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Quantitative risk analysis of oil and gas drilling, using Deepwater Horizon as case study

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ABSTRACT

According to the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, the Macondo blowout requires a reassessment of the risks associated with offshore drilling. The Commission recommends a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the safety case/Quantitative Risk Analysis (QRA) approach in the North Sea. A review of a 15 QRAs from the North Sea reveals that the analyses to a large extent only to calculate the frequency of blowout based on the number of drilling operations. None of the reviewed analyses were initiated based on Risk Influence Factors (RIFs) uncovered in the conceptual phase of well planning. The QRAs do not include Human and Organisational Factors (HOFs). As seen in the Macondo blowout, most of the findings were related to HOFs, e.g. working practice, competence, communication, procedures and management. The narrow drilling window related to deepwater drilling has to be controlled by safety barriers that are dependent on HOFs. There is some research relating to the incorporation of HOFs in QRAs. Further improvements in methodology and datasets are necessary to ensure that the QRAs are valid for the individual facilities, operations and environments.

1. Introduction

According to the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (hereafter, the Commission) the Deepwater Horizon accident requires a reassessment of the risks associated with offshore drilling. The Commission recommends that The Department of the Interior develop a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the "safety case" approach in the North Sea [1].

A safety case is a document, which provides evidence of the duty holder's ability and means to effectively control the risks of major accidents. Major hazards have the potential to cause major accidents. A "major accident" in the oil and gas (O&G) industry is often understood, e.g., by [2], as an accident out of control with the potential to cause five fatalities or more, caused by failure of one or more of the system's safety barriers. According to the UK's Health and Safety Executive (HSE), the Offshore Installations (Safety Case) Regulations 2005 [3] aims to reduce the risks from major accident hazards to the health and safety of the workforce employed on offshore installations, and in connected activities [4]. The main purpose for producing a safety case is to state how the system will be deemed safe in a given context. Therefore, in order to prepare a safety case it is necessary to understand the level of risks involved. In the UK, it is a requirement that all installations have a safety case in order to operate. The requirements for safety cases differ depending on the type of installation (e.g. drilling, production or accommodation rig). Submitting a safety case is generally the responsibility of the operator of a production installation and the owner of a non-production installation [5].

The use of "safety cases" in Norway is similar to those in the UK. There are requirements on carrying out all the necessary risk analyses and on handling risks related to all planned drilling and well activities. The analyses are used to set the conditions for operation, and to classify areas, systems and equipment with respect to the identified risk. Analyses of major accident hazards are given extra attention, and a separate section in the Petroleum Safety Authority Norway (PSA) regulations addresses the requirement to major accident hazards risk assessment [6]. This analysis is often called quantitative risk analysis/assessment (QRA). A risk assessment involves risk analysis, as well as an evaluation of the results. The QRA technique is also referred to as Probabilistic Risk Assessment (PRA), Probabilistic Safety Assessment (PSA), Concept Safety Evaluation (CSE) and Total Risk Analysis (TRA).

Abbreviations: BOP, blowout preventer; GoM, Gulf of Mexico; HPHT, high pressure high temperature; HSE, Health and Safety Executive; LWC, loss of well control; MOC, management of change; NCS, Norwegian Continental Shelf; OCS, Outer Continental Shelf; QRA, quantitative risk analysis; RIF, risk influencing factor

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Despite over two decades of use and development, no convergence towards a universally accepted term has been observed. QRA and TRA are the most commonly used abbreviations [7]. In this article the term QRA refers to all the different techniques.

The Macondo blowout was a result of loss of well integrity. Well integrity can be defined as the application of technical, operational and organisational means to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well [8]. The means to reduce the risks are called safety barriers. Safety barriers are physical or non-physical means intended to prevent, control, or mitigate undesired events or accidents. Barriers may be passive or active, physical, technical, or human/operational systems [9,10]. Authorities in Norway and the UK base their regulations, and operators base their design, on the use of QRAs as a tool to determine, which safety barriers are needed, as well as determining the dimensioning loads and requirements.

Norway requires a risk based approach and the use of QRAs as a follow up of the Alexander Kielland accident in 1980 [7,11]. For some years, Norway was the only country systematically using QRAs. Lord Cullen in his accident report after the Piper Alpha accident [12], recommended that QRAs should be introduced into UK legislation in a similar way as had been undertaken in Norway nearly 10 years earlier. In 1992 the Safety Case Regulations came into force in the UK, and since then the offshore industry in the UK has been required to perform QRAs as a part of the safety cases for both existing and new installations [7].

In the US there is a general focus on risks and risk control. However, there is no specific regulatory requirement on the operator to perform risk analyses, apart from Environmental Impact Assessments (EIA). The EIA is a project-specific analysis that assesses the potential direct and indirect environmental impact on offshore and onshore resources that could be affected by the proposed activities [13]. The Norwegian and UK regulations are mainly risk-based, and accordingly the regulations are mainly performance-based with supplementary prescriptive requirements. This is different than in the US, where the Outer Continental Shelf (OCS) regulations are primarily prescriptive [13,14].

1.1. Objective

The recommendation of the Commission regarding developing a proactive, risk-based performance approach, raises the question of whether the "QRA/safety case" approach in the North Sea reflects the individual facilities, operations and environments related to drilling and blowout hazards. This article focuses on the methods used in QRAs related to blowout, and how the risk influencing factors (RIFs) reflect the individual facilities, operations and environments. A RIF is an aspect (event/condition) of a system or an activity that affects the risk level of this system or activity [15]. The objectives are to:

- briefly describe RIFs for drilling,
- review how the RIFs are analysed in QRAs,
- discuss the ability of QRAs to reflect individual facilities, operations and environments based on experiences from the Deepwater Horizon accident.

A set of 15 QRAs were reviewed in order to describe how blowout modelling is conducted by the operators in Norway. A literature review and the results from the investigations of the Deepwater Horizon accident formed the basis for describing RIFs for deepwater drilling. The Deepwater Horizon accident did occur in deepwater ($>$300 m) and the article mainly focuses on deepwater due to increased activities in deepwater areas (e.g. Brazil, Africa and the Norwegian Sea).

The QRA process is not described in detail. For information about these topics see [7,16,17]. Risk is often characterised by reference to potential events and consequences. This article focuses more on the analysis of the potential events than the consequences of these. The potential events are often described by the expected frequency of the event. The modelling of blowout consequences is often done using event trees and simulation tools such as Computational Fluid Dynamics software.

The Commission recommends a multidisciplinary approach to improve the safety level within the O&G industry. This is often obstructed by extensive use of technical language. This article is intended to be understandable by non-drilling experts. Therefore there are included short explanations of important terms, e.g. kicks and well integrity. A description of deepwater drilling is also included. In addition, we advise the reader to visit http://oilgasglossary.com for further explanations.

2. Deepwater drilling

Prospects in deepwater encounter several RIFs such as, complex casing programs, high pressures, high temperatures, difficult formations, uncertainty of seismology and lack of experienced personnel [18–30]. The Gulf of Mexico (GoM) has a unique combination of these RIFs compared to deepwater wells in other parts of the world; water depths of over 3000 m, shut-in pressures of more than 690 bars, bottom hole temperatures higher than 195 °C, problematic formations with salt zones and tar zones, deep reservoirs at more than 9000 m true vertical depth, tight sandstone reservoirs ($<$10 mD) and fluids with extreme flow assurance issues [27]. Therefore, deepwater drilling consists of complex operations in which engineering and commissioning mistakes, along with major workovers, can cost tens of millions of dollars [28,29]. The drilling window is narrow, and the narrower the window, the more difficult it is to execute drilling operations. Efficient risk management is extremely important in all life cycle phases of a well.

2.1. Well planning

The life cycle phases of deepwater drilling (and drilling in general) can be divided into the well planning phase, the drilling phase (consisting of drilling, running casing, cementing, circulation, fluid displacement and clean-up) and completion. Following is an example about how it is done. In the initial planning phase of a drilling operation, a yearly well development plan is produced. This plan includes an overview of the yearly drilling tasks (well operation plan), including detailed plans for production drilling and intervention. An assignment document defining the well targets, is prepared based on these early preparations. This is regarded as an order to the operational environment, which is handed over to a well planning team during the project's start-up meeting. Often the blowout hazard study is updated based on the well development plan [31].

The conceptual phase is initiated by a start-up meeting, the main intention of which is to agree the objectives and an overall plan for the drilling project. Thereafter, the work begins on the evaluation of alternative draining options for the reservoir. This work proceeds over several work sessions where the assessment of different alternatives take place, until a concept (method) is selected. Finally, a recommendation to drill is prepared that requires final approval. Detailed engineering includes several work sessions and is usually an interactive process between the well programme engineer, the service company and the drilling contractor. Operational procedures are developed. Examples of such are flow-chart models and decision trees [31]. Risk assessments, but not necessarily an update of the QRA, are prepared for the final well programme, and contingency plans are prepared to deal with unforeseen situations during the operation. Approval of the final individual well-drilling plan should be available weeks prior to operation start-up. Preparation for operation start-up involves activities both onshore, and offshore ahead of the operation. A pre-operation meeting is held onshore, organised by the well project coordinator, to inform the rig personnel involved about the well programme. In a meeting onshore before departure, the rig personnel are informed about the well targets and the current operations taking place at the rig, including RIFs they may encounter offshore.

After arrival offshore, pre-job meetings are held, where the detailed operational procedures are reviewed with the personnel involved. Input data are verified, and the procedures are updated according to the actual conditions. Necessary equipment for the job is verified against the specific well programs and the given requirements. Planned deliveries from the contractors are verified, and plans for follow-up of the contractors during operation are prepared. Finally, the "well-slot" is handed over to the well operation team prior to start-up. During the operation, comprehensive operational support is given both from the rig itself and from onshore. The intention is to optimise the plans according to the new or updated information. Any changes from the original plans should be logged, and approved before implementation. Daily rig-status meetings are held to orientate about status and progress in the well operation. The well leader ensures that the contractor, and suppliers in general, are conducting safety job analyses of unfamiliar operations, or operations that are critical with respect to health, safety and the environment. After finalisation of the drilling operation, the well is delivered back to production/operation. Experience gained from the operation then needs to be logged for later use [31].

2.2. Well integrity

In general, there are three categories of undesired incidents that may occur during well operations. The first two categories are unintentional well inflow and well leakage, whereas the third category is blowout. Well inflow is a flow of formation fluid into the wellbore, also called a "kick". A kick is instability in the well as a result of the well taking in gas, oil or water, and may lead to a blowout. Well leakage is characterised by unintentional fluid flowing up through the blowout preventer (BOP) for a limited period of time until stopped by the existing well equipment or by defined operational means [32,33]. The BOP has valves, which can close around the drill string, and in an emergency sever the string and plug the wellbore. Well leakage can be caused by leaks in the hanger packoff, tubing, casing, casing shoe, poor primary cement job, gas lift valve, stinger seal and/or packer seal [34].

Blowouts (whether surface, subsea or underground) are the uncontrolled flow of subterranean formation fluids, such as natural gases, oil, saline water, etc. and/or well fluids, into the atmosphere or into an underground formation. Blowouts are a result of loss of well integrity and can occur when the formation pressure exceeds the pressure applied to it by a column of fluid, such as drilling fluid, cement slurry, cement spacer fluid, brine completion fluid, or any combination thereof in the column of fluid [32].

According to Norwegian regulations, a well should have at least two independent and tested well barriers in all operations. The primary well barrier is the first obstacle against undesirable flow from the source (kick). On the detection of an influx, the well should be closed by the activation of the secondary well barrier. The secondary well barrier prevents further unwanted flow should the primary well barrier fails [35]. The consequences of not maintaining sufficient well integrity have been demonstrated by the Macondo blowout.

3. The Macondo blowout

As the water depth increases, the weight of conventional risers increases to a point that only a few modern floating rigs, like the Deepwater Horizon, have the capability to drill. The deck loads increase tremendously, the volume of mud required to fill the riser increases, and the choke line friction increases to a point to where successfully circulating a kick from the well becomes challenging [36]. Deepwater Horizon was a fifth generation drilling rig finished in 2001. The rig was outfitted with advanced drilling technology and control systems for drilling in deepwater [37].

Deepwater Horizon commenced drilling on the Macondo exploratory well in February 2010, about 66 km off the southeast coast of Louisiana, US. The water depth at the site was around 1500 m, and the well was 5500 m below sea level. After drilling, the plan was to plug the well and suspend it for further completion as a subsea producer well. The drilling of the Macondo well was performed as an overbalanced operation, which uses a mud column to prevent the influx of formation fluids into the well. The pressure of the mud column has to exceed the formation pore pressures encountered in the well. The pore pressure is the pressure of the fluid inside the pore spaces of a formation. A complementary measure in this respect is the fracture gradient, which is the strength of the rock. In overbalanced operations, the mud column is the primary well barrier, which has to exert a pressure greater than the pore pressure, but lower than the fracture gradient (cf. the drilling window). The secondary well barrier in overbalanced operations is the well containment envelope consisting of selected components of the BOP. The Macondo was planned to be abandoned and left underbalanced, by replacing drilling mud with sea water, and with two cement barriers in place [38].

Many deepwater reservoirs have such narrow drilling windows between the pore pressure and the fraction gradient, that resolving one problem often creates another, and resolution of that problem creates another, and so on until the cycle is broken with hydraulic balance or the well is abandoned. The operational drilling problems most associated with non-productive time include lost circulation, stuck pipes, wellbore instability and loss of well control [39].

Twice, prior to the blowout on April 20th, the Macondo well experienced a "kick". The well kicked at 8,970 feet. The rig crew detected the kick and shut in the well. They were able to resolve the situation by raising the mud weight and circulating the kick out of the wellbore. The well kicked again, at 13,305 feet. The crew once again detected the kick and shut in the well, but this time, the pipe was stuck in the wellbore. BP severed the pipe and sidetracked the well. In total, BP lost approximately 16,000 barrels of mud while drilling the well, which cost the company more than $13 million in rig time and materials. The kicks, ballooning and lost circulation events at Macondo occurred in part because Macondo was a "well with limited offset well information and the preplanning pressure data [were] different than the expected case" [40].

A major risk at Macondo was the loss of drilling fluid into the formation, called lost circulation or lost returns. At various points in February, March, and April, the pressure of drilling fluid exceeded the strength of the formation, and drilling fluid began flowing into the rock instead of returning to the rig. The Horizon crew successfully addressed the repeated lost circulation events while drilling the Macondo well.

On April 20th a well control event caused explosions and a fire on the rig, until it sank 36 h later [41]. According to the Commission, the root technical cause of the blowout was that the cement BP and Halliburton had pumped to the bottom of the well and did not seal off the hydrocarbons in the formation [40,42]. The exact reason why the cement failed may never be known, but several factors increased the risk of cement failure at Macondo. These included [40]:

– drilling complications forced engineers to plan a ‘‘finesse’’ cement job that called for, among other things, a low overall volume of cement;
– the cement slurry itself was poorly designed, some of Halliburton's own internal tests showed that the design was unstable, and subsequent testing by the Chief Counsel's team raised further concerns;
– BP's temporary abandonment procedures, only finalised at the last minute, called for rig personnel to severely ‘‘underbalance’’ the well before installing any additional barriers to back up the cement job.

According to the Commission [42], BP's management process did not adequately identify or address the RIFs created by late changes to the well design and procedures. BP did not have adequate controls in place to ensure that key decisions in the months leading up to the blowout were safe or sound from an engineering perspective. While initial well design decisions undergo a rigorous peer-review process, and changes to well design are subsequently subject to a management of change (MOC) process, changes to drilling procedures in the weeks and days before implementation are typically not subject to any such peer-review or MOC process. At Macondo, such decisions appear to have been made by the BP Macondo team in an ad hoc fashion without any formal risk analysis or internal expert review [42].

According to the Chief Counsel's Report [40], Several of BP's decisions like, not using drill collars, not using a mechanical plug, setting the plug in sea water, setting the lockdown sleeve last, may have made a sense in isolation. But the decisions also created RIFs, individually and especially in combination with the rest of the temporary abandonment operation. For instance, BP originally planned to install the lockdown sleeve at the beginning of the temporary abandonment. BP's decision to change plans and set the lockdown sleeve last triggered a cascade of other decisions that led it to severely underbalancing the well while leaving the bottom hole cement as the lone physical barrier in place during the displacement of the riser. There is no evidence that BP conducted any formal risk analysis before making these changes, or even after the procedure as a whole [40]. BP's own investigative report agrees that they did not undertake a risk analysis to consider the consequences of its decision. BP's management system did not prevent such ad hoc decision making. BP required relatively robust risk analysis and mitigation during the planning phase of the well but not during the execution phase [40,41]. Also Transocean's crew appears never to have undertaken any risk analysis nor to have established mitigation plans regarding their performance of simultaneous operations after the cement barrier was judged being safe [40].

4. Analysing risk in drilling operations

A blowout hazard study is carried out as part of a QRA to determine the blowout probabilities during different drilling phases, and with different well-related operations. The blowout hazard study also considers the outflow conditions under various scenarios, in order to determine the potential consequences of fire and pollution [7].

The drilling operation is as an iterative process where changes are constantly made. These changes add, remove or change human, organisational and technical RIFs in order to mitigate hazards and control risks. QRAs have traditionally been focused on technical systems and capabilities [7,43,44]. Much less attention has been focused on the human and organisational factors (HOF). The steps described in the well planning and the Deepwater Horizon includes HOFs to a large extent. Revealing and understanding the HOFs are therefore of great importance when conducting drilling operations.

The knowledge about HOFs started within the field of ergonomics; the art and science of interfacing people with the systems that they design, construct, operate and maintain. This approach focuses on a proactive reduction in the likelihood of malfunctions [44]. During the past decade much research effort has been aimed at revealing, isolating and measuring/predicting HOFs and their influence on risk [45]. There are several methods for analysing HOFs in the O&G industry e.g. the Organisational Risk Influence Model (ORIM) [46], Barrier and Operational Risk Analysis (BORA) [47,48] and Operational Conditional Safety (OTS) [49,50]. Table 1 shows the HOFs that have been defined in the OTS. The main principle of the OTS method was that the assessment of operational safety conditions should be risk based, i.e. that the selection of factors should be based on those that influence major hazard risks [50].

Several of the key findings in the investigation reports [21,40–42,51] are related to the HOFs described in Table 1. The HOFs also resemble the key capabilities for success for drilling professionals described by Boykin [52]. The HOFs also cover most of the weaknesses of current work processes in drilling pointed out by a large research and development (R&D) programme on drilling and wells within integrated operations in the Norwegian petroleum industry [53].

Table 2 describes RIFs sorted according to the Commissions categorisation into individual facilities, operations and environments [40].

In relation to the Macondo Blowout, the cement job involved a number of RIFs related to environment, facility and operational [40]:

– narrow pore pressure/fracture gradient,
– use of nitrogen foamed cement,
– use of long string casing design,
– short shoe track,
– limited number of centralizers,
– uncertainty regarding float conversion,
– limited pre-cementing mud circulation,
– decision not to spot heavy mud in rathole,
– low cement volume,
– low cement flow rate,

Table 1
HOFs that influence major hazard risks [49].

Work practice	The complexity of the given task, how easy it is to make mistakes, best practice/normal practice, checklists and procedures, silent deviations and control activities.
Competence	Training, education,both general and specific courses, system knowledge, etc.
Communication	Communication between stakeholders in the process of plan, act, check, and do.
Management	Labour management, supervision, dedication to safety, clear and precise delegation of responsibilities and roles, change management.
Documentation	Data-based support systems, accessibility and quality of technical information, work permit system, safety job analysis, procedures (quality and accessibility).
Work schedule aspects	Time pressure, work load, stress, working environment, exhaustion (shift work), tools and spare parts, complexity of processes, man-machine-interface, ergonomics.

Table 2
Categories of risk influencing factors.

	Risk categories	Example of RIFs
1	**Environmental-Surroundings** Environmental risk is caused by dynamic conditions like weather and static conditions like water depth and seabed conditions. Drilling equipment and offshore workers are directly exposed to the natural environment.	– Air temperature – Water temperature – Wind (e.g. hurricanes) – Rain/Snow – Waves – Earthquake – Seabed conditions – Water depth – Sea water salt
2	**Environmental-Geological risk** Geological risk is caused by the complexity and uncertainty of geological conditions. Uncertain seismic increase the geological risk.	– Drilling margins – Pressure – Temperature – Sandstone – Flow assurance – Crack and cave – Shut In Pressure – Leak off – Lost returns – Lithological discrimination – Blowout rate
3	**Facility-Technological risk** Safe operations demand the necessary quality and reliability of the drilling vessel, well equipment and well control equipment. Deviation from expected quality and reliability increases technological risk.	– Instrumentation – Reliability and validity of the instrumentation – Performance of drilling fluid – Well control equipment (pump capacity, mud capacity, valves, etc.) – Power generation and emergency power supply – Blowout preventer (BOP) – Cement – Casing – Maturity of new technology
4	**Operational risk** The risk of loss resulting from inadequate or failed internal processes, people and systems.	– Work practice – Competence – Communication – Management – Documentation – Work schedule aspects

– no cement evaluation log before temporary abandonment,
– temporary abandonment procedures that would severely underbalance the well and place greater stress than normal on the cement job.

According to the Commission, the BP engineers did recognise some of these risk factors, and even tried to address some of them. For instance, the team asked Halliburton to use an additional spacer during the cement job to compensate for the limited pre-cementing circulation. But it did not appear, according to the Commission, that any person on BP's team, whether in Houston or on the rig, ever identified all of the risk factors. Nor does it appear that BP ever communicated the above risks to its other contractors, primarily the Transocean rig crew. For instance, Transocean was never aware that Halliburton had recommended more than the six centralizers that were used. More importantly, there is no indication that BP's team ever reviewed the combined impact of these risk factors, or tried to assess the overall likelihood that the cement job would succeed, either on their own or in consultation with Halliburton. Rather, BP appeared to treat risk factors as surmountable and then forgettable [40].

Fig. 1 describes how human interaction is necessary to control a well kick. The bold arrows show the path in the Deepwater Horizon accident. There is some discussion if the shear rams were activated at the BOP by the drilling crew.

5. Analysis of blowout hazards in QRA studies

Altogether, fifteen QRAs for different installations were collected from six different operator companies. The collection was based upon a random sample among all installations on the Norwegian Shelf. Two of the QRAs were for drilling vessels. In addition, two safety cases for UK installations were collected. The QRAs are internal company documents and their results are not published. The document owner is often the installation management, and the QRA is treated as sensitive information owing to the detailed information about the installations' weak spots. As a result, the information retrieval took close to a year. All the QRAs requested except one were collected. The QRAs were performed in the period of 2000–2009.

In Norway, there are three dominant consultancy firms conducting QRAs. The QRAs are usually regulated by framework agreements. The budget in man-hours is usually about 1500–2500 h over a period of 3–5 months. The main results are usually summarised in a main report. In addition, the different hazards are further described in appendices and sub-appendices. The main report is usually about 50–150 pages. The appendices are usually 500–1500 pages. The analyses mostly use the same generic data sources, accident statistics, failure databases (loss of containment, etc.), equipment failure databases, physical properties of various substances and company internal accident and incident databases. The use and interpretation of the data differs.

5.1. Frequency estimations in the QRAs

The QRAs are all based on the frequencies specified in Blowout and Well Release Frequencies based on SINTEF Offshore Blowout Database [54]. The intention of the report is to collect data from all occurring blowouts. However, many blowouts/well releases have never been recorded in the database. This is because public sources, which are the main source of information for blowouts/well releases occurring outside the GoM OCS, UK and Norway, frequently do not describe blowouts/well releases with minor consequences. Therefore, several blowouts/well releases are believed to be missing from the database [55].

SINTEF Offshore Blowout Database [55] documents blowout and well release frequencies based on well operations of the North Sea standard with respect to standards of practice and equipment. A goal of the report is to obtain a mutual understanding of the data selection and use of the frequencies amongst oil companies and risk analysts. Frequencies are calculated for the following categories:

– exploration well drilling,
– wildcat well drilling,
– appraisal well drilling,
– development well drilling.

In addition, the separate frequency estimates for completion, wireline, coiled tubing, snubbing, workover, producing wells and gas injection wells are obtained. The frequencies are calculated per well, per operation or per well year. They are also divided into the categories of shallow gas, normal well and high pressure high temperature (HPHT).

The data includes in the period of 01.01.88–31.12.07, 19,962 wells (excluding sidetracks). A total of 21 blowouts were reported during exploration and development after the BOP is installed on the well and acts as a blowout barrier. One blowout has been reported in the North Sea on the British sector. This blowout occurred on a HPHT well. In the US GoM, 20 blowouts from normal wells were reported. The blowout frequency for the US GoM is about 9 times higher than that for the North Sea. This difference is

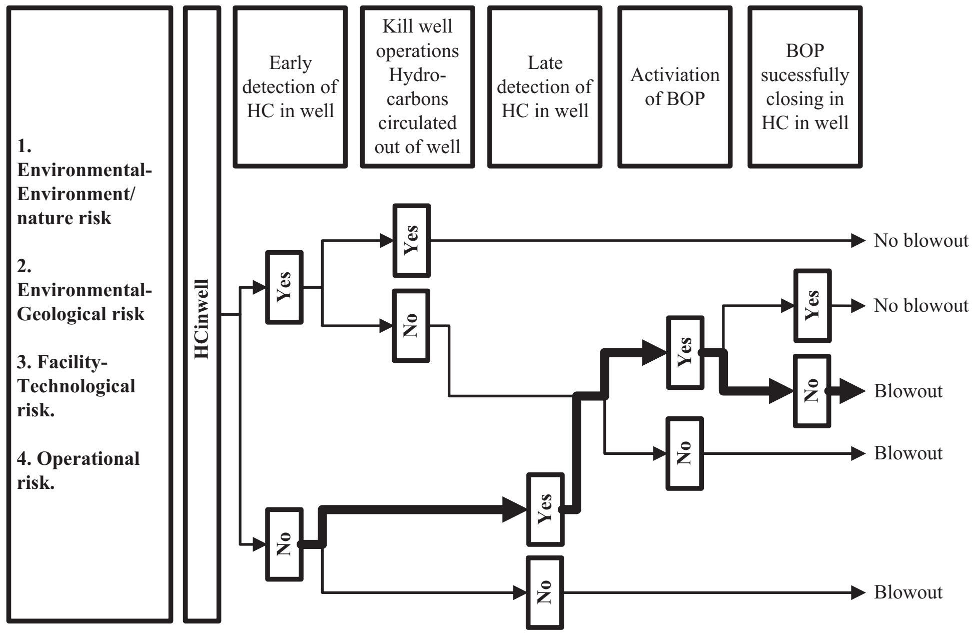

Fig. 1. HC in well and kill operations.

statistically significant. In the North Sea, it is a requirement to always have two barriers throughout the well operations. As this is also the case for the US GoM, it is assumed that the quality of the barriers is the cause of the lower frequency [54].

In the GoM, there were 20 incidents in the period 1973–1995 related to well kicks after cementing surface casing. Another 13 similar incidents have occurred since 1995, with the most serious consequences being gas broaching the surface, cratering, well loss, and rig and platform destruction by fire. Annular flow related to cementing surface casing has been identified as one of the most frequent causes of LWC incidents in the GoM [32]. In deepwater, the frequency of kicks is high, approximately 2.7 times higher in the US GoM deepwater wells than over the whole Norwegian Continental Shelf (NCS). Still, NCS kicks in deep wells, and especially in HPHT wells, have occurred frequently [56].

The frequency estimation in the QRAs is not adjusted according to the RIFs shown in Table 2 related to environmental risk except for HPHT. The blowout frequency for an HPHT well in the QRAs was calculated with a factor of 12.3 higher than for a normal well (including underground blowouts). The reason for the higher frequency is not believed to be the high pressure itself, but rather the narrow drilling window [54,55].

5.2. The QRAs and HOFs

The generic data sources are not sorted or adjusted for any HOFs. In one of the analysis the probability of a shallow gas blowout during development drilling was judged to be negligible based on several years experience. In another of the analyses the frequencies were adjusted based on the operator having extensive knowledge on the reservoir that was going to be drilled.

Ten out of thirteen of the QRAs did explain the importance of HOFs. The explanations were from a few lines to several pages. The explanations were generic, and how the HOFs influence on the technical systems was barely covered. The HOFs were not reflected in the calculation and thereby not reflected in the numerical calculations.

The different operators have procedures and guidelines related to drilling operations, and how to consider an operation to be finished safely. These procedures and guidelines were evaluated in two of the QRAs. The overall risk contribution was considered negligible for the drilling operations due to the assumption that the operations would comply with procedures and guidelines.

Four of the analyses did include experiences from earlier incidents (e.g. kicks). Examples of previous incidents and their relation to major hazard risk were briefly described. It was assumed that the findings and recommendations from the incident reports were implemented. The recommendations were in two of the analyses related to HOFs. The analyses did not follow a structured pattern related to revealing and analysing the HOFs. Experiences from earlier incidents were not included in the QRA-models. The role of HOFs as possible hazard causes, as well as safety barriers, was explained. For example it was assumed that blowouts were often (about 95%) pre-warned, and mustering of non-essential personnel therefore would be preformed. It was assumed that the drilling crew located in the drilling area would attempt to make the well safe as a basis for personnel risk calculations. The drilling crew would therefore have a higher risk due to their exposed location.

The consequences of blowout were calculated based on medium release (gas/oil), wind conditions and fire and explosion simulations. The event tree was divided into immediate, delayed or no ignition. The simulations were combined with personnel distributions. The blowout scenarios were explosion, fire on installation/vessel, fire at sea and hydrocarbon release to sea. The risk consequence calculation shared the methodology with other fire and explosion scenarios, including the release of hydrocarbons from process equipment.

QRAs are conducted when the installation is designed and thereafter updated on regular basis, usually every fifth year. The blowout appendix is sometimes also updated based on well activity plans, but none of the reviewed analyses were initiated based on RIFs revealed in the conceptual phase and/or pre-job meetings.

6. Discussion

The Commission recommended a proactive, risk-based performance approach specific to individual facilities, operations and environments. The QRAs do to a very limited extent reflect the individual facilities, operations and environments. Some reflections are carried out by the categorisation into a few well categories and adjustments for HPHT wells. Others than that are the frequencies not adjusted in the QRAs for any of the RIFs shown in Table 2.

According to Pritchard and Lacy [57], the drilling industry needs to recognise where serious risks exist in complex well development, and to design wells, which deal with the uncertainties in geological risk. They claim that in some categories of complex wells, wellbore stability events are as high as 10% of the total deepwater well time, and well control incidents over four times those of normal wells. Blowout prevention equipment was not intended to become a routine execution tool, but in some of the more complex deepwater wells time spent on the BOP's has been increasing dramatically [57]. This may indicate that serious risk mitigation is a significant issue in drilling complex wells. As a consequence, the industry needs to better assess the risks and monitor well operations. They suggest a method for categorisation of the wells based on geological hazards. The wells are divided into five categories according to a risk index named the Mechanical Risk Index (MRI). MRI provides an industry standard point of reference ranking drilling complexity by a point system. The higher the value of MRI, the more difficult the well is to drill. Deepwater wells are divided according to depth of water, total well depth, number of casing strings, salt penetration, drilling direction, H_2S/CO_2 environment, hydrate environment, depleted sand–Open Hole differential PSI >2000, subsea wellhead installed, mudline suspension EQ installed, salt drilled/penetrated, hole size—open hole $<6'5''$, riserless mud used to drill shallow water flows, loop current—crammed eddies, shallow water flow potential and hole core.

A more complex categorisation of blowout frequencies, e.g. MRI, will reflect the special factors for the operations and environment. The validity can be increased, but this has to be balanced with reliability. The use of historical blowout data to predict frequencies, e.g. [55], is discussed in [58]. The use of a standardised set of frequencies increases the reliability of the analysis, meaning the extent to which the QRA yields the same results when repeating the analysis. The validity is though reduced due to the limited degree which the QRA describe the specific facilities, operations and environments. According to Pritchard and Lacy [57], we often hear that the industry has drilled 50,000 wells in the GoM, implying that no real problem exists. The MRI-metrics does not support that statement and demonstrate that only 43 MRI 3, 4 and 5 category wells have been drilled through the year-end of 2009. So what is the real probability of occurrence of catastrophic failure relative to the BP Macondo. Is it 1/50,000 or is it 1/43? This number poses a totally different perspective when risk analysing deepwater drilling [57].

The MRI-metrics questions if the blowout-frequency related to deepwater drilling might be underestimated. With most of the well materials being pushed towards the extremes of their operating envelopes a distinct increase of technical risk can be incurred. Failure of the equipment, the construction or the borehole integrity of a HPHT well will not necessarily lead to an emergency, but if it results in the loss or suspected loss of a pressure barrier it can escalate to a blowout if not handled correctly by the drilling crew. The severity of the well conditions and hence the time involved to arrange for corrective measures – usually in first instance a well kill – will give rise to an extended period during, which the well pressure integrity relies on the single remaining barrier, the BOP [59]. Kick detection, well kill operations and BOP reliability is therefore of high importance.

Federal regulations required the Deepwater Horizon to have a BOP that included a blind shear ram. The blind shear ram is designed to cut the drill pipe in the well and shut in the well in an emergency well control situation. According to the Commission, even if properly activated, the blind shear ram may fail to seal the well because of known mechanical and design limitations [40]. In a study done for the MMS in 2002 [60] it was concluded that of the seven shear rams tested, five successfully sheared and sealed (71%) based on shop testing only. If operational considerations of the initial drilling programme were accounted for, shearing success dropped to three of six (50%). The limited data set gave a disturbing result regarding the probability of success when utilising the final tool in securing a well after a well control event. According to the study, many operators and drilling contractors had chosen not to perform actual shear testing when accepting new or rebuilt drilling rigs. Thereby the evidence that the installed shear rams would shear was often lacking [60].

The BOP on Deepwater Horizon did not close as intended and in the investigation report DNV recommends that the industry examine and study the ability of the shear rams to complete their intended function of completely cutting tubulars regardless of their position within the wellbore, and sealing the well. It is also recommended that the industry review and revise as necessary the practices, procedures and/or requirements for periodic testing and verification of the back-up control systems [61].

A reliability study of subsea BOPs was performed by Sintef in 1999 [56]. This was a follow up study focusing on the deepwater kicks and associated BOP problems and safety availability aspects. The study was based on information from 83 wells drilled in water depths ranging from 400 m to more than 2000 m in the GoM OCS. These wells had been drilled by 26 different rigs in the years 1997 and 1998. A total of 117 BOP failures and 48 well kicks were observed in these wells [56]. The study also concluded that backup BOP control systems are more important in deepwater drilling than in shallow water drilling to control incidents in which the riser accidentally disconnects from the BOP because of the absence of riser margin in many well sections. Also, modern BOP control systems have less redundancy between the control pods (yellow and blue) compared to older control systems. In some modern systems, a single failure in the hydraulics may cause total loss of BOP control. Such failures have been observed [62]. Problems with the backup control systems and pods were both issues in relation to the Deepwater Horizon accident. The 'deadman' system relied upon at least one of the BOP's two redundant control pods (yellow or blue) to function [40]. A separate study of BOP reliability experienced for wells drilled in the US GoM in the period from 2004 to 2006 concluded that the reliability was significantly better than that of prior studies [63].

Uncertainty, validity and reliability are important aspects when conduction a QRA. Where the analyst considers that a particular evaluation, or calculation, is particularly uncertain, it is considered good practice to aim to err on the conservative side [7]. It can be questioned whether the results from the research related to BOP reliability in deepwater, should lead to a more conservative frequency estimation. The results from the investigations of Deepwater Horizon do support that this question is raised.

To achieve a specific understanding of the individual facilities, operations and environments, there is need for more than simply collecting and classifying historical blowouts worldwide. PSA investigated a number of serious well failures on the Norwegian Shelf. The failures were typically caused by aging effects or design, unclear understanding of barriers, weaknesses in well design and planning processes, and insufficient validation of premises [64]. The risk management process is highly dependent on human judgement to ensure the balance of RIFs. Revealing the HOFs is therefore of great importance for ensuring safe drilling operations. Methods for incorporating HOFs into QRA models need to further developed and used by the O&G industry.

In the Risk Level Project (RNNP) in Norway, so-called leading and lagging indicators are used to assess the risk level of the Norwegian O&G industry on an annual basis. The first report was published in early 2001, based on data for the period 1996–2000. RNNP uses various statistical, engineering and social science methods to provide a broad illustration of risk levels, including risks due to major hazards, risks due to incidents that may represent challenges for emergency preparedness, and risk perception and cultural factors [65,66]. The results and methods from the RNNP can be used to adjust the frequencies used in QRAs, if supported by more data.

HOFs are of high importance to ensure well control and to act when well integrity is being threatened. Kick detection is of high importance, and did fail at the Deepwater Horizon. Transocean recognised the importance of well control. In a Major Accident Hazard Risk Assessment [67], the company gave Deepwater Horizon a 5B risk rating for reservoir blowout, meaning that there was a low likelihood of a blowout occurring, but if one did occur, the event would have extremely severe consequences. Regarding prevention and mitigation measures, Transocean listed (among other things) well control procedures, training of drill crew, and instrumentation indicating well status [40,67].

Human judgement is based on HOFs. BP, Transocean and Halliburton placed great reliance on human judgment. For instance, during the displacement of the riser with seawater, BP relied on the bottomhole cement as the only barrier in the wellbore. But awareness of whether that barrier was in place, because of the negative pressure test, depended on human judgment. Another barrier, the BOP, also relied on human judgment because of the importance of kick detection and kick response. Yet the companies, according to the Commission, failed to provide the rig crew and well site leaders exercising that judgment with adequate training, information, procedures, and support to do their jobs effectively [40]. The personnel were not supported by adequate well monitoring equipment. For example, the data displays depended not only on the right person looking at the right data at the right time, but also that the person understood and interpreted the data correctly [40].

A QRA is conducted approximately every fifth year. This means that the QRA will not capture the day to day risk management. The QRA is supported by a number of other risk analysis/assessments methods. There are also specific risk assessment models for drilling, e.g. the Well Integrity Risk Assessment Model [34]. According to the Commission, problems with risk assessment practices have affected the decision making at Macondo in a number of ways. First, they allowed decision-makers to systematically avoid identifying the risks their procedures created and the steps necessary to mitigate those risks. Second, the absence of a formal risk assessment enabled late and rushed decision making. Third, the lack of rigorous risk assessments led decision makers to solve problems in isolation instead of considering the cumulative impact their solutions might have on the rest of the project [40]. Some may conclude that the "safety case" approach requested by the Commission will not make any difference since the risks are mainly created during the well planning phase, as seen in the Deepwater Horizon accident. Even so, the QRA may support the day to day risk management by describing the overall risk. The QRA show how hazards are identified and assessed on a rig. The QRA also show which barriers that are established to prevent and control those hazards, and which critical activates are needed to maintain the integrity of the barriers. The consequence evaluation of a blowout is often done by simulations using Computational Fluid Dynamics software. Simulations can be a useful tool for ensuring a better understanding of the rig's technical capacity and limitations and their role as safety barriers. It is the authors' impression that offshore personnel have too much confidence in the technical consequence reducing barriers, e.g. detection system, alarm system, power supply, emergency disconnect system, BOP and fire water. As seen in the case of Deepwater Horizon, these systems failed. The systems do also often have to be activated by humans, meaning that human judgement needs to be based on a thorough understanding of the technical systems.

7. Conclusion

According to the Commission a reassessment of the risks associated with offshore drilling is required. The Commission recommends a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the safety case/QRA approach in the North Sea. The review of QRAs revealed that the RIFs for individual facilities, operations and environments are scarcely covered. There is a categorisation into main drilling activities and water depth, but the categorisation does not cover the RIFs for the individual facilities, operations and environments related to blowout frequency. The QRAs do not include HOFs. As seen in the Macondo blowout, most of the findings were related to HOFs, such as work practice, competence, communication, procedures and management. The multiple RIFs related to environment, geology, technology and operation when drilling deepwater, have to be controlled by safety barriers depending on HOFs. None of the analyses reviewed were initiated based on RIFs revealed at the conceptual phase of well planning. There is some research relating to incorporating the HOFs in QRAs, and further improvements are necessary to ensure that the QRAs are valid for the individual facilities, operations and environments. A deeper understanding of the coherence of the RIFs demands that data is collected and processed across the O&G industry worldwide.

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