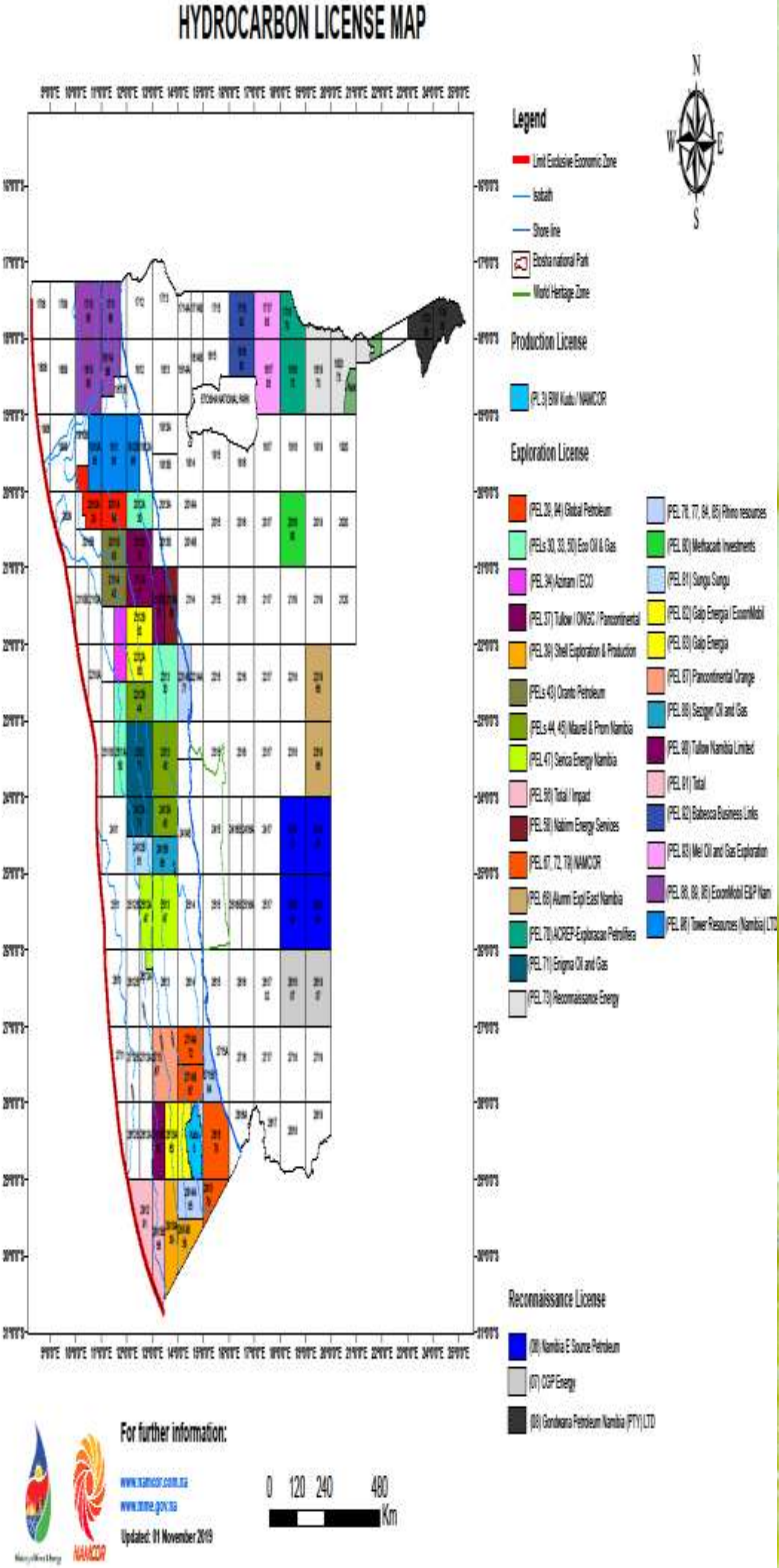

RESERVOIRS

oil and gas

POROSITY
PERMEABILITY
VOLUME AND
LIFESPAN

GABRIEL WIMMERTH

THE POROSITY OF A RESERVOIR DETERMINES THE QUANTITY OF OIL AND GAS. THE MORE PORES A RESERVOIR CONTAINS THE MORE QUANTITY, VOLUME OF OIL AND GAS IS PRESENT IN A RESERVOIR.

BY

GABRIEL KEAFAS KUKU PLAYER WIMMERTH

DISSERTATION PRESENTED FOR THE DEGREE

OF

DOCTORATE IN PETROLEUM ENGINEERING

In the Department of Engineering and Science at the
Atlantic International University, Hawaii, Honolulu,
UNITED STATES OF AMERICA

Promoter: Dr. Franklin Valcin
President/Academic Dean at Atlantic International University

October 2015

Atlantic International University

DECLARATION

I declare by submitting this thesis, dissertation electronically that that the comprehensive, detailed and the entire piece of work is my own, original work that I am the sole owner of the copyright thereof(unless to the extent otherwise stated) and that I have not previously submitted any part of the work in obtaining any other qualification.

Signature: **Date:** 10 October 2015

Atlantic International University

DEDICATION

This work is dedicated to my wife Edla Kaiyo Wimmerth for assisting, encouraging, motivating and being a strong pillar over the years as I was completing this dissertation. It has been quite a tremendous journey, hard work and commitment for me and I would not have completed this enormous work, dissertation without her weighty, profound assistance.

ABSTRACT

The oil and gas industry, petroleum engineering, exploration, drilling, reservoir and production engineering have taken an enormous toll since the early forties and sixties and it has predominantly reached the peak in the early eighties and nineties. The number of oil and gas companies have been using the vertical drilling approach and successfully managed to pinch the reservoir with productive oil or gas. Many others have also failed in the same process.

Namibia on the other hand also tried its luck, onshore and offshore, since the early 1908 but never has been successful in hitting an oil or gas reservoir. They only managed to hit a WILDCAT. What has been the problem in Namibia as its counterpart with the same rock formations Brazil has been successful on several oil and gas reservoirs along their two dominant oil and gas Basins, Santos and Campos?

The thesis will surely outline the above mentioned practical and engineering problem and provide analytical and conclusive solutions. The objective of this thesis is principally centred on the quantity and lifespan of an oil and gas reservoir based on its porosity and permeability. How much oil or gas and what is the quantity of oil or gas in a porous reservoir? Does porosity determine the quantity of oil or gas in a reservoir? In order to achieve this answer and hence conclusively provide answers. I must have executed a vigorous and practical approach.
I had to engage the basic properties of different types of rocks and their ability to store oil or gas in its reserves.

How did I achieve the above mentioned problems and guidelines? I approached oil and gas companies, which are currently busy exploring and drilling for oil or gas onshore and offshore in Namibia. I equally got information on the internet, on these companies. I also demonstrated with my scientific experimental techniques in my study at home, with different types of stones and sponges with different sizes and use the basic sun flower oil in order to determine the porosity of a reservoir, hence to determine the quantity of oil or gas. I alternatively handed out 500 questionnaires to different people, students, teachers and lecturers in trying to find out the porosity of a reservoir, by collecting different types of stones, use either water, sunflower or any liquid of their disposal in trying to find out the porosity and quantity of the fluid in a particular reservoir. The questions on the questionnaire were as follows:

(i) How many circular stones? (ii) Determine the volume of the circular stones. (iii) Determine the volume of fluid, oil or water in the circular container (iv) How many rectangular stones? (v) Determine the volume of the rectangular stone inside the container. (vi) Determine the role of the liquid inside the rectangular container.

(vii) How many triangular stones? (viii) Determine the volume of the triangular stones inside the container.

(ix) The volume of the liquid in the triangular container (x) Mix the fourth container with different types and sizes of stones, circular, rectangular and triangular. How many stones of each shape, circular, rectangular and triangular? (xi) The total volume of the stones in the container, circular, rectangular and triangular.

(xii) The net volume of the fluid inside the mixed container. (xiii) Determine the pressure of the different containers, circular, rectangular and triangular stones inside (xiv) Determine the pressure of the mixed container

(xv) Will pressure determine the porosity of a reservoir? (xvi) Determine the wettability of the container. (xvii) Is it possible that plate tectonics will continuously take place or did it reach its proximity?

It is also practically and scientifically possible that a particular oil or gas reservoir will have different types of porosity and that will be provided by different sizes of stones in a test demonstration of a reservoir.

The reservoir with the different types, sizes of stones, circular, rectangular and triangular provided the best results of a practical reservoir in the oil and gas industry. The earth crust consists of different types of rocks, like the igneous, sedimentary and metamorphic rocks, which are produced by different atmospheric conditions. These types of rocks finally provide the landscape of the earth. On the other hand, different types of rocks provide different types of reservoirs, like the oil and gas reservoirs. The oil and gas reservoirs are formed over centuries of fossil foil deposition and sedimentation. The sedimentation takes place under different types of pressure and temperature conditions, which eventually result into a hydrocarbon of oil and gas.

The rock formations on the different continents are based on the plate tectonics theories, as the PANGAEA and the GONDWANA went through different rock formations over ages and hence underwent certain geomorphologic processes, like crystallization, erosion, sedimentation and metamorphism, in order to be classified as a rock. Crystallization process can take place underground or on the surface. The erosion and sedimentation processes are assisted by wind, running, flowing water and organisms over hundreds and thousands of years. On the other hand is metamorphism a process which only changes the face of an existing rock, in conjunction with the continuously changing temperature and pressure conditions and hence rocks are usually identified by the minerals they are constituting. There are three types of fluids in a reservoir, gas, water and oil. These fluids are flowing differently inside a reservoir, like radial flow, linear flow, spherical and hemispherical flow. The velocity of a fluid has been formulated by Henry Darcy for homogenous fluid in a porous medium. The velocity of a fluid is directly proportional to pressure gradient and inversely proportional to the fluid viscosity.

In other words the size of a pore, will determine the permeability and hence the quantitative volume of oil and gas inside a reservoir.

Any engineer will be able to formulate a suitable mathematical model in order to describe the performance of any reservoir, once a straight line is plotted, based on the observed production and pressure data of the indentified reservoir. The most applicable material balance equation of a simple reservoir and the basic knowledge of reservoir engineers will be based on the following information: (i)The initial hydrocarbon in place of a reservoir (ii) How much hydrocarbon can be produced at different pressures(iii)The primary mechanism for reservoir production(iv)The potential usefulness of varying enhanced recovery techniques.

The frequently changing pressure applications on the earth crust, will determine the quantity of fluid in a reservoir. As long as there is a continuous change in pressure on any reservoir, there will always be different shapes, sizes of pores and permeability in a reservoir. A reservoir, which does not have any pores, will never have any quantity of oil and gas.

A Reservoir Simulation is used tremendously and extensively to identify opportunities and company objectives in securing and increasing oil production in heavy oil deposits and reservoirs. The oil recovery process is enhanced by decreasing the oil viscosity by injecting steam or hot water inside a well with oil. The simulation models and the seismic imaging are very much important and critically advantageous to the respective companies and governments, which are on the attempt of trying to explore, drill and produce any gas or oil in any region or location.

It is of utmost importance to know, whether in a certain area, region or place there is an availability of a resource, like oil or gas before any plans are carried out and this can only be determined by seismic 3D imaging and hence the seismic application. Once an oil and gas reservoir has been identified and located and the companies know that there is oil or gas available, then the planning will start on how to drill and extract oil or gas from deep down the sea, sub-surface. The seismic imaging or data will also bring forth the quantity of the possible oil or gas.

The application of software on the other hand is also of utmost importance in reservoir engineering. This is the very much imperative to use technological applications and software in determining the types of oil and gas reservoirs and hence determine which reservoirs are containing the required and expected oil or gas for production. It is also only through a certain kind of software application any reservoir engineer will be able to determine where and which reservoir contains any volume of oil or gas without physically observing at close distance the containment of a particular reservoir. An office base projection, through a computer, PC application can be used and hence determine, how far an oil or gas reservoir is located and which one contains oil or gas.

Reservoir Simulation is an area of reservoir engineering in which computer models are also used to predict the flow of fluids, oil, water, and gas through porous media. Modelling is one of the main methods of knowledge of nature and society. It is widely used in technology and is an important step in the implementation of scientific and technological progress. The possibilities of geological, geophysical and hydrodynamic cognition of development objects are continuously expanding. Yet these possibilities are far from endless. Therefore, there is always a need to build and use such a field development model in which the degree of knowledge of the object and the design requirements would be adequate

The wettability of porous materials may be two types: (1) uniform or homogeneous and (2) non-uniform or heterogeneous. Uniformly wet porous materials have either a completely water-wet or oil-wet pore surface throughout the porous media. Most of the sedimentary formations are non-uniform as they typically contain separate portions of water- and oil-wet regions.

The Brazil and Namibia oil and gas basins are very much identical as they contain the same rock formations of dominantly consisting of shale, conglomerates, salt and sedimentary rock types. The Brazilian onshore and offshore areas have been successfully indicating oil and gas deposits and explorations. Brazil as the country has been successfully providing oil and gas supplies nationally and internationally. *These simple descriptive conclusions must not be far fetch from Namibia. If Namibia has the same rock formations which indicate the same oil and gas reserves, reservoirs like Brazil, then Namibia must also be able to acquire and find oil and gas in its rock formations.* The technological applications in the exploration, hence the drilling of the reservoirs must be applied successfully and the vertical as well as the horizontal drilling methods must be applied in order to find oil and gas in the Namibia basins, NAMIBE, WALVIS, LUDERITZ, and ORANGE.. There is oil and gas in the Namibia basins and it just requires the financially expensive vigorous drilling by the oil and gas companies.

The reservoirs which contain more pores or which are dominantly porous contain more oil or gas as the ones which do not contain more pores or which are not porous. Namibia offshore basins, NAMIBE, WALVIS, LUDERITZ and ORANGE contain oil and gas. The onshore rock formations also contain, oil and gas.

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The completion of this dissertation in Reservoir Engineering has taken me through a great length of hard work which I could never have completed if it was not the assistance of number of people, professionals, friends, tutors, colleagues and family members and I greatly owe them the debt of gratitude in assisting me to complete this dissertation and I would like to thank them:

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INDEX

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LISTS OF FIGURES

LISTS OF TABLES

LISTS OF ACRONYMS/SCIENTIFIC EQUATIONS AND SI-UNITS (IUPAC)

NAMCOR:	National Petroleum Corporation of Namibia
API:	American Petroleum Institute
GOR:	Gas Oil Ratio
MBE:	Material Balance Equation
scf/STB:	standard cubic foot/Stock Tank Barrels
bbl/STB:	barrels per stock tank barrels
Critical pressure:	pc
Critical temperature:	Tc
Critical volume:	Vc
Critical compressibility factor:	zc
Acentric factor:	T
Molecular weight:	M

v = dp/dx

v:	velocity of a homogeneous fluid in a porous medium
dp:	directly proportional to the pressure gradient
dx:	inversely proportional to the fluid viscosity**.**
q/A:	**q** is the volumetric flow rate in cubic centimetres per second(cm^3/s)
A:	total cross-sectional area of the rock in square centimetres (cm^2)

F = N (Eo + mEg).

rb: reservoir barrels

Volume Balance = Expansion of oil + Originally dissolved gas

N: N is the initial oil in place in *stock tank barrels* (stb)

N(OIL) = V ø (1−Swc) / Boi (stb)

m is the ratio : $\dfrac{\text{initial hydrocarbon volume of the gascap}}{\text{initial hydrocarbon volume of the oil}}$

Np: cumulative oil production in stock tank barrels

R_p is the cumulative gas oil ratio = $\dfrac{\text{Cumulative gas production (scf)}}{\text{Cumulative oil production (stb)}}$

$$G = \frac{mNB_{oi}}{B_{gi}} \quad \text{(scf)}$$

m: Ratio between the mass of the initial volume, empty reservoir, of a reservoir and its volume in quantity, filled reservoir.

$$mNB_{oi}\ (Bg/B_{gi}) \quad \text{(rb)}$$

Therefore, the expansion of the gascap is: $mNB_{oi} \left\{ (B_g/B_{gi}) - 1 \right\}$ (rb)

d (HCPV) = - dVw + dVf : total volume change due to these combined effects

d (HCPV)= - (cw Vw + cf Vf) ∆p: as a reduction or minimization in the hydrocarbon pore volume

Vf: is the total pore volume(HCPV/(1 −Swc))

Vw: is the connate water volume(Vf x Swc = (HCPV)Swc/(1 − Swc).

(1+m)NBoi: total HCPV, including the gascap

$$- \quad d(HCPV)\ (1 + m)NB_{oi} \left\{ \frac{c_w S_{wc} + c_f}{1 - S_{wc}} \right\} \Delta p$$: the HCPV reduction

F = Np (Bo + (Rp - Rs) Bg) + Wp Bw which represents the underground withdrawal (rb)

Eo = (Bo − Boi) + (Rsi − Rs) Bg describing the expansion of oil and its originally dissolved gas(rb/stb)

$$E_g = B_{oi} \left(\frac{B_g}{B_{g1}} - 1 \right)$$ describing the expansion of the gascap gas (rb / stb)

$$E_{fw} = (1 + m) B_{oi} \left(\frac{c_w S_{wc} + c_f}{1 - S_{wc}} \right) \Delta p$$ expansion of the connate water and reduction in the pore volume (rb / stb)

F = N (Eo + mEg+Ef,w) + WeBw **material balance equation**

F = NEo a reservoir has no initial gascap, negligible water influx and for which the connate water and rock compressibility term may be neglected. The observed production is then evaluated as an underground withdrawal.

$$\frac{F}{E_o} = n + \left\{ \frac{W_e}{E_o} \right\}$$

In order to plot a linear function of the **expansion of the oil plus its originally dissolved gas.**

The equation below can still be expressed in a linear form as in which F/Eo should be a linear function of We/Eo.

HCPV = $V\,ø\,(1-S_{wc})$ HydroCarbon Pore Volume

= G/E_i where G is the **G**as **I**nitial **I**n **P**lace**, GIIP,**

Production (sc) = GIIP (sc) - Unproduced Gas (sc)

$G_p = G - (HCPV)E$

$G_p = G - G$

(E/**E**$_i$**):** which can be expressed as

$$\frac{G_p}{G} = 1 - \frac{E}{E_i}$$

or, using equation, as

$$\frac{p}{Z} = \frac{p_i}{Z_i}\left(1 - \frac{G_p}{G}\right)$$

$$d(HCPV) = -dV_w + dV_f$$

initial connate water volume **pore volume final**

$$c_f = \frac{1}{V_f}\frac{\partial V_f}{\partial (GP)}$$

where **GP** is the **grain pressure** which is related to the **fluid pressure** by

d(**FP**) = $-d(GP)$ therefore

$$cf = \frac{1}{V_f}\frac{\partial V_f}{\partial (GP)}$$

$$= \frac{1}{V_f}\frac{V_f}{\partial p}$$

where p is the fluid pressure and the Equation below expresses that:

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$$d(HCPV) = c_w V_w\, dp + c_f V_f\, dp$$

or, as a reduction in hydrocarbon pore volume as

$$d(HCPV) = -(c_w V_w + c_f V_f)\Delta p$$

where $\Delta p = p_i - p$, the drop in fluid (gas) pressure. Finally, formuting and expressing the pore and connate water volumes as:

$$V_f = PV = \frac{HCPV}{(1 - S_{wc})} = \frac{G}{E_i (1 - S_{wc})}$$

$$V_w = PV \times S_{wc} = \frac{G S_{wc}}{E_i (1 - S_{wc})}$$

the reduction in hydrocarbon pore volume can be substituted in the equation below:

$$\mathbf{\frac{G_p}{G} = 1 - \frac{E}{E_i}}$$

$$\frac{G_p}{G} = 1 - \left[1 - \left[\frac{(c_w S_{wc} + c_f)\Delta p}{1 - S_{wc}}\right]\right]$$

as the modified material balance. Inserting the typical values in this equation:

$c_w = 3 \times 10^{-6}$/ psi,

$c_f = 10 \times 10^{-6}$ /psi

$S_{wc} = 0.2$

as well as large pressure drop of $\Delta p = 1000$ psi

Then the term in parenthesis becomes:

$$Gp/G = 1 - \left[1 \left[- \frac{((3 \times 10^{-6} \times 0.2) + 10 \times 10^{-6})\, 1000}{1 - 0.2} \right] \right.$$

$$= 1 - (1 - 0.01325)$$

$$= 1 - 0.988675$$

$$= 0.011$$

Production (sc) = GIIP (sc) - Unproduced Gas (sc)

$$G_p = G - \left[\frac{G}{E_i} - W_e \quad E \right]$$

$$\frac{p}{Z} = \frac{p_i}{Z_i} \frac{1 - \left[\frac{G_p}{G}\right]}{\left[1 - \frac{W_e E_i}{G}\right]}$$

$$W_e = cW\Delta p$$

where c = the total aquifer compressibility (cw + cf)

W = the total volume of water, and depends primarily on the geometry of the aquifer

and Δp = the pressure drop at the original reservoir-aquifer boundary.

Production (sc) = GIIP (sc) - Unproduced Gas (sc)

$$G_p = G - \left[\frac{G}{E_i} - W_e \quad E \right]$$

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$$\frac{p}{Z} = \frac{p_i}{Z_i} \frac{\left[1-\frac{G_p}{G}\right]}{\left[1-\frac{W_e E_i}{G}\right]}$$

$$W_e = cW\Delta p$$

where c = the total aquifer compressibility (cw + cf)

W = the total volume of water, and depends primarily on the geometry of the aquifer

and Δp = the pressure drop at the original reservoir-aquifer boundary.

$$G_a = \frac{G_p}{1 - E/E_i}$$

Apparent Gas

$$G = \frac{G_p - W_e E}{1 - E/E_i}$$

$$G_a = G + \frac{W_e E}{1 - E/E_i}$$

$$\frac{p}{Z} S_{gr} = nRT$$

and, since Sgr is independent of pressure, then for isothermal depletion

$$n \propto \frac{p}{Z}$$

which indicates that a greater quantity of gas is trapped at high pressure than at low.

$$W_e = cW\Delta p$$

where c = the total aquifer compressibility ($c_w + c_f$)

W = the total volume of water, and depends primarily on the geometry of the aquifer

and Δp = the pressure drop at the original reservoir-aquifer boundary.

$$G_a = \frac{G_p}{1 - E/E_i}$$

Apparent Gas

$$G = \frac{G_p - W_e E}{1 - E/E_i}$$

$$G_a = G + \frac{W_e E}{1 - E/E_i}$$

Sgr: gas saturation,

$$\frac{p}{Z} S_{gr} = nRT$$

and, since Sgr is independent of pressure, then for isothermal depletion

$$n \propto \frac{p}{Z}$$

*R*s**:** gas solubility

*S*g: gas saturation

$$F = N(E_o + mE_g + E_{fw}) + W_eB_w$$

where F = underground withdrawal

$= N_p (B_o - (R_p - R_s)B_g) + W_pB_w$

E_o = oil and solution gas expansion

$= (B_o - B_{oi}) + (R_{si} - R_s)B_g$

E_g = gas cap gas expansion

$= B_{oi}(B_g/B_{gi} - 1)$

E_{fw} = hydrocarbon space reduction

$= (1+m)B_{oi}(c_w s_{wc} + c_f)del(p)/(1 - s_{wc})$

$$\frac{F}{E_o + mE_g + E_{fw}} = N + \left(\frac{W_eB_w}{E_o + mE_g + E_{fw}}\right)$$

$$F = N (E_o + E_{fw}) + mNE_g$$

and thus to :

$$\left(\frac{F}{E_o + E_{fw}}\right) = N + mN \left(\frac{W_eB_w}{E_o + E_{fw}}\right)$$

$$F = GE_g + W_e$$

where $F = G_pB_g + W_pB_w$ (3.4.10)

$E_g = B_g - B_{gi}$

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CHAPTER 1
RESEARCH OVERVIEW AND RESEARCH PROBLEM

1.1 INTRODUCTION

This Dissertation and experimental analysis will primarily concentrate on the porosity of a reservoir, its fluid quantity and lifespan of the reservoir. The simple question; ***Does the porosity of a reservoir determine the fluidity, gas, water and oil volume of a reservoir?*** There are surely different types of reservoirs, based on the rock formations and properties and this will eventually determine the type of reservoir, oil or gas.

The approach and the execution of the dissertation will surely be cumbersome as my country, Namibia is not well developed in the industry of petroleum engineering, hence oil and gas industry. How does an individual like me acquire information on this topic of reservoir engineering in order to independently phrase, assess, provide genuine and authentic data and information in an industry which little has been done on the forefront of extracting oil and gas from the reservoirs, deep down from the ocean bottom, 1000 plus kilometres, depth offshore or even onshore. This requires “high tech” and financial muscle from different oil and gas companies and that might be the reason they have never been successful to date in extracting oil or gas from any shore.

The Namibian government and the stakeholders have the free market system, which is has the capitalistic approach on the forefront. Simply stated, one must have capital, finances, money to vigorously engage in this field of study. It will therefore require from me to liaise with oil and gas companies and the State Owned Enterprise, NAMCOR, National Petroleum Cooperation of Namibia in acquiring robust information from their specialists, engineers in their fields of specialization, exploration, drilling, reservoir engineering and production.

The thesis, dissertation will surely at the end, phrase and conclude on its primary goal and objective of the porosity of a reservoir and its fluid quantity, hence its lifespan in providing, catering oil or gas for a certain period of time. It will then also be required to “unleash”, provide enormous information, what happens when an oil and gas reservoir is fully “dried up”. Is it possible to revitalize, reinvigorate such a reservoir, in providing, harvesting oil or gas?

The ultimate question of the Namibia oil and gas basins will also shed more light, whether these basins contain oil or gas and which best technological approaches and techniques can be applied to extract oil or gas onshore or offshore. Namibia must have oil or gas! The ultimate question must also be formulated in this regard: Who must benefit from any oil or gas extraction? It must be Namibians and this will surely be accommodated in any government policies, which the National Petroleum Cooperation of Namibia (NAMCOR) is indebted.

1.2 CURRENT INFORMATION

The porosity of a reservoir determines the fluid content of any reservoir. Only a rock or reservoir which is porous will be able to contain gas, oil or water. A reservoir which does not have pores will not contain any water, oil or gas. Some countries do have the abundance of oil and gas and others not. Why?

1.3 ANALYTICAL DESCRIPTION OF THE DISSERTATION

The basic results of possible acquisitions of oil and gas onshore and offshore will be based on the plate tectonics and the ancient rock formations on different continents and ocean basins. This dissertation will be meaningless, if practical approaches and applications are not well guaranteed and formulated.

The laboratory scientific approaches, step by step analysis and mathematical applications will be the foundation of the thesis. It will also be unjustifiable, if the primary and just application of reservoir simulation and software techniques are not accommodated. The stone, different stone types in containers and different types of sponges will be used to represent the different types of reservoirs, oil or gas.

The precise scientific and mathematical formula, equation calculations will be demonstrated in order to provide the final, conclusive remarks, comments and recommendations on the porosity, quantity of fluid and the lifespan of an oil and gas reservoir. Is it possible to dry up, overused the oil and gas reservoirs and will the Plate-Tectonics Theory continue or did it reach its final stage of migration, continue movement and splitting of the continents?

1.3.1 RESEARCH DESIGN AND METHODOLOGY

The research design stipulates the procedures followed by the researcher, petroleum reservoir aspirant to answer the problem or to test the hypothesis. The finalization of the dissertation in the traditional manner of following the specific outlined research design and methodologies are well applied in any Philosophy of Doctorate candidate but this investigative results finding will be onsite, oil and gas company internship involvement and practical training of the aspirant reservoir engineer. The findings or results will also be based on the experimental demonstration in the science laboratory and study of the researcher, aspirant reservoir petroleum engineer.

1.3.2 RESEARCH DESIGN

The research designs indicate the steps the researcher follows in providing answers to research problem under investigation. The fact finding will be carried out over a period of a year and data will be collected from oil and gas companies, geologists and petroleum reservoir engineers.

1.3.3 METHODOLOGY

The fact finding or data collection will be a face to face interviews and by means of questionnaires. The face to face interviews will be recorded by using my smart phone, Huawei, P30 and these interviews will then be manipulated and printed as factual findings through assignments which will be submitted to the tutor at the Atlantic International University campus via email sending or the virtual university submissions. The collected data from the questionnaires will also be handled in the same manner.

1.4 INVESTIGATIVE RESULTS

Four types of containers will be used, which include the following types of stones, circular, rectangular, triangular and mixed stones, circular, rectangular and triangular in the same container, bottle. The sunflower oil will be used in each container, to represent oil as the fluid. The volume quantity of the porosity will be calculated in each bottle, container and from these calculations the final fluid, oil or gas calculation will be determined. Hence the volume of the fluid will be determined on the porosity of the container, bottle, reservoir. The sponge, representing the different types of reservoirs with different porosities will be used in determining the quantity of oil and a particular sponge, reservoir. The oil will then be squeezed out of the sponge, reservoir to determine the quantity of the oil in a particular sponge, reservoir. The neighbouring sponges will then be filled, wet with oil as the middle sponge will be left dry for a certain period of time, in determining whether the middle sponge, reservoir will be filled with oil again. This exercise, experiment may not be successful as the property, permeability will not be applicable. An alternative exercise of the same sponges will then be implemented where all the sponges will be connected by means of small tubes, in order to attain the permeability property.

1.5 RESEARCH OUTLINE AND SUMMARY

Chapter 1: In this chapter the overview of the hypothesis, dissertation will be given in detailed description.

Chapter 2: The types of rocks and reservoirs will be holistically discussed as different rocks result into different reservoirs of oil or gas.

Chapter 3: Properties of a reservoir and material equation is discussed and formulated with laboratory applications.

Chapter 4: Equilibrium of the reservoir is finally provided for laboratory and practical applications at sites when internships are carried out.

Chapter 5: Reservoir simulation. In this chapter laboratory and PC- modelling will be used to identify and determine the reservoirs which contain oil or gas.

Chapter 6: Reservoir software: It is very much important to use different types of software in reservoir simulation in order to precisely locate a reservoir which contains oil or gas.

Chapter 7: Reservoir volumetric description, hence the quantity of fluid on a reservoir and its lifespan. This is the chapter which evaluates the porosity of a reservoir and the quantity of fluid such a reservoir can produce.

Chapter 8: Namibia oil and gas analysis: Namibia has been a dormant country in the production of oil and gas, although it contains the same rock DNA as Brazil. Namibia basins, Namibe, Walvis, Luderitz and Orange must have and contain oil and gas basins, Santos and Campos of Brazil.

Chapter 9: Synthesis, recommendations and conclusions. In this chapter, I shall finally provide the conclusive findings of the dissertation. A porous reservoir is the only reservoir which can and must produce oil or gas and the lifespan of such a reservoir can be determined. A “dry up” reservoir can also be revitalized in order to produce oil or gas again.

CHAPTER 2

TYPES OF ROCKS AND RESERVOIR

2.1 INTRODUCTION

The earth's landscape is camouflaged by three different types of rocks and the three types of rocks or classes of rocks are the sedimentary, metamorphic and igneous rocks. The differences among them or their makeup have to do with how they were and are formed as the minerals make up rocks and rocks are formed in many environments upon and within the earth's crust.

Each of the three types of rocks is formed in a different way.

- Igneous rock is formed by the transformation and cooling of magma, molten rock, inside the earth or on the surface.
- Sedimentary rock on the one hand is formed from the products of weathering and cementation or precipitation on the earth's surface.
- While the Metamorphic rock is formed by temperature and pressure changes inside the earth.

All three types of rocks constitute the "***make up"*** of the earth's Lithosphere, the outermost layer. The Lithosphere generally on the average is about 100 kilometres in thickness.

Any type of a rock can undergo changes and become any new type of rock. Several processes are involved in the rock cycle that determines this possibility. The key processes which are eventually determining the 'make up' of a rock within the rock cycle are **crystallization, erosion, sedimentation, and metamorphism**.

Let's take a closer look at each of these:

- *Crystallization*. Crystallization occurs when molten material hardens into a rock. An existing rock may be buried deep inside the earth crust as it can melt into magma and then crystallizes into an igneous rock. The rock may then be transported to the earth's surface by natural movements, geomorphologic applications of the earth and Crystallization can occur either underground when MAGMA cools or on the earth's surface when LAVA hardens.

- *Erosion and Sedimentation*. Pieces of rock on the earth's surface are constantly worn down into smaller and smaller pieces. The impacts of running, flowing water, gravitational impact, glacier and ice impacts, plants and animals effects all act to wear down rocks over time. The small fragments of rock which are produced are called sediments. Running and flowing water and wind transport these sediments from one place to another. They are eventually **deposited**, or dropped somewhere. This process is called erosion and sedimentation. The accumulated sediment may become compacted and cemented together into **a sedimentary rock**. This whole process of eroding rocks, transporting and depositing them, and then forming a sedimentary rock can take hundreds or thousands of years.

- *Metamorphism*. Sometimes an existing rock is exposed to extreme heat and pressure conditions deep within the earth crust. Metamorphism happens if the rock does not completely melt but still changes as a result of the extreme heat and pressure conditions and applications. A metamorphic rock may have a new mineral composition and texture.

Note that the rock cycle really does not have a beginning or an end. Therefore, it is a never and ending cycle. The concept of the rock cycle was first developed by James Hutton, an eighteenth century scientist often called the "father of geology". Hutton spoke of the cyclic nature of rock formation and other geologic processes and said that they have "no sign of a beginning and no prospect of an end". The processes involved in the rock cycle take place over hundreds or even thousands of years, and so in our lifetime, rocks appear to be fairly "rock solid" and unchanging. However, a study of the rock cycle shows us that change is always taking place.

The truth is, however, that rocks do change. All rocks on earth change as a result of natural processes that take place at all time. These changes usually happen very gradual and slow. They may even happen below earth's surface so that we do not notice the changes. The physical and chemical properties of rocks are constantly changing in a natural, never-ending cycle called the rock cycle.

The rock cycle describes how each of the main types of rocks is formed, and explains how rocks change within the cycle. A rock is naturally formed by a non living earth material. Rocks are made of collections of mineral grains that are held together in a firm and solid mass. The individual mineral grains that make up a rock may be so tiny that you can only see them with a microscope or they may be as big as your fingernail. A rock may be made of grains of all one mineral type or it may be made of a mixture of different minerals. Most of the rocks contain more than one mineral. Each rock has a unique set of minerals that make it up, and rocks are usually identified by the minerals observed in them. The minerals in a rock contain clues about the conditions, like temperature, that were present when the rock was formed, since different minerals form under different environmental conditions.

Rocks can also be described by their texture, which is a description of the size, shape and arrangement of mineral grains. Rocks may be small pebbles less than a centimetre, or they may be massive boulders that are meters wide. Smaller rocks form when larger rocks are broken apart and worn down.

2.2 TYPES OF ROCKS

2.2.1 Igneous

Igneous rocks are formed when **MAGMA**, molten rock deep within the earth, cools and hardens. Sometimes the magma cools inside the earth and other times it erupts onto the surface from volcanoes; in this case, it is called **LAVA.** No crystals are forming and the rock shiny and glasslike when lava cools very quickly. Sometimes gas bubbles are trapped in the rock during the cooling process, leaving tiny holes and spaces in the rock. All igneous rocks began as magma, molten rock, which cooled and crystallized into minerals. *Geologists classify igneous rocks based on both their crystal size and composition.* Igneous rocks may look different because they may have cooled at different rates and the "mother" magma, original melted rock, was of a different composition. Variations in these two factors have created many different types of igneous rocks. When the magma cools at different rates, it creates different sized minerals. The resulting quick cooling magmas have small minerals, which is actually composed of silica, but has no crystalline structure. **Basalt**, for example, has small minerals, most of which can only be seen under a microscope. On the other hand the quick cooling lavas are called volcanic rocks. Magma that cools slowly creates rocks like **granite**, which have large minerals that can be seen with the naked eye. These igneous rocks cool inside the lithosphere, and are called plutonic rocks.

2.2.2 Sedimentary

Sedimentary rocks are formed from particles of sand, shells, pebbles, and other fragments of material. All these particles collectively are called sediment. Gradually, the sediment accumulates in layers and over a long period of time hardens into rock. Generally, sedimentary rock is fairly soft and may break apart or crumble easily. One can often see sand, pebbles, or stones in the rock and it are usually the only type that contains fossils. Sedimentary rocks form at the Earth's surface in two main ways. Classic material pieces of other rocks or fragments of skeletons may become cemented together and chemical precipitation and evaporation can form sedimentary rocks. Sedimentary rocks are usually associated with liquid water which facilitates erosion, transportation, deposition, and cementation. However, sedimentary rocks may also form in dry, desert environments or in association with glaciers. Examples of this rock type include **conglomerate and limestone**.

2.2.3 Metamorphic

Metamorphic rocks are formed under the surface of the earth from the metamorphosis a change that occurs due to intense heat and pressure, which results in the squeezing of sediments.

The rocks that result from these processes have often ribbon like layers and may have shiny crystals, which are formed by minerals growing slowly over time, on their surface. Metamorphic rocks are igneous, sedimentary, or pre-existing metamorphic rocks that have been changed by pressure and temperature variations within the crust and upper mantle of the earth. The temperatures were not enough to melt the rock, otherwise, an igneous rock would have formed. The pressures were much greater than those required to simply break the rocks into smaller pieces. They were high enough to change the chemical "make up" of the rock by forcing the elements in it to "exchange partners." Different grades of temperature and pressure will cause the same original rock to form very different metamorphic rocks. The Slate, which forms from the sedimentary rock shale, is very dense, smooth and does not contain visible minerals. However, if more pressure and temperature are applied to a slate, it could turn into schist, which has visible layers of minerals. If yet higher temperature and pressure are applied, the schist could turn into gneiss, which shows visible bands of minerals. Examples of this rock type include gneiss and marble.

2.3 CLASSIFICATION OF RESERVOIRS AND RESERVOIR FLUIDS

Petroleum reservoirs are broadly classified and categorised as OIL AND GAS RESERVOIRS.

These broad classifications are further subdivided into different types of reservoirs.

2.3.1 Fundamentals of reservoir fluid behaviour

The type of a reservoir fluid will depend on the following conditions.

2.3.1.1 The composition of the reservoir hydrocarbon mixture.

2.3.1.2 Initial reservoir pressure and temperature.

2.3.1.3 Pressure and temperature of the surface production.

The above mentioned conditions will then be used to classify reservoirs, the naturally occurring of hydrocarbon systems and describe the phase behaviour of the reservoir fluid.

2.4 TYPES OF RESERVOIRS

The classification of reservoirs will depend on the temperature of the reservoir fluid and the critical temperature.

2.4.1 Oil reservoirs — This reservoir will then be classified as an oil reservoir as the reservoir temperature is less than the critical temperature of the reservoir fluid. The oil reservoirs can still be sub divided into the following categories depending on their initial reservoir pressure.

2.4.1.1 Under saturated oil reservoir.

If the initial reservoir pressure, is greater than the bubble-point pressure of the reservoir fluid, then reservoir is labelled as under saturated oil reservoir.

2.4.1.2 Saturated oil reservoir.

When the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid, the reservoir is called a saturated oil reservoir.

2.4.1.3 Gas-cap reservoir.

If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid, the reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapour phase is underlined by an oil phase. The appropriate quality line gives the ratio of the gas-cap volume to reservoir oil volume.

Crude oils are constituting number of physical properties and chemical compositions, and it is often important to be able to group them into broad categories of related oils. In general, crude oils are commonly classified into the following types:

- Ordinary black oil
- Low-shrinkage crude oil
- High-shrinkage (volatile) crude oil
- Near-critical crude oil

The above classifications are essentially based upon the properties exhibited by the crude oil, including physical properties, composition, gas-oil ratio, appearance, and pressure-temperature phase diagrams.

(i) **Ordinary black oil.**

The ordinary black oil are at very low pressures and when it is produced the ordinary black oils usually yield gas-oil ratios between 200–700 scf/STB and the oil gravities of 15 to 40 API. The stock tank oil is usually brown to dark green in colour.

(ii) **Low-shrinkage oil.**

The above mentioned crude oil has got the following properties:

- Oil formation volume factor is less than 1.2 bbl/STB
- Gas-oil ratio less than 200 scf/STB
- Oil gravity less than 35° API
- Black or deeply coloured

(iii) **Volatile crude oil.**

This type of crude oil is commonly characterized by a high liquid shrinkage immediately below the bubble-point. The other characteristic properties of this oil include:

Fundamentals of Reservoir Fluid Behaviour

- Oil formation volume factor less than 2 bbl/STB
- Gas-oil ratios between 2,000–3,200 scf/STB
- Oil gravities between 45–55° API
- Lower liquid recovery of separator conditions.
- Greenish to orange in colour. Another characteristic of volatile oil reservoirs is that the API gravity of the stock-tank liquid will increase in the later life of the reservoirs.

(iv) **Near-critical crude oil.**

If the reservoir temperature is near the critical temperature of the hydrocarbon system, the hydrocarbon mixture is identified as a near-critical crude oil.

The near-critical crude oil is characterized by a high GOR in excess of 3,000 scf/STB with an oil formation volume factor of 2.0 bbl/STB or higher. The compositions of near-critical oils are usually characterized by 12.5 to 20 mol% heptanes-plus, 35% or more of ethane through hexanes, and the remainder methane.

2.4.2 Gas Reservoirs

In general, if the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. On the basis of their phase diagrams and the prevailing reservoir conditions, natural gases can be classified into four categories:

- Retrograde gas-condensate
- Near-critical gas-condensate
- Wet gas
- Dry gas

2.4.2.1 Retrograde gas-condensate reservoir.

If the reservoir temperature lies between the critical temperature and cricondentherm of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir. This category of gas reservoir is a unique type of hydrocarbon accumulation in that the special thermodynamic behaviour of the reservoir fluid is the controlling factor in the development and the depletion process of the reservoir.

2.4.2.2 Near-critical gas-condensate reservoir.

If the reservoir temperature is near the critical temperature, the hydrocarbon mixture is classified as a near-critical gas-condensate. The volumetric behaviour of this category of natural gas is described through the isothermal pressure declines as well as the immediate rapid liquid build-up occurs below the dew point as pressure is reduced. This behaviour can be justified by the fact that several quality lines are crossed very rapidly by the isothermal reduction in pressure. At the point where the liquid ceases to build up and begins to shrink again, the reservoir goes from the retrograde region to a normal vaporization region.

2.4.2.3 Wet-gas reservoir.

The reservoir temperature exceeds the cricondentherm of the hydrocarbon system and hence the reservoir fluid will always remain in the vapour phase region as the reservoir is depleted isothermally. The produced gas flows to the surface, however, the pressure and temperature of the gas will decline. If the gas enters the two-phase region, a liquid phase will condense out of the gas and be produced from the surface separators. This is caused by a sufficient decrease in the kinetic energy of heavy molecules with temperature drop and their subsequent change to liquid through the attractive forces between molecules.

Wet-gas reservoirs are characterized by the following properties:

- Gas oil ratios between 60,000 to 100,000 scf/STB
- Stock-tank oil gravity above 60° API

- Liquid is water-white in colour
- Separator conditions, i.e., separator pressure and temperature, lie within the two-phase region

2.4.2.4 Dry-gas reservoir.

The hydrocarbon mixture exists as a gas both in the reservoir and in the surface facilities. The only liquid associated with the gas from a dry-gas reservoir is water. Usually a system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas. Kinetic energy of the mixture is so high and attraction between molecules so small that none of them coalesce to a liquid at stock-tank conditions of temperature and pressure. It should be pointed out that the classification of hydrocarbon fluids might be also characterized by the initial composition of the system.

From the foregoing discussion, it can be observed that hydrocarbon mixtures may exist in either the gaseous or liquid state, depending on the reservoir and operating conditions to which they are subjected. The qualitative concepts presented may be of aid in developing quantitative analyses. EMPIRICAL EQUATIONS of state are commonly used as a quantitative tool in describing and classifying the hydrocarbon system.

These equations of state require:

- Detailed compositional analyses of the hydrocarbon system
- Complete descriptions of the physical and critical properties of the mixture
  Individual components

Many characteristic properties of these individual components, in other words, pure substances have been measured and compiled over the years. These properties provide vital information for calculating the thermodynamic properties of pure components, as well as their mixtures. The most important of these properties are:

- Critical pressure, pc
- Critical temperature, Tc
- Critical volume, Vc
- Critical compressibility factor, zc
- Acentric factor, T
- Molecular weight, M

2.5 RESERVOIR HETEROGENEITY

Most reservoirs are laid down in a body of water by a long-term process, spanning a variety of depositional environments, in both time and space. As a result of subsequent physical and chemical reorganization, such as compaction, solution, dolomitization and cementation, the reservoir characteristics are further changed. Thus the heterogeneity of reservoirs is, for the most part, dependent upon the depositional environments and subsequent events.

The main geologic characteristic of all the physical rock properties that have a bearing on reservoir behaviour when producing oil and gas is **the extreme variability in such properties within the reservoir itself,** both laterally and vertically, and within short distances. It is important to recognize that there are no homogeneous reservoirs, only varying degrees of heterogeneity. The reservoir heterogeneity is then defined as a variation in reservoir properties as a function of space. Ideally, if the reservoir is homogeneous, measuring a reservoir property at any location will allow us to fully describe the reservoir. The task of reservoir description is very simple for homogeneous reservoirs. On the other hand, if the reservoir is heterogeneous, the reservoir properties vary as a function of a spatial location. These properties may include **permeability, porosity, thickness, saturation, faults and fractures, rock faces and rock characteristics.** For a proper reservoir description, we need to predict the variation in these reservoir properties as a function of spatial locations. There are essentially two types of heterogeneity:

- Vertical heterogeneity
- Areal heterogeneity

Geostatistical methods are used extensively in the petroleum industry to quantitatively describe the two types of the reservoir heterogeneity. It is obvious that the reservoir may be non-uniform in all intensive properties such as permeability, porosity, wettability, and connate water saturation.

2.6 FUNDAMENTALS OF RESERVOIR FLUID FLOW

2.6.1 Types of fluids

In general, reservoir fluids are classified into three groups as the isothermal compressibility coefficient is essentially the controlling factor in identifying the type of the reservoir fluid.

The fluid flow equations that are used to describe the flow behaviour in a reservoir can take many forms depending upon the combination of variables presented i.e., types of flow, types of fluids, etc. By combining the conservation of mass equation with the transport equation (Darcy's equation) and various equations-of-state, the necessary flow equations can be developed.

The fundamental law of fluid motion in porous media is **Darcy's Law**.

The mathematical expression developed by Henry Darcy in 1856 states the velocity of a homogeneous fluid in a porous medium is directly proportional to the pressure gradient and inversely proportional to the fluid viscosity**.**

For a horizontal linear system, this relationship is: $v = dp/dx$

This is **apparent** velocity in centimetres per second and is equal to **q/A**, where **q** is the volumetric flow rate in cubic centimetres per second: cm^3/s

and **A** is total cross-sectional area of the rock in square centimetres: cm^2

In other words, **A** includes the area of the rock material as well as the area of the pore channels. The fluid viscosity, is expressed in centipoises units, and the pressure gradient, dp/dx, is in atmospheres per centimetre, taken in the same direction. The proportionality constant, k, is the *permeability* of the rock expressed in Darcy units. For a horizontal-radial system, the pressure gradient is positive flow, which occurs at higher velocities, the pressure gradient increases at a greater rate than does the flow rate and a special modification of Darcy's equation is needed. When turbulent flow exists, the application of Darcy's equation can result in serious errors.

2.6.2 Incompressible fluids

An incompressible fluid is defined as the fluid, whose volume or density does not change with pressure, i.e.: Incompressible fluids do not exist; this behaviour, however, may be assumed in some cases to simplify the derivation and the final form of many flow equations.

2.6.3 Slightly compressible fluids

These "slightly" compressible fluids exhibit small changes in volume, or density, with changes in pressure. The changes in the volumetric behaviour of this fluid as a function of pressure can be mathematically described, if one knows the volume of a slightly compressible liquid at a reference, initial, pressure.

.2.6.4 Compressible Fluids

These are fluids that experience large changes in volume as a function of pressure.
All gases are considered compressible fluids.

2.7 FLOW REGIMES

There are three types of flow regimes that must be determined in order to describe the fluid flow behaviour and reservoir pressure distribution as an applicable function of time.

2.7.1 Steady-State Flow

This flow regime is identified as a steady-state flow if the pressure at every location in the reservoir remains constant, as the regime does not change with time. In reservoirs, the steady-state flow condition can only occur when the reservoir is completely recharged and supported by strong aquifer or pressure maintenance operations.

2.7.2 Unsteady-State Flow

The unsteady-state flow, is also called *transient flow,* is defined as the fluid flowing condition at which the rate of change of pressure with respect to time at any position in the reservoir is not zero or constant.

2.7.3 Pseudo steady-State Flow

This flowing condition is characterized as the pseudo-steady-state flow when the pressure at different locations in the reservoir is declining linearly as a function of time. This takes place at a constant declining rate. Mathematically, this definition state that the rate of change of pressure with respect to time at every position is constant or it should be pointed out that the pseudo-steady-state flow is commonly referred to as semi-steady-state flow.

2.8 RESERVOIR GEOMETRY

2.8.1 Types of flow

The shape of a reservoir has a significant effect on its flow behaviour. Most reservoirs have irregular boundaries and a mathematical, rigorous, practical and an applicable description of geometry is often and frequently possible with the use of numerical simulators.

For many engineering purposes, however, the actual flow geometry may be represented by one of the following flow geometries:

2.8.2 Radial Flow

A flow into or away from a wellbore will follow radial flow lines from a substantial distance from the wellbore. Fluids move toward the well from all directions and concentrate at the wellbore.

2.8.3 Linear Flow

Linear flow occurs when flow paths are parallel and the fluid flows in a single direction.

In addition, the cross sectional area to the flow must be constant. A common application of linear flow is the fluid flow which takes placed into vertical hydraulic fractures.

2.8.4 Spherical and Hemispherical Flow

It is possible to have a spherical or hemispherical flow near the wellbore, as it depends upon the type of wellbore completion configuration. A well with a limited perforated interval could result in spherical flow in the vicinity of the perforations. A well that only partially penetrates the pay zone, could result in hemispherical flow.

2.9 NUMBER OF FLOWING FLUIDS IN THE RESERVOIR

The mathematical expressions that are used to predict the volumetric performance and pressure behaviour of the reservoir vary in forms and complexity depending upon the number of mobile fluids in the reservoir.

There are generally three phases of flowing systems:

- Single-phase flow (**oil, water, or gas**)
- Two-phase flow (**oil-water, oil-gas, or gas-water**)
- Three-phase flow (**oil, water, and gas**)

The description of fluid flow and subsequent analysis of pressure data becomes more difficult as the number of mobile fluids increases.

2.10 RESERVOIR DRIVE MECHANISMS

In most cases the results which are obtained from the material balance equation are considered in order to have a considerable contribution to the reservoir drive in which all possible sources of energy provide a significant part in producing the reservoir fluids and determining the primary recovery factor. In many cases, however, reservoirs can be singled out as having predominantly one main type of drive mechanism in comparison to which all other mechanisms have a negligible effect. The reservoir fluid hence will determine the type of the drive and the following drives will single out the type of the reservoir and the mechanism which will be covered are as follows:

- solution gas drive
- gascap drive
- natural water drive

2.10.1 Solution gas drive

A solution gas drive reservoir is one in which the principal drive mechanism is the expansion of the oil and its originally dissolved gas. The increase in fluid volumes during the process is equivalent to the production.

Two phases can be distinguished when the:

(a) reservoir oil is under saturated and

(b) pressure has fallen below the bubble point and a free gas phase exists in the reservoir.

The ultimate fact or practical means of keeping the gas in the ground in a solution gas drive reservoir is not obvious. Once the free gas saturation in the reservoir exceeds the critical saturation for flow, then gas will start to be produced in disproportionate quantities compared to the oil and, in the majority of cases, there is little that can be done to avert this situation during the primary production phase. Under very favourable conditions the oil and gas will separate with the latter moving structurally up dip in the reservoir.

The oil production is taken from down dip in the reservoir thus allowing the high compressibility gas to expand and displace an equivalent amount of oil.

This demonstrates a method of keeping as much gas in the reservoir as possible where it can serve its most useful purpose. The economic success of both water and solution gas injection depends upon the additional recovery obtained as a result of the projects. The present day value of the additional oil recovery must be greater than the cost of the injection wells, surface treatment facilities, mainly for water and compressor costs, mainly for gas. In many cases, for small reservoirs, injection of water or gas is not economically viable and the solution gas drive process must be allowed to run its full course resulting in low oil recovery factors.

2.10.2 Gascap drive

Under initial conditions the oil at the gas oil contact must be at saturation or bubble point pressure, *where the first bubble is formed.* The oil further down dip becomes progressively less saturated at the higher pressure and temperature.

For a reservoir in which gascap drive is the predominant mechanism it is still assumed that the natural water influx is negligible and in the presence of so much high compressibility gas, that the effect of water and pore compressibility is also negligible. Under these circumstances, the material balance equation can be written as in which the right hand side contains the term describing the expansion of the oil plus originally dissolved gas, since the solution gas drive mechanism is still active in the oil column, together with the term for the expansion of the gascap gas.

The Equation in this instance is rather cumbersome and does not provide any kind of clear picture of the principles involved in the gascap drive mechanism. **A better understanding of the situation can be gained by using the technique of Havlena and Odeh, for which the material balance, can be reduced to the form**

$F = N (E_o + mE_g)$. The way in which this equation can be used depends on the unknown quantities. For a gascap reservoir the least certain parameter is very often **m**, the ratio of the initial hydrocarbon pore volume of the gascap to that of the oil column. For instance, in the reservoir depicted, the exploration well penetrated the gascap establishing the level of the gas oil contact.

2.10.3 Natural water drive

Natural water drive, as distinct from water injection, has already been qualitatively described in connection with the gas material balance equation. The same principles apply when including the water influx in the general hydrocarbon reservoir material balance. A drop in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir.

2.11 SUMMARY

There are Undefined Petroleum Fractions which are naturally occurring in all hydrocarbon systems and they contain a quantity of heavy fractions that are not well defined and are not mixtures of discretely identified components. These heavy fractions are often lumped together and identified as the plus fraction. A proper description of the physical properties of the plus fractions and other undefined petroleum fractions in hydrocarbon mixtures is essential in performing reliable phase behaviour calculations and compositional modelling studies.

Frequently, a distillation analysis or a chromatographic analysis is available for this undefined fraction. Other physical properties, such as **molecular weight** and **specific gravity,** may also be measured for the entire fraction or for various cuts of it. To use any of the thermodynamic property-prediction models, e.g., **equation of state**, to predict the phase and volumetric behaviour of complex hydrocarbon mixtures, one must be able to provide the eccentric factor, along with the critical temperature and critical pressure, for the defined and undefined, heavy, fractions in the mixture. The problem of how to adequately characterize these undefined plus fractions in terms of their critical properties and eccentric factors has been long recognized in the petroleum industry. Whitson (1984) presented an excellent documentation on the influence of various heptanes-plus (C7) characterization schemes on predicting the volumetric behaviour of hydrocarbon mixtures by equations-of-state.

Riazi and Daubert (1987) developed a simple two-parameter equation for predicting the physical properties of pure compounds and undefined hydrocarbon mixtures.

The proposed generalized empirical equation is based on the use of the molecular weight M and specific gravity of the undefined petroleum fraction as the correlating parameters.

The earth crust consists of different types of rocks, like the igneous, sedimentary and metamorphic rocks, which are produced by different atmospheric conditions. These types of rocks finally provide the landscape of the earth. On the other hand, different types of rocks provide different types of reservoirs, like the oil and gas reservoirs. The oil and gas reservoirs are formed over centuries of fossil foil deposition and sedimentation. The sedimentation takes place under different types of pressure and temperature conditions, which eventually result into a hydrocarbon of oil and gas.

Any rock must undergo certain geomorphologic processes, like crystallization, erosion, sedimentation and metamorphism, in order to be classified as a rock. Crystallization process can take place underground or on the surface. The erosion and sedimentation processes are assisted by wind, running, flowing water and organisms over hundreds and thousands of years.

On the other hand is metamorphism a process which only changes the face of an existing rock, in conjunction with the continuously changing temperature and pressure conditions and hence rocks are usually identified by the minerals they are constituting.

The reservoir classification also depends on the **empirical equations of state**, which are used as quantitative tool in order to describe and classify a hydrocarbon system. Reservoirs also differ in terms of their specific properties as the reservoir heterogeneity is coming to the fore. There are three types of fluids in a reservoir, gas, water and oil. These fluids are flowing differently inside a reservoir, like radial flow, linear flow, spherical and hemispherical flow. The velocity of a fluid has been formulated by Henry Darcy for homogenous fluid in a porous medium. The velocity of a fluid is directly proportional to pressure gradient and inversely proportional to the fluid viscosity.

CHAPTER 3

PROPERTIES OF A RESERVOIR/Material Equilibrium

3.1 INTRODUCTION

This assignment will specifically cover different topics on **MATERIAL BALANCE** and **MATERIAL BALANCE EQUATION** in order to determine the volumetric capacity of an oil and gas reservoir. The material balance of a reservoir will broadly be discussed as well as the respective topics, like the respective balances of gas and oil as well as the gas recovery factor and the reservoir forecasting.

The Havlena-Odeh Linear Material Balance Equation will eventually provide the practical examples of a prospective reservoir.

The material balance of oil and gas reservoir basically refers to the respective quantity of the fluids and the liquid, water in a reservoir. Is the quantity of gas, oil and water the same in a reservoir? What external factor will increase the quantity of water, gas or oil in a reservoir? The pressure availability and intensity in a reservoir has got a crucial role to play in the material balance of a reservoir.

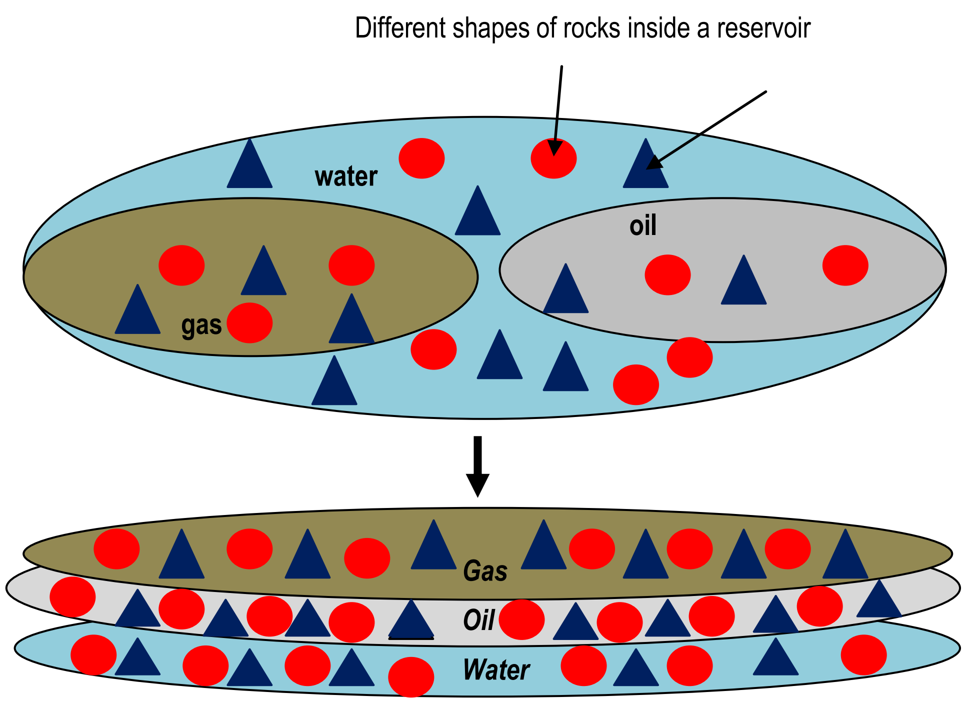


***Figure 1:** The conventional demonstration of three constituents, oil, gas and water in a reservoir*

A proportionate reservoir, whereupon all three of the constituents, gas, oil and water are equal**, is a most rare phenomenon but the possibility can never be excluded.**

The quantity of the volume of any fluid might be the quantity of the porosity of the reservoir. This will eventually result into the actual volume of the fluid from such a reservoir.

The amount of the different types of material will provide the complexity of any reservoir, as numerous chemical reactions had been taking place over centuries inside such a reservoir. The interior of any reservoir might have the completed chemical reactions, then the exterior of such a reservoir. The pressure complexity and intensity inside a reservoir will hence be different as the interior might have the intensity in pressure and therefore provide the completed chemical reactions then the exterior. This complexity in chemical reactions and pressure will also influence the material balance of any reservoir.

The material balance equations or rather formulas will provide the exact or precise quantity of volumes of petroleum products, like oil, gas and water of a reservoir. The material balance formulas will then also be determined by the reservoir properties, like porosity, compressibility, shape, pressure and permeability.

The porosity of any reservoir can have a complexity of porosity. The type of porosity will eventually be based on the type of rock formation and the shape of the different rock material. Some of the reservoirs might dominantly have the same type of rock formation and shape, hence the porosity will be the same or identical, then the type of reservoirs with the different types of rock formation and shape. The volumetric capacity of any reservoir will therefore be determined by the rock formation and shapes of rocks in a reservoir. This will eventually be the crucial and final porosity of a reservoir which will provide final volume of oil and gas in a reservoir.

A material balance equation will also provide the immediate volumetric capacity of any reservoir as many external factors will still have the final output of any reservoir.

The dynamism of geomorphology at the long run will also determine the volumetric capacity of any reservoir.

The reservoir forecasting is one of the most important applications as it provides the capability of any reservoir, in terms of oil and gas capacity and hence the possible delivery. This application also determines the financial assessment of any reservoir. i.e. What is going to be the financial cost in intensively employed the reservoir?

3.2 MATERIAL BALANCE

3.2.1 DETERMINATION OF MATERIAL BALANCE METHODS AND EQUATIONS

The basic material balance equation has been regarded by reservoir engineers for decades as one of the best tools for interpreting and predicting reservoir performance.

The zero dimensional material balance is derived and as a result applied by using mainly the interpretative technique of **Havlena and Odeh**, in order to obtain the comprehensive, complete understanding of reservoir drive mechanisms under fundamental primary recovery conditions.

The basic factors, like **pore compressibility and numerical simulators of a reservoir**, in the material balance equation will be qualitatively and quantitatively discussed and determined as few of the uncertainties in the estimation of the quantity of a volume of a reservoir.

3.2.2 THE MATERIAL BALANCE EQUATION FOR A HYDROCARBON RESERVOIR

The conceptual and standard formula of the material balance equation is derived as a volume balance which equates the collective observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a definite and specific pressure drop. In other words the pressure intensity partly determines the quantity of the fluid which a reservoir will provide.

The general formula determines the volume of a gas, oil or water in any reservoir.

The pressure intensity and the quantitative availability of pores predetermine the quantitative volume of gas and oil in a reservoir.

The ***Standard Formula*** must indicate the following:

(a) The initial pressure of the fluid volume in a reservoir which contains a finite gascap.
(b) Illustrate the effect of manipulating the pressure values by a certain magnitude Δp which will allow the fluid volumes to expand practically in the reservoir.

Thus the volume balance can be evaluated in ***reservoir barrels (rb)*** as underground withdrawal.

Volume Balance	= Expansion of oil + Originally dissolved gas		(rb)
	+	Expansion of gascap gas	(rb)
	+	Reduction in HCPV due to connate water	
		expansion and decrease in the pore volume	(rb)

It is vitally significant in order to define the following parameters before evaluating

the various components in the above mentioned equation.
N is the initial oil in place in *stock tank barrels (stb)*

N(OIL) = V ø (1−Swc) / Boi stb

m is the ratio : $\dfrac{\text{initial hydrocarbon volume of the gascap}}{\text{initial hydrocarbon volume of the oil}}$

Np is the cumulative oil production in stock tank barrels, and

R_p is the cumulative gas oil ratio = $\dfrac{\text{Cumulative gas production (scf)}}{\text{Cumulative oil production (stb)}}$

3.2.2.1 EXPANSION OF OIL AS WELL AS THE ORIGINALLY DISSOLVED GAS

There are two descriptions in this PHRASE and they are:

- Liquid, oil expansion

The N*(stb)* will consist of a reservoir volume of NBoi *(rb)*, which is in most cases determined at the starting or initial pressure, while at the lower pressure the reservoir volume will consists of the N (stb) which will be the NBo. The Bo, term is the oil formation volume factor at the lower pressure. The difference gives the liquid expansion as:

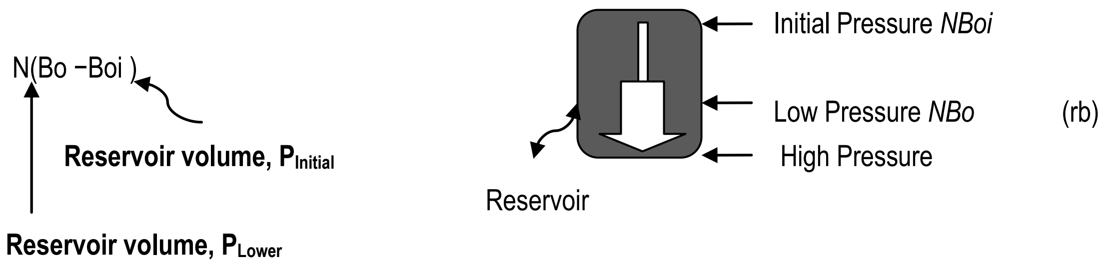


Figure 2: *The pressure differences inside a reservoir.*

- Liberated gas expansion

The oil must be at saturation or bubble point pressure, since the initial oil is in equilibrium with a gascap. Decreasing the pressure below pi will result in the liberation of solution gas. The total amount of solution gas in the oil is NRsi (scf).

The amount of oil which must still be dissolved in the N*(stb)* of the reservoir at the decreased pressure is NRs (scf). Therefore, the amount of gas volume which is liberated or given off during the pressure drop Δp, is expressed or formulated in reservoir barrels at the lower pressure as:

$$N(R_{si} - R)B_g \qquad \text{(rb)}$$

Total amount of solution gas in the oil

3.2.2.2 EXPANSION OF THE TENSION OF THE GASCAP GAS

The total volume of gascap gas is mNBoi (rb), which in scf may be expressed as

m = Ratio between the mass of the initial volume, empty reservoir, of a reservoir and its volume in quantity, filled reservoir.

$$G = \frac{mNB_{oi}}{B_{gi}} \qquad \text{(scf)}$$

This quantity of gas, at the reduced pressure *p*, will occupy a reservoir volume

$$mNB_{oi}\ (B_g/B_{gi}) \qquad \text{(rb)}$$

Therefore, the expansion of the gascap is: $mNB_{oi}\left\{(B_g/B_{gi}) - 1\right\}$ (rb)

3.2.2.3 CHANGE IN THE HCPV DUE TO THE CONNATE WATER EXPANSION AND PORE VOLUME REDUCTION

The total volume change due to these combined effects can be mathematically expressed as:

$$d\,(HCPV) = -\ dV_w + dV_f$$

or, as a reduction or minimization in the hydrocarbon pore volume, as

$$d\,(HCPV) = -\ (c_w V_w + c_f V_f)\,\Delta p$$

where Vf is the total pore volume = $HCPV/(1 - S_{wc})$

and Vw is the connate water volume = $V_f \times S_{wc} = (HCPV)S_{wc}/(1 - S_{wc})$.

Since the total HCPV, including the gascap, is: $(1+m)NB_{oi}$ (rb)

then the HCPV reduction can be expressed as

$$- \quad d(HCPV) \quad (1+m)NB_{oi}\left\{\frac{c_w S_{wc} + c_f}{1 - S_{wc}} \Delta p\right\}$$

This reduction in the volume which can be occupied by the hydrocarbons at the lower pressure, p, must correspond to an equivalent amount of fluid production expelled from the reservoir, and hence should be added to the fluid expansion terms.

3.2.2.4 UNDERGROUND WITHDRAWAL

The observed surface production during the pressure drop, this is Δp is Np (stb) of oil and NpRp(scf) of gas. The volume of oil plus dissolved gas will be NpBo (rb) when these volumes are recorded in the reservoir at the reduced pressure (p).

All that is known about the total gas production is the quantity at the lower pressure,

NpRs (scf) which will be dissolved in the Np (stb) of oil. The remaining produced gas,

Np (Rp $-\Delta$Rs) scf is therefore, the total amount of liberated and gascap gas produced during the pressure drop Δp and will occupy a volume N(Rp $-\Delta$Rs)Bg rb at the lower pressure. The total underground withdrawal term is therefore.

$$N_p\left(B_o + (R_p - \Delta R_s)B_g\right) \quad \text{(rb)}$$

Therefore, equating this withdrawal to the sum of the volume changes in the reservoir, gives the general expression for the material balance as:

Reservoir Volume $P_{initial}$

$$N_p(B_o + (R_p - R_s)B_g) = \left\{ NB_{oi}\left[\frac{(B_o - B_{oi}) + (R_{si} - R_s)B_g}{B_{oi}} + m\left(\frac{B_g}{B_{gi}} - 1\right) + (1+m)\left(\frac{c_w S_{wc} + c_f}{1 - S_{wc}}\right)\Delta p\right] + (W_e - W_p)B_w \right\}$$

Total underground withdrawal **Net water influx**

The final term in the equation, (We −Wp)Bw, therefore is the net water influx into the reservoir. This has been instinctively added to the right hand side of the balance since any such influx must expel an equivalent amount of production from the reservoir thus increasing the left hand side of the equation by the same amount.

3.3 MATERIAL BALANCE EQUATION EXPRESSED AS A LINEAR EQUATION

The **CHILTHUIS MATERIAL BALANCE EQUATION** has been regarded by many engineers as significantly important, since the introduction of sophisticated numerical reservoir simulation techniques. This was a technique which was used in 1940-50 when people were still using slide-rules.

This is the simplest aquifer model and assumes the rate of water influx is directly proportional to pressure manipulation. In this model it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

$$W_e = K\int_0^t (p_i - p)dt = K\sum_{j=0}^{n}\left(p_i - \frac{p_j + p_{j-1}}{2}\right)(t_j - t_{j-1})$$

It is interesting to realize that as late as 1963-4, engineers known as Havlena and Odeh had presented two of the most interesting findings in reservoir engineering on the subject of applying the material balance equation and interpreting the actual practical results or observations in the field.

Their findings described the basic technique of interpreting the material balance as the equation of a straight line graph. One of the findings described the technique and the other illustrated the application of reservoirs.

One of the equations as presented and formulated by Havlena and Odeh requires the definition of the following terms:

$$F = Np\,(Bo + (Rp - Rs)\,Bg) + Wp\,Bw \qquad \text{(rb)}$$

which is the underground withdrawal;

$$Eo = (Bo - Boi) + (Rsi - Rs)\,Bg \qquad \text{(rb/stb)}$$

which is the term describing the expansion of the oil and its originally dissolved gas;

$$Eg = Boi\left[\frac{B_g}{B_{g1}} - 1\right] \qquad \text{(rb / stb)}$$

describing the expansion of the gascap gas, and

$$E_{fw} = (1 + m)\,B_{oi}\left[\frac{c_w S_{wc} + c_f}{1 - S_{wc}}\,\Delta p\right] \qquad \text{(rb / stb)}$$

for the expansion of the connate water and reduction in the pore volume.

Using these terms the material balance equation can be written as

$$F = N(E_o + mE_g + E_{f,w}) + W_eB_w$$

For instance, in the case of a reservoir this has no initial gascap, negligible water influx and for which the connate water and rock compressibility term may be neglected, the equation can be reduced to:

$$F = NE_o$$

in which the observed production is evaluated as an underground withdrawal.

The above mentioned phenomenon or information can be used in order to plot a linear function of the **expansion of the oil plus its originally dissolved gas.**

The dissolved gas will then be calculated from the information of the PVT parameters at the current reservoir pressure.

This interpretation technique or analysis in the reservoir is very much useful and essentially important. If a linear graph is expected and is common for a reservoir and yet the actual plot turns out to be non-linear, then this deviation can itself be diagnostic in determining the actual drive mechanisms in the reservoir.

The equation below can still be expressed in a linear form as

$$\frac{F}{E_o} = n + \left\{ \frac{W_e}{E_o} \right\}$$

in which F/Eo should be a linear function of We/Eo.

3.4 GAS MATERIAL BALANCE: RECOVERY FACTOR

The material balance equation, for any hydrocarbon system, determines the quantity:

- of a volume of gas as well as the
- oil balance.

The above mentioned information must balance the total production of the hydrocarbons, which are based on:

- the difference between the initial volume of hydrocarbons in the reservoir and
- the current volume in the reservoir.

In a gas reservoir the equation will be very simple and will accommodate two separate cases, like

- no water influx into the reservoir
- significant degree of influx into the reservoir.

3.4.1 VOLUMETRIC REDUCTION

The terminology, volumetric depletion or reduction, just depletion, applies to the **Performance of a Reservoir at specific stages of influxes which are based on pressure differences.** The pressure decreases due to production or release of oil or gas and as a result there will be an insufficient amount of water influx into the reservoir from the adjacent aquifer. This might indicate that the adjacent aquifer must be too small, hence the reservoir volume which is occupied by hydrocarbons (HCPV) will not decrease during depletion. The expression for the HydroCarbon Pore Volume can therefore be obtained from the following equation as:

$$HCPV = V \phi \, (1 - S_{wc}) = G/E_i$$

where G is the **G**as **I**nitial **I**n **P**lace**, GIIP,** which is formulated, determined at applied standard pressure and temperature. The material balance is therefore also calculated and applied at standard conditions, for a given volume of production Gp, and resulting drop in the average reservoir pressure $\Delta p = p_i - p$ is then,

$$\underset{(sc)}{\text{Production}} = \underset{(sc)}{\text{GIIP}} - \underset{(sc)}{\text{Unproduced Gas}}$$

$$G_p = G - (HCPV)E$$

$$G_p = G - G\,(E/E_i)$$

which can be expressed as

$$\frac{G_p}{G} = 1 - \frac{E}{E_i}$$

or, using equation, as

$$\frac{p}{Z} = \frac{p_i}{Z_i}\left(1 - \frac{G_p}{G}\right)$$

The ratio Gp/G is the fractional gas recovery which is takes place at any stage during depletion or reduction of a volume of a hydrocarbon. The gas expansion factor E, in the equation is then evaluated at the proposed pressure therefore the corresponding value of Gp/G is the gas recovery factor.

It is vitally important to reconsider the balance expression by means of an equation more thoroughly and holistically before describing how the material balance equation is used in practice or in the field.

It is therefore common practice since the water influx is negligible and need not be considered as the hydrocarbon pore volume remains constant during depletion.

This, however, does not take into consideration two physical phenomena which are related to the pressure decline. These are as follows:

- the connate water in the reservoir will expand and
- the gas (fluid) pressure declines, as the grain pressure increases

The rock particles in the reservoir will pack or move closer as the pore pressure decreases and there will be a minimization in the pore volume. These two factors can be combined to give the total change in the hydrocarbon pore volume as:

$$d(HCPV) = -\underbrace{dV_w}_{\text{initial connate water volume}} + \underbrace{dV_f}_{\text{pore volume final}}$$

where Vw and Vf represent the initial connate water volume and pore volume (PV), respectively. The negative sign is necessary since an expansion of the connate water leads to a reduction in the HCPV. These volume changes can be expressed, in terms of the water and pore compressibility, where the latter is defined as:

$$c_f = \frac{1}{V_f}\frac{\partial V_f}{\partial (GP)}$$

where **GP** is the **grain pressure** which is related to the **fluid pressure** by

$$d(\mathbf{FP}) = -d(GP) \quad \text{therefore}$$

$$cf = \frac{1}{V_f}\frac{\partial V_f}{\partial (GP)}$$

$$= \frac{1}{V_f}\frac{V_f}{\partial p}$$

where p is the fluid pressure and the Equation below expresses that:

$$d(HCPV) = cw\ Vw\ dp + cf\ Vf\ dp$$

or, as a reduction in hydrocarbon pore volume as

$$d(HCPV) = -(cw\ Vw + cf\ Vf)\Delta p$$

where $\Delta p = pi - p$, the drop in fluid (gas) pressure. Finally, formulating and expressing the pore and connate water volumes as:

$$V_f = PV$$

$$= \frac{HCPV}{(1 - S_{wc})}$$

$$= \frac{G}{E_i(1 - S_{wc})}$$

$$V_w = PV \times S_{wc}$$

$$= \frac{GS_{wc}}{E_i(1 - S_{wc})}$$

the reduction in hydrocarbon pore volume can be substituted in the equation below:

$$\frac{G_p}{G} = 1 - \frac{E}{E_i}$$

$$\frac{G_p}{G} = 1 - \left[1 - \left(\frac{(c_w S_{wc} + c_f)\Delta p}{1 - S_{wc}} \right) \right]$$

as the modified material balance. Inserting the typical values in this equation:

$cw = 3 \times 10^{-6} / \text{psi},$

$cf = 10 \times 10^{-6} / \text{psi}$

$Swc = 0.2$

as well as large pressure drop of $\Delta p = 1000$ psi

Then the term in parenthesis becomes:

$$Gp/G = 1 - \left[1 \left[- \frac{((3 \times 10^{-6} \times 0.2) + 10 \times 10^{-6})\,1000}{1 - 0.2} \right] \right.$$

$$= 1 - (1 - 0.01325)$$

$$= 1 - 0.988675$$

$$= 0.011$$

The expansion of the connate water results in the reduction of the hydrocarbon pore volume and these eventually change the material balance slightly by 1.3%.

Pore compressibility can sometimes be very large in shallow unconsolidated reservoirs and it is just unacceptable to omit or ignore the pore compressibility from gas material balance and pore compressibility and connate water from liquid oil material balance.

3.4.2 PRESSURE DIFFERENTIATION

Pressure drops or the change in pressure includes the pressure drawdown in each well, which is the difference between the average reservoir and bottom hole flowing pressures, causing the gas flow into the wellbore.
The pressure drop required for the vertical flow to the surface, and the pressure drop in the gas processing and transportation to the delivery point. This then leads to the, gas reservoirs frequently abandoned at quite high pressures.

Recovery can be increased, however, by producing the gas at much lower pressures and compressing it at the surface to give the recovery (RF) compression.

If the decrease in reservoir pressure leads to an expansion of the adjacent aquifer water volume and the consequent influx into the reservoir, then the material balance equation must be modified as:

$$\underset{(sc)}{\text{Production}} = \underset{(sc)}{\text{GIIP}} - \underset{(sc)}{\text{Unproduced Gas}}$$

$$G_p = G - \left[\frac{G}{E_i} - W_e\right] E$$

where, in this case, the hydrocarbon pore volume at the lower pressure is reduced by the amount We, which is the collective, amount of water influx resulting from the pressure drop. The equation assumes that there is no difference between surface and reservoir volumes of water and again neglects the effects of connate water expansion and pore volume reduction. If some of the water influx has been produced it can be accounted for by subtracting this volume, Wp, from the influx, We, on the right hand side of the equation. With some slight algebraic manipulation, the equation can be expressed as

$$\frac{p}{Z} = \frac{p_i}{Z_i} \frac{1-\left[\frac{G_p}{G}\right]}{\left[1-\frac{W_e E_i}{G}\right]}$$

where (We Ei) /G represents the fraction of the initial hydrocarbon pore volume flooded by water and is, therefore, always less than unity. When compared to the depletion material balance, it can be seen that the effect of the water influx is to maintain the reservoir pressure at a higher level for a given cumulative gas production and also to maintain the reservoir pressure at a higher level for a given increasing gas production. For an aquifer whose dimensions are of the same order of magnitude as the reservoir itself the following simple model can be used

$$W_e = cW\Delta p$$

where c = the total aquifer compressibility (cw + cf)

W = the total volume of water, and depends primarily on the geometry of the aquifer

and Δp = the pressure drop at the original reservoir-aquifer boundary.

A pressure drop in the reservoir is instantly transmitted throughout the entire reservoir-aquifer system as the aquifer is relatively small.

In order to provide the pressure response, the aquifer volume must be considerably larger than that of the reservoir and it is then inadmissible, not to allow or assume an immediate transmission of pressure throughout the system.

One of the unfortunate aspects in the delay of the aquifer response is the primary indication of the linear or straight line graph application of the material balance.

The insufficient production and pressure history information of any reservoir will show the deviation from linearity, then one may easily be tempted to extrapolate the early trends, assuming a depletion type reservoir, which would result in the determination of the big quantity of the GIIP. In such a case, a large difference between this and the volumetric estimate of the GIIP can be diagnostic in deciding whether there is an aquifer or not. This assessment can also be used in order to formulate a mathematical model which can describe the reservoir performance which is based on insufficient data and this can produce incorrect results which will eventually be used to predict future reservoir performance.

If production-pressure history is available it is then possible to make an estimate of the GIIP, in a water drive reservoir, using the following method:

The depletion material balance is first solved to determine the apparent gas in place as

$$G_a = \frac{G_p}{1 - E/E_i}$$

Apparent Gas

If there is an active water drive, the value of Ga which is calculated by using the above mentioned equation, for the known values of E and Gp, will not be exceptional. The continually, substituted and calculated values of Ga will increase as the deviation of p/Z above the depletion material balance line increases, due to the pressure maintenance provided by the aquifer.

The correct value of the gas in place, however, can be obtained or calculated by the following formula:

$$G = \frac{G_p - W_e E}{1 - E/E_i}$$

where We is the cumulative water influx calculated, using some form of mathematic aquifer model, at the time at which both E and Gp have been measured, hence the following equation is derived:

$$G_a = G + \frac{W_e E}{1 - E/E_i}$$

If the calculated values of Ga, are plotted as a function of WeE/(1−E/Ei) then the result should be a straight line, provided the correct aquifer model has been selected.

It is a trial and error business in selecting the correct aquifer model which continues until a straight line is obtained or drawn.

One of the other interesting features is that the maximum possible gas recovery depends on the degree of pressure maintenance which is provided by the aquifer, which is on the other hand smaller for the more responsive aquifers. The reason for this has already been mentioned above that in the immiscible displacement of one fluid by another not all of the displaced fluid can be removed from each pore space. Thus as the water advances or flows through the reservoir a residual gas saturation is trapped behind the front. This **gas saturation, Sgr**, is rather high which is of the order of 30−50% of the pore volume and is largely independent of the pressure at which the gas is trapped. If this is the case, then the application of the following equation of state to the gas trapped per cu.ft of pore volume behind the flood front is more practical.

$$\frac{p}{Z} S_{gr} = nRT$$

and, since Sgr is independent of pressure, then for isothermal depletion

$$n \propto \frac{p}{Z}$$

which indicates that a greater quantity of gas is trapped at high pressure than at low.

The ultimate gas recovery depends both on the **nature of the aquifer and the not considered pressure.** The engineer controls the choice of the abandonment pressure but the choice of the aquifer unfortunately is not determined or controlled by the engineer.

It is, therefore, extremely important to accurately measure both pressures and gas production to enable a reliable aquifer model to be built which, in turn, can be used for performance predictions of any potential reservoir.

3.5 GAS PRODUCTION FORECASTING

3.5.1 PHASES- FUTURE PERFORMANCE

Most reservoir engineering calculations involve the use of the **Material Balance Equation (MBE).** Some of the most useful applications of the MBE require the concurrent use of fluid flow equations, e.g., Darcy's Equation. Combining the two concepts would enable the engineer to predict the reservoir future production performance as a function of time. The MBE simply provides performance as a function of the average reservoir pressure without the fluid flow concepts.

Prediction of the reservoir future performance is ordinarily performed in the following three phases:

Phase 1: The first phase involves the use of the MBE in a predictive mode to estimate cumulative hydrocarbon production and fractional oil recovery as a function of declining reservoir pressure and increasing gas–oil ratio (GOR). These results are incomplete, however, because they give no indication of the time that it will take to recover oil at any depletion stage. In addition, this stage of calculations is performed without considering:

- the actual number of wells;
- the location of wells;
- the production rate of individual wells;
- the time required to deplete the reservoir.

Phase 2: To determine **recovery profile** as a function of time, it is necessary to generate individual well performance profile with declining reservoir pressure. This phase documents different techniques that are designed to model the production performance of vertical and horizontal wells.

Phase 3: The third stage of prediction is the **time–production phase**.

In these calculations, the reservoir and well performance data is correlated with time. It is necessary in this phase to account for the number of wells and the productivity of individual well.

3.5.2 GAS AND OIL RATIO: GOR

The MBE in its various mathematical forms as presented in this assignment is designed to provide estimates of the:

- initial oil in-place: *N*,
- size of the gas cap: *m*,
- and water influx: *W*e.
- the equation of producing (instantaneous) GOR;
- the equation for relating saturations to cumulative oil production.

These auxiliary mathematical expressions are presented below and there are three GOR's.

- **Instantaneous GOR.** The produced GOR at any particular time is the ratio of the standard cubic feet of total gas being produced at anytime to the stock-tank barrels of oil being produced at that same instant.

- **Solution GOR, i.e., gas solubility *R*s:** The solution GOR is a *PVT* property of the crude oil system. It is commonly referred to as “gas solubility” and denoted by *R*s. It measures the tendency of the gas to dissolve in or evolve from the oil with changing pressures. It should be pointed out that as long as the evolved gas remains immobile, i.e., gas saturation *S*g is less than the critical gas saturation, the instantaneous GOR is equal to the gas solubility. That is: **GOR = *R*s**

- **Cumulative GOR *R*p**: The cumulative GOR *R*p, as defined previously in the MBE, should be clearly distinguished from the producing (instantaneous) GOR. The cumulative GOR is defined as:

  *R*p = cumulative (total) gas produced cumulative oil produced

  *R*p = cumulative GOR, scf/STB

3.6 STATE AND USE HAVLENA –ODEH LINEAR MATERIAL BALANCE EQUATION PRACTICALLY

3.6.1 HAVLENA-ODEH

The Havlena-Odeh technique, in terms of a straight line graph has been used for decades in order to solve for several unknown variables in the material balance equation. Havlena and Odeh had grouped similar terms together in order to simplify the application of the relationship and the material balance equation is thus formulated as follows:

$$\mathbf{F = N(E_o + mE_g + E_{fw}) + W_eB_w}$$

where F = underground withdrawal

$= N_p (B_o - (R_p - R_s)B_g) + W_pB_w$

E_o = oil and solution gas expansion

$= (B_o - B_{oi}) + (R_{si} - R_s)B_g$

E_g = gas cap gas expansion

$= B_{oi}(B_g/B_{gi} - 1)$

E_{fw} = hydrocarbon space reduction

$= (1+m)B_{oi}(c_ws_{wc} + c_f)del(p)/(1 - s_{wc})$

$$\frac{F}{E_o + mE_g + E_{fw}} = N + \left[\frac{W_eB_w}{E_o + mE_g + E_{fw}}\right]$$

By plotting $F/(E_o + mE_g + E_{fw})$ against $W_eB_w/(E_o + mE_g + E_{fw})$, a straight line

of intercept N and a slope of 1 (45^o) should be produced.

If water influx is assumed to be negligible, the above Equation reduces to :

$$F = N(E_o + E_{fw}) + mNE_g$$

and thus to :

$$\left(\frac{F}{E_o + E_{fw}}\right) = N + mN \left(\frac{W_eB_w}{E_o + E_{fw}}\right)$$

A straight line of intercept N and slope mN is obtained by plotting functions $F/(E_o + E_{f,w})$ versus $E_g/(E_o + E_{f,w})$. Different set of equations is used when a gas reservoir is being considered, although linearization is still the basis for analysis. The term, $E_{f,w}$ is neglected, since gas is much more compressible than formation water and a rock.

The following equations will eventually be achieved:

$$F = GE_g + W_e$$

where

$$F = G_pB_g + W_pB_w \quad (3.4.10)$$

$$E_g = B_g - B_{gi}$$

It will result in plotting of F/E_g versus W_e/E_g and a straight line of slope 45^o and intercept G will be achieved.

A more sensitive approach may be used in order to determine wether a water drive is present in the reservoir by plotting F/E_g versus G_p and this will finally produce a horizontal line if no aquifer support occurs. A water drive may be affecting the reservoir, If the line slope turns upwards. The line should intercept the vertical axis at G, of the hydrocarbon pore volume.

3.6.2 ALGORITHM

Direct linear equations are used to calculate F, E_o, E_g, and $E_{f,w}$ by using unknown variables, N,m and W_e, in a Havlena-Odeh analysis and they are determined graphically by using the straight line relationships as mentioned above.

There are two methods of calculating.

- The first is a trial and error approach, whereupon the best estimates of water influx are recorded into the spreadsheet until a straight line is achieved.
  This method is however, unscientific and generally unsatisfactory.

- A better and improved method of an aquifer model is used to calculate the water influx for certain pressure drops, according to the analytical approaches of Hurst-van Everdingen, Carter-Tracy, or Fetkovich approach.

  The Fetkovich model for semi-steady state aquifers is built or recorded into the spreadsheet and this spreadsheet will calculate water influx for either a radial or a linear aquifer. This is a direct helpful result recording application.

- The procedure for calculating water influx from a linear graph for an aquifer is identical to the application of radial aquifers for a linear aquifer. However, the productivity constant is calculated as follows :

$$J = 7.08 \times 10^{-3} \; 3khW/2\prod\mu L$$

where J = linear aquifer productivity index (stb/d/psi)

W = aquifer/reservoir width (ft)

L = aquifer length (ft)

3.6.2.1 GASCAP DRIVE - Oil Reservoirs

The size of the gascap (m) and the amount of oil initially in place (N) can be easily determined, if the water influx is negligible and the following functions are essential for this :

- F vs. $E_o + E_{f,w} + mE_g$ and
- $F/(E_o + E_{f,w})$ vs. $E_g/(E_o + E_{f,w})$

The first function of GASCAP 1 should have a slope of N and this must pass through the origin, providing W_e as zero. If the line bends upwards, convex down, then the assumed gas:oil ratio (m) is too small. If the line graph bends down, concave down, then the assumed value for "m" is too large. Therefore, when the line graph is perfectly straight, this will result in a best fit for "m".

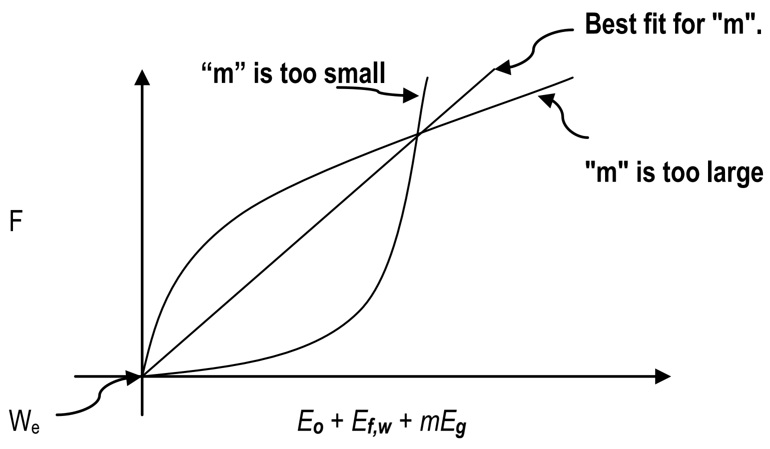


Figure 3: *The graph represents the function: F vs. $E_o + E_{f,w} + mE_g$*

The second function of the GASCAP 2 can be used to verify the results of the first function. The slope of mN and an intercept of N will be provided according to the functions of $F/(E_o + E_{f,w})$ vs. $E_g/(E_o + E_{f,w.}$

The, $E_{f,w}$ term does not have to be considered, since the gas is often too compressible than the formation pore volume and pore fluid.

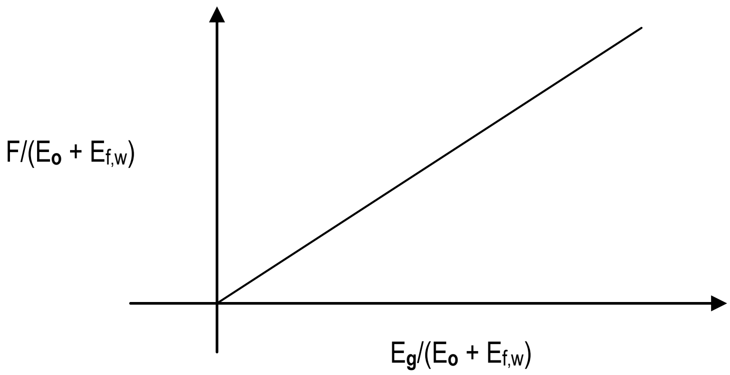


Figure 4: *Represents the graph of function: $F/(E_o + E_{f,w})$ vs. $E_g/(E_o + E_{f,w})$*

3.6 2.2 WATER DRIVE - Oil Reservoirs

The intensity of the water drive can be determined whenever any gascap is assumed to be non-existent or its size is assertively known. The correct aquifer influx is obtained when a straight line of intercept zero, slope N is achieved by plotting the following functions, $F/(E_o + mE_g + E_{f,w})$ versus $W_eB_w/(E_o + mE_g + E_{f,w})$.

This can be obtained by altering the influx quantities directly, or by altering the aquifer model parameters as preferred. The water influx numbers are too small if the line graph curves upwards and when the line graph bends downwards, then the assumed influx is too strong. Note that the aquifer model can be radial or linear, but the solution obtained in either case is not unique. For example, for a given aquifer model, the same influx function can be obtained by lowering the aquifer permeability and increasing the aquifer thickness proportionally.

3.6.2.3 WATER DRIVE - Gas Reservoirs

Material balance analysis is an interpretation method used to determine original fluids-in-place (OFIP) based on production and static pressure data.

The general material balance equation relates the original oil, gas, and water in the reservoir to production volumes and current pressure conditions / fluid properties. The material balance equations considered assume tank type behaviour at any given datum depth - the reservoir is considered to have the same pressure and fluid properties at any location in the reservoir. This assumption is quite reasonable provided that quality production and static pressure measurements are obtained.

Consider the case of the depletion of the reservoir pictured below. At a given time after the production of fluids from the reservoir has commenced, the pressure will have dropped from its initial reservoir pressure ($p_{i,}$) to some average reservoir pressure (p). Using the law of mass balance, during the pressure drop (Δp), the expansion of the fluids leftover in the reservoir must be equal to the volume of fluids produced from the reservoir. The simplest way to visualize material balance is that if the measured surface volume of oil, gas and water were returned to a reservoir at the reduced pressure, it must fit exactly into the volume of the total fluid expansion plus the fluid influx. The general form of the equation can be described as:

Net withdrawal (withdrawal - injection)	**=**	**expansion of the hydrocarbon fluids in the system**	**+**	**cumulative water influx**

This is shown in the equation below.

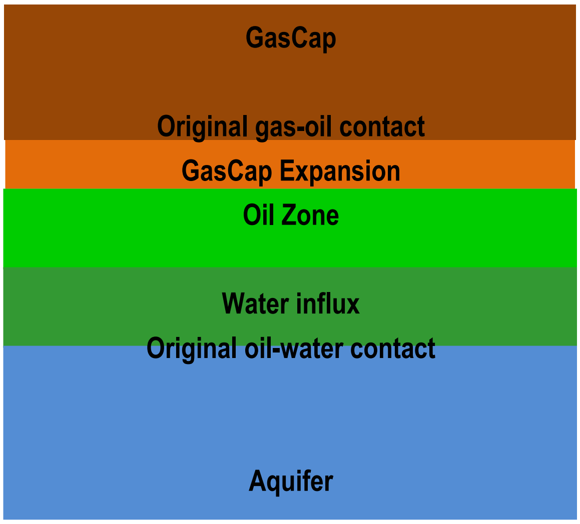


Figure 5: *The general material balance equation relates the original oil, gas and water in the reservoir to production volumes and current pressure conditions and fluid properties.*

$$N_p[B_o + B_g(R_p - R_s)] + W_pB_w - W_{inj}B_{winj} - G_{inj}B_{ginj}$$
$$= N\left\{[B_o - B_{oi} + B_g(R_{si} - R_s)] + \frac{B_{oi}}{B_{gi}}m(B_g - B_{gi}) + B_{oi}(1+m)\left(\frac{c_f + c_wS_w}{1 - S_w}\Delta p\right)\right\} + W_eB_w$$

Each term in the equation can be grouped based on the part of the system it represents. The change in reservoir volume due to net encroached water can be determined from the following equation:

$$\Delta V_{wip} = 5.615\left(W_e - W_pB_w\right)$$

To use this in the material balance, the change in pore volume is taken relative to the initial pore volume, shown below.

$$c_{wip} = \frac{5.615\left(W_e - W_pB_w\right)}{B_{gi}G/S_{gi}}$$

When dealing with this equation, the major unknown value to be determined is water encroachment from the aquifer (W_e). Two aquifer models are provided to determine net encroached water: **Schilthuis Steady-State Model and Fetkovich Model.**

In the **Fetkovich Aquifer**, the aquifer is assumed to be in pseudo-steady state and deplete according to the material balance equation. In this model, both the aquifer volume and transfer coefficient must be determined. The equations are shown below.

$$W_e = \sum_{j=1}^{n} \frac{W_{ei}}{p_i}\left(p_{aq_{j-1}} - p_j\right)\left(1 - e^{-\frac{Jp_i\Delta t_j}{W_{ei}}}\right)$$

$$W_{ei} = c_w p_{aqi} V_{aq}$$

$$J = \frac{kh}{141.2\mu\left(ln\frac{r_e}{r_o} - \frac{3}{4}\right)}\frac{\theta}{360}$$

While the transfer coefficient is defined, the required inputs to calculate the transfer coefficient are often not known. More commonly the transfer coefficient is determined as part of matching the p/Z plot.

3.7 SUMMARY

The pressure intensity and the quantitative availability of pores pre-determine the quantitative volume of gas and oil in a reservoir. The quantity of volume of either the gas or oil of a reservoir will depend on the individual HCPV of a pore.

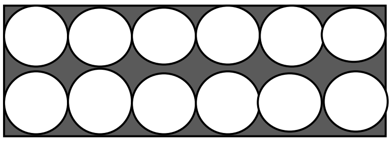
In other words if one pore has a volume of 3 000 litres, or 3 tonnes of crude oil and there are 3 000 000 pores in a reservoir, then the total volume of that particular reservoir will have a total volume of 3 x 3 000 000 = 9 000 000 litres of crude oil.

The shape of a pore as well as the compressibility by pressure will also determine the total volume of a reservoir.

V_i = 55 x 17 x 17

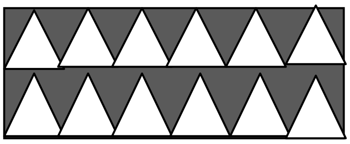
= 15 895 mm^3

Reservoir 1



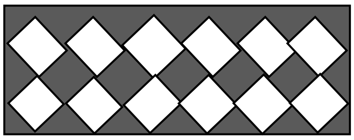
HCPV = 268,083 x12
V_f = 3 216,996mm^3
= 3, 217ml

Reservoir 2



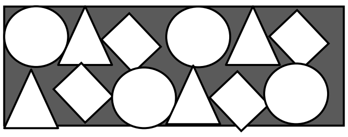
HCPV =333.333x12
V_f =4000mm^3
= 4ml

Reservoir 3

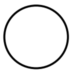


HCPV = 150 x 12
V_f = 1 800 mm^3
= 1,8ml

Reservoir 4

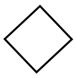


HCPV = (268,083x4)+(333,333x4)+(150x4)
= 1072,332 + 1333,332 + 6000
= 3 005,664mm^3
= 3ml



Sphere: V = $4/3\pi r^3$
= $4/3\pi 4^3$
= 268,083mm^3

Pyramid: V = lwb/3
= 1000/3
= 333.333mm^3



Rectangle: V = l . b. h
= 10 x 5 x 3
= 150 mm^3

Figure 6: *Reservoir calculations on porosity differences.*

In other words the size of a pore, will determine the permeability and hence the quantitative volume of oil and gas of a reservoir. On the one hand the practical application of the pore shape will not be familiar with the above drawn diagrams. The following pictures are real and actual situations in the different reservoirs in oil and gas industry.

Reservoir 1
Large Rocks

Reservoir 2
Small Rocks

Reservoir 3
Medium Rocks

Reservoir 4
Mixed Rocks, Small, Medium and Large

Atlantic International University

Three types of Reservoirs

Figure 7: *Different types of reservoirs and their different porosities and the quantity of fluid.*

Different types of reservoirs have different porosities and these porosities are demonstrated by means of the above mentioned reservoir pictures. It is highly impossible for reservoirs to ONLY have the same size of rocks, like Reservoirs, 1,2 and 3 BUT it is a phenomenon, which cannot be ruled out. The most practical and highly possible Reservoir trype is the mixture of all sizes of roccks, Reservoir 4.

In the model of CHILTHUIS, which determines the MATERIAL BALANCE EQUATION, it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

One of the critical, determining factors in the application of the material balance equation is the assessment of the actual average reservoir pressure at which the pressure depends on parameters in the equation which should be evaluated. i.e. The initial pressure or centroid point or differentiate point is very crucial in the material balance equation, whenever there are different types of constituents in a reservoir of any reservoir. The material balance equation is an equation which determines the volume balance of a reservoir on one hand and then balances the total production of the difference between the starting volume of hydrocarbons in the reservoir and on the other hand the current or final volume of a reservoir.

Any engineer will be able to formulate a suitable mathematical model in order to describe the performance of any reservoir, once a straight line is plotted, based on the observed production and pressure data of the indentified reservoir. This assessment and evaluation is facilitated by the mathematical application which uses simple linear expressions for the material balance equation, as presented by Havlena and Odeh.

The following is the most applicable material balance equation of a simple reservoir:

$$\underline{NmB_{ti}(B_g - B_{gi})}$$

$$\underline{N(B_t - B_{ti})} \quad + \quad \underline{B_{gi}} \quad + \quad \underline{(W_e - B_wW_p)} \quad = \quad 1$$

$$N_pB_t \quad + \left\{ (R_p - R_{sot})\, B_g \;\; N_p \;\; B_t \right\} + \left\{ (R_p - R_{soi})B_g \;\; N_p \;\; B_t \right\} + \left\{ (R_p - R_{soi})B_g \right\}$$

DDI + SDI + WDI = 1

Depletion Drive + Segregation Drive + Water Drive = 1

Depletion Drive (DDI) is the volumetric expansion of the oil. This drive harnesses the energy of the oil that has been compressed due to the high initial reservoir pressure.

Segregation (gas cap) Drive (SDI) is the volumetric expansion of gas. Like depletion drive, it harnesses the energy of the compressed gas..

Water drive (WDI) is the bulk inflow of water from outside the boundaries of the reservoir, typically from an adjacent aquifer.

The Material Balance provides reservoir engineers a great deal of information in Knowing the following details of a potential reservoir:

- The initial hydrocarbon in place of a reservoir
- How much hydrocarbon can be produced at different pressures
- The primary mechanism for reservoir production
- The potential usefulness of varying enhanced recovery techniques.

The material balance equation can be written as:

Oil Expansion + Gas Expansion + Formation and Water Expansion + Water Influx = Oil and Gas Production + Water Production

A phase is a state which is specifically defined as that part of a system that is uniform in physical and chemical properties and it is homogeneous in composition, separated from other coexisting phases by definite boundary surfaces. The most important phases occurring in petroleum production are the hydrocarbon liquid phase and the gas phase. Water on the other hand is also commonly present as an additional liquid phase.

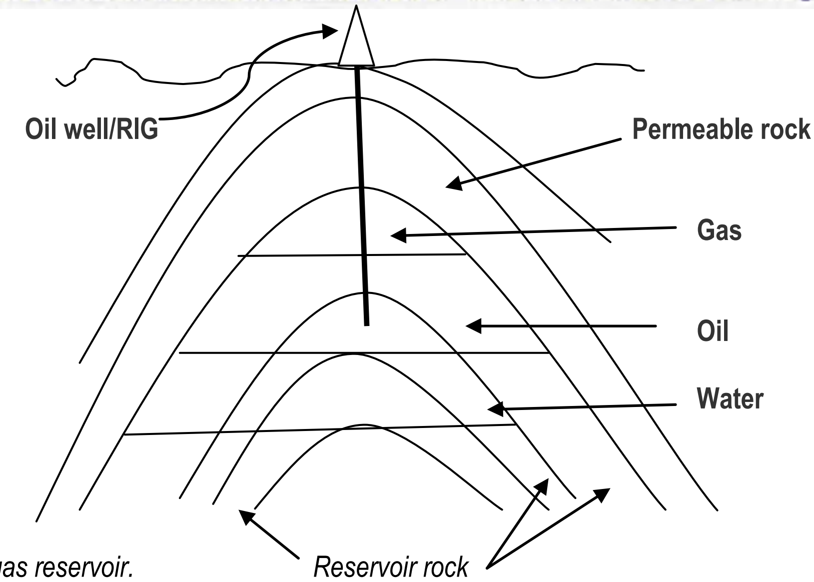


Figure 8: *A profile of an oil and gas reservoir.*

These can coexist in equilibrium when the variables describing change in the entire system remain constant at standard temperature and pressure.

Oil and gas reservoir is a formation of rock in which oil and natural gas have accumulated. The oil and gas which is collected in small connected pore spaces of rock are trapped within the reservoir by adjacent and overlying impermeable layers of rock. The typical and the ultimate rocks are not **pools, lakes or dams** of oil beneath the surface as there is no vast open cavities that contain oil, hence oil and gas reservoirs are also referred as hydrocarbon reservoirs. The conventional and traditional hydrocarbon reservoirs consist of three main parts, the *source rock, the reservoir rock and the cap rock*. The source rock is the rock that contains KEROGEN, there are three types KEROGENS, which contains oil and gas. The reservoir rock is porous, permeable rock layer or layers that hold oil and gas. The cap rock seals the top and sides so that the hydrocarbons are trapped in the reservoir, while water often seals the bottom. In order for the reservoir to exist, oil and gas migrates from the source rock into the reservoir rock and this process takes millions of years. The migration of oil and gas into the reservoir rock takes place as oil and gas have different densities then water. This is also the reason why oil and gas are top layers into the reservoir rock and water forms the base layer.

The reservoir rock contains small pockets of spaces, pores within the rock where oil and gas can settle. The small pockets or pores are interconnected with channels, which then allow the flow of oil and gas when drilling takes place.

CHAPTER 4
EQUILIBRIUM OF A RESERVOIR

4.1 INTRODUCTION

The earth crust is covered by different types of rocks, sedimentary, metamorphic and igneous and they are specifically specialized or classified in different types of reservoirs in the oil and gas industry.

The specific type of a reservoir, which dominantly impregnates oil or gas, is the sedimentary rock. The specific hardness of this rock predetermines it from the other rocks for this purpose. The possibility of other types of rocks, metamorphic and igneous to be classified as oil and gas reservoirs has never been excluded and must also not be excluded.

Not all the sedimentary rocks do also contain oil or gas. And this phenomena or characteristic is then collectively classifying the type of reservoir which will contain oil or gas. The following properties porosity, permeability, shape, pressure, temperature, wettability, saturation determine the quantity of oil or gas in a reservoir.

The above mentioned properties will be discussed individually in this assignment.

This assignment will also determine individually the quantity of oil or gas from different reservoirs. This statement will be accommodated by picture and mathematical calculations in the conclusion section of this assignment.

The speed of decomposition of the carbon contained in fauna and flora depends on the collective chemical reactions related to the above mentioned properties which will determine the actual make up of any rock, reservoir.

The reservoir make up of different continents will also on the other hand depend on the severity of temperature and pressure applications as well as all the other factors, like the actual rock content of the sedimentary, igneous or metamorphic rocks.

It also happens over decades and centuries that a certain region, which contained numerous volumes of oil and gas becomes depleted or a reservoir becomes empty. This statement will also be explained in this assignment.

The question, which will remain investigated over this assignment is the issue of, which properties of the identified properties will really determine the quantity of oil or gas in a reservoir. What is the durability of a reservoir? For how long, how many years will a reservoir be able to supply oil or gas to a particular region?

It must also be understood that the properties of a reservoir are not regionally oriented or assigned as the external or environmental and meteorological factors in the other regions will have a high impact or properties of a particular region or area. There must be a balance or equilibrium on a certain planet.

4.2. PROPERTIES OF A RESERVOIR

4.2.1 CRUDE OIL RESERVOIR

4.2.1.1 POROSITY

The solid particles like sand grains and particles of carbonate materials that make up sandstone and limestone reservoirs usually never fit together perfectly due to the high degree of irregularity in shape. This eventually results in a void space which is created throughout the beds between grains and this is called the pore space or interstice and this is primarily occupied by fluids, liquids and/or gases. Hence the porosity of a reservoir rock is defined as that fraction or open space of the bulk volume of the reservoir that is not occupied by the solid framework of the reservoir.

This can be expressed in mathematical form as:

$$\boldsymbol{\phi = (V_b - V_{gr})/V_b}$$
$$\boldsymbol{= V_p/V_b}$$

where:

ø	=	porosity, fraction.
Vb	=	bulk volume of the reservoir rock.
Vgr	=	grain volume.
Vp	=	pore volume.

EXAMPLE:

A clean and dry core sample weighing 500 g was **100%** saturated with a **1.07** specific gravity (y) brine. The new weight is 550 g. The core sample is ***15*** cm long and 5 cm in diameter.

Calculate the porosity of the rock sample.

$$\boldsymbol{\phi = (V_b - V_{gr})/V_b}$$
$$\boldsymbol{= V_p/V_b}$$
$$\boldsymbol{= \frac{(550 - 500)}{500}}$$
$$\boldsymbol{= 0{,}1}$$

The nature of reservoir rocks which contain oil and gas determines the quantity of fluids trapped within the void space of these rocks and this is known as porosity.

Porosity is:

- The measure of the void, empty space is defined as the porosity of the rock.
- The porosity of a rock is a measure of the storage capacity, pore volume that is capable of holding fluids.
- Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume).

There are two types of porosity, namely:

- Absolute porosity
- Effective porosity

4.2.1.2 ABSOLUTE POROSITY

The absolute porosity of a rock is the ratio of the total pore space in the rock to that of the bulk volume, the actual volume, the size of the reservoir would have made without any pores.

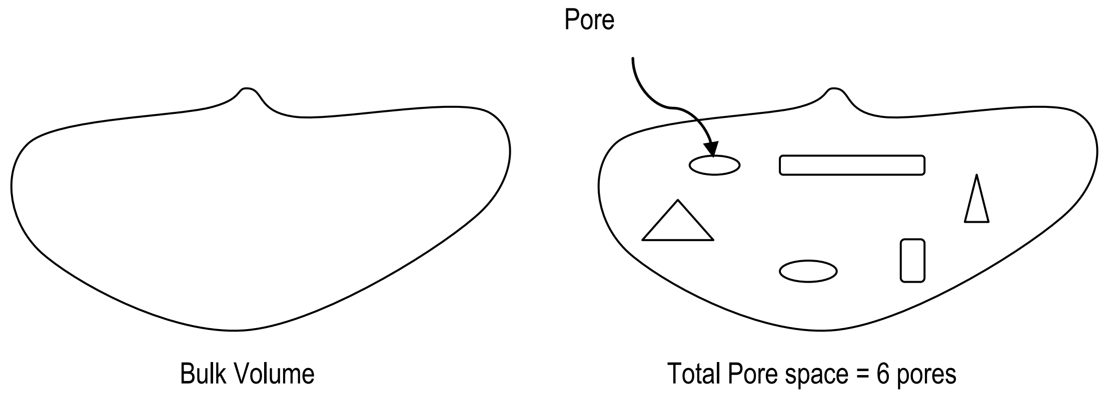


Figure 9: *The absolute porosity of a reservoir is indicated by its total pore space and the bulk volume.*

A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$øa = \frac{\text{total pore volume}}{\text{bulk volume}}$$

$$øa = \frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}}$$

where fa = absolute porosity

4.2.1.3 EFFECTIVE POROSITY

The effective porosity is the percentage of interconnected pore space with respect to the bulk volume, or the effective porosity is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.

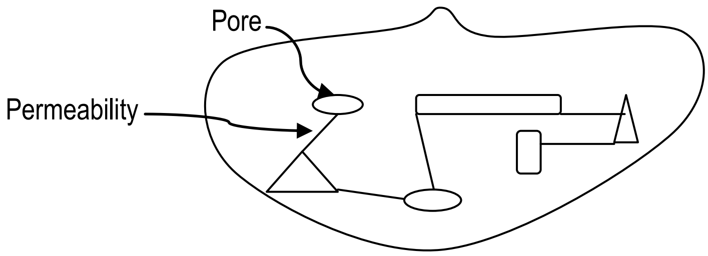


Figure 10: *The effective porosity of a reservoir is demonstrated by its interconnection of pore space.*

Porosity may be classified according to the mode of origin as originally induced.

The original porosity is developed in the deposition of the material, while induced porosity is developed by some geological processes as the result of the deposition of the rock.

The original porosity is classified as follows:

- Inter-granular porosity of sandstones
- Inter-crystalline
- 0olitic porosity of some limestones.

Induced porosity on the other is categorised as:

- The fracture development as found in shales and limestones and
- The slugs or solution cavities commonly found in limestones.

Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is included.

The porosity value becomes significant to a petroleum engineer and reliance must be placed on formation samples which are obtained by curing for direct quantitative measurement of porosity. Hence the particular attention should be paid to the methods used to determine porosity.

For example, if the porosity of a rock sample is determined by saturating the rock sample, 100% with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces.

On the other hand, if the rock sample is crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process.

One important application of the effective porosity is its use in determining the original hydrocarbon volume in place. Consider a reservoir with an arial extent of A, acres and an average thickness of h feet.

The total bulk volume of the reservoir can be determined from the following expressions:

Bulk volume = 43,560 Ah, ft^3 or

Bulk volume = 7,758 Ah, bbl

where A = Arial extent, acres

h = average thickness

Expressing the reservoir pore volume in cubic feet gives:

PV = 43,560 Ahf, ft^3

Expressing the reservoir pore volume in barrels gives:

PV = 7,758 Ahf, bbl

Example 1-4

An oil reservoir exists at its bubble-point pressure of 3000 psia and temperature of 160°F. The oil has an API gravity of 42° and gas-oil ratio of 600 scf/STB. The specific gravity of the solution gas is 0.65.

The following additional data are also available:

- Reservoir area = 640 acres (1hm – 2.471 acres = 259,004 hm)
- Average thickness = 10 ft (1 ft = 30.5cm = 305cm)
- Connate water saturation = 0.25
- Effective porosity = 15%

Calculate the initial oil in place in STB.

Solution

Step 1. Determine the specific gravity of the stock-tank oil.

$$Y_o = \frac{141.5}{42 + 131.5}$$

$$= 0.8156$$

Step 2. Calculate the initial oil formation volume factor by applying Standing's equation:

$$= 0.9759 + 0.00012 \left[600 \left[\frac{0.65}{0.8156} \right]^{0.5} + 1.25(160) \right]^{1.5}$$

$$= 1.306 \text{ bbl /STB}$$

Step 3. Calculate the pore volume: The total volume of the number of pores.

Reservoir area thickness % of effective porosity

Pore volume	=	7758 (640) (10) (0.15)
	=	7,447,680 bbl
	=	1 218 881.649 m^3
	=	1 218 881 649 000 dm^3
	=	1 218 881 649 000 litres

Step 4. Calculate the initial oil in place.

Initial oil in place	=	12,412,800 (1 - 0.25)/1.306
	=	7 128 330 781 STB
	=	7 milliard stb x 260 litres
	=	1 820 000 000 000 litres
	=	2 Billion litres of oil

The reservoir rock may generally show large variations in porosity vertically but does not show very great variations in porosity parallel to the bedding planes. In this case, the arithmetic average porosity or the thickness-weighted average porosity is used to describe the average reservoir porosity. A change in sedimentation or depositional conditions, however, can cause the porosity in one portion of the reservoir to be greatly different from that in another area. In such cases, the areal weighted average or the volume-weighted average porosity is used to characterize the average rock porosity.

These averaging techniques are expressed mathematically in the following forms:

Arithmetic average:	f =	Sfi/n
Thickness-weighted average	f =	Sfihi/Shi
Areal-weighted average	f =	SfiAi/SAi
Volumetric-weighted average	f =	SfiAihi/SAihi
where	n =	total number of core samples
	hi=	thickness of core sample i or reservoir area i
	fi =	porosity of core sample i or reservoir area i
	Ai =	reservoir area i

4.2.1.4. PORE VOLUME

The actual volume of the fuel inside any reservoir will be determined by the actual open space of a pore. The actual quantity of gas or oil depends on the pore volume of any reservoir. The number of pores, which eventually will determine the pore volume and hence the quantity of any oil or gas delivered by any reservoir.

4.2.1.5. FLUID GRAVITY/DENSITY

The crude oil density is defined as the **mass of a unit volume** of crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot.

$$
\begin{aligned}
p &= m/V \\
&= 200 \text{ pounds/ft}^3 \\
&= 439.560 \text{ kg}/0.028\text{m}^3 \\
&= 15\ 698.571 \text{kg/m}^3
\end{aligned}
$$

Several empirical correlations for calculating the density of liquids of unknown compositional analysis have been proposed. The correlations employ limited PVT data such as gas gravity, oil gravity, and gas solubility as correlating parameters to estimate liquid density at the prevailing reservoir pressure and temperature.

4.2.1.6 FLUID VISCOSITY

(i) **Crude Oil Viscosity**

Crude oil viscosity is an important physical property that controls and influences the flow of oil through porous media and pipes. The viscosity, in general, is defined as the internal resistance of the fluid to flow. The oil viscosity is a strong function of the temperature, pressure, oil gravity, gas gravity, and gas solubility. Whenever possible, oil viscosity should be determined by laboratory measurements at reservoir temperature and pressure.

The viscosity is usually reported in standard PVT analyses. If such laboratory data are not available, engineers may refer to published correlations, which usually vary in complexity and accuracy depending upon the available data on the crude oil. According to the pressure, the viscosity of crude oils can be classified into three categories:

(ii) **Dead-Oil Viscosity**

The dead-oil viscosity is defined as the viscosity of crude oil at atmospheric pressure and system temperature.

(iii) **Saturated-Oil Viscosity**

The saturated -oil viscosity is defined as the viscosity of crude oil at the bubble-point pressure and reservoir temperature.

(iv) **Under - saturated-Oil Viscosity**

The under - saturated-oil viscosity is defined as the viscosity of the crude oil at a pressure above the bubble-point and reservoir temperature.

4.2.1.7 PORE SHAPE

There are different types of reservoirs, in terms of the grains or rock structures and formations. Some of the structures, are circular, others are triangular, then rectangular or there are even ones which are having a square shape. There is no single reservoir, which has only the same type of rock shapes...i.e. cannot be rules out. Most of the reservoirs are having mixtures of different shapes of rocks and these are the shapes which also determine the type of porosity.

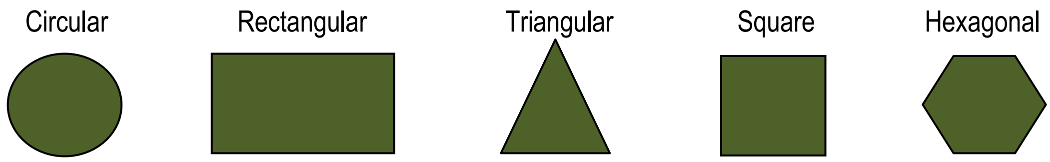


Figure 11: *Different types of pore shape in a reservoir, in terms of the grains or rock structures and formations.*

4.2.1.8 FLUID SATURATION AND WETTABILITY/RETENTION

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}}$$

The wettability of a rock is the wetness of a rock when oil or water flows over it. When the fuel flows over the rock then some of the oil remains on it and this is called wettability or retention of the rock and hence the reservoir.

4.2.1.9 RESERVOIR PERMEABILITY

The ability of a rock to pass on fluids from one pore to another is called the permeability. In addition to being porous, a rock having too many pores, a reservoir rock must have the ability to allow petroleum fluids to flow from one pore to another. The rock's ability to conduct fluids or connect fluids is termed as permeability.

This indicates that non-porous rocks, rocks which do not have any pores, open spaces, have no permeability, as the fluid will never be able to flow. Permeability can also be classified as the conductivity of a rock.
The permeability of a rock depends on its effective porosity, consequently, it is affected by the rock's:

> **grain size, grain shape**, **grain size distribution**, **grain packing**, **degree of consolidation and cementation**.

The type of clay or cementing material between sand grains also affects permeability, especially where fresh water is present. Some clays, particularly smectites (bentonites) and montmorillonites swell in fresh water and have a tendency to partially or completely block the pore spaces.

French engineer Henry Darcy developed a fluid flow equation that since has become one of the standard mathematical tools of the petroleum engineer**.** This equation is expressed in differential form as follows:

$$u = q/A_c$$
$$= \mathbf{(-\ k/\mu)(dp/dl)}$$

where:

u = fluid velocity, cm/s.
q = flow rate cm^3/s.
k = permeability of the porous rock, Darcy (0.986923 pm’).

&	= cross-sectional area of the rock, cm’.
p	= viscosity of the fluid, centipoises (cP).
1	= length of the rock sample, cm.
(dp/dl)	= pressure gradient in the direction of the flow, atm/cm.

$P(x) = (4 - 0.02\,x)$atm   x $q = 10$ cm^3/s

P_o $P_L = P_x$ $\frac{P_L - P_o}{L}$

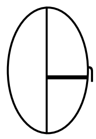
x=0   x = L

= 100cm

$$\frac{P_L - P_o}{L} = \frac{dP}{dx}$$

viscosity

$q = A.\,k/\mu \times -(dP/dx)$



$k = q\,\mu dL/AdP$ $A = \prod r^2$

$= \frac{10.1.\,100}{78{,}540\text{x}100}$ $= 78.540\text{cm}^2$

$= 0.1$ $q = 10\text{cm}^3/\text{s}$

One Darcy relatively indicates high permeability. The permeability of most petroleum reservoir rocks is less than **one Darcy**. In the oil and gas industry, smaller unit of permeability, the millidarcy (mD), is widely used. The SI unit, the square micrometer (pm^2) is also used instead of m^2.

If a rock is 100% saturated with a single fluid or phase then the permeability, k, is termed as ABSOLUTE PERMEABILITY. On the other hand if there are more phases then it is referred as EFFECTIVE PERMEABILITY being, b,k,, or k, being oil, gas, or water respectively. Reservoir fluids have the tendency of interfacing each other during their movement through the porous channels of the rock and consequently, the sum of the effective permeability of all the phases will always be less than the absolute permeability.

The ratio of **effective permeability** of any phase to the **absolute permeability** of the rock is known as the **"relative" permeability** (kr) of that phase, if there is more than one fluid in the rock, For example, the relative permeability of the oil, gas, and water would be:

Oil Relative Permeability:	kro	=	k
Gas Relative Permeability:	krg	=	k
Water Relative Permeability:	km	=	k/k

4.2.1.9.1 CLASSIFICATION OF PERMEABILITY

- Matrix/Primary Permeability

Petroleum reservoirs can have primary permeability, which is also known as the matrix permeability, and secondary permeability. Matrix permeability originated at the time of deposition or original chemical formation and lithification which is the hardening of sedimentary rocks.

- Secondary Permeability

Secondary permeability resulted from the alteration of the rock matrix by compaction, cementation, fracturing, and solution. Whereas compaction and cementation generally reduce the permeability, as fracturing and solution tend to increase it.

4.2.1.9.2 FACTORS AFFECTING THE MAGNITUDE OF PERMEABILITY

Permeability of petroleum reservoir rocks may range from 0.1 to 1,000 or more millidarcies, as shown in Table 1, below. The quality of a reservoir as determined by permeability, in mD, may be classified as:

Table 1: *Permeability indicators.*

Poor:	k	<	1		
Fair:	1	<	k	<	10
Moderate	10	<	k	<	50
Good	50	<	k	<	250
Very good	k	>	250 mD		

Permeability may be recorded as high as 4,600 mD. Reservoirs having permeability below 1 mD are considered “tight”. Such low permeability values are found generally in limestone matrices and in tight gas sands. Stimulation techniques such as hydraulic fracturing and acidizing increase the permeability of such rocks and allow the exploitation of such low permeability reservoirs, which were once considered uneconomical. Only 50 years ago rocks with permeability of 50 mD or less were considered tight.

Table 2: *Permeability and Porosity of selected reservoirs.*

Name of Sand	**Porosity %**	**Permeability (mD)**
"Second Wilcox" (Ordovician) Oklahoma Co., OK	12.0	100.0
Clinch (Silirian) Lee Co., VA	9.6	0.9
Strawn (Pennsylvanian) Cook Co., TX	22.0	81.5
Bartlesville (Pennsylvanian)Anderson Co., KS	17.5	25
Olympic (Pennsylvanian)Hughes Co., OK	20.5	35.0
Nugget (Jurassic) Fremont Co., WY	24.9	147.5
Cut Bank (Cretaceous) Glacier *Co.,* MT	15.4	111.5
Woodbine (Cretaceous) Tyler Co., TX	22.1 3	390.0
Eutaw (Cretaceous) Choctaw Co., *AL*	30.0	100.0
O'Hern (Eocene) Dual *Co.,* TX	28.4	130.0

(a) ***Shape and size of sand grains***

If the rock is composed of **large and flat grains** which are uniformly arranged with the longest dimension oriented horizontal, then its horizontal permeability (kH) will be very high, whereas vertical permeability (kv) will be medium-to-large.

If the rock is composed of mostly large and rounded grains, then its permeability will be considerably high and of same magnitude in both directions.

(b) **Lamination**

Platy minerals such as muscovite and shale laminations act as barriers to vertical permeability. In this case the kv ratio generally ranges from 1.5 to 3 and may exceed 10 for some reservoir rocks. Sometimes, however, kv is higher than kH due to fractures or vertical jointing and vertical solution channels. Joints act as barriers to horizontal permeability only if they are filed with clay or other minerals.

(c) **Cementation**

Cementation in both permeability and porosity of sedimentary rocks are influenced by the extent of the cementation and the location of the cementing material within the pore space.

(d) ***Fracturing and solution***

Fracturing is not an important cause of the secondary permeability in sandstone rocks. Except where sandstones are interbedded with shales, limestones, and dolomites. The solution of minerals percolates the surface and subsurface acidic waters as they pass along the primary pores, fissures, fractures, and bedding planes in carbonates and this increases the permeability of the reservoir rock.

4.3 SUMMARY

There are different types of rocks which are covering the earth crust. These rocks determined the types of reservoirs, which are harbouring oil or gas over centuries and centuries. The specific rock which turned into a reservoir is the sedimentary rock. This type of rock will undergo different types of chemical make up over centuries again and hence it will have a certain complexities, which are called rock or reservoir properties. These properties will be different for different types of sedimentary reservoirs. This has been the reason, why different continents and countries have different quantities of oil and gas reservoirs. The above mentioned properties are as follows. Porosity, Permeability, Shape, Wettability, Saturation, Temperature, Pressure, Gravity, Density, Viscosity, and Pore Volume.

A reservoir can be depleted over decades and centuries BUT can again get pregnant or contain oil or gas. These can be inflows of gas and oil from the neighbouring rocks, as the previous or historically pregnant reservoir, might have provided a good, low pressure area for the harbouring of the a content. This area can be termed as good cuddle place for an infant oil or gas. The inflow can take place over a period of time and this will result in a highly impregnated reservoir, which can deliver in a short while or any time. A highly rich or highly qualified reservoir in terms of oil and gas must have favourable or moderate pressure and temperature application on a reservoir, which will then, determine the shape of a pore. The quantity of pressure application on a reservoir will also predetermine the number of pores in a reservoir. The more pores are there and the high permeability, the more quantity or volume of oil and gas can be delivered by any reservoir.

The more practical application of a particular reservoir is that, any reservoir will have different shapes, sizes of pores. There will not be any reservoir, which has only small, medium or large pores. BUT this possibility can and will never be excluded. The frequently changing pressure applications on the earth crust, will determine this phenomenon. As long as there is a continuous change in pressure on any reservoir, there will always be different shapes, sizes of pores and permeability in a reservoir. A reservoir, which does not have any pores, will never have any quantity of oil and gas.

I am going to demonstrate the porosity and the permeability and the quantity of oil of different types of reservoirs.

Resevoir A: Small Pores

Figure 12: The quantity of pores and its volume of the fluid in a reservoir with small pores.

Small rock size: V_s $= 4/3\pi r^3$
$= 4/3\pi 10^3$
$= 4188{,}790 mm^3$

Volume of 40 rocks in the container:
V_2 $= 40 \times 4188{,}790$
$= 134\ 041{,}287\ mm^3$
$= 134{,}\ 041\ cm^3$
$= 134{,}041$ ml

Volume of Empty container:
V_1 $= (\pi D^2/4)h$
$=(\pi(6.4)^2/4)15$
$= 482{,}549$ ml

V_{final} $= V_1 - V_2$
$= 482{,}549 - 134{,}041$

In other words the quantity of oil in this container is: **= 348,508ml**

Reservoir B: Medium Pores

Medium rocks size: $V_m = 4/3\pi r^3$

$= 4/3\pi 15^3$

$= 14\ 137,\ 167\ mm^3$

Volume of 22 medium rocks:

$V_3 = 22 \times 14\ 137{,}167$

$= 311\ 017{,}673\ mm^3$

Volume of Empty container:

$V_1 = (\pi D^2/4)h$

$=(\pi(6.4)^2/4)15$

$= 482{,}549$ ml

In other words the quantity of oil in this container is:

$V_{final} = V_1 - V_3$

$= 482{,}549 – 311,\ 018$

$=$ **171,531 ml**

Figure 13: *The quantity of pores and its volume of the fluid in a reservoir with medium pores.*

Reservoir C: Large Pores

Large rocks size: $V_l = 4/3\pi r^3$

$= 4/3\pi 20^3$

$= 33\ 510{,}322\ mm^3$

Volume of 22 medium rocks:

$V_4 = 14 \times 33\ 510{,}322$

$= 469\ 144{,}503\ mm^3$

Volume of Empty container:

$V_1 = (\pi D^2/4)h$

$=(\pi(6.4)^2/4)15$

$= 482{,}549$ ml

In other words the quantity of oil in this container s:

$V_{final} = V_1 - V_4$

$= 482{,}549 – 469,\ 145$

$=$ **13,404 ml**

Figure 14: *The quantity of pores and its volume of the fluid in a reservoir with large pores.*

Reservoir D: **Mixed Pores**

Small rock size: V_s $= 4/3\pi r^3$

$= 4/3\pi 10^3$

$= 4188,790 mm^3$

Medium rock size: V_m $= 4/3\pi r^3$

$= 4/3\pi 15^3$

$= 14\ 137,\ 167\ mm^3$

Large rock size: V_l $= 4/3\pi r^3$

$= 4/3\pi 20^3$

$= 33\ 510,322\ mm^3$

Figure 15: *The quantity of pores and its volume of the fluid in a reservoir with mixed pores.*

Volume of small rocks:	V_s	=	5 x 4 188,790	**Vsml**
		=	**20 943,95 mm³**	
Volume of medium rocks:	V_m	=	5 x 14 137,167	
		=	**70 685,835 mm³**	
Volume of large rokcs:	V_l	=	5 x 33 510,322	
		=	**17 551,61 mm³**	

Total volume of all the different sizes of rocks inside the container is equal:

$V = V_s + V_m + V_l$

$= 20\ 943,95 + 70\ 685,835 + 17\ 551,610$

$= 109\ 181,395\ mm^3$

$= 109,181\ cm^3$

Actual volume of the oil in the reservoir is therefore equal:

V_{final} = Volume of the empty container - Vsml

= 482,549 - 109, 181

= **373,368 ml**

It is very clear the actual volume of a reservoir with contains different sizes of rocks, presents the practical application of reservoir's volume of oil.

One can again NOT rule out or exclude the size of the reservoir pores, as they determine the actual volume of the quantity of oil or gas, any reservoir can supply as well as how long this reservoir can be in existence. For how many years will such a reservoir be able to supply oil or gas?

It must never be excluded that reservoirs can also contain the same type and sizes of pores.

The permeability of the different types of reservoirs will specifically depend on the following:

- Number of pores in a reservoir
- Different sizes of pores
- The cementation or how close the pores are spread across a reservoir
  The most productive and durable, lifelong Reservoir will be classified and based on the following practically oriented statements.

A.	The higher the porosity, the higher the permeability.	-	Short Life Reservoir
B.	The lower the porosity the lower the permeability.	-	Long Life Reservoir
C.	**The higher the porosity, the lower the permeability.**	**-**	**Long Life Reservoir**
D.	The lower the porosity, the higher the permeability.	-	Impossible

In other words the reservoir C, has got high density and low viscosity fluid. The low permeability can also be the irregular shape of the rocks. And this extends the life of the reservoir as it can be productive for a longer period.

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CHAPTER 5

RESERVOIR SIMULATION

5.1 INTRODUCTION

Reservoir simulation models are dominantly utilized by oil and gas companies and governments all over the world in the development of new and prospecting fields as well as developed fields where production forecasts are needed in order to make educated and most advantageous investment decisions for a particular company or government. The construction of a more reliable, accurate model of a field study is very time consuming and hence expensive and it is vitally important to only concentrate on large investment projects, as the national budget of countries must be considered or company budgets must be adjusted tremendously. The radical advancement in the simulation software has accelerated the development of a workable model and this has resulted that simulation models can also be operated and data improved from personal computers rather than more expensive workstations. It is also more practical to have personal computers, like laptops, which are easily accessible and useable at all times.

It is very much obvious and highly recommendable that one of the primary goals of simulation models is to assist in developing and identifying possible productive wells for new fields as this will provide the current future needs for artificial lift.

The continuous reservoir management, administration and application of the most practical applications as well as the on trial requisition of models may help to improve oil recovery by applying hydraulic fracturing, as deviated or horizontal wells can also be represented in the region or area. The advanced and specialized software on the identified reservoirs will accelerate the use in the design of hydraulic fracturing and hence the improvements in productivity can be included in the field model for the future improvements for the external factors, like pressure and temperature variations. The injection of water provides water flooding which results in the improved displacement of oil and this is commonly evaluated using reservoir simulation.

Special features in simulation software are needed to represent these processes in order to secure availability of the resource. In some miscible applications, the "SMEARING" of the flood front, also called NUMERICAL DISPERSION, may be a problem. Reservoir simulation is used extensively to identify opportunities to increase oil production in heavy oil deposits. In numerous reservoirs the **Oil recovery is improved significantly in decreasing the oil viscosity by injecting steam or hot water**.

The following typical processes are encouraged in order to determine the viscosity of the oil inside a reservoir:

- steam soaks, as steam is injected, then oil produced from the same well
- steam flooding, a separate steam injectors and oil producers, water is injected in the well, resulting into steam flodding.

The above mentioned processes require simulators with unique and special features in order to account for heat transfer to the fluids involved. In the modelling of coal, simulations are also highly recommendable in the coal bed methane (CBM) production and this application requires a specialized CBM simulator.

In addition to the normal fractured (fissured) formation data, CBM simulation requires gas content data values at initial pressure, sorption isotherms, diffusion coefficient and parameters to estimate the changes in absolute permeability as a function of pore-pressure depletion and gas desorption.

A reservoir simulation model is a critical, important and very, practically applicable tool in optimizing recovery and financial performance which provides:

- A specific and detailed visualization model.
- Providing analysis of oil, gas, water, and solids behaviours,
- Ambiguity analysis and maximum optimization of the availability of the resource, so that potential recovery and artificial lift methods can be evaluated and precisely applied when required.

Reservoir Geomorphologic behaviour enables oil and gas companies to identify the characteristics of a reservoir in order to manage it more effectively.

Heavy oil reservoirs or reservoirs which are indentified as containing high volumes or quantities of oil or gas are often associated with soft, unconsolidated near-surface basins where wellbore stability can be an issue during drilling or production, and poorly-sorted heterogeneous sands can hinder steam chamber growth.

Sand channels or wormholes are the result of sand production in a GEOLOGIC BASIN and this means that special reservoir simulation techniques must be incorporated to adequately model CHOPS and other production mechanisms and these must accurately describe the flow paths, pressure drawdowns, and stimulated productivity that occur because of those channels.

Additional software enables:

- the acceleration of Economic modelling and evaluation of upstream heavy oil projects
- The means to analyze risk at the most required and needed time
- Production forecasts are predicable
- Customized reports provision and
- Sensitivity analysis including steam costs to be performed.

Traditionally there are different types of simulators which dominate both theoretical and practical work in reservoir simulation.

- **CONVENTIONAL FD SIMULATION** is characterized by three physical concepts AAND THEY ARE AS FOLOLOWS:

  (I) CONSERVATION OF MASS, which is the weight of the resource
  (II) ISOTHERMAL BEHAVIOUR of the resource and
  (II) DARCY APPROXIMATION which determines fluid to flow through porous media.

- **THERMAL SIMULATIONS**, which is commonly used for heavy crude oil applications add conservation of energy to this list, allowing temperatures to change within the reservoir. This will also determine the pressure applications inside the reservoir.

The following techniques and approaches are common in **MODERN SIMULATIONS**:

1. Mostly modernised FLUID DYNAMICS SIMUALTION programs allow the construction of 3-D representations for the utilization in either full-field or single-well models.
2. The geometry of the an oil and gas reservoir is accurately represented by the CLASSIFIED DIFFERENTIATED RESERVOIR MODELS which allow discretization of a reservoir theoretically by using both structured and more complex unstructured grids.
3. The FAULTS which are encountered in any reservoir are representations and their transmissibilities are complicated and advanced features which are provided in many simulators. In these types of models, like the inter-cell flow transmissibilities must be computed for non-adjacent layers outside of conventional neighbour-to-neighbour connections.
4. A NATURAL FRACTURE SIMULATION which is known as DUAL POROSITY AND DUAL PERMEABILITY, is an advanced feature, which is a model hydrocarbons, in tight matrix blocks.
5. A BLACK OIL SIMULATOR does not consider changes in composition of the hydrocarbons as the field is produced. The compositional model is a more complex model, where the PVT properties of oil and gas phases have been fitted to an equation of state (EOS), as a mixture of components.

The simulation model computes the saturation change of three phases oil, water and gas and also provides pressure of each phase in each cell at a specific time.

Gas will be liberated from oil as a result of decreasing pressure in a reservoir depletion study. If pressure increases as a result of water or gas injection, the gas is re-dissolved into the oil phase. A simulation project of a developed field usually requires "history matching" where historical field production and pressures are compared to calculate values. In recent years optimisation tools such as MEPO has helped to accelerate this process, as well as improve the quality of the match obtained. A most, justifiable and practically applicable simulation model can be achieved as water, gas and oil ratios are properly matched in terms of their ratios.

5.2 SIMULATION SOFTWARE

Many software, private, open source or commercial, are available for reservoir simulation. The most well known are:

5.2.1 OPEN SOURCE:

- **BOAST** - Black Oil Applied Simulation Tool (Boast) simulator is a free software package for reservoir simulation available from the U.S. Department of Energy. Boast is an IMPES numerical simulator (finite-difference implicit pressure-explicit saturation) which finds the pressure distribution for a given time step first then calculates the saturation distribution for the same time step isothermal.

- **MRST** - The MATLAB Reservoir Simulation Toolbox (MRST) is developed by SINTEF Applied Mathematics as a MATLAB toolbox. The toolbox consists of two main parts: a core offering basic functionality and single and two-phase solvers, and a set of add-on modules offering more advanced models, viewers and solvers. MRST is mainly intended as a toolbox for rapid prototyping and demonstration of new simulation methods and modeling concepts on unstructured grids. Despite this, many of the tools are quite efficient and can be applied to surprisingly large and complex models.

- **OPM** - The Open Porous Media (OPM) initiative provides a set of open-source tools centred around the simulation of flow and transport of fluids in porous media.

5.2.2 COMMERCIAL: CMG

- Suite (IMEX, GEM and STARS) – Computer Modelling Group currently offers three simulators: a black oil simulator, called IMEX, a compositional simulator called GEM and a thermal and advanced processes simulator called STARS.

- Schlumberger **ECLIPSE**- ECLIPSE is an oil and gas reservoir simulator originally developed by ECL (Exploration Consultants Limited) and currently owned, developed, marketed and maintained by SIS (formerly known as GeoQuest), a division of Schlumberger. The name ECLIPSE originally was an acronym for "ECL´s Implicit Program for Simulation Engineering". Simulators include black oil, compositional, thermal finite-volume, and streamline simulation. Add-on options include local grid refinements, coalbed methane, gas field operations, advanced wells, reservoir coupling, and surface networks.

- **ExcSim**, a fully implicit 3-phase 2D black oil reservoir simulator for the Microsoft Excel platform.
- **Landmark Nexus** - Nexus is an oil and gas reservoir simulator originally developed as 'Falcon' by Amoco, Los Alamos National Laboratory and Cray Research. It is currently owned, developed, marketed and maintained by Landmark Graphics, a product service line of Halliburton. Nexus will gradually replace VIP, or Desktop VIP, Landmark's earlier generation of simulator.]

- Stochastic Simulation **ResAssure -** ResAssure is a stochastic simulation software solution, powered by a robust and extremely fast reservoir simulator.

- Rock Flow Dynamics **tNavigator** supports black oil, compositional and thermal compositional simulations for workstations and High Performance Computing clusters.

- GrailQuest's **ReservoirGrail** employs a unique patented approach called Time Dynamic Volumetric Balancing to simulate reservoirs

5.3 SEISMIC IMAGING

The oilfield industry over the past several years has been making vast leaps in drilling efficiency. These gains are not only tallied through advances in casing, drill string or cutting technologies but also through the unsung technologies that have been recently employed, like the 3D seismic imaging and this has seen the greatest returns on investment. Until very recently, the motto of the drilling industry was: READY, FIRE, AIM. There was no room for lost time. Through rather crude geologic surveys, at least compared to modern techniques, drilling companies went into formations somewhat blind. Without *full* knowledge of reservoir characteristics, drilling was far more financially risky and a mortally dangerous endeavour.

Further, even if oil or natural gas was able to flow from the reservoir, lack of information related to the exact hydrocarbon payout ran the risk of the well not being able to cover the costs associated with the drilling operations.

This economic limit is where 3D seismic imaging has proved with worth. With full knowledge of the depths, pressures and reservoir payouts, drillers can now conduct their operations with more precision, safety and economic efficiency.

5.3.1 HISTORY

Drilling companies, mostly opted for 2D imaging technology as 3D technology became cost-effective for exploration, drilling & production. Otherwise known as reflection seismic, this technology resembled sonar and ultrasound technologies. By inducing acoustic waves into the geologic subsurface, geologists would be able to listen to the echoes returning from the stratigraphic boundaries and form a picture of the formation. These acoustic waves would typically be generated by underground explosive charges or by thumping the ground with a large mallet mounted on a specially designed vehicle known as a **VIBROSEIS** truck.

The reverberations felt in the subsurface would be reflected back to the surface and would be "collected" using a special microphone known as a **GEOPHONE/HYDROPHONE**. This data would be collected onto a magnetic tape and then transmuted into readable data via computers. As elementary as this process was, it was far more informative that going off of purely surface-oriented geological surveys. Though it was effective in proving subsurface reservoirs, its shortcoming was a lack of an articulate understanding of subsurface characteristics.

5.3.2 CURRENT SITUATION

Now companies like Dome Energy are cost-effectively implementing 3D seismic imaging to prove the economics of a rather financially risky drilling process.

3D seismic imaging has shares similar technological hallmarks to that of 2D imagining but the differences between the two are undeniable.

The technology employs acoustics imaging but rather than one source of vibration, 3D seismic imaging involves creating a perimeter where multiple acoustic receivers, rather than microphones, are established. These areas for the receivers are known as patches. By capturing seismic shots that lie between two patches geologists and drilling companies obtain uniform reflection information from a subsurface area.

By changing the locations of each patch and repeating the vibration and recording process, companies accumulate overlapping subsurface readings which build a very articulate three dimensional picture.

3D seismic imaging doesn't eliminate 100% of the exploration and drilling risk, it definitely improves success rates and productive wells. The technology allows explorers and drillers with more pinpoint accuracy that goes to and should deliver better production and a slightly longer well life. **More importantly, 3D seismic imaging eliminates the possibility of drilling dry holes in the pool development process.**

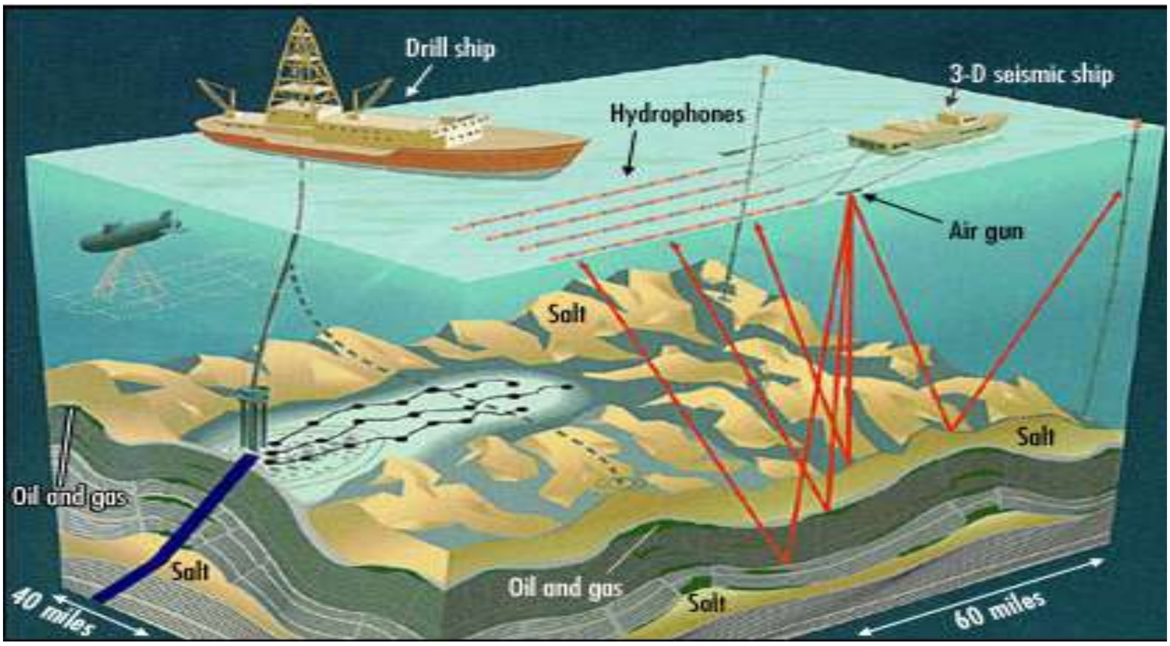

Figure 16: *The 3D- seismic imaging in determining the location of oil and gas in a reservoir.*

5.3.3 SEISMIC DATA PICTURES

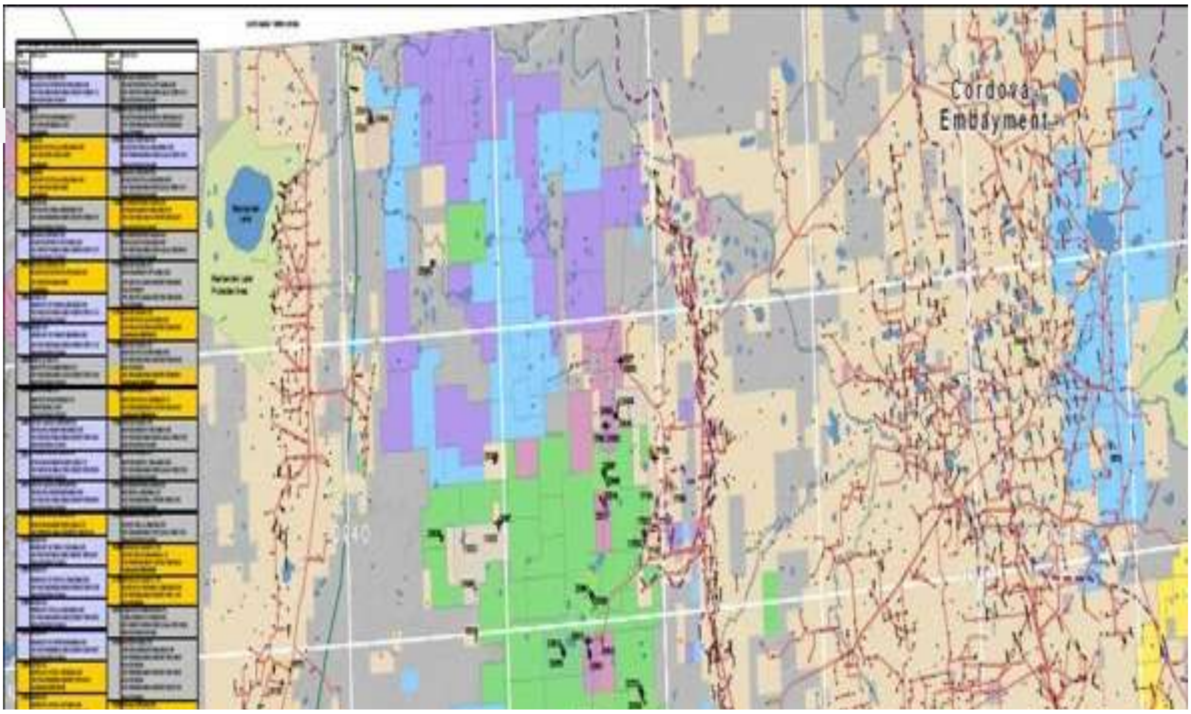

Figure 17: *The seismic picture in different depths and pressure, temperature of a reservoir, indicating, porosity, permeability, pressure gradient, clay content, silica, calcite, carbonate, absorbed gas and average IP.*

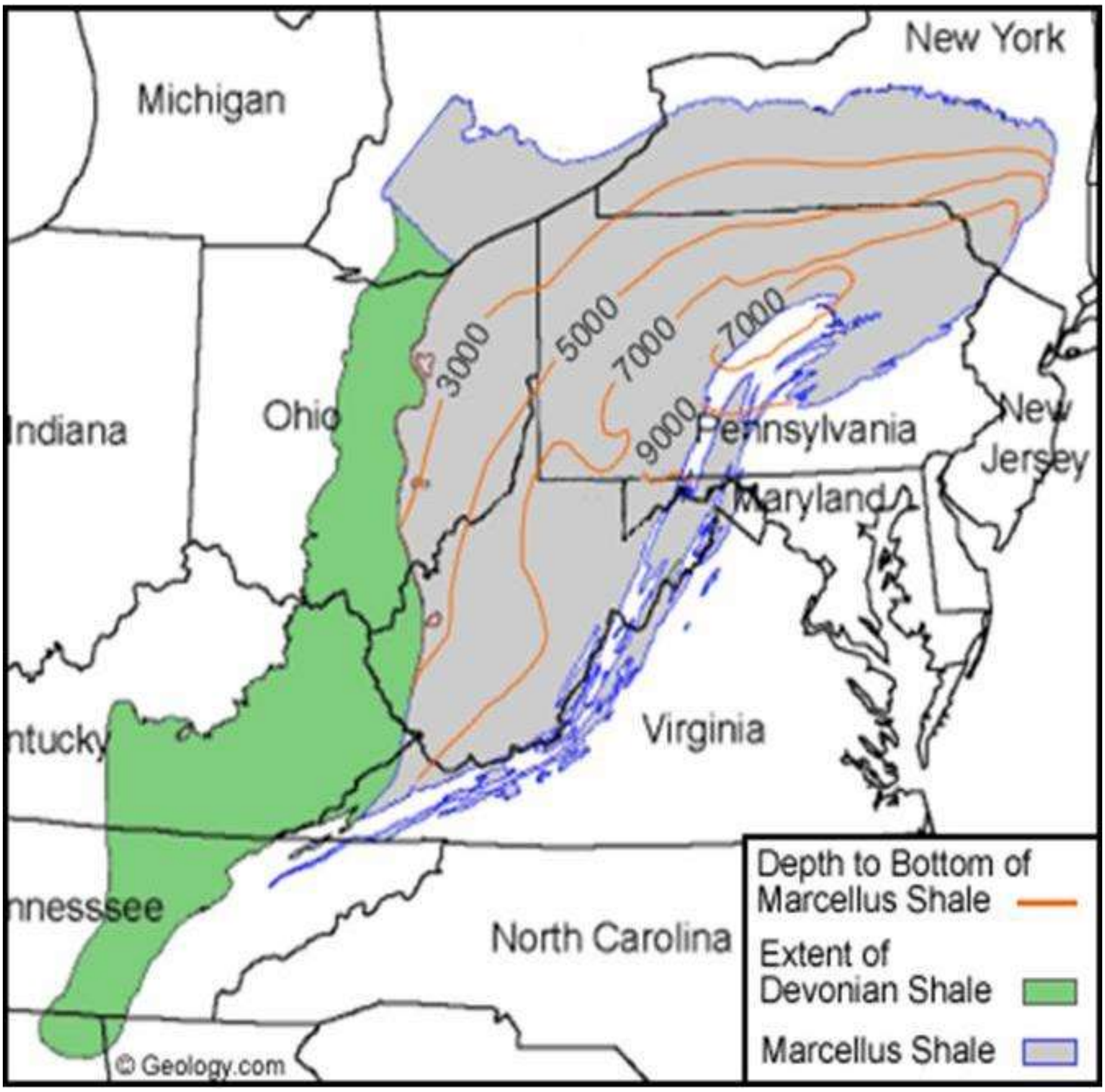

Figure 18: *Different pressure and temperatures in a certain area of the states of United States of America.*

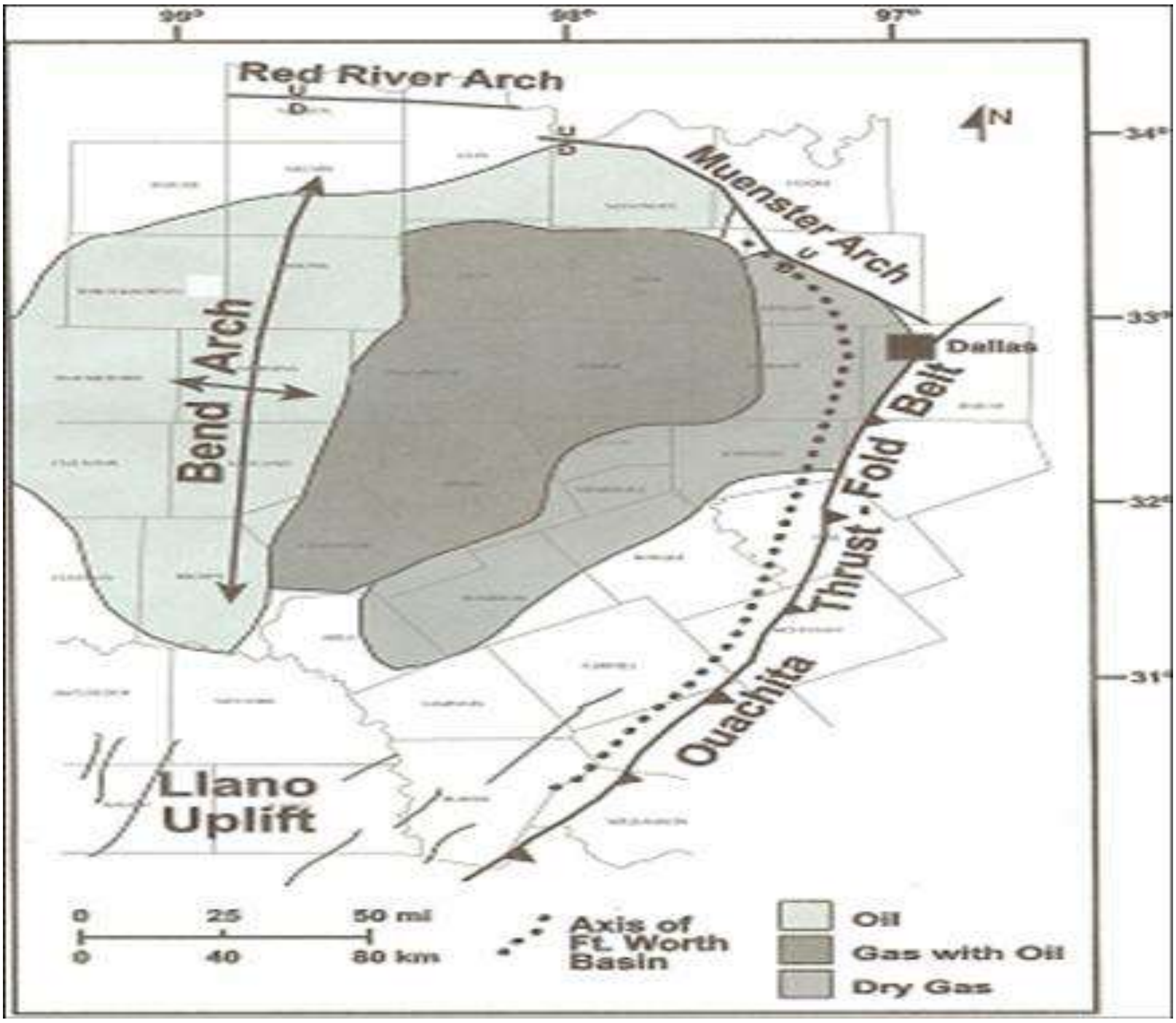

Figure 19: *The oil and gas prospects in a reservoir of the Mississippian area.*

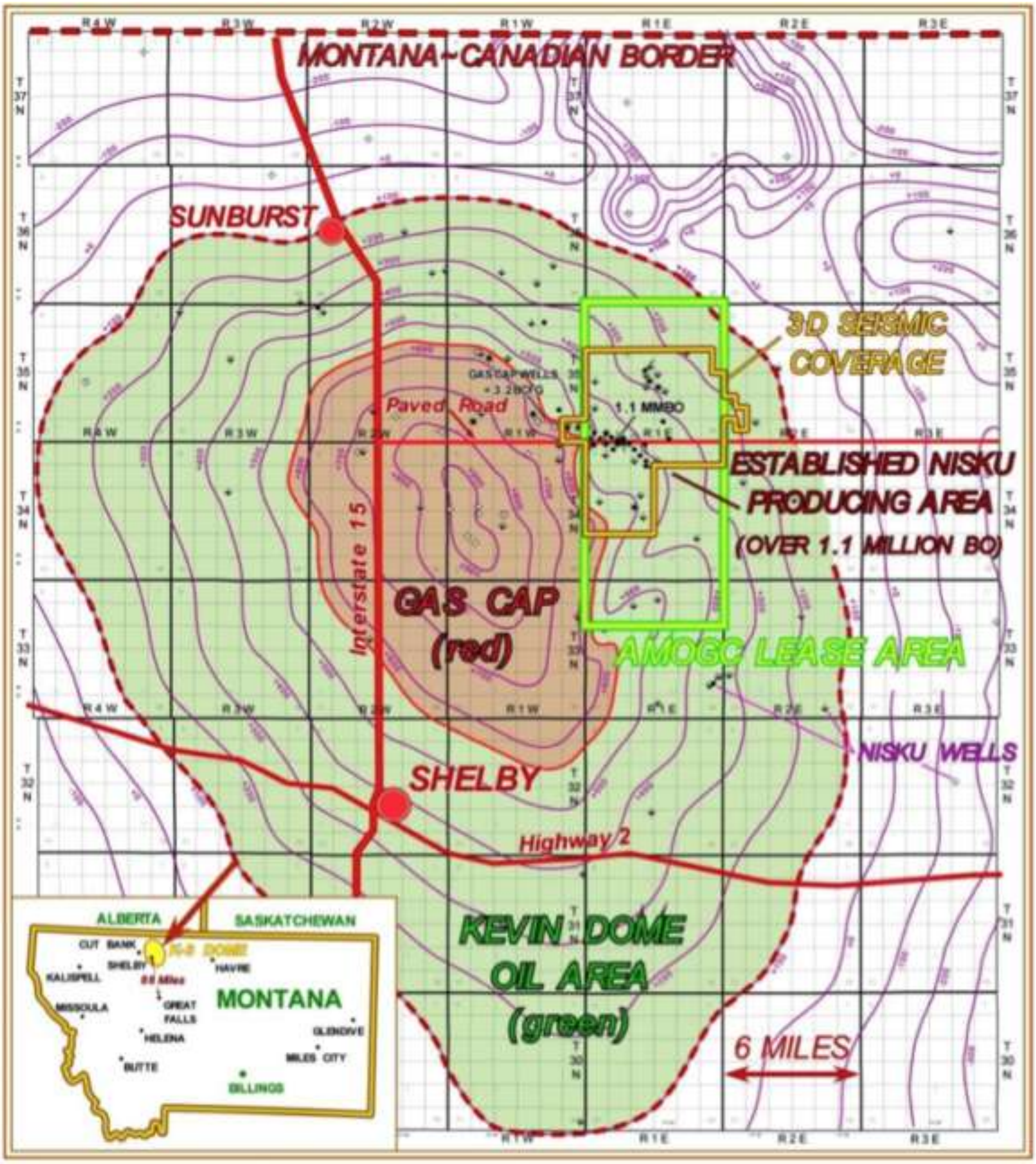

Figure 20: *The topographic map of a reservoir in the Montana area of Canada.*

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5.4 SUMMARY

A Reservoir Simulation is used tremendously and extensively to identify opportunities and company objectives in securing and increasing oil production in heavy oil deposits and reservoirs.
The oil recovery process is enhanced by decreasing the oil viscosity by injecting steam or hot water inside a well with oil. The simulation models and the seismic imaging are very much important and critically advantageous to the respective companies and governments, which are on the attempt of trying to explore, drill and produce any gas or oil in any region or location. It is of utmost importance to know, whether in a certain area, region or place there is an availability of a resource, like oil or gas before any plans are carried out and this can only be determined by seismic 3D imaging and hence the seismic application.
Once a resource, oil or gas reservoir has been identified and located and the companies know that there is oil or gas available, and then the planning will start on how to drill and extract oil or gas from deep down the sea, sub-surface. The seismic imaging or data will also bring forth the quantity of the possible oil or gas.
This can then also determine for how long the companies will be involved in extracting the product.
Thus for sure will also determine the financial budgets of the respective companies for the period of time they will be engaged in a particular location.

Experiments via simulation model have several important advantages versus physical experiments too and the following highlighters are coming to forth.

Value. A simulation model can be used to determine certain parameters in company which is about to explore on an and gas reservoir:

- It can determine the number of personnel needed
- How many advertisements are needed in order to promote the availability of a resource?
- The financial impact of a company can be determined by using a simulation model
- The entire value of such a reservoir can be pre-determined.

Time. This model will obviously inform a company or the reservoir engineers for how long the production process will take place on a particular reservoir.

Repeatability. A marketing team for a petroleum engineering company could make use of a simulation model in order to predict the price range as provided by the market as these parameters or factors might be repeated in the future and it will be better to understand their effects before its too late!

Accuracy. A Simulation model provides the real and natural way of a reservoir and it is based on accuracy and most probable results from practical applications.

Visibility. A simulation model enables the visualization of the system over a period time as animations illustrate the system in operation and hence the graphical outputs quantify the results. This allows engineers to assess and visualize the resulting decision and dramatically simplifies the task of bringing these ideas to client and colleagues.

Versatility. The model simulates real life, which is based on practical conditions and as temperature and pressure are severely fluctuating.

The most fundamental methods for Geophysics is to explore and discover the sub-surface as follows:

- Seismic
- Electromagmetism
- Gravitation
- Magnetism

The marine seismic surveys and electromagnetic techniques are the mostly used and the biggest technological strides of recent years which have been made and vastly utilized in these areas.

These methods have been assisting the petroleum geologists to compile and comprehend the sub- surface structures.

The resulting data can be used to:

- Identify possible oil and gas migration paths over the period of time.
- Estimate the geometry and size of potential traps where the resource might be located.
- Predict directly the presence of hydrocarbons.
- Developing new oil and gas fields and at least provide managing production
- **The seismic data also provides very informative parameters for any Reservoir Engineer or Geophysist.**

The following information is also very crucial for a reservoir:

- Type of rock.
- Maximum area the reservoir covers.
- The quantity of the product, oil and gas.
- The depth the resource/product.
- The possible affecting factors, like pressure and temperature.
- Porosity and Permeability of the rock or reservoir.
- Shape of the reservoir.
- Obtain as maximum product from the reservoir as possible based on its financial application.
- Provides the WELL DESIGNED, practically oriented model.
- The analytic behaviour of oil, gas, water, and solids.
- Provides an evaluation on the uncertainty analysis and optimization, so that potential recovery and artificial lift methods can be carried out.

Heavy oil reservoirs contain very high quantity productivity and they are often associated with soft, unconsolidated near-surface basins where wellbore stability can be an issue during drilling or production processes and poorly-sorted heterogeneous sand surfaces can hinder steam chamber growth as they can easily collapsed. Reservoir simulation is an area of Reservoir Engineering in which computer models are used to predict the flow of fluids, like oil, water, and gas through porous sediments.
This provides the scientific detailed understanding of a real or mentally created structure that reproduces or reflects the object being studied. Modelling or simulation is one of the main methods of knowledge application and it is widely used in technology and is an important step in the implementation of scientific and technological progress.

The creation of models of oil fields and the précised, exact implementation of calculations of field development on their basis is one of the main areas of activity of engineers and oil researchers.
The geological and physical information about the properties of an oil, gas or gas condensate field, as well as the capabilities of the systems and technologies create quantitative ideas about the development of the field as a whole. A system of interrelated quantitative ideas about the development of such a field is a model of its development, which consists of a RESERVOIR MODEL and a MODEL of a FIELD DEVELOPMENT PROCESS. The investment project is a system of quantitative ideas about its geological and physical properties, used in the calculations of field development. A system of quantitative ideas entails a field of deposits and deposits about the process of extracting oil and gas from the subsoil. Generally speaking, any combination of reservoir models and development process can be used in an oil field development model, as long as this combination most accurately reflects reservoir properties and processes. At the same time, the choice of a particular reservoir model may entail taking into account any additional features of the process model and vice versa.

The RESERVOIR MODEL should, of course, be distinguished from its design scheme, which takes into account only the geometric shape of the reservoir. A reservoir model may be a stratified heterogeneous reservoir and in the design scheme, the reservoir with the same model of it can be represented as a reservoir of a circular shape, a rectilinear reservoir, etc.

Layer models and processes for extracting oil and gas from them are always included in a mathematical form, i.e. characterized by certain mathematical relationships.
The main task of the engineer who is engaged in the calculation of the development of an oil or gas field is to draw up a calculation model based on individual concepts derived from a geological-geophysical study of the field, as well as hydrodynamic studies of wells.

Modern computer and computational achievements make it possible to take into account the properties of the layers and the processes occurring in them when calculating the development of deposits with considerable detail.

The possibilities of Geological, Geophysical and Hydrodynamic cognition of development objects are continuously expanding. Hence the possibilities are far from endless as the makeup of the reservoir is continuously changing. Therefore, there is always a need to build and use such a field development model in which the degree of knowledge of the object and the design requirements would be adequate and practically applicable.

CHAPTER 6

RESERVOIR SOFTWARE

6.1 INTRODUCTION

Petroleum engineering is one of the fast growing industries and it requires technologically, more advance software in its applications. The reservoir engineering on its own again will definitely require the specific and applicable software in order to track down the specific reservoirs like the oil and gas. This process on its own is again complicated, sophisticated, and it requires precision as more finances are pumped into this industry and no company would like to waste time on trying to track down a reservoir which is fully quantify in terms of oil or gas.

It is also very much important to know, whether a specific reservoir contains oil or gas and for this reason, any reservoir engineer must be precise and specific.

Therefore the specific software which is going to be utilized must be viable and be able to identify the following factors in terms of a reservoir:

- Types of rocks and reservoirs
- Material Equilibrium
- Properties of a reservoir
- Reservoir simulation
- Volumetric potential of oil and gas reservoir

The above mentioned factors are very much critical in reservoir engineering and they are the ones which will determine the:

- Potential of a specific reservoir.
- Productivity of any reservoir
- Financial capability of an oil and gas company.
- Life span of any reservoir.
- Quantity volume, of oil and gas, of a reservoir

The correct software application is very important and necessary as individual companies are pumping in lot of finances in order to be successful in production.

6.2 TYPES OF SOFTWARE - Foundation Products

TYPE OF SOFTWARE/ Foundation Products	PURPOSE/FUNCTION
6.2.1 Geoframe	GeoFrame reservoir characterization software provides a comprehensive solution for your integrated seismic, geological, mapping, and petrophysical interpretation needs. At the heart of GeoFrame software is a shared project database capable of managing tens of thousands of wells, hundreds 3D seismic surveys, and thousands of 2D seismic lines. Advanced workflow techniques—such as AVO interpretation, volume interpretation and GIS—give geoscientists an advantage in prospect generation and field development. Coupled with easy access to the Petrel E&P software platform, interpretation risks are reduced even further.
6.2.2 GeoX	GeoX exploration risk, resource, and value assessment software provides easy-to-use and scalable decision support for consistent, unbiased, and accurate assessments of your exploration opportunities in any environment or risk scenario. GeoX software can be customized to fit and promote your best exploration practice and it complements subsurface investigations performed in PetroMod petroleum systems modelling software and the Petrel E&P software platform.
6.2.3 Mbal	This incorporate the classical use of material balance calculations for history matching through graphical methods, like Havlena-Odeh, Campbell etc. Detailed PVT models can be constructed for oils, gases and condensates. Predictions can also be made with or without well models and using relative permeabilities to predict the amount of associated phase productions. MBAL can also be tied into GAP for intergraded production modelling studies, providing an accurate and fast reservoir model as long as the assumptions of material balance are valid for the real situation to be modelled. When a well is producing from multiple layers, it is essential for an engineer to know how much each layer has contributed to the total production. Traditionally, this reservoir allocation has been done based on the kh of each layer. This approach does not take the IPR of the layers into account and also ignores the rate of depletion of the layers. The reservoir allocation tool in MBAL improves the allocation by allowing the user to enter IPRs for each layer and calculates the allocation for the model, as well as different start to finish times for the wells. Impurities are also tracked and can provide an effective measure of the quality of the underlying assumptions in the case where few data is available.
6.2.4 Prosper	Prosper is a well performance, design and optimisation program for modelling most types of well configurations found in the worldwide oil and gas industry today. This program can be used to predict tubing and pipeline hydraulics, pressure and temperature with accuracy and speed. Prosper assures a reservoir engineer to build a reliable and consistent well models with the ability to address each aspect of a wellbore. The Prosper tools is good to provide good modelling of the following factors, which will prepare any reservoir engineer properly, PVT, fluid characterisation, VLP correlations, calculation for flow line and tubing pressure loss, and IPR, reservoir inflow.
6.2.5 Topaze	Topaze uses well, reservoir and boundary models. Topaze can simulate pressures from rates and cumulative production from pressures, or both. History similarity is obtained by nonlinear regression of the model on pressures, rates, cumulative production or any weighted average. In more complex cases Topaze numerical models are used to generate geometries beyond the scope of analytical models. This is predominantly 2D, but with 3D refinement where needed. The horizontal multi-fractured well for unconventional resources is included. Numerical models also address nonlinearities, replacing the linear diffusion used in analytical model by the real diffusion equations solving for real gas, non-Darcy flow, pressure related physical properties, multiphase flow, water drives, and desorption based on the Langmuir isotherm, for shale gas (single phase) and coal bed methane (2-phase water-gas).

Table 3: *Different types of software, foundation products for reservoir simulation.*

TYPE OF SOFTWARE- *TOPAZE*	FUNCTION
6.2.5.1 Multi-well processing	The multi well mode of Topaze facilitates the analysis of the production of multiple wells. The production data can be loaded simultaneously in formats including DMP2, Merak, or by drag-drop from KAPPA Server. It is then possible to view this data together in a browser, and conduct quick or detailed analysis of all wells or groups of wells. The results are viewed as tables or bubble maps as required and then it is a single step to construct a field profile from any extension of the selected diagnostic, be it a decline curve or a complex model.
6.2.5.2 Changing well conditions	The numerical module simulates multiple well production where individual wells can be pressure or rate controlled. There is 2D and 3D visualization of the well drainage areas and their evolution with time. If the simulation deviates from the data and indicates a change in the well productivity index the user may assign individual skin values to different production periods. Nonlinear regression is then applied on all skins, resulting in a relationship between mechanical skin and time.
6.2.5.3 Production forecast	Without data, or after history matching, a production forecast for any model may be run based on the anticipated producing pressure. Sensitivity to production improvement or decay can be simulated.
6.2.5.4 Production profile generator	This tool provides a uniform and standardized approach to obtaining quick production estimates for new fields and incremental recovery studies. Valid for oil, gas and condensate the user can model water or gas drive taking into account all producing and or injecting wells. It allows the input of an unlimited number of various well-type profiles and generates a field production profile consistent with the drilling and work over schedule and facility constraints. The profile generator can use a multi-well field profile a
6.2.5.5 Reporting and exporting	Topaze has a range of comparison, reporting, exporting and printing capabilities. The free and unprotected Reader allows files to be read, printed and exported without the requirement for an active license. There is a slide presentation format for LCD projector or copy/paste into PowerPoint™.s a baseline for an incremental study

Table 4: *Tapaze software applications.*

SAPHIR **6.2.6.1** **Data loading and editing**	Saphir can load an unlimited number of gauges, rates, pressure and other data in most formats including ASCII, Excel, PAS and databases via OLEDB & ODBC. Saphir has real time links with acquisition systems, data drag-drop from other modules and KAPPA Server, which can identify build-ups and initialize Saphir on a single click. Multi-layer rates may also be imported from Emeraude.
6.2.6.2 **Extracting ΔP and deconvolution**	One or several periods of interest, generally shut-ins, for one or several gauges may be extracted and used on a semi-log and loglog plot, the latter integrating the Bourdet derivative. Deconvolution can be used to combine several successive shut-ins into a longer 'virtual production'. Available methods are:(1) von Schroeter et al, (2) Levitan (with material balance correction) (3) Houzé et al and (4) a hybrid combination.
6.2.6.3 **Data QA/QC and datum correction**	Saphir offers a range of interactive QA/QC tools including trends, tidal correction, gradient analysis and gauge comparison to detect sensor drift and wellbore effects. Saphir can define or import VLPs and well intake models, either from Amethyste or standard file import. VLPs are used in conjunction with analytical and numerical models to simulate the pressure at gauge depth or at surface. Alternatively they can be used to correct pressure data to reservoir depth.
6.2.6.4 **Test design**	All analytical and numerical models may be used to generate a virtual gauge on which a complete analysis may be simulated. This can take into account gauge resolution, accuracy and potential drift in order to select the appropriate tools or to check if the test objectives can be achieved.
6.2.6.5 **Specialized plots**	Additional specialized analysis plots can be created with options tailored to specific flow regimes. These include very short-term tests or FastTestTM for perforation inflow testing and predefined types such as MDH, Horner, square root and tandem root.
6.2.6.6 **Analytical models**	Saphir offers a built-in analytical catalogue combining well, reservoir and boundary models. External models (see pages 50–51) can be downloaded. Interactive 'pick options' are offered for most parameters for a first estimate by selecting a characteristic feature of the model on the Bourdet derivative. There is an option to use the AI package 'KIWI' as a guide. Additional capabilities include rate dependent skin, changing wellbore storage, interference from other wells, gas material balance correction, well model changing in time, horizontal and vertical anisotropy.

Table 5: *(i) Saphir software applications.*

6.2.6.7 Numerical models	The numerical models are used for geometries beyond the scope of analytical models, as the case complexity increases. These are predominantly 2D but with 3D refinement where needed. This includes the fractured horizontal well model for unconventional resources. These numerical models also address nonlinearity. Pseudo pressures are replaced by the exact diffusion equations for real gas, non-Darcy flow, pressure related physical properties, multiphase flow, water and gas injectors, water drives, and more recently desorption models for shale gas and CBM.
6.2.6.8 Use of HM (Rubis) sectors	A sector of a Rubis full-field 3D reservoir model can be imported and run directly in Saphir for a given time range. The starting point is the dynamic state of the simulation at the extraction time. This enables Saphir to simulate 3D/3-phase flow with gravity and in complete coherence with the reservoir model.
6.2.6.9 Multilayer analysis	The unlimited number of commingled layers that have individual initial pressures can be modelled analytically or numerically. Connected layers can be modelled numerically. Analytical models can superpose internal or external single layer models. Stabilized or transient rates can be loaded and associated with any combination of contributing layers. Rates may be loaded directly from an Emeraude PL analysis. Optimization is performed on both pressure and layer rates.
6.2.6.10 Optimization and sensitivity analysis	Nonlinear regression is used to optimize the model parameters. This may be automatic or user controlled from a list of variable parameters, an acceptable range and weighting of the data. Optimization may be performed on the extracted period(s) or on the whole production history. Confidence intervals may be displayed. Sensitivity analysis may be performed on the same model using different parameters.
6.2.6.11 AOF / IPR	AOF and IPR analyses are available for vertical, horizontal and fractured wells. Test sequences may be flow after flow, isochronal or modified isochronal, with or without an extended stabilized flow. Transient IPRs are also available. Shape factor and average pressure can be calculated for closed and constant pressure systems. IPR facilities are shared with Amethyste.
6.2.6.12 Minifrac analysis	A workflow combines the G-function plot with derivatives to define the leak off behaviour and the closure pressure. It includes square root and after closure analysis plots.
6.2.6.13 Slug/Pulse	Processing allows a modified version of the Ramey function to match the slug pressure response of a DST with Bourdet derivative type-curves. This method can also solve for instantaneous production with wellbore storage.
6.2.6.14 Formation tests	This option enables the interpretation of any number of probes, active and interference, to discriminate vertical permeability. Models for packer-probe and probe-probe interference are included with the latter considering storage and skin. An inbuilt pre-processor handles LAS format files and calculates rates from pump volumes. This temporary (free) Saphir module will be re-written, upgraded and removed in Generation 5 when a dedicated module will be commercially available.
6.2.6.15 Reporting/exporting	Saphir has a range of comparison, reporting, exporting and printing capabilities. The free and unprotected Reader allows files to be read, printed and exported without the requirement for an active license. A slide presentation format is available to use on an LCD projector or to create PowerPoint™ slides.

Table 6: *(ii) Saphir software applications.*

6.2.7. ***ECLIPSE***	The ECLIPSE industry-reference simulator offers the industry's most complete and robust set of numerical solutions for fast and accurate prediction of dynamic behaviour for all types of reservoirs and development schemes. The ECLIPSE simulator has been the benchmark for commercial reservoir simulation for more than 25 years thanks to its extensive capabilities, robustness, speed, parallel scalability, and unmatched platform coverage. With over 30 years of continuous development and innovation, the ECLIPSE simulator is the most feature-rich and comprehensive reservoir simulator on the market—covering the entire spectrum of reservoir models, including black oil, compositional, thermal finite-volume, and streamline simulation. By choosing from a wide range of add-on options—such as local grid refinements, coal bed methane, gas field operations, advanced wells, reservoir coupling, and surface networks—simulator capabilities can be tailored to meet your needs, enhancing your reservoir modelling capabilities. The user environment for the ECLIPSE family of simulators is Petrel Reservoir Engineering, which integrates the static and dynamic modelling process into a seamless workflow. Data flows are transparent, with an easy-to-learn graphical user interface that supports simulation configuration and results visualization. The Petrel platform integrates data from multiple disciplines, allowing experts to combine their knowledge in a unified environment. It also supports extensive uncertainty and optimization workflows.
Platform Products	
6.2.8. **PETREL RE**	The Petrel E&P software platform brings disciplines together with best-in-class applied science in an unparalleled productivity environment. This shared earth approach enables companies to standardize workflows from exploration to production—and make more informed decisions with a clear understanding of both opportunities and risks. Traditionally, applying the right science has meant supporting many disparate applications—isolating the knowledge and disrupting the workflow. The Petrel platform provides deep science across the spectrum—from prestack processing to advanced reservoir modelling—to assisted history matching, and much more. Furthermore, the Ocean software development framework creates advantage by putting the industry's best science inside the Petrel shared earth model—directly into the hands of your teams. As the industry looks to accelerate reserves replacement and boost recovery in difficult reservoirs, increasing productivity is essential. The Petrel platform supports automated, repeatable workflows, to capture best practices and share them across the organization. New data is easily incorporated, keeping the subsurface live and current. Embedded cross-domain uncertainty analysis and optimization workflows enable straightforward testing of parameter sensitivity and scenario analysis. The embedded Studio E&P knowledge environment improves productivity with multiuser database access and collaborative work sessions with team members across the enterprise. The Studio environment lets you capture more than just data—it allows you to store and share the knowledge of how a result was accomplished.
6.2.9 **OMEGA**	The Omega platform offers you the tools to transform your seismic, electromagnetic, micro-seismic, or vertical seismic profile (VSP) data into actionable information which you can use to reduce risks and increase your chances of success across the E&P lifecycle. The Omega platform extends geophysics data processing into reservoir modelling by integrating with the Petrel E&P software platform. The Petrel Earth Model Building (EMB) tools enable a variety of depth imaging workflows, including model building, editing and updating, depth-tomography QC, residual move out analysis, and volumetric common-image-point (CIP) pick QC. These functionalities, in conjunction with the Omega platform's depth tomography and migration algorithms, produce accurate and precise images of the subsurface. Further extension supports solutions for critical subsurface challenges—from the field to final imaging, to prestack seismic interpretation and quantitative interpretation, from exploration to development.

Table 7: *Eclipse software for platform applications*

6.3 SUMMARY

The application of software in reservoir engineering is of utmost importance. This is the very much imperative to use technological applications and software in determining the types of oil and gas reservoirs and hence determine which reservoirs are containing the required and expected oil or gas for production. It is also only through a certain kind of software application any reservoir engineer will be able to determine where and which reservoir contains any volume of oil or gas without physically observing at close distance the containment of a particular reservoir. An office base projection, through a computer, PC application can be used and hence determine, how far am oil or gas reservoir is located and which once contains oil or gas.

Petroleum Engineering makes use of different types of technology in a variety of ways depending on the specialization area. The reason for this software application is based on the ability to extract hydrocarbons from any area as the extraction has become more complex in conjunction to the terrain's, deep-water, arctic and desert, conditions. Therefore, new solutions and ways of successful applications had to be constructed in order to access these hard to reach deposits and this means that Petroleum Engineers need to understand different areas such as thermo-hydraulics, geo-mechanics and intelligent systems. Hence, Petroleum Engineering technology applications have played an increasing and vital role in aiding engineers in their work as a result. Petroleum engineering technology continues to improve and there have been advances in computer modelling and simulation, statistical and probability analysis, as well new technical innovations such as horizontal drilling and enhanced oil recovery. These applications and technologies have substantially improved the tools used by the Petroleum Engineer in recent years, and they will continue to play an important part in their activities as they seek to research and develop new ways to extract new deposits, while lowering the cost of drilling and production.

CHAPTER 7

RESERVOIR VOLUMETRIC DESRCIPTION AND ITS LIFESPAN

7.1 INTRODUCTION

There are different types of reservoirs in the oil and gas industry in terms of the quantities of their pores:

Cricondentherm (Tct)—The Cricondentherm is defined as the maximum temperature above which liquid cannot be formed regardless of pressure (point E). The corresponding pressure is termed the Cricondentherm pressure **pct.**

T_{ct}: The MAXIMUM TEMPERATURE, regardless pressure the quantity on which a liquid cannot be formed. The relationship of temperature and pressure does not necessarily determine the formation of a liquid. Pressure in other words is not a factor.

Cricondenbar (p_{cb})— The Cricondenbar is the maximum pressure above which no gas can be formed regardless of temperature (point D). The corresponding temperature is called the Cricondenbar temperature T_{cb}.

pcb: The MAXIMUM PRESSURE, regardless temperature the quantity of temperature, on which a gas cannot be formed. The relationship of temperature and pressure does not necessarily determine the formation of a gas. Temperature in other words is not a factor.

Critical point— The critical point for a multi-component mixture is referred to as the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal (point C). At the critical point, the corresponding pressure and temperature are called the critical pressure p_c and critical temperature T_c of the mixture.

A CRITICAL POINT is the point where all the properties of a gas and a liquid are corresponding, or the same, or equal.

There are two types of reservoirs, the oil reservoir and the gas reservoir.

- **Oil reservoirs:** If the reservoir temperature T is less than the critical temperature Tc of the reservoir fluid, then the reservoir is classified as an **oil reservoir**.

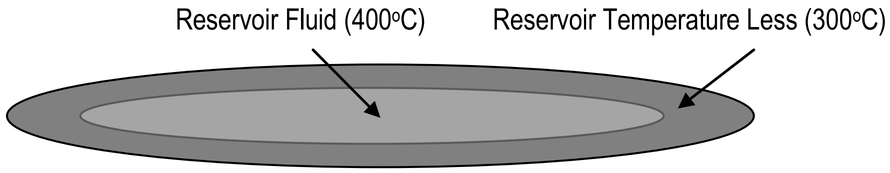


Figure 21: *The oil reservoir indicating the different temperatures.*

- **Gas reservoirs:** If the reservoir temperature is greater than the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir.

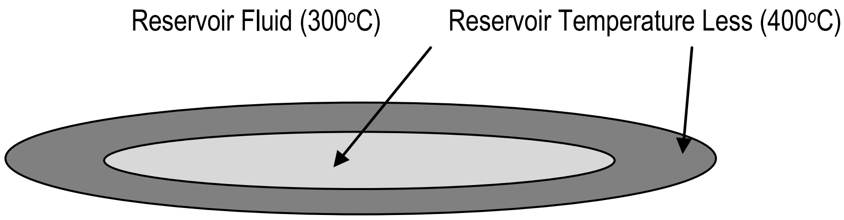


Figure 22: *The gas oil reservoir indicating the different temperatures.*

7.2 Oil Reservoirs

Depending upon initial reservoir pressure pi, oil reservoirs can be sub-classified into the following categories:

1. **Undersaturated oil reservoir.** If the initial reservoir pressure pi is greater than the bubble-point pressure pb of the reservoir fluid, the reservoir is labelled as under saturated oil reservoir.
2. **Saturated oil reservoir.** When the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid, the reservoir is called a saturated oil reservoir.
3. **Gas-cap reservoir.** If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid, the reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapour phase is underlain by an oil phase.

The appropriate quality line gives the ratio of the gas-cap volume to reservoir oil volume. Crude oils cover a wide range in physical properties and chemical compositions and it is often important to be able to group them into broad categories of related oils.

In general, crude oils are commonly classified into the following types:

- Ordinary black oil
- Low-shrinkage crude oil- *Lowly Volatile Crude Oil (High Density)*
- High-shrinkage (volatile) crude oil- *Highly Volatile Crude Oil (Low Density)*
- Near-critical crude oil

The above classifications are essentially based upon the properties exhibited by the crude oil, including physical properties, composition, gas-oil ratio, appearance, and pressure-temperature phase diagrams.

1. **Ordinary black oil.** When produced, ordinary black oils usually yield gas-oil ratios between 200–700scf/STB and oil gravities of 15 to 40 API. The stock tank oil is usually brown to dark green in colour.

2. **Low-shrinkage oil.** The associated properties of this type of crude oil are:

- Oil formation volume factor less than 1.2 bbl/STB
- Gas-oil ratio less than 200 scf/STB
- Oil gravity less than 35° API
- Black or deeply coloured

3. **Volatile crude oil.**

The other characteristic properties of this crude oil include:

- Oil formation volume factor less than 2 bbl/STB
- Gas-oil ratios between 2,000–3,200 scf/STB
- Oil gravities between 45–55° API
- Greenish to orange in colour
- Another characteristic of volatile oil reservoirs is that the API gravity
- of the stock-tank liquid will increase in the later life of the reservoirs.

4. **Near-critical crude oil.**

- The near-critical crude oil is characterized by a
- high GOR in excess of 3,000 scf/STB
- An oil formation volume factorof 2.0 bbl/STB or higher.
- The compositions of near-critical oils are usually characterized by 12.5 to 20 mol% heptanes-plus, 35% or more of ethane through hexanes, and the remainder methane.
-

7.3 Gas Reservoirs

In general, if the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. On the basis of their phase diagrams and the prevailing reservoir conditions, natural gases can be classified into four categories:

- Retrograde gas-condensate
- Near-critical gas-condensate
- Wet gas
- Dry gas

7.3.1 Retrograde gas-condensate reservoir

If the reservoir temperature lies between the critical temperature Tc and cricondentherm Tct of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir. This category of gas reservoir is a unique type of hydrocarbon accumulation in that the special thermodynamic behaviour of the reservoir fluid is the controlling factor in the development and the depletion process of the reservoir. When the pressure is decreased on these mixes-

7.3.2 Wet-gas reservoir

The reservoir temperature is above the cricondentherm of the hydrocarbon mixture. Because the reservoir temperature exceeds the cricondentherm of the hydrocarbon system, the reservoir fluid will always remain in the vapour phase region as the reservoir is depleted isothermally. As the produced gas flows to the surface, however, the pressure and temperature of the gas will decline. If the gas enters the two-phase region, a liquid phase will condense out of the gas and be produced from the surface separators. This is caused by a sufficient decrease in the kinetic energy of heavy molecules with temperature drop and their subsequent change to liquid through the attractive forces between molecules. Wet-gas reservoirs are characterized by the following properties:

- Gas oil ratios between 60,000 to 100,000 scf/STB
- Stock-tank oil gravity above 60° API
- Liquid is water-white in colour
- Separator conditions, i.e., sepa

7.3.3 Dry-gas reservoir.

The hydrocarbon mixture exists as a gas both in the reservoir and in the surface facilities. The only liquid associated with the gas from a dry-gas reservoir is water. Usually a system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas. Kinetic energy of the mixture is so high and attraction between molecules so small that none of them coalesce to a liquid at stock-tank conditions of temperature and pressure. It should be pointed out that the classification of hydrocarbon fluids might be also characterized by the initial composition of the system. McCain (1994) suggested that the heavy components in the hydrocarbon mixtures have the strongest effect on fluid characteristics.

7.4 EXPERIMENTAL APPLICATION – NUMBER OF PORES AND QUANTITY OF OIL AND GAS IN A RESERVOIR.

7.4.1 EQUIPMENT

Two(2) types of sponges, (same type of a sponge with different quantities of pores, 2 glass beakers, wooden box, container, 1 litre sunflower oil and 1 bowl.

7.4.2 STEPS

- **(i)** Pour 500 millilitres of sunflower oil into a bowl.
- **(ii)** Cut the two types of sponges in blocks of 30mmx 50mm sizes as indicated on Figure 23 below and placed them into a wooden container.
- **(iii)** Soak 2 types of sponges into a bowl of sun flower oil.
- **(iv)** At the same time remove all 2 sponges, soaked into sunflower oil and let the oil drip into the 2 glass beakers, simultaneously and determine the volume of the oil in each glass beaker and record the volume of oil.

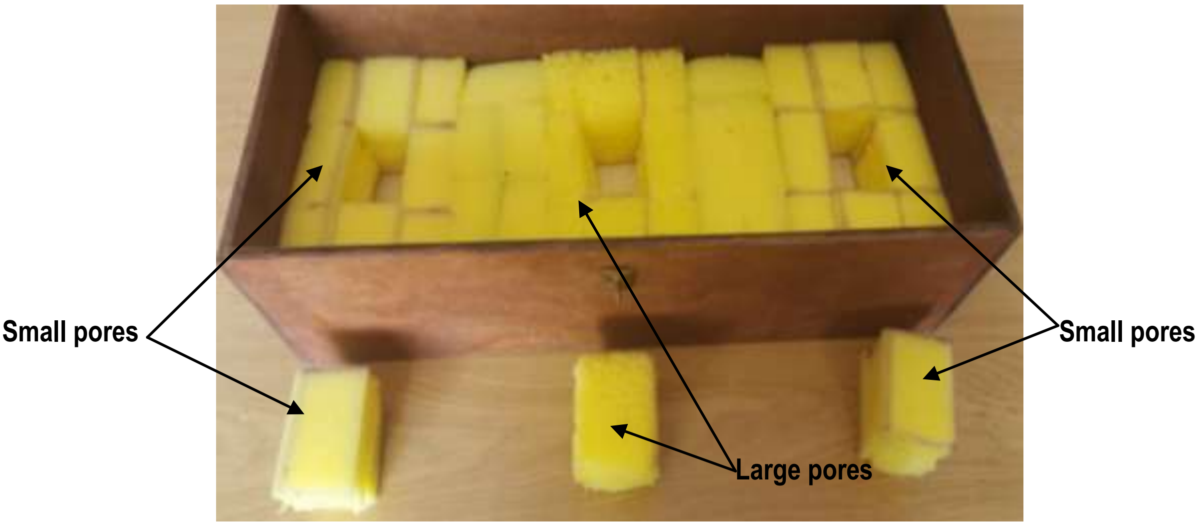


Figure 23: *The different sizes of sponges, representing the porosity of reservoirs.*

7.4.3 ANALYSIS OF RESULTS

7.4.3.1 Determine the porosity of sponge 1(small) = 820 pores

$$
\begin{aligned}
V &= (4/3)\pi r^3 \\
&= (4/3)\pi 2^3 \\
&= (4/3)\pi 8 \\
&= 33.51\text{mm}^3 \times 820 \\
&= 27\,478.2\text{mm}^3 \\
&= 27.478\text{cm}^3 \\
&= 27.5 \text{ ml}
\end{aligned}
$$

The 27.5ml is the volume of 820 pores of one sponge.

7.4.3.2 Determine the fluid, sunflower volume of sponge 1: = **27.5 ml**

7.4.3.3 Determine the porosity of sponge 2(large) = 332 pores

V $= 4/3\pi 3^3$

$= 113.097mm^3 \times 332$

$= 37\ 548.204mm^3$

$= 37.538cm^3$

= 37.5ml

7.4.3.4 Determine the fluid, sunflower volume of sponge 2: = **37.5 ml**

Figure 24: *The volume of two types of pores, small and big.*

7.4.4 CONCLUSIONS

The reservoir with the large sized pores produced bigger volumes of oil. Permeability was ignored in this experiment as the pores were not linked in the sponges. So, the permeability is not applicable but the total volume of the oil from the respective pores was excreted by a total compression of the pores. The number of pores in the large pored reservoir was also bigger or more than the reservoir with the small pores. If the number of pores of the sponge with the big sized pores was the same as the sponge with the small pores, like 820 pores of the sponge with the small pores, then the total volume of the sponge with the big pores will be equal to: $92\ 739.54mm^3$. This will be 92.7ml of oil. In other words the reservoir with a larger porosity will be able to produce bigger volumes of oil and gas. This also means that the reservoir with small pores but the quantity of the pores are more in number compared to the reservoir with big sized pores then the small pored reservoir will be able to produce more oil or gas. This is:

$$
\begin{aligned}
V &= (4/3)\pi r^3 \\
&= (4/3)\pi 2^3 \\
&= (4/3)\pi 8 \\
&= 100.531\text{mm}^3 \times 332 \\
&= 33\ 376.292\text{mm}^3 \\
&= 33.4\text{cm}^3 \\
&= 33.4\text{ml}
\end{aligned}
$$

The diameter of the above mentioned pores which are both spherical are also having different sizes of height, which can form a cylindrical pore of any reservoir and the quantity of oil and gas in these pores will be different as indicated in the following mathematical calculations:

Small pores:	$\mathbf{V_1}$	=	πDh (H=3mm; D=4)	$\mathbf{V_2}$	=	πDh(H=7mm; D=4)
		=	π4x3		=	π4x7
		=	37.699mm^3		=	87.965mm^3
		=	37.699 x **820**		=	87.965mm^3 x **820**
		=	30 913.18mm^3		=	72 131.3mm^3
		=	**30.9ml**		=	**72.1ml**
	$\mathbf{V_3}$	=	πDh (H=3mm; D=4)	$\mathbf{V_4}$	=	πDh(H=7mm; D=4)
		=	π4x3		=	π4x7
		=	37.699mm^3		=	87.965mm^3
		=	37.699 x **332**		=	87.965mm^3 x **332**
		=	12 516.068mm^3		=	29 204.38mm
		=	**12.5ml**		=	**29.2ml**

Big pores:	V_1	=	πDh(H=3; D=6mm)	V_2	=	πDh(H=7; D=6mm)
		=	π6x3		=	π6x7
		=	56.549mm^3		=	131.947mm^3
		=	56.549mm^3 x **820**		=	131.947mm^3 x **820**
		=	46 730.18mm^3		=	108 196.54mm^3
		=	**46.74ml**		=	**108.2ml**
	V_3	=	πDh(H=3; D=6mm)	V_4	=	πDh(H=7; D=6mm)
		=	π6x3		=	π6x7
		=	56.549mm^3		=	131.947mm^3
		=	56.549mm^3 x **332**		=	131.947mm^3 x **332**
		=	18 774.268mm^3		=	43 806.404mm^3
		=	**18.8ml**		=	**43.8ml**

The porosity of any reservoir can be different in the manner of different types of pores too. Some of the pores can be spherical, cylindrical, rectangular etc and this will provide different volumes of gas and oil. The shape and the size of the pores can also be different and no reservoir can and will have the same quantity of oil or gas, hence the lifetime of the different reservoirs will be different. The lifespan of certain reservoirs will also be different in terms of their permeability. Any reservoir can be resuscitated after, all oil or gas is extracted from it. The resuscitation of any reservoir again depends on the **"pregnancy"** in terms of oil or gas availability of the neighbouring reservoirs over a period of time. The biggest quantity of oil and gas of ay reservoir will depend on the reservoirs with big pores, big diameter and deeper, height. The smallest quantity of gas and oil of any reservoir will then depended on their small pores, with small diameters and small heights.

7.5 ROCK PROPERTIES/RESULTS AND APPLICATION

The material of which a petroleum reservoir rock may be composed can range from very loose and unconsolidated sand to a very hard and dense sandstone, limestone, or dolomite. The grains may be bonded together with a number of materials, the most common of which are silica, calcite, or clay. Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir.

Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program.

7.5.1 TWO MAIN CATEGORIES OF CORE ANALYIS TESTS

These tests are performed on core samples regarding physical properties of reservoir rocks and they are as follows:

(i) Routine core analysis tests

- Porosity
- Permeability
- Saturation

(ii) Special tests

- Overburden pressure
- Capillary pressure
- Relative permeability
- Wettability
- Surface and interfacial tension

The above rock property data are essential for reservoir engineering calculations as they directly affect both the quantity and the distribution of hydrocarbons and, when combined with fluid properties, control the flow of the existing phases within the reservoir. i.e. gas, oil, and water.

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship.

7.5.2 TWO TYPES OF DISTINCT POROSITIES

These porosities are based on the geological times, which lead us to:

- Absolute porosity
- Effective porosity

(i) Absolute porosity

The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of interconnection. The absolute porosity is generally expressed mathematically by the relationships of the total pore volume and the bulk volume of a reservoir.

(ii) Effective porosity

The effective porosity is the percentage of *interconnected* pore space with respect to the bulk volume. The effective porosity is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.

7.5.3 POROSITY CLASSIFICATION

Porosity may be classified according to the mode of origin as original induced.

(i) Original porosity

The *original* porosity is that developed in the deposition of the material, while *induced* porosity is developed by some geologic process subsequent to deposition of the rock. The inter-granular porosity of sandstones and the inter-crystalline and oolitic porosity of some limestones typify original porosity.

(ii) Induced porosity

Induced porosity is typified by fracture development as found in shales and limestones and by the slugs or solution cavities commonly found in limestones. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is included. For direct quantitative measurement of porosity, reliance must be placed on formation samples obtained by coring.

7.5.4 WETTABILITY ALTERATION

Wettability of reservoirs is the preferential affinity of the solid matrix for either the aqueous or oil phases." Wettability is an important property of sedimentary formations that affects the fluid distribution, capillary pressure, relative permeability, and behaviour of fluids in reservoirs. Wettability is a measure of the preferential tendency of immiscible fluids to spread over a solid surface. ***Wettability is the movement of a fluid, gas or oil over a solid surface, like a rock.*** Thus, the solid is called a water-wet material when water, oil wet or gas wet tends to spread out to cover the solid surface. Contact angle is a good indication of the spreadability and wetting characteristics of fluids over simple continuous surfaces. A smaller contact angle, 9 < 90°, indicates stronger wettability, and a larger contact angle, 9 > 90°, indicates weaker wettability. 9 ~ 90° indicates intermediate wettability and the probability of a fluid to have exactly 9 = 90° is very small.

The wettability of porous materials may be two types: (1) uniform or homogeneous and (2) nonuniform or heterogeneous. Uniformly wet porous materials have either a completely water-wet or oil-wet pore surface throughout the porous media. Whereas, most sedimentary formations are nonuniform because they typically contain separate portions of water- and oil-wet regions. Two types of wettability nonuniformity may be distinguished in a sedimentary rock: (1) mixed-wettability and (2) fractional-wettability.

Mixed-wettability describes the rocks having only the larger pores being oil-wet and only the smaller pores being water-wet. This mixed-wettability condition is created by oil migration preferentially into larger pores followed by organic deposition, such as asphaltene, paraffins, and resins, to transform the water-wet to oil-wet types. On the other hand, fractional-wettability describes the rocks having sites of different surface characteristics due to the differences in the type of surface mineralogy. Therefore the water-wet and oil-wet pores may encompass over all sizes of pores in a fractionally-wet formation. The wettability of a rock/brine/oil system cannot be described by a single contact angle because it is the multitude of contact angles at the various three-phase contact regions in the pore spaces that determines system wettability. **A complete wettability description requires a morphological description of the pore space with the contact angles as a boundary condition for the fluid distribution."** Therefore, characterization of the wettability of porous materials is a difficult task. The contact angle is a macroscopic concept. Hence, consider a formation preferentially water-wet when the apparent (as measured) contact angle 9 < 30°, preferentially oil-wet when 9 > 150° and mixed-wet when 30° < 9 < 150°. A practical approach to quantify wettability is to facilitate the work involving the fluid displacement processes. The displacement process is referred to as imbibitions when the wetting phase saturation increases and drainage when the wetting phase saturation decreases. The work of displacement per unit bulk volume is equal to the area indicated by the capillary pressure curve. Therefore, **Donaldson and Crocker et al. (1980)** have alleviated the difficulty of defining the wettability of porous media in a practical manner, by defining a wettability index as the logarithm of the ratio of the areas.

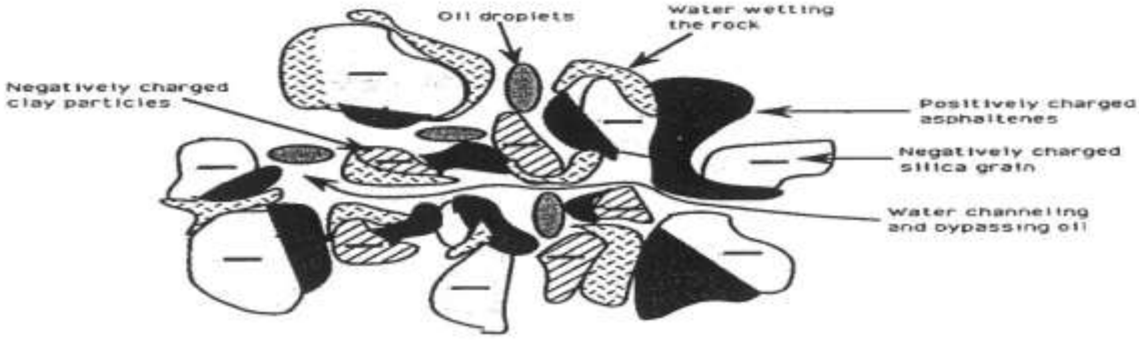


Figure 25: *The wettability of a reservoir indicating the different fluids and pore interaction. .*

7.6 SUMMARY

There are different types of reservoirs, like oil and gas with different properties. The type of the reservoir is described on its difference of temperature within a reservoir. The reservoir temperature and the critical temperature. There are also different types of oil reservoirs, like, Undersaturated oil reservoir, Saturated oil reservoir. Gas-cap reservoir. There are also different types of crude oils and they are commonly classified into the following types: Ordinary black oil, Low-shrinkage crude oil- Lowly Volatile Crude Oil (High Density, High-shrinkage (volatile) crude oil- Highly Volatile Crude Oil (Low Density)and Near-critical crude oil

The different types of crude oil are essentially based upon the properties exhibited by the crude oil, including physical properties, composition, gas-oil ratio, appearance, and pressure-temperature phase diagrams.
The crude oils are then as follows, Ordinary black oil, Low-shrinkage oil, Volatile crude oil and Near-critical crude oil. The natural gas is then also classified into four categories, Retrograde gas-condensate, Near-critical gas-condensate, Wet gas and Dry gas.

The porosities of any reservoir does differ tremendously as the effective porosity is the porosity value of interest to any petroleum engineer, particular attention should be paid to the methods used to determine porosity. For example, if the porosity of a rock sample was determined by saturating the rock sample 100 percent with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces. On the other hand, if the rock sample were crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process. One important application of the effective porosity is its use in determining the original hydrocarbon volume in place. A reservoir with an areal extent of A, measured in acres, hectares or square kilometres and an average thickness of height in feet, meters or kilometres. The total bulk volume of the reservoir can be determined from the following expressions:

Wettability of reservoirs is the preferential affinity of the solid matrix for either the aqueous or oil phases." Wettability is the movement of a fluid, gas or oil over a solid surface, like a rock. Thus, the solid is called a water-wet material when water, oil wet or gas wet tends to spread out to cover the solid surface. The wettability of any rock is then determined by the Contact angle. The contact angle will give the good indication of the spreadability and wetting characteristics of fluids over simple continuous surfaces. The wettability of porous materials are two types, uniform or homogeneous and nonuniform or heterogeneous.

Uniformly wet porous materials have either a completely water-wet or oil-wet pore surface throughout the porous media. Whereas, most sedimentary formations are nonuniform because they typically contain separate portions of water- and oil-wet regions and two types of wettability nonuniformity may be distinguished in a sedimentary rock and these are mixed-wettability and fractional-wettability.

Mixed-wettability describes the rocks having only the larger pores being oil-wet and only the smaller pores being water-wet. The fractional-wettability on the other hand describes the rocks having sites of different surface characteristics due to the differences in the type of surface mineralogy.

CHAPTER 8

BRAZIL- NAMIBIA OIL AND GAS ANALYSIS

8.1 INTRODUCTION

The Plate Tectonics provides the fundamental understanding of how plates have drifted apart from a SINGLECONTINENT to several, numbers of continents and the names are given accordingly. The Geomorphologicforces are the main reason of the drifting apart of several continents.

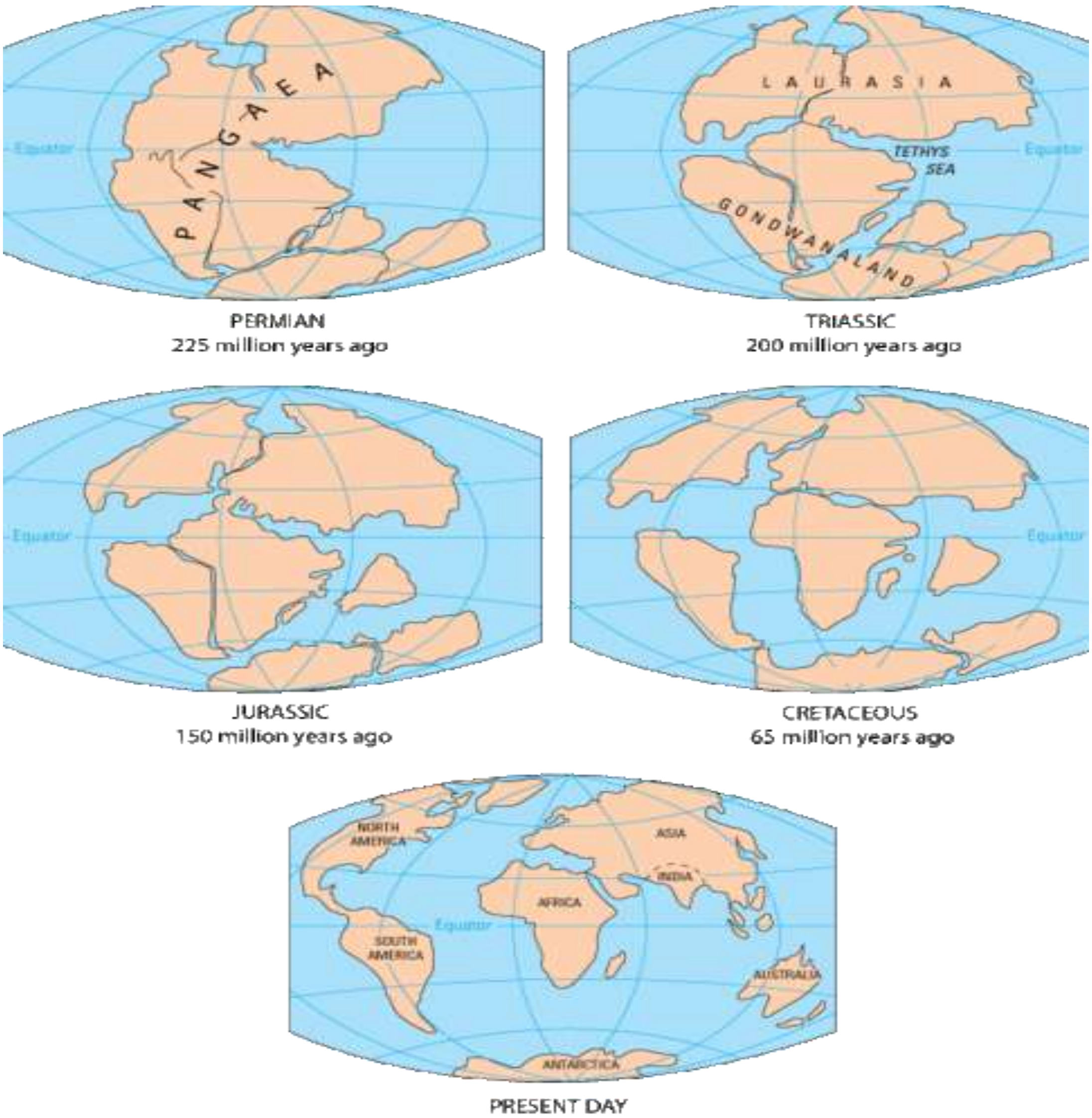


Figure 26: *Plate tectonic theory and the different plates.*

In the early 1912 the well-known historian, Alfred Wegener proposed that several continents had previously been one large continent, Pangaea which had broken apart. The part of the main or rather the mother, parent continent drifted apart and its where they are currently located but eventually it was only during 1960s that the Plate Tectonics theory, principle was fully developed and applied to explain the drifting observations of the plates, the Earth's Lithospheres.

Plate tectonics theory maintains and provides the understanding that the new oceanic crust continuously spreads away from the mid-oceanic ridges in a manner of the movement of a conveyor-belt, hence several or many thousands and millions years later, the oceanic crust eventually descends at oceanic trenches in the mantle. The results being that the old oceanic crust is consumed at the trenches and the new magma rises and erupts along the spreading ridges in order to form new crust. In fact the ocean basins are continuously being renewed, formed again or recycled with the creation of new crust and the destruction of old oceanic lithosphere occurring simultaneously.

The above mentioned concept simply explains the following:

(i) Earth does not expand through sea-floor spreading
(ii) There is so little sediment accumulation on the ocean floor and
(iii) Oceanic rocks are much younger than continental rocks.

The ANCIENT SUPERCONTINENT is called Gondwana or Gondwanaland and it includes the present day: South America, Africa, Arabia, Madasgascar, India, Australia and Antarctica. The name Gondwanaland was formulated by the Austrian geologist and expert on the Geography of the Alps and the Tethys Ocean which splits Laurasia and Gondwana, Eduard Suess, in reference to Upper Paleozoic and Mesozoic formations in the Gondwana region of central India, which are similar to formations of the same age on Southern Hemisphere continents.

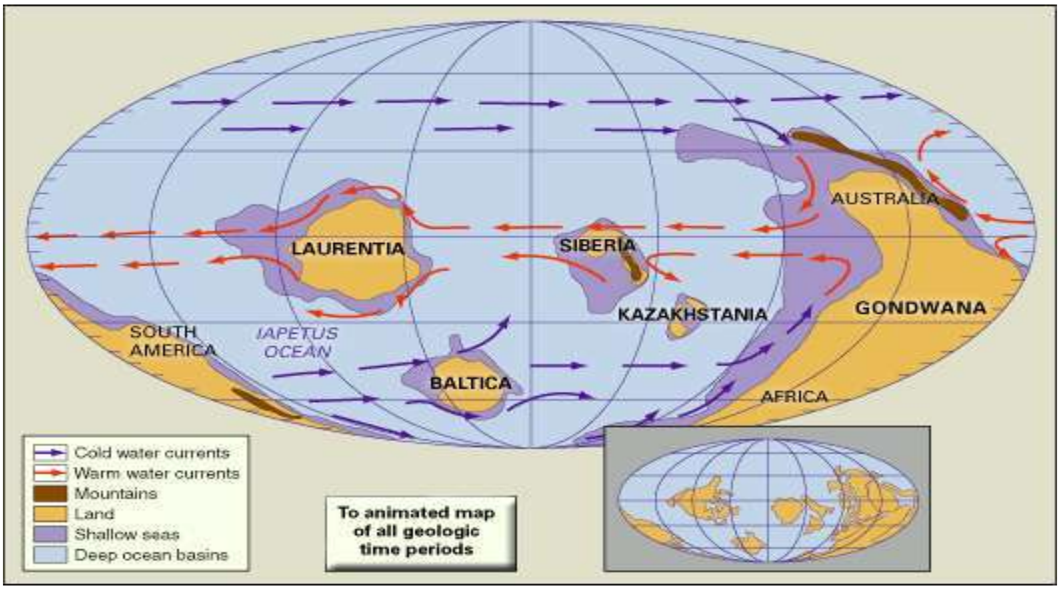


Figure 27: *The ANCIENT SUPERCONTINENT, called GONDWANA or GONDWANALAND and its sub continents, South America, Africa, Arabia, Madagascar, India, Australia and Antarctica.*

The matching shapes of the coastlines of western Africa and eastern South America are identifiable that they are integrating. The geologic and paleontological lines are the factual evidence that linked the southern continents. This then simplifies the fact that all of the continents of the Southern Hemisphere were once joined together as one landmass, Pangaea.

This evidence included the occurrence of glacial deposits—tillites of Permo- Carboniferous age, approximately 290 million years old, and similar floras and faunas that are not found in the Northern Hemisphere.

We have the Gondwana System in India, and the Santa Catharina System in South America. It also occurs in the Maitland Group of eastern Australia as well as in the Whiteout conglomerate and Polarstar formations of Antarctica.

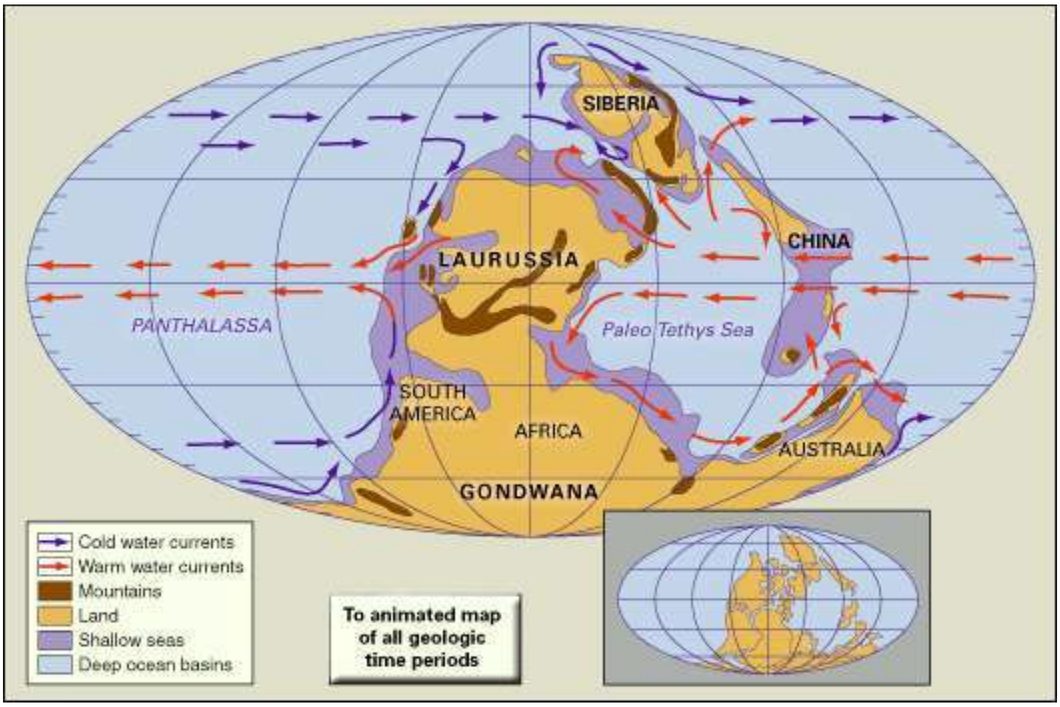


Figure 28: *The Geographic forces and the plates in the southern hemisphere and the eastern block.*

The South Atlantic Ocean opened about 140 million years ago as Africa separated from South America. At about the same time, India, which was still attached to Madagascar, separated from Antarctica and Australia, opening the central Indian Ocean. India eventually migrated and collided with Eurasia some 50 million years ago, forming the Himalayan mountains, while the northward-moving Australian plate had just begun its collision along the southern margin of Southeast Asia—This collision is still under way today.

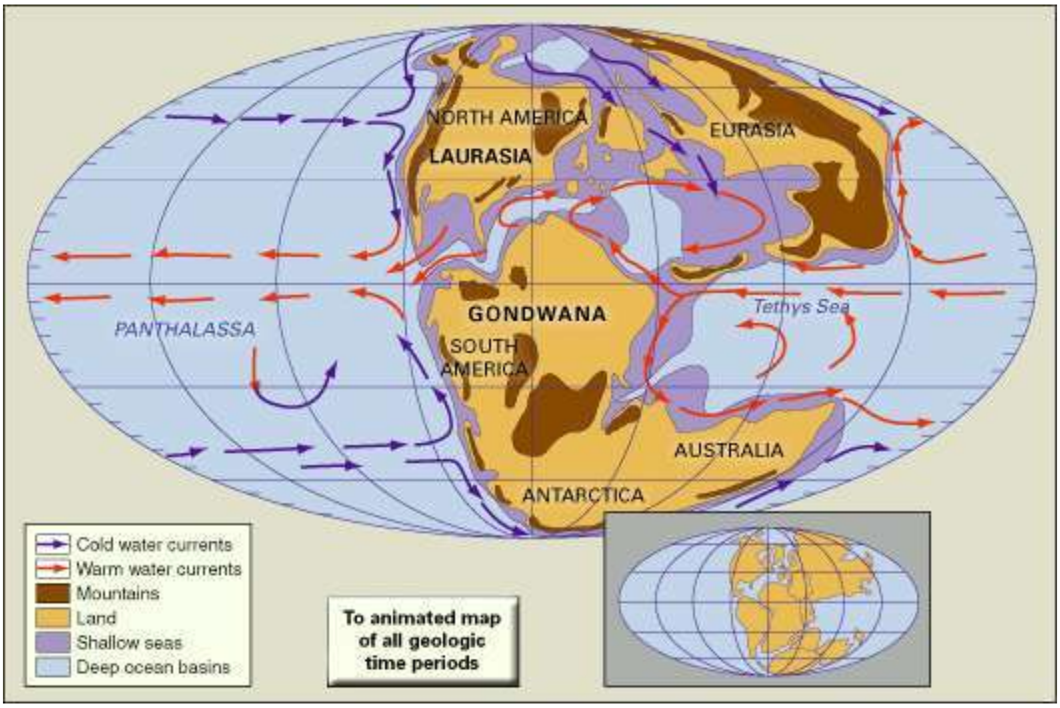


Figure 29: *The Geographic forces and the plates of the western block.*

8.2 BRAZIL - OIL AND GAS BASINS

The first record of oil exploration in Brazil started as early as the 19th century and continued through 1892. Brazil already managed that time to drill a well at a depth of 488 meters, from which two barrels of oil were produced.
In 1907, the Geological and Mineralogical Service of Brazil (GMSB) was established to carry out activities related to oil exploration. GMSB drilled more than 60 wells in several Brazilian states. However, most of these were unsuccessful. A well of 84-meter-deep was also drilled in Mallet, Paraná in 1919 but was unsuccessful.
In 1934, through Decree No. 23,979, the Service for Promotion of Mineral Production (DNPM) was established for the purpose of promoting mineral production in the country. The creation of DNPM was one of the first Brazilian initiatives aimed at a specific policy for the development of mineral activities in Brazilian territory. As it had no expertise in the exploration of Brazilian sedimentary basins, DNPM hired US oil specialists to research and identify potential producer territories. During this period, an independent Brazilian petroleum company asked the DNPM for a rig to prove that an exudation of oil in Lobato would be economically feasible to produce. However, the DNPM refused to comply with this request. This refusal provoked a reaction from the press with the slogan: **"The DNPM was not founded to find oil but to prevent anybody finding it".**
In response to this protest, in 1939 the DNPM drilled well No. 163, with a rotating rig, in Lobato, Bahia. Some oil was discovered, though not enough to be economically feasible. Shortly after this discovery, the government prevented private oil companies from exploring within a 60 km radius of Lobato.

In 1938 the National Petroleum Council in Brazil was established and charged with evaluating the requests for research and mining of oil deposits. The discovery in Lobato (1939) encouraged CNP to continue exploratory work in the Recôncavo Basin, where other discoveries were made in Candeias – a first commercial well was drilled in 1941, Dom João and Água Grande. After the discoveries in Bahia, drilling continued on a small scale, despite the growing demand for oil and oil products in the country. National production at this time was only 2,700 barrels per day, while the consumption was approximately 170,000 barrels per day, most of which was imported in the form of derivatives. Then in 1953 Petrobras was created by Brazilian Government and enacted the monopoly, witht he slogan “Keep Brazillian oil for Brazillians”. The creation of Petrobras reflects the adoption of the nationalist model and provides evidence of a substantial increase of state presence in the Brazilian oil sector.

Petrobras’ first offshore discovery occurred in 1968: the Guaricema field, off the coast of Sergipe. In 1974, Petrobras discovered the fields of Garoupa and Pargo, in the Campos Basin.
Petrobras also redirected its projects from shallow water to deep water and invested in the development of technologies and practices to exploit the Campos Basin.

In 1984 and 1985 Petrobras discovered the giant fields of Albacora and Marlim in the Campos Basin, both in deep water. In 1986, the state created the Program of Technological Innovation and Advanced Development in Deep Water, to create the ability to operate in deep waters, from 2000 to 3000 meters.

Figure 30: *The* Brazilian oil and gas basis, Santos and Campos.

The discovery of Lula field (Tupi prospect) in the province of pre-salt in 2007 considered as one of the largest in the world in the last three decades.

In 2010 the Brazilian government made significant legal changes in its oil sector, inverting the previously undertaken market reforms and intensifying state interference in the sector. The main goal was to increase governmental strategic resource control to guarantee that future Brazilian generations could take advantages of the proceeds of the oil reserves.

In September 2010, the government signed the onerous assignment agreement with Petrobras, granting Petrobras E&P rights under blocks located in the Pre-salt area (Franco, Florim, Northeast of Tupi, South of Tupi, South of Guará, Entorno de Iara and Peroba). In the terms of this agreement, Petrobras has the right to produce up to 5 billion barrels of oil and natural gas for 40 years, extendable by five more.

In 2013 ANP restarted the auctions, organizing the Eleventh Bidding Round, focusing on new technological frontiers and mature areas, and the Twelfth Bidding Round, focusing on the exploration of shale gas, both under the concession regime. The ANP also organized the first Bidding Round to sign a PSA, in which the area of Libra was offered. The Libra area, with estimated volumes between 8 and 12 billion barrels recoverable, was sold by the only consortium that offered a bid in the auction: Petrobras (40%), Shell (20%), Total (20%), CNPC (10%) and CNOOC (10%). The profit oil rate offered was the minimum foreseen in the tender protocol of 41.65%. The Government received R$ 15 billion a signature bonus.

8. 3 THE LITHOSPHERIC STRUCTURE OF THE SANTOS AND CAMPOS BASINS. WHAT TYPES OF ROCKS DO THESE BASINS CONTAIN?

8.3.1 SANTOS BASIN

The Santos Basin is approximately 352,000 square kilometres (136,000 sq mi) large mostly offshore sedimentary basin. It is located in the south Atlantic Ocean, some 300 kilometres (190 mi) southeast of Santos, Brazil. The basin is one of the Brazilian basins to have resulted from the break-up of Gondwana, since the early Cretaceous, where a sequence of rift basins formed on both sides of the South Atlantic; the Pelotas, Santos, Campos and Espírito Santo Basins in Brazil, and the Namibia, Kwanza and Congo Basins in south-western Africa.

Santos Basin is separated from the Campos Basin to the north by the Cabo Frio High and the Pelotas Basin in the south by the Florianópolis High and the northwestern boundary onshore is formed by the Serra Do Mar coastal range. The basin is known for its thick layers of salt that have formed structures in the subsurface due to HALOKINESIS, SALT TECTONICS or HALOTECTONICS, is concerned with the geometries and processes associated with the presence of significant thicknesses of evaporates containing rock salt within a stratographic sequence of rocks.

One of the largest Brazilian sedimentary basins, it is the site of several recently in 2007 and later, discovered giant oil and gas fields, including the first large pre-salt discovery **Lula** *(8 billion barrels),* **Jupiter***(1.6 billion barrels and 17 tcf of gas),* and **Libra,** with an estimated *8 to 12 billion barrels of recoverable oil.* Main **source rocks** are the **LACUSTRINE SHALES** and **CARBONATES** of the pre-salt Guaratiba Group and the marine shales of the post-salt Itajaí-Açu Formation. Reservoir rocks are formed by the pre-salt Guaratiba SANDSTONES, LIMESTONES and MICROBIALITES, the Albian limestones of the Guarujá Formation and the Late Cretaceous to Paleogene turbiditic sandstones of the Itanhaém, Juréia, Itajaí-Açu, Florianópolis and Marambaia Formations. The mobile salt of the Ariri Formation forms regional seals, as well as the shales of the post-salt sedimentary infill.

In 2014, the total production of only the sub-salt reservoirs accumulated to more than 250 thousand barrels per day (40×10^3 m^3/d). In 2017, the Santos Basin accounted for 35% of Brazil's oil, with the northern neighbour Campos Basin at 55%.

The climate of the onshore stretch of the basin ranges from tropical savanna climate, tropical monsoon climate and tropical rainforest climate to a humid subtropical climate. The onshore portion of the Santos Basin is in the Serra do mar coastal forests ecoregion of the Atlantic Forest biome. On the islands of the Superagui National Park in the Santos Basin, the endemic critically endangered Superagui lion tamarin (*Leontopithecus caissara*) has its restricted habitat.

Figure 31: *The Santos Basin formed with the rifting of Brazil and Africa splitting the Congo Craton from the Araçuaí Belt, shown as a thin brown strip.*

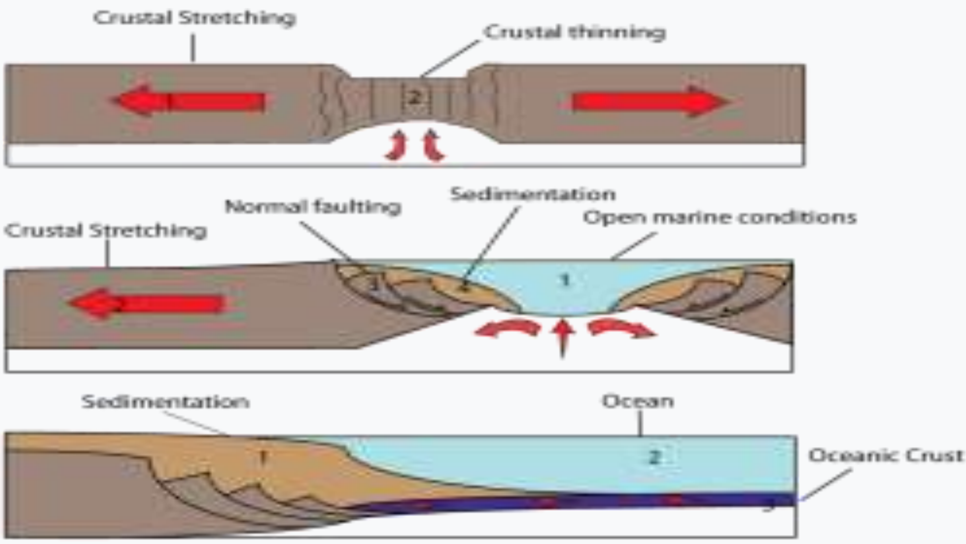


Figure 32: *Schematic diagram of the formation of a passive margin on a rift basin*

The South Atlantic margin developed on Archean stable cratons consisting of hard and resistant rocks and partly on the Neoproterozoic mobile belts composed of less resistant Metamorphic rocks. The Precambrian basement of the Santos Basin is exposed as the Aracuai Belt along the Brazilian coast, most notably in the Inselbergs of Rio de Janeiro, of which Sugarloaf Mountain is the most iconic. The ancient rocks consist of a Neoproterozoic to Cambrian high-grade metamorphic core of granites and gneisses, formed during the collision of Gondwana in the Pan –African – Brasiliano orogeny. Basalts similar to the Parana and Etendeka traps, exposed to the west in the Parana Basin, have been found underlying the Santos Basin. The Tristan da Cunha hotspot, known as the Trsitan hotspot, is considered the driver behind the formation of these flood basalts.

During the early Cretaceous, the former continent GONDWANA, as southern part of PANGEA, starting to break-up, resulting in a sequence of rift basins bordering the present-day South Atlantic. The Pelotas-Namibia spreading commenced in the Hautervian, around 133 million years ago and reached the Santos Basin to the north in the Barremian. Seafloor spreading continued northwards to the Campos Basin in the early Albian, at approximately 112 Ma.

The sag phase in the Santos Basin was characterised by thermal subsidence and generated restricted depocentres with relatively uniform water depths, ranging from 600 to 950 metres (1,970 to 3,120 ft). The Late Aptian climate was arid with high evaporation rates which triggered hypersaline conditions in these marginal sag basins. This resulted in the accumulation of thick layers of evaporites along the Brazilian and southwestern African continental margins, a process continuing towards the north later in the Cretaceous. The deposition of the lowermost 600 metres (2,000 ft) of salt in the Aptian would have taken approximately 20,000 to 30,000 years. With the continental break-up of the Santos and Campos Basins from the opposite NAMIBIA and KWANZA BASINS, oceanic circulation returned during the post-rift stage. The drift phase since the Late Cretaceous produced a thick sequence of clastic and carbonate deposits. Differential thermal regimes and sediment loading of these units produced HALOKINESIS, salt movement in the subsurface. The resulting salt diapirs, listric and thrust faults and various salt-related structures produced several stratigraphic and combined stratigraphic – structural traps for hydrocarbon accumulation in the Brazilian and southwest African offshore.

During the phases of HALOKINESIS, dated to the Albian to Paleocene, several areas of the now deep water distal part of the Santos Basin were exposed to subaerial conditions and suffered erosion. The distal parts of the basin were affected by E-W to NW-SE oriented shortening, sub-perpendicular to the Brazilian margin.

Figure 33: *Sugarloaf Mountain and the other Inselbergs of Rio de Janneiro are the onshore representatives of the basement of the Santos Basin.*

The basement of the Santos Basin is composed of granites and gneisses of the Araçuarí Belt that formed at the western boundary of the Congo Craton. The erosion resistant metamorphic and magmatic rocks are exposed in the Serra do Mar, forming the edge of the Santos Basin along the Brazilian coast.
The total stratigraphic thickness of the sediments in the Santos Basin has been estimated at 23,170 metres (76,020 ft) and has been described in detail by Clemente in 2013.

Figure 34: *The GUARATIBA GROUP is characterised by the presence of MICROBIALITES , like this present-day example in Pavilion Lake, Canada. These organic build-up structures are the reservoir of the giant pre- salt Lula Field, holding 8000 million barrels of oil.*

The GUARATINA GROUP is 4,200 metres (13,800 ft) thick and includes four formations, from old to young the Camboriu, Piçarras, Itapema and Barra Velha Formations. The group is equivalent to the Lagoa Feia Group of the Campos Basin.

Table 8: *The GUARATINA GROUP formations, Camboriu, Piçarras, Itapema and Barra Velha Formations*

FORMATION	THICKNESS	TYPES OF ROCKS
CAMBORIU	4,200 metres (13,800 ft)	Basaltic rocks
PICARRAS	40 metres (130 ft)	Clastic and Carbonate rocks. reddish polymictic conglomerates Clasts of Basalt and quartz in a clay-sandy matrix White, reddish Lacustrine coquinas (shelly limestones) and sandstones, siltstones and shales of stevensite
ITAPEMA	several hundreds of metres thick	Calcirudites (limestones) and dark shales. calcirudite limestones consist of fragmented bivalve shells, frequently Dolomitized and silicified. Organic matter-rich shales. Radioactive shales interbedded with carbonates.
BARRA VELHA	300 to 350 metres (980 to 1,150 ft)	Limestones of stromatolites and laminated microbialites. composed of shales. Interbedded with the laminated microbialites there are limestones with packstones and grainstones textures made up of algal clasts and bioclasts (fragmented ostracods). Carbonates frequently are partly or completely dolomitized.

The age of this formation has been estimated to be Late Barremian to Aptian. It is correlative with the Macabu Formation in the Campos Basin, as both are typified by laminated microbialites and stromatolites. These limestones are one of the sub-salt reservoirs in the Santos Basin.

The Ariri Formation is in the type oil well 581 metres (1,906 ft) thick and may be up to 4,000 metres (13,000 ft) thick in other areas of the basin. It is predominantly composed of evaporites. The formation is characterized by thick intervals of white halite, associated with white anhydrite, ochre greyish calcilutites, shales and marls. The sedimentary environment probably was restricted marine including mudflat sabkhas, evolving under an arid climate. The ostracod assemblages of this formation indicate a neo-Algoas age (local time scale).

Table 9: *The Camburi Group is up to 6,100 metres (20,000 ft) thick and includes three formations, Florianopolis , Guaruja and Itanhaem.*

FORMATION	AGE	THICKNESS	TYPES OF ROCKS
FLORIANOPOLIS	Albian age.	343 metres (1,125 ft) thick	Consists of reddish, fine to coarse-grained sandstones with a clay matrix, reddish micaceous shales and siltstones. Alluvial environments distributed along the western Brazilian basin margin, along the Santos Hinge Line. alluvial environments distributed along the western Brazilian basin margin, along the Santos Hinge Line. further to the open basin with the siltstones of the Itanhaém Formation
GUARUJA	Early Albian. planktonic foraminifera and pollen	832 metres (2,730 ft) thick	Consists of oolitic calcarenites, which laterally grade to greyish ochre and brownish grey calcilutites and grey marls. These facies are interbedded with the alluvial clastics of the Florianópolis Formation. The Guarujá name is restricted to the lowest limestone intercalation. The microfacies indicate a tidal flat to shallow lagoon and open carbonate platform depositional environment
ITANHAEM	Early Albian. planktonic foraminifera and pollen	517 metres (1,696 ft) thick	Consists of dark grey shales, silts and light grey marls, ochre-brown calcisilts and subordinated sandstones. marine environment ranging from sub-littoral (inner neritic) and more rarely to pelagic (outer bathyal) conditions

Atlantic International University

Figure 35: *The depositional environment of the Guarujá Formation has been interpreted as a tidal flat, like this present-day example in Oregon, United States.*

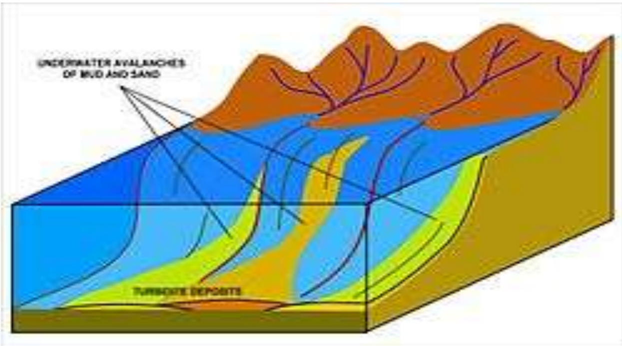


Figure 36: *The Itajaí-Açu and Juréia Formations consist mainly of turbidites, formed at the base of the Brazilian marginal continental slopes. The sands of these formations have proven to be excellent reservoirs worldwide.*

Table 10: The Frade Group is 4,000 metres (13,000 ft) thick and includes three formations: Santos, Itajai-Acu and Jureia. They predominantly comprise turbidites..

FROMATION	AGE	THICKNESS	TYPES OF ROCKS
SANTOS	Late Cretaceous age (Cenomanian-Maastrichtian).	1,275 metres (4,183 ft) thick	Consists of reddish Lithic Conglomerates and sandstones, interbedded with grey shales and reddish clays. These facies are interbedded and change laterally into the Itajai-Açu and Juréia Formations. The sedimentary environment is thought to be transitional continental to marginal marine, ranging from alluvial to braided rivers and deltas.
ITAJAI-ACU	Palynomorphs, calcareous nanofossils and planktonic foraminifera indicate a Late Cretaceous age (Cenomanian-Maastrichtian).	1,545 metres (5,069 ft) thick	The deltas comprise of a thick interval of dark grey clayey rocks, interbedded with the clastics of the Santos and Juréia Formations. Within this formation, the Ilhabela Member includes the turbiditic sandstones occurring along the section. The sedimentary environment is thought to be marine talus to open basin.
JUREIA	Palynomorphs and calcareous nanofossils is Late Cretaceous (Santonian-Maastrichtian	952 metres (3,123 ft) thick	The succession of clastics between the coarse facies of the Santos Formation in the west and the fine-grained clastics of the Itajai-Açu Formation in the east. The formation is characterized by dark grey to greenish and brown shales, dark grey siltstones, fine-very fine sandstones and light ochre calcisilts. The depositional environment is thought to be of a marine platform setting. Two new Ostracod species were identified in the drilling cuttings of wells drilled into the Santonian-Campanian section.

Figure 37: *Ostracods are small crustaceans commonly used to identify paleo-environments and for age dating formations.*

Table 11: Itamambuca Group is 4,200 metres (13,800 ft) thick and includes four formations*, Ponta Aguda, Marambaia, Iguape and Sepetiba.*

FORMATION	AGE	THICKNESS	TYPES OF ROCKS
PONTA AGUDA		2,200 metres (7,200 ft) thick	Consists of conglomerates, coarse to fine-grained sandstones interbedded with siltstones and shales. The dominant facies are coarse to fine-grained quartzitic sandstones. They range from reddish to grey, usually with calcite cements. Intercalated are reddish to light grey claystones and siltstones. Fluvial to shallow marine environment.
IGUAPE	Planktonic foraminifera, calcareous nanofossils and palynomorphs indicate a Tertiary age.	1,103 metres (3,619 ft) thick	Consists of bioclastic calcarenites and calcirudites, containing bryozoa, echinoids, corals, foraminifera, fragmented shells, and algae remains. They are interbedded with grey-greenish clays, siltstones, marls and variegated grey fine-to-medium grained conglomerates. These facies are interbedded with and change laterally to the Marambaia Formation. The depositional environment is thought to be a marine carbonate platform, influenced by the arrival of alluvial clastics in the most proximal areas.
MARAMBAIA	Tertiary age.	261 metres (856 ft) thick	Consists of grey shales and light grey marls interbedded with fine-grained turbiditic sandstones. This formation in places can be found cropping out at sea bottom. The depositional environment is thought to be talus and open marine basin
SEPETIBA		It has a variable thickness due to the proximal erosion of the uppermost part.	Consists of whitish grey fine to coarse grained carbonitic sands. They are feldspar rich, glauconitic coquinas consisting of bivalve fragments and foraminifera. The depositional environment is thought to be coastal

Figure 38: *The uppermost sedimentary layer is formed by coquinas (similar to this sample from Crimea in Europe, carbonitic sandstones composed of broken shells.*

The 4D- Basin analysis of the Santos Basin has revealed insights about the interplay among the elements and processes of the petroleum system in order to assess the source rock potential, vertical and horizontal distribution, thermal evolution of the source rocks, transformation ratio, hydrocarbon generation and charge, timing of migration, oil origin, quality, and volume of petroleum in the main reservoirs. In a basin modelling study performed in 2008 and 2009, a detailed facies model from the pre-salt section was built based on well data and conceptual models from seismic interpretation associated with previous knowledge of the tectono-sedimentary sequences of the Santos Basin.

The predicted VITRINITE MAP*, a **Vitrinite** is one of the primary components of coals and most sedimentary KEROGENS. Vitrinite is a type of MACERAL, as "macerals" are organic components of coal analogous to the "minerals" of rocks,* integrated with all data, indicates that the Coquinas source rock in most of the eastern half area is in the main oil window, whereas the western half is in the late oil/wet gas generation window. In terms of transformation ratio, the Barremian and Aptian source rock systems in the area reached 70% to 80% today where the main depocentres are. The charge and accumulation simulation model for the pre-salt province suggests a potential reserve in the Cluster area of Santos Basin much larger than that reported, getting numbers to 60 billion barrels of oil reserves.

In 2014, the pre-salt reservoirs of the Santos Basin produced more than 250 thousand barrels per day.
i.e 40 x 103 m3/day. This will be 40 million litres per day = 251 588 bbls, 252 000 bbls per day. Thanks to the pre-salt production, compensating for the declining post-salt production, the total oil production of Brazil rose above 2,500 thousand barrels per day (400×103 m3/d) in April 2016. The Lapa Field, originally named Carioca, was taken in production in December 2016. In 2017, the Santos Basin accounted for 35% of Brazil's oil, with the Campos Basin at 55%. In the same year, 76 blocks were open for bidding in the Santos Basin.

8.3.2 CAMPOS BASIN

The **Campos Basin** is one of 12 coastal sedimentary basins of Brazil. It spans both onshore and offshore parts of the South Atlantic with the onshore part located near Rio de Janeiro. The basin originated in NEOCOMIAN stage of the CRETACEOUS period 145–130 million years ago during the breakup of GONDWANA. It has a total area of about 115,000 square kilometres (44,000 sq mi), with the onshore portion small at only 500 square kilometres (190 sq mi). The Campos Basin is bound on the south by the Cabo Frio High, separating the basin from the Santos Basin and on the north by the Vitoria High, forming the boundary with the Espirito Santo Basin. Campos Basin contains the Paraiba do Sul River delta.

The break-up of Pangaea characterised the start of formation of the Santos Basin in the South Atlantic, forming at the same time the Kwanza Basin in Africa.

Crustal stretching Crustal thinning

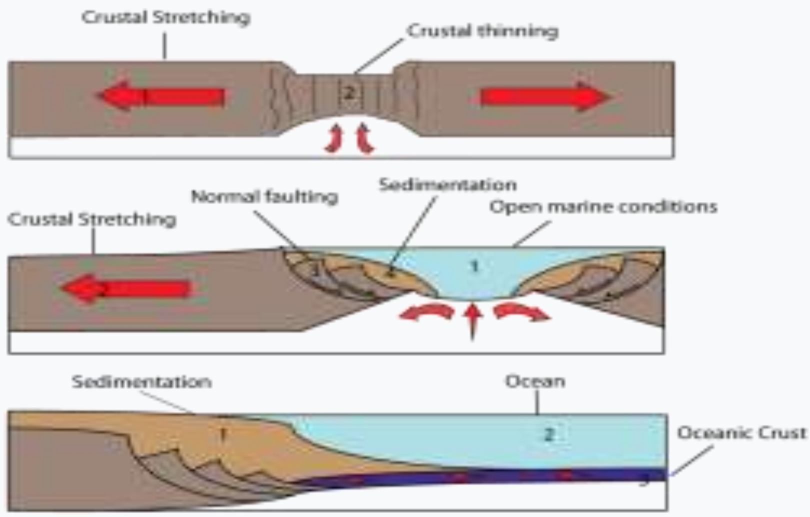


Figure 39: *Schematic diagram of the formation of a passive margin on a rift basin.*

8.4 SANTOS AND CAMPOS BASINS – OIL AND GAS BLOCKS

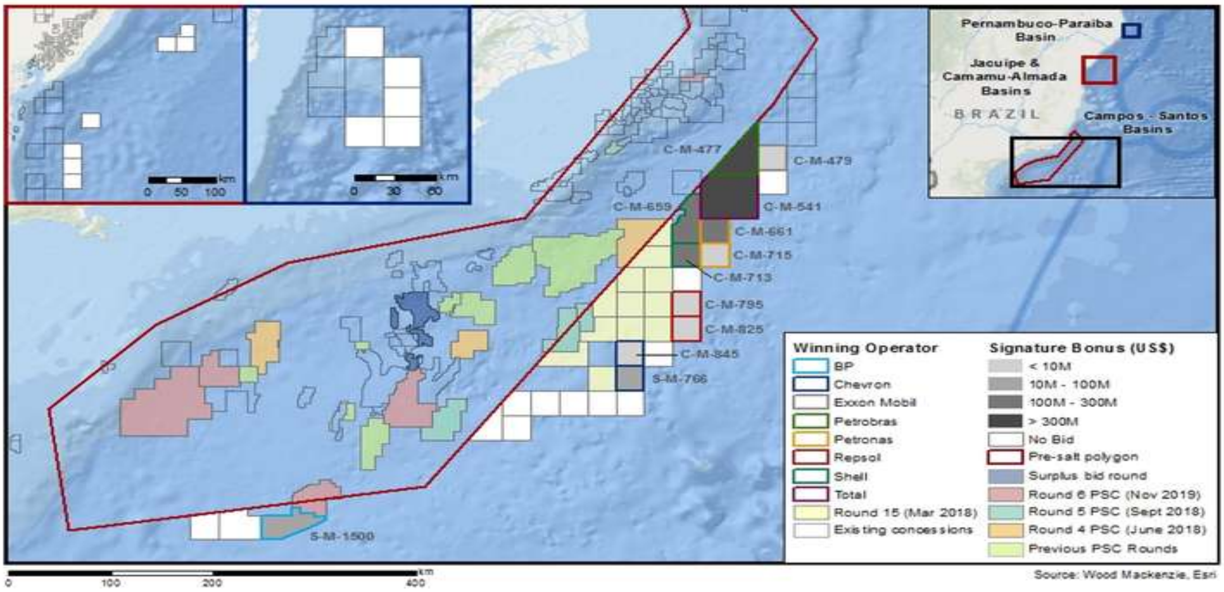


Figure 40: *The oil and gas companies signing bonuses for 12 of 36 offshore blocks offered in Brazil's 16th bidding round. A group led by Total E&P of Brazil, Petronas, and Brazil QPI offered the largest signing bonus ever in a Brazilian concession round: about $1 billion for Block CM-541 in the Campos basin.*

Licensing agency ANP (National Petroleum Agency) said the round will generate investment totalling at least $380 million in exploration phases of the new concession contracts covering a total of about 11,800 sq km. It said the round aimed to explore areas of the Campos and Santos basins outside the pre-salt play and to attract investment to the little-explored Pernambuco-Paraiba, Jacuipe, and Camamu-Alamada basins.

Table 12*: Hydrocarbon map for CAMPOS and SANTOS BASINS to be signed by Feb. 14, 2020, according ANP, National Petroleum Agency.*

COMPANY	BLOCK	BASIN	FINANCIAL INVESTRMENT
PETROBRASS/BP ENERGY	CM 477	CAMPOS	USD 499 MILLION
SHELL BRAZIL/BRAZIL QPI/CHEVRON	CM 659	CAMPOS	USD 171 MILLION
EXXON MOBIL BRAZIL	CM 479	CAMPOS	USD 6.1 MILLION
PETRONAS	CM 611	CAMPOS	USD 268 MILLION
PETRONAS	CM 715	CAMPOS	USD 6 MILLION
SHELL GROUP	CM 713	CAMPOS	USD 132 ,MILLION
REPSOL	CM 795	CAMPOS	USD 2.3 MILLION
REPSOL	CM 825	CAMPOS	USD 3 MILLION
CHEVRON/WINTERSHALL BRAZIL/REPSOL	CM 845	CAMPOS	USD 6.5 MILLION
CHEVRON GROUP	SM 766	SANTOS	USD 13 MILLION
BP ENERGY	SM 1500	SANTOS	USD 74 MILLION

EXPLORATION

The off-shore oil exploration in the Campos Basin began in 1968. The first exploratory well was drilled in 1971. The first field to be discovered was Garoupa in 1974, at a shallow water depth of 120 metres (390 ft), followed by Namorado in 1975 in 166 metres (545 ft) of water. The first oil production started in 1977 from Enchova Field, at a water depth of 124 metres (407 ft). The largest fields, listed by their year of discovery year, include Linguado (1978), Carapeba (1982), Vermelho (1982), Marimba (1984), Albacora (1984), Marlim (1985), Albacora - Leste (1986), Marlim Sul (1987), Marlim Leste (1987), Barracuda (1989), Caratinga (1989), Espadarte (1994), Roncador (1996), Jubarte (2002), Cachalote (2002), and Badejo (2008). The largest Marlim field is located in the northeast of the basin, 110 kilometres (68 mi) offshore in water depths ranging from 650 to 1,050 metres (2,130 to 3,440 ft).

By 2003, 41 oil and gas fields were discovered, which are ranging at distances from 50 to 140 kilometres (31 to 87 mi) from the coast and at water depths varying from 80 to 2,400 metres (260 to 7,870 ft). Of these fields, 37 are being developed by PETROBRAS. By 2003, the oil production from the basin had reached 1.21 million barrels per day. The production comes from a variety of reservoirs including siliciclastic turbdites, fractured basalts, coquinas, calcarenites (limestones). The total cumulative production from the Campos Basin by 2003 was 3.9 billion barrels of oil with remaining reserves of 8.5 billion barrels.
In February 2010, a new 65 million barrel discovery was made by PETROBRAS near the Barracuda oil field.

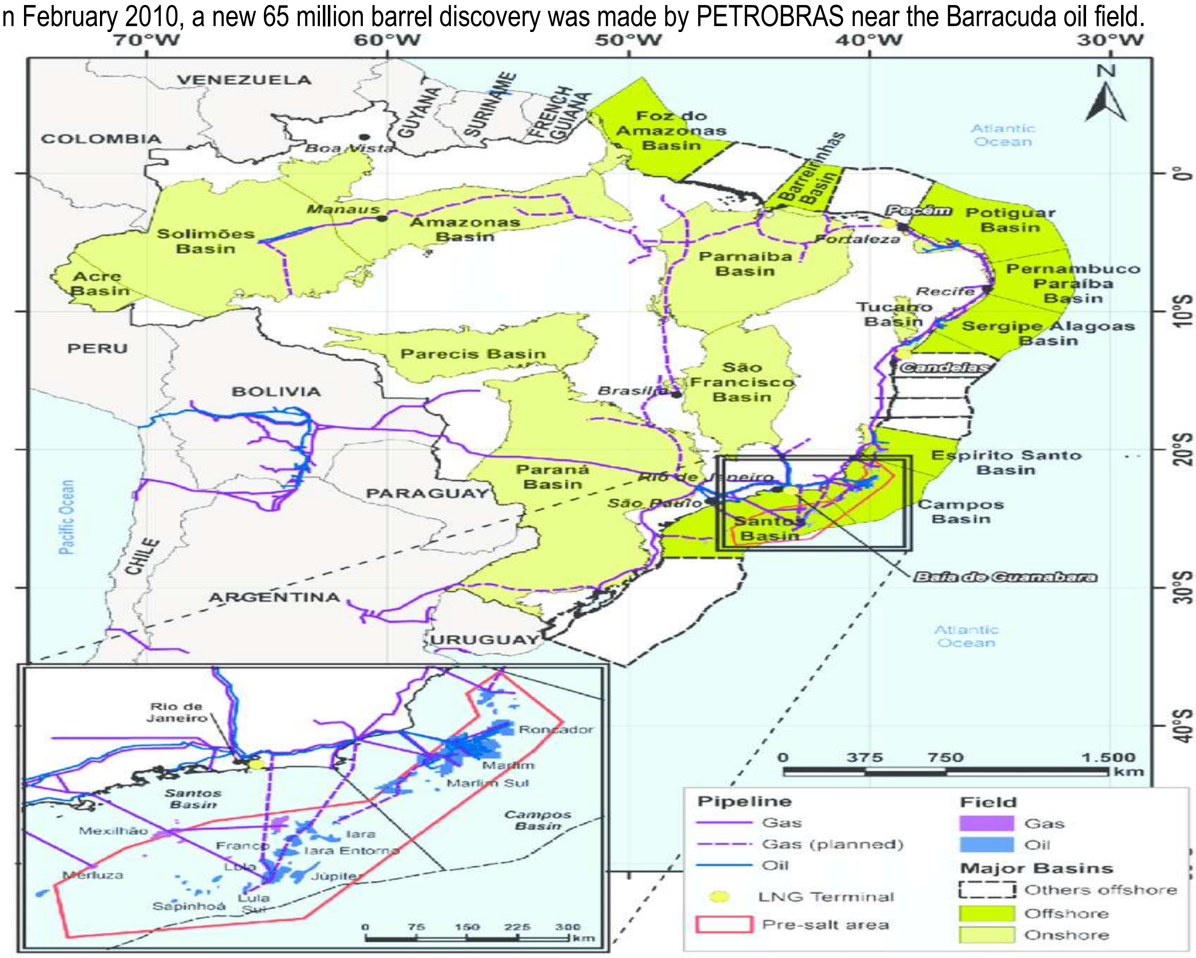


Figure 41: *The onshore and offshore oil and gas basins of Brazil*

8.5 NAMIBIA OIL AND GAS OFFSHORE BASINS

8.5.1 KWANZA BASIN

The KWANZA BASIN is filled with sandstone and shale constituents of the rock type.

8.5.2 NAMIBE BASIN

The NAMIBE BASIN is filled with sandstone, saltstone and shale deposit.

8.5.3 WALVIS RIDGE

The WALVIS RIDGE is occupied by carbonates and shale.

8.5.4 WALVIS BASIN

The WALVIS BASIN is dominantly filled with carbonates, abundant sandstone and saltstone conglomerates.

8.5.5 LUDERITZ BASIN

The LUDERITZ BASIN is the same rock type of the WALVIS BASIN,, filled with carbonates, sandstone and saltstone deposits.

8.5.6 ORANGE BASIN

The ORANGE BASIN is filled with sandstone and shale. A viable seal has been proven in the Kudu gas field and this comprises the thick Upper Cretaceous pro-delta mudstones of the Orange Delta. This is likely to be present throughout the Orange Basin. Further north, extensive mudstone packages are found, probably derived from the Etendeka Group basaltic lavas. These would form excellent seals.

8.5.7 CAPE BASIN

The CAPE BASIN is again filled sandstone and shale.

8.6 HYDROCARBON POTENTIAL OF ONSHORE NAMAIBIA

This year 2019-2020, Namibia has again moved into the spotlight as major oil companies increased their presence along the Namibian margin. ExxonMobil acquired acreage in the Namibe Basin and Total announced it plans to test the giant Venus prospect in the deepwater offshore Orange Basin. Over the last five decades exploration offshore Namibia has been through cycles of consecutive rig activity, with high hopes and excitement alternating with prolonged phases of dormancy, the latter partly relating to the political complexity in southern Africa prior to Namibia's independence in 1990. A Century of Onshore Exploration in Namibia
In a similar but less well known fashion, Namibia's onshore potential has received the attention of various explorers for now almost a century.

Figure 42: *The onshore oil and gas rock formations in the Kuiseb Canyon Area.*

The first onshore exploration well, Berseba-1, was drilled by South West Africa Petroleum Corporation in southern Namibia in 1928. This was 46 years prior to the drilling of the first offshore exploration well, Chevron-Texaco's Kudu 9A-1 in the Orange Basin. Initially Kudu-1 targeted a Tertiary / Upper Cretaceous prospect that turned out to be dry, but then the well continued as a 'stratigraphic well' down into the Lower Cretaceous, leading to the discovery of the Kudu gas field in 1974.

Berseba-1 in 1928 was similarly experimental, and though a gas blow-out was reported at shallow depth during drilling operations, the well did not yield a discovery when it reached TD. Therefore, scepticism about Namibia's onshore potential may have played a role in explaining why only 12, mostly shallow, exploration wells have been drilled to date, thus hardly testing the country's full onshore potential.

Namibia's Onshore Basins: Nama Basin and Owambo-Etosha Basin
Namibia's onshore basins cover over 60% of the country. Two vast Neoproterozoic/Early Cambrian Basins, the Owambo-Etosha Basin in the country's northern part and the Nama Basin in the south, have been receiving most of the attention from exploration companies. These basins cover over 470,000 km^2 and both are flanked by early Cambrian pan-African orogenic belts. Both basins share the prominent Damara Belt, which forms the southern margin of the Owambo-Etosha Basin while delimitating the Nama Basin to its north. To the west the north-north-

west trending Gariep Belt and its northern extension, the Kaoko Belt, form the western margins of the two basins. This means that each basin is flanked by two almost contemporaneous orogens leading to complex foreland basin architectures and the associated high probability for structural traps.

Figure 43: *View of the front of the Naukluft Nappe delineating the Nama Basin to the north. In the foreground are tilted shales and carbonates of the Nama Basin. .*

Migration is predicted to have started in the Cambrian following the Damara orogeny. Post-orogenic deformation events are minor, and therefore there is a good chance that Cambrian hydrocarbon accumulations remained preserved. Predicted deep depocentres and several source and reservoir lithologies observed in core and outcrops have attracted explorers, from small independents to majors. In fact, the exposed orogenic basin margin gives an excellent example of a fossil petroleum system with abundant graphite occurring in metamorphosed rocks originating from hydrocarbon-generating Neoproterozoic syn-rift shales.

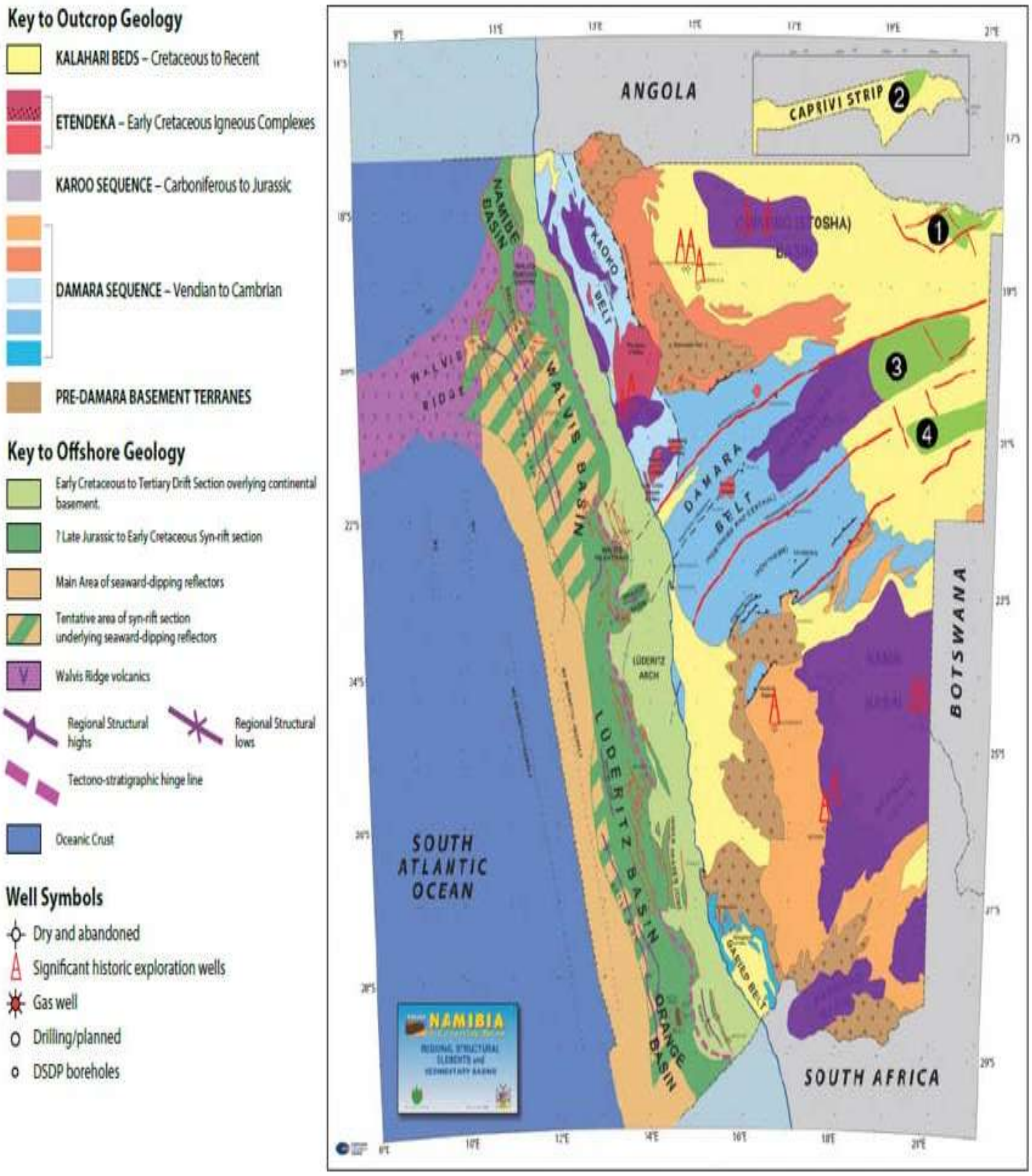


Figure 44: *A geological map of Namibia displaying onshore and offshore sedimentary basins. The Owambo-Etosha Basin is located north of the Damara Belt, while the Nama Basin is situated south of it. Purplish overlays show proven Karoo Basins, green areas show postulated basins under Cenozoic cover: (1) Kavango Basin, (2) East Caprivi, (3) Waterberg East, and (4) Eiseb-Omatako.*

The location of the first well in 1928 in the Nama Basin was solely chosen on field geology studies including the observation of bitumen veins in outcrops. So far, the source for these shows remains speculative; some may relate to matured Neoproterozoic source intervals, while others may rather derive from local hydrocarbon generation caused by basaltic intrusions in Karoo shales (Summons et al., 2008).

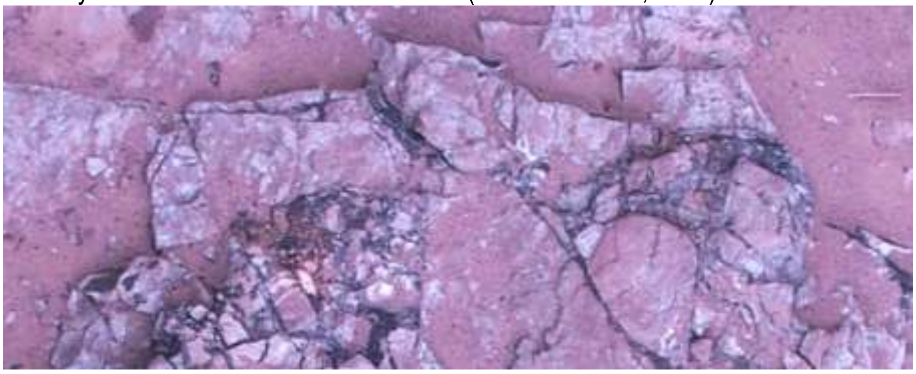


Figure 45: *Bitumen-cemented fault breccia within sandstones of the Fish River Subgroup. Such outcrops motivated early explorers to drill the first oil exploration well almost a century ago.*

In 1968 DeBeers with Shell/BP acquired a concession and conducted the first 2D reconnaissance survey. This was followed by the drilling of Tses-1, which, with a TD of 2,225m, is so far the deepest test well in the basin. A second 2D survey covering 500 km was conducted much later in 2007/08 by Hungarian company INA Industrija Nafte d.d. This provided the first subsurface imaging of reasonably good quality, allowing more detailed structural and stratigraphic interpretations. However, INA did not test its prospects and current explorers will need to be prepared to shoot more seismic and drill new wells.

Exploration in the Owambo-Etosha Basin is more advanced: seismic acquired includes vintage 2D surveys conducted between 1969 and 1995, and a more recent 120 km 2D survey carried out by CGG for Angolan AGREP in 2017. All 2D seismic surveys are widely spaced, and as expected in foreland basins, they reveal more structural elements at the basin margins, while flat reflectors rather characterise the basin interior. In addition, airborne geophysical surveys, soil geochemistry, remote sensing and micro-tremor studies have been carried out during the current decade and preparations for more surveys of this kind are underway.

Figure 46: *Stromatolitic Otavi Group carbonates provide excellent high poroperm reservoir lithologies.*

Between 1964 and 1991 five exploration wells with TDs between 700 and 2,509m were drilled. Only the deepest of these wells penetrated a potential reservoir zone and a minor oil show has been reported. Otherwise the Owambo-Etosha Basin lacks the obvious outcrop hydrocarbon shows of the Nama Basin, probably due to the thick Cenozoic cover of semi-consolidated sediments. Encouraging elements are soil gas geochemistry, remote sensing and micro-tremors studies, as well as the abundant structural elements along the basin margins.

Petroleum basins with Neoproterozoic source rocks, such as in Oman, the Lena-Tunguska Basin in Siberia and others, have been the motivator for keeping exploration in Namibia's two Neoproterozoic/Cambrian basins going. But what have been lacking are more aggressive exploration campaigns with wells down to basement and well-placed denser seismic surveys. Fortunately, recent exploration activities have gained a new momentum, geological concepts have been refined, and now the scene is ready to design new determined exploration programmes.

The Namibian Karoo Basins: New Petroleum Target
Karoo-aged basins hosting late Palaeozoic to Mesozoic strata form another set of basins. In the '80s the Karoo basins were the target for coal exploration, and only more recently have they been considered as a hydrocarbon exploration target.

Continental sediments prevail in the Namibian Karoo basins with marine influence only having been demonstrated in the uppermost Carboniferous. The Permian strata contains not only coal seams, but also extensive organic shales. Perfectly preserved Mesosaurus fossils, a nektonic crocodile-resembling reptile, are described from those shales in Namibia. With Mesosaurus as an index fossil the Namibian black shales correlate well with similar shales across Gondwana, known as the Whitehill Formation in South Africa and as the Irati Shales in South America. Sedimentology and isotopic signatures indicate restricted environments with repeated algal blooms: the perfect conditions for the deposition of oil-prone source rocks.

Figure 47: *Highly friable Upper Carboniferous black shale exposed at the banks of the Fish River in southern Namibia. Those shales may also occur in deeper depocentres and fuel Karoo-aged petroleum systems.*
The Karoo in Namibia covers large areas in Namibia, with outcrops occurring particularly in southern, mid-northern central and coastal north-western Namibia. Outcropping Karoo strata form distinct landscape features such as the Weissrand Escarpment in southern Namibia or the Waterberg Plateau, the latter being a wellknown scenic tourist destination.

In most areas the Karoo forms a veneer of horizontal strata less than a kilometre thick, and this has probably been the reason why hydrocarbons, apart from coal bed methane (CBM), have not been considered as a resource. Exploration wells for CBM were drilled in the Aranos Basin in 2008 and in the Huab Basin in 2012, but the gas contents have not proved economic.

Figure 48: *Southerly trending folded Neoproterozoic turbidites in the Kaoko Belt, which is the pan-African Belt that flanks the Owambo-Etosha Basin to its west.*

Depocentres are aligned along south-west to north-east trending fault systems that essentially follow the pan-African basement grain and are seen as part of the wider Southern Trans-African Rift and Shear System (Granath and Dickson, 2018). The prominent cliffs at the Waterberg and Mt. Etjo are erosive remnants of the top sequence deposited in such a depocentre. Geophysical modelling of magnetic and gravity data promotes the presence of deep Karoo basins exceeding 5 kms of sediment in the north and east of the country, where the terrain is essentially flat and rocky outcrops are very sparse due to the extensive Cenozoic Kalahari sequence cover. The locations of the predicted Karoo depocentres match the extrapolation of known major fault systems. Releasing-bent pull-apart extension is predicted, which would promote the presence of steeply flanked deep basins. In such a scenario episodes of anoxic lacustrine deposition would have probably occurred not only during the Permian, but possibly also higher in the stratigraphy. Given enough overburden, both conventional and unconventional petroleum systems have been hypothesised. The recently proposed Kavango Basin in the northeastern part of the country relies on this concept and preparations for test wells have commenced.
Revealing Namibia Onshore Potential

The deeper parts of both the Neoproterozoic/Cambrian and the Karoo basins are believed to occur under essentially flat terrain with few surface clues indicating what is happening in the subsurface. This allows explorers to think laterally and, as is vital in frontier exploration, to ponder opportunities. The little subsurface data available is truly encouraging and moreover, Namibia offers an essentially friendly environment for exploration.

Now, 91 years after the first onshore well was drilled, explorers have a modern exploration toolbox at hand that will make it much easier to reveal Namibia's real onshore potential. Further Reading on Oil and Gas Activity in Namibia

8.7 NAMIBIA ONSHORE AND OFFSHORE HYDROCARBON LISENCE MAP

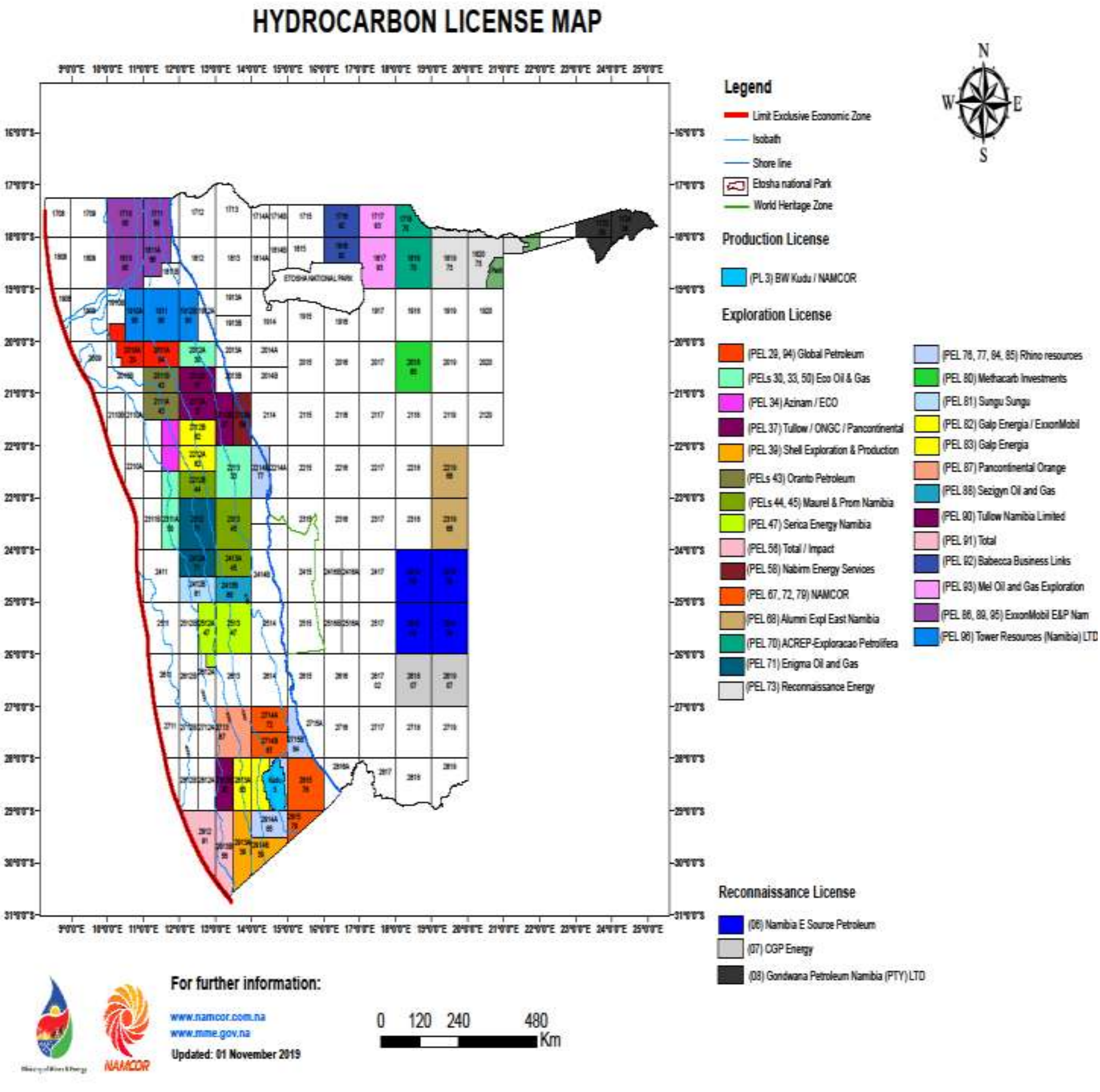


Figure 49: *The onshore Hydrocarbon Licence map of Namibia*

8.8 SUMMARY

The Brazilian oil and gas basins, the CAMPOS and SANTOS are classified and identified by the certain types of rocks. These rocks are also identical to the oil and gas basins of Namibia. These oil and gas basins of the two countries are identical as they are and were regarded as one solid rock type during the tectonic and geomorphologic era. As the continent was one continent, GONDWANA. The fossil fuels process, the Biological decaying process and the scientific, chemical processes which took place over centuries on this one rock type of the GONDWANA must then be the same on the two continents, Brazil and Namibia. This then simply means, if the Brazilian oil and gas basis can produce oil and gas, then the Namibia oil and gas must also produce oil and gas.

CHAPTER 9

SYNTHESIS, RECOMMENDATIONS AND CONCLUSIONS

9.1 INTRODUCTION

The oil and gas industry, petroleum engineering in its different fields of study, exploration, drilling, reservoir and production engineering has produced the most wanted, fought for commodity under the earth crust, onshore and offshore, oil or gas. This commodity, product has been the centre point of most of the oil and gas companies in the different continents and countries all over the world. It has become so significant that the daily lives of each and every human being became so dependent on oil and gas and its by-products. This industry has produced different types of gases for domestic use and the industry at large. The different types of fuels, petrol, diesel and other lubricants have been used in vehicles, apartments, industry plants as well as the offices of different businesses. The residues like bitumen has been used to construct roads and roofs of houses in order to provide comfortable surface for travelling from towns to towns, towns to cities and towns to villages. We has human beings became so dependent on the industry of oil and gas.

This dependency has made most of the elite companies exploring for this product, oil or gas and these companies have also made the possibility of extracting oil or gas so expensive and mostly demanding that the ordinary entrepreneur who earns his/her little income will not be able to engage into this industry. This industry has become the **'ELITE INDUSTRY'** as it has been referred to as the **''BLACK GOLD''**. The industry of the closed friends, presidents, mafias and the directors, chief executives officers of certain and closed business companies.

The exploration and drilling processes have also become so expensive to apply for EPL, Exclusive Prospecting License, for an ordinary citizen, small oil and gas companies finds it so difficult to get these licences as only the wealthy and rich companies are able to get them successfully and then they explore, drill and acquire oil or gas from the respective reservoirs. The selection process in acquiring exploration blocks in the respective countries all over the world is only meant for certain companies, private companies, where only certain individuals benefit and the rest of the companies and the people of a country must stand towed in a long, long queue.

9.2 SYNTHESIS

The tectonics theory and its geomorphologic forces and their applications on the ONE CONTINENT, hence its offsprings, the different continents in the different hemispheres have resulted into formations of oil and gas basins. These basins are so identical in terms of rock, reservoir formations and their respective DNA in the different continents and countries.

9.3 RECOMMENDATIONS

The exploration, drilling and production onshore or offshore on the Namibia oil and gas basis might have been a vertical drilling and the horizontal drilling ought to be applied or the two types of drilling must be simultaneously proposed to the different oil and gas companies.

9. 4 CONCLUSIONS

There are undefined Petroleum Fractions which are naturally occurring in all hydrocarbon systems and they contain a quantity of heavy fractions that are not well defined and are not mixtures of discretely identified components. These heavy fractions are often lumped together and identified as the plus fraction. A proper description of the physical properties of the plus fractions and other undefined petroleum fractions in hydrocarbon mixtures is essential in performing reliable phase behaviour calculations and compositional modelling studies. A distillation analysis or a chromatographic analysis is frequently available for this undefined fraction. Other physical properties, such as molecular weight and specific gravity, may also be measured for the entire fraction or for various cuts of it. To use any of the thermodynamic property-prediction models, e.g., **equation of state**, to predict the phase and volumetric behaviour of complex hydrocarbon mixtures, one must be able to provide the eccentric factor, along with the critical temperature and critical pressure, for the defined and undefined, heavy, fractions in the mixture. The problem of how to adequately characterize these undefined plus fractions in terms of their critical properties and eccentric factors has been long recognized in the petroleum industry.

The earth crust consists of different types of rocks, like the igneous, sedimentary and metamorphic rocks, which are produced by different atmospheric conditions. These types of rocks finally provide the landscape of the earth. On the other hand, different types of rocks provide different types of reservoirs, like the oil and gas reservoirs. The oil and gas reservoirs are formed over centuries of fossil foil deposition and sedimentation. The sedimentation takes place under different types of pressure and temperature conditions, which eventually result into a hydrocarbon of oil and gas. Any rock must undergo certain geomorphologic processes, like crystallization, erosion, sedimentation and metamorphism, in order to be classified as a rock. Crystallization process can take place underground or on the surface. The erosion and sedimentation processes are assisted by wind, running, flowing water and organisms over hundreds and thousands of years.

On the other hand is metamorphism a process which only changes the face of an existing rock, in conjunction with the continuously changing temperature and pressure conditions and hence rocks are usually identified by the minerals they are constituting.

The reservoir classification also depends on the empirical equations of state, which are used as quantitative tool in order to describe and classify a hydrocarbon system. Reservoirs also differ in terms of their specific properties as the reservoir heterogeneity is coming to the fore. There are three types of fluids in a reservoir, gas, water and oil. These fluids are flowing differently inside a reservoir, like radial flow, linear flow, spherical and hemispherical flow. The velocity of a fluid has been formulated by Henry Darcy for homogenous fluid in a porous medium. The velocity of a fluid is directly proportional to pressure gradient and inversely proportional to the fluid viscosity.

The pressure intensity and the quantitative availability of pores pre-determine the quantitative volume of gas and oil in a reservoir. The quantity of volume of either the gas or oil of a reservoir will depend on the individual HCPV of a pore. In other words if one pore has a volume of 3 000 litres, or 3 tonnes of crude oil and there are 3 000 000 pores in a reservoir, then the total volume of that particular reservoir will have a total volume of 3 x 3 000 000 = 9 000 000 litres of crude oil.

The shape of a pore as well as the compressibility by pressure will also determine the total volume of a reservoir.

In other words the size of a pore, will determine the permeability and hence the quantitative volume of oil and gas of a reservoir. On the one hand the practical application of the pore shape will not be familiar witht the above drawn diagrams. The following pictures are real and actual situations in the different reservoirs in oil and gas industry.

Different types of reservoirs have different porosities and these porosities are demonstrated by means of the above mentioned reservoir pictures. It is highly impossible for reservoirs to ONLY have the same size of rocks, like Reservoirs, 1,2 and 3 BUT it is a phenomenon, which cannot be ruled out. The most practical and highly possible Reservoir trype is the mixture of all sizes of roccks, Reservoir 4.

In the model of CHILTHUIS, which determines the MATERIAL BALANCE EQUATION, it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

One of the critical, determining factors in the application of the material balance equation is the assessment of the actual average reservoir pressure at which the pressure dependents on parameters in the equation which should be evaluated. i.e. The initial pressure or centroid point or differentiate point is very crucial in the material balance equation, whenever there are different types of constituents in a reservoir, of any reservoir. The material balance equation is an equation which determines the volume balance of a reservoir on one hand and then balances the total production of the difference between the starting volume of hydrocarbons in the reservoir and on the other hand the current or final volume of a reservoir.

Any engineer will be able to formulate a suitable mathematical model in order to describe the performance of any reservoir, once a straight line is plotted, based on the observed production and pressure data of the indentified reservoir.

This assessment and evaluation is facilitated by the mathematical application which uses simple linear expressions for the material balance equation, as presented by Havlena and Odeh.

The Material Balance provides reservoir engineers a great deal of information in knowing the following details of a potential reservoir, (1) the initial hydrocarbon in place of a reservoir, (2) how much hydrocarbon can be produced at different pressures, (3) the primary mechanism for reservoir production, (4) the potential usefulness of varying enhanced recovery techniques.

The material balance equation can be written as:

Oil Expansion + **Gas Expansion +** **Formation and Water Expansion + Water Influx** **=** **Oil and Gas Production + Water Production**

The sedimentary rocks undergo different types of chemical make up over centuries again and hence it will have a certain complexities, which are called rock or reservoir properties. These properties will be different for different types of sedimentary reservoirs. This has been the reason, why different continents and countries have different quantities of oil and gas. The above mentioned properties are as follows. Porosity, Permeabi9lity, Shape, Wettability, Saturation, Temperature, Pressure, Gravity, Density, Viscosity, and Pore Volume.

A reservoir can be depleted over decades and centuries BUT can again get pregnant or contain oil or gas. These can be inflows of gas and oil from the neighbouring rocks, as the previous or historically pregnant reservoir, might have provided a good, low pressure area for the harbouring of the a content. This area can be termed as good cuddle place for an infant oil or gas. The inflow can take place over a period of time and this will result in a highly impregnated reservoir, which can deliver in a short while or any time.

A highly rich or highly qualified reservoir in terms of oil and gas must have favour bake or moderate pressure and temperature application on a reservoir, which will then, determine the shape of a pore. The quantity of pressure application on a reservoir will also predetermine the number of pores in a reservoir. The more pores are there and the high permeability, the more quantity or volume of oil and gas can be delivered by any reservoir.

The more practical application of a particular reservoir is that, any reservoir will have different shapes, sizes of pores. There will not be any reservoir, which has only small, medium or large pores. BUT this possibility can and will never be excluded.

The frequently changing pressure applications on the earth crust, will determine this phenomenon. As long as there is a continuous change in pressure on any reservoir, there will always be different shapes, sizes of pores and permeability in a reservoir. A reservoir, which does not have any pores, will never have any quantity of oil and gas. I am going to demonstrate the porosity and the permeability and the quantity of oil of different types of reservoirs.

It is very clear the actual volume of a reservoir with contains different sizes of rocks, presents the practical application of reservoir's volume of oil or gas.

One can again NOT rule out or exclude the size of the reservoir pores, as they determine the actual volume of the quantity of oil or gas, any reservoir can supply as well as how long this reservoir can be in existence. For how many years will such a reservoir be able to supply oil or gas? It must never be excluded that reservoirs can also contain the same type and sizes of pores.

The permeability of the different types of reservoirs will specifically depend on the following:

(1) Number of pores in a reservoir (2) Different sizes of pores (3) The cementation or how close the pores are spread across a reservoir.

The most productive and durable, lifelong Reservoir will be classified and based on the following practically oriented statements.

Table 13: *Types of reservoirs and their respective properties.*

Property of a reservoir	Type of Reservoir
The higher the porosity, the higher the permeability	1. Short Life Reservoir
The lower the porosity the lower the permeability	2. Long Life Reservoir
The higher the porosity, the lower the permeability	**3. Long Life Reservoir**
The lower the porosity, the higher the permeability	4. Impossible

In other words the reservoir with high density and low viscosity fluid, low permeability can also have irregular shape of the rocks and this extends the life of the reservoir as it can be productive for a longer period.

A reservoir simulation is used tremendously and extensively to identify opportunities and company objectives in securing and increasing oil production in heavy oil deposits and reservoirs. The oil recovery process is enhanced by decreasing the oil viscosity by injecting steam or hot water inside a well with oil.

The simulation models and the seismic imaging are very much important and critically advantageous to the respective companies and governments, which are on the attempt of trying to explore, drill and produce any gas or oil in any region or location.

It is of utmost importance to know, whether in a certain area, region or place there is an availability of a resource, like oil or gas before any plans are carried out and this can only be determined by seismic 3D imaging and hence the seismic application.

Once a resource, oil or gas reservoir has been identified and located and the companies know, that there is oil or gas available, then the planning will start on how to drill and extract oil or gas from deep down the sea, sub-surface. The seismic imaging or data will also bring forth the quantity of the possible oil or gas.

This can then also determine for how long the companies will be involved in extracting the product.

Thus for sure will also determine the financial budgets of the respective companies for the period of time they will be engaged in a particular location.

Experiments via simulation model have several important advantages versus physical experiments too as it provides any reservoir engineer with the following (1) **Value,** the financial impact**, (2) Time,** the production period, (3) **Repeatability,** the market parameters, like price range can be repeated in the future, in order to understand the effects, **(4) Accuracy,** simulation model provides practical applications, (5) **Visibility**, Illustrates the system in operation and hence the graphical outputs quantify the results, (6) **Versatility, t**he model simulates real life, which is based on practical conditions and as temperature and pressure are severely fluctuating.

Table 14: The marine seismic surveys and electromagnetic techniques *are assisting the petroleum Geologists with data with provide the following information.*

(1) Identify possible oil and gas migration paths over the period of time.
(2) Estimate the geometry and size of potential traps where the resource might be located.
(3) Predict directly the presence of hydrocarbons.
(4) Developing new oil and gas fields and at least provide managing production.
(5) The seismic data also provides very informative parameters for any Reservoir Engineer or Geophysist.
(6) Type of rock.
(7) Maximum area the reservoir covers.
(8) The quantity of the product, oil and gas.
(9) The depth the resource/product.
(10) The possible affecting factors, like pressure and temperature.
(11) Porosity and Permeability of the rock or reservoir.
(12) Shape of the reservoir.
(13) Obtain as maximum product from the reservoir as possible based on its financial application.
(14) Provides the WELL DESIGNED, practically oriented model.
(15) The analytic behaviour of oil, gas, water, and solids.
(16) Provides an evaluation on the uncertainty analysis and optimization, so that potential recovery and artificial lift methods can be carried out.

Heavy oil reservoirs contain very high quantity productivity and they are often associated with soft, unconsolidated near-surface basins where wellbore stability can be an issue during drilling or production processes and poorly-sorted heterogeneous sand surfaces can hinder steam chamber growth as they can easily collapsed.

Reservoir simulation is an area of Reservoir Engineering in which computer models are used to predict the flow of fluids, like oil, water, and gas through porous sediments.

This provides the scientific detailed understanding of a real or mentally created structure that reproduces or reflects the object being studied. Modelling or simulation is one of the main methods of knowledge application and it is widely used in technology and is an important step in the implementation of scientific and technological progress.

The creation of models of oil fields and the précised, exact implementation of calculations of field development on their basis is one of the main areas of activity of engineers and oil researchers.

The geological and physical information about the properties of an oil, gas or gas condensate field, as well as the capabilities of the systems and technologies create quantitative ideas about the development of the field as a whole. A system of interrelated quantitative ideas about the development of such a field is a model of its development, which consists of a RESERVOIR MODEL and a MODEL of a FIELD DEVELOPMENT PROCESS.

The investment project is a system of quantitative ideas about its geological and physical properties, used in the calculations of field development. A system of quantitative ideas entails a field of deposits and deposits about the process of extracting oil and gas from the subsoil. Generally speaking, any combination of reservoir models and development process can be used in an oil field development model, as long as this combination most accurately reflects reservoir properties and processes. At the same time, the choice of a particular reservoir model may entail taking into account any additional features of the process model and vice versa.

The RESERVOIR MODEL should, of course, be distinguished from its design scheme, which takes into account only the geometric shape of the reservoir. A reservoir model may be a stratified heterogeneous reservoir and in the design scheme, the reservoir with the same model of it can be represented as a reservoir of a circular shape, a rectilinear reservoir, etc.

Layer models and processes for extracting oil and gas from them are always included in a mathematical form, i.e. characterized by certain mathematical relationships.

The main task of the engineer who is engaged in the calculation of the development of an oil or gas field is to draw up a calculation model based on individual concepts derived from a geological-geophysical study of the field, as well as hydrodynamic studies of wells.

Modern computer and computational achievements make it possible to take into account the properties of the layers and the processes occurring in them when calculating the development of deposits with considerable detail.

The possibilities of Geological, Geophysical and Hydrodynamic cognition of development objects are continuously expanding. Hence the possibilities are far from endless as the makeup of the reservoir is continuously changing. Therefore, there is always a need to build and use such a field development model in which the degree of knowledge of the object and the design requirements would be adequate and practically applicable.

The application of software in reservoir engineering is of utmost importance. This is the very much imperative to use technological applications and software in determining the types of oil and gas reservoirs and hence determine which reservoirs are containing the required and expected oil or gas for production. It is also only through a certain kind of software application any reservoir engineer will be able to determine where and which reservoir contains any volume of oil or gas without physically observing at close distance the containment of a particular reservoir. An office base projection, through a computer, PC application can be used and hence determine, how far am oil or gas reservoir is located and which once contains oil or gas.

Petroleum Engineering makes use of different types of technology in a variety of ways depending on the specialization area. The reason for this software application is based on the ability to extract hydrocarbons from any area as the extraction has become more complex in conjunction to the terrain's, deep-water, arctic and desert, conditions. Therefore, new solutions and ways of successful applications had to be constructed in order to access these hard to reach deposits and this means that Petroleum Engineers need to understand different areas such as thermo-hydraulics, geo-mechanics and intelligent systems. Hence, Petroleum Engineering technology applications have played an increasing and vital role in aiding engineers in their work as a result. Petroleum engineering technology continues to improve and there have been advances in computer modelling and simulation, statistical and probability analysis, as well new technical innovations such as horizontal drilling and enhanced oil recovery. These applications and technologies have substantially improved the tools used by the Petroleum Engineer in recent years, and they will continue to play an important part in their activities as they seek to research and develop new ways to extract new deposits, while lowering the cost of drilling and production.

The porosity of a reservoir determines the fluidity of a reservoir. Only a rock or reservoir which is porous will be able to contain gas, oil or water. The fluidity or rather the quantity of a fluid, gas, oil or water can be determine inside a reservoir by determining the porosity of a particular and explicit reservoir. Any reservoir engineer can mathematically calculate the porosity of a particular reservoir, by reservoir simulation and determine its porosity. The total area of the reservoir will then determine the total porosity as well as the total net fluid inside the particular reservoir.

The lifespan of any reservoir, oil, water or gas can be and will be determined by the total volume of fluidity in such a reservoir and determining the daily extraction of fluid from such a reservoir from any oil and gas company. This correlation of total fluidity in the reservoir and total annual extraction from such a reservoir will determine the lifespan of such a reservoir. On the other hand the reservoir over a period of time will become dry, if the entire fluid is extracted from it over a period of time, hence the pressure applications of such a reservoir will be totally different. A full oil or gas reservoir has a certain internal pressure, then the empty, no oil, gas or water reservoir. In other words, once the reservoir is empty, it can then collapsed and extract fluidity from the external parts of the reservoir. In other words streams of oil and gas, water will be flowing, streaming to the empty hole and fill it up again or it will just collapsed and remain empty.

The Brazil oil and gas basins, Santos and Campos are fully pregnant with oil and gas. These basins are having the same rock DNA as the Namibia oil and gas basins, Namibe, Walvis, Luderitz and Orange. Thus Namibia basis must also contain oil and gas. Namibia has oil and gas offshore as well as onshore. The quantity of oil and gas onshore will be very limited then the offshore oil and gas reserves. The Namibia Government will have to be cautiously approaching the exploration, drilling of the oil and gas basis and draft policies accordingly. This legal framework must benefit the Namibians and not the foreign companies. Namibia will be dried up, in terms of oil and gas on its basins, if policies or the legal framework are not properly and well crafted in order to benefit Namibians. The Namibia oil and gas, State Owned Enterprise (SOE), NAMCOR, National Petroleum Corporation of Namibia, must acquire at least more percentage in its dealings and contractual obligations with the foreign and international companies. It is also very much crucial for Namibia to open or establish an oil and gas college or incorporate the oil and gas trade at the vocational training centres.

There are different types of reservoirs, like oil and gas with different properties. The type of the reservoir is described on its difference of temperature within a reservoir. The reservoir temperature and the critical temperature. There are also different types of oil reservoirs, like, Undersaturated oil reservoir, Saturated oil reservoir. Gas-cap reservoir. There are also different types of crude oils and they are commonly classified into the following types: Ordinary black oil, Low-shrinkage crude oil- Lowly Volatile Crude Oil (High Density, High-shrinkage (volatile) crude oil- Highly Volatile Crude Oil (Low Density)and Near-critical crude oil

The different types of crude oil are essentially based upon the properties exhibited by the crude oil, including physical properties, composition, gas-oil ratio, appearance, and pressure-temperature phase diagrams.
The crude oils are then as follows, Ordinary black oil, Low-shrinkage oil, Volatile crude oil and Near-critical crude oil. The natural gas is then also classified into four categories, Retrograde gas-condensate, Near-critical gas-condensate, Wet gas and Dry gas.

The porosities of any reservoir does differ tremendously as the effective porosity is the porosity value of interest to any petroleum engineer, particular attention should be paid to the methods used to determine porosity. For example, if the porosity of a rock sample was determined by saturating the rock sample 100 percent with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces. On the other hand, if the rock sample were crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process. One important application of the effective porosity is its use in determining the original hydrocarbon volume in place. A reservoir with an areal extent of A, measured in acres, hectares or square kilometres and an average thickness of height in feet, meters or kilometres. The total bulk volume of the reservoir can be determined from the following expressions:

Wettability of reservoirs is the preferential affinity of the solid matrix for either the aqueous or oil phases." Wettability is the movement of a fluid, gas or oil over a solid surface, like a rock. Thus, the solid is called a water-wet material when water, oil wet or gas wet tends to spread out to cover the solid surface. The wettability of any rock is then determined by the Contact angle. The contact angle will give the good indication of the spreadability and wetting characteristics of fluids over simple continuous surfaces. The wettability of porous materials are two types, uniform or homogeneous and nonuniform or heterogeneous.

Uniformly wet porous materials have either a completely water-wet or oil-wet pore surface throughout the porous media. Whereas, most sedimentary formations are nonuniform because they typically contain separate portions of water- and oil-wet regions and two types of wettability nonuniformity may be distinguished in a sedimentary rock and these are mixed-wettability and fractional-wettability.

Mixed-wettability describes the rocks having only the larger pores being oil-wet and only the smaller pores being water-wet. The fractional-wettability on the other hand describes the rocks having sites of different surface characteristics due to the differences in the type of surface mineralogy.

The Brazilian oil and gas basins, the CAMPOS and SANTOS are classified and identified by the certain types of rocks. These rocks are also identical to the oil and gas basins of Namibia. These oil and gas basins of the two countries are identical as they are and were regarded as one solid rock type during the tectonic and geomorphologic era. As the continent was one continent, GONDWANA. The fossil fuels process, the Biological decaying process and the scientific, chemical processes which took place over centuries on this one rock type of the GONDWANA must then be the same on the two continents, Brazil and Namibia. This then simply means, if the Brazilian oil and gas basis can produce oil and gas, then the Namibia oil and gas must also produce oil and gas.

The following practical experiments were carried out in my study with the different types of sponges representing different types of oil and gas reservoirs as the pores of the sponges are representing the different porosities of reservoirs.

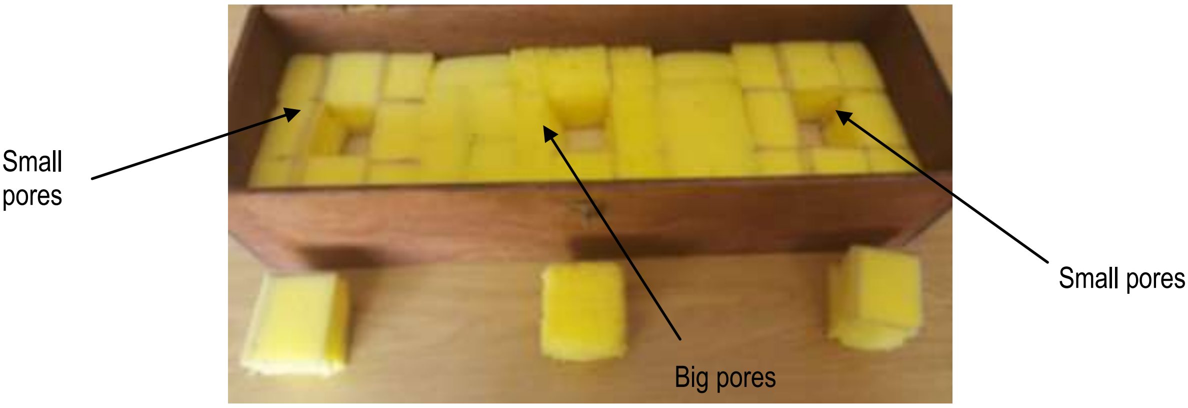


Figure 50: *The different types of reservoirs with different porosities.*

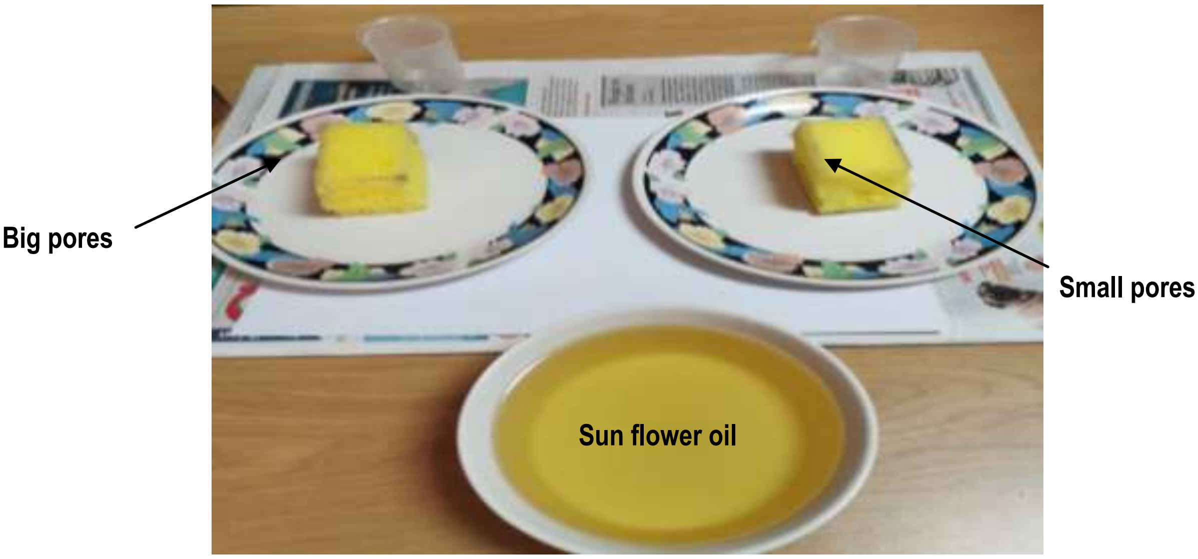


Figure 51: The different types of sponges, representing different reservoirs will be dipped into sunflower. In order to soak the sunflower.

Figure 52: *Soaking different types of sponges, representing different porosities of reservoirs.*

Figure 53: *Excreting the oil from the different sponges, representing different types of reservoirs.*

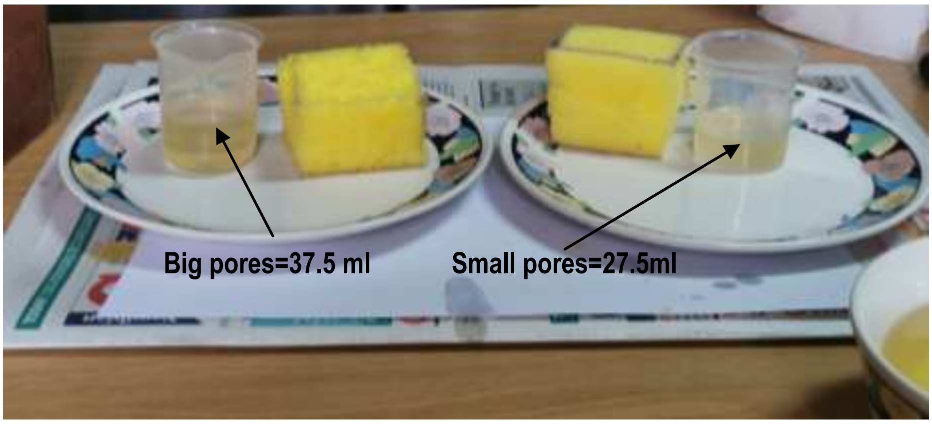


Figure 54: *The volumes of oil, from the different sponges, reservoirs with different porosities.*

Figure 55: *The oil from the centre, central sponge, reservoir is sucked out and the neighbouring reservoirs, sponges are soaked into oil.*

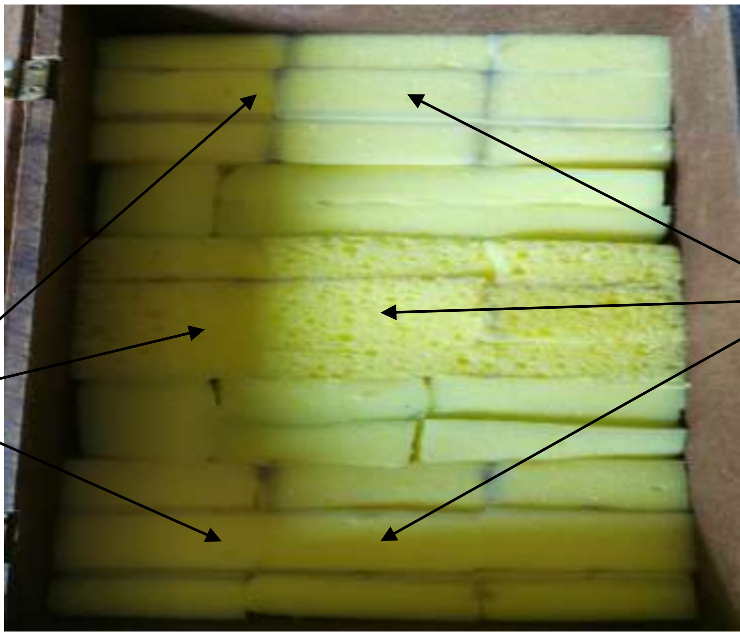


Figure 56: The "Dried up" sponges are placed in their centre positions with the soaked neighbouring sponges and this container is placed for a certain period of time.

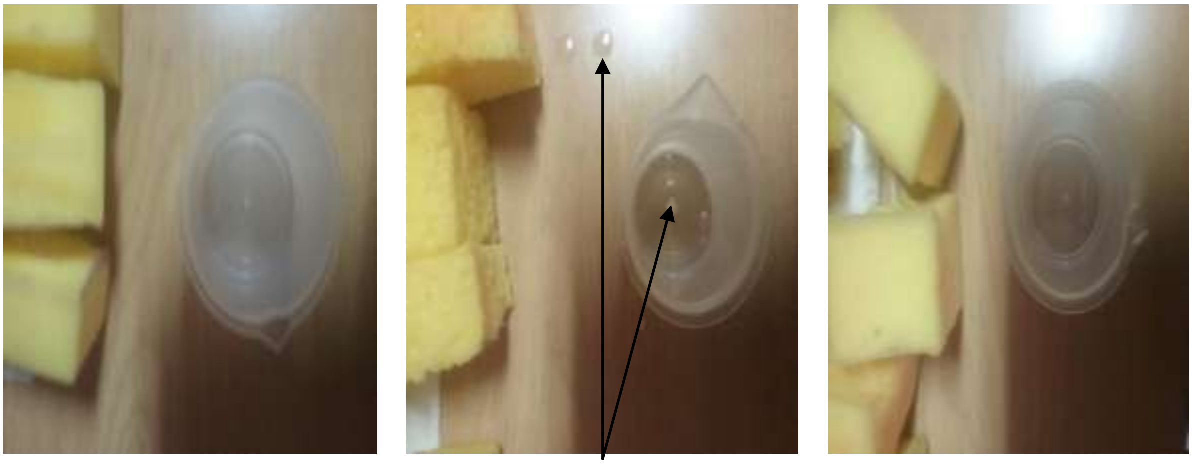
Figure 57: *The "Dried up", centre sponges are oiled again after a certain period of time and the volumes of oil is indicated from the respective sponges.*

The "Dried up sponges did not produce any oil again after a certain period of time in the middle sponges. The container was placed for a period of 7 months and the "Dried up" sponges got wet again. The oil from the neighbouring sponges soaked the "Dried up" sponges as the oil travelled or was channelled from the neighbouring sponges. The quantity, volume of the oil in the "Dried up" sponges was not the same as indicated previously. The middle sponges were wetted with oil but could not produce any volumes of oil in the glass beakers as indicated. The glass beakers of the three sponges in the middle are empty. The oil from the neighbouring sponges did not necessary travel to the middle, "Dried up" sponges via permeability but it only reached the middle, "Dried up" sponges by means of touching each other. In the figure below, Figure 58. The permeability has been improved and the results are as follows.

Figure 58: *The "Permeability" of reservoirs, sponges was improved by connecting the sponges with plastic tubes as indicated in this figure.*

Permeability links, indicated by means plastic tubes, straws

The middle sponges, reservoirs probably containing oil or gas.



No oil from the centred sponge | Oil released from the centred sponge | No oil from the centred sponge

Figure 59: *The "Dried up", centre sponges are oiled again after a certain period of time and the volumes of oil is indicated from the respective sponges. The permeability is adjusted.*

The final reservoir indication, demonstration is more practical as the permeability between the sponges was improved. The sponges will be linked with smaller plastic tubes. This will allow the oil to travel from one sponge to another and this is the way the middle, ''Dried up" reservoirs, will be filled with oil.
This again proves the phenomenon of wetting, filling the "Dried up" reservoirs with oil after a certain period of time. Any reservoir which was completely dried up or drained will always be resuscitated after a certain period of time. It also indicates that any reservoir in the oil and gas basins of any country can be and will accumulate oil or gas and such a reservoir can be drilled in order to produce oil or gas.

Oil and gas reservoirs will keep on producing oil or gas over a longer period of time, unless all the neighbouring reservoirs are also fully drained, drilled out or emptied of oil or gas. The porosity and the quantity of oil or gas of any reservoir will be fully guaranteed for longer periods of time in any oil and gas basins of any country.

The porosity and the effective permeability determine the quantity of volume and the lifespan of any oil and gas reservoirs. The porosity and effective permeability of any two reservoirs will never be identical, hence the quantity of volume of oil and gas and their lifespan will always be different. Any resuscitated oil and gas reservoir will never retain its original oil and gas quantity. Hence it will always produce less quantity of oil and gas. Any reservoir, which does not have pores or zero permeability will never be able to produce any gas or oil.

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APPENDIX A

OIL AND GAS COMPANIES AND THEIR INFORMATION

No	NAME OF COMPANY	TYPE	PHYSICAL ADDRESS	TEL. No/EMAIL/ WEBSITE	CONTINENT	COUNTRY	TOWN	Production	
								Yes	No
1	ACARUS INVESTMENTS (PTY)LTD	PEL	18 Palladium Street, Wkh		AFRICA	NAMIBIA	WINDHOEK		✓
2	ACREP EXPLORACAO PETROLIFERA	PEL			AFRICA	ANGOLA	LUANDA		✓
3	ALUMNI EXPLORATION EAST NAMIBIA	PEL	Fetcham Park House, Lower Road, Fetcham. Leatherhead	+44 1372 371 180/+254 61 23 4656	ENGLAND	SURREY	FETCHAM		✓
4	ALFAPETRO	PEL		447789 826357-0114	UNITED KINGDOM	ENGLAND	LONDON		✓
5	ARCADIA OPERATING LLC	PEL	3811 Turtle Creek Blvd, Dallas, Texas	214 446 1502	NORTH AMERICA	TEXAS	DALLAS		✓
6	AZINAM	PEL	Alexander Forbes House, 5th Floor, Northern Block, 22-23 Fidel Castro Str. Windhoek	+264(0)833 307 300	AFRICA	NAMIBIA	WINDHOEK/ DUBAI		✓
7	BABECCA BUSINESS LINKS	PEL	Rm 2105, Trend Centre, 29-31 Cheung Lee Street	00234 8034946094	ASIA	CHINA	HONG KONG		✓
8	BRITISH PETROLEUM(BP plc)	PEL	St. Jame's, Westminster, London		UNITED KINGDOM	ENGLAND	LONDON		✓
9	BHP BILLION	PEL	10 Marina Boulevard	(65)6421 6000	ASIA	SINGAPORE	MARINA BAY		✓
10	CHARIOT OIL AND GAS LTD	PEL	Praia de Botafogo 501, Sala 207 Torre Corcovado	+55(0)2125469911	SOUTH AMERCIA	BRAZIL	RIO DE JANEIRO		✓
11	CIECO ENERGY SERVICE (UK)LIMITED	PEL	18th Floor, The Broadgate Tower, 20 Primrose Street, London	+44(0)20 7070 5800	UNITED KINGDOM	ENGLAND	LONDON		✓
12	COWAN PETROLEUM AND GAS	PEL	599 Lexington Avenue 20th Floor, New York	+1 646 562 1010	NORTH AMERICA	DISTRICT OF COLUMBIA	NEW YORK		✓
13	ECO ATLANTIC OIL AND GAS LTD	PEL		+44(0)7817295070	NORTH AMERICA	CANADA	TORONTO		✓
14	ECC OIL AND GAS NAMIBIA Energy Contract Company	PEL	7 Lebanon Park, Twickenham, tW1, 3DE, UK	+44(0)20 8891 2905	UNITED KINGDOM	ENGLAND	LONDON		✓
15	ENERGULF RESOURCES	PEL		info@energulf.com	NORTH AMERICA	CANADA	TORONTO		✓
16	ENIGMA OIL AND GAS	PEL	13th Street, Sanlam Centre, Independence Avenue, Windhoek	+26461300470	AFRICA	NAMIIBA	WINDHOEK		✓
17	EXXONMOBIL	PEL	5959 Las Colinas Boulevard, Irving, Texas	75 039 2298	NORTH AMERICA	TEXAS	IRVING		✓
18	FRONTIER RESOURCES INTERNATIONAL	PEL	Unit 514 The Metal Box Factory, 30 Great Guildford Street, London		UNITED KINGDOM	ENGLAND	LONDON		✓

19	GALP ENERGIA	PEL	Rua Tomas da Fonseca A 1600-209 Liboa, Portugal	+351 217 242 500	EUROPE	PORTUGAL	LISBON		✓
20	GLOBAL PETROLEUM	PEL	91 William Street Melbourne, Australia	+61386115333 info@globalpetroleum.com.au	AUSTRALIA	VICTORIA	MELBOURNE		✓
21	GONDWANA PETROLEUM NAMIBIA/EUROPEAN METALS CORP	RL	111 Ahmadi, Crescent Bedford, canda	1-902 802 8847	CANADA	OTARIO	TORONTO		✓
22	GRISHAM ASSETS CORPORATION	PEL			UNITED KINGDOM	ENGLAND	BRITISH VIRGIN ISLANDS		✓
23	HRT PETROLEUM	PEL		www.hrtpetroleum.com.br	SOUTH AMERICA	BRAZIL	RIO DE JANEIRO		✓
24	IMPACT OIL AND GAS	PEL	Griffin House, West Street, Woking	+44 1483 750 588	UNITED KINGDOM	ENGLAND	WOKING		✓
25	JUPITER PETROLEUM NAMIBIA/GLOBAL PETROELUM	PEL	140 Buckingham Palace Road, London	+44 203 875 9255	UNITED KINGDOM	ENGLAND	LONDON		✓
26	LEKOIL E&P	PEL	Churchgate Tower 1, 9th Floor, PC 30 Churchgate street, Victoria Islands, Lagos	+234 1 277 0560	AFRICA	NIGERIA	LAGOS		✓
26	MAUREL PROMOTION NAMIBIA	PEL	51, rue d'Anjou-75008, Paris, France	+33(0)1 53 83 16 00	EUROPE	FRANCE	PARIS		✓
27	MEL OIL AND GAS EXPLORATION	PEL	3039 Amwiler Road NW, Suite 124 Atlanta, GA 30360	770 475 5770	NORTH AMERICA	GEORGIA	ATLANTA		✓
28	METHACARB INVESTMENTS/LETHO RESOURCES CORP	PEL	1177 West Hastings St. Vancouver	(604) 669 0401	CANADA	BRITISH COLUMBIA	VANCOUVER		✓
29	NABIRM ENERGY SERVICES	PEL	Erastus Shapumba Towers, 3rd Floor Unit B3002 Ausspanplatz	info@nabirm.com +26461229187	AFRICA	NAMIBIA	WINDHOEK		✓
30	NAMCOR	PEL	1 Aviation Road, Petroleum House, Windhoek	+264 61 204 5000	AFRICA	NAMIBIA	WINDHOEK		✓
31	NAKOR INVESTMENTS LTD	PEL	Ounpuo 64 Imperium Tower, 306 Aeueooc, Kullpoc		MIDDLE EAST	CYPRUS	LIMASSOL		✓
32	NEPTUNE PETROLEUM (NAMIBIA) LTD	PEL		www.neptune.co.au	AUSTRALIA	VICTORIA	MELBOURNE		✓
33	OS PETRO INCORPORATION	PEL		310 864 8965/801 310 9114	NORTH AMERICA/ AFRICA	NEVADA/ GHANA	LAS VEGAS/ ACCRA		✓
34	ORANTO PETROLEUM	PEL	Plot 8, Water Corporation Way, Off Ligalo Ayorinde, Oniro Estate, Victoria Islands		AFRICA	NIGERIA	LAGOS		✓
35	PAN AFRICAN OIL COMPANY/GONDWANA GOLD INC	PEL	305, 602-11 Avenue SW, Calgary	www.panafricanoil.com	CANADA	ALBERTA	CALGARY		✓
36	PANCONTINENTAL ENERGY	PEL	Level One, 10 Ord Street, West Perth WA	+61 8 6363 7090	AUSTRALIA	AUSTRALIA	WEST PERTH		✓
37	PETROSA	PEL	151 Frans Conradie Drive Parow	+27 21 929 3000 www.petrosa.co.za	AFRICA	SOUTH AFRICA	PAROW		✓
38	PETROTEK	PEL	5935 South Zang Street, Suite 200, Littleton, Colorado	303 290 9414	NORTH AMERICA	COLORADO	LITTLETON		✓
39	PETROBRAS- Brazilian Petroleum Corporation	PEL		www.petrobras.com.br	SOUTH AMERICA	BRAZIL	RIO DE JANEIRO		✓
40	PJ MINING INVESTMENTS	PEL		+44(0)207 7988321	UNITED KINGDOM	ENGLAND	LONDON		✓

41	PREMIER OIL AND GAS	PEL	23 Lower Belgrave Street, London	+44(0)20 7730 1111	UNITED KINGDOM	ENGLAND	LONDON		✓
42	PREVIEW ENERGY RESOURCES NAMIBIA	PEL	32 Schanzen Road, Eros	+264 61 235 638	AFRICA	NAMIBIA	WINDHOEK		✓
43	REGAILS PETROLEUM LIMITED	PEL		+97 15 644 59308	MIDDLE EAST	UNITED ARAB EMIRATES	DUBAI		✓
44	RECONNAISSANCE ENERGY	PEL	Berkeley Square House, Berkeley Square, London		UNITED KINGDOM	ENGLAND	LONDON		✓
45	REPSOL	PEL	C/Mendez Alvaro, 44 Madrid	+34 91 7538100	EUROPE	SPAIN	MADRID		✓
46	RHINO RESOURCES LTD	PEL	Road Town, Tortola, British Virgin Islands	info@rhinoesources ltd.com	UNITED KINGDOM	ENGLAND	ROAD TOWN		✓
47	SENERGY GB LTD	PEL	Kingwells Causeway Ab 15 8Pu, Aberdeen	01224 398 398	SCOTLAND	ABERDEENS HIRE	ABERDEEN		✓
48	SERICA ENERGY NAMIBIA	PEL	48 George Street, London	+44(0)20 7487 7300	UNITED KINGDOM	ENGLAND	LONDON		✓
49	SEZIGYN OIL AND GAS	PEL	Oriel, Bedfordview, Gauteng	+27 11 615 4451 sungusungu@mweb .co.za	AFRICA	SOUTH AFRICA	JOHANNES BURG		✓
50	SIGNET PETROLEUM/SHELL	PEL	Carel van Bylandtlaan 16, 2596 HR, The Hague,Netherlands	+31 70 377 9111	EUROPE	NETHERLAND S	THE HAGUE		✓
51	SHELL ROYAL DUCTH SHELL PLC	PEL	Carel van Bylandtlaan 16, 2596 HR, The Hague,Netherlands	+31 70 377 9111	EUROPE	NETHERLAND S	THE HAGUE		✓
52	SUNGU SUNGU PETROLEUM(PTY)LTD	PEL		+27 11 021 5397	AFRICA	SOUTH AFRICA	JOHANNES-BURG		✓
53	TOTAL	PEL	Tour Coupole 2 Place Jean Millier 92078 Paris	+33(0)1 47 44 45 46	EUROPE	FRANCE	PARIS		✓
54	TOWER RESOURCES PLC	PEL	140 Buckingham Palace Road, Westminster, London	+44 20 7157 9625	UNITED KINGDOM	ENGLAND	LONDON		✓
55	TULLOW OIL	PEL	9 Chiswick park, 566 Chiswick High Road, London	+44(0)20 3249 8801	UNITED KINGDOM	ENGLAND	LONDON		✓
56	UNIMAG TRADING	PEL	Rue du Marche 5, 1204 Geneve, Switzerland	022 310 45 40	EUROPE	SWITZERLAN D	GENEVA		✓
57	UNIVERSAL POWER CORPORATION	PEL	140 Villers Road, Walmer. Port Elizabeth	0415815390	AFRICA	SOUTH AFRICA	PORT ELIZABETH		✓
58	UNX ENERGY CORPORATION	PEL	1800, 715-5th Avenue SW, Calgary	403 984 6430	CANADA	ALBERTA	CALGARY		✓
1	NAMIBIA E SOURCE PETROLEUM	RL							✓
2	BW KUDU/NAMCOR	PL	Rua Lauro Muller 116 Sala 703, Torre do Rio Sul	ir@bwenergy.br +55 21 2244 8350	SOUTH AMERICA	BRAZIL	RIO DE JANEIRO		✓
3	CGO ENERGY	RL	5517 Yeongdong-daero, Gangnam-gu, Seoul	+82 2 3454 1911	ASIA	REPUBLIC OF KOREA	SEOUL		✓

APPENDIX B

AN ARTICLE IN THE LOCAL NEWSPAPER, THE NAMIBIAN ON OIL AND GAS EXPLORATION IN NAMIBIA

22 Friday 8 July 2016 BottomLine THE NAMIBIAN

Status of oil and gas exploration projects

• GABRIEL WIMMERTH

IS IT possible and necessary to construct an oil and gas refinery in Namibia? Twenty-six years after independence, Namibia does not have its own oil and gas refinery.

Too many EPL's on oil and gas have been dished out by the government. The ministry of mines and energy and some Namibians benefited from these EPL's by selling them to the next investor, who then claimed to have all the necessary technological and engineering capabilities, but to date nothing has happened. What is going on?

There are private oil and gas companies along our western coastline, exploring and drilling by applying different types of technologies, but they have been unsuccessful for more than 20 years, and it does not make any sense.

Namibia currently has managed to find gas off its southern coastline, the Kudu Gas Field.

This field is now lying idle, without anything being carried out. Ministers in this industry come and go, and each and everyone is telling us another good story, that in the next two to five years the project will kick off. I really have doubts about the Kudu Gas Field. The porosity of this gas field is around 12%.

Then we had private companies like HRT, Chariot Oil and Gas, Chevron, Sasol, Norsk Hydro and also the Russians, Sintezneftegas Namibia, Arcadia, Enigma, Pancontinental, Ranger, Sasol, Shell, BHP, Petrobras, BP (now Puma), trying their luck to find oil in Namibia since the tenure of former Presidents Sam Nujoma and Hifikepunye Pohamba, but without any success.

The HRT got hold of indications of hydrocarbons, at easy core samples of hydrocarbons, which positively indicated the presence of crude oil. Here again, quick bucks were made by certain individuals, and nothing happened to date.

There are several other companies continuously exploring and drilling along the western coastline for oil and gas. But they do not get any samples of oil or gas. The ministry of energy can provide us with companies, which have been busy along our coastline trying to explore for oil or gas for the past 20 years, and if they have not been successful, give them a red ticket. Let them pack up and go. I also believe the EPL's have a time limit. A non performer must be disqualified immediately.

It has been stated that the age equivalent of sedimentary rock make-up on the Namibian side is thinner than that on the Brazilian side. On the Namibian side, the upper cretaceous sequences are very thick, which suggest an early maturation for the lower cretaceous rocks as compared to the Brazilian side. The continental rift developed asymmetrically between Brazil and Namibia as the Pelotas Basin is characterised by proximal rifts in shallow water, and a wide and very thick rift in deep waters on the African side. There must be oil and gas in Namibia too.

The construction of an oil and gas refinery will cost N$75 billion for a 50 000 to 100 00 barrels a day refinery. Does Namibia as a country have such financial capacity? Not at all.

Namibia as a country is strategically located, and Walvis Bay is one of the leading ports in the world, known for its economical and safety performance. Yes, this is the best location, for an oil and gas refinery, for the southern African region.

POLITICS

This is sometimes the critical factor, which plays a vital role in any decision making. Let us communicate regionally with Angola, as it possesses crude oil. So, the best thing will be to construct a refinery close to the Angolan border or coastline.

So, the question is: Why still selling or providing EPL's in this industry? Stop them all, and let us concentrate on Angola. Namibia might fork out US$5 billion from the national budget, or private companies and local businessmen will grab the opportunity.

We are going to rely on investors and international companies on this project. There are 13 refineries in Brazil, a country with 210 million people, compared to SADC, which has a population of 277 million people. South Africa has the majority of 55 million inhabitants, and the country has six oil and gas refineries. Does Namibia, with a population of 2.4 million people, need to construct a refinery? I guess the answer to this is: Yes, we do need to construct a refinery, as this will elevate us on the industrial scale, on par with the rest of Africa and the world.

Gabriel Wimmerth is a student at Atlantic International University in Honolulu, Hawaii.

PARTNERS ... The National Commission for Research, Science and Technology(NCRST) and the SME Bank Limited have partnered to support Namibia's SME sector through the intensification of research, development, mentorship and business development support programmes. SME bank's CEO Tawanda Mumvuma (left) and NCRST's CEO Eino Mvula are pictured at the official signing ceremony yesterday.

Photo: Contributed

APPENDIX C

Atlantic International University

SURVEY QUESTIONNAIRE

SURVEY QUESTIONNAIRE FOR EMPLOYERS, OIL AND GAS COMPANIES

BACKGROUND

Does the quantity of pores determine the quantity of oil and gas inside a reservoir?

The purpose, goal of the questionnaire is to collect data from the oil and gas companies for the Doctorate research study. The researcher attempts to determine from the oil and gas companies that the porosity of a reservoir determines the quantity of oil and gas inside a reservoir as well as the lifespan of such a reservoir.

The oil and gas companies are edge to confidently and reliably provide information on the types of oil and gas reservoirs they have drilled on the Namibia coastline, offshore and onshore as well as any other oil and gas reservoir they have successfully drilled and obtained oil or gas. The information provided by the oil and gas comp0any by means of this questionnaire will used in order to determine the porosity of an oil and gas reservoir and its quantity of oil and gas released or produced. The results of the study, experimental approach will be used to determine the actual reality of the quantity of oil and gas produced by any porous reservoir.

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INSTRUCTIONS TO COMPLETE THE QUESTIONNAIRE

(i) Please complete the questionnaire to the best of your ability?
(ii) Indicate your choice with a (✓) in the appropriate box, where applicable. In some cases you may mark more boxes than one response.
(iii) There are no right or wrong in providing this questionnaire.
(iv) The completion of the questionnaire will approximately take you 30 minutes.
(v) This is the opportunity for your company to participate and complete this questionnaire as the outcome of this study, scientific analysis will certainly benefit your company in the oil and gas industry.
(vi) The questionnaire must be completed and returned by or before 30 September 2015 as this will enable the researcher to adhere to the timeframe of this study and submit the thesis on time to Head office in United States of America, Hawaii, Honolulu.

PART A: DEMOGRAPHICS

1. Type of the company: *Tick only one.*

(i) oil ☐
(ii) gas ☐
(iii) oil and gas ☐

2. Your gender: *Tick only one.*

(i) male ☐
(ii) female ☐

3. Your position in the company. *Tick only one.*

(i) President ☐
(ii) Managing Director ☐
(iii) Chief Executive Officer ☐
(iv) Supervisor ☐

4. From which country is your company? *Tick one block.*

(i) Brazil ☐
(ii) Portugal ☐
(iii) USA ☐
(iv) Name the country:... ☐

5. **How many crude oil reservoirs, did you company drill within the past 10-40 years?**
Tick one block.

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

6. **How many natural gas reservoirs did your company drill within the past 10-40 years?**
Tick one block.

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

7. **How many crude oil reservoirs were successfully drilled and are currently producing?**
Tick one block.

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

8. **What is the total quantity of natural gas do the above mentioned reservoirs produced?**
Tick one block.

(i) 10 Billion barrels ☐
(ii) less than 10 Billion barrels ☐
(iii) more than 10 Billion barrels ☐

9. **How many natural gas reservoirs were successfully drilled and are currently producing?**
Tick one block.

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

10. **What is the total quantity of natural gas do the above mentioned reservoirs produced?**
Tick one block.

(i) 10 Billion metric tons ☐
(ii) less than 10 Billion metric tons ☐
(iii) more than 10 Billion metric tons ☐

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PART B: THIS SECTION WILL DETERMINE THE SUCCESSFUL DRILLING OF OIL AND GAS RESERVOIRS IN ANY COUNTRY OF A PARTICLUAR COMPANY?

1. In which country did your company start drilling for crude oil or natural gas for the first time? *Tick one block.*

(i) Brazil ☐
(ii) Portugal ☐
(iii) USA ☐
(iv) Name the country:......................................

2. Which country produced crude oil or natural gas from their basins, when drilling took place? *Tick more than one block.*

(i) Brazil ☐
(ii) Namibia ☐
(iii) Venezuela ☐
(iv) Angola ☐

3. How many reservoirs did your company drill in the above mentioned country? *Tick one block.*

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

4. How many reservoirs were successful drilled and producing oil or gas? *Tick one block.*

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

5. How many reservoirs were wincat reservoirs? *Tick one block.*

(i) 5 ☐
(ii) 10 ☐
(iii) less than 5 ☐
(iv) more than 10 ☐

6. **What is the type of rock on which your company was drilling for crude oil or natural gas in the above mentioned countries?** *Tick more than one block.*

(i) Sedimentary ☐
(ii) Igneous ☐
(iii) Metamorphic ☐
(iv) All three of the above ☐

7. **Which country is the largest crude oil or natural gas producer in the world?** *Tick only one block.*

(i) Canada ☐
(ii) United States of America ☐
(iii) United Arab Emirates ☐
(iv) Russia ☐
(v) Saudi Arabia ☐

8. **What is the volume of crude oil the above mentioned country is producing?** *Tick only one block.*

(i) 500 million metric tonnes ☐
(ii) 900 million metric tonnes ☐
(iii) more than 500 million metric tonnes ☐
(iv) more than 900 million metric tonnes ☐

9. **What is the volume of natural gas the above mentioned country is producing?** *Tick only one block.*

(i) 500 million barrels tonnes ☐
(ii) 900 million barrels tonnes ☐
(iii) more than 500 million barrels tonnes ☐
(iv) more than 900 million barrels tonnes ☐

10. **Which country is producing crude oil or natural gas from shale processing?** *Tick more than one block.*

(i) Canada ☐
(ii) United States of America ☐
(iii) United Arab Emirates ☐
(iv) Russia ☐
(v) Saudi Arabia ☐

11. Which African country is the largest crude oil and natural gas producer? *Tick only one block.*

(i) Nigeria ☐
(ii) Republic of Congo ☐
(iii) South Africa ☐
(iv) Angola ☐

12. What are the names of oil and gas exporting organizations of countries in the world?
Tick more than one block.

(i) OPEC ☐
(ii) IEA ☐
(iii) AU ☐
(iv) NATO ☐

PART C: THIS SECTION SEEKS FOR ROCK TYPE, LITHOSPHERE OF THE OIL AND GAS BASINS IN ANY COUNTRY THE COMPANY HAS SUCCESFULLY DRILLED AND PRODUCED OIL OR GAS.

1. What are the types of rocks in the crude oil and natural gas basins your company drilled in any country? *Tick more than one block.*

(i) Sedimentary ☐
(ii) Metamorphic ☐
(iii) Mixture of the above two ☐
(iv) Name the type of rocks...

2. What drilling method did your company used in extracting crude oil or natural gas successfully? *Tick one block.*

(i) Vertical ☐
(ii) Horizontal ☐
(iii) Both of the above ☐
(iv) Name any other method...

3. Which reservoir simulation software does your company currently used in projecting reservoir models? *Tick more than one block.*

(i) Eclipse ☐
(ii) Saphir ☐
(iii) Bothe of the above mentioned ☐
(iv) Name any other software..

4. What is the device called from the vessel,, which is used to radar waves towards the reservoir? *Tick only one block.*

(i) Microphone ☐
(ii) ☐
(iii) Hydrophone ☐
(iv) ☐

5. What is the device called which is receiving the reflected waves from an oil and gas reservoir? *Tick only one block.*

(i) Hydrophone ☐
(ii) Geophone ☐
(iii) Microphone ☐
(iv) Loudspeaker ☐

6. What is the shape of pores in any oil and gas reservoir? *Tick only one.*

(i) Pyramid ☐
(ii) Rectangular ☐
(iii) Spherical ☐
(iv) all of the above ☐

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PART D: THIS SECTION WILL SHED MORE LIGHT ON THE AVAILABILITY OF OIL AND GAS IN THE OIL AND GAS BASINS OF NAMAIBIA.

1. Does your company drill for crude oil or natural gas onshore? *Tick one block.*

(i) Yes ☐
(ii) No ☐

2. Does your company drill for crude oil or natural gas offshore? *Tick one block.*

(i) Yes ☐
(ii) No ☐

3. In which crude oil and natural gas basins offshore was/is your company drilling for oil or gas in Namibia?

(i) Namibe ☐
(ii) Walvis ☐
(iii) Luderitz ☐
(iv) Orange ☐

4. Which method does/did your company use (d) in drilling for oil or gas? *Tick one block.*

(i) Vertical ☐
(ii) Horizontal ☐
(iii) Both of the above mentioned. ☐
(iv) Name the appropriate method of drilling...

5. Do Namibia oil and gas basins contain sufficient oil onshore or offshore? *Tick one block.*

(i) offshore ☐
(ii) onshore ☐

6. Do the Namibia oil and gas basins contain sufficient gas onshore or offshore? *Tick one block.*

(i) offshore ☐
(ii) onshore ☐

7. Do the oil and gas reservoirs in Namibia, onshore or offshore have vast volumes of oil and gas? *Tick one block.*

(i) offshore ☐
(ii) onshore ☐

8. **What are the total quantities, volumes of oil in the oil reservoirs onshore?** *Tick one block.*

(i) 20 Billion metric tons ☐
(ii) less than 20 Billion metric tons ☐
(iii) more than 20 Billion metric tons ☐
(iv) Mention the quantity...

9. **What are the total quantities, volumes of oil in the oil reservoirs offshore?** *Tick one block.*

(i) 20 Billion metric tons ☐
(ii) less than 20 Billion metric tons ☐
(iii) more than 20 Billion metric tons ☐
(iv) Mention the quantity...

10. **What is the lifespan of the oil reservoirs offshore in the oil basins of Namibia?** *Tick one block.*

(i) 30 years ☐
(ii) 50 years ☐
(iii) less than 30 years ☐
(iv) more than 30 years ☐
(n) more than 50 years ☐

11. **What is the lifespan of the oil reservoirs onshore in the oil basins of Namibia?** *Tick one block.*

(i) 30 years ☐
(ii) 50 years ☐
(iii) less than 30 years ☐
(iv) more than 30 years ☐
(n) more than 50 years ☐

12. **What is the lifespan of the gas reservoirs offshore in the oil basins of Namibia?** *Tick one block.*

(i) 30 years ☐
(ii) 50 years ☐
(iii) less than 30 years ☐
(iv) more than 30 years ☐
(n) more than 50 years ☐

13. **What is the lifespan of the natural gas reservoirs onshore in the gas basins of Namibia?** *Tick one block.*

(i) 30 years ☐
(ii) 50 years ☐
(iii) less than 30 years ☐
(iv) more than 30 years ☐
(n) more than 50 years ☐

PART E: THIS SECTION WILL PROVIDE ANSWERS TO QUESTIONS OF THE LIEFSPAN OF ANY OIL AND GAS RESERVOIR.

1. Is it possible for a depleted oil and gas reservoir, when oil or gas has been fully extracted, to be resuscitated? *Tick one block.*

(i) Yes ☐
(ii) No ☐

2. Will a resuscitated oil and gas reservoir, produce oil and gas again? *Tick one block.*

(i) Yes ☐
(ii) No ☐

3. Will a resuscitated oil and gas reservoir produce the same quantity of oil and gas as firstly or previously produced? *Tick one block.*

(i) Yes ☐
(ii) No ☐

4. Is it possible for oil and gas basins to be completely "dried up"? *Tick one block.*

(i) Yes ☐
(ii) No ☐

5. From where does an empty, "dried up "oil and gas reservoir get oil or gas again? *Tick more than one block.*

(i) The top of the reservoir ☐
(ii) Bottom of a reservoir ☐
(iii) Neighbouring reservoirs ☐
(iv) Fossilization takes place faster in the same reservoir and produce oil or gas. ☐
(v) Harvesting, production of oil and gas takes place in the same reservoir. ☐

6. Will the tectonic theory continue or movement of continents continue from the current locations of continents? *Tick one block.*

(i) Yes ☐
(ii) No ☐

END OF QUESTIONNAIRE

Please be so kind and email the completed questionnaire to the following email address:

gkwim.ike@gmail.com

Thank you for taking time from your busy schedule in completing this questionnaire. Your dedicated cooperation is highly appreciated.

OIL AND GAS RESERVOIRS

OIL AND GAS RESERVOIRS are producing oil or gas depending on their porosity and permeability. A reservoir which does not have pores, small cavities will not be able to contain oil or gas. The quantity of oil and gas in reservoirs can vastly be determined by their porosity and permeability. The lifespan of any reservoir also depends on the quantitative availability of oil and gas, hence any "Dried up", fully depleted reservoir can be resuscitated. The Tectonic Theory of continents demonstrated over centuries that continents with identical lithosphere can produce oil and gas.

Gabriel Keafas Kuku Player Wimmerth is a graduate fellow from the University of Namibia with Bachelor for Science(BSc), Higher Education Diploma (HED Sec) and a Bachelor for Education(BED) as well as the Masters in Science(MSc) and Doctorate in Petroleum Engineering(PENG) from the Atlantic International University in Hawaii, USA.

Gabriel Wimmerth was also a teacher and lecturer at different institutions of higher learning.

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