UNIVERSIDADE ESTADUAL DE CAMPINAS
FACULDADE DE ENGENHARIA MECÂNICA
E INSTITUTO DE GEOCIÊNCIAS

PAOLA ADRIANA COCA SUAZNABAR

SUBSEA WELL DESIGN GUIDELINES, BOTH TO REDUCE AND TO EASE THE MAINTAINABILITY

DIRETRIZES PARA PROJETO DE POÇO SUBMARINO PARA REDUZIR E FACILITAR A SUA MANUTENIBILIDADE

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Dissertation presented to the Mechanical Engineering Faculty and Geosciences Institute of the University of Campinas in partial fulfillment of the requirements for the degree of Master in Petroleum Sciences and Engineering in the area of Exploitation.

Dissertação apresentada à Faculdade de Engenharia Mecânica e Instituto de Geociências da Universidade Estadual de Campinas como parte dos requisitos exigidos para a obtenção do título de Mestra em Ciências e Engenharia de Petróleo na área de Explotação.

Orientador: Prof. Dr. Celso Kazuyuki Morooka

Coorientador: Prof. Dr. Kazuo Miura

Este exemplar corresponde à versão final da Dissertação defendida pelo aluno Paola Adriana Coca Suaznabar e orientada pelo Prof. Dr. Celso Kazuyuki Morooka.

Assinatura do Orientador

CAMPINAS

2016

FICHA CATALOGRÁFICA

Agência(s) de fomento e nº(s) de processo(s): CAPES, 33003017

Ficha catalográfica
Universidade Estadual de Campinas
Biblioteca da Área de Engenharia e Arquitetura
Elizangela Aparecida dos Santos Souza - CRB 8/8098

C64s Coca Suaznabar, Paola Adriana, 1991-
Subsea well design guidelines, both to reduce and to ease the maintainability / Paola Adriana Coca Suaznabar. – Campinas, SP : [s.n.], 2016.

Orientador: Celso Kazuyuki Morooka.
Coorientador: Kazuo Miura.
Dissertação (mestrado) – Universidade Estadual de Campinas, Faculdade de Engenharia Mecânica e Instituto de Geociências.

1. Poços de petróleo submarino. 2. Perfuração submarina. 3. Poços de petróleo submarino - Perfuração. 4. Poços de petróleo - Projetos. I. Morooka, Celso Kazuyuki,1958-. II. Miura, Kazuo. III. Universidade Estadual de Campinas. Faculdade de Engenharia Mecânica. IV. Título.

Informações para Biblioteca Digital

Título em outro idioma: Diretrizes para projeto de poço submarino para reduzir e facilitar a sua manutenibilidade
Palavras-chave em inglês:
Subsea oil wells
Offshore drilling
Subsea oil wells - Drilling
Oil wells - Design
Área de concentração: Explotação
Titulação: Mestra em Ciências e Engenharia de Petróleo
Banca examinadora:
Celso Kazuyuki Morooka [Orientador]
José Ricardo Pelaquim Mendes
Ricardo Cabral de Azevedo
Data de defesa: 04-02-2016
Programa de Pós-Graduação: Ciências e Engenharia de Petróleo

UNIVERSIDADE ESTADUAL DE CAMPINAS
FACULDADE DE ENGENHARIA MECÂNICA
E INSTITUTO DE GEOCIÊNCIAS

DISSERTAÇÃO DE MESTRADO ACADÊMICO

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PMI /EP/ USP

Campinas, 04 de fevereiro de 2016.

ACKNOWLEDGEMENT

I would like to thank everyone who contributed to this work:

To my advisor Prof. Dr. Celso K. Morooka for accepting me in this research group, for his guidance and support during this period, and especially for the learned life lessons, thank you so much.

To my co-advisor Prof. Dr. Kazuo Miura for his guidance and patience during the development of this work.

To Prof. Dr. José R. Pelaquim Mendes for the suggestions for this work.

To CAPES for the financial support.

To my family and friends for never left me alone.

RESUMO

Durante a vida útil de um poço de petróleo as perdas de produção relativas ao seu potencial causam a interrupção da produção devido às operações de restauração. As empresas buscam estratégias para prevenir estas restaurações, sendo o *heavy workover* um dos maiores desafios. A restauração de um poço produtor geralmente é uma operação demorada e representa uma das maiores despesas operacionais durante a produção de um campo petrolífero.

O conhecimento das causas de perda de produção durante a etapa do projeto ajuda no desenvolvimento de estratégias para prever situações problemáticas durante a produção. Portanto, o objetivo da presente pesquisa é estabelecer diretrizes e procedimentos para um projeto de poço, de forma a prevenir as restaurações e/ou evitar *heavy workovers* até o final da vida produtiva do poço.

Inicialmente realizou-se uma busca na literatura dos últimos trinta e cinco anos, para identificar as principais causas de perda de produção, fatores para sua ocorrência, soluções e estudos de caso. Foram identificadas vinte e uma causas de perda de produção, e foram divididas em três tipos: 1) garantia de escoamento, 2) falha potencial na integridade e 3) problemas de reservatório.

Por exemplo, para as causas de perda de produção devido à garantia de escoamento a deposição de sólidos no sistema poço/linha foi a principal causa de perda, sendo os fatores fundamentais para esta deposição a composição do fluido de formação (hidrocarboneto e água) e variações de pressão e temperatura.

Com este estudo conseguiu-se identificar mediante a superposição de gráficos (curva de hidratos, temperatura de aparecimento de parafinas, pressão de inicio de asfaltenos e índice de saturação) uma região livre de sólidos, denominada "envoltória de garantia de escoamento". Neste gráfico, são traçadas as condições de fluxo de petróleo. Se estas condições se encontram dentro da envoltória o resultado pode ser uma possível não restauração, caso contrário, o projeto deverá contemplar tratamentos de prevenção para garantir uma mínima restauração e/ou tratamentos de remediação para obter uma fácil restauração (*light workover*).

Mediante a pesquisa realizada, foi possível estabelecer diretrizes e procedimentos para o projeto de poço que são de grande valia para a melhora da produção durante sua vida útil. Para cada uma das causas de perda de produção (vinte e uma) identificou-se possíveis soluções que permitirão a prevenção das restaurações, evitando dispendiosas operações de *heavy workover*.

Palavras Chave: Restauração de poços, Perfuração marítima, Perdas de produção, Projeto de poços, Poços submarinos.

ABSTRACT

During the life of an oil well, production losses relating to its potential causes a production interruption due to well intervention operations. Companies are looking for strategies to prevent these interventions, being the heavy workover one of the biggest challenges. The well intervention of a well producer is usually a lengthy operation and represents one of the largest operating expenditure during the oilfield production.

The knowledge of causes of production loss during the design phase helps in the development of strategies to predict problematic situations during well production. Therefore, the objective of the dissertation is to establish guidelines and procedures for a subsea well design to prevent the well intervention and/or avoid heavy workovers until the end of their productivity life.

A literature research of the last thirty-five years, to identify the main causes of production loss, factors for its occurrence, solutions and case studies was performed. Twenty one causes of production loss were identified, and were divided into three types: 1) flow assurance, 2) potential integrity failures, and 3) reservoir problems.

As an example, the solids deposition in the well/line system were the main cause of production loss due to flow assurance, being the composition of the formation fluid (hydrocarbon and/or water) and changes in pressure and temperature the main factors for this deposition.

A region free of solids known as "flow assurance envelope" was identified in this study through superposition of several graphs (hydrates curve, wax appearance temperature, asphaltene onset pressure and saturation index). In this graph oil flow conditions are plotted and the result is a possible non-intervention if the oil flow conditions are inside the envelope. On the other hand, the well design should implement prevention treatments in order to assure a minimum intervention and remediation treatments (light workover) to obtain an easy intervention.

Through the research performed was possible to establish guidelines and procedures for a subsea well design that are of great value for the improvement of production during its useful life. For each one of the causes of production loss (twenty one) was identified possible solutions that will enable the prevention of well intervention, avoiding costly heavy workovers operations.

Key Words: Well intervention, Offshore drilling, Production losses, Well design, Subsea well

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

AAs	Anti – Agglomerates
AIV	Annulus Isolation Valve
AMV	Annulus Master Valve
AOP	Asphaltene Onset pressure
API	American Petroleum Institute
ARN	Naphthenic acid with molecular of 1227-1235 g/mol
ASV	Annular Safety Valve
AWX	Annulus Wing Valve
BIS	Barrier Integral Set
BOP	Blowout Preventer
C1	Christmas tree cavity
CPM	Cross Polarization Microscopy
CT	Coiled Tubing
DEH	Direct Electric Heating
DHSV	Downhole Safety Valve
DSC	Differential Scanning Calorimetry
E-DHSV	Electric Downhole Safety Valve
EXL	External leak
FAE	Flow Assurance Envelope
FP	Filter Plugs
FPSO	Floating Production, Storage and Offloading
FSN	Fail to Set in Nipple – Fail to Set in nipple/side pocket
FSP	Fail to set packer
FTC	Fail to close – Fail to close on command
FTH	Fail To Hold in nipple – Fail to hold in nipple/side pocket
FTO	Fail to open – Fail to open on command
GLV	Gas Lift Valve
ISO	International organization for standardization
KHIs	Kinetic Hydrate Inhibitors
LCL	Leakage in control line

LCP	Leak Close Position
LDHI	Low Dosage Hydrate Inhibitors
MEG	Mono Ethylene Glycol
MEPTEC	Mobil E&P Technical Center
MODU	Mobile Drilling Unit
NORM	Naturally Occurring Radioactive Material
NTNU	Norwegian University of Science and Technology
OTC	Offshore Technology Conference
PC	Premature closure of the valve
PMV	Production Master Valve
PWV	Production Wing Valve
ROV	Remotely Operated Vehicle
TDS	Total Dissolved Solids
TLP	Tension Leg Platform
SRL	Elastomeric seal
SCP	Sustained Casing Pressure
SOC	Screen Only Completion
SPE	Society of Petroleum Engineers
SSSV	Subsurface Safety Valve
USA	United States of America
VGL	Gas lift Valve
WAT	Wax Appearance Temperature
WBC	Well Barrier Component
WCL	Well control to control line communication
WPT	Wax Precipitation Temperature
WH	Wellhead
XOV	Cross over
X-mas tree	Christmas tree

LIST OF SYMBOLS

A_{lk}	Alkalinity
Bo	Oil formation volume factor [stb/Rb]
C_{Ca}	Total Concentration of calcium (Ca^{2+}) [M]
c_w	Produced fines concentration
E_i	Exponential integral
F_d	Drag forces
F_e	Electrical forces
F_g	Gravitational forces
F_l	Lifting forces
F_1	Geometric factor
F_2	Well spacing factor
h	Initial oil formation thickness [ft]
h_{ap}	Oil column height above perforations [ft]
h_{bp}	Average oil column height below perforations [ft]
h_p	Perforation length [ft]
h_t	Total formation thickness [ft]
$\bar{h}$	Height of water advance [ft]
I	Ionic force
I_S	Scale Index
k_h	Horizontal permeability [mD]
k_{ro}	Oil relative permeability [mD]
k_{rw}	Water relative permeability [mD]
k_v	Vertical permeability [mD]
$(N_p)_{bt}$	Cumulative oil production at breakthrough
$[M^{+,-}]$	Free Metals (Ba^{2+}, Ca^{2+}, Mg^{2+}, SO_4^{2-}, Sr^{2+}
P	Parameter group
p	Pressure [psi]
q_c	Critical coning rate [stb/d]
q_{cD}	Dimensionless critical coning rate

q	Flow rate per unit of thickness [m^3/s]
q_t	Total fluid production rate [Rb/d]
r_w	Wellbore radius [m]
r_e	Drainage radius [m]
S	Skin factor
S_{wi}	Initial irreducible water saturation
S_w	Irreducible water saturation
S_w^*	Mobile wetting-phase saturation
T	Temperature [°F]
t_{bt}	Breakthrough time [d]
T_{Sw}	Sea water temperature [°C]
X_{CO_2}	Mole fraction of CO_2 *in the gas phase*
z	Depth [m]

$\Delta\gamma$	Water-oil gravity difference [psi/ft]
β_s	Formation damage coefficient for straining
λ_s	Filtration coefficient for size exclusion fines capture [1/m]
μ_o	Fluid viscosity [cp]
μ_w	Fluid viscosity [cp]
ρ	Density [ppg]
γ	Specific gravity
γ_o	Oil gravity [psi/ft]
γ_w	Water gravity [psi/ft]
φ	Porosity

TABLE OF CONTENT

1. INTRODUCTION

The production development in a subsea oil well corresponds to the longest phase of the well's life cycle. Figure 1.1 shows a generic profile of a well's life cycle as a function of cash flow (Y axis) and time (X axis). The oil production phase (orange area) is the only phase that results in revenues for oil industry, therefore the biggest challenge for oil industry is to produce without interruptions.

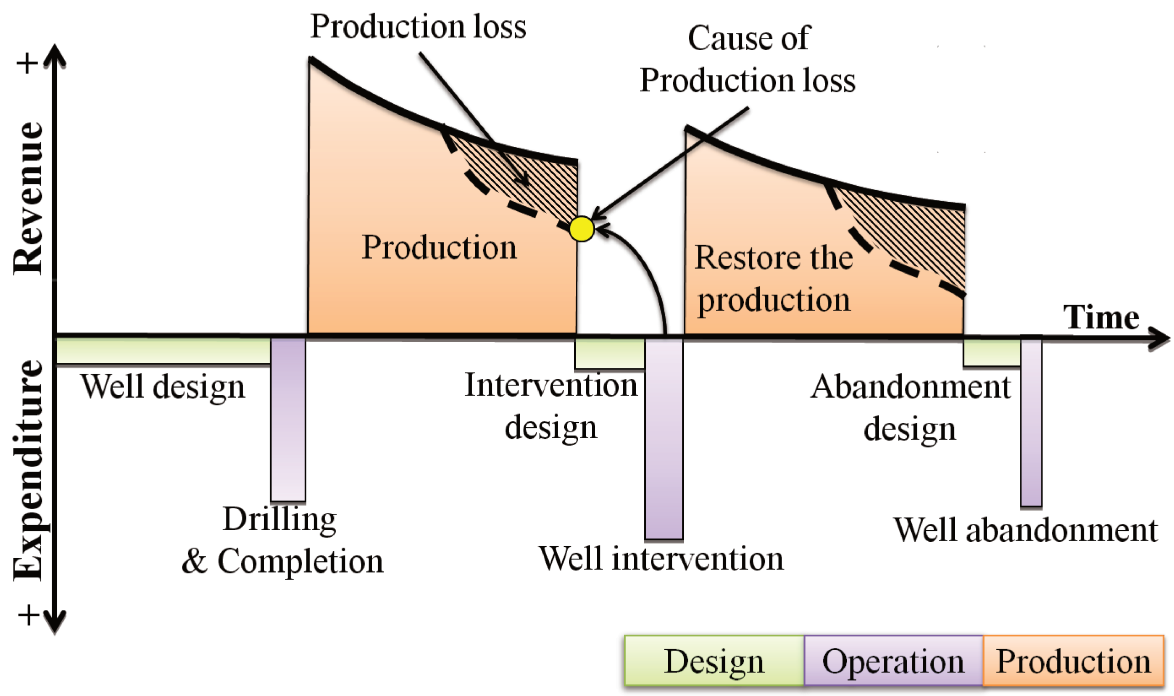

Figure 1. 1 - Profile of a well life cycle.
Source: adapted from Miura (2004).

As seen in Fig. 1.1 the production decline may occur for two reasons. One of them is due to the reservoir pressure drop (natural cause) and the second is due to abnormalities causes (dash line). The difference between the natural and abnormal decline is defined as production loss (shared area).

Note that when the production loss increases the potential production decreases, when this potential is not economically profitable a well intervention is needed.

The well intervention is defined as an operation carried out for maintenance or remedial action. The well intervention design and operation are known as maintenance phase. The purpose of this phase is to reestablish the oil production (Garcia, 1997).

The causes of the production loss are discovered during maintenance phase, and can be defined as the loss relative to the potential production.

Usually the maintenance is not planned during well design phase; therefore intervention costs may represent a problem during production phase.

The well intervention represents one of major operational expenditure for the oil industry especially in subsea wells, due to the cost of equipment and the time of the operation.

In subsea wells, expenditures will be high if interventions are frequent and the consequence is that the well will not be economically profitable. Therefore the well intervention should be kept as low as possible.

Well interventions are classified in two categories: light and heavy workovers.

The most important difference between heavy and light workover is the treatment of the issue. A comparison can explain better:

In heavy workovers it is necessary to remove the Christmas tree (X-mas tree) and to install the drilling BOP (Blowout Preventer). It normally includes the removal of the entire completion string from the well and requires the services of a Mobile Drilling Unit (MODU).

In light workovers it is not necessary to remove the X-mas tree, because the operations may be carried out through the X-mas tree and the production tubing, i.e., using slickline, wireline and coiled tubing operations, and for that reason the use of a MODU is not necessary.

One of the most important remarks is that in light workover the company takes around 15 days to solve the problem and in heavy workover, the operations typically range between 120 to 240 days (Birkeland, 2005). But this period can change; for instance in Campos Basin the light workover may take 15 days and heavy workover 30 days for some wells (Fonseca et al., 2013).

Recently, the oil industry is doing many efforts to create new methods and technologies to prevent well interventions and mainly to avoid heavy workovers.

For all the reasons above, it is very important to understand the causes of production loss in the initial design phase in order to save costs and time in the well interventions until the end of the productive life.

Two fundamental concepts useful for a better understanding of this work are defined below:

- **Minimum intervention:** is defined as the low intervention necessity that can be reaches trough modifications in the well design (prevention treatments) to avoid causes of production loss.

- **Easy intervention:** is defined as the well intervention performed by light workover (remediation treatments) when the cause of production loss cannot be avoided with the minimum intervention.

The purpose of these concepts is to propose guidelines and procedures that should be implemented during well design phase in order to obtain a non-intervention, minimum or easy intervention during production phase.

1.1. Objectives

The main objective of this work is to establish guidelines and procedures to be applied during the well design phase for subsea wells in order to reduce and ease the well intervention until the end of the productive life.

In order to get this point, causes of production loss, as well as prevention treatments and remediation treatments that can be applied with light workovers should be identified.

The procedures are presented in flow charts and are applied in different study cases to show the applicability and to demonstrate the effectiveness.

1.2. Organization

This study is structured and divided in five chapters, in order to understand the proposed objectives. The introduction and objectives are presented in chapter 1.

Chapter 2 presents the methodology of this work together with the selection of offshore petroleum regions.

Chapter 3 presents an analysis for each cause of production loss, identifying the factors why it occurs, possible treatments (prevention and remediation) and case studies for each region.

Chapter 4 discusses the results obtained based on the reports presented; establishes guidelines and procedures for each cause of production loss and presents case studies to verify the guidelines.

Chapter 5 presents the conclusions and recommendations for future works.

2. LITERATURE RESEARCH

This chapter presents the methodology adopted.

Section 2.1 describes the selection of the offshore maritime regions and a briefly explanation of each offshore maritime region chosen.

Section 2.2 describes the procedure carried out for data collection of the main petroleum databases, in order to identify the causes of production loss, prevention and remediation treatments.

2.1. Selection of offshore petroleum region

The offshore petroleum regions have been promissory in the last years and a big challenge faced is perform the well intervention due to the high water deep (Morooka and Carvalho, 2011). Therefore the scope of this work was carried out in offshore petroleum regions.

The criterion for the selection of the maritime regions was the oil production, which as described previously, represents the revenues for oil industry. The selected offshore petroleum regions were: Brazil (Campos Basin), Gulf of Mexico, North Sea and West Africa.

The JPT (2015) reported a total of 80 MMBOPD (Millions Barrels of Oil per Day) of crude oil production in the world until April/2015.

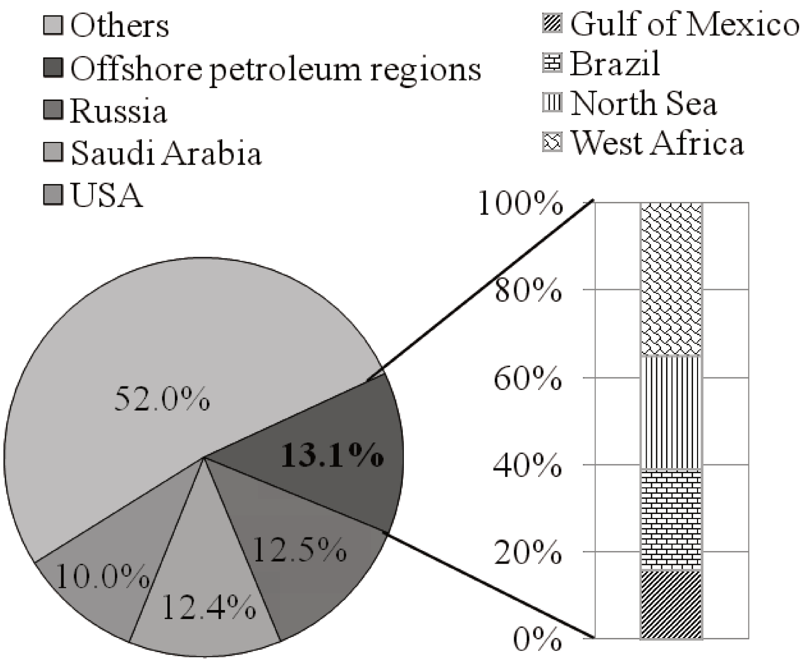

Figure 2. 1 - World crude oil production.
Source: JPT (2015).

Figure 2.1 shows the percentage of crude oil production in the world. The most representative offshore petroleum regions were: Brazil, Gulf of Mexico, North Sea and West Africa, and these regions produce together 10 MMBOPD, representing 13% of the whole crude oil production, placing themselves ahead of the major producers (Russia, Saudi Arabia and USA).

These maritime regions are important in the development of offshore oil production and the new discoveries have placed these regions in a promising position (OE, 2014).

In Brazil, Campos Basin represented a 66% of the total oil production according to ANP (2015) until July 2015 and for this reason, Campos Basin is considered for this study. In the following, there is a brief description of each offshore petroleum region:

- **The Campos Basin** is the main sedimentary area already explored in the Brazilian Coast and has an approximated area of one thousand square kilometers.

  The Campos Basin presents a subtropical current, which means relative strong currents with moderate waves and a hot weather. The production platforms are mostly Floating Production, Storage and Offloading (FPSO), the wells have subsea completion and the water depth typically ranges between 80 – 2400 meters. The majority of the wells are located in deep and ultra-deep waters (Ribeiro, 2013; Barton, 2015). Figure 2.2 shows these features.

  The first field with commercial volume discovered was the Garoupa field in 1974, presenting 124 meters depth. In the next year, the Namorado field was discovered and in 1976 was the Enchova Field. On 13 August of 1977, the Campos Basin started the commercial oil production there.
  Since the beginning of the production in the Campos Basin, Brazil became a representative oil producer in offshore regions (Petrobras, 2015).

- **The Gulf of Mexico** presents calm environmental conditions but with metocean phenomena, such as, winter storms, tropical storms, hurricanes in the summer and a major problem: loop currents that flow in large eddies (Todd and Replogle, 2010).

The production platforms are typically Tension Leg Platform (TLP) and SPAR. The completion is wet and the water depth ranges between 454 – 2896 meters (Fig. 2.3).

The Gulf of Mexico marked the birth of the offshore industry in 1947 with the Creole field. The peak of oil production in this region was in 1971 (shallow water). The oil production started to decline after 1971 leading to new discoveries in deep water. The first deep water oil production was in 1979 in the Cognac field (Pratt, 2014).

- **The North Sea** presents severe environmental conditions with strong winds and currents. Most of the oil fields are characterized by fixed platforms, wet completion and the water depth ranges between 70 – 400 meters (Sangesland, 2010), as presented in Fig. 2.4.

  In the North Sea the main discoveries of oil fields were in 1967 in Norway (Balder Field) and in 1969 in United Kingdom (Arbroath field). The first oil production in the North Sea was in 1975 with the Argyll field. At this time, the world oil prices were high enough enabling the North Sea oil production, which reached the peak in 1999 (Oil Finance Consulting, 2015).

- **The West Africa** sea conditions have long-period swells and several wind sea (Olagnon et al., 2014). The water depth ranges between 40 – 2200 m but the majority of the offshore oil wells are in shallow waters and the main production platforms are FPSO's (OE, 2014; OE 2015), as shown in Fig. 2.5.

  In West Africa the vast majority of the oil produced comes from Nigeria and Angola. Equatorial Guinea, Republic of Congo and Gabon have also a representative oil production (Kgosana et al., 2014).

  In Angola, the first offshore discover was the Malongo field in 1968 (Cabinda province). In 1996 the Elf Petroleum Company discovered the Girassol Field, with 1300 meters depth and production starting in 2001. Nowadays 97% of the production is from offshore fields (Koning, 2014).

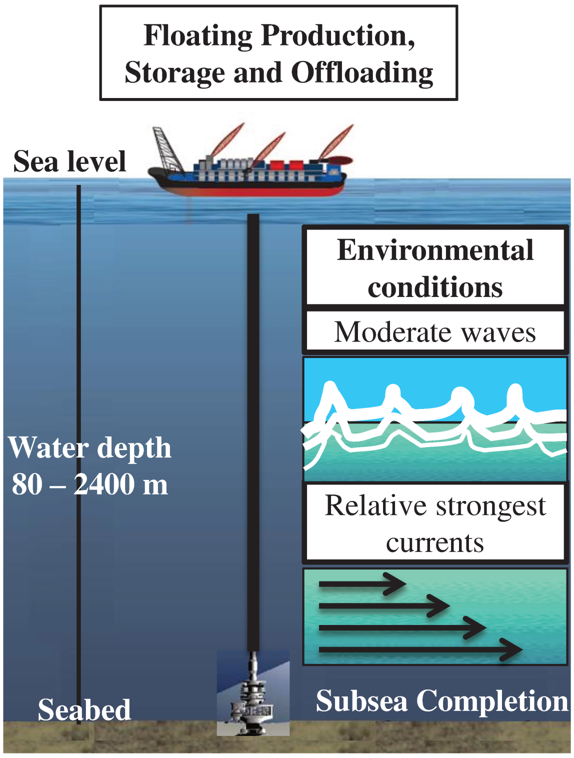

Figure 2. 2 - Campos Basin Context.
Source: adapted from Barton (2015).

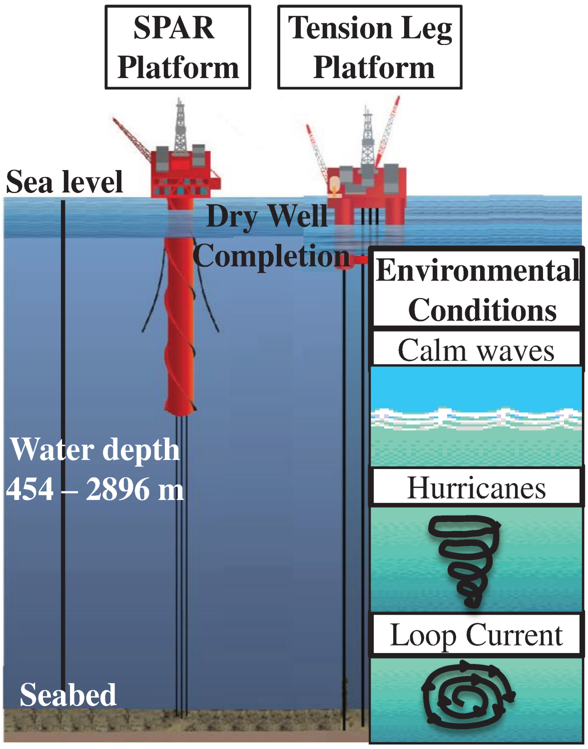

Figure 2. 3 - Gulf of Mexico Context.
Source: adapted from Barton (2015).

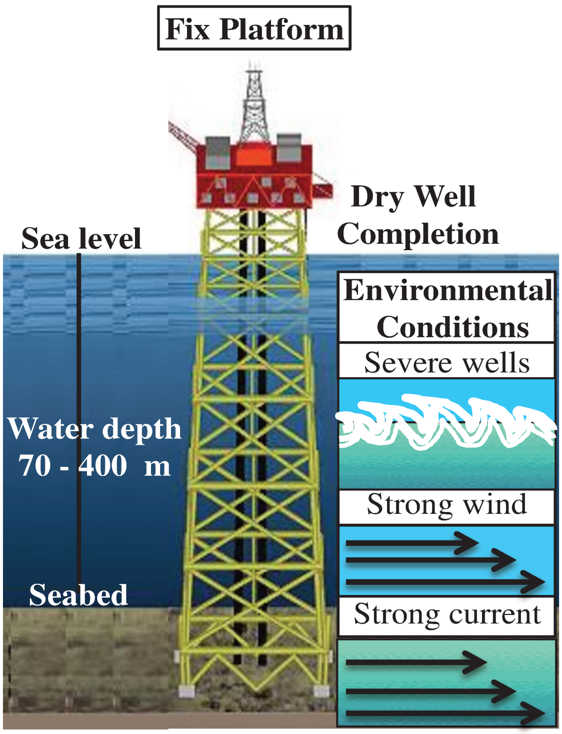

Figure 2. 4 - North Sea Context.
Source: adapted from Barton (2015).

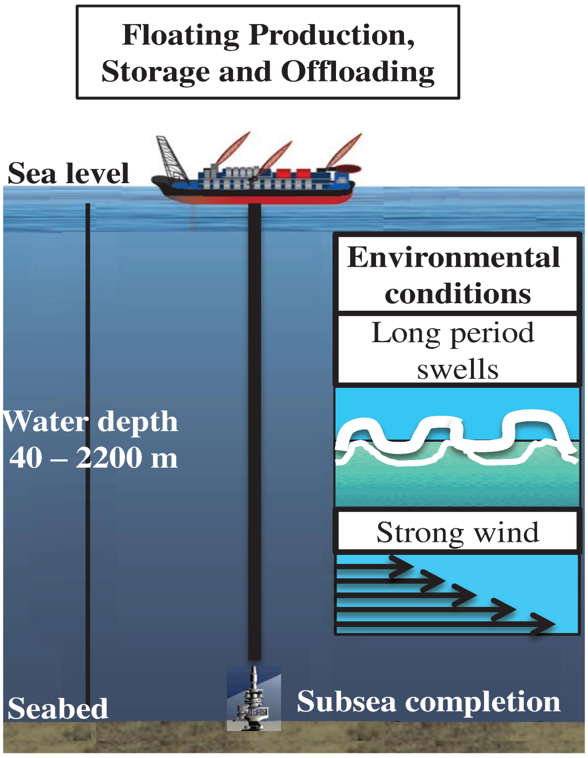

Figure 2. 5 - West Africa Context.
Source: adapted from Barton (2015).

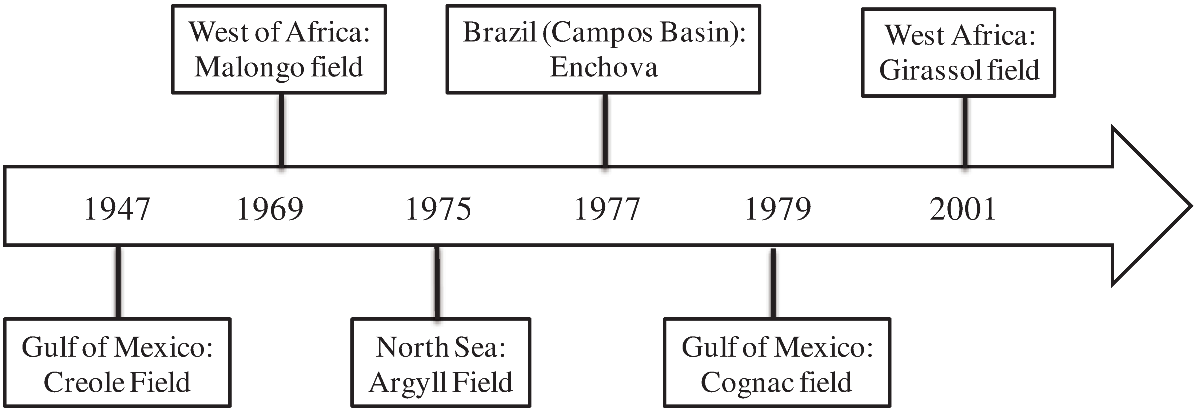

Figure 2. 6 - Timeline of beginning of offshore oil production

Figure 2.6 shows the timeline of beginning of offshore oil production in the four maritime regions. According to the description performed for each offshore petroleum region in the decade of the 80's the North Sea, Gulf of Mexico and Campos Basin were producing oil. In 2001 West Africa became an important region in offshore oil production. As a result of the increasing offshore oil production since the 80's there are more information related to production problems, therefore this work is considering the last 35 years of literature.

2.2. Data collect

The main sources of information taken into account for the literature research were the Society of Petroleum Engineer (SPE), the Offshore Technology Conference (OTC) and the Norwegian University of Science and Technology (NTNU). The literature survey was organized in order to:

- Identify the causes of production loss (why they occur)
- Identify solutions to prevent well interventions and avoid heavy workovers (remediation treatments)

The most relevant document was a master thesis presented by Frota (2003) about causes of failure that lead to a well intervention. This master thesis was the base to identify the main keywords of this work. Several searches were carried out with different keywords. The first set of keywords selected for the search were: production loss, well intervention, maintenance, failures, flow problems, mechanical failures, and reservoir problems.

The results of the searches were a set of documents, as an example, papers, dissertations, thesis and standards. The first filtration of information was based in a review of the abstract, introduction and conclusions, for the reason that in these fields, a general background of the work and the main results are presented.

In order to obtain more documents for the analysis, the references of the selected documents were investigated and a new set of more specific keywords was inserted in the databases, such as “hydrate, deposition, curve, Campos Basin”.

The search was repeated until the required information for each cause of production loss was obtained.

These documents were organized in a tables (see Appendix A) to identify the cause of production loss, the offshore petroleum region, the year of the document and the reference. The most relevant documents were commented.

Table 2. 1 - Organization of documents found.

Cause of production loss	**Offshore petroleum region**	**Reference (Year)**	**Comments**
Hydrate	Campos Basin	Teixeira et al, 1998	In Albacora field, seven months after the beginning of oil production a blockage in two wells resulted due to hydrate formation in the manifold.
		Marques et al, 2002	In a well in Campos Basin a repair of SSSV was scheduled, but was not possible to remove the X-mas tree due to a hydrate deposition. A ROV was necessary to identify the cause of the problem.
Wax	Gulf of Mexico	Alwazzan et al., 2008	Wax deposition in pipelines in Cottonwood field.
Asphaltene	North Sea	Thawer et al., 1990	Asphaltene deposition in production tubing and production facilities in the Ula field.
Fines migration	West Africa	Ezeukwu et al., 1996	A field study to evaluate organic and inorganic agents to determine their effectiveness to eliminate fines.

Table 2.1 is an example of the organization of the documents. After the organization of all the documents, a second filtration was carried out based on the comments on each document. Those documents containing more information were selected and short abstracts were performed with the follow information: problem, approach, solution, conclusions, assumptions and limitations, application and critique.

A new selection of the most relevant documents is possible after this filtration and the result was a data set with two hundred fifty-four documents for the four offshore petroleum regions.

3. ANALYSIS OF PRODUCTION LOSSES

The classifications, in this section, and a description and the solutions of each cause of production loss will be presented based on collected data.

Section 3.1 explains in a detailed form the occurrence of each cause of production loss, the main factors and presents some cases studies in order to demonstrate the statements.

Section 3.2 presents prevention and remediation treatments for each cause of production loss.

3.1. Causes of production loss

According to the literature research, the identification of twenty one causes of production loss was possible. The causes of production loss were considered taking into account the four offshore petroleum regions.

Causes of production loss in specific or in general cases were identified by other authors. A description of these works is given below:

- The causes of intervention could be due to: excessive water or gas production, restricted hydrocarbon production, sand production, equipment failure and reservoirs depleted (Baker, 1980).
- In Campos Basin, failure causes leading to a well intervention in a period of twelve years were mapped, identifying three most important groups of causes: flow, mechanical failure and reservoir. In this study, a total of sixteen failures were possible to identify (Frota, 2003).
- In mature fields of Campos Basin some causes of production loss were identified, such as: hydrates, organic deposition (asphaltenes and wax), sand production, fines migration and scales (Rodriguez et al., 2007).
- In the North Sea and in the Gulf of Mexico, well barrier components that failed and led to a leakage, causing production loss and well intervention were identified (Vignes, 2011; King and King, 2013).

As described, this authors identified no more than twenty one causes, therefore the result of the literature research demonstrate that the search was carried out in an exhaustive, focused and accurate way, in order to identify the main causes of production loss.

In the analysis featured by Frota (2003), it is possible to identify that a real basis data was used. Also, the author was the first one that analyzed the system of occurrences, grouping the causes according to the correlation among them.

Table 3. 1 - Group of causes of failure.
Source: Frota (2003).

Flow problems	Mechanical failure	Reservoir problems
• Hydrates • Wax in flow lines	• ANM • DHSV • Flow lines • Casing • Tubing	• Reservoir • Stimulation • Gravel Pack

Table 3.1 shows one of the most important conclusions from Frota (2003): group the causes of failure in three relevant categories. In addition, there is a less important group which is not considered because it is not related to production phase, e. g, relocation.

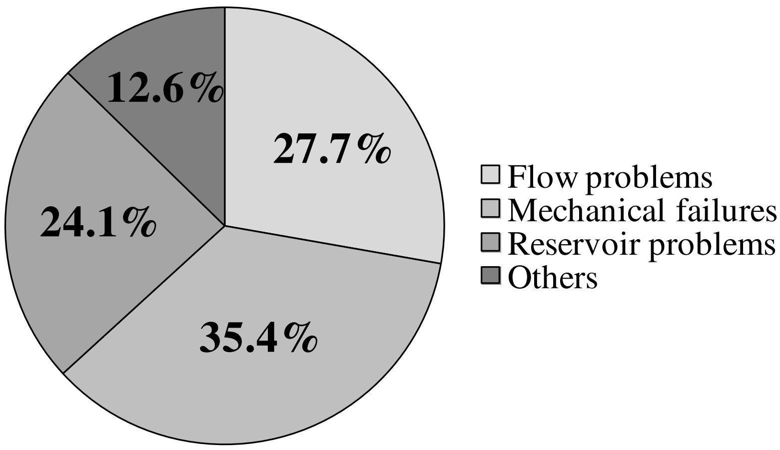

Figure 3. 1 - Causes of failure.
Source: Frota (2003).

Figure 3.1 shows the percentage of well intervention for each group, the total of well intervention was seventy nine.

Three types of causes of production loss were identified based on the characteristics of each cause and considering the groups created by Frota (2003): flow assurance, potential integrity failure and reservoir problems. The definition of each type of cause is given below.

- Flow assurance: an unintentional oil flow reduction due to an increase of pressure load in the well& flow line system.
- Potential integrity failure: a leak threat of the well &line system.
- Reservoir problems: a production reduction due to damages near wellbore.

Table 3. 2 - Types and causes of production loss.

Loss of Flow Assurance	Integrity Failure	Reservoir Problems
• Hydrates • Wax • Asphaltenes • Barium sulfate • Strontium sulfate • Calcium sulfate • Calcium carbonate • Calcium Naphthenate • Naturally Occurring Radioactive Materials (NORM)	• Wellhead • Production casing • Christmas tree • Production tubing • Subsurface safety valve • Gas lift valve • Cement • Packer	• Excessive water production • Excessive gas production • Sand production • Fines migration

Table 3.2 shows the types of production loss and the causes of production loss found in this work; it was possible to insert all of the causes in these three types according to the definitions of each type of production loss.

Table 3.2 can be considered as a base of the main causes of production loss for the most representative maritime regions. Other causes that lead to an intervention may probably exist but they are not presented in the selected maritime regions or it is not reported. For example, emulsions could be considered as a flow assurance problem, but this problem has not been reported in any maritime region selected.

As seen in Fig. 3.1, these causes represented 87% of the well interventions in Campos Basin. It is important to remark: the data set found were two hundred fifty-four reports about causes of production loss for the four offshore petroleum regions, being 61 % for flow assurance, 26 % percent for potential integrity failures and 13% for reservoir problems.

a) Flow Assurance

Flow assurance ensures that oil flow can be moved from the reservoir to separation treatments without any restriction or blocking. These restrictions are mainly due to solids deposition over the production system.

An early identification of the possible solids deposition plays a key role during oil production to prevent and plan future well interventions (Joshi et al., 2003).

The main factors for solids deposition are the formation fluid composition (hydrocarbon or water), pressure and temperature (Ellison et al., 2000; Rodriguez et al., 2007; Cochran, 2003). The areas of solids deposition can be:

- Near wellbore region
- Production tubing
- Subsea wellhead
- Subsea flow lines
- Subsea pipelines
- Separators
- Subsurface valves

A total of 179 reports about causes of production loss due to flow assurance for the four offshore petroleum regions were selected in the researched literature. Analysis of these reports shows that the hydrate and the wax are usually the main solid deposit - which results in an obstruction of the well/line system. On the other hand, scales, asphaltenes and naphthenates may also be a concern.

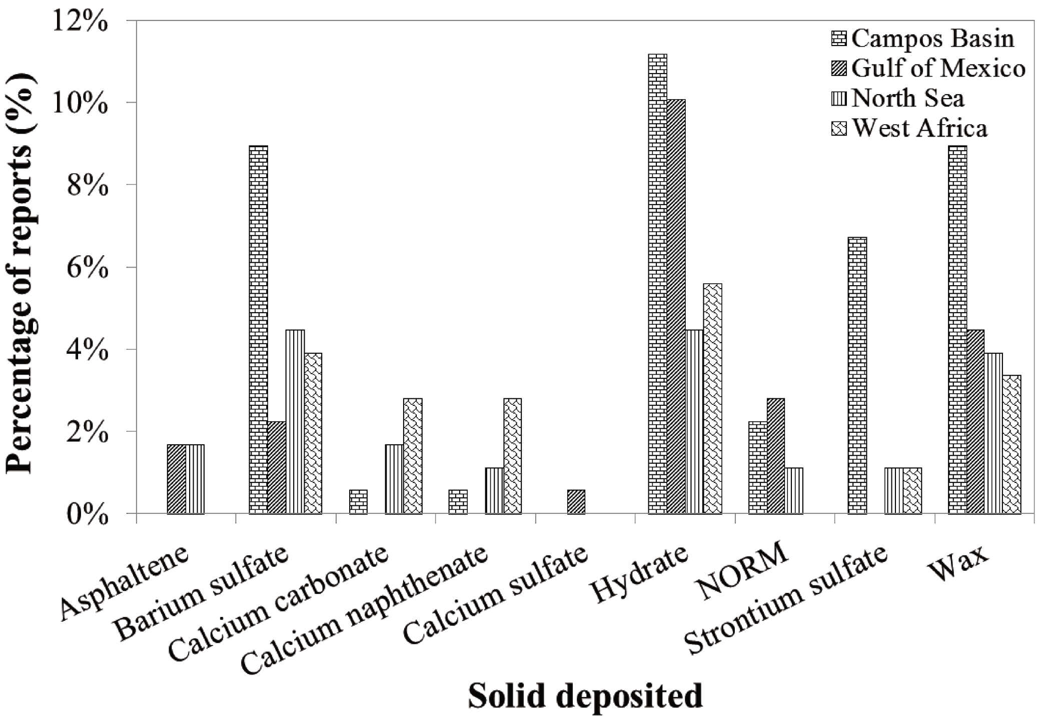

Figure 3. 2 - Percentage of reports for causes of production due to flow assurance by offshore petroleum region.

Figure 3.2 shows the solids deposition by offshore petroleum region. Note that the solids may be different one to each other because the formation fluid composition in each offshore petroleum region is different.

In the present work, considering that the solids deposition depends on the degree of variation on pressure and temperature, a standard well which the temperature varies about 0 to 300 °F and the pressure varies about 0 to 10000 psi is considered. The variations of pressure and temperature represent stability limits of common well service tool components, elastomeric seals and electronic devices (Skeates et al., 2008).

As the approximate minimum temperature of the sea bed is ≈39 °F, this temperature will be considerate as minimum temperature for the calculus.

- **Hydrate**

A hydrate is a crystalline solid, with external aspect very similar to the ice. It is formed by the mixture of gas and water, at specific conditions of pressure and temperature, mainly when the production system operates at low temperatures and high pressures (Pedroso et al., 2009).

Hydrates can block the flowlines during normal production operations but it happens more often during the shut-in and start-up operations. The hydrate deposition is common in pipelines, flowlines and Christmas tree and can be identified in a phase diagram P-T (Camargo et al., 2004; Palermo et al., 2004; Noe et al., 2008).

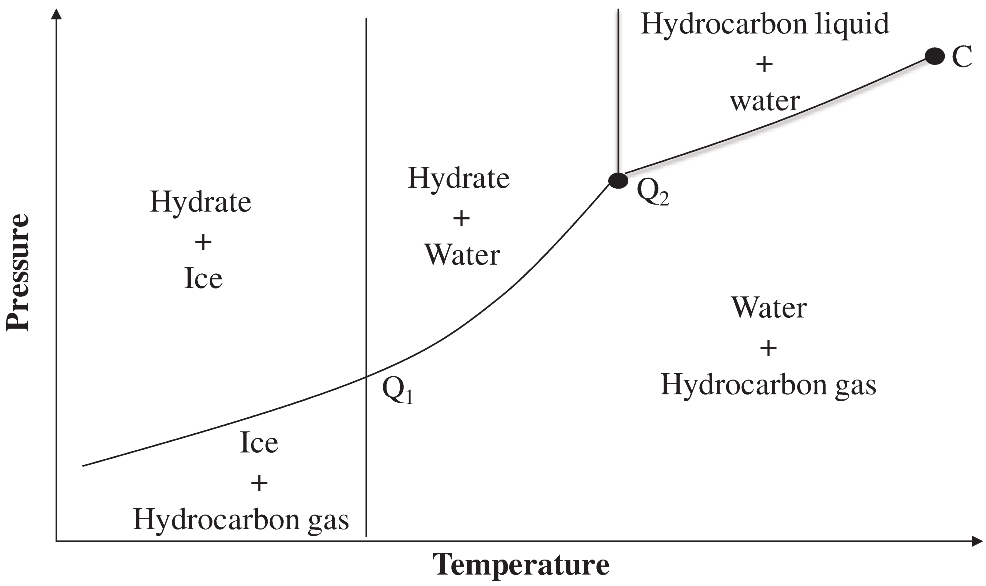

Figure 3. 3 - Phase diagram for a mixture of water and light hydrocarbon.
Source: McCain (1990).

Figure 3.3 shows the phase diagram P-T for a mixture of water and a light hydrocarbon. The most important line of this diagram is Q_1Q_2 and it represents the ideal conditions of the pressure and the temperature in which water mixture with gas to form hydrate, therefore this line separates the region in which water and hydrocarbon gas exist (non hydrate-zone) from the region in which water and hydrate exist (hydrate-zone) (McCain, 1990).

Experimental methods are more indicated to study and solve the issues in the oil industry but they are expensive. As a result, simplified models have been proposed over the years. These models can be classified in four major methods, such as: vapor-solid equilibrium method also known as k-value, modified k-value method, gas gravity method and empirical correlations method (Nasab et al., 2011).

$$T = -238.24469 + 78.99667\log(p) - 5.352544[\log(p)]^2 + 349.47387\gamma + 150.85467\gamma^2 - 27.6040651\log(p)\,\gamma \tag{1}$$

According to Safamirzaei (2015) and other authors the equation proposed by Motiee (1991) is the most used in oil industry because can determine the conditions to hydrate formation at different compositions of natural gas (Eq.1); therefore this equation was selected for the present study.

Table 3. 3 - Gas composition data for each offshore petroleum region.

Component	**Campos Basin (Teixeira et al., 1998)**	**Gulf of Mexico (Szymczak et al., 2005)**	**North Sea (Argo et al., 1997)**	**West Africa (Brezger et al., 2010)**
	Mole fraction (%)			
Methane	76.30	88.54	95.31	88.75
Ethane	11.30	1.17	2.96	5.93
Propane	6.90	0.67	0.53	1.28
I-butane	1.00	0.24	0.10	0.26
N-butane	2.00	0.29	0.10	0.26
I-Pentane	1.00	0.20	0.00	0.09
N-pentane	0.00	0.17	0.00	0.06
N-hexane	0.30	0.31	0.00	0.06
N-heptane	0.30	7.51	0.00	0.10
Nitrogen	0.70	0.26	0.00	0.66
CO2	0.20	0.62	1.00	2.55
	$\gamma = 0.76$	$\gamma = 0.81$	$\gamma = 0.5981$	$\gamma = 0.64$

As previously discussed, the formation of hydrate depends mainly on the gas composition. Table 3.3 presents the gas composition for each offshore petroleum region considered in the present work.

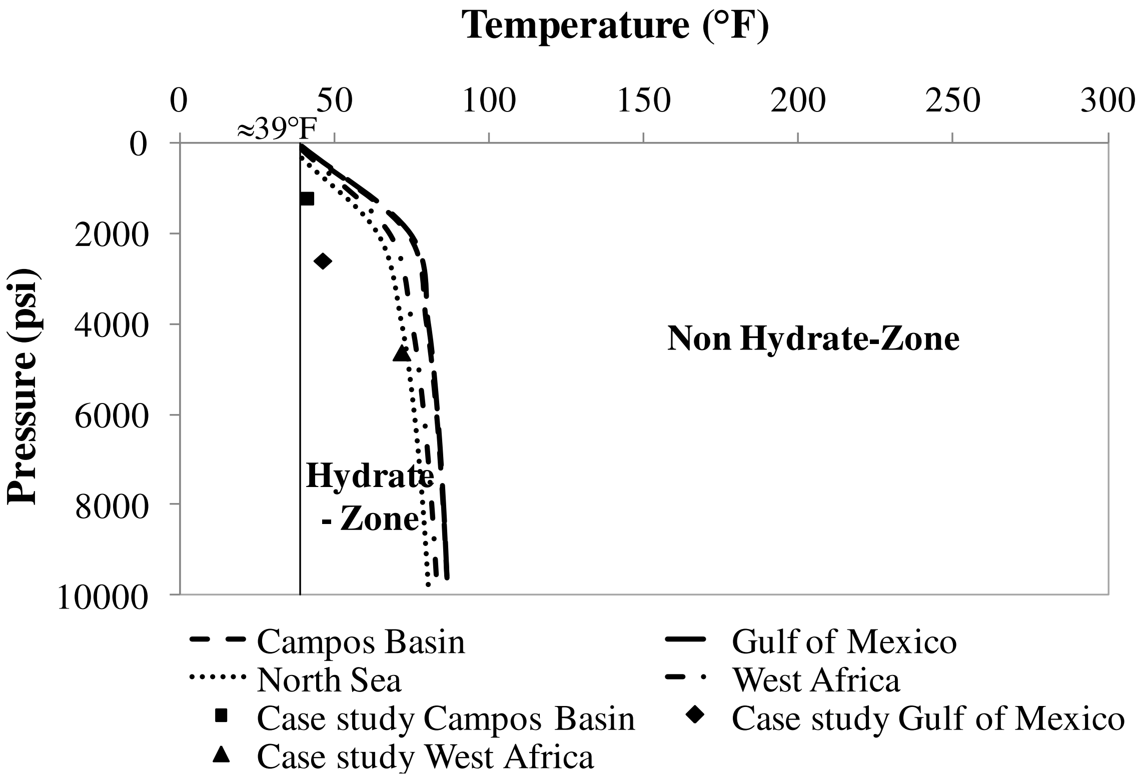

Figure 3. 4 - Hydrate curves for each offshore petroleum region and hydrate deposition case studies.

Figure 3.4 shows the hydrate curve calculated by Eq. (1), and the hydrate and non hydrate-zone based on gas composition of each offshore petroleum region presented in Tab. 3.3. Three case studies are also presented in the Figure and are described below.

Table 3. 4 - Case studies with hydrate deposition.

Offshore petroleum region	**Field**	**Place**	**Oil flow conditions**		**References**
			Temperature (°F)	**Pressure (psi)**	
Campos Basin	Albacora	Manifold	41.0	1,219.0	Teixeira et al., 1998
Gulf of Mexico	Genesis	Pipeline	46	2,600.0	Kashou et al., 2004

Table 3.4 presents some case studies, in which the hydrate curve was not predicted during the well design and hydrate deposition occurring during oil production. If it had been identified that the oil flow conditions were in the hydrate-zone, as shown in Fig. 3.4, the deposition probably would not happen.

Table 3. 5 - Case study without hydrate deposition.

Offshore Petroleum Region	Field	Location	Oil flow conditions		Reference
			Temperature (°F)	Pressure (psi)	
West Africa	Azurite	Subsurface Safety Valve	71.6	4,625.0	Brezger et al., 2010

Table 3.5 presents a case study for a well in West Africa; in this case the oil flow conditions were plotted on the hydrate curve during well design, and the result was a hydrate prone system (as shown in Fig. 3.4). In order to avoid the hydrate deposition, prevention and remediation treatments were applied.

These three cases demonstrate that the prediction of hydrates during well design is vital to avoid the disruption of oil production that causes significant economic impact.

In Campos Basin, from 1991 until 2006 the hydrate represented 27. 2% of well intervention and up to this day it is a challenge for oil industry. Occasionally, even though the ideal condition for hydrate formation is present, its deposition does not occur. This behavior is related to natural surfactants contained in hydrocarbons, acting as anti-agglomerate agents, keeping the formation of crystals dispersed of the oil phase (Camargo et al., 2004, Palermo, 2004

To let deeper the hydrates study the pressure was converted to depth in order to know approximately at which water depth the hydrates became a problem for each offshore petroleum region.

$$z = \frac{p}{0.052\rho} \tag{2}$$

The hydrostatic pressure equation was used (Eq. 2) proposed by Bourgoyne et al. (1986) in order to make the conversion of pressure to depth, with an average seawater density of 8.55 ppg .

$$T_{SW} = 8 \times 10^{-9} z^3 + 3 \times 10^{-6} z^2 - 3.01 \times 10^{-2} z + 22.505 \tag{3}$$

The sea water temperature was calculated with Eq. (3) proposed by Cardoso and Hamza (2014). The seabed temperature became constant from 2788 ft (≈850 m), reaching a minimum temperature of 39 °F (≈ 4°C) approximately.

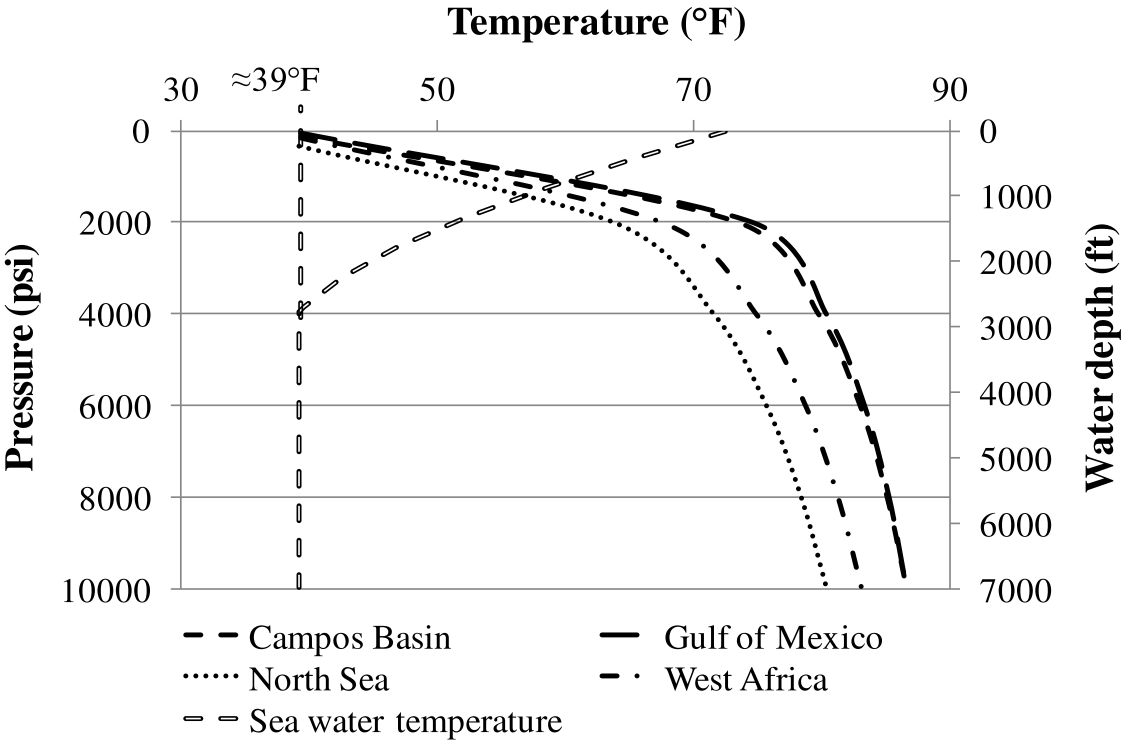

Figure 3. 5 - Depth of beginning hydrate

Figure 3.5 shows the hydrate curve for each offshore petroleum region and the sea water temperature as a function of depth. Note that for Campos Basin and Gulf of Mexico the approximate depth of hydrates deposition is 1640 ft (≈500 m), for West Africa 1870 ft (≈570 m) and finally for North Sea 1968 ft (≈600 m).

In North Sea the water depth ranges between 70 – 400 m, and the possible hydrate deposition occurs from 600 m, then it is unlikely to occur and hydrate deposition. It was proven with the literature survey because in the North Sea the documents quantity to the hydrates deposition is reduced (see Fig 3.2).

- **Wax**

Wax contains paraffin of high molecular weight, with number of carbon molecules ranging from C15 to C75+. The amount of wax generally decreases with decreasing API gravity (Alwazzan et al., 2008; Petrowiki, 2015a).

Wax has a crystalline appearance and tends to crystallize or precipitate from the crude oil at and below their wax appearance temperature (WAT) or wax precipitation temperature (WPT). It is known as the cloud point which is defined as the highest temperature in which the first solid wax crystal is formed at a given pressure (Hammami and Raines, 1999).

The wax deposition on a subsea production system also represents a great concern in the oil industry. Wax depends on the hydrocarbon composition (paraffinic content), and variations of temperature and pressure. The main characteristic in order to identify deposition of the solid is the WAT (Hammami and Raines, 1999). A common prevention treatment to avoid wax deposition is to maintain the temperature of the production system 3°C above WAT (Rodriguez et al., 2007).

The WAT is a laboratory measure. There are several techniques to determine it such as: Differential Scanning Calorimetry (DSC), Cross Polarization Microscopy (CPM), filter plugging (FP) and others (Oschmann and Paso, 2013). The occurrence of wax deposition is undesirable when the hydrocarbon is flowing. However, when the oil flow stops flowing wax particles will interact and join together, forming a gel structure or a solid (Pedersen and Christense, 2007).

The wax zone and non-wax zone can be identified through the WAT. If the oil contains paraffinic components and the operating temperature achieves the WAT, light components start the evaporation then the heavy components transform in wax crystals. Therefore, if the operational temperature is below the WAT, wax deposition can occur.

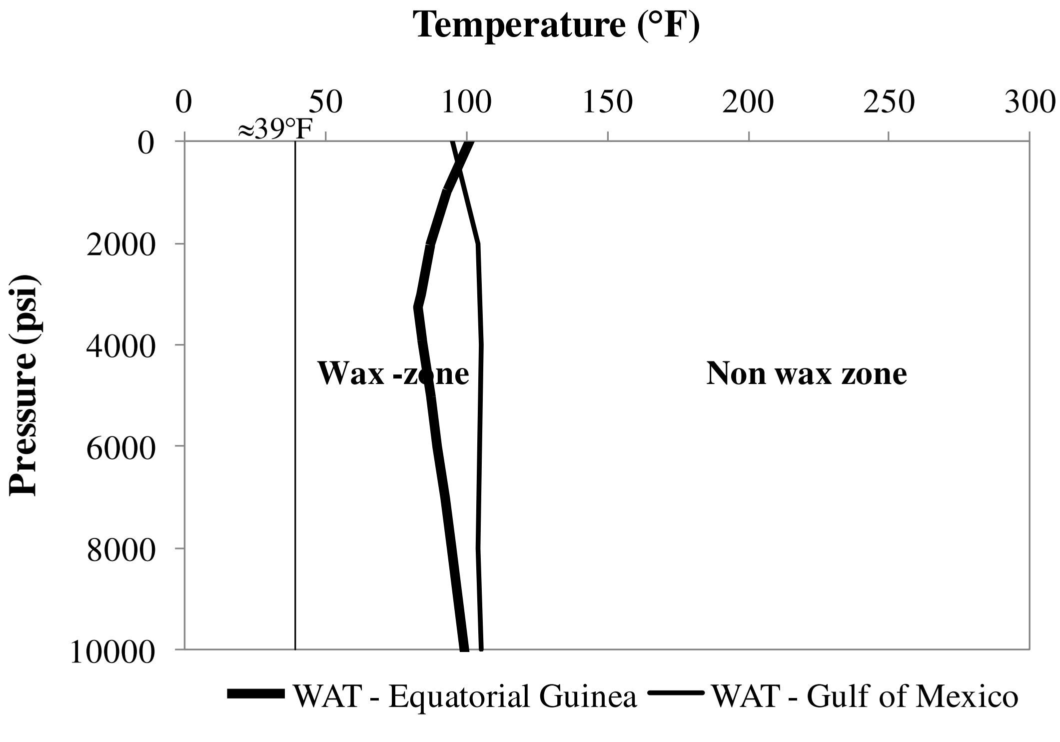

Figure 3. 6 -Wax zone and Non wax-zone for a field in Gulf of Mexico and Equatorial Guinea.

Figure 3.6 shows the WAT as a function of pressure for a field in Equatorial Guinea (Oschmann and Paso, 2013) and the Gulf of Mexico (Ratulowski et al., 2004).

Table 3. 6 - Case study for wax deposition.

Offshore petroleum region	**Field**	**Place**	**WAT (°F)**	**Temperature (°F)**	**Reference**
North Sea	Gannet	Flowlines	96	39	Craddock et al., 2007

The wax deposition was reported in the four offshore petroleum regions (see Fig. 3.1). Table 3.6 shows a case study in which wax deposition was a concern due to lack of prediction of problems related to wax.

In this field, wax deposition was first identified in 1999. After that for a future design, wax prevention and remediation treatments were included. The production can avoid the wax deposition if the project makes an early analysis of wax problems.

- **Asphaltenes**

Asphaltenes are organic materials, which consist of condensed aromatic and naphthenic rings with high molecular weight, containing nitrogen, sulfur and oxygen molecules. They are insoluble at room temperature in n-pentane and n-heptane, and soluble in benzene and toluene. Asphaltene may precipitate due to destabilization of maltene resins (acid contact), outgassing, shear in pumps, electrically charged metal surfaces, temperature reduction, and CO_2 (Pedersen and Christense, 2007)

Such as the hydrate and the paraffin, the main parameter for deposition of the asphaltene is the hydrocarbon composition. If the fraction of n-heptane is higher than 2 mg/l, the hydrocarbon is considered stable despite of variation of pressure and temperature (Akbarzadeh et al., 2007). Otherwise, the deposition is possible, and the pressure will be the main parameter that will promote the deposition.

The hydrocarbon is a mixture of liquid and gas until it reaches the ideal condition of pressure and temperature to cause precipitation of the asphaltene. The limit condition curve is denominated as “the lower asphaltene onset pressure (AOP)”. Bellow of this curve, liquid, vapor and asphaltene are simultaneously present. When the hydrocarbon reaches the bubble point, only liquid and asphaltenes will be present, until the new boundary limit named as “the upper asphaltene onset pressure (AOP)” is attained.

The envelope composed by lower AOP and upper AOP is known as “asphaltene-zone”, and the asphaltene deposition can occur only in the region established by this envelope.

Measurements in the laboratory are necessary to determine the AOP, and techniques such as gravimetric, acoustic-resonance among others are applied (Pedersen and Christense, 2007; Akbarzadeh et al., 2007).

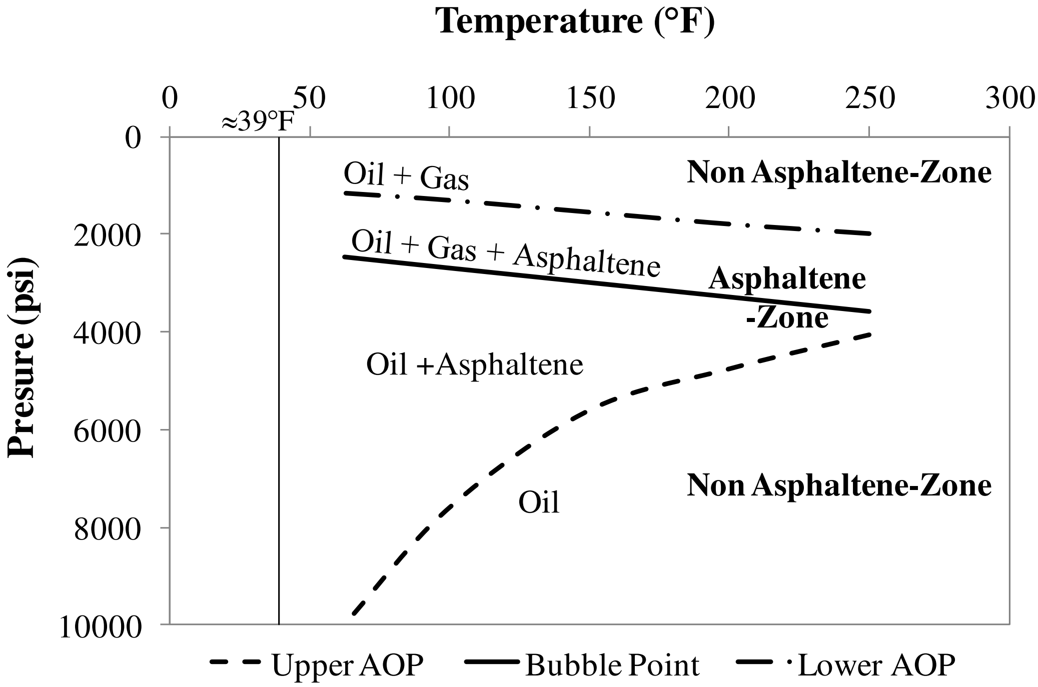

Figure 3. 7 - Boundaries for asphaltene appearance and asphaltene zones.
Source: adapted from Ratulowski et al. (2004).

Figure 3.7 shows a typical asphaltene envelope for an oil well in the Gulf of Mexico, the limit conditions (upper AOP and lower AOP) and the asphaltene-zone and non asphaltene-zone.

Table 3. 7 - Case studies for asphaltene deposition.

Offshore Petroleum Region	**Field**	**Location**	**Asphaltene; Upper AOP-Bubble Point (psi)**	**Operational Pressure (psi)**
Gulf of Mexico (Akbarzadeh et al., 2007)	-	Flowline	Non stable; 7500 – 2900	3000
North Sea (Takhar et al., 1995)	Clyde	Wellbore	Non stable; 2575 – 205	2400 – 1800

Table 3.7 shows case studies related to asphaltene deposition reported in the North Sea and Gulf of Mexico. In both cases, the n-heptane is lower than 2 mg/l, therefore, this hydrocarbon is considered as non-stable, and has the possibility of asphaltene deposition in the production system. Note that the operational pressure was inside the asphaltene zone, and the result was an asphaltene deposition.

If the hydrocarbon composition and the asphaltene deposition zone could be predicted in the initial phase, prevention and mitigation treatments could be applied during the well design.

- **Scales**

Scale is a mineral salt deposit which can occur along the petroleum production flow. The scale mechanism can be a self-scaling process or from the mixture of incompatible waters. The self-scaling process is the precipitation of salts of the formation water due to variations of the pressure and the temperature. And the incompatibility of water generally happens due to the mixture of the seawater (injected water) and the formation water, that's mean in secondary recover (Kan and Tomson, 2010).

The scale is formed when the concentration of a given salt exceeds the saturation limit, and precipitation of the salt happens. The limit for this condition can be obtained by the saturation index that is an indicator or a measure of the scale tendency.

The saturation index is represented by I_S. If $I_S > 0$, the solution presents potential for scaling. When $I_S = 0$, the solution is in the equilibrium. And, if $I_S < 0$, the scale deposition is not possible (Oddo and Tomson, 1982).

Table 3. 8 - Types of scales, primary variables for its occurrence and scale mechanism.

<table>
<tr><th>Chemical name</th><th>Reaction</th><th>Primary Variables</th><th>Scale Mechanism</th></tr>
<tr><td>Calcium carbonate (Calcite)</td><td>$Ca(HCO_3)_2 = CaCO_3 + CO_2 + H_2O$</td><td rowspan="4">• Pressure
• Temperature
• Total dissolved salts
• pH</td><td>• Self-scaling process
• Incompatibly of waters</td></tr>
<tr><td>Calcium sulfate</td><td>$\mathrm{CaSO_4 2H_2O \rightarrow CaSO_4\ ^1/_2\ H_2O}$</td><td>• Incompatibly of waters</td></tr>
<tr><td>Barium sulfate (barite)</td><td>$SO_4^{-2} + Ba^{+2} \rightarrow BaSO_4$</td><td>• Incompatibly of waters</td></tr>
<tr><td>Strontium sulfate (celestite)</td><td>$SO_4^{-2} + Sr^{+2} \rightarrow SrSO_4$</td><td>• Incompatibly of waters</td></tr>
<tr><td>Naturally Occurring Radioactive Materials (NORM)</td><td>$Ba^{2+} + Ra^{2+} + SO_4^{2-} \rightarrow Ba(Ra)SO_4$</td><td>• Ion Lixiviation of radium
• Total dissolved salts</td><td>• Incompatibly of waters</td></tr>
</table>

Table 3.8 summarizes the types of scales in the offshore petroleum regions; in presented table are shown chemical formula, primary variables, and causes (Moghadasi et al., 2003; Chilingar et al, 2008). Note that the main scale mechanism is incompatibility of waters.

These scales can be classified into: “pH-independent” and “pH sensitive”. The sulfates (calcium sulfate, barite and celestite) are not function of pH and carbonates is influenced by pH.

Various correlations have been proposed such as Stiff and Davis (1952) among others. These equations are based on the total dissolved solids (TDS), and the main limitation of this index is that it does not consider the pressure changes. New methods have emerged using CO_2 partial pressure. In the present work, equations proposed by Oddo (1982, 1994) are considered. These equations (Eqs. 4 to 7) are functions of only the formation water and seawater composition data.

$$I_S = \log\frac{C_{Ca}A_{lk}^2}{pX_{CO_2}} + 5{,}89 + 1{,}549 \times 10^{-2}T - 4{,}26 \times 10^{-6}T^2 - 7{,}44 \times 10^{-5}p - 2{,}52I^{\frac{1}{2}} + 0{,}919I \tag{4}$$

Equation (4) is to calculate the saturation index for calcium carbonate. This equation was obtained of derivation using conditional equilibrium constants, and depends of temperature, pressure, water composition and ionic strength. This is more accurate if calcium carbonate did not form before in any part of the production system. Because this equation do not used activity coefficients can be used day by day in the oilfields.

$$I_S = \log\{[Ca^{2+}][SO_4^{2-}]\} + 3.47 + 1.8 \times 10^{-3}T + 2.5 \times 10^{-6}T^2 - 5.9 \times 10^{-5}p - 1.13I^{\frac{1}{2}} + 0.37I - 2.0 \times 10^{-3}I^{\frac{1}{2}}T \tag{5}$$

$$I_S = \log\{[Ba^{2+}][SO_4^{2-}]\} + 10{,}03 - 4{,}8 \times 10^{-3}T + 11{,}4 \times 10^{-6}T^2 - 4{,}8 \times 10^{-5}p - 2{,}62I^{1/2} + 0{,}89I - 2 \times 10^{-3}I^{1/2}T \tag{6}$$

$$I_S = \log\{[Sr^{2+}][SO_4^{2-}]\} + 6{,}11 + 2 \times 10^{-3}T + 6{,}4 \times 10^{-6}T^2 - 4{,}6 \times 10^{-5}p - 1{,}89I^{1/2} + 0{,}67I - 1{,}9 \times 10^{-3}I^{1/2}T \tag{7}$$

The equation (5) is for calcium sulfate, Eq. (6) for barium sulfate and Eq. (7) for strontium sulfate. The equation for calcium sulfate may not be accurate because this scale presents three phases.

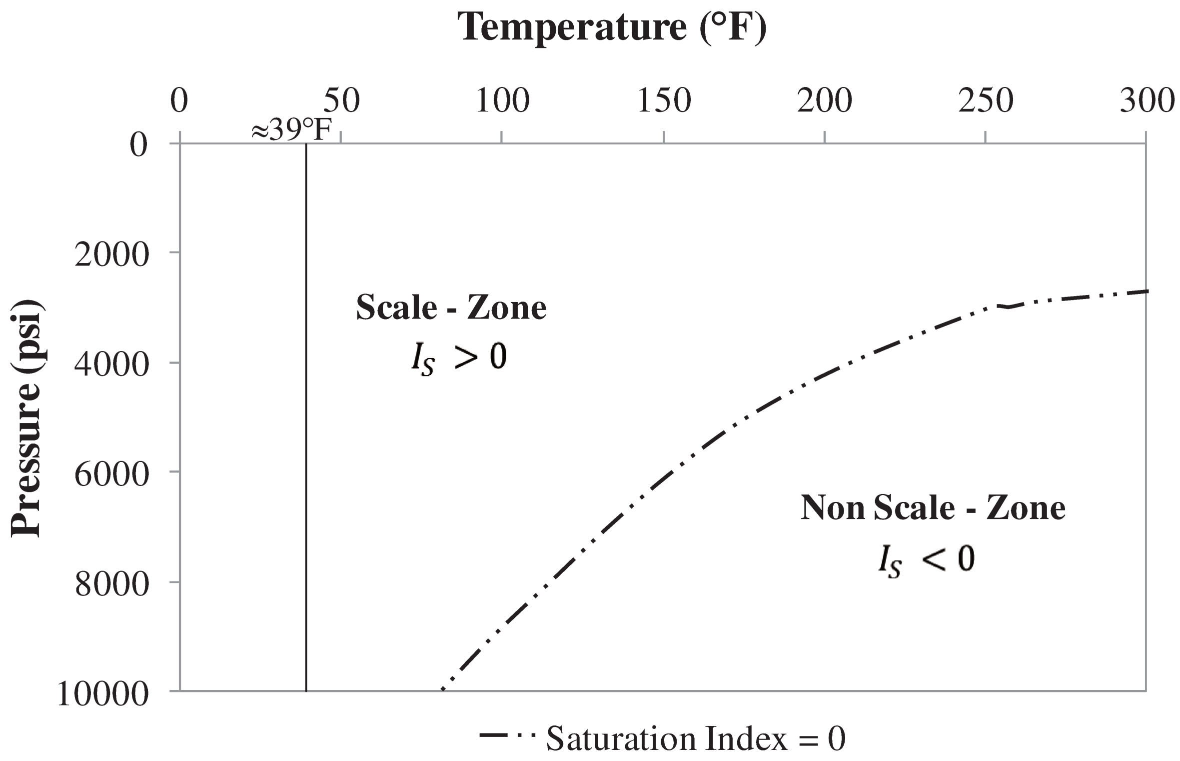

Figure 3. 8 - Scale deposition zones

Figure 3.8 shows the scale zone ($I_S > 0$), non scale zone ($I_S < 0$), and the curve that represents the saturation index equal to zero. This curve can be obtained for each type of scale employing Eq. (4) to (7).

Table 3. 9 - Case studies for scales.

Offshore petroleum region	Field	Scale type	Saturation index	Reference
Gulf of Mexico	Canyon Express	• Calcium carbonate • Calcium sulfate	• 0.44 • 1.10	Yuan et al., 2004

Usually, the maximum saturation index occurs in mixtures containing 50 - 70% of seawater (Rosario and Bezerra, 2001). Table 3.9 shows a case study with scale deposition, in which mixture of waters (formation water and seawater) has the proportion of 50/50 in terms of the volume.

In this case study a prediction of scale deposition during the phase of well design was not performed, then within two months of field production, unexpected scale deposition caused the blockage and resulted in production losses. Therefore the impact of lack of scale prediction may result in an economic challenge during oil production.

In general, the formation water founded around the world presents high levels of 226Ra and 228Ra. The most common NORM is found in barite scales, because NORM unlike other kind of scales does not precipitate directly with sulfate. They usually co-precipitate with barium or strontium (Godoy et al., 1999. Tomson et al., 2003).

In the literature researched, a correlation for saturation index of NORM was not identified; but if the barium sulfate is prevented and properly monitored and controlled, the NORM problems should not occur (Tomson et al., 2003).

NORM problems have been occurring in the North Sea, Gulf of Mexico, and Campos Basin, respectively, as we can see in Fig. 3.2. The big challenge of those offshore regions is the disposal of radioactive materials that can be harmful to humans and the environment. Activities in offshore regions have continuously developed strategies for the management of NORM (Gäfvert et al., 2006; Matta et al., 2002).

- **Naphthenates**

Naphthenate is a salt formed due to reaction between ARN acids (tetra acids with molecular weight above 1200 Dalton) as well as naphthenic acid present in crude oil and alkalis as calcium or sodium presented in produced waters. There are two forms of naphthenates salts: calcium and sodium naphthenates (Oduola et al., 2013). In the present work, reports about calcium naphthenates were found.

The naphthenates formation depends on the pH of the water, which determines the degree of dissociation of the naphthenates acids. Some features help the naphthenates formation: increase of water pH, the production of high CO_2 in connate water, water cuts between 5-50%, significant pressure drop and added heat as the separation process.

In the last years, the crude oil of West Africa has been identified as an acid crude oil, increasing the possibility of production loss due to deposition of naphthenates. As an example, in Gimboa Field the calcium naphthenate was deposited in the separators, bulk oil treaters and hydrocyclones, resulting in a production loss (Junior et al., 2013).

b) Integrity Failures

In the last years, the well integrity has been a big problem in offshore oil wells, because it can affect the oil production, safety, environment, reputation of oil industry and asset value. These situations warned the oil industry to increase the focus in the problem (Corneliussen, 2006; Bourgoyne et al., 1999).

One of the major problems of loss of integrity is the hydrocarbon leakage. If the leakage is not controlled or stopped, it could result in a full blowout. Integrity is related to well components therefore if a well component fails, the well integrity will fail.

For a better understanding of integrity failure it is imperative to define the concept of integrity and different authors defined this term as follow:

The well integrity is defined as a set of solutions to reduce the uncontrolled leakage of formation fluid that flow since the reservoir until surface throughout the life's well cycle (NORSOK D-010)".

Integrity is defined as a continue security function which can fail in any moment, causing uncontrollable leakages of the produced fluid to environment (Corneliussen, 2006).

The well integrity can be defined as a well's capability to keep oil flow under control from reservoir until process facilities, preventing leakage to the environment, using equipment to provide a "fence" or "envelope" denominated as well barriers (Da Fonseca, 2004).

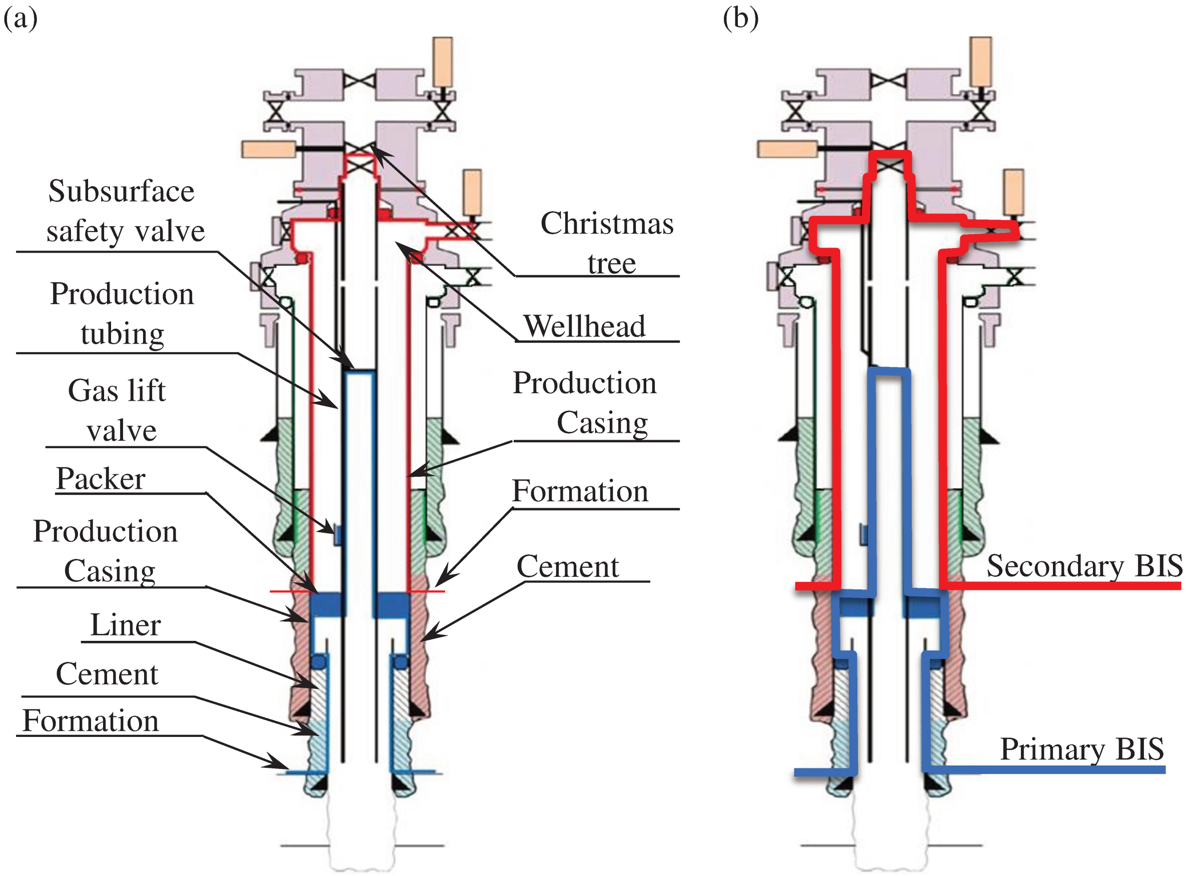

Figure 3. 9 - Barrier integral sets (BIS) for a production well: (a) well barrier components and (b) primary and secondary BIS.
Source: adapted from ISO/TS 16530-2 (2014)

The well barrier components are different in each stage of the well. Figure 3.9 (a) shows the well barrier components for a production well based on ISO/TS 16530-2. This well barrier components form two envelopes based on this norm: primary and secondary. The envelope is known as primary or secondary barrier integral set (BIS).

Figure 3.9 (b) shows the primary BIS represented in blue and secondary BIS represented in red. Primary BIS is the first well barrier envelope and the secondary BIS is the second well barrier both to prevent flow from a potential source of inflow. The secondary BIS operates when primary BIS failure.

In the last years significant well incidents have been reported in Campos Basin, Gulf of Mexico, North Sea and West Africa. The well integrity became a big problem in offshore oil wells, representing a higher production loss, resulting in well intervention. Besides that, sometimes involve loss of lives and environmental damage resulting in huge economic impacts

Based on the literature research, well barrier components that can fail were identified for each maritime region as described below:

- Campos Basin

In the data collection performed by Frota (2003) the well barrier components identified were: flow lines, Christmas tree (X-mas tree), subsurface safety valve, tubing, and casing, being flow lines the component with more failure.

Table 3. 10 - Failure in well barrier component for Campos Basin.
Source: Frota (2003).

Well components	% of failure
Flow lines	11.39
Christmas tree	10.13
Subsurface safety valve	7.57
Production tubing	2.53
Production casing	1.27

Table 3.10 shows the well barrier components with failure for Campos Basin. The main failure of the flowlines is solids deposition, but solids deposition is the main cause of production loss due to flow assurance therefore potential integrity failures and flow assurance production losses are related between then. If flow assurance problems are solved first probably potential integrity failures will not occur.

- The Gulf of Mexico

In the Gulf of Mexico, two studies about well integrity failures were reported in 2004 (Howard, 2004) and 2011 (Saeby, 2011). An average of 13213 wells and a percentage of failure of approximately 58 % was reported. The reliability of this well for one year was approximately of 56%. In both cases the main cause of integrity failure was the connection tubing.

- The North Sea

The North Sea reported four large studies about integrity failures: 2006 (Vignes et al., 2006), two in 2011 (Vignes, 2011; Feather, 2011) and finally in 2013 (King and King 2013).

An average of 1955 wells was reported in these four studies with a percentage of failure of approximately 20%. Considering a period of ten years of oil production these wells have approximately 10% of reliability to avoid failures. The low reliability is due to problems in connections (production tubing and casing), cement, and annular safety valve.

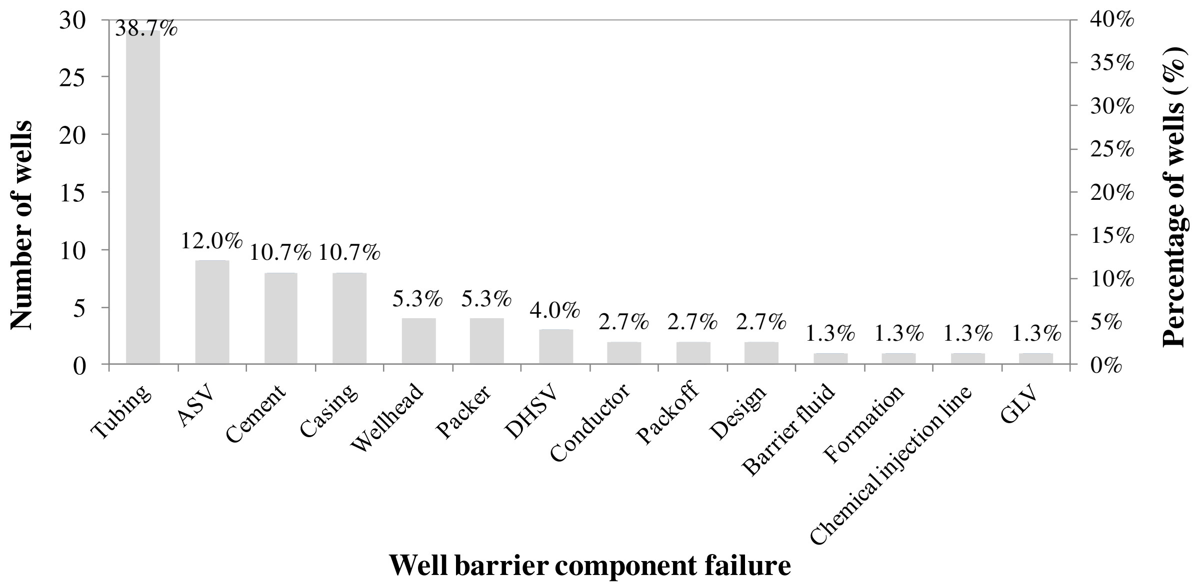

Figure 3. 10 - Number and percentage of wells with fails in well integrity.
Source: Vignes (2011).

Figure 3.10 shows the percentage of wells that had failures in the well barrier components. This study was carried out in the North Sea for offshore oil wells; all of these wells resulted in well interventions (Vignes, 2011).

- West Africa

West Africa reported problems such as: subsurface safety valve (SSSV) failures and minor leaks on X-mas tree and well components. However, it was identified in just one field because in the West Africa we cannot find many studies and reports about this topic (Ebitu et al, 2011).

Table 3. 11 - Well barrier components that can fail.

Primary Barrier Integral Set	**Secondary Barrier Integral Set**
Production casing Production packer Gas lift valve Production tubing Subsurface safety valve	Production casing Cement Wellhead Christmas tree

Table 3.11 shows the well barrier components that can fail for the primary and the secondary BIS. According to Fig. 3.9 (a) not all of the components presented in the four maritime regions are part of the barrier integral set (BIS) of a production well.

Based on Fig. 3.10 and Tab. 3.10 the component with more percentage of failure is production tubing. Also is demonstrating that tubing fail since the first year of oil production until 29 years after the production. Therefore primary BIS fail more than secondary BIS.

Formation is also part of BIS, but Da Fonseca (2012) made a statement saying that formation not fails during well production. So it was not considered as a failure component.

However, the formation was considered in the analysis for the last phase of the well's life cycle: the well abandonment. The well abandonment can be temporary or permanent. In both cases, a well barrier component for primary and secondary BIS is the formation (NORSOK D-010, 2013).

In order to obtain a well abandonment that can be performed by a light workover, the formation should be cemented since the initial phase. If this step is not performed, during the well abandonment will be necessary to pull the tubing string to perform the formation cementation resulting in a heavy workover.

Once identified the main well barrier components that can fail during the well production, is necessary identified the main type of failure that lead to the well intervention as follow each well barrier component will be described:

- **Subsurface Safety Valve**

Also known as Downhole Safety Valve (DHSV), is defined by API 14A as a device that prevent uncontrolled well flow when is closed (API 14A, 2005).

In fixed platforms the SSSV is installed 30 meters below mud line, and in a subsea well is located 10 meters below mud line (De Paula and De Lima Garcia, 2002).

There are two main types of SSSV: Wireline Retrievable (WR-valve) and Tubing Retrievable (TR-valve). WR-valve is installed and retrieved by wireline operation. This valve reduces the ID (tubing), being difficult perform a through tubing operation. TR-valve is an integral part of the tubing string, unlike to WR-valve, this type of valve not is retrieved to perform a through tubing operation, but to replace a valve the tubing has to be pulled. For both valves, two different closing principles are used: ball and flapper, and can be equalizing or non-equalizing.

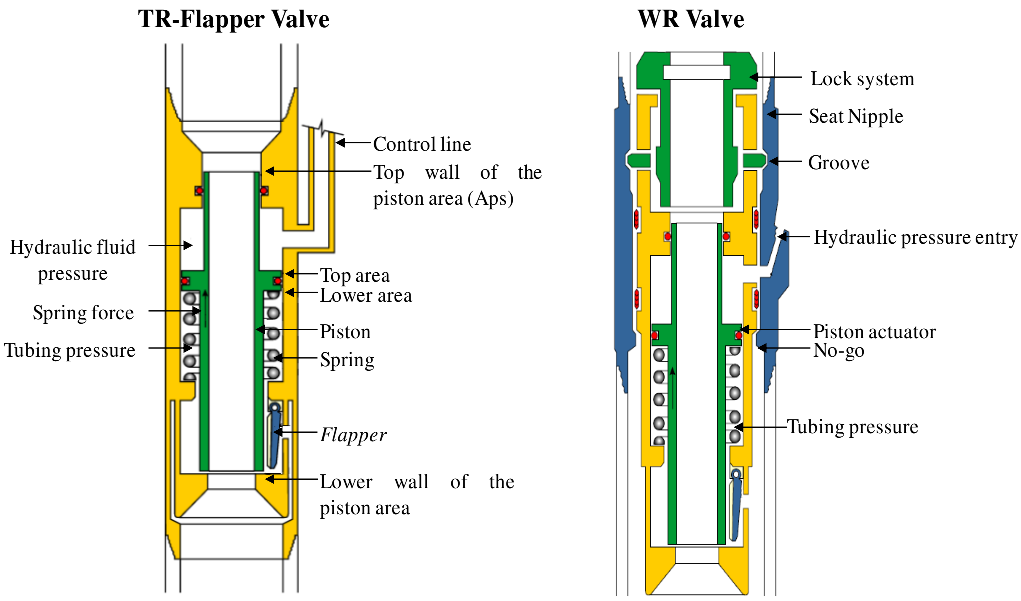

Figure 3. 11 - Left: TR-valve and right: WR-valve.
Source: Miura (1998).

Figure 3.11 shows the TR – Flapper valve and the WR valve (flapper or ball). In accordance with Rausan and Vatn (1998) and Seime (2012) the failure modes to SSSV or DHSV are:

- Fail to close on command (FTC) this failure is caused by corrosion/erosion, improper valve operation and plugged control that result in a damage in the pistons and/or flapper/ball. This failure can be detected during testing or when is necessary close the valve.

- Leakage through valve in closed position (LCP) is an uncontrolled leakage across the valve greater than API RP 14 B, this can be due to damage in flapper/ball or scratches in the seat sealing area that may result of wireline operations. This failure can be detected during testing or by a pressure drop in control line.
- Fail to open on command (FTO) occurs when have a leakage in control line system or sever mechanical damage in the valve that result in the non open position, usually is detected immediately.
- Premature closure of the valve (PC) results due to an unintentional relieve of hydraulic pressure that can lead to a ruptured control line or a leaking seal, usually is detected immediately.
- Leakage in control line (LCL) usually is due to packing failures that result in a backflow of oil/gas in the control line leading to a leakage.
- Fail to hold in nipple (FTH) is only for WR-valve, results of an improperly set valves or locking mechanism. It is detected during testing or abrupt control line pressure drop.
- Fail to set in nipple (FSN) only for WR-valve.

Once the failure modes of subsurface safety valve are known, we must identify the main failure that result in a production loss.

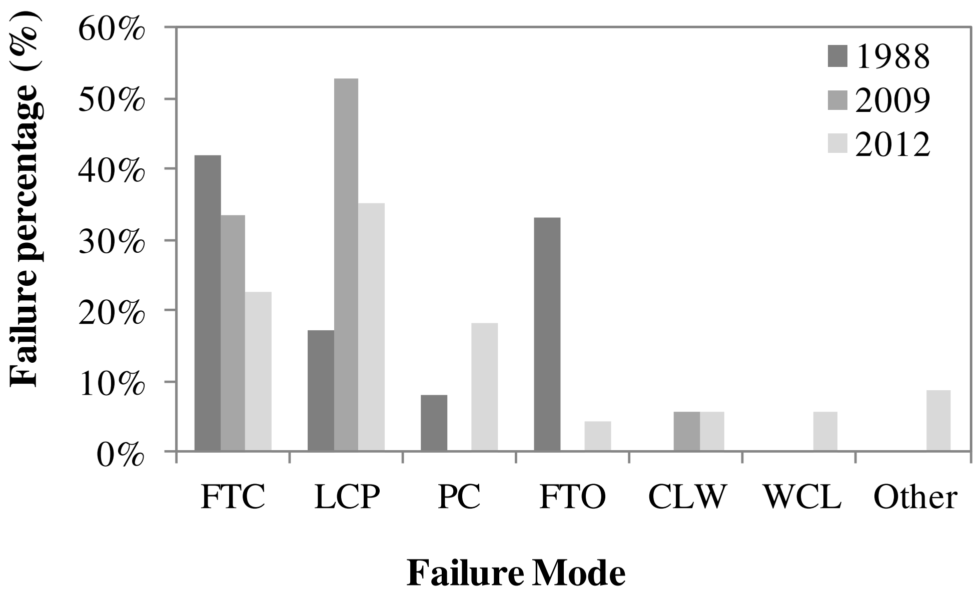

Figure 3. 12 - TR-valve failure modes

Figure 3.12 shows the failure modes of TR-valve. A study by SINTEF in 1988 for 26 wells during a period of four years for North Sea identified four types of failures modes:

FTC, LCP, PC and FTO, of which FTC, LCP and PC are considered as critical failures, being the main failure mode fail to close (FTC) (Lindqvist et al., 1998; Rausand and Vatn, 1998).

In 1993 another study confirmed this affirmation. The control lines maintains the valve in an open position. The control lines are vulnerable to crushing and clogging (solid contamination, bacteria growth and internal corrosion) resulting in FTC.

Some possible treatments are: reduce contamination, package and DHSV with double control line (control line with redundancy).

A treatment proposed by PETROBRAS was control the DHSV by annular pressure that is without control line (Moreira, 1993).

Another study by SINTEF in 2009 stated that the main failure modes were: FTC, LCP and WCL, being the main failure the leak in close position (LCP) (Seime, 2012).

Again in 2012 was confirmed that LCP was the main failure in DHSV. This study was performed in North Sea involving 2600 TR-valves flapper-type.

For LCP we can install a redundancy in valve (TR-valves in series) is the same method adopted in North Sea wells. This solution saves money because only a heavy workover will be necessary if both valves fail (Corneliussen, 2006).

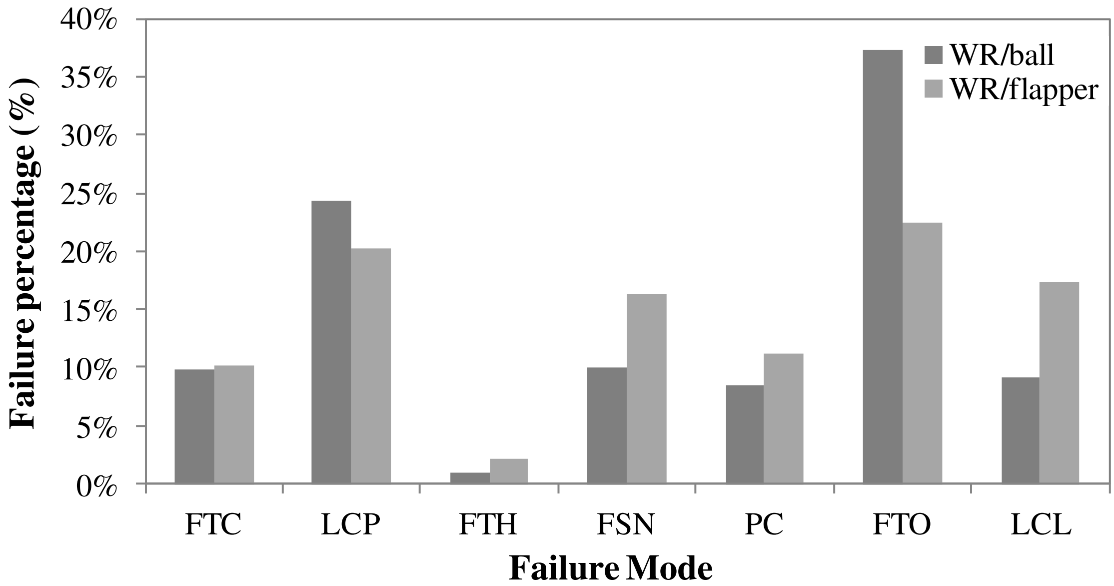

Figure 3. 13 - WR-valve failure modes

Figure 3.13 shows the study performed for the two types of WR-valve: WR/ball and WR/flapper by SINTEF. In opposite to the TR-valve, the WR-valve presents more quantity of failure modes. Note that the ball valve has more percentage of failure than the flapper valve. Then the use of WR-valve and ball valve type are not recommended.

Studies to verify the necessity of install a DHSV in a subsea well were performed. In the same report was identified may be the DHSV can be substitute by the x-mas tree. As proved to remove the DHSV can bring consequences such as: economic consequences and blowout risk can be the result (Vesterkjaer, 2002).

- **Production Packer**

The production packer is a sealing device, and a standard component of a completion string in a well. It forms a seal between tubing and annulus during production. It is run with wireline or production tubing, is usually placed close to the bottom end of the production tubing and above the top of the perforations in a well.

The packer is part of the primary BIS, protecting the well of undesirable produced fluids; therefore it is extremely important that the production packer is set up properly in the casing/liner (Torbergsen et al., 2012).

Packers can be retrievable or permanent. A permanent packer can be removed from the wellbore only by milling. The performance of a permanent packer is better than a retrievable packer. Retrievable packer may or may not be resettable, but removal from the wellbore normally does not require milling.

The International Organization for Standardization (ISO) and the American Petroleum Institute (API) have created a standard for packers. There are three levels, and six grades (plus one special grade) for design verification. The levels are Q_3 to Q_1; with grade Q_1 outlining the highest level of inspection and manufacturing verification procedures and Q_3 carry the minimum requirements. The grades can vary from V6 to V1, being V0 the special grade:

- V6: Supplier/manufacturer-defined
- V5: Liquid test
- V4: Liquid test + axial loads
- V3: Liquid test + axial loads + temperature cycling
- V2: Gas test + axial loads
- V1: Gas test + axial loads + temperature cycling
- V0: Gas test + axial loads + temperature cycling + special acceptance criteria (V1 + zero bubble acceptance criteria)

The use of packers V3 - V6 results in challenges to the industry because they are not qualified for being gas-tight. If the well has a gas lift system or will be exposed to a gas medium the use of V2 - V0 is recommended being V0 the most reliable (Blaauw, 2012).

- **Production Tubing and Casing**

The production tubing is the normal flow conduit used to produce reservoir fluid; this is made up of typical approximately 12 m long tube connected by joints and is assembled with other completions components to make up the producing string.

The production tubing selected for any completion should be compatible with the wellbore geometry, reservoir production characteristics and the reservoir fluids also must be adequately strong to resist loads and deformations associated with production and workovers

The production casing is used to isolate production zones and in the same place the primary completion components are installed (Schlumberger, 2015).

The connections are a critical point to production tubing and casing, because can be a possible potential leak point. If a connection is leaking, it could compromise the tubing string and losing the well integrity, to follow a brief explanation of the two major types of connection used in an oil well:

- API connections, are designed with tolerances specified by API norms (Spec. 5B, 5C e 5C3), this result in a problem, because the connections have a certain limit of operation. In case of leak, they need a certain compound to seal the leak path, but this compound deteriorates over time, making the connection more likely to leak (Blaauw, 2012)
- Proprietary connections, also called premium or special connections, are designed and manufactured by commercial manufactures with capability of handling greater depths with higher pressures (> 4930 psi) and temperatures (> 250 °F), sour environment, gas production, steam well and a large dogleg (horizontal well). The price is five times the cost of API connections. These connections are used to achieve the gas-tight sealing reliability and 100% connection efficiency (Petrowiki, 2015b; Blaauw, 2012).

In 1980 and 1990 Mobil E&P Technical Center (MEPTEC) was performed a research of the tubing leak; they discovered that the main cause of fail was due to connections.

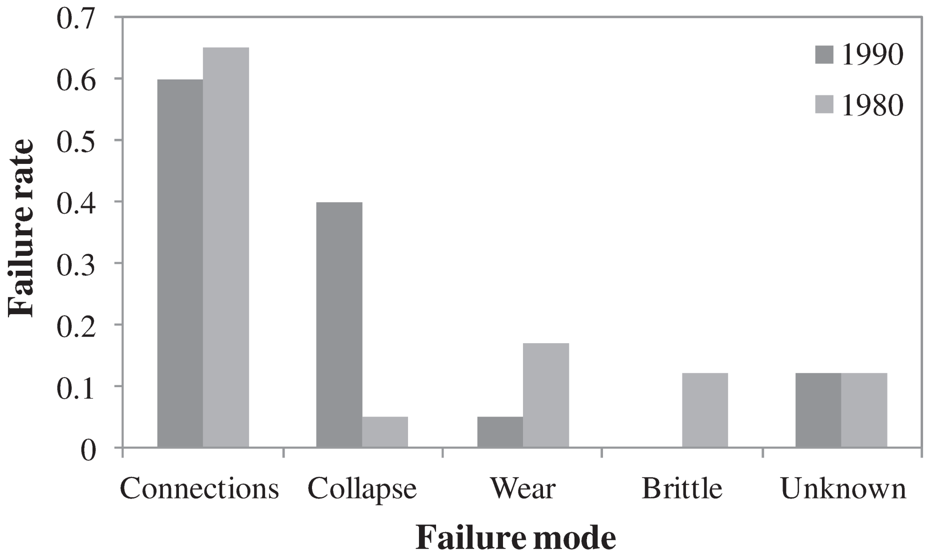

Figure 3. 14 - Production casing and tubing failures.
Source: Schwind et al. (2001)

Figure 3.14 shows the fail rate as a function of failure mode for production tubing and casing. It is important to note that connections have been the main cause of failure since 1980. Collapse has increased since 1980 to 1990 that could be due to the tubing corrosion, but accordingly with this research this increase was due to water depth increase and the tubing was not designed in an adequate way for new forces. The other causes as wear and brittle decrease and unknown failures were equal (Schwind et al., 2001)

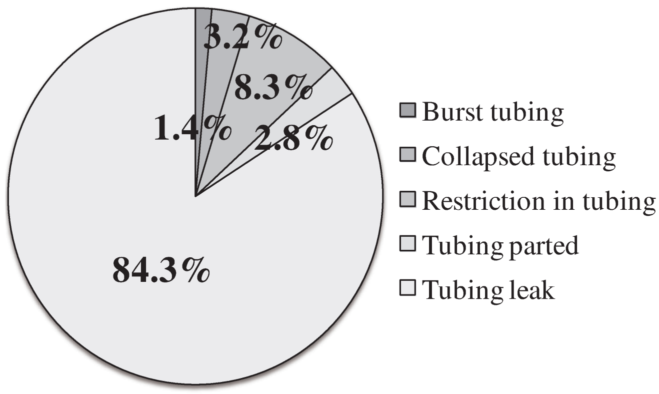

Figure 3. 15 - Production tubing and casing failures.
Source: Molnes (1993).

Figure 3.15 shows another research carried out in 1993 for tubing and casing failures. Failures of casing were collected and analyzed, obtaining a total of 216 failures. The main cause of failure was casing leaks due to connection performance. The other failure modes are related with corrosion inside/outside, combination of high loads, and blockage due to solid deposition.

In 2001 the main cause of failure were still the connections (90%); 55% fail in API connection (API 8 round) and 45% in non-qualified Premium connection.

In 2013 the premium connection due to be modern connection, had a good procedure attachment. The metal-metal seal managed eliminate the leak problem in connections.

Table 3. 12 - Case studies for connections.
Source: King and King (2013).

Date; Well completion number	Connection number	Connection type	Leak percentage for well completion (%)
1961-1964; 1,000	300,000	API 8-round	56.7
1961-1964; 822	253,000	Connection early premium	Average 40.0
1990-1998; > 180	>19,500	Premium	0.0

Table 3.12 shows this improvement, concluding Premium or Proprietary connection managed zero leakage (King and King, 2013).

The Premium connections are mainly recommended for wells with possibility of gas production or that has a gas lift system, if the well does not have a gas lift system API 8-round are recommended.

- **Gas Lift Valve**

The gas lift valve is used in the oil well to allow the injection of gas as a secondary method of recovery. The most used valves are the named King valve that allows the gas pass through to the tubing, and prevents the oil pass to the annulus. The most common valve of this type is the wireline retrievable valve that is inserted in the completion string in a side-pocket mandrel.

The main failure mode is the description when the flow goes to annulus due to non-lock check valve it means FTC, this could be (Gilbertson, 2010; Holand, 2014):

- Detritus blockage the main valve or check valve.
- Incorrect injection pressure
- Fole down pressure and the valve remain open.
- Corrosion of valve haste (main valve or check valve)

Based on a research performed in thirteen wells in the North Sea, gas lift valve reported fifty-two failures due to deposition of scales resulting in fail to close.

The Gulf of Mexico between 1995 and 2010, reports 1,500 case studies in which the causes for fire in the platform were due to gas lift valve failure.

A way to prevent this problem is avoid the formation and deposition of scales, detritus and solids in the valve. Both treatments are recommended: improve the gas lift performance it means modify the design and increase the reliability of the valve and change the valve with slickline operation during the oil production (Holand, 2014).

- **Wellhead**

The wellhead is the termination point of casing and tubing string, it provides a suspension point and pressure seals, it can be located in land, platform or in subsea.

The main point of leakage in the wellhead is the X-mas tree cavity; this is the connection between the X-mas tree and the WH. The leak does not affect in the annulus pressure, therefore is difficult to detect. Sometimes the potential leakage not is recent (mechanical fails in the seal); it may be due to hydraulic residues which cause pressure variation. The main leaks can be due to:

- Design capabilities exceed in operation
- Dirt and hydraulic residues
- Inadequate clean
- Problems related vibration
- Pressure test in DHSV
- Wellhead design fail
- Properties of elastomeric seal (Ohm, 2013)

In the North Sea the increase in gas leakage frequency in wellhead seals became a research topic for several oil industries in Norway (Statoil, Shell and ConocoPillips).

The main research due to wellhead leakage was for Oseberg East field for three wells that presented problems in C1 that can be detected by “sniff test” in a daily routine. This problem may be solved avoiding SRL seals and using CAHN seal of Cameron or a double tandem seal based on these companies’ recommendation.

In another field a little gas leakage in wellhead in the North Sea was reported. This could happen due of lack of practice in testing the seal after installation. The leakage in wellhead can occur between two or three years after the production with gas lift system started or because the seal is not optimized. Some practical recommendations are:

- before the beginning of production the seal must be tested. If the test is negative the well must be prepared for an intervention that can be the use of chemical sealants like “Sealtite”;
- the continuous monitoring of wellhead;
- installing a pressure alarm to alert when the defined pressure exceed;
- draining the hydraulic oil during installation or testing;
- adequate clean of seals;
- depressurizing the C1 cavity before DHSV test;
- replace the fluid in WH cavities by nitrogen;
- not to exceed the design capacities;
- coiled tubing (CT) operations.

Although the wellhead reported leakage during production well, this can be considered as negligible, because does not exist risk of explosion and/or fire (Ohm, 2013).

As mentioned above, as in the North Sea as Gulf of Mexico the dry completion is presented it means we can use the study for wellhead as example for Gulf of Mexico.

In Campos Basin and West Africa so far, there are not available reports about this type of failure. This can happens because is difficult to observe a leakage in wet completion due in higher depth.

- **Christmas tree**

The wet Christmas tree is a submerse equipment that controlled the production/injection of flow in the well, the components are gate valves, control lines and a control system. The dry x-mas tree has the same purpose of wet X-mas tree. The only difference is the location (the dry x-mas tree in platform and the wet x-mas tree in subsea).

There are standards to maintain security operations and avoid accidents as: API 6A, API 17D, ISSO 13628-4 and ISSO 10423:2009. The X-mas tree is composed by seven valves (Albernaz, 2005):

- Production Master Valve (PMV- M1)
- Annulus Master Valve (AMV – M2)
- Production Wing Valve (PWV – W1)
- Annulus Wing Valve (AWV – W2)
- Crossover valve (XOV)
- Production Swab Valve (PSV – S1)
- Annulus Swab Valve (ASV – S2)
- Annulus isolation valve (AIV)

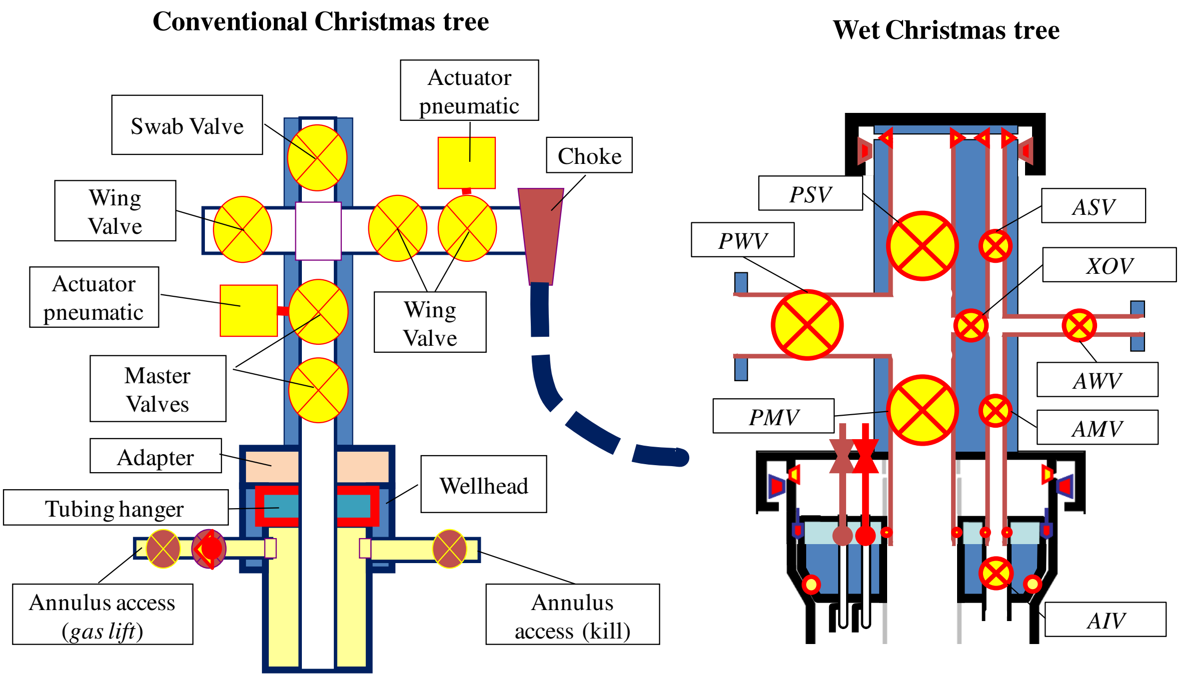

Figure 3. 16 - Left: Conventional Christmas tree and right subsea Christmas tree
Source: Miura (2015)

Figure 3.16 shows the conventional X-mas tree or dry tree and the wet X-mas tree.

In a X-mas tree the main failure is in the gate valves. A study to find the main critical failures in the gate valves was performed, and the result was:

- Fail to close (FTC)
- Leak in close position (LCP)
- External leakage (EXL)

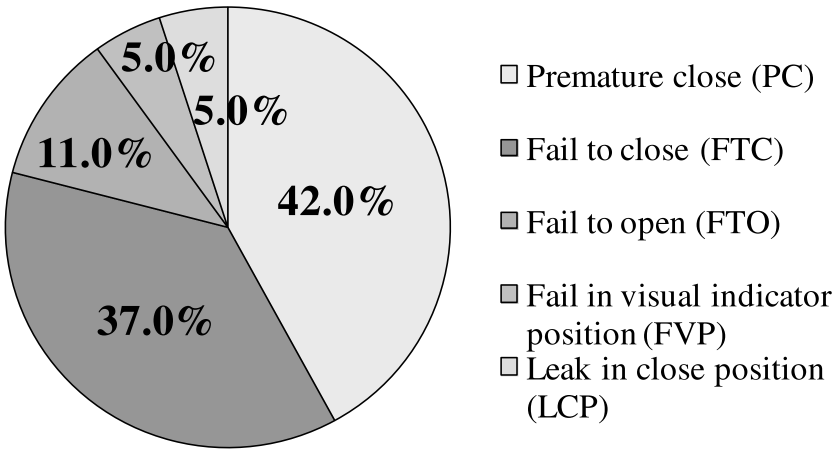

Figure 3. 17 - Failure modes for gate valves - master and wing.
Source: Albernaz (2014).

Figure 3.17 shows the percentage of failures, being the main failure “fail to close (FTC)” followed by “leak in close position (LCP)” concluding that 42% of the failures in the gate valve were critical failures.

Table 3. 13 - Relation between failure mode and water depth.
Source: Alves (2012).

Failure mode	Water Depth		
	Shallow	**Deep**	**Ultra-deep**
Fail to close	Low	Mid	High
Leak in close position	Without variation		
External leak	High	Low	Mid

Table 3.13 shows that the failure mode depends of the well depth: shallow, deep and ultra-deep water. Note that in fail to close (FTC) there are increments of the failure rate regarding water depth. In leak in close position (LCP) the failure rate is practically unaffected by depth variation. The external leak (EXL) is higher in shallow water due to the interaction of external hydrostatic pressure, because it is more expected little bubbles in shallow water than in ultra-deep water.

Also the failure in the valve may depend on the operational years. For example, a X-mas tree that was installed in 1980 presented external leak and in recent project (2000) the fail type was fail to close.

Concluding that the main failure in deep water and ultra-deep water is “fail to close” and for shallow water “external leak” (Alves, 2012; Stendebakken, 2014).

In subsea wells as well as in wellhead, the failure in X-mas tree is difficult to detect. The possible prevention treatments are: perform a valve test before to start the oil production, clean the valve periodically to avoid solid deposition and routine inspections. The best option in case of failure during well production is use a ROV (Alves, 2012).

- **Cement**

Since the beginning of oil industry, the cement was used to isolate the formations; a primary cementation with faults may lead to gas migration through cement. During the well production, the cement is submitted to higher pressures and possible gas migration. If the cement is not bond to the formation the result can be a leak or blowout (Etetim, 2013).

The problems during production well due to inadequate cementation could be:

- Micro-annuls formation interface casing/cement
- Bond break cement/formation
- Fractures through cement
- Cement corrosion
- Cement degradation

The main problem in cementation is a poor or inadequate primary cementation job that may be due to bad well cleaning, cement circulation, casing centralization or login test (Vignes, 2011).

In order to perform a good cementation, some factors may be considerate (Blaauw, 2012):

- When a circulation of cement begins, the wells should be cleaned, because solids residues may increase the pumping pressure due to friction resulting in formation fractures.
- Adequate use of chemical treatments against a corrosive environment.
- Perform a cement evaluation.

Another solution proposed was the use of sealants instead of cement such as: Thermaset, Sandaband Settled barite, Ultra Seall, Fly ash, Ground, Silica, Camseal. However no material is better than cement (Etetim, 2013).

Based on Vignes (2011), Blaauw (2012) and King and King (2013) perform a good primary cementation is the main solution to avoid cement problems.

A symptom to identify the problems related to cement, production casing and tubing during production phase is denominated as sustained casing pressure (SCP), which is defined as the pressure of the casing that is measure after a depressurization due to flow infiltration thought tubing, casing or cement (Rocha-Valadez, 2014).

Table 3. 14 - Case studies of failures in offshore petroleum regions.

Year	**Solution**	**Offshore petroleum region**	**Cause**	**Reference**
2005	A sealant was displacement by squeezing	Campos Basin	Leak in X-mas tree	Rodriguez et al., 2005
2008	Dual control line for the future wells	Gulf of Mexico	Fail in close position SSSV	LeBoeuf et al., 2008
2010	A well intervention was need to replace the valve	North Sea	Control line failure	Barratt et al., 2010

Table 3.14 shows some case studies about well integrity failures in the offshore petroleum regions, in which a well intervention operation was needed.

c) Reservoir problems

Each reservoir is composed of a unique combination of geometric form, geological rock properties, fluid characteristics, and primary drive mechanism.

Reservoir problems also constitute a big production loss because the solutions to avoid or mitigate not always are effective.

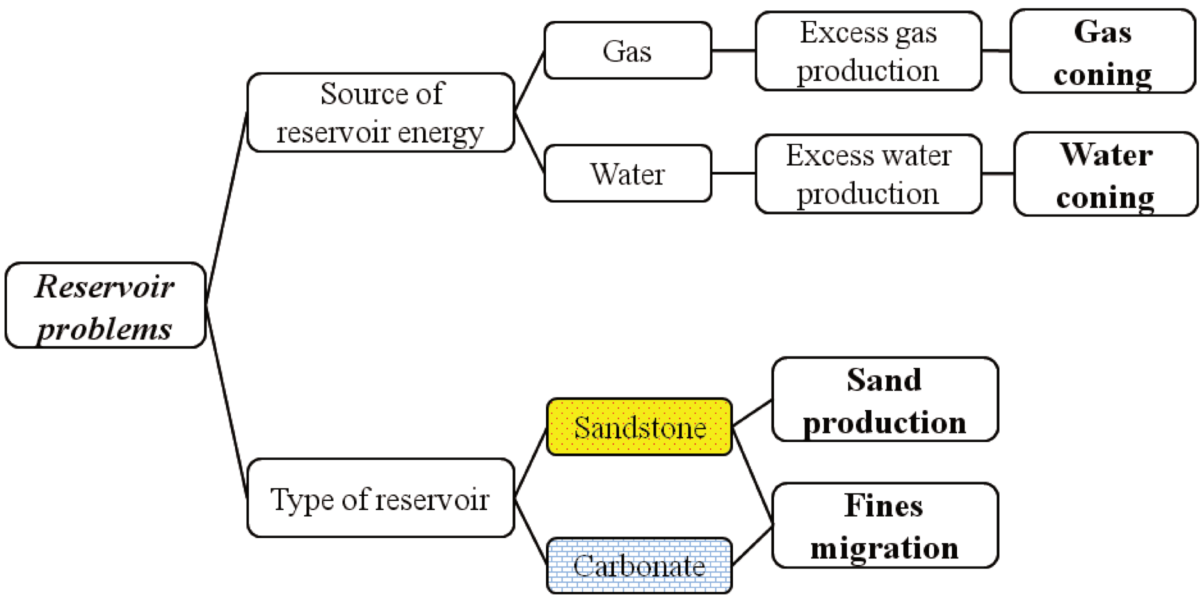

Figure 3. 18 - Causes of production loss due to reservoir problems

Figure 3.18 shows the causes of production loss due to reservoir problems and the main factors for the occurrence. The main factors for the reservoir problems are the energy reservoir source (water and/or gas) and the type of reservoir.

The energy source age in primary and secondary recover:

- In primary recover the drive reservoir mechanism are gas cap, solution gas, water influx and combined mechanism, for the first two gas is the energy source, for the third is water and finally for the fourth water and gas are combined.
- In secondary recover, the methods that inject water or gas, such water injection or gas injection may cause problems during production phase.

For the energy reservoir source (water or gas) the excessive water and gas production are the main causes of production loss and for the type of reservoir the main causes are fines migration and sand production.

- **Excessive water and gas production**

The excessive water production is considered as the major technical, environmental, and economic problem associated with oil production. The water production represents the largest waste stream because the environmental impact of handling, treating and disposing the produced water affects the profitability of the production well (Aminian, 2005).

Coning, fingering, fractures, barrier breakdowns, channels behind casing and others are some reasons for the excessive water and gas production being the coning the main cause (Baker, 1991; Seright et al., 2003).

- Water and gas coning

Coning is the movement of reservoir fluids as water (upward) or gas (down) infiltrates the perforation zone in the oil well. The water comes from water drive and gas from gas cap or solution gas; and both come together from combined mechanism.

In order to originate the water or gas coning two forces are necessary: gravity and viscous. The first one arises from fluid density differences and the second one from pressure gradients associated with fluid flow through the reservoir. Usually, coning is associated with high production rates (Ahmed, 2001).

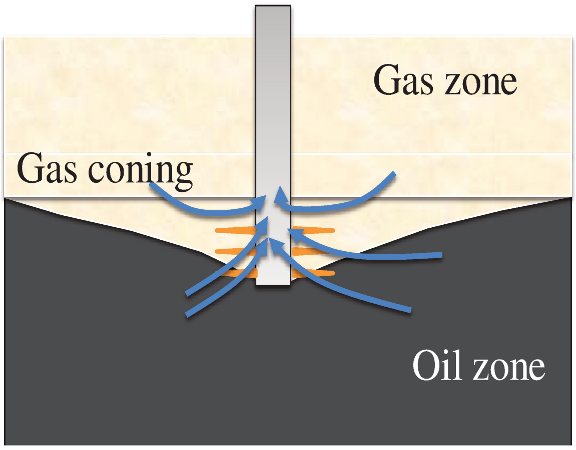

Figure 3. 19 - Gas coning

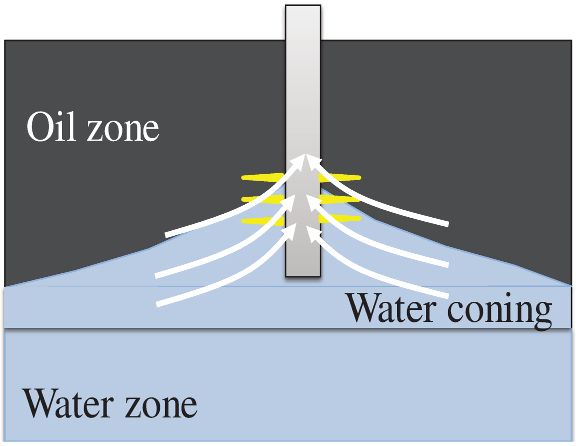

Figure 3. 20 - Water coning

Gas and water coning are shown in Fig. 3.19 and Fig. 3.20 respectively. The term coning is used because the shape of the water or gas movement when a well is producing is an upright cone (water coning) or inverted cone (gas cone) (Petrowiki, 2015 c).

A common practice in the industry to reduce water and gas coning is to produce the wells at or below the critical rate, which is defined as the maximum allowable oil flow rate that can be imposed on the well to avoid a cone breakthrough (Ahmed, 2001).

If the well produces above its critical rate, the cone will breakthrough after a given time period denominated as “time breakthrough” and for the present work represents the needs of a well intervention.

Several authors, such as Muskat and Wyckoff (1935), Chaperon (1986), among others have proposed correlations to determine the critical rate and time breakthrough. The correlations can consider homogeneous or heterogeneous systems, mobility, relative permeabilities, drainage radius, dimensionless functions and others.

In the present work, the first practical method for oil wells proposed by Addington (1981) and Yang and Watternbarger (1991) were considered, in case of gas and water coning respectively.

✓ Water coning

Yang and Watternbarger (1991) presented correlations for vertical and horizontal wells to determine the critical rate and breakthrough time for the water coning. The analysis for water coning through numerical simulation was performed. An empirical coning correlation based on flow equations and regression analysis was developed, being similar to Addington’s gas-coning correlation.

The assumptions of the correlations were: homogeneous but anisotropic reservoir, water-oil mobility ratio smaller than five or non-dominating viscous forces, formation is underlain by a recharged bottom aquifer, only one perforation interval, no flow across the outer boundary, only water and oil are present at reservoir conditions and capillary pressure is ignored.

$$q_c = \frac{k_h k_{ro} h^2 \Delta\gamma}{\mu_o} q_{cD} \tag{8}$$

$$t_{bt} = \frac{\left(N_p\right)_{bt}}{q_t} \tag{9}$$

Equation (8) is for calculate the critical rate and Eq. (9) for breakthrough time. Both equations were applied to the Sw-17, which is an oil well with water influx as the drive mechanism reservoir.

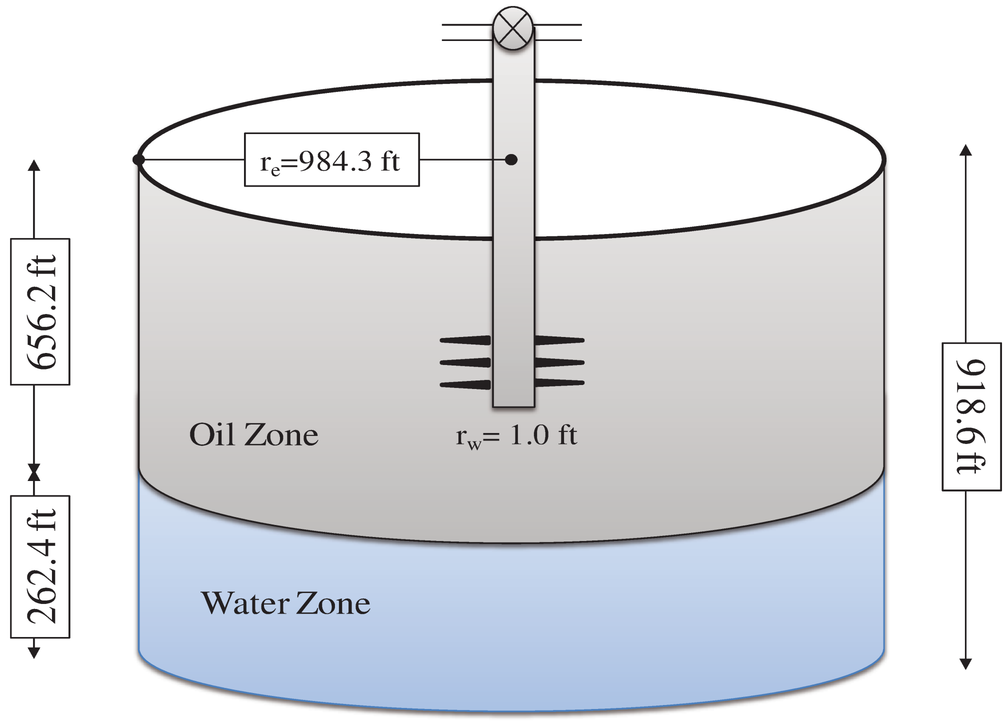

Figure 3. 21 - Reservoir design

Figure 3.21 shows the heights of the well and the dimensions based on data presented by Carrillo (2008). The characteristic is a sandstone reservoir with a poorly sorted formation, containing two zones of fluids (hydrocarbon and water).

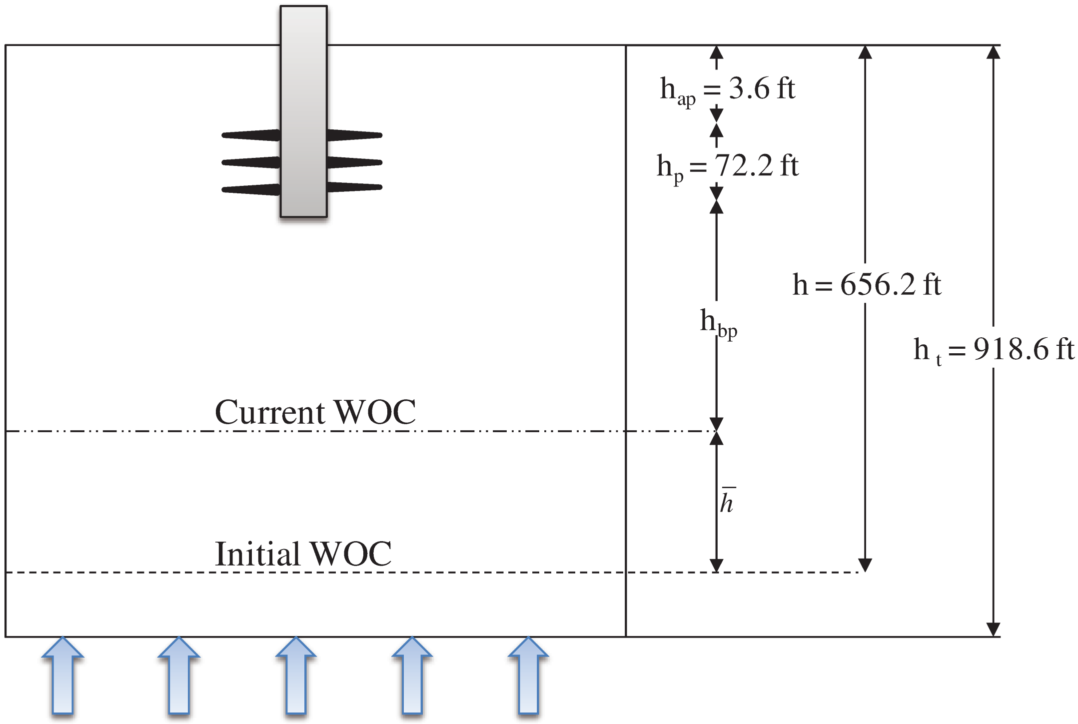

Figure 3. 22 - A sketch of well configuration

Figure 3.22 shows a sketch of the reservoir: total formation thickness - h_t, initial oil formation thickness - h, perforations length - h_p, oil column height above perforations - h_{ap}. The average oil column height below perforations - h_{bp} and the height of water advance $\bar{h}$ are unknowns.

Fluids and rock properties

The fluid and rock properties presented by Pinto et al. (2001), Bruhn et al. (2003), Bagni (2001) and Nilsen et al. (2007) were employed.

$$k_{ro} = (1 - S_w{}^*)^2 \left(1 - S_w{}^{*\,1.5}\right) \tag{10}$$

$$k_{rw} = (S_w{}^*)^{3.5} \tag{11}$$

$$S_w{}^* = (S_w - S_{wi})/(1 - S_{wi}) \tag{12}$$

In order to calculate the relative permeability, the equation presented by Wyllie (Honarpour et al., 1986) is used. Equation 10 calculates the oil relative permeability, Eq. 11 the water relative permeability and Eq. 12 the irreducible water saturation.

Table 3. 15 - Relative permeabilities.

Sw	Sw*	Kro	Krw
0.10	0.00	1	0.00
0.20	0.11	0.70	0.00
0.30	0.22	0.47	0.01
0.40	0.33	0.30	0.04
0.50	0.44	0.17	0.09
0.60	0.56	0.09	0.17
0,75	0.72	0.02	0.38

Table 3.15 present the results after applied the Eq. (10) to (12). The necessary data for this calculus were the initial irreducible water saturation (Swi = 0.1) and residual oil saturation (Sor = 0.25). The Sor was used to calculate the last irreducible water saturation (Sw = 1 – Sor).

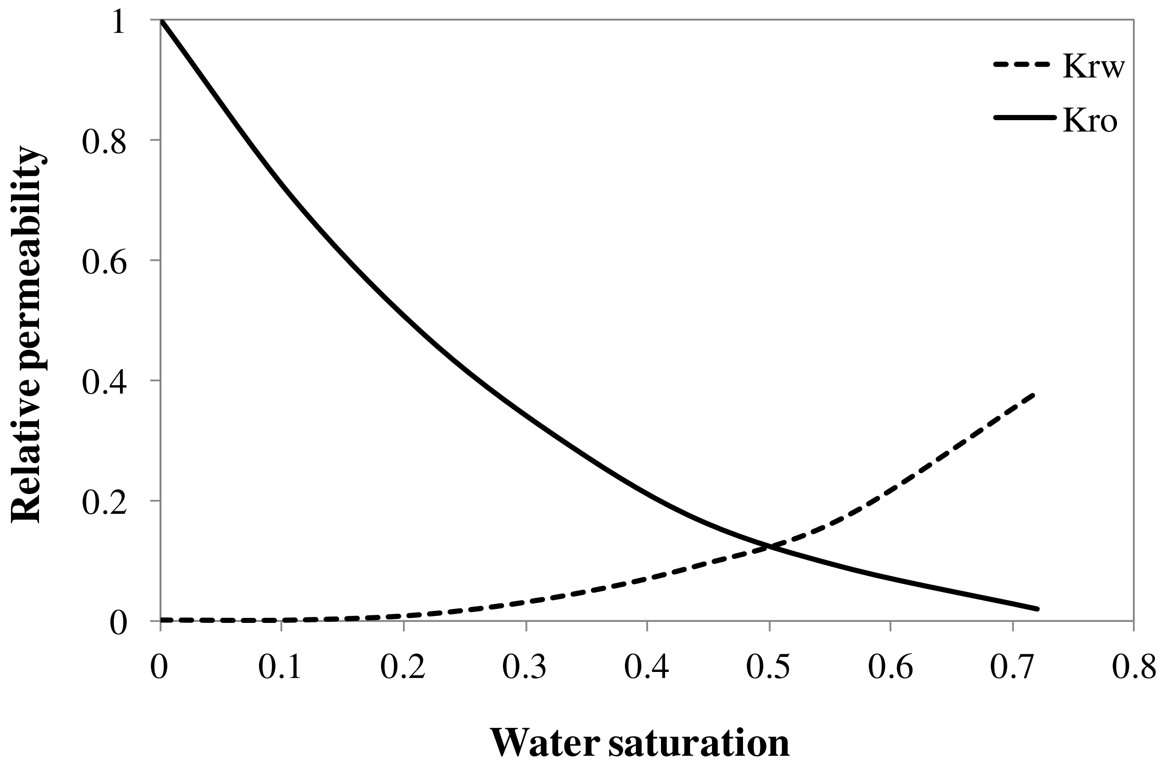

Figure 3. 23 - Relative permeability curve

Figure 3.23 shows the relative permeabilities for water (Krw) and oil (Kro) as function of water saturation (Sw). The data presented on Tab. 3.15 are plotted in this figure.

Table 3. 16 - Fluid and rock properties.

Data set		Units
μ_o	4	cp
μ_w	1	cp
φ	0.3	
kv/kh	0.2	
°API	20	
γ_o	0.405	psi/ft
γ_w	0.433	psi/ft
Bo	1.4	stb/rb
kv	2,000	mD

Table 3.16 presents other fluid and rock properties such as water and oil viscosity, density, porosity, etc for calculation.

Solving the equation

Table 3. 17 - Additional data of well Sw-17.

Total oil production rate at reservoir	8,806	Rb/d
Total oil production rate	6,290	stb/d
Cumulative oil production (9 days)	56,610	stb

Table 3.17 shows the total oil production rate at reservoir and surface conditions and the cumulative oil production. These data are necessary in order to calculate the critical rate and the breakthrough time.

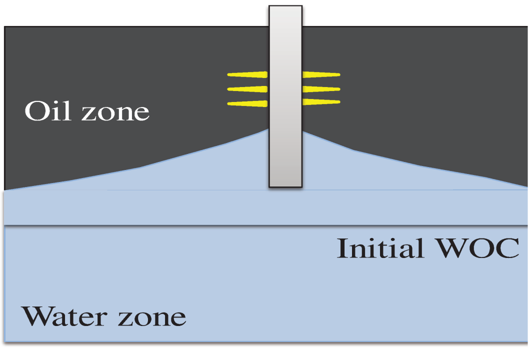

Figure 3. 24 -Water coning (t=29 days)

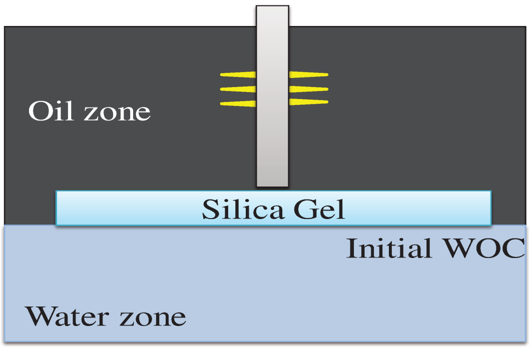

Figure 3. 25 - Water coning with silica gel(t=29 days)

Figure 3.24 shows the water breakthrough for well Sw-17. The critical rate (q_c) at these conditions was 8,109 stb/d and the need of a well intervention was 29 days. An injection of gel or sealants can be applied before the production to avoid this early well intervention. After this operation, the critical rate was 313,965 stb/d and the need of a well intervention occurred in 2.5 years as shown in Fig 3.25.

✓ Gas coning

The correlation presented by Addington (1981) for the critical rate was performed based on field data and a sensitivity analysis correlation for various reservoir and fluid properties was carried out. Some assumptions of his model were: the well receives little or no aquifer support and the reservoir had homogeneous horizontal and vertical permeabilities.

$$P = q_t \left(\frac{k_v}{k_h}\right)^{0,1} \mu_o F_1 \frac{F_2}{k_h \sqrt{h_p}} \tag{13}$$

Equation (13) is used to calculate the critical rate for gas coning. As to water coning for gas coning exists correlations to calculate the time breakthrough such Papatzacos et al. (1991), Benamara and Tiab (2001), among others. The use of these equations depends of the assumptions and restrictions.

- **Fines migration**

Fines migration is defined as the movement or the drag of fines particles until wellbore. The fine-grained are present in most sandstone and some carbonates with a size range of 0.0005 to 0.04 millimeters (0.5 to 40 microns).

The mobilization of fines reaches the perforations, blocking and restricting the oil flow, with severe oil production loss. Fines migration is identified as the most costly sources of well damage (Hibbeler et al., 2003).

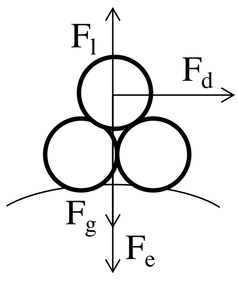

Figure 3. 26 - Forces acting in a fine particle.
Source: You et al. (2013).

Figure 3.26 shows the forces (electrostatic – F_e and gravitational – F_g that attaches it to the rock and drag - F_d and lift F_l that detaches the particle from the grain surface) in which the particle is subjected at the rock surface

In order to predict the damage originated by fines migration and to estimate the necessity of a well intervention, a correlation for steady state production was considered because time, damage and production rate are taken into account.

Zeinijahromi et al. (2012) identified the movement of the fines through porous media in an established time and based on a production rate, in an artesian well. In the first phase he used water and then in the second phase he used oil.

$$S = \frac{\beta_s \lambda_s c_w q t}{2\pi r_w} \left\{ \frac{\lambda_s r_w}{2\pi} \exp(\lambda_s r_w) \left[E_i(\lambda_s r_d) - E_i(\lambda_s r_w) \right] + 1 - \frac{r_w}{r_d} exp[-\lambda_s (r_d - r_w)] \right\} \quad (14)$$

Equation (14) can be used in order to determine the damage from drainage radius until a damage equal to zero and the necessity of a well intervention. As a result, it can support the well engineer in predicting and planning the well intervention.

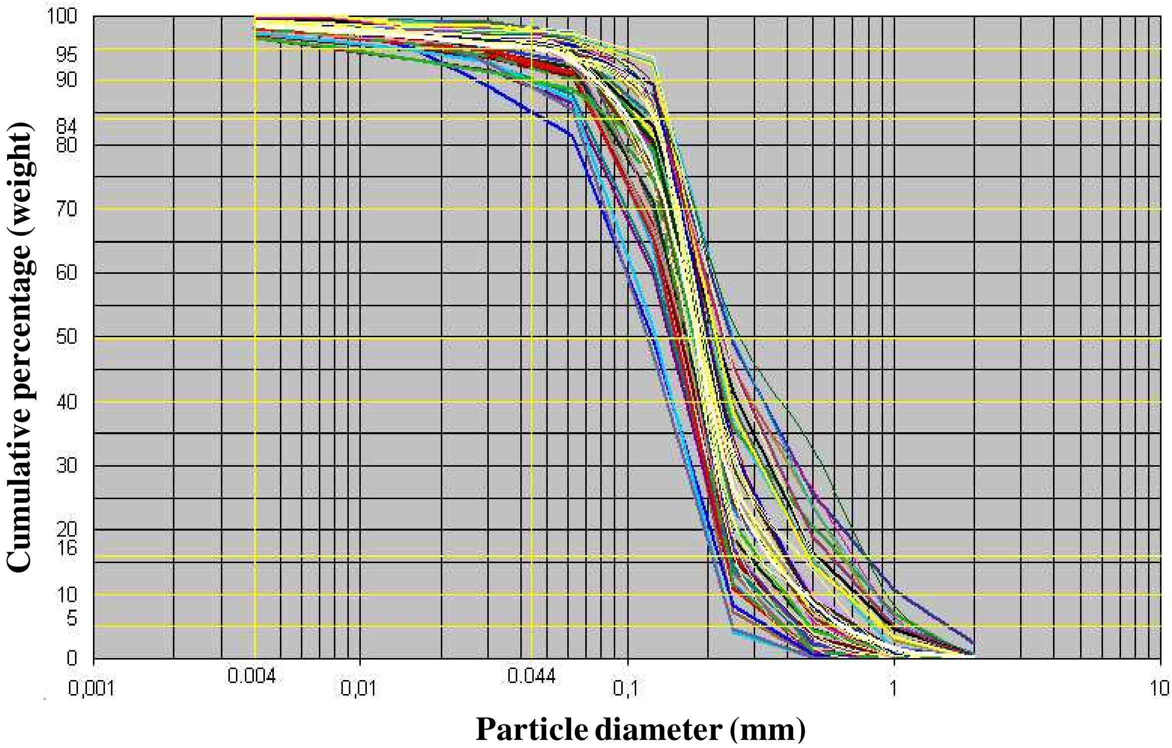

Figure 3. 27 - Granulometry distribution curve for Sw-17.
Source: Carrillo (2008).

In order to shown the application of the Eq. (14), the well Sw-17 was considered. Based on Fig. 3.27 this well have a fine concentration in a range of 95 – 100 %, representing 5% in weight.

Table 3. 18 - Data for fines migration.

Data set		units
β_s	20	
λ_s	0.03	1/ft
c_w	0.05	
q	6290	stb/d
r_w	1	ft
r_d	1.44	ft
t	3650	d

Table 3.18 shows the data for the well Sw-17 presented by Carrillo (2008) and the coefficients: filtration coefficient for size exclusion fines capture (λ_s) and formation damage coefficient for straining (β_s) presented by Zeinijahromi et al. (2011).

A variation of 5”since the drainage ratio was considered with the purpose to measure the distance where the damage starts to be bigger than zero. The goal is to determine the need of the well intervention.

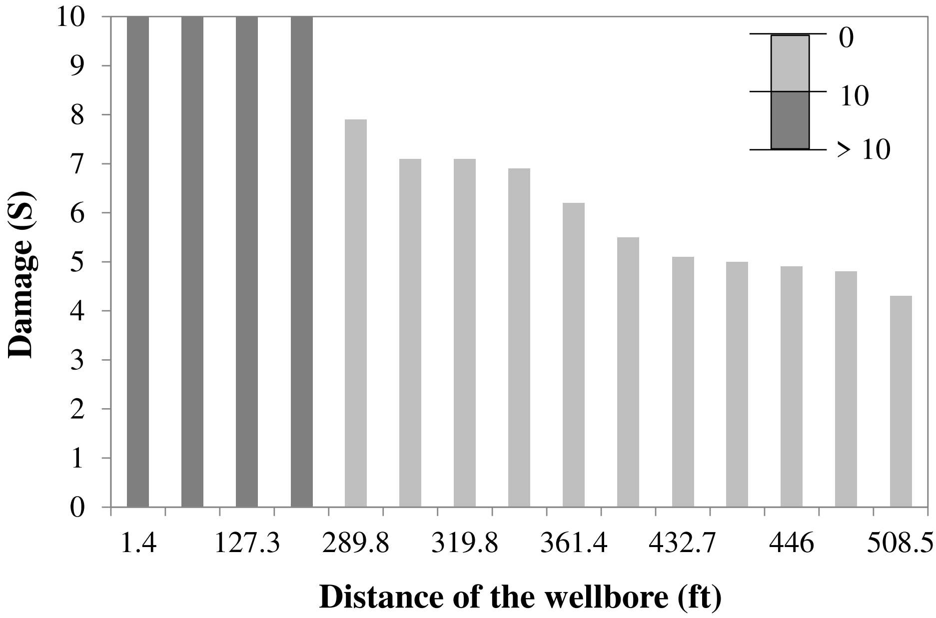

Figure 3. 28 - Damage calculated for fines migration.

Figure 3.28 shows the damage obtained at different radios. The result shows that at this period (10 years) already exists damage that means that the fines probably can cause a production loss. Therefore to identify the necessity of a well intervention will be necessary other calculus for a different period of time.

- **Sand Production**

Sand production occurs mainly in unconsolidated sandstone reservoirs with older formations (Osisanya, 2010). Usually, it is impossible to stop the sand production after the occurrence (Adeyanju and Oyekunle, 2010).

The consequences of sand production are the risk of well failure, erosion of pipelines and surface facilities, sand separation and disposal. The cost of handling and disposing sand is expensive, especially in offshore fields (Adeyanju and Oyekunle, 2010).

The method usually to avoid sand production problems is the use of the sand control completions. An appropriate sand control should be made with the purpose to avoid a re-entry to repair the sand control due to a fail (King and Wildt, 2003). The sand control method depends on site-specific conditions, operating practices and economic considerations (Petrowiki, 2015d)

Two considerations to select sand control are important (Wong et al., 2003):

(1) The identification of the dominant failure mechanism, such as:

a) screen erosion

b) screen corrosion

c) hot spots after screen plugging by scale

d) hot spots caused by inadequate gravel packing in the annulus resulting in localized flow

e) screen collapse due to compaction

f) destabilization of annular pack because of excessive down-hole flowing velocity from perforation

g) screen collapse due to plugging, etc

(2) The maximum constrains for the failures through the calculus of flow velocity. As an example, for cased-hole gravel the required velocities are: the average flowing velocity existing in perforation at the casing inside diameter (ID) labeled as V_c and the flowing velocity on the screen surface directly across the perforation labeled as V_s. These velocities are compared with a conservative maximum velocity limit (V_{cm}) and a maximum screen erosion velocity limit (V_{sm}), respectively.

Table 3. 19 - Failures in sand control completion types.
Source: King and Wildt (2003).

Completion Type	Infant Failure	% of infant failure
Cased and Perforated	Within 30 days of start of production, sand flow to surface (screen aperture)	0
Screen Only Completion (SOC)		0.6
Cased Hole Gravel Pack		0.8
Open Hole Gravel Pack		0.57
High Rate Water Packs		0.53
Frac Pack		0.24
Screenless Fracs		0
Expandable Screens		1

Table 3.19 shows the study performed by King and Wildt (2003) to determine the failure percent in completion types (sand control). Based on this study the recommended sand controls are the cased and perforated and the screenless fracs.

The four offshore petroleum regions are characterized by sandstones reservoir. The typical sand control used in these regions are: Frac Pack and Gravel Pack operations (Marques et al., 2007).

Table 3. 20 - Case Studies for reservoir problems.

Year	Incident	Offshore petroleum region	Reservoir problems	Reference
1995	Exceed of water production in Cantarell field.	North Sea	Water coning	Peng and Yeh, 1995
1995	Amber field has water influx and gas cap drive reservoir mechanism, resulting in exceed of water and gas production	Gulf of Mexico	Water and gas coning	Wu et al., 1995
1996	Exceed of gas production, in order to avoid the gas advance was used foams.	North Sea	Gas coning	Surguchev and Hanssen, 1996
2006	A mathematic model to predict the gas/oil relation and modifications in production rate was suggested.	North Sea	Gas coning	Mjaavatten et al., 2006
2008	Production decrease and the surface facilities failed due to excess water and gas production.	Gulf of Mexico	Excess water and gas production	Daltaban et al., 2008
2008	A water breakthrough resulting in a inhibition of oil production, a heavy workover was need to introduce a swellable packer technology	Campos Basin	Excess water production	Ueta et al., 2008
2009	Massive sand production after a few months of production (expandable sand screen)	West Africa	Sand Production	Guinot et al., 2009
2009-2012	Exceed of gas production	North Sea	Gas coning	Ziegel et al., 2014

Table 3.20 shows some case studies in which a well intervention was necessary for the four offshore petroleum regions.

The main factors leading to production loss and some cases studies showing the severity of the well intervention were described. In the next section prevention and remediation treatments will be presented.

3.2. Prevention and remediation treatments

As previously explained, prevention treatments are expensive but their application during the production phase can help save money, avoiding unnecessary or unplanned well interventions.

The worst of the cases of remediation treatments is to perform a heavy workover. The reason is that it results in a great waste of time, money and sometimes modifications in the platform in order to allow this operation's type.

In this section some prevention treatments that are used nowadays with good results are recommended. The recommended remediation treatments are those performed by light workovers.

For each cause of production loss possible prevention and remediation treatments were identified. These causes may not be always solved through prevention treatments then remediation treatments are necessary.

There are several treatments to prevent and remediate flow assurance problems. Based on Kondapi and Moe (2013) there are four types of technologies:

(1) The aging technologies were used for several years and were replaced for technologies that are cheaper.

(2) Embryonic technology is relative new and still in the development phase, performing experiments and tests.

(3) Emerging technology is being used in oil industry, but until now need a qualification testing process.

(4) Matured technology is used for a several years and day-by-day the oil industry is trying to improve this technology to be environmentally friendly.

Of these four types of technology the matured technology was selected. This type of technology is usually applied in the most of the fields and is available from several suppliers in the service market.

Table 3. 21 - Prevention and remediation treatments for flow assurance.

<table>
<tr><th>Cause of production loss</th><th>Prevention</th><th>Remediation</th><th>References</th></tr>
<tr><td>Hydrates</td><td>• Thermal insulation
• Direct electric Heating (DEH)
• Thermodynamic Hydrate Inhibitors:
✓ Mono Ethylene Glycol (MEG)
• Low Dosage Hydrate Inhibitors (LDHI):
✓ Kinetic Hydrate Inhibitors (KHIs)
✓ Anti agglomerates (AAs)</td><td>• Dead oil/hot oil flushing
• Depressurization</td><td>• Kondapi and Moe., 2013
• Cardoso et al., 2003</td></tr>
<tr><td>Wax</td><td>• Thermal insulation
• Direct electric Heating (DEH)
• Paraffin inhibitors</td><td rowspan="3">• Mechanical removal
• Pigging</td><td>• Kan and Tomson, 2010
• Kondapi and Moe., 2013</td></tr>
<tr><td>Asphaltene</td><td>Asphaltene inhibitors</td><td>• Kondapi and Moe, 2013
• Montesi et al., 2011</td></tr>
<tr><td>Scale</td><td>Scale inhibitors</td><td>• Kondapi and Moe, 2013
• Refaei and Al-Kandari, 2009
• Bezerra et al., 1996</td></tr>
<tr><td>Calcium Naphthenate</td><td>Naphthenates inhibitor</td><td>Mechanical removal</td><td>• Goldszal et al., 2002</td></tr>
</table>

Table 3.21 shows the matured prevention and remediation treatments for each causes of production loss due to flow, besides Kondapi and Moe (2013) another authors are cited because in this documents this treatments were used obtaining good results.

As naphthenates is not a common problem in the offshore petroleum regions, Kondapi and Moe (2013) did not present a solution for this problem but as this cause mainly occurs in West Africa, the main prevention treatment used to solve this problem is Naphthenate inhibitor (Goldszal et al, 2002).

The application of remediation treatments can be perform by methods as bull heading (squeeze) or coiled tubing, that is, light workover operations. The most complicated method and maybe the most expensive is coiled tubing, due to a necessity of a vessel to bring the coiled tubing equipment. Although coiled tubing is considered as a light workover.

Usually the costs of the prevention treatments are expensive but they are more cost effective throughout the life of the well than to apply a remediation treatment during the production phase.

Remembering the description given for each cause of production loss due to flow assurance, the main factors involved in the occurrence of the loss are: temperature, pressure, fluid formation composition (hydrocarbon and/or water formation) and in case of hydrates, the presence of water is a fundamental factor.

As seen in Tab. 3.21 the prevention treatments modify a factor to avoid the deposition in the well line & system. In the case of hydrates, thermal insulation, direct electric heating and hot oil flushing increases the temperature of the production system. For wax deposition, prevention treatments also modify the temperature. For the other causes, the treatments try to keep the component in a dissolved phase over a broader range of pressure and temperature.

The selection of the prevention and remediation treatment depends of each company for instance in Campos Basin the techniques used for prevent and remediate hydrates and scale depositions are (Cardoso et al., 2003):

- Thermal insulation (Prevent hydrate);
- Pigs (remove scales – remediation treatment);
- Umbilical, X-mas tree, and tubing string features to allow chemical inhibitors injection (prevent scales);
- Coiled tubing intervention (remove hydrates or scales – remediation treatment)

For potential integrity failures was identify remediation treatments that can avoid the failure during well design phase with a modification in the well barrier component and prevention treatments that can be applied with light workovers.

The main remediation treatment for leakage in well integrity is the use of sealants. The most used sealants in the oil industry are Sandaband, Thermaset and Seal-tite (Blaauw, 2012).

- Sandaband and Thermaset

To avoid leakage, a gas resistant material is necessary. Sandaband and Thermaset were used in several wells worldwide. The method of bullheading to apply the material in the leakage is used (Sandaband, 2015)

- Seal-tite

It was development in 1995 to apply in SSSV and control lines, and then the applications were extended. The sealant is liquid and when it is injected in the well the molecules are linked together forming a flexible solid. Unlike the other type of sealants, seal-tite can be applied in different leakages as packer, SSSV, wellhead, gate valve of X-mas tree and control lines (Seal-tite, 2015)

For potential integrity failures in the description of each well barrier component solutions to avoid the failure were appointed, these solutions are currently used and until know all the application had a good results. For example, in North Sea wells due to fails in subsurface safety valve a TR-valve in series (redundancy valve) was adopted, it saves money because only a heavy workover will be necessary if both valves fail.

Table 3. 22 - Prevention and remediation treatments for potential integrity failures.

Well barrier component	Prevention	Remediation	Reference
Subsurface Safety Valve	Redundancy in valve	-	• Corneliussen, 2006 • Seime, 2012
Packer	Use Packer V0	-	Blaauw, 2012
Production tubing and casing	Change API connection by proprietary connection in well with gas lift system or a gas environment	-	King and King, 2013
Gas lift valve	Change valve with slickline	-	Holand, 2014
Wellhead	Change elastomeric seal by metal-metal seal • Pressure monitoring • Foam around test plug • Injection of nitrogen to cavities	Chemical sealant	Ohm, 2013
Christmas tree	Test valve before production begins	• Clean the valve periodically • Routine inspections • ROV use	• Alves, 2012 • Stendebakken, 2014
Cement	Check cement job during drilling phase	-	• Vignes, 2012 • Blaauw, 2012 • King and King, 2013

Table 3.22 shows the recommended prevention treatments to avoid or minimize the main failure during well design and remediation treatments when is not possible to avoid the main failure.

Finally for reservoir problems were selected remediation treatments that can be applied with light workover and being usually used, as matured technologies.

The only reservoir problems that have a prevention treatment is sand production. The correlation to determine the damage and critical rate can be considered as a prevention treatment, but his do not avoid the well intervention only estimate the need of the well intervention resulting in a better management, then correlation are considered as a step to select the best remediation treatment.

Table 3. 23 - Prevention and remediation treatments for reservoir problems.

Reservoir problem	Prevention	Remediation	Reference
Water conning	-	• Sealants • Gel • Packer (wireline)	Jaripatke and Dalrymple, 2010
Gas conning	-	• Sealants • Foam	• Seright et al., 2003 • Surguchev and Hanssen, 1996 • Wassmuth et al., 2000
Fines migration	-	• Dispersant • Nanofluid • Solvents	Ezeukwu et al., 1998
Sand Production	Sand control	-	• Petit et al., 2007 • Wong et al., 2003 • King and Wildt, 2003

Table 3.23 shows the prevention and remediation treatments for reservoir problems. Note that the sand production as previously described is the only reservoir problem that have a prevention treatment.

Water-control treatments are usually effective if the target zones are properly isolated. The main treatments are the injection of gels in the oil well. However, it is preferable to inject the gel before water breakthrough, to retard the water movement for the oil zones – see application of well Sw - 17 (Seright et al., 2003).

The treatments for gas coning are also sealants as the water coning. In some places the use of foams is common. Nevertheless the use of gelling foams is preferable, due to the gelation process, where the foam structure solidifies, increasing the ability of the gel-foam (Surguchev and Hanssen, 1996; Wassmuth et al., 2000).

The methods used to apply this remediation treatment can be:

- Bullheading that is considered the most economical treatment. This technique does not use an isolation of the interest zone in some cases the treatment fluid can invade the oil zone, for that reason may considered not appropriate.
- Mechanical packers or bridge plugs through wireline operations (water and gas coning).
- Isoflow techniques the treatment fluid is direct injected in desire zone and a non-sealing to protect oil zone.
- A coiled tubing operation place the treatment fluid to the desire area, is better than bullheading but is more expensive and it takes longer time.

These techniques can be classified as light workover because it is not necessary to remove the X-mas tree (Jaripatke and Dalrymple, 2010).

New technologies for reservoir problems

Some new technologies are developed in the early 90's but only was implemented in 1998 in Troll field – North Sea, this new technology is known as Inflow Control Device (ICD).

The Inflow Control Device is a choking device that can be installed together the sand control screen, integrated with annular isolation, artificial lift and intelligent completion.

This technology is installed during completion phase, and then is considered as prevention treatments, besides this is gained popularity due to the capacity of increase the oil production, minimize water and gas coning, this technology is not usually used (Alkhelaiwi and Davies, 2007).

4. RESULTS AND DISCUSSION

In this section, guidelines and procedures will be proposed, based on the analysis presented in the previous chapter for each type of production loss, in order to obtain a well design of easy and minimum intervention.

Section 4.1 presents the main factors considered for the proposed guidelines and procedures, for each type of production loss.

Section 4.2 presents the application of the guidelines and procedures for different cases, in order to demonstrate the effectiveness and future applications.

4.1. Guidelines and procedures

The three different types of production loss obtained and introduced in Sec 3.1 was considered to propose the guidelines and procedures, these are also based on prevention and mitigation treatments recommended in Sec 3.2. Each guideline and procedure is described below.

a) Loss of flow assurance

In the Sec. 3.1 was identified the causes of production loss due to flow assurance and the main factors for its occurrence.

Table 4.1 - Main factors for flow assurance.

Causes	Main Factor
Hydrates	• Water presence • Hydrocarbon composition • Pressure • Temperature
Wax	• Hydrocarbon composition • Temperature
Asphaltenes	• Hydrocarbon composition • Pressure
Scale	• Water composition • Pressure • Temperature
Naphthenates	• Hydrocarbon composition • Water composition • pH

Table 4.1 shows the main factors for each cause of production loss due to flow assurance. Note that fluid formation composition (hydrocarbon or/and water) is the one of the main factors of each cause of production loss.

In the case of wax although the main factor being the temperature based on Fig. 3.6 the change of temperature is a function of the pressure, this occur also with the asphaltenes that the main factor is the pressure but based on Fig. 3.7 this depend of the temperature.

So, for the analysis (intervention zone) were considered these three factors: fluid formation composition, temperature and pressure, but Naphthenates and NORM were not considered in the analysis because was the literature did not report an equation with those three factors together.

Each cause of production loss due to flow assurance presents a curve as a function of pressure and temperature (Fig. 3.4, Fig. 3.6, Fig. 3.7 and Fig. 3.8). Those curves were superposed to obtain a graph with a region free of solids, denominated as "Flow Assurance Envelope (FAE)".

Some authors, such as Jamaluddin et al. (2003) and Ratuloswki et al (2004) presented a similar diagram for hydrates, wax and asphaltenes deposition. The purpose of those works was to demonstrate that solids might be deposited anywhere in the production system.

In order to identify if the well design is of easy or minimum intervention is necessary to plot the oil flow conditions. When oil flow conditions are inside the FAE the possible result is a non-intervention. Otherwise, the well intervention could be "minimum intervention" with prevention treatments or "easy intervention" with remediation treatment.

The application of prevention treatments during the phase of well design can avoid the well intervention during oil production. Nevertheless, the oil well should be prepared for a well intervention.

Table 4. 2 - Classification of easy and minimum intervention based on the FAE.

Oil Flow Conditions	**Treatment**	**Intervention**
Inside FAE	-	Non - intervention
Outside FAE	Prevention	Minimum Intervention
	Remediation	Easy intervention

Table 4.2 shows treatments and classifications for an intervention based on the FAE. As appointed in Sec 3.1 the minimum temperature considerate for this analysis was sea bed temperature ≈39 °F.

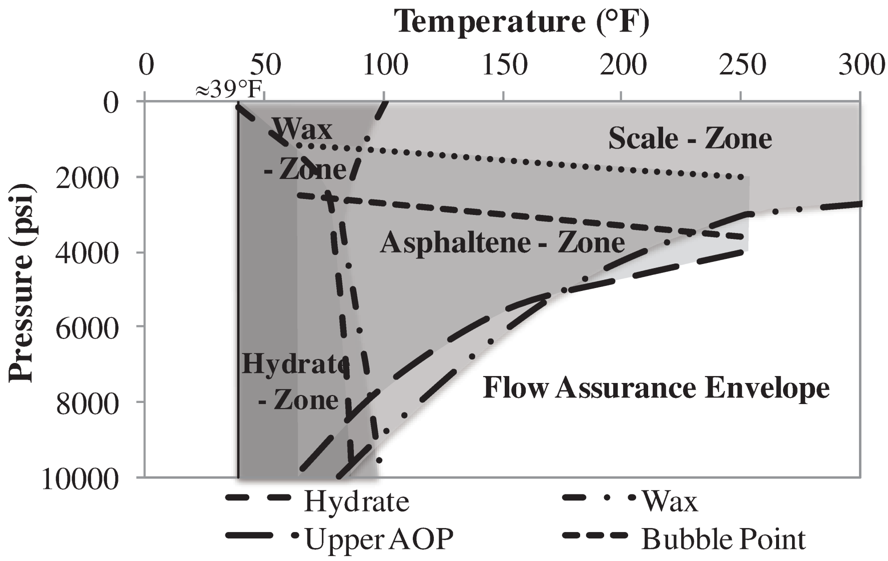

Figure 4. 1 - Solids deposition diagram.

Figure 4.1 shows the flow assurance envelope and zones of solids deposition. The curves are based on formation fluid composition, therefore a region free of solids deposition may not exist.

Based on the previously description, a procedure to obtain a well design of easy and minimum intervention was proposed.

The main data required is the formation fluid composition to determine the curves of solids deposition based on Sec. 3.1 (a).

Highlighting that naphthenates did not present correlations to perform this analysis; the well engineer should be identified if the fluid formation composition had ARN acids percentages to apply prevention treatments and try to avoid this type of problems.

It is important to remember that if barium or strontium sulfate are correctly controlled, problems related with NORM could be avoided.

For the other causes the well engineer should superpose each diagram to obtain the flow assurance envelope as shown in Fig. 4.1.

Sometimes as explained previously may not exists a FAE, even so should be plotted the oil flow conditions (pressure and temperature) i.e. during oil production to identify the possible problems that may be faced.

If the oil flow conditions are inside the flow assurance envelope, the well probably will not present problems during the production phase obtaining a non-intervention.

Otherwise prevention treatments will be necessary to obtain a possible minimum intervention or remediation treatments to an easy intervention; remember that remediation treatments should be applied with light workover (see Tab. 3.21).

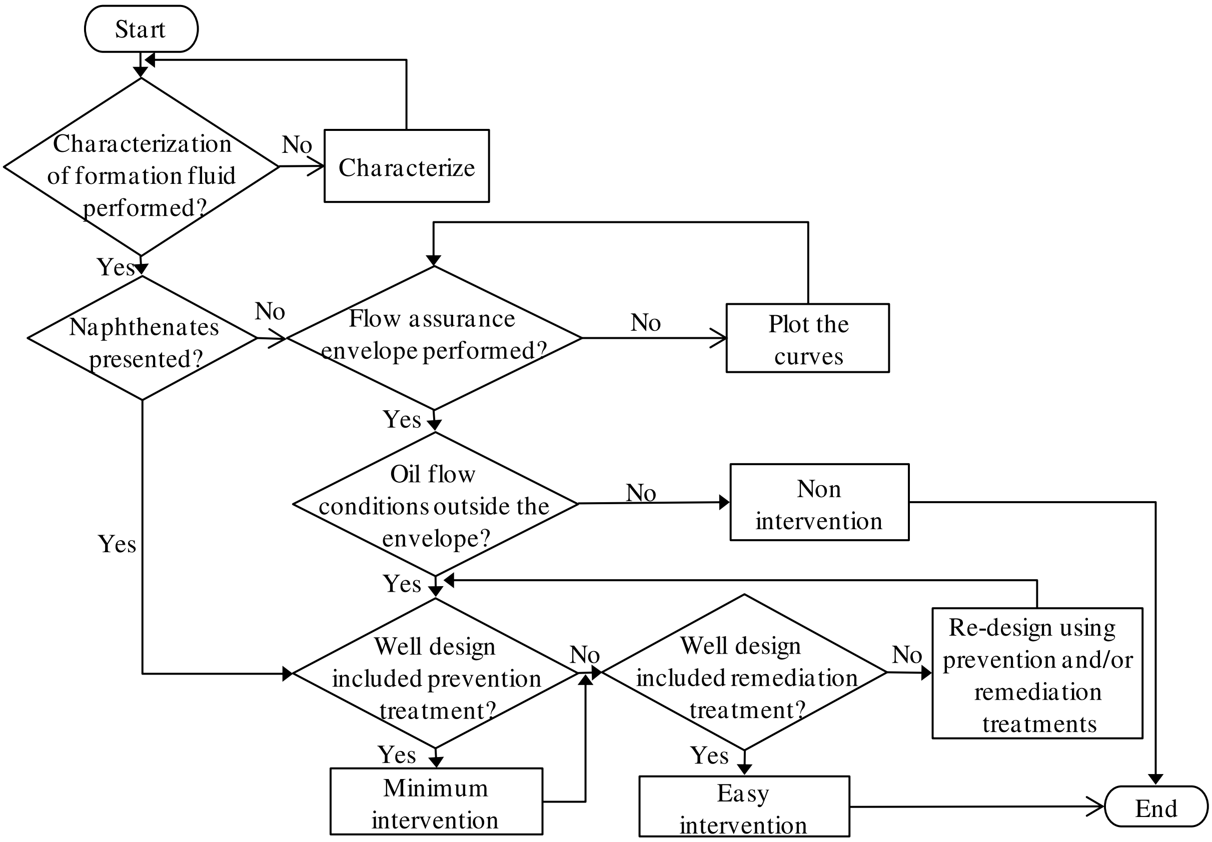

Figure 4. 2 - Procedure for a well design of easy and minimum intervention for causes of production loss due to flow assurance

Figure 4.2 shows the procedure that should be followed to obtain a minimum and/or easy intervention. This procedure is explained in 6 steps:

1. Perform the characterization of formation fluid.
   a. Identify if naphthenates are presented, and apply prevention treatments – **minimum intervention.**
2. Determine the curves for each cause of production loss (see Fig. 3.4, Fig. 3.6, Fig. 3.7 and Fig. 3.8);
3. Superimpose the curve of each cause of production loss (see Fig. 4.1);
4. Identify the flow assurance envelope;
5. Plot the oil flow condition;
6. Identify if the oil flow conditions are inside or outside the flow assurance envelope.
   a. Inside → Possible **non intervention**
   b. Outside → Prevention treatments during well design – **minimum intervention;** and modifications of the well design in order to allow light workover – **easy intervention.**

The main guideline for causes of production loss due to a flow assurance is the step six; because with this step it is possible to achieve the purpose of obtain a minimum and easy intervention.

b) Potential Integrity failures

In Sec. 3.1 (b) the main failure for each well barrier component was identified. As result of this information we can conclude that is possible to have modifications during the well design phase as shown in Tab. 3.22.

Table 4. 3 - Main failures and causes in well barrier components.

Well barrier component	**Failure**	**Failure cause**
Subsurface Safety Valve	Leak in close position	• Damage to flapper • Damage to seal
Packer	Package loss	• Presence of gas
Production tubing and casing	Connection	• API connection in gas lift system
Gas lift valve	Fail to close	• Scales deposition
Wellhead	Seal	• Elastomeric seal • Hydraulic residues
Christmas tree (valves)	Fail to close (deepwater)	• Solid deposition
	Leak in close position (shallow water)	• Heavy structural loads • Corrosion • Erosion
Cement	Lack of bond cement-casing-formation	• Inadequate primary cementation

Table 4.3 shows the main failures and the causes of the failure for each well barrier component. Considering the definition of minimum and easy intervention and based on Tab. 3.22, only gas lift is of easy intervention. For some components, besides the prevention treatments, they also have remediation treatments that avoid the use of heavy workover.

Table 4. 4 - Well intervention classification for well barrier component.

Well barrier component	**Failure is possible to avoid**	**Intervention**
Subsurface Safety Valve	YES	Minimum
Packer	YES	Minimum
Production tubing and casing	YES	Minimum
Gas lift valve	NO	Easy
Wellhead	YES	• Minimum • Easy
Christmas tree	YES	• Minimum • Easy
Cement	YES	Minimum

Table 4.4 shows which well barrier component is of minimum or easy intervention according to Tab. 3.22 and Tab. 4.3.

The establishment of guidelines is based on the analysis presented for causes of production loss due to integrity failures.

In order to know with well barrier components can fail during production phase, first is necessary to identify the primary and secondary barrier integral set of a production well based on Fig 3.9 (a) and (b).

Once identified the well component shall be identified the main failure as presents in Tab. 4.3. If the failure is possible to avoid with modifications in the well design or in the component is considered as a minimum intervention, otherwise prevention treatments will be necessary to obtain an easy intervention.

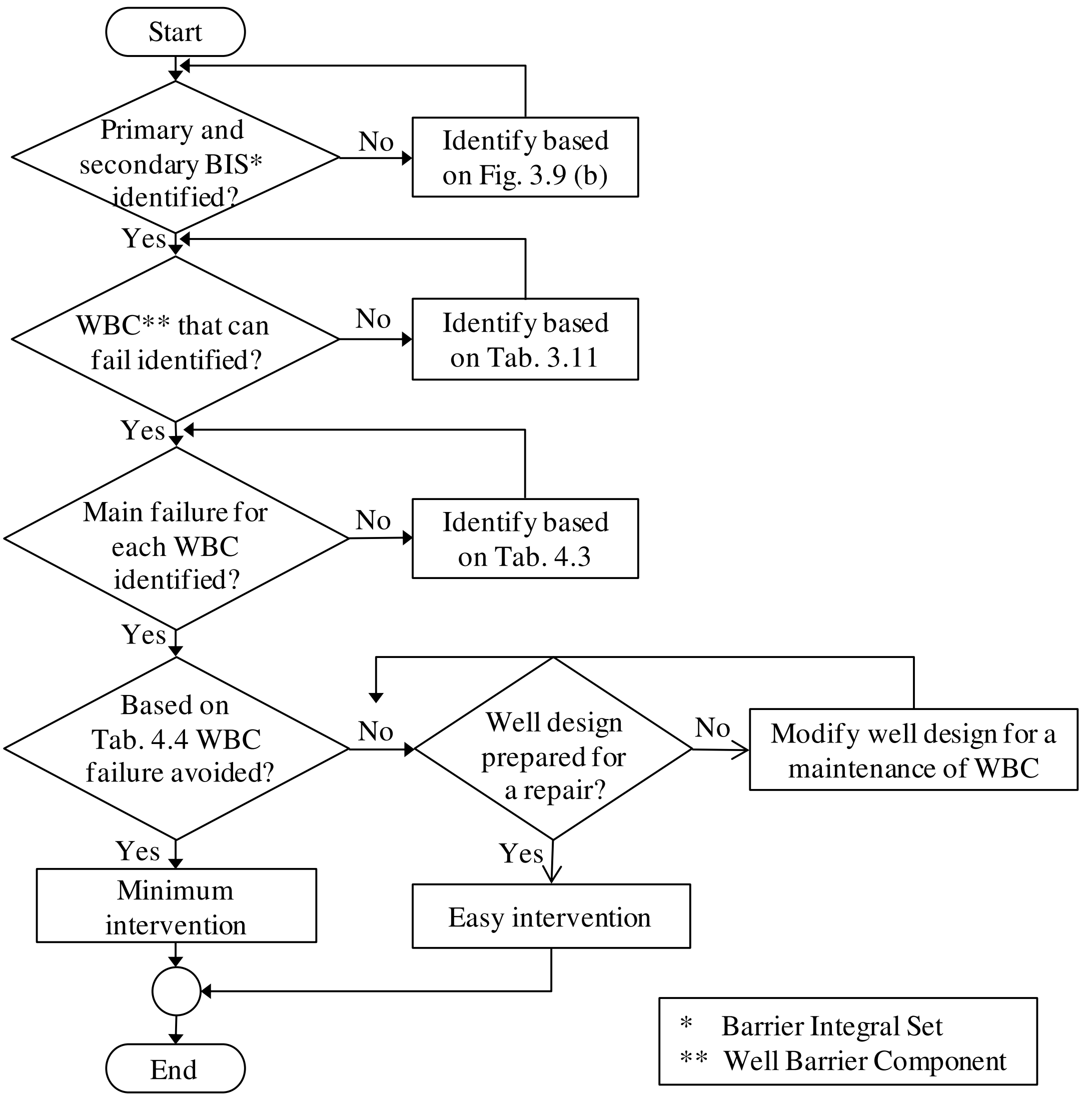

Figure 4. 3 - Procedure for a well design of easy and minimum intervention for causes of production loss due to potential integrity failures

Figure 4.3 shows the procedure that should be followed to obtain a minimum and/or easy intervention for causes of production loss due to integrity potential failures. This procedure is explained in 4 steps:

1. Identify primary and secondary BIS for a production well based on Fig 3.9 (b)
2. Identify well barrier components that can fail based on Tab. 3.11
3. Identify the main failure for each well barrier component based on Tab. 4.3.
4. Determine if it is or not possible to avoid the failure based on Tab. 4.4.
   a. Avoidable, apply prevention treatments, as example Tab. 3.22 – **Minimum intervention**
   b. Non Avoidable, modify the well design to allow the repair of the well barrier component (remediation treatment, as example see Tab. 3.22) – **Easy intervention**

The guideline proposed for this type of production loss is the step 4, because with this is possible to achieve the goal of a minimum and easy intervention

c) Reservoir problems

Based on characteristics of each reservoir problem was possible to conclude that sand production is the only problem that may result in a minimum intervention. For the other reservoir problems the use of correlations aids to estimate the need of the intervention resulting in an easy intervention.

Table 4. 5 - Well intervention classification in reservoir problems.

Reservoir problem	**Intervention**
Water coning	Easy
Gas coning	
Fines migration	
Sand production	Minimum

Table 4.5 shows the causes of production due to reservoir problems and the classification of the intervention (minimum and easy).

The most important thing to evaluate the reservoir problems is identify which reservoir problems are presented in the well based on Fig. 3.18 as well as the reservoir conditions to perform all the calculations.

A sand control completion type will be necessary if sand production is a problem. Some types of sand control completions are presented in Tab. 3.19. The use of correlations to estimate the need of a well intervention based on critical production rate (if water or gas coning are a problem) and damage (if the fines migration is a problem) were necessary to estimate the need of the well intervention as demonstrate in examples in case Sw-17. After that will be necessary to project the well to allow remediation treatments (some are recommended in Tab. 3.23), to obtain and easy intervention.

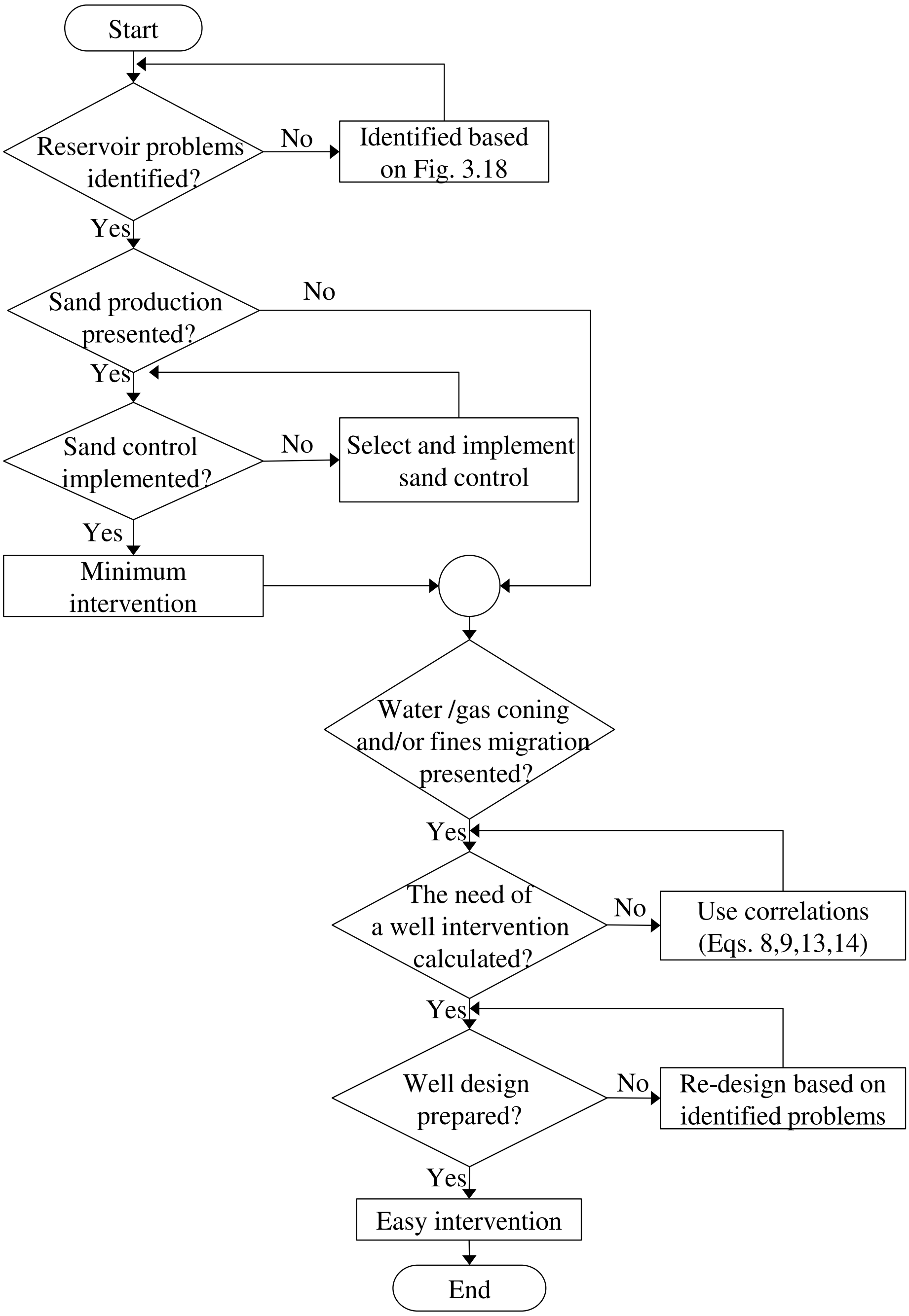

Figure 4. 4 - Procedure for a well design of easy and minimum intervention for reservoir problems

Figure 4.4 shows the procedure that should be followed to obtain a minimum and/or easy intervention for causes of production loss due to reservoir problems. This procedure is explained in 3 steps:

1. Identify reservoir problems based on Fig. 3.18.
2. Select sand control during well design phase if sand production is a problem - **minimum intervention.**
3. Use correlations to determine damage (fines migration), critical production rate (water and gas coning) if those problems were detected:
    a. Estimate the need of a well intervention
    b. Prepare the well design to allow remediation treatments – **easy intervention.**

The steps 2 and 3 are considered as the guidelines to obtain an easy and minimum intervention for reservoir problems.

Note that for the three types of causes of production loss, only the step that results in minimum or easy intervention was considered as a guideline, because this achieves the purpose of the work. The other steps and the set of steps are considered as a procedure.

As explained in previous chapter some causes of production are correlated. In the next section, an application of each procedure and guideline will be demonstrated in different cases and a final case will demonstrate the correlation between the causes.

4.2. Applications

Guidelines and procedures proposed were applied for each type of production loss, different cases validate this proposal.

- **Case study application – Flow assurance**

- Roncador Field – Campos Basin (Brazilian region)

As previously discussed, the first step to obtain a well design of easy and minimum intervention is to perform the flow assurance envelope (Fig. 4.1) based on the solids deposition diagrams and the knowledge of fluid formation composition is necessary.

Table 4. 6 - Data Available Roncador Field.
Source: Minami et al. (2000).

Constituent	Concentration (mg/l)	
	Formation water	**Seawater**
Sodium (Na^+)	65,000	11,500
Potassium (K^+)	410	226
Calcium (Ca^{2+})	7,100	504
Magnesium (Mg^{2+})	800	1,390
Barium (Ba^{2+})	44	1
Strontium (Sr^{2+})	580	9
Chloride (Cl^-)	116,982	21,300
Sulfate (SO_4^{2-})	32	2,834
Bicarbonate (HCO_3)	20	150
Carbon dioxide (CO_2) Gas (%)	0.075	

Table 4.6 shows the data available in the literature for Roncador Field: the hydrate curve, formation water and seawater composition (Minami et al., 2000); with this data the hydrate and scales zones were possible to be identified.

Table 4. 7 - Oil flow conditions for two wells in Roncador Field.

	Place	Oil Flow Conditions	
		Temperature (°C)	**Pressure (Psi)**
Well 1	Flowline	4	2,175
Well 2	Separator	70	213
	Flowline	25	213
	Downhole	65	2,133
	Reservoir	65	4,764

Table 4.7 shows the oil flow conditions for two wells: one for a pressurized flowline and another one for a producing well.

Equation (4) for calcium carbonate and Eqs. (5) to (7) for sulfates were employed to calculate the saturation index. A mixture with volume ratio of 50:50 (formation water/seawater) was taken.

Hydrate, calcium carbonate, barium sulfate, strontium sulfate and calcium carbonate curves were obtained. These curves were superposed to obtain the flow assurance envelope.

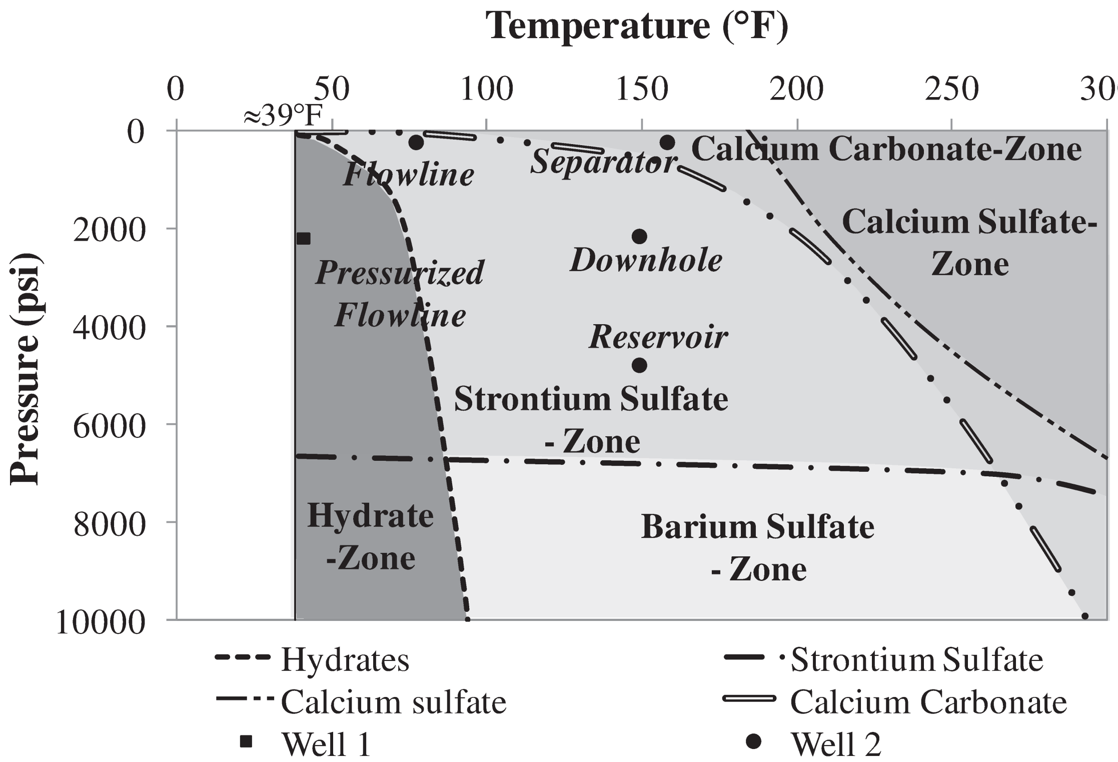

Figure 4. 5 - Diagram of solids deposition for Roncador field.

Figure 4.5 shows the diagram of solids deposition for Roncador field. The result was a diagram without a region free of solids deposition. Therefore a minimum intervention is not possible.

Well 1

Based on Fig. 4.5, three solids can be deposited: hydrate, barium sulfate and strontium sulfate but only hydrate deposition problems were reported (Freitas et al., 2002).

A problem in the X-mas tree valve resulted in pressurization of the flowline. The valve was repaired but the production could not be restored due to hydrate plug in the flowline. Two procedures solved the problem.

The first procedure was hydrate depressurization but is important to note one thing: this treatment was not effective, in reason of that the second procedure Nitrogen/coiled tubing was applied. However, the platform was not prepared for this type of operation and several changes in the platform deck were made to allow coiled tubing operations.

Well 2

During the well design, barium sulfate, strontium sulfate and calcium carbonate deposition were predicted, as shown in Fig. 4.5. Prevention treatments such as inhibitor squeeze and sulfate removal were applied. As a result, production losses were not reported.

Analysis

The well 1 did not follow the guidelines established in the present work, such as:

- ✓ The possible zone of hydrate deposition was not identified;
- ✓ Prevention treatments in the well design were not applied;
- ✓ Modification in the well design to allow light workover was not performed.

And the results were production and time loss due to the remediation treatments applied.

The well 2 followed the guidelines established in the present work:

- ✓ The well engineers predicted the scale deposition at different oil flow conditions;
- ✓ Prevention treatments during the well design phase were applied.

And the result was a production without interruptions.

- Tombua Landana – West Africa

The data available in the literature for Tombua Landana Field are the formation water and seawater composition (Chen et al., 2007). From this data is possible to identify the scale zone.

Table 4. 8 - Data Available Tombua Landana.
Source: Chen et al. (2007).

Constituent	**Concentration (mg/l)**	
	Formation water	**Sea Water**
Sodium (Na^+)	80,425.0	11,020.0
Potassium (K^+)	1,114.0	408.4
Calcium (Ca^{2+})	18,128.0	421.9
Magnesium (Mg^{2+})	1,102.0	1,322.0
Barium (Ba^{2+})	146.0	0.02
Strontium (Sr^{2+})	1,161.0	68.9
Chloride (Cl^-)	158,969.0	19,805.0
Sulfate (SO_4^{2-})	25.0	2,775. 4
Bicarbonate (HCO_3)	14.0	145.0
Carbon dioxide (CO_2) Gas (%)	3.4	0.03

Table 4.8 shows the data available for Tombua Landana field. For the calculus of saturation index, a mixture of 50/50 in volume (formation water/sea water) was considered. Equation (4) for calcium carbonate and Eqs. (5) to (7) for sulfates were employed.

Table 4. 9 - Oil flow conditions for Tombua Landana Field.
Source: Chen et al. (2007).

Place	Oil Flow Conditions	
	Temperature (°C)	Pressure (psi)
Bottom-hole	129.4	4,350.0
Wellhead	60.0	1,100.0

Table 4.9 shows the oil flow conditions for a producing well: Bottom-hole and wellhead oil flow conditions.

The calcium carbonate, calcium sulfate, strontium sulfate and barium sulfate curves were obtained. These curves were superposed to obtain the flow assurance envelope.

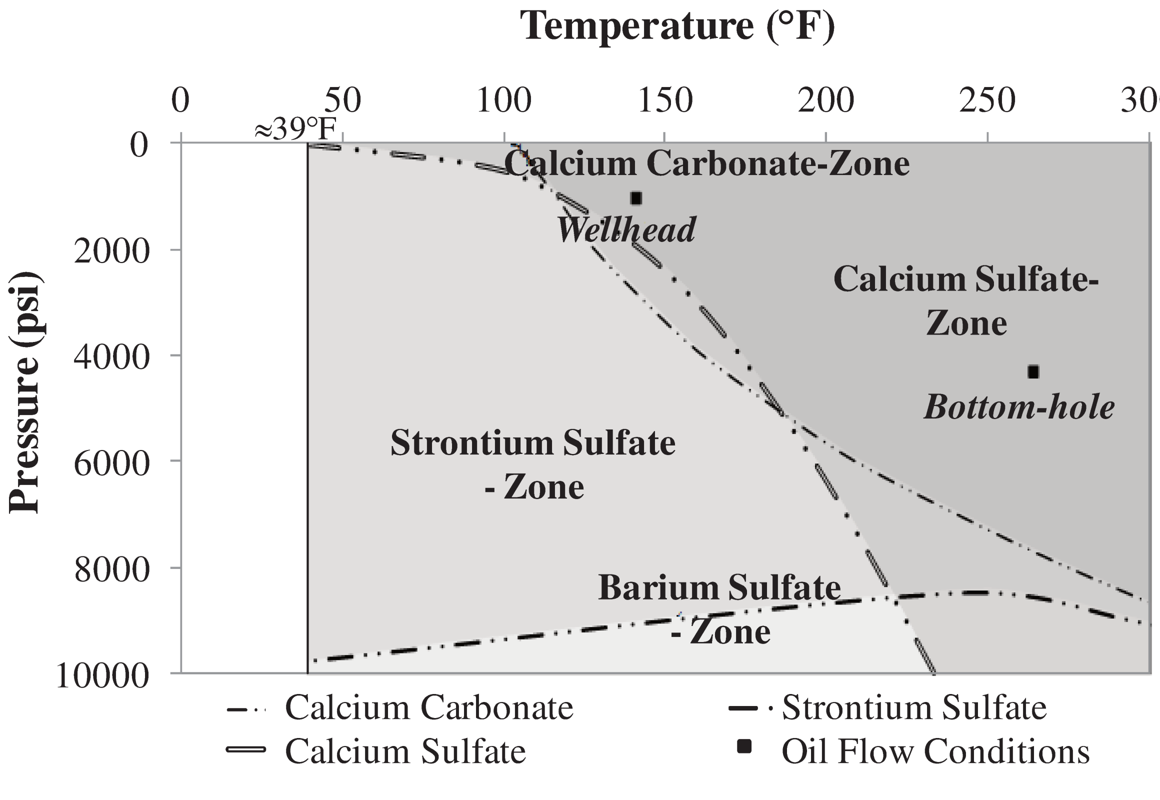

Figure 4. 6 - Diagram of solids deposition for Tombua Landana field

Figure 4.6 shows the diagram of solids deposition for Tombua Landana field. The result was a diagram without a region free of solids deposition. Therefore a minimum intervention is not possible. In this figure oil flow conditions shown in Tab. 4.9 were plotted.

For bottom-hole and wellhead conditions, depositions of calcium carbonate, calcium sulfate and barium sulfate was identified in Fig. 4.6.

During the design of this well, barium sulfate and calcium carbonate were predicted. Prevention treatments were applied such as Split Sulfate Removal, downhole scale inhibitor, installation of additional scale inhibitor injection points, and scale squeeze treatments (bullheading). As a result, production losses were not reported.

Analysis

The well followed the guidelines established in the present work:

- ✓ The possible zone of scale deposition was identified;
- ✓ Prevention treatments in the well design were implemented;
- ✓ A modification in the well design, in order to allow light workover was performed;

Problem with scales were not reported after Chen et al. (2007).

Both cases validated the methodology, i.e., that following the guidelines established during the design phase can avoid oil production losses.

- **Case study application – Potential Integrity Failure**

- Bonga Field – West Africa

In Bonga's Field two different situations were identified (Ebitu et al., 2011). :

1) During oil production, failures occurred in Bonga's Field. Subsurface safety valve (SSSV) failures, minor leaks on various well components and X-mas tree.

   In one production well, a failure in the SSSV occurred. The well was shut-in and a heavy workover was performed. The tubing string was removed to replace the valve. The well was recompleted after two years.

2) Once identified integrity problems, a well integrity management was implemented in Bonga's field, for future wells. The result was an early detection of the failures in the well barrier components, minimal shut-in and consistent compliant of preventive treatments. The Bonga team is also looking for new methods of carrying out remediation treatments avoiding the heavy workover, such as the use of wireline or slickline methods.

Analysis

In the Bonga field two situations were identified:

(1) The guidelines proposed in the present work have not been followed:
- ✓ Well barrier component that can fail was not identified (SSSV);
- ✓ The main failure of the component was not identified;
- ✓ Redundancy in the valve was not implemented.

This situation resulted in a shut-in of two years and a heavy workover to replace the SSSV.

(2) The guidelines proposed in the present work have been followed:
- ✓ Well barrier component that can fail was identified;
- ✓ The main failure of the component was identified;
- ✓ Prevention treatments were implement;
- ✓ Remediation treatments avoided heavy workovers.

The result was a well with minimal interruption in the oil production, cost effective methods of leak repairs, and light workover systems.

- Gulf of Mexico

In Gulf of Mexico several wells experienced sustained casing pressure. Two cases are presented as follow (Bourgoyne, 1999):

- After six years of production an oil well was shut in, but the efforts to restart the production were not enough. The oil production was restored after two years and problems related to sustained casing pressure occurred again and the well had to be abandoned.
- Another well had the same problem. Seven well interventions to restore the oil production were necessary, spending over 20 million dollars.

Analysis

In both wells guidelines proposed were not followed:
- ✓ Well barrier component that can fail was not identified (Cement);
- ✓ The main failure of the component was not identified;
- ✓ Prevention treatment was not applied (Verify cement job during drilling phase),

The result was higher production losses, costly interventions and abandonment of the well.

- **Case study application – Reservoir Problems**

As a case study, guidelines and procedures proposed for reservoir problems in the present work were applied for two cases in the Gulf of Mexico.

- Gulf of Mexico

  ✓ Cantarell Field – This well have a combined drive mechanism. The oil production started to decline after a brief period of production. The cause of production loss was gas and water coning, being the main problem gas coning.

  The reservoir layer thickness varies about 20 and 80 feet. The simulations shown a gas advance of 22.7 feet by month with the production rate adopted. It resulted in a shut-in of the well after four month of production (Datalban et al., 2008).

  ✓ X Field – This deepwater well is located in Gulf of Mexico, and is a sandstone reservoir. After 18 months of production, it started to decline around 7,500 BOPD to 2200 BOPD due to fines migration and failure in the sand screen. The procedure adopted was to sidetrack the well and run a frac-pack completion with nanoparticles (Belcher et al., 2010).

Analysis

Both cases did not follow the guidelines and procedure established in the present work:

✓ The reservoir problems was not identified (gas and water coning, based on reservoir drive mechanism, and fines migration based on type of reservoir)
✓ Correlations to predict the need of a well intervention were not used.
✓ Remediation treatments to avoid heavy workover were not implemented

Higher production losses and the need of a heavy workover resulted.

For each type of production loss, guidelines and procedures were applied in different case studies, following a case study will be presented to shown the correlation between the causes of production loss.

- **Case study application – Correlation between flow assurance and potential integrity failures**

- Ula field – North Sea

The fraction of n-heptane in the hydrocarbon composition is 0.57%. Reservoir temperature is 289 °F (≈143°C) and initial pressure 7,114 psi.

In 1986, the downhole safety valves (DHSV), in two production wells, became hard to open. A heavy workover was necessary to remove the DHSV. In these valves, asphaltene deposition was identified. Asphaltenes also were deposited in the production tubing, restricting the oil production (Thawer et al., 1990).

Analysis

The wells did not follow the guidelines established in the present work, such as:

✓ The possible zone of asphaltene deposition was not identified;

✓ Prevention treatments in the well design were not applied;

✓ A possible failure in the well barrier component (DHSV) was not identified;

✓ A redundancy in the valve was not implemented.

The result was a heavy workover and production losses due to asphaltene deposition in the well/line system and a failure in the DHSV.

In all of the study cases, it is noted that guidelines and procedures match in general with problems reported in operations, which gives confidence to consider guidelines as a methodology to obtain minimum or easy intervention to be accomplished in the well design phase and to avoid oil production losses.

Table 4. 10 - Summary of causes of production.

<table>
<tr><th>Type of cause of production loss</th><th colspan="2">Cause</th><th>Main Factor</th><th>Guideline and intervention</th></tr>
<tr><td rowspan="10">Flow assurance losses</td><td colspan="2">Hydrate</td><td rowspan="9">• Fluid formation composition
• Temperature
• Pressure</td><td rowspan="9">Identify if the oil flow conditions are inside or outside the flow assurance envelope.
• Inside → Possible non intervention
• Outside → Prevention treatments during well design – Minimum intervention; and modifications of the well design in order to allow light workover – Easy intervention.</td></tr>
<tr><td colspan="2">Wax</td></tr>
<tr><td colspan="2">Asphaltene</td></tr>
<tr><td colspan="2">Naphthenate</td></tr>
<tr><td rowspan="5">Scale</td><td>Barium sulfate</td></tr>
<tr><td>Calcium carbonate</td></tr>
<tr><td>Calcium sulfate</td></tr>
<tr><td>Strontium sulfate</td></tr>
<tr><td>NORM</td></tr>
<tr><td colspan="2">Calcium Naphthenate</td><td>• Fluid formation composition
• pH</td><td>Identify if naphthenates are presented, and apply prevention treatments – minimum intervention.</td></tr>
<tr><td rowspan="7">Integrity failures</td><td colspan="2">Subsurface safety valve</td><td rowspan="7">Failure type</td><td rowspan="7">Determine if it is or not possible to avoid the failure.
• Avoidable, apply prevention treatments – minimum intervention
• Non Avoidable, modify the well design to allow the repair of the well barrier component – easy intervention</td></tr>
<tr><td colspan="2">Packer</td></tr>
<tr><td colspan="2">Production and casing tubing</td></tr>
<tr><td colspan="2">Gas lift valve</td></tr>
<tr><td colspan="2">Wellhead</td></tr>
<tr><td colspan="2">Christmas tree</td></tr>
<tr><td colspan="2">Cement</td></tr>
<tr><td rowspan="4">Reservoir problems</td><td colspan="2">Water Conning</td><td rowspan="2">Energy source</td><td rowspan="3">Use correlations to determine damage and critical production rate:
• Estimate the need of a well intervention
• Prepare the well design to allow remediation treatments – easy intervention.</td></tr>
<tr><td colspan="2">Gas Conning</td></tr>
<tr><td colspan="2">Fines migration</td><td rowspan="2">Type of reservoir</td></tr>
<tr><td colspan="2">Sand production</td><td>Select sand control during well design phase if sand production is a problem - minimum intervention.</td></tr>
</table>

Table 4.10 is the summary of the twenty one causes of production loss, main factors for its occurrence and guidelines.

5. CONCLUSION

The extensive literature review resulted in the major causes of production loss for the most representative offshore petroleum regions, along with possible prevention and remediation treatments.

Twenty one causes of production loss were found and those were classified in three types: flow assurance (9 causes), potential integrity failures (8 causes) and reservoir problems (4 causes).

The common cause of production loss due to flow assurance for the four offshore petroleum regions were hydrates and wax, although the amount of reports were different, as shown in Fig. 3.2. There is not a common cause for the potential integrity failures in the four offshore petroleum regions but the well barrier component that presented more failure was the production tubing. Finally, for reservoir problems, the main cause reported was the sand production due to the sandstone formation presented in these regions.

Reservoir problems specially water and gas coning, can be considered as the most difficult production loss to be treated. When the production of water or gas begins in an excessive way, remediation treatments may not be effective and in the worst cases, the result is a well abandonment.

Potential integrity failures may consider environmental risks, because in the case of leak, the fluid formation may go to the sea polluting the environment and also may cause a blowout jeopardizing the platform staff.

As described in Sec 3.1 some causes of production loss may be correlated with each other. As an example, if flow assurance problems are solved in a first stage, problems such as deposition in well barrier components may be avoided, resulting in a solution to prevent potential integrity failures.

Remediation treatments for the three types of production loss may be applied together with light workovers, avoiding the expensive heavy workovers until the end of the productive life.

As described in Sec 3.2 several oil industries are applying these treatments in the oil wells but these treatments were applied after the occurrence of a well intervention. This behavior may be due to the investment of time and money for the analysis of the causes during the well design. The ideal design should detect possible problems during the initial design phase, in order to avoid problematic scenarios or waste money.

The guidelines and procedures for the three types of causes of production loss may be considered as a methodology that should be followed during the well design phase; reducing and easing the well intervention and avoiding unexpected interruptions in oil production, achieving the objective of this work (see Sec. 4.1).

The case studies presented in Sec. 4.2 show the validity of the use of guidelines and demonstrate the effectiveness of the presented proposals.

- Recommendations for future works

The identification of the causes of production loss was carried out for the four most representative maritime regions. Another analysis may be carried out for all the maritime regions in order to identity all of the causes of production loss for subsea wells, including a comparative analysis with causes identified in shallow water, deep water and ultra-deep water.

The work did not present a cost analysis. The cost analysis can be carried out to measure how much money an oil industry spends waiting for the occurrence of the production loss and how much the oil industry would spend applying the procedures and guidelines proposed.

The proposal of this work is related to conventional completions, and a suggestion for a further work is to compare with an intelligent completion. The objective might be to know if the intelligent completion really reduces the well intervention. This analysis may also include the costs of intelligent completions and compare with the costs of the previous suggestion.

Based on the recommended prevention and remediation treatments a study comparing and evaluating the different treatments may be carried out, also considering cost and efficiency.

In this work the guidelines and procedures were represented in flow charts to obtain a well design of easy and minimum intervention. For future works, new guidelines may be increased or the procedure may be presented in a different way.

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APPENDIX A – DATA SET OF CAUSES OF PRODUCTION LOSS FOR 35 YEARS OF LITERATURE REVIEW

Table A. 1 - Organization of documents found

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Asphaltenes	Gulf of Mexico	Cenegy	2001	No
		Montesi et al.	2011	Yes
		Alapati and Joshi	2013	Yes
	North Sea	Thawer et al.	1990	Yes
		Takhar et al.	1995	Yes
		Garshol	2005	Yes
Hydrates	Campos Basin	Teixeira et al.	1998	Yes
		Minami et al.	1999	Yes
		Assayag	2000	No
		Davalath et al.	2002	No
		Freitas et al.	2002	Yes
		Marques et al.	2002	Yes
		Cardoso et al.	2003	Yes
		Cochran	2003	Yes
		Marques et al.	2003	Yes
		Camargo et al.	2004	Yes
		Palermo et al.	2004	Yes
		Davalath et al.	2004	Yes
		Rodrigues et al.	2007	Yes
		Noe et al.	2008	Yes
		Evangelista et al.	2009	Yes
		Pedroso et al.	2009	Yes
		Zerpa et al.	2011 (a)	No
		Zerpa et al.	2011 (b)	No
		Duarte et al.	2012	No
		Duque et al.	2012	No
	Gulf of Mexico	Peavy and Cayias	1994	No
		Yousif and Dunayevsky	1995	No
		Yousif	1996	No
		Frostman	2000	No
		Milkov et al.	2000	No
		Fu et al.	2001	No
		Cochran	2003	Yes
		Cooley et al.	2003	No
		Kashou et al.	2004	Yes
		Szymczak et al.	2005	Yes
		Johnson and Angel	2005	Yes
		Swanson et al.	2005	No
		Harun et al.	2006	No
		Harun et al.	2006	No
		Harun et al.	2007	No
		Kane et al.	2008	Yes
		Gounah et al.	2008	No
		Mazloum et al.	2011	No

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Hydrates	North Sea	Dawson and Murray	1987	Yes
		Fadnes et al.	1994	No
		Lysne et al.	1995	No
		Argo et al.	1997	Yes
		Lervik et al.	1997	Yes
		Wilson et al.	2004	No
		MacDonald et al.	2006	Yes
		Molyneux et al.	2013	Yes
	West Africa	Yahaya-Joe et al.	2000	No
		Cottom et al.	2005	No
		Watson et al.	2006	No
		Lafitte et al.	2007	No
		Owodunni and Ajienka.	2007	No
		Monahan.	2009	No
		Brezger et al.	2010	Yes
		Thant et al.	2011	No
		Oschmann and Paso.	2013	Yes
		Thomson et al.	2013	No
Wax	Campos Basin	Bastos	1994	Yes
		Khalil et al.	1994	Yes
		Gomes et al.	1994	Yes
		Lima and Alves.	1995	Yes
		Gomes et al.	1996	Yes
		Lino et al.	1997	No
		Minami et al.	1999	Yes
		Miranda and Silva	2000	No
		Cardoso et al.	2003	Yes
		Marques et al.	2003	Yes
		Davalath et al.	2004	Yes
		Camargo et al.	2004	Yes
		Rodrigues et al.	2007	Yes
		Noe et al.	2008	Yes
		Garner et al.	2011	No
		Noville and Naveira	2012	No
	Gulf of Mexico	Hammami and Raines	1999	Yes
		Zougari and Hammami	2005	No
		Fung et al.	2006	Yes
		Manfield et al.	2007	No
		Alwazzan et al.	2008	Yes
		Bailey and Allenson	2009	No
		Shecaira et al.	2011	Yes
		Wylde	2011	No
	North Sea	Partley and bin Jadid	1986	Yes
		Marchall	1990	Yes
		Hamouda	1992	Yes
		Starkey	1994	Yes
		Allena and Walters	1999	No
		Labes-Carrier et al.	2002	No
		Craddock et al	2007	Yes

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Wax	West Africa	Hsu and Brubaker	1995	No
		Owodunni and Ajienka	2007	No
		Farayola et al.	2010	No
		Oseghale and Akpabio	2012	No
		Adeyanju and Oyekunle	2013	Yes
		Oschmann and Paso.	2013	Yes
Barium Sulfate	Campos Basin	Bezerra et al.	1990	Yes
		Ferreira et al.	1990	Yes
		Bezerra et al.	1996	Yes
		Minami et al.	2000	Yes
		Marques et al.	2001	Yes
		Rosario and Bezerra	2001	Yes
		Bezerra et al.	2003	Yes
		Bezerra et al.	2004	No
		Mota et al.	2004	Yes
		Bogaert et al.	2006	No
		Bogaert et al.	2007	No
		Guimaraes et al.	2007	No
		Rodriguez et al.	2007	Yes
		Hernandes et al.	2008	Yes
		De Almeida Neto et al.	2009	No
		Gomes et al.	2010	No
	Gulf of Mexico	Mazzoline et al.	1992	No
		Jordan et al	2011	No
		Mackay et al.	2014	No
		Sopngwi et al.	2014	No
	North Sea	Carrel	1987	Yes
		Todd and Yuan	1990	No
		de Vries and Arnaud	1993	No
		Paulo et al.	2001	No
		Mackay et al.	2003	No
		Mastin et al.	2003	No
		Inches et al.	2006	No
		Refaei and Al-Kandari	2009	Yes
	West Africa	Poggesi et al	2001	No
		Davis and McElhiney	2002	No
		Rosseau et al.	2003	No
		Collins et al.	2004	No
		Chen et al.	2007	Yes
		Patterson et al.	2011	No
		Jordan	2014	No
Calcium Naphthenate	Campos Basin	De Olivieira et al	2013	No
	North Sea	Vindstad et al.	2003	No
		Melvin et al.	2008	No
	West Africa	Goldzal et al.	2002	Yes
		Williams et al.	2007	No
		Junior et al.	2013	No
		Odoula et al.	2013	Yes
		Nichols et al.	2014	No

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Calcium Sulfate	Gulf of Mexico	Yuan	2004	Yes
Calcium carbonate	Campos Basin	Rodriguez et al.	2007	Yes
	North Sea	Mitchell et al.	1980	No
		Kostol and Rasmussen	1993	Yes
		Brankling et al.	2001	No
	West Africa	Azaroual et al.	2001	No
		Rosseau et al.	2003	No
		Jordan et al.	2006	No
		Chen et al.	2007	Yes
		Courbot and Hanssen.	2007	No
NORM	Campos Basin	Godoy et al.	1999	Yes
		Matta et al.	2002	Yes
		Schenato et al.	2013	Yes
		Petrobras	2014	No
	Gulf of Mexico	Rutherford and Richardson	1993	Yes
		Shannon	1993	No
		Fletcher et al.	1995	No
		OGP	2005	No
		Chevron	2013	No
	North Sea	Gäfvert et al.	2006	Yes
		Hylland and Eriksen	2013	No
Strontium Sulfate	Campos Basin	Bezerra et al.	1990	Yes
		Ferreira et al.	1990	Yes
		Marques et al.	2001	Yes
		Rosario and Bezerra	2001	Yes
		Bezerra et al.	2003	Yes
		Mota et al.	2004	Yes
		Bogaert et al.	2006	No
		Bedrikovetsky et al.	2007	No
		Rodrigues et al.	2007	Yes
		Hernandes et al.	2008	Yes
		Reid et al	2009	No
		Bezerra et al.	2013	No
	North Sea	Yuan	1989	No
		Todd and Yuan	1992	No
	West Africa	Jordan et al.	2006	No
		Thomson et al.	2013	No
Cement	Campos Basin	Frota	2003	Yes
		Da Fonseca	2012	Yes
	Gulf of Mexico	Hebert	1986	No
		Howard	2004	Yes
		King and King	2013	Yes
	North Sea	Attard	1991	Yes
		Feather	2011	Yes
		Saeby	2011	No
		Blaauw	2012	Yes
		Torbergensem	2012	Yes
		Etetim	2013	Yes
	West Africa	Piot et al.	2001	No
		Rusch et al.	2004	No
		Sonde et al.	2014	No

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Christmas tree	Campos Basin	Albernaz	2005	Yes
		Rodriguez et al.	2005	Yes
		Alves	2012	Yes
	North Sea	Dawson and Murray	1987	Yes
		Stendebakken	2014	Yes
Gas Lift valve	Campos Basin	de Moraes et al.	2014	No
	North Sea	Pucknell et al.	1994	No
		Kinnear and John	1996	No
		Gilbertson	2010	Yes
		Holand	2014	Yes
Packer	Gulf of Mexico	King et al.	2005	No
	North Sea	Kostol and Rasmussen	1993	Yes
		Humphreys and Ross	2009	No
		Blaauw	2012	Yes
Production Casing	Gulf of Mexico	Bourgoyne et al.	1999	Yes
		Bourgoyne et al.	2000	No
		Li et al.	2003	No
		Soter et al.	2003	No
		Ispas et al.	2005	No
		Zhang et al.	2008	No
		Furui et al.	2012	No
	North Sea	Anvik and Gibson	1985	Yes
		Andrews	1988	No
		Vudovich et al.	1988	No
		Attard	1991	Yes
		Bruno	1992	No
		Molnes	1993	Yes
		Barkved et al.	2003	Yes
		Vignes et al.	2008	No
		Innes et al.	2010	No
		Blaauw	2012	Yes
		Etetim.	2013	Yes
	West Africa	Shen	2011	No
Production Tubing	Gulf of Mexico	Bradford et al.	2002	No
	North Sea	Vudovich et al.	1988	No
		Bruno	1992	No
		Kostol and Rasmussen	1993	Yes
		Molnes	1993	Yes
		Hannah and Seymour	2006	No
Subsurface Safety Valve	Campos Basin	Moreira	1993	Yes
		Frota	2003	Yes
		Rodriguez et al	2005	Yes
	Gulf of Mexico	Leboeuf et al	2008	No
		Todd and Replogue	2010	Yes

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Subsruface Safety Valve	North Sea	Engen and Rausan	1982	No
		Moines and Iversen	1990	No
		Molnes and Sundet	1993	Yes
		Brookes	1994	Yes
		Lindqvist	1998	Yes
		Rausan	1998	Yes
		Molnes and Strand	2000	No
		Vesterkjaer	2002	Yes
		Birkeland	2005	Yes
		Corneliussen	2006	Yes
		Vignes et al	2006	Yes
		Barratt	2010	Yes
		Vignes and Aadnoy	2010	Yes
		Vignes	2011	Yes
		Seime	2012	Yes
		King and King	2013	Yes
	West Africa	Wakama et al.	2004	
		Ebitu et al.	2011	Yes
Wellhead	North Sea	Ohm	2013	
Excess of gas	Gulf of Mexico	Wu et al.	1995	Yes
		Daltaban et al.	2008	Yes
		De la Garza et al.	2012	
	North Sea	Surguchev and Hansse.	1996	Yes
		Benamara and Tiab.	2001	Yes
		Mjaavatten et al.	2006	No
		Ziegel et al.	2014	Yes
Excess of water	Campos Basin	Capeleiro Pinto et al.	2003	No
		Carrillo	2008	Yes
		Ueta	2008	Yes
		Sampaio et al.	2012	
	Gulf of Mexico	Wu et al	1995	Yes
		Daltaban et al	2008	Yes
	North Sea	Peng and Yeh	1995	Yes
Fines migration	Gulf of Mexico	Morgenthaler and Fry	2012	No
	West Africa	Ezeukwu et al.	1998	Yes
		Chike et al.	2004	No
		Afolabi et al.	2008	No
Sand Production	Campos Basin	Acosta et al.	2007	No
		Marques et al.	2007	Yes
		Rodrigues et al.	2007	Yes
		Coffee	2008	Yes
		Pedroso et al.	2010	Yes
		Marques and Pedroso.	2011	No

Causes of Production loss	Offshore Petroleum Region	Reference		Comments
		Author	Year	
Sand Production	Gulf of Mexico	Fahel and Brienen.	1992	No
		Wong et al.	2003	Yes
		Stair et al.	2004	No
		Gillespie et al.	2005	Yes
		Oubre and Hasemann;	2010	No
	North Sea	Foo et al.	2013	No
		Kostol and Rasmussen.	1993	Yes
	West Africa	Delattre et al.	2002	No
		Delattre et al.	2004	No
		Ezeukwu et al.	2007	Yes
		Petit et al.	2007	Yes
		Guinot et al.	2009	Yes
		Furgier et al.	2013	No

Table A. 2 - Comments

References		Comments
Author	Year	
Adeyanju and Oyekunle	2013	Present a mathematical model to simulate sand production in Nigeria. Explain that is difficult to stop the sand production after the occurrence. The effect of the sand production in the oil production.
Alapati and Joshi	2013	Asphaltene deposition in the flowlines in Green Canion Block. Prevention and remediation treatments
Albernaz	2005	The objective of this work was to analyze the reliability of the Christmas tree, the main failures and possible solutions.
Alves	2012	A data set of failures in Wet Christmas tree for since 1993 until 2010 from Campos Basin was analyzed in order to determine the main failure mode, the main factors and solutions.
Alwazzan et al.	2008	Wax deposition in pipelines in Cottonwood field.
Anvik and Gibson	1985	Casing deformation in the overburden
Argo et al.	1997	Presents the gas composition of an oil field in North Sea, and prevention technology in order to avoid the hydrate deposition in the pipelines: Threshold Hydrate Inhibitor (THI)
Attard	1991	This paper discusses the occurrence of annulus pressure in Hutton oilfield, the problems associated with this, the causes of annulus pressures, evaluation of safety aspects and concerns associated.
Barkved et al.	2003	Carbonates deposition caused a failure in casing (collapse)
Barratt	2010	Explain a case history occurred in Gannet platform in UK sector of the North Sea. The problem was a blockage in the safety valve control line that rendered the existing tubing retrievable safety inoperable; in order to solve this problem a major rig workover was necessary.
Bastos	1994	Presents causes of well intervention in Albacora field.
Benamara and Tiab.	2001	Correlation for gas coning based on North sea oil wells and Addington (1981)
Bezerra et al.	1990	Barium and strontium sulfate scales in producer wells due to seawater injection and water formation in the Namorado Field
Bezerra et al.	1996	Prevention and remediation treatments for scales (Campos Basin)
Bezerra et al.	2003	Methods for scale prediction

References		Comments
Author	Year	
Birkeland	2005	Comparison between subsea and platforms wells based on well intervention. Classification of subsea intervention. Light and heavy workover discussion. Advantages of Light workover in Norwegian Continental Shelf (NCS)
Blaauw	2012	This thesis presents some of the aspects of the well integrity to consider for obtaining and maintaining adequate well integrity throughout the lifecycle of the well. Describe the well barrier components and the main failures, for example: casing (connections), cement (bad cement job), packer (V3-V6).
Bourgoyne et al.	1999	Analyze the severity and the frequency of the occurrence of SCP in the GoM. Possible causes of these problems are discussed and case studies are described.
Brezger et al.	2010	Explain the hydrate formation management in Azurite Field localized in West Africa, the gas composition, and describe a problem occurred in the surface controlled subsurface safety valve due to hydrate deposition.
Brookes	1994	Present problems occurred in Buchan field as failures in DHSV and leakage in different valves.
Camargo et al.	2004	This paper explain the brief summary about today flow assurance issues presented in Campos Basin as hydrates and wax. Hydrate and wax design criteria. Prevention and remediation treatments.
Cardoso et al.	2003	Describe the flow assurance problems (hydrates, wax, asphaltenes, and scales) that were faced in Albacora, Bijupirá/Salema and Marlim field.
Carrillo	2008	Show some case studies for fines migration, excess of production water/gas for Campos Basin.
Cenegy	2001	Asphaltene deposition in a oilfield (Gulf of Mexico)
Chen et al.	2007	This paper documents a scale risk assessment and the development of a scale management plan during the frontend engineering design of the Tombua-Landa development in West Africa. The major trends observed in water chemical composition was barium and calcium, then the possibility of scale deposition is high. Seawater and Injected water composition are presented.
Cochran	2003	Explain what is hydrates, shows the best practices available and proven technology for deepwater subsea oil fields: insulate flowlines, depressurization, and methanol injection.
Coffee	2008	Sand deposition in the separators of the Albacora Field
Corneliussen	2006	The main objective of this thesis has been the development of procedures and methods for risk assessment of oil and gas wells. Explain about well integrity, well barrier failures, and causes of the failures for the different WBC as Subsurface Safety Valve.
Craddock et al	2007	Describes in detail the removal of wax deposits from Gannet field considered as the major subsea flowline using a chemical dissolver;
Da Fonseca	2012	This master thesis try to estimates the mean time to failure of each BIS identified in completion configuration, the methodology proposed may be used for maintenance intervention resource.
Daltaban et al	2008	Case studies due to water and gas production problems in Cantarell field localized in Gulf of Mexico. Gas coning analysis.
Davalath et al.	2004	Wax and hydrates in the Bijupira and Salema Fields.
Dawson and Murray	1987	Hydrate problems in Magnus field, deposition in flowlines.
Ebitu et al.	2011	Explain the main well integrity issues in Bonga field. Case studies about well barrier components such as subsurface safety valve, casing failures. Explain why is important prevent this problems since the well design phase.
Etetim	2013	This thesis describes the process criteria and consideration of design of wellbore seals to establish well integrity behind casing. Material cements were evaluated in order to improve the primary cementing and avoid leaks during production phase. The main reason of failure in cement is cited.
Evangelista et al.	2009	Typical Campos basin ultra deepwater 1541 m - 4°C seabed

References		Comments
Author	Year	
Ezeukwu et al.	2007	A field study to evaluate organic and inorganic agents to determine their effectiveness to eliminate fines.
Feather	2011	Presents percentage of wells with integrity issues in the Gulf of Mexico and North Sea.
Ferreira et al.	1990	Deposition of strontium sulfate due to water injection in the Namorado Field. The strontium sulfate do not precipitates at temperature range between 50 - 95°C
Freitas et al.	2002	Describes operational procedures carried out in Campos Basin to locate and dissociate gas hydrates plugs in subsea equipments and pipelines. Two cases are discusses in Roncador field and Marlim field.
Frota	2003	A real data base was used from Campos Basin during a period of twelve years. This data base was used in order to identify the main causes of failure that lead to a well intervention. The author identified three groups of causes of failure: flow, mechanical failure and reservoir.
Fung et al.	2006	Pig cleaning in pipelines.
Gäfvert et al.	2006	Shows results from 41 Norwegian offshore platforms during a five-month period in order to analyze the 226Ra, 228vRa and 210 Pb, discharge of these through produced water.
Garshol	2005	Asphaltene deposition in the production tubing in Gyda Field.
Gilbertson	2010	This master thesis presents a study about failures in gas lift valves, and proposes a positive-locking, thermally-actuated safety valve in order to solve the problem. A prototype of this valve is explained.
Gillespie et al.	2005	Gravel pack failure, due to flow rate velocity. The authors adopted some criteria to avoid this problem.
Godoy et al.	1999	Description about NORM in Campos Basin.
Goldzal et al.	2002	Presents a study about prevention methods in order to avoid scale and naphthenate deposition. Also presents a prevention method applied in Dalia field.
Gomes et al.	1994	Flowline problems in Albacora field
Gomes et al.	1996	Solutions for flow assurance issues for Albacora, Marlim and Barracuda field localized in Campos Basin.
Guinot et al.	2009	In Okwori subsea field several downhole-sand control failures was occurred, this represented a rig intervention cost of USD several million.
Hammami and Raines	1999	Explanation about wax deposition, onsets of paraffin crystallization temperatures (WAT) and shows some analysis carried for Gulf of Mexico samples.
Hamouda	1992	Case study in Ekofisk
Hernandes et al.	2008	Bullhead as a solution in the Espadarte Field
Holand	2014	Gas lift incidents, reliability, possible solutions
Howard	2004	Casing pressure problems presented in Gulf of Mexico.
Johnson and Angel	2005	This paper explain the main prevention and remediation treatments for Troika field that should be implemented in order to avoid hydrate plug.
Junior et al.	2013	Calcium naphthenate description. Gimboa field presented calcium naphtehnate problems. Remediation treatments applied.
Kane et al.	2008	Hydrates formation in GEP due to increase of water production in Matterhorn field.
Kashou et al.	2004	A hydrate plug was detected in Genesis field localized in Gulf of Mexico. Temperature of deposition is presented and also remediation and removal techniques applied.
Khalil et al.	1994	A new technology to solve the paraffin deposition in Campos Basin oilfields: Nitrogen Generating Systems.
King and King	2013	Presents an exhaustive literature review about failures in well barrier components as cement and casing. Current solutions at different oil fields.

References		Comments
Author	Year	
Kostol and Rasmussen	1993	Leakage in tubing production, sand production problems, calcium carbonate deposition. Statford field.
Lervik et al.	1997	Hydrates prevention by electrical methods in Troll field.
Lima and Alves.	1995	Remediation treatments for wax deposition. Explanation about pig.
Lindqvist	1998	Presents results from a comprehensive reliability study of SCSSV used in the North Sea. Data collected form 26 oil/gas fields in the North Sea. The main failure modes and description.
MacDonald et al.	2006	Combination between hydrate and corrosion inhibitor in order to avoid hydrate deposition
Marchall	1990	Wax deposition in the pipelines in Valhall field.
Marques et al.	2001	Experiences in the Namorado Field
Marques et al.	2002	In a well in Campos Basin a repair of SSSV was scheduled, but was not possible to remove the X-mas tree due to a hydrate deposition. A ROV was necessary to identify the cause of the problem.
Marques et al.	2003	A wax deposition occurred in flowlines. Some solutions are presented as replace the flowline (6 MM US$), or cleaning with a pig.
Marques et al.	2007	Campos Basin is sandstone reservoir then since the pioneer oil discoveries were realized a sand management strategy to achieve a desirable level of production. This paper presents an overview of the evolution of Petrobras open hole gravel packing operational practices and a description of the main steps taken to improve HOHGP.
Matta et al.	2002	Presents the reports about radion levels (NORM) in Campos Basin.
Minami et al.	1999	Presents case studies for Marlim, Bijupirá and Barracuda. These fields had wax problems in flowlines and pipelines.
Minami et al.	2000	Presents formation and seawater composition of Roncador field, this tables are useful in order to determine the saturation index.
Molnes	1993	Failure mode, number of failures and MTTF of subsurface safety valve - TR (Flapper). Historical development in TR-SCSSV Flapper type reliability (1992-2009)
Molnes and Sundet	1993	This work presents the methodology and results form a major research project on well completion equipment reliability. The main failure modes of DHSV, production tubing, and the well intervention carried out due to these problems.
Molyneux et al.	2013	Hydrate case study in Atlantic-Cromarty field
Montesi et al.	2011	A proposal in order to determine the prediction of asphaltenes and the influence in the CAPEX (Blinf Faith Field)
Moreira	1993	The objective of this work was to investigate the safety aspects in SSSV for a subsea completed. Identify the potential failures, analyze it is possible remove the SSSV. Solutions adopted by Petrobras.
Mota et al.	2004	Deposition from moderate to severe in the Marlim West Field
Noe et al.	2008	Describes the main flow assurance problems in Roncador field and solutions.
Odoula et al.	2013	Explain calcium naphthenate. The problems occurred in two fields in West Africa. Pictures shown the calcium naphthenate deposition. Remediation techniques: CaN inhibitor.
Oschmann and Paso.	2013	Presents a successful implementation of LDHI (Low Dosage Hydrate Inhibitor) and PPD (Pour Point Depressant) for a new deepwater production system offshore Africa. Wax Appearance Temperature for this field as function of pressure.
Palermo et al.	2004	Presents some Petrobras field cases in which hydrate deposition did not happen, because crudes have natural surfactants.
Partley and bin Jadid	1986	Wax deposition in Troll field
Pedroso et al.	2009	Definition of hydrates, temperature of deposition, different types of inhibitors.
Pedroso et al.	2010	ESP problems due to sand deposition in the Carapeba Field

References		Comments
Author	Year	
Peng and Yeh	1995	Discusses the use of horizontal wells in reservoir with was or gas coning problems. Presents cases studies about these problems (Troll field - water coning)
Petit et al.	2007	Wells in Girassol field are localized in unconsolidated sandy turbiditic reservoir. The completion strategies employed in these wells are the installation of sand control. This paper provide an overview of the stand alone screens in open hole and cased hole frac-packs after 5 years of production and injection.
Rausan	1998	Description about the main failure modes of SCSSV and estimation of the mean time to failure and the mean fractional dead-time.
Refaei and Al-Kandari	2009	This paper present a background about scales, the water chemical reactions , location of scale deposition, water treatments, steps that should be taken in order to solve scale problems.
Rodrigues et al.	2007	This paper summarizes the history of the damage and main completion troubles associated to Campos Basin deepwater matured fields. Prediction, prevention and remediation aspects. Presents production problems such as hydrates, wax, sand production, fines migration, scales.
Rodriguez et al	2005	Two cases are presented. The second case presents a leakage in the wet x-mas tree.
Rosario and Bezerra	2001	Presents the methodology for characterization of formation water and scale prediction in the waterflooding project of a deep-water field, from Campos Basin.
Rutherford and Richardson	1993	The purpose of this paper is to explain the involvement with NORM in the Gulf of Mexico. Presents a short history of the NORM in the oil industry.
Schenato et al.	2013	Explanation about NORM, risks, Brazilian laws.
Seime	2012	Description about hydraulic and electrical DHSV, the main failure modes, pros and cons of these two valves, solutions to avoid the main failures.
Shecaira et al.	2011	Wax deposition caused problems in Cottonwood field.
Starkey	1994	Case study in Ness field.
Stendebakken	2014	The main purpose of this work was estimate the retrieval rate of the Christmas tree relating with well intervention; determine the main failure mode of this intervention and possible solutions.
Surguchev and Hansse.	1996	Consequences of sustained casing pressure in GoM.
Szymczak et al.	2005	Describe a case study occurred in Gulf of Mexico, the problems was due to hydrate deposition. Explain possible solutions that should be adopted.
Takhar et al.	1995	Production loss due to asphaltene in the Clyde Field.
Teixeira et al.	1998	In Albacora field, seven months after the beginning of oil production a blockage in two wells resulted due to hydrate formation in the manifold.
Thawer et al.	1990	Asphaltene deposition in Ula Field in the production tubing and production facilities
Todd and Replogue	2010	Presents the metocean conditions for Gulf of Mexico. Subsurface safety valve failures presented in Thunder horse. Hydrate problems.
Torbergensem	2012	Well integrity and well barrier definition. Some cases of loss of well integrity such as casing, wellhead, tubing. Failures in the different well barrier components.
Ueta	2008	A water breakthrough resulting in an inhibition of oil production, a heavy workover was needed to introduce a swellable packer technology in Campos Basin.
Vesterkjaer	2002	The objective of this work is to develop and understanding of the contribution a dowhole safety valve represents to the overall risk in a subsea oil/gas well. Subsurface relation with blowout. Christmas tree and subsurface safety valve discussion.

References		Comments
Author	Year	
Vignes	2011	The objective of this work was present the methods for analyzing, evaluating and communicating the well integrity challenges, trying to find solutions in order to improve well integrity. This work presents five papers writhe by the author discussing the well integrity problems.
Vignes and Aadnoy	2010	Presents a table that shows the percentage of wells with failures in well barrier components such as wellhead, DHSV, GLV, tubing, casing, Packer, cement.
Vignes et al	2006	A description of a pilot project carried out by PSA. Different companies was invited to write a report describing the failure problems in the oil wells. Statistics of the failures in production and injection wells, percentage of failure in the well barrier components.
Wong et al.	2003	Studies about asphaltene deposition, for example increasing the water cut the asphaltene deposition rate can decrease.
Wu et al	1995	Amber field has water influx and gas cap drive reservoir mechanism, resulting in exceed of water and gas production
Yuan	2004	Calcium carbonate and calcium sulfate problems in Canyon Express localized in Gulf of Mexico. Presents the saturation index.
Zerpa et al.	2011 (a)	This work present the importance of developing a gas hydrate model in flow assurance for the oil industry. Explain the model of hydrate formation.
Ziegel et al.	2014	Gas coning in North Sea

Table A. 3 - References

References		Bibliography
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