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REPORT:

BLOWOUT RISK EVALUATION
LABRADOR SEA SOUTH-WEST OF GREENLAND

Executive Summary

DCE, Danish Centre for Environment and Energy (former NERI) has been requested by Bureau of Minerals and Petroleum to prepare a strategic evaluation of the environmental risk for the Labrador Sea, South West of Greenland. A part of this work shall evaluate the probabilities and the consequences of a future spill of hydrocarbons to the environment from oil and gas exploration activity in the area.

In the work presented in this report, the possibilities for a future blowout and its consequences in form of potential blowout rates and duration is analysed and reported.

Potential blowout scenarios for the drilling operations includes both topside and subsea release points and combinations of different flow paths such as through the drill string, annulus or open hole for both oil and gas. An oil find case has been set as basis due to the higher environmental impact when oil is released to the sea compared to gas.

Expected blowout frequencies during exploration drilling have been found by addressing the statistics related to offshore blowouts from *The SINTEF Offshore Blowout Database* [1], from the annual *Scandpower report* [3] which analyses the SINTEF database more in detail and from a more novel methodology developed by DNV [7] which includes trend adjustments in the statistical data based on technological and operational improvements achieved during the last decades.

The blowout rates, i.e. blowout potentials, presented in this report have been found from detailed multiphase simulations carried out by Acona Flow Technology, and are based on information for hypothetic reservoir characteristics which are likely to be explored in the Labrador Sea.

This report also presents discussions of blowout occurrence factors believed relevant for the Labrador Sea, Greenland.

DNV [7] finds that technological and operational high standards increase the operational safety and significantly reduces the overall risk of experiencing an accidental oil spill during drilling operations.

When accounting for technological and operational improvements the overall probability for a future blowout in the Labrador Sea at water depths greater than 1000 meter is found to be one blowout for every 8488 exploration wells drilled.

Most likely expected flow rate of oil released to sea is found to be 519 Sm^3/day of oil.

The most likely duration of such blowout is found to be 14 days.

Disclaimer

The data forming the basis of this report has been collected through the joint effort of Acona Flow Technology AS, Acona AS and the authors.

Acona Flow Technology AS has gathered the data to our best knowledge, ability, and in good faith, from sources believed to be reliable and accurate. Acona Flow Technology AS and the authors have attempted to ensure the accuracy of the data, however, Acona Flow Technology AS make no representations or warranties as to the accuracy or completeness of the information reported. Acona Flow Technology AS and the authors assume no liability or responsibility for any errors or omissions in the information or for any loss or damage resulting from the use of any information contained within this report.

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Revision and Approval Form

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Abbreviations

AFT	Acona Flow Technology AS
AoC	Acknowledgement of Compliance
API	American Petroleum Institute
BARA	Bar Atmosphere
BHA	Bottomhole assembly
BHP	Bottomhole pressure
BMP	Bureau of Minerals and Petroleum
BOP	Blowout preventer
CFR	Code of Federal Regulations (United States)
CGR	Condensate-Gas ratio
CNOPB	Canada Newfoundland Offshore Petroleum Board
DCE	Danish Centre for Environment and Energy (former National Environmental Research Institute (NERI))
DHSV	Down Hole Safety Valve
DMU	Danmarks Miljøundersøgelser (now DCE)
DNV	Det Norske Veritas
DP	Drillpipe
ECD	Equivalent Circulating Density
GOR	Gas-Oil Ratio
HPHT	High Pressure High Temperature
ID	Inner Diameter
IPR	Inflow Performance Relationship
LPM	Litre per Minute
MD	Measured depth
MODU	Mobile Offshore Drilling Units
MSL	Mean sea level
N/G	Net/Gross
NEB	Canada's National Energy Board
OD	Outer Diameter
OH	Open hole
OIM	Offshore Installation Manager
OLF	Oljeindutriens LandsForening (Norway)
PWL	Planned Well Location
RKB	Rotary Kelly Bushing
sg.	Specific gravity
TD	Total Depth / Target Depth
TVD	True Vertical Depth
US GoM	United States Gulf of Mexico
WBM	Water Based Mud

1 INTRODUCTION

The objective for performing this study of hypothetical exploration well operations in the Labrador Sea, South-West of Greenland, is to provide a more realistic environmental risk exposure for possible accidental oil spill related to such an operation.

Estimation of blowout risk in the Labrador Sea is based on a detailed assessment of the blowouts and well control incidents recorded in the SINTEF Offshore Blowout Database [1] from **US Gulf of Mexico**, **Norway** and **UK** from the period 1980 until 01.01.2008. The annual *Scandpower report* [2] on blowout and well release frequencies provides the basis for blowout risk assessments, and the DNV report for "*Environmental Risk Assessment of Exploration Drilling in Nordland VI*" [7].

Further, this report is based on a detailed analysis of the SINTEF Offshore Blowout Database discussed above considering trends and frequency distributions.

A synthetic set of blowout scenarios have been selected related to the locations and prognosis for reservoir properties (pressure, temperature and fluid) likely to be explored in the Labrador Sea.

1.1 BACKGROUND

Danish National Centre for environment research has been requested to prepare a strategic evaluation of the environmental risk for the Labrador Sea, South West of Greenland. A part of this work shall evaluate the probability and the consequences of a spill of hydrocarbons to the environment from oil and gas exploration activity in the area.

The final document will be used as one, out of several, support documents for later political decision-making.

1.2 SCOPE OF WORK

DCE (Danish Centre for Environment and Energy is requested by *BMP* (*Bureau of Minerals and Petroleum)* to prepare a strategic evaluation for the South West Greenland, Labrador Sea. The direct cause of this request is the on-going evaluation to open up this area for oil and gas exploration.

Possible scenarios, and consequences, for future blowouts are one of the aspects to be analysed in this delivery. The following three problems are to be addressed:

1.) *What are the probabilities for a future blowout, or release of oil to sea, in the Labrador Sea given the regulatory, climatic and the possibilities for sea ice in the area which the area is exposed to?*

2.) *Will drilling in deep and ultra-deep waters in the Labrador Sea introduce higher risks of experiencing a blowout compared to drilling at moderate water depths? Will a possible blowout in deep and ultra-deep areas tend to give larger volumes of hydrocarbons to sea or longer duration of the blowout before it can be controlled compared to moderate water depths?*

3.) *Compared to other oil areas, which are under different regulatory and geological regimes, will the Labrador Sea experience higher or lower risks for a blowout, or release of hydrocarbons to sea?*

To answer these three problems, this report is divided into the following sections:

Section 3 – Methodology for establishing blowout probabilities and its most likely duration
In this section data from available sources are extracted, organised and analysed in order to find the overall probability for an accidental oil spill to the environment during drilling of exploration wells in the Labrador Sea. Data are derived from the latest Scandpower report [3], the SINTEF Offshore Blowout Database [1] and DNV [7].

Section 4 – Methodology for calculation of blowout potentials and scenario risking
In this section the methodology used when defining the hypothetical wells is presented. Six synthetic wells have been designed based on wells drilled on Canadian side of the Labrador Sea (input from client) and their respective potential is modelled and combined with pre-defined blowout scenarios. Statistical data for the blowout scenarios are implemented.

Section 5 – Presentation of results
In this section the results of blowout probabilities, blowout potentials and expected blowout durations are presented together with the scenario risking for each of the wells.

Section 6 – Local impact
In this section a discussion is made based on local factors as climate, sea, ice and governing legislations. The discussion also includes a comparison between other oil regions and the Labrador Sea.

2 DESCRIPTION OF THE AREA AND LOCAL ENVIRONMENT

2.1 LEGISLATIONS AND POLICY RECOMMENDATION

The following national legislation and guidelines apply to the Greenland offshore exploration drilling and is found relevant for this work as they might impact the operational risk directly during exploration drilling in the area. [1]

The following requirements shall be met during drilling in the area:

- To operate within the best international standards, including and primarily the Norwegian NORSOK standards, other North Sea standards as well as Arctic standards and regulations. These regulations are among the most stringent in the world.
- The presence of two drilling units, so that a relief well can be drilled immediately, if necessary.
- The most stringent requirements for the drilling units Blowout Preventer (BOP) systems shall be implemented.
- Personnel competence, qualifications, training and drills shall be to the highest standards. For the drilling personnel only the International Well Control Forum – IWCF - certification is accepted. IWCF has the most comprehensive competency requirements including initial training in compliance with the IWCF Syllabus, followed by assessment on a simulator and theoretical tests in well control equipment and principles and procedures.
- Emergency response plans for managing e.g. oil spills, drilling relief wells, and ice/iceberg management as well as for serious accidents must be in place

and approved.

- In addition to the company's emergency response plans, each drilling unit and all support vessels must have prepared their own emergency response plans, which are linked directly to the company plans.

- Moreover, drilling units are required to have an approved Acknowledgement of Compliance (AoC) from the Petroleum Safety Authority Norway or a Safety Case from the British Health and Safety Executive. This is also required by the Norwegian and British petroleum authorities for drilling units.

- Greenland authorities conduct an active supervision and inspection policy to ensure that activities are executed in compliance with requirements and standards. This includes inspection of each drilling unit at least once a month, as well as every time a well is spudded and in connection with all well abandonments/suspensions.

- Specific approval for each drilling campaign based on detailed drilling application.

2.2 Oceanography and Climate

The ocean currents around Greenland are part of the cyclonic sub-polar gyre circulation of the North Atlantic and the Arctic region. The bottom topography plays an important role for guiding the circulation and for the distributing the water masses around South Greenland and the Labrador Basin. As the East Greenland Current rounds Cape Farewell it continues northward in the West Greenland current on top of the West Greenland shelf. At about 64°N major parts of the West Greenland Current turns west and join the Labrador Current while the other part crosses the Davis Strait into the Baffin Bay.

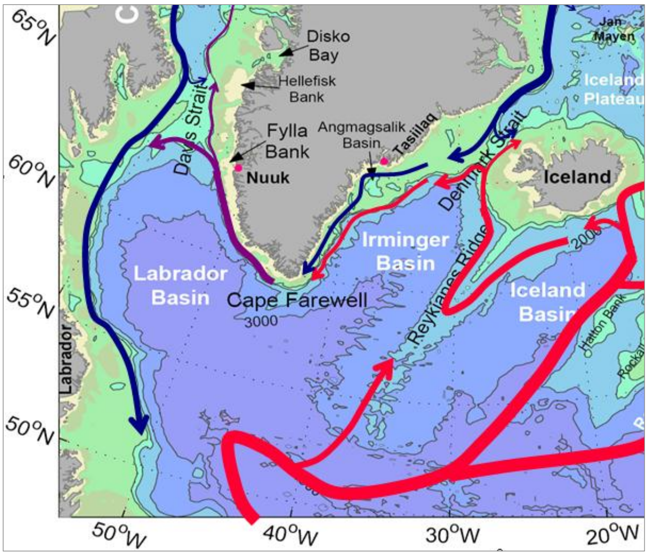


Figure 1: Surface currents. The North Atlantic Current is shown in red. The East Greenland Current (dark blue) rounds Cape Farewell and continues northward in the West Greenland Current (shown in purple). As the West Greenland Current reaches the latitude of Fylla Bank it branches. The main component turns westward and joins the Labrador Current on the Canadian side, while the other component continues northward through Davis Strait.

The weather systems affecting the Labrador Sea and South Greenland waters usually originate from the southwest. Two-thirds of all cyclones approaching South Greenland across the Labrador Sea arrive from directions between west and south-southeast while most of the cyclones affecting West Greenland arrive from directions between south and west. Cyclones approaching Southern Greenland from southwest or south usually split in the vicinity of Cape Farewell with one part moving northward along the west coast, causing very changeable weather in the eastern part of Labrador Sea, while the other moves off towards Iceland. Southern Greenland, in particular, is influenced by severe weather connected to the North Atlantic winter cyclones. Polar lows may occasionally develop rapidly in very cold air masses over open sea in the winter season. The diameter of a polar low is generally 200-300 km. The system will be accompanied by heavy snow showers and surface winds exceeding gale force. Fog is common offshore in the summer season and develops typically in areas with calm winds and moist air over ice or open sea.

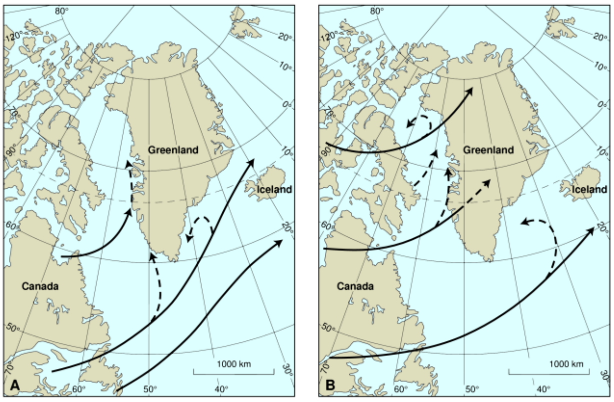
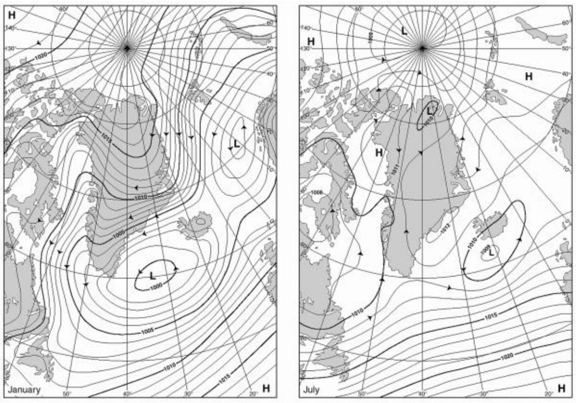


Figure 2: Typical tracks for major cyclones in winter (A) and summer (B).



Error! Reference source not found. Monthly average of Sea Level Air Pressure for anuary (left) and July (right) indicating the intensity and frequency on lows peak in the winter time. Lack of horizontal temperature gradients through the summer season reduces the significance of the weather systems.

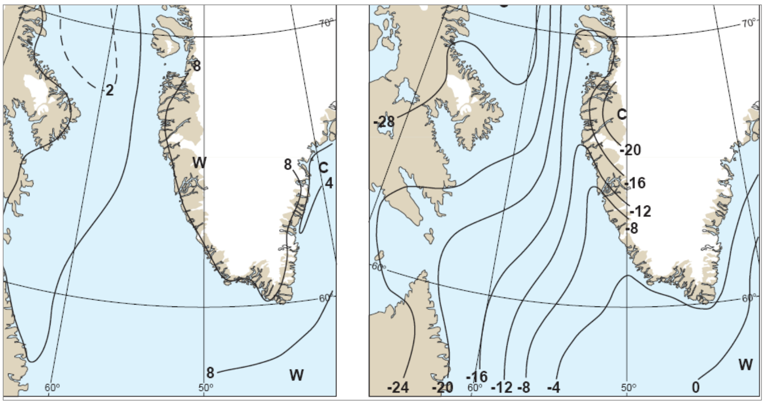


Figure 3: Mean air temperatures for August (left) and February (right) and for South-West Greenland and Labrador Sea. A strong temperature gradient is common across the Labrador Sea.

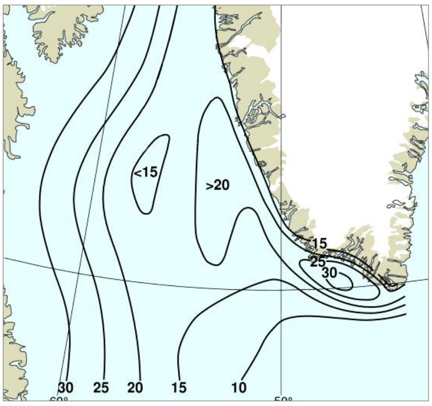


Figure 4: Geographical distribution of fog in the Labrador Sea in percentage in July.

During summer sea surface temperatures in the Labrador Sea varies less than in winter where a strong east-west temperature gradient is common towards Canada.

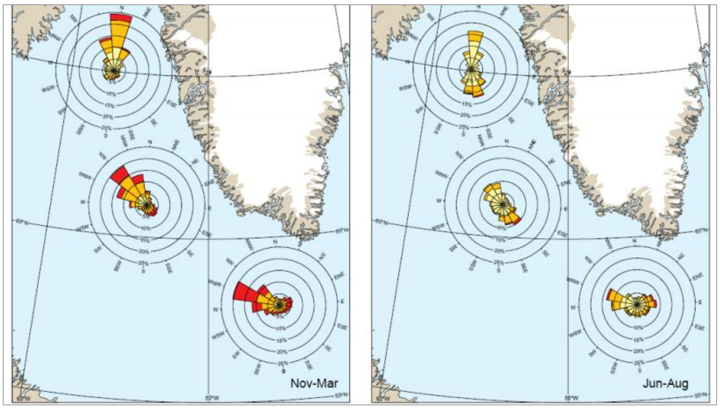


Figure 5: General wind conditions in the East Labrador Sea and Cape Farewell area. Source: ECMWF data.

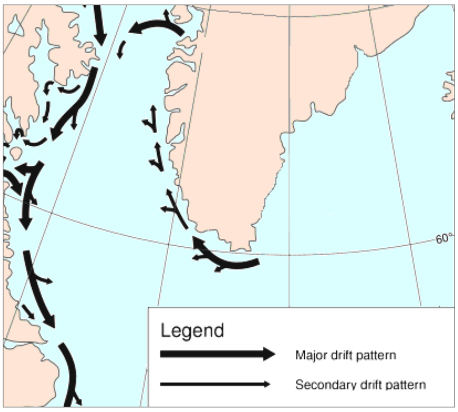


Figure 6: Iceberg drift pattern off South West Greenland and along the coast of Canada.

2.2.1 ICE CONDITIONS

Sea Ice

There are two ice regimes affecting the Labrador Sea. The ice regime along the east coast of Greenland locally termed 'Storis' and the West Ice which dominate the Baffin Bay, Davis Strait and western part of the Labrador Sea.

Table 2-1: Sea ice thickness or stage of development as defined by World Meteorological Organization.

Sea Ice Terminology	
New Ice	(0-10 cm)
Young Ice	(10-30 cm)
First Year Ice	(30-200 cm)
Thin First Year Ice	(30-70 cm)
Medium First Year Ice	(70-120 cm)
Thick First Year Ice	(120-200 cm)
Multi-Year Ice	(>2 m)

The West Ice is a so called marginal ice zone with a maximum sea ice extent in March when the entire Baffin Bay and most of the Davis Strait is covered by sea ice. The sea ice starts to form in the open water near Baffin Island in September and increases steadily from north to south and west to east. Due to the warm West Greenland Current and the east-west temperature gradient, the ice is generally thicker in the western part of the basin and due to the southward Labrador Current extends further south near the Canadian coast. Late in the season ice floes originating from further north in the Baffin Bay reach stages of medium and thick first year ice by the time they reach the Labrador Sea. Only on rare occasions does the West Ice encroach the Labrador Sea and Greenland waters east of 55° W.

The East Greenland Current transports large quantities of multi-year sea ice and icebergs southwards along the East Greenland coast towards Cape Farewell. When the ice has reached Cape Farewell at the tip of Greenland, it continues west and northwards along the west coast where it melts in the warmer northbound West Greenland Current.

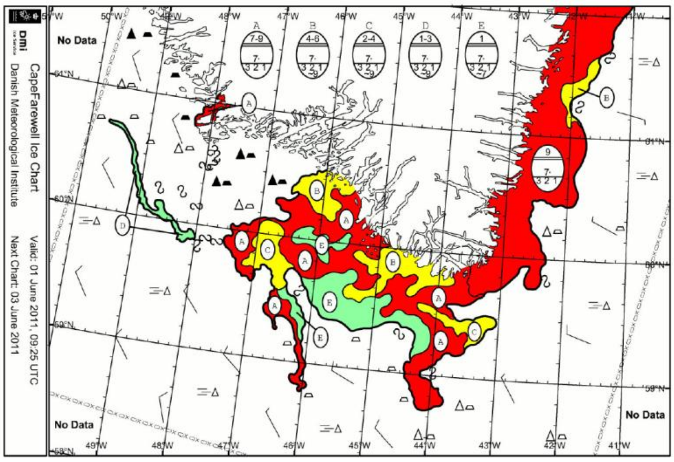


Figure 7: South Greenland Ice Chart. The East Greenland Current transports icebergs and sea ice from the Polar Sea and Greenland coast down around the southern tip of Greenland. Icebergs are common all year whereas the region is normally free of sea ice through August-December.

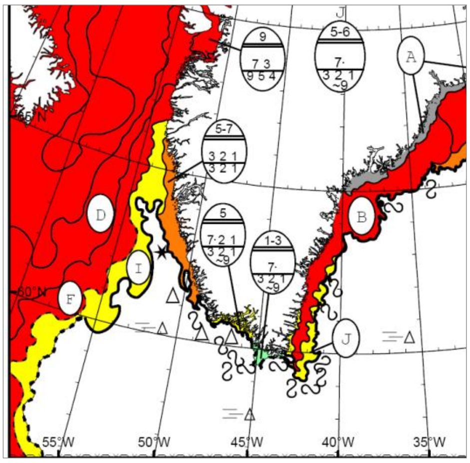


Figure 8: Ice Chart from 9 March 2008 showing the Storis along the and South and East Greenland coast and the West Ice in the Davis Strait and western part of the Labrador Sea

Normally the Storis reaches its maximum distribution in Northeastern Labrador Sea in May or June and melts away in late summer, and it normally takes four to five months for the ice masses formed in the Arctic Ocean north of Greenland to travel all the way southwards along the east coast of Greenland. Under normal conditions the multi-year ice drift to the Cape Farewell area in December-January, is partly depending on the intensity and tracks of low pressure systems in the North Atlantic Ocean. Due to long periods with strong north-westerly winds, as a result of cold air out breaks from northern Canada during the winter, the Storis only passes Cape Farewell for shorter periods. The intensity of the lows normally decreases in spring and summer, and multi-year ice can drift north-westwards along the Southwest Greenland coast in the West Greenland Current. The width, concentration and position of this ice belt vary greatly with the wind, and from year to year. In the most severe seasons the ice reaches the Greenland capital Nuuk but normally the northernmost extent of the multi-year ice on the west coast is in the vicinity of Frederikshåb around 62˚N. The sizes of the ice floes are in general less than 100 m and typically in the 5 to 20 meter range. When multi-year ice occur off Southwest Greenland it is normally characterized by low or medium concentrations over large areas, however, long narrow belts of high sea ice concentrations are common. Infrequent icebergs may occur through the open water season off Southwest Greenland.

2.2.2 ICEBERGS

Icebergs are common near the Greenland and Canadian coasts. In Southwest Greenland there are only minor glacial outlets producing small icebergs, bergy bits and growlers which rarely survive longer than a few days in open sea. Thousands of large icebergs are calved every year from several glacier outlets on the east coast of Greenland but many bergs deteriorate before reaching the Northeastern Labrador Sea. When the icebergs reach open sea they drift southwards in the East Greenland Current and depending on the time of year icebergs are embedded in sea ice. Many icebergs drift off the sea ice edge and melt quickly due to a higher water temperature and wave action. Within the sea ice edge in the cold East Greenland Current, the deterioration of the icebergs is limited. Large variations in the number and size of icebergs rounding Cape Farewell are to be expected due to the variability of the currents, the amounts of sea ice and weather conditions. An important factor controlling the iceberg environment off Southwest Greenland is the input of icebergs to the East Greenland Current at high latitudes. The drift patterns of icebergs are highly complex as winds, deep currents, ocean eddies, iceberg types and bathymetry are important parameters controlling iceberg movements in the open sea. The maximum number of icebergs in the Northeastern Labrador Sea is typically observed in spring and summer. The iceberg minimum is normally during fall and early winter and typically very few off the Greenland coast.

2.2.3 DEEP WATER

Shallow subsea blowouts are mostly characterized by flow of gas that is released from the oil. The high velocity of the gas is driven by the expansion of the liquid natural gas (at reservoir pressure) as it flows upwards and the pressure falls to the ambient pressure at the release point. This situation will also exist in a deep well blowout since the hydrostatic seawater pressure is lower than the pressure necessary to maintain the natural gas in liquid at the reservoir temperature. However, the higher exit pressures associated with deep well blowouts will result in denser and lower volume of gas exiting compared to releases in the shallow water.

Drilling rigs must be designed and built to specifications that enable them to drill in deep water. There are a limited number of these available around the world. The operators must identify available deep water rigs that can be accessed by the company in case of a blowout. Because of the depth of water, it takes longer time to drill a relief well, so there is likely to be more hydrocarbons entering the water.

BMP require two drilling units (2 rig policy). Rigs and vessels must comply with required specifications, and have experience from harsh environment, including exploration drilling and deep water drilling. Each drilling unit is required to have an approved Acknowledgement of Compliance (AoC) from the Petroleum Safety Authority Norway or a Safety Case from the British Health and Safety Executive. This is also required by the Norwegian and British petroleum authorities for drilling units. The operators must identify available deep water rigs that can be accessed by company in case of blowout event i.e. a second rig shall be present in the area while drilling.

Critical equipment that could be required offshore must be available for mobilization within minutes to hours.

2.3 DRILLING IN GENERAL

Exploration drilling rigs use diesel engines to generate power to turn the drill bit, which cuts through the surface and the rock beneath with the help of hydraulic nozzles that use drill fluids (drill mud) pumped down from the surface. As the well bore is extended, the hole is periodically cased with metal pipe (known as casings) inserted into the borehole and cemented into place.

Drilling fluids, known as drilling mud, are pumped down the centre of the drill string, which refers to sections of pipe that are added as the bit descends. The drilling fluid, which lubricates the drill string, removes the cuttings and holds back formation pressure, returns to the surface in the annular space between the drill string and the casing or borehole for cleaning and reuse. The hydrostatic pressure of the drilling mud is the first barrier to prevent any oil or gas in the formation from intruding into the well.

Drilling engineers design drilling mud systems with sufficient density to control the subsurface pressure expected for the oil reservoir, but it is not always possible to predict the exact magnitude of the subsurface pressure, especially when drilling an exploration well in a previously unexplored area.

If the subsurface pressure exceeds the pressure imposed by the column of drilling mud in the well bore, the reservoir formation fluids (e.g., oil and gas) will flow into the well bore in what is known as a kick. A kick can eventually flow to the surface, potentially causing a blowout (an uncontrolled flow of oil and gas from the well). To prevent a kick from becoming a blowout, drilling rigs are equipped with heavy-duty valve assemblies called blowout preventers (BOPs) attached to metal casings cemented into the well bore. Properly designed blowout prevention systems should control excess pressure at the wellhead, but under-designed or malfunctioning systems may fail to contain the excess pressure, resulting in a release of drilling mud and hydrocarbons.

Exploration, or production, in the South-West Labrador Sea, must still overcome a number of obstacles. Due to limited offset data from other wells and limited exploration wells having been drilled in Greenlandic territory, a small diameter pilot hole shall be drilled in accordance with NORSOK Standard D-010 on each new well location prior to commencing the actual drilling program. The depth of the pilot hole may vary from location to location, but shall determine non presence/hazards of shallow gas, and establish safe foundation and setting depths for the surface casings.

The drilling program shall be prepared and documented in accordance with the NORSOK Standard D-010, Well Integrity in Drilling and Well Operations.

The Greenland Bureau of Minerals and Petroleum (BMP) have developed a Guideline for drilling activities offshore Greenland. The operator shall present the application to drill with a dual drilling rig vessel presence. This means that there should be at least one drilling unit available to drill a relief well in the same area as the ordinary wells are drilled in. The drilling unit with the smallest capacity will set the boundaries of the drilling program activities.

3 ASSESSMENT OF BLOWOUT STATISTICS

This section discusses the blowout probabilities, their flow path distributions and their duration estimates in general, for a possible future blowout in the Labrador Sea, south west of Greenland.

Blowout frequencies and duration distributions for potential blowouts are discussed based upon the following data and literature sources:

- SINTEF Offshore Blowout Database 2010 [1]. The database includes information about 584 offshore blowouts and well releases that have occurred world-wide since 1955.
- Latest revision of the Blowout and Well release frequencies [2] from Scandpower. The statistical analysis is based on blowout data from the North Sea (British, Dutch and Norwegian sectors) and US Gulf of Mexico Outer Continental Shelf over a period of 20 years from 01.01.1989 until 12.31.2008.
- Environmental Risk Assessment of Exploration Drilling in Nordland VI. DNV Report No. 2010-0613, 20th of April 2010 [7].

3.1 Blowouts in general

For offshore operations blowouts can be classified in three groups:

- Surface blowouts
- Subsurface blowouts
- Underground blowouts

Surface blowouts are characterized by flow of fluid from a permeable formation to the rig floor, where atmospheric conditions exist. For subsurface blowouts (underground flow) the flow typically exits the well at the mud-line (seabed), where the exit conditions are controlled by the seawater gradient. Surface blowouts have been given the most attention, as they are usually associated with large-scale fires. For subsurface blowouts, the plume of the reservoir fluid may cause reduction of buoyancy to the point where a floating rig would become unstable or even sink. The likelihood of such scenario depends on the water depth, the flowing rate, and the amount of gas dissolved from the formation fluid.

Author's comment: *Loss of buoyancy and subsequent sinking of vessels have been heavily discussed throughout naval and academic history without any clear conclusion. Such scenario should therefore be looked upon as hypothetical only.*

In deeper water a plume of oil could be dispersed horizontally before reaching the surface or could be carried with the ocean currents to a location away from the rig.

The NORSOK Standard D-010 requires that two, and independent, barriers shall be present during all drilling and well operations. The drilling fluid that balances the pressure in the well will typically represent the primary barrier, while the casing and cement with associated equipment (including floats, packers, seal assemblies, wellhead, ring gaskets etc.) and the blowout-preventer (BOP) typically represents the secondary barrier.

In order to make a blowout possible, i.e. to experience total loss of well control, both the primary barrier and the secondary barrier have failed.

3.2 Well control

The Figure 9 below shows a typical well control scenario, where an escalation of a lost well control situation occurs before developing into a blowout situation. During the time of escalation, an experienced and properly trained drilling team offshore with support from the onshore team can circulate out all well influxes through the well control systems in a controlled manner, and thus avoid a blowout. A blowout will not occur unless a major human failure is made and/or the well barriers suffer from a major mechanical failure.

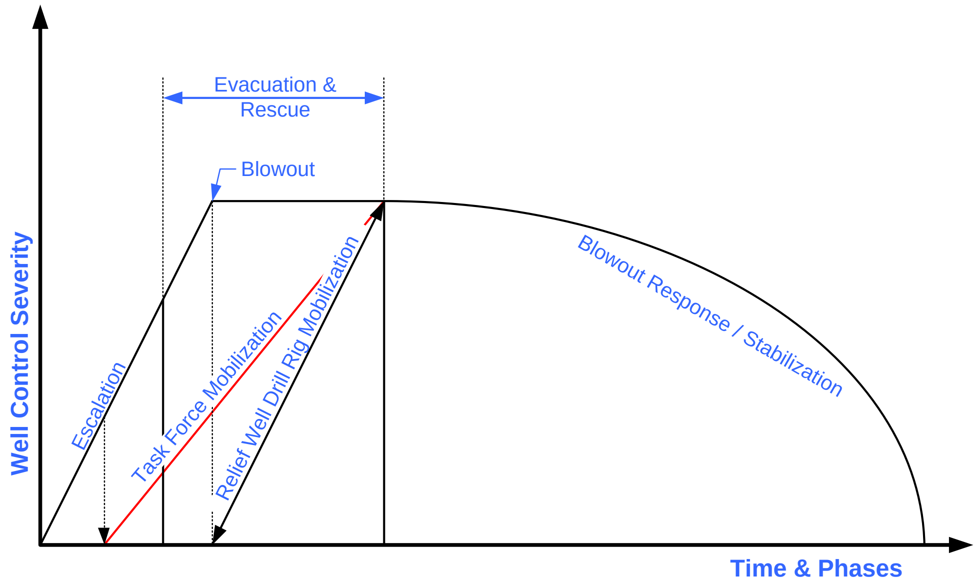


Figure 9: Illustration of different stages of a blowout situation

As Figure 9 illustrate, mobilizing of the task force and preliminary survey for possible rigs to drill a relief well might start shortly after the well control event is unveiled. As most well control incidents are controllable with existing barriers and procedures no further escalation normally are experienced, only a very small number of incidents develops into a release of well fluids and more seriously into a blowout that has to be controlled by external measures.

3.3 Blowout probability

There are a number of ways to estimate the probability/frequency for a blowout related to the well and drilling operations:

- Adjusting historical data for well control incident form historical blowout database.
- Develop scenario-based reliability models for specific situations.

The blowout frequencies presented in this report are extracted from the latest revision of the Scandpower report [3] and are presented in Table 1 and Table 3-2 below.

The basis blowout probability is determined from blowouts in the **North Sea**. (I.e. British, Dutch and Norwegian sectors)

In this report, the following well classifications are used:

- An **exploration well** is drilling for new reserves and includes both wildcat and appraisal wells.
- A **wildcat well** is the first well drilled on a new, clearly defined geological structure. By definition little, if anything, is known about the subsurface geology, especially the pressure regime.
- An **appraisal well** is a well which is drilled to determine the extent and size of a discovery.
- A **development well** is a generic term for wells which are used to produce oil and gas from a field. It covers production wells, injection wells and observation wells.

Table 3-1: Recommended blowout frequencies per drilled well.

Drilling operation	Well category	Frequency, average well	Frequency, gas well	Frequency, oil well
Exploration	Normal	1.12E-04	1.02E-04	1.23E-04
	HPHT	6.92E-04	6.32E-04	7.65E-04
Wildcat	Normal	1.06E-04	9.70E-05	1.17E-04
	HPHT	6.58E-04	6.01E-04	7.28E-04
Appraisal	Normal	1.17E-04	1.07E-04	1.30E-04
	HPHT	7.28E-04	6.65E-04	8.05E-04
Development	Normal	2.37E-05	2.16E-05	2.62E-05
	HPHT	1.47E-04	1.34E-04	1.62E-04

Table 3-2: Inverse value of blowout frequencies, i.e. number of wells drilled per blowout

Drilling operation	Well category	Number of wells drilled per blowout of average well	Number of wells drilled per blowout of gas well	Number of wells drilled per blowout oil well
Exploration	Normal	8 929	9 804	8 130
	HPHT	1 445	1 582	1 307
Wildcat	Normal	9 434	10 309	8 547
	HPHT	1 520	1 664	1 374
Appraisal	Normal	8 547	9 346	7 692
	HPHT	1 374	1 504	1 242
Development	Normal	42 194	46 296	38 168
	HPHT	6 803	7 463	6 173

More detailed descriptions of the findings from Table 1 and Table 3-2 are presented in section 3.3.1 to 3.3.4 below.

3.3.1 Blowout probabilities in Exploration wells

For an exploration well with normal pressure and temperature, the blowout frequency is found to be 1.12E-04 per drilled well in average. i.e. one blowout for every 8929 drilled well.

For an exploration well with normal pressure and temperature drilled as a wildcat well, the blowout frequency is found to be 1.06E-04 per drilled well in average. i.e. one blowout for every 9434 drilled well.

For exploration drilling of a normal gas well, the blowout frequency is 1.02E-04 per drilled well, i.e. one blowout per 9804 drilled wells in mature areas. For exploration drilling of a normal oil well, the blowout frequency is 1.23E-04 per drilled well, i.e. one blowout for every 8130 drilled wells.

3.3.2 Blowout probabilities for Wildcat wells

For an exploration well with normal pressure and temperature drilled as a wildcat well, the blowout frequency is found to be 1.06E-04 per drilled well in average. i.e. one blowout for every 9434 drilled well.

For wildcat scenarios, drilling of exploration gas wells experience a blowout frequency of 9.70E-05 per drilled well, i.e. one blowout per 10309 drilled wells. For exploration drilling of a wildcat oil well, the blowout frequency is 1.17E-04 per drilled well, i.e. one blowout for every 8547 drilled wells.

The small differences found between wells drilled in known, and mature, areas compared to new and unexplored areas are believed to be caused by the higher find-rate in mature areas.

Drilling of HPHT wells, i.e. wells with pressure higher than 690 bar and/or temperatures higher than 150 °C, is believed to experience a significant higher risk for a blowout. Since no new risk assessment are available for HPHT wells, the theoretical value from 1998, still being used in the Scandpower report where HPHT wells have a blowout frequency 6.2 times higher than normal wells.

In average one blowout per 1445 wells drilled for HPHT wells in mature areas, and one blowout per 1520 wells drilled in wildcat scenarios.

3.3.3 Blowout probabilities in Appraisal wells

For an appraisal well with normal pressure and temperature, the blowout frequency is found to be 1.17E-04 per drilled well in average, i.e. one blowout for every 8547 drilled well. For appraisal drilling of a normal gas well, the blowout frequency is 1.07E-04 per drilled well, i.e. one blowout per 9346 drilled wells. For appraisal drilling of a normal oil well, the blowout frequency is 1.30-04 per drilled well, i.e. one blowout for every 7692 drilled wells.

Again, drilling of HPHT wells typically have a blowout frequency 6.2 times higher than normal wells. In average one blowout per 1374 appraisal wells drilled for HPHT regimes.

3.3.4 BLOWOUT PROBABILITIES IN DEVELOPMENT WELLS

Drilling of development wells has significant lower risk for experiencing a blowout due to extensive knowledge of the area from nearby wells. At normal pressures, the average blowout frequency is 2.37E-05 per drilled well, i.e. one blowout per 42194 drilled wells. For gas wells the blowout frequency is 2.16E-05 per drilled well, i.e. one blowout for every 46296 drilled wells. For development drilling of oil wells, the blowout frequency is 2.62E-05 per drilled well, i.e. one blowout for every 38168 drilled wells.

Yet again, drilling of HPHT wells typically have a blowout frequency 6.2 times higher than normal wells. In average one blowout per 6803 development wells drilled for HPHT regimes.

3.4 BLOWOUT PROBABILITIES AS FUNCTION OF WATER DEPTHS

The majority of deep water drilling has been carried out by semisubmersibles, but some wells have been drilled with drill ships. In the Arctic area it is most likely to use drilling ships (Floaters).

Deep water (> 1000 m)

With respect to deep water drilling, the SINTEF Offshore Blowout Database characterises blowouts and well releases data and exposure data with respect to water depths for the North Sea (British and Norwegian sectors) and the US Gulf of Mexico Outer Continental Shelf in the period from 01.01.1980 until 31.12.2008. Assuming deep water in this context to be water depths in excess of 1000 m, 3 blowouts and well releases occurred in deep waters out of a total of 55 incidents occurring at all water depths. The number of wells drilled at deep waters is 1523 out of a total of 42722 exploration and development wells drilled at all water depths.

This indicates that there for normal wells should be an adjustment factor of 1.53 in the blowout frequency for deep water drilling.

Ultra deep water(> 2500 m)

Assuming ultra-deep water is water depths in excess of 2500 m, only 3 exploration wells and 6 development wells are reported to have been drilled since 2003. No blowouts and well releases are reported drilling at ultra-deep waters. The fraction of HPHT wells is likely to increase with ultra-deep drilling.

4 BLOWOUT POTENTIALS

4.1 METHOD FOR CALCULATION OF BLOWOUT POTENTIALS

In this section the methodology for calculation of blowout potentials are presented, and implemented on the hypothetical wells defined.

The objective in this study is to describe the potential outcome of future blowouts in yet unplanned wells in the Labrador Sea. Hypothetical (pseudo) wells are defined and modelled.

These wells are selected based on reference exploration drilling results from the Canadian side of the Labrador Shelf.

Multiple calculations and simulations are performed on these wells in order to model each scenario as correct as possible, while statistical data are implemented in the results from the simulations. By doing so, the statistical sample space can be presented and the statistical most likely values can be predicted.

A distribution between all investigated scenarios and associated expected durations are calculated based on the "*OLF Guidelines for estimation of blowout potentials*" [6].

Simplifications can be applied, but should only be used in order to present data in a more conservative matter, illustrated Figure 10 below.

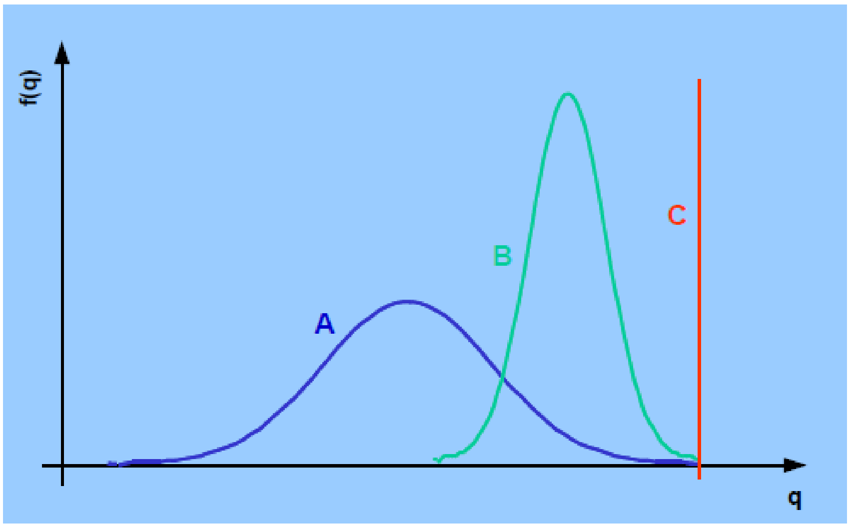


Figure 10: Expectation curves for volume/frequencies and possible simplification strategies. X-axis is the blowout rate and the y-axis is the blowout frequency

In the Figure 10, above, the blue curve A represents a rigorous study with extensive parametric analysis, graph B and C, represents simplifications, though in a conservative matter. All scenarios; A, B and C are acceptable, where A is most work intensive, and alternative C is least work intensive and most conservative.

4.2 RESERVOIR PROPERTIES

In order to span the range of possible scenarios for the risk procedure performed in this study, the following cases have been evaluated:

1. Oil find in reservoir
2. Gas-condensate find in reservoir

All scenarios are evaluated for both surface and seabed release point of blowout.

Table 4-1, Table 4-2 and Table 4-3 on the next page show the reservoir properties used in the simulations for the well presented in this report.

Table 4-1: Reservoir data for the hypothetical wells

Description		Well 01	Well 02	Well 03	Well 04	Well 05	Well 06
Reservoir top	m TVD RKB	1938	2491	3112	2163	3500	4000
Temperature @ res top	°C	55	65	87	58,7	105	120
Pressure @ res	bara	240	282	380	264	470	550
Permeability	mD	100	100	0,65	100	10	20
Zone interval, gross	m	75	325	325	110	75	150
Net to Gross ratio [1)]	-	0.147	0.07	0.07	0.77	0.15	0.2
Net pay, h	m	11	24	24	85	11	30
Porosity	fraction	0.11	0.18	0.11	0.20	0.10	0.11
RKB to MSL	m	25	25	25	25	25	25
Seabed	m	550	141	144	140	1500	1500

1) Net to gross ratio: proportion of the Gross Reservoir interval that contributes to production with the given properties (range is 0 to 1)

Table 4-2: Hypothetic reservoir fluid data for oil the hypothetical wells

Well ID:	Well 01	Well 02	Well 03	Well 04	Well 05	Well 06
Density *[kg/Sm^3]*	890	845	845	845	845	845
GOR *[Sm^3/Sm^3]*	60	125	125	125	300	300

Table 4-3: Hypothetic reservoir fluid data for gas-condensate the hypothetical wells

Well ID:	Well 01	Well 02	Well 03	Well 04	Well 05	Well 06
Density *[kg/Sm^3]*	738	738	738	738	738	738
GOR *[Sm^3/Sm^3]*	8200	8200	8200	8200	8200	8200

All fluid information refers to standard conditions, i.e. 15˚C / 1.01325 bara.

4.3 Well design

For this project, six reference wells have been defined based on exploration drilling results from the Canadian side of the Labrador Shelf. In order to simulate the possible blowout potentials for these wells the following assumptions have been made:

- All six reference wells are assumed to be vertical exploration wells
- For those of the wells being shallower than 3000 m, a 13 ⅜" casing has been assumed followed by 8.5"openhole section. The casing shoe is set at a depth equal to 50% of the soil/overburden thickness
- For those of the wells being deeper than 3000 m, a 9 ⅝" casing has been assumed followed by 8.5" open hole section. The casing shoe is set at a depth equal to 50% of the soil/overburden beyond 3000 m and top reservoir

The alternative with a 12 ¼" hole drilled from the 13 ⅜" casing shoe to TD is excluded as this option might cause extreme challenges with respect to a later well kill operation as very pumping rate and mud volumes must be expected.

In the aftermath of the Montara blowout in Australia in 2009 the Norwegian PSA has ruled out exploration drilling with such slim well design.

This has given the following six reference wells subject to blowout simulations:

4.3.1 Well 01 – Hopedale E-33 Analogue

Well 01 has been modelled for the following design:

- 13 ⅜" casing set @ 1275.1 m MD/TVD RKB
- Top of reservoir is estimated @ 1950.2 m MD/TVD RKB
- An 8.5" section will be drilled from the 13 ⅜" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone
- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.2 Well 02 – Snorri J-90 Analogue

Well 02 has been modelled for the following design:

- 13 ⅜" casing set @ 1353.5 m MD/TVD RKB
- Top of reservoir is estimated @ 2516 m MD/TVD RKB
- An 8.5" section will be drilled from the 13 ⅜" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone
- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.3 Well 03 – North Leif I-05 Analogue

Well 03 has been modelled for the following design:

- 9 ⅝" casing set @ 3062.5 m MD/TVD RKB
- Top of reservoir is estimated @ 3125 m MD/TVD RKB
- An 8.5" section will be drilled from the 9 ⅝" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone
- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.4 Well 04 – Bjarni H-81 Analogue

Well 04 has been modelled for the following design:

- 13 ⅜" casing set @ 1182.5 m MD/TVD RKB
- Top of reservoir is estimated @ 2175 m MD/TVD RKB
- An 8.5" section will be drilled from the 13 ⅜" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone
- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.5 Well 05

Well 05 has been modelled for the following design:

- 9 ⅝" casing set @ 3262.5 m MD/TVD RKB
- Top of reservoir is set @ 3525 m MD/TVD RKB
- An 8.5" section will be drilled from the 9 ⅝" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone

- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.6 WELL 06

Well 06 has been modelled for the following design:

- 9 ⅝" casing set @ 3512.5 m MD/TVD RKB
- Top of reservoir is set @ 4025 m MD/TVD RKB
- An 8.5" section will be drilled from the 9 ⅝" casing shoe through the potential hydrocarbon carrier formation to a total depth well below the gross zone
- OD for the drillpipe used when calculating the blowout rates are 5.5" when drilling the 8.5" section.

4.3.7 WELL SCHEMATICS

The schematics for the different reference wells are in Figure 11 on the next page. The wells are described above.

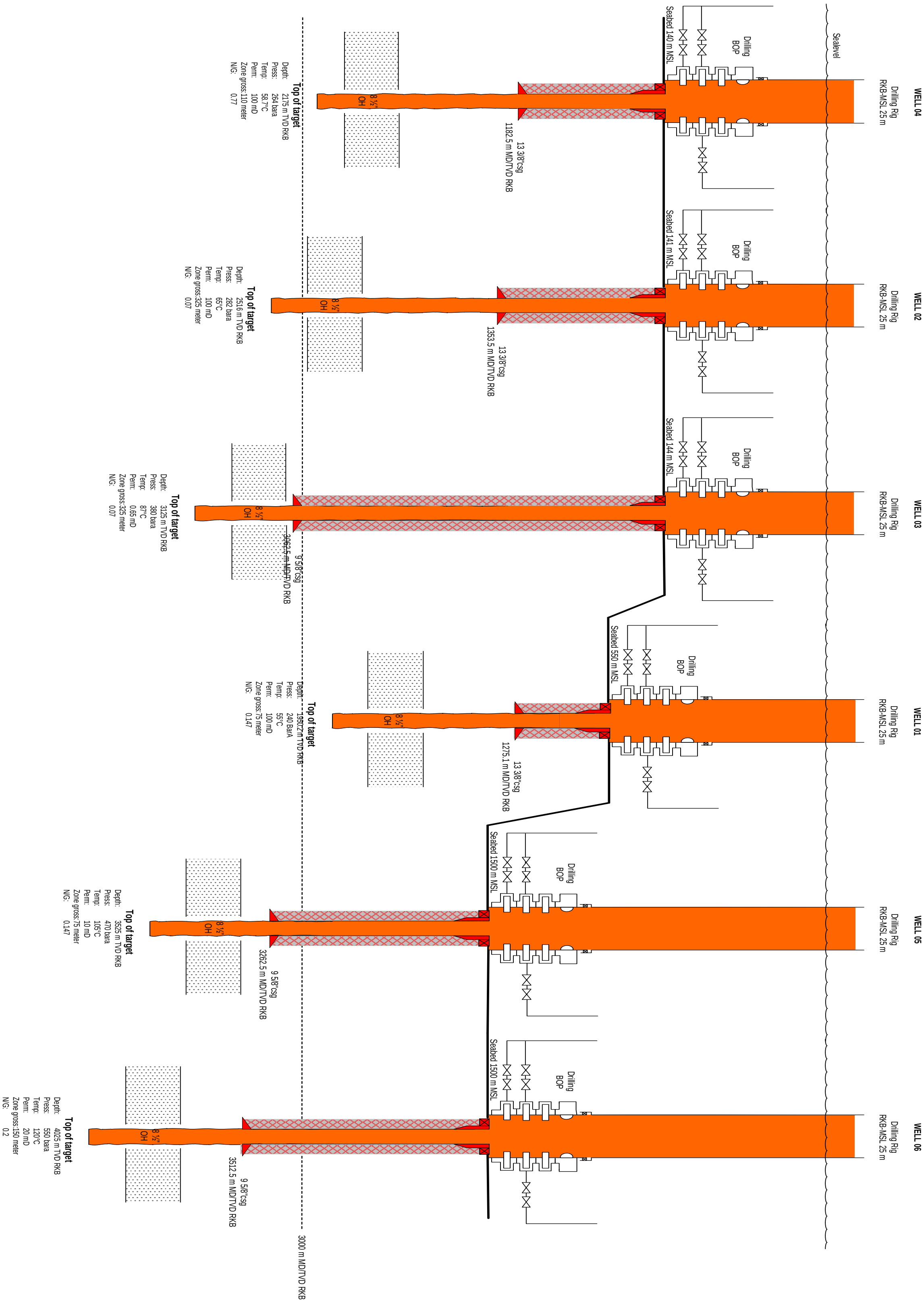


Figure 11: Schematic drawing of the hypothetical wells defined for the Labrador Sea.

4.4 Inflow performance relationship (IPR)

The productivity index is sensitive to parameters such as permeability, penetration length, N/G ratio, the productive height of the reservoir as well as mechanical skin, inflow turbulence or skew drainage due to limited penetration. The productivity index is also a transient parameter that tends to decline shortly after initiation of the production, or as in this case, a blowout. This is caused by the reduction of the near wellbore reservoir pressures.

Note: Skew drainage is defined as reduced productivity from a permeable reservoir due to the fact that only a part of the reservoir is opened for flow. The commingling flow will then not be able to benefit from the whole reservoir potential.

When calculating the blowout potentials, the blowout rates for the different scenarios are strongly dependent on the permeability, pressure, fluid viscosity and the consecutive productivity index. Simulations are based on the most likely properties, as given in Table 4-1 (reservoir data) and Table 4-2 and Table 4-3 (fluid data).

As Table 4-1 shows, the permeability for the 6 reference wells ranges from 0.65-100 mD. This is reflected in the productivity and the corresponding IPRs.

4.4.1 IPR – for the gas/condensate (GC) wells

The IPR relationships for the reference wells holding a gas and condensate as reservoir fluid are given in Figure 12.

The IPR relationships shown are for fully penetrated reference wells in accordance with the scenarios described in Section 4. As can be seen from the figure, high productivity is expected especially for well 04 due to high permeability and large zone interval, while low productivity is expected especially for well 03 due to low permeability.

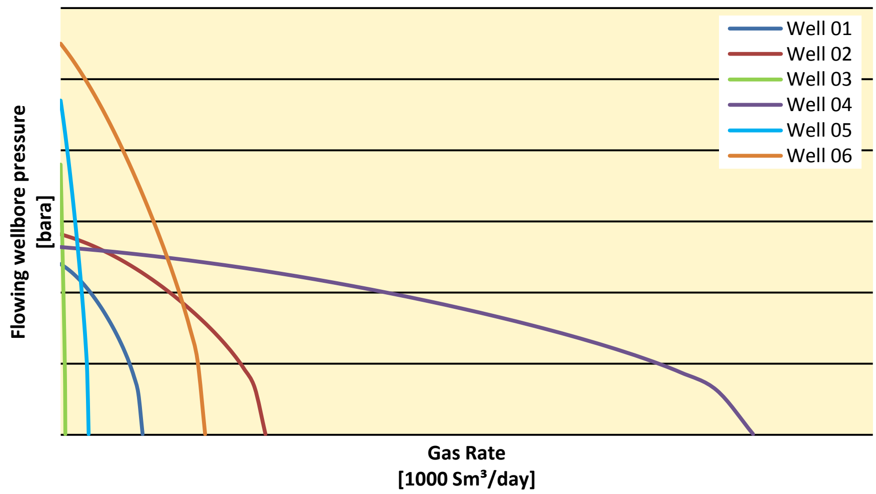


Figure 12: Gas Condensate Inflow Performance – all reference wells

In the calculations performed, a partly penetrated scenario is simulated for each of the wells in addition to the above presented fully penetrated scenarios. For partly exposure, the perforation interval has been reduced to 5 m, which is considered to be conservative.

Note: When drilling an exploration well, special attention is given when approaching possible HC bearing formations. Typically drill & circulate procedures will be implemented or a "drilling break" is observed, which is defined as a sudden increase in penetration rate. The standard procedure for such drilling break is to continue drilling for approx. 3 meter, then stop, perform a flow check and possibly circulate in order to enable cuttings and shows analysis at surface.

4.4.2 IPR – OIL WELLS

The corresponding IPR relationships assuming the reference wells to be filled with oil are given in Figure 13.

The IPR relationships shown are for fully penetrated reference wells. Again, well 04 is the most productive well and well 03 the least productive well.

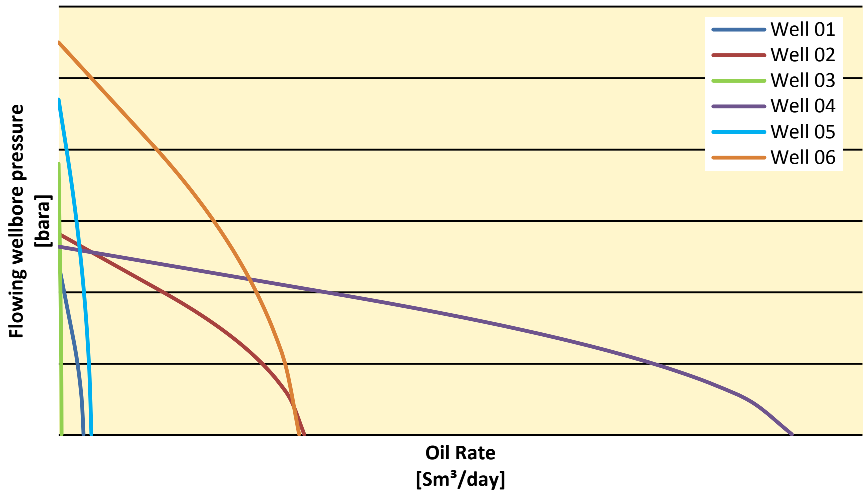


Figure 13: Oil Inflow performance – all reference wells.

In the calculations performed, a partly penetrated scenario is simulated for each of the wells in addition to the above presented fully penetrated scenarios. For partly exposure, the perforation interval has been reduced to 5 m, which is considered to be conservative.

4.5 BLOWOUT SCENARIOS

Hypothetical blowout scenarios have been investigated in this study, all relevant for drilling operations. The analysed scenarios include blowouts through open hole, drill pipe and annulus to drill floor and to seabed. Figure 14 illustrates the possible blowout paths to drill floor. In addition simulation cases for blowouts through a restriction have also been included representing a partly closed BOP or accidental breakage of piping, valves or hoses connected with the BOP.

The statistical values are found based on the *SINTEF Offshore Blowout Database* [1] and the annual report from Scandpower [2], that are based upon a more comprehensive analysis of the SINTEF database.

Furthermore, the operational experience from the Acona group of companies, with more than 25 years of relevant experience is implemented in the calculation of the probability distribution. These evaluations and their weighting are discussed in detail below.

In order to limit the number of scenarios to analyse, two main categories of incidents are simulated and are intended to cover all possible scenarios conservatively. These are "*Partly Penetrated*" and "*Fully Penetrated*" reservoir sections, which together are assumed to cover all kick scenarios.

For the "*Partly penetrated*" scenarios, a penetration pay of 5 meters is used. In reality, the choice of penetration length into the reservoir, i.e. 5 m, is of less importance when evaluating the probability distribution. In fact, it is the mechanisms leading to the blowout that is important. For the partly penetrated case, the occurrence of a blowout is due to a kick scenario in the well. For the fully penetrated case, a swab scenario leads to the possible blowout. The loss of primary barrier by swabbing of reservoir fluids when pulling out of hole can be caused by pulling too fast, insufficient compensation for the drill string displacement volumes or by a combination of these. Borehole pack-off or partly collapse of some strings or formations might increase the risks of swabbing reservoir fluids. Theoretically such swabbing may not be discovered before the BHA is at surface.

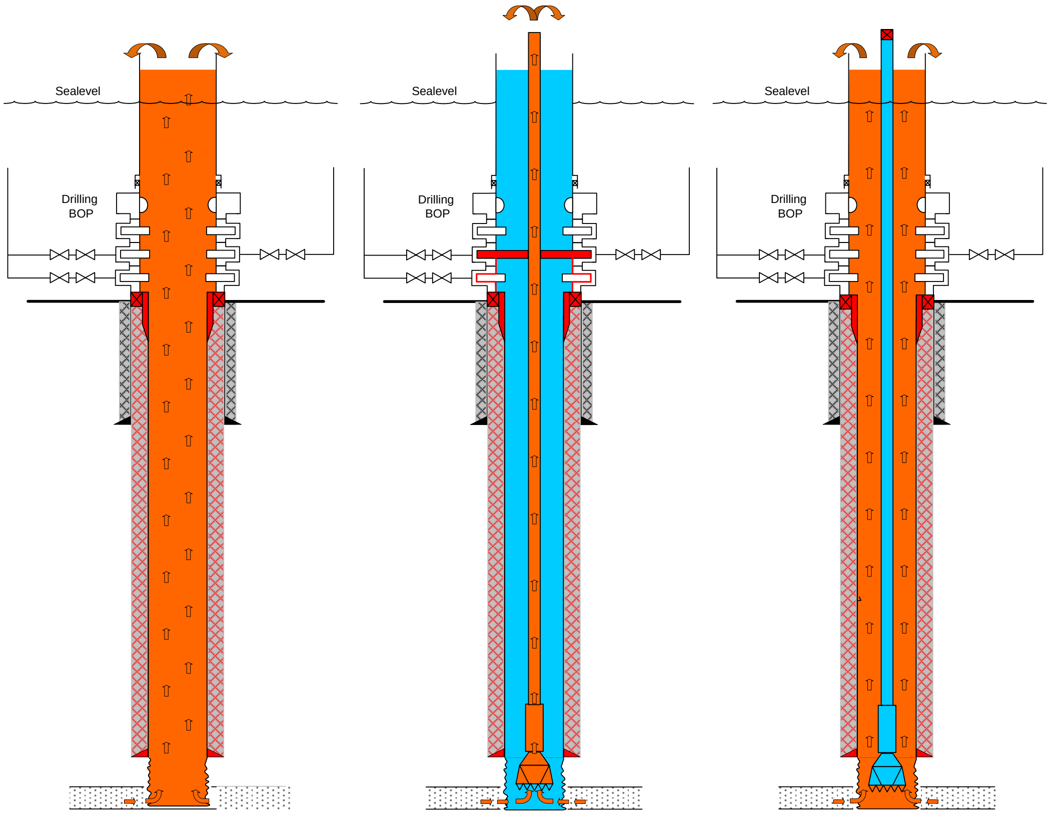


Figure 14: Possible blowout paths for the defined scenarios (illustrative only). From left to right: Open hole, drill pipe and annulus

The following "*Partly penetrated*" scenarios have been investigated:

- Blowout through casing/open hole, reservoir partly penetrated
- Blowout through drillpipe, reservoir partly penetrated
- Blowout through annulus, reservoir partly penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

The following "*Fully penetrated*" scenarios have been investigated:

- Blowout through casing/open hole, reservoir fully penetrated
- Blowout through drillpipe, reservoir fully penetrated
- Blowout through annulus, reservoir fully penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

For all the above mentioned scenarios, the blowout potentials have been modelled, and the results organised.

4.6 STATISTICAL MODELLING OF THE BLOWOUT SCENARIOS

4.6.1 INTRODUCTION

Table 4-4 summarizes relevant statistical findings from drilling, completion and workover activities from the Scandpower report from April 2011 [2]. The statistical basis for the flow path distribution is data from the area of US GoM and North Sea where equipment (i.e. BOP) have been of North Sea standard. During completion and workover, where standard equipment is not relevant the number of blowout is low, but these incidents are assumed would have happened even if the North Sea standard equipment were used. Flow path distribution of these incidents is weighted with a factor of 0.2 by Scandpower.

Table 4-4: Probability distribution of flow paths from 20 years of historical data

Data update: April 2011		**Distribution - Floaters**			
		Subsea		**Topside**	
		Full	*Choked*	*Full*	*Choked*
Drilling (22 incidents)	Outside casing	22.73 %	4.55 %		
	Outer annulus	18.18 %	4.55 %		
	Annulus		31.82 %	4.55 %	4.55 %
	Open hole				4.55 %
	Inside drillstring				
	Inside test tubing				4.55 %
Completion (4.4 incidents)	Annulus				4.55 %
	Inside drillstring	4.55 %		40.91 %	
	Inside prod tubing			4.55 %	45.45 %
Workover (9.4 incidents)	Outer annulus		31.91 %		
	Annulus		21.28 %		
	Inside drillstring			19.15 %	
	Inside prod tubing		10.64 %	12.77 %	4.26 %

When implementing these data for calculation of flow path distribution the following assumptions and methodology have been used:

- Well operations categorized as “dead well”, defined as operations where the fluid column itself is the primary barrier includes the activities *drilling operations, workover operations* and *completion operations*. Loss of well control in these operations are initiated by, and limited to, formation kicks or losses caused by unexpected formation properties, lack of operational fluid control or swabbing of reservoir fluids from *“pulling out of hole”* activities or lack of heave compensation.

  Since all these incidents (kick or loss from/to reservoir, lack of fluid control and swabbing) also are possible from completion and workover operations and that the secondary barrier in these operations also includes the drilling BOP, the statistical data from these two groups are included in the statistical summary together with the data from drilling operations.

- In the final distribution used in this report, the outside casing and outer annulus flow paths are combined with the annulus flow path.

- The test tubing flow path is combined with the drill-string flow path due to comparable inner diameter and thereby comparable expected blowout rates.

- The flow through production tubing is interpreted as flow through open hole/casing.

Acona reviews the statistical values used on annual basis. For data that cannot be derived from statistical sources; operational experience or combination with data are used. The applied data are thoroughly evaluated and quality assured by the Acona review team which consist of Acona`s chief engineers within drilling and well control.

4.6.2 STATISTICAL DISTRIBUTION

The following probabilities are used between partly and fully penetrated reservoirs when drilling Wildcat, Exploration and Appraisal wells:

- Blowout initiated when the formation is partly penetrated 60 %
- Blowout initiated when the formation is fully penetrated 40 %

For later development wells, more focus and time is used in the reservoir section in order to achieve optimum productivity, or injectivity, for each well. Based on this fact, the values are altered for development wells and the following distribution is used for development wells:

- Blowout initiated when the formation is partly penetrated 40 %
- Blowout initiated when the formation is fully penetrated 60 %

For the partly penetrated scenarios, 5 m penetration is used, with an N/G ratio of 1.0, which is considered conservative.

By implementation of the categorization made above, the flow path probabilities in the top penetration scenario, i.e. a partly penetrated scenario, are given the following values:

- Blowout through drill pipe has a probability of 16 %
- Blowout through annulus has a probability of 84 %
- Blowout through open hole to surface has a probability of 0 %

Note: *It is worth to notice that the risk of flowing through open hole (OH), when penetrating top reservoir only, is assumed irrelevant and the probability of this is given a 0.0 % value. This is founded upon the fact that the top reservoir cannot be penetrated without having the DP and the bit in the hole.*

Similarly, the fully penetrated swab scenario is given the following probability distribution:

- Blowout through drill pipe has a probability of 14 %
- Blowout through annulus has a probability of 70 %
- Blowout through open hole to surface has a probability of 16 %

In all drilling operations, and most other well operations as well, a Blowout Preventer (BOP) stack of valves and rams defines the secondary barrier against uncontrolled outflow of reservoir fluids. The BOP testing program and its procedures ensure that a BOP stack is experienced as "extremely reliable equipment". This is further emphasized by the number of independent rams in the BOP and the requirement for accumulator capacity. Based on this, the risk of a total failure of the BOP is assumed to be very low.

Once a blowout has occurred, the BOP has failed or has not been activated. Given such unlikely failures, and based on the *"OLF Guidelines for estimation of blowout potentials" [3]*, the following distribution has been used for partly or full BOP failure:

- Restricted flow area has a probability of 70 %
- No restriction has a probability of 30 %

The different consequences of a partial failure in the BOP are difficult to predict. In the “OLF Guidelines for *estimation of blowout potentials” [5]* it is proposed to model a partial failure as 95% reduction of the available fluid flow area. As restriction in available flow paths also can be caused by pipe in hole, fish/junk or collapse of the borehole itself, Acona Flow Technology suggest that modelling of a partial failure is better described with a restriction equivalent to 64/64” flow area for all scenarios. This is justified by the fact that the remaining flow area now is independent of the wellbore design or the size of the drillpipe used.

When drilling from a floater, anchored or dynamically positioned, the OIM will try to pull the rig off from location shortly after an uncontrollable well integrity issue is unveiled and any surface attempt to stop the flow has not succeeded or has been evaluated as unlikely to succeed.

If the rig is pulled off, the topside blowout release is assumed to change to a subsea blowout release. From the SINTEF Offshore Blowout database summarised in Table 3, 32% of the blowout incidents have a topside release point. DNV [4] reports that 75% of the attempts to pull a floater off from location under a blowout have been successful. Accordingly, the following distribution is proposed:

- Surface release point when drilling from a floater: 10 %
- Seabed release point when drilling from a floater: 90 %

4.6.3 METHOD FOR RISKING OF BLOWOUT POTENTIALS

From the detailed analysis presented in the previous section the probabilities for all relevant scenarios were found. According to the “*OLF Guidelines for estimation of blowout potentials*” all possible scenarios should be risked and blowout potentials shall be weighted respectively. The risk methodology breaks down each of the scenarios as illustrated in Figure 15 below.

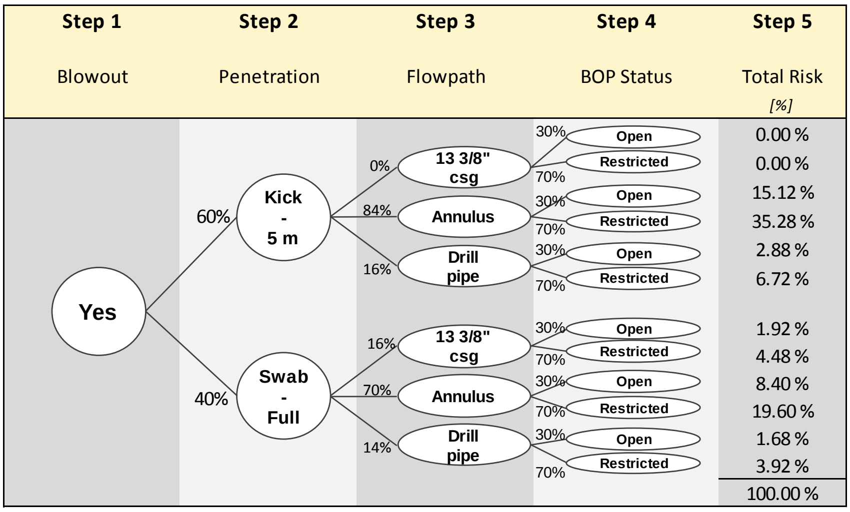


Figure 15: Illustration of methodology used when risking the blowout rates

Next, the blowout potentials are calculated for each of the scenarios and their respective probability from step 5 is multiplied with the maximum blowout potential for each scenario. Potential blowout rates, frequency distribution and total risk weighted, or most likely value can be calculated as shown in figure below.

Step 1 Blowout	Step 2 Penetration	Step 3 Flowpath	Step 4 BOP Status	Step 5 Total Risk [%]	Step 6 Blowout potential [Sm³/day]	Step 7 Risked oil blowout rate [Sm³/day]
Yes	60% Kick - 5 m	0% 13 3/8" csg	30% Open	0.00 %	283	0.0
			70% Restricted	0.00 %	283	0.0
		84% Annulus	30% Open	15.12 %	282	42.6
			70% Restricted	35.28 %	282	99.5
		16% Drill pipe	30% Open	2.88 %	245	7.1
			70% Restricted	6.72 %	245	16.5
	40% Swab - Full	16% 13 3/8" csg	30% Open	1.92 %	534	10.2
			70% Restricted	4.48 %	534	23.9
		70% Annulus	30% Open	8.40 %	531	44.6
			70% Restricted	19.60 %	531	104.1
		14% Drill pipe	30% Open	1.68 %	361	6.1
			70% Restricted	3.92 %	361	14.1
				100.00 %		369 Sm³/day

Figure 16: Example on risk methodology when prediction most likely values.

4.7 Method for estimation of most likely Blowout duration

4.7.1 Introduction

A blowout may be stopped by several remedial actions. These can be divided into the following categories:

- Bridging, i.e. collapse of the near wellbore
- Crew intervention
- Subsea installation of a new barrier system (capping)
- Drilling of relief wells with direct intersect of the blowing well
- Other causes

In the following a more detailed discussion of each of the above is presented. In order to be able to model the statistical success for each of the above given actions, these are modelled as they were the only remedial action imposed to stop the blowout.

Bridging

The majority of blowing wells are killed by themselves because of bridging. According to the Scandpower report approximately 84% of the historical blowouts were stopped by bridging, if this mechanism was the only remedial action imposed. Bridging mechanisms might be:

- Sand or rock accumulates inside the wellbore
- Formation collapses due to high flowing rates and high drawdown pressure
- Formation of hydrates blocking the flow paths

Crew intervention

Crew intervention is defined as activities possible to perform from the existing installation with equipment, or tools, already available or which can be mobilised on short notice. Typical action could be repair, or replacement of hydraulic components, replacement of control system equipment or similar minor repairs. For all activities in this group it is required that there are sufficient parts and equipment on-board the installation and that personnel can operate safely.

Subsea Capping

Several initiatives have been taken world-wide after the Macondo Blowout in April 2010 for pre-fabrication of capping devices that can be transported by commercial air freight and that will be possible to assemble on local bases or on-board an offshore rig or supply vessel.

The working principle of most of these devices are that the subsea disconnect feature of the existing subsea BOP is activated and the marine riser is released. The new capping device, often based upon a standard lightweight BOP, is lowered onto the blowing well in open mode. After successful landing the connection are made up and functions tested before the ram are closed and the blowout is stopped.

Typically, these new capping devices shall be possible to mobilise and assemble offshore in 10 days. Conservatively 5 – 15 more days installation time should be planned for dependent on weather, sea depth or complexity related to preparation of the existing subsea installations.

A time estimate for a capping operation is made as follows:

- Collecting and preparing equipment: 10 days
- Cap and contain operation: 15 days
- Total time for the operation: 25 days

In this report, a capping operation is assumed to have a success rate of 40% in killing the well.

Drilling of relief wells

In most offshore blowouts the drilling of one or several relief wells will be kicked off immediately after a blowout is confirmed. If one or more relief wells are necessary to regain control of the well, the time needed for mobilization of a drilling rig and the drilling itself may vary. It can be assumed that the relief wells can be drilled with the same rate as the exploration well, but in addition ranging runs are required, e.g. with electromagnetic ranging tools to find both the vector and distance from the relief well to the blowing well. This guides the drilling of the relief well to a perfect interception with the blowing well. The magnetic ranging can be performed using raw magnetic surveys from the MWD tools used for surveys in the relief well. This could eliminate the need for wireline runs to steer towards the intercept.

The time required to run such equipment must be taken into account. The time will depend on drilling intersection depth, rig availability in general and in the specified area and weather conditions.

As an example for a typical well, drilling of one relief well down to intersection at the last casing shoe of the blowing well is estimated as follows:

- Decision to drill the relief well: 3 days
- Termination of work, sail to location, anchoring and preparation: 12 days
- Drilling relief well to intersection: 50 days
- Homing in: 10 days
- Total time to kill well: 75 days

Accordingly, assumptions are made that the relief well will successfully kill the well after 75 days in case of a blowout.

Other causes

Other possible mechanisms stopping a blowing well could be:

- Pressure depletion of the blowing reservoir
- Water breakthrough
- Stopping of gas lift, gas- or water injection
- Coning of water or gas into the blowing well

4.7.2 BLOWOUT DURATION DISTRIBUTION

In order to give best possible distribution estimate, the probability distribution for the different historical incidents must be found. Figure 17 below is based on the Scandpower reported data from April 2011[2] and presents the probability that a blowout is still active after a certain number of days based on the use of one single kill mechanism only, such as crew intervention or natural bridging.

The results from such reliability approach are presented in Figure 17 below.

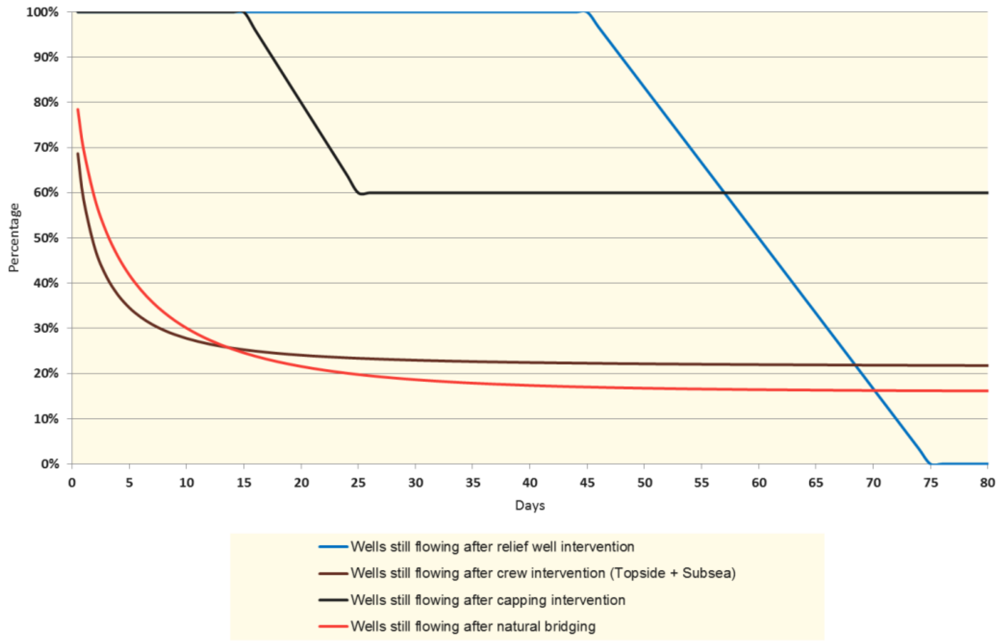


Figure 17: Reliability plots for each of the possible remedial actions

Multiple mechanisms may "work together" in order to stop the blowout. Scandpower reports that 84% of all blowouts will eventually be stopped by natural bridging, 67% will eventually be stopped by crew intervention topside and 35% will eventually be stopped by crew intervention subsea if each mechanism evaluated is the only mechanism to stop the leak.

The installation of a new subsea barrier by cap and contain is assumed to be a uniform distribution with a probability of 40 % that the blowout is eventually killed. The operation starts after 10 days and ends after 25 days.

Drilling a relief well is assumed to be a uniform distribution with a probability of 100% that the blowout is eventually killed. The drilling starts after 15 days and earliest possible kill attempt can be performed after a successful intersection of the blowing well, in this work a uniform distribution between 45 days and 75 days are proposed.

The probability that either of the kill mechanisms is successful may be derived by assuming the individual kill mechanisms are independent events.

The results from Figure 17 above can be combined by statistical methods and a combined reliability curve can be presented as if all remedial actions are imposed together in order to stop a possible future blowout.

The combined reliability curve for a subsea release point is presented in Figure 18 below.

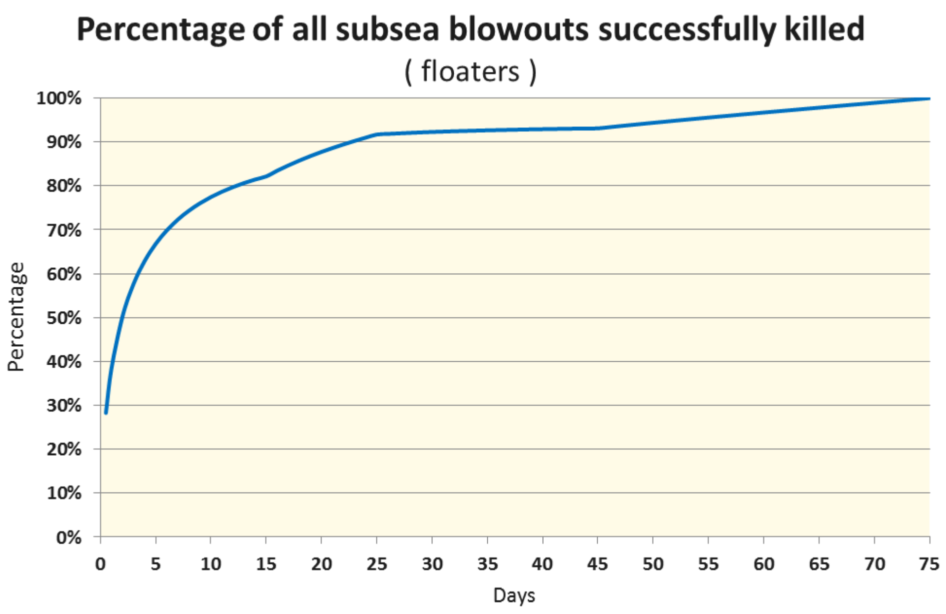


Figure 18: Reliability presentation of all kill actions when combined for a subsea release

Similar the same methodology can be used for estimation of blowout duration with a topside release point. The results of this combination are presented in Figure 19 below.

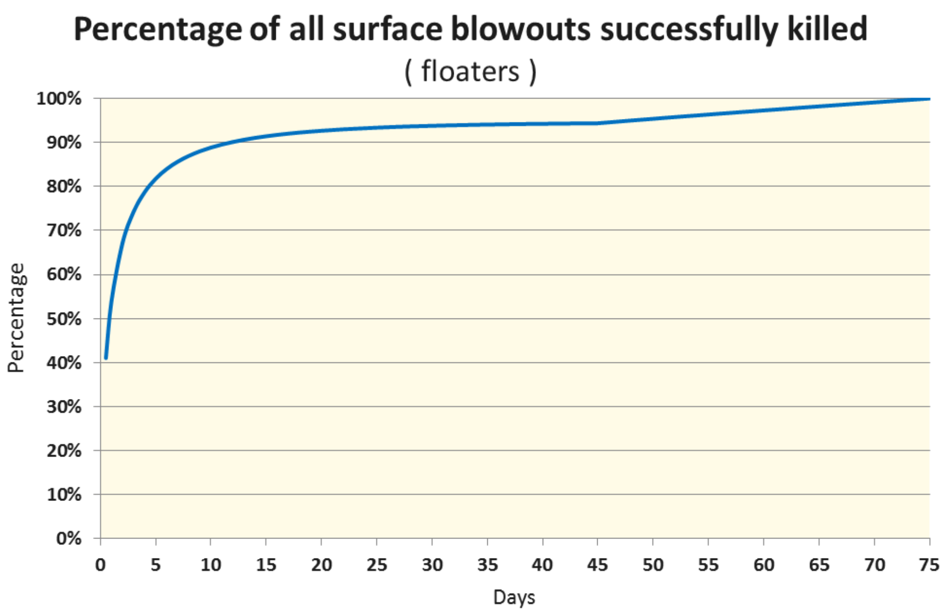


Figure 19: Reliability presentation of all kill actions when combined for a surface release

In order to provide a unique methodology for duration prognosis a simplified discretization is proposed, which represents the four different logical stages in a kill operation.

Table 4-5: Discretization model for duration estimates

Risk of a blowout duration of <=2 days	P_2	The blowout could be controlled by measures performed from the existing rig
Risk of a blowout duration of 3-15 days	P_{15}	The blowout could be controlled by bringing in additional equipment
Risk of blowout duration of 16-25 days	P_{25}	The blowout could be controlled by installation of new barrier system
Risk of a blowout duration of 26-75 days	P_{75}	The blowout will have to be killed by drilling a dedicated relief well.

This discretization methodology makes estimation of possible blowout duration is easy to communicate, and the method can be adapted for shorter or longer drilling time estimates than the 75 days used in this report.

5 RESULTS

In this section the results for both the statistic assessment and the hydraulic calculations are presented.

5.1 PROBABILITY FOR A BLOWOUT

For normal pressure regimes, exploration drilling has a blowout frequency 4.7 times higher than development drilling, ref. Table 1.

Drilling of exploration wells in known, or mature areas, and drilling of appraisal wells have comparable blowout frequencies.

Wildcat drilling in new and unexplored areas has a lower blowout risk than appraisal wells, given by a factor 0.9. One reason for the discrepancy may be that the probabilities of a find are lower for the wildcat wells than for the appraisal wells, hence, an operational failure in a dry exploration well might not develop into a blowout.

HPHT wells with an expected shut-in pressure equal to or higher than 690 bar (i.e. requires 1035 bar equipment) and/or bottom-hole temperature equal to or above 150°C has been modelled back in 1998 to have a blowout frequency 6.2 times higher than normal wells. The significant higher blowout frequency is not believed to be due to the high pressure itself, but rather due to a narrower drilling window, i.e. small margin between the pore pressure and the fracture pressure.

Drilling in deep water has unveiled a higher blowout frequency compared to normal water depths, a multiplier of 1.53 is found from the statistical data when drilling in deep water, ref section 3.4.

DNV [7] have analysed the effect from technological improvements, skills and training on the overall probability for a blowout. DNV utilizes kick frequencies and modern reliability models for prediction of expected blowout frequencies. A reliability model was build and tuned to historical data for kick frequencies. By implementing new and updated data for kick frequencies, the direct effect of technological improvements, skills and training could be derived. DNV found that the blowout frequency could be reduced by a factor 2, compared to the statistical blowout frequency presented in the 2009 revision of the Scandpower report if modern technology and risk reducing measures was implemented. This resulted in an overall blowout frequency of 7.7E-5 per drilled exploration well, i.e. one blowout per 12987 drilled exploration wells.

The 2010 revision of the Scandpower report documents a reduction in overall blowout frequencies for exploration wells from 1.5E-4, i.e. one blowout for every 6667 drilled well in the 2009 revision to 1.06E-4, i.e. one blowout for every 12987 drilled well in the 2010 revision. Such reduction was expected as the effect of technological improvements, skills and training will become more and more important in the moving 20 year of data sample. Hence, it should be expected that the statistical moving average date moves towards the value found from the DNV analysis.

Based on the probabilities discussed in the previous sections, the recommendations for the Labrador Sea, which is an unexplored area, can be represented by the following frequencies:

- When accounting for technological and operational improvements the overall probability for experiencing a future blowout for wells drilled on less than 1000 m water depth in the Labrador Sea is proposed to be 7.7E-5, i.e. one blowout for every 12987 exploration wells drilled.

- When drilling in deep water, i.e greater than 1000 meter, the statistical findings is that the probability should be increased with a factor 1.53, ref section 3.4.

5.2 BLOWOUT DURATION

5.2.1 BLOWOUT DURATION WITH SURFACE RELEASE

Based on the discretization proposed above, reliability values can be extracted from Figure 19 above, this leads to the following duration estimate for the Labrador Sea:

- Risk of a blowout duration less than 2 days: 67 %
- Risk of a blowout duration less than 15 days (91% - 67%): 24 %
- Risk of a blowout duration less than 25 days (93% - 91%): 2 %
- Risk of a blowout duration less than 75 days (100% -93%): 7 %

Assumptions are made that the relief well will successfully kill the well after 75 days, which means that P = 0 % for t >75.

The expected duration can now be calculated in a simplified way:

Expected duration of a blowout in the Labrador Sea with a surface release point is found to be = (2*0.67+15*0.24+25*0.02+75*0.07) = 10.7 days

5.2.2 BLOWOUT DURATION SUBSEA RELEASE

Based on the discretization proposed above, reliability values can be extracted from Figure 18 above, this leads to the following duration estimate for the Labrador Sea:

- Risk of a blowout duration less than 2 days: 50 %
- Risk of a blowout duration less than 15 days (82% - 50%): 32 %
- Risk of a blowout duration less than 25 days (92% - 82%): 10 %
- Risk of a blowout duration less than 75 days (100% - 92%): 8 %
-

Assumptions are made that the relief well will successfully kill the well after 75 days, which means that P_t = 0 % for t >75.

The expected duration can now be calculated in a simplified way:

Expected duration of a blowout in the Labrador Sea with a surface release point is found to be = (2*0.50+15*0.32+25*0.10+75*0.08) = 14.3 days

5.2.3 Overall blowout duration estimate

In section 4.6.2 it was found that for a blowout developing when drilling from a floater only 10 % of the incidents will remain as surface blowouts, the rest of the incidents will develop into a blowout with a subsea release point. This give the following estimate for overall blowout duration in the Labrador Sea.

10.7 * 0.1 + 14.3 * 0.9 =13.94 days **~ 14 days.**

5.2.4 Simplified duration estimate method (information only)

In the industry a simpler and more discrete method is often used. The method is based upon the same discretization as presented above, but is broken down to reliability values for each of the calculated blowout scenarios.

When implementing this methodology for the Labrador Sea the following durations are found:

Simplified duration estimate - surface release

In below duration weights for a surface release point is presented, and in the method is implemented and a simplified duration estimate of 10.6 days for a seabed release is found.

Table 5-1: Duration distribution – surface release

Scenario	P_2 t <= 2 days	P_{15} t = 3 - 15 days	P_{25} t = 16 - 25 days	P_{75} t = 26 - 75 days
	[%]	[%]	[%]	[%]
Openhole	50	30	10	10
Annulus	65	20	10	5
Drillpipe	75	15	5	5

Table 5-2: Duration distribution – Surface release

Surface release									
Step 1	Step 2	Step 3	Step 4	Step 5	Duration distribution				
Blowout	Penetration	Flowpath	BOP Status	Total Risk [%]	P_2 t < 2 days [%]	P_{15} t < 15 days [%]	P_{25} t <= 25 [%]	P_{75} t <= 75 [%]	Risked [days]
Yes	60% Kick - 5 m	0% 13 3/8" csg	30% Open	0,00 %	50 %	30 %	10 %	10 %	15,5
			70% Restricted	0,00 %	50 %	30 %	10 %	10 %	15,5
		84% Annulus	30% Open	15,12 %	65 %	20 %	10 %	5 %	10,6
			70% Restricted	35,28 %	65 %	20 %	10 %	5 %	10,6
		16% Drill pipe	30% Open	2,88 %	75 %	15 %	5 %	5 %	8,8
			70% Restricted	6,72 %	75 %	15 %	5 %	5 %	8,8
	40% Swab - Full	16% 13 3/8" csg	30% Open	1,92 %	50 %	30 %	10 %	10 %	15,5
			70% Restricted	4,48 %	50 %	30 %	10 %	10 %	15,5
		70% Annulus	30% Open	8,40 %	65 %	20 %	10 %	5 %	10,6
			70% Restricted	19,60 %	65 %	20 %	10 %	5 %	10,6
		14% Drill pipe	30% Open	1,68 %	75 %	15 %	5 %	5 %	8,8
			70% Restricted	3,92 %	75 %	15 %	5 %	5 %	8,8
				100,00 %					10,6

Simplified duration estimate - subsea release

In Table 5-3 below duration weights for a subsea release point is presented, and in Table 5-4 the method is implemented and a simplified duration estimate of 15.4 days for a seabed release is found.

Table 5-3: Duration distribution – Seabed release

Scenario	P_2 t < 2 days [%]	P_{15} t = 3 - 15 days [%]	P_{25} t = 16 - 25 days [%]	P_{75} t = 26 -75 days [%]
Openhole	30	20	20	30
Annulus	50	32	10	8
Drillpipe	50	32	10	8

Table 5-4: Duration estimate – Seabed release

Subsea release									
Step 1	Step 2	Step 3	Step 4	Step 5	Duration distribution				
Blowout	Penetration	Flowpath	BOP Status	Total Risk [%]	P_2 t < 2 days [%]	P_{15} t < 15 days [%]	P_{25} t <= 25 [%]	P_{75} t <= 75 [%]	Risked [days]
Yes	60% Kick - 5 m	0% 13 3/8" csg	30% Open	0.00 %	30 %	20 %	20 %	30 %	31.1
			70% Restricted	0.00 %	30 %	20 %	20 %	30 %	31.1
		84% Annulus	30% Open	15.12 %	50 %	32 %	10 %	8 %	14.3
			70% Restricted	35.28 %	50 %	32 %	10 %	8 %	14.3
		16% Drill pipe	30% Open	2.88 %	50 %	32 %	10 %	8 %	14.3
			70% Restricted	6.72 %	50 %	32 %	10 %	8 %	14.3
	40% Swab - Full	16% 13 3/8" csg	30% Open	1.92 %	30 %	20 %	20 %	30 %	31.1
			70% Restricted	4.48 %	30 %	20 %	20 %	30 %	31.1
		70% Annulus	30% Open	8.40 %	50 %	32 %	10 %	8 %	14.3
			70% Restricted	19.60 %	50 %	32 %	10 %	8 %	14.3
		14% Drill pipe	30% Open	1.68 %	50 %	32 %	10 %	8 %	14.3
			70% Restricted	3.92 %	50 %	32 %	10 %	8 %	14.3
				100.00 %	Total risked duration for the Blowout (days):				15.4

Simplified duration estimate – overall

By implementing the same 10% / 90% weighting as found in section 4.6.3 and as used in section 5.2.3 the following overall estimate can be found:

10.6 * 0.1 + 15.4 * 0.9 =13.89 days ~ **14.9 days.**

5.3 Blowout potentials

In this section the results from the hydraulic calculations of the wells potentials to deliver oil and gas to the environment are presented.

The following "*Partly penetrated*" scenarios have been investigated:

- Blowout through casing/open hole, reservoir partly penetrated
- Blowout through drillpipe, reservoir partly penetrated
- Blowout through annulus, reservoir partly penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

The following "*Fully penetrated*" scenarios have been investigated:

- Blowout through casing/open hole, reservoir fully penetrated
- Blowout through drillpipe, reservoir fully penetrated
- Blowout through annulus, reservoir fully penetrated
- Restricted blowout through a leak, 64/64" choke for each of the above

For all the above mentioned scenarios, the blowout potentials have been modelled, and the results organised.

The blowout potentials found for the each of the defined scenarios, assuming the reference wells to penetrate either a gas-condensate filled reservoir, or oil filled reservoir. As can be seen in Appendix B the differences between a surface release point and a subsea release point are small and can be neglected for all practical reasons. In this section only surface release points are presented as these rates are assumed to have the most severe environmental impact if released to the surroundings.

Please be noted that the rates of oil, or more precisely condensate, is very low in the gas-condensate scenarios. This is due to the high gas content and the exact number should be assumed informative only as variations in fluid compositions and reservoir properties will inflect the actual value significantly.

Blowout potentials are defined as the maximum **expected** blowout rates for various scenarios, ref presentation of methodology in section 4.6.3.

Figure 20 below presents the maximum blowout potentials, i.e. rate of oil released to the environment for each of the defined hypothetical wells.

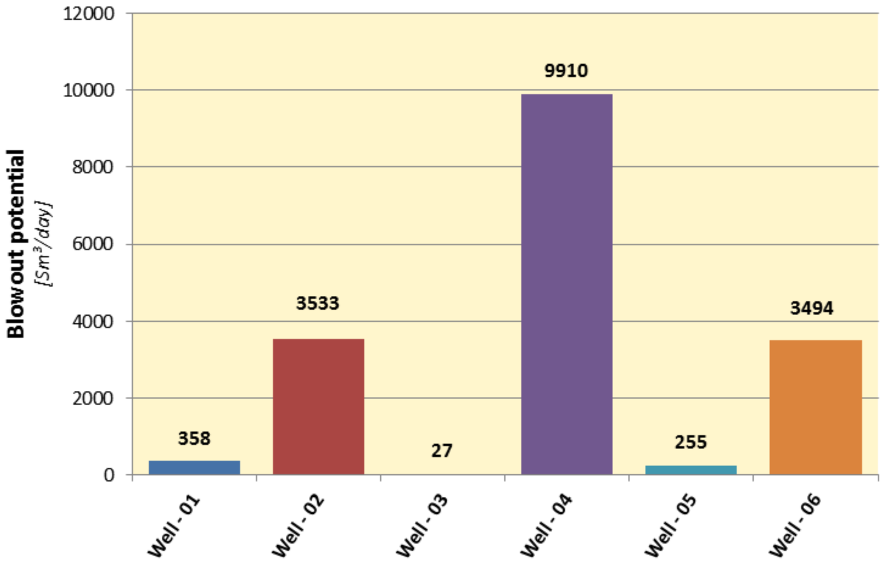


Figure 20: Maximum oil potential for all wells, ref. annex B

Figure 21 below presents the risk weighted blowout potentials, i.e. rate of oil released to the environment for each of the defined hypothetical wells.

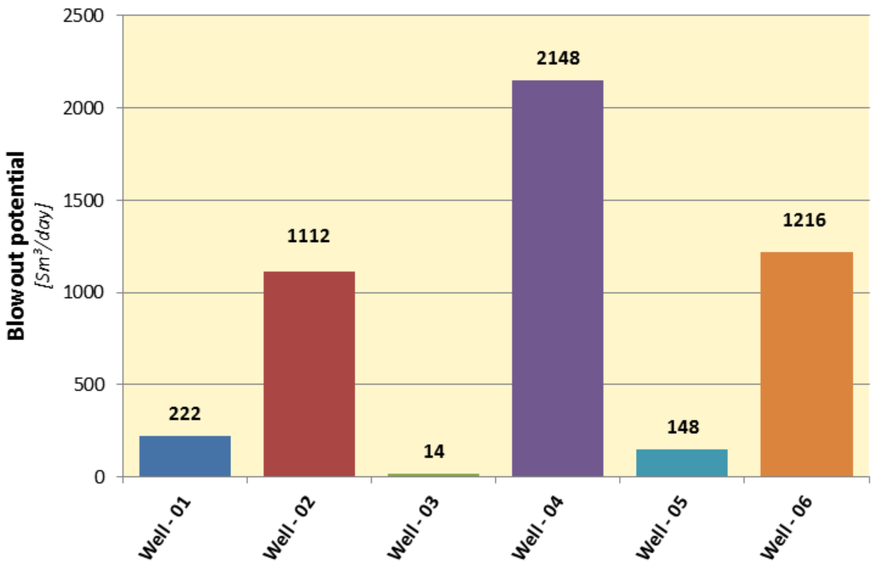


Figure 21: Weighted risk for blowout of oil for all wells, based on assumed GOR for various wells, ref table 12 - 17

The following sections present all the obtained blowout potentials and risked blowout rates for the above mentioned scenarios.

The simulations show that the worst case scenario with regards to blowout potentials is an unrestricted blowout through the 13 ⅜" casing with the reservoir section fully penetrated for hypothetical well no. 04, this scenario result in a maximum blowout rate of 9910 Sm³/day oil. This rate is related to the case where the reservoir is holding oil.

The risk weighted rate for the same well is found to be 2148 Sm³/day, refer to figure 15.

5.4 RISKING OF BLOWOUT POTENTIALS

According to the "*OLF Guidelines for estimation of blowout potentials*" all possible scenarios should be risked and blowout potentials should be weighted correspondingly.

The risk process illustrates the most likely expected blowout rates for an uncontrolled blowout from the well. These values are weighted; therefore both higher and lower rates may be experienced in a real blowout. The risked values are qualified numbers for likely volumes expected, and are to be used when evaluating the possible environmental impact from the well.

Note: *The overall probability of finding hydrocarbons in a well, which again introduces a certain risk for a blowout can preferable, be included in the environmental analysis. This value is neglected in this report.*

5.4.1 RISKED BLOWOUT RATES TO SEA – WELL 01

Table 5-5 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 1.

Table 5-5: Blowout rates – Well no. 1 – surface release, gas condensate and oil

Step 1 Status	Step 2 Penetration Prob. %	Status	Step 3 Flowpath Prob. %	Status	Step 4 BOP status Prob. %	Status	Step 5 Total risk [%]	Step 6 Blowout potential - oil [Sm³/day]	Blowout potential - gas [kSm³/day]	Step 7 Risked Oil blowout rate [Sm³/day]	Step 8 Risked Gas blowout rate [kSm³/day]
Gas-Condensate	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	283	2317	0.0	0.0
					70 %	Restricted	0.00 %	162	1328	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	282	2312	42.6	349.6
					70 %	Restricted	35.28 %	160	1309	56.3	461.8
			16 %	Drill pipe	30 %	Open	2.88 %	245	2013	7.1	58.0
					70 %	Restricted	6.72 %	152	1246	10.2	83.7
	40 %	Swab *Full*	16 %	Open hole	30 %	**Open**	**1.92 %**	**534**	**4376**	**10.2**	**84.0**
					70 %	Restricted	4.48 %	187	1535	8.4	68.8
			70 %	Annulus	30 %	Open	8.40 %	531	4357	44.6	366.0
					70 %	Restricted	19.60 %	184	1511	36.1	296.2
			14 %	Drill pipe	30 %	Open	1.68 %	361	2957	6.1	49.7
					70 %	Restricted	3.92 %	174	1426	6.8	55.9
					Total sum:		100.00 %	**Risked rate:**		**228** *Sm³/day*	**1873.6** *kSm³/day*
Step 1 Status	**Step 2** Penetration Prob. %	Status	**Step 3** Flowpath Prob. %	Status	**Step 4** BOP status Prob. %	Status	**Step 5** Total risk [%]	**Step 6** Blowout potential [Sm³/day]	Blowout potential - gas [kSm³/day]	**Step 7** Risked Oil blowout rate [Sm³/day]	**Step 8** Risked Gas blowout rate [kSm³/day]
Oil	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	162	10	0.0	0.0
					70 %	Restricted	0.00 %	155	9	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	162	10	24.5	1.5
					70 %	Restricted	35.28 %	155	9	54.7	3.3
			16 %	Drill pipe	30 %	Open	2.88 %	162	10	4.7	0.3
					70 %	Restricted	6.72 %	155	9	10.4	0.6
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	**358**	**21**	**6.9**	**0.4**
					70 %	Restricted	4.48 %	301	18	13.5	0.8
			70 %	Annulus	30 %	Open	8.40 %	358	21	30.1	1.8
					70 %	Restricted	19.60 %	302	18	59.2	3.6
			14 %	Drill pipe	30 %	Open	1.68 %	354	21	5.9	0.4
					70 %	Restricted	3.92 %	302	18	11.8	0.7
					Total sum:		100.00 %	**Risked rate:**		**222** *Sm³/day*	**13.3** *kSm³/day*

5.4.2 RISKED BLOWOUT RATES TO SEA – WELL 02

Table 5-6 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 2.

Table 5-6: Blowout rates – Well no. 2 – surface release, gas condensate and oil.

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm^3/day]	[kSm^3/day]	[Sm^3/day]	[kSm^3/day]
Gas-Condensate	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	310	2539	0.0	0.0
					70 %	Restricted	0.00 %	173	1417	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	309	2531	46.7	382.7
					70 %	Restricted	35.28 %	170	1396	60.1	492.5
			16 %	Drill pipe	30 %	Open	2.88 %	265	2174	7.6	62.6
					70 %	Restricted	6.72 %	163	1338	11.0	89.9
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	**1144**	**9377**	**22.0**	**180.0**
					70 %	Restricted	4.48 %	220	1802	9.8	80.7
			70 %	Annulus	30 %	Open	8.40 %	1108	9083	93.0	763.0
					70 %	Restricted	19.60 %	216	1772	42.4	347.4
			14 %	Drill pipe	30 %	Open	1.68 %	494	4048	8.3	68.0
					70 %	Restricted	3.92 %	204	1676	8.0	65.7
					Total sum:		100.00 %	**Risked rate:**		**309** *Sm^3/day*	**2532.6** *kSm^3/day*

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm^3/day]	[kSm^3/day]	[Sm^3/day]	[kSm^3/day]
Oil	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	749	94	0.0	0.0
					70 %	Restricted	0.00 %	427	53	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	745	93	112.7	14.1
					70 %	Restricted	35.28 %	480	60	169.5	21.2
			16 %	Drill pipe	30 %	Open	2.88 %	715	89	20.6	2.6
					70 %	Restricted	6.72 %	553	69	37.1	4.6
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	**3533**	**442**	**67.8**	**8.5**
					70 %	Restricted	4.48 %	1250	156	56.0	7.0
			70 %	Annulus	30 %	Open	8.40 %	3495	437	293.6	36.7
					70 %	Restricted	19.60 %	1314	164	257.6	32.2
			14 %	Drill pipe	30 %	Open	1.68 %	2668	334	44.8	5.6
					70 %	Restricted	3.92 %	1337	167	52.4	6.6
					Total sum:		100.00 %	**Risked rate:**		**1112** *Sm^3/day*	**139.0** *kSm^3/day*

5.4.3 RISKED BLOWOUT RATES TO SEA – WELL 03

Table 5-7 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 3.

Table 5-7: Blowout rates – Well no. 3 – surface release, gas condensate and oil.

Step 1	**Step 2**		**Step 3**		**Step 4**		**Step 5**	**Step 6**		**Step 7**	**Step 8**
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	*[%]*	*[Sm³/day]*	*[kSm³/day]*	*[Sm³/day]*	*[kSm³/day]*
Gas-Condensate	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	19	152	0.0	0.0
					70 %	Restricted	0.00 %	18	150	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	19	152	2.8	23.0
					70 %	Restricted	35.28 %	18	150	6.5	52.9
			16 %	Drill pipe	30 %	Open	2.88 %	18	151	0.5	4.4
					70 %	Restricted	6.72 %	18	150	1.2	10.1
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	32	261	0.6	5.0
					70 %	Restricted	4.48 %	31	255	1.4	11.4
			70 %	Annulus	30 %	Open	8.40 %	32	260	2.7	21.8
					70 %	Restricted	19.60 %	31	255	6.1	50.0
			14 %	Drill pipe	30 %	Open	1.68 %	32	258	0.5	4.3
					70 %	Restricted	3.92 %	31	254	1.2	10.0
					Total sum:		100.00 %	**Risked rate:**		**24** *Sm³/day*	**192.8** *kSm³/day*
Step 1	**Step 2**		**Step 3**		**Step 4**		**Step 5**	**Step 6**		**Step 7**	**Step 8**
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	*[%]*	*[Sm³/day]*	*[kSm³/day]*	*[Sm³/day]*	*[kSm³/day]*
Oil	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	5	1	0.0	0.0
					70 %	Restricted	0.00 %	5	1	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	5	1	0.7	0.1
					70 %	Restricted	35.28 %	5	1	1.6	0.2
			16 %	Drill pipe	30 %	Open	2.88 %	5	1	0.1	0.0
					70 %	Restricted	6.72 %	5	1	0.3	0.0
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	27	3	0.5	0.1
					70 %	Restricted	4.48 %	27	3	1.2	0.2
			70 %	Annulus	30 %	Open	8.40 %	27	3	2.3	0.3
					70 %	Restricted	19.60 %	27	3	5.3	0.7
			14 %	Drill pipe	30 %	Open	1.68 %	27	3	0.5	0.1
					70 %	Restricted	3.92 %	27	3	1.1	0.1
					Total sum:		100.00 %	**Risked rate:**		**14** *Sm³/day*	**1.7** *kSm³/day*

5.4.4 RISKED BLOWOUT RATES TO SEA – WELL 04

Table 5-8 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 4.

Table 5-8: Blowout rates – Well no. 4 – surface release, gas condensate and oil.

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Gas-Condensate	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	300	2457	0.0	0.0
					70 %	Restricted	0.00 %	168	1382	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	299	2450	45.2	370.4
					70 %	Restricted	35.28 %	166	1363	58.7	481.0
			16 %	Drill pipe	30 %	Open	2.88 %	261	2142	7.5	61.7
					70 %	Restricted	6.72 %	160	1313	10.8	88.2
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	2189	17948	42.0	344.6
					70 %	Restricted	4.48 %	223	1826	10.0	81.8
			70 %	Annulus	30 %	Open	8.40 %	2032	16661	170.7	1399.5
					70 %	Restricted	19.60 %	219	1798	43.0	352.4
			14 %	Drill pipe	30 %	Open	1.68 %	549	4502	9.2	75.6
					70 %	Restricted	3.92 %	208	1705	8.2	66.9
					Total sum:		100.00 %	**Risked rate:**		**405** *Sm³/day*	**3322.1** *kSm³/day*
Step 1	**Step 2**		**Step 3**		**Step 4**		**Step 5**	**Step 6**		**Step 7**	**Step 8**
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Oil	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	1097	137	0.0	0.0
					70 %	Restricted	0.00 %	648	81	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	1091	136	165.0	20.6
					70 %	Restricted	35.28 %	698	87	246.4	30.8
			16 %	Drill pipe	30 %	Open	2.88 %	1040	130	29.9	3.7
					70 %	Restricted	6.72 %	760	95	51.1	6.4
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	9910	1239	190.3	23.8
					70 %	Restricted	4.48 %	2020	252	90.5	11.3
			70 %	Annulus	30 %	Open	8.40 %	9609	1201	807.2	100.9
					70 %	Restricted	19.60 %	2060	257	403.7	50.5
			14 %	Drill pipe	30 %	Open	1.68 %	5084	635	85.4	10.7
					70 %	Restricted	3.92 %	1999	250	78.4	9.8
					Total sum:		100.00 %	**Risked rate:**		**2148** *Sm³/day*	**268.5** *kSm³/day*

5.4.5 RISKED BLOWOUT RATES TO SEA – WELL 05

Table 5-9 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 5.

Table 5-9: Blowout rates – Well no. 5 – surface release, gas condensate and oil.

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Gas-Condensate	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	113	930	0.0	0.0
					70 %	Restricted	0.00 %	103	848	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	112	916	16.9	138.5
					70 %	Restricted	35.28 %	103	841	36.2	296.6
			16 %	Drill pipe	30 %	Open	2.88 %	109	893	3.1	25.7
					70 %	Restricted	6.72 %	99	815	6.7	54.8
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	188	1541	3.6	29.6
					70 %	Restricted	4.48 %	150	1229	6.7	55.1
			70 %	Annulus	30 %	Open	8.40 %	183	1501	15.4	126.0
					70 %	Restricted	19.60 %	146	1201	28.7	235.4
			14 %	Drill pipe	30 %	Open	1.68 %	171	1400	2.9	23.5
					70 %	Restricted	3.92 %	139	1137	5.4	44.6
					Total sum:		100.00 %	**Risked rate:**		**126** *Sm³/day*	**1029.8** *kSm³/day*

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Oil	60 %	Kick *5 meter*	0 %	Open hole	30 %	Open	0.00 %	105	32	0.0	0.0
					70 %	Restricted	0.00 %	97	29	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	105	31	15.8	4.7
					70 %	Restricted	35.28 %	97	29	34.1	10.2
			16 %	Drill pipe	30 %	Open	2.88 %	104	31	3.0	0.9
					70 %	Restricted	6.72 %	99	30	6.6	2.0
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	255	77	4.9	1.5
					70 %	Restricted	4.48 %	210	63	9.4	2.8
			70 %	Annulus	30 %	Open	8.40 %	251	75	21.0	6.3
					70 %	Restricted	19.60 %	209	63	41.0	12.3
			14 %	Drill pipe	30 %	Open	1.68 %	241	72	4.1	1.2
					70 %	Restricted	3.92 %	213	64	8.3	2.5
					Total sum:		100.00 %	**Risked rate:**		**148** *Sm³/day*	**44.5** *kSm³/day*

5.4.6 RISKED BLOWOUT RATES TO SEA – WELL 06

Table 5-10 summarizes the detailed simulation results and the risking of blowout potentials for the hypothetical well no. 6.

Table 5-10: Blowout rates – Well no. 6 – surface release, gas condensate and oil.

Step 1	Step 2		Step 3		Step 4		Step 5	Step 6		Step 7	Step 8
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Gas-Condensate	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	220	1803	0.0	0.0
					70 %	Restricted	0.00 %	180	1478	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	214	1757	32.4	265.7
					70 %	Restricted	35.28 %	176	1447	62.2	510.4
			16 %	Drill pipe	30 %	Open	2.88 %	202	1653	5.8	47.6
					70 %	Restricted	6.72 %	168	1378	11.3	92.6
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	901	7388	17.3	141.8
					70 %	Restricted	4.48 %	309	2537	13.9	113.7
			70 %	Annulus	30 %	Open	8.40 %	701	5747	58.9	482.7
					70 %	Restricted	19.60 %	297	2438	58.3	477.8
			14 %	Drill pipe	30 %	Open	1.68 %	470	3856	7.9	64.8
					70 %	Restricted	3.92 %	273	2237	10.7	87.7
					Total sum:		100.00 %	**Risked rate:**		**279** *Sm³/day*	**2284.8** *kSm³/day*
Step 1	**Step 2**		**Step 3**		**Step 4**		**Step 5**	**Step 6**		**Step 7**	**Step 8**
	Penetration		Flowpath		BOP status		Total risk	Blowout potential	Blowout potential - gas	Risked Oil blowout rate	Risked Gas blowout rate
Status	Prob. %	Status	Prob. %	Status	Prob. %	Status	[%]	[Sm³/day]	[kSm³/day]	[Sm³/day]	[kSm³/day]
Oil	60 %	Kick 5 *meter*	0 %	Open hole	30 %	Open	0.00 %	591	177	0.0	0.0
					70 %	Restricted	0.00 %	441	132	0.0	0.0
			84 %	Annulus	30 %	Open	15.12 %	586	176	88.6	26.6
					70 %	Restricted	35.28 %	476	143	167.8	50.3
			16 %	Drill pipe	30 %	Open	2.88 %	575	173	16.6	5.0
					70 %	Restricted	6.72 %	533	160	35.8	10.7
	40 %	Swab *Full*	16 %	Open hole	30 %	Open	1.92 %	3494	1048	67.1	20.1
					70 %	Restricted	4.48 %	1874	562	83.9	25.2
			70 %	Annulus	30 %	Open	8.40 %	3345	1003	280.9	84.3
					70 %	Restricted	19.60 %	1835	550	359.6	107.9
			14 %	Drill pipe	30 %	Open	1.68 %	2749	825	46.2	13.9
					70 %	Restricted	3.92 %	1785	535	70.0	21.0
					Total sum:		100.00 %	**Risked rate:**		**1216** *Sm³/day*	**364.9** *kSm³/day*

5.5 COMBINED BLOWOUT RISK

If all 6 wells are given an equal probability the following estimate can be made for most likely outcome of a future blowout in the Labrador Sea:

Table 5-11: Blowout rates –overall risked average for the Labrador Sea

	Probability	**Oil case**	**Gas Condensate case**
	[%]	*[Sm³/day]*	*[Sm³/day]*
Well no. 1	16.7 %	222	228
Well no. 2	16.7 %	1112	309
Well no. 3	16.7 %	14	24
Well no. 4	16.7 %	2148	405
Well no. 5	16.7 %	148	126
Well no. 6	16.7 %	1216	279
	100.0 %	810	228.5

Most likely blowout rate: **519 Sm³/day**

6 LOCAL IMPACT

In this section a discussion is made based on local factors as climate, sea, ice and governing legislations. The discussion also includes a comparison between other oil regions regarding measures to maintain well control and Greenland.

Comparisons between rules and regulations in Greenland regarding offshore drilling activities have been made with **Arctic Canada**, **United States (Gulf Of Mexico)** and the **Norwegian Continental Shelf**.

6.1 INTRODUCTION, DEFINITIONS AND SOURCES OF INFORMATION

Government legislation varies between bodies in both philosophy and administration in the arctic offshore areas and other areas within drilling activities for hydrocarbons.

The evaluations in the following section is based on information in a report issued by The PEMBINA[1] institute (June 2011) [9] and information stated in Greenland Bureau of Minerals and Petroleum (BMP) Drilling Guidelines (May 2011) [5]. The title of the PEMBINA report is "*Comparing the Offshore Drilling Regulatory Regimes of the Canadian Arctic, the U.S., the U.K., Greenland and Norway*".

For more information about the PEMBINA Institute, *visit www.pembina.org*.

The Greenland BMP guidelines include specific well control guidelines and legislation requirements or reference to such documents from other authorities. Applicable examples include NORSOK standards. Where the NORSOK standards apply it has the consequence that also other industry recommended practices have been made legislative demanded in Greenland. This is due to being directly referred to in the NORSOK standards. Such standards include several API Recommended Practices. With regards to blowout risk and well control equipment the API Recommended Practice 53 (RP53) Blowout Prevention Equipment Systems for Drilling Wells [11] is therefore applicable in Greenland. The current issue is the API RP53 THIRD VERSION, MARCH 1997.

At the time of writing the API RP53 is under revision and FOURTH EDITION Ballot Draft 2 is now being reviewed.

Regarding the precautionary measures having direct and indirect influence on the risk for blowouts the text in the Greenland BMP drilling guidelines is supplemented by chapter 5.2 in the document:

Godkendelse af op til 7 (syv) efterforskningsboringer i henhold til § 15 i tilladelserne 2002/15, 2005/06, 2008/11 og 2011/16. [10]

Translated from Danish:

Approval of up to 7 (seven) exploration wells in accordance with § 15 of the permissions 2002/15, 2005/06, 2008/11 and 2011/16. [10]

Even though the Greenland BMP Drilling Guidelines [5] and the "Approval of up to 7 exploration well ...etc.", were released before the PEMBINA report a number of missing important information in the PEMBINA report have been noted. When such disagreements have been discovered the findings and conclusions in the current report have been based on the documented correct information that is available at

[1] The Pembina Institute is a Canadian non-profit think tank that advances sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance.

the time of writing. For convenient comparison of well control requirements in the different areas a table has been prepared showing a selection of the differences and/or similarities between the requirements under 4 different bodies.

Comparisons between rules and regulations in Greenland regarding offshore drilling activities have been made with **Arctic Canada**, **United States (Gulf Of Mexico)** and the **Norwegian Continental Shelf**.

Precautionary measures having direct and indirect influence on the risk for blowouts can be divided in main barriers including:

- Mechanical barriers
- Organizational barriers
- Legislation barriers
- Operational barriers and
- Barriers by means of competence and skill

All regulations incorporate the main barriers to a degree and administrate this through legislation and policing. "*Acknowledge of Consent*" or "*Godkendelsesbrev*" can only be issued if all requirements are met.

6.1.1 MECHANICAL BARRIERS

Well control equipment includes a number of components

- The BOP Stack with its connected valves, lines, high pressure manifolds and downstream of that the low pressure venting system with mud/gas separator including fluid line and gas vent line.

- Diverters provide means for alternate flow paths for gas-bearing mud returning from the marine riser through vent lines leading the flow overboard and away from the facility and personnel.

- A choke line directs flow of fluid or gas from a side outlet on the BOP stack to the surface choke manifold and through the kill manifold the rig pumps connects to a kill line connected to the a side outlet on the BOP stack directing fluid to the well. Choke and kill lines are manifolded such that each can be used for either purpose. The choke manifold is a set of high pressure valves with chokes and associated piping to which the fluid or gas from the choke line is directed and the backpressure is controlled.

- The rams and annular BOPs in the BOP stack are used to close off the annulus around the pipe in case of a kick or blowout. The blind/shear rams can shear the pipe and there are 4 types of rams: pipe, shear, variable bore and blind-shear.

- When well testing takes place subsurface safety valves are installed in the production tubing intended to isolate well pressure in fail-safe position in case of emergency.

- The assembly of High pressure housing, casing, cement, hangers and seal assemblies are included in the barrier elements below the BOP stack during drilling and later if well testing takes place in the exploration phase.

Equipment control systems

Control systems refer to the surface and subsea well control installations used to activate the subsea BOP and valves. Redundancy in well control equipment is required from some jurisdictions to provide additional back-up of BOP control. Jurisdictions demands that the well control equipment is remotely operated and have additional control options and besides automatic control options for certain situations.

Inspection and test requirements of equipment

Inspection of equipment and testing is critical to ensure that well control equipment is in good working order and is capable of performing its function. Jurisdictions have requirements for frequency of testing and inspection with requirement for record-keeping of test and inspection results.

Well barriers

The term "barrier" and the concept of a barrier are not used in all jurisdictions.

BMP has defined the important precautionary measures against blowouts and the means of contingency combating the effect of blowouts should they anyway occur by legislative requirements to the Operator.

BMP has based the Drilling Guidelines on the Norwegian NORSOK standards which are considered the most detailed and stringent standards used in the industry. Furthermore a number of specific well control precautionary requirements have been mentioned in the Drilling Guidelines.

- The Operator must have a recognized HSE Management System and the rigs and the vessels must have certification of fitness recognized by one of the recognised certifying bodies.
- There is a requirement for safety assessment of the Operator’s facilities, vessels, equipment, operating procedures, contingency plans and personnel including suitability and any limiting factors for operating in Arctic conditions.
- The MODUs (Mobile Offshore Drilling Units) must hold a valid Acknowledgement of Compliance (in Norwegian: Samsvarsuttalelse) or UK Safety Case.
- Drilling can only be permitted with the presence of a dual drilling rig in the area for fast response in the case of severe well control issues. Besides contingency plans for major personnel accidents, oil pollution, ice management and relief well drilling has to be prepared for approval.
- The BOP stack must include as a minimum 2 Pipe Shear Rams, comprising of 1 Blind Shear Ram and 1 Casing Shear Ram. This has been emphasized and is supplementing the requirements laid down by NORSOK D-010 [12] and the current version of the API RP53.
- BMP has emphasized that the BOP Control System must in addition to the regular control system be fitted with:
  - A Remotely Operated Acoustic Control System
  - A Hot Stab System for interference by a Remote operated Vehicle (ROV)
  - An automatic Dead Man Function to operate in case of loss of communication and power between the systems on surface and subsea.

In the following the requirements for well control for offshore drilling operations in the Canadian Arctic, the U.S., Norway and Greenland is reviewed. Legislation and regulations relating to well control fall under these categories:

- Well control equipment
- Equipment control systems
- Inspection and test requirements of pressure control equipment
- Well barriers

6.1.2 WELL CONTROL EQUIPMENT

Canadian Arctic Offshore (Well Control Equipment)

Canada’s National Energy Board (NEB) has performance-based regulations for well control. Section 19(f) of the *Canada Oil and Gas Drilling and Production Regulations* requires operators to conduct drilling and well operations in a manner that maintains full control of the well at all times. Section 35 requires the operator to ensure that adequate procedures, materials and equipment are in place and utilized to "minimize the risk of loss of well control." If there is a loss of control, all other wells in the installation must be shut down until the out-of-control well is secured and operators are required to take "all action necessary to rectify the situation is taken without delay, despite any condition to the contrary in the well approval." The operator must ensure that reliable equipment for well control is installed and operated during all well operations, to control kicks, prevent blow-outs and safely carry out all well activities. Well control equipment in this instance is not defined, but could include BOPs, diverters and wellhead equipment. During drilling, two independently- tested barriers are required, of which a BOP could be one of these. During formation flow testing, a floating drilling unit must have a subsea test tree that includes a valve that can be operated from the surface and can be automatically closed in the event of a loss of well control (a BOP), and a system that allows the test string to be hydraulically or mechanically disconnected within or below the blowout preventers. A fail-safe subsurface safety valve is required on every well capable of flow, and this valve must be designed, installed, operated and tested to prevent uncontrolled well flow. In permafrost regions, the valve must be installed in the tubing below the base of the permafrost. The presence of wellhead valve or Christmas tree equipment is not explicitly mandated, but section 48 of the *Canada Oil and Gas Drilling and Production Regulations [19]* does require that this equipment be designed to operate safely and efficiently under the maximum load conditions anticipated during the life of the well, and section 46 (c and d) require safe operations during testing and production. The NEB requires operators to submit a contingency plan that would contain details of their procedures to regain control of a lost well, including plans to drill a relief well. The NEB, as a policy, prohibits drilling into potential hydrocarbon-bearing zones without the ability to drill a relief well in the same season in the Beaufort Sea. To demonstrate the ability to drill a relief well, operators are required to show that a viable and suitable relief well drilling system would be available.

Comparison to Greenland BMP (Well control equipment)

Greenland has similar performance-based regulations for well control equipment when comparing to the Canadian Arctic offshore. The Greenland BMP guidelines have been based on the NORSOK standards. BMP requires the equipment to conform to NORSOK Standard D-001 Drilling Facilities and/or other international accepted and recognized industry standards and additional requirement set by BMP. Installation and use of diverter and BOP is included in the requirements. The MODU is further required to hold a valid Acknowledgement of Compliance (AoC), (in Norwegian: Samsvarsuttalelse), issued by the Petroleum Safety Authority of Norway, or equivalent a Safety Case issued by the Health and Safety Executives of the United Kingdom. An Acknowledgement of Compliance (AoC) is a decision by the Petroleum Safety Authority Norway that expresses the authorities' confidence that petroleum activities can be carried out using the facility within the framework of the regulations.

Dependant on the age, state of condition, historical and maintenance records among others, BMP may request a full third party review and reassessment of the complete Well Control System onboard the MODU prior to commencement of the drilling operations. This reassessment may also include shear testing of the BOP Shear Rams, test of the dead man system and documentation of the maintenance of the whole BOP system including the dead man system. The Drilling Programme shall be prepared and documented in accordance with the NORSOK Standard D-010 Well Integrity in Drilling and Well Operations.

The safety of the proposed drilling programme is assessed by the BMP prior to the authorization of any drilling programme and 'Approval to Drill'. This assessment is made to consider the safety of the programme by reviewing the system as a whole, including vessels, facilities, equipment, operating procedures and personnel. The operator shall present the application to drill with a dual drilling rig vessel presence policy which allows for fast contingency response in case of severe well control issues. Relief well drilling plan and programme must be submitted and presented to BMP for approval.

Well Testing planning and preparations shall be in accordance with NORSOK Standards D-010 Well Integrity in Drilling and Well Operations and D-SR-007 System Requirements, Well Testing Systems which requires the installation of both surface and subsurface safety valves.

United States (Well Control Equipment)

The U.S. has performance-based regulations for well control but prescriptive measures for BOP installations.

30 CFR 205.401[20] "What must I do to keep wells under control" requires the owner/designated operator to take necessary precautions to keep the well under control at all times by using the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick. All BOP systems (which include the BOP stack and associated equipment) must be designed, installed, maintained, tested, and used to ensure well control. Designs of BOPs must be verified by an independent third party to ensure that that blind-shear rams installed in the BOP stack are capable of shearing any drill pipe in the hole under maximum anticipated surface pressure, that the BOP system is specifically designed to operate in the specific well and conditions where it will be used, and that it is free from damage from any previous use.

It is required that the working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. All BOP systems must include a back-up accumulator, at least two BOP control stations, choke and kill lines on the BOP stack with two valves which can be remotely operated.

Subsea BOPs must meet requirements including:

- An accumulator system that meets or exceeds API RP 53
- A remotely operated vehicle (ROV) intervention capability (and a crew trained in ROV operations must be continually based on a floating drilling rig)
- Autoshear and deadman systems for dynamically positioned rigs
- Operational or physical barriers on BOP control panels
- Development and use of a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects
- For operations with 4 or more subsea BOPs, one BOP must be an annular, two must be equipped with pipe rams, and one must be equipped with blind-shear rams.

The regulations require the use of BOPs during drilling, completion operations and workover operations.

30 CFR 250.430 requires the use of a diverter system (consisting of a diverter sealing element, diverter lines, and control systems) for drilling a conductor or surface hole. The diverter system must be designed, installed, used, maintained, and tested to ensure proper diversion of gases, water, drilling fluid, and other materials away from facilities and personnel.

Subsurface safety valves are required through the incorporation of API Spec 14A [18] into *30 CFR 250.806 "Safety and pollution prevention equipment quality assurance requirements*".

As part of the submission for an exploration plan, operators are required to provide a statement that they are financially capable of drilling a relief well, to discuss the availability of a rig to drill a relief well in the event of a spill, and to estimate the time it would take to drill a relief well, but relief wells are not explicitly required as part of well control.

Comparison to Greenland BMP (Well control equipment)

The Greenland BMP guidelines have been based on the NORSOK standards. Wellbore monitoring and activities to maintain well integrity has been defined by the requirement for well barriers. NORSOK D-010 [12] requires:

- There shall be one well barrier in place during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled cross flow in the wellbore between formation zones.
- There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment.

The well control equipment and arrangement shall be according to NORSOK D-001 and NORSOK D-002. Requirements and guidelines for proper use of a well barrier in order for it to maintain its function and prevent damage during execution of activities and operations shall be described.

Further to the above NORSOK documents also chapter 5.2 in "Approval of up to 7 (seven) exploration wells in accordance with § 15 of the permissions 2002/15, 2005/06, 2008/11 and 2011/16" applies which states the following:

Translated from Danish:

5.2 Primary and secondary well barriers

For all drilling operations in Greenland waters, there must be at least 2 independent safety barriers for all systems, equipment and design. This is called the Primary and Secondary barriers. These barriers must be independent and should always be tested and verifiable.

All parameters relevant for preventing uncontrolled flow from the well shall be monitored. Methods and frequency for verifying the condition of the well barrier/WBEs shall be defined and documented. All instrumentation used for required monitoring of parameters shall be frequently checked and calibrated.

In the event of a failure or loss of a well barrier, immediate measures shall be taken in order to prevent escalation of the situation by activating the secondary well barrier. The situation shall then be normalized by restoring the primary well barrier or establishing an alternative well barrier before activities/operations can be resumed.

Dependant on the age, state of condition, historical and maintenance records among others, BMP may request a full third party review and reassessment of the complete Well Control System on-board the MODU prior to commencement of the drilling operations. This reassessment may also include shear testing of the BOP Shear Rams, test of the dead man system and documentation of the maintenance of the whole BOP system including the dead man system.

NORSOK D-010 [12] makes reference to API RP53 regarding BOP Rated Working Pressure which states that every installed ram BOP should have, as a minimum, a working pressure equal to the maximum anticipated surface pressure to be encountered.

The Greenland BMP Guidelines with the adoption of NORSOK standards with their further reference to supplementary API documents regarding well control systems meets similar or better legislative requirements for the majority of issues than revealed in the United States legislation.

Norway (Well Control Equipment)

Norway has some prescriptive regulations regarding use of well-control equipment, and performance-based requirements for the capability of that equipment to perform its intended function. Section 49 of the *Facilities Regulations* states that well control equipment shall be designed and capable of activation to ensure control of the well, and that well control equipment shall be designed and capable of activation such that it ensures barrier integrity. Section 53 of the *Facilities Regulations* requires that equipment in the well and on the surface shall be designed to safeguard controlled flow rates. Section 49 of the *Facilities Regulations* requires BOPs, diverters and a remote-controlled ram. The guidelines recommend NORSOK D-010 [12] and NORSOK D-001 standards be met in order to fulfil these requirements. Another offshore standard (*DNV-OS-E101[21]; Drilling Plant*) is mentioned in the guidelines as an alternative to NORSOK D-001. This second standard requires two shear rams, as opposed to only one required in NORSOK D-001.

Subsurface safety valves are required for the flow line and annulus (the space between the drill pipe and the sides of the well). Surface valves are also required. Section 86 of the *Activities Regulations* states that a relief well shall be used in the event of loss of well control, and that an action plans to drill this relief well shall be prepared. Guidelines for this section recommend that the action plan should contain a description of mobilization and organization of personnel and facilities, with reference to the NORSOK D-010 [12] standard.

Comparison to Greenland BMP (Well control equipment)

In comparison with Norway, the Greenland BMP guidelines for well control equipment have similar or equal performance requirements as a minimum. The reason as explained above is that the Greenland BMP Guidelines legislation have adopted the NORSOK Standards resulting in equality. The MODU is further required to hold a valid Acknowledgement of Compliance (AoC) or UK Safety Case.

6.1.3 Activation of Well Control Equipment:

Canadian Arctic Offshore (Activation of Well Control Equipment)

Operators are required to submit the details of well control equipment systems to the NEB as part of the application for well authorization, but the regulations do not stipulate where or how well control equipment can be activated. Operators must meet the requirements of section 35 of the Canada Oil and Gas Drilling and Production Regulations, which requires that procedures, materials and equipment be in place and utilized to minimize the risk of loss of well control.

Comparison to Greenland BMP (Activation of Well control equipment)

In comparison with Canadian Arctic Offshore the activation of the BOP Control System shall in addition to the regular control system comprise of a Remotely Operated Acoustic Control System for emergency situations. This BMP requirement is a repetition of the NORSOK D-001 which is identical in this respect and valid in Greenland.

Requirements for activation of BOP Control Systems have been addressed in NORSOK D-001 5.10.3.7 and states: The operation of BOP system, including wellhead, where applicable, shall be possible from the main BOP accumulator unit, and from the drillfloor.

Valid in Greenland is NORSOK D-010 [12] item 4.2.5.3 that has requirements for Remote Operated Vehicle (ROV) interference via panels on the drilling BOP and on the Lower Marine Riser Package LMRP.

United States (Activation of Well Control Equipment)

All BOP systems must include: a back-up accumulator, at least two BOP control stations, choke and kill lines with two valves which can be remotely operated, and outlets on the BOP stack for these lines. Subsea BOPs must have a dual pod control system, ROV intervention capability, autoshear and deadman systems, accumulator and automatic back up for the primary accumulator charging systems, at least two BOP control stations, one of which must be away from the drilling floor.

API Spec. RP16D item 5.9 [17] has autoshear and deadman systems as an optional feature, not always but optionally required as follows:

- 5.9 SPECIAL DEEPWATER/HARSH ENVIRONMENT FEATURES (OPTIONAL) where it states: For deepwater/harsh environment operations, particularly where multiplex BOP controls and dynamic positioning of the vessel are used, special control system features may be employed.

API Spec. RP16D item 5.9.2 describes the Autoshear Systems:

- Autoshear is a safety system designed to automatically shut in the wellbore in the event of disconnect of the LMRP. When the Autoshear is armed, disconnect of the LMRP closes the shear rams.

API Spec. RP16D item 5.9.3 describes the Deadman Systems:

- A Deadman system is a safety system that is designed to automatically close the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission in both subsea control pods.

Comparison to Greenland BMP (Activation of Well control equipment)

In comparison with United States the activation of the BOP Control System has been addressed and it is in alignment with the U.S. requirements including requirements regarding autoshear and deadman systems.

NORSOK D-010 [12] item 5.10.3.8 Special requirements for MODUs:

- When drilling with the BOP system installed on the seabed, an acoustic or an alternative control system shall in addition be installed.

Backup accumulator is addressed in NORSOK D-001 item 5.10.3.8 that for the acoustic system require accumulators for this system.

Two BOP control Stations have been addressed in NORSOK D-001 item 5.10.3.7 stating that the operation of the BOP system, including wellhead connection, where applicable, shall be possible from the main BOP accumulator unit, and from the drillfloor.

In Norway the Framework Regulations Section 49 overrules NORSOK D-001 by the following where 3 locations are required:

- it should be possible to activate the blowout preventer from at least three locations on the facility;
  - one activation panel at the driller's position
  - at least one independent activation panel in a safe area
  - The third activation alternative can be activated directly on the main unit/BOP.

The Norway Framework Regulations have not been referred to in the BMP Exploration Drilling Guidelines and the NORSOK D-001 with 2 locations as a minimum is valid.

The requirement for choke and kill lines with two valves which can be remotely operated has been addressed in NORSOK D-001 item 5.10.3 stating that each of the Choke and Kill outlets on the BOP stack shall be fitted with two gate valves arranged in series and installed close to the BOP. There are also requirements for minimum (1) Choke line outlet and (1) Kill line outlet.

BMP have similar to United States requirements that the subsea BOPs must have a dual pod control system. This is consequence of the implementation of API RP16 which is referred to in NORSOK D-001, where item 3 for HYDRAULIC CONTROL SYSTEMS FOR SUBSEA BOP STACKS states that because the subsea BOP stack is not easily accessible for maintenance and repair, redundant (backup) subsea pods and - umbilical's are provided.

Valid in Greenland is NORSOK D-010 [12] item 4.2.5.3 that has requirements for Remote Operated Vehicle (ROV) interference via panels on the drilling BOP and on the Lower Marine Riser Package LMRP.

Regarding deadman and autoshear systems:

The US requirement for autoshear and deadman systems has not been addressed by NORSOK. Greenland BMP has included dead man system and states:

Dependant on the age, state of condition, historical and maintenance records among others, BMP may request a full third party review and reassessment of the complete Well Control System onboard the MODU prior to commencement of the drilling operations. This reassessment may also include shear testing of the BOP Shear Rams, test of the dead man system and documentation of the maintenance of the whole BOP system including the dead man system.

Norway (Activation of Well Control Equipment)

Section 49 of the *Facilities Regulations* requires that the blind shear ram must be capable of being remotely-controlled. The guidelines for this section recommend that in order to meet the requirement of well control, that the main unit of the activation system should be located at a safe distance from the well, that the BOP can be activated from at least three locations (one in a safe area), and that in the event of well intervention, it should be possible to activate pressure control equipment from at least two locations on the facility (one in a safe area). The pressure control equipment used in well interventions is required to have remote-controlled valves with mechanical locking mechanisms in the closed position. This section also requires that floating facilities have an alternative activation system of the BOP and a system that ensures release of the riser before a critical angle occurs.

Comparison to Greenland BMP (Activation of Well control equipment)

In comparison with Norway, the Greenland BMP guidelines for activation of well control equipment have similar or equal performance requirements as a minimum. The reason as explained above is that the Greenland BMP Guidelines legislation have adopted the NORSOK Standards resulting in equality. The MODU is further required to hold a valid Acknowledgement of Compliance (AoC) or UK Safety Case.

6.1.4 INSPECTION, TEST AND MAINTENANCE REQUIREMENTS OF PRESSURE CONTROL EQUIPMENT

Canadian Arctic Offshore (Inspection, test and maintenance requirements of pressure control equipment)

Canada's National Energy Board regulations requires that all equipment (including pressure control equipment) to be tested under the maximum load conditions that are reasonably anticipated during any operation and those records of all testing are kept. Regulations require that all equipment be kept in an operable condition and that processes for ensuring and maintaining the integrity of equipment must be outlined in the management system.

Comparison to Greenland BMP (Inspection, test and maintenance requirements of pressure control equipment)

Dependant on the age, state of condition, historical and maintenance records among others, BMP may request a full third party review and reassessment of the complete Well Control System on-board the MODU prior to commencement of the drilling operations. This reassessment may also include shear testing of the BOP Shear Rams, test of the dead man system and documentation of the maintenance of the whole BOP system including the dead man system. Greenland BMP requires that the Drilling Programme shall be prepared and documented in accordance with the NORSOK Standard D-010 Well Integrity in Drilling and Well Operations. The NORSOK D-010 [12] standard Annex A (Normative) describes the criteria for Leak test pressures and frequency for well control equipment.

Accordingly the test details including frequency for the entire system including the BOP, Manifolds and other equipment have been laid out which is comprehensive:

Table 6-1: Leak test pressures and frequency for well control equipment, Source : NORSOK D-010, Annex A.

Annex A
(Normative)
Leak test pressures and frequency for well control equipment

Table A.1 - Routine leak testing of drilling BOP and well control equipment

	Frequency / Element	Stump	Before drilling out of casing		Before well testing	Periodic		
			Surface	Deeper casing and liners		Weekly	Each 14 days	Each 6 months
BOP	Annulars	MWDP 1)	Function	MSDP 1)	TSTP 1)	Function	MSDP 1)	WP x 0,7
	Pipe rams	MWDP	Function	MSDP	TSTP	Function	MSDP	WP
	Shear rams	MWDP	Function	MSDP	TSTP	Function		WP
	Failsafe valves	MWDP	Function	MSDP 3)	TSTP	Function	MSDP 3)	WP
	Well head connector	MWDP	MSDP		TSTP		MSDP	WP
	Wedge locks	Function						
Choke/kill line and manifold	Choke/kill lines	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	manifold	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	Valves	Function	Function	Function	Function		Function	
	Remote chokes							
Other equipment	Kill pump	WP 2)		MSDP			MSDP	WP
	Inside BOP	MWDP 2)		MSDP	TSTP		MSDP	WP
	Stabbing valves	MWDP 2)		MSDP	TSTP		MSDP	WP
	Upper kelly valve	MWDP 2)		MSDP			MSDP	WP
	Lower kelly valve	MWDP 2)		MSDP			MSDP	WP

Legend

WP	working pressure
MWDP	maximum well design pressure
MSDP	maximum section design pressure
Function	Function testing: testing shall be done from alternating panels/pods.
TSTP	tubing string test pressure
1)	Or maximum 70 % of WP
2)	Or at initial installation
3)	From above if restricted by BOP arrangement

NOTE 1 All tests shall be 1,5 MPa to 2 MPa/5 min and high pressure/10 min.

NOTE 2 If the drilling BOP is disconnected/re-connected or moved between wells without having been disconnected from its control system, the initial leak test of the BOP components can be omitted. The wellhead connector shall be leak tested.

NOTE 3 The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

The operator is required to deliver a Drilling Programme including a programme for pressure testing of blow-out preventers and casing at different stages in the drilling operations. The pressure test frequency of the BOP and connected pressure control equipment is 14 days and the BOP Control system shall be tested every 7 days.

Maintenance Programmes in line with the Safety Management System need to be in place and demonstrable.

NORSOK D-010 [12] states in Annex A NOTE 3: The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

United States (Inspection, test and maintenance requirements of pressure control equipment)

The regulations 30 CFR 250 require that all BOP systems must be maintained and inspected according to API RP 53. The BOP system must be pressure-tested every 14 days or, when drilling, before each new string of casing or liner. Tests must take place at low and high pressures, and last for at least five minutes. Records of time, date, and results of all pressure tests, actuations, and inspections must be kept for the duration of drilling. Tests must be with water. Subsea BOPs must be inspected every three days. Subsea BOPs must be stump-tested, and the functionality of ROVs, autoshear and deadman systems must be tested regularly. Diverter systems must be activated, and vent lines must be flow tested at least once every 24- hour period after the initial test. Diverter sealing elements and diverter valves must be tested to a minimum of 200 psi after assembling well-control or pressure-control equipment on the conductor casing, and once the diverter is installed, it must be tested every seven days. For floating drilling operations with a subsea BOP stack, the diverter must be actuated every seven days, and testing must be alternated between control stations. Records of time, date, and results of all diverter pressure tests, actuations, and inspections must be kept for the duration of drilling.

The regulations refer to API RP 53 “Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells” for maintenance requirements. This reference states that well control equipment should be disassembled every three to five years.

Comparison to Greenland BMP (Inspection, test and maintenance requirements of pressure control equipment)

The BMP complies with the NORSOK D-010 [12] standard Annex A (Normative) describing the criteria for Leak test pressures and frequency for well control equipment.

Accordingly the test details including frequency for the entire system with the BOP, Manifolds and other equipment have been laid out which is comprehensive.

Maintenance Programmes in line with the Safety Management System need to be in place and demonstrable.

The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

Norway (Inspection, test and maintenance requirements of pressure control equipment)

A maintenance program is required that must include monitoring of the performance and technical condition of equipment, and plans to repair any failures. A number of standards are recommended in the guidelines to help shape the components of the maintenance program. Regulations require that the BOP and associated pressure control equipment be pressure tested and function tested. Guidelines recommend pressure testing every 14 days, and function testing every seven days. Moreover, regulations state that the BOP and associated equipment should be completely overhauled and recertified every five years.

Comparison to Greenland BMP (Inspection, test and maintenance requirements of pressure control equipment)

The Greenland BMP has requirement in relation to maintenance and includes that in line with the Safety Management System the maintenance programme needs to be in place and demonstrable. The applicable NORSOK D-010 [12] Standard Annex A (Normative) describes the criteria for Leak test pressures and frequency for well control equipment. In line with the Acknowledgement of Compliance (AoC), UK Safety Case and NORSOK there are requirements for documentation for maintenance of drilling equipment and installations including BOP with choke manifold (NORSOK D-001). Due to that the NORSOK standards have been adopted the Greenland requirements has a solid foundation.

6.1.5 WELL BARRIERS

Canadian Arctic Offshore (Well barriers)

Canada's National Energy Board requires that at least two independent and tested well barriers are in place during all well operations after setting the surface casing. If a barrier fails, then no activity, other than those intended to restore or replace the barrier, can take place in the well. During drilling, one of the two barriers must be maintained in the drilling fluid column except when the well is underbalanced.

Comparison to the Greenland BMP (Well barriers)

Drilling operations according to Greenland BMP shall be conducted in accordance with the NORSOK Standard D-010 Well Integrity in Drilling and Well Operations. During drilling operations, all necessary steps shall be taken to prevent explosion, blowouts, pollution, or other damage. Apart from possible drilling when setting the conductor pipe and surface casing, drilling must not be carried out before blowout preventers/diverter system and related equipment have been installed and tested.

NORSOK Standard D-010 is the foundation for the well barrier philosophy and is detailed for all well operations. It has definitions and illustrations for elements included in the criteria to meet the objective of two independent barriers while drilling. Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or Well Barrier Elements for its intended use.

There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment.

Additional requirements in Greenland BMP Exploration Drilling Guidelines:

The use of cement bond log or temperature survey must be run when critical tops of cement (TOCs) are required for intermediate and production casing isolation. The cementation of production casing and liners must be checked with cement bond logging in situations where the cement job needs further verification.

United States (Well barriers)

New regulations developed since April 2010 require that two independent tested barriers, including one mechanical barrier, to be present across each flow path during well completion activities as part of the casing and cementing requirements. The new regulations also require identification of mechanical barriers and cementing practices for each casing string as part of an application for a drilling permit.

Comparison to the Greenland BMP (Well barriers)

The Greenland BMP in adoption of the NORSOK D-010 [12] Standard is in agreement with the U.S. philosophy regarding requirement for two independent tested barriers.

Norway (Well barriers)

The concept of well barriers and the control of barriers are prominent in Norway. Barriers are applied to reduce the probability of failures, hazards and accident situations developing and to limit possible harm and disadvantages. Barriers are to be selected based on a determination of the potential to reduce risk, with prioritization for those barriers that reduce collective risk rather than individual risk. Tested barriers are required during drilling and well activities. The regulations do not state how many barriers are required, but do state that when more than one barrier is necessary, each barrier must function independently so that multiple important barriers will not malfunction simultaneously.

If a barrier fails, no other activities shall take place other than those intended to restore the well barrier. Well barriers "shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime." Barriers must also be designed so that their performance can be verified. The guidelines for both sections refers to NORSOK D-010 [12] which requires the operator to define their well barriers and their acceptance criteria prior to commencement of an activity or operation and give guidance on the acceptance criteria for a well barrier and how it can be tested and monitored.

Comparison to the Greenland BMP (Well barriers)

The Greenland BMP in adoption of the NORSOK D-010 [12] Standard is in agreement with the requirements in Norway regarding well barriers.

A comparison of these requirements among all jurisdictions is made in the table below.

Table 6-2: Comparison table of legislator regimes

Regulatory topic	Canadian Arctic offshore	United States	Norway	Greenland
1: Requirements for well control	Operators are required to maintain full well control while drilling and operating.	Operators are required to take necessary precautions for well control at all times.	Operators are required to use equipment to ensure control of the well and maintain barrier integrity.	Operators are required to use equipment to ensure control of the well and maintain barrier integrity.
	Reliably operating well control equipment to prevent blow-outs is required.	Blowout preventers and associated equipment are required.	Well intervention equipment is required in regulations. Guidelines recommend use of blowout preventers and shear rams.	Well intervention equipment is required in regulations. Guidelines recommend use of blowout preventers and shear rams. Minimum 2 pipe shear rams, comprising of 1 blind shear and 1 casing shear rams.
	Regulations do not mention a diverter system.	A diverter system is required by regulation.	A diverter is required in the regulations.	A diverter is required apart from drilling when setting the conductor pipe and surface casing.
	A subsurface safety valve is required on every well capable of flow. Surface safety valves are implicitly required.	Surface and subsurface safety valves are required by legislation.	Subsurface and surface safety valves are required.	Subsurface and surface safety valves are required.
	A policy requires capacity for a relief well in the same season as drilling for operations in the Beaufort Sea.	As part of application, operators must demonstrate financial capability and suggest time require to drill a relief well.	Regulations require that a relief well be drilled in the event of loss of well control. Operators must demonstrate an action plan to drill the well.	A relief well contingency plan is required with the application. Dual drilling rig vessel presence is required.
2: Activation of well control systems	There are no specifications about the control system, but operators must submit information about equipment control systems to the regulator.	Control systems for blowout preventers must include redundant power supply and control centres. Subsea blowout preventers must have ROV control capability.	Blowout preventers must be able to be remotely activated from three locations, where at least one is located in a safe area. Additional acoustic or alternative system is required.	Blowout preventers must be able to be remotely activated from tree locations. Additional acoustic or alternative system is required. ROV intervention capability is required.

Regulatory topic	Canadian Arctic offshore	United States	Norway	Greenland
3: Inspection and test requirements of pressure control equipment	Equipment must be tested at the maximum load conditions that may be reasonably anticipated during any operation. Records of testing must be kept.	Blowout preventers systems must be tested every 14 days, at high and low pressure. They must be visually inspected every three days. Records of testing must be kept.	Regulations require maintenance and monitoring program to be developed based on importance of the equipment. Guidelines suggest testing blowout preventers every 14 days.	License holder must submit a program for testing of blow-out preventers. Min 2 independent tested barriers required before disassembly of BOPs. Testing of BOPs every 14 days is required.
4: Well Barriers	At least two independent and tested well barriers must be in place during all well operations after setting the surface casing.	At least two barriers (at least one mechanical) are required across the flow path during well completion.	Barriers are required for well control. Barrier testing is required, and barriers should be selected based on the ability to reduce risk.	Barriers are required for well control. Barrier testing is required, and barriers should be selected based on the ability to reduce risk.

6.1.6 SUMMING UP

The Greenland Bureau of Minerals and Petroleum Drilling Guidelines provide specific direction where the BMP have been given the authority to prescribe, provide guidance and approve drilling and related activities.

Reviewing the BMP Exploration Drilling Guidelines in comparison with the legislative papers for the other areas used in this report, there are reasons to mention that the Greenland BMP has made thorough preparations for reducing risks and avoiding blowouts.

This evaluation is based on the fact that the BMP guidelines have used the most comprehensive set of regulations in the industry as the foundation for the guidelines in Greenland and made those legitimate.

Examples include as mentioned above:

- Introduction of amongst other NORSOK D-001 [13], NORSOK D-010 [12] and NORSOK D-SR-007 [14], NORSOK R-003 [15] and NORSOK Z-013 [16],
- Use of supplementary industry Standards from American Petroleum Institute
- Introduction of BMP requirements in addition to the above through BMP Drilling Guidelines and letter of approval.

Further it has been noted that important learning from the Macondo blowout in 2010 has been addressed as additional precautionary requirements in the BMP Exploration Drilling Guidelines.

A few examples include:

- Management of change and risk assessment
- BOP with 2 sets of shearing blind rams as a minimum
- Additional BOP controls including both acoustic activation and ROV intervention
- Use of well barrier definitions
- Details regarding casing design
- Details regarding cementing
- Details regarding third party assessment
- Details regarding testing of cement jobs
- Accepting only the most stringent well control certification of drilling personnel
- Crew shift handover routines that must be documented
- Demanded safety meetings and crew drills regarding well control

Risk for blowout cannot be excluded during any drilling operations, but the risk can be reduced by introducing the best practices available in the industry. It is important to keep focus and constantly be alert looking for relevant improvements and then implement such improvements.

7 DISCUSSION OF RESULTS

In this report the risk of experiencing an uncontrolled blowout when drilling exploration wells in the Labrador Sea South-West of Greenland have been addressed together with the potential consequences of such blowout with respect to expected blowout rate and the most likely duration of a blowout.

As the potential blowout rates are highly sensitive to the parameters reservoir properties, pore pressure, permeability and fluid composition 6 hypothetical wells have been designed, which all together is believed to describe the possible outcome of future wells in the area.

By giving the 6 wells equal probabilities, an overall expected blowout estimate can be made for the area.

No HPHT scenarios have been evaluated, as data of relevance is not available.

The statistical probability for a blowout is found to be higher than if addressing the blowout risk with a more modern risk methodology. It is believed that the historical model, which is based upon a 20 year moving average, will respond too slowly to account for technological and operational improvements which enhance the operational safety.

Therefore a blowout risk equal to 7.7E-5, i.e. one blowout for every 12987 exploration wells drilled is estimated for this area.

When estimating the most likely duration of a future blowout, the new initiative to prefabricate subsea capping devices have been implemented and accounted for. It is recommended to use the statistical model when estimating duration, as the simplified model is believed to overestimate slightly.

8 CONCLUSIONS

For drilling in the Labrador Sea the statistical data available for analysing probabilities and consequences for a future blowout is examined. The statistical data is analysed and combined with modern risk methodology as technology development and improved attention in the industry has made early kick detection possible at an early stage in modern drilling operations.

The overall probability for a future blowout in the Labrador Sea is found to be 7.7E-5, i.e. one blowout for every 12987 wells drilled.

Most likely expected rate, i.e. weighted average rate of oil released to sea is found to be 519 Sm^3/day of oil.

As this is the statistical most likely value found, both higher and lower values must be expected.

Maximum blowout potential found for the most productive scenario was 9910 Sm^3/day of oil.

Differences between surface releases and subsea releases are found to be small. Surface rates are presented as the weighted average.

The most likely duration of such blowout is found to be 14 days.

Maximum duration for a blowout in the area is estimated to 75 days based on normal operational progress.

Environmental impact from methane exposure to the atmosphere is not addressed in this report, but should be discussed in the final environmental assessment.

Summary table:

Table of results: Main findings		
Blowout frequency found:	*7.7E-5*	*[-]*
Number of wells drilled pr blowout:	*12987*	*[-]*
Most likely blowout rate of oil:	*519*	*[Sm^3/day]*
Most likely blowout rate of gas:	*3.3*	*[MSm^3/day]*
Maximum blowout potential – oil	*9910*	*[Sm^3/day]*
Maximum blowout potential – gas	*17.95*	*[MSm^3/day]*
Most likely duration of a surface blowout	*10.7*	*[days]*
Most likely duration of a subsea blowout	*14.3*	*[days]*
Most likely duration of all blowouts	*14*	*[days]*

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12. NORSOK D-010: "Well integrity in drilling and well operations", Rev. 3- August 2004

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15. NORSOK R-003: " *Safe use of lifting equipment*", Rev.3, July 2004

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17. API Spec. 16D: "Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment.", 2004

18. API Spec. 14A/ISO 10432: "Specification of Subsurface Safety Valve Equipment",2004

19. Canada Oil and Gas Drilling and Production Regulations SOR/2009-315

20. 30 CFR 250.401: "What must I do to keep wells under control?"

21. DNV-OS-E101:"Drilling Plant.", 2009

10 APPENDIX LIST

A. About Acona Flow Technology AS
B. Detailed listing of simulation results

APPENDIX A - ABOUT ACONA FLOW TECHNOLOGY AS

Acona Flow Technology AS

Since 2006 Acona has built a unique expert team within flow modelling and simulations services, named Acona Flow Technology. This group has the capability and the ambition to contribute to increased operational safety, minimization of risks and increased profitability for its clients.

Acona Flow Technology has the mission to:

- Deliver best-in-class services within blowout modelling and well control
- Provide simulation services based on state-of-the-art tools and models
- Offer in-depth understanding and analytical approach to complex flow phenomena
- Serve various industries worldwide, and transfer know-how across industries
- Attract world-class specialists and enthusiastic talents through outstanding reputation

Acona Flow Technology provides simulations and advisory services to the oil and gas industry within the following areas:

Blowout contingency planning
Risk management and contingency documentation through advanced simulations and operational insight.

Simulation services, advisory services, risk management and peer review services.

Wellkill planning and well control advisory
Transient kill simulations as mandatory documentation of kill capability and to assist well engineering teams.

Emergency response teams
IWCF certified teams available to assist planning, preparation and execution of wellkill operations worldwide

Flow assurance teams
Skilled seniors with long industrial training available for detailed flow assurance studies related to well and flowline hydraulics, thermal performance, production chemistry or metallurgy.

Complete design-basis engineering studies can be delivered.

Computational Fluid Dynamics
Advanced CFD experts are available for in-depth analysis of process related flow phenomena and their interaction with structure.

Wind, gas, explosion, spill, separation, settling, erosion, insulation, combustion and radiation are some of many areas to be covered with CFD.

For more information, please contact Acona Flow Technology.

APPENDIX B DETAILED LISTING OF SIMULATION RESULTS

Gas - Condensate Seabed release

Penetration	Flowpath	BOP Status	Oil blowout potential [Sm³/day]	Gas blowout potential [kSm³/day]
Pseudo well - 01:				
Kick	Open hole	Open	283	2317
5 meter		Restricted	162	1328
	Annulus	Open	282	2312
		Restricted	160	1309
	Drillpipe	Open	245	2013
		Restricted	152	1246
Swab	Open hole	Open	534	4376
Full		Restricted	187	1535
	Annulus	Open	531	4357
		Restricted	184	1511
	Drillpipe	Open	361	2957
		Restricted	174	1426
Pseudo well - 02:				
Kick	Open hole	Open	310	2539
5 meter		Restricted	173	1417
	Annulus	Open	309	2531
		Restricted	170	1396
	Drillpipe	Open	265	2174
		Restricted	163	1338
Swab	Open hole	Open	1144	9377
Full		Restricted	220	1802
	Annulus	Open	1108	9083
		Restricted	216	1772
	Drillpipe	Open	494	4048
		Restricted	204	1676
Pseudo well - 03:				
Kick	Open hole	Open	19	152
5 meter		Restricted	18	150
	Annulus	Open	19	152
		Restricted	18	150
	Drillpipe	Open	18	151
		Restricted	18	150
Swab	Open hole	Open	32	261
Full		Restricted	31	255
	Annulus	Open	32	260
		Restricted	31	255
	Drillpipe	Open	32	258
		Restricted	31	254
Pseudo well - 04:				
Kick	Open hole	Open	300	2457
5 meter		Restricted	168	1382
	Annulus	Open	299	2450
		Restricted	166	1363
	Drillpipe	Open	261	2142
		Restricted	160	1313
Swab	Open hole	Open	2189	17948
Full		Restricted	223	1826
	Annulus	Open	2032	16661
		Restricted	219	1798
	Drillpipe	Open	549	4502
		Restricted	208	1705
Pseudo well - 05:				
Kick	Open hole	Open	113	930
5 meter		Restricted	103	848
	Annulus	Open	112	916
		Restricted	103	841
	Drillpipe	Open	109	893
		Restricted	99	815
Swab	Open hole	Open	188	1541
Full		Restricted	150	1229
	Annulus	Open	183	1501
		Restricted	146	1201
	Drillpipe	Open	171	1400
		Restricted	139	1137
Pseudo well - 06:				
Kick	Open hole	Open	220	1803
5 meter		Restricted	180	1478
	Annulus	Open	214	1757
		Restricted	176	1447
	Drillpipe	Open	202	1653
		Restricted	168	1378
Swab	Open hole	Open	901	7388
Full		Restricted	309	2537
	Annulus	Open	701	5747
		Restricted	297	2438
	Drillpipe	Open	470	3856
		Restricted	273	2237

Oil Surface release

Penetration	Flowpath	BOP Status	Oil blowout potential [Sm³/day]	Gas blowout potential [kSm³/day]
Pseudo well - 01:				
Kick	Open hole	Open	267	2193
5 meter		Restricted	164	1348
	Annulus	Open	267	2190
		Restricted	163	1336
	Drillpipe	Open	247	2028
		Restricted	159	1307
Swab	Open hole	Open	503	4128
Full		Restricted	191	1568
	Annulus	Open	501	4107
		Restricted	189	1553
	Drillpipe	Open	398	3266
		Restricted	184	1513
Pseudo well - 02:				
Kick	Open hole	Open	308	2529
5 meter		Restricted	173	1421
	Annulus	Open	308	2522
		Restricted	171	1402
	Drillpipe	Open	269	2205
		Restricted	165	1355
Swab	Open hole	Open	1141	9355
Full		Restricted	221	1811
	Annulus	Open	1105	9064
		Restricted	218	1785
	Drillpipe	Open	551	4516
		Restricted	208	1704
Pseudo well - 03:				
Kick	Open hole	Open	18	150
5 meter		Restricted	18	150
	Annulus	Open	18	150
		Restricted	18	150
	Drillpipe	Open	18	150
		Restricted	18	149
Swab	Open hole	Open	32	258
Full		Restricted	31	255
	Annulus	Open	31	258
		Restricted	31	255
	Drillpipe	Open	31	257
		Restricted	31	255
Pseudo well - 04:				
Kick	Open hole	Open	298	2446
5 meter		Restricted	169	1386
	Annulus	Open	298	2440
		Restricted	167	1370
	Drillpipe	Open	265	2173
		Restricted	162	1330
Swab	Open hole	Open	2187	17930
Full		Restricted	224	1837
	Annulus	Open	2030	16648
		Restricted	221	1811
	Drillpipe	Open	681	5582
		Restricted	211	1729
Pseudo well - 05:				
Kick	Open hole	Open	93	759
5 meter		Restricted	90	738
	Annulus	Open	92	758
		Restricted	90	735
	Drillpipe	Open	92	753
		Restricted	89	731
Swab	Open hole	Open	149	1219
Full		Restricted	136	1114
	Annulus	Open	147	1206
		Restricted	134	1099
	Drillpipe	Open	144	1183
		Restricted	132	1086
Pseudo well - 06:				
Kick	Open hole	Open	192	1576
5 meter		Restricted	175	1433
	Annulus	Open	190	1555
		Restricted	172	1410
	Drillpipe	Open	186	1525
		Restricted	170	1394
Swab	Open hole	Open	775	6357
Full		Restricted	316	2589
	Annulus	Open	630	5166
		Restricted	305	2503
	Drillpipe	Open	531	4357
		Restricted	298	2442

Gas - Condensate Surface release

Penetration	Flowpath	BOP Status	Oil blowout potential $[Sm^3/day]$	Gas blowout potential $[kSm^3/day]$
Pseudo well - 01:				
Kick	Open hole	Open	162	4.3
5 meter		Restricted	155	4.3
	Annulus	Open	162	4.3
		Restricted	155	4.3
	Drillpipe	Open	162	7.7
		Restricted	155	7.0
Swab	Open hole	Open	358	9.7
Full		Restricted	301	9.4
	Annulus	Open	358	9.9
		Restricted	302	9.5
	Drillpipe	Open	354	19
		Restricted	302	15
Pseudo well - 02:				
Kick	Open hole	Open	749	94
5 meter		Restricted	427	53
	Annulus	Open	745	93
		Restricted	480	60
	Drillpipe	Open	715	89
		Restricted	553	69
Swab	Open hole	Open	3533	442
Full		Restricted	1250	156
	Annulus	Open	3495	437
		Restricted	1314	164
	Drillpipe	Open	2668	334
		Restricted	1337	167
Pseudo well - 03:				
Kick	Open hole	Open	5	0.6
5 meter		Restricted	5	0.6
	Annulus	Open	5	0.6
		Restricted	5	0.6
	Drillpipe	Open	5	0.6
		Restricted	5	0.6
Swab	Open hole	Open	22	2.8
Full		Restricted	22	2.8
	Annulus	Open	23	2.9
		Restricted	23	2.9
	Drillpipe	Open	27	3.4
		Restricted	27	3.4
Pseudo well - 04:				
Kick	Open hole	Open	1097	137
5 meter		Restricted	648	81
	Annulus	Open	1091	136
		Restricted	698	87
	Drillpipe	Open	1040	130
		Restricted	760	95
Swab	Open hole	Open	9910	1239
Full		Restricted	2020	252
	Annulus	Open	9609	1201
		Restricted	2060	257
	Drillpipe	Open	5084	635
		Restricted	1999	250
Pseudo well - 05:				
Kick	Open hole	Open	105	32
5 meter		Restricted	97	29
	Annulus	Open	105	31
		Restricted	97	29
	Drillpipe	Open	104	31
		Restricted	99	30
Swab	Open hole	Open	255	77
Full		Restricted	210	63
	Annulus	Open	251	75
		Restricted	209	63
	Drillpipe	Open	241	72
		Restricted	213	64
Pseudo well - 06:				
Kick	Open hole	Open	591	177
5 meter		Restricted	441	132
	Annulus	Open	586	176
		Restricted	476	143
	Drillpipe	Open	575	173
		Restricted	533	160
Swab	Open hole	Open	3494	1048
Full		Restricted	1874	562
	Annulus	Open	3345	1003
		Restricted	1835	550
	Drillpipe	Open	2749	825
		Restricted	1785	535

Oil Seabed release

Penetration	Flowpath	BOP Status	Oil blowout potential $[Sm^3/day]$	Gas blowout potential $[kSm^3/day]$
Pseudo well - 01:				
Kick	Open hole	Open	73	3.9
5 meter		Restricted	73	3.9
	Annulus	Open	73	3.9
		Restricted	73	3.9
	Drillpipe	Open	73	4.0
		Restricted	73	4.0
Swab	Open hole	Open	163	8.7
Full		Restricted	162	8.7
	Annulus	Open	165	8.7
		Restricted	164	8.7
	Drillpipe	Open	166	9.2
		Restricted	165	9.2
Pseudo well - 02:				
Kick	Open hole	Open	685	86
5 meter		Restricted	499	62
	Annulus	Open	687	86
		Restricted	554	69
	Drillpipe	Open	667	83
		Restricted	574	72
Swab	Open hole	Open	3294	412
Full		Restricted	1378	172
	Annulus	Open	3272	409
		Restricted	1443	180
	Drillpipe	Open	2641	330
		Restricted	1421	178
Pseudo well - 03:				
Kick	Open hole	Open	5	0.6
5 meter		Restricted	5	0.6
	Annulus	Open	5	0.6
		Restricted	5	0.6
	Drillpipe	Open	5	0.6
		Restricted	5	0.6
Swab	Open hole	Open	22	2.8
Full		Restricted	22	2.8
	Annulus	Open	23	2.8
		Restricted	23	2.8
	Drillpipe	Open	24	2.9
		Restricted	24	2.9
Pseudo well - 04:				
Kick	Open hole	Open	1028	128
5 meter		Restricted	726	91
	Annulus	Open	1028	129
		Restricted	778	97
	Drillpipe	Open	991	124
		Restricted	791	99
Swab	Open hole	Open	9437	1180
Full		Restricted	2203	275
	Annulus	Open	9167	1146
		Restricted	2232	279
	Drillpipe	Open	5280	660
		Restricted	2149	269
Pseudo well - 05:				
Kick	Open hole	Open	87	26
5 meter		Restricted	86	26
	Annulus	Open	87	26
		Restricted	86	26
	Drillpipe	Open	87	26
		Restricted	86	26
Swab	Open hole	Open	193	58
Full		Restricted	189	57
	Annulus	Open	193	58
		Restricted	189	57
	Drillpipe	Open	193	58
		Restricted	188	56
Pseudo well - 06:				
Kick	Open hole	Open	389	117
5 meter		Restricted	387	116
	Annulus	Open	413	124
		Restricted	411	123
	Drillpipe	Open	412	124
		Restricted	410	123
Swab	Open hole	Open	2524	757
Full		Restricted	2063	619
	Annulus	Open	2458	737
		Restricted	2023	607
	Drillpipe	Open	2353	706
		Restricted	1977	593

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