

**ASSESSMENT OF SUBMARINE CHANNELS FOR
CO₂ STORAGE IN THE DEEP TARANAKI BASIN,
NEW ZEALAND**

BY

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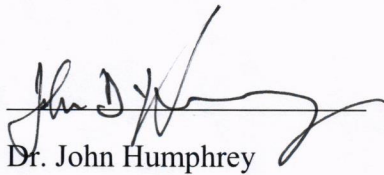
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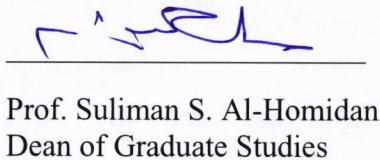
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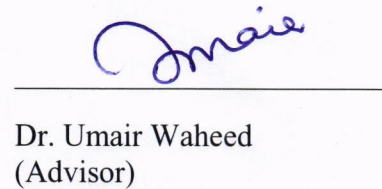
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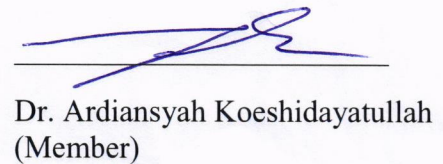


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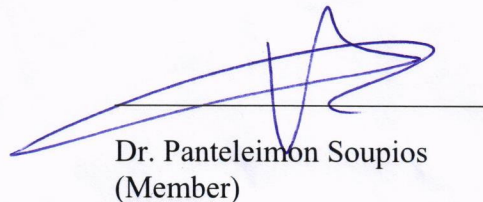
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DEDICATION

This Thesis work is dedicated to my Late Father.

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It is impossible to express my gratitude to everyone who helped me in this work; they are greatly appreciated. To begin with, I would personally extend my deep-felt appreciation to all the people in KFUPM for their support, help, and camaraderie during this endeavor. Your support makes a huge difference, and I want to thank all of you for being here.

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ABSTRACT

Full Name :Maryam Sani Maigana

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The pressing issue of climate change has necessitated implementing effective methods for capturing and safely storing excess CO₂ emissions in underground geological formations. Several options have been explored and evaluated, including unmined coal seams, depleted oil and gas reservoirs, saline aquifers, and basaltic formations. Being the single-producing basin, the Deep Taranaki Basin of New Zealand has become a central contender in such an ambitious carbon capture and storage (CCS) project. This initiative does not only make the region's vast fossil fuel consumption good. Still, it is also on par with the legislative commitment by Aotearoa New Zealand to net zero greenhouse gas emissions by 2050, except for biogenic methane. This study explores the feasibility of utilizing submarine channels as CO₂ storage, considering their extensive and thick presence in the Taranaki Basin. We integrated 3D seismic and sound logs to characterize the reservoir property and connectivity and evaluate seal integrity and geometry. The petrophysical analysis shows an average effective porosity within the formation ranges from 15 to 22%, an average permeability falling between 30 mD and 195 mD for the reservoir, and an effective porosity varying from 3 to 5%. Permeability ranges from 0.1 to 0.4 mD for the seal. This result shows a perfect distribution of porosity and permeability across the reservoir interval, drastically decreasing these parameters as we approach the seal. The 3D models of facies show a slight heterogeneity in the facies distribution across the reservoir, with sandstone facies majorly within the channels and where you have the overbank deposits, with the vertical heterogeneity in the channels creating intraformational seals that are favorable for CO₂ storage. The seal geometry displays regionality across the reservoir, with no significant leakage structures threat; the result of the geomechanical modeling of the fault stability also shows a value of 0.11% for the slip tendency and an average value of 0.5% for the dilation tendency and a distance to failure range of about 2000psi. These results suggest that the faults can tolerate the pressures brought on by CO₂ injection without running the danger of leakage or loss of containment because of a strong seal and fault stability. This research approach would not show the potentiality of submarine channels for storing CO₂

but would complement existing formations and ensure the permanent storage of CO₂ gas. It will also include an inquiry into the scientific type and strategic intervention aimed at mitigating the impacts of climate change through informed data-based interventions.

الخلاصة

الاسم الكامل: مريم ساني مايجانا

عنوان الأطروحة: تقييم القنوات البحرية لتخزين ثاني أكسيد الكربون في أعماق حوض تارانكي، نيوزيلندا

التخصص الرئيسي: الجيوفيزياء

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إن قضية التغير المناخي تتطلب ملح تنفيذ أساليب فعالة لالتقاط انبعاثات ثاني أكسيد الكربون المتزايدة وتخزينها في التكوينات الجيولوجية تحت الأرض بشكل آمن. وقد تم استكشاف وتقييم العديد من الخيارات، بما في ذلك طبقات الفحم غير المستخرجة، وخزانات النفط والغاز المستنفدة، وخزانات المياه الجوفية المالحة، والتكوينات البازلتية. وباعتباره الحوض الوحيد المنتج، فإن حوض تارانكي في نيوزيلندا أصبح منافسًا رئيسيًا في مثل هذا المشروع الواعد لالتقاط وتخزين الكربون. مثل هذه المشاريع لا تجعل استهلاك الوقود الأحفوري الهائل في المنطقة جيدًا فحسب، بل هي أيضًا تساهم على حد سواء مع الالتزام التشريعي من قبل أوتياروا نيوزيلندا بخفض انبعاثات الغازات المسببة للاحتباس الحراري العالمي حتى يصل إلى الصفر بحلول عام 2050، باستثناء الميثان الحيوي. هذه الدراسة هدفت إلى استكشاف جدوى استخدام القنوات البحرية لتخزين ثاني أكسيد الكربون، مع الأخذ في الاعتبار وجودها الواسع في حوض تارانكي. وذلك من خلال دمج السجلات الزلزلة ثلاثية الأبعاد والصوتية لتوصيف خصائص الخزان والتوصيلية وتقييم سلامة الختم وهندسته. أظهر التحليل الصخري الفيزيائي أن متوسط المسامية الفعالة داخل التكوين يتراوح من 15 إلى 22٪، ونفاذية متوسطة تتراوح بين 30 و 195 مللي دارسي للخزان، ومسامية فعالة تتراوح من 3 إلى 5٪. بينما تتراوح النفاذية من 0.1 إلى 0.4 مللي دارسي لصخور الغطاء. تُظهر هذه النتيجة توزيعًا مثاليًا للمسامية والنفاذية في الطبقة الحاملة للسوائل في الخزان، مما يقلل بشكل كبير من هذه المعاملات كلما اقتربنا من صخور الغطاء. تُظهر النماذج ثلاثية الأبعاد للسحنات الصخرية تباينًا طفيفًا في توزيع السحنات عبر الخزان، مع وجود سحنات الحجر الرملي بشكل رئيسي داخل القنوات حيث توجد الرواسب الفيضية، تسهم التغيرات الرأسية في هذه القنوات في تكوين حواجز غير منفذة داخل التكوين مما يجعلها مناسبة لتخزين ثاني أكسيد الكربون. تُظهر نتائج الهندسة الجيوميكانيكية أن الجيومتريا الخاصة بصخور الغطاء بأنها تتميز بالاستمرارية على مستوى الخزان، دون وجود تهديد يُذكر من البنى المتسببة في التسرب. كما أظهرت النماذج للفوالق المستقرة نسبة ميلان طفيفة للتصدع بلغت 0.11٪، ونسبة تمدد بمتوسط 5.0٪، مع هامش تحمل يصل إلى حوالي 2000 رطل لكل بوصة مربعة. تشير هذه النتائج إلى قدرة الفوالق على تحمل الضغوط الناتجة عن حقن ثاني أكسيد الكربون دون خطر التسرب أو فقدان الاحتواء، بفضل الغطاء القوي واستقرار الفوالق. ورغم أن هذا النهج البحثي لا يركز على استكشاف قابلية القنوات البحرية العميقة لتخزين ثاني أكسيد الكربون، إلا أنه يُكمل الدراسات القائمة ويضمن التخزين الدائم للغاز. كما يشمل البحث دراسة استراتيجية وعلمية تهدف إلى تخفيف تأثيرات تغير المناخ من خلال تدخلات مستندة إلى بيانات دقيقة ومدرسة.

CHAPTER 1

INTRODUCTION

The planet is facing an urgent climate crisis, primarily propelled by the increase in greenhouse gas emissions from human activities, notably the combustion of fossil fuels. According to ice core-derived data, the World Meteorological Organization's 2017 report indicates that such activities have driven CO₂ levels from beneath 300 parts per million (ppm) to an alarming 422 ppm as of December 2023. Scholars like Bachu (2002) and Semere et al. (2014) concur that this surge in greenhouse gases is the predominant force behind the escalating global temperatures. In 2007, the Intergovernmental Panel on Climate Change (IPCC) delivered a stark caution. Without decisive action to manage these emissions, we are on a trajectory to exceed a two °C rise in global temperatures, a scenario with dire consequences for our planet's future. Given that CO₂ can persist in our atmosphere for hundreds of years, the situation demands immediate and effective solutions for carbon mitigation(IPCC,2007).

The International Energy Agency (IEA) 2010 responded by setting an ambitious objective to slash CO₂ emissions by 57 gigatons annually, of which carbon storage technologies are expected to play a pivotal role, potentially contributing to a 19% reduction in emissions(Figure 1). Meeting this challenge requires identifying and harnessing vast geological formations that securely store CO₂ underground. Traditional repositories have included saline aquifers, exhausted oil and gas reservoirs, Depleted oil and gas reservoirs, coal seams yet to be mined, and frozen soil. However, advancements in CO₂ sequestration show offshore environment offers a lot more expansive, safer, and more promising alternative to the existing terrestrial sequestration technologies (Xiang et al., 2023); Stevens et al., (2001); Rezaei et al.,(2021); Afzali et al.,(2021); Gale &Freund,(2010); Fox et al., (2020); Kaplan & Kopacz,(2020); Nordbotten et al., (2005); Shaffer (2010); Zhang et al.,(2014) & Randolph(2011).

However, these existing structures are insufficient to meet the IEA's net-zero emissions target by 2050, prompting an urgent exploration for additional geologic storage capacities. This research addresses this gap by exploring the potential of submarine channels in the Deep Taranaki Basin of New Zealand for CO₂ storage. These deep-water channels, which transport sediments from land to ocean depths, share similar characteristics with river channels, including point bars within meander loops, cutoffs, and adjacent levees, as Kolla et al. (2007) detailed. Nestled within expansive channel valleys, these submarine channels offer promising features for carbon storage, such as geological stability and well-defined traps for structural

and stratigraphic containment, and their expansive areal extent makes them particularly attractive for large-scale sequestration efforts. To fully understand and evaluate the potential of these Miocene-age submarine channels, my study synthesizes high-resolution 3D seismic data with information gathered from well logs, check shots, and core samples. This integrated approach allows for a comprehensive assessment of both the reservoir and seal qualities, which are key factors in determining the feasibility of CO₂ storage within these geological structures.

Through this work, I aim to contribute to the scientific community's understanding of carbon sequestration possibilities and offer tangible solutions to one of the most pressing issues of our time. By characterizing these submarine channels, we move closer to achieving the storage capacities needed for the IEA's 2050 net-zero emissions target and, ultimately, securing a more stable climate for future generations.

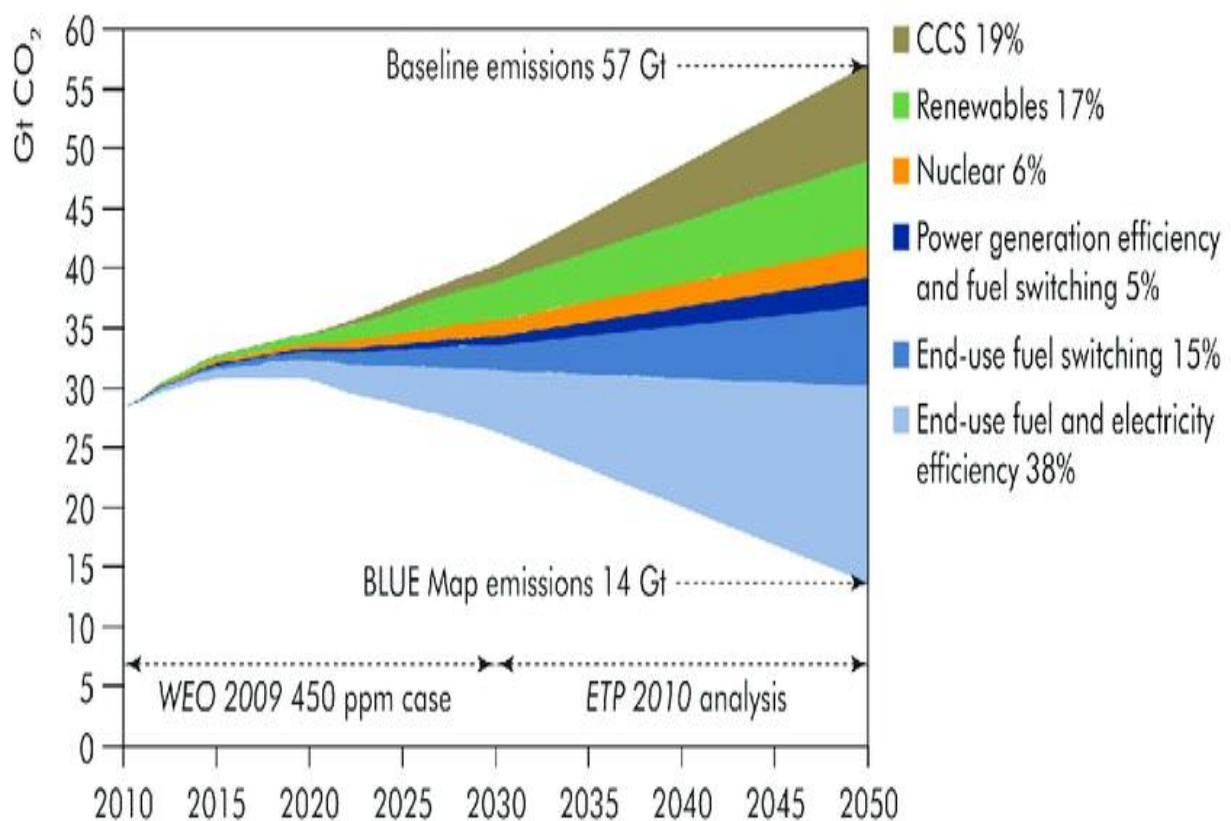


Figure 1:IEA Forecasts of Need Carbon(iv)oxide Emission Reductions (IEA,2010).

1.1 Research Problems

Below are the outlined research problem or research gaps drawn from the previous research:

- No Carbon Capture and Storage (CCS) research on submarine channels; all research previous researches were focused on (Xiang et al., 2023); Stevens et al., (2001); Rezaei et al.,(2021); Afzali et al.,(2021); Gale &Freund,(2010); Fox et al., (2020); Kaplan & Kopacz,(2020)
- CCS has not been implemented in the study area, even with Aotearoa, New Zealand, of zero net greenhouse gas emissions by 2050, except for biogenic methane(Parker, 2007)
- Lack of proper characterization; existing characterizations (Li et al., 2017) rely solely on 3D seismic attributes.
- Lack of 3D facies and property modeling of the channels. Existing models are mostly depositional models(Larsen et al., 2023).
- Non-existing seal characterization and channel analysis are crucial for evaluating sealing potential.

1.2 Research objective

Below is the rundown of the objectives:

- Carry out an integrated reservoir characterization of the Miocene channels using seismic and sound data.
- Carry out an integrated seal characterization and potential analysis
- Produce a 3D model of the Facies and Properties of the reservoir and the seal

CHAPTER 2

LITERATURE REVIEW

2.1 Previous work

Grahame, 2015 reported that Taranaki Basin is one of New Zealand's deep-water systems that has recently received studies on the channel systems. The emphasis will be on special reference to the Miocene period, which has been characterized by major geological activities, the variety of the sedimentary environment, and the geo-tectonic evolution that the basin underwent, starting from the Cretaceous period. Advanced methodologies of seismic via technology like 3D seismic geomorphology together with seismic stratigraphy have been utilized in reservoir characterization for all kinds of subsurface geological formations present within such deep-water environments(Figure 3)

Li et al., 2017 also researched the architecture and development of late Miocene deep-water channel systems in the Southern Taranaki Basin(Figure 2). Seismic analysis of two 3D volumes from Pipeline-3D and Hector-3D shows a transition from simple, low-sinuosity straight channels to more complex high-sinuosity feeder channels. This indicated the dynamic geological processes that were taking place during the channels' formation time. In a different study, with data from the Deepwater Taranaki Basin, interpretations derived from the vast seismic field were employed to gain insights into submarine channel complexes. Various seismic attributes like variance, RMS amplitude, and sweetness were used for the mapping of complexities of the subsurface related to sand distribution within the Miocene submarine channel system and potential reservoir (Naewboonnien, 2021).

The most recent study utilized high-resolution 3D seismic data, and wellbore data were utilized in a comprehensive study on submarine channel development in the Southern Taranaki Basin from the Middle to Late Miocene(Figure 4). Results such as classification of channels, channel seismic analysis, effects upon geology, and channel evolution were found in fourteen submarine channels. This is important because the significant controlling parameters like eustatic sea-level changes, climate variations, and tectonic activities, especially the effect of uplift in the Taranaki basin on channels' evolution, are very significant. Such insights are important to understanding deep-water sediment transport mechanisms and hydrocarbon explorations (Larsen et al., 2023).

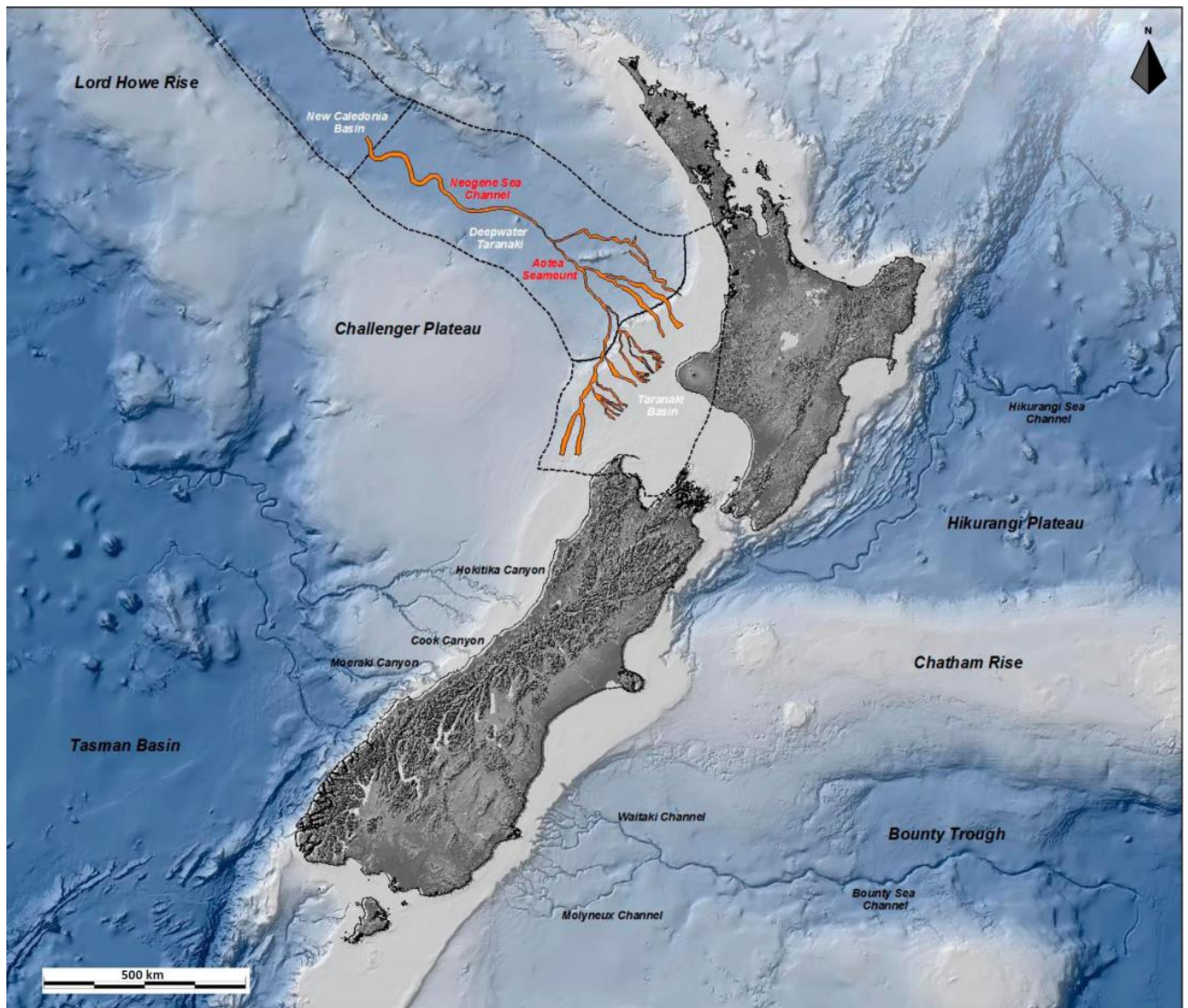


Figure 2: Bathymetric image of New Zealand region with Neogene channel system (orange) illustrated, together with other present-day channel systems(Grahame(2015)).

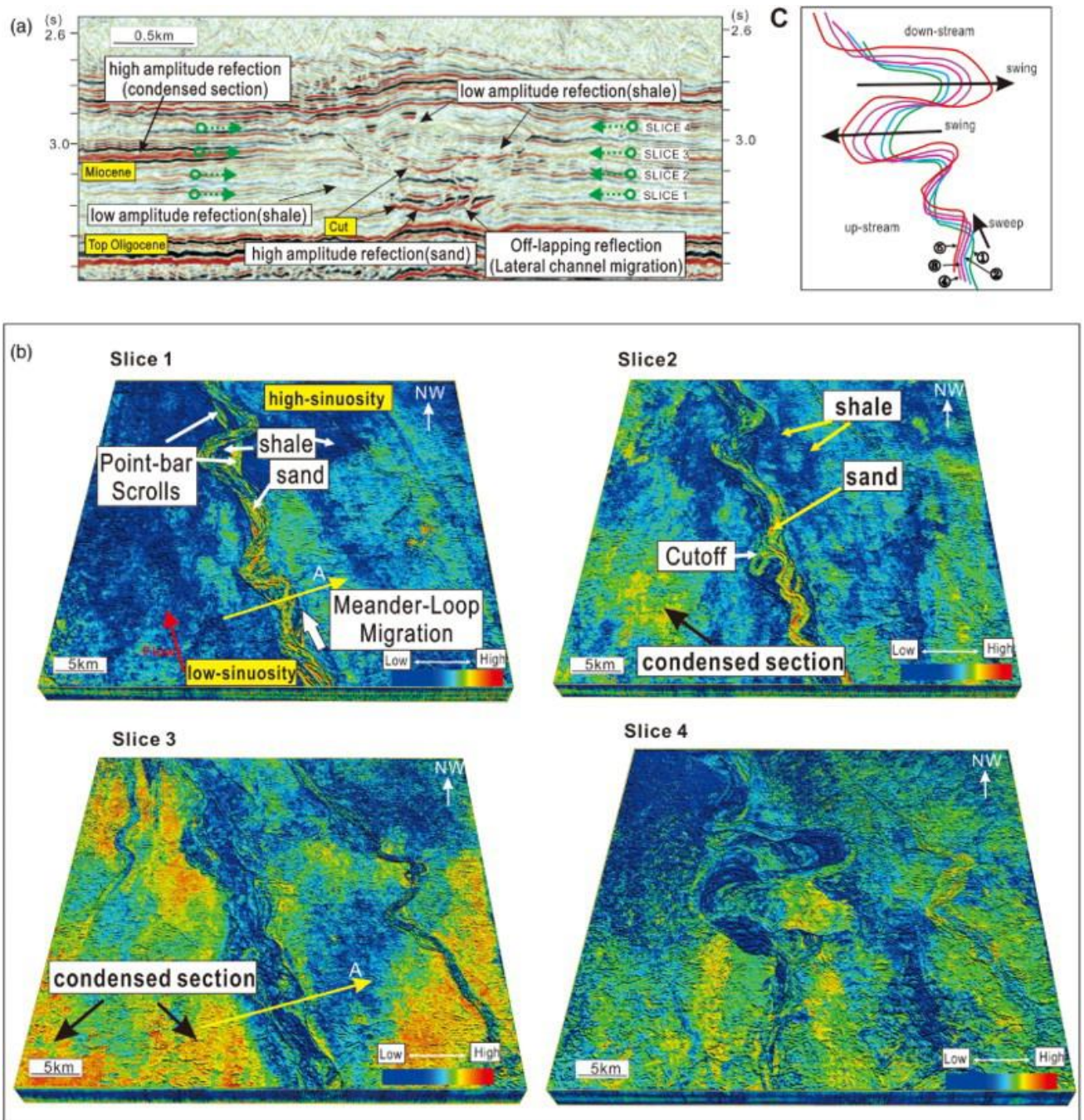


Figure 3: illustrates the development of channels over time, highlighting their downstream progression and lateral movement of point bars(Li et al., 2017).

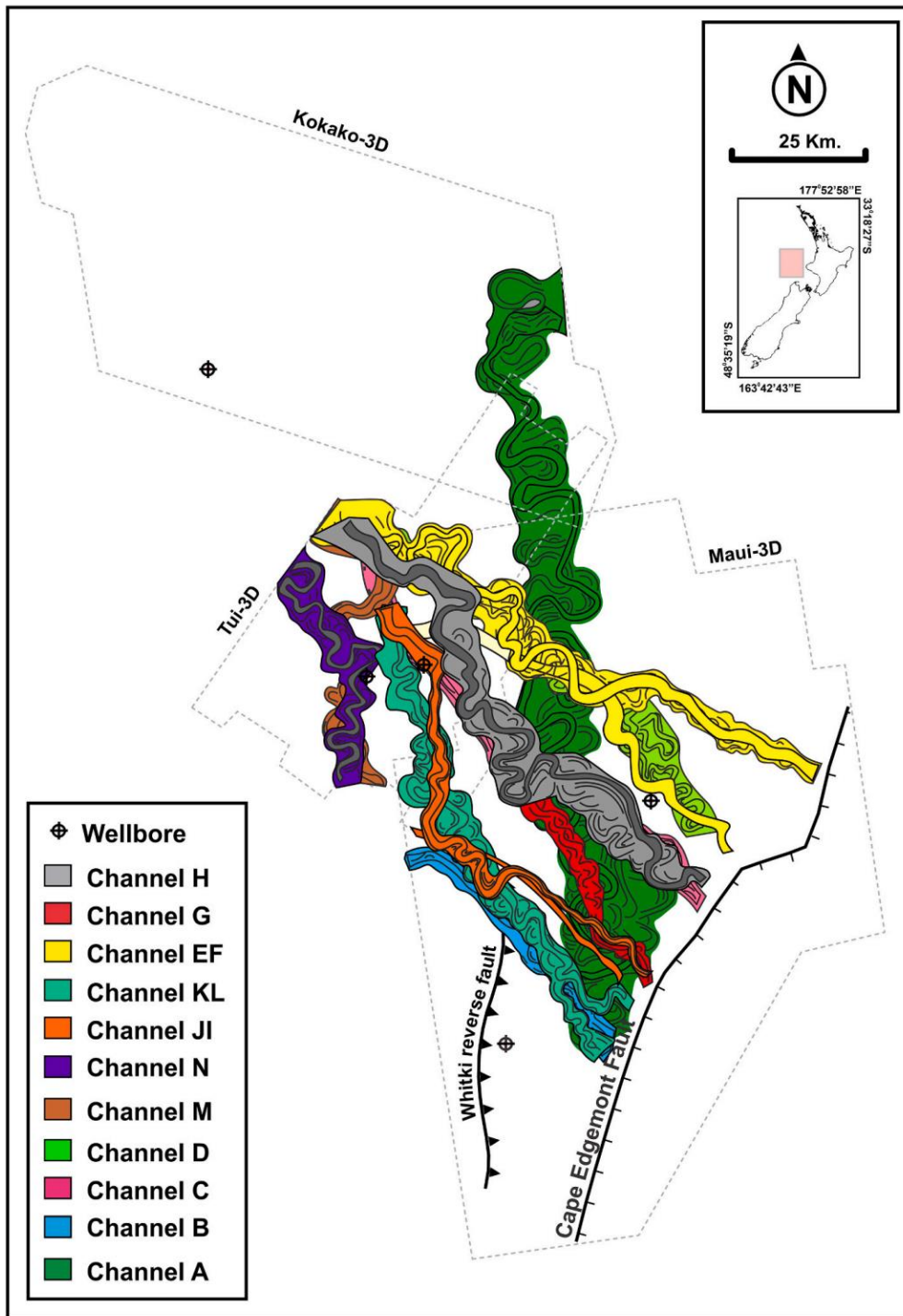


Figure 4: The schematic map shows the lateral and spatial interactions between the interpreted channels in the study area. Most of the channels are terminated on the hanging wall section of the Cape Edgemont Fault(Larsen et al.,2023).

2.2 Regional Geology

2.2.1 Geologic and Tectonic Setting

The Taranaki Basin is situated in the western region of North Island, where we have the Australian and Pacific plate boundary, and is an important geological basin that developed during the Late Cretaceous and Cenozoic periods (Palmer, 1985) (Figure 5). Its development is directly about the rifting of the super-continental slab Gondwana, promoting the partition of Australia from Zealandia and contributing to the formation of several basins, including the Tasman Sea, through extensional forces (Kroeger et al., 2013; Thrasher, 1992)

The developmental history of the Taranaki basin can be segregated into three major phases due to sophisticated initial rifting that occurred from Gondwana fragmentation. This led to the formation of multiple half-grabens, which remained geologically active until the end of the Paleocene. This resulted in the formation of a passive continental margin, which, due to thermal contraction, was accompanied by widespread subsidence over the area during the Eocene to early Oligocene. During this period, the land continued to move slowly downwards throughout the basin, and therefore, both marine and terrestrial sediments were being deposited. The last phase is from the Oligocene to the present when the convergence plate boundary between Australia and the Pacific rose. At that moment, the basin transformed into seas of a healthy-margin active basin. This resulted in rapid subsidence in the eastern part of the basin, while compressive tectonic forces abounded in New Zealand (Baur et al. 2014; Kroeger et al. 2013;).

The history evident in the Taranaki Basin is marked by a series of tectonic events. Significantly, compressive forces in southern New Zealand during the Oligocene period caused a significant increase in sediments, leading to its rapid accumulation under deep water conditions. This compressional period eventually turned into an extensional-wrenching phase related to back-arc spreading during the Pleistocene, which caused further subsidence of the Eastern Mobile Belt and continuous rapid sediment deposits. A variety of superimposed basins, sub-basins, and associated depocenters ranging from the opening of the basin during the Cretaceous to the most recent times containing layers of accumulations of about 9000 meters according to (Palmer & Bulte, 1991; King & Thrasher, 1992).

The basin generally consists of two distinct structural regions: The Western Stable Platform and the Eastern Mobile. In the Western Stable Platform, a broad and stable basement that can go to a depth of 6000 meters has been covered with a deep sedimentary layer, whose westward span is unknown. However, it is found to be about 200km wide towards the Challenger

Plateau(Pilaar & Wakefield, 1978). The Eastern Mobile Belt is a more geologically active zone with an approximately 80-km width. A faulted and depressed landscape characterizes this region, with sediment depths exceeding 11,000 meters(Figure 6). That renders extensive sub-basins active tectonics on the bearing of the Eastern Mobile Belt, making their characteristic as a large number of faulting types such as normal faults, reverse faults, and overthrusts besides uplifted regions (Knox, 1982; Armstrong et al., 1996). Even though most parts of the Eastern Mobile Belt have been strongly affected by the mobility of the complex wrench, this late mobility has not in any way affected the Western Stable Platform in the Tui Field.

Taylor & Karner (1983) reported that during the Pleistocene, an opening around the plate boundary influenced the east of the Taranaki Basin after an active back-arc stimulated subsidence of the Central and Northern Grabens. On the western border fault is the Cape Egmont Fault, which was activated alongside the Northern Grabens in the late Miocene period(Muir et al., 2000). On the other hand, the Western Platform Belt remains unaltered to a certain level by the opening of the plate and the initial compressional phase.

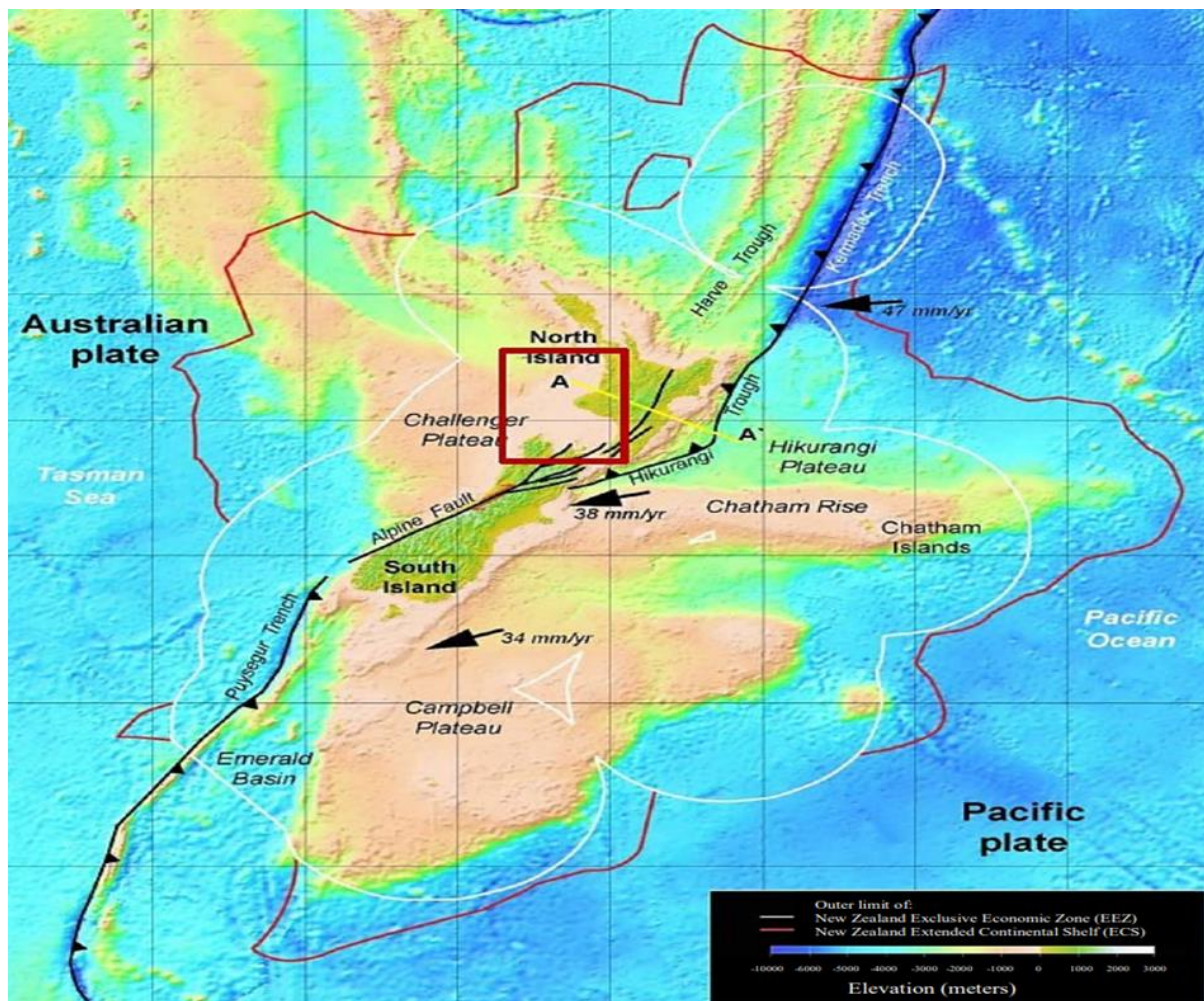


Figure 5: Location of the Taranaki Basin (Modified from Strogen et al., 2012).

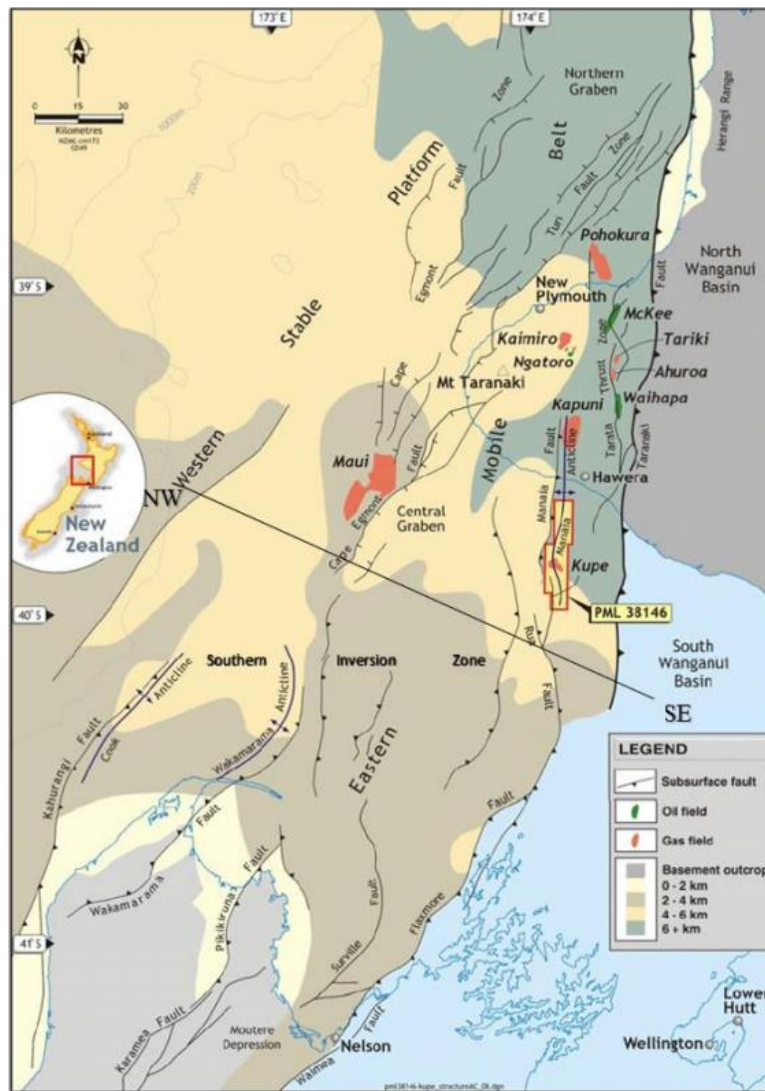


Figure 6: Regional structural elements of the Taranaki Basin showing the Easter and Western Belts (Constantine, 2008).

2.2.2 Generalized Stratigraphy

The Taranaki Basin has a complex sedimentary history due to its mobile nature, making it a fascinating study area. The stratigraphy of the Taranaki Basin is illustrated in Figure 7 (King & Thrasher, 1996). The stratigraphy of the basin is well-defined, with the initial sediment deposition occurring during the Cretaceous to Eocene period. Thick layers of fluvial sand and rich coal were hence delivered to the North Cape and Farewell formations by the ancient waters and landscapes that conspired within the cradle of the Taranaki Basin (King & Thrasher, 1996). Over this interval, domination was regained by their respective depositional elements, which, with time, transgressed into the fine-grained mudstones of the Turi formation, which are deltaic and paralic sediments.

The deposition of the Tikorangi carbonates and settling out of marl and mudstone formed the new chapter with the advent of the Oligocene epoch. There was not so much of an ending to this period, but also at the close that had birthed the continuance of these deposits into the dawning of the Early Miocene (Fohramann et al.,2012). The epoch, Miocene itself, was a time of profound geologic change. The unstable energy beneath the earth's basin floor heightened thermal activity and tectonic movements, affronting a phase of notable subsidence (Palmer, 1985). At the same time, the Miocene epoch set, and the Eocene era rose as the magnanimous Giant Forest Formation initiated the relatively slow but relentless push from the south that, in time, shaped the character of the basin. Though some brief uplift interlude during the Pleistocene in some faulting had occurred in the basin, it remained a crucible of hydrocarbon generation. In 1996, King and Thrasher's studies identified the organic-rich shales of the late Cretaceous-Eocene and coal as prime sources of oil and gas in the Taranaki Basin. Several hydrocarbon reservoirs have been identified within this basin, each with its unique story. Farewell, Kaimiro, Mangahewa, McKee, Moki, Mount Messenger, Mohakatino, and Matemateaonga are all formations that host oil and gas as they testify to the basin's bounty. Of these, the Tikorangi formation is an almost lonely carbonate in this sea of clastic layers.

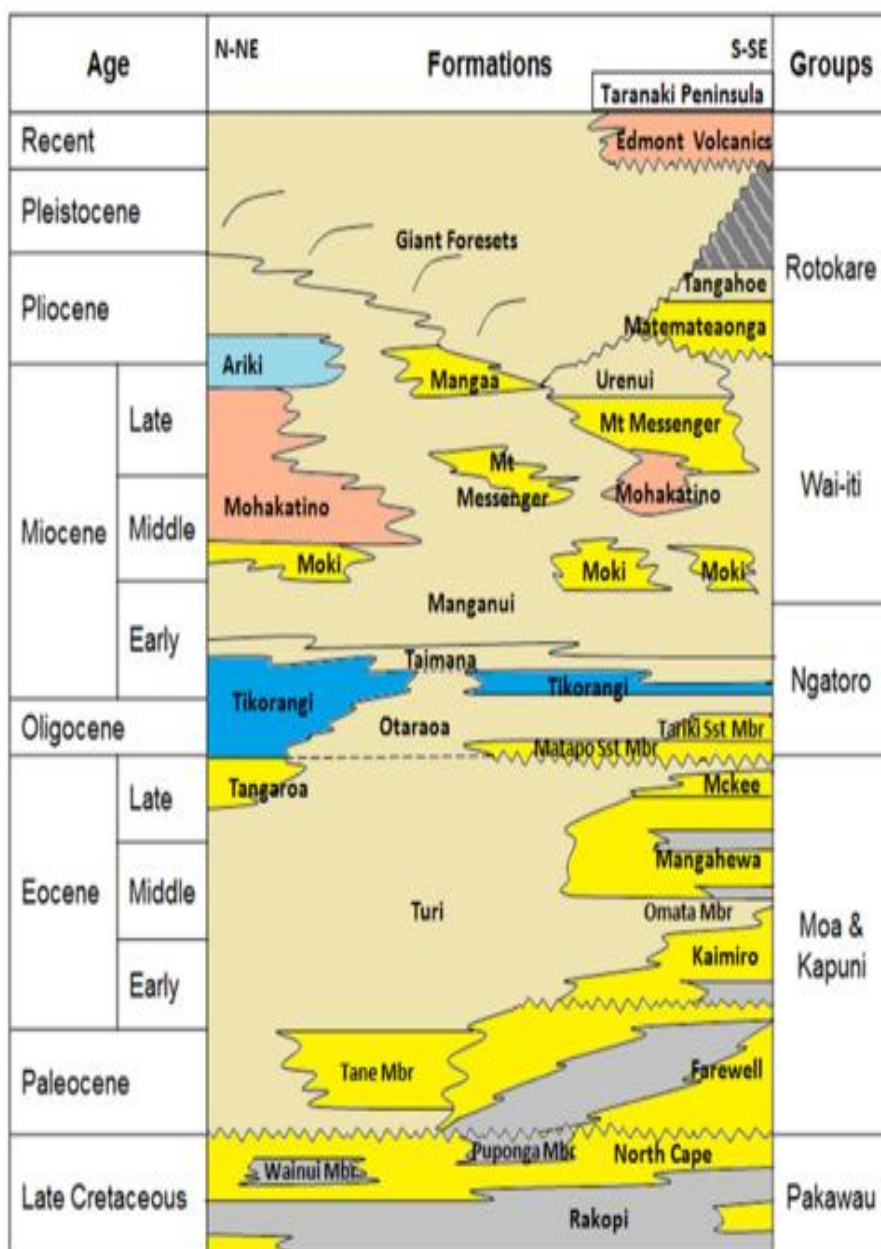


Figure 7: Generalized chrono-stratigraphy of Taranaki Basin (modified from King and Thrasher 1996).

2.2.3 Moki Formation

The Moki formation comprises sandstones intercalated with Siltstones and bathyal clay (Bussell,1994)(Table 1). These deposits are majorly characterized by detrital sedimentation associated with changes in sea level and tectonism associated with the deposition of the sediments as reported by Larsen et al., 2023, during the early to middle Miocene, the deposits extended with the deposition of submarine channels, which is also associated with significant regression (De Bock, 1994). The deposition of this formation started within the deep water region of the Muddy Manganui Formation, with the submarine channels just below the continental slope and towards the basin floor; these sandstone deposits also transgressed with time towards the North (Dauzacker et al., 1996)(Figure 8). The formation is divided into sections Moki Sandstone A and Moki Sandstone B, as seen deposited in the Kahu-1 and Pateke wells(Engbers,2002). The Moki A sandstone was deposited at the base of the slope and is characterized by complex submarine channel complexes trending in the NW-SE traced by sinusoidal channel complexes consistent with a progradation of the slope model (Bussell,1994; Yagci,2016). However, the Moki B sandstone is characterized by fewer channels. The submarine channel complexes present in the Moki A sandstone are the morphological features of interest in this research.

2.2.3.1 Depositional Environment of Moki Formation

Signatures from wireline logs suggest that the Moki sandstone's coarsening upward sequence indicates a channel progradation(Palmer & Andrews,1993; King & Thrasher, 1996). Palmer and Andrews in 1993 suggested that the onshore and offshore Moki formations differ significantly and are two individual submarine formations transporting from two different sources; this is because provenance suggests that the onshore is from metasediments and igneous rocks in the eastern region, while that of the offshore is from a plutonic and subordinate Metamorphic source. A study of facies distribution and Provenance of the Moki formation carried out by De Bock (1994), achieved through the utilization of wireline logs, drill cuttings, and cores, suggested a south deposit source, which in their research showed that the Moki formation as a constricted and lengthened, north to northeast trending parallel to the slope of the eastern fan system, with the middle part of the fan passing through Maari and Maui fields. The transported sediments are supplied offshore through a delta and a broader shelf. They also showed that some of the submarine canyons incised into the outer shelf and combined into one meandering channel, also seen throughout the entire system.

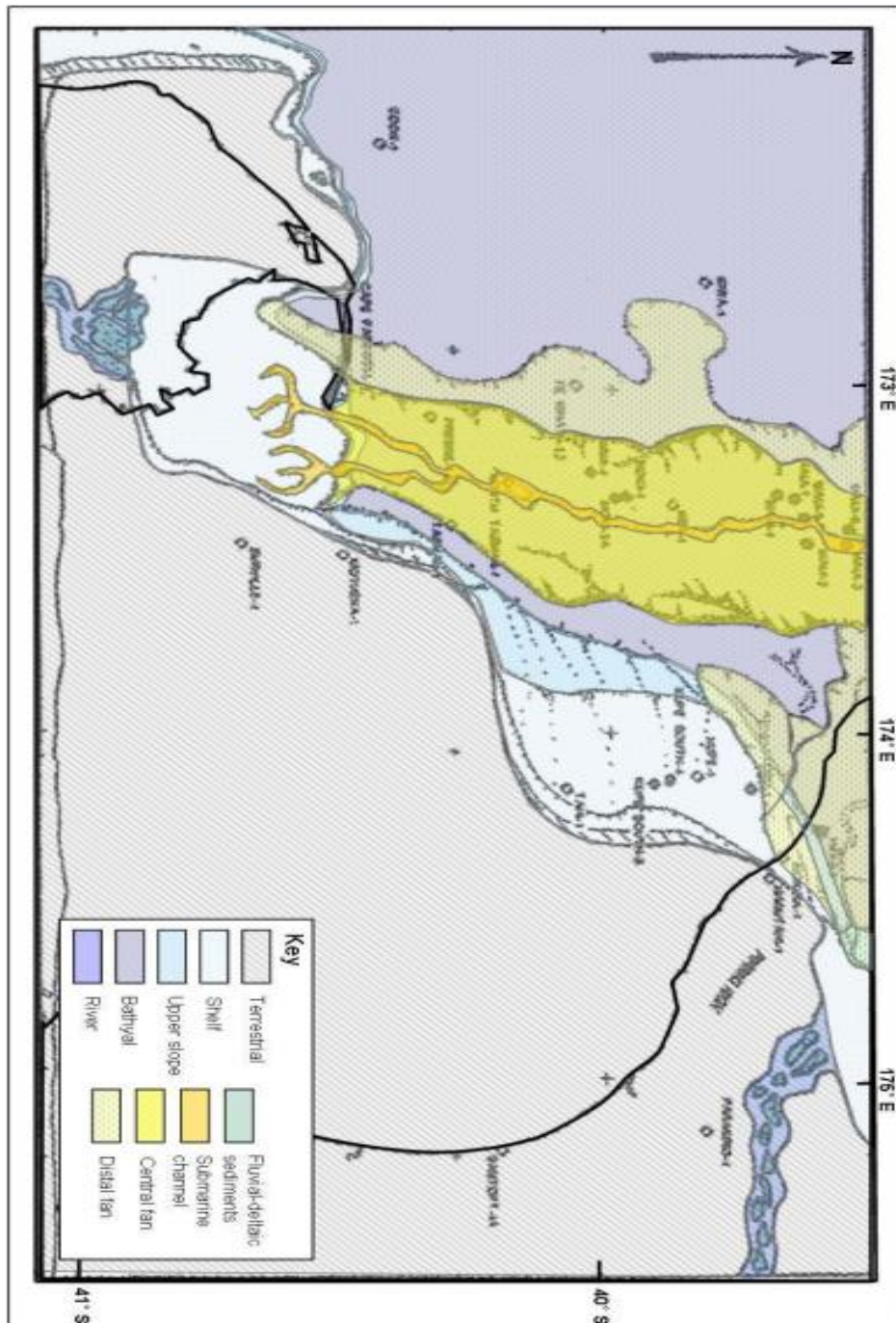


Figure 8: Paleogeography of the southern Taranaki Basin during the deposition of the Moki Formation showing a delta-fed elongate fan system (Modified by Grain, 2008).

Table 1: Sequence groups representing the main stratigraphy and their formations in the Taranaki Basin(Modified from Alzaki,2016).

Age	Phase	Group	Petroleum element	Formation	Abbreviation	Facieses	Environment
Plio-Pleistocene	Regressive	Rotokare	Seal, Reservoir	Mangaa	Ma	Deep-water sandstones	Slope
				Giant Foresets	Gf	Fine grained siltstone and mudstone	Basin floor
				Tanaghoe	Tn	Fine grained interbedded sandstones and mudstone	Shelf deposits
				Matemateaonga	Mt	mudstone shell beds, coal,	Shelf, marginal marine, and terrestrial environments
				Urenui	Ur	Slope siltstone	Slope
Miocene	Regressive	Wai-iti	Seal, Reservoir	Mount Messenger	Mm	Sandstone turbidite	Volcanic sediments
				Mohakaitino	Mk	Deep-water volcanoclastic deposits	Submarine fans
				Moki	Mo	Sandstone turbidite	Submarine fans
				Manganui	Mg	Mudstones	Shelf to basin floor
				Taimana	Ta	mudstone, limestone	Slope
Oligocene	Transgressive	Ngatoro	Seal, Reservoir	Tikurangi	Ti	Limestone carbonates	Outer shelf to the upper slope
				Otaraoa	Ot	Calcareous siltstone and sandstone	Outer shelf to upper bathyal water
				Tangaroa	Tg	Deep marine sandstones	Debris flows
				Turi	Tu	Marine mudstone	Shelf and bathyal regions
				McKee	Mc	Sandstone	Shallow marine
Eocene	Transgressive	Kapuni	Source, Reservoir, Seal	Mangahewa	Mh	Sandstone, coal, mudstone, siltstone	Lower coastal plain and marginal marine
				Kaimiro	Ka	Sandstone, siltstone, mudstone coal	Lower alluvial plain, delta, coastal plain, and marginal marine
				Farewell	Fa	Sandstone, coal mudstone,	Coastal plain
				North Cape	Nc	Siltstone, conglomerate, sandstone, coal seams	Shallow marine
				Pakawau	Ra	Coal measures, sandstone, siltstone, mudstone	Swamp and overbank on fluvial flood plains
Late Cretaceous			Source				

CHAPTER 3

DATA, INTERPRETATION SOFTWARE, AND METHODOLOGY

3.1 Seismic Data

This study's dataset was sourced from New Zealand Overseas Petroleum Limited (NZOP) within the Tui-3D Field (PEP38460), providing us with high-resolution 3D offshore seismic data. This survey, as outlined by Veritas DGC in 2003, spans an area of approximately 352.195 square kilometers (Figure 9). The seismic grid comprises around 1500 inlines and 2471 crosslines, offering detailed subsurface coverage. The survey area is located southwest of New Plymouth, New Zealand, and features an average water depth of 130 meters throughout the entire survey area.

The seismic data was delivered in the industry-standard SEG-Y format, and the header information from the SEG-Y file is detailed in Table (2). The file contains metadata essential for processing and interpretation. With its high-resolution data and substantial coverage, the seismic survey provides valuable insight into the region's subsurface geology, which is particularly relevant for this study's reservoir characterization and modeling efforts.

Table 2:SEG file header text for Tui-3D seismic.

Area	Taranaki_Basin- TUI3D-PR2830 Migration
Survey	TUI-3D
Inline	3000-4500
Cross line	756-3230
Class	3D Seismic

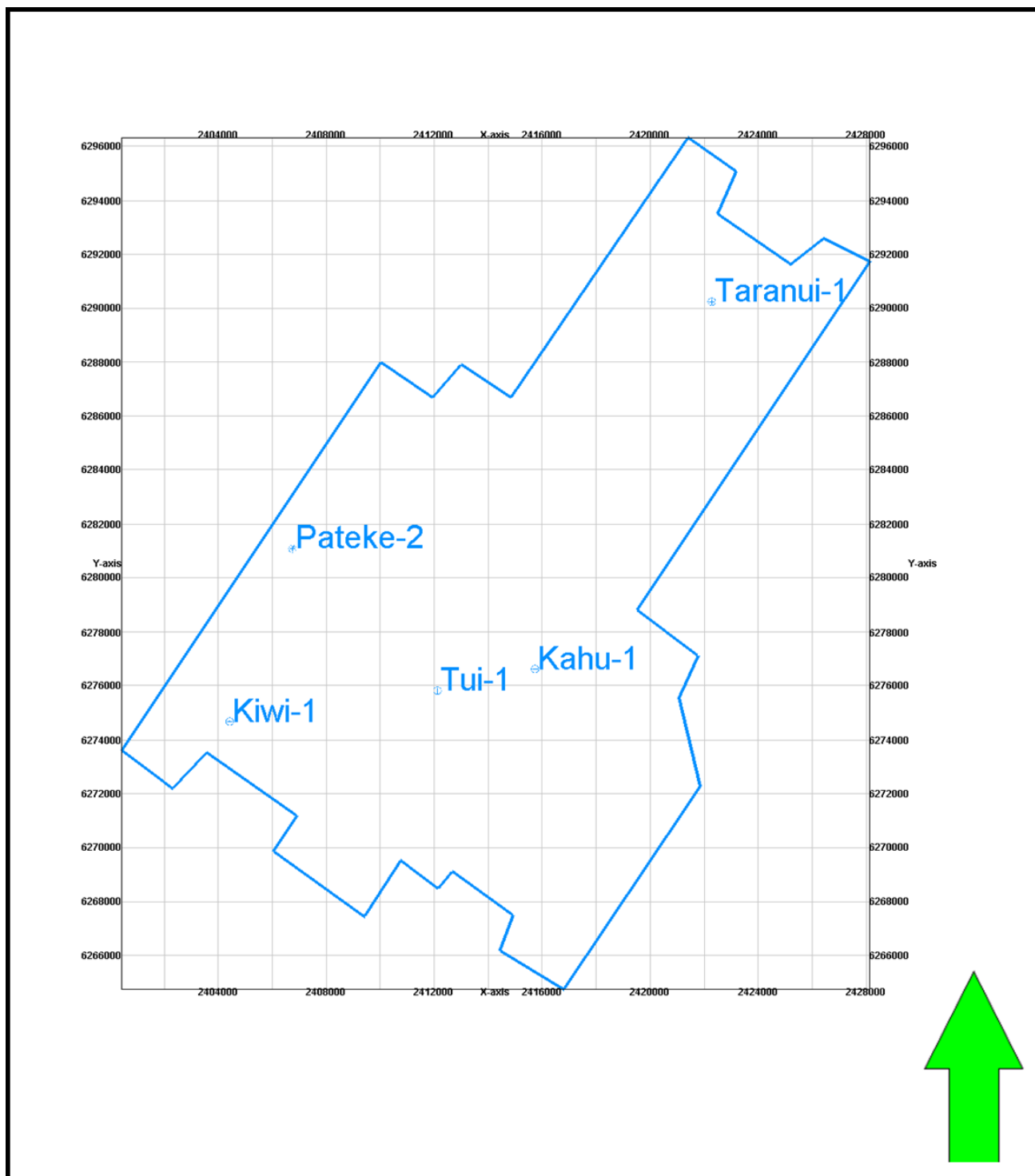


Figure 9: Basemap of the Tui-3D Field showing the wells used for this study.

3.2. Well Data

The data used for the research included five wells, well logs, and checkshot data. Most wells possess various logs, including density, sonic, gamma ray, neutron, and resistivity. (Table 3)

Table 3: Well log summary for the wells.

Well name	well logs										
	GR	DENS	RHOB	NEUT	NPHI	DTC	DTS	RESD	RESM	RESS	SP
Kahu-1											
Pateke-2											
Kiwi-1											
Taranui-1											
Tui-1											

Where;

GR -Gamma-ray

RESS- Shallow Resistivity

DENS -Density

SP- Spontaneous Potential

RHOB- Bulk Density

DTC- Delta-T Compressional

NEUT- Neutron

DTS- Delta-T Shear

NPHI- Neutron Porosity

RESD- Deep Resistivity

RESM- Medium Resistivity

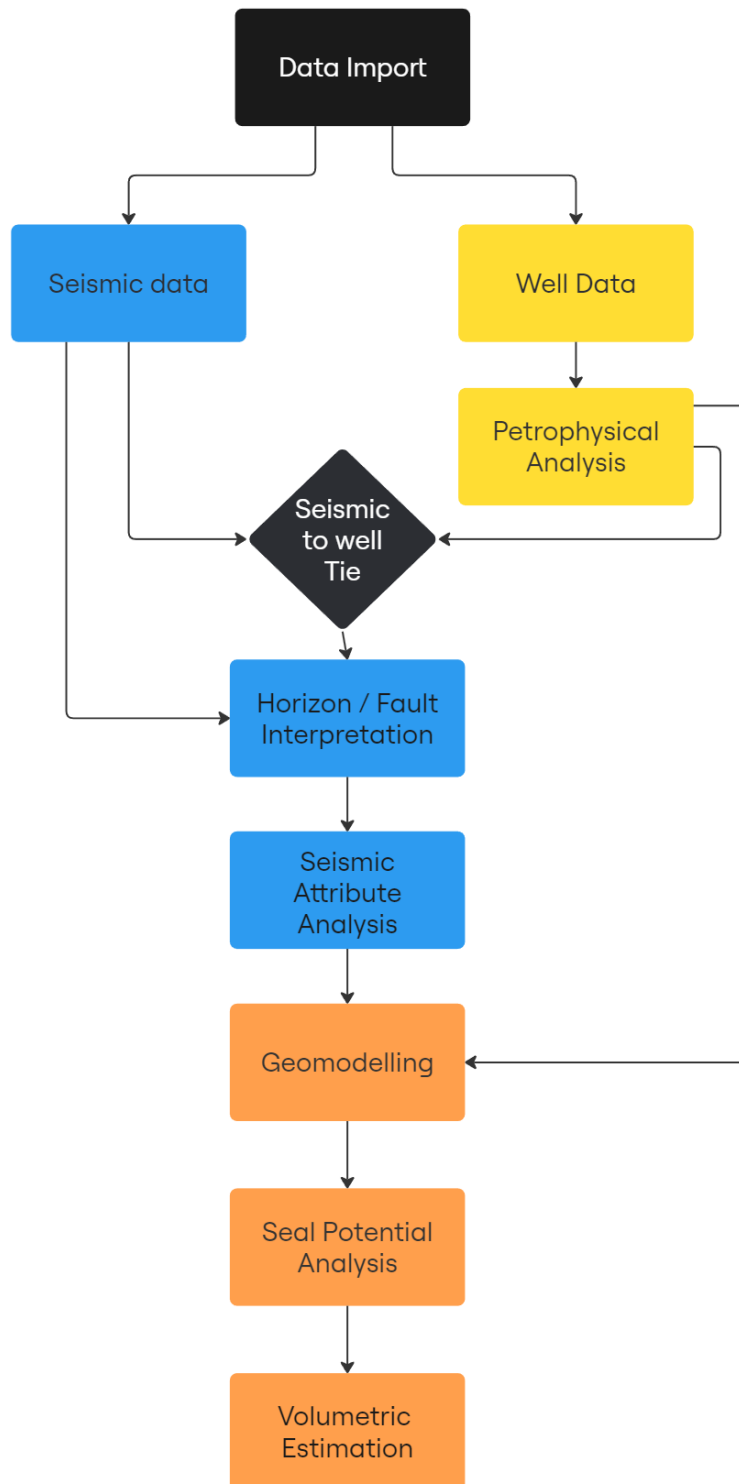
3.3 Checkshot Data

Checkshot data was made available for all the wells in the study, although not all of the data was reliable. Some of the checkshot data contained errors or inconsistencies, which could have compromised the accuracy of the seismic-to-well tie process. These erroneous datasets were carefully identified and set aside to avoid introducing inaccuracies into the subsequent interpretations. However, to maintain consistency and ensure high accuracy, reliable checkshot data from wells with accurate measurements were shared with other wells lacking dependable information. Sharing accurate checkshot data was critical to achieving a successful seismic-to-well tie. The checkshot data provides a crucial link between seismic time and depth, allowing for accurate calibration of the seismic data to the well locations. Without accurate checkshot data, it would be challenging to properly correlate seismic horizons with well data, leading to potential errors in the interpretation of subsurface structures. Using trustworthy checkshot data from other wells, the seismic-to-well tie could be performed with high confidence. This ensured that the well locations accurately matched their corresponding seismic reflections. With the seismic-to-well tie completed, the next steps of the workflow, such as horizon interpretation, could proceed with a robust foundation, ensuring that the geological and structural interpretations were based on accurate, well-tied data. This method greatly enhanced the overall reliability of the seismic interpretation and the subsequent geological model.

3.4 Interpretation software

Techlog (Version 2021), Petrel software 2024(64-bit), and Paleoscan 2023, all Windows-based three-dimensional interactive systems except for Techlog, were used for well-log evaluation and seismic data interpretation. The software enables the user to use accessible packages to generate convincing results. The Petrel software was used extensively during interpretation; the software allowed the user to interpret the horizons and faults, perform a personal seismic attribute analysis, generate various maps, and generate all forms of 3D model generation. Techlog software was used for the well-log analysis and interpretation, which were later exported and incorporated into the petrel software for other interpretations. This software allowed for data display and results in time and depth domains. The Paleoscan software was used in the geobody extraction for the volumetric estimation (Storage capacity estimation); this software enhances the visualization of the Geoboy across each horizon slice in 2D and 3D, considerably improving the interpretation outcomes.

3.5 Methodology



miro

Flowchart 1: Summarized flowchart of methodology.

3.5.1 Petrophysical Evaluation

The reservoir in question, namely the Miocene submarine channels within the Moki formation, is found within the depth range of 2500 meters down to about 2800 meters in some of the wells. Conventional analysis of healthy logs will be conducted to extract various petrophysical properties of the Miocene channel's reservoir and the overlying seal in the region. Analyzing well logs would involve the application of established equations and standard procedures documented in prior literature, such as works by Archie (1942), Poupon, and Leveaux. (1971), Atlas (1979), Asquith and Gibson (1982), and Dewan (1983), Simandoux(1963) all these equations are of equivalent importance in carbon sequestration, and they include;

The Gamma Ray index is estimated with equation(1), after which the volume of shale would be estimated using Steiber's (1970) equation denoted by equation(2)

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \dots \dots \dots (1)$$

Where;

GR_{log} = the Gamma-ray log at the depth of interest

GR_{max} = the Gamma-ray value indicating shale matrix

GR_{min} = the Gamma-ray value indicating sand matrix

$$V_{sh} = \frac{I_{GR}}{3 \times (2 \times I_{GR})} \dots \dots \dots (2)$$

Where;

V_{sh} = is the Volume of shale at the depth of interest

Equations (4) and (5) were used to calculate the total and effective porosity based on density and neutron log data.

$$\varphi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \dots \dots \dots (3)$$

Where;

φ_D = is the density porosity

ρ_{ma} = is the matrix density

ρ_b = is the formation bulk density

ρ_f =is the fluid density

$$\varphi_T = \sqrt{\frac{\varphi_D^2 + \varphi_N^2}{2}} \dots\dots\dots(4)$$

Where;

φ_D =is the density porosity

φ_N = is the neutron porosity

φ_T = is the total porosity

$$\varphi_E = \varphi_T \times (1 - Vsh) \dots\dots\dots(5)$$

Where;

φ_T = is the total porosity

Vsh = is the Volume of shale at the depth of interest

The formation factor is first estimated using equation (6), which accounts for the properties of the shale within channels serving as the intraformational shale layer or shale intercalation. Subsequently, Simandoux's water saturation equation (7) is applied to calculate the water saturation, incorporating the formation bond water of the shale.

$$F = \frac{a}{\varphi_E^m} \dots\dots\dots(6)$$

Where;

F= is the formation factor

φ_E = is the effective porosity

$$\frac{1}{\sqrt{S_w}} = \frac{F \cdot R_t}{a \cdot R_w} + \frac{V_{sh}}{\sqrt{S_w - Sh}} \dots\dots\dots(7)$$

Where;

S_w = water saturation

F = formation factor

R_t = true formation resistivity

R_w = water resistivity

Vshale = shale volume

The irreducible water saturation value was estimated from equation(8) by the use of the formation factor equation quoted in equation(6)

$$S_{\omega irr} = \sqrt{\frac{F}{2000}} \dots \dots \dots (8)$$

Where;

$S_{\omega irr}$ = is the irreducible water saturation

F = is the formation factor

The Permeability is evaluated using the Wyallie- Rose(1950) method in equation 9 below;

$$k = \frac{62500 \times \phi_e^6}{S_{\omega irr}^2} \dots \dots \dots (9)$$

Where;

k is the permeability in mD

ϕ_e is the effective porosity

$S_{\omega irr}$ is the irreducible water saturation

3.5.2 Seismic interpretation and attribute analysis

The seismic interpretation methodology is built and established in the Schlumberger approach but with modifications specific to the use of Petrel Software 2022 for seismic data interpretation. The seismic-to-well correlation will be accomplished using a synthetic seismogram, which aligns the seismic horizons with five identified wells. The results of this tie confirmed that the well locations on the seismic data were accurate.

Due to the absence of a velocity model that would typically generate a Time-Depth Relationship (TDR), time-depth conversion will rely on check shot data. After this conversion, structural interpretation will proceed, followed by horizon interpretation that reflects the basin's structural characteristics.

In addition, seismic attribute maps will play a key role in improving the clarity of the seismic data. These maps are crucial for identifying lithologies suitable for gas storage, understanding the depositional environment, and detecting faults within seismic profiles. Such geological features also shed light on the region's structural development.

Using seismic attributes like RMS and sweetness will help identify seismic anomalies and bright spots, often linked to the potential presence of hydrocarbons or variations in lithology.

Furthermore, variance attributes will be utilized to refine these interpretations and enhance the detection of subtle structural and lithological features.

3.5.3 Geo modeling

Petrel software was employed as a 3D geo-cellular modeling tool in the static modeling process to visualize geological formations, structural elements, and the stratigraphic framework, including the reservoir's sub-layers and fault systems in a three-dimensional space. The fault and structural modeling process involves identifying and defining the faults within the model, using the picked faults and interpreted horizons as input data. This approach follows methodologies similar to those outlined by researchers like Haque et al. (2016) and Islam et al. (2020), where the VBM (Virtual Backfill Modeling) algorithm provides a comprehensive view of the reservoir. The steps include structural modeling, fault definition, horizon interpretation, and the creation of layering and zoning schemes. Facies models are then generated, relying on the upscaled facies logs, with additional guidance from published studies. This process ensures that the facies distribution is accurately represented within the geological framework. Similarly, petrophysical properties are incorporated into the 3D structural grid, resulting in a detailed petrophysical model that aligns with the overall reservoir architecture. By combining facies and petrophysical models within the 3D grid, the static model provides a robust foundation for understanding reservoir characteristics and supporting further dynamic simulation and analysis.

3.5.4 Seal characterization and seal potential analysis

The seal characterization and potential analysis involve seal capacity, geometry, and integrity. Still, for this research purpose, I will only be restricted to geometry and integrity due to the lack of physical core samples for the laboratory experiment for the seal capacity analysis. For the geometry, data provided for the seismic and wells would be used to determine the channels' lateral extent, width, and vertical thickness. At the same time, for integrity, emphasis would be placed on the evaluation of structures as well as the lithology of the seal to avoid future leakages. Moreover, the fault stability analysis (Geomechanical modeling of the fault) will be evaluated to estimate the activation of the fault concerning its position and applied stress due to injection (Morris, 1998).

3.5.5 Geobody Extraction

Geobody extraction involves three steps: identification, isolation, and extraction. Initially, identification is aided by visualization tools such as box probes, surface probes, and well probes, which enable targeted rendering. However, Paleoscan by Elis now allows for improved

understanding and extraction by using numerous seismic attributes across the created horizon slices, resulting in a complete picture of the depositional environment and reservoir type (with present goodies). Isolation and extraction are then conducted with the help of the polygon creation tools, resulting in a refined geobody with highlighted vital characteristics.

3.5.6 Volumetric Estimation

The storage of CO₂ in stratigraphic traps is more or less similar to the storage in depleted oil and gas reservoirs; however, in the case of oil and gas reservoirs, the stratigraphic traps are oil-wet or saturated by oil and gas or mixed wet, but in the case, the system is water wet. Based on the literature, there are two known methods for the determination of a reservoir storage capacity based on the availability of pressure data, namely the production method and the volumetric estimation method; for this research, we would be utilizing the volumetric method due to the unavailability of the production data. For this research, I will use the storage capacity estimation using the volumetric estimation of the Stratigraphic traps according to Bacho et al. (2007) and the gas storage efficiency value suggestions from Goodman et al. (2011). If the geometric volume of the stratigraphic traps is known, as well as the porosity and irreducible water saturation, then the theoretical volume can be estimated from the equation below;

$$V_{CO_2t} = V_{trap} \phi (1 - S_{wirr}) \times E_{gas} \times Cc \times \rho_{CO_2} \dots \dots \dots (10)$$

Where;

$$V_{trap} = A \times h$$

A = Reservoir Area

h = Reservoir Net Thickness

ϕ = Average Effective Porosity

$$E_{gas} = 0.01$$

$$Cc = 0.014$$

$$\rho_{CO_2} = 154.31$$

S_{wirr} = Irreducible water saturation

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Petrophysical evaluation

Table 4: Petrophysical parameters of the reservoir

Well Name	Av. Effective Porosity	Av. Permeability (mD)	Av. Water Saturation	Layer
Kahu-1	19	80	75	Reservior
Pateke-2	22	195	85	Reservoir
Kiwi-1	20	87	79	Reservoir
Taranui-1	15	30	93	Reservior
Tui-1	21	30	89	Reservior

Table 4 highlights the estimated average properties of the Moki Formation reservoir, which are generally regarded as excellent quality. The average effective porosity within the formation ranges from 15 to 22%, while permeability varies significantly, falling between 30 mD and 195 mD. Such high porosity and permeability values are characteristic of submarine fan deposits, which are typically poorly consolidated, leading to enhanced fluid flow properties. These reservoir qualities align closely with similar findings in the Maari Field, located in an adjacent area of the offshore Taranaki Basin. According to a report by ERCE (2021), the Maari Field encountered an effective porosity of approximately 22%, with an average permeability of 100 mD. This confirms the high reservoir quality of the Moki Formation in that field. Alotaibi (2015) also obtained similar porosity estimates in studies conducted within the Maari Field, reinforcing the consistency of these findings; in addition to porosity and permeability, water saturation values across the Moki Formation range from 79% to 93%. These relatively high values reflect the water-wet nature of the channel complexes within the formation. High water saturation is due to the complete water-wetting characteristics of the formation's pore spaces, leaving only a tiny portion of the pore volume unsaturated. The slight deviation from 100% saturation is attributed to shaly intercalations within the channel complexes, which act as barriers to full water saturation. Further support for these findings comes from core analysis

data collected from various onshore and offshore wells within the Moki Formation, where average effective porosity values between 17% and 24% have been observed. Additionally, horizontal permeability in these wells was found to range from 0.31 mD to 90 mD, as Higgs (2004) reported. These values illustrate the variability in reservoir quality across different fields, but the offshore Moki formation has shown better reservoir quality. (Dauzacker et al., 1996 King and Thrasher, 1996 Engbers, 2002) also reported average porosity ranging from 21-23% in the Maui with permeabilities of up to about 588 mD. Therefore, the Moki formation in other fields in the offshore Taranaki basin is an attractive injection target based on the estimated porosity and injectivity values.

Table 5: Petrophysical parameters of the seal.

Well Name	Av. Effective Porosity	Av. Permeability (mD)	Av. Water Saturation	Layer
Kahu-1	4	0.1	99	Seal
Pateke-2	3	0.1	95	Seal
Kiwi-1	4	0.2	97	Seal
Taranui-1	6	0.4	99	Seal
Tui-1	5	0.1	98	Seal

Table 5 shows the evaluated petrophysical properties of the Upper Manganui Formation, serving as the seal, in this case, a mudstone-dominated sequence in the offshore Taranaki Basin. The table illustrates key caprock properties, including average effective porosity, permeability, and water saturation. The value of the effective porosity varies from 3 to 6%, permeability varies from 0.1 to 0.4 mD, and water saturation is 95% to 99%. This fine-grained mudstone acts as a regional caprock, preventing the upward migration of injected CO₂ or from the Moki Formation's underlying, more permeable reservoirs, which is an effective seal in subsurface CO₂ storage scenarios. Note that the permeability results especially were documented after the upscaling of the permeability log using the geometric method of the upscaling, so significance is only given to the non-zero values, in this case, the reservoir, which is the Moki formation.

Moreover, mudstones are typically characterized by low porosity and permeability due to their compact, fine-grained structure, which limits fluid storage and transmission. The very low permeability values indicate the formation's ability to trap CO₂ effectively, preventing leakage and ensuring long-term storage security. The high water saturation values reflect the water-wet

nature of the mudstone, where the pore spaces are almost filled with water, leaving little room for gas or fluid migration. Even though minor fractures or localized zones may occasionally show slightly higher permeability, the overall upscaled values confirm the Manganui Formation's low-permeability characteristics, making it highly effective in containing CO₂. This is particularly important for carbon capture and storage (CCS) projects, where the success of long-term CO₂ sequestration depends on the robustness of the seal. In contrast to the highly porous and permeable Moki Formation, which serves as a potential storage reservoir, the Upper Manganui's mudstones act as the perfect caprock to secure the injected CO₂ within the subsurface, ensuring its containment and preventing environmental leakage. Despite the promising data on the Upper Manganui Formation, much remains unknown due to the lack of extensive research, especially in areas where the Upper Manganui overlies the Moki Formation. Furthermore, the Upper Manganui is considered water-wet, and there is no history of hydrocarbon exploration in this region, which suggests that the presence of hydrocarbons has not compromised the seal's properties. This water-wet condition strengthens the argument that the Upper Manganui Formation is an ideal caprock for CO₂ storage, as the lack of hydrocarbons ensures that the seal remains intact and effective. In summary, the evaluated petrophysical properties of the Upper Manganui Formation, particularly its low porosity, extremely low permeability, and high water saturation confirm its role as a highly effective seal for CO₂ storage. The formation's compact nature and the results of the upscaled permeability data indicate that it can successfully contain CO₂, preventing leakage and ensuring long-term storage security. While additional research may provide further insights into the formation's potential, the available data suggest that the Upper Manganui Formation is a reliable and robust caprock well-suited to support CO₂ storage projects in the offshore Taranaki Basin.

4.2 Seismic Interpretation

4.2.1 Seismic to well tie

The seismic-to-well tie aims to bring an agreement between the log data in depth and the seismic data in time. This is done using the sonic and density logs to create the synthetic seismogram. The time-depth relationship from the velocity data is shared and applied to the wells. Furthermore, the synthetic seismogram was adjusted until the time traces matched the depth traces from the well.

4.2.2 Fault Interpretation

A relatively fault-sparse geological setting characterizes the submarine channel environment in the Tui Field study area. Only five faults have been identified in this region, primarily displaying negligible or minor displacements. Importantly, no major faults have been observed within the study area. The limited presence of faulting is significant, especially in potential CO₂ storage, where fault structures and zones of weakness could either serve as conduits for gas migration or act as barriers if the faults are sealed. In CO₂ storage projects, faults can pose a risk if they act as pathways for escaping injected CO₂. Specifically, if faulting extends through the Upper Manganui Formation, which serves as the regional seal for the reservoir, and if these faults are not effectively sealing, they could compromise the integrity of the seal, creating a leakage pathway for CO₂. This is especially concerning for future CO₂ injection activities, where maintaining the containment of the gas is critical to the success of the storage operation. Within the Tui Field, most identified faults extend vertically from the reservoir to the seal level. However, it is important to note that most of these faults are not observed near the five wells drilled in the field. This could suggest a lower risk of fault-related leakage near the wellbores, but the potential threat posed by faulting in other areas remains a consideration for future injection planning. While the faulting observed in the Tui Field appears to be relatively limited in scale and impact, careful monitoring and further evaluation will be necessary, particularly concerning faults that penetrate both the reservoir and the seal. The presence of these faults underscores the importance of understanding fault behavior concerning CO₂ storage and injection projects. Ensuring that the faults are adequately sealed is critical to preventing CO₂ migration. Figures (10&11) below illustrate the targeted horizons and the minor interpreted faults within the field in 3D view, providing a more precise visualization of the fault architecture.

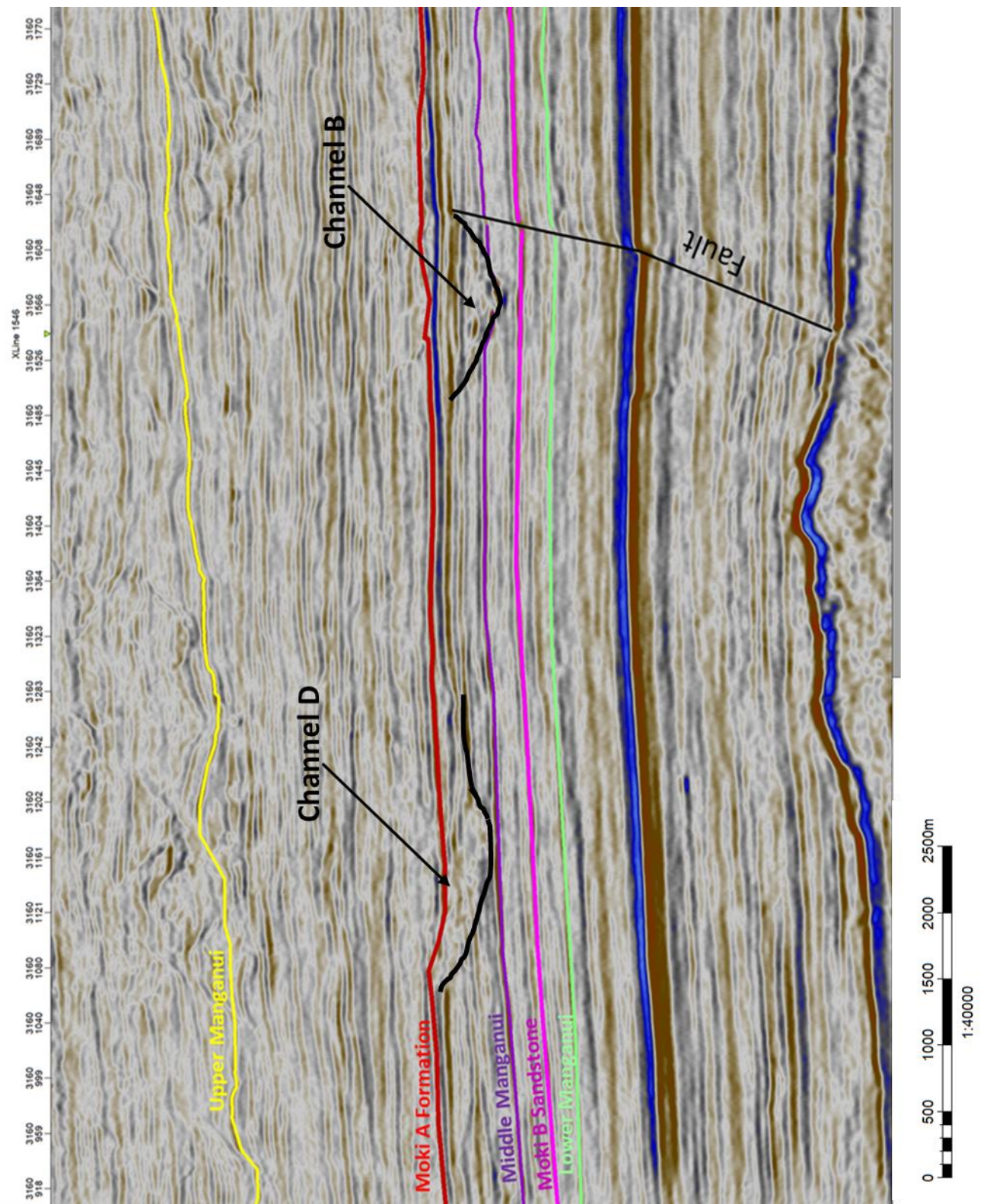


Figure 10: Inline 3160 showing the interpreted fault and corresponding horizon.

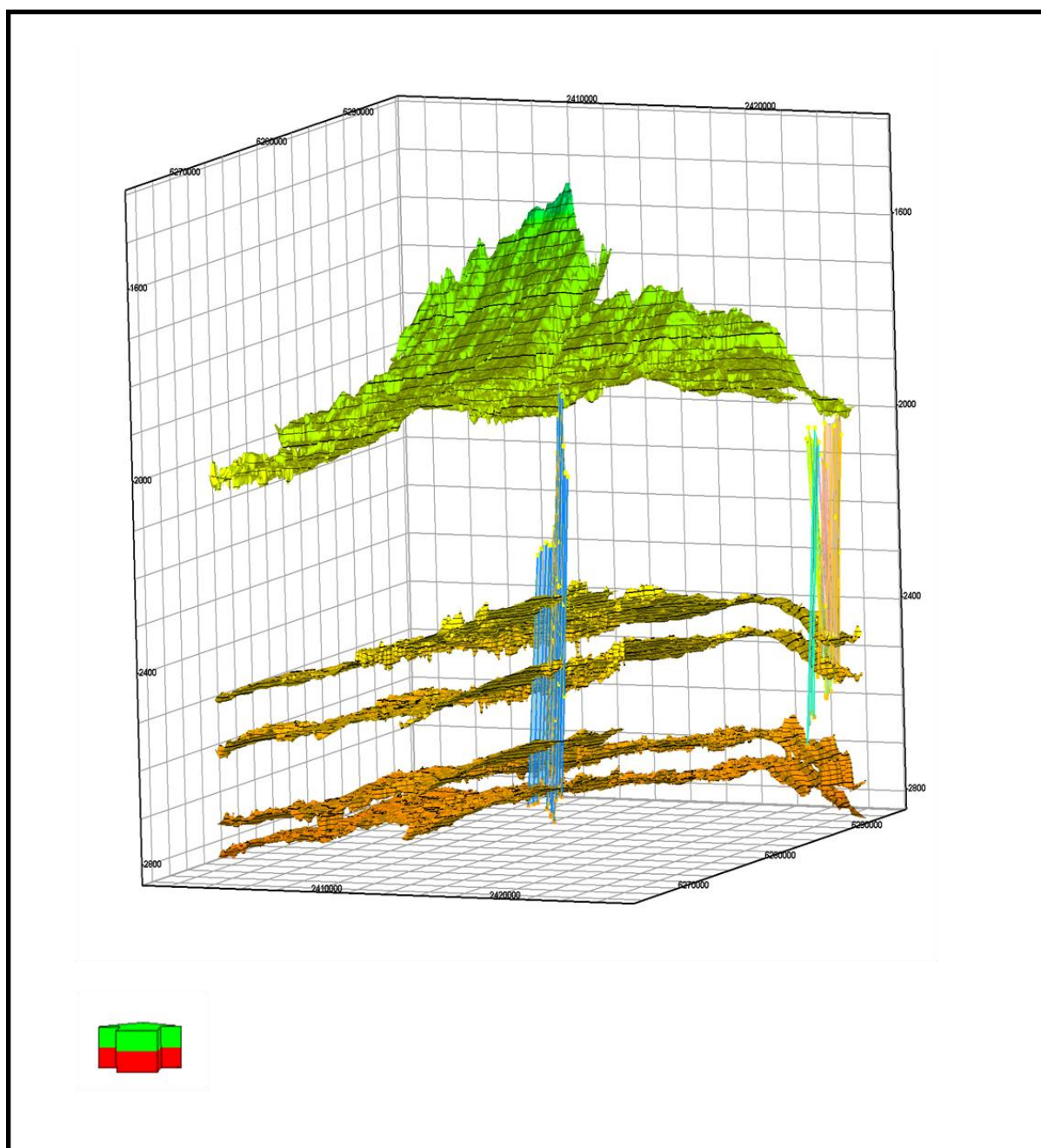


Figure 11: 3D depth view of five horizons: the Upper Manganui, The Moki A Sandstone, the Middle Manganui, The Moki B Sandstone, and The Lower Manganui.

4.2.3 Horizon Interpretation

Following the fault interpretation, the next step involved horizon interpretation, which was conducted using automated and manual techniques. The automated methods included 3D Auto Tracking, 2D Auto Tracking, and 1D Auto Tracking. However, manual interpretation was applied in areas where the data was highly chaotic, and these methods failed to produce accurate results. The stratigraphic formation tops from the wells provided essential guidance for accurately picking the horizons. Five key horizons were interpreted, each associated with a specific geological formation. These included the Upper Manganui Formation, which is represented in yellow. The Moki A Sandstone is marked in red. The Middle Manganui Formation is shown in purple. The Moki B Sandstone is colored pink. The Lower Manganui Formation is depicted in green(Figure 12). These interpreted horizons are displayed in Figure 1, which shows the seismic section in the inline direction. The Moki A and Moki B sandstones deposited within submarine fan systems are considered potential reservoirs. These sandstones are associated with favorable depositional environments for hydrocarbon storage. The Middle Manganui Formation acts as an intraformational seal, while the Upper Manganui Formation is identified as the regional seal, providing a cap over the reservoir. A notable feature observed during horizon picking is the discontinuity of the horizons in the areas associated with channel complexes. These discontinuities are especially apparent in the Moki A and Moki B sand horizons, reflecting the complex nature of submarine channel systems. The interpretation of the Middle Manganui and Moki B horizons highlights the deposition of Manganui claystone within sandy submarine channels. These deposits are attributed to the waxing and waning energy intervals driven by sea-level fluctuations and the amalgamated nature of some of the channel systems. These stratigraphic relationships help to illustrate the dynamic sedimentary processes influencing the area during deposition. At the base, the Lower Manganui Formation marks the end of the Manganui sequence, encapsulating the Moki Sandstone. A distinctive bright amplitude is observed on the seismic section, signaling the onset of the Tikorangi Formation, which overlies the Moki sequence.

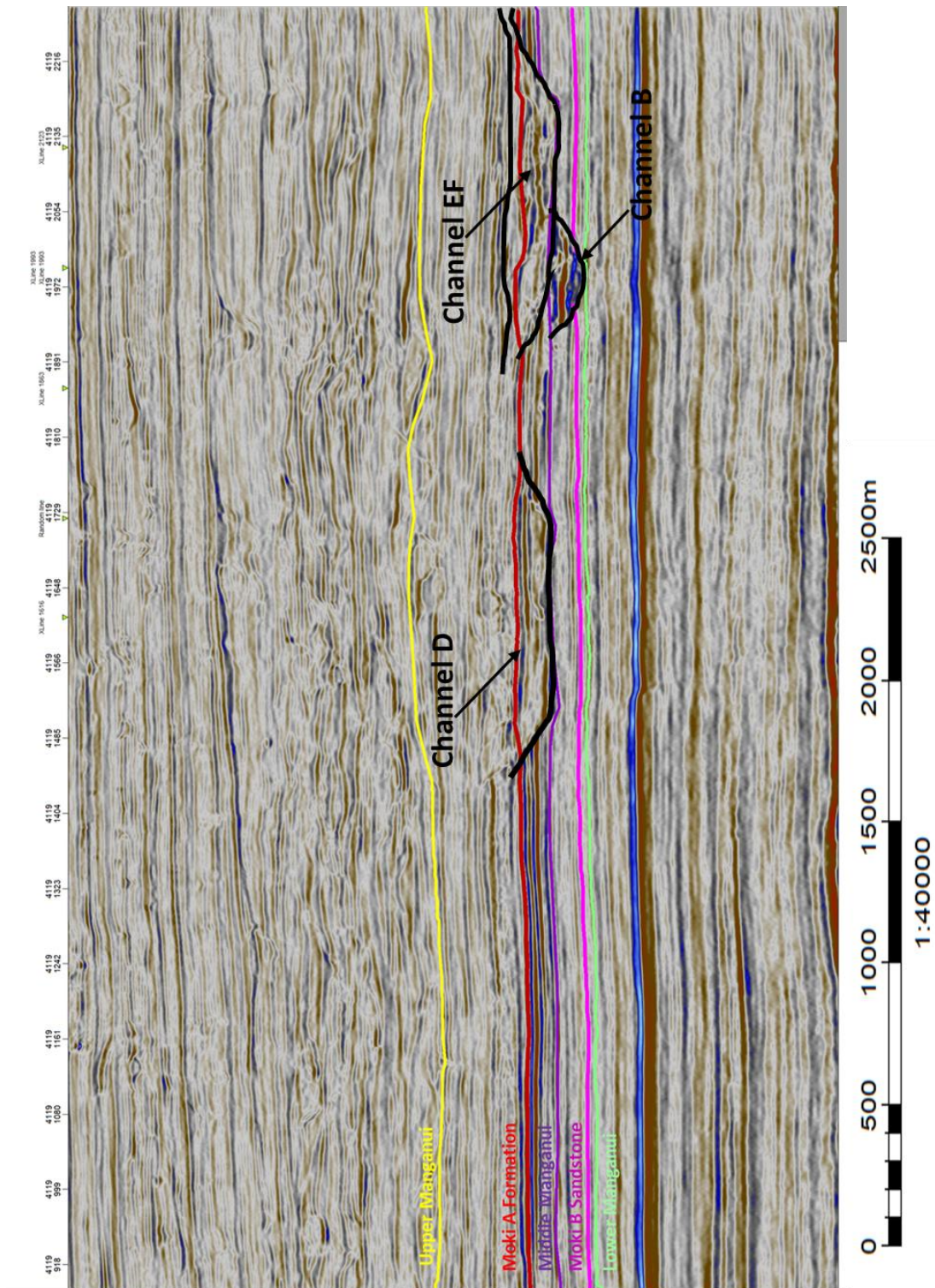


Figure 12: Inline 4115 shows the interpreted horizon.

4.2.4 Seismic Attributes Analysis

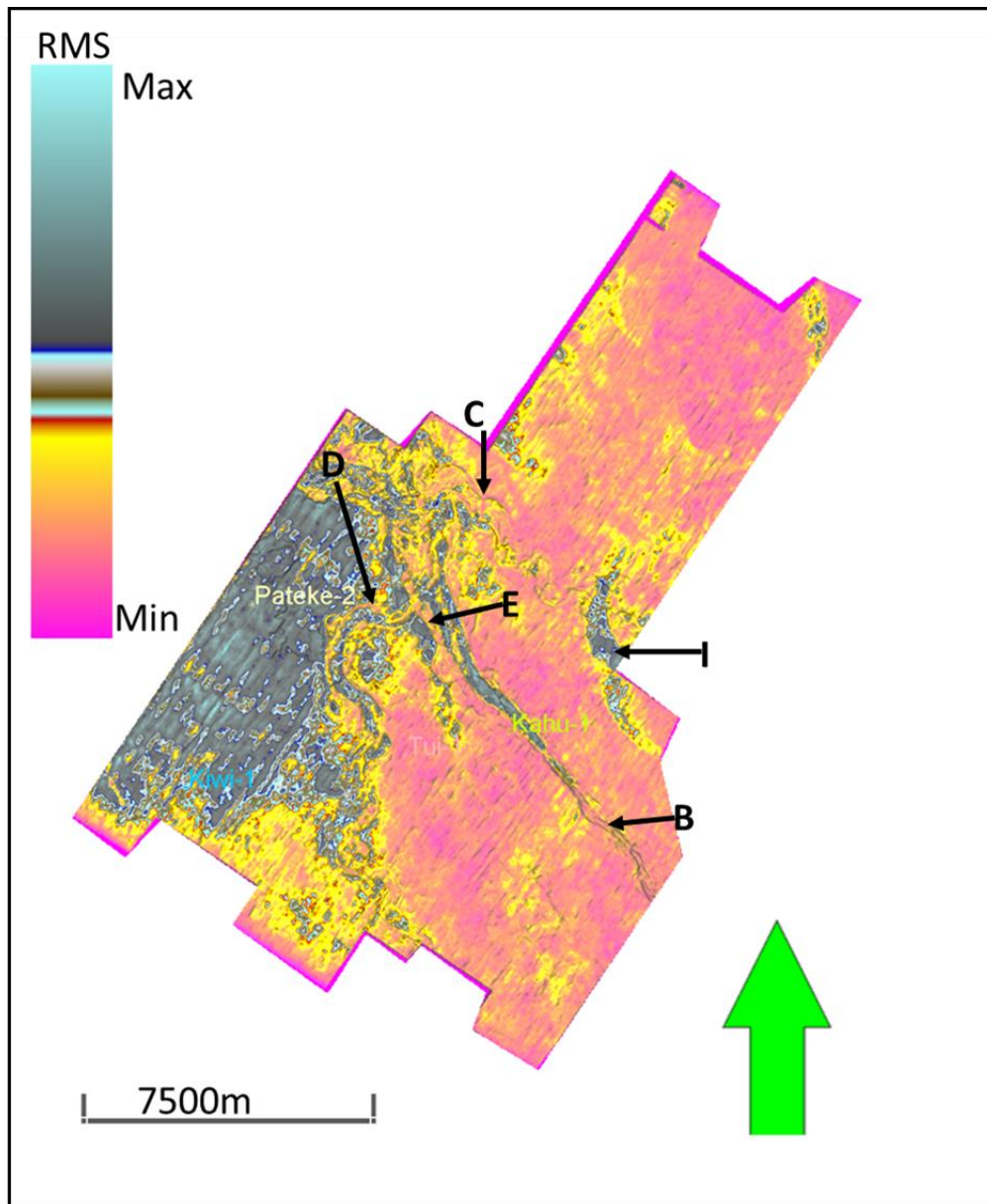
A seismic attribute is a quantitative representation of a seismic feature of interest, and geophysicists have used attribute analysis to understand seismic data reflection since the 1930s (Chopra & Marfurt, 2007). Seismic attributes provide additional information about subsurface geological features based on seismic data. The seismic attributes were used to identify and better understand the submerged channels in the Moki A and Moki B sandstone. The seismic attribute volumes generated include RMS (root mean square amplitude) and Chaos, which are used to analyze submarine channels.

4.2.4.1 Root-mean-Square Amplitude (RMS)

The RMS characteristic is utilized to identify sandy and shaly lithologies in 3D seismic data, particularly in clastic environments. The attribute is a post-stack amplitude estimator, which takes the square root of the additional square amplitudes and divides them by the number of samples within the provided window. Figure (13) illustrates the RMS amplitude map of the Moki A Sandstone. The blueish-blackish high RMS amplitude within the channel interval and the area on the map's west side show overbank sand deposits. In contrast, the yellowish part on the channel's outer edge represents channel levees and, most likely, avulsion deposits.

4.2.4.2 Chaos Attribute

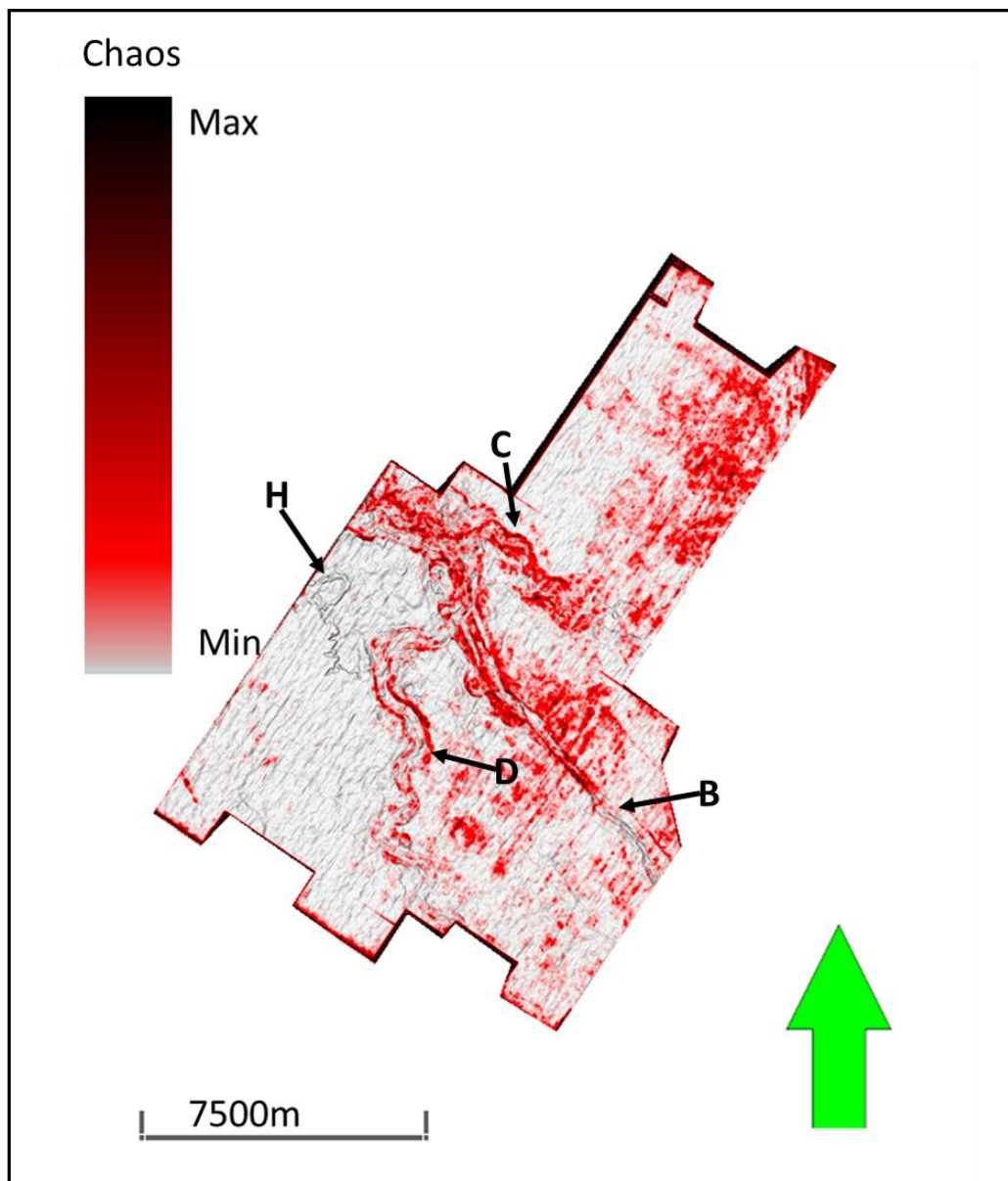
The Chaos attribute shows the chaotic nature of the seismic data using the azimuthal and dip evaluation method, showing the lack of continuity and lesser consistency as the chaotic pattern. This nonconsistency pattern is used to identify discontinuities like fault and other bodies like channels, among others. Pereira, in 2009, reported that the volume attribute of chaos spans from 0 to 1, and 1 is described as the highest non-consistent (Figure 14).



Legend

- B - Channel B
- C - Channel C
- D - Channel D
- E - Channel E
- I - Channel I

Figure 13: The Moki A sandstone's Root-Mean-Square(RMS) amplitude attribute map. Blueish to the blackish distribution of sandy interval within the channels and the overbank deposits.



Legend

- B - Channel B
- C - Channel C
- D - Channel D
- H - Channel H

Figure 14: The Chaos attribute map of the Moki A sandstone showing reddish chaotic signatures around channels; each alphabet reflects a channel.

4.3 Geo Modeling

4.3.1 Structural Modeling

The 3D structural modeling of the Moki Formation framework in the study area includes identifying and defining five interpreted faults. The model highlights a reduced impact of Oligocene to recent tectonic activity on the Tui Field. Specifically, the structural interpretation reveals sparse faulting within the channel interval despite the significant Miocene compressional tectonics that affected other parts of the basin. These faults exhibit a consistent NW-SW trend, extending upward into the Manganui Formation's upper section. This fault orientation and pattern are critical indicators of the region's tectonic evolution (King & Thrasher, 1996). The Taranaki Basin has experienced a complex tectonic history characterized by extensional and compressional phases. During the Cretaceous and early Paleogene, the basin was primarily influenced by extensional tectonics, driven by the opening of the Tasman Sea. However, by the Oligocene and especially during the Miocene, the tectonic regime shifted toward compression, coinciding with the Pacific-Australian plate convergence (King & Thrasher, 1996). This compressional phase is mainly associated with the Miocene period, when the formation of thrust faults and folding impacted much of the basin. Interestingly, the reduced faulting observed in the Moki Formation within the Tui Field aligns with the region's experience of compressional tectonics during the Oligocene to Miocene. Despite the Miocene compressional forces, the Tui Field shows fewer faults, suggesting that this basin area experienced less tectonic stress than other regions. This is likely due to the Tui Field's position near the western margin of the Taranaki Basin. Fields located closer to the eastern margin, which is nearer to the active plate boundary, would have experienced more significant tectonic compression and deformation. This observation underscores the variability and inconsistency of tectonic impacts across the Taranaki Basin. While the Miocene compressional phase profoundly affected some areas, creating significant faulting and structural deformation, the Tui Field remained relatively unaffected, with fewer and more widely spaced faults. The NW-SW trending faults in the Tui Field are consistent with regional fault systems that developed in response to the basin's tectonic evolution. However, the fault density and deformation patterns reflect the specific tectonic context of this field. The 3D structural modeling of the Moki Formation in the Tui Field reveals a distinct tectonic setting where the compressional forces of the Miocene phase had a reduced impact (Figure 11). This is mainly due to the field's location in the western part of the basin, farther from the more tectonically active eastern margin. The observed faulting patterns, along with the reduced fault density, highlight the uneven

distribution of tectonic impacts across the Taranaki Basin, confirming the complexity of the region's geological history (King & Thrasher, 1996; Kroeger et al., 2013).

4.3.2 Facies Modeling

The effective porosity log was key in interpreting facies logs across the reservoir. These facies logs were then upscaled based on the gamma-ray responses from the wells and the corresponding effective porosity data. Applying an arithmetic method for upscaling the facies logs was deliberate because it provides a straightforward approach for averaging continuous properties across the reservoir and the seal intervals. This method ensures that the bulk volume of these properties remains consistent, offering an accurate depiction of critical reservoir and seal characteristics. One of the key advantages of using arithmetic averaging is its simplicity, mainly when there is a slight variation in property values across the formation. This ensures that essential features of the reservoir model are preserved. Object-based stochastic modeling was employed to model the facies in the reservoir. However, instead of relying on the default fluvial channel settings provided by the modeling software, a seismic attribute map derived from the Root Mean Square (RMS) amplitude was used as an input and trend guide. This approach was chosen to ensure a more accurate alignment between the distribution of the reservoir channels and the facies across the target depth intervals. Using the seismic attribute map, the model could reflect a more realistic distribution of channels and facies within the reservoir. A different approach was applied to the seal. The facies modeling algorithm relied on sequential indicator simulation (SIS) to distribute the percentages obtained from the upscaled facies logs. This method allowed for a more accurate portrayal of the facies distribution in the seal section. The results for the facies distribution in the reservoir (specifically for the channels) are displayed in Figure (15a, 15b, 15c & 16a, 16b, 16c). These figures illustrate the transition from the raw facies logs to the upscaled facies logs, which were then used for modeling both the seal and the reservoir. The figures show the distribution of facies by thickness percentage on the horizontal axis, with the vertical axis representing the facies thickness and percentage distribution. This visualization highlights the changes in facies distribution as the logs were upscaled and applied to the reservoir model.

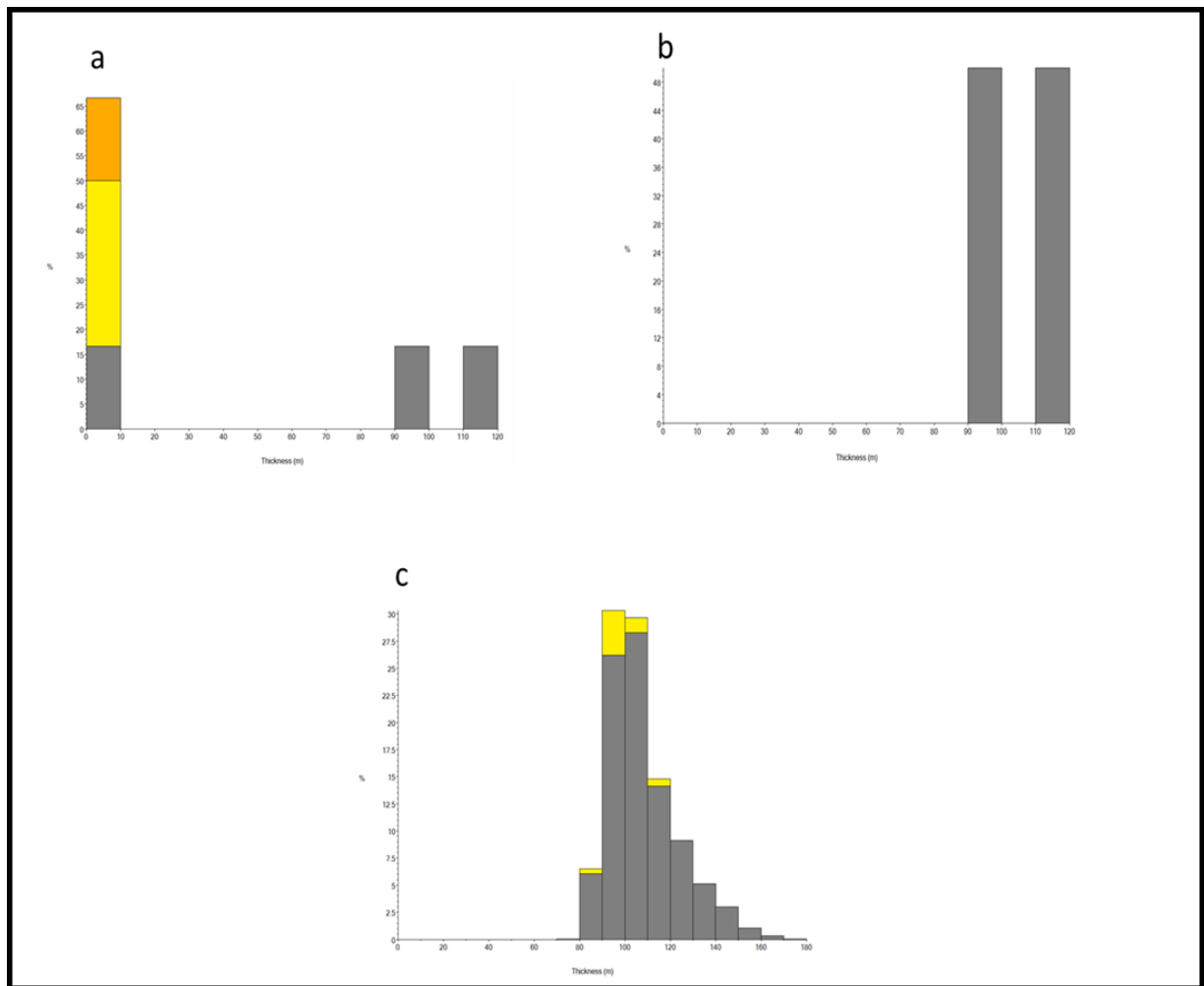


Figure 15 (a,b,c): Distribution of the facies across the seal (Upper Manganui formation), (a) shows the original well-log facies,(b) the upscaled, and (c) the modeled facies.

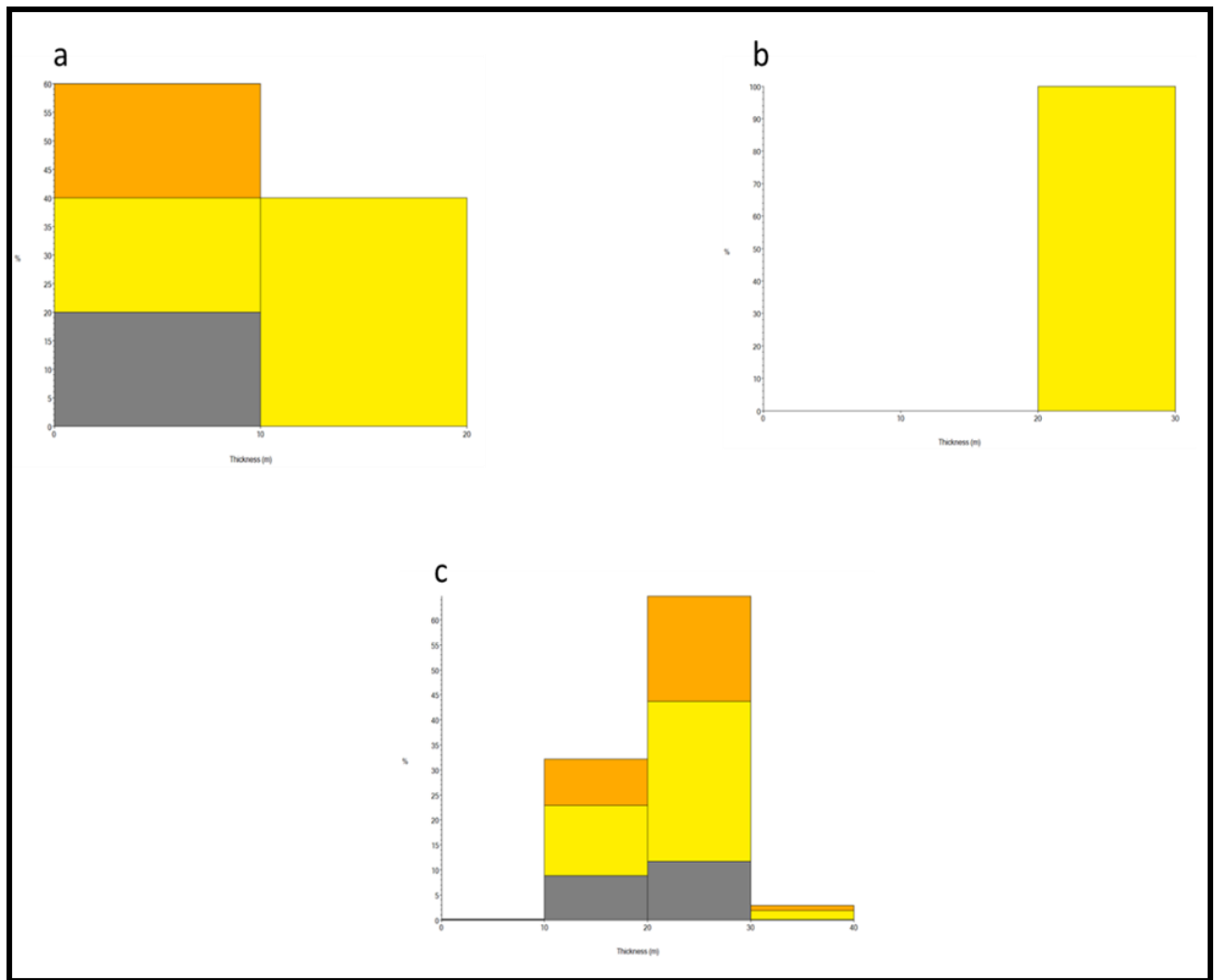


Figure 16 (a,b,c): Distribution of the facies across the reservoir(Moki Formation), (a) shows the original well-log facies,(b) the upscaled, and (c) the modeled facies.

The seal facies exhibit a notable dominance of shale compared to other facies, contrasting with the reservoir, where sandstone facies are more prevalent. This variation is directly tied to the depositional environment associated with deep-water turbidity currents. The sandstone-dominated reservoir facies resulted from higher energy conditions during the deposition of submarine channels, where sand was transported and settled in these environments. In contrast, the seal facies were formed under much lower energy conditions. As illustrated in Figure 17, the constructed facies model of the seal depicts a uniform and extensive distribution of shale facies in both horizontal and vertical directions. The model reveals a thick, continuous layer of shale with more minor, isolated patches of sandstone dispersed throughout. These patches are likely remnants of localized higher-energy depositional events. Still, the overall dominance of shale reflects the waning of energy levels after the deposition of the more energetic submarine channel systems. The figure highlights the thick nature of the shale deposits, a characteristic of

the depositional process during periods of lower energy. After the initial phase of energetic deposition that formed the reservoir channels, energy levels waned significantly, allowing fine-grained sediment, such as shale, to settle and form the thick, laterally continuous seal facies seen in the model. This thick shale layer plays a critical role in the geological seal, ensuring the containment of the CO₂. However, the Upper Manganui is still poorly understood due to its occurrence in only the offshore part of the Taranaki basin, which is still inadequately understood.

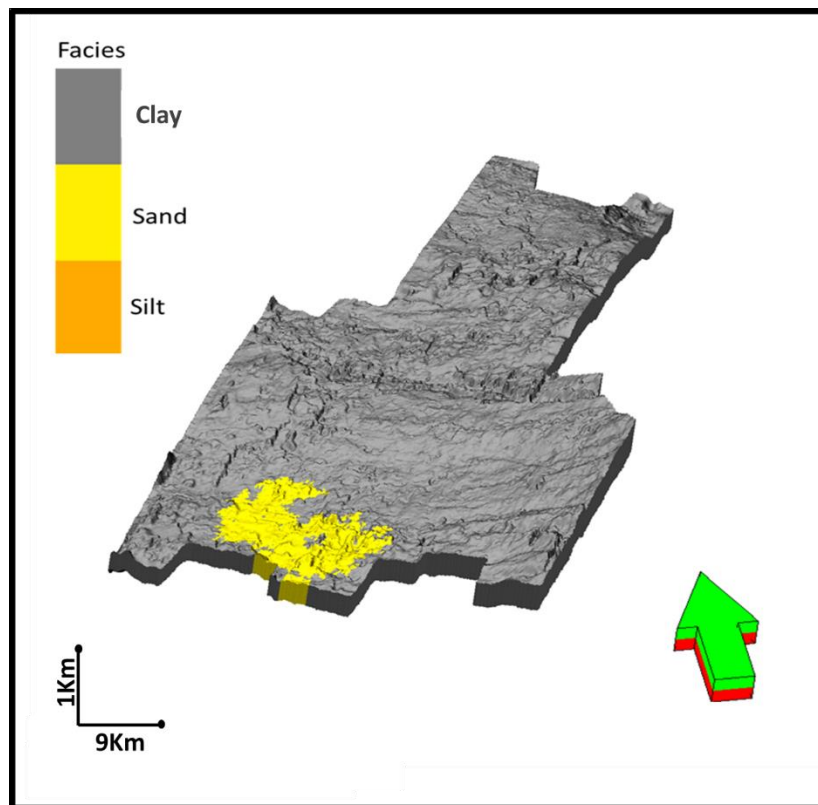


Figure 17: Facies model for the seal showing the pattern and distribution of facies.

The reservoir in this study is predominantly composed of sandstone within the channels and the overbank deposit (Figure 18). The sandstone within the reservoir is described as being well-sorted, a characteristic often attributed to the high-energy depositional processes associated with such environments (Radwan et al., 2021). In the facies model of the reservoir, sandy intervals are primarily observed within the central channel systems. However, they also extend into overbank deposits, highlighting the lateral spread of sand beyond the channels. In addition to these sandy intervals, the model shows silty channel levees and associated avulsion deposits, which form due to the natural shifts in the channel pathways during deposition. While

sandstone dominates the reservoir, the facies are not entirely homogeneous. Clay intervals and thin layers of siltstone are interspersed within the sandstone. This heterogeneity is directly related to the submarine channel depositional environment, where fluctuations in energy levels, driven by waxing and waning currents, influence sedimentation patterns (Browne et al., 2005). During high-energy periods, sand is deposited, whereas lower-energy phases allow for finer materials like clay and siltstone accumulation.

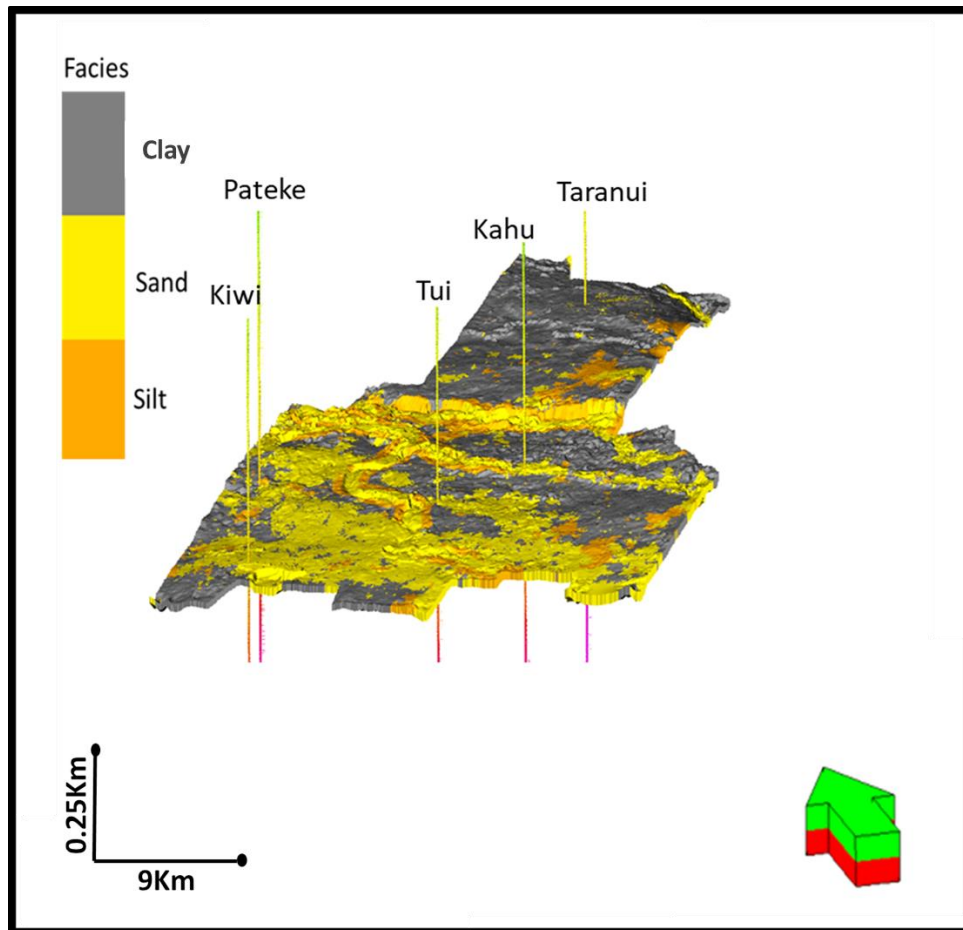


Figure 18: Facies model for the reservoir showing the pattern and distribution of facies.

Figure (19) shows the correlated sand bodies of the Moki Formation, which are interbedded with Clay layers. These clay intercalations between the sand bodies reflect the changing energy conditions during deposition and play a crucial role in the reservoir's ability to compartmentalize fluids. The presence of these shale layers suggests potential barriers to fluid flow, which is an essential consideration for reservoir characterization, particularly for applications such as CO₂ storage, where trapping injected CO₂ within sand-rich intervals is essential for long-term containment. The Gamma Ray logs display a distinctive serrated

pattern, alternating smaller blocky patterns and fining-upward sequences, particularly between the blocky regions. This pattern indicates a recurring shift between the deposition of coarser and finer-grained facies, reflecting an environment where sand-rich and shale-rich materials were deposited in succession. Blocky patterns suggest the influx of sand-rich deposits, representing high-energy events capable of transporting coarser sediments. Each sharp, blocky boundary corresponds to periods of increased energy, likely tied to strong currents or sediment-laden flows that deposited sand within the channel system. In contrast, the fining-upward sequences, where Gamma Ray values gradually increase, signify a decrease or "waning" in depositional energy. As the energy levels drop, the system transitions to depositing finer-grained materials like silt and clay, resulting in a more shale-dominated interval. This shift from sand-rich to shale-rich facies within the channels highlights the dynamic nature of the depositional environment, with alternating episodes of high and low energy. These fluctuations align with cycles of "waxing" (increasing energy and coarser deposition) and "waning" (decreasing energy and finer deposition) during the sedimentary process. Overall, this serrated pattern with interspersed blocky and fining-upward segments captures the episodic nature of deposition, where each cycle reflects the changing flow dynamics within the channel, leading to multiple depositional events and a complex vertical sequence of facies within the system.

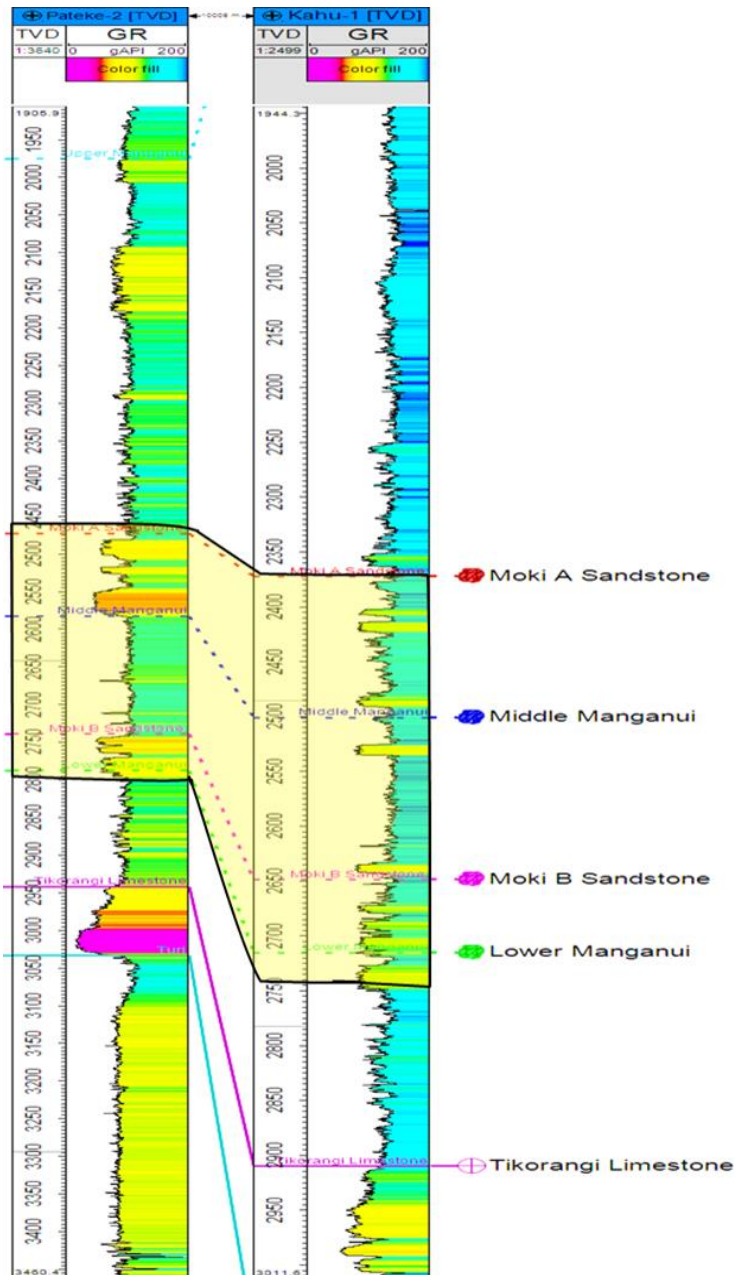


Figure 4: Gamma-ray log character and correlation of stratigraphic units in the Pateke-2 and Kahu-1 well of Moki Formation within the Tui Field.

4.3.3 Property Modeling

The petrophysical properties of the reservoir and the seal were estimated using Techlog software and then transferred to Petrel for further integration into the modeling workflow. Before beginning the modeling process, the logs for effective porosity and water saturation were upscaled using the arithmetic method, which is often appropriate for averaging continuous properties like porosity. In contrast, the geometric method was applied to upscale the permeability logs to provide further weight to non-zero values. This approach helps highlight

the more permeable zones in the reservoir, which are critical for fluid flow, such as CO₂ injection. All property models were subsequently generated using the Sequential Gaussian Simulation (SGS) algorithm, commonly used in geostatistics to create multiple realizations of reservoir properties. The SGS algorithm leverages the facies distribution from the facies model, incorporating both the reservoir and the sealing units in the simulation. By doing so, the model captures the spatial variability of the reservoir properties and honors the geological heterogeneity of the system.

The effective porosity model for the reservoir (Figure 20) depicts the spatial variation of porosity within the Moki sandstone formation. Porosity values range between 15% and 22%, reflecting the different facies within the reservoir. The most porous zones, colored in yellow on the 3D model, correspond to the sandstone units and are primarily associated with the channelized intervals. These channels represent zones of higher effective porosity, indicating areas of better reservoir quality favorable for CO₂ storage. These porous intervals ensure sufficient pore space for CO₂ injection and storage.

The permeability model of the reservoir, also displayed in the 3D view (Figure 21), illustrates the injectivity of the reservoir. High permeability zones are concentrated within the sandy intervals of the channels and the overbank deposits, where permeability values approach 100 millidarcys (mD). These permeable zones, particularly within the submarine channels, highlight the excellent pore connectivity of the Moki Formation. The connectivity and injectivity of these channels support the conclusion that the reservoir is of good quality for potential CO₂ injection and storage. These high-permeability channels suggest that the reservoir can effectively transport and distribute injected CO₂ throughout the formation.

The water Saturation Model of the reservoir (Figure 22) provides an overview of water saturation distribution across the reservoir. Water saturation varies between 75% and 93%, which suggests that the reservoir is nearly entirely water-saturated. Other gases could occupy the small remaining percentage, although the Moki Formation in the Tui field is considered completely water-wet, with no historical evidence of hydrocarbons. This is in contrast to the adjacent Maari field, where the Moki Formation is known to contain hydrocarbons (Alotaibi, 2015). Although the water-wet nature of the Moki Formation means that it is saturated with water, this high water saturation does not necessarily hinder CO₂ injection. Effective porosity and injectivity (permeability) are more critical factors for determining the suitability of the reservoir for CO₂ storage. However, the complexity and heterogeneity of the channelized Moki

Formation, combined with its water-wet character, present challenges that require further study. Much remains unknown about the behavior of the water-wet Moki Formation in the Tui field, especially concerning its complex internal structure and flow characteristics. While the effective porosity and permeability models indicate that the Moki Formation is a promising candidate for CO₂ storage, its water-wet nature and the heterogeneity of the channel system introduce uncertainties that need to be addressed in future studies to fully understand this formation's storage potential.

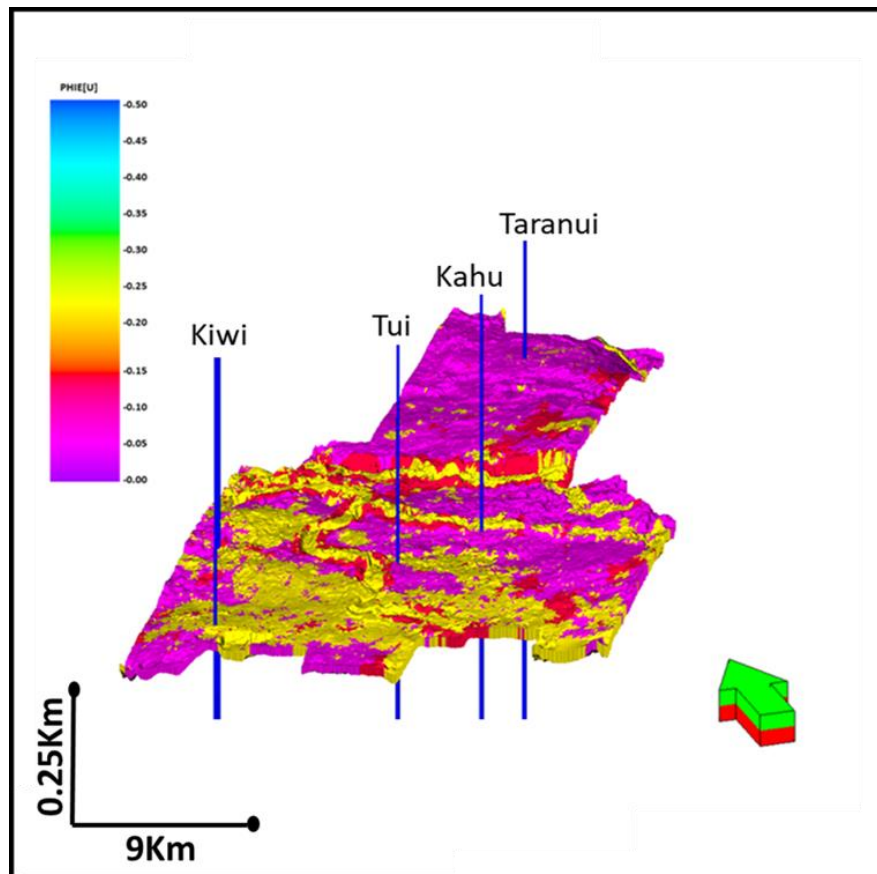


Figure 20: 3D effective porosity Model of the reservoir

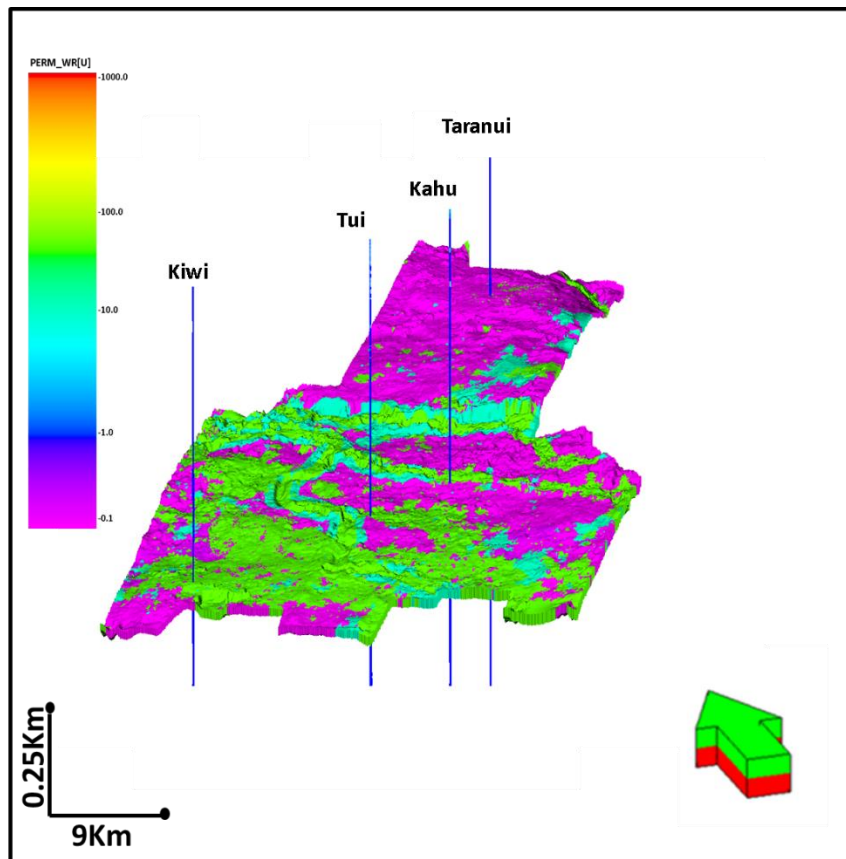


Figure 21: 3D permeability Model of the reservoir.

The effective porosity 3D model of the seal (Figure 23) reveals the effective porosity distribution within the Upper Manganui Formation, which serves as the caprock for the reservoir. The model shows that the effective porosity in the seal ranges from 1% to 5%, a characteristic typical of a shaly formation. This low porosity reflects the predominantly shale-dominated nature of the Upper Manganui Formation, indicating that it functions effectively as a seal for the underlying reservoir. The small patches of porosity approaching 5% can likely be attributed to insignificant sand deposits scattered across the seal, but these do not compromise the overall integrity of the caprock. Figure (24) shows that the seal's permeability model displays permeability values ranging between 0.1 and 0.5 millidarcy (mD). This low permeability is a direct result of the geometric method used for upscaling the permeability log, which de-emphasizes values close to zero, allowing for a more realistic representation of the seal's impermeable nature. The low permeability values underscore the excellent sealing capacity of the Upper Maunganui.

Formation, confirming its ability to effectively trap CO₂ and prevent its migration to the surface or into adjacent formations. This property is essential for the long-term containment of CO₂ in subsurface storage projects. The water saturation model of the seal, displayed in a separate

figure (25), shows that water saturation values range from 95% to 99%, indicating the almost complete water saturation of the shale within the Upper Manganui Formation. This is typical of shales, which often retain high levels of bound water due to their fine-grained nature and high clay content. Previous research by Alotaibi (2015) also highlights the high shale volume within the Upper Manganui Formation, explaining the high water saturation levels observed. This high saturation is consistent with the formation's low permeability and low porosity, further reinforcing its suitability as an effective caprock for sealing CO₂ due to increased capillary entry pressure.

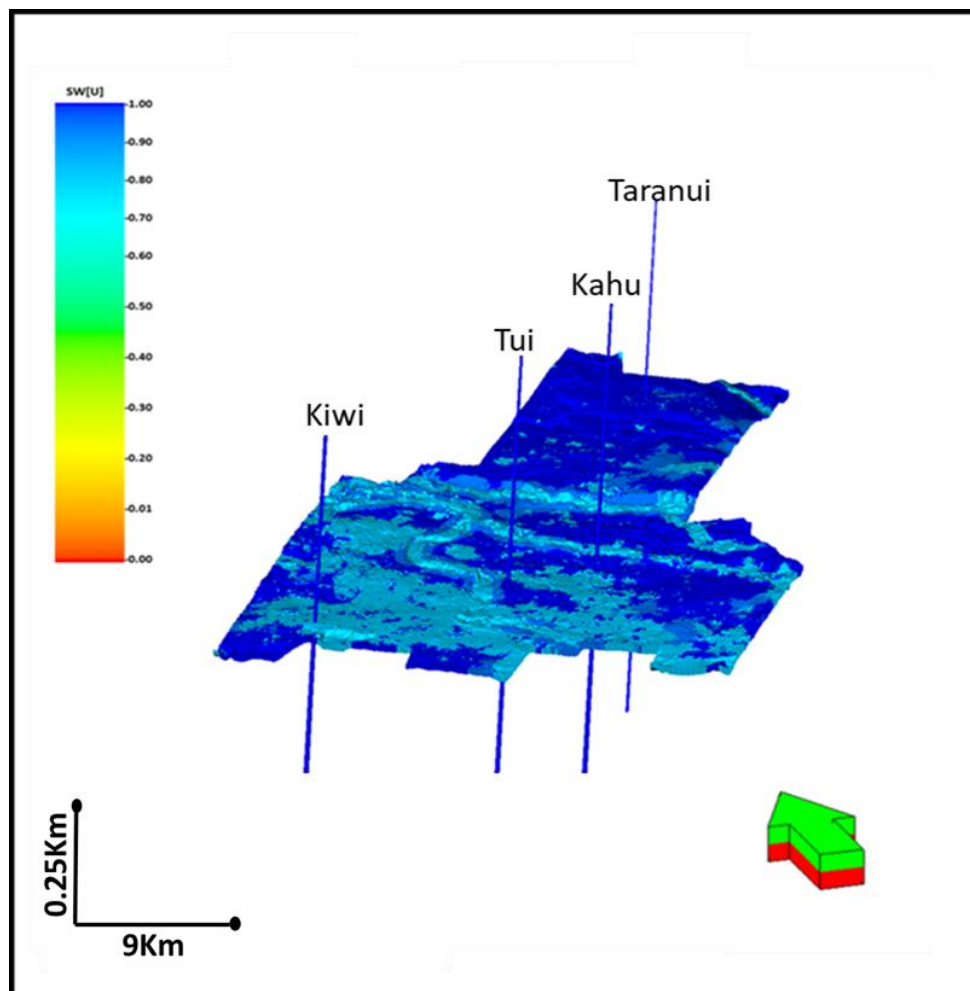


Figure 5:3D water saturation Model of the reservoir.

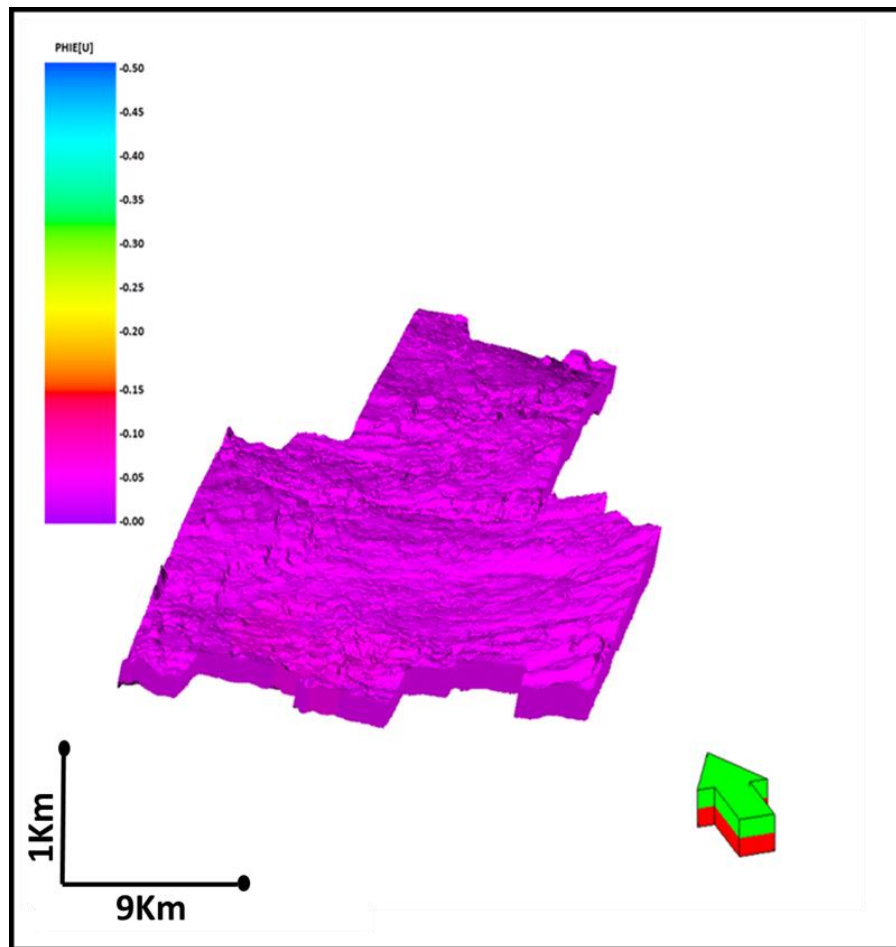


Figure 23: 3D effective porosity Model of the seal.

The Upper Manganui Formation shows strong potential as a caprock for CO₂ storage, given its very low porosity, permeability, and high water saturation. The small sand patches within the seal do not compromise its effectiveness. These characteristics suggest that the seal can adequately contain CO₂ and prevent leakage, making it a critical component of the subsurface storage system.

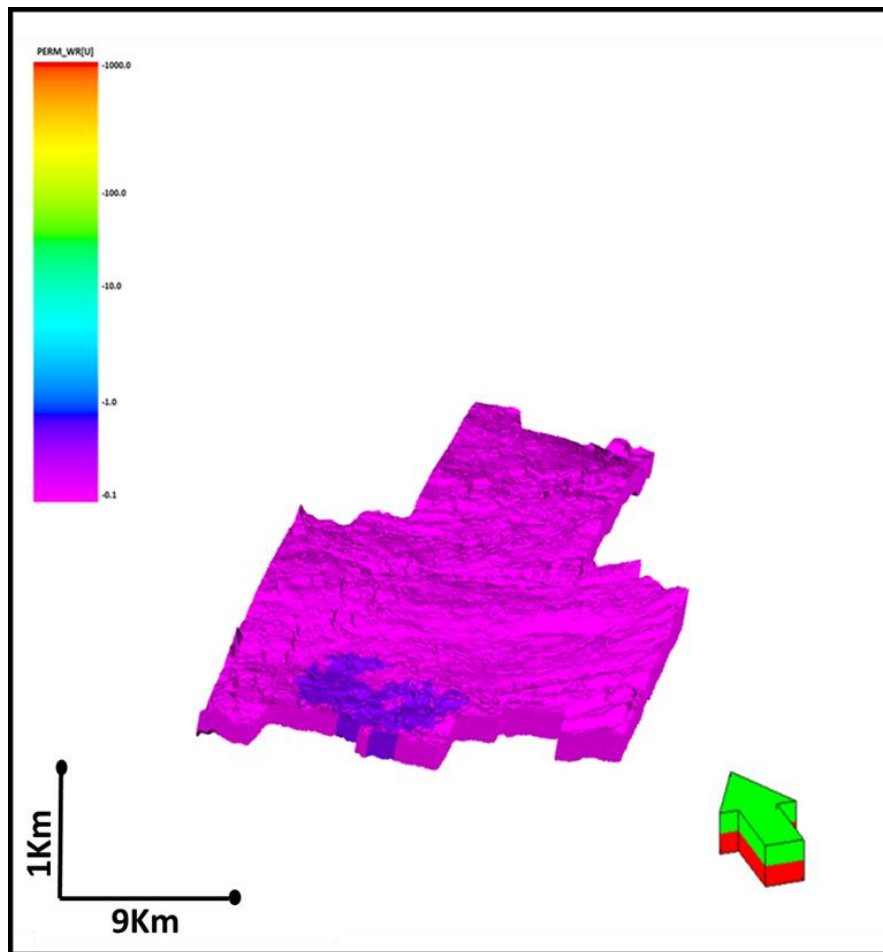


Figure 6: 3D permeability Model of the seal.

4.3.4 Geomechanical modeling of faults(Fault Stability Analysis)

The fault slip tendency, dilatation tendency, and distance to failure were modeled and evaluated in Petrel using the geomechanical modeling tool in the structural tool framework. This method is used in contrast to the usual fault seal analysis and the shale gouge ratio for the fault juxtaposition analysis.

The fault's modeled slip tendency, displayed in Figures (26a and 26b), shows the fault's position relative to the channel positions and extension to the seal. The color legend represents the relative value of the slipping tendency denoted by values; this is explained by the ratio of shear to everyday stress(Morris et al., 1996).

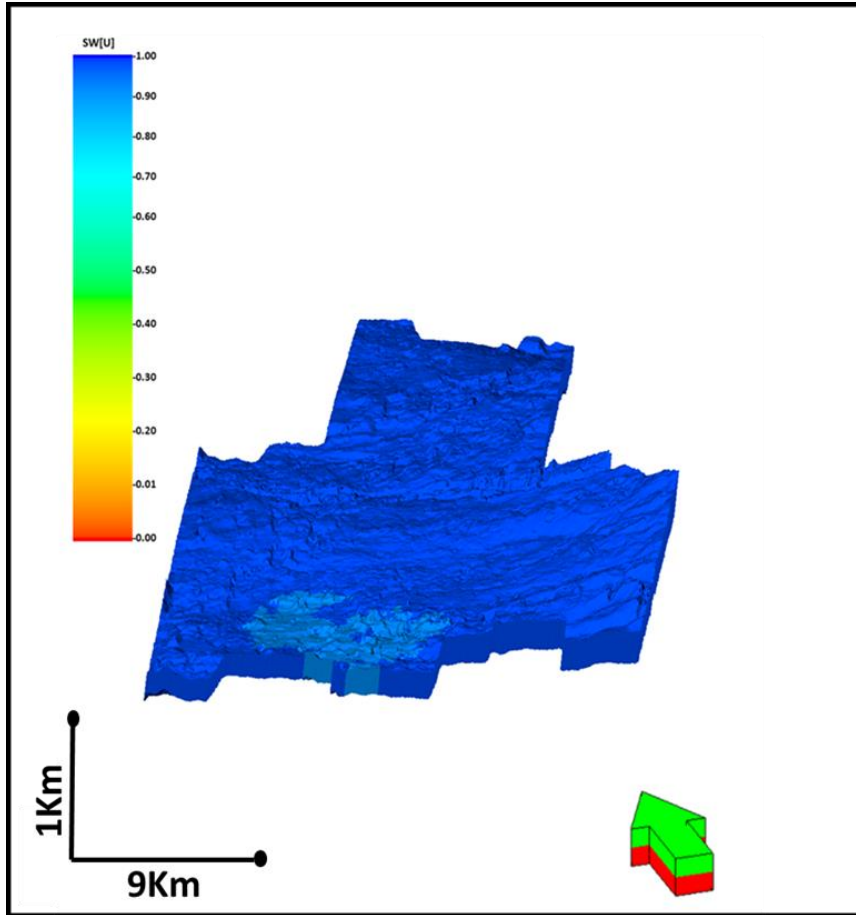


Figure 25: 3D water saturation Model of the seal

The result of the slipping tendency shows a maximum value of 0.11%; this shows that the resolved shear stress is about 0.89% of the Compressional normal stress and is also less than the frictional sliding resistance acting across the fault surface. Slips are less likely to occur, showing relatively stable faults that can withstand considerable stress (Jaeger et al., 1979). These results also show that the fault can withstand the pore fluid pressure likely to be induced by the CO₂, which might have likely increased the slip tendency and, thus, the cohesion strength of the fault and the coefficient static friction of the fault surface also suggest the fault surface would not slip concerning pressure induced by injection.

The model of the dilation tendency is shown in Figures (27a and 27b), with a maximum value of about 0.5% out of 1, with most faults showing about 0.2%. The color legend represents the level of the dilation of the fault part relative to its aperture's position, which is also related to the ability of the fault to serve as a pathway for fluid flow (Morris & Ferrill, 2009). The result shows that most faults are halfway oriented perpendicular to the principal stress and, thus, are not likely to dilate, creating a pathway for the injected CO₂ to escape. Moreover, the

effective everyday stress acting on the fault depends on the degree and direction of the principal stress to the fault plane.

The model of the Distance to failure of the faults shows a maximum value of about 220 bars on the color legend shown in figures (28a and 28b), which is approximately 3190.84psi of pressure the faults can withstand, results of estimated hydrostatic pressure at the reservoir depth using simple hydrostatic pressure estimation equation from Zoback(2007), resulted in a pressure of 1706.81psi and 2134.74psi for depth of 2000 and 2500 meters respectively with the assumption the density of CO₂ is taken at a higher density interval of 600kg/m³ to take into account the reservoir and seal interval where we have the extension of the fault. The result suggests that the faults can withstand a considerable amount of pressure that is more significant than the expected injection pressure, with a difference of about 1000 psi. The overall results of the fault stability analysis show that faults are less likely to be stressed about the injection of CO₂, which often deals with more considerable uncertainties(Jones & Hillis, 2003).

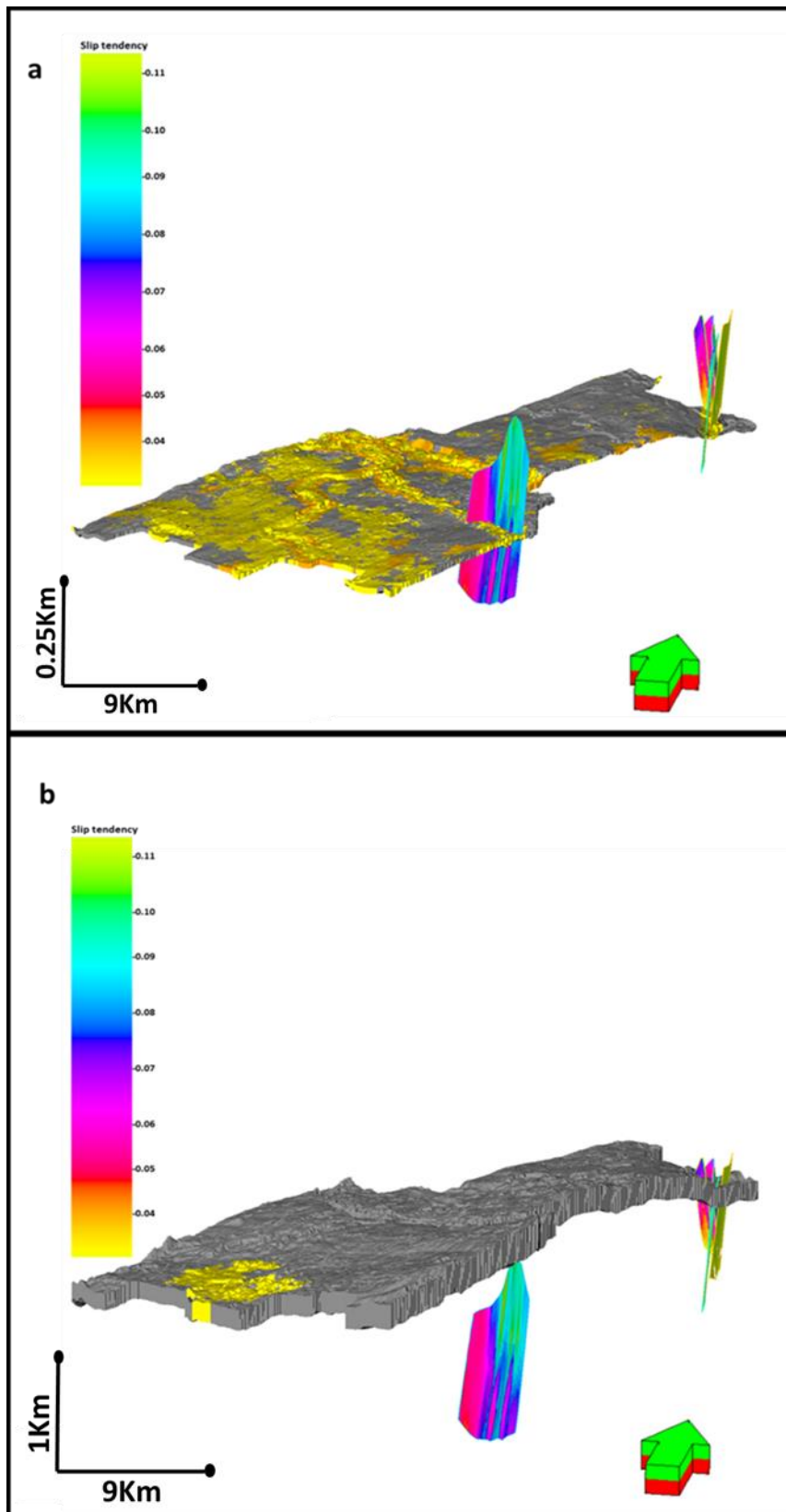


Figure 26 (a&b):3D reservoir and seal facies model showing respective faults along slip tendency.

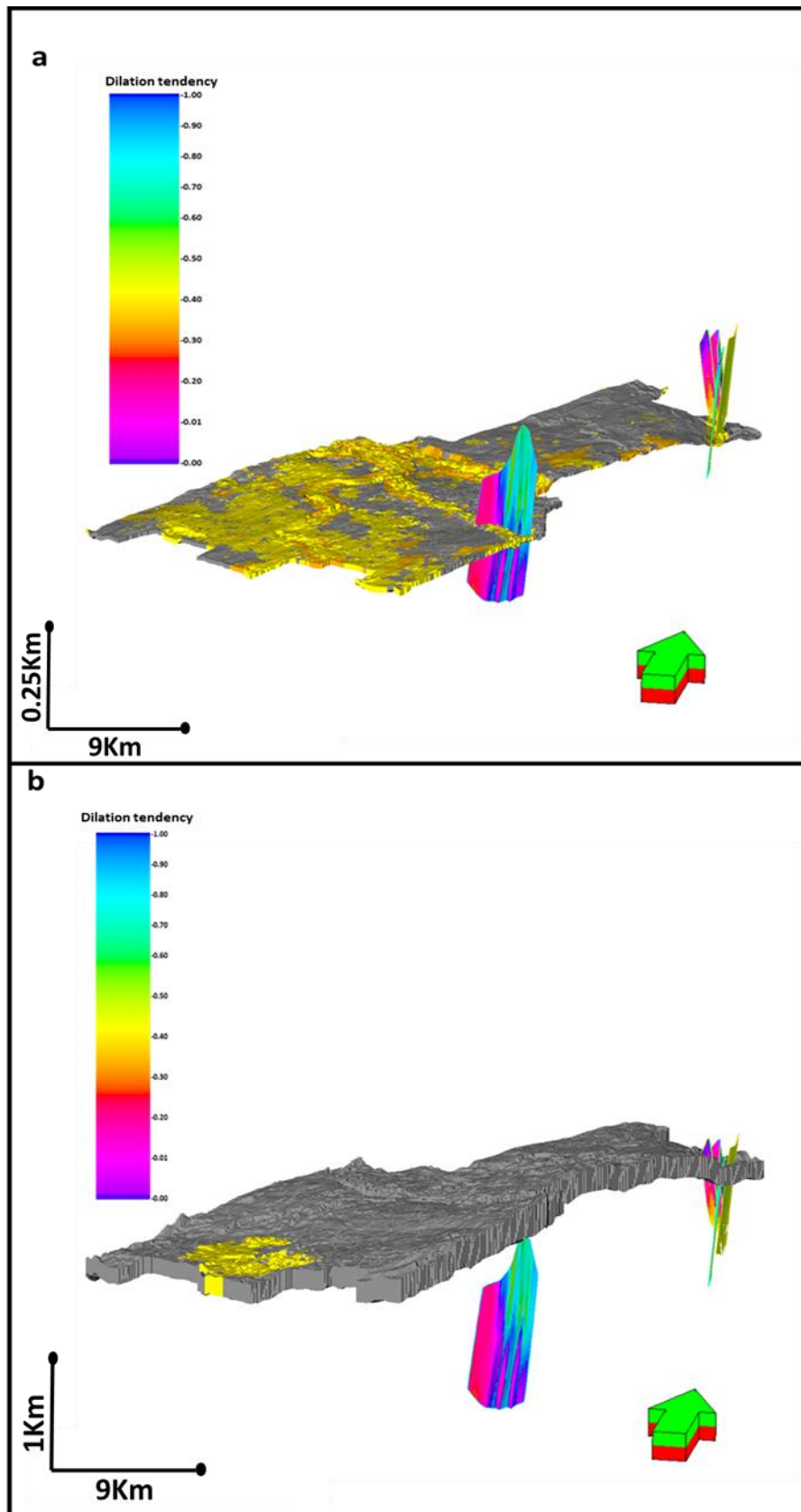


Figure 27 (a&b):3D reservoir and seal facies model showing respective faults and a Dilation tendency.

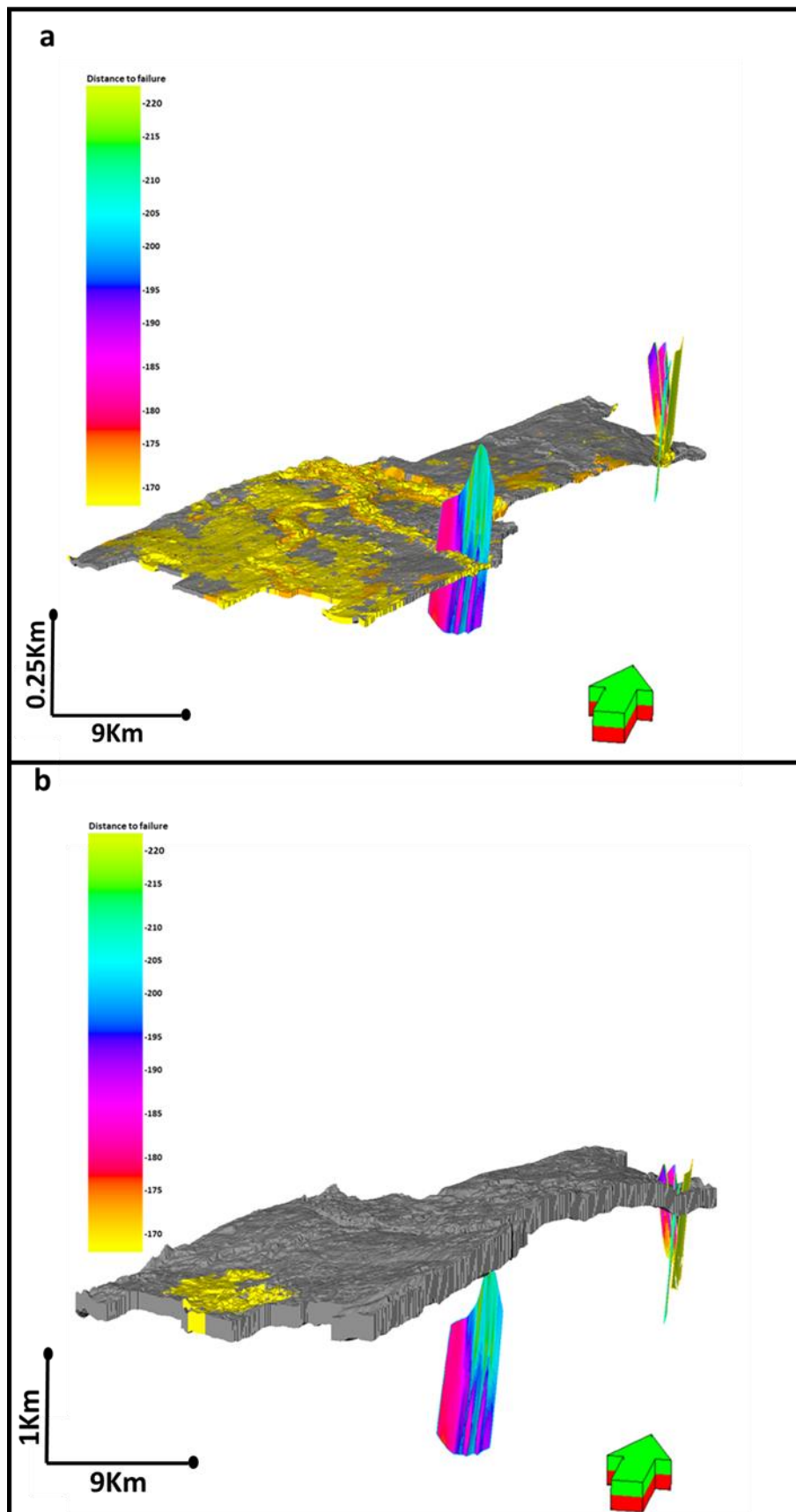


Figure 28 (a&b):3D reservoir and seal facies model showing respective faults and the calculated distance to failure.

4.4 Volumetric estimation(Storage Capacity)

The storage capacity for CO₂ was calculated theoretically using Equation (10) provided in the table. Before this, the individual volumes of each channel were determined through Paleoscan using geobody extraction techniques. This process allowed for an accurate assessment of the volume for each channel, which served as the foundation for estimating the cumulative storage capacity of the area concerning CO₂ sequestration. Below is a detailed description of each channel and their respective estimated volumes. Each channel's volume was first derived from Paleoscan's geobody extraction, which provided a three-dimensional representation of the subsurface features. These volumes were then used to determine the potential storage capacity of the channels when considered for CO₂ storage. The individual volumes reflect the varying sizes and complexities of the channels within the Tui-3D field, offering critical insights into the potential of each channel as a CO₂ storage site(Table 7).

Table 6: Parameters for Storage Capacity Estimation.

Parameters	Values
Average effective porosity	0.18
Irreducible water saturation	0.86
E _{gas}	0.01(1%)
Density of CO ₂	154.31 kg/m ³
Cc	0.014(1.4%)

Table 6 presents the parameters utilized for estimating the CO₂ storage capacity. The irreducible water saturation was derived using a formation volume factor of 14%. For this study, a storage efficiency factor of 1% will be applied, ensuring that CO₂ sequestration occupies no more than 1% of the total pore volume. Additionally, the density of CO₂ used in this calculation is 154.31 kg/m³, a value adapted from AlRassa et al. (2021). This density falls within the broader range of 79.08 to 996.16 kg/m³, as Agunbiade et al. (2023) noted for CO₂ at supercritical conditions, where temperature and pressure significantly influence the density. After that, the capacity coefficient of 1.4% was used to consider the trapping heterogeneity, sweep, and buoyancy(IEAGHG 2009). The methodology considers the variability in CO₂ behavior under these conditions to ensure an accurate estimate of the storage potential.

Table 7: Individual Channels and estimated volume and Theoretical estimated CO₂.

Channel	Volume(km³)	Estimated Storage capacity volume of CO₂(tonnes)	Estimated Effective Storage capacity volume of CO₂(Multiplied by Cc and Egas) (tonnes)
A	972.446	232290004.2	3252060.06
B	791.76	189129199.7	2647808.8
C	694.462	165887443.5	2322424.21
D	1171.26	279781078.2	3916935.09
E	594.471	142002405.4	1988033.68
F	666.82	159284547	2229983.66
G	436.973	104380562	1461327.87
H	676.818	161672788.1	2263419.03
I	667.83	159525807.6	2233361.31
J	141.957	33909535.47	474733.497
Total	1.627863	1.63 billion	22,790,087 million tones

Table 7 shows the estimated individual channel volume and estimated adequate storage capacity; each of the channels is briefly described below;

Channel A

Channel A, characterized as a highly meandering channel with significant sinuosity plays a prominent role within the geological framework of the study area (Figure 29 a&b). According to the detailed observations by Larsen et al. (2023), Channel A has been identified as the most dynamically active channel in this region. It is noteworthy for its deep incision into the Moki Formation, indicating a solid erosional and depositional influence on the surrounding strata. Within the Tui Field, the estimated volume of Channel A is substantial, approximately 972.446 km³, reflecting its vast size and significant geological impact on the subsurface architecture of the field. This volume estimation highlights the scale of the channel's influence within the Tui Field and underscores its importance in understanding the area's stratigraphic and structural development.

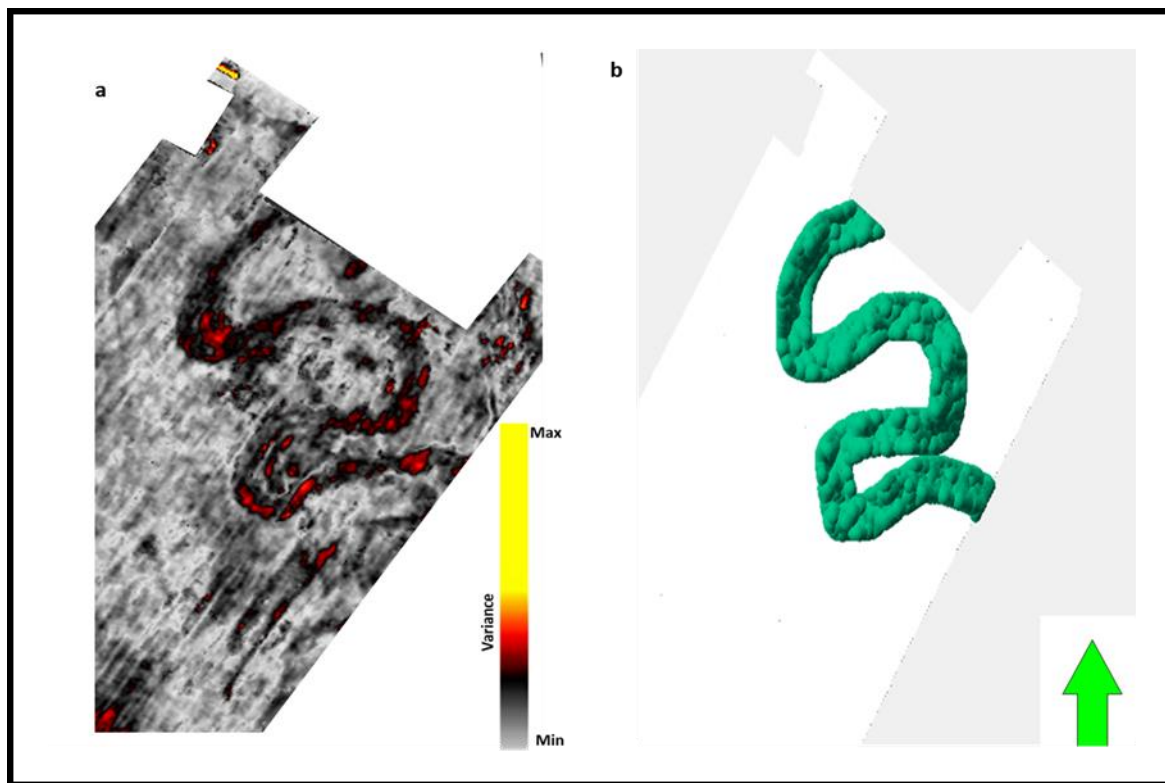


Figure 29 (a&b): Variance time map and schematic diagram showing channel A.

Channel B

Channel B, located within the Tui Field (Figure 30 a&b), is a low-sinuosity channel that exhibits a relatively straight path compared to other channels in the area. This channel is closely associated with a minor fault, which has influenced its development and extends upwards into the overlying Manganui Mudstone, a regional formation of significance. The fault suggests some tectonic activity, which may have contributed to the channel's formation or influenced

its later modification. Reilly et al. 2015, Bull et al., 2019 Franzel and Back, 2019 and Mattos et al., 2019 suggested that the tectonic uplift in the Taranaki basin is another significant contributing factor to the changes in lateral and vertical deposition of sediments in the channel apart from the sea-level changes. The estimated volume of Channel B is approximately 791.76 km³, indicating its smaller size than other channel A in the field. Despite its smaller volume, the relationship between Channel B and the fault system, along with its interaction with the Manganui Mudstone, provides essential insights into the tectonic-sedimentary evolution of the area.

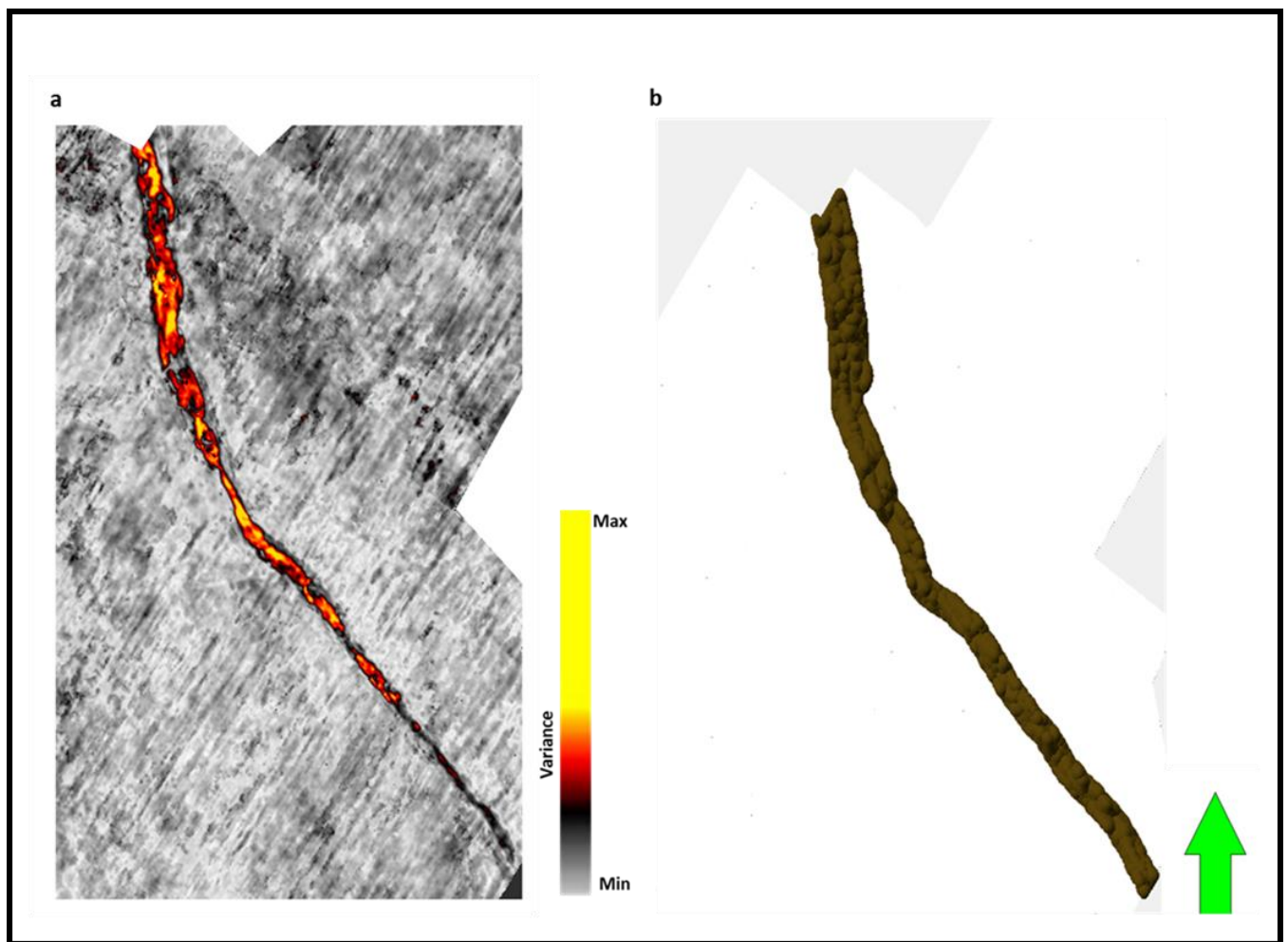


Figure 30 (a&b): Variance time map and schematic diagram showing channel B.

Channel C

Channel C, located within the Tui-3D survey area, is a highly sinuous channel with a winding path indicative of complex depositional processes. The analysis of the sweetness attribute on the time slice reveals notable variations in amplitude throughout the channel. These amplitude differences are attributed to diverse depositional facies within the channel, indicating that sedimentation patterns and material types vary along its course. Such variations likely reflect changes in energy levels and flow dynamics during the channel's formation and evolution. With an estimated volume of approximately 694.462 km³, Channel C represents a significant feature in the subsurface(Figure 31 a&b), providing valuable insights into the Tui Field's depositional environment and stratigraphic complexity.

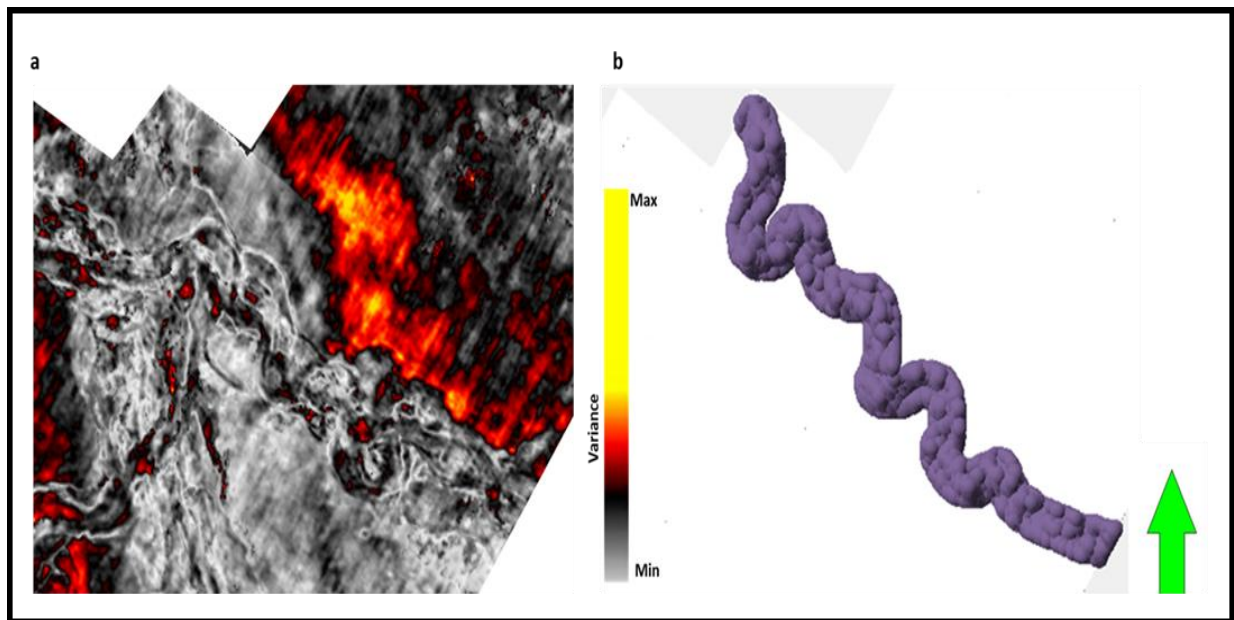


Figure 7 (a&b): Variance time map and schematic diagram showing channel C.

Channel D

Channel D is a distinct geological feature characterized by its discontinuous high amplitudes observed in the lower sections of the channel, which gradually transition into more continuous, lower amplitudes towards the upper portions of the channel fill. This pattern suggests varying depositional processes throughout the channel's history. According to Larsen et al. (2023), Channel D exhibits significant erosional features and associated slump deposits, particularly noticeable in its midsection, where the channel takes on a slightly V-shaped form(Figure 32 a&b). These erosional processes likely played a crucial role in shaping the channel's structure

and sediment deposition. The estimated volume of Channel D is substantial, at approximately 1171.26 km³; the combination of erosional characteristics, slump deposits, and its distinct V-shaped segments make Channel D an essential feature for understanding the study area's sedimentary dynamics and the rule played by the regional tectonics in the evolution and the shaping of the channels.

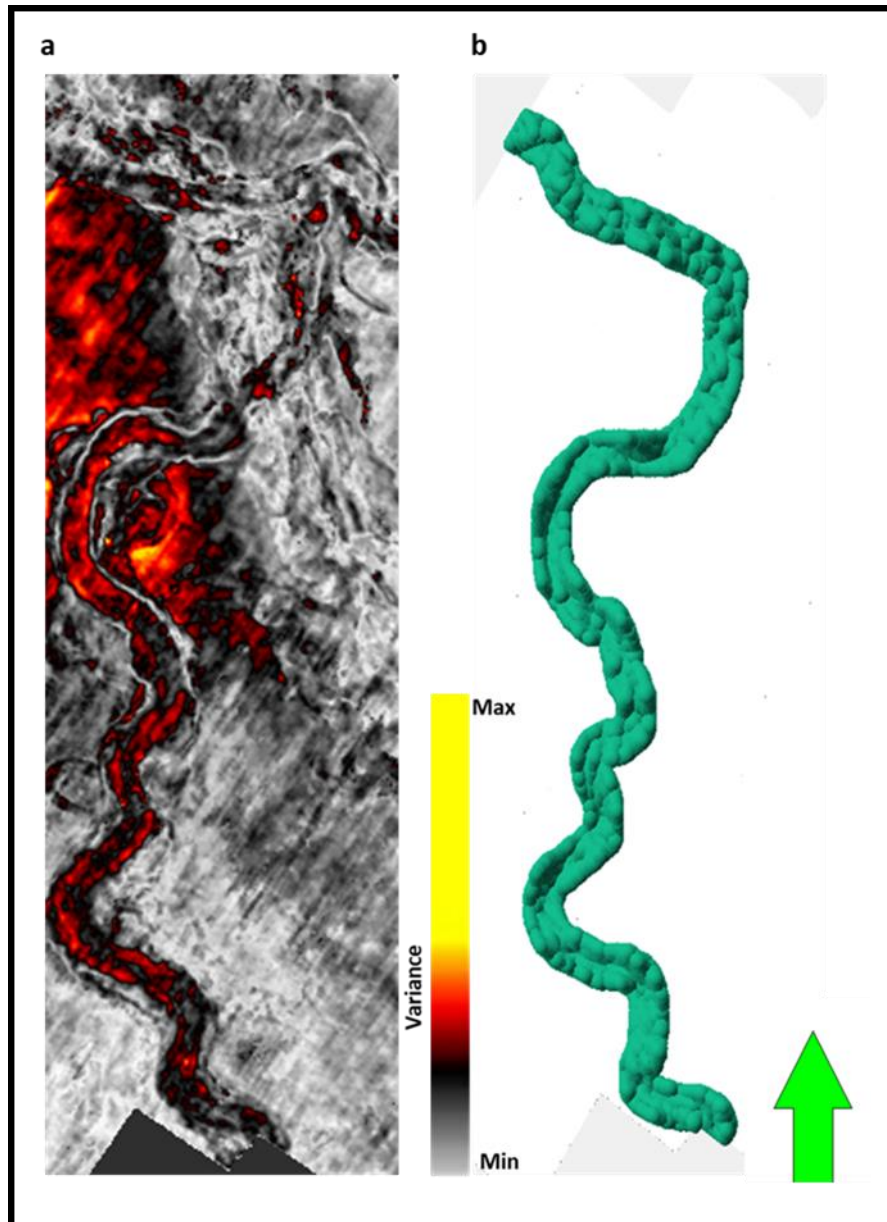


Figure 32 (a&b): Variance time map and schematic diagram showing channel D.

Channel E

Channel E is a notable feature in the northwestern part of the Tui-3D field. It is confined within the region influenced by Channel B, indicating a possible relationship between the two during their depositional history. The interaction of these channels may suggest shared geological processes that shaped this area. Channel E is a substantial structure, with an estimated volume of 594.471 km³, making it a significant feature in the subsurface of the Tui field(Figure 33 a&b)

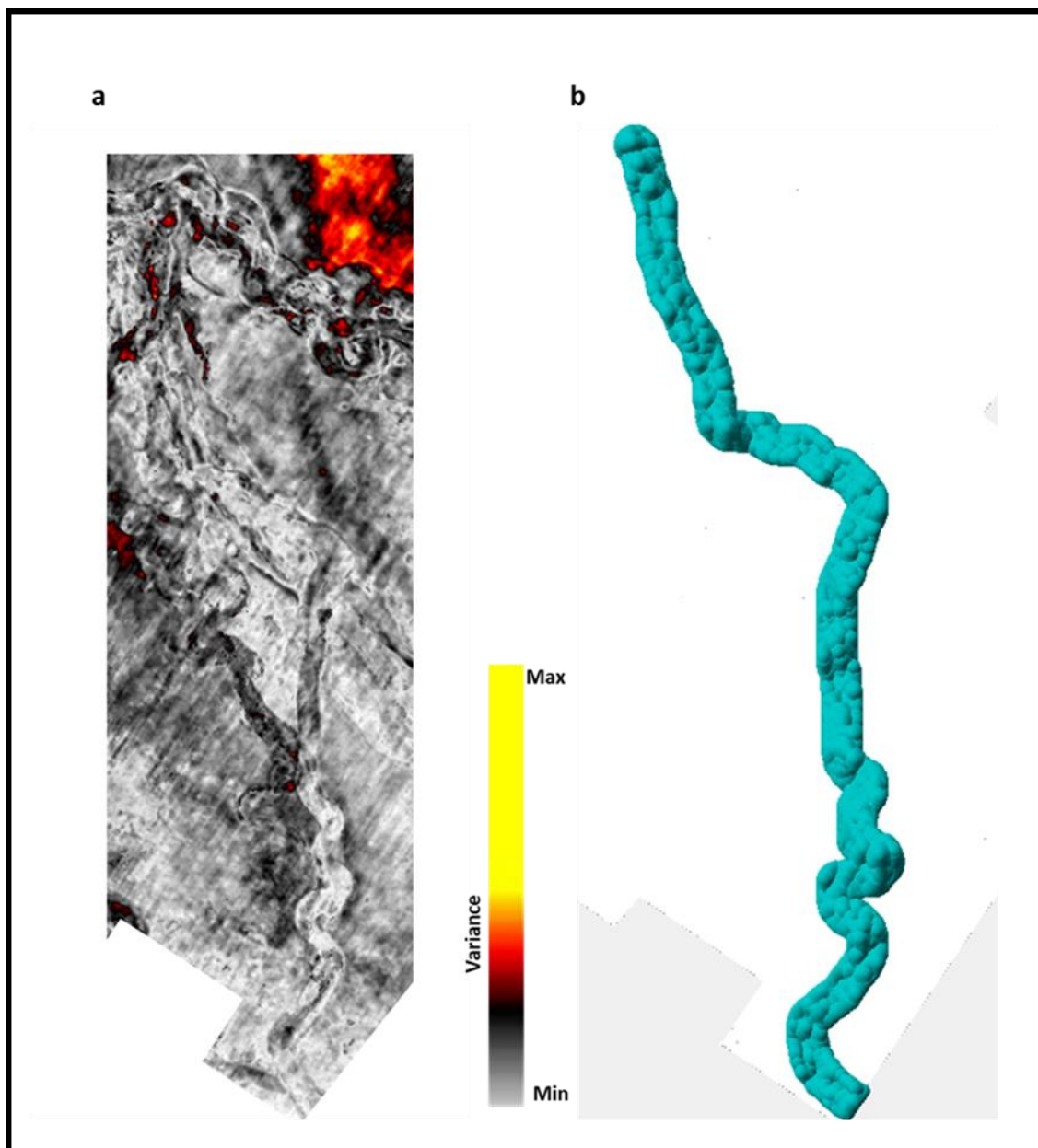


Figure 33 (a&b): Variance time map and schematic diagram showing channel E.

Channel F

Channel F, also interpreted within the Tui-3D field, is another channel with an estimated volume of 666.82 km³. Though not as directly related to other channels as Channel E and Channel B, Channel F represents a critical element of understanding the broader depositional environment of the Tui field (Figure 34 a&b)

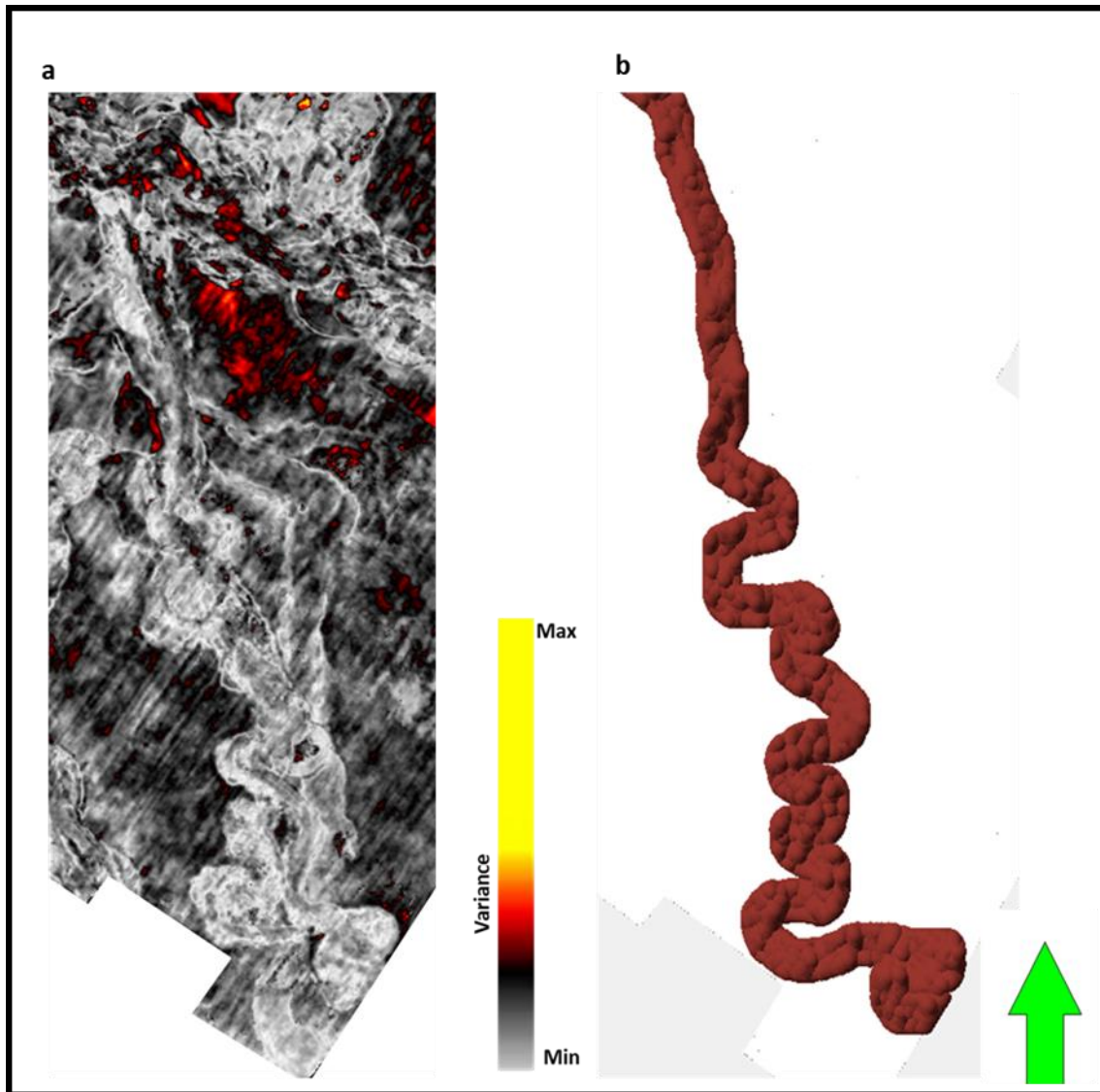


Figure 34 (a&b): Variance time map and schematic diagram showing channel F.

Channel G

Channel G is located in the uppermost portion of the Moki A Sandstone, nearly reaching the overlying Manganui Formation. This channel is distinguished by its high degree of meandering, particularly in the northwestern part of the Tui field. Its sinuous nature suggests a dynamic depositional environment, possibly influenced by shifts in sediment supply or flow

patterns. Its estimated volume is 486.973 km³, highlighting its relatively moderate size compared to other channels in the field (Figure 35 a&b).

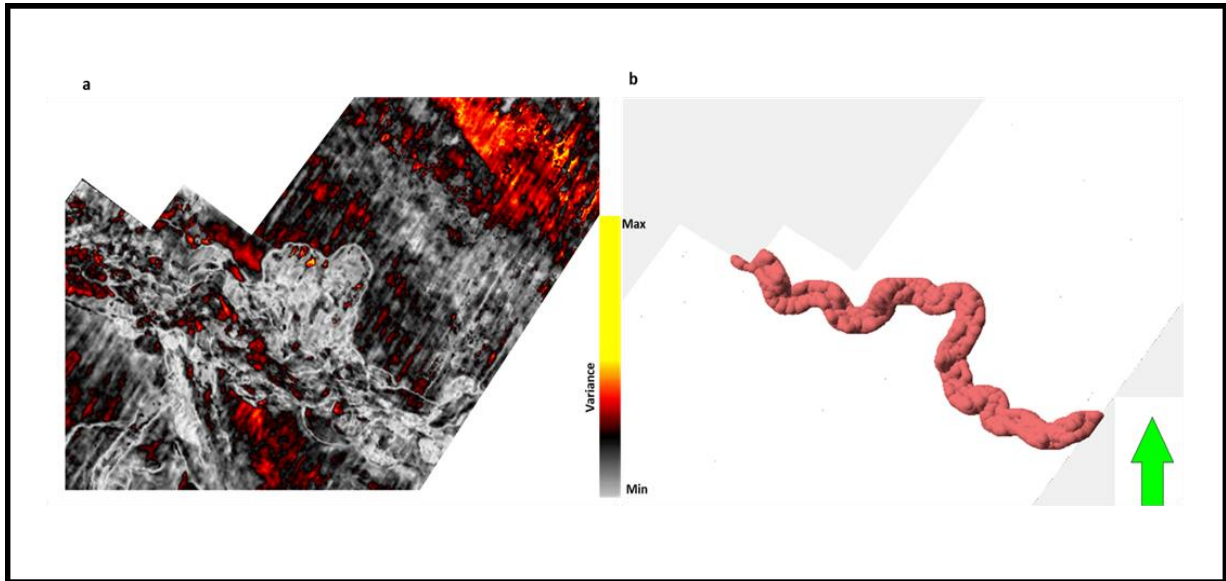


Figure 35 (a&b): Variance time map and schematic diagram showing channel G.

Channel H

Channel H is another highly sinuous feature within the Tui-3D field. Positioned above Channel D, Channel H is marked by numerous inner bends, suggesting complex flow dynamics during its formation. This channel is vital in the stratigraphic sequence, with an estimated volume of 676.818 km³. Its sinuosity and intricate bends offer valuable insight into the processes that shaped the upper layers of the Tui field (Figure 36 a&b)

Channel I

Channel I is interpreted to be a prominent feature within the Tui-3D field. It is characterized by a mix of parallel, semi-continuous, and moderate-amplitude reflections in some areas, while other regions, especially in the middle and northwestern parts, show discontinuous, medium to high-amplitude reflections. According to Larsen et al. (2023), this variability in reflection patterns suggests differing depositional or structural influences across the channel. Channel I has an estimated volume of 667.83 km³, further adding to its significance in the overall geological framework of the Tui field (Figure 37 a&b).

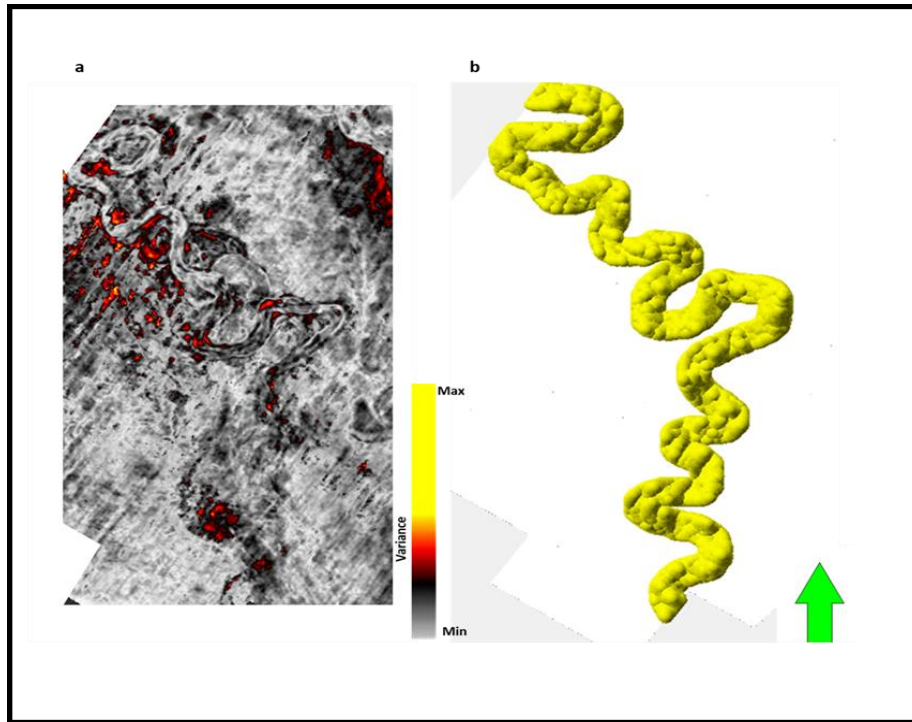


Figure 36 (a&b): Variance time map and schematic diagram showing channel H.

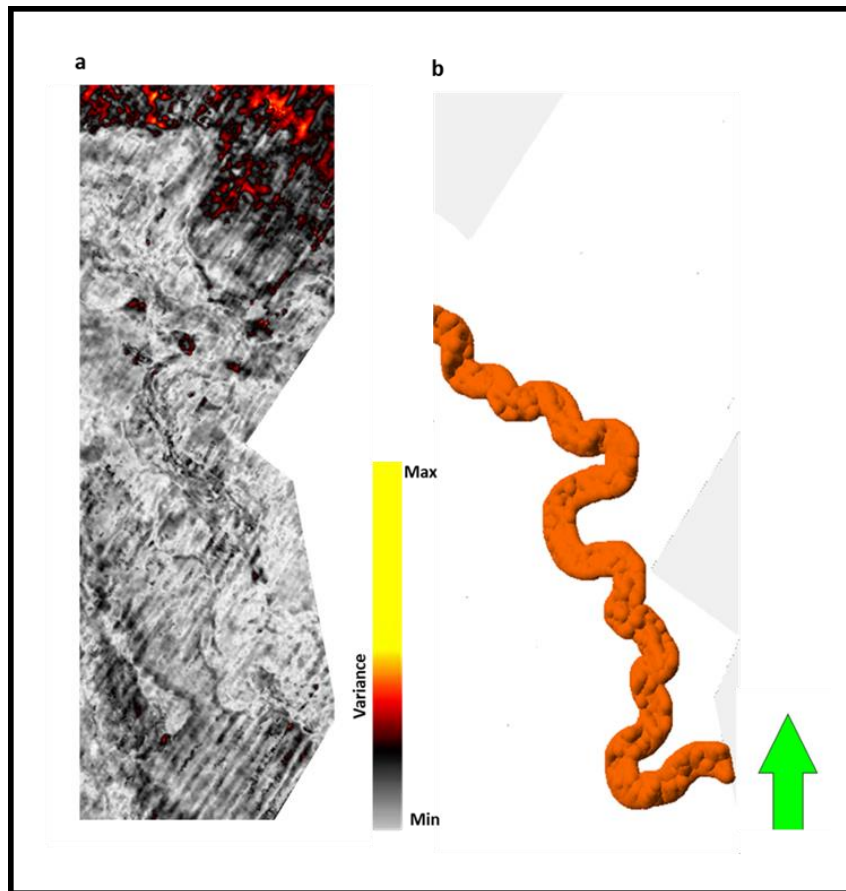


Figure 37 (a&b): Variance time map and schematic diagram showing channel I.

Channel J

Channel J is a minor channel interpreted in the Tui-3D field as you approach the northern part of the cube, where it runs from the west to the east. Unfortunately, the channel was not documented by other researchers due to its small size and only appearance in the minor part of the cube. The channel volume is approximately 141.957 km³ (Figure 38 a&b).

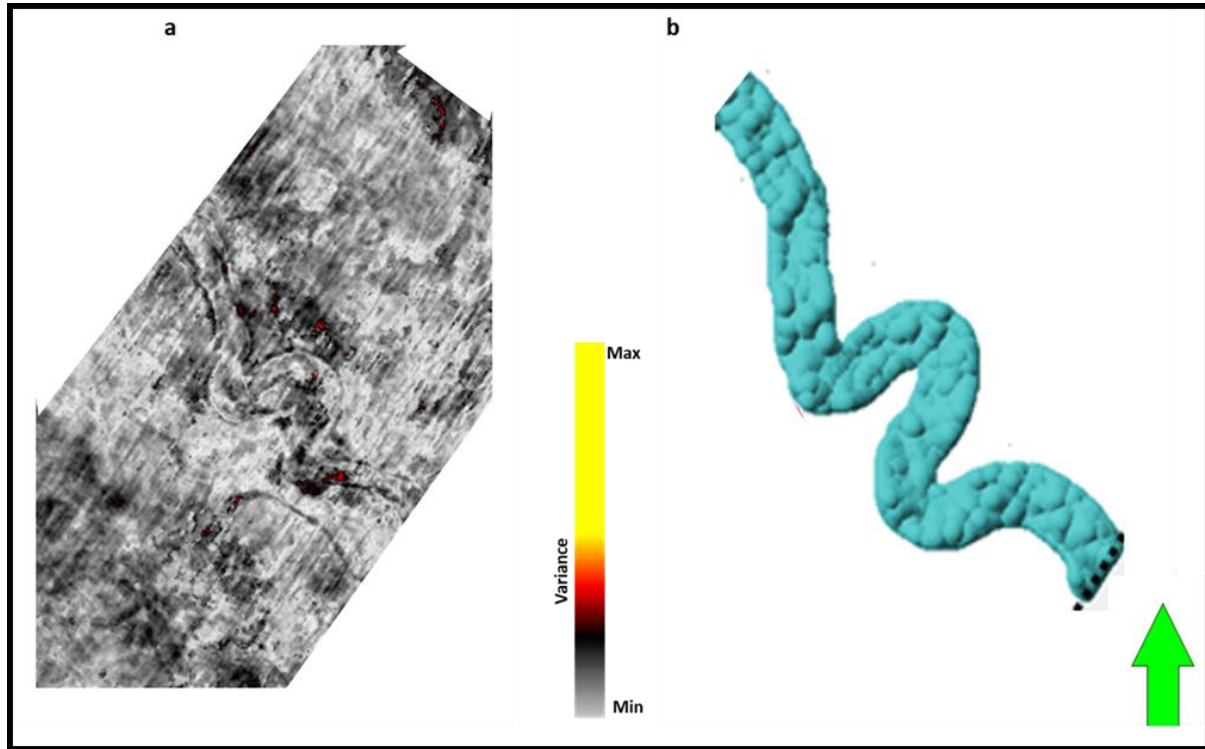


Figure 38 (a&b): Variance time map and schematic diagram showing channel J.

The storage capacity estimated using Equation 10 is presented in Table (7), which highlights the theoretical CO₂ storage capacity for the submarine channels, ranging from 474,733 tonnes to 3,916,935 tonnes. However, it is essential to consider that these submarine channels do not exhibit continuous reservoir characteristics. Due to the heterogeneous deposition and compartmentalization caused by intraformational shaly barriers acting as seals, these channels are discrete. According to Bachu et al. (2007), the CO₂ storage capacity in a hydrocarbon reservoir, regardless of location, is essentially the sum of the individual capacities of all the discrete reservoirs within that system. In this context, the total storage capacity of the ten (10) identified channels can be calculated by summing their capacities. Without accounting for the capacity coefficient, the combined storage capacity of the channels is estimated to be 1.63 gigatonnes (Gt). When the capacity coefficient is applied, which accounts for site-specific factors such as heterogeneity and sweep efficiency, the total storage capacity increases to

22,790,087 million tonnes (Mt). Figure 39 shows the schematic representation of the channels from the oldest to the youngest in ascending order extracted from Paleoscan.

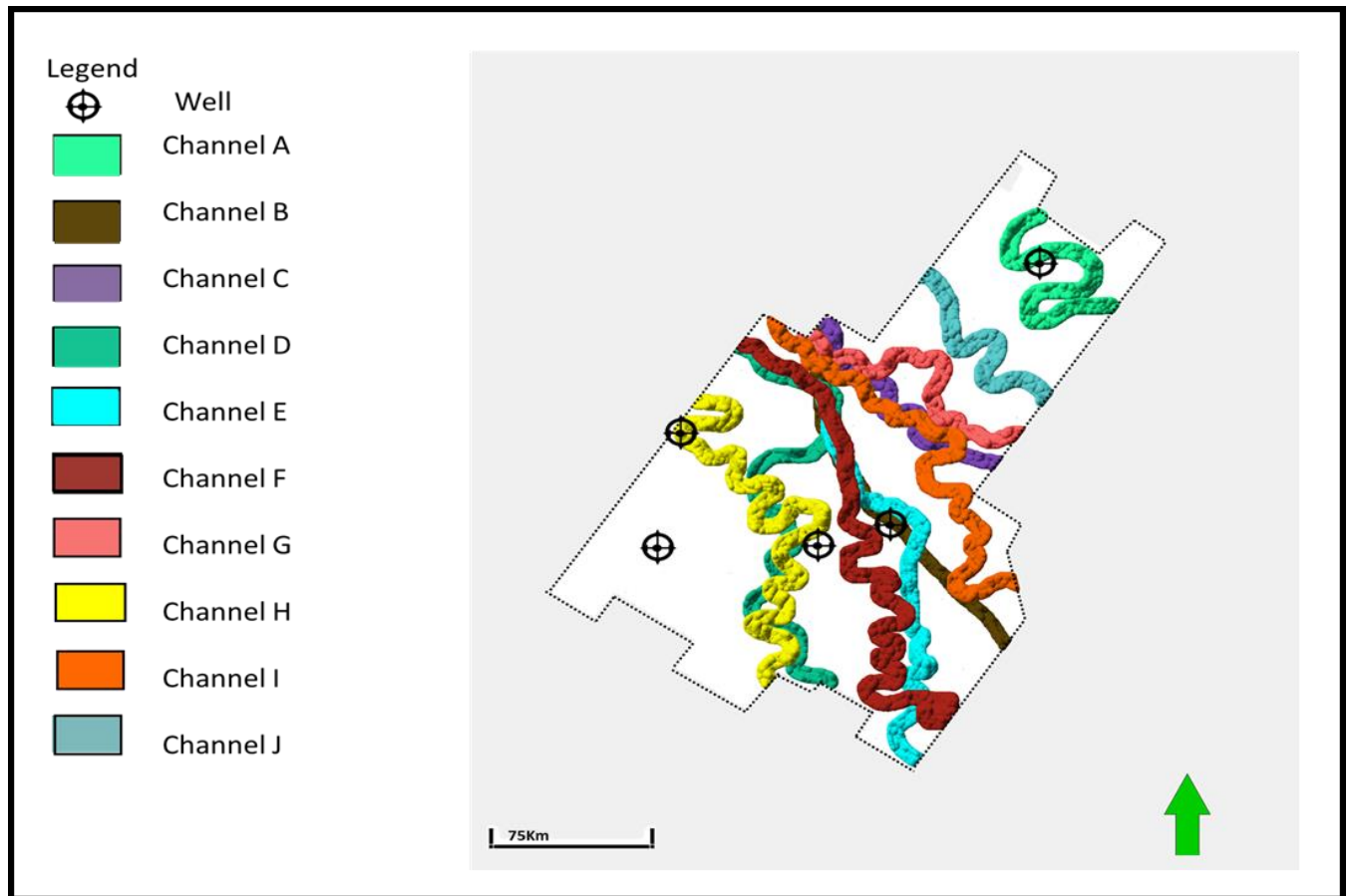


Figure 39: Schematic diagram showing all the channels in the Tui-3D field from the oldest to the youngest in ascending order.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

This study utilized seismic and sound data from the Tui-3D field in the Taranaki Basin to analyze the potential for CO₂ storage thoroughly. The research involved better-detailed reservoir characterization to understand the rocks' properties and behavior. In parallel, seal characterization was conducted to assess the integrity and effectiveness of the seals, which are crucial for trapping and preventing CO₂ migration. To provide a comprehensive evaluation, geomodeling was also performed, allowing for a better understanding of the subsurface architecture and ensuring an integrated approach to evaluating both the reservoir and the seal's suitability for long-term CO₂ storage. This integrated approach ensures that the storage capacity and containment potential are fully understood. In both cases, the modeled 3D facies and properties assist in holistically studying the spatial facies and property distribution. Based on the above, the following conclusions can be drawn from both the reservoir and the seal

5.1.1 Reservoir Characterization

The submarine channels within the Moki Formation, predominantly dating to the Middle Miocene, comprise sandstone units interbedded with shale layers. These shale intercalations are observed in various wells drilled in the area and are linked to changes in depositional energy. The deposition of these channels and their associated shale layers reflects periods of fluctuating sediment supply and energy conditions, which resulted in the waxing and waning of depositional energy. During higher energy periods, sandstones were deposited, while lower energy conditions led to the accumulation of shales, creating the interbedded sandstone-shale sequence. From seismic interpretations, it is evident that the channel systems are not uniform. Instead, they exhibit stacked and isolated geometries, reflecting complex depositional patterns. These stacked channels often indicate multiple phases of sediment deposition, while isolated channels suggest more discrete flow events. The channels in the Moki Formation reach impressive thicknesses, with some sections extending up to 360 meters. This considerable thickness provides a substantial volume for potential CO₂ storage. Additionally, the structural interpretation of the reservoir interval reveals the presence of minor faults, primarily concentrated within the reservoir but, in some cases, extend upward to the overlying seal, potentially influencing the effectiveness of the seal in preventing CO₂ migration. However, the reservoir itself demonstrates promising characteristics for CO₂ storage. The average effective

porosity is approximately 18%, indicating substantial pore space for fluid storage. The average permeability of 84 millidarcy further supports the reservoir's ability to allow fluid flow, making it a viable candidate for CO₂ injection. Water averages around 85%. This high water saturation level suggests that the Submarine channels are largely water-wet. Water-wet conditions favor CO₂ storage because they enhance CO₂ injectivity by maintaining strong adhesion of water molecules to the rock surfaces, ensuring that the CO₂ will predominantly occupy the larger pore spaces. The generated 3D models of the reservoir show that higher porosities and low water saturation coincide well with the channel interval; this combination of high porosity, good permeability, and water-wet conditions highlights the suitability of these submarine channels for CO₂ storage, as they can both store and transmit the injected CO₂ efficiently. The estimated adequate theoretical storage capacity of 22,790,087 million tonnes (Mt) shows the reservoir's capacity to house a considerable amount of CO₂ if adequately harnessed.

5.1.2 Seal characterization and seal potential analysis

The Manganui Formation acts as the primary regional seal for the submarine channels in the study area, providing an essential barrier to fluid migration. This formation predominantly comprises mudstone, making it an excellent sealing rock. There are minor sandy layers within the formation, but these do not significantly compromise the overall integrity of the seal. The submarine channels are essentially encapsulated within the Manganui Formation, and in certain wells, the thickness of this seal exceeds 500 meters, offering a substantial geological barrier to fluid escape. The average effective porosity of the Manganui Formation has been estimated at an average of 4.4%, which suggests that while there is some pore space within the mudstone, it is not substantial enough to facilitate significant fluid flow. The average permeability of the formation is at 0.18 millidarcy. Such low permeability is typical of mudstone and is crucial in maintaining the seal's integrity, especially in a CO₂ storage scenario and an average water saturation of 98%. This high level of water saturation means that nearly all the available pore space in the formation is filled with water, further restricting the movement of other fluids, including CO₂. In addition to the properties of the formation itself, geomechanical modeling has been conducted to assess the integrity of the faults within the seal. These models were used to analyze the potential for fault reactivation, which could compromise the seal's effectiveness. The results of the fault seal analysis are promising. The faults exhibit an excellent slip tolerance of approximately 0.11% and a dilation tendency, with an average dilation function of 0.2%. This further suggests that the faults will not open up or form new conduits for CO₂ migration. Moreover, the distance to failure pressure analysis shows that the faults can withstand

significant pore fluid pressures, with an average failure pressure of 220 bar. This is well above the expected pressures from CO₂ injection, indicating that the faults are unlikely to fail or allow the injected CO₂ to escape. The combination of a robust seal and fault stability means that the system can withstand the pressures induced by CO₂ injection without risking leakage or loss of containment. The combination of low porosity, low permeability, high water saturation, and fault stability makes the Manganui Formation an ideal caprock for CO₂ storage in the submarine channels of the Taranaki Basin.

5.2 Recommendations

In the Tui-3D field, few wells have logging within the Miocene channel interval. To better understand the internal heterogeneity of the channels, I recommend more logging within the channel interval. I also recommend more data integration to reduce the uncertainty associated with data limitations, as well as dynamic modeling of the CO₂ to see how the evaluated parameters of the reservoir and the seal change temporally with respect to injected CO₂.

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