SINTEF REPORT

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TITLE

Deepwater Kicks and BOP Performance, Unrestricted version

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ABSTRACT

A reliability study of subsea BOPs was performed in 1999. This is a follow up study focusing on the deepwater kicks and associated BOP problems and safety availability aspects. The study is based on information from 83 wells drilled in water depths ranging from 400 meters (1312 feet) to more than 2000 meters (6562 feet) in the US GoM OCS. These wells have been drilled with 26 different rigs in the years 1997 and 1998.

A total of 117 BOP failures and 48 well kicks were observed in these wells. The main information source from the study has been the daily drilling reports.

Detailed kick statistics and parameters affecting the kick occurrence and kick killing operation are discussed. The occurrences of BOP failures as a result of wear and tear during the kick killing operations have been investigated.

The BOP as a safety barrier has been analyzed based on the relevant kick experience and the BOP configuration. An alternative BOP configuration and a BOP test procedure that will improve the safety availability and save costly rig time have been proposed.

KEYWORDS	ENGLISH	NORWEGIAN
GROUP 1	Reliability	Pålitelighet
GROUP 2	Offshore	Offshore
SELECTED BY AUTHOR	Blowout Preventer	Utblåsningssikring
	Kick	Brønnspark
	Risk	Risiko

List of Content

List of Abbrivations

BOP	-	Blowout Preventer
BS	-	Blind-Shear
CARA	-	Computer Aided Reliability Analysis
C/K	-	Choke and Kill Valves
FTA	-	Fault Tree Analysis
HPHT	-	High Pressure High Temperature *(A well with an expected maximum*
ID	-	Inner Diameter
IK	-	Inner Kill
ITT	-	Isolation Test Tool
JIP	-	Joint Industry Project
LA	-	Lower Annular
Lbs	-	Pounds
LCL	-	Lower Confidence Limit
LIC	-	Lower Inner Choke
LMRP	-	Lower Marine Riser Package
LOC	-	Lower Outer Choke
LOT		Leak Off Test
LPR	-	Lower Pipe Ram
MFDT	-	Mean Fractional Deadtime
MPR	-	Middle Pipe Ram
MTBK	-	Mean Time Between Kicks
MTTF	-	Mean Time To Failure
MPS	-	Multi Position Lock
MW	-	Mud Weight
NCS	-	Norwegian Continental Shelf
NPD	-	Norwegian Petroleum Directorate
NTNU	-	Norwegian University of Science and Technology
OCS	-	Outer Continental Shelf
OD	-	Outer Diameter
OK	-	Outer Kill
Phase I DW	-	Phase I of the Deepwater BOP Study (/6/ and /7/)
Phase II DW	-	Phase II of the Deepwater BOP Study (/2/)
Ppg	-	Pounds per gallon
ROV	-	Remotely Operated Vehicle
SEM	-	Subsea Electronic Module
SICP	-	Shut-in Casing Pressure
SIDPP		Shut-in Drill Pipe Pressure
UA	-	Upper Annular
UCL	-	Upper Confidence Limit
UIC	-	Upper Inner Choke
UOC	-	Upper Outer Choke
UPR	-	Upper Pipe Ram
VBR	-	Variable Bore Ram
Vs.	-	Versus
WOW	-	Wait On Weather
WOSP	-	Wait On Spare Parts
WOO	-	Wait On Other

Preface

The report documents the study Performance of Deepwater Blowout Preventer (BOP) Equipment During Well Control Events.

The report is based on experienced kicks and BOP failures from subsea deepwater BOPs that have been used in the US GoM OCS in 1997 and 1998.

The Mineral Management Service (MMS) has financed the project. William Hauser has been the MMS contact person. He has provided SINTEF with the necessary raw data from the oil companies.

Per Holand has been the project leader and he has written the majority of the report. Pål Skalle's main work has been in association with identifying, categorizing and analyzing the kicks. Marvin Rausand, Professor at the Norwegian University of Science and Technology (NTNU), has reviewed, and commented on the report.

There are two versions of the report, one of them are restricted. The main differences between the reports are that the restricted version includes the specific rig names, operator names and contractor names.

The project agreement was signed in the end of August 2000, and the project work started in the beginning of October 2000. The draft report was sent to MMS for comments in June 2001.

Per Holand has after the project was started in the fall 2000, resigned from SINTEF and started to work for a consultancy named Exprosoft (http://www.exprosoft.com/). He was then hired to complete the study on behalf of SINTEF.

Trondheim, July 24th, 2001

Per Holand

Summary and Conclusions

Introduction

Deepwater well kick data and BOP failure data have been collected from 83 wells drilled in the US GoM OCS. The well kick data was collected in this study and the BOP reliability data was collected in Phase II DW study (/2/). The main data source has been the daily drilling reports.

Deepwater is in this report defined as waters deeper than 400 meters (1312 ft.). The actual water depths for the wells range from 1335 ft. to 6725 ft. (407 m to 2050 m). The majority of wells included were spudded in the period from July 1 1997 until May 1 1998.

Only the drilling period when the BOP is located on the wellhead has been considered. I.e. shallow gas or water-flows are not considered.

Kick frequency

Table 1 shows the mean time between kicks (MTBK) related to number of BOP-days and number of wells drilled.

Table 1 Mean time between kicks (not incl. shallow kicks)

Phase	No. of kicks	No. of wells	BOP-days in operation	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
Development drilling	9	25	1000	2.8	111.1
Exploration drilling	39	58	3009	1.5	77.2
Total	48	83	4009	1.7	83.5

The entry *BOP-days*, is defined as the number of days from the BOP was landed on the wellhead the first time until it is pulled from the wellhead the last time.

The frequency of deepwater kicks is high. It should be noted that the main criteria for defining a well control incident, as a well kick is that the BOP was needed to control the event. This means that the majority of the "ballooning" backflows from the formation have not been regarded as a well kick. Most ballooning cases are distinguishable from real kicks as flow rate decreases with time. Ballooning is classified as a kick in those cases when the well had to be closed in.

The main reason for the high kick frequency is the low limit between the pore pressure and the fraction pressure.

The overall frequency of kicks is approximately 2.7 times higher in the US GoM deepwater wells than the overall Norwegian Continental Shelf (NCS) experience. The NCS kicks in deep wells, and especially HPHT wells, however, occurred frequently.

Many of the US GoM deepwater wells are deep wells and HPHT wells. The frequency of kicks found in this study is at the same level as the frequency of kicks of *comparable* NCS wells.

No significant difference in kick frequency from area to area in the US GoM OCS could be observed.

The lowest frequency of kicks was observed in the deepest waters, the difference was, however, not significant.

Sixteen different operators were represented. There was a highly variable kick frequency between the different operators, but due to the limited amount of data for each operator, it is not possible to claim that the differences are significant. One of the operators, with a fair amount of drilling days experienced a fairly low frequency.

Six drilling contractors were represented in the study. Two of the contractors have drilled the majority of the wells ("major" drilling contractors), the four other contractors drilled only a "few" wells each ("minor" drilling contractors). One of the major drilling contractors had better performance than the other major drilling contractors. None of the parameters investigated gave an explanation to this result. It is possible that one of the contractors performs better work in terms of keeping the kick frequency low than the other.

Kick characteristics

A series of kick characteristics were investigated, only some of them are included here.

The kick killing operations lasted from some few hours to more than a week, with an average kick killing duration of 2 days. The total kick killing duration was 95.8, days or 2300 hours, this only include the time until the well was hydrostatically controlled. Stuck pipe operations after controlling the well are not included.

The majority of kicks, 45 of 48, included gas. One kick was regarded as a water kick and two as pure mud kicks. Two of the kicks, in addition to gas, also included oil. More of the kicks may have included oil, but it was impossible to deduct that from the daily drilling reports.

For 45 of the 48 kicks the normal drillstring was running through the BOP when the kick occurred. One occurred when the BOP was empty, one with a wireline inside, and one with test tubing running through the BOP.

For many of the kicks the margin between the MW and the LOT is narrow, indicating a small margin between the pore pressure and the fracture pressure, thus making the wells difficult to drill. For 50% of the kicks the LOT - MW was 1 ppg or lower. This effect is further discussed below.

Kick Causes

The main reason for the high kick frequency in these wells is the low margin between the pore pressure and the fracture pressure of many of these wells. The LOT – MW for all the wells drilled deeper than 13000 TVD ft. was closely examined. A total of 43 wells were drilled deeper than 13000 ft. In 15 of these sections they experienced one or more kicks. In the other 28 they did not experience a kick. Table 2 shows the average LOT – MW for the deepest sections of the wells drilled deeper than 13000 ft.

Table 2 Average parameters for "deep" wells with and without a kick

	LOT – max MW, average (ppg)
Sections with kick	1.01
Sections with NO kick	1.31
Average all	**1.21**

The average LOT – MW was lower in the well sections where the well kicked. The deep wells were grouped in two groups; one with the LOT - MW larger than one, and one group with the LOT - MW less or equal to one. It was observed that in 50% of the wells with LOT-MW was less or equal to one *no* kick was experienced. In the group where the LOT – MW larger than one, *no* kick was observed in 80% of the wells.

There was no indication that the well depth or the maximum theoretical shut-in wellhead pressure affected the likelihood of kick occurrences, the main factor is the difference between the pore pressure and mud weight represented by LOT and MW.

Ongoing operations when the kick occurred
The majority of kicks occurred during drilling operations. The majority of them were observed when drilling new hole. Eight incidents were observed when making a connection. Six of the incidents were listed as occurring during circulating mud. Five incidents were observed when tripping out of the hole. One was observed when pulling a wireline out of an empty hole and one when weighting up mud.

Otherwise one kick occurred when fracturing the well prior to a well test and two in association with casing running and cementing. One kick also occurred in association with a well abandon operation.

Cause of kick
The kick causes have been deducted from the descriptions in the daily drilling reports. The daily drilling reports did normally not specify kick causes. Several kicks were given more than one contributing cause of the kick.

In ranked order the most significant contributors to the kick occurrences were:
- Too low mud weight (23)
- Gas cut mud (17)
- Annular losses (9)
- Drilling break (9)
- Ballooning (7)
- Swabbing (5)
- Poor cement (2)
- Formation breakdown (1)
- Improper fill up (1)

The frequent occurrences of too low mud weight and annular losses may to a large degree be explained by the small difference between the fracture pressure and the pore pressure. Annulus friction during circulation is also likely affecting this problem.

Kick killing operations

Circulating heavier mud is, as expected, the most common way of regaining the control of a kick. For many kicks circulating alone could not control the kick and a combination with other methods was required. Circulation only was used for 29 of the kicks. Bullheading was used for six kicks, this in combination with circulating and/or cementing. Cementing was used directly for two kicks. One of them after a poor casing cement job and one in a stuck pipe and kick situation. Once they bled off the pressure to be able to install a casing seal.

Six times it was specifically stated that both the choke and the kill lines were used for circulating out a kick.

Of the 48 kicks evaluated specific problems during the kick killing were observed for 38 of them. When problems are encountered during killing this will cause a prolonged killing duration. For killing operations lasting longer than one day they normally experienced some sort of problems during killing. The observed problems, as described in the daily drilling reports, were categorized and are summarized in Table 3.

Table 3 Distribution of problems during killing operations

No. of kicks	Problems identified during kick killing operations*							No significant problems identified
	Losses (and ballooning)	Hydrate problems	Cement-ing	Drillpipe problems	Pressure transmis-sion	Gas migrat-ion through cement	Fractured during killing	
	29		8	5	8	1		
		3	1	2	1			
			3	1		1	1	
				2				
					1			
								10
48	29	3	12	10	10	2	1	10

* Note that for several kick killing operations more than one problem type were identified

The dominant problem during the well killing operations were losses (and ballooning). The occurrence of this problem was related to the specific LOT - MW, the lower the difference, the higher the frequency of these problems.

For 12 of the kicks they had to squeeze cement to regain control of the well. This was normally done after they had given up circulating the well dead.

For 10 of the kicks the pipe became stuck during the kick killing operations. The typical result of a stuck pipe situation during a kick is that the well, after it is hydraulically controlled and/or cemented, has to be side-tracked or abandoned. Nine of these 10 kicks resulted in a side-track or abandoned well. The time spent from the kick is hydraulically controlled until they were ready to start side-tracking was recorded for these wells. They in total spent 87 days, or approximately 2100 hours, from the kick was controlled until they were ready to continue with the operation. In addition to the time spent, they also had to re-drill, so the operational time losses associated to this type of kicks is extensive.

Problems with signal transmission and hydrates were also observed. During the kick killing operations, stripping drillpipe into the well and jarring/fishing also complicated the killing operation.

Several well parameters were investigated to attempt to find a correlation to the killing duration. None of the well parameters investigated showed clear significant trends. It, however, seemed that there for some were slight correlations. In the following a summary for each of the parameters investigated is shown:

- Water depth vs. killing duration; <u>no correlation</u>
- Well depth (TVD) vs. killing duration; <u>minor correlation</u>
- Drilling fluid type vs. killing duration; <u>no correlation</u>
- Kick size vs. killing duration; <u>minor correlation</u>
- Fracture strength (LOT) – mud weight (MW) vs. killing duration; <u>correlation</u>
- Open hole length vs. killing duration; <u>minor correlation</u>
- Maximum theoretical shut-in pressure vs. killing duration, <u>minor correlation</u>

The reason why there is found little correlation between these parameters and the killing duration is likely that there are so many factors that simultaneously affect the kick killing duration. Further, for some of the well parameters investigated, there are likely no correlation to the killing duration.

BOP Failure Occurrences vs. Kick Occurrences

In general no significant correlation between the occurrence of BOP failures and well control operations was found. However, after or during the kick control operation there have been observed BOP failures that likely were caused by the well control operation. The drilling period, occurrence of kicks, and occurrence of failures were followed by the calendar for each individual rig to identify BOP failures that probably were caused by a kick killing operation.

It was found that for four of the BOP failures the kick killing operations were a likely contributor to the occurrence of the failures. Two of the failures were in the annular preventers, one in choke valves and one in a blind-shear ram;

Rig 51
The inner and the outer choke valve were leaking after 7.5 days of kick control operations

Rig 53
The blind-shear ram failed to test when testing against the cement plug. On the previous test three days before the kick it tested perfect. On this test, 10 days after the kick, the blind-shear ram failed.

Rig 56
Lower annular preventer was leaking. It had been used for stripping during the well control operation.

Rig 58
Packing element in #1 annular failed. It had been used for stripping during the well control operation.

It should be noted that for some kicks the history with respect to BOP failures after the kick, is unknown. Some of these kicks may have contributed to failures.

Only once the kick killing operation was likely to blame for a choke or kill valve failure, indicating that the wear and tear from kick circulation are not a large problem for these valves, when considering the high number of kicks that were taken. The failure mechanism is unknown.

The blind-shear ram failure was likely caused by the kick killing operation because the blind-shear ram functioned perfectly just before the kick and failed to seal just after the kick. The failure mechanism is unknown.

Stripping operations cause annular preventer wear. During six of the 48 kicks the pipe was stripped in or out of the well. Two of the stripping operations caused the annular to fail. In addition for two other kicks, flow was observed in the riser during the stripping operation (Rig 63 and Rig 64). The preventers did not, however, leak when the pipe was kept steady and the annular preventer was closed with normal control system pressure. These incidents are not regarded as annular preventer failures, but more a likely outcome of a stripping operation. The amount of stripping an annular preventer may endure before starting to leak is influenced by the quality of the element when starting the stripping operation and also the type of fluid confined in the BOP. A new element will endure more stripping than an old one, and gas below the annular is more likely to cause a notable flow in the riser than if mud is below the annular.

Recommended BOP Configuration and Testing Strategy for Deepwater Subsea BOPs

The experience the recommendations build on is from drilling operations, and therefore considerations related to specific needs during the completion phase have not been taken. The recommendations are valid for subsea BOPs only, and not surface BOPs.

The objectives with the recommendations listed in this section are:

- Keep the safety level at least as high as today
- Reduce the BOP test time

The analyses show that the proposed BOP configuration and testing will cause an improved BOP safety availability.

Recommended BOP Configuration

The following main BOP stack configuration from top to bottom should be selected:

- Two or one annular preventer
- Two blind shear rams
- Two variable piperams

Replacing the upper pipe ram with a blind-shear ram will increase the probability of being able to close in an open hole, and also improve the shear and sealing probability during an emergency disconnect situation. Based on the deepwater kick experience this will improve the total ability to be able to close in a kick. Taking out the pipe ram from this cavity will not significantly affect the probability of being able to close in a kick with a drillpipe running through the hole.

Both the pipe rams should be able to seal around the “normal” drillpipe running through the BOP. One of the rams should have a geometry allowing maximum hang-off capacity for the normal drillpipe in the hole. (e.g. 5” drillpipe and 3.5”-5” VBR should allow 450 000 to 600 000 lbs hang-off with a 5” drillpipe)

Recommended BOP test practices

The proposed test regime presupposes that a blind-shear ram has replaced the UPR, i.e. there are two blind-shear rams in the stack. Then the detailed pressure testing of the BOP (as required to day) will not improve the BOP stack in terms of the BOP safety availability compared to a regulation requiring a body test and a function test only.

Installation tests

Perform a complete detailed BOP pressure test after landing the BOP at the wellhead the first time and subsequent times. (It should not be required to test the VBRs against all tubular sizes that may be ran in hole)

When the LMRP has been disconnected the connection should be pressure tested after reconnecting against the upper annular.

Periodic tests

The BOP body should be tested against the MPR (ram cavity #3) at least every two weeks to the maximum expected pressure in the next section to be drilled. A complete function test of all relevant functions on both pods should be carried out.

Perform a complete function test both pods every two weeks.

It should never be more than 50 days from the last detailed pressure test of the BOP (similar to the installation test).

Test after running casing or liner

The BOP body should be tested against the MPR (ram cavity #3) after running casing or liner.

Perform a complete function test both pods.

Pressure test the BS rams independently against the casing or liner.

Pros and cons in terms of economic aspects

Additional costs
Replacing the UPR with blind-shear rams in a BOP stack will cause some investments. In the best case a new type of blind-shear ram blocks can be installed. In the worst case boosters need to be installed on the ram and the control system needs to be modified.

Potential time saving
The potential saving with the proposed test strategy will be time saved. For the purpose of illustrating approximate figures for the potential saving all the tests listed with a test time recorded in Phase II DW (/2/) were grouped in the type of test and the test time.

The experienced average BOP test time has been compared with a coarse estimate for the expected test time for the alternative BOP test strategy. The results are shown in Table 4.

Table 4 Estimated test time consumption with proposed test strategy

Type of test	BOP tests recorded in Phase II DW			Estimated time consumption with proposed test strategy	
	No. of tests	Total test time (hrs)	Average test time (hrs)	Average test time (hrs)	Total test time (hrs)
Installation test	78	1110	14.23	14.23	1110
Pressure tests scheduled by time	102	1462	14.33	7.00*	714
Test after running casing or liner	153	2059.25	13.46	4.00*	612
Function test scheduled by time	166	118.5	0.71	0.71	118.5
Total	499	4749.75			2554.5

*No detailed pressure test, only body test and function test

If the proposed test strategy had been utilized for the 83 wells drilled approximately 2200 hours of testing time could have been used for other operations. This represents 2.28 % or approximately one week of drilling for each rig and year.

To further reduce the time used for testing the oil and gas industry should focus on developing plugs that could be ran as a part of the drill string, minimizing the need for tripping to test the BOP. So called compression plugs may be one alternative to look into.

1. Introduction

1.1 Relevant experience within SINTEF/NTNU

From 1981 to 1999, SINTEF has documented results from a number of detailed reliability studies of Subsea Blowout Preventer (BOP) systems (/1/, /2 /, /6-8/ and /10-20/). The project leader for the current study has mainly carried out these studies. The various studies have been financed by:

- Several Oil companies operating in the Norwegian sector of the North Sea.
- The Brazilian state owned company Petrobras and the Italian oil company Agip
- The Norwegian Petroleum Directorate (NPD)
- Minerals Management Service (MMS).

The following studies have been carried out:

Phase I: Analysis of failure data from 61 exploration/appraisal wells drilled from semisubmersible rigs and BOP system analysis.

Phase II: Analysis of failure data from 99 exploration/appraisal wells from semisubmersible rigs and mechanical evaluation of BOP components. Separate report on reliability of control systems.

Phase III: Evaluation of operation and maintenance of subsea BOP components. Evaluation of test procedures and operational control.

Phase IV: Analysis of 58 exploration/appraisal wells, drilled in the period 1982 -1986. The availability of the BOP as a safety barrier against blowout was assessed by fault tree analysis. Time consumption for weekly BOP testing and associated problems were recorded and discussed.

Phase V: Analysis of 47 exploration/appraisal wells, drilled in the period 1987 -1989. BOP failures were recorded and analyzed. Recommendations with respect to BOP test intervals were given. Time consumption for weekly BOP testing was recorded and discussed.

Phase I DW: Analysis of 140 wells drilled in four different countries in the period 1992 - 1997. The report analyses the data collected and further highlights deepwater specific problems. The three control system principles; conventional pilot hydraulic systems, pre-charged pilot hydraulic system, and multiplexed systems were compared by fault tree analysis with respect to the ability to close in a well given a kick.

Phase II DW: Analysis of 83 deepwater (deeper than 1312ft.) wells drilled in the US GoM OCS in the period 1997 -1998. The report presents the reliability of the US GoM OCS deepwater BOPs, the BOP subsea test problems experienced alongside the BOP test time. Further, recommendation for a more efficient BOP testing has been given based on fault tree analysis with respect to the ability to close in a well given a kick.

Nearly 500 wells have been reviewed with respect to the subsea BOP reliability. Several minor spin-off projects related to the main projects mentioned above have also been carried out, the most recent ones are /3-5/.

The most recent subsea BOP reliability study was carried out for the MMS, and completed during fall 1999. This study is referred to as the Phase II DW study (/2/). A total of 83 deepwater (deeper than 1312ft.) wells drilled in the US GoM OCS in the period 1997 –1998 were analyzed. The report presents the reliability of the US GoM OCS deepwater BOPs, the BOP subsea test problems experienced alongside the BOP test time. This study, and the raw data the study was based on, has been the basis for the present study.

In addition, SINTEF has carried out a reliability study related to platform located BOPs used for development drilling (/9/). The analysis was based on failure data from 48 development wells drilled from three North Sea platforms in the period 1986 - 1990. The study was completed in 1992.

The project manager for the current study has since 1990 been responsible for the SINTEF Offshore Blowout Database that is the basis for most blowout risk analyses carried out in the North Sea. This database is updated on a yearly basis. It has also been the basis for a PhD study and a book published by Gulf Publishing, Houston Texas in 1997 (/21/).

The project group has also experience in the area of kick detection on floating vessels (/22-24/), in the dynamics and hydraulics of kicking and blowing wells and insight in the handling of large blowout databases (/24-25/).

1.2 Background for this Project

The MMS posted a Broad Agency Announcement in the Commerce Business Daily on June 30, 1999. The purpose of the announcement was to solicit white papers for the MMS FY 2000 research program. The proposal objectives for the FY 2000 OSER activities included several areas. One of them was the following: (1) performance of deepwater blowout preventer (BOP) equipment during well control events. In July 1999 SINTEF submitted a white paper concerning *Performance of deepwater blowout preventer (BOP) equipment during well control events.* In October 1999 SINTEF was invited to write a project proposal based on the white paper.

In September 2000 SINTEF was informed that they were awarded the contract for the above study.

1.3 Objectives

The overall objectives of the study have been to:

- establish a quantified overview of the deepwater well kick frequencies and the important parameters contributing to the kick frequency
- identify and quantify problem areas in well control operations
- assess the effect of well control operations on the BOP reliability
- analyze how different BOP test strategies affect the blowout probability

2. Overview of Kick Data

2.1 Data Background and Data Sources

Deepwater well kick data have been collected from wells drilled in the US GoM OCS. These are the same wells as the data for Phase II DW (/2/). Deepwater in this report is defined as waters deeper than 400 meters (1312 ft.). The actual water depths for the wells range from 1335 ft. to 6725 ft. (407 m to 2050 m). The majority of wells included were spudded in the period from July 1 1997 until May 1 1998. Four wells were spudded before this period and one well after this period. Approximately 85% of the deepwater wells spudded in this period are included.

When collecting kick data, only the drilling period when the BOP is located on the wellhead has been considered. I.e. shallow gas or water-flows are not considered. If the drilling covers a regular well test this is regarded as a part of the well drilling. Completion activities and workovers are not included.

A total of approximately 83 different wells, where a subsea BOP has been used, are included in the study. Twenty-five of these wells were listed as development wells and 58 as exploration wells in the MMS well file (/33/).

Side-tracks have been treated as separate wells. Some of the wells were abandoned for a period of time before re-entering and continuing operations.

Table 2.1 presents an overview of wells, operational days and drilling vessels for the various water depths.

Table 2.1 Overview of wells, operational days and drilling vessels for the various water depths

Water depth m /(ft) (MSL)	No. of wells	No. of BOP-days	Dyn. pos. drill ships	Dyn. pos. semisubs	Anchored semisubs
400 – 600 / 1312 – 1969	30	1350			30
600-800 / 1969-2625	10	573			10
800-1000 / 2625-3281	10	521			10
1000-1200 / 3281-3937	18	644			18
1200-1400 / 3937-4593	6	475			6
1400-1600 / 4593-5249	2	140	2		
1600-1800 / 5249-5906	4	169	3		1
1800-2100 / 5906-6890	3	137	3		
Total	**83**	**4009**	**8**		**75**

The entry *BOP-days*, is defined as the number of days from the BOP was landed on the wellhead the first time until it is pulled from the wellhead the last time. If the BOP is pulled during the operation due to a BOP failure, this is regarded as included in the BOP-days. If the well is temporarily abandoned and the rig is carrying out other operations before returning to the well, this is not included in the BOP-days.

Data sources
The main data source for identifying, describing and categorizing kicks has been the daily drilling reports from the wells included in the study. These reports were sent to SINTEF as E-mail attachments in various formats, as Microsoft Excel, Microsoft Access, and plain test dump from the daily drilling reporting system in association with performing Phase II DW (/2/). For some wells, hard copies of the daily drilling reports have been used as data source.

The chronological description of the activities in the daily drilling reports has been the main input.

The information collected and systemized in Phase II DW (/2/) regarding the specific BOPs and the BOP failures have been used.

2.2 Kick Frequency and Type of Drilling

Table 2.2 shows the mean time between kicks (MTBK) related to number of BOP-days and number of wells drilled.

Table 2.2 Mean time between kicks (not incl. shallow kicks)

Phase	No. of kicks	No. of wells	BOP-days in operation	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
Development drilling	9	25	1000	2.8	111.1
Exploration drilling	39	58	3009	1.5	77.2
Total	48	83	4009	1.7	83.5

The frequency of deepwater kicks is high. It should be noted that the main criteria for defining a well control incident as a well kick is that the BOP was needed to control the event. This means that the majority of the "ballooning" backflows from the formation have not been regarded as a well kick. Most ballooning cases are distinguishable from real kicks as flow rate decreases with time. Ballooning is classified as a kick in those cases when the well had to be closed in.

Two of the kicks were actually minor blowouts. For one, the 16" casing cement job was very poor. When the kick occurred they observed gas flow from the 30 " wellhead and also from below the mud mat and out from the permanent guide base at a low but steady rate. The well was squeezed three times before they sealed it.

The second minor blowout was an underground blowout. They had drilled out of the 20" casing 2 days before the kick. When drilling at 5736 ft. they flow checked, and the well was flowing. The well was then shut in. After a while the casing pressure disappeared and the formation had fractured. They pumped and squeezed cement to seal the formation.

The main reason for the high kick frequency is the small difference between the pore pressure and the fraction pressure. Kick causes are discussed in section 5 on page 45.

As expected there are more frequent kicks in exploration drilling than in development drilling. The main reason for this increased frequency is that they are drilling in less known formation.

To check whether if the difference in the kick frequency between development and exploration drilling was statistically significant or not, 90% confidence limits were established for the kick frequencies. Figure 2.1 shows the kick frequencies for development and exploration drilling alongside the 90% confidence bands.

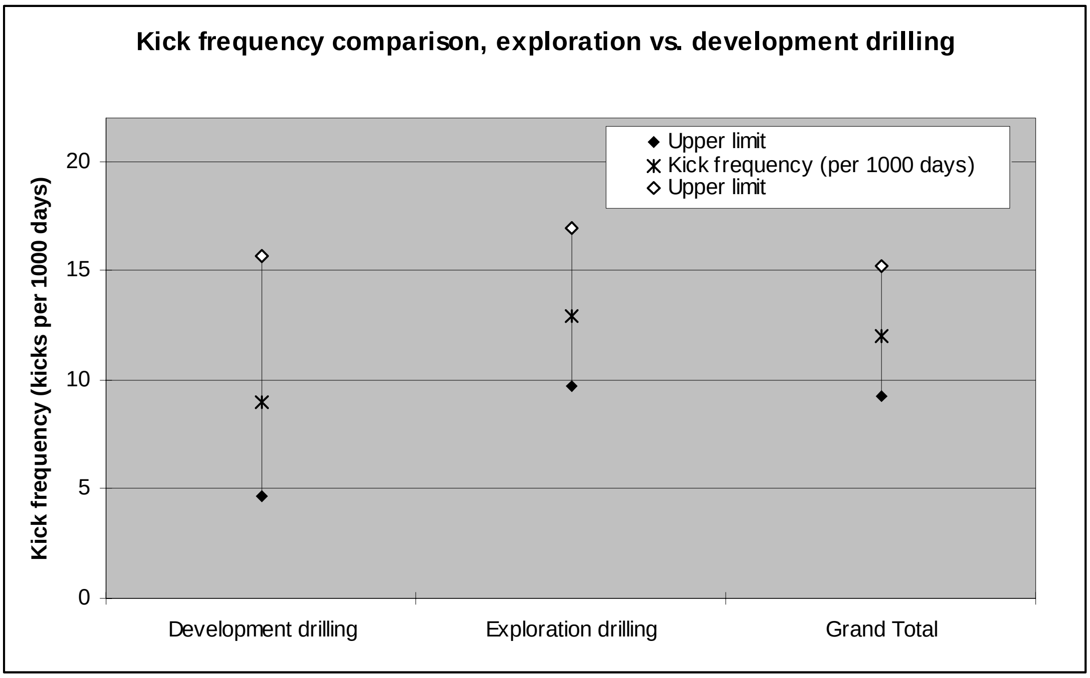

Figure 2.1 Kick frequency comparison, exploration vs. development drilling

Although Figure 2.1 cannot confirm a statistical significant difference (the confidence bands do overlap) it is believed that such a difference exist. If more kick data were collected the confidence bands would not overlap.

2.3 Comparison with Norwegian North Sea statistics

In 1998 a study was carried out concerning blowout probability of High Pressure High Temperature (HPHT) wells in the Norwegian Continental Shelf (NCS) (/29/). A well with an expected maximum shut-in pressure above 10 000 psi (690 bar) and/or formation temperatures above 238 F (150 centigrade) is regarded as a HPHT well.

In association with this study kick frequencies based on all wells drilled in the NCS in the period 1984 until 1997 were established. The shallow kicks were disregarded in the study, the results are therefore comparable with the kick frequencies established in this study.

Table 2.3 shows the NCS overall MTBK (mean time between kicks).

Table 2.3 NCS overall mean time between kicks (data from 1984 - 1997)

Type of drilling	No. of wells drilled	No. of kicks	MTBK (wells between kicks)
Exploration drilling	576	143	4.0
Development drilling	1428	272	5.3
Total	**2580**	**558**	**4.6**

When comparing the results shown in Table 2.2 and Table 2.3 it is seen that the overall frequency of kicks is approximately 2.7 times higher in the US GoM deepwater wells than in the overall NCS experience. It should be noted that nearly all the exploration wells were drilled with floating rigs, while the majority of the production wells were drilled from fixed installations.

In Table 2.4 the NCS exploration wells have been divided in different categories to better explain the kick frequencies in different types of wells.

Table 2.4 NCS MTBK for different types of exploration wells

Type of exploration well	No. of wells	No. of kicks	MTBK (wells between kicks)
Normal (Well depth < 4000m = 13123 ft. TVD)	416	39	10.7
Deep (Well depth > 4000m = 13123 ft. TVD, not incl. HPHT)	111	36	3.1
HPHT wells	49	68	0.7
Total	**576**	**143**	**4.0**

From Table 2.4 it is seen that the NCS kicks in deep wells, and especially HPHT wells occurred at a frequent rate.

When observing the maximum theoretical shut-in pressures and depths for the US GoM wells, as presented in Figure 3.2, page 33, Figure 3.3, page 34, and Figure 3.4, page 34, it is seen that many of these wells are deep wells and HPHT wells. The frequency of kicks found in this study is therefore at the same level as the frequency of kicks of *comparable* NCS wells. It should be noted that the NCS HPHT wells are normally drilled to a depth of 16 000 to 17 000 ft. in 150 to 1000 ft. of water.

The NCS HPHT wells are often characterized by small pressure margins, i.e. small differences between formation strength and pore pressure. Further, the geology is complex, with rapid increase in pore pressure over a short vertical distance (most of the HPHT wells included in the NCS study were drilled in the difficult pore pressure regimes in the North Sea Viking Graben and the Central Trau areas). The small pressure margins are also found in the US GoM deepwater wells (Figure 3.5 on page 35).

2.4 Kick Frequency and Area

Table 2.5 shows an area specific overview of the time in operation and no. of kicks.

Table 2.5 Area specific time in operation and mean time between kicks (MTBK)

Area	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
AC - Alaminos Canyon			-		21	-		21	-
AT - Atwater Area	1	78	78	1	52	52	2	130	65
EB - East Breaks		53	-	3	118	39	3	171	57
EW - Ewing Bank	3	151	50	2	199	100	5	350	70
GB - Garden Banks	2	66	33	11	790	72	13	856	66
GC - Green Canyon	1	104	104	10	894	89	11	998	91
MC - Mississippi Canyon		228	-	12	935	78	12	1163	97
VK - Viosca Knoll	2	320	160			-	2	320	160
Total	**9**	**1000**	**111**	**39**	**3009**	**77**	**48**	**4009**	**84**

It is seen from Table 2.5 that the majority of deepwater drilling was carried out in the Garden Banks, Green Canyon and Mississippi Canyon. When looking at the MTBK only these three areas should be considered. The experienced MTBK is less in the Garden Banks area than the other two areas. To check whether the differences in kick frequency between the different areas were statistically significant or not, 90% confidence limits are established for the kick frequencies. Figure 2.2 shows the area specific kick frequencies alongside the 90% confidence bands.

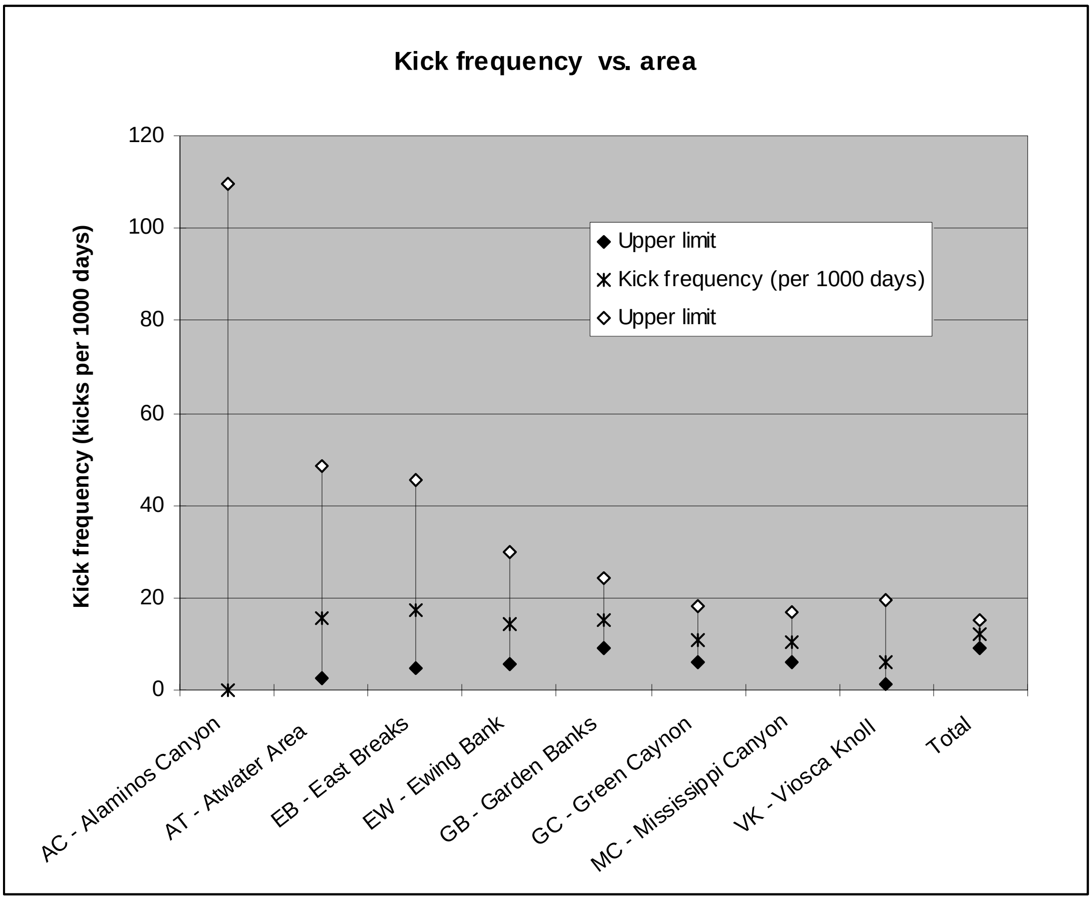

Figure 2.2 Kick frequency vs. area

Figure 2.2 cannot confirm a statistical significant difference between the areas.

2.5 Kick Frequency and Water Depth

Table 2.6 shows the water depth vs. the mean time between kicks.

Table 2.6 Water depth vs. mean time between kicks

Water depth grouped	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Less than 2000 ft	5	377	75	14	973	70	19	1350	71
2000 to 4000 ft	3	545	182	19	1193	63	22	1738	79
Deeper than 4000 ft	1	78	78	6	843	141	7	921	132
Total	**9**	**1000**	**111**	**39**	**3009**	**77**	**48**	**4009**	**84**

From Table 2.6 it is seen that the highest MTBK is observed in the deepest waters. To check whether the differences in MTBK in the various water depths were statistically significant or not, 90% confidence limits for the kick frequencies are established for the kick frequencies. Figure 2.3 shows the water depth specific kick frequencies alongside the 90% confidence bands.

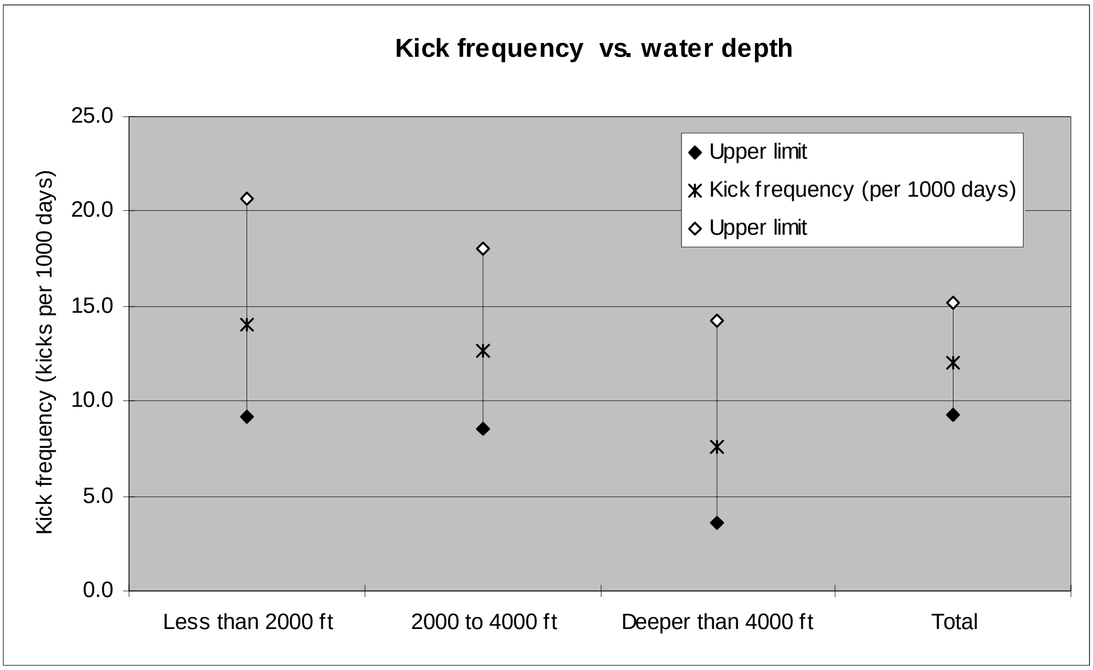

Figure 2.3 Kick frequency vs. water depth

Figure 2.3 cannot confirm a water depth related statistical significant difference on kick frequencies. The water depth influence is further discussed in Section 2.7 on page 26.

2.6 Kick Frequency and Operator

Table 2.7 shows the operator vs. the mean time between kicks.

Table 2.7 Operator vs. the mean time between kicks

Operator	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Operator A	2	66	33	4	314	79	6	380	63
Operator B	2	160	80	1	137	137	3	297	99
Operator C	3	151	50	1	234	234	4	385	96
Operator D	1	78	78	2	99	50	3	177	59
Operator E			-	1	350	350	1	350	350
Operator F			-	3	73	24	3	73	24
Operator G			-	2	98	49	2	98	49
Operator H			-		69	-		69	-
Operator J		87	-		25	-		112	-
Operator K		53	-	3	57	19	3	110	37
Operator L			-	3	77	26	3	77	26
Operator M		119	-	7	526	75	7	645	92
Operator N	1	104	104		134	-	1	238	238
Operator O		182	-	5	419	84	5	601	120
Operator P			-	5	267	53	5	267	53
Operator Q			-	2	130	65	2	130	65
Total	9	1000	111	39	3009	77	48	4009	84

Many operators have been drilling deepwater wells in the US GoM OCS in 1997-1998. The average MTBK varies highly. It is here important to note that each of the companies is represented with relatively few days in service. Figure 2.4 shows the kick frequency vs. operator alongside the 90% confidence bands.

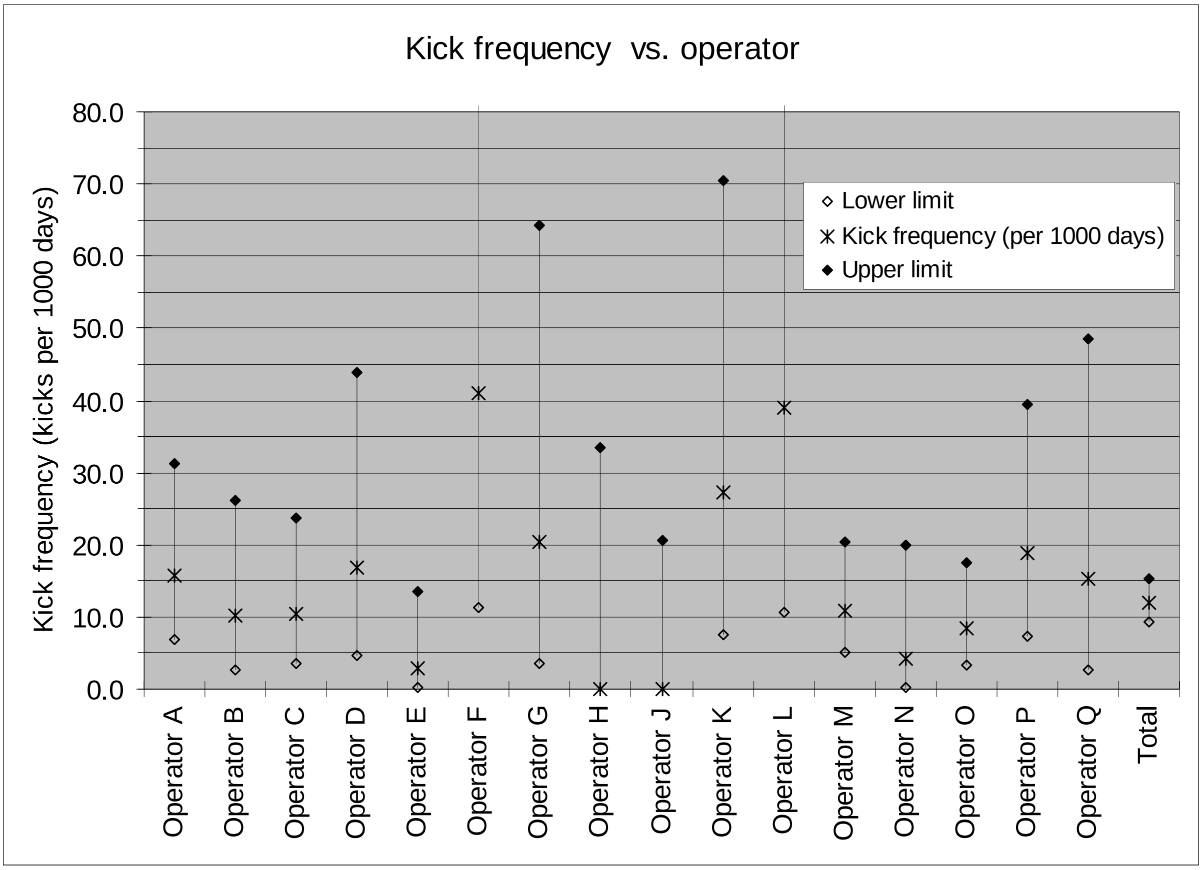

Figure 2.4 Kick frequency vs. operator

As seen from Figure 2.4 the confidence bands overlaps for all the operators, indicating that there can not be stated a statistically significant difference in kick frequency. It is here also important to note that different wells have different difficulties when drilling, i.e. some wells kicks easier than others. The average MTBK should therefore not be used for ranking the operators.

It is however worth to note that Operator E has experienced only one kick in 350 days of drilling while other operators have experienced several kicks with the number of days in operation of the same magnitude. It should be investigated why there is such a difference. If the low frequency is caused by better drilling procedures the other operators should adapt them. Random statistical variations, different formations or other may, however, also be the reason for the difference. All the Operator E wells were drilled in waters deeper than 4000 ft.

2.7 Kick Frequency and Drilling Contractor

Table 2.8 shows the drilling contractor vs. the mean time between kicks.

Table 2.8 Drilling contractor vs. the mean time between kicks

CONTRACTOR NAME	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Contractor A				1	165	165	1	165	165
Contractor B	6	517	86	29	1998	69	35	2515	72
Contractor C			-	2	65	33	2	65	33
Contractor D		53	-	5	194	39	5	247	49
Contractor E			-	1	157	157	1	157	157
Contractor F	3	430	143	1	430	430	4	860	215
Total	9	1000	111	39	3009	77	48	4009	84

Contractor B has carried out 63% of all the drilling and experienced 73% of the kicks, while Contractor F has carried out 21% of the drilling and experienced 8% of the kicks. I.e. the Contractor B MTBK is lower than the average, while the Contractor F MTBK is higher than the average. Four other drilling contractors have carried out the remaining 16% of the drilling. They experienced 19% of the kicks.

The kick frequencies for the different contractors have been compared by using 90% confidence bands in Figure 2.5. It has been selected to group the drilling contractors with a short drilling period in one group.

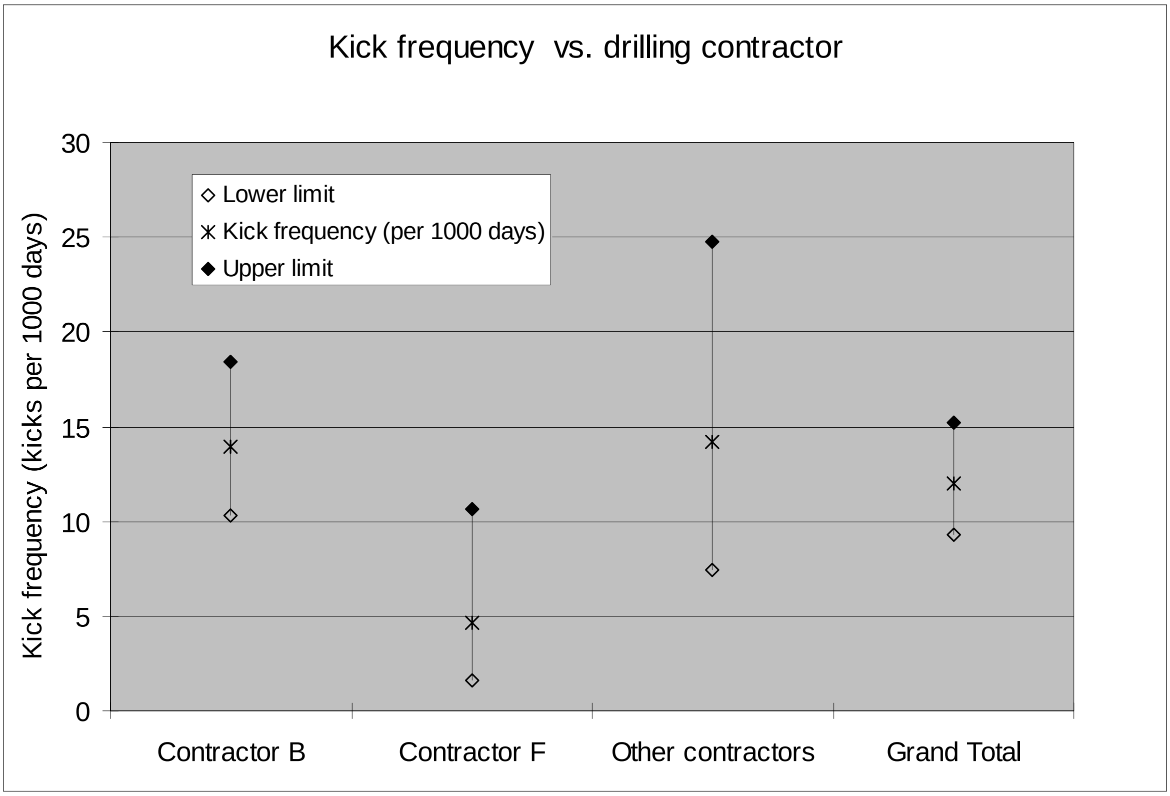

Figure 2.5 Kick frequency vs. drilling contractor

From Figure 2.5 it is seen that the difference in kick frequency between Contractor F and Contractor B is close to being significant. This means that it can be stated with a degree of 90% certainty that the observed difference in kick frequency is not caused by random statistical variations.

To investigate possible causes for this difference in the kick frequency between the operators some parameters related to the drilled wells have been compared. They are:

- Water depth (results shown in Table 2.9)
- Area (results shown in Table 2.10)

Table 2.9 Kick occurrences, drilling contractors and water depth

Water depth grouped (ft.)	Contractor B			Contractor F.			Other operators			All		
	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)	Total	No. of kicks	MTBK (BOP-days)
Less than 2000	1073 *43 %*	18 *51 %*	60	120 *14 %*			157 *25 %*	1 *11 %*	157	1350 *34 %*	19 *40 %*	71
2000 - 4000	967 *38 %*	12 *34 %*	81	294 *34 %*	2 *50 %*	147	477 *75 %*	8 *89 %*	60	1738 *43 %*	22 *46 %*	79
>4000	475 *19 %*	5 *14 %*	95	446 *52 %*	2 *50 %*	223	0 *0 %*		-	921 *23 %*	7 *15 %*	132
Total	2515	35	72	860	4	215	634	9	70	4009	48	84

As seen from Table 2.9, that Contractor F has in average been drilling in deeper waters than Contractor B. The Contractor F MTBK is higher than the Contractor B MTBK for all depth intervals. The Contractor F good "kick performance" in water depths deeper than 4000 ft. is the main reason for good overall results at this depth (Table 2.6).

Table 2.10 shows the no. of kick occurrences and the drilling area for the drilling contractors.

Table 2.10 Kick occurrences, drilling contractors and area

State and area	Contractor B		Contractor F		Other operators		All	
	BOP-days in service	No. of kicks	BOP-days in service	No. of kicks	BOP-days in service	No. of kicks	Total	No. of kicks
AC - Alaminos Canyon			21				21	
AT - Atwater Area			78	1	52	1	130	2
EB - East Breaks	14		47		110	3	171	3
EW - Ewing Bank	350	5					350	5
GB - Garden Banks	467	12	119		270	1	856	13
GC - Green Canyon	998	11					998	11
MC - Mississippi Canyon	599	7	362	1	202	4	1163	12
VK - Viosca Knoll	87		233	2			320	2
Total	2515	35	860	4	634	9	4009	48

The drilling time and the kick occurrences shown in Table 2.10 do not show that Contractor B has been drilling a lot in a specific difficult area. Both Contractor B and Contractor F have for instance been drilling in the Garden Banks area, Contractor B experienced 12 kicks in 467 BOP-days, while Contractor F experienced *zero* kicks in 119 BOP-days. Further in the Mississippi Canyon area Contractor B experienced *seven* kicks in 599 BOP-days, while Contractor F experienced only *one* kick in 362 drilling days. The difficulties in drilling a well would vary from well to well within the same area, so these results do not prove that Contractor F has better procedures for avoiding kicks when drilling. The results, however, indicate that this is an area to look further into. If Contractor F is utilizing better procedures, the other drilling contractors should adapt them as well.

The average leak off test (LOT) pressure minus the mud weight (MW) was checked for the deepest section of the wells drilled deeper than 13000 ft. and compared. The average LOT - MW was slightly higher for the wells drilled by Contractor B (1.27 ppg) compared with the wells drilled by Contractor F (1.22. ppg). The effect of LOT - MW on kick occurrences is discussed in Section 5 on page 45.

2.8 Kick Frequency and Rig

The majority of deepwater drilling has been carried out by semisubmersibles, but some wells have been drilled with drill ships. Table 2.11 shows an overview of the rig type vs. the kick occurrences.

Table 2.11 Rig type and kick occurrences

Rig type	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Drill ship	1	78	78	1	316	316	2	394	197
Semisubmersible	8	922	115	38	2693	71	46	3615	79
Total	9	1000	111	39	3009	77	48	4009	84

Table 2.11 shows that drill ships carried out approximately 10% of the drilling, and 4% of the kicks were observed when drilling these wells. Contractor F drilled all these eight wells in

waters deeper than 4000 ft. The amount of drilling with drill ships is so low that it cannot be stated that using these types of drilling rigs reduces the probability of a kick. Other observations indicate that the frequency of kick occurrences is lower in deeper water, further that Contractor F in general has a better kick statistic.

Table 2.12 shows an overview of the kick occurrences and the number of BOP-days in operation for the various rigs included in the study.

Table 2.12 Rig name and kick occurrences

Rig name	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Rig 50	0	87	-	0	25	-		112	-
Rig 51			-	1	157	157	1	157	157
Rig 52	2	66	33	3	157	52	5	223	45
Rig 53	1	78	78	0	179	-	1	257	257
Rig 54			-	1	137	137	1	137	137
Rig 55	2	160	80			-	2	160	80
Rig 56			-	5	171	34	5	171	34
Rig 57			-	1	165	165	1	165	165
Rig 58	3	151	50	0	69	-	3	220	73
Rig 59			-	1	171	171	1	171	171
Rig 60			-	0	69	-		69	-
Rig 61	0	109	-	3	167	56	3	276	92
Rig 62	0	119	-	0	15	-		134	-
Rig 63			-	5	258	52	5	258	52
Rig 64	1	104	104	0	35	-	1	139	139
Rig 65			-	2	300	150	2	300	150
Rig 66			-	2	130	65	2	130	65
Rig 67			-	3	77	26	3	77	26
Rig 68	0	53	-	3	94	31	3	147	49
Rig 69	0	73	-			-		73	-
Rig 70			-	0	47	-		47	-
Rig 71			-	4	304	76	4	304	76
Rig 72			-	0	52	-		52	-
Rig 73			-	2	100	50	2	100	50
Rig 74			-	1	65	65	1	65	65
Rig 75			-	2	65	33	2	65	33
Total	9	1000	111	39	3009	77	48	4009	84

Many different rigs have been drilling deepwater wells in the US GoM OCS in 1997-1998. The average MTBK varies highly. It is here important to note that each of the rigs is represented with relatively few days in service. Figure 2.6 shows the kick frequency vs. operator alongside the 90% confidence bands.

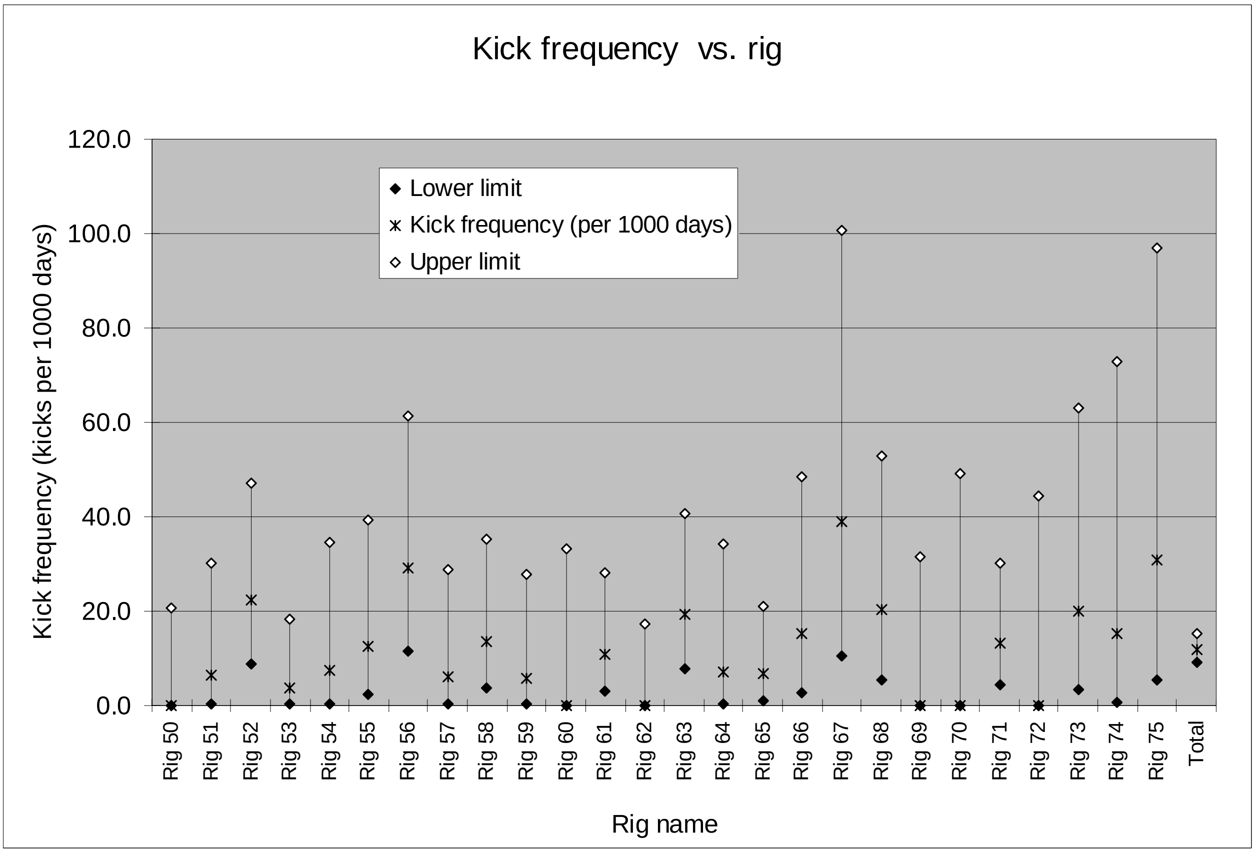

Figure 2.6 Kick frequency vs. rig

As seen from Figure 2.6 the confidence bands overlap for all the rigs, indicating that there cannot be stated a statically significant difference in kick frequency. It is here also important to note that different wells have different difficulties when drilling, i.e. some wells kicks easier than others. The average MTBK should therefore not be used for ranking the rigs.

3. Kick Characteristics

3.1 Theoretical and Measured Shut-in Wellhead Pressures

The maximum theoretical shut-in wellhead pressures for each kick have been estimated based on the following:

- The mud weight when the kick occurred (assumed to represent the pore pressure)
- The true vertical depth of the when the kick occurred.
- Assuming the well was filled with methane gas

It was then estimated that the complete well bore was filled with methane with a density of 0.71 kg/m^3 at atmospheric pressure.

The formula used is as follows

$P_{SI\text{-}Max} = P_{bottom} - \rho_{methane} * g * (D_{TVD} - D_W) * (P_{bottom} + P_{SI\text{-}Max})/ (2 * P_{ATM})$

the solution for P_{SI} will then be:

$P_{SI\text{-}Max} = P_{bottom}\ (1- \rho_{methane} * g * (D_{TVD} - D_W) / 2 * P_{ATM})/(1 + \rho_{methane} * g * (D_{TVD} - D_W) / 2 * P_{ATM})$

For the calculations all English units were converted to Metric units. The results were then converted back to English units.

Where;

D_{TVD}	= True vertical well depth (m)
D_W	= Water depth (m)
P_{bottom}	= $\rho_{mud} * g * D_{TVD}$ (Pa)
$\rho_{methane}$	= density of methane at atmospheric pressure (= 0.71 kg/m^3)
ρ_{mud}	= density of mud (kg/m^3)
g	= gravity force (9.81 m/s^2)
$P_{SI\text{-}Max}$	= Shut-in wellhead pressure (Pa)
P_{ATM}	= Atmospheric pressure (100000 Pa)

Figure 3.1 shows the sorted well depths vs. the theoretical shut-in well pressures when the kicks occurred.

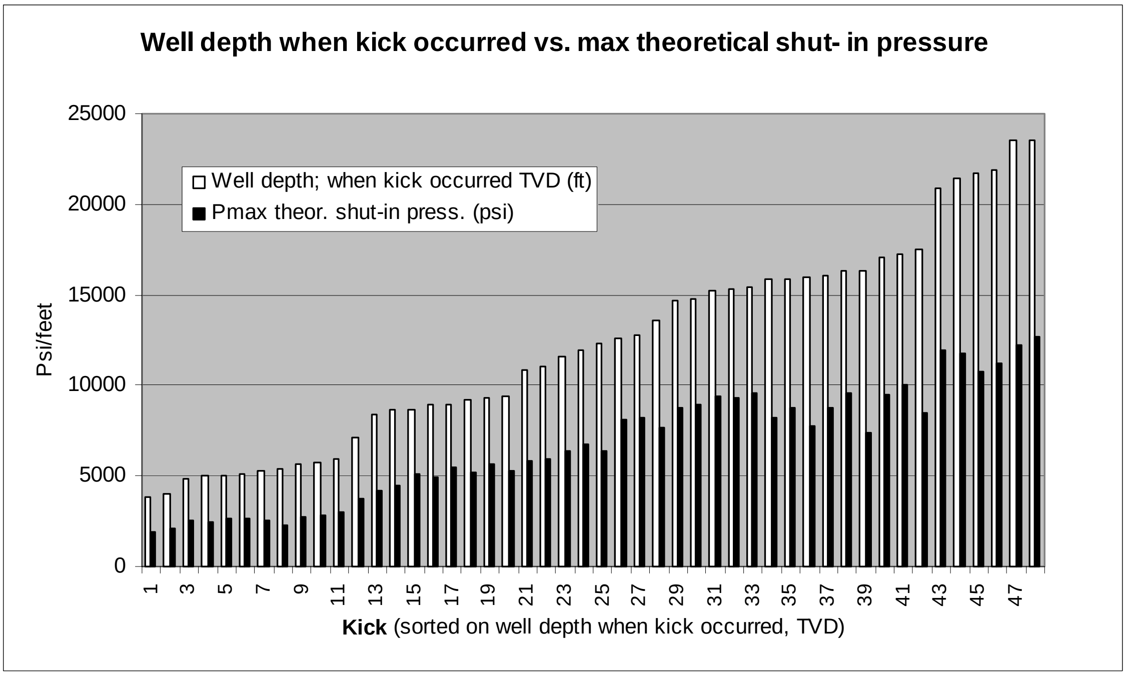

Figure 3.1 Sorted well depth and maximum theoretical shut-in well pressures

As seen from Figure 3.1 some of the wells were very deep and some wells have high pressures. Six of the kicks occurred when drilling deeper than 20000 ft., and 12 kicks occurred when drilling between 15 000 and 20 000 ft.

In the North Sea area wells with an expected maximum shut-in pressure above 10 000 psi (690 bar) and/or formation temperature above 238 F (150 centigrade) are regarded as HPHT wells. Seven of the observed kicks were so-called HPHT kicks, and approximately 15 kicks had a theoretical shut-in pressure between 7 500 - 10 000 psi.

Figure 3.2 shows the maximum theoretical shut-in pressure vs. the measured maximum shut-in casing pressure (SICP) during the kick.

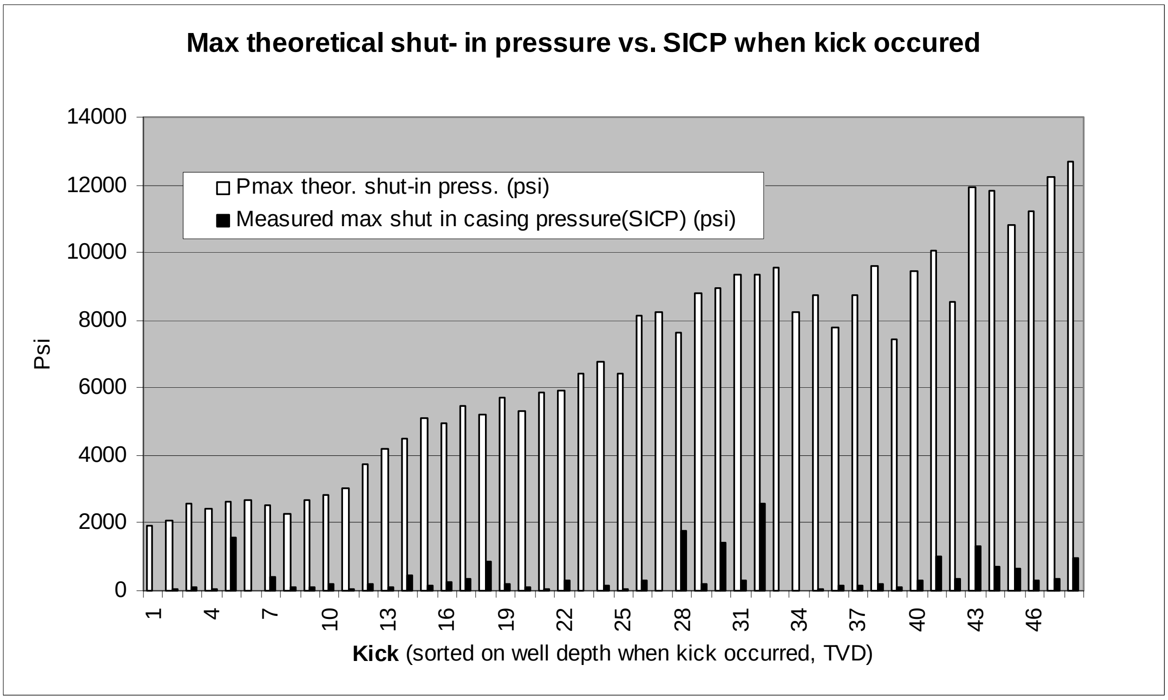

Figure 3.2 Max theoretical shut- in pressure vs. SICP

As seen from Figure 3.2, during the kick killing process there were no incidents with a very high measured shut-in pressure. Only one of the kicks experienced nearly 2500 psi shut-in pressure, four kicks had shut-in pressures between 1000 and 2000 psi, while the remaining kicks all observed maximum shut-in pressures below 1000 psi.

3.2 Well Depth when the Kick Occurred vs. the Casing Shoe Depth

Figure 3.3 shows the well depth when the kick occurred vs. the casing shoe depth (TVD).

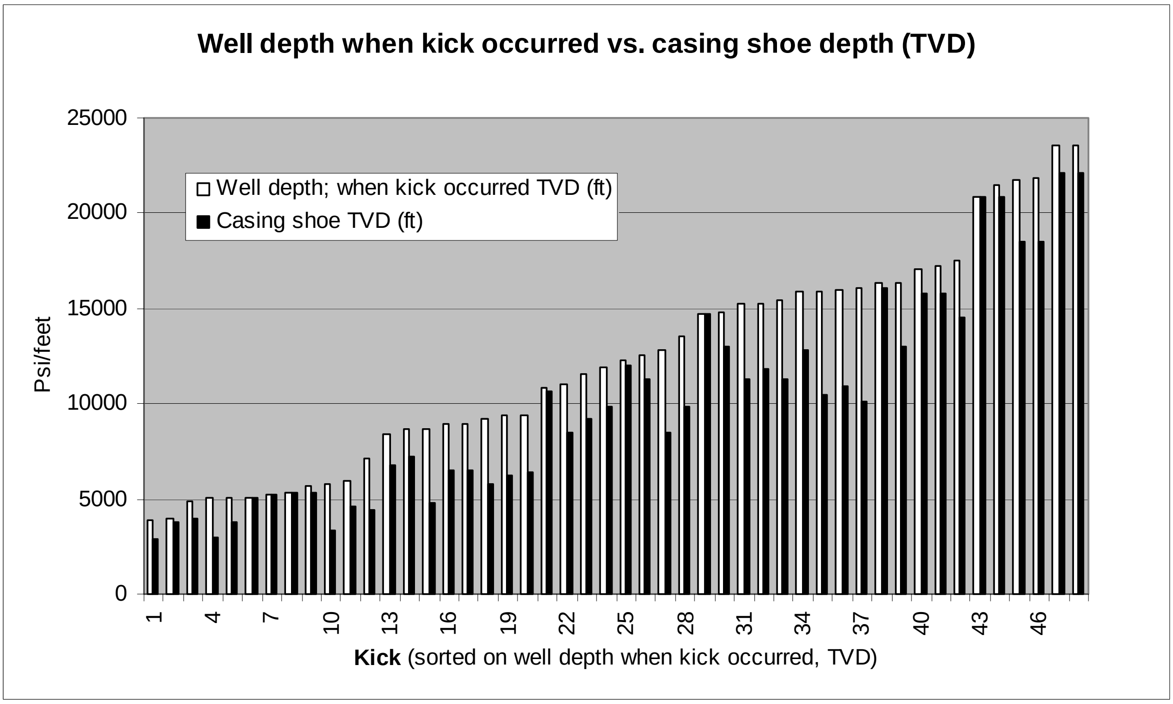

Figure 3.3 Well depth when the kick occurred vs. the casing shoe depth (TVD)

Approximately one forth of the kicks occurred fairly short time after drilling out of casing.

3.3 Well Depth when the Kick Occurred vs. the Total Well Depth

Figure 3.4 shows the well depth when the kick occurred vs. the total well depth.

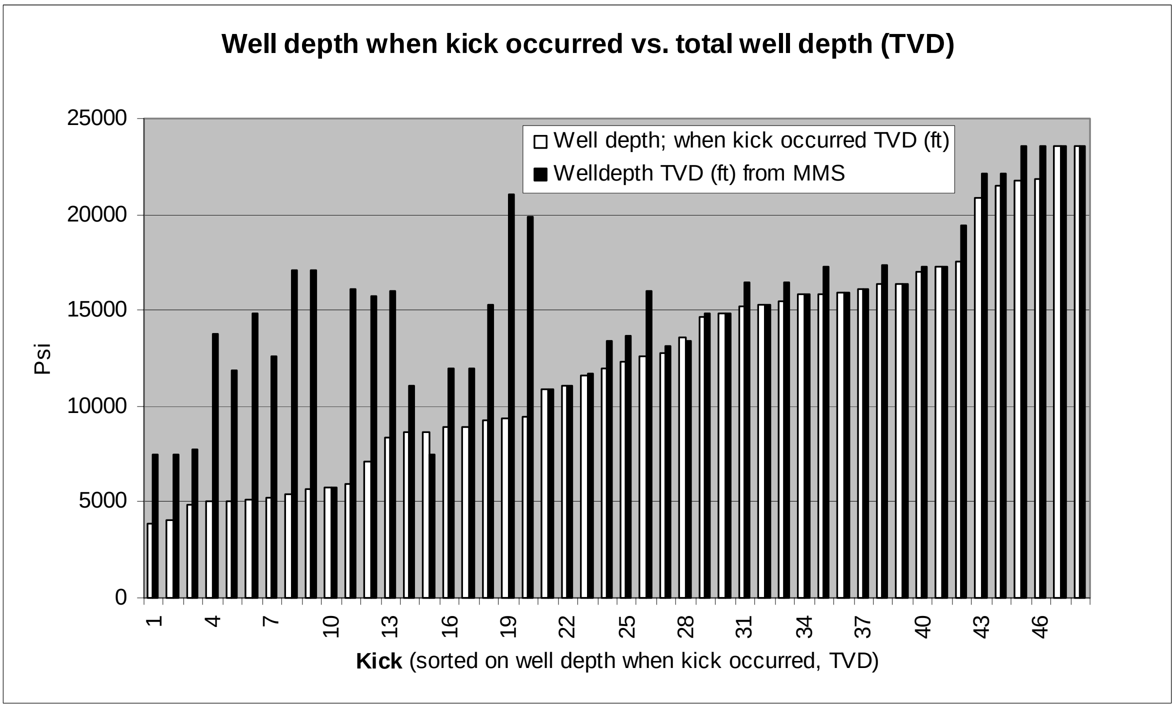

Figure 3.4 Well depth when the kick occurred vs. the total well depth (TVD)

As seen from Figure 3.4 some of the wells were not drilled any further after the kick was controlled. This because the final well depth was reached or that the well bore was side-tracked or abandoned as a result of complications associated to the well killing operations.

3.4 Leak off Test vs. Mud Weight when the Kicks Occurred

Figure 3.5 shows the leak off test (LOT) vs. mud weight (MW) when the kicks occurred.

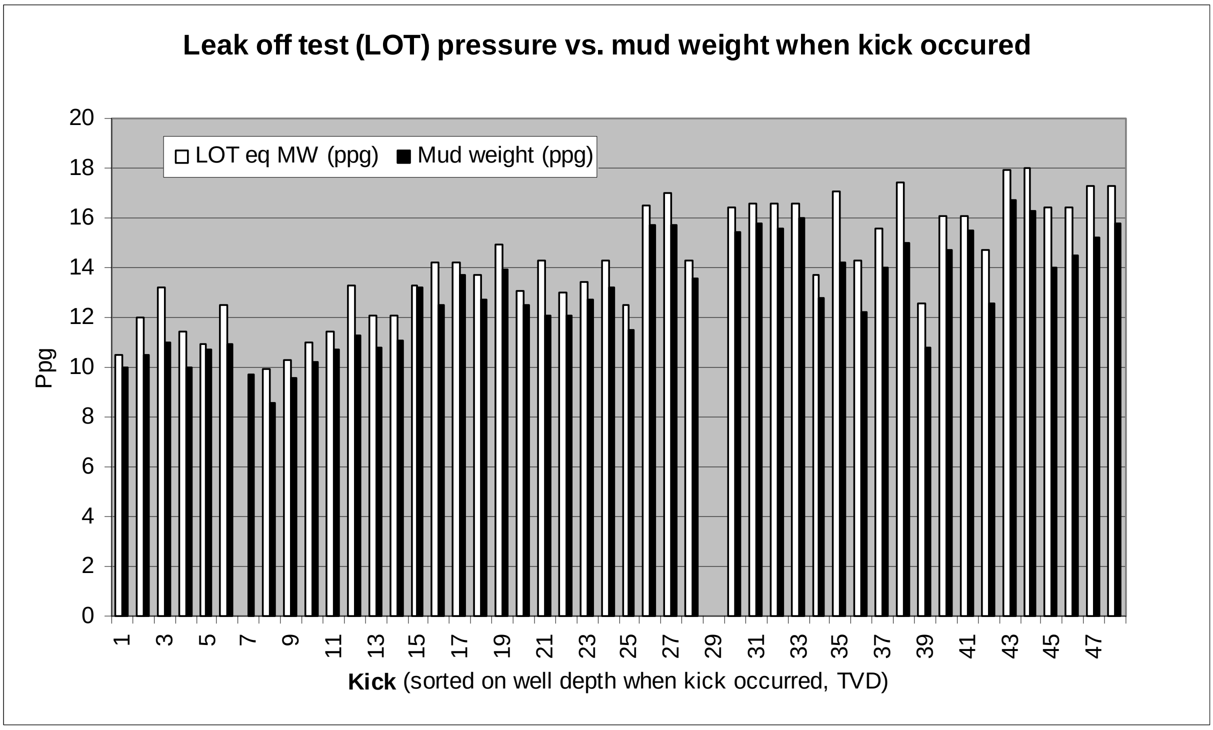

Figure 3.5 Leak off test (LOT) pressure vs. mud weight (MW) when kick occurred

Figure 3.5 shows that for many of the kicks the margin between the MW and the LOT is narrow, indicating a small margin between the pore pressure and the fracture pressure, thus making the wells difficult to drill. For 50% of the kicks the LOT - MW was 1 ppg or lower. The difference between the LOT and the MW and the occurrence of kicks is further discussed in Section 5 on page 45.

3.5 Kick Sizes

Figure 3.6 shows the kick sizes recorded.

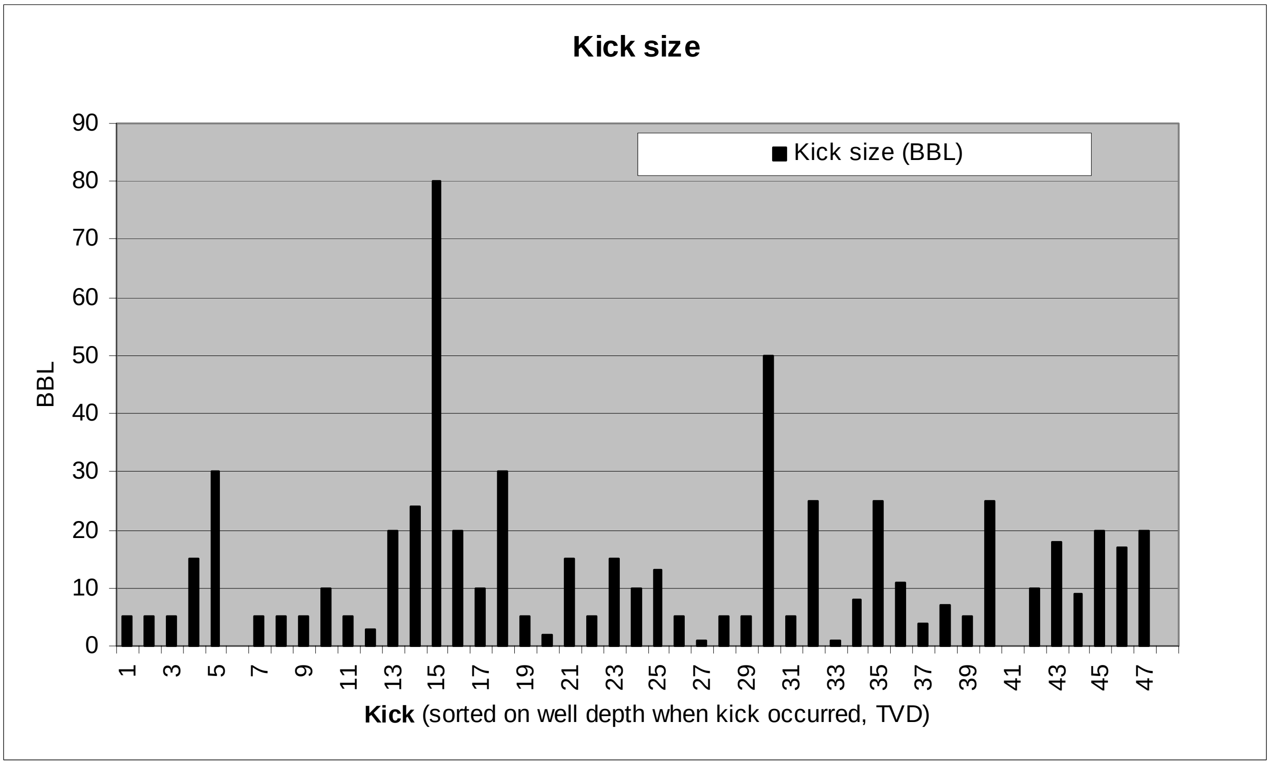

Figure 3.6 Kick size

It should be noted that the gain volume was not specifically listed for all kicks. Some gains were mud gains due to ballooning formation, and some gains also became large because it was not observed before the kick had passed the BOP and expanded in the riser. It seems to be no correlation between the kick size and the well depth when the kick occurred. There was no obvious correlation between the kick size and the water depth.

3.6 Kick Size vs. SICP

In general, there is a correlation between the SICP and the size of the kick. When a kick is detected early, i.e. a small kick, the SICP will be lower than if the kick is detected late. When comparing different kicks, the value of the SICP will also be affected by other factors, such as the kick medium, the depth of the kick, and the radius of the borehole. Figure 3.7 shows the correlation between the kick size and the SICP for all the kicks observed.

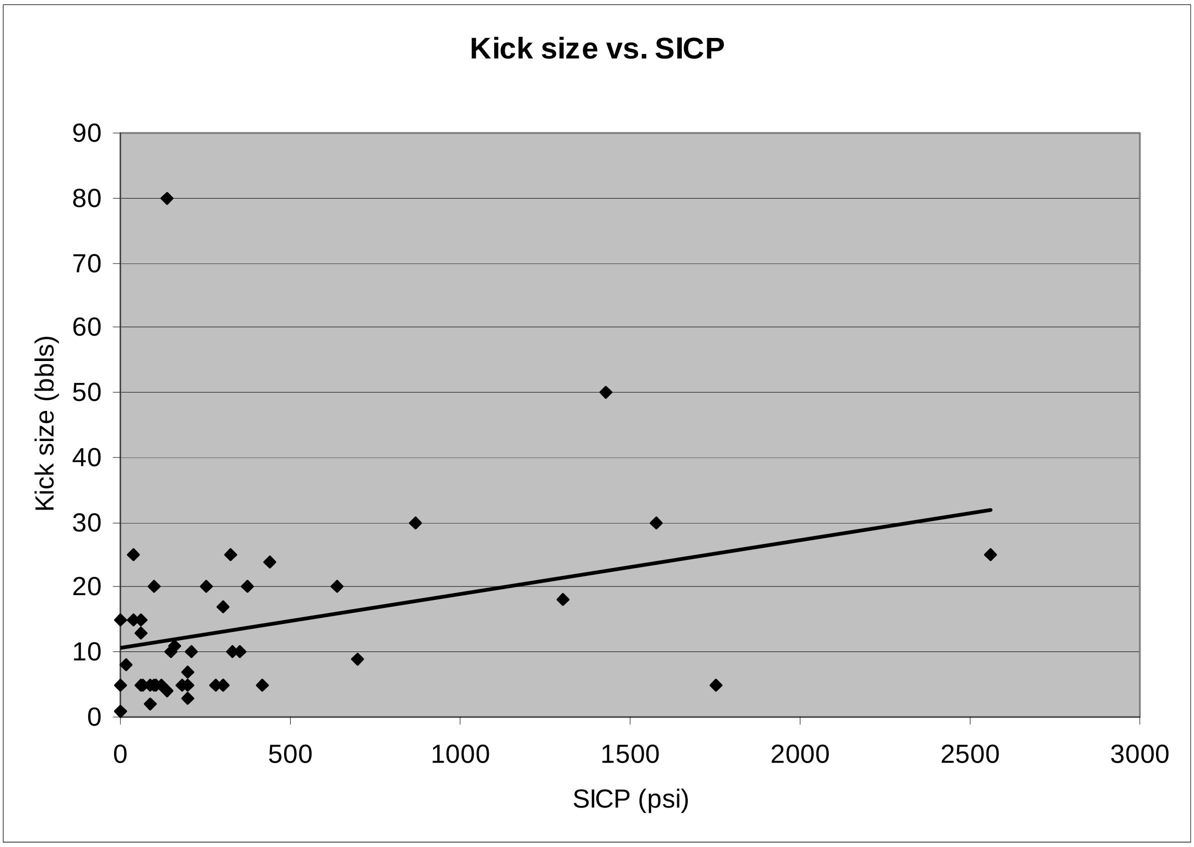

Figure 3.7 Kick size vs. SICP, all kicks

As seen from the regression line in Figure 3.7 there is a correlation between the kick size and the SICP, but not very clear. Many of the kicks involved the ballooning effect. Then the formation actually kicks drilling fluid. This drilling fluid will not disturb the hydrostatic control in the well. The kick size of these kicks is therefore not relevant. Some of the kicks had partially passed the BOP when the BOP was closed and the kick size will then seem larger due to the gas expansion in the riser. Further, for 14 of the kicks the kick size was not specifically mentioned in the daily drilling report and has been estimated when reviewing the daily drilling reports.

To establish a more clear correlation between kick size and the SICP, all the kicks where the ballooning effect occurred and all the kicks where the kick size was estimated were disregarded. The resulting relationship between the kick size and the SICP is shown in Figure 3.8.

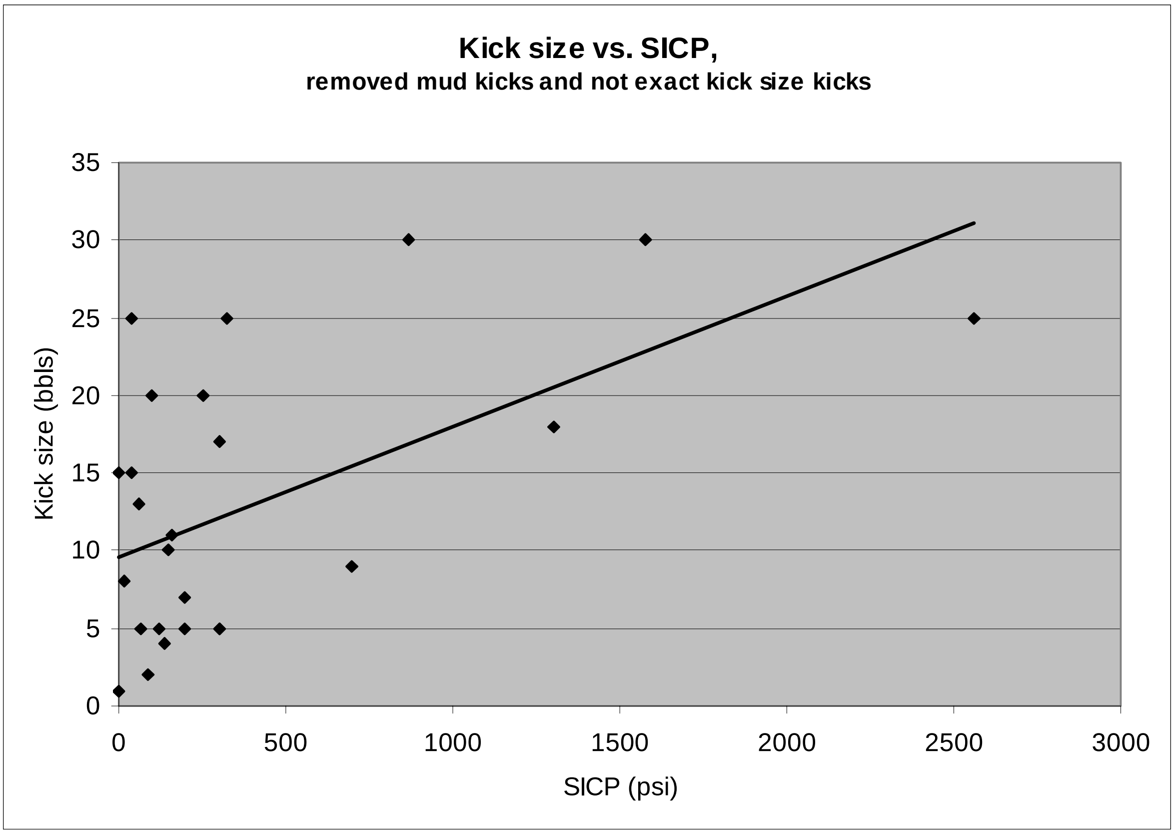

Figure 3.8 Kick size vs. SICP (removed "mud" kicks and "not exact kick size" kicks)

The relationship between the kick size and the SICP became a little clearer. The most mismatched points disappeared from the graph. A further subdivision of the data according to the well depth and the casing size was also carried out, but this did not make the correlation clearer. The number of data points decreased with this subdivision.

3.7 Kick Killing Duration

Figure 3.9 shows the kick killing duration. Included in this time is the time from the kick occurred until the well was controlled and the operations could continue.

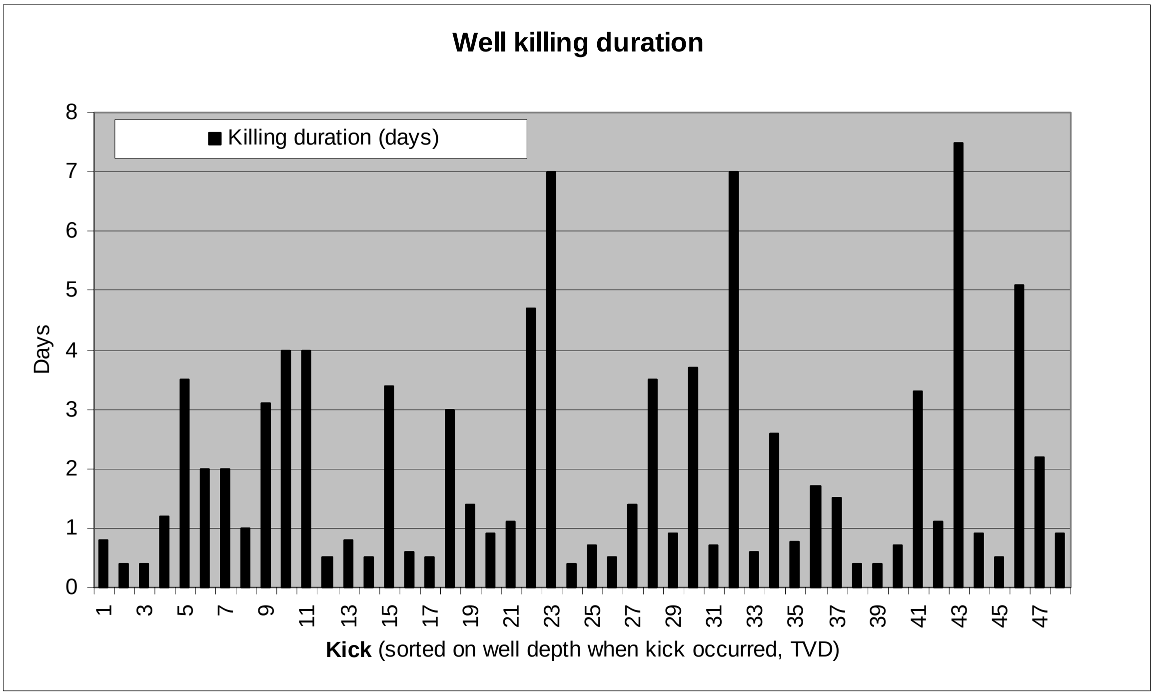

Figure 3.9 Killing duration

Fifty percent of the kicks are controlled within one day. Nearly one third of the kicks lasts more than three days. Ten percent of the kicks lasted approximately one week. There were found no correlation between water depth and well depth with the kick duration. It should be noted that when the kick caused problems with stuck pipe, or other that required the well to be abandoned or side-tracked, this is not included in the killing duration. This is discussed in Section 6.2.3 on page 54. Factors affecting the killing duration are further discussed in Section 6.3 on page 56.

3.8 Mud Type vs. Casing Size

Table 3.1 shows the mud type used vs. casing size when the kick occurred.

Table 3.1 Mud type vs. casing size

Mud type	Casing OD (inch) grouped					
	20	16	13.375 - 13.625	9.625 - 11.75	7 - 7.75	Total
Pseudo-oil based, alphaolefin (ultidrill)				3	2	5
Pseudo-oil based, ester (esterdrill)			1	2		3
Pseudo-oil based, polyalphaolefin (novasol)	1					1
Synthetic, no details available			2	5	1	8
Waterbased, no details available	1	2			1	4
Waterbased, dispersed mud	1	1	1	3		6
Waterbased, lime treated mud				1		1
Waterbased, polymer mud	1	4	1	2	1	9
Waterbased, saltwater systems mud	1				1	2
Waterbased, workover, compl. , drill-in mud					1	1
Unknown	1	2	4	1		8
Total	**6**	**9**	**9**	**17**	**7**	**48**

Water based mud may be used in any section of the well, while pseudo oil based mud is only used in deeper sections of the well.

3.9 Kick Medium vs. Casing Size

Table 3.2 shows the kick medium vs. the size of the inner casing.

Table 3.2 Kick medium vs. casing size

Kick medium	Casing OD (inch) grouped					
	20	16	13.375 - 13.625	9.625 - 11.75	7 - 7.75	Total
Gas	6	7	5	11	3	32
Gas, Mud		1		1	2	4
Gas, Oil				1		1
Gas, Water		1	1	3	1	6
Gas, Water, Mud			1			1
Gas, Water, Oil				1		1
Mud			1		1	2
Water			1			1
Total	**6**	**9**	**9**	**17**	**7**	**48**

Most kicks contain gas. Two kicks were mud kicks only (ballooning). They were regarded as kicks because the BOP was needed to control the situation and the MW was raised to kill the well. The pure water kick was believed to be water only because no reference to gas was made at all, both before and after the incident. For the kicks where both mud and gas are mentioned the ballooning effect may have contributed to the incident. For the kicks where oil and/or water are mentioned, oil and water were specifically stated as a part of the kick fluid in the daily drilling reports. For the 32 kicks categorized as gas kicks, no water or oil were mentioned in the daily drilling reports. Oil or water may, however, have been present in the kick fluid, but it was not stated in the daily drilling reports.

Of all the 83 deepwater wells included in this study (drilled in 97/98), 10 were listed with production in 1999 in the MMS OGOR A files (/28/). All these 10 wells produced both oil and gas. Five of the kicks occurred in these wells. None of the kicks where, however, observed at total depth. Three of the kicks occurred when drilling fairly close to the total depth (200 to 1300 ft. above), and two were far above (3500 and 7000 ft. above).

3.10 Tubular Running Through the BOP when the Kick Occurred

For all the kicks the tubular running through the BOP when the kick occurred was recorded. Table 3.3 shows an overview of the tubular running through the BOP when the kick occurred

Table 3.3 Tubular running through the BOP when the kick occurred

Type of tubular	Size (inches)	No. of kicks
Empty hole	-	1
Wireline	-	1
Test tubing	4.5	1
Drillpipe	5	25
Drillpipe	5.5	9
Drillpipe	Unknown	11
Total		**48**

The majority of kicks occur when there is normal drillpipe running through the BOP. For the incident with empty hole they increased the MW in the riser from 10.8 ppg to 11.1 ppg, and the well became static. For the incident with a wireline in the hole they pulled the wireline and stripped into the hole with drillpipe.

4. General Well Characteristics

4.1 Well Depth vs. Fracture Strength and Mud Weight

In general the equivalent fracture strength (found through LOT) increases with increasing formation depth. This has been visualized in Figure 4.1. For all the kicks the TVD of the casing shoe has been plotted against the LOT of the casing shoe.

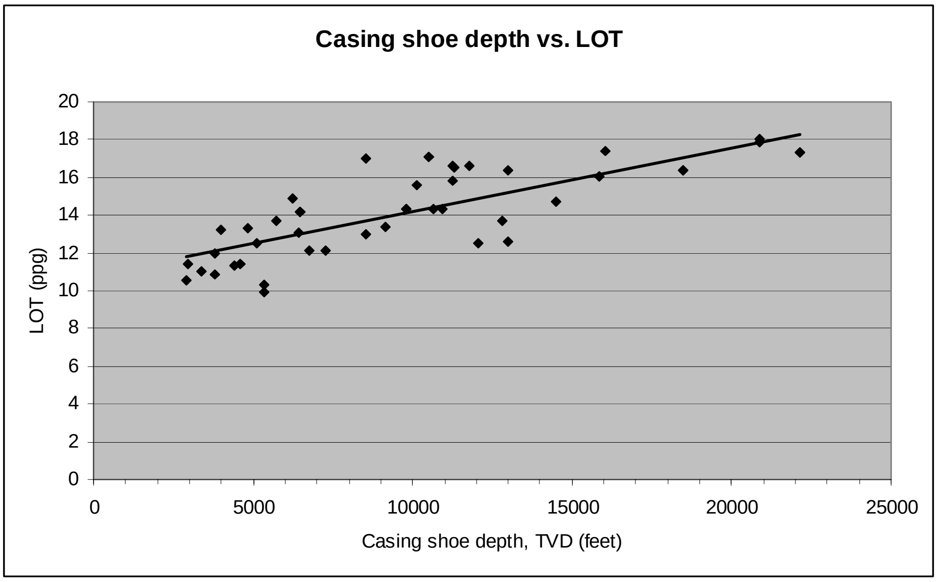

Figure 4.1 Fracture strength vs. casing shoe depth for all kicks

The same trend has been made for the mud weight (or pore pressure) as shown in Figure 4.2.

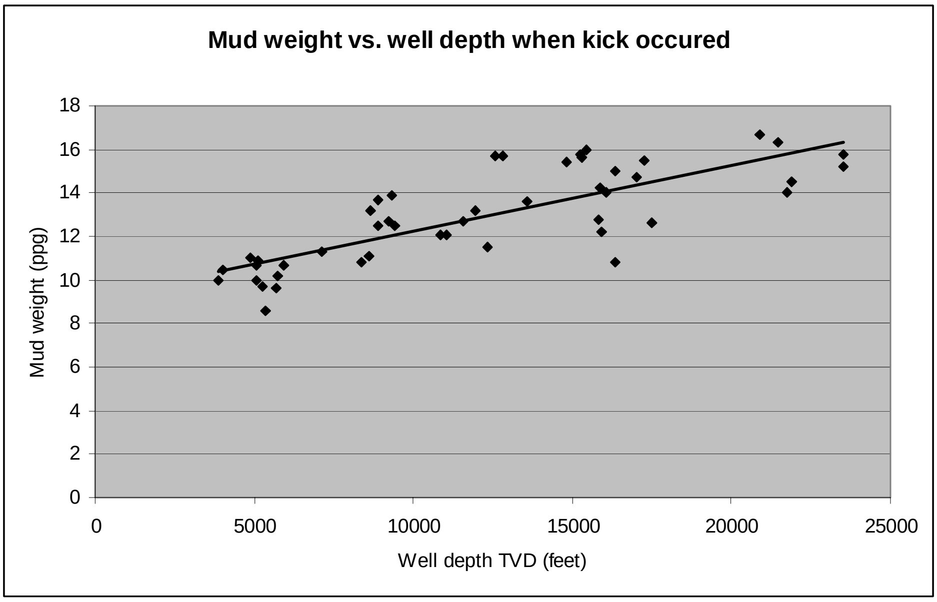

Figure 4.2 Mud weight (or pore pressure) vs. well depth when kick occurred

4.2 Formation Strength vs. Water Depth

Within a selected range of casing shoe depths (8000 and 13 000 ft.), 17 kicks were observed. For these 17 kicks 15 different casing strings were involved (two times two kicks occurred within the same casing string). For this range of casing shoe depths the LOT decreased with increasing water depths. To visualize this Figure 4.3 was drawn.

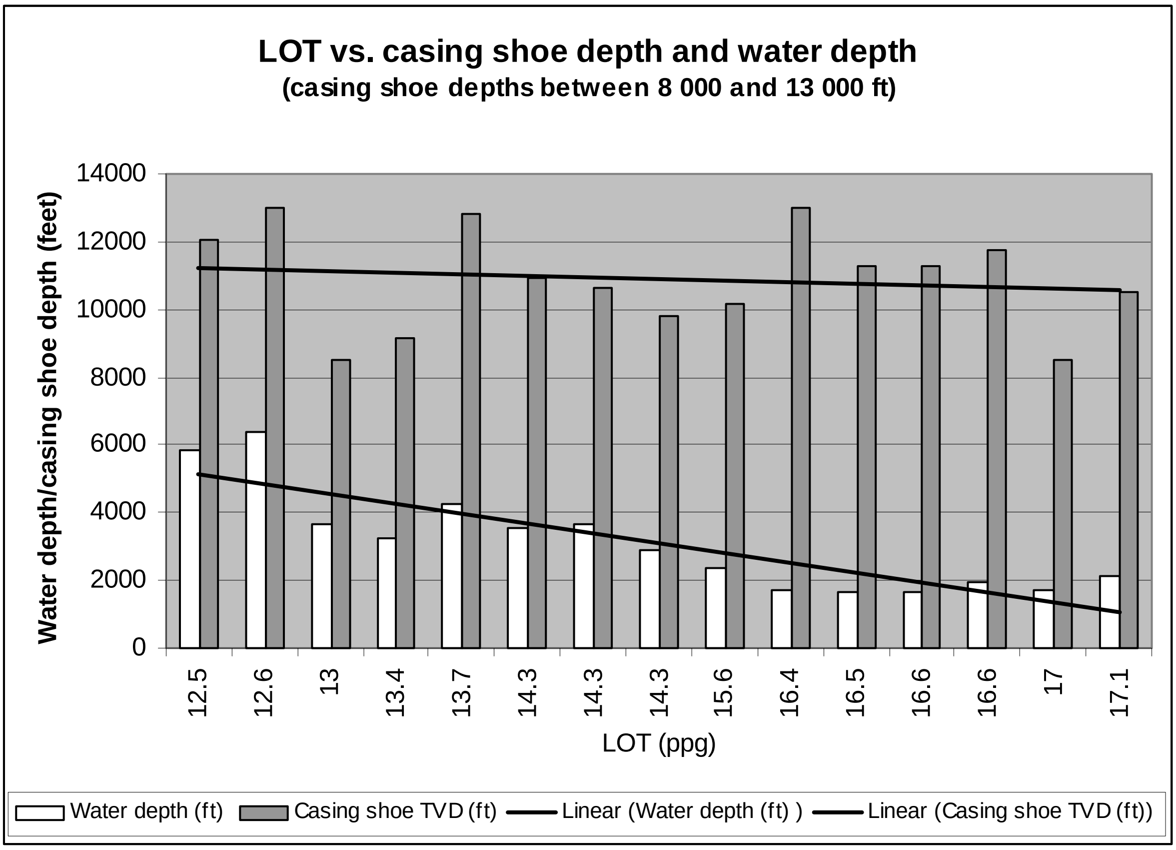

Figure 4.3 Formation strength vs. water depth

As seen from Figure 4.3 the formation strength is increasing with a reduction in the water depth for this specific depth range. This is to be expected because the well depth is measured from the kelly bushing. A 10 000 ft. well in 6000 ft. of water only has 4000 ft. of formation and 6000 ft. of water above the casing shoe. A 10 000 ft. well in 2000 ft. of water has 8000 ft. of formation and 2000 ft. of water above the casing shoe. This means that the formations in shallow water are more compressed than in deep water at the same well depths.

5. Kick Causes

The frequency of deepwater kicks is high (Section 2.2 on page 20). This section focuses primarily on the operation and activities when the kick occurred and the direct reason for the loss of barriers. When analyzing the causes of the kicks it is important to note that the margin between the LOT and MW is in general low for these deepwater wells. The effect of the low LOT - MW difference is discussed in Section 5.4 and 5.5 on page 48.

The causes of kicks have been implemented in the database when collecting the data. It should here be noted that specific causes were normally not stated in the daily drilling report. The kick causes listed have been assessed by evaluating the operations and observations listed prior to the kick.

5.1 Operation Activity when the Kick Occurred

Table 5.1 shows the operation and activity that were ongoing when the kick was observed.

Table 5.1 Operation activity when the kick occurred

Operation	Activity	Development drilling	Exploration drilling	Total
Abandon well	Out of hole (displacing mud in riser)		1	1
Casing running	Cementing	1	1	2
Circulating	Circulating		1	1
	Stuck pipe		1	1
Drilling activity	Actual drilling	2	19	21
	Actual drilling (making connection)	1	7	8
	Circulating	1	5	6
	Trip out of hole	2	3	5
	Pull wireline (in empty hole)	1		1
	Weighting up mud		1	1
Well testing	Fracturing, Circulating	1		1
Total		**9**	**39**	**48**

As expected the majority of kicks occurred during drilling operations. Of these incidents the majority were observed when drilling new hole. Eight incidents were observed when making a connection. Six of the incidents were listed as occurring during circulating mud, it is here however likely that the gas was already inside the well bore. Five incidents were observed when tripping out of the hole. One was observed when pulling wireline out of an empty hole and one when weighting up mud.

Otherwise one kick occurred when fracturing the well prior to a well test and two in association with casing running and cementing. One kick also occurred in association with a well abandon operation.

5.2 Activity and Primary Cause of Kick

It has been selected not to separate the development and exploration wells for the remaining of this section.

Table 5.2 shows the ongoing activity and the assumed (by the project group) cause of the kick.

Table 5.2 Activity and primary cause of kick

Activity	Primary kick cause (Loss of barrier 1)	Total
Actual drilling	Annular losses	1
	Annular losses, ballooning	1
	Gas cut mud	6
	Gas cut mud, drilling break	1
	Too low mud weight	5
	Too low mud weight (no riser margin and external leakage)	1
	Too low mud weight, drilling break	3
	Too low mud weight, gas cut mud	1
	Gas cut mud, too low mud weight, drilling break	2
Actual drilling Total		21
Actual drilling (making connection)	Annular losses, ballooning	1
	Gas cut mud	1
	Gas cut mud, too low mud weight	2
	Too low mud weight	3
	Too low mud weight, drilling break	1
Actual drilling (making connection) Total		8
Trip out of hole	Swabbing	2
	Swabbing, ballooning	1
	Swabbing, gas cut mud	1
	Swabbing, improper fill up	1
Trip out of hole Total		5
Cementing	Annular losses, ballooning	1
	Poor cement, formation breakdown	1
Cementing Total		2
Circulating	Annular losses	2
	Annular losses, ballooning	1
	Gas cut mud	1
	Gas cut mud, drilling break	1
	Poor cement, Too low mud weight	1
	Gas cut mud, too low mud weight, drilling break	1
Circulating Total		7
Fracturing, Circulating	Too low mud weight	1
Out of hole (displacing mud in riser)	Too low mud weight	1
Stuck pipe	Annular losses, ballooning	1
Pull wireline (in empty hole)	Annular losses, ballooning	1
Weighting up mud	Too low mud weight	1
Other Total		1
Total all		**48**

When reading the results in Table 5.2 it is important to note the Figure 3.5 on page 35 and Table 5.4. The narrow margin between the LOT and the MW indicates that it will be fairly easy to experience a kick or annular losses, because both the kick margin and the trip margin have to be kept within strict limits. The effect of a low LOT - MW for the deeper sections drilled is discussed in Section 5.5 on page 49.

It should further be noted that the category "Too low mud weight" also included incidents with an "Unexpected high well pressure". Kicks categorized with the kick cause "Too low mud weight" only, were typical kicks were no specific indication of kick cause was given in the daily drilling report.

In ranked order the most significant contributors to the kick occurrence were:

- Too low mud weight (23)
- Gas cut mud (17)
- Annular losses (9)
- Drilling break (9)
- Ballooning (7)
- Swabbing (5)
- Poor cement (2)
- Formation breakdown (1)
- Improper fill up (1)

The frequent occurrences of too low mud weight and annular losses may to a large degree be explained by the small difference between the fracture pressure and the pore pressure. Annulus friction during circulation is also likely affecting this problem.

Gas cut mud occurs when formation gas mixes with the mud as small gas bubbles. This effect reduces the mud density, and at a certain level it will cause that the hydrostatic control of the well is lost.

When drilling break is listed as a partial cause of the kick, a drilling break has been mentioned in the daily drilling report just prior to the incident. A drilling break may occur when drilling into gas bearing sands.

The ballooning effect is observed in association with annular losses. First annular losses are observed, thereafter the formation partly returns the losses. This effect has contributed to the kick occurrence for several kicks. It should be noted that this effect was observed several times when reviewing the daily drilling reports, but did normally not cause a kick.

Swabbing is typically a main contributor to kicks during tripping out of the hole. If the trip margin is low, the mud weight is cut by gas, or the well is improperly filled up, it is more likely that swabbing will cause a kick.

5.3 Casing Sizes when Kick Occurred vs. Primary Cause of Kick

Table 5.3 shows the casing sizes when kick occurred vs. the primary cause of kick.

Table 5.3 Casing sizes when kick occurred vs. primary cause of kick

Primary cause of kick	Casing OD (inch) grouped					Total
	7 - 7 3/4	9 5/8 - 11 3/4	13 3/8 - 13 5/8	16	20	
Annular losses		1	1		1	3
Annular losses, ballooning	2	1	2	1		6
Gas cut mud		3	1	3	1	8
Gas cut mud, drilling break					2	2
Gas cut mud, too low mud weight		2				2
Gas cut mud, too low mud weight, drilling break	1	1	1			3
Poor cement, Too low mud weight	1					1
Poor cement, formation breakdown				1		1
Swabbing		2				2
Swabbing, ballooning	1					1
Swabbing, gas cut mud				1		1
Swabbing, improper fill up		1				1
Too low mud weight	2	4	3		2	11
Too low mud weight (no riser margin and external leakage)		1				1
Too low mud weight, drilling break		1	1	2		4
Too low mud weight, gas cut mud				1		1
Total	**7**	**17**	**9**	**9**	**6**	**48**

The wells may kick at any depth. Fifty percent of the kicks have occurred when performing operations below the 9 5/8" - 11 3/4" casing shoe, while the remaining 50 % occurred higher up in the well. It is not seen any correlation between the casing size and the primary kick cause. It should be noted that the setting depths of the various casing sizes vary highly from well to well.

5.4 Primary Kick Causes vs. Difference Between the LOT and MW

In half of the cases the margin between the LOT and the MW was only 1 ppg or less (Section 3.4, page 35). Such wells kick "easily" because the mud weight must be kept so low. This is the main reason for the experienced high kick frequency. In this weakened situation the formation is bound to be fractured, either as fully (observed as losses) or partially (observed as ballooning).

For the deep water wells, the fracture gradient is typically much lower than at comparative depths in on-shore wells, causing the breakdown pressure to be closer to the pore pressure than desired.

In Table 5.4 the primary kick causes vs. difference between the leak off test pressure (LOT) and the mud weight (MW) when kick occurred are shown.

Table 5.4 Primary kick causes vs. difference between LOT and MW when kick occurred

Primary kick cause	Difference between LOT and mud weight when kick occurred grouped					Total	
	≤ 1 ppg		> 1 ppg		Unknown		
	No. of kicks	Distri-bution	No. of kicks	Distri-bution	No. of kicks	No. of kicks	Distri-bution
Annular losses	3	14 %				3	6 %
Annular losses, ballooning	3	14 %	3	13 %		6	13 %
Gas cut mud	6	27 %	2	8 %		8	17 %
Gas cut mud, drilling break	1	5 %	1	4 %		2	4 %
Gas cut mud, too low mud weight, drilling break	1	5 %	2	8 %		3	6 %
Gas cut mud, too low mud weight	1	5 %	1	4 %		2	4 %
Poor cement, formation breakdown			1	4 %		1	2 %
Poor cement, Too low mud weight			1	4 %		1	2 %
Swabbing	1	5 %	1	4 %		2	4 %
Swabbing, ballooning			1	4 %		1	2 %
Swabbing, gas cut mud	1	5 %				1	2 %
Swabbing, improper fill up			1	4 %		1	2 %
Too low mud weight	2	9 %	7	29 %	2	11	23 %
Too low mud weight (no riser margin and external leakage)	1	5 %				1	2 %
Too low mud weight, drilling break	1	5 %	3	13 %		4	8 %
Too low mud weight, gas cut mud	1	5 %				1	2 %
Total	22	100 %	24	100 %	2	48	100 %

When reading Table 5.4 it is important to note that this only lists observations for the kicks that have occurred. For the kicks with the low difference between the LOT and MW it seems that the relative proportion of "Annular losses" caused kicks are higher, while the relative proportion of "Too low mud weight" caused kicks are lower. It is here important to note that "Unexpected high well pressure" kick causes are included in "Too low mud weight" (see also page 46.)

The general exposure with respect to difference between the LOT and MW for all wells and all sections drilled is not known. The difference between the LOT and MW in the deeper sections drilled is discussed in Section 5.5.

5.5 Leak Off Pressure vs. Maximum Mud Weight, all “Deep” Wells

To further investigate the possible effect on kick occurrences vs. the LOT – MW all the wells drilled deeper than 13000 TVD ft. were closer examined. For the deepest sections drilled the LOT and the maximum MW used were recorded by reviewing the daily drilling reports for all wells once more. A total of 43 wells were drilled deeper than 13000 ft. In 15 of these sections they experienced one or more kicks. In the other 28 wells, they did not experience any kick. Table 5.5 shows some average parameters for the deepest sections of the wells drilled deeper than 13000 ft.

Table 5.5 Average parameters for “deep” wells with and without a kick

	LOT – max MW, average (ppg)	Total well depth TVD, average (ft.)	Maximum theoretical shut-in pressure, average (psi)*
Sections with kick	1.01	16479	9333
Sections with NO kick	1.31	17486	9431
Average all	**1.21**	**17135**	**9396**

* See section 3.1, page 31

Table 5.5 shows as expected that the average LOT – MW was lower in the well sections where the well kicked. The LOT - MW was thereafter grouped in two groups and related two occurrences of kicks. Table 5.6 shows the results.

Table 5.6 Grouped LOT - MW vs. kick occurrences "deeper" sections

LOT – maximum MW (ppg)	No. of well sections that experienced one or more kicks	No. of well sections that experienced NO kick	Total
0.4 - 1.0	11 52%	10 48%	21
1.1-2.4	4 19%	17 81%	21
Unknown	-	1	1
Total	**15**	**28**	**43**

As seen from Table 5.6, in 50% of the sections where the LOT - MW was 1 or lower a kick was experienced. For the well sections with the minimum LOT - MW above 1, a kick was experienced in only 19% the well sections.

Regarding the well depth the sections with no kick were in average drilled 1000 ft. deeper than the well sections that experienced a kick (Table 5.5). When looking closer at the data the LOT - MW was in average higher for the deeper sections than the more shallow sections. The depth as such is therefore believed not to affect the likelihood of kick occurrences, the main factor is the LOT - MW. The average maximum theoretical shut-in wellhead pressure was at the same level for both the wells that kicked and those that did not kick.

6. Analyses of Kick Killing Operations

This section focuses on the killing procedures, killing problems and killing duration for the 48 experienced kicks. Table 6.1 shows the killing duration of the experienced kicks.

Table 6.1 Killing duration distribution of the 48 kicks

Killing duration (days)	No. of kicks	Total days used
≤ 0.7	15	7.8
0.7 – 0.9	7	6.0
1.0 - 1.9	8	10.4
2.0 – 2.9	4	8.8
3.0– 4.9	10	36.2
5.0 – 8.0	4	26.6
All	**48**	**95.8**
Average		**2.0**

Many of the kicks were time consuming to control. They used more than 1 day to control 50% of the kicks. For 29 % of the kicks they used more than three days to control the kick. The average time spent to control a deepwater kick was 2 days.

The problems and relevant factors affecting the kick killing are discussed in the following subsections. Section 6.1 presents the killing methods in general, Section 6.2 discusses specific problem types observed during the killing of the various wells, and Section 6.3 attempts to identify correlations between the killing duration and well characteristics.

6.1 Killing Methods

The killing methods may be categorized in the following groups;

- Circulating
- Bullheading
- Cementing
- Bleed off
- Diverting
- Capping

Table 6.2 shows the no. of the various killing methods used.

Table 6.2 Specification of killing method

Total no. of kicks	Killing methods utilized*					
	Circulating	Bullheading	Cementing	Bleed off	Diverting	Capping
	42	4	8	1	2	
		2	2			
			2			
				1		1
48	42	6	12	2	2	1

* Note that for several kick killing operations more than one killing method was utilized.

Circulating heavier mud is the most common way of regaining the control of a kick. For many kicks circulation alone could not control the kick and a combination with other methods was required. Circulation alone was used in 29 of the kicks. Bullheading was used for six kicks, this in combination with circulating and/or cementing. Cementing was used directly for two kicks. One of them after a poor casing cement job and one in a stuck pipe and kick situation. Once they bled off the pressure to be able to install a casing seal.

From the text in the daily drilling report it was not obvious to see if the Driller's or the Engineer's method was utilized for the majority of the kicks. The Driller's method was specifically stated two times, and the Engineer's method three times. The volumetric method was stated for one of the kicks only.

Six times it was specifically stated that both the choke and the kill lines were used for circulation. This is done to reduce the choke line friction pressure loss that again reduces the chance of fracturing the formation during circulation. This is typically a deepwater problem. The friction increases as a function of the riser length.

6.2 Problems During Killing Operations

Of the 48 kicks evaluated, specific problems during the kick killing was observed for 38 of them. When problems are encountered during killing this will cause a prolonged killing duration. For killing operations lasting longer than one day they have normally experienced some sort of problems during killing. Killing duration distribution is presented in Table 6.1, and in Figure 3.9 on page 39.

The observed problems, as described in the daily drilling reports, were categorized and are summarized in Table 6.3.

Table 6.3 Distribution of problems during killing operations

No. of kicks	Problems identified during kick killing operations*							No significant problems identified
	Losses (and ballooning)	Hydrate problems	Cement-ing	Drillpipe problems	Pressure transmis-sion	Gas migrat-ion through cement	Fractured during killing	
	29		8	5	8	1		
		3	1	2	1			
			3	1		1	1	
				2				
					1			
								10
48	29	3	12	10	10	2	1	10

* Note that for several kick killing operations more than one problem type were identified

Many kicks were reported with a variety of problems. The total number of listed problems is therefore larger than the number of kicks involved. The dominant problem during the well killing operations was losses (and ballooning). For 29 of the kick killing operations these problems were observed. For 12 of the kicks they had to squeeze cement to regain control of the well. This was normally done after they had given up circulating the well dead. For 10 of the kicks the pipe became stuck during the kick killing operations. For nine of the incidents involving stuck pipe the wells had to be side-tracked or the well was abandoned. Wells that had to be side-tracked or abandoned are discussed closer in Section 6.2.3. For one kick they had to wait for additives to the mud because of bad weather. Problems with signal transmission and hydrates were also observed. During the kick killing operations, stripping drillpipe into the well and jarring/fishing also complicated the killing operation.

6.2.1 Ballooning and Losses

It is likely to assume that the ballooning and losses problems are related to the LOT - MW margin. To check this assumption LOT - MW was investigated for the kicks that experienced ballooning and losses during the kick killing operation with the kicks that did not. Table 6.4 shows the results from this comparison.

Table 6.4 Ballooning/losses problem vs. LOT - MW during killing operations

LOT - MW (ppg)	Ballooning and looses reported	***NO*** ballooning and looses reported	Total
LOT - MW ≤ 1.0	17 77 %	5 23 %	22 100 %
1.0 < LOT - MW ≤ 1.5	5 56 %	4 44 %	9 100 %
1.5 > LOT - MW	6 43 %	8 57 %	15 100 %
Unknown	1	1	2
Total	**29**	**18**	**48**

As seen from Table 6.4 losses and ballooning is a more likely complicating factor during killing operations where the LOT - MW is small than large. It should, however, be noted that ballooning/losses frequently also occur in wells with a LOT – MW that is larger than 1.5 ppg.

The ballooning losses incidents with high LOT - MW were checked more thoroughly for the six kicks. For one of the incidents they had just cut the 13 5/8" casing and was prepared for abandoning the well when the kick occurred. The kick was likely caused by shallow gas or trapped gas behind the casing. The 16" casing LOT - MW was 1.0 ppg (not 1.8 if relying on the 13 5/8" LOT). So this kick is really not relevant in this comparison. The second kick can be explained by relatively high kill mud weight and pressure transmission problems (high resistance in the choke/kill line). For the third incident the LOT - MW was as high as 2.9 ppg. Also for this incident they had pressure transmission problems. They were drilling in 2100 ft. of water. For the forth and the fifth incidents no explanation can be made. For the last of these kicks they experienced pressure transmission problems (3700 ft. of water).

6.2.2 Hydrates and Pressure Transmissions

Not much information was found on the three suspected hydrate occurrences. For all these three incidents it was specifically mentioned in the daily drilling report that they suspected a possible hydrate problem. Hydrates are frequently referred to as a water depth related problem. The average water depth for these three incidents was 3470 ft. The average water depth for all the other gas kicks was 2564 ft.

Pressure transmission problems were normally not stated specifically in the daily drilling reports. We assumed that there were problems with the pressure transmission when;

- No shut-in pressure was observed on the drillpipe or annulus but the well flowed when annular was re-opened (pressure was not transmitted through the choke or kill line)
- SICP was lower than the SIDPP

Pressure transmission problems are assumed to be related to the water depth and the mud properties. We found the average water depth for the 10 kicks reported with a pressure transmission problem to be 3045 ft. The average depth for kicks with no such reported problems was 2547 ft.

Regarding the effect of the mud type there were too few occurrences to investigate.

6.2.3 Stuck Pipe, Side-tracks and Abandonment of the Wells

Stuck pipe was observed in connection with 10 of the kicks. Stuck pipe causes two main problems in kick killing.

1. It becomes more difficult to regain the well control and thereby increase the killing time
2. After regaining the control it is a very high probability that the well has to be abandoned or side-tracked.

This is clearly verified through the average time to control a kick with and without stuck pipe. The average time for controlling kicks with stuck pipe was 3.6 days, vs. 1.66 days for kicks that did not experience stuck pipe.

When reviewing the kicks where stuck pipe occurred it was observed that the LOT - MW varied between 0.6 - 2.2 ppg, 1.22 in average. This is slightly less than the average for all the kicks (1.28 ppg). The well depth varied from 5700 ft. (TVD) to 22 000 ft. (TVD). For half of the kicks water based mud was used, for the other half, synthetic mud was used.

The measured length of the open hole section ($MD_{well} – MD_{casing\ shoe}$) was also investigated for the kicks where the pipe got stuck. The average open hole length was 3238 ft. (ranging from 568 ft. to 5480 ft.). For the kicks with *no* stuck pipe the average open hole section was 2090 ft. (ranging from 0 to 5953 ft.). It is obvious that the pipe will hardly become stuck within a cased hole. The nine kicks with an open hole section less than 500 ft. were therefore taken out of the average calculations. Then the average open hole section was 2693 for the kicks where the pipe did not become stuck. There is a correlation between the probability of becoming stuck during a kick killing operation and the length of the open hole section.

A review was carried out to identify wells that were side-tracked or abandoned due to the kick occurrence and handling. At least 10 of the wells were abandoned or side-tracked as a result of the kick. Before reaching a decision to abandon or side-track the well they have typically been working with the well for some time.

Table 6.5 shows the summary of activities before side-tracking or abandoning the wells after a kick for the 10 identified kicks

Table 6.5 Summary of activities before side-tracking or abandoning the wells after a kick

Kick ID	Result	Comment	Lost time before continue operation (days)
10	Side-tracked well	Set well plug and pulled BOP for repair because the annular had failed due to the stripping operation during the kick. Also got failure on poslocks. (6.1 days). Pulled/drilled plugs, cut and pulled casing (7 days). Started to side-track well 8000 ft. higher in the well. The actual reason for the side-track was not clear from the daily drilling reports.	15
11	Aband-oned well	Worked 3.5 days to free pipe, but failed. Prepared to abandon and abandoned well in 12 days.	12
15	Side-tracked well	When they observed that the pipe was stuck they immediately started preparation to shoot off the string, set cement plugs and side-tracked the well. They spent 4 days. Started side-track 2400 ft. higher in the well (at 3400 ft.).	4
28	Side-tracked well	Worked with stuck pipe. Shot it off close to the bottom of the well. Cemented deep part. Side-tracked at 24 735 ft. (well depth before kick was 25 460 ft.) (this is not recorded as a side-track in the MMS well file)	7.6
37	Side-tracked well	Severed pipe at 7224 ft. Pipe became stuck again. Severed pipe at 6890. Set two plugs and side-tracked well bore at 5791 ft. Original hole depth was 9234 ft.	6
38	Aband-oned well	Worked with stuck and parted pipe for 2.5 days before deciding to plug the well. Plugged well and worked for 7 days before they were ready to pull the BOP	9.5
40	Side-tracked well	After the well was killed they shot off the pipe. Attempted to fish the pipe end, but had problems to come down. Set two cmt. plugs. Original hole 11642 ft., side-track kicked off at 9571 ft.	7
41	Side-tracked well	After the well was killed the pipe was stuck. Backed off pipe. Could not release it. Plugged well back and pulled csg. Original hole was 11528 ft. deep, side-track kicked off at 7700 ft. (note they experienced a kick in the original wellbore at the same depth (kick 40). This kick also caused the well to be side-tracked.)	13
44	Side-tracked well	Ran another cement plug. Tested the BOP and started to side-track the well at 6300 ft. MD before kick was 13067 ft.	2.8
49	Aband-oned well	They worked on stuck pipe and fishing for 250 hrs before they plugged and abandoned the well.	10.4
All			87.3

The main problem during killing resulting in a decision to abandon or side-track a well is stuck pipe. The typical result of stuck pipe situation during a kick is that the well, after it is hydraulically controlled and/or cemented, has to be side-tracked or abandoned.

A total of 10 stuck pipe incidents during the 48 kicks were observed. Nine of them resulted in a side-track or abandoned well.

The time spent from the kick is hydraulically controlled until they were ready to start side-tracking was recorded for the abandoned/side-tracked wells. As seen from Table 6.5 they in total spent 87 days of work from the kick was controlled until they were ready to continue with the operation. In addition to the time spent, they also have to re-drill, so the operational time losses associated to this type of kicks are extensive.

6.3 Relations Between Some Well Parameters and Prolonged Killing Time

Eight different factors have been seen as potential reasons for the problems occurring during killing operations. In this subsection the kick duration vs. the following factors have been evaluated:

- Water depth (Section 6.3.1)
- Well depth (TVD) (Section 6.3.2)
- Drilling fluid type (Section 6.3.3)
- Kick size (Section 6.3.4)
- Fracture strength (LOT) – mud weight (MW) (Section 6.3.5)
- Open hole length (Section 6.3.6)
- Maximum theoretical shut-in pressure (Section 6.3.7)

6.3.1 Water Depth vs. Killing Duration

Figure 6.1 shows an XY plot for the water depth vs. the killing duration.

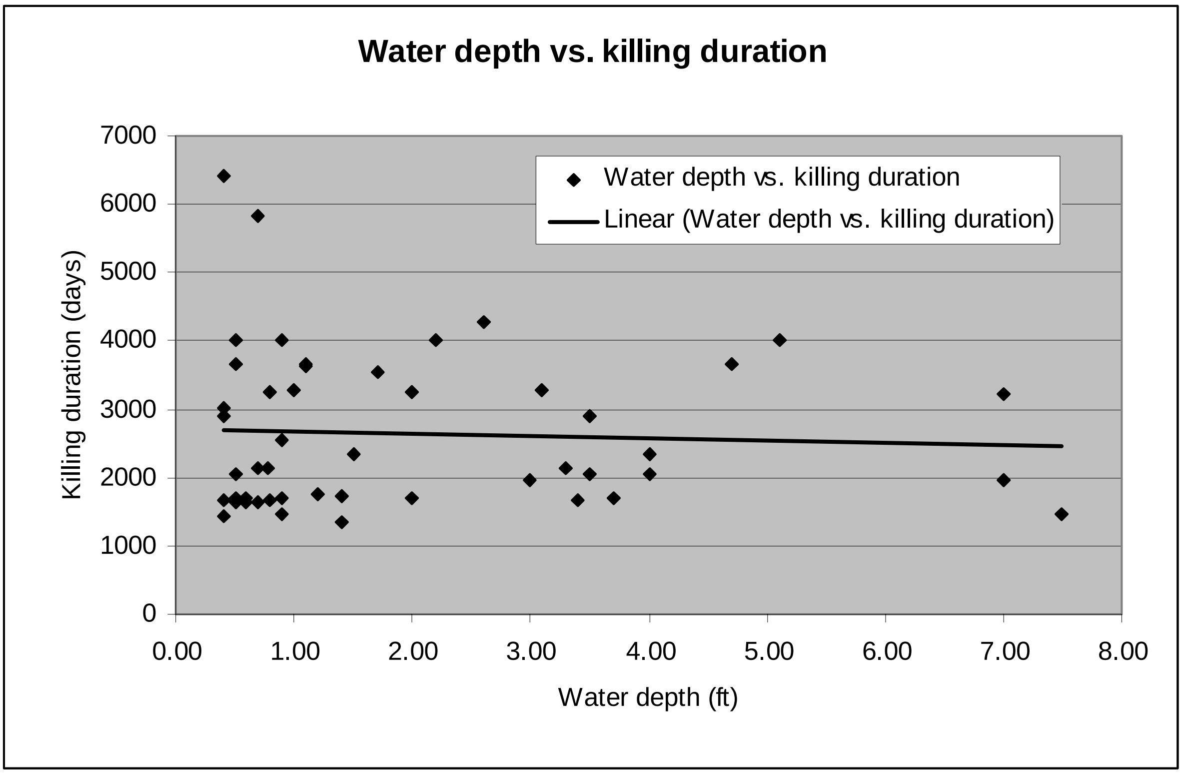

Figure 6.1 Water depth vs. killing duration

As seen from Figure 6.1 there is no trend in the killing time vs. increased water depth.

6.3.2 Well Depth (TVD) vs. Killing Duration

Figure 6.2 shows an XY plot for the water depth vs. the killing duration.

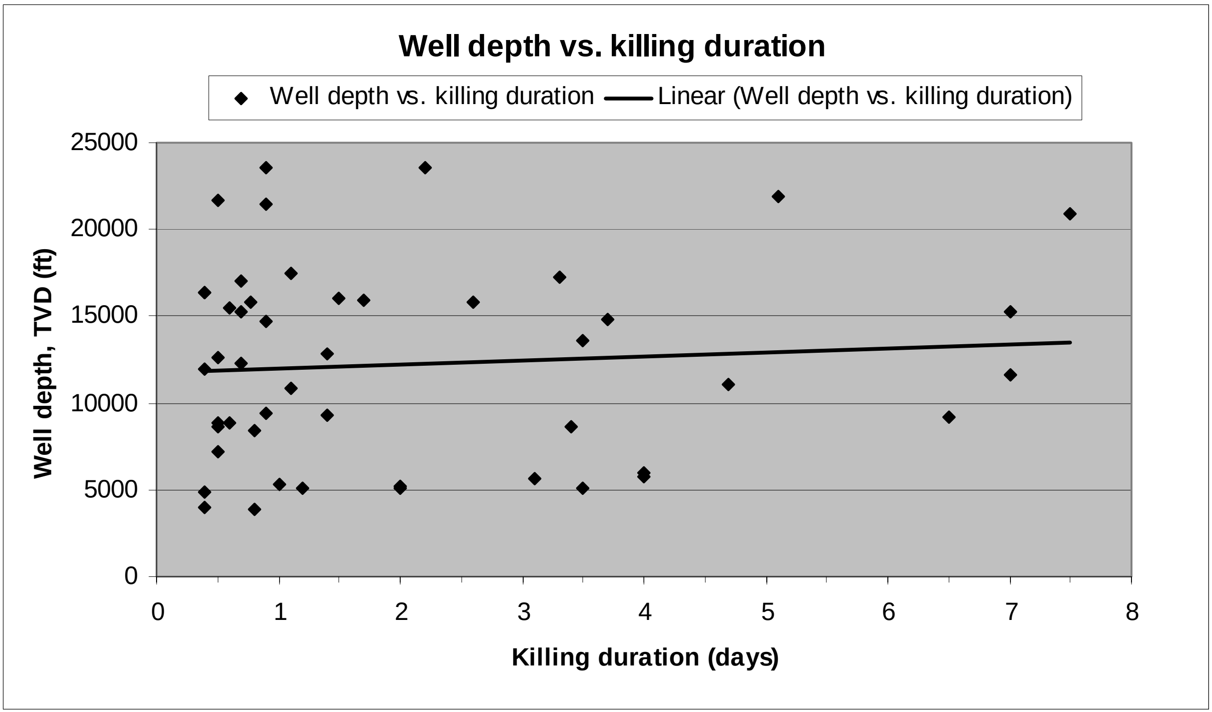

Figure 6.2 Well depth (TVD) vs. killing duration

There is no significant trend in the killing duration with increasing well depth. Mud type, well depth, and kick duration are further discussed in 6.3.3.

6.3.3 Type of Mud vs. Well Depth and Killing Duration

Water based mud may be used at any depth when drilling a well, but pseudo-oil based mud is typically used in deeper parts of the well (Table 3.1, page 39).

Table 6.6 shows mud type and depth specific average killing duration.

Table 6.6 Type of mud vs. well depth and killing duration

Mud type	Well depth	No. of kicks	Total killing time (days)	Average killing time (days)
Pseudo-oil based	less than 10000	1	1.2	1.2
	more than 10000	16	32.1	2.0
	Total	17	33.3	2.0
Water based	less than 10000	13	28.1	2.2
	more than 10000	11	26.0	2.4
	Total	24	54.1	2.3
Unknown	less than 10000	6	4.7	0.8
	more than 10000	1	3.7	3.7
	Total	7	8.4	1.2
Total	less than 10000	20	34.0	1.7
	more than 10000	28	61.8	2.2
	Total	48	95.8	2.0

In average the kick duration has been slightly longer for kicks occurring deeper than 10000 ft. The two most time consuming kicks both occurred when drilling with water based mud. For the unknown mud type the majority of kicks have occurred before reaching 10000 ft. These kicks were likely drilled with water based mud. The average duration of these kicks was very short.

6.3.4 Kick Size vs. Killing Duration

Figure 3.6 on page 36 also shows the kick sizes for the individual kicks. Table 6.7 shows a grouped distribution of the kick sizes.

Table 6.7 Distribution of kick sizes

Kick size (bbls)	No. of occurrences
≤ 5	19
5-15	9
15-30	13
> 30	4
Unknown	3
Total	48

It is likely to assume that the size of the kick and the killing duration is related.

Figure 6.3 shows an XY plot for the kick size vs. the killing duration.

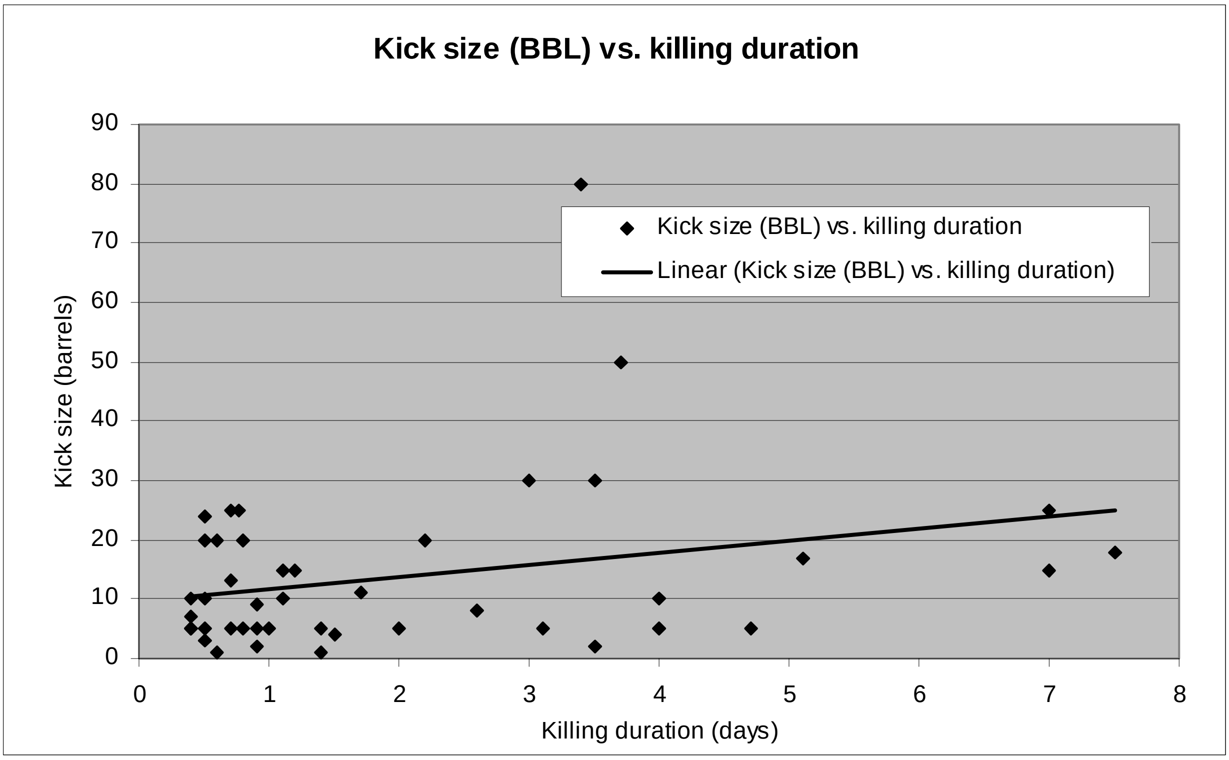

Figure 6.3 Kick size (BBL) vs. killing duration

As seen from the regression line Figure 6.3 there seems to be a slight correlation between the kick size and the killing duration. The killing time increases with the kick size. Most of the small kicks were controlled fairly fast, but for some of them several days were needed. It should be noted that many of the "large" kicks were controlled fairly fast.

Some of the kicks had partially passed the BOP when the BOP was closed and the kick size will then seem larger due to the gas expansion in the riser. For 14 of the kicks the kick size was not specifically mentioned in the daily drilling report and has been estimated when reviewing the daily drilling reports.

6.3.5 The Difference Between Leak off Test (LOT) Strength and Mud Weight (MW)

The difference between the LOT strength and the actually MW used when drilling is an indication of the difference between the pore pressure and the fracture strength of the formation. By experience drilling wells with a small difference between the LOT and MW is more difficult than wells with a large difference. Kicks will occur more frequently due to losses or gains. This is also discussed in Section 5.5 on page 49. Table 6.8 shows an overview of the LOT - MW for the kicks observed.

Table 6.8 The difference between casing shoe fracture strength and mud weight

LOT - MW (ppg)	No. of occurrences
No data	2
≤ 0.5	3
0.5 -1.0	19
1.0 -2.0	16
> 2.0	8
Total	48

For nearly 50% of the kicks the LOT - MW was 1 ppg or lower. This is regarded as a low margin when drilling a well.

It is likely to assume that a low margin between the LOT and the MW also will complicate the killing of the well and prolong the killing time. Figure 6.4 shows a XY plot of the killing duration vs. the LOT - MW.

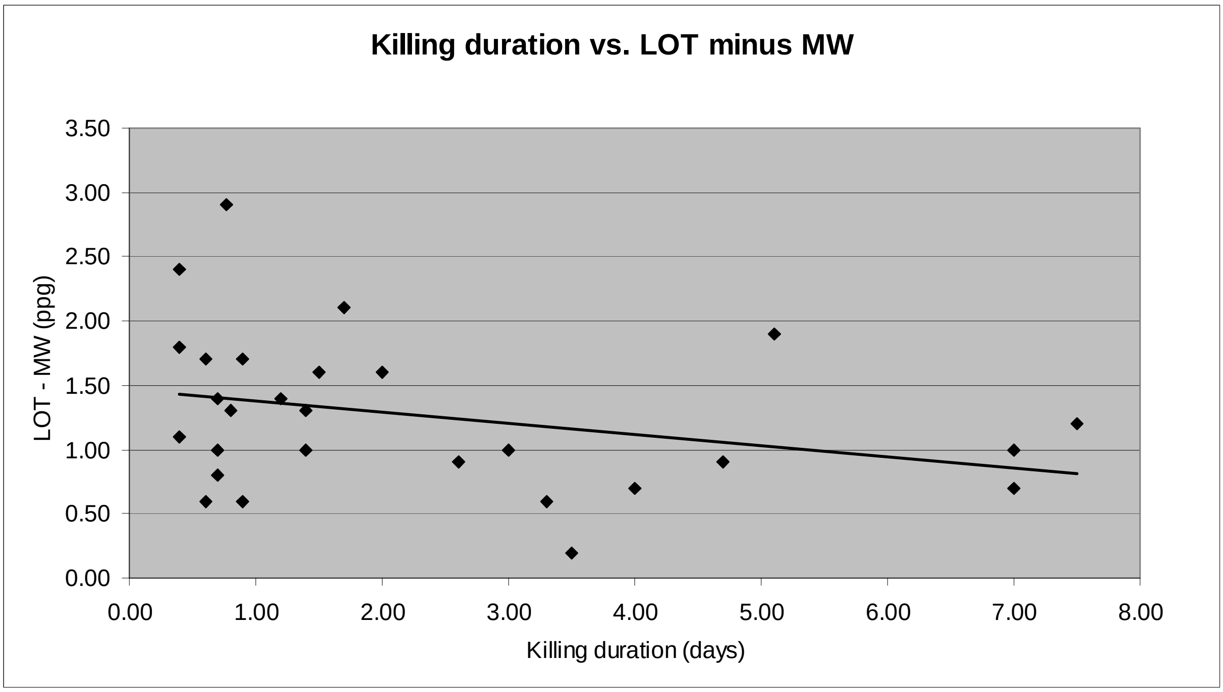

Figure 6.4 XY plot LOT - MW vs. killing duration

As seen from the XY plot in Figure 6.4 there is a correlation between the LOT - MW vs. the killing duration. The analysis shows that with small margins the killing duration is expected to be longer than with larger margins.

6.3.6 Open Hole Section vs. Killing Duration

The length of an open hole well section may influence the handling of a kick. To investigate this three XY diagrams were made based on the measured length of the open hole section (MD_{well} – $MD_{casing\ shoe}$). These diagrams are presented in Figure 6.5 - Figure 6.7.

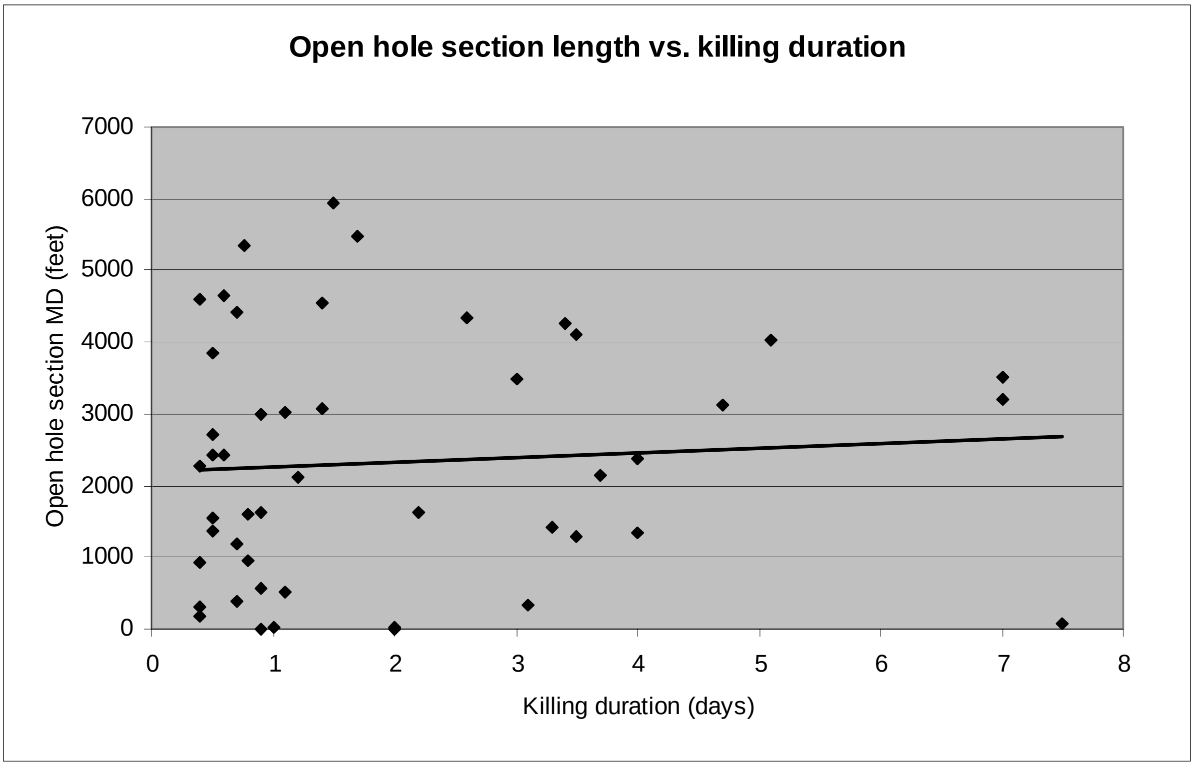

Figure 6.5 Open hole section length vs. killing duration, all kicks

From Figure 6.5 it seems that there is no significant correlation between the length of the open hole section and the killing duration. To further investigate if there may be a possible correlation it was selected to split the data in two according to the well depth when the kick occurred. Figure 6.6 shows the results for the wells that kicked deeper than 10 000 ft., and Figure 6.7 shows the results for the wells that kicked shallower than 10 000 ft.

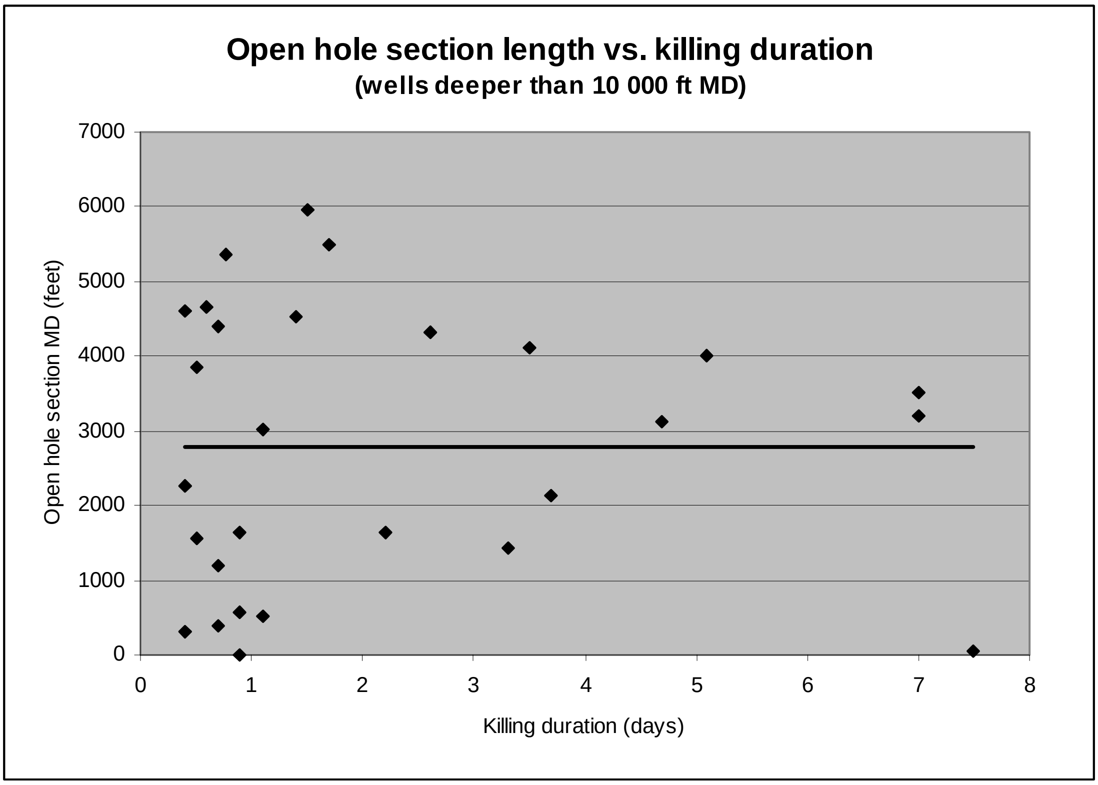

Figure 6.6 Open hole section length vs. killing duration, kicks occurring below 10 000 ft.

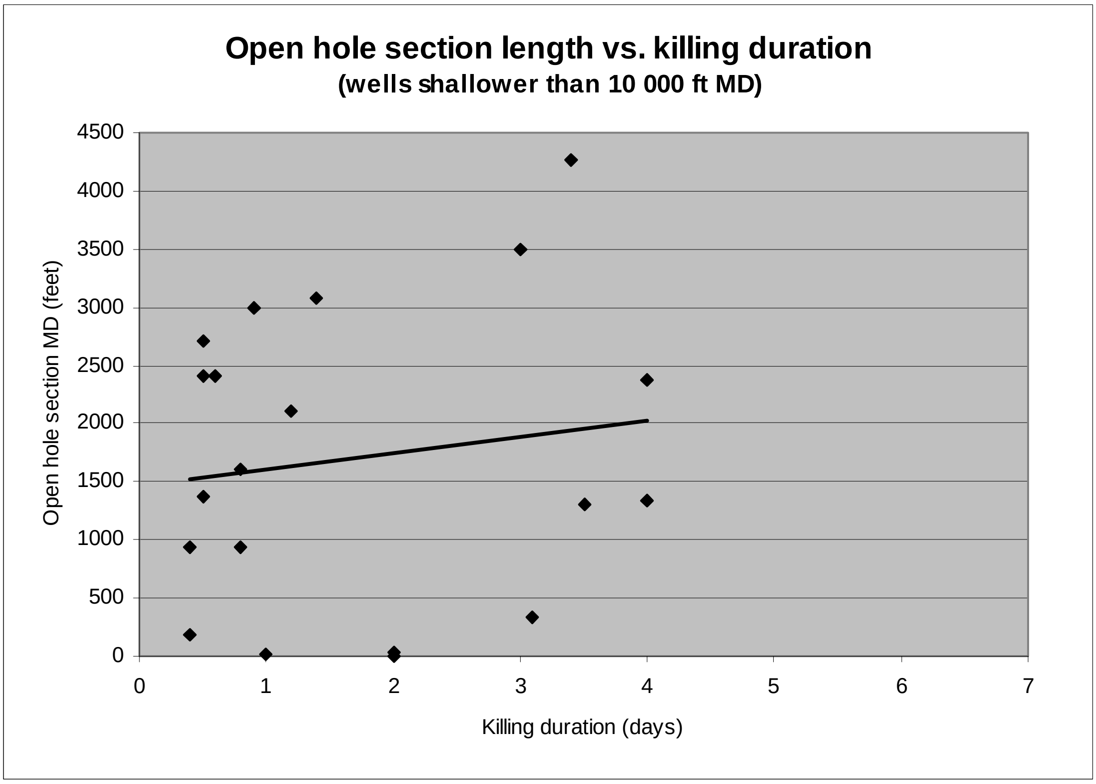

Figure 6.7 Open hole section length vs. killing duration, kicks occurring shallower than 10 000 ft.

From Figure 6.6 and Figure 6.7 it may seem that there is a slight correlation between open hole section and the killing duration for the kicks that occurred shallower than 10 000 ft., but there is no such correlation for the deeper kicks.

6.3.7 Maximum Theoretical Shut-in Pressure vs. Killing Duration

Figure 6.8 shows a XY plot of the maximum theoretical shut-in pressure vs. killing duration.

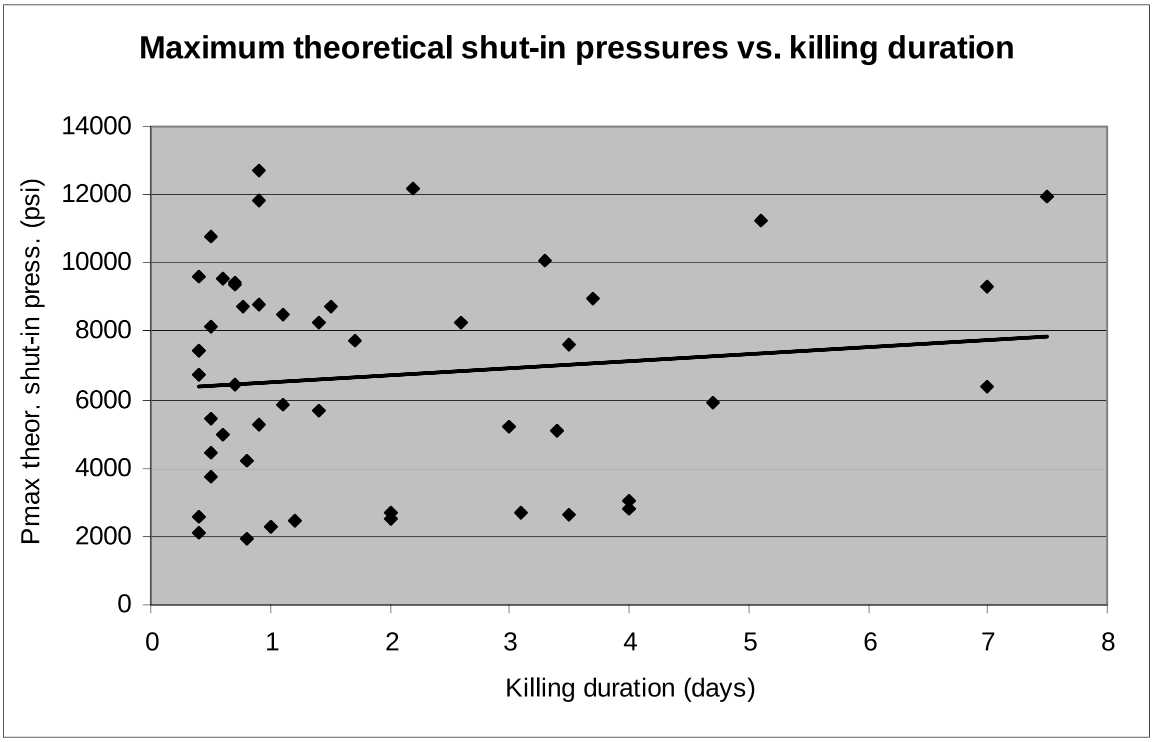

Figure 6.8 Maximum theoretical shut-in pressure vs. killing duration

There is no significant correlation between the maximum theoretical shut-in pressure and the killing duration. It should, however, be noted that the maximum theoretical shut-in pressure is partly a function of the well depth. The slope of the trend line for the well depth (Figure 6.2, page 57) is the same as for the maximum theoretical shut-in pressures. Whether or not the trend slope of the line is random or caused by an increased well depth or increased well pressure cannot be verified.

6.3.8 Summary Regarding Parameters and Killing Duration

Although none of the well parameters investigated showed very clear statistically significant trends, it seemed that there for some were slight correlations. In the following a summary for each of the parameters investigated is shown:

- Water depth vs. killing duration; no correlation
- Well depth (TVD) vs. killing duration; minor correlation
- Drilling fluid type vs. killing duration; no correlation
- Kick size vs. killing duration; minor correlation
- Fracture strength (LOT) – mud weight (MW) vs. killing duration; correlation
- Open hole length vs. killing duration; minor correlation

- Maximum theoretical shut-in pressure vs. killing duration, minor correlation

The reason why there is found little correlation between these parameters and the killing duration is likely that there are no correlation for some of the well parameters and the killing duration. Further, there are so many other factors affecting the kick killing duration. Other factors will heavily affect the killing duration as well. Amongst such factors are; pressure transmission problems, formation of hydrates, ballooning/losses, stuck pipe, friction pressures during circulation, and competence of personnel.

7. Kick occurrences vs. BOP failure occurrences

There is a general opinion that when a BOP has been used for handling a well control operation this will increase the probability of experiencing a failure in BOP due to general wear and tear during the kick control operations.

In Section 7.1 a coarse overview of the BOP failures observed is presented. The kick data and the BOP failure data are collected for the same wells.

Section 7.2 discusses the relation between the well kick killing operations and the occurrence of BOP failures on a general level based on the overall kick and failure data for each rig. Both the rig specific frequencies of kicks and the killing duration have been evaluated.

Section 7.3 focuses on the detailed kick and BOP failure experience. The history of each rig is discussed in terms of kick and BOP failure occurrences.

7.1 Experienced BOP Failures

The BOP failures observed during the Phase II DW study are thoroughly discussed in /2/. This report can be downloaded from the MMS home page on the Internet. Table 7.1 presents an overview of the BOP failures observed, the location of the BOP and the tests during which the various BOP failures were observed.

Table 7.1 Observation of BOP failures

BOP subsystem	*BOP on the rig*			*Running BOP*		BOP on the wellhead				
	Observed on test prior to running BOP	Other obser-vation	Un-known	Test during running of BOP	Other obser-vation	Install-ation test	Test after running casing or liner	Test scheduled by time	Other obser-vation	Total
Flexible joint									1	1
Annular preventer	1					1	4	3	3	12
Ram preventer	3				1	1	5	1		11
Connector	2	2				2			4	10
Choke and kill valve	9					1	1	2		13
BOP attached line	1			1						2
Riser attached line	1			2					1	4
Jumper hose line				1			1			2
Control system	16		3	5		10	6	7	13	60
Dummy Item	2									2
Total	**35**	**2**	**3**	**9**	**1**	**15**	**17**	**13**	**22**	**117**
	34%			**9%**		**57%**				

As seen from Table 7.1, 34% of the failures were observed when the BOP was on the rig prior to running the first time, or subsequent time. Approximately 9% of the failures were observed during running of the BOP and the remaining 57% were observed when the BOP was on the wellhead. Of the 67 failures that were observed when the BOP was on the wellhead, 15 were observed during installation testing and the remaining 52 were observed during regular BOP tests or during normal operations.

An installation test is here defined as the BOP test after landing the BOP the first time or during subsequent landings of the BOP or the LMRP.

7.2 Occurrence of Kicks vs. Frequency of BOP Failures

It was selected to evaluate three types of BOP failure data-sets.

1. All BOP failures (as shown in Table 7.1)
2. All BOP failures (as shown in Table 7.1), but disregarding control system failures
3. BOP failures observed when the BOP was subsea (as shown in Table 7.1), but disregarding control system failures and failures observed during the installation test.

The reason why the control system failures are disregarded (point 2 above) is that there is a general opinion that the control system components will not deteriorate during a kick. These components will not be exposed to wear or increased pressure. During kick circulation the BOP functions are activated, and the control valves are moved. It is a general belief that moving hydraulic components will increase the reliability because this will prevent sticking, ensure lubrication, prevent corrosion, etc.

In point 3 above it was selected to disregard the failures observed on the rig, during running of the BOP and during the installation tests, in addition to the control system failures. The main reason for that is that all these failures are less likely to be influenced by the kick killing operations.

7.2.1 All Observed Failures

For each of the rigs included in the study the frequency of kicks and the frequency of BOP failures are plotted in a XY-plot. Figure 7.1 shows this XY-plot.

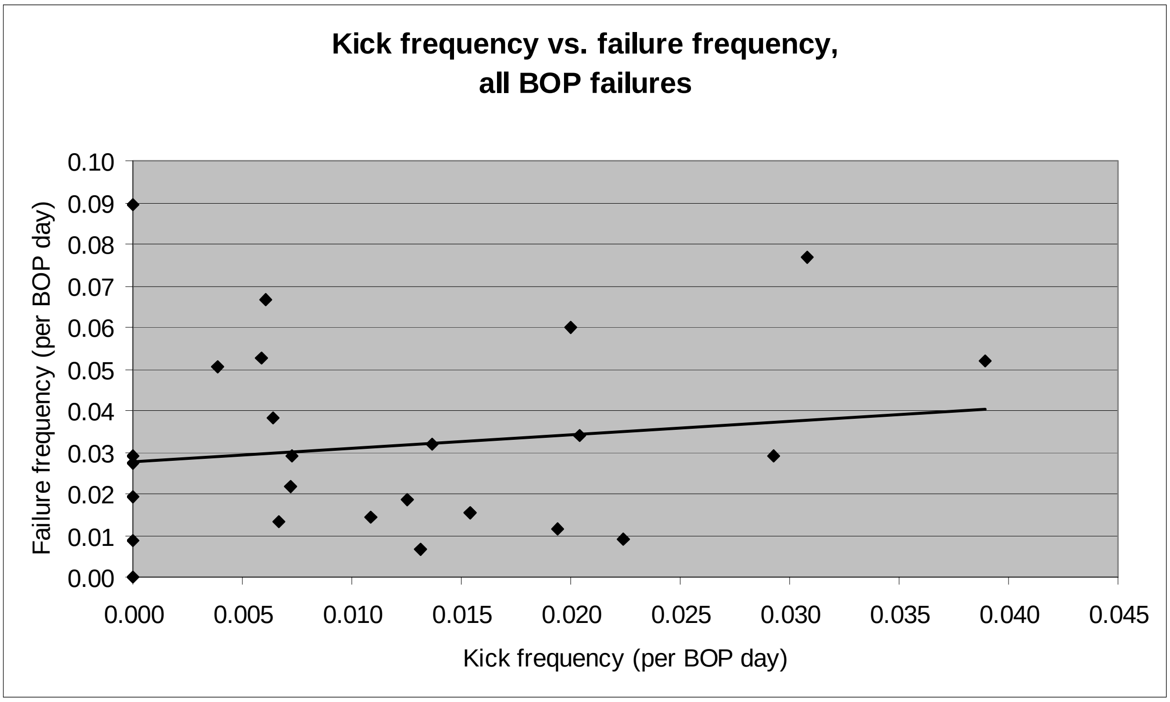

Figure 7.1 XY plot, BOP failure frequency vs. kick frequency

As seen from Figure 7.1 there is found a slight, but not significant correlation between the kick frequency and the occurrence of BOP failures for all the BOP failures. In Figure 7.2 the data-set has been sorted on the rig specific kick frequency and compared to the rig specific BOP failure frequency.

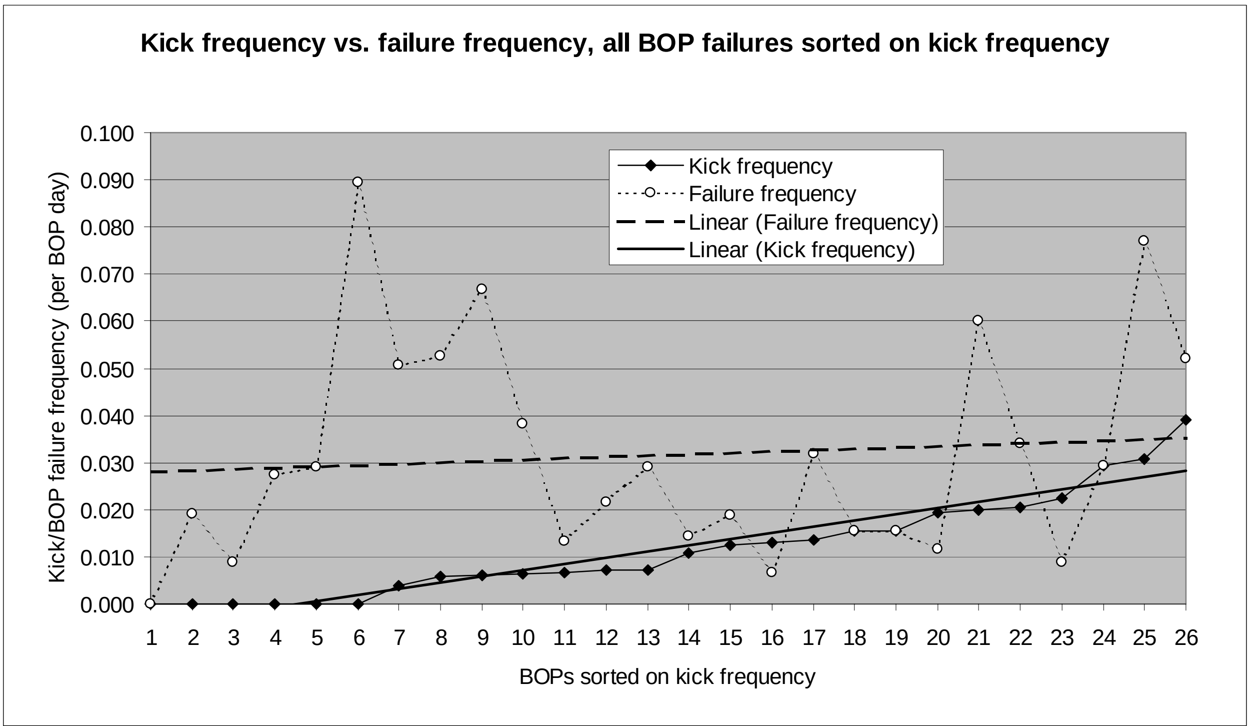

Figure 7.2 Sorted kick frequency plotted against the BOP failure frequency for all failures and each rig

As seen from Figure 7.2 the BOP failure frequency varies highly from rig to rig independent of the kick frequency. The rig with the highest frequency of BOP failures did not experience any kicks at all. The trend line for the failure indicates a slight increase with increasing kick frequency, but there is no significance.

Since the frequency of kicks did not seem to have any significant effect on the overall probability of BOP failures it was selected to use the average time the BOP had been used for kick control operations instead of the kick frequency. This time will represents the time the BOP is exposed to this additional wear, that may seem to be a better measure than the kick frequency itself. The analyses shown in Figure 7.1 and Figure 7.2 were then repeated. Figure 7.3 and Figure 7.4 show the charts from these analyses. When comparing Figure 7.1 vs. Figure 7.3, and Figure 7.2 vs. Figure 7.4 it is seen that the there is no difference in the overall results.

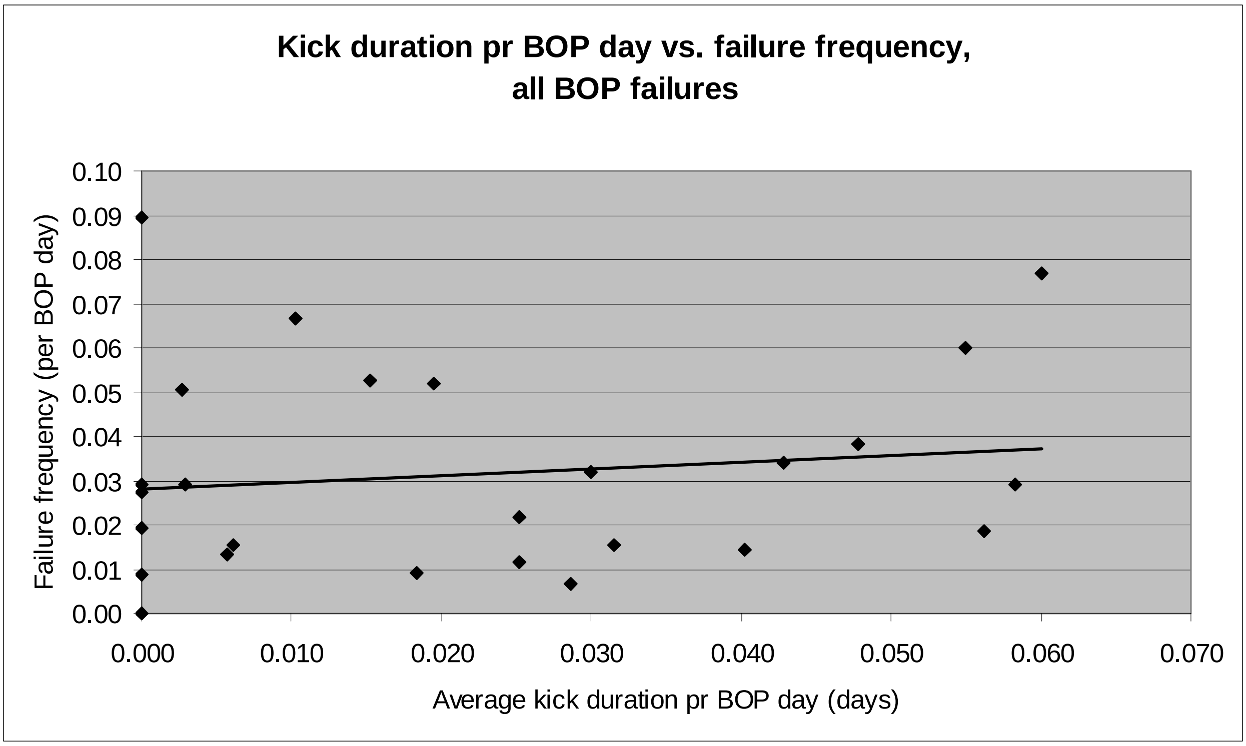

Figure 7.3 XY plot, BOP failure frequency vs. average kick duration per BOP day

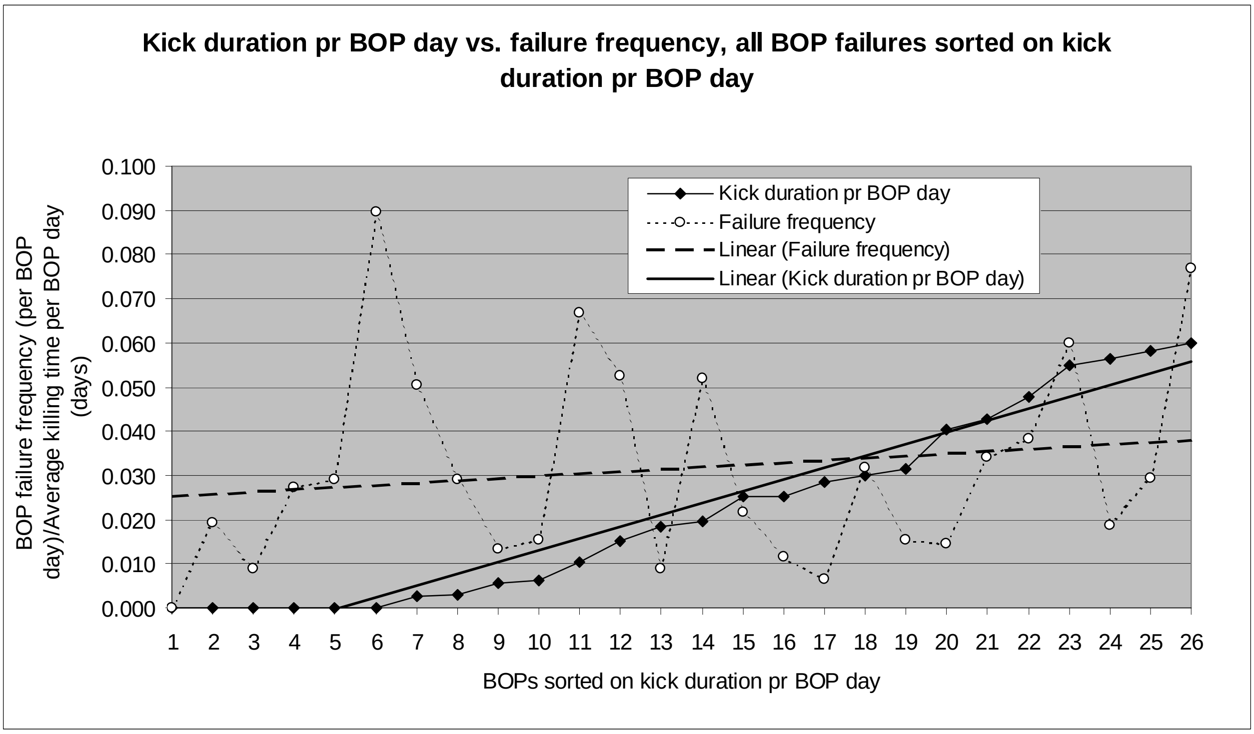

Figure 7.4 Sorted average kick duration per BOP day in service plotted against the BOP failure frequency for all failures and each rig

7.2.2 Not Including Control System Failures

The reliability of control system components is unlikely to be affected by kick control operations. The control system failures were therefore taken out of the data set (see Table 7.1, page 65). The analyses shown in Figure 7.1 and Figure 7.2 were repeated to see if a general correlation between the occurrence of kicks and failures could be observed with this modified data set. Figure 7.5 shows the XY-plot for the data set.

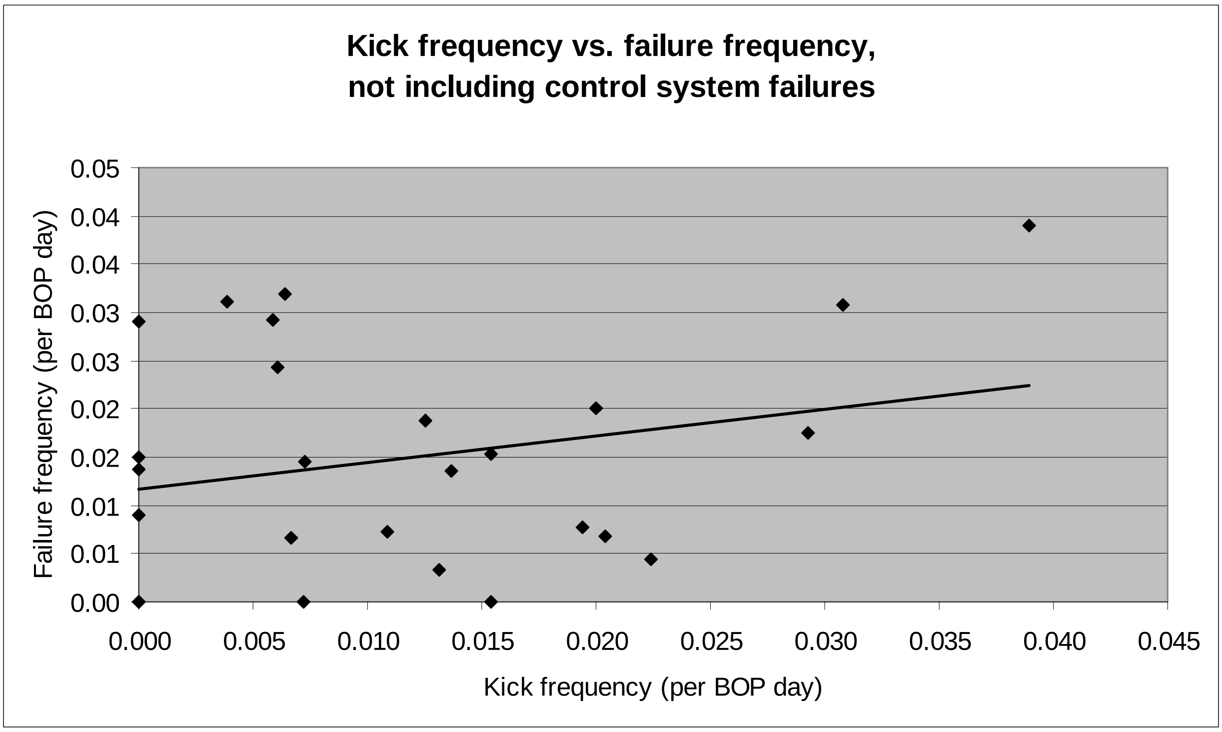

Figure 7.5 XY plot, BOP failure frequency vs. kick frequency (disregarding control system failures)

As seen from Figure 7.5 there is a slight, but not significant, correlation between the kick frequency and occurrence of BOP failures when the control system failures are disregarded. In Figure 7.6 the data-set has been sorted on the rig specific kick frequency and compared to the rig specific BOP failure frequency.

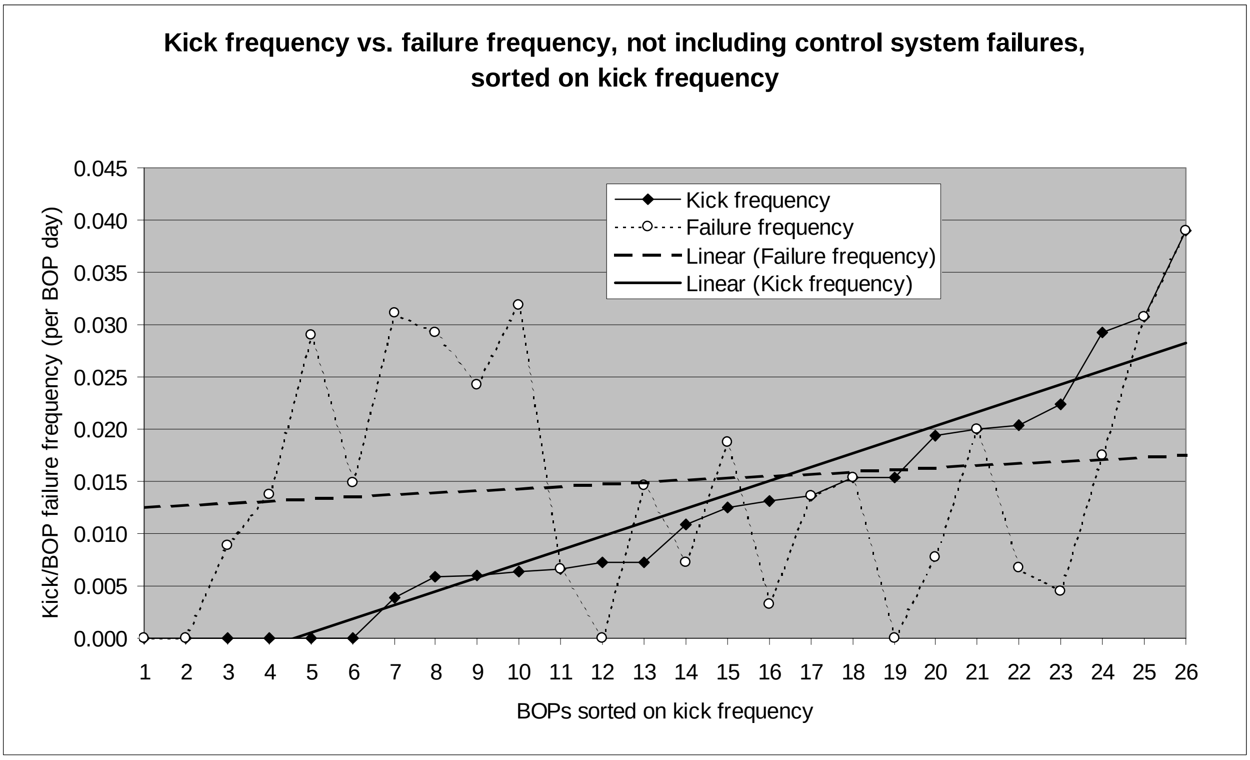

Figure 7.6 Sorted kick frequency plotted against the BOP failure frequency for all failures and each rig (control system failures disregarded)

As seen from Figure 7.6 the kick failure frequency still varies highly from rig to rig. The trend line for the failure indicates a slight increase with increasing kick frequency, but there is no significance.

As for all failures similar analyses as shown in Figure 7.3 and Figure 7.4 related to the average kick duration per BOP day in service were carried out for the data-set without the control system failures. The overall results, however, show the same pattern as in Figure 7.5 and Figure 7.6.

7.2.3 Subsea Failures, Disregarding Control System and Installation Failures

In the following analyses the failures observed on the rig, during running of the BOP and during the installation tests, in addition to the control system failures have been disregarded (see Table 7.1, page 65). This selection has been done because occurrences of the remaining failures are the failures most likely believed to be influenced by the kick killing operations.

The analyses shown in Figure 7.1 and Figure 7.2 were repeated to see if a general correlation between the occurrence of kicks and failures could be observed with the modified data set. Figure 7.7 shows the XY-plot for the data set. In Figure 7.8 the data set has been sorted on the rig specific kick frequency and compared to the rig specific BOP failure frequency.

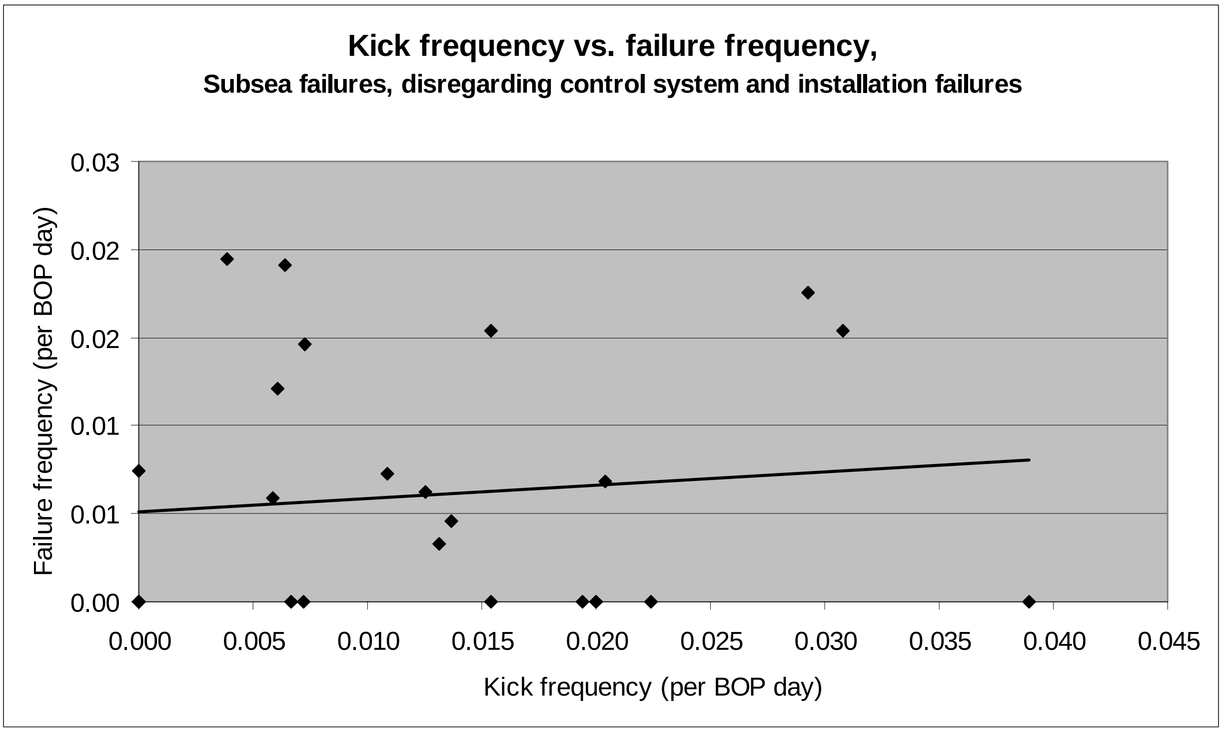

Figure 7.7 XY plot, BOP failure frequency vs. kick (subsea failures, disregarding control system and installation failures)

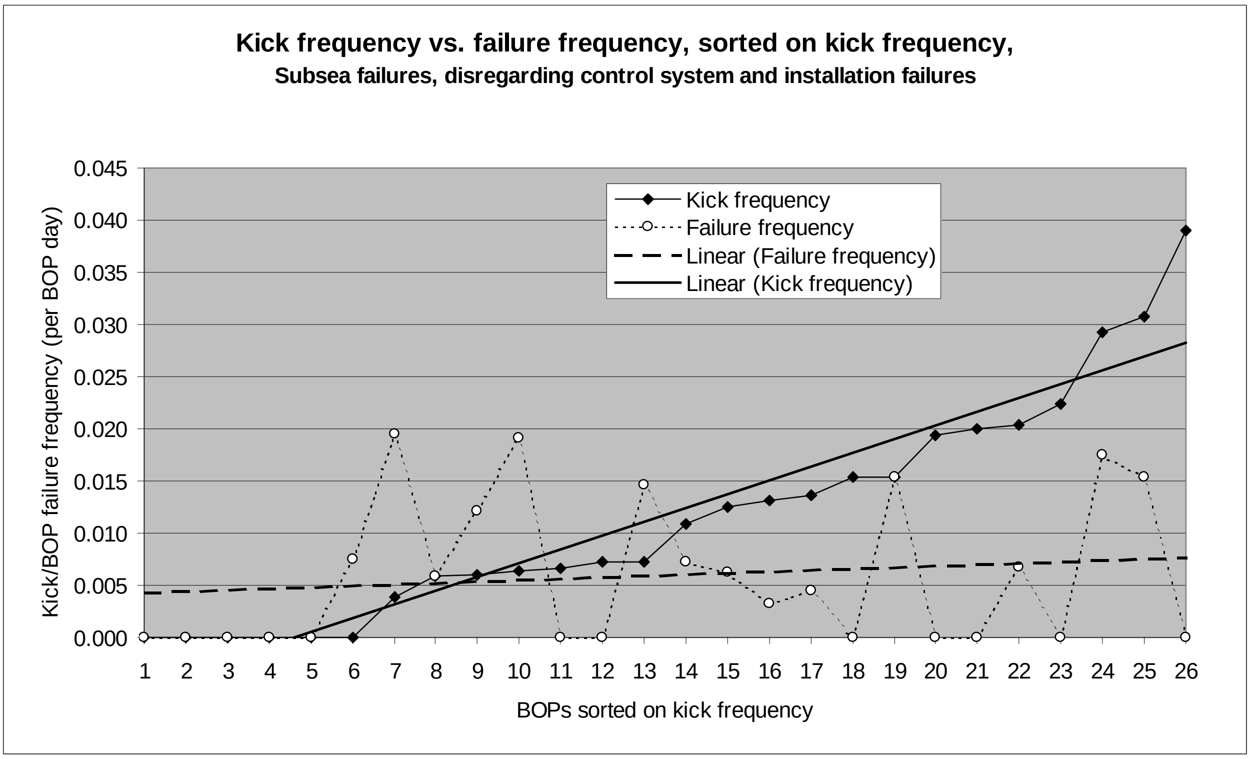

Figure 7.8 Sorted kick frequency plotted against the BOP failure frequency for all failures and each rig (subsea failures, disregarding control system and installation failures)

As seen from Figure 7.7 there is a slight, but not significant, correlation between the kick frequency and the occurrence of BOP failures when only including the subsea failures, and disregarding the control system and installation failures.

As seen from Figure 7.8 the kick failure frequency still varies highly from rig to rig. The trend line for the failure rates is nearly horizontal despite the increasing kick frequency.

As for all failures similar analyses as shown in Figure 7.3 and Figure 7.4 related to the average kick duration per BOP day in service were carried out for the data set only including subsea failures, disregarding control system and installation failures. The overall results from these analyses showed a slightly steeper increasing BOP failure frequency with increasing average kick duration, the trend was, however, not significant.

7.2.4 Summary, Trends Related to Kick Occurrence vs. BOP Failure Occurrence

Although the analyses showed no significant trend, there seems to be a slight correlation between the kick occurrences and the occurrence of BOP failures. This is further investigated in Section 7.3.

7.3 BOP Failures Caused by the Influence From Kick Killing Operations

7.3.1 Detailed Rig Specific BOP Failure Occurrence vs. Kick Occurrence Evaluation

In general no significant correlation between the occurrence of BOP failures and well control operations were revealed. However, after or during the kick control operation there have been observed BOP failures that likely were caused by the well control operation. In this section the drilling period, occurrence of kicks and occurrence of failures are followed by the calendar for each individual rig. It should be noted that the history before and after the collection of data is not known, i.e. kicks occurring before the data collection started may have caused failures that are included. Further, kicks included in the data collection may have caused failures observed after the data collection was ended. Table 7.2 shows an overview of BOP failures and kicks for the specific rigs.

Table 7.2 Overview of BOP failures and kicks for the specific rigs

Rig id	Kicks			BOP failures				
	BOP days in service	No. of kicks	Total killing time	BOP Item	Control system	Choke and kill item	Dummy item	Total
50	112	0	0			1		1
51	157	1	7.5	1	1	4		6
52	223	5	4.1	1	1			2
53	257	1	0.7	8	5			13
54	137	1	0.4	2	2			4
55	160	2	9	2		1		3
56	171	5	9.97	3	2			5
57	165	1	1.7	1	7	3		11
58	220	3	6.6	2	4	1		7
59	171	1	2.6	3	4	2		9
60	69	0	0			2		2
61	276	3	11.1		2	2		4
62	134	0	0	1	10	1		12
63	258	5	6.5	2	1			3
64	139	1	3.5		3			3
65	300	2	1.7	2	2			4
66	130	2	4.1	2				2
67	77	3	1.5		1	3		4
68	147	3	6.3	1	4			5
69	73	0	0	1	1			2
70	47	0	0					0
71	304	4	8.7	1	1			2
72	52	0	0		1			1
73	100	2	5.5		4	1	1	6
74	65	1	0.4		1			1
75	65	2	3.9	1	3		1	5
	4009	48	95.77	34	60	21	2	117

In the following a review of the rig individual kicks and failures is presented. Failure likely caused by the kick killing operations are indented and highlighted with italic.

Rig 50

Rig 50 experienced no kicks and one failure in the lower outer choke valve. Before the failure was observed the BOP had been used for drilling three wells without any problems in this valve.

Rig 51

Rig 51 experienced one kick that they used 7.5 days to control, and as many as six failures in the BOP.

The kick occurred in the beginning of December 1997. After the kick was controlled they ran casing and was testing the BOP. They then experience problems with the ram locking system. The ram failed to open fully. The BOP test plug was below the ram. The fact that the BOP had been used for well control operations some days before did likely not cause this failure. They spent some time to break the ram open, pull the LMRP and install a blind-shear ram below the annular in the LMRP, before rerunning. They then plugged the well and pulled the BOP for ram preventer repair. After they had finished repairing the blind-shear ram, they assembled the BOP and tested it before running.

1. *Then they found that both the inner and the outer choke valve were leaking. They first attempted to flush & grease the valves, but the valvse still leaked. Thereafter they disassembled the valves and found seat & gate scored. They had to wait on spare parts to repair the valves, so they spent 21 hours before they could continue the operation. It is likely that the kick circulation caused this failure.*

Rig 52

Rig 52 experienced as many as five kicks in four different wells. The total killing duration for these five kicks were however only 4.1 days. The kicks occurred in October 97, November 97, beginning of January 98, March 98, and May 98.

An annular preventer failed to seal when tested before running the BOP in middle of February. The previous kick had occurred 45 days before on the previous well. The BOP had been used for drilling approximately 35 days and then been on the rig between wells for 10 days when the failure was observed. The reason of the leak was the annular head, seals for the head and the piston, and not the element as such. It seems unlikely that the previous kick killing operations should have contributed significantly to the occurrence of this failure.

After landing the BOP the 1" supply line on blue pod failed near the pod. The occurrence of this failure cannot be associated to wear and tear from previous kick circulation.

Rig 53

On Rig 53 they experienced one kick with a short duration, but a series of BOP failures, eight in BOP items and five in the control system. The kick was controlled without any problems at all in the end of November 1997. Four of the BOP item failures occurred after the kick had been circulated, and two of the control system failures were observed after the kick had been circulated out.

2. *Ten days after they had controlled the kick the blind-shear ram failed to test when testing against the cement plug before abandoning the well. When testing casing and plug to 1500 psi, the pressure dropped to 235 psi in 10 minutes with returns in the riser. They had tested the blind-shear ram to 1500 psi three days before the kick without problems. It is likely that the kick circulation may have caused this failure.*

When attempting to disconnect the BOP to abandon the well they had problems with disconnecting. This failure is not assumed to be caused by the kick circulation.

When the BOP was on the rig they experienced a problem with the software for the BOP controls. The software had to be reinstalled. This failure cannot be associated to kick control operations that had carried out one month before the failure.

Three to four months after the kick when drilling on the next well they had problems with fully closing the annular preventer two times. The cause of the problem was believed to be an internal leak within the annular body with fluid passing by seal on closing side of piston, going into the open side chamber, then venting to sea through SPM valve. It is unlikely that the kick control operation had any influence on the occurrence of this failure.

When abandoning this well they also had problems with unlocking the wellhead connector. This failure is not assumed to be caused by the kick circulation.

Rig 54

On Rig 54 they experienced one small kick that was controlled in 10 hours. After the kick they continued the abandon well operations and pulled the BOP. The BOP was then on the rig for 25 days before it was landed on the subsequent well. At first 40 days after the kick the experienced an electric/electronic problem with the BOP control system, not caused by the kick. Five days later they had to work the running tool through the upper & lower annulars after a BOP test. This is normally caused by slow relaxation of the annular rubber after an operation, and not linked to the kick control operations carried out 1.5 months before.

Three months after the kick they experienced a pod valve failure when testing the BOP on the rig. This failure was not caused by the kick control operations.

Finally four months after the kick they had some minor problems with the annular preventer, not caused by the kick control operation.

Rig 55

Rig 55 experienced two kicks and three BOP failures in the data collection period. The first kick occurred 30 Oct 1997. They spent two days controlling the kick. Six days after controlling the kick they pulled the BOP to abandon the well. Nov 13 they reran the BOP on a new well. When testing the BOP after running casing, Nov 22 the LPR failed to seal. After pulling the BOP to repair the failure they found that one VBR flexpacker was missing - Both pins on the top seal were sheared which allowed the flexpacker to fall out - the pins on the top seal of the other ram were deformed - Visually inspected all other rubber goods and found all to be in good condition. It is not likely that the kick that occurred three weeks earlier contributed to the occurrence of this failure, because the BOP had been on the rig in-between, further that the ram had been tested both surface and on the wellhead in-between.

On the subsequent well the wellhead connector leaked after landing the BOP (December 16th). This was not caused by the kick control operation.

March 27th they experienced another kick with this rig. The kick control operations lasted for seven days and involved stripping into the well. After controlling the kick and running liner the BOP was tested with no failures. The well was abandoned 10 days later. Data does not exist for the subsequent well.

Rig 56

Rig 56 experienced as many as five kicks and five BOP failures. The first failure occurred before the first kick (August 26th). A control system failure caused problems with closing the upper annular preventer on the yellow pod. They received a waiver from MMS and continued operation. August 29th the first kick occurred. They spent 18 hours to control the well.

September 4th they experienced a problem to fully open the upper annular preventer after a BOP pressure test. This failure may be linked to the above failure, but also stem from slow relaxation of the annular rubber.

September 7th they experienced kick no. 2 on this well. They spent 17 hours to regain control of the well. No specific problems were mentioned.

September 15th the flexible joint splits, mud is lost to the seafloor and the well immediately kicks. This causes a complicated well killing operation that lasts for 3.5 days before regaining the hydrostatic control of the well. Thereafter they had to prepare to and pull the LMRP for repair. In addition the pipe was stuck.

3. *During the preparation they observed that the lower annular preventer was leaking. It had been used for stripping during the well control operations. At first they had to increase the closing pressure to get a proper seal. After the LMRP was repaired and reran they observed that when pulling the wear bushing running tool, pieces of annular rubber came as well. On the subsequent BOP test the lower annular failed to hold the test pressure (test date 24 Sep. 97). Annular leaked at 2400 psi with 2000 psi operating pressure. Increased operating pressure to 2400 psi. Leaked at 2000 psi. The cause of this failure was likely wear and tear during stripping and well control operations.*

They failed to free the pipe and the well was eventually abandoned.

On the next well they experienced another kick two days after drilling out the 20" casing (November 4th). The pipe became stuck and the worked with the well kick for four days before they cemented the well, severed the pipe and started to side track the well.

The fifth kick occurred January 4th. 1.2 days was spent to regain the well control. No specific problems were mentioned. Data was collected until February 22nd, the only BOP failure that occurred in this period was a pod selector valve that failed. This failure was not caused by the kick control operations.

Rig 57

Rig 57 experienced one kick and as many as 11 BOP failures. All the 11 failures were observed before the kick occurred. Seven of the failures were control system failures. One annular preventer failed to fully open after a BOP test. A failsafe valve failed to open during test. They observed an external leakage in a valve to BOP connection when testing the BOP on the rig prior to running. A leak in the choke/kill line was observed during running of the BOP.

After the kick was controlled and the stuck pipe freed, the BOP was tested with no failures. The well was abandoned one week after the BOP test.

Rig 58

Rig 58 experienced three kicks and seven BOP failures. The first failure was in the control system stinger area and occurred before the first kick. The first kick occurred November 23rd 1997. They spent 2 days before regaining the well control.

No BOP failures were observed before the second kick occurred 2nd January 1998. They spent 3.7 days for well control operations. Among the operations carried out were stripping into the well. During the well control operations a leakage in the upper annular was observed. After the well was stabilized the BOP repair action started.

4. *Replaced the failed packing element in #1 annular tested new element. Also replaced badly worn packing element in #2 annular and ram packers, all rubber seals and door gaskets in #4 pipe rams.*

They also disassembled upper choke valves and replaced gates and seal rings. When testing the stack afterwards the upper inner choke valve leaked. This failure was likely caused by poor maintenance and not the kick circulation it self.

They also experience a failure of the blind-shear ram posi-lock. This failure is likely not caused by the kick control operation. They also observed a leakage in the pod area before re-running the stack.

After landing the stack again they side-tracked the well.

In the end of January they got a broken line between the yellow pod receptacle and the shuttle valve. One week later they experienced a hose failure in the hose that connects the shuttle valve to the opening side of the #2 annular. These failures are not caused by well control activities. After the last failure they decided to pull the BOP stack and replace all the lines. They used five days for these repair activities.

The drilling was continued without any problems until June 12th, when they observed a gas flow appearing from 30 " wellhead. They squeezed cement three times to control the flow. The well was abandoned shortly after. They drilled another well also, with no more problems.

Rig 59

Rig 59 experienced one kick and nine BOP failures. Seven of the BOP failures occurred before the kick and two nearly three months after the kick. The well control operations lasted for 2.6 days. The BOP had been subsea in the period after the kick occurred until the BOP failures were observed. The well had, however, been side-tracked a couple of times.

The kick occurred May 24th. August 17th one ram preventer failed to open due to a locking problem. When attempting to pull the BOP to repair the ram failure they had problems to unlock the connector. The kick control operations had no effect on the occurrence of these failures.

Rig 60

Rig 60 experienced no kicks and two failures in the choke and kill lines that were observed during running of the BOP.

Rig 61

Rig 61 experienced three kicks and four BOP failures. A control system failure that prevented the annular preventer to close on the yellow pod and a leaking choke and kill valve were observed before the first kick. The first kick occurred 24th September 1997. They used 1.1 day to control the kick. They were drilling without kick or BOP failures until March 28, then the well kicked. They circulated a while before the pipe became stuck. They then shot of the pipe. They spent three days for controlling the kick. Later the well was side-tracked.

No BOP failures occurred before one month later, then a guideline cable had rubbed a hole on blue pod hose cutting the lower inner choke pilot line. This failure was not caused by the previous kick. After another month they failed to get a good test on the upper inner kill valve. They got a verbal approval from MMS to continue without repairing until after completing the well. It was repaired June 28 after the BOP was pulled. This is a typical failure that could have been caused by kick killing operations, but the failure was observed two months after the kick, and they had carried out five pressure tests in the period between the kick and the failure. It is assumed that the failure was not caused by the kick killing operation.

Six days after the choke/kill valve failure they took another kick. They circulated a while before the pipe became stuck. They then shot of the pipe. They spent seven days for controlling the kick. Later the well was side-tracked. No more BOP failures were observed after the kick. The BOP was pressure tested once and function tested twice with no failures.

Rig 62

Rig 62 experienced no kicks but as many as 10 BOP control system failures. They also had problems with unlocking a connector once, and saw a leakage in a choke and kill line during running.

Rig 63

Rig 63 experienced five kicks and three BOP failures. All the three BOP failures occurred before the first kick was observed. They were observed during the installation test for the first well. After the five kicks no BOP failures were observed. The last of these kicks occurred February 23rd, 1998. In this kick they stripped out of the hole and observed flow from the riser when stripping. This is not regarded as a BOP failure, more a general highly likely problem during stripping in a kick situation. After this kick they carried out 10 pressure tests, - none of them revealed any BOP failures

Rig 64

Rig 64 experienced one kick and three BOP failures. All the three failures were related to the control system, and were not affected by the kick occurrence. The kick occurred October 28th 1997. The kick killing lasted for 3.5 days. This kick killing involved stripping. During the stripping gas leaked by the annular. This is not regarded as a BOP failure, more a general likely problem during stripping when gas is inside the BOP stack. They used the annular later during the kick killing operation without problem. Further, they performed nine pressure tests without failures in the period after the kick was controlled.

Rig 65

Rig 65 experienced two kicks and four BOP failures. Two of the failures were in an annular preventer, one in a connector and two in the control system.

The annular preventer failure and the two control system failures all occurred before the first kick occurrence. The connector failure was observed when the BOP was on the rig after both kicks were controlled. The kick killing did not contribute to the occurrence of this failure.

The kicks occurred 15th of March and 16th of May 1998. Both kick were controlled fairly fast. After the last kick three BOP pressure tests were carried out without failures.

Rig 66

Rig 66 experienced two kicks and two BOP failures. The first kick occurred December 24th 1997, and was controlled in one day. The second kick occurred four days later and was controlled in approximately three days. Just after controlling the second kick the got problems passing the annular preventers with the test tool on the way in. They then washed and reran the tool and passed the annulars with some problems. They had the same problem January 23rd and January 28th. It is not assumed that the kick control operation caused this problem. Annular preventers not fully opening is a well-known problem observed in all BOP studies. The relaxation capability tends to be reduced with increasing age of the element. Other factors may be cuttings and mud behind the annular, low temperatures, or partly damaged element.

After the last kick they carried out five pressure tests on that well without any other problems than the problems mentioned above. The rig drilled another well but there is a time gap in the data collection of nearly three months in between.

Rig 67

Rig 67 experienced three kicks and four BOP failures. All the kicks were killed within 10 to 14 hours. One BOP failure in the choke valve occurred before the first kick occurred. The first kick occurred August 22nd. Then no failures were observed before 30th of October. Then they observed three failures while the BOP was on the rig. One failure was a topside BOP control failure and one was a flexible hose on the BOP that blew. The occurrences of these two failures were not influenced by the kick control operations that were carried out more than two months before. The third failure was a failure in the tail rod of the upper inner choke valve. The kick circulation may or may not have affected the occurrence of this failure. There are no information about the BOP/rig activities for the two months in between the kick occurrence and the failure observation.

The two last kicks occurred November 9th and November 13th 1997. No BOP failures were recorded after these kicks. The BOP was pressure tested twice after the last kick with no failures.

Rig 68

Rig 68 experienced three kicks and five BOP failures. Four of the failures were in the control system and one was a wellhead connector where they had problems unlocking the connector. None of these failures is believed to be influenced by the kick killing operations. The three kicks occurred in September and October 1997. One of them was time consuming to control, 4.7 days. The other kicks lasted 0.5 and 1.1 days. Data was collected from September until mid December 1997, and April and May 1998.

Rig 69
Rig 69 experienced no kicks and two BOP failures.

Rig 70
Rig 70 experienced no kicks and no BOP failures.

Rig 71
Rig 71 experienced four kicks and two BOP failures. One of the BOP failures was a control system failure, the other failure was a ram preventer leakage that was observed before the first kick occurrence.

All the kicks were observed in the same well that lasted for 161 days. The BOP was tested with no failures after the three first kicks. After the last kick no BOP pressure test was carried out, only a function test.

Rig 72
Rig 72 experienced no kicks and no BOP failures.

Rig 73
Rig 73 experienced two kicks and six BOP failures. The first BOP failures were observed when testing prior to running the BOP it the first time, December 25th. First they experienced some problems with the subsea accumulator system. Thereafter they got another problem with the BOP that was not specified. It was only stated that they were repairing the BOP for 27 hours. After landing the BOP, on the installation test they observed a leakage in the connection between the BOP stack and the kill line connection. The BOP was pulled and the failure repaired.

Otherwise they experienced a pilot line leakage, a spurious disconnect of the LMRP and some more accumulator problems when drilling the well. None of these problems were caused by the kick killing operations carried out.

The first kick occurred January 22nd, 1998. The kick killing lasted for four days. After this kick six BOP pressure test were carried out without any problems before the second kick that occurred March 29. In this kick they stripped into the well. The well was abandoned shortly after, and the BOP was not tested, so if this stripping caused the annular to fail is unknown.

Rig 74
Rig 74 experienced one kick and one failure in the BOP control system rigid conduit line. The kick was controlled in 10 hours. After the kick they did not perform any BOP pressure tests, only one function test. The well was abandoned one week after the kick was controlled.

Rig 75

Rig 75 experienced two kicks and five BOP failures. All the BOP failures occurred before the first kick. They were waiting on running the BOP because they had to make BOP repair. The daily drilling report stated that they put the rig on downtime to repair BOPs. They used 89 hours for this repair. During this repair they also revealed two control system failures. One of them was in the Subsea Electronic Module, which they used more than a week to repair. The BOP was landed March 24 1998. During the installation test they observed a surface flowmeter problem. Further, the annular preventer failed to open fully April 26th 1998. The kick occurred May 2nd and May 5th. The total kick duration was four days. Two BOP pressure tests were carried out after the kicks without any failures.

7.3.2 Summary Kick Occurrence vs. BOP Failure Occurrences

It was found that for four of the BOP failures the kick killing operations were a likely contributor to the occurrence of the failures. Two of the failures were in the annular preventers, one in choke valves and one in a blind-shear ram;

Rig 51
The inner and the outer choke valves were leaking after 7.5 days of kick control operations (details page 73).

Rig 53
The blind-shear ram failed to test when testing against the cement plug. On the previous test three days before the kick it tested perfect. On this test, 10 days after the kick, the blind-shear ram failed (details page 74).

Rig 56
Lower annular preventer was leaking. It had been used for stripping during the well control operations (details page 75).

Rig 58
Packing element in #1 annular failed. It had been used for stripping during a kick control operations (details page 76).

It should be noted that for some kicks the history with respect to BOP failures after the kick is unknown. Some of these kicks may have contributed to failures.

Only once the kick killing operation is likely to blame for choke or kill valve failure, indicating that the wear and tear from kick circulation is not a large problem for these valves, when considering the high number of kicks that were taken. The failure mechanism is unknown.

The blind-shear ram failure is likely caused by the kick killing operation because the blind-shear ram functioned perfectly just before the kick and failed to seal just after the kick. The failure mechanism is unknown.

Stripping operations cause annular preventer wear. During six of the 48 kicks the pipe was stripped into or out of the well. Two of the stripping operations caused the annular to fail. In addition for two other kicks flow was observed in the riser during the stripping operation (Rig

63 and Rig 64). The preventers did, however, not leak when the pipe was kept steady and the annular preventer was closed with normal control system pressure. These incidents are not regarded as annular preventer failures, but more a likely outcome of a stripping operation. The amount of stripping an annular preventer may endure before starting to leak is influenced by the quality of the element when starting the stripping operation and also the type of fluid confined in the BOP. A new element will endure more stripping than an old one, and gas below the annular is more likely to cause a notable flow in the riser than if mud is below the annular.

The number of BOP failures caused by kick circulation was few. It should be noted that the data stems from subsea deepwater BOPs only. It is reason to believe that if investigating the same for surface stacks the result could be different. In 1992 SINTEF carried out a study investigating surface BOP reliability. One of the conclusions from the study was that the in-between well maintenance was limited. Typically, both ram and annular elements were replaced when they failed, and not as a result of inspection and wear evaluation as for subsea stacks. Such elements are more likely to fail in a kick situation due to increased wear, than on a subsea stack.

8. BOP Test Strategies and Configurations vs. the Blowout Probability

8.1 Introduction

During drilling the BOP is regarded as a secondary barrier against blowouts. There are other secondary barriers as well, for instance the casing, the formation, the cement outside casing. The primary barrier during drilling is the hydrostatic pressure imposed by the mud column. If the hydrostatic pressure from the mud column becomes too low, a kick has occurred. Then if one of the secondary barriers fails a blowout will result.

In Phase I DW and Phase II DW (/7/ and /2/) a fault tree model was established to assess the probability of the BOP's ability to close in a well kick during various assumed situations. In this present study kick information has been collected. By adding the kick information relevant to the previous collected BOP reliability data a complete fault tree model for blowouts through or via the BOP has been established.

The relevant kick information from this study comprise:

- experienced kick frequencies (Table 2.2, page 20)
- tubulars running through the BOP when the kick occurred (Table 3.3, page 41)
- ram type and size inside the various BOPs during the kick situation (Table 8.1 page 86)
- shut-in casing pressures (Figure 3.7, page 37)

All the data in the fault tree model stems from experience during deepwater drilling. The majority of the data stems from the US GoM OCS, but some of the BOP reliability data also stems from other areas (Phase I DW /6/).

The blowout probability is not regarded as the important parameter in this study, because the historic experienced blowout frequency will likely be a better indication of the blowout probability. However, with a blowout probability model it will be possible to better analyze how the various parameters affect the BOP's total ability to close in the types of kicks that can be expected.

It is important to note that the model only will consider kicks that may be confined by the BOP. The following typical blowouts are not included in the model:

- Shallow gas blowouts (before the BOP is landed)
- Blowouts outside the BOP
- Blowouts through the drillpipe
- Underground blowouts
- Blowouts caused by spurious disconnect of the riser connector and lack of riser margin (also disabling the BOP control)

The main fault tree utilized for the analysis is shown in Appendix 1. For the various analyses shown through this section minor alternations in the fault tree have been done. These alternations have been to the construction itself or to the input data.

Fault tree analysis and symbols are briefly described in Appendix 1 to this report. Several textbooks related to fault tree construction and analyses exist, among them /32/. A more thorough description of how the fault tree was constructed is presented in /7/.

8.2 Parameters Affecting the BOP's Ability to Close in a Well

The BOP stack is tested to verify that the BOP will be able to act as a well barrier in case of a well kick.

In general, it can be stated that the more frequently the BOP stack is tested, the higher the availability the BOP as a safety barrier will be. It is, however, important to note that some parts of a BOP stack are not as important as other parts with respect to testing.

When pressure testing the BOP both the ability to operate the BOP function and the ability to seal off a pressure are tested. When function testing a BOP only the ability to carry out the function is tested and not the ability to close in a pressure.

The effect of the component testing on the BOP's total ability to close in a well kick will depend on:

- The BOP stack design/configuration
- The drillpipe or tubular that runs through the BOP
- The reliability of the various BOP functions
- The test frequency of the BOP function (both function and pressure test)

8.3 Operational Assumptions

8.3.1 The BOP Stack Design

The fault tree analyses are based on the BOP stack design shown in Figure 8.1.

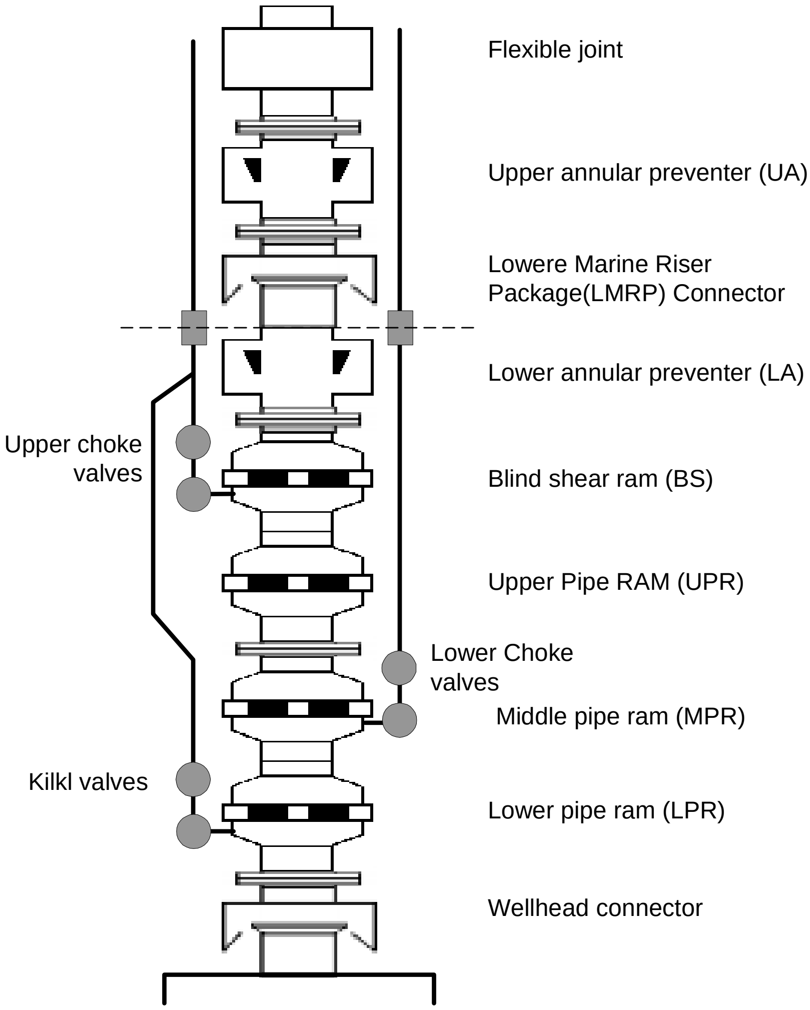

Figure 8.1 BOP stack design used for the fault tree analyses

The base case BOP stack design includes the following:

- Two annular preventers, one above the LMRP connector (upper annular) and one below (lower annular) (20 of 26 rigs had two annular preventers, the remaining had one)
- One blind-shear ram preventer and three pipe ram preventers located in two dual blocks. (24 of 26 rigs had this configuration, one rig had two blind-shear rams and two pipe rams, and one rig had four pipe rams and one blind-shear ram)
- Six choke and kill valves (lower choke outlet below LPR, kill outlet below MPR, and upper choke outlet below the blind-shear ram) (The number of valves utilized on the deepwater rigs varied from four to 10)
- Two hydraulic connectors (one LMRP connector and one wellhead connector)
- The stack is joined together with five clamped flanges

The BOP is equipped with a main control system only. No acoustic backup control system that can operate the blind-shear ram, middle pipe ram, and the lower pipe ram is included.

Assumptions regarding the subsea BOP control systems design and function are presented in /7/ and will not be explained in detail in this report. The fault tree is, however, based on a Shaffer (Koomey) pilot control system from the early 80ties. In principle this control system is similar to other pilot control systems. One important aspect to note is that some newer BOP control systems have less redundancy caused by subsea communication between the pods. The effect of this reduced redundancy on the safety availability is discussed in /7/.

The control system principle chosen does not, however, have a significant effect on the evaluations related to the BOP test practices and BOP configuration.

8.3.2 Input Kick Frequencies

The input kick frequencies used for the fault tree calculation are based on the kick frequencies found in this study (Table 2.2, page 20).

- Kick frequency per 1000 BOP-days: 12.0 kicks/1000 BOP-days
- Kick frequency per well: 0.578 kicks/well drilled

These frequencies do not include shallow kicks, i.e. kicks occurring before the BOP is landed.

8.3.3 Tubulars Running Through the BOP when the Well Kicks

In Phase II DW (/2/), the configuration of each BOP was collected. This included the preventers in the BOP, how they were stacked together and what ram element size that were utilized in the BOPs. This information has been combined with the size of the drillpipe that were inside the BOP when the well kicked. Based on this an overview of the preventers that had the geometrical capacity to be used for closing in the well has been established. Table 8.1 shows this overview.

Table 8.1 Geometric sealing capability during initial kick situation

Available preventers	No. of kicks	Distribution
Only the blind-shear ram could be used (empty hole)	2	4.2 %
The LPR and the MPR could not be used	1	2.1 %
The LPR could not be used	4	8.3 %
All preventers could be used	41	85.4 %
Total	48	100.0 %

The results shown in Table 8.1 are used as input for the fault tree calculation. This means that where relevant an additional basic event with an on demand failure probability have been included in the fault tree.

It is assumed that a pipe ram preventer will never close on a tool joint by mistake during a kick situation.

8.3.4 Confined BOP Pressure Limitation

During none of the observed kicks the confined pressures exceeded the pressure rating of the annular preventers, i.e. the annular preventers were available for closing in a kick for all kicks that occurred when there was a tubular in the well.

8.3.5 BOP Unavailability Calculation and Test Frequencies

The mean fractional deadtime (MFDT) of a component is the mean proportion of the time where the component is in a failed state. Consider a component with failure rate λ. Failures are only assumed to be discovered at tests, which are performed after fixed intervals of length τ. Failed components are repaired or replaced immediately after discovery.

The mean fractional deadtime of such a component is

$$MFDT = (\lambda * \tau)/2 \qquad (/32/),$$

provided that $\lambda * \tau \ll 1$

The availability (A) of such a component can be expressed by:

$$A = 1 – MFDT = 1 - (\lambda * \tau)/2$$

The expressions above assume that the test interval is fixed. In practical situations the test interval may vary. If a variation in the test interval exists and the τ value represents an average test interval, the formula will give too optimistic results.

Further, when this formula is used for each single component in a redundant system (like a subsea BOP) that is tested at the same time the results will be too optimistic.

For the purpose of these analyses it is assumed that the BOP failures relevant for the fault tree analysis are observed during BOP testing only. This is not correct because some of the failures in the control system are observed when they occur. From a safety point of view this is beneficial, i.e., the calculated results will be conservative.

It is further assumed that the failure rate is constant, i.e., independent of time, and that all components are independent.

8.3.6 BOP Test Interval

The following BOP test intervals have been chosen for the purposes of the fault tree analyses in this report unless other test intervals are specifically stated.

- The BOP preventers and choke and kill valves are pressure tested every two weeks (pressure test one pod, function tested one pod)
- The BOP is function tested every two weeks (both pods)

This means that every relevant BOP function will be operated once a week, and that every component will be pressure tested once every two weeks.

When collecting the BOP reliability data in Phase II DW (/2/) the real average time between pressure tests was found to be lower than two weeks, 11,5 days. It has been selected not to utilize the average time between tests in these calculations. When using the average time between tests a correction factor should have been applied. The typical correction factor would be approximately 1,1-1,2 (/13/) that should bring the input data to approximately 13 days between tests. For the comparison of the different test practices this approximation will have no effect.

8.3.7 Initial Situation

The situation when the well kicks and the response of the BOP is required is as follows:

There are no known failures in the BOP stack or the control system.

- The BOP was completely pressure and function tested after it was landed on the wellhead last time
- All choke and kill valves are closed
- Hard shut in, i.e., an annular preventer will be closed without opening the choke line first.

8.3.8 Failure Input Data

The failure data used as input for the fault tree analyses are based on the reliability data collected during both the Phase I DW and Phase II DW projects (/2/ and /6/). The failure frequencies used as input for the fault tree analysis are based on the failure frequencies for failures that occurred in the safety critical period in Phase I DW and Phase II DW. This means that failures that were observed when the BOP was on the rig, during running of the BOP and during the installation test have been disregarded.

8.3.9 Repair Strategies

For the purpose of the calculations presented, it has been assumed that whenever a BOP failure is observed, the failure is repaired before the operation continues.

From the collected data it was noted that MMS from time to time granted a waiver that postponed the repair. These waivers will to some extent reduce the BOP safety availability. The waivers granted were, however, only given for BOP components/functions where a redundancy was present in the stack or the well was nearly completed i.e. the well was safe. For the purpose of these calculations the MMS waivers as practiced today will have an insignificant effect on the results. MMS waivers are presented and discussed in Section 8.4.5 on page 97.

8.3.10 Failure Observation

In the calculations it has been assumed that the BOP failures are observed during tests only. This is not correct, because many failures are observed during normal operations as well. Failures observed during normal operations are typically failures observed because the BOP is operated for other reasons than testing, and that pressurized control system equipment starts to leak.

The effect of this assumption is that the results will be conservative.

8.3.11 Other Assumptions

- The model only considers the probability for a successful control of the initial kick situation. This is a non-conservative assumption. Failures of BOP components during kick circulation are discussed in Section 7.3 on page 72.

- Further, another simplification, adding conservatism to the result, is that when a kick occurs when there is no drillpipe in the well only the blind-shear rams can be used for sealing off the kick. The annulars are assumed not to be able to close on an open hole. The BOP manufacturers claim that an annular can be used for closing on an open hole. During all the SINTEF BOP reliability studies (experience from 500 wells) it has not been observed that they have tested this function once so the success probability of such an operation is unknown.

- When a wireline is in the hole when the well kicks it has been regarded as an empty hole. The wireline, however, have to be cut at surface and dropped, or pulled before the BOP blind-shear ram can be closed. (Most BS rams cannot shear wireline)

8.4 BOP Test Strategy and BOP Configuration vs. the Blowout Probability

The estimates of the blowout probability presented in this chapter should be used with care. The important aspect to focus on is the relative difference between the different test strategies and BOP configurations for the experienced kick situations observed.

8.4.1 BOP Test Strategies Evaluated

For all the BOP test strategies investigated it has been presupposed that a complete BOP installation test always is carried out, including pressure test of all equipment on one pod and function test on the other pod.

Four different main test strategies have been evaluated. The test strategies are presented in Table 8.2.

Table 8.2 BOP test strategies evaluated

Short test strategy description	**BOP test strategy**
Base test case (similar to present regulations)	- Complete BOP installation test (pressure and function test) - The BOP preventers and choke and kill valves are pressure tested every two weeks (pressure test one pod, function test one pod) - BOP is function tested every two weeks (both pods)
Body test* every two weeks, in-between function test	- Complete BOP installation test (pressure and function test) - Body test the BOP every two weeks against UPR. Function test on both pods - Function test both pods every two weeks
Body test* every two weeks, but ***no*** in-between function test	- Complete BOP installation test (pressure and function test) - Body test the BOP every two weeks against UPR. Function test on both pods - No additional function test
Body test* every week incl. Function test	- Complete BOP installation test (pressure and function test) - Body test the BOP every week against UPR. Function test on both pods

* For the body test strategies it has been assumed that the:
- well duration is 50 days
- blind-shear ram is tested every 20 days in association with casing running

8.4.2 Blowout Probability vs. BOP Test Strategy

Appendix 1 presents the fault tree used for the calculation. The relevant collected kick data parameters and the BOP reliability data have been fed into the fault tree model and the expected blowout frequency has been calculated for various BOP test strategies. Table 8.3 shows the results from the calculations. It should be noted that when the frequency of an incident is low, the frequency and the probability are equal.

Table 8.3 Main results, blowout probability

Test strategy (see Table 8.2 for details)	Average probability of failing to close in a kick (%)	Ratio vs. base case	Blowout frequency per well	Number of wells per blowout	No. Of BOP days between each blowout
Base test case (similar to present regulations)	0.125 %	1.00	0.00072	1382	66752
Body test every two weeks, in-between function test	0.134 %	1.07	0.00077	1293	62445
Body test every two weeks, but ***no*** in-between function test	0.137 %	1.10	0.00080	1258	60746
Body test every week incl. function test	0.080 %	0.64	0.00046	2152	103958

As seen from Table 8.3, with the experienced type of kicks, selected BOP configuration, and experienced BOP failure data a test strategy based on a weekly body test of the BOP will ensure a lower blowout probability than a test strategy as followed today.

When evaluating the effect of not carrying out the detailed pressure testing of all the BOP components, as done today, the effect is relative small with respect to the blowout probability. The most important pressure test is the test verifying that there are no external leaks in the lower part of the BOP, i.e. the body test. The additional gain when performing the detailed pressure testing is approximately 10% only. The reason for this little effect is that there exist a lot of redundancies in a BOP to close in the “normal” kicks. The main cause for the 10% difference is the empty hole situation where the fault tree model assumes that only the blind-shear ram can be used for closing in the kick. The effect of adding another blind-shear ram in the BOP stack is discussed in Section 8.4.4 on page 92.

8.4.3 Sensitivity Evaluation

With the expected distribution of tubulars running through the BOP, as shown in Table 8.1, the most critical areas in the BOP is the lower parts with respect to external leaks, and the blind-shear ram with the associated controls for the empty hole kicks.

To evaluate the effect of utilizing under- or overestimated values for the input data the following parameters have been changed and the calculations performed for all the BOP tests strategies shown in Table 8.3.

1. Wellhead connector external leak failure rate divided by two
2. Wellhead connector external leak failure rate multiplied by two
3. Empty hole for 20% of the kicks
4. Empty hole for 2% of the kicks

Table 8.4 shows the results from the sensitivity calculation

Table 8.4 Sensitivity calculation results

Test strategy (see Table 8.2 for details)	Probability of failing to close in a kick									
	As original calculations (see Table 8.3)		*1. WH connector failure rate 50%*		*2 WH connector failure rate 200%*		*3 Empty hole probability 20%*		*4 Empty hole probability 2%*	
	Proba-bility	*Ratio vs. base test case*	Proba-bility	Ratio vs. base test case	Proba-bility	Ratio vs. base test case	Proba-bility	Ratio vs. base test case	Proba-bility	Ratio vs. base test case
Base test case (similar to present regulations)	*0.125 %*	*1.00*	0.089 %	1.00	0.199 %	1.00	0.191 %	1.00	0.116 %	1.00
Body test every two weeks, in-between function test	*0.134 %*	*1.07*	0.098 %	1.10	0.207 %	1.04	0.232 %	1.21	0.120 %	1.03
Body test every two weeks, but ***no*** in-between function test	*0.137 %*	*1.10*	0.101 %	1.13	0.211 %	1.06	0.238 %	1.25	0.124 %	1.07
Body test every week incl. function test	*0.080 %*	*0.64*	0.062 %	0.70	0.117 %	0.59	0.176 %	0.92	0.067 %	0.58

The relative difference between the test strategies has the same ranking for all the different cases calculated. It is seen that the smallest difference between the base test case and the weekly body test strategy is for the empty hole situation where it has been assumed that 20% of all kicks occur when there are no drillpipe in the hole. The blind-shear ram is the only preventer that can close in the kick in this situation. (It is assumed that an annular preventer cannot close on an open hole. This is not correct because an annular preventer can in emergency be used for closing in a well on an open hole. The success probability of such a closure is, however unknown.)

Even when manipulating the data as shown in Table 8.4, a body test every week including a BOP function test will give the lowest blowout probability. A BOP body test every second week instead of the base case testing will give a slightly increased blowout probability. The main contributor to this increased probability is the empty hole situations. For the other situations where a drillpipe runs through the BOP the high redundancy in the BOP stack causes that the detailed testing has no relevant effect on the blowout probability.

Discussion

From a safety point of view the weekly body test including a function is the best way of testing the BOP. This applies for subsea BOP stacks similar to the stack showed in Figure 8.1 on page 85. Surface BOP stacks have less redundancy, and the detailed testing is therefore more important for these BOP stacks.

The Phase II DW study /2/ showed that running and pulling the BOP test plugs and wear bushing consumes in average 7 hours for each BOP test for the US GoM deepwater wells. So if requiring a weekly BOP body test this will likely cause higher time consumption than the present test strategy. Unless more efficient tools/practices for running the BOP test plug are developed/used, the US GoM drilling industry would likely not prefer this change for the deepwater wells.

When testing the BOP after running casing it may be tested against the casing pack-off tool. This is common in Norway and Brazil. Then no additional run is required for a body test and a complete function test on both pods. This type of test will consume approximately 1.5 hours. The scheduled weekly body test would however require a separate test plug run that can be expected to consume 7 hours for US GoM deepwater wells.

This running and pulling time for the plugs is long and thereby costly. The oil industry should investigate if other plugs that can be ran as a part of the drillstring can be used for testing the subsea BOPs. So called compression plugs may be one alternative to look into. There is a large potential for saving.

For subsea BOP used in “shallow” water the running and pulling of test tools are less time consuming. A weekly body test for these BOPs will likely reduce the total testing time in addition to increase the BOP safety availability.

8.4.4 Effect of BOP Stack Configuration on the Blowout Probability

As discussed in the Phase II DW report /2/ the BOP stack configuration varied from BOP to BOP. The effect of some of these variations are discussed below:

- One BOP had 3.5” ram-blocks in the LPR. With this ram size they had no use for the LPR at all in any of the observed kicks. I.e. more possible leak paths to sea are exposed. Some preferred a fixed LPR ram (5 or 5 ½ “), while others preferred a variable. The size of the fixed pipe ram did not always fit the actual drillpipe running through the BOP when the kick occured.
- Some rigs have one annular preventer while others have two.
- One rig had two BS rams while the others had only one. Two BS rams is also the recommended number of BS rams both in the North Sea and Brazilian deepwater drilling.

By alternating the parameters in the fault tree model the effect of these stack configurations on the blowout probability has been assessed for the kicks that were observed and the different BOP test strategies shown in Table 8.2 on page 89.

Fixed vs. variable LPR ram-blocks
The relative effect of choosing various LPR ram-blocks principles on the blowout probability is shown in Table 8.5.

Table 8.5 LPR ram-block selection vs. blowout probability

Test strategy (see Table 8.2 for details)	Probability of failing to close in a kick							
	As original calculations (see Table 8.3)		*VBR ram-block in the LPR*		*3.5" ram-blocks in the LPR*		*Fixed 5 or 5 ½ "ram-blocks in the LPR*	
	Proba-bility	*Ratio vs. base test case*	Proba-bility	Ratio vs. base test case	Proba-bility	Ratio vs. base test case	Proba-bility	Ratio vs. base test case
Base test case (similar to present regulations)	*0.125 %*	*1.00*	0.123 %	1.00	0.144 %	1.00	0.125 %	1.00
Body test every two weeks, in-between function test	*0.134 %*	*1.07*	0.131 %	1.07	0.152 %	1.06	0.133 %	1.06
Body test every two weeks, but ***no*** in-between function test	*0.137 %*	*1.10*	0.135 %	1.10	0.156 %	1.08	0.137 %	1.10
Body test every week incl. function test	*0.080 %*	*0.64*	0.079 %	0.64	0.090 %	0.63	0.080 %	0.64

For one of the kicks it was observed that the LPR was a fixed 3.5" LPR. Utilizing 3.5" ram-blocks in the LPR means that the LPR cannot be used for sealing around the normal drillpipe in the hole. Based on the experienced kicks, this will increase the blowout probability with approximately 17 % compared to using a VBR that can close around all sizes of drillpipe in the well. Fixed ram-blocks with a diameter different from the mostly used drillpipe diameter should not be used in the LPR.

For some wells a combination of drillpipe diameters were used, normally both 5" and 5.5". In the kick data it was observed that for the kicks where both the size of the fixed LPR ram-blocks and the drillpipe diameter running through the BOP were identified, the LPR did not fit the drillpipe for 10% of the kicks. Utilizing a fixed ram-block size similar to the most commonly used drillpipe diameter will cause an increased blowout probability of 2 – 3%, compared to using a VBR ram-block. Some prefer fixed ram-blocks in the LPRs due to higher hang-off capacity. The difference in blowout probability is small, and a fixed ram-block similar to the most commonly used drillpipe diameter is acceptable.

One or two annulars

Some rigs have one annular preventer while others have two. The kick data and the BOP reliability data were combined, and the fault tree modified to evaluate the effect on the blowout probability for the two alternatives.

Table 8.6 One or two annulars

Test strategy (see Table 8.2 for details)	Probability of failing to close in a kick			
	Two annulars (original calculation, see Table 8.3)		*One annular*	
	Probability	Ratio vs. base test case	Probability	Ratio vs. base test case
Base test case (similar to present regulations)	0.125 %	1.00	0.125 %	1.00
Body test every two weeks, in-between function test	0.134 %	1.07	0.134 %	1.07
Body test every two weeks, but ***no*** in-between function test	0.137 %	1.10	0.137 %	1.10
Body test every week incl. function test	0.080 %	0.64	0.080 %	0.64

As seen from Table 8.6 the calculation shows there is no significant difference in the blowout probability if reducing the number of annulars from two to one for the experienced kick situations. The reason why there is no difference is the level of redundancy in a BOP stack when normal drillpipe is running through the BOP. It should here be noted that it is assumed that an annular preventer cannot seal on an open hole. If assuming that an annular can seal on an open hole with a fairly low probability, for instance 0.8, a small difference could have been noted. Further, none of the kicks observed occurred when there were casing in the BOP. These kicks are rare, but this is also a situation where two annulars increase the probability for a successful shut-in of the well.

The analyses consider the initial kick situation, and not the effect of wear and tear during the kick circulation. In this study it was observed that stripping operations caused annular failures twice. This is described in Section 7.3.2 on page 81.

One vs. two BS rams

One rig had two BS rams while the others had only one. Two BS rams is the recommended number of BS rams both in the North Sea and Brazilian waters for deepwater drilling.

The motivation for recommending two BS rams in Norway and Brazil is that deepwater wells frequently will be drilled with dynamically positioned (DP) rigs and without a riser margin. If the DP system fails the rig will drift off. The BS ram then has to close and seal the well, before disconnecting the LMRP connector. When there is no riser margin the automatic result of a drift off will be a well kick. If the BS ram then leaks the result will be a blowout. To reduce the probability of such a leak two BS rams are preferred. The second BS ram is preferably a fifth ram, but may also be the upper pipe ram.

No emergency disconnect incidents were observed in this study, but two blind-shear rams will also be beneficial for empty hole kicks. For the purpose of the following calculations the upper pipe ram has been converted to a BS ram.

It is presupposed that the body test is conducted against the MPR and not the UPR. Further, both the blind-shear rams are tested against the casing one by one, in average every 20 days.

Table 8.7 shows the results from the calculations.

Table 8.7 Blowout probability two blind-shear rams vs. the average BOP configuration

Test strategy (see Table 8.2 for details)	Average BOP configuration (results from Table 8.3, page 90)			UPR replaced by an additional Blind-shear ram		
	Average probability of failing to close in a kick	Ratio vs. base case	Number of wells per blowout	Average probability of failing to close in a kick	Ratio vs. base case	Number of wells per blowout
Base test case (similar to present regulations)	0.125 %	1.00	1382	0.1117 %	1.000	1549
Body test every two weeks, in-between function test	0.134 %	1.07	1293	0.1118 %	1.001	1547
Body test every two weeks, but ***no*** in-between function test	0.137 %	1.10	1258	0.1150 %	1.030	1503
Body test every week incl. function test	0.080 %	0.64	2152	0.0568 %	0.508	3047

As seen from table Table 8.7 replacing the upper pipe ram with an additional blind-shear ram will increase the probability of closing in a kick with approximately 12 % for the base test case. For the other test strategies the effect of this replacement will be higher. The reason for this effect is that the probability of a successful closure on an empty hole will be significantly better than with one blind-shear ram.

It should further be observed that with two blind-shear rams the effect of the detailed BOP testing will be close to zero because with two blind-shear rams there will be a backup alternative for all preventers for all the different kick situations observed. The blowout probability will now be totally dominated by the probability of experiencing a leakage in the lower part of the BOP stack.

Replacing the UPR with an additional blind-shear ram will reduce the redundancy with respect to sealing around a drillpipe. To take away this redundancy will, however, have an insignificant effect because there is still much redundancy left. It should be noted that if using two pipe rams only, at least one of them should be a variable ram.

Another benefit with two blind-shear rams in deepwater wells is that they will have a much higher success probability for sealing off the well in case off a DP rig drift off combined with lack of riser margin.

Lower kill outlet above vs. below the LPR

One of the 26 rigs had the lower kill outlet above the LPR, while the remaining rigs had the outlet below the LPR. Most rigs in the Norwegian sector of the North Sea used to have this outlet above the LPR in the 80ties, but now most rigs have them below.

When these outlets are below the LPR an external valve leak will result in a blowout in case of a kick. Such leaks do not occur frequently, but they have an affect on the probability of a blowout.

Table 8.8 Blowout probability with the lower kill line outlet above LPR vs. the average BOP configuration

Test strategy (see Table 8.2 for details)	Average BOP configuration (results from Table 8.3, page 90)			Lower kill line outlet above LPR		
	Average probability of failing to close in a kick	Ratio vs. base case	Number of wells per blowout	Average probability of failing to close in a kick	Ratio vs. base case	Number of wells per blowout
Base test case (similar to present regulations)	0.125 %	1.00	1382	0.111 %	1.00	1556
Body test every two weeks, in-between function test	0.134 %	1.07	1293	0.120 %	1.08	1444
Body test every two weeks, but ***no*** in-between function test	0.137 %	1.10	1258	0.124 %	1.11	1400
Body test every week incl. function test	0.080 %	0.64	2152	0.073 %	0.66	2358

As seen from Table 8.8, keeping the kill line outlet above the LPR will have a positive effect on the blowout probability with approximately 12 % reduction. Here it is important to note that the analysis only regards the ability to close in the initial kick. During the kick killing operations a line below the LPR is useful. This line is however regarded as a kill line and not a choke line. The line should therefore preferably only be used for pressure monitor and pure killing. It should not be used for circulation to avoid wear in the valve sealing area.

Discussion/conclusion

The lower pipe ram should preferably be equipped with a variable bore ram capable of sealing around all drillpipe/workstring diameters that shall be run into the well. If due to hang-off capacity problems a fixed ram is preferred, the size of the ram-blocks should be in accordance with the size of the drillpipe normally running through the BOP. If running small size work string in the well, the LPR should never have a fixed diameter ram-block to fit to this size. If such a ram-block is required for well operations it should be located in the MPR or UPR. As a general rule fixed rams with a diameter different from the most commonly used drillpipe diameter should not be used in a BOP stack. A variable bore ram that is capable of sealing around both the small diameter and the normal drillpipe should be used instead.

The use of two annulars does not give any significant improvement with respect to being able to close in the initial kick. But experience shows that when stripping is required as a part of the kick killing operation, this will cause that the annular is likely to fail afterwards (a failed annular preventer was observed after two of six stripping operations, described in Section 7.3.2 on page 81).

All subsea BOP stacks used for deepwater drilling should be equipped with two blind-shear rams. If replacing the upper pipe ram with a blind-shear ram, the effect of the detailed BOP pressure testing is eliminated. Body tests against the MPR and individual testing of the blind-shear rams against the casing will be adequate. Such a BOP configuration and testing will reduce the blowout probability compared to three pipe rams and the present BOP test strategy.

8.4.5 Guidance for Granting Waivers for Subsea BOP Failures

For several of the failures observed in Phase II DW (/2/) it was decided not to pull the BOP to repair the failure after MMS had granted a waiver. The failures in question were typically failures in components that were backed up by another component in the BOP stack, or completion of the ongoing operations were regarded just as safe or safer than an immediate repair. A total of 12 such waivers were given by the MMS. In addition for two other incidents MMS also probably granted a waiver, but it was not stated in the daily drilling report.

Table 8.9 shows a brief description of the BOP failures that were granted waivers in the Phase II DW study.

Table 8.9 MMS waivers in Phase II DW

MMS waiver	BOP component/-system	Failure mode	Short incident description
1	Annular preventer	Internal leakage (leakage through a closed annular)	A leak in the lower annular was observed. The failure was repaired 17 days later after the well was abandoned and the BOP stack pulled.
2	Annular preventer	Internal leakage (leakage through a closed annular)	They failed supply the required closing pressure for the lower annular. Fluid was visible venting from both pods. The source of leak was likely internal within annular body with fluid passing by seal on closing side of piston, going into the open side chamber, then venting to sea through SPM valve. The MMS has approved continued operations with the non-functioning lower annular since the upper annular is tested OK.
3	Ram preventer	Internal leakage (leakage through a closed ram)	They were in the process of abandoning the well when attempted to test the cement plug and csg. to 1500 psi against the BS ram. The pressure dropped to 235 psi in 10 minutes with returns in the riser. They got verbal approval from MMS to proceed with the P&A process with the failure.
4	Ram preventer	Internal leakage (leakage through a closed ram)	Failed to test the LPR (3 1/2" x 5 1/2" VBR) against 3 1/2" DP. They pulled the testplug and replaced the 3,5" pipe with 4,5" pipe and tested. OK. The MPR also had 3,5" sealing capability. The operators requested MMS for an approval to continue operations with only 1 ram tested against 3 1/2" DP. MMS replied that they did need a BOP waiver.
5	Choke/kill valve	Failed to open	When attempted to pump through choke & kill line, lower kill line plugged. The lower inner kill failsafe valve could not be opened. MMS granted a verbal approval to continue drilling with lower kill line plugged.
6	Choke/kill valve	Internal leakage (leakage through a closed valve)	The inner lower choke valve leaked on test. MMS granted a waiver, so no repair was carried out. The BOP was pulled 41 days after the failure was observed.
7	Choke/kill valve	Internal leakage (leakage through a closed valve)	During a BOP test they failed to get a good test on the upper inner kill valve. The got a verbal approval from MMS to continue without repairing until after completing the well. The BOP was pulled 29 days after the failure was observed.
8	Control system	Loss of one function one pod	The annular preventer failed to close/open on yellow pod during a function test. They had to open the annular with the blue pod. MMS granted a waiver. The failure was repaired nearly 2 months later when the LMRP was on the rig for other reasons.
9	Control system	Loss of all functions one pod	The yellow pod hose failed during logging operations. MMS approved that they could complete the wireline operations before repairing the pod hose. The day after they pulled repaired and reran the pod hose. When testing they did not get a proper fluid count for several functions. MMS allowed them to continue the ongoing csg operation before repairing the pod. Attempted to test #2 and #3 ram on yellow pod three days after the initial problem was observed, but there were no proper fluid count. The next noted was that the DP was sheared leaving 353 feet of fish in the hole. It is not stated what happened, it was most likely sheared by the blind-shear ram, Two days were then spent for fishing. They then got approval from MMS to continue operations prior to completion work while working on the yellow pod. The yellow pod was not mentioned any more before it was tested after running casing 12 days after the initial failure.
10	Control system	Loss of one function one pod	The yellow pod opening line for the #3 ram had developed a leak. The ram closed and tested properly. When it was opened, the opening fluid pumped away. The yellow pod opening hose for the #3 ram likely was broken between the yellow pod receptacle and the shuttle valve. MMS granted a waiver for continuous operation.
11	Control system	Loss of one function one pod	The upper annular would not close on yellow pod during the installation test. They pulled the yellow pod to surface, but could not find any failure. After the re-ran and tested the yellow pod the day after, the failure was still there. MMS gave verbal approval to proceed with drilling operations with one annular working and tested. The failure was not repaired before after the well was abandoned more than two months later.
12	Control system	Loss of all functions one pod	When closing the 3-1/2" x 5" VBR'S ON 3-1/2" tube the 1" supply line on blue pod failed near pod. MMS approved continued BOP testing on yellow pod. Pulled, repaired and reran the blue pod twice before the failure was cured..
No reference to MMS	Annular preventer	Internal leakage (leakage through a closed annular)	Lower annular low pressure test @ 250 psi increased to 450 psi. They did not repair this failure at once, but waited until the end of the well.)
No reference to MMS	Control system or kill valves	Loss of several functions both pods	During a BOP test it was noted that the lower inner & outer kill line valves were inoperative. The valves remained closed for the rest of the well. No repair was carried out.

From a safety point of view all waivers except number nine above seem to be reasonable. For number nine it seems that they have carried out the casing operation with one pod pulled for repair, but this is unclear.

To help MMS with the decision-making when requested by the operators to grant a waiver, but also to inform the operators and contractors about what failures that have a significant effect on the BOP safety availability the effect of "typical" failures was calculated. The results from the calculations are shown in Table 8.10. This table considers the type of kicks that were observed and represents an "average" kick.

Table 8.10 Effect of various BOP failures on the ability to close in a kick with subsea BOP

Type of failure	Probability of failing to close in a kick	Ratio vs. base case	Risk increase
No known failure in the BOP (base case, from Table 8.3)	0.1251 %	1.0000	0.00 %
One pod is pulled for repair	0.3513 %	2.8074	180.74 %
Inner kill valve (below LPR) leaks in closed position (see Figure 8.1)	0.1329 %	1.0619	6.19 %
Lower inner choke valve (below MPR) leaks leaks in closed position (see Figure 8.1)	0.1262 %	1.0086	0.86 %
Lower annular is leaking in closed position	0.1251 %	1.0000	0.00 %
Blind-shear ram is leaking in closed position	4.3031 %	34.3918	3339.18 %
Upper pipe ram is leaking in closed position	0.1256 %	1.0035	0.35 %
Middle pipe ram is leaking in closed position	0.1263 %	1.0097	0.97 %
Lower pipe ram is leaking in closed position	0.1438 %	1.1490	14.90 %
One pilot valve for lower pipe ram failed, or similar	0.1252 %	1.0005	0.05 %
One pilot valve for blind-shear ram failed, or similar	0.1376 %	1.1000	10.00 %
Manifold regulator one pod fails to supply pressure	0.1379 %	1.1021	10.21 %
Annular regulator one pod fails to supply pressure	0.1252 %	1.0006	0.06 %

As seen from Table 8.10 many failures in BOP components have an insignificant effect on the BOP safety availability, and a waiver to continue the operations until the well is abandoned should be given. The results should however be combined with the engineering judgment related to the specific situation and operations to be carried out.

External leakages in the BOP stack should never be granted a waiver, even in the upper parts of the stack.

If one pod is pulled for repair the probability of not being able to close in a kick is approximately three times higher. To allow continued operation with this failure, the probability of a kick should be low.

If the inner kill valve is known to be leaking this will expose the leakage path external leakage in the outer kill valve. Further, the combination of an outer kill valve internal leak and leakage in the kill line will also be more likely. It should be noted that from time to time the kill or choke valves fails simultaneous. The inner kill valve is the most critical valve with respect to internal leakage because it is the lower most valve. Normally an internal leakage in this valve should not be granted a waiver.

If the lower choke valve leaks internally, the effect on the safety availability will be much less than if the inner kill valve leaks. This because the valve is backed up by the LPR. This type of failure could be granted a waiver.

If one of two annulars are leaking a waiver should be granted. If the BOP includes one annular only no waiver should be given.

If the blind-shear ram is leaking a waiver should not be granted, unless very specific tasks are carried out (as for instance point 3 in Table 8.9).

A leakage in the UPR and the MPR could be granted a waiver, unless the specific ram is equipped ram-blocks for specific purposes.

A leakage in the LPR should not be accepted.

A failed pilot valve for any of the preventers except the blind-shear ram should be accepted.

A failed annular regulator could be accepted, but not a failed manifold regulator.

Once again the results must be combined with an evaluation of the present situation. The above information should only be regarded as guidance. The guidance only considers single failures. If one failure already is granted a waiver a second different failure in the BOP should normally not be granted a waiver. The combined effect of these two failures should at first be thoroughly investigated.

8.5 Recommended BOP Configuration and Testing Strategy for Subsea BOPs

The recommendations are based on the results from the fault tree calculations carried out in Section 8. The experience the recommendations build on is from drilling operations, and therefore considerations related to specific needs during the completion phase have not been taken. The recommendations are valid for subsea BOPs only, and not surface BOPs.

The objectives with the recommendations listed in this section are:

- Keep the safety level at least as high as today
- Reduce the BOP test time

Table 8.11 list and justify the recommendation for an alternative BOP configuration.

Table 8.11 Recommended BOP configuration

The BOP should include the following preventers	Comments
One (or two) annulars	There is no significant difference between one or two annulars in terms the probability of a successful kick shut in. The pros with two annulars are: • Stripping may likely result in an annular failure • One leaking annular should not require the BOP to be pulled The cons with two annulars are: • Increased weight • Increased investment and maintenance cost
BS in ram cavity #1	This cavity is always equipped with a blind-shear ram for subsea BOPs used in deepwater drilling to day.
BS in ram cavity #2	This cavity is normally equipped with a pipe ram. If replacing this pipe ram with a blind-shear ram this will increase the probability of being able to close in an open hole, and also improve the shear and sealing probability during an emergency disconnect situation Table 8.7, page 95. Based on the deepwater kick experience this will improve the total ability to be able to close in a kick. Taking out the pipe ram from this cavity will not significantly affect the probability of being able to close in a kick with a drillpipe running through the hole. If installing BS rams in the #2 cavity, this may require a modification of the ram cylinders and booster systems for the controls. Alternatively both Shaffer and Cameron have developed rams with higher shearing capacity. According to Shaffer the Shaffer Type V Shear ram enhances the features of Shaffer's T-72 shear ram by increasing the range of pipe that can be sheared without modification to the BOP's. The Type V Shear rams are capable of shearing 6-5/8", S-135 drill pipe, at less than 2,700 psi operator pressure. This typically allows the shear ram to be put in any ram cavity on the BOP stack without the addition of booster cylinders or control system upgrades. Cameron has developed a similar ram named DVS shear ram available in some sizes.
Variable pipe ram in ram cavity #3	Both these rams should be able to seal around the "normal" drillpipe running through the BOP. One of the rams should have a geometry allowing maximum hang-off capacity for the normal drillpipe in the hole. (e.g. 5" drillpipe and 3.5"-5" VBR should allow 600 000 lbs hang-off with a 5" drillpipe, but only approximately 300 000 lbs with a 3,5" drillpipe)
Variable pipe ram in ram cavity #4	
Choke and kill valves	The use of choke and kill valves varies highly from rig to rig. No recommendation with respect to use of these valves is given. The location of the lower valves are discussed in association with Table 8.9, page 96.

The proposed BOP stack configuration shown in Table 8.11 will be better than the normally used BOP stack configuration, shown in Figure 8.1, page 85. The main improvement is utilizing two blind-shear rams instead of one.

Recommended BOP test practices

The proposed test regime presupposes that a blind-shear ram has replaced the UPR, i.e. there are two blind-shear rams in the stack. Then the detailed pressure testing of the BOP (as required to day) will not improve the BOP stack in terms of the BOP safety availability compared to a regulation requiring a body test and a function test only.

Installation tests

Perform a complete detailed BOP pressure test after landing the BOP at the wellhead the first time or subsequent times. (It should not be required to test the VBRs against all tubular sizes ran in hole)

When the LMRP has been disconnected the connection should be pressure tested after reconnecting against the upper annular.

Periodic tests
The BOP body should be tested against the MPR (ram cavity #3) at least every two weeks to the maximum expected pressure in the next section to be drilled. A complete function test of all relevant functions both pods should be carried out.

Perform a complete function test on both pods every two weeks.

It should never be more than 50 days from the last detailed pressure test of the BOP (similar to the installation test).

Test after running casing or liner
The BOP body should be tested against the MPR (ram cavity #3) after running casing or liner.

Perform a complete function test both pods.

Pressure test the BS rams independently against the casing or liner.

Pros and cons in terms of economic aspects

Additional costs
Replacing the UPR with a blind-shear rams in a BOP stack will cause that some investments. In the best case a new type of blind-shear ram blocks can be installed. In the worst case boosters need to be installed on the ram and the control system needs to be modified.

Potential time saving
The potential saving with the proposed test strategy will be time saved. For the purpose of illustrating approximate figures for the potential saving all the tests listed with a test time recorded in Phase II DW (/2/) were grouped in the type of test and the test time.

The experienced average BOP test time has been compared with a coarse estimate for the expected test time for the alternative BOP test strategy. The results are shown in Table 8.12.

Table 8.12 Estimated test time consumption with proposed test strategy

Type of test	BOP tests recorded in Phase II DW			Estimated time consumption with proposed test strategy	
	No. of tests	Total test time (hrs)	Average test time (hrs)	Average test time (hrs)	Total test time (hrs)
Installation test	78	1110	14.23	14.23	1110
Pressure tests scheduled by time	102	1462	14.33	7.00*	714
Test after running casing or liner	153	2059.25	13.46	4.00*	612
Function test scheduled by time	166	118.5	0.71	0.71	118.5
Total	499	4749.75			2554.5

*No detailed pressure test, only body test and function test

If the proposed test strategy had been utilized for the 83 wells drilled approximately 2200 hours of testing time could have been used for other operations. This represents 2.28 % or approximately one week of drilling for each rig each year.

To further reduce the time used for testing the oil and gas industry should focus on developing plugs that could be ran as a part of the drill string, minimizing the need for tripping to test the BOP. So called compression plugs may be one alternative to look into.

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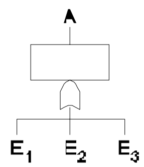
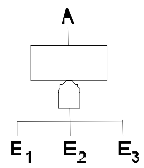
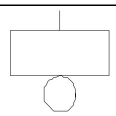
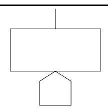
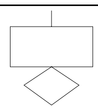
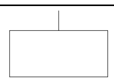
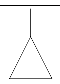
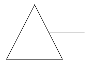
Appendix 1 FAULT TREE CONSTRUCTION

Fault Tree Symbols

A fault tree is a logic diagram that displays the connections between a potential system failure (TOP event) and the causes for this event. The causes (Basic events) may be environmental conditions, human errors, normal events and component failures. The graphical symbols used to illustrate these connections are called "logic gates". The output from a logic gate is determined by the input events.

The graphical layout of the fault tree symbols is dependent on what standard we choose to follow. Table A.1 shows the most commonly used fault tree symbols together with a brief description of their interpretation.

Table A.1 Fault tree symbols

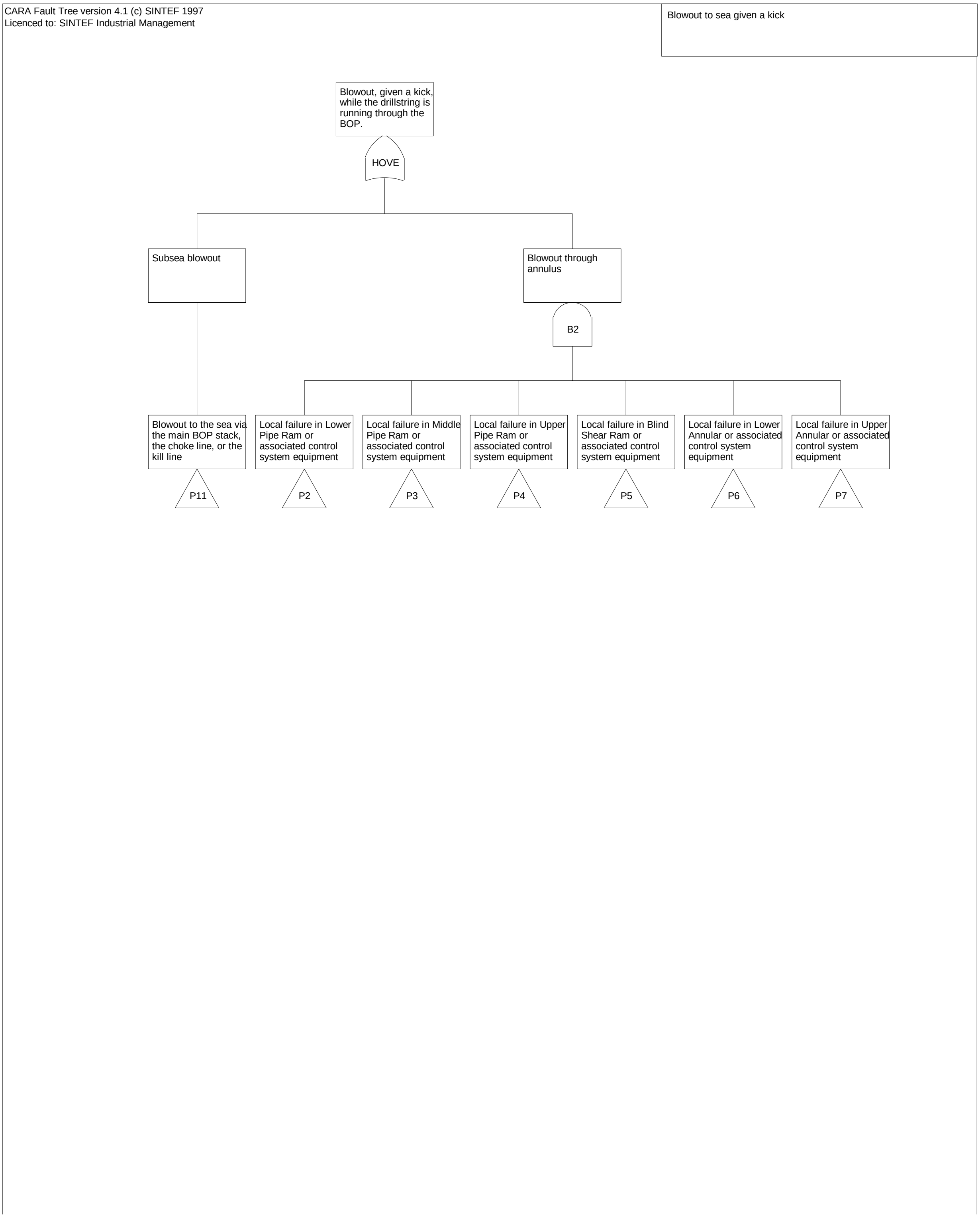
Symbol			Description
Logic Gates	"OR" gate		The OR-gate indicates that the output event A occurs if any of the input events E_i occurs.
	"AND" gate		The AND-gate indicates that the output event A occurs only when all the input events E_i occur simultaneously.
Input Events	"BASIC" event		The Basic event represents a basic equipment fault or failure that requires no further development into more basic faults or failures.
	"HOUSE" event		The House event represents a condition or an event, which is TRUE (ON) or FALSE (OFF) (not true).
	"UNDEVELOPED" event		The Undeveloped event represents a fault event that is not examined further because information is unavailable or because its consequence is insignificant.
Description of State	"COMMENT" rectangle		The Comment rectangle is for supplementary information.
Transfer Symbols	"TRANSFER" out		The Transfer **out** symbol indicates that the fault tree is developed further at the occurrence of the corresponding Transfer **in** symbol.
	"TRANSFER" in		

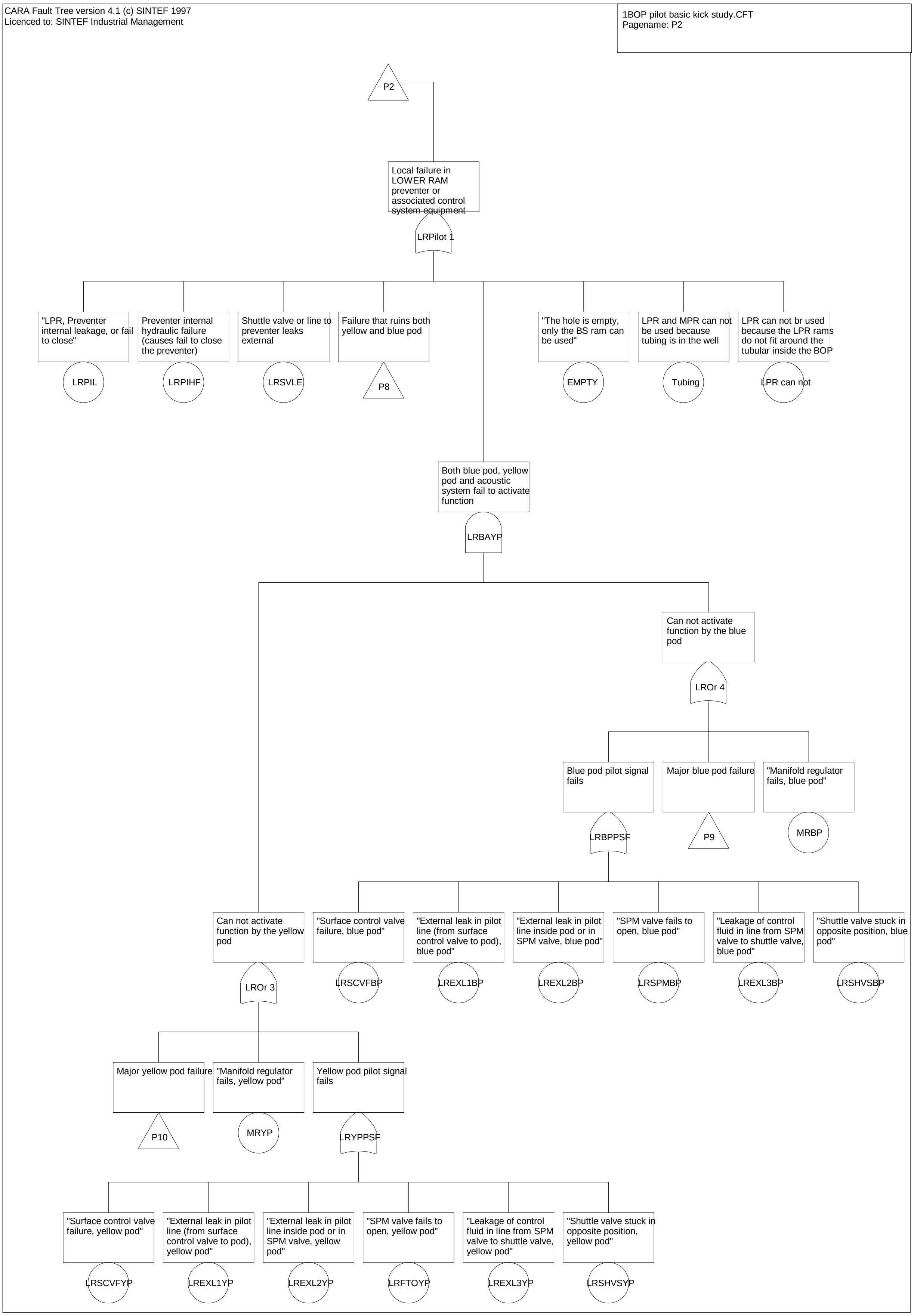
The logic events the basic events and the transfer symbol are the fault tree symbols mainly used in the Fault Trees constructed and analysed in this report. Fault Tree construction and analyses are described in many textbooks, among them /32/.

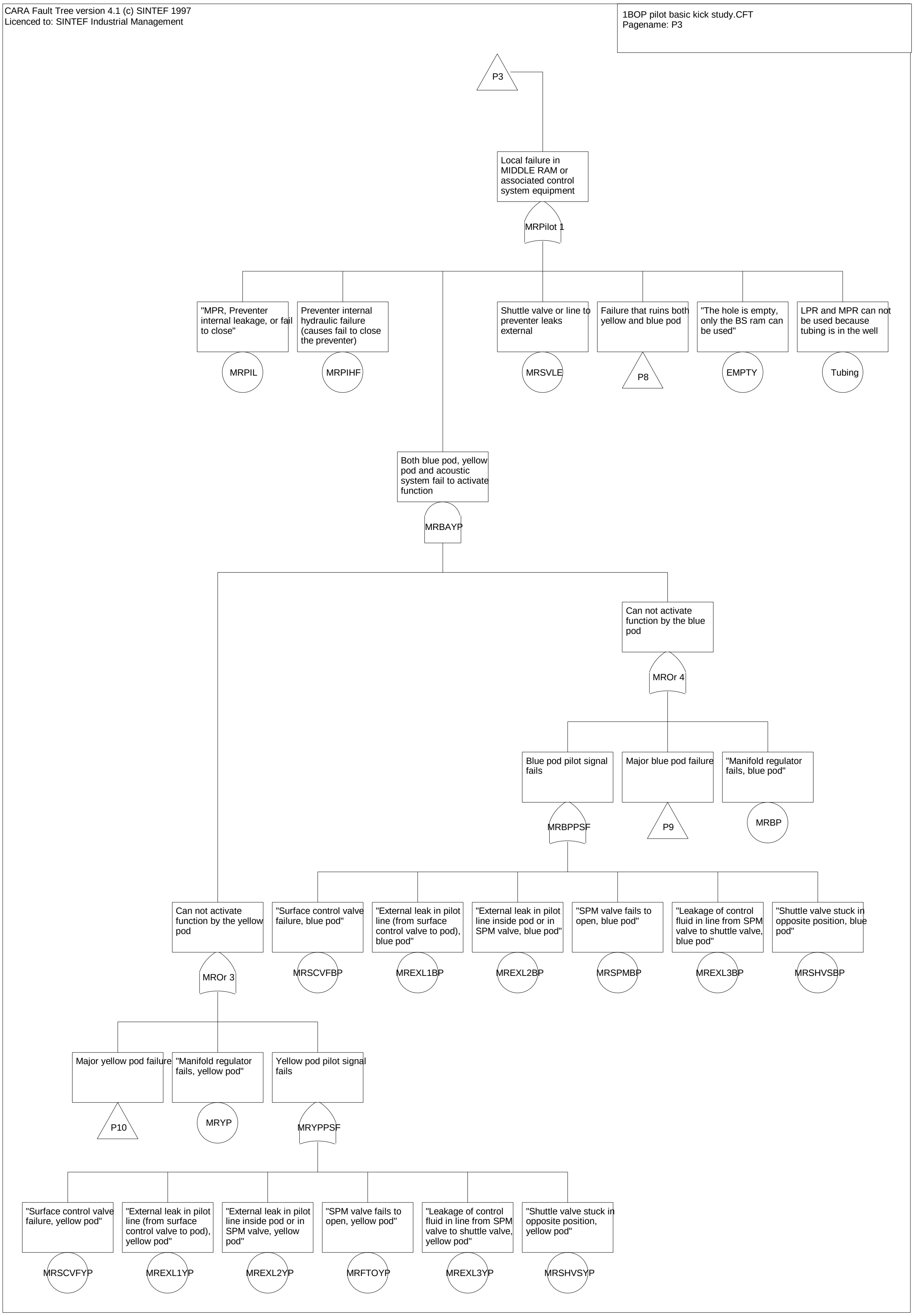
The SINTEF developed program CARA Fault Tree has been used for constructing and analyzing the fault trees (/30/).

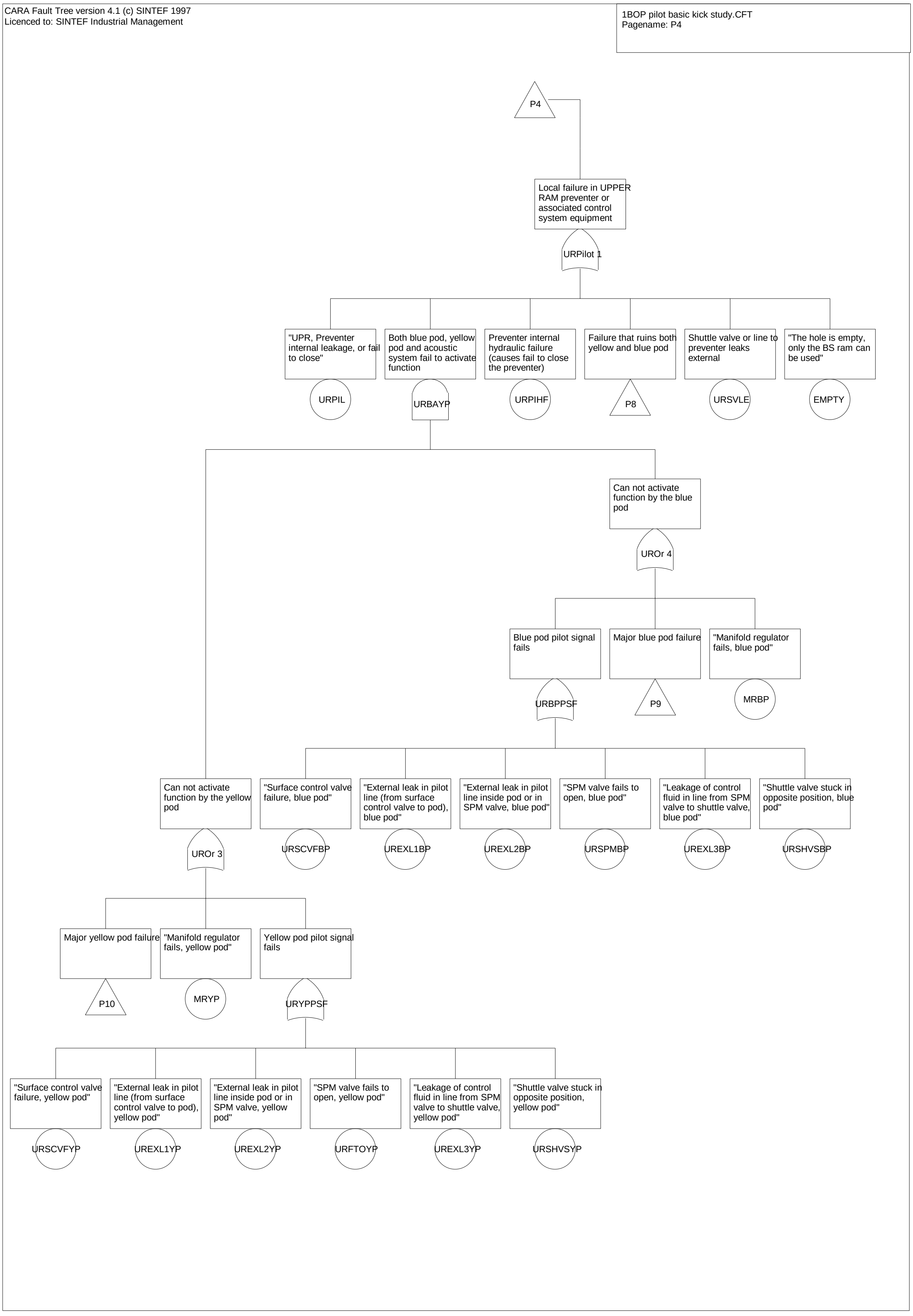
The fault tree utilized for the analyzes are presented on the following pages.

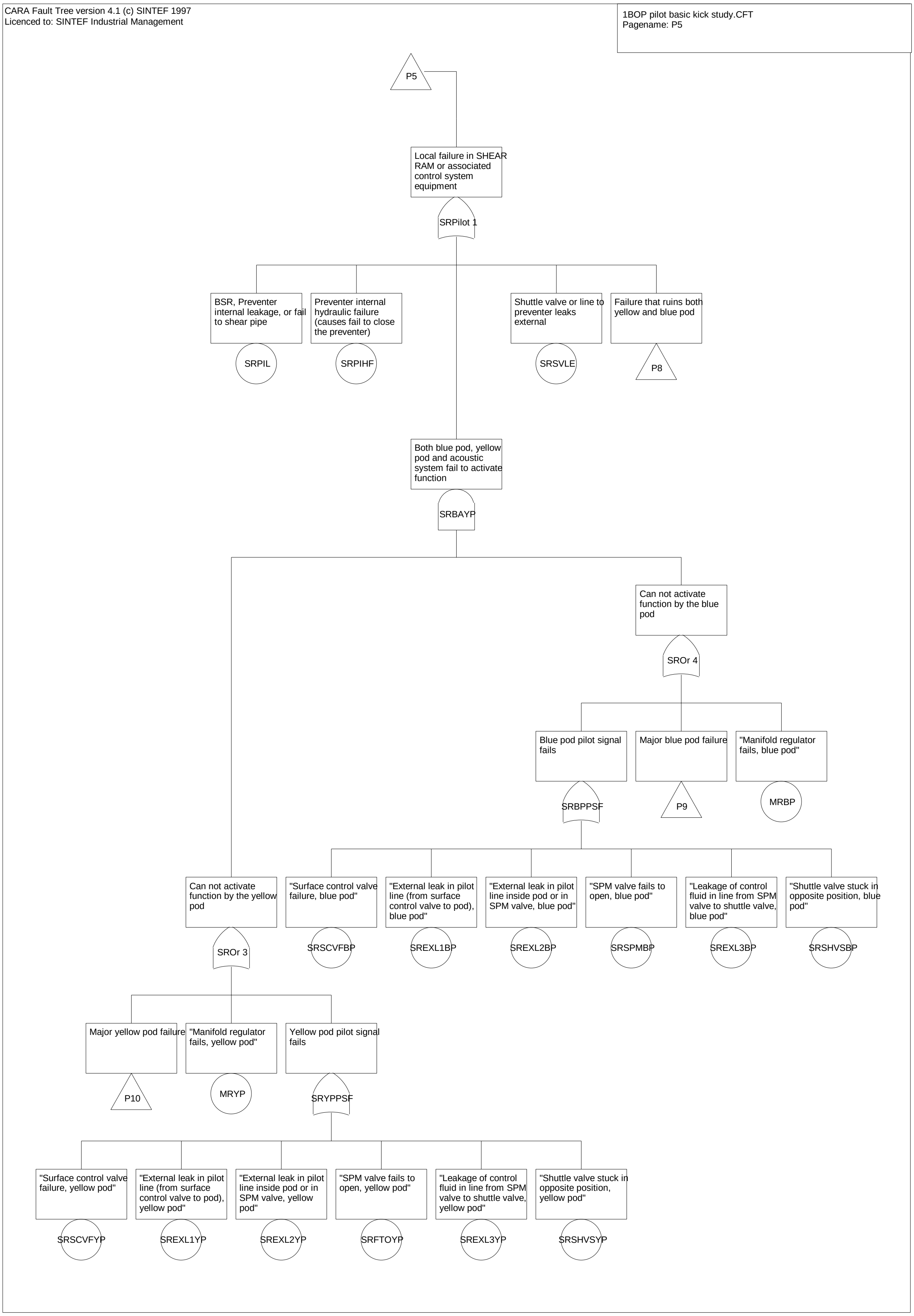
Detailed Fault Tree

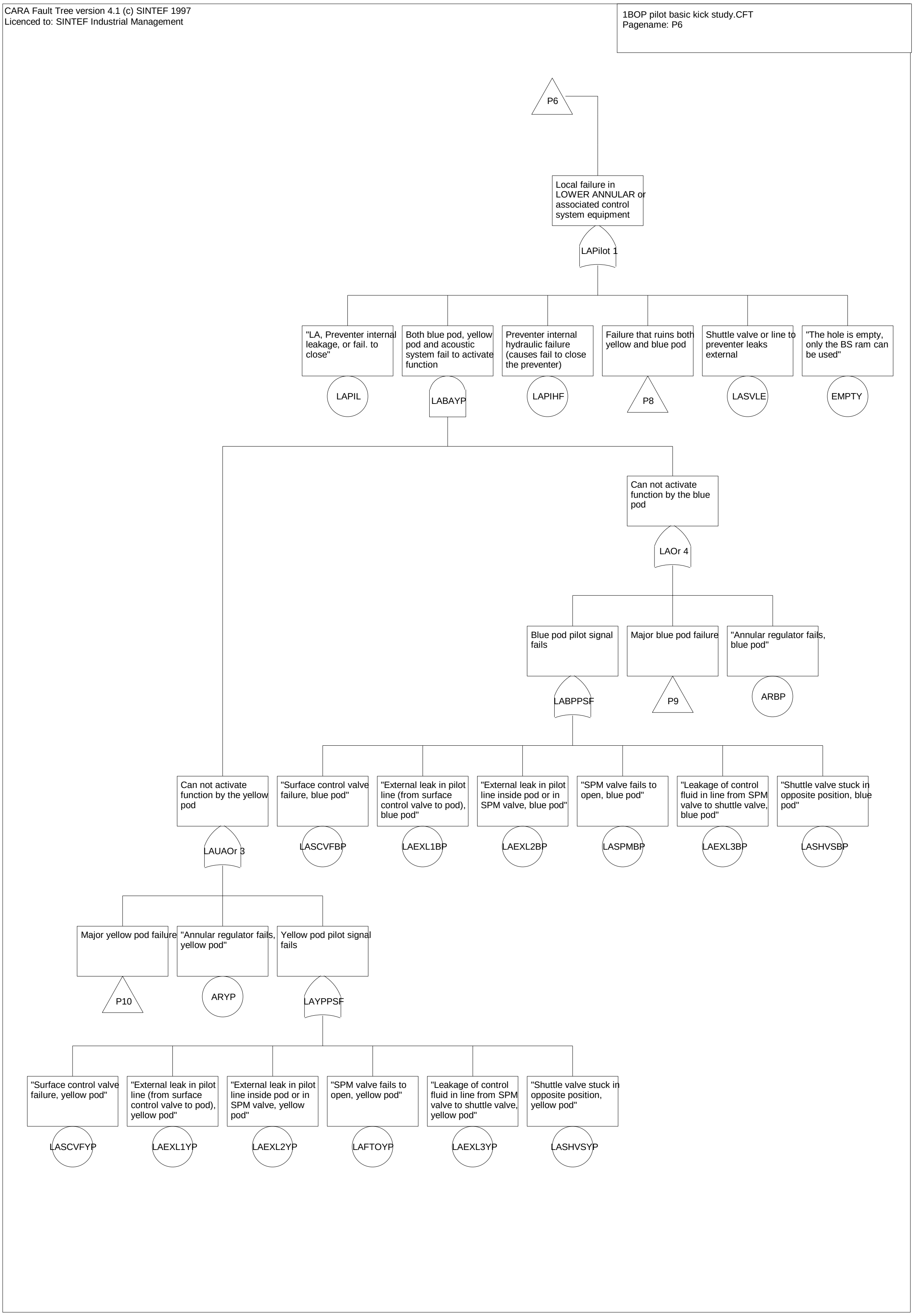


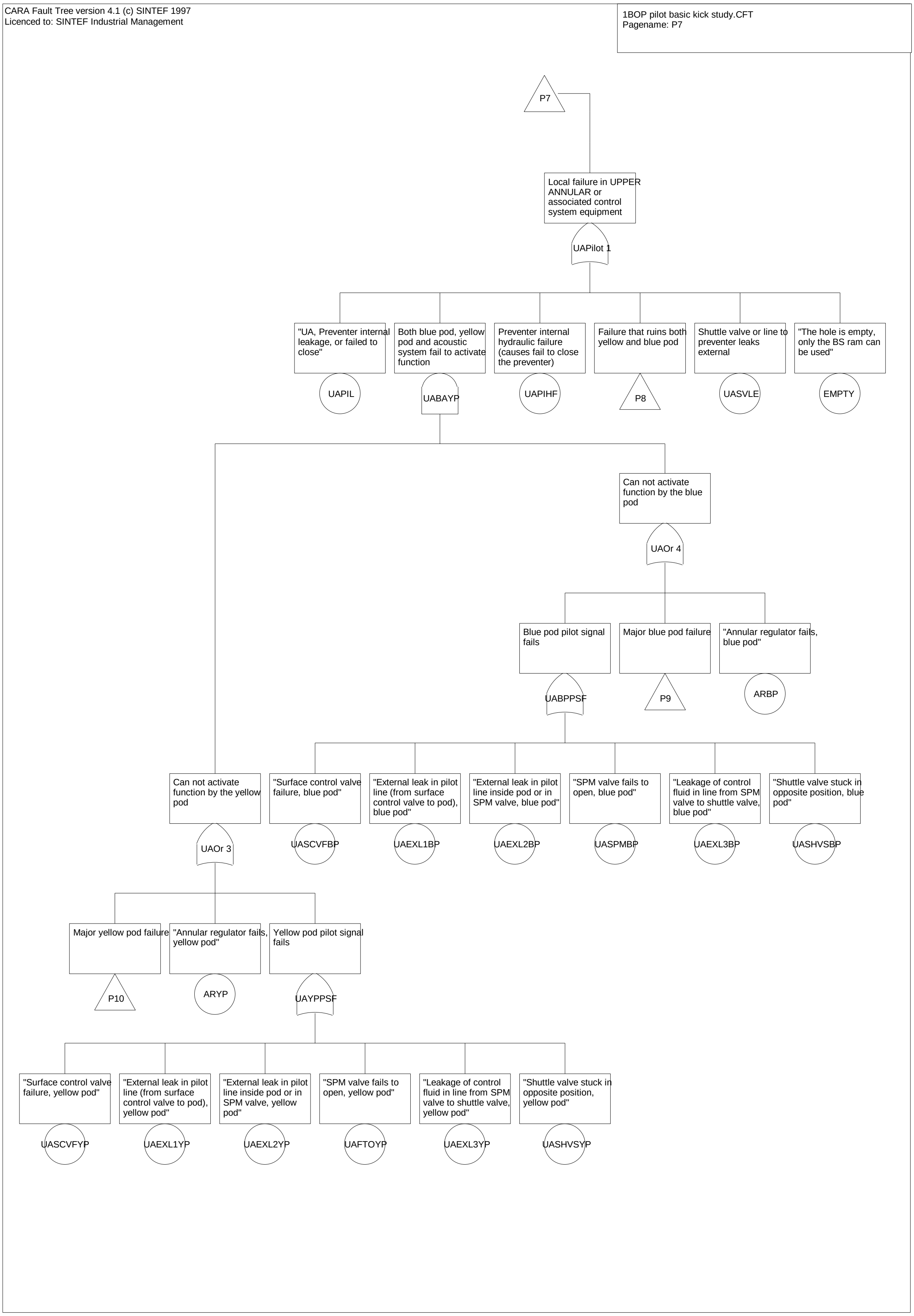

CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic kick study.CFT
Pagename: P2
P2
Local failure in LOWER RAM preventer or associated control system equipment
LRPilot 1
"LPR, Preventer internal leakage, or fail to close"
LRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
LRPIHF
Shuttle valve or line to preventer leaks external
LRSVLE
Failure that ruins both yellow and blue pod
P8
"The hole is empty, only the BS ram can be used"
EMPTY
LPR and MPR can not be used because tubing is in the well
Tubing
LPR can not br used because the LPR rams do not fit around the tubular inside the BOP
LPR can not
Both blue pod, yellow pod and acoustic system fail to activate function
LRBAYP
Can not activate function by the blue pod
LROr 4
Blue pod pilot signal fails
LRBPPSF
Major blue pod failure
P9
"Manifold regulator fails, blue pod"
MRBP
Can not activate function by the yellow pod
LROr 3
"Surface control valve failure, blue pod"
LRSCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
LREXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
LREXL2BP
"SPM valve fails to open, blue pod"
LRSPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
LREXL3BP
"Shuttle valve stuck in opposite position, blue pod"
LRSHVSBP
Major yellow pod failure
P10
"Manifold regulator fails, yellow pod"
MRYP
Yellow pod pilot signal fails
LRYPPSF
"Surface control valve failure, yellow pod"
LRSCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
LREXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
LREXL2YP
"SPM valve fails to open, yellow pod"
LRFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
LREXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
LRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic kick study.CFT
Pagename: P3
P3
Local failure in MIDDLE RAM or associated control system equipment
MRPilot 1
"MPR, Preventer internal leakage, or fail to close"
MRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
MRPIHF
Shuttle valve or line to preventer leaks external
MRSVLE
Failure that ruins both yellow and blue pod
P8
"The hole is empty, only the BS ram can be used"
EMPTY
LPR and MPR can not be used because tubing is in the well
Tubing
Both blue pod, yellow pod and acoustic system fail to activate function
MRBAYP
Can not activate function by the blue pod
MROr 4
Blue pod pilot signal fails
MRBPPSF
Major blue pod failure
P9
"Manifold regulator fails, blue pod"
MRBP
Can not activate function by the yellow pod
MROr 3
"Surface control valve failure, blue pod"
MRSCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
MREXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
MREXL2BP
"SPM valve fails to open, blue pod"
MRSPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
MREXL3BP
"Shuttle valve stuck in opposite position, blue pod"
MRSHVSBP
Major yellow pod failure
P10
"Manifold regulator fails, yellow pod"
MRYP
Yellow pod pilot signal fails
MRYPPSF
"Surface control valve failure, yellow pod"
MRSCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
MREXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
MREXL2YP
"SPM valve fails to open, yellow pod"
MRFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
MREXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
MRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic kick study.CFT
Pagename: P4
P4
Local failure in UPPER RAM preventer or associated control system equipment
URPilot 1
"UPR, Preventer internal leakage, or fail to close"
URPIL
Both blue pod, yellow pod and acoustic system fail to activate function
URBAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
URPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
URSVLE
"The hole is empty, only the BS ram can be used"
EMPTY
Can not activate function by the blue pod
UROr 4
Blue pod pilot signal fails
URBPPSF
Major blue pod failure
P9
"Manifold regulator fails, blue pod"
MRBP
Can not activate function by the yellow pod
UROr 3
"Surface control valve failure, blue pod"
URSCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
UREXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
UREXL2BP
"SPM valve fails to open, blue pod"
URSPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
UREXL3BP
"Shuttle valve stuck in opposite position, blue pod"
URSHVSBP
Major yellow pod failure
P10
"Manifold regulator fails, yellow pod"
MRYP
Yellow pod pilot signal fails
URYPPSF
"Surface control valve failure, yellow pod"
URSCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
UREXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
UREXL2YP
"SPM valve fails to open, yellow pod"
URFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
UREXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
URSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic kick study.CFT
Pagename: P5
P5
Local failure in SHEAR RAM or associated control system equipment
SRPilot 1
BSR, Preventer internal leakage, or fail to shear pipe
SRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
SRPIHF
Shuttle valve or line to preventer leaks external
SRSVLE
Failure that ruins both yellow and blue pod
P8
Both blue pod, yellow pod and acoustic system fail to activate function
SRBAYP
Can not activate function by the blue pod
SROr 4
Blue pod pilot signal fails
SRBPPSF
Major blue pod failure
P9
"Manifold regulator fails, blue pod"
MRBP
Can not activate function by the yellow pod
SROr 3
"Surface control valve failure, blue pod"
SRSCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
SREXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
SREXL2BP
"SPM valve fails to open, blue pod"
SRSPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
SREXL3BP
"Shuttle valve stuck in opposite position, blue pod"
SRSHVSBP
Major yellow pod failure
P10
"Manifold regulator fails, yellow pod"
MRYP
Yellow pod pilot signal fails
SRYPPSF
"Surface control valve failure, yellow pod"
SRSCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
SREXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
SREXL2YP
"SPM valve fails to open, yellow pod"
SRFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
SREXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
SRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic kick study.CFT
Pagename: P6
P6
Local failure in LOWER ANNULAR or associated control system equipment
LAPilot 1
"LA, Preventer internal leakage, or fail. to close"
LAPIL
Both blue pod, yellow pod and acoustic system fail to activate function
LABAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
LAPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
LASVLE
"The hole is empty, only the BS ram can be used"
EMPTY
Can not activate function by the blue pod
LAOr 4
Blue pod pilot signal fails
LABPPSF
Major blue pod failure
P9
"Annular regulator fails, blue pod"
ARBP
Can not activate function by the yellow pod
LAUAOr 3
"Surface control valve failure, blue pod"
LASCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
LAEXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
LAEXL2BP
"SPM valve fails to open, blue pod"
LASPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
LAEXL3BP
"Shuttle valve stuck in opposite position, blue pod"
LASHVSBP
Major yellow pod failure
P10
"Annular regulator fails, yellow pod"
ARYP
Yellow pod pilot signal fails
LAYPPSF
"Surface control valve failure, yellow pod"
LASCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
LAEXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
LAEXL2YP
"SPM valve fails to open, yellow pod"
LAFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
LAEXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
LASHVSYP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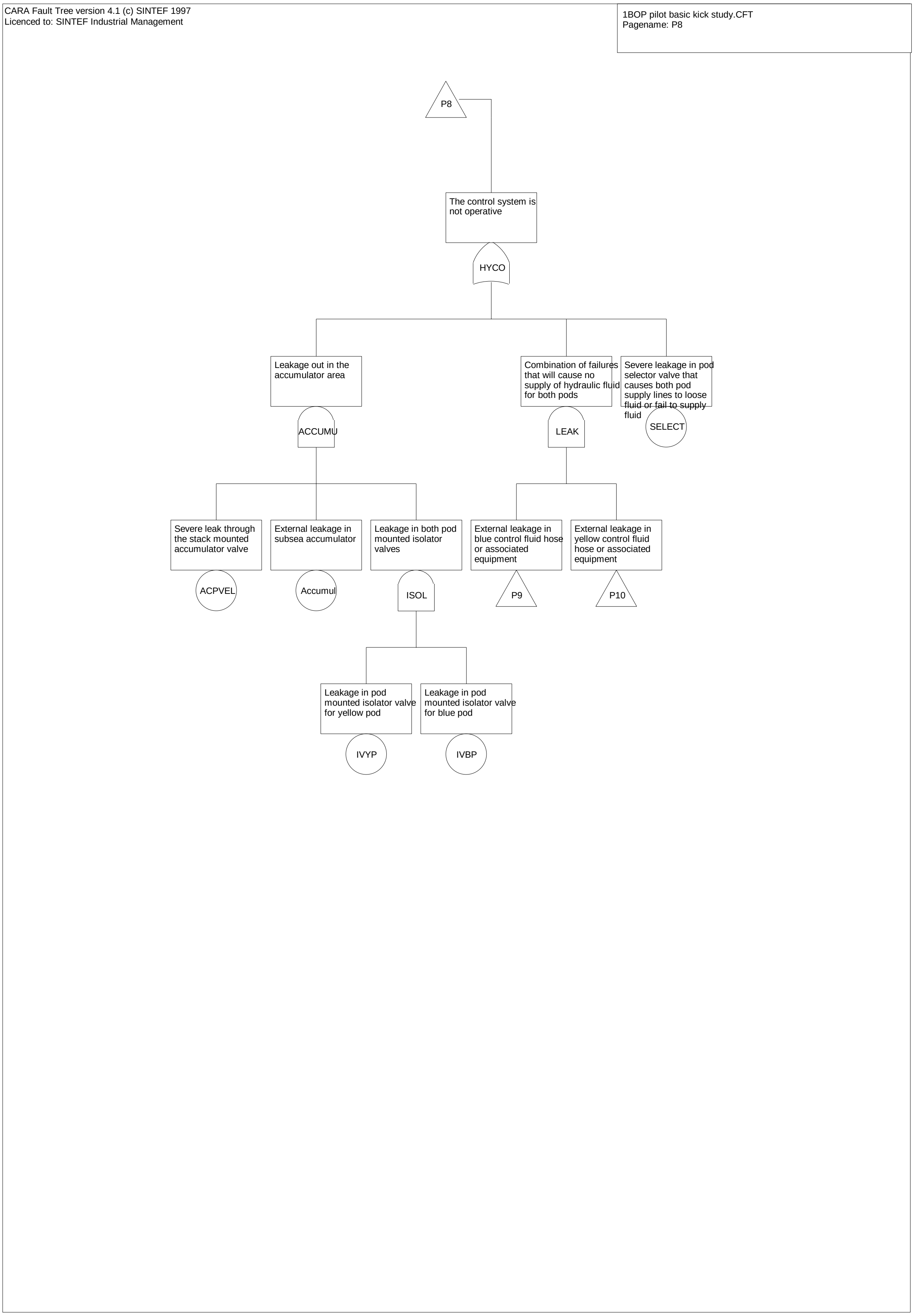
1BOP pilot basic kick study.CFT
Pagename: P7
P7
Local failure in UPPER ANNULAR or associated control system equipment
UAPilot 1
"UA, Preventer internal leakage, or failed to close"
UAPIL
Both blue pod, yellow pod and acoustic system fail to activate function
UABAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
UAPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
UASVLE
"The hole is empty, only the BS ram can be used"
EMPTY
Can not activate function by the blue pod
UAOr 4
Blue pod pilot signal fails
UABPPSF
Major blue pod failure
P9
"Annular regulator fails, blue pod"
ARBP
Can not activate function by the yellow pod
UAOr 3
"Surface control valve failure, blue pod"
UASCVFBP
"External leak in pilot line (from surface control valve to pod), blue pod"
UAEXL1BP
"External leak in pilot line inside pod or in SPM valve, blue pod"
UAEXL2BP
"SPM valve fails to open, blue pod"
UASPMBP
"Leakage of control fluid in line from SPM valve to shuttle valve, blue pod"
UAEXL3BP
"Shuttle valve stuck in opposite position, blue pod"
UASHVSBP
Major yellow pod failure
P10
"Annular regulator fails, yellow pod"
ARYP
Yellow pod pilot signal fails
UAYPPSF
"Surface control valve failure, yellow pod"
UASCVFYP
"External leak in pilot line (from surface control valve to pod), yellow pod"
UAEXL1YP
"External leak in pilot line inside pod or in SPM valve, yellow pod"
UAEXL2YP
"SPM valve fails to open, yellow pod"
UAFTOYP
"Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod"
UAEXL3YP
"Shuttle valve stuck in opposite position, yellow pod"
UASHVSYP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1BOP pilot basic kick study.CFT
Pagename: P8
P8
The control system is not operative
HYCO
Leakage out in the accumulator area
ACCUMU
Combination of failures that will cause no supply of hydraulic fluid for both pods
LEAK
Severe leakage in pod selector valve that causes both pod supply lines to loose fluid or fail to supply fluid
SELECT
Severe leak through the stack mounted accumulator valve
ACPVEL
External leakage in subsea accumulator
Accumul
Leakage in both pod mounted isolator valves
ISOL
External leakage in blue control fluid hose or associated equipment
P9
External leakage in yellow control fluid hose or associated equipment
P10
Leakage in pod mounted isolator valve for yellow pod
IVYP
Leakage in pod mounted isolator valve for blue pod
IVBP

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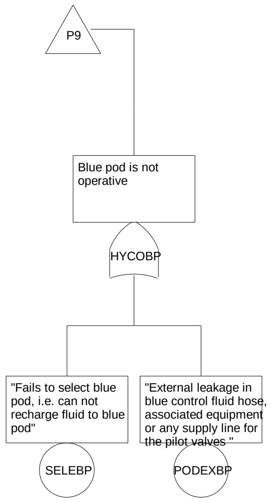
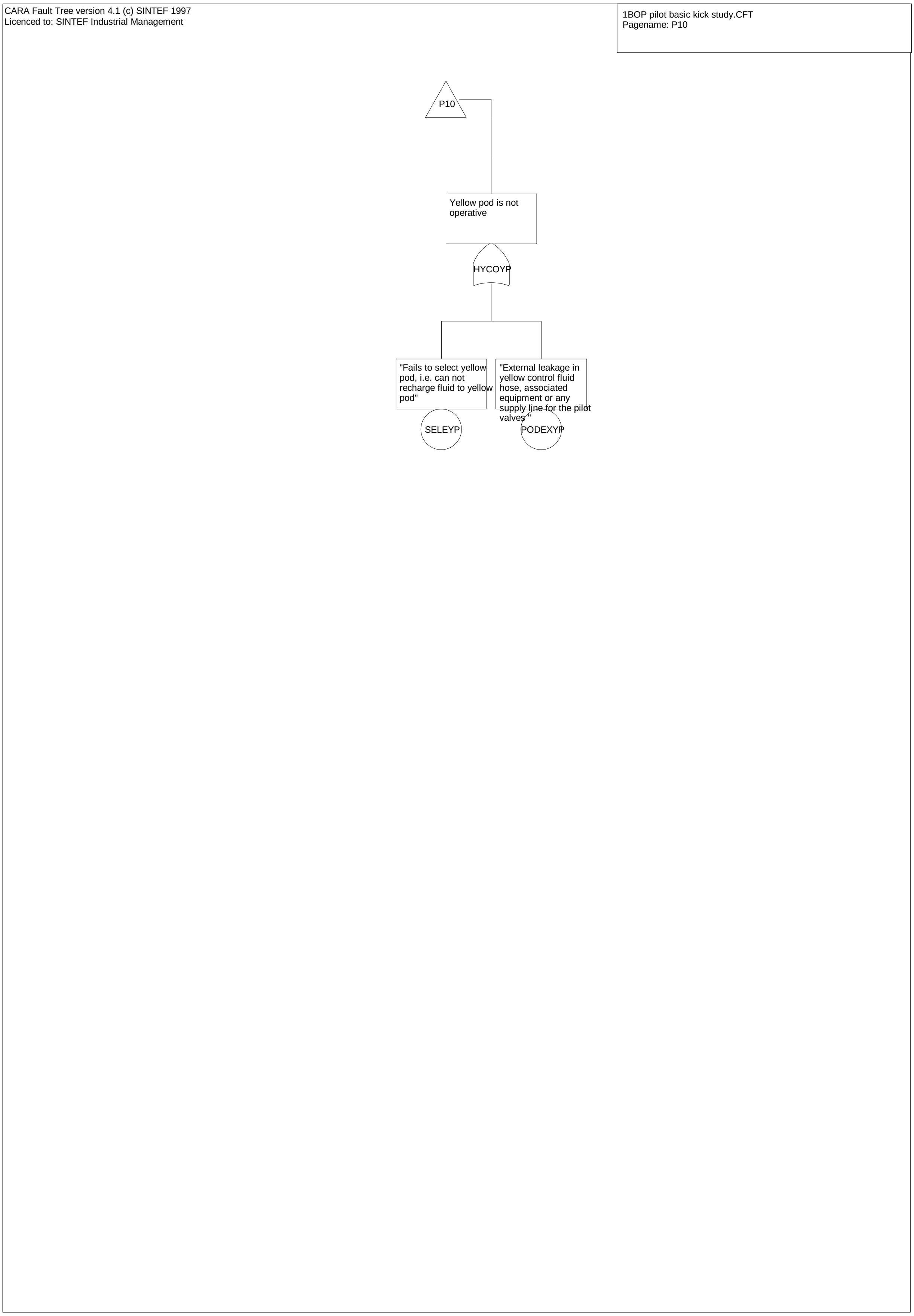
1BOP pilot basic kick study.CFT
Pagename: P9

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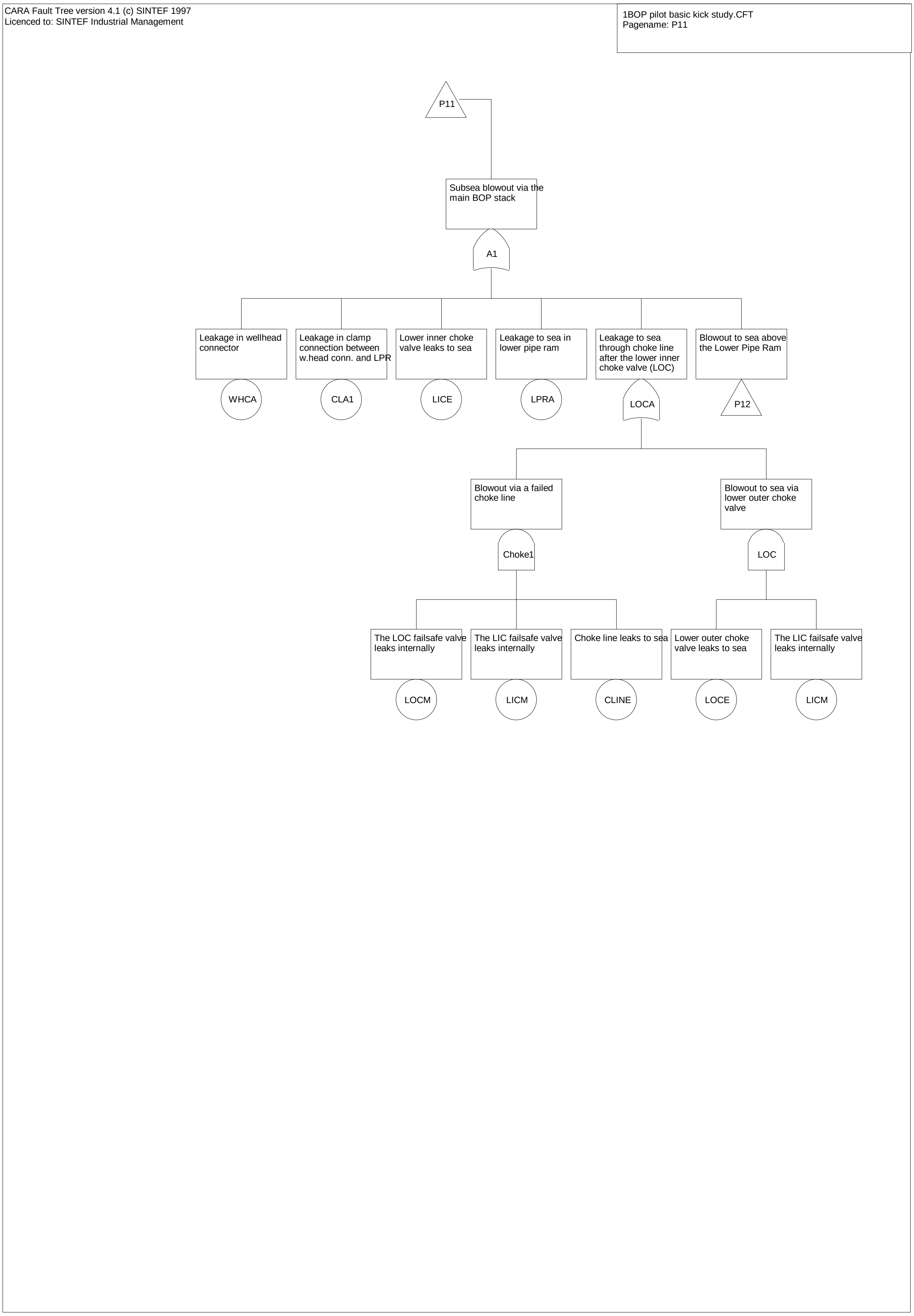
1BOP pilot basic kick study.CFT
Pagename: P10
P10
Yellow pod is not operative
HYCOYP
"Fails to select yellow pod, i.e. can not recharge fluid to yellow pod"
SELEYP
"External leakage in yellow control fluid hose, associated equipment or any supply line for the pilot valves "
PODEXYP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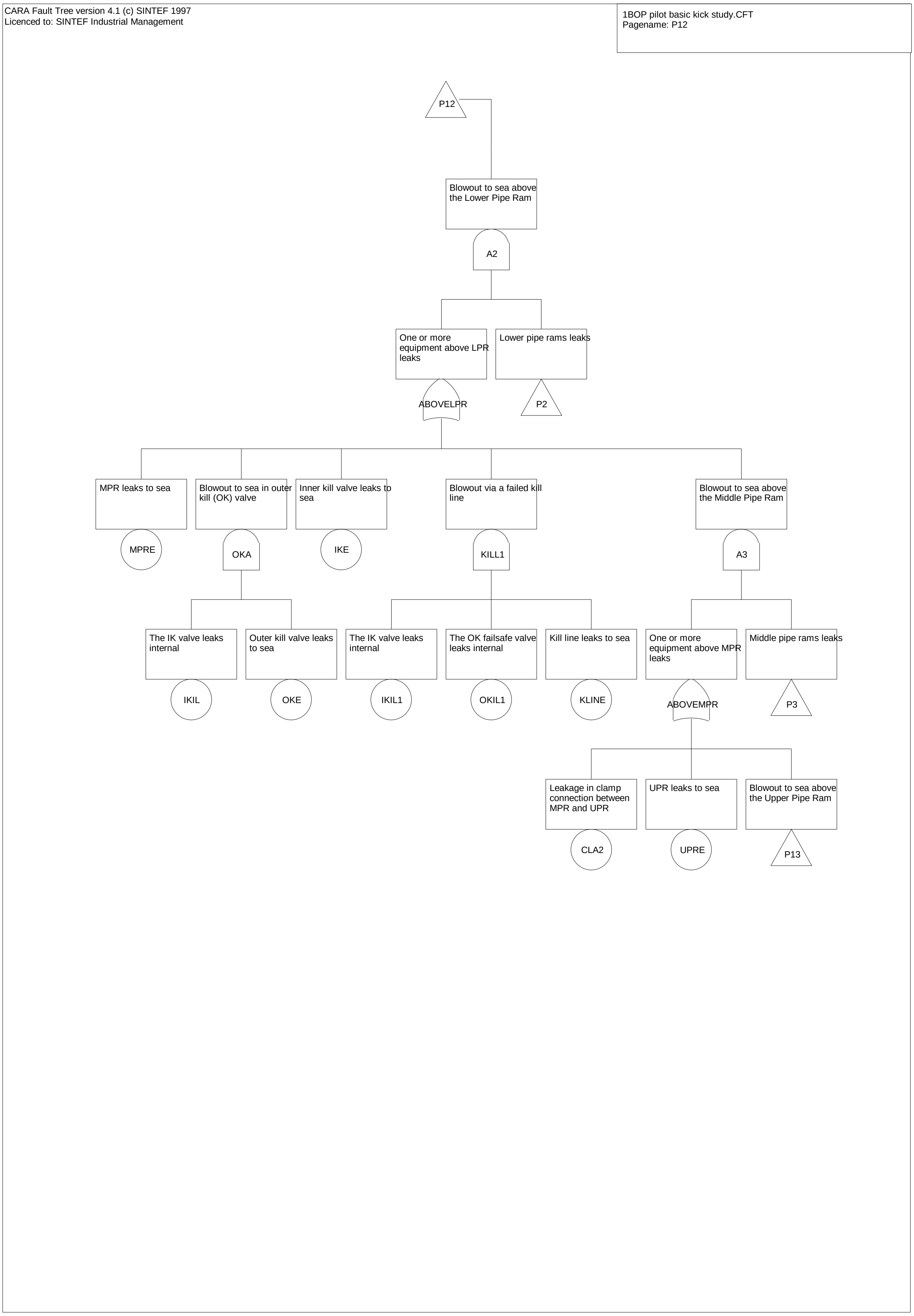
1BOP pilot basic kick study.CFT
Pagename: P11
P11
Subsea blowout via the main BOP stack
A1
Leakage in wellhead connector
WHCA
Leakage in clamp connection between w.head conn. and LPR
CLA1
Lower inner choke valve leaks to sea
LICE
Leakage to sea in lower pipe ram
LPRA
Leakage to sea through choke line after the lower inner choke valve (LOC)
LOCA
Blowout to sea above the Lower Pipe Ram
P12
Blowout via a failed choke line
Choke1
Blowout to sea via lower outer choke valve
LOC
The LOC failsafe valve leaks internally
LOCM
The LIC failsafe valve leaks internally
LICM
Choke line leaks to sea
CLINE
Lower outer choke valve leaks to sea
LOCE
The LIC failsafe valve leaks internally
LICM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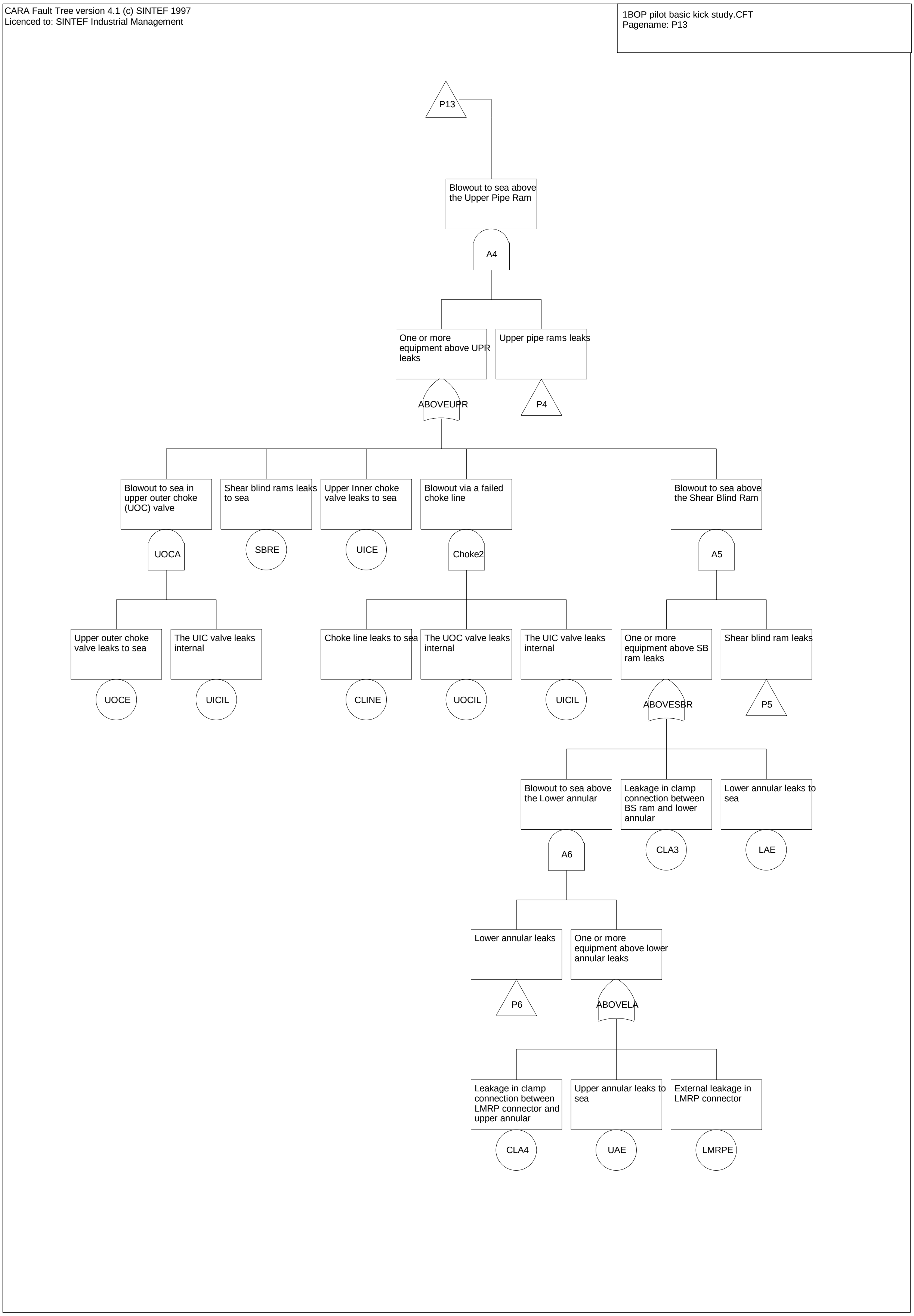
1BOP pilot basic kick study.CFT
Pagename: P12
P12
Blowout to sea above the Lower Pipe Ram
A2
One or more equipment above LPR leaks
Lower pipe rams leaks
ABOVELPR
P2
MPR leaks to sea
Blowout to sea in outer kill (OK) valve
Inner kill valve leaks to sea
Blowout via a failed kill line
Blowout to sea above the Middle Pipe Ram
MPRE
OKA
IKE
KILL1
A3
The IK valve leaks internal
Outer kill valve leaks to sea
The IK valve leaks internal
The OK failsafe valve leaks internal
Kill line leaks to sea
One or more equipment above MPR leaks
Middle pipe rams leaks
IKIL
OKE
IKIL1
OKIL1
KLINE
ABOVEMPR
P3
Leakage in clamp connection between MPR and UPR
UPR leaks to sea
Blowout to sea above the Upper Pipe Ram
CLA2
UPRE
P13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1BOP pilot basic kick study.CFT
Pagename: P13
P13
Blowout to sea above the Upper Pipe Ram
A4
One or more equipment above UPR leaks
Upper pipe rams leaks
ABOVEUPR
P4
Blowout to sea in upper outer choke (UOC) valve
Shear blind rams leaks to sea
Upper Inner choke valve leaks to sea
Blowout via a failed choke line
Blowout to sea above the Shear Blind Ram
UOCA
SBRE
UICE
Choke2
A5
Upper outer choke valve leaks to sea
The UIC valve leaks internal
Choke line leaks to sea
The UOC valve leaks internal
The UIC valve leaks internal
One or more equipment above SB ram leaks
Shear blind ram leaks
UOCE
UICIL
CLINE
UOCIL
UICIL
ABOVESBR
P5
Blowout to sea above the Lower annular
Leakage in clamp connection between BS ram and lower annular
Lower annular leaks to sea
A6
CLA3
LAE
Lower annular leaks
One or more equipment above lower annular leaks
P6
ABOVELA
Leakage in clamp connection between LMRP connector and upper annular
Upper annular leaks to sea
External leakage in LMRP connector
CLA4
UAE
LMRPE