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Department of Hydrocarbon Production

MEMOIRE

To obtain the Master's Degree

Option: professional Production

Presented by:

KHELIL Nour, RAMDANI Gadria

-THEME-

Amelioration of production by well integrity

Supported on: 08/06/2024

Jury:

Chairman:	**GHALI Ahmed**	**UKM Ouargla**
Supervisor:	**BELMILOUD Fatima Zohra**	**UKM Ouargla**
Examiner:	**HADJAJ Sadok**	**UKM Ouargla**

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Mr. GHALI Ahmed and Mr. HADJAJ Sadok

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Thank you all

Dedication

I have the pleasure of dedicating this modest work to my dear father Atia who always gives me hope for life and who has never ceased to pray for me and for his encouragement

To my dear mother who gave me life, who sacrificed herself for my happiness and my success since you are here, mom I don't need anything, your presence alone is enough for me, and your smile alone fill me

To my dear brothers Ramzi, Walid,Okba,Amir

To my darling sistersAhlam,Marwa,Ikram

To my dear friends who always supported me in difficult time: Aboud Aicha,OUCHEN Malak, Ferdous

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Last but not least, I want to thank me for believing in me, I want thank me for doing all these hard work without a day off, thank me for never quitting

KHELIL Nour

Dedication

I dedicate this humble work, fruit of many years above all, to the soul of my pure father Muhammad Al-Hadi, may God have mercy on him

To the dearest and most valuable person in my life, who lit my path with his guidance, and it was a clear sea flowing with an abundance of love, and smiles for those who decorated my life with l the shine of the full moon and the candles of joy for those who gave me the strength and determination to continue the path and were a reason to continue my studies for those who taught me patience and diligence in my mother dear to my heart rezige al hadda

I dedicate my diploma to the Ramadani family, as well as my grandmother, my uncle's house and my aunts

To my brothers, my support in this life, Miloud, Abd al kader

To my little sisters who supported me in my life's journey, and they supported Hinda, Khadidja, Jihad

To the friends of a lifetime and the soul of the path To my relatives who were more than friends to me To my brothers who were not fathered by my mother for their support in difficult times and as long as they are kept by my side throughout my university career Ibrahim, Khadidja, Ferial,

To my friends also Shahinaz and Fatiha

To dear Nour, if they had not submitted this work,

For the master's degree in Professional Production 2023/2024

RAMDANI Gadria

Abstract:

well integrity is the application of organizational, operational, and technical measures to lower the potential risk of an uncontrolled avoid of formation fluids at any point in a well's life cycle. The objective of this work is to define policies and strategies of well integrity, and management of annulus pressure in hassi messaoud (HMD)field.This work requires that annulus pressures beined in the minimum and maximum operating pressure envelope methods for theoretical calculations of maximum pressure limit are discussed.the calculation of maximum permissible surface annulus pressure (MAASP) is done by three methods API, Eclipse and ISO methods to define the method that gives us more secure results which is: ECLIPSE method

Keywords : Integrity, Annulus , pressure, well

Résume :

L'intégrité d'un puits est l'application de mesures organisationnelles, opérationnelles et techniques pour réduire le risque potentiel pour éviter incontrôlé des fluides de formation à tout moment du cycle de vie d'un puits l'objectif de ce travail est de définir des politiques et des stratégies d'intégrité des puits et de gestion de la pression annulaire dans le champ Hassi Messaoud (HMD).Ce travail nécessite que les pressions annulaires soient comprises dans l'enveloppe de pression de fonctionnement minimale et maximale. Les méthodes de calcul théorique de la limite de pression maximale sont discutées. Le calcul de la pression annulaire superficielle maximale admissible (MAASP) se fait par trois méthodes API, Eclipse et ISO pour définir la méthode qui nous donne des résultats plus sécurise qui est : Méthode ECLIPSE

Mots clés : Intégrité, Annulaire, pression, puits

ملخص:

سلامة البئر هي تطبيق التدابير التنظيمية والتشغيلية والفنية لتقليل المخاطر المحتملة لتجنب سوائل التكوين بشكل غير منضبط في أي نقطة في دورة حياة البئر الهدف من هذا العمل هو تحديد سياسات واستراتيجيات سلامة الآبار وإدارة الضغط الفراغي في حقل حاسي مسعود(HMD) . يتطلب هذا العمل أن تكون الضغوط الحلقية ضمن الحد الأدنى والحد الأقصى لضغط التشغيل. ومناقشة طرق الحسابات النظرية للحد الأقصى للضغط. يتم حساب الحد الأقصى للضغط الحلقي السطحي المسموح به (MAASP) من خلال ثلاث طرق API وEclipse وISO لتحديد الطريقة التي تعطينا نتائج أكثر أمانًا وهي: طريقة ECLIPSE

الكلمات المفتاحية: النزاهة، الفراغي، الضغط، البئر.

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List of Abbreviations

SCP Continuous Casing pressure

CRI Cuttings Re-Injection

TAP Trapped Annular Pressure

MOP Maximum Operational Pressure
HPA High Pressure Alarm

OOC Offshore Operators Committee
LOT leak-off test

DHSV down hole safety valve

DST drill stem test

WIMS Well Integrity Management System

MDD Default designation method

MDS Simple Declassification Method

MDE Explicit Declassification Method

AP applied pressure

MD measured depthe

PSA Petroleum Safety Authority

FIT Formation Integrity Test

LCM Lost Circulation Material

AMV annulus master valve

AWV annulus wing valve

ACV annulus circulation valve

COV cross over valve

AVV annulus vent valve

PBR polished bore receptacles

BOP Blow-Out Preventer

WBE Well Barrier Elements

SSV Subsurface Safety Valves

ASV Annular Safety Valve

GLV Gas Lift Valves

TRSV tubing retrievable safety valve

General introduction

In recent years a lot of attention has been placed on the integrity of thousands of wells discovered worldwide for a variety of uses, including geological carbon sequestration, trash disposal, and oil and gas extraction .

The Well Integrity Management Program focuses on improving well management rather than just preventing integrity issues. This includes understanding what is below ground and its condition, forecasting potential outcomes, evaluating risks and their effects, and having backup plans in case the unexpected occurs.

To define well integrity policies and strategies, and to manage annular pressure in the Hassi massaoud field, we used quite significant data from the well and calculation of maximum permissible surface annulus pressure (MAASP) is done by three methods API, Eclipse and ISO methods to define the method that gives us more secure results

Our work is organized into three chapters:

The first chapter is devoted to the fundamental notions of well integrity, some cases of loss of well integrity, his consequences on the production, and risk assessment.

Second chapter about well barriers, their types, annular pressure surveillance and well integrity tests.

Last chapter involves the study of MD-525 wells with all the investigations carried out, the solutions to be made and MAASP calculation.

CHAPTER I: WELL INTEGRITY GENERALITIES AND CONCEPT

I.1.Well integrity definition:

According to Norsok D-010, well integrity is the application of organizational, operational, and technical measures to lower the potential risk of an uncontrolled avoid of formation fluids at any point in a well's life cycle.

This definition means that those in charge of organizing the drilling and completion of wells must find solutions that provide safe well life cycle designs that conform to the standard's minimal standards.

Another effect is that in cases where the equipment planned for use does not meet the standard, it will need to be qualified and improved before being used, and operating companies and service providers will be held accountable for this. Variations from the norm can be made in certain circumstances if the standard permits it.[1]

I.2- Background and History:

Over the last thirty years, there has been a notable technological advancement in the drilling business. The Norwegian Continental Shelf's initial platforms were created with wells that are three kilometers away from the multiple platforms were often needed to cover a vast reservoir.

The historical record demonstrates several significant instances of well integrity failings, including the BP Macondo blowout in the Gulf of Mexico in 1979, the Saga Petroleum subterranean accident in 1989, the Statoil blowout on Snorre in 2004, and the Phillips Petroleum Bravo blowout in 1977 .

In 2010. The current emphasis on well integrity in the oil and gas sector is largely due to these serious mishaps, which serve as a reminder of the possible risks involved.

The Petroleum Safety Authority conducted a pilot study in 2006, revealing that 18% of wells had integrity failures, issues, or uncertainties. 7% were shut in due to these issues. Later studies suggested that each fifth production well and third injection well may suffer from well integrity issues. Old wells had few issues.[1]

I.2.1-- loss of well integrity:

The probability of failure is influenced by its underlying reasons, such as a 100-year ocean wave used in offshore constructions. It provides a mean to compare expected frequency to severity. However, likelihood is also significant if feasible. The PSA study did not address the likelihood problem, as production tubing broke down in many wells, making it likely that a tubing leak will occur. Controlling risk factors and identifying leaks early is crucial.

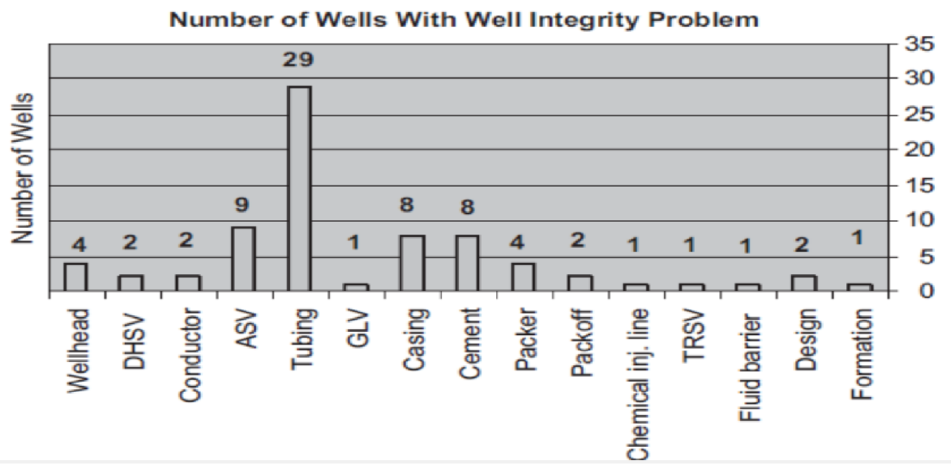


Figure I.1: Example of barrier element failures [2]

I.2.2- loss of well integrity consequences:

The most evident effects are blowouts or leaks, which can result in expensive and dangerous repairs as well as material damage, worker injuries, production losses, and environmental harm .

This demonstrates that maintaining well-integrity depends not only on the durability of the equipment but also on the whole procedure, the organization's capability and resources, and the individual's competency.

We shall address well integrity from a technical standpoint in the following, but bear in mind that problems with well integrity can arise from any other factor, such as an incorrect operational choice.

I.2.3: Some cases of loss of well integrity:

- **Case 1: Failure of surface casing and drop of wellhead:**

It was because of a salty water that had being produced over the oil flow. The connection with the conductor downside of the wellhead was lost by corrosion.**[2]**

The consequences were :

1)The entire platform production stopped for one month resulting in huge production losses .

2)The failed well was back into production after one year .

3)There was a high repair cost for the well .

4) Future installation procedures will not accept open return ports.

- **Case 2: Failure of production casing hanger:**

Several problems occurred in a production well during a workover .

- The production casing hanger failed during a pressure test
- The tubing hanger failed during a pressure test
- The tubing running tool failed under operation

The oil company reported a tubing hanger failure during installation. The hanger was locked down and a test plug was landed in the tailpipe. When pressure was raised to 3500 psi, the hanger pushed past the hold down bolts.

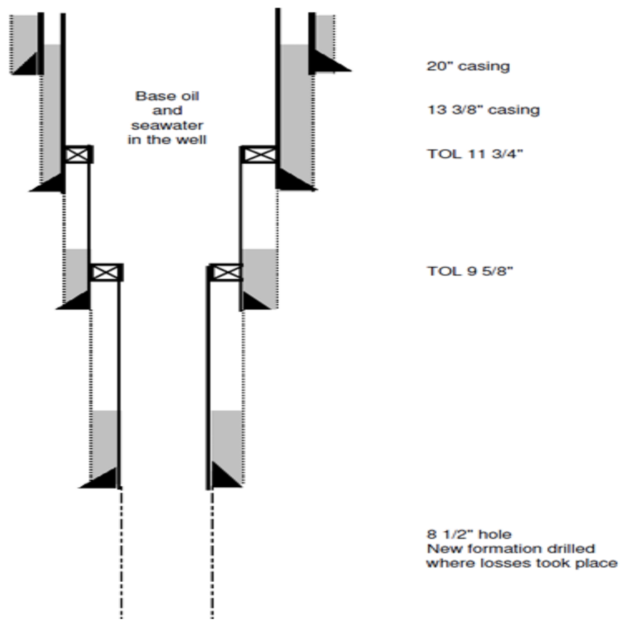
The consequences were :

- High cost of well repair
- The many wellheads of this type can only be used within original specifications .
- Axial load upgrade acceptance was reversed; the casing and tubing hangers can only be used with initial specifications .

- **Case 3: Loss of wellbore:**

A well was drilled and cased, with an intermediate liner and a 9 5/8” drill-in liner. Total losses were encountered, with high mud losses. The rig tried to keep the hole full with pre-mix and base oil, then seawater. Attempts to stabilize the well were unsuccessful, and the annulus was bullheaded with seawater. Pressure was bled off, and wireline equipment was rigged up.

Figure I.2: Well with circulation losses and well control [2]



The consequences were :

- The well had to be sidetracked at high cost
- During the loss/well control events, well barriers were not in place at all times .
- The load imposed on the well during the well control incident exceeded the test pressure that had been applied.
- The barriers were not verified

- **Case 4: Gas leaks in tubing strings:**

In 14 subsea wells, a major operator reported tubing leakage. The wells didn't need to be shut off because the leakage was tiny. The wells are less accessible because they are submerged. There will be a review in the sections that follow.

Table I.1: Number of wells with reported tubing leaks **[3]**

Oil producer	Oil producer/Gas injector	Gas injector
7	3	4

There are many possible sources for leaks and these will be discussed below.

A) Leak in subsea valves:

-These valves could be eroded or damaged by flow particles, which would cause leaks. The valves listed below are in use:

-annulus master valve (AMV)

-annulus wing valve (AWV)

-annulus circulation valve (ACV)

-annulus vent valve (AVV)

b) Leak in the PBR:

All wells have 7” polished bore receptacles (PBR) installed. The installation procedure used is as follows :

-Perforate in overbalance

-Run liner stem, tubing plug, production packer and PBR in separate run .

-Run PBR seal stem and tubing in separate run. Depth based on pipe tally, not on weight.

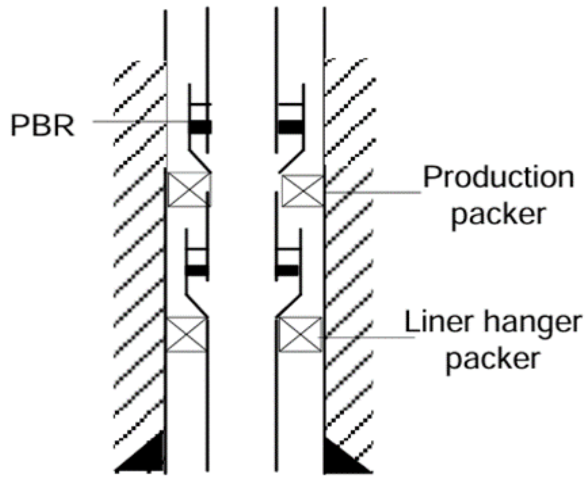


Figure I.3: Sketch showing the tubing stinging into the PBR above production packer [7]

- **Case 5: Production casing failure**

A leak resulted from the failure of the production tube and casing in a North Sea well. A system leak was discovered by pressure testing. At 700 meters, the casing gave way, displaying a 28% decrease in collapse resistance as well as a 30% decrease in collapse resistance.

The consequences of this incident were:

- high cost of replacement for both production tubing and casing.
- High production loss cost due to the well's protracted closure.
- Enhance the qualification process and protocols for casing tests.

- Boost the processes for casing inspection and control.

I.3- Well Construction and Field Development:

I.3.1- Well Types and Well Life Cycle:

A well is the conduit that connects the reservoir rock to the equipment on the surface, enabling hydrocarbon fluids to circulate safely and with as few problems as possible. Each well has a life cycle, which is the well's age at the time of drilling Then finally the production stage until the end.

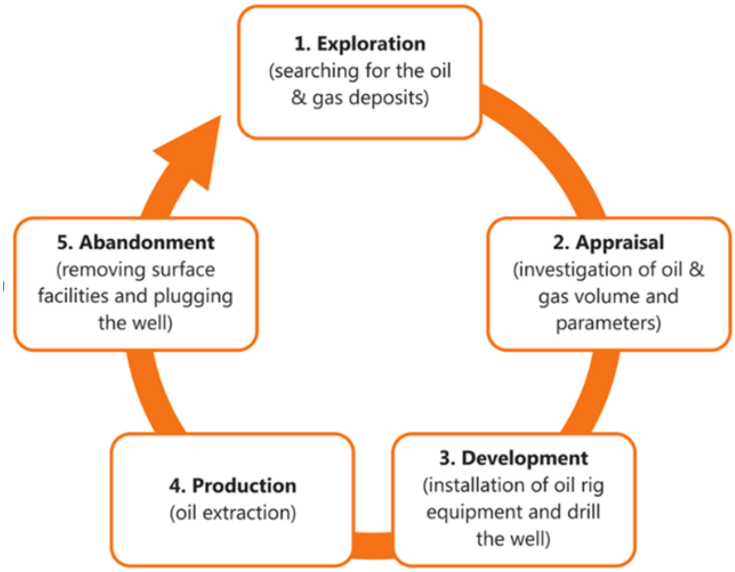


Figure I.4: well life cycle[3]

There are basically two types of wells :

Exploration well: The main purpose of an exploration well is to find potential reservoirs for future development and production. These wells are normally plugged after logging / testing .

Production / injection wells: After drilling, these wells are completed for production and / or injection. Water or gas is normally injected into the reservoir to maintain pressure. After the production phase has ended, plugging and abandonment of the well takes place.

I.3.2-. Subsea drilling :

Drilling fluid circulates through the drill string, bit, and annulus, with casing strings used to stabilize the borehole. A typical casing program for a subsea well involves drilling a 36" hole for a 30" conductor, a 26" hole for a 20" casing, and a 20" casing connected to the wellhead. Cement is typically displaced to the wellhead, and mud recovery systems may be used to avoid drilling fluid return to sea.

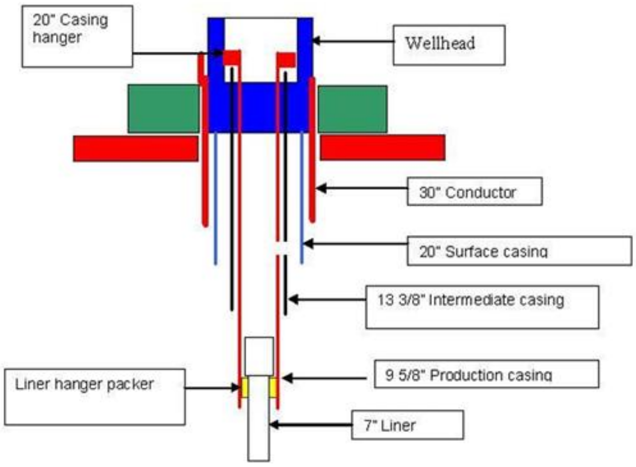


Figure I.5- Typical casing program for a subsea well[3]

I.3.3-Platform drilling:

Because the vessel is stationary and the BOP is situated on the platform, maintenance and operations are easier when drilling a well from a seabed-supported platform as opposed to utilizing a MODU. Normally, the conductor inserted by driving the pipe into the top hole created using the hammer technique. The drilling then proceeds essentially as it did in the previously mentioned underwater drilling. The primary benefits include easy wellhead access, annulus monitoring access, and less expensive and complex well intervention.

I.3.4-Subsea Well Completion

In order to get the well ready for production or injection, well completion is necessary. The following are typical steps :

1 .The production packer is in place, the tubing hanger has landed, and the production tubing is RIH. Next, a pressure test is performed to confirm the completion's integrity .

2. A steel block, or X-mas tree, is affixed to the wellhead and equipped with fluid control valves

3 .The downhole and X-mas tree functions are managed by a control umbilical .

4 .The X-mas tree is connected to a pipeline system for injection or production.[10]

I.3.5-Types of X-mas trees for subsea wells:

The main technique for sealing a well and managing fluid flow during production or injection is provided by the subsea X-mas tree. A subsea tree is made up of a number of valves and fittings that are used to regulate the hydrocarbon flow coming from the well. The valves let the well to be externally sealed off when required. The subsea X-mas tree also serves as a vertical access point for well intervention, a chemical injection point, and well monitoring sites.

There are two main types of X-mas tree :

•Conventional (dual bore / vertical) X-mas tree: The tubing hanger and tubing is suspended in the wellhead .

•Horizontal X-mas tree: The tubing hanger and the tubing are suspended in the X-mas tree .

I.3.6-Surface well completion:

The different casing strings are supported in the wellhead in separate casing hanger spools with annulus access for pressure monitoring .

The X-mas tree is stacked on top of the wellhead as illustrated in Figure below

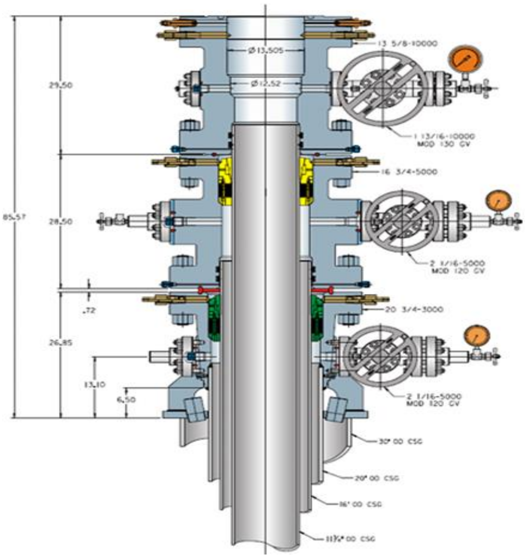


Figure I.6-Surface wellhead system (FMC Energy Systems**)[3]**

I.4-: Hazard Assessment :

The following factors will be taken into consideration for the risk assessment:

I.4.1-Location:

- o the location of the well can influence the risks posed by a well in terms of :
- o the geographical location, e.g. onshore or offshore, urban or remote ,
- o installation / type of well, i.e. platform, submarine, installation or location, inhabited or uninhabited ,
- o the concentration of the pool, e.g. single well, cluster of multiple wells (exists on offshore).

Therefore, the following factors should be taken into account:

- the proximity of the well to workers and the potential health and safety effects of any violation of the integrity of a well barrier envelope caused by any anomaly;
- the proximity of the well to the environment and the potential environmental effects of any damage to a well's envelope caused by any anomaly;
- ability to access the area near the well to mitigate the effects of any potential loss of integrity.

I.4.2-Outflow potential :

The ability of well fluids to flow to the surface or to an essential underground place in the well, with or without the help of an artificial elevator, can cause loss of well integrity and impact of the sources and flow routes.

I.4.3-Well effluent:

The composition of the well's effluent influences the risks posed by a well, both in terms of the effects of well effluents on the barrier envelopes and the health, safety, and environmental risks associated with the potential discharge of these effluents in the event of loss of integrity in the well.

The risk assessment associated with any potential abnormalities concerning:

- acidic components ;
- corrosive components;
- toxic components ;
- carcinogenic components ;
- emulsion and hydrate formation.

I.4.4-External environment:

The integrity of pipes is affected by potential leakage and effluents, and exposure to external environments can lead to potential integrity risks. These risks can be independent of production or injection intervals.

Factors that can affect the integrity of pipes include external:

- corrosion of structure components ,
- exposure to corrosive fluids,
- impact of cyclic and/or thermal charges on soil resistance and structure ,
- external charges associated with soil movements.

I.5-Risk assessment techniques for well integrity:

An assessment of the well integrity risks associated with the planned operation should be carried out. The risk of loss of integrity of the well control incident must be assessed, when assessing the well integrity risk, the primary WEBS loss modes and the availability of the secondary well barrier must be taken into account, if a well Barrier is degraded, the risk assessment should be carried out taking into account the following elements:

1 -Cause of degradation.;

2 -Climbing potential.;

3 -Reactivity and loss mode of primary barriers.;

4 -Availability and accessibility of secondary barriers WEBS;

5 -General plan for restoring or replacing degraded well barriers (technical and chronological).

An on-site safety spots analysis should be performed for:

1- New or non-standard operation.;

2 -Operation involving the use of new technologies or modified equipment.;

3 -Dangerous operations.;

4- Changing real conditions can increase risk.

I.6-Meeting the Well Integrity Challenges:

The range of well integrity problems experienced Internationally is widespread and different issues are more prevalent in different parts of the world. The most Frequently reported well integrity problems are:

O Sustained annulus pressure ,

O Completion string leaks ,

O Wear/corrosion/erosion within the completion String ,

O Casing corrosion ,

O Scaling ,

O Well head movement ,

O Xmas tree and wellhead safety critical element (SCE) leaks.

CHAPTER II: WELL BARRIERS AND WELL INTEGRITY METHODS

II.1. Well Barriers – definitions, classification, and requirements:

II.1.1- Key concepts and definitions:

Well barrier: An envelope composed up of several dependent barrier sections that keeps gases or liquids from accidently leaving the formation and rising to the surface.

II.1.2-The main objectives of a well barrier:

- Prevent any major hydrocarbon leakage from the well to the external environment during normal production or well operations .
- Shut in the well on direct command during an emergency shutdown situation and thereby prevent hydrocarbons from flowing from the well.

II.1.3-Well Barrier Requirements:

A well barrier's efficiency can be described by its :

- **Functionality:** the expected functions and timelines of the barrier
- **Reliability** (or availability); the probability of accomplishing the necessary unctions within the designated time frame and under the defined operating conditions.
- **Survivability:** the barrier's capacity to sustain stress under the designated demand scenarios .

II.2- Technical well barriers:

II.2.1-- Well barrier philosophy:

The general well barrier philosophy states that appropriate mechanical well barriers must be placed in the wells to stop uncontrolled outflow from the reservoir. Furthermore, there is a general rule that no one component breakdown should result in unacceptably dire outcomes .

In practical terms, this means that a well must have two well barriers set up against the reservoir, and that these barriers must be as independent of one another as feasible. Furthermore, adequate barriers must be installed to prevent limited volumes, such as outflow from annulus A in gas raised wells .In addition, primary and secondary well barriers can be illustrated using the Swiss cheese model.[10]

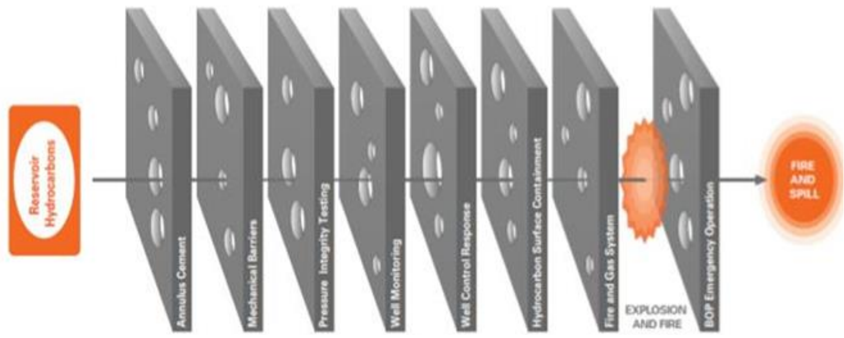


Figure II.1: Swiss cheese model - barriers breached in Macondo field[7]

II.2.2-Typical barrier elements description

The well is protected against undesirable consequences by a variety of barriers, both natural and artificial, that can be assembled inside it. These barriers include:

a) Natural barriers: The formation rock serves as an efficient barrier that keeps the well safe from harmful formation fluids such saline water and others by acting as a container for hydrogen ions. But not every type of formation rock may function as a reliable well barrier element since there are certain requirements that must be met.

You will see that the formation is a component of the envelope in the majority The formation must be able to keep out gases and liquids throughout the duration that it is being utilized as a barrier in order to be used as a component of the barrier envelope . [10]

b) Artificial barriers

In addition to the formation influence on the well, a number of pieces of equipment can be added to the wellbore or well surface to ensure the well's protection, such as:

1 .Cement Casing:

NORSOK D-010 states that the cement barrier needs to have the following characteristics :

a) Impermeable;

B) Durability of integrity;

c) Not contracting;

d) Ductile: Capable of resisting impact and mechanical loads, not brittle.

Usually, this test is a FIT test. The first step following the drilling of a casing shoe track is a Formation Integrity Test (FIT), which evaluates the strength and integrity of a newly formed formation. For the purpose of drilling a well and later work, a precise assessment of the formation and a casing cement job is crucial.

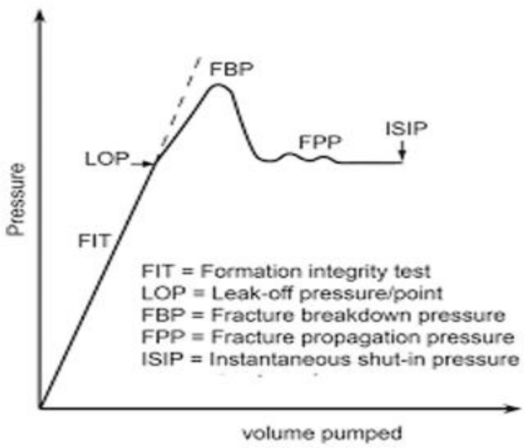


Figure II.2: FIT test plotting.[2]

2.Casing Cement Plug :

Together with the cemented casing string and exterior formation integrity, the casing cement plug is typically utilized as a barrier element for permanent abandonment. For this reason, the cement's characteristics must match those of casing cement.[7]

3.Production packer:

A production packer is an essential component of a well's completion string serving as a seal between the casing or liner's inside and the outside of the production tubing. The production packer is often a component of the main barrier in a well and is used to shield the casing from pressure and produced fluids.

For this reason, it is crucial that the production packer be positioned correctly in the casing or liner in order to preserve well integrity and have a safe well.[7]

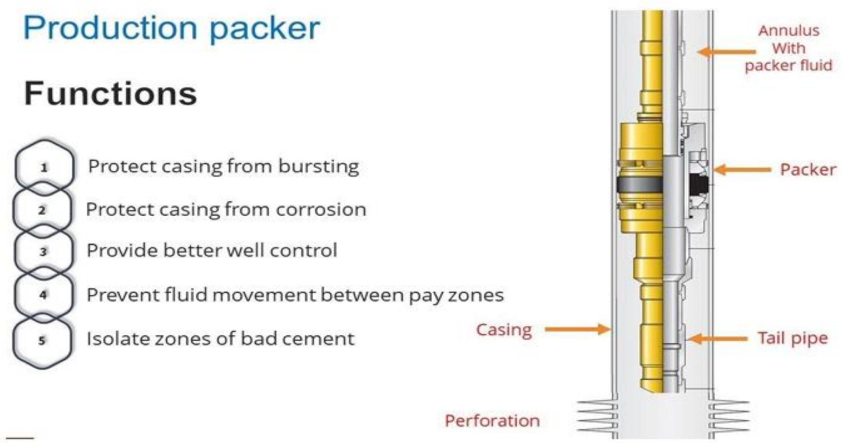


Figure II.3: production packer[3]

II.3- Operational well barriers:

II.3.1- General about operation well barriers:

The status of well barriers is to be known by monitoring the individual Well Barrier Elements (WBE) of the Well Barrier Envelopes during the production life of the well .

Well barrier integrity is commonly monitored by registration of annulus pressure and frequent leak testing of well barrier elements .the following requirements have been specified in NORSOK D-010 :

a) Downhole safety valves, production tree valves and annulus valves shall be regularly leak tested.

b) The pressure in all accessible annuli (A, B and/or C annuli) shall be monitored and maintained within minimum and maximum pressure range limits as defined in the completion design and presented in the hand-over or other relevant field documentation for the well .

c) Registered anomalies shall be investigated to determine the source of anomaly and ifrelevant, quantify any leak rate across the well barrier .[2]

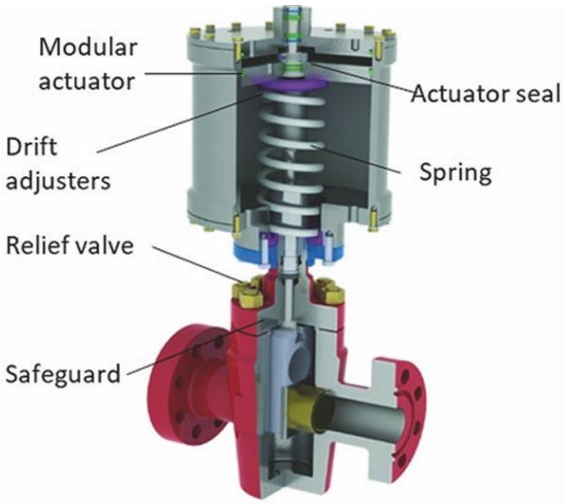
II.3.2- Valves and Christmas Trees:

II.3.2.A-Subsurface Safety Valves (SSV):

Subsurface Safety Valves (SSVs) must meet the following criteria :

- Leak tests must be performed on the valves at predetermined, regular intervals .
- In order to comply with API RP 14B criteria, downhole safety valve testing must be approved .

If it is not possible to measure the leak rate directly, it must be determined indirectly by monitoring the pressure in an enclosed container downstream of the valve.



FigureII.4: Subsurface Safety Valves[3]

II.3.2.B-Annular Safety Valve (ASV):

A downhole safety valve must also be placed in gas raised wells on the annulus that contains hydrocarbons. According to NORSOK D010, an ASV needs to be placed in the well completion string :

1)with the possibility of hydrocarbon injection into the annulus and perforations above the production packer, this might momentarily accelerate a formation .

2) Where the A-annulus is employed for gas lift, barring the existence of any additional downhole well barrier that qualifies beyond what is present in the wellhead area

3)When analysis and/or risk assessment shows that any hydrocarbon volume in the annulus might have unacceptable consequences if the wellhead/surface well barrier is lost [7]

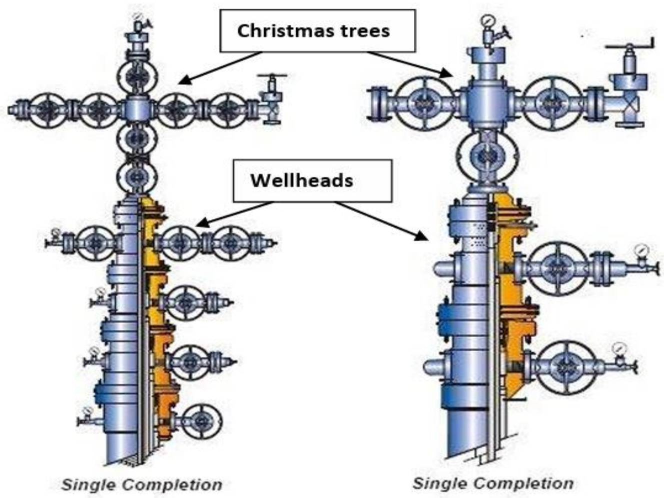
II.3.2.C-Wellhead and Christmas Tree:

A Christmas (X-mas) tree consists of a series of valves, spools, a choke, and connection. The X-mas tree is used in production and injection wells to safely control the producing flow.

Nowadays, there are two primary varieties of wellheads in use:

- Stacked: a setup in which one casing string is supported by each wellhead. New casing heads stack together when a casing string is run again.

- Multi-bowl/unitized: a setup in which multiple strings of casing can be held by a single casing head mechanism.



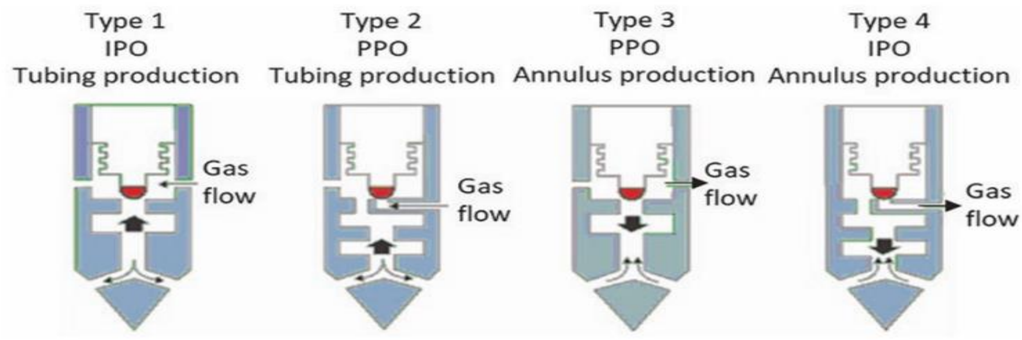
FigureII.5: Examples of wellheads with Christmas trees installed.[2]

II.3.2.D-: Annulus Valves:

A positive pressure should generally be maintained in each annulus with a pressure difference between annulus strings in order to provide ongoing assurance of annular integrity as any pressure drop or rise or equalization between annuli is then obvious to the extent that investigation action can be requested.

II.3.2.E- Gas Lift Valves:

In gas lift operations, the gas flow from the annulus into the tube is managed by the gas lift valve (GLV). Compressed air, water vapor, or other vaporous bubbles are pumped into the tubing as part of the artificial lift technique known as "gas lift," with the intention of lowering the hydrostatic pressure within the "A" annulus relative to the inner tubbing hydrostatic pressure. GLV is a critical well barrier as it serves as a direct connection between the annulus and tubing.



FigureII.6: Typical gas lift valve types[2]

II.3.3-Pressure Monitoring :

II.3.3.A- Annulus Pressure Surveillance Principles :

Annulus Pressure Management involves managing pressure vessels within a well's operating parameters, including completion and inner annuli. Norsok D-010 mandates monitoring pressures in accessible annuli to maintain well barrier integrity. Accurate, representative, and frequency-appropriate tracking is crucial for monitoring well parameters.

II.3.3.B- Types of annular pressures:

Thermal pressures, applied pressures, and sustained casing pressures are the three primary forms of annular pressures seen in wells. We're going examine these .below:

- **Thermal pressure**

Thermal pressure in wells with fluid-filled enclosed annuli varies during warm-up and cool-down phases. Well temperature, pressures in nearby annuli, and flow rate affect annuli pressures during trouble-free normal operation. The temperature differential between injection fluid and well's surrounds determines annulus behavior. After starting a well, annulus pressures stabilize at pre-closed levels

- **applied pressure (AP)**

An annulus can be exposed to pressure for a number of reasons, such as gas lift, Cuttings Re-Injection (CRI), bull heading load compensation, or annulus assistance .

Observing Tests for pressure containment may also contribute to the imposed pressure. To make sure that thermal pressure does not cause MOP to be exceeded, care must be made to ensure that this pressure is bled down after testing to an appropriate value.

- **Continuous Casing pressure (SCP)**

Sustained Casing Pressure (SCP) is a potential issue in wells due to variations in annulus pressure behavior, originating from pressure sources like reservoirs or annulus. It can develop due to well barrier deterioration, leaks from formations, cement, wellhead seals, casing, or tubing.

II.3.3.C- Maximum Operational Pressure (MOP) settings:

A Maximum Operational Pressure (MOP) for an annulus should be defined in addition to the MAASP acceptance requirement for annular pressure .

The maximum pressure that can be applied to an annulus without risk is known as the MOP persistent foundation. For each specific annulus, the MOP is determined in relation to the ambient pressure at the wellhead. For a particular annulus, it sets a safety threshold for evaluating the ultimate integrity limit. The MOP should, in general, not be greater than 80% of MAASP .[2]

II.3.3.D- Management and Control :

❖ **Reaching High Pressure Alarm (HPA) values**

Alert for pressure buildups and set the High-Pressure Alarm (HPA) at the MOP. If pressure exceeds HPA, determine if it's sustained by influx, leak, or thermal production. Drain pressure to less than MOP, minimizing bleed-offs.

If an annular pressure is bled down, the following parameters are to be recorded :

•Pressure before / after .

•Type and estimate of volume of fluid (gas/brine/oil/condensate) .

•Density of fluid in case of liquid .

• Fluid chemical analysis to identify source.[4]

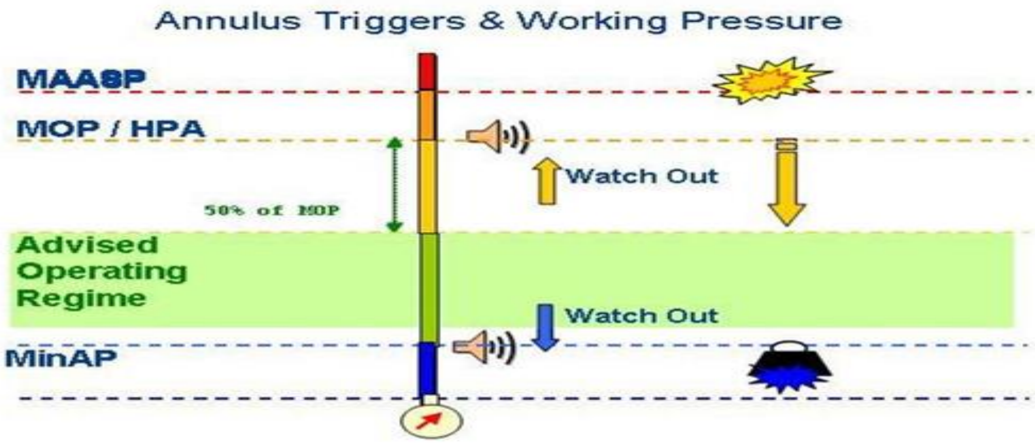


Figure II.7: Annular Triggers & Working Pressures.[4]

II.4 –MAASP Calculation :

The maximum allowable annular surface pressure (MAASP) is the maximum pressure measured at the well head that an annular can hold, without compromising the integrity of the barrier elements of that annular.

annular pressure exists in almost all wells and can vary depending on how a well works, with thermal effects being the main cause of pressure change. The annular pressure can be tolerated up to the maximum value established by the calculations. Potential problems caused by ring pressure determine the criteria used to define MAASP values.

There are three potential losses of integrity that can be caused by excessive ring pressure

- Breakdown of the training at the casing sabot.
- Casing breakdown.
- Collapse of the internal casing/ tubing.

The pressure for each of these failure cases must be calculated, the methodology for each calculation is described below. The lowest of these three calculated values will provide a theoretical maximum value during which a failure could occur.[4]

There are three methods for calculating MAASP:

- Eclipse Method,
- ISO Method (see Annex A),
- API Method.

II.4.1-MAASP calculation procedure:

II.4.1.A-Eclipse Method:

The procedure for calculating the theoretical maximum pressure is as follows:

- Define the characteristics of the annular fluid and pressure and temperature conditions.
- Define the traction resistance characteristics of the pipes.
- Defining cases for sensitivity analysis [5]

- **Formation Breakdown:**

This value is calculated on the basis of the pressure, established during the drilling phase, necessary to cause a fluid leak or a formation break at the outer pipe shaft of the ring concerned. This pressure is determined by the formation integrity test (FIT) or leak test (LOT) performed after piercing the cement into the sabot.

the theoretical maximum pressure is the difference between the pressure required to break the formation and the hydrostatic pressure exerted on the sabot by the fluid column in the annular

This can be calculated using the following formula:

$$\mathbf{MAASP_{FBD} = 0{,}9 \times TVD \times 0{,}433\ (FG\text{-}MG)} \quad \ldots\ldots \mathbf{Eq(II.1)}$$

where :

$MAASP_{FBD}$: MAASP Training Breakdown (psi)

FG: Gradient of formation breakdown (SG)

MG: Gradient of mud in the ring (tubage interne, SG)

TVD: Vertical Depth of Outdoor Pipe Sabot (ft)

Density (SG) conversion to psi/ft gradient: 1 SG = 0.433 psi/ ft

A 10% safety factor is included in this calculation.

In the case that no FIT or LOT has been achieved at the piping sabot level, it is preferable to assume the values obtained from the regional wells in the equivalent formation.[4]

- **Casing burst:**

The theoretical maximum pressure for preventing an outer pipe explosion in an annular space is calculated by comparing the pressure required to break the outer pipe with a hydrostatic freshwater gradient and the pressure exerted on the sabot by the hydrostatic fluid column.

The value can be calculated using the following formula:

$$\mathbf{MAASP_{burst} = (Pb / 1.1) - [TVD \times 0.433 (MG - 1.0)]} \quad \text{……………………….Eq(II.2)}$$

Where:

$MAASP_{burst}$: Pipe Burst (psi)

Pb: External Pipe Burst Pressure (psi)

MG: mud density before cementing of internal pipe (SG)

TVD: Vertical Outdoor Pipe Sabot Depth (ft)

- **Pipe crushing:**

The theoretical maximum pressure to avoid internal pipe crushing of a annular is calculated by comparing the pressure required to crush the internal pipe with a hydrostatic freshwater gradient in the external ring and the pressure exerted on the internal piping by the hydrostatic fluid column. The annular is assumed to be filled with water in the worst case.

The value can be calculated using the following formula:

$$\mathbf{MAASP_{collapse} = Pc - TVD \times 0.433 (MG - 1.0)} \quad \text{…………………………….Eq(II.3)}$$

Where:

$MAASP_{collaps}$e: Pipe crushing MAASP (psi)

Pc: internal pipe crushing pressure (psi)

MG: mud density before internal piping cementation (SG)

TVD: Pipe sabot vertical depth (ft)

- **Tubing crushing:**

This theoretical maximum pressure is the maximum permissible pressure to avoid tubing crushing of the "A" annular. Vacuum tubing is considered the worst scenario. The value can be calculated using the following formula:

$$MAASP_{Tbg\ collapse} = PC - (0.433 \times TVD \times MG) \quad \text{Eq(II.4)}$$

where :

$MAASP_{Tbgcollapses}$: Tubing crushing MAASP (psi)

PC: Pipe crushing pressure (psi)

MG: Density of the supplement fluid (SG) .

TVD: Vertical Packer Depth (ft)

II.4.1.B-API 90-2 method:

This method is based on the rupture and crushing of the tubular also declassification factor of each component [3]

- Head of well .
- Complementary equipment .
- Tubular (Tubing & tubage).

The pressure at which each of these failures must occur must be calculated. The lowest of these calculated values will provide a maximum theoretical value at which a failure could occur.

- **Well head section:**

The MAASP for the well-head component for the under evaluation annular is determined as follows:

$MAASP_{WH}$ = 0,8 PW……………………………………………..…Eq(II.5)

PW: is the minimum operating pressure of the section of the well head supporting the outer pipe after installation or the maximum test pressure of that section.

A safety factor of 80% of PW is used for the calculation.

- **Completion Equipment**

The MAASP for filling equipment for the annular under evaluation is determined as follows:

$MAASP_{equcomp}$= 0.8 (Pcc- ∆Pcc)…………………………...………Eq(II.6)

Where:

Pcc: Maximum internal pressure that the equipment is designed to contain .

Pcc: Differential pressure through the filling equipment has its depth .

A safety factor of 80% is used for the calculation.

- **Formation Breakdown :**

The MAASP for formation break pressure or fracture is based on the minimum formation fracture gradient (FG) determined by a training integrity test (FIT) or a leak test (LOT) at the sabot level. These calculations are only applicable to a training ring .

The MAASP training break for the under-evaluation annular is determined by the following:

$MASSP_{FB}$ = 0,8 [TVD (FG - MG)]…………………………………..Eq(II.7)

Where:

TVD: Vertical depth of the sabot

MG: Gradient of mud .

FG: Training break gradient

- **Tubular:**

The MAASP of tubular components for the under evaluation annular can be evaluated using the following methods, ranging from simple to complex :

- Default designation method (MDD);
- Simple Declassification Method (MDS);
- Explicit Declassification Method (MDE).

The well history and the data at issue will determine the approach that is selected. Various techniques can be applied to separate rings in the same well or to wells that are part of the same field.[4]

II.5- Organizational well barriers:

II.5.1: Responsibilities and roles :

The Petroleum Act mandates licenses for operators and partners to ensure compliance with rules. Operators bear exclusive responsibility for facilities and operations. Norwegian Continental Shelf (NCS) companies must have a management system and HSE control system, outlining roles, responsibilities, interactions, governing documents, standards, and reporting routes. Management systems can be categorized into operators and partners.[2]

II.5.2: Training and Competency :

Personnel involved in drilling and well operations are subject to specific training and competency standards outlined in NORSOK D-010 and the regulations. These prerequisites are not just to well integrity but also to well control and other activities that happen on a rig or platform.

This is because it's important to make sure that the staff members involved in these processes are qualified for the work at hand. The level of skill required for each position on the rig varies depending on the employee's position within the company.[2]

II.6-Diagnostic Methods: Integrity Tests

Maintaining the integrity of deep wells is crucial for public perception and environmental safety, especially for gas and oil wells. Fluids from reservoirs, primarily gasses, can originate from deep thermogenic sources, ensuring they are delivered to the surface safely.

Leakage hazards in wells can be identified through sustaining casing pressure (SCP) and surface casing vent flow (SCVF) measurements. Sealing annuli prevents SCVF but allows hydrocarbon buildup and pressure rise.

II.6.1-Leakage Detection Methods:

Gas leaks in wellbores often show up at the surface, indicating the need for monitoring. Common indicators include dead vegetation, standing water bubbling, and wellhead corrosion. Bubble tests can provide visual signals, while soil gas flux sampling can identify leaks by screening soil samples. [2]

Figure II.8. Visual evidence of gas leakage; gas bubbles coming from the wellhead**[2]**

Pressure sensing has several major advantages over other deep underground detection systems, including :

a. early detection capability,

b. cost-effectiveness,

c. appropriateness for continuous, automated, long-term deployment,

d. suitability for optimal sensing or targeted monitoring,

e. simplicity of its implementation.

II.6.2-Testing for SCP:

The Offshore Operators Committee (OOC) and the American Petroleum Institute (API) have collaborated to develop a recommended practice for gas flow beyond the casing, aiming to standardize industry knowledge on SPC issues.

SCP testing assesses well integrity at the wellhead without shutting down production. Local restrictions dictate how operators maintain wellhead annular valves, determining whether SCP is the target of routine integrity testing.

SCP testing, a method of detecting gas migration, is crucial in identifying leakage within wells, but its significance is limited and cannot confirm gas leakage into groundwater or pinpoint leak sources.[2]

II.6.3-Cement Integrity Testing:

The leak-off test (LOT) is a crucial hydraulic test in assessing the isolation provided by cement in a cement project. It involves drilling out the casing shoe and applying pressure to the interior casing, indicating poor cement work. The drill stem test (DST) also evaluates cement's isolation properties.

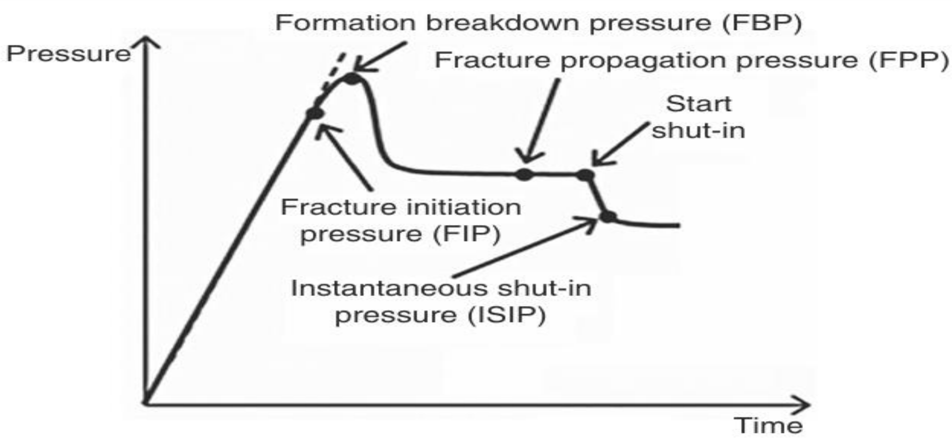


Figure II.9-Typical leak-off test curve. [2]

II.6.4-Fiber Optics:

The oil and gas sector began using fiber optic technology for distributed temperature sensing in the 1990s to log production along wellbores. DTS allows continuous temperature profiles with high resolution, monitoring well temperature progression without well intervention. Temperature anomalies may be related to fluid exchange or pressure changes.

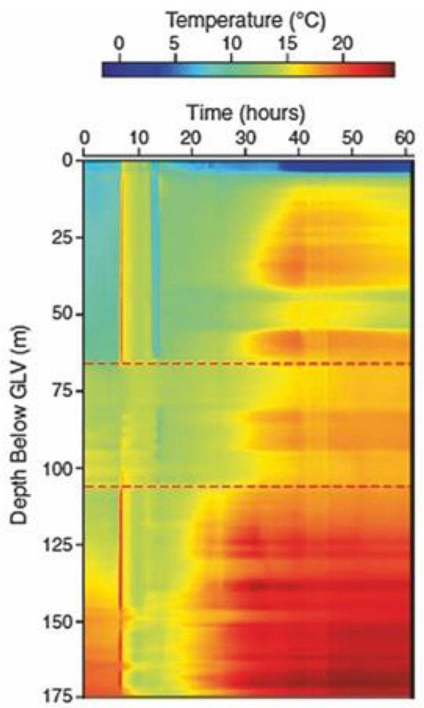


Figure II.10-Example of DTS measurement while cementing the wellbore for 60 h[7]

There are three ways to use fiber optics for wellbore integrity monitoring:

a. use passive acoustic techniques to listen for leaks in the vicinity of the wellbore;

b. examine and identify damage areas using nonlinear time-reversal elastic wave spectroscopy;

c. use fiberoptic sensing to track the evolution of strain and stress in areas close to the wellbore.

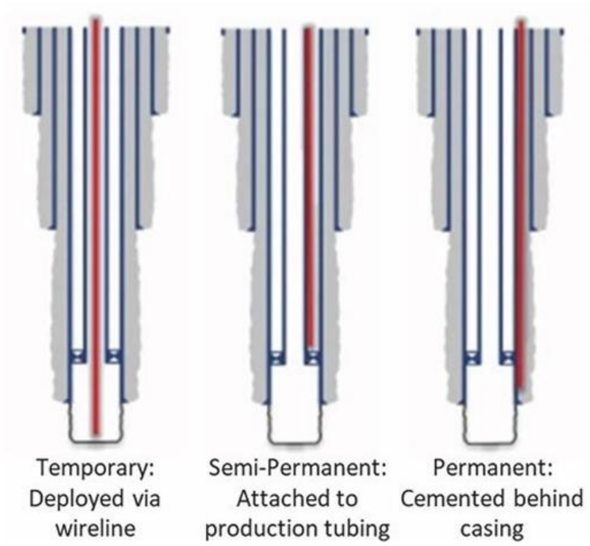


Figure II.11. Different methods of fiber optics deployment.[7]

II.6.5-Tracer Injection:

Gas tracers are essential tools for barrier checking, allowing for the location and monitoring of leaks. They can reveal faults within a matter of days to weeks, and are used in transport/dispersion investigations, leak detection studies, and material location, with two types available: radioactive and nonradioactive.

Radioactive tracers and nonradioactive tracers are substances that emit radiation, with radioactive tracers being a moving substance, while nonradioactive tracers are in gas or liquid phases.

II.6.6-Reservoir Monitoring:

Reservoir monitoring generally includes measurements of temperature, pressure ,flow rate, and constituents, as well as surface deformation, 4D seismic, and micro seismic, which no longer concern the well alone but consider the reservoir as awhole with the surrounding formations. These data can be used to chart the evolution of a heat front in 3D, detect reactivation of a fracture or fault, and inspect thecap rock’s integrity.

Chapter III:Case study-application of well integrity in HMD field

III.1-HASSI MESSAOUD FIELD PRESENTATION

III.1.1-Regional framework:

The Hassi Messaoud region is located in the central part of Algeria's Sahara, known for its productive oil wells mainly in the Cambrian reservoirs .

Hassi-Messaoud Field is one of the most complex fields in the world .

During geological history, this field has, on the one hand, undergone an intense tectonic evolution characterized by distinctive compressive phases. On the other hand, by the diagenetic transformation in the reservoir, when it was buried in geological time, until the depository took its present form or configuration .

III.1.2-Geographical location :

Hassi Messaoud Field is the largest oil field in Algeria, and is located approximately 850 km south-east of Algiers, 280 km southeast of Hassi R'Mel gas field and 350 km west of the Tunisian border (Fi gure 1-1), it covers an area of 2500 km2. He has as coordinates Lambert (LSA) :

X = [790.000 - 840].000] Est

Y = [110,000 - 150].000] North

It is limited to :

- To the northwest by the deposits of Ouargla [Gellala, Ben Kahla and Haoud Berkaoui].
- to the southwest by El Gassi, Zotti and El Agreb.
- To the south-east by Rhourde El Baguel and Mesdar.[9]

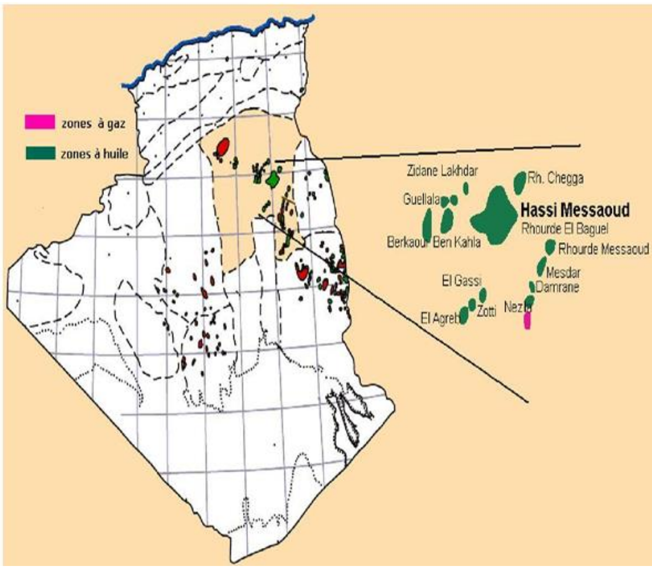


Figure III- 1: Geographical location of the Hassi Messaoud field[9]

III.1.3-Geological context

Hassi Messaoud Field occupies the central part of the Triasian province. By its surface and reserves, which is known for its productive oil wells mainly in the Cambrian reservoirs

Geologically, it is bounded: to the west by the Oued Mya Depression; to the south by the Amguid El Biod Mol. To the north by the Djammâa-Touggourt Structure; and to the east by the Dahar Highlands, Rhourde El Baguel and the Ghadames Depression.

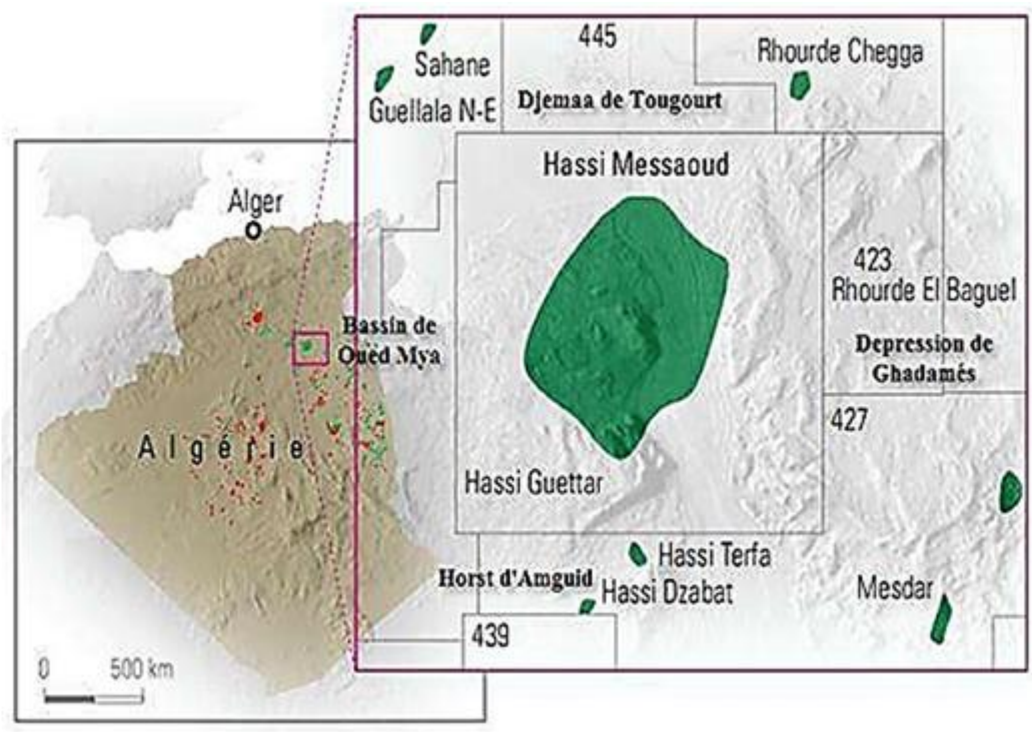


Figure III.2: HMD field geological context.[9]

III.1.4-HISTORY OF HASSI MESSAOUD FIELD:

Hassi-Messaoud was discovered by two separate companies: the Northern Field (OM, ON) CFPA and the Southern Field SN. Repal.

In 1946, the SN.Répal had begun its search through the Algeria Sahara, three years later, began geophysical prospecting by gravimetric recognition

In 1951, the first seismic shooting in the region of Ouargla. This recognition of the surroundings of the Saharan basins will allow SN.Répal and its partner the CFPA, to file their first application for a research permit.

The field of Hassi-Messaoud discovered on 16 January 1956 by SN. Répal whose first drilling (MD1) was initiated and implanted as a result of a seismic refraction companion.

On 15 January of the same year, this drilling allowed to discover the rocks of the oil-producing Cambrian at a depth of 3338m.

In May 1957, 7 km northwest of MD1, the CFPA confirmed the existence of a deposit by the OM1 drill.

From 1959 to 1964, 153 wells were put into operation. After the nationalization of hydrocarbons on 24 February 1971, the number of drills continued to multiply, reaching an average of 34 wells per year in 1977.

The reservoir has first undergone a development phase of “production zones” by vertical drilling until 2000, and a phase to develop structurally complex areas as well as reservoirs with low matrix properties (R2 higher) by non-conventional drilling, since 1997.

Production has been accompanied by several problems, including asphalt salts deposits, as well as gas and water injections.

The surface facilities consist of two industrial complexes that process all the fluids produced and the injection fluids.

III.1.5- HASSI MESSAOUD FIELD: ZONATION:

The evolution of fluid pressures depending on production has divided the Hassi Messaoud deposit into 25 production zones separated by off-zones

A production area is defined as a set of wells that communicate with each other.

This definition actually needs to be revised because field development and injection tests have shown that communication between wells belonging to the same area was not always obvious due to the heterogeneity of the reservoir and/or structural compartments due to failed blocks. (Zeghouani, 2010). Furthermore, if you compare production zone cutting and structural accidents, these limits most often correspond to NE-SW waterproof steering gaps. The poorly defined limits correspond to the non-water breaks from NW-SE to E-W). These areas can therefore be defined as purely geological by considering them as structural blocks separated by tectonic accidents. The geological outline of these areas is constantly revised in the light of new data obtained

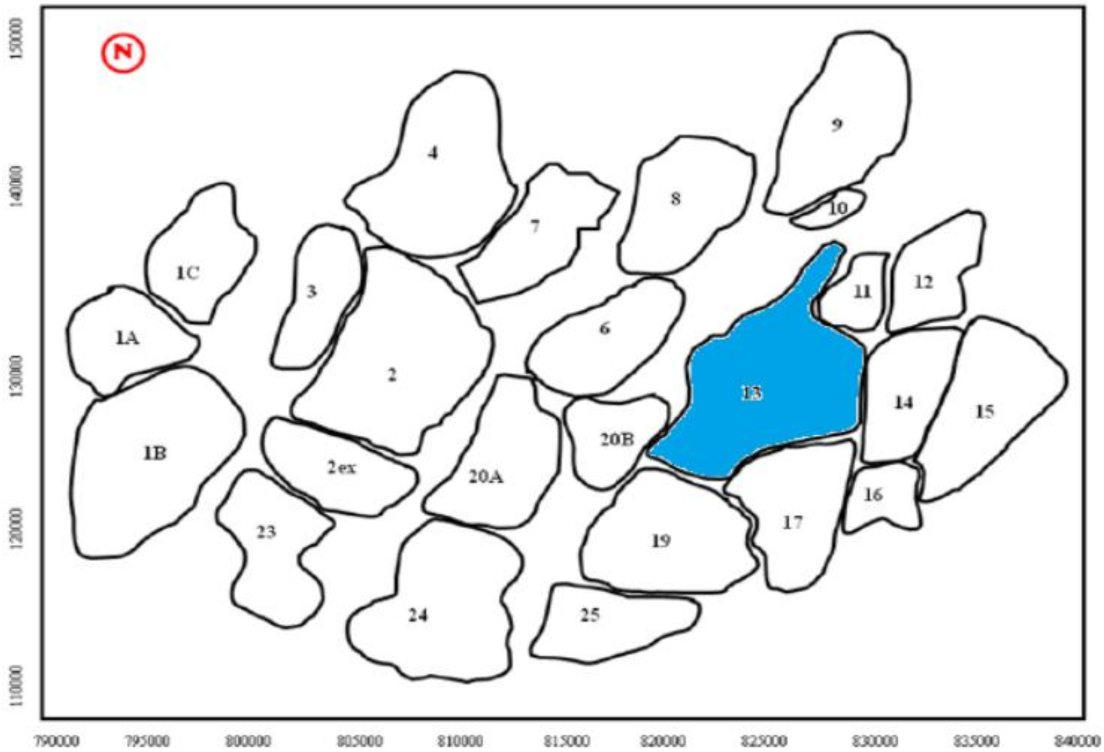


Figure III.3: Hassi Messaoud Field Zone[9]

III.1.6- HASSI MESSAOUD STRATIGRAPHY:

Hassi Messaoud’s field presents itself as a vast molecule on which much of the Paleozoic stratigraphic series is absent, thus removing any evidence of geological history for 230 million years.

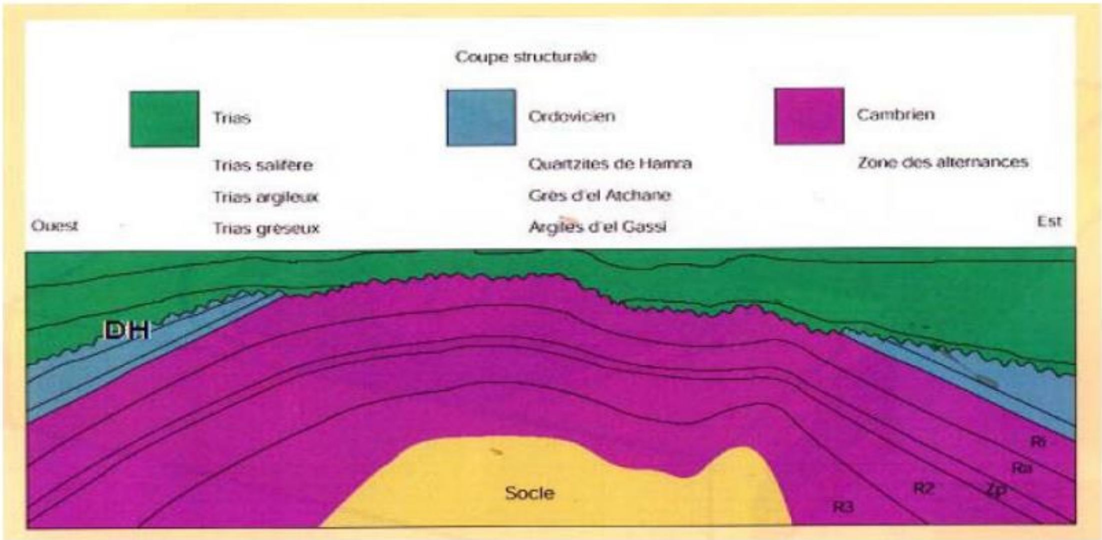


Figure III.4: East-West Geological Cut of Hassi Messaoud Field[9]

III.1.7-Description of the reservoirs:

Hassi Messaoud is located at a depth of between 3100 and 3380 m .

Its thickness extends up to 200 m, it includes three Cambrian-age shallow reservoirs, resting directly on the granite base. It is represented by a muddy series whose Paleozoic post erosion affects a part in the center of the field.

•**Ri:** Isometric area with a thickness of 45 m essentially fine-grain quartzite and tigillite. It corresponds to the D5 drain .

•**Ra:** Anisometric area with an average thickness of approximately 120 m, consisting of silico-argilled cement rods of medium to rough grains. It is subdivided into D1, ID, D2, D3, D4 drains from bottom to top, respectively .

•**R2:** Clay cement series with an average thickness of 80 m .

• **R3**: With a height of approximately 300 m, it is a very rough to microconglomerate series of clay, very clay based on the granite base that has been found at a depth of less than 4000 m. It is a pink porphyroid granite. It is divided into two sub-levels; R4c and R4ab.

III.1.8-Average petrophysical characteristics of the reservoir

The average petrophysical characteristics of the reservoir are shown in the following table:

Table III-1: Average petro-physical reservoir characteristics[9]

Réservoir	Kmin	Kmoy	Kmx (md)	Φmin (%)	Φmoy (%)	Φmax (%)	Swi (%)	Vsh moy
Ri	0.3	1	2	6	7	8	17	15
Ra	2	15	100	6	8	10	10	7
R2	1	2.5	7	-	10	-	17	20
R3		<1			0,11		0,17	30

The characteristics of the oils :

•The oil is light with a density of 0.8 (API = 45.4) .

•The deposit pressure is variable: 400 to 160 kg/cm2 .

•The temperature is about 118°C .

•The GOR is 219 m3/m3 except for gas wells where the GOR can reach 800 m3/m3 or more (in the case of OML 63 and OML 633) .

•The porosity is low on average: 5 to 10% .

•Permeability is relatively low: 2 md to 100 md .

•The viscosity is 0.2 pcs .

•The volume factor is 1.7 .

•A bubble point of 160 kg/cm2

Associated gas characteristics :

•Gas viscosity is 0.02 cp .

• Compressibility is 0.8 bar-1.

III.2-MD-525 well case study:

The MD-2525 was drilled in April 2000 in HMD central field. The well was completed as a producer in May 2000, perforated in November 2000 and commissioned in March 2001. Total volume of oil produced since the start is 37MMbbls with a PPH currently open, oil flow of 1.36 m3/hr and GOR of 3953

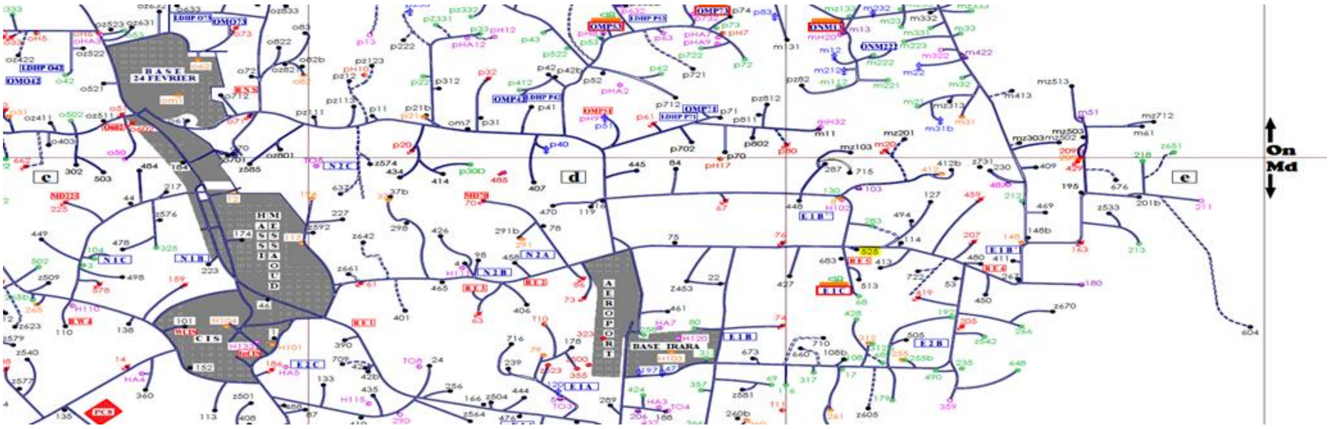


Figure III.5-: well location[6]

oIII.2.1-Production history and last operations on the well:

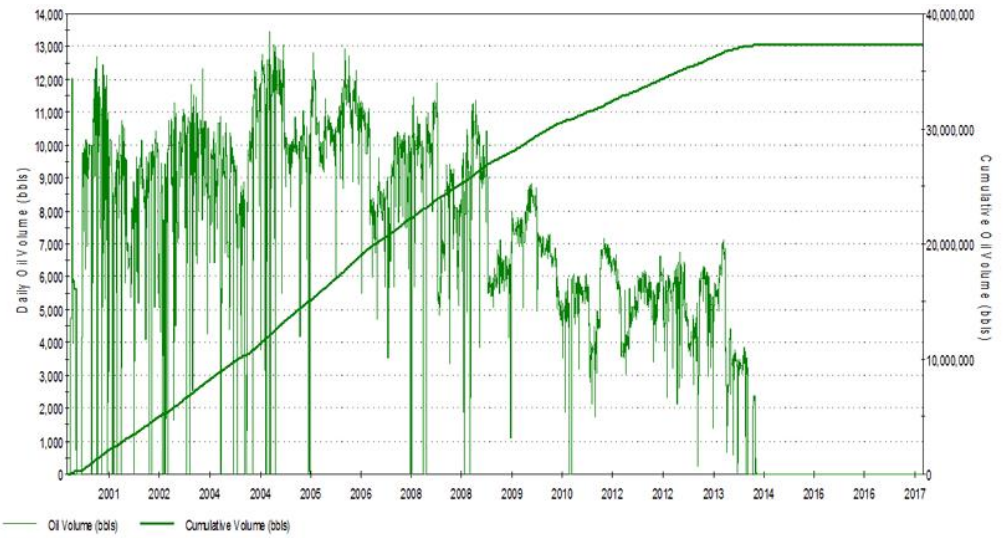


Figure III.6- Cumulative Production Curve of md-525 [6]

This figure shows the evolution of production from 2000 to 2014, This graph indicates that production began in the early 2000s and then varied between [9 m3 and 13 m3] until a sharp decline in production occurred in 2008, leading recommendations to acidify this well. Upon completion of this surgery, it is evident that production has recently grown before stabilizing.

As for cumulative, we notice a continuous increase since the beginning of production until 2014,after which the value stabilizes.

III.2.2: MD-525 corrosion log:

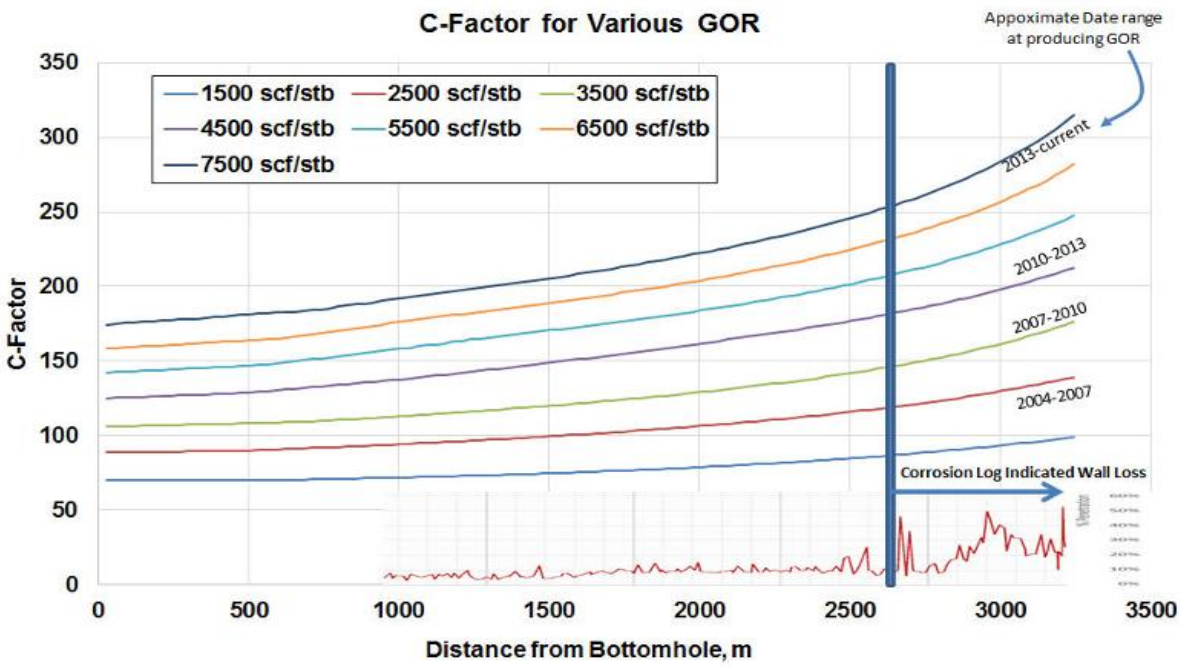


Figure III.7- Erosion Factor Curves and Corrosion Log

According to published research, if the erosion factor "C" is more than 100, it means that the flow rate exceeds the rate of erosion. On wells that don't produce water or sand, this tends to be overprotective .

At the top of the MD-525 well in 2012, the "C" erosion factor most likely surpassed 200. While at the end of 2013, there was initial evidence of communication between the annular "A" and the tube.

III.2.3-Surveillance of annular pressure:

Table III.2-: Surveillance of annular pressure

Monitoring Date	Well state	Wellhead pressure(bars)	Annular space	Initial pressure (bars)	Purge (O/N)	Final pressure (bars)	Observations
18-Aug-21	Open	16	A	60	N		
18-Aug-21			B	198	N		
31-Aug-21		25	A	37	Y	37	Gaz
31-Aug-21			B	170	Y	88	Liquide
10-Sep-21	Open		A	55	Y	55	Gaz
10-Sep-21	Open		B	124	Y	0	Water
29-Sep-21	Open	26	A	56	N		
29-Sep-21	Open		B	87	N		
12-Nov-21	Open	16	A	59	N		
12-Nov-21	Open		B	145	N		Section C, corroded valve and solid plug
8-Jan-22	Open	18	A	35	N		
8-Jan-22	Open		B	160	Y	25	
17-Jul-22	Open	26	A	52	N		
17-Jul-22	Open		B	200	N		

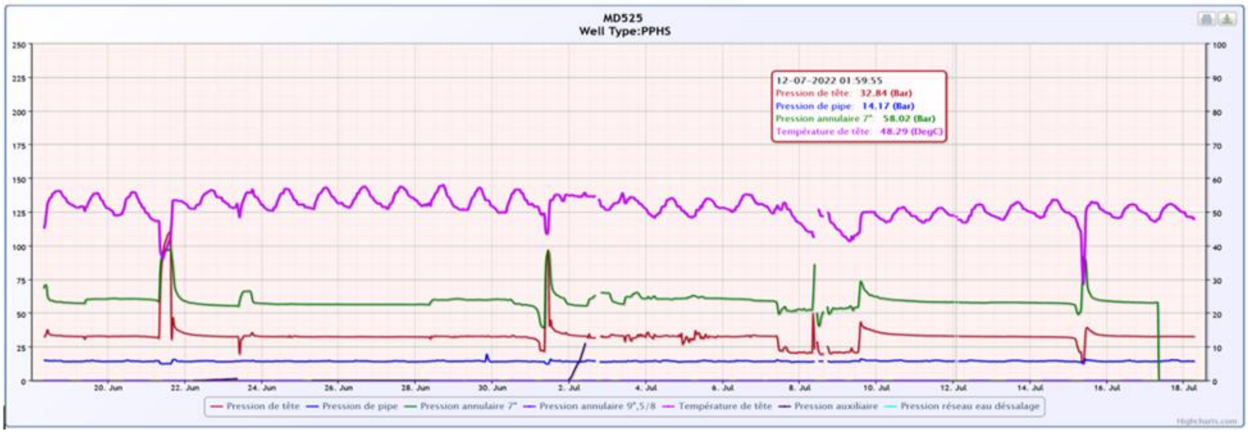


Figure III.8: Pressure recording curves[6]

- **According to table data we observe that:**

o Oil producer with pressure in ring space B.

o Gas returns from EA A following a clearance .

o Low pressure increase of the EA B; on 17 July 22 the pressure was 200 bar.

o Analysis of the sample shows the presence of salmon o Section C is equipped with a corroded valve stuck with cap (no access) .

Result interpretation:

o Annular space A is likely to be subjected to induced pressure.

o Induced pressure in EA B .

o Pressure in EA C could not be checked .

o Failure of the secondary barrier cover with the primary cover not tested.

o to monitor and carry out neutralization

III.2.4-Assessment of MD-525 Well Integrity Management:

The integrity management of wells is based on the assessment of technical, operational and organizational barriers.

Based on this rating, a score between 0 and 1 will be determined. A high score indicates that good integrity management is in place, while a low score shows the opposite.[8]

The rating process and rating guidelines for these barriers are available in Annex D

Category	Sub-Category	Metric	Score (0-10)	Description	Category Score (%)	Well Score (0 to 1)
Technical	Construction	Casing & Tubing	9	1) Tubing & Casings weights & grades adequate for well life environment 2) Premium tubing thread used. A score of 9 has been assigned	61.5%	0.58
		Completion	5	1) Master valves are open and cannot be closed due to operational requirements as a result of running a concentric in the well. A score of 5 has been assigned		
		Wellhead & XMT	9	1) The wellhead & tree are rated for 5,000 psi A score of 9 has been assigned.		
	Barriers	Primary	9	1) Well schematic shows adequate number of primary barriers. A score of 9 has been assigned		
		Secondary	9	1) Well schematic shows adequate number of secondary barriers. A score of 9 has been assigned		
	Annular Pressures	Annulus A	4	1) Potential sustained annular pressure below MAWOP value A score of 4 has been assigned		
		Annulus B	0	1) 200 bar sustained pressure A score of 0 has been assigned		
		Annulus C	2	1) Pressure not determined A score of 2 has been assigned		
		Annular Valve Plugging	9	1) No indication of annular valve plugging. A score of 9 has been assigned		
	Wellhead & XMT	Annulus A	7	1) Annular valves are operable, with mild corrosion on section spool A score of 7 has been assigned		
		Annulus B	6	1) Annular valves are operable, with heavy corrosion on section spool A score of 6 has been assigned		
		Annulus C	2	1) Corroded inoperable valve and solid plug on opposite side A score of 2 has been assigned		
		XMT	7	1) Water leaking from coupling on the supply line to water pump. 2) Needle valve is installed on the tree cap, there is no pressure gauge. A score of 7 has been assigned		
	Cement Quality	7" Casing	3	1) Free pipe across the LD-2 A score of 3 has been assigned		
		9 5/8" Casing	3	1) Free pipe across the Albien A score 3 has been assigned		
		13 3/8" Casing	8	1) No CBL available A score 8 has been assigned		
	Well History	Well age	7	1) Well age is 22 years A score of 7 has been assigned		
		Patches	9	1) No patches in the 7" casing 2) No patches in the 9 5/8" casing A score of 9 has been assigned		
		Pressure Tests	6	1) No annular pressure tests recorded A score of 6 has been assigned		
		Other Anomalies	9	1) No other important anomalies A score of 9 has been assigned		

Figure III.9: Current evaluation of MD-525 well integrity management [6]

Each category of barriers is divided into sub-categories, themselves divided in a set of measures applicable to the type of well for the selected field.

Each criterion is evaluated and awarded a score between 0 and 10, the score of 10 indicates that excellent integrity management is in place and no potential threat, while the rating of 0 means that there is no evidence that integrity is being managed, with potential threats in the future.

A low overall rating indicates poor management with serious potential threats to the integrity of the well in the future.[8]

III.2.5-MD-525 Risk assessment:

Identified primary danger

Hydrocarbon release to the surface or underground eruption.

Failure probability

The probability of the event is described as "Probable". (See annex E**)**

Consequences of failure

The consequence of the event is described as "Elevated." (See annex E)

Criticity Grid

Here is the risk criticality grid for the MD-525 well**:**

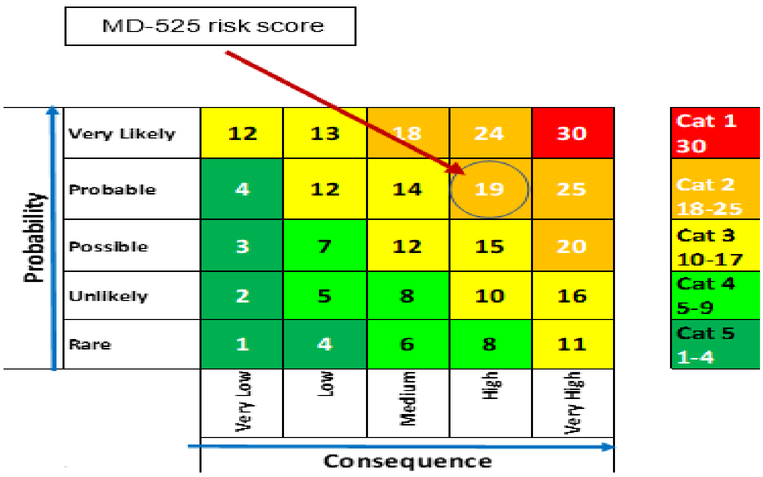


Figure III.10: MD-525 Risk Criticity Grid[6]

III.2.6-Risk Classification

Based on the pressure analysis and risk assessment, the well has a risk score of 19, classified as high risk (Cat 2) .

An attached table shows the relationship between the risk category derived from the critical grid and the level of risk:

Table III.3: MD-525 Risk Level [8]

Catégorie de risque	Niveau de risque
Cat 1	Risque Elevé
Cat 2	Risque Elevé
Cat 3	Risque Moyen
Cat 4	Faible Risque
Cat 5	Faible Risque

III.2.7-Intervention Priority Level:

The priority of intervention arises from the level of risk of wells. The higher the risk level, the greater the priority of the well for intervention .

Establishing this priority is useful when resources are limited.

Based on a high level of risk, **the priority of this well intervention is Level 1.**

The following table shows the relationship between the level of risk and the priority of the intervention**:**

Table 6: Risk level and priority for intervention[8]

Niveau de risque	Priorité pour l'Intervention
Risque Elevé	1
Risque Moyen	2
Faible Risque	3

III.3-MD-525 well Mode Failure:

The well failure mode (WFM) of the MD-525 well is shown below:

Table III.4: MD-525 well Failure Mode [6]

Item	Barrier Element	Well barrier element status	Typical Barrier Failure Mode	Potential Failure Causes	Associated Risks
1	4 1/2" Liner Casing & Cement	Not Verified	1) Failure of liner casing 2) Loss of mechanical properties of liner 3) Bad cement or free pipe	1) Casing corrosion 2) Casing collapse 3) Cement seal loss 4) Well age 5) Bad cement selection and job execution practices 6) Lack of personnel competency 7) Inadequate cementing products	1) Loss of primary barrier 2) Loss of production 3) Inter zonal communication 4) Borehole stability
2	4 1/2" Liner hanger	Not Verified	1) Failure of liner hanger seal	1) Exposure to corrosive fluids 2) Excessive differential pressure across the seal 3) Mechanical overload	Loss of primary barrier
3	Production Packer	Not Verified	1) Leak across the external packing elements 2) Leak across the internal seals	1) Excessive differential pressure across the packer 2) Excessive loads during pumping or production operations 3) corrosive environment 4) Seals damage during installation	1) Loss of primary barrier 2) Loss of production 3) Exposing the production casing to corrosive well fluid 4) Problems with artificial lift
4	Production Tubing	Degraded	1) Tubing failure (Leak) 2) Loss of mechanical properties of production tubing 3) Loss of burst and collapse pressure rating	1) Tubing- packer seals leak 2) Corrosion 3) Erosion due to fluid velocity 4) Excessive loads (collapse & burst) 5) Use of non premium connections 6) Sand production 7) Scaling	1) Loss of primary barrier. 2) Loss of production 3) Increased risk of tubing failure 4) Restrict pumping and well operations 5) Complicate work over and intervention operations
5	Tubing hanger	Not Verified	1) Failure of neck seals 2) Failure of pack off seals	1) Exposure to corrosive fluids 2) Excessive differential pressure across the seal 3) Mechanical overload	1) Loss of primary barrier 2) Sustained annulus pressure in A-annulus

Proposed solutions:

1. Liner casing & cement:

- Using cementing best practices
- Running CBL/VDL tools
- Select the liner casing material to expected fluid composition

2.Liner hanger :

- Ensure produced and/or injected fluids are compatible with liner seals

3.Production packer:

- Ensure best practice during packer installation
- select the packer to withstand expected loads and formation fluid

4.Production tubing:

- monitor a section pressure
- connect well to telemetry

5.tubing hanger:

- Ensure produced and/or injected fluids are compatible with the seals material

III.3-MAASP CALCULATION:

III.3.1-Eclipse method:

				colour key	
well	MD-525				fill in the well name & data details onl y
					confirm data
cement	19,5	ppg	assumed		
prod casing fluid	16,4	ppg	assumed		
OBM	12,6	ppg	assumed		
inter casing fluid	10,6	ppg	assumed		
surface casing fluid	10,6	ppg	assumed		
conductor fluid	9,4	ppg	assumed		
packer fluid	8,5	ppg	assumed		
	NOTE-CHECK & CONFIRM TUBING DETAILS ARE CORRECT				

	Nom (ins)	ID (ins)	Weight (lb/ft)	Grade	depth (TVD/ft)	TOC (TVD-ft)	MG (s.g)	FG (s.g)	burst (psi)	collapse (psi)	depth for (psi)
prod tubing to upper GLM depth					0		0.36				0
prod tubing to packer	4.5	3.96	12.6	L80	7383	0	0.44		8430	7500	0
prod casing to sheo	7	6.18	28 ,	N80	8370	0	0.85	1.01	8160	7030	8370
intermediate casing	9.600	8.76	43.5	N80	3492	0	0.55	1.01	6300	3810	7583
surface casing	13.375	12.62	54.5	K55	3492	0	0.55	0.66	2720	1130	3490
conductor	20	18.75	129.33	X56	1190	0	0.66		3060	1450	

	Nom (m)	ID (m)	Weight (kg/m)	Grade	depth (kg/m)	TOC (TVD-m)	MG (s.g)	FG (s.g)	burst (bar)	collapse (bar)	depth for (bar)
prod tubing to upper GLM depth	0	0	0	0	0		0.149		0	0	0
prod tubing to packer	0.114	0.101	18.7	L80	2250	0	1.020		573	500	0
prod casing to sheo	0.178	0.157	43.1	N80	2251	0	1.967	2.952	555	478	2250
intermediate casing	0.224	0.222	64.7	N80	2311	0	1.266	2.952	431	256	2311
surface casing	0.340	0.320	81.1	K55	1064	0	1.266		186	77	1064
conductor	0.500	0.476	192.4	X56	373	0	1.128		208	99	364

Annulus	collapse	burst	PBG	collapse	burst	PBG	MAASP	
	(psi)	(psi)	(psi)	(bar)	(bar)	(bar)	(psi)	(bar)
A	5000	7330	NV	344	505	NV	5000	344
B	3824	2548	2690	264	175	185	2691	185
C	3396	2060	330	234	142	23	385	26

Figure III.11-Calculation of MAASP for the MD-525 well (Eclipse Method)

N.B.: According on the MD- 525 well MAASP calculation, we are able to determine the maximum pressure in Anneal A, which is 5000 psi. This value can't be reached .

Similarly, Anneal B MAASPs = 2691 psi, and Anneal C MAASPS =385 psi

III.3.2-API-90 METHOD:

API RP 7,5,3-SIMPLE SE RATING METHOD									
well name	MD-525			MAWOP(MAASP)					
				Tubing	A-Annulus	B-Annulus	C-Annulus		
Data Entry	Size	Grade	Weight	Burst		collapse		Depth(TVD)	
Tree &Tubing Head Adaptor	4 1/2	HYCS		6520	psig	N/A		N/A	
Production Casing Spool	7	HYCS		5000	psig	N/A		N/A	
Intermediate Casing Spool	9 5/8	HYCSHYCS		5000	psig	N/A		N/A	
Outer Casing Spool	13 3/8	HYCS		3400	psig	N/A		N/A	
Production Tubing	4 1/2	L-80	14.7	8300	psig	7300	psig	N/A	
Production Casing	7	C-95	27.0	3500	psig	7800	psig	310	mts
Packer				7000	psig	7300	psig	2402	mts
Gas lift Mandell	If ot installed enter Tubing Data			8300	psig	7300	psig	.	mts
Intermediate Casing	9 5/8	P-110	46.0	8000	psig	7000	psig	2300	mts
Outer Casing	13 3/8	P-110	66.0	3200	psig	1900	psig	350	mts
Production Tubing Surface Pressure			4000						
Production Tubing Fluid			12.0						
production Casing Fluid			16.0						
Intermediate Casing Fluid			11.0						
Outer Casing Fluid			11.0						

	Size	Grad	weight		Burst	Collapse	Burst	Collapse	Burst		Collapse	depth	fluid weight	Tubing	A-Annulus	B-Annulus	C-Annulus
wellhead componant														5300 psig	4200 psig	4200 psig	2400 psig
Tree&Tubing head Adaptor	4 1/2	HYCS			6600 psig	N/A	0.78	N/A	5300	psig	N/A						
production casing spool						N/A	0.78	N/A	4200	psig	N/A						
intermediate casing spool						N/A	0.78	N/A	4200	psig	N/A						
Outer casing spool						N/A	0.78	N/A	2400	psig	N/A						
completion Equipment Component														6700 psig	8190 psig		
production tubing	4 1/2	L-80	12.0 ppg		8300 psig	7000 psig	0.79	0.75	6700 psig		5620 psig						
weakest Component					8300 psig	7000 psig	0.79	0.75	6700 psig		5620 psig						
packer					7000 psig	7000 psig	0.79	1.00	7000 psig		7000 psig	2460 mts					
fluidin production tubing													12.50 ppg				
fluidin production casing													16.00 ppg				
hydrostatic pressure above the packer									6722 psig								
Surface VHP									5400								
hydrostatic pressure below the packer									9230 psig								
formation fracture breakdown componant																3930 psig	720 psig
Intermediate Casing FIT	9 5/8	P-110	46.0									2300 mts	11.0 ppg				
outer casig	13 3/8	P-110	68.0									384 mts	11.0 ppg				
Casing													5000 psig				
tubular component																	
production tubing	4 1/2	L-80	11.9		8430 psig	7500 psig	0,79 .	0,79 .	6700 psig		6700 psig			6700 psig	4000 psig	3900 psig	1900 psig
production tubing -To packer	7 .	N-80	33.0		9240 psi	9100 psig	0.6 .	0,79 .	4000 psig		7200 psig						
Intermediate casing -To packer	9 5/8	N-80	45.0		8150 psig	7000 psig	0,6 .	0.79	3900 psig		6500 psig						
Outer casing -To cement	13 3/8	S-95	66.0		6390 psig	3400 psig	0.2	0.79	1900 psig								

Figure III.12: Calculation of MAASP for MD-525 well (API-90 Method)

N.B: After calculating the MAASP by both methods we observe that MAASP in annular A by eclipse method (MAASP A= 5000) is lower than that obtained by API-90 method (MAASP A=5400)

III.3.3-ISO METHOD:

WELL: MD-525		Unit	Safty Fator	Pression EXT (Psi)	Pression de	Gradient de fluide	Gradient de FRAC	Tubing 4 1/2			7" CSG			9-5/8"			13-3/8"			18-5/8"			Annulaire-A	Annulaire-B	Annulaire-C	Densité éffluent (kg/l)	Réservoir		Packer			Equipment MAWOP
								MIYP	MCP	SITHP	MIYP	MCP	Depth (m)	MIYP	MCP	Depth (m)	MIYP	MCP	Depth (m)	MIYP	MCP	Depth (m)	Fluid (kg/l)	Fluid (kg/l)	Fluid (kg/l)		Depth (m)	Pression (bar)	Rating Press	Depth (m)	ΔP Psi	
								###	###	500	###	##	###	##	##	###	##	##	305	##	##	152	1,60	1,40	1,20	0,84	3 100	340	10 000	2 743	4 640	
Annulaire-A	Values: According to SDM (Simple Derating Method)								75%		50%			80%																		
Annulaire-A	External casing 50% (MIYP)	Ps	N	NA	NA	N	NA				###																					
Annulaire-A	Internal Casing 75% (MCP)	Ps	N	NA	NA	N	NA		###																							
Annulaire-A	Adjacent exterior casing 80% (MIYP)	Psi	NA	NA	NA	NA	NA							##																		
Annulaire-A	Pressure over PKR	Ps	N	NA	NA	N	NA																13 489									
Annulaire-A	Pressure under PKR	Ps	N	NA	NA	N	NA																						13 169		
Annulaire-A	completion Eqpt MAOWP	Ps	##	NA	NA	N	NA																							4 288	
Annulaire-A	wellhead Composants	Ps	##	0	###	N	NA																								4 000
Annulaire-A	MAASP(PSI)							5 900																								
Annulaire-B	values : According to SDM (Simple Derating Method)											75%		50%			80%															
Annulaire-B	External casing 50% (MIYP)	Ps	N	NA	NA	N	NA							##																		
Annulaire-B	internal casing 75% (MCP)	Ps	N	NA	NA	N	NA					##																				
Annulaire-B	Adjacent exterior casing	Ps	N	NA	NA	N	NA										##															
Annulaire-B	completion Eqpt MAOWP	Ps	N	NA	NA	N	NA																								
Annulaire-B	wellhead Composants	Ps	##	0	###	N	NA																								4 000
Annulaire-B	Formation Fracture	N	N	NA	NA	N	NA																								
Annulaire-B	MAASP(PSI)							4 212																								
Annulaire-C	Values : According to SDM (Simple Derating Method)														75%		30%			80%												
Annulaire-C	External Casing 30%	Ps	N	NA	NA	N	NA										606															
Annulaire-C	internal Casing 75% (MCP)	Ps	N	NA	NA	N	NA								##																	
Annulaire-C	production Eqpt MAOWP	Ps	N	NA	NA	N	NA													NA												
Annulaire-C	wellhead Composants	Ps	##	0	###	N	NA																								4 000
Annulaire-C	Formation Fracture	Ps	##	NA	NA	20	10											120													
Annulaire-C	MAASP(PSI)							803																								

Figure III.13 :Calculation of MAASP for MD-525 well (ISO Method)

N.B.: According on the MD- 525 well MAASP calculation using ISO method, the maximum pressure in Anneal A, which is 5900 psi, Anneal B MAASPs = 4212 psi, and Anneal C MAASPS =803 psi

Results interpretation:

Results found by the three methods:

	A- ANNULUS	B-ANNULUS	C-ANNULUS
ECLIPSE METHOD	5000	2691	385
API-90 METHOD	54000	3930	720
ISO METHOD	5900	4212	803

After calculating by those methods, we find that :

ECLIPSE method: based on

- The weight (54.5 lb/ft) and depth of the hydrostatic column (3492 TVD/ft) to calculate their MAASP
- Training breakdown .
- The cracking and crushing of these columns A, B, C and the tube.
- Specific gravity (0.55).

All these parameters have an impact on the result of the calculation .

API 90-02: based on crashing and crushing also degradation factor of each component :

- Head of well .
- Complementary equipment .
- Tubular.

ISO method based on:

- Packer pressure (over/under)
- Wellhead component
- Fracture formation

SOwe conclude that the Eclipse method is more secure because the MAASP is lower than the API method, and takes extreme cases into account, and the change in depth and the completion fluid change the MAASP.

GENERAL CONCLUSION

As we see in our braving research, there is no doubt that the integrity of wells is one of the most essential topics in the oil industry. Well integrity problems cause the oil industry huge financial losses throughout the well's life cycle, from drilling to final abandonment. It is therefore essential to implement preventive and corrective measures to prevent and address these problems, in order to reduce costs and ensure the profitable and sustainable exploitation of oil resources.

This work describes monitoring requirements, management guidelines and certain response procedures to ensure an adequate level of integrity of well-being at all times in all wells operated by Groupement HMD.

The calculation of MAASP by the Eclipse method is safer because:

- The MASP is lower than the API 90-2 method and ISO method;
- the MASAP changes with the change in the depth and the flow of completion.

As a final result, we can conclude that the well integrity, cannot be similarly the way to secure the well throughout the life cycle, but it should be considered as apriority without forgetting the other solutions including injection, assistant and the WorkOver's intervention technics such coiled tubing and snubbing, as a result of the relative efficacity of all kinds of petroleum operations whatever its development.

Recommendations:

•Purge the pressure in ring space B below 80% of the MAWOP value. Keep the pressure as low as possible.

•The pressure in the EA C must then be assessed. Check the liquid level and add water with non-corrosive treated water if necessary.

•Conduct void tests to verify the sealing of the hanger tubing and 7” hanger casing.

•Conduct annulus pressure and communication tests. Start with EA A and keep the other ring spaces open during tests. Monitor and record fluid returns from other rings.

•Assess the integrity and ring communication of barriers.

•Restore integrity based on the results of the findings described above.

•Continue to monitor the well on a regular basis pending necessary interventions.

•It is recommended to use a cathodic protection system that would help reduce the severity of corrosion during the life of the well on the piping walls and would help to preserve the capacity of these pipes to withstand pressure.

•It is also recommended that well barriers be checked periodically, at least once every 5 years, or during well interventions, using the method of verifying criteria for well barrier elements.

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ANNEXES

Annex A: Calculation of MASSP by ISO method

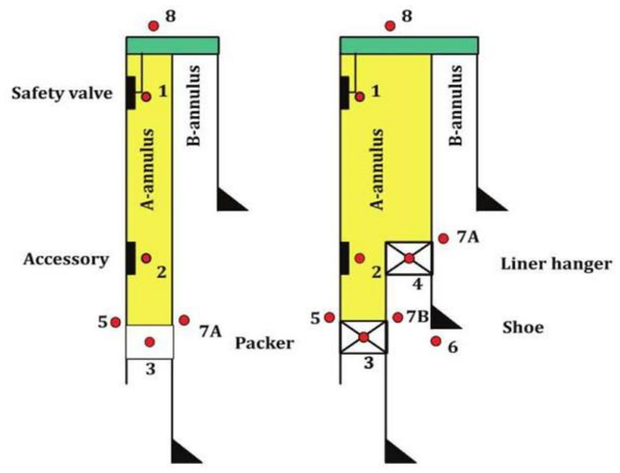
— Symbols and abbreviations used in MAASP calculations

Parameter		Description
Symbol	Abbreviation	
D_{TVD}	TVD	True vertical depth (TVD), expressed in metres (Depth is relative to the wellhead and not the rotary kelly bushing)
∇p_{BF}	BF	Base fluid pressure gradient in annulus, expressed in kilopascals per metre
∇p_{FORM}	FORM	Formation pressure gradient, expressed in kilopascals per metre
p_{MAASP}	MAASP	Maximum allowable annulus surface pressure, expressed in kilopascals
∇p_{MG}	MG	Mud or brine pressure gradient, expressed in kilopascals per metre
p_{PC}	PC	Casing collapse pressure resistance, expressed in kilopascals (Safety factor should be applied to PC prior to calculating the MAASP value)
p_{PB}	PB	Casing burst pressure resistance, expressed in kilopascals (Safety factor should be applied to PB prior to calculating the MAASP value)
p_{PKR}	PKR	Production packer operating pressure rating, expressed in kilopascals
∇S_{FS}	FS	Formation strength gradient, expressed in kilopascals per metre

Subscripts	Description
A, B, C, D	Designation of the annulus
ACC	Accessory (e.g. SPM or landing nipple)
BF	Base fluid (refers to base fluid of mud in outer casing)
FORM	Formation
LH	Liner hanger
PP	Production packer
RD	Rupture disk
SH	Casing shoe
SV	Safety valve
TBG	Tubing
TOC	Top of cement

Annex B

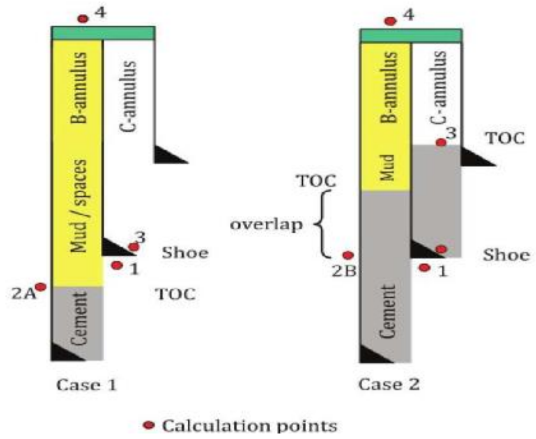
Calculation MASSP for A-Annulus



Case 1 Case 2

Point[a]	Item	Case	MAASP formulae	Remarks / assumptions
1	Safety valve collapse	Both	$P_{MAASP} = P_{PC,SV} - \left[D_{TVD,SV} \cdot \left(\nabla P_{MG,A} - \nabla P_{MG,TBG}\right)\right]$	Highest MG in annulus Lowest MG in tubing
2	Accessory collapse	Both	$P_{MAASP} = P_{PC,ACC} - \left[D_{TVD,ACC} \cdot \left(\nabla P_{MG,A} - \nabla P_{MG,TBG}\right)\right]$	Highest MG in annulus Lowest MG in tubing
3	Packer collapse	Both	$P_{MAASP} = P_{PC,PP} - \left[D_{TVD,PP} \cdot \left(\nabla P_{MG,A} - \nabla P_{MG,TBG}\right)\right]$	Highest MG in annulus Lowest MG in tubing
3	Packer element rating	Both	$p_{MAASP} = p_{PKR} + p_{FORM} - \left(D_{TVD,PP} \cdot \nabla p_{MG,A}\right) - \left[\nabla p_{FORM} * \left(D_{TVD,FORM} - D_{TVD,PP}\right)\right]$	P_{FORM} is the lowest pressure from the formation or reservoir that could act below the packer element in the life cycle p_{PKR} is the pressure rating of the packer element (can require de-rating during the life cycle)
4	Liner hanger element rating	2	$p_{MAASP} = p_{LH} + p_{FORM} - \left(D_{TVD,LH} * \nabla p_{MG,A}\right) - \left[\nabla p_{FORM} * \left(D_{TVD,FORM} - D_{TVD,LH}\right)\right]$	P_{FORM} is the lowest pressure from the formation or reservoir that could act below the liner hanger element in the life cycle p_{LH} is the pressure rating of the packer element (may need to be de-rated during the life cycle)
4	Liner hanger packer burst	2	$P_{MAASP} = P_{PB,LH} - \left[D_{TVD,LH} \cdot \left(\nabla P_{MG,A} - \nabla P_{BF,B}\right)\right]$	Base fluid is assumed on the basis that the residual mud in the B-annulus has degraded. It can be necessary to substitute BF_B for a formation pressure under some circumstances.

Calculation MAASP for B-Annulus :

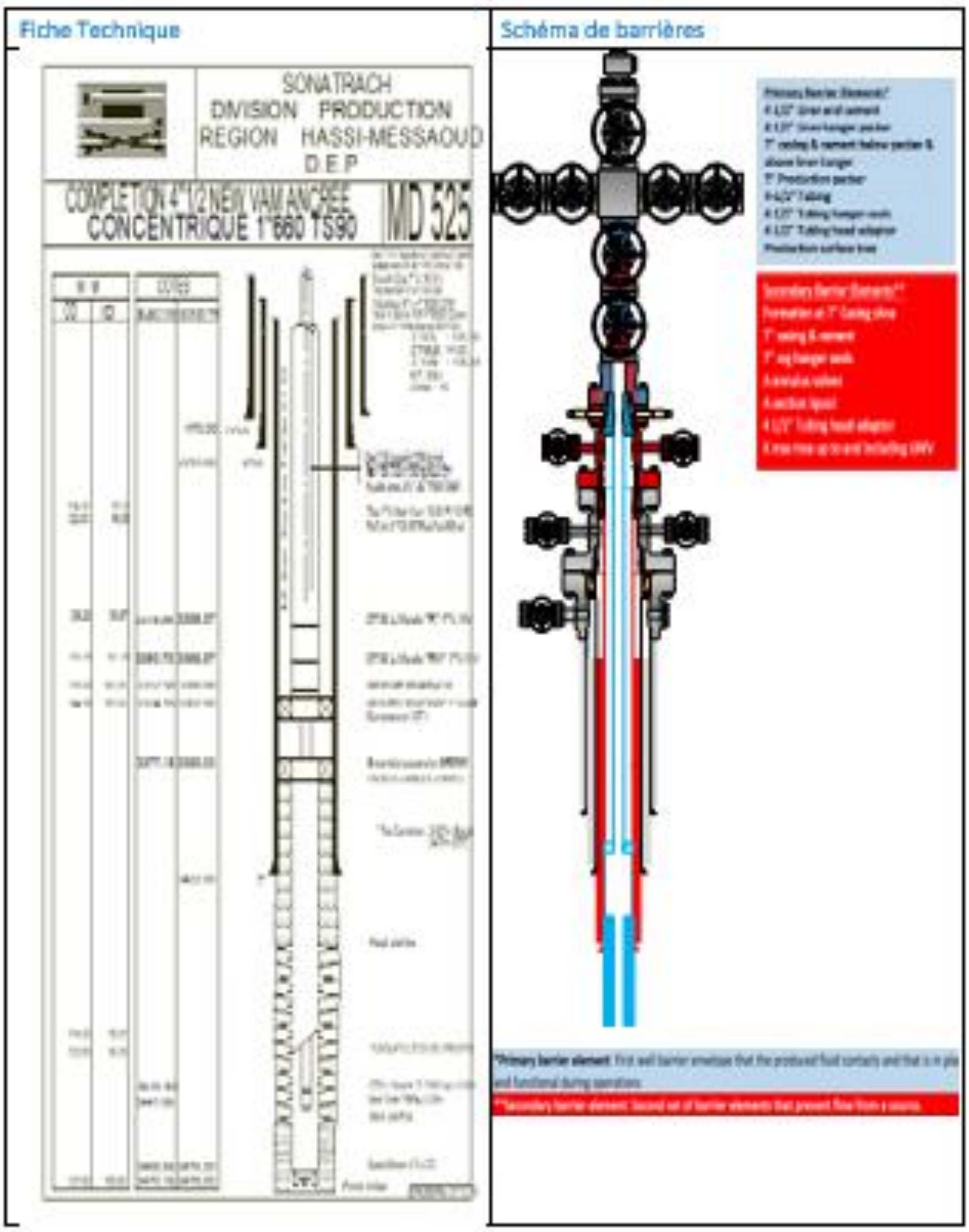


Point[a]	Item	Case	MAASP formulae	Remarks/assumptions
1	Formation strength	1	$P_{\text{MAASP}} = D_{\text{TVD,SH,B}} \cdot \left(\nabla S_{\text{FS,B}} - \nabla P_{\text{MG,B}}\right)$	It is necessary to account for degraded mud, cement spacers and washes.
2	Inner (production) casing collapse	Both	$P_{\text{MAASP}} = P_{\text{PC,A}} - \left[D_{\text{TVD,TOC}} \cdot \left(\nabla P_{\text{MG,B}} - \nabla P_{\text{MG,A}}\right)\right]$	PC is the casing/liner collapse pressure resistance Highest MG in B-annulus Lowest MG in A-annulus (evaluate to use evacuated A case) D_{TOC} to be adjusted for other depths relevant to check (for different casing weight/sizes, etc.)
3	Outer casing burst	Both	$P_{MAASP} = P_{PB,B} - \left[D_{TVD,SH} * (\nabla P_{MG,B} - \nabla P_{BF,C})\right]$	Base fluid is assumed on the basis that the residual mud in the C or D annulus has degraded. Use the deepest depth if the gradient in BF_C is less than MG_B. Otherwise $D_{TVD} = 0$. D_{SH} to be adjusted for other depths relevant to the calculation (for different casing weight/sizes etc. and for TOC in Case 2)
4	Wellhead rating	Both	MAASP is equal to the wellhead working pressure rating.	—
—	Annulus test pressure	Both	MAASP is equal to the annulus test pressure.	—
—	Casing rupture disc	—	$P_{\text{MAASP}} = P_{\text{PB,RD}} - \left[D_{\text{TVD,RD}} \cdot \left(\nabla P_{\text{MG,B}} - \nabla P_{\text{BF,C}}\right)\right]$	Assumption is BF,C is lighter than MG,B

ANNEX C: Lithostratigraphic column of the field of Hassi Messaoud.

CENO-ZOIQUE	NEOGENE	MIO-PLIOCENE (discordance alpine)		240	Sable, calcaire, marne sableuse
		EOCENE		120	Sable, calcaire à silex
MESOZOIQUE	CRETACE	SENONIEN	CARBONATE	107	Calcaire, dolomie, anhydrite
			ANHYDRITIQUE	219	Anhydrite, marne, dolomie
			SALIFERE	140	Sel massif et traces d'anhydrite
		TURONIEN		90	Calcaire crayeux avec quelques niveaux argileux
		CENOMANIEN		145	Anhydrite, marne, dolomie
		ALBIEN		350	Grés, sable avec intercalations d'argile silteuse
		APTIEN		25	Dolomie cristalline avec niveau argileux, calcaire
		BARREMIEN		280	Argile, grés, dolomie
		NEOCOMIEN		180	Argile, marne, dolomie, grés
	JURASSIQUE	MALM		225	Argile, marne, calcaire, grés et traces d'anhydrite
		DOGGER	ARGILEUX	105	Argile silteuse, marne dolomitique avec fines passées de grés
			LAGUNAIRE	210	Anhydrite, marne dolomitique, marne grise
		LIAS	L.D 1	65	Dolomie, anhydrite, argile
			L.S 1	90	Alternances sel, anhydrite et argile
			L.D 2	55	Anhydrite et dolomie cristalline
			L.S 2	60	Alternances sel et argile
			L.D 3	30	Alternances de dolomie et de marne
	TRIAS	SALIFERE	TS 1	46	Alternances de sel, d'anhydrite et de dolomie
			TS 2	189	Sel massif à intercalations d'anhydrite et argile gypsifère
			TS 3	202	Sel massif et traces d'argile
		ARGILEUX		113	Argile rouge dolomitique ou silteuse injectée de sel et d'anhydrite
		GRESEUX		35	Grés, argile
		ERUPTIF (discordance hercynienne)		0-92	Andésites altérées
PALEOZOIQUE	ORDOVICIEN	QUARTZITES D'EL HAMRA		75	Quartzites fines avec traces de tigillites
		GRES D'EL ATCHANE		25	Grés fins à ciment argileux, bitumineux
		ARGILES D'EL GASSI		50	Argiles schisteuses, vertes ou noires, glauconieuses à graptolithes
		ZONE DES ALTERNANCES		20	Alternance de grés et argile. Présence de tigillites
	CAMBRIEN	Ri		50	Grés isométriques, fins, silteux
		Ra		120	Grés à grés quartzitiques anisométriques à niveaux de silts
		R2		100	Grés moyens à grossiers à ciment argileux illitique
		R3		300	Grés grossier à ciment argileux, argile silteuse
	INFRA-CAMBRIEN			45	Grés argileux rouges
SOCLE					Granite porphyroïde rose

ANNEX D:MD-525 Well and Barrier Envelopes Scheme



ANNEX E: Risk assessment

A risk assessment was carried out for the MD-525 well to assess the probability of primary and secondary barrier failure and the impact of this failure on personnel, equipment and the environment.

Danger

• Release of hydrocarbons to the surface or underground eruption.

Failure probability

•The state of the well barrier elements has been examined on the basis of the above-mentioned well failure model. A summary of the state of the well barrier elements is given below:

o The master valves are open continuously due to the concentric passing through.

o Possible failure of the tubing, hanging tubing or production packer due to the presence of gas in EA A; however, the exact source of the leak is not yet confirmed.

o The pressure in the EA B has increased to 200 bars, exceeding the MAASP value, while the pressure in EA C is undefined due to the existence of a solid lid and a corroded valve stuck in the section. A failure of the 9 5/8" pipe would expose the EA C to 200 bars of pressure, which in turn would cause an additional potential failure.

•Based on the above, the probability of the event is described as “Probable.”

Consequences of failure

•The consequences of a failure of the well barrier are the release of hydrocarbons to the surface or the underground eruption which will have the following impacts:

o Injury and death of personnel (near the well of military and nomadic camps that are 500/600 m from the well) o Environmental damage o Damage to the well equipment that will require high costs for repair and security

o Production loss o Possible underground flow of hydrocarbons to another formation and reserve loss.

•Based on the above, the consequence of the event is described as “Elevated”.

Criticity Grid

•A 5x5 risk criticality grid was used to calculate the extent of risk based on the probability and consequences of failures.

•The risk tolerance has been defined throughout the grid so that Cat 1 and Cat 2 represent a high risk, Cat 3 a medium risk, and Cat 4 and Cat 5 a low risk.

•The score in the grid defines the magnitude of the risk, so that the risk increases with the increase of the score in a grid.

ANNEX F: Process and guidance for rating of well integrity management

Score	Evidence Standard and Risk Management
0-1	No evidence available.
1-2	. Evidence exists, but is not available for examination. No risk assessment
2-3	Insufficient or inadequate evidence of the assessment of the criterion and the associated risks.
3-4	Evidence identified but remaining questions or inadequate evidence.
4-5	Successful backgrounds on the ground, with a few incidents, but the evidence raises questions.
5-6	. Successful history, no incident; Evidence demonstrates risk assessment
6-7	. Good history; some evidence is not available; well risk management process in place
7-8	The full evidence available helps to demonstrate risk mitigation.
8-9	. Proof of adequacy and quality available. Good risk management processes.
9-10	. Fully certified, risks have been fully evaluated and implemented