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Review article

Kicks Prevention and Innovative Saving Proposals for an Operator in Oman

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ABSTRACT

In the last ten years, several kicks and blowouts have occurred in the Sultanate of Oman. None of these blowouts escalated. They were controlled within 1–2 days and did not require capping or relief well drilling. The purpose of this study is to identify best practices to prevent further kicks and blowouts from occurring in Oman. The study starts with a brief overview and analysis of kicks and blowouts, which have happened around the world. Based on these examples, some useful recommendations are provided to improve the awareness of well engineering staff. The paper then analyzes kicks in the Sultanate of Oman that happened with one of its operators in the last five years. It divides the wells within this operator into low-risk standard wells (LRSWs) and high-risk complex wells (HRCWs). The article finishes by providing innovative proposals to improve production and performance in LRSWs. These proposals will save approximately USD$13,000,000 annually. This paper has been extracted from the Master Thesis of the first author.

Keywords: Kicks; Blowouts; Oil; Gas; Oman

INTRODUCTION

Primary well control defined as "Prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than formation pressure" [1]. A well is kicked if primary well control is lost and formation fluids enter the wellbore [2]. According to Shell Exploration and Production [2], the various causes of loss of primary well control include swabbing; insufficient mud density; lost circulation; holeslacking adequate fluid density; excessive drilling rates through gas sand; drill stem testing (e.g., packers, which are used to test formation flow); drilling into an adjacent well, including production wells and water injector wells; and equipment failure.

METHODOLOGY

This loss of primary control or secondary controlcould lead to a blowout, which is defined as a loss of control over formation pressure causing an unrestricted flow of formation fluid at the surface [3]. Oskarsen [4] reported three main groups of blowouts-surface blowouts, subsea blowouts, and underground or internal blowouts. Surface blowouts happen when formation fluids flow into the atmosphere. Subsea blowoutsoccuron the seafloor when formation fluids flow through the reservoir and mix with seawater. The most famous subsea blowout in recent years was the 2010 British Petroleum (BP) blowout in the Gulf of Mexico. An underground or internal blowout is marked by crossflow between formations and occurs when fluids flow from high-pressure to low-pressure zones.

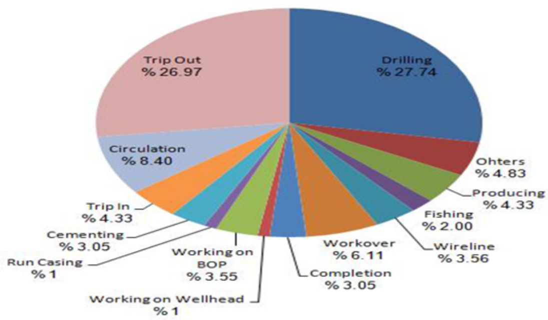

Figure 1: Operation when the blowout occurred [5].

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Several researchers have analyzed kicks and blowouts occurringthroughout the world. Adams and Kuhlman [5] conducted a study to review the type of operations in about 900 blowouts. The results showed that most blowouts occurred during drilling and tripping out operations (Figure 1). Skalle [6] analyzed more than 500 blowouts occurring between 1960 and 1996 in the USA's Gulf Coast and its adjoining states. The analysis indicated that most blowouts occurred during exploration drilling, development drilling, and workover (Figure 2). The analysis indicated that swabbing and elevated pressure were the main causes of blowouts. A system's blowout preventer (BOP) and string valve were often found to have failed after a kick had occurred. The study showed no reduction in blowout frequency during this period despite improvements in regulation, well control training, and the inspection of well control equipment. Findings suggested that improvements were lost because contracts were of the footage type. The effort of the contractors under these contractsfocused on minimizing non-productive time and maximizing the drilling rate,resulting in tripping that was too fast, a failure to circulate bottoms during influx, not filling holes properly, and so on. The study suggested using a day rate contract instead of a footage contract or including a bonus for zero kicks and blowouts when issuing a footage-type contract.

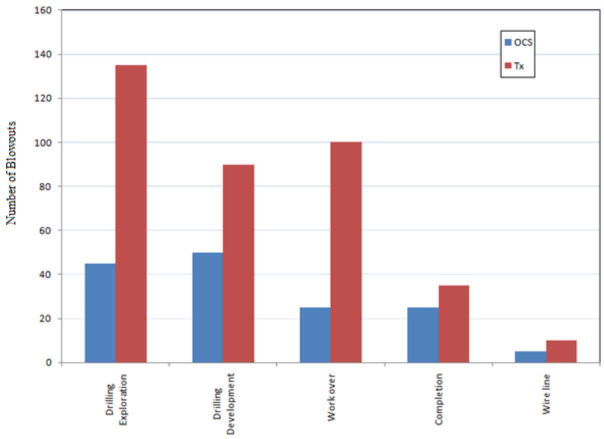

Figure 2: Blowout vs phase in progress (Texas + Outer Continental Shelf) [6].

In China, between 1962 and 1993, there were 25recorded blowouts. Xiangdong et al. [7] analyzed in detail six blowouts of those 25 cases. Their approach in analyzing the blowouts was based on six different types of errors: management error, design error, equipment error, operation error, production error, and testing error. The analysis indicated that operation error was a major factor in blowouts (Figure 3). They also found peakblowout frequency occurred on weekends and early mornings. They suggested implementing a regular duty schedule for drilling operation teams and a proper work/sleep schedule for rig crews.

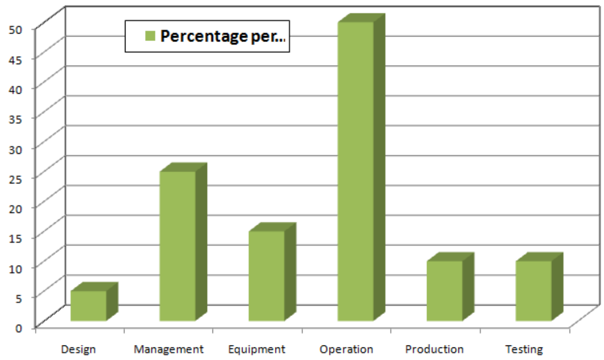

Figure 3: Percentage of each type of error in the total number of errors in six cases [7].

Dobson [8] conducted a review of all of the kicks and blowouts recorded in offshore UK wells from 1999 to 2008. The analysis indicated that most kicks were due to geological conditions. In addition, the analysis indicated that human error, such as failure to shut down water injector wells and not circulatinginflux completely, was a major factor in well incidents.

Based on a literature review, kicks and blowouts can be classified as having immediate causes or underlying causes. Immediate causesare loss of primary control, which occurs due to swabbing, lost circulation, insufficient mud density, drilling into production or water injector wells, and so on. The underlying causeis human error, which occurs due to lack of knowledge and experience; carelessness with and ignorance of well control equipment; inappropriateprocedures from experienced rig crew; prevailing drilling contracts (e.g., footage type); and not regularly checkingor certifying well control equipment.

Human error can be mitigated by providing appropriate training to well engineering staff and drilling crewsso that they can better control equipment and follow procedures; applying consequence management for carelessness with and ignorance of well control; awarding staff bonuses for zero well control incidents under the prevailing contract types; implementing day rate contracts; and checking well control equipment regularly.

The current paper offers tangible business benefits for operators in terms of improving performance, minimizing production loss, reducing reservoir damage, and lessening cost impact. The work will review several kicks and blowouts that occurred in the USA, Mexico, China, and at offshore locations in the UK. The work will look at operations that carry the most risk for kicks and blowouts and examinetheir immediate and underlying causes.

This paper aims to prevent kicks and blowouts from happening as much as possible by improving well engineering staff and drilling crews' awareness of the causes of these issues. To this end, the work divides wells into LRSWs and HRCWs. In addition, the work aims at improvingoperator production and performance by adding innovative proposals, which could save millions of dollars per year.

The work contributes toincreasing awareness of well control systems and operator practices to improve production and performance. Operators can use the same well control systems and practices for all kinds of wells. This paper alsoforwards innovative proposals for LRSWs to reduce time and cost, saving millions of dollars per year.

History of blowout damage

This section focuses on the hazards and effects of blowouts. Blowouts can result in fatalities and injuries as well as property damage in the form of a loss of valuable reservoirs and environmental damage. Blowouts, therefore, place undue financial pressure on drilling companies. Such financial pressure can occur as a result of a loss of reputation or social disruption.

IXTOC1, an oil well in Mexico drilled by the Mexican Petroleum Company, experienced a blowout in 1979. The occurrence pumped 3.5 million barrels of crude oil into the Gulf of Mexico before it was killed by two relief wells (Figure 4). The spills caused huge problems for different sectors [9].

Figure 4: IXTOCI blowout [9].

The Piper Alpha platform experienced a blowout in 1988 in the UK. The blowout was caused by a gas leak from the subsea, which resulted in a massive fire. The explosions killed 167 men, and the whole platform structure collapsed (Figures 5 and 6).

Figure 5: The Piper Alpha platform before the fire [10].

Figure 6: The Piper Alpha fire [10].

Billions of dollars were lost in well control and clean up [10]. Lord Cullen was appointed to represent the company during public legal inquiries about the Piper Alpha disaster. The inquiry sought to determine the cause of the disaster and make recommendations based on lessons learned from the experience. In his report, Lord Cullen made over 100 recommendations that transformed the disaster into a safety case approach [11].

The best example of a blowout that caused a loss of valuable reserves was the Lost Hill Blowout in California [12]. In 1998, the offshore well experienced a blowout which spilled approximately 1400 million cubic feet of gas into the marine environment (Figures 7 and 8).

Figure 7: The Lost Hill blowout [12].

Figure 8: The Lost Hill blowout flowed for six months before it was killed by a relief well [12].

Macondo, or the Deepwater Horizon Blowout, occurred in 2010 in the Gulf of Mexico, spilling 4.9 million barrels of oil before it was killed by a capping operation and two relief wells. As of writing, it is the most massive oil spill in history. The explosion killed 11 men, injured 17 more, and sank the rig (Figures 9 and 10). The oil spill could eventually cost BP USD $21 billion in fines[13]. In addition, millions of dollars have already been spent on clean up and well control[14].

Figure 9: Deepwater Horizon semisubmersible drilling rig before the blowout [15].

Figure 10: Deepwater Horizon blowout [15].

Analysis of data for an operator in oman

This study analyzed reported kicks for the selected operator from 2014 to 2018 and also looked at blowouts occurring in the last twenty years. The operator has three main areas: anexploration and gas area, Block A, and Block B.

Blocks A and B are development fields. Block A has high formation pressure, free flowing wells, and high H2S emission. Block B is constituted of non-free flowing wells with low formation pressure and is in a well-known area. The exploration and gas areas have unknown areas and free flowing wells with high formation pressure. Therefore, in terms of well control, theexploration and gas area and Block A can be classified as HRCWs, whereas Block B can be classified as a LRSW.

Figure 11 shows the number of kicks in the operator's fields in the last five years. The kicks occurred during two major operations: workover and drilling in the exploration and gas area and Block A. Analyses indicated that the major causes of kicks were related to lost circulation/losses, swabbing, and unexpected high pressure (Figure 12).

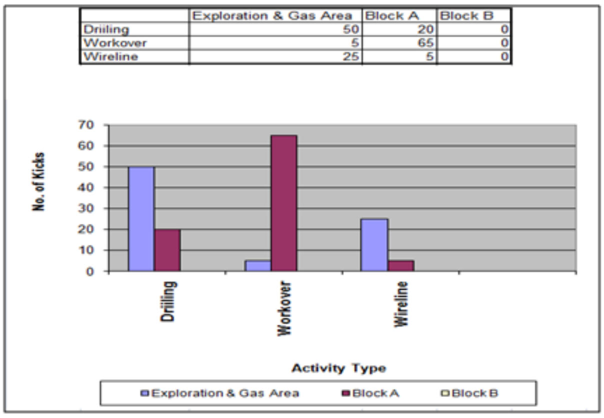

Figure 11: Kicks vs. phase in progress in the last five years.

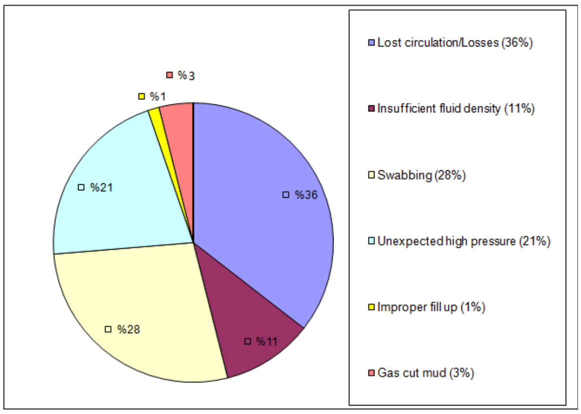

Figure 12: Causes of well kicks through the failure of primary control in the last five years.

Circulation and bull heading were the most frequent killing methods used. Historical data showed that all blowouts occurred in the exploration and gas area and Block A (i.e., the HRCW). BOP and wellhead failures caused these blowouts, which were killed by relief wells and/or surface interventions with dynamic kill methods.

Innovative proposals to save millions in Lrsw (Block B)

Block B is a well-known development field. It is not self-flowing and has very low pressure and very viscous oil. The historical data of the last twenty years show no record of gas kicks in Block B. There were very few oil kicks due to the presence of water injector wells (WIW), and the kicks were killed after closing the WIW. There were a few shallow gas kicks, but they lasted for only a couple of seconds and killed themselves without consequence during drilling inside a shallow gas crest area. An average of 320 wells are drilled, and 1,800 wells are worked over in Block B every year. For rig operations, the approximate rig tariff and overhead cost (ROHC) isUSD $30,000/day. For workover operations, the approximate hoist tariff and overhead cost (WOHC) is USD $20,000/day. The operator uses the same BOP control system and procedures for all areas. The following proposals are only for Block B, which is classified as a LRSW.

Proposal #1

Using a rig BOP as a secondary well control barrier for drilling in a shallow gas location instead of employing a rented diverter system.

Background: There are very few cases of shallow gas kicks while drilling 12 1/4-inch holes inside the shallow gas crest area. In all of these cases, the shallow gas kicks lasted for only a few seconds and killed themselves with no H_2S emission, no fires, and no injuries. In addition, the historical data and formation leak test proved that the formation underneath the last casing was sufficient to hold the maximum anticipated reservoir pressure. All shallow gas kicks occurred because the wells werenot continuously filled with WSW after losses encountered.

The current practice is to use a rented diverter system to drill surface holes inside a shallow gas crest area (Figure 13).

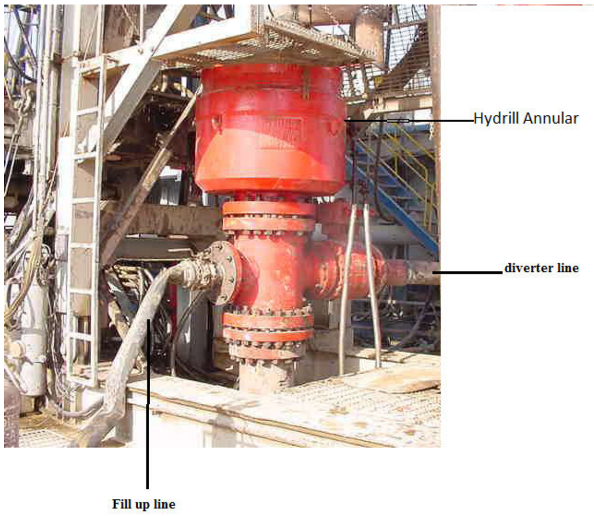

Figure 13: Rented diverter system for shallow gas crest area in Block B.

The fill-up line is used to pump well site water (WSW) at 80 m^3/hr to the annulus once total losses are encountered. If shallow gas kicks occur, the diverter line is used to divert the flow to the waste bit after closing the diverter. In the last 10 years, no shallow gas kicks occurred after using a fill-up line.

Way Forward: The suggestion here is to use a rig BOP system instead of a rented diverter system in shallow gas crest areas. The fill-up line should be used as before to fill the annulus at 80 m^3/hr. If shallow gas occurs, the shallow gas should be diverted to the waste pit through the chock manifold. The annular preventer should then be filled and maintained through the kill line at 80 m^3/hr (Figure 14). In addition, a control measure should be in place to flush the chock line before drilling in the shallow gas crest area.

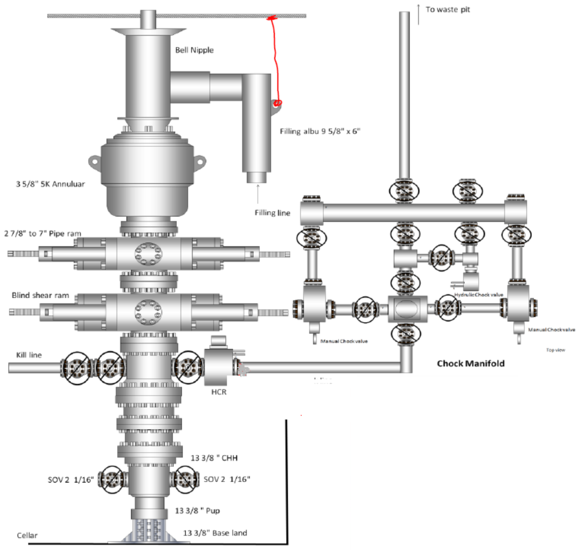

Figure 14: Rig blowout preventer (BOP) system for drilling the shallow gas crest area in Block B.

Intangible savings: Gains can be summarized as follows:

- The diverter takes 12 hours tonipple up (N/U), test functions and pressure, and nipple down (N/D).

- The BOP system takes nine hours to accomplish the same routine.
- The rented diverter system costs USD$40,000/well.

The daily time savings would be 12-9 = 3 hours/well. An average of 50 wells is drilled in the shallow gas crest area in Block B annually. Equation 1 shows the annual time savings while Equation 2 shows the annual monetary savings.

(3 hours)/well × (50 wells)/year = 150 hours/year = 6.25 days/year worth additional activities Equation 1

6.25 days × ($ 30,000)/day (ROHC) + (50 wells)/year × ($ 40,000)/(well rental cost of the diverter system) = USD $2,187,5000/year Equation 2

Proposal #2

Not using a mud gas separator (MGS) for rig operations.

Background: In the last 10 years, no recorded gas kicks have required an MGS. Only a few oil kicks have occurred due to WIWs, and they killed themselves after closing the WIW. The transportation cost of MGS is USD$300/well and takes one hour for rig up (R/U) and one hour forrig down (R/D).

Recommendation: The suggestion is to move the MGS from the rig site to the camp site; it can be mobilized to the rig site within 0.25 day. An MGS should be used once every six months and flushed with fresh water to avoid malfunctions.

Intangible savings: This proposal will reduce rig teams' exposure to unsafe situations by decreasing tripping and R/U and R/D timein the MGS. In addition, it will reduce transportation costs (USD$300/well) andsave two hours/well for R/U and R/D. Equation 3 shows calculations for the annual time savings, and total monetary savings are shown in Equation 4.

(2 hours)/well × (320 wells)/year = (640 hours)/year = 26.7 days/year worth additional activities Equation 3

($ 300)/well × (320 wells)/year + ($ 30,000)/(day) (ROHC) = USD$ 897,000/year

Equation 4

Proposal #3

A lean BOP set up for rigs and hoists

Background: The operator uses the same BOP stack for LRSWs and HRCWs; however, this BOP stack is designed to meet HRCW requirements.It consists of one annular preventer, one pipe ram or variable blind ram (PR/VBR), and one shear blind ram (SBR) (Figure 15). The BOP stack requires R/U and R/D, which must be undertaken in two steps and requires three tests for annular, PR/VBR, and BSR. The BOP stack requiresnine hours for R/U, R/D, and pressure test (P/T).

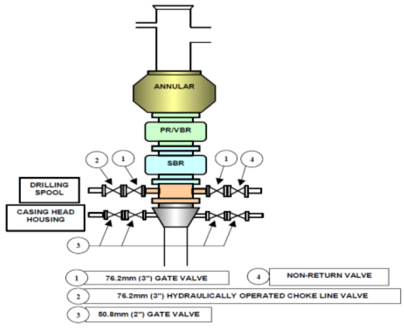

Figure 15: The current blowout preventer (BOP) stack for the exploration and gas area and Blocks A and B [2].

Recommendation: Shell Exploration and Production [2] noted that LRSW could use only one annular preventer for drilling and a workover operation (Figure 16). This BOP stack requires one test and takes four hours for R/U, R/D, and P/T.

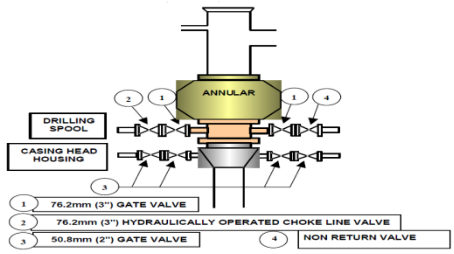

Figure 16: Proposed blowout preventer (BOP) stack for Block B [2].

Intangible savings:A lean BOP set up will cut Health, Safety, and Environment (HSE) Compliance Standards concerns mainly by lessening the likelihood of hand and finger injuries. It will save five hours per well (9 - 4 = 5 hours/well). Equation 5 shows total time savings for the year's drilling operations.

(5 hours)/well × (320 wells)/year = 1600 hours/year = 66.7 days/year Equation 5

Equation 6 shows workover well time savings per year, while Equation 7 shows monetary savings.

(5 hours)/well × (1800 wells)/year = 9000 hours/year = 375 days/year Equation 6

(66.7 days)/year × ($ 30,000)/day (ROHC)+ (375 days)/year × ($ 20,000)/day (WOHC)= USD$ 9,501,000/year Equation 7

Proposal #4

N/U and P/T the Christmas tree (X-tree) after moving a rig

Background: The current practice in drilling rigs is to N/U and P/T Christmas trees (X-trees) after landing. In addition, the current practice supports P/T tubing hanger seals and two-way check valves (TWCV). The procedure is then to R/D the rig mast on the carrier and move the rig to the next location. It takes two hours to N/U and P/T a X-tree and 2.5hours to R/D the mast and move the rig.

Recommendation: The way forward is to R/U and P/T the X-tree after the rig move. In the last ten years, no historical data have shown that the tubing hanger seal or TWCV develop leakswhilenipping up aX-tree. For risk mitigation, the requirements of well activity coordination and control should be emphasized, and isolation certificates for water injector wells should be obtained for sites that need to be closed induring drilling operationsto avoid accidental start-ups.

Intangible savings: This proposal will save two hours of rig time and 26.7 hours annually, as shown in Equation 8, while Equation 9 shows the monetary savings.

(2 hrs)/well × (320 wells)/year = 640 hrs/year= 26.7 days/year worth additional activities

Equation 8

26.7 days × ($ 30,000)/day (ROHC) = USD$ 801,000/year

Equation 9

Annual Savings

The innovative proposals above will cut exposure to HSE concerns and improve operators' production and performance. The proposals will save approximately 126 days of rig operations and 375 days of workover operations. The total savings will be USD$13,386,000/year (Table 1).

Table 1: Total savings of the innovative proposals for Block B (BOP = blowout preventer; MGS =mudgas separator; N/U = nipple up; P/T = pressure test; X-tree = Christmas tree).

No.	Proposals	Rig days saved (days)	Workover days saved (days)	Money saved (USD$)
1	Using rig BOP as a secondary well control barrier for drilling in a shallow gas location instead of in a rented diverter system.	6.25		2,187,500
2	Not using an MGS for rig operations	26.7		897,000
3	Using a lean BOP set up for rigs and hoist	66.7	375	9,501,000
4	N/U and P/T the X-tree after moving the rig	26.7		801,000
Total savings		~126	375	13,386,500

CONCLUSION

The immediate causes of kicks and blowouts are insufficient mud density, swabbing, inadequate density fluid present in the hole, drilling production wells, and so on. Human error is the main underlying cause of kicks and blowouts as expressedin an analysis of several well control incidents thathave occurred worldwide. Human error can be due to a lack of knowledge and experience, carelessness or ignorance in experienced rig crews, and the use of footage type contracts, which are the prevailing contract used in staffing wells. In addition, human error can cause well control equipment failure when the equipment is not regularly checked, tested, and certified.

The operator under study has three different areas: theexploration and gas area and Blocks A and B. Most kicks to date have occurred during the exploration phase for gas in Block A during drilling and workover operations. No gas kicks have occurred in Block B in the last ten years. The operator uses the same well control systems and practices in all areas.

This study suggests innovative approaches for the well control system and procedures for Block B (LRSW) to cut down HSE violations. The proposed approach will reduce time devoted to and cost of drilling and workover operations and will improve production and performance. It will save approximately 126 days of rig operations and 375 days of workover operations. The total savings will be approximately USD$13,000,000 per year.

RECOMMENDATIONS

Human error can be avoided or minimized by ensuring that competence levels are sufficient, and appropriate training for well engineers and drilling crew are conducted regularly. Management should have a reward scheme in place for good working practices, and they should deal firmly with infringements. Moreover, drilling should be contracted at a day rate and not through footage contractsto avoid bypassing well control procedures, save time, and maximize profits. Another option would be toreward crews for zero kicks or blowouts when working under footage contracts.

Operators and contractors should ensure that work is properly planned, communication is well executed, and appropriate equipment is used before attending to drilling or workover wells.

Operators and service companies' managers must make safety their number one priority, emphasizing it over production goals. Such a move would empower employees to stop working in unsafe conditions.

Operators should introduce new well control systems and procedures for LRSWs to reduce costs and improve performance.

Operators should continue to research ways to improve kick detection and deal with kicks and blowouts when they occur. This recommendation might be accomplished by producing a generic well control risk assessment for each area.

The assessment should be based on multiple considerations:

Consequences of the risks present in each area,

The capability for self flow,

Average production rate,

The presence ofthe expectation that equipment will be used until it wears out,

The capabilities of formation pressure to kill the well,

Modeling the well flow versus time after closing wi support,

Hse risks resulting from a period of free flow,

The presence of sensitive areas such as cities or production faculties,

The risk of contaminating shallow fresh water aquifers,

The risk of compromising the integrity of the well,

The presence of potential threats to production, and

The identification of short- and long-term mitigations via a time line.

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