

STRUCTURAL EVOLUTION AND BURIAL HISTORY OF THE DOLPHIN
GRABEN, NORTHERN WALVIS BASIN (BLOCK 1911), OFFSHORE
NAMIBIA

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ABSTRACT

This research is on the structural evolution and burial history of the the Dolphin Graben. The Dolphin Graben is a prominent graben structure situated on the continental slope in the northern Walvis Basin, immediately south of the Walvis Ridge and the Phoenix Volcanic Field. The Dolphin Graben is under-explored with only two wells located in it. Minor oil shows are reported from well 1911/15-1, while well 1911/10-1 is labelled as dry. At least two regional source rock intervals are predicted to be present in the graben, one in the Aptian-Albian, the other in the Cenomanian-Turonian. None of the two exploration wells penetrated the Albian-Aptian source rock. The intersected Cenomanian-Turonian source rocks at the two well sites in the graben are recognized to be immature. Thus, the questions on the presence of a mature source rocks, reservoir charge access and hydrocarbon preservation within the graben remained pending. The project aims at providing the following three studies for the Dolphin Graben: a (1) detailed structural evolution analysis, (2) reconstruction of the burial history in 1D at three locations, and a (3) re-assessment of the hydrocarbon potential of the Dolphin Graben taking into account the structural evolution and burial history models.

Seismic interpretation was carried out in Petrel software, while 1D burial history models were created with PetroMod software. Seismic interpretation formed the foundation of the structural evolution study; it entailed marker horizon mapping, fault mapping and subsequently fault displacements measurements. 1D burial models were created for three locations, namely well 1911/10-1, well 1911/15-1 and for a pseudo well herein labelled as "New well". Subsequent thermal and maturity models were created with calibration data from the two 1911 wells.

A regional and local structural model were created from seismic data. The regional model gives a concept of the wider deeper crustal structure of the northern Walvis Basin, while the local model is rather a reconstruction of phases of fault activity specific for the structures defining the Dolphin Graben.

A main outcome of the study is that the Dolphin Graben is a rift system that is independent from the general Namibian margin syn-rift extension. The graben formed after deposition of the syn-rift sequence and Seawards Dipping Reflectors (SDRs). In fact, most of the graben subsidence occurred during the early passive margin drift phase. The graben development commenced during the Barremian or early Aptian and two main extensional phases (Extension phases I and II) are recognized. The mechanism for this local rift is not fully understood but could relate to local thermal mantle anomalies associated with the volcanism at the adjacent Phoenix Volcanic Field and Walvis Ridge.

Predicted lacustrine source rocks deposited during early extension and they are likely confined to ponds in smaller half grabens. During progressive extension, the smaller grabens became inactive, while extension was accommodated by a few main faults that outline the Dolphin Graben. A continuous marker horizon in the Dolphin Graben has similar seismic characteristics and is located at a similar stratigraphic level as the known Aptian-Albian source rock in the southern Walvis Basin. Hence, this seismic marker is understood as an indication that the Aptian-Albian source rock is well-developed in the Dolphin Graben. There, it is essentially laterally extensive, but condensed or absent on central structural highs and on the graben flanks. Another distinct seismic horizon ties well to the Cenomanian-Turonian source rock in the 1911 wells and it extends over the entire Dolphin Graben. The

1D burial history and thermal models revealed maturity of older presumed lacustrine as well as for the Aptian-Albian source rocks.

A minor oil show is reported in drilled Lower Cretaceous carbonates occurring on a structural high in the central graben. It is possible that hydrocarbons used extensional faults as migration pathways to charge those carbonates.

The Cenomanian-Turonian source rock has been identified as immature to early mature. With 10.6 % TOC it is a potentially excellent source rock, but burial depth within the Dolphin Graben was essentially insufficient for hydrocarbon generation. Therefore, future exploration should focus on petroleum plays that concentrate on the Aptian-Albian source rocks.

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SDFs	Seaward Drifting Facies
SDG	Societies of Exploration Geophysicists
SD	Signal to Noise Ratio
TD	Total Depth
TOC	Total Organic Carbon
TR	Transformer Ratio
EAP	Exploration and Production

LIST OF ABBREVIATIONS AND/ OR ACRONYMS

1D:	One dimensional
2D:	Two dimensional
3D:	Three dimensional
API:	American Petroleum Institute
CRS:	Coordinate Reference System
DHI:	Direct Hydrocarbon Indicator
FIG...:	Figure
NAMCOR:	National Petroleum Corporation of Namibia
ODP/DSDP:	Ocean Drilling Program /Deep Sea Drilling Project
PETROFUND:	Petroleum Education and Training Fund
R/V:	Research Vessel
SDRs:	Seaward Dipping Reflectors
SEG:	Society of Exploration Geophysicists
S/N:	Signal to noise ratio
TD:	Total Depth
TOC:	Total Organic Carbon
TR:	Transformation Ratio
E&P:	Exploration and Production

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UNITS

km: kilometers

km²: square kilometer

m: meter

Ma: million years ago

ms: millisecond

mg_{HC}/g_{TOC}: milligram hydrocarbon per gram of total organic carbon

TCF: Trillion Cubic Feet

TWT: Two Way Time

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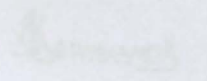
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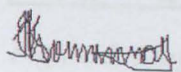
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CHAPTER 1 - INTRODUCTION

1.1 Background

During Gondwanaland break-up and the opening of the South Atlantic a conjugate pair (South America and Africa) of passive continental margins, as illustrated in Fig. 1., evolved (Kukulius, 2004; Gladchenko et al., 1999). These late Jurassic/ Mesozoic geologic events led to the formation of a linear series of four main basins parallel to the Namibian offshore on the African continental passive margin. These depocenters identified within the zone of maximum subsidence are the Namibe, Walvis, Lüderitz and Orange basins from north to south respectively (Fig. 2).

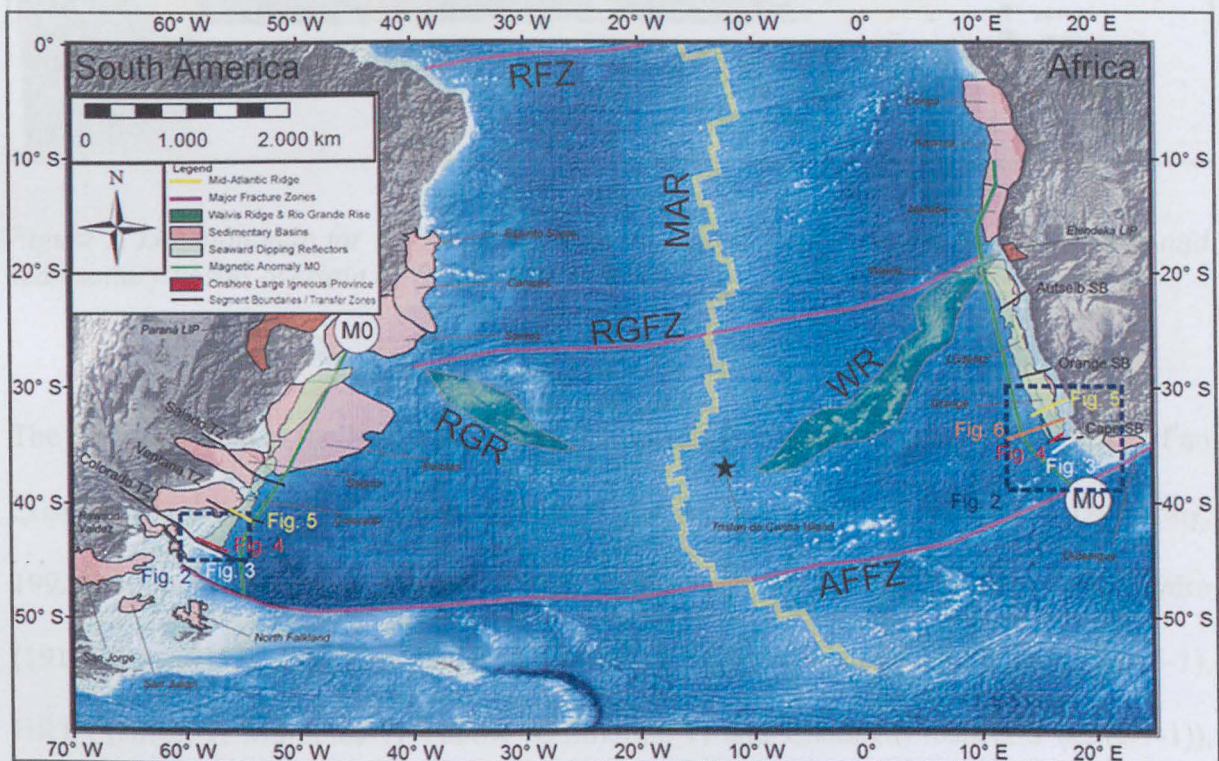


Figure 1. Map of South Atlantic conjugate margin basins (Koopmann et. al., 2014).

The conjugate South Atlantic passive continental margins have long been a focus to hydrocarbon exploration. An extensive hydrocarbon potential has been proven by the

Angolan Mocamedes- and Kwanza Basins, and the Brazilian Santos- and Campos Basins (Fig. 1), respectively (Mello & Katz, 2000).



Figure 2. Location map for the Dolphin Graben consisting regional structural elements and sedimentary basins overlain by (NAMCOR, 2019).

The Kudu gas field in the Namibian Orange Basin offshore Oranjemund gives evidence of an existing petroleum system in the Namibian passive margin (Davies & Van Der Spuy, 1992/93). In respect to the Walvis Basin, seven wells have been drilled: Norsk Hydro (1911/10-1, 1911/15-1), Sasol (2012/13-1), Ranger (2213/6-1), Shell (Shark well-2313/5-1), HRT (Wingat-1, Murombe-1) Tullow (Cormorant-1) and Chariot (Prospect-S (2312/7-1)), see Figure 3. for their location.

These wells penetrate the post-rift succession from approximately 130Ma to recent and only the southernmost well 2313/5-1 offshore Walvis Bay penetrates older clastic syn-rift sediments.

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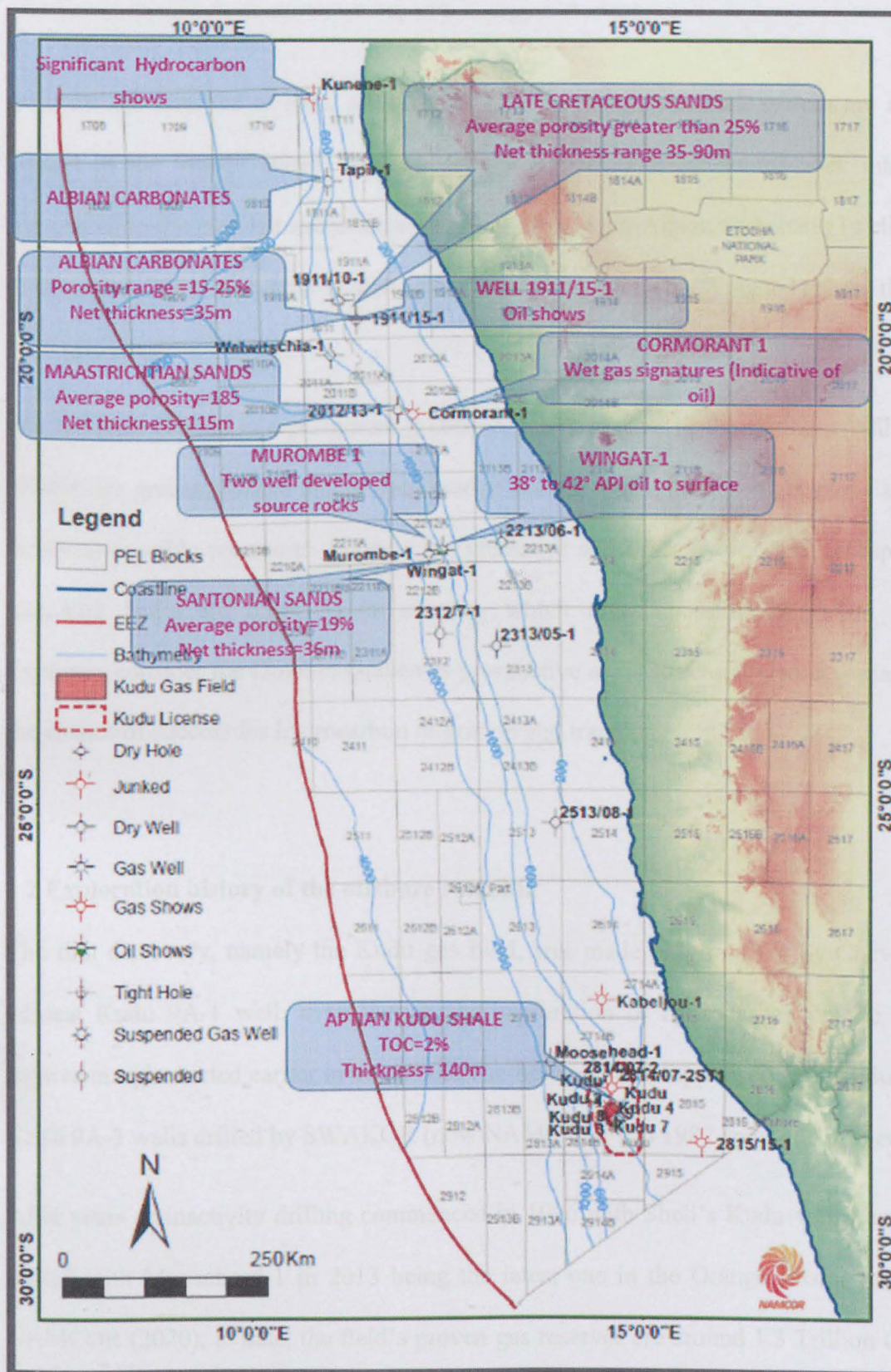


Figure 3. Map of the onshore and offshore Namibia showing wells with and without hydrocarbon discoveries along with gas/oil shows, NAMCOR (2019).

Even though untested to date, all elements of a working petroleum system are apparently present in the Walvis Basin. At least, two potential oil prone source rock intervals are recognized in the post-rift succession. Residual oil in Apto-Albian carbonates (well 1911/15-1) (Kukulius, 2004) and Apto-Albian intra source sand stringers (Wingat-1) show that oil has been generated.

The Dolphin Graben is a prominent graben structure located in the northern Walvis Basin. Within this graben, Maastrichtian deep marine fan sands and base Tertiary reef-like features represent possible reservoirs. Seismic gas chimneys and other hydrocarbon escape features including faults are observed on seismic, which reveal possible migration pathways. Explorers consider the Dolphin Graben as prospective as its structural elements may increase the chance of success for hydrocarbon migration and trapping.

1.2 Exploration history of the offshore Namibia

The first discovery, namely the Kudu gas field, was made only in 1974 by Chevron's first wildcat Kudu 9A-1 well, even though the exploration of hydrocarbon on the Namibian passive margin started earlier in the 1960s. The field was later appraised with Kudu 9A-2 and Kudu 9A-3 wells drilled by SWAKOR (now NAMCOR)'s in 1987 and 1988, respectively.

After years of inactivity drilling commenced in 1996 with Shell's Kudu-4 and further wells drilled with Moosehead-1 in 2013 being the latest one in the Orange Basin. According to NAMCOR (2020), to date, the field's proven gas reserves are around 1.3 Trillion Cubic Feet (TCF). The reserves are hosted within the Barremian sandstones interbedded with volcanics. After independence, Namibia introduced the bidding round system with the first round

executed in 1992 and 1993. During this round, Norsk Hydro, Ranger Oil, Sasol, Chevron and Shell were awarded exploration licenses.

The second licensing round yielded in two licenses being successfully awarded to Shell in the year 1995. The third licensing round did not receive an application, and the fourth round resulted in award of two licenses only. Therefore, Namibia introduced an open licensing system in 1999. Subsequently, exploration activities were steadily increasing and escalated from the year 2008. Seismic data was acquired besides a number of wells drilled.

Overall, a total of 34 wells have been drilled offshore Namibia. These comprise 17 exploration wells, 7 appraisal wells and 10 ODP/DSPD wells. Majority of these wells are located in the Walvis Basin. Exploration wells are the Wingat-1, Murombe-1, 1911/10-1, 1911/15-1, Welwitchia-1, 2012/13-1, 2213/6-1 and the two recent wells Cormorant-1 and 2312/7-1 (Prospect S) (Fig. 3).

1.3 Problem statement

The Dolphin Graben is under-explored with only two wells located in it. Minor oil shows are reported from well 1911/15-1, while well 1911/10-1 is labelled as dry. None of the two wells penetrated the Albian-Aptian source rock (Figs. 4 and 5).

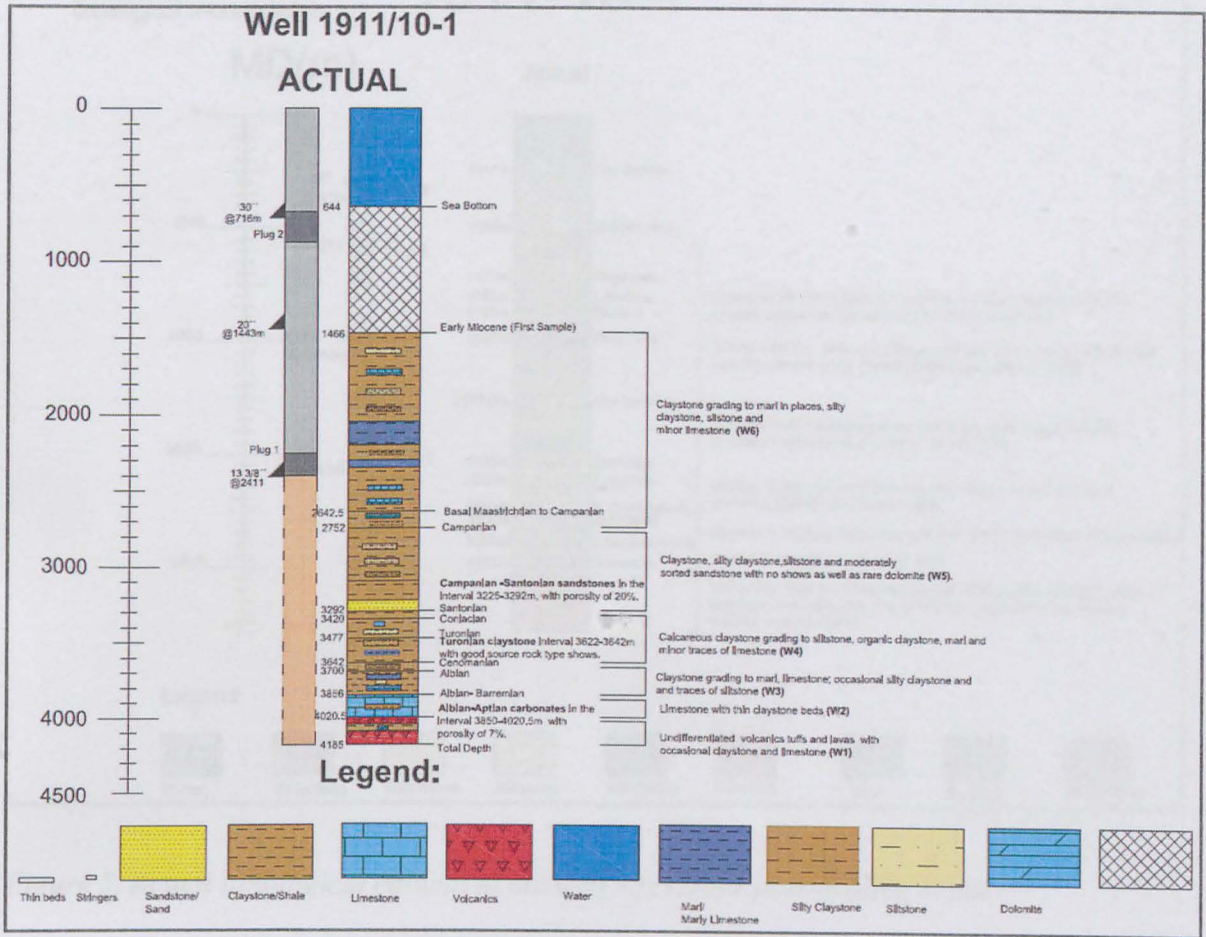


Figure 4. Actual lithological column of the well 1911/10-1 post-drilling results

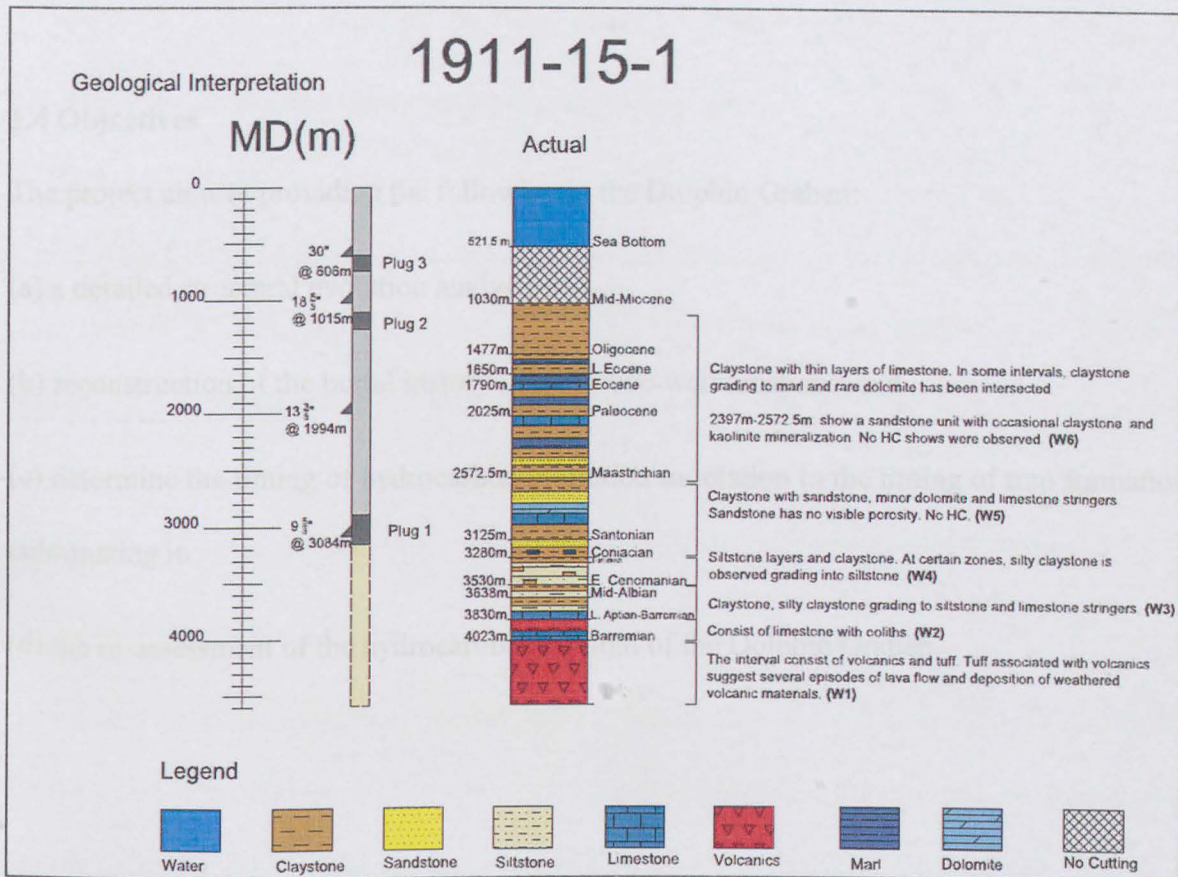


Figure 5. Actual lithological column of the well 1911/15-1 post-drilling results.

The intersected Cenomanian-Turonian source rocks at the two well sites in the graben are recognized to be immature. Therefore, the question of mature source rock presence and effectiveness, charge access and timing, and preservations presents itself. A detailed understanding of the structural evolution and burial history are crucial to evaluate critical petroleum system elements, especially source rock presence and (reservoir) charge access and effectiveness, which are among the main risk factors in the Dolphin Graben. Better constraints for those aspects will assist in de-risking current and new prospects. A subsequent re-assessment of the graben's hydrocarbon potential may awaken further exploration interest and could encourage explorers to undertake new data acquisition and mature and drill prospects in the graben.

1.4 Objectives

The project aims at providing the following in the Dolphin Graben:

- (a) a detailed structural evolution analysis and,
- (b) reconstruction of the burial history in 1D at two well locations, and
- (c) determine the timing of hydrocarbon migration in relation to the timing of trap formation, culminating in
- (d) the re-assessment of the hydrocarbon potential of the Dolphin Graben.

CHAPTER 2 - LITERATURE REVIEW

2.1 Overview of South Atlantic passive margin evolution

2.1.1 *Origin of the South Atlantic margin*

The South Atlantic passive margin owes its establishment to the breakup of Gondwana (Maystrenko et al., 2013; Nürnberg & Müller, 1991). Numerous studies have addressed aspects of the rifting and continental break-up of the South Atlantic passive margin (e.g. Light et al., 1991; Maystrenko et al., 2013; Gladczenko et al., 1998; Seranne & Anka, 2005; Stewart et al., 2000; Bauer et al., 2000; Clemson et al., 1999; Bray, 1999; Maslanyj et al., 1991, and Mello et al., 2011).

Africa and South America were connected as part of Gondwana supercontinent during the Triassic time (Gladczenko et al., 1998). Rifting and breakup of western Gondwana resulted in the separation of South America from Africa (Hirsch et al., 2010; Fig. 6) and the opening of the South Atlantic in the Late Jurassic to Early Cretaceous (Seranne & Anka, 2005; Granot & Dymant, 2015). However, primary subsidence related to crustal stretching began at least as early as from Permo-Triassic times (Maslanyj et al., 1991; Clemson et al., 1999).

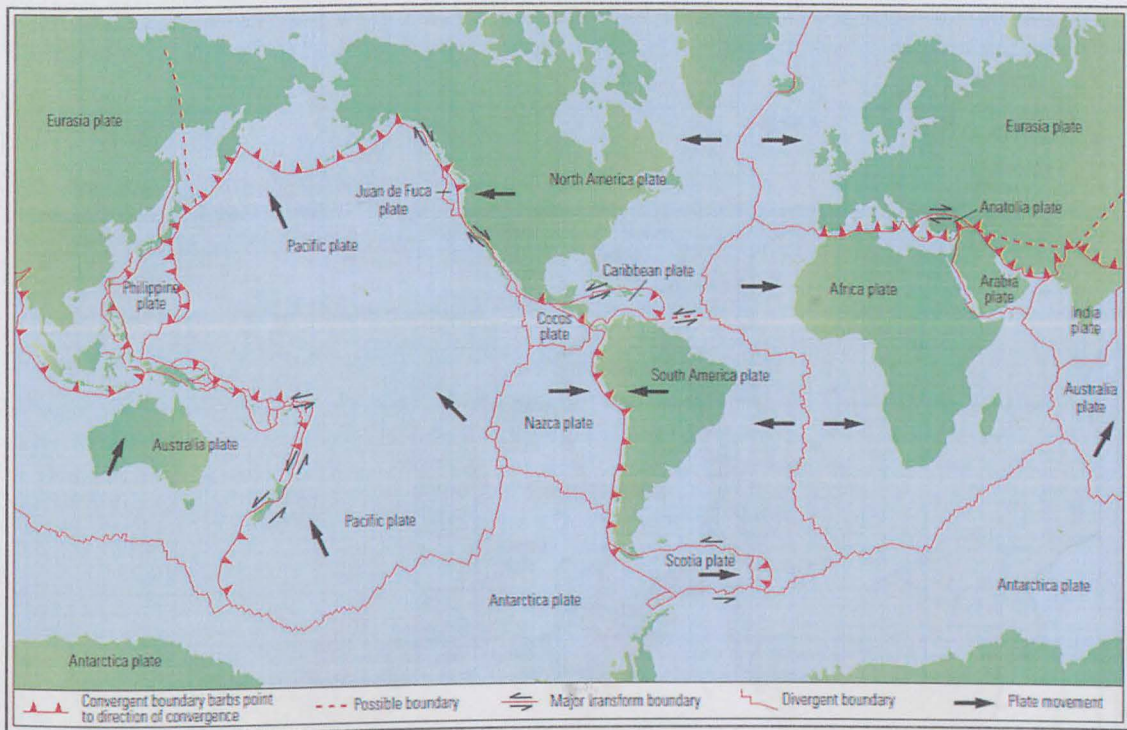


Figure 6. Map showing the plates dividing the Earth's lithosphere as well as the relative motion (indicated by arrows) of plates (Bryant, 2012).

The extensional stresses caused by the opening of the South Atlantic resulted in a conjugate (South America and Africa) pair of passive continental margins (Fig. .6) (Kukulus, 2004; Gladczenko et. al., 1998).

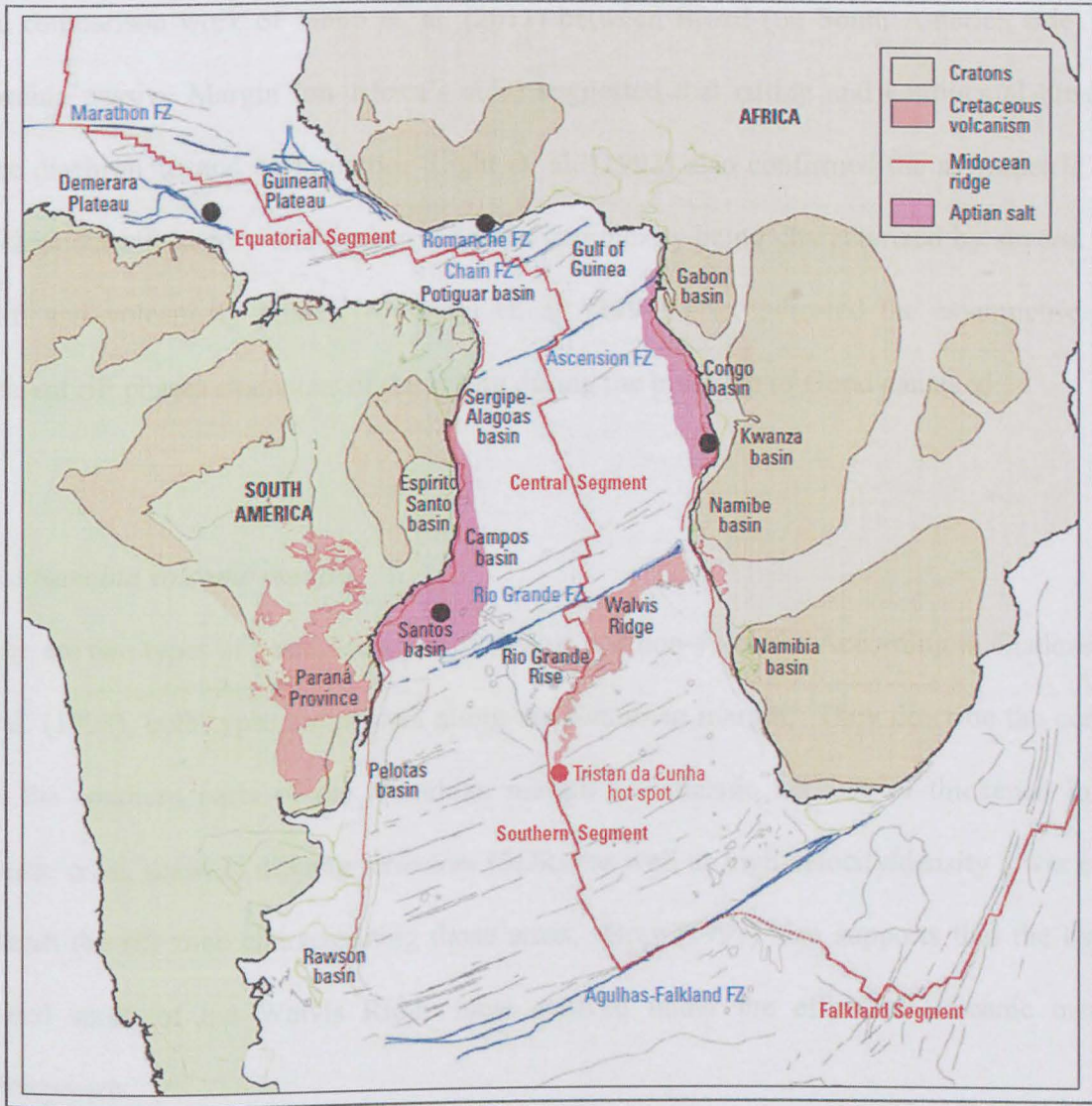


Figure 7. Tectonic map of the South Atlantic Ocean at the end of magnetic polarity chron 34 (MC34, 84) (Bryant et al., 2012).

Part of Maslanyj et. al. (1991)'s study discussed the initial break-up of Gondwana as the accomplishment by simple shear associated with crustal passive stretching. In contradiction to the latter, other sections of Maslanyj et. al. (1991) also consider that the stretching could alternatively be related to changes in the plate boundary stresses, due to a changing relationship between rifting in the South Atlantic and subduction processes active on the Pacific margin of West Gondwanaland (Fig. 7).

The comparison work of Mello et. al. (2011) between Brazil (on South America side) and Namibia passive Margin (on Africa's side) suggested that rifting and continental breakup were diachronous and asymmetric. Light et. al. (1992) also confirmed the asymmetric and diachronous rift history and further added its complexity being characterized by several rift, uplift and volcanicity phases. Maslanyj et. al. (1991) also indicated the asymmetric and different rift phases characters of the rifting during the break-up of Gondwanaland.

2.1.2 Namibia volcanic margin

There are two types of passive margins: volcanic and non-volcanic. According to Gladchenko et. al. (1998), both types are present along the Namibian margin. They describe the central and the southern parts of the Namibian margin as volcanic because of thickened initial oceanic crust, seaward dipping reflectors (SDRs) as well as high velocity/density lower crust beneath the rift zone characterizing those areas. Bray (1999) also supports that the basins located south of the Walvis Ridge have evolved under the effect of volcanic margin development.

On the other hand, the northern section of the Namibian margin located north of Walvis ridge (Walvis Fault Zone) is considered non-volcanic (Gladchenko et. al., 1998; Seranne & Anka, 2005). This is in line with Bagguley & Prosser's (1999) observation that the Namibe Basin (Fig. 8), located to the north of the Walvis Ridge, has a markedly different basin architecture and history. The Walvis Ridge is formed from the persistent magmatism associated with the Tristan plume (Maslanyj et. al., 1991; Bauer et. al., 2000; Gladchenko et. al., 1998) and divides the two margin types (Figure 6). In contrary, other authors such as Kirkpatrick et. al. (2019), Koopmann et.al, (2013), Clemson (1997), Maystrenko et. al. (2013) and Bray (1999) regard the Namibian passive margin as purely volcanic.

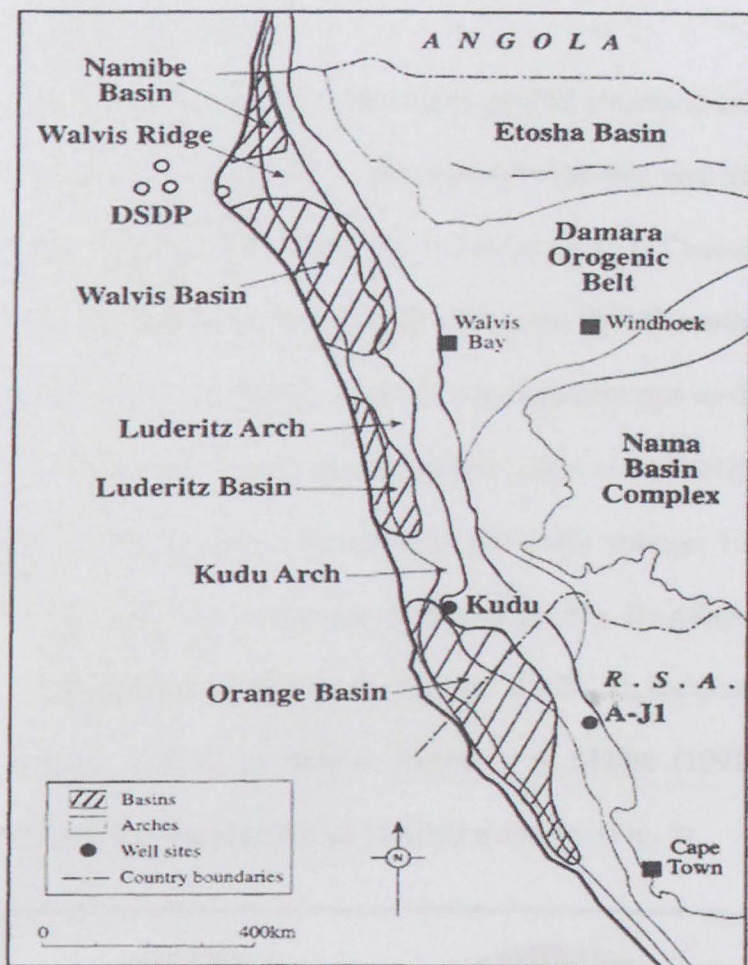


Figure 8. Map showing the location of the different offshore depocenters/basins located along the Namibian passive continental margin (Bagguley & Prosser, 1999).

The Namibian margin has been affected by two major phases of tectonism associated to Gondwanaland break-up (Maslanyj et. al., 1991; Light et. al., 1993). Work of Maslanyj et. al. (1991) backed up this statement by adding that the Namibian margin is an ultimate model/example of a rifted continental margin which have undergone considerable, transient/short-lived magmatic activity during final continental breakup and preliminary sea floor spreading.

2.1.3 Margin structure

A general north-south (N-S) margin-parallel structural grain, with some east-west-orientated fractures were produced by the regional extension and rifting initiated during the Mesozoic. Light et. al. (1992), Nürnberg & Müller (1991), Clemson et. al. (1997), Kukulus (2004), Mello et. al. (2011), and Granot & Dymant (2015) confirmed the northward propagation of rifting with time, starting from the southernmost part of the South Atlantic Ocean. The latter is affirmed by seismic data evaluation (Light et. al. 1992). Evaluation shows that faulting in the syn-rift sequences becomes progressively younger further north (Stewart et. al., 2000). Authors such as Cartwright & Booth (1997), Jungslager (1999), Clemson et. al. (1997), Gladchenko et. al. (1999), de Vera et. al. (2010), Kuhlmann et al. (2011), Rabinowitz & La Brecque, (1979), as well as Nürnberg & Müller (1991) emphasized that South Atlantic opening has happened in an unzipping manner (Fig. 9).

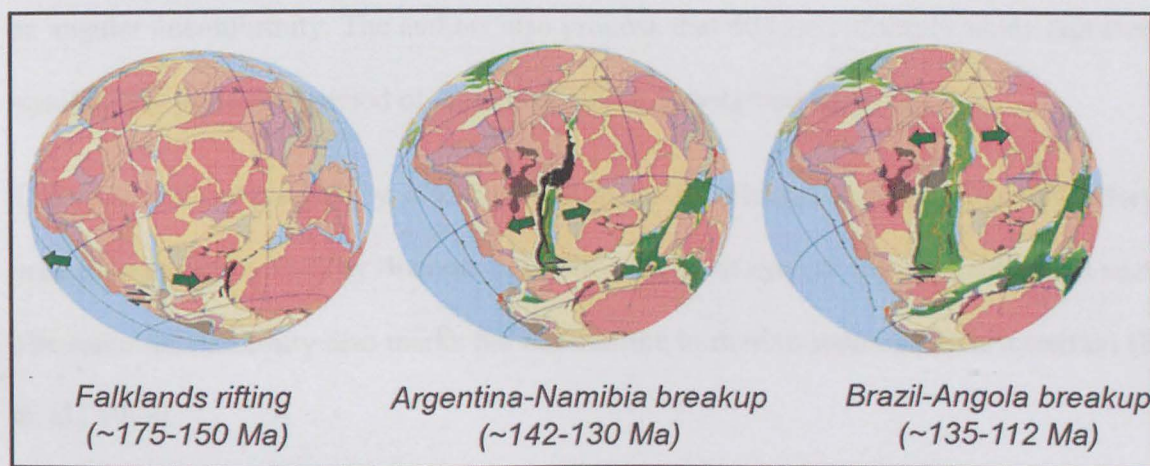


Figure 9. Tectonic evolution of Gondwana during the Mesozoic rifting period. Copied from Conti (2014).

2.2 Tectono-stratigraphy of the Namibian passive margin

The tectono-stratigraphic megasequences identified on the Namibian passive margin are pre-rift, syn-rift, transitional and thermal sag megasequences (Bray et. al., 1998, Light et. al., 1992, and Clemson et. Al., 1999). Minor variations in the terminology was used by few authors. Bray et al. (1998) and PGS (2014) use a terminology of pre-rift, syn-rift, early drift and late drift (post-rift) for the Namibian megasequences. This research uses the terminology of Bray et al. (1998) to describe the recognized tectonic-stratigraphic units of the Namibian passive margin (Fig. 10).

Major unconformities divide the megesequences/units. Base rift unconformity separates early Cretaceous syn-rift from the pre-rift Karoo. The pre-rift is assumable Permo-Carboniferous to Triassic in age (Bray et. al., 1998). According to Aizawa et al. (2000) and Clemson et al. (1999) these Karoo Supergroup rocks are preserved in the half grabens and are truncated by an angular unconformity. The authors also propose that this unconformity likely represents a significantly prolonged period of erosion of Karoo Supergroup material.

The base drift unconformity also referred to as the Hauterivian/Barremian boundary as marked at the Kudu field by Bray et. al. (1998), separates syn-rift from the early drift section. The same unconformity also marks the non-marine to marine sedimentation transition (Bray et. al., 1998).

The syn-rift section is made up of mainly siliciclastic and volcanics of late Jurassic to early Cretaceous age (Clemson et al., 1999). This was proved at the Kudu field, where the syn-rift unit was intersected, there it provides a reservoir interval consisting of aeolian and nearshore sandstones intercalated with basalts. Characterized by tilted blocks with several north-south trending half-grabens, the rift runs the entire length of the margin (Spectrum, 2012).

Similarly, the syn-rift section passes westwards into a thick wedge of seaward dipping reflectors (SRDs), which are considered to have a volcanic origin (Gladchenko et al., 1999).

The early drift section is mostly dominated by marine claystone and is believed to be Late Barremian to Cenomanian, and this section encompasses vital source rock intervals (Mello et al., 2000).

The Turonian to Recent late drift section makes up the main part of the basin fill. This megasequences encompasses the Base Tertiary unconformity (Figure 9). Otherwise, the drift sequence in general regarded as progradational with several transgressive-regressive cycles.

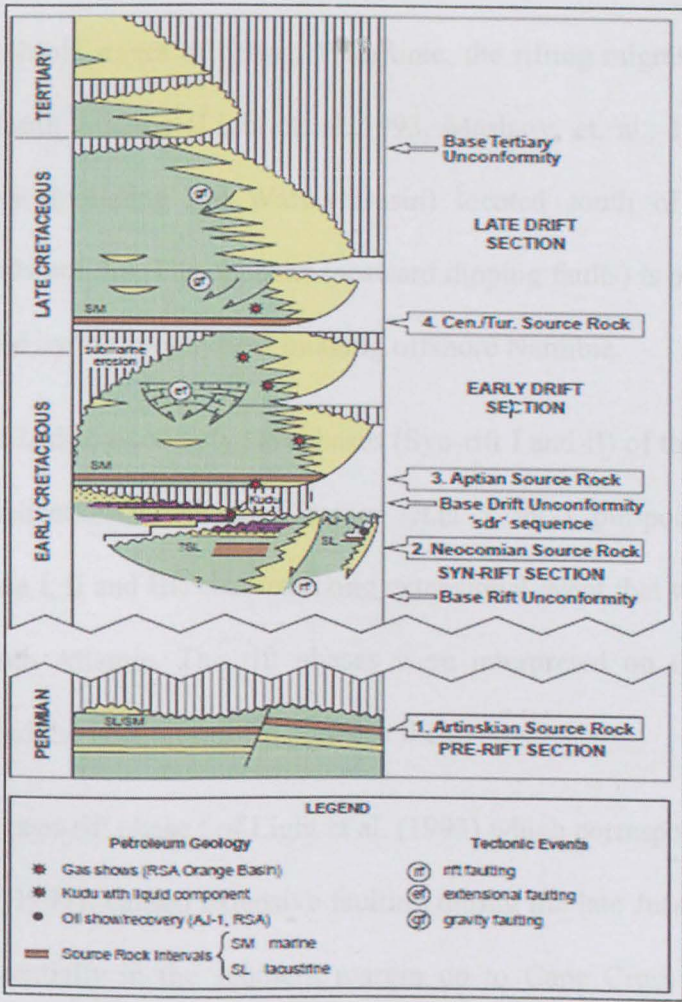


Figure 10. Generalised Stratigraphy, source rocks and unconformities of the offshore Namibia (Bray et al., 1998).

2.3 Geology of the Walvis Basin

The Walvis Basin is an elongate offshore embayment lying parallel to the Namibian coastline. It is one of the many depo-centers lying along the African and South American continental margins which was formed during initial break-up of Gondwana supercontinent (Maslanyj et.al.,1992). The basin continues northwards up to the volcanic Walvis Ridge of northern Namibia and extends southwards until the Lüderitz Arch, an area of relatively thin shelfal sediment cover (Fig. 8).

According to Maslanyj et.al. (1992), it is speculated that the initial subsidence associated with crustal stretching initiated around Permo-Triassic age. The persistent stretching of the crust has given rise to multiple stages of rifting. With time, the rifting migrated northwards from the southernmost South Atlantic (Light et. al.,1993, Maslanyj et. al., 1992). The main rift faults in the basins (including the Walvis Basin) located south of Walvis Ridge are characterized by landward dip. The opposite (seaward dipping faults) is observed north of the ridge as demonstrated by the geophysical imaging offshore Namibia.

Maslanyj et. al. (1992) discussed only two phases (Syn-rift I and II) of the late Mesozoic rift. However, later publications, such as Clemson et.al. (1997) pin-pointed out three rift sequences (Rift Phase I, II and III) characterizing extensional event that were followed by the opening of the South Atlantic. The rift phases were interpreted on the basis of seismic reflection patterns and the unconformities between them.

The early rift phase (syn-rift phase I of Light et al. (1993) which corresponds with the syn-rift I of Clemson et al. (1997)) caused extensive faulting during the late Jurassic to Valanginian. It is recognized essentially in the southern margin up to Cape Cross Segment Boundary (Maslanyj et al., 1992; Clemson et. al., 1997) and therefore essentially absent in the Walvis Basin.

In contrast, the rift phase II is well-recognized in the Walvis Basin. Clemson et. al. (1997) characterizes the rift phase II (Synrift II) as high-amplitude, continuous to discontinuous and often abruptly terminating seismic reflections. They further observed that syn-rift faulting in the Walvis Basin caused a less pronounced divergence of seismic reflection compared to the basins farther south. The Presence of syn-rift II in the Walvis Basin is confirmed by Maslanyj et. al. (1992), they also recognized its prompt thickening northwards towards the Walvis Ridge.

Clemson et al. (1997) defined an additional rift phase III which corresponds with the upper section of syn-rift II of Maslanyj et al. (1992). The seismic reflections' amplitude of this rift phase III in all Namibian offshore basins is lower in comparison to that of rift phase II (Clemson et al., 1997). The top of rift phase III is correlated to the rift-drift unconformity and the onset of normal oceanic crust production. Seismic correlation in the Walvis Basin suggests that, the break-up transpired clearly during the early Aptian (Clemson et al., 1997).

2.4 The Dolphin Graben

The study area, Dolphin Graben, is a prominent graben structure located in the northern part of Walvis Basin within the 1911 license block (see Fig. 2). It extends into the Namibe Basin to the north making it to be a common feature for the Namibe and Walvis Basin.

The Walvis Ridge with four structural highs is found to the west of the graben. The Gamma, Alpha, Beta and Delta are the structural highs identified by previous explorers from South to North respectively, located on the Walvis Ridge as shown in (Fig. 11). These structural highs have also been identified by the work of Clemson et. al. (1997). The East of the graben is bounded by the Elephant Platform and the Phoenix volcanic complex. These features are identifiable in the seismic and aeromagnetic data.

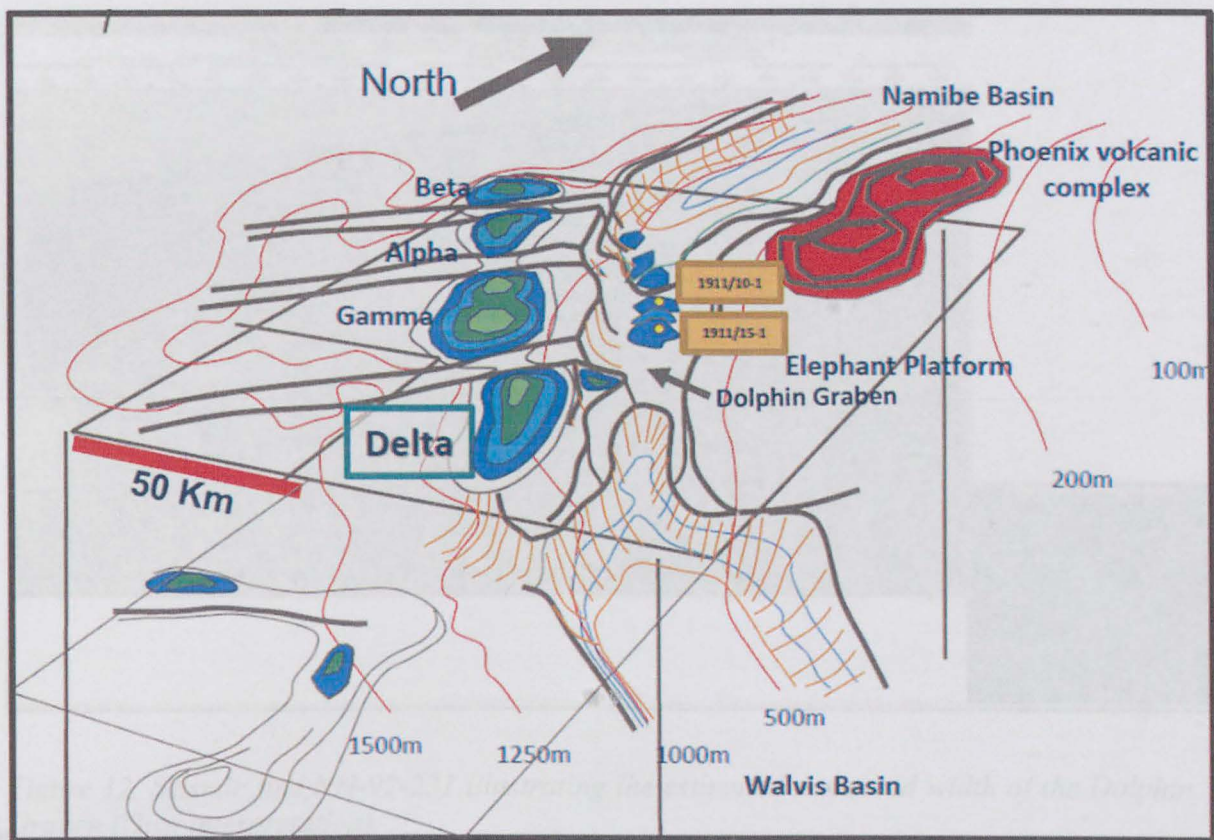


Figure 11. A 3D drawing depicting the Dolphin Graben and the features around it (Tower, 2010).

The graben follows the Namibian offshore basins' N-S direction (N-S) parallel to the Namibian coast line. On average, the graben is approximately 40.50km (Fig. 12) wide as identified in seismic.

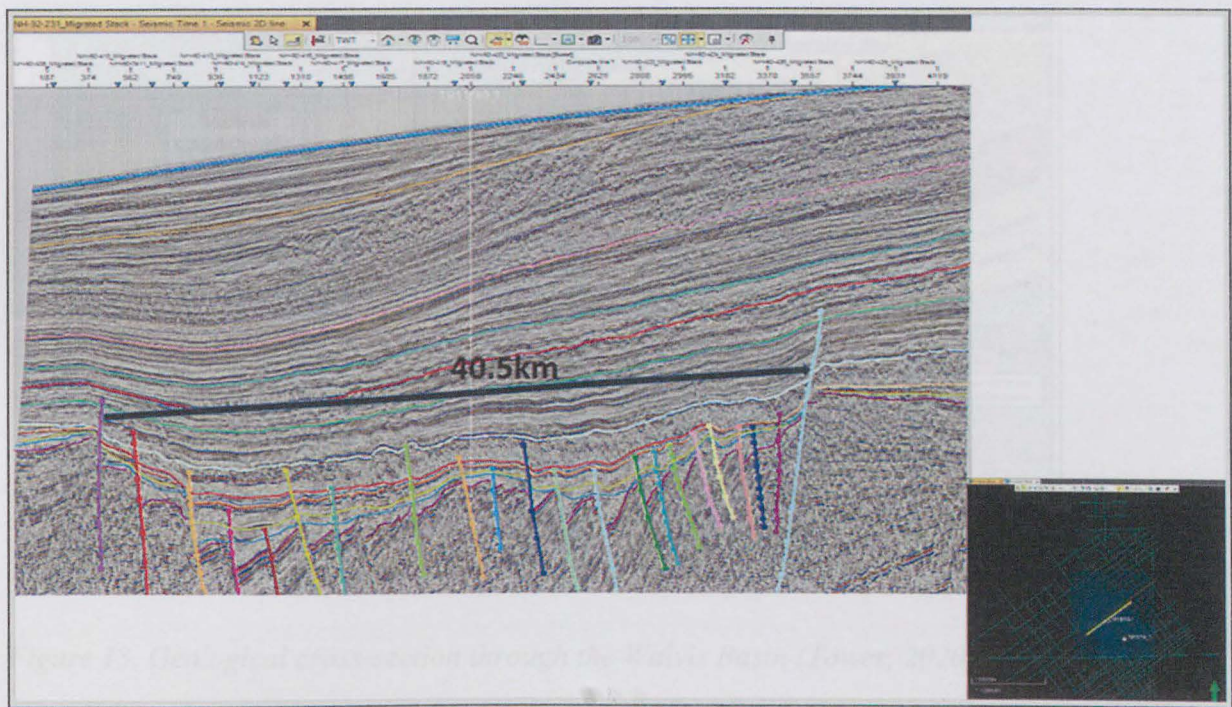


Figure 12. Seismic line NH-92-231 illustrating the estimated measured width of the Dolphin Graben (Own interpretation).

The proposed petroleum plays for the Dolphin Graben includes Maastrichtian (late Cretaceous) deep marine fan sands, Albian carbonates and Base Tertiary reef-like features as possible reservoirs, identified in the central Walvis basin by Kukulus (2004) and described in well reports. Seismic gas chimneys interpreted as hydrocarbon escape features as well as faults observed on seismic reveal possible migration pathways (Kukulus, 2004). Explorers consider the Dolphin Graben as prospective as its structural elements increase the chance of for hydrocarbon migration and trapping. Most uncertainty is on source rock presence, richness and maturity in the graben.

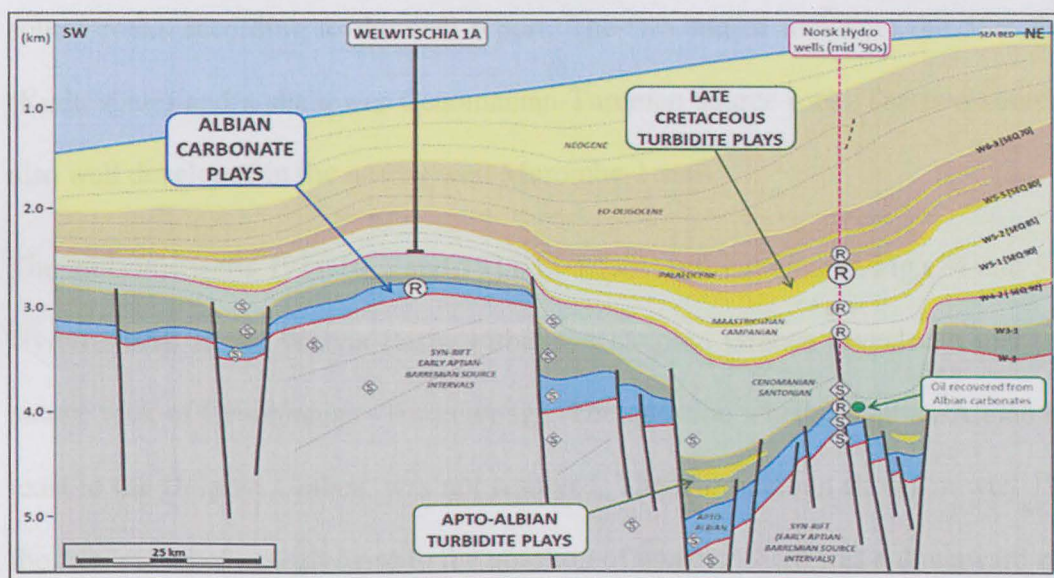


Figure 13. Geological cross-section through the Walvis Basin (Tower, 2020).

2.5 Hydrocarbon potential of the Walvis Basin

The extraordinary oil and gas potential of the offshore Namibia margin has undoubtedly been underestimated. In comparison with other margins in the world, exploration of the Namibian offshore margin is still in its embryonic stage. The Walvis Basin including the Dolphin Graben is under-explored. This is because it covers an area greater than 90 000km² but only 10 wells (Fig. 13) have been drilled in comparison to other basins. If compared to other basins in the world, the wells drilled are a few for a basin of such an extent. The wells in the Walvis Basin are: Welwitschia-1A, 1911/15-1, 1911/10-1 (in the Dolphin Graben), 2012/13-1, 2213/6-1, Cormorant-1, Wingat -1, Murombe-1, 2312/7-1 and 2313/5-1 (Fig. 3).

A working oil- prone petroleum system has been proven by regional drilling offshore Namibian passive margin. Different source rocks and reservoirs intervals have also been recognized/identified by seismic data interpretations and drilling results. Potential of oil field existence in Walvis Basin is supported by HRT's Wingat-1 drilled in 2013. The well recovered 38° to 42° API oil to surface. Wingat-1 has in addition confirmed two oil-prone

source rocks according to the well report. The two source rocks are the 58m thick Aptian (Kudu shale) and a shallower Cenomanian-Turonian source rock. The two source rocks are also well developed in the nearby well Murombe-1 well.

The mid- 90s wells 1911/10-1 and 1911/15-1 (see well columns in Fig.s. 4 and 5) drilled by Hydro Norsk in the Walvis Basin within the Dolphin Graben revealed a marine oil prone source rock of Cenomanian -Turonian age. The question whether Aptian-Albian source rock exist in the Dolphin Graben, was not resolved. The hydrocarbon shows in well 1911/15-1 in the Albian carbonates give rise to the question of whether there was a downward migration of the hydrocarbon or there exists an older, mature source rock in the Dolphin Graben.

Spectrum (2012) and Bray et. al. (1998) speculate that, besides the Aptian-Albian and Cenomanian-Turonian source rocks, there might be a third much older source rock. The third source rock interval is speculated to have been a result of lacustrine environments developed during early rifting, which could preserve organic rich, oil-prone claystones. Such a lithology is intersected onshore Namibia in the Toscanini well. However, at Toscanini it is believed to be gas prone (Bray et al., 1998). Therefore, the pre-rift section should be considered to contain source rock interval on a regional level.

According to the well reports, the reservoirs in the Walvis Basin are the Upper Cretaceous sands (Santonian and Maastrichtian), Albian Carbonates and Albian siliciclastic turbidites. Porosity of reservoirs in the basin ranges from 18-25% for sands and 15-25% for the carbonates. Net thickness of the reservoir's ranges from 35-90m in the Upper Cretaceous and 35m for Albian sands and carbonates respectively.

In addition to the Wingat-1 well, a working oil-prone system has been proven by the recently drilled Tullow Cormorant-1 well. The well demonstrated wet gas signatures which are an indication of oil presence.

CHAPTER 3 - MATERIALS AND METHODS

The research concentrates on the interpretation of 2D seismic data complemented with well data from Northern Walvis Basin, license block 1911. The interpretation was carried out in two software platforms housed in workstations. The seismic interpretation was done in the Schlumberger Petrel E&P software package, while PetroMod software platform was used to interpret well data for the 1D burial and thermal history models generation. Both, datasets and methodologies are elaborated below. All data were made accessible by Pioneer Oil and Gas Consulting for this study.

3.1 Data sets

3.1.1 Seismic data

Two 2D seismic surveys datasets were the central input for the seismic subsurface interpretation utilized for this research. The 2D seismic data contain 253 seismic lines including in-lines (lines parallel to the direction of survey acquisition) and crosslines (lines perpendicular to acquisition of survey).

The first seismic dataset is the 7111 km multi-client 2D NH-92 seismic survey (Fig. 14). The survey was shot by TGS in the year 1992. It was acquired by R/V Western Anchorage. The shot point interval was 26.66m, record length was 7 seconds and the sampling interval was 2 seconds. Norsk Hydro reprocessed the data.

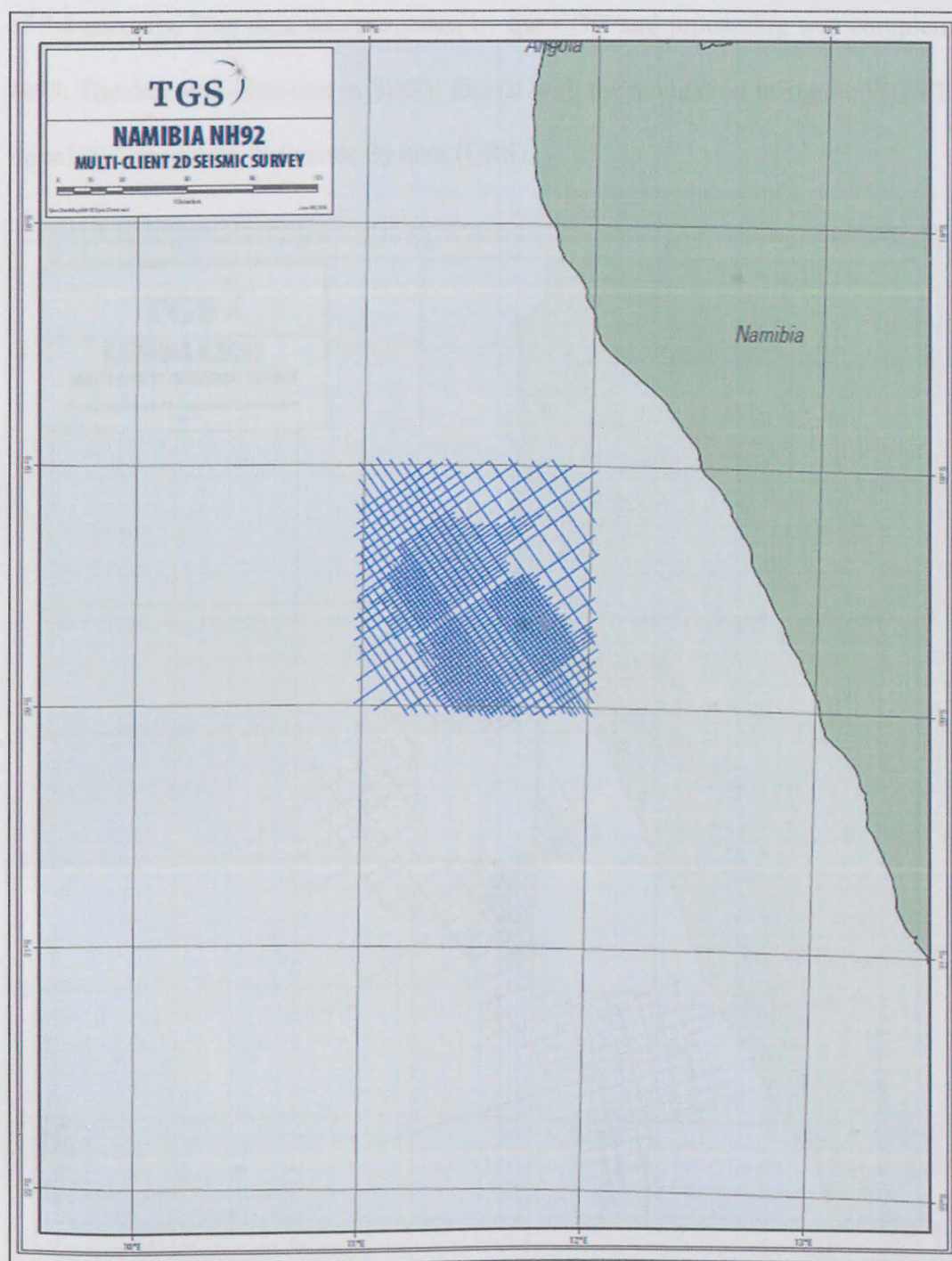


Figure 14. NH92 survey lines, Northern Walvis Basin, offshore Namibia (TGS, 2011).

The second seismic dataset N2R93 (Fig. 15) was also acquired in 1992. This 10 167km survey was acquired by CGG. The SN358 recorder was used during the acquisition. Shot point interval were 25m with 2 millisecond sampling intervals and reached a recording length

of 7-8 seconds. This data was processed by the CGG and processing was completed by July 1993. The data was available in SEG-Y format with the navigation using the WGS 1984 UTM Zone33S Coordinate Reference System (CRS).

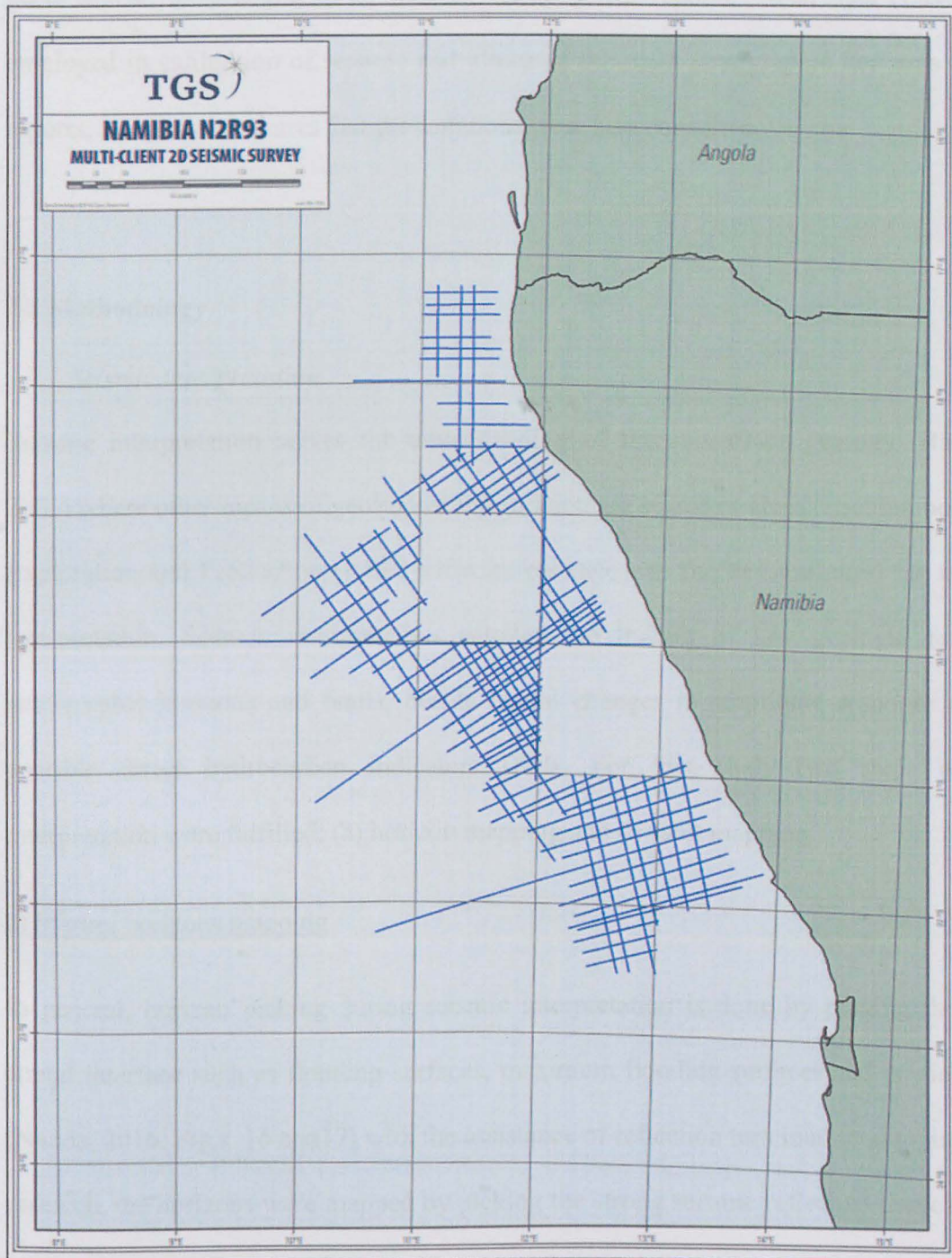


Figure 15. N2R93 survey lines, Northern Walvis Basin, offshore Namibia (TGS, 2011).

3.1.2 Well data

Apart from the seismic data, well data (reports and logs) for 1911/10-1 and 1911/15-1 wells in the Dolphin Graben were used. The well reports utilized comprise well completion, geochemical, biostratigraphy as well as petrophysical reports. Well data (Las files) was employed in calibration of seismic and allocated the main stratigraphic horizons. Published reports, company brochures and presentations were also consulted.

3.2 Methodology

3.2.1 Seismic interpretation

Seismic interpretation serves the understanding of the subsurface geology (Bacon et.al., 2003) where other means of geological information are scarce or absent. Schlumberger Petrel Exploration and Production (E&P) software package was the key tool used for the seismic interpretation. Seismic interpretation entailed the tracing of key geologic features i.e. stratigraphic horizons and faults, beside lateral changes in amplitude response serving as possible direct hydrocarbon indicators DHIs. For this study two steps of seismic interpretation were fulfilled; (a) horizon mapping and (b) fault mapping.

a) Marker horizons mapping

In general, horizon picking during seismic interpretation is done by picking the common stratal interface such as flooding surfaces, maximum flooding surfaces and erosion surfaces (Nanda, 2016, Fig.s. 16 and 17) with the assistance of reflection termination mapping. For this research, the horizons were mapped by picking the strong seismic reflectors that can serve as marker horizons and ideally can be assigned to stratigraphic ages based on well ties. Complementary, horizon mapping was also grounded on the more generally accepted understanding of the geologic events of the South Atlantic passive margin, specifically the

Namibian margin (see sections 2.1, 2.2 and 2.3 of the literature review). In addition, the well reports for the two wells (1911/15-1 and 1911/10-1) in the Dolphin Graben were also reviewed before the mapping of stratigraphic horizons.

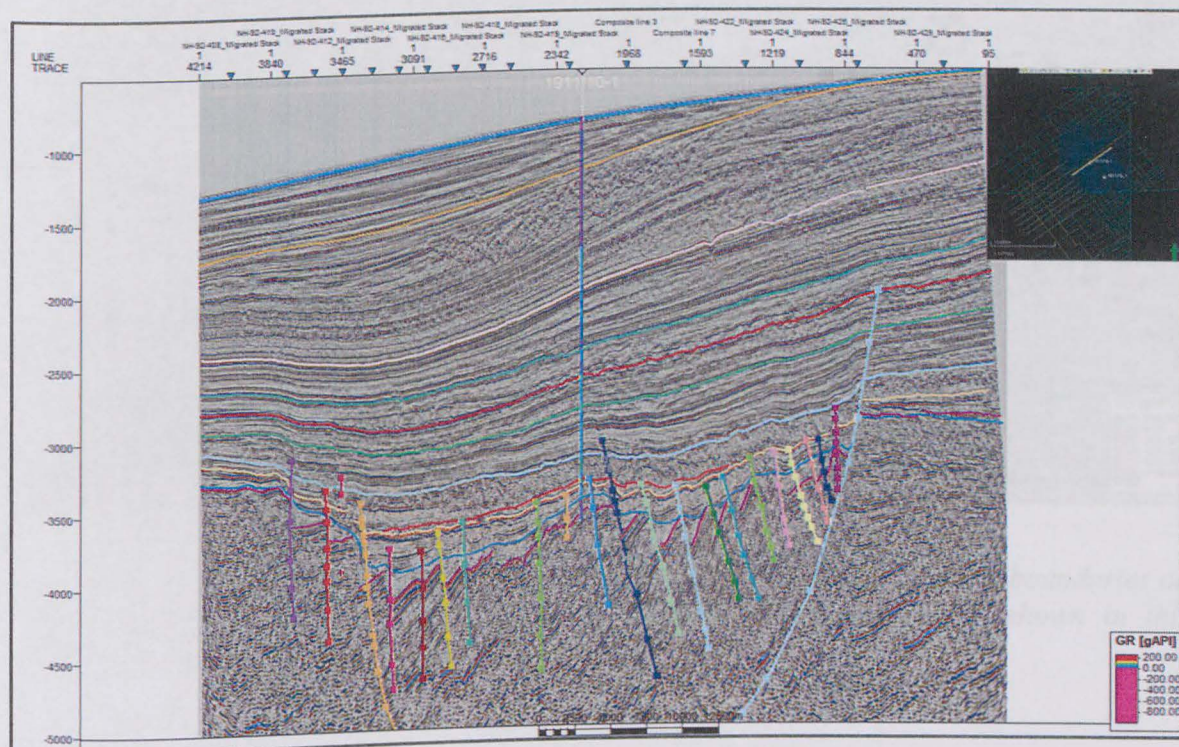


Figure 16. Gamma ray log for 1911/10-1 used to identify sequence boundaries on NH-92-230 seismic line.

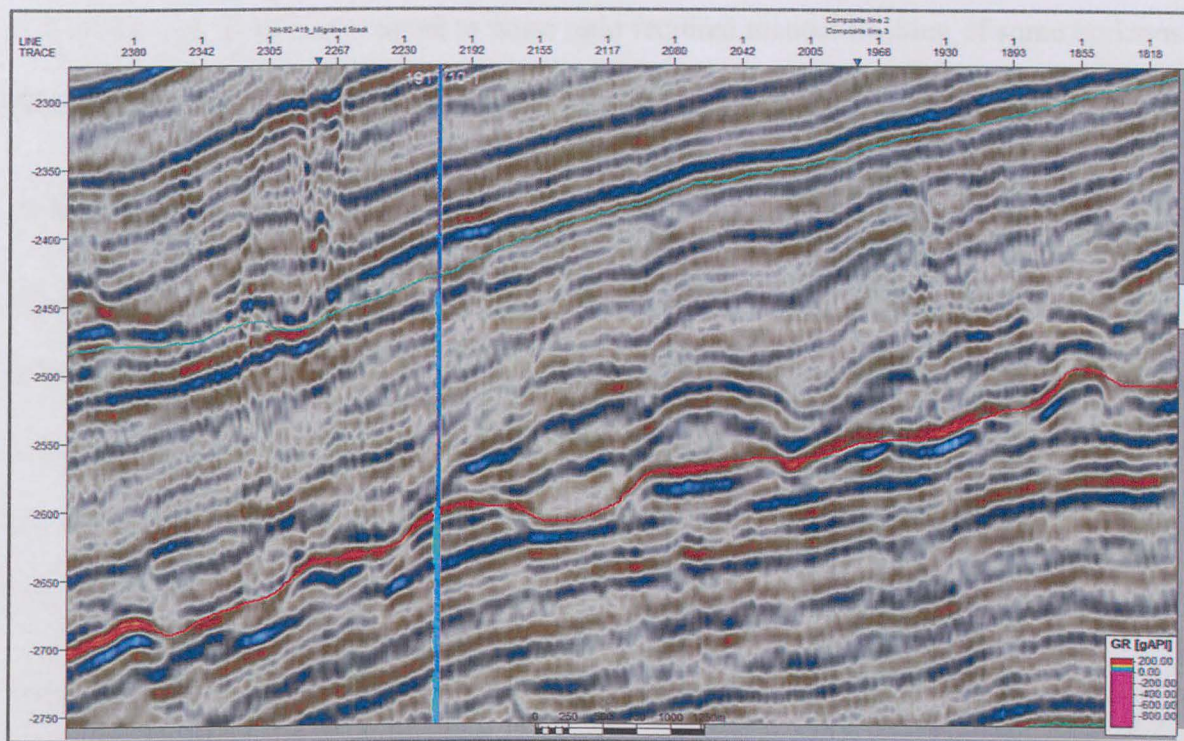


Figure 17. Zoom-in of Gamma ray log for 1911/10-1 used to identify sequence boundaries on NH-92-230 seismic line. Identified marker horizons/sequence boundaries shown in this section are top Paleocene (green) and Base Tertiary (red).

Horizons mapping followed the methodology as per American Standard of Interpretation (Bacon et al., 2003; Brown, 2011), which has been also used by Mhalalela (2018) for the Orange Basin. Horizon picking also followed the interpretation methodology recommended by Bacon et. al. (2003). The stratal surfaces picked are Seabed, and Pliocene, Eocene, Paleocene, Base Tertiary, Campanian, Santonian, Cenomanian, Albian, Aptian/Albian UC (Base Drift) and Barremian/Aptian. Well reports reveal that all the chosen stratal surfaces are erosional surfaces/unconformities or their correlative conformities.

The upper surfaces (Seabed, Pliocene, Eocene, Paleocene, Base Tertiary,) were interpreted using the seeded 2D auto-tracking and partial manual interpretation as they are characterized by high amplitude and continuity. All deeper stratigraphic surfaces were tracked manually due to limited continuity and/or strong amplitude variations. Continuity is limited in rift strata

due to faulting. Also, a low signal to noise ratio required manual tracking of some horizons. After horizon tracking, surface maps were created.

b) Fault mapping

Faults are shear fractures alongside which shear offset is detectable. Faults are vital in different geological aspects (Davis et al. 2011). In petroleum geology, faults can be a hydrocarbon conduit or a sealing faults (Bacon et.al., 2003). Faults' attributes include displacement and length, orientation (dip/azimuth) and curvature (Kolyukhin & Torabi, 2012).

Faults mapped in this project were recognized in seismic lines at places where seismic reflectors terminate. They were also identified by analyzing displacements of the seismic reflector across the fault plane (Bacon et al., 2003). In the study by Mhlalela (2018) the same technique was successfully used. The study area for this project is an extensional environment, and hence steep normal faults were most common. Herein the definition of normal faults follows that of Davis at al. (2011) who strictly define them as faults with hanging wall thrown downwards.

3.2.2 Structural evolution

For this research, reconstructing the structural evolution entailed the usage of the tracked seismic horizons and faults to determine the fault throws (displacements); identify growth strata, and deduce phases of fault activity (structural kinematics). Displacement measurements were executed by measuring the throws of representative randomly selected faults at different stratigraphic levels in 11 seismic cross lines.

The resulting measurement are listed in tables 3 to 13 in the appendices section. A structural kinematic study was carried out on line (NH-92-230 and on a composite line through well 1911/10-1 and 1911/15-1. On the NH-92-230 seismic line, the kinematic of stratal intervals (growth strata, pre-kinematic and post-kinematic strata) in relation to the fault activity was identified. Structural evolution of the Dolphin Graben is discussed in the context of the regional tectonic events at the Namibian margin and more local events.

3.2.3 Burial history and maturity

The burial history of a basin controls the thermal history of sediments contained in it. Hydrocarbon generation and migration directly depend on the temperature history in oil-prone carbonaceous sediments where peak temperature and their duration play a critical role (Miall, 1984).

Even though there are two proven source rock intervals (Aptian-Albian and Cenomanian-Turonian) in all four basins offshore the Namibian margin none of the two wells in the Dolphin Graben penetrated the Aptian-Albian source rocks. These two wells are located on local structural highs on which the Aptian-Albian was either not deposited, or is strongly condensed and was thus not recognized. The Cenomanian Turonian source rock was penetrated, but proved to be immature according to the well reports.

Therefore, the questions of the presence of the deeper Aptian-Albian source rocks in the graben, as well its effectiveness, and possibly timing of HC generation and accumulation arise. To address these questions, three 1D burial and thermal history models have been created. Two models for the actual well sites (1911/15-1 and 1911/10-1) within the graben, followed by a pseudo well (referred as “New Well”) located adjacent to the structural high of well 1911/15-1. At this pseudo well location (Fig. 18) the seismic section indicates clearly the

presence of the Aptian-Albian interval; hence it was included in the burial and thermal modelling.

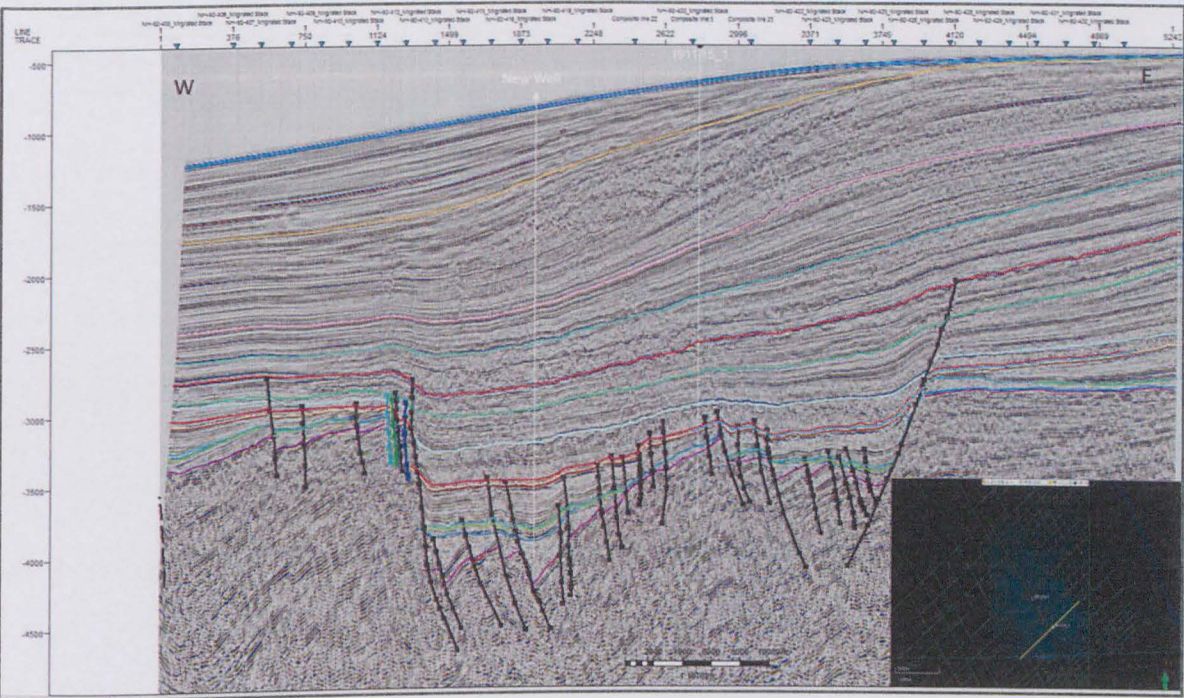


Figure 18. Seismic line NH-92-214 showing the “New Well” location

Input and calibration data

Information on lithologies with their depths and ages were extracted from the final well reports for both 1911 wells. Paleo- water depth and depositional breaks linked to phases of non-deposition / sediment bypass were extracted from the biostratigraphic well report for well 1911/10-1 (see Appendix 2); the seismic interpretation did not indicate any substantial phases of erosion.

The above stratigraphic information was used as input to create burial history models in PetroMod. The resulting burial history curves enabled the recognition of phases of burial and uplift. The burial history was thereafter converted into a thermal history by using vitrinite

reflectance and Horner corrected bottom hole temperatures for each well for calibration. For wells 1911/15-1 and 1911-10-1 those values were available from the respective well reports. For the pseudo well "New Well", the thermal calibration of the nearby well 1911/15-1 was used for the corresponding depths.

Geochemical source rock parameters (TOC, HI, kinetic model) for the Cenomanian-Turonian source rock were taken from the respective well reports and industry presentations. For the presumed Aptian-Albian source rock in the pseudo well the parameters of the Wingat-1 well, located in the southern Walvis basin, were used as the wells in the Dolphin graben did not reveal this source rocks.

For all models the PetroMod integrated McKenzie passive margin heat flow evolution model, and the Wrygala (1989) model for paleo water -sediment interface temperatures were used.

The thermal history allowed conclusion of the timing and degree of source rock maturity, i.e. the timing when the source rock intervals reach or pass through thermal windows of hydrocarbon generation.

CHAPTER 4 - RESULTS AND ANALYSIS

According to Nanda (2016), a pre-requisite for 2D seismic data structural analysis requires first an analysis of seismic horizons involving the following steps: a) identification and correlation of (marker) horizons, b) contouring horizons with faults (fault mapping); and c) creation of different maps types to be able to describe geologic details. The latter are structural maps like time structure maps, depth/structure maps, relief maps as well as isochron and isopach maps. The herein presented results follow the above order of workflow.

4.1 Marker horizons

The mapped horizons are identified as unconformities and their correlative conformities. The horizon served as reference surfaces to execute a structural evolution study for the Dolphin Graben. The Figure 19 displays a composite section with all marker horizons used for the subsequent structural evolution study.

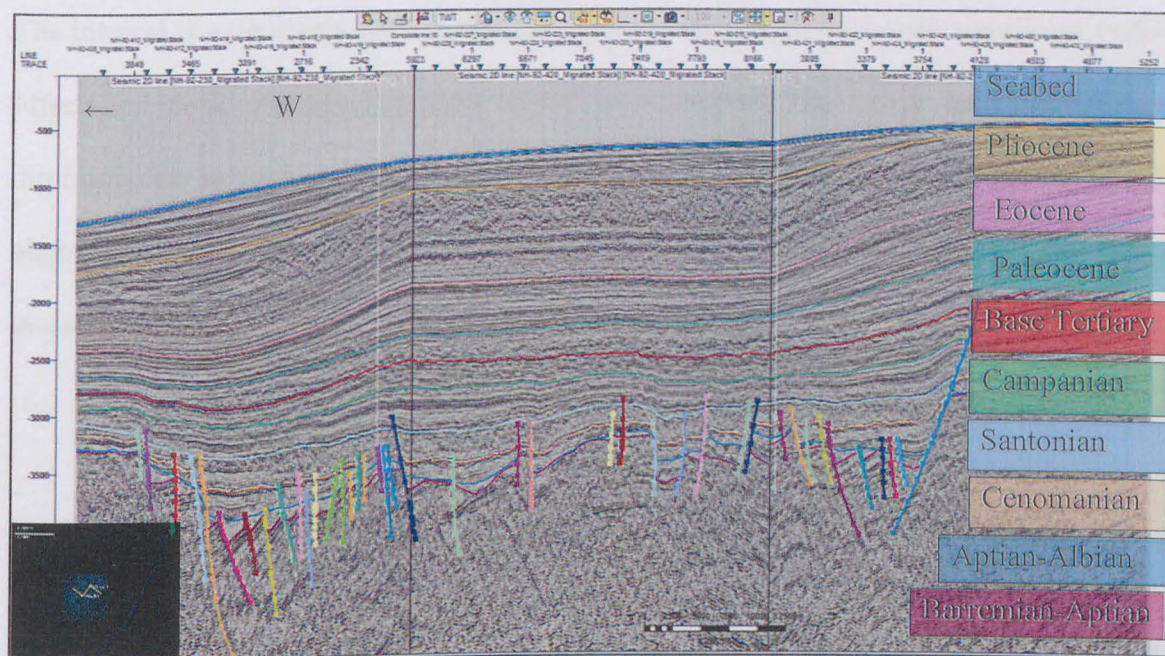


Figure 19. Seismic composite line through the 1911/10-1 and 1911/15-1 wells depicting mapped marker horizons in the study area.

4.1.1 Barremian to top SDRs

The lower boundary of this interval is poorly defined, while the top forms a reflective marker, mostly but not always, as a trough/negative amplitude. This interval is believed to be of (?) Barremian-Aptian in age, and occurs between of 1500ms TWT on the horsts/ rift shoulders and over 3000ms in the graben. Internal reflections are of high amplitude and largely parallel and believed to be part of the Seaward Dipping Reflectors (SDRs) sequence.

4.1.2 Top SDRs to Intra Aptian-Albian Unconformity

The Intra Aptian-Albian Unconformity is depicted by a positive reflection between 3300-3900ms TWT. The lower boundary of the interval is the top of the SDR sequence mostly represented by medium to high amplitude reflections. The boundary is unconformable, but erosional truncation of the SDRs was not observed.

The interval is extensively faulted, forming small-scale half grabens with significant vertical offsets and block rotations. Divergent reflections accompanied by a clear decrease in tectonic dip from older to younger reflections prove presence of growth (Fig. 20). The growth leads to almost doubling of strata thickness towards the footwalls of the normal faults.

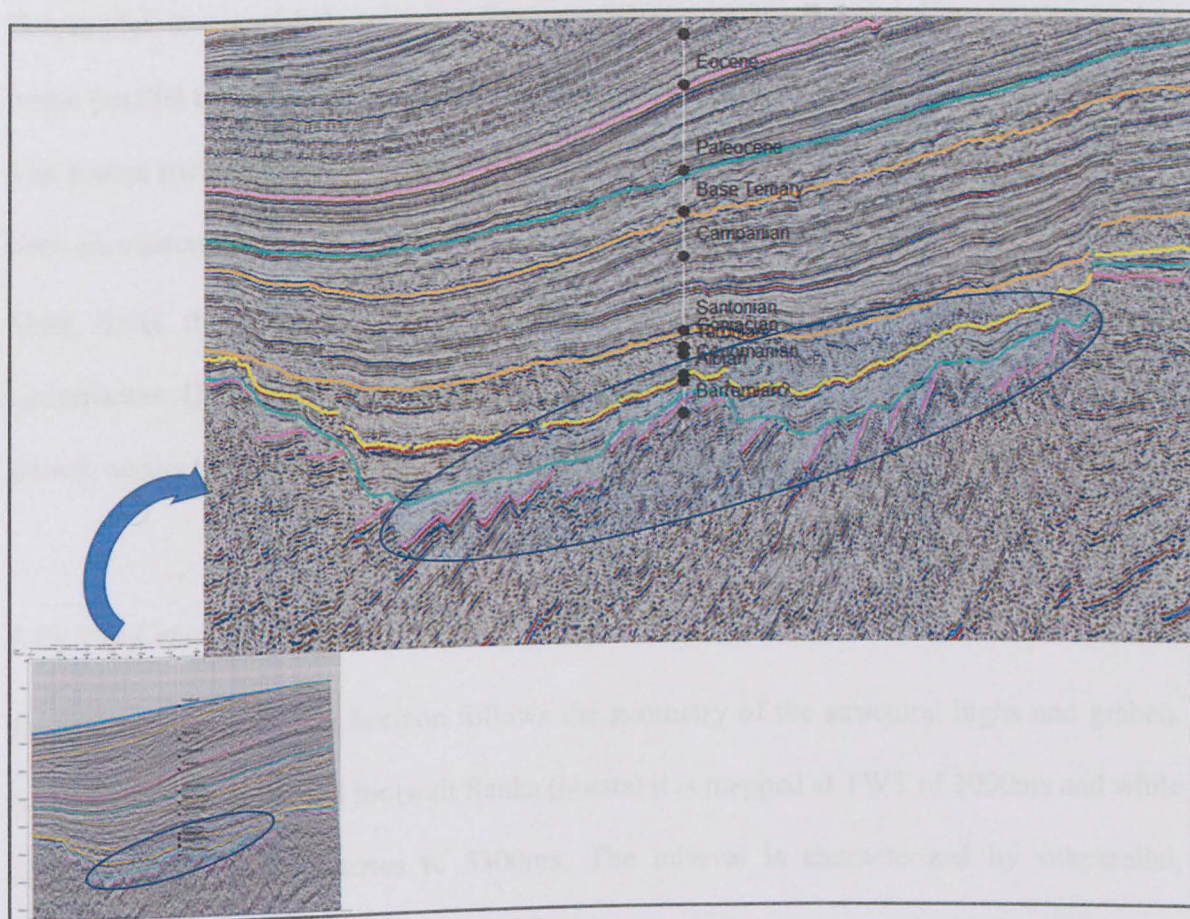


Figure 20. Seismic line NH-92-230 zoomed in to show growth strata character.

The growth strata in the half-grabens are believed to contain an older source rock deposited in anoxic lacustrine pods.

4.1.3 Intra Aptian-Albian Unconformity to top Cenomanian

The top Cenomanian horizon was picked between 3300ms and 3600ms TWT, a positive high amplitude peak. The lower boundary is an unconformity surface that is tentatively placed around the Aptian/Albian boundary therefore termed the Intra-Aptian-Albian unconformity. Subparallel, low amplitude seismic reflections characterize this interval. Conspicuous are two bright parallel high amplitude horizons that are interpreted as the Aptian/Albian source rocks. The source rocks are absent on the drilled structural highs, instead carbonate built ups have been encountered there.

Most faults that originate from the deeper extensional levels propagate through the Cenomanian. Horizons show strong amounts of flexure (dragging) across faults. Evidence for growth occurs towards the graben margins, most obvious at the eastern margin (Fig. 20).

4.1.4 Top Cenomanian to top Santonian

The top Santonian marker horizon follows the geometry of the structural highs and graben. On the structural highs and footwall flanks (horsts) it is mapped at TWT of 3000ms and while in the graben TWT increases to 3300ms. The interval is characterized by subparallel, discontinuous low amplitude seismic reflectors.

In the lower portion of this interval occurs a bright amplitude horizon that overlays the top Cenomanian horizon. This bright amplitude horizon is interpreted as Cenomanian-Turonian source rock. This agrees with a positive gamma ray peak identified in the 1911/15-1 and 1911/10-1 wells that ties well to this high amplitude horizon. Above this horizon occur high amplitude bodies interpreted as sand bodies (Fig. 22). Faulting becomes significant compared to the younger intervals.

4.1.5 Top Santonian to top Campanian

The top Campanian marker horizon forms a positive amplitude reflection, which was picked at TWT of 2800ms at shallower areas and reached 3200ms in deeper parts of the basin. The top Santonian to top Campanian interval includes bright amplitude bodies which are interpreted as sands. Only major faults and very few minor faults have intersected or passed the Campanian interval.

4.1.6 Top Campanian to Base Tertiary

The base Tertiary is a regional marker horizon that coincides with the end of Cretaceous Sequence. It is a well-known regional unconformity on the Namibia passive margin. The Base Tertiary was picked between TWT of 2500- 2800ms (Fig.s 19 and 21), it gently incises in the underlying strata on the structural highs, where erosive truncation of the uppermost Cretaceous strata can be observed. The interval from the Campanian to the end of the Cretaceous (Base Tertiary) is signified by subparallel, continuous to discontinuous high amplitude reflections. In some seismic lines, several faults terminate at the Base Tertiary, especially the major faults bounding the Dolphin Graben (Fig. 22). Within this interval (top Campanian to Base Tertiary), no obvious growth strata have been recognized. Hence, fault reactivation just prior to deposition on the Base Tertiary unconformity is implied.

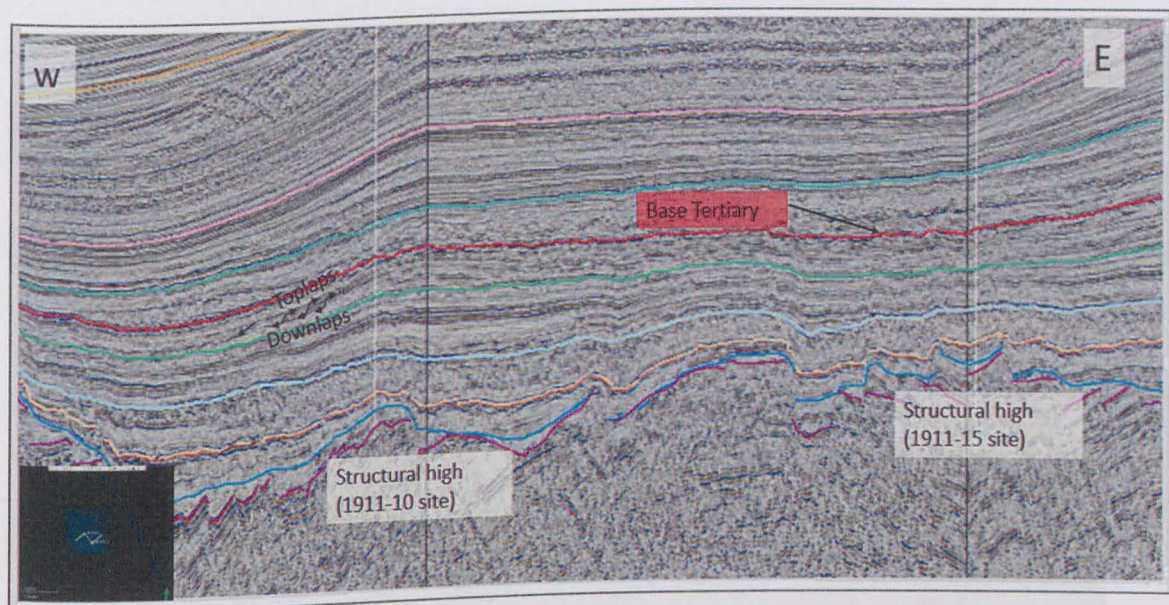


Figure 21. A composite of seismic line showing Base Tertiary horizon.

4.1.7 Base Tertiary to top Paleocene

The top Paleocene marker horizon reveals a slightly sigmoidal character at some places. It is signified by a peak reflection with a positive amplitude, picked in the time depth range of 2600-2800ms. The Paleocene peak is mostly continuous with some disruptions due to slumping (Figs. 20 and 22), especially above the graben area. The Paleocene interval includes continuous and non-continuous slightly sigmoid shallow clinoform reflections.

Contortions and mounded reflections occur in the lower portion of the interval. High amplitude facies are seen at base of this horizon at the boundary with the Cretaceous; these are interpreted to be upper Cretaceous/Paleocene sands. According to the well reports, these bright amplitude bodies were one of the targets for the wells 1911/15-1 and 1911/10-1. These sand body are believed to have porosity up to 24% according to well reports. The lower Paleocene interval is dissected by few normal faults.

4.1.8 Top Paleocene to top Eocene

Eocene's negative peak was picked at time depth of 2000ms landward (east) of study area and at 2400ms basinward (west). Distinctive features of the Eocene interval are the sub-parallel, continuous high amplitude, slightly sigmoidal prograding clinoform reflections (Fig. 22).

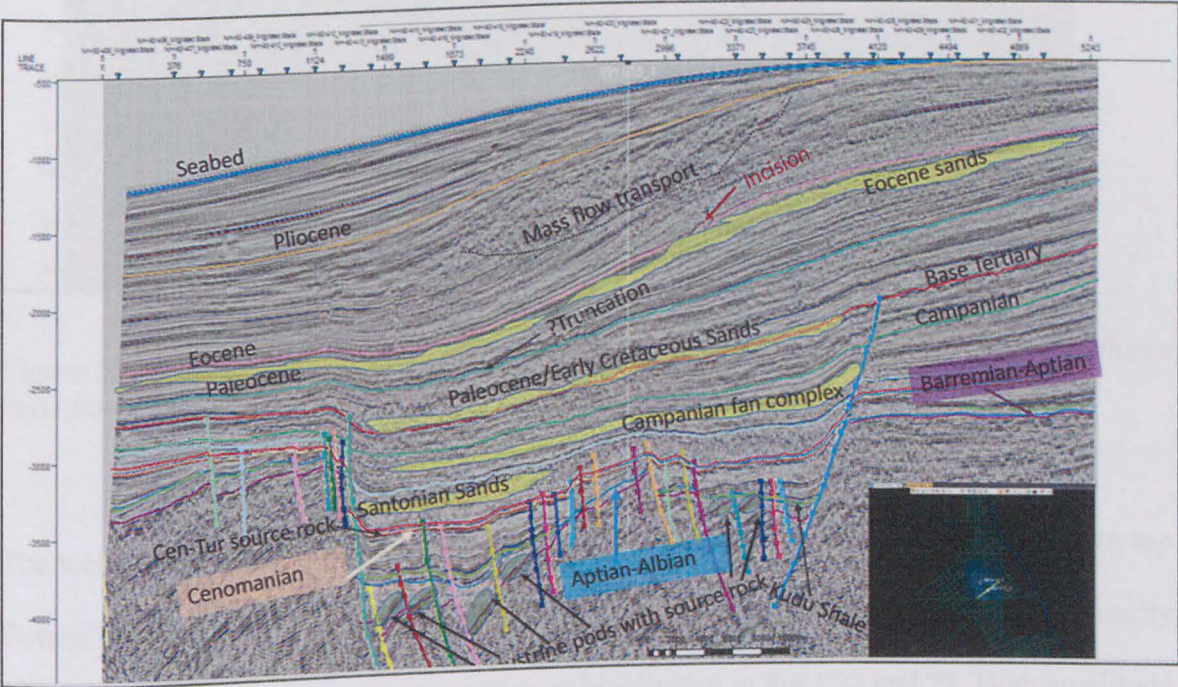


Figure 22. Seismic line NH-92-214 through Well 1911/15-1 depicting different petroleum system elements. The red arrow highlights how the Pliocene's mass flow complex affects the Eocene horizon.

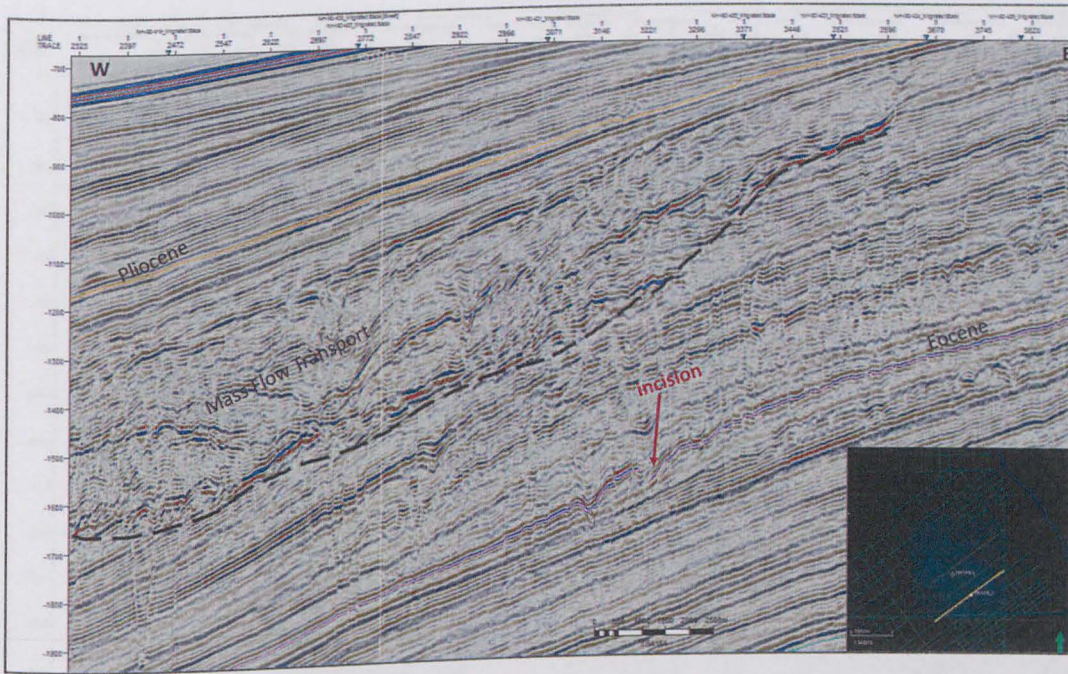


Figure 23. Zoom in line NH-92-214 to highlight the top Eocene deformation by the Pliocene mass flow complex.

The westwards progradation coincides with a westward thinning of the top Paleocene to top Eocene interval. The top Eocene reflection (trough) is still affected by the previously described Pliocene mass transport complex as highlighted in Figs 22 and 23. High amplitude bodies observed in the uppermost part of the Eocene interval represent reservoir sands, verified in well 1911/15-1.

4.1.9 Top Eocene to top Pliocene

The top Pliocene is represented by a well-defined continuous reflection and could therefore be largely auto-tracked. The Pliocene interval is characterized by subparallel, continuous to discontinuous reflections. The reflections within the interval form a prograding sigmoidal clinoform across the seismic section (Fig. 24). At some places on the slope, volumes of contorted to chaotic reflections occur, interpreted as mass flows (Fig. 24). The Pliocene horizon is denoted by a peak reflection with a positive amplitude.

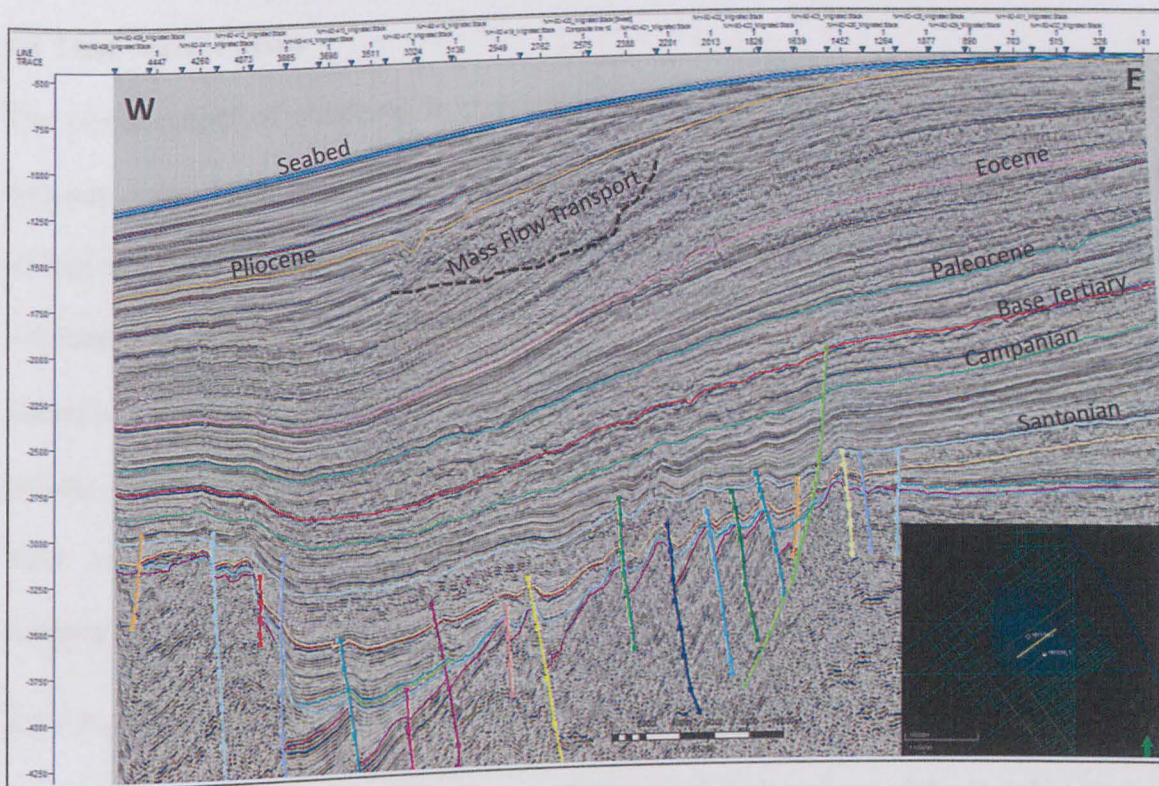


Figure 24. Seismic line NH-92-223 depicting mass flow transport within the Pliocene interval.

4.1.10 Top Pliocene to Seabed

In comparison to other mapped marker horizons (Fig. 20), seabed surface was the easiest to map. The surface is signposted by a zero-phase peak reflection with a bright amplitude, indicating normal SEG polarity. Due its continuity this surface was interpreted using 2D auto-tracking.

The seabed surface was picked at time depths of around 700-1000ms at some places, reaching maximum time depths of around 1300ms at deeper parts, (basinward/westward). The interval from the seabed to the top of the Pliocene is built by westward dipping sub-parallel chiroform reflections of high continuity, displaying an overall aggradational pattern.

4.2 Time surface maps

The prime output of structural interpretation are horizons contoured in time to produce structure maps. These outline the trends and geometries of the subsurface horizons. The time surface maps were created using the mapped marker horizons as inputs in Petrel 2015 software. The seismic resolution for the study area is sufficiently good with a good S/N ratio. Therefore, most surfaces (Seabed-Cenomanian) did not undergo the surface smoothing process, except the lower two surfaces (SDRs and Intra Aptian-Albian Unconformity). The latter two are extensively faulted unconformity surfaces explaining their structural complexity.

4.2.1 Top SDRs surface

The top SDRs surface defines best the morphology and fault pattern of the Dolphin Graben and neighboring structures, as fault density and fault throws are largest at this level (Fig. 25).

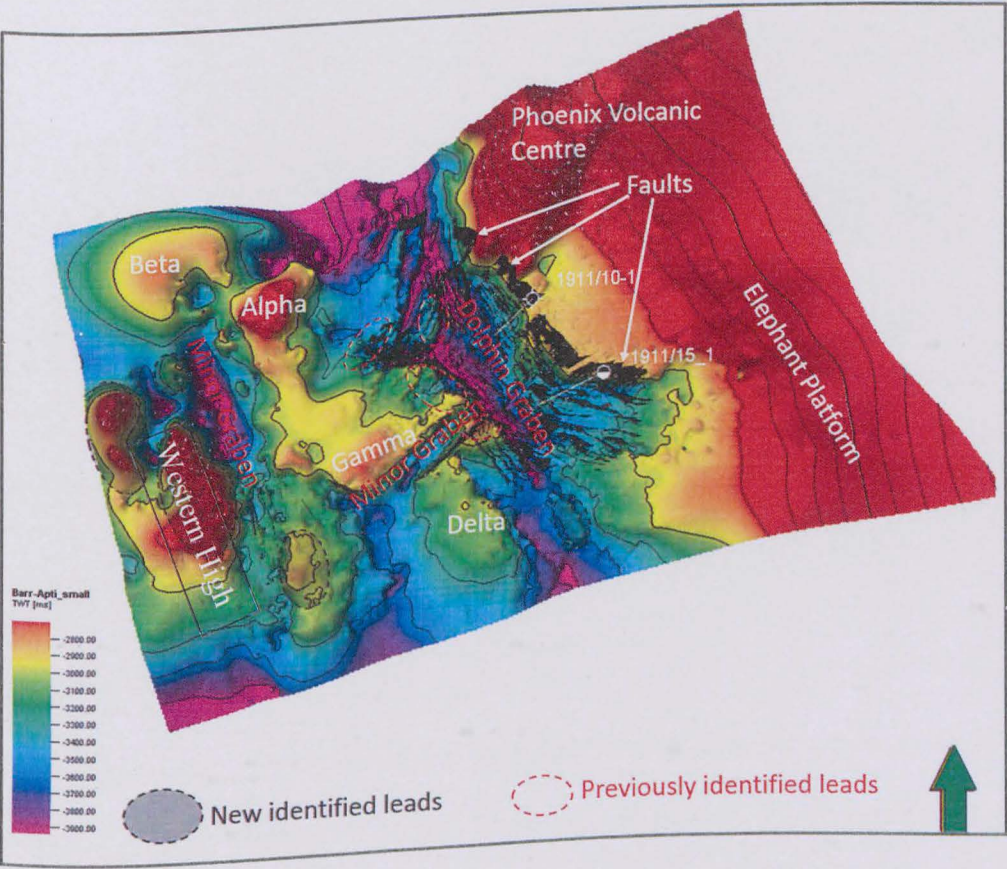


Figure 25. Top SDRs marker horizon surface in time domain.

4.2.2 Intra Aptian-Albian Unconformity

Even though the time surface map (Fig. 27) still illustrates the closures and structural highs to the west, as well as the Phoenix Volcanic Centre, the Intra Aptian-Albian Unconformity is extensively faulted by normal faults. Two minor grabens (one parallel and one perpendicular to the Dolphin Graben) are well recognized west of the Dolphin Graben (Fig. 26).

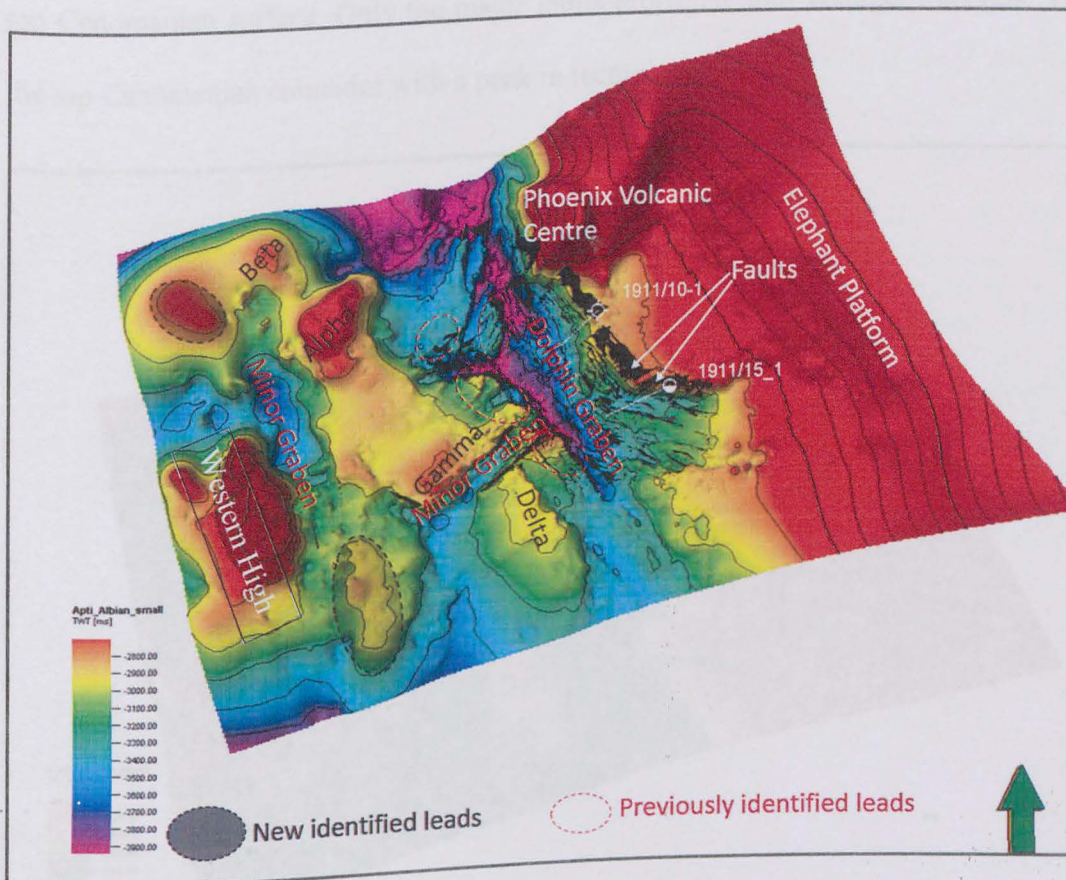


Figure 26. Intra Aptian- Albian Unconformity time domain structure map.

4.2.3 Cenomanian

The Cenomanian marker horizon's time surface discloses the same closures (Alpha, Beta, Gamma, Delta), Phoenix Volcanic Centre as the Santonian. West of the Dolphin Graben

western rift shoulder closures (Alpha, Beta, Gamma, Delta) a parallel minor graben can be recognized. On the rifts shoulder of this western graben an additional closure becomes apparent named herein as the “Western High” (Fig. 27). The time structure map also depicts that the Dolphin Graben deepens to the north towards the Namibe basin. The Cenomanian interval is penetrated by a much higher number of faults than the younger intervals. Most fault terminate within the upper Cenomanian, and the majority of them propagate beyond the top Cenomanian surface. Only the major faults propagate into younger intervals. Therefore, the top Cenomanian coincides with a peak in tectonic activity.

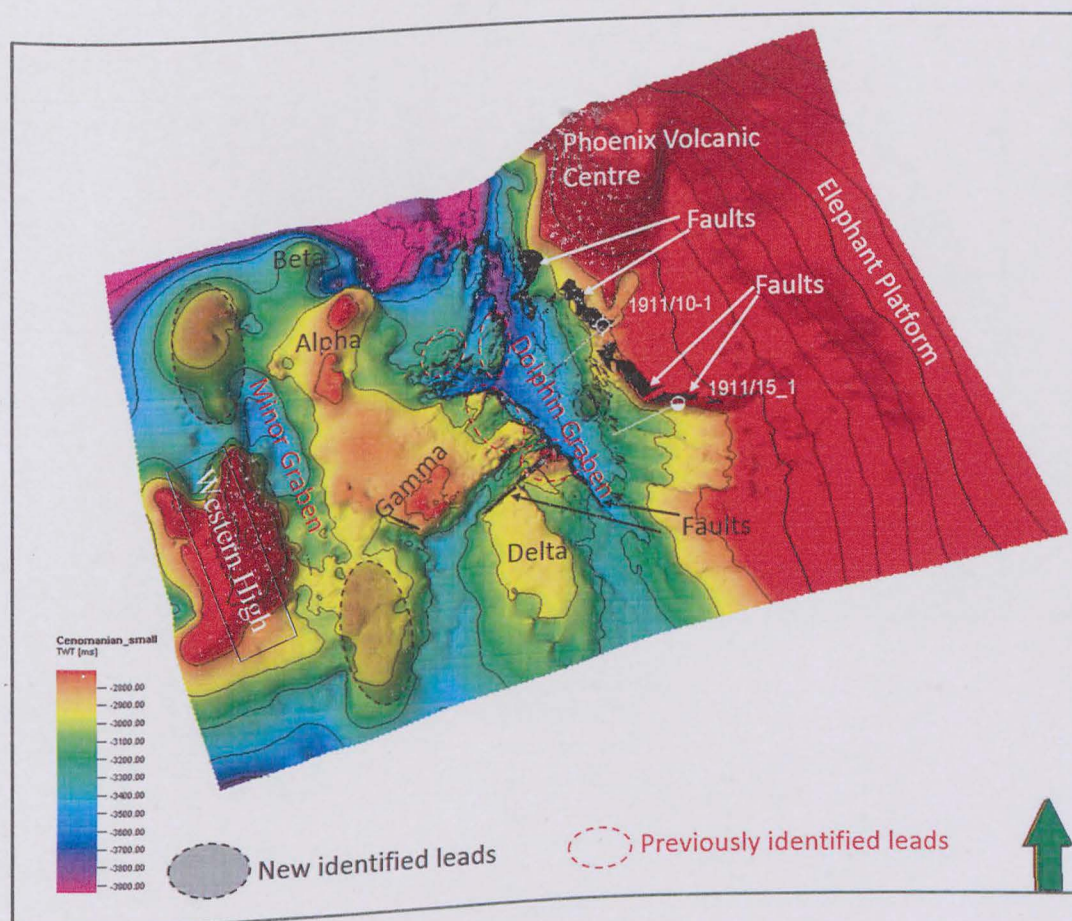


Figure 27. Cenomanian time domain structure map.

4.2.4 Campanian and Santonian

Both, the Campanian (Fig. 28) and Santonian (Fig. 29) surfaces show similar morphologies and reveal similar structural highs as at the Base Tertiary surface (four structural high leads and Phoenix Volcanic Centre). The morphology of the Dolphin Graben and the Phoenix Volcanic Centre is more pronounced and their boundaries better delineated by the contours. This trend increases from the Campanian to the Santonian. Both horizons are moderately faulted with the Santonian being more dissected compared to the Campanian.

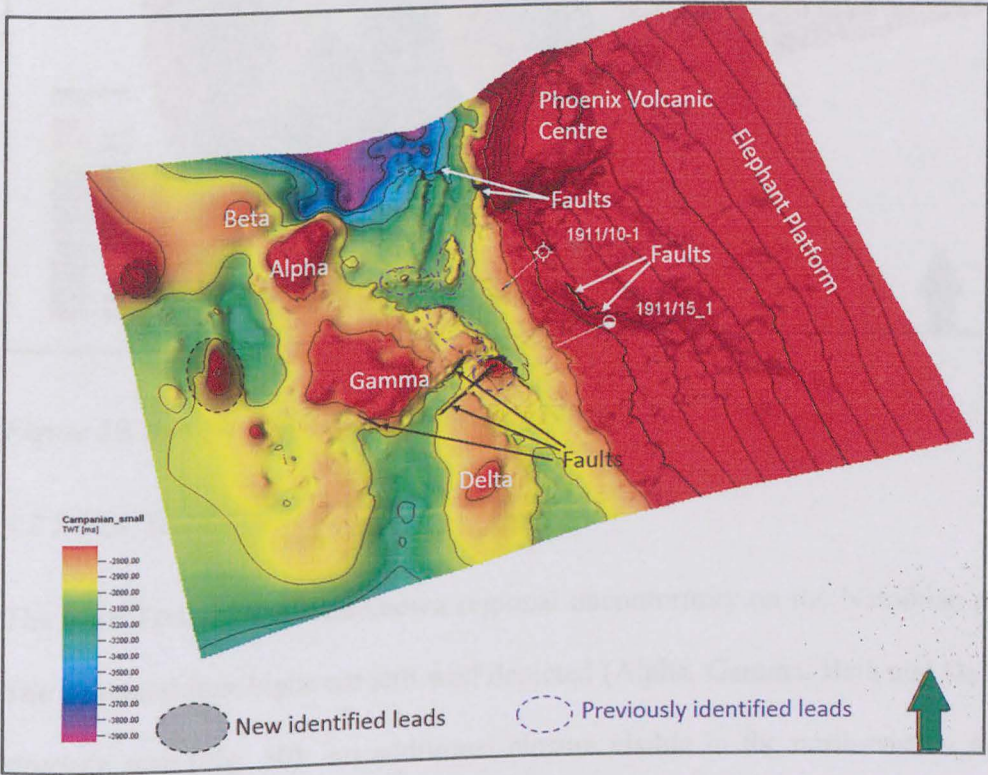


Figure 28. Campanian time domain structure map.

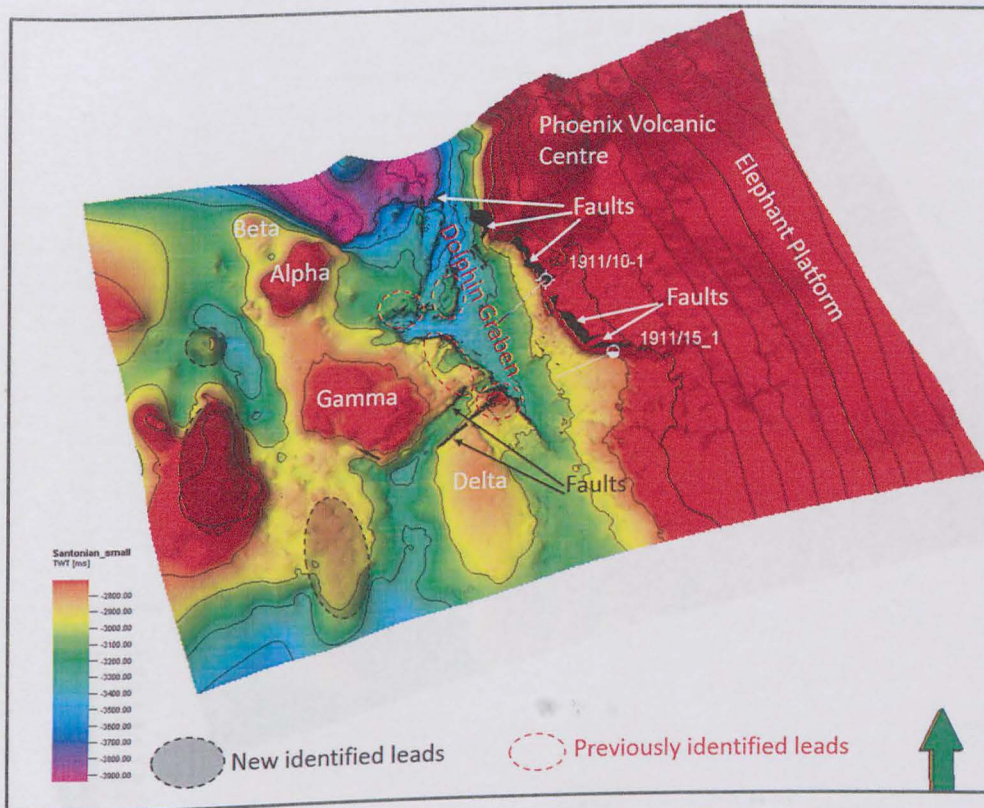


Figure 29. Santonian time domain structure map.

4.2.5 Base Tertiary

The Base Tertiary is a well-known regional unconformity on the Namibian passive margin. The structural four highs are still well depicted (Alpha, Gamma, Beta and Delta) on the time structure map (Fig. 30). An additional closure visible in the north-eastern domain, derives from the underlying Cenomanian/Turonian Phoenix volcanic Centre. Several faults dissecting deeper layers terminate at the base Tertiary marker horizon. Locally, some time contours parallel the main faults.

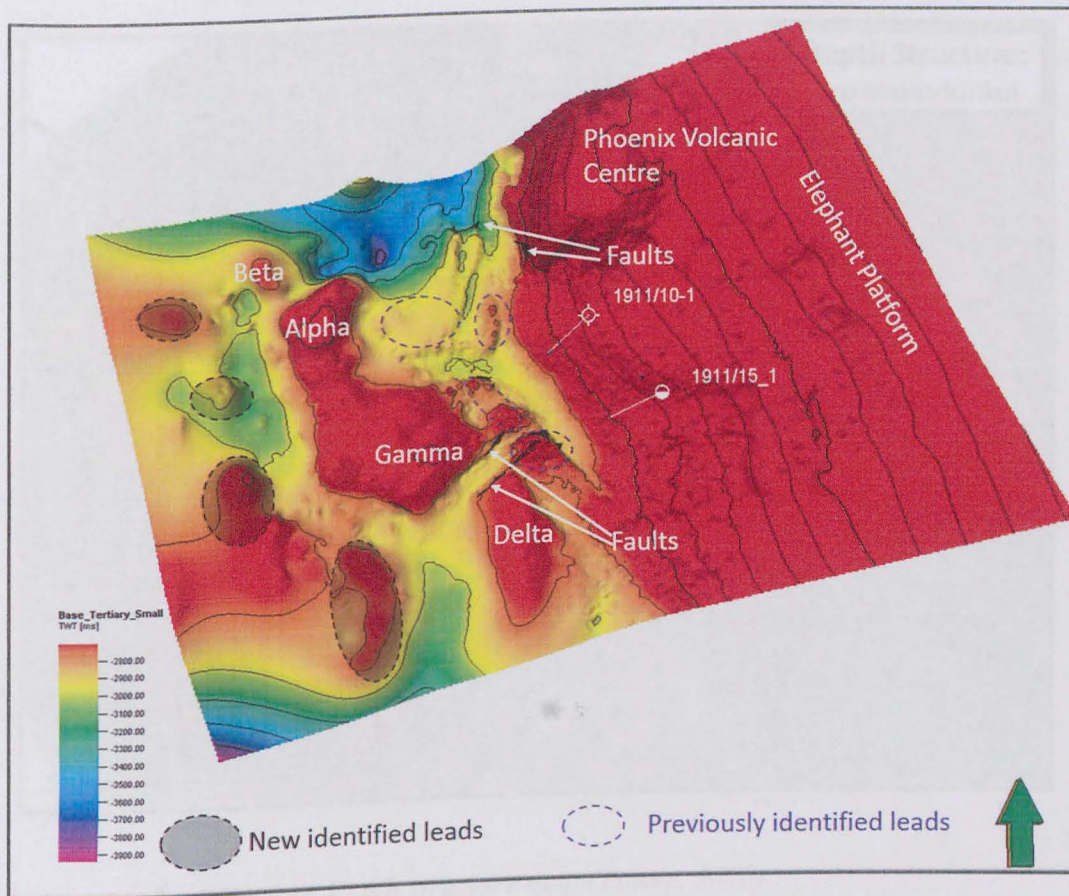


Figure 30. Base Tertiary marker horizon time domain structure map.

The Base Tertiary surface (Fig. 30) exhibits the approximately same morphology as the Tower (2020) Top Maastrichtian depth structure map (Fig. 31).

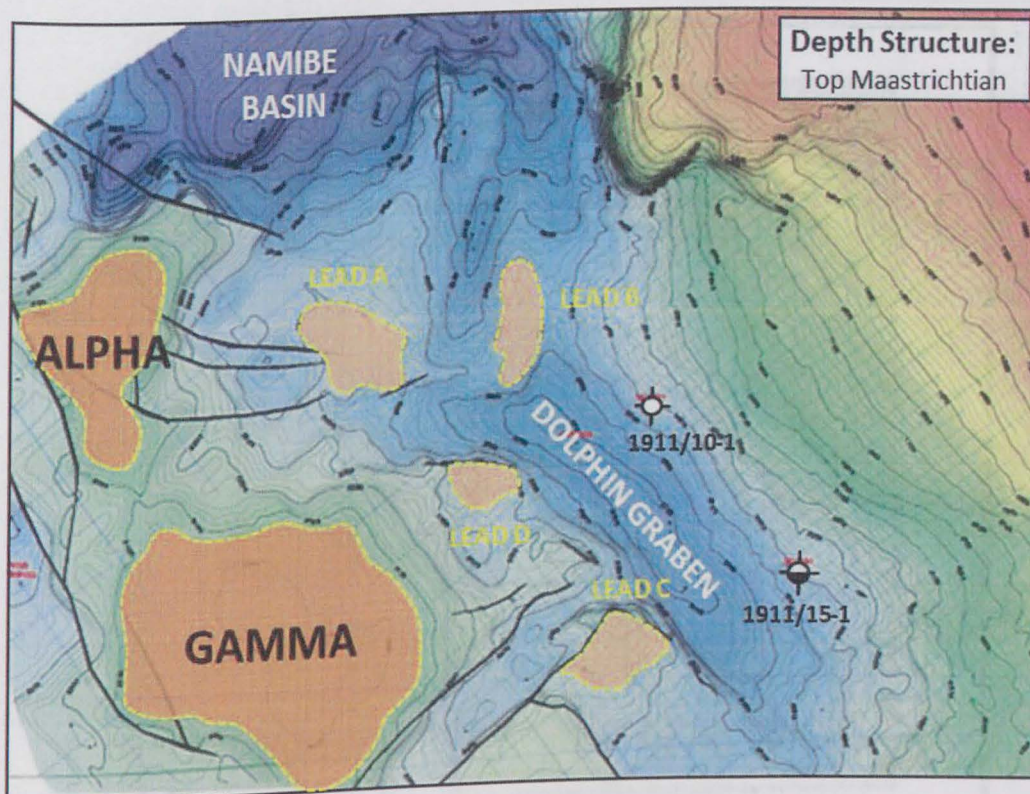


Figure 31. Base Tertiary Depth structure map (Tower, 2020)

4.2.6 Eocene and Paleocene

The Eocene and Paleocene horizons were delineated by high amplitude markers (troughs) on seismic lines. Four closures (Alpha, Beta, Gamma and Delta) occur along strike on the seismic lines. Those closures were identified by Arcadia (2011) and Tower Resources (2020) companies, which regard them as exploration prospects (Fig.32).

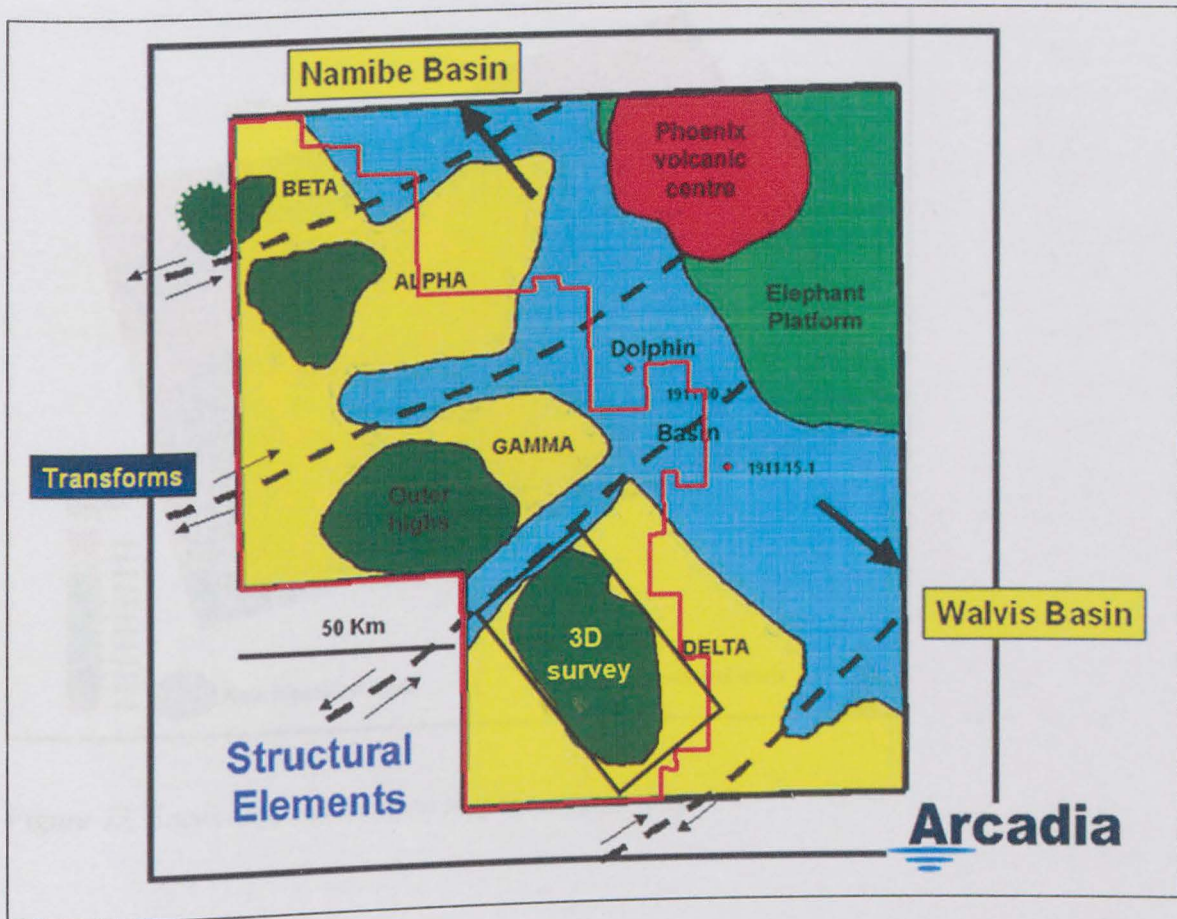


Figure 32. Identified structural elements within and in the vicinity of the Dolphin Graben (Arcadia, 2011).

These companies also identified other small closure in the graben as lead. Two additional (new) closures (large and minor closures) identified in this research are visible far west on the Dolphin Graben. The later can be new leads (Figs 33 and 34).

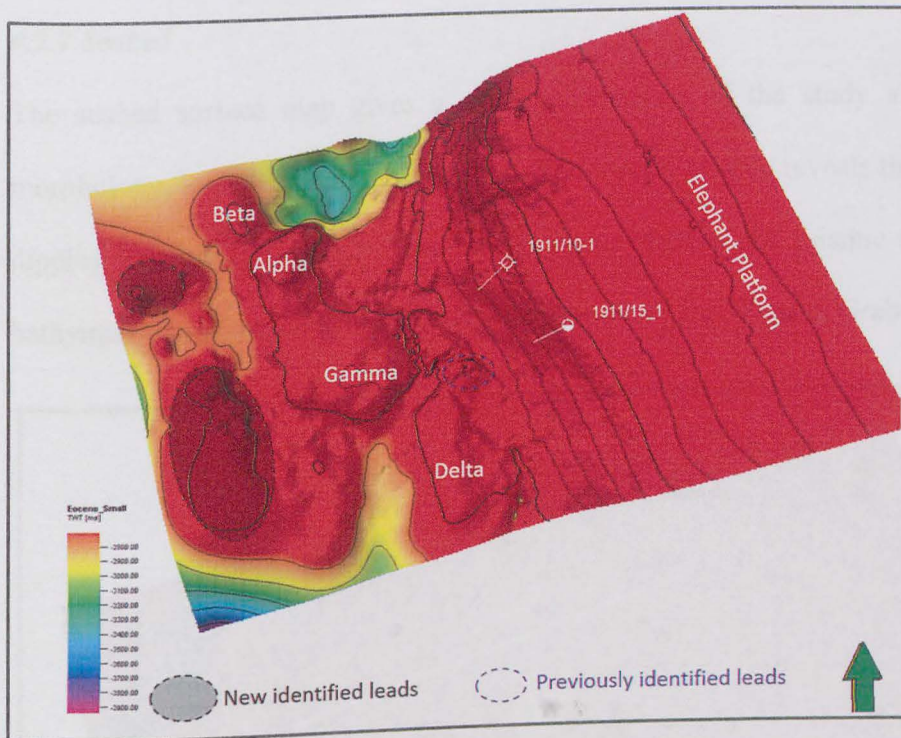


Figure 33. Eocene marker horizon surface map in time

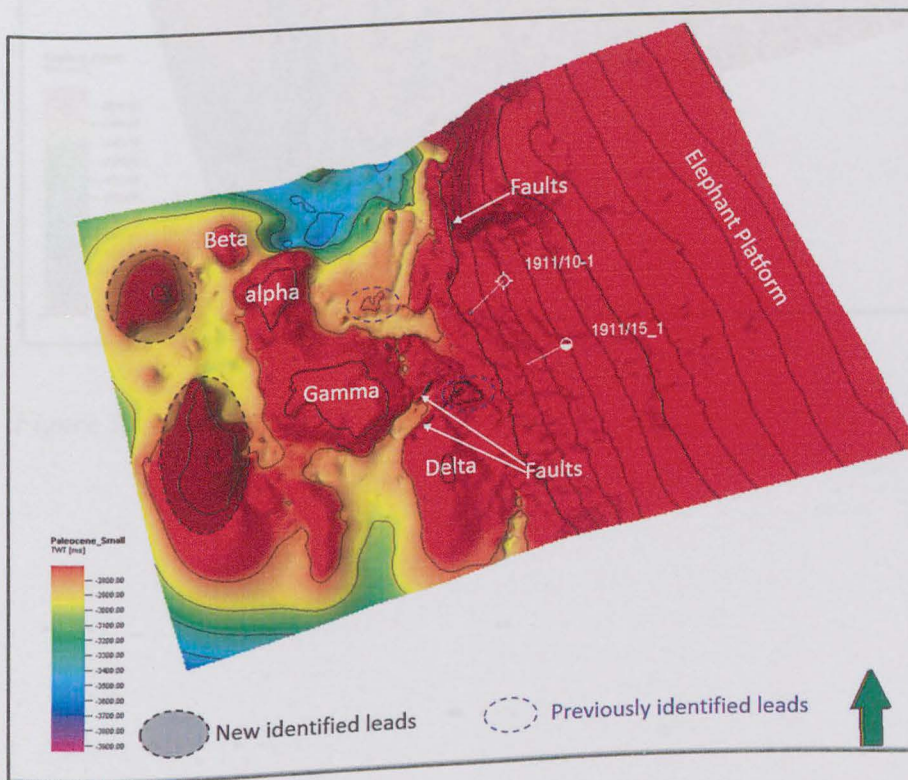


Figure 34. Palaeocene marker horizon surface in time.

4.2.7 Seabed

The seabed surface map gives a good presentation of the study area's bathymetry and morphology, both regionally and locally. The seabed surface reveals the seaward (westward) dipping of sediments (Fig. 35), which is also visible in the seismic (Fig. 37). The seabed bathymetry does not show the presence of the underlying Dolphin Graben.



Figure 35. Seabed in time.

4.3 Structural evolution analysis

4.3.1 Fault mapping

A total of 341 fault planes were mapped for this project (Fig. 36). The faults structural style compliments an extensional environment. As a rule of thumb, an extensional environment is characterized by a dominance of normal faults. Planar non-rotational, planar rotational as well as listric faults are the main types of normal faults (Jian, 2014).

The Dolphin Graben is characterized by planar-rotational faults as depicted by the westward rotations of the top SDRs surface. Younger growth strata bilevels much of the rotation giving the impression of minor block rotations at shallower surfaces. Geometry of planar rotational faults require a curvature of the faults at depth, usually in the form of a common listric detachment at the brittle ductile transition or a rheological weak lithology, such as shale or salt (Jian, 2014). Seismic resolution deteriorates rapidly beneath the top SDRs surface, and hence the continuation of the faults was not traced to depth.

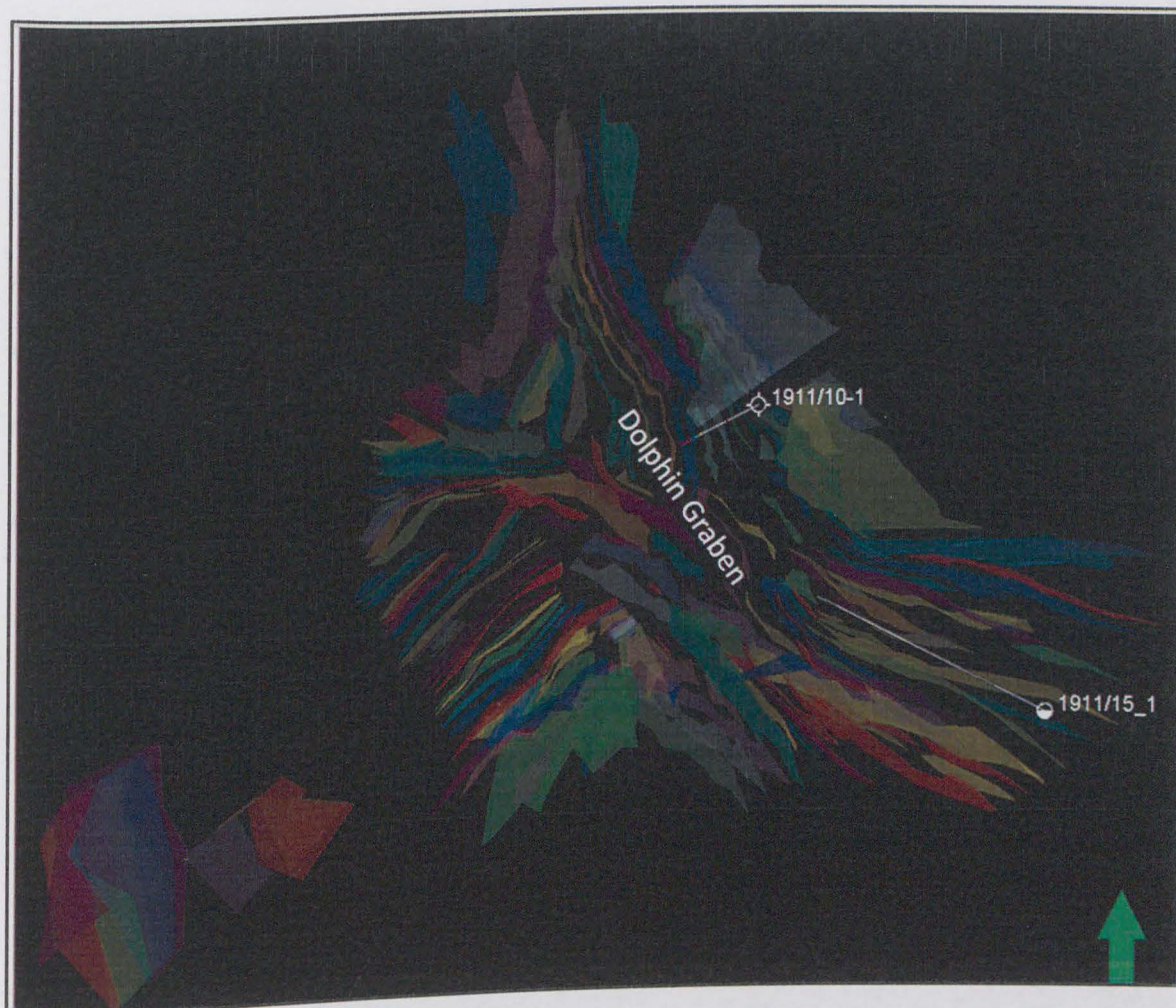


Figure 36. Mapped 341 normal fault planes displayed in Petrel 3D viewer.

Genetically, faults can be divided into synthetic and antithetic. Synthetic faults are the faults with displacements in accordance with the overall movement of the compartment in which they are inserted (Jian,2014). On the other hand, antithetic faults do not behave harmonically with the overall deformation.

In the Dolphin Graben, distinguishing between synthetic and antithetic faults is delicate as the common detachment is not imaged. The graben is bounded by two main conjugate faults dipping in opposite directions. The western main fault dips eastward together with all other

faults in the graben. The eastern boundary fault dips to the west. The westwards tilted blocks within the graben are synthetic to the western boundary fault.

The small rotational block immediately west of the eastern boundary fault is dipping to the east and has therefore rotated antithetical with the western boundary fault, but synthetical with the eastern one. A central structural high divide the graben into a western and eastern domain, each is compartmentalized by smaller half grabens (Fig. 37).

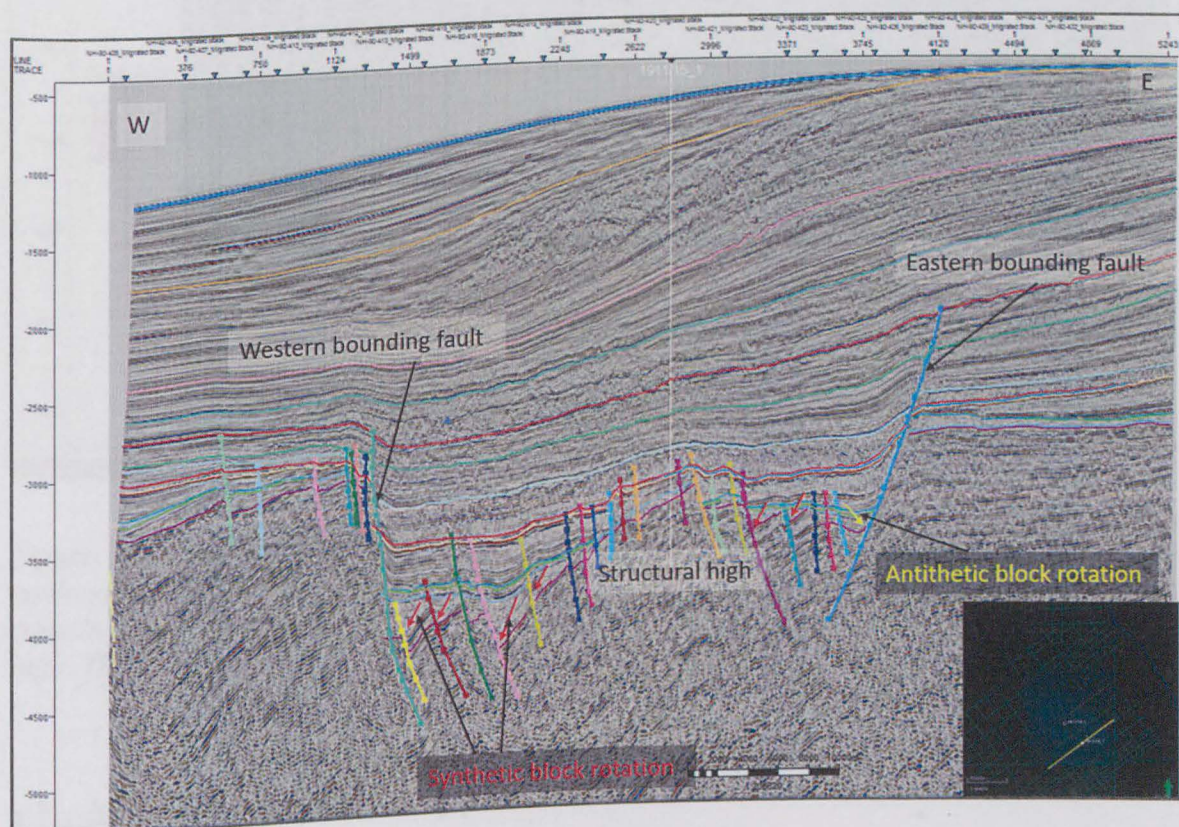


Figure 37. Seismic line NH-92-214 showing faults delineating the graben as well as the structural morphology of the Dolphin Graben.

All extensional faults dissect the older marker horizons - top SDRs (Barremian-Aptian), Intra Aptian-Albian unconformity and top Cenomanian. The main faults terminate at shallower levels, mostly within the Santonian, with few reaching the Paleocene (Fig. 39).

Younger faults in the post Eocene are not deeply rooted (Fig. 38), they are therefore interpreted to have formed by minor gravitational and compactional movements.

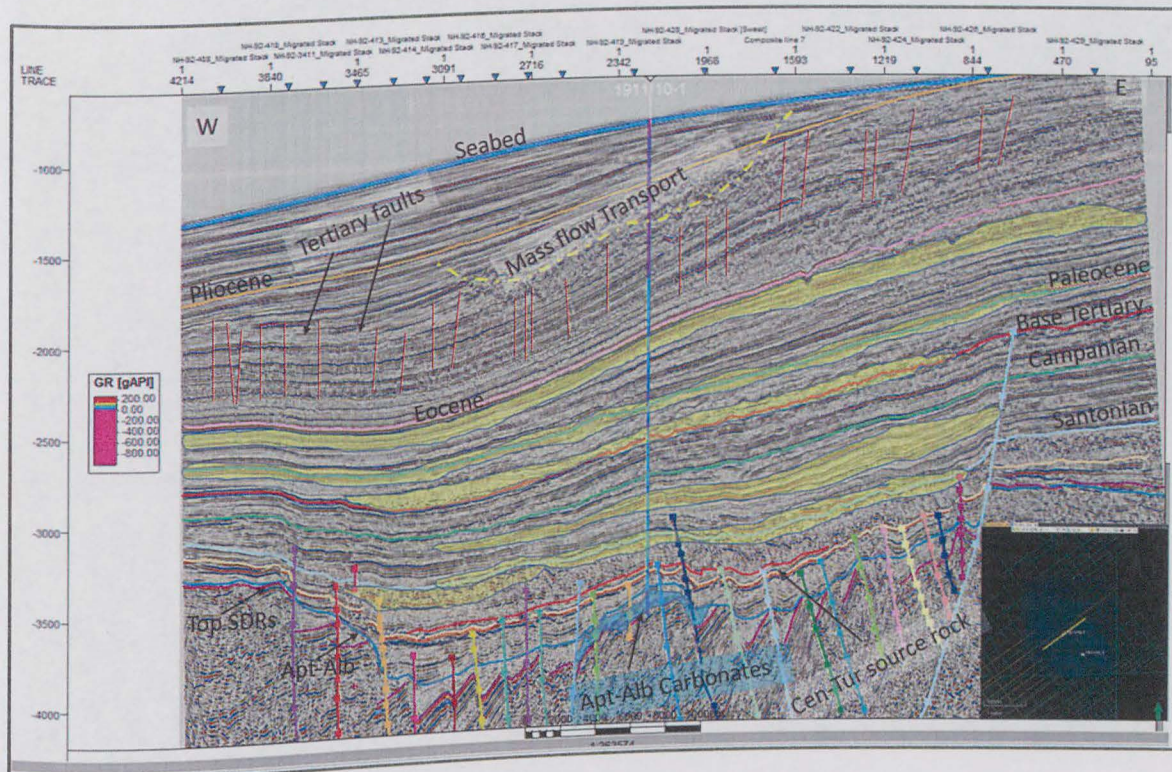


Figure 38. Seismic line NH-92-230 showing Tertiary and older faults, sandstone bodies (yellow) and carbonate reservoir (blue) located in the central structural high. The carbonates contain minor oil shows, which could have been charged by the normal faults flanking the high. This concept has been already considered by Tower Resources /Arcadia (2010).

4.3.2 Fault throws and fault activity phases

Faults throw measurements were carried out by measuring how much the hanging walls were thrown down from the footwalls at each marker horizon (Fig. 39). The fault throws were measured on every third seismic dip-line; on each line the main graben boundary faults as well a representative selection of intra graben faults was selected for measurements.

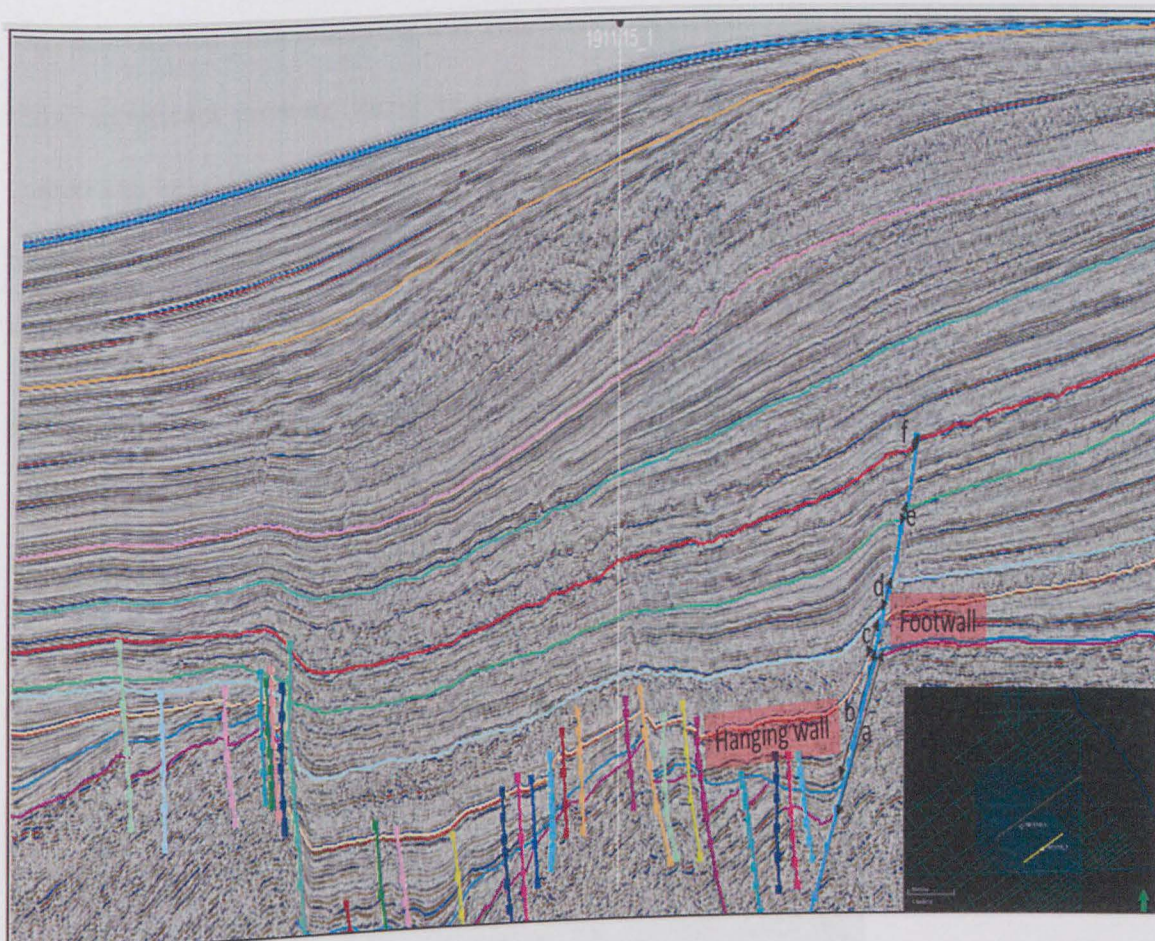


Figure 39. Seismic line NH-92-214 showing footwall and hanging wall and letters indicating how displacement were measured. Letters represent displacements for a-Aptian-Barremian, b-Aptian-Albian (unconformity), c-Cenomanian, d-Santonian, e-Campanian and f-Base Tertiary throws.

Fault throws were measured on 12 seismic lines (NH-92-205, NH-92-208, NH-92-211 NH-92-214, NH-92-215, NH-92-220, NH-92-223, NH-92-227, NH-92-230 NH-92-234, NH-92-238 and NH-92-242). All fault throw measurements are given in tables 1-12, Appendix 1.

The measurements indicate that most faults displace at least the lower Cretaceous marker horizons (top SDRs, Intra-Aptian-Albian Unconformity), while some of the more prominent and lateral extensive faults may reach up into the Tertiary (Paleocene) (Fig. 40).

The throw measurements reveal maximum displacement at the top SDRs level, while displacements decrease successively towards higher (younger) stratigraphic levels.

This implies that peak extension was after SDRs deposition. The top SDRs surface does not show significant erosion; therefore, extension must have occurred while the developing graben was below base level and the accommodation space was timely filled. Growth strata is best developed in the top SDRs – Intra Aptian-Albian Unconformity interval, and diminishes from the late Cenomanian and becomes unrecognizable in the early Santonian.

Figures 20 (page 36) and 40 shows Barremian to Intra Aptian-Albian Unconformity growth strata thickening towards the west against each eastward dipping normal fault. Complementary onlaps against the rotating footwalls occur in easterly direction. This interval shows the strongest growth and is therefore termed *Extension Interval I* with the top SDRs surface as its base.

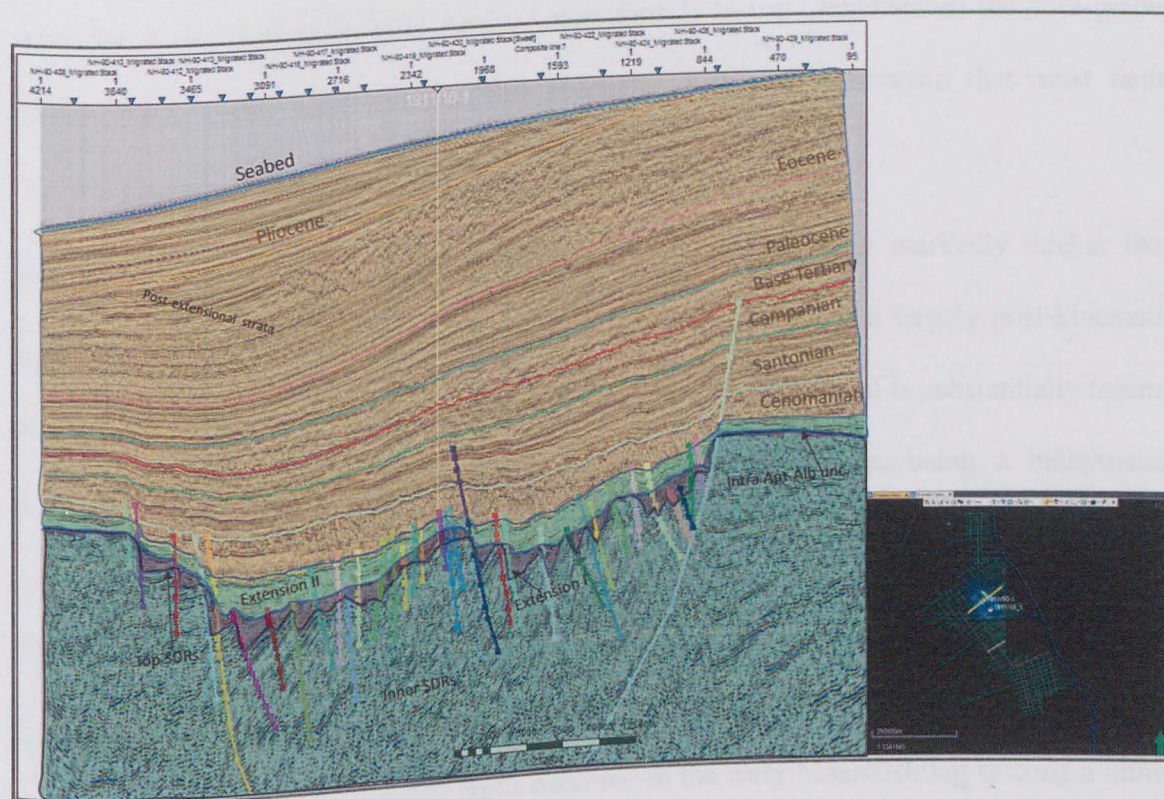


Figure 40. Local kinematic analysis on the line NH-92-230 for the Dolphin Graben. The line shows *Extension I*, *Extension II* and *Post extensional strata*.

The Intra Aptian-Albian Unconformity marks the beginning of another extension phase with less growth against individual intra-graben faults, but an overall growth from the 1911/10-1 structural high located at the graben centre towards the graben boundary faults either side. This phase is termed *Extension Interval II* and tentatively lasted until the top of the Cenomanian. Herewith, the Intra Aptian-Albian Unconformity is the base of Extension Interval II that marks the transition from rapid extension accommodated by small rotational fault block to extension that is chiefly controlled by the main graben boundary faults. Thus, the geometry of the *Extension Interval II* graben fill resulted from a combination of syn-kinematic sedimentation, mostly controlled by the main bounding faults, and draping of the pre-existing smaller wavelength graben morphology created during the first extension phase.

After Extension Interval II (Intra-Aptian Unconformity to top Cenomanian) the intra-graben faults became essentially inactive. This coincides with the observation that most faults terminate below or within the lower Santonian interval.

The graben fill from the top Cenomanian to Santonian interval is markedly thicker than equivalent strata outside the graben, implying that this interval is a largely post-kinematic graben infill. The following top Santonian to top Campanian interval is substantially thinner west of the western graben boundary, showing that the graben, being a bathymetric depression, acted as a sediment trap. Absence of growth strata geometries confirm a tectonic rather inactive phase and herewith rather a passive sediment infill.

With the end of the Campanian the graben morphology has been completely levelled. Reactivation of the main boundary faults occurred in the early Maastrichtian causing a minor re-creation of the graben morphology during the end of the Cretaceous. Growth strata are not obvious in the Maastrichtian interval indicating that the phase of tectonic activity was short,

and most of the Maastrichtian was rather post-kinematically draping the rejuvenated subtle graben morphology.

Small displacements across the boundary faults are recognizable up into the lower Paleocene, indicating a smaller phase of renewed fault activity. The residual graben morphology faded during Paleocene/ Eocene deposition.

4.4 Burial and thermal history

4.4.1 1D models

For the purpose of understanding the burial and thermal history and associated hydrocarbon generation and its timing within the Dolphin Graben, two 1D models have been created for the two wells (1911/15-1 and 1911/10-1) drilled in the graben.

Additionally, a third model pseudo well location (named “New Well”) has been selected west of the structural high of well 1911/15-1 (Fig. 18, page 32). There, the seismic sections indicate presence of the Aptian-Albian source rock. In addition, the proximity of the model well to the actual well gives high confidence for the input parameters.

The New Well 1D model was created to estimate Aptian-Albian source rock maturity in the graben, as the source rock facies were not developed on the structural high of the 1911/15-1 and 1911/10-1 well locations. However, reported hydrocarbon shows on well 1911/15-1 indicate nearby presence of a matured source rock. As a hypothesis, the shows could have been sourced from an Aptian-Albian source rock that has been seismically mapped in the deeper part of the graben.

Burial history

Figures 41, 42 and 43 below show the burial history reconstruction for the Dolphin Graben, carried out at the modelled three wells: 1911/10-1, 1911/15-1 and New Well. The burial history curves below display also the paleo water-depths, with estimates deduced from the biostratigraphy report for well 1911/10-1.

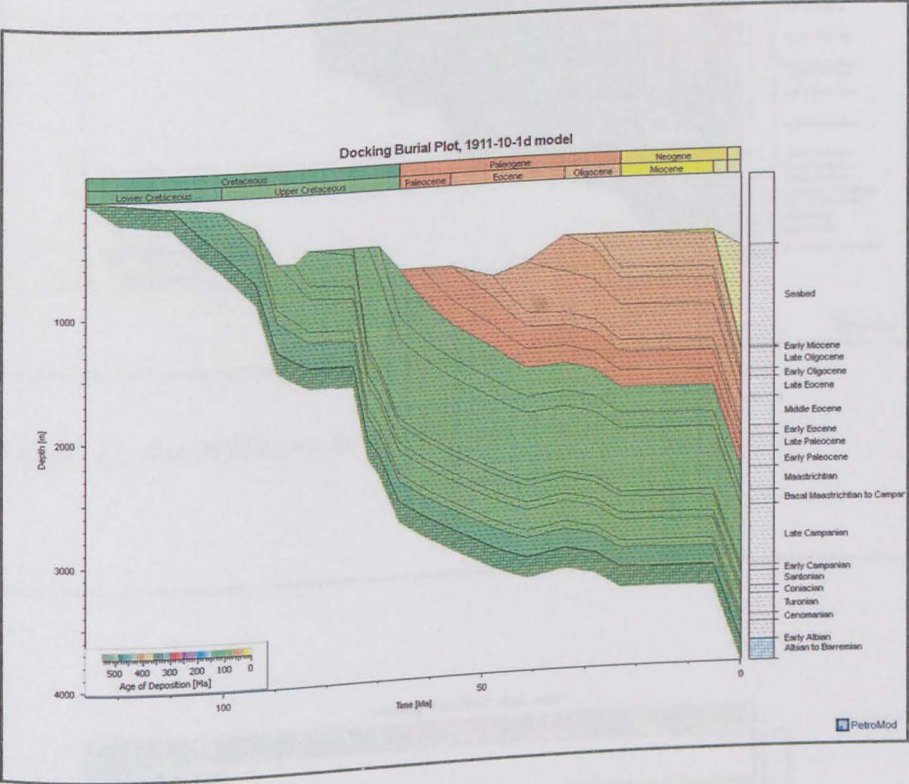


Figure 41. Burial History for the 1911/10-1 well location.

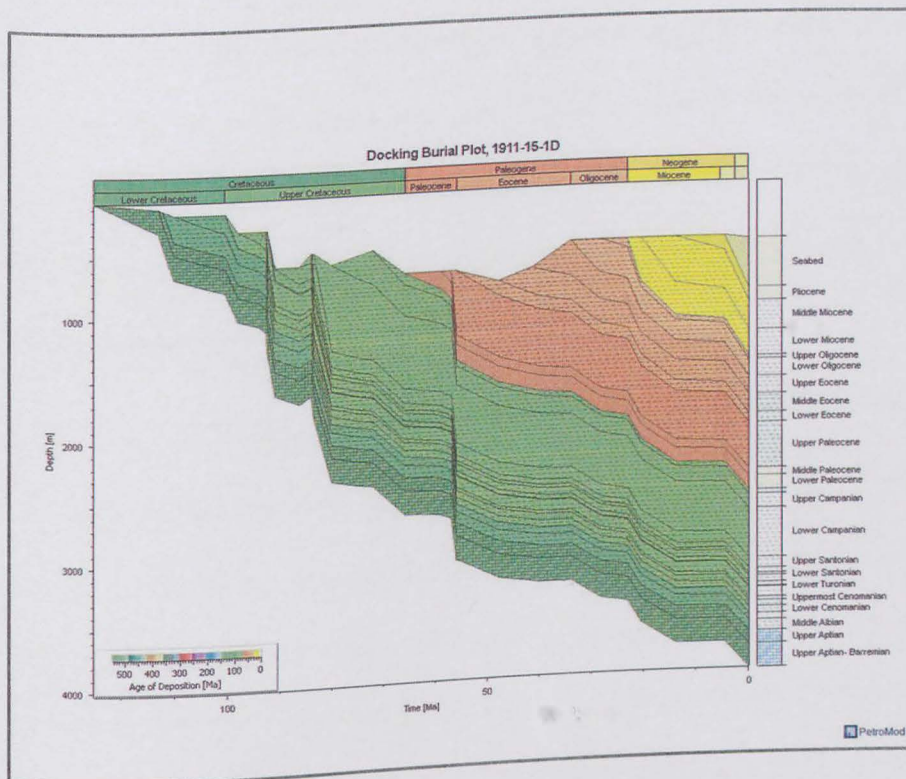


Figure 42. Burial History for the 1911/15-1 well location.

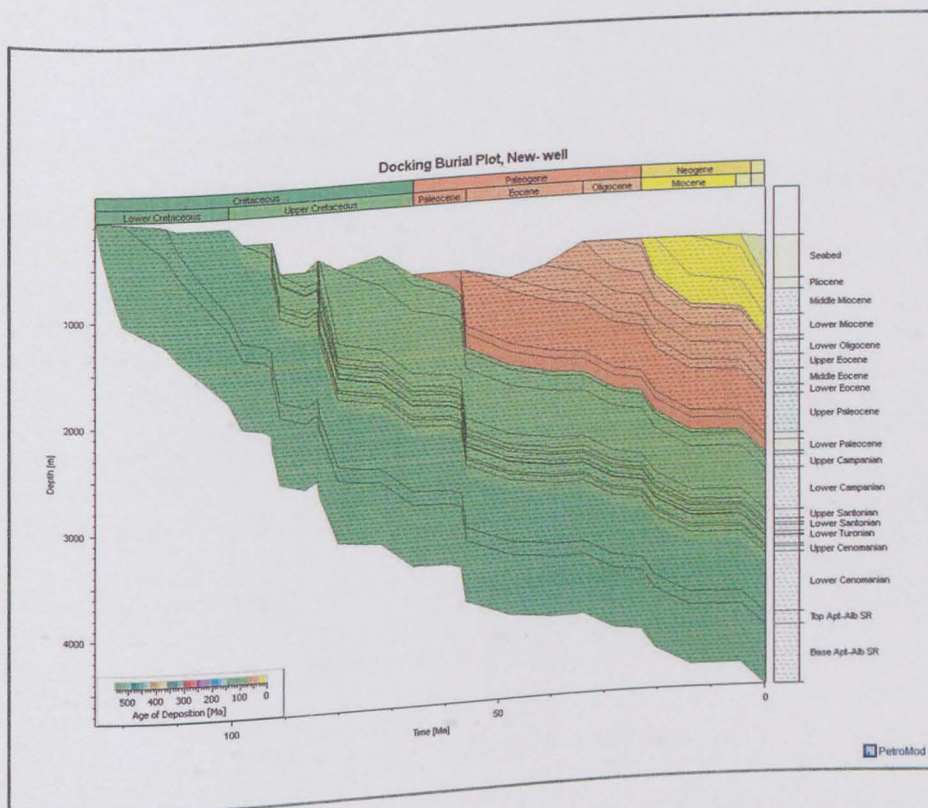


Figure 43. Burial History for the New Well location.

The paleo water-depths are as a result of tectonic subsidence, compaction, sediment input and eustasy. In the lower Cretaceous subsidence is largely compensated by sediment fill, as indicated by growth strata (Fig. 40, page 58), to maintain shallow water depths. In the Upper Cretaceous subsidence is still pronounced, but sediment input was insufficient to maintain shallow water depth.

The Tertiary deposition increased while the subsidence curve flattens, resulting in a reduction of water depth. The New Well shows rapid subsidence in the small internal half graben during the *Extension Interval I* in the early Lower Cretaceous, while the two wells situated on the structural high (1911/10-1 and 1911/15-1) did not undergo this initial phase of rapid subsidence (Fig. 41- section 4.3.2). Another significant phase of subsidence is recognizable in all three well locations during the middle of upper Cretaceous between 95-85ma, which coincides with *Extension Interval II*. A late Paleocene phase of subsidence can be depicted in Figures 42 and 43. This suggests a third extension phase. The seismic section in Figures 19, 22, 24, 37 and 39 show a thickening of the Paleocene strata across the western graben boundary into the graben, however fault control is not obvious. Therefore, probably a more passive graben fill together with more subtle fault movements account for the thickening of the strata across the western graben flank. Subsequent minor inversion is conceivable along the upwards extrapolation of the western graben fault up to Eocene level.

The general flattening of the subsidence in the Tertiary reflects the mature stages of passive margin development according to the McKenzie model (McKenzie et al., 2005). A detailed backstripping would serve to obtain more details on the ratio of tectonic subsidence components, but this was beyond the scope of this study.

The New Well (model well) portrays the deepest burial as it involves the additional accommodation space that was created during initial formation of the small half grabens,

while the other two wells are located on the adjacent host which defines the structural high in the central Dolphin Graben.

Thermal history

Figures 44, 45 and 46 below show the thermal history reconstruction of the Dolphin Graben based on the modelled three wells: 1911/10-1, 1911/15-1 and New Well.

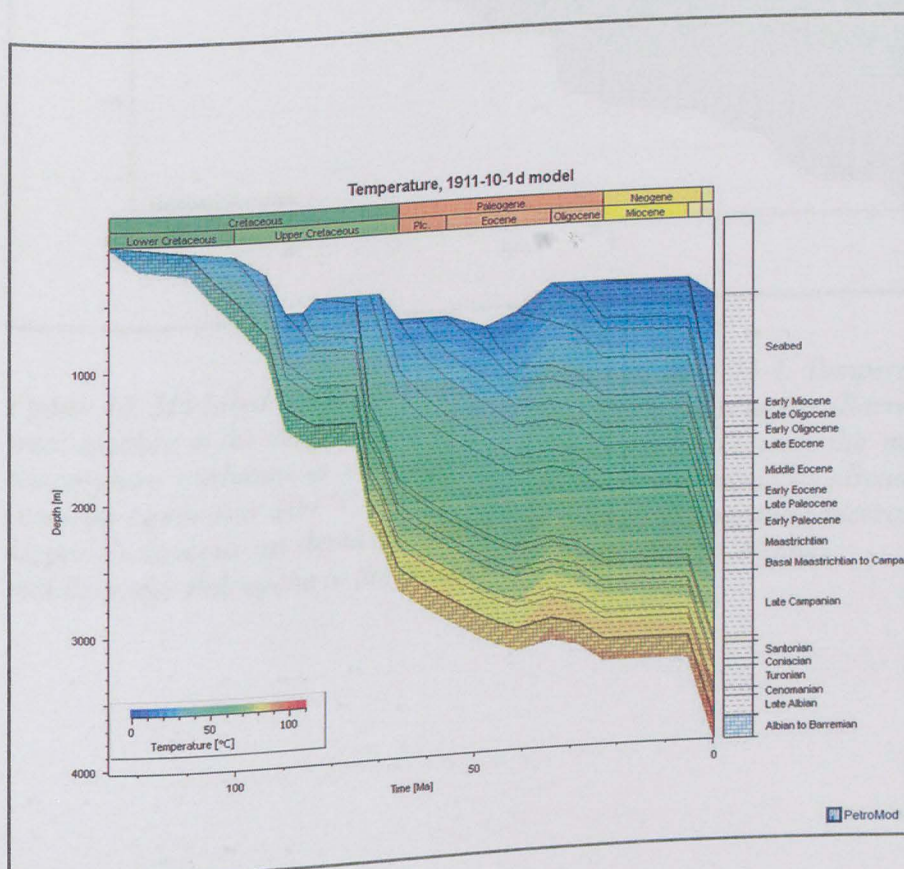


Figure 44. Modelled temperature evolution for well 1911/10-1. Temperatures of over 100°C were reached at the deeper depth in the Lower Cretaceous layers (Barremian to Albian). A temperature of over 90°C was already reached during the Upper Cretaceous (at depth of 2800m) while temperature increased slightly until the Miocene, from where with further burial a more rapid increase up to recent times becomes apparent.

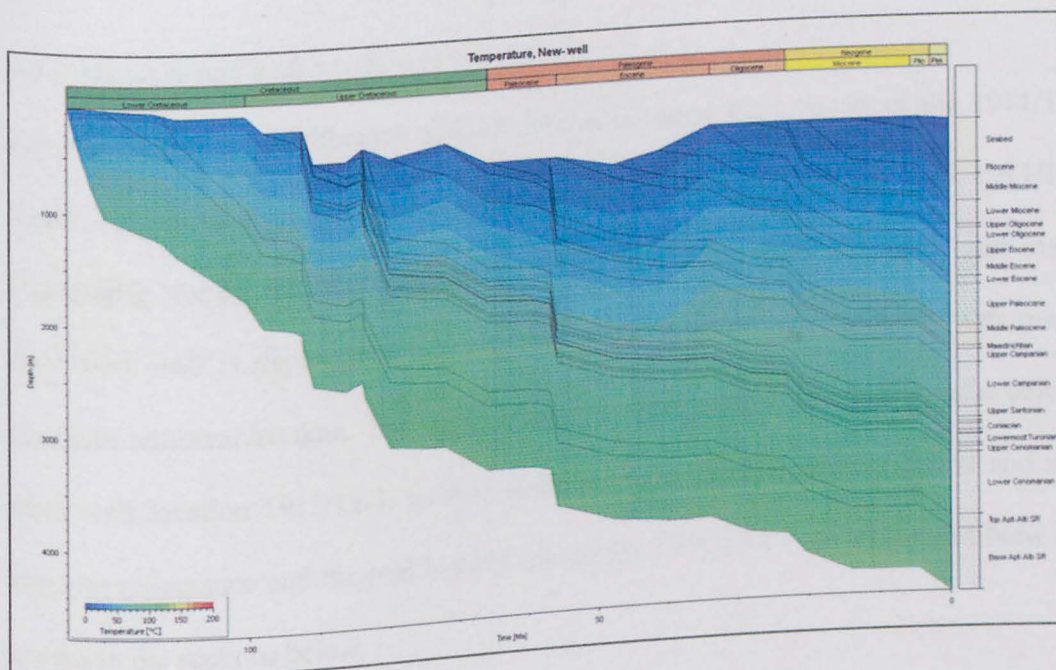


Figure 46. Modelled temperature evolution for the New Well location. Temperatures of over 130 °C were reached at deeper depths in the Lower Cretaceous (Barremian to Albian). The temperature evolution is again similar to the previous wells.

As a rule of thumb, the maximum temperatures are attained by layers which are buried deeper following the geothermal gradient at a given time. PetroMod included the basal heat flow following the evolution trend during the syn-rift and post-rift phase for passive margins. The syn-rift (130-120 Ma) is characterized with a steep heat-flow increase reaching its peak at continental break-up. Thereafter the heat flow significantly subsides during the early post rift with the decrease asymptotic flattening to the current heat flow in the late post-rift, some 20Ma ago.

This evolution of basal heat flow explains that temperatures of the lower strata are relative constant from some 110 to 50Ma in all three well locations; during this period the decrease from basal heat flow was more or less balanced with increase of burial.

4.4.2 Maturity and hydrocarbon generation

Thermal history was calibrated with vitrinite reflectance (R_o) data from the 1911/15-1 well report containing four (4) data points. Vitrinite reflectance data for well 1911/10-1 was unavailable during the execution of the research. Hence, thermal history and maturity at 1911/10-1 well is dependable on modelled vitrinite reflectance inferred from present-day borehole temperature data. The New Well was calibrated with vitrinite reflectance values from well location 1911/15-1, as it is situated in its vicinity. The modelled and measured vitrinite reflectance and thermal history curves for 1911/15-1, 1911/10-1 and New Well are shown in the sections below.

1911/15-1

The modelled R_o for 1911/15-1 (Figs. 47 and 48) well is slightly not in agreement with measured Vitrinite Reflectance values.

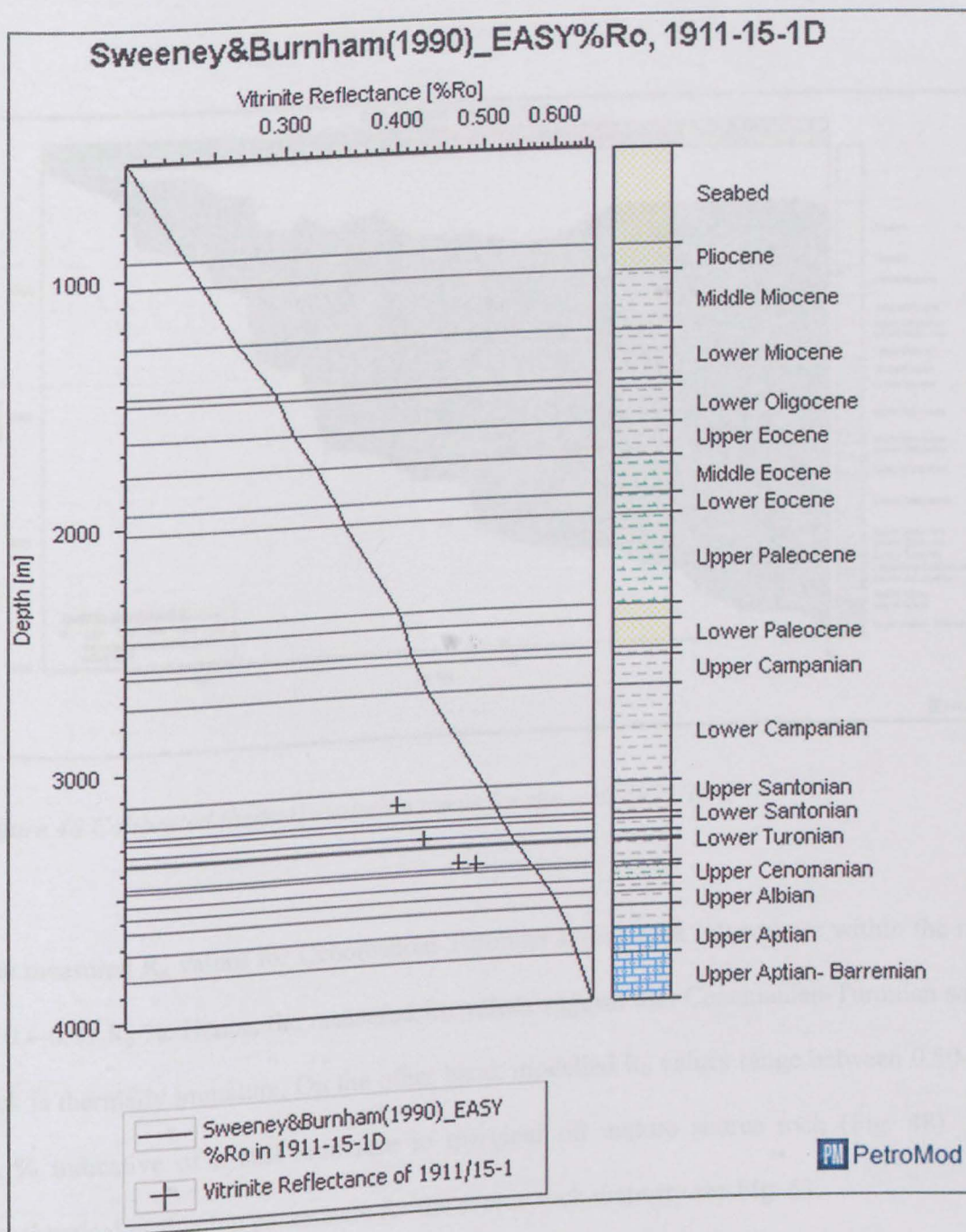


Figure 47. Model vitrinite reflectance curve and measured values (crosses) for 1911/15-1 well location.

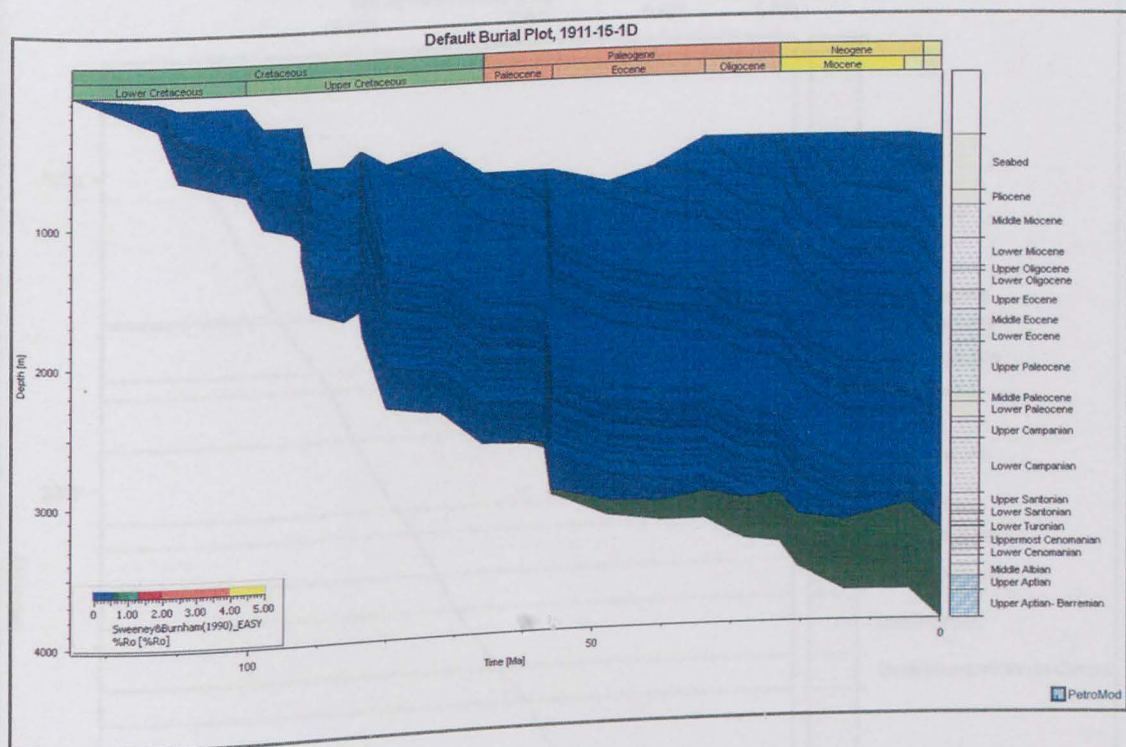


Figure 48. Calibrated thermal evolution curve for the well 1911/15-1

The measured R_o values for Cenomanian-Turonian source rock interval are within the range of 0.4-0.49 R_o %. Hence, the measured R_o values suggest that Cenomanian-Turonian source rock is thermally immature. On the other hand, modelled R_o values range between 0.50-0.59 R_o % indicative of a still immature to marginal oil mature source rock (Fig. 48). For Geochemical evaluation parameters for the source rock maturity see Fig. 53.

1911/10-1

For well 1911/10-1 (Figs. 49 and 50) modelled R_o for Cenomanian-Turonian is in the range of 0.5-0.6, implying immaturity to top of oil window, similar as for well 1911/15-1. Measure values were not available for this study.

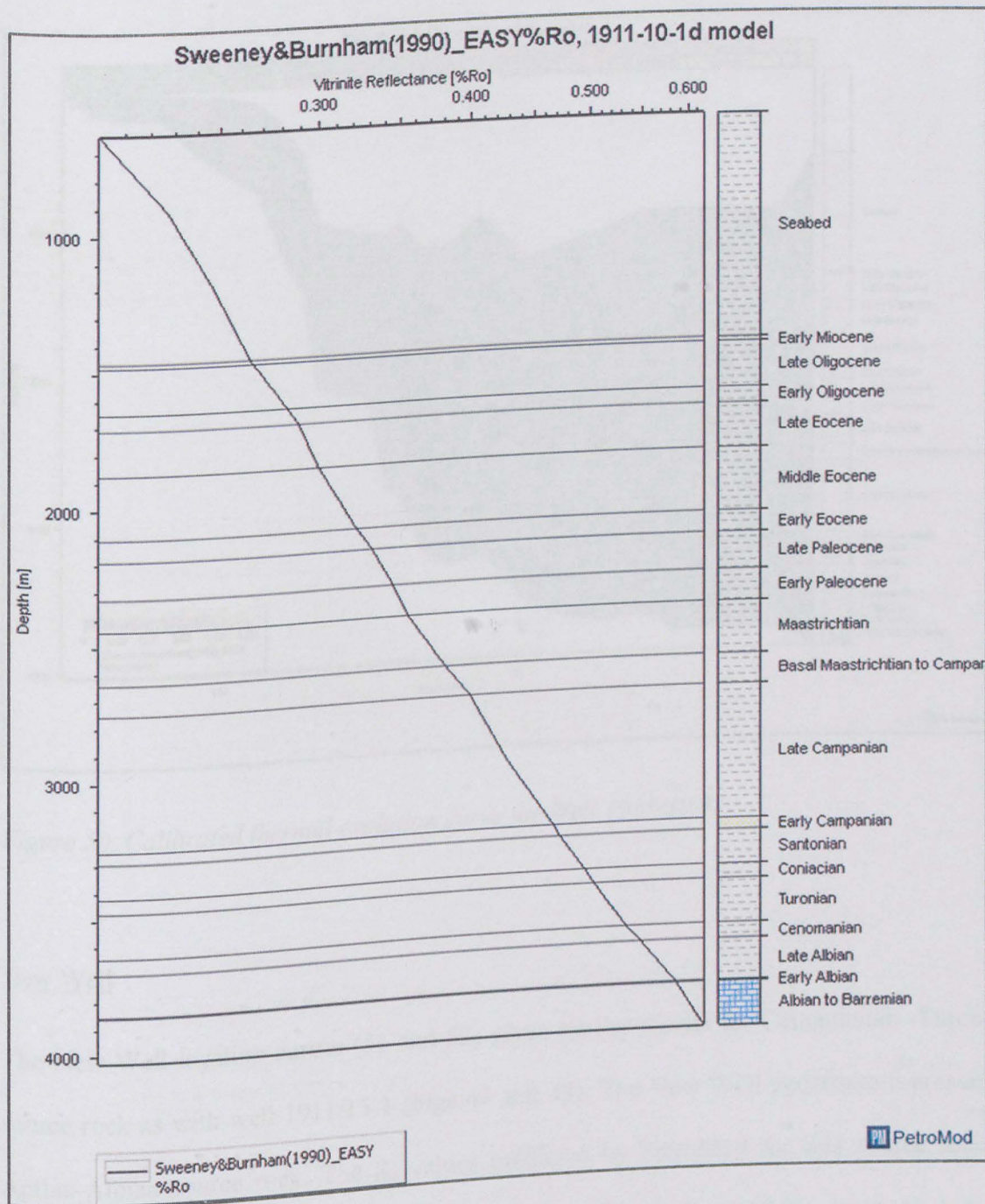


Figure 49. Model vitrinite reflectance curve and measured values (crosses) for 1911/10-1 well location

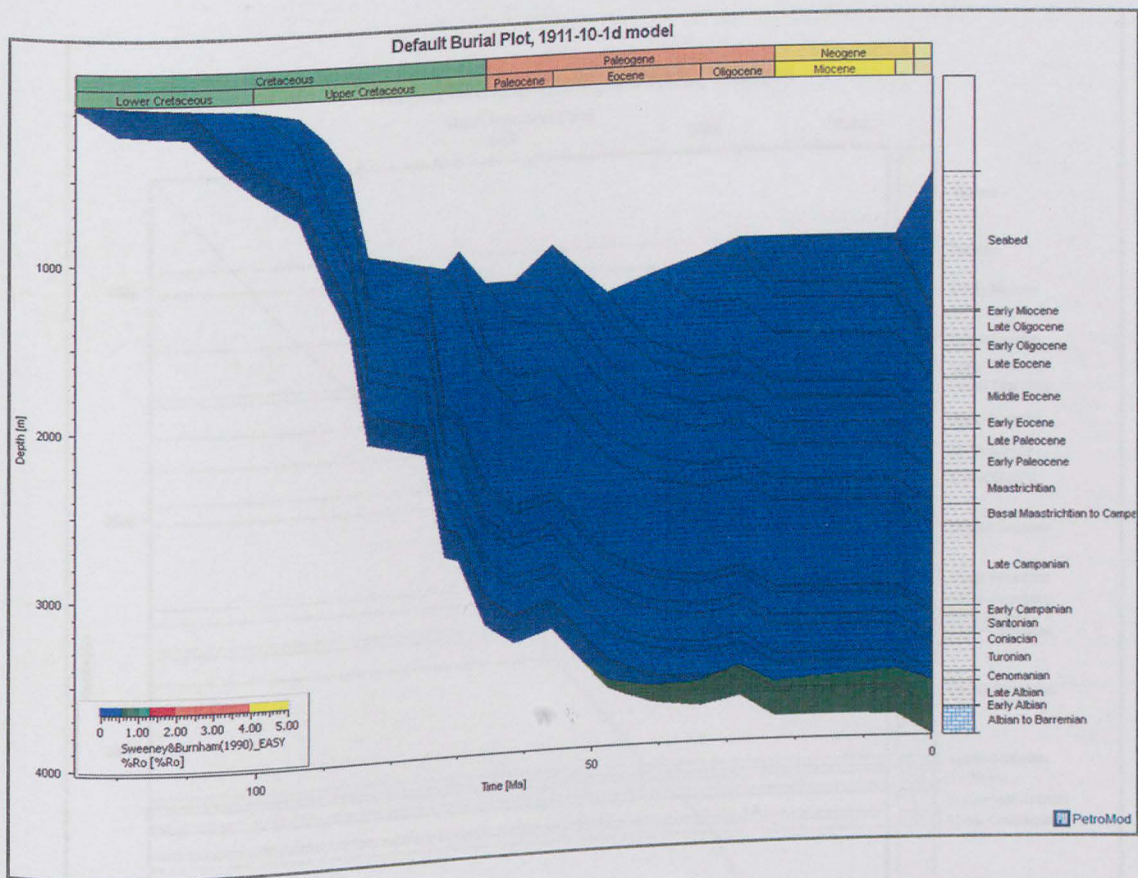


Figure 50. Calibrated thermal evolution curve for Well 1911/10-1.

New Well

The New Well location curves (51 and 52) gives similar results for Cenomanian -Turonian source rock as with well 1911/15-1 (Figs 47 and 48). The New Well penetrates a presumed Aptian-Albian source rock. The R_o values predicted by PetroMod for this source rock is between 0.58-0.63, which would imply early maturity. At the level of the presumed Aptian-Albian source rock occurs a conspicuous seismic marker within the deeper Dolphin Graben, therefore this result is important for further prospects in the graben.

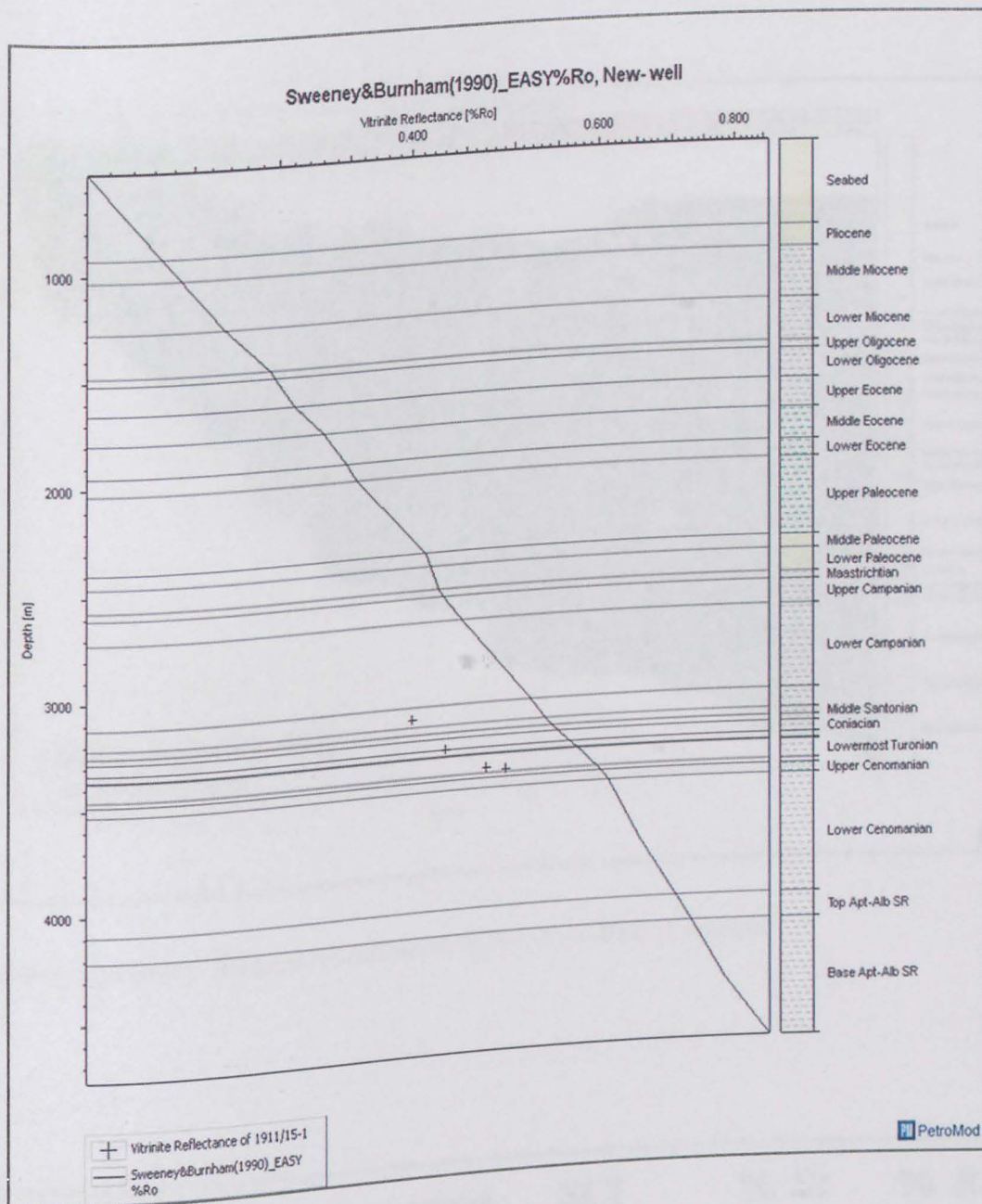


Figure 51. Model vitrinite reflectance curve for the "New Well" well location. The crosses are the measured Ro values for the adjacent 1911/15-1 well.

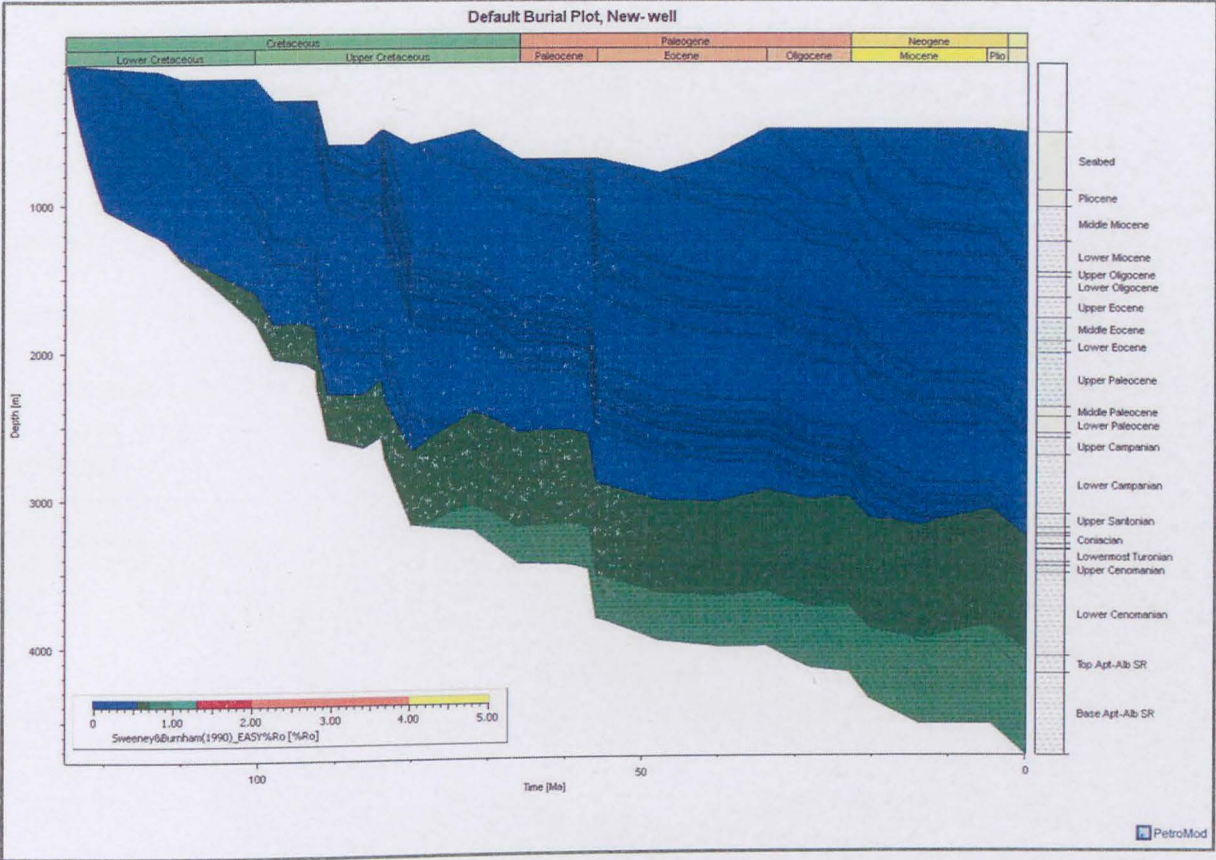


Figure 52. Calibrated thermal evolution curve for 'New Well' Location.

Hydrocarbon generation zones	SCI	% <i>St</i>	% <i>Ro</i>
Immature	< 3.5	< 3	< 0.35
Early mature	3.5–5	3–5	0.35–0.5
Middle mature	5–7	5–7	0.5–0.75
Late mature	7–8.5	7–10	0.75–1.3
Post mature	8.5–10	> 10	> 3

Figure 53. Table showing geochemical evaluation parameters for source rock maturity. Copied from Collins (1991).

4.4.3 Transformation Ratio

Burial histories for the three 1D models were overlain with calculated kerogen to hydrocarbon Transformation Ratios (TR). However, the model only indicated transformation of kerogen into hydrocarbons for the “New Well” location (Fig. 54), while 0 % TR has been calculated for the other two well locations. As the Aptian-Albian source rock has not been sampled in the Dolphin Graben, a typical TOC of 3% and the Burnham (1989) Type-II kinetic was used. The TR may vary significantly if source rock parameters are significantly different.

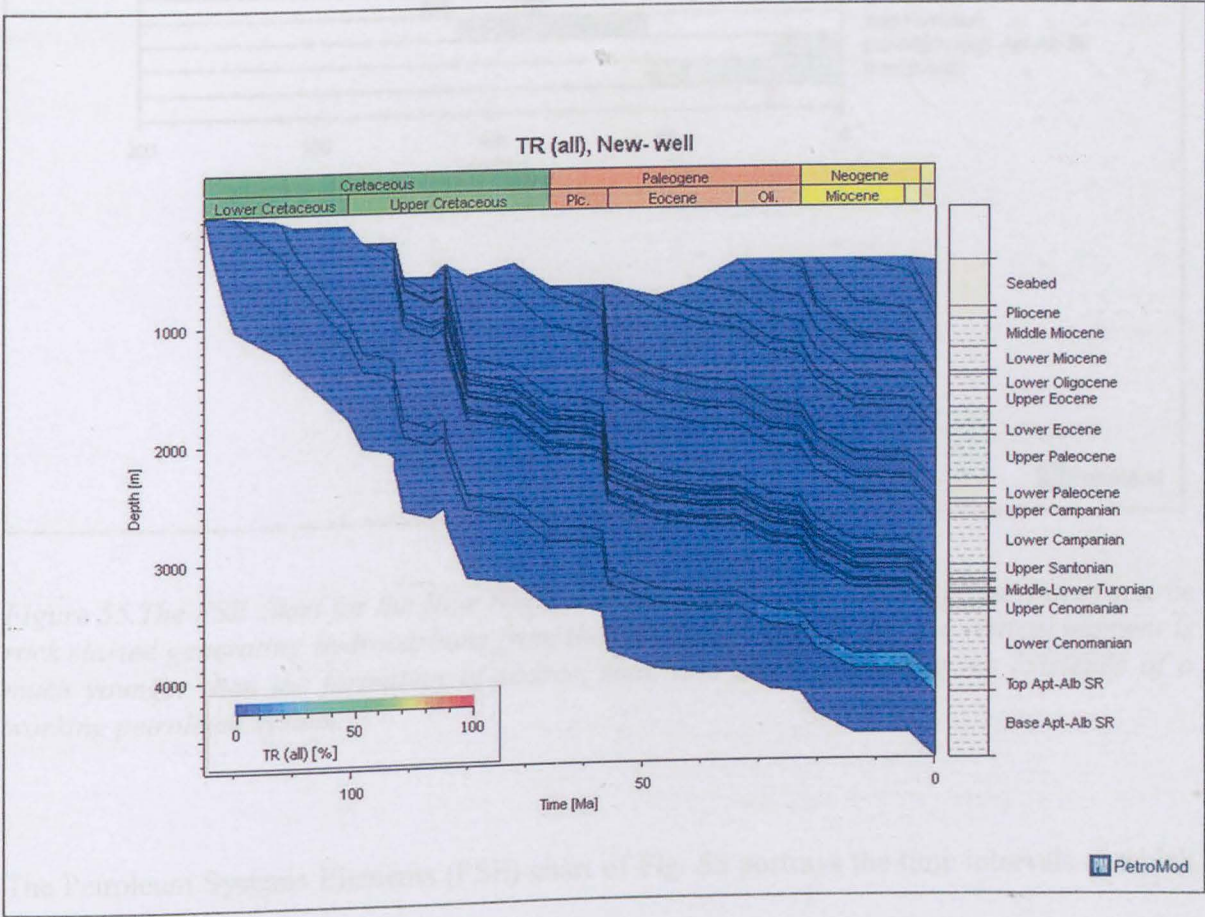


Figure 54. Transformation Ratio for the New Well location. The Aptian-Albian source rock reaches maturity from the late Oligocene.

4.4.4 PSE Chart

A mature Lower Cretaceous (Aptian-Albian) source rock has been predicted only for the New Well. Hence, a Petroleum Systems Elements (PSE) chart was generated with PetroMod (Fig. 55) to test the possibility of a working petroleum system.

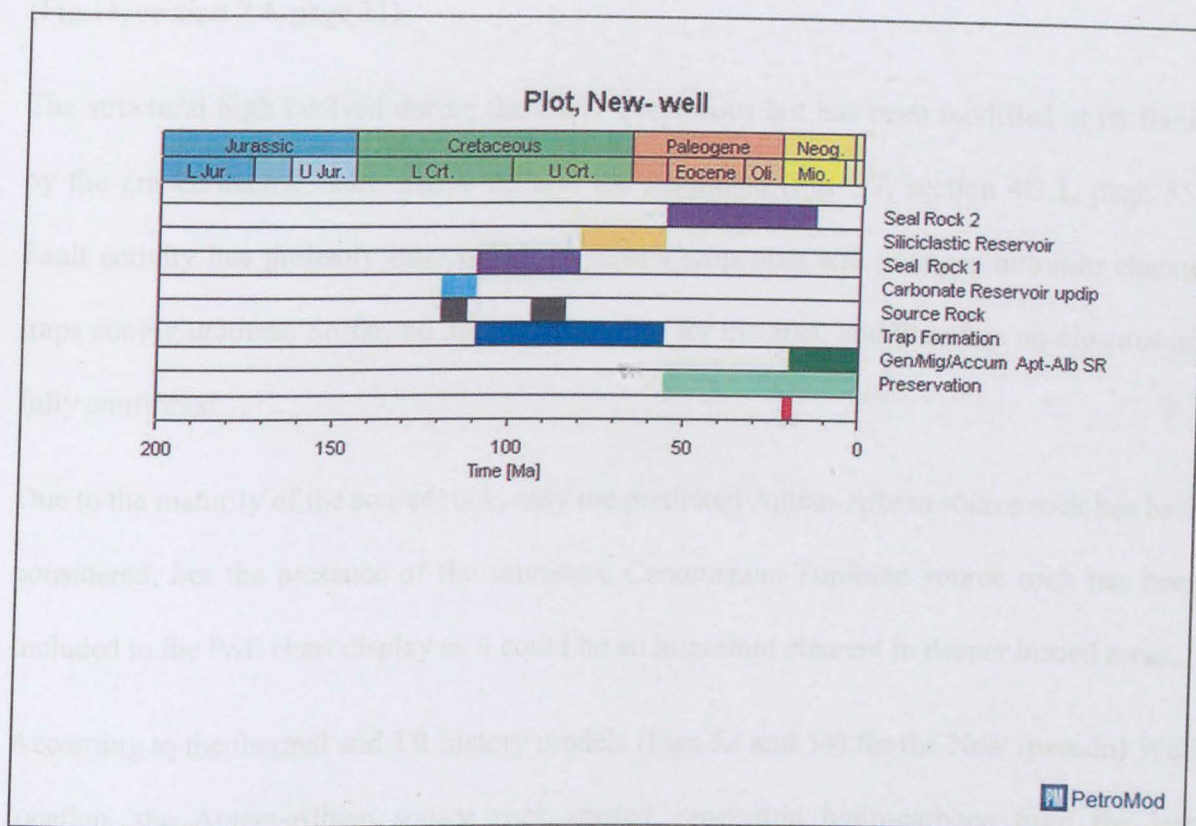


Figure.55. The PSE chart for the New Well location. In this scenario the Aptian-Albian source rock started generating hydrocarbons from the late Oligocene. Hence, the critical moment is much younger than the formation of source, seal, and traps, proposing the existence of a working petroleum system.

The Petroleum Systems Elements (PSE) chart of Fig. 55 portrays the time intervals at which petroleum system elements and processes have occurred. For the New Well the same reservoirs and seal stratigraphic intervals including the associated structural and stratigraphic traps as proposed for the 1911/15-1 and 1911/10-1 well locations were chosen (Tower, 2020). These include Lower Cretaceous (Albian) carbonate build-ups and Upper Cretaceous (Campanian) to Paleocene turbidite sand bodies (channels) as potential reservoir of fair to

good reservoir quality intersected in the 1911 wells. Sealing shales are ubiquitous outside the above reservoir lithologies throughout the Cretaceous and Paleogene. Trapping configurations are essentially stratigraphic including channel-pinch outs for the turbidites and a drape anticline over the graben central structural high for the Lower Cretaceous carbonates (Fig.13, section 2.4, page 21).

The structural high evolved during the Early Cretaceous but has been modified at its flanks by the graben central faults active up into the Santonian (Fig. 37, section 4.3.1, page 55). Fault activity has probably little effect on most Campanian and younger turbidite channel traps configurations. So far, no 3D seismic exists for the area, and therefore no closures are fully confirmed.

Due to the maturity of the source rock, only the predicted Aptian-Albian source rock has been considered, but the presence of the immature Cenomanian-Turonian source rock has been included in the PSE chart display as it could be an important element in deeper buried areas.

According to the thermal and TR history models (Figs 52 and 54) for the New (pseudo) Well location, the Aptian-Albian source rock started generating hydrocarbons from the late Oligocene. The TR model of Figure 54 indicates a TR ratio of 40%, depending on the source rock texture and composition, can be enough for effective hydrocarbon expulsion and migration. Hence, the critical moment for hydrocarbon generation and migration is much younger than the formation of source, seal, and traps, proposing the existence of a working petroleum system.

CHAPTER 5 - DISCUSSION

5.1 Dolphin Graben structural evolution

The Dolphin Graben is located close to the Walvis Ridge on the lower continental slope. The slope is shallower and more gently deepening seawards here, compared to the margin south of the Dolphin Graben where the continental slope has a steeper gradient. Furthermore, the Walvis Ridge defines a major structural boundary: to its South syn-rift faults dip landwards, while most of them dip seawards north of the ridge (Light et al., 1993; Maslanyj et al., 1992).

To account for this special geological position of the Dolphin Graben, two crustal models have been created. The first model describes the larger and deeper crustal structure of the area immediately south of the Walvis Ridge, while the second model illustrates the structural evolution of the Dolphin Graben from incipient faulting to its current state.

5.1.1 Deeper crustal structure south of the Walvis Ridge

The regional and deeper crustal architecture is best imaged on a composite line that spans from the outer shelf to the western SDRs, close to the continental/oceanic crust transition. The composite line shows Planke's et al. (2000) architecture of a volcanic margin with inner and outer SDRs separated by an outer structural high (Fig. 56). The inner SDRs form the top sequence of an inner central half graben which is located beneath the present-day outer shelf and reaches underneath the Dolphin Graben. The seismic characteristics of the lower half-graben fill correspond best with the syn-rift II fill of Maslanyj et al. (1992) and Light et al. (1993). According to these authors syn-rift I occurs only south of the Cape Cross Segment boundary, which is in-line with their general model that rifting propagated from South to North. Clemson et al. (1997) recognized three syn-rift sequences (rift phase I, II and III), of

which phase III is interpreted as largely volcanic in the west, with increasing continental input to the east.

At least the upper portion of Clemson's et al. (1997) rift phase III correlates well with the SDRs farther west. Therefore, the rift phase III should be rather seen as an east-wards continuation of the SDRs, likely receiving more continental detritus towards the hinge line of the central half-graben. Reflections converge to the east proving the syn-kinematic deposition of this rift-phase. The outer basement high subdivides the SDRs packages into a western domain, herein termed outer SDRs, and an eastern domain, termed inner SDRs. Thus, the inner SDRs essentially correspond with the rift-phase III of Clemson et al. (1997). The outer SDRs are of similar seismic character as the inner SDRs/ rift phase III, however their seaward dips are more pronounced, and reflections are less divergent. The outer SDRs do partially overlay the inner SDRs indicating a westwards migration of SDRs deposition.

According to Clemson et al. (1997), the top of the inner SDRs/ rift phase III marks the transition from advanced rifting to continental break-up with the production of oceanic crust tentatively dated around the Barremian/Aptian boundary. This definition of the break-up unconformity is arbitrary, as it is not clear at which exact stage a spreading centre became active. Planke et. al. (2000) discuss the possibility that SDRs, especially the outer SDRs may have been deposited after initiation of a spreading centre, which would place the break-up unconformity beneath the (outer) SDRs package.

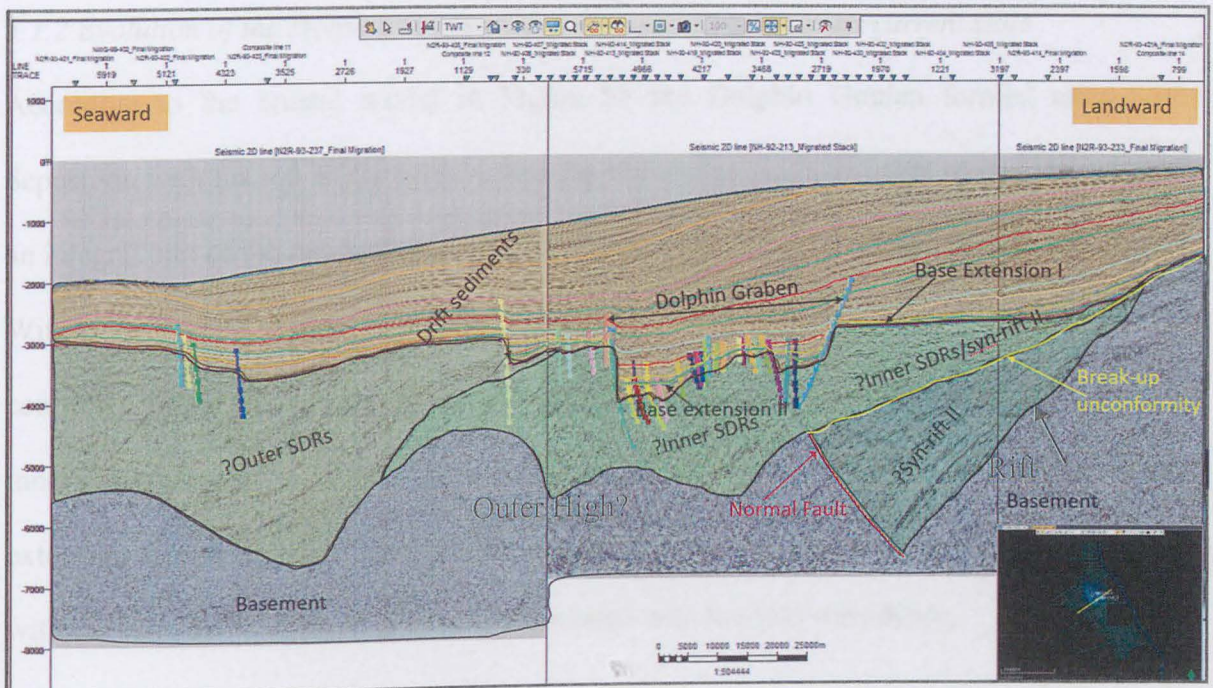


Figure 56. Regional structural (kinematic) analysis model on the composite line 1 incorporating passive margin and the Dolphin Graben structural evolution.

In the model in Figure 56 the break-up unconformity is defined by the top SDR surface. The SDR surface is followed by post-rift sedimentation. The post-rift sediments form a clastic wedge across the margin and also form the fill of the Dolphin Graben. The break-up unconformity is a high amplitude reflection that marks the base of the graben infill (Fig. 57).

5.1.2 Evolution of the Dolphin Graben from incipient faulting to its current state

According to the crustal model in Figure 55 the Dolphin Graben formed after SDRs deposition with the top SDRs surface forming the graben floor. In other words, the graben is an integral part of the regional post-rift / drift sediments but is a local rift structure on its own. Within the graben, Aptian to Cenomanian strata are syn-kinematic deposited during fault-controlled graben subsidence. Thus, graben subsidence commenced almost immediately after inner SDRs deposition on top of the break-up unconformity. Herewith, the Dolphin Graben extension is younger than the syn-rift extension along the Namibian margin but coincides with the early post rift phase generally associated with thermal subsidence.

This for the Namibian margin uncommon rifting during the post rift phase could be explained with the proximity of the Walvis Ridge, which is essentially a centre of enhanced volcanic activity. The nearby Phoenix Volcanic Field, located immediately to the northeast of the Dolphin Graben, had been active from the Late Albian to the late Cenomanian (Holtar & Forsberg, 2000). Rifting in the Dolphin Graben was most pronounced during this interval as indicated by growth strata geometries, suggesting that a local thermal mantle anomaly and upwelling has been causing the tensional stresses to form the Dolphin Graben. The thickened SDRs package towards the Walvis Ridge (Cartwright et al., 2008) underneath the graben may have also contributed to post rift extensional stresses as they cause a thickened crust of relatively higher gravitational potential.

For the syn-kinematic graben fill the term Extension phase I and II sequence are used (Fig. 56) to have a clear distinction from the older, general Namibian margin syn-rift sequences.

Rifting commenced with a set of small en-échelon half grabens (0.8-7.5km wide) accommodating Extension Sequence I (early Aptian to Albian). Faults are dipping landwards, and block rotations are seawards, herewith synthetically with the structures of the deeper

Central Graben (Fig. 56). This relation suggests that older Central Graben faults had some control on the architecture of the superimposed developing Dolphin Graben.

During deposition of Extension Sequence II (Cenomanian) most faults became inactive and graben subsidence was almost solely caused by the main graben boundary faults.

A minor reactivation of the boundary faults is recognized towards the end of the Cretaceous. Herewith two main extensional phases are recognized, the first (Extension phase I) spans from the early Aptian to the Intra-Aptian-Albian unconformity during which extension was accommodated by a number of narrow half-grabens and associated block rotations. Therefore, the Aptian-Albian interval is intensely faulted and the strong block rotations cause pronounced divergent reflections identified as growth strata. Extension phase II spans from the Intra-Aptian-Albian unconformity to the end of the Cenomanian. During Extension phase II only the main boundary faults of the wider rift - now defining the Dolphin Graben - accommodate the extension. Reflections are more continuous as they are less intersected by faults, but overall, the basin fill still shows diverging growth strata geometry indicating continued syn-kinematic deposition. Such an evolution is typical for rift basins: during progressive rifting successively fewer, but longer and more prominent faults accommodate the extension (Gawthorpe and Leeder, 2000).

In accordance with previous companies' models (Tower and Arcadia) the Extension phase I is believed to comprise an older source rock formed in lacustrine pods confined in the half grabens.

The interval overlying the well-developed growth strata deposited during Extension phase I still displays syn-kinematic geometries, hence it is termed Extension phase II. The interval deposited during Extension phase II is moderately faulted and thinning towards the central highs within the Dolphin Graben, i.e. at the 1911 well locations. The Aptian-Albian source

rock was mapped close to the base of this interval but it is absent or condensed beyond seismic resolution recognition at the 1911/10-1 and 1911/15-1 well sites. This source rock is a good candidate to have charged the synchronous to slightly younger carbonates at the 1911/15-1 location where oil shows have been reported.

Regionally, the two extensional phases (Extension phase I and II) are contained in the Clemson et al (1997)'s Early Drift section which is Barremian to Cenomanian in age.

The post-extensional strata identified for the Dolphin Graben is believed to be Turonian to recent in age (Fig. 57). Stratigraphically, this interval is coinciding with Clemson et. al. (1997)'s Late Drift section. For this research project, the Cenomanian-Turonian source rock is mapped immediately beneath the base of post-extensional interval.

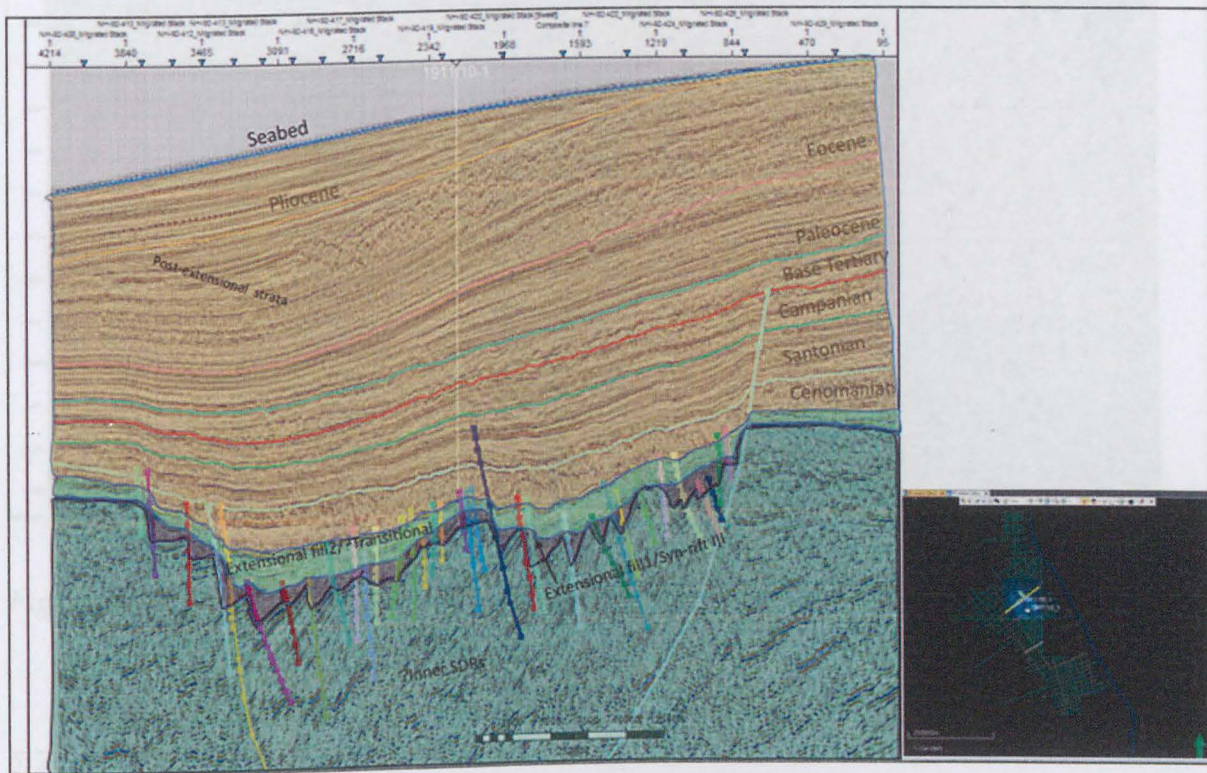


Figure 57. Seismic line NH-92-230 depicting a local structural model created for the Dolphin Graben.

5.2 Implication on source rock presence and maturation

Three source rock intervals have been postulated for the Dolphin Graben by current and previous explorers (Arcadia Petroleum, Tower Recourses). A (1) lacustrine source rock located in the deeper graben fills, here termed Extension Sequence I, the (2) Aptian-Albian Source Rock (Kudu Shale) near the base of the Extension Sequence II, and (3) Cenomanian/Turonian Source Rock deposited during an eustatic highstand (Haq & Shutter, 2008) on top of Extension Sequence II (Fig. 58). The latter has been intersected in both 1911 wells, it has an excellent hydrocarbon generation potential, but is immature.

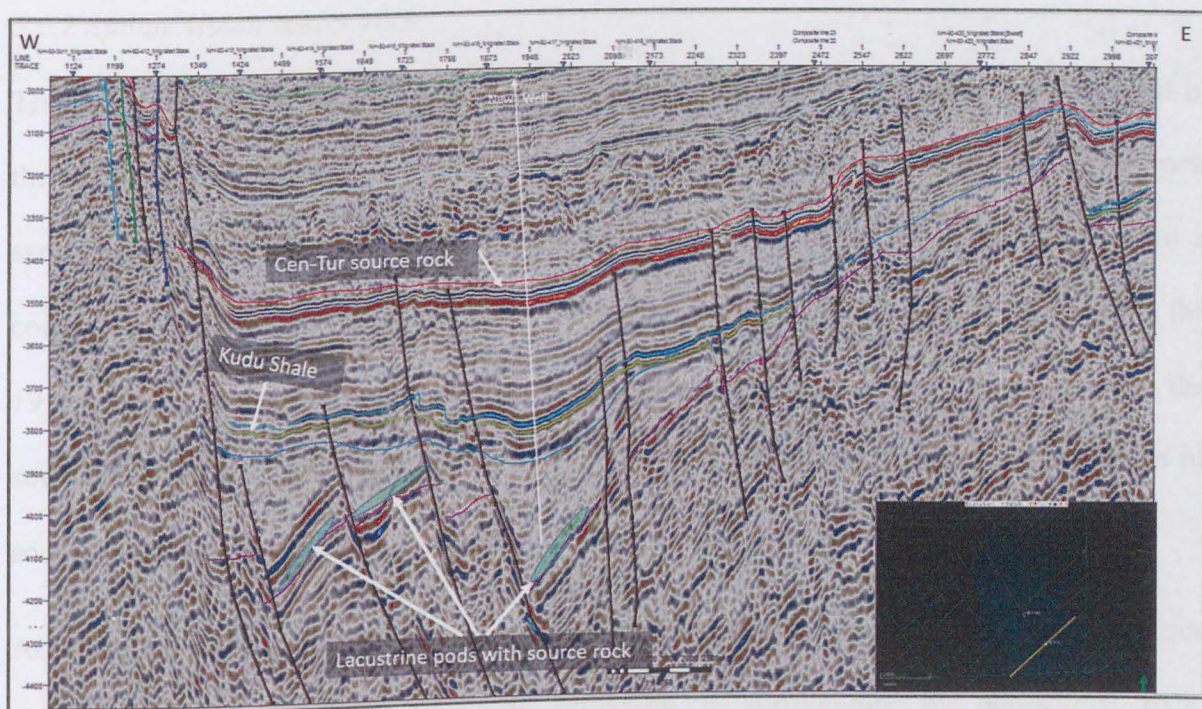


Figure 58. Source rock intervals identified in the Dolphin Graben

5.2.1 Lacustrine source rock

This source rock is predicted to have deposited in anoxic lakes occupying the developing half grabens during Extension Sequence I. Lakes may have only developed in the deeper sections (? early Aptian) and be fringed by alluvial and fluvial deposits. The central structural high

was probably emergent from the early Extension Sequence I, hence no source rock has been deposited there.

Pods of lacustrine sediments may have also deposited deeper, within the Inner SDRs (Rift Phase III of (Clemson et al. 1997) during phases of volcanic quietness.

The presence of lacustrine source rocks is indicated by biomarkers identified in likely migrated oil shows occurring in the Albian carbonates sampled in well 1911/15-1.

5.2.2 Aptian/Albian source rock

The Aptian/Albian source rock ("Kudu Shale") has been intersected in the Wingat-1 well in the Southern Walvis Basin. Light oil of 41° API grade was recovered from intra source rock sand stringers proving at least early maturity. At Wingat-1 the source rock ties well to a continuous seismic marker. In the Dolphin Graben no source rock facies was identified in the 1911 wells, but away from the central structural high a seismic maker has been mapped as the source rock, following Loseth's et al. (2011) (Fig. 59) criteria for seismic identification of source rocks.

According to Loseth et al. (2011), Fig. 59, seismic studies demonstrate that a mature source rock often causes a high amplitude reflection if surrounding by non-source rock. Additionally, mature source rocks are characterized by top negative amplitude and positive amplitude reflection at the base. The presumed Aptian-Albian source rock in the Dolphin Graben exhibits these seismic reflection characteristics suggested by the Loseth et al. (2011) (Fig. 59) strongly suggesting the presence of an (early) mature Aptian-Albian source rock in the Dolphin Graben. The burial and thermal history 1D models (Figs. 43, 46; 5.2 section 4.4.1) also predicted early maturity at the New Well location, in line with the negative Reflection Coefficient (trough reflection) at the presumed top of the source rock interval.

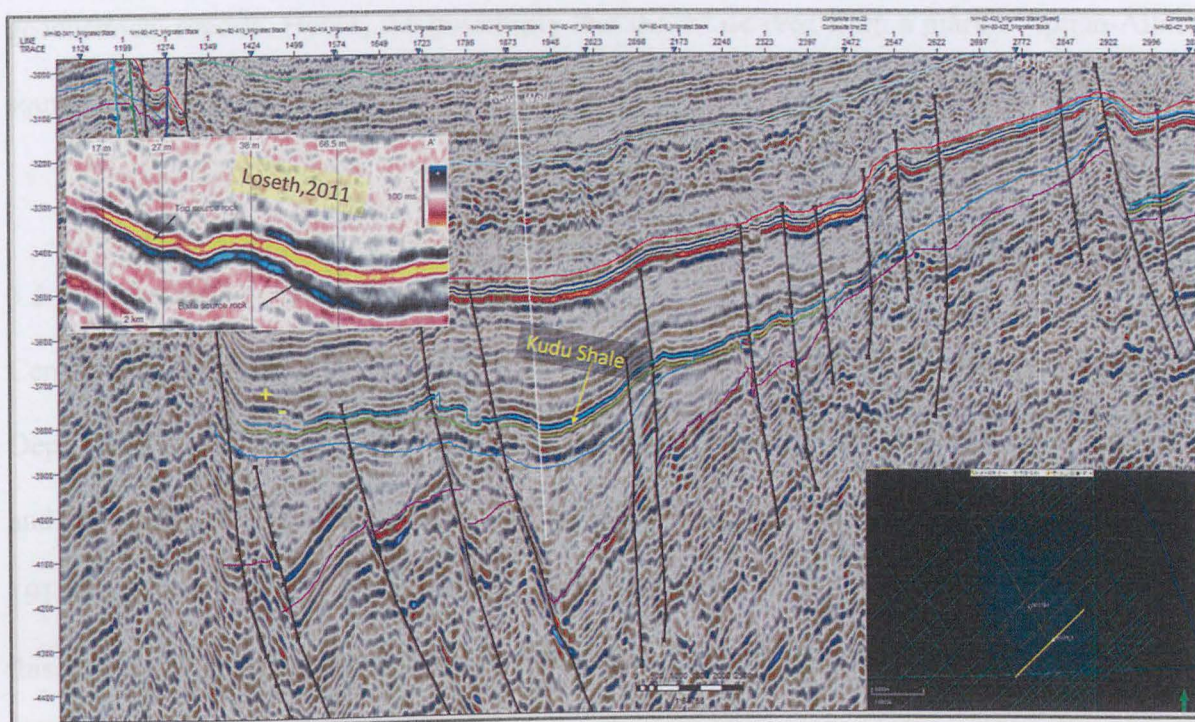


Figure 59. Comparison of the amplitude response of the Kudu Shale in the Dolphin Graben with the source rock studied by Loseth et al. (2011). A negative RC is observed at the top, while a positive RC at the bottom of a mature source rock interval, if bracketed in non-source rock shale lithologies. Insert copied from Loseth et al. (2011).

Regionally, the Aptian-Albian source rock is known as a transgressive marine shale deposited during the first flooding of the South Atlantic. This shale was deposited when the circulation in the slowly widening South Atlantic was still restricted facilitating anoxic bottom waters (McDonald et al., 2013). Circulation in the approximately 35 km wide depression of the Dolphin Graben may have been even more restricted than in the more open areas further south, and hence conditions may have been particularly favorable for bottom water anoxia and associated source rock deposition. At shallower water, i.e. on the central structural high, conditions were more favorable for the contemporaneous deposition of the carbonates that had been intersected in both 1911 wells. The source of the oil shows in those carbonates is unclear but is likely from migrated and not indigenous oil. The biomarker signature suggests a possible lacustrine origin, but the data shows substantial ambiguity according to

geochemical reports. Hence, the possibility that the oil derived from a marine Aptian-Albian source remains.

5.2.3 Cenomanian - Turonian source rock

Cenomanian-Turonian marine anoxic black shales are ubiquitous in the South Atlantic. Deposition of this interval may have been related to the Early Turonian sea level highstand and the associated global anoxic event (Bray et. al. 1998). The 2012/13-1, 1911/15-1, 1911/10-1, and DSDP 530 wells in the central and northern Walvis Basin have documented this source rock. In the Dolphin Graben the latest Cenomanian claystones of well 1911/15-1 have HI values of 600mg_{HC}/g_{TOC} and TOC of up to 10.6% (Norsk Hydro Namibia, 1993), indicating a particularly good type II kerogen oil prone source rock (Holtar & Forsberg, 2000). South of the Dolphin Graben e.g. in well 2012/13-1 TOC reaches 5.45%.

This source rock has been found immature in samples of the 1911 wells, coinciding with the modelled burial and thermal histories described in section 4.4.

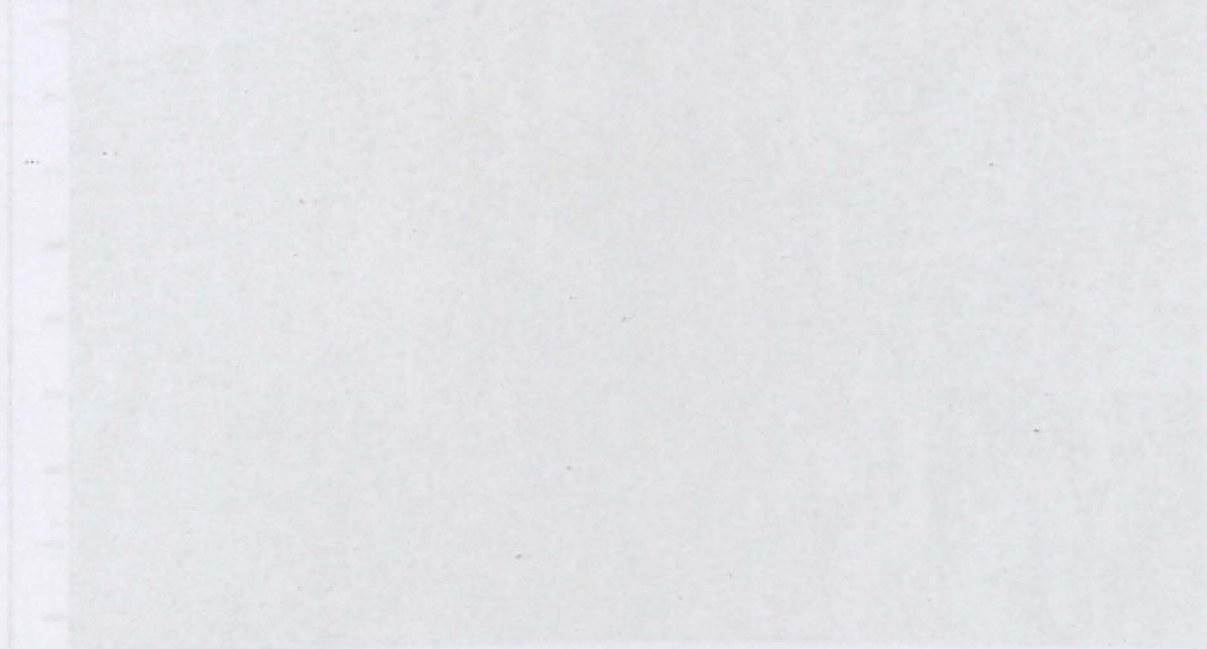


Figure 60: Fluid escape structure associated with the Dolphin Graben boundary fault. Shallow depth anomalies are interpreted as gas accumulation.

5.3 Hydrocarbon potential of the Dolphin Graben

A working petroleum system has been proven with the Wingat-1 oil discovery in the southern Walvis Basin from where light-oil samples had been retrieved (Hodgson & Intawong, 2013). In the northern Walvis Basin, i.e. the Dolphin Graben, small amounts of migrated hydrocarbons had been detected in well 1911/15-1, but the source itself has not been intersected. Another hint for a working petroleum system in the Dolphin Graben gives fluid escape structures identified above the western boundary faults of the graben (Fig. 60).

Those fluid escape features have been identified as “gas chimneys” by Kukulus (2004). Above the vertical “gas chimneys” shallow (<300ms TWT beneath seabed) bright amplitudes occur, which are interpreted as shallow gas accumulations. Their position above the gas chimneys suggest that these are rather accumulations of thermogenic than biogenic gas.

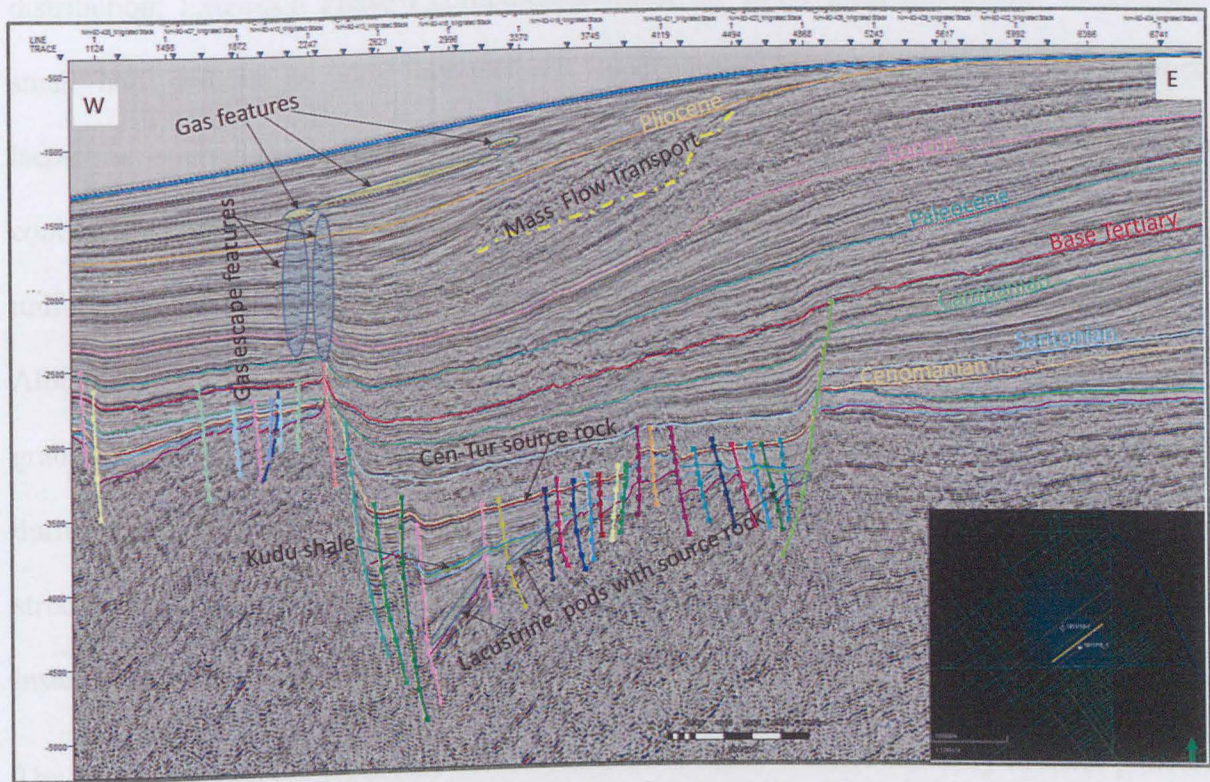


Figure 60. Fluid escape structures interpreted as gas chimneys above the western Dolphin Graben boundary fault. Shallow bright amplitudes are interpreted as gas accumulations.

Candidates for mature source rocks are the seismically identified marine Aptian-Albian (Kudu Shale) and possible deeper (Neocomian-Barremian) likely lacustrine shales.

As outlined in section 4.4.4 reservoirs rocks of high to moderate reservoir quality are the Aptian Albian carbonates on the central structural high, and shallower turbidite sandstones.

5.3.1 Source rock distribution

The Aptian-Albian source rock is laterally extensive in the Dolphin Graben and is only condensed or absent on the central structural highs and graben flanks. Deeper lacustrine source rocks are expected to be restricted to local pods associated with volcanic and clastic material deposited in smaller half grabens of the early Extension Sequence I.

The two distinct extension phases of the Dolphin Graben controlled the above source rock distribution: Extension Phase I compartmentalized the developing continental margin into small half grabens as local syn-tectonic depocentres allowing only laterally confined lacustrine source rock deposition. With the onset of Extension Phase II subsidence concentrated at the main boundary faults of the evolving Dolphin Graben, forming a more uniform depository during the first marine incursion and subsequent deposition of the Aptian-Albian source rock. Reflections of the lowermost Extension Sequence II thin out towards the graben flanks and the central structural highs, suggesting either condensed or non-deposition during initial transgression. Thus, the Aptian-Albian source rock did not develop on the structural highs, probably because bottom waters were oxic at shallow water depth, and instead of carbonaceous shales, shallow water carbonates deposited.

The deeper speculative lacustrine source rocks have likely reached maturity in most parts of the Dolphin Graben, whereas the shallower, but more extensive Aptian-Albian source rocks achieve maturity only in its deeper parts, away from the flanks and structural highs. The

Dolphin Graben provides an important local depocentre for relatively deep burial of Cretaceous sediments on the otherwise relative shallow slope of the northern Walvis Basin. Hence, source rocks deposited adjacent, but outside of the Dolphin Graben are unlikely to have reached maturity.

5.3.2 Charge access

All faults are associated with early Cretaceous growth strata, suggesting a uniform timing of fault initiation. This is much before the deposition of the thick Cainozoic sequence which caused the burial of Lower Cretaceous strata to thermal maturity depths (Figs. 44-46). Hence, all faults that could serve as quasi vertical migration pathways to younger reservoir rocks had been present prior petroleum generation. Most faults terminate in the Santonian interval, while those at the Dolphin Graben boundary reach into the Paleogene. Hence, fault augmented charge access to Tertiary strata is best at the margins of the Dolphin Graben, while the intra-graben faults could have rather augmented charge access to early upper Cretaceous reservoirs.

Migration along bed boundaries or intra source permeable sand stringers should be considered as an alternative or additional possibility for source to reservoir migration. In the Wingat-1 well light oil was recovered from intra source rock sand stringers, suggesting that oil can migrate laterally within the wider Aptian-Albian source rock interval. In the same sense, the Aptian-Albian carbonates situated on the structural highs can be directly charged from the downdip correlative source rock facies.

Aptian-Albian shallow water carbonates on the structural high show that the sea level rose quickly above the structural high contemporaneously with source rock deposition in the deeper graben. Hence, the Aptian-Albian carbonates are located directly up-dip of the

contemporaneous source rocks which enhances the change of charge access by lateral migration along bed boundaries, or intra source sand stringers analogue to the Wingat-1 well.

of the Dolphin Graben. The Dolphin Graben system is described into two parts, in terms of (1) its regional geological setting in the northern Waiyapa Basin, (2) of graben evolution and associated extension phases. The reconstruction of the Dolphin Graben was achieved and consequently, led to assignment of the source rock sequence and maturity as well as the determination of timing and hydrocarbon migration. All these, related to the hydrocarbon assessment of the Dolphin Graben.

6.1 Detailed Structural Evolution

6.1.1 Regional setting of the Dolphin Graben

The Dolphin Graben is a local rift situated immediately south of the Walvis Ridge and the Phoenix Volcanic Field on the continental slope. In the area of the graben the slope is shallower compared to the northern Walvis Basin, probably due to thickened crust beneath Dipping Reflectors (SDRs) of both the main SDRs and to a lesser extent, the cover SDRs package forms the basement to the graben. The initial syn-rift sequence is accumulated in the central half graben, which is older and located immediately east of the Dolphin Graben. Therefore, the Dolphin Graben is a rift system that is independent from the general N-S trending margin syn-rift sequences. In fact, most of the graben subsidence occurred during the early passive margin drift phase. The mechanism for this local rift is not understood but could relate to local tectonic anomalies associated with the volcanism at the adjacent Phoenix Volcanic Field and Walvis Ridge.

CHAPTER 6 - CONCLUSIONS AND RECOMMENDATIONS

This study has refined the geological understanding (structural evolution and burial history) of the Dolphin Graben. The detailed structural evolution is described into two parts: in terms of (1) its regional geological setting in the northern Walvis Basin, (2) of graben evolution and associated extension phases. The reconstruction of the burial history was achieved and consequently, led to assessment of the source rock presence and maturity as well as the determination of timing and hydrocarbon migration. All these, culminated in the hydrocarbon re-assessment of the Dolphin Graben.

6.1 Detailed Structural Evolution

6.1.1 Regional setting of the Dolphin Graben

The Dolphin Graben is a local rift situated immediately south of the Walvis Ridge and the Phoenix Volcanic Field on the continental slope. In the area of the graben the slope is shallower compared to the southern Walvis Basin, probably due to thickened crust. Seawards Dipping Reflectors (SDRs) of both, the inner SDRs and to a lesser extent, the outer SDRs package forms the basement to the graben. The initial syn-rift sequence is accommodated in the central half graben, which is older and located immediately east of the Dolphin Graben. Therefore, the Dolphin Graben is a rift system that is independent from the general Namibian margin syn-rift sequence. In fact, most of the graben subsidence occurred during the early passive margin drift phase. The mechanism for this local rift is not understood but could relate to local mantle anomalies associated with the volcanism at the adjacent Phoenix Volcanic Field and Walvis Ridge.

6.1.2 Dolphin Graben evolution

Extension of initially smaller en-échelon half grabens commenced soon after SDRs deposition and created accommodation space for Extension Sequence I that occupied the area of the evolving Dolphin Graben. Graben fills are syn-tectonic growth strata of likely continental deposition. From the Intra-Aptian-Albian unconformity onwards, extension concentrated to the western and eastern boundary faults while the intra-graben faults became largely inactive. This led to a more connected depository within the graben that was now deep enough to allow marine deposition of Extension Sequence II. Central structural highs formed within the graben as a result of differential faults throws and block rotations. The graben master faults became inactive within the lower Paleogene, while the intra-graben faults already terminated in the Santonian. The graben morphology was successively filled and finally draped in the mid-upper Paleogene. Figure 61 below depicts summary of stages of the Dolphin Graben structural evolution.

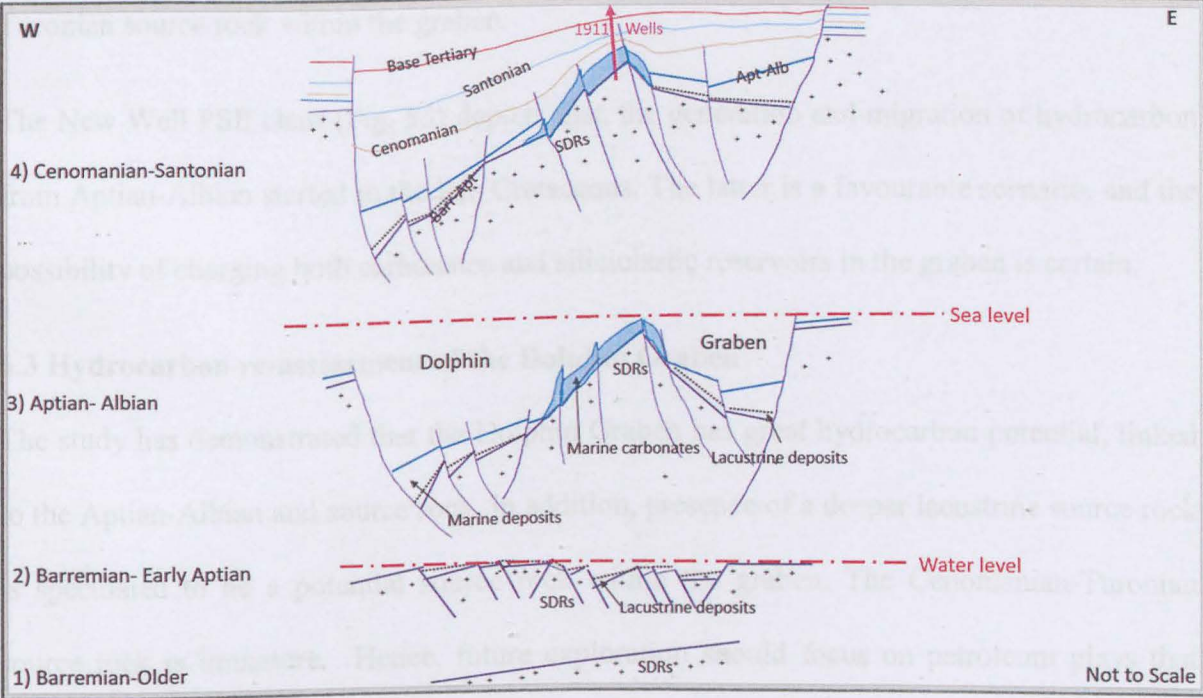


Figure 61. Cartoon summarizing the Dolphin Graben structural evolution.

6.2 Burial History

6.2.1 *Source rock presence and maturity; determination of timing and hydrocarbon migration*

Three source rock intervals are postulated to occur within the Dolphin Graben. Local lacustrine source rocks may have been deposited in local rift lakes during Extension Sequence I. The second source rock interval formed during the Aptian-Albian marine transgression, and it has been identified as a seismic marker is, laterally extensive, but absent on the structural highs. The third source rock interval was deposited during the global Cenomanian-Turonian highstand. This source rock has been identified in two exploration wells located in the central Dolphin Graben, and it ties well with a continuous seismic marker horizon.

Burial and thermal modelling revealed early to middle stages of oil window maturity for the lacustrine and Aptian-Albian source rocks, but at best only early maturity of the Cenomanian-Turonian source rock within the graben.

The New Well PSE chart (Fig. 55) depicts that, the generation and migration of hydrocarbon from Aptian-Albian started in the late Cretaceous. The latter is a favourable scenario, and the possibility of charging both carbonates and siliciclastic reservoirs in the graben is certain.

6.3 Hydrocarbon re-assessment of the Dolphin Graben

The study has demonstrated that the Dolphin Graben has great hydrocarbon potential, linked to the Aptian-Albian and source rock. In addition, presence of a deeper lacustrine source rock is speculated to be a potential source rock within the graben. The Cenomanian-Turonian source rock is immature. Hence, future exploration should focus on petroleum plays that involve the Aptian-Albian source rocks. This source rock is laterally extensive with good chances for maturity and hydrocarbon expulsion in the deeper areas of the Dolphin Graben.

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APPENDICES

Appendix 1: Tables with fault displacement measurements carried out in Petrel software

Table 16. Fault displacements measurements on seismic line NH-92-205

Fault displacements measurements for the seismic line NH-92-205									
Fault #	Fault stick/ plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
1	Blue	262.42	43.46	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
64	Red	111.9	30.43	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
11	Purple	106.18	39.12	12.91	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
5	Light Pink	97.93	43.63	20.53	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
22	Red	44.58	35.61	22.55	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
23	Dark Pink	161.64	85.35	58.42	30.96	17.69	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
2	Bluish Green	401.12	96.31	62.5	43.49	24.41	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	

Table 17. Fault displacements measurements on seismic line NH-92-208

Fault displacements measurements for the seismic line NH-92-208									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)						Remarks	
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary		Paleocene
1	Blue	420.72	132.11	77.78	14.45	11.89	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
64	Red	68.80	36.15	14.12	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
11	Purple	58.08	22.11	14.66	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
5	Light Pink	281.96	65.17	42.16	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
22	Red	56.44	40.93	26.45	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
23	Dark Pink	216.03	75.10	57.10	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	
2	Bluish Green	629.06	203.40	93.40	90.18	25.10	Beyond seismic resolution/ not recognised	Beyond seismic resolution/ not recognised	

Table 18. Fault displacements measurements on seismic line NH-92-211

Fault displacements measurements for the seismic line NH-92-211									
Fault #	Fault stick/plane color	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
1	Blue	356.50	322.45	167.19	108.24	48.14	38.37	Beyond seismic resolution not recognised	
64	Red	58.78	25.49	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
11	Purple	306.02	130.05	16.30	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
5	Light Pink	149.92	40.45	27.61	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
22	Red	0	0	0	0	0	0	0	Absent/Not visible on this line
23	Dark Pink	0	0	0	0	0	0	0	Absent/Not visible on this line
2	Bluish Green	810.33	683.14	308.47	179.25	39.06	22.88	Beyond seismic resolution not recognised	

Table 19. Fault displacements measurements on seismic line NH-92-214

Fault displacements measurements for the seismic line NH-92-214									
Fault #	Fault stick/plane color	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
1	Blue	615.30	540.85	109.1	98.53	51.61	25.60	Beyond seismic resolution not recognised	
64	Red	0	0	0	0	0	0	0	Absent/Not visible on this line
11	Purple	155.90	152.86	25.36	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
5	Light Pink	0	0	0	0	0	0		Absent/Not visible on this line
22	Red	0	0	0	0	0	0		Absent/Not visible on this line
23	Dark Pink	0	0	0	0	0	0		Absent/Not visible on this line
2	Bluish Green	987.87	695.56	272.18	196.15	44.42	17.06	Beyond seismic resolution not recognised	

Table 20. Fault displacements measurements on seismic line NH-92-215

Fault displacements measurements for the seismic line NH-92-215									
Fault #	Fault stick/plane color	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
1	Blue	622.24	454.58	161.78	111.94	59.34	32.26	Beyond seismic resolution/not recognised	
64	Red	0	0	0	0	0	0		Absent/Not visible on this line
11	Purple	110.94	54.29	26.03	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Absent/Not visible on this line
5	Light Pink	214.77	24.88	17.04	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	
206	Green	63.54	36.90	29.87	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	Beyond seismic resolution/not recognised	
23	Dark Pink	0	0	0	0	0	0		Absent/Not visible on this line
2	Bluish Green	927.36	838.16	463.21	248.60	55.78	47.70	Beyond seismic resolution/not recognised	

Table 21. Fault displacements measurements on seismic line NH-92-220

Fault #	Fault stick/plane colour	Fault displacements measurements for the seismic line NH-92-220							Remarks
		Fault displacements/throws in (negative) time (ms)							
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
3	Yellowish green	282.84	186.60	170.14	43.44	26.26	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
61	Greenish blue	93.36	34.53	21.68	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
44	Neo-green	235.60	146.47	67.65	27.74	14.71	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
6	Lavender (light purplish blue)	488.27	230.66	49.11	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
20	Bright green	79.59	51.80	38.16	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
23	Dark Pink	0	0	0	0	0	0	0	Absent/Not visible on this line
2	Bluish Green	375.35	329.60	70.35	46.26	29.28	14.97	Beyond seismic resolution not recognised	

Table 22. Fault displacements measurements on seismic line NH-92-223

Fault displacements measurements for the seismic line NH-92-223									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
3	Yellowish green	208.55	82.97	50.33	37.89	25.67	18.43	Beyond seismic resolution not recognised	
61	Greenish blue	247.94	127.82	27.09	14.21	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
44	Neo-green	155.95	76.51	51.51	29.89	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
6	Lavender	637.00	392.32	35.98	28.88	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
334	Red	64.61	43.11	37.81	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
23	Dark Pink	0	0	0	0	0	0	0	Absent/Not visible on this line
18	Navy blue	185.59	124.11	112.17	40.36	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	

Table 23. Fault displacements measurements on seismic line NH-92-227

Fault displacements measurements for the seismic line NH-92-227									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
3	Neon	161.27	55.91	40.06	32.49	22.83	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
61	Greenish blue	168.85	54.43	31.38	23.01	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
30	Light blue	267.07	62.33	27.55	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
49	Blue	271.1	58.93	24.61	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
4	Orange	483.98	260.43	116.16	29.88	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
6	Lavender	116.6	58.97	30.41	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
334	Red	0	0	0	0	0	0	0	Absent/Not visible on this line
23	Dark Pink	0	0	0	0	0	0	0	Absent/Not visible on this line
18	Navy blue	356.96	228.49	166.84	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	

Table 24. Fault displacements measurements on seismic line NH-92-230

Fault displacements measurements for the seismic line NH-92-230									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	Remarks
31	Light blue	260.36	188.00	64.61	33.28	21.65	12.16	Beyond seismic resolution not recognised	
33	Light Yellow	87.35	60.69	23.28	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
30	Light blue	172.44	47.53	18.55	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
36	Navy blue	168.15	107.06	62.14	41.34	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
49	Blue	38.64	20.82	12.78	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
4	Orange	187.89	87.29	64.14	30.15	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
271	Lavender	0	0	0	0	0	0		Absent Not visible on this line
46	Navy blue	0	0	0	0	0	0		Absent Not visible on this line

Table 25. Fault displacements measurements on seismic line NH-92-234

Fault displacements measurements for the seismic line NH-92-234									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
31	Light blue	117.33	77.21	35.75	26.80	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
33	Light Yellow	66.07	43.04	20.24	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
66	Navy blue	154.54	27.77	14.69	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
65	Pink	152.29	134.13	25.93	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
29	Light pink	125.10	75.56	35.41	24.37	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
4	Orange	659.66	567.62	363.99	88.63	50.31	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
271	Lavender	0	0	0	0	0	0	0	Absent Not visible on this line
46	Navy blue	0	0	0	0	0	0	0	Absent Not visible on this line

Table 26. Fault displacements measurements on seismic line NH-92-238

Fault displacements measurements for the seismic line NH-92-238									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
31	Light blue	102.28	87.67	66.99	57.56	24.44	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
33	Light Yellow	117.14	27.46	11.77	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
66	Navy blue	68.84	20.95	14.74	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
65	Pink	290.84	81.02	56.55	27.18	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
29	Light pink	74.01	43.11	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
26	Bluish green	273.04	74.35	47.35	18.25	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
271	Lavender	0	0	0	0	0	0	0	Absent Not visible on this line
46	Navy blue	0	0	0	0	0	0	0	Absent Not visible on this line

Table 27. Fault displacements measurements on seismic line NH-92-242

Fault displacements measurements for the seismic line NH-92-242									
Fault #	Fault stick/plane colour	Fault displacements/throws in (negative) time (ms)							Remarks
		Base Ext I (?Barr-Apt)	Base Ext II (?Apt-Alb)	Cenomanian	Santonian	Campanian	Base Tertiary	Paleocene	
133	Bluish green	113.98	23.76	20.73	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
8	Light green	226.32	158.12	158.12	118.45	39.53	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
339	Neo	73.12	40.19	17.50	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
338	Bluish green	56.98	38.41	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
27	Neo	316.15	60.49	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	Beyond seismic resolution not recognised	
29	Light pink	0	0	0	0	0	0	0	Absent Not visible on this line
26	Bluish green	0	0	0	0	0	0	0	Absent Not visible on this line

Appendix 2: Tables with input data for the three locations (well 1911/10-1, well 1911/15-1 and New (Pseudo) well) modelled in PetroMod

Table 28. Input table for 1911/10-1

Main input for 1911-10-1d model

Present day input: ☒ Depth ☐ Thickness ☐ Show paleo balance ☐ Model from picks... ☒ Top names ☐ Layer names

☒ 6.00

Age [Ma]	Name top/well pick	Depth [m]	Thickness [m]	Event type	Name layer/event	Paleodeposition/ erosion [m]	Lithology	PSE	Kinetic	TOC [%]	H# [mgHC/gTOC]
0.00	Seabed	631	835	↓ Deposition	Seabed		Shale (typical)	Overburden Rock			
5.30	Early Miocene	1466	14	↓ Deposition	Early Miocene		Shale (organic lean, silty)	Overburden Rock			
23.03	Late Oligocene	1480	14	↓ Deposition	Late Oligocene		Shale (organic lean, silty)	Overburden Rock			
28.30	Early Oligocene	1649	60	↓ Deposition	Early Oligocene		Shale (organic lean, silty)	Overburden Rock			
33.90	Late Eocene	1709	163	↓ Deposition	Late Eocene		Shale (organic lean, silty)	Overburden Rock			
41.20	Middle Eocene	1872	237	↓ Deposition	Middle Eocene		Shale (organic lean, silty)	Overburden Rock			
47.80	Early Eocene	2109	78	↓ Deposition	Early Eocene		Shale (organic lean, silty)	Overburden Rock			
56.00	Late Paleocene	2188	136	↓ Deposition	Late Paleocene		Shale (organic lean, silty)	Overburden Rock			
61.60	Early Paleocene	2323	119	↓ Deposition	Early Paleocene		Shale (organic lean, silty)	Overburden Rock			
66.00	Maastrichtian	2442	196	↓ Deposition	Maastrichtian		Shale (organic lean, silty)	Overburden Rock			
70.00	Basal Maastrichtian to Campanian	2638	114	↓ Deposition	Basal Maastrichtian to Campanian		Shale (organic lean, silty)	Overburden Rock			
72.10	Late Campanian	2752	498	↓ Deposition	Late Campanian		Shale (organic lean, silty)	Overburden Rock			
75.00	Early Campanian	3250	42	↓ Deposition	Early Campanian		Sandstone (typical)	Reservoir Rock			
83.60	Santonian	3292	128	↓ Deposition	Santonian		Shale (organic lean, silty)	Overburden Rock			
86.30	Coniacian	3420	57	↓ Deposition	Coniacian		Shale (typical)	Overburden Rock			
89.80	Turonian	3477	165	↓ Deposition	Turonian		Shale (organic rich, typical)	Source Rock			
93.90	Cenomanian	3642	58	↓ Deposition	Cenomanian		Shale (organic rich, typical)	Source Rock			
100.50	Late Albian	3700	150	↓ Deposition	Late Albian		Shale (organic lean, silty)	Overburden Rock			
110.00	Early Albian	3850	6	↓ Deposition	Early Albian		Limestone (acid grainstone)	Reservoir Rock			
120.00	Albian to Barremian	3956	164	↓ Deposition	Albian to Barremian		Limestone (acid grainstone)	Reservoir Rock			
127.00	Barremian	4020	0	↓ Deposition	Barremian		Basalt (weathered)	Underburden Rock			
128.00	Barremian to Older	4020									

Table 29. Input table for 1911/15-1

Main input for 1911-15-1D											
Present day input: ☒ Depth ☐ Thickness ☐ Show paleo balance ☐ Model from picks... ☐ Top names ☐ Layer names											
☒ 0.00											
Age [Ma]	Name top/well pick	Depth [m]	Thickness [m]	Event type	Name layer/event	Paleodeposition/erosion [m]	Lithology	PSE	Kinetic	TOC [%]	HI [mgHC/gTOC]
0.00	Seabed	522									
		400	↓ Deposition	Seabed			Sandstone (typical)	Overburden Rock			
4.50	Pliocene	912									
		108	↓ Deposition	Pliocene			Sandstone (typical)	Overburden Rock			
13.82	Middle Miocene	1030									
		240	↓ Deposition	Middle Miocene			Shale (typical)	Overburden Rock			
20.44	Lower Miocene	1230									
		207	↓ Deposition	Lower Miocene			Shale (typical)	Overburden Rock			
23.03	Upper Oligocene	1477									
		33	↓ Deposition	Upper Oligocene			Shale (typical)	Overburden Rock			
28.10	Lower Oligocene	1530									
		140	↓ Deposition	Lower Oligocene			Shale (typical)	Overburden Rock			
33.90	Upper Eocene	1650									
		140	↓ Deposition	Upper Eocene			Shale (typical)	Overburden Rock			
41.20	Middle Eocene	1790									
		155	↓ Deposition	Middle Eocene			Marl	Seal Rock			
47.80	Lower Eocene	1945									
		80	↓ Deposition	Lower Eocene			Marl	Seal Rock			
56.00	Upper Paleocene	2025									
		372	↓ Deposition	Upper Paleocene			Marl	Seal Rock			
57.00	Middle Paleocene	2387									
		66	↓ Deposition	Middle Paleocene			Sandstone (subarkose, typical)	Reservoir Rock			
59.00	Lower Paleocene	2463									
		110	↓ Deposition	Lower Paleocene			Sandstone (subarkose, typical)	Reservoir Rock			
66.00	Maastrichtian	2572									
		34	↓ Deposition	Maastrichtian			Shale (typical)	Overburden Rock			
72.01	Upper Campanian	2607									
		120	↓ Deposition	Upper Campanian			Shale (typical)	Overburden Rock			
80.10	Lower Campanian	2727									
		398	↓ Deposition	Lower Campanian			Shale (typical)	Overburden Rock			
83.60	Upper Santonian	3125									
		90	↓ Deposition	Upper Santonian			Shale (typical)	Overburden Rock			
83.90	Middle Santonian	3215									
		40	↓ Deposition	Middle Santonian			Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	3.06	432.00
84.10	Lower Santonian	3255									
		25	↓ Deposition	Lower Santonian			Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	5.15	432.00
86.30	Coniacian	3280									
		52	↓ Deposition	Coniacian			Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	3.12	432.00
91.10	Middle-Lower Turonian	3332									
		33	↓ Deposition	Middle-Lower Turonian			Shale (organic rich, typical)	Source Rock	Burnham(1989)_TII	2.40	432.00
92.00	Lower Turonian	3365									
		5	↓ Deposition	Lower Turonian			Shale (organic rich, typical)	Source Rock	Burnham(1989)_TII	2.99	432.00
92.50	Lowermost Turonian	3370									
		85	↓ Deposition	Lowermost Turonian			Shale (typical)	Overburden Rock			
92.60	Uppermost Cenomanian	3455									
		24	↓ Deposition	Uppermost Cenomanian			Shale (organic rich, 8% TOC)	Source Rock	Burnham(1989)_TII	8.56	596.00
93.90	Upper Cenomanian	3479									
		51	↓ Deposition	Upper Cenomanian			Siltstone (organic lean)	Overburden Rock			
98.10	Lower Cenomanian	3530									
		50	↓ Deposition	Lower Cenomanian			Shale (organic lean, silty)	Overburden Rock			
100.50	Upper Albian	3580									
		58	↓ Deposition	Upper Albian			Shale (typical)	Seal Rock			
110.10	Middle Albian	3638									
		86	↓ Deposition	Middle Albian			Shale (typical)	Seal Rock			
112.10	Upper Aptian	3724									
		106	↓ Deposition	Upper Aptian			Limestone (ooid grainstone)	Reservoir Rock			
113.00	Upper Aptian-Barremian	3830									
		192	↓ Deposition	Upper Aptian-Barremian			Limestone (ooid grainstone)	Reservoir Rock			
125.00	Barremian	4022									

Table 30. Input table for New (Pseudo) Well

Main input for New-well											
Present day input: ☒ Depth ☐ Thickness ☐ Show paleo balance ☐ Model from picks... ☐ Top names ☐ Layer names											
Age [Ma]	Flame top/well pick	Depth [m]	Thickness [m]	Event type	Flame layer/event	Paleodeposition/erosion [m]	Lithology	PSE	Kinetic	TOC [%]	HI [mgHC/gTOC]
0.00	Seabed	532									
			400	↓ Deposition	Seabed		Sandstone (typical)	Overburden Rock			
4.50	Pliocene	922									
			108	↓ Deposition	Pliocene		Sandstone (typical)	Overburden Rock			
13.82	Middle Miocene	1030									
			240	↓ Deposition	Middle Miocene		Shale (typical)	Overburden Rock			
20.44	Lower Miocene	1270									
			207	↓ Deposition	Lower Miocene		Shale (typical)	Overburden Rock			
23.03	Upper Oligocene	1477									
			33	↓ Deposition	Upper Oligocene		Shale (typical)	Overburden Rock			
28.10	Lower Oligocene	1510									
			140	↓ Deposition	Lower Oligocene		Shale (typical)	Overburden Rock			
33.90	Upper Eocene	1650									
			140	↓ Deposition	Upper Eocene		Shale (typical)	Overburden Rock			
41.20	Middle Eocene	1790									
			155	↓ Deposition	Middle Eocene		Marl	Seal Rock			
47.80	Lower Eocene	1945									
			80	↓ Deposition	Lower Eocene		Marl	Seal Rock			
56.00	Upper Paleocene	2025									
			372	↓ Deposition	Upper Paleocene		Marl	Seal Rock			
57.00	Middle Paleocene	2397									
			66	↓ Deposition	Middle Paleocene		Sandstone (subarkose, typical)	Reservoir Rock			
59.00	Lower Paleocene	2463									
			109	↓ Deposition	Lower Paleocene		Sandstone (subarkose, typical)	Reservoir Rock			
66.00	Maastrichtian	2572									
			35	↓ Deposition	Maastrichtian		Shale (typical)	Overburden Rock			
72.01	Upper Campanian	2607									
			120	↓ Deposition	Upper Campanian		Shale (typical)	Overburden Rock			
80.10	Lower Campanian	2727									
			398	↓ Deposition	Lower Campanian		Shale (typical)	Overburden Rock			
83.60	Upper Santonian	3125									
			90	↓ Deposition	Upper Santonian		Shale (typical)	Overburden Rock			
83.90	Middle Santonian	3215									
			40	↓ Deposition	Middle Santonian		Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	3.06	432.00
84.10	Lower Santonian	3255									
			25	↓ Deposition	Lower Santonian		Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	5.15	432.00
86.30	Coniacian	3280									
			52	↓ Deposition	Coniacian		Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	3.12	432.00
91.10	Middle-Lower Turonian	3332									
			33	↓ Deposition	Middle-Lower Turonian		Shale (organic rich, typical)	Source Rock	Burnham(1989)_TII	2.40	432.00
92.00	Lower Turonian	3365									
			5	↓ Deposition	Lower Turonian		Shale (organic rich, typical)	Source Rock	Burnham(1989)_TII	2.99	432.00
92.50	Lowermost Turonian	3370									
			85	↓ Deposition	Lowermost Turonian		Shale (typical)	Overburden Rock			
92.60	Uppermost Cenomanian	3455									
			24	↓ Deposition	Uppermost Cenomanian		Shale (organic rich, 8% TOC)	Source Rock	Burnham(1989)_TII	8.56	596.00
93.90	Upper Cenomanian	3479									
			51	↓ Deposition	Upper Cenomanian		Siltstone (organic lean)	Overburden Rock			
98.10	Lower Cenomanian	3530									
			562	↓ Deposition	Lower Cenomanian		Shale (organic lean, silty)	Overburden Rock			
112.00	Top Apt-Alb SR	4092									
			121	↓ Deposition	Top Apt-Alb SR		Shale (organic rich, 3% TOC)	Source Rock	Burnham(1989)_TII	5.00	780.00
120.00	Base Apt-Alb SR	4212									
			555	↓ Deposition	Base Apt-Alb SR		Shale (typical)	Underburden Rock			
125.00	Barremian	4767									