Sudan University of Science & Technology

College of Oil & Mining Engineering

Exploration Engineering Department

CALCULATIONS OF OIL RESERVE - BENTIU FORMATION IN JAKE OIL FIELD, USING VOLUMETRIC METHOD

حساب الإحتياطي النفطي لتكوين بانتيو في حقل جيك النفطي بإستخدام الطريقة الحجمية

A Project Submitted In Partial Fulfillment For The Requirements Of The Degree Of B-TECH (Honor) In Exploration Engineering

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الآيـه

قال تعالى: ﴿...وَقُل رَّبِّ زِدْنِى عِلْمًا﴾

(طه ١١٤)

DEDICATION

I begin my humble research by thanking Allah for inspiring me to be able to write this research

To the beacon of knowledge and the chosen Imam, to the master of creation, our honorable messenger, our prophet Muhammad, may Allah bless him and grant him peace.

To the one who nursed me love and tenderness, to the symbol of love and healing balm to the white heart (dear mother).

To give me a drop of love To the one who doses the cup empty, to the one who worked hard and did his best to give us a moment of happiness, to the one who moved thorns from my wy to pave the path of knowledge for me, to the big heart (my dear father).

To the angels of the earth, the anemones, who embraced me and planted roses in my path (my brothers).

To the comrades of the path, the builders of the future, the truest and most wonderful (my friends).

To everyone who enlightened the mind of others with his knowledge or guided the correct answer to the confusion of their questioners, so by their grace they showed the humility of the scholars and their generosity of the knowers (my teachers), especially my supervisor (Dr. Adel Abdelmajid).

I say to them: You have endowed me with life, hope and upbringing on the passion for knowledge.

I ask His Almighty, Allah acceptace and succes, and to guide me to what He loves and is pleased with.

ACKNOWLEDGEMENT

Thanks to everyone who taught us and worked hard and sacrificed everything dearly and precious in order to reach this stage, starting with our parents and passing through all teachers and reaching the administration of this prestigious educational institution, Sudan University of Science and Technology in general, which gave us a lot, especially the College of Petroleum and Mining Engineering and its management represented by the Dean, heads of departments, teaching staff, employees and others, and all thanks to the honorable father, Dr. Supervisor Adel Abdul Majid, who did not spare us anything of his vast knowledge.

ABSTRACT

The study area (Jake oilfield) is located on the Western Escarpment of the Fula Subbasin of the Muglad Basin, which is bounded by the latitudes 11°20’ and 11°36′ N and longitudes 28° 30′ and 29° 36′ E. This oilfield has been structurally subdivided into three main structures of Jake, Jake Central and Jake South. The goal of this study is to identify reservoir type, and calculate the latent and recoverable oil reserves in “Jake oil field“, to achieve this goal in successful way the information and data of four wells (Jake South -3, Jake South -4, Jake South -7 and Jake South -8), were made available, then the evaluation of the wells data has been processed using the interactive petrophysic software (IP 3.5) version. The wireline logging data had been carefully evaluated during the process of the data application, and data quality was thought to be good. For the Reservoir identification the most useful indicator was obtained from the behavior of the gamma ray, density, and neutron logs. The thickness of pay zone in the well (Jake South-8) was determined, its equal 26.2 ft, The water oil contact in the depth 1503 m. The reservoir area has been calculated using (ArcMap 10.4.1) version, and found it is equal 6 acres. The latent and recoverable oil reserve existing in reservoir are calculated by using volumetric method, and founded: the latent oil reserve equal 253426.6221 STB, and the recoverable oil reserve equal 51597.66026 STB.

المستخلص

تقع منطقة الدارسة (حقل جيك النفطي) في حوض الفولا الفرعي لحوض المجلد بين خطي عرض $11° 20'$ و$11° 36'$ شمال وطول $28° 30'$ و $29° 36'$ شرق ، يقسم هذا الحقل النفطي من حيث التركيب إلي ثلاثة تراكيب هي جيك ، جيك وسط و جيك جنوب ، تهدف هذه الدارسة لتحديد نوعية المكمن وحساب الإحتياطي الكامن والإحتياطي القابل للإستخراج في حقل جيك النفطي ، ومن أجل الوصول لهذا الهدف بصورة ناجعة تمت الأستعانة بمعلومات وبيانات أربعة من الآبار في منطقة الدارسة هي (جيك جنوب -3 و جيك جنوب -4 و جيك جنوب 7 و جيك جنوب -8) تمت المعالجة لبيانات هذه الآبار ببرنامج:

interactive petrophysis software (IP 3.5) version. وتم تحديد المكمن من معطيات نتائج تسجيلات أشعة قاما ، والكثافة والنيوترون في البئر (جيك جنوب -8). إلي جانب ذلك تم تحديد سمك الطبقة الحاملة للزيت بصورة ناحجة في البئر (جيك جنوب -8) ، ووجد أنها تساوي ٢٦,٢ قدم ، ونقطة إتصال النفط مع الماء في العمق ١٥٠٣ متر. وتم حساب مساحة المكمن بإستخدام (ArcMap 10.4.1 version) ، ووجد أنها تساوي ٦ فدان. وتم حساب المسامية بإستحدام برنامج IP وتسجيلات النيوترون والكثافة ، تم حساب تشبع الماء بإستخدام برنامج IP ومعادلة آرشي. وتم حساب الإحتياطي الكامن والإحتياطي القابل للإستخراج الموجود في المكمن بإستخدام الطريقة الحجمية ووجد أن: الإحتياطي الكامن في الموقع يساوي 253426.6221 STB ، أما الإحتياطي القابل للإستخراج يساوي: 51597.66026 STB.

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LIST OF ABBREVIATIONS

IP	Interactive Petrophysic Software
SRR	Speculative Recoverable Resources
PIIP	Total Petroleum Initially-In-Place
UR	Ultimate Recovery
PR	Potential Recovery
PI	Proved Reserve
SPE	Society of Petroleum Engineers
WPC	World Petroleum Congress
AAPG	American Association of Petroleum Geologists
SPEE	Society of Petroleum Evaluation Engineers
OUT	Oil-Up-To
ODT	Oil-Down-To
GDT	Gas-Down-To
P2	Probable Reserve
WUT	Water-Up-To
P3	Possible Reserves
SPRCS	Sudan Petroleum Resources Classification System
SRR	Speculative Recoverable Resources
EPSA	Exploration and Production Sharing Agreement
IOR	Improved Oil Recovery
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
TRR	Technically Recovered Resources
GOR	Gas to Oil Ratio
SCF	Standard Cubic Feet
STB	Stock Tank Barrel
API	American Petroleum Institute
SG	Specific Gravity
CASZ	Central African Shear Zone
SR	Speculative Resources
EV	Expected Value
FVF	Formation Volume Factor

CHAPTER ONE

INTRODUCTION

1.1 GENERAL CONCEPTS

The reservoir study of a specific field is a complete study process to match the behavior of the past, predict the future and recommend the best possible way to benefit from the reservoir.

Hydrocarbons are usually found under the influence of high pressures and high temperatures in traps or in the form of gatherings of various shapes surrounded by rocks so as not to escape from these traps.

Oil is often found in sedimentary rocks, which consist of sand or cohesive rocks such as limestone and dolomite .

The reservoir is defined as that part of the trap that contains hydrocarbons, which must be connected to each other and have good mobility in the reservoir.

This project will deal with calculating the volume of hydrocarbons present in Jake oil field.

The methods used to calculate the volume of hydrocarbons are the volumetric method, the material balance method, the decline curves Analysis method, and the reservoir simulation method.

The main objective of the study is to calculate the latent and recoverable oil reserves in "Jake oil field" And that is for its economic importance to the country.

1.2 INTRODUCTION

Sudan is located in northeastern Africa, it is bordered by seven countries, Oil and gas sector is an important extractive sector in Sudan, high hydrocarbon potential areas in Sudan has been divided to 24 blocks including area of study (Jake oilfield block-6).

The Muglad Basin area is a flat plain of low relief surrounded by hilly crystalline rocks exposed to the northeast in the Nuba Mountains, isolated basement and Mesozoie sedimentary outcrops in the north and basement rocks in the southwest, With the exception of some isolated sandstone outcrops of Miocene to Pliocene age cast of the Muglad town, the basin area is covered in the north by stabilized sand dunes locally veneered by silt or clay.

Location: The Muglad basin idealizes part of Central Africa Rift System. It is oriented NW-SE. The basin is situated within Sudan and South Sudan, and it covers area of approximately 120,000km².

The Muglad basin is characterized by thick non-marine clastic sequence of Late Jurassic - Early Cretaceous and Neogene age and it contains a number of hydrocarbon accumulations of various sizes, the largest of which are the Heglig and Unity oil fields. A total of 44 wells have been drilled in the Jake oilfield. There are four proven hydrocarbon-bearing formations: Ghazal, Zarqa, Bentiu and Abu Gabra, and two producing formations: Bentiu and Abu Gabra.

The study area (Jake oilfield) is located on the Western Escarpment of the Fula Subbasin of the Muglad Basin, which is bounded by the latitudes 11°20’ and 11°36′ N and longitudes 28° 30′ and 29° 36′ E. This oilfield has been structurally subdivided into three main structures of Jake, Jake Central and Jake South.

The goal of this study is to identify reservoir type, and calculate the latent and recoverable oil reserves in “Jake oil field“, to achieve this goal in successful way the information and data of four wells (Jake South -3, Jake South -4, Jake South -7 and Jake South -8), were made available, then the evaluation of the wells data has been processed using the interactive petrophysic software (IP 3.5) version. The wireline logging data had been carefully evaluated during the process of the data application, and data quality was thought to be good.

For the Reservoir identification the most useful indicator was obtained from the behavior of the gamma ray, density, and neutron logs. The neutron - density cross plot is the best method for lithology and porosity identification.

The reservoir area has been calculated using (ArcMap 10.4.1) version, and found it is equal 10 acres.

1.3 PROBLEM STATEMENT

Calculate the volume of hydrocarbons present in Jake oil field.

1.4 OBJECTIVES

The main objective of the study is to calculate the latent and recoverable oil reserves in “Jake oil field“ And that is for its economic importance to the country.

1.5 METHODOLOGY

For the Reservoir identification the most useful indicator was obtained from the behavior of the gamma ray, density, and neutron logs.

The pay zone in the well (Jake South-8) was determined, its equal 26.2 ft

The water oil contact in the depth 1503 m.

The reservoir area has been calculated using (ArcMap 10.4.1) version, and found it is equal 10 acres.

The evaluation of the wells data has been processed using the interactive petrophysic software (IP 3.5) version.

Porosity are calculated by using IP software and neutron-density combination.

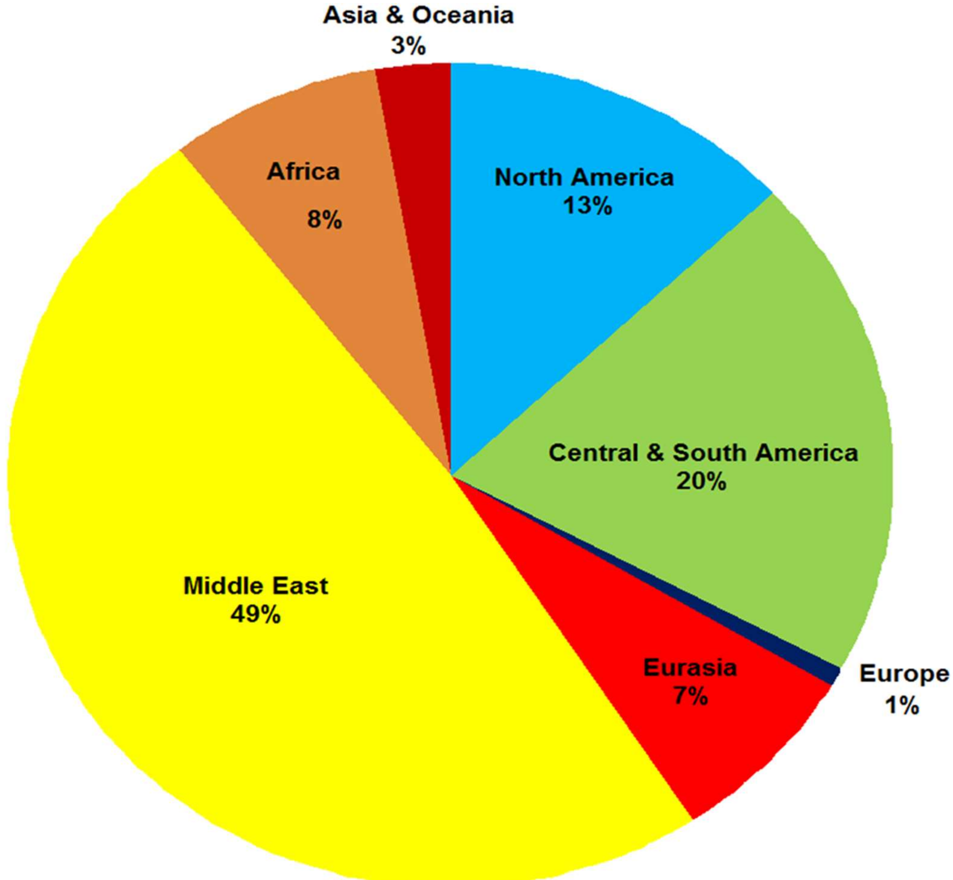
Water saturation are calculated by using IP software and archie's equation.

The latent and recoverable oil reserve existing in reservoir are calculated by using volumetric method.

CHAPTER TWO

BACKGROUND
AND LITERATURE REVIEW

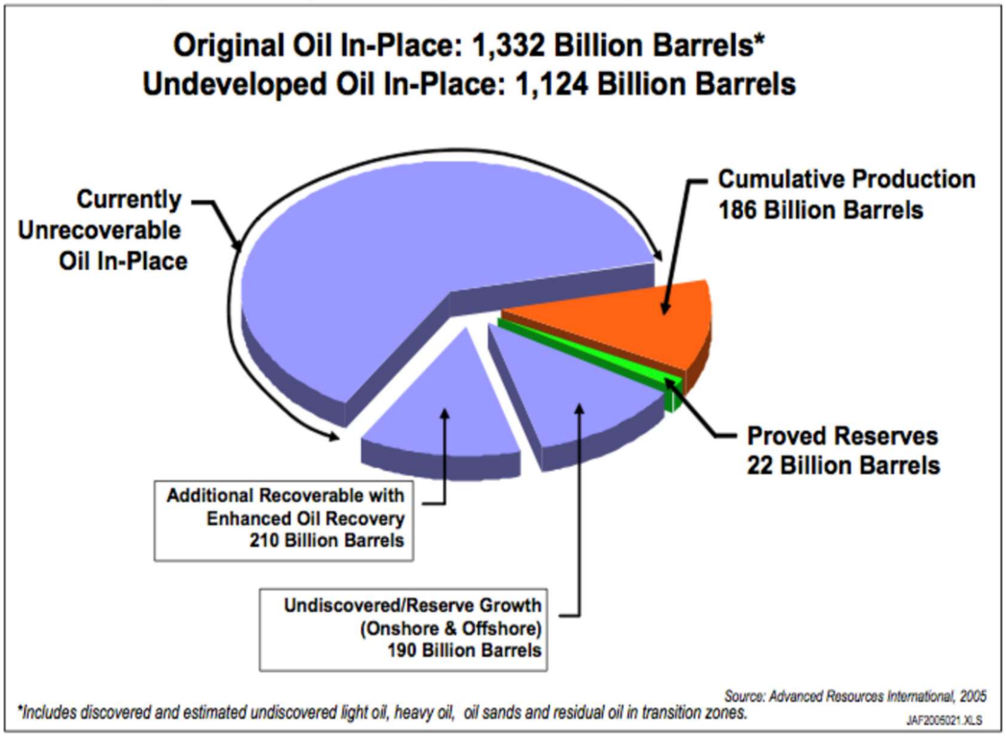
(Fig 2.1) World oil reserves by region



Data source: US Energy Information Administration (2013)

Reserves are the estimated quantities of crude oil, which are, with reasonable certainty to be recoverable

(Fig 2.2) Original developed and undeveloped domestic oil resources



Source: Advanced Resources International, 2005

2.1 PURPOSE OF RESERVES ESTIMATION

Estimates of petroleum reserves are prepared for a specific reason. The purpose of the estimate will in large measure dictate the method employed and the time spent in making the estimate. The estimate is seldom an end in itself, but is merely the first step in a series of calculations for the purpose of gaining knowledge that will influence current or future decisions.

Some of the more important reasons for such estimates are as follows:

2.1.1 For corporate purposes

in setting depletion and depreciation rates, (a) for corporate accounting and (b) for tax accounting.

2.1.2 For tax purposes

(a) income tax, (b) inheritance tax and (c) county or state taxes.

2.1.3 For financing purposes

(a) bonds and debentures, and (b) bank loans.

2.1.4 For purposes of purchase or sale of companies or properties

(a) outright sale or purchase, (b) merger and (c) consolidations.

2.1.6 For budget purposes

(a) development drilling, (b) production income and (c) refinery runs.

2.1.6 For purposes of unitization or joint operations division of ownership

in a field or property.

2.1.7 For purposes of gas sales

in interstate commerce, (a) for determination of production rates and (b) for price determination.

2.2 Resources Versus Reserves:

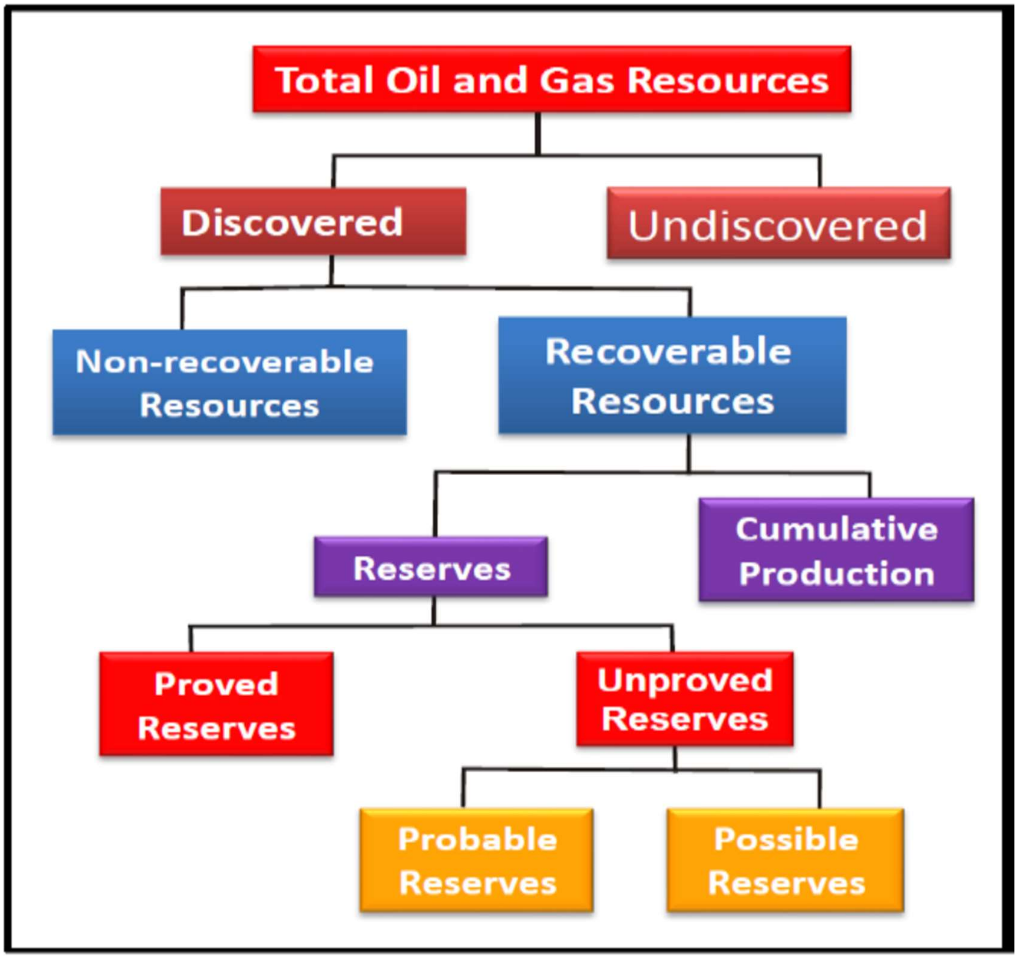
• Resources are the total estimated in-place quantities of petroleum at a specific date to be contained in, or that have been produced from known accumulations. Plus those speculative quantities yet to be discovered.

• Reserves are the estimated remaining quantities of petroleum anticipated to be commercially recoverable from known accumulations by established operating practices, at a specific date, under existing economic conditions and complying with the current Government regulations.

2.2.1 The Term (Resources) is:

Generally applied to all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced.

2.3 Resources Classification:



(Fig 2.3) Resources flow chart
(Conceptual scheme for oil and gas resources and reserves)

The following definitions apply to the major subdivisions with the resource classification:

2.3.1 Total Petroleum Initially –In– Place (PIIP):

Is all quantities of petroleum that are estimated to originally in naturally occurring accumulation, discovered and undiscovered, before production.

2.3.2 Discovered (PIIP):

Is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. The discovered resources comprise commercial and sub-commercial hydrocarbon quantities that have been deciphered based on known technology under specified economic conditions which are generally accepted as being reasonable outlook for the future. The commercial and sub-commercial accumulations are referred to as reserves and potentially recoverable resources, respectively.

2.3.3 Undiscovered (PIIP):

Is the quantity of petroleum estimated, as given date, to be contained within accumulations yet to be discovered.

2.3.3 Speculative Recoverable Resources (SRR):

defined as the undiscovered resources at a specific date to be contained in unproven traps, undrilled provinces, structures or deeper reservoirs underlying productive fields, In which Case, the geological conditions are believed to be favourable for the accumulation of petroleum which, if present, may eventually be recovered.

Since there are uncertainties associated with the quantities of such resources, SRR are generally determined probabilistically based on a conceptual geological model.

The estimated quantities are subdivided into Low, Expected and High values, the Low and High values are associated with confidence or probability levels of at least 85% and 15% respectively.
This means there are 85% and 15% probabilities that the corresponding estimated quantities would be recovered.
The mostlikely case, the Expected values the estimated quantities which will be recovered with confidence levels of at least 50%.

2.3.5 Unrecoverable Resources:

Are that portion of either discovered or undiscovered PIIP evaluated, as a given date, to be unrecoverable by currently defined projects.
A portion of these quantities may be become recoverable in the future as commercial circumstance change, technology is developed or additional data are acquired.

2.3.6 Cumulative Production:

It is defined as the total quantities of petroleum that have been produced at a specific date.

2.3.7 Contingent Resources:

Are those quantities of petroleum estimated, as given date, to be potentially recoverable from known accumulations by application of development projects not currently considered to be commercial, it have associated chance of development.
Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist.

Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

2.3.8 Prospective Resources:

Are those quantities of petroleum estimated as given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of geological discovery and chance of development.

Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

2.3.9 Ultimate Recovery (UR):

This is defined as the discovered resources anticipated to be commercially recoverable from known accumulations by established operating practices at a specific date, under existing economic conditions and current Government regulations.

The Ultimate Recovery is the sum of the Cumulative Production and Reserves.

2.3.10 Potential Recovery (PR):

It is defined as the discovered resources that are recoverable, but not producible at a specific date due to economic, political, environmental or technological reasons.

The PR is equivalent to the Contingent Resources of the SPE/WPC/AAPG/SPEE (2007) resources classification system.

The designation for proved, probable and possible categories in the Potential Recovery (PR) are also P1, P2 and P3, respectively. This is to avoid the complex approaches like P4, P5 and P6 used by some super majors, or CI, C2 and C3as in the SPE/WPC/AAPG/ SPEE (2007) resources classification system. The technical definitions for, and the confidence levels of these PR subcategories P1, P2 and P3 are, therefore, the same for the reserves, except that they are not "currently" Producing for the above mentioned reasons. The PR is likely to be developed in the "near future" when the conditions become favourable.

2.3.11 The Potential Recovery (PR) may include:

• Accumulations being held in an inventory; such as marginal fields, relinquished fields.

fields under dispute, or reservoirs with inconclusive data.

• Accumulations that will probably he commercially recoverable in the near future/short term, under currently forecasted conditions, but further evaluation work will be required before they can be qualified as Ultimate Recovery. Examples of such accumulations are new discoveries undergoing appraisal or fields under negotiation.

• Accumulations that have no plans for developments in the near future/short term, because they are judged to be sub-commercial under currently forecasted conditions based on their size, location, technology requirements or economies.

• Accumulations contained in a non-producing reservoir due to:

a) Adverse parameters such as very low or erratic porosity development, low permeability, high pressure and high temperature reservoir conditions.

B) Unfavorable petroleum parameters such as heavy, high pour point or high viscosity oil.

C) Extreme non-hydrocarbon content, for example CO_2, and H_2S.

D) Impact of improved oil recovery (IOR) methods that changes characteristics of the fluid in the reservoir through injection steam, gas or chemicals.

2.3.12 Reserves:

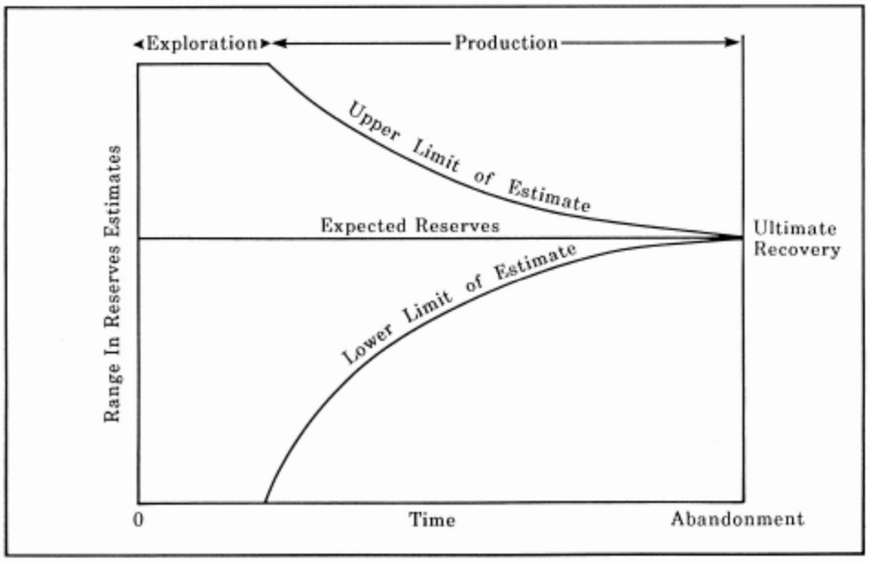
Reserves are estimated volumes of crude oil, condensate, natural gas, natural gas liquids, and associated substances anticipated to be commercially recoverable from known accumulations from a given date forward, under existing economic conditions, by established operating practices, and under current government regulations.

2.3.13 Reserves must satisfy criteria:

Discovered, recoverable, commercial and remaining based on the development projects applied.

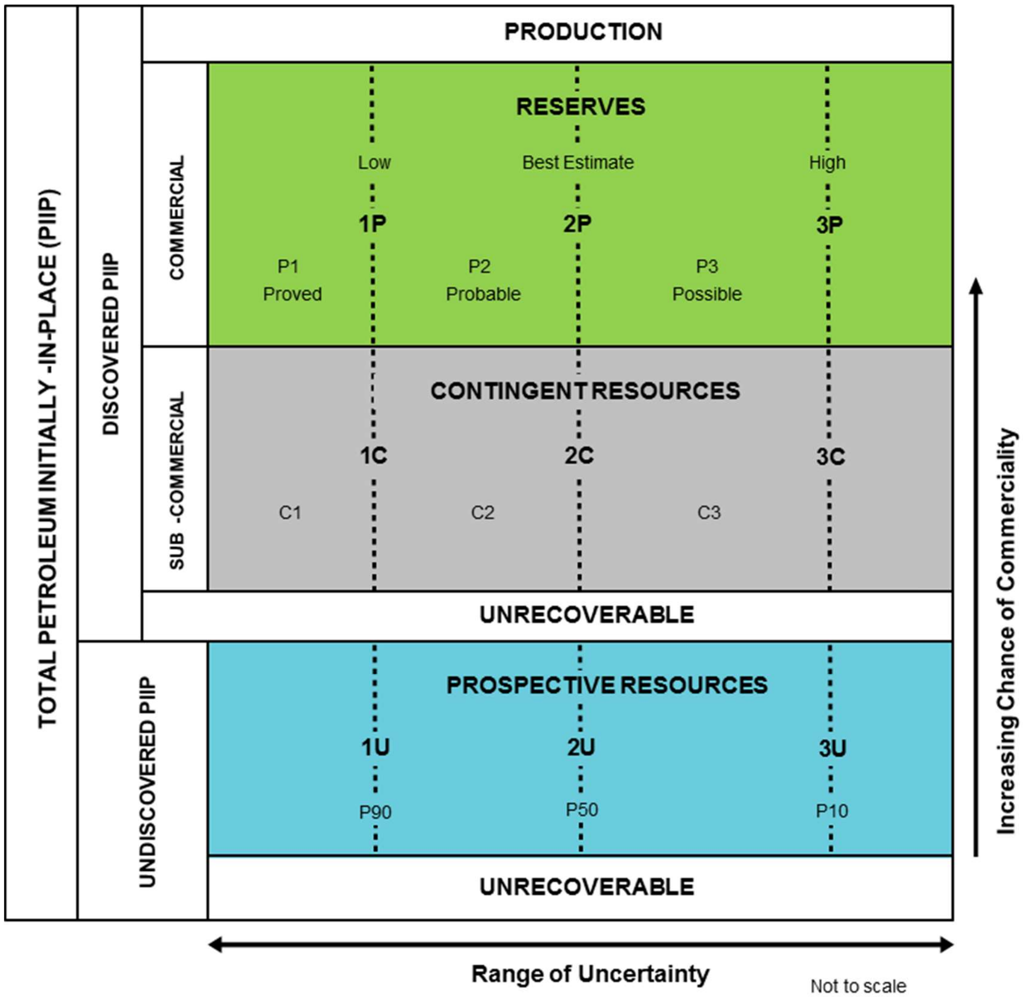
All reserves estimates involve some degree of uncertainty, The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

Reserve estimates are based on geologic and/or engineering data available at the time of estimate. Reserves estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively.



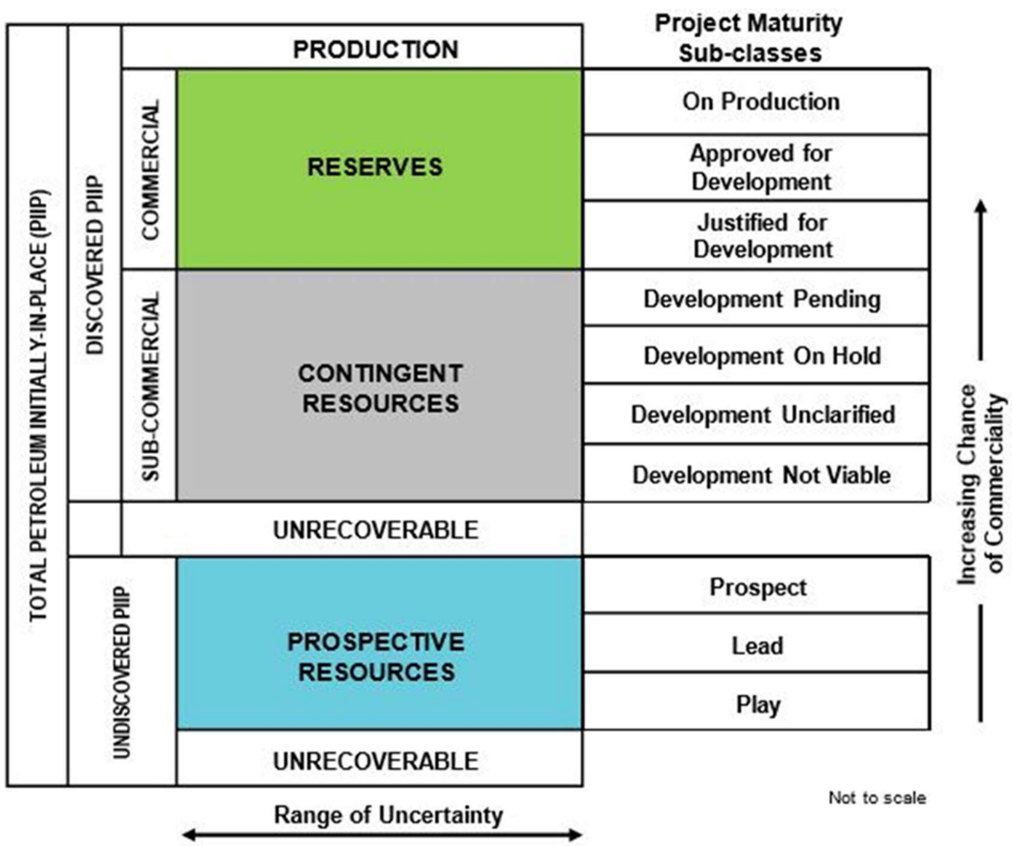
(Fig 2.4) Magnitude of uncertainty in reserves estimates
Source: © 2003-2004 Petrobjects www.petrobjects.com

(Fig 2.5) Resources Classification Framework



Source: Natural Gas Reserves Audit Report for ENEVA Participating Interest Fields in Parnaiba and Amazonas Basins, Brazil as of December 31, 2018

(Fig 2.6) Sub-Classes Based On Project Maturity



Source: Natural Gas Reserves Audit Report for ENEVA Participating Interest Fields in Parnaiba and Amazonas Basins, Brazil as of December 31, 2018

2.4 RESOURCES CATEGORIZATION

All resource estimates of involves some degree of uncertainty depending chiefly on the amount, reliability and the interpretation of the geological, geophysical and engineering data available at the time of estimation. The relative degree of uncertainty may be conveyed by placing Reserves in one of two categories; either **Proved** or **Unproved**.

The Unproved reserves are further classified into Probable or Possible reserves. The use of consistent terminology promotes clarity during communication of the evaluation results. For Reserves, the general cumulative terms Low, Expected, High estimates that are used for undiscovered speculative resources are denoted as 1P, 2P and 3P, respectively.

The proved, probable and possible reserves categories are designated P1, P2 and P3, respectively. The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (SPE, WPC, AAPG and SPEE, 2007).

2.4.1 Categories of Undiscovered Resources:

The terms "Low", "Expected" and "High" are used to define and categorize the undiscovered resources on the basis of uncertainty or confidence level.

- For "Low" probability distribution, there should be at least 85% probability (P85) such that the actually recovered quantities will equal or exceed the low estimate.
- For "Expected", there should be at least a 50% probability (P50) such that the actually recovered quantities will equal or exceed the best estimate (= expected estimates).
- For "High" there should be at least a 15% probability (P15) such that the actually recovered quantities will equal or exceed the high estimate.

2.4.2 Categories of Discovered Resources:

The terms "Proved or P1", "Probable or P2" and "Possible or P3" are used to define and categorize the discovered resources on the basis of uncertainty or confidence level.

2.5 TYPES OF RESERVES

2.5.1 Proved (PI) Reserve:

These are defined as the remaining quantities of petroleum which can be estimated with "reasonable certainty" to be recoverable from known accumulations at a specific date, under existing economic condition, by established operating practices and under current Government regulations. "reasonable certainty" means a probability (or confidence level) of at least 85% that the estimated quantities will be recovered.

The existing economic condition includes prices and costs prevailing at the time of the estimation. Pl can be categorized as developed or undeveloped reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production test or conclusive formation test. In certain instances, proved reserves may be assigned based on wireline logs, formation tests and/or core analysis. The afore mentioned analyses should indicate that the subject reservoir is petroleum bearing (analogous to productive reservoirs in the same area) and have demonstrated the ability to produce on a formation test and/ or supported by conclusive surface oil/gas samples, In the above cases, the proven petroleum accumulation may be commercial (proven reserves) or sub-commercial (proven, speculative recoverable resources) as illustrated.

Note that the terms proven, probable or possible are used to express confidence levels in resource estimation, but not the commerciality or project status.

The area of a reservoir which is considered proved includes:

i) the area delineated by drilling and defined by fluid contacts, if any, and

ii) the undrilled areas that can be reasonably judged as commercially productive on the basis of available geological, geophysical and engineering data. In the absence of data on fluid contacts, the lowest and highest known structural occurrence of petroleum, control the proved limit for each petroleum accumulation as explained hereafter:

• In the case of oil, between Oil-Up-To (OUT) to Oil-Down-To (ODT).
• In the case of gas, between structural crest and Gas-Down-To (GDT).

Caution should be taken since the above conditions may be overridden by some other geological, geophysical and engineering data, in which the basis and assumptions must be clearly stated. For example the above mentioned approach is more suitable for simple homogeneous reservoirs such as the Bentiu Formation (in the **Muglad Basing**).

On the contrary, the reserves may be overestimated in complex heterogeneous reservoirs such as Aradeiba or top Abu Gabra formations (in the **Muglad Basing**). In any case, prudent judgments, based on the understanding of geological elements such as sand body geometries and distributions, should be exercised, and preferably static and dynamic modeling should be applied for the reserve estimation.

The proved commercial reserves must have facilities to be processed and transported to the market. These facilities should be operational at a specific date, or there is a commitment or a reasonable expectation to be installed in the future.

The reserves that can be produced through the application of established improved oil recovery or enhanced oil recovery (IOR/EOR) methods, are included in the proved classification When:

i) successful testing by a pilot project or a fovourable production or pressure response of an installed program in that reservoir, provides support for the engineering analysis on which the project or program is based. This testing can be applied in a reservoir with similar rock and fluid properties in the immediate vicinity, or:

ii) it is reasonably certain that the project will proceed. The reserves to be recovered by IOR/EOR methods that have yet to be established through repeated commercially successful applications are included in the proved classification only:

1) after a favourable production response from the subject reservoir from a representative pilot or an installed program, where the response provides support for the engineering analysis on which the project is bused, and

2) if it is reasonably certain that the project will proceed.

2.5.2 Unproved Reserve:

Unproved reserves are defined based on geological, geophysical and engineering data similar to that used in estimates of proved reserves, but less certain to be recovered than proved reserves, and may be sub-classified into **Probable** (P2) or **Passible** (P3) to denote progressively increasing uncertainty. Unproved reserves could be based on anticipated developments and or the extrapolation of current economic conditions.

2.5.3 Probable reserve (P2):

Probable reserves are defined as the remaining quantities of petroleum which can be estimated with "sufficient degree of certainty" to be recoverable in the future from known accumulations. "Sufficient degree of certainty" means a probability (or confidence level) for proved plus probable (P1+P2) of at least 50% that the estimated quantities will be recovered.

In the case of oil probable reserves for each petroleum accumulation include:

• From Oil-Up-To (OUT) to halfway between Oil-Up-To (OUT) and Gas-Down-To (GDT) or structural crest if Gas-Down-To (GDT) has not been established.

• From Oil-Down-To (ODT) to halfway between Oil-Down-To (ODT) and Water-Up-To (WUT) or structural spill if Water-Up-To (WUT) has not been established.

In the case of gas probable reserves for each petroleum accumulation include:

• From Gas-Down-To (GDT) to halfway between Gas-Down-To (GDT) and Oil-Up-To (OUT), or

• From Gas-Down-To (GDT) to halfway between Gas-Down-To (GDT) and Water-Up-To (WUT).

The above conditions may be overridden by some other geological, geophysical and engineering data, of which the basis and assumptions must be clearly stated. Probable reserves may also include:

• Reserves anticipated to be proved by normal step-out drilling, where subsurface control is inadequate to classify these reserves as proved.

• Reserves in formations that appear to be productive, based on log characteristics but lack core data or conclusive tests, and which are not analogous to producing or proved reservoirs in the area.

• Incremental reserves attributable to infill drilling that otherwise could be classified as proved, but closer spacing had not been undertaken at the time of the estimate.

• Reserves attributable to an IOR/EOR method which has been established by repeated commercially successful applications when a project or pilot is planned, but not in operation, though rock, fluid, and reservoir characteristics appear favourable for commercial applications.

• Reserves in an area of formation that have been proved productive in other areas of the field, but the subject area appear to be separated from the proved area by faulting or a geological barrier. In this case, the geological interpretation indicates that the subject area is structurally higher than the proved area. The above conditions may be overridden by some other geological, geophysical and engineering data, of which the basis and assumptions must be clearly stated.

• Reserves attributable to a successful workover, treatment, retreatment, change of equipment, or other mechanical procedure, which procedure has not been proved successful in wells exhibiting similar behavior in analogous reservoirs.

• Incremental reserves in a proved producing reservoir where an alternative interpretation of performance or volumetric data indicate significantly more reserves than can be classified as proved.

2.5.4 Possible reserves (P3):

The possible reserves are defined as the remaining quantities of petroleum which can be estimated with "low degree of certainty" in order to be recoverable in future from known accumulations. A "Low degree of certainty" means a probability (or confidence level) for proved plus probable plus possible (PI+P2+P3) of at least 15% that the estimated quantities will be recovered.

Possible reserves for each petroleum accumulation in the case of oil and or gas include:

• From halfway between Oil-Down-To (ODT) and Water-Up-To (WUT) or structural spill if Water-Up-To (WUT) has not been established, to Water-Up-To (WUT) or structural spill.

• From halfway between Gas-Down-To (GDT) and Water-Up-To (WUT) or structural spill if Water-Up-To (WUT) has not been established, to Water-Up-To (WUT) or structural spill.

• From halfway between Oil-Up-To (OUT) and structural crest to structural crest. The above conditions may be overridden by some other geological, geophysical and engineering data, of which the basis and assumptions must be clearly stated. Possible reserves may also include:

• Reserves suggested by structural and/or stratigraphic extrapolation beyond areas classified as probable, based on geologic and/or geophysical interpretation.

• Reserves in formations that appear to be hydrocarbon bearing, based on logs or cores but that may not be productive at commercial rates.

• Incremental reserves attributable to infill drilling that are subject to technical uncertainty.

• Reserves attributable to an improved recovery method when a project or pilot is planned but not in operation, and the rock, fluid, and reservoir characteristics are such that a reasonable doubt exists about the commerciality of the project.

Reserves in an area of formation that has been proved productive in other areas of the field but the subject area appears to be separated from the proved by faulting or geological barrier, though the geological interpretation indicates that the subject area is structurally lower than the proved area. The above conditions may be overridden by some other geological, geophysical and engineering data, of which the basis and assumptions must he clearly stated.

• Incremental reserves attributable to an alternative interpretation of performance or volumetric data, i.e. hydrocarbon in-place parameters and/or recovery factor, indicate significantly more reserves that can be assigned to the proved and probable categories.

• The portion that includes all the high-risk upside volumes such as:

A) Areas with limited seismic coverage.

B) Questionable reservoir continuity and quality.

C) Additional recovery from improved recovery processes.

D) Better average reservoir parameters.

2.5.5 Resource Classification:

Referring to the SPE/WPC/AAPG/SPEE (2007) system, the basic classification requires the establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects, and hence between Reserves and Potential Recoverable (PR) Resources in known accumulations.

The following terminologies are used in the current Sudan Petroleum Resources Classification System (SPRCS) which is adopted by the Government and the operating companies in Sudan:

• Speculative Recoverable Resources (SRR) for undiscovered petroleum.

• Potential Recoverable Resources (PR) for discovered, sub-commercial petroleum.

• Reserves and cumulative production for discovered commercial petroleum.

Based on the status of the petroleum project in a discovered field, reserves can be classified into:

2.5.6 Developed Reserves:

(Proved Developed Oil and Gas Reserves):

These reserves are defined as the estimated quantities of petroleum expected to be recovered from existing wells (including reserves behind pipe). Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively low.

In accordance with guidelines adopted by the Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC), Developed reserves may be subcategorized as:

Producing or Non-producing.

Producing reserves are expected to be recovered from the completion intervals open at a specific date. Improved recovery reserves are considered to be producing only after an improved recovery project is in operation.

Non-producing reserves include shut-in and behind pipe reserves. In cases where the quantities behind pipe are deemed non-commercial, it will then fall into the Potential Recovery class Shut-in reserves are expected to be recovered from completion intervals open at a specific date but had not started producing, or were shut in for market conditions or pipeline connection Also, they were not capable of production for mechanical reasons and that the time for starting the sales is uncertain.

2.5.7 Undeveloped Reserves:

(Proved Undeveloped Oil and Gas Reserves):

Undeveloped reserves are expected to be recovered as follows:

• From new wells on un-drained portion of the reservoirs.

• From deepening existing wells to a different reservoir.

• Where a relatively large expenditure is required to recomplete an existing well, or in- stall production/transportation facilities for primary or improved recovery projects.

2.6 Revision of Petroleum Resources:

Reserve estimates are based on interpretation of geological, geophysical and engineering data available at the time of estimation. The estimates are generally based on static and dynamic models, and would be revised when reservoirs start production, additional geological, geophysical and engineering data become available, or when the economic and political conditions change.

The economies may change due to the expiration of an Exploration and Production Sharing Agreement (EPSA) or production contract. (±Improved) Reserves may be attributed to primary natural reservoir energy and improved oil recovery (IOR) approach, which employs enhanced oil recovery (EOR) methods in order to increase the Ultimate Recovery from the reservoir. Such methods include among others pressure maintenance, gas cycling, water flooding, thermal methods, chemical flooding and the use of miscible and immiscible displacement fluids.

Other termed used in resources assessments include the following:

2.6.1 Estimated Ultimate Recovery(EUR).

Is not a resources category or class but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to defined those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantity already produced from accumulation or group of accumulations.

2.6.2 Technically Recovered Resources(TRR).

are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations.

2.7 RESERVES PETROLEUM FLUIDS

2.7.1 Phase states of Hydrocarbons in Reservoirs:

Under initial reservoir conditions, the hydrocarbon fluids are in either a **single-phase** or a **two-phase** state.

• The single phase may be a liquid phase in which all the gas present is dissolved in the oil. Therefore, there are dissolved natural gas reserves as well as crude oil reserves to be estimated.

• The single phase may be a gas phase. If there are hydrocarbons vaporized in this gas phase that are recoverable as natural gas liquids on the surface, the reservoir is called gas-condensate. In this case there are associated liquid (condensate) reserves as well as the gas reserves to be estimated.

• Where the accumulation is in a two-phase state, the vapor phase is called the gas cap and the underlying liquid phase, the oil zone. In this case there will be four types of reserves to be estimated: the free gas or associated gas, the dissolved gas, the oil in oil zone, and the recoverable natural gas liquid from the gas cap.

2.7.2 Dry Gas:

Dry Gas is a natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use. (Also called Lean Gas).

2.7.3 Wet Gas:

Wet (Rich) Gas is a natural gas containing sufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

2.7.4 Natural Bitumen:

• Natural Bitumen is the portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state it usually contains sulphur, metals and other nonhydrocarbons. Natural Bitumen has a viscosity greater than 10,000 centipoises measured at original temperature in the deposit and atmospheric pressure, on a gas free basis.

• In its natural viscous state, it is not normally recoverable at commercial rate through a well. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen).

2.7.5 Natural Gas:

Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include amounts of non-hydrocarbons.

2.7.6 Natural Gas Liquids:

Natural Gas Liquids are those portions of natural gas which are recovered as liquids in separators, field facilities or gas processing plants. Natural Gas Liquids include but are not limited to ethane, propane, butanes, pentanes, and natural gasoline. Condensate may or may not be included.

2.7.7 Non Hydrocarbon Gas:

• In the event that non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale. Hence, if gas sold as produced includes a proportion of carbon dioxide, for example, the reserves and production should also include that CO_2.

• In the case of the CO_2 being extracted before sale and the sales gas containing only hydrocarbon gases, the reserves and production should reflect only the hydrocarbon gases that will be sold.

2.7.8 Non-Associated Gas:

Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.

2.7.9 Non-Conventional Gas:

Non-Conventional Gas is a natural gas found in unusual underground situations such as very impermeable reservoirs, hydrates, and coal deposits.

2.8 CLASSIFICATION OF RESERVOIRS BASED ON: PRODUCTION AND PVT DATA

2.8.1 Dry Gas Reservoirs:

• GOR > 100,000 SCF/STB

• No liquid hydrocarbon produced at surface (water can be produced)

• Mostly methane and some intermediates

• Gas composition and specific gravity are the same at surface and reservoir conditions

2.8.2 Wet Gas Reservoirs:

• GOR > 50,000 SCF/STB

• Liquid S.G. between 60-70 ºAPI

• Light in color/ transparent

• "Wet" refers to the hydrocarbon liquid which condenses out at surface conditions

• Water can be produced

2.8.3 Gas Condensate/Retrograde Gas Reservoirs:

• GOR between 3,000-100,000 SCF/STB

• Liquid S.G. between 50-70 ºAPI

• Light in color

• C7+ composition < 12.5%

2.8.4 Volatile Oil Reservoirs:

• GOR between1,000-8,000 SCF/STB

• Density between 45-60 ºAPI

• Oil FVF > 2.00 (high shrinkage oils)

• Light brown to green in color

• C7+ composition between 12.5% and 20%

• Producing GOR and API gravity will increase after production begins when reservoir pressure drops below bubble point.

2.8.5 Black Oil Reservoirs:

• GOR less than 1,000 SCF/STB

• Density less than 45 ºAPI

• Reservoir temperatures less than 250 ºF

• Oil FVF less than 2.00 (low shrinkage oils)

• Dark green to black in color

• C7+ composition > 30%

CHAPTER THREE

Muglad Basin

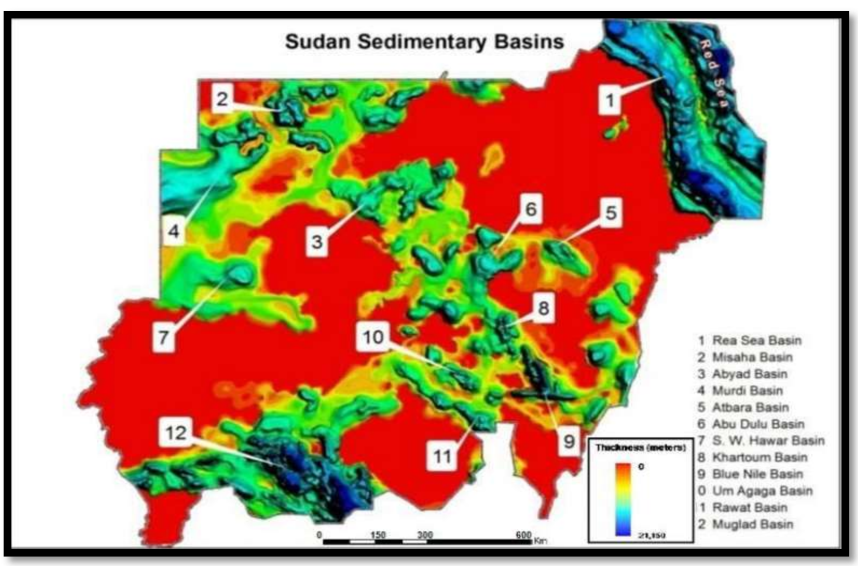
INTRODUCTION

3.1 Sudan Petroleum History and Geology:

Sudan is located in northeastern Africa. It is bordered by seven countries: Egypt to the north, the Red Sea to the northeast, Eritrea and Ethiopia to the east, South Sudan to the south, the Central African Republic to the southwest, Chad to the west and Libya to the northwest. Sudan has significant deposits of chromium ore, copper, iron ore, mica, silver, gold, tungsten, and zinc, but Petroleum is Sudan's major natural resource.

Oil and gas sector is an important extractive sector in Sudan, high hydrocarbon potential areas in Sudan has been divided to 24 blocks including area of study (block-6).

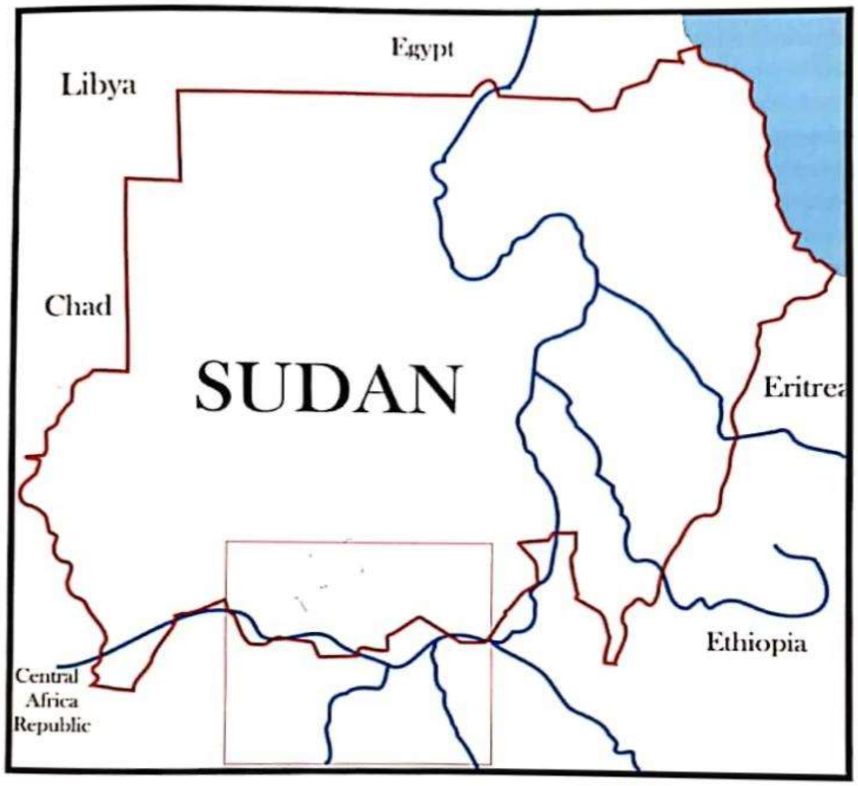
Sudan geological structure consists twelve basin including of many Rift Basins: Red Sea Basin, Misaha basin, Abyad basin, Murdi basin, Atbara basin, Abu Dulu basin, S. W. hawar basin, Blue Nile Basin, Khartoum Basin, Um Agaga basin, Rawat basin and Muglad basin. Below figure explains Sudan sedimentary basin locations.



(Fig 3.1) Sudan Sedimentary Basins

Source: Petroleum Geology And Resources Of The Sudan, Geozon Science Media UG; 1st edition, (2 Dec 2015).

Muglad Basin



(Fig 3.2) Location map of the Muglad Basin

Source: Petroleum Geology And Resources Of The Sudan, Geozon Science Media UG; 1st edition, (2 Dec 2015).

The Muglad Basin is the largest graben structure straddling Sudan and Southern Sudan Republics (Fig3.2). The total area of the basin is approximately 120,000 km2 extending 800 km in a NW-SE direction with a maximum width of 200 km. The basin comprises nine sub- basins oriented in a NW-SE to NNW-SSE direction; with extensional and strike-slip structural histories.

Geophysical and geological data (Schull, 1988; Kaska, 1989; Fairhead et al., 2012) have pointed to the presence of probably more than 16,000 m of non-marine? Cretaceous-Cainozoic sediments in the deepest parts. The sedimentary successions in several deep wells within the basin consist of thick Lower Cretaceous to Palaeogene and Neogene strata of clay stones, fluvio-lacustrine sandstones and siltstones (Schull, 1988). The basin is terminated in the NW against the Central African Shear Zone (CASZ), a regional structure which extends from the Cameroon through Chad into Sudan (Browne and Fairhead, 1983; Fairhead, 1988). The NW-trending basin has resulted from extensional tectonics caused by conversion of shear stress via the CASZ (Schandelmeier and Pudlo, 1990). The structural development of the basin was marked by three major rift cycles, each characterized by coarsening-upward sequences clastic sediments (Schull, 1988).

A study by Fairhead et al. (2012) has compiled the high resolution land and airborne gravity and magnetic data over the basin in which detailed 2D gravity modeling, constrained by well density logs and depth converted seismic sections have been used to define the representative density-Depth function for the basin. This density-depth function was then used to invert the residual gravity data into a 3D depth to basement model. This 3D model reflects the complex geometry of subsurface basement relief. The defined basement highs are known to control many of the oil fields on the northeast side of the basin.

Exploratory drilling for hydrocarbons in the Muglad Basin began in October 1977. The first oil was discovered in the basin from the second Unity-1 well in May 1978. The first significant oil flow was found in the fifth well, Abu Gabra-1 in August 1979. The first important discovery at Unity-2 happened in early 1980 (Schull, 1988).

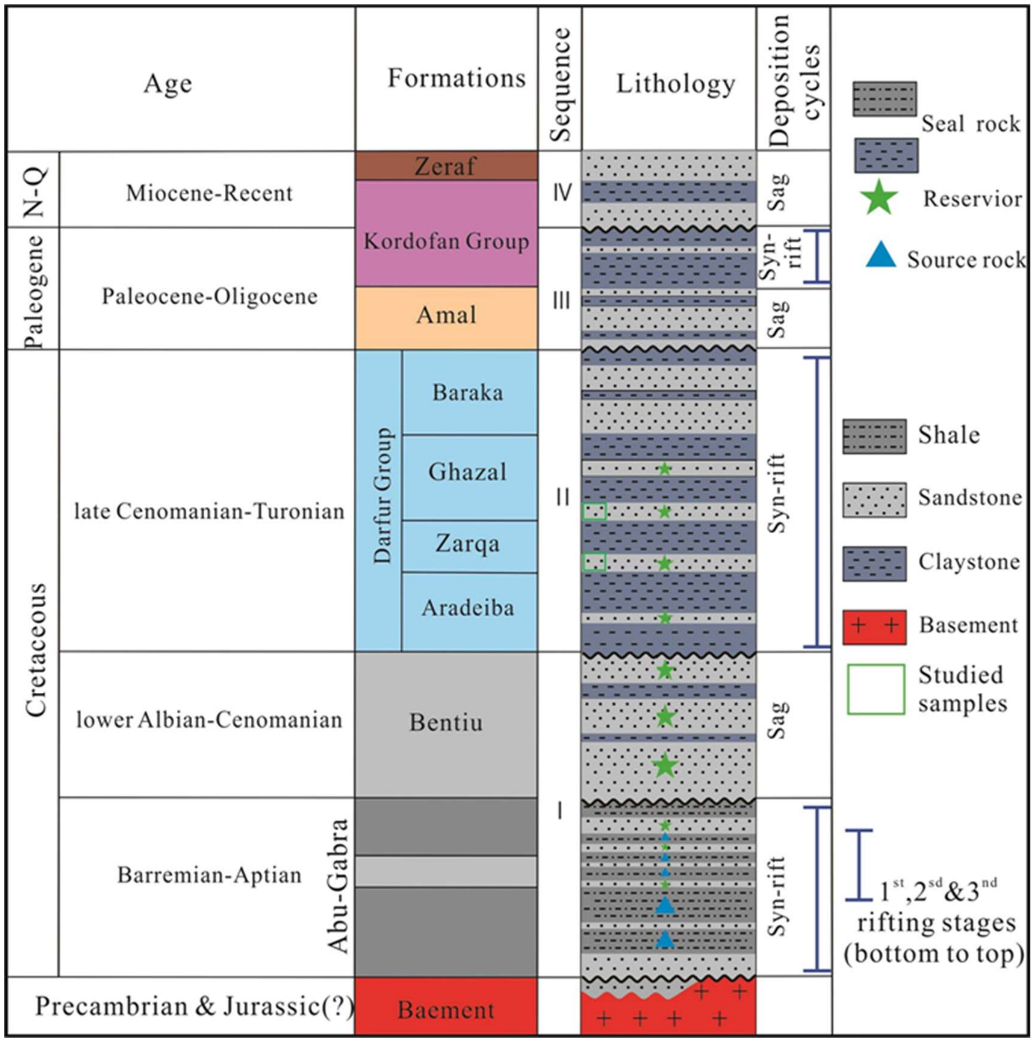
3.2 Geologic and tectonic setting:

The Muglad Basin area is a flat plain of low relief surrounded by hilly crystalline rocks exposed to the northeast in the Nuba Mountains, isolated basement and Mesozoie sedimentary outcrops in the north and basement rocks in the southwest. With the exception of some isolated sandstone outcrops of Miocene to Pliocene age cast of the Muglad town (El Shafie, 1975), the basin area is covered in the north by stabilized sand dunes locally veneered by silt or clay. Black soils cover the southern and southeastern parts, whereas, swamp deposits, alluvial and wadi sediments border the eastern side of the area. The underlying basement rocks in the northern art of the basin are believed to be of Early Proterozoic age (e.g. Stem et al. 1994; Abdelsalam et al, 2003).

The Muglad Basin witnessed three major episodes of rifling which initiated during the early Cretaceous and continued to the end of the Oligocene (Browne and Fairhead, 1983; Schull, 1988: Fairhead et al. 2013). Each rifting cycle consists of basal sandstone, followed by a coarsening-upward section of lacustrine shales grading through marginal lacustrine mudstones and sandstones into fluvial mudstones and sandstones, and capped by fluvial and alluvial sandstone (MeHargue et al.., 1992). It is possible that the clay/shale intervals within each cycle represent the syn-rift sediments, while the sandstone beds at the top of each cycle represent post-rift thermal sag sediments (MeHargue et al.., 1992). However, Blevin et al. (2009) claimed a pre-rift basin phase from the Permo-Triassic to Jurassic age and assigned six basin forming events. Which are named (basin phases). spanning from about the Jurassic to the Neogene interval. The pre-rift basin-forming event appears in seismic section as abland interval with consistent thickness. The presence of rotated fault blocks beneath the Jurassic Early Cretaceous interval in the southern Muglad Basin may embrace Karroon-aged equivalent strata (Blevin et al.., 2009); however, none of these pre-rift strata has a proof of age.

3.3 Stratigraphic and sedimentological characteristics:

Based on sedimentological evidence, seismic and log interpretations, Schull (1988) subdivided the Muglad succession into twelve formations: Sharaf, Abu Gabra, Bentiu, Darfur Group (Ara- deiba, Zarga, Gahzal and Baraka) and Kondofan Giroup (Amal, Nayil, Tendi, Adok and Zeral). Due to the non-marine nature of the sediments filling the basin, age determination of the various units was solely based on terrestrially-derived palynomorphs (e.g. Kaska, 1989; Stead and Awad, 2005; Eisawi et al. 2012).



(Fig 3.3) The main stratigraphic column of the Northeastern region of the Muglad Basin.

It compares sediments succession from Late Jurassic/Early Cretaceous-Quaternary with four sequences (I–IV) that separated by unconformities.

Source: Scientific reports, https://doi.org/10.1038/s41598-020-80831-y By Yousif M. Makeen, Xuanlong Shan, Habeeb A. Ayinla, Ekundayo Joseph Adepehin, Ndip Edwin Ayuk, Nura Abdulmumini Yelwa, Jian Yi, Osman M. A. Elhassan6 & Daijun Fan, (12 January 2021).

Age		Formation		Lithology and Environments
Tertiary	Recent-Middle Miocene	Zeraf		Predominantly iron-stained sands and silts with minor claystones interbeds. Braided streams/ alluvial fans.
		Kordofan	Adok	
	Oligocene- Upper Ecocene	Kordofan	Tendi	Predominantly claystone/ shale interbedded with sandstones. Fluvial/ floodplain and lacustrine.
			Nayil	
	Paleocene	Amal		Predominantly massive medium to coarse sandstones sequences. Braided streams/alluvial fans.
Cretaceous	Upper Senonian Turonian	Darfur	Baraka	Predominantly sandstones with minor shales and claystones interbeds. Fluvial/ alluvial fans.
		Darfur	Ghazal	Predominantly sandstones with claystones and minor shales interbeds. Fluvial/ alluvial fans.
		Darfur	Zarga	Predominantly sandstones, shales with interbeds of siltstones and sandstones. Floodplain/ lacustrine with fluvial/ deltaic channel sands.
		Darfur	Aradeiba	
	Cenomanian Upper Albian	Bentiu		Predominantly thick sandstones sequences. Braided / meandering streams.
	Albian- Aption	Abu Gabra		Predominantly claystones and shales with sandstone and fine siltstones. Lacustrine/ deltaic.

	Source rocks		Reservoir rocks

(Fig 3.4) Stratigraphic units of the Muglad rift basin, SW Sudan, their lithology and depositional environment

Source: (adapted from Schull 1988).

3.4 Bentiu Formation (Aptian-Cenomanian):

The Abu Gabra Formation is in parts unconformably overlain by the Lower Bentiu Formation, the latter comprises a massive sandstone sequence with some thin claystone interbeds. This unit represents the main reservoir mck in the Muglad Basin. The Bentiu Formation corresponds to the biostratigraphic units designated as Zones II, III and IV (Eisawi et al. 2012) The unit was deposited mainly under alluvial and fluvial (braided and partially meandering streams) environments.

The palynofacies is dominated by common occurrence of well-preserved humic debris, vitrinite and stnuctured inertinite together with prominent cutinite and palynomorphs (common Classopollis spp.) reflecting high energy environment.

3.5 Petroleum system:

Geological and geophysical studies conducted since mid-1970's confirmed the existence of active petroleum system in the Muglad basin. More than 1000 exploration and production wells in at least 80 fields have been drilled, most of which have been successful (Blevin et. al, 2009) Accurding to Beicip-Franlab (2004), the oils in the Muglad Basin are generally characterized by low gas/oil ratios (GOR), low Sulphur, high pour point (80-105 F) and high wax content indicating a lacustrine source. API gravity ranges from 9-645F.

3.6 Source Rocks:

Three potential source rocks exist in the Muglad Basin namely: Abu Cabra-lower Bentiu Formations (Early Cretaceous), Baraka Formation (Late Cretaceous) and Nayil-Tendi Formations (Eocene- early Miocene). Of these, the dark grey lacustrine claystones and shales of the early rift phase (Neocomian-Aptian/Abu Ciabra-Lower Bentiu) are the only proven source rocks which show positive correlations with oils in the northern

Muglad Basin Although the younger source intervals have relatively high TOC (up to 10 wt % for Tendi Formation). there is limited opportunity for them to reach maturity, except in the deeper parts of the Kaikang Trough where the top of the Baraka Formation may be reached at more than 2,500m (Beicip-Franlab, 2004; Blevin et. al, 2009). A conforming remark comes from Balulla (2011) who noted that the majority of samples from the Tendi Formation in Kaikang west-1 well are mature with T max range from 435-442 C and this fall at the beginning of the oil generative window.

CHAPTER FOUR

FUNDAMENTALS OF ROCK PROPERTIES AND VOLUMETRIC METHOD

4.1 ROCK PROPERTIES

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.

There are basically two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. These are:

4.1.1 Routine core analysis tests:

- Porosity
- Permeability
- Saturation

4.1.2 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 (i.e., gas, oil, and water) within the reservoir.

4.2 POROSITY

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:

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}} \qquad (1)$$

where φ=porosity

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

4.2.1 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 pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$\phi_a = \frac{\text{total pore volume}}{\text{bulk volume}} \qquad (2)$$

Or

$$\phi_a = \frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}} \qquad (3)$$

where Φa = absolute porosity.

4.2.2 Effective porosity:

The effective porosity is the percentage of interconnected pore space with respect to the bulk volume, or

$$\phi = \frac{\text{interconnected pore volume}}{\text{bulk volume}} \qquad (4)$$

where Φ=effective porosity.

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. Porosity may be classified according to the mode of origin as original induced. The original porosity is that developed in the deposition of the material, while induced porosity is that developed by some geologic process subsequent to deposition of the rock. The intergranular porosity of sandstones and the intercrystalline and oolitic porosity of some limestones typify original 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. Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity.

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 arealweighted 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	$\phi = \Sigma\phi_i/n$
Thickness-weighted average	$\phi = \Sigma\phi_i h_i/\Sigma h_i$
Areal-weighted average	$\phi = \Sigma\phi_i A_i/\Sigma A_i$
Volumetric-weighted average	$\phi = \Sigma\phi_i A_i h_i/\Sigma A_i h_i$

where n = total number of core samples

h_i = thickness of core sample i or reservoir area i

ϕ_i = porosity of core sample i or reservoir area i

A_i = reservoir area i

4.3 SATURATION

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:

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}} \qquad (1)$$

Applying the above mathematical concept of saturation to each reservoir fluid gives

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}} \qquad (2)$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}} \qquad (3)$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}} \qquad (4)$$

where S_o = oil saturation
S_g = gas saturation
S_w = water saturation

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100%. By definition, the sum of the saturations is 100%, therefore

$$S_g + S_o + S_w = 1.0$$

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to their density, i.e., oil overlain by gas and underlain by water. In addition to the bottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as capillary forces because they are important only in pore spaces of capillary size. Connate (interstitial) water saturation Swc is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table. Another particular phase saturation of interest is called the critical saturation and it is associated with each reservoir fluid.

4.3.1 Average Saturation:

Proper averaging of saturation data requires that the saturation values be weighted by both the interval thickness *hi* and interval porosity *Φ*. The average saturation of each reservoir fluid is calculated from the following equations:

$$S_o = \frac{\sum_{i=1}^{n} \phi_i h_i S_{oi}}{\sum_{i=1}^{n} \phi_i h_i}$$

$$S_w = \frac{\sum_{i=1}^{n} \phi_i h_i S_{wi}}{\sum_{i=1}^{n} \phi_i h_i}$$

$$S_g = \frac{\sum_{i=1}^{n} \phi_i h_i S_{gi}}{\sum_{i=1}^{n} \phi_i h_i}$$

where the subscript i refers to any individual measurement and *hi* represents the depth interval to which *Φi*, *Soi*, *Sgi*, and *Swi* apply.

4.4 DISCUSSION

For the Reservoir identification the most useful indicator was obtained from the behavior of the gamma ray, density, and neutron logs.

The pay zone in the well (Jake South-8) was determined, its equal 26.2 ft

The water oil contact in the depth 1503 m.

The reservoir area has been calculated using (ArcMap 10.4.1) version, and found it is equal 6 acres.

Porosity are calculated from neutron - density log by using IP software, its equal 0.24

Porosity from IP equal 0.24 = 24%

Porosity from archie's equation equal 0.25 = 25%

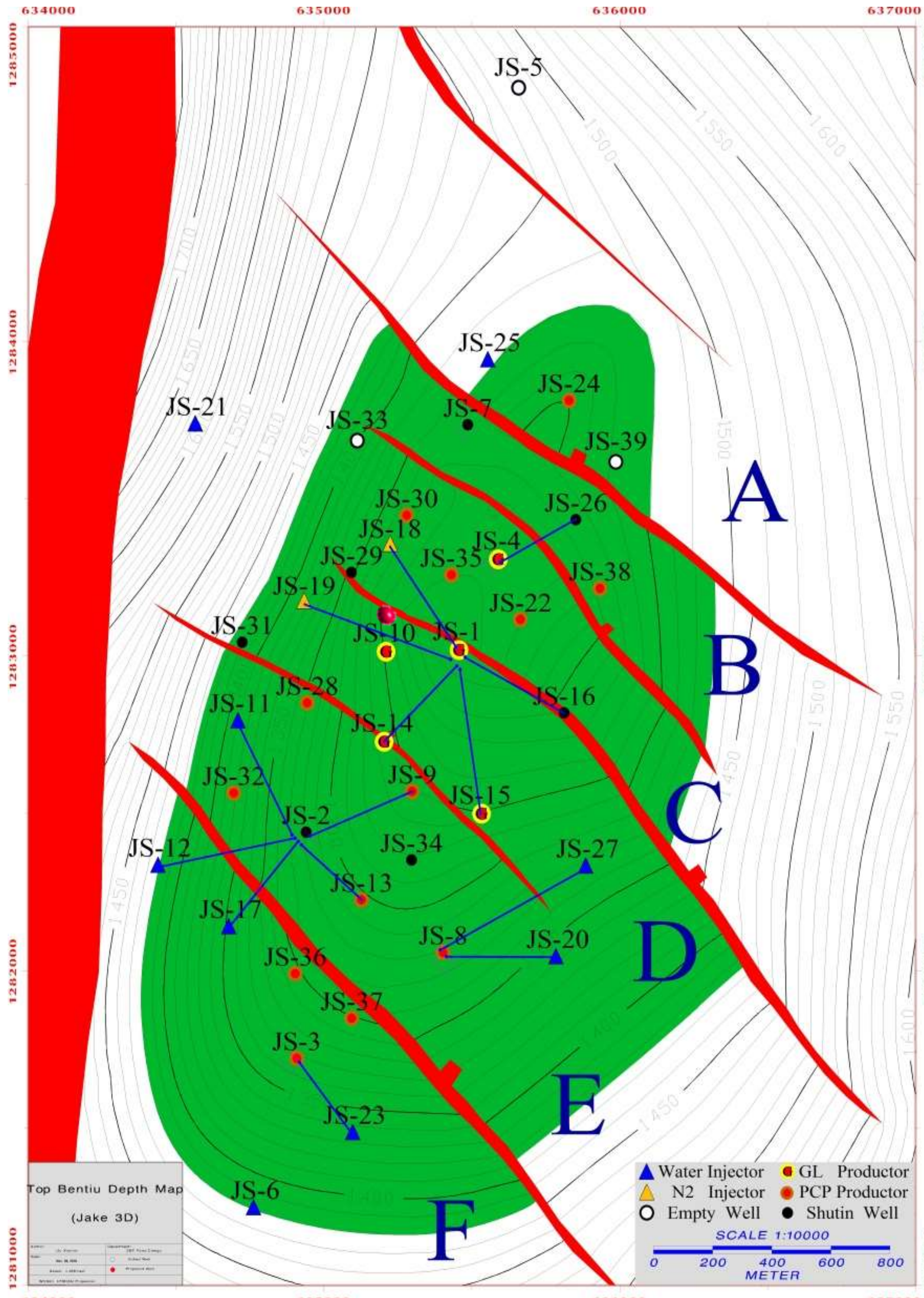
Water saturation from IP equal 0.09 = 9%

Water saturation neutron-density combination equal 0.13 = 13%

RE = 20.36% ERPR August 2021

FVF 1.051

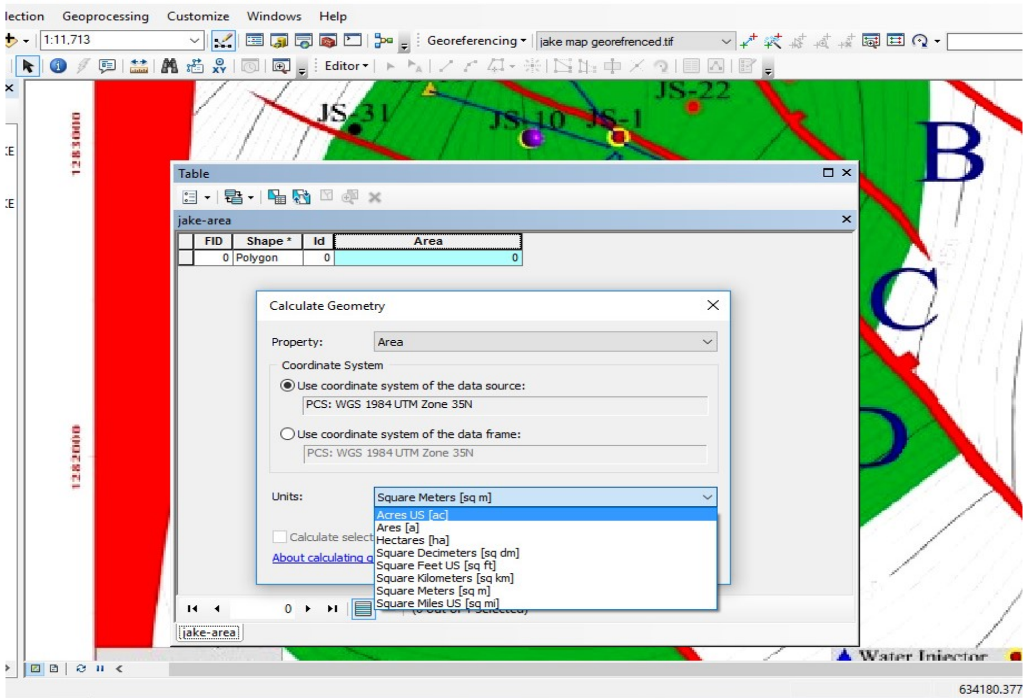
The oil reserve are calculated by using volumetric method.

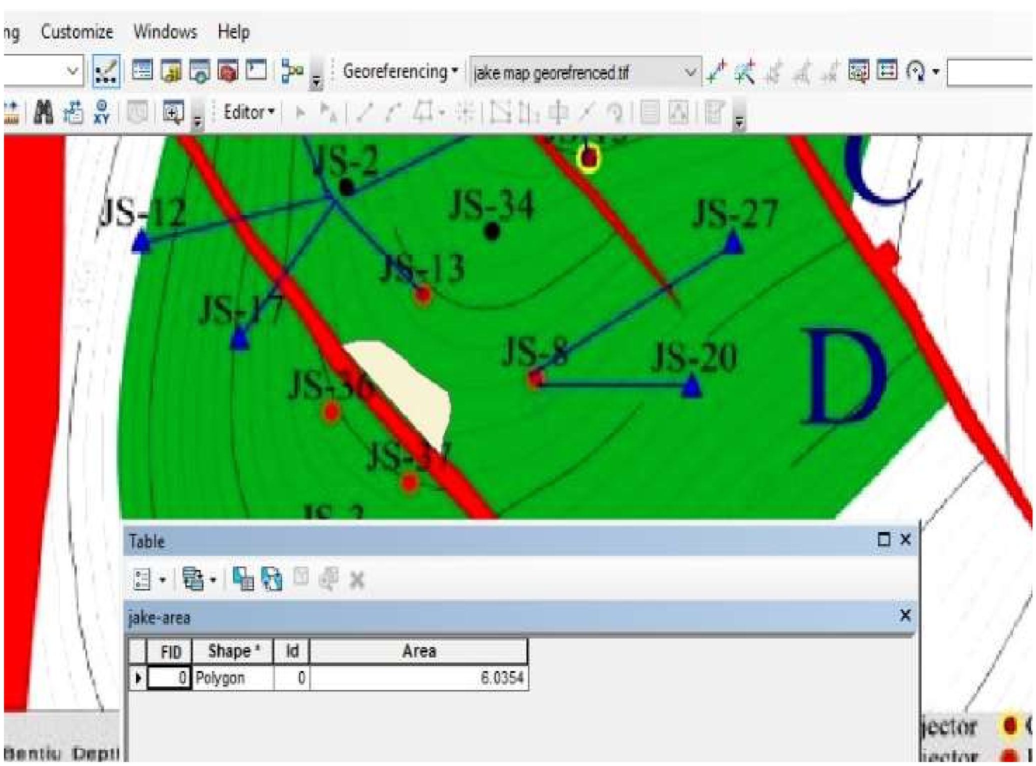


(Fig 4.1) Jake oil field structure map

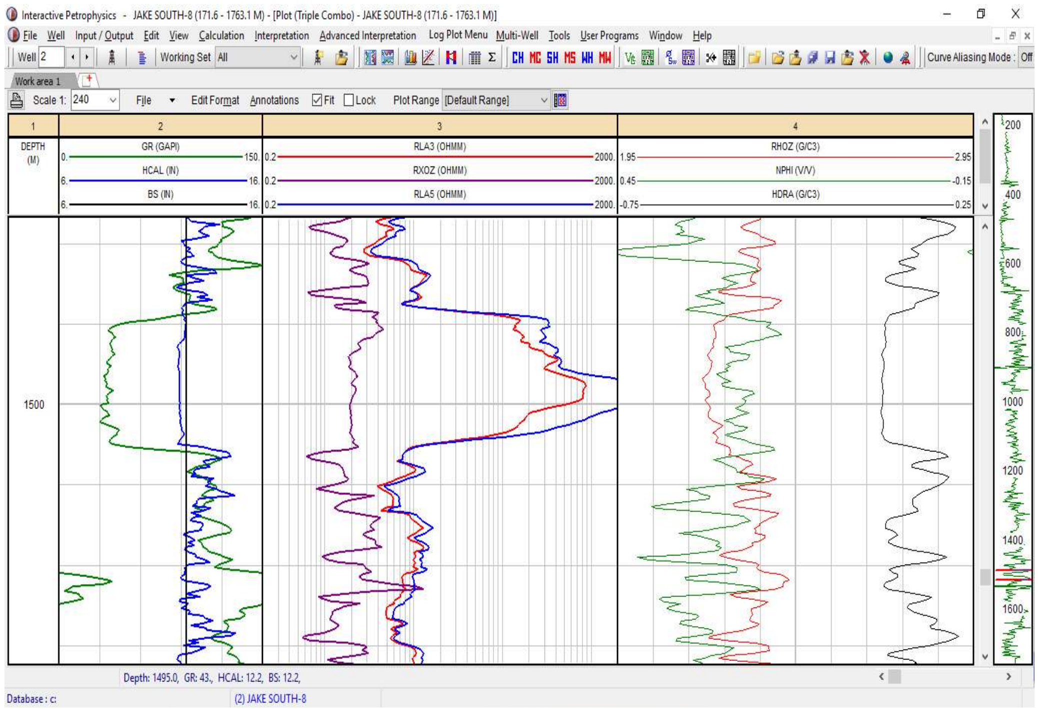
Source: Created by petro-energy E&P co., ltd

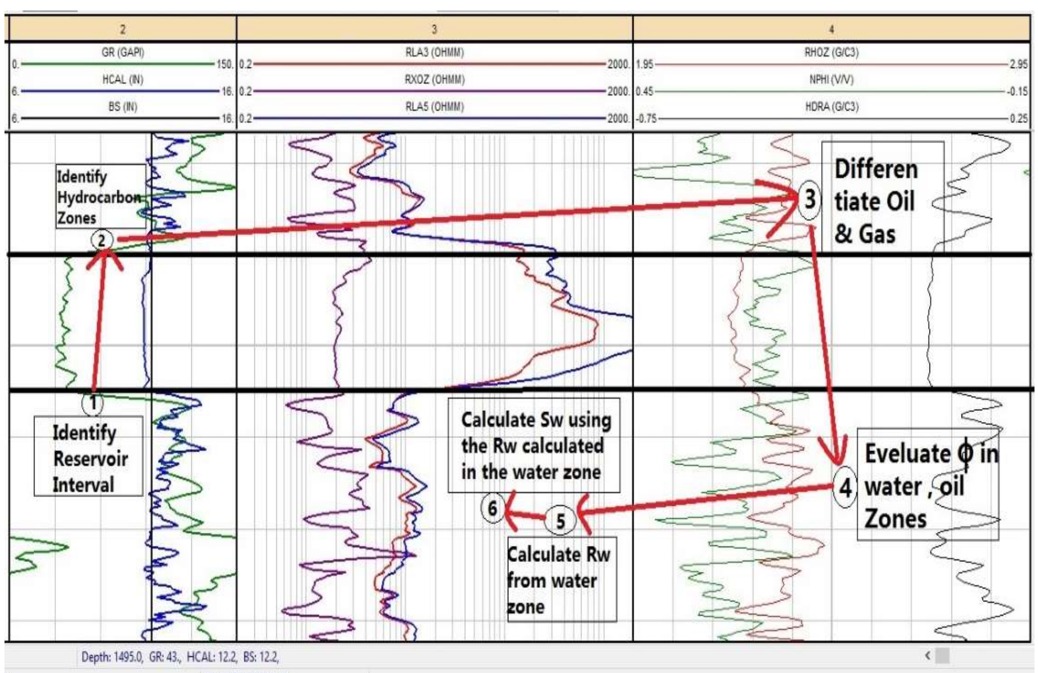
(Fig 4.2) Area calculation using ArcMap

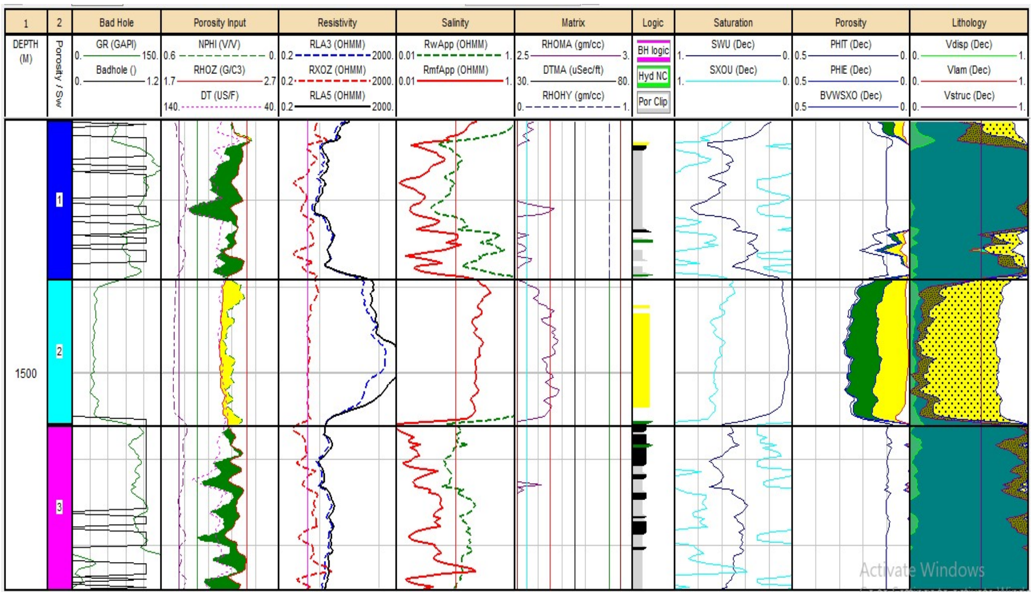


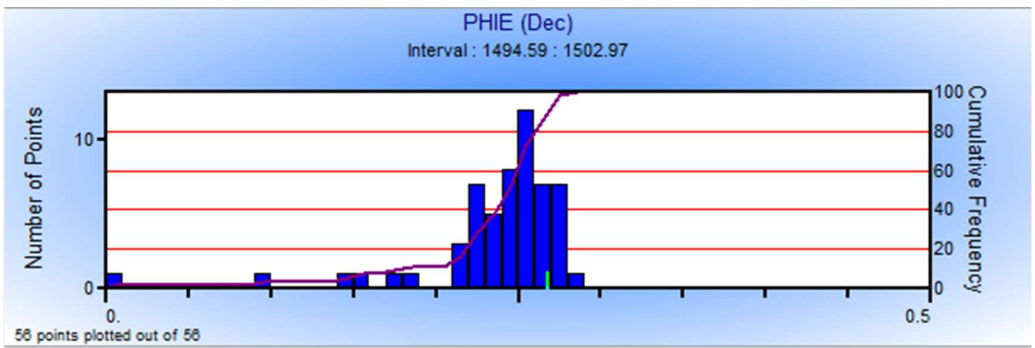


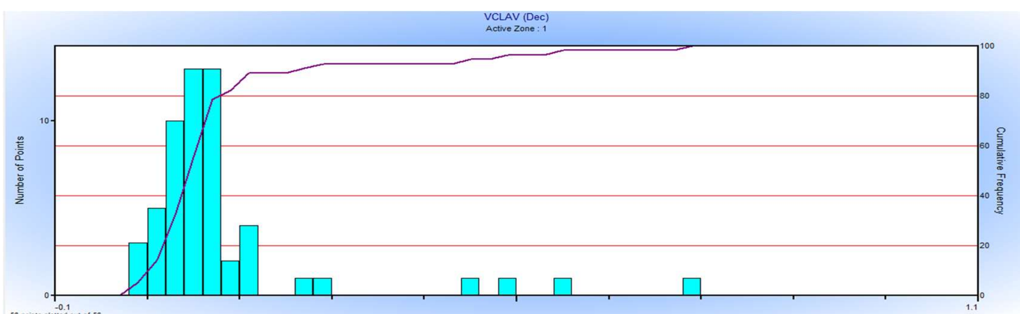
(Fig 4.3) Petrophysics parameters calculation using IP software

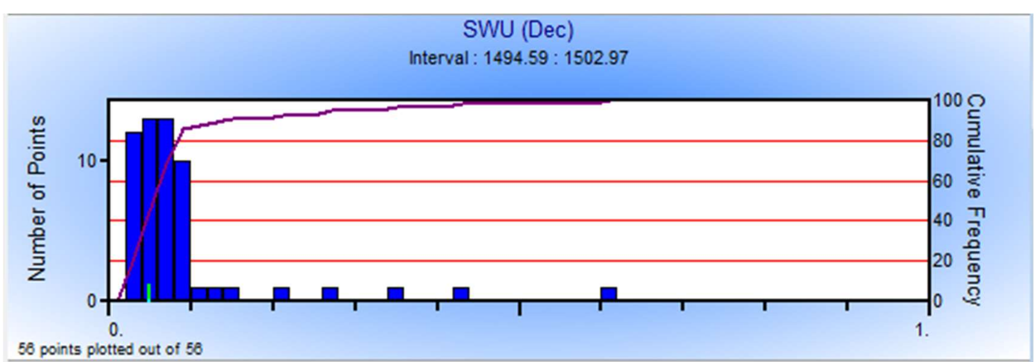







PHIE (Dec)
Interval : 1494.59 : 1502.97
Number of Points
Cumulative Frequency
56 points plotted out of 56


VCLAV (Dec)
Active Zone : 1


SWU (Dec)
Interval : 1494.59 : 1502.97
Number of Points
Cumulative Frequency
56 points plotted out of 56

4.5 SHALE VOLUME FROM GR LOG

- For estimating the volume fraction of shale in a formation V_{Sh} :

1) Scan the log for minimum and maximum GR readings (GR_{min} & GR_{max}).
2) The minimum reading is then assumed to be the clean point (0% shale), and the maximum reading is taken as the shale point (100% shale).
3) Then the GR reading in API units at any other point in the well (GR_{log}) may be converted to the GR index I_{GR} by linear scaling:

$$I_{GR} = \left[\frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}}\right]$$

V_{sh} can then be calculated using different approaches, either through linear or using nonlinear empirical approaches.

- Linear approach: $V_{sh} = I_{GR}$

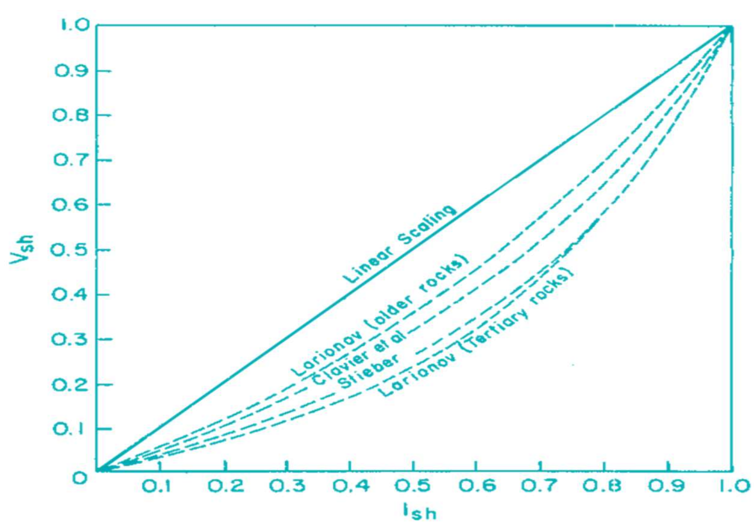
  Although frequently used, this approach tend to exaggerate the shale volume.
- Non-linear approach:

Larionov for Tertiary rocks: → $V_{sh} = 0.083\left(2^{3.7*I_{GR}} - 1\right)$

Larionov for Older rocks: → $V_{sh} = 0.33\left(2^{2*I_{GR}} - 1\right)$

Stieber Equation: → $V_{sh} = I_{GR}\left(3 - 2*I_{GR}\right)$

Clavier et. al equation: → $V_{sh} = 1.7 - \left[3.38 - \left(I_{GR} + 0.7\right)^2\right]^{1/2}$



4.6 NEUTRON-DENSITY COMBINATION

- The Neutron & Density porosities responses can be combined together to obtain a reliable estimate of the effective porosity and shale volume.

$$\phi_D = \phi_e + V_{sh}(\phi_D)_{sh} \rightarrow eq.(1)$$

$$\phi_N = \phi_e + V_{sh}(\phi_N)_{sh} \rightarrow eq.(2)$$

$$\phi_e = \left(\frac{\phi_D + \phi_N}{2}\right) - V_{sh}\left[\frac{(\phi_D)_{sh} + (\phi_N)_{sh}}{2}\right]$$

$$V_{sh} = \left(\frac{\phi_D - \phi_N}{(\phi_D)_{sh} + (\phi_N)_{sh}}\right)$$

- The two equations can be solved for ϕ_e and V_{sh} provided that the pure shale zone can be identified (e.g using GR) for obtaining density and neutron shale porosities $[(\phi_D)_{sh}$ & $(\phi_N)_{sh}]$.
- A correlation can be established between V_{sh} obtained this method and I_{GR} obtained from GR.

4.7 ARCHIE'S EQUATION

- In its final form, Archie's formula can be written as following:

$$S_w = \left[\frac{aR_w}{\phi^m R_t}\right]^{1/n}$$

Where:

S_w = water saturation
F = formation factor (a/ϕ^m)
a = tortuosity factor
m = cementation exponent
R_w = resistivity of formation water
R_t = true formation resistivity as measured by a deep reading resistivity log
n = saturation exponent (most commonly 2.0)

- Constants a, m, & n need to be determined for the particular field or formation.
- Then if R_w is known or can be determined, R_t can be read from the log and used to calculate the water saturation.

This equation is only valid for clean sandstone formations with uniform pore system.

4.8 VOLUMETRIC METHOD

The volumetric method, on the other hand, entails determining the areal extent of the reservoir, the rock pore volume, and the fluid content within the pore volume. This provides an estimate of the amount of hydrocarbons-in-place. The ultimate recovery, then, can be estimated by using an appropriate recovery factor.

Each of the factors used in the calculation above have inherent uncertainties that, when combined, cause significant uncertainties in the reserves estimate.

4.8.1 Volumetric analysis:

- Estimate the volume of subsurface rock that contains hydrocarbons.

The volume is calculated from the thickness of the rock containing oil or gas and the areal extent of the accumulation.

- Determine a weighted average effective porosity.
- Obtain a reasonable water resistivity value and calculate water saturation.
- The volumetric method on the other hand, entails determining the

areal extent of the reservoir, the rock pore volume, and the fluid content within the pore volume. This provides an estimate of the amount of hydrocarbons in place.

$$N = \frac{7758\ \emptyset A h (1 - sw_i)}{\beta_{oi}}$$

Were:

A = Drainage area, acres

h = Net pay thickness, feet

7,758 = API bbl per acre-feet (converts acre-feet to stock tank barrels)

∅ = Porosity, fraction of rock volume available to store fluids

S_W = Volume fraction of porosity filled with interstitial water

B_O = Formation volume factor (Reservoir bbl/STB)

The ultimate recovery, then, can be estimated by using an appropriate recovery factor.

$Nul = RF \times N$

$$N = \frac{7758 * 0.24 * 6 * 26.2(1-0.09)}{1.051}$$

$$N = 253426.6221\ STB$$

Nul = N * RF = N * 0.2036 = 51597.66026 STB

Porosity and water saturation from IP software.

$$N = \frac{7758 * 0.25 * 6 * 26.2(1-0.13)}{1.051}$$

$$N = 252382.2816\ \ STB$$

Nul = N * RF = N * 0.2036 = 51385.03253 STB

(Water saturation from archie's equation, porosity from neutron-density combination).

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

These results were obtained from the Jake oil field, which is located on the Western Escarpment of the Fula Subbasin of the Muglad Basin.

The latent oil reserve equal 253426.6221 STB

The recoverable oil reserve equal 51597.66026 STB

(Porosity and water saturation from IP software)

The latent oil reserve equal 252382.2816 STB

The recoverable oil reserve equal 51385.03253 STB

(Water saturation from archie's equation, porosity from neutron-density combination).

5.2 RECOMMENDATIONS

- We recommend to provide all information about this field, to get more accurate.
- Dicline carve analysis one of the must approved way, so we recommend to use dicline carve analysis method, to get more accurate, after production data is available.
- We recommend to repeat this study in the future, after accurate information about oil formation volume factor is available, because the oil formation volume factor changes with reservoir pressure and therefore with production.
- The IP program is effective and fast for a precise result of accounts in less time as possible.
- The ArcMap program can be relied entirely in the area calculation.

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