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2D SEISMIC INTERPRETATION AND 2D BASIN MODELING OF HYROCARBON GENERATION, MIGRATION AND ENTRAPMENT IN THE NORTH VIKING GRABEN.

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Abstract

The aim of the project is to use 2D basin modelling methodology in order to understand the petroleum system of the North Viking Graben. 2D seismic interpretation has been done regional and semi-regional lines using Petrel software. 2D basin modelling of selected lines followed the interpretation work and depth converted lines using PetroMod software.

The North Viking Graben petroleum system consists of the source rocks (Heather and Draupne Formations) of Bathonian to Kimmeridgian and Oxfordian to Ryazanian age respectively, reservoirs (Statfjord and Brent Groups) of Early and Middle Jurassic age respectively and seal (Cromer Knoll Group) of Lower Cretaceous age. The maturity of the source rock was analyzed by using temperature, vitrinite reflectance and transformation ratio.

The maturity history through time shows that the source rock started to mature and reaches early window during late Cretaceous period. Generation of hydrocarbons continues to present day. Transformation ratio shows that significant amounts of the source rocks have been transformed to produce hydrocarbons.

The deposition of reservoir, source and seal rocks occurred before the petroleum system processes (generation, migration and accumulation) took place. These processes were started during late Cretaceous time, which was followed by the period during which hydrocarbons within the petroleum system are preserved or destroyed. Traps were formed before hydrocarbon generation, in the late Jurassic to early Cretaceous. All these events occurred in the proper timing, which are very important for hydrocarbons to accumulate.

Migration of hydrocarbons from the source rocks is mainly vertically downwards, as the reservoir rock is older than the source rock. However, there is an area where the hydrocarbons have escaped through the faults and accumulate above the source rock. The generated hydrocarbons are both oil and gas.

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CHAPTER 1: INTRODUCTION

This chapter covers the concept of seismic data interpretation, basin and petroleum system modelling, previous studies, objectives of this study and location of the study area.

1.1 Seismic Data Interpretation

One of the most important tools for exploration of oil and gas is seismic data. Through the techniques of seismic data interpretation, which involves picking and interpreting laterally continuous and high amplitude reflectors, subsurface information can be acquired. Seismic data interpretation is a powerful tool in hydrocarbon exploration that requires a high level of understanding in its application.

Onajite (2013) argued that seismic data have become an important tool for the development of oil and gas fields as well as for monitoring oil/gas production and not just as an exploration tool. In addition, because of the importance of seismic data to the oil and gas industry, graduate geoscientists need to have clear understanding of seismic data. This will help to increase their opportunities for employment and make them more competent, effectively and integrate faster when working with an experienced geoscience team.

1.2 Basin and Petroleum System Modelling

Basin modelling as defined by Hantschel and Kauerauf (2009) is "*the dynamic modelling of geological process in a sedimentary basin over geological time spans*". Generally the deposition in the sedimentary basin starts with the oldest layer at the bottom and ends with the youngest layer at the top. Modeling a sedimentary basin involves reconstructing the whole history of the basin including periods of sedimentation, non-deposition, uplift and erosion.

In order to reconstruct the geological history of the sedimentary basin, it is important to build a model. The model is based on input data, which are simulated over several time steps and represents the geological processes (deposition, compaction, heat flow analysis petroleum generation etc.) that took place in the respective basin area and facilitate its development.

A Petroleum System is a geologic system that encompasses the petroleum source rocks and all related oil and gas accumulation, and which includes all of the geologic elements and processes that are essential if a petroleum accumulation is to exist (Magoon and Dow, 1994).

In order for the petroleum system to work successfully, six important elements are needed (Fig 1). All these should occur in the proper timing of events.

I. Rich and mature source rock, which is capable of generating hydrocarbons
II. High quality reservoir rock in terms of porosity and permeability
III. Migration pathway from source rock to the reservoir rock/trap
IV. Reservoir rock/trap to store the hydrocarbons
V. Seal rock with adequate sealing capacity that prevents hydrocarbons from further migration or leaking to the surface.
VI. Timing of the petroleum generation, migration and trap formation.

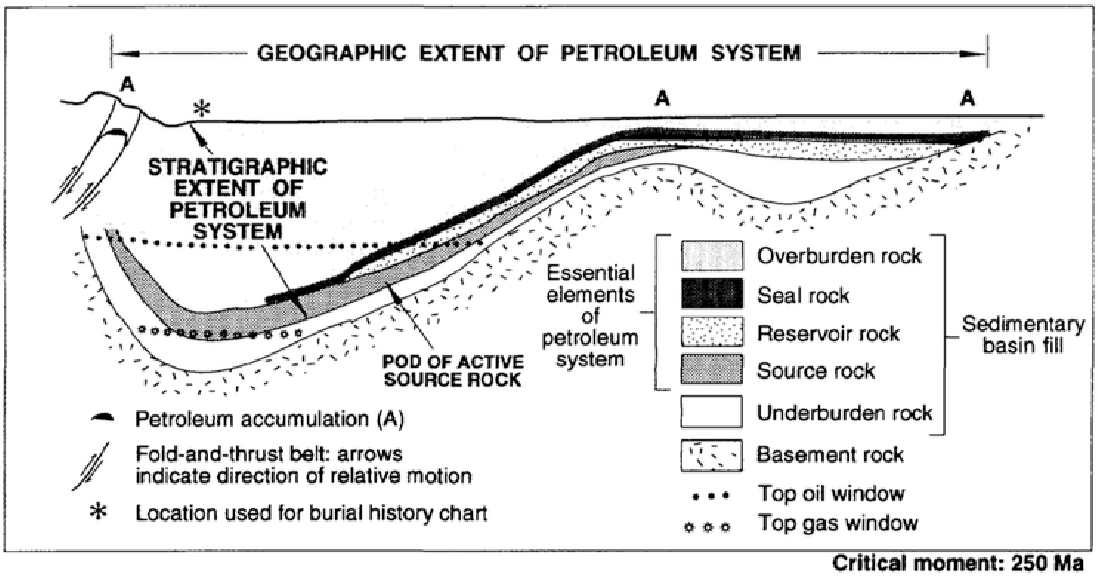


Figure 1: Petroleum system elements at the critical moment (250 Ma) (Magoon and Dow, 1994).

1.3 Previous Studies

Various studies in the Viking Graben basin and petroleum system modeling have been carried out and the findings have been used in improving the exploration activities in and around the area. Some examples are:

Earlier studies include that of Goff (1983), who investigated hydrocarbon generation and migration from Jurassic source rocks in the East Shetland Basin and Viking Graben. The approach used in his study was the first to define the hydrocarbon source rocks and their present day maturity, which were determined from vitrinite reflectance measurements on the Brent Formation coals and early Jurassic to mid-Cretaceous mudstones in 12 wells.

Other studies include that of Iliffe et al. (1991). They performed basin analysis predictions of known hydrocarbon occurrences, using the North Viking Graben as a test case. They used both 1D and 2D modeling techniques aimed at describing the structural and burial history of the North Viking Graben area; they determined a viable thermal history by considering different methods of calculating paleo-heat flow, as well as assigning a reasonable range of paleo-heat flow histories and testing the validity of the modeling in the area. One of their findings was that the Draupne Formation began hydrocarbon generation at 115 Ma in the centre of the graben finishing by about 75 Ma, whereas in the exterior parts of the graben generation began at around the Cretaceous-Tertiary boundary and continues to present.

Schroeder and Sylta (1993) performed 3D modeling of the hydrocarbon system of the North Viking Graben. A 3D model of the hydrocarbon system within the North Viking Graben was developed. The objectives of their study were to gain quantitative insights into the local hydrocarbon system and to use the results to aid in the risking and ranking of prospects.

Kubala et al. (2003) in the Millennium Atlas (chapter 17) showed both 1D and 2D modelling and their calibration was based upon available temperature and vitrinite reflectance data. They showed three 2D profiles in order to model timing and direction of expelled hydrocarbons from the main kitchen areas and to help in explaining the observed distribution of the hydrocarbon accumulations.

More recent research is that of Schlakker et al. (2011) focusing on burial, thermal and maturation history in the northern Viking Graben. They used seismic and exploration wellbore data from the northern part of the Viking Graben. Their major conclusion was that the source rocks of the study area were matured enough to generate oil and gas from the late Cretaceous time and the hydrocarbons are still being generated in the area at the present day. They also stated that the Brent sandstones and Heather sandstones can function as reservoirs, but suggested that further 3D modelling would be necessary to understand the migration in the study area.

1.5 Objectives of the Study

The main objective is to understand the petroleum system in the Northern Viking Graben Area through the use of 2D basin modelling methodology.

Specific objectives include:

- To determine the hydrocarbon generation history in the study area through subsidence history and thermal maturity modeling
- To model hydrocarbon migration pathways and accumulation (entrapment) by performing 2D modeling using PetroMod software

1.6 Location of the Study Area

The Viking Graben is a part of the North Sea graben system, which also includes the Central Graben and Moray Firth-Witch Ground graben. It is located between 59^0 40'N and $62^0$00'N, and from $2^0$00' to $4^0$00'E (Schroeder and Sylta, 1993). The East Shetland Basin and Tampen Spur in the west and the Horda Platform bound it to the east and the Sogn Graben bounds it to the north (Fig 2).

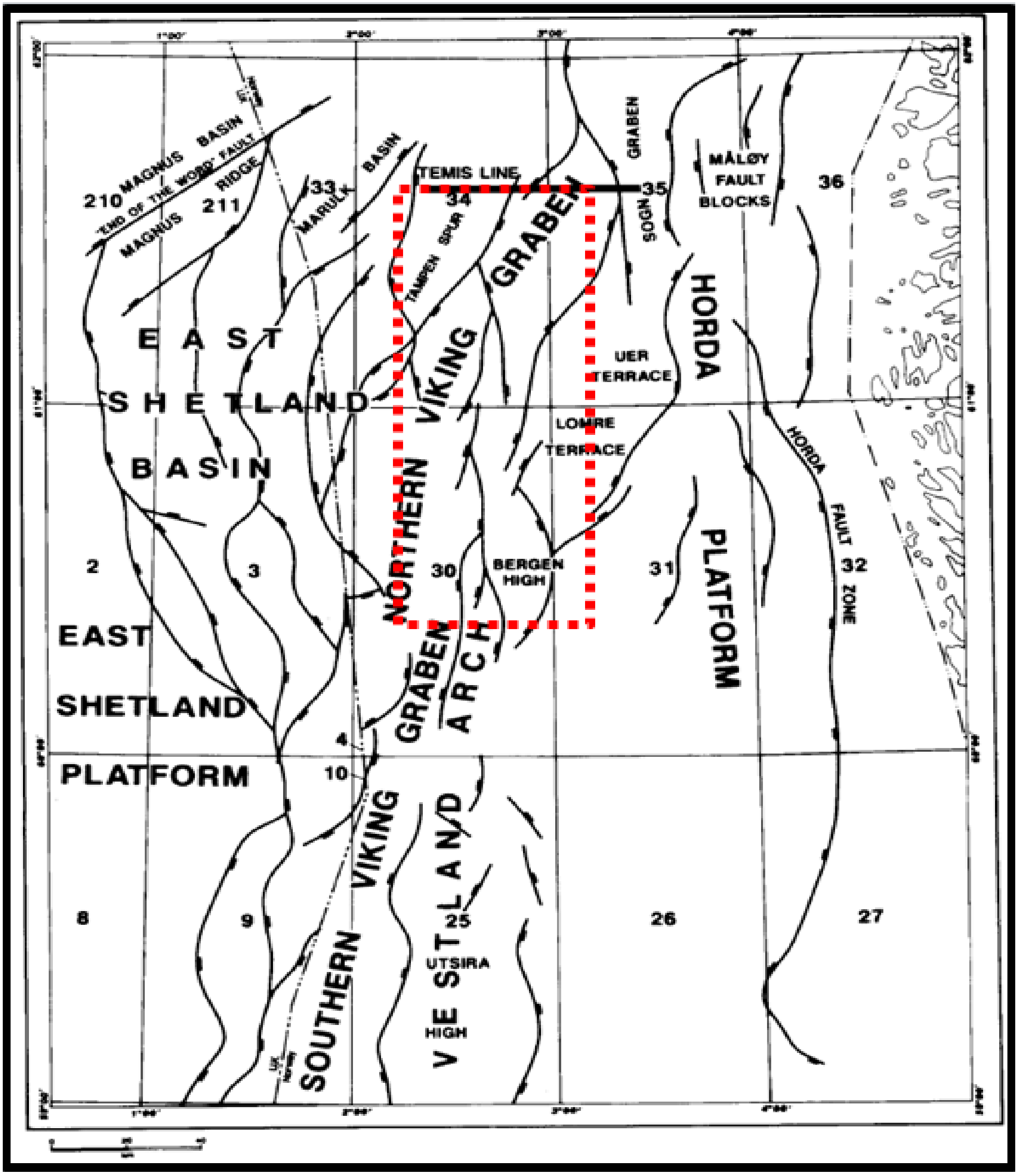


Figure 2: Regional map showing the location of the study area indicated by the red rectangle (modified from Moretti and Deacon, 1995).

CHAPTER 2: GEOLOGICAL SETTING

2.1 Brief Exploration History of the Northern North Sea

Generally the exploration activities in the North Sea began in the late 1960 to early 1970's. According to Pegrum and Spencer (1990), exploration in the northern North Sea up to 1990 involved the drilling of 1750 exploration and appraisal wells and resulted in 270 discoveries with originally recoverable hydrocarbon reserves and resources of 8.5 x 10^9 Sm^3 oil equivalent (50 x 10^9 bbl.). In 1971, Shell/Esso drilled a large buried structure in the northern North Sea and discovered the Brent field (Gautier, 2005). Mid-Jurassic deltaic sandstones of pre-rift origin characterize the Brent reservoirs. In addition, the discovery of Brent field, with 2 billion barrels of the recoverable liquids, prompted a new exploration strategy in the North Sea, resulting in numerous discoveries, mostly in the late 1970's especially in the northern North Sea.

Gautier (2005) suggested that the pursuit of the Brent exploration model, seeking shallow-marine or marginal-marine sandstone reservoir in fault blocks, resulted in the discovery of 10 major fields during the following 4 or 5 years, including the Statfjord field. Statfjord is one of the giant fields in the northern North Sea and is located mainly in Norwegian blocks 33/9 and 33/12, but extends into UK blocks 211/24 and 211/25. It is the North Sea's largest producing field, with recoverable reserves of 3 x 10^9 barrels of oil (Brennand et al., 1998).

The late Jurassic to early Cretaceous rifting event is one of the major factors which influenced to the occurrence of hydrocarbons as it created the trapping mechanism beneath the younger sediments. This is explained by Pegrum and Spencer (1990) who suggested that the occurrence of the hydrocarbons is intimately associated with the presence of a complex late Jurassic to early Cretaceous rift system buried beneath a Cretaceous and Tertiary cover. In addition to this, thick, organic-rich, syn-rift mudstones were laid down throughout most of the rift system and provide the main source rocks.

2.2 Structural Setting

The Viking Graben is believed to have undergone two rifting phases, each of which was followed by thermal subsidence. Badley et al. (1988) recognized the first episode as the Permo-Triassic with east-west extension producing a north-south trending graben system. This was followed by thermal subsidence during the late mid-Triassic to mid-

Jurassic period, which ended with the deposition of the Brent Group sands. The second rift phase as explained by Doré et al. (1985) took place during the late Jurassic depositing syn-rift sediments of the Heather and Draupne Formations. This episode was again followed by post rift subsidence.

2.2.1 Permo-Triassic Rifting Phase

Faleide et al. (2015) explained that an older major rift basin of Permo-Triassic age underlies the Viking Graben and its margins. Late Permian subsidence of the Moray Firth basin and the east-west trending Northern and Southern Permian Basins was possibly coeval with the initiation of subsidence in areas that were later to become the Viking and Central Graben systems (Glennie and Underhill, 1998). Thick, coarse-grained sediments, deposited along the rift margins, characterized the first rifting episode. Ravnas et al. (2000) suggested that the Permian-early Triassic syn-rift succession consists predominantly of non-marine, arid to semi-arid, aeolian, sabkha, alluvial and lacustrine strata, probably interbedded with marine strata. Although deeply buried, pre-Jurassic fault-blocks have been recognized both west and east of the Viking Graben, although the precise age of this extension is not known (Færseth, 1996).

2.2.2 Early to Middle Jurassic Pre-rift Phase

The transition from Triassic to Jurassic approximately coincides with a change from continental to shallow marine depositional environments and the climate also gradually became more humid (Faleide et al., 2015). According to Færseth (1996) Lower-Middle Jurassic strata have generally been assigned a post-rift status, and interpreted as representing a response to thermal subsidence following the late Permian-early Triassic rifting. The progressive regional thickening towards the basin centre of Triassic, Lower and Middle Jurassic sediments from both sides of the northern Viking Graben basin may be an expression of thermal subsidence associated with the Permo-Triassic rifting (Badley et al., 1984). In addition, Badley et al. (1984) deduce from thickness relationships that the Triassic rate of deposition was much higher than those of the Lower and Middle Jurassic, indicating waning subsidence with time, a characteristic of post-rift basin development.

2.2.3 Late Jurassic to Early Cretaceous Rifting Phase

Extension during this period resulted in the renewed generation of large tilted fault-blocks, and also in a marked compartmentalization creating of mosaic of smaller fault blocks, which represent the main hydrocarbon-trapping style in the northern North Sea (Færseth, 1996). Late Jurassic sediments gradually thicken towards the basin centre, with some local thinning on the footwall blocks (Giltner, 1987). The sequences formed during this time are the Heather and Draupne Formations of the Viking Group, which contain important source rocks in the Viking Graben area. It has been suggested that half-graben and wedge shaped infill geometries characterize both the Permo-Triassic and late Jurassic stretching events in the northern North Sea (Nottvedt et al., 1995). Fig 3 shows the rift margins with the major intra-basinal highs resulted from Permo-Triassic and late Jurassic rifting phases.

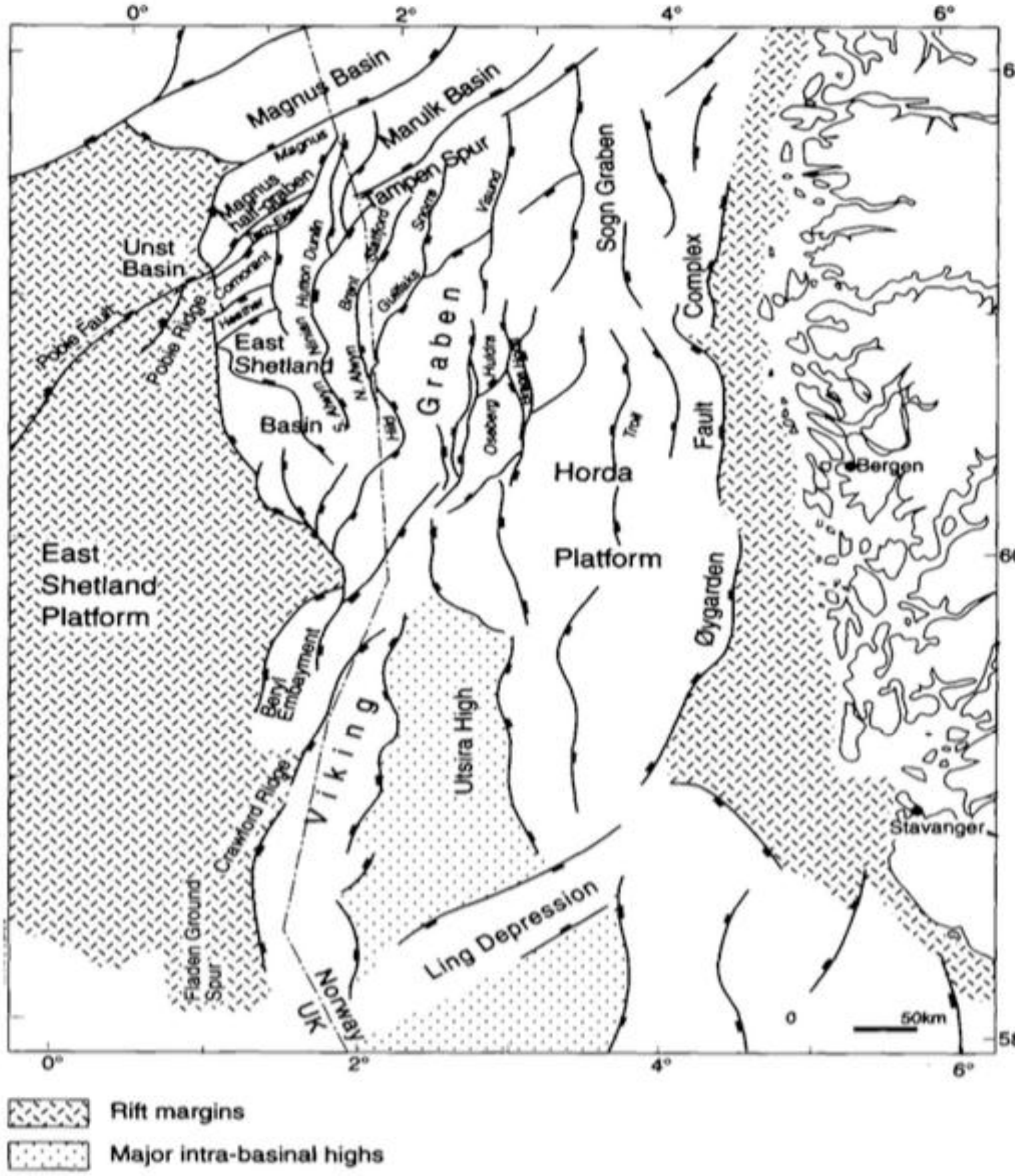


Figure 3: The northern North Sea rift zone resulting from Permo-Triassic and Late Jurassic rifting phases (Færseth, 1996).

The rifting events ceased during the early Cretaceous and were followed by thermal subsidence, although there was continued rifting along the flanks of the graben. The thermal subsidence, which was accompanied by faulting, resulted in the deposition of the thick early Cretaceous sediments from Ryazanian to Albian/Early Cenomanian.

Fig 4 from Christiansson et al. (2000) illustrates how the structures within the study area are characterized by large rotated fault blocks with sedimentary basins in asymmetric half-grabens associated with extension and crustal thinning.

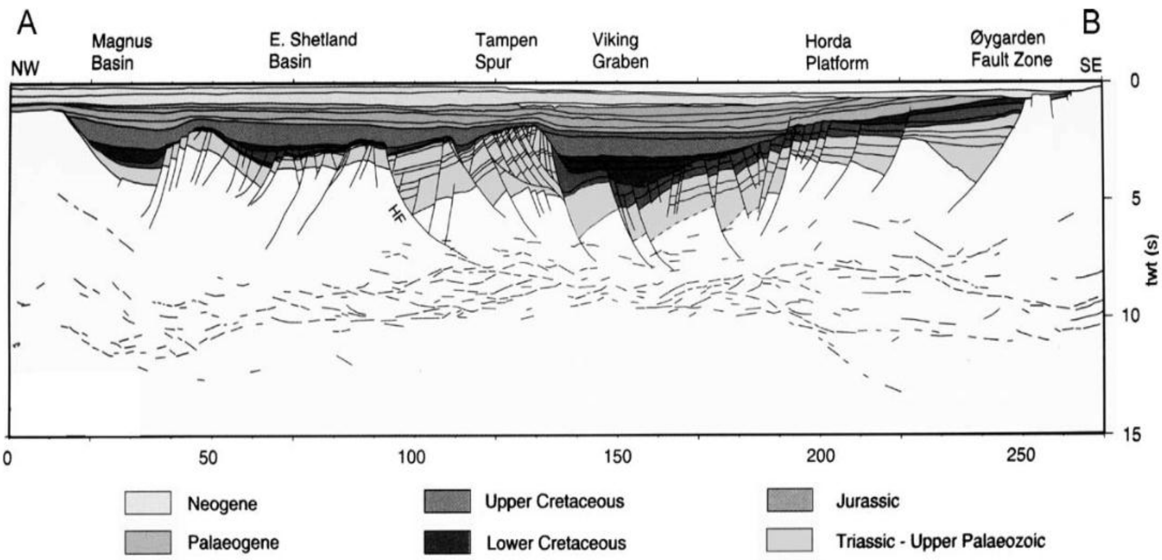


Figure 4: Interpreted regional seismic line depicting the broad stratigraphy and structure across the Viking Graben and its flanks (Christiansson et al., 2000).

2.2.4 Late Cretaceous to Cenozoic Post-rift Phase

Sediment deposition continued during the Cretaceous following the regional subsidence, which occurred in the late Cretaceous period and resulted in the deposition of the Shetland Group consisting mainly of shales, marls and mudstones. According to Badley et al. (1988), the subsidence became more extensive during this period, and was accommodated both by progressive basin-marginward movement of planar normal faulting, and also most of the basin was undergoing relatively uniform thermal subsidence.

2.3 Stratigraphy

The stratigraphic succession for the northern North Sea is given in Figure 7.

2.3.1 Permo-Triassic

The development of the northern Viking Graben began during the Permian-Triassic period, where regional extension resulted in the formation of a generally N-S trending graben system. The Hegre Group, which consists mainly of interbedded sandstones, shales and marls deposited from Scythian (Lower Triassic) to Rhaetian, is considered as the oldest; however there may be older sediments below it. According to Faleide et al. (2015) rifting occurred in late Permian to earliest Triassic time and the Triassic to Middle Jurassic succession reflects a pattern of repeated outbuilding of clastic wedges. Several features evidence the occurrence of the first episode of rifting event prior to the Triassic period. Badley et al. (1984) suggested that the regional basinward thickening of the Triassic, Lower and Middle Jurassic sediments is suggested to be a post-rift expression of the earlier rifting. Differential subsidence across faults throughout this period has also been reported and the Øygarden Fault forming the eastern margin of the Permo-Triassic basin was active throughout most of the time interval (Faleide et al., 2015). Sediment deposition continued throughout the Triassic period and, according to Ziegler (1981), the graben was almost completely infilled with sediment thicknesses reaching 3-4 km.

2.3.2 Jurassic

The early to middle Jurassic period was characterized by little faulting activities. The sediment deposition during this period resulted in the formation of Lower Jurassic Statfjord Group, which is an important reservoir rock in the northern North Sea. Above the Statfjord Group is the Dunlin Group, which consists of dark argillaceous marine sediments, but it lacks sufficient organic matter to become a potential source rock. The Brent Group was deposited in the Middle Jurassic between Bajocian to early Bathonian. The sandstones of the Brent Group form important reservoirs in the northern Viking Graben and coals within the Brent Group are potential source rocks.

The main second rifting event occurs in the late Jurassic. Moretti and Deacon (1995) suggested that the late Jurassic rifting phase led to the current morphology of the major tilted blocks, with eventual rotation and then erosion of the crests. Moreover, in the half graben, the deposits are mainly shaly (Heather and Draupne Formation), but sand bodies resulting from erosion of the Brent and other older sandy horizons are also found at the foot of the major faults. The Heather and Draupne Formations form important source rocks in the northern Viking Graben.

2.3.3 Cretaceous

The early Cretaceous period was characterized by major transgression following the last rifting phase in late Jurassic. Although the rifting had ceased, a few faults were active mainly outside the margins of the trough and this resulted in widening of the basin. This period was affected by erosion truncation, which resulted to the development of the major and well-known unconformity, the Base Cretaceous Unconformity (BCU) (Fig 5). The unconformity is frequently associated with an abrupt change in tectonic style between the heavily faulted Upper Jurassic (syn-rift) and the relatively unfaulted Cretaceous (post-rift) sequences (Kyrkjebø et al., 2004). The BCU is largely unfaulted and in the margin onlaps of the overlying layers are common. Above the unconformity, the Cromer Knoll Group was deposited between Ryazanian and Albian. Fine-grained argillaceous, marine sediments with varying content of calcareous materials dominate the deposited sequence. The Shetland Group was deposited on top of the Cromer Knoll during the late Cretaceous following the regional subsidence between Cenomanian and Danian. It consists mainly of limestones, marls and calcareous shales and mudstones. Goff (1983) showed that the regional subsidence occurred across the Viking Graben during late Cretaceous time, and up to 2500 m of deep water mudstones and thin limestones (Shetland Group) were deposited.

Thermal cooling following the late Jurassic rifting event resulted in the subsidence during Cretaceous period. Badley et al. (1988) attribute all later fault movements in the Cretaceous period to the results of thermal subsidence.

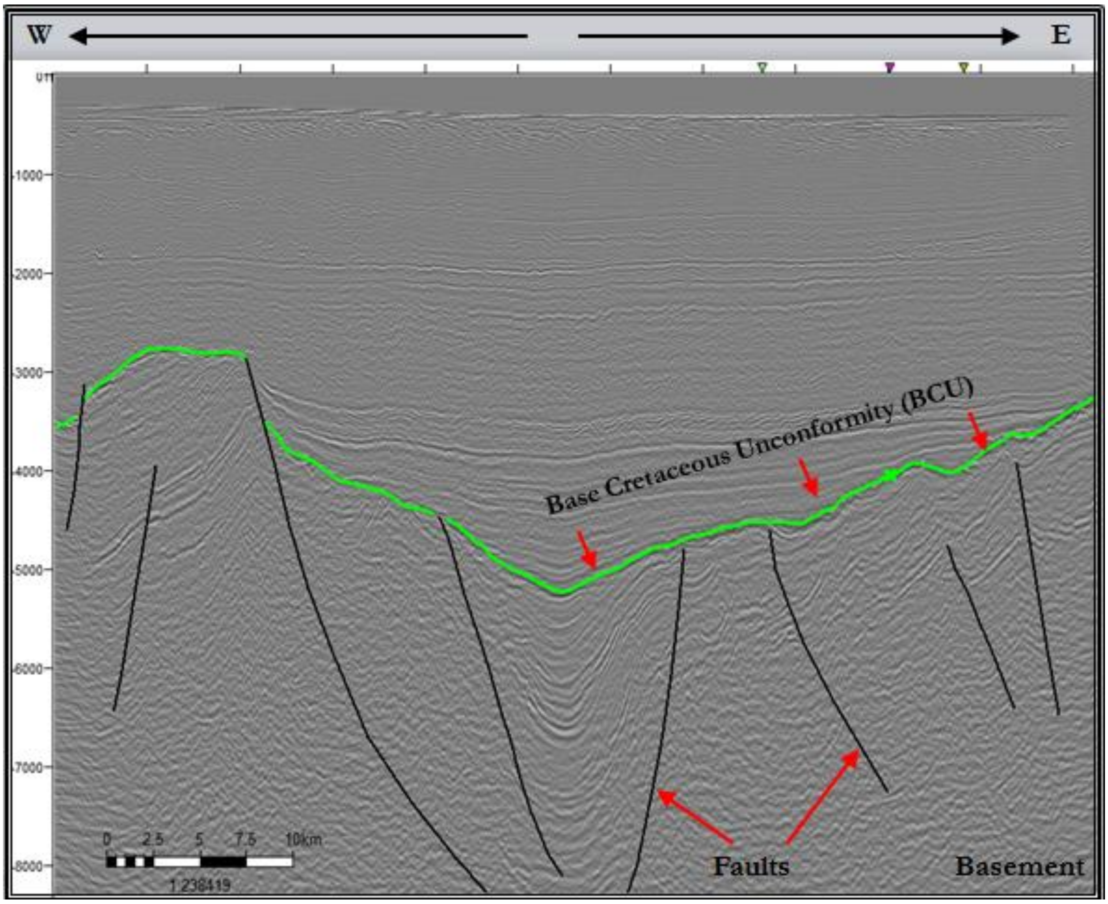


Figure 5: Seismic line VGNT98-113 showing the Interpreted Base Cretaceous Unconformity, which marks the end of the rifting and the beginning of Cretaceous subsidence. Overlying strata onlap the unconformity.

2.3.4 Cenozoic

This period was characterized mainly by subsidence. The Rogaland Group was deposited in a relatively deep marine environment as submarine fans between Paleocene to early Eocene. The dominant lithology is mainly sandstones interbedded with shales. Above the Rogaland Group, the Hordaland Group was deposited in deep marine environment from Eocene to early Miocene. Marine claystones with minor sandstones dominate the group. The Utsira Formation was deposited during the middle to late Miocene above the Hordaland Group and consists mainly of shallow marine sandstones.

The Cenozoic sedimentation was relatively rapid and the clayey sediments had little time to compact sufficiently to reduce the water content (Faleide et al., 2015). The Nordland Group was deposited in an open marine environment with glacial deposits from Plio-Pleistocene to Recent. Since uplift and erosion characterized the Cenozoic period, it resulted to the development of unconformity in the middle of the Nordland Group.

The unconformity is known as Base Quaternary Unconformity (BQU) (Fig 6). The dominant lithology is the Nordland Group is marine claystones.

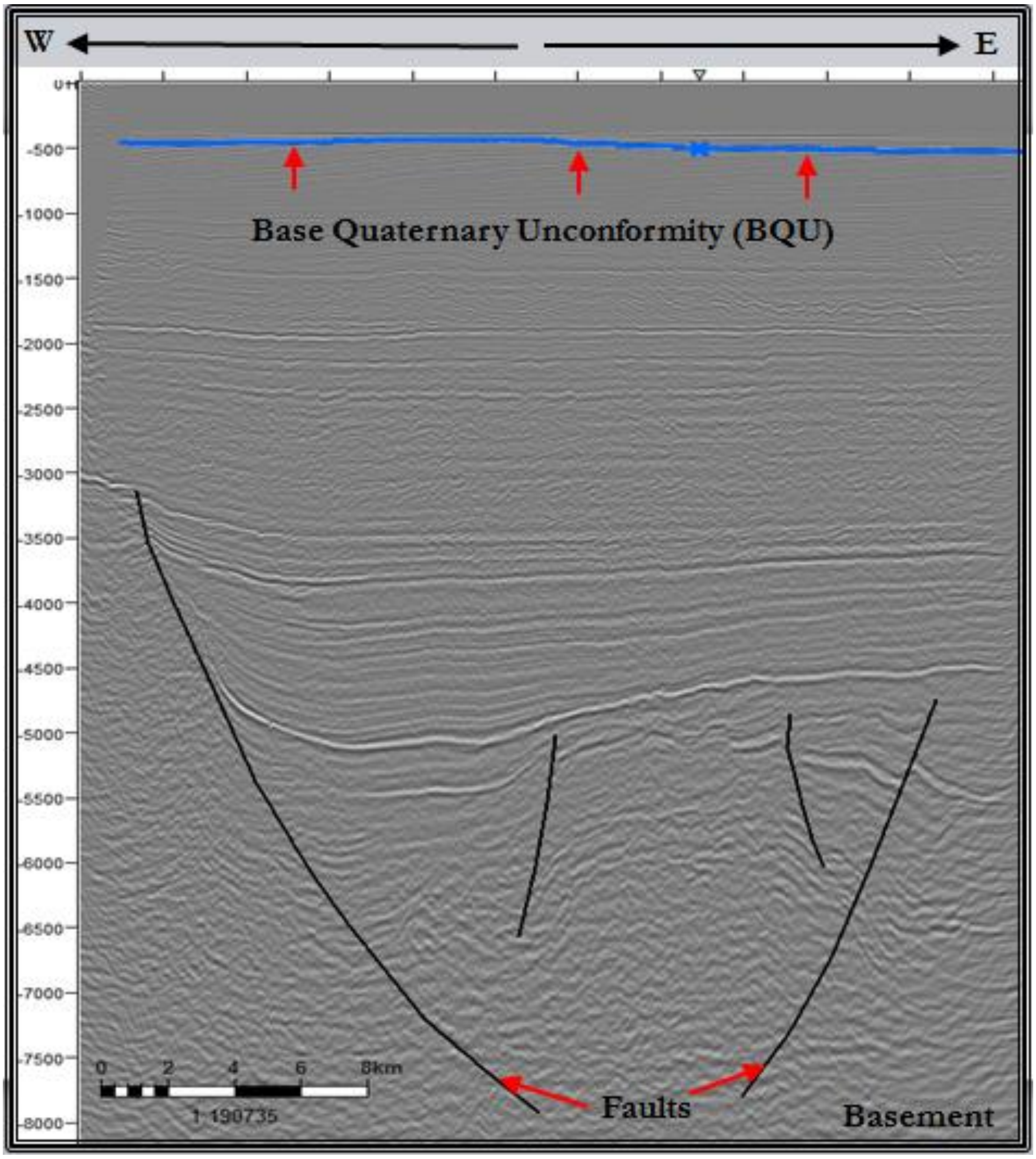


Figure 6: Seismic line VGNT98-110 showing Base Quaternary Unconformity (BQU), which is flat almost, unfaulted on top of the fault block and uniform sedimentary packages.

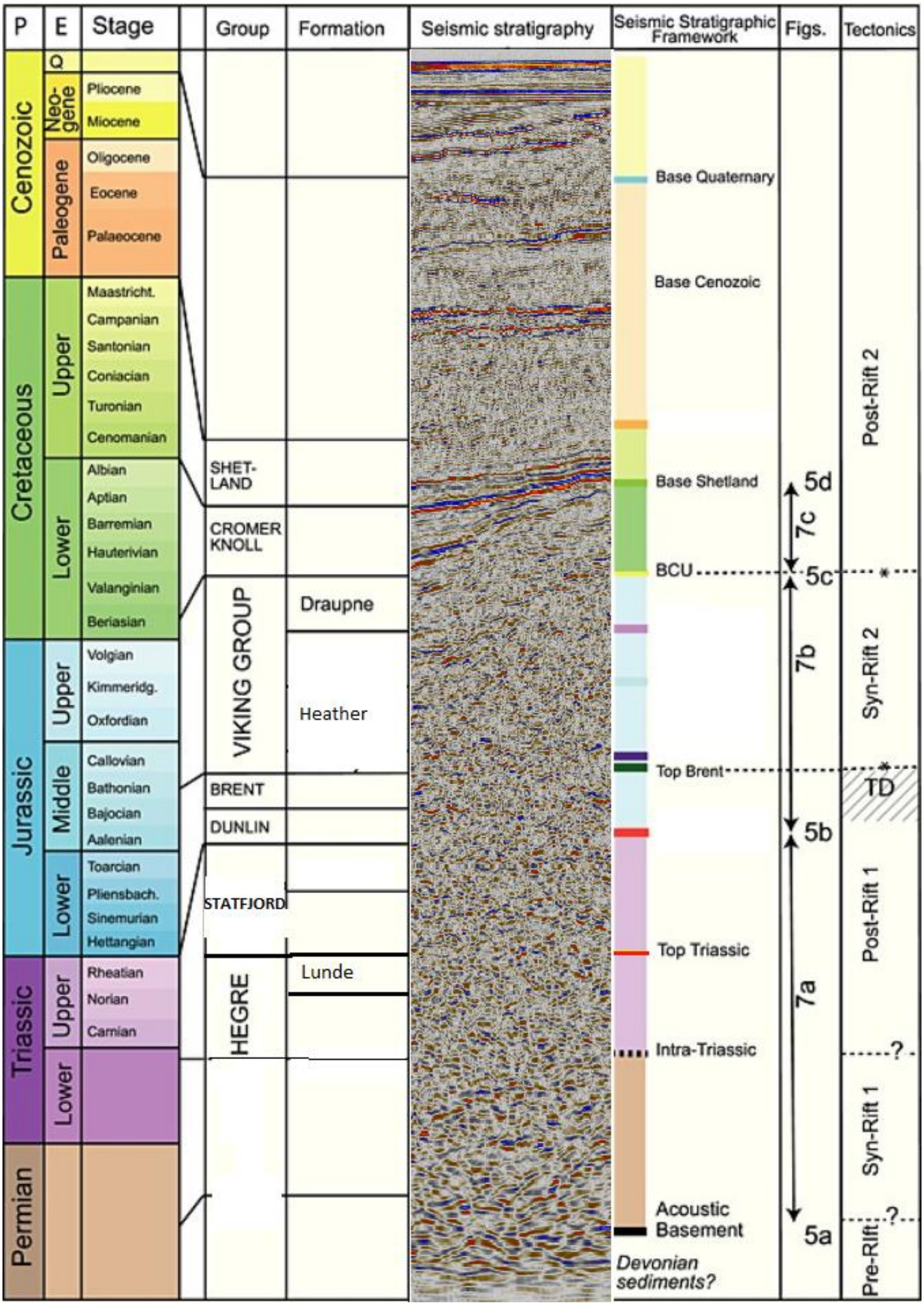


Figure 7: Lithostratigraphic column for the northern North Sea (modified from Bell et al., 2014). P=Period and E= Epoch. Names of key Groups and Formations discussed in this work are provided in this column.

CHAPTER 3: NORTH VIKING GRABEN PLAYS

The North Viking Graben is a highly productive hydrocarbon province in which a large number of oil and gas fields have been discovered in a rifted setting (Gormly et al., 1994) (Fig 8). The presence of hydrocarbons in the Viking Graben area is influenced mainly by the presence of the key elements such as hydrocarbon source rocks, which are matured enough for the generation of commercial hydrocarbons, reservoir rocks, seals and traps. All these were formed in the proper sequence of events, which allows hydrocarbons to be generated, migrated and accumulated.

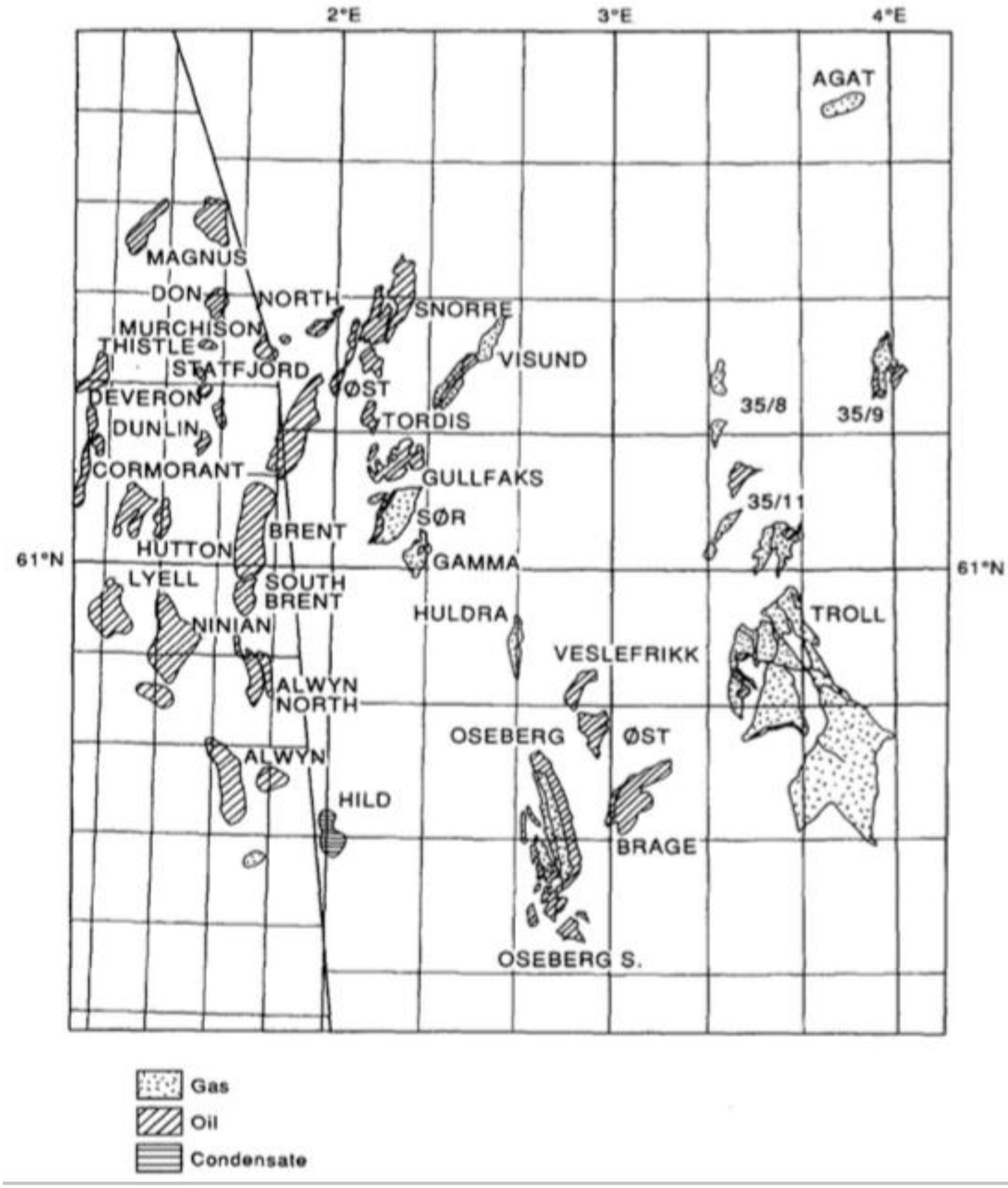


Figure 8: Oil and gas fields in the North Viking Graben (Gormly et al., 1994).

3.1 Hydrocarbon Source Rocks

Cornford (1998) defined the classical hydrocarbon source rock as an organic-rich, dark olive-grey to black, laminated mudstone, which from an industrial point of view must be capable of generating and expelling commercial quantities of oil or gas. Under the influence of temperature and time, the source rock must be matured enough in order to produce commercial oil and gas accumulations. Miles (1990) explained that the Jurassic source rocks vary from thermally immature on the platform areas to post-mature for oil generation in the deepest parts of the Viking Graben, with a depth range from about 1700 m to in excess of 7000 m in the graben. The maturity of the source rock depends on temperature and time i.e. as the temperature and time increases; the source rock maturity increases. Fig 9 shows the relationship between vitrinite and source rock maturity where the source rock maturity increases with vitrinite reflectance. The most important source rocks in the Viking Graben are the Draupne and Heather Formations of the Viking Group and the coals (Ness Formation) within the Brent Group.

3.1.1 Draupne Formation

The Upper Jurassic Draupne Formation is amongst the most studied source rocks with respect to petroleum generation. It is widely distributed throughout the North Sea and is the source of most oils with a marine source rock signature in Middle Jurassic, intra Upper Jurassic and Cretaceous chalk reservoirs in the region (Keym et al., 2006). The Draupne Formation was deposited in a marine environment mainly below wave base and according to Doré et al. (1985) the age of the Draupne Formation is Oxfordian to Ryazanian. It consists of dark grey to black marine mudstones, claystones and shales. An evaluation of total organic carbon (TOC), pyrolysis yield (S2) and hydrogen index (HI), showed that the Draupne Formation consists of a rich, oil-generative source rock, with the best source rock quality found in early to middle Volgian (Johannesen et al., 2002). According to Moretti and Deacon (1995), the Draupne is oil-prone with the beginning of the conventional oil window (TR=10%) around 110 ^{0}C, at about 3100 m with a heat flow of 67 mW/m^{2} and a gas/condensate window at 4000 m.

Kubala et al. (2003) recognized the Draupne Formation as the main source rock for both oil and gas in the North Viking Graben. The maturity for oil generation was reached during the late Cretaceous (early maturity at about 71 Ma, peak oil maturity at about 54 Ma) and the unit has been mature for significant gas generation since about 14 Ma. Active generation continues at present.

3.1.2 Heather Formation

While the Draupne Formation is recognized as the primary source rock, data suggest that the Heather shales can also have source rock potential (Gormly et al., 1994). The Heather Formation, which was deposited between Bathonian to Kimmeridgian in an open marine environment, consists mainly of grey silty claystones with thin streaks of limestone. According to Gormly et al. (1994), oil and condensates that are derived from the Heather Formation include those in the 35/8-1, 35/8-2 and 35/9 discoveries, parts of Troll Field, and Middle Jurassic reservoirs in 35/11 discoveries in a slightly over-pressured area. The Heather Formation was only locally found to be good oil-generative source rock with hydrogen indices averaging about 250 and seldom higher than 300 (Johannesen et al., 2002). The Heather Formation, despite its marine origin, is mainly gas-prone (Moretti and Deacon, 1995).

3.1.3 Ness Formation

The Ness Formation is inhomogeneous and comprises interbedded sandstones, mudstones and coals. It is a coastal plain deposit with widespread lagoonal and fluvial developments (Miles, 1990). This formation is within the Brent Group and the coal within this group is believed to be important source for gas generation. According to the study done by Schroeder and Sylta (1993), coals within the Brent Group contain terrestrial organic matter and they are believed to generate only gas. In addition, the richest source rocks in the Viking Graben are the oil prone Draupne Formation (Kimmeridge Clay) and the gas prone Brent Formation coals and coaly mudstones (Goff, 1983). Gas accumulations are likely to be sourced from the Draupne Formation unit, and additionally from coal-bearing intervals within the Brent Group which become gas mature during the Oligocene (at about 27 Ma) (Kubala et al., 2003).

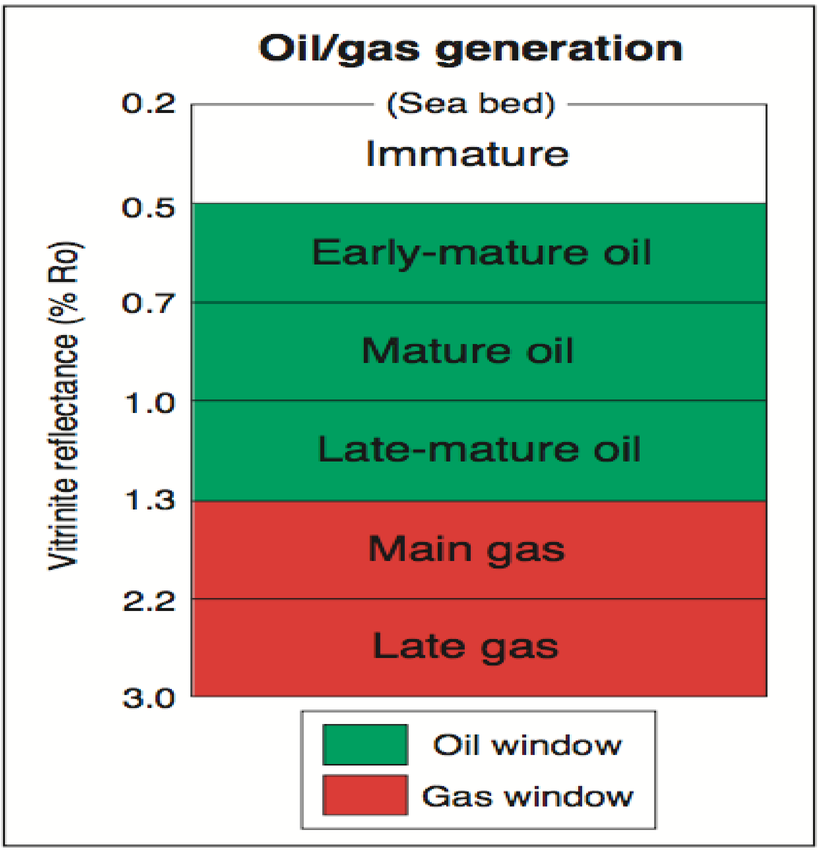


Figure 9: The relationship between values of vitrinite reflectance and source rock maturity (Kubala et al., 2003).

3.2 Reservoir Rocks

These are mainly sandstones and carbonates, which are porous enough to store commercial quantities of petroleum and also permeable enough for petroleum to flow through. It has been suggested by Miles (1990) that the current reservoir depth broadly ranges from 2000 m to greater than 4000 m. She added that deeper reservoirs tend to be poorer in quality owing to several phases of diagenesis. Two main reservoirs are known to exist in the northern Viking Graben, within the Statfjord and Brent Groups, which belong to early Jurassic and middle Jurassic respectively.

Although the reservoir rocks are older than the source rocks, the movement of the hydrocarbons from the source to the reservoir rocks was possible because of the presence of faulting in late Jurassic, which brought the source and reservoir rocks into contact. Fig 10 is taken from Sorensen (1996) and illustrates the Middle Jurassic play of the study area and the fault tectonics during the late Jurassic, which brought the source and reservoir rocks into contact with each other.

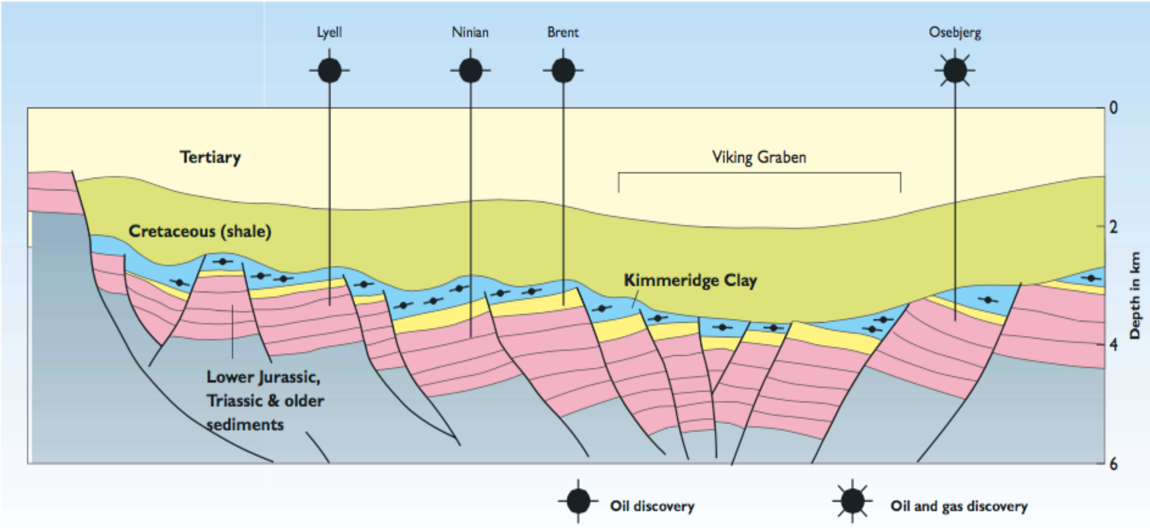


Figure 10: The Middle Jurassic play. The yellow layer represents the Brent sandstone (Sorensen, 1996).

3.2.1 Statfjord Group

The main reservoir intervals comprise thick, fluvial-dominated sandstones, particularly the Triassic/Lower Jurassic Statfjord (Johnson and Fisher, 2009). The Statfjord Group consists of shallow marine sediments, grey, green and sometimes red shales interbedded with siltstones, sandstones and dolomitic limestones. Johnson and Krol (1984) explained that the Lower Jurassic Statfjord Group is highly heterogeneous reservoir mainly comprising a variable alternation of sandstones and shales. According to Gautier (2005), more than 200 m of high-porosity sandstones are present at the Statfjord Group.

3.2.2 Brent Group

The Brent Group comprises dominantly deltaic sediments that prograded from south to north along the graben axis (Miles, 1990) (Fig 11). The group consists of mainly grey to brown sandstones, siltstones and shales with subordinate coal beds and conglomerates. It was deposited during Middle Jurassic between Bajocian to early Bathonian. Gautier (2005) explained that the uppermost rocks of the Brent Group are transgressive sandstones that are overlain by Upper Jurassic (Callovian and younger) marine shales.

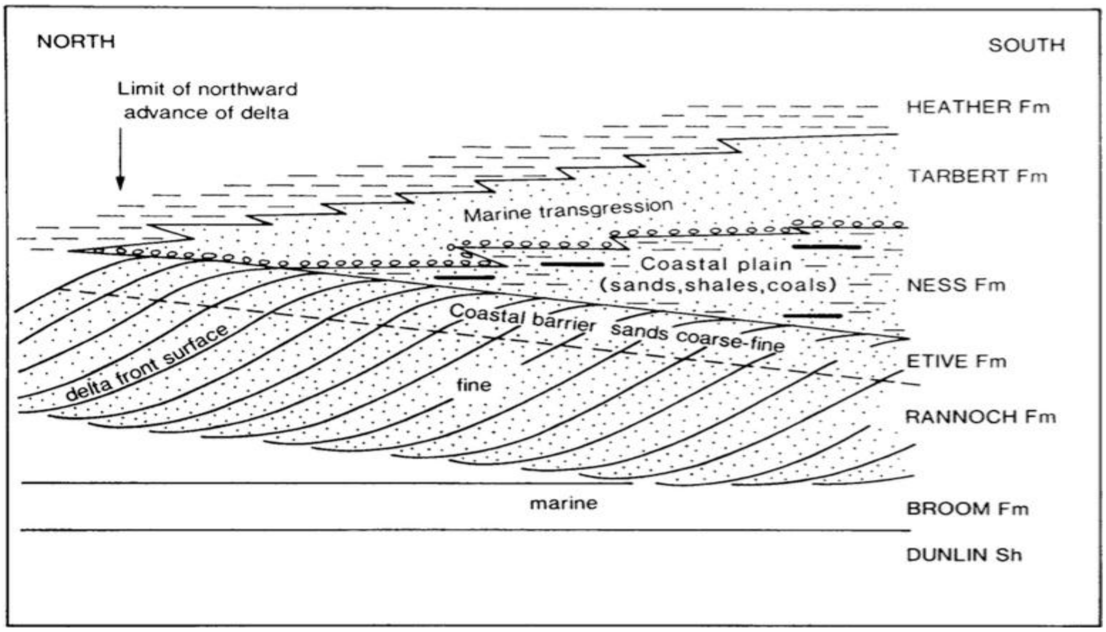


Figure 11: Schematic development of the Brent Group lithofacies (Miles, 1990).

3.3 Traps and Seals

The trap is an arrangement of the reservoir rocks that allows significant accumulation of petroleum in the subsurface. Seal refers to the low permeability rocks that prevent migration of petroleum out of the trap. Examples of seal rocks are shales, evaporites and cemented limestones but the most effective seal rock is halite. Seals may also develop along the faults by juxtaposition between permeable rocks like sandstones and impermeable rocks like shales or by clay smearing (gouge). According to Johnson and Fisher (2009), the majority of the traps in the study area are formed by rotated fault blocks, with closure provided by a combination of fault seal (reservoirs juxtaposed against Upper Jurassic and Lower Cretaceous shales). These provide erosional truncation capped by top-seal shales and dip closure down the fault-block flanks. Miles (1990) explained that the majority of the traps were formed during the tectonic activity at the end of the Jurassic. Most faults are planar, some are listric, and all are normal, down to the east and down to west faults that juxtapose Upper Jurassic source rocks and Middle Jurassic reservoirs.

CHAPTER 4: METHODOLOGY

The 2D seismic data used in this study come mainly from two sets of regional seismic lines (NVGTI-92 and NVGTI-2-92) and one set of detailed lines (VGNT-98) (Fig 12). The basin modelling presented here is based mainly on two lines, NVGTI-92-105 and NVGTI-92-106. For seismic interpretation work, Schlumberger Petrel Software has been used. After finalizing the interpretation, the interpreted and depth-converted section has been imported to the software PetroMod for basin modelling.

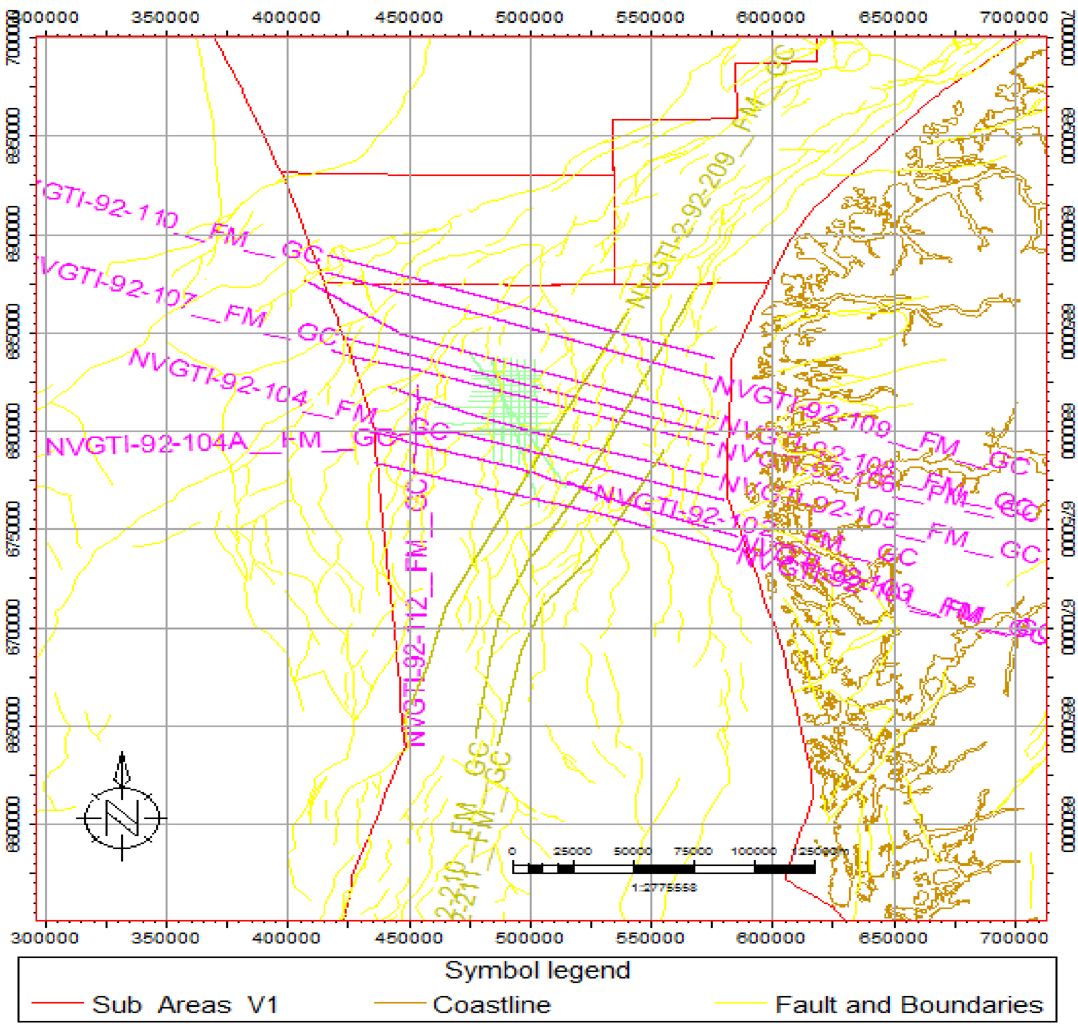


Figure 12: 2D seismic lines including regional lines (NVGTI-92, and NVGTI-2-92) shown in pink colour and the detailed survey lines (VGNT 98) shown in green colour in the middle part of the map.

The following procedures were used during the course of the study:

4.1 Data Compilation

This is the most critical and time-consuming step as it involves gridding of the seismic data, which needs to be interpreted in time domain before converted to depth domain after velocity model creation.

4.2 Velocity Model Creation

According to Etris et al. (2001) the velocity model can be evaluated numerically, visually and intuitively for reasonableness and also enables the use of velocity information from both seismic and wells, providing a much broader data set for critical review and quality control. In this study, the velocity model was created using the surface maps, well tops from the well information available in Petrel and interval velocity for each package, which is picked directly from the synthetic generation window in Petrel (Fig 13). The average value was taken to represent packages with more than one velocity value. Table 1 shows all parameters used to create the velocity model.

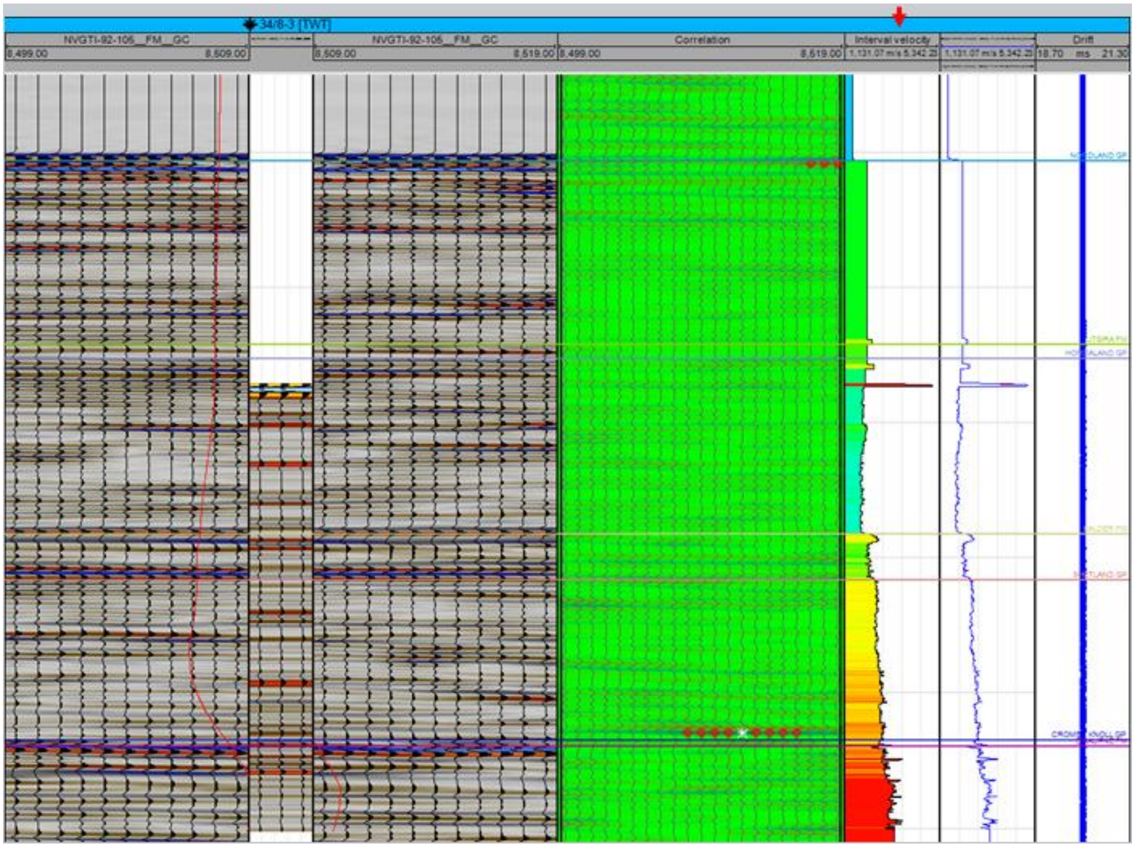


Figure 13: Synthetic generation window showing the interval velocity (red arrow) of the interpreted horizons, which are used for velocity model creation.

Make velocity model | Hints

Create new: Velocity model

Edit existing: Velocity model

Convert from: TWT to: Z

Datum

Time: SRD

Other:

Apply filter: Saved searches

Base			Correction					Model
Surface		Nordlan	Well tops		NORDL	V=V0=VInt	V0: Constant	1574
Surface		Top Uts	Well tops		UTSIR	V=V0=VInt	V0: Constant	1912
Surface		Hordlan	Well tops		HORD	V=V0=VInt	V0: Constant	2230
Surface		Top Bal	Well tops		BALDE	V=V0=VInt	V0: Constant	2306
Surface		Shetlan	Well tops		SHETL	V=V0=VInt	V0: Constant	2334
Surface		Top Cr	Well tops		CROM	V=V0=VInt	V0: Constant	2600
Surface		Draupn	Well tops		DRAUP	V=V0=VInt	V0: Constant	2900
Surface		Top Tri	Well tops		STATF	V=V0=VInt	V0: Constant	3200

Table 1: Parameters used to create the velocity model.

4.3 Time to Depth Conversion

The interpretations of geological structures are performed from the seismic sections in the time domain. In order to create a geological model, these time domain interpretations need to be converted to true depth (the actual depth in the subsurface) using a velocity model. The main reason to perform the depth conversion is to remove the structural uncertainties as the interpretation in time domain involves some risks, such as assuming a constant velocity model. Table 2 shows the depth converted seismic lines, which are selected for 2D modelling.

Depth convert

Velocity model: Velocity model

	Domain	Object	Direction
1	Seismic	NVGTI-92-105__FM	Forward
2	Seismic	NVGTI-92-106__FM	Forward
3	Seismic	NVGTI-2-92-209__F	Forward
4	Seismic	NVGTI-2-92-210__F	Forward
5	Seismic	VGNT98-113__FM_	Forward
6	Seismic	VGNT98-110__FM_	Forward

Table 2: Depth converted seismic lines used for 2D modelling.

4.4 Seismic Interpretations

Because the section and the horizons must be converted to true vertical depth (TVD) before exported to PetroMod for modelling, the lines, which are converted to depth domain, were interpreted. The available wells were tied to the depth converted seismic section through synthetic seismograms. Fig 14 shows the depth-converted line along with the tied wells in depth domain.

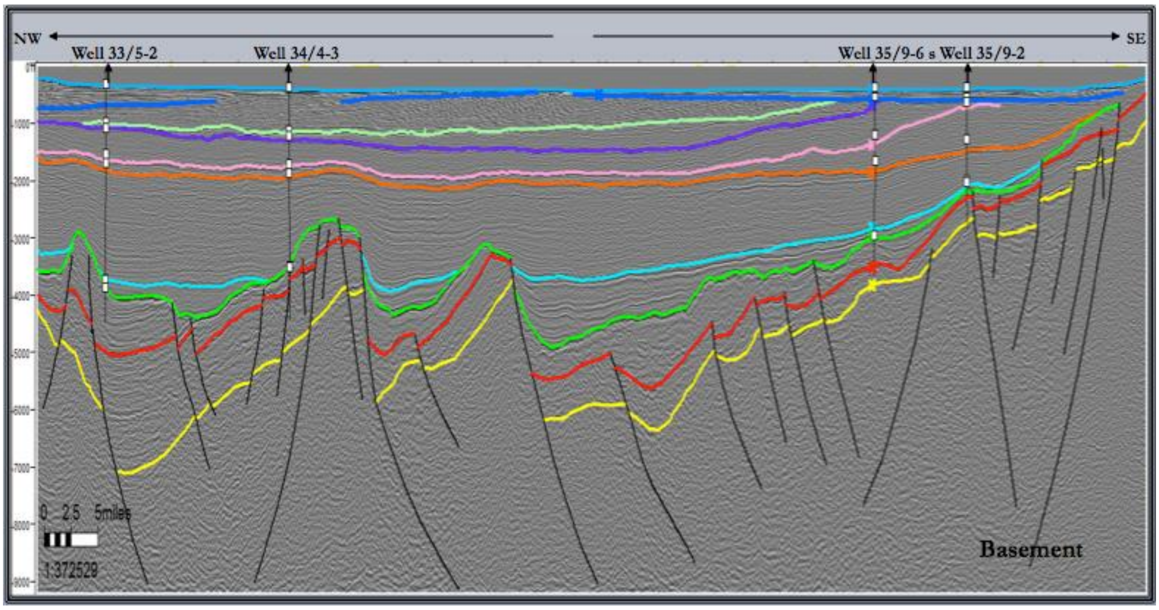
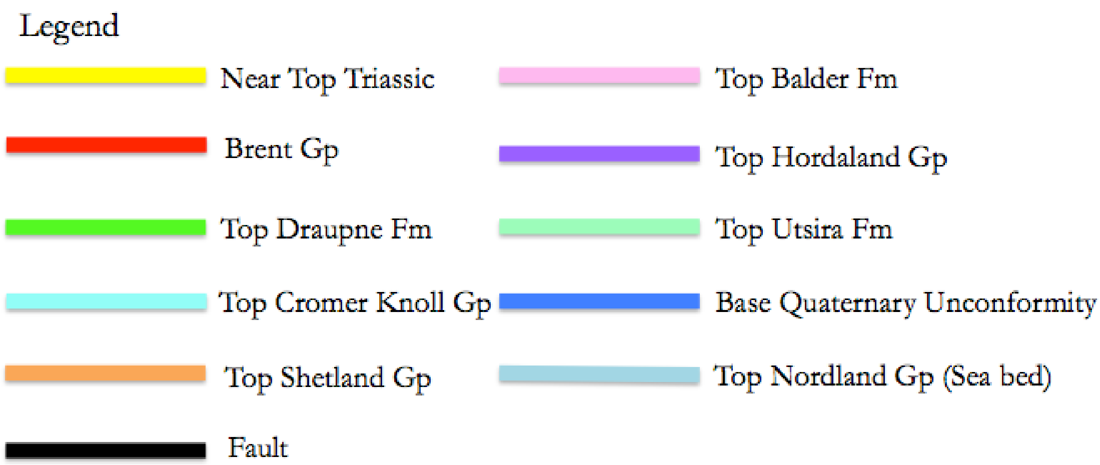


Figure 14: Depth converted seismic section NVGTI-92-106 along with the well ties.



The total of nine horizons and the Base Quaternary Unconformity, were chosen and interpreted in order to interpret the geological evolution of the area. The interpreted horizons are: Top Nordland Group (Sea bed), Top Utsira Formation, Top Hordaland Group, Top Balder Formation, Top Shetland Group, Top Cromer Knoll Group, Top Draupne Formation, Top Brent Group and Near Top Triassic. The horizons are high amplitude, continuous reflectors and they correspond to the tops of different sedimentary packages.

The near Top Triassic reflector is a more or less continuous, low to medium amplitude reflector, which is highly affected by faults. It consists of wedge shaped geometry especially in the middle part of the section, which is evidence for syn rift event (Fig 15).

Top Brent Group is characterized by high to moderate amplitude, low to high frequency, discontinuous faulted reflector. It is gentle inclined, which is caused by tectonic activities of the faulted blocks. In southeastern part of the section, it is highly eroded and overlain by the Base Cretaceous Unconformity (BCU) (Fig 15).

The Top Draupne reflector (Base Cretaceous Unconformity) is marked by a high amplitude and discontinuous reflection. It is the major erosional surface developed at the base of the Cretaceous. This reflector is less affected by fault compared to the Top Brent and near Top Triassic reflector.

The packages above the Base Cretaceous Unconformity (Cromer Knoll Group) are thickening towards the central part of the basin and away from the basin centre the post-rift sediments onlap onto the unconformity (Fig 15). The thickening of sediments and the presence of onlaps on top of the Base Cretaceous Unconformity is evidence that the sedimentation occurred after the rifting had ceased. The package is defined as the post-rift meaning that they were deposited after the rifting event.

The Top Shetland Group reflector is characterized by high to medium amplitude, discontinuous, which is less or not affected by faults. The packages enclosed by this reflector are thickening towards the middle of the section and they thin towards the end of the section. This can be partly due to change in sediment supply relative to the basin location and the distance from the sediment source. The Shetland Group sediments onlap the Base Cretaceous Unconformity in the eastern end of the section (Fig 15).

The Top Balder Formation, Top Hordaland Group and Top Utsira Formation are sub horizontal continuous reflectors, which are not affected by faulting. These reflectors are affected by truncation erosion in southeastern part of the section (Fig 15), which resulted in the Base Quaternary Unconformity (BQU).

The BQU is more or less horizontal and it is developed as an angular unconformity. Above this unconformity is the Nordland Group, which is characterized by continuous and high amplitude reflectors.

The quality of the sections is not good below the Base Cretaceous Unconformity as the Jurassic and Triassic formations have been highly faulted, tilted, and also eroded. The interpretation below the unconformity was very difficult due to he fact that most of the horizons are not continuous. The Jurassic and Triassic sediments are not uniform in thickness, as most of the sediments tend to occur in half grabens, which are created by the faulting process during rifting. Some faults are clearly visible while others are very difficult to interpret due to the fact that the area is strongly influenced by tectonic movements, which makes the interpretation complicated. All faults are interpreted as normal and most die out at the Base Cretaceous Unconformity (Fig 15).

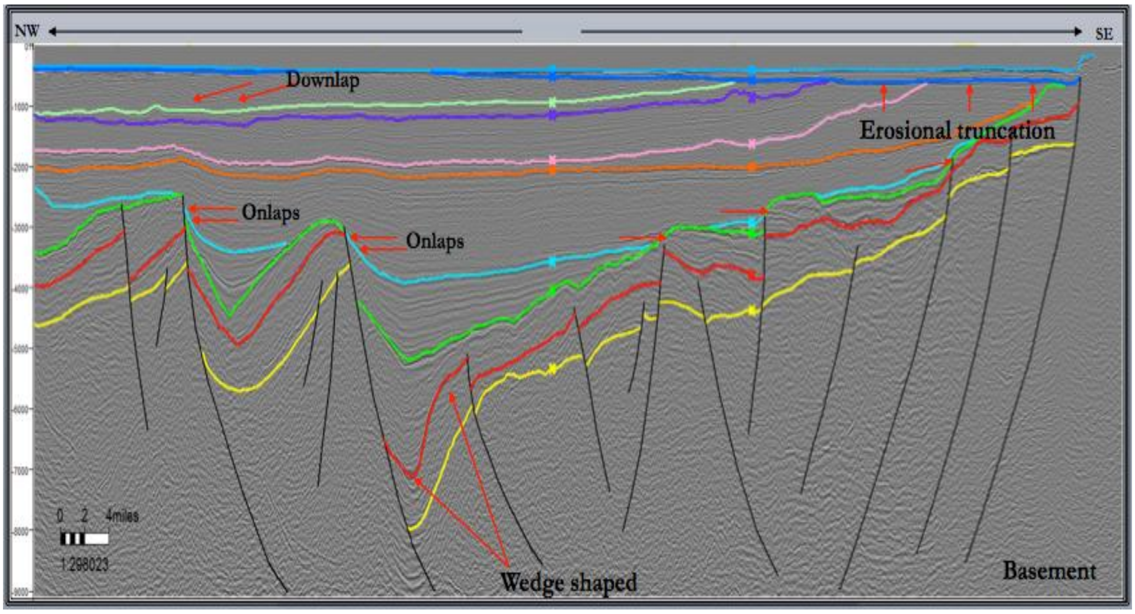


Figure 15: Interpreted depth converted section NVGTI-92-105 showing the stratigraphic termination (onlaps, downlap and erosional truncation) and the rifting phases indicated by wedge shaped sedimentary packages.

CHAPTER 5: 2D BASIN MODELLING

5.1 Software

PetroMod Software was used for modelling through PetroBuilder 2D, which is used as an input module for building 2D petroleum system models. This software combines seismic, wells, and geological information to model the evolution of a sedimentary basin. This enables to predict if the reservoir is filled with hydrocarbons or not, the source rock and timing of hydrocarbon generation, migration pathways, quantities of hydrocarbon present at the subsurface as well as hydrocarbon type in the subsurface or surface conditions.

Fig 16 shows the basic model building process, which includes:

- Import data/image and digitizing horizons and faults.
- Fault assignment.
- Gridding and age assignment.
- Layer processing.
- Facies assignment.
- Setting boundary conditions: paleo water depth (PWD), sediment water interface temperature (SWIT) and heat flow (HF).
- Setting the simulator options.

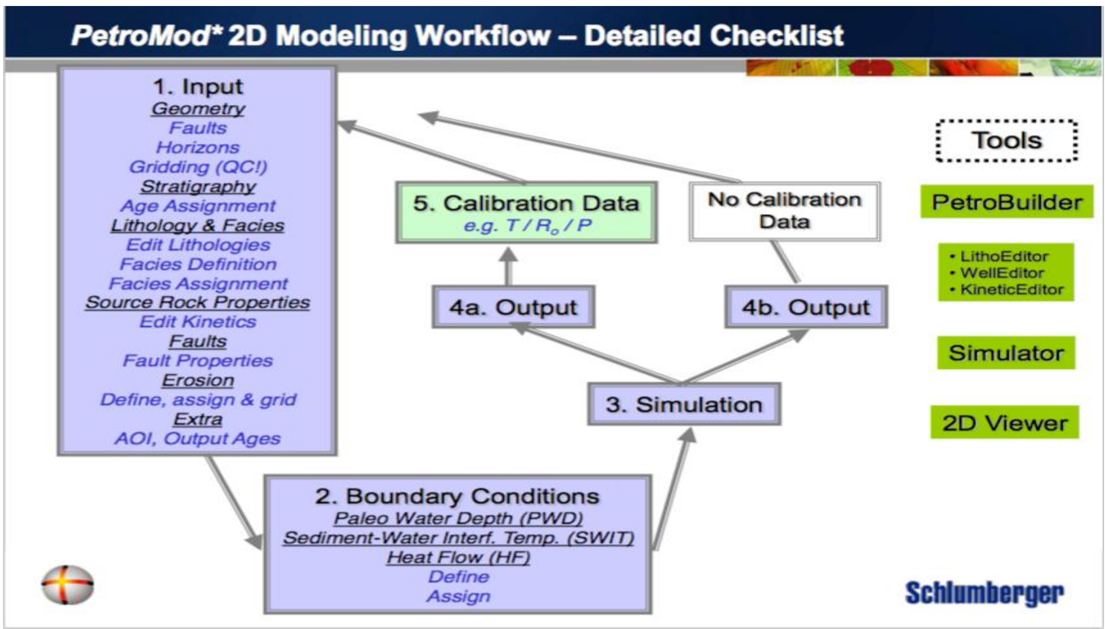


Figure 16: 2D Modelling workflow.

5.2 Data Input

Most of the information, which was used for modelling, was taken from the Norwegian Petroleum Directory (NPD) fact pages. After final interpretation of the selected depth converted seismic lines in the Petrel Software, the sections have been directly imported in the PetroMod Software for 2D basin modelling process. The interpreted horizons and faults are digitized manually using the digitizing option menu of the software. After the process of digitization was completed, the fault model was created followed by gridding process. Pre-grid horizons and faults need to be gridded to ensure that each node of the digitized horizon or fault intersect on a grid point and extend to the model boundaries. Once the digitization, fault model creation and gridding of all horizons and faults are completed, the section is ready for model development. Figs 17 and 18 show the pre-grid model view of the digitized horizons and faults.

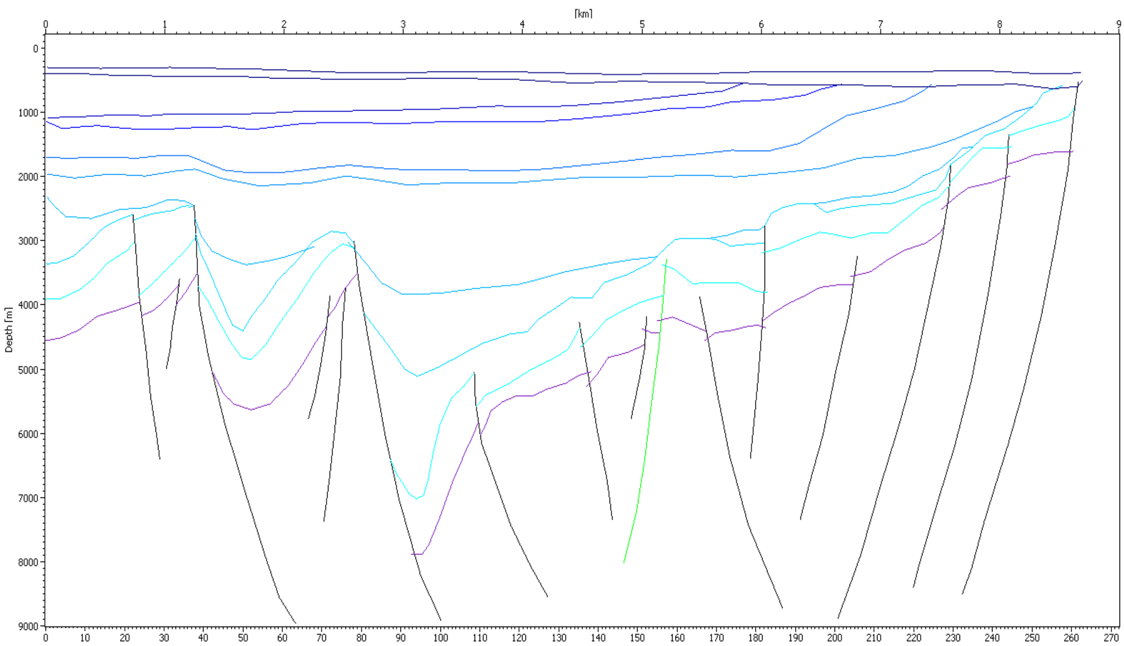


Figure 17: Pre-grid model view of the digitized horizons and faults for model 105.

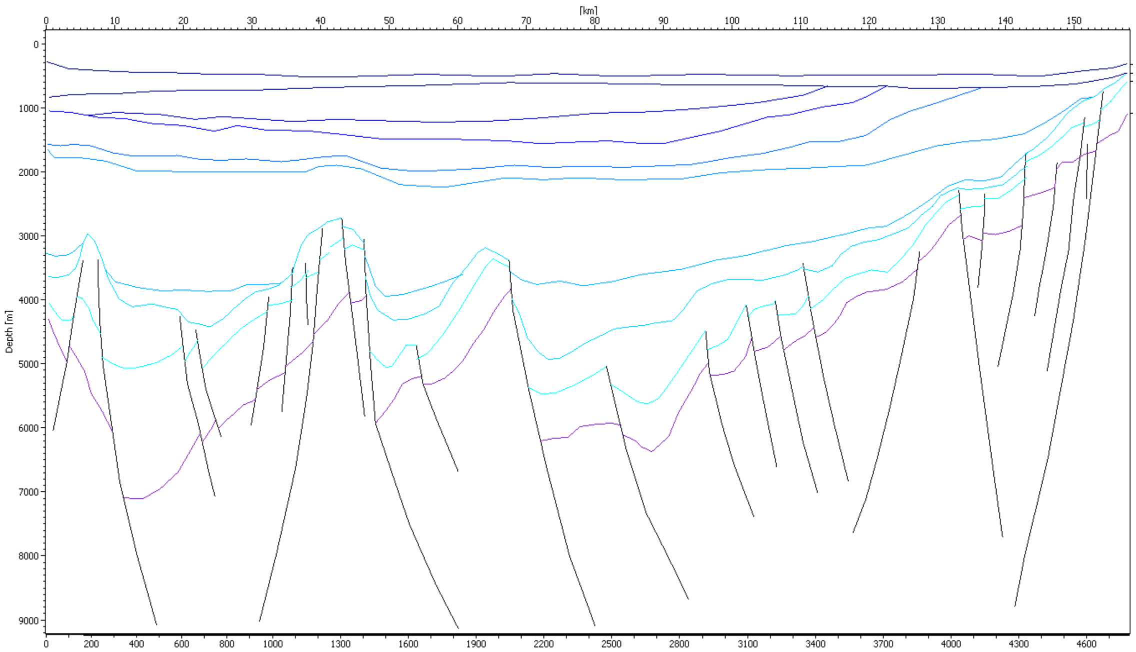


Figure 18: Pre-grid model view of the digitized horizons and faults for model 106.

5.3 Fault Properties Definition

The properties of the faults can be defined including;

- Age, the time period during which the fault shows the defined properties in the table.
- Period and type, it is possible for the fault to have more than one period of movement, i.e. the same fault can change from an open fault to closed fault at different time interval.

Eight major faults have been chosen to be delineated in model 105 and in model 106 eleven major faults were chosen. These faults are related with the late Jurassic to early Cretaceous rifting event. Hence, on the fault property definition table, all faults were assigned as generated during the late Jurassic period (145 Ma). It is possible that some faults were open at a particular time, especially during the second episode of rifting, but there is no clear evidence to explain the age at which the faults were open. We have, however the evidence that some faults were reactivated during the second rifting event, so some faults were assumed to remain open after the second rifting event ceased, while others were assumed to be closed (Tables 3 and 4).

Name	-	Period	Age from [Ma]	Age to [Ma]	Type
Fault_01		1	145.00	0.00	Open
Fault_02		1	145.00	0.00	Closed
Fault_03		1	145.00	0.00	Open
Fault_04		1	145.00	0.00	Closed
Fault_05		1	145.00	0.00	Closed
Fault_06		1	145.00	0.00	Closed
Fault_07		1	145.00	0.00	Open
Fault_08		1	145.00	0.00	Closed

Table 3: Fault properties definition table for model 105.

Name	-	Period	Age from [Ma]	Age to [Ma]	Type
Fault_01		1	145.00	0.00	Open
Fault_02		1	145.00	0.00	Closed
Fault_03		1	145.00	0.00	Open
Fault_04		1	145.00	0.00	Closed
Fault_05		1	145.00	0.00	Open
Fault_06		1	145.00	0.00	Closed
Fault_07		1	145.00	0.00	Open
Fault_08		1	145.00	0.00	Closed
Fault_09		1	145.00	0.00	Closed
Fault_10		1	145.00	0.00	Open
Fault_11		1	145.00	0.00	Closed

Table 4: Fault properties definition table for model 106.

5.4 Age Assignment

The age information of the interpreted horizons (Tables 5 and 6) was assigned based on the information available in Norwegian Petroleum Directorate (NPD) fact pages website and the 2009 Geologic time scale. The oldest reflector is the Near Top Triassic, which is around 201 Ma and the youngest is the Top Nordland Group reflector (Sea Bed) with 0.00 Ma. Two major unconformities: Base Cretaceous and Base Quaternary Unconformity have been assigned in this model. The erosion map in the age assignment table shows the thickness of the eroded parts of the layer, which are calculated by PetroBuilder. In order to define erosion, age and thickness of the eroded unit is required. Due to this the thicknesses of the eroded layer were estimated to be around 200 m for duration of 10 Ma and 100 m for duration of 2 Ma for Base Cretaceous and Base Quaternary Unconformities respectively. Base Cretaceous erosion, occurred after deposition of the Draupne Formation and the Base Quaternary erosion occurred in the middle of the Nordland Group. The amount and duration of erosion assigned in the table is based on Kyrkjebø et al. (2004).

	Age [Ma]	Horizon	-	Pre-grid Horizon	Gridded Horizon	Erosion Map	Layer	-	Event Type	Facies Map	No. of Sublayers	Max. Time Step [Ma]
1	0.00	Top Nordland Gp (Sea Bed)		Horizon_10	Horizon_1_Map							
2							Nordaland Gp 1		Deposition	Map_Layer_1_Facies	1	10.00
3	2.60	Erosion_30_Top										
4							Erosion_30		Erosion			10.00
5	4.60	Base Quaternary Unconformity		Horizon_9	Horizon_3_Map	ErosionMapID2_5.600						
6							Nordaland Gp 1_1		Deposition	Map_Layer_2_Facies	1	10.00
7	13.00	Top Utsira Fm		Horizon_8	Horizon_4_Map							
8							Utsira Fm		Deposition	Map_Layer_3_Facies	1	10.00
9	23.00	Top Hordaland Gp		Horizon_7	Horizon_5_Map							
10							Hordaland Gp		Deposition	Map_Layer_4_Facies	1	10.00
11	55.00	Top Balder Fm		Horizon_6	Horizon_6_Map							
12							Balder Fm		Deposition	Map_Layer_5_Facies	1	10.00
13	65.50	Top Shetland Gp		Horizon_5	Horizon_7_Map							
14							Shetland Gp		Deposition	Map_Layer_6_Facies	1	10.00
15	99.00	Top Cromer Knoll Gp		Horizon_4	Horizon_8_Map							
16							Cromer Knoll Gp		Deposition	Map_Layer_7_Facies	1	10.00
17	135.00	Erosion_28_Top										
18							Erosion_28		Erosion			10.00
19	145.00	Top Draupne Fm		Horizon_3	Horizon_9_Map	ErosionMapID1_145						
20							Draupne Fm		Deposition	Map_Layer_8_Facies	1	10.00
21	168.00	Top Brent Gp		Horizon_2	Horizon_10_Map							
22							Brent Gp		Deposition	Map_Layer_9_Facies	1	10.00
23	201.00	Near Top Triassic		Horizon_1	Horizon_11_Map							

Table 5: Age assignment table (model 105) for the interpreted horizons.

	Age [Ma]	Horizon	-	Pre-grid Horizon	Gridded Horizon	Erosion Map	Layer	-	Event Type	Facies Map	No. of Sublayers	Max. Time Step [Ma]
1	0.00	Top Nordland Gp (Sea Bed)		Horizon_10	Top Nordland Gp (Sea Bed)_Map							
2							Nordaland Gp 1		Deposition	Map_Layer_1_Facies	1	10.00
3	2.60	Erosion_21_Top										
4							Erosion_21		Erosion			10.00
5	4.60	Base Quaternary Unconformity		Horizon_9	Base Quaternary Unconformity_Map	ErosionMapID2_4.600						
6							Nordaland Gp 1_1		Deposition	Map_Layer_2_Facies	1	10.00
7	13.00	Top Utsira Fm		Horizon_8	Top Utsira Fm_Map							
8							Utsira Fm		Deposition	Map_Layer_3_Facies	1	10.00
9	23.00	Top Hordaland Gp		Horizon_7	Top Hordaland Gp_Map							
10							Hordaland Gp		Deposition	Map_Layer_4_Facies	1	10.00
11	55.00	Top Balder Fm		Horizon_6	Top Balder Fm_Map							
12							Balder Fm		Deposition	Map_Layer_5_Facies	1	10.00
13	65.50	Top Shetland Gp		Horizon_5	Top Shetland Gp_Map							
14							Shetland Gp		Deposition	Map_Layer_6_Facies	1	10.00
15	99.00	Top Cromer Knoll Gp		Horizon_4	Top Cromer Knoll Gp_Map							
16							Cromer Knoll Gp		Deposition	Map_Layer_7_Facies	1	10.00
17	135.00	Erosion_19_Top										
18							Erosion_19		Erosion			10.00
19	145.00	Top Draupne Fm		Horizon_3	Top Draupne Fm_Map	ErosionMapID1_145						
20							Draupne Fm		Deposition	Map_Layer_8_Facies	1	10.00
21	168.00	Top Brent Gp		Horizon_2	Top Brent Gp_Map							
22							Brent Gp		Deposition	Map_Layer_9_Facies	1	10.00
23	200.00	Near Top Triassic		Horizon_1	Near Top Triassic_Map							

Table 6: Age assignment table (model 106) for the interpreted horizons.

5.5 Facies Definition

The facies of the various layers and their characteristics are defined in the facies definition table (Tables 7 and 8). The Draupne and the Heather Formations, which belong to the Viking Group, are defined as the source rocks. In source rocks, properties like Hydrogen Index (HI), Total Organic Carbon (TOC) and Kinetics need to be assigned. According to Kubala et al. (2003) the TOC contents of shales within the Heather Formation are around 2-2.5%, but exceed 4% in a limited area. In addition to that the HI is above 200 mg/gTOC in some areas but rarely exceeds 300 mg/gTOC. They are commonly in the range 100-200mg/gTOC, but may be less than 100 mg/gTOC, mainly along the axial regions of the North Viking Graben where the Heather Formation is at a late-to post mature stage of oil generation. The assigned HI ranges between 400-600 mg/gTOC, whereas the TOC is assigned 6%. This agrees with Kubala et al. (2003) that the TOC content for the Draupne Formation is around 6%, locally reaching values in excess of 10% or as low as 2%. HI varies considerably depending upon the kerogen composition, type II amorphous kerogen is about 600 mg/gTOC, mixed type II and type III kerogen is about 200 to 400 mg/gTOC. In the North Viking Graben, where the formation is deeply buried, the hydrogen indices are less than 100 mg/gTOC. The reaction kinetics used is Burnham (1989)_TII because the Draupne Formation is the type II source rock.

The Brent Group was defined as the reservoir rock whereas the Cromer Knoll Group was defined as the seal rock. The study done by Schroeder and Sylta (1993) shows that most hydrocarbons in the northern Viking Graben are preserved in Middle Jurassic Brent Group and older sandstones. The remaining layers were defined as the overburden and underburden rocks. The overburden rock is very important as explained by Magoon and Dow (1994) that it provides the overburden necessary to thermally mature the source rock and also has considerable impact on the geometry of the underlying migration path and trap.

Name	Color	Lithology Value	TOC Mode	TOC Value [%]	TOC Map	Kinetics	HI Mode	HI Value [mgHC/gTOC]	HI Map	Petroleum System Elements
Nordland Gp1		Marine Claystone								Overburden Rock
Nordland Gp2		Marine sandstone and claystone								Overburden Rock
Utsira Fm		Marine Claystone and sandstone								Overburden Rock
Hordaland Gp		Marine Claystone and sandstone								Overburden Rock
Balder Fm		Laminated shale								Overburden Rock
Shetland Gp		Chalky limestone/Marls								Overburden Rock
Cromer Knoll Gp		Marl								Seal Rock
Draupne Fm		Shale (black)	Value	5.00		Burnham(1989)_TII	Value	500.00		Source Rock
Brent Gp		Sandstone (quartzite, typical)								Reservoir Rock

Table 7: Facies definition table for model 105.

Name	Color	Lithology Value	TOC Mode	TOC Value [%]	TOC Map	Kinetics	HI Mode	HI Value [mgHC/gTOC]	HI Map	Petroleum System Elements
Nordland Gp1		Marine Claystone								Overburden Rock
Nordland Gp2		Marine sandstone and claystone								Overburden Rock
Utsira Fm		Marine Claystone and sandstone								Overburden Rock
Hordaland Gp		Marine Claystone and sandstone								Overburden Rock
Balder Fm		Laminated shale								Overburden Rock
Shetland Gp		Chalky limestone/Marls								Overburden Rock
Cromer Knoll Gp		Marl								Seal Rock
Draupne Fm		Shale (black)	Value	4.00		Burnham(1989)_TII	Value	600.00		Source Rock
Brent Gp		Sandstone (quartzite, typical)								Reservoir Rock

Table 8: Facies definition table for model 106.

5.6 Boundary Conditions

Boundary conditions define the basic energetic conditions for the temperature and burial history of the source rock and consequently, for the maturation of organic matter through time (PetroBuilder 2D_User Guide version 2014.1). Three boundary conditions need to be defined during the model building process; these are Paleo Water Depth (PWD), Sediment Water Interface Temperature (SWIT) and Heat Flow (HF). The paleo water depth (Tables 9 and 10) was assigned based on Kyrkjebø et al. (2001) and it varies between 100 to 700 m in northern Viking Graben.

The sediment water interface temperature (Tables 9 and 10) is defined using the Auto SWIT function in PetroMod. The latitudinal position of the Viking Graben was assigned 62^0, Northern Europe. The global mean surface temperature of the area at present day shows that SWIT is around 5 ^{0}C (Fig 19).

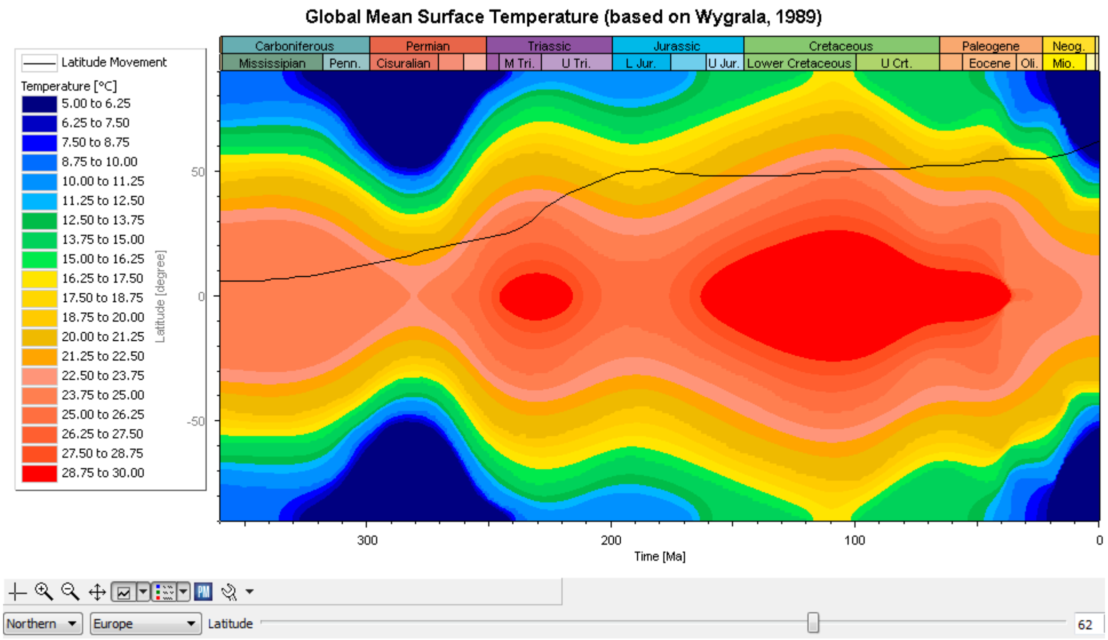


Figure 19: Sediment Water Interface Temperature (SWIT) definition.

Heat flow is important in modelling of the sedimentary basin as it allows understanding and predicting maturity of the source rocks. In this case, the heat flow trend needs to be created after setting some heat flow parameters like rift phase interval, which is assigned to be 165-145 Ma, pre rift thickness for the crust was between 28000 m to 30000 m and the mantle thickness was varying between 50000 m to 55000 m. Stretching factors for the crust were 1.5 while the value for the mantle was changed between 1.5 to 2. The current heat flow is around 56 mW/m^2, whereas high heat flow was observed during the rifting event between 165-145Ma (Table 9 and 10). Note that, the boundary conditions used in this model are the same as the one used in my specialization project work, which involved 1D basin modelling of the North Viking Graben.

The boundary condition trends for both models are shown in figs 20 and 21 below;

Age [Ma]	PWD [m]
0.00	382
20.00	220
40.00	650
55.00	710
65.00	370
85.00	450
100.00	370
125.00	305
142.00	250
160.00	201
180.00	180
200.00	159

Age [Ma]	SWIT [°C]
0.00	5.00
20.00	12.77
40.00	10.05
55.00	14.00
65.00	15.90
85.00	16.50
100.00	19.00
125.00	19.59
142.00	19.99
160.00	20.56
180.00	19.65
200.00	18.76

Age [Ma]	HF mW/m^2
0.00	56.89
7.25	56.92
14.50	56.96
21.00	57.01
31.00	57.08
43.50	57.18
50.75	57.31
58.00	57.48
65.25	57.72
72.50	58.05
75.00	58.49
80.00	59.09
88.00	59.90
101.00	61.00
108.30	62.48
116.00	64.46
123.00	67.10
130.00	70.52
137.00	74.83
145.00	80.74
147.00	79.60
149.00	78.00
151.00	75.78
153.00	74.15
155.00	72.42
157.00	70.63
159.00	68.83
161.00	67.05
163.00	65.30
165.00	63.47
168.00	63.00
172.00	62.00
178.00	60.00
181.00	58.00
185.00	57.00
193.00	56.00
197.00	55.00
201.00	53.00

Table 9: Boundary conditions for model 105.

Age [Ma]	PWD [m]
0.00	496
20.00	240
40.00	660
55.00	690
65.00	340
85.00	440
100.00	350
125.00	280
142.00	130
160.00	105
180.00	100
200.00	110

Age [Ma]	SWIT [°C]
0.00	5.00
20.00	12.39
40.00	10.00
55.00	13.88
65.00	16.15
85.00	16.77
100.00	19.27
125.00	19.96
142.00	19.77
160.00	17.99
180.00	17.51
200.00	17.11

Age [Ma]	HF mW/m^2
0.00	56.89
7.25	56.92
14.50	56.96
21.00	57.01
31.00	57.08
43.50	57.18
50.75	57.31
58.00	57.48
65.25	57.72
72.50	58.05
79.00	58.49
87.00	59.09
94.00	59.90
101.00	61.00
108.25	62.48
116.00	64.46
123.00	67.10
130.00	70.52
137.00	74.83
145.00	79.89
147.00	78.67
149.00	77.30
151.00	75.78
153.00	74.15
155.00	72.42
157.00	70.63
159.00	68.83
161.00	67.05
163.00	65.30
165.00	63.47
168.00	63.00
172.00	62.00
178.00	60.00
181.00	58.00
185.00	57.00
193.00	56.00
197.00	55.00
201.00	53.00

Table 10: Boundary conditions for model 106.

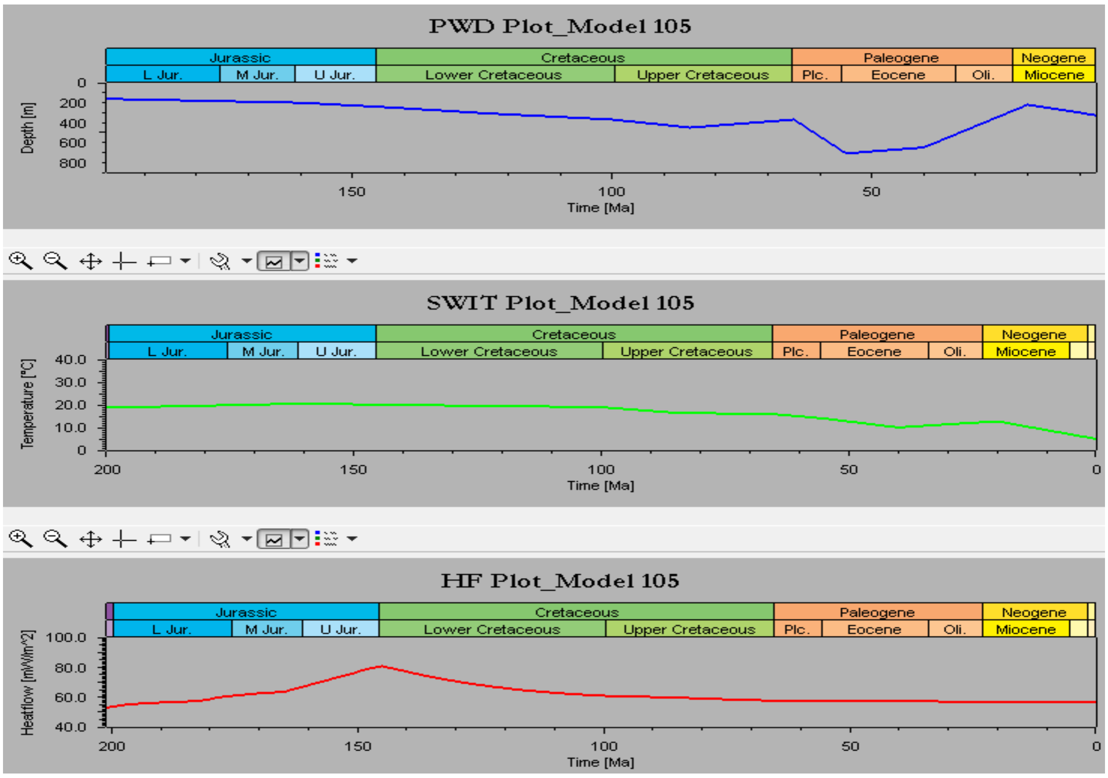


Figure 20: Boundary conditions trends for model 105.

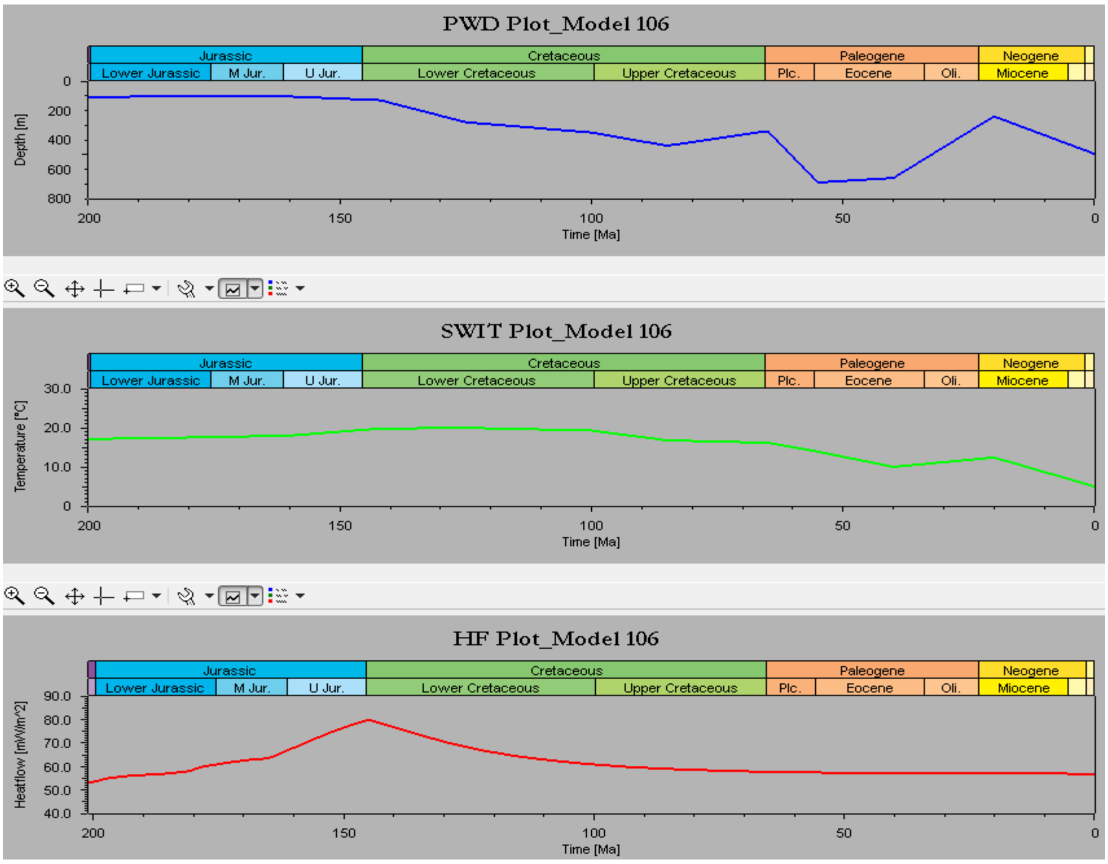


Figure 21: Boundary conditions trends for model 106.

5.7 Petro Charge Layer

Petro charge layers are used to determine the direction of hydrocarbon migration from the source rocks and also to define the carrier beds i.e. the reservoir rocks. In this work, the Draupne Formation source rock, which is younger than the Brent Group reservoir rock, is set to have 100% hydrocarbon downward migration. The Brent Group is defined as a carrier bed (Table 11).

Layer	Carrier	Downward Expulsion [%]
Nordaland Gp 1	No	0.00
Nordaland Gp 1_1	No	0.00
Utsira Fm	No	0.00
Hordaland Gp	No	0.00
Balder Fm	No	0.00
Shetland Gp	No	0.00
Cromer Knoll Gp	No	0.00
Draupne Fm	No	100.00
Brent Gp	Yes	0.00

(a) Model 105

Layer	Carrier	Downward Expulsion [%]
Nordaland Gp 1	No	0.00
Nordaland Gp 1_1	No	0.00
Utsira Fm	No	0.00
Hordaland Gp	No	0.00
Balder Fm	No	0.00
Shetland Gp	No	0.00
Cromer Knoll Gp	No	0.00
Draupne Fm	No	100.00
Brent Gp	Yes	0.00

(b) Model 106

Table 11: Petro charge layer setting for petroleum model.

5.8 Model Simulation

2D simulator was used to set the parameters prior simulation run. Calibration models used was Sweeney and Burnham (1990)_EASY%Ro and the kinetic reaction used was Burnham (1989)_TII. The default value was used in most of the parameters in the simulation option and run control panes. Only migration method was changed to hybrid migration method. Ben-Awuah et al. (2013) explained the hybrid migration method as a combination of both Darcy and Flow path algorithms and a simplified percolation calculation. The simulation run was successful and the log summary for both models is presented in Appendix 1 and 2.

CHAPTER 6: MODELLING RESULTS AND DISCUSSION

6.1 Burial History, Erosion and Uplift

The subsidence history of a sedimentary basin through geological time is referred as the burial history. Subsidence, uplift and erosion are analyzed by using burial history graphs, which play a key role in providing the present day maximum burial depth.

The northern Viking Graben started to form during the Permo-Triassic rifting. During the Triassic period the subsidence of the basin was slow and probably the sediments were deposited in non-marine environments. In early Jurassic, the basin experienced slow to high subsidence rates and the maximum subsidence occurred during the middle and late Jurassic period. The late Jurassic was a period of active faulting in response to continued crustal extension and fault-controlled subsidence had a marked influence on stratigraphic thicknesses and facies, especially during the late Jurassic (Zervos, 1986).

Uplift and erosion are observed during the late Jurassic to early Cretaceous, and this is caused by crustal extension, which accelerated during this period. This resulted in the formation of the Base Cretaceous Unconformity. The extension resulted in the subsidence and uplift of large rotational fault blocks during the late Jurassic as shown in Fig 22, and this was followed by slower subsidence in the early Cretaceous (Fig 23). The late Cretaceous to Paleocene period was characterized by thermal subsidence and sediment deposition. The Jurassic rifting created more accommodation space for the post rift sediments to be deposited at the end of Cretaceous. The continued thermal subsidence and sediments supply resulted into the deposition of thick sediments of Shetland and Rogaland Group of late Cretaceous and Paleocene age respectively (Figs 24-25).

The Cenozoic was dominated by mainly subsidence compared to rifting and faulting in the Mesozoic. Sandstones interbedded with shales, which is the dominant lithology in Rogaland Group were deposited in deep marine environment during the Paleocene and early Eocene time. The subsidence continued to create more deposition space in deep water between Eocene to early Miocene, which resulted to the deposition of the marine claystones of the Hordaland Group and the Utsira Formation of the Middle Miocene (Figs 26-27). Uplift and erosion during this period lead to the development of Base

Quaternary Unconformity in the middle of the Nordland Group (Fig 28). Fig 29 shows the present day configuration.

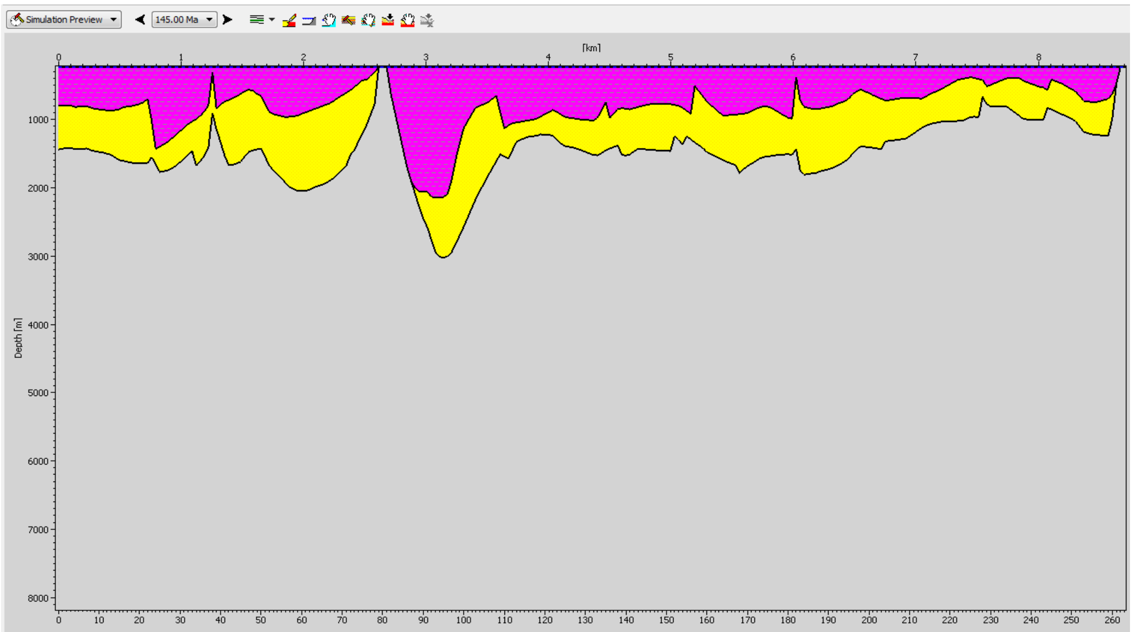


Figure 22: 145 Ma, end of deposition of the late Jurassic Draupne Formation, which was followed by erosion and the formation of the Base Cretaceous Unconformity.

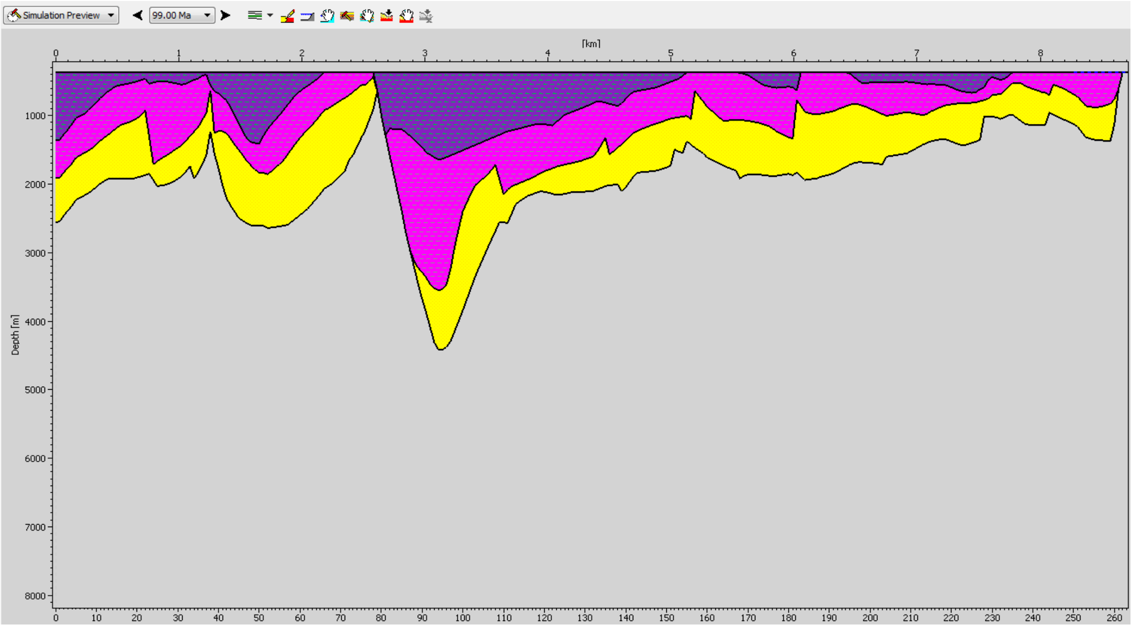


Figure 23: 99 Ma, end of deposition of the early Cretaceous Cromer Knoll Group.

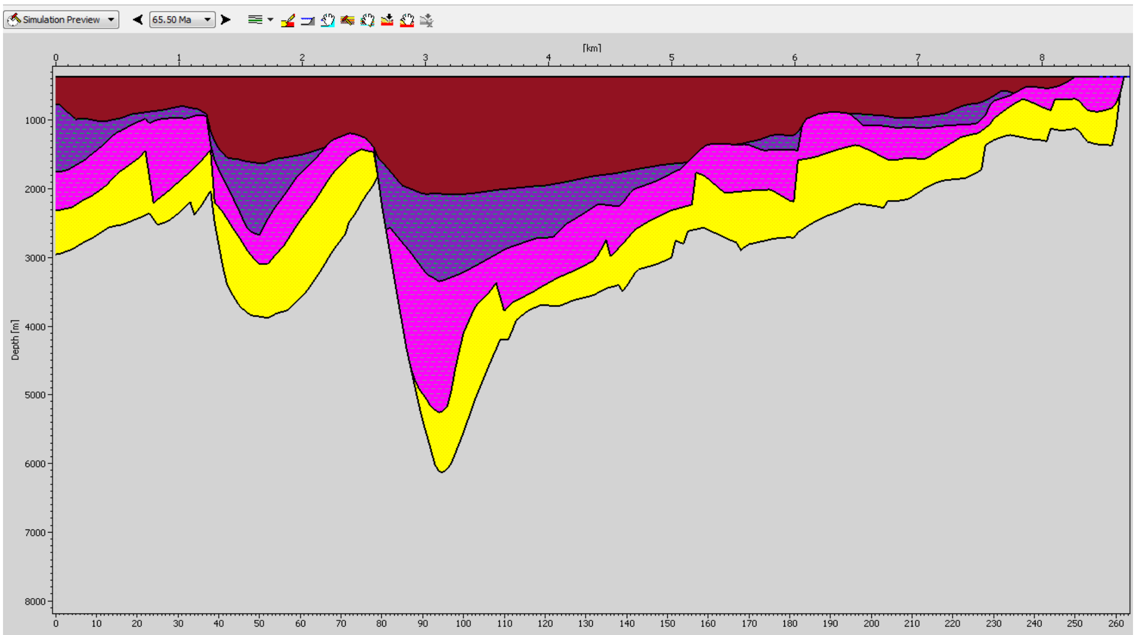


Figure 24: 65.5 Ma, end of deposition of the late Cretaceous Shetland Group.

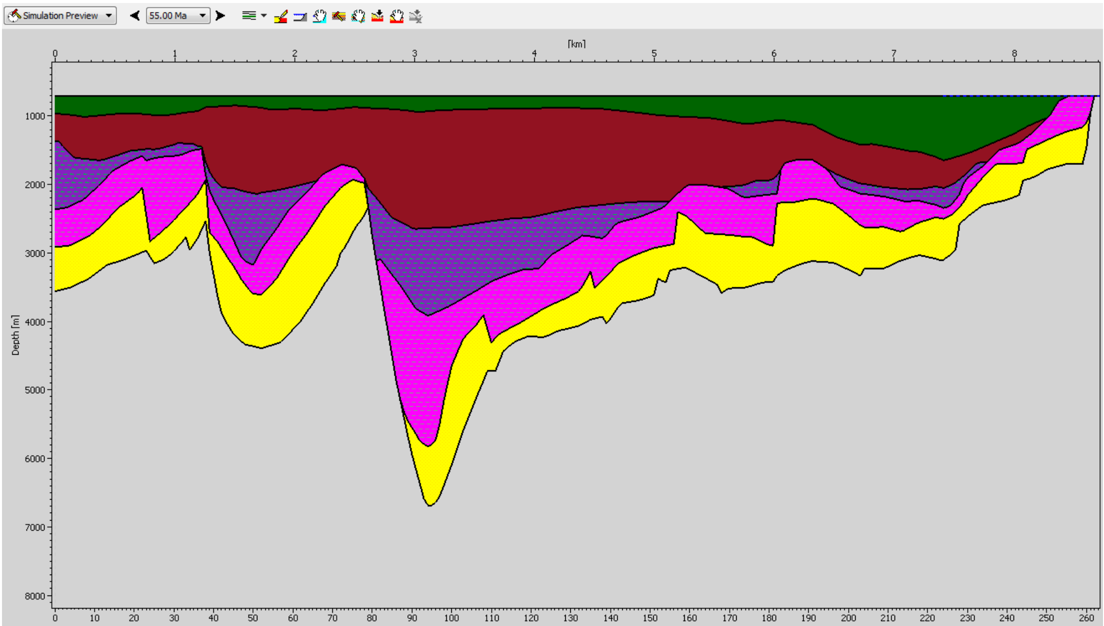


Figure 25: 55 Ma, end of deposition of the early Paleocene Rogaland Group.

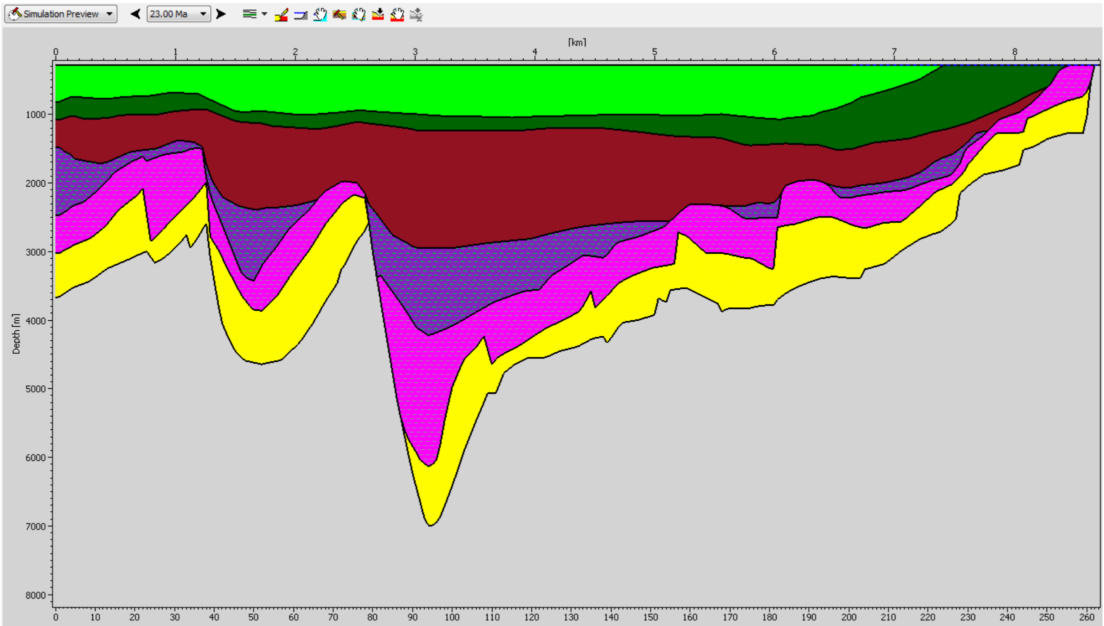


Figure 26: 23 Ma, end of deposition of the early Miocene Hordaland Group.

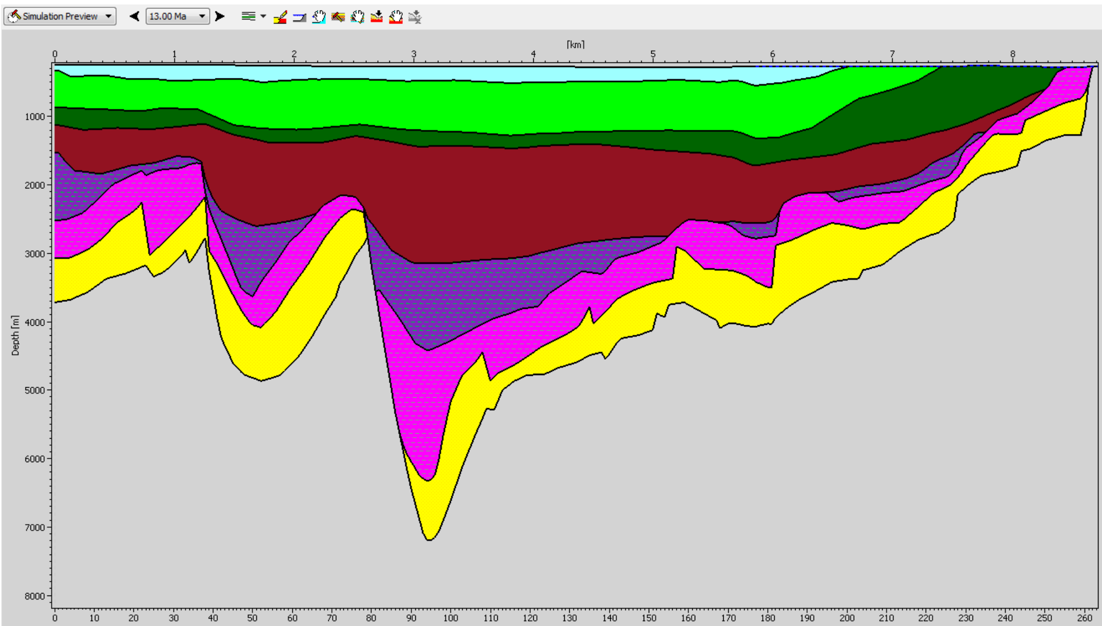


Figure 27: 13 Ma, end of deposition of the middle Miocene Utsira Formation.

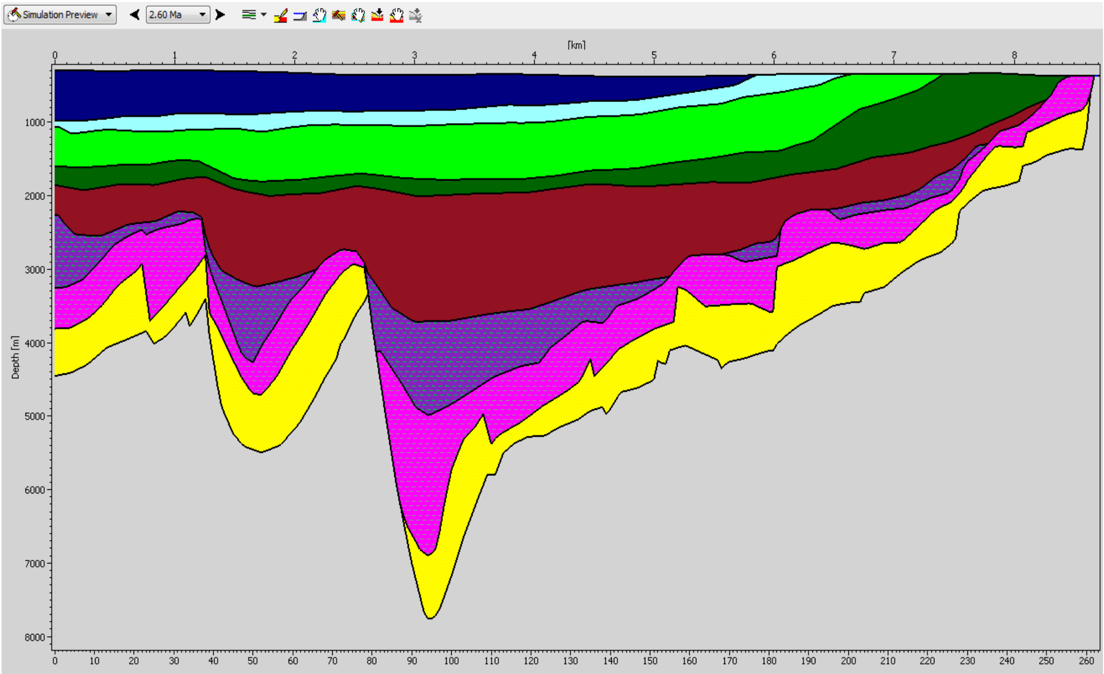


Figure 28: 2.6 Ma, formation of the Base Quaternary Unconformity in the middle of the Nordland Group.

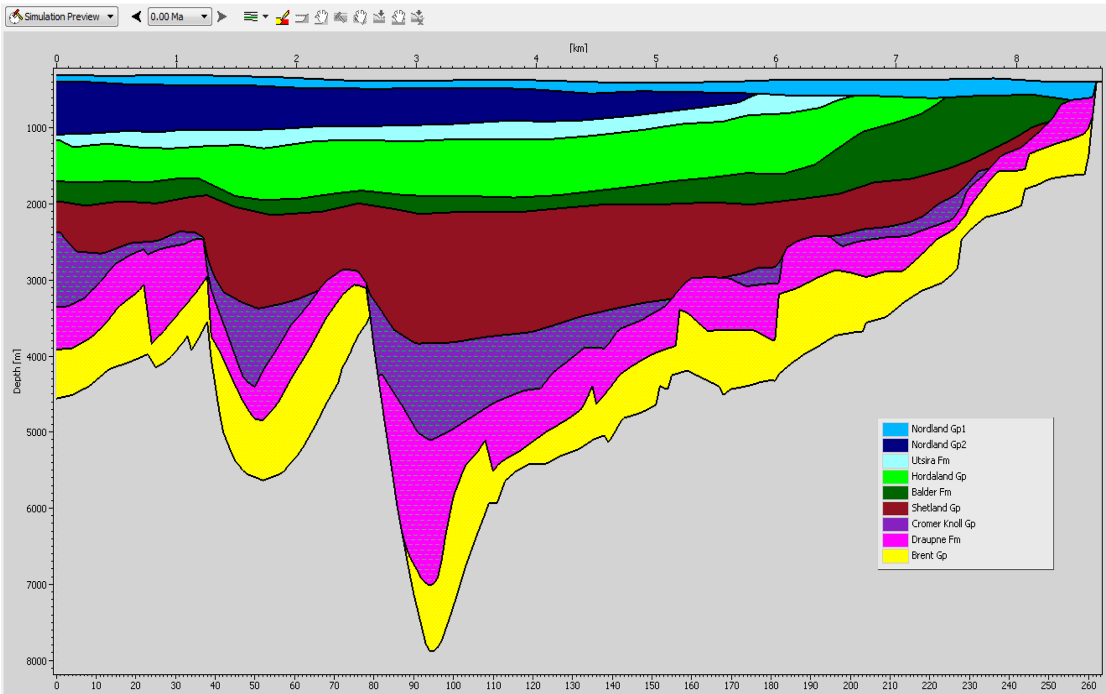


Figure 29: 0.00 Ma, Present day basin configuration.

6.2 Source Rock Maturity and Hydrocarbon Windows

The simulation result of the northern Viking Graben was displayed in the 2D viewer option in PetroMod. The maturity parameters (temperature and vitrinite reflectance) were used to analyze the maturity of the source rocks and the results show that the source rocks are matured enough to produce both oil and gas. Always, temperature increases with increase in depth and as the temperature increases, the large hydrocarbon molecules in kerogen that are very stable at low temperature, are broken down to form oil, gas or both depending on the kerogen type and temperature. The temperature history of the model shows that the base of the sediments in the deeper parts of the basin reaches maximum temperatures of about 320 ^{0}C in model 105 and 350 ^{0}C in model 106. The source rock (Draupne Formation) reaches maximum temperature at about 240 ^{0}C in model 105 (Fig 30) and 268 ^{0}C in model 106 (Fig 31). This ranges of temperature provides evidence that the source rock is over matured and reaches the dry gas window in the deepest parts of the basin.

Vitrinite reflectance (Sweeney & Burnham (1990)), which is the standard indicator for maturity (Figs 32 and 33), shows that the source rocks are matured enough to produce both oil and gas. As the depth increases, temperature increases and vitrinite reflectance also increases, so there is a linear relationship between it and maximum temperature. Tables 12 and 13 summarize the depth and vitrinite reflectance value ranges for different types of hydrocarbons.

By using these two parameters (temperature and vitrinite reflectance) it shows that maturation of the source rocks started during the late Cretaceous when the early oil generation began. During this time, the sediment temperature was around 120 ^{0}C, whereas the vitrinite reflectance value was in the range of 0.55 to 0.70. However, the sediments, which are located in the deepest parts of the half graben, experience higher temperatures (200 ^{0}C), which resulted to high vitrinite reflectance value. As a result, this part of the basin was transformed earlier to produce hydrocarbons and become mature compared to the rest of the basin (Figs 32 and 33).

Figs 34 (a to d) summarize the source rock maturity evolution from Late Cretaceous to present. At 99 Ma, early and main oil generation has been started in the deeper part of the basin with a minor wet gas generated in the deepest part of the basin. At 55 Ma most parts of the Draupne Formation, which is deposited in deeper part of the basin has generated oil with wet gas and few dry gas. Subsequently, at 23 Ma, all parts of the

Draupne Formation have generated oil, wet gas and dry gas. At the present day, the Draupne Formation is at mature stage with the dry gas window followed by overmature source rock dominating the deeper part of the basin.

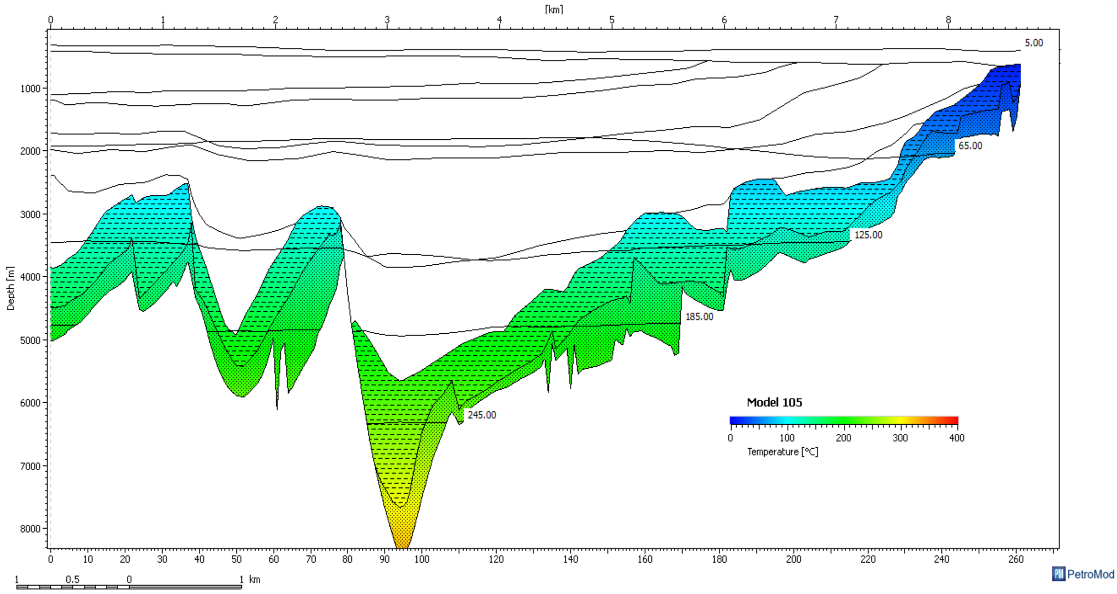


Figure 30: Burial history overlay with temperature for model 105.

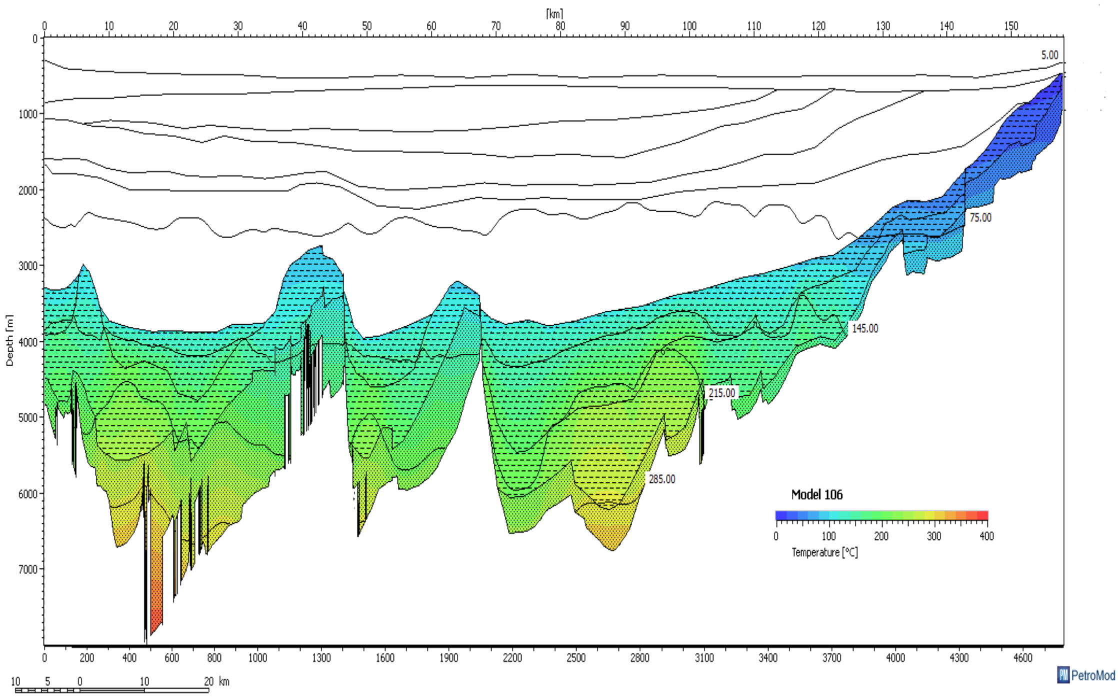


Figure 31: Burial history overlay with temperature for model 106.

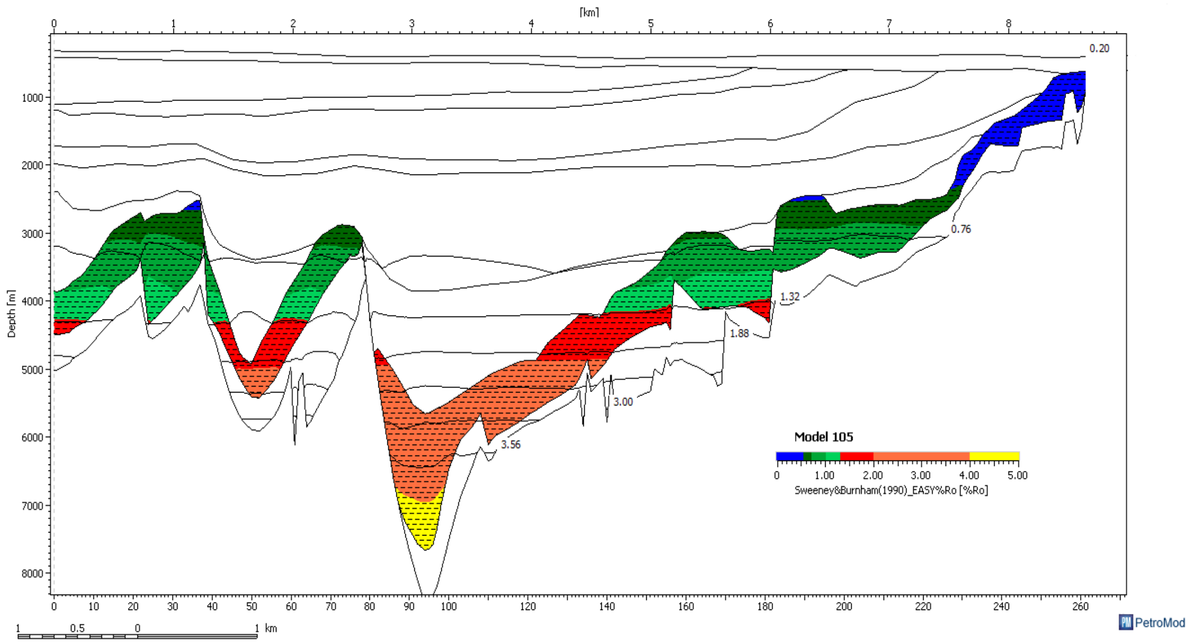


Figure 32: Burial history overlay with vitrinite reflectance for model 105.

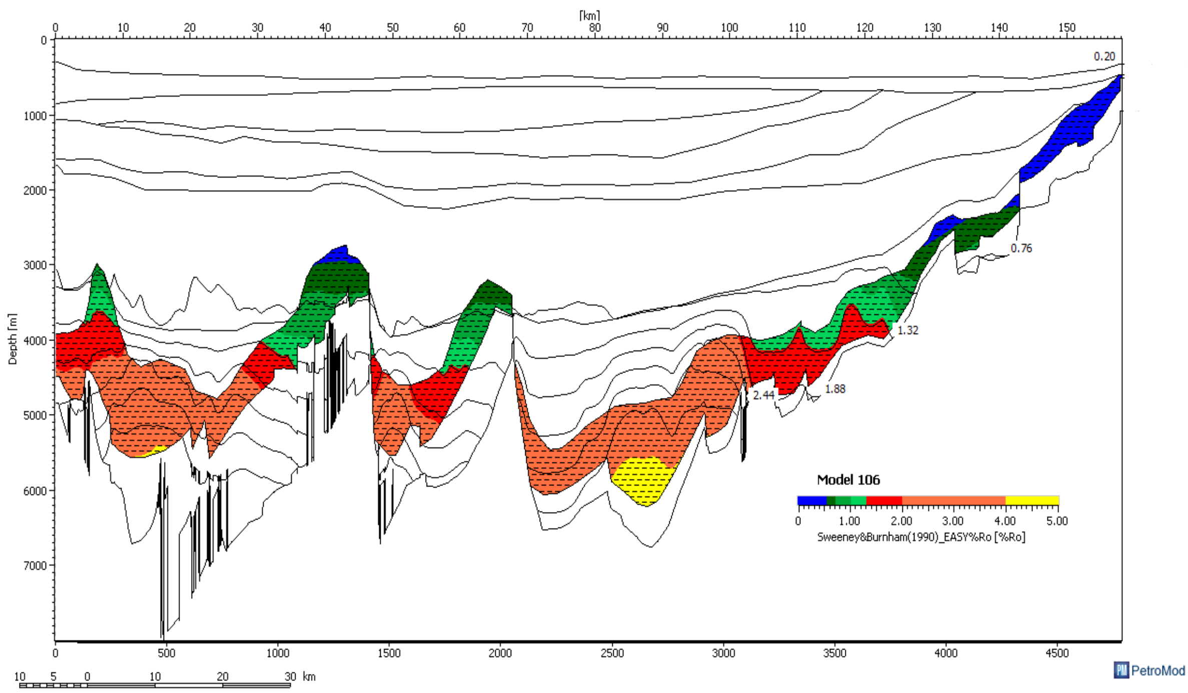


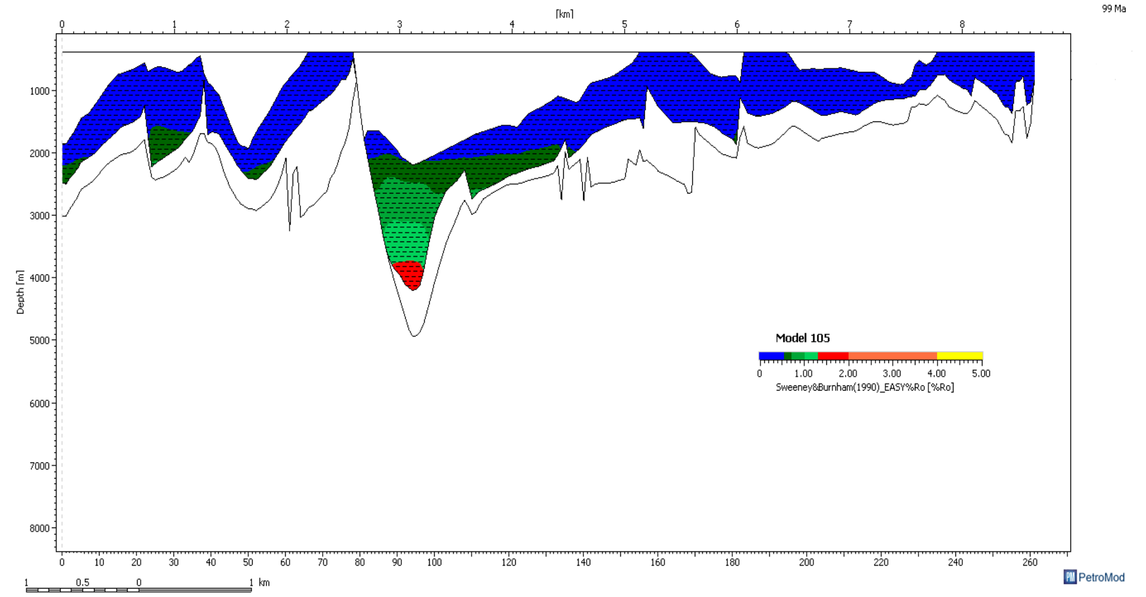
Figure 33: Burial history overlay with vitrinite reflectance for model 106.

Hydrocarbon type	Depth (km)	Vitrinite reflectance (Ro)
Immature	2.5	0---0.55
Early oil window	2.5---2.8	0.55---0.70
Main oil window	2.8---3.5	0.70---1.00
Late oil window	3.5---4.1	1.00---1.30
Wet gas window	4.1---5.1	1.30---2.00
Dry gas window	5.1---7.2	2.00---4.00
Overmature	Above 7.2	4.00---5.00

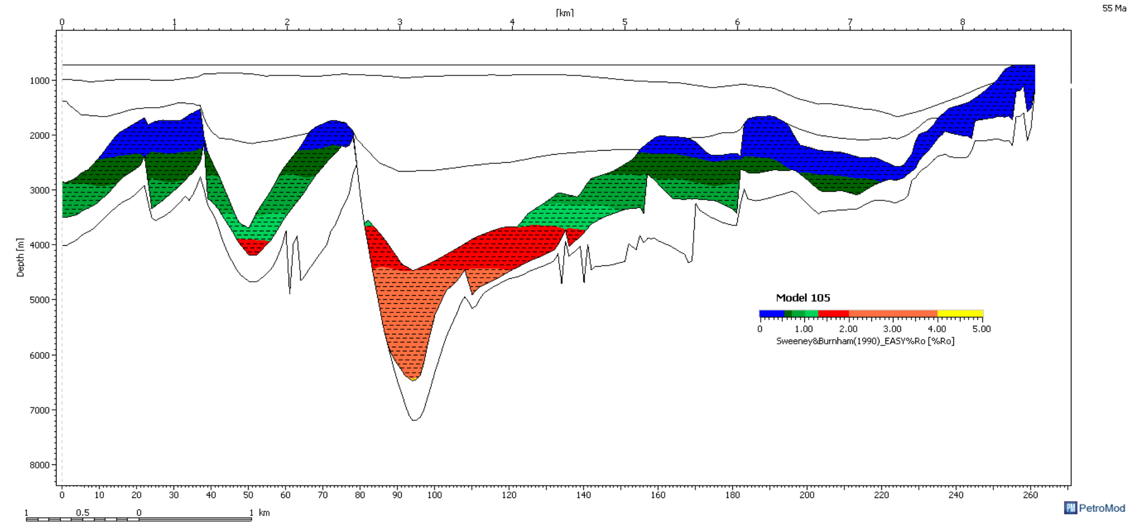
Table 12: Hydrocarbon generation windows for model 105.

Hydrocarbon type	Depth (km)	Vitrinite reflectance (Ro)
Immature	2.8	0---0.44
Early oil window	2.8---3.2	0.44---0.56
Main oil window	3.2---4.1	0.56---0.80
Late oil window	4.1---4.6	0.80---1.04
Wet gas window	4.6---5.5	1.04---1.60
Dry gas window	5.5---6.3	1.60---3.20
Overmature	Above 6.3	3.20---4.00

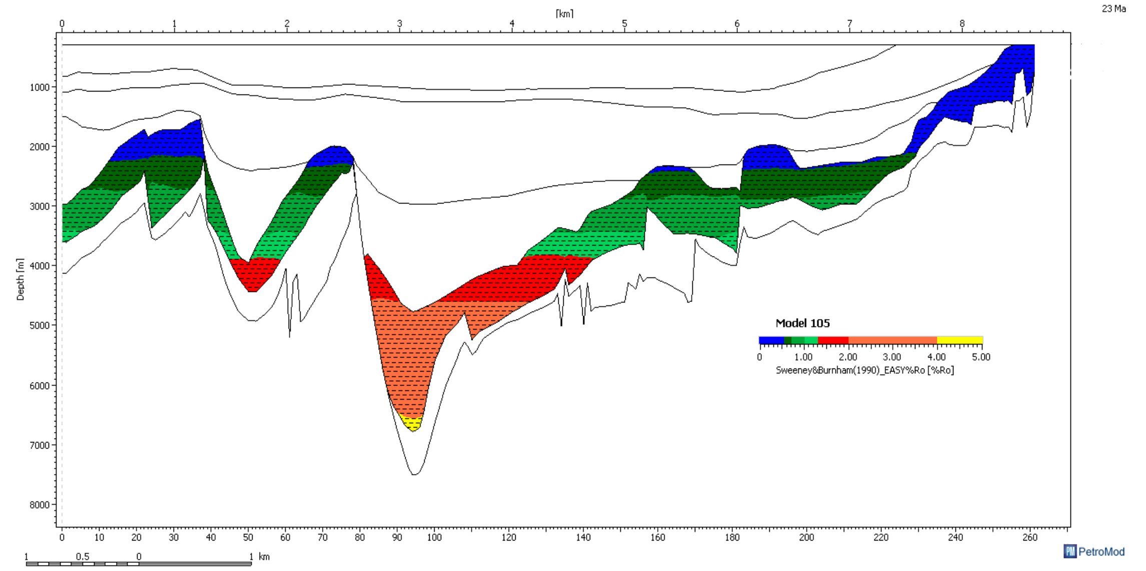
Table 13: Hydrocarbon generation windows for model 106.



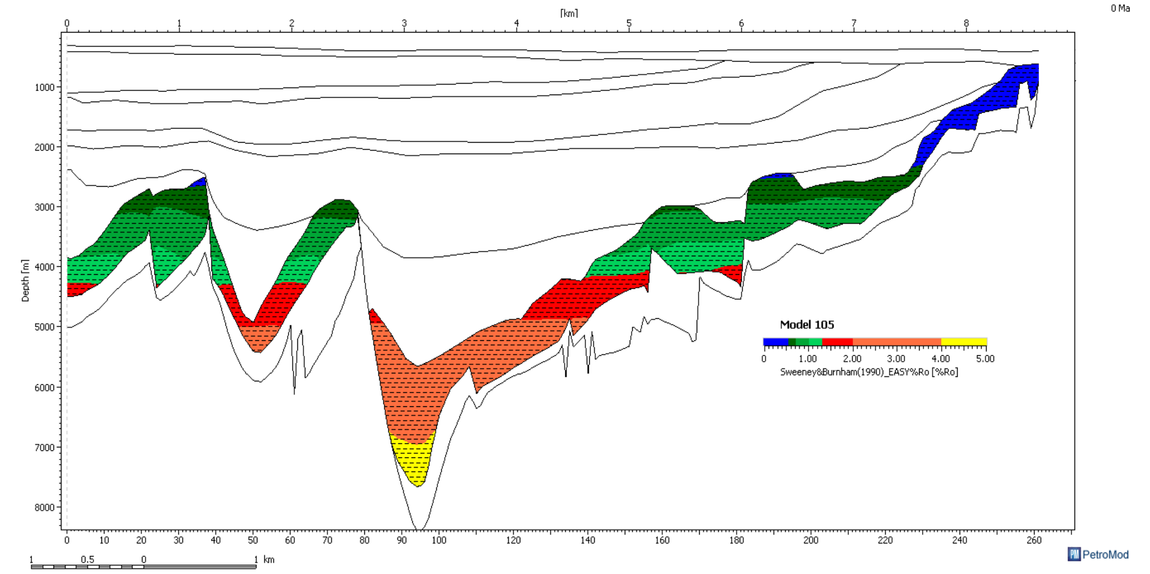
(a) 99 Ma



(b) 55 Ma



(c) 23 Ma



(d) 0.00 Ma

Figure 34: (a to d) Source rock maturity evolution from late Jurassic to present. The blue colour indicates immature stage of source rock, green the oil window, red the gas window and yellow overmature source rock.

Transformation ratio is also used to measure maturity. For a fully matured source rock, which has generated all hydrocarbons, the transformation ratio value is 1 and for completely immature source rocks, the transformation ratio value is 0. Model results indicate that in some part especially deeper part of the basin, 100% of the source rock has been transformed, and the rest part 55-82% is already transformed. This means that, the source rock in some parts of the northern Viking Graben still generates hydrocarbons at the present day (Figs 35 and 36). Figs 37 and 38 show the remaining kerogen bulk in the Viking Graben. So we expect more hydrocarbons to be generated with increase in temperature.

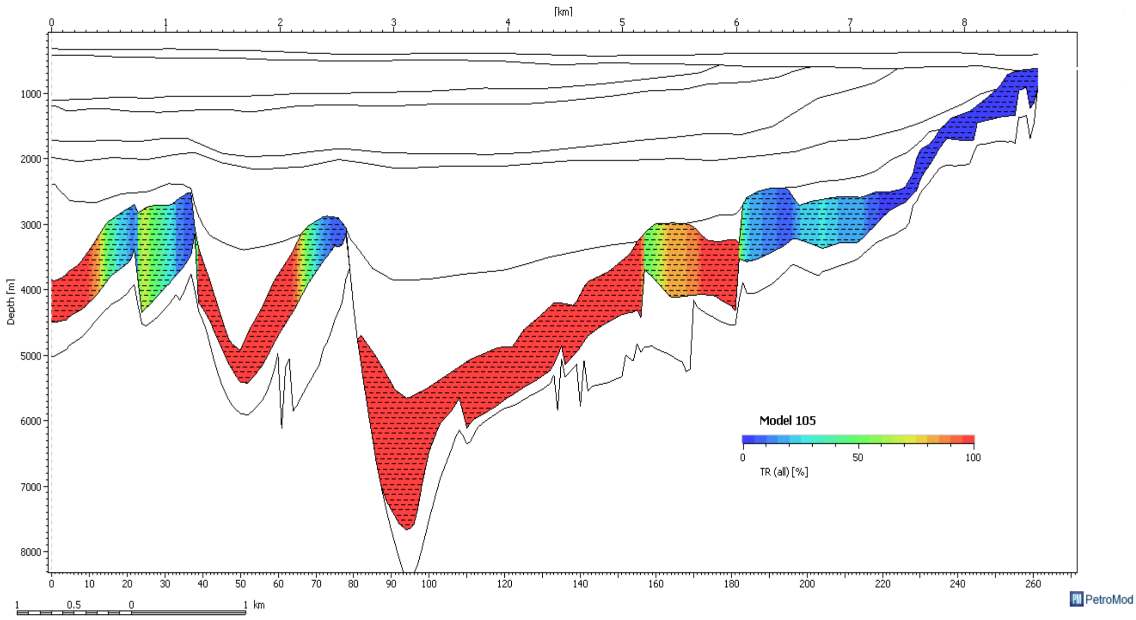


Figure 35: Transformation ratio for model 105.

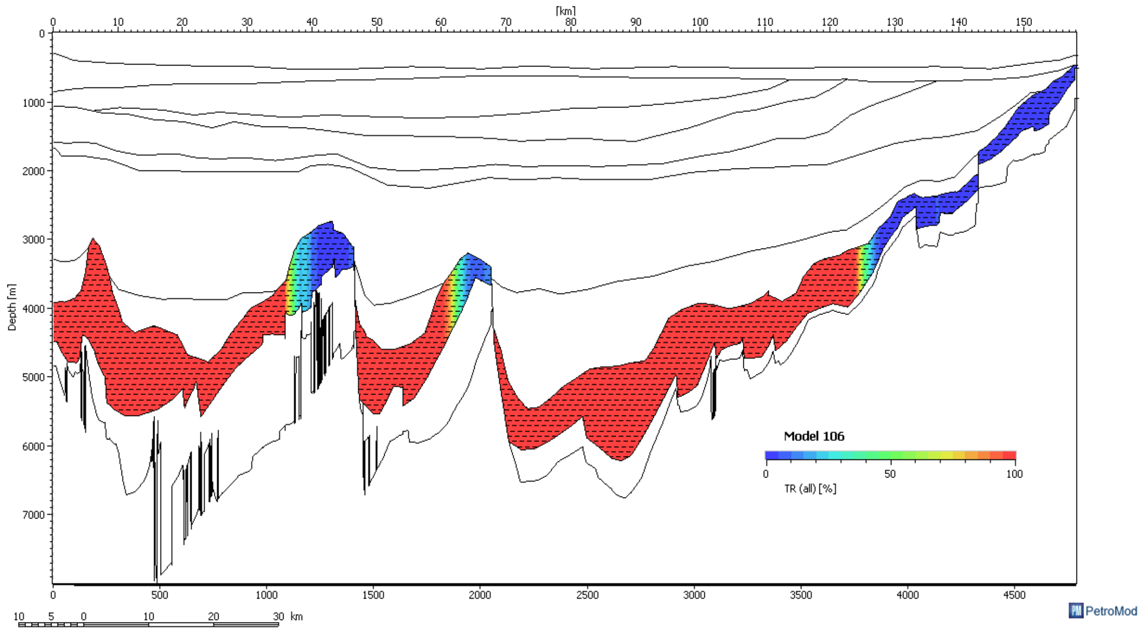


Figure 36: Transformation ratio for model 106.

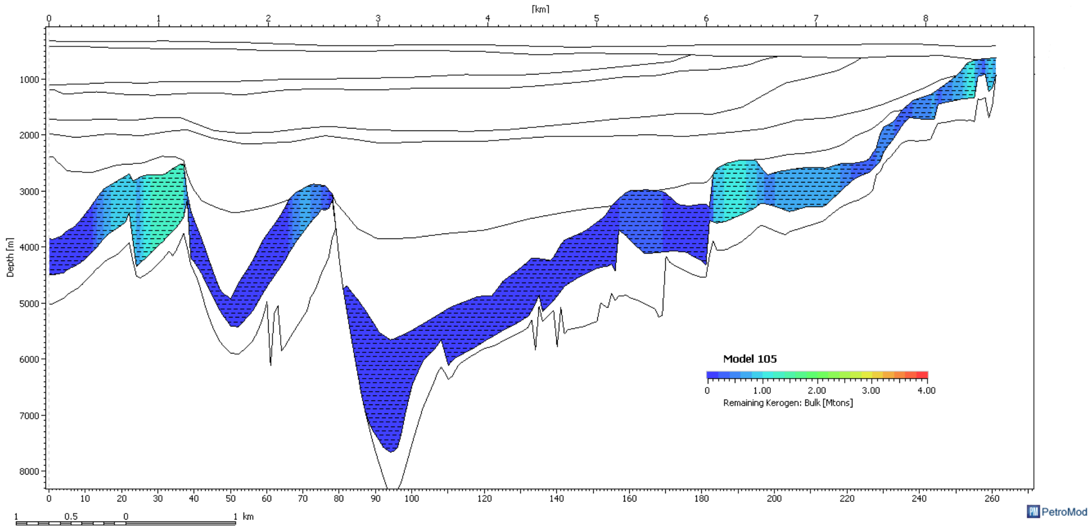


Figure 37: Remaining kerogen bulk for model 105.

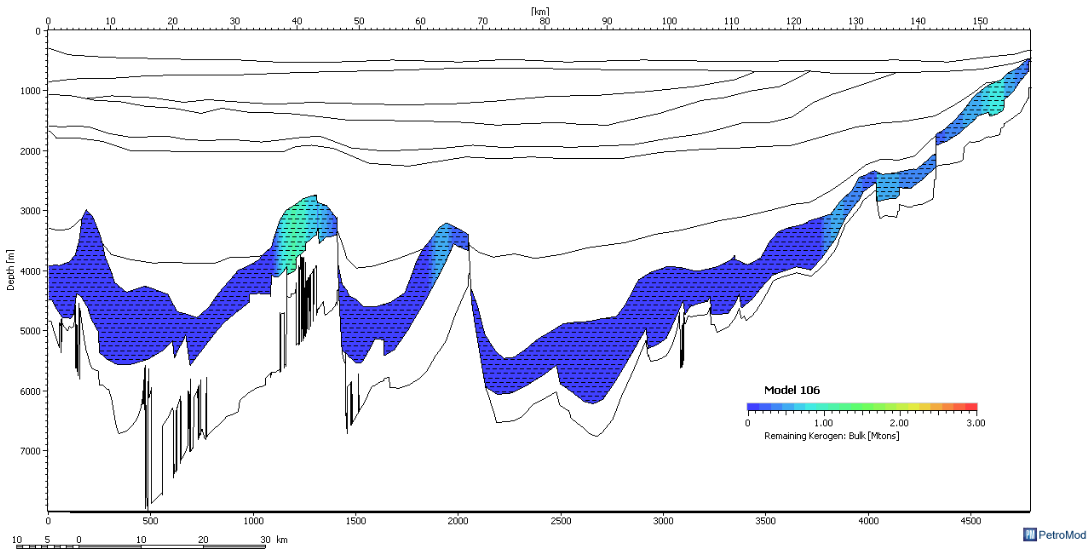


Figure 38: Remaining kerogen bulk for model 106.

6.3 Hydrocarbon Generation, Migration and Accumulation

In order to predict the hydrocarbon generation, migration and accumulation, it is important to reconstruct a petroleum system event chart, which is essential to show the elements, processes and timing of petroleum system (Fig 39). The deposition of reservoir, source and seal rocks occurred at proper timing before the petroleum system processes (generation, migration and accumulation) took place. Generation, migration and accumulation of hydrocarbons started during the late Cretaceous time, which was followed by the time during which hydrocarbons within the petroleum system are preserved or destroyed. Traps were formed before hydrocarbon generation, which was late Jurassic to early Cretaceous time. Since these events occurred at the proper timing, then it was possible for the hydrocarbons to migrate and accumulate in the reservoirs. According to Magoon and Dow (1994), the point in time selected by the investigator that best depicts the generation, migration, and accumulation of most hydrocarbons in a petroleum system is referred as critical moment. This is the time when most of the hydrocarbons are generated at TR =50 % and in this case, the critical moment, which is represented by red line, is considered to be 60 Ma.

Swarbrick (2005) explained the importance of considering the timing of petroleum migration relative to the time of deposition of the reservoir/seal combinations and the creation of structure within the basin. This is because, if hydrocarbon migration takes place before the deposition of reservoir and seal, then hydrocarbons will not accumulate. The hydrocarbon migration pathways are mainly vertically upward or downward from the source rock kitchen into the reservoir rock. The reservoir rocks that are placed close to the source rock have high possibilities to receive hydrocarbons first. In this study the source rock is younger than the reservoir rock and therefore we expect the migration to be vertically downward. However, some of hydrocarbons have migrated from the source rocks along faults and accumulated in the layers above. Indications of high amplitude anomalies observed in seismic sections along the plane of faults it can be suspected as fluids migrating from the subsurface up to the surface.

The model results show that there are possible prospects and accumulated hydrocarbon reserves present in the study area (Figs 40 and 41). The visible accumulation at reservoir conditions is about 5.65 MMbbls of oil and 3.14 Mm^3 of gas, whereas the amount flashed to surface condition are 4.88 MMbbls of oil and 34.44 Mm^3 of gas (Model 105). Model 106 show 42.62 Mm^3 of gas are visible accumulation at reservoir condition and 7576.29 Mm^3 of gas are flashed to the surface conditions. No visible oil accumulation observed in this model. From the saturation model, the source rock are saturated with hydrocarbon in the range of 30 to 70%, however some parts are 100% saturated while other are 0% saturated (Figs 42 and 43).

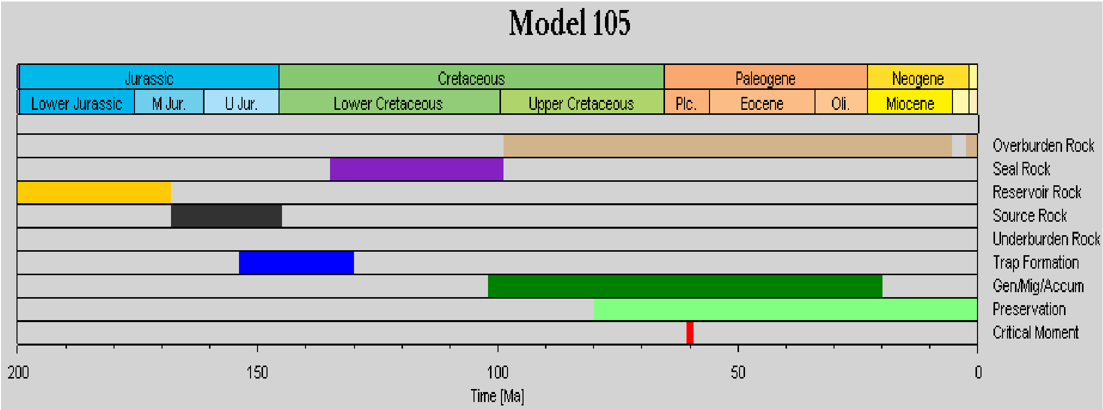


Figure 39: Event chart.

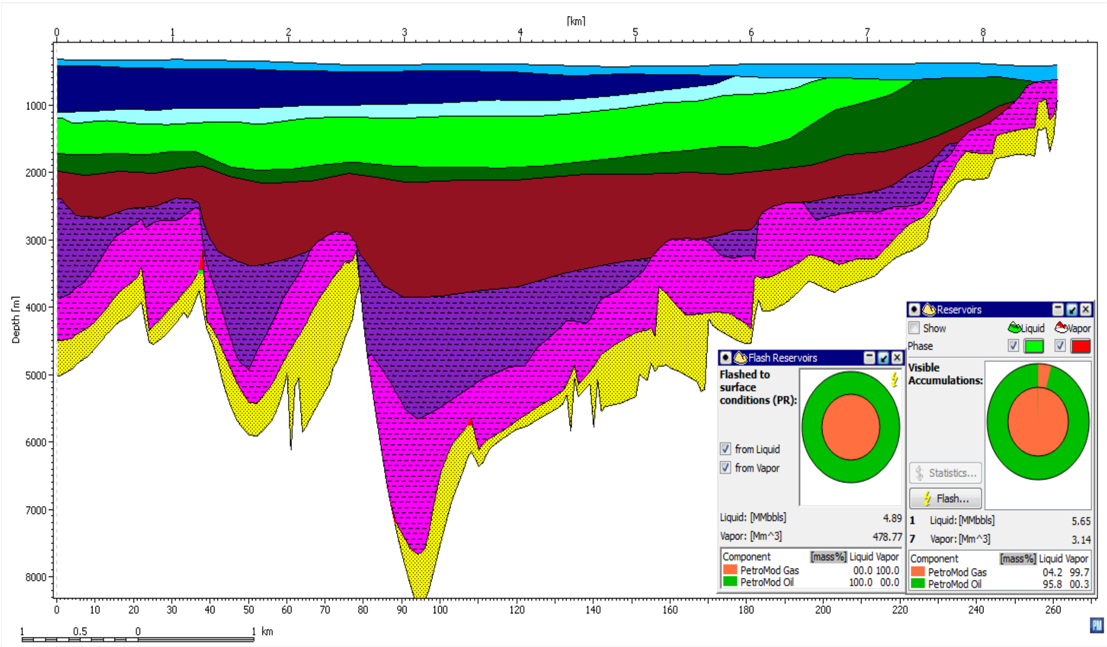


Figure 40: Hydrocarbon accumulation for model 105. A green and red dot indicates oil and gas accumulation respectively.

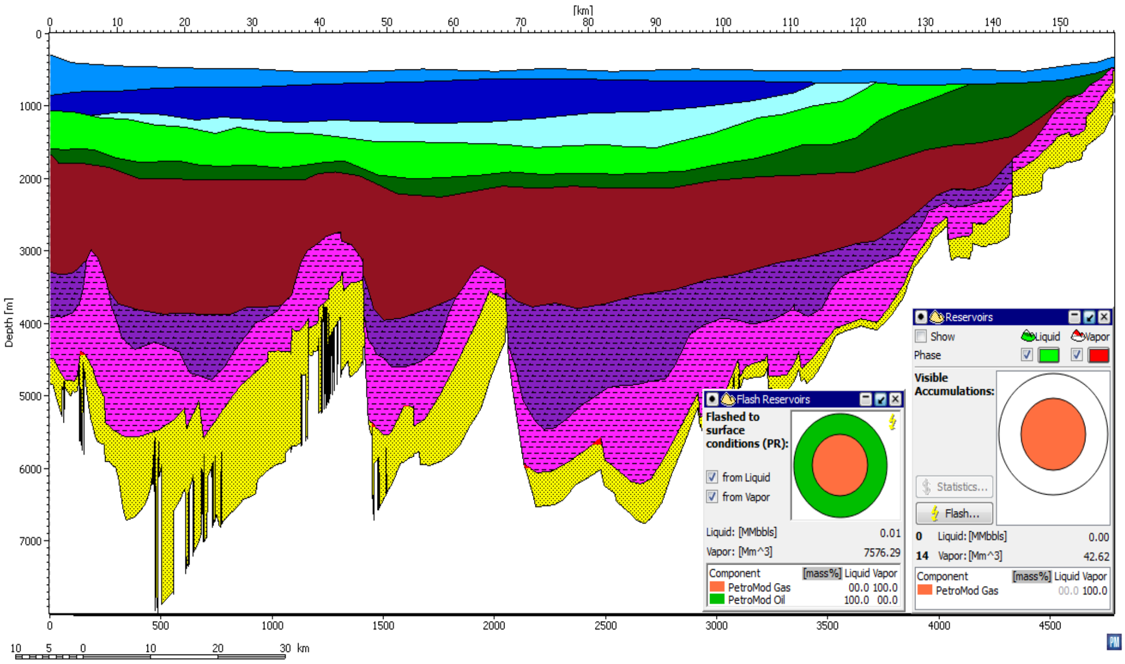


Figure 41: Hydrocarbon accumulation for model 106. A green and red dot indicates oil and gas accumulation respectively.

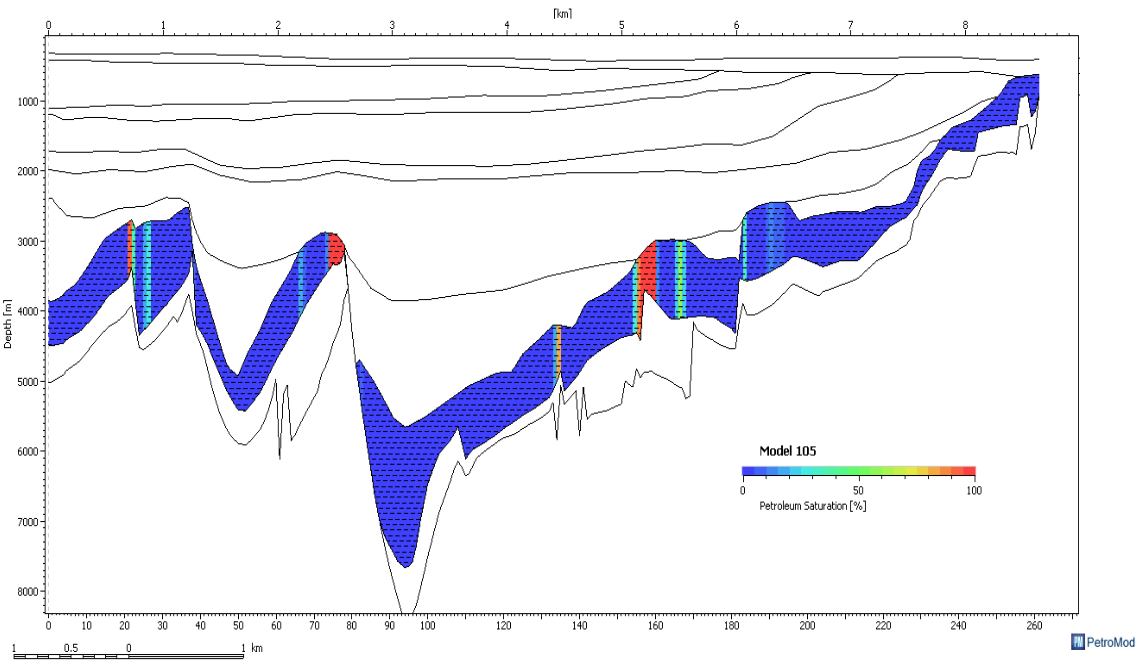


Figure 42: Burial history overlay with hydrocarbon saturation of the source rock for model 105.

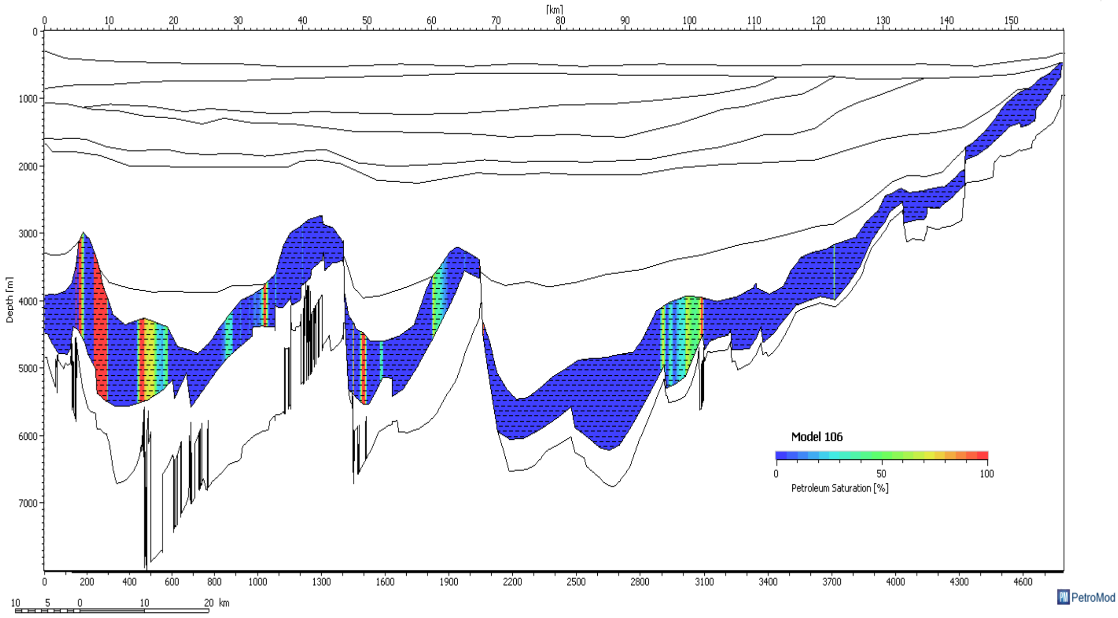


Figure 43: Burial history overlay with hydrocarbon saturation of the source rock for model 106.

CHAPTER 7: CONCLUSION

The North Viking Graben represents an important petroleum province dominated by a number of producing fields, which have been a key factor for the economic growth of Norway.

The evolution of the Viking Graben basin is mainly through two rifting phases, each of which were followed by thermal subsidence. During Permian-Triassic time, the basin started to form and this period is known as Permo-Triassic rifting phase. This was followed by thermal subsidence before the occurrence of a second rifting event during the late Jurassic, which resulted in crustal stretching and rapid subsidence of large rotational fault blocks. The deposition of the syn rift packages associated with uplift and erosion and resulted in the formation of an unconformity at the boundary between late Jurassic and early Cretaceous (Base Cretaceous Unconformity). After the second rifting event ceased, thermal subsidence and sediment loading followed and this resulted in the deposition of a thick post rift sequence, which forms the seal rock (Cromer Knoll Group) and the overburden rocks.

The syn-rift Jurassic sequence i.e. Heather and Draupne Formations, which belongs to the Viking Group and the Brent Group coals are considered as the potential source rocks, of the area. The main reservoir rocks are Statfjord Group and Brent Group sandstones. The Draupne Formation is rich in organic material and has high total organic carbon content (6%) and hydrogen index (400-600 mg/gTOC).

Vitrinite reflectance and temperature data were used to determine the maturity of the source rocks and the results show that oil and gas were generated from matured source rocks. The maturity history through time shows that the source rock started to mature and reaches early window during the late Cretaceous period. Generation of hydrocarbons both oil and gas continues until present day, however in some parts especially the deeper parts of the basin, the source rock has become overmature. The transformation ratio shows that the source rock is transformed to a significant level, which allows the hydrocarbons to be generated. This observation is supported by Snorre oil field, Troll gas field, Oseberg field, Brage oil field, Brent field, Gullfaks and other field (Fig 8), which are among the field-producing hydrocarbon in the area to present day.

Since the reservoir rocks (Brent and Statfjord Groups) are older than source rocks ((Draupne and Heather Formations), it is mostly likely that the downward migration from the source to the reservoir rocks is what has occurred. Also there are some hydrocarbon accumulation on the top of the source rock, probably this may migrate through the faults. The migration of hydrocarbons through the faults is evidenced by the presence of high amplitude anomalies along the fault, however not all fault show this feature.

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APPENDICES

```
 Simulation Run Successful !
 Optimization:  17.07 % relative difference (Largest difference: 162.3 %)

 --------------------------------

 --------------------------------

 CPU Times:

 Preprocessor                          2   sec,     3.45 %
 Pressure Analysis                     2   sec,     3.45 %
 Compaction                            0   sec,     0.00 %
 Heat Analysis                         1   sec,     1.72 %
 Reaction Kinetics                     0   sec,     0.00 %
 Mul Kinetics                          0   sec,     0.00 %
 Migration                             5   sec,     8.62 %
 Darcy Migration                      11   sec,    18.97 %
 PetroCharge                           5   sec,     8.62 %
 Breakthrough & Fault Injection        0   sec,     0.00 %
 Misc. Output                          0   sec,     0.00 %
 PetroCharge Final                    31   sec,    53.45 %
 Postprocessor                         1   sec,     1.72 %
 Total                                58   sec,   100.00 %

 incl. Percol. (Fault)                 0   sec,     0.00 %
 incl. Percol. (Break Through)         0   sec,     0.00 %
 incl. Overlay Output                 18   sec,    31.03 %

 --------------------------------

Date/Time Tue Aug 16 10:31:17 2016
Simulation finished at: Date/Time Tue Aug 16 10:31:17 2016
```

Run: 2D/3D temperature and pressure   Migration Method: Hybrid

```
Simulation started ...
Simulation has finished!
```

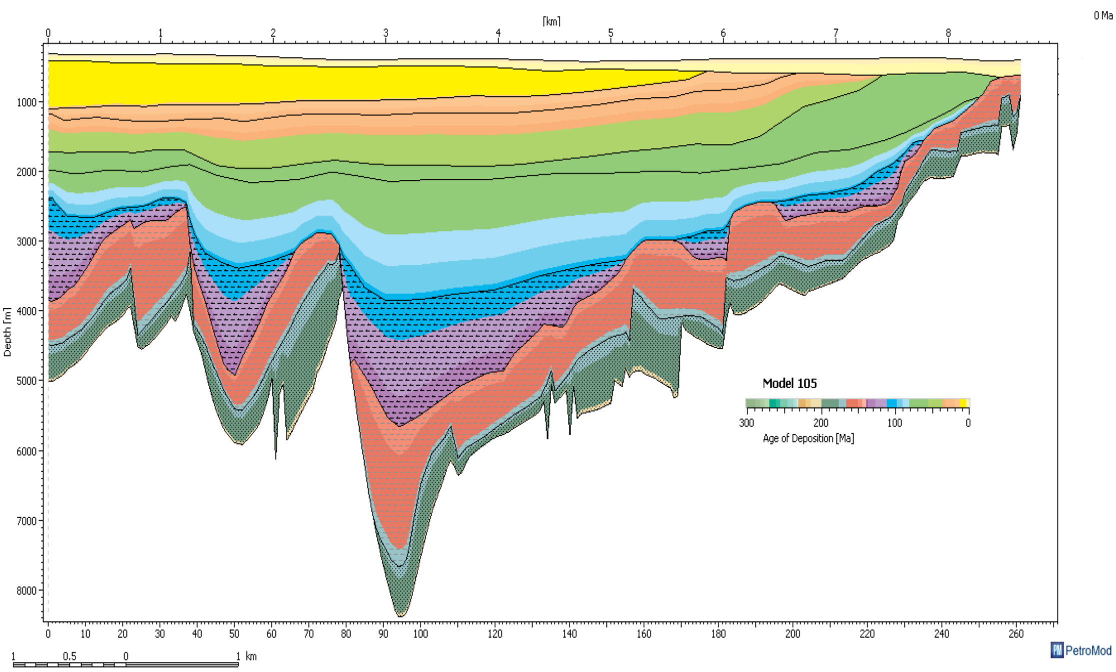
Appendix 1: Simulation log run for model 105.

```
 Simulation Run Successful !
 Optimization:  16.8 % relative difference (Largest difference: 207.1 %)

 --------------------------------

 --------------------------------

 CPU Times:

 Preprocessor                           3   sec,      0.24 %
 Pressure Analysis                     16   sec,      1.28 %
 Compaction                             4   sec,      0.32 %
 Heat Analysis                         18   sec,      1.44 %
 Reaction Kinetics                      5   sec,      0.40 %
 Mul Kinetics                           1   sec,      0.08 %
 Migration                            297   sec,     23.70 %
 Darcy Migration                      572   sec,     45.65 %
 PetroCharge                           15   sec,      1.20 %
 Breakthrough & Fault Injection        15   sec,      1.20 %
 Misc. Output                           1   sec,      0.08 %
 PetroCharge Final                    304   sec,     24.26 %
 Postprocessor                          2   sec,      0.16 %
 Total                               20.9 min,    100.00 %

 incl. Percol. (Fault)                  0   sec,      0.00 %
 incl. Percol. (Break Through)          1   sec,      0.08 %
 incl. Overlay Output                  15   sec,      1.20 %

 --------------------------------

Date/Time Tue Aug 16 11:03:06 2016
Simulation finished at: Date/Time Tue Aug 16 11:03:06 2016
```

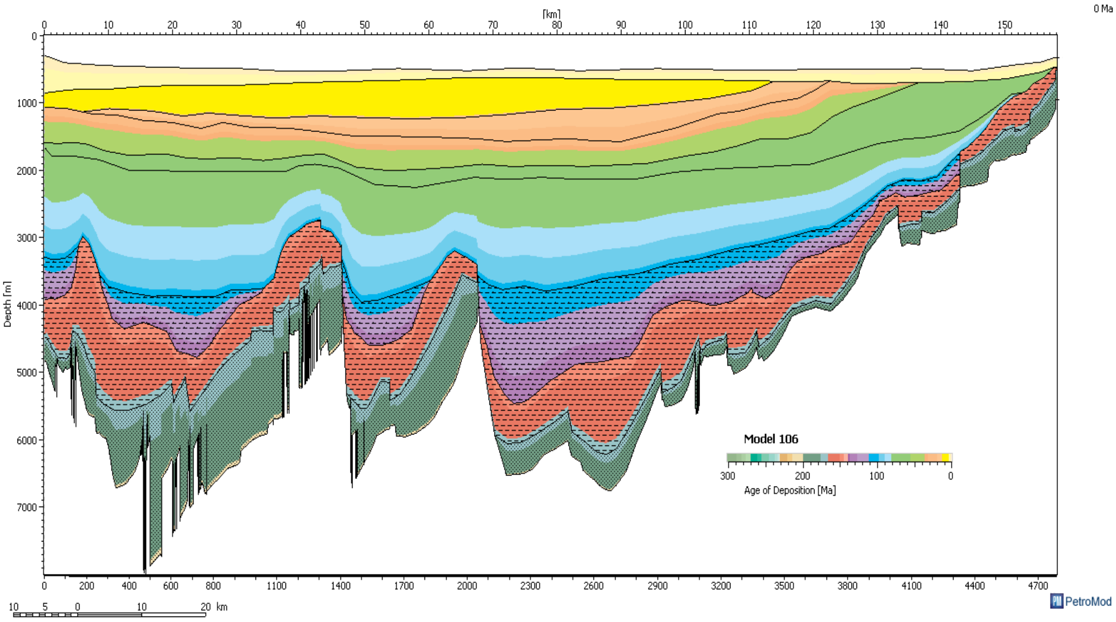
Run: 2D/3D temperature and pressure   Migration Method: Hybrid

```
Simulation started ...
Simulation has finished!
```

Appendix 2: Simulation log run for model 106



Appendix 3: Burial history overlay with age of deposition for model 105



Appendix 4: Burial history overlay with age of deposition for model 106