PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA
MINISTRY OF HIGHER EDUCATION AND SCIENTIFIC RESEARCH
M'HAMED BOUGARA DE BOUMERDES UNIVERSITY

Faculty of Technology
Industrial Process Engineering Department

Final dissertation
To obtain the Master's degree in:

Field: Science and Technology
Sector: Industrial Hygiene and Safety (HSI)
Specialization: Industrial Hygiene and Safety (HSI)

Title:

Reliability study of blowout preventer "BOP" during drilling operations in Hassi Messaoud

Introduced by:

Mohammed Liwaa Eddine BENHALILOU

Supervised by:

Mme Zahia KEBBOUCHE

Presented and publicly defended on 10/07/2023 before the jury composed of:

President	Mme. BOUGHERARA Saliha	**UMBB**
Promoter	Mme. KEBBOUCHE Zahia	**UMBB**
Examiner	Mme. KORSO Saliha	**UMBB**

2022-2023

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Dedication

"I dedicate this final year project to my family, whose unwavering love and support have been my constant source of strength and motivation. Your belief in my abilities and encouragement throughout my academic journey have propelled me to overcome challenges and achieve this significant milestone"

Acknowledgment

We would like to thank God for giving us the courage to carry out this modest work, and we like to begin our work with:

بسم الله الرحمان الرحيم

I would like to express my sincere gratitude and appreciation to all those who have contributed to the successful completion of my final year project. Without their support, guidance, and encouragement, this endeavor would not have been possible.

First and foremost, I extend my heartfelt thanks to my supervisor, **Mme Zahia KEBBOUCHE,** for their invaluable guidance, expertise, and unwavering support throughout this project. Their insightful feedback, constructive criticism, and dedication to my academic growth have been instrumental in shaping the direction and quality of this work.

I am deeply grateful to the faculty members and professors at **M'HAMMED BOUGUERRA BOUMERDES UNIVERSITY** for their commitment to excellence in education. Their profound knowledge, passion for teaching, and engaging lectures have expanded my horizons and fostered my intellectual curiosity.

I would also like to acknowledge the assistance and cooperation of the staff and resources and all the HSE team at **SLB (Ex-Schlumberger)**, specially my technical supervisor **Mme Assala DOB**. Their willingness to provide technical support, access to research materials, and logistical assistance have greatly facilitated the smooth progress of this project.

I would like to express my appreciation to my friends and classmates who have been a constant source of inspiration and support. Their willingness to engage in fruitful discussions, share insights, and offer valuable feedback have enhanced the quality of my work and made this journey more enjoyable.

Lastly, I want to extend my deepest gratitude to my family for their unconditional love, encouragement, and belief in my abilities. Their unwavering support, understanding, and sacrifices have been the driving force behind my academic achievements.

Abstract:

By examining the blowout preventer (BOP) system’s reliability, we want to prevent significant risks in drilling operations. We have devised four approaches: We begin with a risk analysis to show the value of the BOP in well control using the fault tree method. Second, the relationship between the various BOP components and their failure mechanisms is then studied. This section involves breaking down the system using the SADT method's functional analysis. The third step to carry out an analysis for our system's failure mode using the FMECA approach. The final part, to determine the probability of failure on demand, the components presenting failure modes that the FMECA found non-tolerable must be gathered. All of this is done under the assumption that the failure of any of these components would fail the BOP.

ملخص:

من خلال فحص موثوقية نظام مانع الانفجار (BOP)، نريد منع المخاطر الكبيرة في عمليات الحفر. لقد قمنا بأربعة مناهج: نبدأ بتحليل المخاطر لإظهار قيمة مانع الانفجار BOP في التحكم في البئر باستخدام طريقة شجرة الأخطاء. ثانيًا، يتم بعد ذلك دراسة العلاقة بين مكونات مانع الانفجار BOP المختلفة وآليات فشلها. يتضمن هذا القسم تقسيم النظام باستخدام التحليل الوظيفي لطريقة SADT. الخطوة الثالثة لإجراء تحليل لوضع فشل نظامنا باستخدام نهج FMECA. الجزء الأخير، لتحديد احتمال الفشل عند الطلب، يجب جمع المكونات التي تقدم أنماط الفشل التي وجدها FMECA أنه غير مقبول. يتم كل هذا على افتراض أن فشل أي من هذه المكونات سيفشل مانع الانفجار BOP.

Résumé :

En examinant la fiabilité du système de prévention des éruptions (BOP), nous voulons prévenir des risques importants dans les opérations de forage. Nous avons mis au point quatre approches : Nous commençons par une analyse des risques pour montrer la valeur du BOP dans le contrôle du puits en utilisant la méthode de l'arbre de défaillance. Ensuite, la relation entre les différents composants du BOP et leurs mécanismes de défaillance est étudiée. Cette section consiste à décomposer le système en utilisant l'analyse fonctionnelle de la méthode SADT. La troisième étape consiste à effectuer une analyse des modes de défaillance de notre système à l'aide de l'approche AMDEC. Enfin, pour déterminer la probabilité de défaillance à la demande, il faut rassembler les composants présentant des modes de défaillance jugés non tolérables par l'AMDEC. Tout cela se fait en supposant que la défaillance de n'importe lequel de ces composants entraînerait la défaillance du BOP.

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List of acronyms

BOP	Blowout Preventer
SADT	Structured Analysis and Design Technique
FMECA	Failure Mode and Effect Critical Analysis
CEO	Chief Executive Officer
OFS	Oil Field Service
SS	Support Services
HSE	Health, Safety and Environment
P&SC	Planning & Supply Chain
TLM	Technology Lifecycle Management
PSD	Project Supply & Delivery
CTS	Coil Tubing Services
WCF	Well Construction Fluid
WPS	Wireline & Perforation Services
MM	Machinery Maintenance
HR	Human Resources
IT	Information Technology
HARC	Hazardous Analysis and Risk Control
NSAM	North and South America
EACR	Europe, Africa, Centrale Asia, Russia
APME	Asia-Pacific, Middle East
IOGP	International association for Oil and Gas Producers
BP	British Petroleum
API	American Petroleum Institute
FTA	Fault Tree Analysis
MC	Minimum cut
FR	Feared Event (Évènement redouté)
REX	Experience Retour
PFD	Probability of Failure on Demand
RBD	Reliability Block Diagram
HMD	Hassi Messaoud
MTBF	Mean Time Between Failures

General introduction

The oil sector is currently the most significant industry in the world. It has an impact on industries all around the world. Oil is the major source of income and the backbone of the Algerian economy, as shown by the Statistical Report on Algeria's Foreign Trade in 2019, published by the Customs Department. Hydrocarbon exports made up 93% of the overall exports of the nation.

Daily events and catastrophic catastrophes in the oil sector have created headlines, which has prompted the adoption of risk management—also known as risk control—to decrease or eliminate risks and advance the oil industry.

On April 20, 2010, 11 workers died, and an explosion on the Deep Horizon seriously injured 17 on an offshore drilling rig located approximately 50 miles off the coast of Louisiana, called Macondo accident. And with a horrible environmental impact, the Death of 800,000 birds, 170,000 sea turtles, 8.3 million oysters, and more...

International organizations have created and revised various well integrity and control standards in response to significant threats. Within multinational corporations, their use is now both highly advised and required. To avoid blowouts and ensure well sealing in the case of overpressure flow, these standards specify the safety barriers to be used and information on their operating, maintenance, and inspection conditions.

A blowout preventer (BOP) failure during drilling operations might severely affect brand reputation and cause significant financial, human, and environmental losses. Therefore, researching this equipment's reliability is crucial for risk analysis and avoidance.

Algeria's top provider of drilling BOPs is **Cameron**, a **SLB (Ex-Schlumberger)** company. This study aims to evaluate the reliability of BOPs used in drilling operations in the southern Algerian region of Hassi Messaoud by examining potential equipment faults and calculating and estimating the equipment's availability and reliability.

The exploitation of oil and gas reserves often takes place in challenging and remote locations that require the highest level of safety measures. Among the most dreaded accidents in petroleum and gas exploration projects is the **blowout**. Companies operating in this industry, such as **Cameron International**, a **SLB** company, face numerous challenges. In order to maintain its position in the market, **Cameron International** aims to develop new approaches, particularly in the maintenance of Blowout Preventers (BOPs), to make them more cost-effective and applicable within shorter time frames.

The primary objective of our study is to evaluate the reliability of various BOP systems operating in the region of Hassi Messaoud and propose appropriate recommendations.

Our main question to achieve the objective of our study:

- How to ensure BOP functionality in the event of a blowout in the Hassi Messouad region?

In order to answer this question, we need to answer these following questions:

- How important is the BOP for blowouts?
- Can component failure be the cause?
- How reliable are the BOPS used within the company?

We used a four-stages methodology to address the issue and accomplish the stated goal:

1. **Risk assessment of blowouts during drilling operations:** This first stage aims to demonstrate the importance of the BOP as a piece of machinery for guaranteeing well safety during drilling operations.
2. **System Functional analysis**: The aim is to deconstruct the BOP system, in order to understand its mechanism.
3. **Locating critical failures:** Using the Failure Mode, Effect and Criticality Analysis (FMECA) method, we will identify the failure modes of the BOP system and classify them from the most critical to the least critical. In this section, we will establish the relationship between the failure of a specific sub-system/component and the loss or impairment of the system's primary function.
4. **Reliability study:** We shall determine the BOP's reliability at this stage. To achieve this, we'll examine a sample of four BOPs in the Hassi Messaoud region and determine the likelihood that each sub-system or component will fail based on its prior failure history and the time between two functional tests. The likelihood of the system failure will then be calculated, and the results of the four samples will be compared.

CHAPTER I:
Study’s general context

1. Company presentation

SLB "Ex-Schlumberger" is the largest multinational oilfield services company. The story of this company begins with what truly means to be a technology innovator. The common sense of purpose unites 82,000 people representing 170 nationalities with products, sales and services in more than 120 countries. They supply the industry's most comprehensive range of products and services, from exploration through production, and integrated pore-to-pipeline solutions that optimize hydrocarbon recovery to deliver reservoir performance sustainably.

"AS ENERGY POWERS SOCIETY'S PROGRESS, OUR INNOVATIONS ACCELERATE THIS PROGRESS"

Figure 1: Who is SLB?

1.1. History

SLB was born of an idea—that if an electric field could be generated below ground, voltage measurements at the surface could be mapped to reveal subsurface structure under the name in French language "Société de prospection électrique" on 1926, in Paris, by two brothers *Conrad* & Marcel Schlumberger.
Now it's a multinational company in many countries in the world specialist in petroleum services. Its main offices (Headquarters) are located in Houston, Paris, and La Hague with a research & development center in Clamart. *Olivier Le Peuch* is the Chief Executive Officer CEO of **SLB** company.

1.2. Brands

This company has other related companies which solidify their portfolio of services and technologies that comprise the industry's most comprehensive range of oilfield services.

a. **Cameron:** has been a Schlumberger company since 2016, this company provide industry-leading flow equipment products.

b. **M-i Swaco:** has been a Schlumberger company since 2010, they have teams of innovative drilling fluid engineers helping oil and gas operators increase efficiency by developing drilling fluid systems and additives for a wide range of drilling environments.

c. **Smith Bits:** has been a Schlumberger company since 2010, their people are working to better understand drilling applications our customers encounter and how to develop advancements that make a difference.

d. **Western Geco:** has been a Schlumberger company since 2000, They have the expertise, the seismic data and the digital capabilities to help you get to first oil faster and maximize your recoveries.

e. **Omni Seals:** is a full-service rubber-molding company that engineers a range of quality products and delivers a suite of services.

f. **K&M Technology Group:** is a leading drilling engineering consulting group that uses science-based engineering approaches to plan and execute relief wells.

1.3. Company organization in Algeria

Schlumberger Algeria has a hierarchical organizational structure by function. It is composed as follows:

- General management.
- An administrative and financial department.
- An operations department.

A. General management:

It deals with the application of the general policy of the group in the host countries and coordinates all activities of the subsidiary.

B. Administrative and financial department:

It's responsible for:

- Financial management.
- Analysis of profits and losses.
- Keeping accounting and tax records.
- The management of local personnel in accordance with the rules in force in the country.

C. Operations department:

It's the essential part of the organization of the company, it groups together all the Product Lines:

- Fluid and tool management.
- Well construction.
- Well production.
- Logistics and transport.
- Well testing and measurement.
- Reserves Evaluation.

1.4. Organigramme of SLB:

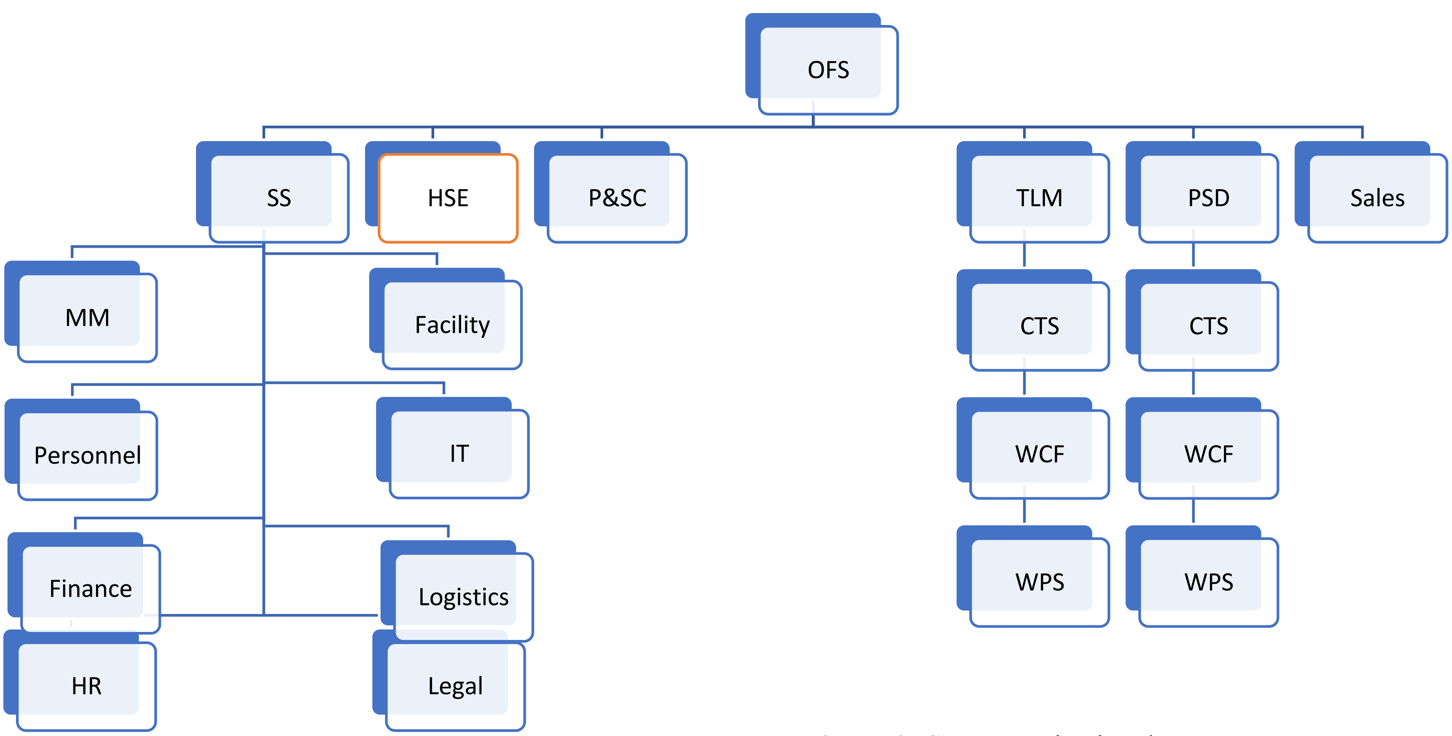


Figure 2: SLB organizational structure

1.5. SLB policies:

- HSE policy.
- Driving policy.
- Personal security policy.
- IT security policy.
- Substance abuse policy.
- Risk management policy.

1.6. SLB standards:

1. Driving.
2. Reporting.
3. Personal Protective Equipment.
4. Crisis and emergency management.
5. Training and competency.
6. Health.
7. Audit.
8. Environment.
9. Schlumberger Empowered Team.
10. Exemptions and management of change.
11. Asset and personal security.
12. Contracting.
13. Mechanical Lifting.
14. Pressure.
15. H2S.
16. Firefighting.
17. Injury prevention.
18. Explosion.
19. Radiation.
20. Hazard Analysis & Risk Control (HARC)
21. Information security
22. Well integrity.
23. Drops.
24. Chemicals.
25. Electrical.
26. Covid-19.
27. Lithium battery.

1.7. Organization, mode of distribution of the markets:

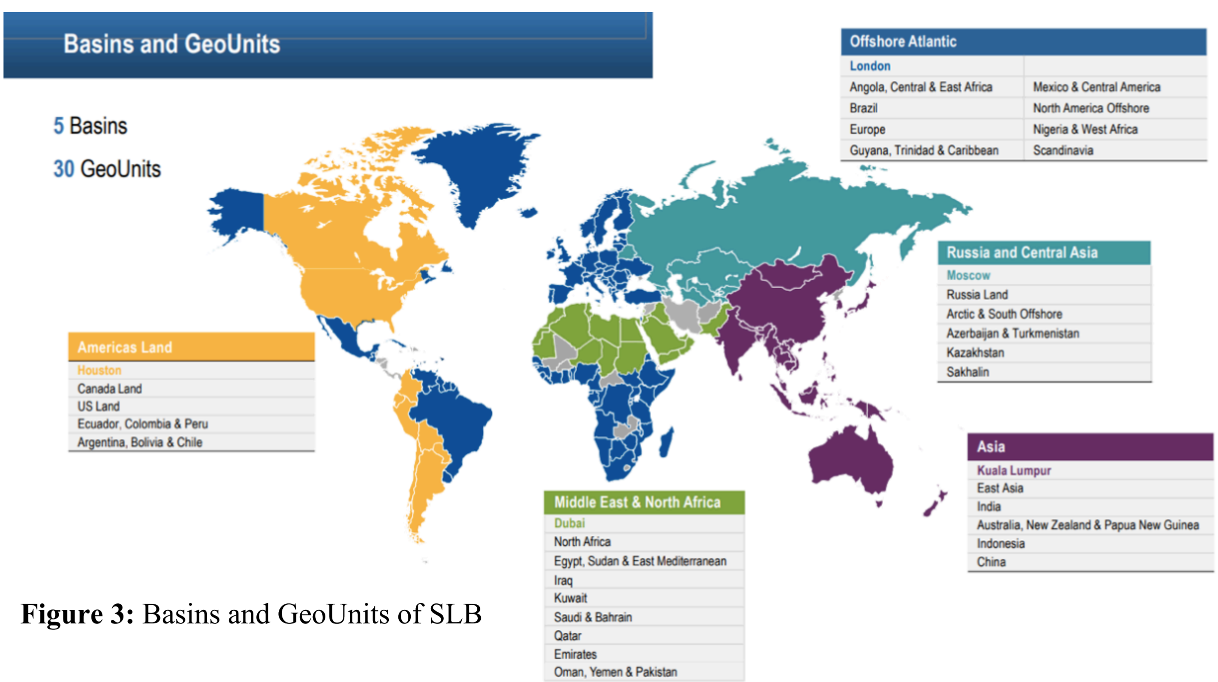


Figure 3: Basins and GeoUnits of SLB

Cameron International is an American global oil and gas corporation located in Houston, Texas, that was formed in 1833. The firm produces highly dependable equipment for oil and gas exploration, transportation, and production, and it constantly develops and improves technology that might benefit the sector.
The firm works at more than 300 sites worldwide and is separated into three primary geographic zones. Cameron's global geographic distribution is seen in the table below:

NSAM	North & South America
EACR	Europe, Africa, Centrale Asia, Russia.
APME	Asia-Pacific, Middle East.

Table 1: Global Geographic Distribution of Cameron

The year 2015 was a watershed moment for the international corporation, as it was bought by Schlumberger for $14.8 billion in stock and cash.

Cameron operates in nine sectors, each of which is dedicated to supplying sophisticated wellhead, surface, and flow control products, systems, and services to businesses.
The following table depicts the company's many segments:

Wellhead Systems Conventional and compact solutions for onshore and platform applications
Fracturing and Flowback Equipment Services Reliable technology to maximize stimulation efficiency
Rig Equipment Comprehensive suite of onshore and offshore rig equipment
Pressure Control Complete systems for containing wellbore pressure and diverting formation fluids
Valves Comprehensive solutions for global energy and industrial markets
Processing and Separation Treatment solutions from the wellhead to the refinery

Production Trees Innovative designs to streamline operations and enhance safety
Safety Systems Customized technologies and services to achieve ultimate valve control and well safety
Measurement Custody transfer, allocation, and quality sampling and analysis systems

Table 2: Cameron's Segments

Our practical training for our end-of-study project will take place at Cameron, specifically in the pressure control segment, where we will work on a problem involving the reliability of the blowout preventer (BOP) manufactured by Cameron for the drilling operation in the various oil wells in the Algerian desert.

2. Problematic, study objective and methodology

2.1. Study's problematic:

The exploitation of oil and gas reserves often takes place in challenging and remote locations that require the highest level of safety measures. Among the most dreaded accidents in petroleum and gas exploration projects is the **blowout**. Companies operating in this industry, such as **Cameron International**, a **SLB** company, face numerous challenges. In order to maintain its position in the market, **Cameron International** aims to develop new approaches, particularly in the maintenance of Blowout Preventers (BOPs), to make them more cost-effective and applicable within shorter time frames.

2.2. Objective of study:

The primary objective of our study is to evaluate the reliability of various BOP systems operating in the region of Hassi Messaoud and propose appropriate recommendations.

2.3. Methodology:

We used a four-stages methodology to address the issue and accomplish the stated goal:

5. **Risk assessment of blowouts during drilling operations:** This first stage aims to demonstrate the importance of the BOP as a piece of machinery for guaranteeing well safety during drilling operations.
6. **System Functional analysis**: The aim is to deconstruct the BOP system, in order to understand its mechanism.
7. **Locating critical failures:** Using the Failure Mode, Effect and Criticality Analysis (FMECA) method, we will identify the failure modes of the BOP system and classify them from the most critical to the least critical. In this section, we will establish the relationship

between the failure of a specific sub-system/component and the loss or impairment of the system's primary function.

8. **Reliability study:** We shall determine the BOP's reliability at this stage. To achieve this, we'll examine a sample of four BOPs in the Hassi Messaoud region and determine the likelihood that each sub-system or component will fail based on its prior failure history and the time between two functional tests. The likelihood of the system failure will then be calculated, and the results of the four samples will be compared.

3. Accidentology review and regulations

3.1. Accidentology review "Macondo":

We did a global accident assessment to determine the operation with the highest frequency of blowouts and to understand the distribution of blowout accidents during various oil operations.

The information in the table comes from the IOGP (International Association for Oil Gas Producers) study (1), which compiles accident input from 15 years (2000–2015) on the frequency and magnitude of onshore and offshore well control losses from various nations:

Table 3: Accident input from 15 years (2000-2015), IOGP

Operations	Number of Wells Drilled	Blowout Numbers (Incident)
Drilling	47,809	96
Completion	303,733	11
Wireline	303,733	4
Coiled Tubing	303,733	2
Snubbing	303,733	4
Workover	303,733	19
Production	303,733	19

With the aid of this data, we were able to create the pie chart depicting the frequency of blowouts concerning the type of oil operation that was carried out, as seen in Figure:

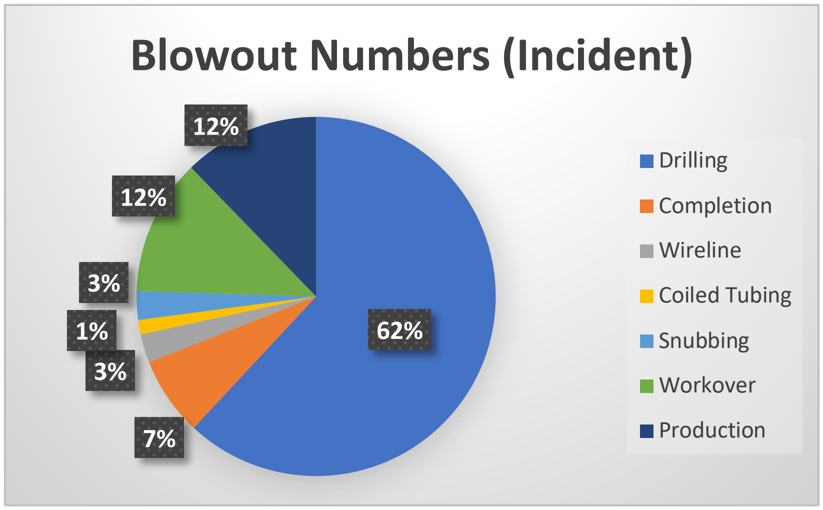


Figure 4: Blowout Incident's Numbers in different segment chart

According to the distribution in the diagram, a blowout occurred most frequently during drilling operations from 2000 to 2015, accounting for 62% of all operations, compared to 12% of Production operations, 12% of Workover, 7% of Completion, 3% of Subbing, 3% of Wireline and 1% of Coiled Tubing.
The frequency of 62% indicates that the drilling operations are the most susceptible to Blowout Incidents.

The Macondo well and the Blowout: (2)

The Minerals Management Service accepted BP's payment of little more than $34 million in March 2008 in exchange for an exclusive license allowing it to drill in Mississippi Canyon Block 252, a nine-square-mile area in the Gulf of Mexico. Although there are numerous productive oil fields in the Mississippi Canyon region, BP knew little about the geology of Block 252, and Macondo would be its first well on the new lease. In addition to learning more about the local geology, BP intended to drill the well to a depth of 20,200 feet because it believed that, based on the geological information at its disposal, it would discover an oil and gas reserve that would justify the installation of production equipment at the site. BP would have had excellent reason to believe that the well might provide a sizable profit at the time.

Figure 5: Macondo well blowout

But a little over two years later, BP found itself shelling out tens of billions of dollars to stop an oil blowout at the Macondo well, stop millions of gallons of oil from flowing into the Gulf of Mexico, and pay hundreds of thousands of people and businesses who had been harmed by the spill. And that's probably just the start. The additional billions required to repair the damage the spill caused to the natural resources would likely fall under the responsibility of BP, its partners Anadarko and MOEX, and its major contractors, namely Halliburton and Transocean.

The well blew out because several separate risk factors, oversights, and outright mistakes combined to overwhelm the safeguards meant to prevent just such an event from happening. But most of the mistakes and oversights at Macondo can be traced back to a single overarching failure (a failure of management). Better management by BP, Halliburton, and Transocean would almost certainly have prevented the blowout by improving the ability of the individuals involved to identify the risks they faced and to properly evaluate, communicate, and address them. A blowout in deep water was not a statistical inevitability.

The Immediate Cause of Macondo Blowout: (2)

Failure to control hydrocarbon pressures in the well was the direct cause of the Macondo blowout. The cement at the well's bottom, the mud in the well and the riser, and the blowout preventer are three items that may have held those pressures in check. However, errors and a lack of risk awareness undermined each of those potential barriers, gradually depriving the rig crew of safety measures until the blowout was unavoidable and, in the end, uncontrollable.

The Macondo Blowout results: (3)

The lifeboat was used to evacuate the bulk of the 126 personnel, but 11 individuals were never discovered and 17 others were hurt, three of them critically. The platform sunk on the morning of April 22, 2010, despite the efforts made and the boats, mobilized for 36 hours, the fire becoming uncontrollable. Before the well could be sealed off by a relief well, the blowout continued to develop on the seabed for 87 days. An estimated 4.5 million barrels of oil were leaked into the sea as a result of this catastrophe, which had a devastating effect on the ecology and the stability of the economy throughout the whole southern area of the United States.

3.2. International and National Regulations:

We will use international organizations like the American Petroleum Institute (API), which has revised rules for the design and construction of a well and its maintenance with maximum reliability, to deal with the effects of the Deepwater Horizon platform disaster:

- **API 6A:** Specifications for Wellhead and Christmas Tree Equipment.
- **API 53:** Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells.

The rules in Algeria attempt to avoid the many dangers that may develop in the oil business and reduce the likelihood of accidents occurring; this legislation is always changing. We can cite the following legislative documents as examples:

- Law no. 04-20 of December 25, 2004 on major risk prevention and disaster management as part of sustainable development.
- Law 05-07 of April 28, 2005, amended and supplemented, relating to hydrocarbons.
- Executive decree n° 21-319 du 5 Moharram 1443 corresponding to August 14, 2021, concerning the specific operating authorization regime for hydrocarbon installations and structures, as well as the terms and conditions for approving risk studies relating to research activities and their content.

CHAPTER II:

General drilling process and well control

1. Oil drilling process

A drilling technique ensures material extraction for the construction of a well. This task is accomplished through cooperating with various organs and in various processes. This chapter describes the principles and methods involved in drilling an oil well, the well control system, and the functioning of a BOP (Blow Out Preventer) in the event of an incident.

1.1. Drilling principles: (4)

Power: Diesel engines that provide power to the rig are typically situated on the ground behind the rig. Diesel fuel is kept in tanks close to the engines. The hoisting and circulation systems consume the majority of the electricity. Some of it is also sent toward the rotating system, rig lights, and other motors.

Hoisting system: The hoisting system is a lifting system used to lift and lower equipment and hang it in the well.

Circulating system: The circulation system pumps drilling mud into and out of the well hole. Drilling mud is kept on the ground beside the rig in many steel mud tanks.

Rotating system: This system is responsible for cutting the hole and going deeper using a drill string suspended from the hook.

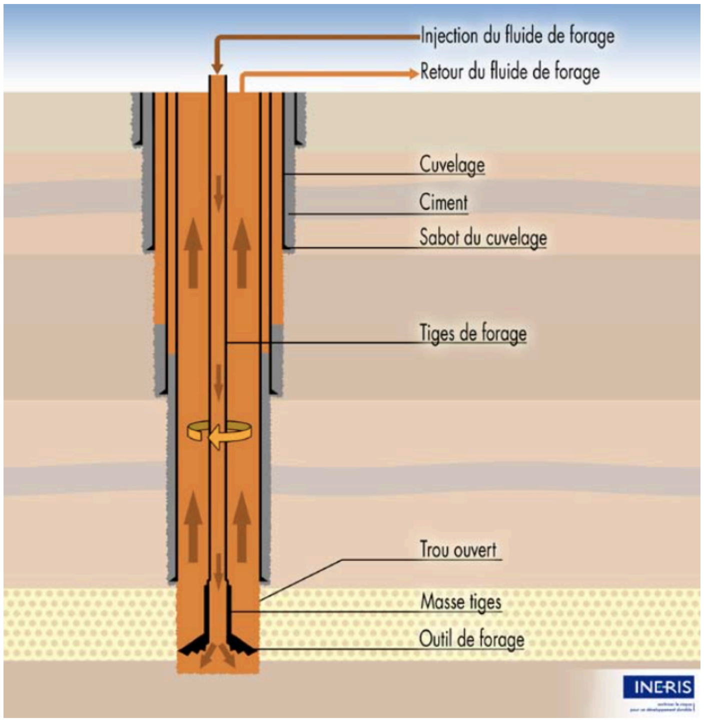


Figure 6: Rotary drilling principle (7)

1.2. Drilling Rig: (5)

Drilling requires a lifting system to hold, add rods, and transmit the weight to the drill bit, a rotating system to allow the drill bit to bore, and a circulation system to remove the drilling cuttings.

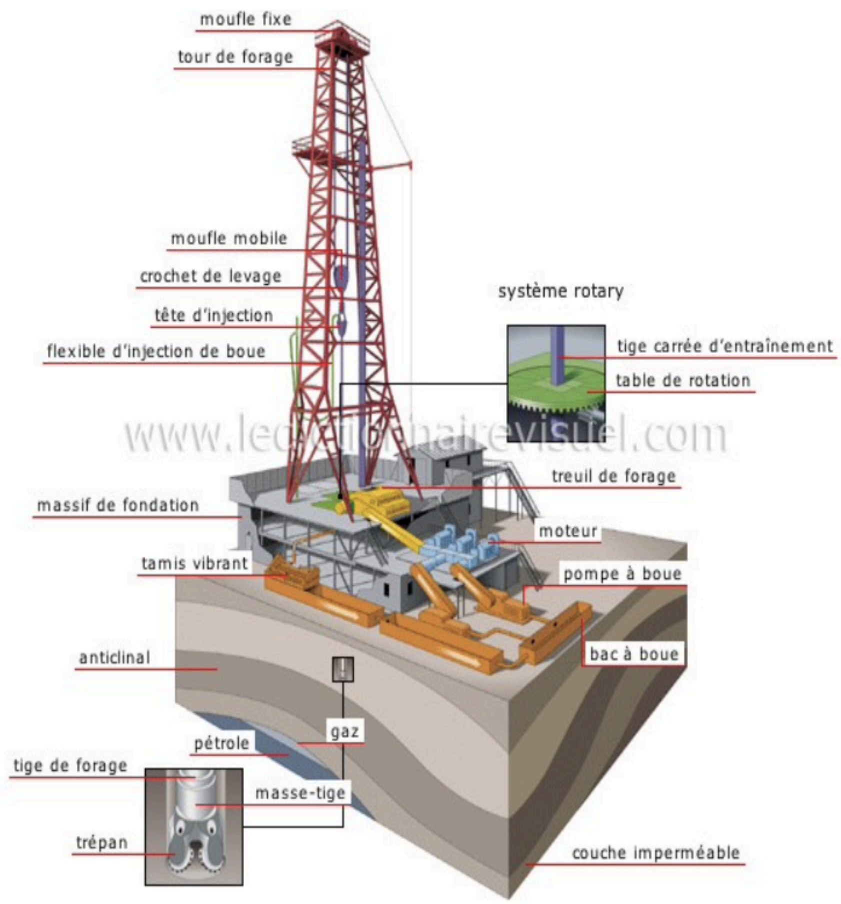


Figure 7: Drilling Rig (5)

A. Lifting system:

1- The primary structure: Mast or Tower:

The mast is a metal structure in the shape of an extended pyramid. The mast on land rigs might be detachable, collapsible, or telescopic.

In water drilling confined to modest depths, telescoping masts are often supported by a truck or trailer. These masts can be guyed or stabilized with many anchor cables.

2- The cable for drilling:

The drilling rope is constructed with a metal core and six strands of steel wire twisted around it. The strand wires are often arranged in the opposite direction as the strand wires on the core, giving the drill rope a stiff (hard) and non-rotating property. The diameter of the drill rope varies greatly but should not exceed 1.5 inches (3.8 cm).

The drilling cable is coiled onto the winch drum, then fed through the fixed and movable snatch blocks before being joined to the Rea at the dead end. The Rea is a hydraulic cell that measures the weight the hook supports. The cable is coiled onto the reel (power reel for the new cable) after the Rea.

The cable must be spun regularly to spread wear. The new component is supplied from the dead end at the Rea, and the extra rope is threaded from the other end at the drum. After numerous spins, the drum fills up, and we must cut a section of the rope. The cable's work sets the spinning and cutting operations of the drilling cable.

3- Sheaves (Fixed & Moved):

The fixed block is a pulley assembly positioned on the tower's roof. The drilling cable is routed through these pulleys and forms the block. The moveable block is a sheave assembly that holds the hook in place.

It should be noted that the load on the fixed block is larger than the load on the moveable block. This is because there are two extra strands on the fixed block (an active strand: connected to the winch) and a dead strand (attached to the Rea). For example, if the block has ten strands and the load on the hook is 100 tons, each strand can hold 10 tons. Therefore, the fixed block can support 120 tons.

4- The winch:

The winch is an important component of the drilling rig; its power determines the rig's class and the maximum depth that may be reached. The winch can be electric or mechanical, and it primarily consists of a drum on which the drilling wire is arranged (coils and rows) and a gearbox capable of giving at least two speeds (low speed and high speed). The winch has two braking systems: a band brake capable of halting the load and a magnetic brake solely used to slow the movement.

5- Floor Accessories

For lifting and managing the drill string, many attachments are used:

- The wedges: are used to keep the drill string from slipping off the main furring when connecting the rods or performing movements.
- Arms and lifter: used to raise the drill string during maneuvers; the arms and elevator are utilized to elevate the drill string directly by the hook. Rotation and mud injection is not permitted in this system.
- Connection wrench: This tool delivers the appropriate tension to screw and unscrew the drill rods.
- Safety collar: it is a safety accessory used in conjunction with wedges and used for fittings that do not have a post, such as the mass rod, or when the weight of the rods is insufficient to allow the wedges to work properly.

B. Rotation System:

1- Kelly's system:

A rotation table, powered by an electric motor or a winch, drives the Kelly rotation mechanism. Its revolution speed is measured in revolutions per minute and ranges between 50 and 150 rpm on average.

The square drive (Kelly Bushing) is driven by the rotation table, which directs the square or drive rod (Kelly). The rotating injection head (Swivel) connects the square rod to the hook, simultaneously allowing slurry injection and rotation of the square rod. A safety valve at the top of the square rod blocks the sludge circulation circuit inside the rod. A safety valve at the top of the square rod blocks the sludge circulation circuit inside the rod. An exchangeable wear fitting (Kelly Saver Sub) is connected to the base of the square rod to protect it from frequent screwing and unscrewing during drilling operations.

The rotating table also sustains the drill string load when put on the wedge through the main sleeve, which is interchangeable to accommodate various types of the drill string. If necessary, the table's rotation can be mechanically secured.

<u>2- The motorized injection head (Top Drive):</u>

Some strong drilling rigs have an electric or hydraulic motor linked to the hook steered by rails attached to the mast. This motor (Top Drive) permits rotation and mud injection and takes the rotation table, square drive, square rod, and rotating injection head position. The motorized injection head, on the other hand, allows for quicker and more efficient drilling maneuvers and operations, which significantly lowers drilling time. However, this motor's cost is the same order of magnitude as the complete rig!

C. System of circulation:

1- Mud drilling:

Drilling mud is a fluid that plays a critical role in drilling success:

- Cuttings are removed.
- Resist formation stresses.
- Drill bit and drill string cooling and lubrication...

2- The circulation circuit for drilling mud:

- Basin in use
- Drilling rig
- Runs up through the annular area to the Fountain Tube from inside the drill string and out via the drill bit ports
- Clears the Chute
- Screens that vibrate
- Basins for solids treatment (sand trap, centrifuge)
- Active basin.

3- Mud pumps

Drilling pumps are also an essential component of the drilling process's performance. There are at least two of them, and they can generate a large amount of power (approximately 1000 HP), allowing them to pump at a flow rate of around 3000 l/min at pressures that can surpass 300 Bar. The drilling pump typically comprises three pistons that operate in either a single- or double-acting triplex.

There are, however, pumps with only two pistons (duplex) that have a lower flow rate and do not reach significant depths. The volume pushed with each stroke is determined by the volume of the piston sleeve. Drillers can adjust the liners and pistons to vary the pump's flow rate depending on the necessity (flow rate or pressure).

1.3. Principle Operations: (6)

1- Drilling:

Although this is the most basic function, it has the fewest employees. Only the postmaster operates the winch. The rotary table drives the drill string and rod assembly as it spins. The brake lever is the primary control.

By pressing on this brake, the foreman controls and limits the fall of the drilling hook. As previously stated, the drill bits are employed at a consistent weight. By assessing the weight hanging from the hook before striking the bottom, the driller may determine the weight of everything hanging from the hook.

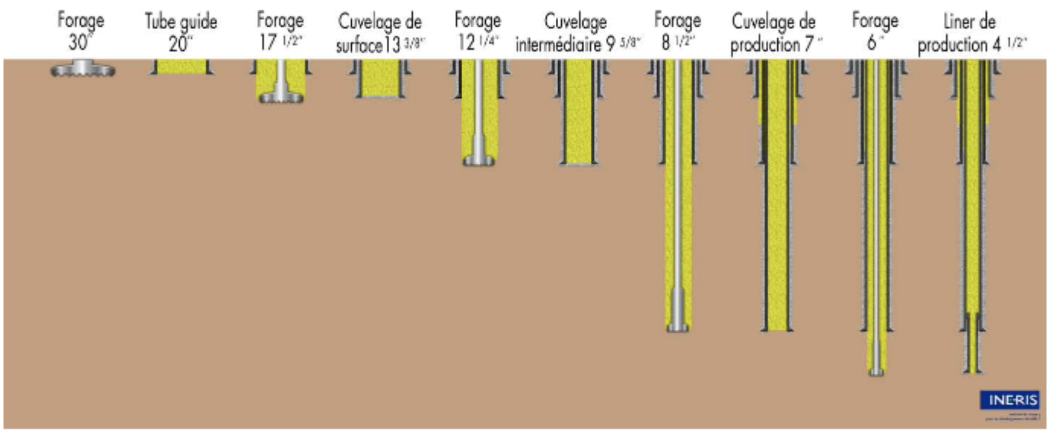


Figure 8: Phases of drilling a well (7)

The weight imparted to the tool is the difference in weight between the suspended tool's hook and the weight of the installed tool.

This is the differential that the driller sees on the weight indicator (also known as the Martin Decker) and must maintain by allowing the driving rod to drop at the same rate as the drilling tool progresses.

The other two parameters, rotation and mudflow, usually are fixed; the driller manages and modifies the values according to the program, particularly ensuring that the delivery pressure to the pumps is and continues to comply.

2- Including a stem:

After drilling a length of rod (30 ft) using the tool, the drill string must be extended by the same amount by putting a drill bit under the driving rod. The various sequences are described.

- The floor workers inserted a rod into a mousehole near the rotating table during the drilling.
- The shift supervisor activates the winch, which lifts the packing to the first drill pipe under the driving pipe. The drillers install the wedges, and the driving rod may now be unscrewed because the packer hangs on the turntable. The mud's circulation is naturally halted.

- The foreman raises the drive rod and drills the pipe assembly using the winch. After tightening and securing the new rod onto the liner, the foreman restarts the drilling fluid circulation.
- Drilling can continue when the driller squares the Kelly drive in the rotary table.

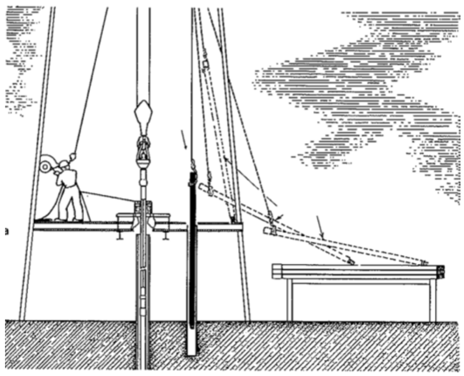


Figure 9.a: Adding a stem: placing a stem in the mouse-hole (6)

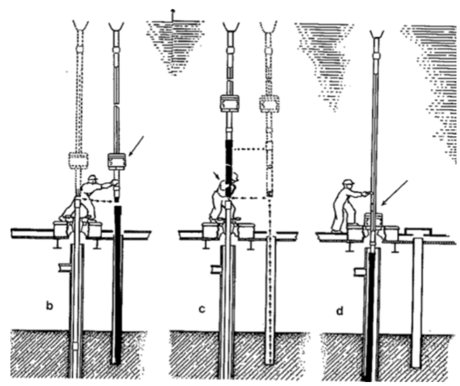


Figure 9.b: Adding a stem: screwing the Kelly onto the stem in the mouse-hole. c. Adding stem: screwing the Kelly and the stem onto the insert. d. placing the Kelly, resuming drilling (6)

3- The Maneuver:

When the tool wears out, or the required depth is achieved, the entire set must be reassembled to change the tool or lower the casing tubes.

The first step is disconnecting the injection head from the drilling hook and storing the driving rod and injection head assembly, which is still linked to the pumps through the hose, in a sheath called a ret-hole.

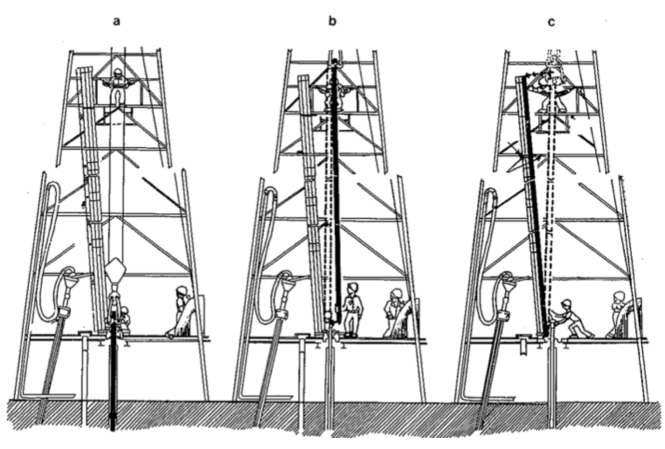


Figure 10: Trim operation (6)

The elevator is closed beneath the tool joint of the first rod by the floor welders, and the shift supervisor uses the winch to hoist the trim on a hoist equivalent to three rods.

The wedges wedge the fourth rod into the table, and this connection is unscrewed using the keys. The elevator is then hung by three rods. The floor sounders push the lower end of this length (stand) to rest on a stacker (set back), at which point the hooker on a catwalk in the tower opens the elevator, holds the length, and then stores the top end of this identical length in racks.

We keep going until we get to the sledgehammers, which are similarly stored vertically by three.
The tower's height determines the stacking length. The giant machines are piled in threes, the lightest in twos and the smallest in one. The lowering motion (tripping in) is performed in the same manner.
It should be remembered that the filling cannot be turned or moved during this procedure. The driving rod must be removed from the rathole and screwed back onto the rods if required.

4- Tubing:

With the drilling done to the depth anticipated for this phase, it is time to drop the casing pipes into the well. This procedure is hazardous due to the narrow space between the casing and the hole and the inability to rotate the column. At the bottom of the descent, the cement is inserted into the tube by direct circulation (injection of the fluid via the interior of the tube and return via the annulus).

5- Wellhead assembly:

Once a casing is cemented in the well, different suspension and sealing devices must be mounted on its higher end.
At aerial wellheads, these activities are performed manually.
This wellhead equipment also enables the installation of obturators outfitted with high-pressure pipes known as the kill and choke lines.
A series of pressure tests on the casing, suspensions, and BOPs complete this assembly. If everything meets safety standards, the next drilling phase can commence.

6- Completion:

Following the installation of the last casing string (production casing), this final operation consists of dropping the production equipment into the well: packer, tubing, safety vane, etc. Drilling, perforating, acidizing, fracturing, and other methods are frequently required to complete the layer/hole connection.
Although drillers frequently perform these procedures, their methodologies are part of downhole production, which is the subject of another book.
The following chapters are designed to thoroughly describe the equipment and operational procedures utilized during a drilling operation.

1.4. Risks associated with drilling operations:

An oil rig is a complicated unit comprising several systems required for drilling activities, but this unit also poses hazards to human life, the installation, and the environment. As a result, it is necessary to suggest solutions, instructions, and steps to remove or limit these risks.

We have categorized the hazards existing at the drilling site into four groups to aid in risk analysis:

- Physical family.
- Chemical family.
- Biological family.
- Ergonomic family.

Table 4: Hazard categories

Family	Risk
Physical	- Risk of noise exposure - Risk of vibration - Burns caused by contacting hot objects or corrosive products - Risks associated with the weather when working outside (hot, cold, rain, wind) - Mechanical risks - Electrical risks - Risk from ionizing radiation - Road risk
Chemical	- Toxic risk - Risk related to lack of hygiene - Fire/Explosion
Biological	- Food poisoning - Risk of exposure to biological agents - Infectious diseases and dangerous animal bites
Ergonomic	- Risks related to gestures and postures - Stress mental workload - Sensory load (visual stress, screen work)

2. Well Control System:

2.1. Kick: (7)

A kick occurs when formation fluids-water, oil, or gas-intrude into the well. Unchecked, this might result in a blowout.

2.1.1. Kick Control: (7)

Primary and secondary control are the two basic divisions of a well's control.
The primary control is to keep the drilling mud's hydrostatic pressure at or just above the pore pressure while avoiding going over the fracture pressure of the weakest formation. This prevents formation fluid from entering the well.
Secondary control is the formation of fluid introduced into the well when the bottom hole pressure drops below the pore pressure.
This incursion can be prevented only once the well has been sealed off using safety equipment (BOP well control system).

2.1.2. Kick Causes: (6)

Preventing an influx must start with researching and comprehending the factors that contribute to the inflow.

- Filling failure during the maneuver: If the well is not filled with a volume of mud comparable to the volume of steel removed, the mud level in the annulus causes a reduction in bottom pressure, which might cause an inflow.
A maneuvering tank and a maneuvering sheet are necessary to prevent and identify filling abnormalities.

- Pistoning upwards: This occurrence happens when the well's liner rises, leaving a depression at the bottom. One may identify pistoning upwards by closely monitoring the return to the chute and balancing the quantities in the drilling mud tank.

- Circulation loss: When there is a complete loss of circulation, the hydrostatic pressure drops, and if it falls below the pore pressure, formation fluid will enter the well.

- Insufficient Mud Density: If the density falls below the equilibrium density of a porous and permeable formation, the mud density becomes a crucial issue in primary well management.
The lack of density may be caused by:

  - Underestimating pore pressure.
  - Inadvertently lowering the density of the mud on the surface.
  - The forming fluid contaminates the sludge.

- Gas contamination of drilling mud: When drilling in gas-containing formations, the gas combines with the mud, reducing its effective density. This reduction becomes even more pronounced as the gas approaches the surface.

- Mud cut by water: An influx of salty water happens when drilling runs into a porous zone holding sandy water at a pressure more significant than the hydrostatic pressure of the mud.
The inflow will be identified by the emergence of chloride, a change in density, a change in the rheological features of the mud, or gains to the basins, depending on the differential pressure between the formation and the hole and the permeability of the formation.

2.2. Blowout:

"A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed" (8)

2.2.1. Blowout Scenario: (6)

A blowout happens when the primary and secondary safety barriers of the well failure one after the other.

1. The primary barrier is made up of the fluid column that is intended to overcome the pressure of the formation fluids.
2. The secondary barrier comprises the envelope, which comprises cement, casings, and the surface safety device.

In other words, for a blowout to happen, formation fluids must first enter the well (primary barrier failure). Then they must do so unchecked, meaning that the cement, casings, or BOP must have failed to do so (secondary barrier failure).

2.3. Well Control System Description:

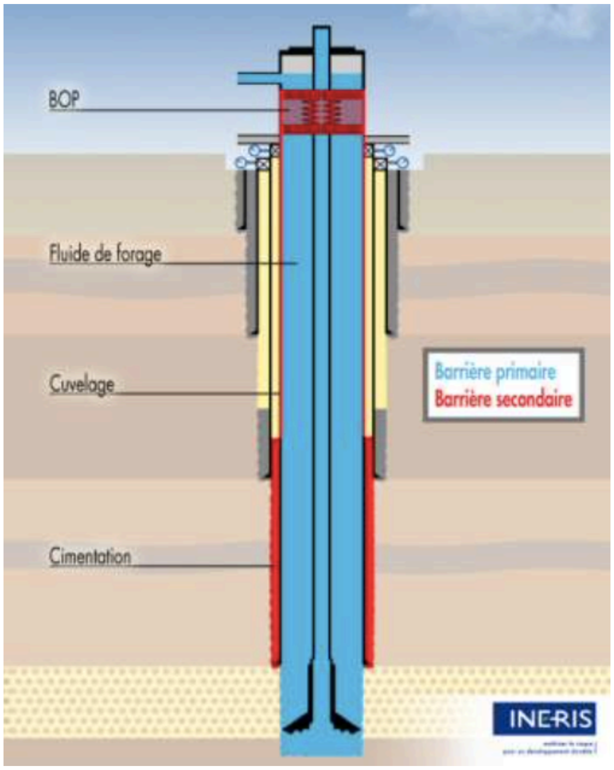


Figure 11: Safety barriers for a well during the drilling phase (6)

2.3.1. BOP's composition & use: (7)

A BOP is employed throughout a well's lifespan, including during suitable interventions, drilling, completion, and well abandonment. It performs several operational and safety-related tasks. In terms of safety, its primary duties are to:

- Make sure the well is closed in the event of an arrival.
- Permit circulation to recondition the mud and remove any fluid seeped into the well (this is the technique for regulating occurrences).

The **choke** and **kill lines** are two sets of auxiliary lines extending laterally from a BOP. When the BOP is closed, these facilitate fluid circulation in the well.

2.3.2. BOP's shutters types: (7)

A BOP includes a variety of shutter types. We differentiate:

- **Annular preventers**: which may be closed on any piece of machinery, even an empty hole (not advisable), allow the maneuver of the drill string, the well-being closed and under pressure (stripping);
- **Pipe rams:** they close only on tubular of a defined diameter;
- **Variable-bore rams:** they close on tubular of variable diameters;
- **Blind rams:** they allow the well to be closed entirely in the absence of any element in the well;
- **Blind shear rams:** they allow to shear tubular elements (typically drill pipes but not casings) and to completely close the well.

1. **Annular types:** (9)

The is positioned at the very top of the BOP stack and is equipped with the capacity to apply closing pressure to seal off anything in the bore or shut off an open hole.

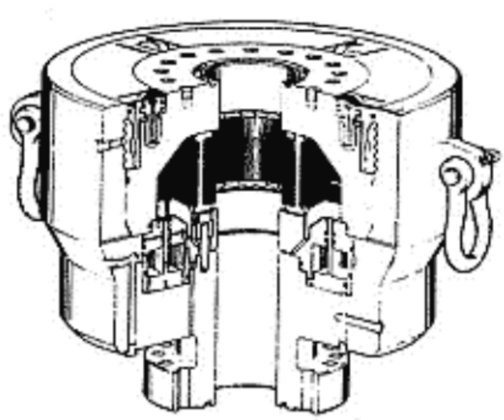


Figure 12: Annular BOP (9)

2. **Ram's types:** (9)

A big bore valve is what a ram-type blowout preventer is.

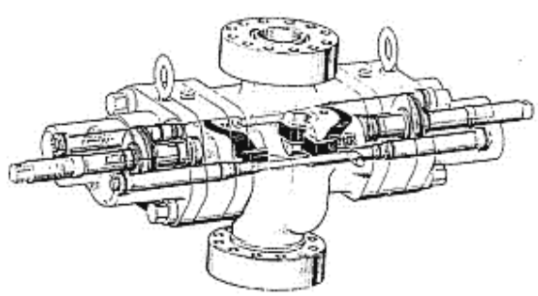


Figure 13: Ram BOP (9)

The purpose of the ram blowout preventer is to close up the well bore when there is pipe, casing, or tubing within the well. Ram preventers are in a BOP stack between the annular BOP and the wellhead. There're four rams in a BOP:

2.1. Pipe Rams:

The sealing element is designed to fit around a range of tubular, including production tubing, drill pipe, drill collars, and easing that will shut off the wellbore all around it.

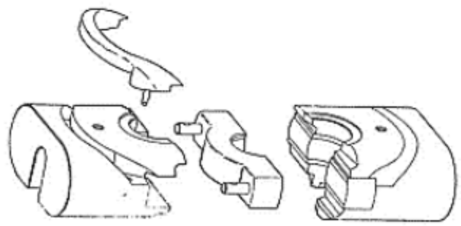


Figure 14: Pipe Rams (9)

2.2. Variable-Bore Rams:

The sealing component is significantly more intricate and enables sealing around a specific range of pipe diameters.

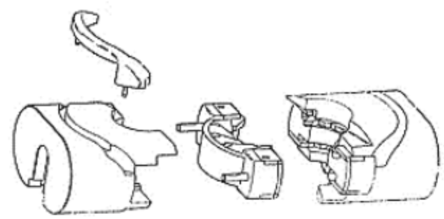


Figure 15: Variable-Bore Rams (9)

2.3. Blind Rams:

The flat rubber sealing piece may seal the wellbore even without any fluid.

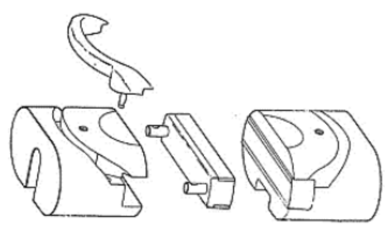


Figure 16: Blind Rams (9)

2.4. Blind Shear Rams:

The drill pipe is sheared or sliced by the ram's blade part, and a seal is created, much like a blind ram.

(10)

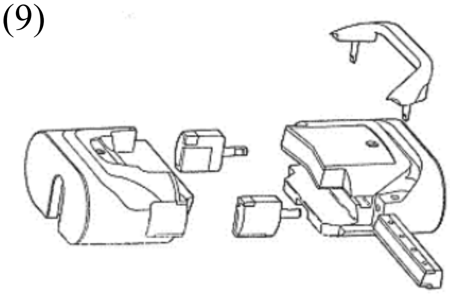


Figure 17: Blind Shear Rams (9)

2.3.3. BOP control or Hydraulic Power plant: (10)

All valves are hydraulically regulated and function by the idea of two-direction, double-acting hydraulic cylinders. The idea is always to have a supply of pressurized fluid (accumulators) to ensure the valves will permanently close or open. A specialized machine is used to secure the opening and closing positions.

To maintain constant pressure in the accumulators, which serve as the reserve of hydraulic motor fluid, a control unit comprises several pumps that start and stop automatically (see figure below).

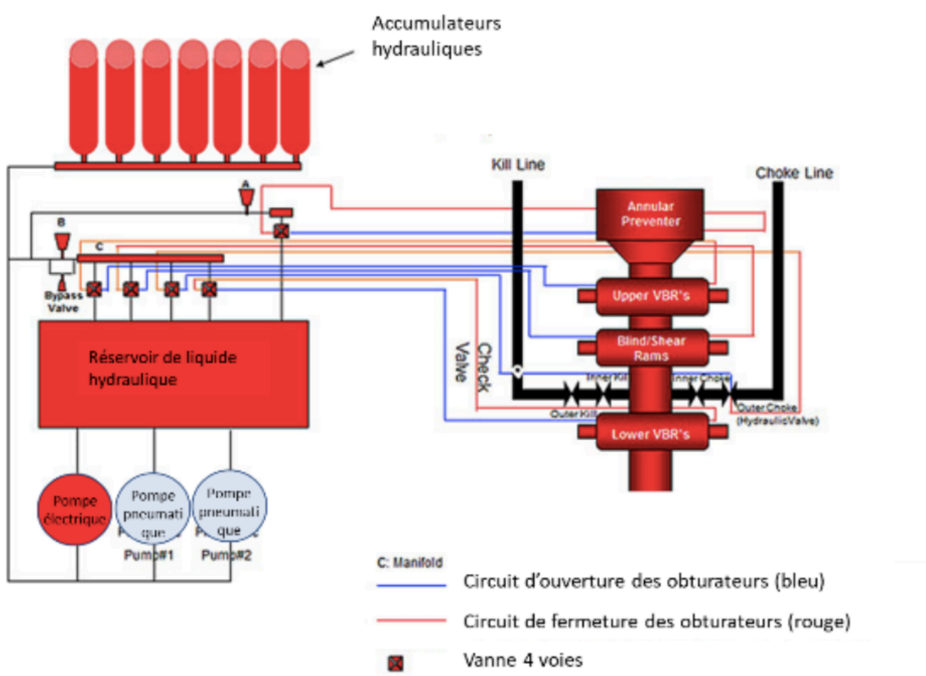


Figure 18: Operating diagram of a control unit connected to a BOP (10)

2.3.4. Pump System: (9)

There may be one or many pumps in a pump system. Primary and secondary pump systems should have separate power sources, such as electricity or air.

Each pump system needs enough pumps in the correct numbers and sizes to carry out the following tasks successfully:

The pump system should be able to close the annular BOP (excluding the diverter) on the used minimum-size drill pipe, open the hydraulically operated choke valve(s), and provide the operating pressure level advised by the annular BOP manufacturer to affect a seal on the annulus within two minutes once the accumulators have been taken out of service.

2.3.5. Choke Line & Kill line: (10)

Two lines extending from the BOP regulate the flow of fluids from the well during well shut-in: the choke line and kill line.

The choke line permits flow from the well's bottom to the surface, lowering the well's pressure. Drilling mud is injected into the well via the kill line during well control procedures. When there is an overpressure in the well, the pressure flow should proceed through the choke line, the choke manifold, the mud tanks, and the reserve pit.

The choke and kill lines are installed between the wellhead and the lowest BOP, or between two BOPs.

2.3.6. BOP Testing and Maintenance: (10)

A protocol for testing and maintenance must be followed while using security equipment.

Internal standards, statutory requirements, normative criteria, supplier requirements, and internal or external input may all be used to define this maintenance policy.

Only some components of a safety barrier need to be tested and maintained on a consistent schedule.

As mentioned above, controlling every component of the safety chain that connects the various parts of the BOP is crucial.

Test and maintenance while drilling operations:

Leakage tests call for observing no leakage, at a steady pressure, for a predetermined amount of time. According to API 53:

Table 5: Recommended Pressure Test Practices (21)

Component to be Tested	Recommended Pressure Test – Low Pressure, psi	Recommended Pressure Test – High Pressure, psi
1. Rotating Head	N/A	Optional
2. Diverter Element	Optional	Optional
3. Annular Preventer • Operating Chambers	200-300 (1.38 - 2.1 MPa) N/A	Minimum of 70% BOP working pressure. N/A

4. Ram Preventers • Fixed Pipe • Variable Bore • Blind/Blind Shear • Casing (prior to running csg) • Operating Chamber	 200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) Optional N/A	 Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. Optional N/A
5. Diverter Flowlines	Flow Test	N/A
6. Choke Line & Valves	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
7. Kill Line & Valves	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
8. Choke Manifold • Upstream of Last High-Pressure Valve • Downstream of Last High-Pressure Valve	 200-300 (1.38 - 2.1 MPa) Optional	 Greater than the maximum anticipated surface shut-in pressure. Optional
9. BOP Control System • Manifold and BOP Lines • Accumulator Pressure • Close Time • Pump Capability • Control Stations	 N/A Verify Precharge Function Test Function Test Function Test	 Optional N/A N/A N/A N/A
10. Safety Valves • Kelly, Kelly Valves, and Floor Safety Valves	 200-300 (1.38 - 2.1 MPa)	 Greater than the maximum anticipated surface shut-in pressure.

11. Auxiliary Equipment • Mud/Gas Separator • Trip Tank, Flo-Show, etc.	Optional Flow Test Flow Test	N/A N/A

2.3.7. Inspection and Certification: (10)

Specific checks must be performed in addition to the criteria for using pressure equipment. The administration must receive the inspection programs.

1. **Certification:**
   - Shutters (annular and clamshell).
   - Valves (particularly on discharge and control lines, as well as non-return valves and check valves).
   - Discharge and control lines themselves (as well as flexible lines).
   - All equipment is intended to operate under pressure.

By and at the device's maker every five years. Recertifying equipment used in the workplace is not permitted (acceptable business practice). API 16A or 16C, if used in an acid environment, specifies certification tests and how frequently they should be performed.
Every five years, accumulator cylinders must undergo a hydraulic pressure test.

2. **Inspections :**

At sites that might be in danger of erosion, specific inspections should be carried out:

- Inspection programs to verify metal thickness must be carried out on the points posing the highest risk (curves and angles).

Especially when the ratio of radii (measured from the generator as outer radius divided by internal radius) is less than 10.
The minimum frequency of this check is every two years.

CHAPTER III:
Risk management

1. Risk management:

Risk management is the collection of coordinated actions taken to decrease risks to an extent regarded as bearable or acceptable at a particular moment and in a specific situation. The risk management language is presently defined by several sources, although there are still some rather significant variances between them. Beyond the language, it is crucial to stress that each document describes a management process that is, at its core, the same. Risk analysis is critical to this process, even if it is rarely mentioned explicitly [13].
The analysis techniques can be divided into two categories:

- A qualitative approach that identifies the risky events, their patterns that could result in a dangerous situation (scenario), as well as their causes and effects
- A quantitative approach that quantifies and analyzes the failures' impact and frequency of occurrence

In this chapter, we outline the methods employed to address our problem.

2. Method for blowout risk assessment: Fault Tree Analysis

One analytical method for tracing the potential contributing events is fault tree analysis. It may be applied to a thorough hazard analysis and accident investigation. The fault tree is a logic diagram built on the multi-causality principle that follows all possible paths for events that might result in an accident or failure. Sets of symbols, labels, and identifiers are used. (11)

2.1. Basic Description: (12)

- Determines sources, or root causes, of potential faults.
- Qualitative and quantitative.
    - Graphical, top-down approach.
    - Uses Boolean algebra, logic, and probability.
    - Can handle multiple failures.
    - Can support probabilistic risk assessment.
- Part of system design hazard analysis type (SD-HAT)

2.2. Benefits of constructing a Fault Tree: (13)

- The fault tree displays all the many connections required to produce the top event.
- By building the fault tree, a complete grasp of the logic and fundamental reasons leading to the top event is acquired.
- The fault tree is a visual representation of the methodical examination of the reasoning and fundamental factors that led to the top event.
- The fault tree offers a structure for comprehensive qualitative and quantitative analysis of the top event.

2.3. FTA methodology: (14)

- **Gathering pertinent data:** The information required to comprehend the system under investigation must be gathered in this initial phase. This might contain details about the method employed, the equipment's properties, the climate at the site, the geographical circumstances, etc. The limitations of the system can be determined by consulting accident reports.
- **Definition of the dreaded event:** Once all pertinent data has been gathered, it is crucial to identify the feared occurrence.
- **Looking for the INS causes:** This is unquestionably the trickiest part of building the tree. It is essential to move step-by-step while choosing the intermediate events, keeping in mind to identify the immediate and direct causes of the event in question and to assess their sufficiency. If not, the tree can be inaccurate or just partially complete.
- **The construction of the tree:** After that, we go on to the graphical depiction of the tree, where logical gates are used to show the causal connections between the antecedent events and the examined event.
- **Utilization of the results:** By calculating the minimal cut (MC), this stage aims to identify the lowest set of circumstances that can result in an emergency room visit. The vertex event won't happen if we remove just one of its pieces from a minimum cut.

The order of a cut is defined as the number of combined events that appear in this cut, and the MC is calculated using the BOOLE algebra's principles. We may depict our reduced tree after we've located the CM.

We conduct a qualitative or quantitative review to determine the primary reason for the FR.

We may determine how much a failure contributes to the occurrence of the dreaded catastrophe using qualitative exploitation. The initial occurrences are taken to be equally likely for this purpose, and we then follow the path via the logic gates to the outcome. The CM enables us to quickly access the system under study's most important events. As a result, the probability that the ultimate event will occur increases with decreasing order of a minimal cut.

Quantitative exploitation entails predicting or calculating the likelihood of the top event of the tree based on the likelihood of the fundamental events. Although this method does not allow us to pinpoint the precise likelihood of each cause, it does allow us to rank them in order of likelihood so that we can implement effective preventative measures. The lack of probabilities for the fundamental occurrences is one of the challenges of quantitative exploitation, however, we may still use:

  - Databanks.
  - Feedbacks.
  - Tests.
  - The teams' experience working on the installation itself or something similar.

- **Action plan:** Quantitatively or qualitatively estimate the likelihood that the events leading up to the end event will occur.

3. Methods and tools for determining critical failures:

3.1. Structural Analysis and Design Technics (SADT):

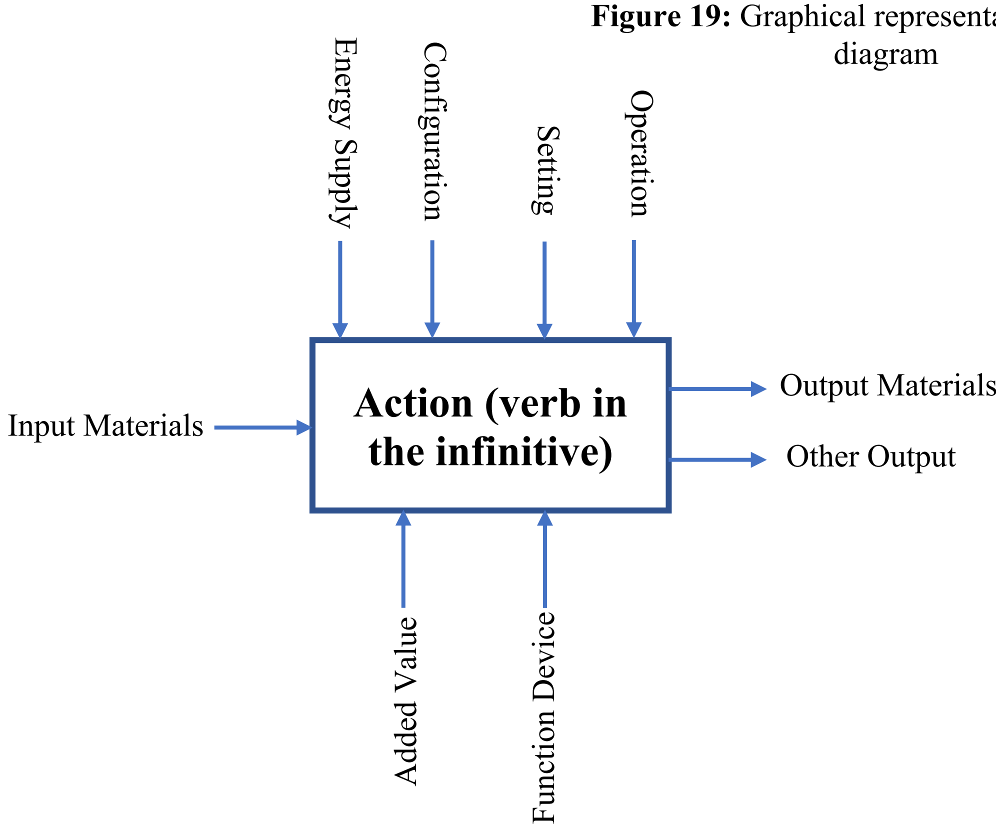
3.1.1. Historic:

Software engineering has a long history with SADT. Ross (1977) created it as a result of ongoing research (1969–1973) on problem-solving that began in the 1950s at Softech. According to Dickover and colleagues (1977), the graphical language SADT was widely used to describe complex systems in communication designs, military planning, and computer-aided manufacturing. Although SADT has been successfully utilized in functional specifications and issue analysis (Ross and Schoman, 1977; Ross, 1985), it has been employed most successfully in the requirements definition stage of software design. (15)

No matter how complicated a process or system is, this approach may be used to functionally analyze it by breaking it down into simpler parts utilizing increasing degrees of detail. It enables the explanation and presentation of an activity's production processes and procedures, as well as the identification and understanding of system abnormalities and associated issues.

3.1.2. Graphic Representation:

Figure 19: Graphical representation of SADT diagram



Top-down decomposition and visual analysis are both used in the analysis. Datagrams are boxes that serve as a representation of the functions. Arrows connecting them signify the restrictions that exist between them. (15)

3.2. Failure Mode, Effects and Criticality Analysis (FMECA): (16)

The 1960s saw the introduction of Failure Mode, Effects and Criticality Analysis (FMECA) in the aerospace sector.
Since then, additional businesses, including those in the chemical, oil, and nuclear sectors, have begun to employ it.
In fact, it is primarily designed for the investigation of material and equipment failures and may be applied to systems utilizing a variety of technologies, including electrical, mechanical, hydraulic, and other systems.

3.2.1. FMECA principles: (16)

The principles are the foundation for the investigation of failure mechanisms and their repercussions:

- Failure, which is the loss of an element's or system's capacity to carry out a necessary function,
- failure mode, how a system component is affected by a failure,
- the cause of failure, or the circumstances that give rise to failure modes,
- The effects of a failure mode, or what happens when an element can no longer carry out a necessary function.

3.2.2. FMECA Procedures: (16)

An FMECA has the following structure, which is extremely schematic:

1. Select an element or component of the system first.
2. Pick a mode of operation (regular operation, shutdown, etc.).
3. Pick a first failure mode for this component or element and this condition.
4. Determine the root causes of this failure mode and its effects on the component in question as well as the entire system.
5. To investigate the methods for detecting the failure mode and those intended to stop it from happening or to lessen its impact.
6. To go on to evaluate the gravity and probability of this failure mode's criticality.
7. If the risk assessment reveals the need, devise additional measures or means.
8. Determine if the pair (P, G, D) is appropriate.
9. Re-examine the analysis in point 4 and take into account a new failure mode.
10. The analysis in point 3 should be repeated once all failure modes have been taken into account.
11. After all operational states have been taken into account, choose a different system element or component and repeat the analysis in point 2 with that new element or component.

The FMECA table used contains the following columns (16):

- Subsystem.
- Component.
- The main function of the component.
- Failure modes.
- Causes of failure.
- Effects of failure on the system
- Effects of the failure on the system.
- Preventive measures.

CHAPTER IV:
Managing blowout risks during drilling operations

1. Blowout risk assessment:

Well control is based on two safety barriers (17):

The first one is the drilling mud, which prevents the well from collapsing by applying a hydrostatic pressure (Ph) superior to or equal to the formation pressure (Pf), and at the same time, with a specific density, it prevents the occurrence of a kick.

The second barrier is the blowout preventer (BOP), which prevents blowouts and is used to hold unpredictable pressures of a flow flowing from a well during drilling activities. The BOP maintains the well seal while allowing the drill pipe to be inserted into the hole's bottom during drilling.

1.1. The feared event identification and its causes:

A "blowout" is the anticipated outcome in our situation. We may infer from the previous data “REX” that a blowout can result from various simple occurrences. In the table below, we list the primary reasons:

Table 6: The primary reasons of blowout

	Event
A	BOP Failure
B	No Detection
C	Swabbing / Surging
D	Pressure Zone
E	Density Measuring Equipment Failure
F	Operator Error
G	Bad Cementation
H	Bad Casing
I	Pump Failure
J	Power Loss
K	Mud Tanks Leakage
L	Pipe Leakage

1.2. Fault Tree construction:

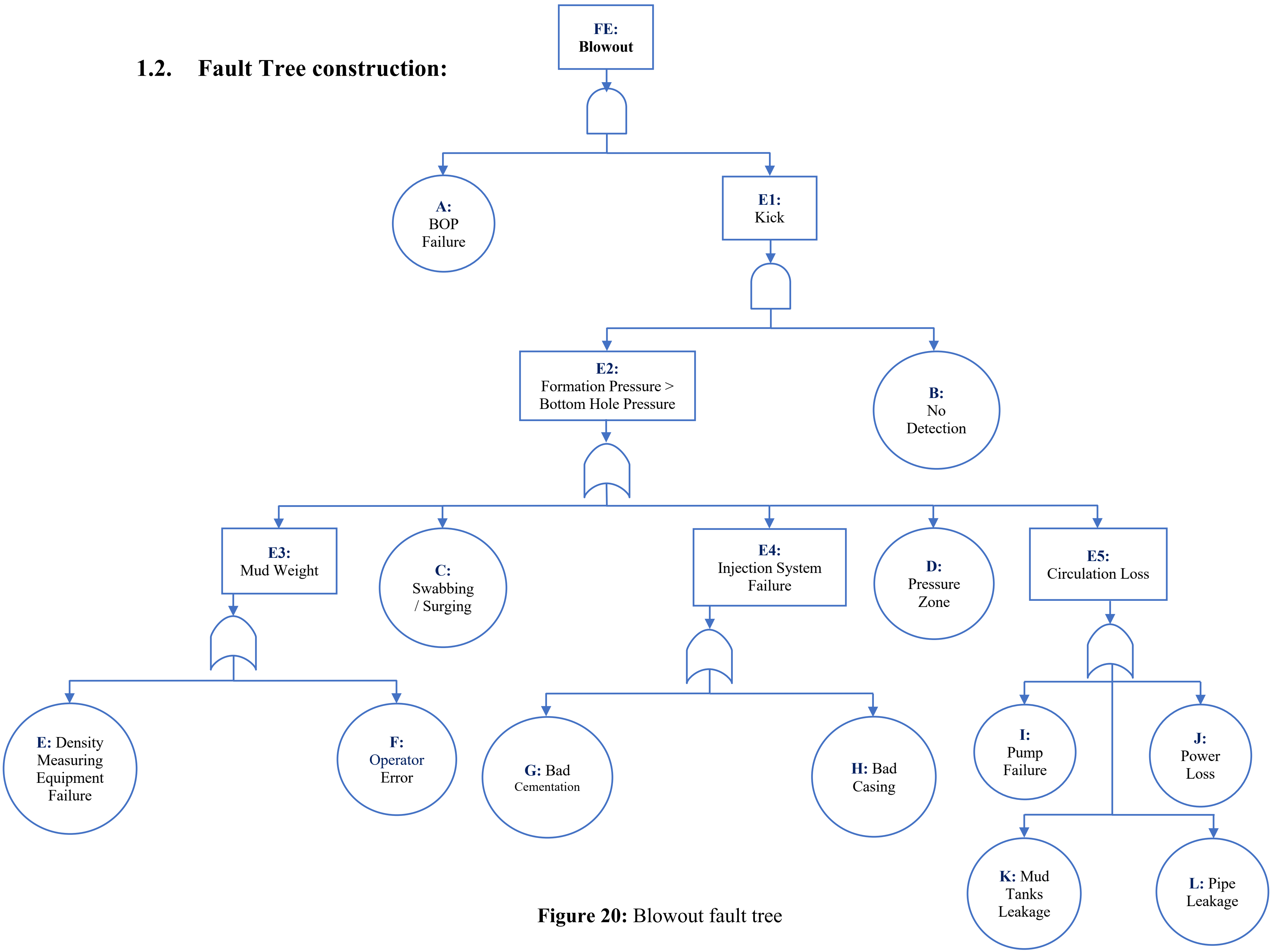


Figure 20: Blowout fault tree

1.3. Fault Tree exploitation:

We go on with its reduction by employing BOOLE algebraic principles to use the generated tree. The figure below is the outcome:

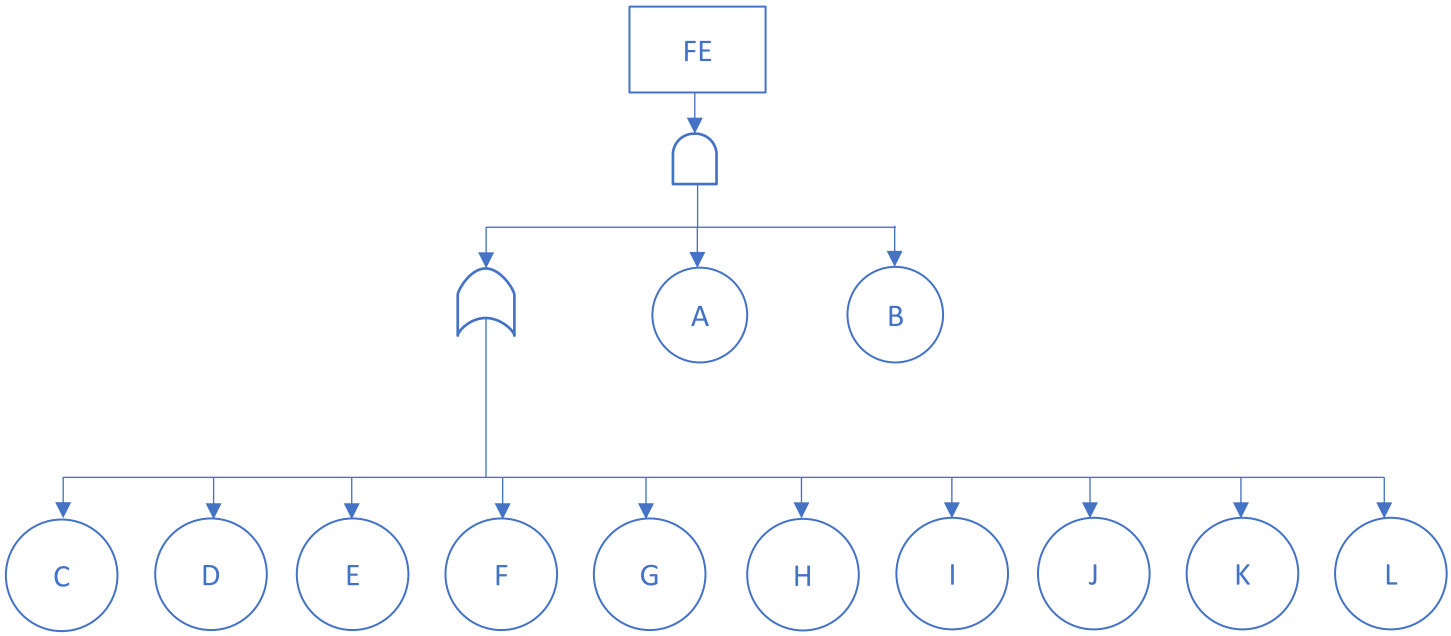


Figure 21: Reduced blowout fault tree

Minimum cuts for this tree are: **ABC**; **ABD**; **ABE**; **ABF**; **ABG**; **ABH**; **ABI**; **ABJ**; **ABK**; **ABL**.
We have 10 minimum cuts with two elementary events, and BOP failure and kick no detection are frequent causes. By lowering their probabilities, we decrease the likelihood of the FE.
The Failure Tree demonstrates how important a piece of machinery the BOP is and how crucial its perfect performance is in closing the well. Knowing when the BOP could stop serving its intended purpose allows us to plan for its chance of failure (reliability).

2. <u>Critical failures determination:</u>

2.1. Functional analysis (SADT):

We will do a functional analysis of the BOP utilizing the SADT diagram of the complete blowout control procedure during drilling operations to comprehend how the system under investigation operates.
The A0 level of the process is illustrated in the image below:

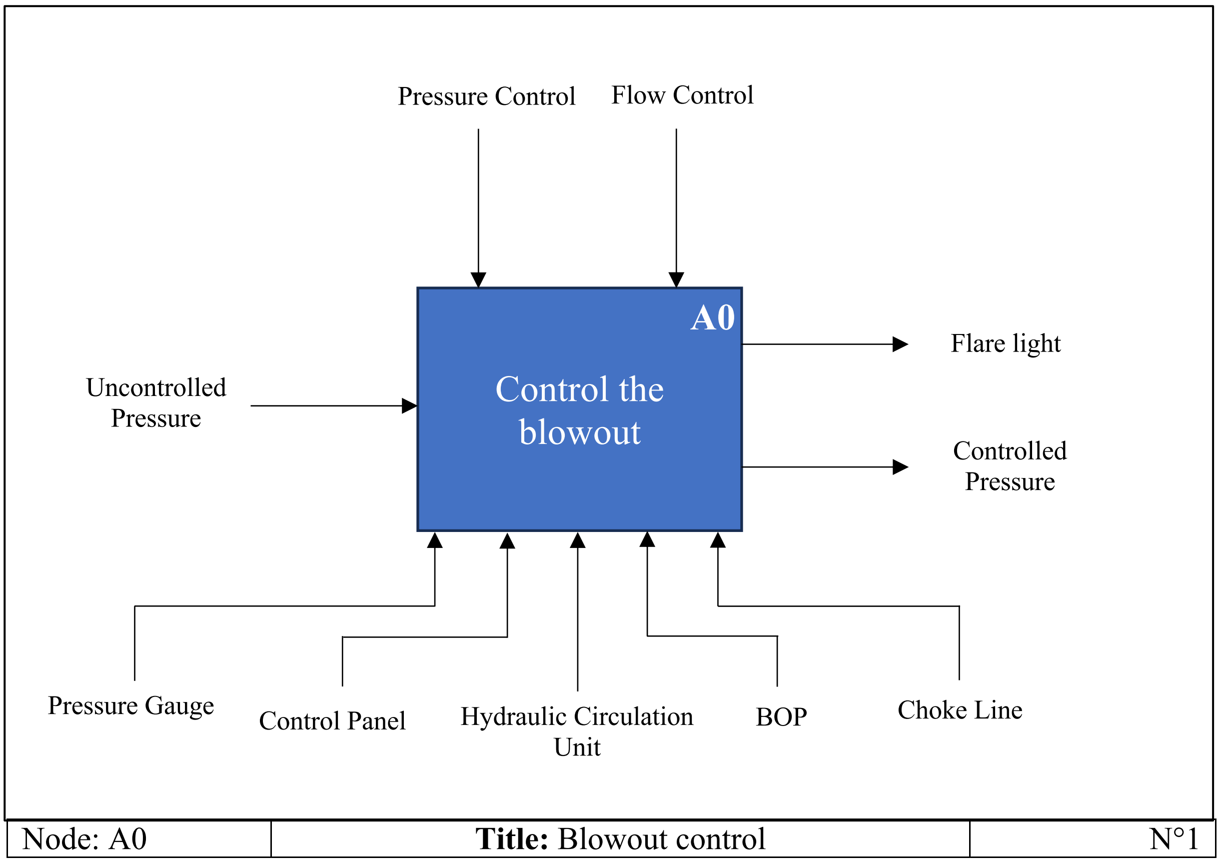


Figure 22: SADT diagram, Level A0

The image below illustrates the detailed A0 level to aid in understanding the major systems and their subsystems:

Node: A0	**Title:** Blowout control	N°2

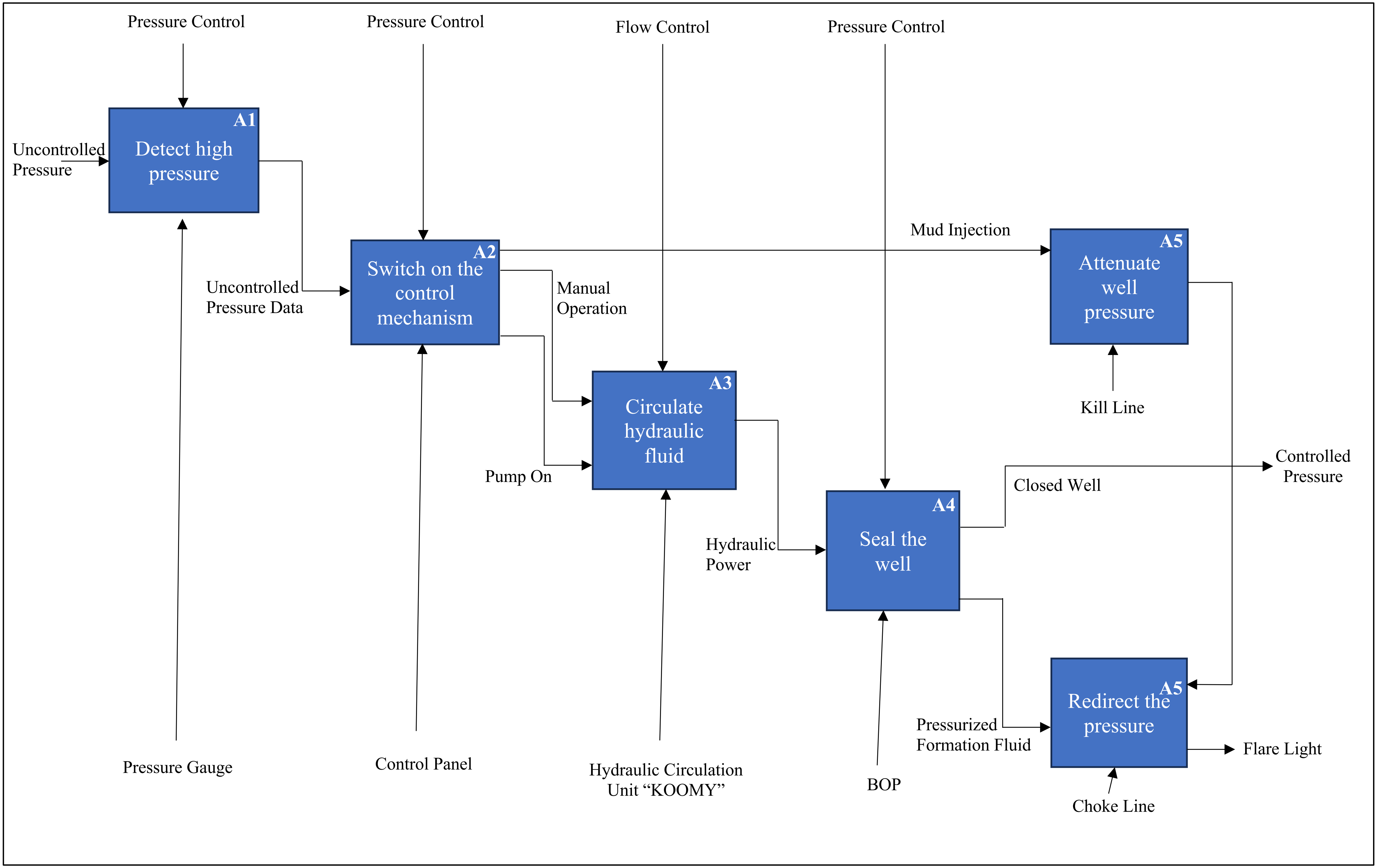


Figure 23: SADT diagram, Detailed Level A0

The detailed SADT level A0 graphic shows five primary sub-systems that may be separated:

<u>Sub-system 1</u>: Detecting High Pressure: Pressure gauges pick up unusual increases in formation pressure in the well, and the control panel processes this data.

<u>Sub-system 2</u>: Switching on the control mechanism: The emergency stop procedure starts when the abnormality is discovered at this level. The supervisor commands the mud injection and turns on the hydraulic circulation unit.

<u>Sub-system 3</u>: Circulating hydraulic fluid: The control panel or the accumulator unit can be used to control it.
The detailed A3 level is displayed in the graph below:

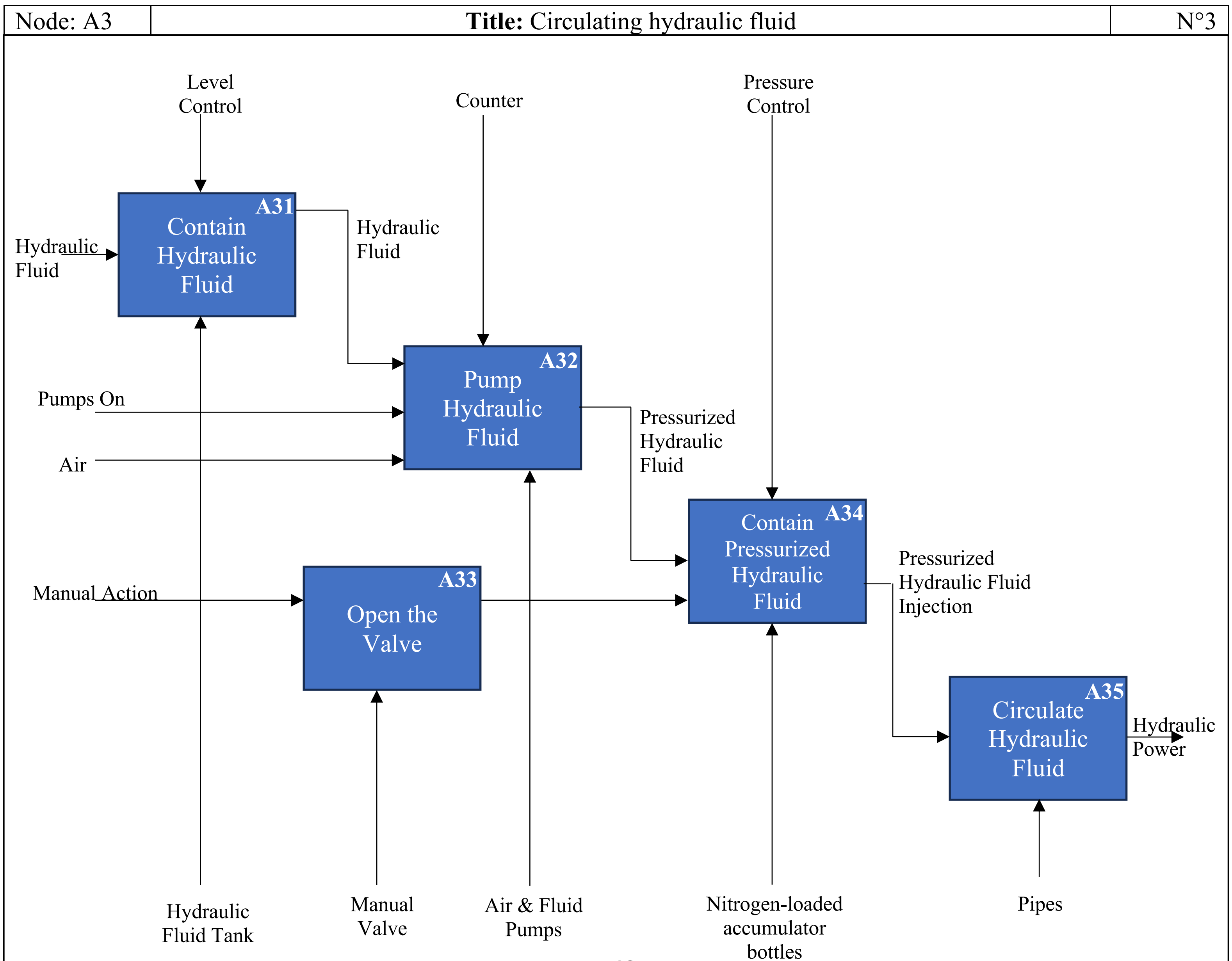


Figure 24: SADT diagram, Level A3

<u>Sub-system 4</u>: **Sealing the well:** Closure of the rams and annulus, which activates the shaft sealing mechanism.
Below is a picture of this level in more detail:

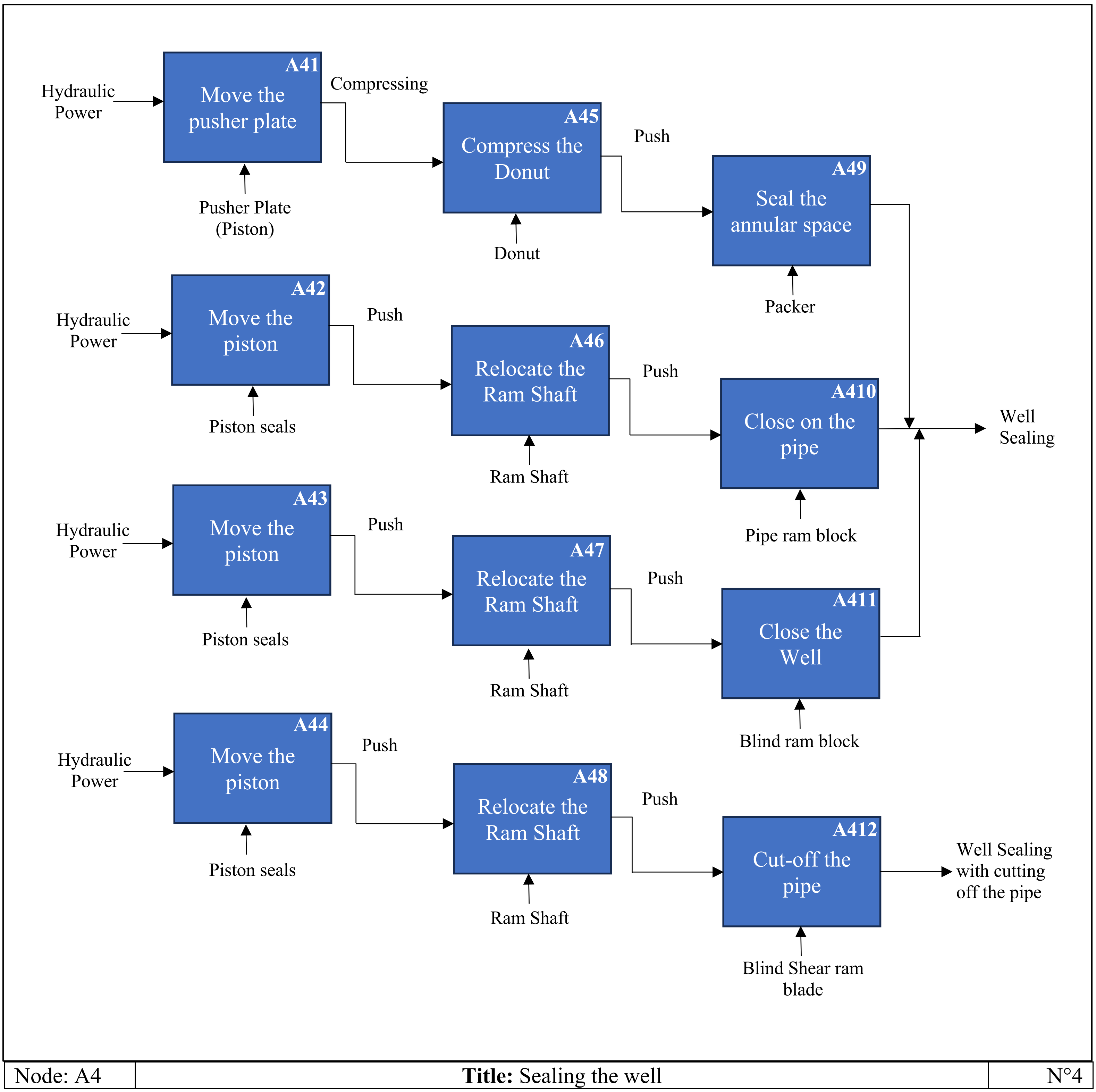


Figure 25: SADT diagram, Level A4

<u>Sub-system 5</u>: Redirect the pressure: The pressure from the BOP must be sent to the choke manifold once it has shut the well.
Below is a picture of this level in more detail:

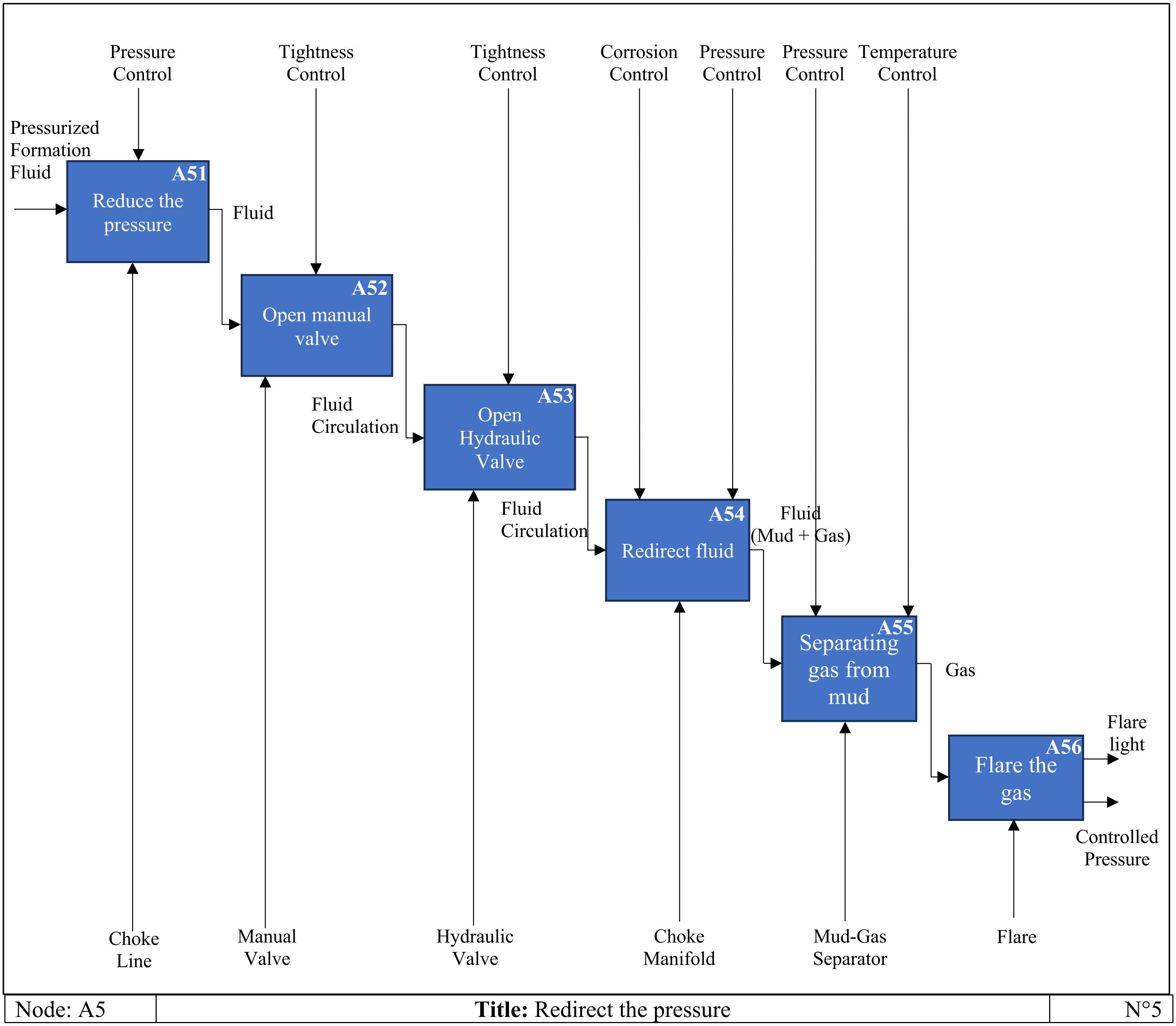


Figure 26: SADT diagram, Level A5

2.2. Failure modes identification and assessment:

2.2.1. Failure modes identification:

We will determine the failure modes of each subsystem using the data acquired above and the functional analysis. The FMECA table in the results section illustrates how different components may have the same failure mode. Still, the reason and impact of the failure may vary from one component to another.

2.2.2. Failure modes evaluation:

On a scale of 1 to 5, the failure's occurrence, severity, and detectability were used to evaluate the failure modes. We can determine how critical a failure is by multiplying these factors:

$$\boldsymbol{C = O \times S \times D}$$

C: Criticality
S: Severity
O: Occurrence
D: Detection

In our study we used:

- **Occurrence Scale:**

Table 7: Failure occurrence probability scale

Score	Occurrence probability
1	Improbable
2	Low
3	Moderate
4	High
5	Very high

- **Severity Scale:**

Table 8: Failure severity scale and repair time

Severity	Repair time
1	No impact on the BOP's main function, but maintenance is required after the end of the operation.
2	Partial loss of the BOP's main function and temporary stoppage of a few hours to a day on site.
3	Partial loss of main BOP function and temporary stoppage between 2 and 7 days.

4	Partial loss of main function from 8 days to one month.
5	Total loss of the BOP's main function, major repair required at the manufacturer's plant, unspecified timeframe (several months)

- **Detection Scale:**

Table 9: Failure detection scale

No Detection	Detection
1	Detection by simple visual assessment
2	Detection possible with sensors (pressure, level, etc.)
3	Defects are detected by weekly inspections (checklist, sampling)
4	Failure detected during preventive maintenance
5	Failure is detected by periodic tests (hydraulic and hydrostatic pressure tests)

- **Quotation grid:**

Table 10: Quotation Grid

Criticality	Signification
$0 \leq C \leq 30$	Tolerable risk
$31 \leq C \leq 50$	Moderate risk
$51 \leq C \leq 125$	High risk

- A failure mode does not create significant danger if the criticality is less than 31.
- The failure mode is not a priority but may produce long-term events when the criticality rating is between 31 and 50.
- The failure mode poses a significant risk regarded as intolerable when the criticality exceeds 50.

2.2.3. Results:

We pinpointed the failure modes influencing BOP operations thanks to FMECA. We could categorize them based on their criticality, thanks to their evaluation. The table below shows the outcomes that were attained:

Table 11: FMECA Results

BOP sub-systems	Component name	Component function	Failure Mode	Effect of failure	Cause of failure	Evaluation			Criticality (C)	Additional information and recommendations
						P	G	D		
Annular Preventer	1. Packer	Sealing the annular space	F1.1. Blocking	- Packer does not close completely around pipe	- Solidified cement particles under the packer are preventing it from operating properly	2	4	4	32	- Inspection before and after cementing work - Supervision of cementing work.
			F.1.2. Deformation	- Packer does not close completely around pipe	- Wear and tear	3	4	2	24	- Packer flaking after prolonged exposure to temperatures above the maximum limit. - Change the packer periodically
	2. Hydraulic Components	Converting hydraulic energy into mechanical energy	F2.1. Joint Deformation	- Pressure Loss	- Wear and tear	3	4	4	48	- Periodic inspection/control
			F2.2. Piston Corrosion	- Failure to open/close ring finger correctly	- Quality of the fluid used in the hydraulic system - Aggressiveness of well fluid	2	5	4	40	- Periodic inspection/control - Periodic Test
			F2.3. Piston Failure	- Reduced mechanical force intensity	- Aging / Wrongful operation	2	4	4	32	- Periodic inspection/control - Periodic Test

	3. Housing (Body)	- Interior isolation from the exterior	F3.1. External Crack	- Liquid leaking from the well	- Excessive shock during delivery, installation, and/or on-site	2	5	1	10	
			F3.2. Grooves corrosion/scratch	- Liquid leaking from the well	- Aggressiveness of well fluid - BOP's bad storage - Shock - Sand, rock from high pressure well	2	4	3	24	
			F3.3. Sealing zones damage	- Fluid penetration in reverse circuit	- Sand particles are rubbed against the piston's body surface.	3	4	4	48	
BOP Rams	1. Pipe Ram	- Sealing the well around the pipe	F1.1. Packer deformation	- Seal Loss (packer not anchored around pipe)	- Wear and tear - Aging	3	4	3	36	- Change the packer periodically - Packer flaking after prolonged exposure to temperatures above the maximum limit.
			F1.2. Joint deformation/ cutting	- Hydraulic fluid leak	- Wear and tear - Aging	4	4	3	48	- Periodic inspection/control - Periodic Test

			F1.3. Holes in ram body	- Ram Damage	- Sand, rock from high pressure well	3	3	4	36	- Periodic inspection/control
	2. Blind Ram, Shear Ram, Blind Shear Ram	- Sealing the well by cutting the pipe (sealing open well also without a drill pipe)	F2.1. Packer deformation	- Seal Loss (packer is not closing/cutting the pipe)	- Wear and tear - Aging	3	2	4	24	- Change the packer periodically - Packer flaking after prolonged exposure to temperatures above the maximum limit.
			F2.2. Damaged shear blade	- No pipe cutting	- Wear and tear	2	3	4	24	- Periodic inspection/control
			F2.3. Blade unable to cut	- No pipe cutting	- Insufficient hydraulic pressure - Ram inadequate for hose type and geometry	1	3	2	6	- Periodic inspection/control
			F2.4. Holes in ram body	- Ram Damage	- Sand, rock from high pressure well	3	3	4	36	- Periodic inspection/control - Periodic Test
	3. Hydraulic System	- Opening/ closing of rams	F3.1. Components Corrosion (Piston…)	- Reduced mechanical force intensity - Failure to open/close rams	- Quality of the fluid used in the hydraulic system - Aggressiveness of well fluid	3	4	4	48	- Periodic inspection/control

			F3.2. Joint Deformation	- Fluid penetration in reverse circuit	- Wear and tear	3	4	5	60	
			F3.3. Piston scratch	- Impaired piston function	- Penetration of debris in hydraulic fluid	3	4	5	60	
	4. Mechanical System	- Moving to push rams to seal the wellbore due to a hydraulic power	F4.1. Grooves corrosion/scratch	- Liquid leaking from the well	- BOP's bad storage - Shock - Sand, rock from high pressure well	4	4	4	64	
			F4.2. Corrosion/ Scratch of ram's cavities	- Ram damage - Well Fluids Penetration into the operating chamber	- Aggressiveness of well fluid - BOP's bad storage	4	5	5	100	
			F4.3. Non-tightening of bolts on the body	-Thread damage -Hydraulic fluid leak	- Operator error	4	5	4	80	

Based on the above analysis, the breakdown distribution is illustrated in the figure below:

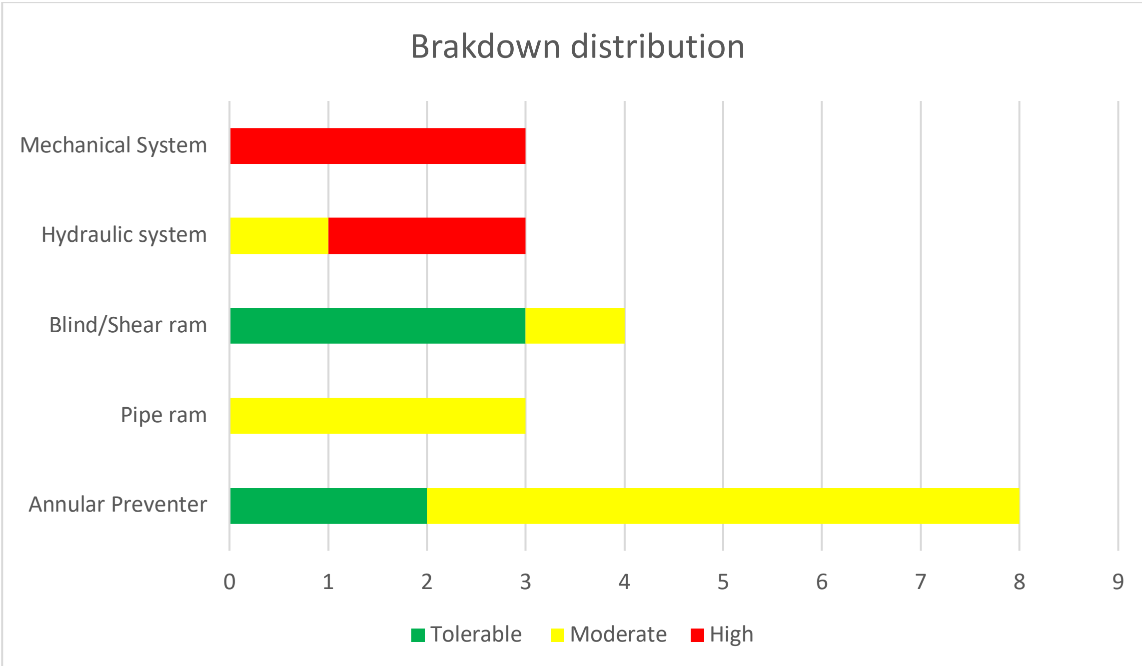


Figure 27: Failure Modes distribution by criticality Diagram

This graphic demonstrates that the subsystems affected by failure modes with a $31 \leq C \leq 50$ are as follows:

- Annular preventer.
- Pipe ram.
- Blind/shear ram.
- Hydraulic system.

And the subsystems affected by failure modes with a $51 \leq C \leq 125$ are:

- Hydraulic system
- Mechanical system

To this end, we will consider all these subsystems in the reliability calculation presented in the next chapter.

CHAPTER V:

Calculating the probability of BOP failure

1. Probability of Failure on Demand (PFD):

The average probability of failure on demand PFD_{avg} calculation is one of the methods that can offer crucial information on the reliability and availability of this barrier because the BOP functions in demand mode.
The reliability law is given by the law shown in equation (1):

$$PFD = R(t) = e^{-\lambda t} \tag{1}$$

The PFD formula is given by the equation (2) (18):

$$PFD_{avg} = \frac{1}{TI}\int_{0}^{Tt} PFD\ (t)dt$$

$$PFD_{avg} = 1 - \frac{1}{\lambda\pi}(1 - e^{-\lambda t}) \tag{2}$$

Using Taylor development, the equation (2) transfer into:

$$PFD_{avg} = 1 - \frac{1}{\lambda\pi}(\lambda\pi - \frac{(\lambda\pi)^2}{2} + \frac{(\lambda\pi)^3}{3!} + \frac{(\lambda\pi)^4}{4!} + \cdots + \frac{(\lambda\pi)^n}{n!}) \tag{3}$$

If $\lambda\pi < 10^{-2}$:

$$PFD_{avg} \approx 1 - \frac{1}{\lambda\pi}(\lambda\pi - \frac{(\lambda\pi)^2}{2}) \tag{4}$$

After simplification:

$$PFD_{avg} \approx \frac{\lambda\pi}{2} \tag{5}$$

2. Reliability Block Diagram (RBD):

RBD is "A diagram that gives the relationship between component states and the success or failure of a specified system function." (18)

An RBD:
- One starting statement (a) and one ending point (b)
- Use rectangles or squares to symbolize each task (or function) performed by the system objects.
- To demonstrate the logical connection between the functions, use lines, series, parallel structures, or a mix.

2.1. RBD application:

We understood how the BOP system worked, including its upstream and downstream functions, thanks to the functional analysis done during the SADT diagram study. The risks connected to each component were then listed, along with their corresponding criticality, based on the likelihood, seriousness, and detectability of the failure in the issue.

The logical order and redundancy of the components with the most severe failures impacting the BOP function are diagrammed in this section.

We must first identify the kind of stack utilized in the area where our samples operate to create the BDF of the system "Hassi Messaoud". The accompanying table illustrates that the BOP utilized must be in the 10k class since the pressure in this area may reach up to 10,000 psi:

Table 12: Stacking possible according to API 53 for surface BOPs (21)

Pressure class	Minimum number of BOPs to be installed	Type and number of BOPs required			
		Annular Preventer	Pipe ram	Blind ram	Shear ram
2000	2	0	1	1	0
		0	1	0	1
3000	3	1	1	1	0
		1	1	0	1
5000	3	1	1	1	0
		1	1	0	1
10000	4	1	1	1	1
		1	2	1	0
		1	2	0	1
15000	4	1	1	1	1
		1	2	1	0
		1	2	0	1
20000	4	1	1	1	1
		1	2	1	0
		1	2	0	1

According to the previous table, the schematic of the bop configuration used in our study:

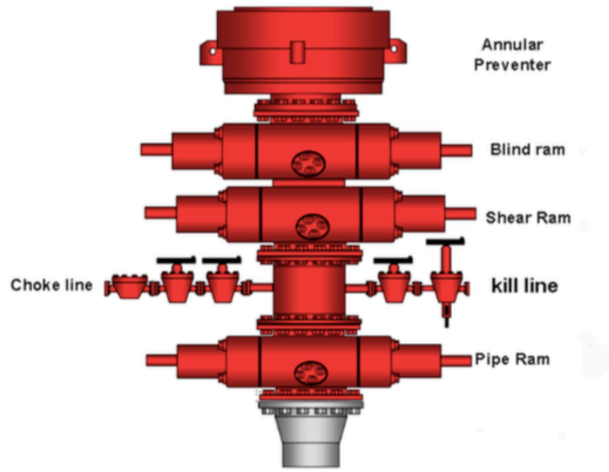


Figure 28: Cameron BOP configuration stack

The RBD of the system is shown in the figure, depending on the type of stacking used:

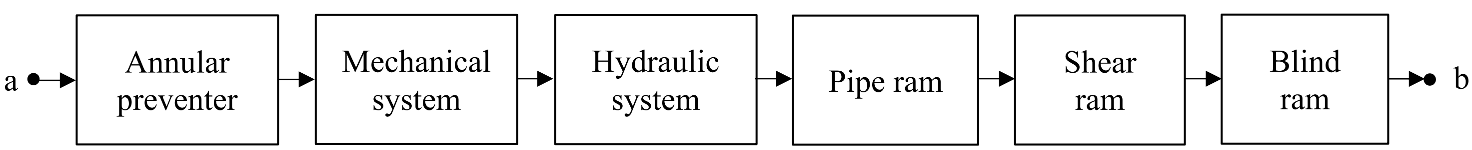


Figure 29: Reliability Block Diagram of
BOP with the type of stacking used

3. <u>Characteristics of Hassi Messouad drilling regions:</u>

Geographical location:

The greatest oil reserve in Algeria and on the whole African continent is found in the Hassi Messaoud (HMD) zone, situated north of the Berkine Basin. Around 350 kilometers west of the Tunisian border, 280 kilometers south of the Hassi R'Mel gas condensate field, and 850 kilometers south of Algiers are the locations of the HMD field.

HMD region features:

Table 13: Reservoir Characteristics of HMD

Reservoir depth	3600 m
Drilling pressure	4000 à 6000 psi
Presence of natural gas tanks	A little bit
H2S Presence	No

4. PFD_{avg} Calculation:

The study was done using the aforementioned stacking technique and four (4) BOPs. The BOP's owner, a Cameron client, owns the information in the table below:

Table 14: Practical Data (CAMERON)

Components		**Annular preventer**	**Mechanical system**	**Hydraulic system**	**Pipe ram**	**Blind ram**	**Shear ram**
Days (π)		**21**	**21**	**21**	**21**	**21**	**30**
BOP 1	MTBF	838	510	655	512	1113	702
	Failure rate (10^{-3})	1,19	1,96	1,52	1,95	0,90	1,42
BOP 2	MTBF	613	639	410	439	721	691
	Failure rate (10^{-3})	1,63	1,56	2,43	2,27	1,38	1,44
BOP 3	MTBF	713	521	574	821	962	712
	Failure rate (10^{-3})	1,40	1,91	1,74	1,21	1,03	1,40
BOP 4	MTBF	812	721	620	912	922	544
	Failure rate (10^{-3})	1,23	1,38	1,61	1,09	1,08	1,83

The PFD calculation results for each component are shown in the table below:

Table 15: Calculation results of PFD for each component

PFD_{avg}	Annular preventer	Mechanical system	Hydraulic system	Pipe ram	Blind ram	Shear ram
BOP 1	0,0125	0,0206	0,0159	0,0205	0,0095	0,0213
BOP 2	0,0171	0,0163	0,0255	0,0238	0,0145	0,0216
BOP 3	0,0147	0,0201	0,0183	0,0127	0,0108	0,021
BOP 4	0,0129	0,0145	0,0169	0,0115	0,0113	0,0275

All components are organized in series by the dependability diagram depicted in the figure, which implies that failure of any one component will prevent the BOP from carrying out its task,

(6)

rendering the system inoperable. For the $\boldsymbol{PFD_{sys}}$ calculation for subsystems arranged in series the following equation (19), (20):

$$PFD_{sys} = \sum PFD_{avg}$$

The calculation of the $\boldsymbol{PFD_{sys}}$ for each sample is presented in table below:

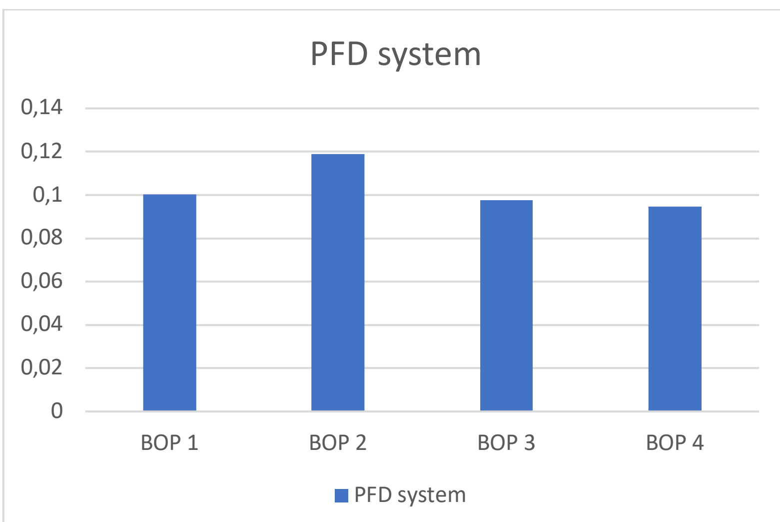
Table 16: Calculation results of $\boldsymbol{PFD_{sys}}$ For each BOP

BOP's	$\boldsymbol{PFD_{sys}}$
BOP 1	0.1003
BOP 2	0.1188
BOP 3	0.0976
BOP 4	0.0946

According to the data shown in the previous table, the minimum $\boldsymbol{PFD_{sys}}$value for BOP 4 is 0.0904, whereas the values for the remaining samples are 0.1003, 0.1188, and 0.0976 for BOPs 1, 2, and 3, respectively.

A $\boldsymbol{PFD_{sys}}$ value of 0.09 indicates that, on average, there is a 9% risk that one of the components processed during the computation will fail, preventing the BOP from performing one of its primary duties.
The flowchart in the following graphic displays the calculation outcomes:

Figure 30: Flowchart of $\boldsymbol{PFD_{sys}}$calculation outcomes for each BOP



The four BOPs exhibit variety, as seen in the preceding diagram, and this diversity in outcomes are caused by the HMD area's various properties. Therefore, the highest figure for the probability of a failure in one of the BOP components is 12%.

General Conclusion

The most harmful accidents in terms of loss of life, environmental harm, and financial damages are major. According to the typology of oil industry accidents, 67% include well occurrences (such as blowouts, inflows, safety barrier failures, etc.). These accidents are among the worst in terms of material destruction, but especially in terms of their impact on the ecosystem.

Specifically, during drilling operations in a Saharan region of Algeria (HMD), this investigation evaluated and quantified the reliability of safety equipment and the BOP, the last well barrier.
We approached the issue using a strategy based on four axes:

First axis, the fault tree approach dissects the drilling process to create a risk analysis that includes blowout potential. After doing this investigation, we concluded that one of the critical elements may combine to cause blowouts in drilling operations:

- BOP system failure.

Second, the overpressure flow control system is functionally analyzed on this axis, which divides the system into several components that work together. As this section of the demonstration showed, the BOP relies on upstream and downstream systems to carry out its duty.
Various parts and pieces interact during the good control process, and multiple systems run redundantly to guard against failures. The vital part of the BOP is its hydraulic system, which converts the hydraulic energy from the circulation unit into the mechanical energy required to move the rams and shut the well.

Third, each component's failure modes were examined, and we awarded a risk score for each one based on the likelihood, seriousness, and detectability of the failure in the issue. The failure modes were then divided into groups based on their criticality.

Fourth, since the reliability block diagram shows the important components in series, the BOP's probability of failure on demand (PFD) axis is the fourth axis. We determined that a component failure may prevent the BOP from performing its duty.
The PFD of each sample was then calculated after calculating the PFD of each component of the chosen 4 samples. Here is what we discovered:

- The BOP has an average dependability of 88% when the assumptions stated are considered.
- The BOP's operating circumstances have an impact on its dependability.
- Tanks with pockets of natural gas might accelerate the deterioration of some parts and hence affect the degree of dependability.

Finally, to make the BOP reliability higher it's recommended to:

- The right knowledge, by providing trainings to the technicians a field technician can learn to assess equipment for its applied design capabilities by using fundamental skills and knowledge.
- Make tests and inspection before the equipment placed, to make real time assessment on reliability.
- All the technician should know the failures mode of the equipment, they are less likely to ignore obvious problems that will lead to equipment failure.
- Periodic maintenance and testing of BOP components.

By creating a methodology that allowed us to respond to the challenge, we carried out a thorough technical investigation as part of this project, from risk identification and analysis to the evaluation of equipment reliability and the variables impacting it.

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