POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering
Master of Science in Petroleum Engineering

Master Thesis Project

ANALYSING OF ABNORMAL ANNULAR PRESSURE AND APPLICATION OF MITIGATATION TECHNOLOGIES TO PROTECT WELL INTEGRITY

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“Esiste nella vita una sola felicità: amare e essere amati. George Sand”

DECLARATION

I announce that this work that I have given to you is of my sincere work and commitment. It is delivered under the requirements of the Master of Science degree in Petroleum Engineering at Politecnico di Torino, Italy. And in no other university was it offered for any academic degree or examination.

DEDICATION AND ACKNOWLEDGEMENTS

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ABSTRACT

During casing design operations there are product spaces generated between casings strings or between tubing and casing that are called annuli, it is the product as a result of design and not created purposely. The ideal case is these annuli must be filled with cement, but for some reasons such as limited cement technologies and weak formations, these annuli are filled with small-compressibility fluids (generally weighted mud, cement spacers, or transparent brines) to avoid fracturing of the weak formation and lost circulation during cementation. In high-pressure high-temperature wells (HPHT) these fluids will be heated during drilling operations and production activities by the fluids that coming from heat formations in the bottom of the well and as a result, it will expand and if the annulus was closed it will generate a trapped annulus pressure (TAP), it is the first type of annular pressure, this pressure can reach a very high value (10,000 - 12,000 psi or more). This pressure is more problematic in subsea wells (SSW) where the wellhead of SSW doesn't permit annulus venting except for annulus 'A' (production casing - tubing). The second type of annular pressure is sustain casing/annular pressure (SC/AP), that caused by the failure of internal or external barriers of well integrity, involving casing and cement, in some cases when the annulus fluid pressurized by formation fluids invasion due to pressure difference between formation and annulus and there is a passageway through microfractures and channels in poor cement where there is a failure in the external barrier of well integrity, or it can be generated mechanically by tubing leak inside annulus or linking between annuli due to seals or casings damage, where there is an internal integrity barrier failure. Both of these two types of annular pressure are harmful when becoming abnormal annular pressure. Abnormal annular pressure is one of the most important issues that threaten the casing of wells from the annulus and may result in a casing failure. Because the casing is the major part of a well integrity system, so annular pressure impacts the well barriers and may lead to damage of the well integrity. Analysing the annular pressure by the source of this pressure, type, possible location, causes of generation, and calculation of permissible and present limits are more important during well design. The last conventional casing design for deep-water HPHT and SSW shows insufficient control of abnormal annular pressure and safety of well integrity by recording some accidents in most of the deep-water wells in the Gulf of Mexico (GOM) and other locations of the same problems. So, it is obligate to account for annular pressure in the new unconventional design that is provided in this research based on mitigating the effect of abnormal annular pressure and provide a complete risk plan to provide a robust design. We consider the annular pressure, apply risk analysis and define permissible limits to show the possible impaction to the well integrity, that study the case by identifying the possible risk, evaluate the risk level and probability of failure, then provide the ways to mitigate this risk to protect the well integrity barrier with applying risk treatment to the most critical (unacceptable) risk levels. Also, we apply an optimization strategy for mitigation devices selection for TAP and optimization for the new design and possible remediation for SCP. Furthermore, there is another type of annular pressure it can be the third type, called applied pressure, that generated intentionally by the operator in a specific value, such as gas lifting and injection wells, this type has a control risk because it programmed based on annulus properties and consideration of its effect on surrounding annuli. In this research we focal on the first two types of annular pressure for development, analysis, calculation, and application in new well design.

LIST OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

APB: Annular Pressure Build up

TAP: Trapped Annular Pressure

SSW: Sub Sea Well

HPHT: High-Pressure High-Temperature well

PVT: Pressure-Volume- Temperature

SLA: Service Life Analysis

AP: Applied Pressure

SCP: Sustain Casing Pressure

SAP: Sustain Annular Pressure

GOM: Gulf Of Mexico

WCD: Worst Case Discharge

MOP: Maximum Operation Pressure

ECD: Equivalent Circulation Density

TOC: Top Of Cement

PPFG: Pore Pressure Fracture Gradient

DPZs: Distinct Permeable Zones

VIT: Vacuum Insulated (isolated) Tubing

CRA: Corrosion Resistant Alloy

IPF: Insulated Packer Fluids

BTU: British Thermal Unit

MMA: Methyl Methacrylate monomer

YPL: Yield Power Law Fluids

ROV: Remote Operating Vehicle

CCI: Cement Casing Interface

AFE: Annular Fluid Expansion

PCT: Pressure Crystallization Temperature

MMS: Minerals Management Services

MAASP: Maximum Allowable Annular Surface Pressure

HAZID: Hazard Identification technique

HAZOP: Hazard and Operability Analysis

FMEA: Failure Modes and Effective Analysis (Qualitative risk analysis)

FMECA: Failure Mode and Consequence Analysis (Quantitative risk analysis)

FTA: Fault Tree Analysis

ETA: Event Tree Analysis

RIE: Reference Initiating Event

EI: Initiating Event

ALARP: As Low As Reasonably Practicable

SCE's: Safety Critical Elements

FST: Formation Strength Test

FIT: Formation Integrity Test

LOT: Leak of test

MASP: Maximum Anticipated Surface Pressure

MAWOP: Maximum Available Wellhead Operating Pressure

MIYP: Minimum Internal Yield Pressure

SCFM: Standard Cubic Feet per Minute

WHP: Well Head Pressure

pptf: Pounds (per square inch) Per Thousand Feet (of depth)

THP: Tubing Head Pressure

SCSSSV: Surface-Controlled Subsurface Safety Valve

Pcsg: Casing Well-head pressure at the surface, Psi

RL: Risk level

ESP: Electric Submersible Pump

ASME: American Society of Mechanical Engineers

BHP: Bottom Hole Pressure

BHT: Bottom Hole Temperature

SIWHP: Shut In Well Head Pressure

INTRODUCTION

The major subsurface structural elements of wells are casing strings, liners, and the cement annulus between casing and formation, and between different tubulars of casings. The successful casing design should account for the scope of scenarios during well existence, unpredictable geological conditions, modeling outcomes, variability and decline of tubular properties due to well aging and future developed loads, so the design considers the development of abnormal annular pressure with effect on the tabular standard design and expected changes from the initial installation condition. These analyses are including in designing the operation of new unconventional well design based on the application of the service life analysis (SLA), the interested stress is by taking the effect of annular pressure generated by heat up and fluid expansion, gas migration, leakage scenarios and applied annular pressure into design considerations with a risk analysis of potential damage. The conditions of HPHT are a common issue in oil and gas offshore resource exploration. Transferring exploration of oil and gas offshore is associated with big challenges, one of these challenges is TAP (Zhang et al., 2019). As for deep-water HPHT wells & SSW, the annular fluid temperature increases rapidly when the production of hot oil & gas is starting and generate TAP. There are many reported accidents for casing loads failure even some wells are abandoned, these accidents are caused by TAP, as in steam injection well in the "Canada Peace River area" (Brown et al., 2016), "shale gas well in China Changning-Weiyuan area, and geothermal well in North German". Also one of the important reported accidents (Vargo et al., 2002) by British Petroleum (BP) for well damage in the Marlin development in Deepwater Gulf of Mexico (GOM), within the first time of production start-up. Controlling TAP in SSW is very important and difficult at the same time because of the complex geology of the formation, limited technologies of cementing, and inaccessible annuli. The controlling of TAP is achieved by some methods principled by releasing TAP, providing extra space to accommodate the expanded liquid, eliminating the trapped annular volume, increasing casing strength, balancing the thermal expansion volume, insulating the heat transfer channels…. etc. These methods are the outcome of a long time of researches organized by companies, proficient, and research centers. These mitigation measures different in operational situations, reliability, cost of equipment manufacturing, and transportation. None of them merits robust promotion and compliance also there is no unit solution for all cases of mitigation application. Their respective advantages and drawbacks are also correlated and analyzed (Dong & Chen, 2017). The second type of annular pressure called SCP can be happened both in normal pressure and HPHT wells (Zhang et al., 2018), but it was more problematic in HPHT wells. Treating and mitigation for this type of annular pressure recorded as a big challenge in oil & gas industry since starting exploration and drilling of wells.

Mitigation for this type (SCP) required deep investigation for the causes and effect and knowing of the well environment. Generally excessive annular pressure can cause some issues such as casing burst, collapse, seal failure, well head movement and consequently damage to well integrity and can lead to well abandonment. So, the analysing of abnormal annular pressure has been given much attention on well design in the modern petroleum industry.

CHAPTER ONE
ANALYSING OF ANNULAR PRESSURE

1.1 Tubular annulus

The completed well annulus is defined as (Riggs, 2001) the space surrounded between two string of tubular such as tubing - casing or casing - casing and bounded by wellhead sealing from up and cement, packer or open formation from down. Annuli differentiate from other well's elements in that they are not typically the product of -
purposeful design. They are the result of tubular -
design and the method of constructing wells. So, the ability of each annulus to hold and resist the existing annular pressure depends on annulus type and tubular properties, these properties must be checked and confirmed during the design process. If the annulus is bounded from down by an impermeable component such as packer or cement, it is called trapped annulus as shown in Figure1.1.

1.2 Types of annuli

As shown in Figure1.1the completed well annuli can be classified as:

1- Annulus type I

This type of annuli created between the production tubing and casing in the well, it is confined by wellhead seals from the top and by completion element from the bottom. This annulus is also called annulus 'A' based on the position from the well centre.

2- Annulus type II

This type is named as annulus 'B', 'C'. etc. depending on the annulus position from the well centre. In this type, there are no completion elements in the bottom section of the annulus, so it can be found in intermediate or surface casings annuli. The bottom of these annuli is the top of cement (TOC) where the TOC can be under the last shoe or above it is depending on the design plan and purposes.

1.3 Types of trapping ways in the annuli

There are two possible annulus trapping ways (Pilko & Tx, 2016)

1-Un conditionally trapped annulus

It is a closed annulus system, which means the annulus is surrounded by tubular from the sides and cement from the bottom. Along with the pressure of the hydrostatic head of the sealing fluid in the annulus, the TAP will be increased rapidly in the annulus system.

2-Conditionally trapped annulus

This means the standard lithological parts cannot bear an unconditional increase in pressure and the permeable section of the annulus can be clogged by the deposition of the weighting agent of annular fluids.

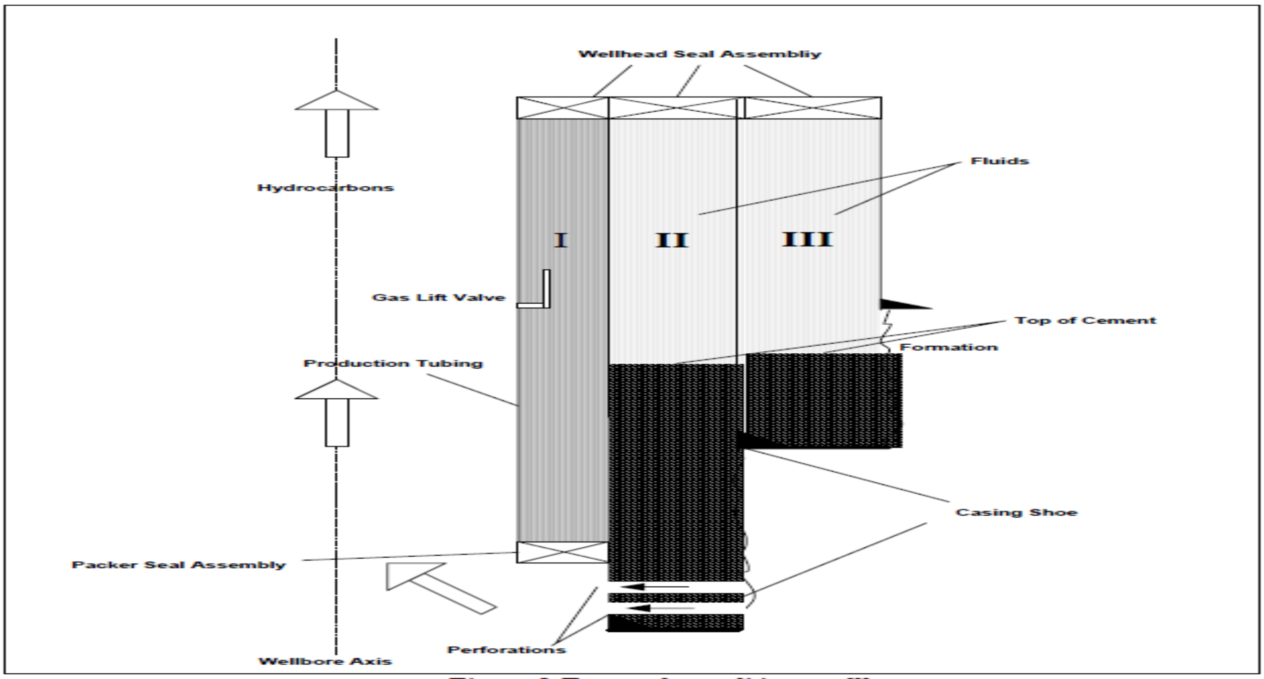

Figure 1. 1Schematic of annuli types (Riggs, 2001)

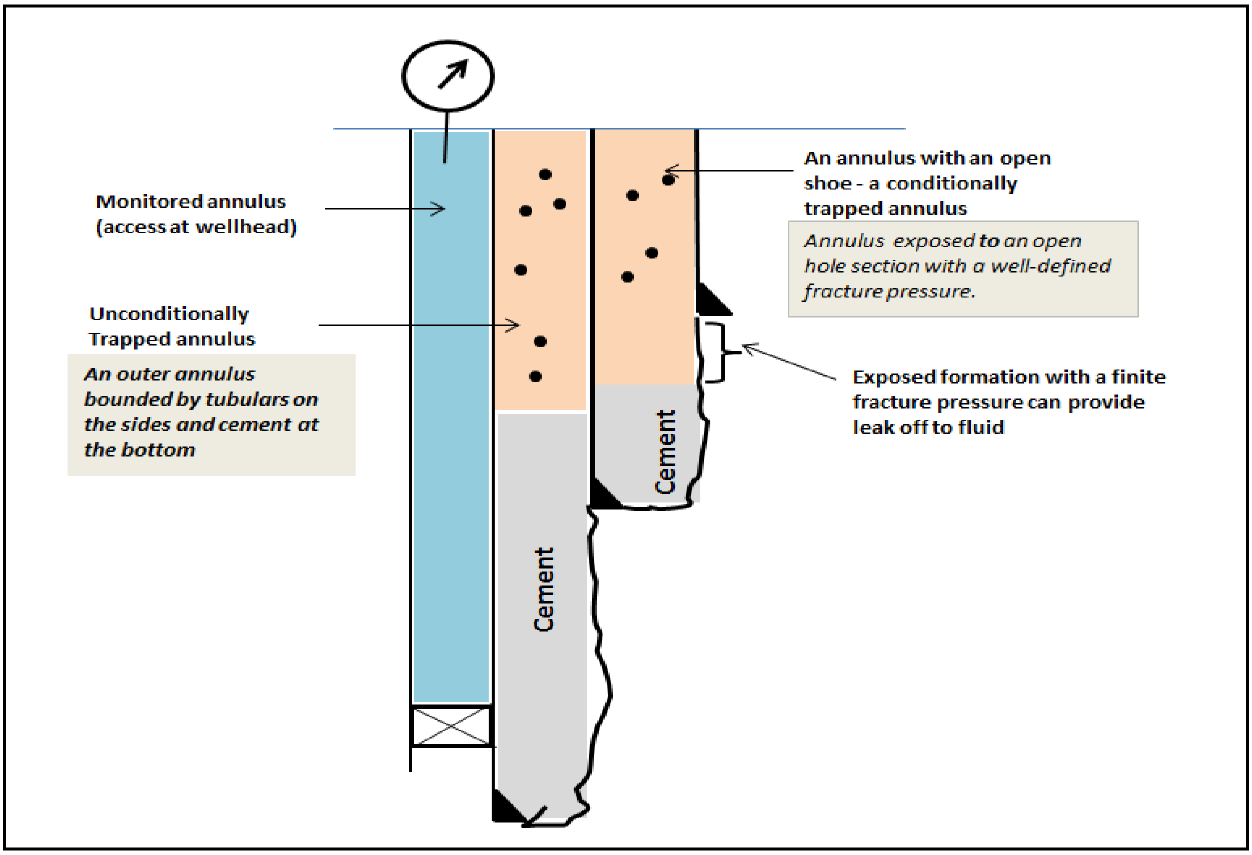

Figure 1. 2Types of trapping ways in SSW (Pilko & Tx, 2016)

1.4 Annular pressure

From the previous definitions, it can easily define it as the pressure that generates by the annular fluid inside the annulus due to volume expansion, fluid migration into the annulus, or operator intentionally performing. Or in a special case can generate accidently due to uncontrol flow from well. It will be normal in case of annular pressure less than the permissible limit and abnormal if it exceeds permissible limits.

1.5 Types of annular pressure

There are three major types of annular pressures (Sangesland, S., Rausand, 2012), thermal Pressure also known as (TAP or APB), SCP also is known as SAP and Applied Pressures. We focus on the first two types because it can be abnormal and harmful, these will be discussed as follow:

1.5.1 Thermal pressure

This type of annular pressure happens due to the thermal expansion of the trapped fluid in the annulus. Thermal pressure is recognized by bleeding (when possible) it will stable at bleeding value (no build-up again). The major basic conditions that must be found for generation TAP are two. First, is the heat source redistributing the temperature of the wellbore? Second, the closed annulus zone is filled with low compressibility sealed liquid to have a fluid volume change (Zhang et al., 2017).

1.5.1.1 Feature that characterizes thermal pressure loads

To analyse thermal pressure, the list of the features that characterize its loads in HPHT and SSW must be introduced for each annulus (Sathuvalli et al., 2016).

1- Unconditionally potential of developing APB, the pressure increases in addition to hydrostatic of the fluid in the annulus it is led to extra pressure can cause early severe failure to the casing strength loads.

2- The annuals are bounded by inner and outer string, the greatest differential pressure (burst or collapse load) happened when one side of the annulus has a TAP and the neighbouring annulus have not. Irrespective of the operational situation that creates the TAP, this assumption reflects the condition that gives rise to the most severe differential loads on the strings of the annulus.

3- The temperature change during production or drilling phases will be larger at shallower and colder outer annuli. Therefore, outer annuli can sometimes develop higher APB relative to the inner annuli.

4- The profiles of pore and fracture pressure that already showed increases with depth, the outcome of the drilling process is that the outer string is design to face a lower MASP so it has a larger ratio between outer diameter and thickness (D_{out}/t) compared to the inner followed casing strings(production, liners…etc.).

5- The collapse of the inner string in the trapped annulus is likely to accrue before the rupture of the outer string. Therefore, an APB load has the potential to cause the collapse of the frontal inner string and cascade toward the production tubing (P. D. Pattillo et al., 2007).

6- The management of the integrity of SSW (to production induced APB loads) cannot be simplified by adjusting tubular strength, annular pressure must be mitigated and managed during the life of the well.

1.5.1.2 Factors affecting thermal pressure

Some factors affect the amount of generated TAP, as follow:

1- Fluid thermodynamic property

The numerical coefficient linked the thermal expansion and fluid compressibility in most cases of calculations are consider constant, but in the reality, these coefficients are changed as a function of temperature even the temperature change is the same. There are different range of annular pressure in different temperature, so there is an inaccurate calculation of ABP, for that reason must consider the coefficient of temperature-dependent of thermal expansion and compressibility of the trapped fluid But, the problem concentrate at the difficulty of getting the coefficient of thermal expansion and compressibility of mud/fluid in the annulus however a published research (Yin & Gao, 2014) indicate that synthetic mud (annular sealing fluid) thermodynamic property are similar to tap water as shown in Figure1.3 so, the thermodynamics property of tap water is adopted to study APB calculation. The build-up pressure versus temperature is shown in Figure1.4. It indicates the different relationships between pressure and temperature for a different initial condition of temperature, when there is a high change in temperature the difference will be bigger, so in high temperature rang the APB will be quicker relative to the case of the lower temperature limit.

2- Boundary conditions of the annulus

The different boundary condition of annuals can be explained (Yin & Gao, 2014) by an expansion of casing at the annuals zone and both expansion and compression of fluid at the annuals, it will explain and calculated concerning the temperature change at the temperature section.

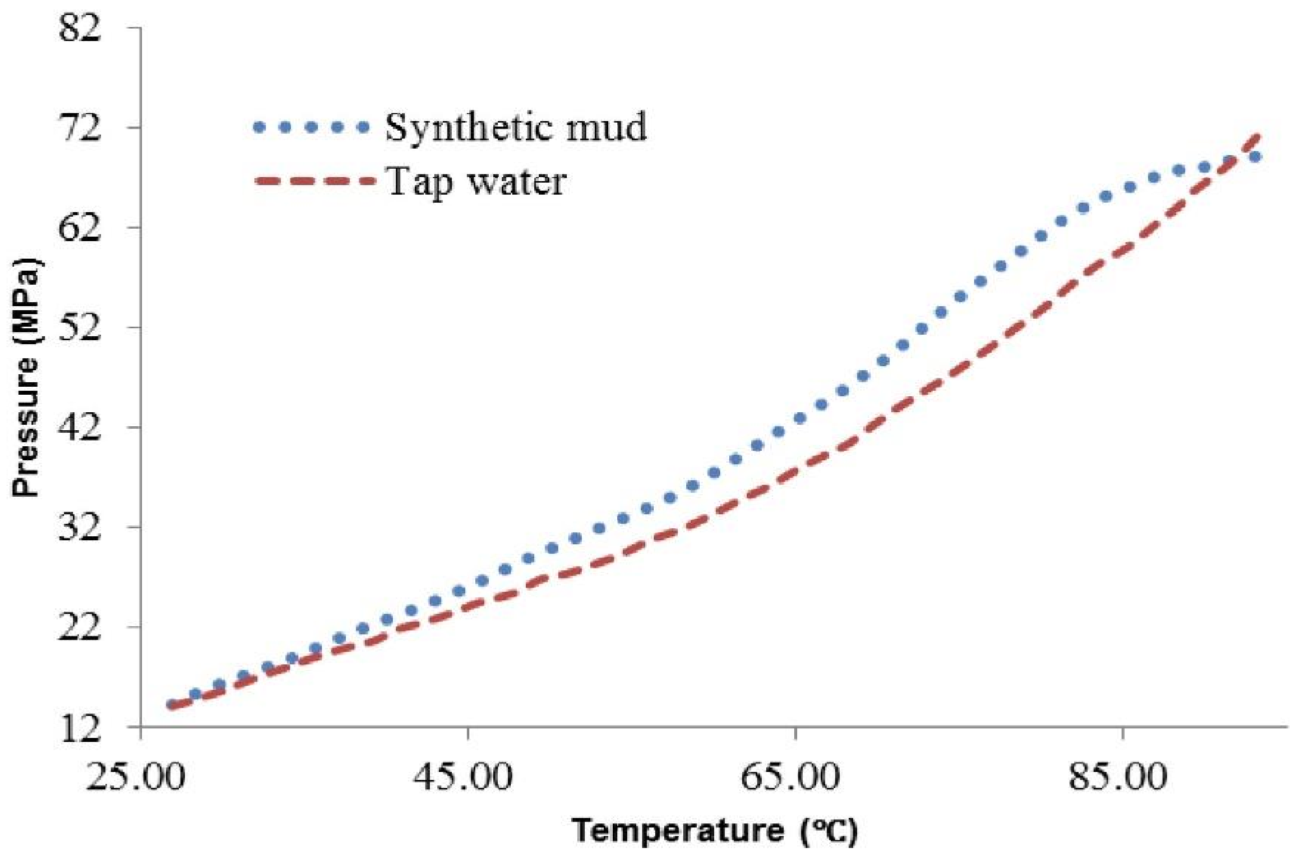

Figure 1. 3 Pressure versus temperature from experimental data (Yin & Gao, 2014)

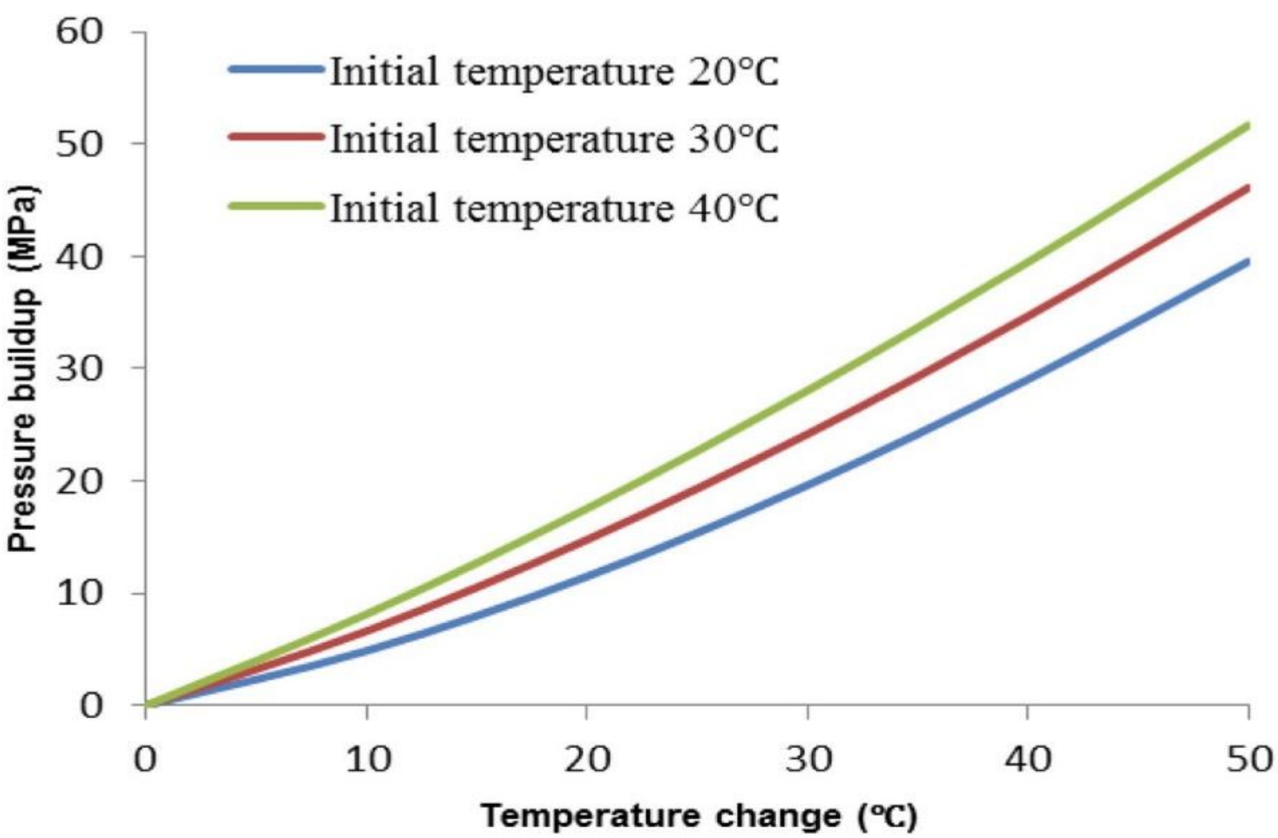

Figure 1. 4 APB versus temperature change in various temperature ranges (Yin & Gao, 2014)

3-Thermodynamic condition

In XHPHT or uHPHT wells, the temperature effect is directly proportional to the production rate, annulus length, and well depth (J. Liu et al., 2015). The effect of temperature change with depth is shown in Figure1.5 indicate the temperature difference along well depth and compared to the temperature difference during drilling and production. The boundary condition and the analysis of PVT for annular fluid determine the type and stiffness of the annulus, the stiffness of annulus is the measure of the expected pressure increase in the annular fluid per unit temperature increases are expressed as (psi/ºF). The predicted APB pressure in trapped subsea annuli tends to be about 80 to 150 psi/ºF of fluid temperature increases, generally, APB magnitude during production or drilling sometimes exceed the design strength (burst and collapse) of the annulus tubular (Sathuvalli et al., 2016).

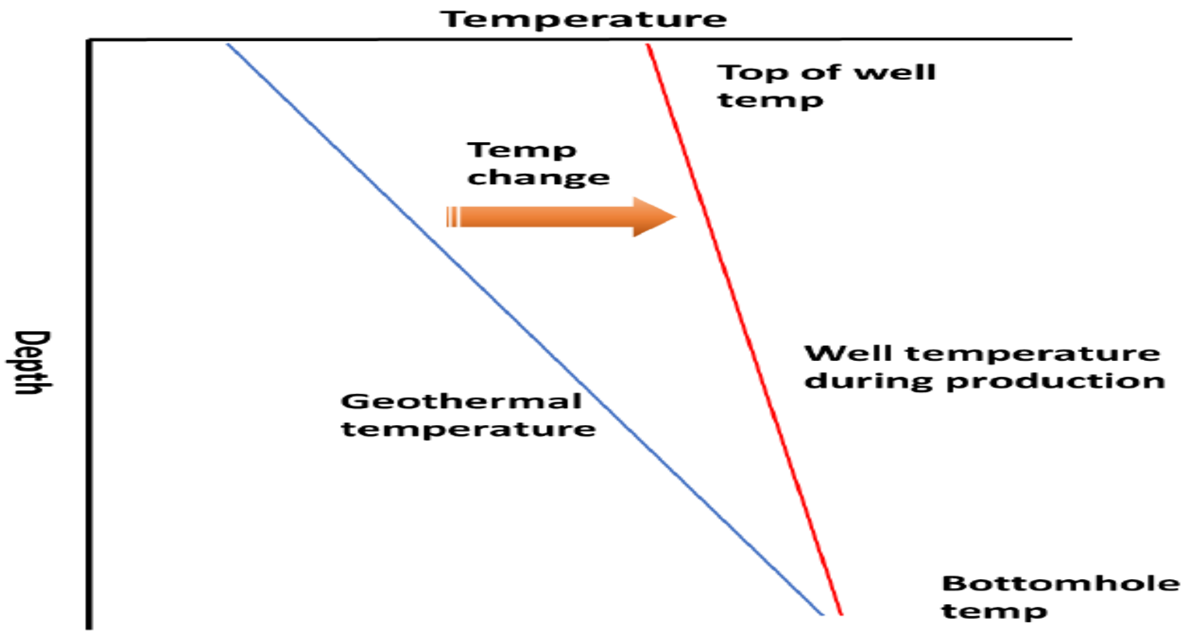

Figure 1. 5 Influence of temperature in HPHT wells

1.5.1.3 Behaviours and evaluations of thermal pressure in the annulus

In general, annulus integrity in deep-water HPHT wells can be threatened in three ways (Ansari et al., 2014)

1-Over-pressurizing of the wellhead/hanger/casing above the maximum absolute pressure.

2- Override the maximum burst pressure differential (outward).

3- Override the maximum collapse pressure differential (inward).

To be able to evaluate the APB it is important to clarify the pressure and casing strength and concentrate on the relation between the temperature and pressure of trapped space.

There are four types of evaluation methods can be applied to estimate the ABP, these methods are (Dong & Chen, 2017)

I- Measurement of annular pressure practically by installing a gauge on the annulus 'A' for pressure and temperature measurement these devices can be wired or wireless gauges.

II- Measurement of APB by using experimental internal simulation with creating a synthetic environment in the special lab to simulate the APB by pressure and temperature change that can occur in a real environment. Also, this type can be used for mitigation techniques testing, and evaluation.

III- Using prediction modelling for estimation of APB. This model is establishing depending on the fundament of energy conservation, PVT state equation, and wellbore heat transference equation. It is the more accepted one for engineering calculation especially the analytical one. This type is applied for designing purposes.

IV- Smart observation method for annular pressure of tubing and casing during well life.

1.5.1.4 Modelling and calculation of TAP for Multiple Annuli

The standard casing design of almost SSW is generally composed of various annuli (Yin & Gao, 2014). Figure1.6 shows the standard casing program of SSW with different annuli. The main distinction between APB modelling applications is the principle of computing methods of fluid volume variation-

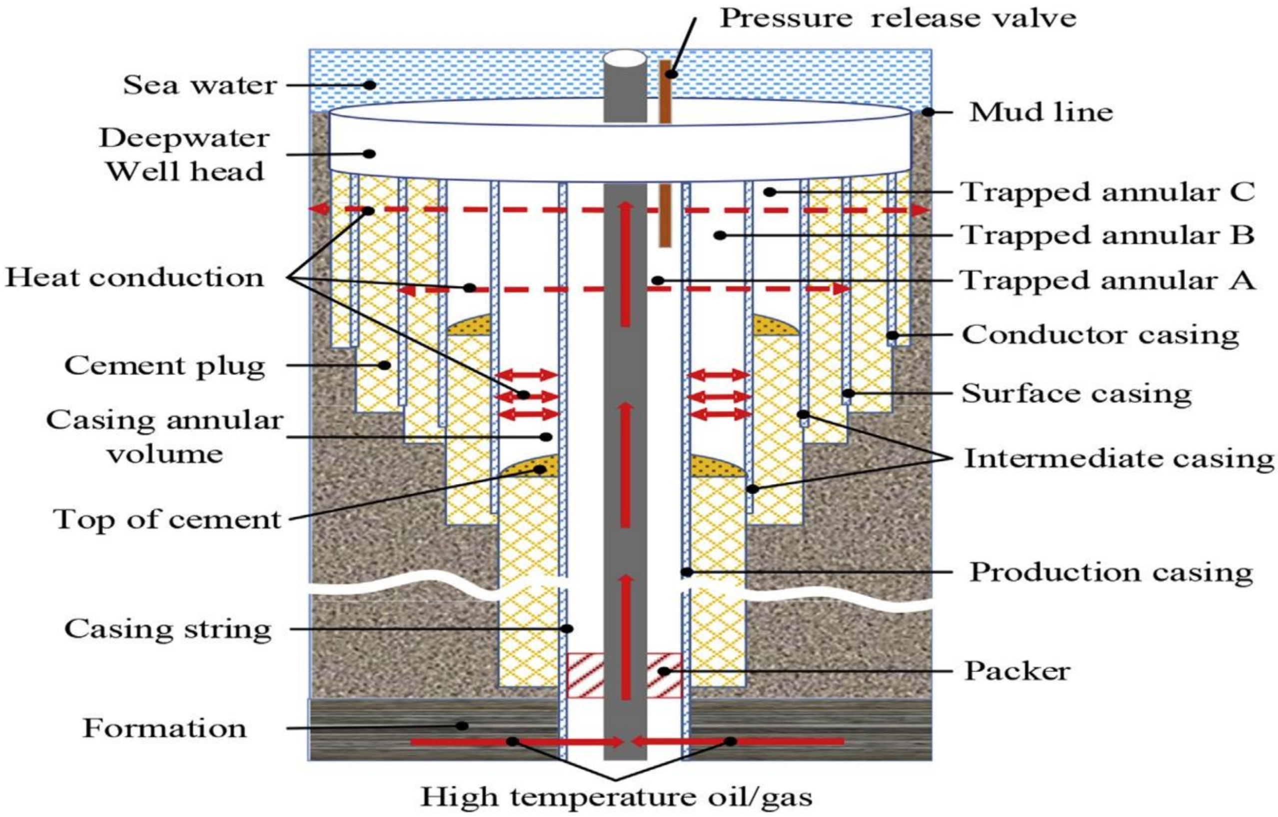

Figure 1. 6 Standard casing design for deep water wells (Yin & Gao, 2014)

(Sathuvalli et al., 2005), (Oudeman & Kerem, 2004). The application of a new unconventional casing design(multi-string casing design) is based on the TAP effect on the annulus of casing strings, this design needs to analyze and determine the annular pressure by using modules for calculation (Halal & Mitchell, 1994). The TAP depends on the ability of the trapped fluid to expand and the allowable annular space for expansion due to geometry changes as a result of displacements of casings and tubing. The pressure increase will change the volume of the annular space due to the elasticity of the steel (Adams, 1991). Based on Lame's equations or thin wall shell theory, the estimation of APB based on PVT fluid analysis, pressure with temperature changes, and resultant volume change. The annular volume change as a result of some factors that are thermal expansion of steel, compression of the internal casing, and ballooning of the external casing. So we review the model developed by (Yin & Gao, 2014) to explain the way of APB calculation for multiple annuli.

Model assumption:

1- The annular pressure at annulus 'A' is constant.

2- The annular temperature at annuli 'B' and 'C' approximately similar.

3- The changing of the annular temperature is uniform.

4- There is No leakage or influx in each annulus.

When the change in temperature of the annular occurred during well activities such as drilling, well test, or production this change defined as **ΔT**, and the change in pressure of 'B' and 'C' annuli are defined as ΔP_1, ΔP_2 respectively, so the analysing of the annulus are built on two sections:

1- Analyzing of annulus casing

- Thermal expansion of the casing

When temperature increases the casing's, the wall displaces radially and annular volume decreases. In the cylindrical coordinate system, the displacement of the casing is:

$$ur = \frac{1+\mu}{1-\mu}\frac{\alpha c}{r}\int_{ri}^{r}\Delta T r dr \quad \text{------(1-1)}$$

Where:

u_r**:** Radial displacement of the casing wall. μ: Casing Poisson's ratio.

r: Casing radius, m. α_c: Casing thermal expansion coefficient, °C^{-1}

ΔT: Annulus temperature change, °C

The production casing radial displacement outside the wall is

$$u_{1o} = \alpha_c . \Delta T . (1+\mu) / (1-\mu). (r_{1o}^2 - r_{1i}^2) / (2.r_{1o}) \quad \text{-----------(1-2)}$$

Idioms mean

$\mathbf{u_{1o}}$: Production casing outside wall radial displacement.

$\mathbf{r_{1i}}$: Production casing internal radius, m. $\mathbf{r_{1o}}$: Production casing external radius m.

The radial displacement of the outside wall of the intermediate casing is given by:

$$u_{2o} = \alpha_c \cdot \Delta T \cdot \frac{1+\mu}{1-\mu} \frac{r_{2o}^2 - r_{2i}^2}{2 \cdot r_{2o}}$$ ----------------- (1-3)

Where:

$\mathbf{u_{2o}}$: Intermediate casing outside wall radial displacement.

$\mathbf{r_{2o}}$: Intermediate casing outer radius, m. $\mathbf{r_{2i}}$: Intermediate casing inner radius, m

The decreasing volume of annular zone "B" due to thermal expansion of production casing is given by:

Where: $$\Delta V_{B1} = \pi\left[\left(r_{1o} + u_{1o}\right)^2 - r_{1o}^2\right] L_1$$ ------------------ (1-4)

$\mathbf{\Delta V_{B1}}$: Volume decrease of annulus "B".

The decreasing in the volume of annular zone "C" due to thermal expansion expressed:

Where: $$\Delta V_{C1} = \pi\left[\left(r_{2o} + u_{2o}\right)^2 - r_{2o}^2\right] L_2$$ ------------------- (1-5)

$\mathbf{\Delta V_{c1}}$: Volume decreasing of annulus "C".

- Casing Ballooning and compression

The change in annular pressure due to thermal expansion leads to a change in the volume of the annulus. The increment of the volume is assigned to outside casing ballooning and compression of the inside casing part.

Based on the Lame formula, the casing radial displacement under internal and external pressures is given by:

$$u_i = \frac{1+\mu}{E}\left[\frac{r_i^2 r_o^2 + (1-2\mu) r_i^2 r^2}{(r_o^2 - r_i^2) r} p_i - \frac{r_i^2 r_o^2 + (1-2\mu) r_o^2 r^2}{(r_o^2 - r_i^2) r} p_o\right]$$ -----------------(1-6)

Where:

$\mathbf{u_1}$: Casing radial displacement, **E**: Young's modulus of the casing, Mpa.

$\mathbf{r_i}$: Casing internal radius, m. $\mathbf{r_o}$: Casing external radius, m.

$\mathbf{P_i}$: Internal pressure, Mpa. $\mathbf{P_o}$: External pressure, MPa at the pressure change of annulus zone "B" that already defined as ΔP_1, the radial displacement of production casing external wall is given by:

$$u_{1o}' = -\frac{1+\mu}{E}\frac{r_{1i}^2 r_{1o} + (1-2\mu) r_{1o}^3}{(r_{1o}^2 - r_{1i}^2)}\Delta p_1$$ --------------- (1-7)

Where:

u_{1o}: Radial displacement of the outside wall of the production casing.

ΔP_1: Pressure change of annulus "B", MPa

The resulting volume increase of "B" annulus is:

$$\Delta V_{B2} = \pi\left[(r_{1o} + u_{1o})^2 - (r_o + u_{1o} + u_{1o}')^2\right]L_1$$ ----------------- (1-8)

Where:

ΔV_{B2}: Volume expansion of annulus "B". **L_1**: length of "B" annulus, m

The radial displacement of intermediate casing inside the wall at pressure changes of zone "B" ΔP_1 and ΔP_2 for zone "C" is given by:

$$u_{2i}' = \frac{1+\mu}{E}\left[\frac{r_{2i} r_{2o}^2 + (1-2\mu) r_{2i}^3}{(r_{2o}^2 - r_{2i}^2)}\Delta p_1 - \frac{r_{2i} r_{2o}^2 + (1-2\mu) r_{2o}^2 r_{2i}}{(r_{2o}^2 - r_{2i}^2)}\Delta p_2\right]$$ --------- (1-9)

Where:

u_{2i}: Radial displacement of intermediate casing inside the wall.

ΔP_2: Pressure change of annulus 'C', MPa

The increased volume resulting in section 'B' annulus is:

$$\Delta V_{B3} = \pi\left[(r_{2i} + u_{2i}')^2 - r_{2i}^2\right]L_2$$ ----------- (1-10)

Where:

ΔV_{B3}: Volume increase of annulus 'B'. **L_2**: length of 'C' annulus, m

However, the outside wall of intermediate casing radial displacement is obtained by:

$$u_{2o}' = \frac{1+\mu}{E}\left[\frac{r_{2i}^2 r_{2o} + (1-2\mu) r_{2i}^2 r_{2o}}{(r_{2o}^2 - r_{2i}^2)}\Delta p_1 - \frac{r_{2i}^2 r_{2o} + (1-2\mu) r_{2o}^3}{(r_{2o}^2 - r_{2i}^2)}\Delta p_2\right]$$ ---------------- (1-11)

Where:

u_{2o}: Intermediate casing radial displacement outside the wall.

This resulting volume increase of section C annulus is:

$$\Delta V_{C2} = \pi\left[(r_{2o} + u_{2o} + u_{2o}')^2 - (r_{2o} + u_{2o})^2\right]L_2$$ ------------ (1-12)

Where:

ΔV_{C2}**:** Volume increase of annulus 'C'.

2- Analysing of trapped fluid in the annulus

- Fluid thermal expansion

The fluid in the annular zone 'B' will be expanded due to the heat exchanging and the volume increases under constant pressure is given by:

$$\Delta V_{B4} = \alpha_l \pi (r_{2i}^2 - r_{1o}^2) L_1 \Delta T \quad \text{-------------------- (1-13)}$$

Where:

ΔV_{B4}**:** Volume increase of the fluid of annulus 'B'.

α_1: Coefficient of thermal expansion of fluid, °C^{-1}

The same for the fluid of annular zone of 'C' the volume is given by:

$$\Delta V_{C4} = \alpha_l \pi (r_{3i}^2 - r_{2o}^2) L_2 \Delta T \quad \text{------------------- (1-14)}$$

where:

ΔV_{C4}: Volume increase of the fluid of annulus 'C'.

r_{3i}: Surface casing inner radius, m.

- Fluid compression

Due to pressure increase in the annular pressure, the fluid will be compressed in the annular 'B' and 'C'. It can be expressed as:

$$\Delta V_{B5} = \kappa_T \pi (r_{2i}^2 - r_{1o}^2) L_1 \Delta p_1 \quad \text{------------ (1-15)}$$

$$\Delta V_{C5} = \kappa_T \pi (r_{3i}^2 - r_{2o}^2) L_2 \Delta p_2 \quad \text{---------- (1-16)}$$

Where:

ΔV_{B5}: Volume decrease in the fluid of annulus 'B'.

ΔV_{C5}: Volume decrease in the fluid of annulus 'C'.

κ_T: Compressibility of fluid, MPa^{-1} can be taken as tap water compressibility as mentioned previously at the fluid thermodynamic property.

Therefore, the change in fluid volume should be equal to the change in casing annular volume. The following expression can be applied

$$-\Delta V_{B1} + \Delta V_{B2} + \Delta V_{B3} = \Delta V_{B4} - \Delta V_{B5} \quad \text{--------------- (1-17)}$$

$$-\Delta V_{C1} + \Delta V_{C2} = \Delta V_{C4} - \Delta V_{C5} \quad \text{-------------- (1-18)}$$

By substation of formulas (1-1) ~ (1-16) into the formulas (1-17) ~ (1-18) the pressure changes in the annular zones 'B' and 'C' that represented by Δp_1 and Δp_2 finally can be calculated.
The TAP of two annular zones can be solved from the above formulas it is almost covered all situations of thermal expansion cause of generation of TAP, if there are three circular annuli need to be calculated, a set of equation similar can be applied to do this calculation (these situations are extremely rare). The aim of this development (modelling of APB) is to show one of the possible ways for determining the APB and how this calculation can be applied with factors affecting this calculation and show APB software's working principle.

1.5.1.5 Phases of TAP occurrence

There are three basic phases for TAP, production /stimulation, drilling, and uncontrol flow phase that is known as worst-case discharge (WCD).

1-TAP in production and stimulation phase

As reported at the sample well shown in Figure1.7 we can observe that the APB-

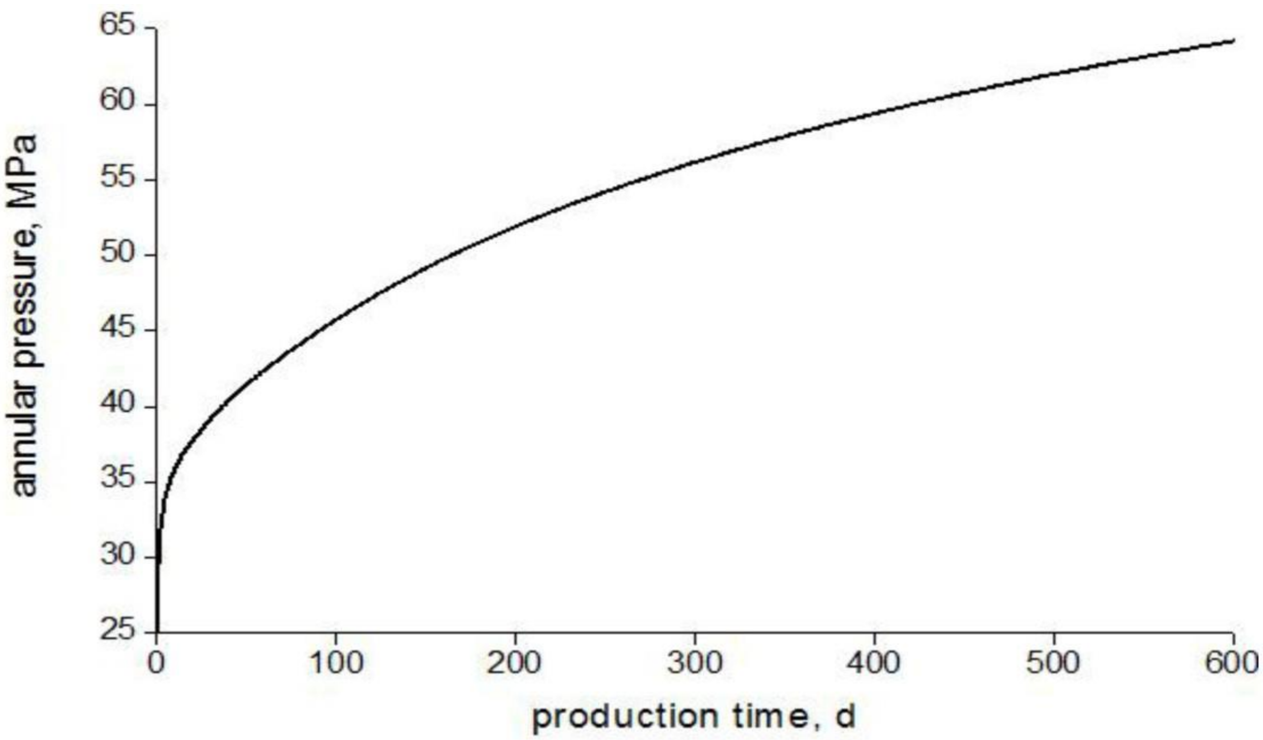

Figure 1. 7 Effection of Annulur pressure with production time (Zhang et al., 2016)

reaches a maximum recorded value (65 Mpa) within 600 days of production time. It is indicated that the annular pressure starts to build up at the point of trapped fluid expanded due to the heat exchanging and continues increasing proportional to production time, but the speed of expansion decreases with time due to a decrease of the temperature difference between the annulus and produced fluid. The maximum pressure is recorded at the highest production time that suspects the highest TAP for casing design failure scenarios.

2-TAP in the drilling phase

In the previous case TAP analysis, casing failure accrued at the production well, but in the case of the drilling operation, the same problem can be happened due to heating by drilling mud that carries the heat from the bottom hole to the upper part of the well (Phillip D. Pattillo, Cocales, et al., 2004). In HPHT for deep-water SSW or some land wells the temperature of the sealing fluid in the multi annuli (in the upper part of well) is low (about 4ºC) and it is reached to (120 - 500)ºC or more for the deeper section at the bottom of the hole, as shown in Figure1.8 the hot mud when carrying up the heating to the upper part of well can generate TAP which looms up the integrity of casing and wellhead that can cause a stick of drill string as a result of the existing casing collapse.

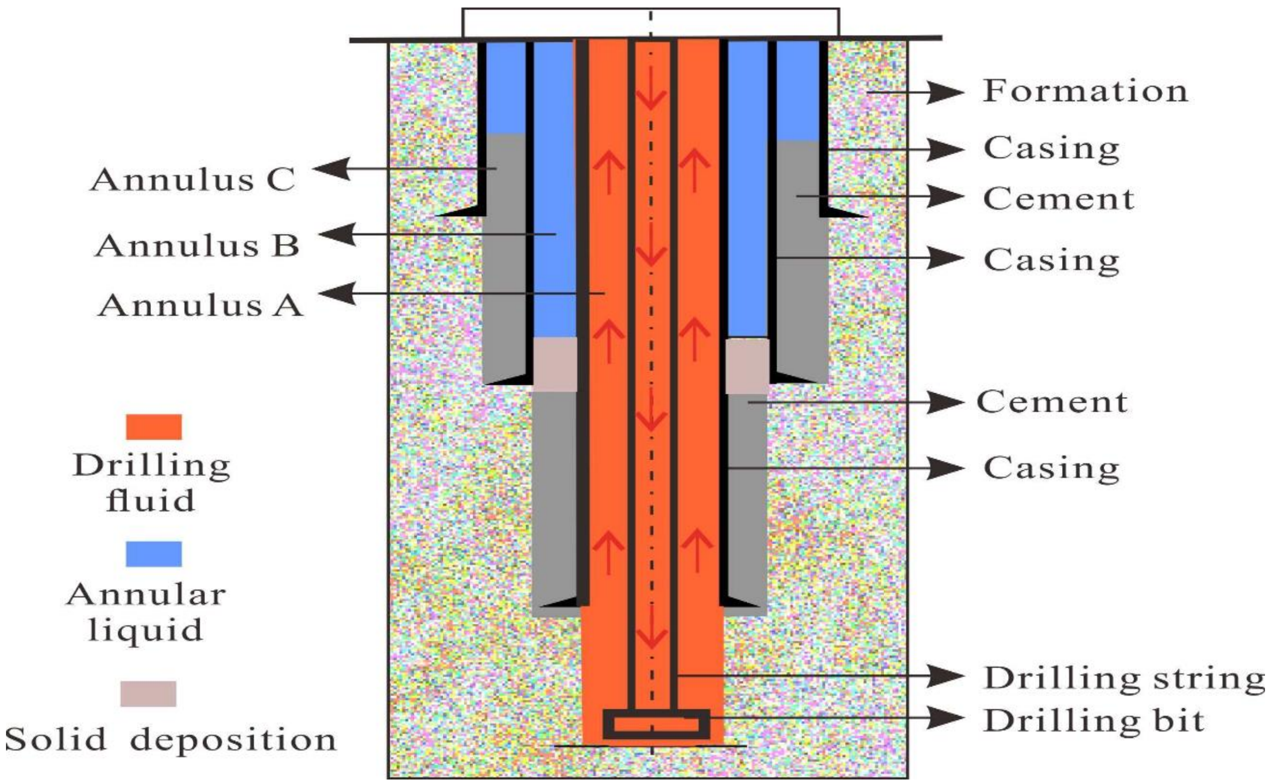

Figure 1. 8 Sketch map of TAP during drilling (Zhang et al., 2019)

As reported the problem of sticking drill string in well pompano A-31 in GOM due to damage of 16″ casing (Zhang et al., 2016). The annular pressure prediction will be fundamental when drilling goes deeper (J. Liu et al., 2017). The same approach that was explained previously at APB modelling is used to calculate TAP and accounted for in casing design and TAP mitigation techniques.

3-TAP in WCD

This is a special case of TAP happen accidentally in some cases of uncontrolled flow from the well due to loss of well control, so the high uncontrol flow will cause a high temperature come from the bottom hole, and as a consequence, the trapped annular volume will expand highly and generate high TAP can cause huge damage to well integrity if it is not accounted properly. For offshore HPHT wells, the WCD, as introduced by the Bureau of Safety and Environmental Enforcement (BSEE), is the empty hole (no drill string in the hole) uncontrol flow to the seabed with a fully opened reservoir and no flow limitation. WCD analysis was authorized by the U.S. government after the disaster of the "Deepwater Horizon oil spill" happened. WCD is calculated by linking a reservoir/inflow model to a nodal analysis model (Ansari et al., 2014)

1.5.1.6 Possible cases and locations of trapped annuli

There is some location the designer must be expecting trapped annulus occurrence and make their analysis before making the well design.

1- Deepwater wells

Deep-water wells contain various annuli resulted from the complex casing construction and cementing technology (Zhang et al., 2016). The Subsea wellhead is generally taking in the deep-water section, also the annuli are isolated beneath the seafloor by wellhead. The annular liquid temperature raises during drilling and production operations due to the high-temperature difference between the fluid inside the well and the surrounded environment of the annulus. As a consequence, for this reason, TAP widely appears in deep water wells. As examples reported in GOM, South China Sea, and more.

2- Wells in gas storage and high-temperature gas field

TAP can happen in gas filed recognized by a high-temperature or in gas storage because of the annulus created by the production casing and the tubing is injected with conservative materials to avoid acid corrosion and reduces the pressure difference on packers. So this liquid will expand and create a high TAP, as reported cases in gas storage in "North China, Xinjiang Province in China, and Sichuan Yuanba and Puguang gas fields" (Halliburton, 2012).

3- Multiple packers oil and gas wells

This technique is mostly used in wells to perform staged fracturing or isolated layer stimulation.

As shown in Figure1.9. Trapped space is generated between closer packers. Similarly, the space trapped between the liner hanger and the packers will also permit the creation of TAP. The same problem was happened in "Tarim Oil Filed, Elly & Luke Oil Field in the North Sea, Denmark, and Magnolia Oil Field in GOM" (Zhang et al., 2019).

4- Steam injection wells and shale gas reservoirs horizontal wells

Poor cement and low displacement performance may contribute to APB in shale gas and steam injected wells. The horizontal segment in the shale gas wells may be largely extended, as shown in Figure1.10 and it can be decentred to the casing. For these situations, the mantle of cement can be absent between casing and surrounded formation. The shale layers are poor in permeability, the lost part of the cement mantle becomes trapped location. furthermore, this space may be existing in gaps of cement mantle between the outer production and inner intermediate string. The fluid in this trapped space will warm up during drilling, production, or injection operation so APB could happen. This type of TAP sometimes gives rise to damage of casing in steam injection and shale gas wells as reported in the "Canada Peace River area and China Changning-Weiyuan area" (Zhang et al., 2019).

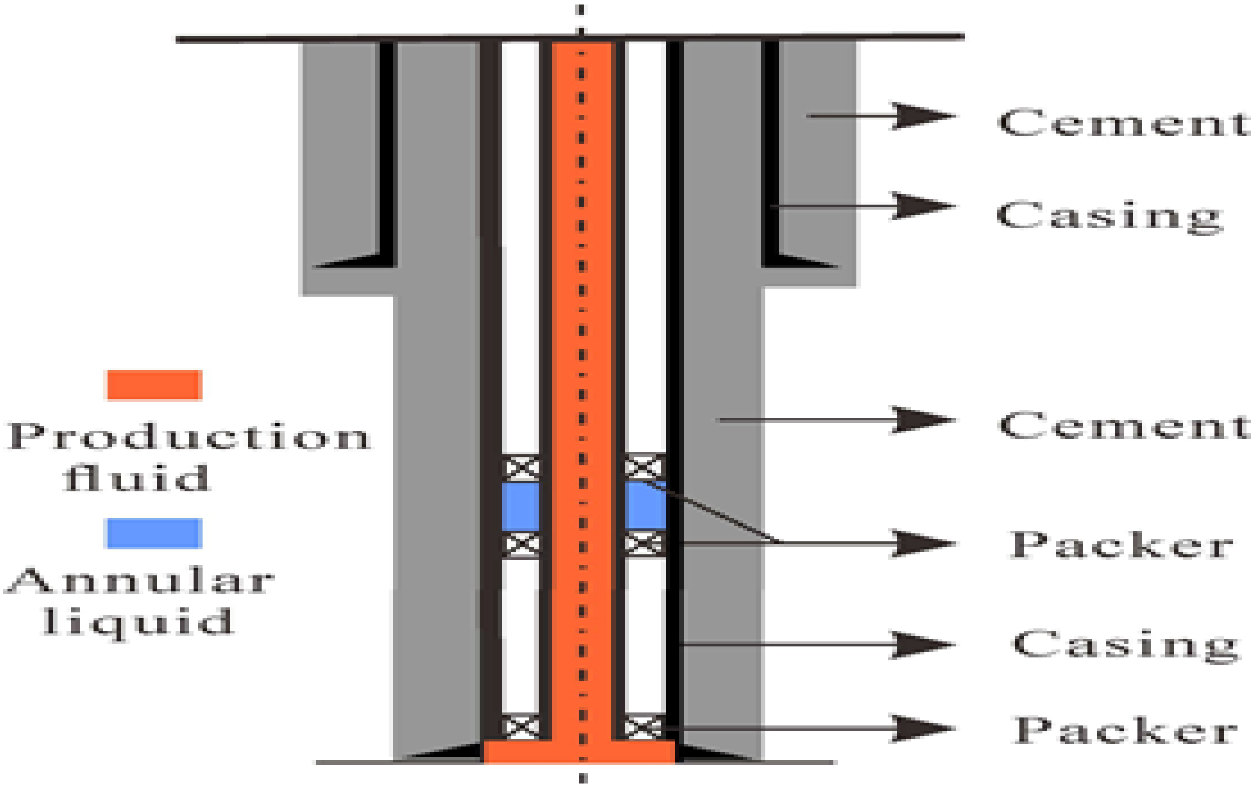

Figure 1. 9 Representation of packers trapped annulus generation (Zhang et al., 2019)

Based on these analyses and field reports, The TAP possible to found in three generated annuli, depending on the well structural design, cementing technologies, and evaluated quality.

1- Casing and wellhead are generate trapped annulus, as explained previously.

2- The trapped annulus is generated by the nearby packers and must be considered in the production plan and avoided.

3- Trapped gaps found in the cement due to low cement quality or patchy wellbore and must be prevented by cement improvement and indicated by cement bound quality check.

The density of the fluid and drilling type has a low effect on the TAP. For the particular well, these parameters are helping to determine whether the annular trapped happened out whether.

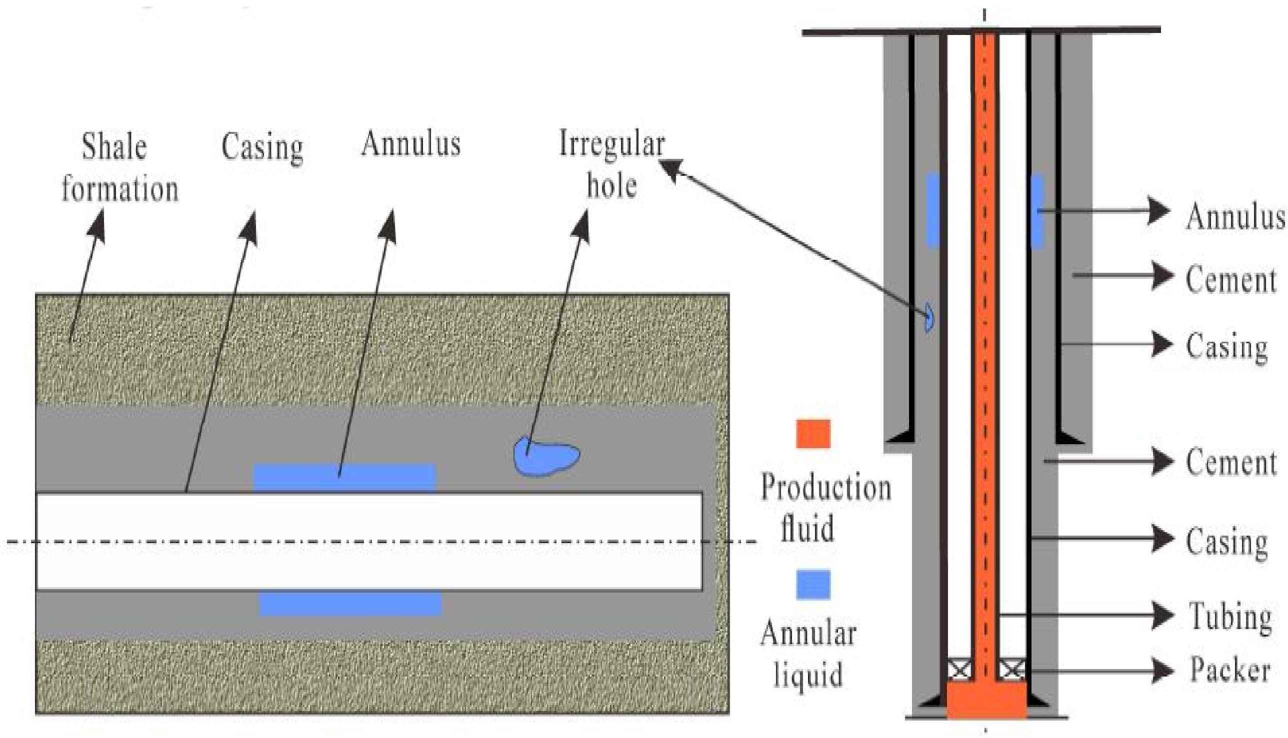

Figure 1. 10 Annulus of horizontal section due to poor cement (Zhang et al., 2019)

1.5.2 Sustained casing/annular pressure SCP or SAP

The SCP is recognized from other types by the ability to raising again after bleeding because it depends on the pressure difference between the annulus and feeding source(formation or leakage tubing) and permeability or severity of channelled cement (Zhang et al., 2018). The annular sealing may fail due to cementation operation errors such as incorrect mud displacement, gas leaks through cement liquid-solid transition, and cracking of cement sheath during well age. The pressure measure in all of the casing strings after the well completion, it must be zero, when there is a steady-state condition of well flowing, and there is a little fluid volume generated the effect of thermal expansion it should be vent through the wellhead to equalize the annulus casing pressure to the normal atmospheric pressure. (Zhu et al., 2012).

1.5.2.1 Causes of SCP

Generally, SCP happened due to failure in internal or external well integrity barriers and developed to worst-case by broken all well barrier of integrity to casing damage and surface leakage.

1.5.2.1.1 SCP by internal integrity failure

It is happening as a result of tubbing leaking inside the annulus, or seepage between casing strings. This cause is likely to occur when the tubular impacted by corrosion, poor connection of threads, thermal stress cracking, or rupture happened mechanically (Riggs, 2001). It can be indicated quickly by changing inside string pressure and observe the casing pressure, if there is an equilibrium that means it is linked by the leak. Or in some cases can be indicated from routine production records. This is a recurrent case of SCP and it can easily be recovered by well work-over operations.

1.5.2.1.2 SCP by external integrity failure

In this case, the pressure generated due to passageway from pressured zone such as hydrocarbon-bearing, water-bearing, shallow gas zone, shallow water zone, or of biogenic origin. This case technically difficult repairing and can cause poor zonal isolation and risk to the casing loads integrity. Furthermore, it may cause surface leaking (Rocha-Valadez et al., 2014). External integrity failure can happen due to:

1- Poor cementing

Occurred when the gas migrates from its zone to the upper annular part due to the bad or channelling cement bond between casing and formation and pressure difference.

2- Failure of primary cement after setting and generation of micro-fractures

The casing, cement, and formation will have a big variation in elastoplastic between cement and casing at CCI and when the thermal displacement reaches a specific level, the cement will be converted from elastic to plastic deformation. Plastic deformation cannot be recovered. As a result, the casing displacement can be recovered when the casing internal pressure decreases while cement cannot. Cement and casing will no longer be still located in close contact when tensile stress override the interface bonding strength, and then displacement variation occurred between the cement internal surface and casing outer surface (Zhang et al., 2018), the microfracture will be generated and provide a passageway for the pressured fluid to flow up into the annulus. Also, micro-annulus/channelling in the annular cement sheath can occur due to bad mud displacement during cementation (Mwang'Ande et al., 2019). This poor isolation will eventually lead to the flow of water or gas and generate SCP (Animesh Kumar et al., 2017). There is some parameter affecting this annular pressure (in case of gas migration) These specifications concern but are not limited to the existence and volume of the gas cap at the head of the casing, the height of the mud column as well as the permeability of the gas through the cement column (Bourgoyne et al., 2000).

1.5.2.2 Modelling of SCP

The model appropriate for accounting of SCP that is fixed for the transmission process of the system. Statistical indication shows the probability of SCP occurrence increases during the well ages. To analyse, calculate SCP, and then be able to account for the risk for SCP and get the optimum well design or select optimum remediation operation. (Milanovic & Smith, 2005), we present an analytical solution published by (Rocha-Valadez et al., 2014), a gas model that migrates up the annulus through both the cement sheath and the liquid column, to show the possible way for determining SCP and apply it in calculations.

-Model assumption

1- Vertical flow of gas in the annulus through the liquid column.

2- Constant mud density and formation pressure.

3- Slightly compressible fluid.

4- The well produces at a constant rate to ensure that the oscillating flow at the pipe does not encourage any heat transfer that affects the result of the calculation.

- Formulation of the model

Modelling of SCP by gas seepage through weak or channelled cement shown in Figure1.11, where the gas section has a length of L_g and annular sealed mud column of L_f, with a cement section of length L_c, the gas pass through the mud column during its migration and collect up due to buoyancy then form a gas cap. The casing must be opened and release all the pressure to the initial pressure value (P_o) at the beginning of the test, the valve of the annulus A at the casing head is closed, that permit the migrated gas bubble to move up the mud section at the annulus. The hydrostatic mud pressure is constant, but the mud will be compressed due to the expansion of gas volume above the mud and the slight compressibility of mud. So, the gas flow rate (q) of migration through the channelled cement section expressed by

$$q = \frac{0.003164\, K\, A\, Tsc}{Lc\, \mu i\, Zi\, Psc\, T} * (Pf^2 - Pc^2) \qquad \text{----------------(1-19)}$$

where

q = Gas migration flow rate scf/day

K = Permeability of cement to gas, md.

A= Annular Cross-section area. ft^3

T_{sc} = Standard condition temperature (=491.7 ºR).

L_c = Length of cement section, ft.

μ = Viscosity of gas, cp.

Z = Deviation factor of gas, dimensionless.

P_{sc} = Pressure at standard condition (14.7psia).

T = Source formation temperature ºR.

$P_{f=}$ Source formation pressure.

P_c = Pressure at T.O.C, psia

Gas moles (n) are calculated by using gas law **P V = n R T**

where **P** is the pressure of the gas cap, **V** is the volume of gas, **T** is gas temperature, **R** is the constant of gas (=10.731ft^3.psi/ºR.Ib-mol).

The change in gas volume can be accounted for by the compressibility of the mud section. the differential equation for casing pressure transient behaviour is expressed as:

$$\frac{dp}{dt} = \frac{\frac{0.003164\ K\ A\ Tw\ h}{Lc\ \mu i\ Zi\ Psc\ T}(Pf^2+0.0052\rho m\ Lf)^2}{Vi+CmVmp(1+\frac{1}{1+Cmp})} \qquad \text{----------------(1-20)}$$

where

L_f is a vertical depth of mud (ft), **T_{wh}** is wellhead temperature ºR

ρm is mud density at the annulus (Ibm/gal), **vi** is the initial volume of the gas chamber (ft^3)

Cm is mud compressibility psi^{-1}, **vm** is mud volume (ft^3)

Mud pressure in the annulus expressed by

$$P_{mud}=0.0052\ \rho m\ L_f \text{ (psi)}$$

simplified analytical solution of the differential equation (2) and included deviated well with expression independent of time the solution will be:

$$t= \frac{[(\alpha-1)Vi-\alpha\beta Vm]tanh^{-1}(\frac{P+b}{Pf})}{Pfd(\alpha-1)} + \frac{CmVm\{2\ln(1+Cmp)+(2-\alpha)\ln[Pf^2-(p-b)^2]\}}{2d(\alpha-1)} \qquad \text{-------(1-21)}$$

Where

t is independent variable **P** is casing head pressure, psia

Besides estimating the annular pressure increment and gas flow rate, we can account for cement seepage factor K_s by applying the generalized reduced gradient method with the formula of mean square error MSE

$$MSE= \frac{1}{n}\sum_{i=1}^{n}(yi^\wedge - yi)^2 \qquad \text{------------------(1-22)}$$

Where

yi is true value vector, variable unit, **yi^** is prediction value vector, different unit

Also, there is another advantage for this analytical equation it is used for estimating the maximum attainable casing head pressure P_{max} by equalization the derivative (eq 1-20) to zero we got this formula

$$\frac{0.003164\ K\ A\ Tw\ h}{Lc\ \mu i\ Zi\ T}[(Pf^2 - (Pmax + 0.0052\rho m\ Lf)^2] \to 0 \qquad \text{--------------(1-23)}$$

$$Pmax + 0.0052\rho m\ Lf \to P_f$$

Equation (1-23) make intrinsic sense can fell when the total of casing head pressure and the mud column head pressure $=0.0052\rho m\, Lf$ equivalent to the formation pressure P_f, there is no differential pressure available to the gas to leak into the annulus, that is the maximum casing pressure reached. This model can be applied to both oil and gas wells (Rocha-Valadez et al., 2014). This model can be applied by computer software supporting to make it faster and more useful. We present this model to show an example model for SCP calculation.

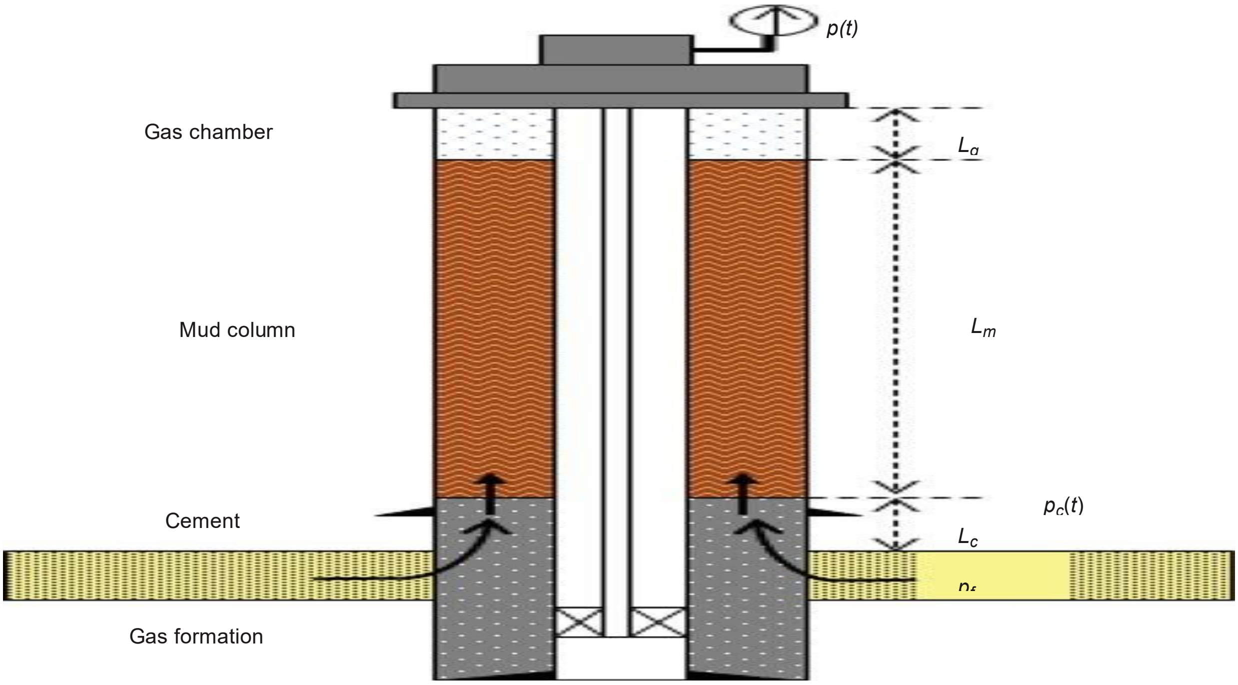

Figure 1. 11 Annular system of cement/mud and gas chamber (Rocha-Valadez et al., 2014)

1.5.3 Applied Pressure (AP)

The pressure can be applied to an annulus intently for different purposes, such as injection wells, gas lift, cuttings re-injection (CRI), recompense for bull heading loads, or helping in annulus monitoring and during pressure test operation. It is required to understand that applied pressure to one annulus can generate a pressure build-up in neighbouring annuli as a result of the ballooning effect. Attention must be taken to guarantee this pressure is vent after testing to a specific acceptable value to ensure that pressure does not result in MOP being overridden. This type of pressure is controlled by the operator, so it needs to control it within the permissible limit. In this research, we concentrate on the first two types.

CHAPTER TWO
DESIGNING OF ANNULAR PRESSURE MITIGATION TECHNIQUES

In this part, we discuss the possible solution for the annular pressure effect by applying a mitigation device for TAP and mitigation methods for SCP, also possible remediation methods that can be applied for well with damage due to SCP.

2.1 Mitigation of TAP

In most drilled HPHT wells, the TAP raised quickly at a rate of approximately 30 psi/min to reach a maximum value of 5000 to 8000+ psi, this pressure will threaten well integrity by possible annulus casing failure (Sathuvalli et al., 2005). For the land HPHT wells, this TAP can be easily vented from the wellhead. But in the SSW, "annulus 'A'" is the only attainable annulus, and the other annuli can't be controlled. So, it needs to design a new technique to protect casing integrity against TAP. It is a technique used to reduce or keep the TAP within the permissible range. The design of an APB mitigation strategy is focused on knowing how each subject annulus and mitigation system would react to the pressure-temperature in the wellbore. The mitigation system triggered an "operating point" predetermined. The operating point characterized by the thermal condition in that annulus and it is connected to the permissible APB. The using of mitigation device are introduced in unconventional casing design as survival design.

The survival design means the design of structure under extreme magnitude loads that may be accrued either with very low probability, but it can cause huge damage to the structure when this loads will happen, especially for deep-water HPHT wells, the loads applied is abnormal annular pressure and the risk is the loss of well integrity by structure damage, such loads cannot be modified by conventional design (Suryanarayana & Lewis, 2016).

2.2 Function of TAP mitigation device

The mitigation device must be able to (Phi et al., 2019)

1- Hold up the maximum expected loads to control pressure in the worst case.

2- Prevent casing failure at annulus with high unexpected thermal pressure.

3- Provide a barrier to improve and protect well integrity during well life (high reliability).

2.3 Design procedure for TAP mitigation

1-Select the annulus section ('A', 'B', 'C'…. etc.) with the expecting of abnormal pressure occurring.

2- Confirm factors of initiating the TAP (thermal exchanging that can make fluid expand and restricted annulus). Risk analysis can detect this hazard.

3- Calculate APB for both drilling and production scenarios with annulus analysis by applying a model of calculation as mentioned previously.

4- Compare the TAP value with the allowable value that is already defined by analysing annulus string properties (collapse and burst).

5- If TAP < Allowable annular pressure ‣‣‣ The design acceptable. Risk analysis indicates the level of risk and possible future failure to take into account if it needs any modification during design.

6- If TAP > Allowable annular pressure ‣‣‣ Risk case, then go to step (7).

7- Check if the annulus is trapped conditionally or unconditionally. This part is a critical section on design because it needs accurate analysis and a lot of scenarios to check the open section (if presence) ability to protect annulus.

A- If the annulus is unconditionally trapped for annulus 'A'

TAP can be observed and vented, the design acceptable after evaluating the risk of well integrity. In some companies' policies, the venting device for the annulus 'A' is not accepted and a mitigation device must be selected.

B- If the annulus is unconditionally trapped for annulus 'B', 'C', etc.

The casing strength modification or mitigation device must be applied.

8- First modify the tubular by redesign it (increase strength, change the size, weight grade possible), if the new allowable APB of the new design becomes greater than TAP the design accepted after a risk analysis, otherwise go to step (9).

9- Design a mitigation device based on TAP magnitude, condition of the annulus, production rate, pressure and temperature profile, trapped fluid composition, expected well age, production plan, and the most important part of design decided after a risk analysis.

10- Optimize selection of mitigation device, by applying risk analysis and cost-benefit analysis with possible implementation mitigation device then select the optimum from the list of possible design.

11- Uncertainty and lack of data or used expected value are negatively impact the design and selection, so the designer must be far as possible from these criteria during design and analysis.

12- Cost is one of the design criteria and limitation but it not the target because failure means loss of well barrier (casing and/or wellhead) of well integrity or may lead to lost the well, also the remediation for this failure (if possible to remediate) costed much more the prevention.

13- Standard such as API, ISO, Norsok…etc. and government rules must be included during the design and selection of mitigation devices.

2.4 Common techniques for APB Mitigation

Based on effective mitigation time there are two major categories of applied mitigation techniques (Zhang et al., 2016).

2.4.1 Active mitigation methods

This type of mitigation technique is based on preventing abnormal annular pressure generation by eliminating its causes. These techniques principled on wholly annulus cementing, isolate heat source and decrease generated heat from the source.

1- Cementing to surface: Trapped annulus will eliminate when the cement top is back to the wellhead.

2- Thermal-isolated pipes: They can enhance wellbore heat transfer resistance, and then reduced the speed of pressure increasing.

3- Heat-isolated liquid: Inject this treated liquid in the casing-tubing annulus zone to improve heat transfer strength.

4- Decrease production rate: Reducing the rate of production leads to less heat transportation into the wellbore, so annular pressure will be lowered.

2.4.1.1 Cementing to surface

Overall cementation eliminates the annulus fluid by extending the cement to the wellhead, as shown in Figure2.1. It’s the principle of the core, the expansion of cement smaller than the mud and pre pad.

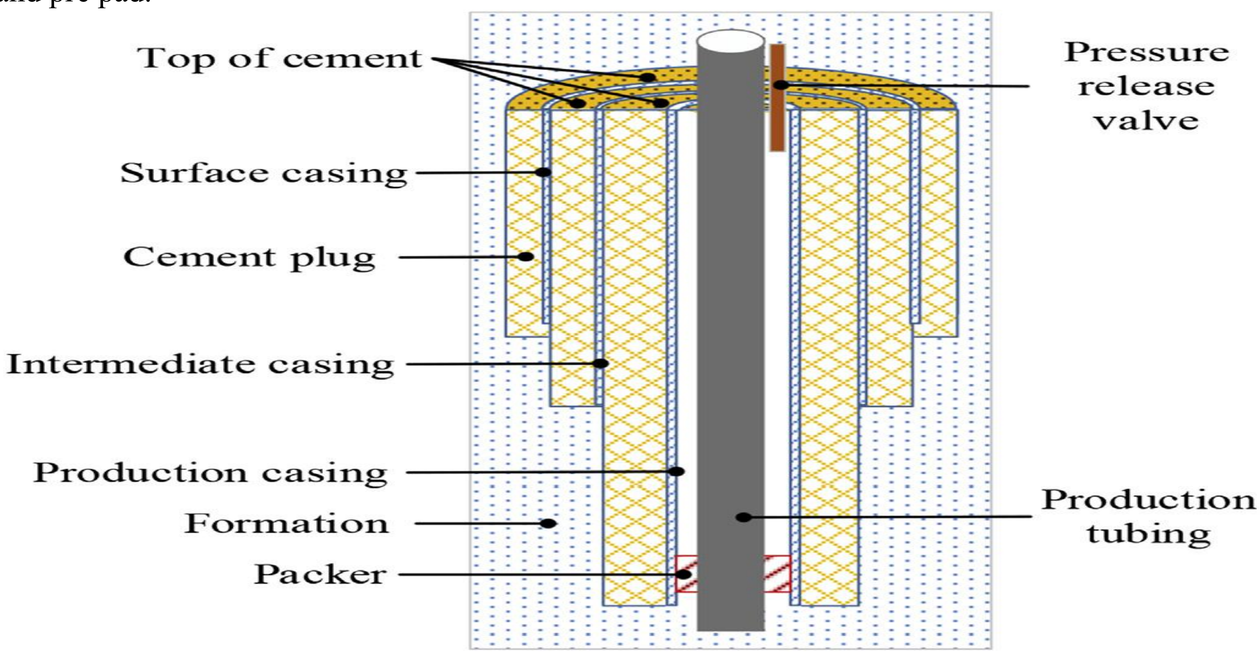

Figure 2. 1The schematic diagram of a well cement to the surface (Dong & Chen, 2017)

The drawback of this technique is that if in case of drilling fluids in the annular space is not substituted by cement, so TAP may also happen. Furthermore, deep water upper-hole formations are under-compacted and soft, so that high-density fluid can easily break the formation. (Dong & Chen, 2017).

Implementation of cement to surface technique

To achieve this technique there is a cementation method and consideration must be applied as

1- Top-Down Cementation

Removing the annular fluid and confined space (annulus) are the two majors of APB inhibitive, by filling the annulus with cured cement. Zonal isolation requirements can prevent leaving the annulus to expose. A narrow PPFG window maybe not accommodate the required equivalent circulating density to rise cement back to the wellhead. So, this consideration must be included in cementation design, the Figure2.2 show the head of cement modified with PPFG for sampling well.

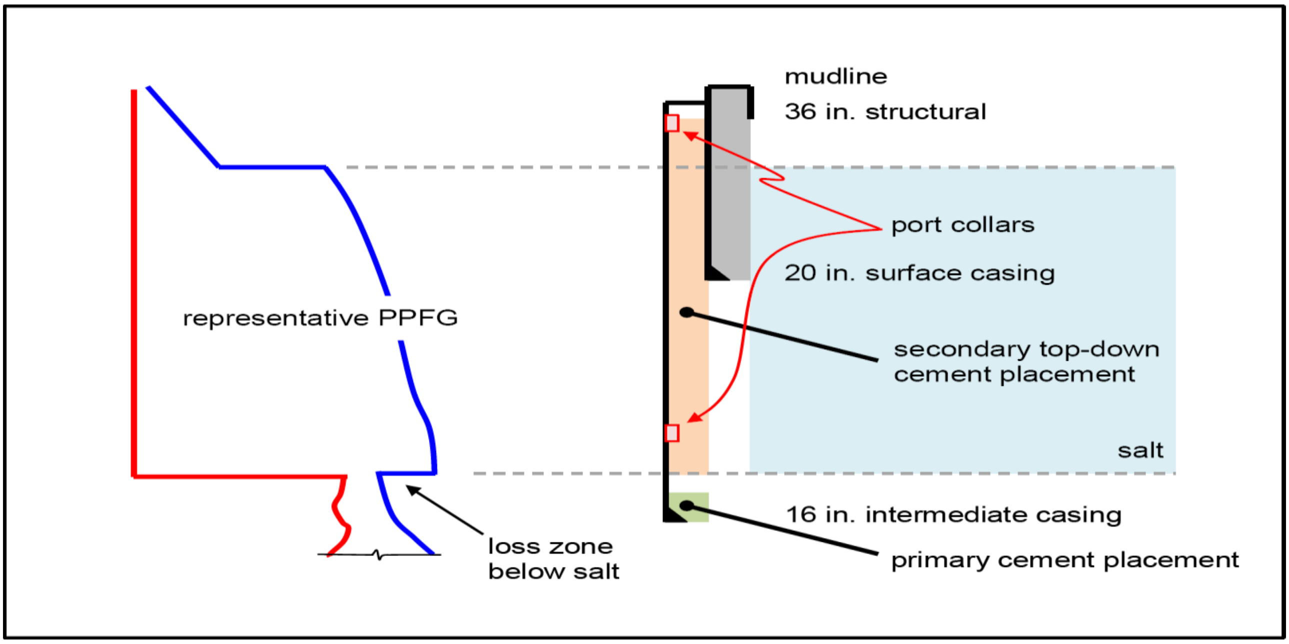

Figure 2. 2 PPFG and schematic showing loss zone and top-down cement placement of a well in GOM (Miller et al., 2018)

2- Top-down cementing design considerations

Tight clearance ECDs exceed the formation fracture pressure to challenge the zonal isolation in the hole portion where the smallest fracture pressure is below the cement top required (TOC). Achieving cementing objectives (reach to the surface) may need cement placement in multiple stages to reach a competent shoe, primary normal cement placement followed by top-down cement placement to separate possible flow zones above the smallest fracture pressure. While top-down cementing, the fluid at the annular above the first stage TOC can be injected in the weak formation. The squeeze of top-down cement was designed to override a weak formation fracture pressure in the open hole, which is specified during well planning. In case there is a potential of flow zones at the place proximity to the weak formation, there might be a lack of certainty as to which zone will take losses. this design scenario would raise the importance of setting the first stage cement top at, or just beneath, the upper DPZ. Unlike primary cementing where gravity tends to sustain the heavier slurry beneath the mud while annular placement, gravity tends to promote a heavier slurry to channel through a lighter mud. Controlling and designing rheological properties improve cementing operation to achieve the best result of cementation. as shown in Table 2.1 the difference between conventional and top-down stages of the cement slurry. Some top-down cement placement benefits from preparing cement with more than two formulations with different thickening times as an operating condition required (Miller et al., 2018). This method (cement shortfall) could cost a lot and take more time for application.

	Conventional	Top-down
Density	ρdrilling fluid < ρspacer < ρslurry	ρdrilling fluid ≥ ρspacer ≥ ρslurry
Viscosity	μ drilling fluid < μspacer < μslurry	μdrilling fluid ≤ μspacer ≤ μslurry

Table 2. 1 Density and rheological hierarchy for the two cement stages (Miller et al., 2018)

2.4.1.2 Thermal-isolated Pipes (Vacuum Insulated Tubing VIT)

Application of VIT was first used in 2003 by ChevronTexaco, to eliminate the TAP in deep SSW at Tahiti in GOM (Dong & Chen, 2017), it is usually run in a hole to (900-1200)m below the mud line. The VIT design is different between single-layer and multi-layer thermal isolation annular trap. As reported for the SSW, the most successful mitigation technique in almost cases is the use of VIT. This technique success in keeping an acceptable level of temperature for the annular fluid. Apart from its cost and operation, it is a suitable solution for high-temperature wells that have a problem of high thermal pressure (Gosch et al., 2002). The approach of the protection approved by the VIT technique is reaching in two ways. First, the profound section of wells reaching the stress limits of the VIT tubing designs due to the highest hanging weights. Second, the highest depths are also providing higher temperatures. (Bloys et al., 2008). The VIT usually consists of a double-wall tubular product, as shown in Figure2.3. The two tubes are connected together at the ends of the stumpy tube (e.g., the tube that does not contain connection threads) to build isolated annulus space. The VIT is connected by a threaded coupling connector, by connection in the inner tube or connection on the outer tube (each type of connection has a specific property) (Phillip D. Pattillo, Bellarby, et al., 2004). The installed VIT pipe therefore consisting of a vacuum and connectors part. The vacuum suction is better than the connector in the isolating effect, especially when the connector is not well insulated (Kang et al., 2017). Thermal-isolated pipes contain two walls and one inter-layer. commonly, the inter-layer is vacuum or stuffed with thermally isolated materials such as high-yield point fluid, viscous fluid, or just with light cement to increase the radial thermal strength. The expected lowest annular pressure is found when both setting depths are the top of the cement of annular 'B'. This tells that the best setting depth is the depth of TOC of annular 'B'. This is because the annulus radial heat inhibition will no longer be improved in the case of setting depth override TOC. To reach mitigation demand, thermal-isolated production casing and tubing can be used at the same well (Figure 2.4combination.2) or isolation tubing only (Figure 2.4 combination.1). To reduce the cost associated with operational, engineering, and suppling, VIT is always applied in combination with ordinary tubing. The VIT string is run from the midline to a strategically chosen point, below which ordinary tubing is applied. The setting depth, heat influxes, and the combination can be decided by numerical simulations of the wellbore and experimental methods or both. VIT tubes increase overall well cost and in limited equipping, also "cold-worked corrosion-resistant alloy (CRA) materials" are incompatible with the welding operations (Payne et al., 2007).

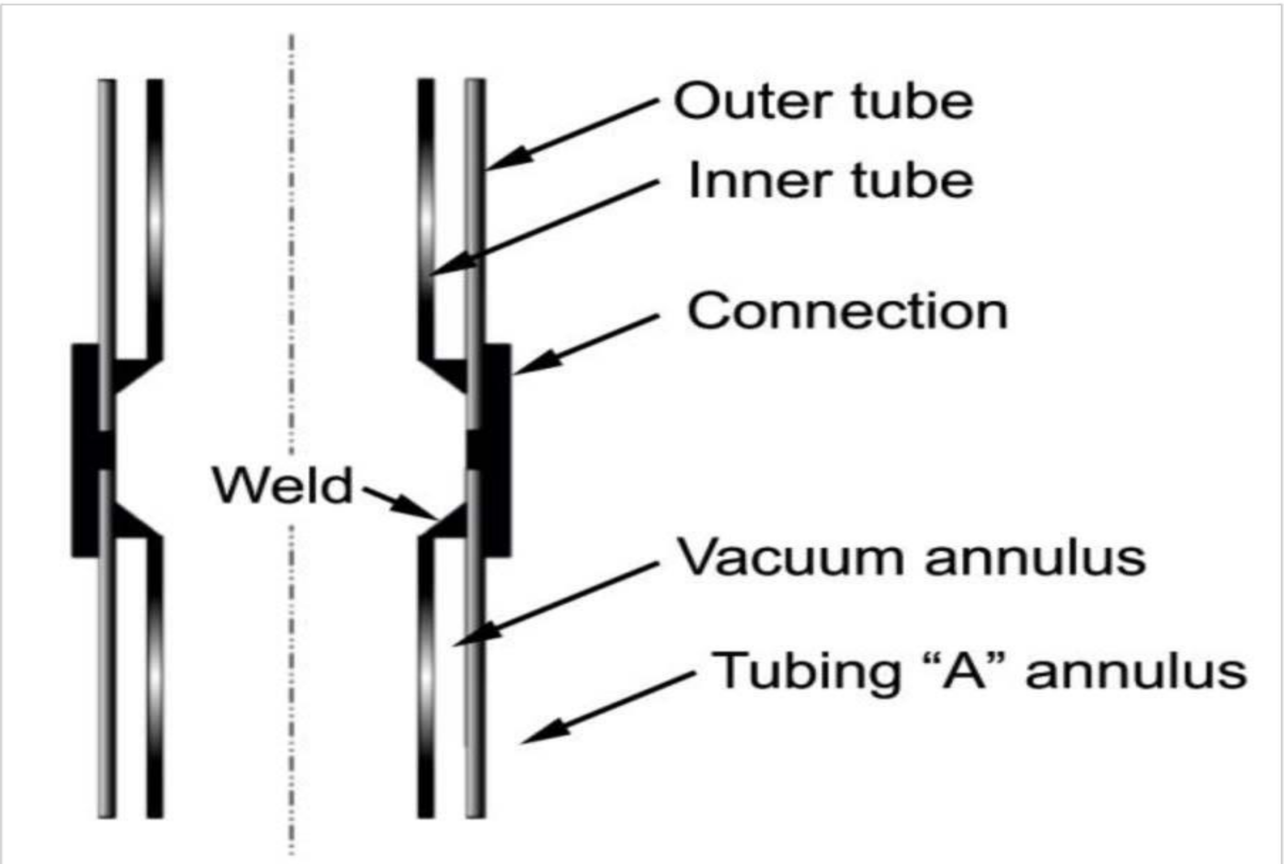

Figure 2. 3 Typical VIT schematic with connection on the outer tube (Kang et al., 2017)

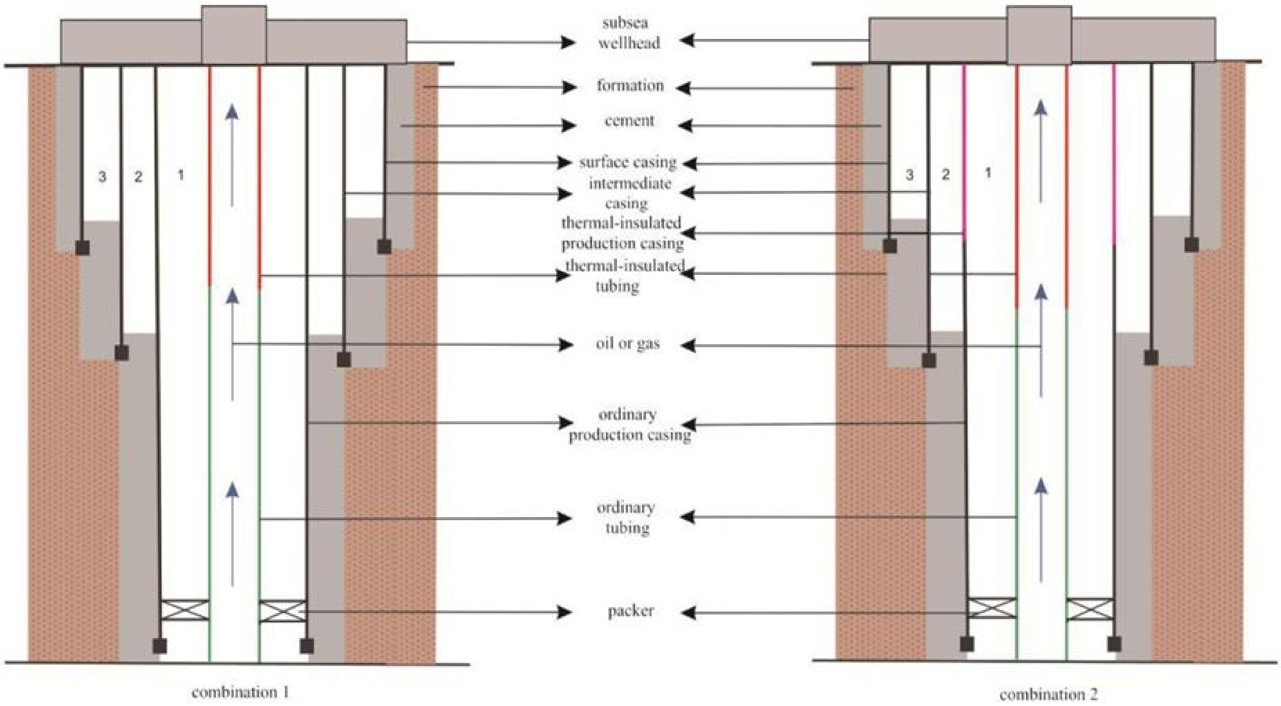

Figure 2. 4 Thermal- insulated pipes combination (Zhang et al., 2016)

2.4.1.3 Thermal isolating packer fluid (IPF)

The thermal-isolated liquid work by injected it at the casing-tubing annulus (annulus ‘A’). The principle of it is working are the same as VIT. The experimental data presented in Figure 2.5 demonstrate the effect of annular pressure change as conductivity increases of injected IPF. The annular pressure lowered as thermal conductivity reduced, but the speed of change differs. This indicates that IPF with small thermal conductivity can provide a good mitigation effect without paying attention to the rate and time of production, also indicated that the annular pressure becomes more sensitive to fluid thermal conductivity at high production rates and long production time. Furthermore, it is simple to decrease annular liquid thermal conductivity by mixing some chemicals such as polyhydric alcohols or soluble salt, such as ethanediol, propanediol, triglycol, KCl, NaCl, CaBr2, and so on. But there is one important thing that must be noted when using IPF, there is an effect on casing corrosion because some of them have a negative impact on the casing (Zhang et al., 2016). The reported data from experiments and application show that this technique work in a range of temperature of fluids from 250 to 270° F (~120 to 132° C) (Payne et al., 2007). IPF provides an alternative for VIT by reducing the cost for about 64%, increase flow assurance, ability to used downhole tool to be applied with production string, and reducing the time of application of this technique relative to using VIT (Ezell et al., 2010). One reported case is an example of a problem case solved by the application of IPF instead of VIT(Halliburton, 2012). In GOM location. The operator had applied VIT on the last wells, but only after introducing the N-SOLATE 275 IPF, where they can significantly decrease costs in the following ways:

i- Decreased isolation cost compared to VIT

ii- Decreased rig working time with not running VIT

iii- Ease of locating of N-SOLATE 275 fluid

iv- Elongated life of N-SOLATE 275 fluid

v- Decreased subsurface wellhead pressure

vi- Effectively decreased APB in outer casing annuli

It can be indicated that using IPF is best than VIT when the case required one of them if the condition permits applying IPF especially when we have a long heavy string of tubing so VIT cannot support these loads.

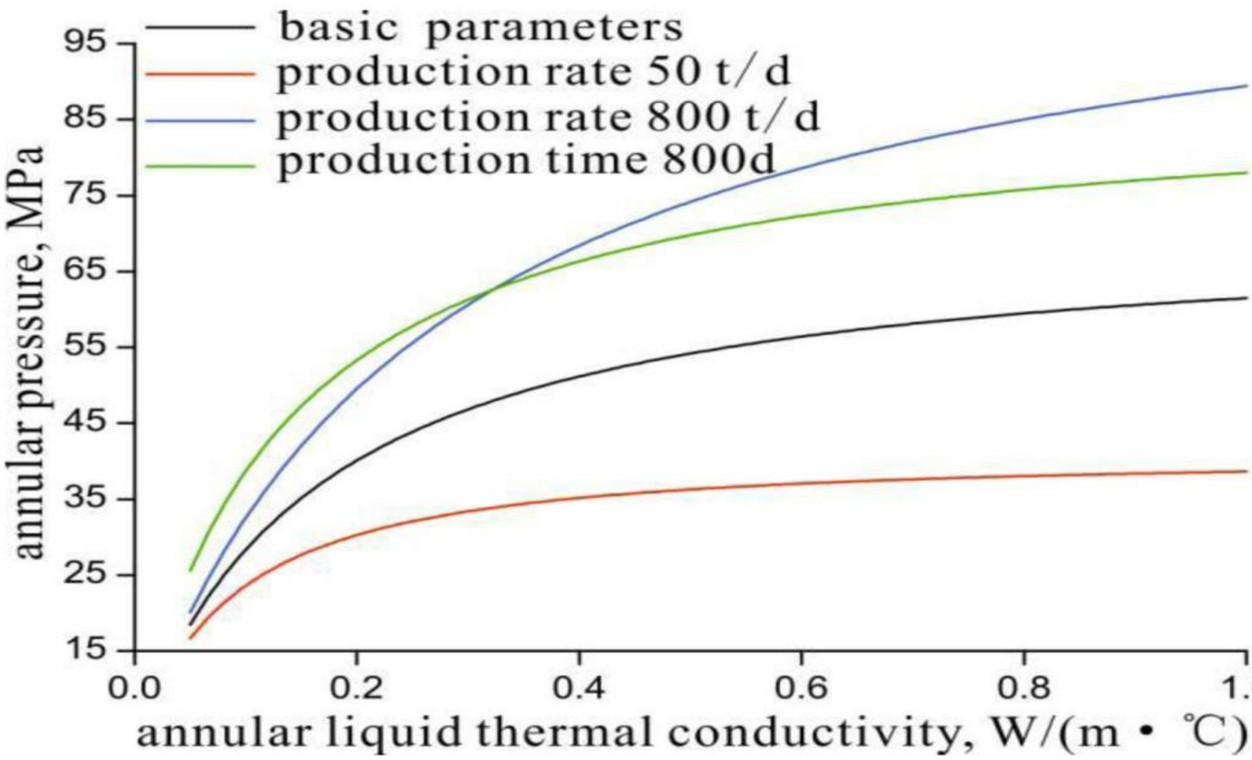

Figure 2. 5 Effect of annular pressure with thermal conductivity (Zhang et al., 2016)

2.4.1.4 Decrease production rate

Managing APB for sustaining well deliverability is essentially crucial in SSW, where intervention is consisting of many interconnecting parts or elements. The experimental data showed that APB increases when the production rate increases due to temperature increases. there are several models, such as the two analytic models of semi steady-state approach and transient approach (Hasan et al., 2010), for estimating APB to defining the amount of production rate decreasing on the way to APB relief. Moreover, the model can provide a guideline to the operators on the amount of venting volume required to get a better operable domain of production rate. Estimation of APB and bleed volume help to improve the methodology applied, for diagnosis and mitigation together. This method useful in case of the presence of TAP for production well that has not to design mitigation or to support the insufficient designed mitigation, but not suggested to decrease the production rate for the new design, so selecting another mitigation device is the best for new well design.

2.4.2 Passive mitigation methods

This type of mitigation technique is activated after the generation of TAP, these techniques are principled on venting APB, provide extra space for expanded volume, relief of the APB, and improve annulus properties to accept extra APB.

1-Cement shortfall

Provide a natural or pressurized fracturing venting way for the fluid pressure to bleed into formation by leaving TOC under the previous casing shoe to leak into formation in case of annular pressure is high enough.

2- Using high compressibility fluid

Increase the compressibility of the trapped fluid makes the final Annular pressure lower through increasing confined system compressibility (Loder et al., 2003).

3- Pressure Relief

It is the classical category of techniques that is the bulk. It contains the following techniques: valves to the atmosphere, hole at the wellhead with ROV, rupture disk, casing perforation, and Annular pressure relief collar (Santos et al., 2015), (Dong & Chen, 2017).

4- Compressible foam

Using a Foam placed on the casing outside surface will be compressed when pressure increased and absorb the APB also can be titled under the means of increasing confined system compressibility.

5- Casing structural strength increases

Increasing casing physical properties to increase loads (collapse and burst) integrity (Leach & Adams, 1993).

6- Mitigation casing

Using special casing type contain space and valve to accommodate the extra volume due to trapped fluid expansion.

7- Additional chamber

Similar to the mitigation casing but in this type the casing is supplied with a chamber and valve placed at the casing as accessories (Dong & Chen, 2017).

8- Sacrificial casing

Design a multi-string casing with a pointed weak point of the casing to damage at TAP and protect the other part of the annulus.

2.4.2.1 Cement shortfall

This technique based and restricted by formation properties also can cause some other potential risk. This technique may be impacted by cement channelling due to the poor mud displacement caused by bad casing cantering or weak erodibility of the fluid at the wellbore in primary cementing operation. Besides, trapped pressure can happen when there is a barite sag* occurred following drilling operations or when the completion fluid is set in the annulus (Calçada et al., 2016). In most cases, SSW is not completed directly after finishing the drilling operation due to the time required for other components of the production infrastructure (Vargo et al., 2002). A long time can lead to settling of the weighting agent of annulus fluid and cause plugging in the exposed formation, this problem restricted cement shortfall technique. Mathematical models and experimental data were applied to design rheological properties of sealing fluids to control barite sage (Calcada et al., 2017).

2.4.2.1.1 Application of cement shortfall (Open shoe) technique

It should be noted that, even with the open shoe, problems will occur on formations with high fracture gradient or in section opened in salt formations. It cannot be applied in wells that have permeable zones that require isolation at the section of the few meters below the shoe. In these cases, the formation must be cemented, and a confined annulus is required for design considerations, the formation is considered to fracture when the pressure exceeds the ($\mathbf{P_f}$) fracture gradient at depth ($\mathbf{H_f}$). In this design, an important argument is that the gradient of fracture is not a deterministic feature. Rather, it's a set of values where failure may occur. Geomechanically studies conducted for shoe setting usually consider the lowest value that can cause the failure ($\mathbf{P_{f\ mini}}$). On the other hand, for an APB analysis, it is suggested to use the highest value the shoe should be able to withstand ($\mathbf{P_{f\ max}}$), with a certain degree of confidence. In other words, ($\mathbf{P_f = P_{f\ max}}$) should be used from the geomechanically studies. Naturally, the probability distribution function f($\mathbf{P_f}$) must be applied when performing a probabilistic design. With this value at hand, it should be tested if casings can withstand collapse and burst loads before shoe fracture.

Analytically, if the casing at depth (H_c) has a collapsing force (P_c), the fluid in the confined annulus has a constant density (ρ) and the fluid in the internal annulus has pressure (P_{int}) then.

$$P_C > \rho_f . g. H_f - \rho .g.(H_f - H_c) - Pint$$

Similarly, if the casing at depth H_b has a P_b burst strength, the fluid in the confined annulus has a stable density and the fluid in the annulus has a P_{ext} pressure

$$Pb > \rho f. g. Hf - \rho .g.(Hf - Hb) - P_{ext}$$

If the pack-off resists such loads, it should also be confirmed. To this objective, if the pack-off is at depth H_p, has a pressure level below P_p, the fluid in confined annulus has a constant density ρ_f and the above pack-off fluid has pressure $P_{ab,p}$ then

$$Pb > \rho f. g. Hf - \rho . g. (Hf - Hp) - P_{ab,p}$$

Additionally, must be confirmed if the locking capacity of the pack-off is higher than the resulting axial force. For this objective, assuming that the locking capacity is F_R, pressure below pack-off is $P_{b,p}$, area below pack-off is $A_{b,p}$, pressure above pack-off is $P_{ab,p}$, the area above pack-off is $A_{ab,p}$ and axial force from the thermo-structural simulator are F_a, then:

$$F_R > F_a + P_{b,p} . A_{b,p} - P_{ab,p} . A_{b,p}$$

A significant remark is that the critical point for casing could be near pack-off or close to the shoe (Santos et al., 2015).

2.4.2.2 Using high compressibility fluid

2.4.2.2.1 Nitrified Spacers

This technique represents the primary technique applied in the Marlin project in GOM. A relatively low nitrogen volume (5 - 10)% form annulus volume was needed to absorb adequate volume to prevent the annular pressure risk of casing integrity (Kutchko et al., 2014). Nitrogen injection is used in this technique to absorb the annular pressure. However, insufficient volume of injection cannot treat the TAP problem, also too much nitrogen volume will lead to less effect and economic loss. To obtain the optimal volume of nitrogen required for injection we use theoretical methods and prediction models with a specific assumption to match each case (Yin & Gao, 2014). The technical process is safe and has high reliability for providing an excellent fundamental cementing job. More than 500 nitrified cement jobs have been successfully applied in the GOM. The use of this technique provides an effective mitigation method for wells that have potential APB issues (Vargo et al., 2002). A nitrified spacer as shown in Figure 2.6 is set above the TOC in the spacer dissipates, and the migration of nitrogen occurred up the annulus.

The purpose of foaming the cement along with the spacer was a dual way. Firstly, the foamed cement natural advantages, it would promote the cement sheath during the life of the well. Secondly to the general improvement of the cement annulus between the external and internal annulus casings to absorb the expanded liquid volume over time,

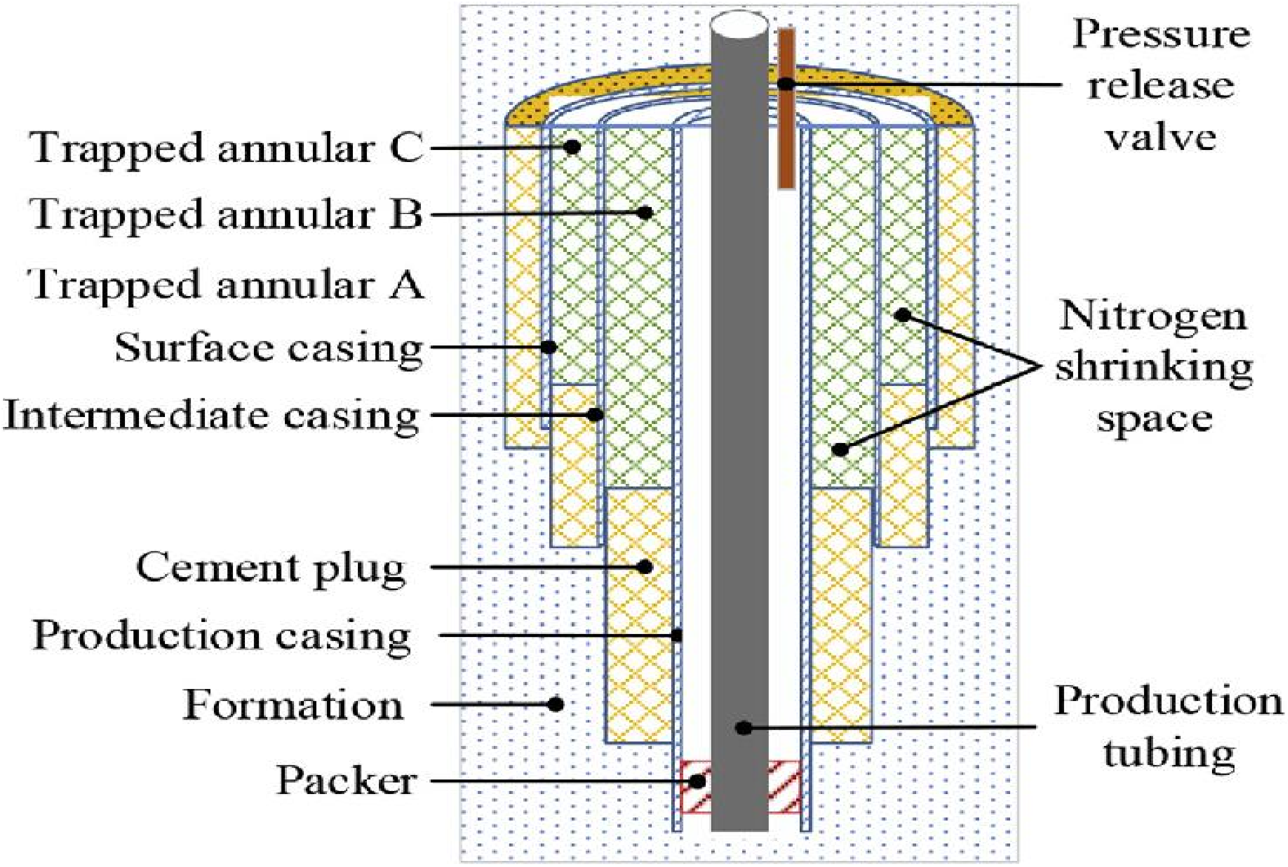

Figure 2. 6 well schematics with nitrogen spacer at annulus (Dong & Chen, 2017)

, and provide suitable mitigation of APB, the displacement of the spacer physically depends on the final placed position of the cement and spacer. The nitrogen properties are obtained from PVT analysis for real gas and applied at the final prediction equation of annulus gas-liquid volume calculation under various pressure and temperature (Wang et al., 2018). The Figure2.7 express the effect of annular pressure with a various range of release space ratio.

Experiments also show that mitigation efficiency has no effective action when nitrogen is more than 20% of annular volume, the mitigation efficiency will be stronger when liquid compressibility at the range 3.0 and $6.0 \times 10^{-4} MPa^{-1}$, and the mitigation efficiency become very low or not match the requirement when liquid compressibility is higher than $8.0 \times 10^{-4} MPa^{-1}$ (Zhang et al., 2016).

*** Advantage of application this technique**

1- It is a safe and successful method to eliminate TAP due to the successful application reported in GOM.

2 -The spacer improved mud removal and water wetting of formation and casing.

*** Drawback reported during testing and application of this technique**

1 -Require cement modelling and spacer accurate calculation before all cement operations.

2 -More difficult performing at tight annulus clearance, when using casing with a heavyweight.

3 -The spacer design needs to be effective for removing mud, provides water-wet formation and casing, keep stability for 3 days, provide enough nitrogen.

4 -Consideration for extra casing scenario may raise the cost casing due to consider build-up pressure of nitrogen during migration up at the end of primary cementing operations that must be accountable and maintain under the casing burst pressure (Vargo et al., 2002).

5- There is uncertainty in both the placing depth of nitrified foam spacers and their activity in reducing pressures (Miller et al., 2018).

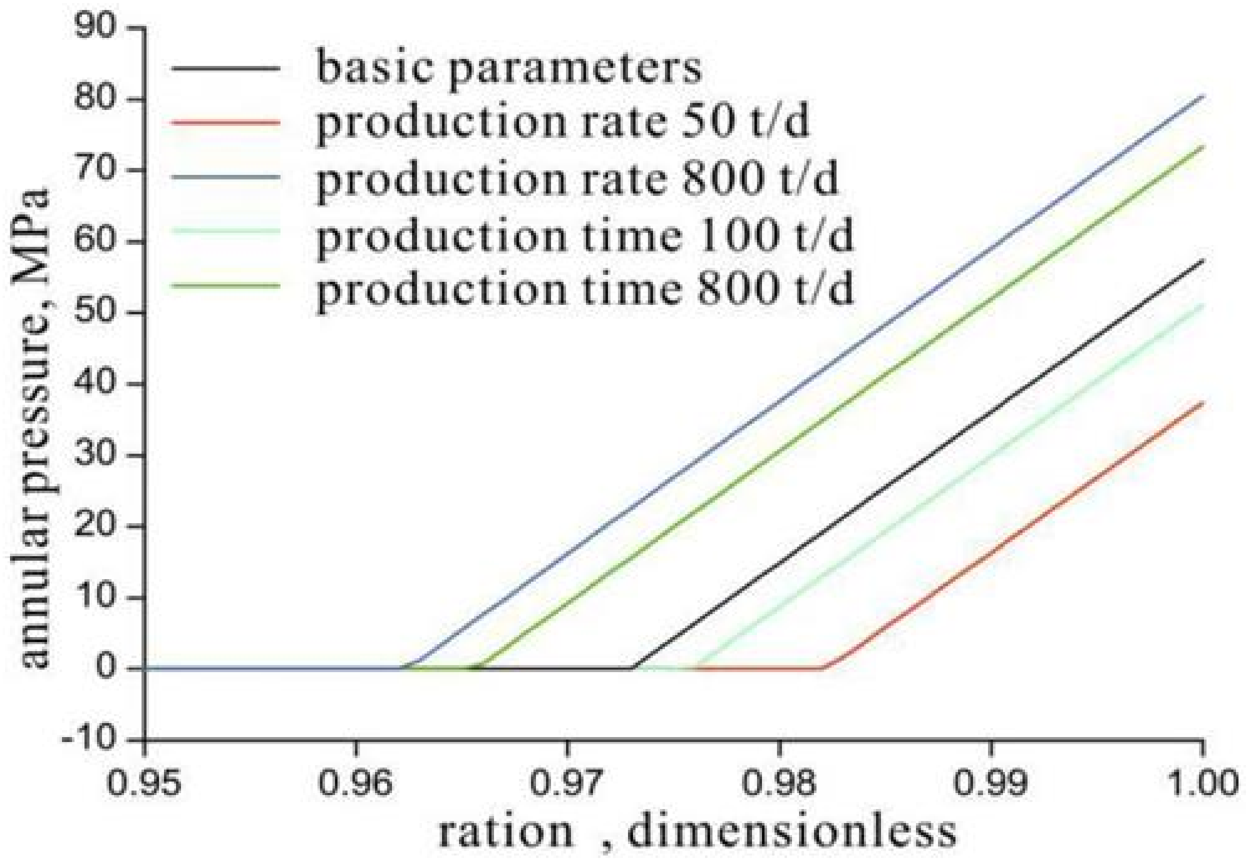

Figure 2. 7 Change of annular pressure as ration of released space and annulus volume (Zhang et al., 2016)

2.4.2.2.2 Water-Based Spacer (Fluid That Shrinks)

The water-based spacer is a modern solution that has been developed to mitigate APB with moderate to low range and can only be used ahead of the cement. During polymerization, the MMA phase volume shrinks by 20%, providing space for the residual fluid to extend thermally but without creating dangerous and destructive pressure. The polymerization activated by heat and the target temperature can be controlled by selecting the suitable chemical initiator type and concentration. early polymerization of the placement of spacer can be avoided by a suitable type and quantity, of inhibitor. A spacer formation (viscosifier, emulsifiers, MMA, weighting materials, inhibitor, etc.) is improved which provides the range of densities that can be expected in deep water wells conditions. To obtain the types and amounts of initiator and inhibitor required to change the polymerization temperature to the range of temperatures anticipated in the field, a matrix of benchtop tests is applied. These findings were verified in an advanced PVT cell that simulates the downhole conditions closely. Safe handling procedures for mud plant preparation, transportation, and application of rig sites were developed. This mitigation method is cheaper than nitrogen spacer, crushable foam, and VIT.

2.4.2.2.3 Drilling fluids Spacer

In some cases, the drilling fluid that lifted in the annulus can help to reduce the effect of TAP when it was low and not need to use other costed mitigation methods. The mud properties were improved to be the mitigation device for APB. There are some recommendations obtained by experimental results and model approaches show that compressive yield stress, variance in density between the solid and liquid phases of drilling fluid, practical size of solid and annular space geometry, are four essential parameters that locate the rate of sedimentation. These criteria are used to describe YPL annular fluid properties to minimize sedimentation rate and consequently to minimize free convective flow, this approach applied to analyse the reliability and sustainability of the isolating activity of drilling fluids (Ettehadi Osgouei, R., 2014). This technique applied for wells with relatively low to moderate APB (to the permissible limit). When there is one design scenario of a very low probability (risk level) threat the casing by TAP and can be treated by this mitigation method.

2.4.2.3 Pressure relief device

2.4.2.3.1 Valves to the atmosphere

Although it is confined to onshore and dry wells of completion (Santos et al., 2015), the technique is listed here, as it is the most common technique in those situations. It consists of venting the trapped pressure from the trapped annulus directly by a venting device at the wellhead. Therefore, the surplus of the fluid that is pressurized during well start-up will go out into the atmosphere. If the well has an APB, definitely open the valve that reaches the annulus of interest and vent the excess pressure by removing a fixed volume of annular fluid. This will stop any incremental pressure from APB, this technique is restricted application because it cannot be applied for all the annuli in SSW, where annulus B, C., etc. are not attenable.

2.4.2.3.2 Hole at the wellhead with an ROV

In many cases, the remotely operated vehicle (ROV) can drill a hole in the wellhead to vent the TAP. Usually, more than one casing should be drilled. Besides, the success of this operation typically includes world-class ROV and special equipment. This hole permitted the fluid to expand in the confined annulus without any rise in pressure. In this case, fluid leaked to the sea as it spreads. Then, an environmentally friendly water-based mud must be hired. An inspection of the safety barriers should be done when applying this technique. If there are permeable areas of hydrocarbons, the efficiency of cementing should be evaluated, as a cement failure may establish a direct route to the sea (Santos et al., 2015). This technique is usually applied to relief wells with existing or in expected TAP.

2.4.2.3.3 Rupture disk technique

It is one of the most applicable mitigation devices equipped with adjusted casing coupling in the externally cemented zone as shown in Figure 2.8. Engineered rupture disks bleed abnormal annular pressure before overriding casing collapse ratings. By creating a venting way in external casings to ensure they mitigate internal strings of a given annulus from collapse (Payne et al., 2007). A rupture disk (Z. Liu et al., 2016a) is a venting tool that can burst/collapse at a fixed pressure difference that is selected by the designer as the operating pressure. The rupture disk has the advantages of minimal cost and limited footprint and giving well designers more flexibility to control APB-associated issues. But also, it is broken the well external integrity (cement), so formation fluids can enter the well, and for that reason, the rupture disk must set at a suitable depth separated by a single cement layer and define operating point relative to the annulus casing physical properties. Modelling and simulating rupture disk burst/collapse can give useful information to help in the wellbore tubular design. The implementation of this feature in a commercial software platform would help the well designer engineers to improve unconventional casing design for their wells with a dependable safety margin at an affordable cost. An additional drawback for the rupture disk is when installed in casing and run-in well, it cannot be repaired in case of damaged or not worked, so to ensure reliability several disks are used by installing it in the opposite position (Vargo et al., 2002).

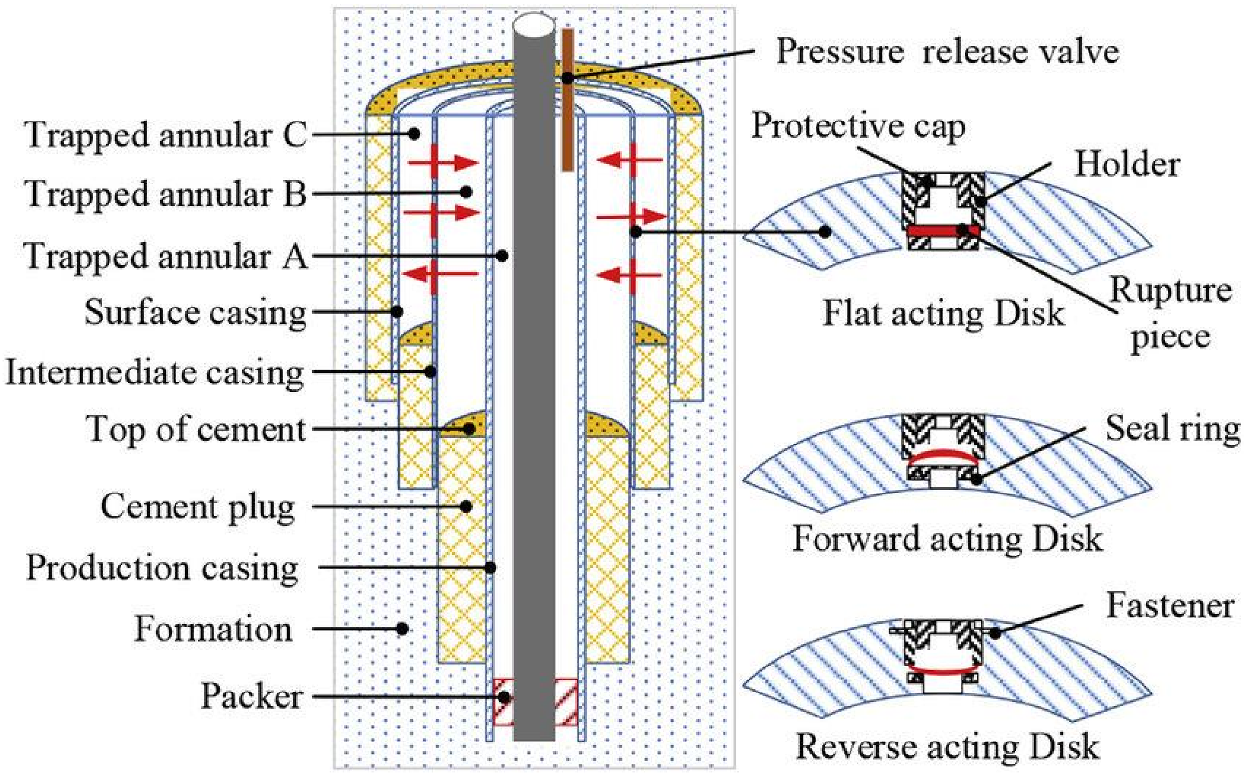

Figure 2. 8 Graphic diagrams of rupture disk content and possible fitting in casing design (Dong & Chen, 2017)

Modeling of rupture disk

The rupture disk is described by operating point (pressure) and installation depth. When the trapped fluid expanded cause, annular pressure increases and reached to specifically designed limit the disk will be ruptured and the pressure equilibrium at both sides of the annulus. The rupture disk can be a burst disk or collapse disk depend on the bleeding direction and operating pressure.

The simple calculation of rupture disk depends on the direction of bleeding the fluid pressure, for burst the disk responds to differential burst pressure, and the same for collapse it follows the collapse of different pressure. The rupture disk calculation is simply set to determine the operating pressure and optimum working depth. As published (Sathuvalli et al., 2016), for the case of APB in the annulus 'X' (production-intermediate casing).

The disk ruptured outward when APB function the following calculations

$$P_{BD\,nom} \pm \Delta P_{BD} = [\Delta P_{APB} + \gamma_X (Z_{BD} - Z_{ref,X})] - P_e (Z_{BD}) \text{ -----------(2-1)}$$

Where:

$\pm\Delta P_{BD}$: Manufacture tolerance, ±5% from the normal working pressure ($P_{BD\,nom}$).

γ_R: Pressure gradient of the annulus fluid in annulus 'X'.

$Z_{ref,\,X}$: Datum depth of the calculated pressure.

P_e: Fracture strength of the formation at the depth of setting disk.

Z_{BD}: Depth of rupture disk.

The APB for activating the disk can be determined by

$$APB_{min} \leq APB \leq APB_{max} \text{ ------------(2-2)}$$

$$APB_{min} = \{(P_{BD} - \Delta P_{BD}) + [Pe(Z_{BD})]_{min} - \gamma_X (Z_{BD} - Z_{ref,X})\} \text{ --------(2-3)}$$

$$APB_{max} = \{(P_{BD} - \Delta P_{BD}) + [Pe(Z_{BD})]_{max} - \gamma_X (Z_{BD} - Z_{ref,X})\} \text{ --------(2-4)}$$

Then define Z_{coll} as the depth of most collapse can happen due to differential pressure effect in a given annulus (B), the maximum collapse pressure due to differential pressure in the inner annulus can be determined by

$$\Delta P_{coll} = \{\Delta P_{APB} + \gamma_X (Z_{coll} - Z_{ref,X})\} - \{(1-\frac{2t}{do})\gamma_L (Z_{coll} - Z_{ref,L})\} \text{ ----(2-5)}$$

Where:

t/do: is the diameter-wall thickness ration of the inner annulus.

γ_L: is the gradient of a given annulus (X) hydrostatic pressure of the liquid.

$Z_{ref, L}$: is the datum depth of the calculated pressure (these depths are changed for every annulus).

In order to protect the annulus from collapse, the following relation must be proved

$$\Delta P_{coll} \leq \Delta P_{coll, max}$$

$$\Delta P_{coll, max} = \{\Delta P_{APB,max} + \gamma_X (Z_{coll,max} - Z_{ref,X})\} - \{(1-\frac{2t}{do})\gamma_L (Z_{coll,max} - Z_{ref,L})\} \text{--------(2-6)}$$

To perfectly protect annulus from collapse the following situation must be confirmed

$$\Delta P_{coll, max} \leq DF_{coll,} Pc \text{ ------------(2-7)}$$

Where:

Pc: collapse working pressure for inside givin annulus string (adjusted by temperature).

$DF_{coll, Pc}$: design factor of collapse rating.

To ensure that the APB never overcome the allowable APB limit, the following situation must be confirmed

$$\Delta P_{APB, MAX} \leq \Delta P_{allow} \text{ ------------(2-8)}$$

When the disk operating pressure is selected, the effect of drilling loads to the casing is not influenced, so the equation (2-9) is written as

$$P_{API,MYIP} < P_{BD} - \Delta P_{BD} < P_{BD} + \Delta P_{BD} < P_{Rupture} \text{ -------(2-9)}$$

Where:

$P_{API, MYIP}$: Physical properties of pressure strength for the selected casing

$P_{Rupture}$: Rupture limit of the selected casing.

The equations (2-1----2-9) are applied repeatedly to reach suitable disk depth and operating pressure.

2.4.2.3.4 Casing perforation

In this technique, a perforation device is set in the hole after running the casing in front of the problematic part of the annulus and the outer casing is perforated. In most cases, this technique treats the problem of TAP, but it may cost high, based on the depth of perforated casing as required. If this depth is too shallow, the exposed formation maybe cannot resist the pressure gradient of the fluid, and fracture may accrue. A liner and tie-back configuration become necessary to be used in this case, to prevent an underground blowout. Since running liner and tie-back generally takes longer than the running casing, costs increase significantly. A negative pressure test should be applied after installation of the liner and before perforation of the casing, to evaluate the hydraulic isolation of the cement interference. Then, the perforation job can be performed safely.

The design procedures (Santos et al., 2015) are similar to the open shoe one. Casing collapse and burst loads integrity, until fracture at the perforation, should be verified. Analytically, if the casing at depth H_c has a collapse resistance P_c, the density of the confined fluid in the annulus is

$$P_c > \rho_f . g . H_f - \rho . g . (H_f - H_c) - P_{int}$$

constant $\boldsymbol{\rho}$ and the pressure of the fluid in the internal annulus is P_{int} then

In the same way, if the depth of casing is H_b has a burst resistance P_b, the density of the fluid in the confined annulus is constant $\boldsymbol{\rho}$ and the fluid pressure in the internal annulus is P_{ext} then:

$$P_b > \rho_f . g . H_f - \rho . g . (H_f - H_b) - P_{ext}$$

Also, pack-off should be verified resists to these efforts. For that reason, assuming that the depth of

pack-off is H_p, and its strength is P_p, the density of the fluid in the confined annulus is constant $\boldsymbol{\rho}$ and the pressure of the fluid above the pack-off is $P_{ab,\,p,}$ then:

$$P_b > \rho_f . g . H_f - \rho . g . (H_f - H_p) - P_{bc}$$

Besides, a significant note is that the critical position for casing can be near pack-off or shoe.

2.4.2.3.5 Relief collar for annular pressure

This technique (Dong & Chen, 2017) was first applied to mitigate deep-water TAP by Halliburton in 2004. The device can be turned ON and OFF frequently on the internal casing of the annular trap to transmit surplus pressure to the annulus ‘A’. Then the pressure vented for annulus ‘A’ by pressure release valve fitted on the wellhead to seawater. The device as shown in Figure 2.9

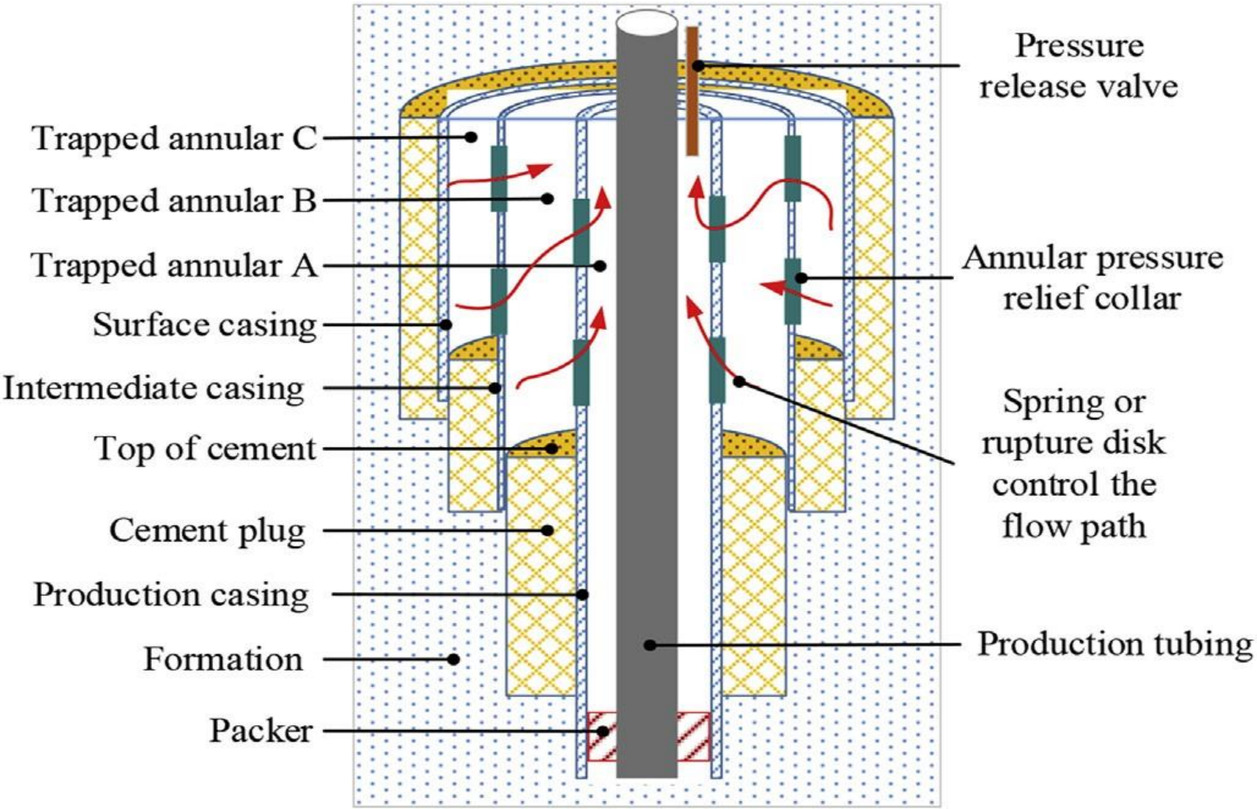

Figure 2. 9 Graphical representation for relief collar for annular pressure (Dong & Chen, 2017)

consist of a short tool that has a small volume possible to be installed symmetrically on the same plane of section. Even though this technique can vent pressure many times, it does not get quite an application. The main point is in the complication of fitting, application, and managing, also the tool cannot be changed in case of failure.

2.4.2.4 Mitigation by using syntactic foam (Hollow glass)

It is one of the common mitigation techniques to relieve APB in HPHT SSW. In general, syntactic foams are placed around the outer casing wall as can be seen in Figure 2.10. When the annular pressure exceeds a specific pressure of foam crushing at a specific temperature, the foam will collapse, and extra space is provided for the annular fluid to expand and prevent APB. Modelling and simulation of syntactic foam's, behaviour of annular fluid during expansion analysis, and casing load analysis can provide valuable information to improve wellbore tubular design (Z. Liu et al., 2016b). The application and modelling of synthetic foam are first verified and applicated in the North Sea at an offshore HPHT well. The syntactic foam contains small spheres of hollow glass are filled with air under atmospheric pressure, these spheres are collapsed when annular pressure reached a certain level to absorb this pressure and prevent more generation of pressure due to the expansion of trapped fluids. Reported data indicated that volume needs for an effective solution are nearly (2 – 8)% from the annular volume (Williamson et al., 2007). The cost in the comparison between mitigation by using syntactic foam and the same case for using upsizing casing (heavyweight) method for a typical well in the North Sea indicate that this technique provides

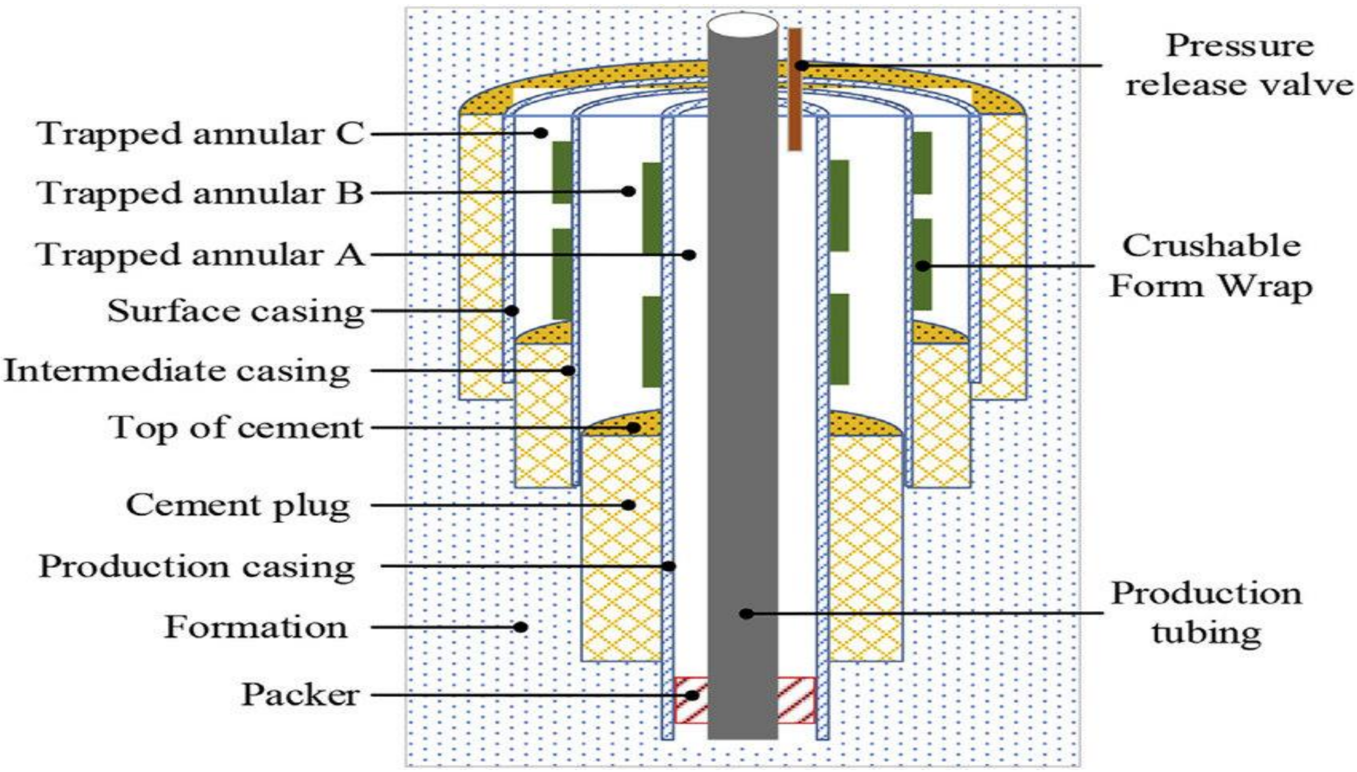

Figure 2. 10 well schematics with crushable foam warp (Dong & Chen, 2017)

substantial cost savings, particularly for HPHT deep wells. The cost of foam wrap application is around one-third the cost of casing upsizing (Leach & Adams, 1993).

2.4.2.5 Heavyweight/high yield casing (Improve structural strength)

Improving a casing grade of steel and wall thickness can be the first option for the designer at a specific range of annular pressure and limited choice of the casing. But it extremely depends on accurate information on the pressures themselves. In the last years, this method has seen quite rapid development, first with the rooting for the important principle for multi-string casing design, and then with its application as commercially available computer software. Both of these, with the facility for precise forecasting of the temperatures in the different casings and annuli, has made it able to reliably size well tubular for the annular heat-up load (Leach & Adams, 1993). Improving casing products through raised casing capacities make casing structural accept a higher degree of loading stress pressure and prevent damage to the casing or well integrity. This type of mitigation significantly increases cot, furthermore the casing that satisfied this requirement almost dropped out of API standard (Zhang et al., 2019).

2.4.2.6 Mitigation casing

This type of mitigation device is a casing designed with extra capacity to accommodate the expanded volume instead of pressurized. As shown in Figure 2.11

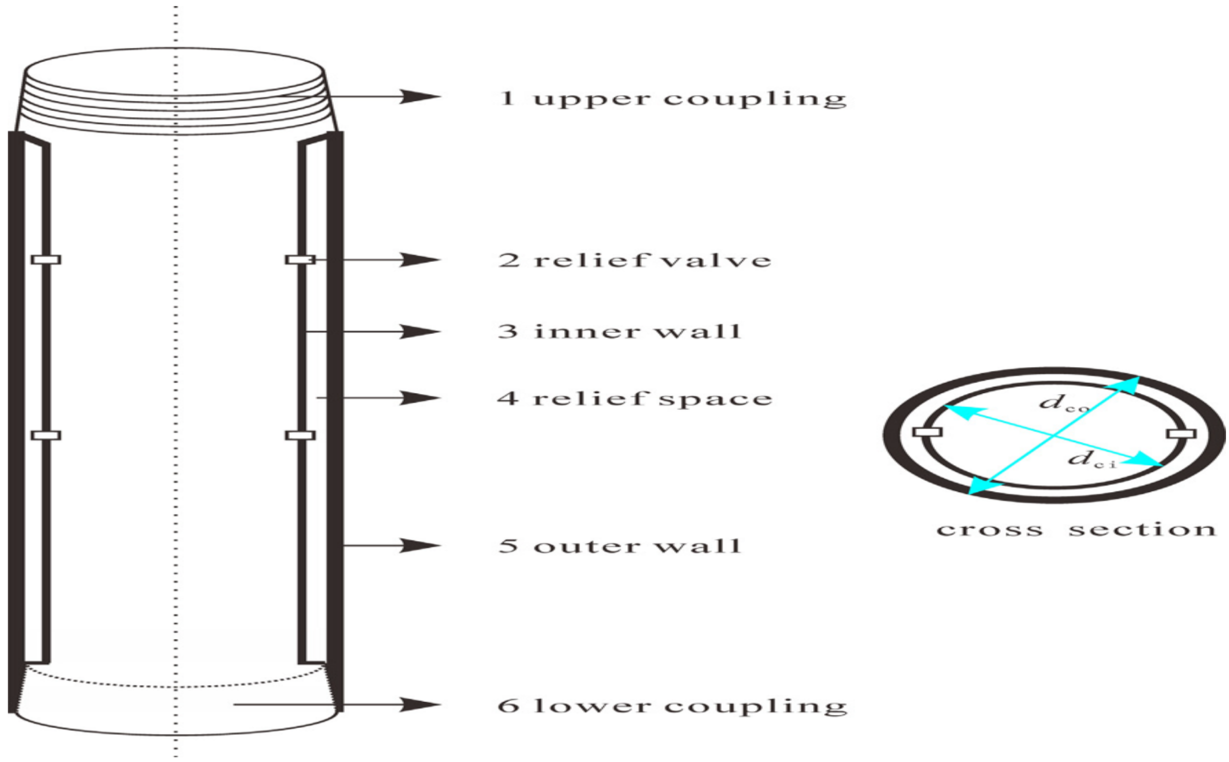

Figure 2. 11 Section pipe of mitigation casing (Zhang et al., 2017)

it consists of top coupling, venting valve, internal wall, relief area, external wall, and down coupling. The relief valve is set in the internal wall. The external wall is used to withstand internal pressure and collapse pressure. The relief area is isolated and filled with nitrogen. when the relief valve is closed, the relief area is still isolated to annular liquid before production operations. TAP rises when production continues and finally reaches the pressure of opening relief valve, at this time, trapped annulus and relief area are linked, to provide extra annular volume, expanded fluid in the annulus will flow into the relief space, so annular pressure will minimize. This technique is attached in a casing string, so it is not restricted by well structure, the property of formation and drilling operation (Zhang et al., 2017). The mitigation effect becomes higher and higher as the mitigation joints number increases. The number of mitigation casing must be designed according to the expected change in annular temperature and mitigation goals.

2.4.2.7 Additional chamber

This technology was discovered by Chevron in 2006. It was special designed for the production casings and tailpieces in deep water wellbore layout, then applied effectively on the casing 13⅜in. at the "Tahiti oil field". The chamber is placed in the borehole annular trap, as shown in Figure 2.12.

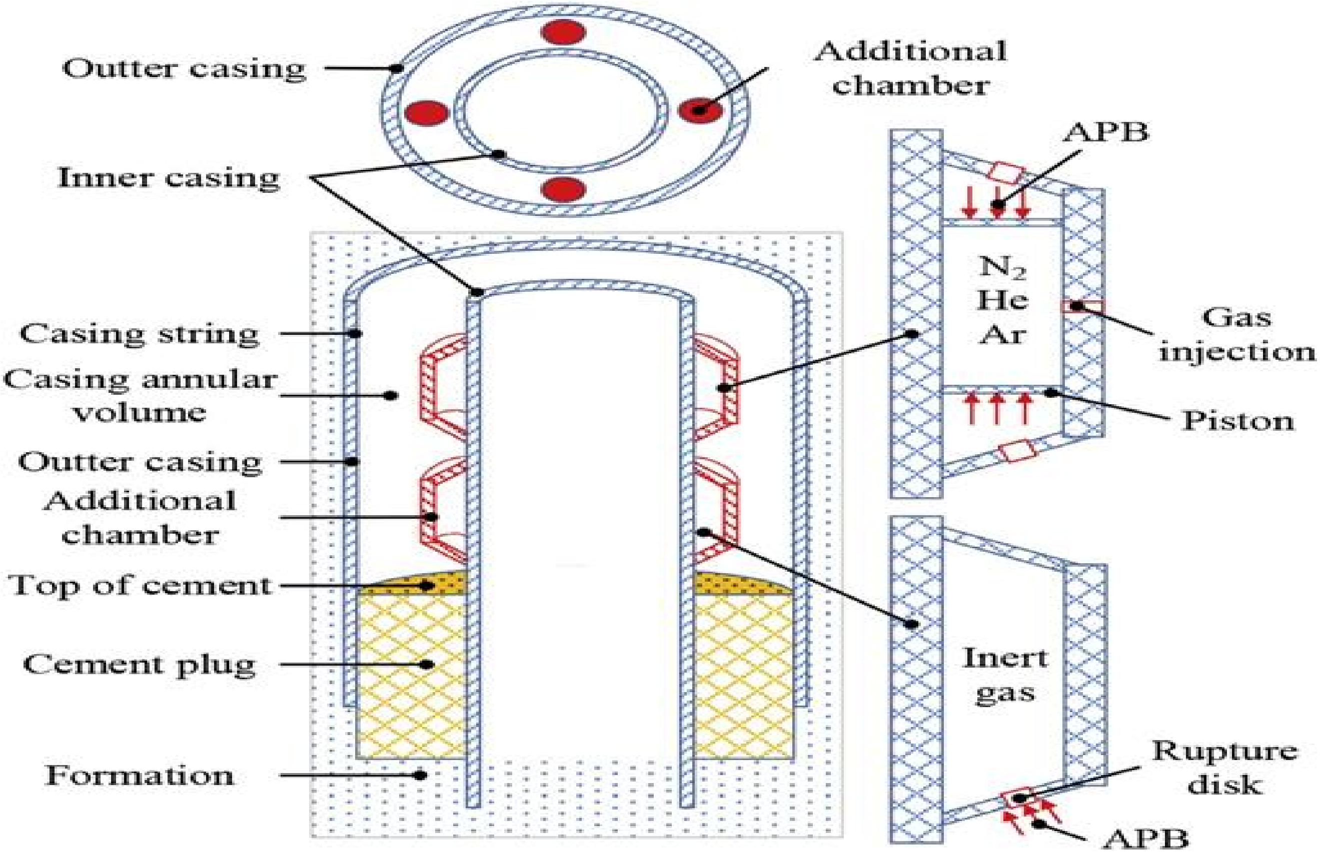

Figure 2. 12 The graphical diagram of installing additional chamber (Dong & Chen, 2017)

It was connected to the pipe string by couplings. The chambers are divided into two types. The first one consists of two pistons that can inject a specified size of inert gas (N_2, He, or Ar) and their mixture into the chamber. During the expansion of the annular fluid, the generated pressure will be transmitted to the chamber by the hole, the piston was compelled to compress the inert gas in the room, and then TAP minimized as a result of increased space for expansion. The latter kind of chambers contains a valve installed on the chamber, when the TAP arrived at a certain range, the valves activate instantly to pressurized inert gas in the chamber to absorb the extra rise of the TAP. The inert gas pressure in the first kind chamber may be adjusted based on the calculations. for the second kind the activation point of the pressure of the chamber can be different, too. In this way, the APB issue can be fixed separately and in stages. Compared to other methods, this device is a suitable choice for deep-water wells (Dong & Chen, 2017).

2.4.2.8 Sacrificial casing

Design a casing with multi-string and select a section of the casing with lower required strength at a specific depth to be the weak point that protects the whole string from damage by TAP. As shown in Figure 2.13,

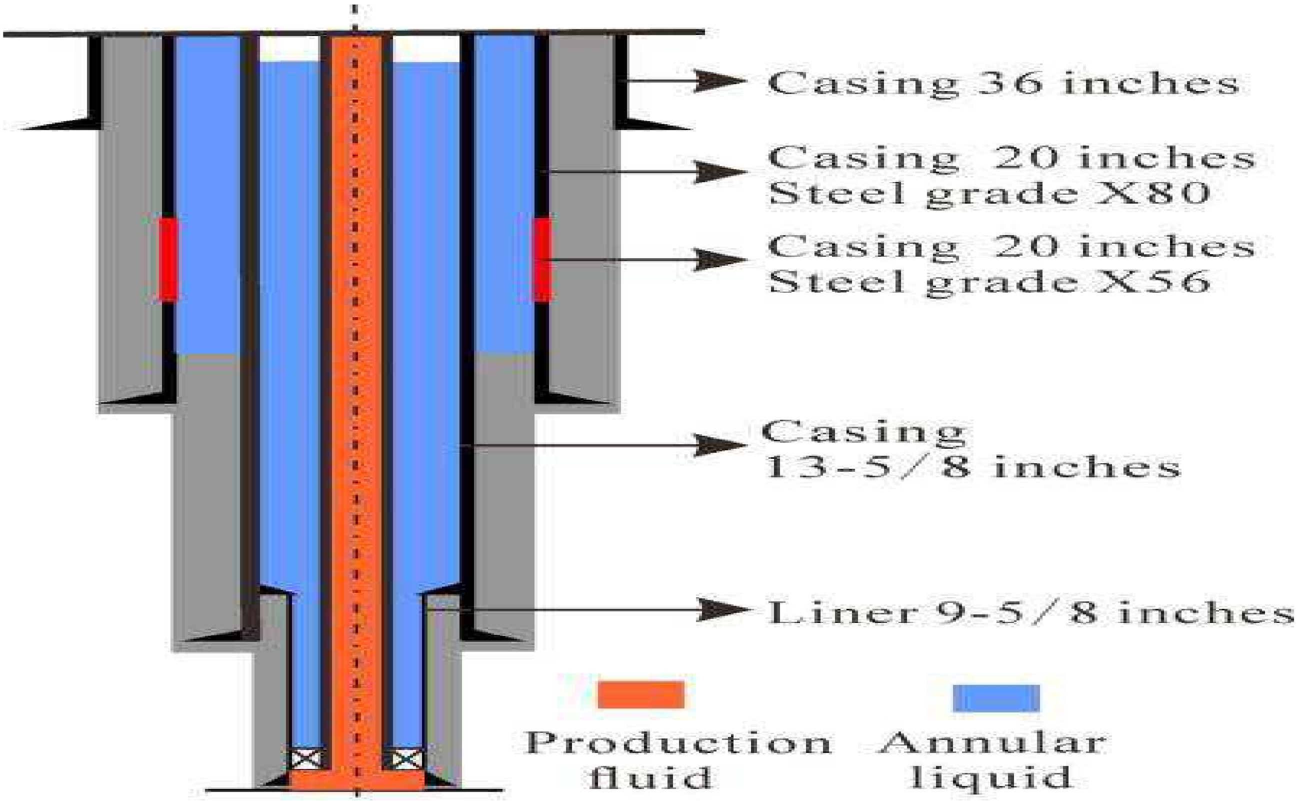

Figure 2. 13 Sketch of well with sacrificial casing (Rizkiaputra et al., 2016)

for the sample well of the deep-water area in Indonesia, the 20in.casing grade of steel is X-56 at the section extended from depth 381.30m - 518.56m when the designed steel grade of 20in. the casing string is X-80 consequently, the X-56 casing will collapse under TAP firstly and thus provide a passageway to the annular liquid to pass into the formation instead of damage all the casing string. This technique overcomes the negative impact of solid settling. The position and strength of this device should be designed depending on the formation property, stress of casing string, and amount of expected TAP. It has been used in Indonesia deep-water well as an alternative selection device when the rupture disc cannot be used for some constraints (Rizkiaputra et al., 2016).

2.4.3 Summary of TAP mitigation devices

Table 2.2 shows a list of details for TAP mitigation devices.

Category	Mitigation technique	Principal	Advantage	Disadvantages	Cost	Reliability	Difficulty	Mitigation performance	Application	Notes	Preferred condition for application
Active Mitigation Techniques	Cement to surface	Eliminate annulus	No trapped annulus, No APB effect	1-If mud at the annulus not replaced totally the TAP will happen. 2- fracture of the top-hole formation may happen. 3- The wellhead may plug with cement.	High	Moderate	High	Good	Little	Limited cementing technologies	Moderate temperature less than 250ºF, with the formation of high fracture pressure.
	VIT	Isolate heat transfer	revent or Reduc fluid expansion	1- high cost and limited supply 2- long preparing time, and application 3- incompatible with the welding process.	High	High	Low	Good	Wide	Applied for hig temperature that cannot control by other technique	High-temperature wells wit on possibility for another mitigation device
	IPF	Isolate Heat transfer	revent or Reduc fluid expansion	1-Complex injection equipment an high cost. 2-some isolated material cause casing corrosion.	High	Moderate	Moderate	Good	Wide	High cost but relatively less than VIT cost	High temperature with the development of TAP can be controlled in annulu A.
	Reduce production rate	Decrease heat source generation	Decrease heat transfer	1- Economic impact 2- It is a relief option, not recommended for new well design	High	Low	Low	Moderate	Little	Relief option	Well develop TAP with no designed mitigation.

Category	Mitigation technique	Principal	Advantage	Disadvantages	Cost	Reliability	Difficulty	Mitigation performance	Application	Notes	Preferred condition for application
Passive Mitigation Techniques	Cement shortfall	Provide venting way for TAP	Economic and easy to applicate	1- High operation risk. 2- Hole enlargement o uncertain cement slurr 3- Plugging of formation fail this device.	Low	Low	Low	Bad	Little	Reduce the life of wells. So, it is not recommended to apply just in case there is evidence supporting this device.	Moderate temperature less than 250ºF, with th formation of high fracture pressure.
	Nitrified Spacers	Provide highly compressible trapped fluids	Mitigate TAP safely	1- Needs modeling and special requiremen for spacer preparation. 2- Improved casing properties may require. 3- Special injection device. 4- the uncertainty of spacer placement and mitigation activity	High	High	High	Good	Moderate	Required high cement technologies and modeling	If the recorded last data showed poor cement bound and evidence of SCP behind TAP with limited application fo other mitigation techniques
	Water Based spacer	Reduce TAP	Lower cost	Limited used for low TAP and the spacer needs chemical treatment.	Low	Low	Low	Low	Little	effectively applied in SSW tha not require gas lift	Slightly low Temperature and low risk of APB

Category	Mitigation technique	Principal	Advantage	Disadvantages	Cost	Reliability	Difficulty	Mitigation performance	Application	Notes	Preferred condition for application
Passive Mitigation Techniques	Drilling mud spacer	Reduce TAP	Lower cost	Needs treatment, not applied for long time protection	Low	Low	Low	Not Bad	Little	Applied for low-temperature wells	Slightly low Temperature and low risk of APB
	Valve to atmosphere	Venting TAP from annulus 'A'	lower cost and application	Limited application for limited annulus and cannot be applied for SSW	Low	High	Low	Good	Wide	Limited application, suggested for onshore wells	TAP developed and can be controlled by annulus 'A' only
	Hole at the wellhead with an ROV	Venting TAP	Relief casing from TAP	Needs evaluation for cement and permeable zone, water base mud as sealing fluid must be found, it is the impact well, integrity.	Moderate	Moderate	High	Moderate	Moderate	Applied as a relief solution, and difficult to keep th application for long time.	Relief wells with existing TAP
	Rupture disk	Balance the expansion volume	Mature industry, convenient installation and transportation	1- Reduce casing load capacity. 2-Burst disk cannot be used again. 3- despite control TAP it has a negative impac to well Integrity.	Low	Moderate	Low	Good	Wide	Recommended for apply with redundant number of disks	The outer string is cemented (single sheath of cement), no salt formation are present contacting with disk and cannot be applied for annulus 'A'

Category	Mitigation technique	Principal	Advantage	Disadvantages	Cost	Reliability	Difficulty	Mitigation performance	Application	Notes	Preferred condition for application
Passive Mitigation Techniques	Casing perforation	Venting TAP	Relief casing from TAP	The risk with surface leakage and difficulty o application, also casing liner and tie-back must be used, a negative pressure test must be performed.	High	Moderate	High	Moderate	Little	Well with existing TAP without mitigation devices applied during the design	Relief wells with existing TAP
	Annulus pressure relief collar	Venting TAP	Relief casing from TAP	Difficulty of fitting and application , the device is unchangeable in case of damage	High	High	High	Good	Little	Limited application	No other choice
	Mitigation by using syntactic foam	Provide extra volume to the expanded fluid in the annular space	The Compressible foam prevents APB Generation, Cheaper than casing weighting (up-sizing)	1-foam warp decrease the annular clearance 2-difficult transportation 3-difficult injection and may damage during injection	High	High	High	Good	Wide	Required Advance cementing job	Extremely high temperature and abilit to perform advanced cement job

Category	Mitigation technique	Principal	Advantage	Disadvantages	Cost	Reliability	Difficulty	Mitigation performance	Application	Notes	Preferred condition for application
Passive Mitigation Techniques	Casing structural strength increases	Improving casin esistance for TA	Reliable within th pipe strength rang	1- Reduce casing effectively diameter 2-limited by the processing and construction process of the casing. 3- Reliable when the temperature changes slightly	High	Moderate	Low	Moderate	Moderate		Low temperature and completion program permits application
	Mitigation casing	Provide extra volume to the expanded fluid in the annular	1- Wide variety of applications 2-Eliminate TAP	1- Failure of relief valve not repairable. 2- Decrease annular clearance	Moderate	High	Low	Moderate	Wide		Limited application
	Additional chamber	Provide a venting space for expanded volume	Provide a venting place for TAP	1- Difficult operation an prosses, not repairable valve failure. 2- Decrease casing strength 3- Restricted for limited conditions	Moderate	High	Low	Moderate	Little		Limited completion program
	Sacrificial casing	Releasing expanded annular fluid	Releasing Expanded volume of fluid	1- High operation risk 2- Effect casing strength 3- Do not conform to abandoned well specifications.	Low	Low	Low	Moderate	Moderate	Risk if a permeable zone presence at a damaged section of casing	Limited application

Table 2. 2 List of TAP mitigation techniques

2.5 Mitigation techniques for SCP

Mitigation for this type of annular pressure is one of the more important issues due to the high chance of happening for this problem. All types of wells either offshore or onshore for normal or HPHT wells can sever from SCP, also the probability of this problem increased with the well ages and in some cases can occur after well abandonment. The general concepts of SCP mitigation are based on three ways (Bourgoyne et al., 2000)

1- Application of new practice and formulation of cementing.

2- Using of annular packer for the casing.

3- Internal pressure controlling during well life operations.

These concepts can be applied as improvements during well design or as practices and technologies during operations, as follow

2.5.1 Mitigation through well design

When the possibility of SCP accruing is defining and addressed during well design constructions, it is easier and best than future remediation operation. Identifying the possible influx from the formation can lead to select an external packer or apply cement isolation for this formation. Also, casing setting depths are set based on formation strength and kick tolerability. The probability of crossflow between formations around casing is highly raised if the difference between formation pressure gradient at the lower part of the section and the fracture gradient at the upper part of the section is permitted to be very little value. The MMS set the minimum density margin between shoe strength and density of mud provided to drill the section is 0.5 Ib/gal (Bourgoyne et al., 2000) otherwise it will increase the chance of fluid channeling for in set cement. The construction parameter of well design must be suitable for the expected conditions (temperature, pressure, production rates…etc.) and take the effect of possible invaded fluid types such as H_2S, water, hydrocarbon…etc, and composition into account to set casing and wellhead resistivity to corrosion and derating.

2.5.2 Mitigation by foamed spacer technology

The use of traditional spacer technology has in many instances struggled to create a strong cement bond. Foaming the spacer (Animesh Kumar et al., 2017) greatly increases its ability to displace drilling mud and drill cuttings efficiently. Generally, the foamed spacer also has a higher yield point (YP) that aids in the proper removal of mud. Furthermore, foaming will increase spacer volume. The results of laboratory experiments and computer simulations demonstrate that the foamed spacer has improved properties of rheological sweep performance compared to traditional spacer fluid. The foamed spacer was successfully employed to increase drilling fluid displacement and help to erode the partially dehydrated filter cake in the well. The design and execution of the foamed spacer not only dramatically reduced the need for remediation of cement work and lube-and-bleed activities for SCP remedial work, but also enabled the assessment of cement bond and inter-zonal isolation. A full review for well design must be performed when the well functionality is changed such as production well changed to injection or gas lifting applied to the production well, also take the effect of transformed well to the vicinity wells.

2.5.3 Mitigation by applying cement pulsation method

The idea (Wojtanowicz et al., 2002) starts by keeping the cement slurry at motion after placement to control the gas migration by keeping the hydrostatic pressure of cement by using the cement pulsation technique. This technology is applied first to control gas migration in Western Canada. Gas or fluid flow through cement once it has been placed is mainly caused by the reduction of hydrostatic pressure in the gas zone before the cement has built enough strength to stop gas flow. In between these two events, the period is called the transition time, to prevent gas migration, it is important to minimize the transition time of cement This technique involves performing low frequency, hydraulic pressure pulse to the annulus from the wellhead directly after cement placement. These pulses (about 550 kPa – 1,000 kPa) pressure pulses to the annulus with frequencies of 30 to 60 seconds. It is applied instantly after stop pumping; the BOP's are closed, and the cement pulsation unit starts to perform pulses to the annulus through the surface casing vent valve. The reported results showed that the pulses could be transferred as deep as 2,650 meters which permits full hydrostatic pressure to be transferred downhole in the gas area and decrease the gel strength of cement slurry. This special technique utilizes low permeability cement to avoids gas from entering into the slurry. Even though it was successful, it didn't function uniformly in all areas (Dusterhoft et al., 2002) due to limited cement technologies, control cement rheological properties with the condition of ambient, especially in some deep wells.

To prevent gas migration and improve cementing operation to avoid forming micro annulus and channels it is recommended to apply these some recommendations (Milanovic & Smith, 2005)

1- Fully deplete gas pockets encountered while drilling before cementing.

2- A "mud-filled external casing packer" should be run just above the zone of expected high background gas (as part of the production casing string) if possible.

3- Displacement of cement, if operationally possible, should be done by a fluid of the same density of the mud that will be used for the next hole section or the density of the brine to be lifted in the annulus 'A' after well completion to minimize the micro annuli formation.

4- Losses must be treated and eliminate gas presence before starting cementing.

5- The cement design should be adapted to individual wells and considering events such as losses and high background gas during the drilling process.

6- Using a high surplus amount of cement (Tahmourpour et al., 2010) to provide a sufficient volume of pure cement and displaced with a high rate (as possible) with accurate displacement volume.

7- Use of alternative cement types (Phi et al., 2019) such as sodium silicate activated slag/blended with fly ash, Calcium aluminate phosphate, and foam cement instead of Portland cement that shows a weak cement bond in XHPHT and geothermal wells due to degradation caused by acidic environments and high temperature.

2.6 Review of remediation methods of SCP

In case of well have an SCP there are a lot of technologies that can be applied as remediation methods. One includes terminating the inner casing string and setting a cement plug. This approach was recorded only if there is no cement sheath behind the inner casing. A further rig technique is section milling, which implies milling of a casing portion and pumping cement to inhibit gas flow. The key challenge for this technique was the complexity of standardizing the size of the milling tool, where the inner casing is irregular in comparison with the outer casing. Another cheap rig fewer methods are pumping killing mud in the annulus to kill the SCP and increase the hydrostatic pressure above TOC or using sealant materials to plug the annulus. Rig-less methods of SAP remediation encompass external remediation of the casing annulus employing a collection of bleeding off the pressure and injecting a sealing/killing fluid either at the wellhead (Bleed and Lube) or at depth through flexible tubing inserted into the annulus. Another researches and experiments developed for this purpose by pumping down an alloy metal that has a low-melting-point inside the SCP annulus and collecting this material above the cement top then melting it with a heating instrument to make a ring plug, that prevents the fluid leakage from the formation (Carpenter et al., 2004). Some of this remediation developed to used new procedures and technologies, some of them applied by using rigs or rig less depending on the size of the damage and associated risk (Milanovic & Smith, 2005). The diagnostic test analysis and risk analysis plan provide the guide for analysing the problem and set a suitable remediation plan.

1-Bleed-and-lube method

We choose this method (Nishikawa et al., 2001) as an example of the best common remediation methods and the lowest cost of all other remediation techniques. This technique represents the displacing of fluid in the annulus by successive cycles of pressure expulsion by venting continued with lubrication of small pits of killing fluid. In some cases, recorded some decrease in surface casing pressures and mentioned that Zinc Bromide was partially effective when used as a kill fluid, the reported cases show that decreasing pressure is not sufficient to control the SCP. Also, the application of heavy killing mud or high pumping pressure may impact the weak point at the shoe or any weak part at the annulus section and could open a new leaking path from intermediate to production casing, this leaking path impact the analysis and technique goals to control SCP, this technique applied by using heavy mud or brine, but the injection of brine into water-based mud can create a plugin the upper part of the annulus that prevent complete displacement of the volume required of the annulus. Furthermore, using brine with water can solve this problem but need a lot of injection cycles to achieve the total annulus displacement. The annulus fluid analysis is the key to decide the type of killing fluid and displacement. The immiscible gravity displacement of annular fluid applied with immiscible kill fluids by highest density, friction coefficient, and interfacial tension, displaced in the minimum time is the cheapest and effective one for application on this technique for eliminating the SCP.

2-Other technical practices for remediation

Due to high cost-effectiveness – low efficiency, the operators usually searching for other remediation alternative treatments to the SCP issues. Some of these methods are:

1 .Periodic venting of excrescent pressure.

2 .Partial venting then lubricating in a higher weighted fluid.

3. Using a mini size of tubing to be entered into the annulus that has an SCP to permit shallow annular circulation.

CHAPTER THREE
RISK ANALYSIS OF ABNORMAL ANNULAR PRESSURE

3.1 Well integrity

The well integrity is defined as (NORSOK, 2004) implementation of technical, practical, and organizational solutions to decrease the risk of uncontrolled release of underground fluids during the life cycle of the well. The casing-cement system Performs essential structural and insulation tasks to ensure the integrity of the well during its life cycle and it is known as the second well barrier. So, if abnormal annular pressure is not managed correctly during design, it will threaten this barrier and may lead to damage to well integrity. Mechanical properties of the casing and/or tubing forming the annulus, and the probability of generation abnormal annular pressure enabling to assess the likelihood of integrity failure. (Gouveia et al., 2020). In HPHT deep-water wells and SSW, maintaining the physical integrity of the wells is extremely important, it is given high attention due to the high cost of the investment, hard to access, and the awareness of the surrounding environment. The minimum and maximum annulus pressure levels are defined to protect the integrity of the structure, tubular, and X-mas tree, particularly to prevent environmental excursions of formation fluids and to maintain pressure containment in the wells. So, we concentrate on risk analysis for well integrity during casing design effect by abnormal annular pressure and possible mitigation application for well integrity assurance.

3.2 Annulus integrity

Annulus integrity is the part of well integrity that effected by abnormal annular pressure directly and as a consequence the damage of well integrity, so the most important scenarios that can be applied during well integrity risk analysis threat by annular pressure are based on (Bellarby et al., 2013)

1- Maximum wellhead pressure.

This type of pressure can pressurize the wellhead, hanger, or cemented casing.

2- Maximum differential burst pressure of uncemented casing

This pressure put this part of the casing under the risk of the burst. The differential burst pressure of the uncemented part of the casing will increase when both of the annulus pressure of the outer and inner are decreases.

3- Maximum differential collapse pressure

This pressure put the packer and production casing/tubing at the risk of failure.

Based on these scenarios the analysis of risk calculation depending on production-related loads and venting of annuli (it can be considered), and the outcome of this analysis can provide the level of risk of annular pressure on the given annulus and its effect on well integrity.

3.3 Risk management

Risk management and analysis recognize (Vamanu B., Necci A., Tarantola S., 2016) the need to implement mitigating action or ensure design practicing against the presence of abnormal annular pressure. If the well can still sustain healthy performance, mitigation steps do not have to be taken since there is abnormal annular pressure but the risk analysis shows acceptable risk and no damage can happen, so this analysis shows the possibility of preserving the well is safe, although additional safety costs are not spent. Or show the point of maximum spending cost to provide safety and which point of the spending will become useless.

- Risk management aims to

1- Investigate a system in terms of failures and errors to increase its robustness and detect weak and failure points with the probability of failure.

2- Identify and suggest PREVENTIVE MEASURES (design review, preventive maintenance, etc.) for reducing the probability of occurrence.

3- Identify and suggest the MITIGATION MEASURES (design review of protection systems, land use planning, emergency planning, etc.) and select possible alternative measures for reducing the effect of possible damage.

4- Compare different design solutions in order to choose the safer one, then optimize the possible choice by cost and qualitative risk analysis.

3.3.1 Stages of risk management

The stages of managing risk include context establishment, a risk assessment that consists of (risk identification, risk analysis, and risk evaluation), and risk treatment.

3.3.1.1 Context establishing

The major goal of this step is to assess the basic parameters of the risk assessment process and to decide the range and acceptance specifications for the remaining process. This phase should include the definition of the current risk assessment, introduce the plant with analysis and system boundaries, define the goal of assessment application, introduce the modules and possible methods for risk assessment application and recognize the risk threshold with standard acceptable limits.

3.3.1.2 Risk assessment

It comprises risk identification, risk analysis, and risk evaluation. This assessment is divided into two types, qualitative (estimate) and quantitative (measurable) risk assessment.

I. Qualitative risk assessment

Qualitative assessment is used to estimates the risk of well barrier failures against expected abnormal annular pressure. These assessments are usually applied in oil and gas risk management and are worthy of the first procedure in the risk analysis operation. They add strictness and structure to the current risk assessment process of brainstorming. Some examples of qualitative assessments are HAZID, HAZOP, Bowtie Analysis, and FMEA.

I.I Hazard identification (HAZID)

This step applied to identify the possible risk and source of this risk, also to apply precursory prioritization in terms of intensity. The methods performed in hazard identification are qualitative. Several methods can be used in the identification of hazards they are (Vamanu B., Necci A., Tarantola S., 2016). (Safety review, HAZID, Hazard review, Preliminary analysis, What-if analysis, Checklist analysis, HAZOP, FMEA, FTA, ETA).

Usually applied at the starting of the project, it is the beginning point to perform a qualitative assessment of major incident risks. For the application for abnormal annular pressure, we define the possible risk based on allowable annular pressure for both build-up (APB) MAASP for SCP, despite MAASP are consider for all annular pressure types.

I.II Hazard and Operability (HAZOP)

It is a strategic approach for the hazard identification and issues in design and functionality operations that arise as a consequence of anomalies from the expected operating condition.
Complicated designs are usually evaluated as a series of smaller nodes and define possible failure modes with details. This part of the analysis shows the weak points and effect of each element on the system integrity.

I.III The Bow Tie Methodology

It is also defined as ‘Barrier Diagram’ applied as a risk control assessment and it can be used as an optimum way to define risk boundaries, also in a visible mode, the relationships between known hazardous events, concerning causes, linked consequences, and the active preventive and mitigative barrier. The bow tie provides information about reference initiating event (RIE) who is the worst probable scenario that can be occurred, also bow tie identify the probable causes to RIE and possible result of RIE. Besides bow tie provide the integrity and efficiency of each barrier.

I.IV Failure Modes and Effects Analysis (FMEA)

It is an individual analysis of plant (well) equipment, possible failure modes, and the result of those failures on the equipment itself or plants. The failure mode is an expression of how the equipment integrity and possible failure (deviated from designed function).

II. Quantitative Risk Assessment

A risk assessment of well integrity cannot be applied as a quantitative model because the outcome will be a specific numerical result for the risk level (RL). The unreliability of quantitative risk assessment is particularly applied because of the shortage of historically recorded data concerning the event of number and kinds of well barrier faulting. Most of the operators record their incidents data of well integrity failure, but they would never want to share this important information it is company policies. These assessments are used empirical data to obtain and specify numerical values to risks. It usually follows the primary qualitative assessment, concentrating on the highest-priority risks introduced. Some examples of methods of qualitative assessments that commonly applied in the oil and gas industry are includes:

II.I Failure Mode and Effect Criticality Analysis (FMECA)

It is different from FMEA by including a rating of the potential frequency and severity of consequences of a failure mode. FMECA can be both qualitative and quantitative, based on the approach. The quantitative FMECA uses a quantitative criticality analysis and the qualitative FMECA uses a qualitative criticality analysis.

II.II Assessment of the frequency

This process aims to identify the risk in terms of the possibility of happening. The most familiar method performed in this step are:

(Failure history, FTA, ETA, Human analysis for reliability, common cause failure analysis).

3.3.1.3 Risk evaluation and representation

The evaluation of risk includes comparing rated levels of risk with risk criteria that were introduced when the context was established, to obtain the sensitivity of the level and type of risk. Risk evaluation utilizes the realization of risk determined during risk analysis to make decisions for future activity. Ethical, legal, economic, and other observance, including observation of risk, are also applied to decision making. The usual approach is to separate the risks into three parts as follow:

1- The upper part

Where the level of risk is considered as intolerable whatever advantage the activity possible to bring, and the treatment of risk is fundamental for whatever cost.

2- The middle part (or 'grey' area)

Where costs and advantages, consider and chances balanced against possible consequences.

3- The lower part

Where the risk level looks as negligible, or too little. So that not needs any risk treatment measures.

The ALARP or 'as low as reasonably practicable' criteria system applied in safety employment. Where, in the middle part, there is a slipping scale for low risks where costs and advantages can be directly compared, and for high risks, the possibility for damage must be decreased, until the cost of further reduction is entirely disproportionate to the safety advantages gained. The most familiar methods performed in this step are includes:

Risk profile, Risk matrix, F-N curve, Risk index, and Risk isopleth.

The risk matrix is the most familiar application for risk representation.

3.3.1.4 Risk treatment

Applied when the risk evaluation has been completed.

The treatment requires selection and acceptance with one or more specific methods in order to reduce the likelihood of occurrence and the risk effect or both. The new modified level of risk must be correlated with the older one by check the RL in terms of severity and probability of happening, make a complete picture for deciding if is there are needs to apply another or additional treatments.

3.3.2 Monitoring and reviewing the risk

As a section of the management for the risk, the process is by observation and reviewing the calculated risks and applied mitigations regularly to confirm that:

• Validity of the risk assumptions.

• Validity of which the risk assessment depends, including the outer and inner context.

• Validity of expected results.

• Risk assessment results are matching with real experience.

• Validation of performed risk assessment techniques.

• Performed treatment of risk is effective.

Responsibility for performing and monitoring reviews should be confirmed.

3.3.3 Application of abnormal annular pressure risk in well integrity

First, define the parts of well integrity impacted by abnormal annular pressure as follow

i- Well cement seals impaction

Changing of wellbore inner pressure due to abnormal annular pressure (Zhang et al., 2018) will reduce the cement seal integrity and might cause a failure of this seals by the generation of microfractures and micro annulus, this annulus could create a leakage way to fluid and generate an SCP especially in gas wells. Also, the abnormal annular pressure can decrease the packer sealing quality due to a change in pressure difference down and above the packer.

ii- Casing strength impaction

If the thermal pressure is not taken into account in casing design for HPHT wells, it will impact the casing by collapse and burst loads, decrease the casing stability by increasing axial load due to high annular pressure and increase casing corrosion by stress casing with annular pressure and contacting of migrated corrosive fluid with casing in case of SCP presence.

iii- Wellhead stability impaction

Based on "Hooke's law", the variation of annular temperature and pressure could cause casing axial displacement, so the wellhead may move up that lead to a change in well structure and impact on wellhead stability. Due to this phenomenon, the free part of the casing and tubing work like a spring.

3.3.4 Annulus investigation

It is one of the hazard identifications for wells that have the possibility of abnormal annular pressure. It can be applied for both the designing phase based on recorded data or for the operation phase to indicate the source of abnormal annular pressure. Annulus investigation in the operating phase defined as the series of tests performed systematically on the well, valves, and annulus to investigate the main cause of the observed pressure source or loss of containment, such as the reservoir, neighboring annulus, leaking valve, or surrounded environment (Ajayi et al., 2014). There are some safety-critical elements (SCE's) in every well which are integrity obstacles that require regular checks, verification, and maintenance. For each field, there is a list of critical elements and optimum tests must be applied for these elements. Examples for annulus investigation tests in the operating phase are the diagnostic test for SCP, LOT for open annulus integrity investigation, and thermal analysis for APB. During annulus investigation we have to consider for each annulus a slight positive pressure must be sustained with a little DP (differential pressure) among annulus strings to ensure continued annular integrity as defined in the well's operating envelopes. Any pressure loss, or increase, or equalization of the annulus pressures relative to permissible defined limits of MAASP or Min AP will trigger an annulus investigation.

3.3.5 Annular pressure limits calculation

To define the abnormal annular pressure in the annulus, the first step is by calculating the annulus limit boundary that must not be exceeded and each value of annular pressure above this limit must be considered as a risk issue and analysis of risk with the probability of failure must be defined. This part is firstly defined by MAASP as the maximum threshold of annular pressure for a given annulus and below this value, the risk alarm point must be defined as MAWOP that provides a response time to intervene repairing.

- **Calculation of MAASP**

MAASP (Sangesland, S., Rausand, 2012) should be defined for each annulus to be the threshold of presence annular pressure and limit working rate pressure for any operation applied for that annulus. MAASP must be determined for each annulus and updated during well life. The major parameters for determination are the minimum values of physical specifications of annulus content (casing/tubing burst & collapse, accessories + packer rating, casing hanger pressure… etc.) and formation fracture pressure at shoe (for the open formation). The factors affecting on MAASP of an annulus is the same that limit the boundary condition of this annulus, and they are:

1- Inner casing collapse (annulus inner boundary)

2- Outer casing burst (annulus outer boundary)

3- Wellhead working pressure (annulus upper boundary)

4- Strength of formation (annulus lower boundary for annulus type III)

5- Completion element working pressure, such as Packer, liner hanger, and tubing/casing accessories working pressures (annulus lower boundary for annulus type I). Also, if the annulus bottom is cement (annulus type II) the annulus limit pressure is based on upper and side boundaries.

The general equation for MAASP calculation can be written as:

$P_{MAASP} = P_{\text{component}} \text{ x } SF - P_{\text{hydrostatic}}$ ---------(3-1)

Where:

SF = Safety factor as explained in Table 3.1.

$P_{\text{hydrostatic}}$ = Differential hydrostatic pressure created by different fluids in inner/outer annuli at the depth of component.

$P_{\text{component}}$ = Working pressure (burst/collapse) for the used component.

Item	Safety factor	Explanation
Formation fracture pressure	1.0	If value is available from drilling leak-off test
	0.9	If value is estimated from regional data
Tubing collapse pressure Casing collapse pressure Casing burst pressure	1.0	If recently run tubing/casing, If wear or corrosion is not considered significant
	0.9 for 10% metal loss 0.8 for 20% metal loss 0.7 for 30% metal loss	If wear or corrosion is considered significant, but metal loss not known use 0.7 for safety factor

Table 3. 1 Safety factors for calculation of MAASP (A. RP, 2006)

Assumptions of calculation MAASP

1- Collapse calculation should be considered to be the lowest part of the cement top (if known) or casing shoe.

2- The formation strength must be accounted at the casing shoe.

3- The calculation of casing burst and collapse pressure must be accounted for all casing profile sections (weight/grade) and tubing collapse.

4- Original mud in surrounding annuli is degraded to base fluid (water or oil) due to aging and sagging.

5- Tubing is evacuated for the collapse calculation of annulus ‘A’.

6- Annulus ‘A’ is evacuated for the annulus ‘B’ collapse calculation.

The MAASP calculator is an application to calculate the MAASP of each annulus. The MAASP value for a specific annulus is the minimum value obtained from the calculations of each component. In the calculation of the reservoir, MAASP must consider the pressure against the perforations zone and its purpose is to determine the MASP permitted during the well intervention to prevent formation fracturing. It cannot be used to determine a well integrity MAASP limit for the operational phase.

When accounting for well aging, the MAASP (Amit Kumar et al., 2018) in this case criteria for the annuli differ over the time and wall thickness changes, density, and composition of the annulus fluid (if not assumed base fluid). So, the calculation must take into account the derated physical properties and the value are different with the well age.

3.3.6 Application of risk analysis for annular thermal pressure

For HPHT wells with trapped annulus contain a fluid able to expand and create thermal pressure, the probability of casing failure depends on the amount of generated thermal pressure relative to the permissible limit. So, the risk level will be treated based on an acceptable TAP limit under thresholds and type of mitigation device applied.

3.3.6.1 Calculation of thermal annular pressure threshold

It is the annular pressure that an annulus can withstand without affecting the burst or collapse integrity of the related tubular strings. The thermal pressure threshold is set based on the value of allowable APB that is determined based on annular pressure calculation as previously discussed (temperature, annular fluid PVT and compressibility analysis, annulus tubular strength, and production fluid properties). So, the allowable annular pressure limit calculated as follow

I- Allowable APB in annulus 'A'

The allowable APB in Annulus 'A' can be obtained from API (A. RP, 2006), which states that the MAWOP of annulus 'A' is 50% of the MIYP of the production casing (the outer casing of the annulus 'A'). Therefore,

$\Delta P_{allow,\,'A'} = 0.5\ P_{MIYP} - P_{ann,\,'A'}\ ML$ ----------------(3-2)

where:

P_{MIYP} is the minimum internal yield pressure of the production casing,

$P_{ann,\,A}$ ML represents the annulus hydrostatic pressure at the midline.

II- Allowable APB in an outer annuli ('B', 'C'…etc.)

It is rated (Sathuvalli et al., 2016) as the minimum of the $\Delta P_{allow\text{-}coll}$ and $\Delta P_{allow\text{-}bur}$.

where these two idioms represent respectively the APB at which the collapse of the inner string or burst of outer string safety factor is equal to the collapse or burst design factor. In this description two hypotheses are implicit:

1- The subject annulus is trapped and will have APB.

2- The next neighbour annulus not developed APB.

The inner string experiences a collapse load, and the outer string undergoes a burst load, keep with these assumptions. The appropriate APB may now be connected to tubular design factors First, think about the inner string which experiences a collapse load. The minimum collapse safety factor $SF_{coll,\,min}$ is obtained from

$$SF_{coll,min} = \frac{Pcoll}{[\Delta P + Pann - \left(1 - \frac{2t}{do}\right) Pint,L]max} \quad \text{----------------(3-3)}$$

where:

P_{coll} is the temperature adjusted collapse strength of the string, d_o and t are the outside diameter and wall thickness of casing, respectively.

The safe design must ensure that $SF_{coll,\,min} > DF_{coll}$ ---------------(3-4)

Idioms means:

DF_{coll} is collapse differential pressure on the string

The denominator illustrates maximum collapse differential pressure on the string. The external pressure on the string is the APB (Δp) acting on the hydrostatic pressure (p_{ain}) of the fluid in the annulus. The internal pressure $P_{int,\ L}$ is the minimum anticipated pressure profile in the neighbouring annulus (to the left of the working annulus). The allowable APB for the collapse of the inner string, $\Delta p_{allow\text{-}coll}$ is determined by setting the minimum collapse safety factor in Eq. (3-3) equal to the design factor, then

$$\Delta p_{allow\text{-}coll} = \left\{P\mathrm{coll}/DF\ coll + \left(1 - \frac{2t}{do}\right) Pint, L\right\} max\ -\ \{Pann\} max \text{-------(3-5)}$$

In the equation above, the subscript "max" refers to that the quantities indicated are measured at a depth where the differential pressure of collapse is maximum. We calculate APB for the burst of the outer string, by a similar case, so

$$\Delta p_{allow\text{-}bur} = Pbur/DF\ bur + \{P\mathrm{ext}, \mathrm{R}\} max - \{Pann\}\mathrm{max} \text{----------------(3-6)}$$

Idioms means:

P_{bur} is the temperature adjusted internal pressure strength of the annulus outer string,

$P_{ext,\ X}$ is the minimum anticipated pressure profile in the neighboring annulus (annulus 'X' to the right of the working annulus).

The allowable APB for the annulus is obtained by

$$\Delta P_{allow\text{-}ann} = \min\ \{\Delta P_{allow\text{-}coll}\ ,\ \Delta P_{allow\text{-}bur}\} \text{-----------------(3-7)}$$

The burst and collapse safety factors are equal to their general definition (the ratio between differential pressure to the strength rating). In order to determine the allowable of APB, there are some point that must be noted when used these safety factors definitions

1- The collapse of the inner string is the govern for the allowable annular pressure in most situations the collapse rating of the inner string is either the API collapse rating or the manufacturing rating in the case of own tubular.

2- The minimum acceptable safety factor for TAP is not always rigidly adhered to, but it should be a break after careful consideration of a problem in the hand.

3- The TAP collapse design load usually 1.1, for this design is 10% above the factor of design of drilling collapse loads, the purpose of this increase is to account for

A- Validity in stiffness of cement and formation, fluid PVT attitude, the initial temperature distributed at the annulus.

B- Faulting in thermal analysis, assessment to be on the order of 10%.

C- Unknowns or unaccounted parameters such as the wearing effect of the casing is sometimes set by prediction.

4- The estimation of maximum differential pressure in the string is done by a variety of conditions. These conditions are included some parameters such as shallow barite plugs at the shallow annulus points, mud settling, and another condition depends on the application.

3.3.6.2 Possible outcomes from thermal pressure risk analysis during design

After identifying allowable APB there are two possible cases can be evaluated by risk analysis

1. TAP < allowable APB → Safe case

When TAP less than allowable APB it will be the safety case for the selected design, so the probability of failure, in this case, depends on

I- Reliability of selected casing physical properties (collapse, burst) with taking the effect of well again based on expected production of field and well effect during life. The probability increases with low reliability.

II- Amount of uncertainty of annular pressure calculation (module used for calculation and accuracy of the parameter of heat and pressure, the scenario of well design). The probability will increase when uncertainty increase.

III- Source of data such as expected for explorer wells or taken from previously drilled wells and for selected annulus casing properties (API casing or non-API for high strength casing) the probability of failure will increase when we are far from API or using some predictions.

IV- Safety factor applied for design (burst, collapse, tension), high safety factor will decrease the probability of failure, but the safety factor must be selected in the range of API recommendation.

V- Amount of pressure difference between TAP and allowable limit, the high difference decreases the probability of failure.

VI- Presence of another source of annular pressure such as AP or/and SCP. That will increase the probability of failure, in this case, the risk analysis of each annular pressure type must be applied separately, and the final risk will be summed and checked.

2. TAP > allowable APB → Risk case

In this case, the designer must use one or more of the mitigation methods (as listed in chapter two) starting with casing strength and wall thickness improvement. In this case, the probability of well integrity failure by casing failure due to abnormal annular pressure is built on the reliability of the mitigation device that is applied. The new risk calculation is based on the amount of annular pressure after modification by mitigation device, this value will be re-entered with an acceptable probability of failure in the new risk equation then the final risk is the base of accepting this modification by taking into account the principle of selecting the optimum mitigation device.

3.3.6.3 Reliability analysis

The quantitative risk assessment are built on reliability analysis of mitigation device that protects well integrity against abnormal annular pressure for APB, so the reliability analysis must perform as follow (Sangesland, S., Rausand, 2012)

1- Define and become familiar with the system

This step consists of the define the operational situation, review of the well diagram, construction of annuli properties and fluid composition (annulus boundary and PVT analysis), and listing of possible mitigation devices with their functions.

2- Define failure modes and causes of failure

Applied for selected mitigation devices. By analysing possible failure modes of applied device and effect on mitigation system and well integrity. The best method for failure investigation is FMECA. The target of the FMECA is to define all the expected failure modes, cause of this failure, and effects for each of the elements of the system, also application of HAZOP can provide the worst failure scenario for mitigation device failure with effect on the system(well integrity) failure and plant impaction.

4- Build a reliability model of the mitigation system

There are many alternative models available, and the selection of models depends on what type of system states and available data to support the models. For more easy work recommended using FTA, since this method is axiomatic and easy to understand (at least for the qualitative parts).

3.3.6.3.1 Determination of Reliability for TAP mitigation techniques

Generally, the reliability of an engineering part can be obtained in two ways:

1- Estimate reliability from frequency data.

2- Estimation of reliability by full-scale counting of the sample space and counting favorable results.

The first approach needs data about quality and product failure. The latter approach includes a detailed physical model (or process) of the system and the engineering parameters governing its output. The reported data of abnormal annular pressure accidents does not permit a direct evaluation of the reliability of a given annular pressure mitigation device due to the following reasons:

1- The outer annuli of an SSW cannot be directly monitored.

2- Published reports of downhole pressure-temperature measurements in annuli do not contain the application of TAP mitigation techniques (other than the open hole).

3- The investigation of case studies of TAP records failures (the Marlin (Bradford, D. W., 2002), Mad Dog (P. D. Pattillo et al., 2007) and the Pompano wells (Phillip D. Pattillo, Cocales, et al., 2004)) investigate the cause(s) of failure of the casing(s) and define APB in an annulus without a mitigation technique as a probable cause.

4- This is only one published case study contains fibber optic cables (device to measure the temperature) of the fluids in the annulus “A “ in Marlin re-designed well, so it can determine the performance of the VIT and the IPF.

It is evident from the previous discussion that the efficiency of the TAP mitigation system must be assessed during the design process, and its effect on the well's life should be calculated using other approaches.

Reliability evaluation for mitigation device is performed in four phases:

1- Define the multiple failure modes (as applied in the wellbore system).

2- Evaluate the reliability of the mitigating system by the individual (element).

3- Assess the mitigating instrument's effect on the structural strength of other elements.

4- Determine the effect on life expectancy and the need for intervention.

Quantifying these aspects of a mitigation strategy can be difficult or even impossible since numerical results from simulation cannot represent the real reliability of the system. So, Phase.1 may be the only measurable step for this evaluation.

3.3.6.4 Result reporting

It is essential that all outcomes of risk analysis are reported, along with the assumptions and limitations made. Strategies requiring further follow-up, whether looking right to the need for redesign or revising planning, operating or maintenance procedures, need to be adequately emphasized. Responsible persons or departments must always be appointed to recommendations.

3.3.7 Application of risk analysis for SCP

The development of risk analysis based on managing of SCP and probability of presence during well life to decide for casing selection and future remediations. So, the probability of failure and risk calculation depends on:

I- Accurate calculation of SCP by applying the appropriate model as discussed in chapter one for new wells design and based on pressure measurement on wellhead for current wells.

II- Type of the fluid in the annulus (by checking removed fluid), and the remaining hydrostatic of annuls original fluid (almost water base).

III- Source of data, expected, or recorded. In some cases, there is a rough assumption by using the source formation pressure directly.

IV- Risk assessment after final well status when including final cement quality and annulus testing.

V- Well type, function (production, injection…etc.) and expected well life and well plan (to consider well aging).

VI- Combination annular pressure SCP, TAP and AP.

VII- The acceptable risk threshold (allowable annular pressure) will be updated with well aging and future scenarios of well plan and functionality (production, injection, shut-in, etc..).

3.3.7.1 Diagnostic test of SCP

It can be defined as tests or methods conducted to assess the severity of the presence of casing pressure and to help to identify the source of this pressure in certain situations and possible remediation methods. These tests consist of the analysis of sampling fluids, logging of well, fluid levels monitoring, pressure tests, maintenance of wellhead, Build-up, and Bleed down test of pressure (B-B test).

- Fluid sampling

Applied to identify the influx source by analysing fluid sample properties (density and composition).

- Logging analysis of well

Applied to detect the location of the fluid and source formation by using CBL, temperature and noise analysis, also oxygen activation log to detect water feeding channels and TDT logs to detect the accumulation of gas in the annular.

- Fluid level monitoring

Applied to detect and verify the tubing leaks by performing a conventional acoustic test. But this test most of the time is not as easy because of gas cut fluids, the 90 degrees well head turns, and annular geometry.

- Pressure tests

After SCP bleed down the pressure test applied to determine the annular fluid density and indication of surface pressure by assuming the lifted annulus fluid can be replaced by gas.

- Maintenance of wellhead

This operation can help to detect and eliminate the connection between annulus strings if it is found at the wellhead. So, the greasing of the wellhead can help to eliminate this problem.

- Build-up and bleed down of pressure (B-B test)

This test is usually applied through a ½.in venting valve. It can provide information about the volume of annular, content of gas and flow capacity of channel or micro-annulus, source of fluids, and flow rate. The flow rate of the bleed-off test can be accounted for and correlate to the time curve to determine the total bleed volume. The pressure of the casing is also recorded, and a system of data acquisition or recorder chart can also be utilized. This will provide the highest information needs to identify communication among annulus strings.

This test provides the complete picture of casing pressure as follow:

A- Checks if the casing pressure is less than 20% of the MIYP or,

B- Checks if the casing pressure can be completely vented to zero psig.

C- Possibility of SCP growth back up in 24 hr and to know the build-up rate.

D- Draw and analyse the pressure pattern of casing pressure as shown in Figures 3.1 and 3.2.

These include bleed-down / build-up (B-B) tests, fluid analysis, and bleed-down fluid volumes, assessment of accessible pressure data real-time, production logs, operational supervision, and so on. API (A. RP, 2006) recommended applying this test in case of casing pressure noticed higher than 100 psig. Also, this test suggests applying in case of a pressure increase relative to previous monitoring (above the last recording) and the case of new operation applied such as acid job, working on sliding sleeves, and changing of valves in gas lifting. The diagnostic tests (Milanovic & Smith, 2005) should be repeated when the casing pressure is monitored to over 20% of the MIYP of the affected annulus. The API (14B RP, 1999) presents an acceptable limit for the allowable rate of leakage for gas 15 SCFM and liquid 400 cc/min. These criteria can be overridden if they ensure no hydrocarbon can be present in the influx source.

3.3.7.2 Analysis of the Bleed-down/Build-Up diagnostic test

It is a step of risk assessment to the analysis of the presence of annular pressure risk and rates its level. According to API recommendation (A. RP, 2006), there are three possible results when applying the B-B test, as can be seen in Figure 3.1.

i- Pressure vent to zero psig with No Build-up

Annuli that have a pressure of 100 psig or less, the annulus, in this case, have not SCP and the risk will be low and must be monitored only, the source of pressure could be thermal in origin or a mini rate leak. The barriers to hold the pressure are deem effective.

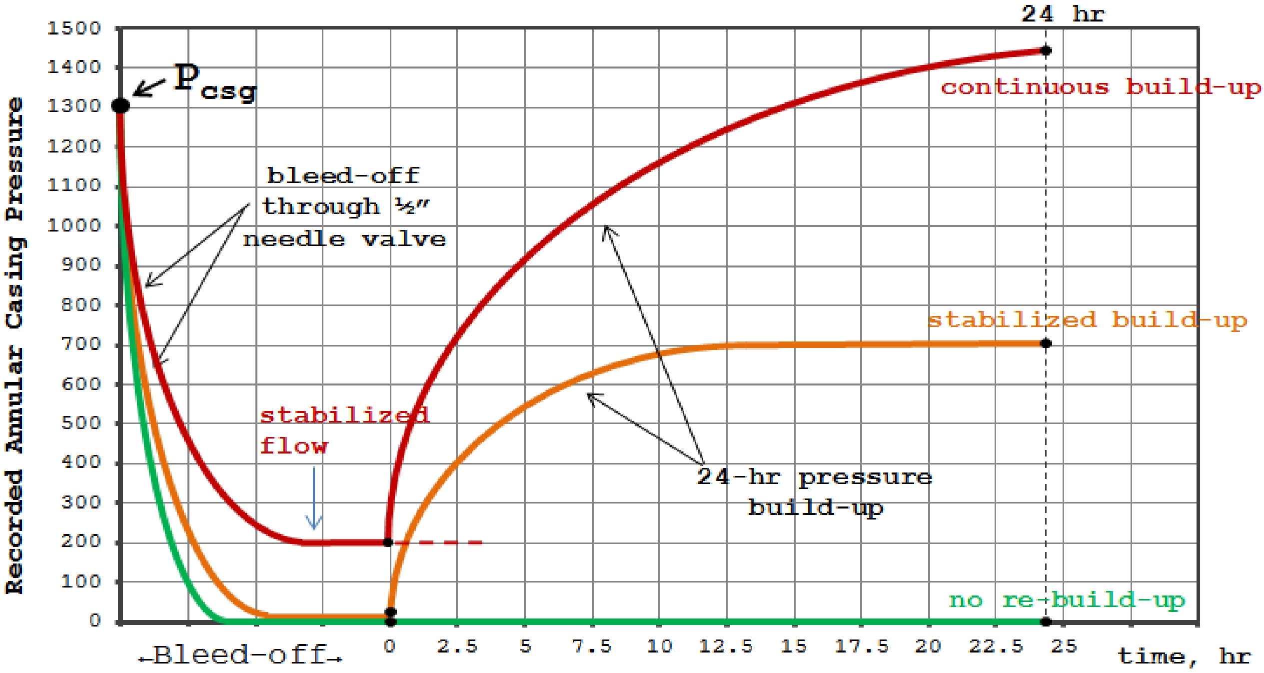

Figure 3. 1 Expected results in the diagnostic test (syntactic example)

ii- Pressure vent to zero psig with Build-up

Annuli that have a pressure of higher than 100 psig but less than MAWOP, if they can be vented to zero pressure and if build-up reaches to same or lower original limit within 24 hr it shows an acceptable risk (Kinik & Wojtanowicz, 2011). The leak rate is supposed to be acceptable and the barriers to hold the pressure are deemed enough if the pressure doesn't exceed the threshold limit. Suggested to make regularly check to ensure the acceptability of barriers. The source of pressure could be (mini leakage rate, big gas cap at the upper part of the annulus, thermal effect, or slow migration of gas).

iii- Pressure does not vent to zero psig (risk case)

Annuli with pressure greater than MAWOP or where annulus pressure can't completely vent. In this case, the barrier to hold the pressure could have partially damage and, for some cases, the leak rate could be unacceptable. This case indicates that the leakage rate is greater than the venting rate of bleeding, this well must be treated on the case by case basis. The risk, in this case, needs to treat or mitigate by applying some practices or devices. Dealing with "rogue" wells is decided by the operator. Reporting of these wells is different for each country depending on its jurisdiction and recommendations. During the test for a given annulus, it should be monitoring the other annuli to check if there any communication between annuli and need to be repaired.

3.3.7.3 Analysis of SCP pressure pattern

There are two patterns of SCP bleed-down and three patterns of SCP build-up (Xu & Wojtanowicz, 2003).

1- Instant SCP bleed-down pattern

As shown in Figure 3.2-A, this type is popular in vent and lubricate remediation techniques. The casing pressure will quickly be vented with the release of annulus fluid and followed by the injection of killing mud, amount, and properties of released fluid that will be measured and recorded.

2- Long bleed-down pattern

This type as indicated in Figure 3.2-B is a special case of instant bleed-down with the limited opening of the needle valve and without fluid removal from the annulus or in sometimes, the operators control the venting valve to decrease the removed fluid. The casing pressure will stabilize at a value not reached zero.

3- Normal build-up pattern

This type as shown in Figure 3.2-C represents the normal performance of annulus pressure build-up for a well under SCP problem. After the bleed-down, the pressure of the casing will rise instantly (early time performance) then stabilize at a specific value (late time performance), the transition part of pressure performance represents a gradual increase. The stabilized pressure of the casing was obtained by the weight of mud and the pressure source of the formation fluid. Transient time is managed by the severity of fluid migration in the cement channel and through the mud column.

4- S-shape build-up pattern

This type is a special case of the normal build-up pattern as shown in Figure 3.2-D, different by no gas found in the column of liquid in the pressure build-up at an early stage, at this stage no significant casing pressure increase. The pressure increases gradually and stabilizes finally at a specific level.

5- Incomplete build-up pattern

After bleed-down, if the pressure of formation is higher enough the build-up response shows an incomplete pattern. The casing pressure rises continuously as shown in Figure 3.2-E with slow and steady increases due to the constant flow of gas from cement channels, and no late time found during the build-up period (one day), also the pressure needs long enough time (more than one day) to stabilize. Almost the final pressure will be high and risky.

Interpretation of these patterns can provide information about the level of risk and discuss the possibility of decrease this risk by select an optimum remediation plan.

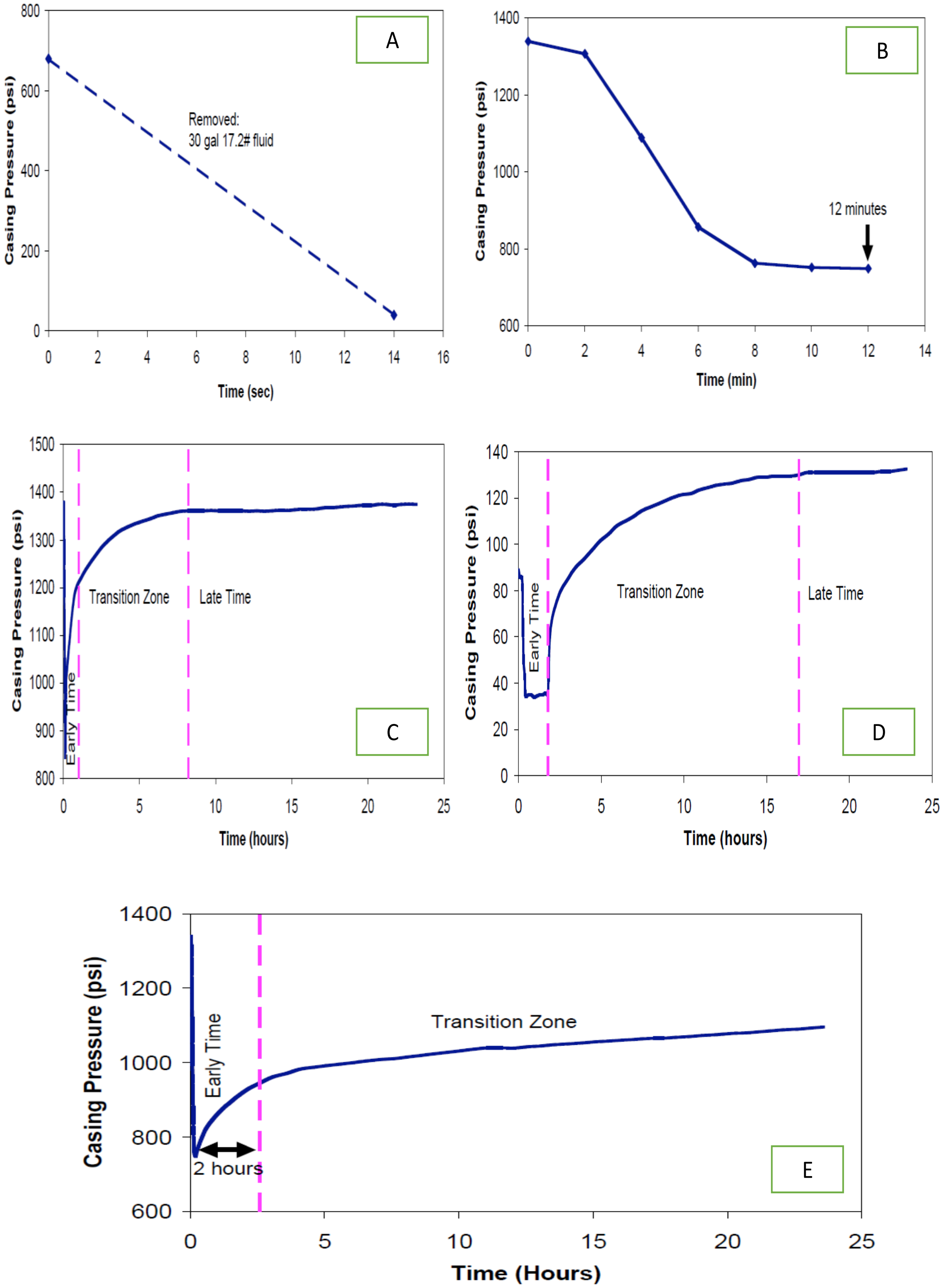

Figure 3. 2 Bleed-down and build up a detailed pattern of SCP (Xu & Wojtanowicz, 2003)

3.3.7.4 Risk evaluation for anomalies SCP

For the cases of abnormal casing pressure presence, we follow the risk matrix for risk level evaluation as an example shown in Figure 3.3 of the risk matrix applied by British petroleum (BP) (ROO WIMS ROO-WELLS-GEN-STD-015) for normal pressure-temperature wells in Iraq.

RISK MATRIX AND FAILURE MODE											
Well type		1	2	3	4	5	6	7	8	9	9
Function		OP	OP	OP	OP	WI	WI	WI	WI	WD	WD
7" csg to surface		NO	YES	NO	YES	NO	YES	NO	YES	NO	YES
Packer		NO	NO	YES	YES	NO	NO	YES	YES	NO	NO
MAWOP A		...	...	1000	1000	...	...	500	500	...	
MAWOP B		100	500	100	500	100	500	100	500	...	...
MAWOP C		...	100	...	100	...	100	...	100	...	...
Failure discription and risk level evaluation											
Failure discription	**Abbre viation**		**Risk level**								
External leak	EXL	5	5	5	5	5	5	5	5	5	5
TBG leak failure	TL	0	0	3	3	0	0	2	1	3	3
A annulus leak failure	AL	4	3	3	2	4	2	2	1	3	3
B annulus leak failure	BL	1	3	1	2	1	2	1	1	0	1
C annulus leak failure	CL	0	1	0	1	0	1	0	1	0	1
TBG & A ann leak failure	TAL	4	3	4	3	4	2	4	2	3	3
A & B ann failure	ABL	4	4	3	3	4	4	2	2	0	2
B &C ann failure	BCL	0	3	0	2	0	2	0	1	0	1
A, B &C ann failure	ABCL	0	4	0	3	0	4	0	2	0	2
TBG & A &B ann leak failure	TABL	4	4	4	4	4	4	4	4	0	3
SCP A annulus	AP	0	0	3	3	0	0	3	3	0	1
SCP B annulus	BP	2	3	2	3	2	3	2	3	0	1
SCP C annulus	CP	0	2	0	2	0	2	0	2	0	1
A & B annulus SCP	ABP	3	3	3	3	3	3	3	3	0	1
B & C annulus SCP	BCP	0	3	0	3	0	3	0	3	0	1
A,B & C annulus SCP	ABCP	0	3	0	3	0	3	0	3	0	1

Risk level discription			
Operation sate	Risk level	Discription	Days to repair
Operable	0	No issues	....
	1	Low	....
	2	Medium	180
	3	High	90
Not Operable	4	Critical	30
	5	Emergency	0

Figure 3. 3 SCP risk matrix and failure mode

Where:

OP: Oil Production well, WI: Water Injection well, WD: Disposal Well

3.3.7.5 Managing of SAP with the effect of well aging

In order to decrease HSE risks related to SCP in aging wells, MAASP, and MAWOP determinations depending on corrosion derating factors must be considered in calculations

(Amit Kumar et al., 2018). For smooth management of aging wells (40 years or older) beyond their design period, its important to accurately identify MAASP thresholds and consider well aging effects. Casing corrosion directly impacts the integrity of the well and can result in structural failure and well collapse with the likelihood of release of hydrocarbon into the environment. The derating factor should be used to account for well aging and corrosion effects. Many recommendations published by various industry standards as outlined in Table 3.2 can be used for this purpose.

API RP90 (2012)	ISO 16530-2 (2014)	NORSOK D10 (2004)

• Only MAWOP and no MAASP
• MAWOP defined using derated casing burst, collapse, completion equipment rating, formation fracture with appropriate derating/ safety factors pressure
• MAWOPs of inner annuli are minimum of
  ○ 50% of MIYP or burst
  ○ 80% of MIYP of next outer casing
  ○ 75% of collapse of inner tubular
  ○ 80% of completion equipment rating
  ○ 80% of wellhead rating
• MAWOP of outer annulus is minimum of
  ○ 30% of MIYP
  ○ 75% of collapse of inner tubular
  ○ 80% of completion equipment rating
  ○ 80% of wellhead rating
  ○ 80% of formation fracture
• Recommends use of derating factors in case of excessive wear/ corrosion/ erosion
	• MAASP and upper threshold operating pressure limit
	• MAASP is minimum of casing burst, collapse, casing test pressure, formation fracture and completion equipment pressure constraints, etc.
	• Unlike API RP-90 standard, no guidance on safety factors is provided for burst and collapse pressure calculations
	• Upper threshold operating pressure limit is
	  ○ 80% of MAASP value of the annulus being evaluated
	  ○ 100% of the MAASP of the adjacent outer annuli
	• Recommends using derating factors for MAASP calculations based on tubing conditions but does not provide any guidance
		• Describes MAASP and MOP (maximum operating pressure)
		• No specific guidance on MAASP and calculation procedure
		• Recommends using derating factors based on tubing conditions due to corrosion and wear without any guidance

Table 3. 2 Summary of MAASP and MAWOP calculations as defined in various industry standards (Amit Kumar et al., 2018)

3.3.7.5.1 Derated Casing Burst Pressure (P_b)

Reduction in casing wall thickness due to corrosion will decrease the casing burst pressure. Derated burst pressure of casing is calculated using Barlow’s equation (Amit Kumar et al., 2018), suitable to thin wall tubes as the following

$P_b = 0.875*(2*Yp*t)/D$-------------------------(3-8)

where:

P_b: Burst pressure of casing

Yp: is the specified casing minimum yield strength (in psi),

t: is the remaining wall thickness (in inches) of the casing,

D: is the nominal outside diameter (in inches).

The remaining wall thickness is calculated by subtracting the wall loss over years from the original nominal wall thickness.

0.875: Is the factor of allowable manufacturing tolerance of –12.5% on wall thickness.

By using the published burst pressure of casing (P_{pub-b}) and Equation (3-8) we can calculate the casing burst derating factor (fb) as follows:

$$fb = P_b / P_{pub-b} \text{ ----------------------------------(3-9)}$$

Equations (3-8) & (3-9) represent the casing burst derating factor, fb, rely on casing properties, and the remaining wall thickness which is affected by well age, cement conditions, annulus fluid, and service environment.

* A standard five percent (5%) wall loss is used in the burst derating calculation to compensate for wear during drilling and completion.

3.3.7.5.2 Derated casing collapse pressure (P_c)

The main factor in the determination of pressure collapse of the casing is D/t,

where

D: Outer diameter, t: is the remaining wall thickness.

The 'D/t' ratio determines the failure range in which the pipe will fail and the equation to determine the collapse load.

Then the casing collapse derating factor (f_c) is calculated as follows:

$$f_c = P_c / P_{pub-c} \text{ ----------------------------(3-10)}$$

where

P_c: is derated casing collapse,

P_{pub-c}: is published collapse pressure rating of the casing

From a practical standpoint, this approach identifies a realistic situation in which someone may accidentally or unjustifiably bleed the pressure of annulus.

3.3.7.5.3 Effect of casing corrosion rate at annulus risk threshold

the corrosion as discussed previously decreases the casing wall thickness and as a consequence leads to decrease physical properties of the casing, so the annulus boundary pressure limit will be decreased, and this effect must be taken at pressure limit calculation to update risk analysis. There are some factors affect the corrosion factor of the casing such as (casing contact with annulus corrosive fluid or oxygen seawater (for offshore wells), presence of acid gases or bacteria, poor cement, the temperature of casing, the water content of PH, salinity and temperature, and poor cathodic protection). The corrosion effect can be detected by using ultrasonic wall thickness measurement. The corrosion rate is represented as mm/year and may override 1 mm/year in carbon-steel tubing with production fluid. Because of the broad variation in environmental conditions, wells are divided into three classes depending on the service conditions and associated with the corrosion rate as can be shown above in Table 3.3

Category	Corrosion severity	Typical environmental conditions	Installation age	Total corrosion rate (mm/yr)
A	Low	Tubular strings with • proper cathodic protection (CP), and/or • tubulars isolated from aquifers with good cement bond, and oil mud treated with corrosion inhibitors, H_2S scavengers and biocide, etc.	Initial 15 years	0.10
			After 15 years	0.20
B	Moderate	Tubular strings with • insufficient cathodic protection (CP), and/or • tubulars with poor cement bond, and/or • having issues with annular pressure	Initial 15 years	0.15
			After 15 years	0.25
C	High	Tubular strings with • material is in contact with highly corrosive fluid, oxygen ingress, dissimilar materials, and/or • with known corrosion issues	Irrespective of age	0.50

Table 3. 3 Corrosion rate in the casing dependent on well age and environment (Amit Kumar et al., 2018)

3.3.7.6 Calculation of SCP threshold

3.3.7.6.1 By integrated approach of MAASP and MAWOP

The trigger threshold of pressure is a little above pressure fluctuation at normal production operations, but below the MAASP and MAWOP value. The aim of trigger pressure is a value less than MAASP that can give a less chance to reach MAASP and provide a time to pressure response to manage pressure before reaching a threshold value, so it is used as an indicator for abnormal annular pressure and investigation have to be applied to find the source of SAP. The allowable SAP limits are introduced as the advised operating regime, so the highest threshold limit of the advised operating regime is 50% of MAWOP (Amit Kumar et al., 2018) as can be demonstrated in Figure3.4. So, the threshold of failure probability at risk analysis is the MAASP and MAWOP.

Figure 3. 4 Typical annulus trigger pressure (Amit Kumar et al., 2018)

Calculation of MAWOP

It Is the highest pressure that is allowed to be sustained in the annulus before bleed-off is performed, it is valid for all annular pressure types. And it must be less than MAASP in all cases. The target venting the pressure must be less than 20% of MAWOP of that annulus. MAWOP is determined from the MAASP of the assessed annulus and of the neighbouring annulus.

- The MAWOP of the inner annuli is the minimum of (A. RP, 2006)

A- 50 % of the MIYP of the casing or production riser string would be assessed, or

B- 80 % of the MIYP of the next outer casing or production string, or

C- 75 % of the Minimum Collapse Pressure of the inner tubular pipe.

Generally defined by the formula

$MAWOP = mini\ (75\%\ S_{cA},\ 50\%S_{bA},\ 80\%S_{bB})$ -----------------(3-11)

Idioms meaning:

S_{cA}: TBG collapse pressure, S_{bA}: Production CSG burst pressure, S_{bB}: Intermediate CSG burst pressure.

- The MAWOP of the outer annuli is the minimum of

A- 30 % of the MIYP of the casing or production riser string would be assessed, or

B- 75 % of the Minimum Collapse Pressure of the inner tubular pipe.

Proactive governance of SCP who uses this approach enables safe production operations with a reduced probability of the well integrity failure including the leak of hydrocarbon to the environment and/or structural damage.

3.3.7.6.2 By probabilistic approach of casing shoe failure by SCP

In some cases of wells, the shoe fails before reaching the MAWOP, so the SCP limit is restricted by casing shoe fracture pressure. And this is affected by casing setting depth, casing strength, pressure source intensity, and depth (Kinik & Wojtanowicz, 2011). The actual fracture pressure obtained from various test types of formation strength (FST) that are applied to check the strength of the cement bond and rock, such as formation integrity test (FIT), leak-off test (LOT), or extended leak-off test (XLOT). Simply fracture pressure can be obtained from LOT by using the following equation

$P_{ff\ actual} = P_{surface} + P_{hyd} + \Delta P_{gel} + \Delta 6_{\ thermal\text{-}stress} + \Delta P_{mud\ compressibility}$ ------------(3-12)

where:

$P_{ff\ actual}$: fracture pressure, $P_{surface}$: surface pressure at LOT, P_{hyd}: hydrostatic pressure of mud, ΔP_{gel}: gel strength effect, $\Delta 6_{\ thermal\ stress}$: effect of thermal stress, $\Delta P_{mud\ compressibility}$: effect of mud compressibility.

The risk analysis gives a probability of shoe failure that must be considered in the SCP permissible range. So, from these two approaches, we select the lowest value between LOT (probabilistic approach) and MAWOP (integrated approach) to be the limit for SCP allowable in each annulus.

3.3.8 Annular pressure monitoring

The best practice for abnormal annular pressure risk indication and applied mitigation effectiveness (A. RP, 2006) done by periodically monitoring of casing pressure by indicating P_{csg} presence and its value. There are differences between onshore and offshore wells monitoring:

I- Onshore wells

the surveillance of casing pressure is easier by installing a gauge on the annulus from the wellhead and make a monthly checking or as required to ensure the annulus follows the acceptable and safety criteria.

II- Offshore wells

Surveillance of casing pressure is various between SSW and fixed platform, in the SSW the annulus pressure of tubing-casing (annulus 'A') is the only that can be observed, for other annuli are separated after landing of the casing, so it is a technical challenge for monitoring annular pressure in these annuli. For fixed platform wells, the annulus pressure can be observed monthly from each non-structural casing strings that are equipped with a gauge and the annular pressure will be checked from the wellhead by the fitted taps or flanges for each annulus. Increasing monitoring frequency will improve the capability to detect casing pressure. This operation performs for producing, injection, shut-in, and temporarily abandoned wells to early indication, performance evaluation, and control of annular pressure risk. The monitoring can be done by different strategies like but not limited to Supervisory Control and Data Acquisition system (SCADA), a recorder chart pressure pen, scaled pressure gauges. All monitoring must be reported. The monitoring is classified in to:

1- Normal observation to well that has No casing pressure

Any annulus able to contain pressure must be continuously or regularly monitored for determination if the pressure of casing is present in the annulus. The minimum, routine monitoring must be applied at least once each six months.

2- Observation of wells that have SCP

Minimum routine observation of annuli with SCP should be applied once every month. And minimum, for the other annuli of the well that do not record casing pressure, must be observed at the same frequency. The monitoring frequency influenced by the operativity of the platform, recorded annulus pressure relative to annulus pressure threshold, the behaviour of pressure increasing, source of annular pressure of other annuli of the well (AP, TAP), risk level recorded by monitoring.

3- Observation of wells that have a thermal casing pressure or TAP

The important section of monitoring for this type is at well start-up, the operator must set the frequency of wells observation where one or more annuli showed a thermal casing pressure. The monitoring result should be recorded. The minimum, routine observation of annuli that have thermal casing pressure should be applied once every month. Production wells with thermal casing pressure should be observed during choke size increase. The minimum, observation for other annuli of the well that do not exhibit casing pressure should be observed at the same frequency. The monitoring frequency was influenced by operativity of the platform, recorded annulus pressure relative to annulus pressure threshold, the stable characteristic production of the well, the stability of annular pressure, presence of annular pressure for the other annuli.

4- Observation of wells with applied annular pressures (AP)

Applied pressure by the operator should be observed and recorded as per requiring this applied pressure. The minimum, routine observation of the annuli with AP should be applied once every month, and for the other annuli in the well should be observed in accordance with the timeframe set by the operator and based on the purpose of AP and limits, also for any case of applied pressure change, the annulus monitoring mandatory performed.

3.3.9 Final risk assessment

Here the designer has all the data and possible scenarios to build the complete risk tree (analysis). The risk level must be defined based on standard risk calculation and show the severity of this risk with possible treatments and evaluation of risk after toleration. As made by a set of assumptions for possible failure scenarios of well integrity failure by abnormal annular pressure (NORSOK, 2004), the operator company policies, government rules, and analysis of previous accidents and scenarios will guide the designer at this task.

CHAPTER FOUR
LIMITATIONS AND OPTIMIZATION OF SELECTING ANNULAR PRESSURE MITIGATION TECHNIQUES

The abnormal annular pressure mitigation techniques are different in terms of cost, operating difficulty, reliability, applied condition, failure rate, and working mechanism. Reported data and field experiences show that there is not a universal solution for abnormal annular pressure mitigation (Payne et al., 2007). The selection of an optimum mitigation technique is based on some parameters, starting by analysing the case step by step. This section specialized in TAP mitigation devices.

4.1 Definition of the design environment

1- Type of the well based on onshore (platform and SSW) and offshore wells.

2- Type of well based on a range of bottom hole pressure and temperature.

4.1.1 Type of the well based on onshore wells, offshore wells

A- Onshore wells

This type of well is easier for control TAP due to the ability to access all the annuli and vent the pressure when needs, also monitor the casing pressure during production. This type of wells does not need to apply a mitigation device for APB.

B- Offshore wells for SSW

This type of well is more difficult to control TAP due to limited access to all annuli, the annulus ‘A’ is the only one that can be reached and vented. So, a mitigation device needs to be applied in this case when dangerous TAP is present. Remediation for this well due to damage by annular pressure is highly costed, limited, low possibility of success, and difficult operationally, also in some cases the well abandon. The selection of an optimum mitigation method is a big challenge based on well condition, range of TAP, well functionality, formation pressures properties, and annulus fluid properties. All scenarios of drilling, production, and injection must be considered during design.

4.1.2 Type of well Based on the range of bottom hole pressure and temperature

For HPHT wells, the optimization of design depends on the range of pressure and temperature. There are three ranges (Payne et al., 2007).

1. High-pressure High-temperature wells HPHT

These wells are specified by BHP (10-15) Ksi and BHT (300-350) ºF. In deep water wells (depth of water exceeding 600 m LAT (Lowest Astronomical Tide)), especially in SSW, the casing design must be account for APB.

2. Ultra-High-pressure High-temperature wells uHPHT

These wells are specified by BHP up to 20Ksi and BHT 400ºF. In this type, TAP will be higher and casing maybe not sufficient to withstand this pressure and suggested not used high casing strength in this case as a mitigation strategy because it may fall out of API standards and well-aging decrease casing properties so select another mitigation strategy.

3. Extreme-High pressure High-temperature wells uHPHT

These wells are specified by extremely high BHP up to 30Ksi and BHT 500ºF, this type of wells currently specified for deep gas wells. This type is expected to develop very high TAP due to a very large volume resulted from the expansion of the annular fluid. Also, expect a high probability of SCP accruing, so this type may need more than one mitigation technique to control TAP. Besides this type of well have a big challenge in keeping well integrity, so the designer must keep into account these challenging conditions.

4.2 Limitation of TAP mitigation devices selection

There are some limitations for choosing one mitigation device without the other, these limits are defined as:

4.2.1 Design condition (input data)

Such as temperature profile, APB magnitude…. etc. as discussed previously.

4.2.2 Acceptance of risk level

Associated with well case and selected mitigation device. Each operator has the own rules (based on context establishing of risk), types of risk standard, and acceptance limits, for example, some companies don't prefer to modify casing to mitigate TAP, some of them prefer active than passive mitigation devices.

4.2.3 Well geometry, functionality, and well life future scenarios

One of the most important aspects for restriction of mitigation selection is the well geometry that can accept one device and not permit using the other, for example, annulus clearance, length of section, type of well (vertical, directional,…etc.), type of well completion, the function of well such as production, injection, etc. and what future required workover operation. Also, the scenario of the future forecasting model of well to include the max flow rate during production with produced fluid properties and what is equivalent during drilling by keeping in to account the scenario of WCD, also temperature profiles that will be changed when produced fluid properties are changed or well functionality changed. This requirement may give a limited option of selection and the optimum will be not the cheapest, it will be more accepted. So more accurate data used for design can optimize the selection.

4.3 Optimization parameters for TAP mitigation devices selection

In most cases there is more than one possible solution for TAP mitigation device application for the same case, the selection of optimum mitigation device is based on some factors as follow:

4.3.1 Reliability of the mitigation techniques

The optimization of mitigation device selection is mainly based on the reliability of a given device at a given function and condition. In most cases, the reliability data have come from experimental data and industrial recommendations that almost match the real case with some field previous reports. The reliability also defined by the codes (1 – 5) refers to (lowest-highest) reliability as can be shown in Figure 4.1

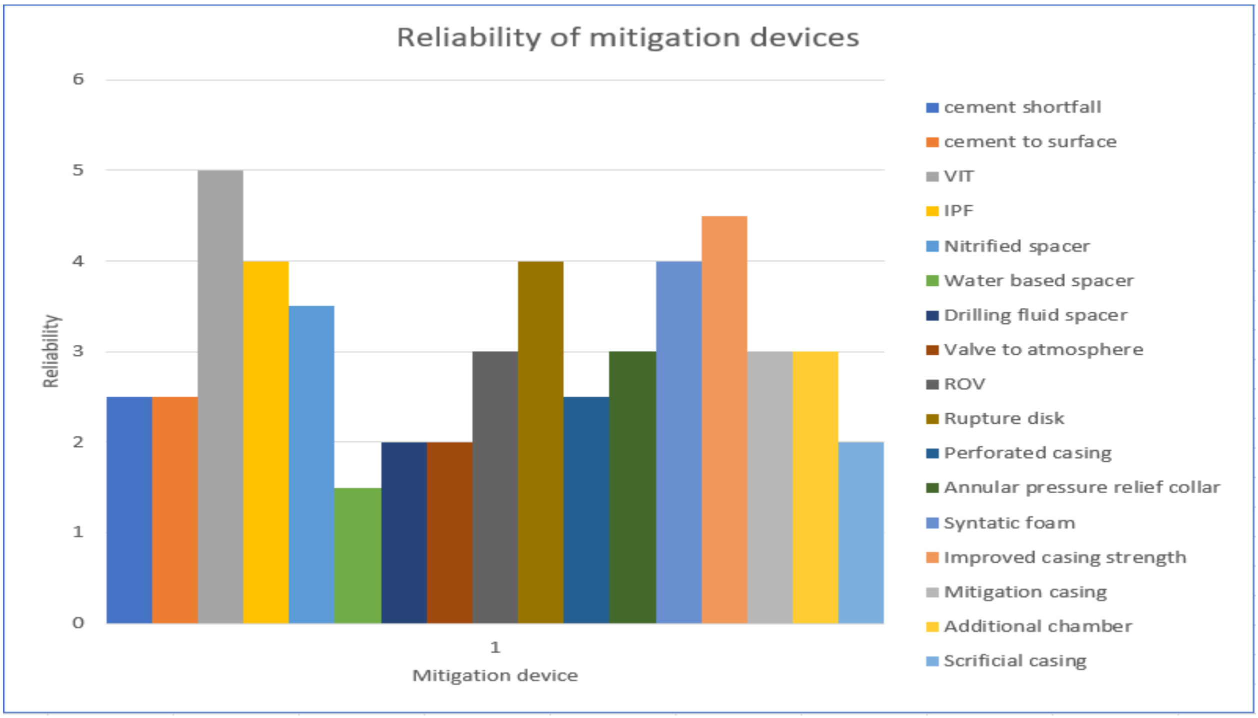

Figure 4. 1 Reliability analysis correlation for different mitigation devices

4.3.2 Cost analysis of mitigation techniques

Cost is one of the important aspects of optimization. When the designer has more than one possible option of mitigation device that shows the acceptable risk level then the optimum selection will be built on cost analysis. Also, the operation cost, time, and limited supply are calculated as an extra cost for different reasons. The amount of cost can be defined by the codes (1–5) refers to (cheaper – more expensive) as can be seen in Figure 4.2

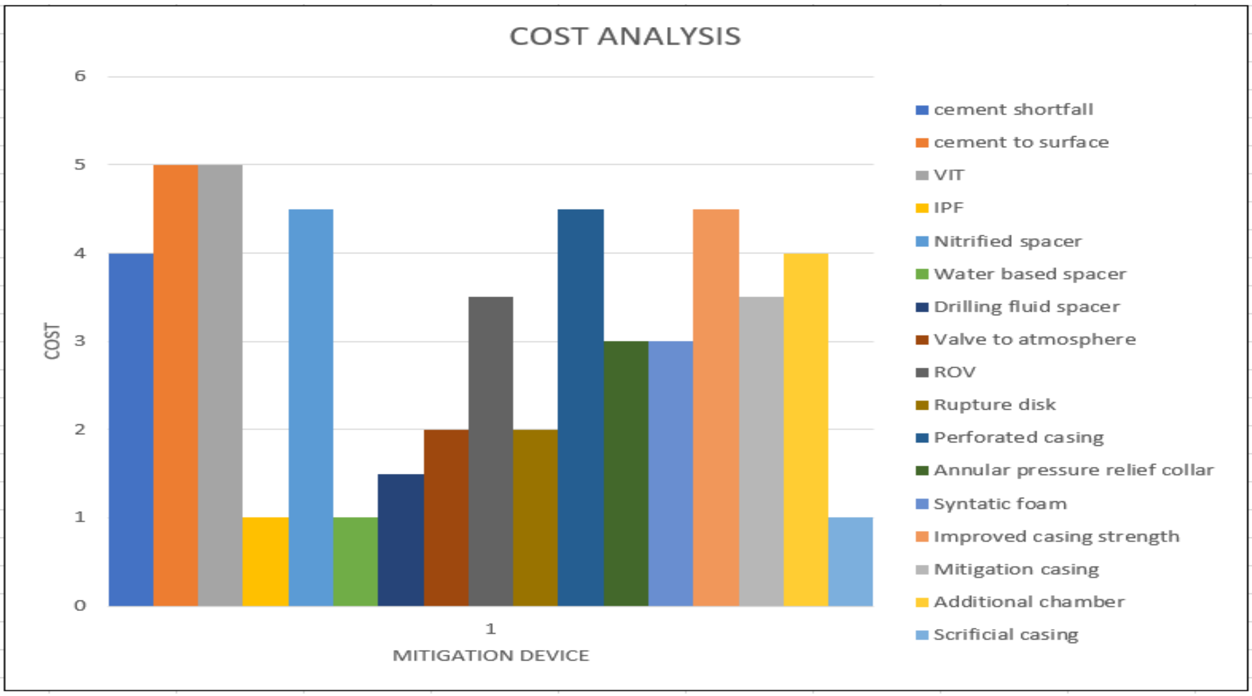

Figure 4. 2 Cost analysis correlation for different mitigation devices

4.3.3 Risk assessment

The most important part of optimum mitigation device selection is the risk analysis, which provides information about the level of risk associated with applying a given mitigation device and the possibility of tolerating risk and intensity of damage when happen.

4.3.4 Application difficulty

For each technique there are operation/application difficulty, so based on the severity of TAP and limitation of selection we can accept one difficult application technique more than others. The difficulty of the application diagram as can be demonstrated in Figure 4.3 is defined by the same scale of codes (1-5) refers to (Easy to apply – Very difficult application).

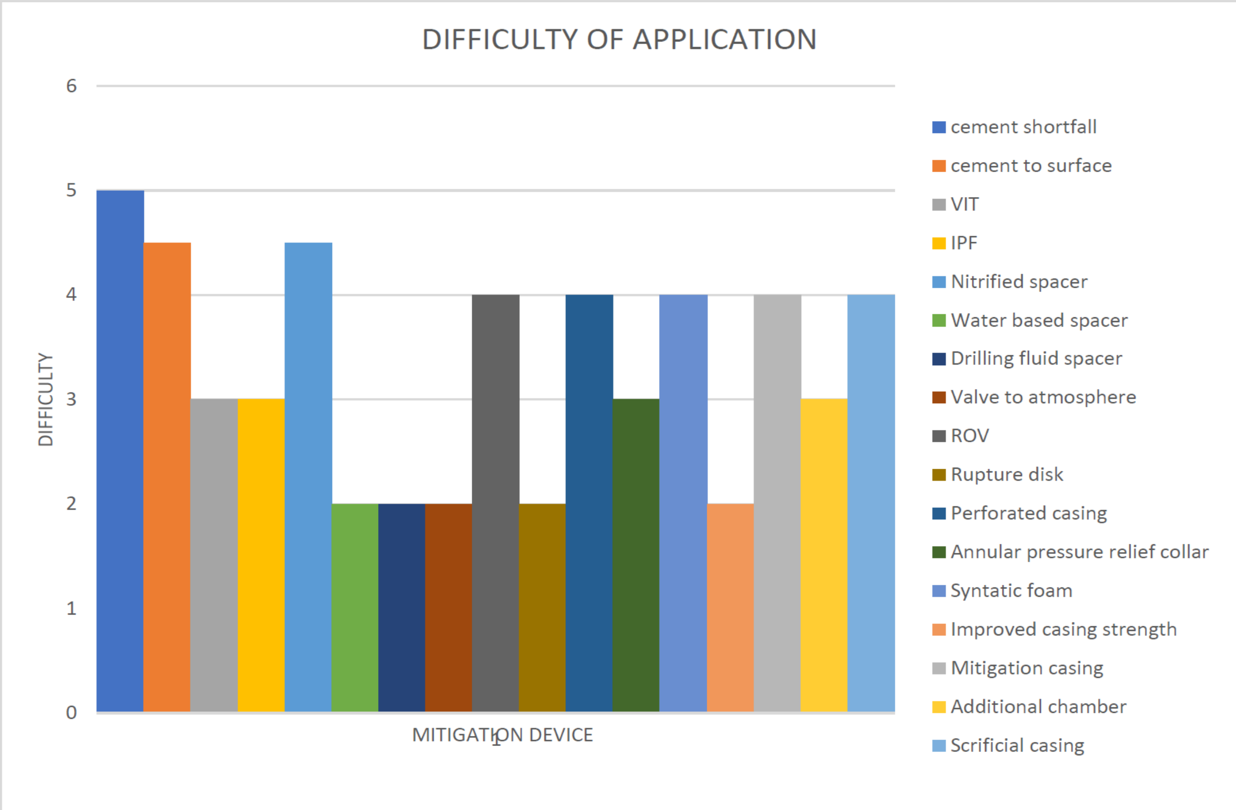

Figure 4. 3 Application difficulty analysis correlation for different mitigation devices

4.3.5 Performance of mitigation device

The overall performance of the mitigation device can be shown in Figure 4.4 by level (1-5) define as (poor- good)

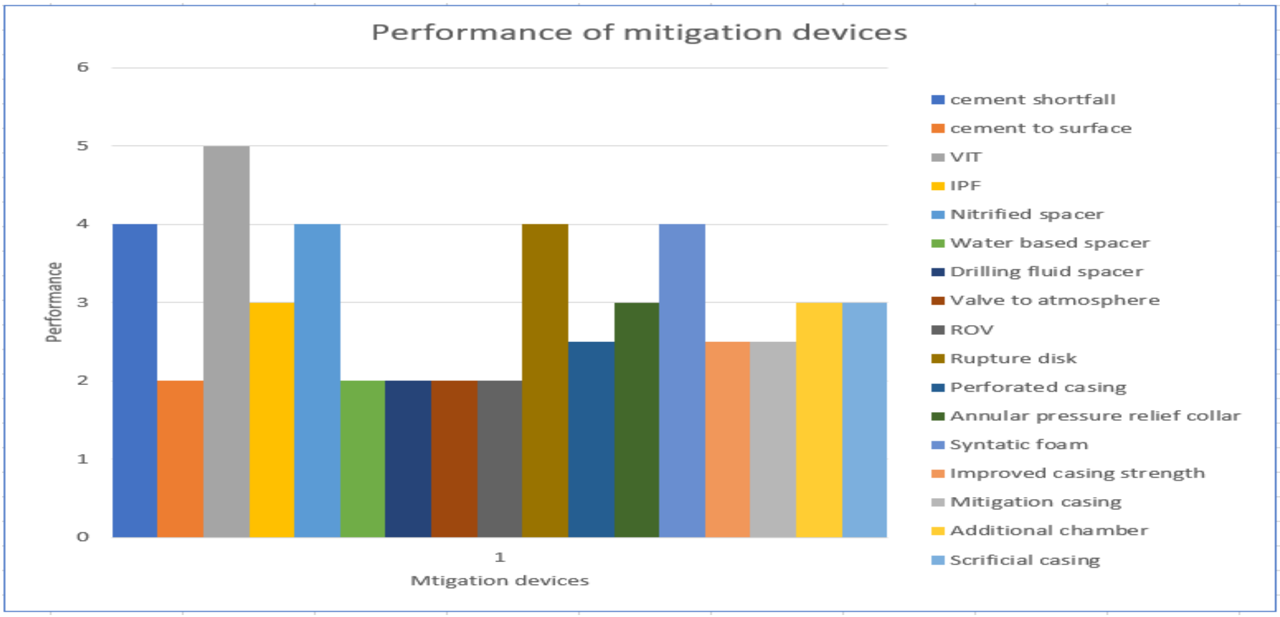

Figure 4. 4 Performance correlation for different mitigation devices

4.4 Optimization summary

The optimum device will select based on previous analysis, for the function of the TAP mitigation device must have the lowest cost, highest reliability, easer feasibility, and must provide good performance with safe condition. So, the recommended option applied as follow:

1- High-cost methods applied in the case of high-temperature wells and no other choice can be applied instead.

2- High reliability required for all methods, but for some of them such as rupture disk the reliability can be increase by the increasing number of disks used, for others that have not high reliability the decision making based on RL and possible modification.

3- Low (easy) operation requirements are required for all applications, but for a special condition such as required of a nitrified spacer or syntactic foam the application is overcome relative to well condition.

4- High performance is required for each method, but relative to well condition and optimization parameter, the designer can modify the selection.

4.5 Priority of mitigation devices selection

By application of these points we can set the final strategy of optimum selection as

I- Increasing casing strength.

A- Improving casing steel grade.

B- Improving casing wall thickness.

II- Eliminate the annular trapped volume.

A- Wholly annulus cementation.

III- Venting the TAP.

A- Open shoe.

B- Using rupture disk.

IV- Balancing the volume of heat expansion

A- Annular pressure relief collar.

B- Compressible foam.

C- Additional chamber.

D- Spacer shrinkage fluid.

E- Hollow microsphere.

V- Isolate the source of heat.

A- IPF.

B- VIT.

CHAPTER FIVE
CASE STUDIES AND ANALYSIS

5.1 Case study one

Application of TAP mitigation

This case represents the development of risk analysis in casing design by analysing the probability of the well integrity failure due to casing fail under possible scenarios of abnormal annular pressure. The well data and APB calculation adopted from reference (Sathuvalli et al., 2016), also this study show the common steps and practices that applied for unconventional casing design and mitigation design criteria with applying optimization based on risk analysis for the selected mitigation device built on qualitative and quantitative risk analysis and show the effect of the mitigation device on the whole well integrity.

STEP.1

Case description

The well shown in Figure 5.1, has a 10¾ in. production CSG, in one of the design scenarios, indicated that the selected CSG has a connection part whose working pipe body strength was only 50% of the pipe body external pressure rating, in the time of the minimum probable pressure profile in annulus 'B' is created by the scenario of evacuation to 1640 ft, and hydrostatic of freshwater (8.33 ppg) equilibrium the formation pressure at the depth of the perforation. APB analyses the anticipated collapse of the 10¾ in CSG when the 13⅜in. CSG shoe will be trapped.

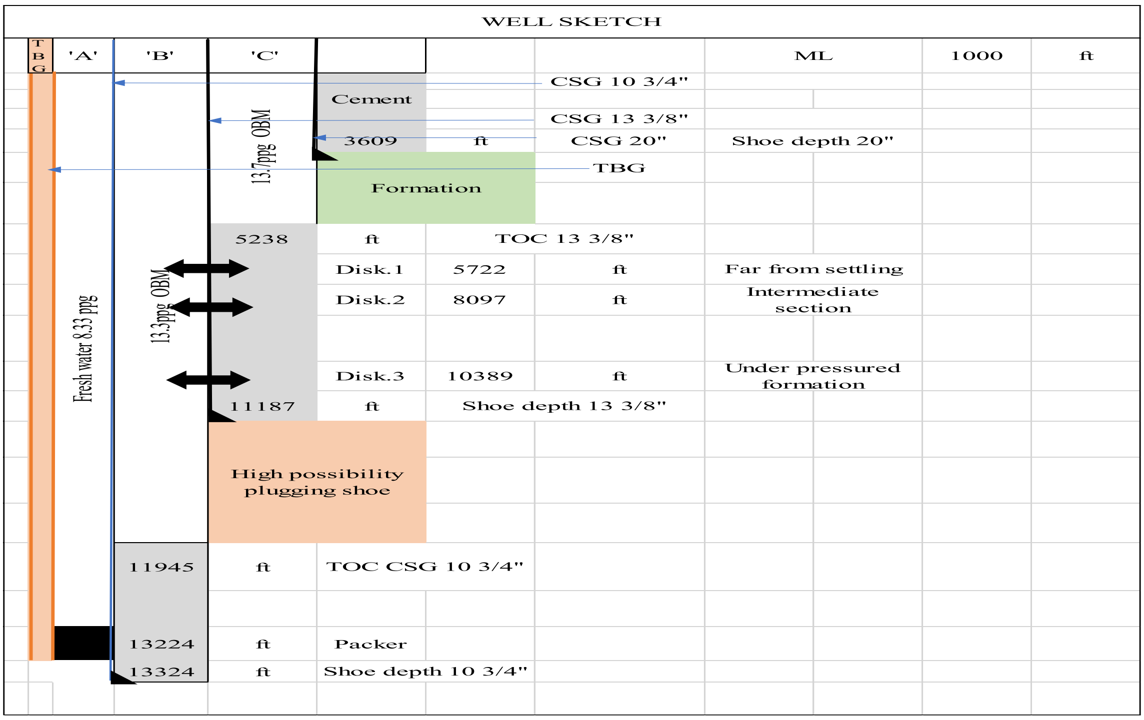

Figure 5. 1Model well graph

STEP.2

In this step we define a well barriers against the expected abnormal annular pressure, these barriers are divided into three types

1- Wellhead seals

These barrier work against abnormal annular pressure, but it represented the last barrier for well integrity and design of this barrier based on rating pressure (wellhead) and annulus content (PVT of trapped or expected invaded fluid). So, the importance to provide another barrier to be the primary protection line in the annulus when the secondary integrity failure or APB exceeds permissible limits.

2- Casing annulus strength

Enhancing this barrier is not the most suitable choice for high APB and SLA in well design for our case study because of standardization, higher cost, and well production strategies limitations. So, there is an obligation to provide another protection/mitigation system for the well integrity to protect casing annulus.

3-Protection system (selected mitigation device)

- Case problem

The risk of selected casing design shows a failure in production casing by the scenario of evacuation, while the annulus 'A' is balanced by freshwater (8.33 ppg) to the packer depth.

- Possible solution

By correlating and optimize the possible mitigation devices options as follow:

3-I- Try with active mitigation techniques

- Cement to surface

The application of this technique is not possible due to the low fracture pressure of subsurface formations, higher cost, and difficulty of application.

- Improve casing strength and capacity >>> Increase cost of the casing to 25%, in the time that we apply a mitigation device to decrease casing cost.

- VIT, IPF >>> Increase cost and not the optimum solution for one possible scenario of casing threatening.

- Open shoe >>> Not suitable solution due to the high probability of annulus fluid settling (as will explain in the next analysis).

3-II- Try with passive mitigation techniques

- Rupture disk

Type Burst disk is chosen to protect the 10¾ in. from collapsing when abnormal annular pressure is present in annulus 'B' as a scenario of evacuation. The annular pressure was affected by the hydrostatic pressure of the trapped fluid that has expected density ranged (15-7) ppg, and for each density, there is a different point of APB operation pressure of disk.

STEP.3

Calculation of disk activation pressure (operating point APB, Allowable APB)

The data of APB calculation for activating rupture disk are shown in Table 5.1. The annulus parameter is calculated by using equations ((2-1) ----(2-9)), as follows

- We choose the depth of the first disk (Z_{BD}) @ 5722 ft and original mud weight (13.3 ppg) for rupture disk APB activation pressure.
- Maximum differential collapse pressure in 10¾ in. × 97/8 in. string will be **8074psi**, this pressure happens when annulus 'A' evacuated to 1640ft and filled with fresh water that has a base density (7ppg). and it will create a collapse of the production casing.
- Maximum allowable APB ($\Delta P_{coll,\ max}$) = **5255 psi** (based on evacuation scenario).
- Nominal disk activating pressure $P_{BD\ nom}$ = 5973 psi. (for original density 13.33ppg and setting the depth of 5722ft ‣Disk.1).
- ΔP_{BD} = 5% $P_{BD\ nom}$ = 298.65psi,

Lower tolerance to activate rupture disk = 5973-298.65 = **5674.35 psi**.

***** Because of the lower tolerance is higher than 13⅜in MYIP (5380psi) so we apply this value and extend it to be 5800psi as the operating point of rupture disk.

Note that the highest possible differential pressure on the 10¾ in. × 9 7/8 in. string can happen at depth 1640 ft (within 10¾ in Csg, depth of evacuation scenario) when annulus 'B' densities are lower than 8.33 ppg. In case of densities greater than 8.33 ppg, the critical point goes at the 10¾ in × 9⅞ in. cross over. This gap is visible in the allowable APB curve as can be seen in Figure 5.2.

*** When the activation pressure of the rupture disk greater than 13⅜in MYIP it means the activation pressure will be greater than the maximum formation pressure of the section below 13⅜in (where the disk is set) because MYIP is designed to behold maximum expected formation pressure of this section. So, no formation fluid will inter to the well due to disk activation.**

Disk.1 2*1 (180º)	Ann 'A' density (ppg)	Ann 'B' density (ppg)	Ann fluid depth (ft)	Disk depth (ft)	$P_{formation}$ (psi)	Max APB in Ann 'B' to activate the disk	Mini APB in Ann 'B' to activate the disk
Original **ρ**		13.3				5074	4493
Degraded **ρ**	8.33	7	11945	5722	2947	4578	3998
Operational phase **ρ**		15				6956	6376
Disk.2 2*1 (180º)	**Ann 'A' density (ppg)**	**Ann 'B' density (ppg)**	**Ann fluid depth (ft)**	**Disk depth (ft)**	**$P_{formation}$ (psi)**	**Max APB in Ann 'B' to activate the disk**	**Mini APB in Ann 'B' to activate the disk**
Original **ρ**		13.3				5009	4429
Degraded **ρ**	8.33	7	11945	8097	4523	4308	3728
Operational phase **ρ**		15				7673	7093
Disk.3 2*1 (180º)	**Ann 'A' density (ppg)**	**Ann 'B' density (ppg)**	**Ann fluid depth (ft)**	**Disk depth (ft)**	**$P_{formation}$ (psi)**	**Max APB in Ann 'B' to activate the disk**	**Mini APB in Ann 'B' to activate the disk**
Original **ρ**		13.3				4627	4047
Degraded **ρ**	8.33	7	11945	10389	5733	3727	3147
Operational phase **ρ**		15				8045	7464

Table 5. 1 Rupture disk calculations

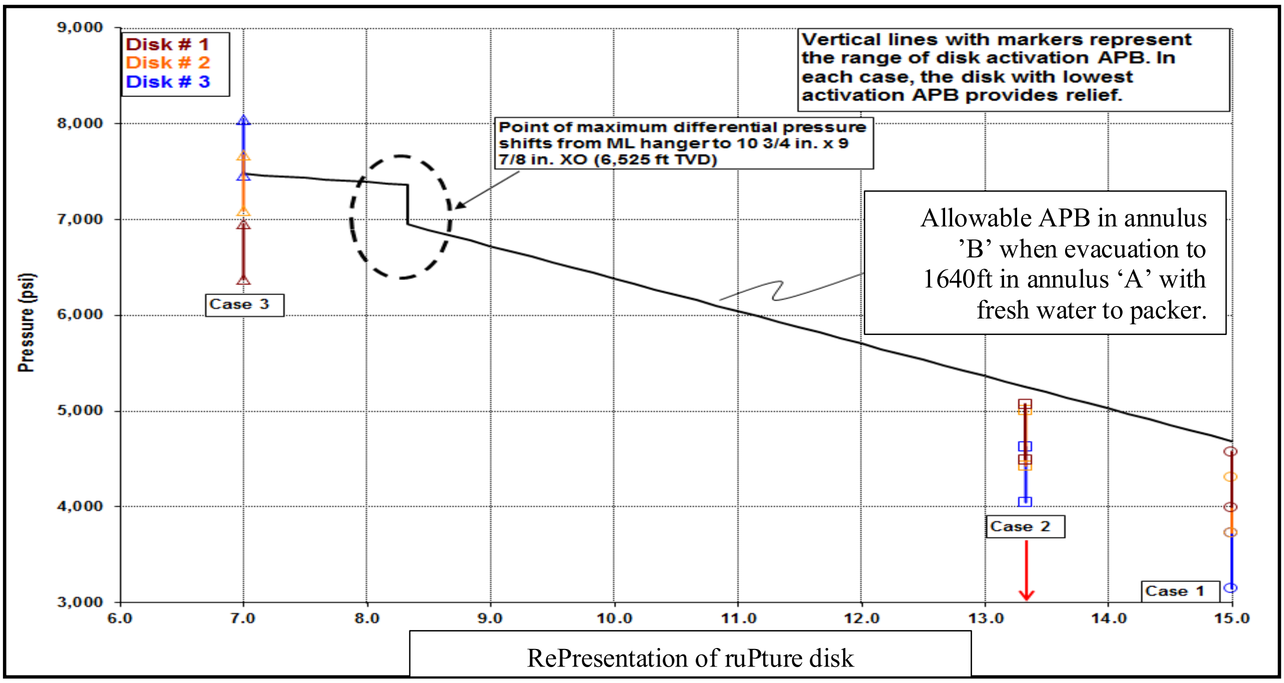

Figure 5. 2 Rupture disk performance (Sathuvalli et al., 2016)

STEP.4

Application of risk analysis associated with the failure of the mitigation system

Apply risk analysis associated with the probability of failure of well integrity due to failure of the mitigation system is applied during unconventional casing design when the mitigation disk failure to do its function at the worst scenario of selected casing failure. Then set the optimum solution for each probable failure mode and finally check if the selected parameters (setting depth, annular fluid densities, mitigation device activation pressure, and allowable APB) are satisfied?

1- Application of risk analysis

The risk analysis applied in both qualitative and quantitative analysis as follows

1-A- Qualitative risk analysis

1-A-I- Hazard identification (HAZID)

First define the annulus system, as discussed previously the scenario of casing design show a failure in production casing by collapse load failure, so the protection system must be installed in annulus 'B' to provide bleeding and pressure equilibrium. The analysis applied for the annuli that production casing bounded it (Ann 'B') to indicate the weakest point, expected failure that can be occurred and performance of the selected mitigation system (Rupture disk).

The geometrical composition of Ann 'B' as shown previously in Figure 5.1 that product from casing design, can be described as:

- Annulus side boundary (inner production casing 10¾in. – outer intermediate casing13⅜in. with single cement sheath).
- Annulus upper boundary (wellhead seals).
- Annulus lower boundary (open formation).
- Annulus protection system (Rupture disk).

1-A-II- FMEA analysis

By using the standard risk matrix as shown in Table 5.2, and apply the analysis made by failure mode effects analysis (FMEA) for the mitigation device applied, the products are shown in the Table 5.3.

1- Frequency index		
Index	Meaning	Description
1	Practically non-credible occurrence	Could happen once in the Oil &Gas Industry, not yet reported
2	Rare occurrence	Reported once in the Oil &Gas Industry
3	Credible occurrence	Has occurred at least once in the last 20 years in the Oil &Gas Industry
4	Probable occurrence	Can occurred sometime in the life of the plant
5	Likely/frequent occurrence	Can occurred several time in 3 years in the plant

2- Damage index – Safety for people		
Index	Meaning	Description
1	Slight health effect	1 work day lost
2	Minor health effect	Up to 7 work days lost
3	Major health effect	Up to 30 work days lost
4	Irreversible injury or 1 fatality	Irreversible effects
5	Multiple fatalities	Irreversible effects

People / Environment RS, REN		Frequency				
		1	2	3	4	5
Damage	1	L	L	L	L	L
	2	L	L	M	M	M
	3	L	M	M	M	H
	4	L	M	M	H	H
	5	M	M	H	H	H

3- Damage index – Safety for environment		
Index	Meaning	Description
1	Slight effect	Effect limited to a small area of the plant
2	Minor effect	Effect limited to an relevant area of the plant
3	Local effect	Effect on local area around the plant
4	Major effect	Effect on the region where the plant is located
5	Extensive effect	Effect at the national level

Asset / Production RA		Frequency				
		1	2	3	4	5
Damage	1	L	L	L	L	L
	2	L	L	L	M	M
	3	L	L	M	M	M
	4	L	L	M	M	H
	5	L	M	M	H	H

4- Damage index – Safety for asset and loss of production		
Index	Meaning	Description
1	Slight damage	Equipment to repair, negligible loss of production
2	Minor damage	Several equipment to repair, up to 8 hours of loss of production
3	Local damage	An entire subsystem to repair, up to 1 week of loss of production
4	Major damage	An relevant part of the plant is out of service, up to 4 weeks of loss of production
5	Extensive damage	At least 1 months of loss of production

5- Risk Matrix		
Risk level	Index	color
High	H	Red
Medium	M	Yellow
Low	L	Green

Table 5. 2 Risk matrix calculation (Vamanu B., Necci A., Tarantola S., 2016)

Where:

S: Safety of personnel's, **EN**: Environment damage, A: Asset and loss of production, R: Risk

FMEA ANALYSIS FOR THE RUPTURE DISK															
COMPONENT	FUNCTION	FAILURE MODE	FAILURE CAUSE	CONSEQUENCE			F	DAMAGE			RISK			RECOMMENDATION	APPLIED SOLUTION
				local effect	unit	plant		S	EN	A	RS	REN	RA		
PROTECTION SYSTEM (RUPTURE DISK)	PROTECT INNER CASING FROM BURST	INADEQUATE SETTING DEPTH	ERRORE IN SETTING DEPTH	ERRORE IN ACTIVATION POINT PRESSURE	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	4	1	1	5	4	4	20	CHOOSE DIFFERENT SETTING DEPTH	APPLIED THREE DIFFERENT SETTING DEPTHS
		ERRORE IN ANNULUS FLUID DENSITIES	IN COMPLETE SCENARION	ERRORE IN ACTIVATION POINT PRESSURE	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	4	1	1	5	4	4	20	CHOOSE DEFFERNT EXPECTED DENSITIES	APPLIED THREE DIFFERENT DENCITIES
		ERRORE IN ACTIVATION PRESSURE	ERRORE IN SELECTED SCENARIO	INADEQUATE EFFECIENCY	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	2	2	4	4	4	8	SELECT ACCURATE DATA AND SCENARIOS	APPLIED THREE DIFFERENT DENCITIES AND THREE DIFFERENT SETTING DEPTHS
		FAIL TO OPEN	MANUFACTURE	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	2	2	5	4	4	10	INSTALL REDUDANT NUMBER OF DISKS	2 DISKS WITH 3 POSITION
		PLUGGING	BAD DESIGN	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	2	2	5	4	4	10	SELECT DIFFERENT SETTING LOCATION	3 POSITION
		CORROSION	ERRORE SELECTION	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	1	1	1	3	1	1	3	SELECT SUTABLE DISK ELEMENTS	ANNULUS CONDITION MATCHING
		LEAKAGE	ERRORE CONNECTION	LESS EFFECIENCY	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	1	2	3	2	4	6	SURFACE CHECKING OF DISKS	
		OPEN AT LESS ACTIVATION PRESSURE	ERRORE IN DESIGN SCENARIOS	LESS EFFECIENCY	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	3	1	2	3	3	6	9	ACCURATE DESIGNING	INCLUDE ALL POSSIBLE DESIGN SCENARION OF DISK DESIGN
		OPEN AT HIGH ACTIVATION PRESSURE	ERRORE DESIGN	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	1	1	4	2	2	8	ACCURATE DESIGNING	INCLUDE ALL POSSIBLE DESIGN SCENARION OF DISK DESIGN
		FAILURE DURING HANDLING	OPERATION ERRORE	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP PRODUCTION	2	1	1	3	2	2	6	CAREFUL HANDLING	
		FAILURE DURING DRILLING PHASE	ERRORE IN DESIGN SCENARIOS	LOST OF PROTECTION SYSTEM	DAMAGE ON ANNULUS INTEGRITY	STOP OPERATION AND LOST TIME	4	2	2	4	8	8	16	INCLUDE OPERATIONAL PHASE DENSITY SCENARIO	APPLIED DENSITY OF 15PPG

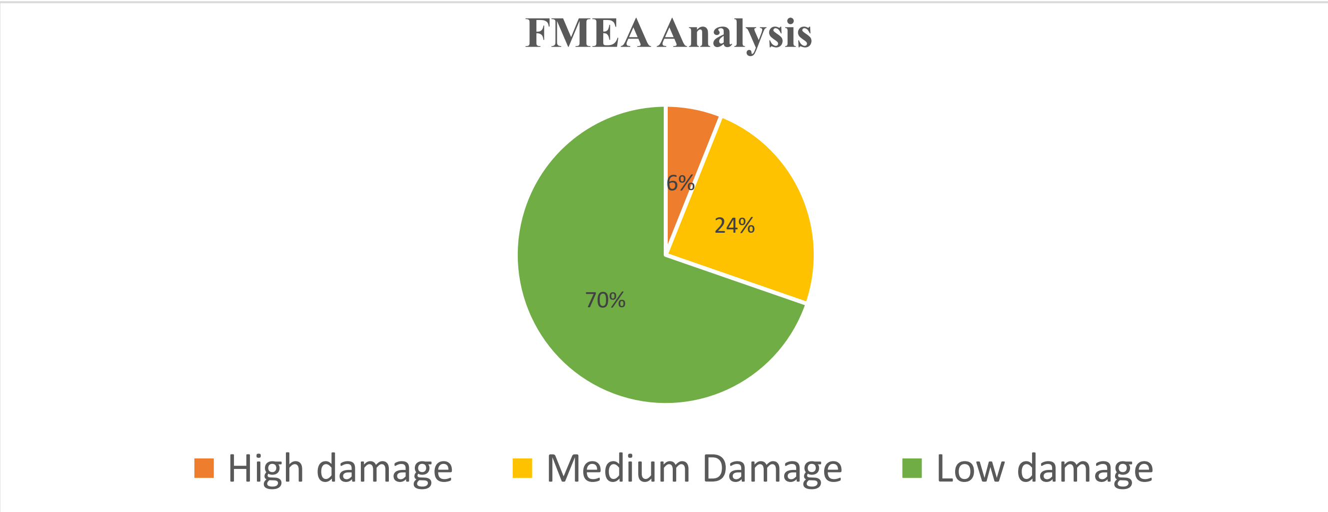

Table 5. 3 FMEA for rupture disk

Analysis of the FMEA results for disk failure

The FMEA analysis demonstrates that the majority of the risk is low (70%) and (24%) are a medium risk with only (9%) recorded at high risk. The high and moderate risk was recorded in cases of rupture disk failure due to error in setting depth and selecting annulus densities. So, these failure modes represent the critical element that will be treated as follow:

1- Disk failure due to error in setting the depth of disk

To overcome this effect, we select three couples of disks and set it in three different positions by 180º between each one.

Disk.1 set at depth ~ 500 ft below TOC of 13⅜in Csg in single sheath cement. So, the solid settling was not affected the disk behaviour.

Disk.2 set in the intermediate part of single sheath outside cemented section at depth 8097 ft, selected to activate at upper limit APB of annulus ’B’ by assuming that annulus fluid keeps its density at the original one (13.3 ppg).

Disk.3 set in at the face of pressured formation in-depth 10389 ft, at single sheath cement. To be activated during the operational phase (density 15 ppg).

2- Disk failure due to error in expecting annular density

To overcome this effect, we select three different densities based on scenarios of expected settling.

Case. I (ρ = 13.3 ppg)

The fluid density is the original mud density (13.3 ppg), the APB will be slightly high, so Disk.1 is the protector and Disk.2 relief annulus in max APB activation pressure of Disk.2 when Disk.1 fail.

Case. II (ρ = 15 ppg)

This failure is expected to accrue during operation phase fluid density (15 ppg), so the APB will be less, but it can cause casing failure. In this case, Disk.1,2,3 can protect the casing.

Case. III (ρ = 7PPg)

The annulus fluid density will be degraded to the base fluid (7 ppg), in this case, the APB will be the highest, so Disk.1 is the only operable one.

1-A-III- HAZOP analysis

The hazard and operability analysis applied for the well integrity to indicated and evaluate the possible failure during the life of the well. The analysis applied for annulus ’B’ by dividing it into four nodes as shown in Figure 5.3, **node.1** represents the mitigation system (applied for single rupture disk), **node.2** represent open formation, **node.3** represents the boundary casing of annulus

‘B’ and **node.4** represents wellhead seals. Table 5.4 shows the HAZOP analysis of the annulus ‘B’ system.

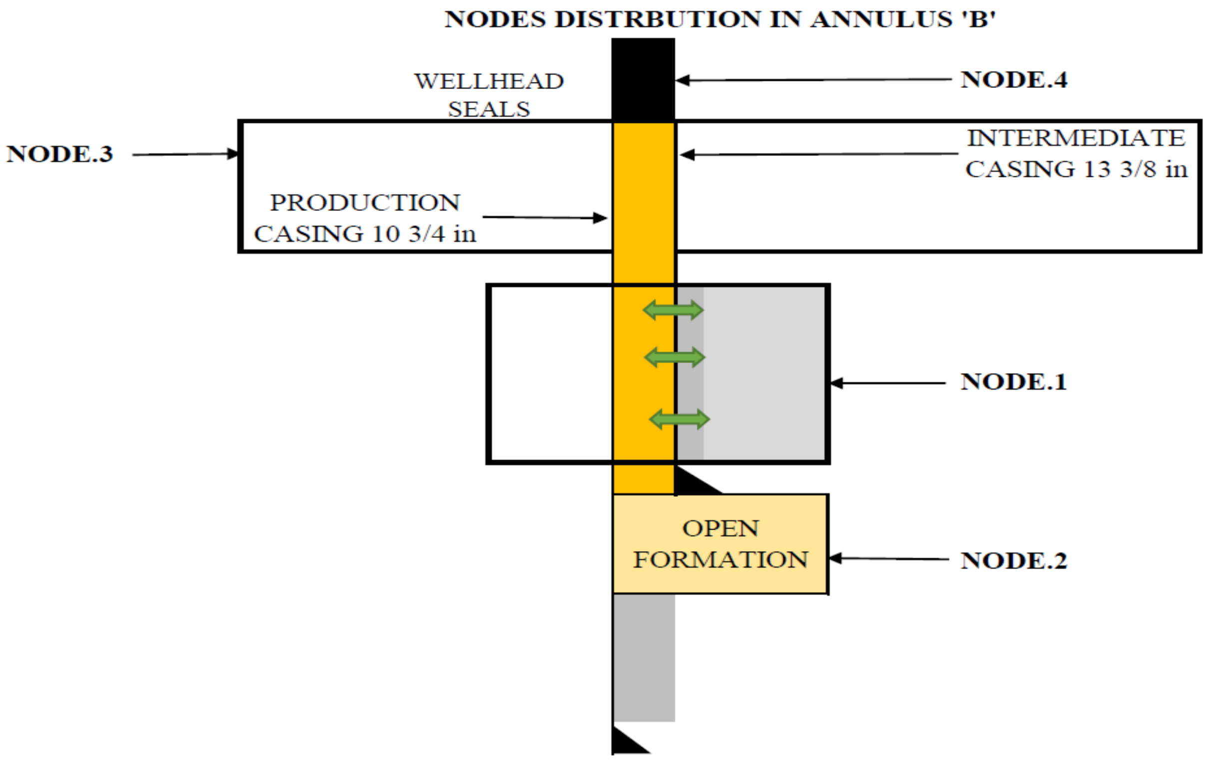

Figure 5. 3 Node distribution

GUID WORD	PARAMETER	DEVIATION	CAUSE	CONSEQUENCE	SAFEGUARD	L	S	R	RECOMMENDATION	RL
NODE.2 HAZOP ANALYSIS OF OPEN FORMATION										
HIGH	PRESSURE	HIGH ANNULAR PRESSURE IN THE ANNULUS 'B'	FORMATION CLOGGING BY SETTLING	COLLAPSE IN PRODUCTION CASING	RUPTURE DISK	4	1	4	INSTALL RUPTURE DISKS	L
			FRACTURE PRESSURE OF FORMATION > APB			2	1	2		L
NODE.3 HAZOP ANALYSIS OF CASING ANNULUS										
GUID WORD	PARAMETER	DEVIATION	CAUSE	CONSEQUENCE	SAFEGUARD	L	S	R	RECOMMENDATION	RL
HIGH	PRESSURE	HIGH ANNULAR PRESSURE IN THE ANNULUS 'B'	RUPTURE DISK CLOGGING BY SETTLING	COLLAPSE IN PRODUCTION CASING	RUPTURE DISK	2	5	10	INSTALL ABUNDANCE DISKS	M
			ERRORE IN SET ACTIVATION PRESSURE			2	4	8	DOUBLE CHECK TO THE INPUT PARAMETER	L
			RUPTURE DISK FAILURE			2	5	10	INSTALL ABUNDANCE DISKS	M
			UN EXPECTED SCENARIO			1	4	4	INCLUDE ALL POSSIBLE SCENARIOS	L
NODE.4 HAZOP ANALYSIS OF WELLHEAD SEALS										
GUID WORD	PARAMETER	DEVIATION	CAUSE	CONSEQUENCE	SAFEGUARD	L	S	R	RECOMMENDATION	RL
HIGH	PRESSURE	HIGH ANNULAR PRESSURE IN THE ANNULUS 'B'	RUPTURE DISK FAILURE	WELL INTEGRITY FAILURE AND OUTER LEAKAGE OF PRODUCT	RUPTURE DISK	3	5	15	INSTALL ABUNDANCE DISKS	H
			WELLHEAD SEALS FAILURE			1	5	5	DOUBLE CHECK TO THE INPUT PARAMETER	M
			UN EXPECTED SCENARIO			1	5	5	INCLUDE ALL POSSIBLE SCENARIOS	M

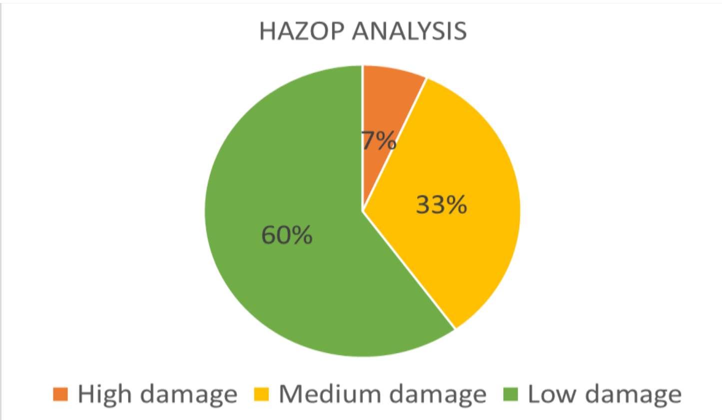

Table 5. 4 HAZOP analysis of well integrity for annulus 'B'

The majority of the risk is low risk (60%) it is acceptable to risk, with (33%) of medium risk and only (7%) in Node.4 is a high risk from the total risk, also all the risk associated with disk failure scenarios and it can be tolerated.

1-B- Quantitative risk analysis

Due to a lack of failure data so, we less trust the quantitative analysis. This analysis was built on industrial data from manufacturing companies and test laboratories. We concentrate on the failure of the rupture disk as indicated by HAZOP analysis that shows the possibility of system failure due to disk failure.

1-B-I- Availability of mitigation system

The availability (A(t)) of the mitigation system explained as

Success criteria are venting annular pressure on demand in case of APB > Allowable annular pressure.

The unavailability (Q(t)) of the mitigation system

The top Event is not venting annular pressure on demand.

Assumptions

• Single disk per position (from the couple) is sufficient to control abnormal annular pressure and protect production casing, so we need to fail both two disks (couple) that installed in the same depth (180º in between) to make a system failure for the selected annular density and depth.

• All the mitigation system sets (depths of each couple disks) are needs for control APB.

• Life of plant (well) is 20 years (175680 h).

1-B-II- Reliability of mitigation system (Rupture disk)

The reliability (R(t)) of the mitigation system explained as

Success criteria are continuous operations to control the annular pressure for 20 years.

The unreliability (F(t)) of the mitigation system

The top Event is not able to control abnormal annular pressure for 20 years.

Assumptions:

• Single disks per position (from the couple) are sufficient to control abnormal annular pressure and protect production casing, so we need to fail both two disks that are installed in the same depth (180º in between) to make a system failure for the selected annular density.

• All the mitigation system sets (depths of each couple disks) are needs for control APB. As expected of different annular fluid density and the effect of settling.

• Life of plant (well) is 20 years (175680 h).

* Because of the mitigation system applied is rupture disk and it is unrepairable, so the reliability equal to the availability so we develop one and it will equal to the other.

1-B-2-1- Reliability estimation

The calculation of the reliability of the rupture disk is applied by using a BELL CURVE (ZOOK, 2020).

A "bell curve" is a common term for a Gaussian application of Probability, since it has the

the shape of a bell, as can be seen in Figure 5.4. As developed by ASME, a "bell curve" is an applicable way to explain the average against the extremes performance. In rupture disc expression that can be applied to determine the probability of a disc function within tolerance. Ordinary distribution is a mathematically quite- known bell curve performed mostly in statistics and science. The reliability of the rupture disk obtained by using the bell curve is based on experimental data by taking about 100 samples of disks and the result of testing drawn on a chart to have a forum like a bell. The result of the bell curve mathematical approach show that the statistical curve of bell follows the "68 - 95 - 99.7" rule that mentions to;

• 68% of the disks are probable to be in one norm deviation of the mean.

• 95% of the disk is highly probable to be within two norms deviation of the mean.

• 99.7% of the disks are inevitable to be within three norms deviation of the mean

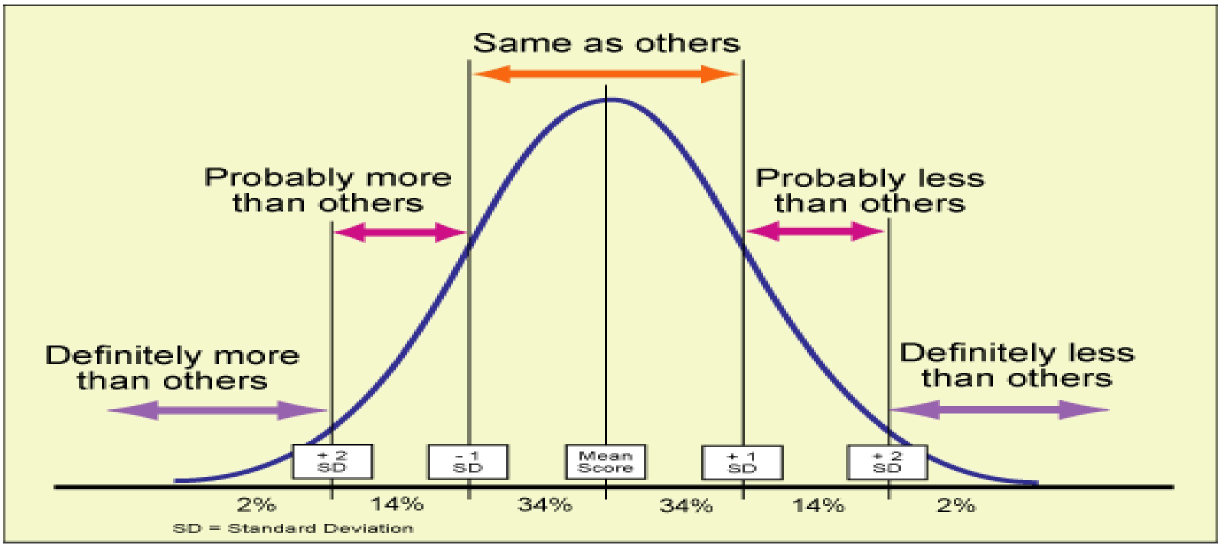

Figure 5. 4 Bell curve for rupture disk evaluation

From the previous analysis the reliability of the rupture disk as traditionally applied in R(t) = 99.7%, so the unreliability F(t)= $3*10^{-3}$ and it is equal to the unavailability (Q(t) = $3*10^{-3}$). The ASME states that the rupture tolerance must be ± 5% of the rating burst pressure for known working pressures greater than 40 Psi and ± 2.0 psi for marked working pressures ranged (15.0 - 40.0) psi. This recommendation is applied as a way to overcome the likelihood of failure in the rupture disk due to the activation function failure mode.

By this analysis, we confirm the ability of the selected mitigation device (rupture disk) to control the APB within the acceptable limit and show a tolerable risk of failure by decrease the probability of each expected failure with higher particular reliability. So, the final design of the casing is safe and supports well integrity with minimum cost and acceptable risk.

5.2 Case study two

Application of SCP analysis, a case study from south Iraqi oil fields

This case was developed to show the analysis of the presence risk of SCP by investigating the causes of this problem and set the possible solutions and recommendations for remediation and new well design for a field case study in the Rumaila field at the south of Iraq. Rumaila is one of the biggest Iraqi fields, it is managed by BP with the Rumaila operating organization (ROO). The field was discovered in 1953. This field contributes to 12% of Iraq's oil reserves. Rumaila is said to be the biggest oilfield ever discovered in Iraq and is considered the third-largest oil field in the world. The field contributes to 40% of the total Iraqi oil product. The field was divided into two parts, the south (Su) and north (R) parts as geographic locations. The field show SCP for a lot of wells and some of them show accidentally a surface leakage.

Types of wells in the Rumaila field

The wells generally classified into three types, production, injection, and disposal wells with nine well schematic types (1---9) and four barrier schematics (A, B, C, and D) as shown in Figure 5.5

Well Type	Well Function	Casing to surface	Completion	Schematic	Barrier min. requirements		
					Required	Exist	Compliant
1	Oil Producer (OP)	9 5/8"	Packerless	D	2	1	No
2		7"	Packerless	B	2	2	Yes
3		9 5/8"	Packer	C	2	2	Yes
4		7"	Packer	A	2	2	Yes
5	Water Injector (WI)	9 5/8"	Packerless	D	1	1	Yes
6		7"	Packerless	B	1	2	Yes
7		9 5/8"	Packer	C	1	1	Yes
8		7"	Packer	A	1	2	Yes
9	Disposal well	9 5/8"	Packerless	-	1	1	Yes

Figure 5. 5 well schematic types

The well barrier envelopes are shown in Figure 5.6

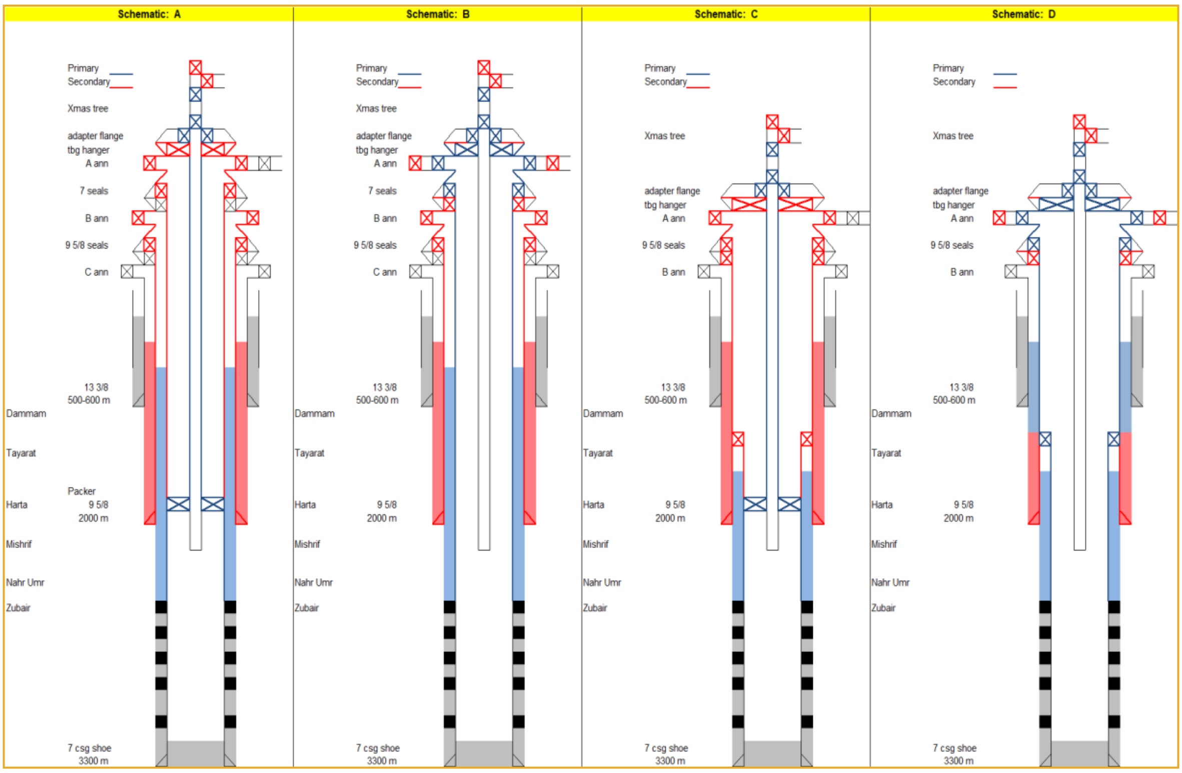

Figure 5. 6 Well barrier envelopes

The risk case generally for the wells was defined as Low RL for the wells that have shut in wellhead pressure (SIWHP) less than 150 psi, so for this wells single mechanical barrier are sufficient, Medium RL for well with SIWHP (150 – 1500) psi, for this well needs two independent barriers, and High RL for wells with SIWHP greater than 1500 psi for this wells two independent barriers are required.

Review for SCP problem in the Rumaila field

By looking for the wells in Rumaila fields, the field contains 1230 wells (till November-2019), 30 wells of them are water injection wells and 12 of them are disposal wells. It can be indicated that there are about 500 wells have a problem associated with SCP issues, some of these wells already treated, and 22 wells are abandoned because of SCP issues. Data are collected from 60 wells that show SCP problems during normal annulus monitoring and need intervention for diagenetic testing. The RL of the 60 well evaluated based on the risk matrix introduced by ROO Well Integrity Management Standard (ROO-WELLS-GEN-STD-015), that's set based on API recommendation and BP polices (Figure 3.3. in chapter three). The SCP RL for the 60 wells demonstrated that 34% of them have an RL.2 (Medium risk), 23% have an RL.3 (High risk) and 31% have RL.4 (Critical risk) and the remaining 12% well have RL.5 (Emergency risk), so the risk in level 4 and 5 are switch the wells is not an operable phase and requisite immediate interruption for maintenance. The details scall of RLs of Rumaila wells can be explained in Figure 5.7

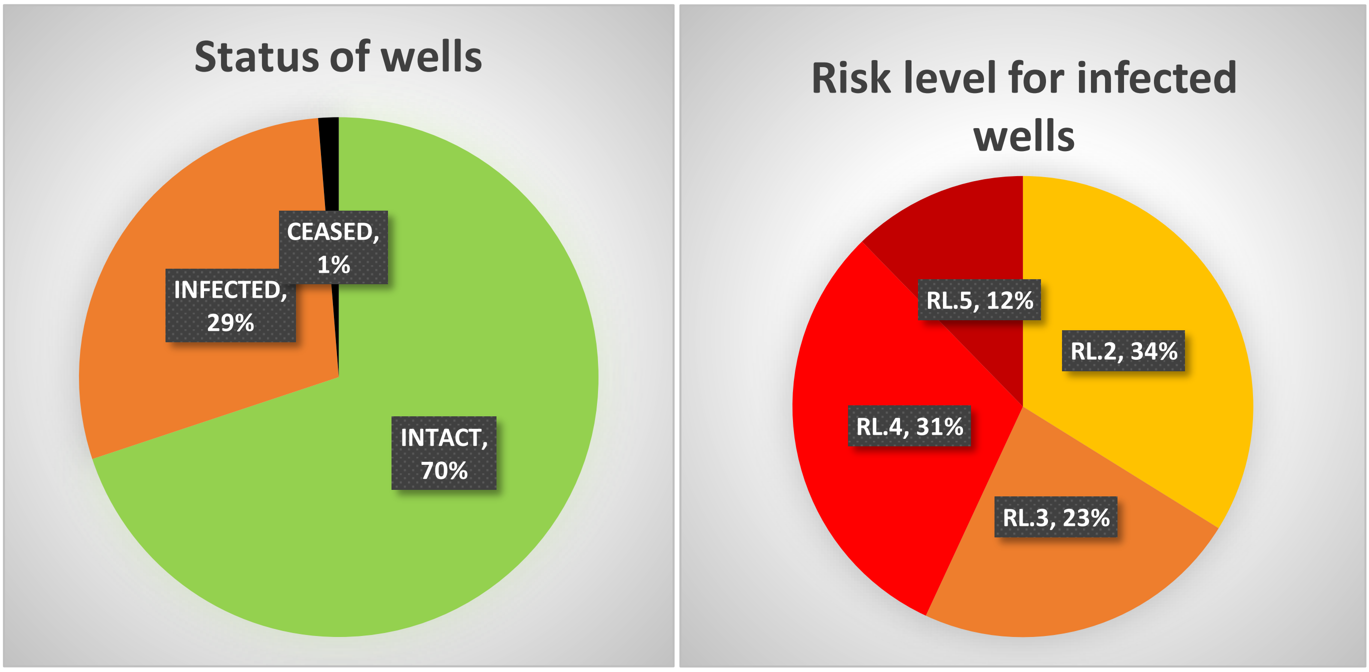

Figure 5. 7 Status of wells affected by SCP and risk level

Common causes of SCP in the Rumaila field

1- Internal integrity failure

Investigation for the causes of SCP showed that there are about 10% of the infected wells has SCP as follow:

1- SCP at annulus 'A' due to tubing leaks, packer leaks, and completion components damage, this case normally happens with the well aging, corrosion by the presence of H_2S, and in some causes by completion equipment failure.

2- SCP indicated by annuli communication during annulus monitoring and confirmed by diagnostic test and running logs (corrosion, bound. etc). In some wells found wellhead seals damaged due to excess SCP caused a leak between annuli.

2- External integrity failure

The investigation showed that most of the infected wells in the field have SCP caused by external integrity failure due to poor cement that provides a passageway to the fluid to pass through channels and collect in the annulus near the wellhead and show a casing pressure. This is an important issue that needs analysis to set the possible prevention and remediation plan.

Analysing of wells annuli in the Rumaila field

1- For the annulus, 'A' the major cause of SCP is created by internal integrity failure.
2- For the annulus 'B' (between production and intermediate casing) there is a gas come from a formation called Nhr-Umr and pass through cement channels. Due to poor cement of production

casing or in some cases the gas comes from the pay zone.

3- Also, For the annulus ‘B’, the gas can come from the pay zone (Mishrif formation or Zubair formation).

4- For the annulus ‘C’ (between the surface and intermediate casing) in the production and injection wells, due to the setting of the surface casing at the top of Dammam formation and this formation is a weak formation, so almost the oil stations (degassers) used this formation for injection of the disposal water. For some wells close to this disposal wells there is an indicator of this water collected at the annulus, it can cause casing corrosion and developed for annulus communication as a result of casing damage.

5- Also, for the annulus ‘C’ for production and injection wells, the intermediate casing mostly passes through a formation called Tayarat that contains Sulphur water, it will pass through channels of cement for poor cement and increase the casing corrosion. It may provide new holes and annulus communication. Also, the sulphur water causes a cement failure due to the pollution of cement.

- Normal annulus monitoring and diagnostic reports

The routine annulus monitoring is carried out as programmed and casing pressure measured at production annulus (annulus ‘A’) and other annuli (‘B’, ‘C’...etc) as planned previously by the operator, the recorded results are indicating an abnormal annular pressure. The operator is alarmed by the unacceptable risk level and suggests applying the annulus investigation and pressure test to analyse the cause of this pressure. In general, for the total wells in this field, the plan was made to review the existing designs and analyse for the causes of SCP in these wells with possible modifications and recommendations.

- Well design review

The data used for analysing completion and drilling designs are collected from some infected wells in the fields that recorded SCP during monitoring and compared with other intact wells. The base data are collected from the end well report for completion and workover operations that are:

- Well Kill Data & Chart (Killing fluids and pressure records)

The analysis shows

* The effect of neighbouring annuli during killing well (annuli linking) almost found due to wellhead sealing damage. In few wells found due to casing damage, confirmed by performing logs, so the analysis of annulus fluid shows corrosive materials (oil, gas, sulphur water), and the source of these fluids is defined as logs records and type of fluid that match the known formation source.

* Recorded losses in some wells, the investigation show, by neglecting the losses that may happen in pay zone in annulus ‘A’, the second reason when circulate killing fluid in other annuli (after providing circulation way), linked with corrosion logs and casing damages, there is a possibility of casing shoe failure, this point will be rechecked in drilling design analysis and LOT records.

- Corrosion Report analysis

* Analysis indicated that corrosion has happened for some old wells that are not supplied by the new corrosion resist tubing and for the casing, the most causes of damage are poor cement and formation fluid invasion. Example of a corrosion graph for a well in South Rumaila shown in Figure 5.8

Figure 5. 8 Screen shoot for metal static graph

- Cementing Reports

1- Surface casing cementing are planned to reach the surface by primary cementing and top-job cement, the CBL show a whole annulus cement with an accepted bound. So, the infection of annulus ‘C’ caused by annuli linking (casing damage or wellhead seals damage) and/or well aging.

2- Intermediate casing cement also planned to reach the surface, but for cases of losses in Dammam and Hartha formations the cement fails to reach the surface, so they used a differential cementing valve to perform two-stage cementing and top job cement. CBL in some wells shows that poor cement bound and a thick layer of fluid above the top of cement, that indicate primary fluid migration happened during cementation. This point takes into consideration for new well design.

3- Production casing cement planned to set cement top below the surface (above intermediate shoe) because of the presence of weak formation and pay zone pressure limitations. The CBL show for most wells the cement provides zonal isolation with the presence of some cement gaps above the pay zone. The gas migration in this case introduces by the flow of gas in poor cement and column of fluid. Diagnostic test for wells that have early SCP shows that the annulus fluid contains gas and liquid in the base fluid, that indicate early degradation of completion fluid and sagging of weighting materials. This point is useful for new wells design to improve annulus fluid rheological properties. In addition, the cement report does not show any evidence of microfractures that means the axial loads are taken into account and supported by casing landing operation also this result is expected because there are no high differential temperature changes associated with normal well in the Rumaila field to cause the generation of microfracture in cement.

* Generally, the cement purpose was accepted nevertheless the quality control key was missing.

* In some wells for production casing cemented below the surface the TOC found under the shoe of the intermediate casing, so suggest to re-asses the cement quantity and excess factor be safer, also the uncemented part must be at casing – casing annulus with TOC (800 – 1000)m below surface.

- Logging reports analysis

Production Log Tools (PLT) used to define the annulus fluid and fluid movement. Figure 5.9 shows an example PLT of well in Rumaila that has an SCP in annulus B, C. The log shows the worst case of casing damage and free pipe (biggest uncemented part).

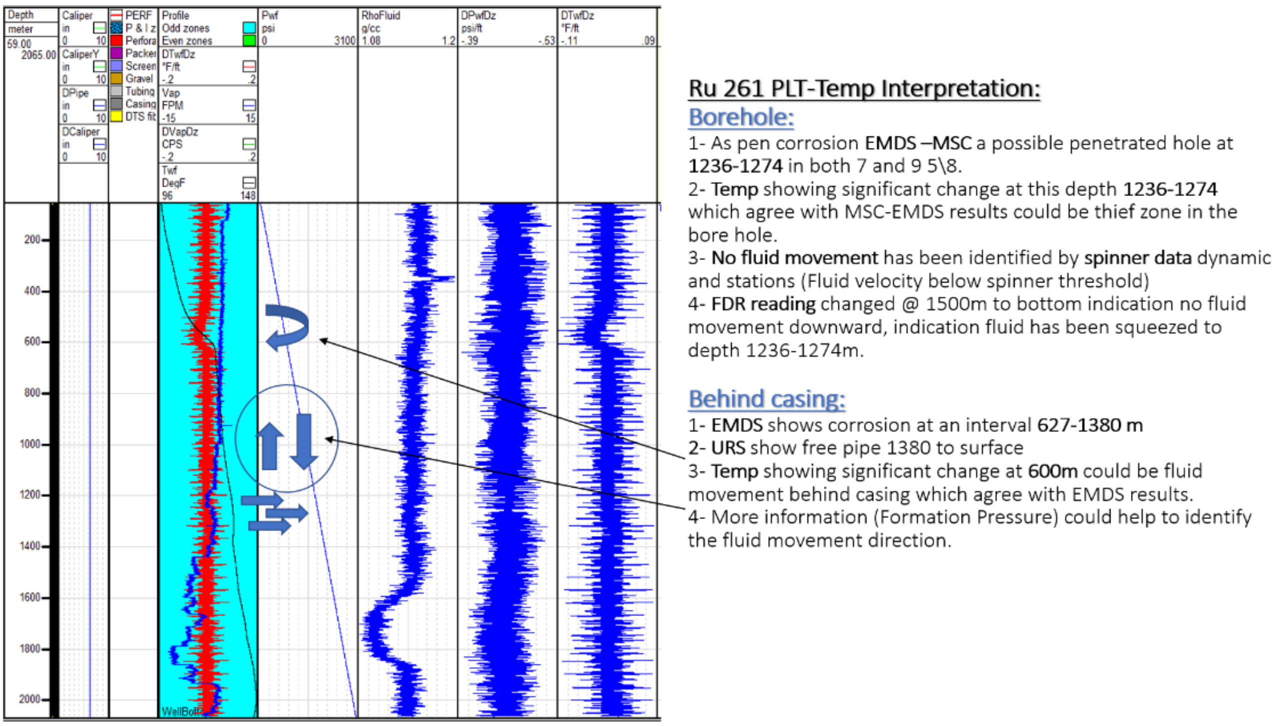

Figure 5. 9 PLT interpretation

- Pressure Test Charts

Analysing for pressure tests already applied during the analysis.

- Well Schematic, updated during well life

Will be covered in drilling design analysis. Analysing for casing setting depth and expected hole problem that affects annulus integrity during the well life cycle.

- ESP Running Report

Analysing for ending report for some wells show, No effect for SCP due to the presence of ESP.

- Completion of fluid report

Anti-corrosion completion fluid is used, and no gaps are found in this issue.

- Analysis of casing design

The analysis of casing design show that the design built on the approach of" Maximum load concept", which consist of:

Burst load design, Collapse load design, Tension load design, Buckling and wellhead loads design

Analysis of these details indicates that the currently used casing design for the production and injection wells are meet the required load-bearing, and SCP problems in most cases related to that the designer supposes that target TOC provided by primary cementation or top job cementing can decrease the effects of casing wearing, cost of cement, and by decrease the pressure of cement slurry head to reach optimum TOC. But the evidence of cement bond breakdown in some cases due to poor cement and early well aging refers to that some cases have not adequate TOC. The evidence of cement evaluation leads to conclude that there is a secondary gas migration in the annulus 'B' by channels in cement. To suggest that casing must be cemented as close to the surface as possible to prevent formation fluids migration, decrease annulus space for migrated fluids accommodation, and provide more support to the casing.

- Design improving recommendations

To avoid and mitigate the effect of SCP the process applied by improving the well design with some recommendations as follows:

1- Removed all the presence gas of drilled formations (gas pockets) before cementing, especially for Nhr-Umr formation and production zones. Applied final circulation before cementing carefully and check mud return and acid concentration.

2- The hydrostatic pressure of cement while the time of solidification to control the formation of fluid migration must be kept at less equal to the gradient of mud applied during drilling till the cement built the sufficient bound.

3- Application of a "mud-filled" packer for the outer annulus, should be used above the zone that has a high possibility of fluid migration or unable to perform success cement job (intermediate casing cementing) to isolate this formation then perform a secondary cement job, as successfully applied by Weatherford company in Rumaila field at intermediate casing to isolate sulphur water.

4- During the displacement of cement it suggested using a fluid with weight the same as the weight of the fluid that will be used for the next hole.

5- Annulus fluid for annuli cemented below the surface must be treated carefully for corrosion and sagging.

6- Losses when occurred must be treated before cementing operation and ensure the well is controlled and stable. As recorded, there is partial to complete losses in the second and third holes.

7- Primary gas migration can be avoided by improving cement slurry characterization, cementing operation, displacement mechanism. Secondary gas migration can be avoided by providing a suitable buckling design for the casing to prevent the generation of microcracks.

8- After performing CBL before production, if the result shows poor cement, open discussion, and set possible remediation before perforating the well and start production to prevent SCP development.

9- It is recommended to perform a nitrified cement job for the new well's design for the section of field that has well records a high severity of SCP. The cost of applying a lot of remediation jobs, production interruption, costed operation and early abounded of wells (as indicated from analysis most of the remediation jobs are useless) are high relative to nitrified cement job.

Remediation recommendations

When the maintenance and fixing must be applied outside of the production casing, the operation becomes technically hard and costly. So, remediation for the wells of SCP problem due to external integrity failure is very difficult and depend on the type of well and production casing size as follow

1- Wells with 7 in. casing to the surface

The remediation reports show that about 70% of remediation for the well that has 7in. production casing is failed because of un ability to perform cement remediation jobs due to damage and weak casing caused by high corrosion resulted by contacting of corroded fluid or well aging, the problem for these wells that not show a risk case of SCP in the primary time of well age because of the contaminate fluid has relatively low pressure but when the case developed, casing damage, annulus linking, or annular fluid settling accrued, the casing pressure increased and inter the high RL. For that reason, we suggest checking the cement bound quality and make cement remediation before start production and each time of work over. In this case, the most acceptable method for SCP risk treatment is by following the periodic bleeding of excessive pressure. It is crucial to pay attention to that some operators considered the procedure of periodic bleed-off will increase the severity of the SCP level. Otherwise, other operators consider that periodic bleeding provides a temporary limit to the severity of the SCP problem. The BP operators apply this method to control the severity of SCP problem for the wells that have MAASP very low (less than required injection pressure of work over operation), remediate low SCP, relief high SCP temporarily and for wells with severity casing damage or at the end of production life age. Another remediation method is by lubrication in weighted brine or mud for the cases that permit pressure injection on the annulus.

2- Wells with 9⅝ in. casing to the surface

The analysis of case wells showed that this type has the more ability to perform remediation jobs due to the presence of tie-back option, most remediation jobs for casing and cement remedial are successful applied for this type. Based on MAASP for annuli, the operator as can be indicated by analysis can apply a lot of remediation methods (as discussed in risk analysis in chapter three).

3- Abandoned wells

It is a long-term study and analysis, the decision makes finally when the well case is threatening the safety production and environment standard. These types need more analysis and more check when the MAASP reached zero psi that means the remediation operation has to be applied without any pressure this challenge in most cases (as per the study) lead to abandoned the well and by this state, the well also follows the safety standard for isolation and closing with ensuring the presence of barrier sufficient to still the well secure and timely observation will be programmed to observe well and check for any unexpected seals failure. Besides there are some justification must be found and analysed before well abandoned, such as reached the end of the production plan, there are high damage and unbenefited for apply remediation, change in well functionality required with the situation of well cannot satisfied and when there is high risk and cannot be treated.

CONCLUSION

I- Deepwater HPHT and SSW design must consider the thermal effect by providing scenarios for all expected cases related to operations and functions of well for all service life cycle.

II- The target of reaching or maintain annular pressure equal to zero is not the best choice in all cases, it is enough to maintain annular pressure under the permissible limit and keep the cost.

III- Cement quality must be confirmed and fluid movement behind the casing must be checked before the well start-up, also applied for any work over interruption, to prevent or reduce the chance of SCP accruing.

IV- Rupture disk is the more accepted mitigation technique, due to it is lower cost, reliability improvement, and easier operation, also it preferred because of the APB threat the outer annuli due to high-temperature difference and the outer annuli have a single cement sheath the two favourable conditions for rupture disk application.

V- TAP for the normal annulus distribution of deep-water HPHT wells tend to threaten the collapse resistance of the inner casing of annulus than the burst of the outer one, so the application of TAP mitigation must concentrate on the intermediate casing and back saving the production casing.

VI- The temperature profile of SSW must be modified during well life due to a change in production rate and produced fluid composition that affects PVT properties of the annular fluid.

VII- The final selected mitigation device must be able to protect well integrity from all possible failure scenarios by TAP, treat all expected risks, have optimum cost (supply, operation, and performance), higher reliability (even if it is improved), support the expected functionality changing of well and protecting the environment.

VIII- By organizing mitigation techniques in terms of cost, time, and operation we recommended using Rupture Disks, Nitrified Spacers, IPF, Syntactic Foams, and VIT.

IX- Allowable annular pressure must be set first during design then updated as the change in MAASP and MAWOP by derating factor due to well aging.

X- When well functionality changed (transfer from production to another function), design review must apply and introduce new scenarios with new risk analysis based on annular pressure state permissible limits and last records of (CBL, Corrosion, workover, temperature, and pressure profile) to test the feasibility of applying the new activity.

XI- For the wells that suspect to develop complex abnormal annular pressure, suggested applying nitrified spacer technology to mitigate TAP & SCP at the same time.

XII- The probability of cement channeling by formation fluids during migration from higher to lower pressure formation is increased if the setting depth of casing elongated by drilling ahead with drilling fluids densities close to reaching the top-hole formation fracture equivalent density.

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