PETROLEUMSTILSYNET

Investigation report

Report	
Report from the investigation of a hydrocarbon leak on Heimdal, 26 May 2012	Activity number 001036006

Security grading

☑ Public	☐ Limited	☐ Strictly confidential
☐ Not publicly available	☐ Confidential	

Summary

The hydrocarbon leak occurred in connection with the testing of two emergency shutdown valves (ESDVs).

To prepare for the test, a bleed-off pipeline was to be blown down to the flare. The pipe connection to the flare contained a manual shut-off valve with a 16-bar pressure rating as the final barrier against the flare. This valve stood in the closed position and was exposed to a pressure of 129 bar.

The pressure caused the gasket in the valve flange to fail, resulting in a gas leak estimated at 3 500 kilograms. The initial leak rate was 16.9 kilograms per second (k/s). Gas was detected across a large area of the installation.

This incident has been investigated by the Petroleum Safety Authority Norway (PSA). Our conclusion is that the incident created a very serious position on Heimdal which, under marginally different circumstance, could have resulted in a major accident.

Involved

Main group T-1	Approved by/date
Members of the investigation team Jorun Stornes Stålesen - logistics and emergency preparedness Odd Tjelta - process integrity Elisabeth Lootz - working environment, organisational safety	Investigation leader Bjarne Sandvik – logistics and emergency preparedness

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1 Summary

A hydrocarbon leak occurred on Statoil's Heimdal installation at 12.41 on Saturday 25 May 2012 in connection with the testing of two emergency shutdown valves (ESDVs). Ahead of the test, parts of the production had been shut down and depressurised for maintenance.

Preparations for testing the ESDVs included the blowdown of a bleed-off pipeline to the flare. This pipeline incorporates a main control valve (HCV) operated from the central control room (CCR), and three manual shut-off values designated NC1, NC2 and NC3 in this report. The HCV has a pressure rating of 180 bar, while the final manual shut-off valve before the flare (NC3) has a design pressure of 16 bar.

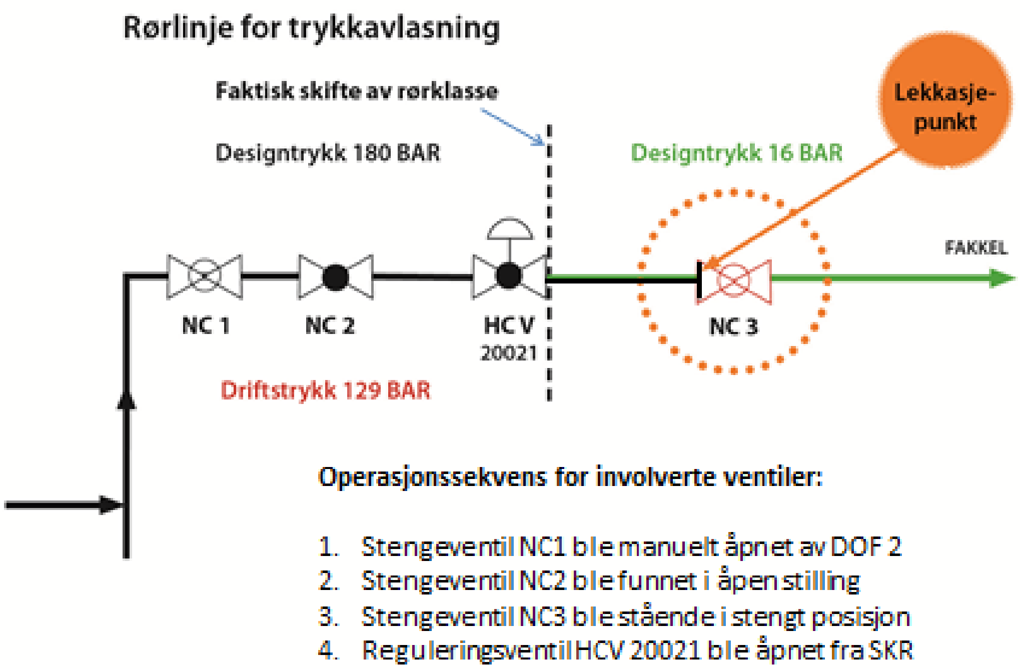

Figure 1: The pipeline for blowdown and a description of the operational sequence performed by the operator in the field, hereafter designated DOF2.

Key: Rørlinje for trykkavlastning: Bleed-off pipeline; Faktisk skifte av rørklasse: Actual change of pressure rating; Designtrykk: Design pressure; Lekkasjepunkt: Leak site; Fakkel: Flare; Operasjonssekvens for involverte ventiler: Operating sequence for valves involved: 1. Shut-off valve NC1 manually opened by DOF2; 2. Shut-off valve NC2 found open; 3. Shut-off valve NC3 left closed; 4. Main control valve HCV 20021 opened from CCR.

The NC3 valve which functioned as the final barrier to the flare was closed. When blowdown was initiated by opening the HCV, NC3 was exposed to a pressure of 129 bar. As a result, the gasket, insulation and enclosure around the flange were blown off. The gas pressure twisted the metal plates out of place, pieces of the aluminium enclosure and the insulation were blown off, and gas leaked out into the Module 40 (M40) area.

Following immediate notification from the operator in the M40 process area, the CCR operator shut the HCV. The valve finally closed after about four minutes and the leak ceased at 12.45. The reason for the delay in the valve system remains unclarified. Gas was detected in the M30, M40 and M50 modules, and the gas detector in M60 was also activated. Gas persisted on the installation for about 30 minutes.

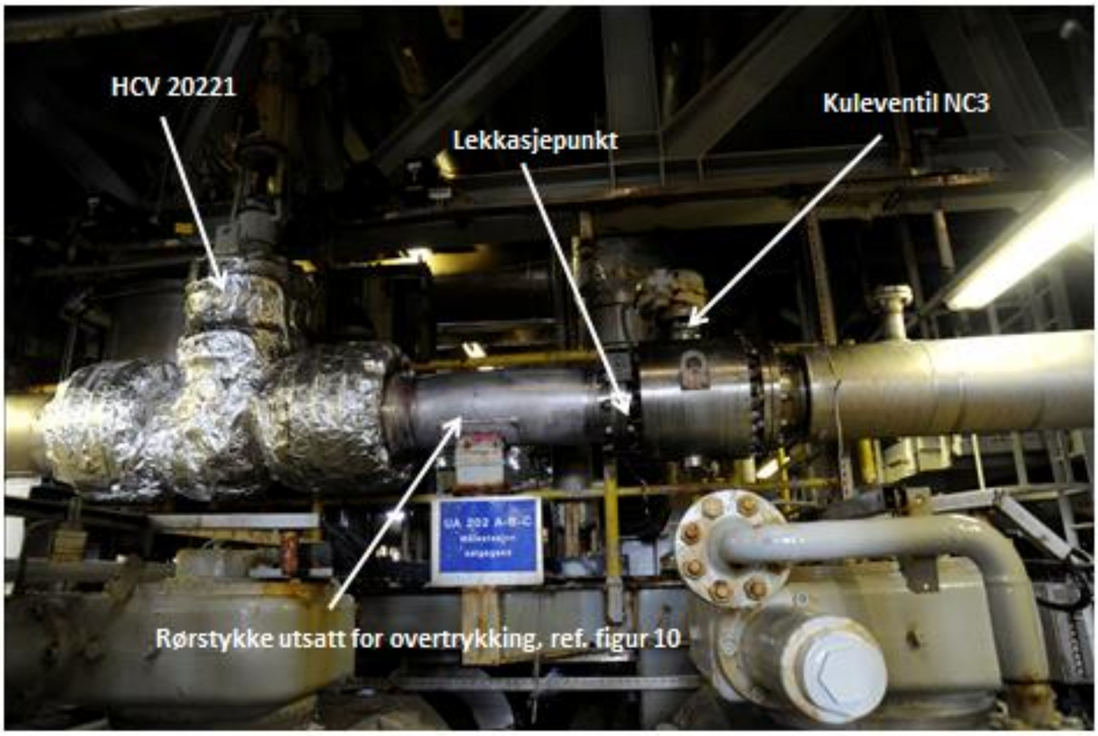

Figure 2: The pipe section between HCV 20021 and the NC3 manual shut-off valve.

Key: Lekkasjepunkt: leak site; Kuleventil: Shut-off valve; Rørstykke utsatt for overtrykking, ref figur 10: Pipe segment subject to overpressure, see figure 10.

The operator in the M40 module was standing in the immediate vicinity, about 10 metres from the leak (site inspection by the operator involved, the police and the PSA). He observed the spread of the gas cloud, but it is unclear how far he was exposed to it. He suffered no demonstrable injuries and has been followed up subsequently by Statoil's medical service.

The general platform alarm (GPA) and firewater were initiated and all personnel, except those in the emergency response organisation, mustered at the lifeboats.

The leak is one of the most serious gas emissions on the Norwegian continental shelf (NCS) for several years (see the RNNP reports for 2001-11)). By Statoil's own calculations (see doc 43), the leak on Heimdal released a total of 3 500 kg of gas over 252 seconds, with an initial rate of 16.9 kg/s. Total gas volume in the pipe segment was 53.49 cu.m at 129 bar and 9°C.

The PSA has investigated the incident, and its most significant observations are:

- a deficient design solution
- failure to identify the deficient design solution
- deficient descriptions of how the work was to be done
- weaknesses in Statoil's document management

- weaknesses in risk assessment during planning
- weaknesses related to expertise and risk understanding.

Weaknesses were also identified in experience transfer and learning in the Heimdal organisation after earlier incidents.

2 Introduction

The PSA resolved on 29 May 2012 to conduct its own investigation of the incident, in addition to supporting the police investigation.

2.1 The PSA's investigation team

The investigation team from the PSA has comprised

Bjarne Sandvik	- logistics and emergency preparedness, investigation leader
Elisabeth Lootz	- working environment, organisational safety
Jorun Stornes Stålesen	- logistics and emergency preparedness
Odd Tjelta	- process integrity

2.2 Mandate

The PSA's investigation has had the following mandate.

a. Clarify the scope and course of the incident, with the emphasis on safety, working environmental and emergency preparedness aspects.
b. Assess actual and potential consequences
    1. harm to people, material assets and the environment
    2. the incident's potential for harm to people, material assets and the environment.
c. Assess direct and underlying causes, with the emphasis on human, technical and operational (HTO) and organisational aspects from a barrier perspective.
d. Discuss and describe possible uncertainties/lack of clarity.
e. Identify nonconformities and improvement points related to the regulations (and internal requirements).
f. Discuss barriers which have functioned.
g. Assess the operator's own investigation report.
h. Assess the effect on Heimdal of improvement initiatives implemented by Statoil to reduce hydrocarbon leaks.

2.3 Method and data acquisition

The investigation team flew out to Heimdal on 30 May 2012 and returned on 1 June.

Inspection of the site and interviews with management and personnel involved in planning and executing a safety-critical job were conducted on the Heimdal installation on 30 May-1 June 2012. Relevant documents, such as procedures and logs, were collected. A number of interviews were also conducted with personnel in Statoil's operations (OPS) organisation and people with technical system and specialist responsibility (plant integrity – AI).

When the investigation team arrived (see sections 2.4 and 2.5), the site was cordoned off with tape. Since pipe systems containing gas under pressure had been involved in the incident, steps had been taken to secure these systems. That included installing a new gasket in the flange between the pipe and NC3, and washing, pressure testing and readying the valve. Insulation and the metal enclosure were removed. We were told that Statoil had done this work during a full shutdown of the pipeline, which has subsequently been taken out of service. The site was accordingly not intact during our inspection.

However, the platform management had ensured that photographs were taken before implementation of the safety measures.

2.4 Cooperation with the police

The police resolved at an early stage to investigate the incident, and flew out to Heimdal with tacticians and technicians. The PSA was requested to assist the police inquiries, and inspections and meetings with personnel on Heimdal were conducted jointly. The PSA participated in the police questioning of personnel on the installation.

2.5 Statoil's corporate investigation team

The PSA flew out with the police and Statoil's corporate investigation team, and joint kick-off and concluding meetings were held. Statoil's investigation report was presented and submitted to the PSA on 23 October 2012.

3 Information on the Heimdal gas centre

Heimdal is a gas field located in 120 metres of water in the central part of Norway's North Sea sector. It was approved for development on 10 June 1981 with Elf as the operator, and came on stream in 1985 with an integrated steel production, drilling and quarters facility.

The process plant was designed in 1981-84 by Kværner, with Brown & Root as sub-contractor. Elf Aquitaine was responsible for development and operation. Production began on 13 December 1985. The dimensioning production life for the Heimdal main platform (HMP) is 30 years, and expires on 13 December 2014.

Norsk Hydro took over as operator on 1 January 1998, and the plan for development and operation (PDO) of the Heimdal gas centre was approved on 15 January 1999. This described modifications to the HMP and the construction of the Heimdal riser platform (HRP), tied to the HMP by a bridge.

The Heimdal gas centre began operation in 2000. Gassco became operator for the HRP in 2002. Following the Statoil-Hydro merger of 1 October 2007, the HMP operatorship was awarded to StatoilHydro.

Gas was originally piped from Heimdal to Kårstø via Statpipe and on to continental Europe. When Heimdal was established as a gas centre, a new gas pipeline was tied into the existing line from the Frigg field. Gas can currently be piped through Vesterled to St Fergus in the UK. The Huldra, Skirne and Vale fields deliver gas to Heimdal. Gas from Oseberg is also piped via Heimdal. Heimdal delivers gas to Grane for injection, and condensate to Brae in the UK sector. Gas is piped via Statpipe to/from Draupner. Heimdal is a North Sea gas hub today.

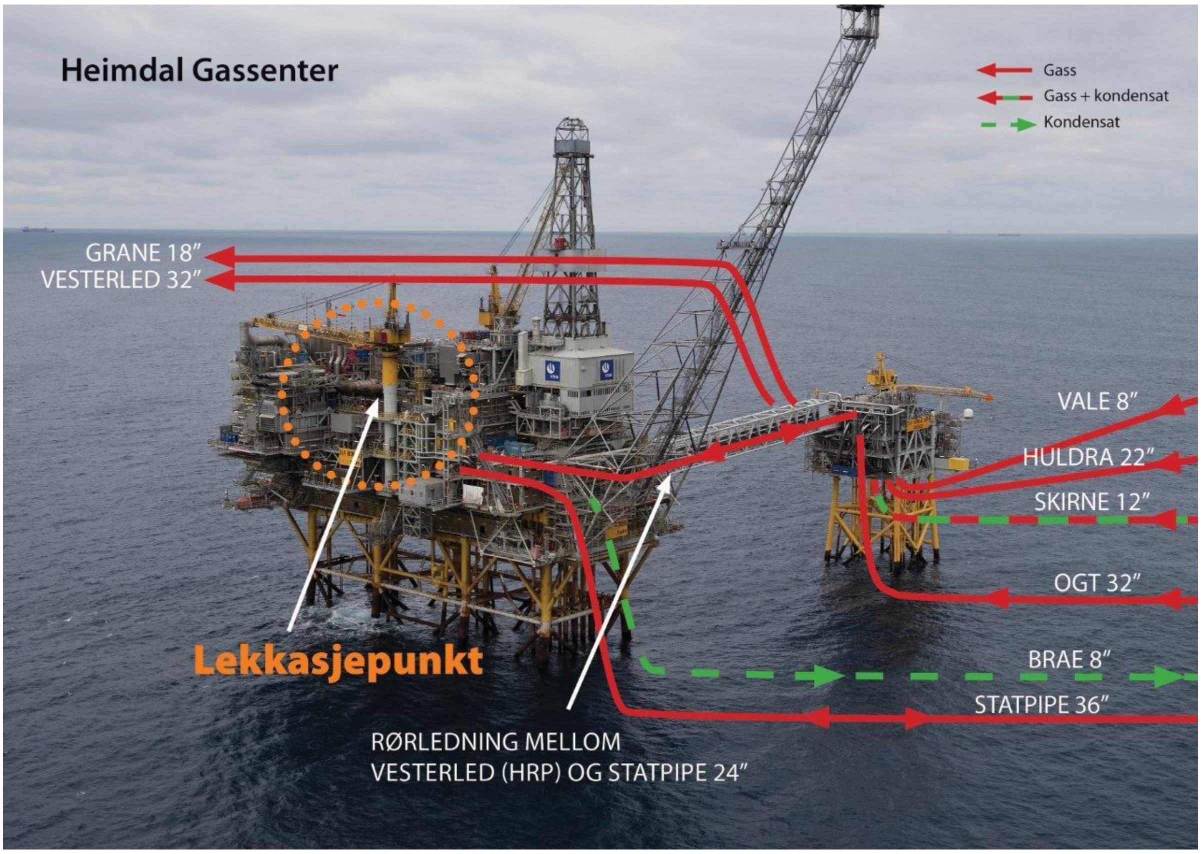

Figure 3: The Heimdal gas centre.

Key: Lekkasjepunkt: Leak site; Rørledning mellom Vesterled (HRP) og Statpipe 24": Pipeline between Vesterled (HRP) and Statpipe 24".

3.1 Heimdal field – time line

Date/time	Activity	Description
10.6.81	PDO approved	Heimdal development approved with Elf as operator.
1981-85	Design and construction	Kværner Engineering was main contractor. Brown & Root delivered design of the process plant as a sub-contractor. The pipeline in fig 1 was built for manual blowdown of Statpipe and designed with change of pressure rating as shown in the figure.
13. 12.85	On stream	The Heimdal installation began production.
1998	Hydro became operator	
15.1.99	PDO approved	Heimdal gas centre with Hydro as operator.
1999-2000	Installation shut down	From October 1999 to October 2000 .
2000	Heimdal gas centre on stream	
2002	Leak testing of ESDVs	Hydro assessed acceptable internal leak rates for safety-critical valves in the Heimdal gas centre.

2002	Gassco operator	HRP.
2003	First testing of ESDVs	History in SAP goes back to the 2003 turnaround. Probably the first time Hydro tested ESDVs.
2004-11	Annual testing of ESDVs	The valves can be tested with nitrogen or by reading off the pressure difference across the valve. Depressurisation to the flare can be done via the blowdown line or manually via HCV 20021.
2005	Technical safety condition (TST)	
1.10.07	StatoilHydro operator for HMP	Operator responsibility was assigned to StatoilHydro after the merger of Statoil and Hydro.
2009	Condition monitoring of technical safety (TTS)	A TTS review noted that isolation valves downstream from blowdown valves did not have pull pressure rating.

3.2 Hydrocarbon leaks on the Heimdal field

The table below shows leaks above 0.1 kg/s on Heimdal recorded in the PSA's incident database and covered by a quality assurance process through the RNNP from 1996 to 2011. A separate column shows whether a work permit (WP) is described as used in connection with the leak. In certain cases, the leak occurred under normal operation and is listed as OPS.

Year	Date	Installation	Investigated	Leak rate (kg/s)	WP	Cause
2002	6.9.02	Heimdal	Investigated	0.1	OPS	Dealing with process plant interruptions
2002	6.10.02	Heimdal	Investigated	1.0	OPS	Undesirable process conditions in condensate tank
2003	27.4.03	Heimdal	Notification form	0.2	_	No report available
2003	23.7.03	Heimdal	Investigated	2.5	No	Readying system after maintenance
2005	16.7.05	Heimdal	Investigated	0.1	No	Autoblock lacking as barrier to pressurised system
2005	24.9.05	Heimdal	Investigated	0.1	No	Hose leak during DB&B
2005	30.11.05	Heimdal	Notification form	0.5	_	No report available
2006	22.8.06	Heimdal	Investigated	0.2	No	No barrier during work on

						pressurised system
2006	25.12.06	Heimdal	Notification form	0.9	_	No report available
2007	06.4.07	Heimdal	Investigated	0.8	OPS	High pressure in condensate tank during preparations for dewaxing heat exchangers and process disruptions caused high pressure in the condensate tank. That led to hydrocarbons being transferred via liquid seal to sump caisson and to atmospheric venting on the weather deck
2011	2.2.2011	Heimdal	Investigated	0.5	No	Bleed hose not installed in secure area
HRP						
2005	19.4.2005	HRP	Notification form	0.5	_	No report available
2005	20.06.2005	HRP	Investigated	1.8	No	Broken hose
2006	11.3.2006	HRP	Notification form	0.2	_	No report available
2010	18.4.2010	HRP	Investigated	0.2	OPS	Weld cracking

4 Course of events

This chapter describes the course of events from the discovery of a leak in the hot oil system on 21 May 2012 until the emergency on Heimdal was normalised on 26 May.

4.1 The incident

Monday 21 May 2012. A leak of hot oil (a heat medium) was discovered in a shutdown valve in the plant. This led to production on Heimdal being shut down and a partial blowdown the following day. We were told in interviews that a production shutdown on Heimdal allows maintenance activities on the installation which require a shutdown to be carried out.

Tuesday 22 May. At the daily morning meeting between the offshore leadership, the OPS department and the AI department on land, it was decided to implement leak testing of ESDVs during the production shutdown rather than waiting for the annual emergency shutdown test in order to reduce work during the latter, which was scheduled for 3 June 2012.

Thursday 24 May. The operations and maintenance (O&M) leader and the technical leader for operations in O&M offshore began planning leak testing of ESDVs. Procedures for testing such valves also include test results from early annual leak tests. They are collected in a binder, and the department wanted to make signed and dated corrections to these.

In order to secure the involvement of experienced process operators, it was resolved that one of these – hereafter DOF1 – with experience of similar testing should be responsible for the ESDV tests. The testing accordingly involved an experienced O&M leader, a CCR operator and DOF1, who had all participated in earlier annual leak testing on Heimdal. DOF1 arrived on the field that afternoon.

Friday 25 May. A fault arose in the operator station in the CCR normally used for monitoring the Heimdal process, and it was taken out of service. The alternative workstation made it difficult to maintain oversight of the overview images, alarms and camera pictures. It was used on the following day – the day of the incident – and in the subsequent emergency response when the leak occurred.

A meeting was held in the morning to review the execution of ESDV testing in the HMP process plant. Those present were the CCR operator, DOF1 and two trainee operators. This meeting has been characterised as "a kind of pre-job discussion" by the participants.

The WP meeting in the afternoon decided that WPs for the following day should be reduced from 40 to 20 in order to create time to do the leak testing on that day. The relevant test was not gone through at the meeting.

Saturday 26 May, the day of the incident. Activities were conducted as detailed below with approximate times.

The regular morning meeting at **07.00** for all technical sections reporting to the O&M leader reviewed the status of the leak testing. Tests were to be conducted with nitrogen on some ESDVs and on ESDVs connected to Statpipe and the pipeline from the HRP. See figure 3. It emerged from interviews that leak testing with nitrogen was regarded as the most critical activity, since it required accurate readings by the operator in the plant. DOF1 and the two trainee operators were involved with these tests. The investigation team has noted that the procedures for these tests are very detailed and describe the operation of valves, blowdown and communication between the CCR and the process operator in detail. It was noted at the meeting that the hot oil leak would soon be repaired and they must not forget the ESDV testing. It was indicated that time was becoming short.

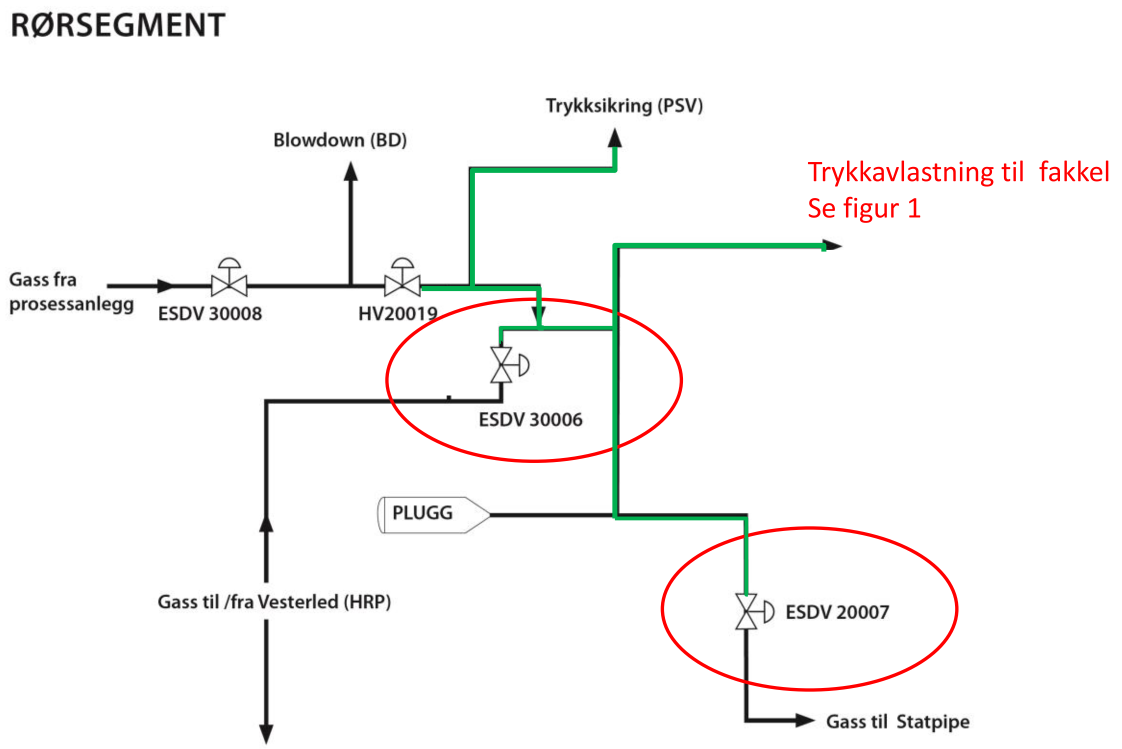

Figure 4: Simplified illustration of the pipe segment with valves. The gas volume for blowdown is shown in green.

Key: Rørsegment: Pipe segment; Trykksikring: Pressure safety valve; Trykkavlastning til fakkel. Se figur 1: Blowdown to flare. See figure 1; Gass fra prosessanlegg: Gas from process plant; Plugg: Plug; Gass til/fra Vesterled (HRP): Gas to/from Vesterled (HRP); Gass til Statpipe: Gas to Statpipe.

From **07.30**, the CCR operator prepares for leak testing of ESDV 30006 and EDSV 20007. The test involves isolating the pipe segment (coloured green in figure 3) by closing the ESDVs, (and all manual valves connected to the pipe segment) and isolating from the HMP process. The procedure thereafter specifies only blowing down to the flare in order to identify possible ESDV leaks when the segment is depressurised. The procedure for ESDV 30006 states that it must be blown down via HCV 20021, while that for ESDV 20007 calls for blowdown to the flare. It emerged from interviews that that the blowdown valve was isolated (HV 20019 closed), so that the natural blowdown route was via HCV 20021 to the flare (see figure 4).

At **10.30,** the CCR operator contacts Gassco (operator of HRP and the transport network, including Statpipe) to exchange information about the test duration. He estimates that it will be over by 13.00, and secures Gassco's acceptance for keeping Statpipe closed off until then. The CCR operator contacts DOF1 to inform him that the ESDVs are ready for leak testing and blowdown to the flare via HCV 20021. DOF1 is busy reading off nitrogen pressures (logged every minute) during leak testing of his assigned valves and cannot leave the test.

At **12.00**, the CCR operator has finished his lunch, and DOF1 breaks for lunch. The latter has not had time to open the manual values for blowdown to the flare.

At **12.20**, the CCR operator contacts the WP office to obtain another process operator to open the valves. This process operator (DOF2) is responsible for the relevant area but has not been involved in planning the job, since DOF1 has arrived as an extra process operator for the leak test. DOF2 has other things to do at the time, but agrees to bleed off to the flare since this will only take him a couple of minutes. The CCR operator and DOF2 review the work in SAP on their respective P&IDs, known as “process and instrument diagrams” in Statoil.

At **12.25**, DOF2 goes to M40 and finds the relevant pipeline to be blown down. He loses radio contact with the CCR, and accordingly goes there to change batteries. In the CCR, the operator and DOF2 review the procedure for the job. The procedure does not specify which manual valves in the pipeline are to be opened, or in which order.

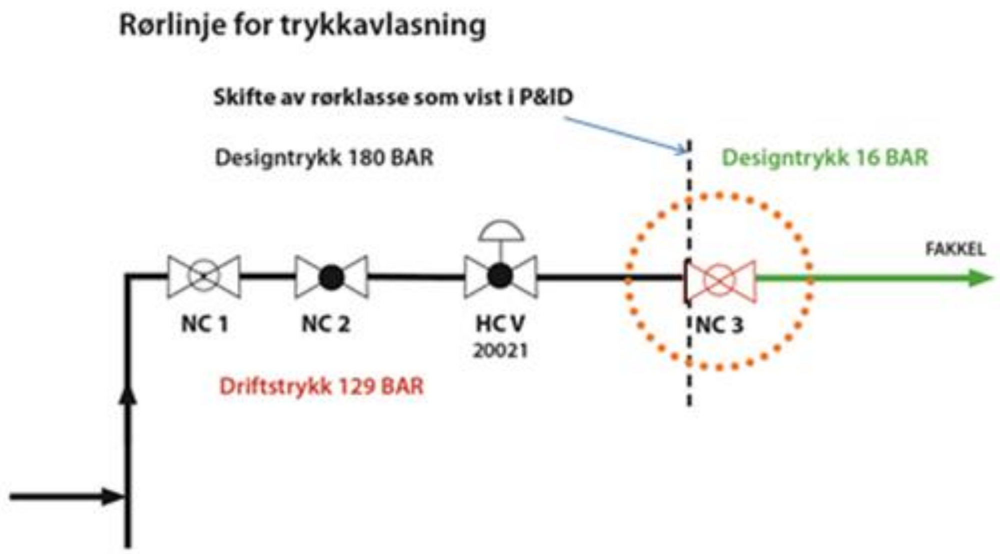

Figure 5: The pipeline for blowdown illustrates the change of pressure rating as shown in the P&ID.

Rørlinje for trykkavlasning: Bleed-off pipeline; Skifte av rørklasse som vist i P&ID: Change of pressure rating as shown in P&ID; Designtrykk: Design pressure; Fakkel: Flare.

At **12.35**, DOF2 returns to the pipeline in M40. He first opens NC1 and finds NC2 open, and then descends from the platform on which NC1 and NC2 are located in order to be in a position to hear when gas flows to the flare, while ensuring that nobody walks under M40 during blowdown.

NC3 is not opened.

At **12.41**, DOF2 notifies the CCR that everything is ready to open HCV 20021 and blow down to the flare. The CCR operator asks DOF2 to report when he hears that gas has reached the flare, since flaring will not visible because of fog.

The CCR operator uses the panel display and PC mouse to open HCV 20021 a few per cent at a time. He opens HCV 20021 to two-three per cent and again asks DOF2 to report when he hears gas flow. The valve is opened further to four-six per cent.

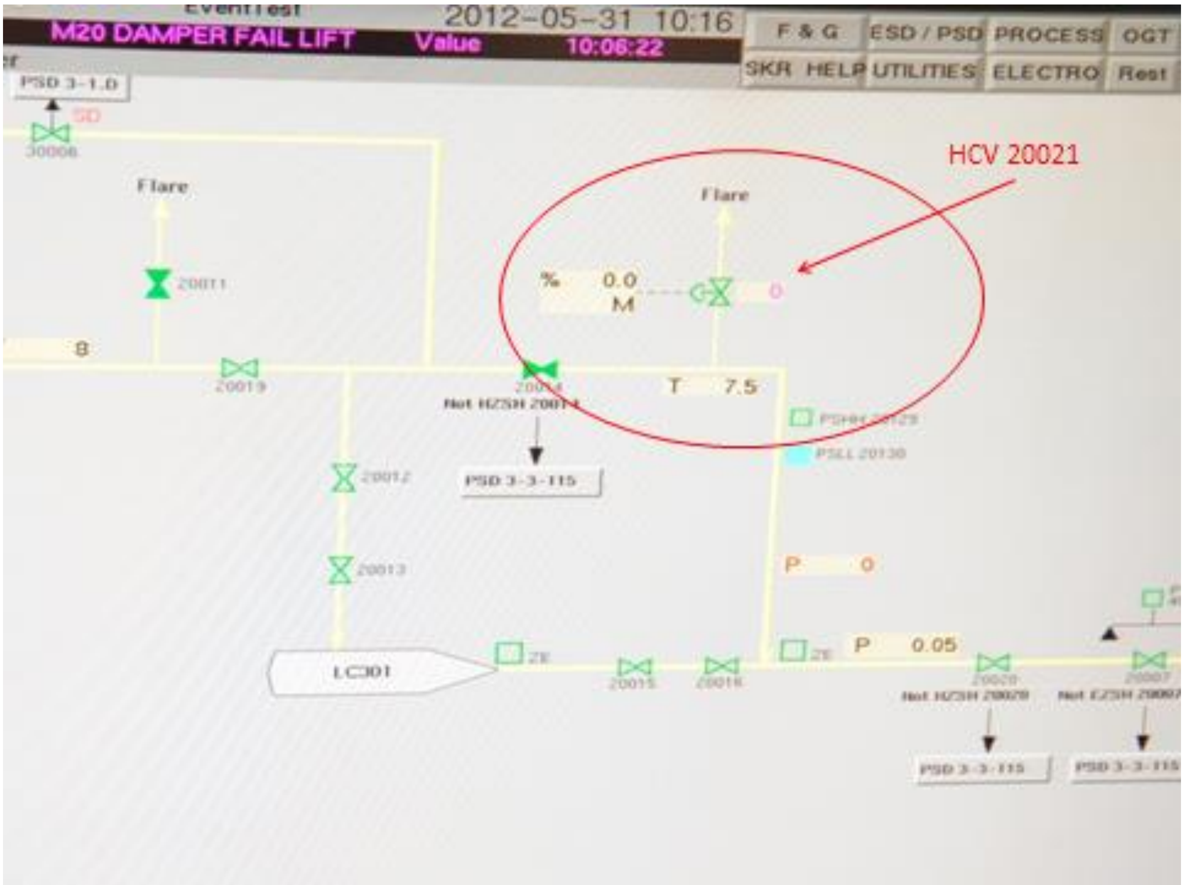

Figure 6: The CCR operator had a limited overview of the valve configuration.

The gasket, insulation material and enclosure are blasted off NC3 and gas leaks out.

DOF2 hears a loud bang in M40 and finds himself in the following scenario:

- *Turns his head away*
- *Insulation is raining down everywhere*
- *Gas at ground level, like an avalanche flowing across the deck*
- *Sees a cloud of fumes passing by*
- *Has a yellow key in his hand and throws it away*
- *Shouts CLOSE, CLOSE, CLOSE over the radio to the CCR*
- *Becomes nervous at failing to establish contact the CCR*
- *Runs out behind the crane, sees yellow flashing lights*
- *Shouts CLOSE, CLOSE once more over the radio*
- *Hears the GPA*
- *Returns to M40 to see whether gas is present*
- *Sees that the deluge has activated*
- *Smells gas*
- *Leaves the area and talks with the damage site leader*
- *Reports where the leak is probably coming from*

Figure 7: The operator's position and distance from the leak site (source: police).

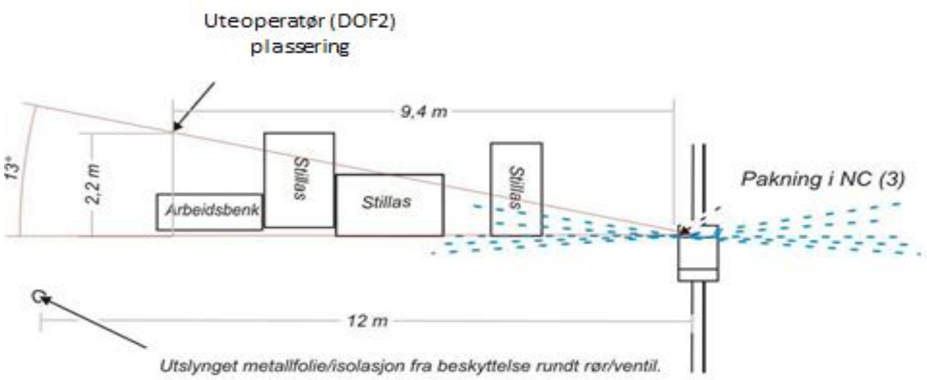

Figure 8: Operator's position in the area near the leak site (source: police).

Key: Uteoperatør (DOF2) plassering: DOF2 location ; Arbeidsbenk: Workbench; Stillas: Scaffolding; Pakning i NC (3): Gasket in NC3: Utslynget metallfolie/isolasjon fra beskyttelse rundt rør/ventil: Metal foil/insulation slung out from protection around pipeline/valve.

The CCR operator repeatedly presses "0 and enter" at his operator station to shut down HCV 20021. It takes four minutes for the valve to shut down.

<u>The emergency response organisation mustered with the key times specified:</u>

The first gas alarms close to the leak site were activated virtually immediately. Gas detectors initiate a number of automatic actions in the emergency shutdown system, including disconnecting ignition sources and starting firewater pumps. Firewater is released in M40 and M30, and the personnel evacuation alarm is activated.

At **12.45**, gas is detected in several areas, and firewater is released manually by the CCR in M55 and M20. Pressure in the firewater line is thereby reduced from 14 to 11 bar, and the amount of water released in each area declines. It later transpires that no gas is detected in one of the areas where firewater is released. In addition, a paint container with gas detectors was moved two years ago from M60 to M40, with its gas detector still addressed to M60 (the drilling area). Firewater is released manually to M60.

At **12.55**, the emergency response leadership has an overview of personnel on board (POB).

At **13.34**, the gas detectors show no gas on Heimdal.

The emergency response team then initiated planning to remove the remaining gas volume in the pipe segment (Statoil later calculated this as about 3.5 tonnes of a total seven tonnes of gas). According to interviews, the solution finally adopted is to blow down cautiously over a bypass around 2ESDV 30006 to the flare. The segment is blown down by **15.00**.

According to Statoil's investigation report, one fire pump ran out of coolant at **14.40** and had to be halted. This meant that no deluge was operational in the process areas until **15.30.**

At **16.07**, the emergency is normalised and the damage site, according to Statoil's investigation report, cordoned off.

5 Actual and potential consequences of the incident

5.1 Consequences of the actual course of events

The incident, a gas leak in the M40 area, is estimated to involve the release of 3 500 kg of gas over 252 seconds, with an estimated initial emission rate of 16.9 kg/s. The gas spread to several neighbouring areas (M20, M30 and M50) on the weather deck. Ignitable concentrations in the gas cloud lasted about seven minutes, and escaped gas had been ventilated away after about 30 minutes. Total gas volume in the pipe segment was 53.49 cu.m at 129 bar 9°C, calculated to be about 7 000 kg.

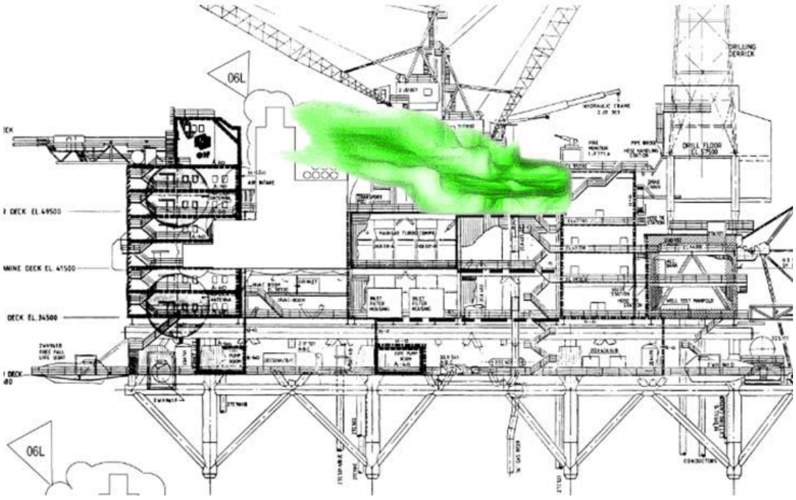

Figure 9: Facade drawing with a projected gas cloud, viewed from south to north. (Source: Statoil's Flacs analysis)

Figure 10: Gas cloud projected down to the weather deck at 230 seconds into the incident. Red dots show detectors, which activated at 20 per cent LEL. Blue dots show detectors which did not detect gas during the incident. (Source: Statoil's Flacs analysis)

An operator stood about 10 metres from the leak site (see figures 7 and 8) and, according to information from interviews, was exposed to the gas cloud. The extent of this exposure has not been clarified. The operator was not subject to obvious immediate injury from the gas or fragments of gasket and insulation blown off from NC3 in the incident. The operator was investigated by health personnel on the installation and followed up subsequently to identify possible delayed effects.

5.2 Potential consequences of the actual leak

The incident had a substantial potential for harm in the event of ignition or under marginally different circumstances.

5.2.1 Potential consequences of a fire, given the actual leak

The fire which could have occurred would have been a jet fire lasting about four minutes, equal to the leak duration. The PSA cannot see that such a fire would have caused spreading or escalation. This is based on information from Statoil that the equipment/pipe would have withstood the heat developed by such a fire. Statoil has also reported that M40 is designed to withstand a 30-60 minute jet fire.

5.2.2 Potential consequences of an explosion, given the actual leak

In the event of ignition at an “unfavourable moment”, the incident could have created an explosive pressure which exceeded the design pressure of the fire/explosion wall to another main area. That could have caused injury and/or loss of human life both in the initial incident area (M40) and in the adjacent main area (M50). According to Statoil, M50 is designated as a mud module. Since drilling has ceased on Heimdal, this module is not operational with hydrocarbons. However, possible personnel in M50 would have been exposed.

In addition, ignition would have caused substantial financial loss.

5.3 Potential consequences under different circumstances

The total gas volume in the pipe segment at the time of the incident was 7 000 kg, half of which escaped during the incident. The whole gas volume could have leaked out had the pipe section between HCV 20021 and the leak site fractured. About two metres long, this section is designed for 16 bar. According to Statoil, it could have withstood a substantially higher pressure, but is unlikely to have coped with the 129 bar in the pipe segment being blown down.

Statoil has reported that the gasket which failed in NC3’s upstream flange was a fibre type, and should have been replaced in line with Statoil’s own requirements by a spiral wound gasket with a steel facing. It emerges from Statoil’s investigation report that a spiral wound gasket would probably not have failed under the relevant pressure. The pipe section was deformed (see figure 8), and would probably have fractured longitudinally had the gasket not failed first. This would in all likelihood have meant that the whole gas volume of 7 000 kg escaped before HCV 20021 managed to close.

Figure 11: Deformed pipe section between HCV 20021 and the leak site. (Source: Statoil's investigation report)

5.3.1 Potential consequences of an explosion or jet fire

A gas volume of 7 000 kg under high pressure and with a high flow rate would have created a large gas cloud, but this scenario has not been risk-assessed by the PSA or Statoil. Two fire walls would have been exposed to the explosion. One of these, to the living quarters, is designed according to Statoil for 0.1 bar and the other, to the drilling area, has a design pressure close to 0.3 bar. Drilling has ceased on Heimdal, which means that the biggest threat for an explosion escalating is that the wall to the living quarters could not withstand it.

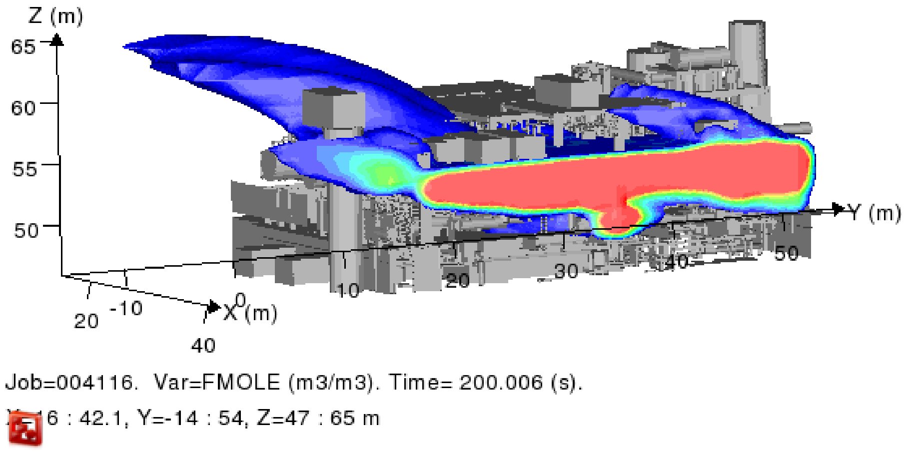

Figure 12: Gas cloud with the ignitable gas area shown as a green band around the red area, which has too high a density to ignite. (Source: Statoil's Flacs analysis)

Other ventilation conditions and/or a lower leak rate could have increased the explosion risk because the gas cloud might have increased in size and/or acquired a more favourable composition for the explosion phenomenon.

In its GL0131 guideline for estimating leak rates, Statoil has specified on a general basis that the maximum size of a gas cloud is a good indicator of the risk contribution from a gas emission. GL0131 states:

*"*The risk contribution increases sharply with growing cloud size. Put simply, a gas cloud A which is 10 times larger (in volume within the LEL) than B contributes 100 times more to risk than B. The size of the gas cloud accordingly provides an appropriate parameter when seeking to classify/grade leaks for risk potential. A close relationship naturally exists between the size of a gas leak and cloud size. This relationship is rather complex, since a number of factors are involved. The most important of these are the emission's character (rate over time, jet/impulse or diffuse), geometry/arrangement, inventory, ventilation/wind direction and strength."

The PSA agrees with this general description and assessment of the risk contribution.

5.3.2 Potential consequences for personnel

The NC1 valve opened by DOF2 before the leak is located about 10 metres from the leak site, and the HCV 20021 opened from the CCR is about two metres from the leak site. Interviews with other personnel reveal that operators who have earlier conducted annual leak tests stayed in the immediate vicinity of the leak site when a corresponding operation was conducted. Had that been the case in this incident, the operator might have suffered serious injury or death from breathing hydrocarbon (HC) gas. He could also have been hit by fragments from the valve. In high concentrations, HC gas can have a narcotic effect and lead to unconsciousness and possible death.

In addition to the operator in M40, another operator was in M44. In the event of a possible explosion, they could have suffered serious injuries or been killed.

The incident occurred at a time when most of those working outside the living quarters (modification, maintenance and operating personnel) were at lunch. The leak area in M40 was normally a work station, and it was fortuitous that no other personnel were there.

The PSA concludes that the incident could have led to a substantial accident under marginally different circumstances.

6 Direct and underlying causes

6.1 Direct causes

The direct cause of the incident was clarified at an early stage.

To prepare testing of two ESDVs (ESDV 20007 and ESDV 30006), a pipe segment was to be blown down to the flare. A shut-off valve with a 16-bar pressure rating was installed in the pipeline as the last barrier to the flare. This valve was closed, and subjected to a pressure of 129 bar. That caused the gasket in the valve flange to fail.

6.2 Underlying causes

Based on observations and the grounds for these in chapters 7.1-7.7, we take the view that weakened performance-influencing factors, illustrated in figure 13, represent the most significant underlying causes which have contributed to the incident being able to happen.

Figure 13: An overview of most significant underlying causes.

Key: Barrier function; Barrier elements; Technical; Operational; Organisational; Lack of performance requirements and/or performance-influencing factors; • Design of pipe segment • Pressure-rating change • Deficient planning of job • Operational risk assessments not done satisfactorily • Deficient description of how the work is to be done • Weaknesses in handling procedures – access – checking – contribution to updating • Design solution weaknesses not identified • Inadequate understanding of system responsibility in AI and OPS • Weaknesses in document management – access – checking – updating • Work not covered by a WP • Inadequate learning after earlier HC leaks • Weaknesses in identifying, considering and communication safety-critical conditions on Heimdal.

7 Observations

The PSA's observations fall into two general categories:

- nonconformities: this category embraces observations which the PSA regards as a breach of the regulations
- improvement points: these relate to observations where the PSA sees deficiencies, but lacks sufficient information to be able to establish a breach of the regulations.

7.1 Nonconformities

Deficient design in combination with inadequate risk assessments and inadequate procedures for opening and closing valves represented the most important causes of the incident.

7.1.1 Deficient design solution

<u>Nonconformity</u>

A deficient design solution made it possible to expose part of the pipeline to the flare to overpressure, and was thereby not robust in restricting opportunities for human error.

<u>Grounds</u>
The applicable standard, Norsok P-001 2006, recommends (see figure A.7 – *Manual blow down for maintenance purposes)* that a change of pressure rating must always follow the final block valve before the flare. In addition, this valve must be open. The purpose is to establish a robust design which ensures that a leak does not occur because of excessive pressure on valve or pipe. The applicable regulations when the HRP was designed and built (1980) state that "Equipment must be safeguarded in accordance with API RP 14 C" and that the gas blowdown system must be dimensioned in accordance with API RP 521. The chosen design solution breaches the basic protection principles in these standards, and the safety functions are not robust.

The relevant pipeline on Heimdal has a change in pressure rating from 180 to 16 bar downstream from HCV 20020. Block valve 3 (NC3) in the pipeline, and the pipe between NC3 and HCV 20020, were subjected during the incident to a pressure higher than they were designed for.

The regulations which applied at the date of the PDO[1] and during the construction period specified a requirement to establish and comply with a procedure which ensures that block valves installed in connection with the process safety system were secured in the correct position. This also applied to block valves installed in connection with the gas blowdown system. Block valve 3 (NC3) in the pipeline to the flare, see figure 1, was not secured in the correct position (in other words, open), which made it possible to overpressure part of the pipe and the valve itself. No routine had been established to ensure that the valve was in the right position.

<u>Requirements</u>
- *Section 5 of the management regulations on barriers, sub-sections 1 and 2*
- *Section 10 of the facilities regulations on installations, systems and equipment, sub-section 1, see regulations for production and auxiliary systems (1980), sections 3.1 and 3.1.1 in chapter 3 on vessels, pipe systems and mechanical equipment, sections 7.3, 7.3.10 and 7.3.14 in chapter 7 on process safety, and section 9.3.5 in chapter 9 on the gas blowdown system (sections 3.1. and 7.3 specify the use of API RP 14C, and section 9.3 specifies the use of API RP 521).*
- *Section 10 of the facilities regulations on installations, systems and equipment, sub-section 1, see the guideline which refers to Norsok P-001 for process facilities.*
- *Section 24 of the activities regulations on procedures*

7.1.2 Deficient design solution not identified

<u>Nonconformity</u>
Statoil has failed to identify through analyses, operation and maintenance that the design solution is deficient. In addition, changes in the use of the pipeline have not led to risk associated with the design solution and/or the use of this solution being assessed and identified.

<u>Grounds</u>

[1] Regulations for production and auxiliary systems on production installations, etc, 1980.

Extensive changes were made to Heimdal in 1999 when it was established as a gas centre. The impact assessment of June 1998 for modifications on Heimdal states that Norsk Hydro will conduct risk assessments related to safety. When requested, Statoil has been unable to document that risk analyses – such as process Hazop – were carried out in connection with the modification work and conversion to a gas centre in order to confirm that the existing design solution for the process plant was satisfactory, given the change in use of the facility.

As far as the investigation team could ascertain, the pipeline was primarily used for blowdown of the Statpipe line until 2003. It was thereafter used for blowdown when testing ESDVs. The design weakness was not identified as part of this change of use.

During interviews, we were told that MIS, Timp and TTS are tools used with notifications to monitor technical condition in the process plant. When TTS was implemented in 2009, no deficiencies were identified in the relevant pipeline, but a pressure rating change which did not comply with the regulations was identified in another pipeline. We note that Statoil has not actively used this observation to identify similar deficiencies elsewhere in the plant, such as in the relevant pipeline.

In TR1055 (version 4), PS 8.4.1 *Emergency depressurisation*, Statoil has specified a requirement that "block valves in emergency depressurisation lines shall be secured open". The TTS verification failed to identify that the NC3 block valve before the flare was in the wrong position (closed) pursuant to this requirement. In our view, the pipeline used for maintenance work should have been checked on the basis of a safety assessment in the same way as pipelines with pressure safety valves (PSVs) and for automatic blowdown.

The deficient design solution has not been identified when using the pipeline and valves in the annual ESDV leak tests.

During the interviews, the view was expressed that MIS/Timp/TTS are normally not sufficiently finely meshed to identify design faults/weaknesses. These tools accordingly cannot be used for the necessary updating of P&IDs.

<u>Requirements</u>

- *Section 5 of the management regulations on barriers, sub-sections 3-7*
- *Section 11 of the management regulations on the basis for making decisions and decision criteria, sub-section 1*
- *Section 16 of the management regulations on general requirements for analyses, which specify that the responsible party shall ensure that analyses are carried out that provide the necessary basis for making decisions to safeguard health, safety and the environment, sub-sections 1 and 4*
- *Section 20 of the activities regulations on installation and commissioning, sub-section 1 and sub-section 2, letter b.*
- *Section 25 of the activities regulations on use of facilities, sub-section 1*

7.1.3 Inadequate description of how the work should be done

<u>Nonconformity</u>

The level of detail in the description of the activity was not tailored to the safety significance of the work process. The procedure was not unambiguous and user-friendly.

Grounds
The test procedures, including the applicable P&ID, for 2ESDV 20007 and 2ESDV 30006 are crucial in planning safe work. The *Leak test of 2ESDV 20007 gas export to Statpipe* procedure states that "blow down the test segment via 2HCV20021 to 1.05 bara". The procedure does not specify which manual valves are to be handled or the order they should be opened.

Plans call for 2ESDV 20007 and 2ESDV 30006 to be tested annually. It emerged during the interviews that this pipeline is seldom in use, most recently in 2004, and that personnel on board knew little about its position and design. These conditions mean that opportunities for the personnel involved to become familiar with the design is limited, and should thereby indicate a need for a greater level of detailing in the procedure for safe operation.

The P&ID must show the correct design of the process plant, and represents a key element in the ability to operate the facility safely. In the procedure submitted, the P&ID appears in A4 format on the reverse of the procedure. Some of the symbols and texts in the P&ID are indistinct. This means it is not possible to read the change of pressure rating on the pipeline. The position of the valves is also hard to discern. In addition, several errors appear on the P&ID, including ones related to the pipeline involved. See nonconformity 7.1.1.

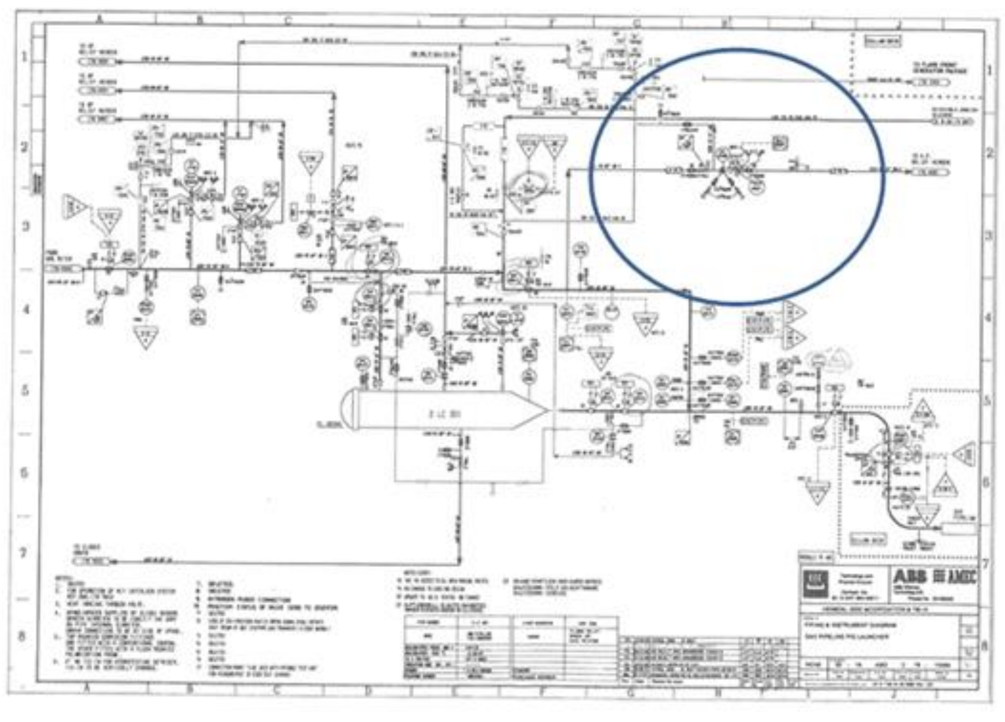

Figure 14: The P&ID (in A4 format) on the reverse of the test procedure, with the relevant pipeline circled.

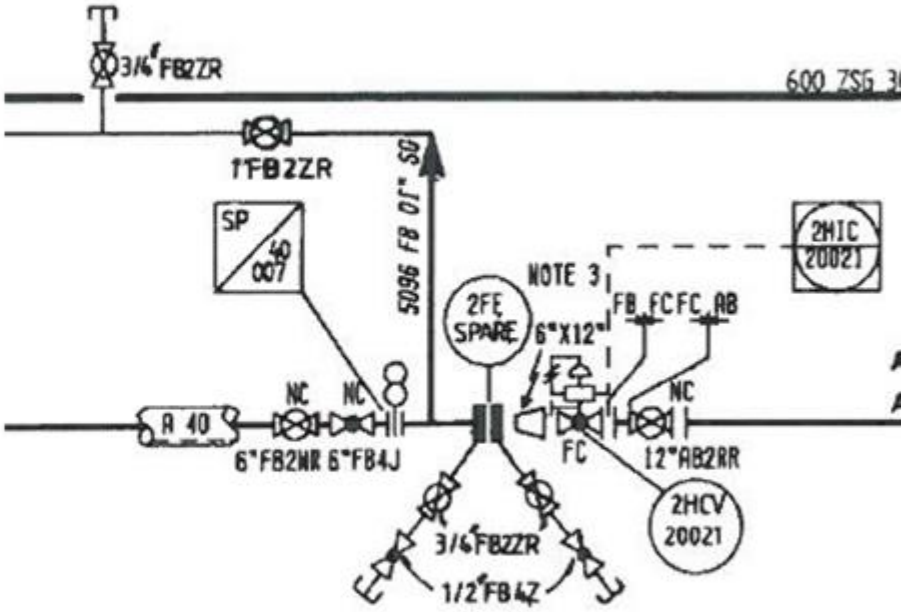

Figure 15: The relevant pipeline in detail.

The NC2 control valve was found in the open position by DOF2. This valve was marked NC (normally closed) on the P&ID. There was no extra notation on NC2 or in the P&ID that this valve was open. It also emerged during the interviews that NC2 was difficult to operate at times, and was described as "stiff", "crooked" and "rusty". The real status of the pipeline and the information on the P&ID do not correspond, which could indicate a failure to spot such lack of correspondence and/or update the test procedure the last time it was implemented.

The CCR operator's display diagram of the pipeline to the flare showed no valves other than the HCV 20021 he was to open himself for blowdown to the flare (see figure 6). NC1, NC2 and NC3 were not visible to the CCR operator, but he used the "master" P&ID of the pipeline when planning the blowdown.

The procedure did not contribute to detecting, communicating and reacting to the lack of correspondence between the valve's position and the P&ID.

Nor did the procedure for testing 2ESDV 20007 and 2ESDV 30006 contain information on which valves were to be opened by the process operator out in the plant.

Labelling as a necessary condition for preparing unambiguous and user-friendly work descriptions.
The PSA's report from the 2011 audit of operational and maintenance management on Heimdal and the HRP identified deficient labelling of equipment as a nonconformity with section 10 of the facilities regulations on installations, systems and equipment. The audit report states: "During conversations, personnel involved in the operation and maintenance discipline said that they found deficiencies in labelling to be a problem, not least in the form of increased time to identify equipment in SAP and in the field. Deficient labelling could enhance the probability of erroneous operation of equipment – and thereby of incidents." Action to label equipment in the process plant had been initiated on Heimdal, but not

completed. While NC1, NC2, and NC3 were temporarily marked with plastic labels, this labelling was not shown on the P&ID.

Requirements

- *Section 24 of the activities regulations on procedures, sub-section 2*
- *Section 13 of the management regulations on work processes, sub-section 2 and sub-section 3, second sentence*
- *Section 10 of the facilities regulations on installations, systems and equipment, sub-section 2*

7.1.4 Weaknesses in Statoil's document management

Nonconformity

Governing documents, including technical operating documents, had not been checked, were not available in updated versions and were not accessible in the management system.

Grounds

The investigation identified inadequate document management at three levels:

- access to the procedures
- checking of the documents
- updating.

Access to the procedures

The test procedures for 2ESDV 20007 and 2ESDV 30006 were not included in Statoil's formal part of the management system (SAP), but were stored on a local PC belonging to the responsible leader in O&M offshore. As a result, the procedures were not subject to checking by AI, which has technical system responsibility or is "owner" of the procedure. In an interview with AI, this was said to be at odds with correct document management.

Aris was implemented on 18 May 2012, and access to Apos simultaneously removed. During the interviews, it emerged that a number of people had not received training in Aris and reported that they could not find individual documents. They had no access to Apos after 17 May 2012.

Document control

Test procedures for 2ESDV 20007 and 2ESDV 30006 were being updated when the incident occurred. This work had begun before then. The procedures had not been updated since 2004. They lacked a revision history and revision dates, and no information was given on who was responsible for or had approved them. They also had deficiencies (see nonconformity 1).

Updates

P&IDs are key documents in day-to-day management of process plants. An error in them could have major consequences for planning and executing work at and modifications to the facilities. Responsibility for updating P&IDs rests with AI in Statoil.

The master version of the applicable P&ID for the pipeline shows 2009 as its most recent revision year. However, the P&ID for the test procedure carries a revision date of 2004. The applicable P&ID is still sub-titled *Heimdal 2000 Modification & Tie-In*, for example.

Four specific errors in the applicable P&ID, which also forms part of the test procedures for 2ESDV 20007 and 2ESDV 30006, were discussed during the interviews on land with AI. Three of these were directly related to the relevant pipeline.

Representatives for AI, which has technical system responsibility, could not refer to activities or routines intended to ensure correspondence with the technical construction of the process facilities on Heimdal and how this is represented on the P&IDs. See nonconformity 7.1.3. They referred to the offshore organisation's responsibility for entering notifications if a P&ID and the plant failed to correspond. The P&ID contained errors in the following areas.

- The description of the pipeline in the P&ID does not correspond with the actual point where pressure rating changed in the plant. See nonconformity 7.1.3. Change of pressure rating is part of the original 1984 design and had never been identified as an error on the P&ID.

- On the P&ID, the final block valve (NC3) is marked NC when, according to Norsok P 001, it should have been labelled NO (normally open).

- Documentation shows that the final revision date on the P&ID is 2009 and that some of the identified errors date back to the original 1984 design.

We have also identified weaknesses with regard to function, including the level of detail and format, in the applicable test procedure. See nonconformity 7.1.3.

The operation manual[2] submitted represents operational documentation which, with the P&ID, can be used for training, modifications and work in a plant. The pipeline was last used in 2004 for blowdown of Statpipe in connection with the Jotun pipeline breach. Since then, it has primarily been used for blowdown in connection with annual ESDV leak testing.

The operational documentation has not been updated to reflect this change of use. No revision history or identification of the responsible owner of the document has been provided. That casts doubt on its status and validity.

<u>Requirements</u>

- *Section 6 of the management regulations on management of health, safety and the environment, with guidelines, sub-section 2, see NS-EN ISO 9004:2000 4.2.3, and sub-section 4*
- *Section 20 of the activities regulations on startup and operation of facilities, with guidelines, sub-section 2, letters a and b*

7.1.5 Weaknesses in risk assessment during planning

<u>Non-conformity</u>

Planning of the activities failed to ensure that important contributors to risk were identified, and the activities were not managed and executed in a way which prevented the incident.

<u>Grounds</u>

Overview of the segment included in the test

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[2] *Operation Manual Book 3, Volume 1, Part C: Flare and Atmospheric Vent.*

Before the work was initiated, the pipe segment contained large volumes of hydrocarbons. Pursuant to Statoil's TR1055, PS 8.4.1 governing document, no segment in the process facility may contain more than 1 000 kg of hydrocarbons unless connected to an emergency disconnect package (EDP). During the incident, the relevant segment contained 7 000 kg of hydrocarbons, and the presence of hydrocarbons in this segment was not identified and applied when planning of the test. After the incident, the segment contained an estimated 3 500 kg, which presented substantial challenges for depressurisation.

The A standard

Pursuant to Statoil's own requirements in *The Statoil Book*, an A standard will always be maintained during work operations. See doc 48. This describes a "common pattern of behaviour" for the Statoil organisation. An A standard will identify the risk of an activity, requirements for the activity pursuant to formal demands, and the working method to be adopted. The work team must assess whether further methods, requirements or risk assessments are needed. In addition to the A standard, *The Statoil Book* highlights the importance of compliance and leadership. Managers are responsible under an A standard as communicators, role models, trainers and guides. Continuous risk assessments must also be performed during a job.

A number of improvement measures were adopted and presented to the PSA in 2010 following a hydrocarbon leak on Gullfaks B. Measure 20 specifies: "In connection with a hydrocarbon-carrying system, performance of an A standard behavioural pattern assessment will be signed off on the WP form for the relevant job. For work on a hydrocarbon-carrying system which does not require a WP (such as readying and resetting), performance of an A standard behavioural pattern assessment will be signed off on the valve and blind list."

Described in the letter to the PSA of 28 April 2011 from Øystein Michelsen, executive vice president for development and production Norway (DPN) in Statoil, this measure is not reflected in updated procedures (revision date 18 May 2012). The requirement to sign off an A standard review is not included in OM01.05.05 *Operate system and equipment in operation* procedure, for example.

An audit was carried out on Heimdal on 16 May 2012 (10 days before the incident). The report, entitled *Measures to reduce gas leaks when working on normally pressurised systems – Heimda*l, finds that "An A standard review in connection with the isolation plan appears to be unknown to some people".

It emerged during the interviews that the A standard behavioural pattern was not used in planning and execution of the ESDV test. During our investigation, we have identified seven gatherings/meetings of involved personnel as part of the preparations for the ESD test. Our assessment is that none of these meetings, individually or in total, satisfy Statoil's requirements for an A standard behavioural pattern or meet other requirements for risk assessments related to the relevant job. The importance of opening the isolation valves in the right order during blowdown, for example, and the risk posed by erroneous operation, were not the subject of a safe job analysis (SJA), a pre-job discussion, a workmate check, or use of the valve and blind list or other forms of checklists.

We cannot see that management on land and offshore in the Heimdal organisation has functioned as a role model, trainer or guide for implementing the A standard behavioural pattern with associated risk assessments. As far as we can ascertain, no manager has called for either an oral or a written A standard related to the relevant job – even when is was decided to replace operative personnel. Statoil’s requirement for an A standard have not been adequately conveyed or understood, even by senior personnel on Heimdal. During interviews offshore, it was said that “we only use the A standard when we are going to enter the system”.

A high level of activity was mentioned by several people during the interviews. It was reported, for example, that personnel did a job alone even if the work method was based on execution by a team – in other words, at least two people. We saw signs that operative managers lacked the time to follow up planning activities. During the investigation, we observed that the workload, particularly for the O&M leader, was so high that it threatened to undermine activities inherent in the A standard for him as a role model.

Change of operative personnel
Neither the process operator (DOF1) intended to do the work in the plant, or the person (DOF2) who ended up doing it, took part in planning the blowdown job. DOF1 admittedly attended the planning meeting on 25 May 2012 with the CCR operator and two assistants who were to help in the work, but risk associated with blowdown was not discussed there either.

The process operator in the plant was replaced immediately before the work began, without consideration being given to the need for extra risk assessment/planning. It emerged during the interviews that DOF2 lacked experience with this type of test or pipeline, and that personnel with experience from similar tests were given responsibility for doing this work.

Before the job began, what was described as “a kind of pre-job discussion” took place between the CCR operator and DOF2, who carried out the work. They jointly took out the P&ID, looked at it, and reviewed the procedure for testing 2ESDV 20007. During the planning, DOF2 – who was to be in the plant – and the CCR operator did not jointly agree which valves were to be opened and in what order before DOF2 went out to open them.

It emerged during the interviews that communication and work orders between the process and CCR operators were unclear. The valves were not individually labelled. See nonconformity 1. They were in radio contact during the job, and we were told that the order “Open NC-NC-NC” was given by the CCR operator. Orders from the CCR operator were not confirmed by DOF2 until work on blowdown to the flare started.

Valve configuration did not conform to the P&ID
When doing the work, DOF2 observed that NC2 was not closed and reported this by phone to the CCR operator. Work was not halted to discuss the possible consequences.

NC3 was not opened by DOF2. This was because, according to the interviews, an understanding existed that it was in the open position.

The CCR did not ask for confirmation that all three valves, NC3, NC2 and NC1 successively, had been opened before HCV 20021 was opened by the CCR operator.

The AI/OPS group has not enabled operations personnel offshore to do a safe job. Work operations were characterised by a lack of involvement from management personnel at every level. Lack of risk assessments of the process plant and the work to be done, planning for the job, inadequate labelling of valves with specific numbers, deficient specification in procedures of how the work was to be done, and a P&ID which was both difficult to read and deficient, provided a poor decision base.

Requirements

- *Section 11 of the management regulations on the basis for making decisions and decision criteria, sub-section 1*
- *Section 12 of the management regulations on planning*
- *Section 17 of the management regulations on risk analyses and emergency preparedness assessments, sub-section 1*
- *Section 29 of the activities regulations on planning, sub-section 1*
- *Section 30 of the activities regulations on safety clearance of activities*
- *Section 32 of the activities regulations on transfer of information at shift and crew changes*

7.1.6 Weaknesses in experience transfer and learning in the Heimdal organisation after earlier incidents

Nonconformity

Statoil has not made adequate provision to ensure that information from earlier incidents is processed, communicated and applied to improvement and learning in the Heimdal organisation. No provision has been made to ensure that lessons learnt through experience from its own activities or those of others are applied to improvement work on Heimdal.

Grounds

It was explained during the interviews that incidents are reviewed at regular HSE meetings, both on land and offshore. However, no specific knowledge emerged of investigation reports from earlier hydrocarbon leaks on Heimdal, or other causes which it could be relevant to know about in order to plan and operate the process facility there in a safe manner.

Knowledge of the frequency of, reasons for and development over time with hydrocarbon leaks on Heimdal was limited. That also applied to other hydrocarbon leaks in the mature fields entity, in Statoil generally or on the NCS. Little was known in the Heimdal organisation about measure instituted at DPN level in Statoil to reduce the risk of hydrocarbon leaks.

Compared with other installations on the NCS, Heimdal has experienced a large number of hydrocarbon leaks in recent years. A review of leaks exceeding 0.1 kg/s reported to PSA shows that the HMP had two incidents in 2002, two in 2003, three in 2005, two in 2006, one in 2007 and one in 2011. A review of leaks exceeding 0.1 kg/s reported to PSA shows that the HRP had two incidents in 2005, one in 2006 and one in 2010 (see chapter 3.2).

Including the HRP, Heimdal is the set of installations on the NCS with the highest frequency of gas leaks above 0.1 kg/s, averaging 1.5 per year from 2002 to 2011. However, it emerged from the interviews that knowledge about this leak frequency or the causes of the leaks which had occurred was very limited in the Heimdal organisation, both offshore and on land. It was stated that Heimdal was probably “well placed” and “middle of the road” for the average frequency of hydrocarbon leaks on the NCS. When asked, relevant personnel were unable to account for the causes of previous hydrocarbon leaks, not only on Heimdal but also at a Statoil level generally or for the NCS.

Interviews offshore and in the Heimdal land organisation gave the investigation team an overall impression that responsible personnel paid little attention to the risk of hydrocarbon leaks on Heimdal.

Moreover, the risk of hydrocarbon leaks on Heimdal and the importance of preventing these is not discussed in important strategic documents and systems (TTS, Timp) which form the basis for safe operation of the installation, including O&M's strategy document.

A review of investigation reports from Hydro and Statoil after hydrocarbon leaks on Heimdal (2002-11, see docs 30-41, 57, 59 and 61) indicate that most incidents reflect a combination of technical failure, weak design and plant operation. A number of these investigation reports note that similar incidents have repeatedly occurred before the investigated hydrocarbon leaks (see docs 30, 31, 33, 34, 37 and 41). The investigations refer, for example, to repeated challenges in securing spare parts for old valves (see doc 41), a number of registered leaks from autoclave blocks and Mapegaz valves (see docs 34, 37 and 41), repeated incidents related to the same TEG system (see doc 30) and a number of incidents related to faulty routines for closure plans (see doc 33).

The investigation reports note that many conditions have been known about and reported on repeated occasions, without this resulting in measures to reduced the probability of a recurrence. Despite a number of hydrocarbon leak investigations on Heimdal, it emerged from the interviews that personnel were not familiar with patterns in the causes of previous hydrocarbon leaks on the installation, or with recommended measures for reducing these.

A number of investigation reports following earlier hydrocarbon leaks on Heimdal note that procedures/job descriptions which are unclear or lacking in specific detail have been significant for the occurrence of the leak (see docs 31, 34 and 35).

The operator's investigation reports (2002-11) do not compare Heimdal's leak frequency with other installations operated by Hydro (2002-07) of Statoil, or with other installations on the NCS. However, a number of reports note a lack of knowledge of earlier incidents on the installation (see docs 30, 31, 33, 34, 37 and 41).

A review of 10 investigation reports (2002-11) following hydrocarbon leaks on Heimdal shows that five of these incidents occurred in connection with preparations for and execution of maintenance. The others were caused by disruptions in the process plant. As far as the investigation team has been able to ascertain from documentation on the incidents, no WP application was made in connection with any of the incidents. These incidents can be related to "normal" operating activities (in OPS), and it seems that operational jobs requiring a WP and an SJA have not led to incidents on this scale. During the interviews, operators and management offshore stated that WPs were only utilised a few times a year by OPS. Personnel in the Heimdal organisation were not aware that earlier leaks had largely occurred in connection with work done by OPS. See the discussion in chapter 8 on the use of WPs.

"After all, we're a gas centre," it was said during the investigation. Heimdal has no drilling activity, and hydrocarbon leaks accordingly appear to be the biggest contributor to risk for its installations.

The PSA's annual RNNP report on trends in risk level in the petroleum activity contains a major accident risk indicator for hydrocarbon leaks above 0.1 kg/s, with data from the operator companies. Each company reports its own incidents to the RNNP, and they should therefore be known to Statoil and to those parts of its organisation for which they are relevant. A study was conducted for the RNNP in 2010 on causes and measures related to hydrocarbon leaks on the NCS. This notes that a number of such leaks have arisen because of human intervention in technical solutions with an unfortunate design. The study identified a need to redesign away from poor solutions to reduce risk. Information on the study was sent to Statoil after it had been completed, and was also sent to the company in connection with an audit launched in the autumn of 2011. We cannot see that this knowledge has been made known to or assessed for use by the Heimdal organisation.

The hydrocarbon leak on Heimdal on 26 May 2012 has features in common with causes identified in the study. See nonconformities 7.1.1, 7.1.2 and 7.1.5. During the interviews, it emerged that nobody was aware of the content of the studies or could refer to other similar studies or information on the causes of hydrocarbon leaks. At the final interview, conducted on 21 August 2012, it emerged that Statoil had carried out a causal analysis of hydrocarbon leaks in 2010 for installations in its mature fields entity. However, nobody was able to refer to this analysis during the interviews, or to it being used to develop risk-reducing measures for avoiding future leaks on Heimdal. This suggests that Statoil DPN and its North Sea west OPS team have failed to ensure that the Heimdal organisation was familiar with the risk of hydrocarbon leaks on its own installations.

The Gullfaks B hydrocarbon leak of 4 December 2010 has formed the basis for extensive improvement measures in Statoil. These are described, for instance, in a letter dated 28 April 2011 from the company to the PSA. See doc 62. Statoil has confirmed to the PSA that all its entities have reviewed the overall measures, and that relevant packages of measures have been established locally. During the interviews, however, it emerged that there was no knowledge of this initiative by DPN or other risk-reducing measures related to hydrocarbon leaks on Heimdal over the past five years. It emerged from the investigation interviews that the causes of the Gullfaks B incident in 2010 were little known.

Our understanding after the interviews is that people relate primarily to individual incidents on the basis of Synergi reports and safety circulars issued after incidents, and assesse measures on that basis. Available statistical data from incidents, investigations or studies are not processed, systematised and applied to risk-reduction work on Heimdal.

Requirements

- *Section 15 of the management regulations on information*
- *Section 19 of the management regulations on collection, processing and use of data, sub-section 1, letters a, c and e*
- *Section 23 of the management regulations on continuous improvement*

7.1.7 Weaknesses related to expertise and risk understanding

Nonconformity

Statoil has failed to ensure that personnel in Heimdal's land and offshore organisation have the expertise and risk understanding required to perform the work in a safe manner.

Grounds

The following emerged from the interviews with personnel offshore and on land, and at all organisational levels.

- Knowledge about the risk of hydrocarbon leaks on one's own installation was weak in the Heimdal organisation. Personnel in the land and offshore organisation had not been informed of relevant experience data about hydrocarbon leaks. See nonconformity 7.1.6.
  The Heimdal organisation had not been informed about relevant analyses, such as the 2010 causal analysis of hydrocarbon leaks from the mature fields entity, the RNNP study of 2010 and measures after the Gullfaks C incident and the causal analysis from mature fields. See nonconformity 7.1.6.
- The Heimdal organisation had not assessed the use of other risk analysis tools for identifying the condition of the process facility, see nonconformity 7.1.2, and had thereby failed to help secure relevant information for users of the facility.
- Personnel had not received sufficient training in Statoil's management system, specifically for document management. See nonconformity 7.1.4.
- Personnel in Heimdal's organisation on land and offshore had different interpretations of whether the relevant job – and a number of other jobs – was subject to the requirement to apply for a WP. This suggests that they had not received sufficient or unambiguous training in applying the WP system (see chapter 8, discussion of uncertainties).
- Personnel lacked updated information material. The system manual states that the pipeline is only to be used for blowdown of Statpipe. Training manuals have only been updated to a limited extent. See nonconformity 7.1.4.
- Personnel had not received information on or training with the pipeline involved.
- The AI process entity was unclear about its responsibility for the work procedures, and about ownership and necessary revisions of P&IDs. AI process involved itself only in changes to the P&IDs related to modifications or on the basis of error messages/notifications from the offshore organisation.

Management at all levels of DPN and in the Heimdal land and offshore organisation have failed to ensure that relevant risk conditions are identified and used for personnel training. It is also unclear to us who is responsible in Statoil for acquiring, processing and conveying knowledge about safety-critical conditions to and in the Heimdal organisation.

Information from the interviews, the totality of identified nonconformities and the grounds specified in the above-mentioned points indicate that safety understanding in the Heimdal organisation related to the threat of hydrocarbon leaks on the installation was deficient.

Requirements

- *Section 6 of the management regulations on management of health, safety and the environment, sub-section 2*
- *Section 21 of the activities regulations on competence, sub-section 1*

7.1.8 Inadequate capacity in the firewater system

Nonconformity

The firewater system was unable to supply sufficient firewater to ensure adequate capacity when parts of the system were inoperative.

Grounds

It emerged from documentation received and interviews that the firewater supply was affected by faults for a time in connection with the incident. We note that Statoil's investigation report states that firewater supply was inoperative for about an hour. A fire pump ran out of coolant and had to be shut down.

Requirements

- *Section 5 of the management regulations on barriers*
- *Section 36 of the facilities regulations on firewater supply, see regulations for production and auxiliary systems (1980), chapter 12, sections 12.2.4, 12.2.6 and 12.4.3 on firefighting*

7.1.9 Inadequate capacity in explosion wall between production and drilling areas

Nonconformity
The area separating production and drilling is not designed to ensure that the consequences of an explosion are adequately contained.

Grounds
Ignition of the gas cloud, identified in Statoil's explosion analysis, would quickly have exceeded the design pressure to the mud module in the drilling area. The wall between modules M40 and M50 is not designed to withstand the explosive pressure from the relevant gas cloud in the incident.

Requirement

- *Section 7 of the facilities regulations on main safety functions, see regulations for production and auxiliary systems on production installations, etc (1980), chapter 2.6, section 2.16.1 on the arrangement of individual areas.*

7.2 Improvement point

7.2.1 The normal operator station in the CCR was out of operation

Improvement point
The operator was required to use an alternative station to monitor key data in connection with the incident.

Grounds
Requirements for workstations specify that provision must be made to ensure that personnel with control and monitoring functions can acquire and process information on such conditions in an efficient manner.

The normal workstation in the CCR failed on 25 May, the day before the incident, and a repair was notified in SAP. The workstation was out of service during the incident.

This meant that the CCR operator

- had to turn round to see the alarm rate and other safety-critical information
- had to relate to a surge of alarms during the incident from an unfavourable position, which made it difficult to understand what was happening, and the alarms failed to provide good decision support
- had to ask DOF2 to report when he heard anything "because his station was damaged"

Comments on the efficiency of the alternative workstation made during the interviews:
- *sat with his back to the KOS and the flare*
- *could not see the flare because of fog*
- *thought the leak was in the flare system*
- *working conditions in the CCR were a great disadvantage*
- *the job was made a little harder*
- *the phone was out of reach*
- *extremely irritating*

Figure 16: Shows the CCR operator at the temporary workstation as during the incident. The dedicated but inoperative workstation is to the left with a dark display.

Observations related to information on the display schematic:
- Insufficient safety-critical information was presented on the display. It was not possible to call up a more detailed schematic showing all the valves in the pipeline involved.
- The CCR operator sees only the valves in the pipeline involved, he cannot see the other valves operated by the process operator out in the plant.

Communication
Radio communication between the process and CCR operators became inoperative/unstable.

Requirement
- *Section 31 of the activities regulations on monitoring and control, sub-section 1*

8 Discussion of uncertainties and conditions of significance for the incident

The following points illustrate areas where the investigation has identified conditions without drawing clear conclusions on nonconformity with the regulations or has received conflicting information from the various interviews, but considers these areas important for the causes of the incident.

HCV 20021 took four minutes to close

According to Statoil's investigation report, maintenance was carried out on HCV 20021 in March 2012. After this work, the valve was tested and then took about 40 seconds from closed to fully open and from open to shut. The valve showed no indication at that point of uneven speed.

During the incident, the HCV was opened about six per cent, and took four minutes to close pursuant to pressure registrations in the pipeline. Statoil has not found out why the valve took four minutes to close and was thereby a significant contributor to the potential of this incident.

Use of the pipeline

Statoil's investigation report on the incident cites 2004 as the last time the pipeline was in use. During interviews offshore, we were told that it had been used later. We have not succeeded in establishing when and on what occasion the pipeline was last used before the incident.

Potential

The leak segment was bounded against Statpipe and the OGT/Vesterled tie-in with Statpipe by 2ESDV 20007 and 2ESDV 30006. These ESDVs could have had an internal leak rate on a par with their acceptance criteria. A possible fire could have been fed by this leak rate for a long time after the volume originally confined in the pipe segment was depleted. What consequences such a fire would have had for financial assets is unclear. That depends both on what had happened to the installation and the possible shutdown of the pipelines (with production consequences for other fields).

Management system

We have observed that Aris, which occupies a key place in the management system, describes the process, the roles for personnel involved and requirements, but does not ensure that the work process for the relevant job is of the quality required for a safe operation. In our view, the Aris process management tool is not fully adequate for describing the total process for this specific work operation. As has been demonstrated, Aris is still not sufficiently well developed to embrace all the necessary management elements. We saw that DocMap and Teamsite had to be used in addition to Aris and SAP to secure access to all necessary documents. In our view, SAP remains the main tool where procedures with P&IDs lie, and where notifications from the installations are conveyed to the land organisation. The systems were demonstrated in connection with the investigation, and the importance of accessibility and connectivity between the various systems emerged clearly. During the demonstrations, three months after Aris was implemented, the connection with SAP failed to work and it was not possible for us to gain access to SAP during the meeting.

Information that Statoil's maintenance operations are inadequately described in its management system for Heimdal emerged during the interviews. We were informed by interviewees about other installations where maintenance operations are better managed. If correct, that suggests differing practice in the Statoil organisation, but going into this question in greater depth is beyond the investigation team's mandate.

Parallel working in the process plant

We were told by several informants offshore that hot work (needle scaling) was under way in the process plant that day, but was not being pursued during the incident because of lunch. However, we have been unable to establish whether hot work was actually under way on the day in question. We have been presented with a list of WPs issued that day – see doc 11 – but have not seen a WP for this or for parallel work in the process plant that day. Statoil's own investigation report states that a WP was issued for needle scaling/grinding equipment (Hot B permit in M30). The WP was activated in the CCR at 08.12, but had not been started before the incident.

<u>Differing interpretations of concepts when planning the work</u>
A WP application for the leak test of the ESDVs was not considered. A WP with associated risk assessment was not implemented, with reference to this being normal practice for routine work in the offshore OPS department. We would question this practice. Interviewees expressed uncertainty about when a WP should be sought for this type of work.

The investigation report after the hydrocarbon leak on the HMP on 22 August 2006 noted that the relevant job was not adequately planned pursuant to the regulations. It found that differing interpretations of the concepts was one of the factors contributing to the incident. It was noted that the area operator can carry out or prepare for maintenance without a WP. "This means that the area operator plans, prepares the job and takes care of the barriers". The report continues: "The investigation team believes that the current formulations in Apos concerning work on pressurised systems are not sufficiently precise. That applies particularly to the sections which describe what the operator can do without a WP". The investigation team proposed measures in 2006: "The process owner for operations must review as soon as possible the formulations in the management system for permitted work on pressurised systems". Differing interpretations of whether "work on pressurised systems" should require a WP or not emerged during the interviews in 2006.

Michelsen's letter of 28 April 2011, see doc 62, states that, on all installations, "In connection with a hydrocarbon-carrying system, performance of an A standard behavioural pattern assessment will be signed off on the WP form for the relevant job. For work on a hydrocarbon-carrying system which does not require a WP (such as start-up and resetting), performance of an A standard behavioural pattern assessment will be signed off on the valve/blind list". This indicates that Statoil has seen a need to clarify when a WP is to be used and when a written A standard is required and sufficient. No written A standard was provided in the Heimdal incident of 26 May 2012 (see 7.1.5).

It emerged from the interviews conducted during the investigation into the incident of 26 May 2012 that different interpretations still prevailed within the Heimdal organisation about when a WP was required. Definitions of what comprises "work on pressurised systems", "work on hydrocarbon-carrying systems", "intervention in the system" or "safety-critical operations" were examples of concepts interpreted differently by interviewees.

OM05.01 states that "a WP is required for work with a high level of risk and ... which requires coordination and clearance at installation level". It follows from the work process described in Aris that utilisation of a WP unleashes a number of planning elements, such as an SJA, a pre-job discussion and a signed valve and blind list, which can contribute to safe operation.

OM05.01 states that activities which can be pursued without a WP will mainly be "normal operations within production ...". Examples cited include "inspections which can be executed without physical intervention in the inspected equipment". As we understand it, it was this formulation in connection with the relevant job which permitted testing to be initiated without a WP. The work was not defined as "intervention in the system". The requirement for not using a WP is that "the work is done within applicable procedures and requirements", which was not the case since the specific procedure OM05.01.01 *Readying normally pressurised systems/equipment for activities which require isolation* did not cover this job. The sole associated procedure, see nonconformity 7.1.5, covered only testing of the ESDVs. No procedure ensured that blowdown to the flare was conducted in a safe manner.

It emerged clearly from the interviews that various interpretations prevail about which work operations require a WP prevail in the Heimdal organisation, in Statoil, and perhaps in the whole technical process community related to which jobs should be covered by the WP system and which do not need to be covered by such a permit.

AI provided us with this description: "Turning a wheel involves opening, operating the facility. This (the relevant job) is clearly an operation which requires a WP. Anything else is inconceivable". However, the OPS entity said: "This has been interpreted as an operational activity and requires no WP ... It's not work on a normally pressurised system, and there's nothing to turn on".

Differences in working method have been observed, including ones related to other operations. It emerged from interviews on land and offshore that differences always existed between the OPS and maintenance departments offshore. We were told that OPS does not normally use WPs, while maintenance always does. In the interviews, operators and management offshore stated that WPs were only used by OPS a few times per year. Nobody knew that earlier hydrocarbon leaks on Heimdal related mainly to OPS (see 7.1.6).

Statoil personnel in the maintenance department offshore confirmed that they virtually always issued a WP before work was initiated in the process plant. The explanation given to the investigation team was that OPS comprised process operators who worked on their "own" facility and therefore did not require a WP. Technical process expertise and local knowledge of the process plant were cited as justifications for not requiring WPs as a general rule. It was also stated that "opening and closing valves is what we do all the time, after all ...", "we obviously wouldn't have any time at all if we had to apply for WPs" and "... who's going to sign a WP, then? This is our plant, after all?".

Differences have been seen in AI's land organisation over the approach to planning and executing work offshore. The technical safety department seems to make thorough preparations using WPs. The department said it was necessary for this type of job "to think aloud and check tags, look at possible hazards and see what could go wrong. Must seek a WP supplemented by an A standard". Similarly, another person in AI commented that "... thought this type of job was covered by a WP. Believed that this was done. Preventive maintenance should lead to a WP. Don't know why a WP wasn't issued". By contrast, others in AI said it was unusual for operators in OPS offshore to seek a WP.

Work on normally pressurised systems is governed by the OM05.07.01.01 *Readying normally pressurised systems/equipment for activities which require isolation* procedure. This contains a detailed work process description, including requirements for using a valve and blind list as well as a written A standard. The problem with this procedure is that it is too narrow to embrace the relevant job. In the investigation team's view, the definition of what ranks as "work on normally pressurised systems" is too narrow to identify work-related risk in a plant. It is particularly the formulation "work on" which leads to different interpretations of jobs requiring a WP.

Statoil's GL 1112 *Personal HSE handbook in DPN* provides examples of work which **could** be excluded from the WP system: "Inspection which can carried out without physical intervention in the equipment". The investigation team considers that differing interpretations of this sentence, and other descriptions of WP requirements, could have influenced the causes of hydrocarbon leaks in a number of incidents over a decade on Heimdal, where it has generally been found that WPs were not in use.

The investigation team has noted that "Undefined" appears under the heading "Purpose" in OM05.01 *Work permits (WP)*.

During the interviews, the terms "operational activity" and "routine job" were used for work not covered by WPs. Testing ESDVs in a pipe system with a pressure of 129 bar, involving the opening of several valves and blowing down to the flare was not considered a critical job but was described as a "routine assignment". This meant that a WP was not considered for leak testing the ESDVs. As a result, no WP with associated risk assessments was carried out, with reference to this being normal practice for OPS offshore ("routine work").

When work to be done is identified as not requiring a WP, a number of risk-identifying planning elements are simultaneously dropped. In addition, differing interpretations also applied to the question of whether to implement a full A standard pattern of behaviour, and whether this should be documented in writing (see 7.1.5.). An overall assessment should have determined that a WP was required.

In the RNNP 2010 study of hydrocarbon leaks on the NCS, 37 investigation reports are categorised by the phase in which the leak occurred (start-up 22 per cent, shutdown 19 per cent, normal operation 40 per cent, maintenance/testing 14 per cent, modifications five per cent). A rough interpretation is that 60-90 per cent of these activities are conducted by ordinary OPS personnel operating their process equipment. When related to the description provided during the investigation – namely, that OPS personnel do not normally apply for a WP with associated planning and risk assessments – begs the question of whether this is a robust practice.

The investigation team has asked itself whether this can be related to the fact that a review of 10 investigation reports (2002-11) following hydrocarbon leaks on Heimdal shows that all these incidents can be related to "normal" operational activities (in the OPS department), and that operational work requiring a WP/SJA. The incident of 26 May 2012 follows this pattern. We also question this interpretation of the need for a WP in process organisations, not only in Statoil but also probably throughout the petroleum industry. It is conceivable that a change could influence major accident risk in a positive direction.

<u>Organisation and responsibility</u>
The investigation has shown that, with certain exceptions, managers on land and on the installation, specialists on land and operators offshore had little knowledge of or thoughts

about the major accident potential of the relevant leak or of hydrocarbon leaks in general (see nonconformities 7.1.6 and 7.1.7).

A certain degree of irritation was expressed by some interviews at detailed questions about planning activities related to the relevant job, and risk assessments which could have been implemented. A manager offshore, for example, stated “This is making a mountain out of a molehill. The incident was a gasket which failed”. A good way into the investigation process, somebody who works on Heimdal had the following formulation: “This was just a slip-up”.

Such statements during the investigation are a sign that the seriousness of this type of incident is not understood (see nonconformities 7.1.6 and 7.1.7).

Signs emerged from the interviews that the understanding of the individual’s responsibility and role in handling major accident risk was also deficient in the land organisation (AI). That applied to such aspects as procedures, P&IDs and their significance for equipping offshore personnel to operate process facilities in a safe way. The investigation has identified faults in design (see nonconformity 7.1.1) and the applicable P&ID (see nonconformity 7.1.4), and our attention was called during interviews with AI personnel to several errors in relevant P&IDs. They said that lack of correspondence between the process plant and P&IDs was not uncommon on Heimdal, but did not seem to regard this as a big problem. A review of the correspondence between P&IDs and process facilities on Heimdal was considered unrealistic because of the amount of work involved. No uniform understanding existed among those we interviewed of AI’s role in and responsibility for ensuring good-quality procedures and updated P&IDs.

The Heimdal installation has been operational for 28 years, with two-three different operators, and plans have twice been drawn up to shut it down. This was identified by a number of people, particularly offshore, as the reason that no adequate overview of the facility existed.

An organisational division has been established between AI, responsible for technical integrity on the installation, and the OPS department with responsibility for selecting methods to operate the process facilities, for instance. AI is the “owner of” and has responsibility for the process plant, but has no budget authority and must go via the production manager to get technical measures taken offshore. It emerged during interviews that OPS and AI do not always have the same priorities. Statoil’s investigation report identifies a big workload in AI. A combination of an aging installation with substantial maintenance challenges, the intention to apply for an extension of producing life to 2034, a lack of budget authority and a high workload accordingly constrain working conditions of AI personnel.

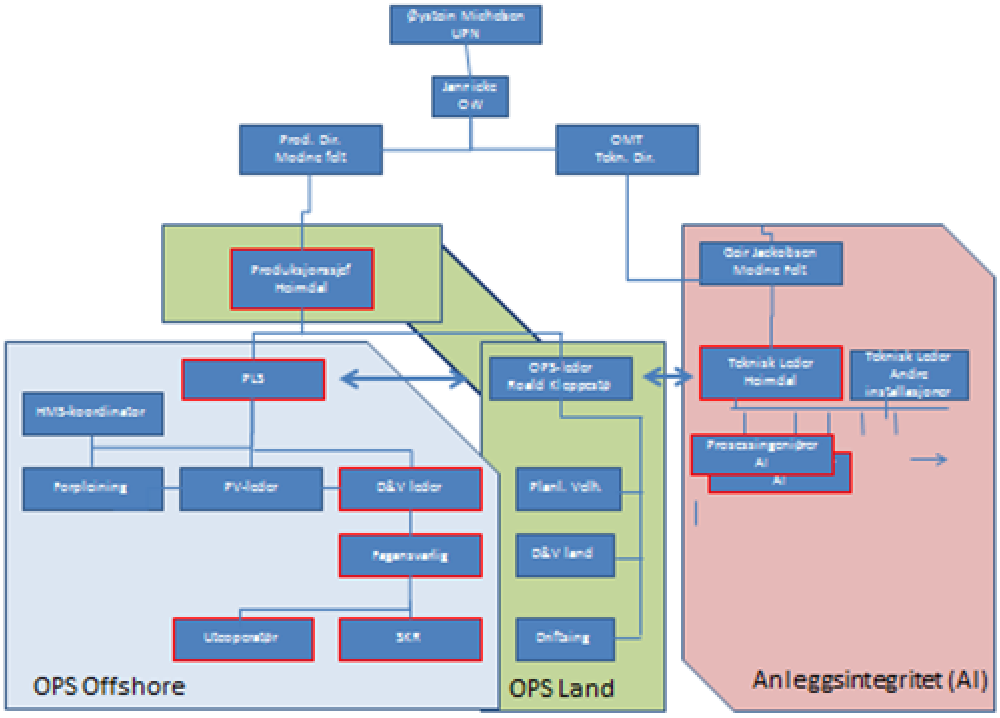

Figure 17: Outline in principle of the organisation, with the AI/OPS interface.

In addition, it is clear that AI also depends on information from the offshore organisation about deficiencies in the plant. According to our information, notifications represent the most important and perhaps the only contribution to verifying P&IDs against the plant. There are signs that the offshore organisation does not contribute sufficient information to AI on necessary changes.

<u>Overview of technical condition of process plants in operation</u>
Given a substantial number of aging installations on the NCS and a number of applications for extending producing life because of improved recovery, the investigation team considers it important that Statoil and other operators have an adequate overview of the technical condition of their process facilities (see nonconformity 7.1.2), which is extended to updated P&ID (see nonconformity 7.1.4). The question we nevertheless ask is whether appropriate analysis tools (see nonconformity 7.1.2), which inspires confidence that the companies have a correct picture of the technical condition of their process facilities, are adopted and whether this information is applied to assess whether the design makes it possible for human intervention in the plant to cause leaks.

Tools other than TTS, Timp and information from Synergi had not been considered for mapping the Heimdal process plant (see nonconformity 7.1.2), even though interviewees considered that these tools would not pick up design faults on the relevant pipeline or other unfortunate design faults on Heimdal.

The investigation has revealed deficiencies related to the use of experience data and information communication/organisational learning in the Heimdal organisation and perhaps in other parts of the Statoil organisation as well (see nonconformity 7.1.6). Management at various levels bear partial responsibility for communicating information, but where specific responsibility for this lies is unclear to the investigation team. However, it is not unreasonable to imagine that such information would have contributed to a different awareness of the safety significance of own work, such as obtaining updated procedures and P&IDs, ensuring the adoption of appropriate analysis tools for mapping the technical condition of Heimdal's process plant or ensuring appropriate risk assessment when planning jobs.

Statoil possesses, then, a number of tools for ensuring safe operation from planning (on land) to the executor level offshore. Experience data and their analysis form part of an operations and maintenance strategy for process facilities which provides the basis for plans, describes activities and include risks. In addition, Statoil has a number of tools available for mapping the technical condition of an installation's process plant and for detailed work planning: OTS, TTS, Timp and Hazop. In the operational phase, it has such tools as the A standard, WPs, SJA and pre-job discussions for identifying risks when planning work. Procedures with P&IDs are intended to provide information which contributes to correct and safe work execution.

The hydrocarbon leak on Heimdal of 26 May 2012 showed failures at a number of levels (barrier elements and performance-affecting conditions). See doc 63. It might appear that the responsibility for handling a technical system in a safe way nevertheless rests on the operator, the human player.

9 Assessment of Statoil's investigation report

Statoil's investigation report was submitted to the PSA on 23 October 2012. This provides a detailed review of the incident and the formulation of recommended measures. However, we observe that conditions we consider to be key reasons why the incident was allowed to develop – such as inadequate use of experience data, management involvement at a number of organisational levels, risk understanding and work planning – receive less attention in the Statoil report.

In assessing the incident's potential, Statoil considers that more than a marginal difference in circumstances would have been required for it to develop into a major accident. The PSA investigation team does not share this view. As a consequence of the Flacs analysis carried out by the company, Statoil has assessed "worst case" scenarios. However, the PSA considers their scope to be inadequate. Statoil also writes that personnel involved were not exposed to gas. We consider it likely that DOF1, who was involved in the incident, was exposed to gas.

Appendices

A: The following documents have been used in the investigation

1. POB list for the accident date
2. POB list at the present time
3. List of personnel involved (part of the kick-off presentation)
4. Organisation charts: OMC 01 *Organisation DPN* and OMC01 *Organisation mature fields*
5. Work orders
6. Overview drawings of the relevant area
7. Log entries relevant to the issue
8. All reports of undesirable incidents (RUH) in the area for the past year

9. All relevant procedures
10. Necessary extracts from governing documents covering relevant procedures
11. Overview of parallel operations in the area, copies of all work orders/safety declarations for the 24 hours leading up to the incident
12. Print-outs of qualifications, schedule and overtime for all personnel involved
13. Maintenance plan/history for equipment involved
14. All certificates for equipment involved
15. Maintenance history (covered under item 13)
16. P&ID for the three relevant valves tested
17. Photographs taken at the site (electronic only)
18. Alarm log – electronic on request
19. Pressure logs in pipeline, before and after
20. Process flow diagram
21. Risk assessments/WPs
22. Aris OMM 05.07.01.01 *Readying normally pressurised systems,* Aris OMM 05.07.01.02 *Resetting normally pressurised systems*
23. The A standard
24. Timp
25. TTS
26. GL 114 *Requirements for reliability*
27. Overview plan of the platform
28. Overview photographs/weather deck (see items 6 and 27)
29. Gas detectors: logs of alarms triggered in the affected areas
30. Investigation report, HMP 6 September 2002
31. Investigation report, HMP 6 October 2002
32. Notification form, HRP 19 April 2005
33. Investigation report, HRP 20 June 2005
34. Investigation report, HMP 16 July 2005
35. Investigation report, HMP 24 September 2005
36. Notification form, HRP 11 March 2006
37. Investigation report, HMP 22 August 2006
38. Notification form, HMP 25 December 2006
39. Investigation report, HMP 6 April 2007
40. Investigation report, HRP 18 April 2010
41. Investigation report, HMP 2 February 2011
42. Hydrocarbon leaks on HMP and HRP larger than 0.1 kg/s reported to the PSA (2002-11)
43. Dispersion calculations for leaks on Heimdal (draft submitted 31 August 2012)
44. Regulations for production and auxiliary systems on production installations, etc, for exploitation of petroleum resources in Norwegian internal waters, in Norwegian territorial waters and in the parts of the continental shelf which are under Norwegian sovereignty. Issued by the Norwegian Petroleum Directorate 3 April 1978 with later amendments, latest 1 July 1980, pursuant to Royal Decree of 9 July 1976, cf Delegation of Authority made by the Royal Norwegian Ministry of Industry and Handicraft 12 July 1976.
45. PDO for Heimdal, PL 036, 1998.
46. Impact assessment for modifications on Heimdal, 1998
47. Statoil investigation report COA INV, *Investigation of gas leak on Heimdal*, 16 September 2012
48. Statoil, *The Statoil Book*

49. Statoil FR06 *Operation and maintenance*
50. Statoil OMC01 – 004 – DPN operations *Organisation, management and control*, with supplements
51. Statoil work order no 22342028 ESDV gas export, 17 March 2012
52. Statoil gas hazard analysis, gas leak on Heimdal of 26 May 2012, 13 September 2012
53. Statoil OM05.01 *Work permits (WP)*, 18 May 2012
54. Statoil OM05.03 *Implementing safe job analysis*, 18 May 2012
55. Statoil OM02.01.06 *Carrying out maintenance*, 18 May 2012
56. Statoil OM01.05.05 *Operating systems and equipment in operation*, 18 May 2012
57. Investigation report, HMP, 23 July 2003
58. Statoil, Leak test of 2ESDV 20007 gas export to Statpipe, undated
59. Notification form, HMP, 27 April 2003
60. Trends in risk level in the petroleum activity (RNNP), main reports 2001-11
61. Notification form, HMP, 30 November 2005
62. Letter of 28 April 2011 from Øystein Michelsen, executive vice president DPN at Statoil to the PSA, Statoil ref AU-EPN OWE GF-00234
63. http://www.ptil.no/getfile.php/PDF/Prinsipper%20for%20barrierestyring%20i%20petroleumsvirksomheten.pdf *Principles for barrier management in the petroleum activity* (in Norwegian only)

B: Overview of people interviewed

(removed from the internet version)

C: Abbreviations

AI	Plant integrity department
A standard	New behavioural model in Statoil for compliance and continuous improvement of work processes
Apos	Work process-oriented management system
BDV	Blowdown valve
CCR	Central control room
CFD	Computational fluid dynamics
DAL	Dimensioning accidental load
DB&B	Double block and bleed
ESD	Emergency shutdown
ESDV	Emergency shutdown valve
Flacs	Flame acceleration simulator (CFD-type calculation programme)
HMP	Heimdal main platform
HRP	Heimdal riser platform (operated by Gassco)
HSE	Health, safety and the environment
HTO	Human/technical/organisational (model for incident and causal

analysis)

HCV	Main control valve
LEL	Lower explosion level (for concentrations of flammable gas)
LFL	Lower flammability level
MIS	Performance management in Statoil
NCS	Norwegian continental shelf
O&M	Operation and maintenance
OPS	Operations department
OTS	Operational safety condition, Statoil
P&ID	Called a process and instrument diagram in Statoil
PM	Preventive maintenance
POB	Personnel on board
PSV	Pressure safety valve
RNNP	Trends in risk level in the petroleum activity (annual PSA report)
SAP	Statoil's system for maintenance administration
TST	Technical safety condition, Hydro
TTS	Condition monitoring of technical safety, Statoil
UEL	Upper explosion level
WO	Work order
WP	Work permit (permission to execute a WO)