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ชื่อโครงการ 3D-BASIN MODELING TO IDENTIFY MIGRATION PATHWAY OF PETROLEUM IN NORTHERN PART OF PATTANI BASIN, GULF OF THAILAND

ชื่อนิสิต ALANGKARN TANGJAIPEAM

ภาควิชา GEOLOGY

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คณะวิทยาศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย

หัวข้องานวิจัย : แบบจำลอง 3 มิติเพื่อระบุเส้นทางการไหลของปิโตรเลียมในพื้นที่ทางตอนเหนือของแอ่งปัตตานี อ่าวไทย

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อาจารย์ที่ปรึกษา : อ.ดร.เครือวัลย์ จันทร์แก้ว

ภาควิชา : ธรณีวิทยา

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บทคัดย่อ

การสำรวจหาแหล่งพลังงานปิโตรเลียมจะอาศัยข้อมูลทางธรณีวิทยาและการแปลความข้อมูลคลื่นไหวสะเทือน แต่การศึกษาปกตินั้นไม่สามารถยืนยันการมีอยู่ของปิโตรเลียมในพื้นที่ก่อนทำการเจาะได้ แบบจำลองแอ่งสะสมตะกอนจึงเป็นอีกวิธีที่ช่วยในการประมวลผลข้อมูลทางธรณีวิทยา ธรณีเคมีปิโตรเลียมและข้อมูลทางธรณีฟิสิกส์เพื่อช่วยในการยืนยันการมีอยู่ของปิโตรเลียมในพื้นที่ศึกษา โดยงานวิจัยนี้จะเป็นการศึกษาเส้นทางการไหลของปิโตรเลียมในพื้นที่ศึกษาทางตอนเหนือของแอ่งปัตตานีในอ่าวไทย

งานวิจัยจะแบ่งการศึกษาแบบจำลองแอ่งสะสมตะกอนออกเป็น 2 ส่วนหลัก คือการศึกษาแบบจำลองแอ่งสะสมตะกอน 1 มิติและ 3 มิติ โดยแบบจำลองแอ่งสะสมตะกอน 1 มิติจะพิจารณาข้อมูลปิโตรเลียมของแต่ละหลุม ในขณะที่แบบจำลอง 3 มิติจะพิจารณาข้อมูลปิโตรเลียมทั้งพื้นที่ศึกษา การศึกษาแบบจำลอง 1 มิตินั้นจะรวบรวมข้อมูลลำดับชั้นหิน ข้อมูลธรณีแปรสัณฐาน ข้อมูลความร้อนและข้อมูลธรณีเคมีปิโตรเลียมของหินต้นกำเนิดในแต่ละหลุมเพื่อนำมาสร้างเป็นประวัติการตกสะสมตัวของตะกอนและประวัติปิโตรเลียม ทั้งนี้ได้ทำการเปรียบเทียบผลการศึกษาที่ได้จากแบบจำลอง 1 มิติกับข้อมูลหลุมและมีการปรับแก้จนค่าอุณหภูมิและค่า Vitrinite Reflectance (Ro) ที่ได้จากการสร้างแบบจำลอง 1 มิตินั้นตรงกับข้อมูลหลุมมากที่สุด สำหรับการศึกษาแบบจำลองแอ่งสะสมตะกอน 3 มิตินั้นได้มีการรวบรวมข้อมูลคลื่นไหวสะเทือนร่วมด้วยเพื่อเป็นตัวแทนของลำดับชั้นหิน 3 มิติ และพิจารณารอยเลื่อนในพื้นที่ศึกษายอมให้ไฮโดรคาร์บอนไหลผ่าน ซึ่งผลลัพธ์ของแบบจำลอง 3 มิติ คือเส้นทางการไหลของปิโตรเลียมในพื้นที่ศึกษาจากหินต้นกำเนิดไปสู่พื้นที่กักเก็บปิโตรเลียมในปัจจุบัน

ผลการศึกษาแบบจำลอง 1 มิติแสดงให้เห็นว่าในพื้นที่ศึกษา หินต้นกำเนิดมีการแตกตัวให้น้ำมันมากกว่าก๊าซ โดยหินต้นกำเนิดในพื้นที่ทางตะวันออกเฉียงใต้เริ่มมีการสร้างปิโตรเลียมหนัก (C6+) ประมาณ 4 ล้านปีก่อนและสร้างปิโตรเลียมเบา (C1-5) 4 ล้านปีก่อน และแบบจำลองแอ่งสะสมตะกอน 3 มิติแสดงให้เห็นถึงการไหลของไฮโดรคาร์บอนจากพื้นที่ทางตะวันออกเฉียงใต้-ตะวันออกไปยังพื้นที่ทางตะวันตกเฉียงเหนือ-ตะวันตก ในแนวหลักตะวันออกเฉียงใต้-ตะวันตกเฉียงเหนือ

Research: 3D-BASIN MODELING TO IDENTIFY MIGRATION PATHWAY OF PETROLEUM IN NOETHERN PART OF PATTANI BASIN, GULF OF THAILAND

Researcher: Alangkarn Tangjaipeam

Advisor: Dr.Kruawun Jankeaw

Major: Geology

Academic year: 2015

ABSTRACT

Petroleum exploration usually follows the geological data and seismic interpretation. A standard method of study cannot confirm the presence of petroleum in the area. Consequently, basin modeling is considered by integrating the geological data, petroleum geochemistry data and geophysics data to help identify petroleum accumulation area. For this research, the study area is located at the northern part of Pattani Basin, Gulf of Thailand.

This research will study 2 types of basin modeling; 1D-basin modeling and 3D-basin modeling. The 1D-basin modeling will provide petroleum data based on 1 well data while the 3D-basin modeling takes consideration of the whole area. For the 1D-basin modeling, the essential data for creating a 1D model are stratigraphy, tectonics, heat data and petroleum geochemistry data. The final results are burial history and petroleum history curve. Moreover, the outputs of 1D-basin modeling will be compared with raw data in calibration step by comparing the temperature and vitrinite reflectance (Ro). In case the results do not fit with the raw data, adjustment would be taken. After the results of 1D model are satisfied, 3D-basin model is created. Seismic surface, represents stratigraphic layer, is used to generate a 3D model together with fault interpretation. The final result is 3D model showing migration pathway of petroleum from the expelled area to the accumulation area.

The study result of 1D-basin modeling shows the proportion of oil to gas in source rock generation. The source rock in southeastern zone started to generate heavy hydrocarbon (C6+) and light hydrocarbon (C1-5) at 4 Ma. The 3D model shows the migration of petroleum in the area of south-southeastern to north-northwestern.

Acknowledgement

I would like to give infinite thanks to everyone who helped me achieve this project, 3D-Basin Modeling to Identify Migration Pathway of Petroleum in the Northern Part of Pattani Basin, Gulf of Thailand. I could not imagine how the project would be done without all the support of yours.

First of all, I am very thankful to my advisor, Dr.Kruawun Jankaew, whose advice was very helpful. I would like to give my thanks to Chevron Thailand Exploration and Production, Ltd. for letting me have the project with the company, and Halliburton Energy Service, Inc. for providing all of the software. I deeply thank K. Ken Wegner and K. Korakot Surarat from Chevron Thailand Exploration and Production, Ltd. for their helps. I deeply appreciated K. Jatuphat Natepracha from Halliburton Energy Service, Inc. and all staff from Halliburton who always kindly gave their suggestions about the program. I would like to thank my family and friends for cheering up me and everything.

Alangkarn Tangjaipeam.

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Contents

Appendix Iv: Maps

List of Table

List of Figures

Chapter 1 Introduction

1.1 Background and Rationale

Petroleum takes a very important role in the energy industry. Studying petroleum will help us understand all the processes of petroleum generation in order to produce petroleum. Basically, petroleum can be generated only if the proper conditions and all necessary elements are in place, this is known as the petroleum system. Petroleum system contains 5 elements: source rock, reservoir, trap, seal and migration pathway. Nowadays, petroleum geology can be studied using 3D-basin modeling which aims to understand the petroleum generation, expulsion and migration in the area. Moreover, this modern study in petroleum exploration and production can help us reach the best production which is what all oil and gas companies want to.

Pattani Basin is a Tertiary basin with North-South trending, it is located in the Gulf of Thailand (Fig 1.1), and it is one of the most important basins for producing resources in Thailand. This basin covers more than 1,000 square km. Its length is 400 km and width is 70 km. The basin has been depositing since Tertiary and, now, it can be divided in 5 sequences deposited in different depositional environments, from the lacustrine- to shallow marine depositional environment. Source rock in the basin is considered to be in Sequence 1 and 3, but mostly in Sequence 1. To study using 3D-basin modeling, the source rock maturity and stratigraphy will be used to identify petroleum generation, exploration and migration.

This project studies an area in the North of the Pattani Basin and covers more than 145 square km. Three wells are used to study the petroleum system. The project kindly received support with data from Chevron Thailand Exploration and Production company and software from Halliburton Thailand company.

1.2 Problems Defined

From 3 wells drilled in the study area, only 2 wells found hydrocarbons. The 2 successful wells are located in the northwestern area, while the other which did not find hydrocarbon in the southeastern zone of the study area. Referring to the above situation, migration pathway of hydrocarbon should be considered in studying the petroleum system. Finally, the project will provide the data of burial, source rock generation history and migration pathway which would help understanding the petroleum system in the area.

1.3 Objectives

1. To understand maturity, generation and expulsion of source rock in northern part of Pattani Basin, Gulf of Thailand.

2. To create a 3D-basin model and identify migration pathway of hydrocarbon in northern part of Pattani Basin, Gulf of Thailand

1.4 Expected Outputs

1. For 1D-basin modeling, the expected outcomes are burial history curve, maturation and production times of source rock in the area.

2. For 3D-basin modeling, the expected outcome is 3D-basin model showing migration pathway of hydrocarbon in the study area.

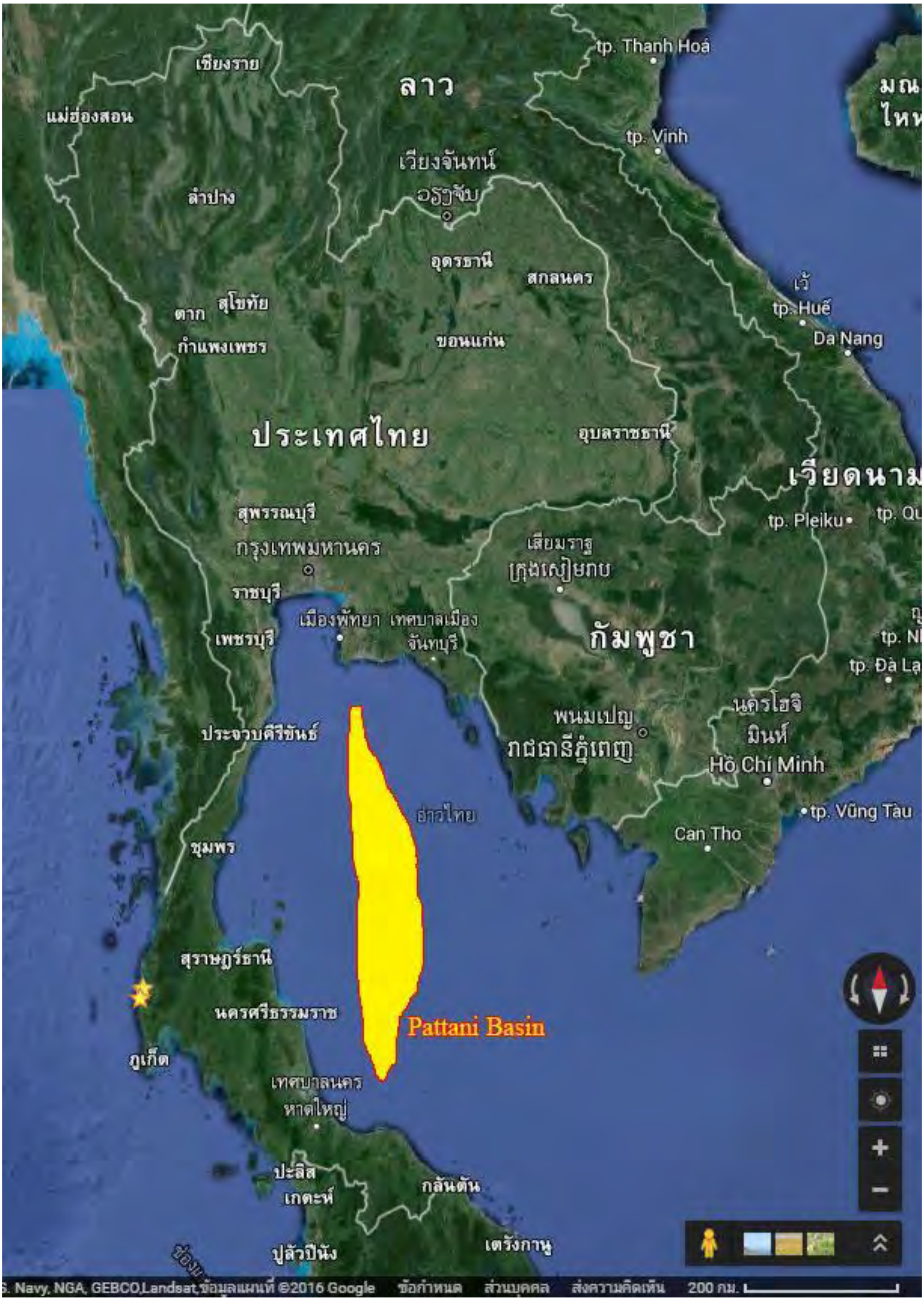

Fig 1.1 – Location of Pattani Basin, Gulf of Thailand. The background map is from google earth (2015) while the yellow area representing the Pattani basin is referred from Charusiri (2009).

1.5 Literature Review

1.5.1 Tectonic Evolution of Tertiary Basins in Thailand (Charusiri and Pum-Im, 2009)

Tertiary basins in Thailand, including Pattani basin, are the result of tectonic compression between the Indian and Eurasian tectonic plates (showing in Fig 1.2). Four phases of basin development are recognized herein and interpreted based upon the plate-tectonic regime including; phase 1 (pull-apart and syn-rifting), phase 2 (quiescent thermal subsidence), phase 3 (transgressional wrenching) and 4 (post-rifting) .

Pull-apart and Synrifting Episode (~55 Ma to 35 Ma)

This first phase commences with the onset of transtensional rifting in predominantly north-northwestern trending extension forming Sequence 1 in Pattani Basin in lacustrine environment. Faults NE-trending represent the North-South convergent which may have occurred in 55 Ma . The convergent plate tectonic of India and Eurasia, in NS trend, caused the rifting phase in the Andaman Sea and, also, in the Gulf of Thailand which resulted in extensive crust thinning by the extension in EW trend (Fig 1.2). As a result of this tectonic episode, Pattani Basin was forming as graben -and half graben -type of basin in late Eocene to late Oligocene. Moreover, this perhaps leads to the occurrence of Mid-Tertiary Unconformity (MTU) which can be observed clearly by seismic data (Jardine, 1997).

Quiescent Thermal Subsidence Episode (~35 to 15 Ma)

After the last episode of pure extension decreased, transtensional tectonic became important. The basin started to be widespread. This began with fluvio-deltaic deposits as Sequence 3 in the Pattani basin. The extension of the basin was also caused by the thermal contraction from the withdrawal of heat at the back-arc region of mantle plume and caused the strike-slip movement. The thinning of the continental crust due to high heat flow results in the rapid basin subsidence with the sedimentation rate reaching up to 1 m per 1000 years.

Transpressional Wrenching Episode (~15 to 10 Ma)

The on-going dextral shear eventually produced a change in tectonic style, becoming transpressional in the late Middle Miocene, leading to folding and inversion of basins in Thailand in the very late Neogene. The evidence of this episode is marked by the Mid-Miocene to early Late Miocene unconformity, MMU which is observed from geophysical signals. In the Gulf, transpression may have caused the marked uplift or basement highs, and extensive regression with widespread erosion may have developed separately from the basin inversion. All the age data leads to infer that the Ko Kra Ridge and other relevant basin highs in the gulf may have developed significantly at this time, although dating data imply that they may have formed earlier than that. This leads to the readjustment of the crust south of the Khorat, and as result deeper and larger basins may have developed for the eastern – Gulf subsegment compared to those of the western gulf sub-segment, the latter being narrower and shallower.

Post-rifting Episode (~10 Ma to Present)

After the extensive transpressive episode, the overall region may have been adjusted. In the Gulf, basins were subsided without significant tilting or rotating, giving rise to transgression and deposition of predominant marginal marine deposit in the Upper Miocene. The subsidence rate in those basins decreased with time.

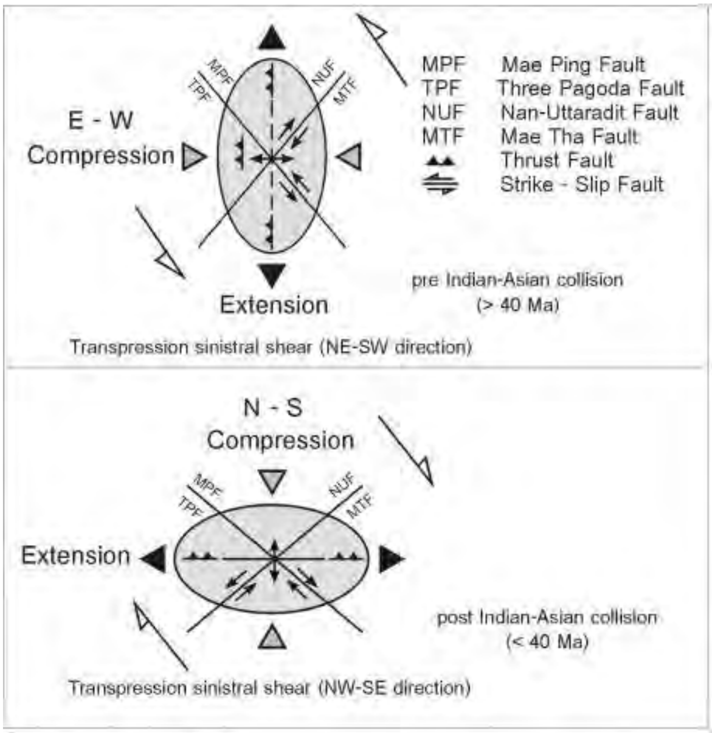

Figure 1.2 - Strain ellipsoids showing the development of major fault zones in Thailand (Charusiri and Pum-Im, 2009).

1.5.2 Stratigraphy of Pattani Basin (Jardine, 1997)

Stratigraphy in Pattani basin can be divided in to 5 sequences, Sequence 1 to 5 following Chevron Thailand Exploration and Production (CTEP classification). There were 2 periods of non-deposition, caused erosional surface, which occurred at 25 Ma and 10 Ma, are called Mid-Tertiary Unconformity (MTU) and Mid-Miocene Unconformity (MMU), respectively. The sequences in Pattani Basin have been deposited both in non-marine and marine depositional environment (Fig 1.3).

The first sequence of Pattani Basin started in lacustrine environment, known as Sequence 1. The next sequence, Sequence 2, was forming after changing environment from lacustrine to fluvial environment in Lower Miocene. The transgression of fluvial and marginal marine started in Middle Miocene causing deposition of Sequence 3. After that, the environment changed to regression causing the deposition of sediment in fluvial and alluvial environment called as Sequence 4. Finally, the transgressive marginal marine deposited in Upper Miocene to recent, Sequence 5.

Reservoirs in the Pattni Basin, Gulf of Thailand, are considered to be fluvial and fluio-deltaic sandstone in Sequence 2,3 and 4. The provenance of these sandstones are believe to be from the margin of the basin, following this hypothesis, near-margin lithology would contain a greater proportion of sandstone in the rocks.

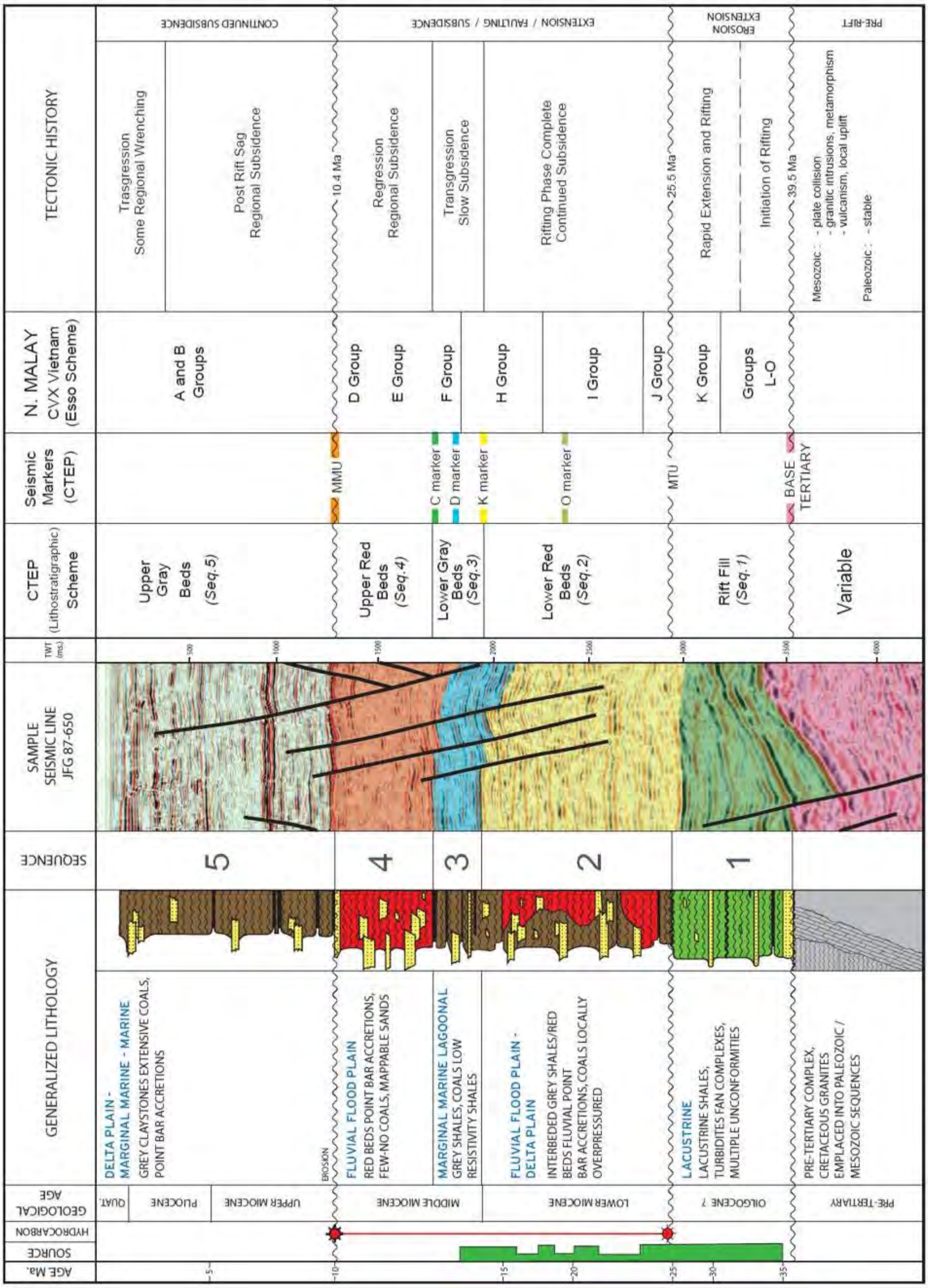

Figure 1.3 -Stratigraphy of Pattani Basin (CTEP).

1.5.3 Petroleum System of Pattani Basin (Jardine, 2006)

1.5.3.1 Source rock

Source rock in Pattani Basin is considered to be in Sequence 1 and 3 which were deposited in lacustrine and marginal marine environment respectively. Lacustrine shale in Sequence 1 acts as the main oil-prone source rock in the area. Sequence 1 was deposited in lacustrine environment in the South and as alluvial plain at the basin margin . Measured Total Organic Carbon (TOC) value in this lacustrine shale averages below 1.0 % but may be richer, up to 3.0 % in some areas. Moreover, a secondary contribution to the oil in the basin may come from a younger source, which is richer in hydrocarbon, like marine-transgressive shale (sequence 3). There may be an additional oil-prone source rock but it is still considered that the main oil-prone source in the area is algal lacustrine shale of Sequence 1.

For the gas-prone source rock, it is thought to be coals and coaly shales in Sequence 2,3 and 4 (terrestrial deposit). The terrestrial vascular plant material, type III kerogen, is the dominant organic matter type in the coals and coaly shales. It has poor hydrocarbon potential but has high vitrinite reflectance (%Ro) which shows that it is in range of gas and condensate generation.

1.5.3.2 Reservoir

Sequence 2, 3 and 4 are considered to be the main reservoir of the basin which was found to be red bed strata deposited in fluvial environment.

1.5.3.3 Seal, Trap and Migration

The seal is an intraformation of seals of overbank shale in Sequence 2 and transgressive shale in Sequence 4. Trap in the area is controlled by fault. Migration pathway is in a south to north trend, from the deeper part of the basin to the shallower part.

1.5.4 Basin Modeling (Amonpantang, 2012)

Welt and Yalcin (1987) proposed that studying basin modeling is the same as to study source rock for the modern petroleum exploration and production. This kind of knowledge allows every geologist to integrate all of the complicated geological processes and examine the basin evolution through geological time. To create basin modeling, one needs to have raw data to input into the proper program before changing it into model. Normally, there are 3 main types of basin modeling; 1D-basin modeling, 2D-basin modeling and 3D-basin modeling. 1D-basin modeling helps in understanding the burial and petroleum system history. Timing of petroleum generation and expulsion can be calculated from the program also. On the other hand, 2D -and 3D-basin modeling will be something more. 2D-basin modeling shows about cross section of the area of interest which contains stratigraphic and petroleum system data . In 3D-basin modeling, a lot of cross sections, are 2D-basin modeling, will be stacked together and become volume. Moreover, the results of 3D-basin modeling are not only stratigraphy and petroleum system data, but it also provides the data of migration pathway of petroleum. Nowadays, basin modeling is a very important part of petroleum exploration and production for the following reasons;

1 . It allows model coverage of the whole area of the basin, by allowing the combination of data from drilled -and non-drilled area (u sing only seismic data)

2 . View of the basin can be constructed in to a 3D-basin model

3. The model integrates geological, geophysical and geochemical attributes.

Yalcin (1991) added that basin modeling can be used to study basin evolution, from the generation, migration to accumulation of hydrocarbon. To do this the essential parameters need to be put in to the computer program, including heat flow (or heat flux) and geochemical data of source rocks. Poonyachotwanich (2012) also proposed that basin modeling is the best way to reduce risk in the petroleum exploration by making sure of the presence of types and volume of hydrocarbon in a prospect with geological structure from seismic data.

The main purpose of 1D-basin modeling is to perform heat flow simulation and the simulation of geological modeling to construct petroleum generation and expulsion map for evaluating the maturity of source rock. While 2D-basin modeling adds more features than 1D-basin modeling. It creates a map and can be analyzed Darcy flow and base flow path.

1.5.5 Permedia Software

Permedia is software support from Landmark, Halliburton. The software provides a complete end-to-end workflow for basin modeling: builds sophisticated earth models, forward model pressures and temperatures, add source generation and seal characteristics, and migration fluids using the most advanced simulator in the industry.

Permedia is designed for the petroleum geologists for easy integration of petroleum system from the seismic interpretation and other geological data to create 1D-, 2D -and 3D-basin models for petroleum study. It has a lot of advantages for petroleum exploration and production (E&P) industry mainly by reducing risks for drilling prospects or exploration.

Typical Application

1 .Permedia Petroleum Systems Software

2 .Pernedia Petroleum Systems 1D Software

3 .Permedia Viewers Software

4 .Permedia Suite Software

5 .Permedia Pore Pressure Software

6 .Permedia CO2 Software

Chapter 2 Methodology

The model can be easily constructed in 3 main parts; well log interpretation, 1D-basin modeling and 3D-basin modeling. For the first part, lithology and hydrocarbon zone are interpreted from well log data through Total Vertical Depth Subsea (TVDss). After the earlier interpretation, 1D-basin modeling is constructed. The 1D-basin modeling will provide burial history and hydrocarbon generation history which will be further used in 3D-basin modeling. Seismic data is considered together with the earlier data to create the 3D-basin model. Details of each part will be illustrated in this chapter.

2.1 Well log interpretation

To interpret log data, 3 types of log curves are considered; gamma ray, resistivity and crossover of neutron-density. Lithology can be easily identified by gamma ray curve. Resistivity and neutron-density crossover provides data of hydrocarbon zone. To interpret log data, there should be a cut-off number for each log as a standard for each interpretation. In this work, the cut-off number of 85 is considered as shale base line for gamma ray log and 10 for resistivity log as hydrocarbon and water separation line.

2.1.1 Gamma ray log

This log is used to identify lithology through depth. Fortunately, the study area is located in the northern part of Pattani Basin which mostly contains sandstone and shale. However, it would be easier for lithology identification to use Vshale curve which is calculated from the gamma ray log. Vshale curve represents volume of shale. So, 100% (or 1) value of this curve means 100% of shale in sequence. The shale base line of 40 (or 0.4) is used to separate shale and sandstone.

2.1.2 Resistivity log

Resistivity log is used to confirm hydrocarbon zone together with neutron-density crossover. Working on this log follows the basic science that hydrocarbon has more electrical resistivity that water. Moreover, oil-water contact can be observed from this curve also.

2.1.3 Neutron-Density curve

Crossover of neutron and density curve is used to indicate the hydrocarbon zone. The reason is the density of hydrocarbon which is less than water. On the other hand, neutron log represents the porosity by detecting H index (different HI from petroleum geochemistry) in pore and calculate porosity from detection. In pore, it should have water within it. However, whenever the pore fluid is hydrocarbon, it affects by decreasing the bulk density value.

2.2 1D-Basin Modeling

To construct 1D-basin model, the input parameters are required by Permedia. Firstly, lithologic sequences need to be input as well as the age of each sequence. After that, we have to fill in the petroleum geochemistry data for every source rock, including vitrinite reflectance (% Ro) and Hydrogen Index (HI). Heat flux and surface/mudline temperature are put into the model. When all the parameters are already put in, curve of the temperature and Ro will be generated after model running. If the curve of temperature and vitrinite reflectance do not fit with the raw data, heat flux and surface/mudline temperature have to be modified. After the heat flux and surface/mudline temperature adjustment, 1D-basin model will be run again. The expected outputs for this part are burial history curve and petroleum generation history.

2.2.1 Gathering data step

To run the model, the following data are required; stratigraphy, vitrinite reflectance (%Ro), Hydrogen Index (Hi), Total Organic Carbon (TOC) and age. Moreover, some of the data has to be extracted from the literature review such as heat flow history and erosional thickness.

- Stratigraphy of the study area is interpreted from well log data through TVDss depth. 5 sequences are considered. Furthermore, there are 2 erosional surfaces encountered in the sequence; Mid-Tertiary Unconformity (MTU) and Mid-Miocene Unconformity (MMU). The MMT and MMU mark as top Sequence 1 and 4, respectively. From the literature review the erosional thickness is about 1300 m for MMU in the South of the basin (Fujiwara, 2010).
- Petroleum geochemistry data (vitrinite reflectance (% Ro), Hydrogen Index (HI) and Total Organic Carbon (TOC)) are collected from source rock properties reports.
- Temperature (or surface/ mudline temperature) is the Bottom Hole Temperature (BHT) and was not included with the data provided by Chevron company. So, the temperature value used in the simulation is from the literature review of the well temperature in northern part of the basin.

- Heat flux (or Heat flow) is the rate if heat transferred through the surface from time to time. It is one condition of thermal boundary which directly affects petroleum generation. The heat flux used in the modeling is from the report of Chonchawalit (1985). However, the heat flux data from the literature review are from the south area of the basin which means the value is higher than in the study area which is located in the north. Consequently, the heat transfer should be adjusted before using in the model in calibration step.

2.2.2 Calibration step

This step is to adjust the input data which would affect the coming outputs. The values that need to be calibrated are temperature and vitrinite reflectance (%Ro). Adjust the relevant parameters; heat flux and surface/mudline temperature to fit with the output temperature and vitrinite reflectance data.

2.3 3D-Basin Modeling

3D-basin modeling is possible on Permedia software. This work would consider the petroleum system is the area by using stratigraphic data, temperature vs depth, pressure vs depth, surface/ mudline temperature vs depth and petroleum geochemistry data together with seismic surface data. Firstly, all the inputs would be set up in a sequence map to create a 3D model. Before running the modeling, we can create a cross section which is able to show variables such as pressure, temperature or vitrinite reflectance (% Ro). If the results are not satisfied, the inputs of temperature, pressure and mudline/surface temperature vs depth would be adjusted. 1D- and 2D-basin models could also be simulated from this cross section. After the results are satisfied, all the data needs to be converted to something the program understands, called 'mesh sequences'. Then, the dynamic migration will be created before showing it on the 3D model. The final result is a 3D model showing accumulation area and migration pathway.

2.3.1 Gathering data step

Data from the 1D-basin modeling are gathered for simulation in the 3D model. 1D model from 3 wells are used to guide modeling. The necessary variables in cross section will be checked with the results from the 1D model and the input will be adjusted until the results of the cross section is the same as the 1D model. Maps of top Sequences 1, 2, 3 and basement are included for 3D-basin modeling. To use the maps, fault characteristics in the area should be considered first if it acts as a barrier or conduit (Chapter 5: Discussion). For this project, fault conduit is considered.

2.3.2 Creating curves

Used curves include temperature, pressure and surface/mudline temperature vs depth for creating 3D-basin model. The curves can be easily done by the automatic simulation in Curve Editor in Permedia and used to create a cross section of the area. The cross section is able to show the output variables such as temperature, pressure or vitrinite reflectance (% Ro) vs depth. If the results are not satisfied, these curves need to be modified.

2.3.3 Simulating 2D-basin model in cross section

This step is the first parameters check. If a 2D model can be simulated from the cross section, then it should be able to continue further in 3D-basin modeling.

2.3.4 Creating mesh sequences

Creating mesh sequence is to convert all the data to something which the program would understand. Mesh sequence represents stratigraphic sequence as stacked layers. This is a very important part of creating a 3D-model. The editor can set the maximum layer thickness for the mesh sequence. Thickness of sequences in model will follow the maximum number set up before.

2.3.5 Creating dynamic migration

This step creates source rock scenario for the 3D-basin model. The properties of each source rock would be input to create the source rock scene following the mesh sequences. Finally, the mesh sequences showing in 3D-basin model contains all of the sequences and source rock layer within it, which can be calculated further into migration pathway.

Chapter 3 Results

This chapter contains all of the study results, including the results from log interpretation, 1D-basin modeling and 3D-basin modeling.

3.1 Log Interpretation

3 wells data was used for the log interpretation to identify lithology through depth (Figท. 3.1 – 3.3). 3 types of log curves are used to help interpretation, gamma ray in track 1, Vshale curve in track 2, crossover of neutron and density in track 3 and resistivity in track 4. Results from interpretation are shown representing the different colors show different lithologies, brown represents shale, yellow represents sand and green represents source rock layer.

3.2 1D-Basin Modeling

3.2.1 Calibration results

After trying to calibrate temperature and vitrinite reflectance from the modeling and raw data, the results are shown in Fig. 3.4.

3.2.2 Burial history curves

Figs. 3.5-3.7 are burial history curves of wells A, B and C showing the deposition of each well through time. From the burial history curve, it shows tectonic event following the input data. However, there are some strange events at about 13.84 Ma between well A and wells B and C which will be discussed in Chapter 4: Discussion and Conclusion. The burial history curve of wells B and C show the huge layer above the top of Sequence 3 because the program merged of Sequence 4 and 5 together following the absence of the top of Sequence 4 picks in those wells. The overburden, combined Sequences 4 and 5, in burial history curve of wells B and C is considered to be Shale (Jardine, 1997).

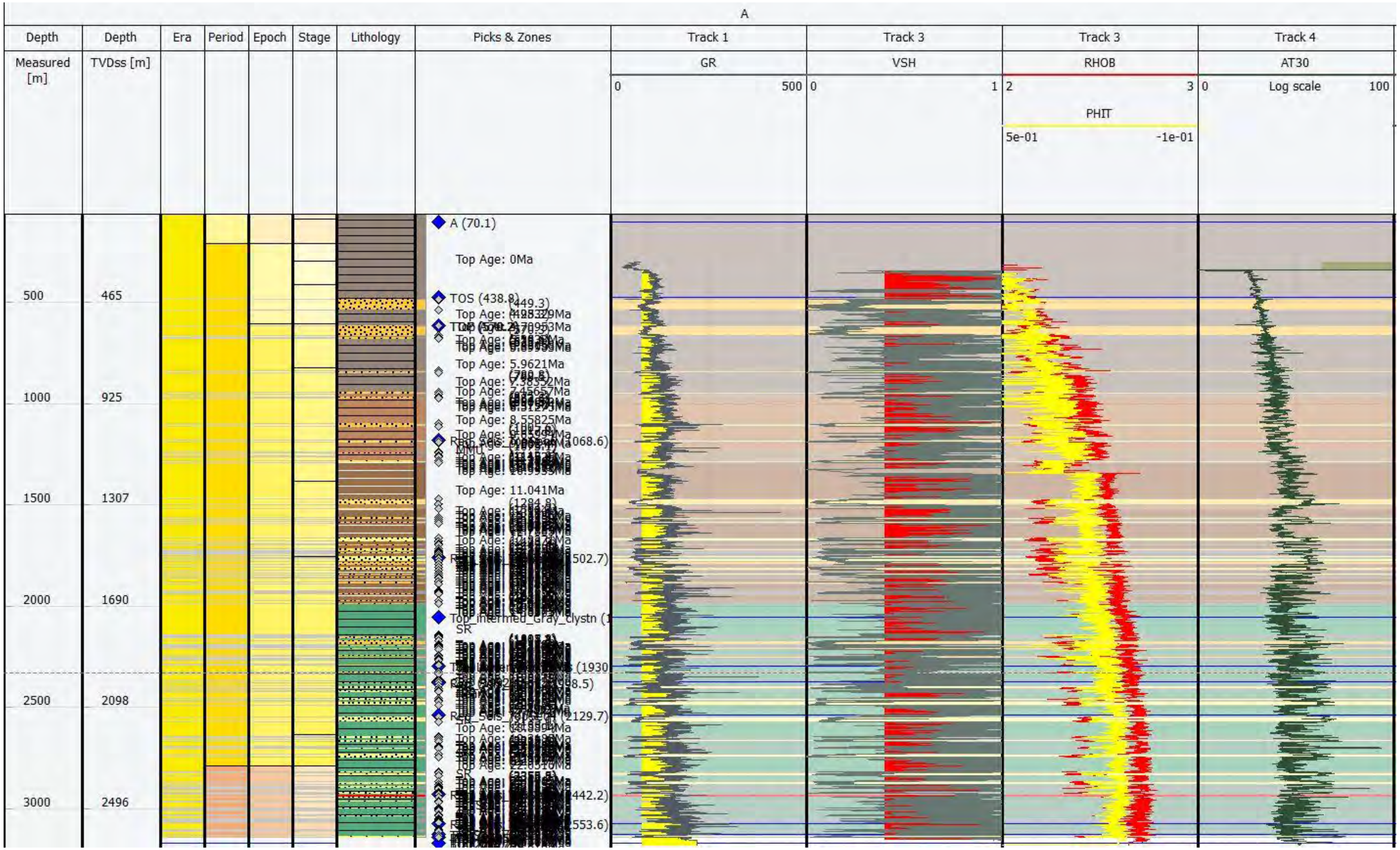

Fig 3.1 – Log interpretation of well A shows interpreted different lithologies.

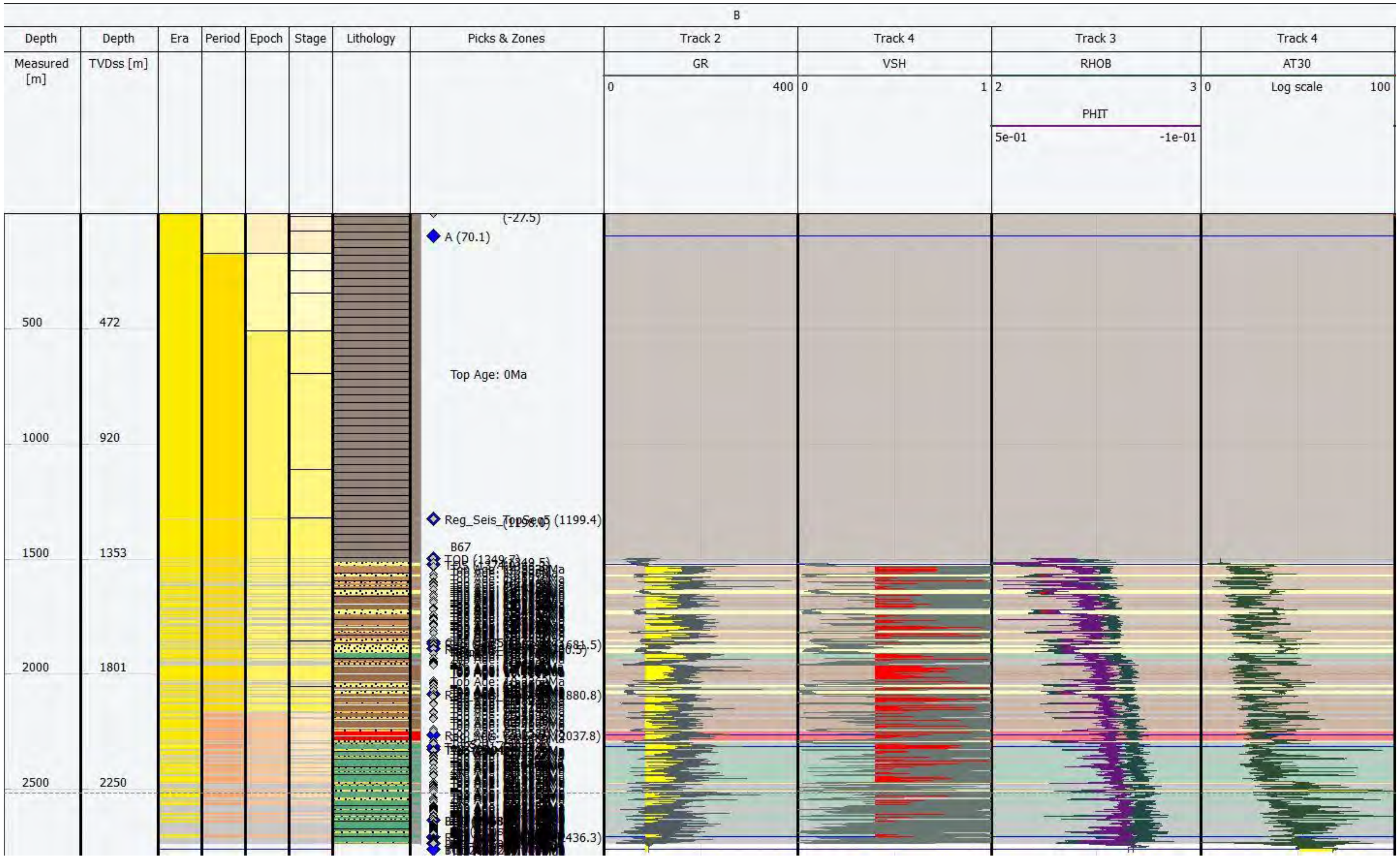

Fig 3.2 – Log interpretation of well B shows interpreted different lithologies.

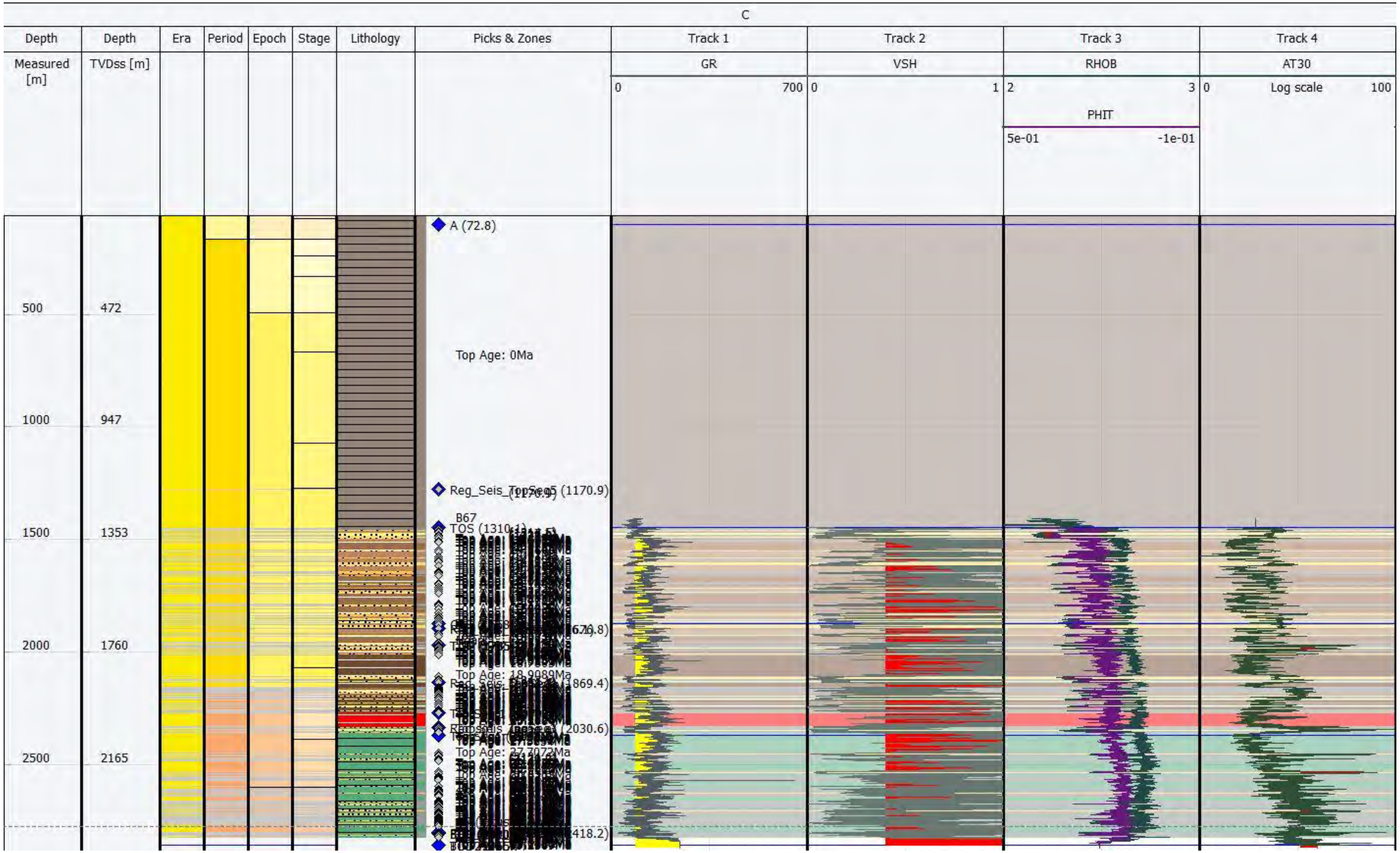

Fig 3.3 – Log interpretation of well C shows interpreted differentlithologies.

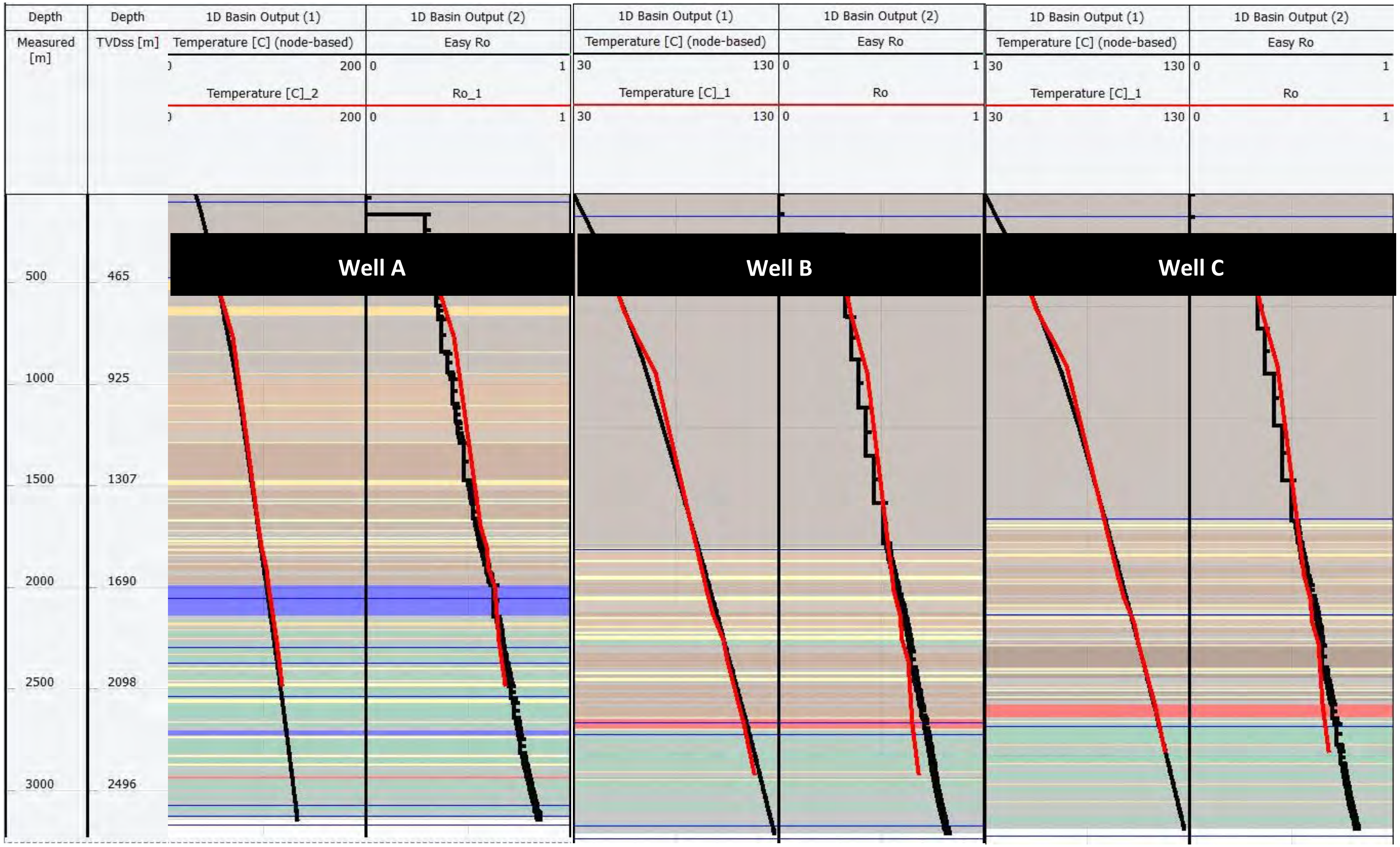

Fig 3.4 – Results from calibration step (red line = raw data, black line = modeling results).

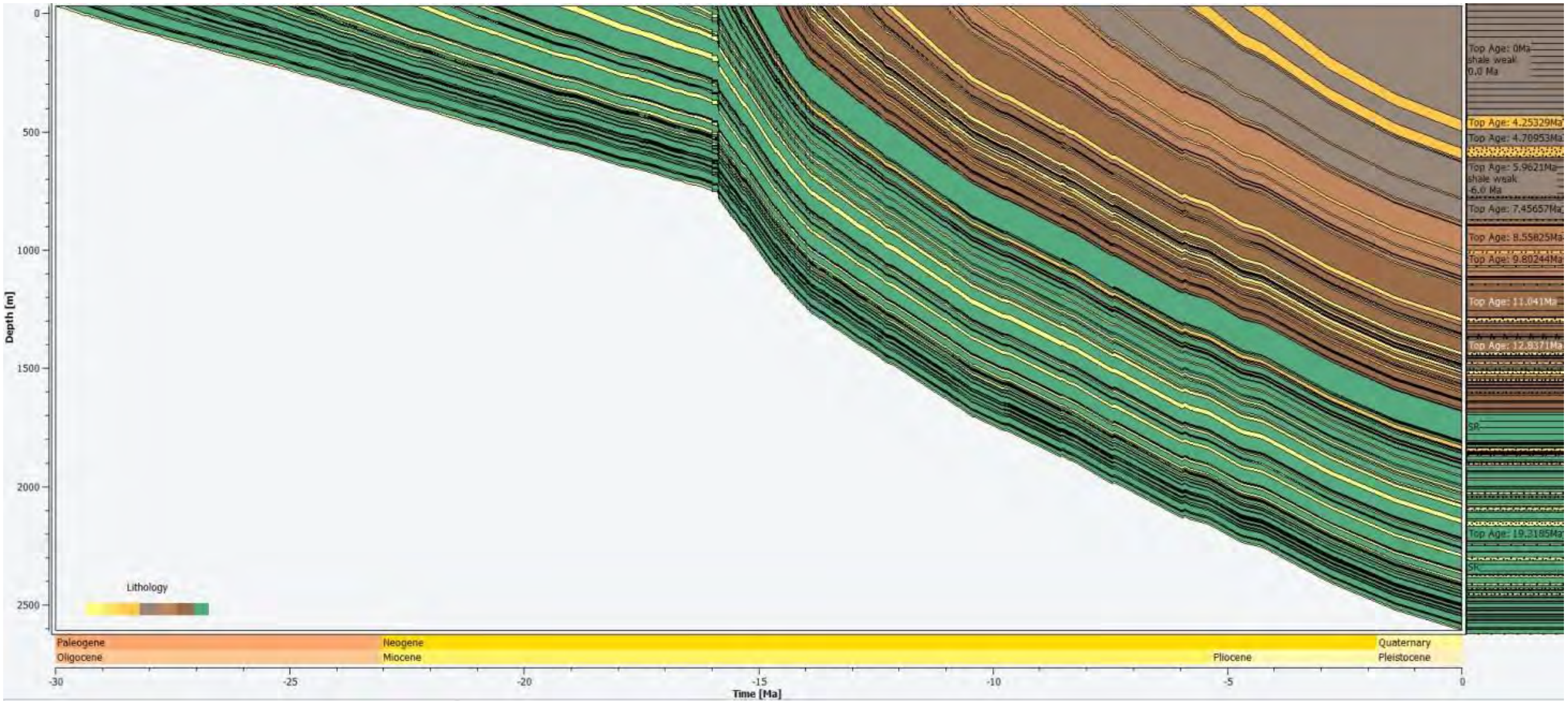

Fig 3.5 – Burial history curve of well A.

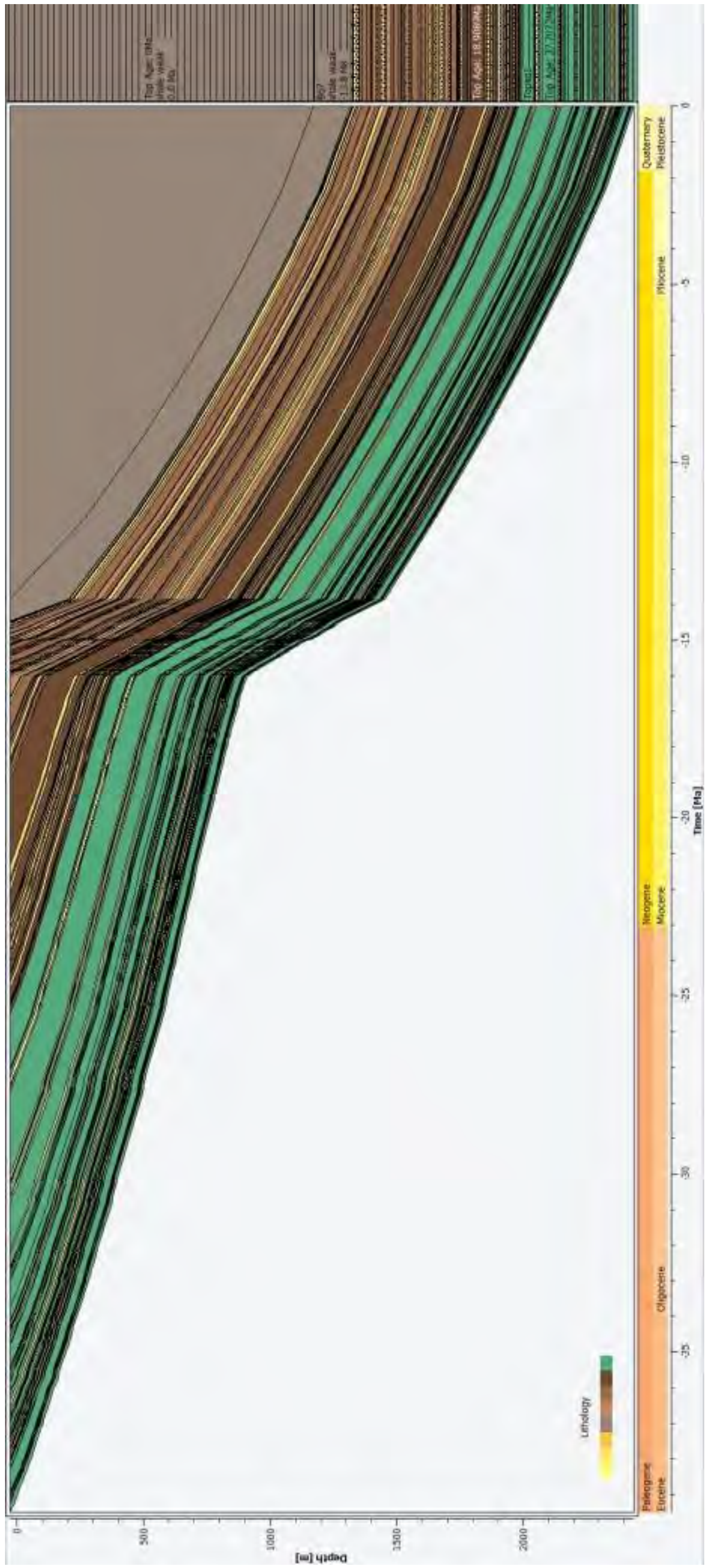

Fig 3.6 – Burial history curve of well B.

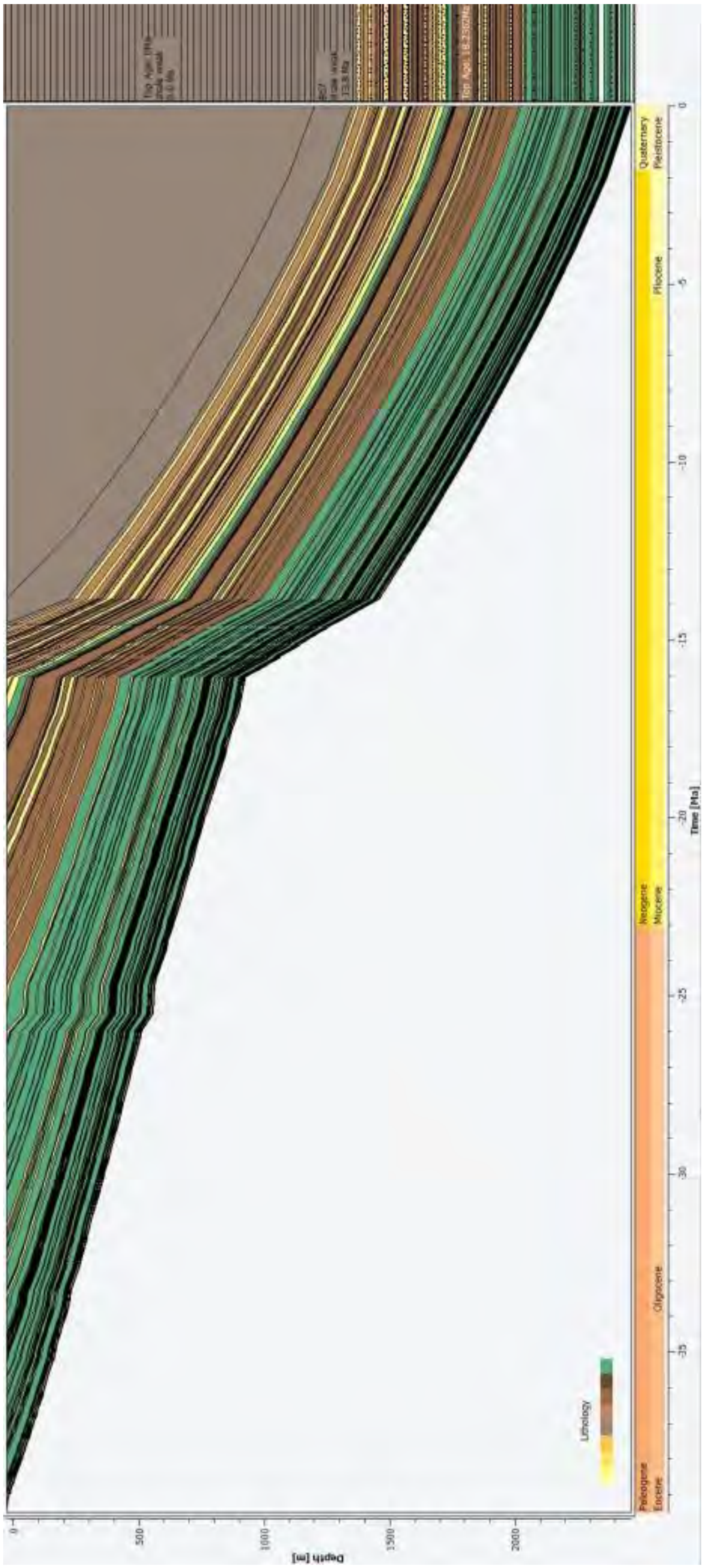

Fig 3.7 – Burial history curve of well C.

3.2.3 Petroleum History

From the results, well A representing southeastern zone shows that oil and gas both generated at 3 Ma while wells B and C representing northwestern zone show oil and gas generated at 4 Ma (Figs 3.8-3.10). The results show that the deeper area generated hydrocarbon after the shallower area. The explanation for this will be included in Chapter 4: Discussion and Conclusion.

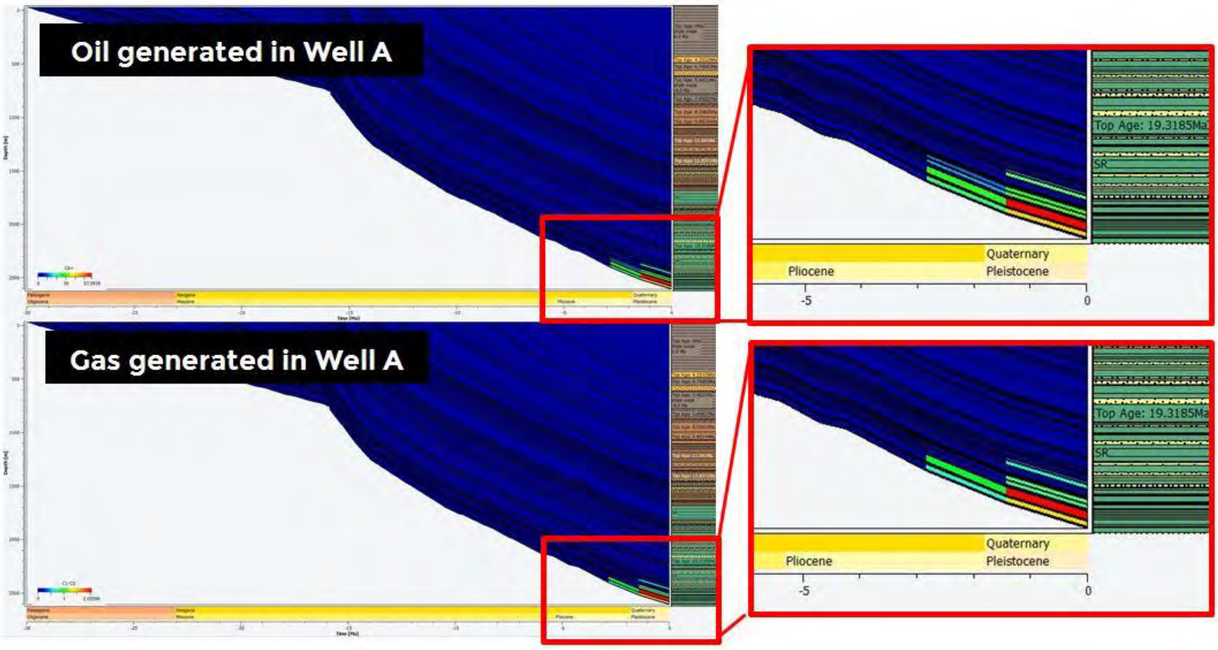

Fig 3.8 – Oil and gas generated in well A (Southeastern area).

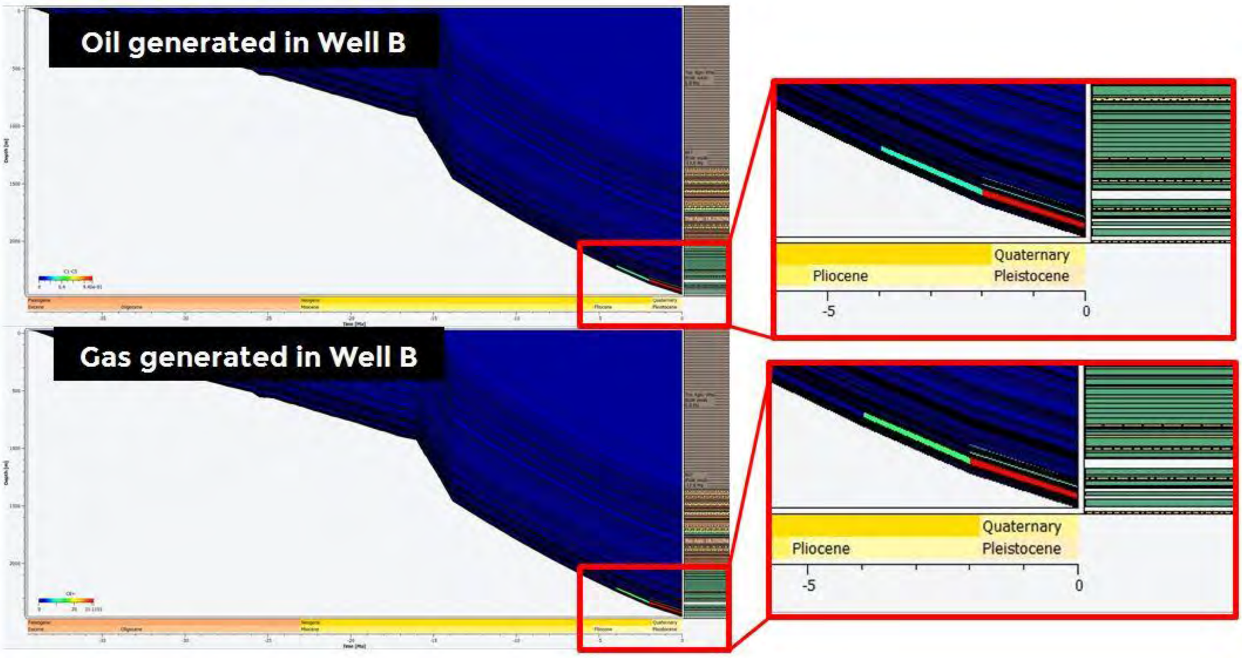

Fig 3.9 – Oil and gas generated well B (Northwestern area).

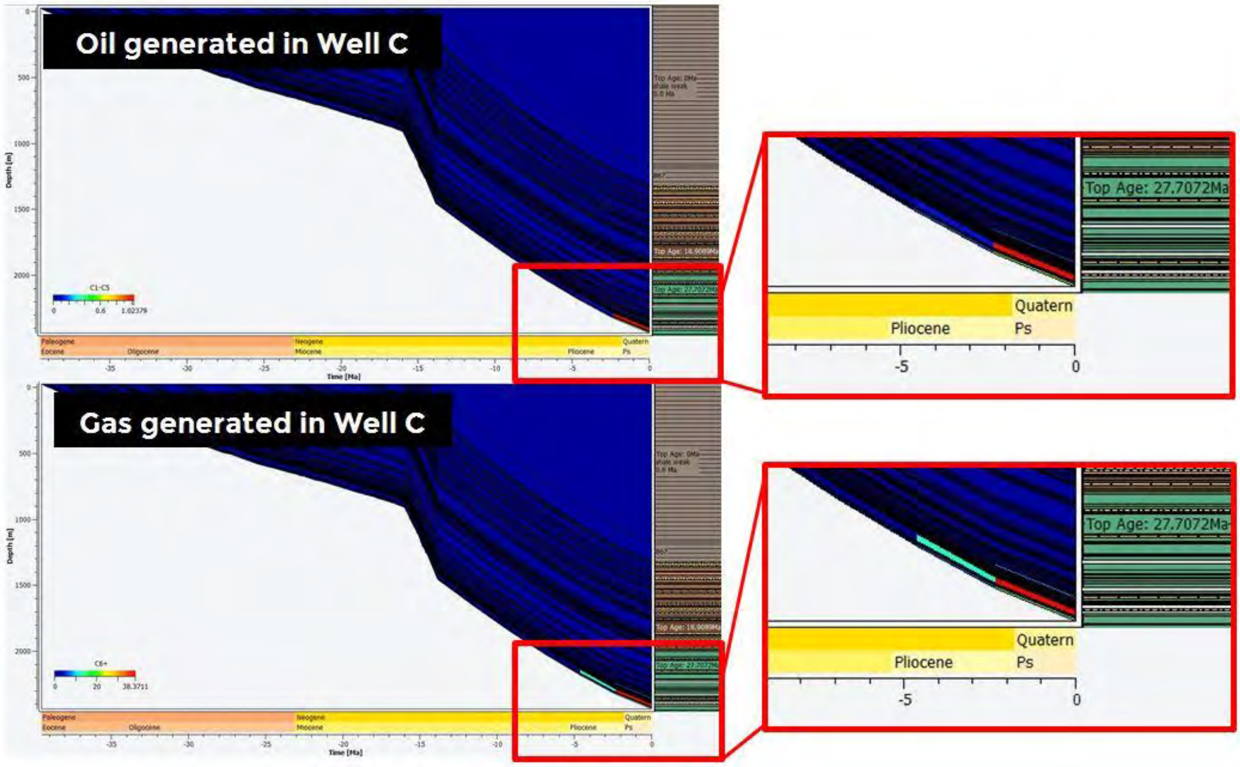

Fig 3.10 – Oil and gas generated well C (Northwestern area).

3.3 3D-Basin Modeling

3.3.1 Mesh sequences

The mesh sequence is used as a stratigraphic sequence in the 3D model. From the 3D model result, different colors represent different stratigraphic sequences (Fig 3.11), classified by CTEP. The 3D-basin model will be divided into 4 layers, Sequences 1, 2, 3 and Overburden. Green layer is source rock of lacustrine shale in Sequence 1. Yellow layer is sandstone in Sequence 2. Dark brown layer is shale in Sequence 3. Light brown layer is overburden shale in Sequences 4 and 5. The layer showing in the picture is the bottom layer of the whole sequences (Fig 3.12).

Fig 3.11 – Side section of the 3D-basin model showing 4 layers; Sequences 1, 2, 3 and overburden (Sequence 4+5).

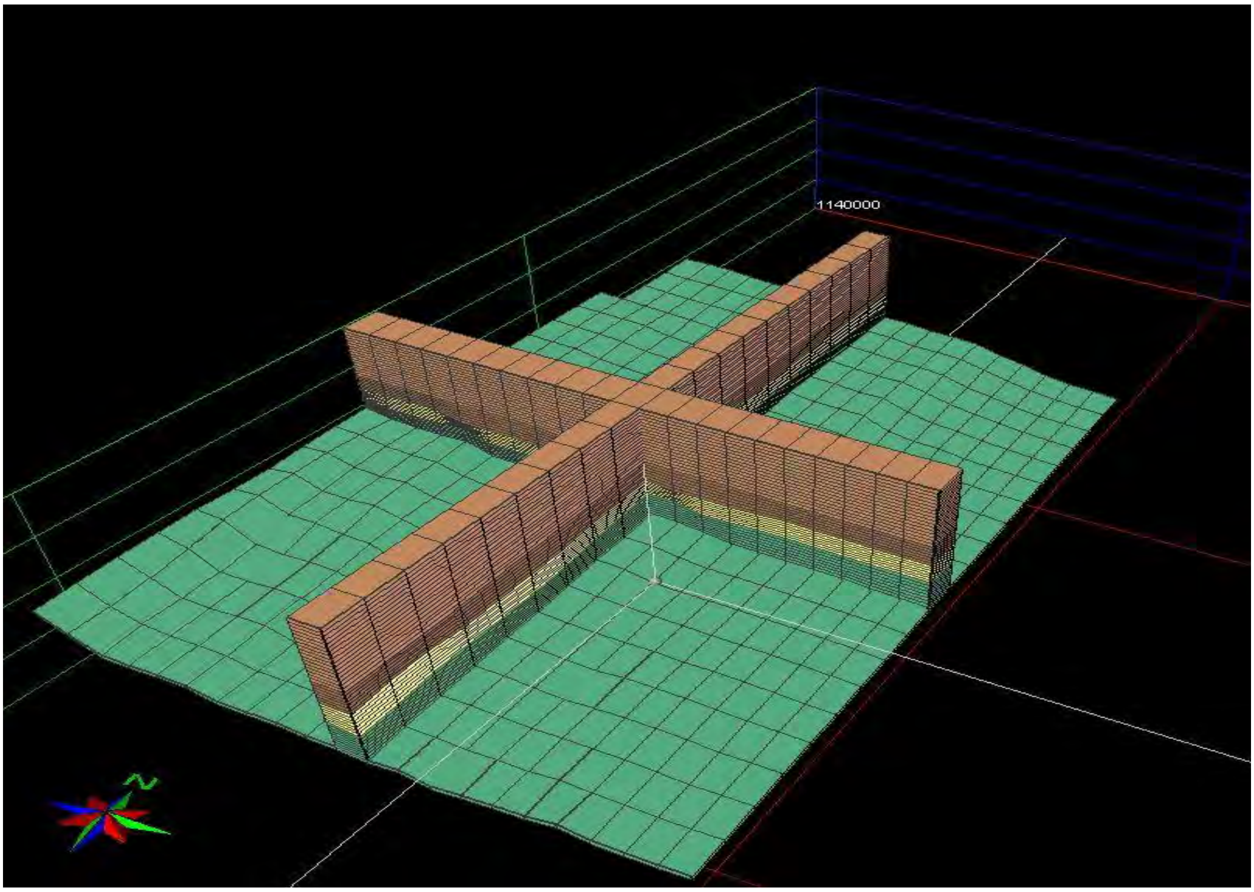

Fig 3.12 – 3D model shows mesh sequences (black line as layer representing stratigraphic layer) in the study area.

3.3.2 Accumulation area through time

Accumulation area shows the area of hydrocarbon deposits. Studying the development of accumulation area through time can roughly describe the migration pathway (Fig 3.13). The models in Fig 3.13 show top view of the study area overlaid with the area of expulsion of source rock and accumulation area which is shown in different colors. Yellow area represents expulsion area of source rock while red area represents accumulation area.

From the results, the hydrocarbon started to expel from the source rock in Sequence 1 at 12.06 Ma from gaining enough heat flow (or heat flux). The generated hydrocarbon started to trap at 7.68 Ma in nearby the area of expulsion. From the development of accumulation area through time, the migration pathway in the area can be roughly identified to be from south-southeastern to north-northwestern. The present accumulation area is shown in Fig 3.14.

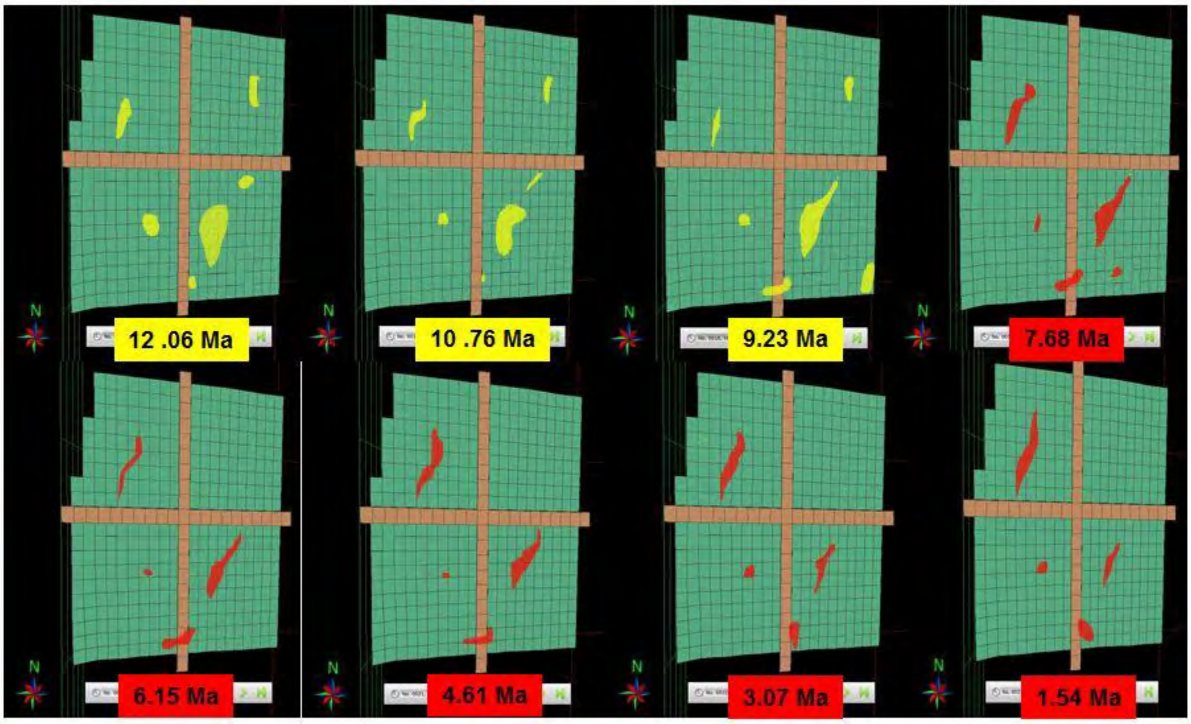

Fig 3.13 – Shows the development of accumulation area through time.

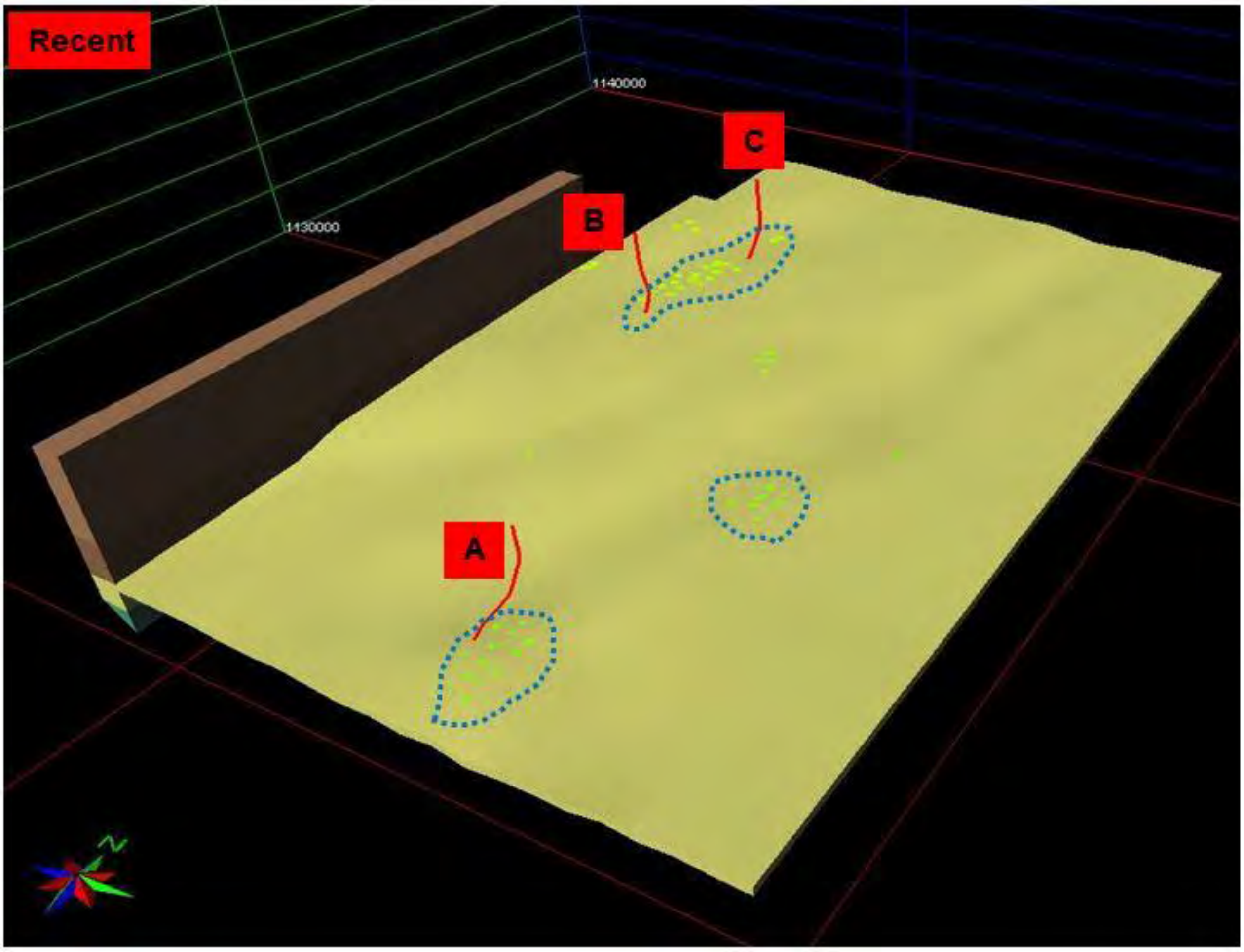

Fig 3.14 – The present accumulation areas are in blue dotted line.

Chapter 4 Discussion and Conclusion

This chapter will discuss the results, encountered problem and make a conclusion.

4.1 Discussion

4.1.1 Petroleum generation time

Generally, the deeper area should gain more heat flow and lead to earlier hydrocarbon generation in comparison with shallower areas. However, the results of this study show that well A, which is penetrated deeper, generated after wells B and C, which are shallower (Fig 4.1).

This abnormality can be explained by different bottom hole (BH) depth of each well. In the northwestern area, Sequence 1 is thinner and encountered at a shallower depth than the southeastern area. Wells B and C penetrated the basement layer which means it penetrated through the whole layer of Sequence 1. On the other hand, well A only penetrated through the upper part of Sequence 1. The late hydrocarbon generation in the results of well A could be due to the fact that not all of Sequence 1 is considered.

4.1.2 Fault Characteristics

To create 3D-basin model, fault characteristics should be considered first. The different characteristics of fault definitely affect the migration of hydrocarbon. Faults can allow hydrocarbon to migrate through fault plane, as fault conduit, or not allow hydrocarbon to move through it which would trap hydrocarbon on its side, as a fault barrier. It is very crucial to know if the fault in the area is a conduit or not. Then, fault analysis is recommended. This project does not include fault analysis, but fault characteristics would be tested in another simpler way.

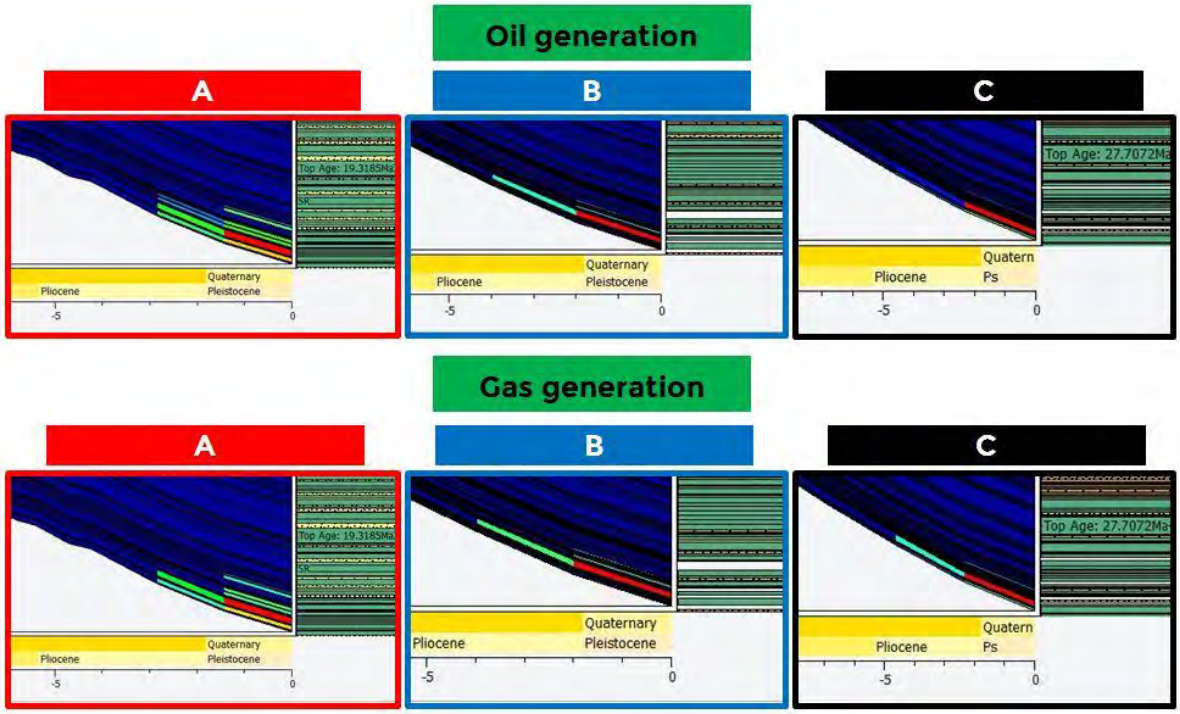

Fig 4.1 – Oil and gas generation time of well A, B and C.

In fact, the different characteristics should be set up for each fault. To do it in an easier way, 2 cases would be considered. In the first case, every fault in the area would be considered as a barrier. Another case would be opposite, a case of fault conduit.

To test 2 cases, 2 maps would be created to study the basic migration; maps of fault barrier and fault conduit (Figs 4.2-4.3). This basic migration is following only the structure of the area, from deeper to shallower area or called high structure. Finally, the basic migration results will be compared with real scenario (i.e. current discovery of petroleum in the study area) and a suitable case will be selected to further use in 3D-basin modeling.

In fault barrier case, there is no hydrocarbon accumulation within the area of wells B and C. In another case, wells B and C are located in hydrocarbon accumulation area which fits with the real situation. Therefore, faults in the area are considered as conduit (Fig 4.4).

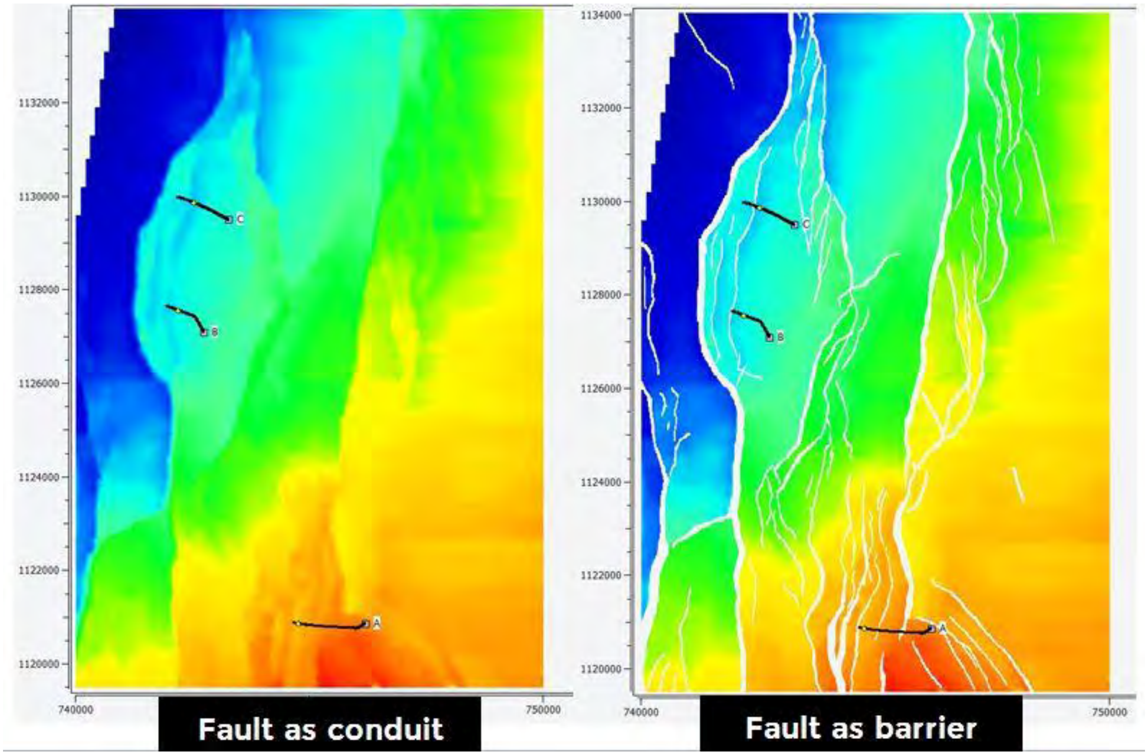

Fig 4.2 – (Left) map for fault conduit case (right) map for fault barrier case.

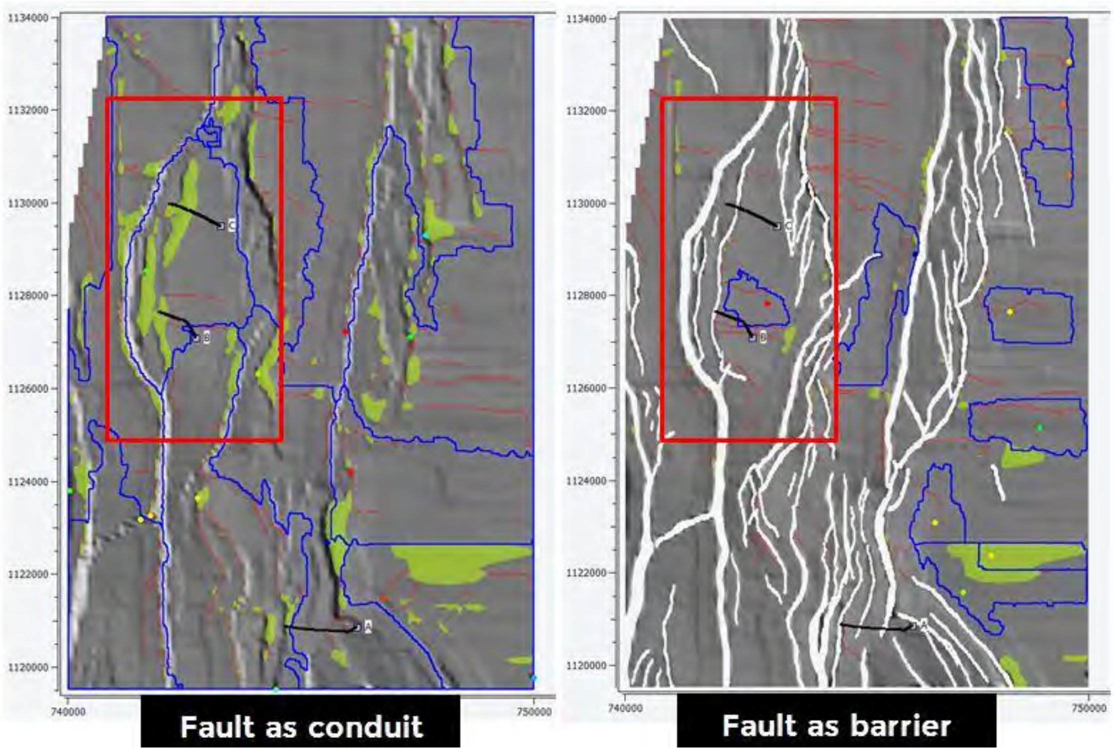

Fig 4.3 – (Left) map shows basic migration in fault conduit case (right) map shows basic migration in fault barrier case.

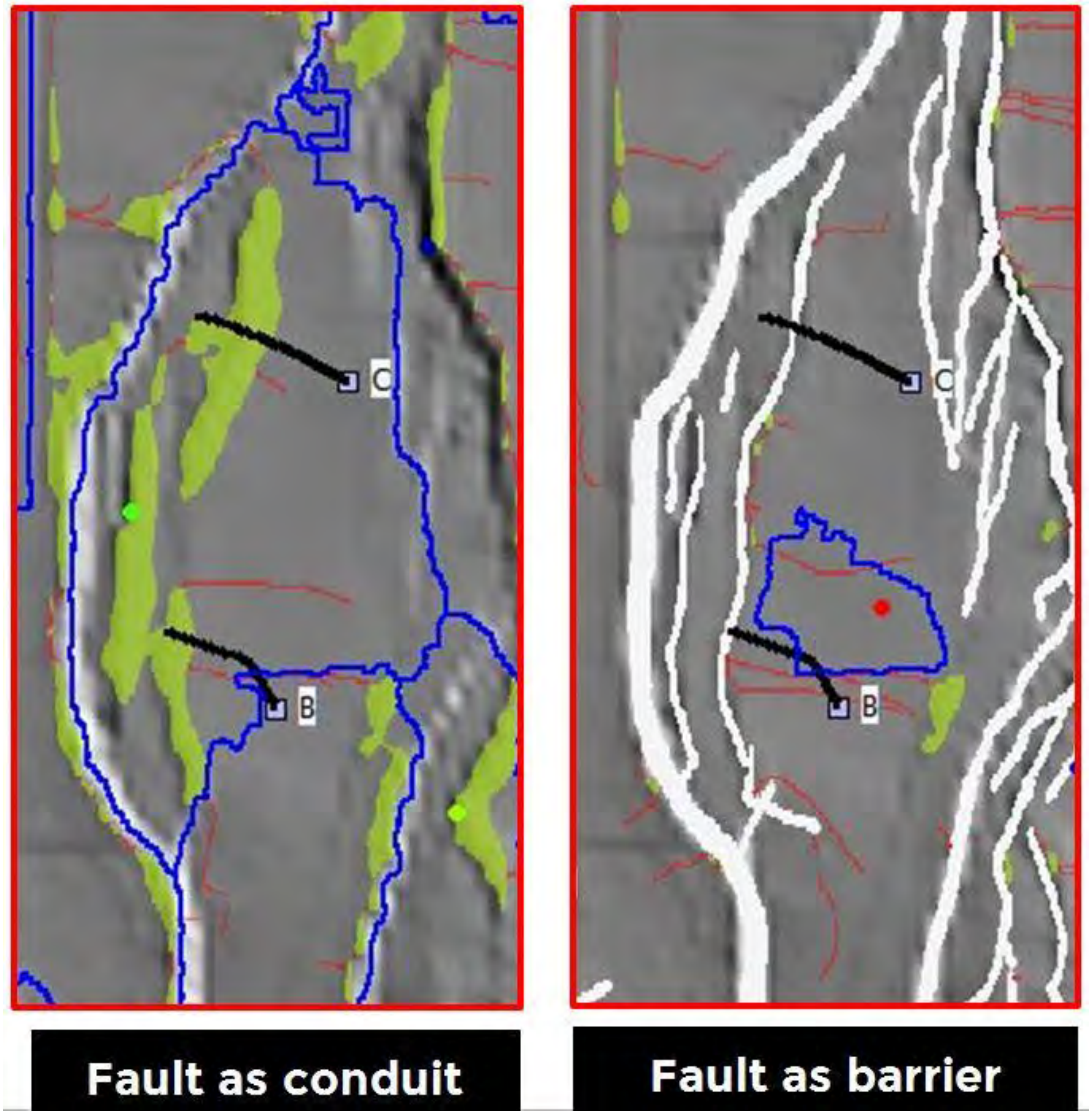

Fig 4.4 – Zoomed in pictures of the red square areas from Fig 4.3.

4.1.3 Tectonic Description

Following the study results of burial history curve, there are differences between well A and wells B and C at an age of about 13.84 Ma (Fig 4.5). The age of 13.84 Ma is the same age of the top of Sequence 3, the differences in burial history curve must be caused by the top of Sequence 3. Firstly, the input for each well for generating 1D-basin model is not exactly the same. For well A, the picks which were used in log interpretation covers to the top of Sequence 4 while for the rest of the wells does not. Wells B and C only contain picks up to Sequence 3. The lacking picks in those 2 wells may cause a different computation of the program showing some rapid deposition at 13.84 Ma.

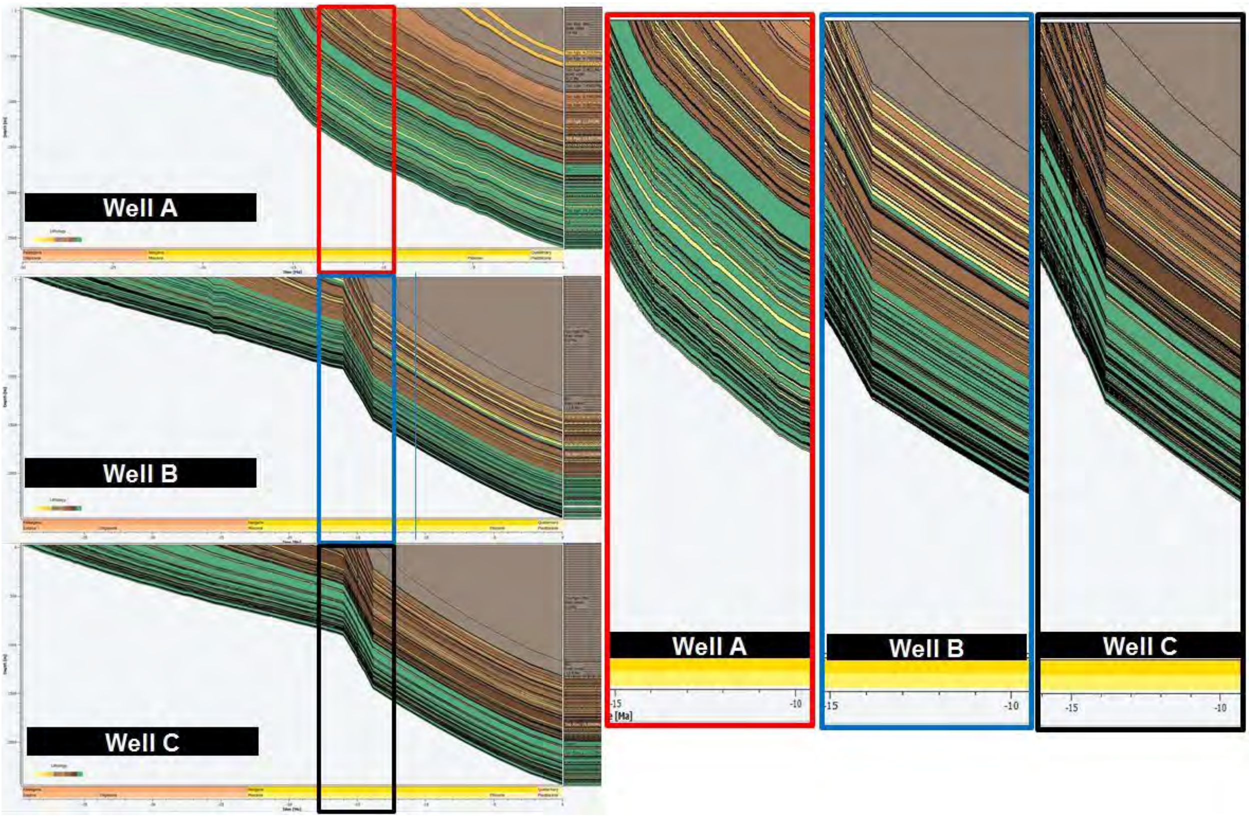

Fig 4.5 – Burial history curves of well A, B and C showing different deposition at age 13.84 Ma.

4.2 Conclusion

4.2.1 Oil and gas generation

Well A, represents southeastern zone of the study area, it has generated both oil and gas since 3 Ma. Wells B and C, represent northwestern zone of the study area, they have generated both oil and gas since 4 Ma (Fig 4.6 I, II).

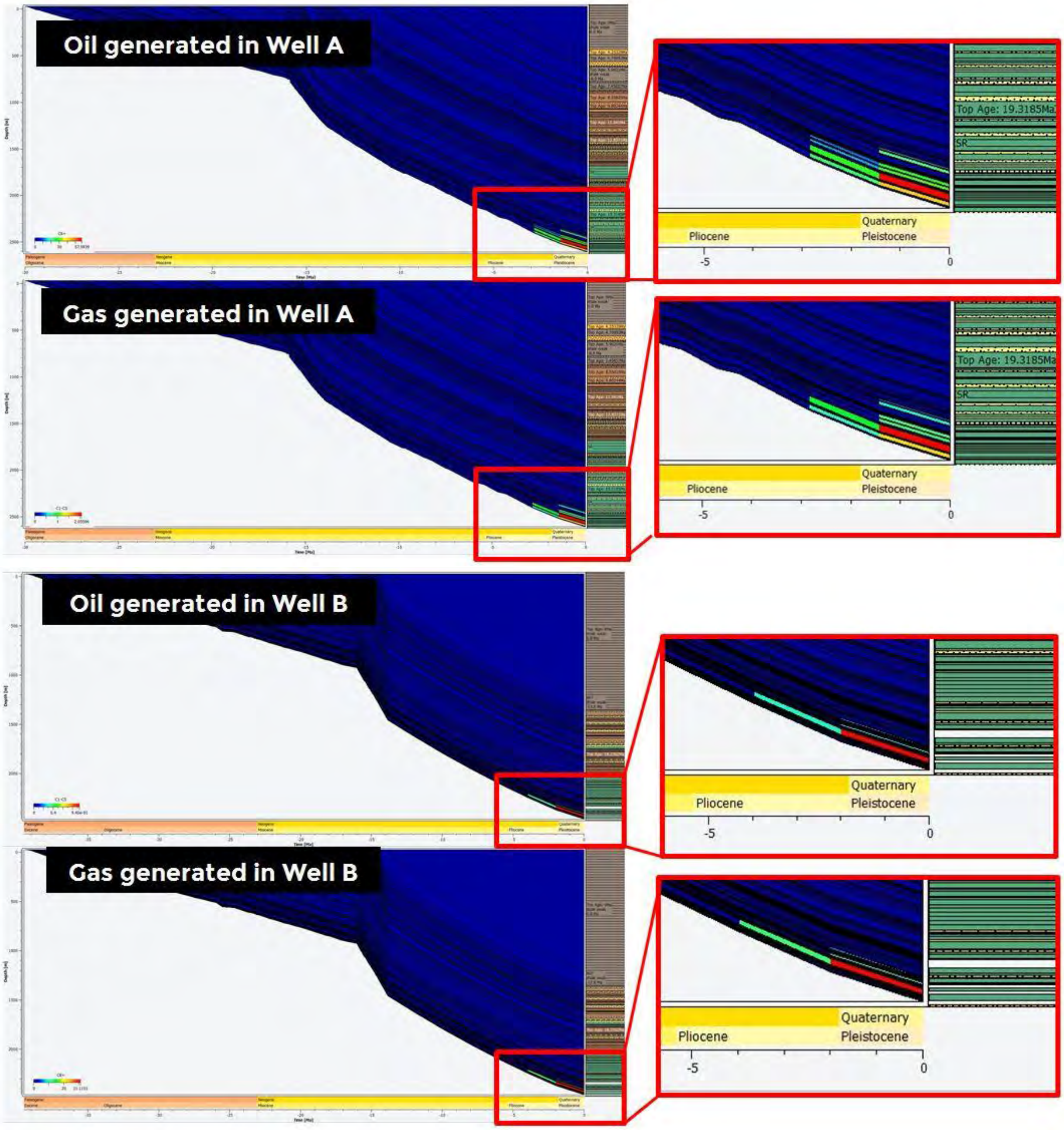

Fig 4.6 (I) – Petroleum generation of wells A and B.

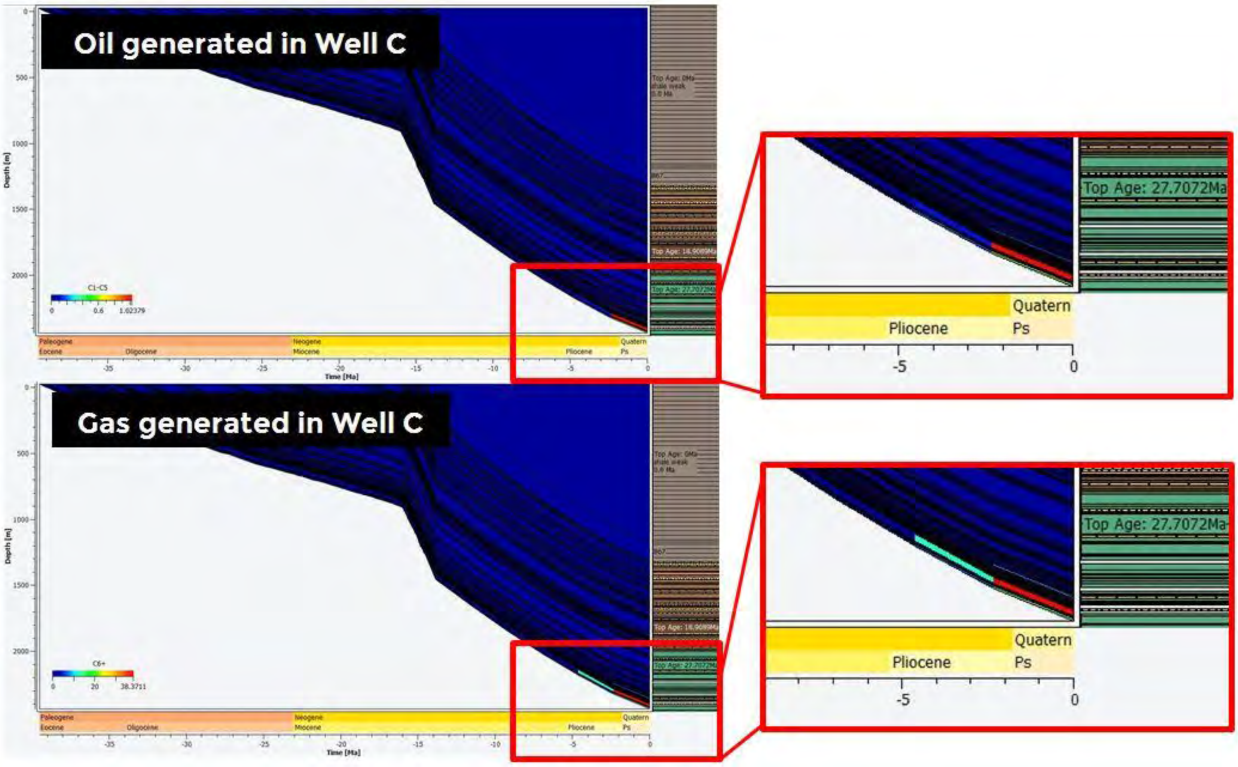

Fig 4.6 (II) – Petroleum generation of well C.

4.2.2 Migration pathway

From the study results of the development of accumulation area through time, the migration pathway of petroleum is in south-southeastern to north-northwestern trend.

4.3 Recommendation

More properties of each sequence will provide more accuracy for the model. Moreover, fault seal analysis will make fault characteristics in the model more precise. A greater number of wells in the area would confirm more on lithology and hydrocarbon zone in the study area. More data of petroleum geochemistry of the source rock would affect the source rock scenarios in a better way.

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Appendix I: Data Gathering for 1D-basin modeling

Petroleum Geochemistry of well A

Table A.1 – Petroleum geochemistry data of well A.

Well Name	Depth (ft, tvdss)	Depth (m, tvdss)	Lithology	TOC (wt%)	S1 mg HC/g rock	S2 mg HC/g rock	S3 mg CO2/g rock	Tmax (deg.C)	HI	OI	Ro(%)
A	-1,064	-324.303	SMS	0.57							
A	-1,154	-351.722	SMS	1.33							
A	-1,244	-379.03	SMS	3.35	0.08	1.02	1.80	427	30	54	0.32
A	-1,332	-406.118	SMS	1.27							
A	-1,420	-432.917	SMS	1.03							
A	-1,507	-459.358	SMS	2.91							
A	-1,592	-485.373	SMS	6.59							
A	-1,676	-510.96	SMS	16.85	0.88	24.54	1.22	422	146	7	0.35
A	-1,760	-536.334	SMS	1.47							
A	-1,843	-561.758	SMS	5.40							

A	-1,927	-587.216	SMS	1.63							
A	-2,010	-612.751	SMS	1.88							
A	-2,094	-638.327	SMS	1.09							
A	-2,178	-663.845	SMS	5.26							
A	-2,262	-689.343	SMS	2.79							
A	-2,345	-714.893	SMS	1.53							
A	-2,429	-740.511	SMS	2.99							
A	-2,514	-766.145	SMS	5.85	0.24	7.55	1.16	424	129	20	0.43
A	-2,598	-791.745	SMS	1.10							
A	-2,681	-817.09	SMS	2.09							
A	-2,762	-841.999	SMS	1.03							
A	-2,843	-866.458	SMS	0.85							
A	-3,614	-1101.4	Redbeds	0.84							
A	-3,680	-1121.72	Redbeds	0.45							
A	-3,747	-1142.22	Redbeds	0.23							
A	-3,815	-1162.78	Redbeds	0.66							

A	-3,882	-1183.3	Redbeds	0.58						
A	-3,949	-1203.8	Redbeds	1.70	0.26	3.27	1.22	418	192	72
A	-4,017	-1224.34	Redbeds	1.54						
A	-4,084	-1244.95	Redbeds	1.73						
A	-4,152	-1265.55	Redbeds	1.84						
A	-4,220	-1286.14	Redbeds	1.31						
A	-4,287	-1306.64	Redbeds	1.46						
A	-4,354	-1327.11	Redbeds	0.86						
A	-4,421	-1347.59	Redbeds	1.75	0.21	3.63	1.22	428	207	70
A	-4,489	-1368.13	Redbeds	0.53						
A	-4,556	-1388.77	Redbeds	1.61						
A	-4,624	-1409.54	Redbeds	1.11	0.14	1.76	1.18	413	159	106
A	-4,693	-1430.42	Redbeds	0.21						
A	-4,762	-1451.41	Redbeds	0.72						
A	-4,830	-1472.33	Redbeds	0.46						
A	-4,899	-1493.16	Redbeds	0.27						

A	-4,967	-1514.02	Redbeds	0.30							
A	-5,036	-1534.98	Redbeds	0.35							
A	-5,105	-1556.03	Redbeds	0.54							
A	-5,174	-1577.18	Redbeds	0.31							
A	-5,244	-1598.45	Redbeds	0.33							
A	-5,314	-1619.85	Redbeds	0.50							
A	-5,385	-1641.34	Redbeds	0.20							
A	-5,456	-1662.89	Redbeds	0.65							
A	-5,527	-1684.55	Redbeds	0.53							
A	-5,598	-1706.4	Redbeds	1.30	0.10	1.86	1.27	425	143	98	0.56
A	-5,671	-1728.4	Redbeds	0.88							
A	-5,695	-1735.74	Redbeds	0.86							
A	-5,719	-1743.09	Redbeds	0.78							
A	-5,743	-1750.44	Redbeds	1.21							
A	-5,767	-1757.8	Redbeds	0.92							
A	-5,791	-1765.17	Redbeds	1.03							
A	-5,815	-	Redbeds	0.67							

		1772.55									
A	-5,840	-1779.96	Redbeds	0.85							
A	-5,864	-1787.39	Redbeds	0.69							
A	-5,889	-1794.84	Redbeds	0.72							
A	-5,913	-1802.3	Redbeds	1.01							
A	-5,938	-1809.78	Redbeds	1.06	0.08	1.53	1.26	423	144	119	0.59
A	-5,962	-1817.25	Redbeds	0.81							
A	-5,987	-1824.72	Redbeds	0.74							
A	-6,011	-1832.18	Redbeds	0.61							
A	-6,036	-1839.63	Redbeds	0.64							
A	-6,060	-1847.07	Redbeds	0.40							
A	-6,084	-1854.51	Redbeds	0.96							
A	-6,109	-1861.94	Redbeds	0.73							
A	-6,133	-1869.38	Gray Shale	0.79							
A	-6,158	-1876.82	Gray Shale	0.87							
A	-6,182	-1884.26	Gray Shale	0.61							

A	-6,206	-1891.7	Gray Shale	0.69							
A	-6,231	-1899.15	Gray Shale	1.84							
A	-6,255	-1906.6	Gray Shale	1.68							
A	-6,280	-1914.06	Gray Shale	2.04	0.08	3.17	1.29	430	155	63	0.52
A	-6,304	-1921.55	Gray Shale	3.94							
A	-6,329	-1929.04	Gray Shale	1.36							
A	-6,354	-1936.55	Gray Shale	0.96							
A	-6,378	-1944.08	Gray Shale	0.96							
A	-6,403	-1951.62	Gray Shale	0.90							
A	-6,428	-1959.18	Gray Shale	0.35							
A	-6,453	-1966.76	Gray Shale	1.19							
A	-6,478	-1974.36	Gray Shale	0.48							
A	-6,502	-1981.94	Gray Shale	0.59							
A	-6,527	-1989.52	Gray Shale	0.52							
A	-6,552	-1997.08	Gray Shale	0.57							
A	-6,577	-	Gray	1.13	0.10	1.80	1.23	418	159	109	0.45

		2004.64	Shale								
A	-6,602	-2012.2	Gray Shale	1.06							
A	-6,626	-2019.75	Gray Shale	1.00							
A	-6,651	-2027.3	Gray Shale	0.90							
A	-6,676	-2034.85	Gray Shale	0.53							
A	-6,701	-2042.4	Gray Shale	0.53							
A	-6,725	-2049.93	Gray Shale	0.45							
A	-6,750	-2057.44	Gray Shale	0.42							
A	-6,775	-2064.94	Gray Shale	0.51							
A	-6,799	-2072.42	Gray Shale	0.51							
A	-6,824	-2079.87	Gray Shale	0.52							
A	-6,848	-2087.31	Gray Shale	0.46							
A	-6,872	-2094.74	Gray Shale	0.92							
A	-6,897	-2102.16	Gray Shale	0.93							
A	-6,921	-2109.59	Gray Shale	0.66							
A	-6,946	-2117.01	Gray Shale	1.00	0.10	1.30	1.22	414	130	122	

A	-6,970	-2124.44	Gray Shale	0.44
A	-6,994	-2131.87	Gray Shale	0.49
A	-7,019	-2139.29	Gray Shale	0.48
A	-7,043	-2146.7	Gray Shale	0.31
A	-7,067	-2154.09	Gray Shale	0.34
A	-7,091	-2161.47	Gray Shale	0.28
A	-7,116	-2168.82	Gray Shale	0.29
A	-7,140	-2176.17	Gray Shale	0.27
A	-7,164	-2183.49	Gray Shale	0.25
A	-7,188	-2190.83	Gray Shale	0.31
A	-7,212	-2198.17	Gray Shale	0.25
A	-7,236	-2205.53	Gray Shale	0.39
A	-7,260	-2212.9	Gray Shale	0.26
A	-7,284	-2220.29	Gray Shale	0.37
A	-7,309	-2227.69	Gray Shale	0.26
A	-7,333	-2235.1	Gray	0.34

			Shale								
A	-7,357	-2242.51	Gray Shale	0.50							
A	-7,382	-2249.92	Gray Shale	0.52							
A	-7,406	-2257.33	Gray Shale	0.33							
A	-7,430	-2264.74	Gray Shale	0.32							
A	-7,455	-2272.16	Gray Shale	0.85	0.09	1.91	1.09	424	225	128	0.79
A	-7,479	-2279.57	Gray Shale	0.37							
A	-7,503	-2286.96	Gray Shale	0.47							
A	-7,527	-2294.32	Gray Shale	0.46							
A	-7,551	-2301.67	Gray Shale	0.58							
A	-7,575	-2308.98	Gray Shale	0.40							
A	-7,599	-2316.28	Gray Shale	0.32							
A	-7,623	-2323.55	Gray Shale	0.35							
A	-7,647	-2330.8	Gray Shale	0.42							
A	-7,671	-2338.05	Gray Shale	0.35							
A	-7,695	-	Gray Shale	0.28							

		2345.29		
A	-7,718	-2352.52	Gray Shale	0.33
A	-7,742	-2359.74	Gray Shale	0.25
A	-7,766	-2366.95	Gray Shale	0.31
A	-7,789	-2374.15	Gray Shale	0.49
A	-7,813	-2381.34	Gray Shale	0.26
A	-7,836	-2388.52	Gray Shale	0.41
A	-7,860	-2395.7	Gray Shale	0.34
A	-7,883	-2402.86	Gray Shale	0.38
A	-7,907	-2410.01	Gray Shale	0.49
A	-7,930	-2417.16	Gray Shale	0.74
A	-7,954	-2424.29	Gray Shale	0.50
A	-7,977	-2431.4	Gray Shale	0.32
A	-8,000	-2438.5	Lustrine	0.34
A	-8,024	-2445.59	Lustrine	0.54
A	-8,047	-2452.66	Lustrine	0.65
A	-8,070	-	Lustrine	0.56

		2459.72									
A	-8,093	- 2466.79	Lustrine	0.49							
A	-8,116	- 2473.86	Lustrine	0.40							
A	-8,140	- 2480.94	Lustrine	1.09	0.24	4.98	1.14	425	457	105	0.68
A	-8,163	- 2488.04	Lustrine	0.84							
A	-8,186	- 2495.14	Lustrine	0.60							
A	-8,209	- 2502.25	Lustrine	0.57							
A	-8,233	- 2509.37	Lustrine	0.56							
A	-8,256	- 2516.48	Lustrine	0.59							
A	-8,279	- 2523.59	Lustrine	0.58							
A	-8,303	- 2530.69	Lustrine	0.63							
A	-8,326	- 2537.79	Lustrine	0.83	0.15	3.60	1.18	423	434	142	
A	-8,349	- 2544.89	Lustrine	0.75							
A	-8,373	- 2551.99	Lustrine	0.67							
A	-8,396	- 2559.09	Lustrine	0.40							
A	-8,419	-	Lustrine	0.60							

A	-8,443	2566.19 -2573.3	Lustrine	0.45		
A	-8,466	- 2580.41	Lustrine	0.40		
A	-8,489	- 2587.52	Lustrine	0.41		
A	-8,513	- 2594.64	Lustrine	0.43		
A	-8,536	- 2601.74	Lustrine	0.43		
A	-8,559	- 2608.84	Lustrine	0.41		
A	-8,582	- 2615.94	Lustrine	0.43		
A	-8,606	- 2623.02	Lustrine	0.53		
A	-8,621	- 2627.74	Lustrine	0.54		

Petroleum geochemistry of well B

Table A.1 – Petroleum geochemistry data of well B.

Well Name	Depth (ft, tvdss)	Depth (m, tvdss)	Lithology	TOC (wt%)	S1 mg HC/g rock	S2 mg HC/g rock	S3 mg CO2/g rock	Tmax (deg.C)	HI	OI	Ro(%)
B	-1,018	-310.283	SMS	0.35							
B	-1,108	-337.714	SMS	0.42							
B	-1,198	-365.145	SMS	0.57							
B	-1,288	-392.574	SMS	2.87							
B	-1,378	-419.991	SMS	3.70	0.23	1.72	4.23	435	46	114	0.33
B	-1,468	-447.381	SMS	2.83							
B	-1,557	-474.718	SMS	3.28							
B	-1,647	-501.93	SMS	2.51							
B	-1,736	-529.037	SMS	0.30							
B	-1,824	-556.012	SMS	4.38	0.15	3.14	4.00	434	72	91	0.37
B	-1,912	-582.85	SMS	1.12							
B	-1,999	-609.378	SMS	3.26							
B	-2,085	-	SMS	1.99							

		635.545									
B	-2,169	-661.2	SMS	1.59							
B	-2,251	-686.023	SMS	0.89							
B	-2,330	-710.033	SMS	3.43	0.09	3.65	1.74	430	106	51	0.39
B	-2,407	-733.508	SMS	3.08							
B	-2,482	-756.556	SMS	1.48							
B	-2,556	-779.046	SMS	3.32							
B	-2,630	-801.557	SMS	1.34							
B	-2,704	-824.194	SMS	1.93							
B	-2,779	-847.14	SMS	1.16							
B	-2,855	-870.206	SMS	2.00							
B	-2,931	-893.441	SMS	1.40							
B	-3,008	-916.79	SMS	1.25							
B	-3,085	-940.247	SMS	3.61							
B	-3,162	-963.701	SMS	4.42	0.13	5.66	1.63	431	128	37	0.37
B	-3,239	-987.175	SMS	0.86							
B	-3,316	-1010.71	Redbeds	0.57							

B	-3,393	-1034.32	Redbeds	0.58							
B	-3,471	-1058.04	Redbeds	0.88							
B	-3,549	-1081.79	Redbeds	0.59							
B	-3,627	-1105.38	Redbeds	0.48							
B	-3,704	-1128.93	Redbeds	0.60							
B	-3,782	-1152.65	Redbeds	2.04	0.10	2.30	0.91	435	113	45	0.42
B	-3,859	-1176.26	Redbeds	0.88							
B	-3,937	-1199.9	Redbeds	0.72							
B	-4,016	-1224.01	Redbeds	1.31							
B	-4,096	-1248.31	Redbeds	0.42							
B	-4,175	-1272.55	Redbeds	2.06	0.03	1.63	0.79	434	79	38	0.41
B	-4,253	-1296.4	Redbeds	1.64							
B	-4,332	-1320.38	Redbeds	3.13							
B	-4,412	-1344.68	Redbeds	0.49							
B	-4,492	-1369.2	Redbeds	0.86							
B	-4,573	-1393.74	Redbeds	0.82							
B	-4,653	-	Redbeds	0.26							

		1418.28									
B	-4,734	-1442.82	Redbeds	1.26	0.10	3.02	0.78	432	240	62	0.46
B	-4,814	-1467.32	Redbeds	0.40							
B	-4,894	-1491.75	Gray Shale	0.38							
B	-4,974	-1516.14	Gray Shale	0.76							
B	-5,055	-1540.69	Gray Shale	0.96							
B	-5,136	-1565.35	Gray Shale	1.03							
B	-5,216	-1589.89	Gray Shale	4.00	0.18	9.57	1.23	428	239	31	0.46
B	-5,243	-1598.03	Gray Shale	0.80							
B	-5,270	-1606.16	Gray Shale	0.58							
B	-5,296	-1614.3	Gray Shale	0.69							
B	-5,323	-1622.44	Gray Shale	0.58							
B	-5,350	-1630.59	Gray Shale	0.55							
B	-5,376	-1638.75	Gray Shale	0.41							
B	-5,403	-1646.92	Gray Shale	0.74							
B	-5,430	-1655.1	Gray Shale	0.31							

B	-5,457	-1663.29	Gray Shale	0.31							
B	-5,484	-1671.48	Gray Shale	0.20							
B	-5,511	-1679.68	Gray Shale	0.22							
B	-5,538	-1687.88	Gray Shale	0.18							
B	-5,565	-1696.09	Gray Shale	0.26							
B	-5,592	-1704.3	Gray Shale	0.30							
B	-5,619	-1712.53	Gray Shale	0.21							
B	-5,646	-1720.76	Gray Shale	0.29							
B	-5,673	-1729	Gray Shale	0.29							
B	-5,700	-1737.26	Gray Shale	0.57	0.11	0.67	0.65	417	118	114	
B	-5,727	-1745.52	Gray Shale	0.35							
B	-5,754	-1753.8	Gray Shale	0.30							
B	-5,781	-1762.09	Gray Shale	0.29							
B	-5,808	-1770.37	Gray Shale	0.25							
B	-5,835	-1778.66	Gray Shale	0.23							
B	-5,863	-	Gray Shale	0.31							

		1786.94		
B	-5,890	-1795.22	Gray Shale	0.21
B	-5,917	-1803.51	Gray Shale	0.36
B	-5,944	-1811.79	Gray Shale	0.28
B	-5,971	-1820.06	Gray Shale	0.37
B	-5,998	-1828.33	Gray Shale	0.26
B	-6,026	-1836.59	Gray Shale	0.22
B	-6,053	-1844.83	Gray Shale	0.25
B	-6,080	-1853.07	Gray Shale	0.18
B	-6,107	-1861.31	Gray Shale	0.26
B	-6,134	-1869.53	Gray Shale	0.15
B	-6,161	-1877.75	Gray Shale	0.05
B	-6,188	-1885.97	Gray Shale	0.22
B	-6,215	-1894.19	Gray Shale	0.14
B	-6,241	-1902.41	Gray Shale	0.26
B	-6,268	-	Gray	0.23

		1910.62	Shale								
B	-6,295	-1918.83	Gray Shale	0.19							
B	-6,322	-1927.05	Gray Shale	0.23							
B	-6,349	-1935.26	Gray Shale	0.21							
B	-6,376	-1943.47	Gray Shale	0.20							
B	-6,403	-1951.69	Gray Shale	0.10							
B	-6,430	-1959.91	Gray Shale	0.15							
B	-6,457	-1968.13	Gray Shale	0.14							
B	-6,484	-1976.35	Gray Shale	0.13							
B	-6,511	-1984.57	Gray Shale	0.14							
B	-6,538	-1992.81	Gray Shale	0.35							
B	-6,565	-2001.04	Gray Shale	0.21							
B	-6,592	-2009.28	Gray Shale	0.45							
B	-6,619	-2017.52	Gray Shale	0.50							
B	-6,646	-2025.77	Gray Shale	0.37							
B	-6,673	-2034	Gray	0.66	0.08	1.02	0.87	433	155	132	

			Shale								
B	-6,700	-2042.22	Gray Shale	0.29							
B	-6,727	-2050.44	Gray Shale	0.34							
B	-6,754	-2058.65	Gray Shale	0.18							
B	-6,781	-2066.84	Gray Shale	0.18							
B	-6,808	-2075.03	Gray Shale	0.34							
B	-6,835	-2083.22	Gray Shale	0.38							
B	-6,862	-2091.41	Gray Shale	0.37							
B	-6,888	-2099.6	Gray Shale	0.22							
B	-6,915	-2107.78	Gray Shale	0.23							
B	-6,942	-2115.97	Gray Shale	0.30							
B	-6,969	-2124.15	Gray Shale	0.17							
B	-6,996	-2132.33	Gray Shale	0.22							
B	-7,023	-2140.52	Gray Shale	0.47							
B	-7,050	-2148.7	Gray Shale	0.24							
B	-7,076	-2156.88	Gray Shale	0.74	0.15	2.07	1.03	435	280	139	0.64

B	-7,103	-2165.07	Gray Shale	0.61							
B	-7,130	-2173.25	Gray Shale	0.28							
B	-7,157	-2181.43	Gray Shale	0.26							
B	-7,184	-2189.62	Gray Shale	0.35							
B	-7,211	-2197.8	Gray Shale	0.31							
B	-7,237	-2205.98	Gray Shale	0.30							
B	-7,264	-2214.17	Gray Shale	0.37							
B	-7,291	-2222.35	Gray Shale	0.17							
B	-7,318	-2230.53	Gray Shale	0.23							
B	-7,345	-2238.7	Gray Shale	0.28							
B	-7,372	-2246.87	Gray Shale	0.37							
B	-7,398	-2255.02	Gray Shale	0.36							
B	-7,425	-2263.16	Gray Shale	1.31	0.09	2.27	1.29	436	173	98	0.73
B	-7,452	-2271.3	Gray Shale	0.72							
B	-7,478	-2279.43	Gray Shale	0.53							
B	-7,505	-	Gray Shale	0.36							

		2287.57		
B	-7,532	-2295.72	Gray Shale	0.61
B	-7,559	-2303.89	Gray Shale	0.30
B	-7,586	-2312.07	Gray Shale	0.24
B	-7,612	-2320.26	Gray Shale	0.34
B	-7,639	-2328.47	Gray Shale	0.27
B	-7,666	-2336.68	Gray Shale	0.26
B	-7,693	-2344.9	Gray Shale	0.34
B	-7,720	-2353.13	Gray Shale	0.40
B	-7,747	-2361.37	Gray Shale	0.39
B	-7,774	-2369.61	Gray Shale	0.29
B	-7,801	-2377.86	Lacustrine	0.41
B	-7,828	-2386.11	Lacustrine	0.43
B	-7,856	-2394.37	Lacustrine	0.38
B	-7,883	-2402.64	Lacustrine	0.28
B	-7,910	-2410.9	Lacustrine	0.38

B	-7,937	-2419.18	Lacustrine	0.17
B	-7,964	-2427.45	Lacustrine	0.30
B	-7,991	-2435.73	Lacustrine	0.23
B	-8,018	-2444	Lacustrine	0.27
B	-8,045	-2452.25	Lacustrine	0.27
B	-8,072	-2460.49	Lacustrine	0.36
B	-8,099	-2468.72	Lacustrine	0.23
B	-8,126	-2476.94	Lacustrine	0.24
B	-8,145	-2482.69	Lacustrine	0.19

Appendix II: Temperature, Pressure and Heat Flow

Temperature Profile (Temperature vs Depth)

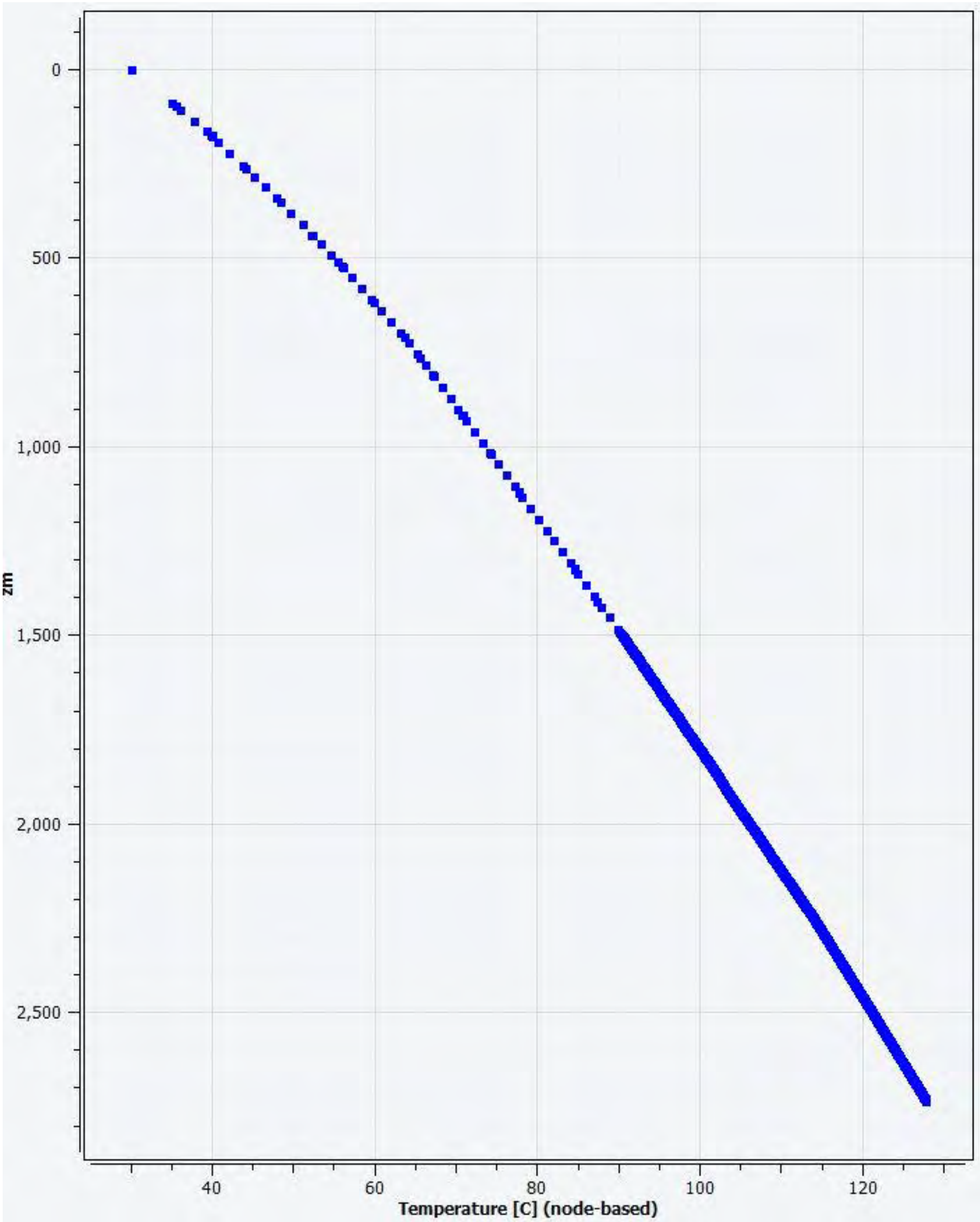

Fig A.1 – Temperature profile used in modeling.

Pressure profile (Pressure vs Depth)

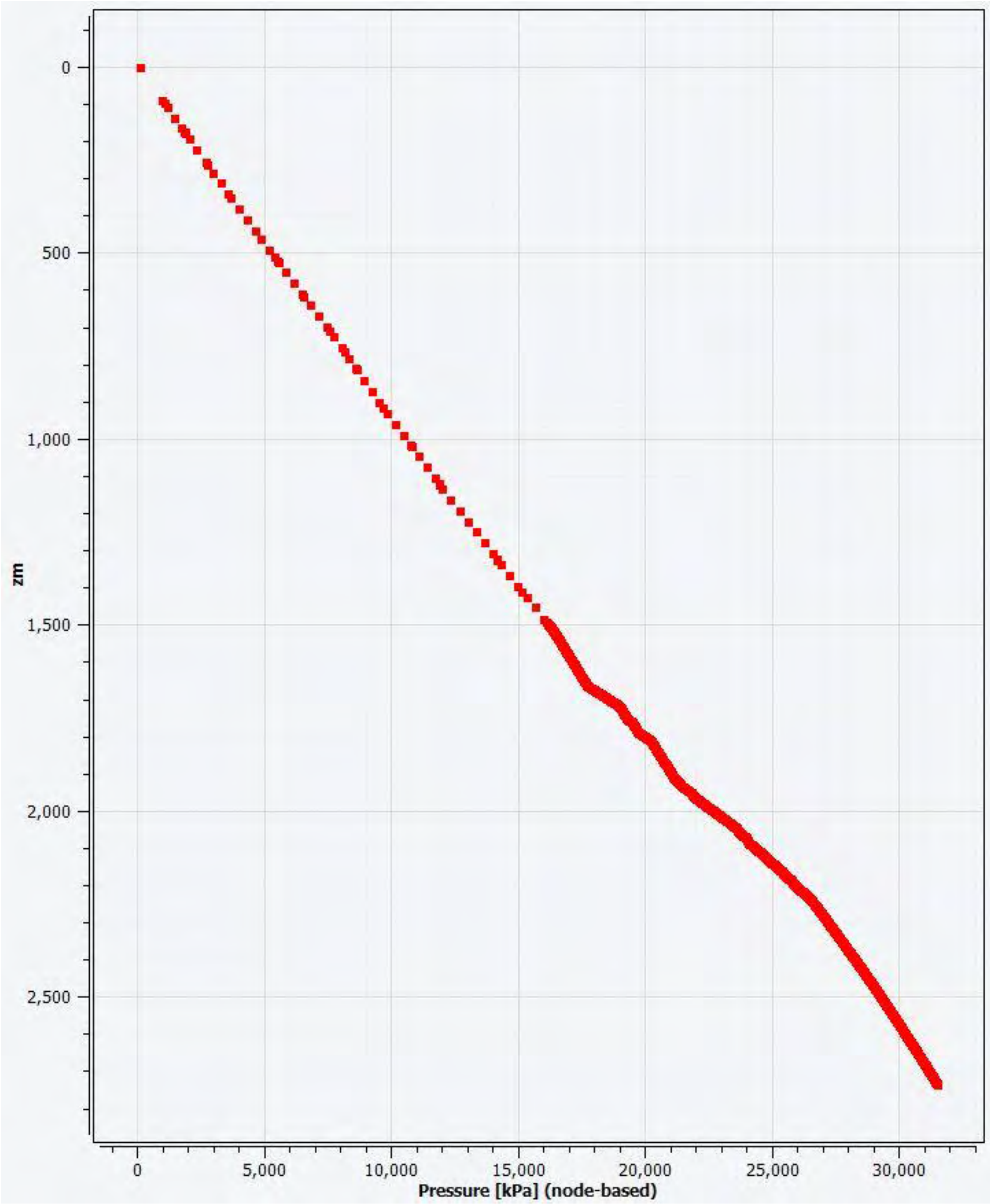

Fig A.2 – Pressure profile used in modeling.

Heat flow history

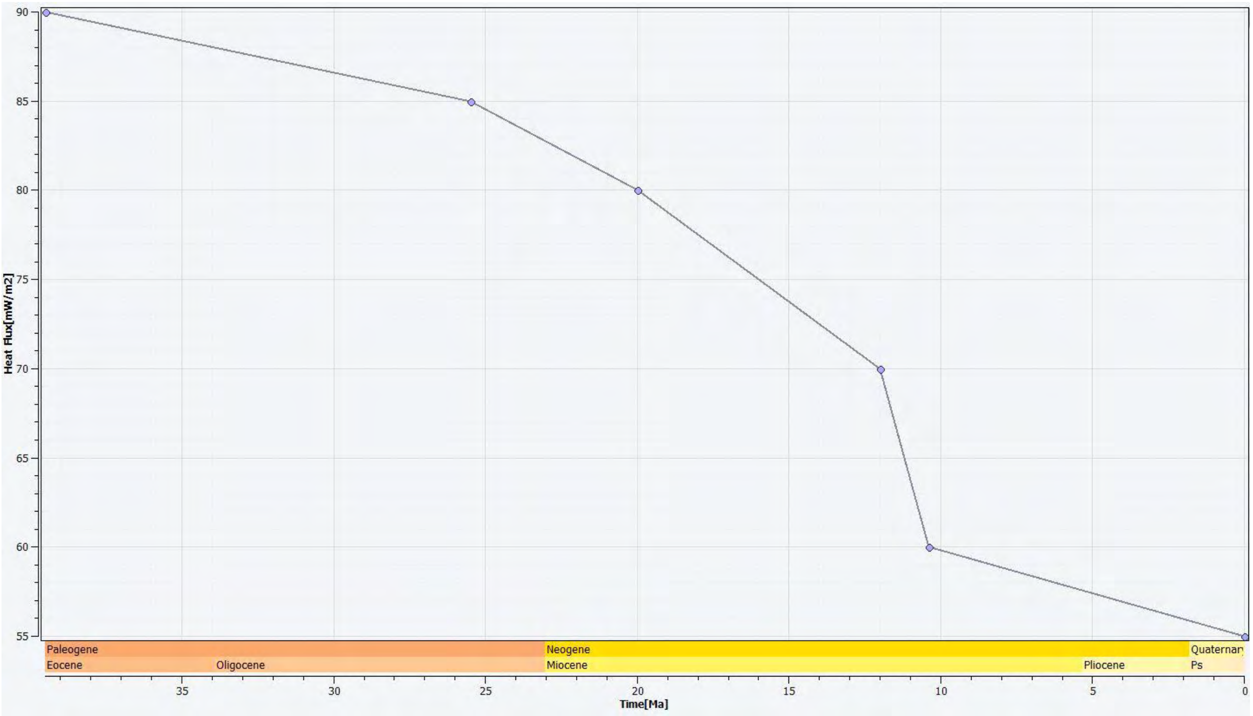

Fig A.3 – Heat flow history used in modeling.

Appendix III: 1D-Basin Models

Transformation Ratio of well A

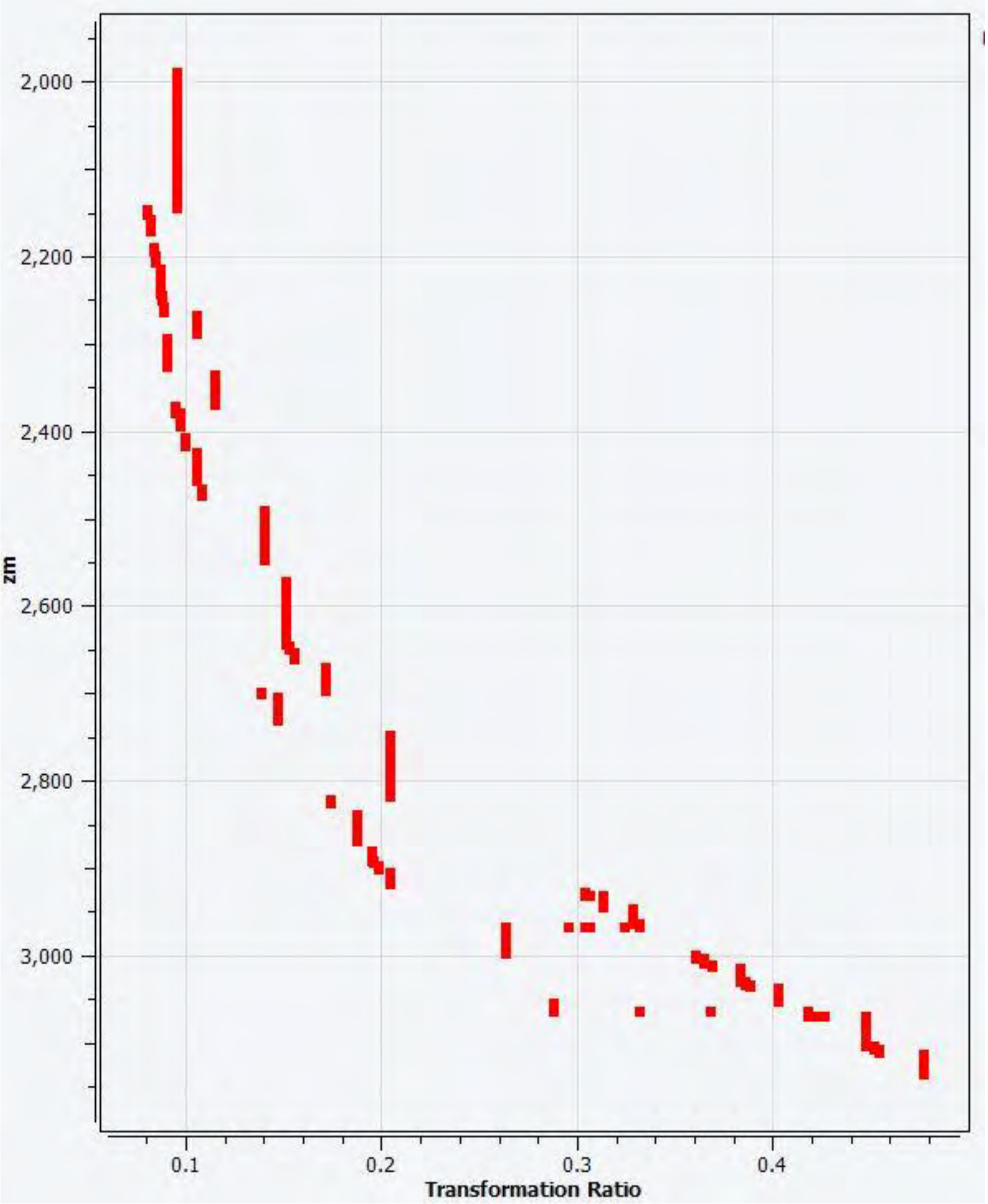

Fig A.4 – Transformation ratio of well A.

Transformation ratio of well B

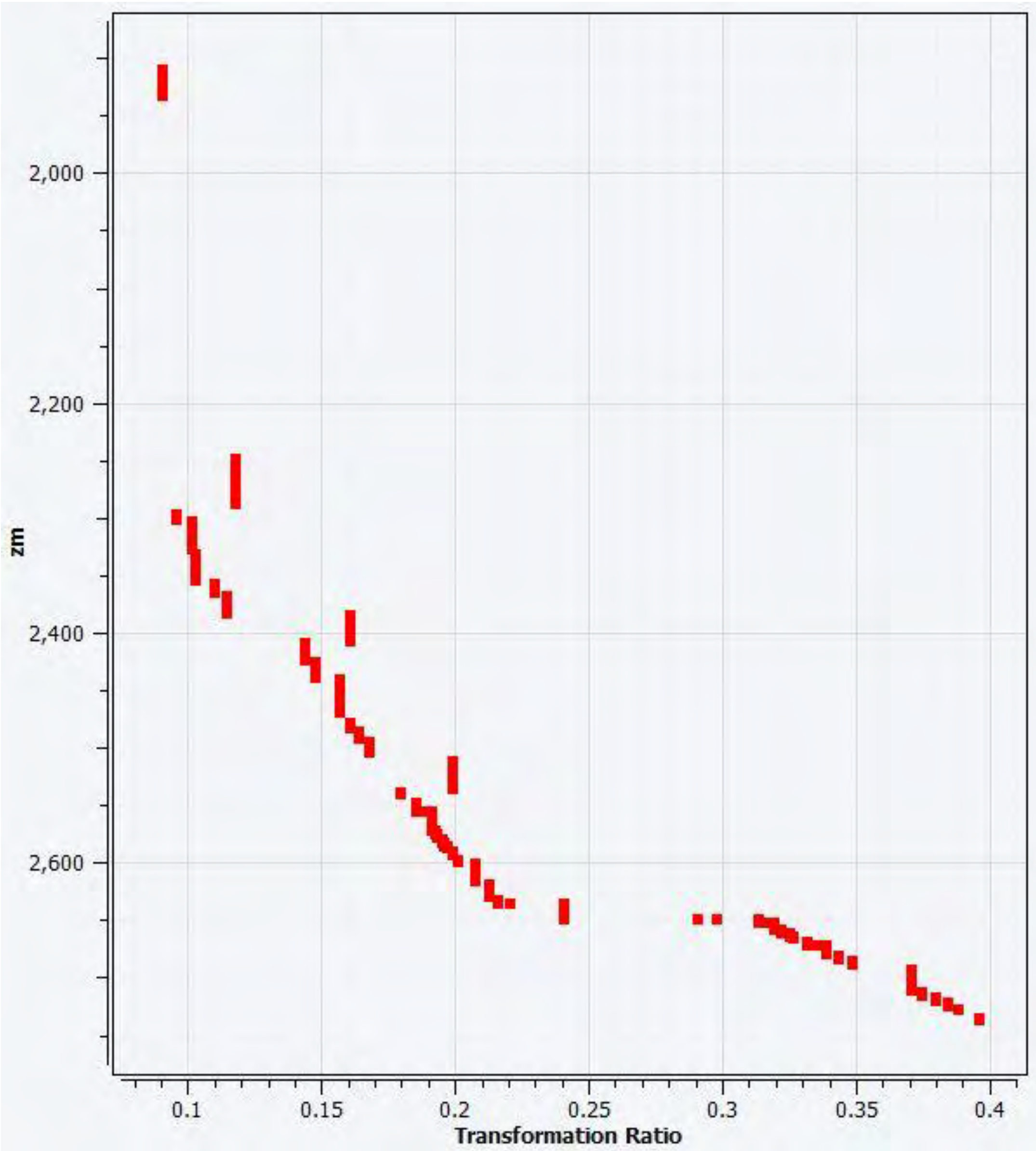

Fig A.5 – Transformation ratio of well B.

Transformation ratio of well C

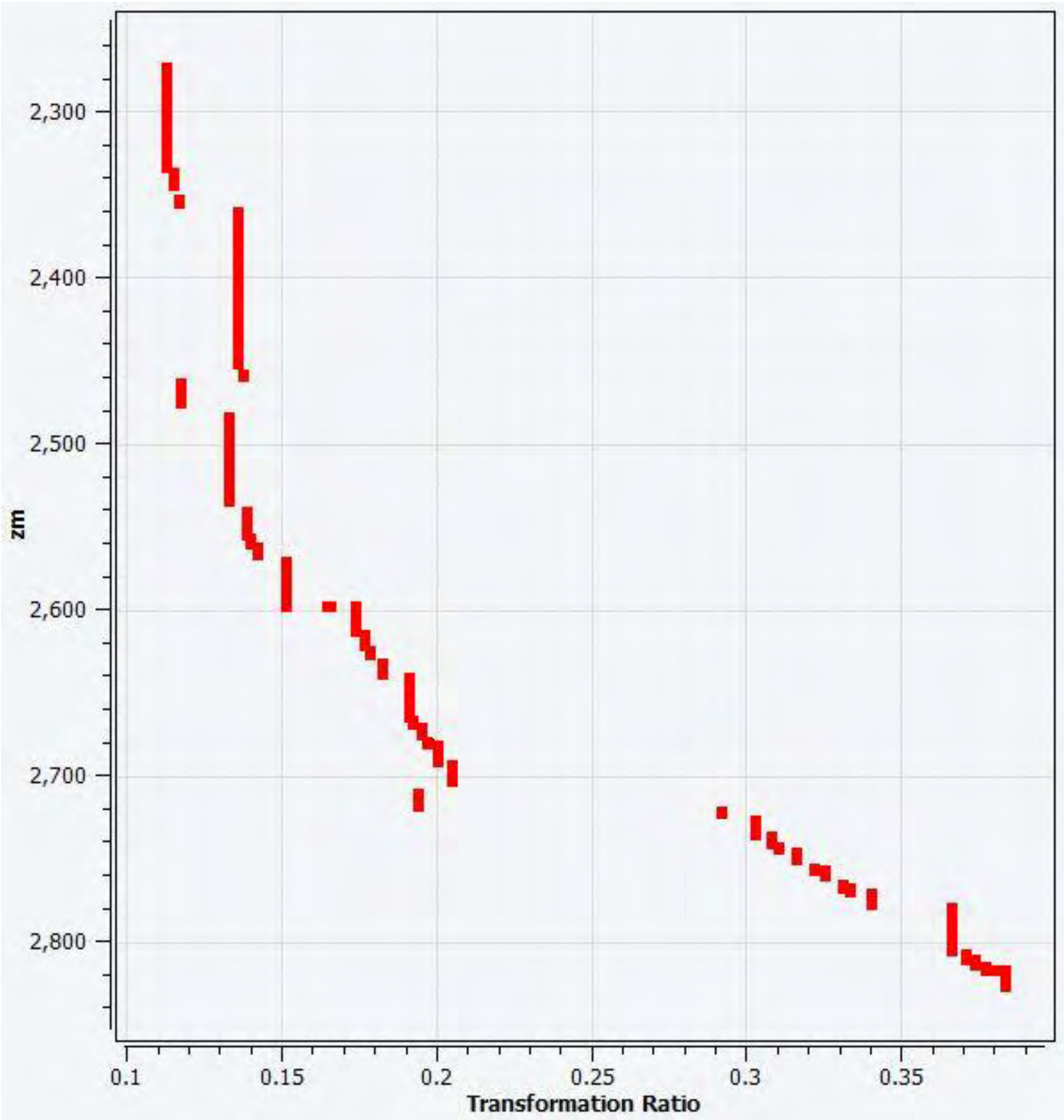

Fig A.6 – Transformation ratio of well C.

Appendix IV: Maps

Depth structural map of the top of Sequence 1

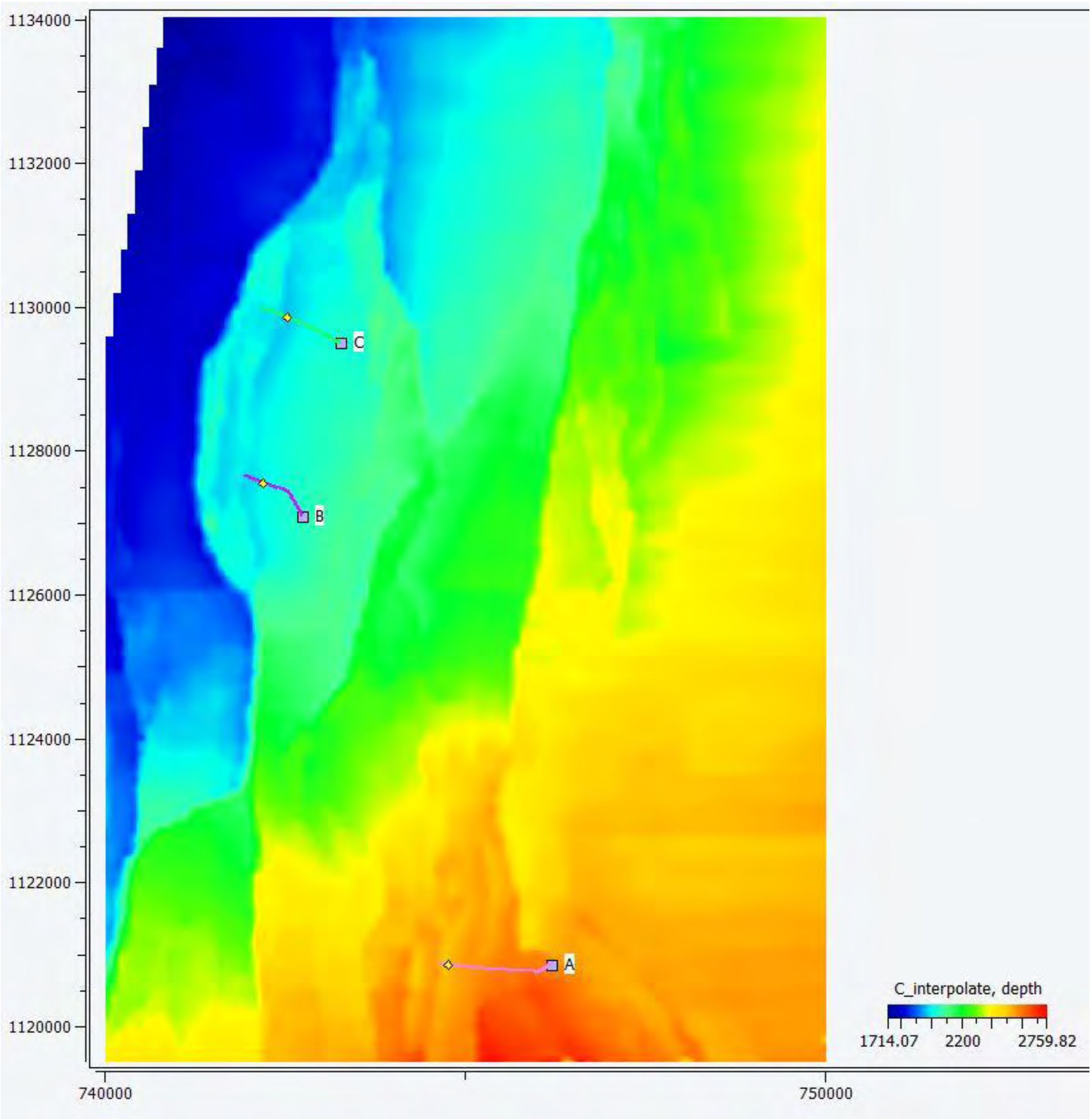

Fig A.7 – Depth structural map of the top of Sequence 1.

Depth structural map of the top of Sequence 2

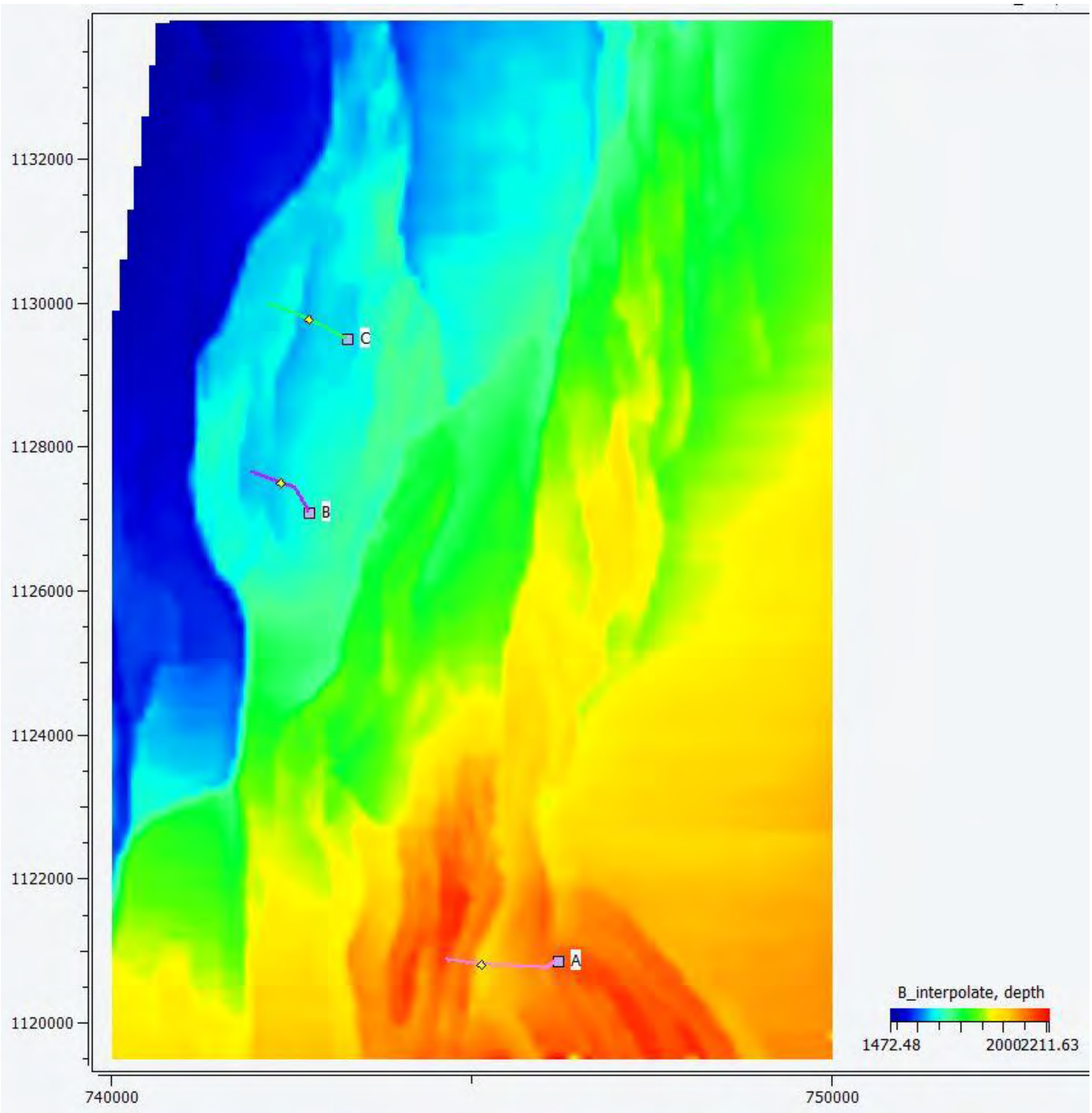

Fig A.8 - Depth structural map of the top of Sequence 2.

Depth structural map of the top of Sequence 3

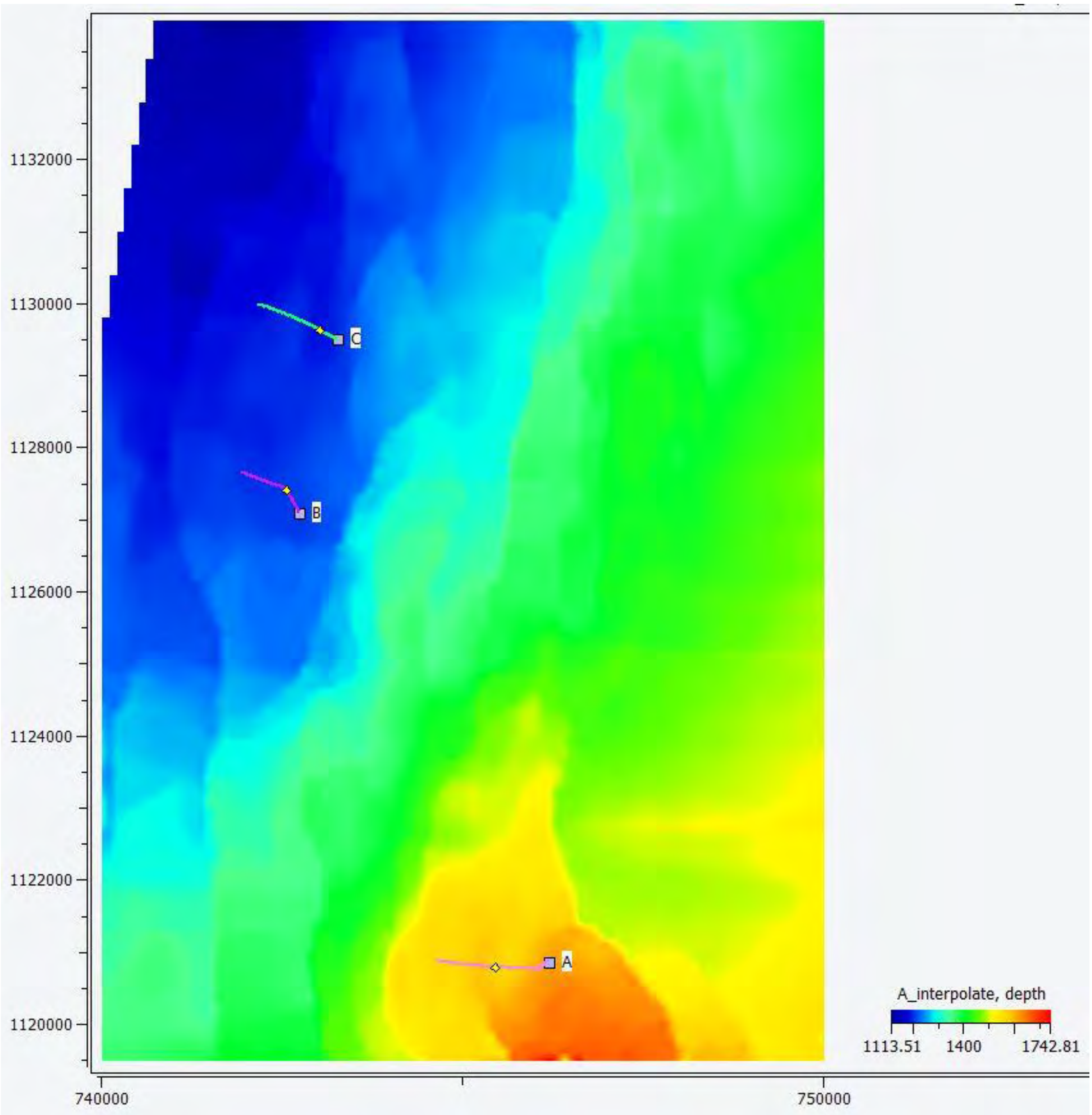

Fig A.9 - Depth structural map of the top of Sequence 3.

Depth structural map of basement

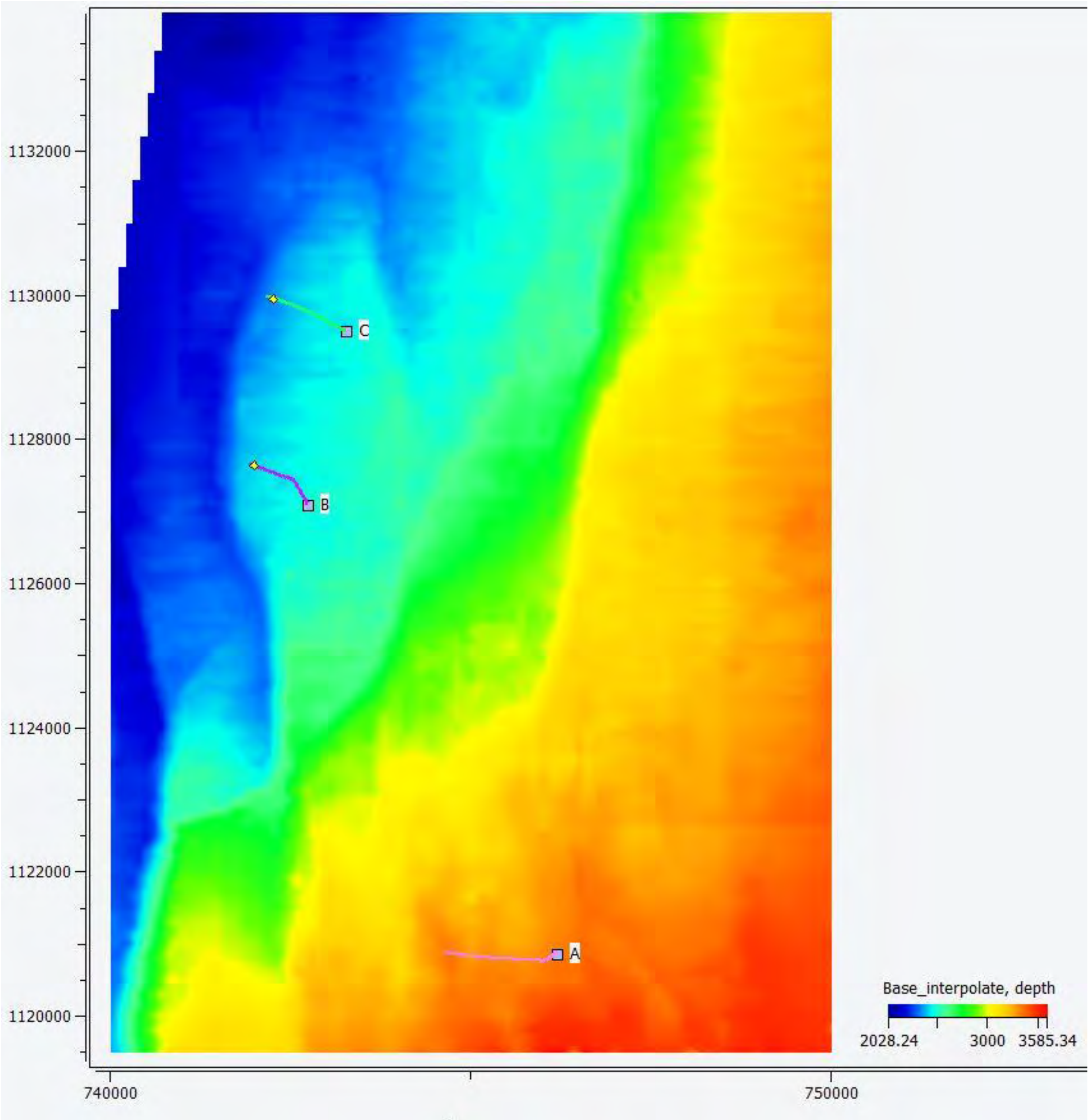

Fig A.10 - Depth structural map of the top of basement.

Depth structural map of the top of Sequence 1 with fault cut

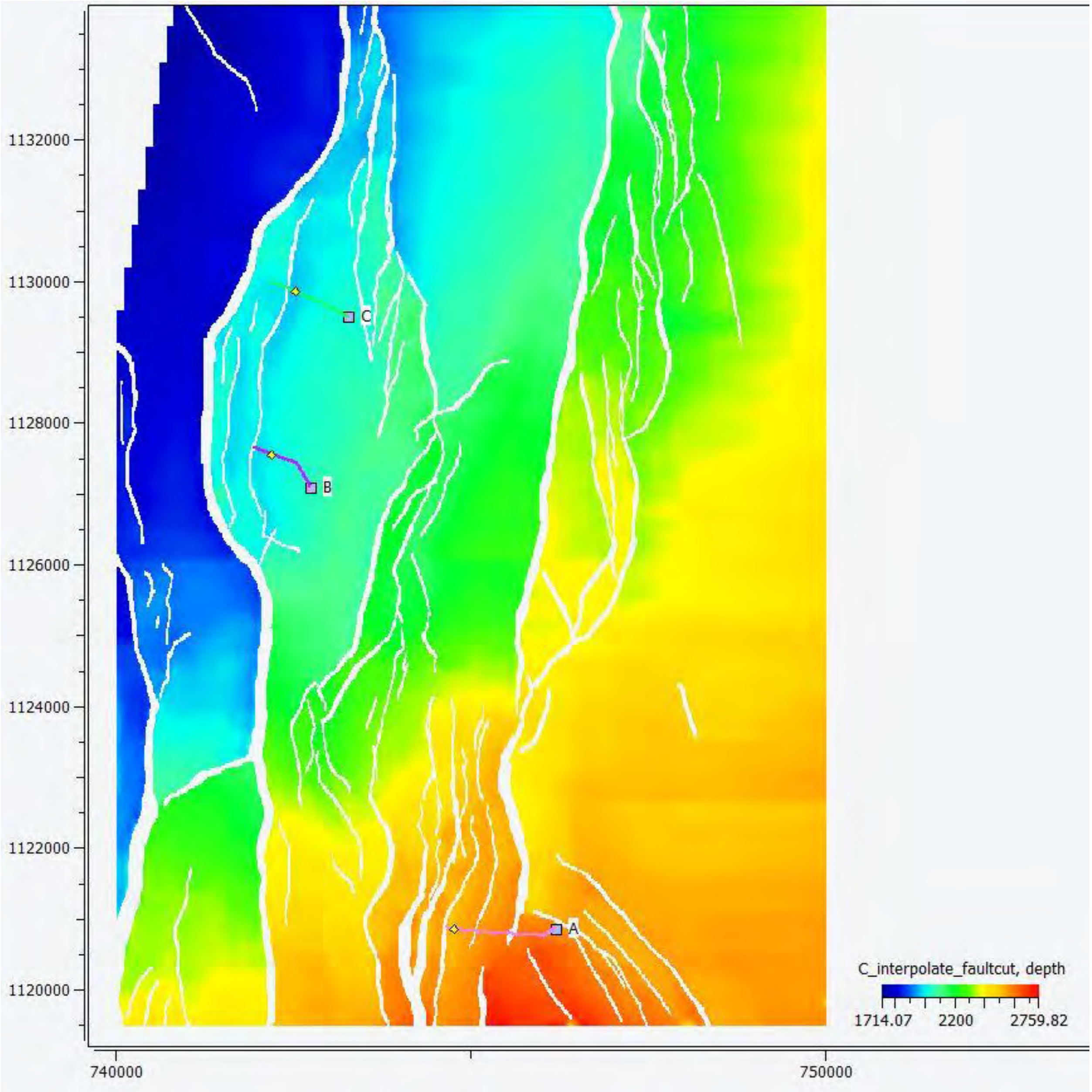

Fig A.11 - Depth structural map of the top of Sequence 1 with fault cut.

Depth structural map of the top of Sequence 2 with fault cut

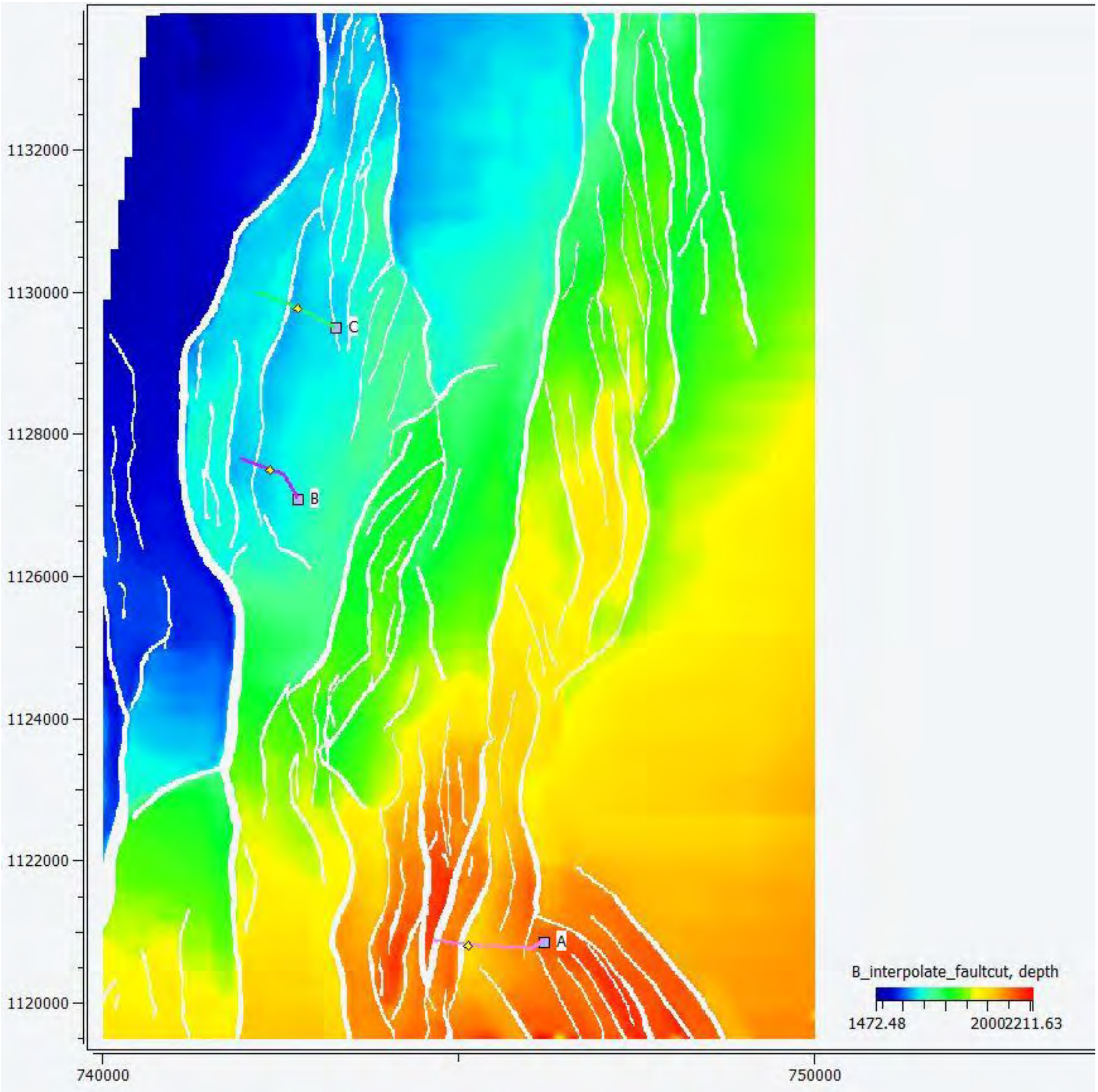

Fig A.12 - Depth structural map of the top of Sequence 2 with fault cut.

Depth structural map of the top of Sequence 3 with fault cut

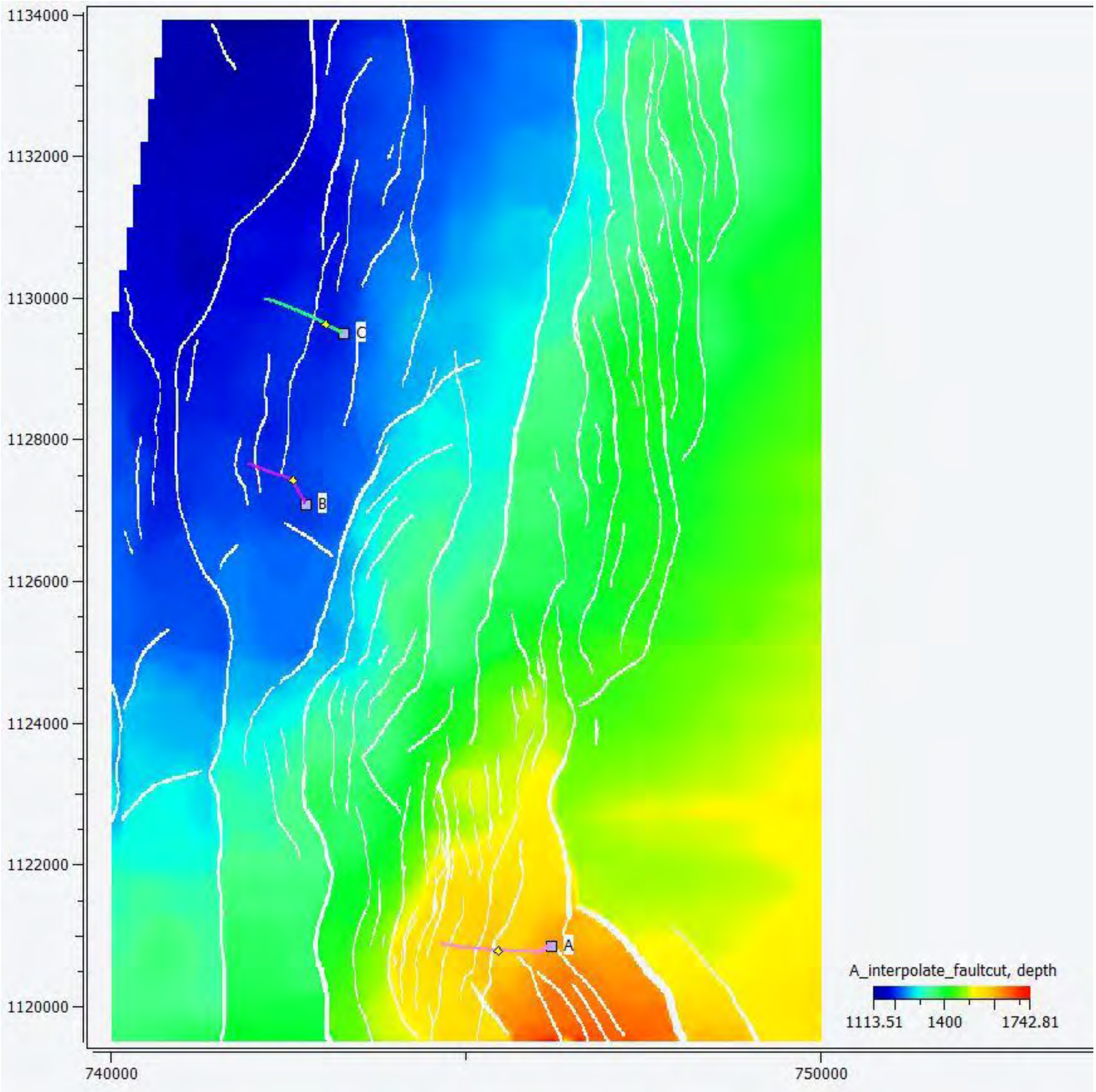

Fig A.13 - Depth structural map of the top of Sequence 3 with fault cut.

Depth structural map of basement with fault cut

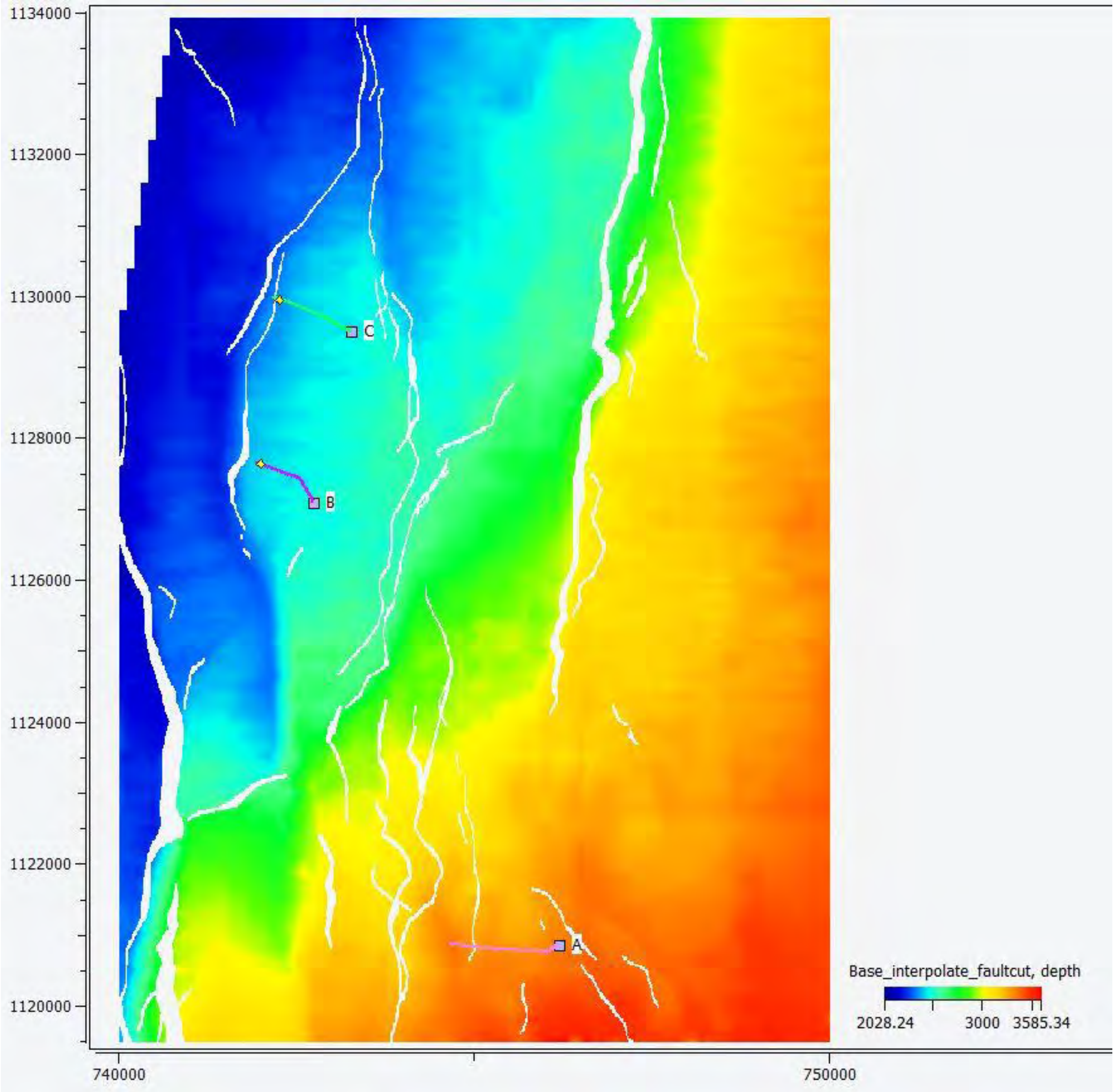

Fig A.14 - Depth structural map of basement with fault cut.