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การวิเคราะห์คุณสมบัติการเป็นชั้นหินกักเก็บจากข้อมูลหลุมเจาะ ของหมวดหินนอร์ทเคป แอ่งทารานากิ ประเทศนิวซีแลนด์

โดย

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โครงการนี้เป็นส่วนหนึ่งของการศึกษาระดับปริญญาตรี
ภาควิชาธรณีวิทยา คณะวิทยาศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2560

RESERVOIR PROPERTY ANALYSIS FROM WELL LOG DATA
OF NORTH CAPE FORMATION,
TARANAKI BASIN, NEW ZEALAND

Ms.Boontigan Kuhasubpasin

A Project Submitted in Partial Fulfillment of the Requirements
for the Degree of Bachelor of Science Program in Geology
Department of Geology, Faculty of Science, Chulalongkorn University
Academic Year 2017

การวิเคราะห์คุณสมบัติการเป็นชั้นหินกักเก็บจากข้อมูลหลุมเจาะ
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นางสาวบุญฑิกานต์ คูหาสรรพสิน

โครงงานนี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรวิทยาศาสตรบัณฑิต
ภาควิชาธรณีวิทยา คณะวิทยาศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
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Project Title:	RESERVOIR PROPERTY ANALYSIS FROM WELL LOG DATA OF NORTH CAPE FORMATION, TARANAKI BASIN, NEW ZEALAND
By:	Ms.Boontigan Kuhasubpasin
Field of Study	Geology
Project Advisor:	Piyaphong Chenrai, Ph.D.

Submitted date..

Approval date..

....

Project Advisor

(Piyaphong Chenrai, Ph.D.)

บุญฑิกานต์ คูหาสรรพสิน : การวิเคราะห์คุณสมบัติการเป็นชั้นหินกักเก็บจากข้อมูลหลุมเจาะของหมวดหินนอร์ทเคป แอ่งทารานากิ ประเทศนิวซีแลนด์. (RESERVOIR PROPERTY ANALYSIS FROM WELL LOG DATA OF NORTH CAPE FORMATION, TARANAKI BASIN, NEW ZEALAND) อ.ที่ปรึกษาโครงงานหลัก: อาจารย์ ดร. ปิยพงษ์ เชนร้าย, 57 หน้า.

แอ่งทารานากิเป็นแอ่งผลิตปิโตรเลียมทางตะวันตกของประเทศนิวซีแลนด์ มีพื้นที่ผลิตปิโตรเลียมหลักอยู่บริเวณชายฝั่งในชั้นหินกักเก็บยุคซีโนโซอิก อย่างไรก็ตามชั้นหินกักเก็บแบบตะกอนรูปพัดในยุคซีโนโซอิกนี้ไม่สามารถสะสมตัวไปถึงบริเวณนอกชายฝั่งซึ่งเป็นพื้นที่ส่วนใหญ่ของแอ่งได้ ดังนั้นหินทรายในยุคครีเตเชียสของหมวดหินนอร์ทเคปที่สะสมตัวในแอ่งย่อยขณะเปิดแอ่งในช่วงแรกน่าจะเป็นชั้นหินกักเก็บปิโตรเลียมหลักของพื้นที่นอกชายฝั่ง อย่างไรก็ดีชั้นหินกักเก็บในยุคครีเตเชียสนี้ยังมีการศึกษาเพียงเล็กน้อยเท่านั้นเนื่องจากข้อจำกัดทางด้านข้อมูล ในการศึกษานี้จึงจะใช้ข้อมูลหลุมเจาะเพื่อมาอธิบายลักษณะของหินทรายในหมวดหินนอ์ทเคป การแปลผลทางปิโตรฟิสิกส์ถูกใช้ในการอธิบายลักษณะการสะสมตัวและความสามารถในการเป็นชั้นหินกักเก็บ โดยผลลัพธ์ที่ได้ทำให้เข้าใจลักษณะของหินทรายในหมวดหินนอร์ทเคปมากขึ้น จากการวิเคราะห์ข้อมูลค่าความพรุนของหินอยู่ที่ระหว่าง 10 ถึง 27 เปอร์เซ็นต์ ขณะที่ค่าความสามารถในการซึมผ่านมีค่าสูงสุดที่ 700 มิลลิดาซี ค่าความพรุนของหินในหลุมเจาะที่อยู่บริเวณใกล้ชายฝั่งมีค่าน้อยกว่าค่าความพรุนของหินที่อยู่บริเวณหลุมเจาะนอกชายฝั่ง ค่าความพรุนจึงน่าจะถูกควบคุมด้วยการบดอัดซึ่งเป็นผลมาจากตะกอนชายฝั่งที่ตกสะสมตัวปิดทับ โดยสมมติฐานนี้มีความสัมพันธ์กับลักษณะคลื่นไหวสะเทือนที่แสดงการสะสมตัวของตะกอนจากแหลมทารานากิและข้อมูลสัดส่วนของแร่ดินเหนียวที่สัมพันธ์กับลำดับขั้นของการบดอัด อีกปัจจัยหนึ่งที่มีผลต่อค่าความพรุนคือสภาพแวดล้อมการสะสมตัว จากการศึกษาพบว่าหินทรายที่สะสมตัวในสันดอนทรายมีค่าความพรุนมากที่สุดเมื่อเปรียบเทียบกับหินทรายบริเวณทางน้ำและที่ลุ่มน้ำขึ้นถึง จึงสามารถสรุปได้ว่าหินทรายในหมวดหินนอร์ทเคปมีความสามารถในการเป็นชั้นหินกักเก็บปิโตรเลียมโดยเฉพาะในบริเวณนอกชายฝั่งโดยมีปัจจัยควบคุมคุณสมบัติของหินคือสภาพแวดล้อมการสะสมตัวและการบดอัดจากตะกอนที่ปิดทับ

ภาควิชา........................ธรณีวิทยา..........................ลายมือชื่อนิสิต...

สาขาวิชา......................ธรณีวิทยา..........................ลายมือชื่อ อ.ที่ปรึกษาหลัก..

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BOONTIGAN KUHASUBPASIN: RESERVOIR PROPERTY ANALYSIS FROM WELL LOG DATA OF NORTH CAPE FORMATION, TARANAKI BASIN, NEW ZEALAND. ADVISOR: PIYAPHONG CHENRAI, Ph.D., 57 pp.

Taranaki basin is the petroleum production basin along the western side of New Zealand. The main production fields have been along the marginal zone with Cenozoic reservoirs. However, the Cenozoic fan reservoirs are restricted to the offshore zone which is the majority of the basin. Therefore, Cretaceous sandstones in the North Cape Formation which deposited in sub-basin at the initial phase of basin formation might be the target reservoir in the deepwater block. Nonetheless, the Cretaceous reservoir is still in its infancy due to the limitation of the data. In this study, well log data were used to reveal the North Cape Formation characteristic. The petrophysical interpretation was used to identify depositional environment and reservoir properties. The result gives evidence of reservoir properties of sandstone in the North Cape Formation. The porosity is between 10% and 27% while permeability is up to 700 mD. The porosity of sandstones in wells located near the peninsular is lower than wells located in the offshore zone. The porosity might be controlled by compaction as a result of overburden sedimentary successions. This hypothesis relates to seismic data showed progradation of sediment from the Taranaki peninsular and proportion of clay minerals which referred to the degree of compaction. Another factor controlling the porosity is depositional environment. Barrier bar sandstone shows the highest porosity compared with channel and tidal flat sandstone. In conclusion, the North Cape Formation sandstone has potential to become a reservoir especially in the deepwater field, and the main factors controlling reservoir properties are depositional environment and degree of compaction.

Department: ....Geology...................Student's Signature...
Field of Study: ....Geology....................Advisor's Signature..
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Chapter 1
Introduction

1.1 Introduction

Taranaki sedimentary basin is a high potential petroleum production area on the western side of New Zealand. The main production fields have been along the peninsula with Cenozoic reservoirs (Ministry of Business, Innovation, and Employment, 2014). However, the Cenozoic fan reservoirs are only restricted within nearshore zone and could not prograde to offshore zone which is the majority of this basin. There is only the North Cape Formation sandstone, which deposited in Late Cretaceous throughout the basin, presented in the deepwater area of the Taranaki basin (King et al., 1993).

The North Cape Formation sandstone was deposited in sub-basins in a shallow marine environment and overlaid the source rock strata of the Rakopi formation (Stogen et al., 2012). However, the Cretaceous reservoir is still in its infancy and is poorly understood on it reservoir properties due to a limitation of the data such as a small number of outcrops and sidewall core data. The outcrops and core data show that the factors affecting reservoir properties are sandstone composition, a volume of clay minerals and degree of compaction that related to burial depth (Higgs et al, 2010 and Bal and Lewis's 1994).

Reservoir properties are one of the essential petroleum elements. In this study, porosity and permeability are the properties that were focused on. Well log data were used to interpret sand correlation and reservoir properties of the North Cape Formation. Well log data represents relationships between depth and physical parameters of subsurface rock strata, i.e., gamma ray, resistivity, and bulk density. Petrophysical analysis is used to document lithology, porosity, water saturation and permeability of the formation (Schlumberger, 1998). The result gives evidence of reservoir properties of sandstone in North Cape Formation in the deepwater block.

1.2 Objective

To study reservoir properties of sandstones in North Cape Formation by using well log data

1.3 Study Area

The study area is in Taranaki basin, located along the west of the North Island, New Zealand. This basin covers approximately 100,000 square kilometers with more than 400 exploration wells and about 12 petroleum fields (New Zealand Petroleum & Minerals, 2013). This study focused on offshore exploration blocks in the west of Taranaki peninsular or the Western Platform region which cover the majority of the basin (Figure 1-1).

Figure 1-1 Taranaki basin located on the western side of the North Island, New Zealand (Modified from www.ezilon.com)

1.4 Scope of Studying

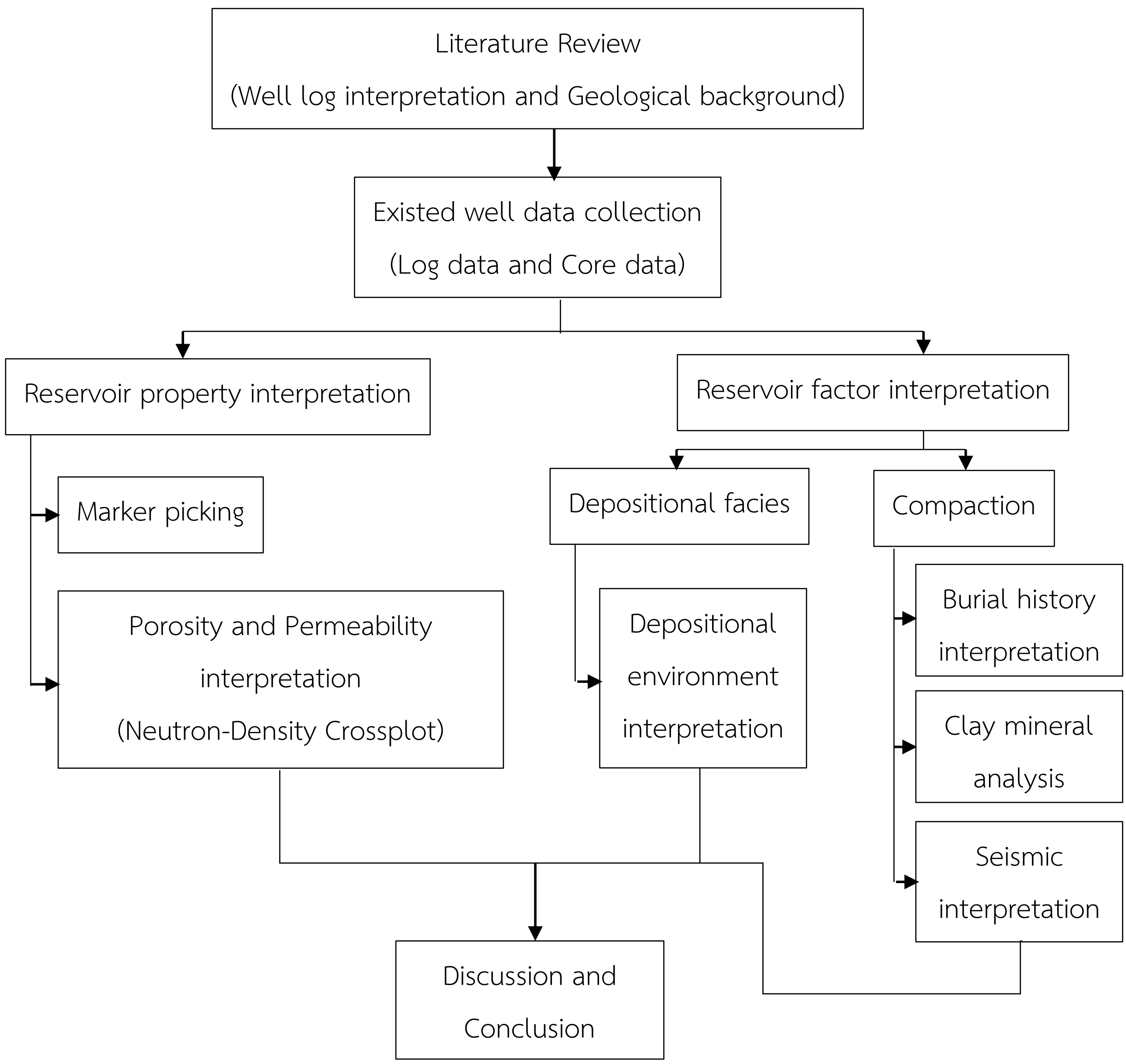
Western Platform of Taranaki basin is the study area. Well log data play the important role in this study for interpreting the reservoir properties of the North Cape Formation. From all wells drilled in the Taranaki basin, 15 wells drilled deeply enough to analyst the North Cape Formation were used in this work. Core data and seismic data are also used for supporting the interpretation. Therefore, the data analysed in this study are:

a. Well log data from 13 wells

b. Core data from 15 wells

c. 2D seismic data from 8 lines

1.5 Methodology



Chapter 2
Geological Background

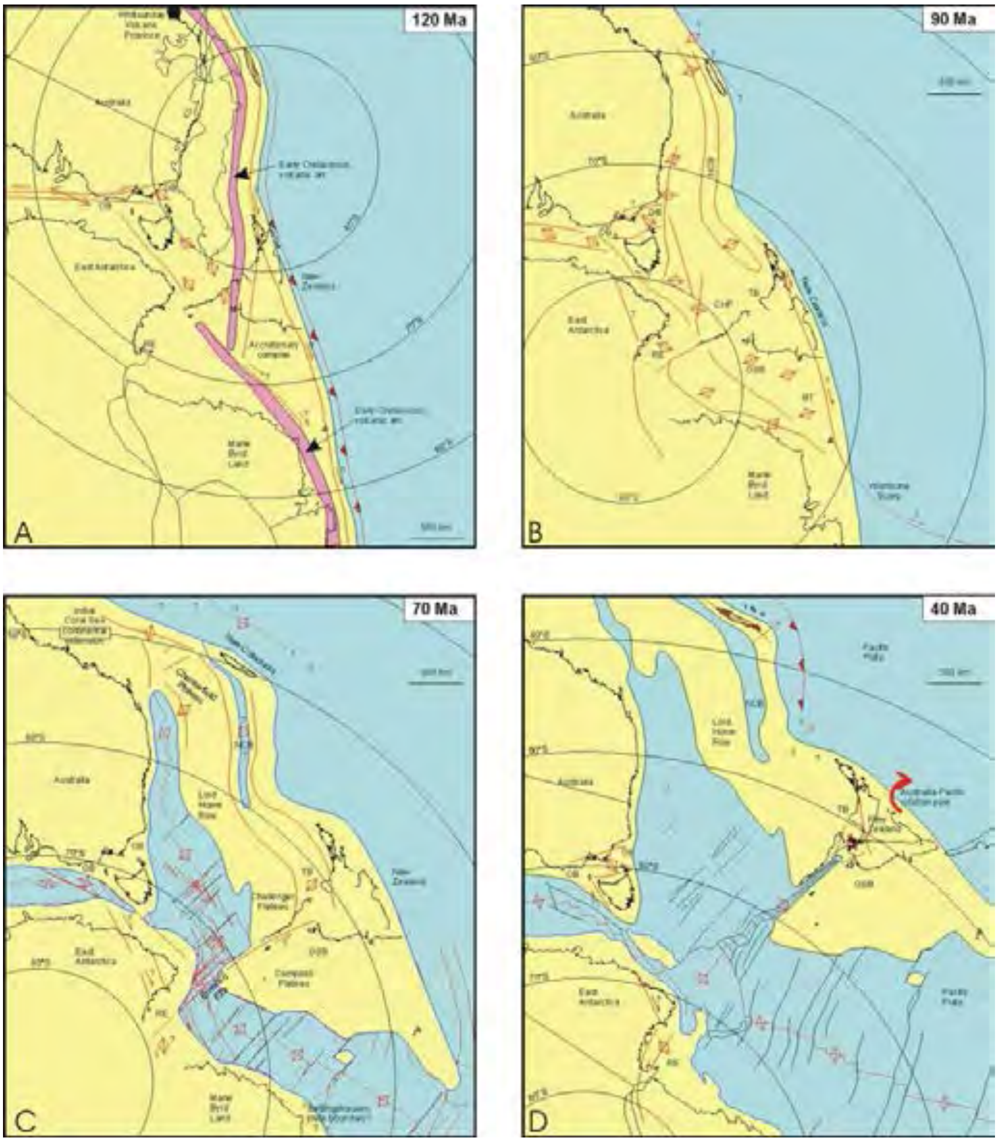
The Taranaki basin contacts the Reinga basin to the north and the West Coast basin to the south. More than 400 exploration and production wells were drilled both onshore and offshore (New Zealand Petroleum & Minerals, 2014). About 418 million barrels of oil and 6190 billion cubic feet of gas have been produced from this basin (New Zealand Petroleum and Minerals, 2016). The basin was occurred approximately 80 million years ago and has been through complicated history from Late Cretaceous to present day related to rifting phase of the Gondwana, passive subsidence and compression of Australian-Pacific plate boundary (King and Thrasher, 1996).

2.1 Tectonic Evolution

The Taranaki basin has a complex morphology due to various tectonic evolution states throughout 80 million years, from Cretaceous to the present day. There are plenty of geological structures such as normal faults, reverse faults, and uplifted areas (King and Thrasher, 1996). Figure 2-1 shows tectonic evolution of the Taranaki basin which could be divided into 4 main phases: subduction of east Gonwana, failed rift of the New Caledonia basin, the Tasman Sea extension, and opening of the Southern Ocean.

From the Triassic to the Late Cretaceous, New Zealand was a marginal part of the Gondwana super-continent (Bache et al., 2013). Basements such as volcanic rocks, plutonic rocks, and metasedimentary rocks were developed by an igneous and metamorphic processes (Uruski, 2007). Since 160 Ma, the New Caledonia Basin had been developed as a back-arc rifting due to subduction (Uruski and Baillie, 2004) and paused about 105 million years ago. The tectonics replaced by Tasman Sea extension or the separation of Australia from Zealandia (Uruski, 2007).

The failed rift of New Caledonia Basin brought the Taranaki delta deposited from 100 to 75 Ma, while the Tasman Sea extension might initiate around 80 Ma (Sutherland et al., 2001). About 75 Ma, the unconformity caused by this divergent plate boundary represented in the transgressive Cretaceous sediments. The spreading of the Tasman Sea occurred with thermal subsidence and led to the deposition of sediments in this basin until the Paleocene (55 Ma). After that, New Zealand gradually moved away and sank into a sea (Stogen et al., 2014).



TB-Taranaki Basin, NCB-New Caledonia Basin, GB, Gippsland Basin, OB-Ottway Basin, CHP-Challenger Plateau, RE-Ross Embayment, GSB-Great South Basin, BT-Bounty Trough. Pink polygons on A represent the Brook Street terrane

Figure 2-1 Tectonic evolution of New Zealand at 120 90 70 and 40 Ma after Sutherland et al. (2001) and Urashi (2007).

A. In the Early Cretaceous, there was subduction in the eastern side of Gondwana.

B. Failed rift of the New Caledonia Basin was the reason for the Taranaki delta deposition.

C. The Tasman Sea extension separated New Zealand from Gondwana

D. During the Eocene, divergent movement of the Tasman Sea developed with the opening of the Southern Ocean

During the Eocene, the divergent movement of the Tasman Sea developed with the opening of the Southern Ocean. This phenomena caused the anti-clockwise shifting affecting the extension to the southern part (Turnbull et al., 1993) and compression to the northern part of New Zealand (Uruski et al., 2002). Lastly, open folds and minor faults were developed in deepwater Taranaki basin (King & Thrasher 1996).

Since 25 Ma, the current tectonics dominated this basin. There was an obduction of sedimentary and igneous rocks and also a volcanic arc on the North Island. The plate boundary rotated to present-day position with NNE trend. As a result, the volcanoes were gradually younger to the south. This rotation also affected the older extensional fault to the South of Taranaki peninsular. Although, the deepwater Taranaki or the Western platform was still unaffected by these tectonics except the slighted uplifted and erosion (Sarma et al., 2014).

2.2 Stratigraphy

The Institute of Geological and Nuclear Sciences (1997) explained that the stratigraphy of the Taranaki basin was very complicated. The tectonostratigraphy of the basin can be divided into three main stages following the tectonic which showed in the sequence stratigraphy in Figure 2-3 (King and Thrasher, 1996).

Period I: From Late Cretaceous to Paleocene, the basin was dominated by rifting. Therefore, the sediments presented at this time were terrestrial to shallow marine sediments in Pakawau Group, accumulated in limited areas controlled by minor faults. Pakawau Group can be divided into two formations. The lower one is the Rakopi terrestrial Formation deposited in fan and meandering stream. The other formation is the shallow marine North Cape Formation which related to regional flooding period (Thrasher, 1992).

Period II: From Eocene to Oligocene, this area was a passive margin associated with thermal subsidence. Sediments were controlled by inactive tectonic event, erosion and marine transgression. The rock succession can be divided into two units deposited at the same time: the shallow marine Kupuni Group and the fully marine Moa group. These sedimentary groups were overlaid by marine mudstone of Turi Formation associated with minor submarine fan sediment of Tangaroa Formation (King and Thrasher, 1996)

Period III: From Oligocene to Recent, the Australia-Pacific convergent plate boundary led the regional deformation of rocks in the basin. The convergence developed two tectonic setting: active margin in the Eastern mobile belt and passive margin in the stable western platform. During the Oligocene, rapid subsidence occurred related to the evolution of the new plated boundary. As a result, the calcareous Tikorangi Formation deposited along the shelf area of the basin (Hood, Nelson, and Kamp, 2003). All regions except the south had reached the bathyal depths at this time. During Miocene, compression resulted in the faults and uplifts that increased the sedimentary supply related to marine regressive in the basin (King & Thrasher 1996; Kamp et al. 2002).

In general, in the late Cretaceous, the rifting-terrestrial sediment deposited throughout the area. Then in the Paleocene, marine transgression dominated the deposition of siliciclastic marine sediment associated with limestone that accumulated in the Oligocene. In the Miocene, the change of tectonic setting from extension to compression influence the structure of the basin.

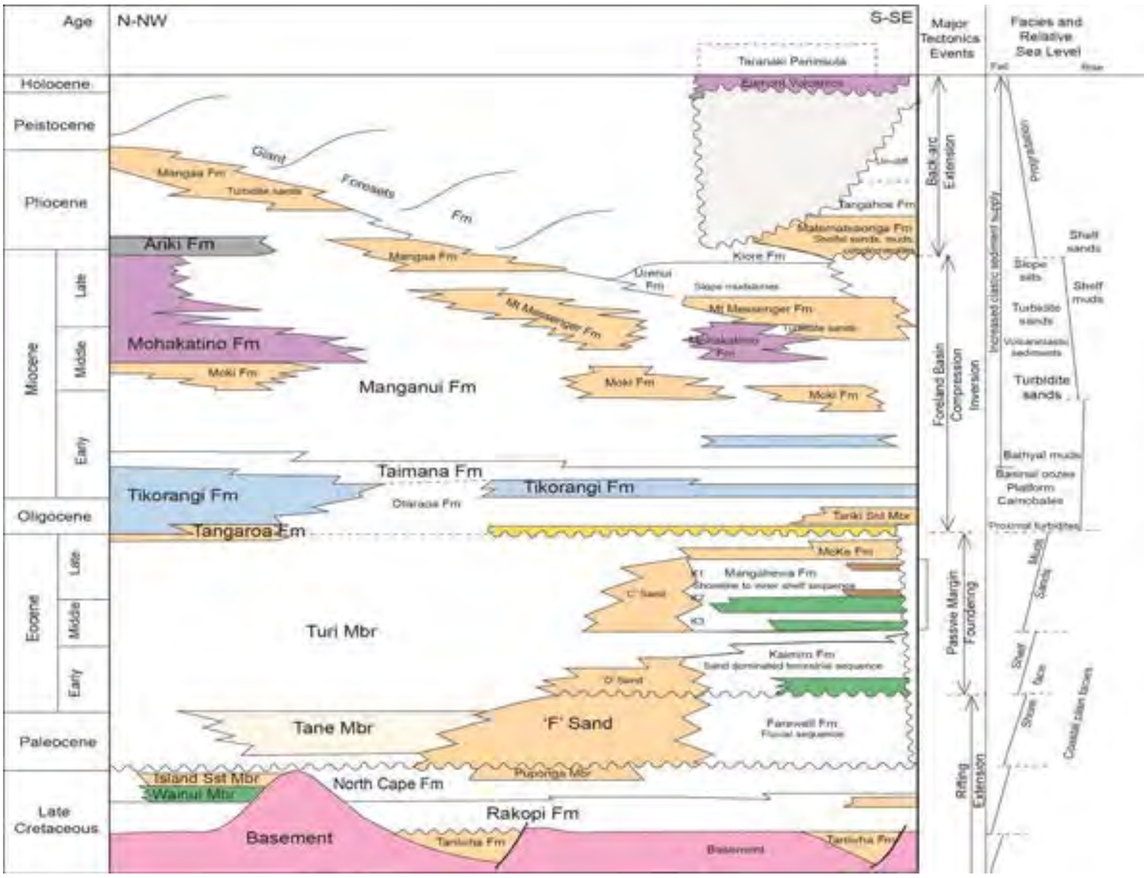


Figure 2-2 Chronostratigraphy, lithology and relative sea level of the Taranaki basin

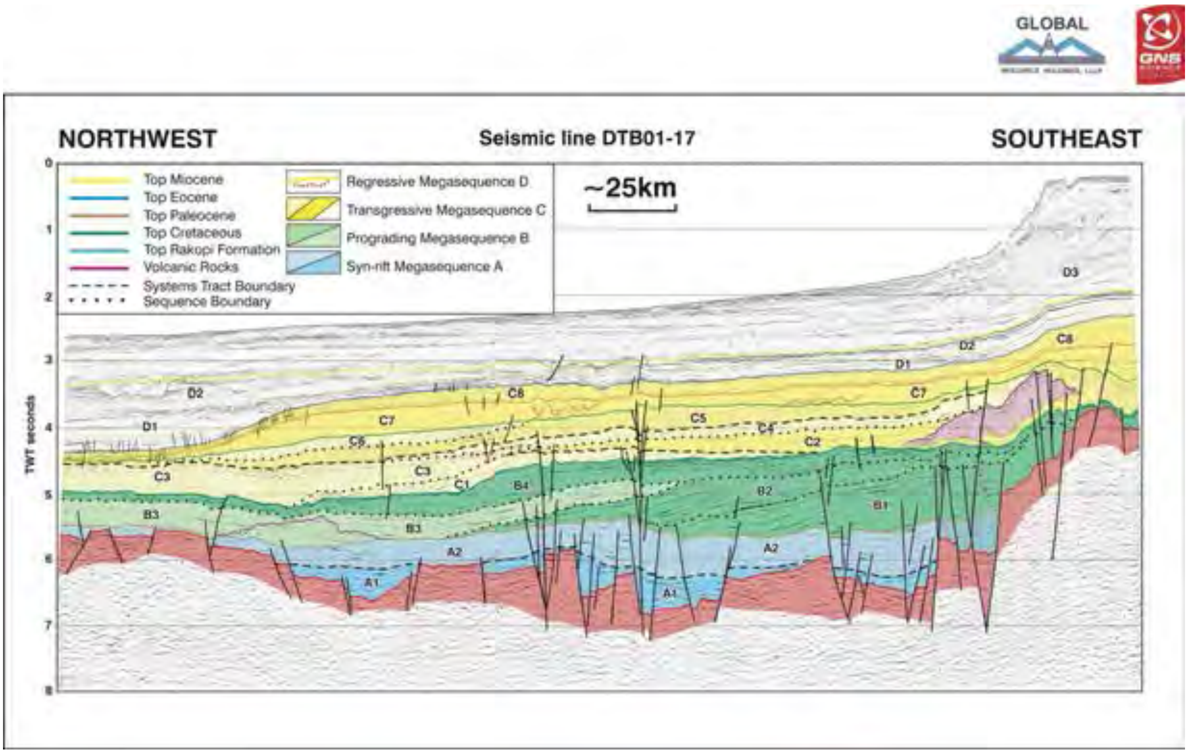


Figure 2-3 Sequence stratigraphy of Taranaki basin from Cretaceous to the present day (Uruski, 2007)

2.3 Reservoirs in the Taranaki Basin

The currently producing reservoirs in the Taranaki basin are sediments that deposited from Paleocene to Pliocene shown in petroleum system element chart in Figure 2-4. The significant hydrocarbon of the Paleocene reservoirs is gas-condensate and oil. Whereas, oil is the primary hydrocarbon found in Neogene reservoir. The petroleum fields are only presented in the onshore and nearshore area as demonstrated in Figure 2-5. Although there is no producing reservoir in Cretaceous, it remains being a possible petroleum reservoir of the Taranaki basin.

The Paleocene sandstone in the Farewell Formation deposited in a fluvial environment and distributed almost all the basin is a high-quality reservoir for Kupe, Maui and Tui fields.

The Early to Middle Eocene sandstone in the Kaimiro Formation deposited in alluvial plain and shallow marine environment and distributed throughout coastal area is also a reservoir of Maui field.

The late Eocene sandstone in the Mangahewa, McKee and Tangaroa Formation which deposited in terrestrial, shallow marine and turbidite environment, respectively, are the reservoir of Kapuni, Maui, Mangahewa, Pohokura, McKee, Tangaroa and Kora fields.

Limestones in the Tikorangi Formation deposited in Oligocene throughout the basin can also be a reservoir of Waihapa-Ngaere, Toko, Piakau, Kupara, Rimu fields.

Sandstone in the Moki, Mount Messenger, Urenui and Mangaa Formations are the slope and seafloor turbidite sandstone which deposited in Late Miocene. They are reservoirs of Maari, Kaimiro, Ngatoro, Cheal and Karewa fields.

Lastly, marginal sandstones and conglomerates of the Matemateaonga Formation deposited in Latest Miocene to Early Pliocene is a reservoir of Moturoa oil field. (New Zealand Petroleum & Minerals, 2014)

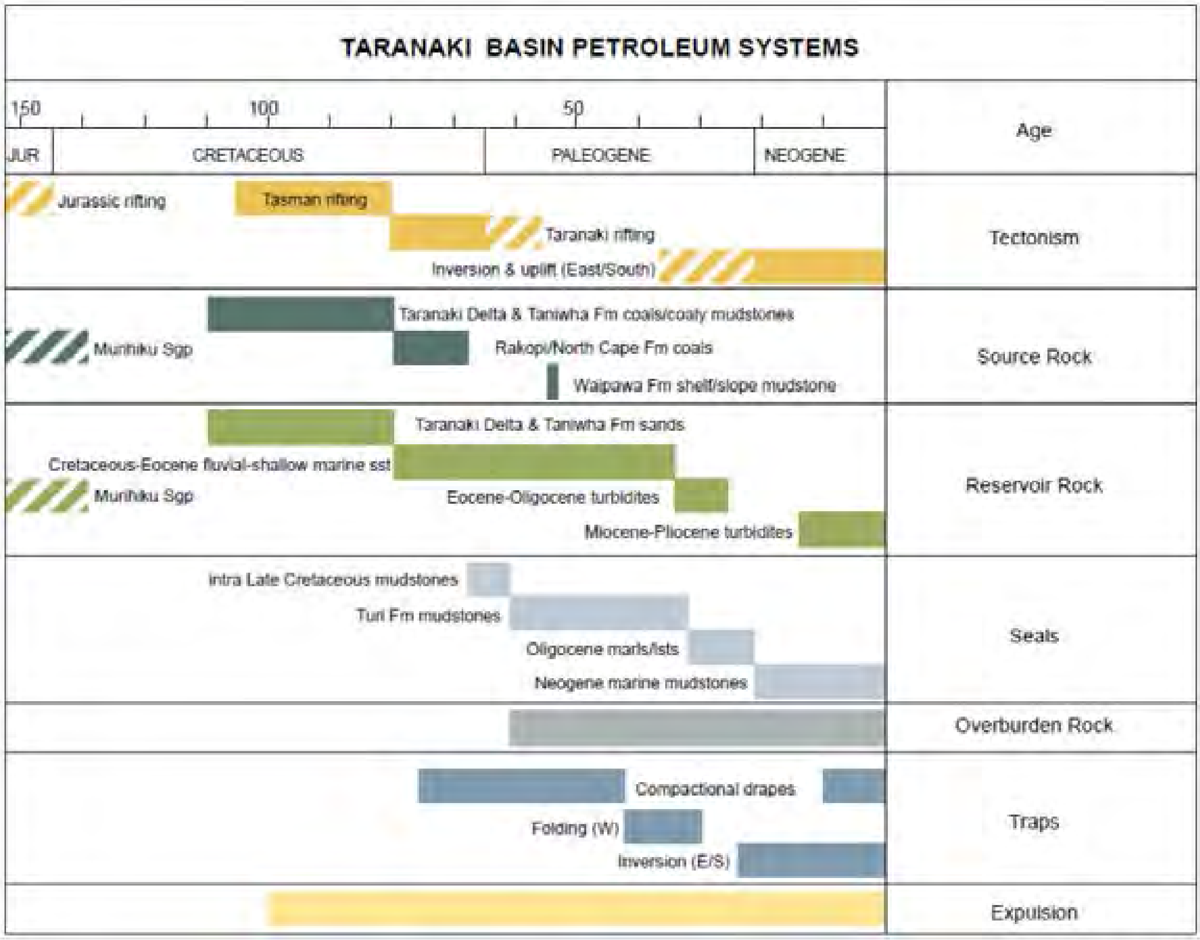


Figure 2-4 Petroleum system elements of the Taranaki basin (New Zealand Petroleum & Minerals, 2014).

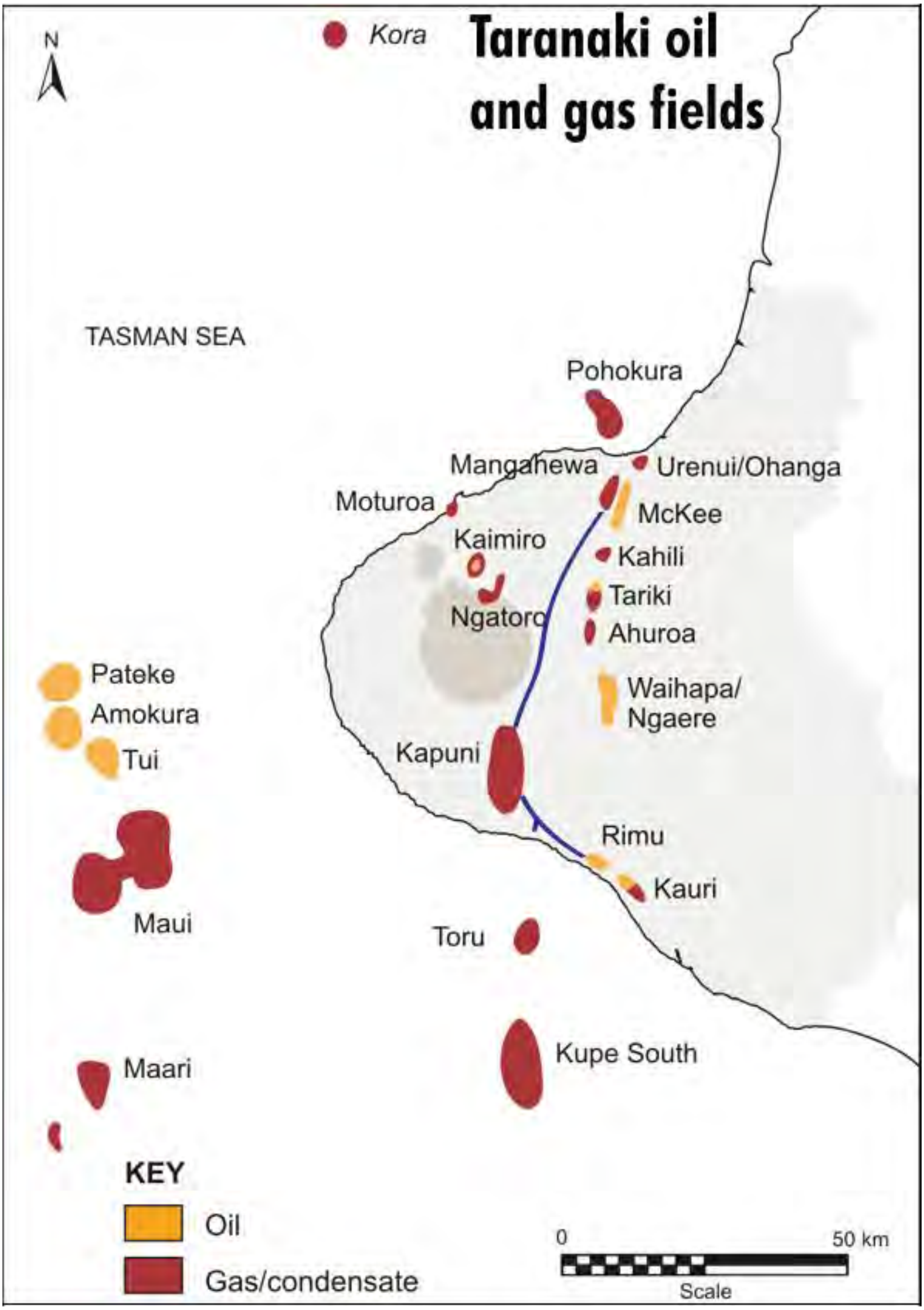


Figure 2-5 Taranaki oil and gas fields (Staff, 2014)

2.4 Pakawau Group

Thrasher (1992) studied the Taranaki basin by focusing on the late-Cretaceous phase. He founded that sediments deposited at this time related to the continental rifting. The rifting associated with an extension of the Caledonia basin and opening of the Tasman Sea. Sediments accumulated in plenty of small en-echelon basins resulted from the divergent plate boundary. The paleogeography which identified by log and biodtratigraphy presented in Figure2-6.

Pakawau group is a rock unit that dominated Taranaki basin in the Late Cretaceous during syn-rift period (Thrasher, 1992). This formation distributed across the south and central of Taranaki basin. It overlied Paleozoic to Mesozoic metasedimentary and plutonic basement rocks (Bishop, 1971; Thrasher, 1992) and it was overlain by Cenozoic marine sediment in the Mao group and terrestrial sediment in the Kapuni Group (Thrasher, 1992). The Pakawau group distribution is about 500 m to 4.2 km thick according to depositional location (King and Thrasher, 1996). It can be divided into two formation: the Rakopi Formation and North Cape Formation.

2.4.1 Rakopi Formation

The Rakopi Formation was accumulated since 80 Ma related to the initiation of the basin. From it was up to 3000 m thick and presented in small fault-controlled basins (Thrasher, 1992).

Major sediment of the Rakopi Formation is terrestrial coal measures (King and Thrasher, 1996). The basal part of this formation is conglomerates in the Otimataura Member (Bishop, 1971; King and Thrasher, 1996). This member consisted of schist breccia clasts with quartzose matrix conglomerate and thin-bedded coal and mudstone (Carter and Kintanar, 1987). The sediments deposited in fluvial floodplain with marine interfere environment (Browne et al., 2008) at Haumurian, Campanian-Maastrichtian, Late Cretaceous.

According to the depositional environment as mentioned above, the Rakopi Formation is identified by interbedded and heterolithic sections of sandstone, siltstone, coal and conglomerate lithofacies (Browne et al., 2008). High-amplitude gamma ray which gradually decreases upwards is the characteristic of this Formation. Some minor sandstones can be found in this formation presented by a crossover of the density and neutron porosity curves (Roncaglia et al., 2013). Seismically, the Rakopi formation has high amplitude and laterally discontinuity reflection (King and Thrasher, 1996).

2.4.2 North Cape Formation

The North Cape formation was deposited from 72 to 70 Ma in a marine transgressive period. The transgression occurred until 65 Ma giving large marine embankments. After that, the basin was dominated by marine regression at the Paleocene bringing the terrestrial Kapuni group overlie the North Cape Formation. The thickness of this formation is up to 1500 m. (Thrasher, 1992).

The North Cape Formation presented in the embayment area was dominated by shallow marine, shoreline and lower coastal plain depositional facies (Thrasher, 1992) which was deposited at Late Haumurian, Late Maastrichtian, and Late Cretaceous.

The rocks in this formation consisted of light gray to brownish carbonaceous sandy siltstone and silty sandstone with minor coal and conglomerate. Indeed, coaly sediments presented throughout the formation as the Wainui Member (Roncaglia et al., 2013). The marine sediments of the North Cape Formation showing in siltstone and sandstone dominated strata is identified by steady Gamma Ray curve. The sediments also presents a fining upward sequence. Sediments gradually change to shale and mudstone in the Turi Formation (King and Thrasher, 1996). Seismically, the North Cape formation characterized by more chaotic seismic reflection (King and Thrasher, 1996).

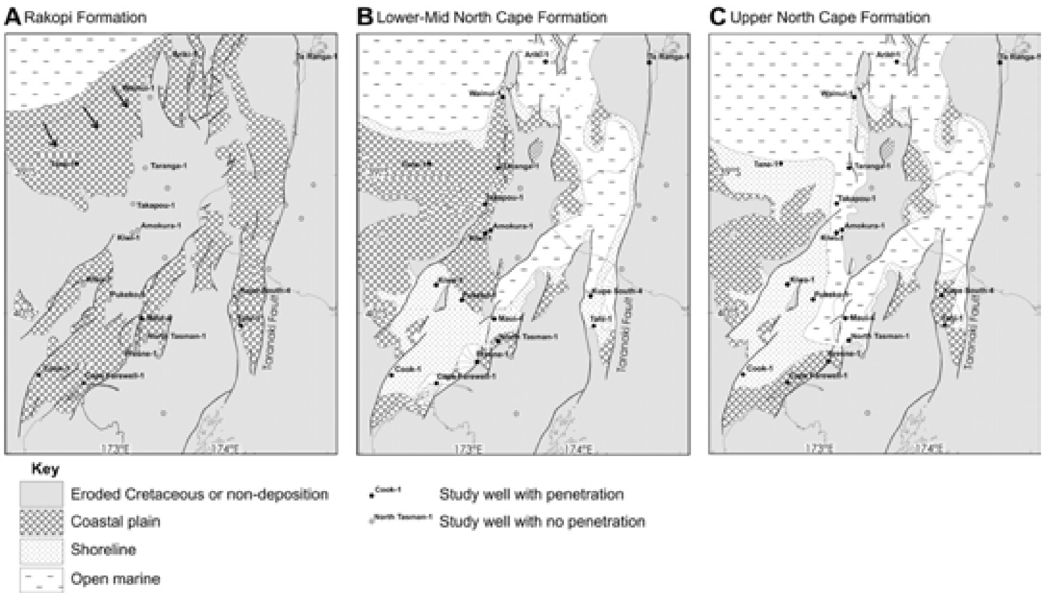


Figure 2-6 Peleogeographic map of the Taranaki basin presented accumulation of A. Rakopi Formation B. Lower-Mid North Cape Formation and C. Upper North Cape Formation. (Modified after King and Thrasher (1996)

Chapter 3
Methodology

3.1 Database

The data used in this study consists of well log data, core data, and seismic data shown in Figure 3-1.

3.1.1 Well log data from 13 wells which drilled deep enough to reach the North Cape Formation are used in this study. These wells are Ariki-1, Amokura-1, Fresnel-1, Kiwa-1, Kiwi-1, Kupe South-4, North Tasman-1, Pukeko-1, Tahi-1, Takapao-1, Tane-1, Taranka-1, and Wainui-1.

3.1.2 Core data from 15 wells, namely: Ariki-1, Amokura-1, Cape Farewell-1, Fresnel-1, Kiwa-1, Kiwi-1, Kupe South-4, Maui-4, North Tasman-1, Pukeko-1, Tahi-1, Takapao-1, Tane-1, Taranka-1, and Wainui-1 were used to support well log interpretation. All data are from well completion reports.

3.1.3 There are 8 2D seismic lines used in this work, namely: DTB01-32, DTB01-35, SUN, RWT1001, RWT1002, RWT1004, MOHOA, OMV07-03, and TL-01

In this work, well log data are used to interpret petrophysical properties of the formation such as shale volume, water resistivity, and porosity and used to make a well correlation and identified depositional facies. Core data provide the cutting analyzed data, i.e., permeability and clay mineral proportion. Lastly, seismic data are used to make a regional correlation and used to analyse the effect of compaction.

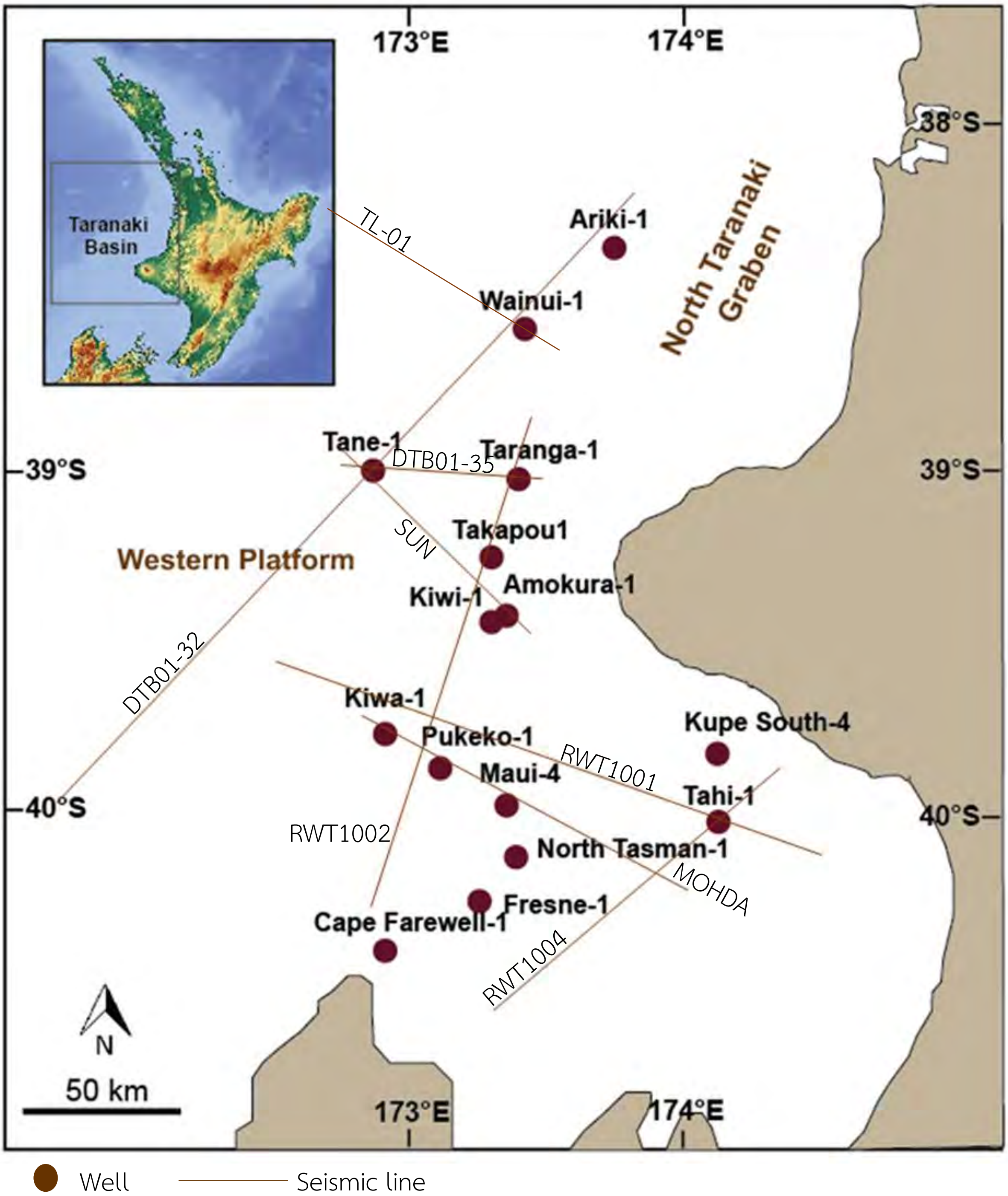


Figure 3-1 The study area and data used in this study.

3.2 Well Log Interpretations

The properties of reservoir are sandstone body geometry, connectivity, heterogeneity, porosity and permeability. The most common properties are porosity and permeability. In this study, these two properties were interpreted by using well log data to describe sandstone in the North Cape Formation.

3.2.1 Basic Log Interpretation

Well logs data represents relationships between depth and physical parameters of subsurface rock strata, i.e., gamma ray, resistivity, bulk density and neutron porosity (Figure 3-2). These parameters are used to document lithology, porosity, water saturation and to identify pay zone in the formation (Schlumberger, 2006).

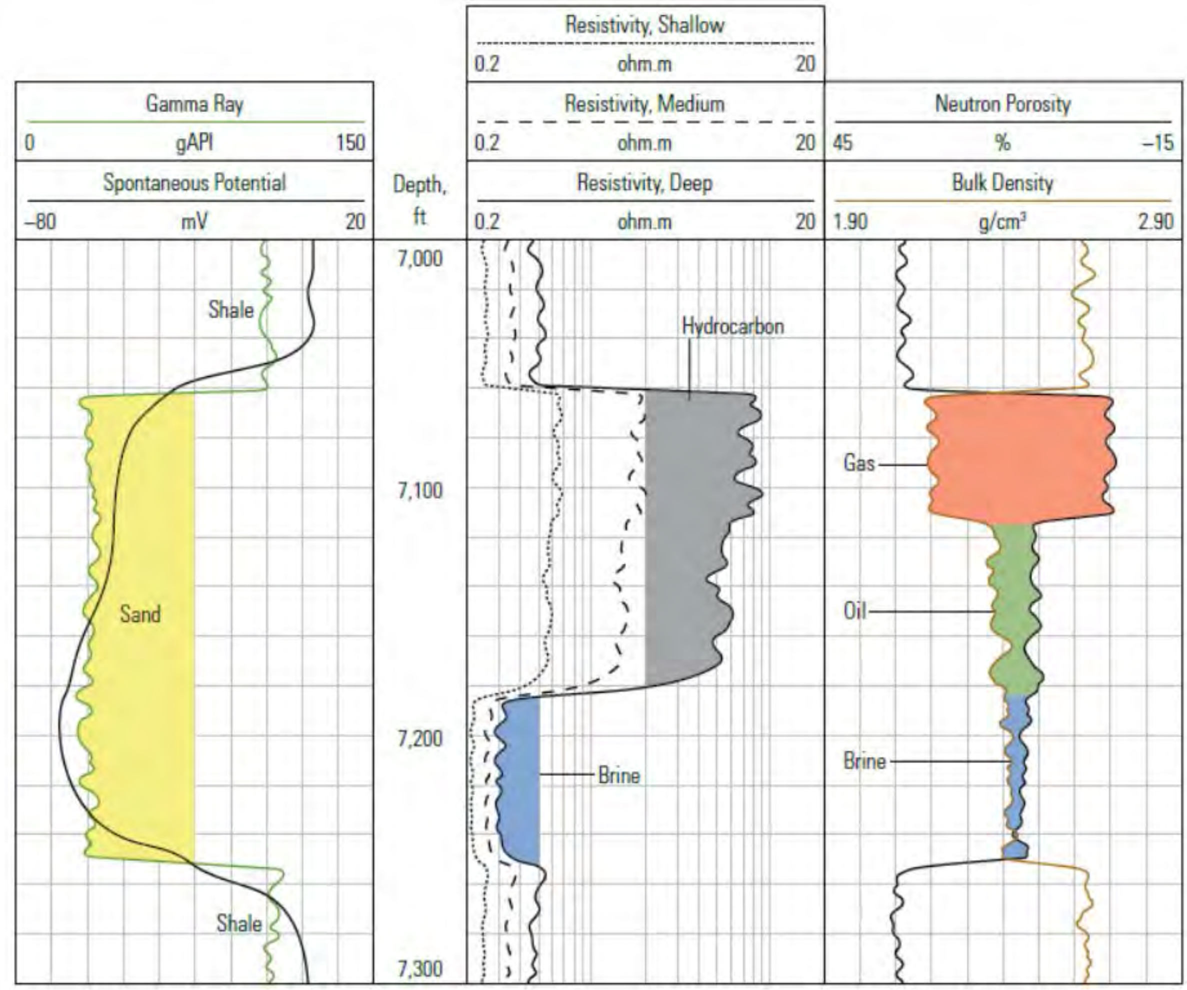


Figure 3-2 Example of well log data interpretation. Gamma ray log is used to identify lithology. Resistivity log represents fluid type. Neutron porosity and bulk density show porosity of the formation and it could be used to identify fluid type (Schlumberger, 2006).

3.2.1.1 Gamma Ray Log

The gamma ray tools measure radioactive elements in the formation. The major radioactive elements in rocks consist of uranium, thorium, and potassium which are abundant in clay minerals and feldspar. Thus, shale and igneous rock containing the high percentage of these minerals have more gamma ray value than fresh sandstone or limestone.

3.2.1.2 Resistivity Log

It is the earliest log used in petroleum exploration. The resistivity is an ability to conduct electric current flow through the formation. It is measured in ohm.m. The conductivity relates with the present of water in the pore space. Although freshwater does not conduct electricity, saline water which has salt ions is an excellent media for electric conductivity. Therefore, if the formations have high water saturation, they are presented in the high conductivity or low resistivity zone. And resistivity value increases if there are oil and gas in the formation.

3.2.1.3 Bulk Density Log

The bulk density comes from the ratio of mass to volume of rocks. The density tools emit gamma rays into the formation. After that, gamma ray hits electrons in rock's atoms, loses some energy and scatters followed Compton Scattering. The gamma ray's remaining energy relates to the number of electron and density of the formation. If there are low energy or more scattering gamma ray coming back to the detection, the formation has high formation density.

3.2.1.4 Neutron Porosity Log

Measuring porosity by using neutron relating to a number of hydrogen atoms. Hydrogen is a significant component of water, gas, and oil trapping in the formation pore space. Therefore, the percentage of hydrogen atoms can be used to identify fluid-filled porosity of the formation. Hydrogen atoms have the same mass as neutrons. When neutron logging tools emit neutrons from a neutron generator, the neutrons hit hydrogen atoms and lose the maximal energy. Then it could not come back to the detector. Therefore, a low proportion of remaining neutrons can indicate the presence of fluid in the formation. The number of neutrons is used to identify neutron porosity.

3.2.2 Well Correlation

Well log data represent physical properties of subsurface rocks which are mainly controlled by lithology, porosity, compaction and fluid filled in the pores. An individual well log data was interpreted regarding to its physical properties that can be used to define some features of the formation. Besides, using log combination can make well correlation more accuracy. Rocks in the same formation have same physical properties and they will be shown in the same log pattern.

Well correlation focuses on a lateral extension of sedimentary strata. In this study, Petrel and Interactive Petrophysics are software that were used for marker picking and well log correlation. The first process is marker picking. Distinct log patterns were picked from each well. Logs that usually used in this process are gamma ray log, resistivity log, density log, and neutron porosity log. The gamma ray log is a primary log that can be used to classify lithology of rock. It can separate sandstone and shale dominated strata. Another log that was used for marker picking is resistivity log. Rocks in different formations usually have different grain components, compaction and fluid effecting resistivity. Therefore, rocks in different formations will be shown in different average resistivity. Neutron-density log which is significant indicated porosity and fluid types in the formation are also useful for well correlation. Each rocks has its own density range, there each formation which different dominated rocks are shown in different average density.

Some strata which have vivid characteristics are used to be key beds for well correlation. For example, limestone beds have low gamma ray due to the low proportion of the radioactive elements. They also show high bulk density and low neutron porosity. This unique log characteristics are used for picking the limestone bed in the well log data. Another key bed is coal and carbonaceous shale. Coal bearing beds, which have low radioactive element, normally have low gamma ray value, while carbonaceous shale has been shown in high gamma ray value like the typical shale. However, these rocks show the same neutron and density log characteristic. Because of organic matter existenced in coal and carbonaceous shale beds, the density of rocks decrease significantly. These characteristics are used to interpreted source rock beds.

3.2.3 Depositional Environment Analysis

Gamma ray log is the most common log using for this depositional environment interpretation because it responses rock types and proportion of sand and clay contents (Kessler and Sachs, 1995). Commonly, Gamma Ray log is classified into five patterns that related to depositional environment (Cant, 1992) (Figure 3-3).

3.2.3.1 Cylindrical Shape

This shape distinguishes with that sharp top and bottom boundary. It represents the homogeneous lithology in the formation. Cant (1992) characterized cylindrical log shape as sediment deposit in aeolian, beach, fluvial channel, and submarine canyon environment. Moreover, a cylindrical shape can be divided into a left boxcar and light boxcar. A Left boxcar with low gamma ray could be interpreted as a channel sandstone, while a right boxcar with high gamma ray could be identified as a muddy tidal flat (Siddiqui et al., 2013)

3.2.3.2 Funnel Shape

The funnel shape is characterized by upward decreasing of gamma ray response or coarsening upward sequence. There is a sharp contact at the top of the section. This log shape could be interpret as regressive barrier bar, prograding submarine fans, prograding deltas, and crevasse splays (Selly, 1978). It could also be interpreted as river mouth bar, delta front, and shoreface. Moreover, this shape might indicate changing of clastic rock to carbonate rock or changing from the anoxic to the oxic environment.

3.2.3.3 Bell Shape

The bell shape is characterized by upward increasing of gamma ray or fining upward sequence. There is a sharp contact at the bottom of the section. The bell shape pattern is usually indicated braided streams, meandering stream, tidal point bar, tidal channel or fluvio-deltaic channel in a channel-dominated environment. In a shallow marine environment, it could be interpreted as transgressive sand or shoreline shelf system. This shape also indicated deep marine channel or turbidity sequence.

3.2.3.4 Symmetric Shape

It shows a gradually coarsening upward sequence in the bottom of the succession. When it reaches the maximum value, it begins an opposite trend, a fining upward sequence. This shape usually represents progradation and retrogradation of clastic sediments and might be seen in the shallow marine environment which is dominated by sea level change.

3.3.1.5 Irregular Shape

This log pattern shows the fluctuation of gamma ray. The gamma ray changes abruptly. This shape represents laminated beds of various rock tpes in succession. It might describe as a fluvial floodplain, storm-dominated shelf, tidal flat, and distal deep-marine slope.

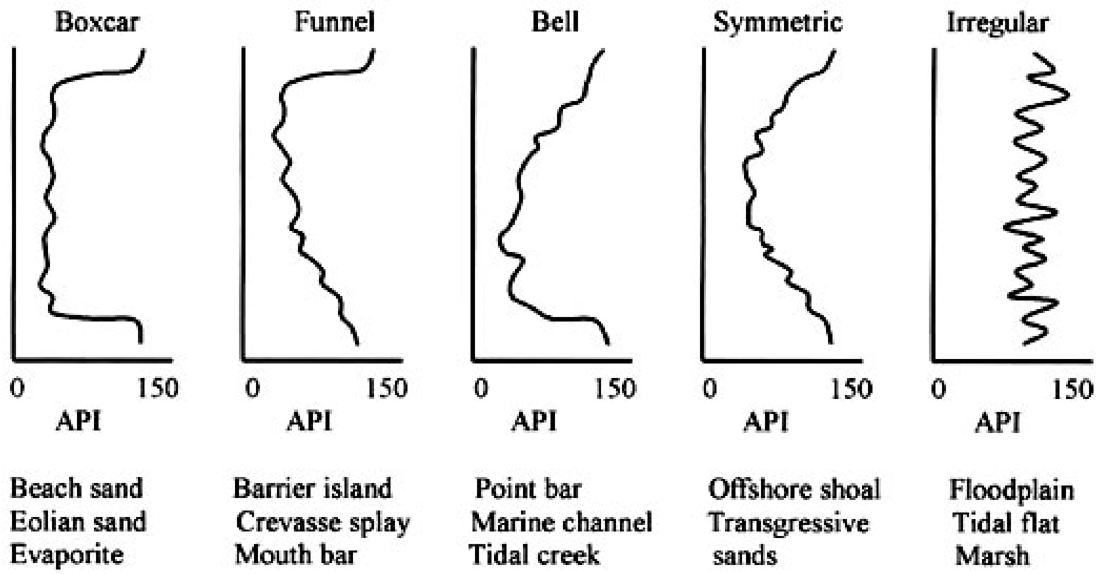


Figure 3-3 Depositional environment classified by Gamma Ray log pattern (Cant, 1992).

3.3 Reservoir Property Analysis

3.3.1 Porosity Analysis

There are plenty ways to determine formation porosity such as calculation by using measurements of neutron porosity log, density log, and sonic log, although porosity from these logs are just an overall porosity and not practical for the real porosity identification. Calculation by using only one log relies on specific properties of matrix. For example, the porosity from density log depends on the density of matrix of the rocks (equation 1 and 2). Therefore, in some formations which hve an unknown matrix or consists of at least two matrixes, using only one log is not enough. In these case, cross plot which is a porosity interpretation technique that use 2 properties together is used to identify porosity. There are various types of crossplot such as neutron-density crossplot, sonic-density crossplot, and neutron-sonic crossplot. The most common cross plot is the neutron-density cross plot.

3.3.1.1 Porosity from Density Log

For a non-fluid formation, density depends on a matrix or rock type, ρ_{ma}. If the formation has a porosity, ø, and fluid with density ρ_f, the formation bulk density ρ_b will be:

$$\rho_b = \varnothing\,\rho_f + (1-\varnothing)\,\rho_{ma} \qquad \text{(Eq. 3-1)}$$

From this equation, it can be converted for finding a formation porosity as this following equation:

$$\varnothing = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f} \qquad \text{(Eq. 3-2)}$$

3.3.1.2 Porosity from Neutron Log

The apparent porosity can be determine from a neutron porosity log directly. However porosity from this technique is uncertain by the effects of lithology, clay content and fluids in the formation. It is used just for a quicklook or as a basic support information for density log and sonic log.

3.3.1.2 Neutron-Density Crossplot

Neutron-density crossplot is the most common graph for identifying porosity. The graph consists of bulk density in the Y-axis and neutron porosity in the X-axis. Inside the plotting area, there are separations of the quartz, limestone and dolomite lines related to matrix type (Figure 3-4). Although sandstone matrix consists of both quartz and calcite, porosity in crossplot is still presented in the similar area. This technique can decrease an error of matrix picking in finding a porosity with only density or sonic log.

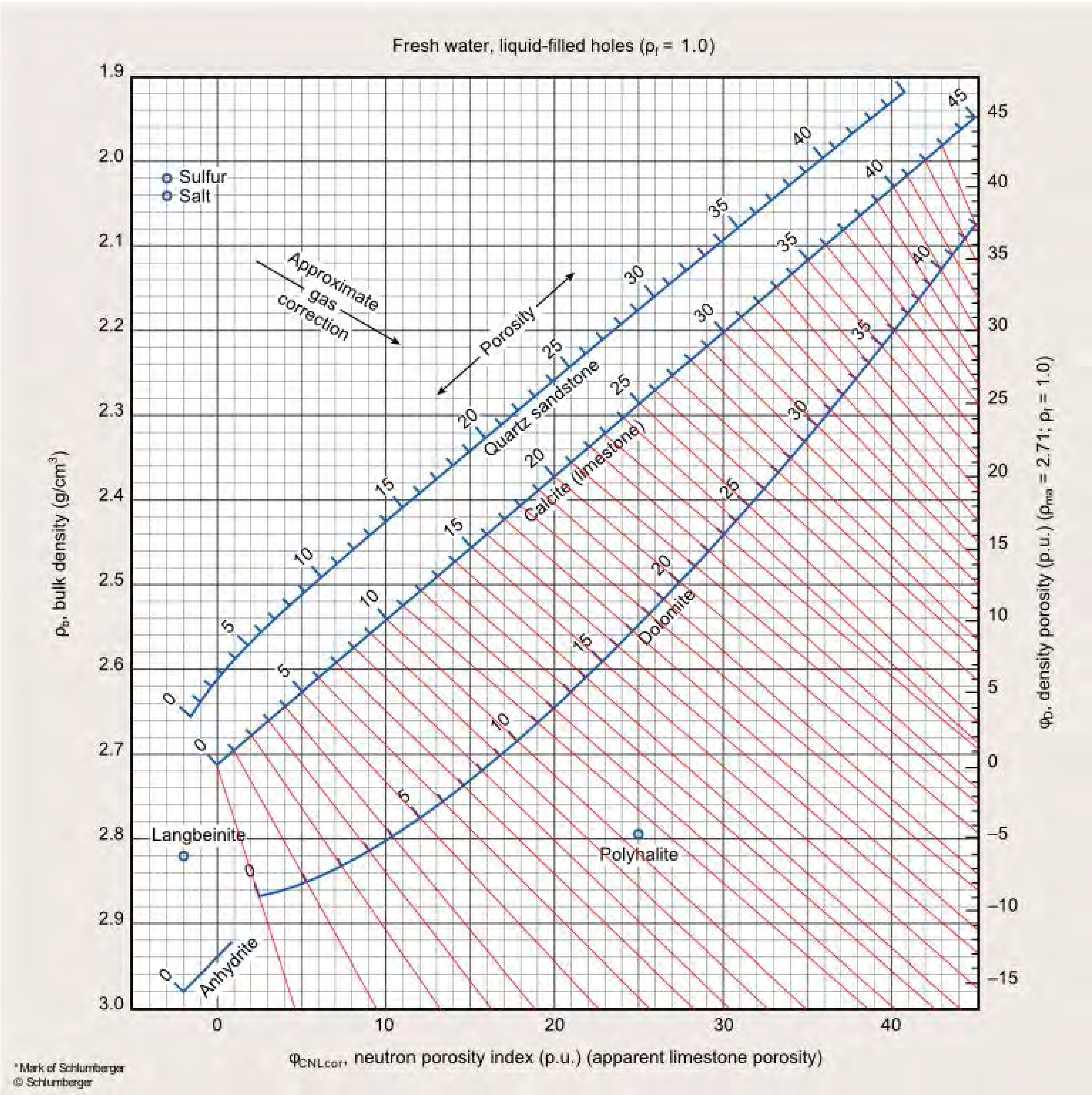


Figure 3-4 neutron-density crossplot standard graph. The x-axis is neutron porosity and y-axis is bulk density which referred to well log data. The porosity is indicated followed standard porosity lines of quartz sandstone, calcite and dolomite.

3.3.2 Permeability Analysis

Permeability is a measure of the capability of a formation to permits fluid flow. Normally, permeability is evaluated from rock samples analysised by using a Darcy's Law. The certain permeability cannot derived from only well log data. However, the most noticeable factor controlling permeability is porosity which can be defined by well log data as mentioned above. Therefore, we can use porosity from log to define permeability.

The permeability and porosity from rock samples analysis are used to find the relationship between these two properties by using the porosity-permeability or poroperm crossplot. It is the plot between permeability in logarithm scale and porosity and it results in a trend of relationship between porosity and permeability (Figure 3-5). The equation of the trend line is used for permeability calculation for areas that do not have permeability data reported from rock sample analysis. The limitation of this poroperm cross plot technique is homogeneity of rocks in the formation. If the graph is plot from formation that has various rock types, the result might be a high sampling distributions and the equation might has low degree of reliability.

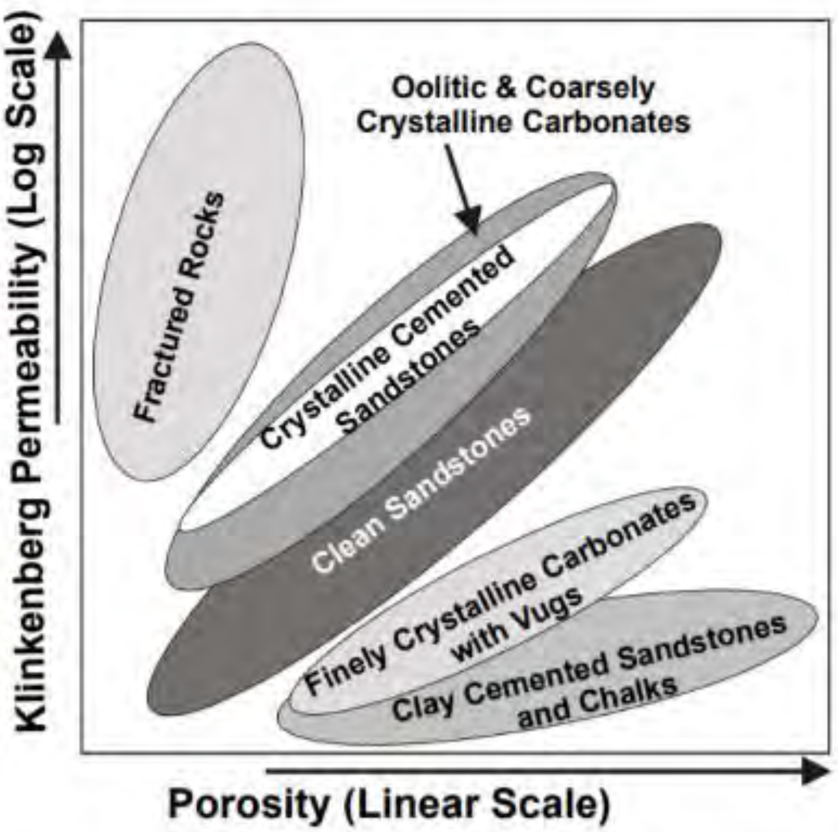


Figure 3-5 Poroperm crossplot showing the effect of rock types in a trend line. (Glover, 2015)

3.4 Burial History analysis

One-dimensional modeling of burial history is generated for being support data. The model was used to analyse the deposition of sediments in the Taranaki basin over 75 million years. It was also used to explain the effect of overburden sediments on the reservoir properties of the North Cape Formation succession.

PetroMod was used to create the burial history model. Lithology, thickness and depositional age of each formation were input in the software. There are three main boundary conditions for model simulation: paleowater depth, sediment-water interface temperature, and heat flow. Paleowater depth can be derived from biostratigraphy, while heat flow relates to tectonic events. Sediment-water interface temperature could be auto-generated by the software. With these data, the software could simulate the model showing the deposited of sediment throughout the time.

3.5 Seismic Interpretation

Seismic data were used in this study for defining the sediment succession in the regional scale. Because there is no 3D seismic survey covering the study area, only 2D seismic survey lines were used for interpretation in this study. The interpretation can be divided into two main processes: structural and stratigraphic interpretation.

The main structural feature in seismic sections is faults. Faults were indicated by discontinuous seismic reflection. Fault interpretation was based on the idea of tectonic setting in the basin. Because Taranaki basin was controlled by rifting tectonic setting, the most common fault in this area is normal faults.

Stratigraphic interpretation is an identification of top formation horizons. The key marker horizons come from well log data. Because the markers have already presented in the given data, there is no need to generate a synthetic seismic or make a seismic well tie in this study. By using well log data, key markers of each formation were indicated in the seismic section, and the markers were used to interpret horizons of each formation.

Chapter 4
Results and Interpretation

4.1 Log Interpretation

Well log data were used for petrophysical analysis to estimate rock properties such as lithology, porosity, permeability, and fluid saturation. In this study, the major logs that were mainly used for well log interpretation are gamma-ray log, resistivity log, neutron porosity log and bulk density log.

4.1.1 Marker Picking

Sediments or rocks deposited in different events exhibit in the various lithology and properties, showing in different log patterns in well log data. Therefore, we can use log characteristic to classify rock formations and pick well tops of geological formation. We called this process a marker picking. Moreover identification well top makes us know the regional stratigraphy of the study area.

In this study, five main rock successions are identified based on the unique log pattern: Unit A, Unit B, Unit C, Unit D, and Unit E. Looking at the well log data of Takapou-1 well (Figure 4-1), log characteristics of each unit are described as following and summarized in Table 4-1.

In unit A, GR (gamma ray) value shifts to the right side. In the other words, this unit has high GR value. It could be interpreted that rocks of this formation have high shale proportion. Resistivity shifts to the right side which means that there is a hydrocarbon existed in the

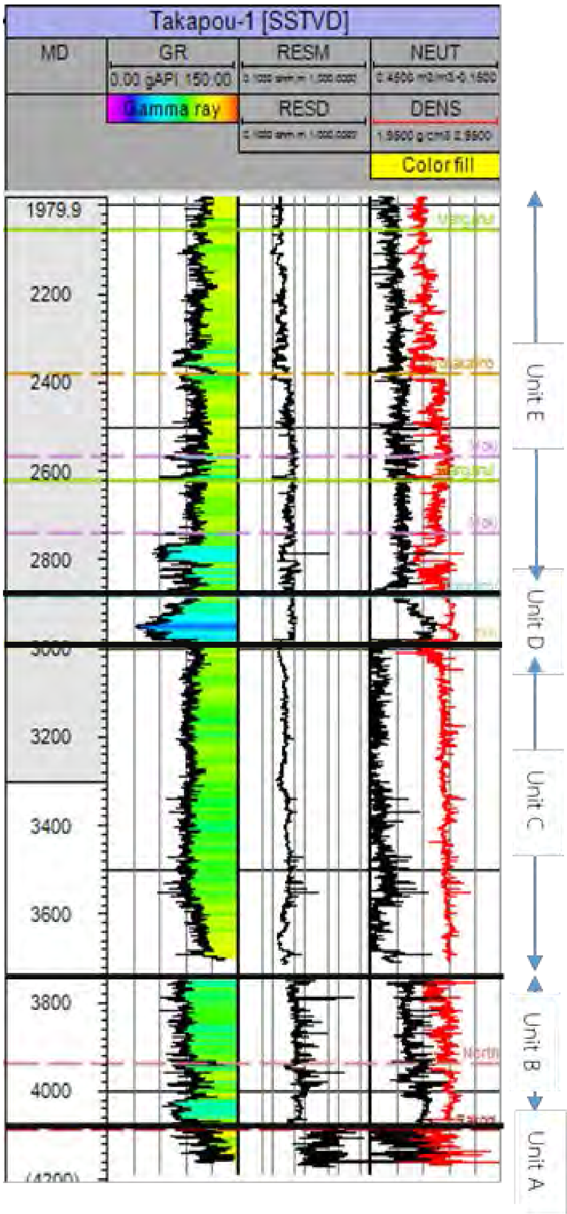


Figure 4-1 Log characteristic and marker picking of well Takapou-1

formation or the rock might be very tight resulting that brine water could not fill in the pores in the formation. Neutron and density shift to the left side or low density and high neutron porosity. These properties indicate that this formation is probably a carbonaceous shale which could be a source rock of the basin. Comparing with King and Tresher (1996), this formation could be correlated to the Rakopi Formation.

In unit B, GR has a serrated log pattern and shifts to the left side. It could be interpreted that sediments deposited in the unit have more sand content compared with the previous strata. Average resistivity of this formation is lower than Unit A. It might be interpreted that rocks in this layer are looser than unit A. There are some peaks of resistivity in the formation which may related to the existence of hydrocarbon. Moreover, neutron porosity log and density log come closer and crossover in some depth. From all these log characters, this succession might be dominated with sandstone and could be correlated with the North Cape Formation.

Unit C has high GR value and could be referred to high clay mineral content. The low resistivity might relate to high water proportion in the formation. Density and neutron porosity log significantly separated. All these log characteristics could be interpreted that the rock dominating this formation is shale and it could be correlated to the Tui Formation.

Unit D is the key bed for this marker picking. This unit is apparent with very low gamma ray, high resistivity, and right shifting of the neutron-density log. It is identified as carbonate beds in Tikoranki Formation. This layer also deposited throughout the basin. Thus, it is suitable to be a key bed for doing the regional correlation.

In Unit E, GR shifts to the right side and serrated which related to high clay mineral content. Neutron porosity and density separate with each other. It could be analyzed that this Unit is related to shale in the Manganui formation. In some section, low GR is presented. Density and neutron porosity come closer. It is probable the Moki fan sandstone, sediments that prograded from the continent.

This study emphasizes deposition and properties of rocks in the North Cape formation. Therefore, depth of this formation is adjusted from the stratigraphy in well completion report and previous study of Higgs (2010) by using log characteristic as described above and the result presents in the Table 4-2.

Table 4-1 Log characteristics of rock units in deepwater Taranaki basin

Unit	Gamma Ray	Resistivity	Neutron-Density	Correlation
A	High	Very high	Shift to the left side	Rakopi Formation
B	Low	Fluctuated	Come closer and crossover	North Cape Formation
C	High	Steady low	Significantly separate	Turi Formation
D	Low	Steady high	Shift to the right side	Tikoranki Formation
E	High	fluctuated	Separate	Manganui Formation

Table 4-2 Depth of the North Cape Formation

Well	Depth (m)	Well	Depth (m)
Amokura-1	3680-3960	North Tasman-1	2005-2430
Ariki-1	4319-4762	Takapou-1	3935-4095
Fresnel-1	1230-1325	Tahi-1	1167-1391
Kiwa-1	3688-3839	Tane-1	3445-3995
Kiwi-1	4030-4168	Taranga-1	4000-4179
Kupe South-4	3660-3795	Wainui-1	3710-3835

4.1.2 Well Correlation

After picking the top of each unit in each well, top formations are correlated to interpret regional stratigraphy of the study area.

(Figure 4-2) The average trends of gamma ray (GR) are not similar in an individual well. Ariki-1 and Wainui 1 located in the north of the basin have low GR trend. The average GR value of these wells is about 30-50 GAPI. While Tane-1 and Taranka-1 located in the center of the study area have higher GR value than Ariki-1 and Wainui-1 wells, having approximately 60 GAPI. Lastly, Takapou-1 and Amokura-1 wells located the most southern part of the basin among these six wells have the highest GR value at 90 GAPI.

Even though each well has different GR trend, the unique characteristics of each formation still represent in almost every wells. Therefore, we can use this feature for doing well correlation. The result is demonstrated in Figure 4-2.

The first stage of basin formation, terrestrial shale, carbonaceous shale and coal of the Rakopi Formation (Unit A) deposited almost throughout the basin. It is presented at the bottom of each well except some located in high regions. After that, sea level increased in a marine transgressive period due to break up of New Zealand from the Gondwanaland supercontinent. As a result, the shallow marine sediment in the North Cape Formation (Unit B) deposited in the basin. The sea level continue increased, and deep marine shale of the Turi Formation (Unit C) deposits over the North Cape Formation. The short regional inversion in Eocene brought an accumulation of limestone in the Tikoranki Formation (Unit D). Then it had become a regressive period because of subduction between Australian plate and Pacific plate. A deep-marine shale in the Manganui Formation (Unit E) was dominated the basin. Subduction caused fan sediments that prograded from continental area to the deepwater area and represented in the Moki Formation. It also activated igneous process and caused deposition of volcaniclastic rocks in Mohakatino Formation. The last sediment covered the basin is the Giant Forset Formation, sediments prograded from the rapid erosion of the continental shelf.

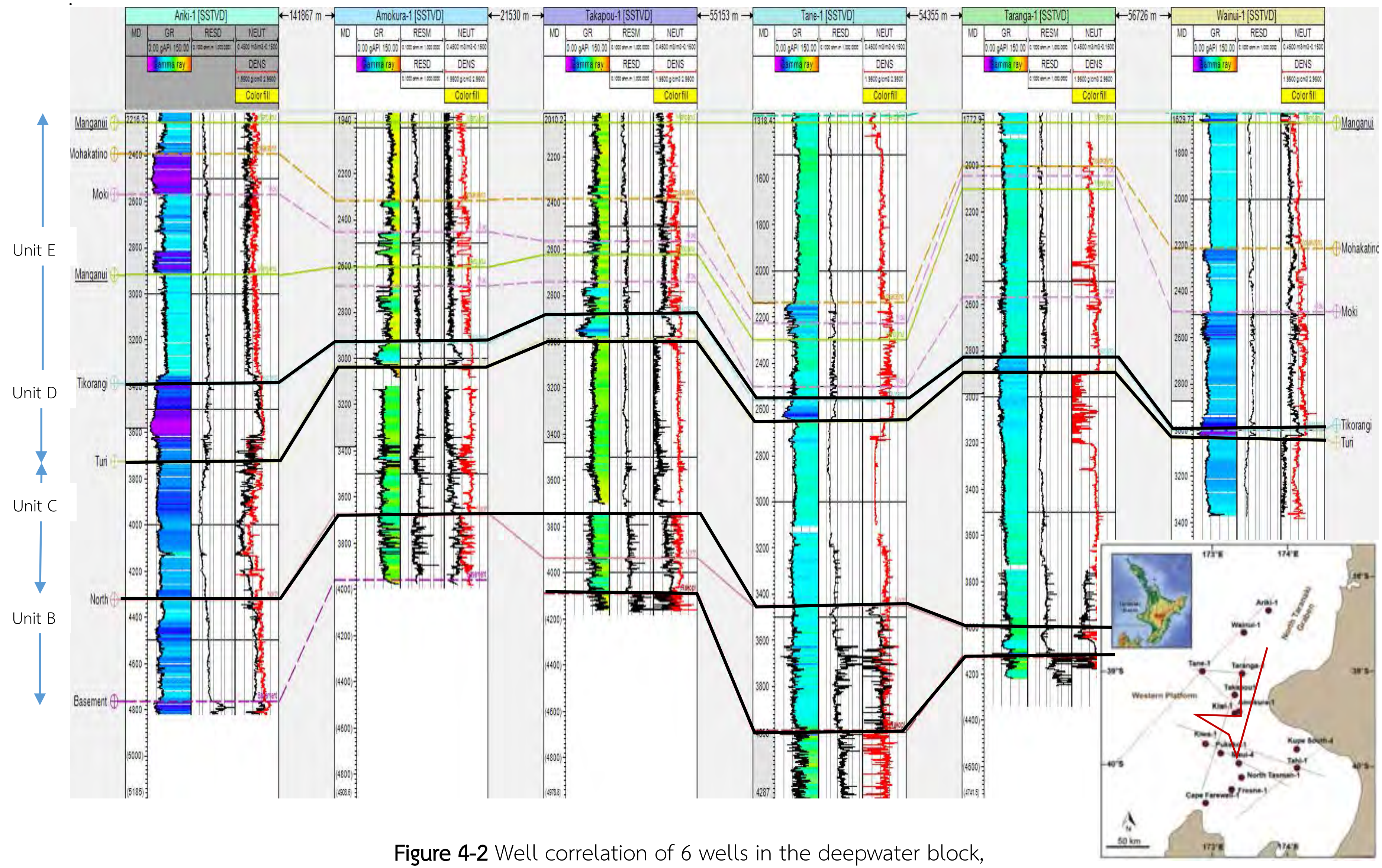


Figure 4-2 Well correlation of 6 wells in the deepwater block, Taranaki basin showing regional correlation and top formations.

4.1.3 Depositional Environment

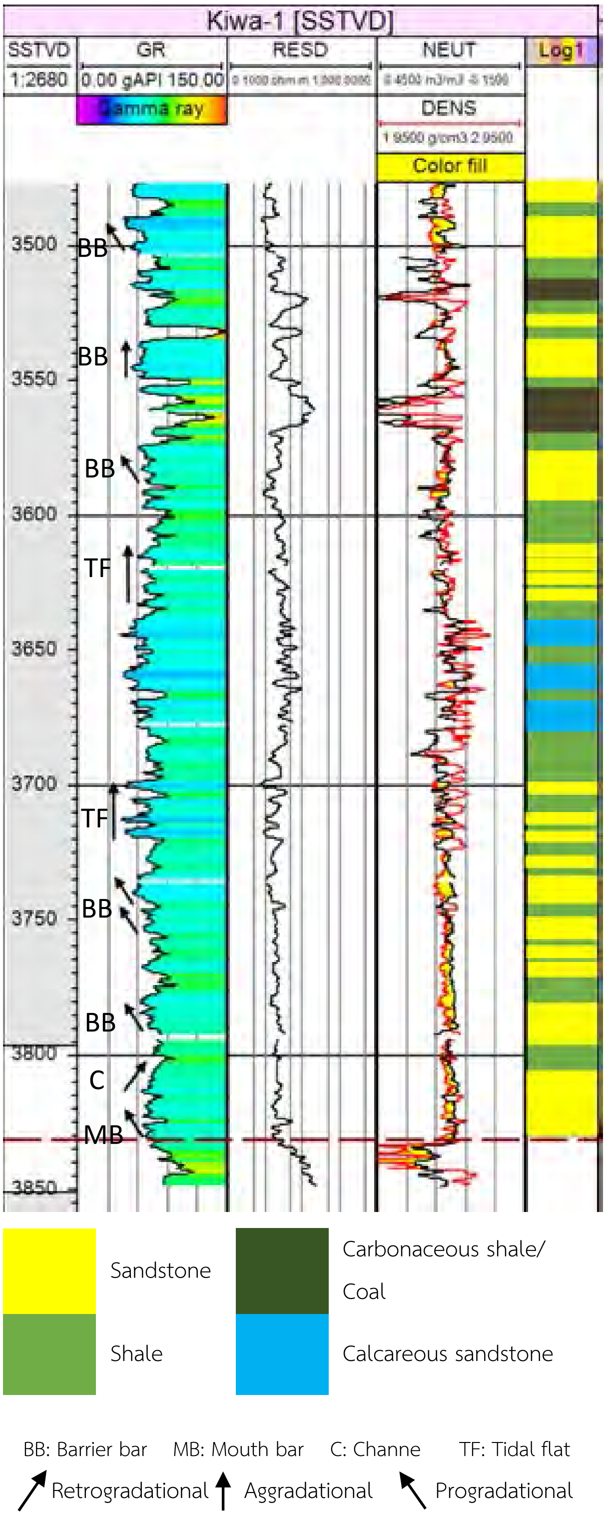


Figure 4-3 Lithology and depositional environment interpretation of the North Cape Formation in Kiwa-1

From the pattern of gamma ray log, resistivity log, and neutron-density log, it could be interpreted that shale and sandstone are dominated in the North Cape formation. Carbonaceous shale and calcareous sandstone could be found as minor proportions.

For example, in Kiwa-1 well shown in Figure 4-3, the percentage of sandstone is almost 50 % of rocks in the North Cape Formation, the rest is shale. Deposition of these rocks including sandstone, shale, calcareous sandstone and carbonaceous shale could represent the shallow marine environment.

The gamma ray log pattern is used to interpret more specific depositional environment. Interpretation focused on sandstone zones. The most common gamma ray log shape in this well is a funnel shape and serrated shape. The funnel shape might represent a shoreface mouth bar, or barrier bar sandstone in a shallow marine environment. Whereas, interbedded of sandstone and shale in serrated shape could be determined as a tidal flat. The symmetrical log shape at the bottom of the well relates with regressive and transgressive delta.

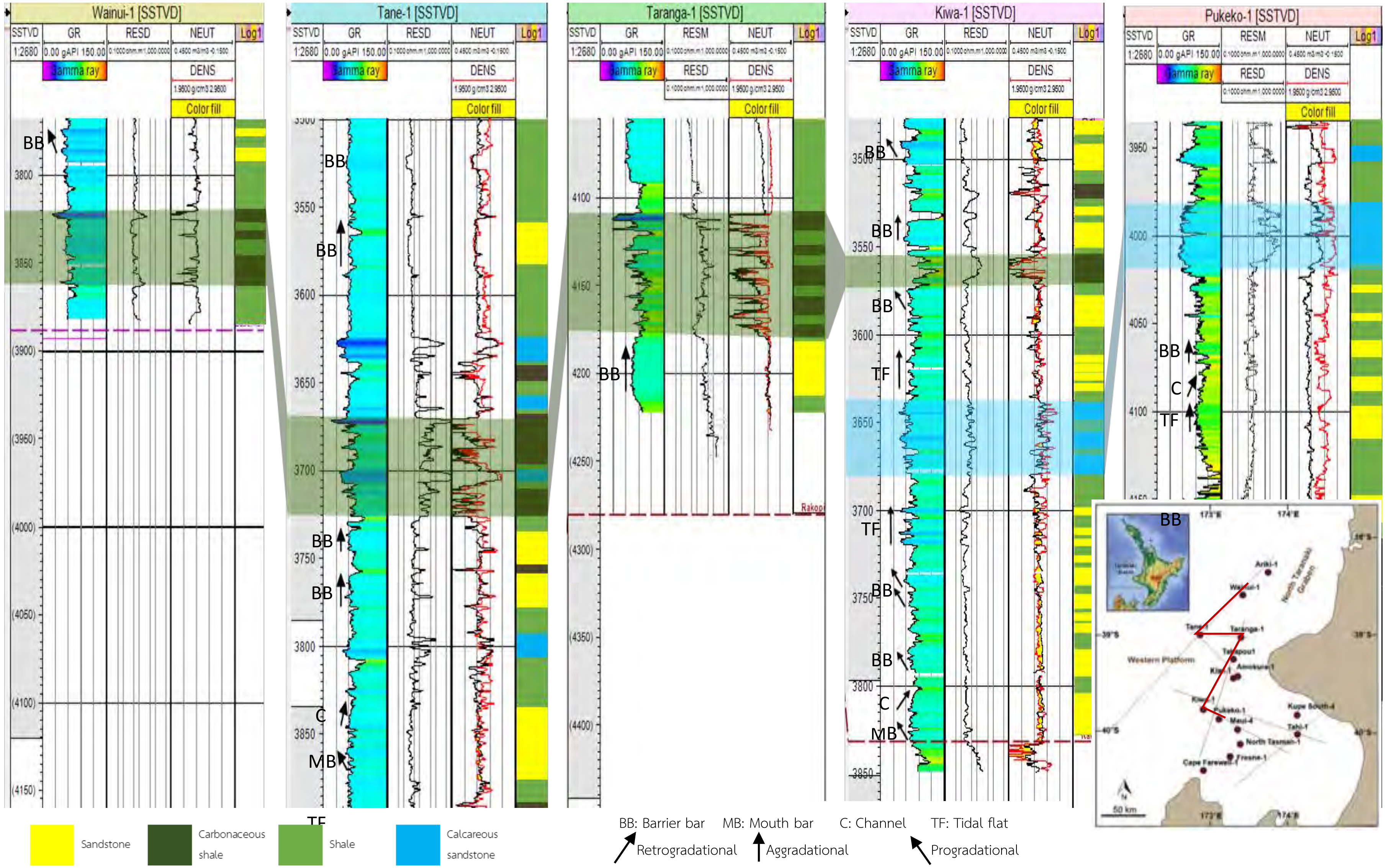


Figure 4-4 Well correlation of the North Cape Formation, showing lithology and depositional environment

4.2 Reservoir Properties

4.2.1 Porosity

Because of the complex lithology of the North Cape Formation, neutron-density cross plot technoque is used to identify porosity of sandstone in the Formation.

First, neutron and density values are classified with depth to see the overall trend of the North Cape Formation porosity compared with other rock formations (Figure 4-5(a)). The graph shows the zone of the North Cape formation which deposited in the deepest layer of Ariki-1 well, which represents in reddish purple scattering points.

From Figure 4-5(b), neutron and density were plotted with gamma ray. It could be classified that dark blue scatters, which have low gamma ray, are refer to limestone or carbonate rock layer because of high density and low porosity. Whereas, sandstone is represented in a blue color with medium gamma ray and about 20 percent porosity. Shale is a rock that has the highest gamma ray value and the lowest bulk density and it is presented in pink scattering points.

This method is used to determine the porosity of sandstone in The North Cape Formation of each well, and the results are demonstrated in Figure 4-6.

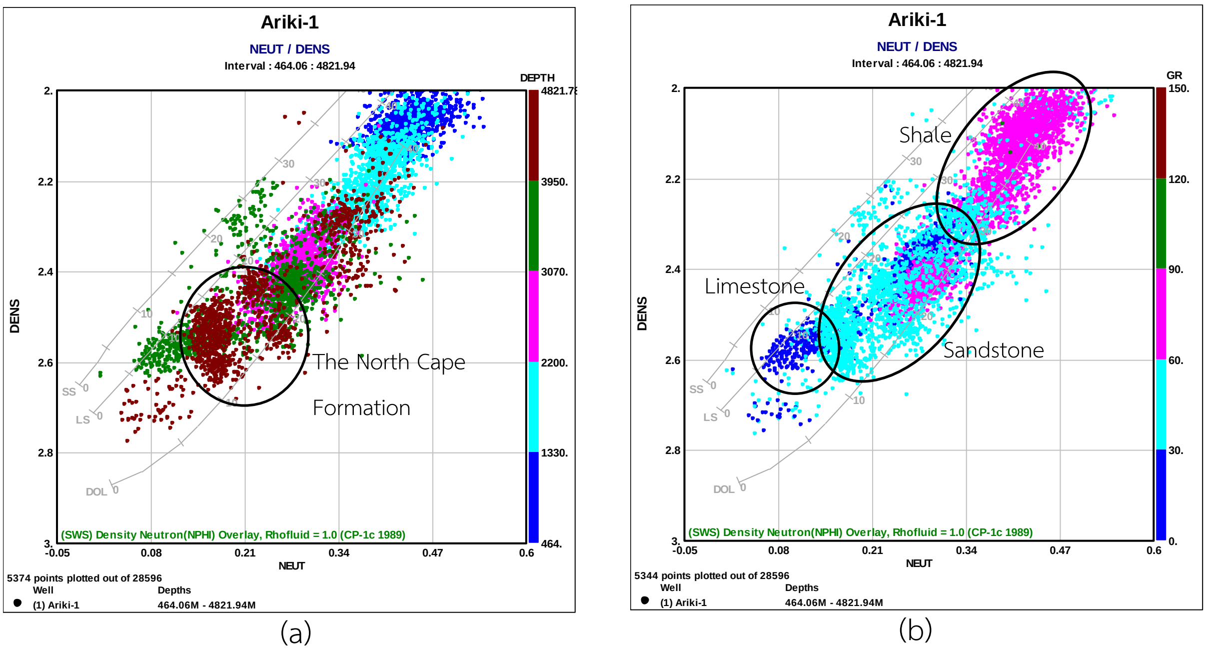


Figure 4-5 (a) Neutron-Density crossplot from Ariki-1 classified by depth showing the porosity zone of the North Cape Formation

(b) Neutron-Density crossplot from Ariki-1 classified by gamma ray showing the zones of different rock types

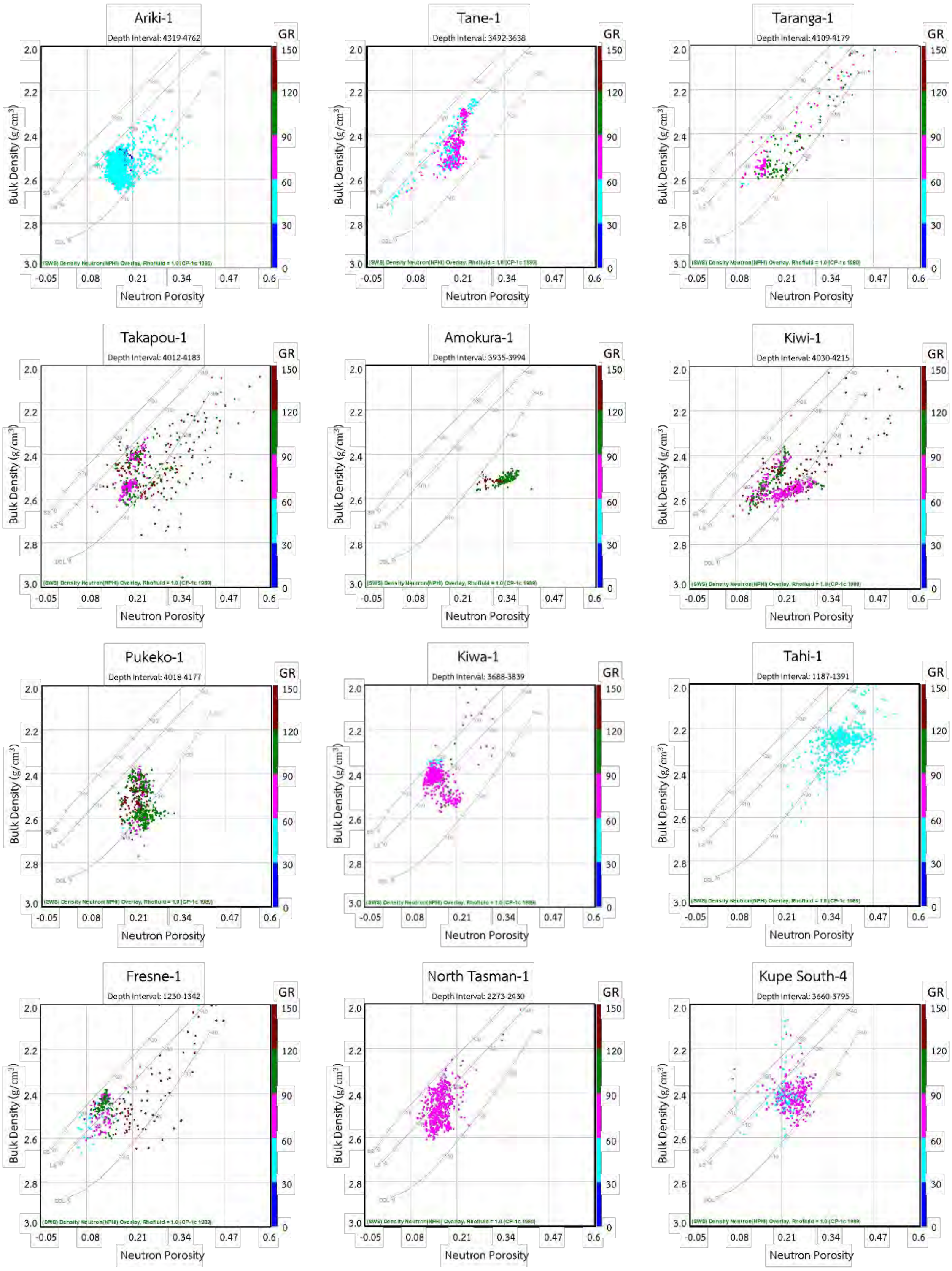


Figure 4-6 Neutron-Density crossplot of wells used in this study. The scattering points come from depth interval of the North Cape Formation. The graphs are used to estimate porosity of sandstone in the formation by comparing with standard lines. Color refer to ranges of gamma ray which indicates rock types.

Table 4-3 Porosity of sandstone in the North Cape Formation

Well	Porosity (%)
Amokura-1	18-20
Ariki-1	10-17
Fresnel-1	10-17
Kiwa-1	14-20
Kiwi-1	13-21
Kupe South-4	18-23

Well	Porosity (%)
North Tasman-1	11-20
Pukeko-1	13-22
Takapou-1	12-20
Tahi-1	15-20
Tane-1	15-27
Taranga-1	12-18

From the above table, the porosity of sandstone in the North Cape Formation is approximately 10-27%. Amokura-1 and Tane-1 wells have highest porosity which is about 15-27%. They are followed by Tahi-1, Kupe South-4, Takapou-1, Pukeko-1, Kiwi-1, Kiwa-1 and North Tasman-1 respectively. Whereas, wells that have lowest porosity are Taranga-1, Ariki-1 and Fresne -1 which 10-17%.

4.2.2 Permeability

In general, permeability mainly comes from rock samples analysis which not shown in well log data. Therefore, porosity and permeability from core data analysis from well completion reports is used to find the relationship equation between porosity and permeability. Cook-1, Pukeko-1, Tahi-1, and Tane-1 wells, which have a permeability analysis shown in the reports are used for being a reference in the poroperm crossplot.

(Figure 4-7) Because of a high sampling distribution, the data are divided into two groups with different trend lines. The group of sandstone with low permeability has a poroperm trend line with this following equation:

$$\text{Permeability} = 0.008e^{0.3193\ (\text{porosity})} \qquad \text{Eq. 4-1}$$

Whereas, the group of sandstone with high permeability has a poroperm trend line with this following equation:

$$\text{Permeability} = 0.3728e^{07138\ (\text{porosity})} \qquad \text{Eq. 4-2}$$

These equation were used for permeability calculation by input porosity from neutron-density crossplot. The results are presented in Table 4-4.

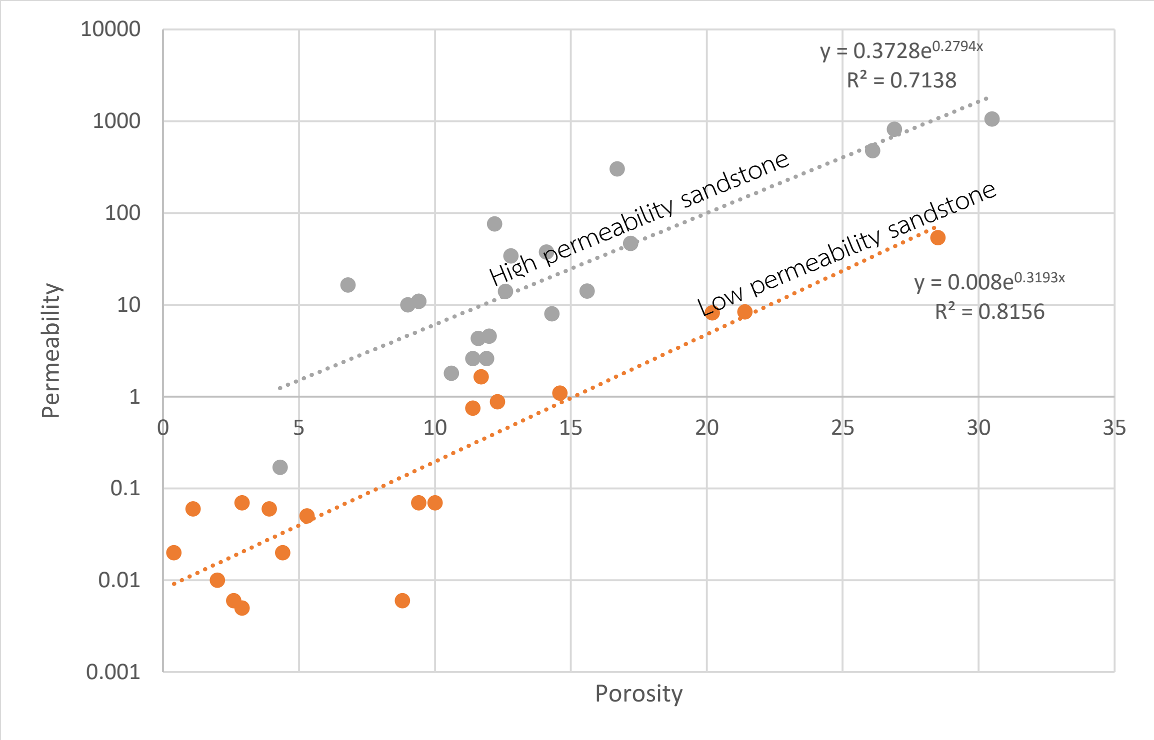


Figure 4-7 Porosity-permeability crossplot from Cook-1, Pukeko-1, Tahi-1, and Tane-1 wells showing relationship the relationship equation between these two properties

Table 4-4 Permeability calculated from porosity by equation 4-1 and 4-2

Well	Porosity	Permeability (Eq. 4-1)	Permeability (Eq. 4-2)
Amokura-1	18-26	2.51-32.25	56.94-532.56
Ariki-1	10-17	0.19-1.82	6.09-43.08
Fresnel-1	10-17	0.19-1.82	6.09-43.08
Kiwa-1	14-20	0.70-4.75	18.63-99.61
Kiwi-1	13-21	0.51-6.53	14.09-131.72
Kupe South-4	18-23	2.51-12.37	56.97-230.32

Well	Porosity	Permeability (Eq. 4-1)	Permeability (Eq. 4-2)
North Tasman-1	11-20	0.27-4.75	8.06-99.61
Pukeko-1	13-22	0.51-8.99	14.09-174.18
Takapou-1	12-23	0.37-12.37	10.66-230.32
Tahi-1	20-23	4.75-12.37	99.61-230.32
Tane-1	15-27	0.96-44.38	24.61-704.22
Taranga-1	12-18	0.37-2.51	10.66-56.97

4.2.3 Other Reservoir Properties

Interactive Petrophysics is a software that was used to identify other properties of rocks in the North Cape Formation. The gamma ray log, resistivity log, neutron log and density log, and properties of rocks including apparent water resistivity, water saturation, porosity, bulk volume water, water and hydrocarbon content, clay volume, lithology, and permeability are calculated and demonstrated in Figure 4-8.

The summary of reservoir properties of individual wells are represents in Table 4-5. Apparent water resistivity of rock in the North Cape Formation is approximately 0.10 ohm except in coal-bearing layer that has 10-500 ohm water resistivity. Water saturation value is about 1.1 which is lower than the Rakopi Formation. About hydrocarbon and water content, it is significant that fluid dominated the formation is water with a high proportion of hydrocarbon in the coal-bearing layer. This log analysis consistents with well completion report showing that there is no significant hydrocarbon showed in this formation. Lithology log represented deposition of sandstone with shale in almost same proportion. The average proportion of sandstone is more than the proportion of clay. Permeability is calculated from porosity and irreducible water saturation.

Table 4-5 Average petrophysical parameters of sandstones in the North Cape Formation

	RWapp	Porosity	SW	BVW	Vsh	Sand content	Permeability
Amokura-1	0.05	0.20	1.0	0.20	0.20	0.60	90
Ariki-1	0.02	0.06	1.3	0.06	0.30	0.64	0.02
Fresnel-1	0.05	0.10	1.3	0.10	0.07	0.83	0.60
Kiwa-1	0.03	0.15	1.3	0.15	0.25	0.60	5.00
Kiwi-1	0.03	0.10	1.3	0.10	0.18	0.72	0.15
Kupe South-4	0.03	0.12	1.3	0.12	0.40	0.48	0.50
North Tasman-1	0.05	0.14	1.3	0.14	0.15	0.71	1.40
Pukeko-1	0.03	0.17	1.3	0.17	0.20	0.63	2.0
Takapou-1	0.07	0.15	1.1	0.15	0.40	0.45	5.0
Tahi-1	0.01	0.10	1.3	0.10	0.50	0.40	1.00
Tane-1	0.10	0.22	1.1	0.22	0.40	0.38	15
Taranga-1	0.001	0.05	1.3	0.05	0.40	0.55	-

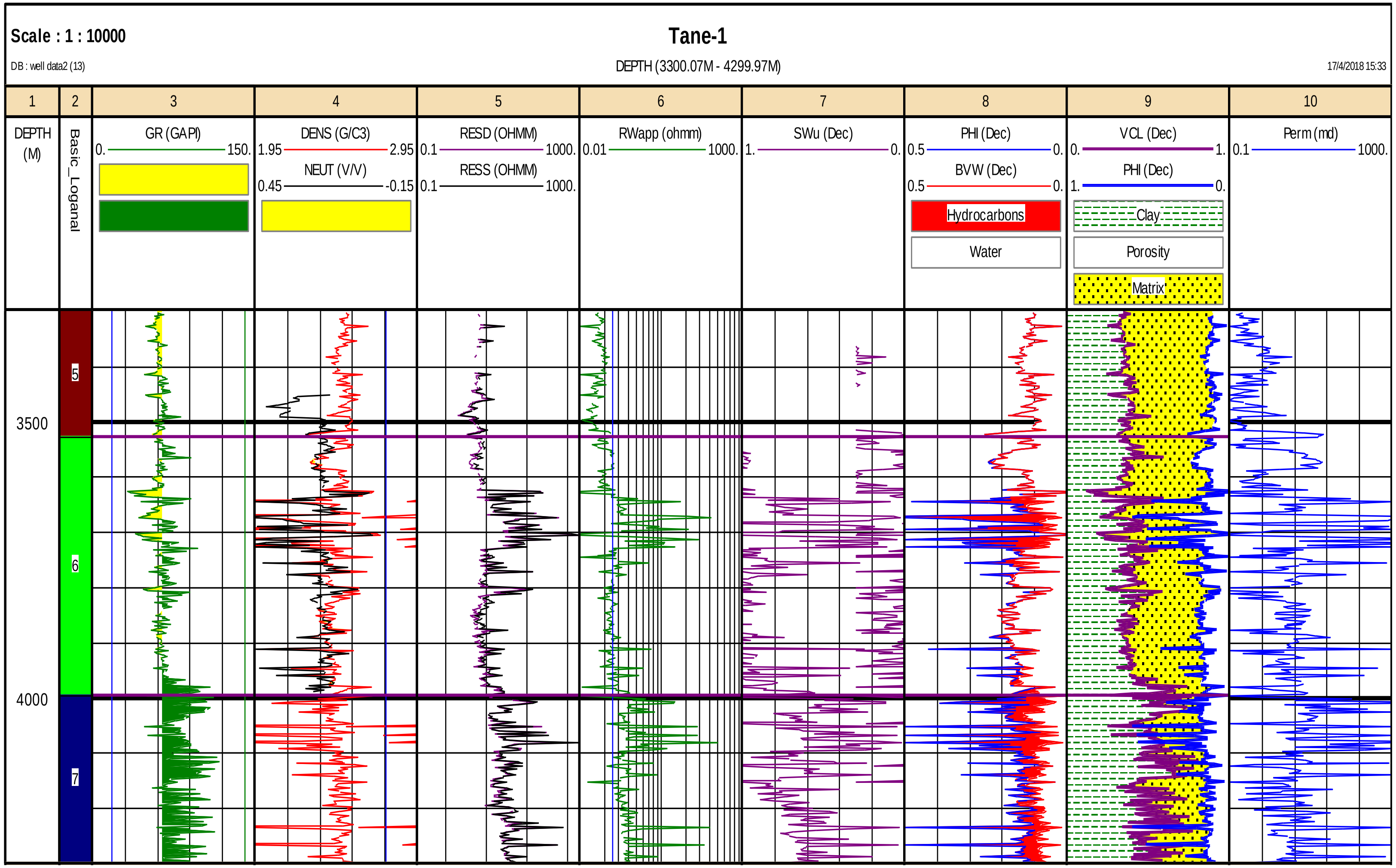


Figure 4-8 Rock properties focused in the North Cape Formation in Tane-1

4.3 Core Data Interpretation

Side wall core and core samples analysis are reported in well completion reports. These data are used to interpret burial history and clay minerals for supporting well log data interpretation.

4.3.1 Burial History

Burial history demonstrates deposition of rocks in the basin throughout the period. It shows the effect of more recent sediment on the older deposit.

The main inputs are lithology, thickness and depositional time of each formation. The lithology comes from mud logging adjusted with marker picking using log characteristic. In this study, estimation of deposition time utilized fossils found in the rocks recorded in a biostratigraphy section is from well completion reports. The mains input for modeling burial history of rock succession in Tane-1 is showed in table 4-6.

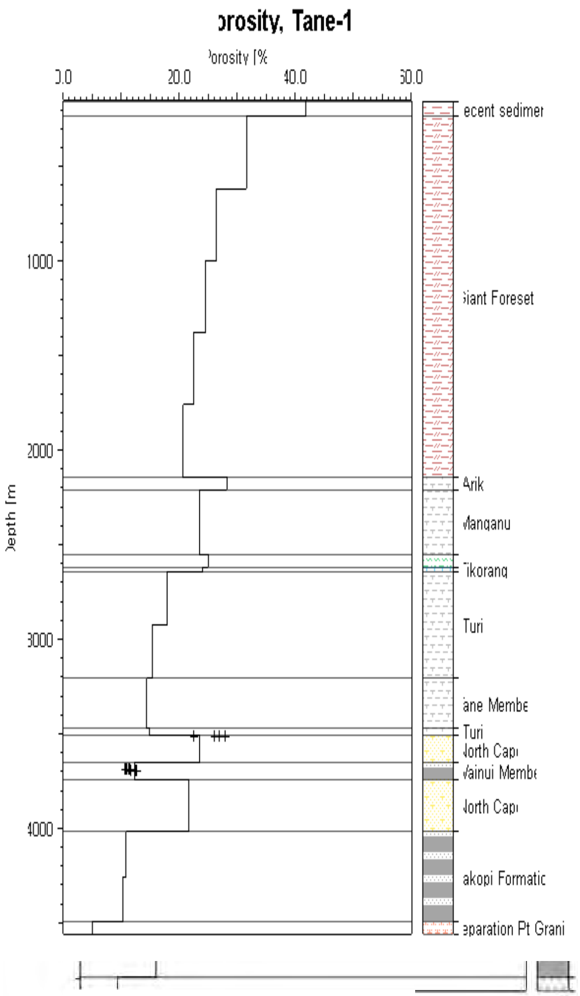
Table 4-6 Main input data for making burial history of well Tane-1

Layer	Top (m)	Base (m)	Thick (m)	Depo. From (Ma)	Depo. To (Ma)	Lithology	PSE
Recent sediment	153	235	82	1.5	0	SHALE	
Giant Foresets	235	2141	1906	5	1.5	SHALEsilt	
Ariki	2141	2209	68	6	5	Shale (typical)	
Manganui	2209	2547	338	14	6	Shale (organic lean, silty)	
Taimana	2547	2610	63	26	14	Marl	
Tikorangi	2610	2633	23	35	26	Limestone (shaly)	
Turi	2633	3194	561	60	35	Shale (typical)	Seal Rock
Tane Member	3194	3455	261	62	60	Shale (organic lean, sandy)	Reservoir Rock
Turi	3455	3492	37	65.5	62	Shale (typical)	Seal Rock
North Cape	3492	3638	146	67	65.5	Sandstone (quartzite, typical)	Reservoir Rock
Wainui Member	3638	4000	362	76	67	COALsandy	Source Rock
Rakopi Formation	4000	4475	475	90	76	COALsandy	Source Rock
Separation Granite	4475	4539	64	100	90	Granite	

Boundary conditions consist of paleowater depth, sediment-water interface temperature, and heat flow. Figure 4-9 presents the boundary conditions of Tane-1. Paleowater depth is identified by biostratigraphy. Fossils can indicate paleoenvironment or depth of water they had lived. Surface water interface temperature data is auto-generated by a location of each well, and it is adjusted by using present day SWI temperature. Heat flow is depended on tectonic events. It reached a peak at the time this basin was rifting and went down when a number of sediments eroded and deposited in the basin.

Figure 4-9 Boundary condition for modeling burial history of Tane-1

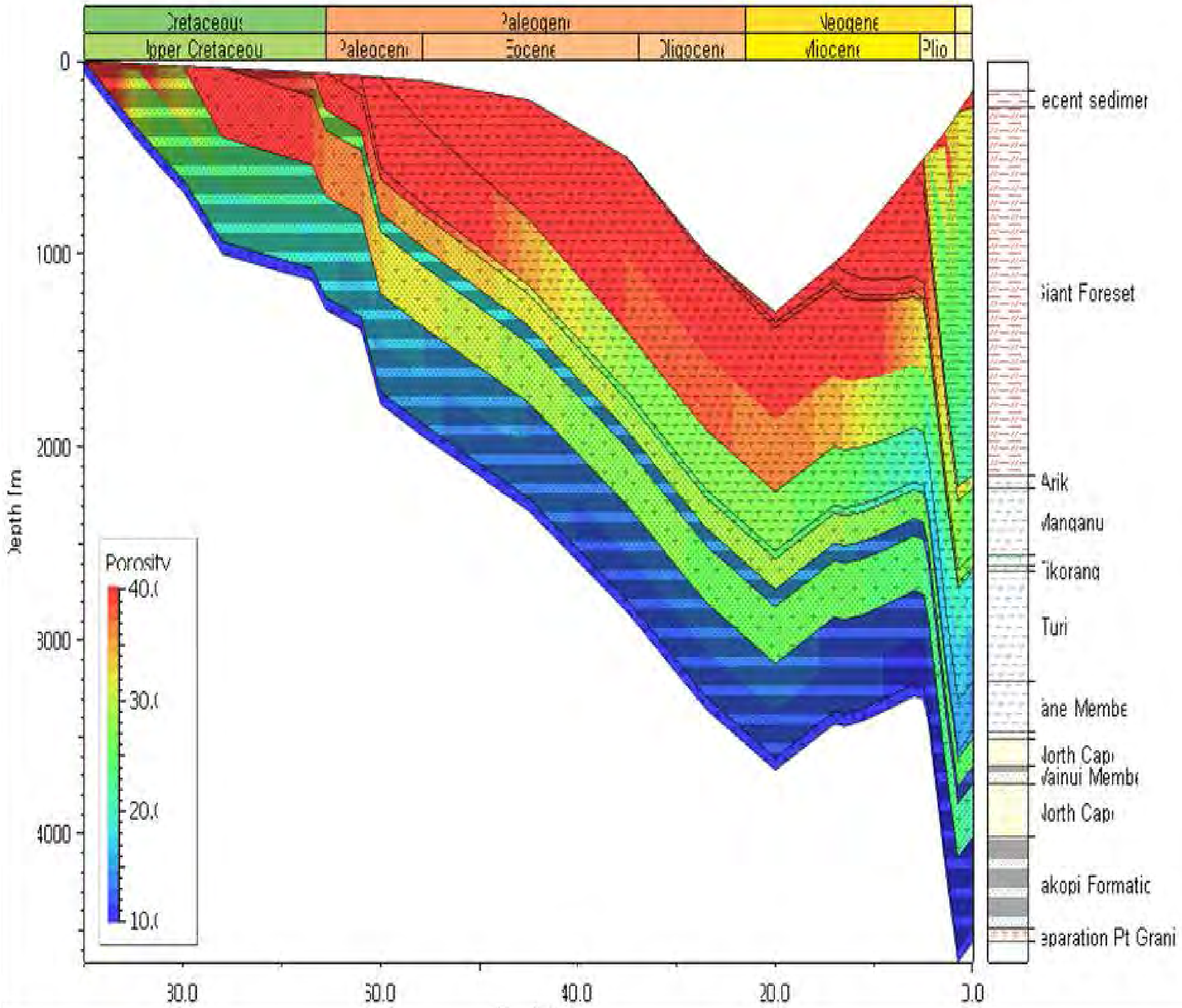
From burial history model generated from Petromod (Figure 4-10(b)), the porosity of the North Cape Formation sandstone was about 40% when the sediment deposited in the basin at the Late Cretaceous. The model shows a slight decrease in porosity over a period of time. The current porosity of the North Cape Formation sandstone is about 25%. Decrease in porosity might be the result of compaction because of the overburden sediments. Comparing between the model and the data from sample analysis in Figure 4-10(a), the porosity is consistent.



+ Porosity from core data analysis

from well completion report

(a)



(b)

Figure 4-10 (a) Depth plot of Tane-1 well showing porosity of sediment successions

(b) Burial history model of Tane-1 showing decrease of porosity over a

4.3.2 Clay Mineral Analysis

Clay minerals related to the degree of compaction. Feldspar is one of the main minerals in sandstones, and it plays an important role in sandstone in the North Cape Formation. Most of the sandstones in this formation have a high proportion of feldspar (Higgs et al., 2010). When it is altered, it changes to clay minerals. This chemical alteration affects a decrease in porosity of rocks. Therefore, the percentage of each clay mineral is analyzed in this study. The data come from well completion reports that were collected and summarized by Higgs (2010).

In this study, the percentage of clay mineral was plotted with porosity to confirm the effect of clay minerals to the porosity of sandstone in the North Cape Formation.

In Figure 4-11, at 5 percent of chlorite, the porosity of sandstone is approximately 1-2 percent. While at the same percentage of kaolinite and illite-smectite, the porosity is about 8 percent and 10 percent, respectively.

Considering 10 percent of each clay minerals, having 10 percent of chlorite causes 1 percent porosity. While having 10 percent of kaolin represents 2 percent porosity. Then, 8 percent porosity is described in the plot of illite-smectite.

From these graphs, increasing of chlorite caused the most significant effect on the porosity, following by rising of Kaolinite and illite-smectite. Whereas, the effect of illitised kaolin is not distincted in this study due to lack of information.

The proportion of each clay mineral is plotted for comparison in each well showing in the Figure 4-12. According to the graph, a well that has the highest percentage of chlorite is Kupe-South 4. Wainui-1 is the well that has the highest proportion of Kaolinite followed by Tane-1. Illitied kaolinite is only presented in Tane-1 and Taranka-1 with minor proportion. Lastly, illite-smectite has been found in all wells, but Pukeko-1 is the well that has the highest percentage this mineral.

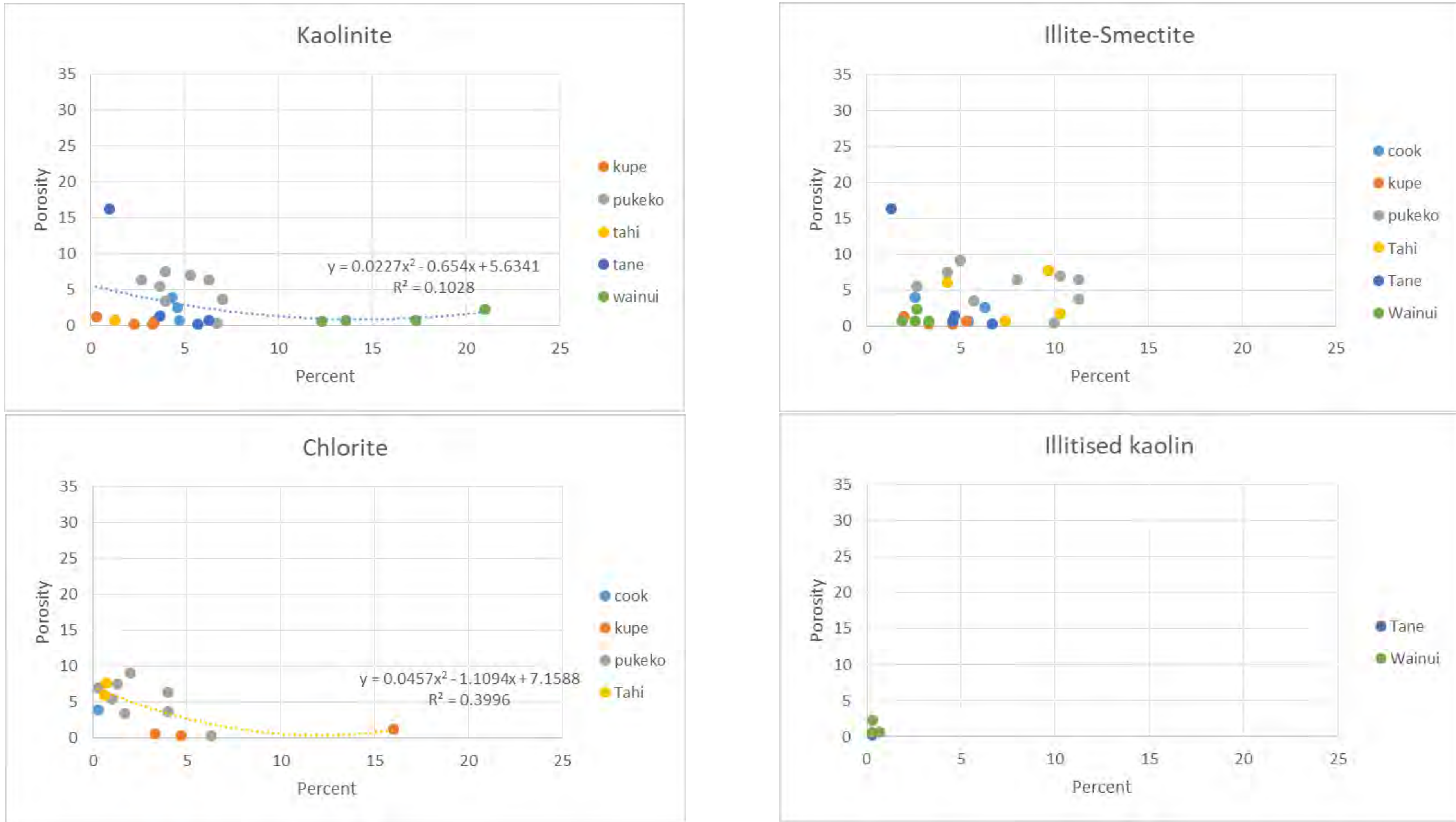


Figure 4-11 Relationship between the percentage of clay minerals and porosity

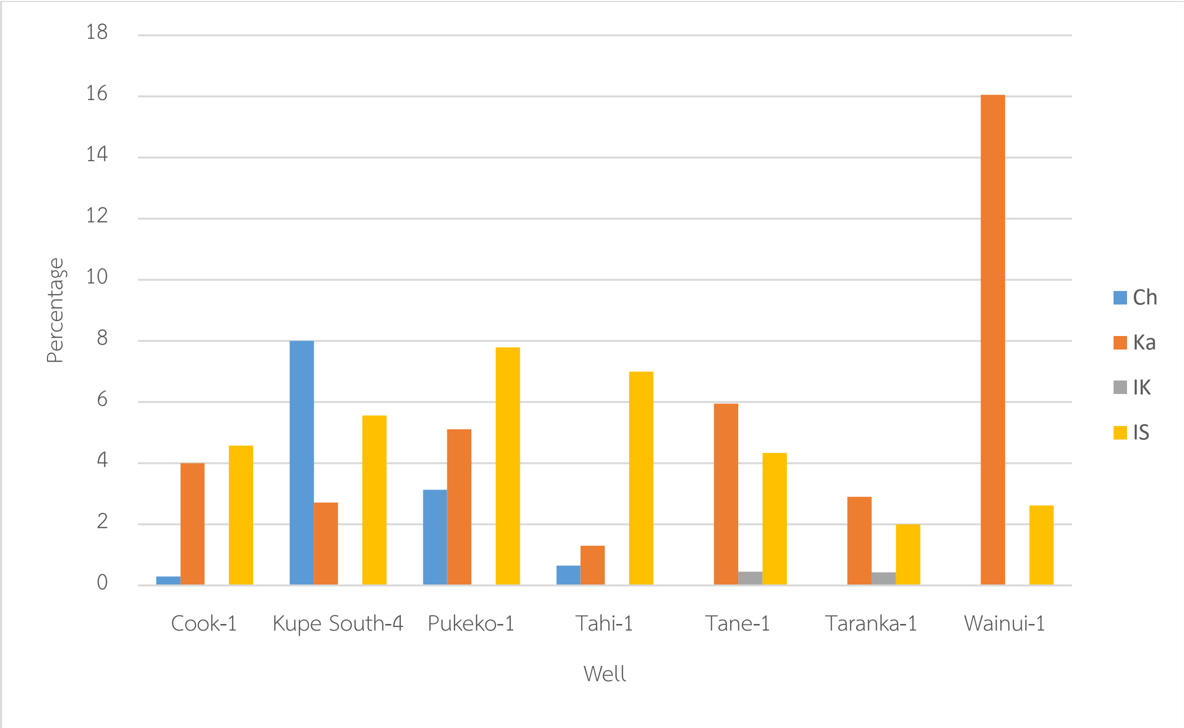


Figure 4-12 Percentage of clay minerals in each well

4.4 Seismic Interpretation

In this study area, connecting each well has to use 2D seismic data. In the deepwater exploration block, there is no 3D seismic survey which is large enough to cover all the area. Therefore, 8 seismic 2D lines were used to interpret structure and depositional characteristic of the succession.

Figure 4-13 shows seismic line SUN which passes through Taranga-1 and Tane-1 well, Formation tops are identified base on seismic characteristics and drilled well data. Because the study area is located on the western platform of the Taranaki basin, which is a stable and inactive area, only minor faults presented in this seismic section. This section also shows the progradation of sediment in the Giant Forset Formation with clinoform geometry of seismic reflection.

(Figure 4-14) The 2D seismic line DTB01-32 is paralleled to the Taranaki Penisular. The horizons of top formation presented in this section is not smooth and continuous like what presented in the seismic line SUN. In this section, the Giant Forset Formation does not show a clinoform geometry which means that this section was not parallel with the depositional direction of sediment in the formation. Moreover, this section shows structural highs which relate to well locations.

(Figure 4-15) The 2D seismic line TL-01 presents sediment successions in the deepwater zone of the Taranaki basin. This section shows the termination of the Giant Forset Formation which is about 200 m far from the Taranaki Penisular. Igneous intrusion, Miocene turbidite and channels can also be seen in the north-west of the section.

From seismic interpretation, the chaotic seismic reflection in the bottom of the seismic section is igneous and metasediment basement. Above basement, the Rakopi or coal-bearing formation is distinct with high amplitude and discontinuous seismic reflection. It is overlaid by the North Cape Formation and Tane member which have low amplitude and unclear seismic reflection. The Turi Formation dominated by shale is shown in the low amplitude but continuous seismic reflection. The Tikoranki and Ariki Formations dominated by limestone have high amplitude and discontinuous reflection. The Giant Foresets Formation is very vivid with a clinoform shape due to progradation of sediments from the continent to an offshore area. All of these formations are overlaid by recent deposits which are represented in linear and continuous seismic reflection.

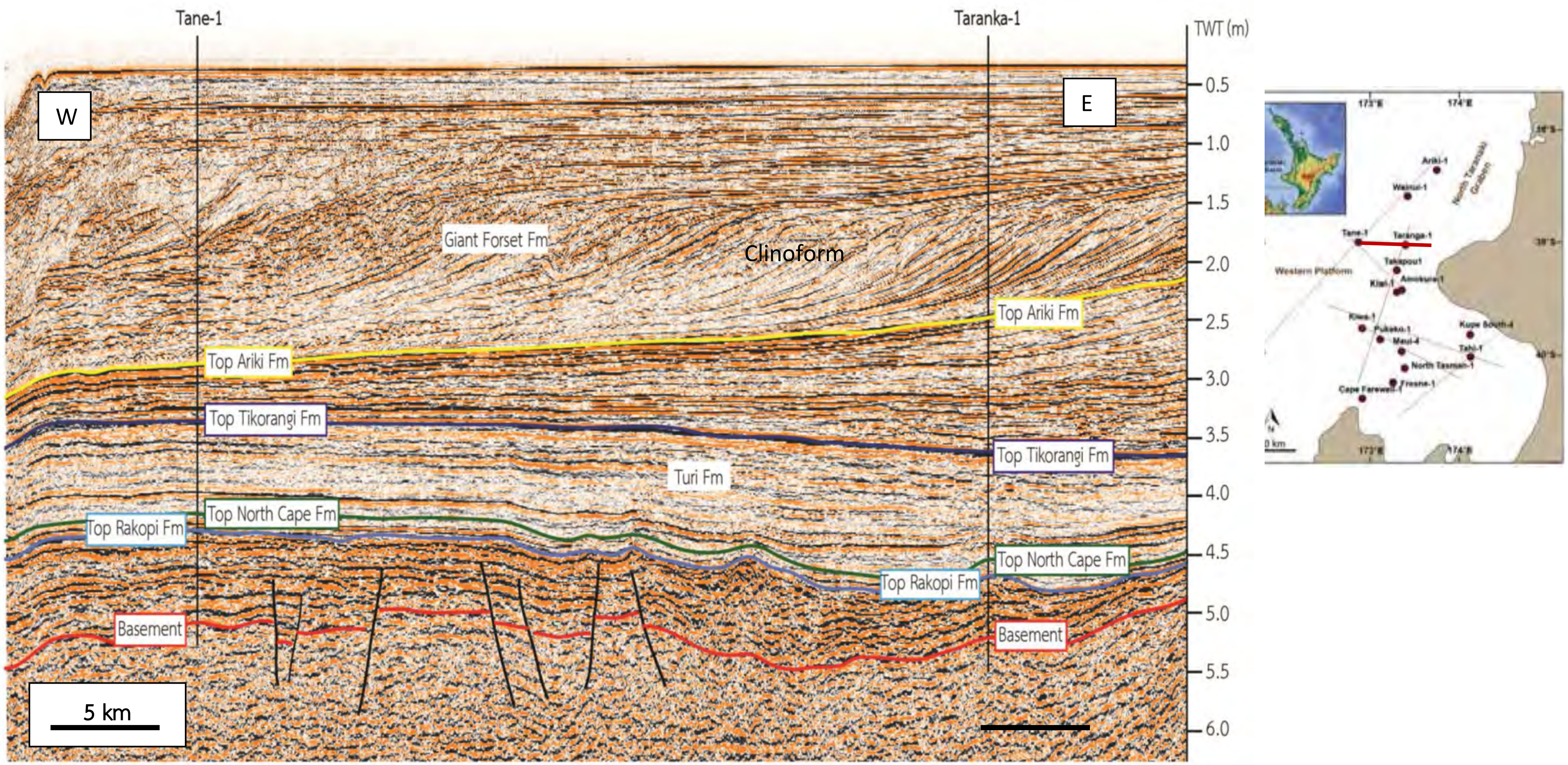


Figure 4-13 2D seismic interpretation of seismic line SUN with well top formations. This section show clinoform geometry of Giant Forset Formation sediments.

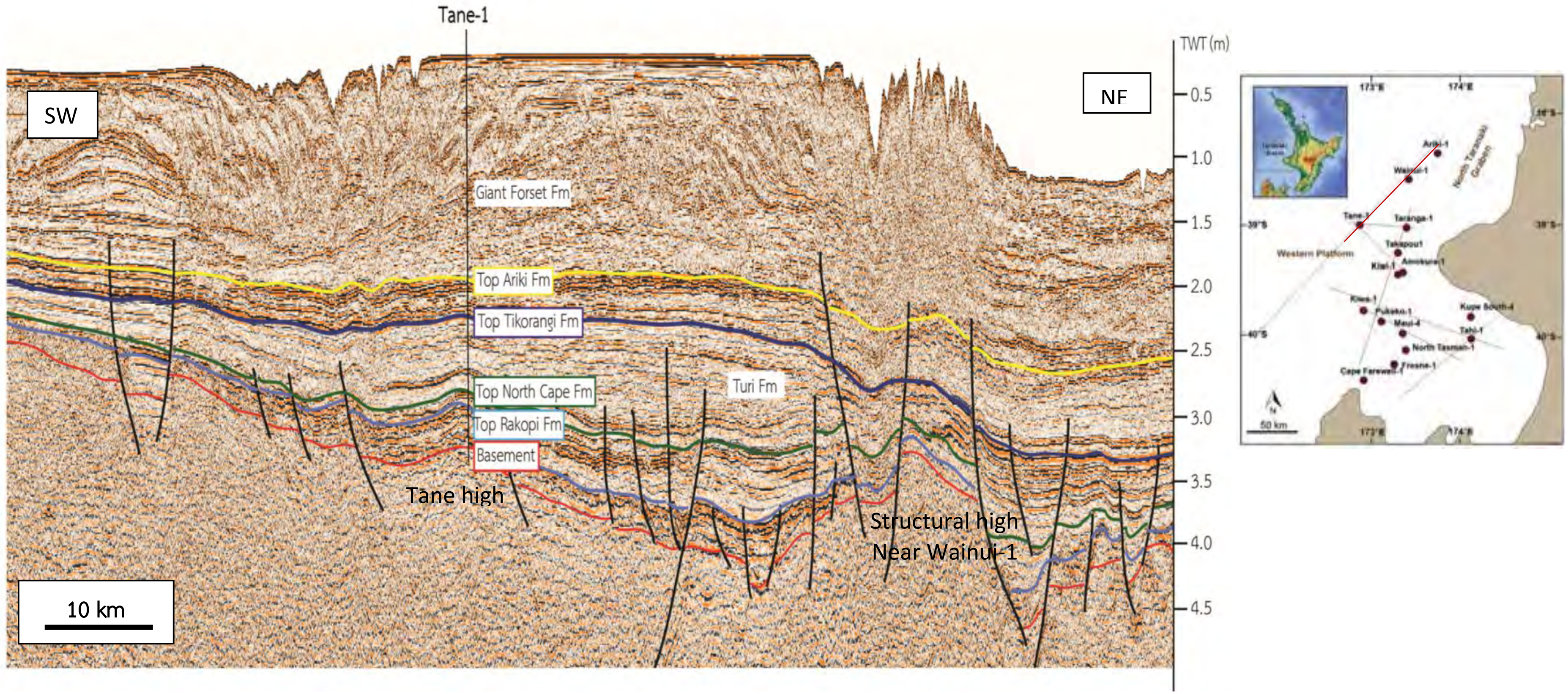


Figure 4-14 2D seismic interpretation of seismic line DTB01-32 with well top formations showing sediment successions in the section parallel the Taranaki Penisula

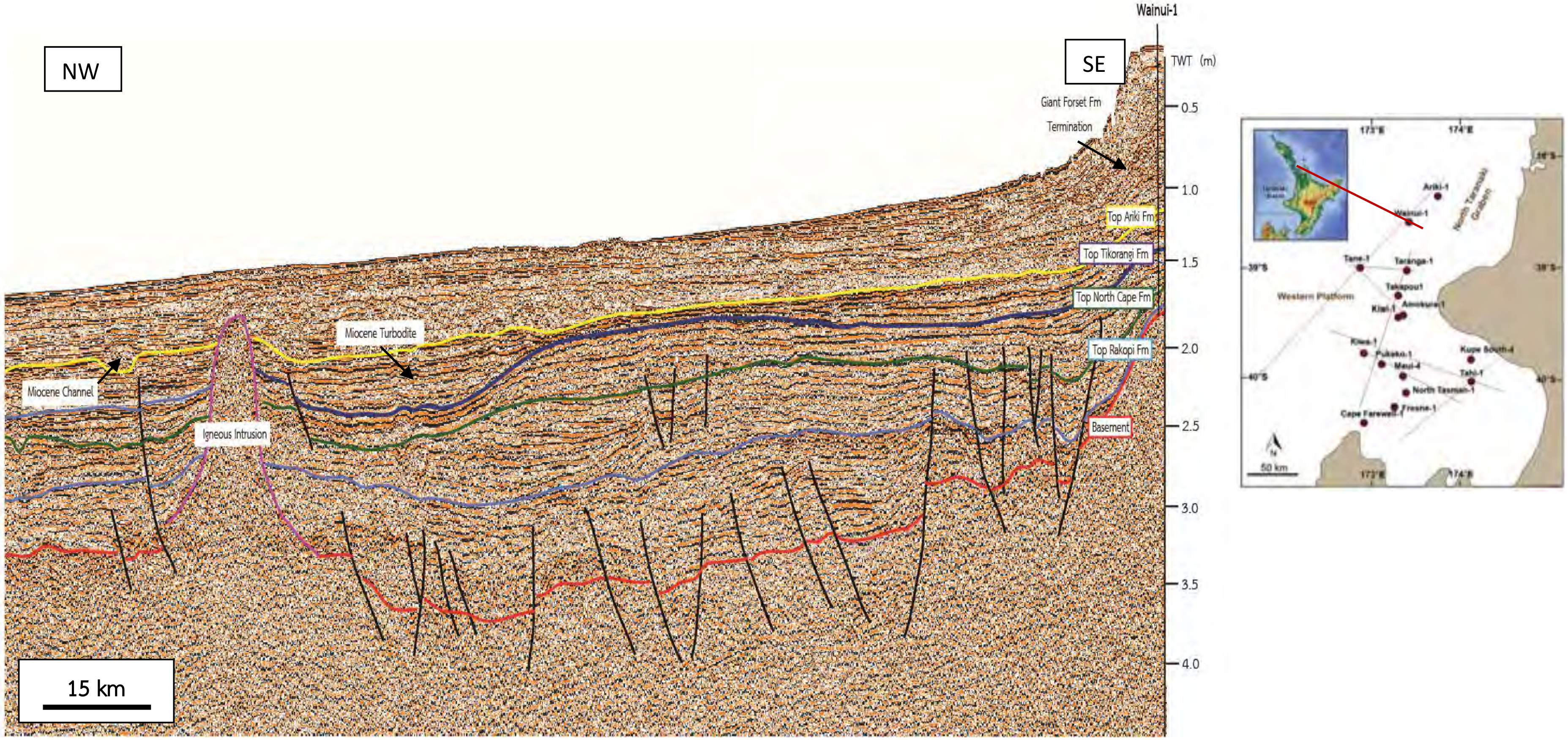


Figure 4-15 2D seismic interpretation of seismic line TL-01 with well top formations showing sediment successions in the deepwater zone of the Taranaki basin

Chapter 5
Discussion

5.1 North Cape Formation Depositional Environment

From well log interpretation, the North Cape Formation succession consists of four main rock types: sandstone, calcareous sandstone, shale, and carbonaceous shale. Sandstone and shale are the majority rocks of the formation. Carbonaceous sandstone and Calcareous shale are only presented as thin layers, although they are the essential evidence for depositional environment identification.

The presence of carbonaceous shale in succession possibly indicates deposition of organic matter which could be preserved only in an anoxic environment. Combining with source rock analysis from well completion reports stated that the source rock in the basin contains hydrocarbon kerogen type III which relates to land plants, it could be interpreted that this carbonaceous shale deposited in transitional zone where land plans grew, then died and preserved when saline water flooded to the land.

Calcareous sandstone is a sandstone that contains the amount of calcium carbonate. Calcium carbonate is precipitated from marine organisms which are abundant in the shallow marine environment. Carbonate also dissolves when it goes deeper than carbonate compensation depth. Therefore, the presence of calcareous sandstone indicates deposition of sediments in the shallow marine zone.

In addition, gamma ray log shape used for depositional environment interpretation shows that the most common log shape found in this formation is funnel shape. This log shape relates to a coarsening upward sequence which refers to barrier bar sandstone. The presence of bars can indicate marginal zone which experienced sea level change. Moreover, the shale ratio is increased from the bottom to the top of the succession which could be explained that the formation deposit in the marine transgressive period. In conclusion, the North Cape Formation deposited in transitional to the shallow marine environment.

This interpretation was supported by the presence of dinoflagella and marine algae fossils in sediments of the North Cape Formation (Wizevich et al., 1992). The sediment structure such as cross-bedding, mud-draped, bidirectional cross-lamination and bioturbation which indicated marginal environment are also presented in outcrops (Raaf and Boersma, 1971; Terwindt, 1988).

5.2 Reservoir Properties

The reservoir properties of sandstone in the North Cape formation are calculated from the neutron-density cross plot and petrophysical analysis. The sandstone in this formation has a porosity between 10 and 27. Porosity can be used to characterize the reservoir quality (Table 5-1). With porosity as mentioned above, the sandstone in the North Cape Formation is a fair to very good reservoir which means that this sandstone has potential to become a reservoir in the Taranaki basin.

Moreover, the porosity varies in the different well. There are two zones of high porosity. First, at Tahi-1 and Kupe-1 in Mania sub-basin which have about 15-20% porosity. The North Cape Formation sandstone in this sub-basin could be a good reservoir. The other high porosity area is Tane-1, Kiwa-1, Kiwi-1, and Pukeko-1 in Western platform. The porosity of sandstone in this area is about 17-22% which refers to a good to very good reservoir.

From the porosity contour map (Figure 5-1), the porosity of sandstone in wells located in the offshore zone is higher than wells near the peninsular. Therefore, sandstone of the North Cape formation at the deepwater area, which is a majority of the basin, might has high porosity and could be a good to very good reservoir for petroleum exploration.

Table 5-1 Porosity and reservoir quality (Jankeaw, 2016)

Porosity	Reservoir quality
0-5%	Negligible
5-10%	Poor
10-15%	Fair
15-20%	Good
>20%	Very good

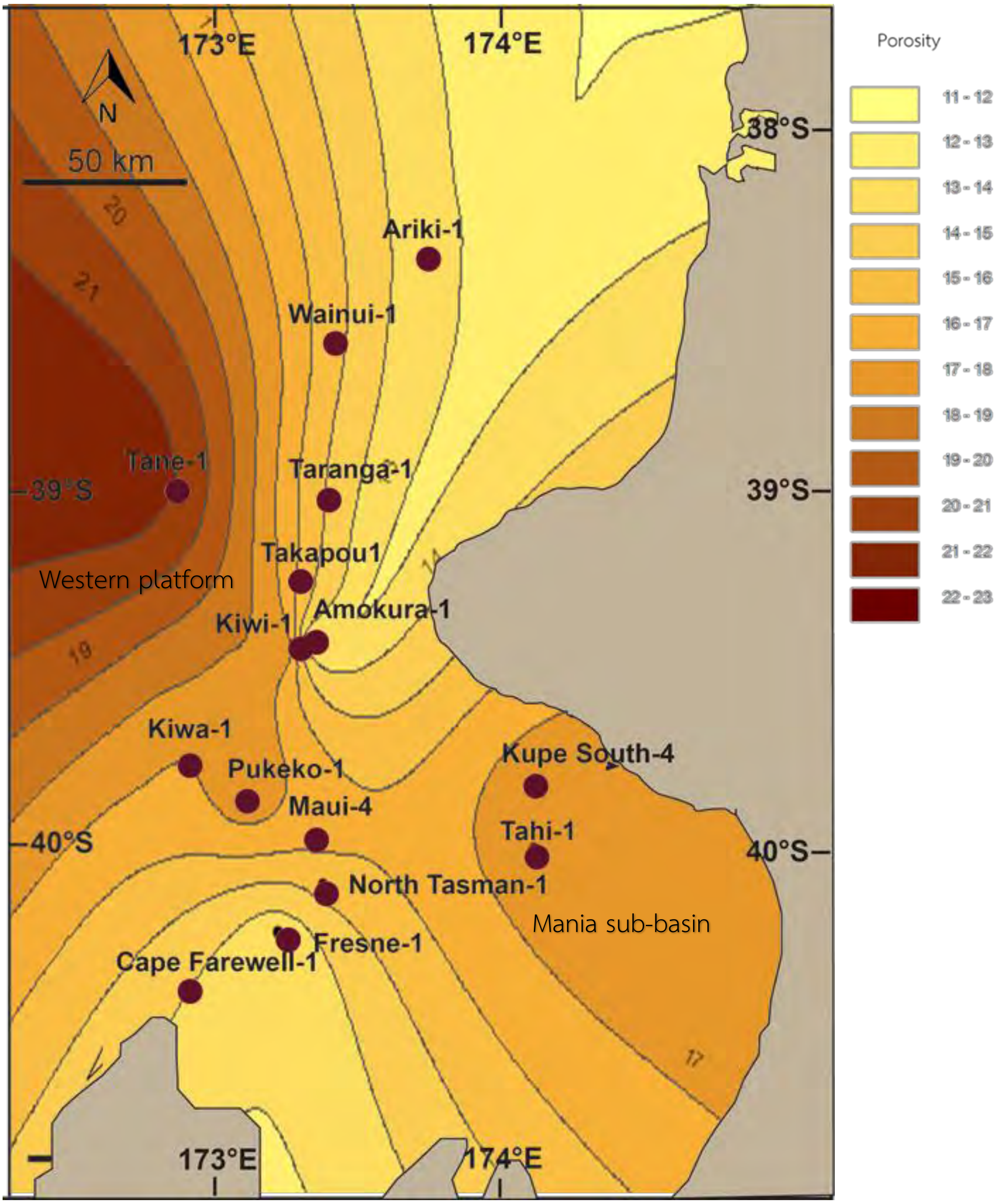


Figure 5-1 Porosity contour map of sandstone in the North Cape Formation

5.3 Depositional Environment and Reservoir Properties

Gamma ray log patterns which present in well log data consist of funnel shape of barrier bar sandstone, bell shape of channel sandstone and serrated shape of tidal flat sandstone. (Figure 5-2) Sandstone beds with different depositional environments are plotted to observe the relationship between the environment and porosity. The graph shows that barrier bar sandstone has significantly high porosity comparing with channel and tidal flat sandstone. The reason for this result might be the proportion of sand and clay in the formation. Barrier bar sandstone which relates to high energy environment usually observed as clean sandstone with the high percentage of sand. Channel sandstone in the North Cape Formation might be deposited as a distributary or tidal dominated channel due to deposition in the marginal zone. These types of channel might have fair to good reservoir quality resulting from the influence of fine grain sediments transported by channel. Tidal dominated environment is usually presented with a high degree of heterogeneity with the low percentage of sand component. Therefore, the porosity of barrier bar sandstone in the North Cape Formation is higher than the other environments.

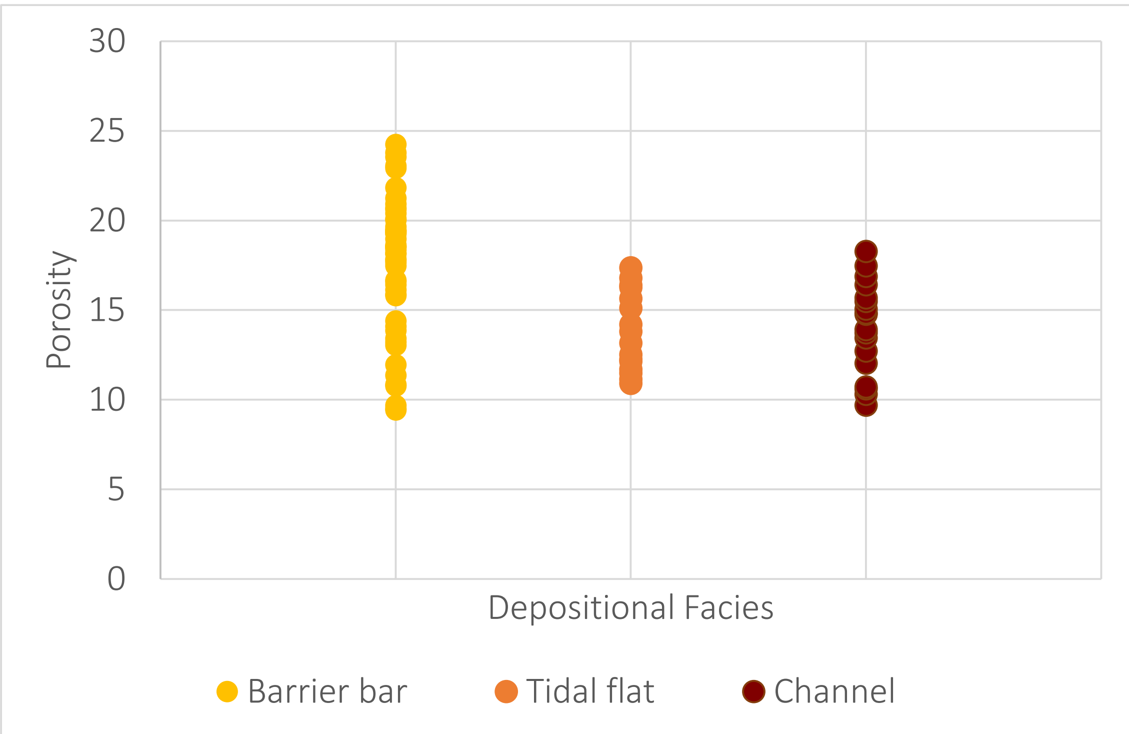


Figure 5-2 Relationship between depositional facies and pososity of sandstone in the North Cape Formation

5.4 Overburden Sediment and Reservoir Properties

Overburden sediments affect the secondary porosity of the sandstone. Feldspar which composed of the rocks could be alternated to be clay minerals and fill in the pore. The result is a decrease in porosity (Morris and Shepperd, 1981). Moreover, sedimentary weight can induce compaction of the underlying rocks resulted in lowering of the reservoir properties by reducing porosity in a formation.

From burial history model it is obvious that porosity of the sandstone in the North Cape Formation gradually decreased when overburden sediments deposited in the basin. The decrease is approximately 15% porosity over this 75 million years.

Another indicator of the effect of overburden sediments is clay minerals. Based on the relationship between clay minerals and porosity, the increase of clay minerals responds to the decrease in porosity. This effect is significant in kaolinite and chlorite, while the effect of illite-smectite is not apparent in this area. Kaolinitisation is often interpreted as an early diagenetic phase mineral. While chlorite was usually found in late diagenesis or early metamorphic rocks (Galán, 2006; Wilkinson et al., 2006). Therefore, the presence of chlorite can indicate the high degree of compaction. Well that located far from the Taranaki peninsular such as Wainui-1, Tane-1 and Taranga-1 have the high percentage of Kaolinite, and there is no chlorite presents in the rocks. Whereas, Kupe south-4, Pukeko, and Tahi-1 which located near the present day marginal area show the high percentage of chlorite. It could be concluded that the degree of compaction of sandstone in the North Cape Formation of wells located far from the marginal zone is lower than well located near the marginal zone.

As mentioned above that overburden sediments affect the degree of compaction of sandstone in the North Cape Formation, seismic reflection is used to interpret the depositional direction of the overburden sediments. The seismic reflection shows the clinoform geometry of sediment in the Giant Forsets Formation. The presence of clinoform can indicate progradation of sediment. The sediment in the Giant Forsets Formation was deposited from the east to the west of the basin. The terminal of clinoform seismic reflection of the Giant Foreset Formation is approximately 200 km from the Taranaki peninsular. Thus, the North Cape Formation sandstone in the area far from the peninsula more than this distance might has the low degree of compaction and good reservoir properties.

Chapter 6
Conclusions

The North Cape Formation succession consists of sandstone, calcareous sandstone, shale and carbonaceous shale. Sediments in this formation deposited in shallow marine environment related with a marine transgressive period. The most common depositional environment of sandstone in the formation is barrier bar. Porosity analysis from neutron-density crossplot indicates that sandstone in the North Cape formation has about 10-27% porosity which means that this sandstone can be a fair to very good reservoir. Permeability was calculated by the equation came from the porosity-permeability crossplot. With the equation, the permeability of sandstone in the North Cape Formation is up to 700 mD. The porosity of each well was used to generate the porosity contour map. The map demonstrates that the porosity of sandstone in wells located near the peninsular is lower than wells located in the offshore zone. The factors controlling the porosity of sandstone might be depositional environment and compaction because of overburden sediments. The graph showing relationship between depositional facies and porosity points out that barrier bar sandstone has the highest porosity, comparing with channel and tidal flat sandstone. Burial history model, clay minerals, and seismic reflection support the effect of overburden sediment on porosity. From burial history model, the porosity of sandstone decreased when the overburden sediments deposited in the basin. Compaction causes diagenesis of clay minerals which affects the decrease in porosity. And the seismic data show progradation of overburden sediments from the Taranaki peninsular. Because sediments prograded from the continent in the east of the basin, The North Cape Formation sandstone in the marginal area might experience more degree of compaction than sandstone in the deepwater area and it results in the low porosity of sandstone in the marginal zone.

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Appendix

Appendix 1 Porosity and permeability of rock samples analysis from well completion reports

Well	Depth (m)	Porosity (%)	Permeability (mD)
Cook	2338.27	14.3	8
Cook	2338.33	9	10
Cook	2338.82	0.4	0.02
Cook	2338.94	6.8	16.4
Cook	2339.13	2.9	0.07
Cook	2341.87	9.4	10.9
Cook	2342.54	9.4	10.9
Cook	2343.45	1.1	0.06
Pukeko	3601.7	15.6	14.1
Pukeko	3732.1	2	0.01
Pukeko	3892.6	2.9	0.005
Pukeko	3913.8	14.1	37.6
Pukeko	3914.8	12.8	34
Pukeko	3917.1	4.3	0.17
Pukeko	3980	11.7	1.65
Pukeko	4056.1	4.4	0.02
Pukeko	4060.8	17.2	46.6
Pukeko	4063	12.6	14
Pukeko	4067	10	0.07
Pukeko	4083	12	4056

Well	Depth (m)	Porosity (%)	Permeability (mD)
Pukeko	4092	3.9	0.06
Pukeko	4097.3	14.6	1.09
Pukeko	4099	12.3	0.88
Pukeko	4130	9.4	0.07
Pukeko	4137.5	2.6	0.006
Pukeko	4142.4	12.2	76
Pukeko	4145.8	8.8	0.006
Pukeko	4153.8	16.7	303
Tahi	1250	20.2	8.2
Tahi	1320.5	30.5	1055
Tahi	1381.9	28.5	54
Tahi	1476.65	5.3	0.05
Tahi	1495.9	21.4	8.4
Tane	3514.6	26.9	816
Tane	3514.78	26.1	477
Tane	3691.15	11.4	0.75
Tane	3692.32	10.6	1.8
Tane	3693.43	11.4	2.6
Tane	3694.08	11.6	4.3
Tane	3695.15	11.9	2.6

Appendix 2 Clay mineral proportion of sandstone in the North Cape Formation from well completion reports.

Well	Depth	porosity	Clay (%)			
			Ch	Ka	IK	IS
Cook	2341.23	4	0.3	4.3	-	2.6
Cook	2338.4		-	2.4	-	4
Cook	2343.24	0.7	-	4.7	-	5.4
Cook	2339.03	2.6	-	4.6	-	6.3
Kupe	3714	1.3	16	0.3	-	2
Kupe	3626	0.3	4.7	2.3	-	3.3
Kupe	3527	0.3	-	3.3	-	4.6
Kupe	3619	0.6	3.3	3.4	-	5.3
Kupe	3723		-	1	-	8
Kupe	3758		-	6	-	10.2
Pukeko	4142.4	5.5	1	3.7	-	2.7
Pukeko	4060.8	7.5	1.3	4	-	4.3
Pukeko	4152.8	9.1	2	-	-	5
Pukeko	4137.5	3.5	1.7	4	-	5.7
Pukeko	4063	6.4	4	6.3	-	8
Pukeko	4067		6.7	6.3	-	9.3
Pukeko	4130	0.4	6.3	6.7	-	10
Pukeko	4083	7	0.3	5.3	-	10.3
Pukeko	4097.3	6.4	4	2.7	-	11.3
Pukeko	4099	3.7	4	7	-	11.3
Tahi	1270		-	-	-	3.3
Tahi	1381.9	6	0.6	-	-	4.3
Tahi	1736	0.7	-	1.3	-	7.4
Tahi	1320.5	7.7	0.7	-	-	9.7
Tahi	1478.9	1.7	-	-	-	10.3
Tane	3515	16.3	-	1	-	1.3
Tane	1694.25		-	11.7	-	4.3
Tane	4052		-	7.3	0.6	4.4
Tane	3691.45	0.7	-	6.3	-	4.6
Tane	3600	1.4	-	3.7	-	4.7
Tane	4177	0.3	-	5.7	0.3	6.7
Taranga	4138.5		-	2.9	-	2
Wainui	3785	0.7	-	17.3	0.3	1.9
Wainui	3804	0.6	-	12.3	-	2.6
Wainui	3776.5	2.3	-	21	0.3	2.7
Wainui	3867	0.7	-	13.6	0.7	3.3