Petrophysics and fluid mechanics of selected wells in Bredasdorp Basin 
South Africa.

Master of Science in Applied Geology

By

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South Africa

Key Words

South Africa
Block 9
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Petrophysics
Sandstone unit
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Shale base line
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Fluid substitution
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Log analysis
Fluid and matrix properties
Well prognosis
Pore/ fracture pressure gradient
Cut off and summation
Amplitude versus offset
Abstract

Pressure drop within a field can be attributed to several factors. Pressure drop occurs when fractional forces cause resistance to flowing fluid through a porous medium. In this thesis, the sciences of petrophysics and rock physics were employed to develop understanding of the physical processes that occurs in reservoirs. This study focussed on the physical properties of rock and fluid in order to provide understanding of the system and the mechanism controlling its behaviour.

The change in production capacity of wells E-M 1, 2, 3, 4&5 prompted further research to find out why there will be pressure drop from the suits of wells and which well was contributing to the drop in production pressure. The E-M wells are located in the Bredasdorp Basin and the reservoirs have trapping mechanisms of stratigraphical and structural systems in a moderate to good quality turbidite channel sandstone. The basin is predominantly an elongated north-west and south-east inherited channel from the synrift sub basin and was open to relatively free marine circulation. By the southwest the basin is enclose by southern Outeniqua basin and the Indian oceans. Sedimentation into the Bredasdorp basin thus occurred predominantly down the axis of the basin with main input direction from the west.

Five wells were studied E-M1, E-M2, E-M3, E-M4, and E-M5 to identify which well is susceptible to flow within this group. Setting criteria for discriminator the result generated four well as meeting the criteria except for E-M1. The failure of E-M1 reservoir well interval was in consonant with result showed by evaluation from the log, pressure and rock physics analyses for E-M1.
Various methods in rock physics were used to identify sediments and their conditions and by applying inverse modelling (elastic impedance) the interval properties were better reflected. Also elastic impedance proved to be an economical and quicker method in describing the lithology and depositional environment in the absence of seismic trace.
Declaration

I declare that, Petrophysics and fluid mechanics of selected wells in Bredasdorp Basin, South Africa is my own work and that it has not been submitted for any degree or examination in any other university. Furthermore, all of the sources I have used or quoted have been indicated and acknowledge by complete references.

Researcher: Anthony Ile

Date: 15/2/2014

Signed: [Signature]

UNIVERSITY of the WESTERN CAPE
Dedication

In memory of Mrs comfort Allen-Ile.
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Chapter one
Introduction

The development of integrated reservoir models is built on petrophysics, which is the study of the physical and chemical properties of rock and the contained fluid. Beyond the well log analysis ran on wire line, drill string, conventional and special core analysis, drilling fluid logging, fluid sampling and formation testing, petrophysics is an analytical method which can be applied to deviated and horizontal wells for either laminated or dipping beds. A robust petrophysical analysis is 3D and accounts for formation anisotropy, transverse and longitudinal differences in rock properties in lieu of understanding the effective porosity and permeability of the reservoir or rock of study (Worthington, 2011).

The history of every petroleum pool may be divided into static and dynamic periods (Levorsen, 2004). Geological elements form the static structures which are reservoir rock, reservoir fluid and the trapping mechanism restricting fluid movement and these elements remain in equilibrium if undisturbed. But when a pool is found and field development begins the equilibrium is upset and the pool begins a dynamic period, where changes occur very rapidly. As this natural resource is extracted information about the subsurface is gathered and processed. The mechanics that accompany the withdrawal of fluids from the reservoir as a result of changes in pressure is similar to the mechanics of the fluid in static state (fluid at rest) and understanding of this is important for sustaining constant production rate (Pellerin et al, 2007).
1.1 Background Studies

One-quarter of sedimentary rocks are made up of Sandstone which are sediments that could be potential reservoirs (Boggs, 2009). Sandstone facies are highly distinct in their physical property and in the oil and gas industry, particle composition and size are the best methods for its classification. The composition is used to understand the course of diagenesis in sandstone and this can show the quality of porosity and permeability distribution within the rocks. Sandstones are composed of grains with variable sizes and these grain sizes are between 62.5 microns and 2000 microns in diameter, making it easy to determine with reasonable accuracy by merely using petrographic microscope and by experience one can virtually recognize the difference in particle sizes which may include various rock fragments and variety of minerals (Passey et al., 2010).

Sediments of the Bredasdorp basin are mainly organic, clastics and clay from marine and fluvial channel environments, constituents of rich intrabasinal biogenic, detrital sediments from dead organisms; hydrocarbon reservoirs in this basin have been located in Cretaceous sandstones. The Cretaceous gas bearing reservoir sandstones are evaluated within an interval of 50meters for each well. The basin deposition occurred in a relatively confined region and the shape is controlled by the topography which is predominantly elongated in the direction of the North-West and South- East axis of the basin, with influences of deviatoric stress (uneven force field), compartmentalisation, granulated materials and shale units. Based on these factors the geology of the basin becomes relatively difficult to quantify (PASA report, 2013).

Petrophysical evaluation is poised towards describing the rock properties; porosity, permeability, saturation, volume of shale, and fluid behaviour, net to gross ratio. These quantities are derived from Well log data provided. Well logs are down-hole measurement made in borehole using tools conveyed on moving cable.
There are many uses of Well log measurement other than that used in this research but this investigation only emphasises on well log measurement that are useful for understanding the properties of the targeted rock interval. Well logs do not directly measure petrophysical properties of the formation, but it measures formation parameters that can be translated to the required property, for example porosity is not what is measured but the relative fluid content of the pores, from which porosity can be deduced.

Gas shows were detected just below horizon c, from a depth of about 2200m across the wells of interest (fig. 1.1), and the trapping mechanisms were mainly stratigraphical in domal closure (from well report data made available to the researcher).

1.2 Problem Statement

The sudden decrease in pressure of the E-M suits production field is a problem hitherto unresolved. From the literature perused a lot has been done on the geological controls, but a re-evaluation of the petrophysical and fluid properties have not been looked into adequately to identify reasons in pressure drop from a well.
Figure 1.1: Major tectonic elements, Outeniqua basin

PASA report: www.petroleumagencyza.com
1.3 Scope of the Research

In the exploration of oil and gas challenges encountered by geophysicists, reservoir and production engineers are solved by the understanding of the geology. In solving the research problem the approach adopted was, building understanding of the geology of the basin, calculation of petrophysical properties from only well logs, analyses of these logs and applying the science of rock physics to the log outputs. Geology as the base was used to understand the subsurface structure, depositional environment and facies distinction. The approach used in this research into resolving the stated problem was to apply the sciences of rock physics and the engineering description of fluid behaviour in justifying the bases for pressure drop from a well. The aim was to present a holistic approach to solving production problems in the oil and gas industry.

Describing the behaviour of fluid using the science of fluid mechanics enabled the proper understanding of the forces controlling the flow of fluid in that section. Fluid flow is controlled by differential in pressure when the fluid is not in motion pressure is hydrostatic and hydrodynamic pressure is when the fluid is in motion. It is important to understand that it has a unique application in geology the knowledge of the behaviour of fluid within various types of rocks will enable us to know the diverse origin of various fluid potentials and to predict the probable effects of a given flow system upon the accumulation of petroleum (Levorsen, 2004).

This research adopted only Well Log data for the investigation, interactive petrophysics (IP) was used for computational analysis due to the robust and vast statistical modules available. Interactive petrophysics is software for the petrophysicists were you can do saturation calculation, volume of clay/shale and advance interpretation like rock physics.
1.4 Oil and Gas Investigation

The E-M gas field was discovered in 1983 about 50km west off F-A gas field (fig. 1.2 & fig. 1.3) as a result of a massive exploration activity that began in offshore of South Africa. From 1981 to 1991 one hundred and eighty one appraisal wells were drilled (PASA manual, 2013) and by 1992 the first production shipment was let out through a pipe from offshore to the PetroSA GTL plant at Mossel bay and converted to the different petroleum products like petrol, diesel and petrochemicals. The whole of E-M gas field was completed in 2001 by the Petroleum oil and gas of South Africa (PetroSA) PTY. Limited results of these activities witness the discovery of small fields and ever since then the basin has been a depot for most seismic and drilling activities in South Africa. It is one of the basins with most explored and proven reserves of hydrocarbon in South Africa (Broad, 2004). PetroSA owns and operates the gas fields offshore, at block 9 (90km offshore) there are the F-A and E-M gas fields (fig. 1.2) and by 2006 these fields produced 160 MMscfg/d 3900 BOPD.

F-A and E-M offshore gas fields has been the biggest source of condensate and wet gas in South Africa. The change in production capacity of the E-M gas field generated questions and avenues for further research into the problem. The Bredasdorp basin has a complex tectonic setting and very interesting structures, an elongated geometrical shape which apart from posing a challenge in accurately describing the geology it also will make the fluid behaviour unstable (fig. 1.1). The E-M gas field is of shallow marine sandstone with a domal and stratigraphic trapping mechanism beneath horizon c. Controlled by the localised stratigraphic structure its hydrocarbon accumulation is in an anticlinal closure. The sea floor is divided into zones- Agulhas formation (x), Agulhas formation (k), Top upper Sundays River sequence (Q), within the upper Sundays river sequence (E), there are two submarine fans- Top lower Sundays Rivers Sequence(c), within the lower Sunday’s river’s sequence (v).
Figure 1.2: Block 9 showing F-A/E-M gas fields (reproduced from Hugh, 2005)
Figure 1.3: Bore-hole locality map (PASA well report data, pers.comm. October, 2012)
1.5 **Aim and Significance of the Research**

The aim of this research is to show that problems in the oil and gas industry can be solved with the combined knowledge of geology and engineering principles. Most solutions are focussed either on an elaborate geological work or on an engineering approach, due to this dichotomy problems are not tackled holistically. So when there was drop in production from the E-M well structure investigation was only toward geological reason for this problem, now this research looks at methods to combine the geological information with engineering science.

The introduction of fluid mechanics into this research has given it a whole new face and brought into lamplight the practicability of inverse modelling. Flow problems in the oil and gas industry are one of the biggest challenges, and this problem can occur at the reservoir, wellbore, well or surface faces. For problems like this oil and gas production are affected. With the increasing complexity in drilling and producing from an oil and gas pool, solution are no longer one dimensional but multidisciplinary to provide information that will not only be used for a field but can be applied to any other field having similar problems. This research is built on the geology of the field as well as the use of inverse modelling technique (elastic impedance) and the application of the science of fluid mechanics in solving the research problem.

The need to qualitatively understand fluid behaviour is very important in production as rock and fluid properties begin to alter as soon as production begins because most of the intrinsic properties of the rock and fluid changes like pressure, temperature, viscosity, and compressibility. These properties involve the understanding of engineering science like fluid mechanics to fully understand motion of the fluid material that upon solidification becomes the rocks that make up the earth (Huppert, 1986).
Figure 1.4: Pore system- interconnected and isolated structures after Dandekar (2006)
1.6 Research Problem and Objectives

The problem tackled by this research is the drop in production capacity of a well. This research used a different technique in evaluating reservoir rock and fluid property. The study used well logs with wide range of theoretical analysis in establishing the reason why the production capacity of a well will drop. The major objective after identifying the well that is susceptible to flow was to model a pressure draw-down equation from a pore scale model of that reservoir interval. The flow path for a fluid within the pore space has a unique pattern due to the structure of isolated and interconnected pores (as in fig. 1.4); any other abnormal geological structure in that area will now cause hindrance to flow (fig. 1.5). This thesis looks at that abnormal structure within a flow path and the impact it has on flow pressure.

Figure 1.5: Idealize model of the matrix compressed by fluid flow
Little information is available about evolution of sedimentary basins and fluid flow processes that control accumulation. The only way to build understanding on the flow path for any reservoir interval is through the science of fluid mechanics, fluid mechanics involves the study of forces acting on a fluid that is stationary or in motion. In developing a theoretical model the geometry of the system was taking into account and applied to the well interval identified as problematic. This method uncovered a new vector quantity which has an impact on the flow mass and energy of the fluid.

**Challenges**

- Inability of the author to do coring and detailed laboratory analyses.
- Insufficient field work by the author.
- Their investigation solely relied on well log data and well reports.
- Obsolete data and delay in data acquisition used in this research.
- Unpredictable flow behaviour of the basin in questioned.

**Core objectives**

- Determination of petrophysical properties from well logs.
- Build link between rock physics properties and sediments.
- Elastic impedance lithology model.
- Flow discriminator for permeability population.
- Determination of temperature profile.
- Evaluation of overburden, pore and fracture pressure gradients.
- Pore scale modelling.
- Flow modelling and interpretation.
1.7 Brief Summary of the Chapters

This thesis is organised into chapters that cover the areas of investigation as highlighted in the core objectives. Chapters one and two of this thesis serve as the preliminary foundation into introduction to the basin. Chapter one begins with the development of the study area showing the locality map, analysis tools, the scope of work and challenges and objectives of the research. Chapter two reviews the geology of the Outeniqua basin, its stratigraphic, the tectonics and deformation of the basin, sedimentary depositional environment and the petroleum systems and some properties of its rocks and fluid.

Chapter three, “Research methodology”, includes enumeration of logs and theoretical methods used for the investigation. The Logging tools, software (computational) methods properties of the logs.

Chapter four homes in on the Bredasdorp basin the basin of interest, and discusses the tectonics, Stratigraphy, petroleum system and general depositional environment.

Chapter five, “Petrophysical analysis and log interpretation,” covers the petrophysical evaluations of the well interval of interest. Applied statistics was adopted in describing and analyzing the variability of the data, clay distribution, identification of baseline and its application, reservoir and sealing surfaces, pore pressure analysis, the elastic impedance curve, temperature estimation, lithology description, cut-off and summation.

Chapter six introduces fluid mechanics and its application to the research problem statement. Chapter seven is the discussion of results obtained in the investigation.

Chapter eight, deals with the Conclusions and recommendations.
Figure 1.6: Flow chart showing data synthesis
Chapter Two
Literature Review

2.1 Introduction

South Africa’s continental margins around the coastline cover an area of approximately 165000 km$^2$ of continental shelf and most of the underlying Mesozoic sedimentary basins originated from the late Jurassic to earlier Cretaceous (Thomas et.al., 2006). Offset off the southern tip of Africa lies the Outeniqua basin bordered in the west by the Columbine-Agulhas Arch, in the east by the Port Alfred Arch and to the south by the Diaz Marginal Ridge (Fig. 1.1& 2.1). The basin is made up of rift sub-basins, which from west to east are the Bredasdorp, Pletmos, Gamtoos and the Algoa sub-basins. They are separated by fault-bounded basement arches comprising of Ordovician to Devonian metasediments of the Cape Super group, while the arcuate (curved) trend of the basin bounding fault systems is mostly inherited from the structural grain of the underlying orogenic Cape fold belt (Thomas et.al., 2006).

As described by Van der Merwe et al (1992), the Bredasdorp sub-basin shows evidence of a lot of tectonic inversion. The basin contains two phases of synrift sedimentation: synrift sedimentation from the early Jurassic was tilted leading to the formation of an unconformity. The blocks are faulted with shallow marine sediments below overlying deep marine sediments. The synrift II interval contains deep water shales dating back to Hauterivian, which is found wrapped over tilted faulted blocks indicating rapid subsidence and wide spread flooding.
2.2 The Study Area

The Bredasdorp sub-basin is situated between Columbine-Agulhas and Infanta arches. It’s a south-easterly trending rift basin, approximately 200 km long and 90 km wide, occupying some 18 000 km² (fig. 1.2 & 2.1). It is filled with marine aptian to maastrichtian deposits, deposited between pre-existing Jurassic to early Cretaceous fluvial and shallow marine synrift periods. The rift basin trends south east and is filled with upper Jurassic and lower cretaceous synrift continental and marine strata with post cretaceous and Cenozoic rocks developed during a divergent episode (Hugh, 2005), which have also been observed onshore where the define outcrops showed significant organic rich rocks, the basin witness high level of petroleum exploration and drilling activities. Bounded by Infanta and Agulhas arches the offshore wells’ basement consists of slates of the Bokkeveld group (Devonian) and quartzites of the table mountain group (Ordovician – Silurian). Synrift I sedimentation which started in the middle of Jurassic, can be observed in the northern section of the basin. The synrift I succession is cut short by a regional unconformity separating block faulted shallow marine sediments below from overlying deep marine sediments (Jungslager 1996).

Synrift II sedimentation is represented by the onset of the unconformity this is as a result of the initial movement along the Agulhas-Falkland Fractured Zone (AFFZ at about the time of the Valanginian/ Hauterivian boundary (~12 Ma). It is at this period of regional tectonism; block faulting, reactivation of faults and local inversion and folding that the stage was set for economic structures to be in place, providing the trap necessary for the accumulation of oil and gas (Van Der Merwe et al., 1992). Synrift II interval consists of deep water shale dating back to Hauterivian, trapped over tilted fault blocks, which is an indication of subsidence and wide spread flooding forming the second phase of half graben infilling (fig. 2.2).
Figure 2.1: Sedimentary basin of Southern Africa (www.petrosa.co.za)
The influence of tectonism, eustatic sea level changes and probably thermal subsidence, is expressed in the repeated episodes of progradation and aggradations’. A study of the sequence Stratigraphy of the drift sequence shows correlation of this episode with worldwide eustatic events (Brown et.al., 1996). During the sea-level high stands, deposit of organic rich hydrocarbon source shale must have taken place. Sediments at the basin floor indicate high turbidity, resulting in porous and permeable sandstones. Low-stand witness the development of sediments and these sediments where then developed to economic petroleum systems within the basin floor.

In the Bredasdorp basin the hydrocarbon reservoirs have been located in the cretaceous sandstones, the gas and oil contained have been generated in one or more carbon rich source rocks found within the limits of the basin in the Western part of the Southern Outeniqua basin. The wet gas condensates are composed of liquid oils and traces of high molecular weight fluids considered to be residues.

This may suggest an environment of high organic feed but depleted dissolved oxygen. In most conditions like this, oxygen does not get to the deeper levels due to high barriers like mud; tectonic activities that have taken place could lead to a prevention of good exchange of water. When stagnation of this nature occurs’ temperature variation with depth becomes highly unstable. As a result a favourable environment for bacterial oxidation of the materials occurs more rapidly than the rate of oxygen supply.
Figure 2.2: Graben and half graben systems
Paleontological Research Institution (www.priweb.org)
2.3 Stratigraphy

The southern Outeniqua sub-basin is a distal extension of the Northern sub-basin where below the 300m isobaths the Mesozoic sediments reach a thickness of about 800m. These sediments were deposited during the Kimmeridgian/Portlandian era, and cores collected from wells drilled in the Falkland Plateau rocks were found to be of Oxfordian age (Wise, 1983). Sedimentary rocks distributed all through the basin are mostly sandstone, clay stone, and conglomerates. The basin’s rock units suggest a strong influence of the continental separation and movement of the AFFZ. A very rich organic (non magnetic), stratified basement suggesting a probable continental origin, trends sub-parallel to- and is abridged by the AFFZ (Ben-Avraham et al., 1993, 1997).

Stratigraphy is concerned with vertical and lateral relationships between units of sedimentary rocks. These are defined based on: lithology (physical rock properties), paleontology, and geophysical properties, age correlation, and geographic position and Stratigraphy and –distribution. Simply stated it is the study of layered rocks (fig. 2.3 & 2.4). Fig. 2.3 shows the vertical and lateral contacts between lithologic units, stratigraphic units are quite complex in nature because the way in which rock structures are layered depends on the depositional history, transgressive and regressive processes, mechanical factors and mineral constituents and their chemical properties and physical stability.

In petroleum movement or –migration, stratigraphic barriers play a very important role as they encapsulate the geologic phenomena that reduce permeability laterally up the dip. Cementation, facies changes, truncation and overlap are some common sources of permeability variation that influence petroleum pools. Permeability is not totally eliminated in any case but its reduction may increase the entering pressure just enough to bar further movement of oil and gas. The stratigraphic units are studied base on the interval and each interval of deposition may represent millions of years.
Sequences representing rock stacking are mostly repeated dozens of time so that the properties and distribution of potential source rocks vary systematically at several vertical and lateral scales, from lamina to super sequences spanning tenths of millimetres to thousands of meters (Passey et al., 2010).

Figure 2.3: Litho-Stratigraphical column
Thomas et al.,(2006)
The Outeniqua basin is heavily faulted (fig. 1.1& 2.5), this regional faulting is eminent in its sub-basins, and these sub-basins are found onshore through to offshore expanding from West to East (fig. 2.1). Two of these sub-basins and their Stratigraphy can be viewed in fig. 2.4 and fig. 2.5. Gamtoos has an extending line of its basins projecting westwards from Oudtshoorn, bounded by the Gamtoos fault in the north. Distal offshore, is the Algoa sub-basin having three half-grabens. The onshore Sundays River and offshore Troughs with the Uitenhage trough, and the Port Elizabeth Trough can be seen clearly in fig. 2.5.

The Stratigraphy of these basins as synrift deposits, contain continental conglomerates and sandstones of the Enon formation and Swartkops member this is overlying continental deposits in a brackish environment of shales, siltstones and sandstones known as the Kirkwood formation (Winter, 1973, see fig 2.4). In turn the marine shales and sandstones of the Sundays River formation form units consisting of the Uitenhage Group, which is dated back to Portlandian to early Valanginian. It’s quite difficult to correlate the onshore formations with their offshore reflections. Fig. 2.4 shows the horizon 1At1 as an unconformity which lies within the lower part of the Sundays River Formation.

Regionally the Outeniqua sub-basin appears to be the same across its length, and is made up of similar depositional systems. The tectonics varies slightly with the carbon rich source rock feeding the basin is the same for the entire basin while located within the limits of the southern part of the basin.
Figure 2.4: Sequence chrono-stratigraphic framework (Based on Soekor, 1994)
Figure 2. 5: Major structural elements Gamtoos and Algoa (PASA, pers.comm, 2013)
Offshore Gamtoos and Algoa synrift sediments were not intersected but synrift I sedimentation probably began in the Early or rather Middle Jurassic and comprise of continental clastics deposited in incipient half grabens. Drilling reports from these sites contain information of the lithology which is made up of sandstone, siltstone, and shale, deposited in an environment varying from abyssal to shallow marine to continental and fluvio-deltaic.

The Algoa sub-basin is significantly more arenaceous than the Gamtoos sub-basin as it consists of particles of sand or sand like grain sizes. In both basins the synrift succession contains thick organic-rich marine shales, which have economic significance as petroleum source rocks. The Later synrift sediments have probably been removed by extensive erosion and canyon formation, while preserving deep water clay stones and siltstones.

Transitional and drift phases were marked by lengthy period of uplift, erosion and canyon formation starting from the late Barremian or early Aptian (McMillan et al., 1997), followed by the canyon fill sedimentation in the Aptian and Albian. Erosion was deep and cut at least 1000 meters into the underlying drift and synrift section, resulting in a wide spread angular unconformity which marks the canyon floor. This predominantly contains sediments of argillaceous deposits from deep marine environment dated back to late Aptian to Albian. There are seismic markers at the top canyon of late Albian and a coeval with 14At1 unconformity within the Bredasdorp sub-basin. Late Cretaceous and Tertiary sedimentation was fairly uniform across the Gamtoos and Algoa sub-basins, the other sub-basins have fairly similar description.
2.4 Sedimentary Depositional Environment

This describes the physical, chemical and biological processes involved in the deposition of sediments and the kind of rocks that will be formed after lithification. Accumulation of rich organic sediments is a function of the prior processes listed by Bohacs et al., (2005), predicting accumulation of hydrocarbons requires integration of the understanding of plate tectonics, geodynamics, structural development of the basin and reconstruction of paleo-environmental conditions (fig. 2.6).

Figure 2.6: Rifted half graben sub-basins of Outeniqua basin, reproduced from Hugh, 2005
These activities are beyond the scope of this thesis, which is focussed on an understanding of the reservoir geology from the analysis of logs, porosity and fluid behaviour. The Outeniqua basin spans from onshore to offshore areas, running from west to east with the youngest on the west and oldest on the east side of the basin, the productive wells are off shore, the depositional environment is fluvial, shallow marine and deep marine, though the deep marine environment has not been extensively investigated on.

Deep water depositional systems cannot be easily reached, observed and studied in the modern environment in contrast to other systems hence it requires many remote observation systems each of which can provide only a partial view of the entire depositional system. The basin is made up of series of sandstones alternating with claystone beds. Core samples from different well locations of the sub-basins reflect the conclusive fact that the sequences and bed characteristics show thinning and fining upwards, and fan channels being abandoned progressively, which is evidence of fan deposits (Emmanuel and Carey, 2011).

Fan progradation is evident from the observation on cores that confirms thickening and coarsening upwards of facies, depicting the activities of marine regression and transgression. A third description shows thinning-and fining-upwards sequences which are characteristics of fan channels being abandoned progressively. For highly faulted basins the Brown et al, (2004) model still remains a perfect model for the basin description, in which third-order low stand is the proximate situation for the development of growth. By this hypothesis third-order low stand, growth faulted sub-basins develop seaward off the shelf break, where coarser grained sediments accumulate on unstable slope mud that was deposited in previous transgressive and high stand system tracts (Fig. 2. 7)
Figure 2.7: Depositional environment and submarine fan deposition
(Reproduced from Emmanuel et al., 2011)
2.5 Tectonics and Deformation

Gondwanaland witnessed major drifting activities during the Cretaceous and Tertiary periods where the African plate was completely separated from its neighbouring parts and members of Gondwanaland (fig. 2.8), subjecting the interior of the sub-continent to erosion. Direction of the sediment transportation was to the continental margins and adjacent ocean basins. Drifting between the African and South American plates marks the origin of the South African super plate, and there was a separation between the Falkland plateau and the Agulhas bank in the Outeniqua basin.

Figure 2.8: Pre-break up distribution of rift basins within Southwest Gondwana
(Jungslager, 1999)
The Agulhas bank marine condition is dated to be upper Valanginian correlated with south east Atlantic Ocean and the Natal Valley. The most extensive Cretaceous and Tertiary sequences in South Africa lie offshore, under the continental shelf, slope and rise in the adjacent ocean basins (Newton et al., 1983).

Understanding the reservoirs offshore poses a greater challenge than onshore, due to the fact that most offshore exploration is done using seismic and the correlation between the seismic reflectors in comparison to the structures and stratigraphic events recognised at outcrops onshore may not be linked: accuracy is lost in converting thicknesses on seismic records expressed in sound wave travel time into thickness in meters. This disparity in structural and stratigraphic events between onshore and offshore indicates the complex tectonic episode under the Eastern Falkland Plateau which confirmed the earlier South American and African super plate break up.

The implication is that the South Atlantic drift after oceanic crust was progressively created from north to south in the Natal Valley with synchronous ocean crust emplacement in south East Cape Basin. The sub-tectonic tract shows that Southern Africa has two major plates, Agulhas plateau and the Mozambique ridge. Extensive work has been done on the Agulhas plateau which Newton et al.,(1983), suggested it was an abandoned oceanic spreading centre which is 18 km thick in the North and 15 km thick South with a distinct discontinuity between the two parts separated by a fracture zone (Fig. 2.8 & 2.9). Figure 2.9 gives a combination of onshore and offshore seismic data, geology and magnetotellurics of Southern Africa showing the Agulhas/Falkland fracture zone (AFFZ), the Mozambique ridge, Natal valley and the Agulhas Plateau. Magnetotellurics (MT) is an advanced electromagnetic geophysical technique which is time dependent and marks the variation in the earth’s magnetic field as its source, while the output is the earth’s induced electric field.
Figure 2.9: Magneto-Tellurics model Agulhas-Karoo transect

(Ben et al., 1997)
The oceanic areas of the South African coast still show evidence of marked massive encroachment of deformation extending into the Atlantic South West of Cape Town to about 1600 km. The Natal Valley Transkei Basin and Mozambique basin have well established geomorphological features. Evident on the sedimentary basin are crustal subsidence which is fully developed around the South African continental region dating back to the Aptian/Albian era.

The upper Cretaceous (Albian) of the Outeniqua basin largely shows features of high tectonism. Large boundary faults and narrow but deep sedimentary basins (taphrogenic style) implies inversion from horst to graben basement dislocation. As a result of these large marginal basins developing (with no major coast-parallel basement discontinuity) there was an ocean ward progradation and shift of the depo-centres. In line with this activity there were large elongated depo-centres on the continental margins, having tendencies for prograding ocean wards with rapid extension beyond the confines. Surfaces of the older taphrogenic basins shows destruction, a phase of subsidence in the elongated region with normal faulting, brief transgression followed by regression and deposition of non marine sediments controlled by growth fault. The section of Outeniqua basin behind the Agulhas marginal fractured ridge showed no evidence of these activities.

South East of the Outeniqua basin (Agulhas bank) is without a continental rise. This is in contrast to the well developed rise prism along the west coast and in the Natal Valley. The deformation of the Outeniqua basin from taphrogenic to epeirogenic (phase of non-accumulation & erosion, marine transgression with fine-grained sediments accumulating in low relief) crustal subsidence matches approximately with the boundary between the upper Sundays River and the alphard formations.
2.6 Reservoir Fluid Mechanics

The application of reservoir fluid mechanics to solving problems in geology is becoming necessary as this method builds new ideas into the understanding of the behaviour of fluid. Reservoir fluid mechanics (RFM) deals with the behaviour and the impact subsurface structures like salt dome and granulated seam has on flow capacity. The properties of fluid that are looked into are the rheology (viscosity) and density; these are the mechanical properties that determine the flow capacity of fluid. According to H. Huppert (1986) viscosity and density are affected by composition, temperature and pressure. When the pore space containing the fluid has low crystallinity and less isolated pores the flow of fluid can be likened to behave as a Newtonian fluid (fig. 2.10).

Figure 2.10: Viscosity - temperature model plot
(Huppert, 1986)
The Newtonian fluid obeys the second law of motion (Equation 2.1); that an appreciable force will make the fluid to flow from static condition. In the rheology profile shown above (fig 2.10), the viscosity is inverse of the temperature.

\[ F = ma \quad \rightarrow \text{Newton's second law} \quad 2.1 \]

From equation 2.1 F is force; m is mass and represents acceleration. Fluid flow is the consequence of the variation of pressure with depth. When reservoirs are discovered the hydrostatic pressures are expected to be just enough to take the fluid to the surface although for some reservoirs this may not be the case; artificial lifts are required to produce from such wells (Fig. 2.11).

Figure 2.11: Pressure profile (After Gryenko, 2012)
Equation 2.2 shows the counteracting effect by the pore fluid to normal stress and this exerts a direct influence on the mechanical responses. These influences can be seen in sediments compaction to shear stress and sliding stability of tectonic faults (equation 2.3).

\[
\sigma'_n = \sigma_n - P_f \quad \text{(2.2)}
\]

\[
\tau = b + \sigma_n \cdot \mu \quad \text{(2.3)}
\]

The symbol \(\tau\) and \(\sigma_n\) represent shear and normal stress, \(\sigma'_n\) denotes the counteracting effect of the normal stress, \(b\) is combination of forces that represents cohesion between the rock and the fluid, \(\mu\) is viscosity and \(P_f\) is the fluid pressure within the pore space.

In addition to the pore pressure the permeability of the zone also plays an important role in the primary control of drainage pattern and flow rates. Permeability of a reservoir is constantly changing because of the drilling and production activities. The compacted sediments form a low permeability zone affecting the fluid’s ability to access high permeable channels, creating the development of over-pressured areas. The flow of fluid can also be affected by permeability anisotropy which is as a result of grain orientation and the layering of sediments. Permeability can be generated from well logs for a zone but generally the permeability (equation 2.4) is measured in the laboratory using core samples and mathematically by Darcy’s equation (equation 2.4),

\[
k = \frac{\mu q x}{A \Delta P} \quad \text{(2.4)}
\]

Where \(q\) is volume flux per unit time (m/s), \(\mu\) is fluid viscosity (cp), \(x\) is distance (m), \(k\) is permeability (mD), \(A\) is cross sectional area (m\(^2\)), and \(\Delta P\) is pressure gradient.
2.7 Petroleum System

A Petroleum System is made up of petroleum generating source rock and physiochemical system (Mille, 2012; equation 2.5). This system requires convergence of certain geologic elements and events essential to formation of petroleum deposits which include: matured source rock, expulsion, secondary migration, accumulation, and retention. The petroleum system classification is primarily based on three elements (fig. 2.12)

\[
\text{source rock} + \text{reservoir} + \text{seal(trap)} = \text{petroleum system}
\]  

Figure 2.12: Petroleum system (Mille, 2012)
The accumulation of organic rich rocks (ORR) has a complex formation of many interacting processes (Passey et al., 2010; fig 2.13), and a full understanding of its integration requires the knowledge of a lot of disciplines, plate tectonics, basin’s structural development with reconstruction and geodynamics these studies are used in processed based models for occurrence, distribution, and characterization of the source rock. A source rock starts from a favourable depositional environment and the accumulation of organic matter which controls the non-linear interactions of three proximate controlled variables; rate of production, destruction and dilution. Organic production generates energy with minimal amount of oxygen providing the environment for kerogen build up and transformation. The Proximate controls are nutrients, supply rate of energy and water. Equation 2.6 shows the production rate

$$\frac{\partial p}{\partial t} = N_0 e^{-rt}$$  \hspace{1cm}  \text{(2.6)}$$

Organic production rate is a function of time $N_0$ which is nutrient input is a function of supply history and population growth of various organism, $r$ is the inherent growth rate of the organism. Nutrients are supplied through transgression and regression processes while the secondary consumers further degrade the material for transformation into hydrocarbons. Equation 2.7 shows the carrying capacity of the ecosystem as a function of the organic production rate.

$$\frac{\partial p}{\partial t} = \frac{KN_0}{(K - N_0)e^{-rt} + N_0}$$  \hspace{1cm}  \text{(2.7)}$$
Figure 2.13: Dilution, destruction, & organic production processes and controls
(Passey et al, 2010)
Geological activities occur over long period of time, slowly with subsequent compaction and lithification of sediments. After the process of sedimentation and lithification, this organic matter in an anoxic condition becomes a source of hydrocarbon by the action of metazoans. The activities of the metazoans turn the organic substance into kerogen.

\[ \frac{\partial O}{\partial t} = a \frac{\partial O}{\partial x} + b \frac{\partial O}{\partial y} + c \frac{\partial O}{\partial z} + \sum_{i=1}^{n} O_i \frac{\partial d}{\partial t} + O_i \frac{\partial d}{\partial z} - O \]  

The destruction of organic matter is expressed by equation 2.8, 1 is the advection of oxidants, 2 - diffusion of oxidants, 3 - oxidant consumption. Microbial respiration and inorganic oxidation are the other conditions needed for destruction of organic matter as expressed in component 2 and 3 of equation 2.8. The destruction of organic matter and accumulation of organic and inorganic material in an anoxic condition leads to the build-up of the hydrocarbon pool (fig. 2.13; table 2.1).

The hydrocarbon pools are generated from the source rock and for source rock to be an effective generator of hydrocarbon it needs high concentration of organic content, dilutions of biogenic organisms and clastic deposits. In the Outeniqua basin of South Africa, the Sundays River Formation consist of synrift II deposition which is made up of deep marine clay stones and thin turbidites containing organic rich shales which are elements of petroleum source rock (see table 2.1).

There are high concentrations of organic material and strong thermoclines towards the East side of the Outeniqua basin, the evidence of thermoclines indicates slow decomposition and high level of cation and anion exchange (equation 2.9 & 2.10).

\[ HS^- + 2 O_2 \rightarrow HSO_4^- \]  

\[(CH_2O)_{106}(NH_3)_{16}H_3PO_4 + 53 SO_4^{2-} \rightarrow 53 CO_2 + 53 HCO_3^- + 53 HS^- + 16 NH_3 + 53 H_2O + H_3PO_4 \]
<table>
<thead>
<tr>
<th>Country</th>
<th>Period/Stag.</th>
<th>Environment</th>
<th>Local Name</th>
<th>Quality</th>
<th>Area</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Africa</td>
<td>Mid Cretaceous</td>
<td>Anoxic marine</td>
<td>15A</td>
<td>WG/OIL</td>
<td>Burden (1992)</td>
<td>Oil Also called Upper Sundays Rivers Formation</td>
</tr>
<tr>
<td>South Africa</td>
<td>Early Cretaceous</td>
<td>Dysoxic marine</td>
<td>13A</td>
<td>Oil</td>
<td>Burden (1992), Davies (1996)</td>
<td>Also called earliest Upper Sundays Rivers Formation</td>
</tr>
</tbody>
</table>

**Outeniqua basin source rocks, Southern Africa (PASA)**

**Remarks**
- Mid Cretaceous
- Early Cretaceous
- Also called Upper Sundays Rivers Formation
- Also called earliest Upper Sundays Rivers Formation

**Reference**
- Burden (1992)
- Davies (1996)
- Malan (1993)
Figure 2.14 shows the different types of petroleum reservoir traps which are stratigraphical and structural. In the Outeniqua basin broad scale structural and stratigraphic settings have been widely published by McMillan et al., (1997) on the influences of basement structure and rifting location and style. The shape of the strike in Outeniqua basin shows swing as a result of the Cape fold belt structural grain. Ben et al., (1993) described the swing shaped faults to strike slip on the Agulhas-Falkland Fractured Zone (AFFZ) a major transform fault associated with the break-up of Gondwana. The Outeniqua basin’s magnitude of swing faults can been seen from west to east as the fractured zone on the Southern Outeniqua basin draws closer to the sub-basins in the east producing more deformation at that section (fig. 2.15).

The half graben sub-basin’s deformity can be seen as massive faults. Grabens are formed as a result of failed rifting, and these deformations created fault traps and anticlinal traps all over the basins (fig. 2.15). Around the northern rim there are deposits of interbedded clay stones, shelf sandstones and floor sandstones in the depocentres.

Stratigraphic traps were formed due to the changes in rock types which are the sandstone- shale sequences commonly found in the basin. The high presence of shale units in the basin formed various seals on the reservoir beds which affected the permeability distribution within the producing formation. Permeability changes in the reservoir are either horizontally or vertically and are as a result of a lot of factors. The changes induced by interbedded rock size or grain size and granulation seams affect the overall performance of the reservoir. Despite the fact that stratigraphic traps can be positive, the changes in rock type resulted into the formation of granulation seams formed as a result of deviatoric stress (unequal stress field in all direction). These seams have challenging effects on fluid flow from a reservoir.
Structural traps

Stratigraphic traps

Figure 2.14: Petroleum traps
Paleontological Research Institution (www.priweb.org)
Figure 2.15: Structural elements of locality map
(PASA, pers.comm, October 2012)
2.8 Reservoir Rock and Fluid Properties

The basic understanding of the rock and fluid property is the key to a successful petrophysical study using well logs. The interpretations are used as an exploration tool to describing the local Stratigraphy, structure, facies relationships and environment.

2.8.1 Porosity

Porosity is the volume percent of pore space in a rock, pore spaces between the solid rock particles are usually occupied in sedimentary rocks by fluid such as water, gas and/or oil (fig 2.16). Porosity can be estimated with equation 2.11;

\[
\text{porosity (\%)} = \frac{\text{pore volume}}{\text{Pore volume + Grain volume}} \times 100
\]

Figure 2.16: Bulk model (Millie, 2012)
The porosities analysed in this research are the total porosity and effective porosity. Total porosity is the sum of all pores or voids whether connected or not. But the most important part of porosity is the effective porosity and this is the ratio of the interconnected pore spaces to the bulk volume (fig. 2.17).

Figure 2.17: Pore system- interconnected and isolated structures
(After Jahn et al., 2003)
There are two types of porosity determined by the time of formation, and these are;

- Primary porosity: controlled by depositional environment, particle size and nature of material that makes the rock.
- Secondary porosity: controlled by activities after deposition (diagenesis), solution re-deposition, and cementation and fracturing.

### 2.8.2 Permeability

This is the measure of the ease in which a fluid flows through a rock (fig 2.18), it is the key parameter in determining the rate of production and is a function of the interconnected pore spaces (effective porosity). By using experimental measurements Darcy was able to derive an equation for flow through a porous medium (equation 2.12);

\[ k = \frac{Q \cdot \mu \cdot L}{A \cdot \Delta P} \]  

Where:

- \( k \) = Permeability (Darcy)
- \( Q \) = Flow rate
- \( A \) = Cross sectional area of the rock (M²)
- \( L \) = Length of the rock (M)
- \( \mu \) = Viscosity of the flowing medium (Cp)
- \( \Delta P \) = Pressure drop or differential
The Permeability is the property of a rock and is independent on the nature of fluid. The units of permeability are milidarcies or Darcys (one Darcy is equivalent to one thousand milidarcies). Porous rocks exhibit permeability of one Darcy when a single phase fluid with viscosity of one centipose (that is the viscosity of water at 68 °F) completely fills the entire pore space. Permeability can be determined from well testing operations, wire line or drill stem test, measurements from side wall samples, core analysis using plug type or core measurements and from well logs.

Figure 2.18: Core permeability measurement (Mille, 2012)
Permeability is affected by grain shape, and permeability increases where the shape deviates from true spheres. There are two types of permeability measurements. The first one is horizontal permeability ($k_h$) which measures parallel to the bedding. This is the major contributor to fluid flow into the well bore. The second one is vertical permeability ($K_v$); this is normally lower than the horizontal permeability because of the presence of minerals, bedding laminations and shale. Sometimes pore spaces contain more than one fluid; gas, oil, and water. In such a case the effective permeability must be considered. The effective permeability is the permeability of a rock to a medium when another medium is present in the pore space.

The effective permeability is always less than the absolute permeability; absolute permeability is the flow of a single fluid through the rock. The relationship between the effective permeability and the absolute permeability is shown in equation 2.13,

$$ Relative \ permeability \ (k_r) = \frac{effective \ permeability \ (k_e)}{absolute \ permeability \ (k_a)} $$

Relative permeability is the ratio of effective permeability to absolute permeability. Relative permeability describes the flow of one fluid during a multiphase flow while the absolute permeability describes flow of that fluid during a single phase flow through the reservoir rocks (fig. 2.19).
Both water and gas flows

Figure 2.19: Relative permeability model (After Mille, 2012)
Fluid saturation is the porosity percentage of a rock occupied by a specific fluid. For a three-component system the total fill up of the pore space is summed up to hundred percent (equation 2.14).

\[ S_o + S_g + S_w = 100\% \]  

Where:
- \( S_o \) = Oil saturation
- \( S_g \) = Gas saturation
- \( S_w \) = Water saturation

The percentage of proportion is in relationship to the pore space, for example 50% water saturation means that half of the pore space is occupied by water. In computing fluid saturation it is the ratio of the pore space occupied by a fluid to the total pore space of the rock (equation 2.15);

\[
\text{Fluid saturation } (S_f) = \frac{\text{proportion of pore space occupied by fluid}}{\text{total pore space of the rock}} \tag{2.15}
\]

Fluid can occur as a funicular, pendular and insular saturation (fig 2.20). Funicular saturation is the occurrence of a non-wetting phase as a continuous web in the pore space (fig. 2.20 A). Pendular saturation is when the wetting phase of the pore space that covers the rock surface is in contact with a non-wetting phase which interconnects the pore throats (fig. 2.20B). Insular saturation is a type of saturation in which the non-wetting phase occurs as isolated globules in the continuous wetting phase (fig. 2.20 B and C).
2.8.4 Resistivity

This is the resistance of a material to the flow of electric current; it is measured in ohm-m. The resistivity of any formation is a function of the amount of water in that formation and the resistivity of the water itself. Hydrocarbons are normally insulators while water is conductive (saltwater), resistivity can be calculated from the following (equation 2.16);

\[ R = r \frac{A}{L} \]  

Where;

- \( R \) = resistivity, ohms m
- \( r \) = resistance, ohms
- \( A \) = cross sectional area m\(^2\)
- \( L \) = length of material, m\(^2\)

Resistivity logs are useful in understanding of formation fluid, lithology boundaries, and formation permeability. The various types of resistivity logs are normal, lateral, laterlog, and induction log. The basic methods in generating the resistivity logs are the sending down of electric current through the bore-hole and measurements recorded; resistivity is the inverse of conductivity.
Chapter Three
Research Methodology

3.1 Introduction

In South Africa, off-shore Outeniqua basin is the most explored basin for oil and gas. This basin is made up of four sub-basins (Bredasdorp, Pletmos, Gamtoos, and Algoa) and Bredasdorp has the most viable productive block in the country. In addition to the understanding of the basin’s geology this thesis is designed to re-evaluate the petrophysical properties for the investigated well intervals and apply the science of rock physics in their analyses.

Petrophysical analysis is built around framework of interpretive algorithm that relates measurable parameters to reservoir parameter. These methods of analysis are data driven and the interpretive algorithm changes from reservoir to reservoir. A good petrophysical analysis takes time and cost money because it requires an integrated multi-discipline approach. The study of the reservoir and well behaviour is better understood when the petroleum field is fully developed and in production. This study will generate well log data that is used for further evaluation of the production capacity and conditions for the intervals.

The information from well log data is very useful in development plan both for surface and the subsurface developmental plans. During the investigation of this research well log data were used to calculate the petrophysical properties for each well and to study the conditions of their intervals. This thesis applied several methods in the evaluation of their petrophysical properties for E-M1 to E-M5 well intervals with evaluations done for their pore and fracture pressure gradient, temperature and productive capacity for each interval.
The modelling of flow behaviour was done with the use of fluid static principle and this shows how granulated seam structure influenced the flowing pressure of fluid for that well interval. It is in modelling this properties that petrophysics plays a significant role. Petrophysical modelling is a strategic development of fluid contact, net pay and cut offs from the log measurement. Petrophysicist work with data and information from different sources like well report, geological information, well log data and engineering report to properly explain the condition of the rock and fluid properties of the reservoir.

For this thesis the Archie’s equation was adopted. Archie’s equation is an empirical formula used in well logs analysis to evaluate the hydrocarbon content of a reservoir; the equation establishes the quantitative relationship among porosity, electrical resistivity and hydrocarbon saturation of reservoir rocks. Archie’s equation (equation 3.1) was adopted for computation because water saturation values for the wells were not greater than one (fig. 3.1).

\[
S_w = \left(\frac{1}{I_r}\right)^\frac{1}{n}
\]

3.1

\[
S_w \leq 1
\]

Where \(S_w\) is water saturation, \(n\) is saturation exponent, and \(I_r\) – electrical resistivity for the material.
Figure 3.1: Water saturation histogram

The result in fig. 3.1 shows that E-M1 has the highest proportion for water saturation.
3.2 Well Logs

Well log is a term which implies the use of geophysical log measurement to measure rock and fluid properties of any formation in the petroleum industry (Rider, 2002). It is the continuous recording of geophysical parameters like gamma ray, resistivity and acoustic properties along a bore hole. This measurement is a function of depth and the properties measured shows lateral variation, for example the gamma ray log measures the natural radioactivity of the sand the value of measurements are plotted against depth (fig. 3.2).

Figure 3.2: Log measurements (after Rider, 2002)
Well logging starts from the lowering of the tool into the bore hole and the sensors are stimulated to send signal into the formation, recorders are attached to the tool to peak up any reflected signal. These instruments are suspended from steel cables (wire line) or embedded in the drilling strings (logging while drilling LWD). The well logging instruments was first developed in 1927 by the brothers Conrad and Marcel Schlumberger. They developed resistivity tool to detect differences in the porosity of sandstones for an oil field at Meerkwiller Pechelbronn in Eastern France (Schlumberger, 1989).

When drilling samples are collected these samples are called drill cuttings. From these samples geological information of the formation are generated this method of information gathering is known as measurement while drilling (MWD). The first information to build is always the lithology. Geological sampling gives quicker and cheaper information about the subsurface than the more sophisticated recording obtained from the mechanical coring which is slow and expensive. These logs needs interpretation and the data are quality checked, environmental corrections are made and noise filtering is done on them. The deflection on the logs represents the variation in gross lithology, mineralogy, fluid content and porosity of the subsurface environment (fig. 3.3).

![Wire line logging set up](Jahn et al, 2008)
The recorded information also known as logs are collated and filtered the very necessary measurements are eventually picked and used for formation evaluation. The responses of rock differ from one another and these are represented in the deflection seen on the log display, correlations are made with the lithology based on a unit or successions of unit represented on the log graph. These correlations permit recognition of pinch-outs and facies changes that may be potential traps of oil and gas, the curve also represent a variety of rock properties such as porosity and fluid content.

There are basically two types of well logging measurements;

- Logging while drilling (LWD)- done during drilling

- Logging after drilling - these are made after drilling the tool is inserted into the borehole and measurement made starting from below to the top (fig. 3.4).

Figure 3.4: Bore-hole measurement tool
3.2.1 Gamma Ray

Gamma ray log is the measurement of formation radioactivity there are two types of gamma ray measurements which are simple gamma ray log (fig 3.6) and the spectral gamma ray log (fig 3.6). The simple gamma ray log measures the radioactivity of elements such as uranium, thorium and potassium together, while the spectral gamma ray log measures the amount of each individual elements contributing to the radioactivity. Radioactivity is as a result of heavier elements found in nature with unstable nuclides that tend to easily breakdown to form a more stable ones (equation 3.2). For example Uranium has a radioactive decay of;

\[
\frac{238}{92}U \rightarrow \frac{4}{2}He + \frac{234}{90}Th \tag{3.2}
\]

Uranium disintegrates into Helium and Thorium. The gamma ray log shows the degree of radioactivity in the formation. Radioactive decay is exponential and mathematically can be resolved by solving the differential equation that represents the physical processes. Equation 3.3 is the radioactive decay equation and equation 3.4 is the solution;

\[
\frac{dy}{dt} = Ny \tag{3.3}
\]

\[
y(t) = ce^{Nt} \tag{3.4}
\]

y is the original amount that decays with time (t), N is the physical constant representing a value and these values are determined experimentally, known for different substances, graphically the amount of substance can be seen to decrease with time, many of these substances are very much present in shales, feldspars, mica and in sandstone formation and reservoirs.
Gamma ray logging is used for lithology analysis, correlating formation, estimation of clay content, mineral identification and facies analysis. Gamma ray log with deflection less than forty-five (<45) indicates clean sands and greater than seventy-five (> 75) shows high gamma reading or shaly zones. The deflection represents the amount of shale and radioactive elements as a function of depth but gamma ray measurements do not only measure shale content but all other radioactive substance.

### 3.2.2 Spectral Gamma Ray Log

Spectral gamma ray log records specific radioactive elements in any emission based on their difference in energy level. The spectral gamma ray tool detects the energy level of any emission and records them in separate windows. This special case gamma ray reading is most relevant when closer and detailed information needs to be spotted out like the quantitative volume of each radioactive mineral.

From this method of radioactive analysis information generated are the calculated mineral volume, dominant clay mineral, fracture detection and marine source rock identification. Both the gamma ray and spectral gamma ray tool consist of the scintillation counter and a photo multiplier which are the ray detectors (fig. 3.5; 3.6).

The scintillation counter is a sodium iodide crystal and flashes when gamma ray passes through it, for natural gamma ray this tool counts the spectral after being stored. For spectral gamma ray the sodium iodide crystal volume is bigger and has an additional functionality that peaks the intensity of the energy distribution with a window that separates the minimum and maximum peaks for the frequency.
Figure 3.5: Scintillation counter Gamma ray tool (after Rider, 2002)
Figure 3.6: Natural and spectral gamma ray logs (after Rider, 2002)
3.2.3 Spontaneous Potential (SP)

The spontaneous potential log measurements shows the potential difference between two electrodes one in the borehole and the other on a reference electrode at the surface. There are no artificial current added to the circuit, it is the difference in electrical charges of the drilling mud and the contacting formation that causes charged particles to flow from high to low potential area and it is this magnitude of flowing charged particles that is recorded by the log (Fig. 3.7 & 3.8).

![S.P. circuit and S.P. log illustration](image)

Figure 3.7: Illustration of the principle of SP log measurements. Through the beds, permeable beds can be seen by deflection to the negative potential of the SP (Rider, 2002)
Spontaneous potential log is useful in identifying formation water resistivity, permeable beds and occasionally can be used to calculate the volume of shale and do facies analysis. There are three main sources of electric current (the flowing of charged particles); the first two are electrochemical while the last one is electrokinetic in nature;

- Membrane potential- has the largest effect on the SP log and this is caused by the difference in proportion of the charged formation water particles like sodium chloride (NaCl) and the mud filtrate. The sodium chloride undergoes ionisation, splitting into sodium ion (Na⁺) and chloride ion (Cl⁻); shales are more permeable to sodium ion than chloride ion hence there is flow of sodium ions (positively charged particles) through the shale bed. Membrane potential is on the interface between the invaded zone and the virgin zone; on both sides the proportion of charged particle are not the same that will cause a potential difference as a result mobile ionic interchange that will occur at the junction of the invaded and virgin zones.

- Liquid- The junction potential is same as membrane potential although it is more of a term to describe the current and potential created at the invaded and virgin zones.

- Streaming potential- This occurs and become important when there is slight pressure across the formation, caused as a result of flow which is the movement of mud filtrate through the mud cake the effect is small as long as the pressure across the formation is not above normal.

The measured potential difference produced by the log is cumulative and accentuates the amplitude of the sp curve (fig 3.7).SP currents are measured in millivolts (1 * 10⁻³ volts) and the scale is in positive or negative millivolts depending on the curve deflection; deflection to the left is negative while positive deflection is to the right.
Figure 3.8: Example of gamma ray deflections and interpretation

(Reproduced from Hugh, 2005)
3.2.4 Resistivity

This is the measurement of the difficulty an electric current has in passing through formations. Rocks are insulators and they do not conduct electrical current but the conductive substances are the fluid contained in the pore spaces. Ohm derived an equation to describe the behaviour of the electrical current flowing through a material equation 3.5.

\[ r = \frac{E}{i} \]  

Where \( r \) means resistance measured in Ohm’s, \( E \) is the electromotive force measured in volts and \( i \) is current measured in amperes. Resistivity represents a measure of the resistance for a given volume of material equation 3.6.

\[ R = r \frac{A}{L} \]  

\( R \) is the resistivity measured in Ohm-m, \( A \) the cross sectional area in m\(^2\), length of the material \( L \), in meters. Resistivity is the function of the volume measured and the configuration of the measuring instrument; resistivity indicates the presence of fluid like water. Formation with high content of water has a low resistivity because water is highly conductive while hydrocarbons are normally insulators having high resistivity value or reading. Resistivity logs can be grouped into three, laterlog, induction logs, and micro-resistivity measurement.
3.2.5 Neutron Log

The neutron logs are used for the identification of porous formations as long as they contain fluid (water and or hydrocarbon) and for the correlation of porosity in rocks. Neutron logs measures the density of hydrogen content of fluid occupying the pore spaces of rocks and as such is an indirect indication of the rock porosity (Tiab, D and Donaldson, E.C., 2012). The neutron log tends to yield too low porosity value when gas is present and so can be used to determine gas zone or gas-liquid contact. There are three types of neutron logging instruments;

- Convectional neutron-gamma
- Side wall epithermal neutron
- Compensated neutron

The principle involve in using this tool is on the ability of the nuclei of the encountered fluid within the pore space to slow down the neutrons from the tool (fig. 3.9). The neutron density which is been slowed in the vicinity of the detector is determined basically by the composite hydrogen index of the medium between the source and the detector. Neutron log dose not detect pore spaces but the density hydrogen ion concentration of the contained fluid within the pores of the rock in any instance.

It is possible to distinguish between water, gas and oil because the density of hydrogen ion concentration in each fluid varies and the neutron log records this variation. Information can be extracted from the log on the porosity and the type of fluid contained in the pore space. Neutron logs can be used with better precision when combined with density and acoustic log to determine porosity and to identify mixed lithology, and clay content. The logs are measured in terms of standardize arithmetic scale of limestone porosity units.
Figure 3.9: Compensated neutron tool showing the source and the detector held pressed against the Borehole wall (After Rider, 2002)
3.2.6 Density Log

Density log is the continuous measurement of the formation bulk densities. The bulk density is the sum of the rock matrix and the pore fluid. This form of logging is based on emission of high energy gamma ray that is generated from a chemical source containing mainly Cs$^{137}$ which interact with the electrons from the formation. A section of the wellbore, mostly the formation adjacent to the well bore is irradiated with photons which is a stream of gamma ray, this ray will transverse matter and some will either be absorbed, pass through or scattered. The formations ability to attenuate this bombarding gamma ray is recorded and measured. The recorded quantity is the intensity of scattered gamma ray at two fixed distances from the gamma ray source.

The record is made by two detectors that count the number of returning gamma ray and this represent the formation electron density, the formation electron density is related to the bulk density through the equation 3.7.

$$\rho_b = \varphi \times \rho_f + (1 - \varphi)\rho_{ma}$$  \hspace{1cm} 3.7

Where;
- $\rho_b$ = formation bulk density
- $\rho_f$ = average density of the pore fluid
- $\rho_{ma}$ = matrix density
- $\varphi$ = porosity

The recent spectral tool distinguishes recorded measurement into lower energy level and higher energy level. High energy level is recorded by Compton scattering which is the measure of the bulk density and the lower energy rays is due to photoelectric effect. Compton scattering effect can be seen from Fig. 3.10.
Figure 3.10: Compensated density log tool showing Compton scattering of Gamma rays and compensated density sonde the principles in Measuring the bulk density of the rock (reproduced from Hugh, 2005)
3.2.7 Caliper

The caliper log is a measurement of the well bore diameter. It is made up of four springs-actuated arms when they are opened makes contact with the sides of the bore hole pulling on the wall of the bore hole (fig. 3.11). The simple mechanical caliper measures only the vertical profile of the whole diameter and a more improved version of the tool measures the bore-hole shape and orientation.

Figure 3.11: Example of the four arm caliper tool measuring

The borehole diameter (Schlumberger, 1989)
The caliper tool contains extended arms that are hinged to a chamber, this is connected to a rheostat as the tool moves through the bore hole the variation in bore hole-diameter affects the pressure of the arm which is recorded by the rheostat as potential change. This change is measured and plotted as the caliper log. The calliper logs often can give a qualitative indication of porous zones and provide data for quantitative porosity determination from other logs, the basic uses of calliper logs are:

- To calculate the amount of cement necessary to fill up the annular space between the casing and the well.
- To select Parker seats
- To determine the accuracy of the bore hole diameter

The Caliper logs measures the bore-hole diameter in inches and can be combined with other log measurement to interpret various electrical and radioactivity logs. Both the simple tool and the more advance caliper tool measurements are group into two which are:

- Simple two arm calliper reading- records mechanical response to the formation on drilling, hole size diameter same as the drilling bit diameter.
- Four arm calliper tool- definition of azimuth and bore-hole geometry.
3.3 Computational Software

Petrophysical studies are meant to give understanding on the geological interpretation from well logs. The method of getting information for petrophysical evaluation is the analysis of well logs, core samples and production data. Well logging has always been the easiest and less expensive method of information gathering for the formation.

Physical properties for rock and fluid are evaluated from well log measurements and information such as lithology, pore volume and depositional environment are interpreted. This information is used in production and reservoir monitoring. Logging information is necessary almost in all units of the industry, exploration, drilling, production and reservoir engineering, and the parameters derived are also needed by geologist, geophysicist, and engineers.

The log measurements are saved in a format that can only be processed by special purpose software. For this research interactive petrophysics was used to analyse and evaluate these log data, interactive petrophysics (IP) is mainly used for petrophysical computations. This software is window based and is user friendly, fast and computationally robust to do a lot of petrophysical evaluation. Interactive petrophysics could analyze and give results for single and multi-well analysis. Basic and advanced tool makes it possible to apply rock physics and mechanics modules to the data.

Data set can be loaded into IP in different format (LAS/LBS, DLIS, ASCII), pictures, capillary pressure data, text curves and data from excel spread sheet can be incorporated with IP. The software database can also be linked to petrel, petrolog DB, petcom DB making sharing of information and processing easy and effective, all computations and statistical analysis for this research were done with interactive petrophysics.
Chapter Four
Bredasdorp Basin

4.1 Introduction

Bredasdorp basin is among the four sub-basins in Southern Outeniqua basin of South Africa. Outeniqua basin was developed due to the breakup of Gondwana land and super-imposed on the older Cape Fold Belt trending North-West to South-East direction. In addition to Bredasdorp sub-basin there are Pletmos, Gamtoos, and Algoa sub-basins in Outeniqua basin. Bredasdorp basin has an area of 18 000 km² and the basin is highly fractured and faulted with structural and stratigraphic traps (fig. 1.1).

In South Africa Bredasdorp sub-basin is the most viable basin and the most explored basin for hydrocarbon. Through these exploratory activities a lot of information on the viability of Outeniqua basin has been generated. The depositional environment of Bredasdorp sub-basin is dysoxic marine with fairly to good quality wet gas and oil reservoirs. The petroleum field was completed in 2001 by South Africa’s oil giant company PetroSA although the production from block 9 in the sub-basin started in the mid eighties. As a result of the sudden drop in the production capacity from the E-M gas field more light needed to be shed on the reasons why production wells will encounter a decrease in their production pressure. This challenge is well conversant within the oil industry and affects further development of fields from that basin this can also hinder the trust by investors on their investment who are expecting a return of their investment.
4.2 Sequence Stratigraphy

The depositional system of Bredasdorp basin was formed due to the changes in global sea level. These changes controlled the construction of the whole stratigraphic structure. There are about 22 seismically resolved post rift cretaceous unconformity and associated depositional structure between the drift onset and the synrift I depositional history which is between 145Ma and 23Ma ago (fig. 4.1).

The sequence succession is denoted as a number and a letter while surfaces are estimated to be of type one (1) written as t1. These surfaces represent the unconformities in the deposition of sediments. Six of the first order surfaces show evidences of high tectonic and erosional activities. There are also second orders and third order surfaces in the Bredasdorp basin and most of them are poorly developed as you will have in the first order surfaces.

The depositions of the post-basement and pre-rift are fluviatile, lacustrine and estuarine environments with red and green sandstones and shales. From the well data and report (PASA, Pers.comm, October 2012) on Bredasdorp basin the rocks were classified into three main units which are;

- Sundays River Beds (marine to estuarine grey shales and clastics)
- Marls and Wood Beds (estuarine to lacustrine clastics and shales)
- Enon conglomerates (fluviatile coarse red beds).
The source of hydrocarbon content in the Bredasdorp basin has its origin from the Southern Outeniqua basin where the early to lower Cretaceous Sundays River Beds overlays the other two rock types as described. The Sundays River Beds are separated into two sections by a major unconformity at horizon C. The depositions of lacustrine sediments at the lowest areas suggest ponding and subsequent formation of a source rock.

The Sundays Rivers Formation of the Bredasdorp basin contains rich organic content than the other two formations of the basin. The cretaceous sediments overlays the cape sequence and is covered by tertiary strata, Sundays Rivers Formation is partly upper Valanginian deposit of marine ostracodes dated by analysing the foraminifera and ammonite fragments as Barremian (Dingle, 1993). The oldest faults are the rifts faults on the onset of transform motion of AFFZ onset of rift II, 1At1.

Bredasdorp basin’s half graben structure is formed by a result of tensional forces this tensional force creates a vertical movement of the earth crust and as a result normal fault are formed. Normal faults have a listic geometry and detach onto decollement, the fault system in the basin are so much different this implies that they occur at different geologic time at different stress field.

There are two faults system for the Bredasdorp basin the older fault system and the younger fault system. The youngest fault system displaced the base Tertiary unconformity and they are formed from compactional origin rather than crustal extension, while the older faults onset of unconformity 1At1 where formed as a result of tensional forces followed by the post rift sequence fault activities which displaced the 1At1 fault system (fig. 4.1).
Figure 4.1: Sequence chronostratigraphic framework
(Thomas et al, 2006)
The depositional environment controls the systematic variation and the stratal stacking. Depositional process intrinsic to the environment form lithofacies packages and stratal surfaces that are the basic building blocks of the geologic record. At the sequence scale in the reconstructed shelf margin settings, the track forms a series of relatively conformable marine bounded surfaces also known as parasequence which is shown in fig. 4.2.

Figure 4.2: Modelled sequence type 1 with shelf slope break

Developed on a margin (reproduced from Hugh, 2005)
4.3 Sequence Boundary

Sequence boundary is a technique used in understanding the depositional history and period of no deposition. In Bredasdorp basin the sequence boundary is seen as the unconformable surfaces and the correlative conformity. These changes at the surface can be linked to the fluctuations in sea level, for example the post rift Cretaceous stratigraphic sequence of the Bredasdorp basin show a lot of unconformities and periods of no deposition.

Depositional sequence is the recording of a cycle of relative sea level, above and below that unit and is bounded by unconformities distinguishing that unit from the rest. The boundaries of these sequences are diachronous, capping the previous high-stand systems tract. Erosional activities are the major reason for the boundary sub-aerial sediments to be exposed to the surface from the earlier sequence, in fig 4.2 the boundaries of these sequences are marked by a thick black line showing major deposition below and above the unit.

The stratigraphic boundaries and surfaces of the Bredasdorp basin are poorly developed. In fig 4.1 the Aptian and Albian unconformities comprises of enhanced tectonic eroded surfaces which coincides with the second order and third order surfaces, the basin’s depositions trend are North-West to South-East a rather elongated form of depositions, this makes the boundary rather difficult to distinguish.
4.4 Low Stand System Tract

When depositional system experiences a low tide, the depositions still occur but not as rapid as when the tide is high. The deposition formed at such time is the low stand system tract. Low stand system tract is formed after the sequences boundary has been formed and is less when the sediments production is high that is during transgressive periods of the sea.

During these sea level changes sediment reductions are high on the rimmed shelves due to cut down in water level necessary for sediments production. The Low stand system tracts (LST) are made up of two distinct parts which are;

- Low stand fan
- Low stand wedge

The low stand fan formation is when the relative sea level has fallen drastically and clear shelf slope break exist if these conditions are not in place then only a low stand wedge will be formed. At the time of the relatively lowest sea level the river incises into the exposed shelf and the sediments gets redirected into the shelf edge to feed the submarine fan. The basin floor sub-marine fan is one of the components of the low stand fan and displays an aggradational stacking which is overlaid by low stand wedge.

The sequence boundaries are generated when there is rise in sea level and as a result of this sea level changes there are build-up of progradational stacking of sediments in the basin. In addition to sediment production there is slow rate of accommodation due to regression from the continental slope. At the continental slope para-sequences are built up, para-sequences are formed from the low stand wedge as a result of sea level changes.
4.5 Transgressive Surfaces and System Tract

Transgressive surfaces are marine flooding surfaces and they are the first significant flooding surface in a sequence. The successions are mostly siliciclastic and some carbonate followed by periods of high rate availability in accommodation space that is much larger than the rate of sediments supply. This periods mark the foundation of the retrogradational parasequence stacking patterns of the transgressive system tract.

The flooding surfaces are composed of high facies with strong degree of sediment starvation that makes it thinner than the system tract. This is due to the imbalance in rapid sea rise and accommodation space sediments that are more infilling onshore than offshore making offshore deposition thinner.

4.6 Maximum Flooding Surface

The maximum flooding surfaces are surfaces of deposition at the time of maximum transgression (Allen et al, 1999). This is at a time of maximum flooding into the shelf and it shows a separation of the transgression and high stand system tracts.

As a result of the transgression the basin is highly rich in organic shales and radioactive elements the surface is also associated with marine shelf and basinal sediments. The surface indicates the point of clear demarcation between the coarsening and fining upwards cycles these fine sediments makes up the condensed section.
4.7 High Stand System Tract

The high stand system tract para-sequences are made up of aggradational and progradational signatures and this unit is placed on top of the maximum flooding surfaces which is just at the top of the next sequence boundary. The period is characterised by slow sea activities-rise and fall, as a result the sediments fill up the shore line’s differently. At seaward progradation sediments are deposited at the inner part of the outer shelf because the sea is under the high rate of sediment production. As a result these activities there are gradual formations of new sequence boundary and the eroding of the underlying high stand system tract.

4.8 Tectonics of the Basin

The five continental plates as a result of Gondwanaland breaking up (fig. 4.3) are associated with the opening of the South Atlantic. The Agulhas-Falkland zone was transform as a result of transtension; this generated lateral movement separating the South American plate and African plate. At the offshore section tecto-stratigraphic plates were formed see fig. 4.3 and 4.4.
Figure 4.3: Gondwanaland break-up (reproduced from Hugh, 2005)
Figure 4.4: Pre-break up tectonics of rift basins within Southwest Gondwana (After Jungsler, 1999)
At early cretaceous the broad margins of the western part of Southern African plate was associated with the opening of the South Atlantic, break up of Africa, Madagascar and Antarctica this activity also generated sub-basins at the South East offshore of the Southern Africa plate. The tectonic of Southern Africa plate was largely influenced by extensional forces and normal faulting as such half graben structures were formed. This graben structures shows evidences of variable thicknesses of drifted sediment which was largely seen in South Central Bredasdorp basin (fig 4.4). The South central Bredasdorp basin contained sandstone, low stand tracts of intermediate cretaceous that are overlying type 1 unconformity of Albian age. They are connected to erosional submarine channels of the lower continental slope; their gradient steepening can be linked to fracture zone and less significant tectonic activities of the Agulhas.

By observing the post rift sequence the lowest part showed evidences of displacement where the oldest rift fault sustains its position despite the drift at the beginning of the unconformity and the displacement was a result of the youngest rift fault on the lowest part of the basin. Unconformity was displaced by youngest faults at the Tertiary base and the distinctive series of repetitive cycle of the depositional sequence was reduced by these activities; diminishing rift tectonics, thermal cooling and inferred eustatic variation in global sea level.

The structural nature of Outeniqua basin is faults and graben structures (fig. 2.15); as a result of the basin’s structure it creates opportunity for the formation of hydrocarbon reservoirs. The valleys and canyons are indented on the mounded and sheet like submarine and basin floor fans. The submarine channels are filled with associated mounds and fans, the deltaic low stand wedges extends the basin, the channel fills and fan’s wedges are sealed at the top. The build up of source rock for hydrocarbon is as a result of the transgressive shale and marine condensed sections that were deposited at the time of regional transgression of shale at the shoreline.
The sea level rise was followed by channelized slope fans, deltaic and coastal low stand wedge progradation. The deltaic and coastal system progradation exhibits a well defined clinoforms but the shorelines show much erosion due to the incised valleys and subsurface canyons below the mean sea level. This poor defined transgressive system tract in the basin is as a result of flooding of the shelf with sediments, it is these build up of organic rich sediments at the low stand tracts that generated the hydrocarbon system occurring in the mounded (pile of rocks) basin floor turbidite fans. These fans are channelled fill with draped sheets found around the upper dip pinch out of deltaic and costal sandstones.

4.9 Depositional and Petroleum System

4.9.1 Depositional Environment

The Bredasdorp half graben basin developed from fan deltas, river dominated to wave dominated deltas and mostly associated with coastal system (fig. 4.5). This basin and slope system develops with fine grained mass (density) and deposits of suspended leveed slope and basin floor turbidite fans. The changes in deposition are due to the responses to the second order tectonic episode which is the reason for variation in sediments, supply rates, accommodation rate and increasing open ocean processes.

In central Bredasdorp basin it is the high gradient fluvial systems that supplies sediments into the basin during the super cycle 1-5 ≈ 126 – 118 Ma. At the super cycle of 6-12 ≈ 118 -112Ma the basin was dominated with deltaic coastal system and the deposition followed an uplift and erosion of the second order unconformity; Petroleum agency of South Africa’s brochure (2005). Miniature canyons provided pathways for fluvial sediments to be introduced to the low stand shorelines eroding into the shelf edge. Upper Barremian 9A LST basin floors comprised of several individual submarine fans.
Figure 4.5: Evolution of deep marine channel deposit (reproduced from Hugh, 2005)
4.9.2 Petroleum Systems

Source Rock Maturity

Source rock for petroleum generation can be fined-grained sediments which naturally is matured enough to produce and release mobile hydrocarbon to form commercial accumulation of oil and gas. Geologic elements necessary for accumulation of oil and gas in sufficient quantity viable for economic exploitation (fig. 4.6) are;

- Rock rich in organic content (TOC)
- Reservoir rock of good porosity and good permeability to accumulate hydrocarbon
- Trap and seal system to prevent escape of the hydrocarbon

The organic material content of the source rock is also known as kerogen, and maturity of the kerogen is important in determining the quality of the hydrocarbon. Good source rock depends also on the time-temperature relationship and ease with which the kerogen degrades. The sandstones of Bredasdorp Basin that forms the reservoirs are present in both the synrift and drift sections. The shallow marine to fluvial drifted sandstone contain deep marine turbidite deposits. The Structural and truncated system formed the trapping mechanism, and the drifted marine shales provided the main seals.

The synrift section contains second type of sealing structure of tilted fault block. The onshore of Algoa sub-basin towards the east of Outeniqua basin has oil prone Cretaceous source rock of Kimmeridgian to Berriasian strata. The source rock quality is moderate to good at horizon 11 and E where there are deposits of hemipelagic shales these shales provide a good source of hydrocarbon. The studied area in this thesis Bredasdorp basin has its source rock interval of Barremian origin and the producing block is locally named as block 9A.
The formation of hydrocarbon was as a result of the anoxic condition of the basin at temperature for the basin ranging from one hundred and ten degrees Celsius to one hundred and eighty five degree Celsius (110 °C – 185 °C). The hydrocarbon content of the basin is between wet gas and late crude oil with kerogen types of two and three.

Figure 4.6: Petroleum source rock, migration pathway and subsurface fluid mechanics
Paleontological Research Institution (www.priweb.org)
Chapter Five
Petrophysics and Log Analysis

5.1 Introduction

This chapter evaluates the rock and fluid properties for each well using the various well log data available. The petrophysical properties evaluated are; volume of clay, porosity and saturation for each well interval while for the input data; gamma ray log, bulk density log, neutron porosity log and spontaneous potential logs were used in the lithology analysis and interval interpretation of the rock physical properties. Further studies on the rock properties were carried out by applying the concept of rock physics. Evaluation on the Pore pressure for each well were done to understand pressure anomaly and build inferences on flow capacity from each well interval. Rock physics analysis involved the generation of shear sonic and compressional logs, elastic impedance log, the estimation of density and applying of fluid substitution while the pore pressure calculation involved the evaluation of overburden gradient and the pore and fracture pressure gradient.

In this research the intervals of interest do not have cores so it was an attempt to also show that cheap and useful information can be generated from just well log data. For a research of this nature in other to draw conclusion a lot of computational and analytical methods have been used such as geo-statics, this is to enable better explanation of the variability of geological bodies. The description and analyses of data variability for each interval’s explanation using statistical methods involved the arrangement of log data into frequency distribution, plotting of data into histogram and cumulative curves. Bore-hole analyses of logs further showed the well and hole-diameter qualities. This gave an indication of which hole interval is damaged, the bed permeability quality and the nature of formation resistivity.
5.2 Bore-Hole Analysis

Bore-hole analysis involved bed description based on caliper log display; caliper log gives well log measurement that provides information about well bore quality. Caliper log provides information on bore-hole size, shape and quality. Krygowski (2003) identifies four uses of caliper log and these are:

- Independent caliper supplies detailed information about borehole condition.
- Calipers that are attached to other type of tool supplies hole-size information and can be used for corrections for other measurements.
- Log quality control.
- Qualitative indication of permeability.

The caliper tool takes measurement of the bore-hole by mechanically recording of variation as the arm on the caliper tools moves along the drilled well (fig. 3.11) and converting this mechanical movement of the arm into diameter measurement through an electrical circuitry. To interpret the caliper log, the log is displayed alongside with gamma ray log, resistivity, neutron, bulk density logs (fig. 5.1a). For wells E-M1, 2, 3, 4, and 5 the interpretation of the bed has been shown using caliper log. The caliper tool measurement of a bore-hole diameter is dependent on the changing resistance through the formation and this varies from well to well. For example the caliper log display for E-M4 has no diameter variation. A number of reasons may be responsible for this but E-M4 does not follow the trend observed in other wells; E-M1, E-M2, E-M3 and E-M5 (track 5, fig. 5.1a, 5.1b and 5.1e) were the caliper logs for this well interval shows a remarkable variation in hole-diameter as indicated by the arrow on the figures.
**Figure 5.1a: Suite of well log from Bredasdorp basin**

<table>
<thead>
<tr>
<th>DEPTH (M)</th>
<th>F_GRN (api)</th>
<th>F_LLDC (ohmm)</th>
<th>F_MSFLC (ohmm)</th>
<th>F_CALI</th>
<th>F_NPHIC (dec)</th>
<th>F_RHO8C (g/cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.</td>
<td>150.</td>
<td>2000.</td>
<td>2000.</td>
<td>16.</td>
<td>0.45</td>
<td>2.95</td>
</tr>
<tr>
<td>1.95</td>
<td>-0.15</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Scale: 1 : 600**

**E-M1**

**DEPTH (2602M - 2652M)**

09/11/2013 12:57
Figure 5.1b Suite of well log from Bredasdorp
<table>
<thead>
<tr>
<th>DEPTH (M)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.</td>
<td>GR (GAPI)</td>
<td>150.</td>
<td>LLD (OHMM)</td>
<td>200.</td>
<td>CALI</td>
</tr>
<tr>
<td>0.2</td>
<td>MSFL (OHMM)</td>
<td>200.</td>
<td></td>
<td></td>
<td>6.16</td>
</tr>
<tr>
<td>1.95</td>
<td>NPHI (v/v)</td>
<td>-0.15</td>
<td>RHOB (G/C3)</td>
<td>2.95</td>
<td></td>
</tr>
</tbody>
</table>

| 2600       | Sandstone | Clay |
| 2650       |           |      |

Figure. 5.1c Suite of well log from Bredasdorp
### Scale: 1:500

#### E-M4

**DEPTH (2711.96M - 2761.95M)**

<table>
<thead>
<tr>
<th>Depth (M)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0</td>
<td>0.2</td>
<td>GR (GAPI)</td>
<td>150.</td>
<td>0.2</td>
<td>2000.</td>
</tr>
<tr>
<td>0.0</td>
<td>SFLUC (OHMM)</td>
<td>2000.</td>
<td>CALI 6.16</td>
<td>0.45</td>
<td>NPHI (v/v)</td>
</tr>
<tr>
<td>1.95</td>
<td>RHOB (G/C3)</td>
<td>2.95</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Figure. 5.1d Suite of well log from Bredasdorp**
Figure. 5.1e Suite of well log from Bredasdorp
E-M5 showed more changes in bore hole-diameter than the rest of the wells. The bore-hole changes in diameter may be attributed to various reason, faulty equipment, rock mechanical properties, and the type of clay present (fig. 5.1e).

5.3 Volume of Shale

The volume of shale ($V_{sh}$) is the volume of wetted shale per unit volume of reservoir rock. It is the volume of water that is chemically bound to mineral grains in shale clay mineral (Norman, 1991).

\[
V_{sh} = \frac{\text{volume of wetted shale}}{\text{volume of reservoir rock}}
\]

Shale is very common in clastic sedimentary rocks, and it is composed of clay size particles with some or no silt (Norman, 1991). The dominant mineral in shale is clay minerals. Shales are identified by their grain size and they form the major part of sealing structures and source rocks. Helsop model is used to show the relationship between gamma ray and grain sizes (fig. 5.2).

![Gamma Ray Increases](https://example.com/gamma-ray-increases.png)

**Figure 5.2:** Variation of shale content (Heslop 1972)
5.4 Shale Base Line

The shale base line is the vertical line on a gamma ray log, or on a spontaneous potential (SP) curve that marks the maximum deflection to the left in track one on a well log (Norman, 1991). Shale base line is important because it shows the median mark for the transitions from sand to shale. In practice shale base line is extracted from the gamma ray log and has a value of sixty API, for this thesis the shale base line value was generated as the mean value from the histogram plot for the five wells.

The multiwell histogram shows the total depth and the minimum and maximum values from which the mean was calculated. The mean values from the wells were chosen as the working baseline value which was 77.0036API (fig. 5.3). The applications of baseline to the wells are shown from fig. 5.4a – 5.4e with better distinction of the sandstone / shale zones. Base-line understanding is important because it gives quicker information on porosity and pore size distribution, and the nature of the porosity. Shale base line does not show a quantitative result but it could help in decision making on where the possible reservoir sandstone quality is best. For this research the calculation of shale base line was done using equation 5.2;

\[ B_{LC} = \frac{\sum \text{mean values for each well}}{\text{total number of wells} \ (T_{wl})} \]  

Where:

\( B_{LC} \) = Base line calculated (API)

\( T_{wl} \) = total number of wells (5 wells used in this thesis)
Figure 5.3: Histogram for Gamma ray data
5.5 Application of Baseline Showing Reservoir and Sealing Units for Each Well (E-M1- E-M5)

Application of baseline for E-M1 interval gives better sandstone to shale distinction and clarity of the reservoir seal. Reservoir seal is an impermeable rock that forms the impermeable barrier on top and below the reservoir section fig. 5.4a.
The value used for shale base line gave better picture of the sand to shale transition. E-M 2 has a pore sealing structures but good reservoir interval (fig. 5.4). This could affect the retention of fluid for this reservoir interval.
The quality and clarity of the sandstone to shale transition is based on the technique used in generating the value for shale base line. The reservoir for this interval has poor sealing structures the reservoir interval has poor gross thickness with high intercalations of shale units (Fig. 5.4c).
Application of baseline to E-M4 reservoir interval gave better sandstone to shale distinction and better clarity of the reservoir seals. Reservoir sealing quality is poor fig 5.4d and the reservoir interval shows high indications of the presence of clay minerals.
Fig. 5.4e is similar to Fig. 5.4d the reservoir interval shows high presences of clay minerals. The reservoir sealing quality is good and the clarity of the information about this section (Fig. 5.4e) was made easier due to the method used in the selection of the shale baseline value for the wells.
5.6 Interpretation for Volume of Clay

In this thesis the gamma ray log was used to calculate the volume of clay for the well intervals. The gamma ray log represents the magnitude in radiation of radioactive elements from any formation. The amount of radiation for clay is dependent on the amount of radioactive elements saturated within the interval under investigation. These elements basically are; Potassium, Uranium and Thorium. The relationship between the measure of gamma ray emission and the clay content is either linear or non-linear.

Linear method: Gamma ray index ($I_{GR}$):

\[
I_{GR} = \frac{GR_{\text{clean}}}{GR_{\text{clay}} - GR_{\text{clean}}}
\]

$I_{GR} = \text{Describes a linear response to clay content}$

$GR_{\log} = \log \ \text{reading at the depth of interest}$

$GR_{\text{clean}} = \text{Gamma Ray value in a nearby clean zone}$

$GR_{\text{clay}} = \text{Gamma Ray value on the shaly section}$

Linear Gamma Ray clay volume relationship:

\[
V_{cl} = I_{GR}
\]
Non linear methods of estimating Gamma Ray and clay volume relationship;

Steiber:

\[ V_{cl} = \frac{I_{GR}}{3.0 - 2.0 * I_{GR}} \]  

Clavier:

\[ V_{cl} = 1.7 * [3.38 * (I_{GR} + 0.7)^2]^{0.5} \]  

Larionov (Tertiary rocks)

\[ V_{cl} = 0.083 * (2^{3.7*I_{GR}} - 1) \]  

Larionov (older rocks)

\[ V_{cl} = 0.33 * (2^{2*I_{GR}}) - 1.0 \]  

In Fig. 5.6 the cross plot between depth and volume of clay gave the general distribution of clay for each well interval. The knowledge of clay volume distribution is necessary because it hinders an effective and successful drilling programme. The most challenging problem in exploring traps is the presence of heaving shale where clay mineral forms the major facies. Heaving shales are extremely crowded volume of shale that is under high pressure and tends to squeeze the sides of the bore-hole together. This heaving shale is as a result of water adsorption and base-exchange phenomena in the clay minerals.
Table 5.1 is the minimum and maximum value used in the calculation of the volume of clay for this interval. The values are generated by plotting the histogram for gamma ray log like the one in Fig. 5.7. The maximum value represents the GRclay maximum where the magnitude of natural radiation is at its highest (in table 5.1=112.95).
Table 5.2 show minimum and maximum value used for calculating the volume of clay for this interval. The values are generated by plotting the histogram for gamma ray log like the one in Fig. 5.7. The minimum value represents GRclean where the magnitude of natural radiation is at its lowest (in table 5.2=87).
Table 5.3 represents the minimum and maximum values used for calculating the volume of clay. The GR clean is the minimum value and GRclay is the maximum value these values represent where the magnitude of natural radiation is at its lowest and highest.
Table 5.4 Gr clean and Gr clay values for E-M4 well interval

<table>
<thead>
<tr>
<th>Well</th>
<th>GRclean</th>
<th>GRclay</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-M4 Interval</td>
<td>37</td>
<td>136.12</td>
</tr>
</tbody>
</table>

Table 5.4 is the minimum and maximum value used in the calculation for volume of clay within this interval. The values are generated by plotting the histogram for gamma ray log like the one in Fig. 5.7. The maximum and minimum values for gamma ray measurement give an indication of the magnitude in natural radiation for this interval.
Table 5.5e Estimation of volume of clay

Table 5.5 Gr clean and Gr clay values for E-M5 well interval

<table>
<thead>
<tr>
<th>Well</th>
<th>GRclean</th>
<th>GRclay</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-M5 Interval</td>
<td>33.093</td>
<td>139.75</td>
</tr>
</tbody>
</table>

Table 5.5 is the minimum and maximum value used in the calculation of the volume of clay for this interval. The maximum value from gamma ray log represents the GRclay maximum where the radiation measures are highest (in table 5.5=139.75).
Two reasons largely accounts for the importance of clay in reservoir studies and these are (1) the smallness of the individual crystal particles, many being less than two microns ($8 \times 10^{-5}$ inch) in diameter and some to most active being less than $8 \times 10^{-5}$ inch; (2) the chemical and physical activity of the clay minerals especially of the montmorillonite group (Levorsen, 2004).
Figure 5.7: Histogram of continuous distribution, equal class width, E-2 & E-M5 has the most in extended tail

Fig 5.7 histogram plots distribution of clay volume for each well. The points represents random variable (volume of clay) and the cumulative frequency assigns a real number \((-\infty < \text{real number} < \infty)\) to each point in the sample space \(S\). The sample space is the volume of clay from the x-axis, and random variable denoted by \(X\) is related to the cumulative distribution function in equation 5.9;

\[
F(x) = P(X \leq x) \text{ for } -\infty < \text{real number} \ (x) < \infty \tag{5.9}
\]

If \(f(x)\) is the total area =1, and \(x\) is any number, \(\Delta x\) is greater than zero, then for a total area \((x, x + \Delta x)\) which is an area under \(f(x)\) between \(x, x + \Delta x\) then;

\[
P(X \in [x,x + \Delta x] = \int_{x}^{x+\Delta x} f(y)dy \tag{5.10}
\]

That is continuous random variable \(X\) is more likely to fall in an interval above where \(f(x)\) is large. Where; \(X = \text{user define variable (volume of clay etc).}\)
5.7 Log Analyses

The measurement of rock and fluid properties are done by measuring tools and devices. This is usually carried out by a servicing company for the purpose of description and characterization of sedimentary rocks and their pore fluids. The uses of well logs are fundamental methods in formation evaluation and these measures are reflection of the physical properties of rock and the pore fluid. They are the primary sources of information on the reservoir quality and productivity. Some of the properties measured are electrical, acoustic and magnetic properties of the rock.

Well log measurements are done during drilling of wells known as wildcat or appraisal wells. These wells are drilled purely for gathering of data and they are sometimes converted to production wells. Petro-physical measurements are acquired from the logging process and these properties measured enables engineers and geologist make proper evaluation on the lithology, porosity, shale volume, saturation, and Permeabilities of the reservoir rock. These evaluation from the log are done section by section (fig. 5.8a – 5.8e), analysis are made on the displayed response of the graph for any reservoir interval. In log analyses several well log measurements are used for interpretation. Generally the type of well log to analyze is based on the kind of information that is required for any study.

In this investigation log analysis was used as a method to understanding the electrical properties and the qualitative indication of permeable zones. The set of logs employed for this analysis were;

- Gamma ray log (curve)
- Spontaneous potential log (curve)
- Volume of clay log (curve generated)
Reservoirs are shown as deflections either positive or negative from relative baseline (Fig 5.8a). In the Spontaneous potential track (track three, Fig. 5.8a) the direction of the deflection is determined by the relative salinities (resistivity) of the formation water ($R_w$) and the mud filtrate ($R_{mf}$). Track two (Fig. 5.8a) shows the interpretation of the depositional environment and relative sea level interpretation using well log. The fining upwards sequence indicates alluvial/fluvial channel also meaning transgressive shelf sand. Coarsening downwards indicates deltaic progradation or shallow marine progradation.
The highly permeable and resistive bed is as a result of the plateau on the negative side of the SP curve (toward left track two, fig. 5.8b) due to the presence of hydrocarbon. Deflection on permeable bed two is due to the presence of water. The slope’s variation with convexity of log tending to shift to the right or positive direction indicates an impervious and conductive beds or highly resistive formation between impervious beds. The volume of shale distribution depicts the presence of varying clay minerals and severalty in grain size distributions for sandstone this interval shows clear bed boundaries and distinctive changes in potentials at the wellbore.
Fig. 5.8c, track one interpretation indicates the presence of heavy mineral deposition causing a lot of spiking in the gamma ray log. The interval show less remarkable distinction of the pore fluid content. The fining downwards is an indication of high current and evidence of the depositional area with active transgression and regression activities. This interval shows a consistent deposition and very thin reservoir sands. The facies changes are minimal mostly of sand-shale interplay.
Fig. 5.8d, the track for volume of clay shows that the composition has varying grain sizes. Between depth 2729m to 2746m there are indications of heavy radioactive elements like Thorium, and the high wiggling also indicates good organic rich minerals with varying grain sizes. The SP curve shows consistent wiggling and sloping movements indicating high resistivity for this interval in line with the gamma ray log interpretation.
Fig. 5.8e, the volume of clay and gamma ray tracks indicates high depositional energies. The high wiggling of the logs shows the varying eustatic conditions and depositional energies. The spontaneous potential track has been used to show the electrical property of the well, the constant sloping indicates high resistive areas and implies that there was the same energy level in both transgressive and regressive conditions.

Where, \( V_i = \) Liquid junction potential and \( V_m = \) membrane potential.
5.8 Two-Mineral Cross Plot

The two mineral cross-plots between bulk density and neutron porosity showed the facies composition for each interval. There is no well intervals with a single rock type the three facies lines; sandstone, limestone and dolomite are used to empirically estimate the rock type compositions for each interval (Fig. 5.9). E-M1 has facies of sandstone and limestone. E-M2, E-M3 E-M4 and E-M5 well intervals have mixtures of lithology between sandstone, limestone and dolomite.
5.9 Pore and Fluid Analysis

5.9.1 Total and Effective Porosity

Total porosity is the sum of isolated and connected pores while the effective porosity takes into account only the connected pores. Porosity represents the volume of pore space available for the accommodation of fluid. The input curves used in estimating porosity from logs (original data) were:

1. Neutron log
2. Bulk density
3. Volume of clay
4. Sonic log

The porosity curve generated is a function of depth. The model adopted in evaluating porosity was the density model. This was chosen because the bulk density log invariably is the most reliable method for porosity calculation (Benedictus, 2007), the advantages of using this log are:

1. The existence of a clear and linear theoretical relationship between bulk density and porosity.
2. High resolution data are available on matrix densities.
3. The possibility to evaluate fluid density values directly from resistivity measurements.
Density model:

\[
\phi = \frac{\left(\rho_{ma} - \rho_b - V_{CL} \ast (\rho_{ma} - \rho_{cl})\right)}{\left(\rho_{ma} - \rho_{fl} \ast S_{xo} - \rho_{HyAp} \ast (1 - S_{xo})\right)}
\]

Where:

\[
\phi = \text{porosity}
\]

\[
\rho_{ma} = \text{matrix density}
\]

\[
\rho_b = \text{input bulk density}
\]

\[
V_{CL} = \text{input wet clay volume}
\]

\[
\rho_{cl} = \text{wet clay density}
\]

\[
\rho_{fl} = \text{filtrate density}
\]

\[
S_{xo} = \text{flushed zone water saturation}
\]

\[
\rho_{HyAp} = \text{appperent hydrocarbon density}
\]

Total porosity is calculated from the dry clay porosity using equation 5.12:

\[
\phi_{tclay} = \frac{\left(\rho_{dryclay} - \rho_{wetclay}\right)}{\rho_{dryclay} - \rho_{fl}}
\]
Where:

\[
\phi_{tclay} = total\ clay\ porosity \\
\rho_{dryclay} = dry\ clay\ input\ parameter \\
\rho_{wetclay} = wet\ clay\ input\ parameter \\
\rho_{fl} = filtrate\ densities
\]

Estimation of effective porosity from equation 5.13;

\[
\phi_e = \phi_t + V_{cl} \times \phi_{tclay} \tag{5.13}
\]

Where

\[
\phi_e = effective\ porosity \\
\phi_t = total\ porosity
\]

The studying of porosity for any reservoir interval provides useful information on the reservoir fluid behaviour. There are two types of porosities and understanding of porosity is built around explanation on these two which is; total porosity and the second is effective porosity. Proper description of the second porosity which represents distribution of interconnected pores is useful for an effective exploitation of oil and gas from that reservoir interval. The subsequent sub heading establishes understanding on the porosity across the interval of interest in relationship to the matrix and fluid densities (Fig. 5.10a – 5.10e).
5.9.2 Porosity and Density Logs

Figure 5.10a: Porosity and bulk density relationship

Total porosity and effective porosity logs are similar in nature Fig. 5.10a. But by the arrow indication total porosity values are larger than effective porosity values. Matrix and hydrocarbon densities for this interval are constant and not changing. Matrix density values are 2.65gm/cc (sandstone) while the hydrocarbon density is 0.8gm/cc.
Total porosity and effective porosity logs are the same with just slight difference in effective porosity log Fig. 5.10b. Hydrocarbon density’s value is 0.8gm/cc, while the matrix has the highest density of 2.75gm/cc (mixture of limestone and dolomite). “A” shows the most compatible correlation between porosity and matrix density. The analysis from this interval shows that matrix densities changes due to the presence of different rock types and rock densities.
Correlation between porosity logs and matrix density log made the application of interval analysis possible (Fig. 5.10c). Detailed rock types are predicted using this method. For this interval hydrocarbon density is 0.8gm/cc while the rock type interpretation for A3 is between 2.59gm/cc - 2.78gm/cc this values correspond with sandstone - limestone and dolomite.
Applying interval interpretation fig. 5.10d shows good correlation at section D and B. Section B has larger matrix density due to heavy mineral elements. The matrix density goes as high as 2.98gm/cc (Anhydrite); D has matrix density value 2.77gm/cc (shale). This indicates facies mixtures of sandstone - limestone and dolomite and clay.
Based on the interval interpretation Fig. 5.10e correlates at x, g, y and z. The hydrocarbon density for this interval is 0.8gm/cc, and at points x, y, z, and g the matrix densities are 2.55gm/cc, 2.52gm/cc, 2.65gm/cc, and 2.71gm/cc. This shows facies mixture of sandstone-limestone and dolomite with clay. With this method faster and quicker information on the various rock types and masses have been achieved.
5.9.3 Tri-Porosity Multiwell Evaluation Method

Figure 5.11: Theoretical analysis porosity (matrix) versus neutron

Fig. 5.11 represents multiwell fluid analysis for intervals E-M1, 2, 3, 4 and 5 wells. Total porosity is used as matrix; interpretation for total porosity depends on the effective porosity and the fluid content. Neutron porosity is used for fluid distinction; distinction between gas and water is possible because neutron log shows the degree of composite hydrogen index. Hydrogen is found in fluids (water, gas and oil). Scattered points reflect more than one matrix/fluid relationship as a result of the differences in lithology / rock types. The differences in rock densities affect the rate of travel time for the neutron particles.
5.9.4 Spatial Distribution (Ogives)

The multiwell histogram shows distribution of total porosity for the reservoir well intervals (fig. 5.12). The cumulative frequency distribution curve for the data is an s-shaped increasing monotone from zero to one meeting the x-axis at half of its total length. This represents transformation from discrete to a continuous distribution with distributive function evaluated using equation 5.14,

\[ f(x) = \frac{1}{\sigma \sqrt{2\pi}} \int_{x_1}^{x_2} \exp \left[ -\frac{1}{2} \left( \frac{x^3 - \mu}{\sigma} \right)^2 \right] dx \]

Equation 5.14

\( f(x) \) = distributive function (total porosity or effective porosity).
Spatial Distribution (Ogives)

Figure 5.13: Expression of data from interval as histogram of continuous distribution and theoretical cumulative distribution function for effective porosity columns.

Discrete random variable total porosity or effective porosity ($\phi_t$ or $\phi_e$), $p(x)$ represents actual probability for the value $x$, for any real number $x$ the probability association is;

$$P(\phi_t = x) = P(\phi_t \in [x_1, x_2]) = \Phi_t = \frac{1}{\sqrt{2\pi}} \int_{x_1}^{x_2} e^{-\frac{u^2}{2}} du$$ \hspace{1cm} 5.15

$\Phi_t$ = discrete random variable (total porosity or effective porosity)

$du = \rho_d \left(\frac{x_3 - \mu}{\sigma}\right)$

$u^2 = \left(\frac{x_3 - \mu}{\sigma}\right)^2$

$x_3$ = discrete random variable (number)

$\rho_d$ = Density of the estimated variable
5.10 Water Saturation (Pickett Plot Analysis)

The Pickett plot analysis is a graphical solution of Archie’s equation in terms of resistivity and it provides useful information on the formation characteristics. This cross plot utilizes basic rearrangement of the Archies equation.

\[
S_w^n = \frac{aR_w}{\phi^m R_t} = \frac{R_o}{R_t}
\]

Re-arranged:

\[
\log R_t = -m\log \phi + \log(aR_w) - n\log S_w
\]

If \( Sw \neq 100\% \) then

\[
\log R_t \neq -m\log \phi + \log(aR_w)
\]

Where: \( Sw = \) Water saturation

\( Rw = \) resistivity of water

\( Ro = \) resistivity of a rock (with its pore space)

\( RT = \) true resistivity of the rock

\( m = \) Cementation exponent

\( n = \) Saturation exponent

\( a = \) Constant determined empirically

The lines on the Pickett plot (fig. 5.14) represent the percentage of water saturation. The red line represent hundred percent water saturation while the points below the line with value 0.2 represent 20 percent water saturation with complementary hydrocarbon saturations.
Figure 5.14: Plot between resistivity and effective porosity

Table 5.6: Pickett plot analyses result

<table>
<thead>
<tr>
<th>Parameters from Pickett plot</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water resistivity (Rw):Ohm-m</td>
<td>0.0452 Ωm</td>
</tr>
<tr>
<td>Cementation exponent (m)</td>
<td>1.98</td>
</tr>
<tr>
<td>Saturation exponent (n)</td>
<td>2</td>
</tr>
<tr>
<td>Tortuosity factor “a”</td>
<td>1</td>
</tr>
<tr>
<td>Water saturation lines</td>
<td>0.2, 0.3, 0.5</td>
</tr>
</tbody>
</table>

Table 5.6 Pickett plot analysis results; the intercept of the water line predicts a formation water resistivity of 0.0452 Ωm and a cementation factor, m, of 1.98 with a constant Tortuosity factor of one. This implies that the cementation for this multiwell well interval sandstone is moderately cemented.
5.11 Clay Bound Water and Sonic Interpretation (Fluid and Matrix Properties)

This section will look at the porosity and the contained fluid using shear sonic (DTS) logs. The use of clay bound water (SWB) log is applied to understand the impact of clay minerals on the interpretation the lithology. Because the Bredasdorp basin is a gas well the Compressional sonic log (DT) given was converted to shear sonic log (DTS) mainly due to the fact that gas response will be evident more with shear sonic than compressional sonic. The Voit-Reuss-Hill technique is used to generate the DTS output curve. With this technique the equivalent velocities for pre-defined minerals are estimated first then weighted arithmetic and weighted harmonic of the created mineral volume are then averaged to generate the shear sonic log.

Clay bound water saturation:

\[ S_{wb} = 1 - \frac{\Phi_e}{\Phi_t} \]  \hspace{1cm} 5.19

Shear sonic:

\[ v_s = \frac{1}{2} \left( \sum_{i=1}^{4} X_i \cdot V_{si} \right) + \left( \sum_{i=1}^{4} \frac{X_i}{V_{si}} \right)^{-1} \]  \hspace{1cm} 5.20

Where;

\( S_{wb} \) = Clay bound water

\( DTS = V_s = \) shear velocity (DTS = Vs)

\( X_i \) = volume of ith mineral

\( V_{si} \) = shear velocity of ith mineral
Figure 5.15a: Shear sonic log and clay bound water analysis

Fig. 5.15a is the qualitative correlation of lithology; pore fluid types, and clay bound water. The interval is a mixture of only two matrix components and the fluid in the pore space. The matrix components are the clay and sand, from the neutron porosity and bulk density curve the clean matrix is between 2.65 to 2.68 gm / cc.
5.11a Fluid and Matrix Properties E-M1

Table 5.7: Fluid and matrix properties E-M1 interval

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Quartz</th>
<th>Wet clay</th>
<th>Dolomite</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)2602 – 2652</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (gm/cc)</td>
<td>2.65</td>
<td>2.6</td>
<td>2.85</td>
<td>2.71</td>
</tr>
<tr>
<td>Modulus (Gpa)</td>
<td>9.699</td>
<td>3.023</td>
<td>1.369</td>
<td>1.062</td>
</tr>
<tr>
<td>Velocity (m/sec)</td>
<td>6050</td>
<td>3410</td>
<td>6930</td>
<td>6260</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid distribution</th>
<th>Brine</th>
<th>Oil</th>
<th>Gas</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)2602 – 2652</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (rho)</td>
<td>0.9975</td>
<td>0.33</td>
<td>0.1913</td>
<td>gm/cc</td>
</tr>
<tr>
<td>Bulk modulus (K)</td>
<td>2.312</td>
<td>0.2369</td>
<td>0.0722</td>
<td>Gpa</td>
</tr>
<tr>
<td>Velocity (V)</td>
<td>1522.4</td>
<td>847.4</td>
<td>614.5</td>
<td>m/sec</td>
</tr>
</tbody>
</table>

Table 5.7 results are the mechanical properties of the interval. The fluid properties for the reservoir are important in fluid substitution calculation and petroleum field operations. The gas/oil ratio, gas density, water salinity, water resistivity, reservoir temperature and pressure are obtained from the source data which were used for fluid properties calculation. Matrix density remains the same because the rock type does not change, but the fluid mechanical property (bulk modulus) changes from well to well. The value of the bulk modulus indicates incompressibility level for the fluid while the inverse of the bulk modulus shows the compressibility. For this research the bulk modulus was calculated by using equation 5.21.

Bulk modulus equation;

\[ K = \rho \cdot V^2 \]  

5.21
Figure 5.15b: Shear sonic log and clay bound water analysis

DTS curve shows stress gradient (Fig. 5.15b) as a result of high clay intrusion to the sand matrix. This affects the pressure of the interval due to the swelling property of clay. The loss in shear-wave based on Biot theory is as a result of the average motion of the fluid with respect to the solid frame, ignoring the viscous loss within the pore fluid.
**5.11b Fluid and Matrix Properties E-M2**

Table 5.8: Fluid and matrix properties E-M2 interval

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Quartz</th>
<th>Wet clay</th>
<th>Dolomite</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2670–2720</td>
<td>2670–2720</td>
<td>2670–2720</td>
</tr>
<tr>
<td>Density (gm/cc)</td>
<td>2.65</td>
<td>2.6</td>
<td>2.85</td>
<td>2.71</td>
</tr>
<tr>
<td>Modulus(Gpa)</td>
<td>9.699</td>
<td>3.023</td>
<td>1.369</td>
<td>1.062</td>
</tr>
<tr>
<td>Velocity (m/sec)</td>
<td>6050</td>
<td>3410</td>
<td>6930</td>
<td>6260</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid distribution</th>
<th>Brine</th>
<th>Oil</th>
<th>Gas</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2670–2720</td>
<td>2670–2720</td>
<td>2670–2720</td>
</tr>
<tr>
<td>Density (rho)</td>
<td>1.0056</td>
<td>0.4264</td>
<td>0.1517</td>
<td>gm/cc</td>
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<tr>
<td>Bulk modulus (K)</td>
<td>2.4081</td>
<td>0.0718</td>
<td>0.0353</td>
<td>Gpa</td>
</tr>
<tr>
<td>Velocity (V)</td>
<td>1547.5</td>
<td>410.3</td>
<td>482.2</td>
<td>m/sec</td>
</tr>
</tbody>
</table>

Table 5.8 results are the estimated mechanical properties of this interval. Fluid properties for the reservoir are important in fluid substitution calculation and petroleum field operations. Parameters such as gas/oil ratio, gas density, water salinity, water resistivity, reservoir temperature and pressure were obtained from the source data. Matrix density does not change because the rock type remains the same while the fluid mechanical property (bulk modulus) changes due to effect from drilling, production and depositional environment. Bulk modulus is used to evaluate the compressibility and incompressibility of fluids. When the bulk modulus is greater than zero then pressure is inversely related to volume. This means that when pressure increases the volume will decrease.
In predicting the bulk modulus of saturated rocks from dry rock the best method is to build understanding on mechanical properties and the velocity of any interval. Wave propagation is the best way to analyse the fluid types present in the pore space. On the shear sonic log it can be interpreted based on the response of the log (fig. 5.15c).
### Fluid and Matrix Properties E-M3

Table 5.9: Fluid and matrix properties E-M3 interval

<table>
<thead>
<tr>
<th>Matrix</th>
<th>Quartz</th>
<th>Wet clay</th>
<th>Dolomite</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2621–2671</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (gm/cc)</td>
<td>2.65</td>
<td>2.6</td>
<td>2.85</td>
<td>2.71</td>
</tr>
<tr>
<td>Modulus (Gpa)</td>
<td>9.699</td>
<td>3.023</td>
<td>1.369</td>
<td>1.062</td>
</tr>
<tr>
<td>Velocity (m/sec)</td>
<td>6050</td>
<td>3410</td>
<td>6930</td>
<td>6260</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Brine</th>
<th>Oil</th>
<th>Gas</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2621–2671</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (rho)</td>
<td>1.0354</td>
<td>0.5231</td>
<td>0.1089</td>
<td>gm/cc</td>
</tr>
<tr>
<td>Bulk modulus (K)</td>
<td>2.4965</td>
<td>0.104</td>
<td>0.0287</td>
<td>Gpa</td>
</tr>
<tr>
<td>Velocity (V)</td>
<td>1552.8</td>
<td>445.9</td>
<td>513.5</td>
<td>m/sec</td>
</tr>
</tbody>
</table>

Table 5.9 results are the estimated mechanical properties of this interval. Fluid mechanical properties are important for petroleum field operations and fluid substitution calculation. Parameters used in the calculation of these properties were from the source data. The mechanical property for the matrix are the same for all well interval because the rock type does not change while the fluid mechanical property varies (bulk modulus) due to impact of drilling, production and the nature of the depositional environment. The value of the bulk modulus gives an idea on the fluids level of incompressibility or compressibility. When the bulk modulus is greater than zero then pressure is inversely related to volume and this means that when pressure increases volume will decrease.
By observing the displacement of the shear sonic curve one could tell the energy of the wave. When the displacement is furthest from the zero mark it means higher energy and the exhibited energy for a wave is proportional to the densities of the medium and the viscosity of the fluids. In fig. 5.15d: 2, 3, 4 show high wave energy.
5.11d Fluid and Matrix Properties E-M4

Table 5. 10: Fluid and matrix properties E-M4 interval

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Quartz</th>
<th>Wet clay</th>
<th>Dolomite</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2712– 2762</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (gm/cc)</td>
<td>2.65</td>
<td>2.6</td>
<td>2.85</td>
<td>2.71</td>
</tr>
<tr>
<td>Modulus(Gpa)</td>
<td>9.699</td>
<td>3.023</td>
<td>1.369</td>
<td>1.062</td>
</tr>
<tr>
<td>Velocity (m/sec)</td>
<td>6050</td>
<td>3410</td>
<td>6930</td>
<td>6260</td>
</tr>
</tbody>
</table>

**Fluid**

<table>
<thead>
<tr>
<th>Fluid distribution</th>
<th>Brine</th>
<th>Oil</th>
<th>Gas</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameters</td>
<td>Interval (M)</td>
<td>2712– 2762</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (rho)</td>
<td>0.9785</td>
<td>0.9537</td>
<td>0.1608</td>
<td>gm/cc</td>
</tr>
<tr>
<td>Bulk modulus (K)</td>
<td>2.5225</td>
<td>1.4643</td>
<td>0.0545</td>
<td>Gpa</td>
</tr>
<tr>
<td>Velocity (V)</td>
<td>1605.6</td>
<td>1239.1</td>
<td>582.1</td>
<td>m/sec</td>
</tr>
</tbody>
</table>

Table 5.10 results are the estimated mechanical properties of this interval. Fluid mechanical properties are important in understanding the flow behaviour of fluids. In deriving the fluid mechanical properties other parameters such as gas/oil ratio, gas density, water salinity, water resistivity, reservoir temperature and pressure were obtained from the source data. The mechanical property for the matrix remains the same because the rock type does not change while the fluid mechanical property (bulk modulus) changes due to the difference in fluid composition and depositional environment. The value of the bulk modulus gives an idea on the fluid’s level of incompressibility or compressibility, when the bulk modulus is greater than zero then pressure is inversely related to volume - when pressure increases volume will decrease.
Fig. 5.15e: Shear sonic log and clay bound water analysis

The high wiggling in fig. 5.15e shows fluid viscosity and densities effects on travelling wave through a medium. When waves are propagated through the medium energies are dissipated or lost to the confining fluid and matrixes creating a particular signature for that substance different from the adjacent rock. The high wiggling of the sonic log in fig. 5.15e is based on the different rock densities and nature of fluid within the bulk volume as the wave is propagated through that interval it reflects these changes.
### Fluid and Matrix Properties E-M5

Table 5.11: Fluid and matrix properties E-M 5 interval

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Parameters</th>
<th>Quartz</th>
<th>Wet clay</th>
<th>Dolomite</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (gm/cc)</td>
<td>Interval (M)</td>
<td>2.65</td>
<td>2.6</td>
<td>2.85</td>
<td>2.71</td>
</tr>
<tr>
<td>Modulus (Gpa)</td>
<td></td>
<td>9.699</td>
<td>3.023</td>
<td>1.369</td>
<td>1.062</td>
</tr>
<tr>
<td>Velocity (m/sec)</td>
<td></td>
<td>6050</td>
<td>3410</td>
<td>6930</td>
<td>6260</td>
</tr>
</tbody>
</table>

**Fluid**

<table>
<thead>
<tr>
<th>Fluid distribution</th>
<th>Parameters</th>
<th>Brine</th>
<th>Oil</th>
<th>Gas</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (rho)</td>
<td>Interval (M)</td>
<td>1.0164</td>
<td>0.2532</td>
<td>0.203</td>
<td>gm/cc</td>
</tr>
<tr>
<td>Bulk modulus (K)</td>
<td></td>
<td>2.3547</td>
<td>1.0623</td>
<td>0.0593</td>
<td>Gpa</td>
</tr>
<tr>
<td>Velocity (V)</td>
<td></td>
<td>1522.1</td>
<td>2048.2</td>
<td>540.3</td>
<td>m/sec</td>
</tr>
</tbody>
</table>

Note: Mechanical property for the matrix does not change because the rock properties are the same for the well intervals. The evaluation from fluid substitution predicts E-M4 and E-M5 mechanical properties for oil to be greater than one (>1gm/cc) while E-M1, 2, and 3 fluid mechanical properties for oil is less than one (< 1gm/cc). For the well intervals from E-M 1, 2, 3, 4 and 5 gas mechanical properties evaluated are less than zero point one (< 0.1 gm/cc). This result shows high fluid incompressibility for E-M1, 2, and 3. The compressibility of these fluids can be understood by taking the inverse of bulk modulus.
The use of sonic log is best applied when information on the nature and type of fluids needs to be extracted from an interval. From sonic log interpretation it was observed that gas saturated pores decreases wave propagation which was seen as an attenuation (decreasing signal; fig. 5.15e) while liquid will have the opposite effect. The shear sonic log is an expression of strain in terms of displacement vector (U=u, w,ε) equation 5.22;

\[
\rho \frac{\partial^2 u}{\partial t^2} = (\lambda + \mu)\nabla \Delta + \mu \nabla^2 \nu
\]

By taking the curl:

\[
\frac{\partial^2 \theta_i}{\partial t^2} = \frac{\mu}{\rho} \nabla^2 \theta_i
\]

Where \( \lambda \) and \( \mu \) are known as Lame’s constant and \( \mu \) is the measure of the shear or rigidity modulus. The change in volume per unit volume is called the dilation and is represented by \( \Delta \)

\[
\Delta \approx \frac{\partial \sigma_{xx}}{\partial x} + \frac{\partial \sigma_{xy}}{\partial y} + \frac{\partial \sigma_{zx}}{\partial z}
\]

Where the expression, \( \frac{\partial \sigma_{xx}}{\partial x} + \frac{\partial \sigma_{xy}}{\partial y} + \frac{\partial \sigma_{zx}}{\partial z} \) represent the net unbalanced force per unit volume in the x direction.
5.12 Permeability Distribution

The permeability for each well interval was calculated using evaluated porosity and water saturation logs. This thesis main interest was to seek why production capacity from a well will suddenly drop. The production capacity from a reservoir is a function of its effective porosity and this represents the amount of connected pores. For fluid flow to be effective a lot of factors need to be considered including the impact of clay bound water to fluid flow. The Permeability curves used where generated after estimating the following parameters;

1. volume of clay
2. porosity
3. water saturation and clay bound water

In calculation the Timur constant where applied to the following equation (equation 5.25);

\[ k = a \cdot \frac{\Phi_{\text{eff}}^b}{S_{\text{wb}}^c} \]

Where;

\( k = \text{Permeability} \)

\( a = \text{constant (8581)} \)

\( b = \text{constant (4.4)} \)

\( c = \text{constant (2)} \)

\( \Phi_{\text{eff}} = \text{effective porosity} \) & \( S_{\text{wb}} = \text{bound water saturation} \).
5.12.1 Permeability Logs for E-M1 to E-M5

Table 5.12: Permeability summary for each well

<table>
<thead>
<tr>
<th>WELL</th>
<th>MEAN VALUE (permeability)</th>
<th>Appraisal of Reservoir Permeabilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-M1</td>
<td>7.6168</td>
<td>1.0 – 10md = Fair</td>
</tr>
<tr>
<td>E-M2</td>
<td>8.2716</td>
<td>10 – 100md = Good</td>
</tr>
<tr>
<td>E-M3</td>
<td>7.327</td>
<td>100 – 1,000md = Very good</td>
</tr>
<tr>
<td>E-M4</td>
<td>9.4775</td>
<td>(Levorsen, 2004)</td>
</tr>
<tr>
<td>E-M5</td>
<td>9.5063</td>
<td></td>
</tr>
</tbody>
</table>
Fig. 5.16 multiwell logs displays Permeabilities curves for E-M1, 2, 3, 4 and 5 while comparing their permeability distribution for each interval. E-M4 has very low permeability variation for this interval, E-M1 and E-M2 has very high permeability changes, E-M3 and E-M5 shows moderate variations. The decrease in permeability reading for certain depth along the logs (E-M2, fig. 5.16) is as a result of low interconnected pores at these depths, since permeability is a measure of rock’s ability to transmit fluid through the connected pores available. For this research the flow quality for any rock type is assumed to be only from the interconnected pores which are the measure of the effective porosity or permeability. The higher the decreasing permeability curves for any section the lower the effective porosity and the lower the ability for that interval to transmit fluid effectively.

This means that E-M1, 2 and 3 will have higher chances of having fluid flow problems based on their permeability logs and the mean values for the Permeabilities of their intervals (fig. 5.16; table 5.12).

Table 5.12 has two sections the first section is the calculated permeability’s mean values for E-M1, 2, 3, 4, and 5. The mean permeability values for E-M3 and E-M1 is the lowest, while E-M5 and E-M4 have the highest mean permeability values. The second section to table 5.12 is the interpretation of these values by Levorsen, (2004). By this interpretation all well intervals under investigation for this research has a permeability classification as fair.
Effective porosity is commonly 5-10 percent less than total porosity (Levorsen, 2004). At 2570-2593 meters “A” (fig. 5.17a) is an abnormal variation for effective porosity log cutting across total porosity and returning to expected pattern. The question of this research is what happened at this section and how does it affects fluid flow? Section “B” is the expected path for effective porosity curves.
Decreasing permeability as the porosity is also decreasing, the effective porosity of this section is low a reflection of poor flow units (Fig. 5.17b).
Here the effective porosity has very close measurement with total porosity (2669 meters shown by the arrow). This section shows that porosity and permeability can change at any depth. At 2639 the permeability decreased greatly reflected also in the porosity log.
D: D’ and F: F’ of Fig 5.17d are the same section but the corresponding points on permeability log do not have the same curve reflection. This difference in the curve signatures implies that both log’s quantity of measurement are not the same. While permeability measures the capacity of the flow units, porosity log on the other hand measurements are the rock interstices which is dependent on the depositional environment, particle size, nature of the material that makes up the rock, cementation and fracturing.
The interval 1 to 2 of E-M 5 (Fig. 5.17e) shows reduction in permeability, effective porosity for this interval is poor. Effective porosity and permeability are two most important properties for a reservoir rock. These properties are mostly influenced by volume of clays, diagenesis, rock types and water saturation. This thesis ability to resolve the research problem is based on the accurate understanding and evaluation of the porosity and permeability for the well intervals studied.
Fig. 5.18 is the application of semi-logarithm graph to plot permeability and porosity data. There is no direct relationship between permeability and porosity values but the logarithmic representation shows slope corresponding to the power law for the porous samples ($\phi < 0.1$). From 0.01 to 10 mD is a good representation of the exponential law of permeability $[K = f(\phi^n)]$ relation.
5.12.4a Spatial Distribution and Density Function

![Multiwell histogram of spatial distribution and density function](image)

Figure 5.19: Multiwell histogram of spatial distribution and density function

Each peak on the histogram indicates the level of fluid transmissibility by the rocks. The application of statistics was to predict variability of this property for each well interval. The Gaussian distribution gives the trend of these changes and information on the symmetry of the distribution (symmetry at 10Md). The probability density function (PDF) can be estimated with equation 5.26;

\[
F(x) = \exp\left[\frac{- (x - m)^2}{2s^2}\right] / \sqrt{2\pi s^2}
\]

\[5.26\]

\[x = \text{variable (permeability)}, \ m \text{ and } s = \text{mean and standard deviation}, \ s^2 = \text{variance and } \exp(x) = \text{exponential } x.\]
5.12.4b  Spatial Distribution and Discrimination

Figure 5.20: Histogram result after the application of discriminators

Fig. 5.20 is the results using discriminators model. This model applies different set of display criteria for different curves; discriminators set of rules can differentiate between gas sands and water sands. This technique was used as a prognosis to identify good gas sand from the well intervals. The criteria sets were neutron porosity (curve), the mathematical function used was greater than (>) and the sets of values were 0.045 v/v and 0.65v/v with hydrocarbon density = 0.8gm/cc. E-M2, 3, 4 & 5 met the criteria except E-M1 and further analyses were done to ascertain this anomaly.
5.13 Permeability and Porosity Summary

Porosity and permeability are independent properties of sediments (Braide, 2012). The quality of permeable beds depends on the effective porosity or the interconnected pores, effective porosity is a dimensionless quantity and these quantities are evaluated using equation 2.27 and 2.28;

\[
edf = \frac{pore\ volume\ (v_p)}{bulk\ volume\ (v_b)}
\]  

\[
k = \frac{v \times \mu \Delta x}{\Delta P}
\]

Where v is flow rate, \(\Delta P\) is pressure difference, \(\mu\) is the relative thickness of the fluid known as viscosity, \(\Delta x\) change in length towards the x-axis and \(\Delta P/\Delta x\) is the pressure gradient.
5.14 Bulk Analyses and Interpretation using Elastic Impedance

Elastic impedance (EI) is a pseudo-impedance attribute. EI is also a far offset equivalent to the conventional zero-offset acoustic impedance (Mavko et al., 2009). Far offset is the distance away from the reference point for example a shot point. It refers to measurements taken away from that shot but between the distance of the shot point and a geophone (recording machine). The elastic impedance makes use of the compressional velocity and shear velocity ratio (Vp/Vs); these curves were displayed alongside with volume of clay and gamma ray log. The velocities for this media is evaluated based on the assumption that:

- The media is homogeneous
- Isotropic
- Elastic

Compressional velocities are estimated by equation 5.29;

\[ v_p = \frac{k + \frac{3}{4} \mu}{\sqrt{\rho_b}} \]  

Shear velocities are estimated by equation 5.30;

\[ V_s = a \cdot V_p^2 + b \cdot V_p + c \]

Where

- \(K\) = bulk modulus
- \(\rho_b\) = bulk density (g/cc)
- \(\mu\) = shear modulus
- \(V_p\) = compressional velocity (m/s)
- \(V_s\) = shear velocity (m/s)
- \(a\) = constant = 0
- \(b\) = constant = 0.76969
- \(c\) = constant = -0.86735
Due to the obsolete nature of the data and logs fluid substitution modelling was applied to each well interval. This was done with the well log to generate the best possible result from the logs available and to increase the accuracy in prediction of the results. Fluid substitution is the prediction of a given quantity for a rock to same quantity in another rock for example velocities for a gas filled pore to velocity for oil filled pore (IP manual). This thesis did not look into the algorithm involved in fluid substitution models as it was beyond the scope of investigation the application of fluid substitution modelling was done using interactive petrophysics (IP) and it involves these steps;

- Generating the fluid properties (see table 5.7-table5.11)
- Applying the input curves (estimating DTS from DT, density, porosity and saturation logs)
- Gassmann estimation
- Selection of fluid to be substituted- oil for gas or vice versa
- Vs and Vp curve are output curves generated from the above steps

When the fluid substation modelling is completed the output curves are then used in estimating the elastic impedance. Elastic impedance curves are purely an approximate but can be employed in reservoir characterisation when it is used with log data (Mavko et al, 2009).

Assumption/advantages and limitations of the use of elastic impedance curves;

- Assumes one dimensional convolutional model for far offsets
- K has a constant value \((Vs/Vp)^2\)
- Involves angle of incident- high angle \(\leq 20^\circ\) and low angles \(\geq 30^\circ\)
- Limitations: errors in estimating the assumptions above
- Angles above 30° low angle equation becomes unstable
Elastic impedance is the product of the compressional velocity, shear velocity, and bulk density.

\[ I_e(\theta) = v_p^{(1+sin^2\theta)} v_s^{(-8 \times k \times sin^2\theta)} \rho_b^{(1-4 \times sin^2\theta)} \]  

5.31

Where;
- \( V_p \) = compressional velocity
- \( V_s \) = shear velocity
- \( K \) = constant represents the average \( V_s^2/V_p^2 \) for the interval
- \( \rho_b \) = bulk density
- \( \Theta \) = angle of incident

The elastic impedance is more an approximate inversion modelling technique and the numerical value is not important in understanding the qualitative representation of the curve to lithology, pore fluid and rock properties. It is economical and simple to use but in line with any inversion techniques to effectively extract information from the log it is important to calibrate with other logs like gamma ray log.

Elastic impedance can be reduced to acoustic impedance when the angle between a shot point and the geophone measurement is zero then equation 5.31 will be reduced to bulk density and compressional velocity \( (I_a = \rho_b V_p \text{and } \theta=0) \). The benefit of elastic impedance over acoustic impedance is that the elastic impedance is not a function of the rock properties alone but it also depends on the angle of incidence.
5.15 Elastic Impedance Log and Interpretation (E-M1 – E-M5)

Fig. 5.22a has low angle (EI 10°) and high angle (EI 30°) clearly distinct from each other. This is an indication of high instability towards the normal (angle 90°) and may be due to varying rock types (heterogeneity) of the interval. Elastic impedance can determine interval properties from the band limited reflectivity (Mavko et al., 2009). Colour coding is used to describe the interval lithology based on their velocities and impedance logs.
The colour coding describes the interval lithology based on their velocities and impedance logs (Fig. 5.22b). The elastic impedance curve gives information on the lithology/mineral content, pore-size and fluid. The wiggles and gathers are a reflection of the material in contact with. Gas sand shows low impedance while clay gathers will have high impedance.

Figure. 5.22b: Interval lithology base on elastic impedance log
In Fig. 5.22c colour coding is used to describe the interval lithology based on their velocities and impedance logs. Low impedance gives high amplitude which indicates the presence of fluid within the pore space, while high impedance has decreasing amplitude this indicates shale/clay gathers. The use of elastic impedance is faster and cheaper than the seismic trace in analysing interval properties for any reservoir interval.
Elastic impedance is used to predict the cement bond quality for any interval. Cementation is based on the quality of clay and the distribution of the volume of clay for that interval. A high impedance section indicates good cementation and compaction. Cementation and compaction reduces permeability based on primary porosity (Levorsen, 2004), primary and secondary porosity cannot be identified from elastic impedance but it those indicate the presence of very high variable grain size densities.
Fig. 5.22e describes the interval lithology based on their velocities and impedance logs. The intermediate angle (EI 20°) show a close resemblance to the high angle (EI 30°) for all the wells except in E-M2 where interval B, C, D and F shows remarkable difference the curve significantly points towards each other, clearly a contradiction in the rock and or fluid responses as seen from other well interval. This might be sections of hydrocarbon and water or oil and gas phases.
Table 5.13: Vp velocities by Mavko et al (2009)

<table>
<thead>
<tr>
<th>P-wave velocities of sedimentary rocks</th>
<th>Compressional velocities, Vp (m/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>5480 - 5950</td>
</tr>
<tr>
<td>Limestone</td>
<td>6400 – 7000</td>
</tr>
<tr>
<td>Dolomite</td>
<td>7000 – 7925</td>
</tr>
</tbody>
</table>

Fig. 5.23 results for P- Wave responses from the multiwell cross plot are between 2790 m/s to 5400 m/s which fall within the responses for sedimentary rocks. The critical porosity separates the mechanical and acoustic behaviour into two domains; solid and suspension. This depends on the internal structure of the rock. Table 5.13 gives the compressional velocity’s prediction by Mavko et al, (2009) for different rock types. These values were used in interpreting the cross plot of compressional velocity versus total porosity.
Fig. 5.24 result displays the multiwell cross-plot for compressional velocity and shear velocity. This technique was used to describe the nature of the grains the aim was to know the distribution of consolidated and loosed grains for each well interval. Loosed grains suspend in fluids to form solid concentrates which is the percent volume of solids; both dissolved and undissolved in a liquid. Solids can affect the drilling and production activities if not controlled. Compressional velocity reading between 2790 m/sec to 4395m/sec indicates more suspended or loosed grains for all the well intervals investigated on.
Fig. 5.25 Pore grains

Fig. 5.25 is a multiwell cross plot for Vp/Vs ratio and elastic impedance. This cross plot gives information on the solid mineral material within a low porosity value and fluid suspension properties as the porosity approaches critical porosity (used by Mavko et al, 2009). The modulus- elastic impedance and Vp/Vs ratio shows each interval properties for the dry rock at any porosity ($0 < \phi < \phi_c$). This plot suggests systematic trends between the mineral values at zero porosity to fluid-suspension values at the critical porosity which are characteristic of each class of rock ($V_s = 0, V_p = V_{suspension} \approx V_{fluid}$).
Fig. 5.26 is a multiwell cross plot between density, compressional velocity and gamma ray. This cross plot shows the rock physics properties for E-M1, 2, 3, 4, and 5 intervals under considerations. The sandstones for these intervals are either gas-saturated or water-saturated as such the facies are loosely connected and scattered. There are great overlaps between clusters and the properties do not change much as we move from the brine saturated sands to gas saturated sands.
The rock physics template adopted from Aveseth et al (2013), is used to predict the lithology and hydrocarbon content of the area (Fig. 5.27). The gas sand decreases in porosity at increased acoustic impedance this gives a relative indication that the fluid which is the medium of propagation for sound (acoustic) decreases in that direction. This technique can be used in deciding where to drill a well which will be based on the section with the highest fluid recovery percentage.
5.16 Temperature Estimation and Heat Content Relationship

Temperature is one of the parameters used in the analysis of porosity and water saturation. Single values for temperature are assigned to recorded depth intervals. The values for the well are plotted against mean depth for each interval and represented with a histogram plot showing the average thermal gradient. The gradient is mathematically described by the formula (equation 5.32);

\[ T = 0.455D - 1086.39 \]  \hspace{1cm} 5.32

Where

- \( T \) = Temperature (°F)
- \( D \) = depth in meters

Temperature relatively remains constant during production unlike pressure that declines with the production of oil and gas (Levorsen, 2004). Abnormalities in temperature could cause problems in cementation programmes and casing leaks. The effect of temperature is more on liquid than gasses, temperature affects the viscosity of liquid and the liquid shrinks at high temperatures due to high rate of evolved gasses. The relationship between temperature, density and pressure is resolved by equation 5.33 a re-arrangement of the ideal gas equation.

\[ \rho = \frac{pM}{zRT} \]  \hspace{1cm} 5.33

Where;

- \( \rho \) = Density; \( p \) = pressure (psia),
- \( M \) = molecular weight; \( R \) = gas constant
- \( T \) = temperature.
5.17 Well Prognosis: Temperature cross plot for each well interval

Fig. 5.28 histogram plot shows frequency distribution for each well interval. The frequency denotes the degree of randomness which is a reflection of the heat content of any body. The greater the heat content the closer the degree of randomness will be towards the colour red. Temperature of a body result from the transfer of heat or energy but temperature is not the measure of the quantity of heat. A body may not read high temperature value but possesses large quantity of heat (energy) it is the magnitude of heat content that affects flow regime.
5.18 Temperature Profile

Fig. 5.29 histogram plot is the modelled temperature profile for the well intervals. The peak represents the highest temperature level for that interval. For temperature profile for EM2 and EM4 interval’s point A and B is the same. Point A, B, C, D and E on the profile show abnormal deflection from the expected curve. The tail reduces in length as the profile moves upwards (areas 1, 2, and 3) this interprets negative skewness an indication of abnormal temperatures toward that direction.

The understanding and interpretation of temperature profile and quantity of heat for any well or reservoir interval is important because it affects fluid viscosity and ultimately determine the type of flow regime (turbulent or smooth) for the hydrocarbon recovery.
5.19 Pressure Evaluation

This thesis runs on the premise of only well log measurements. Well logs employed during this research are gamma ray log, density, sonic, neutron, and caliper logs subsequently additional logs and parameters were generated from the given initial logs . Some of the log measurements and parameters generated in the cause of this research are; porosity, permeability, water saturation, shear sonic curve and elastic impedance, fluid and matrix properties. The main purpose in deriving these quantities was to understand the relationship between pore and fluid content within the ambient of the data given.

In line with evaluating the rock and fluid properties pore and fracture pressure evaluation were done as an empirical model in predicting the overburden, pore and fracture pressure gradients. Pore pressure (fluid pressure) is the pressure exerted by the formation fluid on the walls of the pores in the formation (Hyne, 1991). These pressures were estimated for each well using the pore pressure module of interactive petrophysics. The information derived from these pressure analyses provides preliminary bases for predictive real time (while drilling) and post-drilling analysis to update and refine overburden, pore and fracture pressure gradient models. Before proceeding with the pore pressure evaluations the parameters listed below where estimated first;

- Density estimation
- Overburden gradient calculation
5.19.1 Density Estimation

In estimation of the specific density, compressional sonic log was converted to shear sonic curve (DTs). The shear sonic curve represents the tensile response of the rock when estimated acting force is from gasses and not liquids. There are three models available in IP for the evaluations of these properties which are:

Garner method;

\[ Rho = a \times v_p^b \]  \hspace{1cm} 5.34

AGIP Bellotti method;

Consolidated formations;

\[ Rho = 3.28 \times \frac{Dts}{89} \]  \hspace{1cm} 5.35

Unconsolidated formations;

\[ Rho = 2.75 - 2.11 \frac{(Dts - 47)}{(Dts + 200)} \]  \hspace{1cm} 5.36

Lindseth method;

\[ Rho = \frac{v_s - 3460}{0.308 \times v_s} \]  \hspace{1cm} 5.37

Where;

Rho = density

Vs = compressional sonic velocity

DTs = compressional sonic curve

a = Constant – 0.23 (default)

b = Constant – 0.25 (default)
5.19.2 Overburden Gradient Estimation

This section deals with the evaluation of overburden gradient (OBGrad) and overburden pressure (OBPres) for each well. Overburden gradient is the weight of the overlying rocks per unit depth estimated as one (1) psi/ft and the overburden pressure is the subsurface pressure exerted by the weight of the overlying rocks. In IP the evaluation of these parameters become functional only after density estimation has been done for each well interval. The overburden pressure is in contrast to the pressure of the fluid in the pore space of the rocks (Hyne, 1991). These parameters are calculated by integration done on the evaluated density data shown by equation 5.38 and 5.39.

Overburden pressure;

\[ P(z)_{ob} = P_0 + g \int_{z_1}^{z_2} \rho_z \, dz \]  

5.38

By differentiating;

\[ \frac{dp}{dz} = P_0 + g \left( \frac{d \rho_z}{dz} \right) \]  

5.39

Where;

\( P_0 \) = datum pressure (pressure at the surface)

\( P(z)_{ob} \) = overburden pressure of the overlying rocks at depth \( z \)

\( \rho_z \) = density of the overlying rocks at depth \( z \)

\( g \) = acceleration due to gravity

\( \frac{dp}{dz} \) = overburden pressure gradient

\( \frac{d \rho_z}{dz} \) = overburden density gradient
5.19.3 Pore and Fracture Pressure Gradient Estimation

Pore pressure and fracture pressure gradient estimation for the selected well intervals of study were analyzed. The method of analyses for the pore and fracture pressure gradient calculation implemented by the software module is the Eaton, Matthews and Kelly methods (Interactive petrophysics manual). The input curves for this analyses were shear sonic (DTs) and resistivity logs; equations 5.40 and 5.41

Resistivity;

\[
\frac{P}{D} = \frac{S}{D} - \left( \frac{S}{D} - \frac{P}{Dn} \right) \ast \left[ \frac{Rsh \text{ observed}}{Rsh \text{ normal}} \right]^{1.2}
\]  

Sonic;

\[
\frac{P}{D} = \frac{S}{D} - \left( \frac{S}{D} - \frac{P}{Dn} \right) \ast \left[ \frac{\Delta T \text{ shale normal}}{\Delta T \text{ shale observed}} \right]^{3.0}
\]  

Where;

\[
\frac{P}{D} = \text{formation pore gradient (psi/ft)}
\]

\[
\frac{S}{D} = \text{overburden stress gradient (psi/ft)}
\]

\[
\frac{P}{Dn} = \text{normal pore pressure gradient (psi/ft)}
\]

\[
Rsh = \text{shale resistivity (ohm-m)}
\]

\[
\Delta T \text{ shale} = \text{shale travel time (usec/ft)}
\]

Flow of fluid is largely dependent on pressure, and in understanding of fluid dynamics pressure needs to be studied. Fluid pressure can either be studied when the fluid is in motion or not in motion. If the fluid is in motion then the resulting study is hydrodynamics but if the forces acting on the fluid is studied when the fluid is not in motion then it is hydrostatics. This section shows the pore pressure plot and pressure gradient graphs for each well section.
5.19.3a  Pore and Fracture Pressure Analysis (EM1 – EM5)

Figure 5.30: Pore and fracture pressure evaluation for E-M1

Fig. 5.30a predicts overburden and pore pressure as a counteracting weights to each other because both has an initial pressure of 4.5 psi/ft while the pore pressure is increasing with decreasing depth the reverse is the case for overburden pressure. Fig. 5.30b is the predictive mud weight equivalent to the pressures exerted by formation fluid and overburden. E-M1 formation has high resistivity due to the increasing overburden pressure. This well’s pressure gradient is higher than normal (hydrostatic) pressure which is 0.45 psi/ft while for overburden is 1 psi/ft.
Fig. 5.31 predicts overburden and pore pressure gradients as 0.9 psi/ft and 0.48 psi/ft. Evident from these values the well possesses normal overburden and pore pressure gradient even though the pore pressure gradient has a slight fraction increase of its value than normal hydrostatic pressure (0.45 psi/ft) the formation is still within the normal hydrostatic pressure range. From Fig. 5.31b the pore pressure is outside the mud weight widow prediction interprets low formation fluid pressure.

Figure 5.31: Pore and fracture pressure evaluation for E-M2
Fig. 5.32 predicts only an overburden pressure gradient of 0.89 psi/ft for this well. The overburden pressure is within the limits of pressure psi/ft for any formation. No detected pore and fracture pressure for this formation.
Fig. 5.33a and b interprets pressure profile different from the rest of the wells. The resistivity and sonic models for pore pressures gradient shows clear disparity, pore pressure from the sonic model is between 0.56 to 0.97 psi/ft while for resistivity is 0.56psi/ft. The overburden pressure gradient is 0.89 to 1 psi/ft. The disparity in pore pressure measured by the resistivity model from that of pore pressure measured by the sonic model is due to the fact that the sound signals were travelling perpendicular to the source in the direction of an increasing porosity it also indicates the type of fluid in the pore space; hydrocarbon will decrease the sound velocity more than water.
Fig. 5.34 predicts only an overburden pressure gradient of 0.92 psi/ft for this well. The overburden pressure is within the limits of pressure psi/ft for any formation which is 1psi/ft. No detected pore and fracture pressure from this formation.
5.20 Cut-Off and Summation Result

Cut-off and summation is the estimation of average petrophysical properties from porosity, clay volume and water saturation. Cut-offs and summation module allows the defining of net reservoir and net pay cut-offs criteria and zones. This allows the computation of zonal average properties for reservoir intervals containing different fluid types. The criteria set for computation of the zonal averages are for the net reservoir and pay zones (see x);

- Reservoir flag / Pay flag; porosity ≥ 0.1, V_{clGR}, GR, S_w ≤ 0.5.................x

When these values are applied the result is displayed in form of a log. The reservoir and pay flags are shown in different colours; reservoir flag is green and pay flag is red. Evidence of the averages for each column is seen as a vertical display of blocks. The columns formed by these blocks have different areas and show disconnect from one another at some point. Zones averages for the parameter are of more practical results or values because it takes into account the overall changes for that reservoir interval.

The net, gross, net to gross ratio, and the averages of the parameters calculated are useful in estimating the volume of oil and gas original oil in place and production capacity. For any company to produce from a reservoir the risk analysis gives a greater percentage for informed decisions to be taken on drilling programmes and that is why the petrophysical parameters produced from cut-off and summation forms the bedrock in reservoir engineering calculations. The duty of the petrophysicist is to produce as much information on the producing capabilities of the formation for management to understand the risks in producing from that reservoir.
Figure 5. 35a: Reservoir and pay flag thickness plot.

Fig. 5.35a shows the reservoir flag which is the computation for the gross interval (productive and unproductive zones). It shows the layers to which the gross interval are connected or disconnected.
Fig. 5.35b displays the evaluated gross interval (productive and unproductive zones), the average porosity for the zone was evaluated using equation 5.42.

Averages can be calculated as; average porosity:

\[ \phi_{avg} = \frac{\sum_{i=1}^{n} \phi_i \times h_i}{\sum_{i=1}^{n} h_i} \]  

5.42
Fig. 5.35c poor gross interval. The Pay flag sets on evaluating criteria for net pay interval; it shows the thickness or layers of economical and producing units for the reservoir interval. Averages for clay bound water were evaluated using equation 5.43:

Average Clay bound water: \( S_{avg} = \frac{\sum_{i=1}^{n} \phi_i \times h_i \times (1 - S_{wb})}{\sum_{i=1}^{n} h_i} \)  

5.43
Fig. 5.35d: Reservoir and pay flag display.

Fig. 5.35dvery good gross interval but poor thickness of the economical or producing unit for this reservoir interval. Averages for volume of clay/ gamma ray were evaluated with equation 5.44.

Average volume of clay/ gamma ray:

$$V_{clavg} = \frac{\sum_{i=1}^{n} V_{clgr_i} \times h_i}{\sum_{i=1}^{n} h_i}$$

5.44
Figure 5.35e: Reservoir and pay flag display.

Fig. 5.35e no producing units for this reservoir interval but the interval has good gross thickness. From equation 5.42 to 5.44 hi is the interval thickness, $\sum$; symbol meaning summation.
Summary of Petrophysical Properties

Table 5.14: Summary of petrophysical properties for each well

<table>
<thead>
<tr>
<th>Well</th>
<th>Top</th>
<th>Bottom</th>
<th>Net</th>
<th>Gross</th>
<th>N/G</th>
<th>Average Porosity</th>
<th>Average Water saturation</th>
<th>Average Volume of clay</th>
</tr>
</thead>
<tbody>
<tr>
<td>EM1</td>
<td>2602</td>
<td>2652</td>
<td>39.03</td>
<td>50.00</td>
<td>0.78</td>
<td>0.13</td>
<td>0.89</td>
<td>0.24</td>
</tr>
<tr>
<td>EM2</td>
<td>2670</td>
<td>2720</td>
<td>39.60</td>
<td>50.00</td>
<td>0.79</td>
<td>0.13</td>
<td>0.73</td>
<td>0.21</td>
</tr>
<tr>
<td>EM3</td>
<td>2621</td>
<td>2671</td>
<td>7.92</td>
<td>50.00</td>
<td>0.16</td>
<td>0.11</td>
<td>0.49</td>
<td>0.16</td>
</tr>
<tr>
<td>EM4</td>
<td>2712</td>
<td>2762</td>
<td>49.39</td>
<td>50.00</td>
<td>0.99</td>
<td>0.17</td>
<td>0.59</td>
<td>0.12</td>
</tr>
<tr>
<td>EM5</td>
<td>2628</td>
<td>2678</td>
<td>44.36</td>
<td>50.00</td>
<td>0.89</td>
<td>0.16</td>
<td>0.71</td>
<td>0.30</td>
</tr>
</tbody>
</table>

Table 5.14 summarises the estimated average petrophysical properties from porosity, clay volume and water saturation logs and analysis. The table shows the calculated values for each well interval from E-M1, 2, 3, 4 and 5. These values represent net, gross, net to gross, average porosity, average water saturation and average volume of clay. E-M 5 has the highest volume of clay and E-M4 has the lowest volume of clay. The analysis of clay volume is important because of its swelling properties also the presence of heaving shales causes major problems in drilling and production.

The average porosity gives the volume of pore spaces. These values do not represent quantity of the contained fluid or the nature of the porosity but it can be used for estimating reservoir properties in reservoir engineering calculations.

The quantitative indication of water saturation gives the fraction or percentage of the pore volume that is occupied by formation water, the remainder of the pore space is occupied by oil and oil/gas (see E-M1; table5.14).
Chapter Six
Fluid Mechanics

6.1 Introduction

In the previous chapter the rock and fluid properties were evaluated using their well logs. The studying of physical properties and changes of reservoir rock and fluid is important in understanding fluid behaviour and in predicting production capacity. The two most dominant conditions that affect every petroleum reservoirs are pressure and temperature each one is a form of stored energy. It is the difference in pressure that causes fluid to flow from point to point. The ease at which this fluid flows is influenced by the viscosity (thickness) of the fluid and the flowing temperature of the fluid.

In this chapter the flow behaviour will be analysed. Subsurface fluid pressures are either hydrostatic or hydrodynamic; hydrostatic pressure is imposed by column of fluid at rest and hydrodynamic pressures are caused by fluid pressure under flowing conditions. This thesis considers the hydrostatics pressure of the pore fluid and the impact of an isolated granulated material on the flowing pressures of fluid.

E-M1well interval used is as the result obtained during the permeability analysis of each well (fig. 5.19 & 5.20). Each peak on the histogram graph showed the permeability quality for each well interval. By applying discriminator module using interactive petrophysics E-M 1well interval failed the display criteria set for the curves which was set to differentiate gas sands from water sands. The criteria combined set of curves (neutron porosity log and hydrocarbon density log) and values (0.045 dec, 0.65 dec and 0.8 gm/cc).The objective in applying the discriminator model was to differentiate gas sand well interval from water sand well interval.
Subsurface fluid mechanics is based on the pressure and temperature relationship mathematically expressed as the ideal gas equation (6.1);

\[
\frac{PV}{T} = nR
\]

Where;
P = absolute pressure (psia)
V = volume (ft\(^3\))
T = absolute temperature (°F)
n = no of moles of gas (lb.mole)
R = universal gas constant

The pore model for E-M1 well interval was designed using the elastic impedance/lithology log display. Re-arranged with the geological coordinates of the basin (Bredasdorp basin) the pore model generated an isolated seam (fig. 6.1).

Figure 6.1: Pore scale model
Granulated material are individual quasitabular bands of crushed rock commonly less than 1cm in thickness they are formed under conditions of high faulting and deviatoric stress. Granulation seams where seen in the cores recovered from the Bredasdorp basin. They are stress indicators through compaction of sand and affects permeability and fluid flow pressures from that reservoir interval. The forces associated around the granulated material were identified and used in modelling of the fluid static equation. The fundamental equation of fluid static states that pressure increases with depth, the increment per unit length been equal to the weight per unit volume see equation 6.2;

\[ dp = -\rho g dz \]  \hspace{1cm} 6.2

Where \( dp \) is the increment in pressure, \( dz \) is the increment in depth (\( z \) is a vertical distance measured positively in the direction of decreasing pressure), \( \rho \) is the density (mass per unit volume), and \( g \) is the gravitational acceleration. The minus sign means that pressure decreases with increasing depth (\( z \)). From the free body diagram (fig. 6.1) effective flow of fluid depends on the forces acting on the body which are; the pressure as a result of the fluid weight of the element and the angle the structure makes with the horizontal (\( \rho gdzA\theta \)); the degree of the slope the structure makes with the datum influences flowing fluid by reducing the flow energy of the fluid in motion.

Equating these forces; differential pressure (\( d\rho dA \)) and the fluid weight;

\[ d\rho dA = -\theta \rho g dz dA \]  \hspace{1cm} 6.3

\[ dp = -\theta \rho g dz \]  \hspace{1cm} 6.4
By re-arranging and integrating the above equation becomes;

\[ \int_{b}^{a} \frac{dp}{\theta \rho g} = - \int_{b}^{a} dz \]  

6.5

\[- \int_{b}^{a} dz = -(z_a - z_b)\]

If the density is assumed to be constant then the above equation becomes;

\[ p_a - p_b = -\theta \rho g(z_a - z_b) \]  

6.6

Where;

\(Z_a - Z_b\) = difference in depth between two points

\(p\) = Pressure on the tope surface of the element

\((p + dp)\) = is the pressure on the bottom surface

\(\theta\) = angle of inclination with the datum

\(h\) = Height of the isolated seam structure

From equation 6.6 flow Pressures are influenced by the degree of slope the structure makes with a datum; the flowing energy generated by fluid in motion gets absorbs by the isolated seam. Subsurface rock deformations are common drilling and production problems encountered in the oil and gas industry. In this research it was shown that the use of inverse modelling provides alternative method of describing both the interval properties and understanding the impact an isolated seam structure will have on fluid flow. This method does not only provide information on depositional environment but will reduce drilling risk and cost estimation both lithological and structural features.
6.3 AVO Responses at Selected Depth from E-M1well interval

The modelling of wave propagation from DT (compressional sonic), DTS (shear sonic) and RHOB (density) logs are done by using the first order linear form of Zoeppritz equation (Aki and Richards., 1980). This equation evaluates one dimensional model of angle. The amplitude versus angle cross plot displays these gather (reflections) while information about the interval can be extracted directly. The rock and fluid changes are reflected on the AVO/AVA cross plot. In this thesis the cross plot predicts the magnitude of heterogeneity in rock and fluid types for E-M1 well interval by sampling three depths from that interval.

From the compressional sonic, shear sonic and density logs the corresponding velocities were estimated. The outputs which are P-velocity (Vp) and the S-velocity (Vs) are combined with density log they are used in populating the synthetic seismogram model. The created propagated wave is used by fluid substituted scenario model to generate the AVO/AVA response cross plot. This cross plot reflects the wave variation as it travels through these medium.

The amplitude versus angle cross plot for E-M1well interval was taken at three different depths, and the fluids considered for the model were gas and oil. Description of the wave propagation has been done based on the gather, deflection, distortion and interferences. Velocity (wave displacement/time) and amplitude (maximum displacement of wave from a datum) are the wave characteristic properties that determine the composition, pore-space condition and pore-fluid content in each case.
6.4 Amplitude versus Angle Cross plot / Analysis E-M1
(DEPTH; 2611, 2624 & 2644)

Figure 6.2: Amplitude versus Angle Cross plot / Analysis at depth of 2611m

Aki and Richards applied (equation 6.7);

$$R(\theta) = \left[ \frac{1}{2} - 2 \left( \frac{\bar{V}_s}{\bar{V}_p} \right) \sin^2 \theta \right] \frac{\Delta \rho}{\bar{\rho}} + \left[ \frac{1}{2} Sec^2 \theta \right] \frac{\Delta V_p}{V_p} - \left[ 4 \left( \frac{\bar{V}_s}{\bar{V}_p} \right) \sin^2 \theta \right] \frac{\Delta v_s}{\bar{v}_s}$$

Where;

$\theta$ = Angle of incidence

$\Delta$ = An operator denoting the contrast in each property across the interface

$\bar{}$ = The super script denotes the average of each property across the interface

Aki et al (1980) approximations is only valid for $\theta < 60^\circ$ (sixty degrees)
Aki et al (1980) simplified equation assumes small layer contrast and the result are conveniently expressed in terms of $V_p$, $V_s$, and $\rho$ (equation 6.7). The amplitude anomaly in certain section is an indication of bright or dim spot on the pre-stack gather for a seismic map; when amplitude is high on the seismic reflection it means bright spot and verse versa if the amplitude is low (Hyne, 1991). The differences in reflected amplitude from the subsurface reflectors are largely due to the differences in lithology, porosity and pore-fluid content. Increased amplitude is a reflection of gas sand and decreased amplitude is a reflection of shale. This technique was applied in description for the figures 6.2 to 6.4.
Figure 6.4: Amplitude versus Angle Cross plot / Analysis at depth of 2644m

The behaviour of amplitude away from gas sand is important vital information can be deduce from the cross plot. In fig. 6.3 an interval of no gas reflectivity has been indicated. This section maybe interpreted to be high pressure fluid section or an undersaturated zone. Amplitude versus angle (AVO/AVA) cross plot could reveal minute details of the formation that may not be pictorially visible with partial-stack or pre-stack gather (seismic traces).
Chapter Seven
Discussion of Results

7.1 Introduction

This research identified the reason for drop in production pressure and designed an integrated approach in solving this problem. The research work was based on the well logs and well reports data of the wells. Extensive analyses were done using the petrophysical and rock physics properties; volume of clay, porosity, fluid analyses, permeability, shear sonic, temperature, shear and compressional velocity, elastic impedance and pressure evaluations. By applying discriminator using interactive petrophysics criteria’s were set with neutron porosity (curve), a mathematical function (>), and sets of values 0.045 v/v and 0.65v/v with hydrocarbon density = 0.8gm/cc to differentiate gas sand from non-gas sand amongst the investigated well intervals.

Only four wells met this criteria (E-M2, 3, 4 & 5) further analyses was done on E-M1 to ascertain the reason for its exclusion. Based on this result the pore model for this well interval was designed to discover the presence of an isolated seam structure (fig. 6.1). The impact of the granulated material on flowing pressures has been evaluated using fluid static equation.

In the Bredasdorp basin no research has been carried out on the impact of granulation seam as the reason for pressure drop in the E-M structure. Rather authors have focused their research on the evolution of the petroleum system and detailed geological structure of the basin, like Brown et al., (1996) and Hugh, (2005). Hugh, (2005): Assessment control on reservoir performance and the affects of granulation seam mechanics in the Bredasdorp Basin, South Africa, identified clearly the presence of these seams from core analyses and in his recommendation suggested more research on how these seam inhibits fluid flow.
7.2 Discussion

These well logs were used in evaluating the petrophysical parameters: neutron-porosity log, bulk density log, gamma ray log, resistivity log, caliper log, spontaneous potential log, and sonic log, were the only data sets available for this research. The caliper log displayed in fig. 5.1a to fig 5.1e indicates that no two well intervals have the same response because for each well interval the hole size diameter was indented at different depths: E-M1 (2571m), E-M2 (2670m &2713m), E-M3 (2678m), E-M4 (no indentation), E-M5 (2671 – 2700m). It was for this reason that the well intervals were studied separately except on occasions where bulk analyses were required in which case multiwell plot was employed.

The result from multiwell plots used in this research analyses the bulk volume for the well intervals investigated like in the selection of shale base line the mean value (77.0036 API) from gamma ray measurement for the entire well depth was used instead of the industry standard of 60 API. The mean value 77.0036 API gave better display results for sandstone - shale transition used in fig. 5.4a to 5.4e. From fig. 5.9, the two mineral cross plots between bulk density and neutron porosity indicate that no interval has a single rock type. The model predicts E-M1well interval has facies of sandstone and limestone while E-M2 to E-M5 well intervals is composed of sandstone, limestone and dolomite.

Tri-porosity cross plot was further used to analyze the bulk interval’s fluid and storage capacity. From fig. 5.11 neutron porosity against total and effective porosity cross plot results show that neutron porosity values for the interval are between 0.05-0.28 v/v which is within the range of the standard value for hydrogen index for gas (0.045v/v, Mille, 2012). The bulk interval’s total porosity is 25% while the effective porosity is 20%; the effective porosity is thus 5 % less than the total porosity which is consistent with what was reported by Levorsen (2004).
The results presented in fig. 5.14 (Pickett plot bulk analyses) predict the water resistivity value to be $0.0452 \text{ ohm-m}$, a cementation factor, $m$, of 1.98 and a constant $a = 1$. These results show that most sandstone for the well intervals is moderately cemented with water saturation for the rock types less than 50% of water bearing rocks. This is consistent with the results obtained from the cross plot between elastic impedance versus VpVs ratio (fig. 5.27). The conclusion is that the bulk of the volume has gas sand porosity above 25% with a small quantity of shaly sand (the cementation property).

Fig. 5.26 indicates the rock physics properties for the bulk volume. The multiwell interval cross plot between density and compressional velocity qualitatively shows the gas sand and brine sand with indications of shale. The sand grain properties for this bulk interval could be observed from fig. 5.24 where loosed grains are more evident for E-M1, 2, 4 and 5 than for E-M4. Loosed grains can be described to be suspension of sand grains or rock particles in liquid. The degree of loosed grains can affect production equipments and facilities.

Temperature also affects production facilities: in figure 5.28 (which is a cross plot between depth, temperature and frequency for each well interval) the colour code is interpreted using the frequency scale. Frequency has been established to be the degree of randomness or cycles per second which is the quantity of heat or energy a body possess. The heat profile fig. 5.29 shows the implication of the heat content for any well interval. E-M1, 2 and 4 exhibited abnormal heat profiles unlike E-M3 and 5 that showed the expected trend.
In order to justify the result obtained from applying discriminator, pore and fracture pressure analyses were done for each well. From literatures normal hydrostatic pressure gradient is 0.45 psi/ft and the overburden pressure gradient is 1 psi/ft (Braide, 2012). From figure 5.30 to 5.34 it could be observed that E-M1 has an abnormal high pressure result (table 5.15) for both the pore and overburden pressure gradient.

Table 6.1: Overburden and pore pressure gradient results for each well

<table>
<thead>
<tr>
<th>Well</th>
<th>Pore Pressure Gradient (psi/ft)</th>
<th>Overburden Pressure Gradient (psi/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>E-M1</td>
<td>4.5</td>
<td>4.5</td>
</tr>
<tr>
<td>E-M2</td>
<td>0.48</td>
<td>0.9</td>
</tr>
<tr>
<td>E-M3</td>
<td>-</td>
<td>0.9</td>
</tr>
<tr>
<td>E-M4</td>
<td>0.56</td>
<td>0.9</td>
</tr>
<tr>
<td>E-M5</td>
<td>-</td>
<td>0.9</td>
</tr>
</tbody>
</table>

The pore and overburden pressure gradient results (table 5.15) is consistent with that from figure 5.17a (the log display for permeability, total porosity, and effective porosity) where E-M1 well interval show an abnormal pattern. From 2570 meters to 2597 meters for the well interval the effective porosity was 90 to 95 % more than the total porosity, a deviation from the other four well intervals and literatures (Levorsen 2004).
Chapter Eight
Conclusions and Recommendations

8.1 Concluding Remarks

As part of explaining why there was a decrease in production capacity from the E-M suits, this study applies formation evaluation and there for focuses on calculation of petrophysical parameters, porosity, permeability and pressure gradients in particular for the reservoir wells; E-M1, 2, 3, 4 and 5. Porosity and permeability evaluations were used to identify the well interval that is susceptible to decreasing fluid flow pressure and it was observed in E-M1 well that the presence of granulated material for a particular reservoir interval affects the flowing capacity of fluid.

From the pressure analyses done E-M1 well has the highest pore and overburden pressure gradient values (4.5 psi/ft). The overpressures for well E-M1 are due to lithological barriers caused by the granulated seams. These seams create closed pore fluid environments, and the fluid pressure cannot be transmitted through permeable beds to the surface.

Formation evaluation gives better results when the parameters used are specific to the wells under investigation. For instance, in this study instead of using the industry standard for shale base line which is = 60API, the mean value = 77.0036 API was used which was found to give better display results for sandstone to shale transition for all the wells.

In the research of this project it was found that the isolated seam structure became visible after the pore model for well E-M1 interval was aligned with the geographical co-ordinates of the basin i.e. North West/ South East orientation.
It then became apparent that the Bredasdorp basin’s depositional system is largely controlled by the topography.

In summary this research was able to develop a theoretical method of applying inverse modelling to demonstrate how seam structures can affect flowing pressures. This method can be applied to other regions.

8.2 Recommendations

This project has found the following gaps in the inverse modelling method which our research has not resolved and it is therefore recommended that future research should:

1. Investigate how to apply inverse modelling to reservoir characterisation which is a cheaper means of extracting information than seismic methods.

2. Investigate how reservoir properties variation in space can be combined with inverse modelling as this will establish an understanding of rock-flow physics as well as rock and fluid structure behaviour.

3. Develop methods to efficiently incorporate geology, core data and laboratory analyses into inverse modelling.

4. Develop methods of extracting information on porosity, composition and fluid content from inverse modelling.
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