A review of a small production gas field in Central Bredasdorp Basin, based on new seismic, integrated with core and log data.

Masters Thesis

BY

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A thesis submitted in fulfilment of the requirements for the degree of Magister Scientiae in the Department of Earth Sciences, University of the Western Cape

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November 2016
Declaration

I declare that “A review of a small production gas field in Central Bredasdorp Basin, based on new seismic, integrated with core and log data”, is my own work, that it has not been submitted for any degree or examination in any other university, and that all the sources I have used or quoted have been indicated and acknowledged by complete references.

Rotondwa Masindi                     November 2016

Signature
A review of a small production gas field in Central Bredasdorp Basin, based on new seismic, integrated with core and log data.

Rotondwa Masindi

Key words
Bredasdorp basin
Core description
Wireline logs
Seismic Interpretation
Structural Modeling
Petrophysical Modeling
Volumetrics
Abstract

The study area is a small production gas field located in the Bredasdorp basin. The basin is situated off the south coast of South Africa. It covers an area of approximately 18000 km². The field of study comprises of three wells which contain gas in the 13A and 10A sands. Prior seismic has limited resolution and production disproves previous geological and seismic understanding. Previous studies have shown that the reservoirs in this field are difficult to map due to thin sandstone beds which are below seismic resolution. The project is aimed at obtaining a more detailed regional stratigraphic and structural interpretation based on new seismic data.

The study methods integrated seismic, core and wireline log data. Core logging and wireline logging were done to determine facies and ultimately the depositional environment. Seismic interpretation was done by mapping horizons and faults. This resulted in the generation of surfaces maps which were converted from time to depth using a velocity model. The depth surfaces were used as input for structural and petrophysical modeling. All interpretation and model construction was done using the Petrel Software. At the end the volume in place was calculated.

The four facies determined from the combination of core logging and wireline logs were: claystone, fine sand, fine – medium sand and medium sand. The depositional model deduced is that of the outer lower fan in a deep marine environment. The lower fan is characterised by a succession of sands at the base and claystone at the top.

The structural geology of the study area was determined from seismic interpretation. The horizons above the 13At1 horizon are fairly flat. The horizons below 13At1 are tilted, especially horizon 10At1. The depth maps show structural high areas at the 13At1 and 10At1 events. A high area on a structural map must have all contour lines coming all the way around all sides. This gives a closure in order to prevent the hydrocarbon from spilling. A structural trap is therefore deduced at the area of study as all contours close up.

Well Y-01 has the best petrophysical results compared to the other two wells in the study area. The porosity and permeability for this well is good. The well exhibits a good net/pay ratio and low water saturation. The volume in place of the 10A sands combined is higher than that of the 13A sands. The total volume in place of the current study is higher than that of the study conducted in 2005 by PetroSA. This is a result of improved seismic resolution.
However, it is recommended that the seismic must be reprocessed in order to improve the visibility of 10A sands as well as the faults.
Acknowledgement
I would like to thank God for the strength he has given me to complete this thesis. It has not been an easy journey, but the Lord has given me strength and inner peace to dedicate myself to complete my thesis.

To my supervisor Dr. Opuwari, thank you so much for the dedication you had in my work. For all the time you spent in proof reading my work and giving me guidance, thank you. You were very patient with me and motivated me into achieving the final goal.

I would like to thank PetroSA for providing me with the seismic data, reports and other additional information to use as inputs for my study. In particular, I would like to thank Jody Frewin for helping me in collecting the data that was required for my thesis. It was not easy getting the data from various employees within the company, but with your help I managed to gather all the data I needed.

Thanks to Petroleum Agency SA (PASA) for allowing me to come do some core logging at your offices. The staff member that assisted me with laying out the core was very kind and helpful. I was also given enough time to perform the core logging.

To Leah Hossain from Schlumberger, thank you so much for training me on Petrel and helping me with the petrel tools and processes that I needed to complete my project. You were very patient with me considering it was my first time using Petrel.

I would also like to thank my husband Hudson Falala for the support, both financially and emotionally. You have been very good at encouraging me to work hard and complete my thesis.

Lastly, to my former colleagues as well as classmates, Latoya and Kalidasen, Thank you for taking this journey with me.
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Chapter 1

1. Introduction

1.1. Background

The Bredasdorp basin is situated off the south coast of South Africa (Figure 1). It covers an area of approximately 18000 km$^2$. The F-A/E-M and satellite gas fields are situated 90km offshore and are owned and operated by PetroSA. Drilling for hydrocarbons in the Bredasdorp basin began in 1973 and this led to discoveries of the F-A gas field around 1980. Further discoveries led to production of gas and condensate which are transported by a pipe line to the Mossel Bay Gas to Liquid (GTL) plant. At the GTL plant, the gas is converted to petrol, diesel, paraffin and petrochemical products.

South Africa’s first oil production began in 1997 at the Oribi oil field. Adjacent to this field is the Oryx oil field. The third field is known as sable and commenced production in August 2003. The Oribi/Oryx field are now almost depleted and only have minor production. The Sable field is now producing gas to sustain the GTL plant. Production from South’s African’s gas field is declining and this will affect the country’s energy availability.

The South Coast GAS (SCG) field is aimed in providing the additional gas required to sustain the GTL plant. It comprises of a number of fields such as: E-CE, Cluster field (E-CA, E-AA, E-BA and E-BB) and E-S field. Exploration and production has been done by PetroSA and is still in progress. Poor quality channel, overbank and sheet sand (distal fan) deposits are not resolvable from seismic (Grobbler, 2005). The reservoirs in this field are difficult to map due to thin sandstones beds which are below seismic resolution.

Prior seismic has limited resolution and production disproves previous geological and seismic understanding. The project is aimed at obtaining a more detailed regional stratigraphic and structural interpretation based on new seismic data. Core logging and interpretation of petrophysical logs will be done. Correlation between wells will be done using petrophysical and core description. A more detailed structural model will be built to understand the extent of the field using new seismic data. Reservoir characterisation and distribution of properties within the chosen field will be done using Petrel. This will result in an estimate of hydrocarbon in place and uncertainty.
Figure 1: Location of the Bresdasdorp Basin, (Petroleum Agency of South Africa (PASA), 2012).
1.2. Research problem

Previous Studies

A lot of work has been done at the Bredasdorp Basin. The geology of the area is well known. Studies describing the reservoirs that contain hydrocarbon have been done. What these studies have in common is the description of the thin reservoirs that are not resolvable on seismic.

Nico Grobbler studied the Barremian to Aptian gas fairway in 2005. The study gives characterises of deep marine reservoirs. The generally pre-Aptian central basin gas charged reservoirs are narrow and have been a problem when producing a geological model and commercially (Grobbler, 2005). Poor quality channel, overbank and sheet sand deposits are not visible on the seismic, especially in the SCG area.

In a geological modelling study done by Frewin et al 2005, it was mentioned that the sandstone reservoirs in the SCG area are not resolved on seismic data due to the relatively small contrast in acoustic impedance between the sandstone and shale beds below and above the reservoirs and also the interbedded shale.

Problem statement

Prior seismic has limited resolution and production at the study area does not follow or represent the proposed geological models which were once built.

Aims and objectives

The aim of the project is to analyse the new available seismic which have an enhanced resolution; in order to develop a more detailed stratigraphic and structural interpretation of the study area. This will help in understanding the reservoir properties and lead to building of a model which will improve the understanding of how much hydrocarbon is in place. The new seismic data will help in understanding the extent of the reservoirs. Geological structures will be better recognised on the new seismic. This will result in a clear visualisation of the structures and also the regional tectonic frame work. The project will result in a facies distribution model based on core logging and petrophysical studies. A model will be built in order to interpret the characteristics of reservoir and calculate the hydrocarbon in place.
1.3. Research design
The study is focused on building models to best understand the geology of the field of study as well as review the amount of the initial hydrocarbon in place. The study uses an integrated approach which will best describe the geology of the study area.

The scope of work will cover the following:

- Understanding the geology of the Bredasdorp Basin and field of study
- Classification of facies using core description
- Well correlation using log data
- Horizon and fault mapping
- Providing a velocity model which will be used to convert surfaces from depth to time.
- Building a 3D grid
- Populating 3D grid with facies and petrophysical properties such as porosity, permeability and water saturation
- Calculation of initial hydrocarbon in place
Figure 2: Project design layout.
1.4. Delineation of study area

The study area (Figure 3) is field Y and is located in the central part of the Bredasdorp basin. Field X was included in the project in order to get a wide correlation across field Y. Field X has one well named X-01 and field Y has 3 wells: Y-01, Y-02 and Y-03. The distance between well X-01 and field Y is 5651.4m. A short description of each well is given below.

X-01

X-01 was the only well drilled in field X. It is a discovery well and was drilled vertically. The primary target was horizon 5At1-13At1 that is found within deep-marine fan lobe complexes. The well was drilled up to 3860m. Hydrocarbons were detected within the 5At1 to 13At1 interval. The joint gas flow rates from the reservoirs in the 5At1-to 13At1 sequence were in excess of 555MMscf/d (Wolmarans et al., 2000). The oil zone was intersected below horizon EQIV and flowed ± 4000 bbls/day. X-01 was characterised as a well with potential commercial gas and oil production rates.

Y-01

This is a wild cat or discovery well which was drilled vertically. It was the first well drilled in field Y. The well was drilled up to 3320m below rotary table (BRT). The primary targets were the 9A–14A sequence. The 9A – 13A interval was intersected during drilling and it consists of thick sandstones interbedded with claystones. A total of 73.3m of these sandstones contained wet gas and 17m in the 13A sequence contained oil. The poroperm properties range from 11-14% porosity and 2-30 mD permeability. The 10A sequence comprised of sandstones with wet-gas. The sandstone package was approximately 36m. The poroperm properties were 12% porosity and 15 mD permeability. The flow rate in the middle 10A channel was 32.2 MMSCFD (Simonis, 1992). The 14A sequence has approximately 12m of sand contains oil, but displayed poor poroperm properties. Well Y-01 was characterised as a well with potential commercial gas production rates, poor condensate and encouraging oil shows.
Y-02

The first appraisal well to be drilled in field Y was borehole Y-02. The well is located 465 meters south-west of Y-01. The primary targets were 9A, 10A and 13A sequence. The secondary targets were deep marine sandstones above 13Amfs and 14At1. The well interested the 9A, 10A and 14A reservoir sandstones. The 13A reservoir sandstone was 19m thick and flowed 12 MMSCFD and 890 BCPD (Simonis et al., 2001). The reservoir had a porosity of 10.6%. The other intervals intersected did not have significant hydrocarbons.

Y-03

This well was drilled approximately 40m northeast of the discovery well Y-01. The primary targets were similar to that of Y-01. The total depth of the well is 3019m BRT. The 10A and 13A sands were intersected. The 10A sandstone had a porosity of 8-13%. The porosity of the 13A sands was 10%. Gas was found in both 10A and 13A sequence. The well flowed at a maximum gas rate of 21.95 MMSCF/D from the lower 10A sands and a maximum rate of 13.65 MMSCF/D from the upper 10A and 13A sands (Simonis et al., 2008).
Figure 3: Location map of the study area
Chapter 2

2. Geology of the Bredasdorp Basin

2.1. Regional Setting

South Africa’s Offshore basin can be divided into three sections. The Western offshore comprises of a passive margin basin which is associated with the opening of the South Atlantic during the early cretaceous period. The basin along this margin is known as the Orange basin. The Eastern offshore is a narrow margin that was formed as a result of the breakup of Gondwana (Figure 4) during the Jurassic period (PASA, 2012). The Southern offshore region is known as the Outeniqua basin. The basin was formed during the middle to late Jurassic, before the separation of east and west Gondwana, and extended onto what is known today as the Falkland plateau (Roux, 1997).

Figure 4: Map representation of the Breakup of Gondwana, Steph Wilk (After Wilson, 1989).

The Outeniqua basin is sub dived into 4 sub-basins known as the Bredasdorp, Pletmos, Gamtoos and Algoa (Figure 5 and 6). According to Bally and Snelson (1980), the
Southern offshore basins exhibit features of rift basins and more specifically divergent margins. Examples of rift basin features are normal faults and grabens. The four sub-basins of the Outeniqua basin display half graben features (Figure 6). These half graben structures develop as a result of hanging-wall block tilting towards the normal fault and creates a depression known as a half graben. The basin was formed as a result of rifting of continents and it evolved through the transition between rift and drift and finally during the drifting period. Sediments were accumulated during these periods. The four sub-basins of Outeniqua basin have comparable histories, although responses to specific events affecting sub-basins are often distinctly different in each case (McMillan et al., 1997). The oldest sediments have been recovered by drilling in the Gamtoos and Algoa basin and were dated Kimmeridgian (late Jurassic) in age (McMillan et al., 1997).

In Southern Africa, rifting is considered as having begun with preliminary fracturing of Gondwana into east (Antarctica-Australia-India) and west (South America-Africa) portions (McMillan et al., 1997). The rifting began during the middle to late Jurassic. Normal faults were formed as a result of rifting. These normal faults are parallel to the compressional tectonic grain of the Permo-Triassic Cape Fold Belt (Roux, 1997).

The drifting started during the Valanginian age. During the Valanginian, right-lateral shear stresses developed along the Agulhas-Falkland fracture zone (Roux, 1997). As a result, there was folding and strike-slip movement along the existing normal faults. The resulting right lateral movement along the fracture zone detached the Falkland plateau from the African plate and bisected the Outeniqua rift basin (Roux, 1997).
Figure 5: Major tectonic elements in the Outeniqua Basin (PASA, 2012).
Figure 6: Cross Sections of the Outeniqua Basin (PASA, 2012)
2.2. Local Geology

The Bredasdorp basin is situated off the south coast of South Africa. It covers an area of approximately 18000 km$^2$. It is a sub-basin of the Outeniqua Basin. The Bredasdorp basin lies between the infant and Agulhas - Columbine Palaeozoic arches which are located NE and SW respectively (Broad et al., 2000). It is a south-easterly trending basin. The sediments that have mostly filled this basin are of Aptian to Maastrichtian age. These are marine sediments and were deposited on pre-existing Late Jurassic to Early Cretaceous fluvial and shallow marine rift deposits (Grobbler, 2005).

2.2.1. Structural framework of Bredasdorp Basin

The structural evolution of Bredasdorp basin can be explained in 5 main stages. These stages are discussed below and a stratigraphy showing the different events is shown below in figure 7.

**Syn - rift Tectonics**

*Mid-Jurassic to Valanginian (Basement to At1)*

The event that occurred at this time is known as synrift I and is marked from basement to the 1At1 unconformity. Initial rifting was characterised by the development of horst and graben structures and that is typical of extensional tectonics (McMillan et al., 1997). Isostatic uplift on both flanks of the half graben caused erosional truncation of synrift I sediments. Termination of active rift sedimentation is marked by the 1At1 unconformity which records significant uplift and truncation of underlying sediments along the basin margins (McMillan et al., 1997).

**Post - rift Tectonics**

*Late Valanginian to Hauterivian (1At1 to 6At1)*

This period is marked by the 1At1 to 6At1 sequence boundary. It is the synrift II phase and was characterised by rapid subsidence and widespread flooding. During this period the northern flank of the Bredasdorp Basin, including the gas field areas suffered erosion (McMillan et al., 1997). Uplift continued and this resulted in further truncation of structural highs. Deposition of deepwater sequences took place within
rift depocentres and Southern Sub-basin and this led to the formation of source rocks (PASA, 2009).

**Hauterivian to Aptian (6At1 to 13At1)**

Transitional early drift phase occurred at this time and is characterised by the 6At1 to 13At1 sequence boundary. During the early Aptian age, subsidence rates and faulting show marked declines and this signify a more stable Bredasdorp Basin (McMillan et al., 1997). The Arniston Fault in the north ceased effective movement due to the fact that the basin was stable. There was merging between the depocentre to the south of the fault and depocentre in the central and southern Bredasdorp Basin (McMillan et al., 1997). A major shoreward advance of sedimentation occurred along the entire north-eastern flank of the basin, and as a result deposition occurred over the entire region of the gas fields (McMillan et al., 1997).

**Albian to Maastrichtian (13At1 to 15At1)**

The 13At1 to 15At1 time signify the drift phase. During this phase, there was regional subsidence which was driven by thermal cooling and sediment loading (PASA, 2003). There was faulting reactivation and this led to continuation of movement of the Arniston Fault. The 15At1 unconformity shows clear microfaunal evidence of erosion, postulating minor deformation and uplift during the Late Cenomanian (McMillan et al., 1997).

**Paleocene to Present Day (15AT1 to seafloor)**

The last phase of structural evolution of the basin was the upper drift phase. During this phase, the source rocks formed earlier in synrift depocentres as well as central Bredasdorp Basin entered the main stage of oil generation. There was minor subsidence which resulted from Early Tertiary Alkaline intrusion activity over the Central high. There was late tilting of the Bredasdorp Basin combined with uplift of the Northern Flank and as a result erosion occurred up to 600m (PASA, 2009).
2.2.2. Depositional system

Throughout the rift episode, the basin was supplied by clastic sediments that were transported from the north and northeast. The clastic supply was also from erosion of orthoquartzites and slates of Cape Supergroup and sandstones and shales of the Karoo Supergroup (McMillan et al., 1997). The sediments transported during rifting are not found have not been intersected in the central basin area and the basinward extent of sandstone is therefore unknown (McMillan et al., 1997). According to McMillan et al. (1997), in more proximal localities, particularly in the northern section of the basin, sediments transported during rifting episode comprise entirely of red and green claystone lithologies with non-marine sands.

As mentioned earlier, graben structures were formed during the rifting. The grabens were filled with sediments that comprise of alluvial fanglomerates and braided and meandering fluvial sediments with occasional tuffaceous interbeds which are postulated to have formed during alternating volcanic activity (Broad et al., 2000). Lacustrine deposits and halite beds have also found in the graben structures (McMillan et al., 1997).

McMillan et al. (1997) described the lithogenic units of the syn - rift and post - rift sequences. A stratigraphy with the different lithogenic units is shown in figure 8.
Syn-rift Sedimentation

Lower Fluvial Interval

The interval comprises of red and minor green argillites containing caliche horizons with secondary reddish sandstones and occasional conglomerates.

Lower Shallow Marine Interval

On the northern flank of the basin the first marine incursion occurred at horizon V which is known as an erosional regional unconformity. This interval comprises of glauconitic sandstones that are clean, fine-grained, well sorted and locally biotubated. The depositional environment is interpreted as tidal to estuarine shallow marine, and the sediments formed in this type of environment were laid down above active water-base. Sandstone beds that are coarsening upwards were observed locally, and these suggest progradational depositional environment.

Upper Fluvial Interval

The overlying upper red interval is characterised fining - upward cycles, and comprises of interbedded sandstones that do not have glauconite mineral, red and green claystones and siltstones. The interval is regarded as having accumulated in an environment with an alluvial flood-plain characterised by meandering fluvial channels.

Upper Shallow Marine Interval

The interval formed on an unconformity that follows a second major marine transgression into the Bredasdorp Basin. The transgression was followed by an overall regressive phase which was dominated by recurring progradational deposition.

Post-rift Sedimentation

During the Late Valanginian to Hauterivian, the northern flank of the Bredasdorp Basin had restricted sedimentation or erosion occurred. During the Barremian to Aptian, sedimentation was dominated by turbidity flows into a deep marine basin that had poor circulation of water and poor oxygen supply. The 13A channel is characterized by submarine fan-channel complexes. Overlying the 13A sequence is
the 14A sequence which is characterized by basin floor fans that are found in the central part of Bredasdorp Basin.

Figure 8: Generalized stratigraphic of the Bredasdorp Basin (PASA, 2012)
2.2.3. Petroleum potential of the Bredasdorp Basin

Exploration and Production History

Since 1980, of the four sub-basins in Outeniqua Basin, seismic and drilling activity was mostly done in the Bredasdorp Basin (PASA, 2003). The result of extensive exploration in the Bredasdorp Basin led to the discovery of small oil and gas fields, and the commercial producing oil and gas (PASA, 2003). Below is a cross section showing the hydrocarbon discoveries in the Bredasdorp Basin.

Figure 9: Schematic geological cross-section showing Bredasdorp Basin discoveries (PASA, 2003).

From the figure above it can be seen that most of hydrocarbon is contained in reservoir rocks that are Valanginian to Mid Albian. On the NE direction, it can be seen that the fault structures that were formed during the Break up of Gondwana, during the Jurassic period, are responsible for trapping the hydrocarbons in this case.

PetroSA owns and drives exploration activities in the F-A/E-M and Satellite fields (Figure 10). In these fields, production started in 1992 and gas and condensate are transported to PetroSA’s GTL plant in Mossel Bay by a pipeline (PASA, 2003). The gas transported to the GTL plant is converted to petrol, diesel, paraffin and petrochemicals.
In 2006, the average daily production from these fields was approximately 160 MMscfd (million standard cubic feet of gas per day) and 3900 BOPD (barrels of oil per day) (PASA, 2003).

Figure 10: Oil and gas discoveries of the Bredasdorp Basin - depth contours on horizon 14At1 (PASA, 2003).

The first oil production in South Africa was in 1997 after the Oribi oil field began flowing at an initial rate of 25 000bbl/d. A refinery in Cape Town is supplied with
crude oil transported by a shuttle tanker which gets filled up by the floating production facility known as the Orca (PASA, 2003). The field adjacent oil field known as Oryx was also brought on stream using the same facilities. In August 2003, a third field known as Sable commenced. The Oribi/Oryx field are now almost depleted and only have minor production. The Sable field is now producing gas to sustain the GTL plant. Production from South’s African’s gas field is declining and this will affect the country’s energy availability.

**Petroleum System elements**

A basin must have a petroleum system for hydrocarbons to be accessible. It is important to understand the petroleum system of a basin before exploration can commence. The 5 parameters that make up a petroleum system are source rock, reservoir, trap, seal, and migration. Time also plays a very important factor in the petroleum system, especially the timing of migration. The Bredasdorp basin also has a petroleum system, which so many people have studied and hydrocarbons can the associated with such a petroleum system.

**Source Rocks**

Source rocks are deposited as sediments rich in organic carbon with high hydrogen content. Every Hydrocarbon is comprised of hydrogen and carbon. A hydrocarbon generating source rock must have high hydrocarbon content.

Most of the oil prone source rocks are found in the Central Bredasdorp basin and lie between 100 and 300m beneath the 14A lowstand reservoirs in deep marine, transgressive and early highstand tracts of the Aptian sequence known as 13A (Burden et al., 1997). These source rocks are shales. The average thickness of these shales is more than 90m and covers an area of about 3300 km$^2$.

A good source rock is determined by assessing a number of elements. Some of these elements are Total Organic carbon (TOC), vitrinite reflectance and hydrogen index. The amount of organic matter in a source rock is determined by the TOC. The vitrinite reflectance gives an indication of the oil and gas window and type of hydrocarbon produced.
The source rocks in the central Bredasdorp basin have an average TOC of 2.8% and at some areas it exceeds 4% (Burden et al., 1997). TOC of between 2-5% has high hydrogen content. Visually almost all the kerogen is type 2. Type 2 organic matter is commonly marine material but can be lacustrine in some places. In the case of Bredasdorp basin, the organic material is in a marine environment. It is comprised of herbaceous and cuticular plant debris and animal material from plankton and bottom-living organisms. Type 2 organic matter generates both oil and gas.

**Reservoir**

**Syn-rift**

Reservoir sandstones found in the Upper Shallow Marine (USM) depositional environment. Good reservoir quality of the USM sandstones is responsible for the presence of Mossel Bay gas fields along the northern flank of the Bredasdorp basin within the gas fairway (McMillan et al., 1997). These reservoir sandstones can be seen in figure 10. The USM sandstones are the best reservoirs of the fields comprising of gas and have good porosities and permeability.

**Post-rift**

There was deposition of basin floor reservoir sandstones during the lowstand (Broad et al., 2000). The 13A and 14A sequence comprise of the most important reservoirs.

**Trap**

Most of traps of the hydrocarbons in the Bredasdorp Basin are structural and some are truncated (Figure 11). The synrift succession is truncated by 1At1 unconformity which in some areas cuts deeply into the reservoir sandstones comprising of gas (Broad et al., 2000). Potential traps for hydrocarbon were formed during the breakup of Gondwana.

**Seal**

The shelf comprises of glauconite clays and biogenic clays with minor sands (Figure 8). These lithologies act as good seals.
Figure 11: General description of prospects showing different petroleum elements of the Bredasdorp Basin (PASA, 2009).
Chapter 3

3. Materials and methodology

3.1. Methodology Research

3.1.1. Core sampling and logging

A core sample is described as a cylindrical section (of usually a naturally occurring substance). Core sample can be taken to obtain a portion of the reservoir rock, so that it may be analysed in the laboratory to provide geological and engineering information. Two types of coring methods are discussed.

**Side wall coring**

In sideward coring, a slim wireline coring tool is run into the hole. The tool is either rotatory sidward or percussion. The side wall coring tool uses a diamond bit (Figure 12) that rotates at 2000 RPM. The core sample is broken by a slight movement of the bit. The sample is withdrawn into the tool, and the core pushed into the receiver tube. An indicator reveals that a core sample has just been received. The tool is then ready for the next selected core point. Usually, cores about 1” in diameter and 1” to 2” long can be retrieved with this method.

This method is cheaper than conventional coring. The method is much quicker. Cores can be taken in hours, instead of days.

Figure 12: Side wall core (Baker Hughes website).
Conventional coring

A regular drill bit is removed from the hole. It is replaced with a core bit which is used to grind out and retrieve a heavy cylinder of rock. The core bit is usually coated with small, sharp diamonds that are capable of grinding through the hardest rocks.

At the well-site, the core recovered is carefully marked, cut into 1 meter pieces and sent for examination. At the laboratory, the plug samples are drilled out of the core sample, to allow measurement of petrophysical and other properties.

Figure 13: Core obtained from conventional coring (Halliburton website).

The objective of core logging is to collect information that leads to more efficient oil and gas production (American Petroleum Institute, 1998). Some information which is collected during core logging includes:

Geologic Objectives

a) Lithological information
   - Rock type
   - Depositional environment
   - Pore type
   - Mineralogy/geochemistry
b) Fracture orientation

Petrophysical and reservoir engineering

a) Permeability information
- Permeability/porosity correlation
- Relative permeability

b) Capillary pressure data
c) Data for refining log calculation
   - Electrical properties
   - Grain density
   - Mineralogy and cation exchange capacity
d) Enhance oil recovery studies
e) Reserve estimate
   - Porosity
   - Fluid saturation

**Drilling and completions**

a) Fluid/formation compatibility studies
b) Grain size data for gravel pack design
c) Rock mechanics data

### 3.1.2. Wireline logs

Logging, electro logging or well logging means the continuous recording of a physical parameter of the formation with depth. The well logs are results of several geophysical measurements recorded in a well bore. The primary objectives of wireline logging are:

- Identifying the reservoir
- Estimation of the initial hydrocarbon in place
- Estimation of recoverable hydrocarbon.

The logging operations done at different rigs are decided based on the well requirements. These operating procedures are carried out by truck mounted logging units which are placed in front of the catwalk of the rig. The logging tools are placed into the well by using a logging cable. Two sheaves are used to lower the logging tools. The bottom of the sheave is tied to the derrick floor and is placed near the opening of the well and the top sheave is hung to the travelling block in order for the tools to be lowered into the well. The tools are assembled and connected to the logging cable via a rope socket on the catwalk. The tools are then lowered to the
depth of interest and data is acquired while the tool is pulled up. When the survey is completed, the tool is pulled out and rig down processes in started.

There are various physical parameters that can be recorded in the logs depending on the well requirements. Some of the types of well logs are described below.

**Gamma Ray Log**

The Gamma Ray (GR) log is used to measure natural radioactivity of soils and rocks, and is mostly useful in distinguishing between shales and sandstones and in determining depositional environment (Hsieh et al., 2005). GR energy spectrum is processed to identify the windows associated with potassium, uranium and thorium and the contribution to the total GR determined. In sedimentary formations, the GR log reflects the clay or shale content. Shales usually have higher GR readings because they contain sufficient quantities of radioactive elements such as potassium, uranium and thorium. Sands will normally have low GR reading because they lack radioactive elements. However, some sands may show signs of medium to high GR readings if the sand contains feldspars and micas. The units for gamma ray are API.

Some of the main uses for GR log are:

- Provides a more comprehensive dataset for clay quantification and clay typing.
- RATIOS OF Th/U, TH/K, U/K are used for clay mineral identification
Neutron porosity (NPHI) logs (Figure 15) are porosity logs that measure hydrogen ion. Tools are calibrated in standard test pit facilities in portions of fresh water bearing limestone. Neutron porosity is affected by rock matrix properties and hydrocarbon. In water bearing limestones, neutron directly reads the porosity (Jawoodien, 2011). Corrections have to be made in order to convert neutron porosity to reservoir porosity. The neutron porosity log can be used to identify gas zones. In clean formations, where the pore spaces are either filled with water or oil, the neutron log measures liquid filled porosity (Jawoodien, 2011). Water and oil tend to have high neutron readings as compared to gas, because the water and gas have high hydrogen concentration. When the pore spaces are filled with gas, the neutron reading are low because there is less concentration of hydrogen in gas. The measurement for neutron porosity is pu (porosity units).
**Density Log**

The density log (Figure 15) measures the density of formation. The measuring tool contains radioactive source that emits GR’s at a known constant energy level. With time, the energy levels reduce as GR’s pass through the formation. The reduction in energy levels between two detectors is measured by a pad on the tool. The drop in levels at high end of the GR spectrum is a function of the electron density which is equated to the bulk formation density.

Density log response is a combination of the matrix density and the density of fluids in their relative proportions. Density logs can be used to compute porosity for a known matrix and saturating fluid densities. The units used are gm/cc. A combination of density and neutron log can be used to indicate the presence of hydrocarbon.

The main use to density log is to quantify porosity and identify lithologies in conjunction with other log types.

**Resistivity Log**

Resistivity logs (Figure 15) measures conductivity. The unit for resistivity is ohm-m. Electrical current primarily conducted through water. Rock matrix and hydrocarbons are non-conductive. In order for a current to flow, the conducting medium which is water must provide a uninterrupted network through the formation (Jawoodien, 2011). Water conductivity is dependent on two factors which are salinity and temperature. Hydrocarbon in the reservoir reduces the volume of conductivity water and therefore it reduces the conductive capability of the formation. Higher resistivity is exhibited in the following: Fresh water, low porosity, low permeability and high hydrocarbon saturations.
Figure 15: Different petrophysical logs (Gamma ray, porosity, density and resistivity, (Olsen, 2009).

**Spontaneous Potential (SP) log**

The spontaneous potential (SP) log (Figure 16) measures natural electrical potential between borehole and water formations. The log unit is mv. Potential is a result of salinity differences between mud and water formation. This only occurs across permeable zones when two fluids come into contact. Two contributions to the measured spontaneous potential are:

- An interface between fluids on permeable formations.
- In surrounding clays which form a diffuse interface between borehole and interstitial waters.

SP is used to identify permeable zones and estimate formation water resistivities and salinities. If the formation permeability is controlled by shale content, then SP can be
used as a shale indicator and is commonly used for correlation purposes in a deltaic sequence (Jawoodien, 2011).

**Sonic/Acoustic Log**

Sonic log measures the compressional wave transit time. The units are us/ft. A tool transmits an acoustic signal and measures time of first arrival at two receivers. The transit time is computed between receivers. The measured formation sonic transit time (DT) is dependent on the proportions of individual acoustic properties of all the formation components (Jawoodien, 2011). The largest DT contract is found between rock matrix and pore fluids. DT is therefore an important measurement for quantifying porosity. DT is affected by the matrix properties and is used for lithology typing in conjunction with other logs.

**Caliper Log**

The caliper log measures borehole diameter. The units are inches or cm. The hole size is affected by lithology. The caliper log can indicate mudcake which is associated with permeable reservoir formations. A single caliper is recorded with a pad and used conjunction with other logs such as density and micro-resistivity logs (Jawoodien, 2011). Multiple calipers can be recorded to indicate borehole shape and maximum breakout direction. The direction of maximum breakout can indicate fracture orientation.
3.2. Materials

This chapter describes a detail technique used for the project. Data was provided by PetroSA and PASA. Petrophysical logs such as gamma ray, density, porosity, resistivity, sonic etc, were provided by PetroSA. Seismic data was also provided by PetroSA. The core from different wells was logged at PASA. Only 2 wells were logged, well Y-01 and Y-02. Well Y-03 did not have any core cut.

The softwares used to generate results were Schlumberger Petrel and Sedlog. The Petrel software was used mainly for well correlation, seismic interpretation and generating models. The Sedlog was used to capture core data that was logged.
Data list

- Geophysical logs
  
The geophysical logs used were: Gamma Ray log, Density log, Neutron Log, Resistivity log (LLD).

- Seismic Data (2D) SEG – Y format
  
The seismic data covered all the wells in Field Y.

- Well Reports
  
The following reports were used for the study:
  
  - Recommendation to drill
  - Geological well completion report
  - Core photography
  - Special core analysis report
  - Audit report

3.3. Methodology Approach

3.3.1. Core Description

The core for well Y-01 and Y-02 were laid out at the PASA core shed. The core was watered so as to see the grain size and any structures available. A description of the lithology was done, as well as describing parameters such as grain size, structure, minerals available and facies distribution. A tape was used to measure the depths of interest. Core photos were taken. All the core description was recorded in a log sheet. The recorded data was transferred to the Sedlog software. The software was used to illustrate the lithologies observed during core logging and changes observed in the core.

3.3.2. Data Loading

Wireline logs were loaded in petrel. The wireline logs were loaded in a Petrel Project. The data was received in LAS format, but was loaded into Petrel in ASCI format. Different templates for the logs were chosen at the beginning of data loading. Setting
a template for logs is useful to avoid duplicates when loading different logs for different wells.

The seismic data was received in Seg – Y format. The seismic files were imported into the Petrel project in seismic bricked format. Full stack, Near stack and Mid angle stack seismic data was provided.

3.3.3. Quality Control

Quality control was done to ensure the data provided is correct and can be used for interpretation. The horizon markers were quality checked with the provided seismic well tie for well Y-01. Some of well markers used for the well correlation were quality checked with the core markers, especially the top of the sand markers.

3.3.4. Wireline log interpretation

Wireline log interpretation was used for stratigraphic modeling. Stratigraphic modeling allows the determination of similarity rock bodies at different locations where well data is available. The logs were displaced in a well section window and both lithostratigraphic and chronostratigraphic correlations were performed.

3.3.5. Seismic Data Interpretation

Seismic interpretation included horizon mapping and fault interpretation. The different methods for horizon mapping were used.

Seismic horizon interpretation

Horizons were interpreted in a 3D and interpretation windows. The 2D window was used as a guide as to how far the interpretation has been done along crosslines and inlines. The different methods used for horizon interpretation are described below.

Guided autotracking: This methods works by selecting two or more points and the tracking finds the best route from one point to the other (Schlumberger (SLB), 2013). This provides a high degree of control as to how the interpretation will develop further.
Figure 17: Guided autotracking on a seismic section.

**Seeded 2D autotracking:** This method allows one to select one seed point. The horizon is tracked in the direction of the displayed crossline or inline (SLB, 2013). The horizon is tracked only to a point where it cannot justify the tracking parameters because of the occurrence of a fault, amplitude decay, or reverse polarity.

Figure 18: Seeded 2D autotracking on a seismic section.

**Seeded 3D autotracking:** One or several seed points are selected. The horizon is tracked outwards from these seed points, in all directions. If the reflectors have good quality, this method is very quick way of interpreting through a seismic cube (SLB, 2013).

**Manual picking:** Manual picking is a method that allows you to click on a point in a seismic section and follow the horizon by picking the point as much as it is visible...
This is very useful in areas where the seismic is not very visible, as the horizon does not show clear continuity.

Figure 19: Manual picking on a seismic section.

**Fault interpretation**

Faults were interpreted in a 2D and interpretation windows by displaying the inlines and xlines. The faults were interpreted manually. The faults were mapped by identifying the area of discontinuity in the horizon.

3.3.6. **Velocity Modeling**

Three different methods were used to create the velocity models. The best velocity chosen was used for domain conversion.

**Method 1: Velocity model using Well TDR (Time depth relationship)**

This method uses checkshots from the wells. Before the velocity modeling is done, the checkshots must be Qc’d. The checkshots are plotted in a function window to display the relationship between TWT (two way time) and Average velocity (Figure 20).

The method uses the Equation: \( V=V_0=V_{\text{int}} \): At each XY location, the velocity is constant through the zone (SLB, 2013). The surfaces in time were used.
Method 2: Velocity Model using Interval surfaces

Interval velocity surfaces are created using stacking velocity. A stacking velocity model was loaded into petrel (Figure 21). The velocity cube covers the field of interest. The stacking velocity was converted using Dix Formula. The Dix conversion allows creation of new attributes for the data set. The new attributes include interval and average velocities and these can be used for various purposes. In this case, a new set of velocities (interval) for each surface was created i.e. interval velocity attributes were created between 13At1 and 10At1 surfaces (in time). The interval velocity attributes are point data sets. These point data sets are used to create Interval velocity surfaces (Figure 22).
Figure 21: Study area overlain by a stacking velocity model in a 2D window

Figure 22: Velocity model inputs using interval velocities (SLB, 2013)

\[ V = V_0 + K \times Z \]

At each XY location, the velocity changes in vertical direction by a factor K. \( V_0 \) represents the velocity of datum. \( Z \) represents the distance (in length units, not time) of the point from datum. \( V_0 \) is the velocity at \( Z = 0 \) (SLB, 2013).
The base surfaces and well tops were still used in method 2, similar to method 1. Instead of Well TDR, interval velocity surfaces created from the stacking velocity were used.

**Method 3: Velocity Model using average velocities**

This method combines well velocity data and stacking velocities to build a velocity model. A simple grid was created using surfaces. Well velocities (checkshots) were converted to points. These point attributes were upscaled using the well log upscale process. The simple grid (3D) was populated with the average velocity property. The average velocities of the checkshots were appended by those of the stacking velocity. The petrophysical model process was used to populate the average velocity throughout the grid.

![Image of Velocity Model](http://etd.uwc.ac.za)

Figure 23: Velocity model inputs using average velocities (SLB, 2013)

**Avg.property:** If the 3D grid is used to define the zone and includes a property representing average velocity, then this can be used to depth convert the interval (SLB, 2013).

### 3.3.7. 3D structural Modeling

There are 4 different methods that can be used to build a structural model; only 3 methods were used in this study. The methods are described below.

**Simple Grid:** The simple grid (Figure 24) is a simplified method to construct a grid as it only includes surfaces horizons.
Corner Point Gridding: Corner point gridding is a complex process for creating a structural model in Petrel. It involves fault modeling, pillar gridding and horizon making. This method was not used as there were no complex faults mapped in the study area. The fault modeling and pillar gridding are not of importance in the study area.

Structural Framework: Structural framework is a quick method that allows interpreted data to be combined to construct a model (SLB, 2013). It does not involve fault modeling and pillar gridding. This method can therefore be used in an environment where the faults are not very complex. It involves the following three simple steps: Geometry definition, fault framework modeling and horizon modeling (Figure 25).
**Structural gridding:** Structural gridding process (Figure 26 and 27) allows the direct construction of corner point gridding from the Petrel structural framework without using pillar gridding workflows (SLB, 2013).

![Figure 26: Structural gridding modeling procedure (SLB, 2013).](image)

![Figure 27: Structural gridding model (SLB, 2013).](image)

### 3.3.8. Property modeling

Property modeling is the process of filling cells of the grid with discrete (facies) or continuous (petrophysical) properties (SLB, 2013). This process assigns property values between well logs, based on the upscaled well logs. Facies, porosity, permeability and water saturation were modelled.

Before property modeling was done, upscaling of logs was completed. The upscaling method assigns a value in every grid cell that is intersected by the wells, and is based on raw log values. This step needs to be completed when using deterministic methods. Raw logs of facies, porosity and permeability were upscaled.

The three methods used for property modeling are described below and shown in figure 28.
**Geometrical modeling**

The process uses predefined functions to generate properties, such as bulk volume, depth and height above contact. The height above contact property was used in the process on generating a water saturation model.

**Facies modeling**

Facies modeling is a way of distributing disconnected data (for example facies through a 3D model (SLB, 2013). A facies log was created, and this was followed by the upscaling process. The facies log was obtained by differentiating lithologies with the help of the gamma ray log. The facies modeling process allows the lithologies such as sands and shale to be populated in the grid. The sequential indicator simulation algorithm was used. This algorithm distributes the property using the histogram. Directional settings, such as variogram and trends of the lithologies are taken into account.

**Petrophysical modeling**

Petrophysical modeling is the interpolation of continuous data (permeability, porosity and water saturation) throughout the grid model (SLB, 2013). Upscaled continuous well data was used to create the models. Porosity and permeability models were created using the same process. Before modeling, a detailed data analysis was performed to quality check that the data used as input for the modeling is precise. The Gaussian random function simulation algorithm was used during the modeling process. This algorithm is a stochastic method that can produce local variation and replicate input histograms (SLB, 2013). Subsequently, if 100 different realizations are run, there will be 100 different outputs. All the results will match the input, because the input is given by a distribution. The value given to each cell can be different based on the range of this distribution.
Water saturation modeling

Water saturation is part of the petrophysical properties, but it was modelled differently from the other properties (porosity and water saturation) because modeling of water saturation (Sw) can be very complex. Simply upscaling and using an average method does not work well for water saturation due to that averaging methods could cause the values to increase (SLB, 2013). This would lead to miscalculated volume. Below is a description of the method used to model water saturation.

An above contact property was created using Geometrical modeling. This property is the height above the gas water contact. An above contact log was created. The above contact log was plotted versus the water saturation and outliers in the crossplot were deleted. A raw crossplot was created to make a new data set from the plotted points. A nonlinear function was obtained from the crossplot. The nonlinear curve was edited. A new water saturated for the 3D is calculated using water saturation function and the above contact property (created using the geometrical modeling process). The equation used to compute the property assigns the water saturation values from the saturation function into the 3D grid for the corresponding above contact values.

The process of creating a water saturation model is shown below in figure 29.
3.3.9. Volumetrics

The volume calculation process is based on delineation of reservoir by making contacts and using the properties in a 3D grid (SLB, 2013). The area of interest contains gas; therefore gas water contacts (GWC) were created using Petrel. Petrophysical properties such as porosity, permeability and water saturation were obtained from well completion reports and core analysis reports.
Chapter 5

4. Results

4.1. Core Logging

Well Y-01

Well Y-01 had 8 cores cut. Only three cores were logged. These are core 5, 6 and 7. These cores were logged because they cover the depth below the 13At1 horizon and above the upper 10A sands. No core was available for the reservoir sections, hence core 5, 6 and 7 were the best to observe. Below is a description of the lithologies observed in core 5, 6 and 7.

Core 7

Core 7 was cut from depth 2894 – 2894.65m (Figure 30). The base of the core comprises of fine sandstone which is interbedded with claystone. The sandstone is grey in colour and well sorted. Pyrite nodules were observed in this sandstone (Plate 1a).

The fine sandstone is overlain by a medium grained sandstone. The sandstone is grey in colour and is very well sorted. Symmetrical ripples were observed in this sandstone (Plate 1b).

Two facies were identified from this core. That is a fine grained sandstone and a medium grained sandstone. A coarsening upwards sequence was observed.

Plate 1: a) Medium grained sandstone with symmetrical ripples. b) Pyrite nodules in fine grained sandstone.
Figure 30: Full interpretation of log section of well Y-01 core 7.

<table>
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<tr>
<th>DEPTH (m)</th>
<th>LITHOLOGY</th>
<th>LIMESTONES</th>
<th>STRUCURES/BIOFURBATION</th>
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</tbody>
</table>

- Grey, medium sand, well sorted, symmetrical ripples
- Grey, fine sand interbedded with claystone, well sorted, pyrite nodules

Corsening upwards
Core 6

Core 6 was cut from depth 2872 – 2877m (Figure 31). The base comprises of claystone which is dark grey to black in colour. The claystone is fine grained. The base of these claystone is more friable and darker; as compared to the upper section which is lighter and very hard (Plate 2a). A quartz vein was observed at 2874.4 - 2874.46m.

Above the claystone is a fine grained sandstone which is dark grey in colour. A gradational contact separates this sandstone from the medium grained sandstone above (Plate 2B). The sandstone is grey and well sorted with calcareous clasts.

Three facies were identified in this core. The 3 facies are: claystone, fine sand and medium grained sandstone. As in core 7, a coarsening upward sequence was observed in this core.

Plate 2: a) Fine grained friable claystone. b) Gradational contact between claystone and fine grained sandstone which grades into medium grained.
Figure 31: Full interpretation of log section of well Y-01 core 6.
Core 5

Core 5 was cut from depth 2846 - 2856.47 (Figure 32). The base of the core comprises of a medium grained sandstone which is grey in colour. The sandstone is well sorted and has poor-fair porosity and permeability. Asymmetrical ripples were observed at depth 2856-2856.19m (Plate 3a). A mafic mineral which are well aligned were observed in this sandstone.

The medium grained sandstone is overlain by a fine grained sandstone which is grey in colour. The contact between these two sandstones is more gradational. An alignment of mafic mineral was also observed in this sand unit (Plate 3b).

The two facies observed in core 5 were fine sandstone and a medium sandstone. A fining upward sequence was observed.

Plate 3: a) Medium grained sandstone with Asymmetrical ripples. b) Fine grained sandstone with alignment of mafic minerals.
Figure 32: Full interpretation of log section of well Y-01 core 5.
Well Y-02

Well Y-02 has 3 cores that were cut. Only core 1 and 2 were logged. This was because core 1 and 2 are within the 10A sands. Core 3 is below the base of the 10A sands. The 10A sands are the main reservoir. Below is a description of the lithologies observed in core 1 and 2.

Core 2

Core 2 was cut from depth 2948 – 2962m (Figure 33). The base of the core comprises of claystone. The claystone is dark grey in colour and well sorted. This unit is interbedded with some sandstone in some sections of the core (Plate 4a and c). The mentioned sandstone is medium grained and has slumping structures between 2959.65 – 2959.77m (Plate 4b).

The claystone is overlain by a medium grained sandstone which is dark grey in colour. The sandstone is well sorted. Lamination was observed depth 2951.08-2951.6m (Plate 4c). The sandstone above has a similar texture to the previous one. The only difference is in the colour. It is light grey in colour. Micro - faults were observed at a depth of 2948.16 – 2948.34m (Plate4d).

Two facies were identified. That is claystone and medium grained sandstone. The grain size changed from medium grained to fine grained. A coarsening upward sequence was observed.

Plate 4: a) Fine grained friable claystone. b) Sandstone with slumping structures at the base. c) Medium grained sandstone with lamination. d) Micro - faulted medium grained sandstone.
Figure 33: Full interpretation of log section of well Y-02 core 2.
Core 1

Core 1 was cut at a depth of 2890.90 – 2900.45m (Figure 34). The base of the core comprises of claystone which is greyish black in colour. The claystone is fine grained and laminated (Plate 5a).

Above the claystone is a medium grained sandstone which is grey in colour. This sandstone is well sorted. At a depth of 2898.62 – 2898.86m, the sandstone is interbedded with a greyish black claystone which is laminated (Plate 5b).

The medium grained sandstone is overlain by a thin claystone layer that is interbedded with find sand (Plate 5c). The claystone is very fine grained and friable at some sections. Very distinct lamination structures were observed.

An intercalation of claystone and fine sandstone overlies the thin layer of claystone (Plate 5d). The claystone is similar to the one below. The sandstone has a range of textures from fine grained to fine-medium grained. It is very well sorted. Sections of the top claystone layer are laminated.

A massive sandstone (Plate 6a and d) marks the top of core 1. The sandstone generally grey in colour and has a range of textures from fine-medium grained and medium grained. Grains of this massive sandstone are moderately sorted. At a depth of 2895.55m, an alignment of iron minerals was observed (plate 6a). The iron minerals are red in colour. A few thin claystone layers were observed at a depth of 2893.2m, where there is possible evidence of slumping activity (Plate 6b). A small section of this sandstone is much darker in colour. This is at a depth of 2892.66 – 2892.20m. Carbonaceous friable material (Plate 6c) was observed at this section of the sandstone. The grains at this depth are poorly sorted. Aligned mafic mineral are visible at the Top section of core 1.

Four facies were identified in core 1. These facies are: Claystone, fine sandstone, fine-medium sandstone and medium sandstone. A coarsening upward sequence was observed.
Plate 5: a) Laminated fine grained claystone. b) Sandstone interbedded with laminated claystone. c) Claystone interbedded with sandstone. d) Intercalation of sandstone and laminated claystone.
Plate 6: a) Fine to medium grained sandstone comprising of iron red minerals. b) Sandstone interbedded with claystone comprising of slumping structures. c) Carbonaceous material in medium grained sandstone. d) Top section of a massive sandstone.
Figure 34: Full interpretation of log section of well Y-02 core 1.

<table>
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<th>Depth (m)</th>
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- **Grey, massive sandstone, fine-medium grained, fair sorting, carbonate material at 2892.56m. From depth 2893.25-2893.44m, the sandstone is interbedded with claystone.**
- **Intercalation of claystone and fine sandstone. Claystone black and sandstone grey, fair sorting, claysite laminated in most sections.**
- **Grey, medium grained, fair sorting, at depth 2886.52-2888.66m sand interbedded with blackstone, laminated.**
- **Greyish black, fine grained, well sorted, laminated.**
4.2. Well Correlation

The results below show correlation of the geological horizons. Correlation was done for the horizons just above and below the hydrocarbon zones. The sand units were used to assist in correlating the horizons. This is because the sand units were much more visible that the shales which are interbedded with sand in some localities. The wireline logs used for correlation purposes are gamma ray, Density (RHOB), Porosity (NPHI: Neutron Porosity) and Resistivity (Figure 36).

The Gamma Ray log was used to identify the lithology. The limit for the logs used is 0-150 API (Figure 35). The low gamma ray readings (0-75 API units) indicate the presence of sands. High gamma ray readings from 75-150API units indicate the presence of shale. The top of the 13A sands contain hydrocarbon. The top (13A) and bottom (13At1) of these sands were correlation. The 13A sands have similar thickness throughout the three wells in the field.

Below the 13A sands is the 10A sands. Three main sands were identified between the Top (marker: 10A) and bottom (marker: 10At1) of 10A sands. There is a significant slope change of horizon 10A from well X-01 to Y-01. The 10At1 horizon marks the base of the 10A sands. Well Y-01 has similar sand bodies to well Y-03. The sand bodies are much thicker when compared to well Y-02. Gamma ray signatures are much lower in these sand bodies.

The NPHI (neutron porosity) log has limits from -0.15 – 0.4; and the RHOB (Bulk density) log has limits from 1.95 -2.95 g/cc (Figure 36). The two logs were combined to determine a cross over between the two. A crossover indicates the presence of hydrocarbon. This is helpful for well correlation due to the fact that a cross over may occur throughout the wells in the same field at the position where there is hydrocarbon. In this case a crossover is noted at all the 13A sands across wells in the X field and those of the Y Field. The top and base of the 13A sands could then easily be correlated across the fields. The top and base of the 10A sands are also marked with a crossover between the NPHI and RHOB logs.

The limits for the resistivity log are from 0.2 -2000 ohm.m (Figure 36). The resistivity log is in log scale. The log signatures have higher values were there is sandstones and presence of hydrocarbons. Both the 13A and 10A sands contain hydrocarbon.
Figure 35: Well correlation between X-01, Y-01, Y-02 and Y-03 using gamma ray log.
Figure 36: Well correlation between X-01, Y-01, Y-02 and Y-03 using gamma ray, neutron porosity, density and resistivity logs.
4.3. Seismic Interpretation

Seismic well tie

Well data is measured in depth and seismic data is measured in time. Seismic well ties allow the well data to be compared to seismic data. The sonic and density logs are used to generate a synthetic seismic trace. These logs are combined to give Acoustic Impedance. The difference in Acoustic Impedance between different lithologies affects the reflection coefficient (Schlumberger glossary).

Seismic well tie was only provided for well Y-01. The other wells did not have check shots; hence seismic well tie was done generated for those wells. Below is an image of the seismic log trace for well Y-01 (Figure 37). It is noticeable that the peak (bright colour) from the log trace matches the peak reflector on the seismic section. The trough matches the blue seismic reflector on the seismic section. The peak is showing a point of zero crossing from positive to negative. The trough displays a point of zero crossing from negative to positive.

Figure 37: Seismic section displaying well Y-01 with its log trace
**Horizon Mapping**

A base map grid was provided. The base map has X-lines and In-lines. The Y field is within the following X-lines (3945 - 4045) and In-lines (2600 - 2750) (Figure 38). A base map showing which areas the seismic data covers is shown in figure 39. In the north-west section of the field, not much seismic lines are visible.

![Figure 38: Base map of the study area](image)

Figure 38: Base map of the study area
The following horizons were mapped: Seabed, 22At1, 14At1, 14At1, 13At1, 12At1 and 10At1.

The shallower horizons (Seabed, 22At1 and 14At1) (Appendix A) are not of interest because the hydrocarbons are capped in the 13At1 and 10At1 reservoirs. These were mapped for velocity modeling purposes. All these horizons were mapped on a peak. 3D Auto-tracking was used to map the seabed and horizon 22At1. These two horizons are fairly flat and continuous throughout the seismic, hence the seeded 3D Auto-tracking method was used. The 14At1 horizon has a few displacements in some areas and is not very visible in some areas; therefore the Seeded 2D Auto-tracking was used to map this horizon.

The first horizon of interest is the 13At1. This marks the base of the 13A sands. It is a visible unconformity and was mapped on a peak wavelet. 2D Auto-tracking was used to map the horizon and manual interpretation in some areas where the sands thickness varies.
The variation in thickness of the 13A sands makes it difficult to map the 13At1 horizon. Sands have a higher or positive Acoustic Impedance, and this creates a peak wavelet.

Figure 40: 2D window with 2D Autotracking of the 13At1 horizon

The top of the 10A sands/12At1 horizon was also mapped at a peak wavelet. The top of these sands are difficult to resolve on seismic. The sands do not appear brighter on seismic and are eroded at some areas, especially close to the wells. 3D auto-tracking was used to map the top of the sands around the wells since the sands appear bright at this section (Figure 41).

The base of the 10A sands (10At1) horizon is much more visible than the top of the sands, although difficult to map close to the position of the wells (Figure 43). The base of the sands was also mapped on a peak. 2D Auto-tracking was used to map the base of the sands, although manual interpretation was used at areas where there was more difficulty in identifying the horizon.

A random line was drawn from well Y-02–Y01–Y-03 (Figure 43). The random line shows a seismic section with mapped horizons from 22At1 to 10At1.
Figure 41: 2D window with 3D autotracking of the 12At1 horizon / Upper 10A sands.

Figure 42: Figure X: 2D window with 2D Autotracking of the 10At1 horizon.
Figure 43: Random line with horizon interpretation across well X-01, Y-02, Y01 and Y-03.

Mis-ties

Mis-ties occur when the position of the mapped horizon on a xline differs with that of an inline. The seabed and horizon 22At1 are continuous, hence no mis-ties were encountered. Horizon 13At1 appears as a doublet instead of a single line, and this caused mis-ties as the horizon could not be easily followed on the same position (Figure 43). More mis-ties were experienced when mapping horizon 10At1. This is due to the fact that the 10A sands have poor visibility on seismic (Figure 43). The mis-ties were fixed by shifting the position of the horizon to be in the same position in both x-lines and in-lines. No mis-ties were present before the surface gridding was done.
**Fault Mapping**

The field area is faulted but the faults are not resolvable on seismic. A few faults mapped are displaced below the in 2D and 3D window (Figure 44). The faults do not have huge displacements and therefore do not show much of shift in the horizon. The faults and horizons shown below are in time units. These faults only intersect the 10At1 horizon.

![Faults displaced on a 2D and 3D window](http://etd.uwc.ac.za)

**Surface Gridding**

A surface or 2D grid is defined by points arranged in an array of equally spaced row and columns. The intersection of the rows and the columns delineates the grid nodes (Schlumberger, 2013).

There are numerous types of data that can be used as input when generating a surface, e.g. lines, points, well tops, fault cuts etc. Horizon interpretation (seismic data) was used as input to generate a gridded surface. Well tops were also used to link the horizon marker position to the seismic events. Fault polygons were not used as input because there are not many visible faults intersecting the surfaces and the faults intersecting the surfaces do not have a significant displacement.

The surfaces are in two way time (TWT) units. The seabed and 22At1 surfaces do not show any structures but continuous contour lines (Appendix B). Horizon 14At is also fairly flat with a few small displacements and erosion at some areas (Appendix B). Horizon 13At1 is also continuous throughout the field (Figure 45). Horizon 12At1/ Top of 10A sands shows a structurally high area where there is Field Y, and there is a closure
at contour 2065 m/s (Figure 46 and 47). The Peak is above contour 2080 m/s. Horizon 10At1 also has a structurally high area at field Y.

Figure 45: 13At1 surface in TWT.
Figure 46: TWT surfaces of the 12At1 horizon
Figure 47: TWT surfaces of the 10At1 horizon
4.4. Depth Conversion
Surfaces in time were converted to depth before any modeling was done. A velocity model was used to depth convert the time surfaces to depth. Velocity models can be defined using constant values, surfaces and horizons (SLB, 2013). Three different velocity methods were done and at the end one method was selected. Below are the results of each method used.

Method 1: Velocity model using Well TDR (Time depth relationship)

This method uses checkshots. Before a model was generated, the check shots were quality checked. The relationship between the check shots and average is directly proportional. The check shots displayed in figure 48 are of well X-01 and D-01. These two wells are adjacent to the field of study. There were no outliers displayed. In a case were outliers are displayed, they must be deleted so that a linear trend between the TWT and average velocity exists.

Figure 48: Average velocity versus original checkshots.
Figure 49: Well section window displaying average velocity versus original checkshots.
The relationship between average velocity and interval velocity was also displayed in a well section window (Figure 49) above. The checkshot data begins at a depth of 1500 TWT. It is noticeable that the average velocity increases with depth (TWT). The interval velocity increases with average velocity as the depth increases.

The results for method 1 are presented in figure 50 below. The surface below another surface is the base surface i.e. the base of 13At1 is 10At1. Above A seismic reference datum (SRD) surface was created in order to obtain interval velocities above the seabed. The constant SRD unit is 1500. Well tops of each surface were used as a correction measure. The well TDR were used as a constant. The well tops of seabed, horizon 22At1 and 14At1 match the surfaces.

![Layered surfaces generated from velocity model 1.](image)

**Method 2: Velocity Model using Interval surfaces**

The interval velocity surfaces were used as input to generate the second velocity model. The interval velocity surfaces from Seabed to 14At1 are saved in Appendix C. Below is surfaces showing interval velocities between horizon 14At1 – 13At1 and 13At1 – 10At1. The interval velocity surface between 14At1 – 13At1 has a contour...
interval of 50 m/s and the interval velocity at the field of study is approximately 4100 m/s. The contour interval between the 13At1 – 10At1 surface is 20 m/s and the interval velocity is approximately 4490 m/s.

The velocity model results for method 2 are also displayed in figure 53. All surfaces match the well top except for horizon 13At1 and 10At1.
Figure 51: Interval velocity surfaces between horizons 14At1 – 13At1
Figure 52: Interval velocity surfaces between horizons 13At1 – 10At1
Figure 53: Layered surfaces generated from velocity model 2.

**Method 3: Velocity Model using average velocities**

Results of the model are displayed in figure 54. The well tops of this surface match with the surfaces. There was less depth correction between the original position of surfaces and the position created by the velocity model process. This was therefore the best method to depth convert the surfaces and faults.
Figure 54: Layered surfaces generated from velocity model 3.

The depths surfaces for the seabed, horizon 22At1 and 14At1 are displayed in Appendix D. The depth surfaces for horizon 13At1 and 10At1 are displayed below (Figure 55 and 56). These depth surfaces were used to create structural models. The 13At1 surface map has a contour interval of 10m, and the field of study is between 2800 – 2860m. The contour interval increases in the north west and south east direction away from the field.

The 10At1 depth surface also has a contour spacing of 10m. The 3 wells of the field are enclosed by the 2860m contour. Similar to the 13At1 surface, the depths increase towards the NW and SE direction away from the field.
Figure 55: Horizon 13At1 depths surface
Figure 56: Horizon 10At1 depths surface
4.5. 3D Structural Modeling

The results of three different methods to build a structural model are presented below. The best model that is suitable for use in property modeling was chosen.

**Simple Grid**

A simple grid was created using depth surfaces from 14At1 to 13At1 (Figure 57). This grid has no faults cutting the surfaces as the construction does not include faults. The study area does not have complex faults as a result of poor seismic visibility. This method is therefore suitable in representing the geometry of surfaces.

Figure 57: Simple grid of the Y field showing adjust wells X-01 and D-01
**Structural Framework**

Depth horizons and faults were used to construct the model. The structural framework modeling was done in preparation for structural gridding. Below is the model with edges on the surfaces (Figure 58). On figure 59 the edges were removed in order to expose the faults. It is noticeable that the faults cut the 10At1 surface. This grid cannot be used for property modeling as it does not have layering between the surfaces to capture heterogeneity.

![Figure 58: Structural framework grid](http://etd.uwc.ac.za)
Figure 59: Structural framework grid with faults intersecting the 10At1 horizon.

**Structural gridding**

The structural grid below (Figure 60) shows 2 regions. Region 1 is between 14At1 and 13At1 surfaces and represents the 13A sands. Region 2 is between the 13At1 and 10At1 surfaces and represents the 10A sands. The thickness of region 2 is much thicker than that of region 1. Surfaces separated by regions do not sure the geometry of surfaces in finer detail.

Layering was done between the two regions in order to produce a finer detail of the surface geometry. It is noticeable that towards the eastern side there is a fill structure (Figure 61). The surfaces follow a regular or straight continuous pattern in the southern direction.

The structural gridding model was chosen as the best model to be used for property modeling because it displaces the surface geometry better than the other models.
Petrophysical models such as porosity, permeability and water saturation were populated in this grid.

Figure 60: Structural gridding model displaying region 1 of the 13A sands and region 2 of the 10A sands.
4.6. Property Modeling

Upscaling Properties

Facies

Four facies were selected for the facies modeling process (Figure 62). These facies were described in the core description as well as the wireline log. The facies were obtained using the guide of a gamma ray, and the following cut offs were used:

Claystone: 75 – 150 API

Fine sand: 25 – 75 API

Fine – Medium sand: 15 – 25 API

Medium sand: 0 – 15 API
Layering was done to capture the very fine sand which is found in between the claystones or the thin claystone layers in between the sands. Different layering options were done to see which one best captures heterogeneity well, in particular to zone 2 (13At1-10At1) where all four facies exist and the presence of intercalation of facies. The different layering scenarios are presented below. The images captured in particular facies between 13A and 10A sequence.

Case 1:

The following layering option in figure 63 was used:

Zone 1 (14At1-13At1): 30 Layers

Zone 2 (13At1-10At1): 35 Layers
The upscaled facies log matched the original facies log in zone one when 30 layers are used, but there is no relationship between the upscaled log and original log in zone 2 when using 35 layers to separate the lithology.

Figure 63: Well section window displaying case 1 of layering between zone 1 and 2.

Case 2:

The following layering options in figure 64 were used.

Zone 1 (14At1-13At1): 25 Layers

Zone 2 (13At1-10At1): 45 Layers

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Similar to case 1, the heterogeneity is captured well in zone 1 and the upscaled log matches the original facies log in zone 2 but the thin claystone layers in between the 10A sands are not well represented.

Figure 64: Well section window displaying case 2 of layering between zone 1 and 2.

Case 3:

The following layering options in figure 65 were used:

Zone 1 (14At1-13At1): 25 Layers

Zone 2 (13At1-10At1): 55 Layers

The upscaled facies log matches the original facies log. The heterogeneity is well captured where there is intercalation of facies.
Case 3 was chosen as the best option to be used to create a facies model. Zone 1 which is between 14At1 – 13At1 was modelled with 25 layers. Zone 2 which is between 13At1 – 10At1 was modelled with 55 layers. Zone 1 comprises of fewer layers than zone 2 as it has less complex facies. Zone 1 comprises mainly of claystone and fine sand. Zone 2 comprises of all four facies and there are also stringers of sand in the claystones and stringers of claystones in the sand. Therefore more layers were required to capture the heterogeneity. The well section below (Figure 66) shows the gamma ray log, facies, upscaled facies as well as the number of layers used to capture the heterogeneity.
Figure 66: Well section window displaying gamma ray log, facies, upscaled facies and layering log.

**Permeability and Porosity**

Porosity and permeability results are shown in the well section window in Figure 67. Both properties were only available for one well (Y-02). The upscaled properties were populated in the grid to produce a property model. Claystones have a low porosity and permeability. Sands exhibit a higher porosity and permeability. The properties in Figure 67 are presented in the following table:

Table 1: Results of the upscaled property values

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Figure 67: Well section window displaying gamma ray logs with porosity and permeability upscaled logs.

**Petrophysical modeling**

**Facies and Porosity Model**

The surface and cross section (Figure 68 and 69) of the models below show that the porosity of the field of study ranges between 5 – 12%. It is observed that the fine – Medium sand facies in the field have higher porosity. The sand body is trending in the north – south direction.
Figure 68: Porosity (left) and facies (right) surface models.
Figure 69: Cross section of porosity (left) and facies (right) through the wells.
Facies and Permeability Model

The surface and cross section model below (Figure 70 and 71) shows that the upper sequence has lower permeability than the lower sequence. The upper sequence (13A sands and above) have permeabilities ranging from 0.5 – 10 mD. The lower zone (10A sands) exhibit permeabilities ranging from 0.5 – 90 mD. An increase in permeability is observed in the north and north – eastern side of the field.
Figure 70: Permeability (left) and facies (right) surface models.
Figure 71: Cross section of permeability (left) and facies (right) through the wells.
Facies and Water Saturation

The water saturation models were done separately for the 13A sands and 10A sands. This is due to that different Gas Water Contacts (GWC) were used when building the model. The water saturation results are presented below:

13A sands

The water saturation in the 13A sands and facies model are presented below in figure 72. The 13A sands in the field of study show water saturation between 40 –70%. The water saturation is higher on the western side of the field of study and lower towards the west.

10A Sands

The surface models of the top and bottom of the 10A sands are shown below in figure 73 and 74. The 10A sands show water saturation ranging between 40 – 55%. Similar to the 13A sand model, the water saturation is higher at the western side of the field and lower at the eastern side of the field. A bright spot meandering sand body is observed in the north – south direction. This bright spot also passes through the field of study. The sand body has water saturation ranging from 35 – 45%.
Figure 72: Water saturation in the 13A sands (right) and facies (left) surface model
Figure 73: Upper section of the water saturation in the 10A sands (left) and facies (right) surface models.
Figure 74: Lower section of the water saturation in the 10A sands (left) and facies (right) surface models.
The well section window below (Figure 75) displays the gamma ray, facies, and water saturation wireline log and water saturation results from the models. The claystones show higher water saturation than sands. Below is a table showing a comparison in water saturation between the different sequences.

Table 2: Water saturation results deduced from the models

<table>
<thead>
<tr>
<th>Sequence</th>
<th>Water saturation %</th>
<th>Average Water Saturation %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Above 13A sands (claystones)</td>
<td>90-100</td>
<td>95</td>
</tr>
<tr>
<td>13A sands</td>
<td>40-70</td>
<td>45</td>
</tr>
<tr>
<td>10A sand Upper</td>
<td>40-65</td>
<td>35</td>
</tr>
<tr>
<td>10A sand Lower</td>
<td>20-30</td>
<td>25</td>
</tr>
</tbody>
</table>
Figure 75: Well section window displaying gamma ray, facies, zone and water saturation log, as well as the water saturation modeling results.
4.7. Volumetrics

The reservoirs in the field of study comprise of gas. Therefore the gas initial in place was calculated. Below are images of the surfaces with the GWS’s (Figure 76, 77 and 78). The GWC is displayed with the red colour. The surface shown above the contacts contains hydrocarbon. A contact which is the pink colour was plotted in order to determine the spill points. The spill points are area’s beyond the contact where hydrocarbon would escape the reservoir. The following GWC’s were obtained from well completion reports. The contacts were also quality checked by plotting the water saturation log, gamma ray and resistivity logs in a well section window. The following GWC were used as inputs for calculating the initial gas in place.

Table 3: Sequences of interest and GWC’s

<table>
<thead>
<tr>
<th>Sequence</th>
<th>GWC (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13A sands</td>
<td>2580</td>
</tr>
<tr>
<td>10A sands Upper</td>
<td>2889</td>
</tr>
<tr>
<td>10A sands Lower</td>
<td>2926</td>
</tr>
</tbody>
</table>
Figure 76: Surface 13At1 and GWC surface.

Figure 77: Surface 10A upper and GWC surface.
The Bulk Rock Volume (BRV) is another parameter required for the volumetric calculation. The BRV was calculated using the Petrel software. The calculation determines the volume and area above the hydrocarbon contact. Table 4 below shows the BRV and area results obtained from the Petrel software. The 10A sands combined cover the largest area and have a higher BRV than the 13A sands.

Table 4: Results of bulk rock volume and area for each reservoir section

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Volume m$^3$</th>
<th>Area m$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>13A</td>
<td>7.20267E+7</td>
<td>4.12063E+6</td>
</tr>
<tr>
<td>10A Upper</td>
<td>4.73573E+7</td>
<td>3.67908E+6</td>
</tr>
<tr>
<td>10A Lower</td>
<td>6.03346E+7</td>
<td>4.323E+6</td>
</tr>
</tbody>
</table>

The net/pay and petrophysical properties such as porosity and water saturation are also parameters required as inputs for the volumetric calculation. The net/pay is the ratio of the thickness of sand (reservoir) that contains hydrocarbon / the total thickness of the reservoir. These properties are presented below in tables 5, 6 and 7.
The parameters were obtained from core analysis results and well completion reports. The following cut off's were applied for the petrophysical properties.

**Porosity:**

5 – 10% Fair

10 – 25% high

25 – 40% Exceptional

**Water saturation:**

0 – 50% Low

50 – 60% Average

60 – 100% High

Table 5: Petrophysical parameters for the 13A sands

<table>
<thead>
<tr>
<th>Well name</th>
<th>Sequence</th>
<th>Net pay/Gross</th>
<th>Porosity</th>
<th>Water Saturation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Y-01</td>
<td>13A</td>
<td>0.885</td>
<td>0.1</td>
<td>0.54</td>
</tr>
<tr>
<td>Y-02</td>
<td>13A</td>
<td>0.935</td>
<td>0.11</td>
<td>0.37</td>
</tr>
<tr>
<td>Y-03</td>
<td>13A</td>
<td>0.778</td>
<td>0.1</td>
<td>0.29</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td>0.866</td>
<td>0.103</td>
<td>0.400</td>
</tr>
</tbody>
</table>

In table 5 above, well Y-02 has the highest porosity with a low water saturation for the 13A sands. Same applies to well Y-03, although the water saturation is slightly higher than that of well Y-02. Well Y-01 has good porosity, but the water saturation is above 50%. The net pay/gross is higher in well Y-02.
Table 6: Petrophysical parameters of the 10A sands upper

<table>
<thead>
<tr>
<th>Well name</th>
<th>Sequence</th>
<th>Net pay/Gross</th>
<th>Porosity</th>
<th>SW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Y-01</td>
<td>10A Upper</td>
<td>0.920</td>
<td>0.08</td>
<td>0.48</td>
</tr>
<tr>
<td>Y-02</td>
<td>10A Upper</td>
<td>0.570</td>
<td>0.08</td>
<td>0.52</td>
</tr>
<tr>
<td>Y-03</td>
<td>10A Upper</td>
<td>0.711</td>
<td>0.09</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td><strong>0.734</strong></td>
<td><strong>0.083</strong></td>
<td><strong>0.433</strong></td>
</tr>
</tbody>
</table>

Table 6 above indicates that well Y-01 has similar porosities (fair) for the 10A sands in the upper section. The water saturations are also slightly higher, although well Y-02 exhibits higher water saturation than well Y-01. The porosity for well Y-03 is fair, and the water saturation is lower than that of the other wells. The net pay/gross is higher in well Y-01.

Table 7: Petrophysical Parameters of the 10A sands lower

<table>
<thead>
<tr>
<th>Well name</th>
<th>Sequence</th>
<th>Net pay/Gross</th>
<th>Porosity</th>
<th>SW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Y-01</td>
<td>10A Lower</td>
<td>0.720</td>
<td>0.12</td>
<td>0.38</td>
</tr>
<tr>
<td>Y-02</td>
<td>10A Lower</td>
<td>0.57</td>
<td>0.07</td>
<td>0.46</td>
</tr>
<tr>
<td>Y-03</td>
<td>10A Lower</td>
<td>0.470</td>
<td>0.13</td>
<td>0.2</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td><strong>0.587</strong></td>
<td><strong>0.107</strong></td>
<td><strong>0.347</strong></td>
</tr>
</tbody>
</table>

In the table above, it is observed that well Y-01 and Y-03 have good porosities (above 10%), while well Y-02 has a fair porosity. The water saturation is below 50% in all three wells, with well Y-03 having the lowest water saturation. The net/gross is the highest in well Y-01, average in well Y-02 and below average in well Y-03.

The calculation of the hydrocarbon in place was calculated using Petrel and excel. In petrel, the BRV and area was calculated. In the excel spreadsheet, the volume in place was calculated using the following formula.
Volume in place = \textbf{Constant} \times \text{BRV} \times \text{NTG} \times \text{porosity} \times \text{oil or gas saturation} (1-\text{Sw})

\textbf{Oil or gas Formation Volume Factor (Bo or Bg)}

\text{BRV} = \text{Bulk rock volume (m}^3\text{)}

\text{NTG} = \text{Net pay thickness/total thickness of reservoir}

\text{Porosity} = \text{Fraction of rock volume}

\text{Sw} = \text{Water saturation (fraction)}

\text{Bg} = \text{Gas formation volume factor (Rm}^3\text{/Sm}^3\text{: reservoir cubic meters per standard cubic meters)}

\text{Bo} = \text{Oil formation volume factor}

The field of interest comprises of gas. A table with the volumetric results is displaced below. The calculation for gas in place can be simplified into the following equation:

\textbf{Gas in place = Constant} \times \text{Ah} \times \phi \times (1-\text{sw}) \times \text{Bg}

\text{A} = \text{Drainage area (m}^2\text{)}

\text{H} = \text{Average net pay thickness (m)}

\phi = \text{porosity (fraction of rock volume)}

\text{Sw} = \text{Water saturation (fraction)}

\text{Bg} = \text{Gas formation volume factor}

The results for the amount of gas in place are shown below in table 8.
Table 8: Results of amount of gas in place

<table>
<thead>
<tr>
<th>Level</th>
<th>Hydrocarbon</th>
<th>HWC (m TVDSS)</th>
<th>Zone</th>
<th>BRV (m$^3$)</th>
<th>NTG</th>
<th>Porosity</th>
<th>Sw</th>
<th>Bg</th>
<th>m$^3$ to ft$^3$</th>
<th>GIIP (ft$^3$) Deterministic</th>
<th>GIIP Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>13A</td>
<td>2580</td>
<td>13A</td>
<td>7.20E+07</td>
<td>0.866</td>
<td>0.103</td>
<td>0.400</td>
<td>0.005</td>
<td>35.3147</td>
<td>27226097878</td>
<td>27.2261</td>
<td></td>
</tr>
<tr>
<td>10A Upper</td>
<td>2889</td>
<td>10A Upper</td>
<td>4.74E+07</td>
<td>0.734</td>
<td>0.09</td>
<td>0.433</td>
<td>0.005</td>
<td>35.3147</td>
<td>12528355809</td>
<td>12.53</td>
<td></td>
</tr>
<tr>
<td>10A Lower</td>
<td>2926</td>
<td>10A Lower</td>
<td>6.03E+07</td>
<td>0.587</td>
<td>0.107</td>
<td>0.347</td>
<td>0.005</td>
<td>35.3147</td>
<td>17477810045</td>
<td>17.48</td>
<td></td>
</tr>
</tbody>
</table>

57.23
Chapter 6

5. Discussion and Conclusion

Depositional Environment

The depositional model of the area was deduced from core descriptions and well correlation. Both the core and logs give an indication of the type of facies available at the field. The core shows four facies: Claystone, fine sand, fine – medium sand and medium grained sand. The scale for the core is at reservoir scale, therefore much bigger as the reservoirs can easily be identified. The top and base of the 10A sands was very visible in well Y-02. This was used as a guideline to find the exact depth of the 10A and 10At1 markers used for well correlation. The gamma ray log on the other hand shows only two facies: Claystone and sand. The depths of the logs which were cored were therefore easier to subdivide the facies further into fine – medium sand and medium sand.

In well Y-01, core 7 comprises of fine sand at the base and more medium sand at the top. This indicates a coarsening upward sequence. Core 6 comprises of claystone at the base and medium grained sand at the top. This also indicates a coarsening upward sequence. Core 5 comprises of medium sand at the base and fine sand at the top. This represents a fining upward sequence. If the wireline logs were taken into consideration in determining the sequence, a fining upward sequence for well Y-01 is depicted due to the fact that the logs show sands at the base and claystone at the top. It is unfortunate that only a certain portion of the core was cut in this well. Therefore not only core description was used when determining the sequence but a combination of both core and logs information.

Core was cut in the 10A sands in well Y-02. At some sections of the core, the sands are interbedded with claystone. The base of core 1 comprises of claystone and the top is composed of sand. A similar case is seen in core 2, although there is an intercalation of sand and claystone. Two coarsening upward sequences were observed in these cores. If the gamma ray log is taken into account, above the 10A sands are overlain by claystone. Above the claystone the 13A sands were deposited and the entire top of the core is just claystones. This confirms that above the 13At1 unconformity, there was a period of relative sand starvation in the basin.
Based on the above information integrated between core and log data, the depositional model deduced is that of the outer lower fans in a deep marine environment. The lower fan is characterised by a succession of sands at the base and claystone at the top.

The lower fan of the deep marine environment represents a good petroleum system. The 13A and 10A sands are good reservoirs, especially the 10A sands as they exhibit good petrophysical properties. The claystones above the sands act as good seals.

**Structural interpretation**

The seismic was used in determining the structural geology of the area of study. It was observed from the seismic that faults occur below the 13At1 unconformity. Above horizon 13At1, the horizons are flat and elongated. Even through the 10A sands are displaced, it was difficult to obtain the exact amount of displacements as the faults are difficult to map due to poor resolution of the seismic. Instead of using faults to depict the structure of the area, the depth maps were used. The depth maps of 22At1 and the seabed show that the contours are continuous and do not close up. The 14At1 depth map has few contours closing up, but around the area of study the contours are continuous. Therefore the sediment are structurally flat around these horizons. It was noticeable that the 13At1 and 10At1 have closed up contours. The depths increase towards the south east and north west direction. At the centre of the field the depth values are lower. This indicates that field Y is at a structural high area. A high area on a structural map must have all contour lines coming all the way around all sides. This gives a closure in order to prevent the hydrocarbon from spilling. A structural trap is therefore deduced at the area of study as all contours close up where the wells are located.

**Comparison of the volume in place between the 2005 and current study**

The current study is compared with the last study which was done in 2005 by PetroSA before the seismic was reprocessed. The seismic was reprocessed in 2012. The comparison between the two studies is demonstrated in appendix E. The volume in place of the current study will therefore differ with the study done in 2005 as different seismic was used to generate depth maps and ultimately creating models used to calculate volumetrics. In the 2005 study, the 10A sands were divided into three channels. In the current study only the upper and lower sections of the 10A sands were identified. Both the 13A sands and 10A sands combined have a higher volume in place in the current study, as compared to the study conducted in 2005.
The total volume in place has increased by almost twice that of the previous study. It can be concluded that the seismic resolution has improved as mapping of events has become much easier than before and as a result there is an increase in the volume in place.

**Uncertainty of petrophysical properties and hydrocarbon in place**

The main petrophysical properties used in the volume calculation are porosity and water saturation. These properties were calculated in the Petrel software and compared against the core analysis results found in the well completion reports. The petrophysical modeling in Petrel showed a porosity and water saturation of 8 – 10% and 40 – 75% respectively for the 13A sands. The upper section of the 10A sands have a porosity and water saturation of 7 – 8% and 40 – 50% respectively. Lastly, the lower 10A sands exhibit porosity and water saturation properties of 5 – 7% and 35 – 45% respectively. These results obtained from property modeling are similar to those from the core results. The petrophysical inputs used in calculating the volume in place were that from the core analysis as the raw data would have less uncertainty than the results generated using the Petrel software. Any error in the measurements may lead to errors in the final hydrocarbon in place. A 10% error in the petrophysical calculations does not have a significant change from the initial volume in place. The results demonstrating how a 10% error would have an effect on the volume calculation are presented in appendix F. It is noticeable that the upper and lower case are not far off from the base case. Therefore it can be concluded that there will only be a significant change in the volume in place if the error in petrophysical calculation is much higher.

The parameter that could significantly increase or decrease the volume in place is the bulk rock volume which was calculated using the Petrel software. The method used is “volume below surface”. There could be a slight error in the position of the depth surfaces used to calculate the volume, as this depth surfaces were generated by depth conversion using a velocity model. The velocity model is not necessarily the only parameter that could have errors, but the initial error begins from interpretation of the seismic section. As mentioned in the results, the 10At1 horizon is difficult to map on seismic due to poor seismic resolution. Any change in the way the horizon was mapped could change the surface maps gridded and the steps to follow in modeling.

In conclusion, the volume in place is not only affected by the petrophysical parameters but by a lot of processes which build up the models used to calculate the volume in place. Therefore,
every step is important, from identifying the right horizon markers and doing the well correlation correctly. This will determine where the horizon markers will be placed on the seismic section and also the steps that follow in obtaining the volume in place. Petroleum geology is therefore a very integrated study where everything is intertwine.
Chapter 7

6. Recommendations

An integration of core logging and thin sections observations can be useful in improving the determination of facies. It is recommended that PetroSA or PASA cuts thin section at various zones of interest, especially at the reservoir sections. The thin sections are not only good in determining lithology and grain size but sedimentary structures which are useful in deducing the depositional environment.

More checkshots of the wells in the field must be generated. Only well X-01 which is adjacent to the field of study has checkshots. If more checkshots of the wells are generated, it would increase the accuracy of the seismic well tie, as the well with the best checkshots would be used for the time depth relationship. Currently the checkshot of well X-01 cannot be compared to any other checkshots of the wells in the study area. The checkshots are also useful in velocity modeling.

It is recommended that PetroSA does another reprocessing of the seismic data, especially at depths below the 13At1 event. Above this event the horizons are more flat; therefore it is easier to interpret the seismic. Below the 13At1 the horizons are tilted and the poor resolution makes it difficult to follow the event. The seismic resolution is even poorer around the 10At1 event. Seismic visibility would increase the accuracy of how the horizons are mapped and ultimately the surfaces generated which are used to build models. With good seismic visibility, more faults can be mapped accurately and a better structural model would be built.

The future study should incorporate seismic attributes. The attributes enables identification and delineation of structural and stratigraphic elements. The use of seismic attributes would increase the visibility of fault signatures.

Additional porosity and permeability logs are required for petrophysical modeling. Only well Y-01 has petrophysical logs. More petrophysical logs from the other wells in the field would be useful in populating the facies model with petrophysical properties by averaging the properties between all wells in the study area instead of extrapolating the properties from only one well.
References


Adapted from oral presentation at AAPG Annual Conference and Exhibition, Cape Town, Africa.


Websites

Figure A1: 3D Autotracking of the seabed
Figure A2: 2D Autotracking of horizon 22At1
Figure A3: 2D Autotracking of horizon 14At1
Appendix B

Figure B1: Seabed surface in TWT
Figure B2: 22At1 surface in TWT
Figure B3: 14At1 surface in TWT
Figure C1: Interval velocity surface between the Seabed and horizon 22At1
Figure C2: Interval velocity surfaces between horizons 22At1 – 14At1
Figure D1: Seabed depth surface
Figure D2: Horizon 22At1 Depth Surface
Figure D3: Horizon 14At1 depth surface
Appendix E

Table 1: Comparison between a study done by PetroSA in 2005 and the current study

<table>
<thead>
<tr>
<th>Zone</th>
<th>2005 Study (PetroSA) GIIP (Bcf)</th>
<th>Current Study GIIP (Bcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13A</td>
<td>20.54</td>
<td>27.23</td>
</tr>
<tr>
<td>10A channel 1</td>
<td>3.37</td>
<td>12.53</td>
</tr>
<tr>
<td>10A channel 2</td>
<td>1.33</td>
<td>17.48</td>
</tr>
<tr>
<td>10A channel 3</td>
<td>2.42</td>
<td></td>
</tr>
<tr>
<td>Total GIIP of the 10A sands</td>
<td>7.12</td>
<td>Total GIIP of the 10A sands</td>
</tr>
<tr>
<td>Total GIIP</td>
<td>27.66</td>
<td>Total GIIP</td>
</tr>
</tbody>
</table>
### Appendix F

Table 1: Results of amount of gas in place in the 13A sands with a 10% increase or decrease of the base case petrophysical parameters.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Base Case</th>
<th>Possibility 1</th>
<th>Possibility 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRV (m³)</td>
<td>7.20E+07</td>
<td>7.20E+07</td>
<td>7.20E+07</td>
</tr>
<tr>
<td>NTG</td>
<td>0.866</td>
<td>0.7794</td>
<td>0.9526</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.103</td>
<td>0.0927</td>
<td>0.1133</td>
</tr>
<tr>
<td>Water saturation</td>
<td>0.4</td>
<td>0.36</td>
<td>0.44</td>
</tr>
<tr>
<td>Bg</td>
<td>0.005</td>
<td>0.0045</td>
<td>0.0055</td>
</tr>
<tr>
<td>GIIP Bcf</td>
<td>27,23</td>
<td>26,14</td>
<td>27,95</td>
</tr>
</tbody>
</table>

Table 2: Results of amount of gas in place in the 10A upper sands with a 10% increase or decrease of the base case petrophysical parameters.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Base Case</th>
<th>Possibility 1</th>
<th>Possibility 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRV (m³)</td>
<td>6.03E+07</td>
<td>6.03E+07</td>
<td>6.03E+07</td>
</tr>
<tr>
<td>NTG</td>
<td>0.734</td>
<td>0.6606</td>
<td>0.8074</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.09</td>
<td>0.081</td>
<td>0.099</td>
</tr>
<tr>
<td>Water saturation</td>
<td>0.433</td>
<td>0.3897</td>
<td>0.4763</td>
</tr>
<tr>
<td>Bg</td>
<td>0.005</td>
<td>0.0045</td>
<td>0.0055</td>
</tr>
<tr>
<td>GIIP Bcf</td>
<td>12,53</td>
<td>12,14</td>
<td>12,73</td>
</tr>
</tbody>
</table>

Table 3: Results of amount of gas in place in the 10A lower sands with a 10% increase or decrease of the base case petrophysical parameters.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Base Case</th>
<th>Possibility 1</th>
<th>Possibility 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRV (m³)</td>
<td>7.20E+07</td>
<td>7.20E+07</td>
<td>7.20E+07</td>
</tr>
<tr>
<td>NTG</td>
<td>0.587</td>
<td>0.5283</td>
<td>0.6457</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.107</td>
<td>0.0963</td>
<td>0.1177</td>
</tr>
<tr>
<td>Water saturation</td>
<td>0.347</td>
<td>0.3123</td>
<td>0.3817</td>
</tr>
<tr>
<td>Bg</td>
<td>0.005</td>
<td>0.0045</td>
<td>0.0055</td>
</tr>
<tr>
<td>GIIP Bcf</td>
<td>17,48</td>
<td>16,57</td>
<td>18,20</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total GIIP Bcf</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>57,23</td>
<td>54,84</td>
<td>58,88</td>
</tr>
</tbody>
</table>