Report

Blowout rates and duration

Exploration well 7018/5-1 Spissa

Rev 1 – 18th November 2019

Ranold.

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Executive Summary

This report summarizes the blowout rate simulations and corresponding duration evaluations performed for the 7018/5-1 Spissa exploration well in the Norwegian Sea.

The well is to be drilled as a vertical well, exploring the potentially hydrocarbon bearing Stø reservoir. Two alternative reservoir fluid combinations are evaluated; oil with overlying gas cap and gas filled Stø.

The expected/alternative fluids to be found are an oil with a GOR of 61 Sm^3/Sm^3 and a dry gas with GOR/GCR of 996000 Sm^3/Sm^3.

The following two alternatives are evaluated:

- Case 1 – Stø: Oil layer with overlying gas cap (NOTE)
- Case 2 – Gas filled Stø

Blowout rates are calculated for openhole, annulus and drillstring flow paths, with and without restriction, with both seabed and surface release points, and partly and fully penetrated reservoir. The worst-case scenario with respect to oil spill to sea is a blowout represented by Case 1, through a fully open and unrestricted flowpath, exposed to fully penetrated reservoir consisting of an oil layer with an overlying gas cap. Such a blowout will result in a maximum blowout rate of 2349 Sm^3/day of oil and 4.91 MSm^3/day of gas.

The corresponding rate for a blowout represented by Case 2 is 14 Sm^3/day of oil/condensate and 13.63 MSm^3/day of gas. The low resulting rates of oil/condensate in Case 2 are due to the expected properties of the dry gas.

A large number of scenarios have been calculated to span a range of possible outcomes with respect to blowout rates of oil and condensate. The rates are presented and risked according to the Norwegian Oil & Gas (NOROG) Association guidelines and statistical data from the SINTEF offshore blowout database.

NOTE: The gas cap is conservatively disregarded when evaluating a partial exposed reservoir in Case 1.

Disclaimer

The data forming the basis on this report has been collected by Ranold AS, hereinafter named Ranold. Ranold has gathered the data to the best of our knowledge, ability, and in good faith from sources to be reliable and accurate. Ranold has attempted to ensure the accuracy of the data, though, Ranold makes no representations or warranties as to the accuracy or completeness of the reported information. Ranold assumes 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. This document may set requirements supplemental to applicable laws. However, nothing herein intends to replace, amend, supersede or otherwise depart from any applicable law relating to the subject matter of this document. In the event of any conflict or contradiction between the provision of this document and applicable law as to the implementation and governance of this document, the provision of applicable law shall prevail.

Revision and Approval Form

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Abbreviations

ANN	Annulus
AOF	Absolute open flow
BHA	Bottomhole assembly
BHP	Bottomhole pressure
BOP	Blowout preventer
CGR	Condensate gas ratio
DHSV	Down hole safety valve
DP	Drillpipe
FBHP	Flowing bottomhole pressure
GCR	Gas condensate ratio
GOR	Gas oil ratio
ID	Inner diameter
IPR	Inflow performance relationship
LPM	Liters per minute
MD	Measured depth
MSL	Mean sea level
NOROG	Norwegian Oil and Gas Association
N/G	Net/Gross
OD	Outer diameter
OH	Open hole
OIM	Offshore Installation Manager
OWC	Oil water contact
PWL	Planned well location
RKB	Rotary Kelly bushing
sg	Specific gravity
TD	Total depth
TVD	True vertical depth
WBM	Water based mud

1 INTRODUCTION

This study is part of establishing input for required approval and contingency planning purposes as required in NORSOK D-010 in terms of estimating the expected blowout rates and their duration for the 7018/5-1 Spissa exploration well in the Norwegian Sea.

Ranold AS, an independent and specialized center of competence for flow modelling and simulation services, was contacted and asked to perform blowout and dynamic kill analysis for different possible case scenarios during drilling of the well.

This report summarizes the blowout simulations and duration evaluations performed. The main objective of the well is to explore for commercial HC potential in the Stø reservoir.

2 SCOPE

The objectives of this study are:

- Calculate and present an expected range of potential blowout rates for the well, including the worst-case flow rates of oil and gas to surface.
- Estimate flow rate and duration distributions of the blowout rates based on updated historical blowout data and reliable distribution statistics.

The flow rate and duration distributions will be estimated based on the SINTEF Offshore Blowout Database [1][2] and the latest approved evaluation of the SINTEF Database data from Lloyd's Register Consulting [3].

Two different reservoir fluid scenarios are evaluated; one assuming a gas filled Stø and one assuming oil filled Stø with an overlying gas cap. The following main scenarios are evaluated based on Client request:

- **Case 1 – Reservoir fluid: Gas and oil**: Drilling the 8 ½" section through an oil filled Stø reservoir with an overlying gas cap (**NOTE**)
  - Calculate blowout rates
  - Produce duration estimates
- **Case 2 – Reservoir fluid: Gas**: Drilling the 8 ½" section through a gas filled Stø reservoir
  - Calculate blowout rates
  - Produce duration estimates

NOTE: The gas cap is conservatively disregarded when calculating blowout rates from a partially exposed reservoir, i.e. for Case 1 “Partial exposure” accounts for 5 m exposure to the oil zone.

Blowout rates will be calculated for partial and full reservoir exposure, with release to both seabed and surface.

The duration estimates are shared for the two cases.

The blowout rates have been simulated in Prosper (Petroleum Experts).

3 DATA & INFORMATION COLLECTION

3.1 Location and water depth

The well will be drilled in block 7018/5, approx. 105 km north-northwest of Tromsø. The water depth at location is 298 m.

Figure 1: Location of Block 7018/5 (source: www.npd.no)

3.2 Drilling facilities

The well will be drilled by the semi-submersible drilling rig West Hercules, shown in Figure 2, is of the GVA 7500-N design. RKB-MSL is 31 m.

Figure 2: The semi-submersible drilling rig West Hercules (Source www.seadrill.com)

3.3 Reservoir properties

The well is to be drilled through the Stø reservoir for investigation of HC potential. The reservoir could either hold gas or oil with an overlying gas cap. Both options are evaluated. When evaluating partial exposure to the reservoir in Case 1, the gas cap is conservatively disregarded.

Table 1 shows the reservoir data based on customer input [8] used as basis for the well presented in this report. The resulting inflow performance (ref. AOF in Table 1 and IPRs in Section 3.6) are calculated from Ranold models using Prosper.

Table 1: Reservoir data for the Spissa well

Reservoir property	Unit	Case 1		Case 2
		Stø – Gas	Stø – Oil	Stø - Gas
Top formation	m TVD RKB	719	735	719
Temperature @ res top	ºC	19.5	19.5	19.5
Pressure	bara	78.8	79.3 (76.7*)	78.8
Gross interval depth, total HC sand	meter	16	100	116
N/G ratio	-	0.78	0.78	0.78
Net interval depth, HC layer	meter	12.5	78	90.5
Porosity	fraction	0.25	0.25	0.25
Connate water sat.	fraction	0.15	0.15	0.15
Permeability (effective)	mD	1000	1000	1000
Skin	-	0	0	0
Water cut	%	0	0	0
AOF (5 m exposure)	Sm^3/d	-	385	2.3 M
AOF (100% exposure)	Sm^3/d	5.5 M	3160	39.6 M
* Pressure at top Stø for “Partial exposure” scenario in Case 1				

3.4 Reservoir fluid information

The expected properties of the reservoir fluid are listed Table 2 and Table 3. These properties are based on Client input [8]. The fluids are represented by a black-oil model in all simulations presented in this report and tuned according to the data listed Table 2 and Table 3.

The potential oil has a GOR of 61 Sm^3/Sm^3 while the potential gas is dry with a GCR of 996000 Sm^3/Sm^3.

Table 2: Fluid properties for the expected OIL reservoir fluid

Standard conditions		**Oil**
Oil density*	kg/Sm^3	870.5
Gas density*	sg	0.702
Gas to Oil/Condensate Ratio (GOR, GCR)	Sm^3/Sm^3	61
*std conditions defined as 15˚C / 1.01325 bara		

Reservoir conditions (calculated)		**Oil**
Oil density**	kg/m^3	843.5
Oil viscosity**	cP	6.05
Bubble point (calculated)	bar (˚C)	122
Oil formation factor, Bo	Sm^3/Rm^3	1.45
** res conditions: 84.7 bara / 19.5˚C		

Table 3: Fluid properties for the expected GAS reservoir fluid

Standard conditions		**Gas**
Condensate density* (estimated)	kg/Sm^3	850
Gas density*	sg	0.817
Gas to Oil/Condensate Ratio (GOR, GCR)	Sm^3/Sm^3	996000
*std conditions defined as 15˚C / 1.01325 bara		

Reservoir conditions		**Gas**
Gas density**	kg/m^3	70.7
Gas viscosity**	cP	0.0132
Dew point	Bar	156.3
Gas formation factor, Bg	Rm^3/Sm^3	0.005315
** res conditions: 84.7 bara / 19.5˚C		

3.5 Well design

The well is to be drilled as a vertical exploration well with the following well design:

Case 1 and Case

- 36" conductor pipe set @ 389 m MD/TVD RKB
- 9 ⅝" reservoir caising set @ 644 m MD/TVD RKB
- An 8 ½" section will be drilled through the Stø reservoir
- 4" DP is assumed in the blowout rate calculations

The well schematics are illustrated in Figure 3.

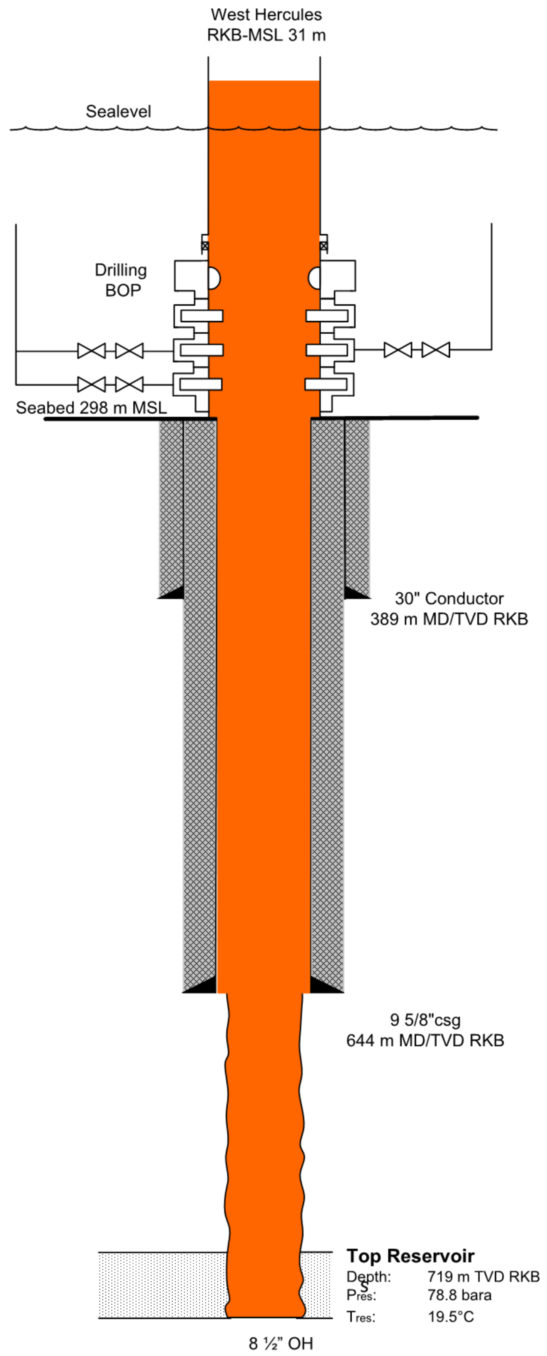

Figure 3: Schematics for Spissa, both cases

3.6 Inflow Performance Relationship

The productivity index or, more generally, the inflow performance relationship describes how the pressure drawdown from reservoir to well increases with increasing flow rate. It is sensitive to parameters such as permeability, fluid viscosity, penetration length, N/G ratio, the productive height of the reservoir as well as mechanical skin, inflow turbulence and 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 pressures.

When calculating the blowout potentials, the blowout rates for the different scenarios are strongly dependent on the reservoir pressure and on the parameters that affect the inflow performance relationship. Simulations are based on the inflow performance (IPR) calculated from the parameters in Section 3.3 and 3.4.

The IPRs for the Spissa well are given in Figure 4 and Figure 5. The IPRs shown are for both full and partial penetration according to the scenarios described in Section 2.

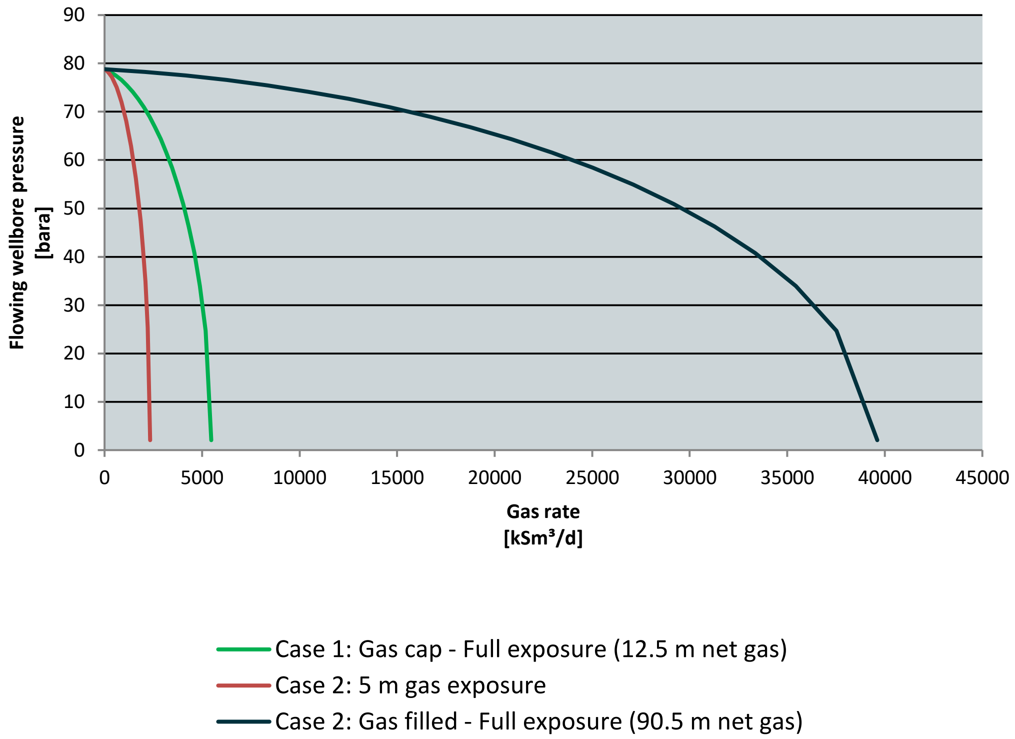

Figure 4: Gas inflow performance – Case 1 gas cap and Case 2 gas filled Stø

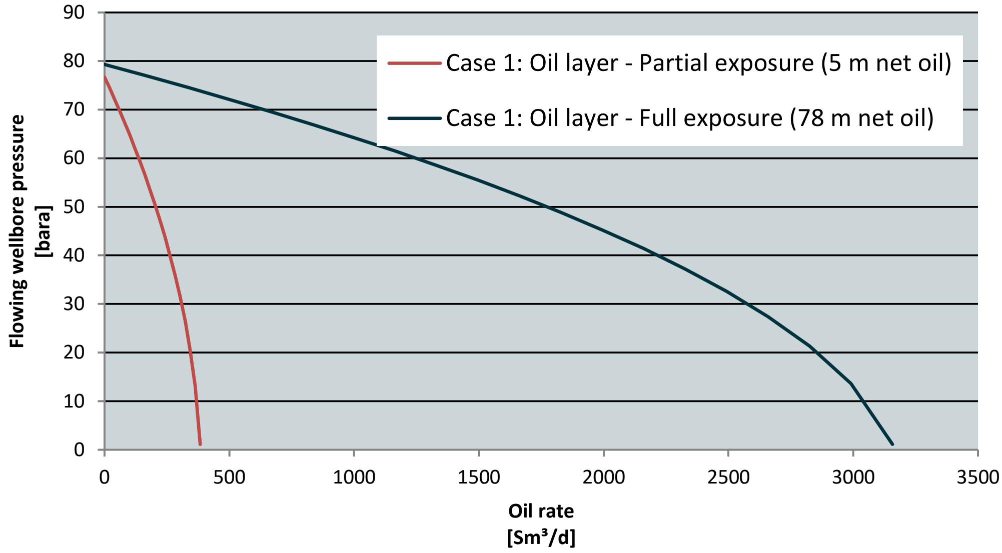

Figure 5: Oil inflow performance – Case 1

3.7 Water

It is conservatively assumed that no formation water will enter the well in a blowout situation.

4 BLOWOUT POTENTIALS AND DURATION

Blowout potentials are defined as the maximum expected blowout rates for various scenarios. Most likely **expected** parameters are to be used, or a weighted distribution of the same parameters. Whenever necessary, parameters and calculation results should be risked in order to establish the most reliable probability distributions for **expected** rates.

The "NOROG Guidance on calculating blowout rates and duration" [4] are used as basis for all flow rate calculations presented in this report. Distributions of possible flowpaths are given in accordance with data from the SINTEF Offshore Blowout Database [1][2] and the latest evaluation of the SINTEF Database data in the report from LR Consulting [3].

4.1 Blowouts in general

A blowout is defined as an unwanted and uncontrolled flow from a subsurface formation which is released at surface, seabed or into a secondary formation, and cannot be closed by the predefined and installed barriers.

For offshore operations, blowouts can be classified in three groups:

- Surface blowouts
- Subsea blowouts
- Underground blowouts

Surface blowouts are characterized by flow of fluid from a permeable formation to the rig floor, where atmospheric conditions exist. For subsea blowouts, the flow typically exits the well at the mud-line, where the exit conditions are controlled by the seawater. Surface blowouts have been given the most attention, as they are usually associated with large-scale fires. For subsea blowouts, the plume of the reservoir fluid may cause exposure of HC gas at surface. In deeper water, the plume of oil can be dispersed before reaching the surface or could be carried with the ocean currents to a location away from the rig.

The North Sea Standard requires that two 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 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.

Blowout potentials, i.e. the expected rates of oil, water and gas, are highly dependent on the scenario in which the blowout occurs. Lost pipe, junk or complex escape paths for the fluid will result in considerably lower blowout rates than a fully open 9 ⅝" casing all the way from formation to surface.

4.2 Blowout potentials

In the following, the methodology for calculation of blowout potentials is presented and implemented on the defined hypothetical wells.

Multiple blowout scenarios are simulated as accurately as possible, and the resulting blowout rates are then used as input to statistical models that provide a complete overview of the sample space for the blowout rates together with the expected value, i.e. the probability-weighted average of the simulated blowout rates.

The probability distribution among all investigated scenarios and associated expected blowout durations are based on the “NOROG Guidance on calculating blowout rates and duration” [4]. Conservative simplifications can be made, as illustrated in Figure 6, where curve A represents a rigorous study with extensive parametric analyses, whereas curve B and C represent conservative simplifications. All scenarios A, B and C are acceptable; alternative A is most work intensive, and alternative C is least work intensive, but most conservative. This study is based on a simplified A (i.e. alternative A without extensive parameter variations). This is in accordance with the requirements in NORSOK D-010.

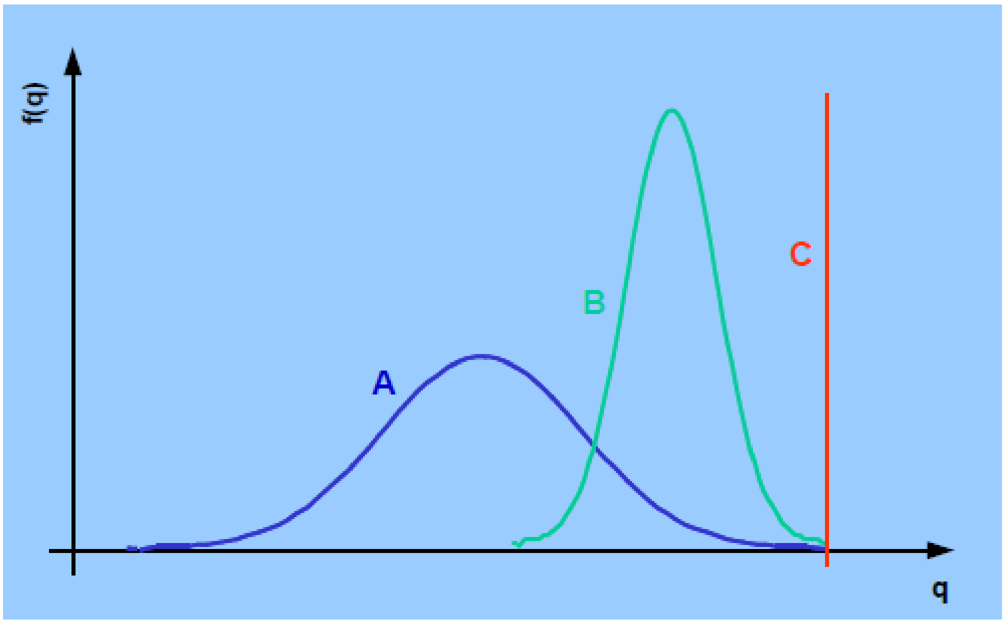

Figure 6: Expectation curves for volume/frequencies and possible simplification strategies

4.3 Blowout scenarios

Hypothetical blowout scenarios have been investigated in this study, all relevant for drilling operations. The analyzed scenarios include blowouts through open hole, drill pipe and annulus to drill floor and to seabed. Figure 7 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 rupture of piping, valves or hoses connected with the BOP.

The statistical values are found based on the SINTEF Offshore Blowout Database [1][2] and the annual report from LR Consulting [3], which are based upon a more comprehensive analysis of the SINTEF database. Hence, irrelevant cases are removed and probability distributions are adjusted according to observed trends.

Furthermore, Ranolds operational collaboration with 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 and swab scenarios.

For "*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 not of importance when evaluating the probability distribution. In fact, it is the mechanisms leading to the blowout that are 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. Loss of the primary barrier by swabbing of reservoir fluids when pulling out of hole can be caused by pulling too fast, insufficient compensation of the pumping rates or by a combination of these. Borehole collapse or partial 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.

Detailed descriptions of each blowout scenario and their associated reservoir exposure were specified in Section 2. Figure 7 illustrates the different flowpaths simulated.

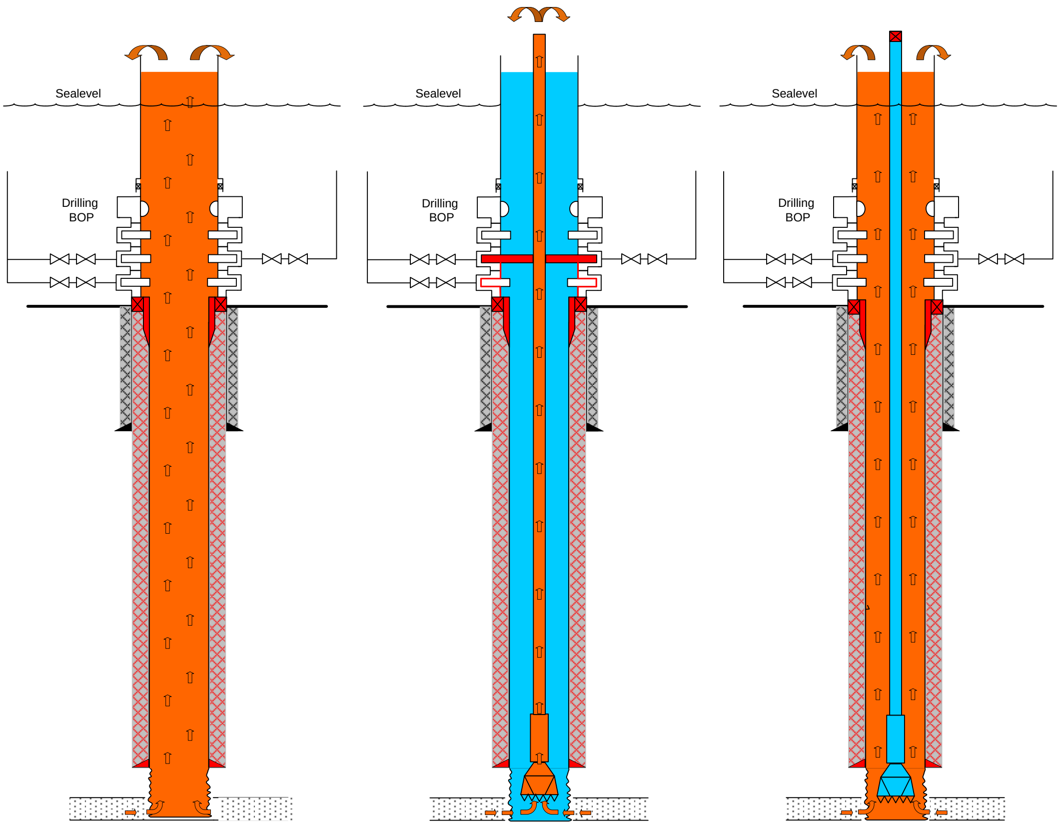

Figure 7: Possible blowout paths for the defined scenarios (illustrative only)
From left to right: Open hole, drill pipe and annulus

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 organized.

4.4 Statistical modelling of the blowout scenarios

The statistical modelling of flow path distributions is based on the analysis performed by *LR Consulting* [3] of the *SINTEF Offshore Blowout Database* [1][2]. All blowouts in the US Gulf of Mexico and the North Sea since 1980, where equipment has been in accordance with the North Sea standard, form the statistical basis. For completion and workover where the number of blowouts is low, blowouts characterized as “Standard of equipment not relevant” are included with a weight of 0.2 indicating that 20% of the incidents would have happened even if North Sea standard equipment were used.

Table 4 summarizes relevant statistical findings from drilling, completion and workover activities described in the *LR Consulting* report from April 2019 [3].

Table 4: Probability distribution of flow paths from more than 30 years of historical data

Data update: April 2019		**Distribution - Floaters**			
		Subsea		**Topside**	
		Full	Restricted	Full	Restricted
Drilling (25 incidents)	Outside casing	20.00%	4.00%		
	Outer annulus	24.00%			
	Annulus		32.00%	8.00%	4.00%
	Open hole				4.00%
	Inside drillstring				
	Inside test tubing				4.00%
Completion (7 incidents)	Annulus			14.29%	2.86%
	Inside drillstring			34.29%	14.29%
	Inside prod tubing	14.29&		5.71%	14.29%
Workover (11.6 incidents)	Outside casing	25.86%	8.62%		
	Outer annulus		8.62%		
	Annulus		17.24%		
	Inside drillstring			8.62%	
	Inside prod tubing	8.62%	8.62%	10.34%	3.45%

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, include the activities:

- Drilling operations
- Work-over operations
- Completion operations

Loss of well control in these operations is 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
- Lack of heave compensation.

Since all these incidents (kick or loss from/to reservoir, lack of fluid control and swabbing) are also possible from completion and workover operations and 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 work, 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 therefore comparable expected blowout rates.
- The flow through production tubing is interpreted as flow through open hole/casing.

Ranold reviews the statistical values on an annular basis. For data that cannot be derived from statistical sources, operational experience is used. The applied data are thoroughly evaluated and quality assured by the Ranold review team which consists of Ranold chief engineers within drilling and well control.

4.4.1 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 are 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:

- 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 15%
- Blowout through annulus has a probability of 85%
- Blowout through open hole 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 12%
- Blowout through annulus has a probability of 72%
- Blowout through open hole 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 “NOROG Guidance on calculating blowout rates and duration” [4], the following distribution has been used for partial 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 “NOROG Guidance on calculating blowout rates and duration” [4] 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 the hole, fish/junk or collapse of the borehole itself, Ranold 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 is now independent of the wellbore design or the size of the drillpipe used.

The release point distribution depends on the location of wellhead and BOP/X-mas tree and therefore on rig type. For a floater, the following statistical distribution is found from the *SINTEF Offshore Blowout database* summarised in Table 4:

- Surface release point 31%
- Subsea release point 69%

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. DNV [5] 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%

4.4.2 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 “NOROG Guidance on calculating blowout rates and duration” all possible scenarios should be risked and blowout potentials should be weighted accordingly. The risk methodology breaks down each of the scenarios as illustrated in Figure 8 next.

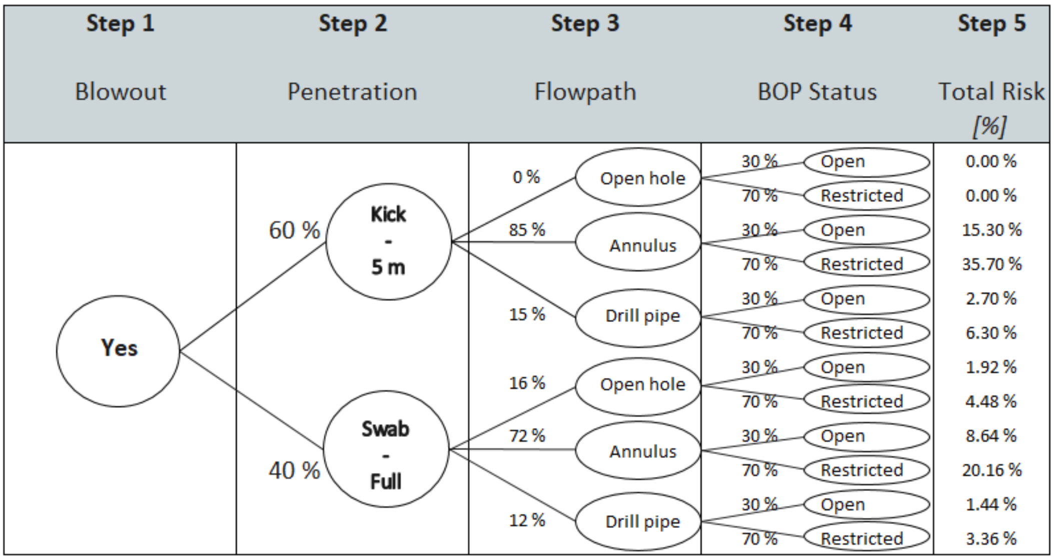

Figure 8: Typical methodology for risking of blowout rates for exploration wells

4.5 Method for estimation of most likely blowout duration

4.5.1 Remedial actions

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 formation
- 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 is presented for each of the above categories. In order to be able to model the statistical success for each of the above given actions, these are modelled as if 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 LR Consulting report approximately 63% 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 mobilized on short notice. Typical actions could be repair or replacement of hydraulic components, replacement of control system equipment or similar minor repairs. Prerequisites common to all activities in this group are that there is appropriate working equipment onboard the installation and that people and equipment can be operated 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 onboard an offshore rig or supply vessel.

The working principle of most of these devices is 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 is made up and function tested before the rams are closed and the blowout is stopped.

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

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

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

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

Drilling of relief wells

In most offshore blowouts, 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 is 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. 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.

For this evaluation, the following estimates are used for the duration evaluation for drilling down to and intercept the blowing well at the last casing shoe. Most likely estimates are used [8]:

- Decision to drill the relief well: 3 day
- Termination of work, sail to location, anchoring and preparation: 12 days
- Drilling relief well to intersection: 14 days
- Homing in and kill: 10 days
- Total time to kill well: 39 days

Consequently, the assumption is made that the relief well will successfully kill the blowing well after 39 days of 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

4.5.2 Blowout duration distribution

In order to give the best possible distribution estimate, the probability distribution for the different historical incidents must be found. Figure 9 is based on data from April 2019 [3] reported by LR Consulting, and on engineering values for capping and relief well actions. The figure 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.

From the statistical data available in the SINTEF Offshore Blowout database and from the latest revision of the LR Consulting report, reliability relations can be derived for each of the remedial actions, as if each of them was the only action imposed. The results from such reliability approach are presented in Figure 9.

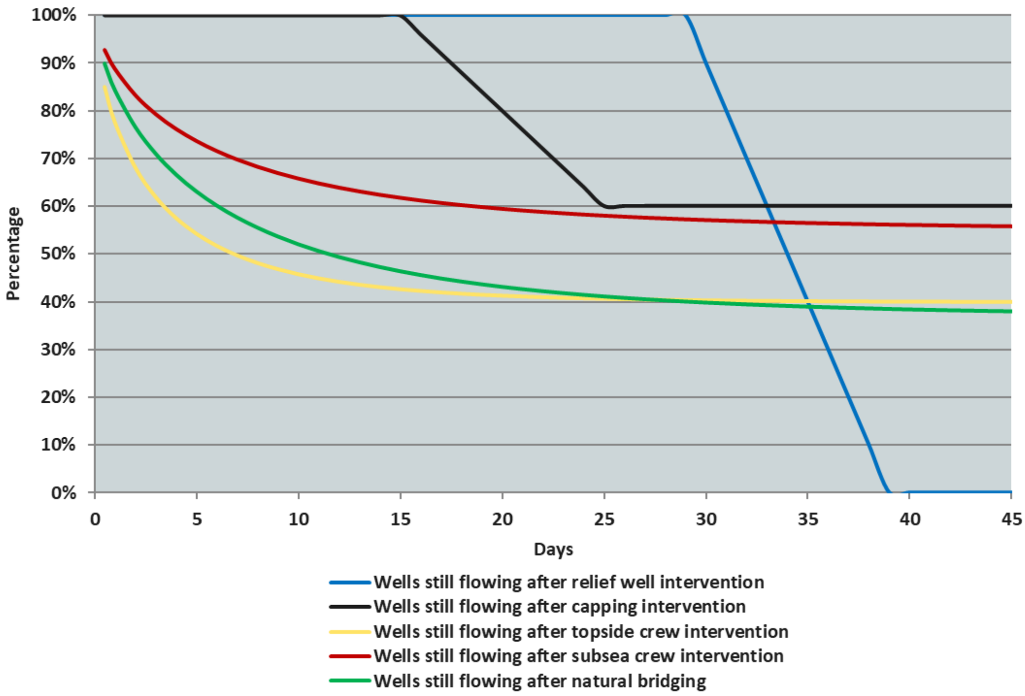

Figure 9: Reliability plots for each of the possible remedial actions

Multiple mechanisms may "work together" in order to stop the blowout. LR Consulting reports [3] that 63% of all blowouts will eventually be stopped by natural bridging (ref the green graph), 60% will eventually be stopped by topside crew intervention (ref the yellow graph) and 45% will eventually be stopped by subsea crew intervention (ref the magenta graph), if each mechanism evaluated is the only mechanism to stop the leak. Furthermore, the installation of a new subsea barrier by cap and contain is assumed to give a uniform distribution with a probability of 40% that the blowout is eventually killed (ref the black graph). The operation starts after 15 days and ends after 25 days.

Drilling a relief well is assumed to give a uniform distribution with a probability of 100% that the blowout is eventually killed. The drilling starts at the latest 12 days after the decision to start drilling has been taken (15 days including decision time) and earliest possible kill attempt can be performed after a successful intersection of the blowing well. In this work, a uniform distribution between 29 days and 39 days is proposed (ref the blue graph). 29 days represents the minimum time estimate to drill a relief well [8] and kill the well.

The probability that either of the kill mechanisms is successful may be derived by assuming that the individual kill mechanisms are not mutually exclusive, but rather independent events.

The results from Figure 9 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 seabed release point is presented in Figure 10 next.

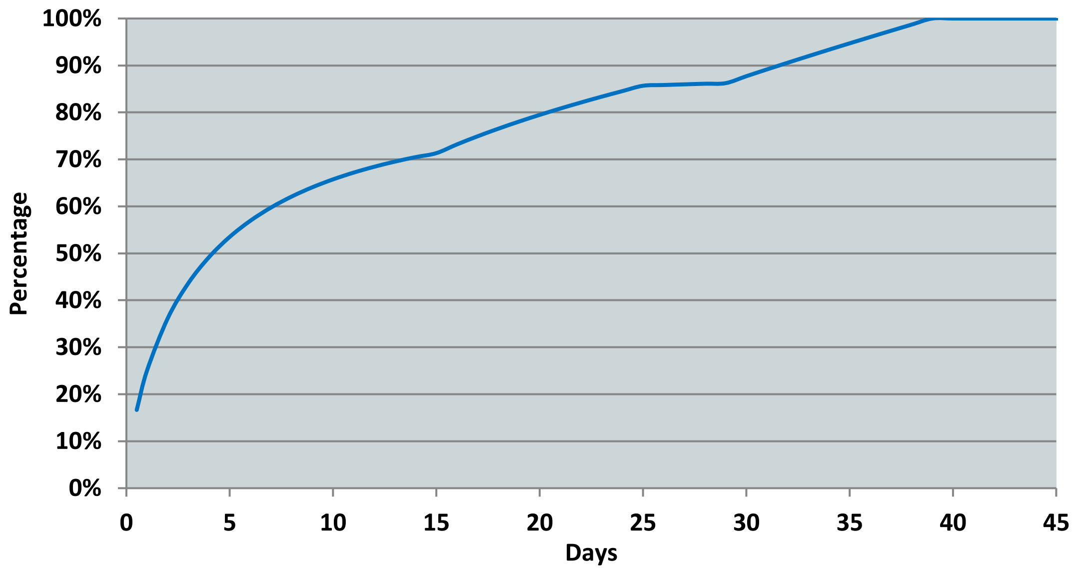

Figure 10: Reliability presentation of all kill actions when combined for a seabed release

Similarly, 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 11.

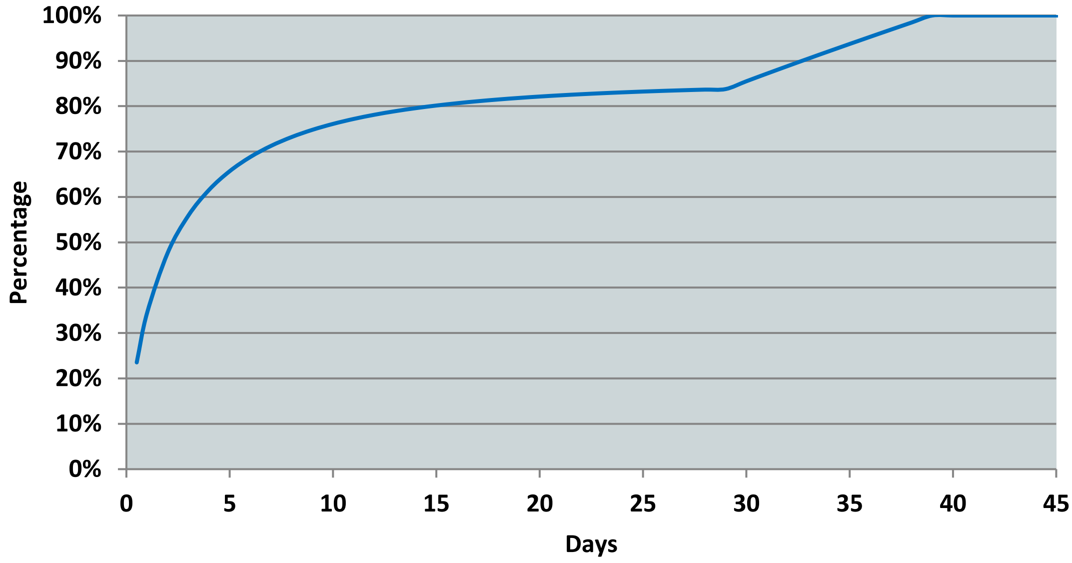

Figure 11: Reliability presentation of all kill actions when combined for a surface release

In order to provide a unique methodology for duration prognosis a simplified discretization is proposed in Table 5. The model represents five different logical stages in a kill operation.

Table 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 5 days	P_5	The blowout could be controlled by equipment from local base/facility
Risk of a blowout duration of 15 days	P_{15}	The blowout could be controlled by bringing in additional equipment
Risk of blowout duration of 25 days	P_{25}	The blowout could be controlled by installation of new barrier system
Risk of a blowout duration of 39 days	P_{39}	The blowout will have to be killed by drilling a dedicated relief well.

This discretization methodology makes estimation of possible blowout duration easy to communicate, and the method can be adapted to drilling time estimates shorter or longer than the 39 days used in this work.

When the statistical probabilities are to be found, the incremental value from previous values is to be derived, i.e. the value to be used at day 15 should be found as P_{15}- P_5.

4.6 Blowout duration estimate for the Spissa well

4.6.1 Blowout duration with surface release

Based on the discretization proposed above, reliability values can be extracted from Figure 11 above, which leads to the following duration estimate. The figure shows that 47% of the blowouts to surface would be killed in less than 2 days, 65% in less than 5 days, 80% in less than 15 days, 83% in less than 25 days and 100% in less than 39 days.

- Risk of a blowout duration less than 2 days: 47%
- Risk of a blowout duration between 2 days and 5 days (65% - 47%): 18%
- Risk of a blowout duration between 5 days and 15 days (80% - 65%): 15%
- Risk of a blowout duration between 15 days and 25 days (83% - 80%): 3%
- Risk of a blowout duration between 25 days and 39 days (100% - 83%): 17%

Assumptions are made that the relief well will successfully kill the well after 39 days, which means that P_{40}= 0%. A weighted duration can now be calculated in a simplified way and is found to be as follows for a blowout with surface release point:

$$2 * 0.47 + 5 * 0.18 + 15 * 0.15 + 25 * 0.03 + 39 * 0.17 = \mathbf{11.5\ days}$$

4.6.2 Blowout duration with seabed release

Based on the discretization proposed above, reliability values can be extracted from Figure 10 above, which leads to the following duration estimate. The figure shows that 36% of the blowouts to seabed would be killed in less than 2 days, 53% in less than 5 days, 71% in less than 15 days, 85% in less than 25 days and 100% in less than 39 days.

- Risk of a blowout duration less than 2 days: 36%
- Risk of a blowout duration between 2 days and 5 days (53% - 36%): 17%
- Risk of a blowout duration between 5 days and 15 days (71% - 53%): 18%
- Risk of a blowout duration between 15 days and 25 days (85% - 71%): 14%
- Risk of a blowout duration between 25 days and 39 days (100% - 85%): 15%

Assumptions are made that the relief well will successfully kill the well after 39 days, which means that P_{40} = 0%. A weighted duration can now be calculated in a simplified way and can be as follows for a blowout with seabed release point:

$$2 * 0.36 + 5 * 0.17 + 15 * 0.18 + 25 * 0.14 + 39 * 0.15 = \mathbf{13.6\ days}$$

4.6.3 Overall blowout duration estimate

In section 4.4.1, it was found that for a blowout developing when drilling from a floater, only 10% of the incidents will remain as surface blowout, the rest of the incidents will develop into a blowout with a seabed release point. This gives the following estimate for overall blowout duration:

$$11.5 * 0.1 + 13.6 * 0.9 \sim \mathbf{13.4\ days}$$

5 BLOWOUT RATES

This section lists the findings from the analysis performed with respect to calculating blowout rates of oil to sea. Section 6 takes into account probabilities for different flowpaths, while this section provides a simpler listing of the different scenarios to show the resulting oil, gas and water rates together with flowing bottom hole pressure (FBHP). The flowing wellbore pressure (FBHP) is taken at the top of the reservoir.

The blowout rates are presented for release of HC to surface and seabed for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths, and for full and partial reservoir exposure.

5.1 Detailed blowout rates – Case 1 – Gas cap and oil layer

Detailed blowout rates for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths are presented.

NOTE: The gas cap is conservatively disregarded for calculations involving a partial exposure to the reservoir.

Table 6: Blowout rates Case 1 – Surface release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm^3/d]	Gas rate [MSm^3/d]	FBHP [bara]
Surface	5 m exposure to 78 m net oil layer	OH	368	0.02	10.1
		ANN	365	0.02	11.8
		DP	314	0.02	28.6
	100% exposure both gas cap and oil layer	OH	2349	4.91	35.4
		ANN	1808	4.28	47.8
		DP	73	0.92	76.2

Table 7: Blowout rates Case 1 – Seabed release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm^3/d]	Gas rate [MSm^3/d]	FBHP [bara]
Seabed	5 m exposure to 78 m net oil layer	OH	122	0.01	62.1
		ANN	129	0.01	61.2
		DP	192	0.01	52.1
	100% exposure both gas cap and oil layer	OH	2005	4.52	43.6
		ANN	1360	3.66	56.3
		DP	155	1.20	75.1

The worst-case blowout scenario is an unrestricted openhole to surface with full reservoir exposure. In such an unlikely event, the maximum blowout potential is found to be 2349 Sm^3/day of oil and 4.91 MSm^3/day of gas.

5.2 Detailed blowout rates – Case 2 – Gas filled Stø

Detailed blowout rates for unrestricted openhole (OH), annulus (ANN) and drillpipe (DP) flowpaths are presented.

NOTE: Due to the dry gas properties the resulting blowout rates of oil/condensate are very low.

Table 8: Blowout rates Case 2 – Surface release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm³/d]	Gas rate [MSm³/d]	FBHP [bara]
Surface	5 m exposure to gas filled Stø	OH	2	2.28	13.1
		ANN	2	2.24	21.1
		DP	1	0.96	70.6
	100% exposure to gas filled Stø	OH	14	13.63	71.7
		ANN	9	8.64	75.3
		DP	1	1.15	78.5

Table 9: Blowout rates Case 2 – Seabed release point

Release point	Reservoir exposure	Flowpath	Oil rate [Sm³/d]	Gas rate [MSm³/d]	FBHP [bara]
Seabed	5 m exposure to gas filled Stø	OH	2	2.11	33.2
		ANN	2	2.07	36.2
		DP	1	1.16	67.0
	5 m exposure to gas filled Stø	OH	13	12.94	72.3
		ANN	8	8.16	75.6
		DP	1	1.32	78.4

The worst-case blowout scenario is an unrestricted openhole to surface with full reservoir exposure. In such an unlikely event, the maximum blowout potential is found to be 14 Sm³/day of oil/condensate and 13.63 MSm³/day of gas.

6 BLOWOUT DISTRIBUTIONS

This section takes into account the statistical data discussed in Section 4.4. From the detailed analysis presented the probabilities for all relevant scenarios were found. According to the *"NOROG Guidance on calculating blowout rates and duration"* [4] 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 while drilling the Spissa well. These values are risk 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, only. The risked blowout rates shall not be used for evaluating possible kill methods or requirements.

Note: The overall probability of finding hydrocarbons in a well, which again introduces a certain risk for a blowout is neglected in this report but could preferably be included in the environmental analysis.

6.1 Risked Blowout rates – Case 1 – Gas cap and oil layer

The risked blowout rate distributions are listed in Table 10 for surface release and Table 11 for seabed release, for a blowout represented by Case 1.

Table 10: Risked blowout rates Case 1 – Surface release point

Scenario		Flowpath		BOP Status		Total Risk	Oil blowout potential	Risked Oil blowout rate	Risked Gas blowout rate
Prob.%	Exposure	Prob.%	Status	Prob.%	Status	[%]	[Sm^3/day]	[Sm^3/day]	[MSm^3/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	368	0	0.00
				70	Restricted	0.00	167	0	0.00
		85	Annulus	30	Open	15.30	365	56	0.00
				70	Restricted	35.70	178	63	0.00
		15	Drillpipe	30	Open	2.70	314	8	0.00
				70	Restricted	6.30	276	17	0.00
40	Full reservoir exposure	16	Open hole	30	Open	1.92	2349	45	0.09
				70	Restricted	4.48	50	2	0.01
		72	Annulus	30	Open	8.64	1808	156	0.37
				70	Restricted	20.16	58	12	0.06
		12	Drillpipe	30	Open	1.44	73	1	0.01
				70	Restricted	3.36	61	2	0.02
					Total sum:	100		364	0.59

Table 11: Risked blowout rates Case 1– Seabed release point

Scenario		Flowpath		BOP Status		Total Risk	Oil blowout potential	Risked Oil blowout rate	Risked Gas blowout rate
Prob.%	Exposure	Prob.%	Status	Prob.%	Status	[%]	[Sm^3/day]	[Sm^3/day]	[MSm^3/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	122	0	0.00
				70	Restricted	0.00	121	0	0.00
		85	Annulus	30	Open	15.30	129	20	0.00
				70	Restricted	35.70	127	45	0.00
		15	Drillpipe	30	Open	2.70	192	5	0.00
				70	Restricted	6.30	189	12	0.00
40	Full reservoir exposure	16	Open hole	30	Open	1.92	2005	38	0.09
				70	Restricted	4.48	10	0.4	0.03
		72	Annulus	30	Open	8.64	1360	118	0.32
				70	Restricted	20.16	9	2	0.12
		12	Drillpipe	30	Open	1.44	155	2	0.02
				70	Restricted	3.36	8	0.3	0.02
					Total sum:	100		243	0.58

The expected oil blowout rate is 364 Sm^3/day for a surface release point and 243 Sm^3/day for a seabed release point. The corresponding risked blowout rates of gas are 0.59 MSm^3/day for a surface release point and 0.58 MSm^3/day for a seabed release point.

6.2 Risked Blowout rates – Case 2 – Gas filled Stø

The risked blowout rate distributions are listed in Table 12 for surface release and Table 13 for seabed release, for a blowout represented by Case 2.

Table 12: Risked blowout rates Case 2 – Surface release point

Scenario		Flowpath		BOP Status		Total Risk	Oil blowout potential	Risked Oil blowout rate	Risked Gas blowout rate
Prob.%	Exposure	Prob.%	Status	Prob.%	Status	[%]	[Sm^3/day]	[Sm^3/day]	[MSm^3/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	2	0.0	0.00
				70	Restricted	0.00	1	0.0	0.00
		85	Annulus	30	Open	15.30	2	0.3	0.34
				70	Restricted	35.70	1	0.2	0.22
		15	Drillpipe	30	Open	2.70	1	0.0	0.03
				70	Restricted	6.30	1	0.0	0.03
40	Full reservoir exposure	16	Open hole	30	Open	1.92	14	0.3	0.26
				70	Restricted	4.48	1	0.0	0.03
		72	Annulus	30	Open	8.64	9	0.7	0.75
				70	Restricted	20.16	1	0.1	0.13
		12	Drillpipe	30	Open	1.44	1	0.0	0.02
				70	Restricted	3.36	1	0.0	0.02
					Total sum:	100		2	1.83

Table 13: Risked blowout rates Case 2– Seabed release point

Scenario		Flowpath		BOP Status		Total Risk	Oil blowout potential	Risked Oil blowout rate	Risked Gas blowout rate
Prob.%	Exposure	Prob.%	Status	Prob.%	Status	[%]	[Sm^3/day]	[Sm^3/day]	[MSm^3/day]
60	Partial reservoir exposure	0	Open hole	30	Open	0.00	2	0.0	0.00
				70	Restricted	0.00	1	0.0	0.00
		85	Annulus	30	Open	15.30	2	0.3	0.32
				70	Restricted	35.70	1	0.2	0.23
		15	Drillpipe	30	Open	2.70	1	0.0	0.03
				70	Restricted	6.30	1	0.0	0.04
40	Full reservoir exposure	16	Open hole	30	Open	1.92	13	0.2	0.25
				70	Restricted	4.48	0	0.0	0.02
		72	Annulus	30	Open	8.64	8	0.7	0.70
				70	Restricted	20.16	0	0.1	0.10
		12	Drillpipe	30	Open	1.44	1	0.0	0.02
				70	Restricted	3.36	0	0.0	0.02
					Total sum:	100		2	1.72

The expected oil blowout rate is 2 Sm^3/day both for a surface release point and a seabed release point. The corresponding risked blowout rates of gas are 1.83 MSm^3/day for a surface release point and 1.72 MSm^3/day for a seabed release point.

7 REFERENCES

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   c) Drill times down to 9 5/8” casing, email from Tolleif Grønås 24.10.2019

Appendix A
About Ranold AS

Ranold AS

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

Ranold AS 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

Ranold 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

- Trained and 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

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Flow matters

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