III

DOWN HOLE BLOWOUT PREVENTER

3.1 DESCRIPTION OF THE DOWN HOLE BLOWOUT PREVENTER

The Down Hole Blowout Preventer (DHBOP) is a combination of oil tools products in one equipment, which can be placed almost everywhere in the drill string and can be activated by a simple downlink in case of a kick situation. This system is an additional component of the wellbore control system and, in any case, will not replace the standard equipment, such as the Blowout Preventer (BOP).

The Down Hole Blowout Preventer (DHBOP), also known as the Down Hole Isolation Packer (DHIP), has been developed to separate a formation from the rest of the borehole in a kick situation, by inflating a packer element and closing a valve within the string. By activating the packer element, the gas will be stopped from entering the borehole above it.[19]

The placement of the DHBOP does not depend on the main BHA. Due to its autonomy, it is possible to place it anywhere in the drill string. Activation and deactivation of the packer is done via downlinks with low flow rates in the range between 400 and 750 L/min.

The downhole BOP is adapted to fit between two pieces of concentric drill pipe or at near the bottom of the concentric coiled tubing, such that the annulus and inner tube of the downhole BOP and the annulus and inner pipe or tube of the concentric drill string essentially line up. Thus, the annular passage and the inner passage of the concentric drill string are in fluid communication with the annular passage and inner passage of the downhole BOP, respectively.

3.2 MOTIVATIONS TO USE A DOWN HOLE BLOWOUT PREVENTER

A well control issue, caused by formation influx entering the borehole, can cause several problems; in fact:

- It may lead to a surface or underground blow-out.
- It may develop into a severe HSE matter.
- It may result in tools lost in hole of.
- It is always costly and time consuming.

The deployment of a new downhole tool, as part of the drill string, with the purpose to isolate the flowing formation directly, is a good practice to solve such a problem.

3.3 MAIN FUNCTIONS OF A DOWN HOLE BLOWOUT PREVENTER

The use of a DHBOP does not replace a conventional BOP. The surface BOP will always be closed first, as standard procedures dictate, in case of a kick situation.

The four main functions of the DHBOP are:

- Shut-in the drillstring.
- Shut-in the annulus by inflating the packer element.
- Allow circulation above it to remove the gas influx and increase the mud weight.
- Measure the shut-in drill pipe pressure.

There are two points that should be taken into consideration:

- The DHBOP has to be activated prior to closing the surface BOP.
- The DHBOP has to be fully deactivated in case of mechanical or electrical failure of the tool.

3.4 SAFETY BENEFITS IN THE USE OF A DOWN HOLE BLOWOUT PREVENTER

- The pressure above the DHBOP does not need to be increased while circulating the influx out. This means that drilled formations are protected from gas influx. A bypass, above the packer, makes possible to circulate out the already entered gas and weight up the mud above the packer element. Compared to the standard well control procedures, this feature saves time by preventing new gas entering the borehole.
- The well is sealed off close to the kicking formation (30-50 m above the bit).
- It completely isolates the well from the kicking formation, when activated.
- When a DHBOP is used during reverse circulation, drilling with concentric drill pipe provides a variety of advantages, as follows : (a) there are no hydrocarbons escaping on the rig floor while concentric drill pipe is tripped in or out of the wellbore; (b) when drilling with a liquid drilling medium, the annular passage and inner passage of the inner pipe of the concentric drill pipe can be closed each time a new joint of drill pipe is added to the drill string. This prevents the loss of drilling fluids into the formation containing hydrocarbons; (c) upon entering an underpressured formation, the annular passage and the inner passage of the inner pipe of the concentric drill pipe can be closed and the hydrostatic weight of the drilling fluid can be reduced below formation pressure by adding a gas, such as nitrogen. The overbalanced drilling fluid is not lost into the formation, while the gas is added to the drilling fluid; (d) if kill fluid were required to control an over-pressured situation in the wellbore, it could be pumped down both the annulus and the inner space of the inner pipe of the concentric drill pipe; and (e) the inner pipe of the concentric drill pipe

could also be used to bleed down the wellbore pressure in an over pressured situation. [20]

3.5 OPERATING MODES

- Stand by: The flow path is open trough the tool.
- Fill packer: The drill string is closed, the packer is filled and the bypass open.
- SIDPP measurement: During flow off. open String Valve for a certain time and close it subsequently (programmable).
    - This mode provides the possibility to determine the bottom hole pressure by measuring the shut in drill pipe pressure at surface.
- Deactivate DHBOP: Deflate Packer completely. Drill string is open.
    - Go back to the Standby mode, but the Packer Outlet Valve remains open.

Notice that all modes can be individually selected from surface.

3.6 OPERATIONAL PROCEDURE

In case of a kick during drilling a well, the procedure recommended by eni e&p is the following:

- Stop pumps, close surface BOP.
- Open choke lines.
- Downlink at low flow (~500 L/m).
- Shut-in annulus (downhole).
- Read shut-in drill pipe pressure.
- Shut-in pipe, open bypass.
- Circulate out influx above DHBOP.
- Open surface BOP (optional).
- Circulate “kill mud”.
- Close surface BOP.

- Deactivate DHBOP.
- Circulate-out kick below DHBOP.
- Open surface BOP.

3.7 DOWNHOLE BLOWOUT PREVENTER- SURFACE-DOWNHOLE COMMUNICATION

- Monitor alternator voltage at low flow rate.

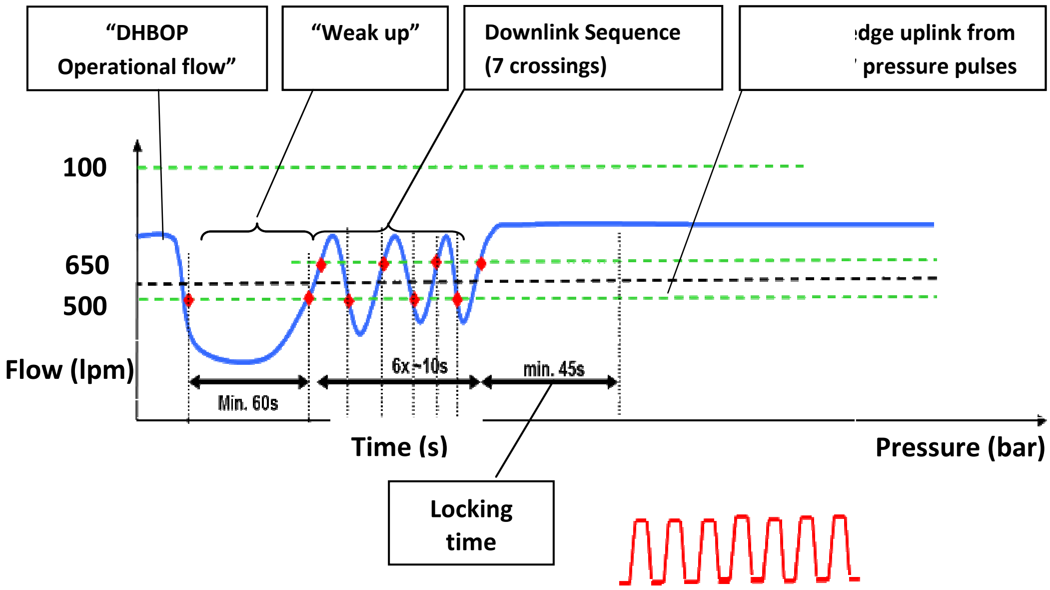

Figure 3.1 Surface-Downhole Communication

In Figure 3.1 the blue line represents the flow rate. Downhole there is a sensor in the string and each time the flow rate exceeds a threshold value, that means that it is greater than the upper threshold or it is smaller than the lower threshold values, the DHOBOP receives a series of commands, like 0 1 0 0 1.

According to the sequence of 0 and 1 that we send, the tool performs a different function.

- **Activation**

The activation of the packer, in case of a kick, needs to be done with a minimum of flow; the first idea is to send Down Link (DL)#3 and continue flowing until the locking time is elapsed and the packer inflates. However, it is common wellbore control practice to immediately shut in the pumps and try to prevent the link, continuing to enter into the borehole. In this way circulating would be counter-productive. Therefore, the sequence of activation is changed and now is possible to send around 650 liter for 5 seconds. This means a reduction in the unwanted effect of circulating the kick too fast and too far up the annulus.

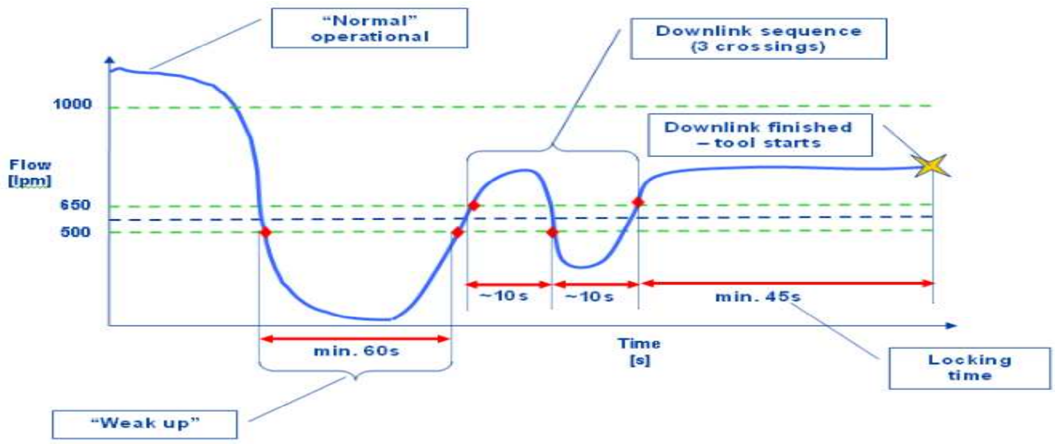

Figure 3.2 "Old" Procedure of DHBOP Activation

- **Deactivation**

To deactivate the tool, DL#7 has to be sent twice. After the first DL#7, a confirmation uplink of seven pulses is sent from the tool to surface. DL#7 has to be sent again to confirm the first deactivation downlink. When the second DL#7 is confirmed by an uplink, the tool starts to deactivate. The second DL#7 is implemented to minimize the chance for a deactivation by accident.

3.8 FIRST FIELD TEST

The test was carried out in Oklahoma, January, 2010.

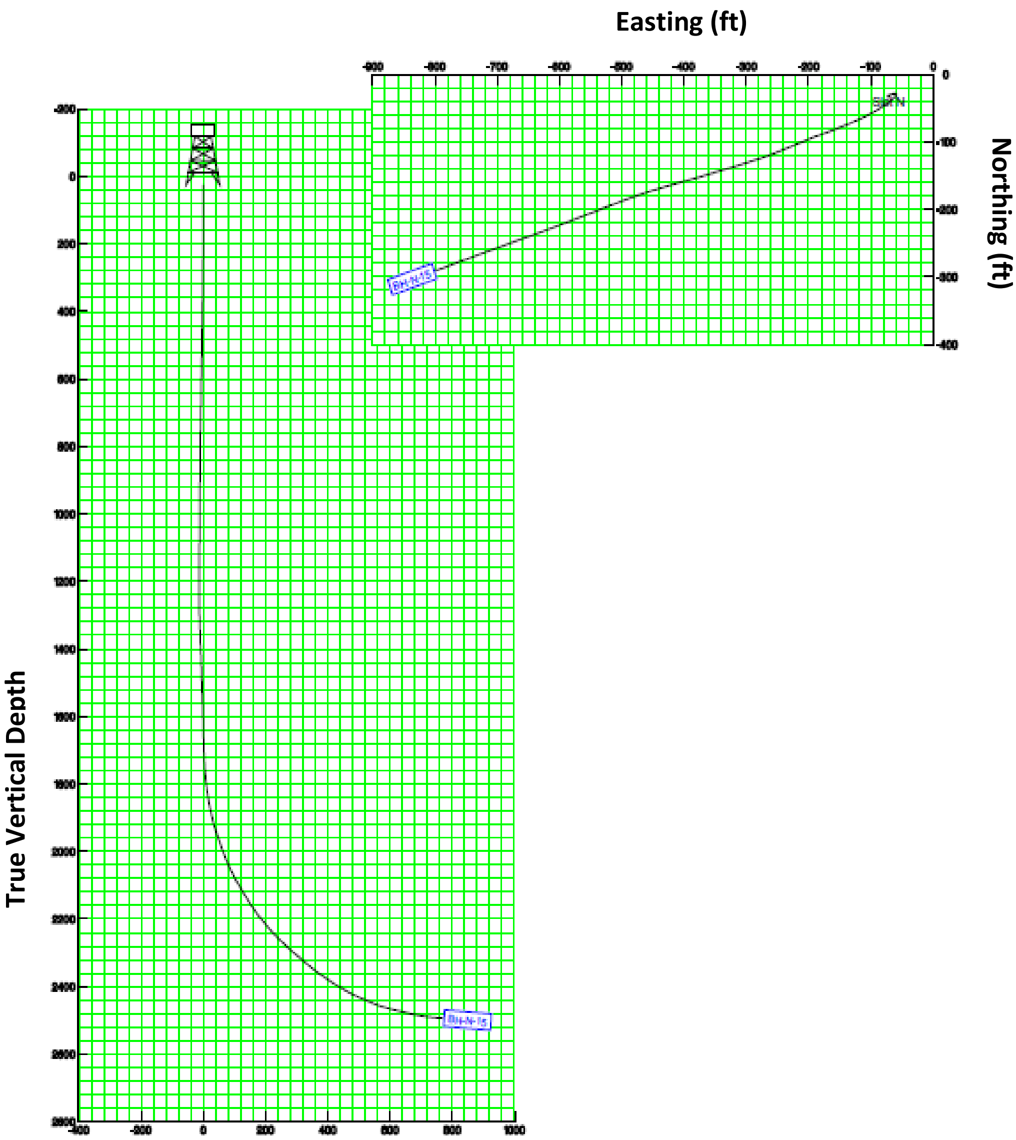

Figure 3.3 BH-N-15 Well Plan

3.8.1 System Description

The downhole isolation packer has been developed to separate a formation from the rest of the borehole in a kick situation, by inflating a packer element and closing a valve within the string.

By activating the packer element, the gas will be stopped from entering the borehole above the packer element. Already drilled formations are then protected from gas influx.

A bypass above the packer makes it possible to circulate out the already entered gas and weight up the mud above the packer element. Compared to the standard well control procedures, this procedure saves time by preventing new gas entering the borehole.

3.8.2 Test Objectives (from FT-Plan)

Following several laboratories and flow loop analyses, this test was planned to confirm the functionality of the hardware, the electronics and the software in a real well. Unfortunately, the system could not be tested for its purpose, that is isolate a "kicking" formation from the rest of the borehole, but the inflating of the packer element and the operation procedures were checked as well, prior to the next field test, where hazards of kicks will be real.

By using Wired-Pipe Telemetry System (WPTS), all functions of the DHBOP could be proven due to a real-time view on the system performance and internal processes.

In general, it was planned to activate and deactivate the DHBOP 3-5 times at slightly different depths.

Detailed Test Objectives for DHBOP at BETA

- Activation of the inflatable packer
    - Activate the inflatable packer element via simple downlink.

- Monitor the pressure characteristics and backup this information for further deployments.
- Check pulses (uplinks), that indicate the DHBOP is functioning properly.

- Open string valve to measure "shut in drill pipe pressure" (SIDPP)
  - Downlink to "shut in drill pipe pressure (SIDPP)" and check if the string valve opens up and enables the measurement of the downhole pressure from surface.
  - Check downlink confirmation that will be sent up via a pre defined pulsing sequence (uplinks) after the tool has received the simple downlink.
  - Stop circulation.
  - Check if the tool closes the string valve after the pre-defined opening time has elapsed.

- Deactivation of the inflatable packer
  - Deactivate the inflatable packer element via a simple downlink.
  - Check if deactivating the DHBOP by mistake is possible by sending different downlinks.
  - Check downlink confirmation that will be sent up via a pre-defined pulsing sequence, after the tool has received the simple downlink.
  - Check if the tool will open the string valve, deflate the packer element and close the by-pass valve after receiving DL#7, twice (deactivating DHBOP).

3.8.3 Test Results

- **Mechanical Integrity**

The mechanically exposure of the BHA, including packer, bypass and control sub in regards of bending and wear, was very low due to a straight vertical well. The well was already drilled and, therefore, the system was not exposed to lateral and axial vibrations or stick slip. The string was also not rotated for most of the time.

Further, the system will probably be stressed more, but for this FT it has to be stated that no wear or washouts were observed after disassembling.

The inflated packer element was exposed to push and pull with 35 kip. The packer kept the position very well. After POOH, the packer element was deformed as expected, but still functioning to specifications. The highest measured diameter of the packer element after inflating was 8.275" compared to 7.448" prior to be run in hole (RIH). It is, therefore, confirmed that the packer element can be used more than once and that an already used packer element will not have major influence on circulating, due to its stable shape showing just a slightly increased diameter after inflation.

Figure 3.4. Packer After Push & Pull

After the first run, the packer element came out with damage on the "low side". This damage probably happened while running in hole, after passing the casing or the casing shoe. The functionality of the packer element was not affected with this kind of damage, but a slight design change might protect the packer from damages while tripping in or out of the hole.

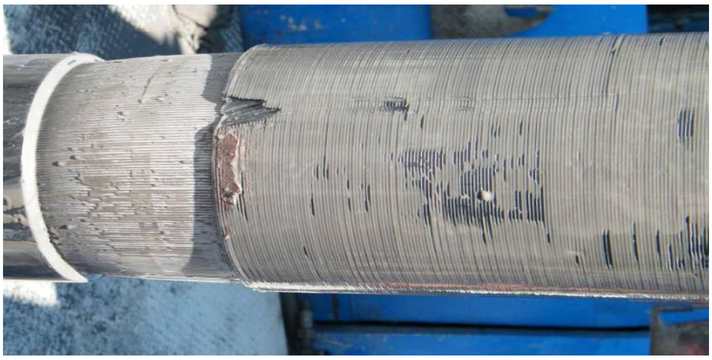

Figure 3.5. Damage on Rubber Sleeve

- **Sealing of Packer Element**

To test the packer element on it is sealing behaviour (maximum sealing pressure), the packer was inflated inside the casing and the BOP was closed with the highest possible pressure. The tool was set in SIDPP mode and the annulus was pressurized through the choke line.

- **Activation**

As mentioned, the activation of the packer in case of a kick needs to be done with a minimum of flow. It was verified the possibility to activate the DHBOP by starting up the pumps just twice to 650 litres for 5 seconds. This is a significant improvement reducing the unwanted effect of circulating the kick too fast and too far up the annulus.

- **Filling and Refilling Cycle**

The packer pressure is a pre-defined value, which can be entered into the tool prior of running in hole. The system will maintain this pressure by initiating a re-filling cycle, when the pressure drops below a certain value (Hysteresis Function).

In this test campaign, it was noticed at the FT that the packer element frequently lost pressure and needed to be refilled. Obviously, the formation hardness has a major impact,. The pressure loss, depending on the formation, is more or less severe. Overcoming this pressure loss requires a certain flow through the upper section from time to time to re-pressurize the packer. This has no influence on the isolated area below the packer.

The impact of the formation on pressure lost could be clearly seen at the FT, when activating the DHBOP in different formation types and inside the casing. Both tools showed the same behaviour in the formations, so that malfunction of the tool could be excluded.

In relatively soft formations like sandstones, the packer probably expands into the formation. This expansion results in a pressure decrease during the refilling cycle. It can be clearly seen that the refilling cycles decrease over time, which leads to the assumption that the formation is not yielding so strong after time and a balance between formation resistance and packer becomes established.

- **Uplinks**

Uplinks are generated by closing the bypass valve, which will create a pressure increase that can easily be measured up hole. They are used after a Downlink to confirm the correct response (DL#3 >> Uplink#3). They are also sent every 10 minutes to confirm an activated tool.

- **SIDPP Measurement**

The shut in drill pipe measurement mode was successfully activated by sending DL#5. The tool also responded with the expected uplink. After the pumps were turned off, the tool closed the by-pass valve and opened the string valve for 12 minutes, which is an adjustable value. After the time had elapsed, the tool closed the string valve and opened the by-pass valve again. No problems with this mode were seen, apart from the already known issue that downlinks might interfere with uplinks or refilling cycles.

- **Deactivation**

As mentioned, the deactivation of the tool was make using DL#7, which was sent twice. After the first DL#7 a confirmation uplink of seven pulses is sent from the tool to surface. DL#7 has to be sent again to confirm the first deactivation downlink. When the second DL#7 is confirmed by an uplink, the tool starts to deactivate. The second DL#7 was implemented to minimize the chance for a deactivation by accident.

3.9 SECOND FIELD TEST

A second test was carried out in Val d'Agri, Italy, January 2011. The test was divided in two runs: the first one when drilling the first cement plug at the tie back, and the second one when drilling the second plug at the casing shoe of the 7" production liner.

The well path and casing profile are shown in **Figure 3.6**.

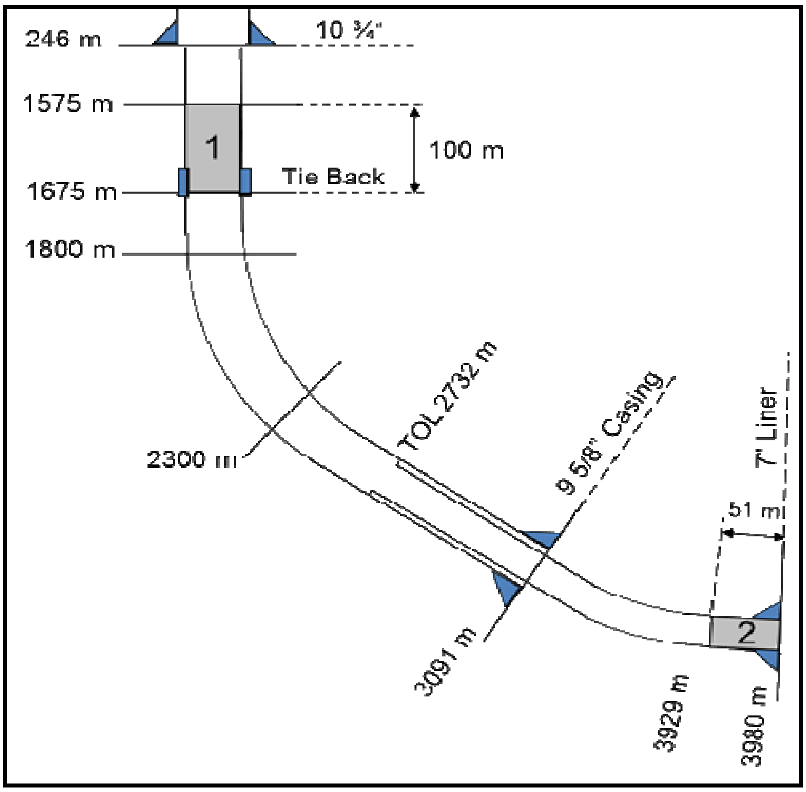

Figure 3.6 Val d'Agri Well ME 10orB Plan and Path

3.9.1 DHBOP- First Test Procedure

Position of the 1st Tool: in the section where was located the cement plug at the Tie Back.

- The DHBOP was inside the vertical section of the 9 5/8” (8.535” ID) casing during the entire drilling operation.
- DHBOP was positioned in between drillpipe 1000 m above the bit.
- DHBOP testing depth is 550 m (bit depth was 1550 m).
- 100 m cement to drill.
- One test prior to drilling, one after finishing the drilling.

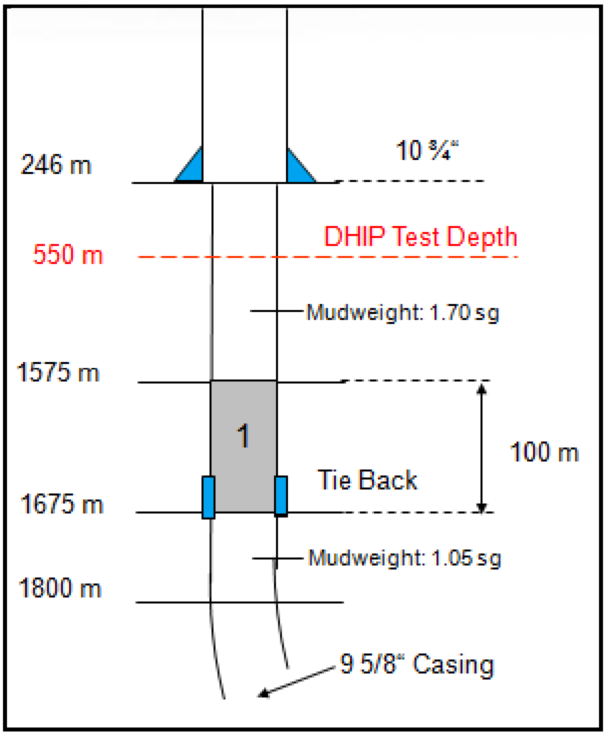

Figure 3.7 Position of the DHBOP

3.9.2 DHBOP- Procedure of First Run

The test was executed on Thursday, 06 January 2011 at 8:00; the procedure was the following:

- Pick-up tool 1.
- Run in hole (~1 stand).
- Functionality test (30 min).
- Pick-up tool 2.
- Run in hole (~1 stand).
- Functionality test (30 min).

- Trip in to 1500 m.
- Circulate Bottoms Up.
- Pressure Test (60 min).
- Standby Test (90 min).
- Drill Cement Plug.
- After Drilling Cement Plug, displace mud and run bit to top of liner (2732 m).
- Pull out to 1550 m.
- Pressure Test (60 min).
- Standby Test (90 min).
- Rack back Tool 2.
- Pull out of hole to pick up 6” bit and new BHA

The test finished on Saturday, 08 January 2011 at 23:00.

3.9.3 DHBOP- Second Test Procedure

Position of the second tool; in the section where was located the cement at the casing shoe.

- The DHBOP was inside the vertical section of the 9 5/8” (8.535” ID) casing during the entire drilling operation.
- DHBOP was positioned in between drill pipe 2550 m above the bit.
- DHBOP testing depth is 550 m (bit depth is 3090 m).
- Landing collar + Float sub + cement = 51 m (stop drilling at 3975 m).
- One test prior to drilling, one after finishing the drilling.

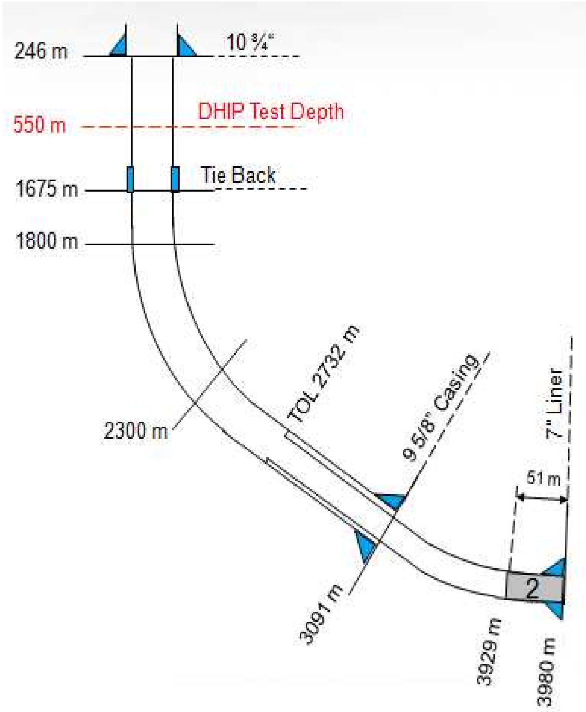

Figure 3.8 Position of the DHBOP

3.9.4 DHBOP- Procedure of the Second Run

The test was executed on Sunday, 09 January 2011 at 0:15; the procedure was the following:

- Pick-up Tool 2.
- Run in hole (~1 stand).
- Perform Decoding & Downlink Test (BHA) (20 min).
- Functionality Test (30 min).
- Trip in to 3090 m.
- Pressure Test (60 min).
- Standby Test (90 min).
- Drill Cement.
- After drilling cement, pull out to 3100 m.
- Pressure Test (60 min); this step covered the part of activation and deactivation, as different of the first test; the standby test was not performed.
- Pull out to 2650 m.

- Lay down Tool 2.

The test finished on Monday, 10 January 2011 at 19:00.

3.9.5 DHBOP- Test Summary

Table 3.1 Test Summary

	1st Run	2nd Run	Sum
Duration of the run	43 hours	44 hours	87.0 hours
Drilling time	2 hours	11 hours	13.0 hours
Drilled distance	100 meter	46 meter	146 meter
Rotation time	2 hours	14 hours	16.0 hours
Circulation time	18 hours	19 hours	37.0 hours
Testing time	8 hours	7 hours	15.0 hours
Activations	5	4	9

3.9.6 DHBOP- Testing Description

- Perform decoding & downlink test (BHA) (20 min).
  - Establish expected drilling flow.
  - Check MWD decoding.
  - Check Downlink MWD funcionality.

- Functionality Test (20 min)
  - Activate Packer Element.
  - Deactivate Packer Element.

- Pressure Test (40 min)
  - Activate DHIP
  - Activate SIDPP Mode of DHIP

- Note down the exact time when Uplink#5 is recognized (no continuous circulation is allowed for 30 minutes).
- Begin to pump carefully a few strokes through stand pipe.
- Look at standpipe pressure and also at returns to the shaker.
- Raise standpipe pressure step by step until max pressure of 120 bar is reached.
- If standpipe pressure drops, pump again a few strokes to confirm maximum pressure.
- Release pressure.
- After 30 minutes have expired since Uplink#5 was recognized, check whether string valve is closed and bypass valve is open, then deactivate DHIP by DLK#7.

- Standby Test (70 min)
  - Activate Packer Element.
  - Wait ~ 1h without flow.
    Observe packer inside pressure
  - Deactivate Packer Element.

3.9.7 DHBOP- Test Results

After 9 activations of the packer and 37 hours of circulation, a slight deformation (7.5”) was observed.

Figure 3.9 Deformation in the Packer

- **Pre-drill Pressure Test 2nd Run, 2nd Tool**

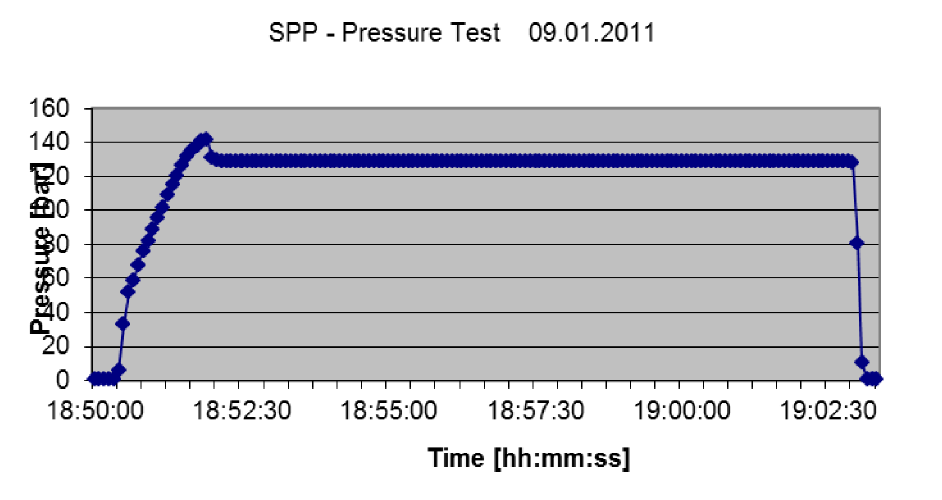

Figure 3.10 Behaviour of the Packer during the Test 2nd Run, 2nd Tool

The packer showed very good sealing behaviour for most than 10 minutes.

• **Post-drill Standby Test 1st Run, 2nd Tool**

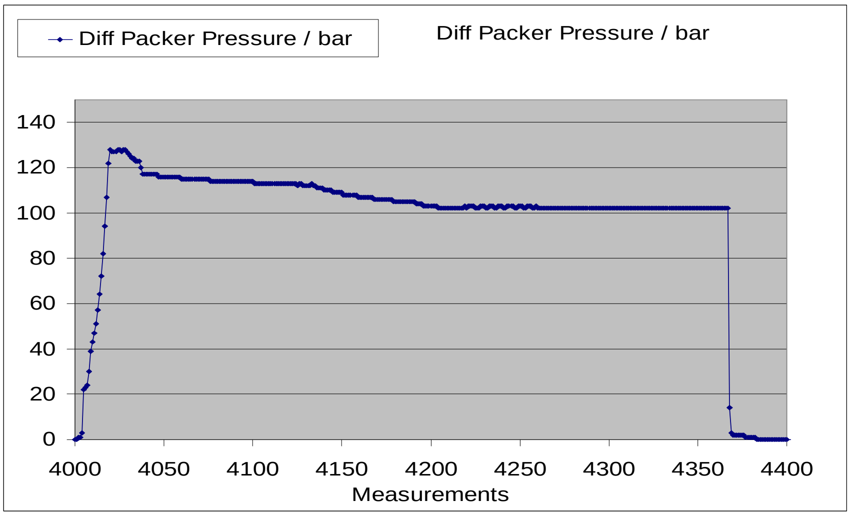

Figure 3.11 Behaviour of the Packer During Post-drill Standby

After setting of the packer, the inflation pressure was stable for 1 hour.

3.9.8 DHBOP- Second Tool Issue

The following situation was discovered during the last post-drill test and represents communication difficulties:

- DLK#4 recognized after 3rd attempt; the packer was definitely inflated.
- DLK#5 not recognized after 2 attempts.
- DL#7 recognized after 3 attempts.
- Decision to trip out and lay down DHBOP.

This situation has to be investigated in order to know what happened during the test.

3.10 RISK ASSESSMENT

According to regulations relating to use and implementation of risk analysis in the petroleum activities issued by eni e&p, it is mandatory for any operator to establish acceptance criteria for environmental risk in the activities and carry out environmental risk analysis.

After all recent problems with the occurrence of difference blowouts, the risk of a blowout is one of the major contributors to the total risk picture on oil and gas installations. The consequences can be significant with respect to loss of lives, material assets and damages to the environment.

In this thesis, the main focus is describing how blowouts occur and how to prevent them to happen. The risk of blowouts still remains a threat to this industry. In this analysis, the variation in the frequency of a blowout and the correlated dependency on several risk elements identified in the well, on the platform and the procedures and in the organization will be reviewed.

3.10.1 Risk Assessment Methodologies

Choice of Approach

Definitions

The terminology for risk studies is:

- Risk analysis - the estimation of risk from the basic activity "as it is".
- Risk assessment - a review as to acceptability of risk, based on comparison with risk standards or criteria and the trial of various risk reduction measures.
- Risk management - the process of selecting appropriate risk reduction measures and implementing them in the on-going management of the activity.

3.10.2 Selection of Approach

Risk assessment can be applied in different approaches as Qualitative, Semi-Qualitative and Quantitative. In this thesis, it was applied a quantitative approach in order to provide most details for understanding and also showing the best basis if significant expenditure is involved. However, there is no single correct approach for a specific activity.

It is not possible to create a simple flow chart, with YES-NO branches, to define a suitable approach to risk assessment. But there are broad factors, that can be used to aid the selection of a suitable risk assessment approach. These key factors include:

- Lifecycle stage.
- Major hazard potential.
- Risk decision context novelty/ uncertainty/ stakeholder concern.[21]

Once these drivers are defined, it is then feasible to select amongst the wide range of methods for risk assessment. These are the following:

- Hazard Identification Tools
  - Judgement
  - FMEA – Failure Modes and Effects Analysis.
  - SWIFT – Structured What-If Checklist Technique.
  - HAZOP – Hazard and Operability Study
- Risk Assessment Approaches
  - Rules based approaches: regulations, approved codes of practice, Class Rules.
  - Engineering judgement.
  - Qualitative risk assessment.
  - Semi-quantitative risk assessment.
  - Quantitative risk assessment.
  - Value-based approaches.
- Risk Assessment Techniques
  - Qualitative (risk matrix).

- Semi-Qualitative: use of structured tools (fault trees, events trees) – Bow-Tie approach.
- Quantitative risk assessment (coarse and detailed levels).
- Stakeholder consultations.

- Hierarchy of Options Approaches for risk reduction
  - Eliminate the hazard.
  - Prevent the occurrence.
  - Mitigate the consequences.
  - Escape, Evacuation, Rescue and Recover.
- Decision making

  Level within organization and tools (design team, senior management judgment, cost benefit analysis).

3.10.3 Quantitative Methods

Quantitative risk analysis (QRA) is one of the most sophisticated techniques of risk assessment, but it should be used where it gives a clear benefit and it is provided clear database. In order to predict the blowout risk, this thesis used a traditional approach applied as a starting point for the prediction of the blowout frequency. Then, the second step included an assess standard of equipment and crew, comprehending an evaluation of topside equipment, procedures, safety cultures, management system and organization. This step of adjustment was performed through a comparison of the specific site aspects against a standard operation, relevant to the generic blowout frequency. In this case, reliability data base of the kick frequency will be shown and then a comparison between these data with the use of a Down Hole Blowout Preventer. To make this comparison, the QRA used was Fault Tree Analysis.

3.10.4 Fault Tree Analysis

Fault Tree Analysis (FTA) is a logical representation of the many events and component failures that may combine to cause one critical event (e.g. a system failure). It uses ‘logic gates’ (mainly AND or OR gates) to show how ‘basic events’ may combine to cause the critical ‘top event’. The top event would normally be a major hazard, such as “loss of position keeping”.[21] In this case the possible consequence was estimated as a risk presentation and shows how various risk contributors combine to produce the overall risk, named “Blowout”.

The construction started with the top event and works down towards the basic events. For each event, it considers what conditions are necessary to produce the event and represents these as events at the next level down. If any one of several events may cause the higher event, they are joined with an OR gate. If two or more events must occur in combination, they are joined with an AND gate.

If quantification of the fault tree was the objective, downward development stopped once all branches have been reduced to events that can be quantified. If the tree is simple and each event only occurs once, the frequency of the top event can be determined manually using the appropriate formulae.

An illustrative example of a fault tree is shown in **Figure 3.12**; it is a representation of the quantity probability that a blowout occurs while using the conventional Blow Out Preventer. In this fault tree, the main causes of a blowout were taken into account; such as: kick and failure of the safety systems and this one was divided in BOP failure or lack of intervention to close the rams, failure wellhead/BOP connection and lack of warming.

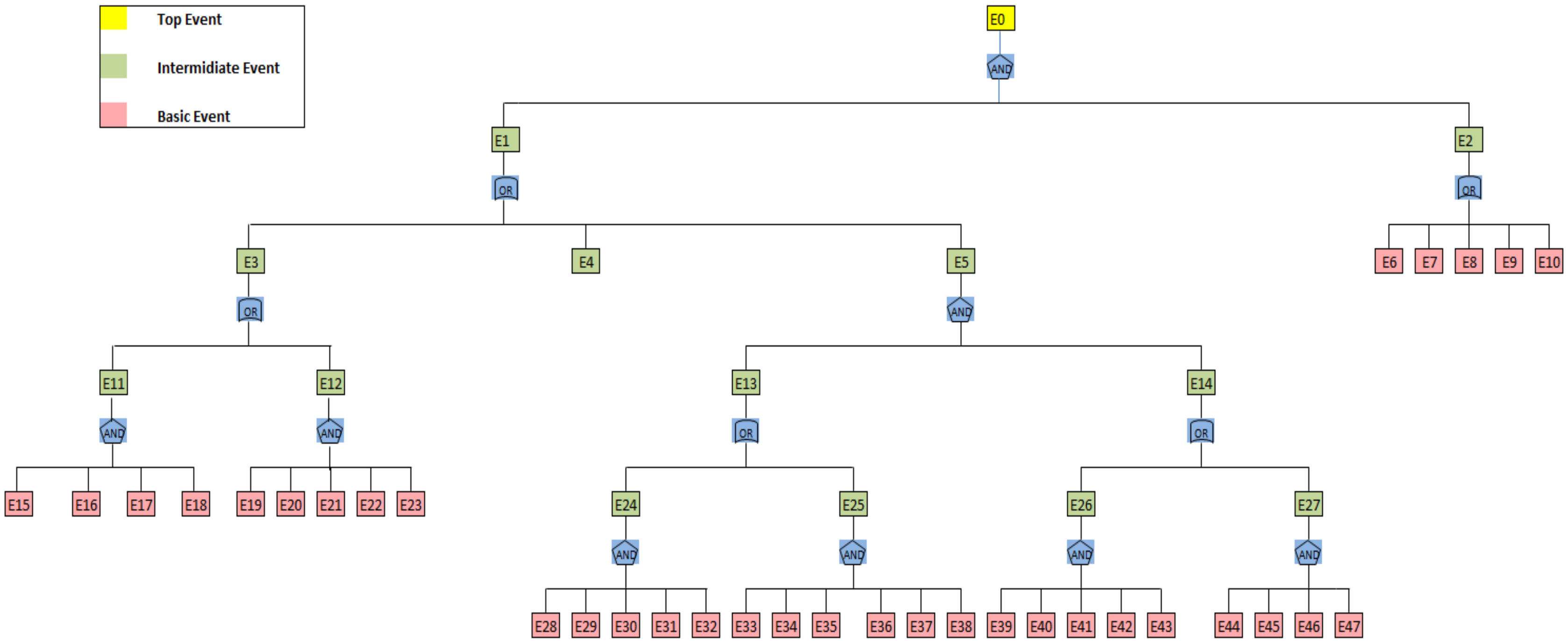

Figure 3.12 Fault Tree Representing a Blowout while using a Blowout Preventer

Figure3.13 shows the fault tree representation of the quantity probability that a blowout occurs when using conventional BOPs combined with the DHBOP; the possible event that contributed to the failure of the DHBOP was also considered, such as: activation delay, lack of sealing, command system failure and mechanical failure. It has been noticed that the risk of a kick is the major contributor to the total blowout risk. Further, the occurrence of a failure in the DHBOP and BOP in combination is almost neglected (4,1E-21).

Table 3.2 and **Table 3.3** show a list of possible combinations of events that can result in the occurrence of the top event, while using a BOP and while using a BOP in combination of a DHBOP, respectively. We can appreciate that the probability of occurrence decreases to 1,6E8 times, which represents a major contribution to the total risk estimation on oil and gas installations.

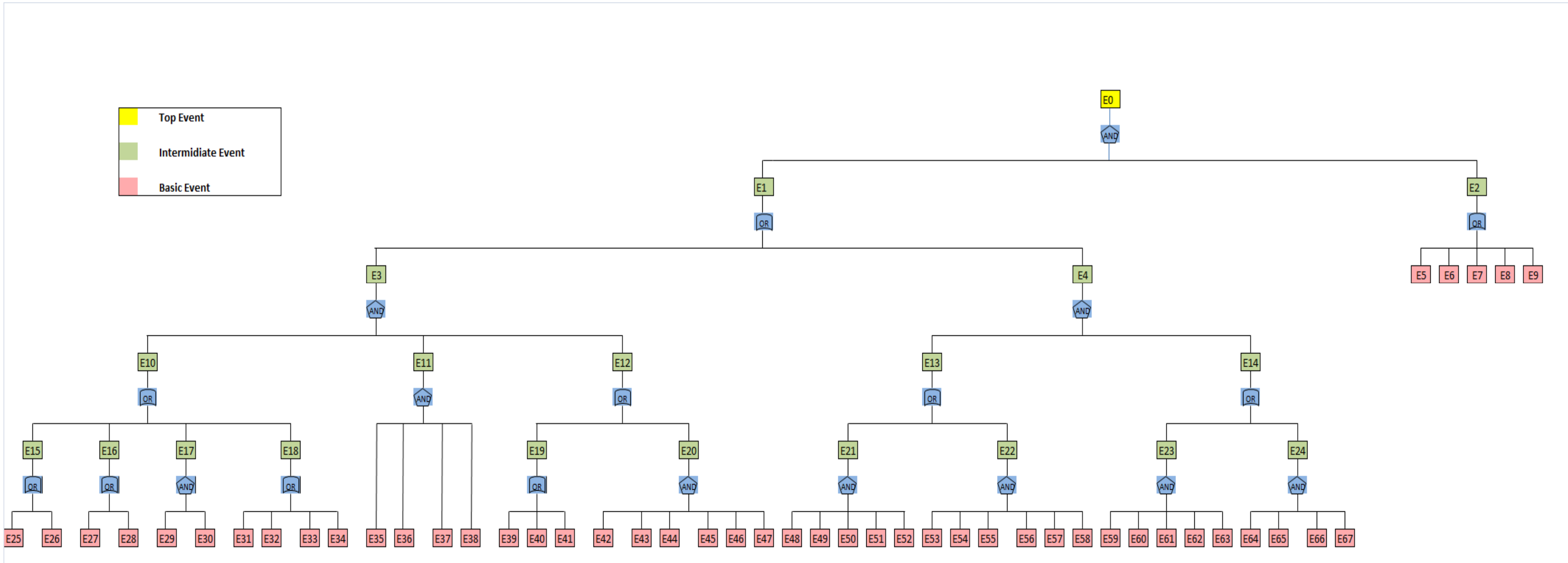

Figure 3.13 Fault Tree Representing a Blowout while using a Blowout Preventer in Combination with a Down Hole Blowout Preventer

Table 3.2 Possible Combinations of Events that Can Result in a Blowout Using a Down Hole Blowout Preventer

Event	Description	Probability
E0	Blowout	4,50E-07
E1	Failure of the safety systems	8,60E-06
E2	Kick	5,2E-02
E3	BOP failure or lack of intervention to close the rams	7,50E-06
E4	Failure wellhead / BOP connection	1,20E-06
E5	Lack of warning	6,00E-14
E6	Loss of circulation	5,00E-02
E7	Contaminated mud	1,00E-03
E8	Wrong mud density	7,50E-06
E9	Lack of fill-up	7,50E-06
E10	Swabbing	5,0E-0,4
E11	Lack of BOP closure	7,50E-06
E12	BOP failure	8,70E-14
E13	Lack of warning (mudlogging-pipe ramp)	2,20E-07
E14	Lack of warming (pipe ramp)	2,80E-07
E15	Driller wrong decision	4,70E-02
E16	Driller assistant wrong decision	4,70E-02
E17	Drilling responsible wrong decision	4,70E-02
E18	Tool pusher wrong decision	4,70E-02
E19	Failure pipe rams (1)	1,00E-03
E20	Failure pipe rams (2)	1,00E-03
E21	Failure pipe rams (3)	1,00E-03
E22	Failure shear rams	1,50E-01
E23	Failure annular preventer	5,00E-04
E24	Failure measurement systems	2,20E-07
E25	Lack of warning	8,10E-12
E26	Failure measurement systems	2,20E-07
E27	Lack of were take into account	6,50E-08
E28	Failure drilling mud pit gain-loss indicator	4,60E-02
E29	Failure speed indicator	4,60E-02
E30	Failure gas detection indicator	4,60E-02
E31	Failure drilling mud density indicator	4,60E-02
E32	Failure drilling mud flow indicator	4,60E-02
E33	Mudlogger 1 lack of warning	1,40E-02
E34	Mudlogger 2 lack of warning	1,40E-02
E35	Mudlogger 3 lack of warning	1,40E-02
E36	Company man lack of warning	1,40E-02

Table 3.2 (Continuation): Possible Combinations of Events that Can Result in a Blowout Using a Down Hole Blowout Preventer

E37	Mud engineer lack of warning	1,40E-02
E38	Geologic engineer lack of warning	1,40E-02
E39	Failure drilling mud pit gain-loss indicator	4,60E-02
E40	Failure speed indicator	4,60E-02
E41	Failure gas detection indicator	4,60E-02
E42	Failure drilling mud density indicator	4,60E-02
E43	Failure drilling mud flow indicator	4,60E-02
E44	Driller lack of warning	1,40E-02
E45	Assistant driller lack of warning	2,30E-02
E46	Drilling rig responsible lack of warning	1,40E-02
E47	Tool pusher lack of warning	1,40E-02

Table 3.3 Possible Combinations of Events that Can Result in a Blowout Using a Down Hole BOP in Combination with a Down Hole Blowout Preventer

Event	Description	Probability
E0	Blowout	2,9E-15
E1	Failure of the safety systems	5,5E-14
E2	Kick	5,2E-02
E3	DHBOP and BOP failure	4,1E-21
E4	Lack of warning	6E-14
E5	Loss of circulation	5,0E-02
E6	Contaminated mud	1,30E-03
E7	Wrong mud density	7,50E-06
E8	Lack of fill-up	7,5E-06
E9	Swabbing	5,0E-04
E10	Fail DHBOP	8,0E-02
E11	Lack of command	4,9E-06
E12	Fail BOP	1,1E-14
E13	Lack of warning (mudlogging)	2,1E-07
E14	Lack of warning (pipe ramp)	2,7E-07
E15	Activation Delay	7,8E-02
E16	Lack of Sealing	1,1E-03
E17	Command system failure	4,0E-10
E18	Mechanical failure	1,0E-07
E19	Command system failure	1,1E-14

Table 3.3 (Continuation) Possible Combinations of Events that Can Result in a Blowout Using a Down Hole BOP in Combination with a Down Hole Blowout Preventer

E20	Mechanical failure	9,0E-20
E21	Failure measurement systems	2,06E-07
E22	Lack of warning	7,5E-12
E23	Failure measurement systems	2,1E-07
E24	Lack of warning	6,3E-08
E25	Human error in down link procedure	4,0E-02
E26	Decision delay	4,0E-02
E27	Packer damage	1,0E-04
E28	Weak formation	1,0E-03
E29	Failure of down link system	1,0E-04
E30	Failure of wired-line pipes systems	4,0E-06
E31	Failure of packer	2,5E-08
E32	Failure of electronic system	2,5E-08
E33	Failure of valve	2,5E-08
E34	Failure of pressure sensor	2,5E-08
E35	Driller wrong decision	4,70E-02
E36	Driller assistant wrong decision	4,70E-02
E37	Drilling rig responsible wrong decision	4,70E-02
E38	Tool pusher wrong decision	4,70E-02
E39	Failure of accumulator	3,5E-15
E40	Failure of signal system	3,5E-15
E41	Failure of high pressure fluid system	3,5E-15
E42	Failure pipe rams (1)	1,0E-03
E43	Failure pipe rams (2)	1,0E-03
E44	Failure pipe rams (3)	1,0E-03
E45	Failure shear rams	1,50E-01
E46	Failure annular preventer	5,0E-04
E47	Failure wellhead connection	1,2E-06
E48	Failure drilling mud pit gain-loss indicator	4,6E-02
E49	Failure speed indicator	4,6E-02
E50	Failure gas detection indicator	4,6E-02
E51	Failure drilling mud density indicator	4,6E-02
E52	Failure drilling mud flow indicator	4,6E-02
E53	Mudlogger 1 lack of warning	1,4E-02
E54	Mudlogger 2 lack of warning	1,4E-02

Table 3.3 (Continuation) Possible Combinations of Events that Can Result in a Blowout Using a Down Hole BOP in Combination with a Down Hole Blowout Preventer

E55	Mudlogger 3 lack of warning	1,4E-02
E56	Company man lack of warning	1,4E-02
E57	Mud engineer lack of warning	1,4E-02
E58	Geologic engineer lack of warning	1,4E-02
E59	Failure drilling mud pit gain-loss indicator	4,6E-02
E60	Failure speed indicator	4,6E-02
E61	Failure gas detection indicator	4,6E-02
E62	Failure drilling mud density indicator	4,6E-02
E63	Failure drilling mud flow indicator	4,6E-02
E64	Driller lack of warning	1,4E-02
E65	Assistant driller lack of warning	2,3E-02
E66	Drilling rig responsible lack of warning	1,4E-02
E67	Tool pusher lack of warning	1,4E-02

CONCLUSIONS

- The Driller's Method is the first and most popular displacement procedure.

- A kick can occur due to many reasons; more than 50% of blowout cases are a combination of abnormal pressure, insufficient mud weight and swabbing.

- Specific location and equipment planned to be used can drastically change the outcome of the overall risk analysis, since some areas are more susceptible than others to different causes.

- The pressure above the DBOP does not need to be increased while circulating the influx out. This means that drilled formations are protected from gas influx. Compared to the standard well control procedures this one saves time by preventing new gas entering the borehole.

- Using a DHBOP the well is sealed off close to the kicking formation (30-50 m above the bit).

- This device allowed to isolate the well from the kicking formation when activated.

- The worst blowouts until now are: The Deepwater Horizon oil spill (also referred to as the BP oil spill**)** with 4.900.000 barrels released, another notable blowout was Enchova Central with twice leaving 42 fatalities.

- The most Expensive Accidents was Piper Alpha with a cost related of 1.270.000.000 $.

- Most frequent primary barriers failures result from swabbing, while the secondary barriers fail resulted while closing the BOPs.

- The field DHBOP tests performed in Oklahoma, in January, 2010. Gave a good overview on the overall system and its performance in the case of a kick situation.

- The main concern during the First Field Test was the fact that the packer element lost pressure. This was even the case when the packer was inflate inside casing. The objective of the test was not fully achieved. Despite that during the second test the design was change and was observed just a slight deformation and also the inflation pressure was stable for 1 hour.

- During the First Field Test was noticed an unpredictable deactivation of the Packer. During the second test not unpredictable deactivation was noticed in a sum of 87 hours run, also during the activation of the packer the required volume decreases significantly. This represent a solution which is practicable and safe.

- After a risk analysis of the variation in the frequency of a blowout. It was applied a quantitative approach using a Fault Tree analysis in which was noticeable that the risk of a kick is the mayor contribution to the total blowout risk. Further, the occurrence of a failure in the DHBOP in combination with a BOP is almost neglected.

- Using a DHBOP in combination with a BOP we can appreciate that the probability of occurrence decreases in 1,6E8 times that represents a major contribution to the total risk estimation on oil and gas installations. The tool is technically feasible.

SUGGESTED FUTURE WORK

Only primary failures from each component were taken into consideration in this work, because the main purpose was to have a preliminary risk analysis, in order to know if the implementation of the tool is technically feasible. Future work should include second and tertiary failures as chain events and their consequences.

A general scenario was used in the risk assessment; future work should take into consideration if the well in case is on-shore or off-shore and also the facilities and equipment available.

Main components of the pressure control equipment were used to perform this analysis; a specific risk of the system can be done using the evaluation of a particular arrangement.

Future tests or real runs of the tool should be performed in deepwater in order to know if the tool can maintain the pressure in a different environment and without losses.

The tool design also need a final revision in order to avoid slight deformations.

REFERENCES

[9] Associated Press. (2010). *Blown Out BP Well Finally Killed.* From http://www.wwltv.com/news/Blown-out-BP-oil-well-finally-killed--103237684.html.

[10] Brenner, N et al. (2010). *Coast Guard Confirms Horizon Sinks.* From http://www.upstreamonline.com/live/article212769.ece

[19] Baker Hughes. (2011). *Downhole Isolation Packer (DHIP) Field Test Report Glenpool Field BH-N-15.* p.3,6, 7, 15.

[21] Det, N. and, Norway, H. (2004) *Marine risk assessment.* p. 21.

[16] Dagmar, S. (without date). Modeling Oil Spill Response and Damage Costs. p. 1.

[1] eni e&p. (1998). *Well Control Equipment Manual.* p. 12

[2] [6] [7] eni e&p Division. (2007). *Well Control Policy Manual*. pp. 21,28, 49.

[4] [5] Grace, R. *Blowout & Well Control Handbook*. pp. 54-58, 70-80. United States of America: Gulf Professional.

[20] James, I. (2011). *Patent application title: Downhole Blowout Preventor*. pp. 2-3.

[8] Kate, S and Adams. (2008) *Quantitative Assessment of Blowout Data as It Relates to Pollution Potential*. p. 2,7.

[15] Kaufman, L. (2010). *Search Ends for Missing Oil Rig Workers.* From http://www.nytimes.com/2010/04/24/us/24spill.html?hpw

[15] Kenneth P and Green, S. Hayward (2010). *The Dangers of Overreacting to the Deepwater Horizon Disaster*. From http://www.aei.org/outlook/100965

[11] Kirkham, C (2010). Rescued oil rig explosion workers arrive to meet families *From:http://www.nola.com/news/index.ssf/2010/04/rescued_oil_rig_workers*

[18] Offshore Risk Assessment (1999). *Human error blamed for oil rig blowout*. From http://home.versatel.nl/the_sims/rig/ekofiskb.htm

[13] Resnick-Ault, J and Klimasinska, K (2010). *Transocean Oil-Drilling Rig Sinks in Gulf of Mexico as Coast Guard Looks for Survivors.* From http://www.bloomberg.com/news/2010-04-22/transocean-rig-sinks-in-gulf-of-mexico-following-blaze-coast-guard-says.html

[3] Roy, R "et all". (2007). *Driller's Method vs Wait and Weight Method: One offers distinct well control advantages*. p. 68.

[12] Schwartz, N and Weber, H. (2010). *Bubble of methane triggered rig blast*. From http://www.scpr.org/news/2010/05/08/14902/bubble-methane-triggered-rig-blast/

[17] The Royal Society of Canada. (2004) *Report on Science Issues Related to Oil and Gas Activities*. From http:// http://home.versatel.nl/the_sims/rig/ixtoc1.htm.

[14] U.S. Department of the Interior. (2010). *Flow Rate Group Provides Preliminary Best Estimate of Oil Flowing from BP Oil Well. Fromhttp://*doi.gov/news/pressreleases/Flow-Rate-Group-Provides-Preliminary-Best-Estimate-Of-Oil-Flowing-from-BP-Oil-Well.cfm