PETROLEUMSTILSYNET

Investigation report

Report	
Report title Investigation report Visund - well-control incident in well 34/8-A-20 AH, 16.3.2016	Activity number 001120023

Classification		
☐ Public	☐ Restricted	☐ Strictly confidential
☐ Exempt from public disclosure	☐ Confidential	

Summary

On 16 March 2016, in connection with a well wash in the construction phase of well 34/8-A-20 AH at Visund A, a well-control incident occurred involving flow from the reservoir (a well kick). In advance of the incident, Statoil assumed that barriers, notably in the form of a cemented 7" liner, had been verified. Shortly after the washing process was completed and the well was filled with seawater, the drill string was raised and a volume increase was observed. The well was shut in using a valve on the BOP. Pressure was observed in the well, which finally stabilised at 84 bar.

In preparing to kill the well by circulating heavy drilling fluid, it was discovered that both the kelly cock valves below the top drive had jammed. One was jammed in the closed position, which prevented the use of normal kill procedures. Alternative kill methods were assessed, while an attempt was made to operate the jammed kelly cock valves. 1st-line emergency response mustered on board and a well-control team from onshore mustered in accordance with Statoil's contingency plan for well incidents. Non-essential personnel were demobilised to shore (Florø).

Just over a day after the incident occurred, it was managed to open the jammed hydraulic kelly cock valve and a normal kill operation was performed by circulating in heavy drilling fluid. The situation was then normalised and production restarted.

What made this incident special is that the barrier envelope was assumed to have been verified in the form of a confirmed inflow test, and that normal well-control methods for killing the well were prevented by a jammed valve below the top drive. In very slightly different circumstances, the well kick might have led to a complicated and long-lasting kill operation with the potential for escalation of risk.

Parties involved	
Main group T-1	Approved by / date Kjell Marius Auflem / 14.6.2016
Investigation group participants Eigil Sørensen, Tore Endresen, Aina Eltervåg, Roar Sognnes	Investigation leader Roar Sognnes

Contents

1 Summary 4
2 Definitions and abbreviations 4
3 Introduction 5
4 Sequence of events 7
4.1 Planning 7
4.2 Execution 8
4.3 Handling of the well-control incident on 16 March 2016 10
4.4 Normalisation 13
5 The potential of the incident 13
5.1 Actual consequences 13
5.2 Potential consequences 14
5.2.1 Hydraulic kelly cock valve 14
5.2.2 Cutting of the drill string 14
6 Observations 16
6.1 Non-conformity 16
6.1.1 Inadequate design of well barriers 16
6.1.2 Inadequate verification of well barriers 16
6.1.3 Deficient classification of safety-critical equipment 16
6.1.4 Defective maintenance programme for kelly cock valves 17
6.1.5 Deficient risk assessment of configuration of subsea BOP at Visund 17
6.2 Improvement point 18
6.2.1 Deficient barrier diagram in the activity programme for completion and in the DOP 18
6.2.2 Older version of risk register used in DOP document 18
6.2.3 Defective training and drills 18
6.3 Barriers 18
6.3.1 Barriers that did function 19
6.3.1.1 Detection of inflow 19
6.3.1.2 Isolation of well 19
6.3.2 Barriers that failed 19
6.3.2.1 Mechanical integrity 19
6.3.2.2 Conventional handling of the well-control situation 19
7 Discussion concerning uncertainties 20
7.1 Possible proximate causes 20
7.1.1 Effect of movement of the drill string immediately prior to the incident 20
7.1.2 Long rathole 21
7.2 Cause of escalation of the incident 21
7.3 Possible underlying causes 21
7.3.1 Kelly cock valves below the top drive 21
8 Annexes 21

1 Summary

On 16 March 2016, in connection with a well wash in the construction phase of well 34/8-A-20 AH at Visund A, a well-control incident occurred involving flow from the reservoir (a well kick). In advance of the incident, Statoil assumed that barriers, notably in the form of cemented 7" casings, had been verified. Shortly after the washing process was completed and the well was filled with seawater, the drill string was raised and a volume increase was observed. The well was shut in using a valve on the BOP. Pressure was observed in the well, which finally stabilised at 84 bar.

In preparing to try to kill the well by circulating heavy drilling fluid, it was discovered that both the kelly cock valves below the top drive had jammed. One was jammed in the closed position, which prevented the use of normal kill procedures. Alternative kill methods were assessed, while an attempt was made to operate the jammed kelly cock valves. 1st-line emergency response mustered on board and a well-control team from onshore mustered in accordance with Statoil's contingency plan for well incidents. Non-essential personnel were demobilised to shore (Florø).

Just over a day after the incident occurred, it was managed to open the jammed hydraulic kelly cock valve and a normal kill operation was performed by circulating in heavy drilling fluid. The situation was then normalised and production restarted.

What made this incident special is that normal well-control methods were prevented by a jammed valve below the top drive, and that there was originally an assumed verified barrier envelope in the well in the form of a confirmed inflow test.

In very slightly different circumstances, the well kick might have led to a complicated and long-lasting kill operation with the potential for escalation of risk.

2 Definitions and abbreviations

Top drive	The drilling machine in the derrick
FPDU	Floating Production Drilling Unit
Inflow-test	Also called negative pressure test
MD	Measured depth, along the wellbore
TD	Total depth, the final depth of the well
Liner	Casing extension
Liner shoe	Lower end of a liner, with a one-way valve
Rathole	A drilled hole that is not covered by casing or liner
Kelly cock	Shut-off valve below the top drive
DOP	Detail Operation Procedure
MFCT	Multifunction circulating tool in the wash string

List of figures

Figure 1 Visund A (Source: Statoil.com).. 6
Figure 2 Statoil's diagram of the well as it was when the incident occurred on 16 March........ 7
Figure 3 shows selected drill data from the time when the incident was discovered and the well shut in with a pipe ram in the BOP 10
Figure 4 Diagram illustrating the height of the section of drill string above the drillfloor immediately after the incident.. 12

Figure 5 Barrier diagram once the incident has been ascertained and the well shut in with BOP and fixed/jammed kelly cock valve 13
Figure 6 Diagram of Visund BOP on the sea bed, with kill & choke lines 16
Figure 7 Identified barriers linked to technical, organisational and operational factors 21

3 Introduction

The Visund oil and gas field, in blocks 34/8 and 34/7, is 22 kilometres northeast of the Gullfaks field in the Tampen area. Oil production began in 1999 and gas production in 2005. The field has been developed using the Visund FPDU, a semi-submersible drilling, processing and accommodation platform, in a water depth varying between 270 and 380 metres on the west slope of the Norwegian Trench. The field was subsequently developed with further wells from well templates on the sea bed, called Visund Sør and Visund Nord, respectively. The wells from the main field and the wells from Visund Nord are tied to the Visund A platform by flexible risers. The Visund field contains oil and gas in several angled fault blocks with different pressure and fluvial systems. The reservoirs are in Middle Jurassic sandstone in the Brent Group and Late Jurassic sandstone and Upper Triassic sandstone in the Statfjord Group and the Lunde Formation. The reservoirs are at 2,900-3,000 metres deep. Oil is piped to Gullfaks A. There it is stored and exported by tanker. Gas is exported via the Kvitebjørn gas pipeline and onwards to Kollsnes, where NGL is separated out and dry gas is exported on to market.

Figure 1 Visund A (Source: Statoil.com)

Statoil is the operator and they have awarded Odfjell Drilling a contract for drilling services and maintenance of the drilling equipment. For servicing, Halliburton has the cementing contract and Geoservice the mud logging contract, with monitoring of the drilling operation from onshore.

On 16 March 2016, in connection with a well wash in the construction phase of production well 34/8-A-20 AH at Visund A, a well-control incident occurred involving inflow from the reservoir (a well kick). The well was planned as a horizontal production well and an 8½" reservoir section was drilled close to the horizontal out to a TD of 5,049 metres MD. A 7" liner was run down and out into the well to 4,647.5 metres MD, and then cemented in accordance with normal procedures. The cementing job was assessed as good, and the two samples of the cement mix that were retained to verify setting both set within the expected setting time.

The well was then to be washed inside the casing and liner. A multifunction washing tool with a packer arrangement, called a "Well Commissioner", and an adjustable circulating valve, called an MFCT, were run down the well on a string of 3½" and 5 7/8" drill pipe. The packer arrangement was to be positioned at/over a polished section (PBR) of 7" liner hanging from and attached to 10¾" casing. There was also a magnet in the string to collect iron filings etc.

Shortly after the washing process was completed and the well was filled with seawater, the drill string was raised and a volume increase was observed. The well was shut in using a valve on the BOP. Pressure was observed in the well, which finally stabilised at 84 bar.

Figure 2 below shows a diagram (originally from Statoil) of the well with the wash string in it, as it was when the well-control incident occurred. The well was filled with sea water.

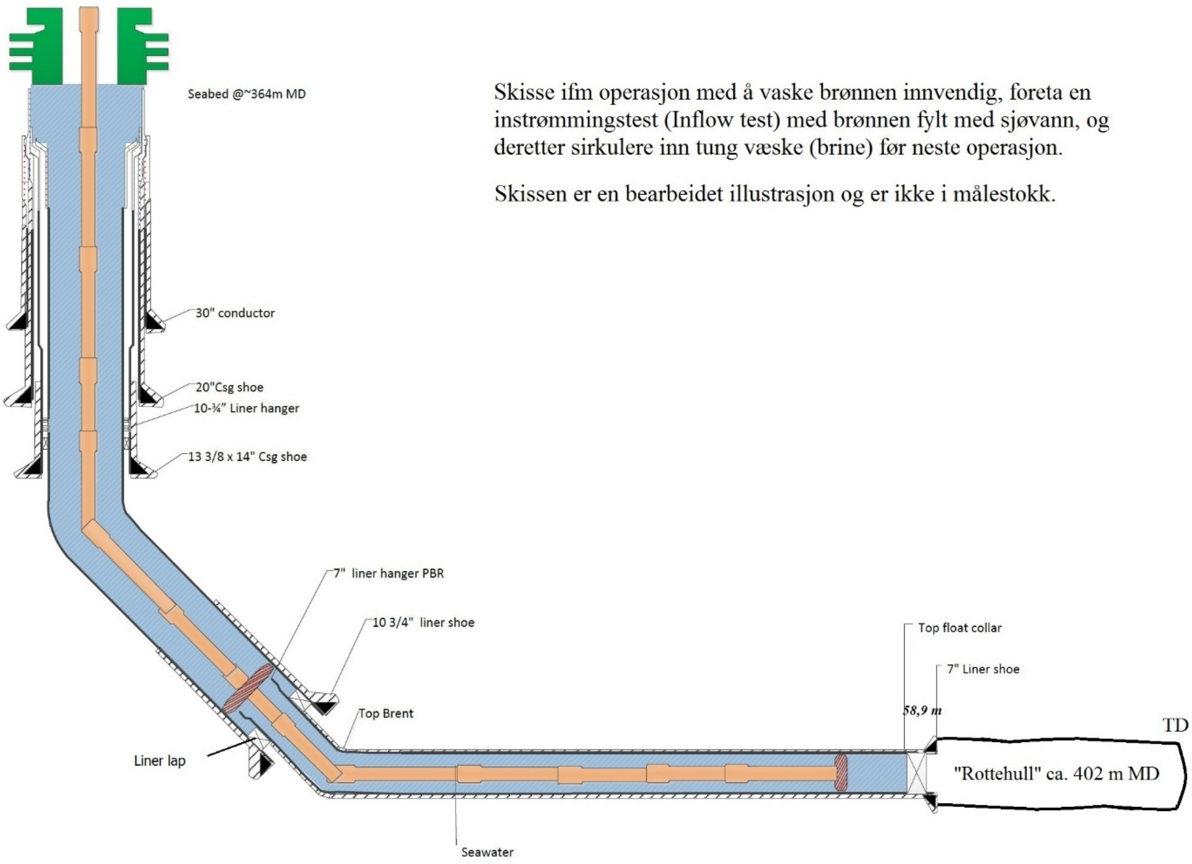

Figure 2 Statoil's diagram of the well as it was when the incident occurred on 16 March.

While working to kill the well, it was discovered that both the kelly cock valves in the top drive had jammed. One was jammed in the closed position, which prevented the use of normal kill procedures. On 18 March 2016, the PSA decided to perform its own investigation of the incident.

<u>Composition of the investigation group</u>:

- Roar Sognnes — Drilling and wells — (investigation leader)
- Eigil Sørensen — Drilling and wells
- Tore Endresen — Drilling and wells
- Aina Eltervåg — Logistics and emergency preparedness

<u>Procedure:</u>

After the event, the PSA interviewed persons connected to the planning and management of the operations relating to the well-control incident at Visund on 16 March. Staff from both Statoil and Odfjell Drilling were interviewed. Some interviews were conducted by video, with the platform, with Statoil's planning and operations centre in Bergen, and with Odfjell Drilling at Sandsli. Interviews were also conducted with managerial and operational personnel from Statoil and Odfjell Drilling at Statoil's premises at Sandsli in Bergen. The documentation collected and received for the investigation is shown in Annex A.

As a basis for this investigation report, an MTO (man, technology and organisation) diagram was drawn up in order to map the underlying and proximate causes.
The MTO diagram uses the concepts of operational, organisational and technical factors.

Mandate:
The following mandate was issued for the PSA's investigation:

a. *To clarify the scope and progression of the incident, with an emphasis on safety factors.*
b. *To evaluate actual and potential consequences of harm to people, equipment and the environment.*
c. *To evaluate proximate and underlying causes, emphasising technical, operational and organisational factors, from a barrier perspective.*
d. *To discuss and describe any uncertainties/unclear issues.*
e. *To identify non-conformities and improvement points in respect of the regulations (and internal requirements).*
f. *To discuss barriers that worked (i.e. barriers that helped prevent a hazardous situation developing into an accident, or barriers that reduced the consequences of an accident).*
g. *To evaluate the participants' own investigation report (our evaluation to be communicated in a meeting or by letter).*
h. *To prepare a report and accompanying letter (possibly with proposal for use of tools) per template.*
i. *Recommend - and assist in - further follow-up.*

The investigation team shall perform an investigation of a well kick in well 34/8-A-20 AH at Visund in accordance with the PSA's investigation procedure. The investigation shall cover both Statoil and Odfjell Drilling, and shall focus on the participants' planning and execution of activities relating to cementing of a 7" liner, an inflow test and preparations for completion. No offshore activities are planned in respect of the investigation. The team shall also keep the police informed.

4 Sequence of events

4.1 Planning

The Visund platform is a semi-submersible steel facility with drilling and production installations. During drilling and completion operations, a blowout preventer (BOP) is used on the wellhead on the sea bed. The BOP consists of two drill pipe valves (an upper pipe ram and a lower pipe ram), a blind/shear ram and an annular valve; see also Figure 6. There are also outlets for choke and kill lines that run along the drill riser to choke and kill manifolds, respectively, on the installation.

Visund well 34/8-A-20 AH was planned as a horizontal production well in a new segment of the field.

The documentation shows that a risk register for the operations was set up on 17 January 2016, and was then updated regularly throughout the operation. The final risk register will therefore reflect the operations as they were actually performed. An activity programme and draft DOPs (detailed operating plans) with sequences for each sub-operation were established on 8 February 2016. Each DOP was reviewed with key implementing personnel on the facility prior to the operations. The programme for completion, using a wash string and the tool in it, and an inflow test of the well and subsequent circulation of seawater, new inflow verification before circulating heavy fluid etc. was signed off by relevant functions on shore on 15 February 2016.

4.2 Execution

An 8½" pilot hole was drilled out of the 10¾" casing into the reservoir. This drill hole was plugged back and an 8½" wellbore for the production well was drilled along the planned path in the reservoir. The 8½" section was drilled nearly horizontally out to the planned TD at 5049 m MD on 5 March 2016. Pressure points were recorded in the section before the drill string was withdrawn.

On 7 March 2016, it was started to run a 7" liner in the hole for a landing string of 5 7/8" drill pipe. After a thorough evaluation of drill hole data, it was decided to extend the liner. It was therefore pulled back to the drillfloor and extended with new lengths, before being rerun into the well, reaching a depth of 4,647 m MD on 10 March 2016.

Later on the same day, cement was pumped with full return up the outside of the liner, in accordance with calculated pump strokes to cement the liner in place. The line hanger was then set and excess cement/spacer fluid was circulated out before the landing string was withdrawn from the hole.

On 11 March, the well was pressure-tested to 230 bar with 1.54 sg drilling mud for 10 minutes.

Wash string #1 was then run in, consisting of 3½" drill pipe at the bottom and 5 7/8" drill pipe at the top. In the wash string, a combined packer/circulation tool (Well Commissioner/MFCT) was mounted in order to isolate washing in or above the liner as desired. The purpose of the wash string was to inflow test the 7" liner and liner lap, clean and circulate out the heavy drilling fluid, pump cleaning chemicals and then displace the well with completion fluid. In wash string #1, a scraper and magnet were also fitted to collect any iron filings etc. in the wash procedure.

On 12 March, circulation was initiated to wash inside the casing and liner. While the bottom of the wash string was down at 4,588 m MD, on 13 March, an attempt was made to inflow test the well to verify that the liner lap, 7" liner and shoe were fluid tight. This was done by trying to anchor the packer in the wash string against the inside of the 10¾" casing, right above the 7" liner hanger and PBR, then closing the circulation valve in the wash string and pumping light base oil down the drill string to set the well in underbalance. A good test was unachievable since the valve in the wash string could not be operated to the desired position.

It was therefore decided to pull wash string #1 from the well, and the wash tool and valve were dismantled and sent ashore for inspection and troubleshooting. It turned out that the packer which should have anchored the wash string above the 7" liner hanger/PBR was incorrectly mounted and had not worked as expected.

On 14 March, the annulus valve and pipe rams in the BOP were tested. The kelly cock valves in the top drive were also pressure-tested at 20/360 bar respectively in low and high pressure tests.

On 15 March, a new wash tool was fitted in the drill pipe and run into the well (wash string #2)- The bottom of the string was run in to 4,588 m MD, corresponding to locating the packer in the wash string above the 7" liner hanger/PBR. The packer was set on the 10¾" casing and the valve in the wash tool was then operated and verified.

On 16 March, base oil was pumped down the drill string to set the well in underbalance in order to perform inflow test #2 to verify that the liner lap, liner and shoe were tight for inflow. The inflow test was approved within normal acceptance criteria and concluded at 12:30. The well's barriers were now assumed to have been verified.

More wash chemicals were pumped before the well was finally circulated with sea water while the purity of oil content was measured. At 16:40, the well was filled with sea water.

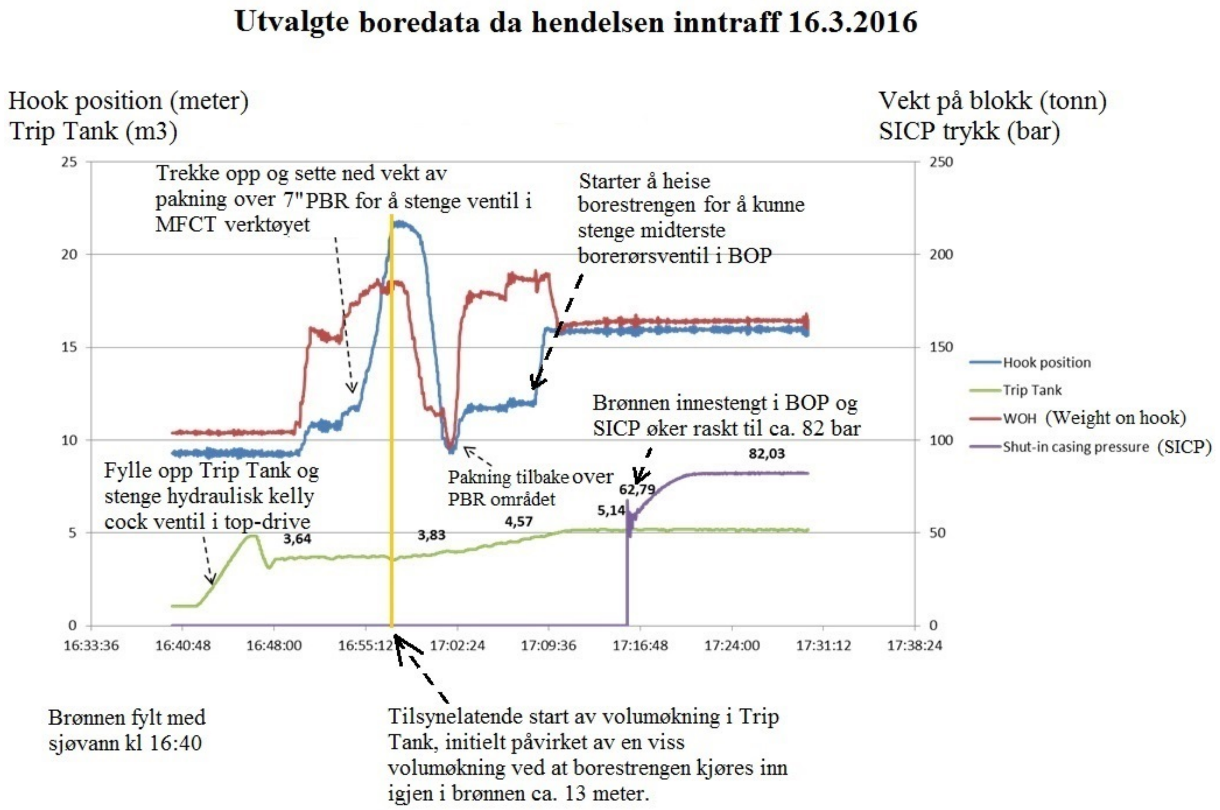

Figure 3 shows selected drill data from the time when the incident was discovered and the well shut in with a pipe ram in the BOP

At around 16:45, the automatic kelly cock valve in the top drive was shut to fill the trip tank and prepare for observing the well at the trip tank. This was for monitoring any changes in volume and to subsequently inflow-test. The drill string was therefore pulled up a few short steps to close the circulation valve (MFCT) in the wash tool down in the drill string and then up a further 10 metres, before it was resunk so as to read the upweight and downweight of the drill string.

During the last of these operations and immediately afterwards, the level gauge in the trip tank showed an increase in volume (green curve in the figure). This was detected at around the same time by a driller and assistant toolpusher on the drillfloor, while the drilling supervisor and toolpusher observed an increase on their screens showing realtime drilling data. The mud logger also observed the increase (from realtime drilling data onshore) and called up the driller on the facility. The driller and assistant toolpusher decided to move the drill string to the desired position and close the upper pipe ram in the BOP to shut the well. The hydraulic kelly cock valve below the top drive was already closed. The well was shut in at approx. 17:15 and a rising pressure was observed at the choke manifold, increasing from around 62 bar to 82 bar in the course of a few minutes, with a measured increase in volume (inflow) at the trip tank of 1.4 m^3. SICP pressure subsequently stabilised at around 84 bar.

4.3 Handling of the well-control incident on 16 March 2016

After the pressures and volumes were evaluated, an attempt was made to open the hydraulic (auto) kelly cock valves below the top drive in order to circulate out the inflow in accordance with standard well kill procedures, but the valve could not be opened. A person was hoisted up in a harness to close the manual kelly cock valve in the top drive using a long spanner, but it too was jammed.

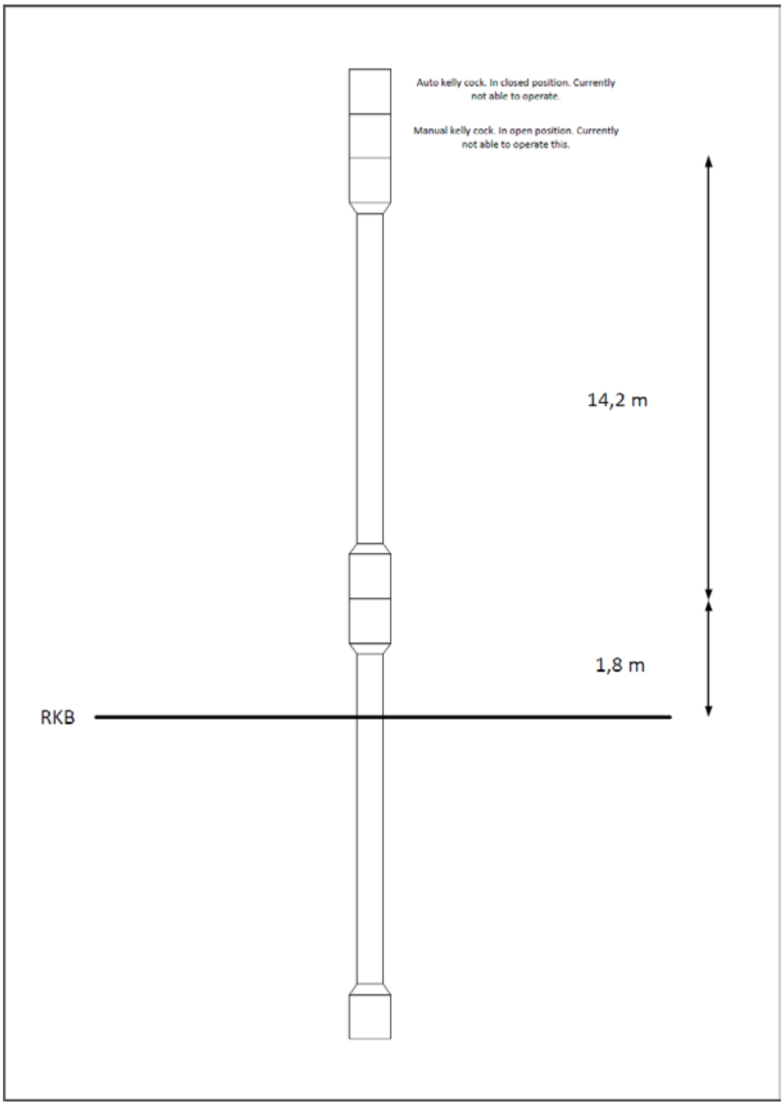

Figure 4 Diagram illustrating the height of the section of drill string above the drillfloor immediately after the incident

The situation then was that the primary barrier (pressure- and inflow-tested cemented liner shoe and liner hanger) was breached and that the secondary barriers (BOP, casing, etc.) was intact. Production on the field was then shut down and the facility depressurised. The weather was good with a gentle breeze, 5.7 m/s from the north and the significant wave height was about 1 m.

Figure 5 below illustrates the barriers for the incident, where red secondary barriers have been activated because a breach has occurred in the blue primary barrier (failure in the inflow-tested liner). The failure in the primary barrier was assumed to be at bottom (inflow-tested cemented liner shoe).

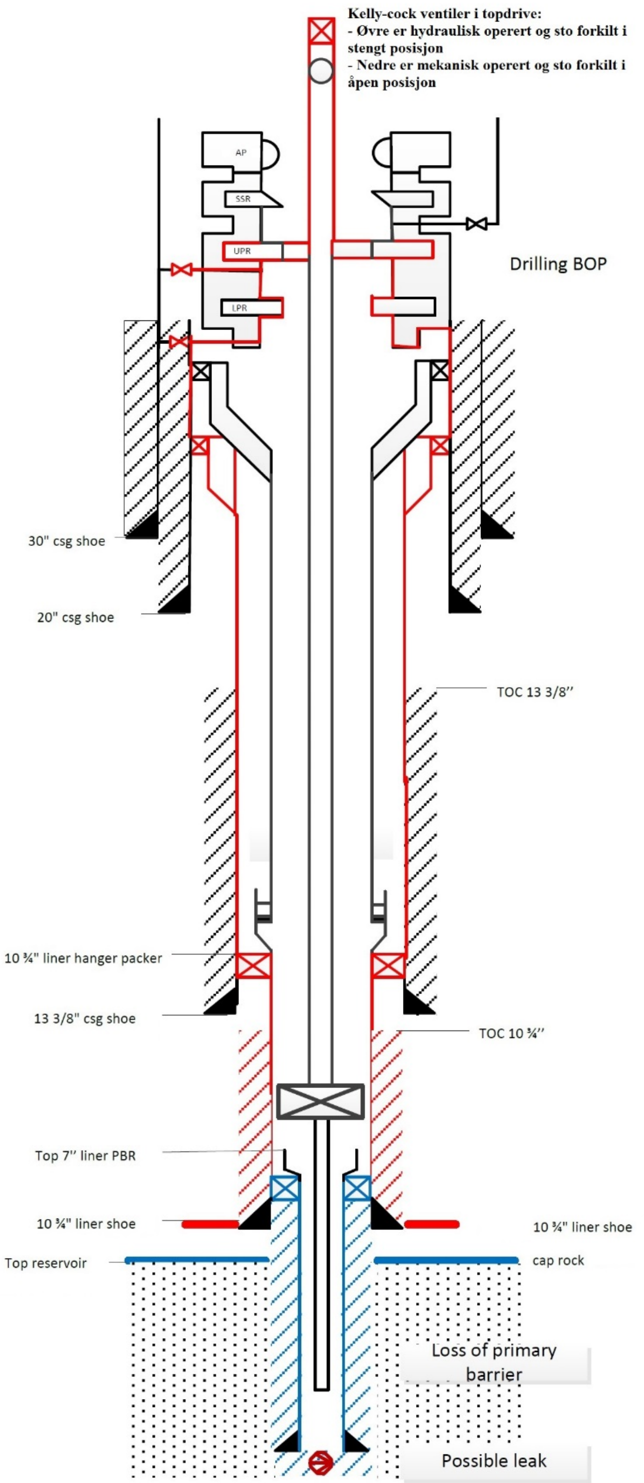

Figure 5 Barrier diagram once the incident has been ascertained and the well shut in with BOP and fixed/jammed kelly cock valve

The situation involving inflow into the well, which could not be handled by standard well-control procedures due to jammed kelly cock valves, was assessed as critical.

The process facility was depressurised and production shut down. The emergency preparedness management and well safety team mobilised during the evening of 16 March 2016. Statoil, with the assistance of Odfjell Drilling, mobilised a Well Control Response

Team on shore to support the operations at Visund, in accordance with established procedures.

The kelly cock valve supplier was contacted and asked about procedures for operating the jammed kelly cock valves. Heavy oil-based drilling mud that had been transferred to a ship earlier in the operation was taken back on board ready to be circulated in the well as kill mud. To be able to circulate in the kill mud, the hydraulic kelly cock valve in the top drive had to be opened. It was not possible to get this valve open and circulation was not possible.

Later in the same evening, at 21:00, the Offshore Installation Manager held an information meeting for personnel on board, informing them that the well had contacted the reservoir and that, in preparing to pump heavy mud down into the well, problems had arisen in opening a hydraulic kelly cock valve at the top of the drill string. This valve had to be opened in order to pump heavy mud down into the drill pipe to kill the well. The valve and BOP were tested on Monday 14 March 2016.

The Joint Rescue Coordination Centre, the police and the PSA were notified of the well kick and the problems killing the well.

On 17 March 2016, at 07:00, the OIM held a new information meeting for personnel on board, informing them that the pressure in the annulus had increased overnight to 84 bar, and that the emergency preparedness management had decided to demobilise all non-essential personnel. At 08:00 on the same day, the transfer of non-essential personnel from Visund to Florø by 3 helicopters therefore began. Personnel in the emergency preparedness management and well safety team, as well as essential personnel from the servicing companies, remained on board (70 people in all).

Eventually, information on the maximum hydraulic pressure arrived from the kelly cock valve supplier, and personnel on the platform tried a step-by-step approach to getting the automatic kelly cock valve open. It was managed to get it open at 21:00 on 17 March.

4.4 Normalisation

The well was killed using an oil-based drilling fluid of 1.54 sg. During the kill operation, around 1.4 m^3 of oil were circulated out via a mud-gas separator. The primary barrier was reestablished with a heavy column of fluid in the well and the BOP was opened at approx. 20:15 on 18 March.

5 The potential of the incident

5.1 Actual consequences

The facility was depressurised and production at Visund was shut down.

No personal injuries, material damage or emissions to the external environment were recorded as a result of inflow into the well. The inflow was stopped by the BOP upper pipe ram being closed (see Figure 6) and the hydraulic kelly cock valve below the top drive being closed at the time of inflow.

Restitution of lost barriers (casing/liner) should normally have occurred by heavy fluid being circulated into the well through the drill string. After 1.54 sg OBM was transferred back to the rig, it gradually became clear that the hydraulic valve below the top drive could not be opened using normal operational pressure. This meant that the lost barrier could not be replaced by kill fluid since circulation was not possible. The situation then was that the well was held in control by the one remaining barrier (casing/wellhead/BOP + valve in DP), but it was not possible to circulate out the inflow and restitute the primary barrier (heavy fluid).

After a full day, the hydraulic valve below the top drive was opened and the well was killed and the barriers restituted with the aid of conventional methods for handling well-control incidents.

5.2 Potential consequences

What made this incident special is that normal well-control methods were prevented by a jammed valve below the top drive, and that there was originally an assumed verified barrier in the form of a confirmed inflow test. In very slightly different circumstances, the well kick might have led to a complicated and long-lasting kill operation with the potential for escalation of risk.

5.2.1 Hydraulic kelly cock valve

If the hydraulic kelly cock valve could not have been opened, it would have been a more challenging operation to reestablish the lost barrier. As it was rigged, it was not possible to decouple the jammed kelly cock valve to create a circulation path. The manual kelly cock valve mounted below (see Figure 5) the hydraulic kelly cock was locked in the open position and could not be closed.

During the incident, alternative methods for reestablishing lost barriers were assessed. Statoil identified the following methods among others:

- freezing of an ice plug to establish a temporary barrier inside the drill pipe in order to establish a circulation path above the ice plug.
- bullheading of kill fluid down the annulus side of the well.

Freezing of an ice plug
A method which is not considered a conventional well-control method on the Norwegian Continental Shelf. There were a number of factors concerning this operation which would have had to have been closely assessed (hot-tapping of the drill string to verify the ice plug, establishing a circulation path, access and movement of the platform, which is floating).

Bullheading
A method which can be considered conventional, but in this case there would be uncertainty concerning injectivity through the leak point.

None of the methods were discussed in detail with the PSA, and none of the methods were used since the situation was resolved by opening the kelly cock.

5.2.2 Cutting of the drill string

In the event of a possible decoupling of the Lower Marine Riser Package (LMRP) while shut in (e.g. weather conditions), or the well being exposed to loads (pressures) it was not tested for, it would have been necessary to activate the shear valve in the BOP.

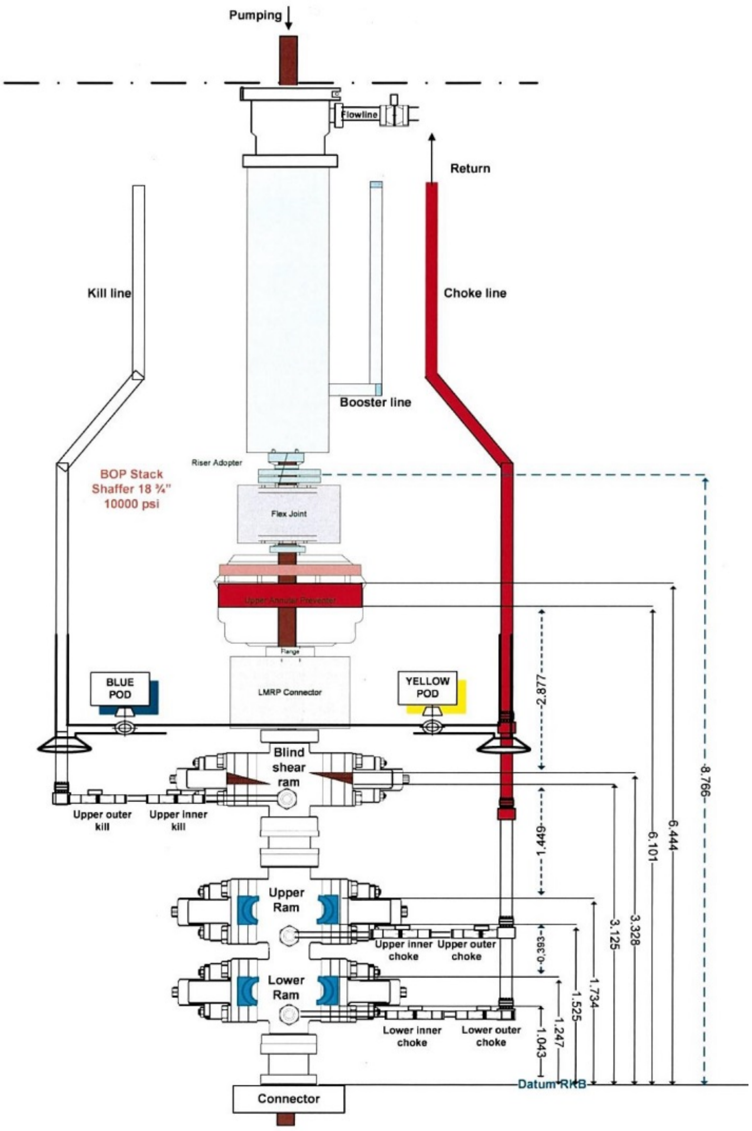

Figure 6 Diagram of Visund BOP on the sea bed, with kill & choke lines

A number of factors would have affected the potential for keeping the well shut in and subsequently reestablishing lost barriers;

- Positioning of the tooljoint
- Shear capacity
- The shear valve's ability to not leak after shearing
- The potential for establishing a circulation path down the drill string after shearing

Before shutting in the well using the upper pipe ram, the drill string was positioned so that the tooljoint was 4-5 m above the BOP shear valve. It was not assessed whether to hang-off a tooljoint in the upper pipe ram after this was closed.

Based on existing documentation, there are reasons for assuming that the shear valve has the necessary characteristics/capacity required for shearing and isolating the well with the actual drill pipe dimension that was in the well. Tables of necessary cutting forces for drill pipes were posted in the driller's cabin.

By cutting the string at the right location, it would have been possible to take control of the well and at the same time be able to circulate in kill fluid down the kill or choke lines between the Blind/Shear Ram and the upper pipe ram, returning it up the kill or choke lines under the upper pipe ram. During the incident, the nearest tooljoint was above the Blind/Shear Ram and this presumes that the string had been sunk in and hanged up before potential shearing had taken place. If shearing had been done as the drill string was situated, this would have meant that it was impossible to circulate into the well. This would have caused further complication of the situation when it was necessary at a later time to try to reestablish the lost barrier.

6 Observations

The PSA's observations generally fall into three categories.

- Non-conformity: This category contains observations where the PSA believes there has been a breach of the regulations.
- Improvement point: Concerns observations where we see deficiencies, but do not have sufficient information to determine a breach of the regulations.
- Compliance/barriers that worked: Used in the case of demonstrated compliance with the regulations.

6.1 Non-conformity

6.1.1 Inadequate design of well barriers

Non-conformity: The well barrier was not designed so as to prevent unintended inflow into the well.

Reason: The design of the 7" liner with cemented shoe as barrier elements was not sufficient to prevent unintended inflow.

Requirement:
The Facilities Regulations, Section 48, Well barriers

6.1.2 Inadequate verification of well barriers

Non-conformity:
Verification of 7" liner and cemented shoe as barrier elements was inadequate.

Reason:
The well was not in sufficient underbalance during the inflow test using base oil relative to what it was later subjected to during circulation of seawater, immediately before the incident occurred. It is the PSA's assessment that the inflow test as planned and performed did not provide an adequate safety margin in relation to string operations in the well using only a seawater gradient. The planned inflow test using base oil did not appear to take account of uncertainty in the calculation of the hydrostatic column, performance of the pumping operation and other operations in the well.

Requirements:
The Activities Regulations, Section 85, Well barriers
The Management Regulations, Section 5, Barriers

6.1.3 Deficient classification of safety-critical equipment

Non-conformity:
The kelly cock valves mounted on the top drive were not identified as safety-critical equipment in the drilling contractor's maintenance system.

Reason:
The kelly cock valves are identified as barrier elements in accordance with the drilling contractor's well-control manual. In an interview, it was discovered that the valves did not have their own identification in the maintenance system.

Requirements:
The Activities Regulations, Section 46, Classification
The Management Regulations, Section 5, Barriers

6.1.4 Defective maintenance programme for kelly cock valves

Non-conformity:
The kelly cock valves were not subject to a maintenance programme appropriate for monitoring their performance and technical condition, and which would ensure that developing fault modes would be identified and corrected.

Reason:
Maintenance of kelly cock valves was defective and not in accordance with the supplier's recommendation. In an interview, it was discovered that the kelly cock valves were not replaced and checked at fixed intervals as recommended by the supplier/manufacturer. Among other things, in the supplier's maintenance manual, it is described that the kelly cock valves must be cleaned, dismantled, inspected, reassembled and tested after each well or at intervals of 5-7 months.

Requirement:
The Activities Regulations, Section 47, Maintenance Programme

6.1.5 Deficient risk assessment of configuration of subsea BOP at Visund

Non-conformity:
No risk analysis was performed of the configuration of the subsea BOP at Visund suitable for providing a nuanced and complete picture of the risk associated with a major accident and of environmental risk connected with acute pollution during well operations.

Reason:
There is no risk assessment of the configuration of the BOP at Visund.

Risk assessment of the BOP configuration is described in Odfjell Drilling's "Well Control Manual Mobile Units 5.1.2 Minimum Requirements Subsea BOP Stack" and "5.1.3 Subsea BOP Stack Risk Assessment for Moored Vessels", and in NORSOK D-010 chap. 15.4 C. Design construction section chap. 2.

***Requirement*s**:
The Management Regulations, Section 17, Risk analyses and emergency preparedness assessments
The Facilities Regulations, Section 48, *Well barriers with guidelines, with ref. to NORSOK D-010*

6.2 Improvement point

6.2.1 Deficient barrier diagram in the activity programme for completion and in the DOP

Improvement point:
The barrier diagram for the inflow test and seawater displacement does not show the correct barrier elements.

Reason:
In the activity programme for completion and in the DOP for relevant operations, there is an imprecise barrier diagram with incorrect barrier elements after seawater displacement in the well.

Requirement:
The Activities Regulations, Section 85, Well barriers

6.2.2 Older version of risk register used in DOP document

Improvement points:
A defective systems approach associated with the use of the risk register in DOP documents. Different versions of the risk register are reproduced in the documentation.

Reason:
Documentation received and statements made in interviews show that different versions of the risk register were in use during operations relating to the well-control incident.

Requirements:
The Management Regulations, Section 17, Risk analyses and emergency preparedness assessments
The Activities Regulations, Section 24, Procedures

6.2.3 Defective training and drills

Improvement point:
No exercises were performed for stripping with a closed BOP annular valve and drill string hung in the pipe ram in the BOP ready for shearing the drill string.

Reason:
During interviews, it emerged that no drills were performed for stripping with a closed BOP annular valve and drill string hung in the pipe ram in the BOP ready for shearing the drill string.

For similar incidents, the well-control manual for Visund (Odfjell Drilling Well Control Manual Mobil Units 7. Section – Well Control Drills) describes that hanging a drill pipe joint in a pipe ram in the BOP is a preventive measure prior to possible shearing of the drill string.

Requirement:
The Activities Regulations, Section 23, Training and drills

6.3 Barriers

The incident occurred after transition from drilling phase to completion phase in the well. In the drilling phase (running and cementing of the liner), 1.54 sg drilling fluid is defined as a primary barrier. 10¾", 13 3/8" casing and the BOP/wellhead are defined and elements of a secondary barrier.

After the 7" liner has been run in and cemented, it is subjected to an inflow test to verify the barrier performance, i.e. the 7" cemented liner and shoe are tight and can be considered as verified barrier elements. Together with the formation strength, these will constitute barrier elements that can assume the drilling fluid's role as primary barrier.

6.3.1 Barriers that did function

6.3.1.1 Detection of inflow

From interviews, it is clear that relevant crew on board were highly focused on volume control. Inflow into the well was detected by level gauges in the trip tank and was quickly observed by several of those specially involved in monitoring the well.

It was relatively quickly evaluated and concluded that shutting in the well using a valve in the BOP was required.

6.3.1.2 Isolation of well

The drill string was positioned so that the upper pipe ram in the BOP could be closed around the drill pipe. The annulus side of the well was then isolated by activating the BOP and preventing further inflow into the well.

The hydraulic kelly cock valve in the top drive was already closed at the time the inflow in the well was detected. This functioned as a barrier element inside the drill string.

The 10¾" and 13 3/8" casing and wellhead also functioned as barrier elements when the inflow occurred.

6.3.2 Barriers that failed

6.3.2.1 Mechanical integrity

At Visund, a 7" cemented liner apparently worked as a barrier for an hour, and subsequently lost its integrity in connection with washing and displacing seawater into the well.

6.3.2.2 Conventional handling of the well-control situation

In order to restitute the lost primary barrier (7" cemented liner), it is necessary to be able to replace the seawater with a kill fluid. Normally, this will be done by pumping this down the drill string that is still in the well. It gradually became clear that this option was prevented by the hydraulic kelly cock valve being unopenable. This same valve which had a barrier function against well pressure now became an obstacle to restituting a barrier and an escalating factor in the incident.

After a full day, the valves were opened and the barriers reestablished by means of conventional well-control procedures and the use of kill mud as a barrier.

Remaining barrier elements

The BOP shear valve was assessed as being available during the incident.

The onshore organisation reacted immediately by mobilising a dedicated well-control team to work on the incident.

The table below shows which barriers did not function and which did. These barriers are identified using the MTO methodology. The barriers are also shown in relation to technical, organisational and operational barrier elements.

Time	Barriers that did not function	Barriers that did function	Technological factors	Organisational factors	Operational factors
16:57	Cemented liner (primary barrier)				
16:57-17:02		Detection of inflow in the well at the trip tank	Trip tank gauges	Driller, Assistant Toolpusher, Mudlogger	Observe volume increase on screens, evaluate and interpret data
17:02-17:15		Isolation of well	Close BOP pipe ram	Driller, Assistant Toolpusher	Position drill string in BOP
			Hydraulic kelly cock below top drive (drill pipe).		
			Casing/Wellhead		
Following isolation of the well	Circulating out and killing of the well (reestablish primary barriers)		Jammed hydraulic kelly cock below top drive.		Not possible to circulate in kill mud
		Notification and mobilisation of emergency preparedness organisation			
1 day after isolation of the well		Circulating out and killing of the well (reestablish primary barriers)	Kill mud, BOP	Driller, Mud Engineer	Specific procedures for circulating out

Figure 7 Identified barriers linked to technical, organisational and operational factors

7 Discussion concerning uncertainties

The investigation did not detect unambiguous causes of the incident, whether direct or underlying. However uncertainties emerged during the investigation which may explain potential causal factors. These are discussed below:

7.1 Possible proximate causes

7.1.1 Effect of movement of the drill string immediately prior to the incident

From approx. 16:55, minutes before the inflow was detected, the drill string was moved more than 10 metres upwards. With a combination of a closed kelly cock valve in the top drive, possibly closed MFCT valve, and a nearly full-gauge packer in the drill string round the 10¾" casing immediately above the 7" liner hanger, the inflow of liquid past the packer into the well to compensate for the movement of the drill string would have been made more difficult, It is possible that this may have caused a considerable swab in the well which strengthened the underbalance already there due to being filled with seawater. This may have induced a weakness in the liner shoe.

7.1.2 Long rathole

The well was constructed with a long rathole, more than 400 metres of horizontal length. This may have contributed to poor distribution of cement around the shoe and liner, channelling, and so forth, and contributed to a weakened liner shoe which had an insignificant margin over the underbalance in the inflow test.

7.2 Cause of escalation of the incident

The fact that the kelly cock valves were jammed after the incident contributed to considerably increased complexity in the handling of the well-control situation and necessitated the demobilisation of non-essential personnel to Florø. That the valves were not subject to their own maintenance routines and that the supplier's recommendations had not been taken into account may have contributed to their jamming.

7.3 Possible underlying causes

7.3.1 Kelly cock valves below the top drive

The kelly cock valves were not identified as barrier elements in the activity programme and DOP. Instead, a stab-in kelly cock was defined as a secondary barrier element, even though it would not be utilised in accordance with well-control procedures if the top drive was coupled to the drill string, as was the case.

The kelly cock valves were sent for analysis, but no reply was forthcoming as to why they became jammed during the well-control incident.

8 Annexes

A: Documents used as a basis for the investigation
B: List of interviewed personnel