

Hydrocarbon Potential of Eastern View Group Reservoir Rocks, Bass Basin, Australia

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CHAPTER 1

1. Introduction

1.1. The Bass Basin

The Bass Basin is a predominantly offshore Early Cretaceous to Recent intracratonic basin located in southeastern Australia (Fig. 1.1) which covers ~42000 km² (Blevin, 2003; Cummings et al., 2004). Together with the flanking Gippsland, Otway and Sorell basins, the Bass Basin was initiated in the Late Jurassic to Early Cretaceous as part of the Southern Rift System (Etheridge et al., 1985; Stagg et al., 1990; Willcox and Stagg, 1990; Blevin et al., 2005). It was subsequently affected by rifting in the flanking Tasman Basin associated with the fragmentation and spreading of eastern Gondwana (Veevers and Etreim, 1988; Veevers et al., 1991, Blevin et al., 2005).

The Bass Basin is separated into the Cape Wickham and Durroon sub-basins by the Chat Accommodation Zone (Fig. 1.1). The basin contains sediments ranging in age from Early Cretaceous (possibly latest Late Jurassic) to Recent. Older meta-sediments are present in the pre-rift basement blocks that floor the Mesozoic basin (Blevin, 2003). The Eastern View Group (EVG) sediments, which contain the Durroon, Bass and Aroo megasequences, ranging in age from Mid Cretaceous to Middle Eocene, are the most prospective within the basin; they contain both source and reservoir rocks. The succession consists of predominantly Early Cretaceous to Eocene interbedded fluvio-deltaic and lacustrine deposits overlain by marine siliciclastics, which are in turn overlain by late Tertiary to Recent marine carbonates. Multiple episodes of volcanism occur within the succession, often associated with large rift faults and accommodation zones. Limited geochemical analysis has suggested that inter-bedded coals, which have generated and expelled liquid and gaseous hydrocarbons, together with lacustrine shales, are the principal source rocks within the Bass Basin (Boreham et al., 2003).

The Bass Basin contains commercial reserves of gas and condensate. The Yolla Project produces over 20 petajoules of sales gas, one million barrels of condensate and 65,000 tonnes of LPG per year (Origin, 2006). White Ibis-1 well contains over 85 BCF (Billion Cubic Feet) of gas (Lennon et al., 1999) and Trefoil-1 reserves are estimated to be in the range of 200-300 CBF of gas and 14-21 MBBS (Million Barrels) of associated liquids (ASX, 2004).

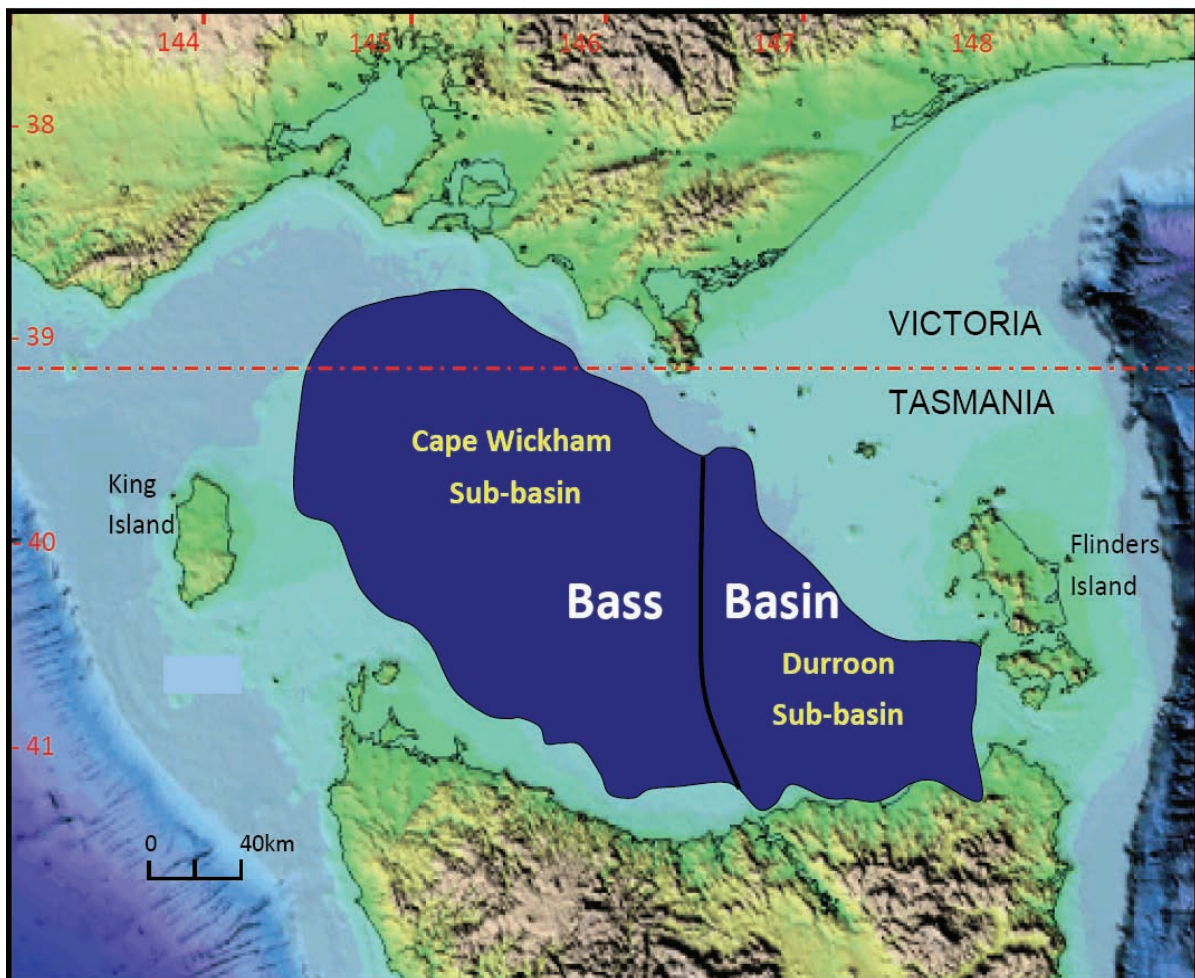


Figure 1.1: location map of the Bass Basin and adjacent region, Southern Australia (after Blevin, 2003).

1.2. Bass Basin Structure

The Bass Basin, together with part of the Gippsland and Otway basins, form a failed arm of the Southern Margin Rift system that developed through the initial separation of Australia and Antarctica (Stagg et al., 1990 and Cummings et al., 2004). Structural

activity within the basin strongly reflects the complex development of the southern and southeastern margins of Australia (Cummings et al., 2004).

The Bass Basin formed during multiple periods of extension, initiated in the late Jurassic to early Cretaceous as a result of the separation of Australia and Antarctica. Based on seismic mapping and well log interpretations, there are three phases of extension, recognised by previous research (Etheridge et al., 1985; Lennon et al., 1999; Blevin, 2003; Cummings et al., 2004). They are:

- Late Jurassic to middle Early Cretaceous, Southern Ocean rifting
- Late Cretaceous Tasman rifting (Cenomanian to Middle Campanian)
- Late Cretaceous to Middle Eocene sinistral shearing of Australia and Antarctica along the Tasman-Antarctic Shear Zone.

Recent research has suggested that oblique far-field stresses caused the latest stage extensional reactivation from the Palaeocene to the Middle Eocene (Cummings et al., 2002; Blevin, 2003; Cummings et al., 2004; Blevin et al., 2005). Bass Basin source rocks were deposited throughout the period of late Cretaceous to Middle Eocene rift-transition (Boreham et al., 2003; Blevin, 2003), therefore coals are thought to be an important source of liquid hydrocarbons in the basin. The Bass Basin later underwent Oligocene - Miocene reactivation, believed to be dominated by right-lateral wrench deformation and localised inversion of the Cretaceous-Middle Eocene rift structure (Cummings et al., 2004).

Southern Ocean rifting between the Australian and Antarctic continents started in the Late Jurassic. During the Tithonian, rifting extended towards the east with deposition commencing within the Duntroon, Otway and Gippsland basins (Norvick and Smith, 2001). This rift valley complex was situated in the Otway Basin, Torquay Sub-basin, Strzelecki Ranges and Gippsland Basin, which are north of the Bass Basin. By mid Late Cretaceous times, the region was undergoing post-rift thermal subsidence, and sedimentation extended beyond the boundaries of the primary rift depocentres and into the Bass Basin (Cummings et al., 2002).

The eastward spread of the Southern Ocean break-up failed to expand into the eastern Otway and Bass basins due to a sudden shift in the locus of extension to the south of Tasmania during the Cenomanian to Middle Campanian (Cummings et al., 2002).

The Bass Basin is characterised by a half-graben structural style with tilted Palaeozoic and Proterozoic basement blocks. Multiple rift events in an area with complex basement fabric, together with differential subsidence and deposition within the terrestrial basin, have resulted in complex facies relationships within the Bass Basin (Blevin, 2003).

Whereas all sedimentary basins in southern Australia initiated with Southern Ocean rifting, the Bass Basin did not proceed to break-up once the extension transferred to the south of Tasmania (Palmowski et al. 2004).

The Bass Basin, as a failed rift basin, is unique in southeastern Australia. The initial Southern Ocean rifting in the Otway and Gippsland basins and the opening of the Tasman Sea had a significant effect on the Gippsland Basin, but bypassed the Bass Basin, allowing it to remain a landlocked alluvial and lacustrine basin. This suggests the regional stress regime did not destroy older structures and they were preserved almost as they were. Therefore, understanding the structure of the Bass Basin and its older source rocks could help hydrocarbon exploration along the entire southern margin of Australia. Other basins in the area (e.g., offshore Otway and Sorell basins), which are thought to have similar Early to Late Cretaceous source rock systems as the Bass Basin, are all buried deep and/or are under a much deeper water column at present, which makes exploration uneconomic. Understanding and finding preserved and active petroleum systems in the Bass Basin will help build models for hydrocarbon exploration in other basins along the southern margin.

1.3. Petroleum Geology of the Bass Basin

The Bass Basin contains a comparatively thick succession (up to 7.5 km) of mainly terrestrial syn-rift and early post-rift sediments, overlain by a thinner (up to 2 km) late

post rift succession of fine-grained marine clastics and carbonate rocks (Blevin et al., 2005). With several hydrocarbon discoveries at the Yolla, Trefoil, White Ibis and Pelican fields, previous hydrocarbon exploration has proved the presence of petroleum systems in the basin. Despite the fact that the Bass Basin is a moderately to under-explored basin, the failure to discover more hydrocarbon accumulations suggests that the system may be complex with several risk factors present (Blevin et al., 2005). The complexity of the petroleum systems in the Bass Basin has been interpreted by Boreham (2003) to be related to the terrestrial nature and distribution of coals and interbedded shales, which are the primary source rocks. This involves several factors including thickness and lateral continuity of source facies, thermal maturity, generation and expulsion, hydrocarbon migration and charge. Other significant geological risks include the identification of good quality reservoir sands coupled with fine-grained sealing facies with high sealing capacity, and the juxtaposition of reservoir/seal facies across faulted structures (Blevin et al., 2005). The Bass Basin has undergone Late Oligocene-Miocene inversion, in which the oblique nature of the compressive stresses to pre-existing structures resulted in strike slip and local inversion within the Cape Wickham Sub-basin (Cummings et al., 2004). This event reactivated several faults suitably oriented to the direction of the inversion, which may have affected hydrocarbon migration paths and some in-place accumulations.

1.3.1. Accommodation cycles and sequence stratigraphy

Rifting episodes in the Bass Basin resulted in the deposition of a sedimentary section up to 9 km thick in the Yolla and Cormorant troughs.

The first accommodation cycle (Crayfish Megasequence) was coincident with Southern Ocean rifting (Late Jurassic-Early Cretaceous) and was confined to the central region of the Cape Wickham Sub-basin (Cummings et al., 2004). The stratigraphy, age, lithological character and source richness of the Crayfish Megasequence are uncertain because this megasequence is inferred from seismic data and has not been intersected by any wells drilled in the basin to date. However,

because of its similarity to the Crayfish Group in the Victorian offshore Otway Basin, it is believed to contain fluvial channel sands with flood plain shales and siltstones.

The Early Cretaceous Otway Megasequence succession consists of stacked volcanoclastic, blocky fluvial channel sands with thin coaly overbank floodplain siltstones. Organic-rich facies are typically thin, but the frequency of coals increases in the uppermost 650 m of the sequence (Blevin et al., 2005). The sediments of this megasequence overlie basement throughout the basin, except for in the central Cape Wickham Sub-basin where it overlies sediments of the Crayfish Megasequence.

The Durroon Megasequence was deposited as a result of the second rift phase (Tasman rifting), during Turonian to Campanian times. The succession consists of shale, siltstone and sandstone overlying a basaltic unit (Blevin et al., 2005).

The Bass Megasequence was deposited during the third rift phase (Late Cretaceous to Early Cretaceous extension) and has been subdivided into three component sequences: the Furneaux, Tilana, and Narimba sequences (Blevin et al., 2003, 2005). The Furneaux sequence ranges from interbedded fluvio-deltaic sandstones and freshwater lacustrine shales to fluvio-deltaic sandstones and thin interbedded overbank or delta plain shales and coals (Blevin et al., 2005).

The Tilana sequence consists of fluvial channel sandstones overlain by thick lacustrine shales, grading upward to progradational lacustrine deltaic and shoreface sandstones capped by thin coal beds (Blevin et al., 2005).

The Narimba sequence consists of thinly bedded shale, sandstone and coal deposited in lacustrine, lower delta plain and peat mire environments (Blevin et al., 2005).

The Aroo sequence was deposited during the post-rift sag (Subsidence Phase-1) (Blevin et al., 2003). It consists of interbedded sandstones, siltstones and carbonaceous shales and frequent coal seams (Meszoly, 1986). The frequency and

thickness of coals increased in response to a slowdown in the rate of accommodation (Blevin et al., 2005).

The Flinders sequence was deposited during the post rift sag (Subsidence Phase-2) and is a transgressive-regressive succession, consisting of channel and progradational sandstones and shales. The sequence contains the Boonah Sand, Anglesea Formation and the regional sealing facies of the Demons Bluff Formation (Blevin, 2003, Blevin et al., 2005). Upper Middle Eocene sediments of the Middle *N. asperus* zone span the boundary between the EVG and overlying Demons Bluff Formation (Meszoly, 1986; Boreham et al., 2003).

The Torquay sequence was deposited as a response to the latest post-rift sag (Subsidence Phase-3). The lower part of this sequence consists of shallow marine clastics (siltstone and marl) and the upper interval consists of open-marine carbonates (Blevin et al., 2005).

1.3.2. Source rock geochemistry

Interbedded coals together with fluvio-deltaic and lacustrine shales of early Palaeogene age are the potential source rocks in the Bass Basin. Interbedded coals ranging from 5-25 m thick are the dominant source rocks while the lacustrine shales are low potential source rocks. Results from geochemical analysis proved that liquid and gaseous hydrocarbons can be generated from these source rocks (Boreham, 2003). Moreover, the same analysis suggests that coals are the dominant source for the recovered hydrocarbon liquids.

The dominant coal-bearing section is the upper Cretaceous to Eocene succession. The coal deposition is related to the occurrence of deep lakes across the central and northwestern part of the Bass Basin (Partridge, 2002). The existence and distribution of coals and other source rocks depends on depositional environment, thus identifying source rock distribution has great importance for the understanding of fluvial and terrestrial sediments such as those in the Bass Basin.

1.3.3. Reservoir rocks

During deposition the Bass Basin was a land-locked alluvial and lacustrine basin, with an opening to the sea that became progressively more important with time. Meandering fluvial channel belt or distributary channels are the highest-ranked reservoir facies developed in the Bass Basin. Fine to medium-grained lacustrine shoreface and foreshore facies also make good reservoir facies (Lang et al., 2003). Hence, the geometry, thickness and lateral extent of these sands are important for finding trapped hydrocarbons.

Unlike reservoirs of the Gippsland Basin, the reservoirs of the Bass Basin lack marine influence. In general, reservoirs of the Bass Basin are silty, fluvial channel sands and lacustrine delta sands (Lemon, 2003). Nevertheless, exploration wells drilled in the Bass Basin have revealed many good reservoir sands.

Upper Eastern View Group (EVG) sands with some marine influence are favourable for high quality reservoir development (Lemon, 2003). However, despite the good reservoir distribution, the potential lack of hydrocarbon charge in the Upper EVG is a significant risk for this play. Therefore, one of the major factors determining the prospectivity of the Bass Basin is the reservoir quality of the Lower and Middle Eastern View Group where the charge risk may be lower (Baillie & Tingate, 1991).

The main influences on reservoir quality in the Bass Basin are maturity of the original sediments, grain size and depth of burial. Marine influence, level within stratigraphic succession and possibly heat flow are also significant factors (Lemon, 2003). Reservoir quality within the Eastern View Group depends mainly on depositional environment and compaction, and almost all previous workers (Partridge, 2002; Lemon, 2003; Lang, 2003; Blevin, 2003) agree that only medium to coarse-grained sands demonstrate good quality reservoir. They can preserve good reservoir characteristics down to depths of 3000 m (Baillie & Tingate, 1991). Despite common acceptance that the Upper Eastern View Group is the only potential good quality reservoir, some authors believe there are good quality reservoir sands at depths 2500 m (Cubitt, 1992). In addition to resistance to compaction, the presence of

fractures and secondary porosity are likely to be important factors in increased reservoir quality, (Meszoly, 1986).

The deep reservoir and production test conducted over perforated interval 3141m-3150m from the recent Trefoil-1 well drilled in the Bass Basin provides evidence of deep reservoirs and demonstrates that even the poorest quality gas-bearing reservoir zones can flow at commercial rates (Rigzone, 2004).

Average core porosity typically reduces with depth within the Bass Basin, but local departures from this trend occur in some wells. The post depositional history of the Eastern View Group sandstones have been categorised by Meszoly (1986) into two principal patterns based on their diagenetic history: the Bass-type and Pelican-type. The Bass-type principally feature a high degree of dolomite/siderite cementation, the Pelican-type has a diagenetic history characterised by extensive dissolution at depths greater than 2000 m associated with secondary porosity (Meszoly, 1986).

There appears to be a broad divergence between porosities measured from different methods within the Bass Basin. Porosities measured from thin sections are normally lower than those of other methods, and plug porosity can be highly variable. While Meszoly (1986) utilised available porosities derived from various wireline logs during well operations, they appear to give consistently high readings and he considered the log porosity as unreliable. Given the importance of wireline log porosity estimation, further investigation into log porosity trends and their relation to other porosity estimates was undertaken in this study. Aggradational, retrogradational and progradational stacking patterns can be recognised from porosity-depth plots which highlight grain size. The sand bodies with porosity that increases with depth display fining-upward cycles. These cycles are interpreted by Baillie et al. (1991) as meandering fluvial systems which are ranked as the best quality reservoir facies.

The Middle EVG succession contains thick sand bearing zones with excellent lateral continuity and regional extent, which preserved good porosity even at depths greater than 3000 m. Coarser grained sandstones have resisted compaction and cementation and have preserved better intergranular porosity and reservoir characteristics. Fining-upwards cycles potentially provide top seals for the clean reservoir sands, as finer grained clastics are deposited on top of coarser grained

clastics. The presence of fine-grained clastics with good sealing capacity overlying sand bodies with good reservoir characteristics is important for hydrocarbon exploration, especially as the deeper reservoirs in the Bass Basin are closer to the mature source rocks.

1.3.4. Seal evaluation

Fine-grained sediments of the Demons Bluff Formation with their excellent regional extent and thickness (100-395 m) have been described by all previous authors as the regional seal (e.g. Daniel & Kaldi, 2003; Blevin, 2003; etc.). A recent Mercury Injection Capillary Pressure (MICP) test on several samples of the Demons Bluff Formation undertaken in conjunction with this study suggests an excellent sealing capacity for the tested samples. Some samples have the capacity to support up to 2342 m of oil column (Olsen, 2008). The regional sealing facies of the Demons Bluff Formation overlies thick Upper EVG channel sands with good reservoir quality, which make potential hydrocarbon traps that have been targeted during previous hydrocarbon exploration of the basin.

In addition, the mainly coarse-grained clastics of the EVG contain several lacustrine, flood plain and delta plain shales and coals. A previous seal capacity study suggests very good to excellent seal capacity for intraformational seals. Lower shoreface carbonaceous mudstones showed the highest sealing capacity with up to 1400 m of oil column (Daniel & Kaldi, 2003). The authors stress that many of the core samples selected for the MICP analysis were taken during exploration drilling, which focused on the recovery of reservoir facies. As such, the samples selected represent the fine-grained intervals within the cores examined.

The fact that many wells drilled in the basin confirm the occurrence of overpressure below depths of 2700 m, several hundred metres below the regional seal, proves the effectiveness of the intraformational seals within deep sections of the EVG succession, which may have a reasonable regional extent.

1.4. Previous exploration

The hydrocarbon exploration within the Bass Basin started in the early 1960s, with mainly the Upper EVG targeted as potential reservoirs within fault blocks and anticlinal structures. The early exploration strategy was partly due to the stratigraphic equivalence of the Eastern View Group to the hydrocarbon-rich Upper Latrobe Group in the Gippsland Basin.

Many unsuccessful wells were drilled during previous exploration as a result of this strategy. A well audit has categorised the thirty-three wells (Trigg, 2003) drilled in the Bass Basin. Six wells within the Bass Basin were considered invalid tests due to poor data quality, which resulted in geological misinterpretation followed by off-structure drilling (Crist et al., 2001; Trigg, 2003). Bass Basin exploration has suffered from a lack of good seismic data quality in the past. Until recently there were neither extensive seismic data sets available, nor regional interpretations carried out in the basin. Some of the previous studies misinterpreted structures, and in some cases, volcanic intrusions were identified as hydrocarbon accumulations or stratigraphic structures (Das and Lemon, 2000). Ten wells were unsuccessful due to lack of hydrocarbon charge (Trigg, 2003).

Prior to this study, apart from 1D basin modelling, no 2D or 3D hydrocarbon generation/migration/entrapment and preservation modelling has been carried out in the Bass Basin. Such studies are crucial in determining expulsion timing, migration pathways, time of entrapment and current locations of hydrocarbon accumulations.

Seal breach and seal integrity problems caused the failure of eight wells (Trigg, 2003). Trap breach is a significant exploration risk along much of the northern basin margin, particularly in the northwest (as in Cormorant-1 and Barramundi-1). The Late Oligocene-Miocene inversion resulted in faulting and fracturing of the overlying Demons Bluff regional seal (Kempton et al., 2005). The influence of Late Oligocene-Miocene structural reactivation on trap integrity is often referred to as one of the key exploration risks within the basin (Blevin, 2003; Cummings, 2004).

Five wells drilled within the Pelican Trough, despite intersecting hydrocarbon accumulations, were uneconomic due to poor reservoir quality in the Upper Eastern View Group (Trigg et al., 2003; Lemon, 2003).

Only four wells have resulted in commercial to potentially commercial hydrocarbon accumulations (Yolla, White Ibis, and Trefoil fields). These hydrocarbon accumulations are located in the central and western parts of the basin (Fig. 1.2). With increases in gas price over time, production from some of these fields has become economic. In June 2006, the \$750 million Bass Gas Project commenced production. It is now providing a significant supply of gas to the Victorian market. The Yolla Field has enough reserves to meet around 10% of the growing Victorian gas demand for the next 15 years (Origin, 2006). The facilities in that field have been designed and constructed to allow easy tie-in of the nearby Trefoil Field. With the development of Trefoil Field, the next candidate for add on will be the White Ibis Field (Rigzone, 2004).

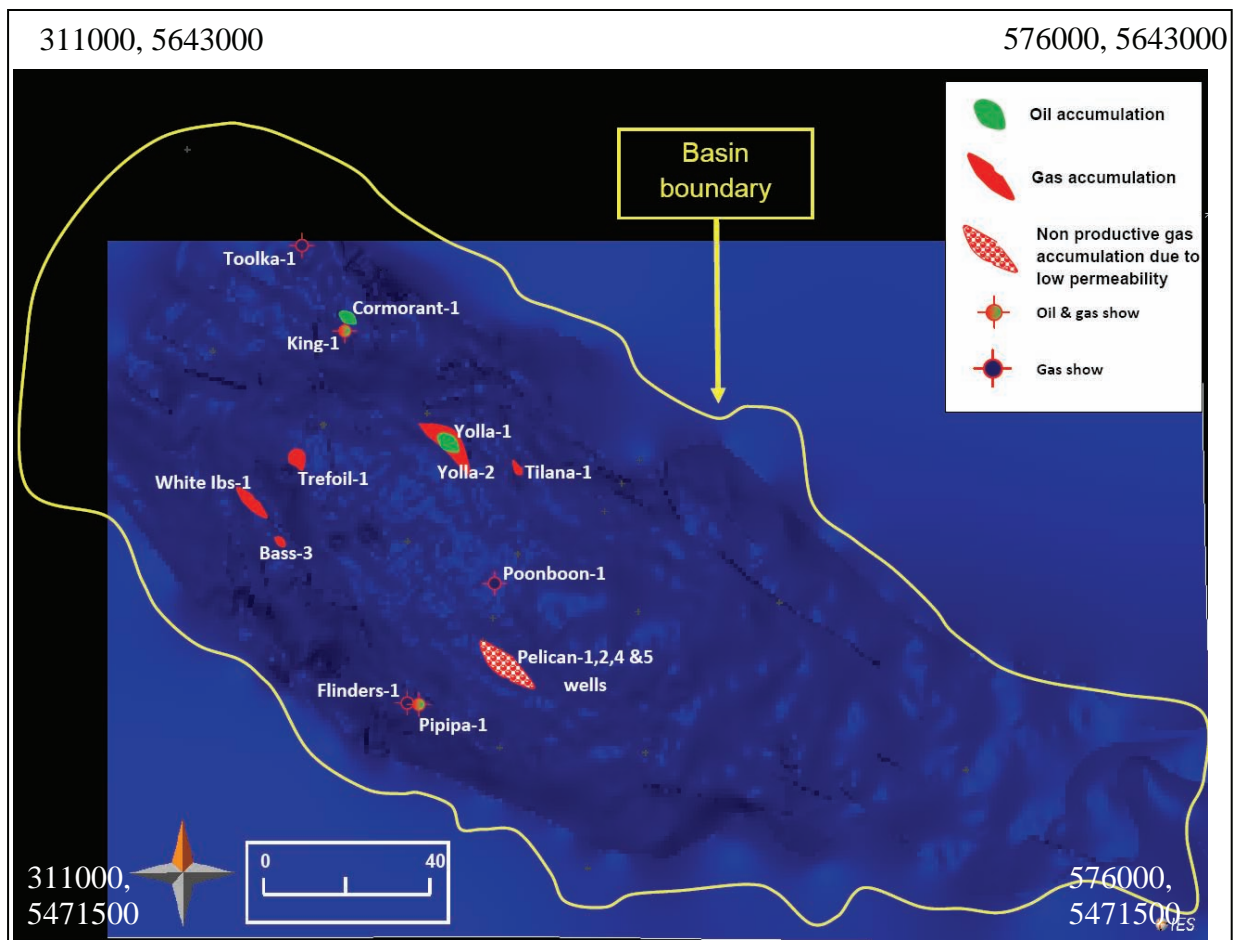


Figure 1.2: Hydrocarbon accumulations and shows in the Bass Basin.

With the Bass Gas Project infrastructure in place, the Bass Basin has become more prospective and will hopefully attract more exploration. Nevertheless, reducing the exploration risks remains an important task for future hydrocarbon exploration in the area. Risks associated with trap identification, hydrocarbon charge and seal capacity and integrity, as well as poor reservoir quality of the Upper Eastern View Group within the Pelican Trough, have contributed to exploration failure in most parts of the basin. Partial exploration success in other parts of the basin is evidence that a new research approach is necessary. Understanding hydrocarbon generation and expulsion times, together with identifying possible hydrocarbon migration pathways, should increase the chance of more accurately predicting the locations of hydrocarbon accumulations, which will improve the prospectivity of the Bass Basin

1.5. Main issues

Petroleum exploration in the Bass Basin started more than 40 years ago. Despite numerous hydrocarbon shows and the discovery of a number of sub-economic to commercial hydrocarbon accumulations, the exploration risk in the Bass Basin remains high. There are many uncertainties regarding the basin's structure and its petroleum systems. It is evident that exploration in the Bass Basin was undertaken using models from successful exploration in the Gippsland Basin, disregarding the fact that the Bass Basin has its own structure and characteristics. Successful exploration requires investigations tailored to the unique character of the Bass Basin.

Previous researchers have documented four main areas of exploration risk (Trigg et al., 2003; Blevin, 2003):

- 1- Invalid tests due to poor seismic data quality, especially in the early years of exploration in the Bass Basin.
- 2- Lack of hydrocarbon charge to reservoirs of the Upper EVG.
- 3- Trap integrity and seal risk.
- 4- Reservoir quality.

The migration pathways have been almost totally ignored by previous authors and little information is available in this regard. The main reason for disregarding the issue is possibly the existence of the Demons Bluff Formation as a regional seal overlying thick good quality reservoir sands of the Upper Eastern View Group. Vertical migration for mature source rocks was probably expected as this is the case in the neighbouring Gippsland Basin. Previous investigators have disregarded the issue of baffles and intra-formational seals, as well as the fault conductivity issue. Thus the question of reservoir quality in the deeper sections of the Eastern View Group was neglected. Considering the nature and lithology of the entire EVG succession and the presence of mature source rocks in the lower sections of the EVG succession and older sediments, understanding hydrocarbon migration is one of the most important issues in the Bass Basin,

1.6. Objectives, Aims and Scope

With only thirty-three wells drilled during almost a half century of hydrocarbon exploration, the Bass Basin is categorised as a moderate to underexplored basin. Thus, due to a lack of exploration interest, the Bass Basin has not been studied in detail. In general, classic passive margins around the world have been recognised as potentially large hydrocarbon provinces (Palmowski, 2003). Therefore, more detailed basin and petroleum systems studies could potentially make the Bass Basin more prospective.

The aim of this thesis is to predict hydrocarbon accumulation locations, possible accumulation breaches and secondary migration pathways, as well as the preservation of hydrocarbons within the reservoirs.

To achieve this aim requires the following tasks:

1. Conduct a detailed 2D seismic interpretation of the entire Bass Basin in order to map the tectonostratigraphy and lithostratigraphy of the sediments and utilise them to assemble 2D and 3D basin models, in order to have a better understanding of the basin's structure and history, which is crucial for the development of basin models.

2. Determine the presence of good reservoir sands within Lower and Middle EVG by investigating regional porosity trends from well completion reports and log data.
3. Construct 2D hydrocarbon generation, expulsion, migration, and accumulation models for different parts of the basin, in order to constrain petroleum systems and source rock maturity in the basin.
4. Assess the top seal issues in the Bass Basin, and their implications for hydrocarbon accumulation distribution in the Bass Basin.
5. Investigate the fault seal of the Bass Basin and its implications for 2D basin modelling.
6. Examine the thermal regime throughout the basin and its effects on mature source rock distribution.
7. Construct 3D generation, expulsion, migration, accumulation and preservation models.
8. Investigate the sensitivity of the 2D and 3D models to variations of input parameters.
9. Develop scenarios of hydrocarbon generation, expulsion, migration, entrapment and preservation within the basin.
10. Integrate the 3D basin model with seal assessment, to determine the Bass Basin's prospectivity.

Near the end of the study the sponsor and other government agencies developed an interest in the CO₂ storage capacity of the Bass Basin and a regional geosequestration assessment was also carried out as a part of this thesis.

CHAPTER 2

2. 2D Seismic Interpretation

2.1. Introduction

Seismic records rely on physical changes in rocks, which lead to acoustic impedance contrasts. Acoustic impedances are the product of rock density and seismic velocity. Variations in impedance contrasts will result in varying reflection amplitudes (Palmowski, 2003). The coherent events on processed seismic sections are mostly reflections from bedding surfaces and unconformities. Fault planes can also be reflective in some circumstances, such as when dips are low (Vail et al., 1977; Palmowski, 2003). Seismic reflections follow chronostratigraphic surfaces and can be used to analyse seismic sequences and facies, based on the spatial distribution of reflection characters, such as coherency, continuity, energy, etc. When combined with well data, seismic data provides a powerful tool for inferring the stratigraphic and structural patterns in sedimentary rocks (Vail et al., 1977; Van Wagoner et al., 1995)

Interpreting and subdividing sedimentary sections into packages that are defined by bounding unconformities and diagnostic internal surfaces is called seismic stratigraphy (Vail et al., 1977). This technique was used to interpret 11 horizons from 2D seismic sections from the Bass Basin, based on Lennon et al. (1999), Blevin (2003) and Cummings (2004). Structural interpretation of the seismic data involved connecting seismic reflection terminations to interpret fault planes. Several seismic surveys during different periods of time were shot in the Bass Basin. The seismic lines were recorded to suit the needs of the survey. Regional lines were recorded to 12 second TWT, but local lines were recorded to 5 seconds TWT only. The primary purpose of this 2D seismic interpretation was to provide 2D and 3D horizons (gridded from a network of 2D horizons) for constructing 2D and 3D petroleum systems models. Therefore, the interpretation aimed to identify the tectonostratigraphic tops of the sedimentary section, rather than the deeper crustal

structure. Five seconds TWT data was sufficient for that purpose. No low dip faults were identified in the sedimentary section.

Interpreted horizons from 2D seismic lines were gridded, then the outputs (3D horizon surfaces) were depth converted to be used for 3D basin modelling.

2.2. Data sets and methods

2.2.1. Data

2.2.1.1 Seismic data

The seismic dataset utilised for this study consisted of 16 open-file 2D seismic surveys which contain 433 lines (Fig. 2.1), making a total of over 20,000 km. The surveys were shot in different periods during the last 43 years of exploration. The majority of the lines were recorded to 5 seconds, but some regional lines were recorded to 12 seconds. The seismic dataset provides excellent regional coverage, excluding the north-western part of the Koorkah Terrace. The density of the seismic lines decreases in the Durroon Sub-basin. The BMR88 survey was provided to the Australian School of Petroleum (ASP) by Geoscience Australia and two regional lines (090-25 and 090-27) were provided by FUGRO Multi Client Services. The seismic data were loaded into the Schlumberger GeoFrame Software for a previous project at the ASP by Aaron Cummings. The same database has been used by this study to interpret over 350 available 2D seismic lines using the Schlumberger GeoFrame software packages IESX and GeoViz. The three uppermost horizons (top Torquay-1, top Torquay-2 and top Demons Bluff Formation) interpreted by Aaron Cummings were incorporated into this interpretation. In order to present adequate well control, synthetic seismograms from 25 wells were tied to seismic lines.

The GeoFrame software IESX package for seismic interpretation was used, which allowed several different ways to display a set of seismic traces. Many of the single and double gradational display settings suitable for specific seismic interpretation were utilised to achieve detailed seismic analysis. However, gray gradational scale was used most frequently, because it emphasises low amplitude events and reflection terminations.

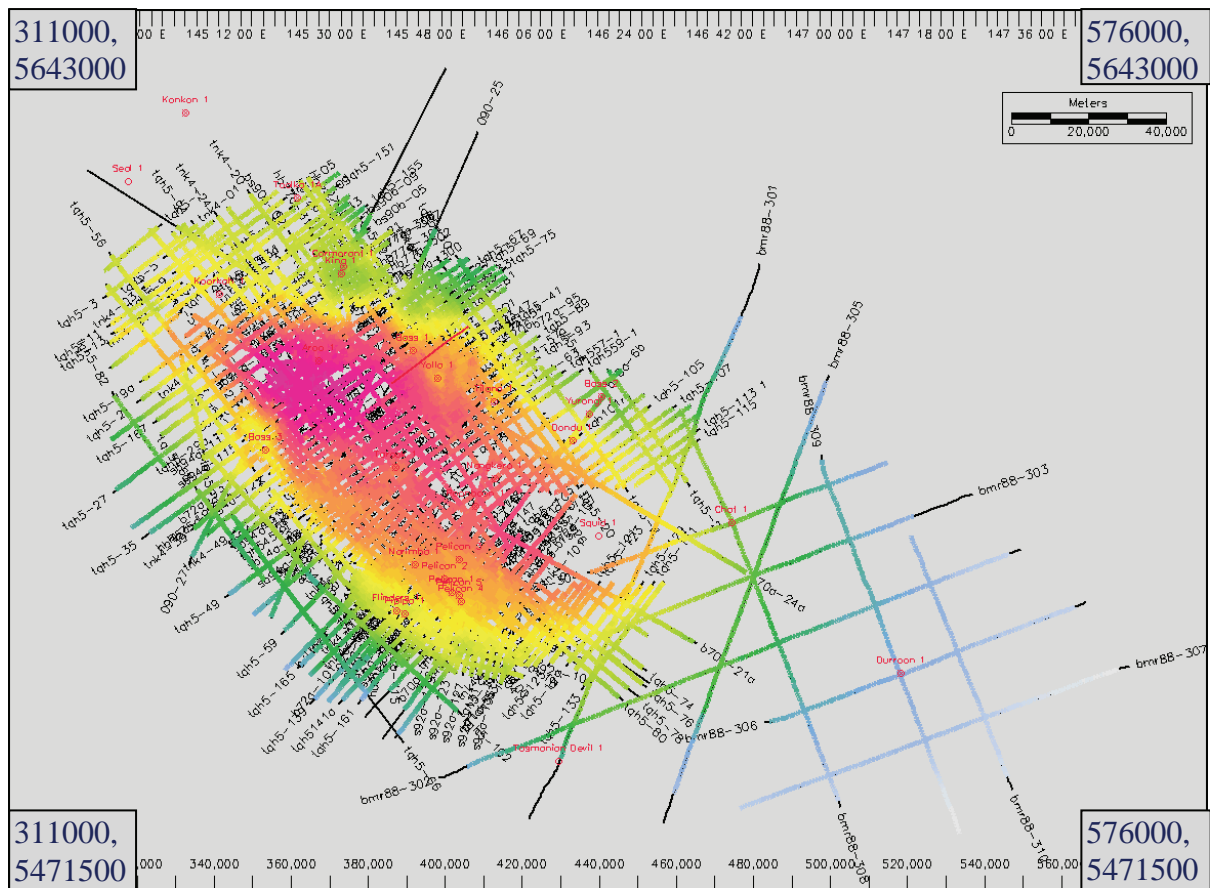


Figure 2.1: 2D seismic lines interpreted in the Bass Basin.

2.2.1.1.1. Data quality and display types.

Despite improving technology, seismic images are not always representative. Distortions and noise in seismic data need to be recognised for improved interpretation.

a) High and low velocity anomalies

Due to the large number of volcanic features in the Bass Basin, many seismic lines suffer from poor imaging of underlying bedding reflections. These are called velocity pull ups and are due to the high seismic velocity of the igneous rocks (Fig. 2.2). Recognising this problem is particularly important to avoid misinterpretation when interpreting top reservoir horizons (e.g. top Upper EVG). Canyon fill can also cause velocity pull ups and push downs. Velocity push downs result when canyons are filled with slower seismic velocity sediment than surrounding sediments (Fig. 2.3).

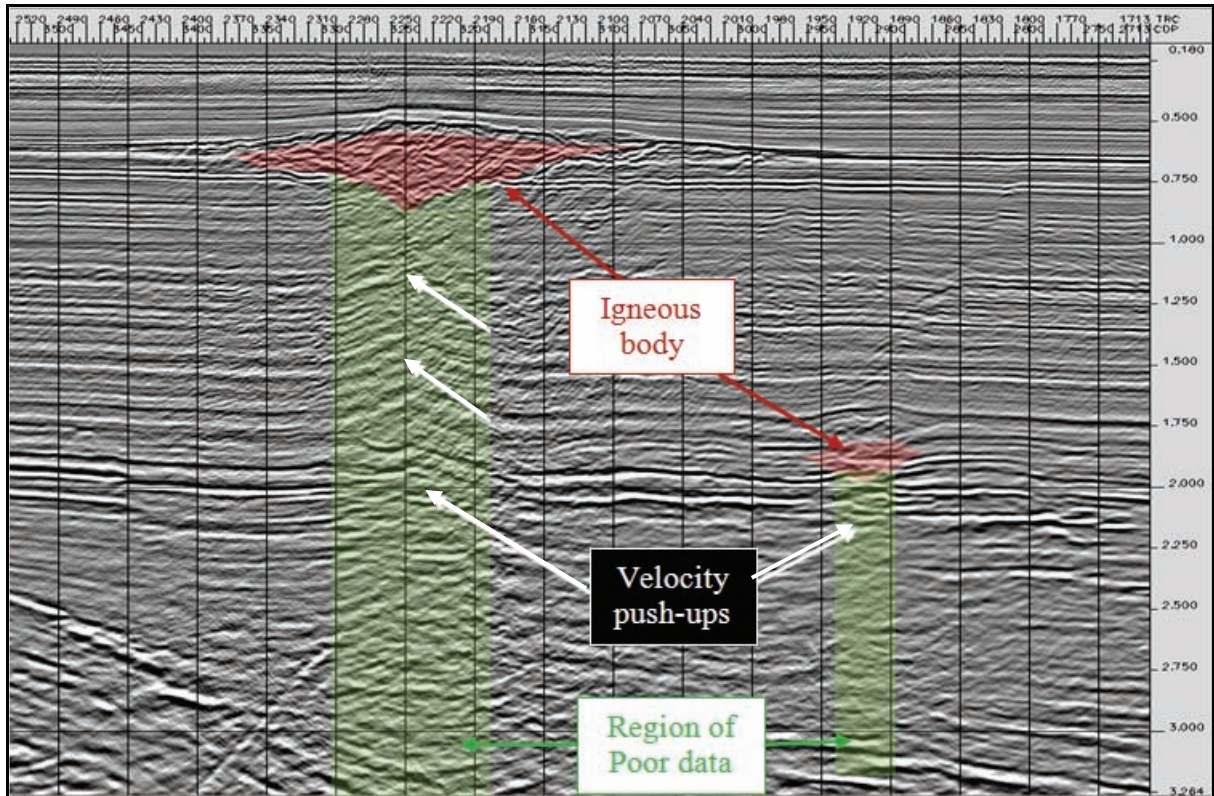


Figure 2.2: Velocity differences between high velocity igneous rocks and surrounding rocks resulted in poor seismic quality and pull-ups in reflections of underlying beds along the intrusion zone. The poor data quality caused by narrowing stacking velocities, example from seismic line TQH5-37.

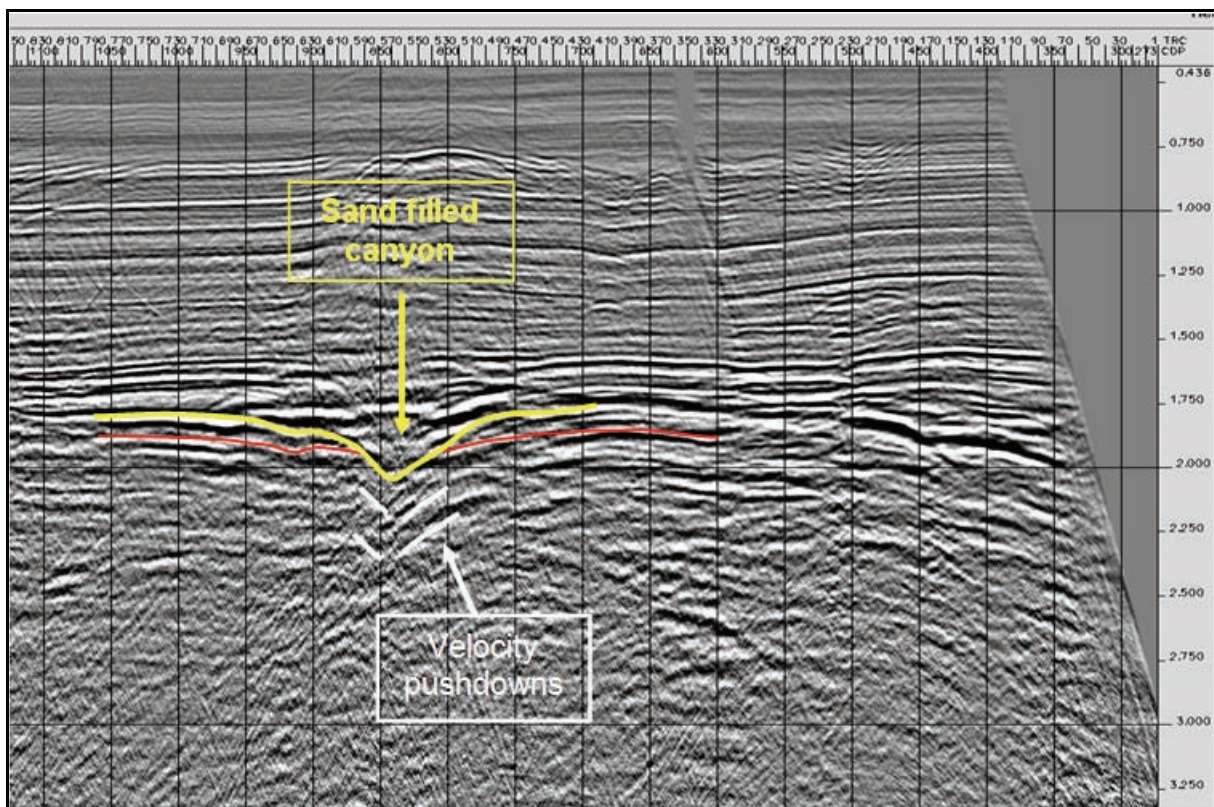


Figure 2.3: An example of velocity push-downs from seismic line (TNK4-17). Velocity differences between low velocity sand filled canyon and surrounding sediments caused velocity push-downs underneath the canyon.

b) Fault shadow

Velocity variation across faults (usually extensional faults) can cause ray-path complications under the fault plane, which may result in wedges of unreliable data within footwall bed reflections. These zones of poor data are called fault shadow and normally appear to be separated by a reverse fault from the remainder of the foot wall (Fig. 2.4). Fault shadows can be serious obstructions to successful seismic interpretation if not considered.

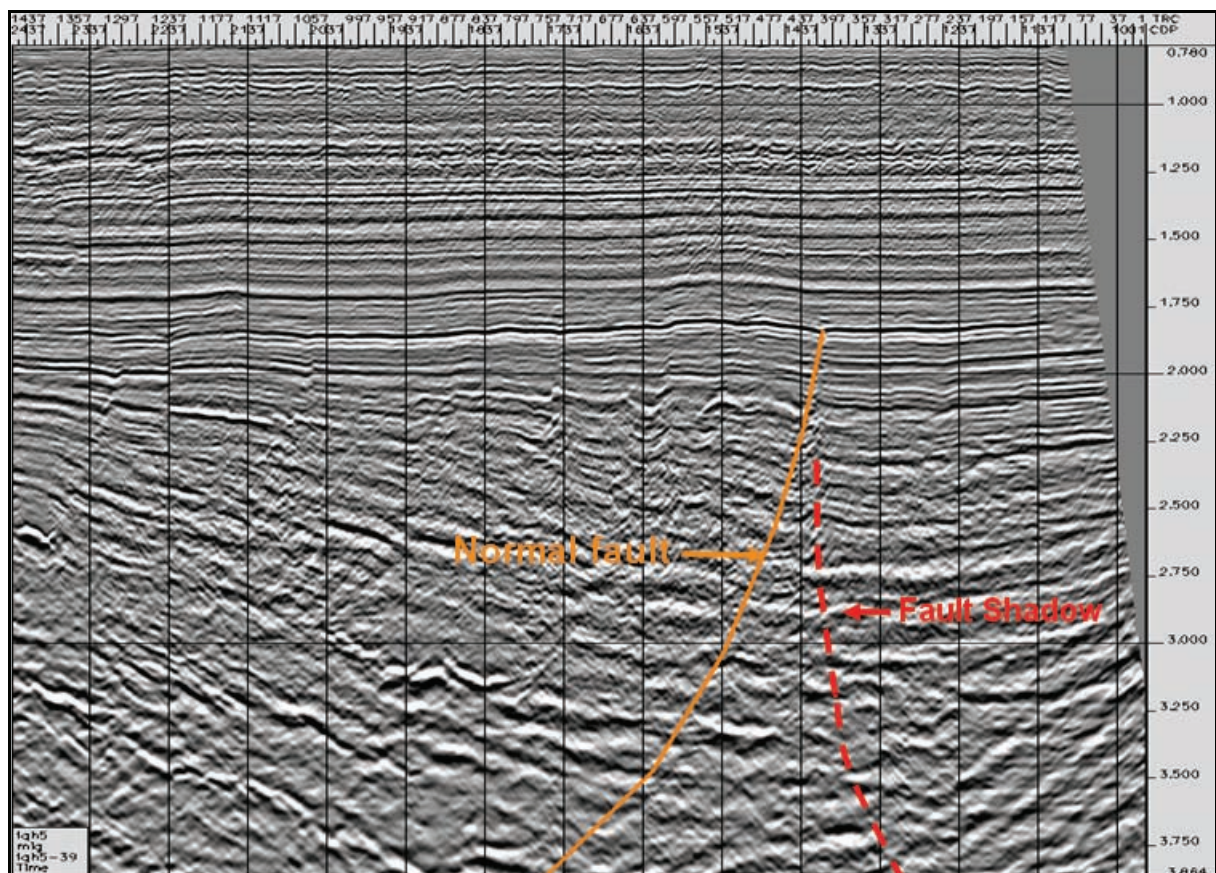


Figure 2.4: An example of fault shadow from seismic line (TQH5-39), which appears like a reverse fault under the fault zone

c) Automatic gain control

Due to spherical propagation, absorption and dispersion, the seismic energy decays rapidly when travelling through the earth. The deep layers cannot produce strong amplitude reflections and need to be amplified to be consistent with high amplitude reflections of upper layers closer to the surface. GeoFrame software with its automatic gain control application allows the amplification of the deeper weak

reflections and reducing stronger near-surface amplitudes (GeoFrame users manual).

In general, the seismic data of the Bass Basin were of good quality, but some seismic lines contain very poor reflections of the deeper layers and it was not possible to solve the problem with automatic gain control. These poor quality seismic lines were not chosen for interpretation.

2.2.1.2 Well data

Well completion reports were downloaded from MRT's database (Minerals Resource Tasmania) on their webpage <http://www.mrt.tas.gov.au>. In addition, some check-shot surveys and formation tops were downloaded from GA's database (Geoscience Australia) on their webpage <https://www.ga.gov.au>. Stacking velocities were also obtained from Geoscience Australia.

Twenty-five wells across the Bass Basin were used to generate synthetic seismograms which were tied to seismic lines in order to present adequate well control. In general, data from 29 wells throughout the basin have been used to guide this interpretation. Formation tops from well completion reports were used to compare horizon depths after their depth conversion.

2.2.2. Methods

The Schlumberger GeoFrame software packages IESX and GeoViz were used for this seismic interpretation. Two uppermost interpreted horizons, top Torquay-1, top Torquay-2 (from previous investigator Aaron Cummings), were included in this interpretation with minor changes where needed. Sonic and density logs from 25 wells were utilised to produce synthetic seismograms. Created synthetics were put side by side with available synthetic seismograms created by Aaron Cummings for comparison purposes. Megasequence and sequence boundaries were identified using sequence stratigraphy techniques. Interpreted horizons were gridded using GeoFrame software's IESX package and then exported. Gridded and exported

horizons together with exported fault traces for each horizon were imported into Petrosys software for depth conversion purposes.

2.2.2.1. Megasequences and sequences

Analysing sequence stratigraphic information from seismic reflections is a technique called seismic stratigraphy, which can be used to subdivide sedimentary sections into rock packages that are defined by bounding unconformities and diagnostic internal surfaces (Vail et al., 1977; McQuillin et al., 1984; and Palmowski, 2003). During the development of extensional basins and continental margins, tectonic subsidence occurs at different rates (McKenzie, 1978). The initial syn-rift phases demonstrate rapid subsidence during crustal extension and are characterised by a series of opposite-facing half-graben units (Das, 2001). Later, post-rift phases are characterised by gradually decreasing thermally driven subsidence (Palmowski, 2003). Megasequences are often characterised by unique mappable seismic facies in the seismic record (Hubbard, 1998, Palmowski, 2003).

Formation depth and palaeontological data obtained from well completion reports were converted to Two-Way Travel Time (TWT), and together with palaeontological interpretations, were placed over the seismic displays and used to interpret seismic reflections. Only major sequence boundaries with basin-wide specific seismic character were chosen for interpretation. The identified reflections were mapped across the basin and showed reasonable consistency between the palaeontological interpretation and formation tops (Fig. 2.5).

To overcome the problem of horizon correlation across the faults, GeoFrame software was used to form an image from one side of the fault, and that image was moved interactively along the fault to match seismic reflectors on the other side of the fault plane. Identified seismic reflections were followed and mapped accordingly.

However, due to limited well control, deep horizons, such as the top Otway Megasequence and the top Crayfish Megasequence, were mainly identified from their unique seismic facies. Durroon-1 is the only well that penetrated deeper sedimentary successions in the basin, including the Otway Megasequence.

Sediments of the Crayfish equivalent Megasequence are not penetrated by any wells in the basin. Therefore, the Otway Megasequence top has been tied to the penetrated top from the Durroon-1 well, and the recognisable seismic facies of the reflection has been followed across the basin. The Crayfish top has been identified from its unique seismic facies only.

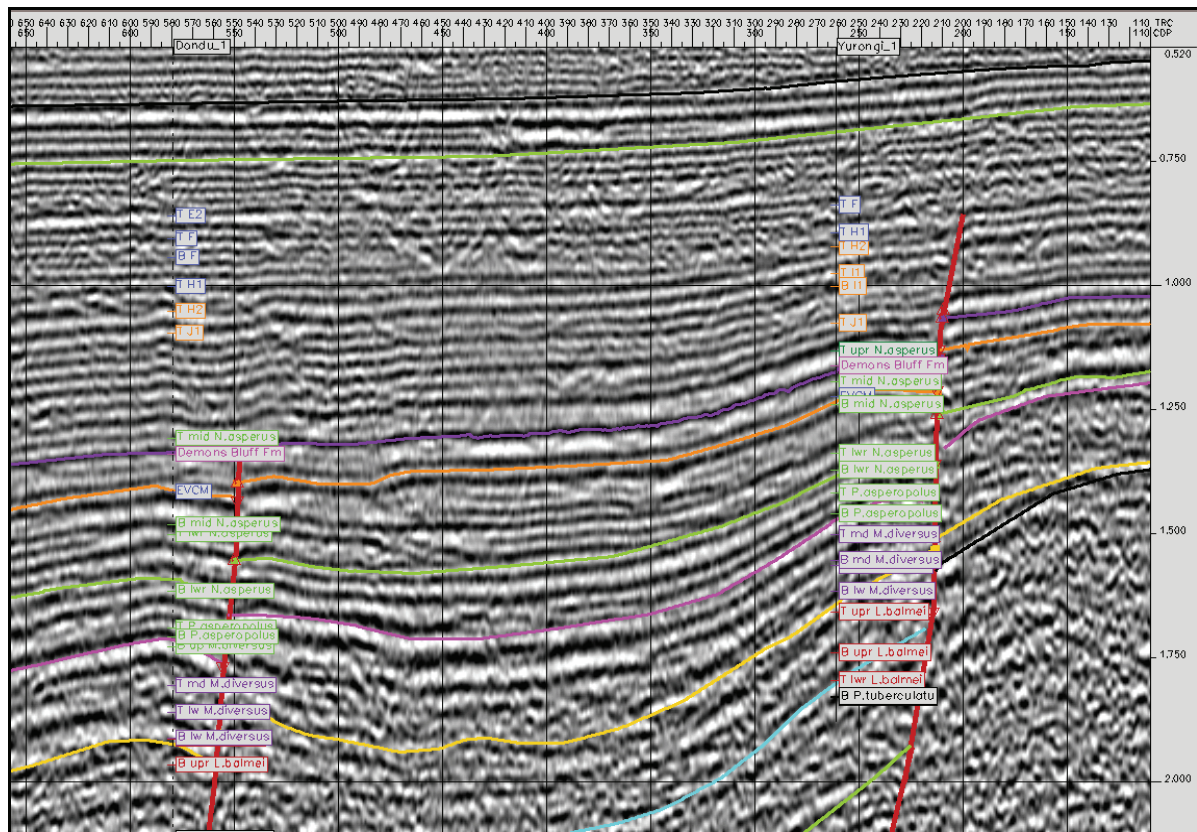
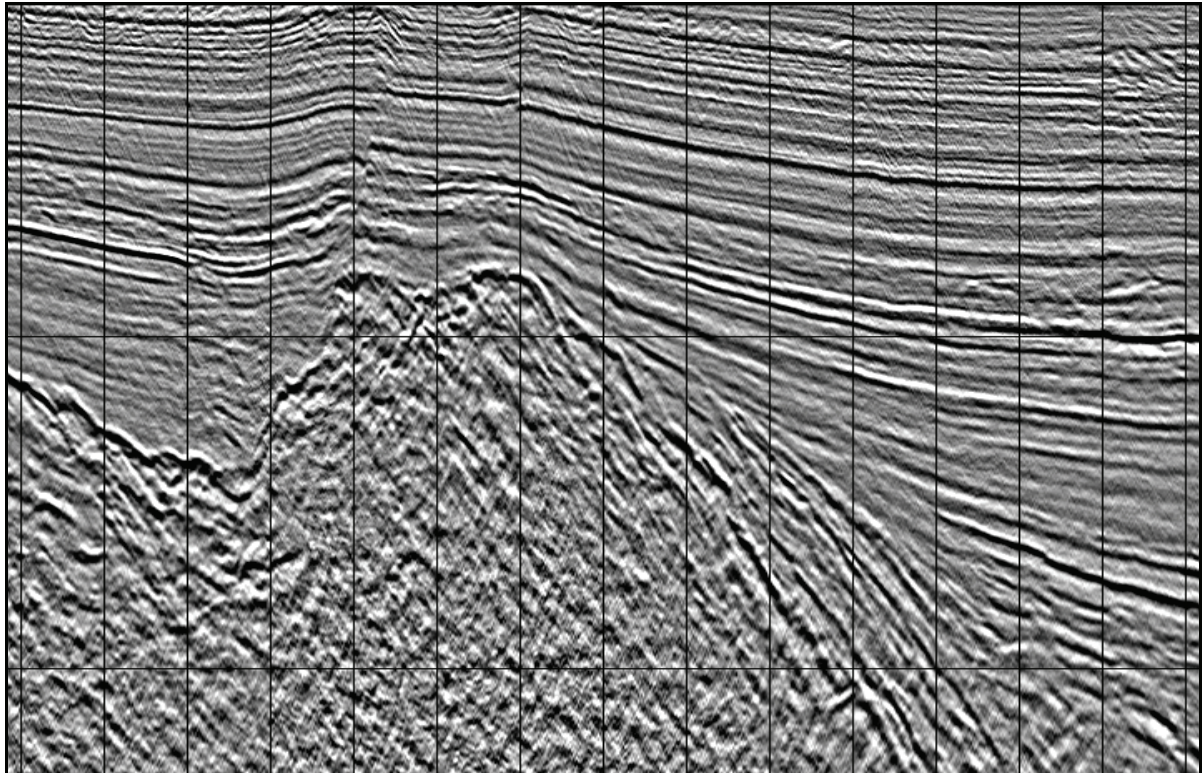


Figure 2.5: Showing well ties (formation tops and paleontological interpretation) with seismic data.

2.2.2.2. Faults and structural interpretation

Most fault planes are steeply dipping surfaces that are not easily imaged in seismic data displays, but there are several lines of evidence that assist in fault identification. For example, patterns of abrupt reflection terminations on vertical and horizontal sections, zones of zero or very low amplitudes, changes in reflection patterns, fault plane reflections, drape in overlying sediments and other evidence can be used to identify a fault plane.



a: Part of seismic line TQH5-35 from the central Bass Basin (uninterpreted).

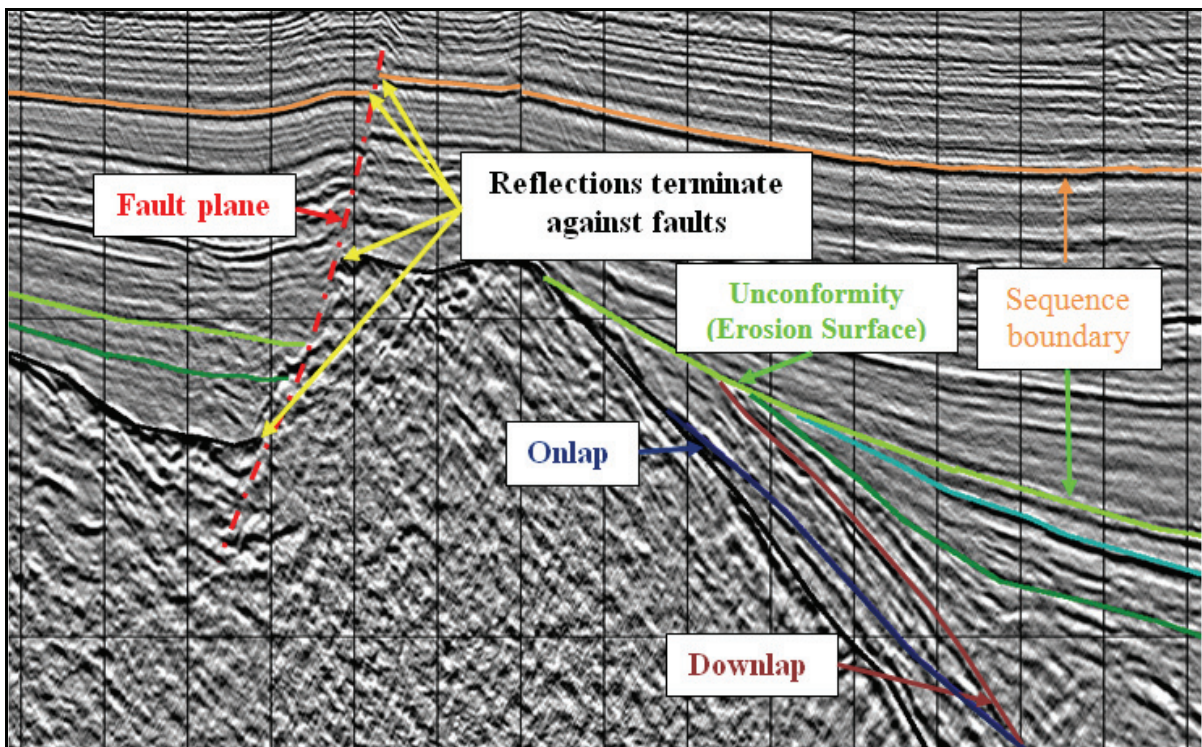


Figure 2.6: Part of the seismic line TQH5-35, demonstrating termination of reflectors and showing fault plane reflectivity. In addition, a sequence boundary, erosion surface, downlap and onlap are shown. The black reflector is the top of Basement, dark blue, dark green, light green and orange reflectors are sequence boundaries. The light green sequence boundary is defined by erosional contact unconformity (brown, light green and light blue reflectors are cut by the light green reflector).

Reflection terminations against fault planes are normally sharp and easy to identify (Palmowski, 2003). Most fault planes are interpreted simply by connecting seismic reflection terminations (Fig. 2.6). To avoid over-interpretation, only clearly imaged reflection terminations were interpreted as faults. When fault dips are low, fault planes can be interpreted from coherent reflections rather than reflection terminations (Vail et al., 1977; Prosser, 1993; Palmowski, 2003). Some faults within the metasediments of the basement were identified from fault plane reflections. Hence, these deeper faults or parts of the faults were only used to build an overall general structural picture of the basin and not used for basin modelling purposes.

To avoid complexity in 3D basin models, faults with very small displacement (less than ~50msec) were ignored and horizon lines were mapped across ignored fault traces.

2.3. Basin architecture

The Bass Basin was initiated with extension (Southern Ocean rifting), which started in the Early Cretaceous (possibly Late Jurassic), and was related to the initial separation of Australia and Antarctica. The basin developed with another extensional rifting event during the Tasman rifting (Cenomanian-Campanian). A third event occurred during the Cenomanian-Late Eocene related to separation of Australia and the Antarctic Plate along the Tasman-Antarctic Shear Zone and the Tasman Fracture Zone (Stagg, et al., 1999; Cummings, et al., 2004; Blevin, et al., 2005). Despite the dominant extensional geometry of the Bass Basin, recognised pulses of compressive reactivation signature are also present. The basin also contains compaction related polygonal faulting (Cummings, et al., 2004).

The Bass Basin is characterised by rotated half-graben blocks characterised by across-strike reversal in structural polarity (opposite dip directions). Blevin (2003) recognised a basin-wide accommodation zone that marks the boundary between the western and eastern depocentres. The zone is defined by a change in rift polarity and is named the Chat Accommodation Zone. This zone subdivides the basin into two sub-basins: a) The Cape Wickham Sub-basin in the northwestern region, which is

defined by half-grabens that are predominantly thicker towards the northeast and b) the Durroon Sub-basin in the southeastern region, which is defined by half-grabens that are predominantly thicker towards the southwest (Blevin, 2003; Cummings et al., 2004).

2.3.1. Redefinition of basin boundaries

As mentioned earlier a 2D seismic database of 433 lines was utilised for this seismic interpretation, including the complete interpretation of 359 lines and the partial interpretation of 74 lines. This database covered the entire Bass Basin excluding the northwestern part of the Koorkah Terrace. The seismic data and other well data have been utilised to determine the 3D image of the Bass Basin using PetroMod's 3D SeisStrat package and was used to redefine basin boundaries.

In the southern and southwestern side of the basin, the basin outline is defined by northwest-trending basin edge faults and depositional hinges as described by Blevin (2003). However, in the northwestern side of the Cape Wickham Sub-basin, a series of southeast-trending basin edge faults are present (Fig. 2.7). Unlike those in the southern and southwestern side, the faults are close to vertical and display huge throws that exceed several kilometres (Fig. 2.8). Blevin (2003) noticed and recognised the extent of Late Miocene to Recent sediments beyond the basin boundary onto shallow basement, and concluded they are not highly prospective for petroleum exploration.

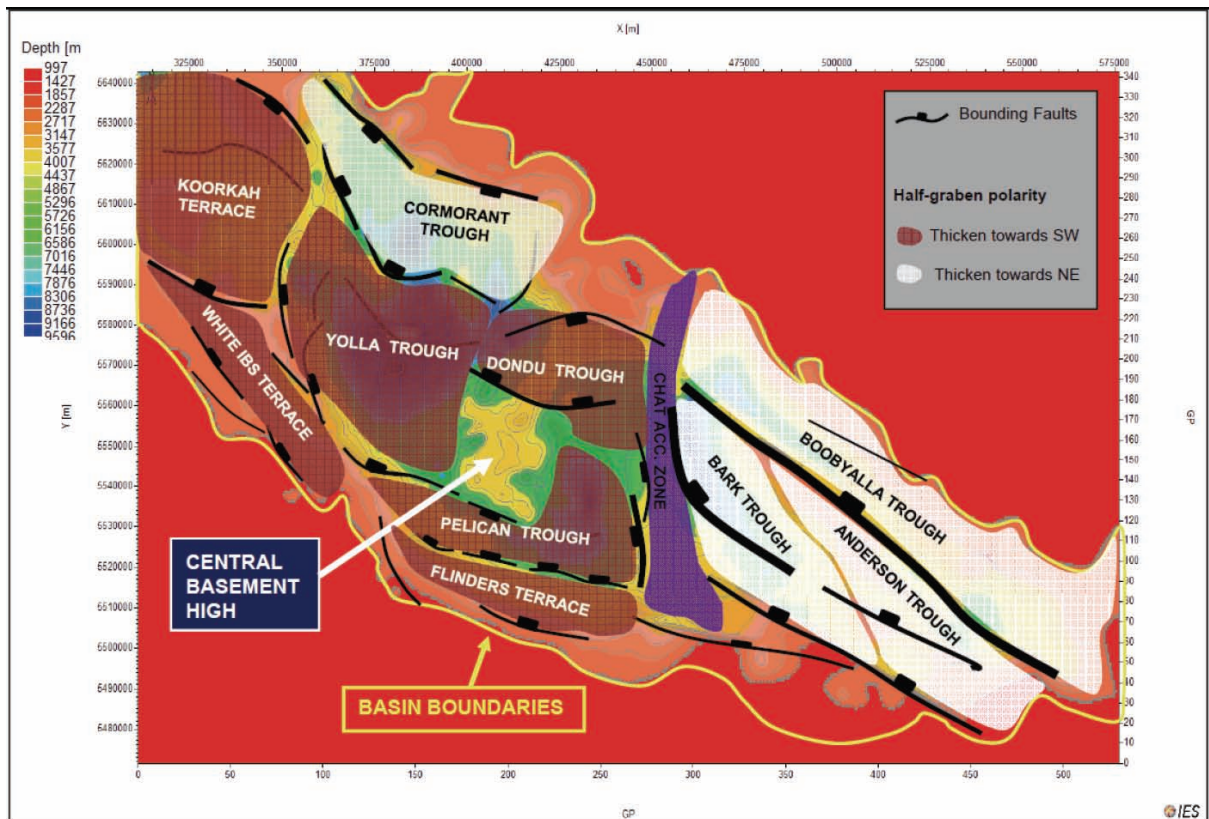


Figure 2.7: Map of the Bass Basin showing boundaries and structural elements.

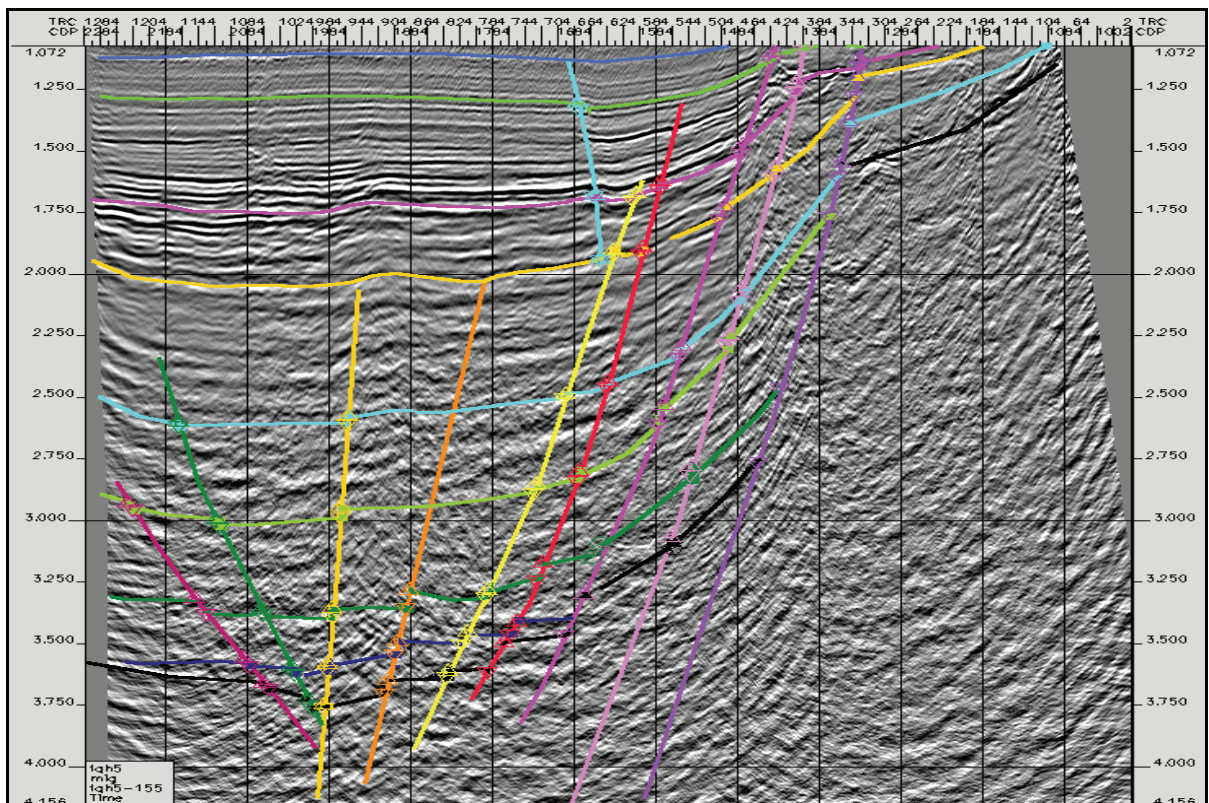


Figure 2.8: Part of the seismic line TQH5-155 exhibits steep southeast-trending faults that define the northeastern basin boundary.

2.3.2. Structural elements

The structural elements of the Bass Basin were defined by Lennon et al. (1999). The Cormorant, Yolla, Pelican and Dondu troughs were identified as the deepest depocentres of the basin and two adjacent areas, where sediments are thinner, were named Tertiary platforms. Blevin (2003) redefined these boundaries and introduced the White Ibis Trough in the central part of the basin. The interpretation in this study has redefined the boundaries of the previously recognised troughs in the basin and has defined the White Ibis and Flinders Terraces (Fig. 2.7).

A basement high in the central part of the Bass Basin separates the Pelican, Dondu and Yolla troughs. This area and its eastern adjacent area were termed the Tertiary Platform by Lennon et al. (1999). Later Blevin (2003) indicated that the basement beneath the Tertiary Platform was deeper than identified earlier. Blevin (2003) also suggested that this area is underlain by a basement block that was not affected by upper crustal deformation during the early Palaeogene. However, this study suggests the basement in the eastern part of the previously termed Tertiary Platform is as deep as that in the Pelican Trough. It is not easy to separate this part of the basin from the eastern parts of the Pelican Trough in the early stages of the development of the Bass Basin, but by the end of the Otway rifting phase it was separated from the Pelican Trough to form a part of the Dondu Trough.

There is a change of rift polarity evident in the southern region of the Chat Accommodation Zone which is characterised by a significant rotation in boundary faults towards north-south. North-east trending faults change orientation to a predominantly eastern trend in the eastern side of this region and are mirrored by a small number of south-west trending faults in the western side (Fig. 2.7). The Boobyalla, Bark and Anderson half-grabens, to the south of the Chat Accommodation Zone, thicken towards the south-west. The half-grabens in the Cape Wickham Sub-basin, except the Cormorant Trough half-graben, thicken towards the north-east.

There is a small trough south of the Pelican Trough which extends past Flinders-1 and dies out further to the northwest. The shallow nature of this feature indicates it is unlikely to be a source of petroleum. However, because of the size of the area and

its location adjacent to the Pelican Trough, which had the potential to allow hydrocarbon migration into the region, it has been identified as a feature in its own right and named the Flinders Terrace (Fig. 2.9).

Another small trough, similar to the Flinders Terrace, occurs to the west of the White Ibis-1 well (Fig. 2.10). Blevin (2003) indicated the possibility of this small trough based on a smaller seismic data set. The structure is shallow, narrow, and small in size (~ 4 km x 40 km) and is unlikely to be prospective for locally sourced hydrocarbons. However, considering its location within the basin, it is a candidate for possible hydrocarbon migration. This area is termed the White Ibis Terrace in this study. White Ibis-1 is the closest well.

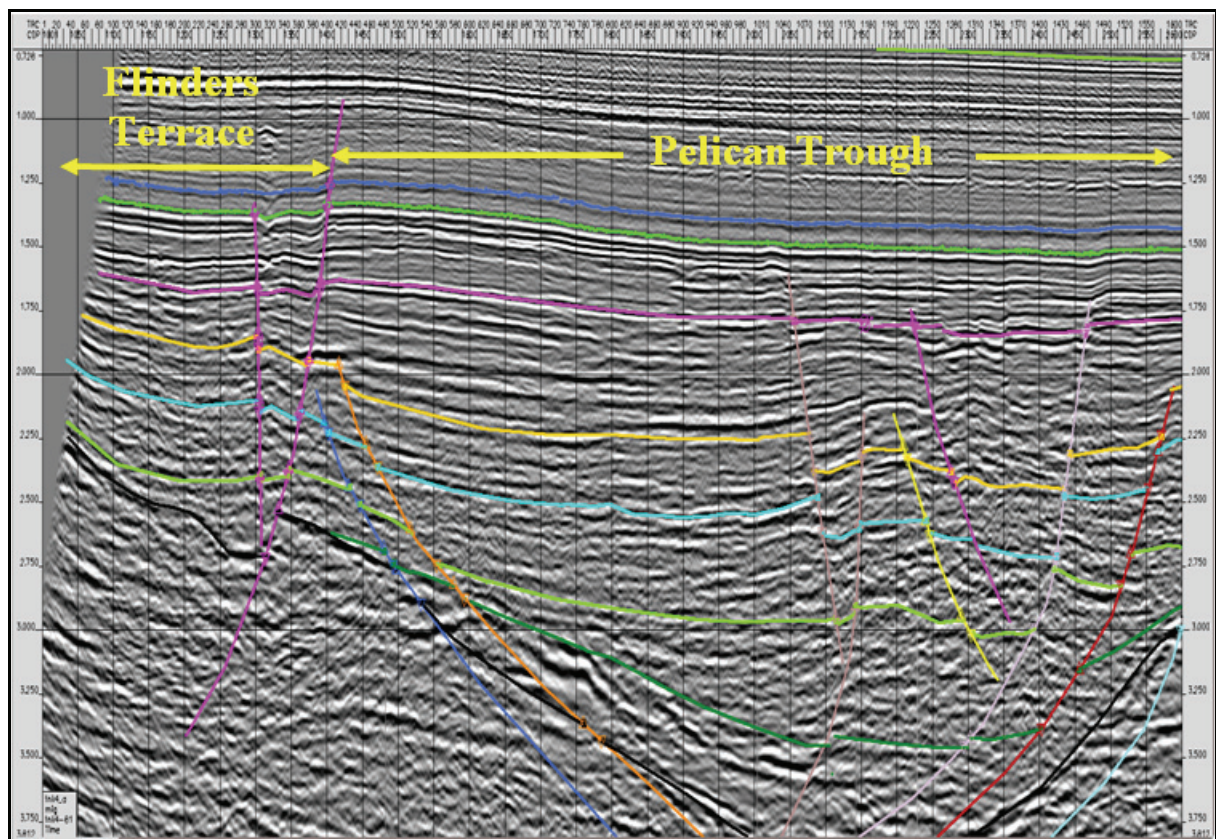


Figure 2.9: Part of the seismic line Tnk4-81, showing the Pelican Trough and the Flinders Terrace.

The mapping undertaken by this study could not recognise the White Ibis Trough as proposed by Blevin (2003), and suggests that the originally proposed White Ibis Trough is actually part of the Yolla Trough (Fig. 2.10). Therefore, this study recognises this depocentre as part of the Yolla Trough proposed by Lennon et al. (1999) and accepted by Cummings et al. (2004).

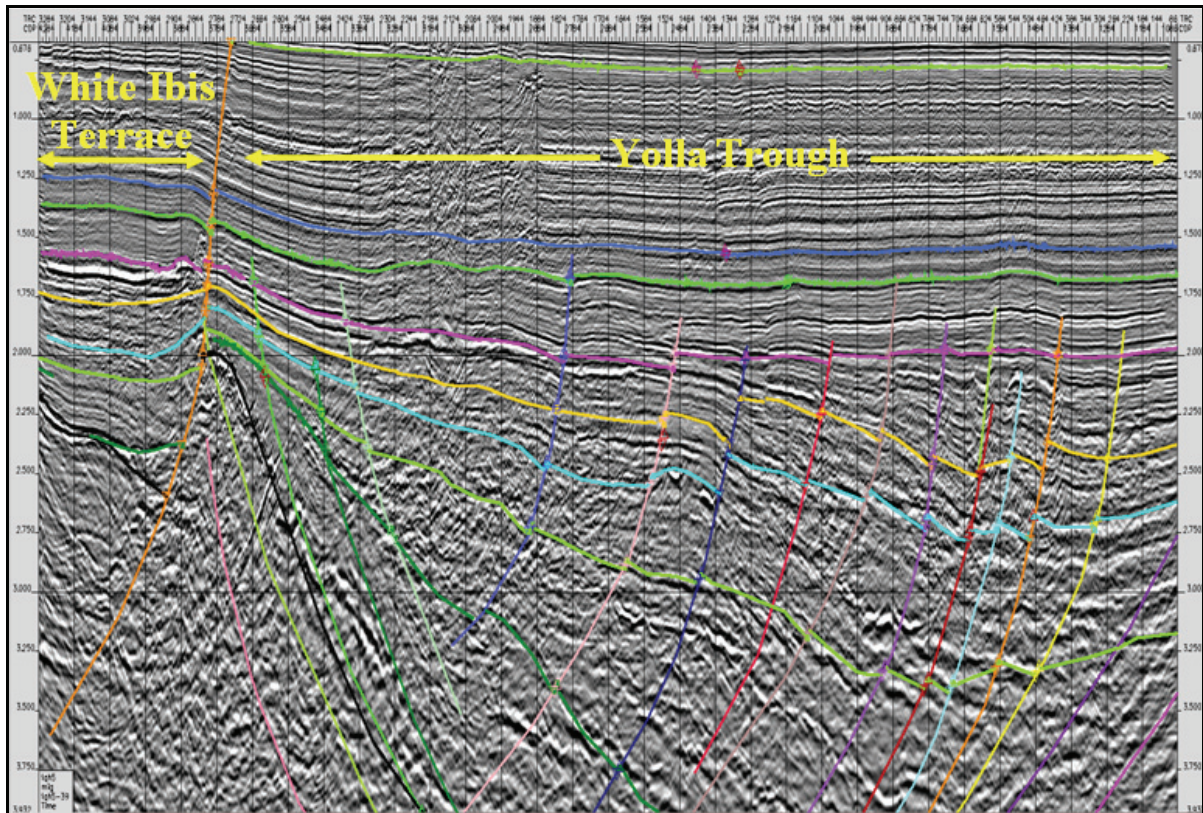


Figure 2.10: Part of the seismic line TQH5-39, showing the occurrence of the Yolla Trough and the White Ibis Terrace.

Apart from regional faults that form half-graben bounding fault systems, the Bass Basin displays NW-SE to E-W synthetic and antithetic regional faults oblique to the bounding faults, as well as NNW-SSE strike-slip fault zones.

2.4. Seismic stratigraphy in the Bass Basin

The Bass Basin contains sediments that range in age from Early Cretaceous (possibly Late Jurassic) to Recent. The development of accommodation space and the nature of the sedimentation reflect continuous deposition into an intracratonic rift basin (Cummings, 2004).

The interpretation of the seismic data set in the Bass Basin resulted in the identification of several sedimentary successions. Four megasequences were identified relating to at least three crustal phases of upper crustal extension, spanning the Early Cretaceous (possibly latest Jurassic) to Early Eocene. The tectonic regimes include a rift-sag transition phase and two thermal subsidence phases

identified by previous workers (Cummings et al., 2004; Blevin et al., 2005). They are:

- 1- Late Jurassic - Early Cretaceous Southern Ocean rifting.
- 2- Cenomanian - Campanian Tasman rifting.
- 3- Turonian - Late Eocene Bass rifting. Separation between Australia and Antarctic plates along the western margin of Tasmania.

The Bass Basin was initiated during the Late Jurassic – Early Cretaceous Southern Ocean rifting associated with the initial separation of Australia and Antarctica. Early rifting pulses resulted in increase of accommodation space and deposition of the Crayfish Equivalent Megasequence, which is confined to the central part of the Cape Wickham Sub-basin, particularly deeper parts of the Yolla Trough.

The second rifting period was related to upper crustal extension during the Cenomanian – Campanian that preceded spreading in the Tasman Basin to the east. The effect is clearly evident within central and southern parts of the basin via occurrence of the ENE –WSW faults. The new space has accommodated deposition of the syn-rift Durroon Megasequence, which is intersected by Durroon-1 well within the Durroon Sub-basin and is noticeably evident from seismic.

The third rifting phase corresponded separation between Australia and Antarctic plates along the western margin of Tasmania during the Turonian - Late Eocene, which include a series of oblique far-field upper extension stress pulses (Blevin, 2003). Wide variation in the Bass Megasequence sediments probably reflect localised nature of such far-field pulses.

Based on Lennon et al. (1999); Blevin (2003); Cummings et al., (2004) and Blevin et al., (2005), four rift-related stratigraphic megasequences including the Crayfish Equivalent, Otway, Durroon and Bass megasequences were identified. The Bass Megasequence is divided into three component sequences (Furneaux, Tilana and Narimba sequences). Three younger sequences (Aroo, Flinders and Torquay sequences) were also identified and mapped (Fig. 2.11). In addition, the top regional sealing facies of the Demons Bluff Formation within the Flinders Sequence was

mapped, as well as the dominant regional seismic reflections within the Torquay sequence, which were identified by Aaron Cummings and were adopted and named top Torquay-1 and top Torquay-2, respectively. Top Torquay-2 represents the top Late Oligocene-Miocene unconformity in the Bass Basin. The top of the metasediments of Palaeozoic and older age have been identified as Basement top.

2.4.1. Basement

The Proterozoic and Palaeozoic basement is characterised by irregular and discontinuous reflections. The sequence boundary is characterised by thick seismic facies (Fig. 2.12) and is interpreted to represent top Basement. Near the western margin of the basin, intersected basement rocks in the Bass-3 well are interbedded quartzite, recrystallised siltstone, fine-grained sandstone and low-grade metamorphosed shales (ESSO, 1967; Brown, 1976; Das, 2001). The basement rocks encountered in the Bass-2 well, which is located on the shoulder of the eastern margin of the Bass Basin, are highly fractured tuffaceous mudstones dated as Early Palaeozoic, possibly as old as Cambrian (Brown, 1976; Das, 2001).

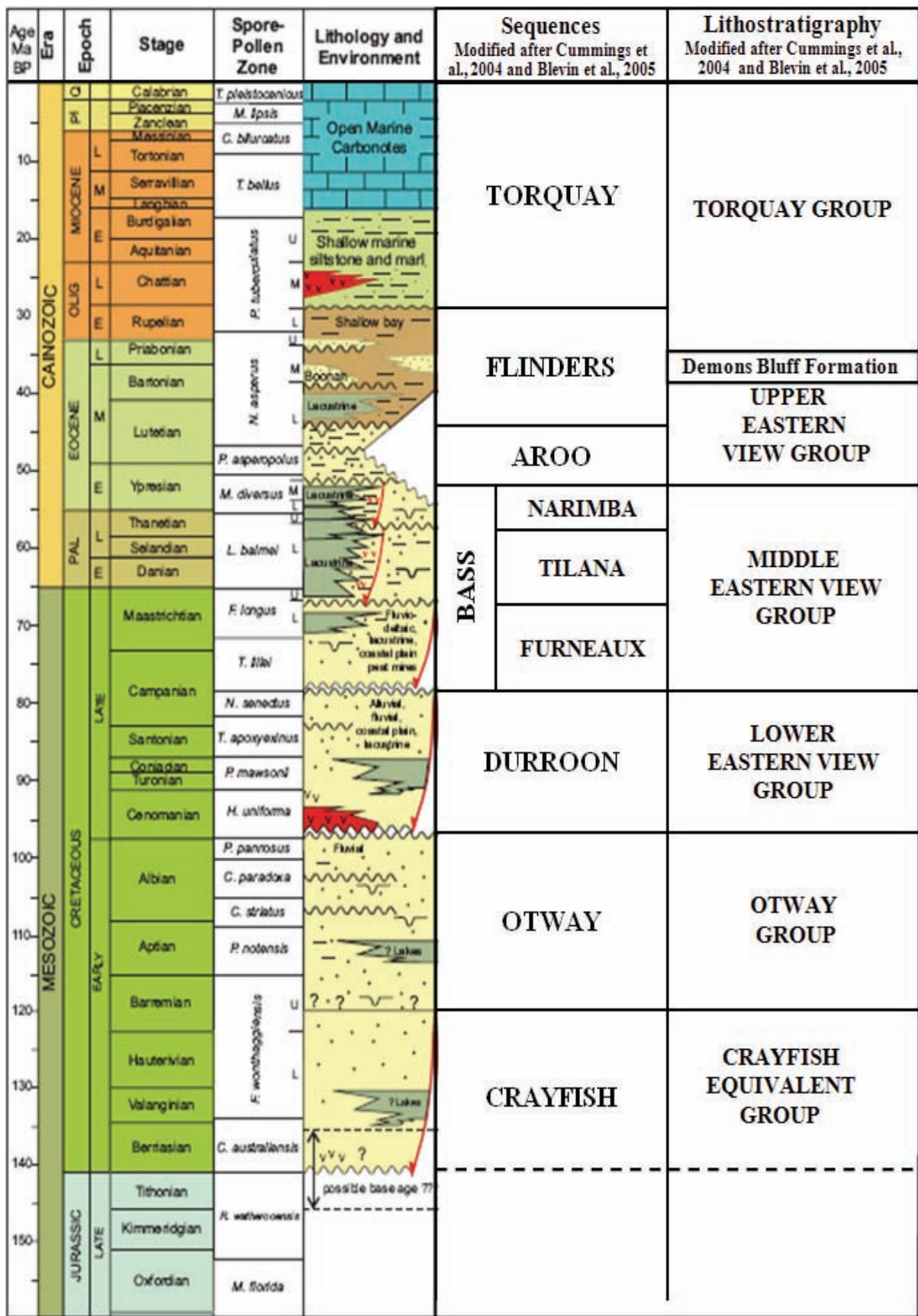


Figure 2.11: Generalised stratigraphy of the Bass Basin (after Lennon et al., 1999; Cummings et al., 2004 and Blevin et al., 2005).

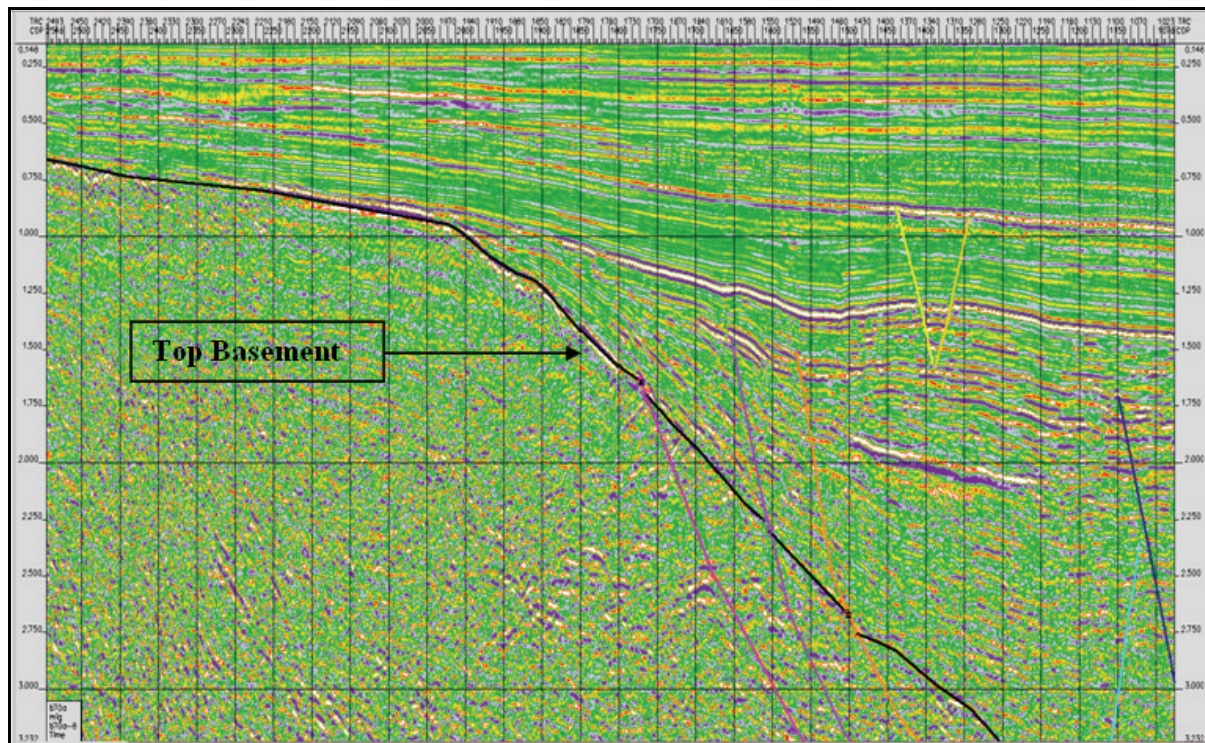


Figure 2.12: Part of the seismic line B70-A-8 illustrating top basement.

The basement is overlain by sediments deposited in response to Southern Ocean rifting, which include sediments of the syn-tectonic Crayfish Equivalent Megasequence in the central region of the Cape Wickham Sub-basin and widespread sediments of the thermal sag-related Otway Megasequence.

2.4.2. Crayfish Equivalent Megasequence (Early Cretaceous “possibly latest Late Jurassic-Early Cretaceous”)

The Crayfish Equivalent Megasequence was recognised from seismic facies by Cummings et al., 2004. It has not been documented by any other previous authors. However, because of its unique seismic facies (Fig. 2.13), it can be clearly recognised on seismic in the Yolla Trough. This megasequence illustrates strong syn-tectonic development of strata against the bounding normal faults associated with the Southern Ocean rifting and is confined to the central region of the Cape Wickham Sub-basin (Cummings et al., 2004). To date, no wells have penetrated the sediments of this deeper sequence, therefore, its age and lithological character are unknown. However, because of its similarity to the Crayfish Group in the Victorian Onshore Otway Basin and Torquay Sub-basin, it is considered to be

Tithonian/Berriasian (?)- Barremian in age (Cummings et al., 2004) and possibly contains a succession of fluvial channel sands with floodplain shales and siltstones (Boult and Hibburt, 2002; Kempton et al., 2005 & 2008).

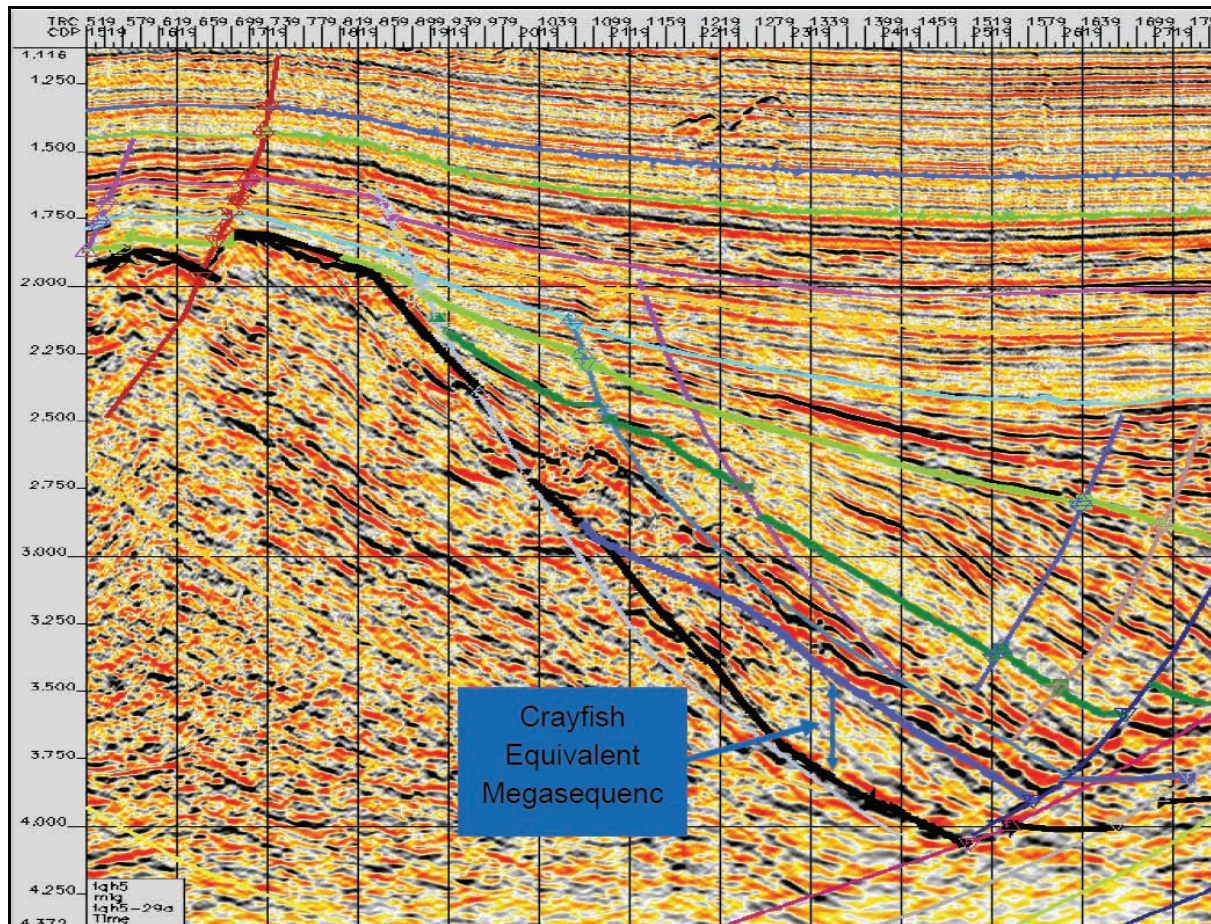


Figure 2.13: Part of the seismic line TQH5-33 showing interpreted Crayfish Equivalent Megasequence (highlighted in blue).

2.4.3. Otway Megasequence (Early Cretaceous)

The top Otway Megasequence is characterised by a strong reflector which has been tied to the formation top pick in the Durroon-1 well in the Durroon Sub-basin (Fig. 2.14). Durroon-1 is the only well to intersect these deep sediments in the Bass Basin (Baillie and Pickering, 1991; Das, 2001; Blevin et al., 2005). The Durroon-1 well is located over a basement fault block where the onlapping beds have thinned and some erosion related to footwall uplift has occurred. It encountered 1452 m of Aptian to Late Albian succession (Blevin et al., 2005), which consisted of stacked successions of volcanoclastic, fluvial channel sands with thin carbonaceous to coaly overbank-floodplain shales (Cummings et al., 2004; Blevin et al., 2005).

The Otway Megasequence syn-rift succession usually overlies basement except in the central region of the Cape Wickham Sub-basin where it overlies the Crayfish Equivalent Group. It is the pre-rift section of the later syn-rift succession of the Durroon Megasequence and is the chronostratigraphic equivalent of the post-rift Eumeralla Formation in the Otway Basin, and the post-rift Upper Strzelecki Group in the Gippsland Basin (Norvick and Smith, 2001; Blevin et al., 2005). Unlike the underlying syn-tectonic Crayfish Equivalent Group, sediments of the Otway Megasequence were deposited during a widespread thermal sag (Cummings et al., 2004) or a period of slow subsidence within a low-relief trough (Blevin et al., 2005). Angular conformities in the direction of the uplifted shoulders of the rotated fault block can be observed in the Otway Megasequence sediments (Fig. 2.15).

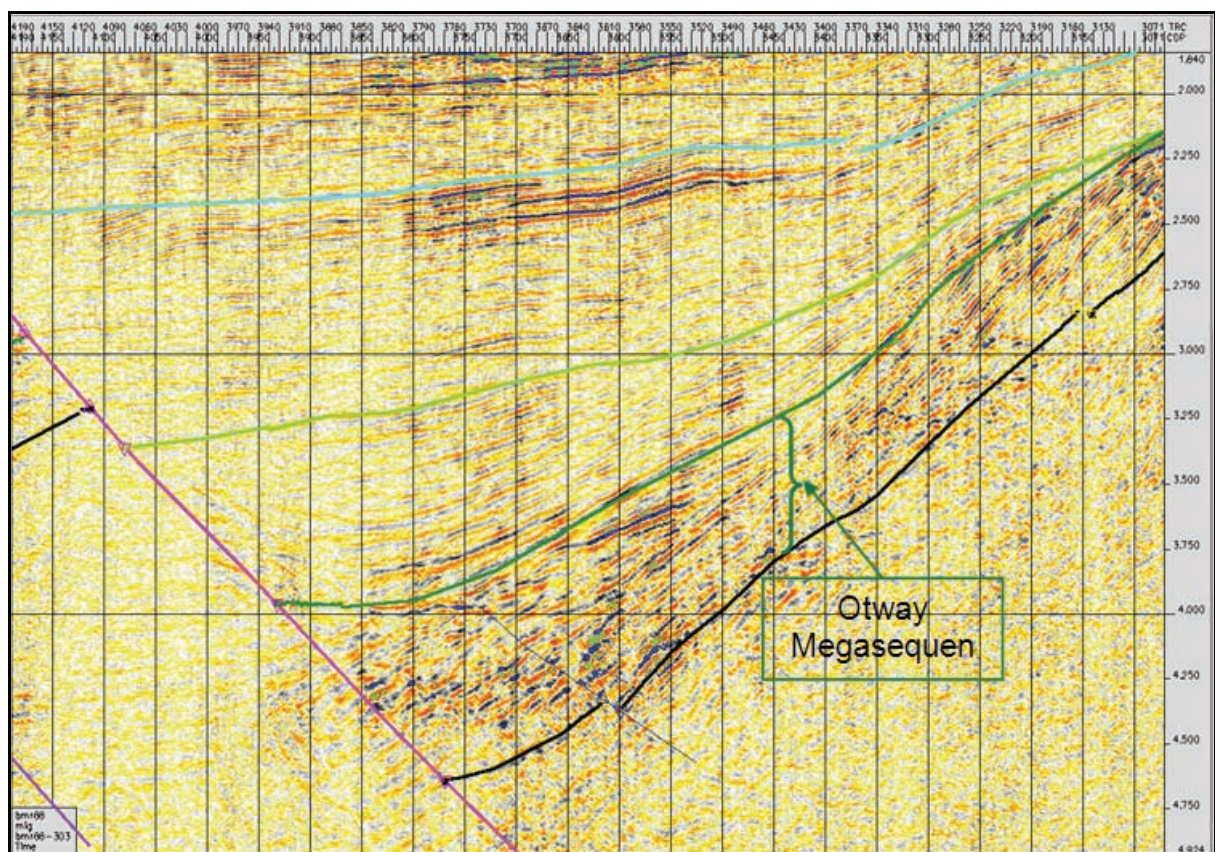


Figure 2.14: Part of the seismic line BMR88-303 showing recognisable seismic facies characteristics of the Otway Megasequence (defined between black and dark green lines) as well as its syn-rift nature.

According to Smith (1986), sediments of the Otway Megasequence have undergone substantial diagenesis that led to porosity loss. The majority of the sandstones of this succession show very poor reservoir characteristics; the good sands only show 8-

20% porosity and 0-100md permeability (Das, 2001). Potential sealing facies are restricted to thin intraformational shales interbedded with coals. The frequency of coals increases in uppermost 650 m of the succession, potential sealing facies remain limited to thin intraformational shales interbedded with coals (Blevin et al., 2005).

2.4.4. Durroon Megasequence (Early Late Cretaceous “Turonian to Campanian”)

The strong seismic reflection of the top Durroon Megasequence is easily recognised (Fig. 2.15), and correlates to well data where intersected (e.g. Durroon-1, Chat-1 and Koorkah-1). The Durroon Megasequence as a second syn-tectonic phase also demonstrates strong growth of strata against bounding faults. The Durroon Megasequence was deposited as a response to the upper crustal extension during the Cenomanian to Campanian. Extension ceased following the break-up and spreading in the Tasman Sea to the east of the Bass Basin during the latest Santonian to Early Campanian (Cummings et al., 2004; Blevin et al., 2005).

The Durroon Formation is pervasive throughout the basin and is the chronostratigraphic equivalent of the youngest part of the Kipper Shale in the Gippsland Basin (Norvick and Smith, 2001; Blevin et al., 2005). As intersected by the Durroon-1 well, the megasequences consist of slightly carbonaceous lacustrine shale, siltstone and sandstone. Biostratigraphic studies suggest deposition of the Durroon Formation in a distal, probably deep fresh water lacustrine environment (Partridge, 2002; Blevin et al., 2005).

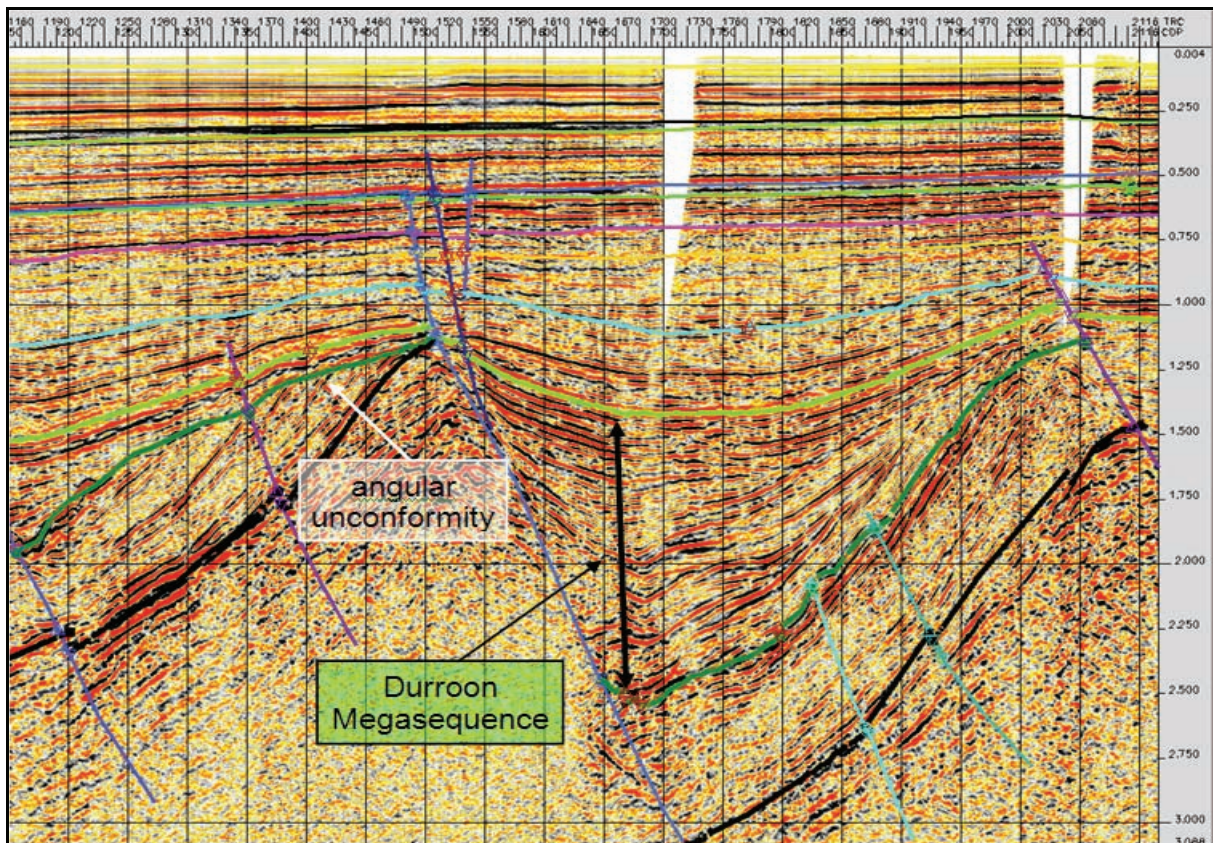


Figure 2.15: Part of the seismic line BMR88-306 showing strong syn-rift character of the Durroon Megasequence and its distinguished seismic facies. It also illustrates an angular unconformity on top of the Otway Megasequence sediments.

2.4.5. Bass Megasequence (Late Cretaceous-Early Eocene)

Three sequence component boundaries resembling the three component sequences of the Bass Megasequence (Furneaux, Tilana and Narimba) were recognised from seismic reflections. The change in seismic character of these boundaries caused problems with mapping across the basin, especially the top Furneaux boundary, which was mapped with a heavy reliance on well data.

The Bass Megasequence sediments are the third syn-tectonic successions in the basin, deposited as a response to the extension that affected mainly the central and western parts of the Bass Basin (Blevin et al., 2005). The deposition of the Bass Megasequence sediments was associated with the separation between Australia and the Antarctic plates along the western margin of Tasmania during the Cenomanian to Late Eocene (Lennon et al., 1999; Cummings et al., 2004; and Blevin et al., 2005). Tectonic activity persisted during the Cenomanian to Late Eocene across the Sorrel Basin along western Tasmania and parts of the Otway

Basin (Moore et al., 2000; Exon et al., 2001; Blevin et al., 2005). Due to the shift in locus of accommodation between different structural elements within the basin, sediments of this megasequence vary widely in facies type, environment and thickness (Blevin et al., 2005). The Bass Megasequence correlates with the Middle Eastern View Group and is subdivided as shown below.

2.4.5.1. Furneaux Sequence (Campanian - Maastrichtian)

The deepest sequence boundary recognised within the Bass Megasequence is the top Furneaux. The seismic reflection for this boundary is not as obvious as the strong seismic reflections of the upper sequence boundaries, but it correlates reasonably with the well and palaeontological data (Fig. 2.16) across the seismic section. The Furneaux sequence sediments were deposited in response to re-activation of older Early Cretaceous extensional faults during the Mid-Late Campanian to latest Maastrichtian. The sediments consist of interbedded fluviodeltaic sandstones and lacustrine shales, as well as thin interbedded overbank or delta-plain shales and coals (Blevin et al., 2005).

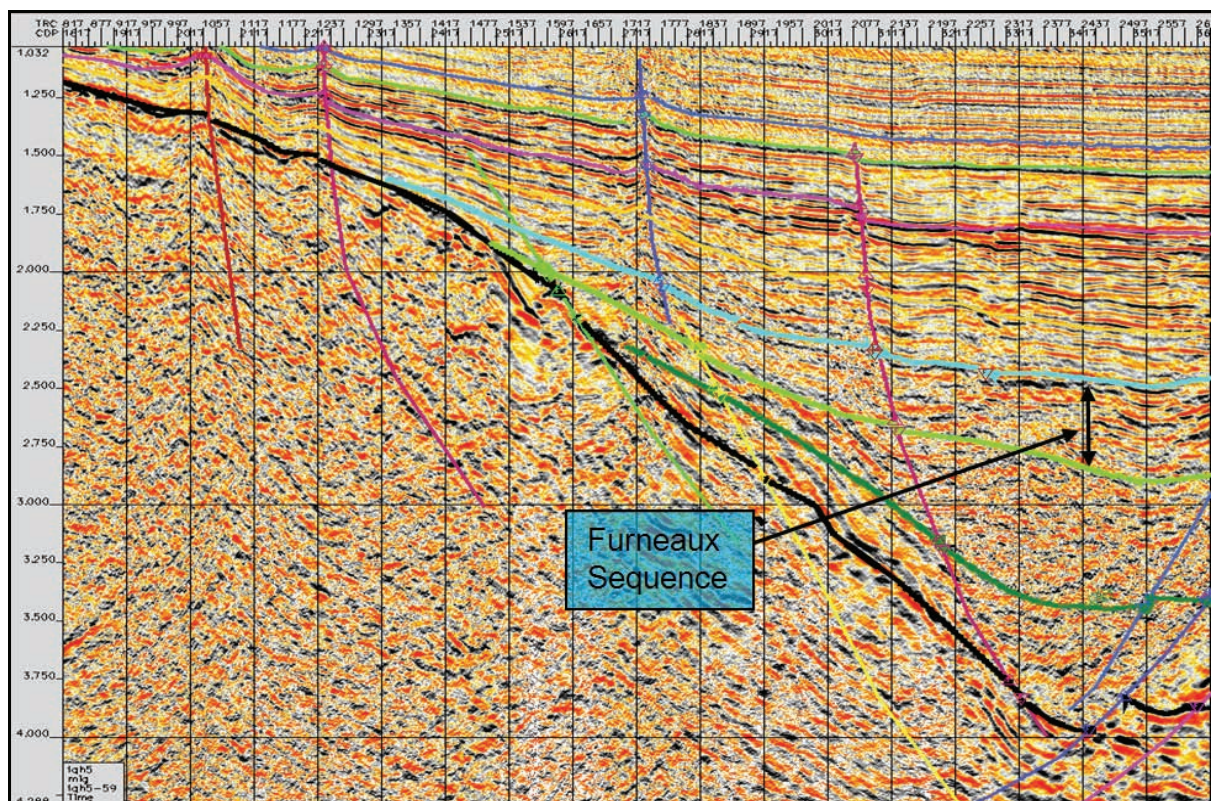


Figure 2.16: Part of the seismic line THQ5-59 showing seismic facies of the Furneaux sequence.

2.4.5.2. Tilana Sequence (late Maastrichtian - Thanetian)

The top Tilana sequence is usually characterised by a strong seismic reflector (Fig. 2.17), but in places (e.g. the Pelican Trough region) mapping was difficult due to the large thickness changes of sediments and sometimes seismic facies changes. The sediments of this sequence were deposited as a result of renewed extension on older Early Cretaceous faults during the latest Maastrichtian to Late Palaeocene. Lacustrine sediments of the Tilana sequence correlate with the Lower Koorkah Lake cycle (Partridge, 2002). Intersected basal fluvial-channel sandstones of the Tilana sequence, in several wells, are overlain by thick (100+m), freshwater lacustrine shales, grading upward to progradational lacustrine deltaic and shoreface sandstones capped by thin coal beds (Blevin et al., 2005).

In contrast to the strongly aggradational and progradational nature of the Koorkah Lake facies, deltaic to lower coastal plain facies with thinly bedded fluvio-deltaic sandstones, floodplain shales and thin peat mire coals characterise areas like the Tertiary Platform where subsidence rates were low (Lennon et al., 1999; Blevin et al., 2005). The terrestrial nature of the interbedded coals and shales would suggest the presence of a potential gas-prone (Type III) source rock. However, geochemical analysis by Boreham et al. (2003) suggests coaly clastic rocks with TOC >10% are oil-prone.

2.4.5.3. Narimba Sequence (Thanetian-Ypresian)

The top Narimba sequence produces a strong continuous reflector (Fig. 2.17) on seismic data, which correlates well with the relatively abundant well data, as the Narimba sequence is penetrated by most wells drilled in the basin. The Narimba rift phase involved re-activation of the suitably oriented underlying Cretaceous rift faults during the latest Late Palaeocene to Early Eocene (Blevin, et al., 2005). Seismic interpretation suggests the syn-tectonic phase of the Narimba sequence re-activation has affected a lesser number of earlier faults because the extension direction was closer to perpendicular on bounding normal faults. By the end of deposition of the Narimba sequence, only a small number of older faults survived to propagate to the next stage.

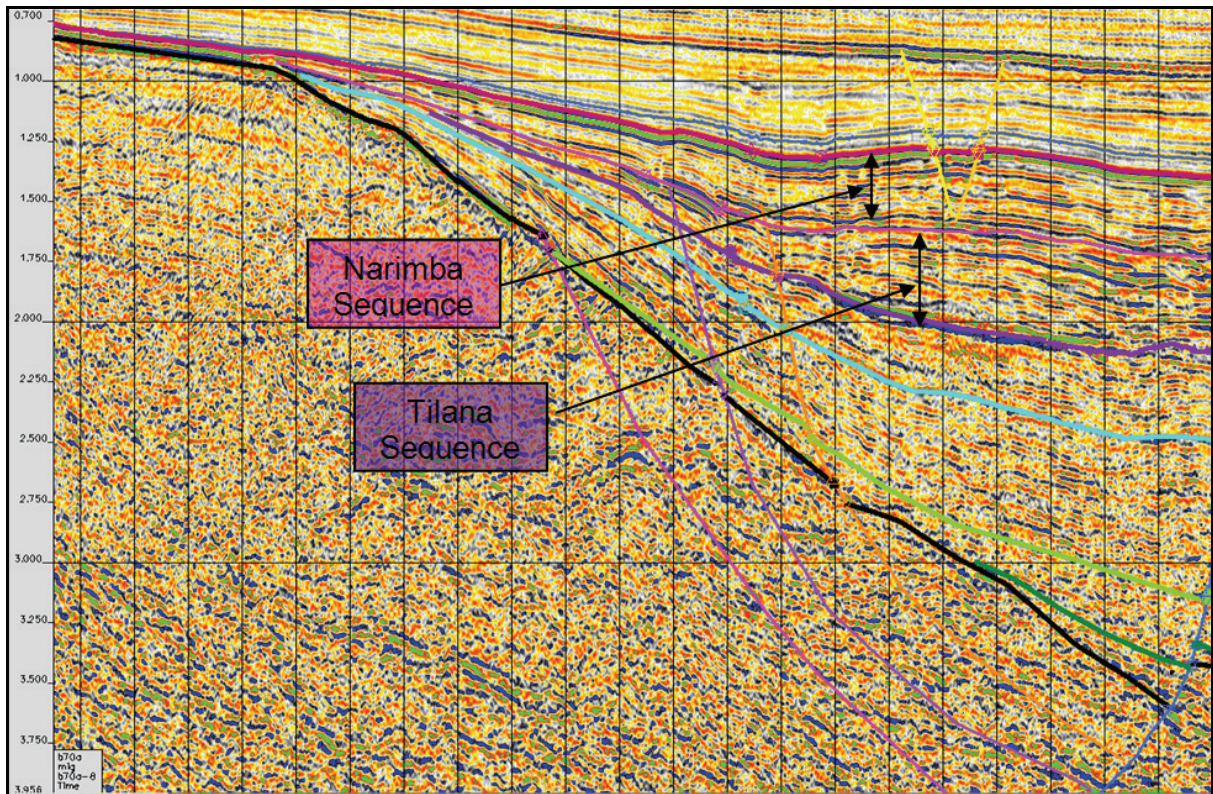


Figure 2.17: Part of the seismic line B70a-8, illustrating seismic facies of Tilana and Narimba sequences.

The Narimba sequence sediments consist of a succession of aggradational fluvio-deltaic to floodplain sandstones, shales and thin coal beds. The Narimba sequence is equivalent to the Upper Koorkah Lake facies recognised in Koorkah-1 (Partridge, 2002). The Narimba sequence shows a broad range in lithologies, environment and thickness, but the maximum flooding surface within the succession is a distinctive event. This maximum flooding surface marks the turnaround from transgressive to regressive facies. Coals are rare in the transgressive parts but become more frequent and thicker in the regressive succession as shown in Poonboon-1 (Blevin et al., 2005). MICP tests carried out on the fine-grained clastics within reservoir facies of this succession demonstrate a high sealing capacity for intraformational seals, especially the hydrocarbon retention capacity of the transgressive shales (up to 1400 m of oil and over 560 m of gas column height (Daniel and Kaldi, 2003)). Geochemical analyses suggest coaly sediments of the Narimba sequence generally have high hydrocarbon potential and are oil-prone, whereas the carbonaceous shales have low source rock potential (Boreham et al., 2003).

2.4.6. Aroo Sequence (Early-Middle Eocene)

The top Aroo sequence has been recognised from its clear reflection on the seismic sections, which correlates well to the palaeontological and well data (Fig. 2.18). This horizon was mapped initially only for structural interpretation purposes, but has been integrated into the modelling process as a part of the Upper EVG succession.

During deposition of this sequence, most of the Early Cretaceous faults stopped renewed extension and a new set of NNW-SSE to N-S striking faults were formed as a response to the rotation in extensional stress directions.

Sediments of the Aroo sequence were deposited in response to a slowdown in the rate of accommodation space generation during the Early Eocene to mid Middle Eocene (Blevin et al., 2005). By the Middle Eocene, due to rotation in the stress directions, a new set of N-S striking faults were created to accommodate crustal extension space (Fig. 2.19).

Sediments of this sequence consist of a succession of progradational lagoonal sediments in the northwest to sand-dominated fluvial systems in the south-southeast. The frequency and thickness of coals increased during deposition of the Aroo sequence. The concentration of coals within this sequence is clearly observed on seismic data (Blevin et al., 2005).

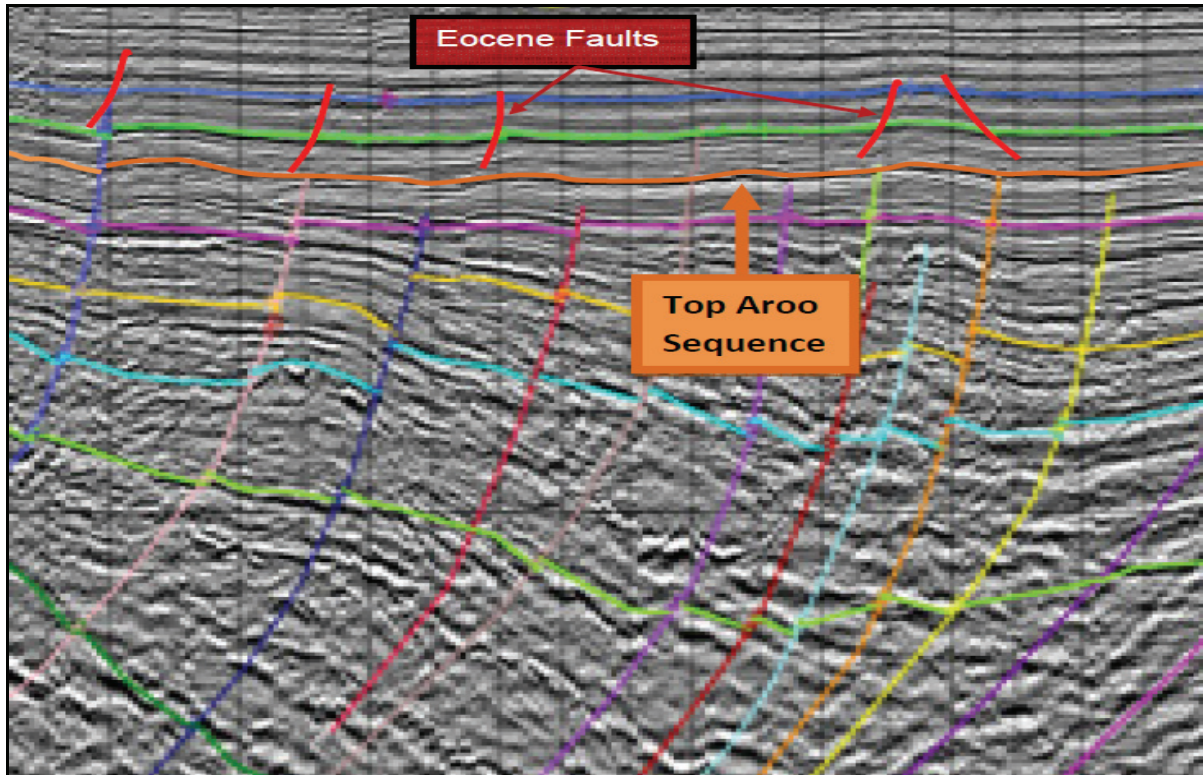


Figure 2.18: Part of the seismic line TQH5-39, showing seismic facies of the Aroo sequence, also Eocene faults are evident from this section.

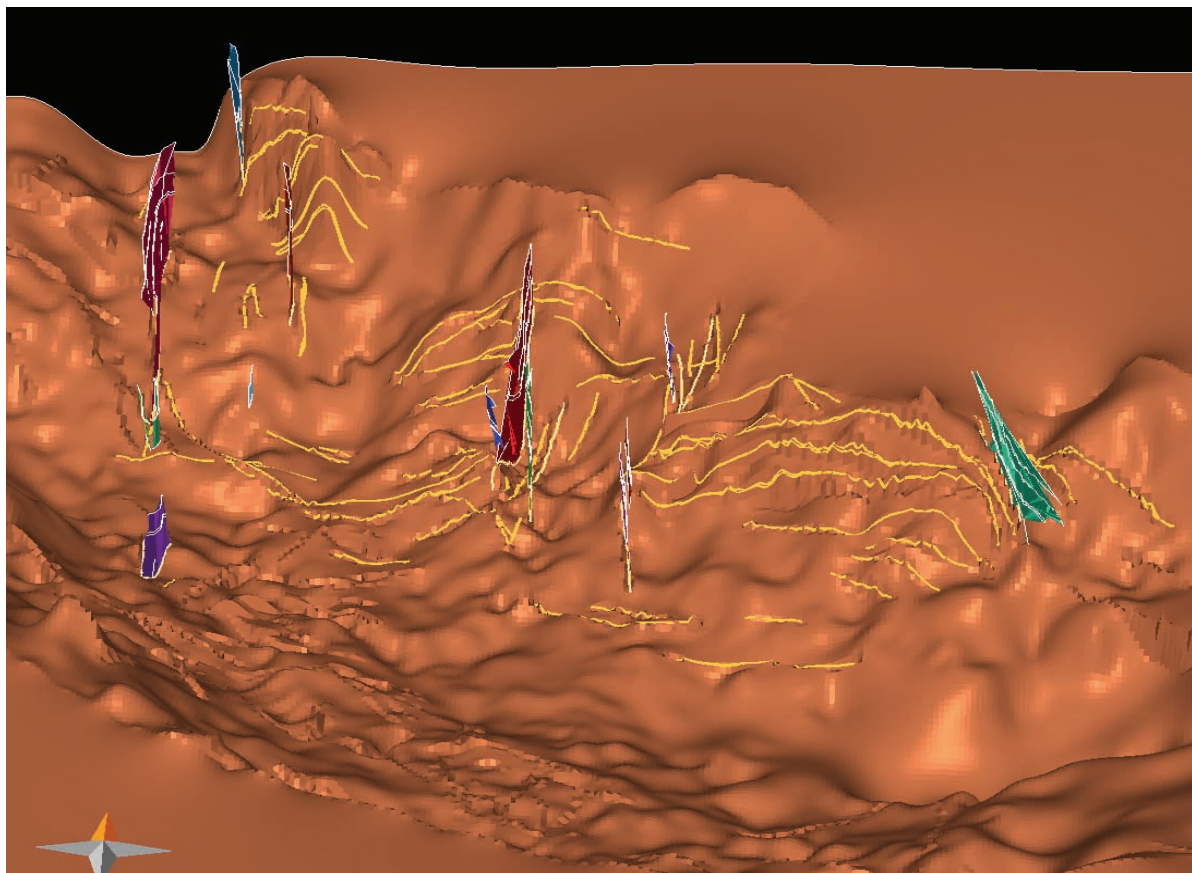


Figure 2.19: Examples of Eocene faults (N-S striking) due to rotation in paleostresses. Cretaceous faults which are NW-SE to S-E striking, appear as fault traces (yellow lines)

2.4.7. Flinders Sequence (Middle Eocene - late Early Oligocene)

The Flinders sequence was first proposed by Blevin et al. (2005). It consists of a transgressive-regressive succession deposited as a result of a later stage of thermal subsidence during the Middle Eocene to Early Oligocene. Post-rift sag subsidence (phase 2) coincided with the slow onset of a post-rift transgression that began with fluctuations in the base level before any wide-spread marine influence commenced in the basin (Blevin et al., 2005). The lower part of this sequence consists of thick fluvial sandstone known as the Boonah Formation, overlain by thick marine-influenced siltstones and shales of the Anglesea Formation, including the regional sealing facies of the Demons Bluff Formation.

A palaeontological study by Partridge (2002) interpreted the presence of the Toolka Lake in the western Bass Basin during the Middle Eocene. The Toolka Lake covered a broader area than the previous fault-controlled Upper Cretaceous to Palaeocene Koorkah Lake. A tectonostratigraphic study by Blevin et al. (2005) recognised two lacustrine cycles from well log correlations and suggests the areal extent of Toolka Lake expanded and contracted through time. The same author suggested that the Toolka Lake ended as a result of the fall in base level in the late Middle Eocene (base Middle N. asperus zone), which resulted in deposition of fluvial-lacustrine systems across the basin. This boundary was marked with deposition of the regional fluvial sandstone known as the Boonah Formation, which is the uppermost reservoir unit within the Bass Basin.

As mentioned earlier, the lithological top of the Upper EVG, which is recognised by its strong seismic character and well data, is equivalent to the top of the Boonah Formation and was mapped throughout the basin. The top of the regional sealing facies of the Demons Bluff Formation was also recognised from its strong seismic reflection and was mapped across the basin (Fig. 2.20).

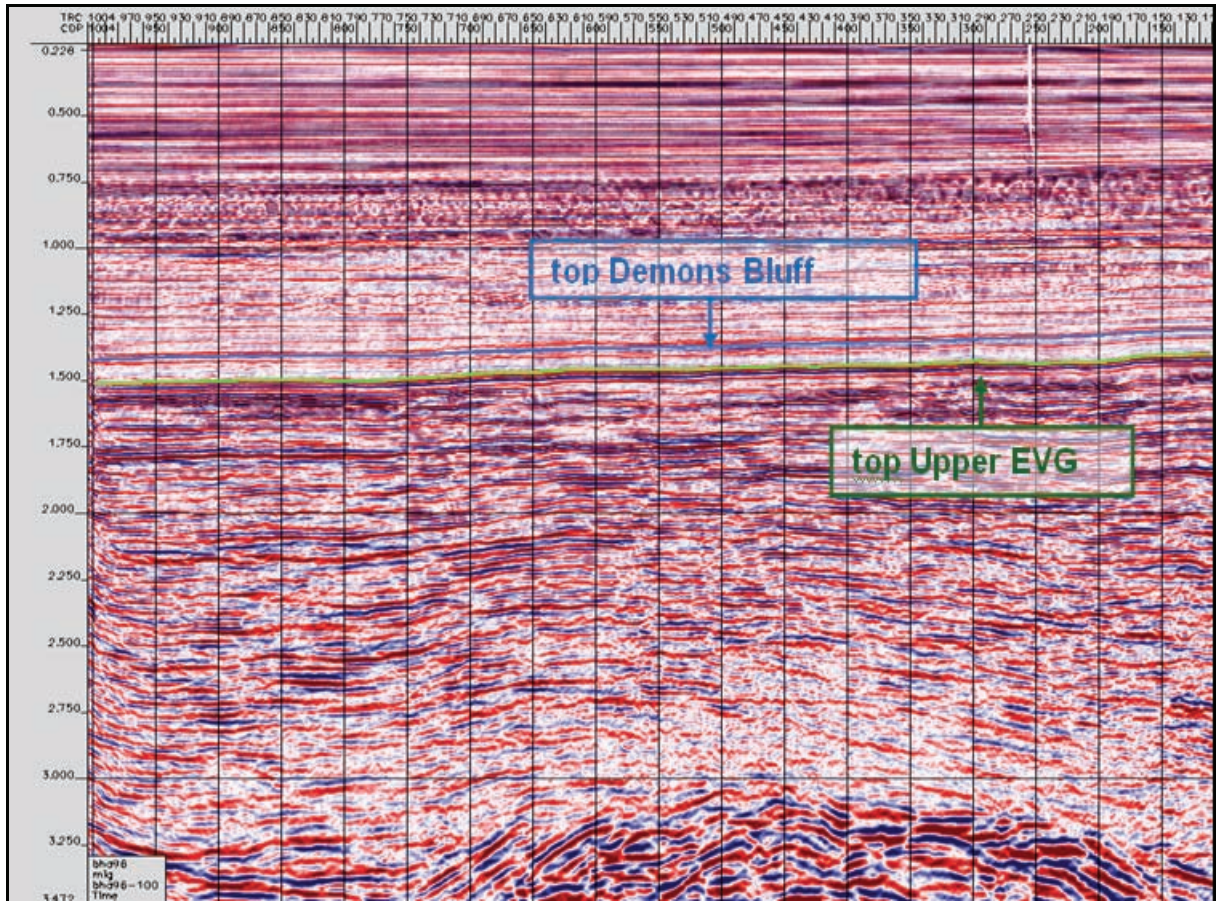


Figure 2.20: Seismic line BHA96-100, showing an example of seismic facies in the Bass Basin with top Upper EVG as top of uppermost reservoir facies in the basin, and top Demons Bluff Formation as top of the regional sealing facies.

2.4.8. Torquay Sequence (Late Oligocene-Recent)

A significant sea-level fall occurred in the Early - Late Oligocene that was followed by a rise in sea level which flooded the Bass Basin during the Late Oligocene (Cummings et al., 2004). Sediments of the Torquay sequence were deposited when progressively more marine conditions developed. Marine clastic sediments such as siltstone and marl were deposited. By the Middle Miocene, an open marine environment had developed and resulted in deposition of bioclastic carbonates (Blevin et al., 2005). Two dominant regional seismic surfaces within the Torquay sequence were mapped across the entire basin by Aaron Cummings and were incorporated into this study and named Torquay-1 and Torquay-2 respectively.

The sea floor horizon which represents the top Torquay sequence has not been mapped from current seismic interpretation because it was not present on most 2D seismic lines. It was gridded from measured water depths from well locations and

later compared to an acquired bathymetry map provided by Geoscience Australia (GA).

2.5. Preparation of 3D Surfaces and Faults

2.5.1. Gridding

For the purpose of 3D basin modelling, all the mapped horizons, together with the interpreted faults have been gridded using the GeoFrame software package, which was used for interpretation. The uneven line spacing caused some difficulties during gridding, especially the coarse line spacing in the Durroon Sub-basin.

Regardless of minor rotations and unequal spacing, a grid cell size of 500 m x 500 m was achieved in the Cape Wickham Sub-basin and the same cell size was used in the Durroon Sub-basin but with less confidence.

The gridded regional interpretations of the 2D seismic lines to 3D surfaces were exported from GeoFrame and imported to the Petrosys software, where all the surfaces were rechecked and prepared for depth conversion.

2.5.2. Depth conversion

Checkshots for the wells in the Bass Basin were obtained from well completion reports. Checkshot data were plotted against depth and all the wells (excluding the Durroon-1 well) showed similar time-depth curves with minor differences (Fig. 2. 21). The Durroon-1 well which is located in the central part of the Durroon Sub-basin shows a different time-depth curve to the rest of the wells in the Bass Basin. The different time-depth curve from the Durroon-1 well could be the result of velocity differences in the Otway Group sediments, as they are intersected at this location only. Within the depth range of the checkshot data (~500 to 3000 m), there is a scatter of between 100 and 200 metres in depth for any given TWT. This presumably reflects lateral velocity variations between the wells. Considering the area involved, this scatter is relatively small. Nevertheless, it represents the minimum error likely to be incurred by using a single time-depth curve used to depth convert seismic times in

the Bass Basin. Regardless of the function used to extrapolate, depths will become progressively less certain as time increases below the maximum checkshot depth.

For the purpose of comparison, several empirical functions were fitted to the checkshot data (Fig. 2.22a) as follows:

- power law function $Z = aT^n$
- cubic polynomial $Z = aT + bT^2 + cT^3$
- quatric polynomial $Z = aT + bT^2 + cT^3 + dT^4$
- linear $v(z)$ law
- tanh $v(z)$ law functions.

To see the behaviour of the fitted functions below the checkshot data, the time and depth scales (Fig. 2.22b), as well as velocity functions, were extended (Fig. 2.23). Figure 2.23 shows a wide range of differences between the velocity functions. Cubic and linear $v(z)$ functions predict very fast velocities for deeper depths, as fast as about 10000 m/sec at 5000 sec two-way time (TWT). The power law function behaves unrealistically at very shallow depths and predicts very low velocities at deeper depths (less than 4000 m/sec at 10000 sec two-way time). While the quatric function predicts reasonable velocities until about the depth of 5000 m, it reverses for deeper depths. The tanh $v(z)$ law function is the most satisfactory formula as it fits check shot data well and continues behaving steadily at greater depths (Fig. 2.22b). As a result it was selected as the preferred equation for the depth conversion process. Depth converted 3D surfaces were calibrated against formation tops recognised from drilling at well locations (Table 2.1). Deeper horizons such as the Otway Group and the Crayfish equivalent group, which are not intersected by many wells, were accepted and not subjected to formation top calibration.

Depth converted 3D horizon surfaces (Figs 5.24a - 5.24j) were exported from Petrosys as ready horizon maps to be used for creating 3D basin models. Horizon maps in time and depth converted, including fault polygons are also attached (Appendix 1)

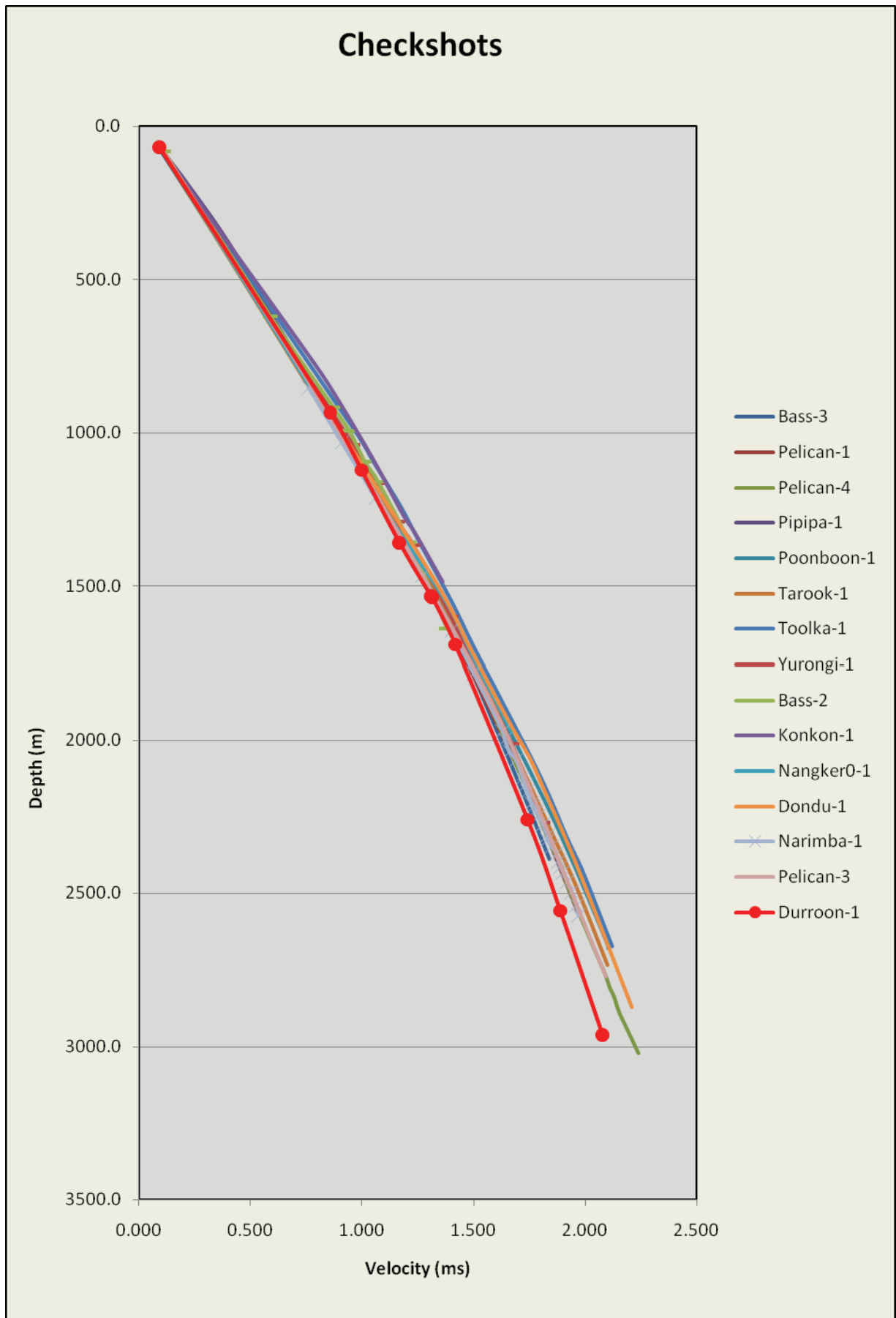


Figure 2.21: Plot of checkshot velocities in the Bass Basin, highlighting the different behaviour of Durroon-1 compared with the rest of the wells.

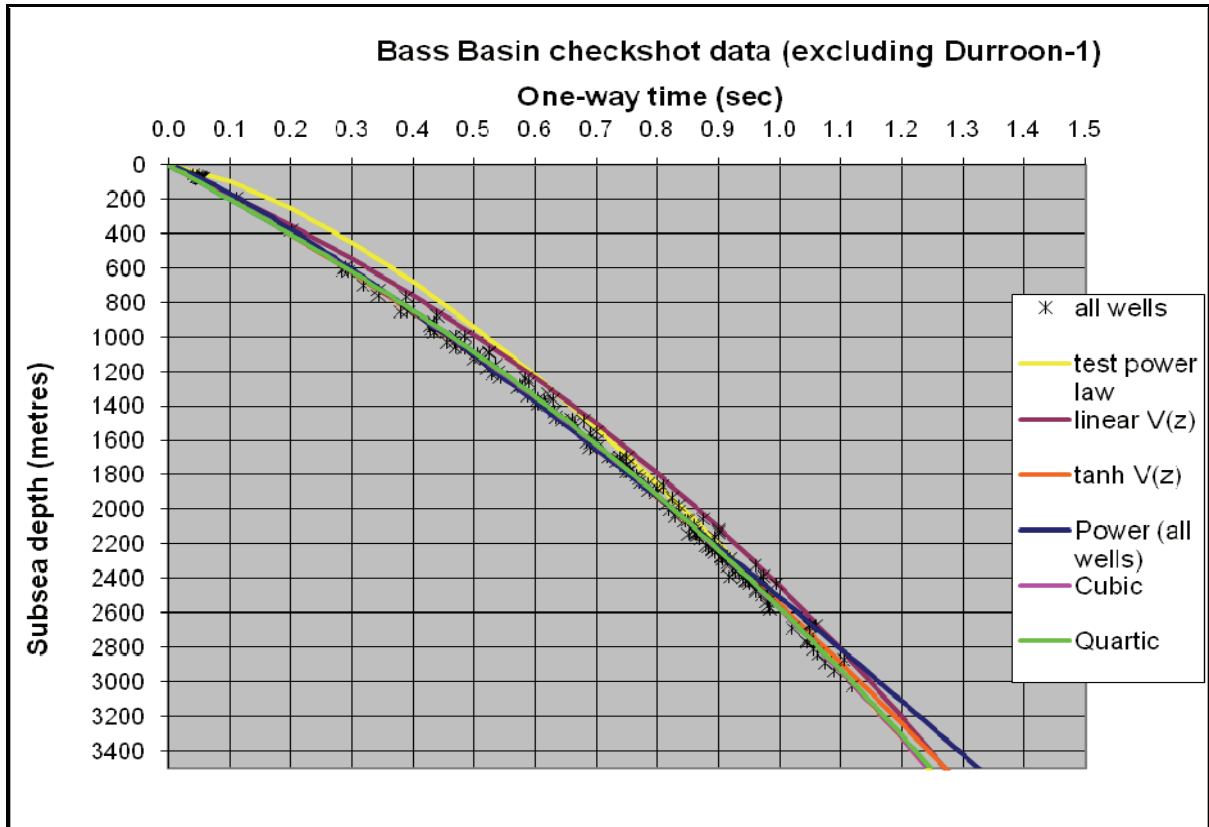


Figure 2.22a: Time-depth plot empirical functions fitted to the check shot data

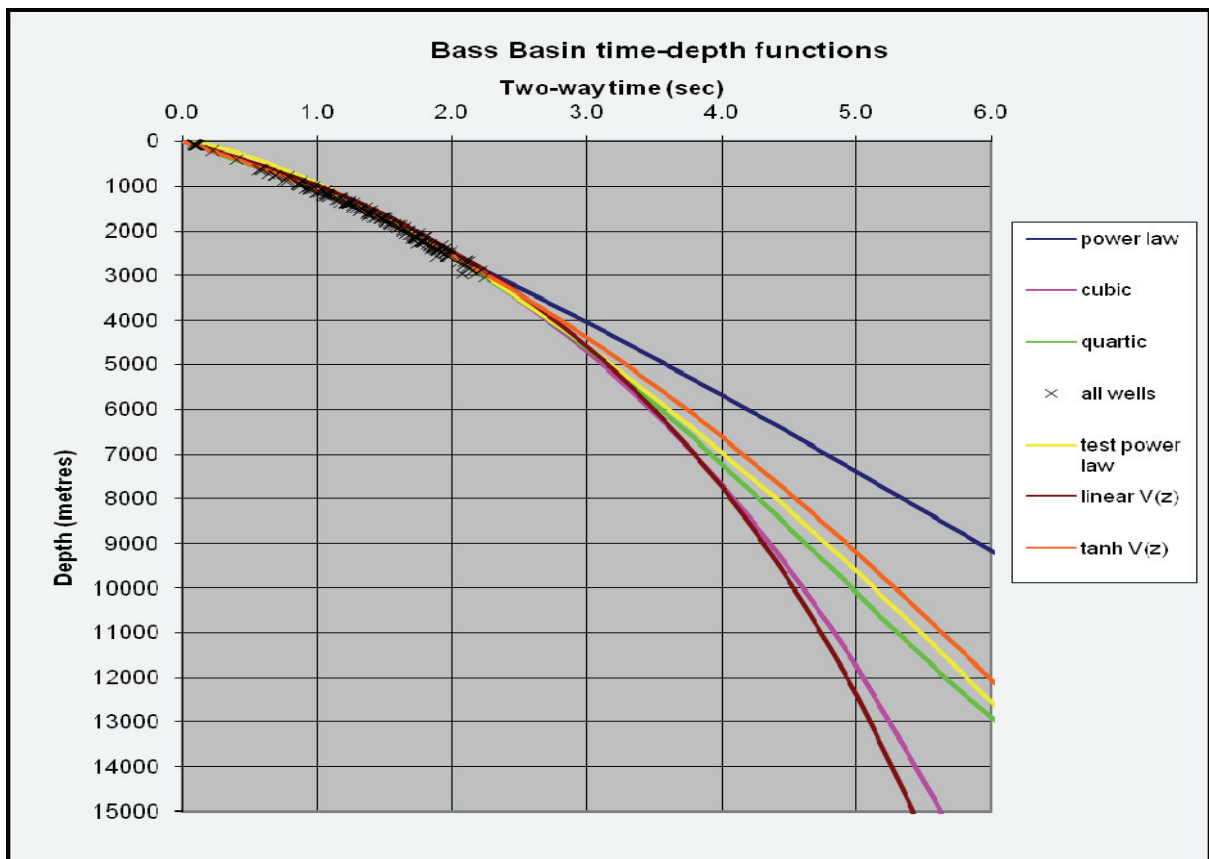


Figure 2.22b: Behaviour of the fitted empirical functions below the checkshot data. For direct comparison with the seismic data, the fitted functions are in two way time (TWT).

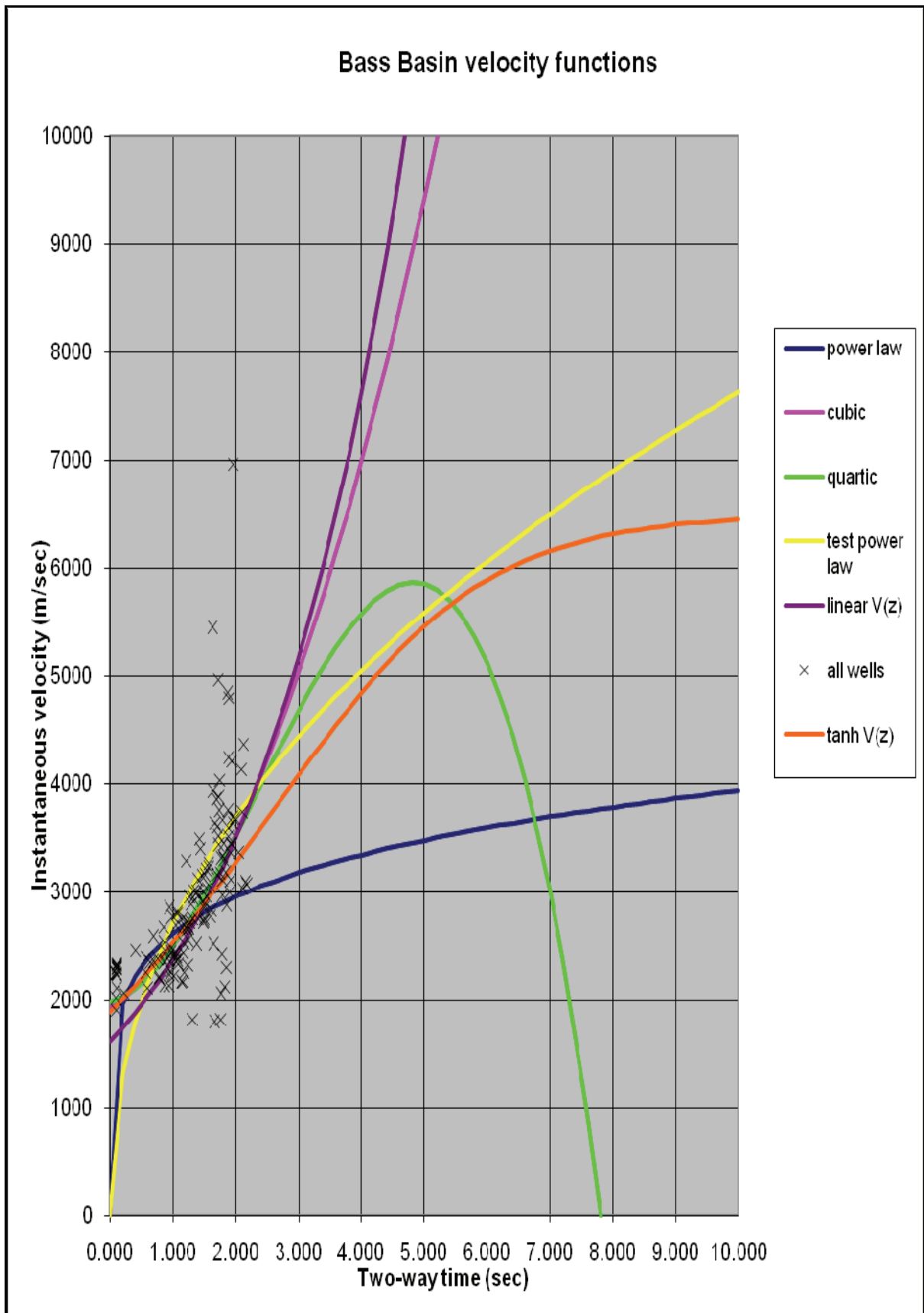


Figure 2.23: Cross plot between instantaneous velocity (m/sec) and two-way time, showing behaviour of the fitted empirical functions.

Well Name	Upper EVG top from wells (m)	Upper EVG top from seismic (m)	Differences (m)
Aroo 1	2049	2080	31
Bass 1	1680	1780	100
Bass 2	1171	1226	55
Bass 3	1617	1665	48
Chat 1	1181	1250	69
Cormorant 1	1235	1350	115
Dondu 1	1599	1661	62
Durroon 1	634	645	11
Flinders 1	1523	1559	36
King 1	1269	1350	81
Koorkah 1	1583	1630	47
Nangkero 1	1881	1925	44
Pelican 1	1725	1814	89
Pelican 2	1765	1830	65
Pelican 3	1777	1866	89
Pelican 5	1725	1802	77
Pipipa 1	1501	1545	44
Poonboon 1	1892	1943	51
Seal 1	1003	1047	44
Squid 1	1831	1848	17
Tarook 1	1862	1901	39
Tilana 1	1624	1725	101
Toolka 1	1319	1421	102
Trefoil 1	2057	2071	14
White lbs	1577	1608	31
Yolla 1	1799	1795	-4
Yolla 2	1844	1863	19
Yurongi 1	1379	1509	130

Table 2.1: Correlation between depth-converted seismic tops and well formation tops for calibration purposes, the Upper EVG top as an example.

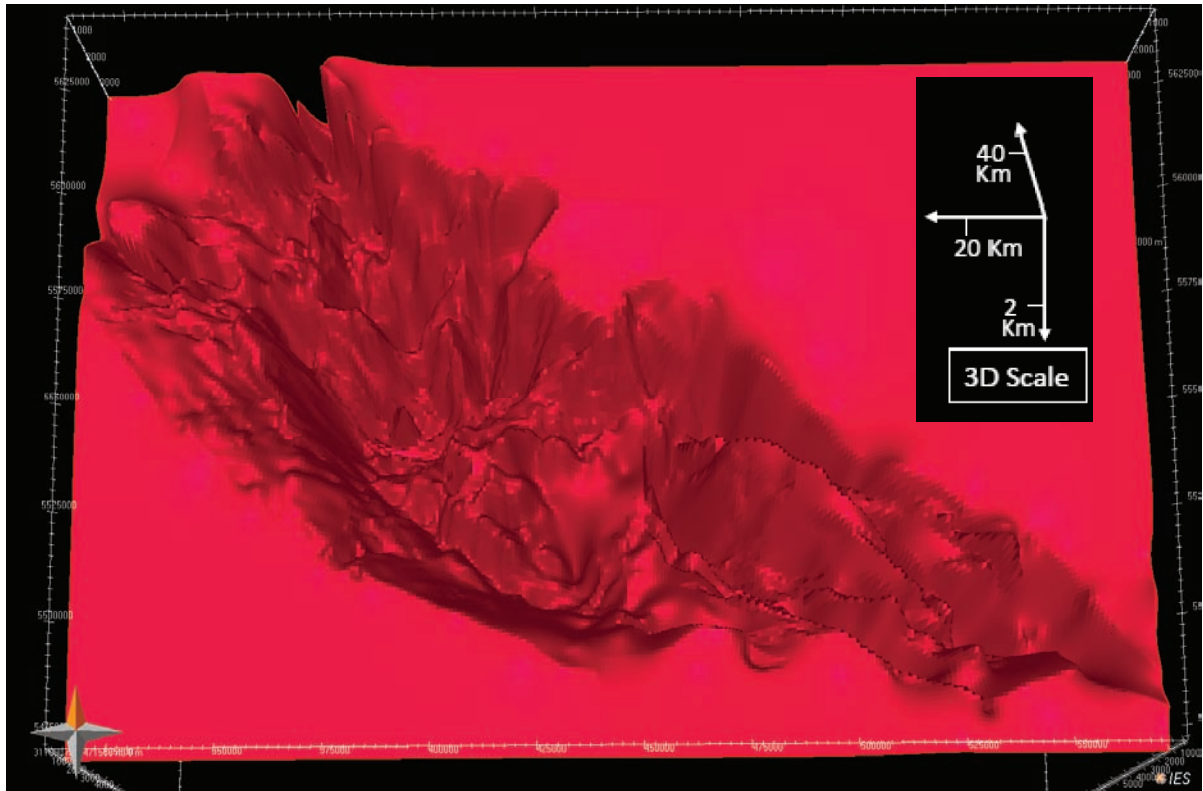


Figure 2.24 a: Depth converted top Basement horizon gridded from 2D seismic interpretation and shown as a 3D map.

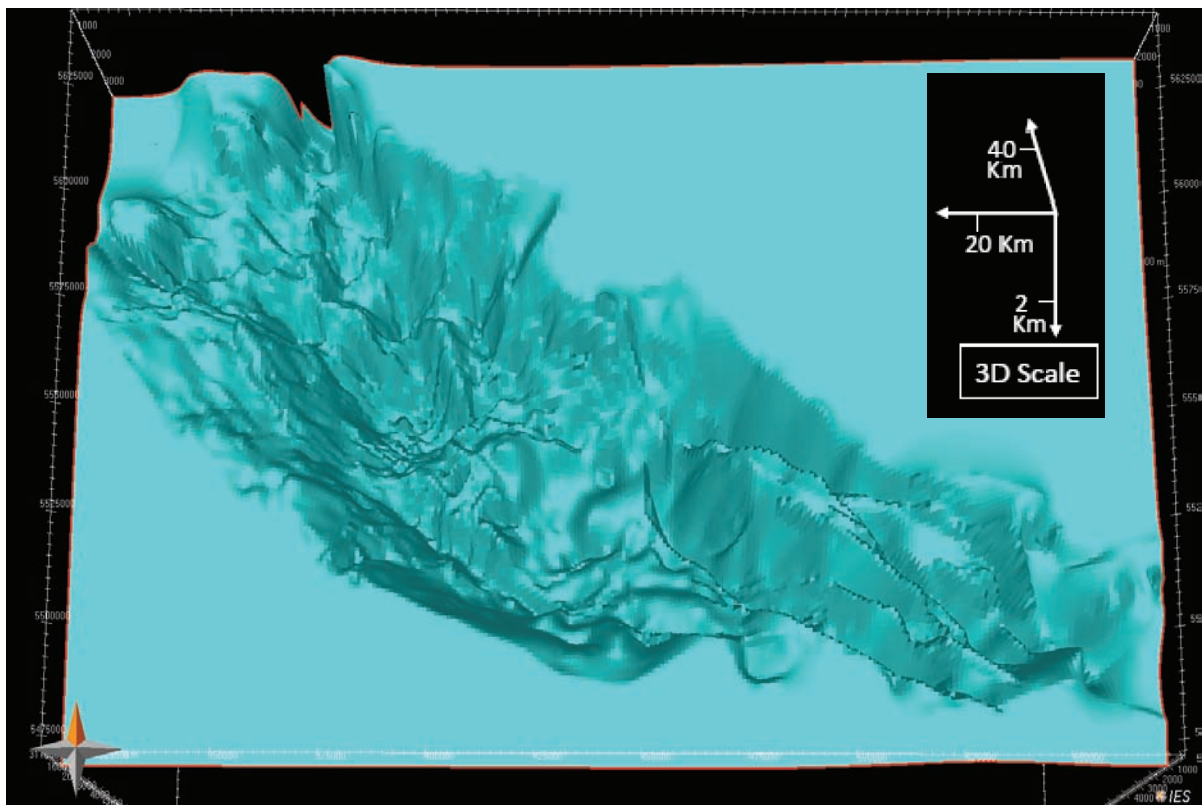


Figure 2.24b: Depth converted top Otway Megasequence gridded from 2D seismic interpretation and shown as a 3D map.

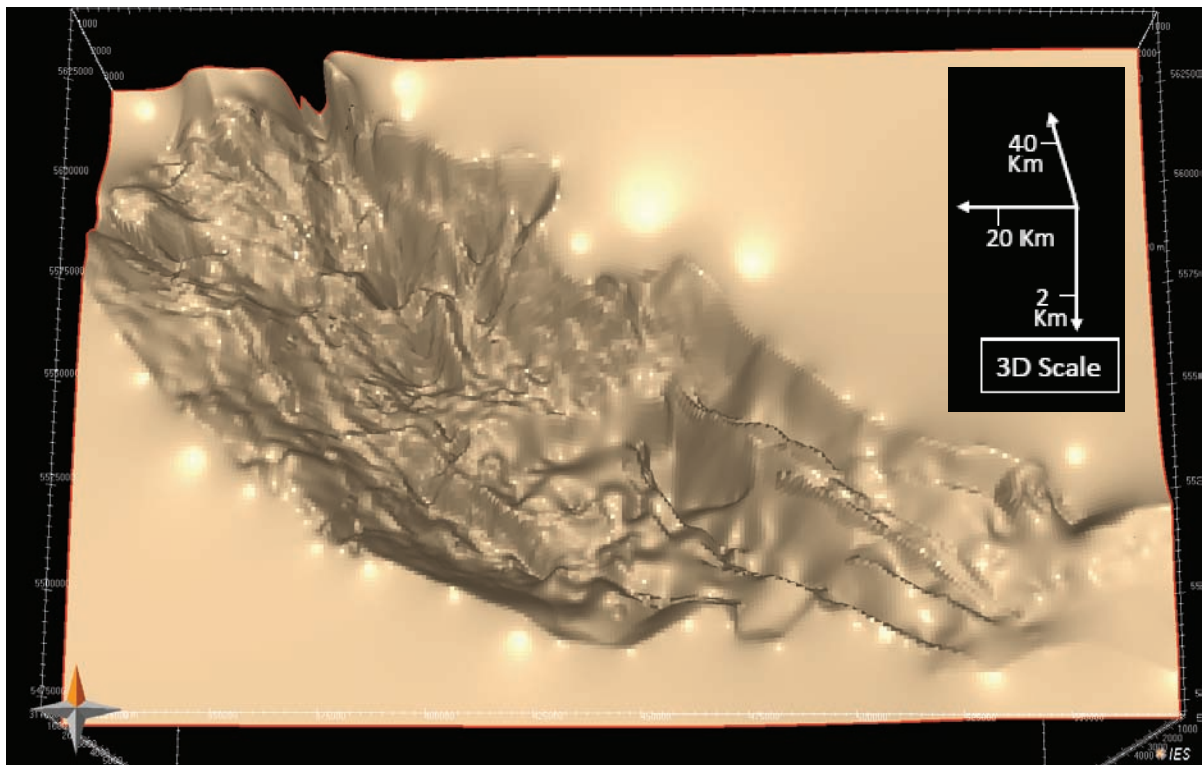


Figure 2.24c: Depth converted top Durroon Megasequence gridded from 2D seismic interpretation and shown as a 3D map.

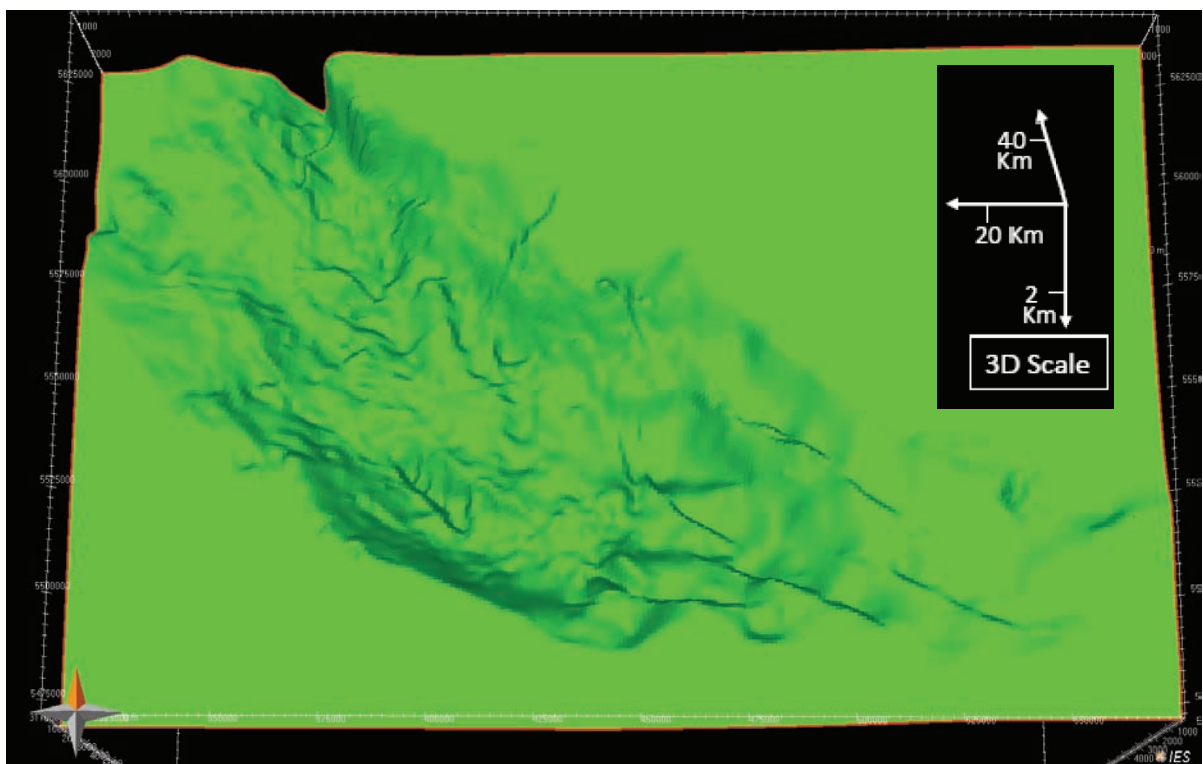


Figure 2.24d: Depth converted top Fureneaux sequence gridded from 2D seismic interpretation and shown as a 3D map.

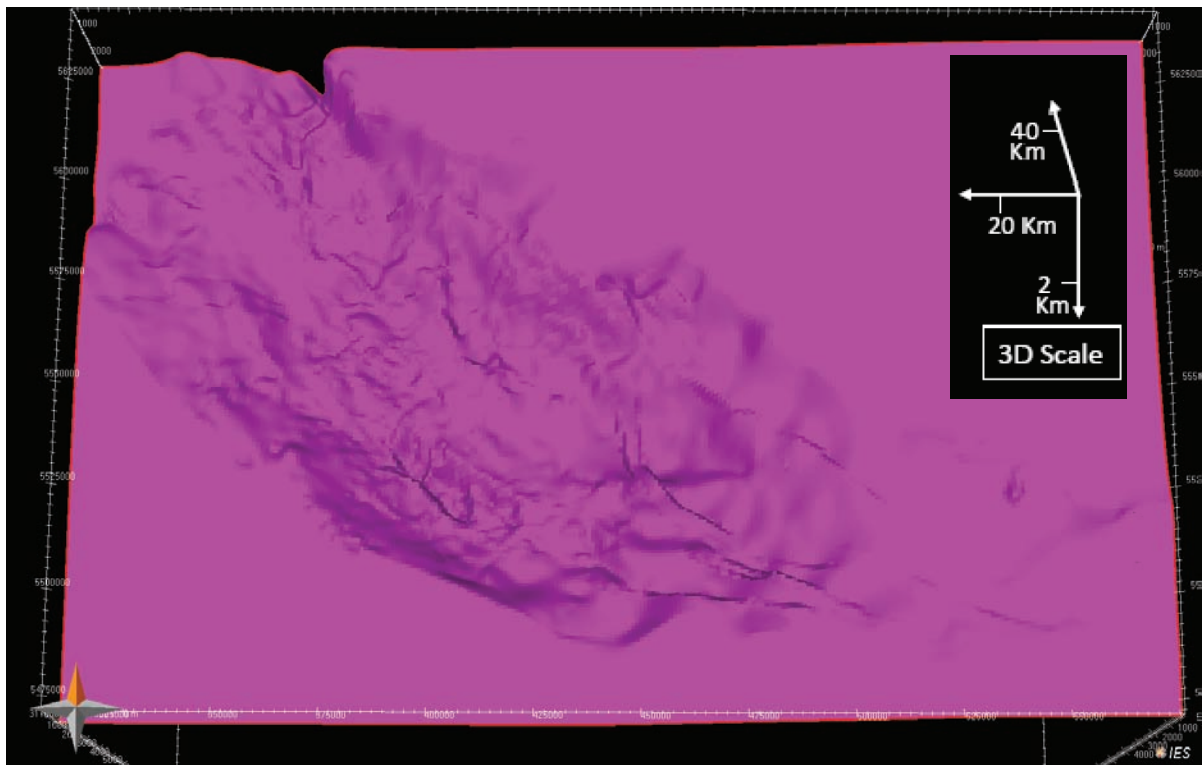


Figure 2.24e: Depth converted top Tilana sequence gridded from 2D seismic interpretation and shown as a 3D map.

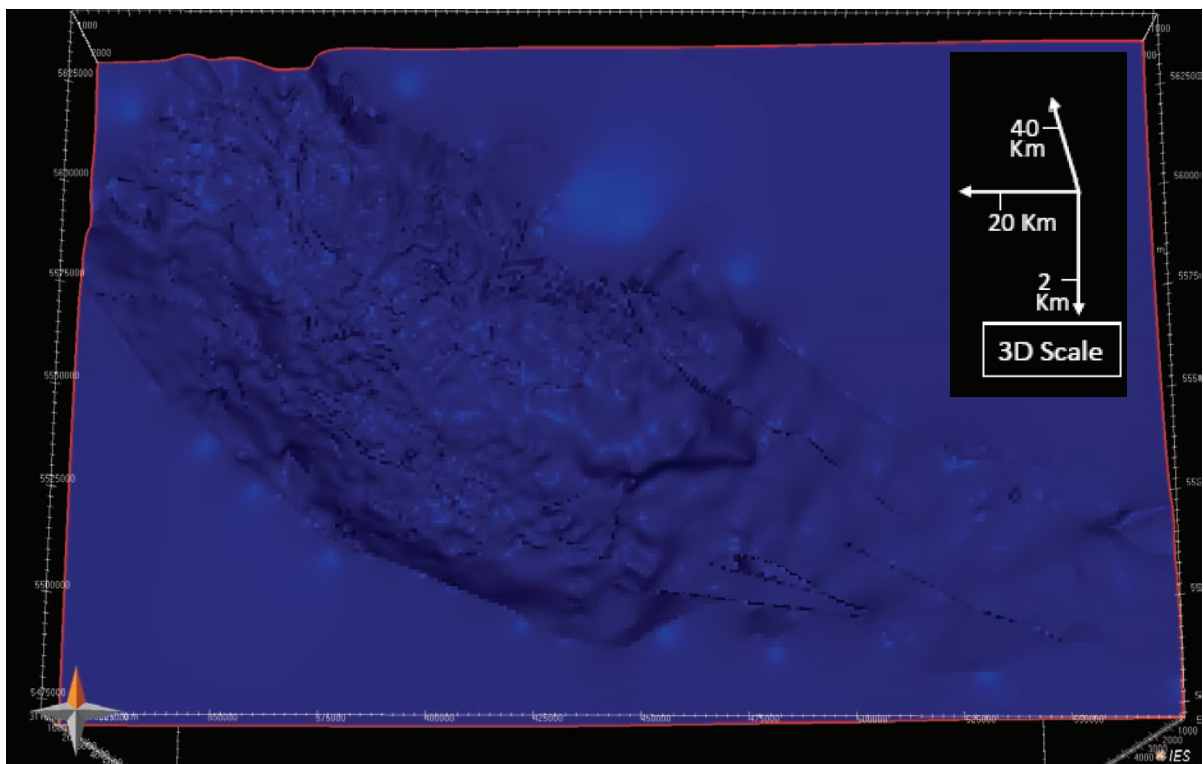


Figure 2.24f: Depth converted top Narimba sequence gridded from 2D seismic interpretation and shown as a 3D map.

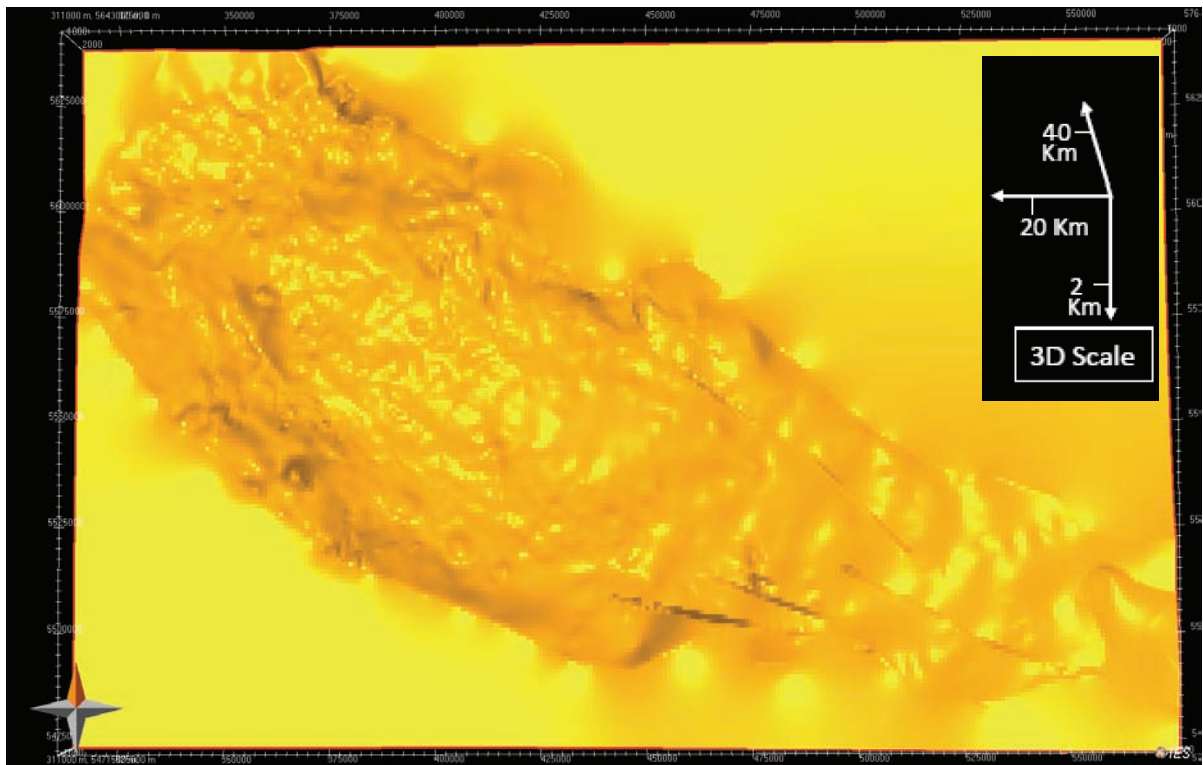


Figure 2.24g: Depth converted top EVG gridded from 2D seismic interpretation and shown as a 3D map.

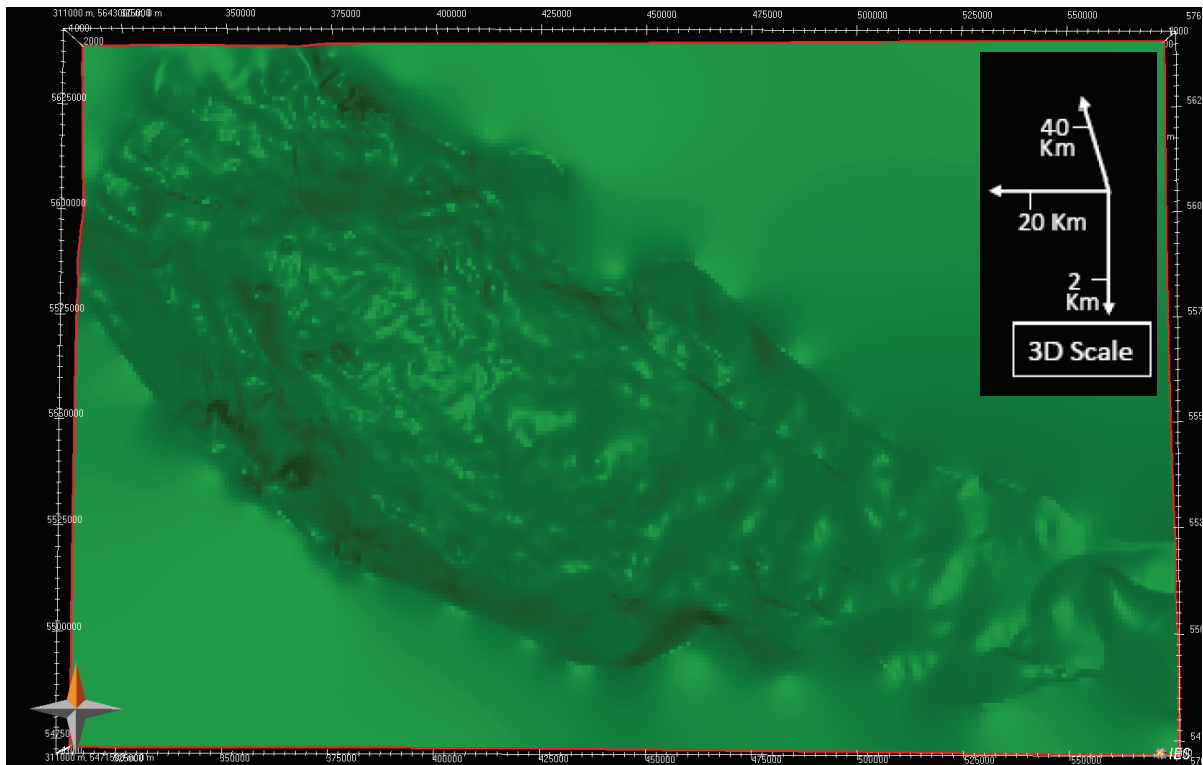


Figure 2.24h: Depth converted top Demons Bluff Formation gridded from 2D seismic interpretation and shown as a 3D map.

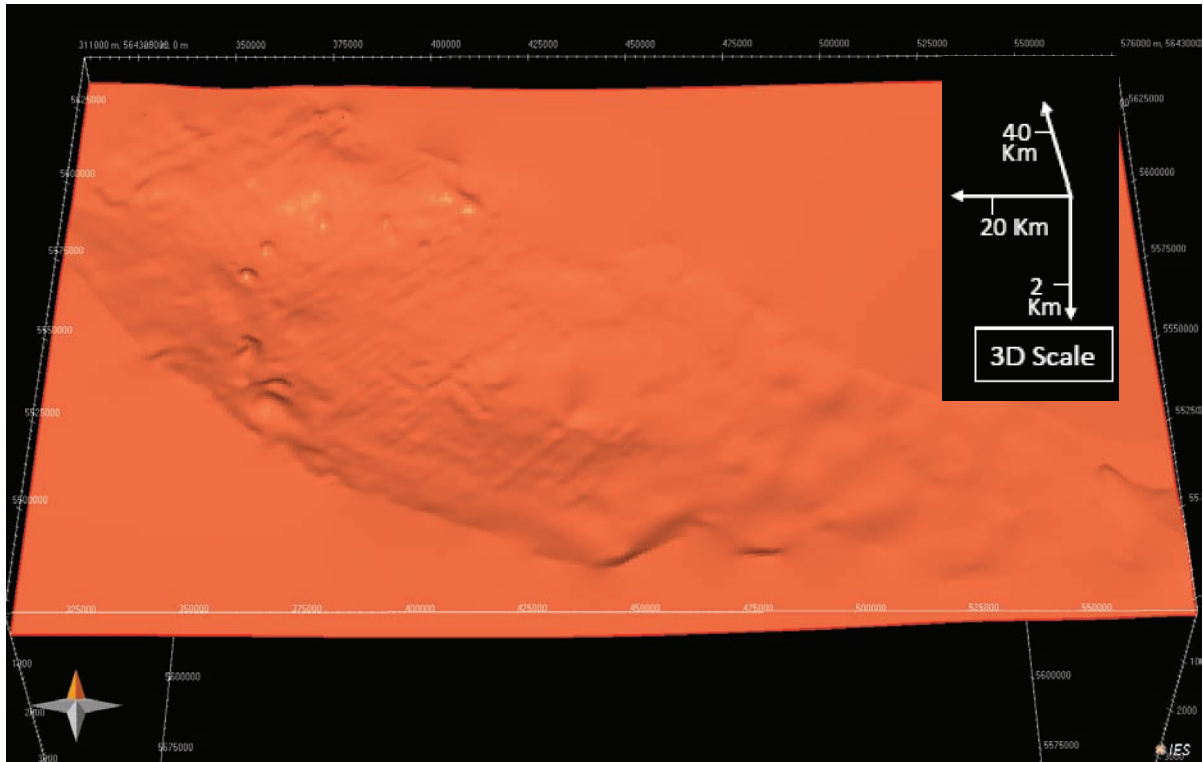


Figure 2.24i: Depth converted top Torquay-2 horizon gridded from 2D seismic interpretation and shown as a 3D map.

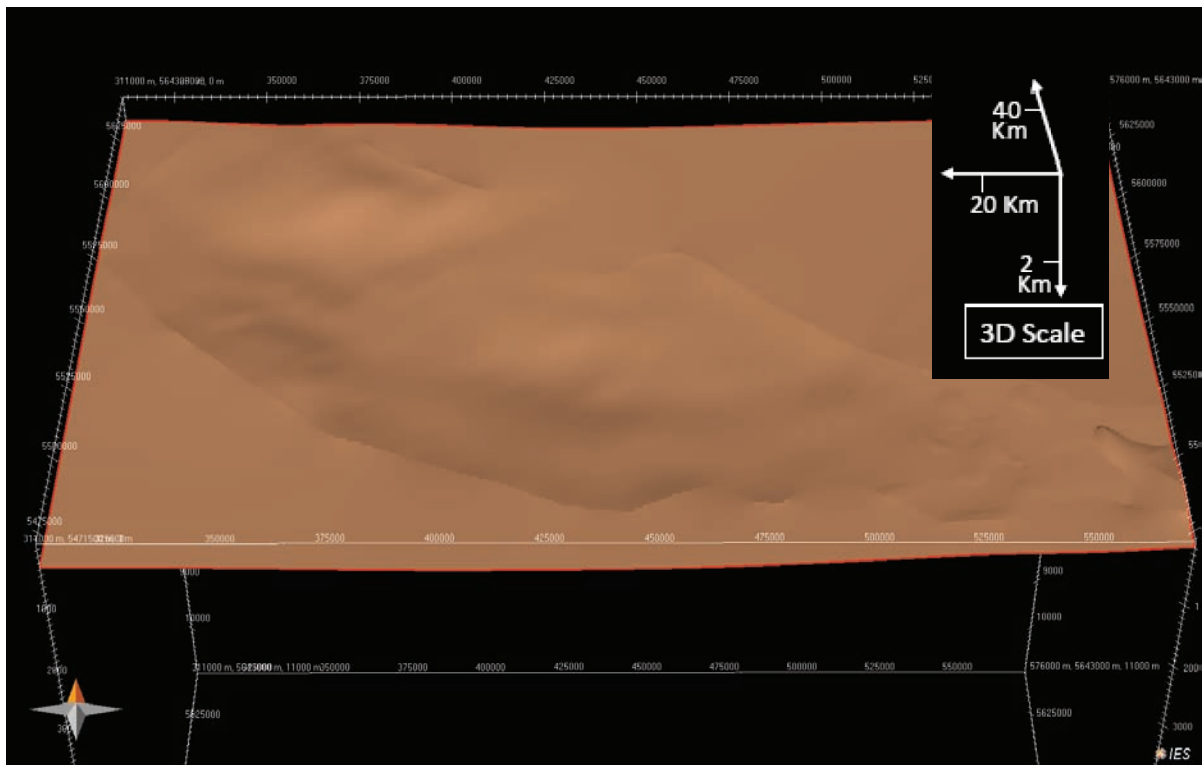


Figure 2.24j: Depth converted top Torquay-1 horizon gridded from 2D seismic interpretation and shown as a 3D map.