Petroleum Systems Modelling Onshore Tasmania

Annual Report – May 2003

An interim report of work completed up to May 2003 as part of the ARC Linkage Grant between the Federal Government, the University of Tasmania and Great South Land Minerals Limited.

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Summary

The Australian petroleum system nomenclature is applied to the two systems recognised onshore Tasmania. The Larapintine Petroleum System is based on Ordovician tropical carbonates and the unconformably overlying Gondwanan Petroleum System is based on Permian glacial sediments. The gas–prone Larapintine is comparable to that in the producing Amadeus Basin of central Australia and the Gondwanan is comparable to producing oil and gas basins in Oman, Brazil (Parana) and in Australia (Cooper, Perth and Bowen Basins). Source rocks in both systems have generated hydrocarbons onshore Tasmania. Although the first commercial, Australian oil and gas was found in the Bowen and Cooper Basins in the early 1960's the similar age Tasmania Basin was largely ignored by explorers until exploration was initiated by the predecessor companies of Great South Land Minerals in the early 1980's.

Maturation indices (T_{max}, conodont CAI and biomarkers) show that the Ordovician carbonates of the Gordon Group in central Tasmania are in the wet to dry gas windows. On the west coast of Tasmania the paleo-heat flow was higher but the widespread distribution of bitumen indicates that oil was generated and later degraded. In central Tasmania, the Gordon Group limestones of the Upper Limestone Member have fair to good TOC source potential and a crushed sample liberates mainly methane with lesser amounts of C2 to C9. Extractable organic matter from a different sample yields 38% saturates and 19% aromatics. Its alkane ratios indicate an algal source for the kerogen, its C27, C28 and C29 ratios show a carbonate source for the oil and a diasterane/pristine – phytane plot indicates an anoxic paleoenvironment. A large Devonian-age north-westerly plunging antiform (Bellevue) is identified and mapped on the seismic lines near Lake Echo which probably contains the elements of the Larapintine Petroleum System.

The Gondwana Petroleum System within the Late Carboniferous-Late Triassic Tasmania Basin consists of five Permian source rocks (Tasmanite Oil Shale, pelionite, Woody Island-Quamby Formation and the Macrae Mudstone and mid-Permian coals within the Liffey Group). Source Potential Index (SPI) calculations show that the mature area of the Tasmania Basin may have generated 113 billion barrels of oil equivalent. Assuming 95% of this generation has been lost by seepage along faults, erosion, bacterial degradation and contact metamorphism then over 5 billion barrels of oil equivalent may be retained in the Tasmania Basin. Based on S1/TOC ratios there is some doubt as to the expulsion efficiency of parts of the Woody Island-Quamby Formation. A seep of low sulfur heavy crude oil at Lonnavale in the south of the basin is definitely sourced from *Tasmanites*-rich shale. Oil drops, some showing prominent gas bubbles, are found in Liffey Group sandstones in Hunterston #1.

The mid-Permian Liffey-Faulkner Group glacifluvial sandstones have average porosities ranging from 6.1% to 11% with thicknesses ranging from 10-25 metres over the central part of the basin and are similar in age and paleoenvironment to reservoirs in other Gondwana basins. Vuggy porosity with high permeabilities is found in 3m of pre-Liffey Group conglomerates in Hunterston #1. Thick and effective seals are present above the potential reservoir sandstones of the Liffey Group. Numerous fault traps and some fold traps containing the Gondwanan Petroleum System have been seismically identified in the north and central parts of the basin. Gas was encountered by Mines Department drillers in two shallow holes in the Tertiary Longford Basin and a dome, seismically mapped within the Tertiary at Bracknell, is a potential trap for gas derived from underlying petroleum systems.

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Introduction (Dr Clive Burrett, Chief Investigator)

This report summarises work to May 2003 on the Australian Research Council (ARC) Linkage Grant "Petroleum Systems Modelling Onshore Tasmania". This 3 year grant was awarded to the School of Earth Science and Great South Land Minerals in 2001 and commenced in May 2001 with the appointment of postdoctoral fellow Dr Catherine Reid. Three PhD candidates; Alan Chester, Jubo Liu and Andrew Stacey enrolled at the end of 2001 and commenced studies at the beginning of 2002. The 2000 grant application was reviewed by three independent, expert assessors appointed by the ARC. They were clearly convinced of the petroleum prospectivity of onshore Tasmania and of the team's ability to achieve the project's aims. Paul Lane joined the team in 2002 and studied the Tertiary of the Longford Sub-basin. All participants in the project are using the results and interpreting the 660km of 2D seismic carried out by GSLM during 2001 at a cost of AUD$3.5million.

At the beginning of the project, two petroleum systems were recognised in Tasmania (Bendall *et al*., 2000). These are:

1. The Ordovician to Lower Devonian Larapintine Petroleum System based on the Gordon Group limestones and Eldon Group siliciclastics.
2. The unconformably overlying Permo-Triassic Gondwanan Petroleum System based on Parmeener Supergroup infill of the Tasmania Basin.

The Larapintine source rock was assumed to be petroliferous-odor Ordovician Gordon Group limestones which were known to have generated oil during the Early Paleozoic of the (now) overmature west coast region of Tasmania and which were now in the wet gas window in central Tasmania. Analogies were made with the producing Larapintine Amadeus Basin of central Australia and the Tarim Basin of NW China (Bendall *et al*., 1991, 2000).

One Gondwanan source was identified on the basis of the discovery by Mines Department geologist Dr Ralph Bottrill of a seep of heavy crude oil at Lonnavale in southern Tasmania, shown to be generated from the Lower Permian Tasmanite Oil Shale (or tasmanite). The tasmanite is also extremely well known because it is the typical Type 1 Kerogen and because it was quarried in outcrop in northern Tasmania from 1910 to 1939 and 1.68megalitres of oil were artificially distilled. Other Gondwanan sources were thought to be the Lower Permian Quamby / Woody Island Formations and the mid-Permian coals of the Liffey Group. Analogies were made with the first basins to produce commercial oil and gas in Australia - the Bowen and Cooper Basins and with the highly productive South Oman Basin of the Sultanate of Oman. The Tasmania, Bowen, Cooper and South Oman Basins are all typical glacially influenced Gondwana supercontinent basins with Permian sandstone reservoirs.

The Tertiary infill of the Longford Sub-basin (see Lane 2002), although containing some oil shales and carbonaceous shales is most probably too immature to contain an indigenous source. However, the record of gas strikes in the Conara and Cleveland water bores within the Longford Sub-basin in 1990 and 1963 (which reportedly frightened the drillers) and the report of gas at 336m in Tertiary sands in the Iles (Sassafras) bore (Bacon *et al*., 2000 p.18 and 85) suggests that structures such as the Bracknell Dome (see Lane 2000) could be prospective for gas derived from older petroleum systems.

Report on investigations into petroleum systems hosted by the Wurawina Supergroup Late Cambrian Middle Devonian onshore Tasmania (Alan Chester).

Introduction

The search for petroleum onshore Tasmania has a long history with the first recorded drilling in 1915 (Bacon, *et al*., 2000). Oil shale was discovered in the Mersey Valley in the 1850's (Wilkinson 1991) and these deposits were exploited until 1935. Periodic reports of oil seeps sparked interest in wildcat drilling for oil but no systematic attempt at exploration took place until the 1980's.

Consistent reports of bituminous odours from freshly fractured Ordovician Gordon Limestone stimulated interest in these sediments being possible source rocks for hydrocarbons. Reports of seeps related to Gordon Limestone have not been substantiated but the environmental conditions during deposition indicate potential as source rocks. Possible reservoir and seal rocks are contained in the Eldon Group, which overlie and have been folded synchronously with the Gordon Group. Thus the components of a possible petroleum system exist within the Wurawina Supergroup.

This investigation is to evaluate the potential of the Wurawina Supergroup sediments as possible hosts to a petroleum system in an attempt to provide some scientific basis for an exploration program to locate hydrocarbon reservoirs onshore Tasmania. Using the petroleum system classification system developed by Magoon and Dow (1991) this possible system would be part of the Larapintine 2 as defined by Bradshaw (1993).

Larapintine petroleum system throughout Australia

The Larapintine petroleum system takes its name from the Early Ordovician Larapintine Seaway (Nicoll, *et al*., 1988), which was a long lasting epicontinental seaway. During the Early Ordovician, what is now Australia was positioned in low latitudes with the equator lying along the Larapintine Seaway (Webby 1978). The extent of the Larapintine Seaway over a modern outline of Australia is shown in Figure 1. Warm, shallow water provided productive upper waters and anoxic conditions on the sea floor, characterised by lack of benthic fauna, provided ideal conditions for the development of oil-source beds.

In central Australia marine regression occurred during the Early Silurian caused by uplift and aeolian and fluvial sediments were deposited over the Ordovician sediments (Jackson, *et al*., 1984). These sediments provided the depth of burial necessary for thermal maturation of organic matter within the source rocks and also provided reservoir potential.

The Larapintine petroleum system has not been fully explored but some commercially important finds have been made including one of Australia's most significant onshore oil fields, Mereenie. Discoveries at Mereenie include 19 mmbbls of oil and 0.8 Tcf gas (Longley, *et al*., 2000). Other commercially important occurrences are at Pictor and Blina in the Canning Basin and gas fields at Palm Valley and Gilmore (Goldstein 1991). Currently production from the Larapintine petroleum system occurs within the Amadeus Basin (Hopkins 1989) shown in Figure 2.

Figure 1. Larapintine Seaway during Early Ordovician. After Webby, 1978.

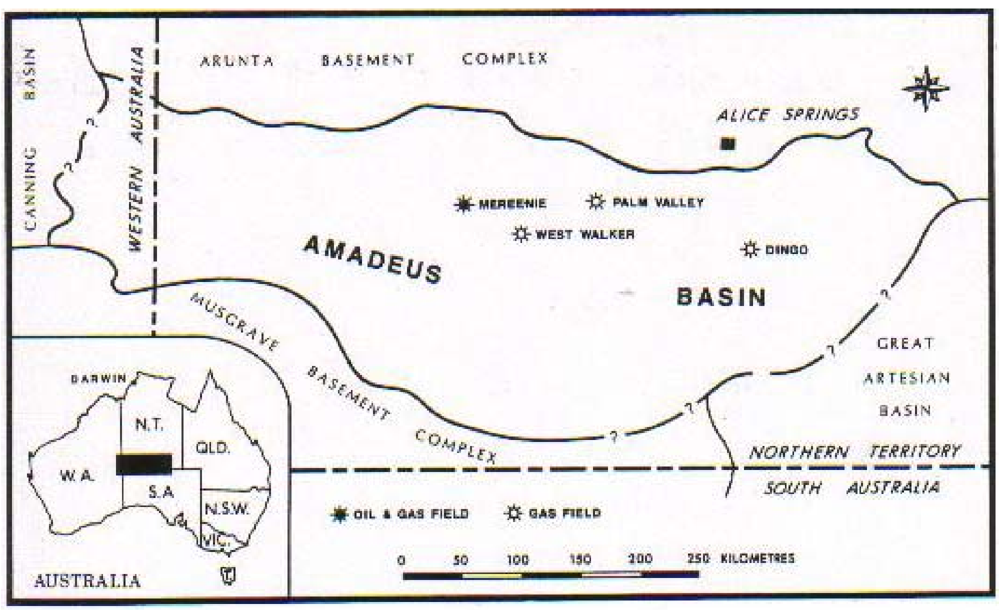
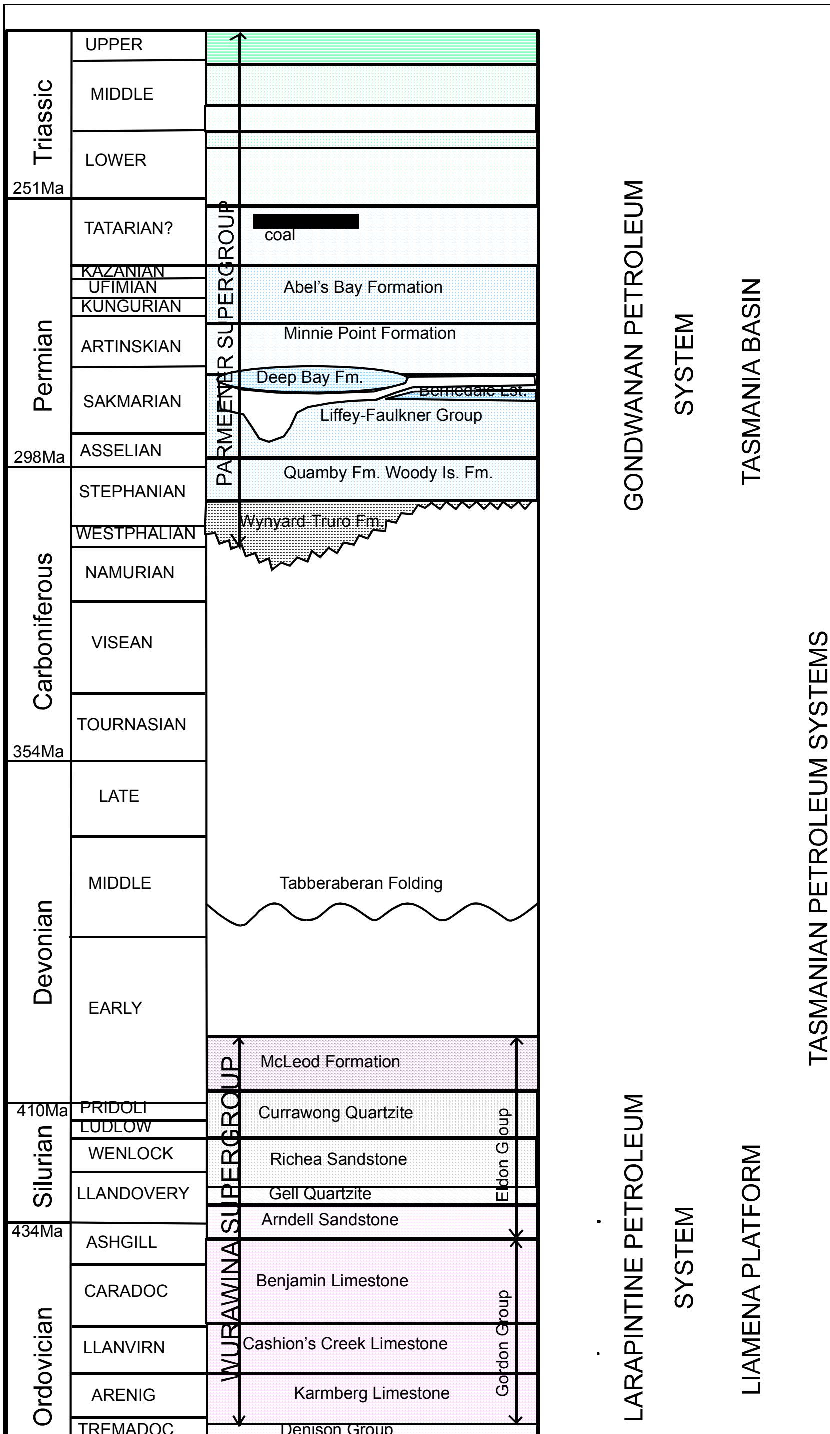


Figure 2. Map of Amadeus Basin showing petroleum occurrences. Hopkins, 1989.

Larapintine 2 petroleum system in Tasmania.

The Larapintine petroleum system has a number of subunits based on the time of deposition of the source beds with subunit 2 (Ordovician) applicable to Tasmania. In Tasmania the Larapintine 2 petroleum system is composed of the Wurawina Supergroup sediments ranging from the Denison Group through the overlying Gordon and Eldon Groups to an angular unconformity with the Parmeener Supergroup. Deposition occurred from Tremadoc to Early Devonian. Figure 3 shows the stratigraphic relationships of the Larapintine and Gondwanan petroleum systems in Tasmania.



BASED ON SEYMOUR AND CALVER, 1998

Figure 3. Stratigraphic relationships of Larapintine and Gondwanan petroleum systems in Tasmania. Based on Seymour and Calver, 1998.

Figure 4 shows a map of Tasmania with the inferred extent of the Gordon Group sediments and thus the inferred extent of the Liamena Platform. Much of this area is now covered by younger sequences and large parts have been removed by erosion. As implied by the term petroleum system all the geological factors necessary for oil and/or gas fields to exist are contained within it – source beds, reservoirs, seals, traps and the overburden required for maturation and migration pathways. Figure 5 shows petroleum system geological factors of the Larapintine 2 petroleum system in diagrammatic form.

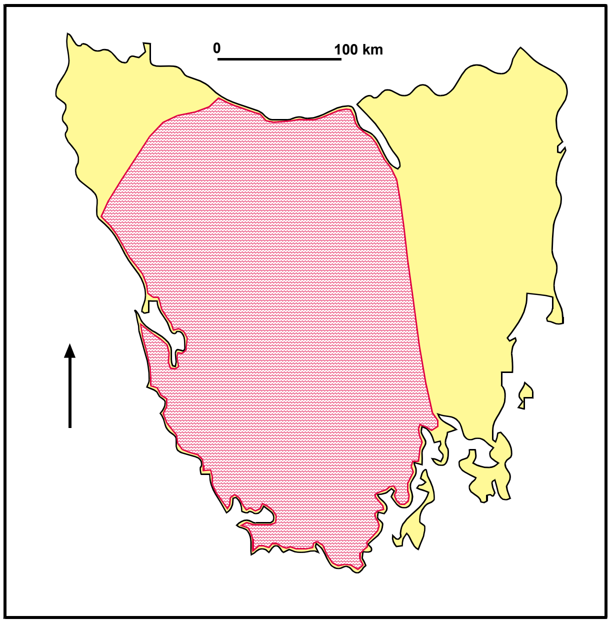


Figure 4. Inferred extent of Liamena Platform.

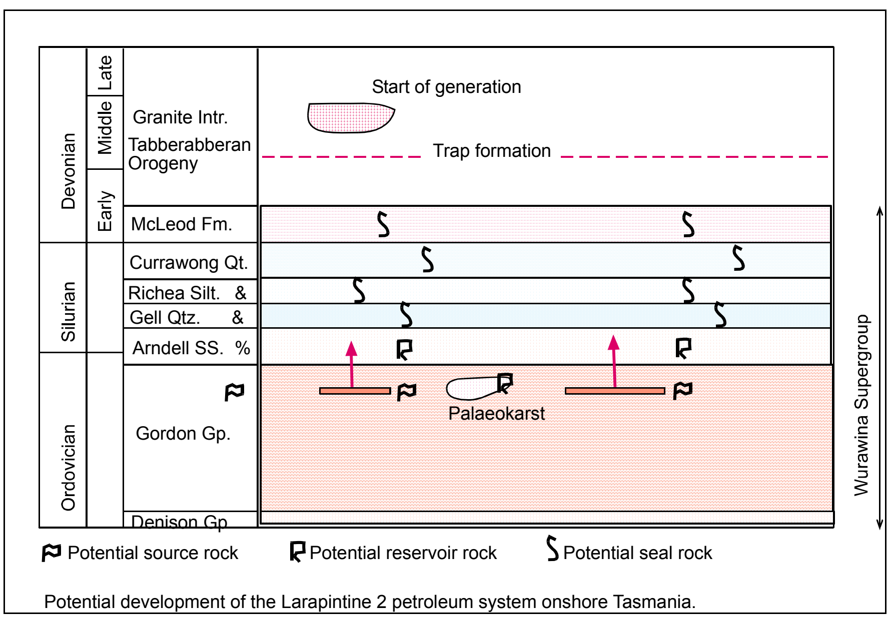


Figure 5. Diagram showing the geological components of Larapintine 2 petroleum system within Tasmania.

Indications of petroleum system host potential of the Wurawina Supergroup

Gordon Group limestones have often been reported as having a bituminous odour when struck by a hammer and although this is a highly qualitative indication it certainly shows that hydrocarbons are present. Petroliferous odours, were also noted in another part of the Larapintine petroleum system, the Amadeus Basin, before oil was discovered (Ranneft 1963).

Bituminous films have also been noticed in thin sections of Gordon Group limestones, particularly along stylolites and this may be evidence that oil has been generated within these rocks and migrated along stylolites. Figure 6 is a photograph of a core section of Gordon Limestone from Grieves Siding (Zeehan area, Western Tasmania) showing a bituminous stylolite. Further evidence has come from occurrences of pyrobitumen present within and close to Gordon Limestone at Comstock and Grieves Siding, both near Zeehan and at Bubs Hill, east of Queenstown. These pyrobitumen occurrences occur near probable Mississippi Valley Type (MVT), zinc-lead, prospects (Morris and Taylor 1995). Bitumen and kerogen is nearly ubiquitous with MVT deposits and is a key factor in the precipitation of zinc and lead sulphides (Spangenberg and Macko 1998).

A sample of the Upper Limestone Member of the Gordon Limestone from the Florentine Valley was crushed and the gas liberated was analysed by Dr. Noel Davies at the Central Science Laboratories, University of Tasmania. The major gas liberated is methane with gases up to C_9 identified thus clearly indicating a thermogenic origin for the gases. This is a positive indication of the potential of the Larapintine 2 system onshore Tasmania to generate hydrocarbons. Figures 7 and 8 are chromatograms showing the analysis of gases trapped within Gordon Limestone from the Florentine Valley.

Figure 6. Bituminous stylolite within drill core from Gordon Group limestone at Grieves Siding, near Zeehan.

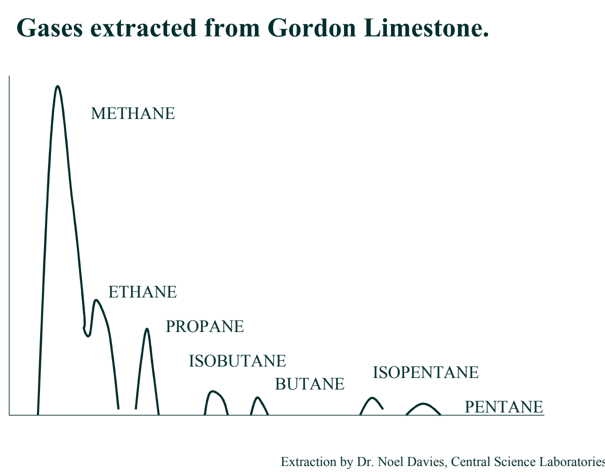


Figure 7. Chromatogram of major gases extracted from a sample of Gordon Limestone, Florentine Valley.

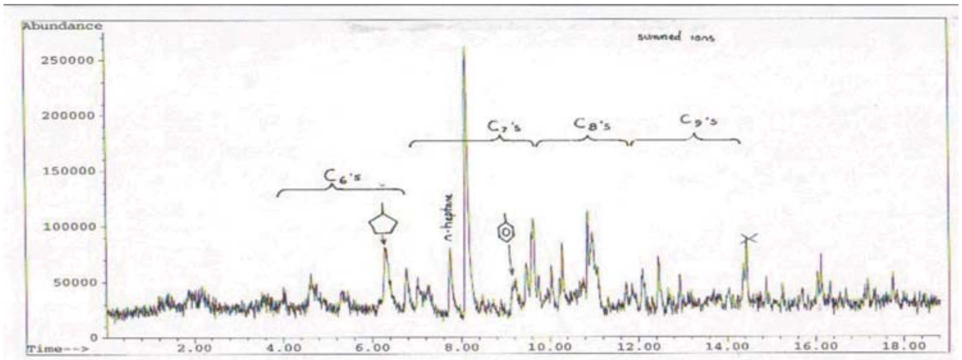


Figure 8. Chromatogram of minor gases extracted from a sample of Gordon Limestone, Florentine Valley. Source potential of the Gordon Limestone.

Outcrop samples of Gordon Limestone have been tested by Rock-Eval to determine potential as source rocks. Black shale horizons, which appear near the top of the Gordon Limestone, return results indicating they have fair to good potential as source rocks. One horizon about 200 mm thick has been followed for five kilometres along strike in the Florentine Valley and the same bed has been identified four kilometres across strike on a parallel fold indicating wide lateral extent of the source bed. A similar bed has been identified near Lune River approximately 100 km to the south suggesting wide distribution of potential source horizons. Possible source bed exposures occur along the full north-south extent of the prospective area and also across the full east-west extent of the Upper Benjamin Limestone portion of the Gordon Limestone. The following table summarises the results of Rock-Eval analysis of possible source rocks.

Table 1. Rock-Eval results from Gordon Limestone samples

Sample	**TOC**	**Tmax**	**$S_1 + S_2$**
LR2	0.40	496	0.38
CB30	0.43	488	0.22
UL25	0.46	469	0.28
175	0.48	465	0.63
172	0.57	522	0.32
CB16	0.58	545	0.46
CB32	0.64	520	0.55
CB26	0.70	508	0.29
CB13	0.70	446	0.11
SM1	0.78	461	0.11
MC1	0.80	467	0.30
1716	0.80	439	0.43
WQR1	1.16	544	0.29
11R1	1.37	518	0.06
CB14	1.83	467	0.05

Parameters to evaluate the figures are shown in Table 1.

TOC; 0-0.5 Poor, 0.5-1.0 Fair, 1.0-2.0 Good, 2+ excellent.
T_{max}; oil generation 430-470, 470+ gas generation.
$S_1 + S_2$; is an evaluation of the genetic potential of the source rock.

$S_1 + S_2$ values may mean that generation is almost complete and that migration of hydrocarbons may have occurred. T_{max} ranges indicate maturity in the gas generation field. Figure 9 shows a conventional graph of HI vs. T_{max} from which maturity values of samples can be visualised.

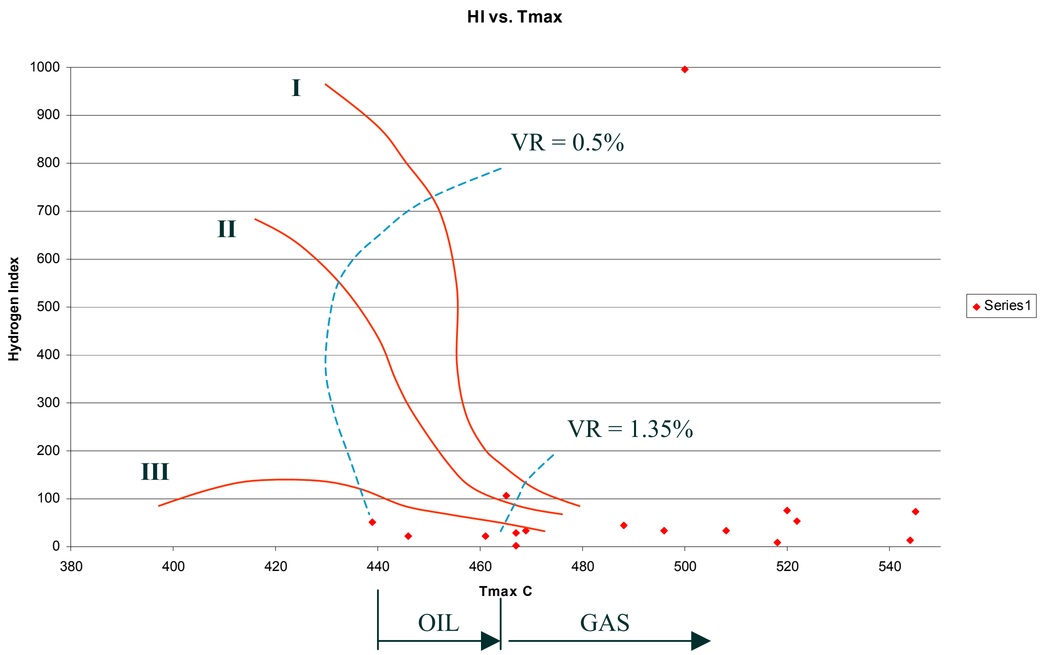


Figure 9. Hydrogen Index vs. T_{max} chart derived from Rock-Eval pyrolysis of samples of Gordon Limestone.

Analysis of extractable organic matter (EOM) from a sample of Gordon Limestone gave a composition of 38% Saturates, 19% Aromatics and 43% nitrogen, sulphur and oxygen compounds. Alkane ratios from the same extract indicated an algal source for the kerogen which is in accord with Ordovician occurrences in other parts of the world where *Gloeocapsomorpha prisca* is the dominant contributor to organic matter to sediments of this age.

Ordovician oils worldwide have a unique geochemical fingerprint, which is characterised by;

1. Odd over even preference in the C_{15}-C_{19} n-alkanes.
2. Low abundance of C_{20+} n-alkanes.
3. Absence of pristane and phytane.

(Reed, *et al*., 1986).

Larapintine 2 sediments in the southern Canning Basin, Australia, have this signature (Hoffman, Foster *et al*., 1987) and indications so far show that Tasmanian samples also have this signature.

Gas chromatograms comparing the n-alkane distribution from Ordovician sediments containing mixtures of *G. prisca* and amorphous matter show that as the concentration of amorphous matter increases the C_{20+} n-alkane abundance increases along with pristane and phytane (Guthrie and Pratt 1995) shown in Figure 10. A gas chromatogram of the

Gordon Limestone from Queenstown, Figure 11 (Volkman 1999), has a range of n-alkanes indicative of 80% input from amorphous organic matter. Source affinity derived from pristane/n-C_{17} versus phytane/n-C_{18} is a mixture of Type II and III kerogens affirming above assessment. Low Hydrogen Index values from Rock-Eval are probably due to this mixture of kerogen types, which indicates low source potential for hydrocarbons.

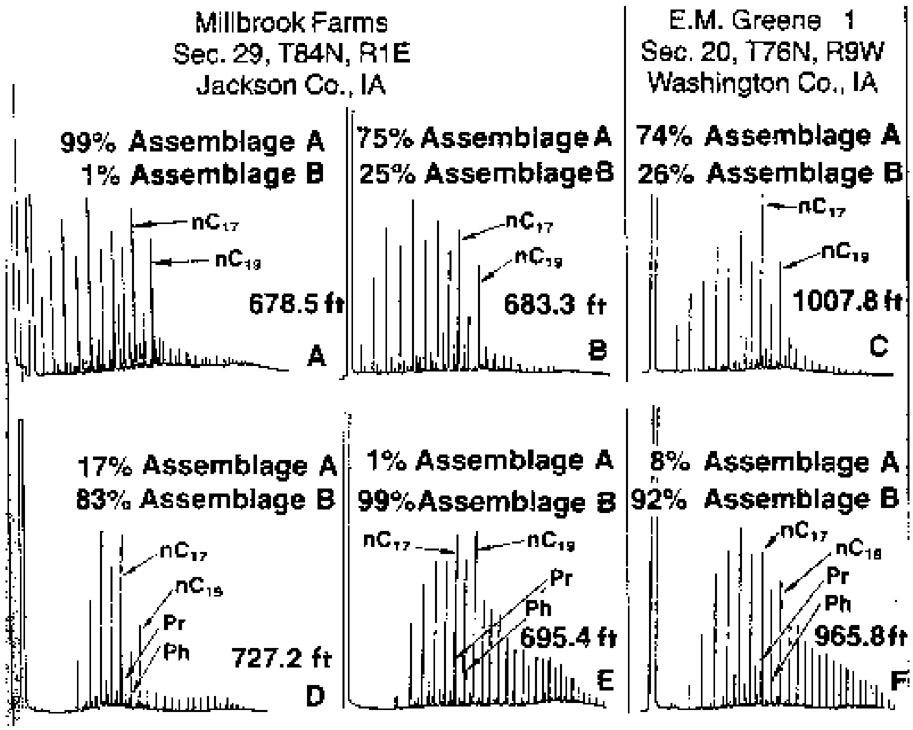


Figure 10. Gas chromatogram comparing n-alkane distributions from source rocks containing mixtures of organic matter derived from *G.prisca* (Assemblage A) and amorphous matter (Assemblage B). Guthrie and Pratt, 1995.

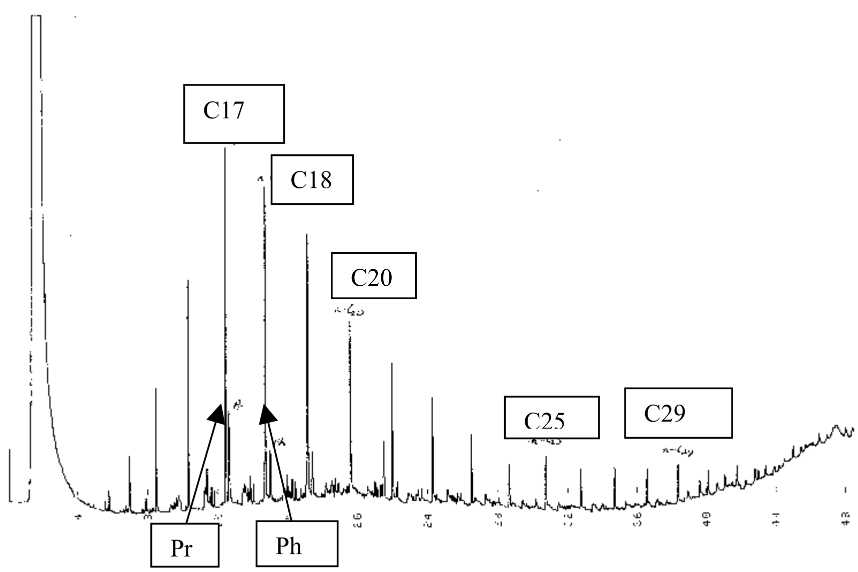


Figure 11. Gas chromatogram of n-alkane distribution extracted from a sample of Ordovician Gordon Limestone from Queenstown, Tasmania. Volkman, 1999.

Maturity of Gordon Limestone source rocks

Conodont geothermometry studies using the Colour Alteration Index (CAI) to measure maturity levels of Gordon Group limestone (Burrett 1992) shows that an area in southeast Tasmania is within the gas window (CAI 3 or less). Rock-Eval results on samples taken within the CAI 3 zone confirm the results of CAI analysis as maturity from T_{max} indicates late oil to gas maturity levels. Two independent measures have thus confirmed that Gordon Group limestone outcropping in southeast Tasmania is mature for gas generation.

Reservoir potential

Directly overlying the Gordon Group limestone in the Tiger Range area is the Arndell Sandstone a sequence some 250 m thick. This very fine-grained sandstone with 5% apparent porosity, could act as a gas reservoir. The Arndell Sandstone is conformable with and has been folded synchronously with the Gordon Group limestone during the Tabberabberan Orogeny.

Karst features are commonly seen in sub-aerially exposed Gordon Group limestone. This implies that any Gordon Group limestone sub-aerially exposed before Parmeener Supergroup deposition may also have developed karst features. Palaeokarst features have in fact been found within Gordon Group at Eugenana (Burns 1964), Florentine Valley (Goede 1976), Tyenna (Calver 1992), Ida Bay (Houshold and Spate 1990), Lake Sydney (Kiernan 1989) and possibly Moina (Hughes 1957). Palaeokarst can provide excellent hydrocarbon reservoirs (Loucks 1999) and from the examples noted in outcrop it is likely buried examples are present within the Gordon Group limestone.

Possible seals

Seal horizons can be divided into local and regional possibilities. Regional seals are provided by Wynyard tillite, which extends right across the base of the Parmeener Supergroup and has thickness, in places, in excess of 500 m (Clarke 1989). Jurassic dolerite may also provide a regional seal.

Local seals for individual reservoirs are likely to be provided by the Eldon Group, which directly overlies the Gordon Group limestone. Directly above the Arndell Sandstone is the Richea Siltstone fine-grained, competent siltstone 130 m thick, which is likely to provide an excellent seal. Extra sealing capacity could be provided by the overlying Currawong Quartzite, which has beds of siltstone and mudstone. Enclosing Gordon Group limestone would provide seals for possible palaeokarst reservoirs hence there are adequate seals.

Possible traps

The structure of the Wurawina Supergroup beneath the Tasmania Basin is the key to understanding the types of traps that may be present. As very little direct information is available structural details at this stage are largely inferred from visible structures in northern and western Tasmania and by comparisons with other fold and thrust belts.

A comparison of Tasmania with a productive petroleum basin in eastern north America, the Appalachian Fold and Thrust Belt, indicated that a series of structural zones exist from east to west across Tasmania as shown in Figure 12. The eastern terrane, consist largely Ordivician-Devonian turbidites, has been thrust westwards over the western terrane. The thrust and fold belt is a zone where thrust slices, Precambrian-Devonian, have been stacked. The folded zone consists of parallel open folds, which curve around in an arc to follow the eastern and northern edges of the Tyennan Region. This zone is likely to be the most prospective for hydrocarbon traps. In the west, the Precambrian craton has acted like the fixed jaw of a vice while the fold and thrust zone has been deformed by the moving jaw, eastern terrane, thrust westwards.

Support for these inferences has come from results of deep drilling at Hunterston, Tunbridge, Ross and The Quoin and also from GSLM's seismic survey. Small outcrops of thrust slices also occur, such as at O'Connor's Peak near Poatina.

The majority of the Wurawina Supergroup beneath the Tasmania Basin is likely to have been involved in fold and thrust movements during the Tabberabberan Orogeny as can be observed in northern Tasmania (Woodward, *et al*., 1993). Drill hole data, outcrops of thrust slices and seismic, magnetic and gravity data indicate that thrusting has extended from the east to a line approximately north-south from Deloraine to New Norfolk and wrapping around the north of the Cradle Mountain Block. Thrusting has stacked thrust slices and these may form traps if reservoir beds were sealed against impermeable rocks. Small anticlines may also have formed at the thrust fronts and provide traps.

Traps of different types may exist within the probable Larapintine 2 petroleum system. Large anticline traps would be desirable, however, the exposed outcrop of Gordon Limestone indicates that deep erosion has removed the tops of all major anticlines leaving isolated synclines. Parasitic anticlines on the limbs of large synclines are the most likely form of anticlinal trap to be found and these are most likely to be faulted.

Palaeokarst traps although desirable would be very difficult to find as no effective method of locating traps of this type exists. Palaeokarst is likely to occur within high points of palaeotopography and so is likely to occur near the crests of anticlines, as such, traps of this type may be found during normal exploration for anticlinal traps. Cartoons of the likely styles of traps to be found are shown in Figure 13.

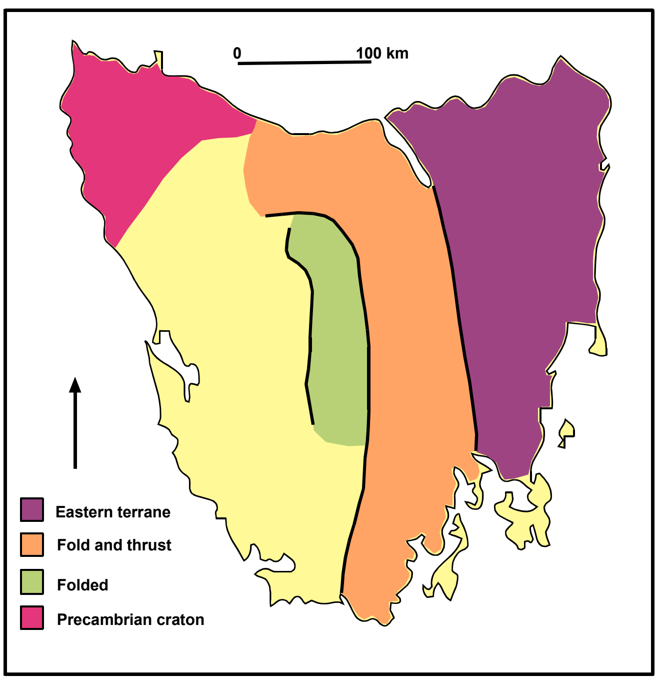


Figure 12. Inferred structural zones in Tasmania as they apply to petroleum exploration.

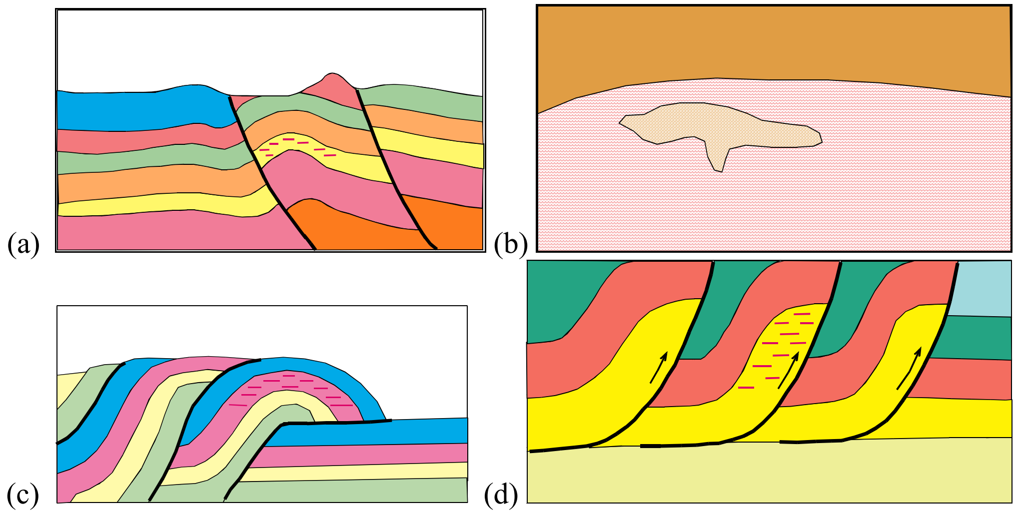


Figure 13. Cartoons of possible trap types within the Wurawina Supergroup. (a) Faulted anticline trap. (b) Palaeokarst trap. (c) Thrust front anticline. (d) Stacked thrust slices.

Migration pathways

Bituminous films and pyrobitumen occur along stylolites in core samples and thin sections of Gordon Limestone indicating that stylolites form pathways for petroleum migration. Thin dolomitic, shaly beds may also provide migration pathways. Fractures and faults probably would provide the most effective pathways but these may also continue through reservoirs and seals and allow hydrocarbons to escape. All of these possible pathways for migration do exist and the close bedding relationships between source and reservoir rocks provides short pathways.

Timing of petroleum system events

A Time Risk Chart is shown in Figure 14 showing that a sequence of events has occurred such that hydrocarbons could have been generated and successfully trapped. Timing of hydrocarbon generation has been determined as having occurred during the Devonian due to the high heat flows from granitoid intrusions. CAI zoning in Tasmania does not reflect burial depths as it does in other petroleum basins such as the Appalachian Basin (Epstein, *et al*., 1977) and the Canning Basin (Nicoll, Owen *et al*., 1988). In Tasmania CAI values show higher maturity to the north and west and particularly in the northwest burial is likely to have been shallow so CAI zonation is reversed to that expected from comparisons with other basins. This implies that heat from granitoid intrusions has been the cause of the high maturity values within the Gordon Limestone and generation of hydrocarbons probably commenced soon after the intrusion events.

Folding and thrusting would have occurred before the intrusion events as granitoids have been intruded through folded sediments (McClenaghan 1989). Traps and seals would have been in position before hydrocarbon generation started. Rock-Eval pyrolysis results show that some samples are still within the oil generation zone so it is likely that hydrocarbon generation and migration is still continuing.

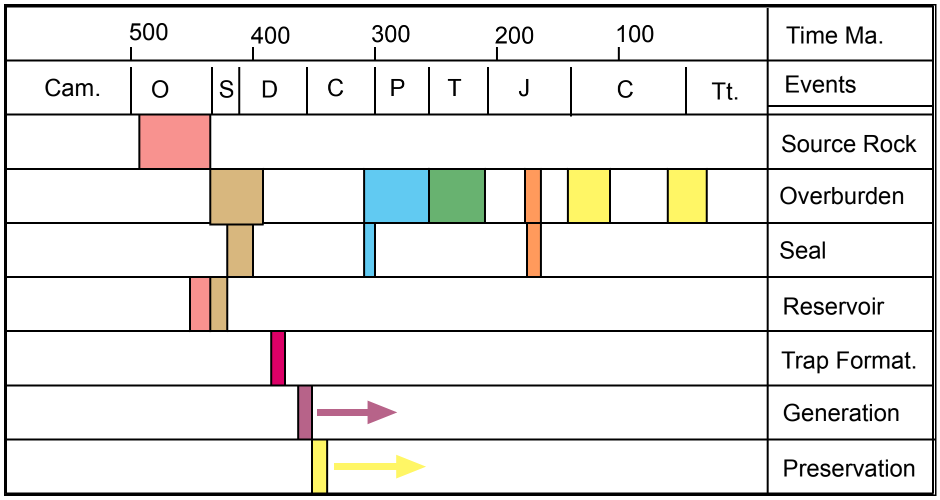


Figure 14. Time-risk chart for the Larapintine 2 petroleum system within Tasmania.

Prospective areas

Prospective areas have been identified on the basis a combination of CAI zones within the oil and gas windows, CAI 3 or below, and structural zones likely to provide traps. The western boundary of the Exploration Lease more or less follows the CAI 3 isograd and so defines the upper limit of maturity for gas, it also follows the western limit of sediments within the Wurawina Supergroup beneath the Tasmania Basin. The northern boundary of the prospective area is the CAI 3 isograd, which runs from near Derwent Bridge across the northern part of the Great Lake and thence eastwards. The eastern boundary is the inferred thrust front probably a line running north-south from near Deloraine to New Norfolk.

The Derwent Graben crosses this zone and due to the structural complications imposed by faulting may not be prospective. South of the Derwent Graben the prospective zone continues until just south of the Huon River. South of the Huon River Wurawina structures appear to be open to the west and so migrating hydrocarbons are likely to have escaped from this region.

A zone of approximately 3, 500 square kilometres is thus identified as prospective for gas within the Larapintine 2 petroleum system in Tasmania. Figure 15 shows this prospective zone on a map of GSLM's exploration lease.

Conclusion.

All the elements required to form a petroleum system within the Wurawina Supergroup exist and appear in an appropriate sequence to have been able to generate and trap petroleum. Indications are that the most likely product from this probable petroleum system would be gas.

Systematic deep drilling is required to substantiate inferred stratigraphy below younger cover within the defined prospective area. Structural information is critical to hydrocarbon exploration and this has largely been inferred at this stage. Further seismic surveying particularly in lines across the strike of major structures and tied into results of drilling would be particularly useful to define structures for possible traps and to define extent of drainage areas.

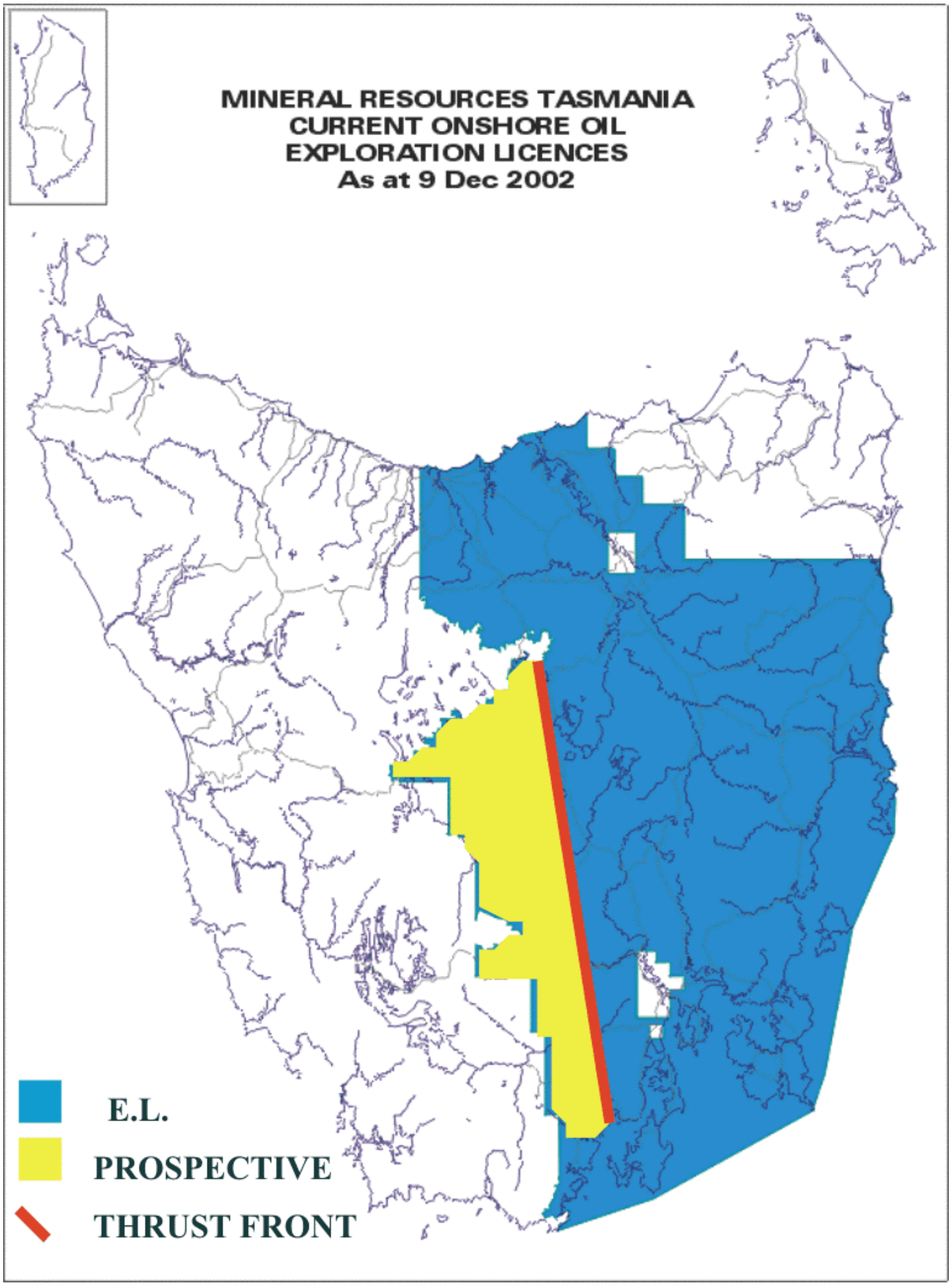


Figure 15. Prospective zone within GSLM's exploration lease. Lease area to the west of red line is prospective for the Larapintine 2 petroleum system.

Biomarkers from Gordon Limestone (Alan Chester)

GC-MS was used to analyse biomarkers from a sample of potential Gordon Limestone source rock, collected from outcrop in the Florentine Valley. Calculated vitrinite reflectance values were determined using five different equations to establish the maturity of this sample. Results are shown in Table 2.

Table 2. Calculated Vitrinite Reflectance from aromatic maturity indicators.

A	B	C	D	E
0.87	1.83	1.17	0.77	1.14

A, $VR_{calc.} = 0.6MPI + 0.4$ (for VR<1.35%)
B, $VR_{calc.} = -0.6MPI + 2.3$ (for VR > 1.35%)
C, $VR_{calc.} = 0.99 \log_{10}MPR + 0.94$ (VR = 0.5 – 1.7%)
D, $VR_{calc.} = 0.7MPI + 0.22$ (for VR < 1.7%)
E, $VR_{calc.} = -0.166 + 2.242MPDF$

These values show a similar range to the T_{max} values derived from Rock-Eval of samples from the same bed and confirms that maturity is within the wet gas window.

Genetic affinity determined from the pristane/n-heptadecane versus phytane/n-octadecane plot (Figure 16) shows that the organic matter has been derived from an algal/bacterial source. Source affinity from a plot of pristane/phytane versus C_{29}/C_{27} diasterane (Figure 17) indicates an algal source in anoxic conditions. These findings are in line with expectations from the depositional environment of the Gordon Group limestone and results from similar Ordovician source rocks.

The sterane maturity-migration plot (Figure 18) shows that the sample tested has plotted along the modal source-rock maturation curve. Sample 175 plots in a position to indicate post-oil maturity and this also confirms maturity in the wet-gas window.

The ternary diagram (Figure 19) shows the distribution of C_{27}, C_{28} and C_{29} regular steranes with zones colour coded to show typical distributions for particular hydrocarbon types, marine oils from shales, marine oils from carbonates and lacustrine shale oils (Hunt 1995). The peaks C_{27}, C_{28} and C_{29} represent zones where the steranes are derived from respectively red algae and zooplankton, green algae and diatoms, higher plants and red and green algae. Sample 175 plots in the field of marine oil from carbonates as expected for a sample from Gordon Group limestone.

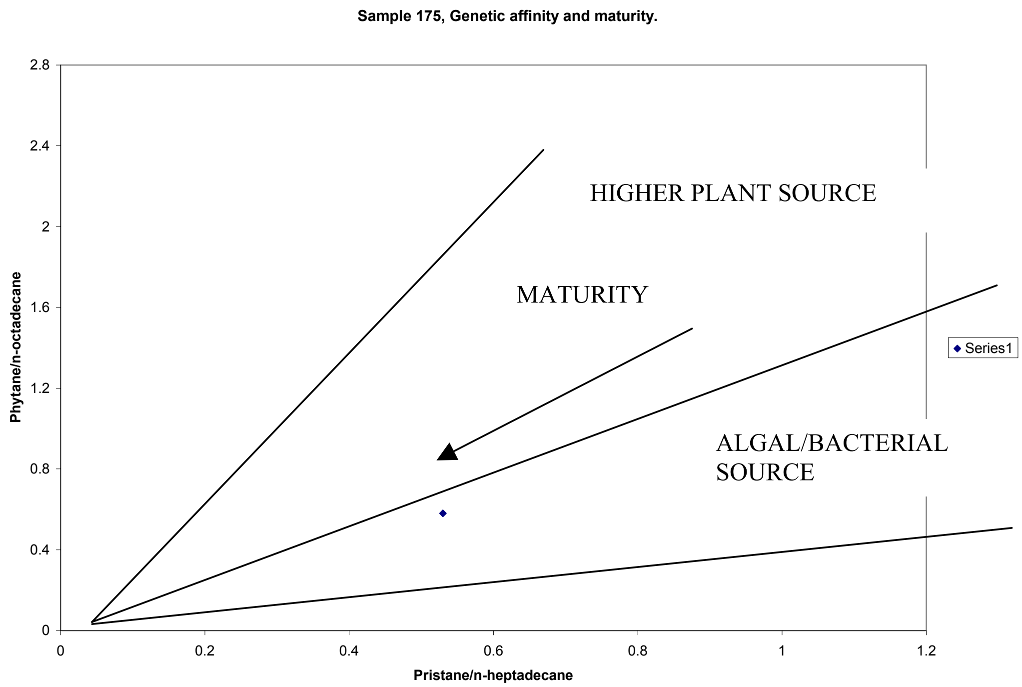


Figure 16. Genetic affinity and maturity for Gordon Group limestone sample.

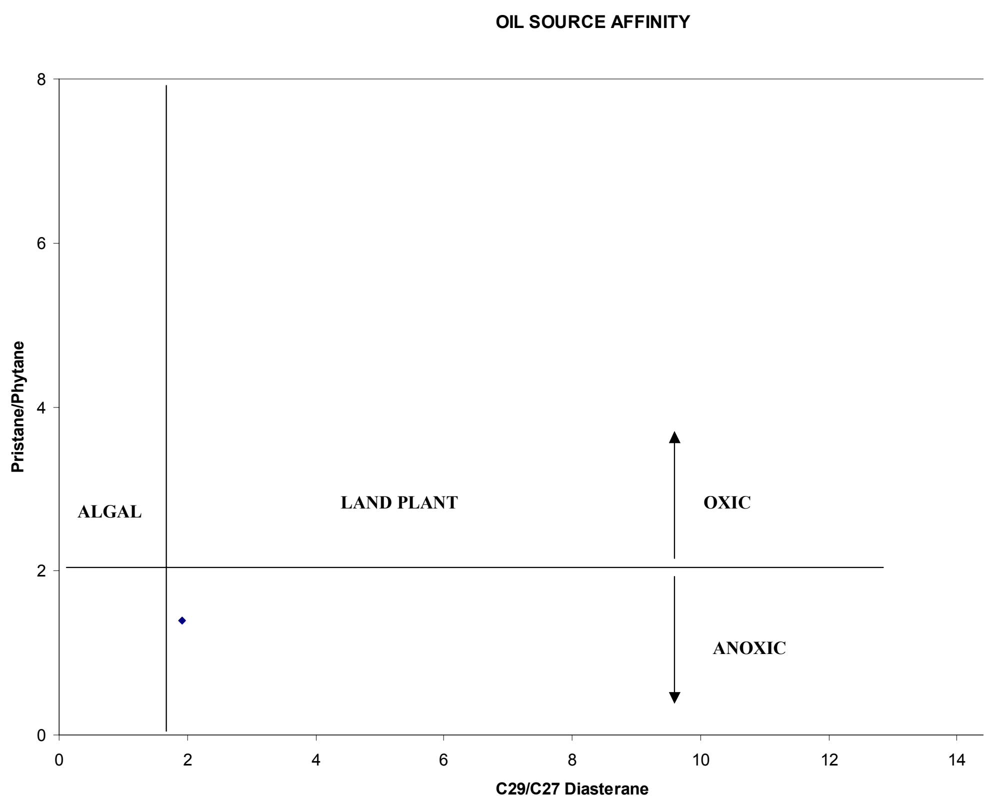


Figure 17. Oil source affinity for Gordon Group limestone sample.

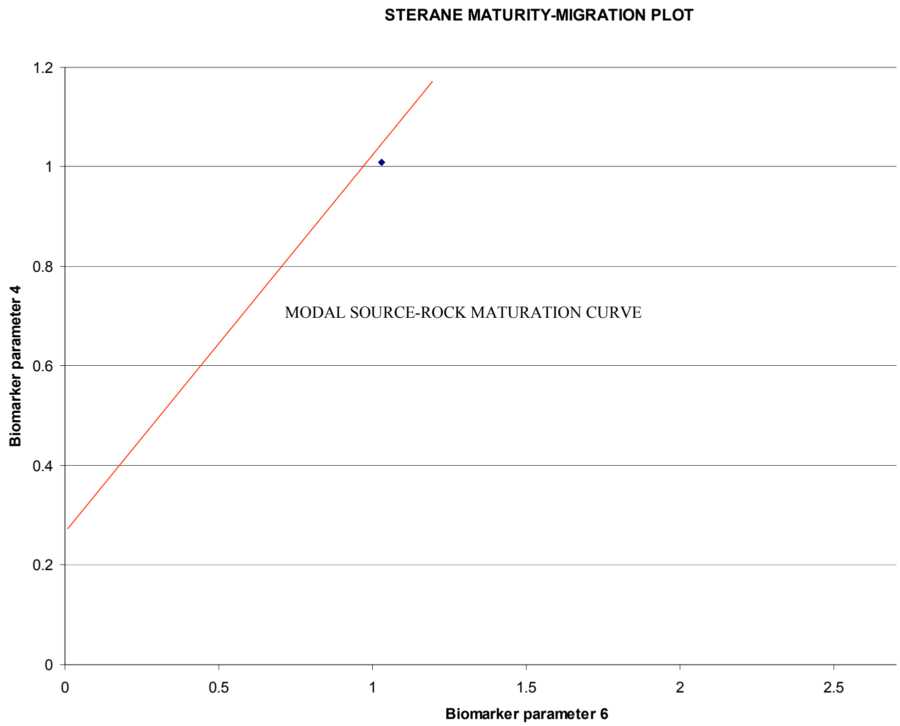


Figure 18. Sterane maturity-migration plot for Gordon Group limestone sample

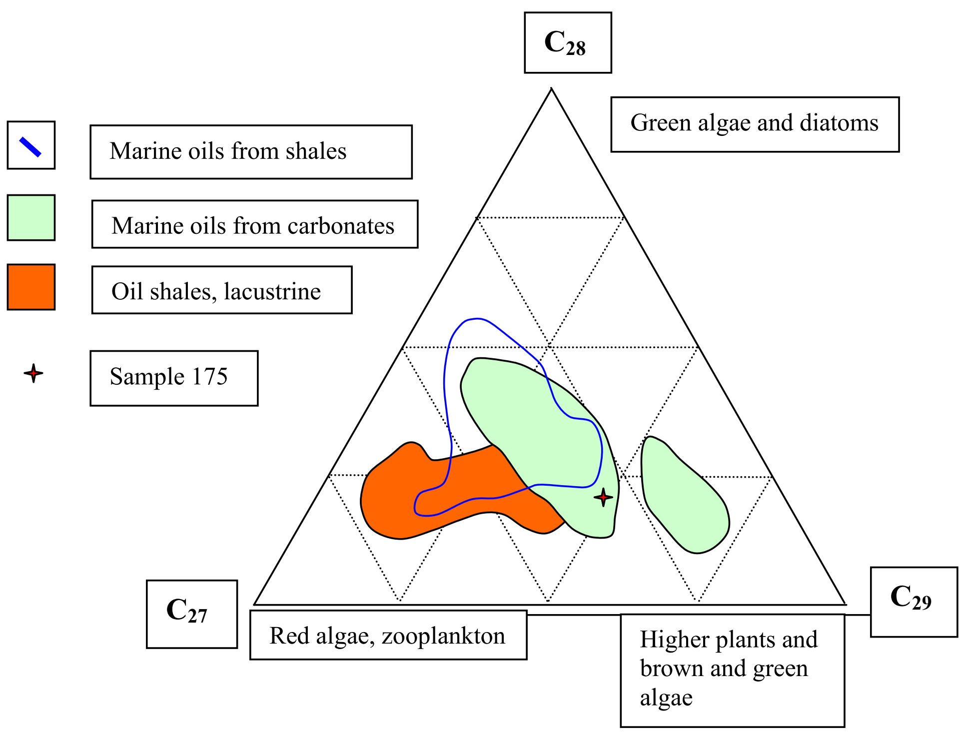


Figure 19. Ternary diagram of abundances of C_{27}, C_{28} and C_{29}, showing the zones for some typical types of oils and the position for Gordon Group limestone sample. After Hunt, 1995.

Petroleum Systems in Gondwana (Dr Catherine Reid)

Gondwanan System

The southern continent of Gondwana lay at high latitudes during the Late Palaeozoic. In the late Carboniferous glacial environments developed across much of Gondwana, and are reflected in several basins with extensive glaciomarine and glacioterrestrial sediments. The Tasmania Basin has long been recognised as having a glacial influence in the Late Palaeozoic, along with basins of mainland Australia, South Africa, India, Arabia and South America. The distribution of glacial basins is shown in Figure 20 during the Late Carboniferous, when the Tasmania Basin was close to the magnetic South Pole.

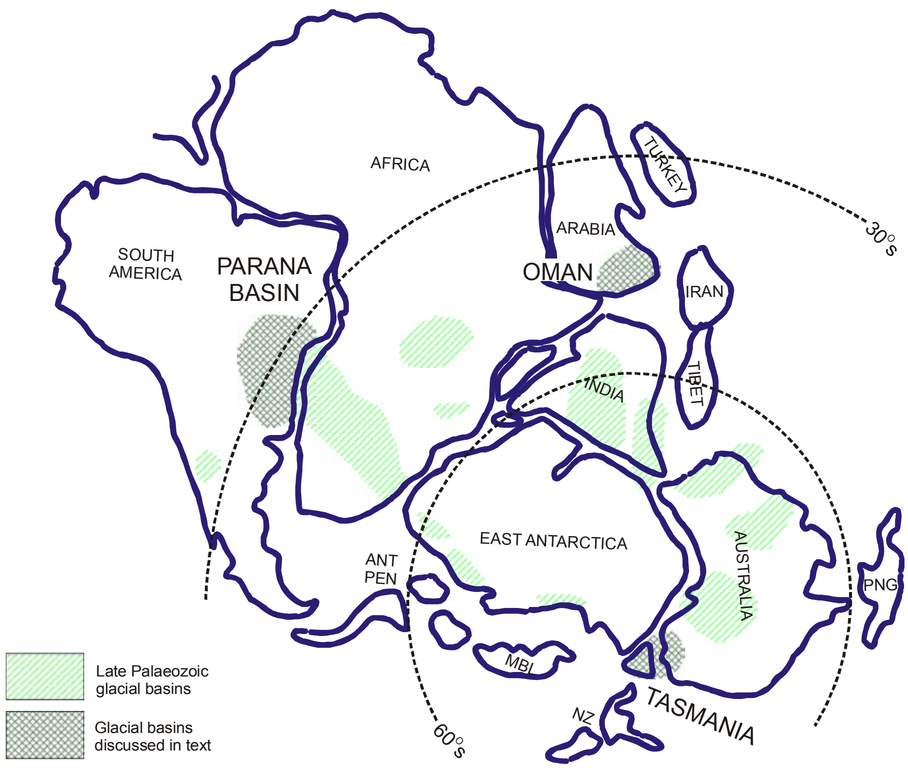


Figure 20. Reconstruction of Gondwana during the Late Carboniferous, with glacial basins highlighted. After Lawver and Scotese (1987).

These glacial basins all contain thick deposits of diamictites, of marine and terrestrial origin, along with sandstones and shales. All basins contain organic shales, although in varying paces in the stratigraphy. Despite the cold-water conditions, productivity was high in the marine setting, with organic remains of algae and other organisms forming low to high grade and thick source rock deposits.

The glacial depositional environment is not one immediately associated with petroleum basins, however significant finds in the Oman Basin of Arabia, and the Parana Basin of Brazil, have led to exploration these kinds of sediments elsewhere.

Case Study One – South Oman

The presence of glacial sediments in south Oman was confirmed in the late 1980s although there had been earlier, unconfirmed, reports. The initial exploration for hydrocarbons in Oman was not instigated by their association with glacial sediments, however the discovery of oil in the 1970's led to their recognition and appreciation in hydrocarbon basins. 3.5 billion barrels of heavy oil have been found in place (Levell *et al*., 1988) in the glacigenic rocks in Oman, south of the Oman Mountains.

Glacial deposits are found in the lower part of the Haushi Group, in the Al Khlata Formation and Rahab Shale (Figure 21). The upper parts of the Haushi Group, the Gharif and Khuff Formations, are not of glacial origin.

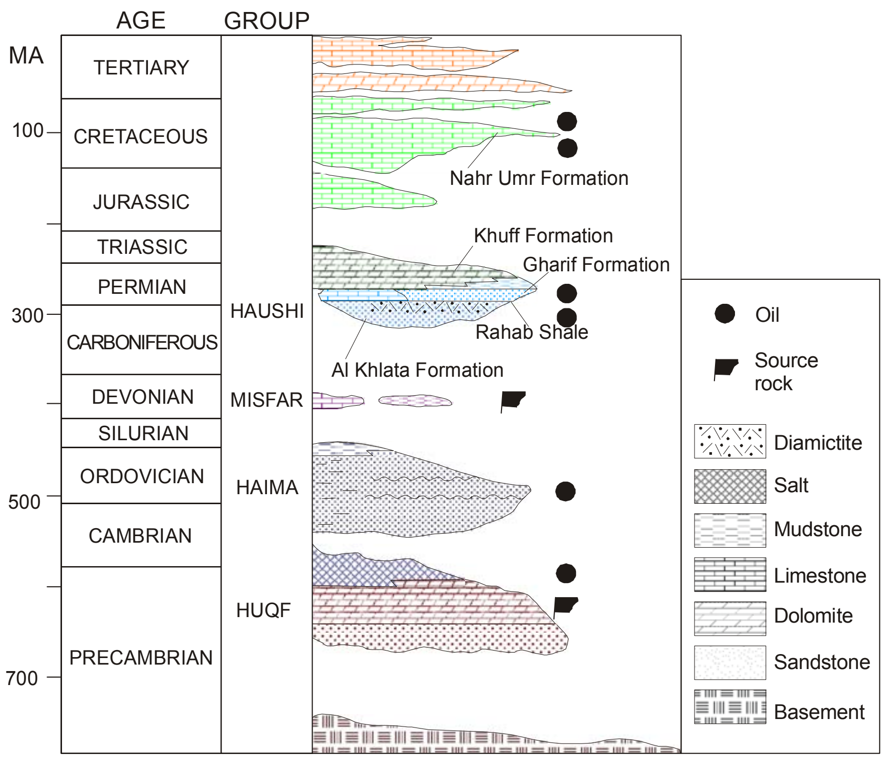


Figure 21. Stratigraphic column for south Oman, showing major depositional phases, source and reservoir rocks. After Levell *et al*., (1988).

Hydrocarbons found in the glacigenic sequence of south Oman are sourced from the Precambrian Huqf dolomites. Source rocks have not yet been identified within the glacigenic sequence. Heavy oils have been generated from Precambrian algal material, bacteria and cyanobacteria (Grantham *et al*., 1988), and are trapped within the Al Khlata interbedded glacial sands and diamictites, and pre-glacial salt produced structures (Levell *et al*., 1988). The Al Khlata Formation glacial deposits consist of glaciofluvial and glaciolacustrine sands interbedded with shales and diamictites. The Cretaceous Nahr Umr Formation provides the regional seal in south Oman, however the glacial shales and diamictites are of low permeability and provide intraformational traps and seals. The reservoir sands have porosities of 16-26% and permeabilities of 1-3000mD (Alsharhan *et al*., 1993).

The Gondwanan Petroleum System of the Tasmania Basin is similar to the south Oman hydrocarbon field, in its glacial depositional setting and sediment types. The Tasmania Basin does not have the extensively developed interbedded diamictites and sandstones of the Al Khlata Formation, but other facies types are present as suitable reservoir rocks, as thin sands within the source rocks and basin wide freshwater sandstones. It does however, demonstrate the ability of diamictites to form seal rocks, and by their extensive basin wide occurrence in the Tasmania Basin, may form suitable seal and trap relationships over basement karst topography.

Case Study Two – Parana Basin, Brazil

The Parana Basin of Brazil provides a more interesting comparison to the Tasmania Basin, as both source and reservoir rocks are found within the one glacial to non-glacial succession, and younger intrusive rocks, provide both heat for hydrocarbon generation, and seal and trap relationships.

Glacigenic sediments are found with the Carboniferous to Early Permian Itarare Group, consisting of sandstones and diamictites overlain by the organic rich shales of the Irati Fm (Arauyo *et al*., 2000). Glacigenic fill of the Parana Basin commenced in the Late Carboniferous, and deposition was continuous through to the non-glacigenic and terrestrial Triassic to Jurassic sediments in the upper part of the basin. Cretaceous diabase intrusive and thick extrusive sequences form the top of the Parana Basin (Figure 22).

There are two hydrocarbon systems within the basin. The first has a pre-glacial source charging the glacial sands, after hydrocarbon generation by diabase sills and dykes and the overburden of extruded magmas. The source is in Devonian shales of the Ponta Grossa Formation. The shales have a low average TOC of 3% (Milani and Catto, 1998),with hydrocarbons generated from type II and II organic matter. The source rock was matured (to overmatured) by the Cretaceous intrusions. Hydrocarbon reservoirs are found within the sands of the Permo-Carboniferous glacial system, with both fine-grained sedimentary units and Cretaceous sills forming sealing rocks (Milani and Catto, 1998).

The second hydrocarbon system has an upper Permian source, with heavy oils found within the overlying Triassic fluvial and eolian sands. The Permian source shales of the Irati Formation have a high TOC level, of up to 23%, and oil-prone organic matter. Analysis of burial histories from the overlying sedimentary pile shows the source rocks as immature (Milani and Catto, 1998). Oils have again been generated by heating from the Cretaceous intrusives, and the thick accumulation and overburden of up to 2km of volcanic extrusives (Milani and Catto, 1998).

The nearby frontier Pilar Basin, which is partially joined to the Parana Basin, again shows glacial sediments. A Devonian marine source is thought to have generated hydrocarbons into overlying Carboniferous glacial sands that are interbedded with diamictites (Delaney, 1998).

The relationship in the Parana Basin of intrusive rocks, forming both heat source and seal is important in respect to exploration in the Tasmania Basin. The Jurassic dolerites of the Tasmania Basin should be considered as possible heat sources for maturation. In the Parana Basin the thick overburden will assist in closing fracture porosities within the intrusive rocks. While the relatively shallow depth of the intrusives in the Tasmania Basin will probably be insufficient for forming seal rocks themselves, the frequent alteration of marine shales and calcareous rocks to form clays mean the intrusives may indirectly form seal units.

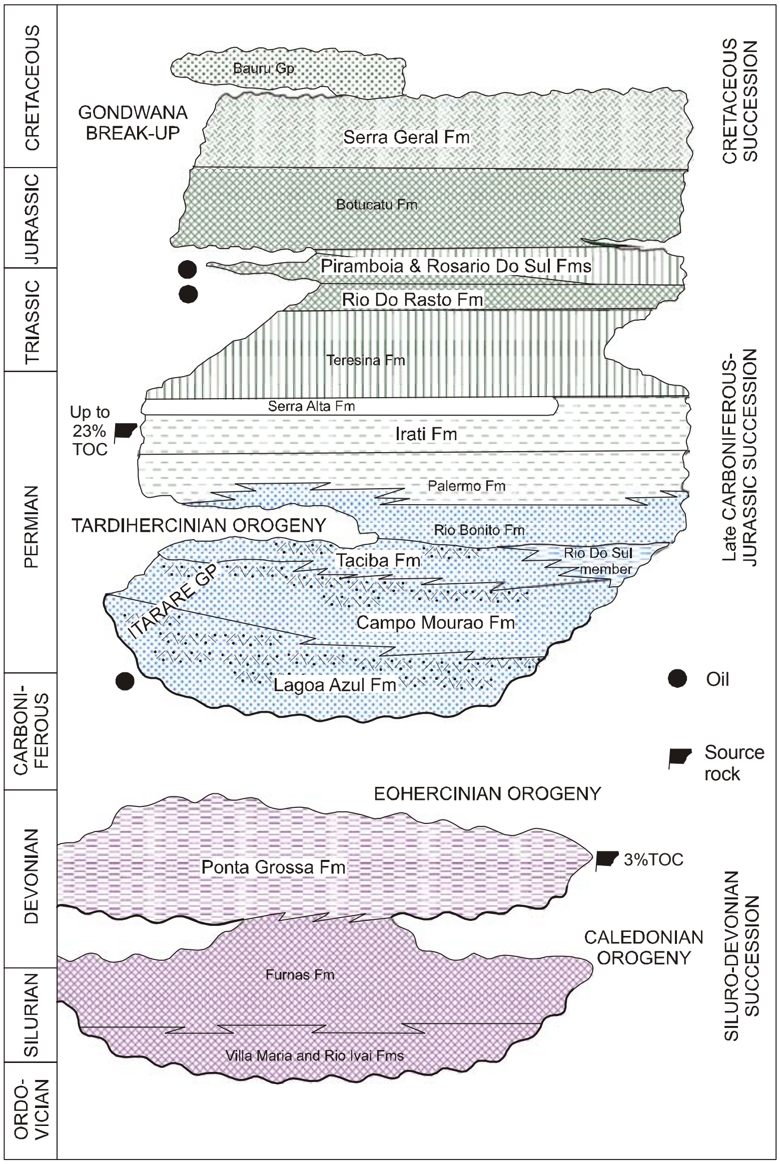


Figure 22. Stratigraphic column for the Parana Basin, showing source and reservoir rocks. After Eyles *et al*. (1993).

Comparison of Tasmania Basin to south Oman and Parana Basin

The Tasmania Basin glacigenic sequence, contains suitable source rocks in cold-water organic siltstones, and has likely reservoir and seal rocks in the freshwater sequence and overlying siltstones and mudstones. Table 2 shows comparative features between Oman, and the Parana and Tasmania Basins. Like both the Oman and Parana petroleum systems, there is potential for additional source rock in older dolomites and limestones beneath the Tasmania Basin. The intrusive rocks of the Parana Basin, have had a two-fold benefit to that system, in providing heat for source rock maturation and seal rocks higher in the system. Potentially the same scenario could be seen in the Tasmania Basin, where the dolerite intrusives heated the source rock, and higher in the system provide alteration clay seals, above the reservoirs.

Table 2. Comparison chart for the Tasmania Basin, south Oman and Parana Basin.

	South Oman	Parana Basin	Tasmania Basin
Depositional environment	Glacigenic	Glacigenic	Glacigenic
Source rock	Precambrian dolomite & Devonian shales	Devonian & Permian shales	Ordovician limestones & Permian siltstones
Reservoir rock	Sands interbedded with diamictites	Sands interbedded with diamictites, and fluvial sands	Fluvial sandstones ? Leached conglomerates ?
Seal rocks	Diamictites & and shales	Diamictites, shales & igneous intrusives	Shales ?, siltstones ? and igneous instrusives?

Australian System

Exploration for hydrocarbons within onshore Australian basins has been occurring since the early 20th century. Exploration accelerated in the 1950's, with the presence of commercial seismic services, interest in Australian basins from United States companies, and the Petroleum Search Subsidy Act (Randal, 1982). Hydrocarbons exist throughout Australia, and in systems of many ages. However, across western, eastern and central Australia the major producing basins contain a Permian source and or reservoir (Figure 23).

Permian sequences commonly form rich source rocks supplying petroleum to younger basins. The Permian marine and freshwater rocks of the Bowen Basin of Queensland provide the source, to charge Permian and younger reservoirs in the Surat Basin, and the Permian-Triassic freshwater Cooper Basin of Queensland and South Australia contain source rocks charging both the Cooper and overlying Eromanga Basin.

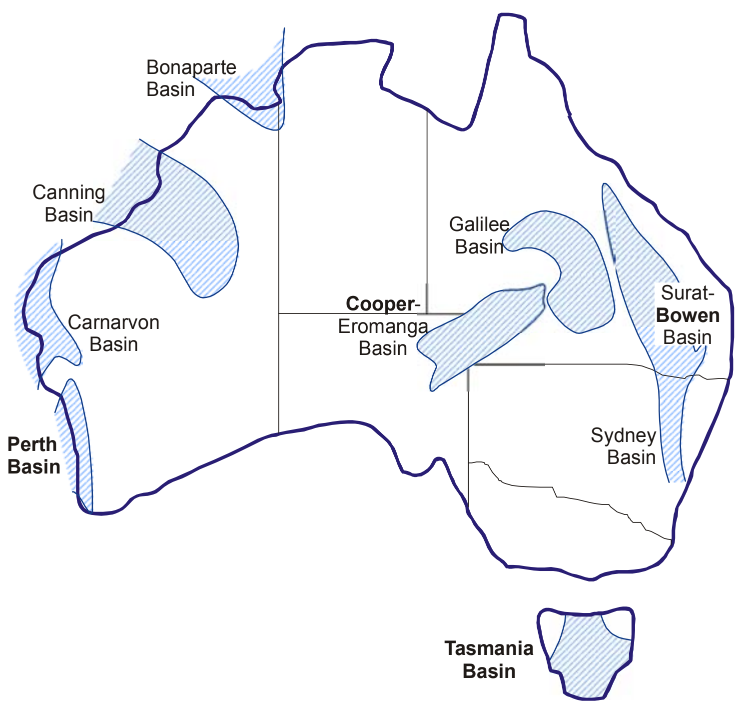


Figure 23. Australian basins containing Permian petroleum systems. Those in bold discussed in text.

Western Australia

Permian rocks are found in the Perth, Carnarvon, Canning and Bonaparte Basins petroleum systems. The Bonaparte Basin extends off-shore of north-west Australia, and has commercial fields sourced from Devonian reefs and Carboniferous deep marine sediments (TOC 0.08-1.82%), and are hosted within intraformational seals and traps (Warris, 1993). The Permian sequence in the Bonaparte Basin is as yet uncommercial, but contains both source and reservoir rocks, with large undeveloped gas fields in the Petrel Sub-basin (Edwards *et al*., 1996).

The northern Canning Basin contains a Devonian-Permian petroleum province, with source rocks in several Lower Permian marine units. Reservoir and seal rocks are also present (Warris, 1993).

Only the Perth Basin is restricted to Permian rocks, and is a commercially proven basin, with several gas fields (Warris, 1993). Early Permian coal measures provide a rich source, along with sandstone reservoirs sealed by overlying marine shales.

Cooper Basin

The Cooper Basin, of Carboniferous to Late Triassic age, is a commercially productive basin for gas, and some oil. Exploration began in the 1950s with the first commercial success in the 1960s (Randal, 1982). The whole of the Permian sequence in the Cooper Basin is mature for hydrocarbon generation, with generated gas trapped mostly within the basin itself, and generated oils charging the Jurassic to Cretaceous Eromanga Basin (Lowe, 1998). Source rocks are Permian coals and carbonaceous shales, with an average TOC of 5% (Schwebel *et al*., 1980). The Toolachee and Patchawarra Coal Measures comprise narrow sandy fluvial distributory channels (Hughes *et al*., 2000), and are the principal reservoir rocks of the Cooper Basin. Sandy fluvial units within the Toolache and Patchawarra Formations are interbedded with fine-grained lacustrine flooding channels, forming intraformational seals (Hughes *et al*., 2000).

In some areas of the basin hydrocarbon maturity was reached before the onset of Eromanga Basin deposition, largely due to the older basement uranium rich granite intrusives (Schwebel, *et al*., 1980).

Bowen Basin

The Bowen Basin contains a number of commercial hydrocarbon fields, mostly gas, sourced from Permian marine and non-marine units. The first exploration wells were drilled in the 1930s giving shows only. Exploration increased in the 1950s with government incentives, and the first commercial gas fields were discovered in the 1960s (Randal, 1982). The overlying Jurassic to Cretaceous Surat Basin contains oil and gas sourced from Bowen Basin Permian units (Figure 24).

All of the Permian units of the Bowen Basin are within the hydrocarbon generation window, with most hydrocarbons generated from Permian marine and non-marine units, and overlying Permo-Triassic non-marine units (Randal, 1984). There are six regional source rock units within the Bowen Basin (Shaw *et al*., 1999), covering the majority of the stratigraphy of the Permian sequence. The marine Back-Creek Group has been identified as the source for the currently producing Permian Cabawin well, and the Blackwater Shale (Black-Alley Shale?) is related to oils in Triassic and Jurassic reservoirs (Philp & Gilbert, 1986).

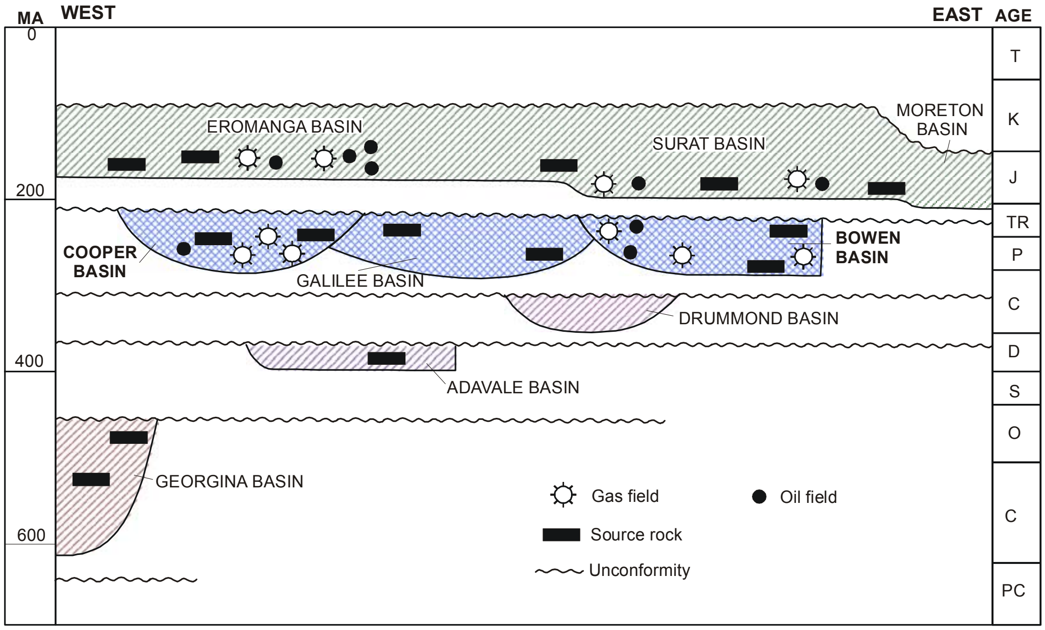


Figure 24. Schematic cross-section through central Australia and Queensland showing the stratigraphic distribution of the petroleum basins of this region. From Randal (1984).

Potential source evaluation by Shaw *et al*., (1999) recognise the latest Permian Baralaba Coal Measures as contributing two-thirds of the source potential of oil in the Bowen-Surat Basin. The Baralaba Coal Measures and the mid Permian Buffel to Banana marine and non-marine formations may potentially contribute over two-thirds of the gas source within the Bowen-Surat Basin (Shaw *et al*., 1999).

Exploration is continuing throughout all of the above mentioned Permo-Carboniferous basins and as recently as May 2002 Mosaic Oil announced the discovery of light oil in the "Downlands-3" well in the Bowen-Surat Basin. Downlands-3 is within Permian sandstones, with an earlier find, Spring Grove, nearby ("Australian", 28th May 2002).

The Tasmania Basin – Gondwanan Petroleum System (Dr Catherine Reid)

Basin Development Late Carboniferous to Triassic

The Parmeener Supergroup (Banks, 1973) contains both marine and terrestrial rocks from the Tasmania Basin, ranging in age from Late Carboniferous to Late Triassic. The supergroup is divided (Forsyth *et al*., 1974) into the Lower Parmeener, of mostly marine Late Carboniferous to Permian rocks, and the Upper Parmeener of terrestrial origin and Late Permian to Triassic age. The Lower and Upper Parmeener Supergroups are lithostratigraphic units and their boundary does not correlate to the Permian and Triassic biostratigraphic boundary, which is in the lower part of the Upper Parmeener Supergroup.

Mapping and drilling programs by the Geological Survey of Tasmania and private companies have revealed many of the details of the Lower Parmeener Supergroup.

The Lower Parmeener Supergroup

The Parmeener Supergroup lies with pronounced unconformity on older folded and metamorphosed sedimentary and igneous rocks. The Late Carboniferous Tasmania Basin was a broadly north-south trending basin with pronounced highs in the northeast, northwest and southwest. During the mid-Carboniferous much of Gondwanaland was under widespread glaciation (Crowell & Frakes, 1975), and many Late Palaeozoic deposits reflect this glacial influence. Continental ice was developed in the Tasmanian region, with fjord glaciers and ice sheets reaching sea-level that left glacigenic deposits of mostly glaciomarine origin (Hand, 1993) as the ice sheet retreated. The lowermost Parmeener rocks (Figure 25A) are debris flow diamictites, dropstone diamictites, glacial outwash conglomerates and sandstones, pebbly mudstones and rhythmites (Clarke, 1989; Hand, 1993). Glacial retreat combined with a marine transgression and thick sequences of marine pebbly siltstones and mudstones were deposited (Woody Island Siltstone/Quamby Formation; Figure 25B), with a high organic content, in coldwater environments (Domack *et al.*, 1993). The alga *Tasmanites* is common in these siltstones, and in the lower part is concentrated to form the Tasmanite Oil Shale. The oil shale is known in the northwest to northeast, with dispersed *Tasmanites* elsewhere. It is not known if the oil shale exists through the central Highlands, and conglomerates occur in the DuCane region and were encountered in the Hunterston DDH. However, it is likely that it does extend through some of this area. The oil shale has high TOC levels, and in many areas is a mature or partially mature source rock for hydrocarbons. The remaining thick siltstones have dispersed *Tasmanites* and lower TOC, but their great thickness (100-250m) increases their source potential, and they are the dominant source rock for hydrocarbons in the Tasmania Basin. The Woody Island Siltstone is thickest in the middle of the Tasmania Basin.

Marine conditions continued with the deposition of fossiliferous siltstones and minor sandstones (Figure 25C) as the Tasmania Basin was gradually filled (Banks, 1989; Clarke, 1989). In the Western Tiers region, a quiet water organic siltstone was deposited (Macrae Mudstone) and, although of limited vertical and lateral extent, is of suitable quality to have contributed hydrocarbons to the basin.
Filling of the Tasmania Basin resulted in a relative regression of the shoreline southward and deposition of freshwater sandstones and carbonaceous siltstones (Figure 25D). Prominent coal beds were developed in northern parts of the basin, with sandier coastal deposits in central and southern areas. In the far south marine conditions persisted, with deposition of marine siltstones. In the Western Tiers and Midlands regions the sandstones

are medium to coarse grained and well sorted. Porosity values vary up to 27% (Maynard, 1996), average porosity through the central basin is approximately 10%.

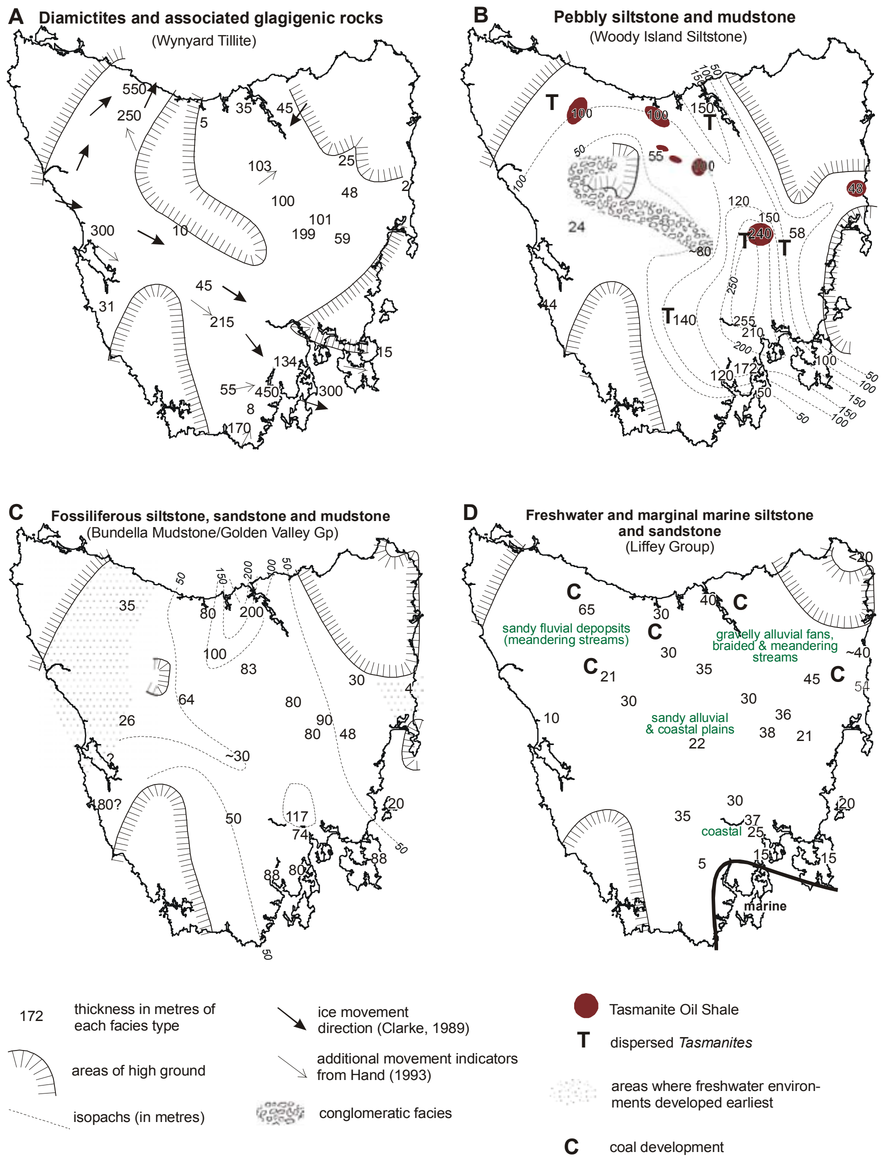


Figure 25. Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – diamictites (Wynyard Tillite); B – pebbly siltstone (Woody Island Siltstone); C – fossiliferous siltstone (Bundella Mudstone; D – Freshwater sandstone and siltstone (Liffey Group).

Following this widespread freshwater deposition in the Early Permian, a marine transgression saw deposition of marginal marine then shallow shelf marine fossiliferous siltstone, limestone and minor sandstone (Clarke, 1989; Figure 26A). Thick limestone was developed in the Hobart region. The development of these fossiliferous beds was diachronous across the Tasmania Basin, with an apparent depositional hiatus before gradually younger deposition north and northeastward. Faunas in these units are rich with abundant molluscs, brachiopods, bryozoans and crinoids. Dropstones are present but are not abundant, indicating the presence of minor rafted ice in a cold-water carbonate environment (Clarke, 1989). Clay horizons indicate volcanic activity at this time, however discrete horizons have not been traced between outcrops. The calcareous units were overstepped from the south by fossiliferous siltstone and sandstone (Farmer, 1985; Figure 26B). In the southern, and deeper, part of the basin turbidites are seen where at the same time in northern shallower environments calcareous siltstones were still being deposited. The sandstone sequences are thick in the south of the basin and thin northward dramatically and become restricted in time.

Continued deposition led to an almost filled basin by the early Late Permian, leading to quiet shallow water poorly fossiliferous mudstone and siltstone deposition (Figure 26C). Throughout the basin these shallow marine, estuarine to marginal marine fine-grained deposits are thick and generally monotonous except for minor sand and conglomerate horizons that probably represent lag deposits and/or times of minor tectonic instability (Clarke, 1989). These mudstones are thick and well developed and form the most obvious regional hydrocarbon seal in the Tasmania Basin.

The overall stratigraphy and general basin development are shown in Figures 27 and 28. Potential source reservoir and seal rocks are highlighted. These rocks will be discussed in detail later.

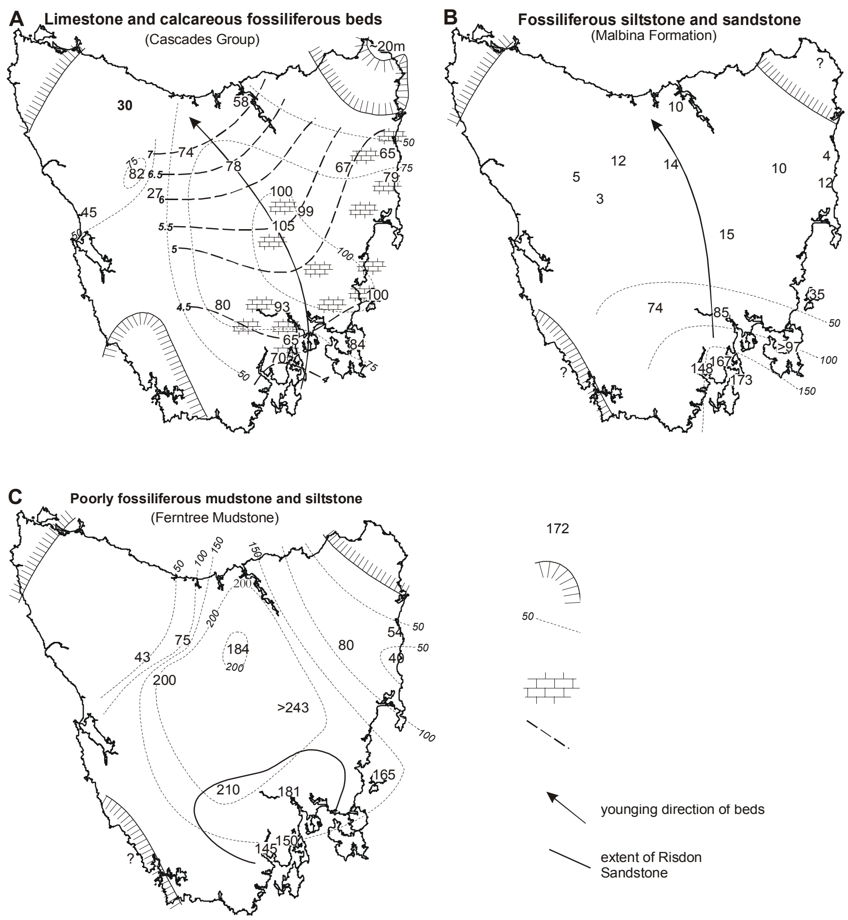


Figure 26. Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – calcareous fossiliferous beds (Cascades Group); B – fossiliferous siltstone and sandstone (Malbina Fm and correlates); C – siltstone and mudstone (Ferntree Mudstone).

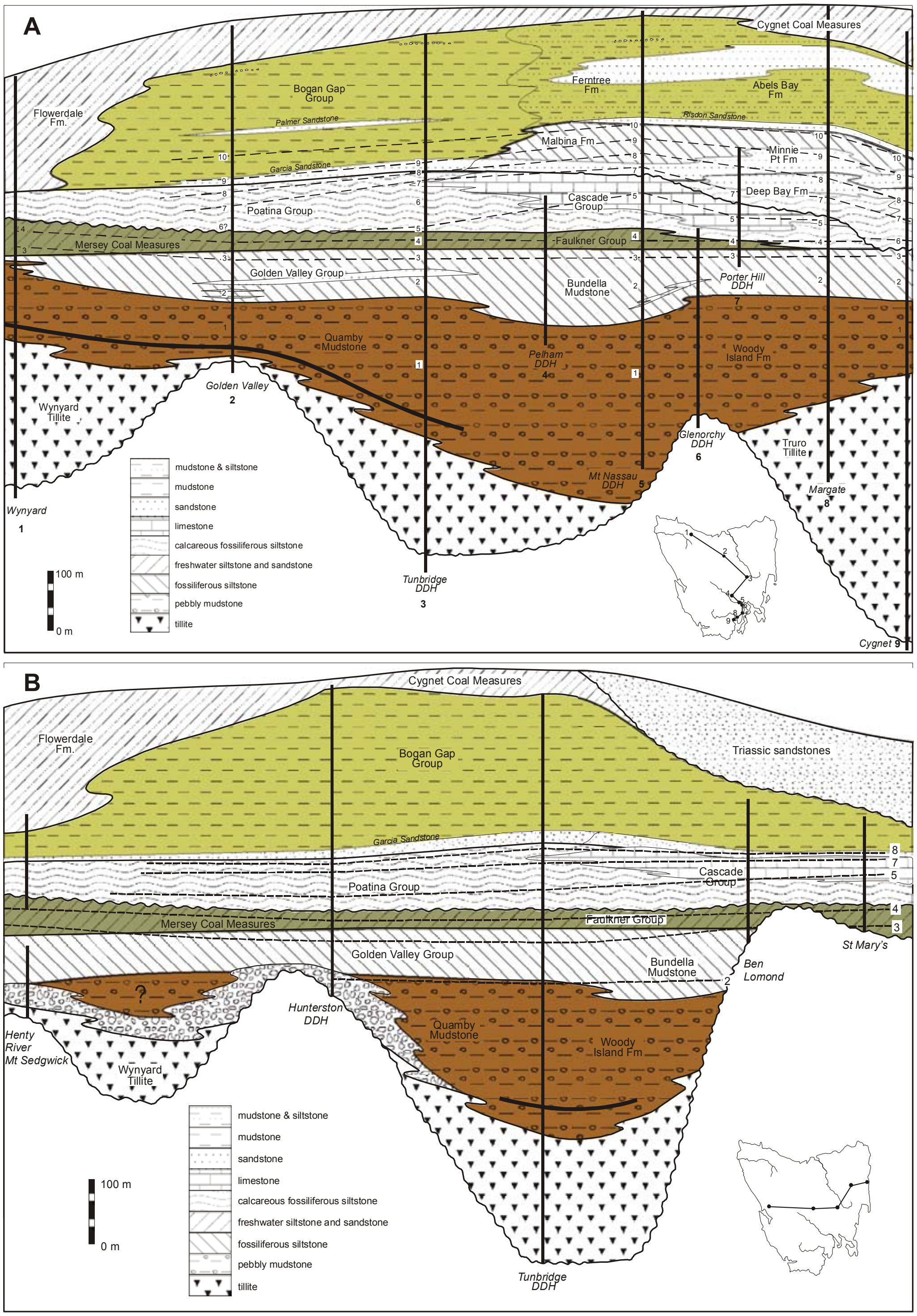


Figure 27. Stratigraphic development of the Lower Parmeener Supergroup. A Section line from Wynyard to south of Hobart, B, Henty to St Marys. Potential source, reservoir and seal rocks are indicated.

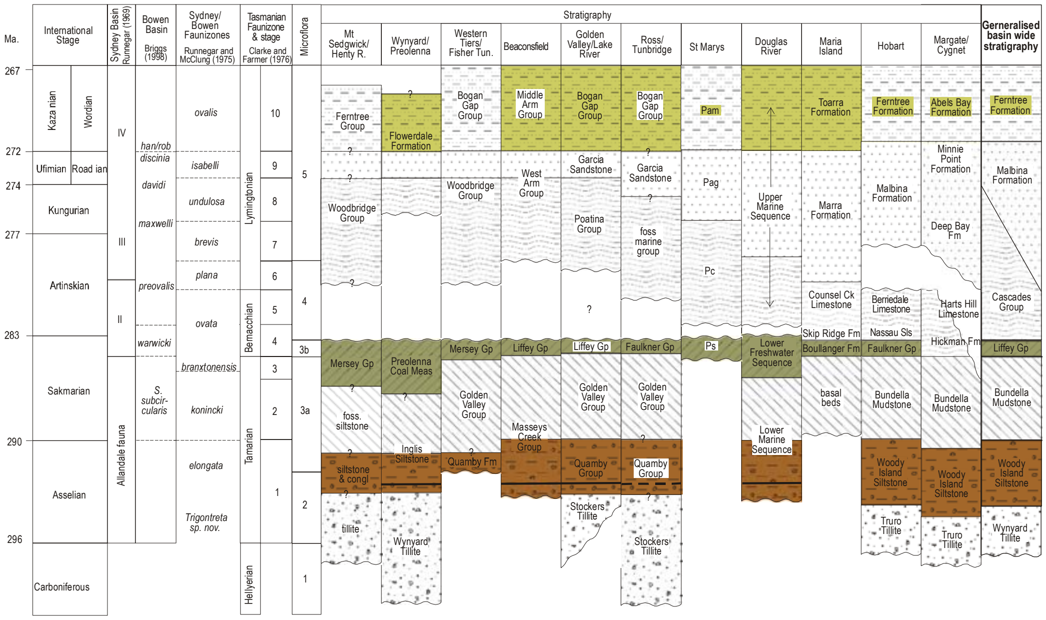


Figure 28. Biostratigraphic correlation of the Lower Parmeener Supergroup.

Upper Parmeener Supergroup

The marginal marine beds of the uppermost Lower Parmeener Supergroup were progressively overlain by the carbonaceous sandstone and lutite of the basal Upper Parmeener Supergroup (Figure 29A). Beds included in the Cygnet Coal Measures and equivalents, include the carbonaceous beds between the underlying marine Lower Parmeener Supergroup and the overlying generally non-carbonaceous quartzose massive bedded sandstones (Forsyth, 1989). The beds are carbonaceous with inter-bedded well sorted cross-bedded or ripple laminated sandstone and lutite. In southern Tasmania feldspathic sandstone is fine to medium grained, and sandstones and mudstones pass laterally into sandstones with thin coal seams (Cygnet Coal Measures) with a Permian flora (Farmer, 1985). Coal seams are also present on Bruny Island (Adventure Bay Coal Measures). Across the Western Tiers these units are cross-bedded quartz and carbonaceous feldspathic sandstone interbedded with dark grey carbonaceous shale (Pike, 1973). In the north micaceous and carbonaceous fine to medium grained quartz sandstone occurs and contains leaf and plant stem remains (Gee & Legge, 1974). The Permian Triassic boundary is generally taken as coincident with the boundary between the carbonaceous beds and overlying non-carbonaceous quartzose beds.

An abrupt depositional change is apparent with the development of well-sorted glistening quartz sandstone and feldspathic quartz sandstone with lutite (Ross, Knocklofty and part Cluan Formation, Forsyth, 1989; Figure 29B). Regionally this sequence is divided into a lower generally sandstone dominated sequence, and an upper, thinner interval of dominantly lutite. Regionally the quartz sandstone interval is in the order of 200-300 m thick, and sandstone dominated beds are up to 230m thick through the central axis of the basin (Forsyth, 1989).

Sandstone beds exist as cycles or eroded cycles grading from medium to coarse sandstone to finer rocks upwards. Lutites occur throughout as finer beds in the cycles, as isolated lenticular beds or interbedded with sandstone. The lutite dominant interval is up to 60m thick and consists of red, purple, grey carbonaceous and blue-grey to green grey lutites. The quartz sandstones reflect low sinuosity rivers with palaeocurrents predominantly southeast to east. Lutite intervals reflect abandoned channel slack water, lacustrine and over bank environments (Forsyth, 1989). Faunas are varied and microfloras indicate a Greisbachian to early Anisian, or late Early to Mid Triassic, age (Forsyth, 1989).

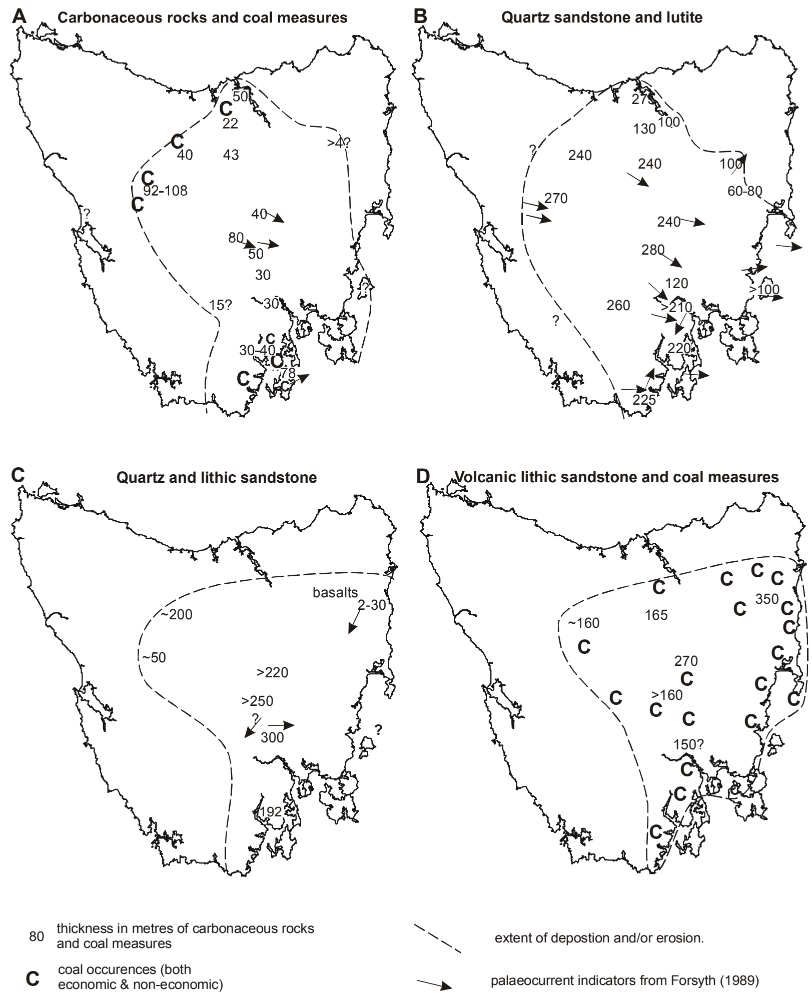


Figure 29. Palaeogeography of the Upper Parmeener Supergroup. Isopachs of facies thicknesses in metres. Based on Forsyth (1989).

Following quartz sandstone and lutite deposition there is a broad basin wide change to lithic dominated sandstone with two prominent quartz sandstone intervals (Figure 29C). The lower quartz interval is often absent, and the upper quartz sandstone is diachronous and lenticular (Forsyth, 1989). Hiatuses are common and in the northeast the upper quartz sandstone forms the base of this unit, resting on Lower Triassic sandstone, Lower Parmeener Supergroup or older rocks (Forsyth, 1989). Macro and microfloras are present throughout the quartz and lithic sandstone sequence and have an overall Anisian to Ladinian (Middle Triassic) age. Basalts in the upper sandstone interval have yielded a 233 ±5 Ma potassium-argon radiometric age (Calver & Castleden, 1981).

The uppermost sequence in the Upper Parmeener Supergroup consists of predominantly volcanic lithic sandstone and lutite, with coal seams of economic grade, and rare tuff and conglomerate beds (Figure 29D). The sequence is about 270m thick in the Midlands (Forsyth, 1984), and up to 350m in the St Marys region where it is mined for coal. In the northeast, eight coal seams (named seam A to H from top to bottom) are recognised over 220m of vertical stratigraphy. The coals are generally dull, with a few lustrous bands, and are interbedded with carbonaceous mudstone (Calver in Turner & Calver, 1987). The depositional environment of the volcanic lithic sandstone cycles is one of channel deposits in high sinuosity rivers, with finer grained beds as channel fills and coal developed from peat swamps that were at times eroded by the reappearance of major channels (Forsyth, 1989). Microfloras correlate with the *Craterisporites rotundus* and *Minutosaccus crenulatus* zones (Forsyth, 1989) (late Carnian to late Norian, or Late Triassic). Biotite from a tuff in the upper part of the volcanic lithic sequence in Denison Rivulet (Calver in Turner & Calver, 1987) has been dated at 214 ± 1 Ma (Bacon & Green, 1981).

Within the Upper Parmeener Supergroup high TOC levels will be associated with the coals and carbonaceous beds making them an obvious hydrocarbon source, however analyses are not available at this stage. However burial depths may be insufficient for source maturity. Repeated sandstones within the sequence may be suitable as reservoir rocks, with lutites forming seals, however porosity and permeability data is absent, and again burial depths are unlikely to be produce sufficient confining pressures. For these reasons research efforts are concentrated on the deeper buried Lower Parmeener Supergroup.

Maturity and source potential of the Lower Parmeener Supergroup

The Tasmania Basin Gondwana petroleum system has potential source, reservoir and seal rocks contained within the Lower Parmeener Supergroup. The freshwater Upper Parmeener Supergroup, also has potential for source, reservoir and seal rocks to be contained within it. However work to date has concentrated on the mostly marine Lower Parmeener Supergroup.

In the Lower Parmeener Supergroup, potential source rocks are contained within the Woody Island Siltstone, which includes the Tasmanite Oil Shale, and within the freshwater Liffey Group and correlates. Potential reservoir rocks are found within the freshwater Liffey Group rocks, with local seals immediately above in the marine shales. A potential regional seal exists with the Ferntree Mudstone and correlates. Overburden sufficient for hydrocarbon generation was achieved by the late Early Cretaceous, and the intrusion of igneous dykes and sills (dolerite) in the Jurassic may also have provided a thermal maturity source. The intrusion of the dolerite, creating localised sill and dyke swarms, along with clay alteration of calcareous marine rocks, is a possible candidate for trap formation. Folding and faulting in the Cretaceous should have created structural traps suitable for hydrocarbon accumulation.

The basin maturity and source, reservoir and seal rocks are considered below, with a summary of basin stratigraphy and events shown in Figure 30.

Basin Maturity

Rock eval pyrolysis of Woody Island Siltstone, Tasmanite Oil Shale and Lower Freshwater rocks has revealed source potential for all of these units (Figure 31A). Source rock maturity data indicates the basin is generally immature in the north, but mature through the main body of the basin as indicated in Figure 31B.

Data indicators include T_{max}, Hydrogen Index (HI) and Production Index (PI) and inferred vitrinite reflectance (Figure 32). The temperature range for generation of hydrocarbons is 430 – 465^{o}C (Hunt, 1996). T_{max} may vary with the type of organic matter, in immature samples, and some of the data points just inside the maturity window of Figure 32 may be affected by this. The HI value determined during pyrolysis is also an indicator of kerogen types. The data indicate mostly types II and III kerogen (oil and gas prone) with the Tasmanite samples type I (oil prone) (Hunt, 1996). The inferred vitrinite reflectance data in Figure 32, for the most part indicate maturity. A limited number of samples have had vitrinite directly measured, and are included on Figure 31B. At Tunbridge, the $R_v$max of 1.74 has been affected by contact metamorphism, and had a likely pre-contact reflectance of about 0.6-0.7% (Cook, 2002). The measured mean $R_v$max values at Hunterston range between 1.06 and 1.28%, and although they are within 65-85m of a 650m thick multiple dolerite intrusion, they are probably little elevated beyond regional non-dolerite values (Cook, 2003). In general terms the basin maturity increases in a south and southwesterly direction across the basin, with highest measured maturity (not known to be affected by dolerite intrusion) in the Styx Valley. The end of oil generation is around R_0 = 1.3%, however, wet gas (condensate) may be generated up to 2% and dry gas up to 3.5%.

In the Golden Valley, Styx, Wynyard and Interlaken regions, T_{max} versus HI plots for the Woody Island Siltstone indicate maturity, falling within the vitrinite reflectance range of 0.5 to 1.35%. Samples from Douglas River have low vitrinite reflectance and are immature to mature. At Wynyard, the Tasmanite Oil Shale is generally immature according to T_{max} versus HI estimates of vitrinite reflectance, in conflict with the result for the Woody Island Siltstone. The data for this area has been supplied from external sources, and stratigraphic positions are not available. Further sampling should help solve this problem. However, the high HI values indicate a good quality oil prone source rock. At Douglas River source rocks are indicated as variably mature to immature.

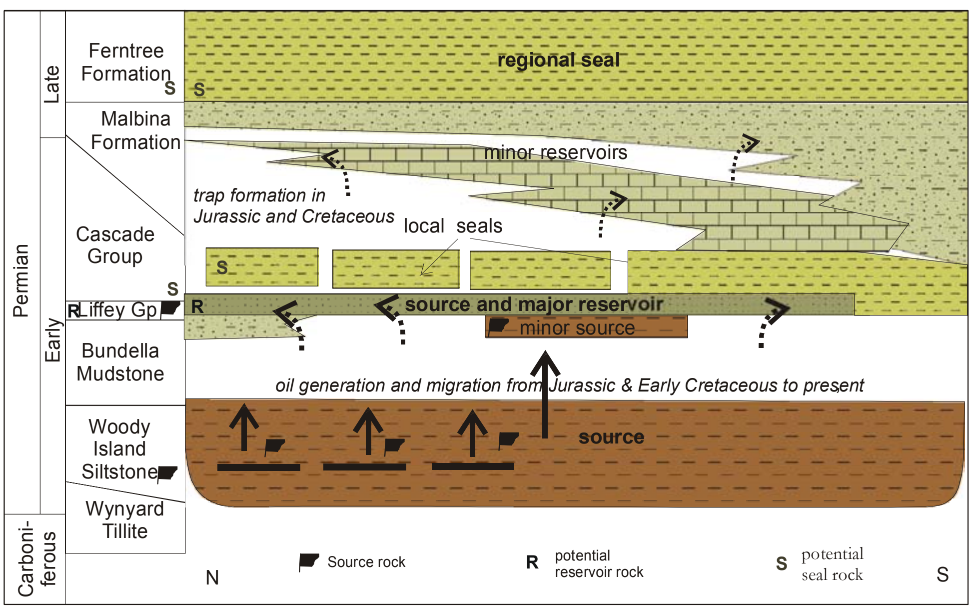


Figure 30. Potential development of the Gondwanan petroleum system in the Tasmania Basin.

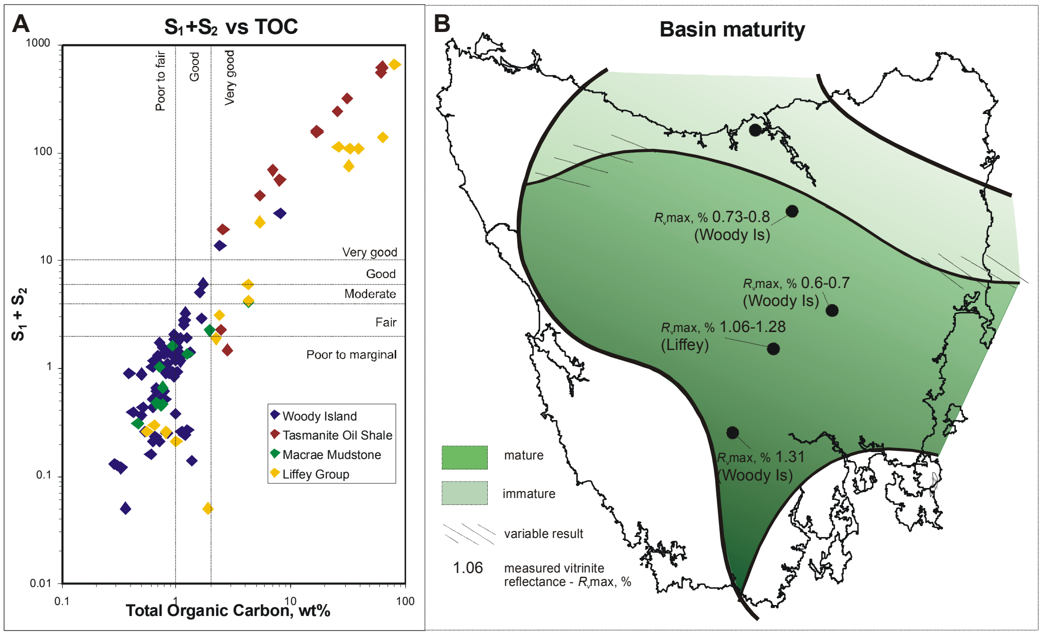


Figure 31. A, Quality of potential source rocks in the Tasmania Basin. Data from Bacon *et al*. (2000) and new rock-eval analyses. B, Source rock maturity of the Gondwanan system, Tasmania Basin. Maturity determined from T_{max}, Hydrogen Index, Production Index, and inferred and measured vitrinite reflectance.

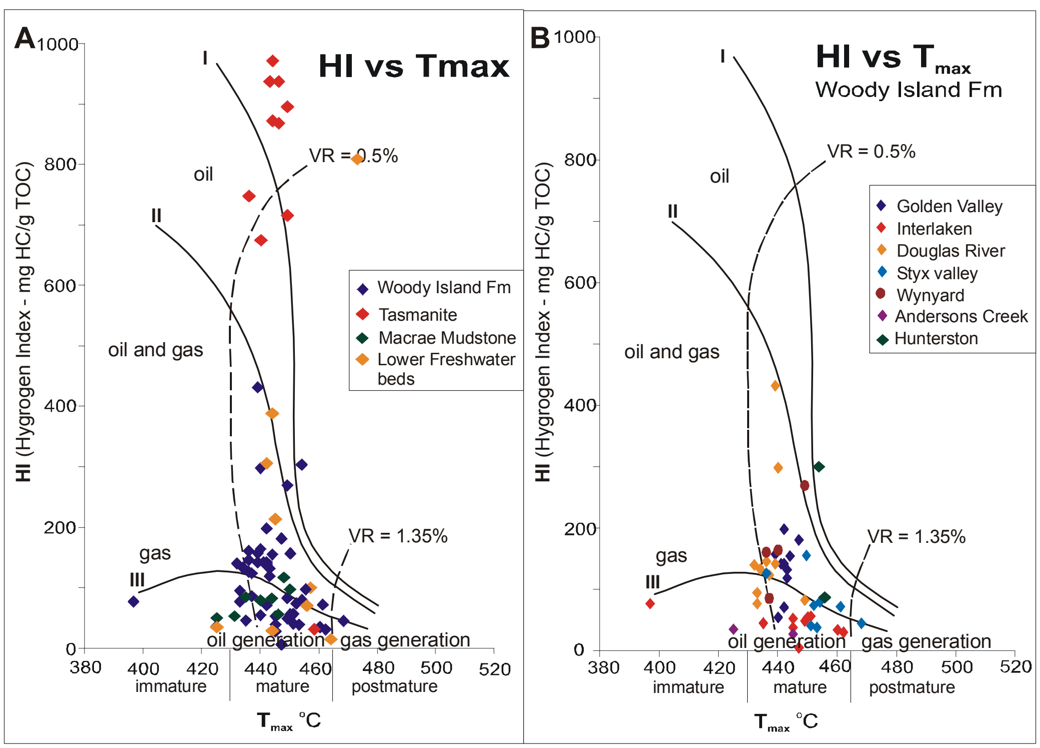


Figure 32. HI vs T_{max} plots for source rocks in the Lower Parmeener Supergroup. A – HI vs T_{max} for all potential source rocks in the Lower Parmeener Supergroup. B – HI vs T_{max} for the Woody Island Formation, divided into geographic regions.

Potential Source Rocks

The Tasmanite Oil Shale has TOC between 2.58 and 63%, and very high S_2 (hydrocarbons generated during pyrolysis) values. Source Potential Index (Demaison and

Huizinga, 1991) calculations for immature Tasmanite Oil Shale indicate up to 0.6 metric tons, or 3.78 barrels, of hydrocarbons per square metre of oil shale (Figure 33A), may be generated. The known extent of the oil shale is limited, however a significant volume of hydrocarbons may be generated from this horizon.

In comparison TOC and S_2 values for the Woody Island Siltstone are much lower. However the great thickness of this unit makes it an attractive prospect for hydrocarbons. Rock eval and SPI calculations on immature samples indicate an average potential generation of 0.96 metric tons (6.05 barrels/1228.8m^3 gas), of hydrocarbons per square metre (Figure 33B). TOC, S_1 and S_2 values from immature samples in the Wynyard region are better than elsewhere, however, samples are of isolated outcrop and thicknesses are not known. Rock eval and SPI calculations on mature or partially mature Woody Island Siltstone are much lower, with an average 0.307 metric tons (1.935 barrels/392.96m^3 gas), of hydrocarbons per square metre. As the SPI of immature source rocks represents all that may be generated, it may be considered that the SPI of the partially mature or mature rocks represents what has not yet been generated. Therefore the difference between the SPI of immature and mature rocks represents hydrocarbons potentially generated. In this case the Woody Island Siltstone may have already generated 0.653 metric tons (4.114 barrels/835.84m^3 gas) of hydrocarbons per square metre. At this volume it is calculated that the mature area of the Tasmania Basin may have generated 1.79x10^{10} metric tons (1.13 x10^{11} barrels/2.29x10^{13}m^3 gas) of hydrocarbons.

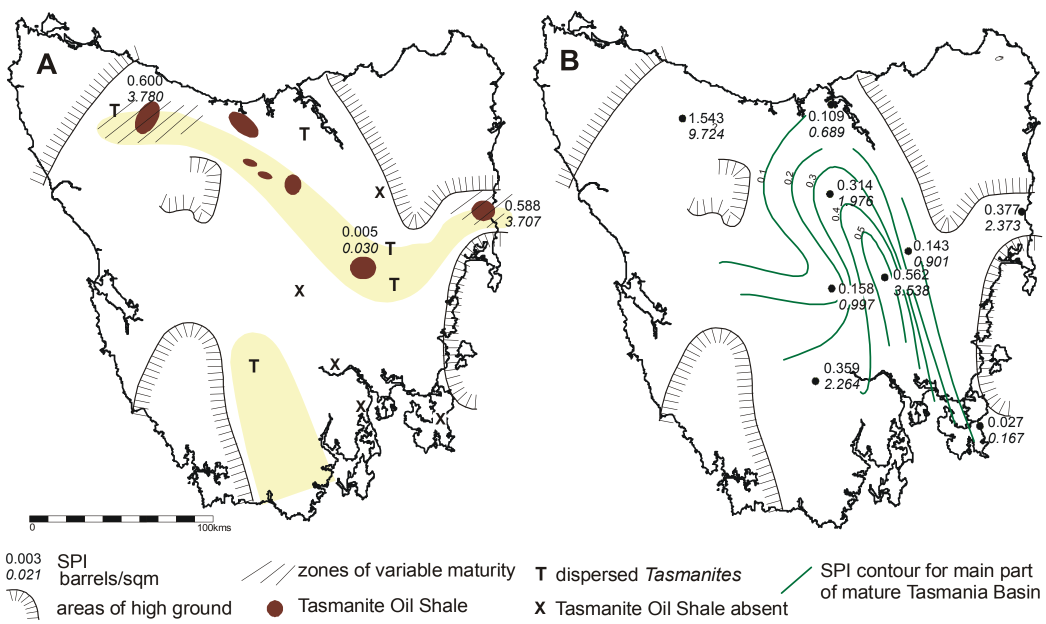


Figure 33. A, Source Potential Index (SPI) data for the Tasmanite Oil Shale outcrops within the Tasmania Basin. Data available only for Wynyard, Douglas River and Tunbridge Tier DDH. B, Source Potential Index (SPI) data for the Woody Island Formation within the Tasmania Basin.

In the Golden Valley area organic mudstones are well developed in the upper part of the fossiliferous Bundella Mudstone (or Golden Valley Group). These beds are restricted in area, although the Hunterston, Tunbridge and Ross DDHs all show an extended marginal marine facies at the top of the Bundella Mudstone, immediately beneath the freshwater Liffey Group. Although of limited areal extent rock eval analysis indicate up to 0.03 metric tons (0.189 barrels/38.4m^3 gas) of hydrocarbons may be generated per square metre of this unit.

The freshwater sandstones and siltstones within the Lower Parmeener Supergroup are also a viable source rock, as well as being the potential reservoir rock. Carbonaceous layers and coal horizons have high TOC, and SPI results indicate a basin wide average of 0.155 metric tons (1.136 barrels/198.4m^3 gas) per square metre. A pelionite sample from Mt Pelion in the north-west, has source quality parameters equalling that of the Tasmanite Oil Shale, however exposures of this horizon are poor, and the region has not yet been drilled. Vitrinite reflectance estimates indicate maturity of this unit, however more data is required through the central areas of the Tasmania Basin to better determine the overall hydrocarbon potential of this unit.

SPI calculations give the amount of hydrocarbons that can be produced by volume if the entire volume of rock reaches maturity. Although most of the main body of the Tasmania Basin has reached hydrocarbon maturity, vitrinite reflectance estimates are low, indicating the early stages of maturity. Therefore fewer hydrocarbons will have been generated than if full maturity had been reached. However, the potential volume of hydrocarbons is so large, that even if only a proportion have been expelled from the source rock, the Tasmania Basin could still have produced a significant quantity of hydrocarbons.

Styx River

Outcrops of Woody Island Siltstone in the Styx River Valley are known to have a petroliferous odour on freshly broken surfaces. BHP Ltd held a license for the area in 1981 and 1982, to investigate outcrops in the Waterfall Valley region. Two drill holes were completed, however the Tasmanite Oil Shale was not encountered, and BHP ceased exploration.

The Woody Island Siltstone in the Styx River region, while not containing the oil shale itself, has abundant dispersed *Tasmanites* in its lower part. New forestry roads and quarries, some 7-8km to the northwest of the BHP drill sites, have shown the petroliferous odour was not an isolated occurrence. Exposures in a new forestry road (north off Muellers Rd), show the stratigraphy from the basal tillite, upwards for approximately 50m of the Woody Island Siltstone. In its lower 30m the Woody Island rocks exhibit a petroliferous odour when fresh surfaces are exposed. A quarry near the junction of Muellers and Styx Rd has Woody Island Siltstone with a very strong petroliferous odour.

However, 150m away, the odour is absent in weathered rocks that have been exposed for some time. The upper parts of the road section do not show any odour, however rock exposure is not far beneath the soil profile. This rapid loss of this petroliferous odour suggests that it may be a more common phenomenon, but is not being recognised in weathered exposures.

It is apparent, however, that hydrocarbons have been generated in this south-western area, where a thick accumulation of Woody Island Siltstone occurs. Within close geographical proximity is Lonnavale, where oil seeps from a dolerite quarry are derived from a source rich in *Tasmanites* (Revill, 1996; Wythe and Watson, 1996).

Expulsion ability

From rock-eval pyrolysis S_1 represents the free hydrocarbons already present in the sample, and S_2 represents the hydrocarbons generated during pyrolysis. Free hydrocarbons are those already produced from organic material and will be proportional to the Total Organic Carbon (TOC) of any given source rock. As a general guide the Ocean Drilling Program (ODP) uses S_1/TOC of 1.5, to determine the presence of indigenous vs migrated or non-indigenous hydrocarbon levels (Hunt, 1994). While this in itself is not significant, the Tasmania Basin data (Figure 34A) shows that all source rocks contain an expected level of S_1 hydrocarbons for their given TOC.

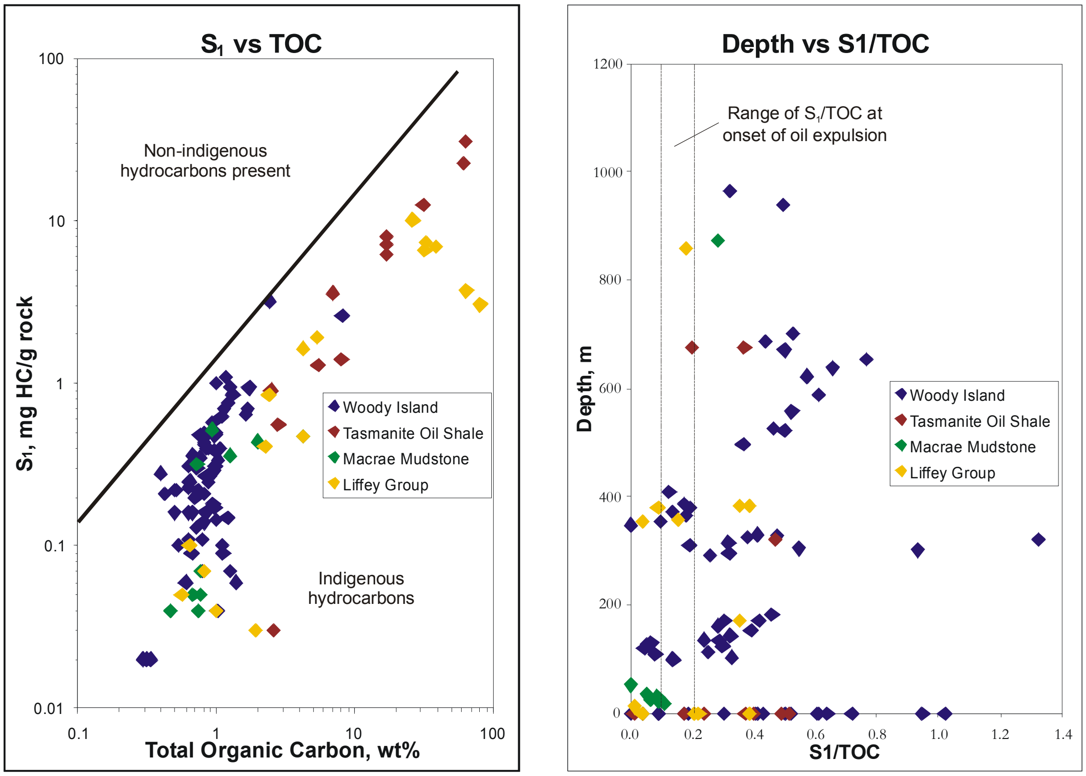
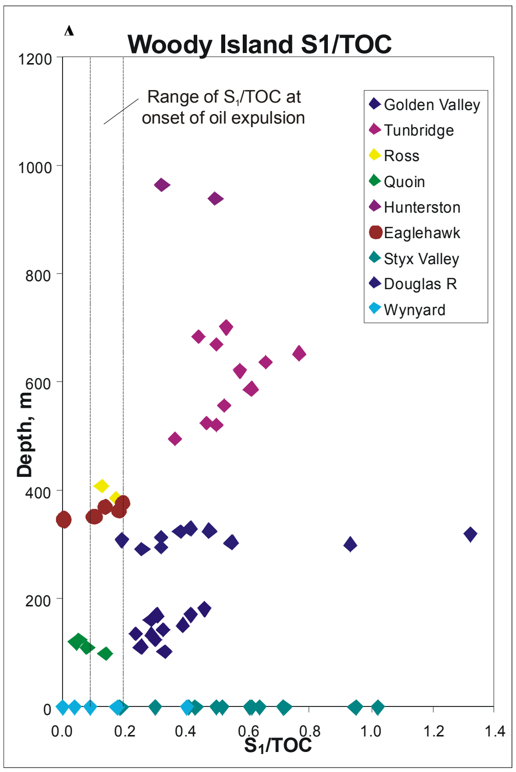


Figure 34. Geochemical parameters and expulsion indicators of Tasmania Basin source rocks. A, S1 vs Total Organic Carbon (TOC), after ODP guidelines as an indicator of indigenous and non-indigenous hydrocarbons. B, S1 vs TOC ratio as an indicator of oil expulsion.

Perhaps problematic is the fact that the Liffey Group, both source and reservoir, is not showing migrated hydrocarbon levels, however potential reservoir facies have not undergone pyrolysis and all data is from fine-grained non-porous source facies.

Smith (1994) determined, from Shell Oil's data base, that S_1/TOC had to reach 0.1-0.2 for oil expulsion to start. In other words hydrocarbons may be generated but S_1 steadily increases before being expelled. In an ideal situation S_1/TOC increases as thermal maturity increases, and after expulsion remains constant and then gradually decreases with increasing depth and maturity. Figure 34B shows S_1/TOC vs depth for Tasmania Basin source rocks, where majority of samples are well above the oil expulsion window of 0.1 to 0.2. This is particularly evident for the Woody Island Formation, that whilst not a rich source, its bulk provides the majority of the calculated potential hydrocarbons for the Tasmania Basin. This suggests that the Woody Island Fm is acting as an effective seal as well as source, and that hydrocarbons cannot be released without fracturing or faulting. The Woody Island Fm as a unit is characteristically massive without fracturing where not associated with faulting, and therefore much of its oil potential is lost to the Tasmania Basin.

Closer consideration of the Woody Island Formation (Figure 35A) shows the Tunbridge and Hunterston data have good maturity indicators and are well outside the zone of start of oil expulsion. The Wynyard data is largely undermature, and the Bicheno data has variable indicators, and has a spread of S_1/TOC. The Styx Valley material is all mature, however plots on the baseline as samples were from outcrop not drill holes. Sample S3 from the Styx Valley, which has a strong petroliferous odour when fresh surfaces are cracked has the highest S_1/TOC ratio. This indicates that while hydrocarbons may be being generated they are not yet being expelled, hence the petroliferous odour on sampling. If the right margin of the data is assumed to indicate a rise then fall in S_1/TOC with depth, then it may be considered that the Woody Island Formation is beginning to expel oil. However this is not clear, and the only contained set of data to possibly show this trend is the Tunbridge Tier DDH samples. However, as S_1/TOC is much higher than the range of 0.1-0.2 given by Smith (1994) it would suggest that the Woody Island Formation is not freely releasing hydrocarbons.



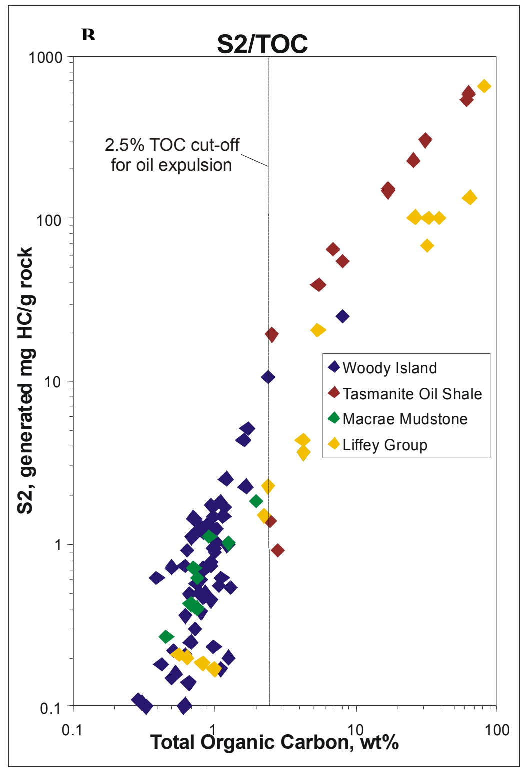


Figure 35. Geochemical parameters and expulsion indicators of Tasmania Basin source rocks. A, S1 vs TOC ratio as an indicator of oil expulsion for the Woody Island Siltstone. B, Percentage TOC for Tasmania Basin potential source rocks.

Lewan (1987) determined from petrographic observations that rocks having less than 2.5% TOC may not be capable of forming a continuous bitumen network for primary oil explusion. During increasing thermal stress a continuous bitumen network forms, that forms oil as temperatures increase. The decrease in density of the bitumen and oil vs the original kerogen ultimately results in expulsion of oil (Hunt, 1994). All but one of the Woody Island Formation samples have TOC wt % below 2.5%, most below 1.5% (Figure 35B). In consideration of gas generation and expulsion potential Figure 32 shows much of the Woody Island siltstone is mature for oil generation, with the peak gas generation window not reached. Therefore while the fine grained/low TOC nature of the Woody Island Siltstone may not inhibit gas expulsion, optimum conditions for gas generation have not yet been reached, although the maturity of the sediments may mean that a portion of their gas potential may have been realised. The same applies to the marine Macrae Mudstone.

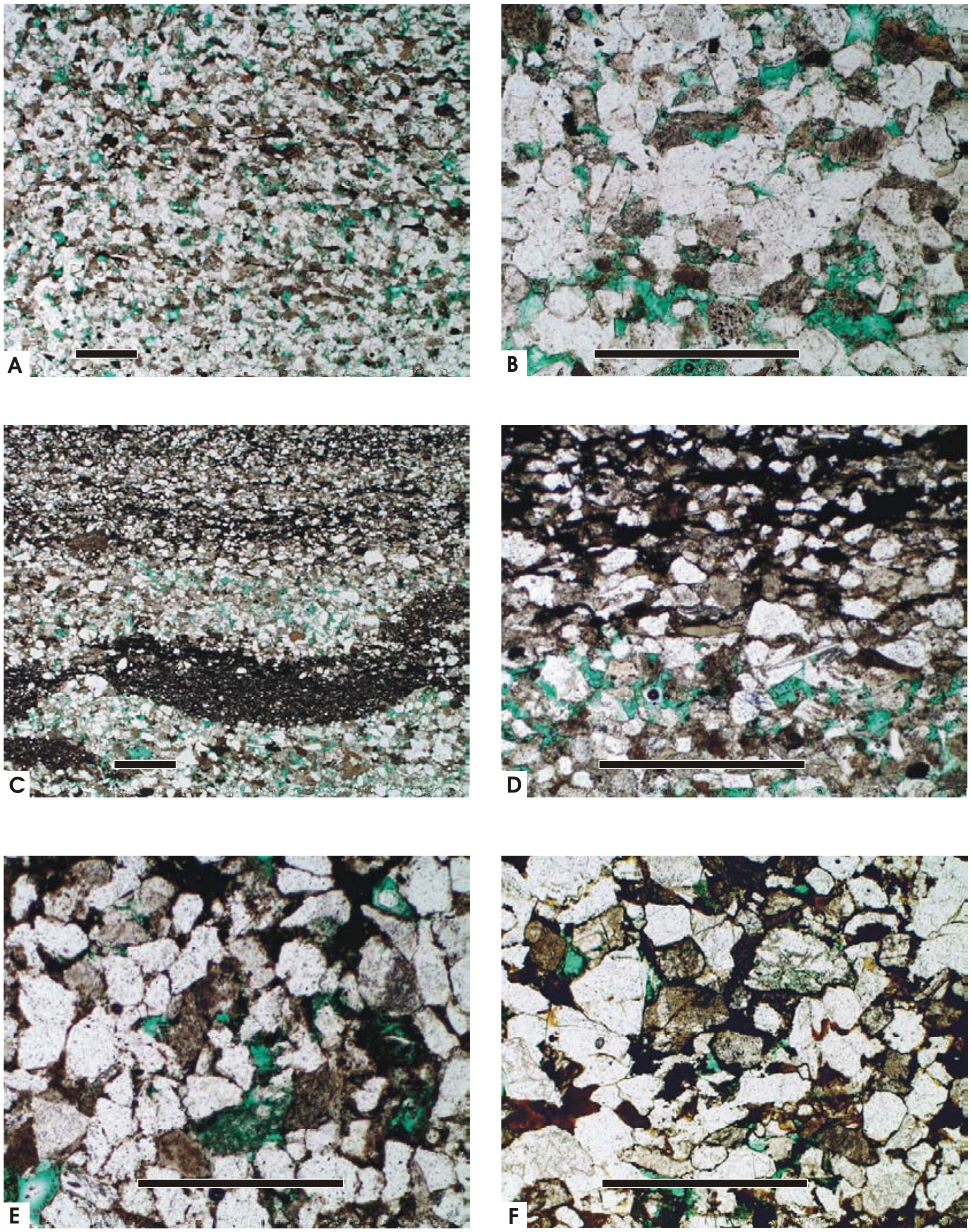


Figure 36. Thin section porosity of potential reservoir rocks in the Lower Parmeener Supergroup. All scale bars 1mm. A-B – Ross DDH, 156.6m, Liffey Group sandstone, green material dyed araldite revealing pore space of 14.9% (Helium Injection). C-D – Granton DDH, 160.7m, Faulkner Group sandstone, C, showing pore space of 7.6% in non-carbonaceous sand, D, exclusion of pore space (0%) by fine-grained carbonaceous material. E – Ross DDH, 149.5m, Liffey Group bioturbated sandstone, showing angular to sub-rounded grains in carbonaceous matrix, with a point count porosity of 9.2%. F – UTGD 132503, Glencoe DDH, 6.22m, Liffey Group sandstone, showing authigenic clay matrix, point count porosity 6.2%.

The only sample with a suitable TOC (Hunterston DDH, TOC 8.1%) is not typical Woody Island facies and is of probable terrestrial rather than marine origin. Both the Liffey Group and Tasmanite Oil Shale have suitable TOC's for oil expulsion to occur by primary migration, however, as the Tasmanite Oil Shale is within the Woody Island Siltstone it will require local faulting for hydrocarbon migration.

If the Woody Island Formation is not able to contribute hydrocarbons, or at least few, then the total calculated hydrocarbon potential for the Tasmania Basin falls significantly, and exploration needs to target the Tasmanite Oil Shale and the Liffey Group carbonaceous beds as source rocks. Suitable areas for this are the Golden Valley/Longford Basin region where both the Tasmanite and Liffey beds occur along with suitable reservoir rocks, and the Maydena/Styx Valley region, where maturity indicators and source rocks are suitable. The Lonnavale seep is within this region and is confirmation of oil expulsion from *Tasmanites* bearing rocks.

Reservoir rocks

Freshwater sandstones

As a potential reservoir the freshwater sandstones of the Liffey Group and correlates are extensive, although with variable porosity. Through much of the central Tasmania Basin area sandstone porosities range from 4.1 to 14.9%, with an average of 9.6% (helium injection), and in Golden Valley are up to 27% (Maynard, 1996). The sandstone beds exist as laminated well-sorted fine and medium sands, with rare, coarse sand, and are generally 3 to 5m thick. The beds reflect an alluvial plane environment and sandstone beds are repeated and interbedded with carbonaceous siltstones. The carbonaceous siltstones have low porosity, as pore is filled by fine material, and locally may act as seals. Figure 38 shows the nature of the sandstones, and interbedded siltstones in thin section. Where sandstone and carbonaceous silt are interbedded, or carbonaceous material defines laminations within sandstones, overall porosity is reduced. Granton samples show moderate porosity in small scale sand lamination, but the ratio of carbonaceous silt reduces the overall porosity (and permeability).

In Figure 37 the central area of the Tasmania Basin is shown, where sandstones have suitable porosities. Through this region there is up to 25m of sandstones with porosities greater than 5% (as accumulated beds, not single beds). Average porosities in localities vary from 6.1 at Hunterston to 11% at The Quoin. In the Hobart region siltstone dominates over sandstone, that tends to be micaceous, and porosity is less than 5%. Porosity measurements in the Styx Valley region are not indicative, as all samples are from partially weathered surface outcrop.

Permeability of the reservoir rock acroos the basin is generally poor, varying from 0.4 to 8.8 mD. Only in the Ross and Quoin DDHs have permeabilities been recorded over 1mD (threshold for oil), however at all other localities, except Hunterston, permeabilities are mostly over 0.1mD (threshold for gas). The reservoir unit at Hunterston has been affected by late diagenesis associated with intrusion of dolerite.

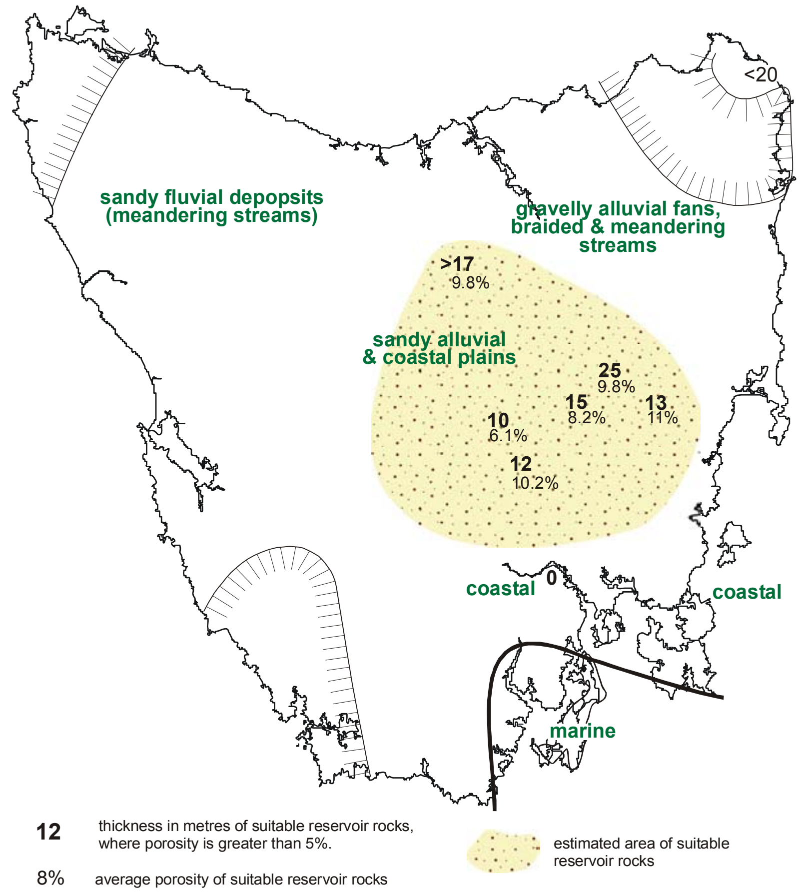


Figure 37. Porosity distribution across the central Tasmania Basin, and total thickness of beds with porosity above 5%. Porosity data from Helium Injection and thin section point count.

Reservoir diagenesis

Well sorted quartzose sandstones show an early stage silica cementation, clasts boundaries are indistinct as clay coatings have not been able to develop, and the resultant sandstone looks more like an intergrown igneous formation. Grain compaction is generally low, however, where lithic clasts are common and soft they can be seen to have been slightly distorted before silica cementation. Porosity is low where silica cementation is complete. Authigenic clay cement may be developed after silica cementation, and subsequent dissolution provides a secondary porosity.

Where reservoir rocks are associated with dolerite intrusions, as in the Hunterston DDH, the overlying limestones have contributed carbonate to the pore fluids, increasing pH, and temperature from the intrusion. Carbonate cementation is later than both silica and clay, but may destroy both (Figure 38). In many samples original quartz clasts have been eroded, and orthoclase feldspar has been pervasively replaced by calcite. In the Hunterston DDH carbonate cement is well developed, however it is the late dissolution of carbonate that produces a thin-section secondary porosity.

In summary, future exploration for suitable reservoirs needs to focus on regions where dolerite intrusion is not closely associated with potential reservoir rocks and related limestones. One such area is the Styx Valley region where outcropping dolerite is mapped (Calver & Forsyth, 2001; 2002) as intruding Upper Parmeener, and the Lower Parmeener

Supergroup is apparently free of pervasive dolerite intrusion. As discussed above, suitable mature source rocks also exist in this area.

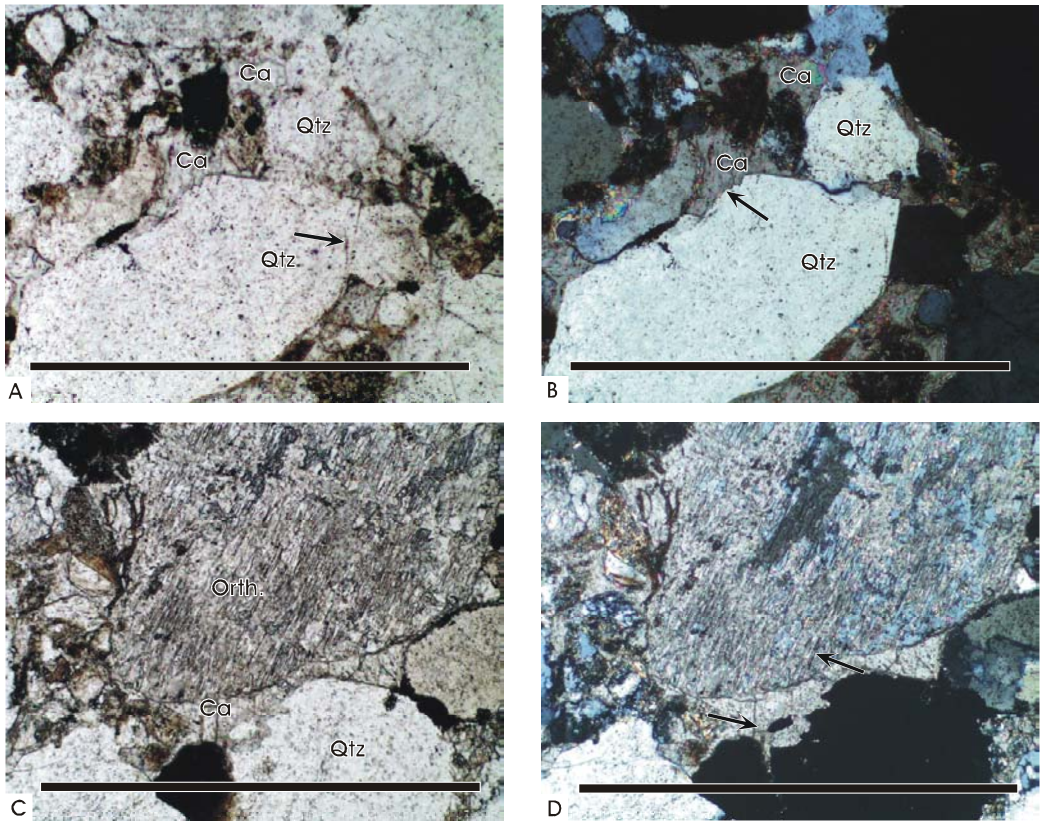


Figure 38. Diagenetic features of Liffey Group sandstone in the Hunterston DDH, sample at 850.5m, all scale bars 1mm. A – plane light showing quartz overgrowths, with barely visible grain boundaries indicated by arrow. B – polarised light view of A, showing dissolution of quartz overgrowth and grains by carbonate cement. C – plane light view showing perthitic dissolution of orthoclase feldspar by calcite, and calcite cement. D – polarised light view of C showing dissolution of orthoclase and quartz by calcite cement, arrow. Qtz = quartz, Ca = calcite, Orth = orthoclase feldspar.

Oil Inclusions in Liffey Group

Samples of Liffey Group sandstones from the Hunterston DDH have been reported with oil inclusions, within both quartz and carbonate (Cook, 2003). Oil inclusions form during crystallisation of diagenetic minerals, and through brittle deformation and fracturing of detrital and diagenetic grains during burial (George *et al*., 1996). The inclusions within detrital Liffey quartz grains would have formed by fracturing at some time in their diagenetic history. As the timing of precipitation of the carbonate is known to be associated with Jurassic dolerite, the presence of oil inclusions is important. While they may have formed by fracturing at any given time, they may also have been directly included during crystallisation of the carbonate cement in the Jurassic. This has important implications for the basin as a whole. If the oil was already present before dolerite intrusion, it would appear that carbonate fluids have driven it off. If the inclusions have occurred by fracturing after crystallisation, when Liffey Group sandstones closely associated with dolerite have reduced porosity and permeability, oil can only be stored as small inclusions rather than in sandstone framework porosity. Either way it appears that reservoirs need to be well away from dolerite intrusion to retain suitable reservoir characters.

Besides the above points the presence of oil inclusions is positive, as it is clear that oil has been generated at some time in the history of this area of the Tasmania Basin, whether as part of normal burial maturation, or by local heating associated with dolerite intrusion.

Fault produced porosity

In the Hunterston DDH faults low in the Parmeener sequence are frequently shown to be brecciated (Figure 39). Also associated with these brecciated fault zones, is dissolution of fossil material and carbonate clasts within the Bundella mudstones and conglomeratic facies. Several of these brecciated zones occur around 900m depth, each with an associated "hallow" of carbonate dissolution, and replacement by silica, ranging from 0.5 to 10m in thickness. The dissolution of carbonate material is assumed to be by fluids introduced along fault structures. The degree of brecciation is severe, resulting in shattered rubble like core, and rock samples could not be taken for analyses. However the high porosity and permeability led to loss of drilling pressure, indicating such horizons would be highly suitable reservoirs, providing there is a suitable seal on the fault away from the zone of dissolution.

Near the base of the Lower Parmeener Supergroup in the Hunterston DDH at 957m, one such dissolution horizon, involving strong carbonate dissolution and siliceous replacement of a conglomerate, over 3m, has not been brecciated and the porosity and permeability can be seen to be very high (Figure 40).

Analysis of this brecciation and dissolution zone continues, but it is possible that it is related to a likely Cretaceous hydrothermal event in the Styx and Weld regions. The diagenetic effects produced are not those commonly found associated with dolerite intrusion as seen higher in the Hunterston stratigraphy.

Seal rocks

Sedimentary

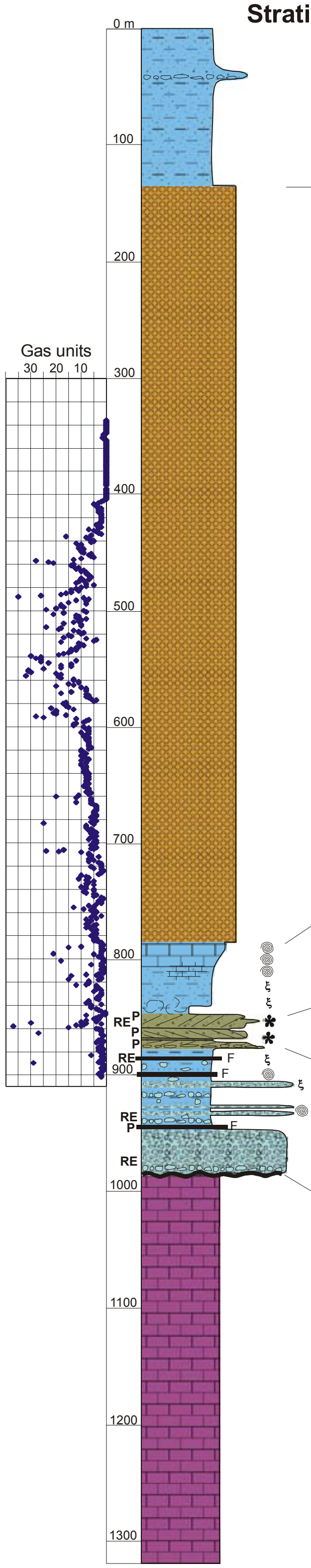
Sedimentary seal rocks within the Tasmania basin exist regionally as the Ferntree Mudstone, which extends as an up to 200m thick sequence of interbedded mudstone and dirty siltstone. As a unit the Ferntree Mudstone is somewhat brittle in surface exposure and exhibits block fracturing by release of overburden. However at depth this would not occur. There are also a number of other suitable units to serve as seal rock. Immediately above the freshwater reservoir units are fine-grained mudstone and dirty siltstone, of marginal marine facies in the base of the Cascades Group. Through the central basin area, this facies is generally present, although it is somewhat siltier in the Ross DDH.

Through this facies, and the calcareous siltstone and limestone above, are frequent thin clay horizons. These are volcanic ash horizons that have been altered to form soft ductile clay horizons. The preservation and thickness of these clays is variable, depending on the degree of biogenic reworking of sediments, but are evident in most areas as thin 1-5cm white-grey soft clay bands.

Within the freshwater reservoir unit, as discussed above, are carbonaceous siltstones interbedded with the reservoir sandstones, that may serve as local seals.

Stratigraphy of Hunterston DDH. Based on drilling to 1324m.

Catherine Reid



Ferntree Mudstone - to 134m

Generally monotonous sequence of bioturbated siltstone, with dispersed granules and pebble horisons. Not fossiliferous.

Dolerite intrusion - 650m thickness

Massive dolerite, generally fine to medium grained. Probably multiple instrusive events

P - Permeability and Porosity analysis (ACS Labs)

	depth	helium porosity %	point count porosity %	grain density g/cm3	Permeability mD
Liffey	849.2		1.8		
Liffey	850.5		0.9		
Liffey	853.3	8.7	10.4	2.68	0.06
Liffey	862.5	4.1	2.6	2.68	0.04
Liffey	869.3	5.6	6.5	2.67	0.05
Bundella	957.5	16.9		2.6	6323.0

RE - Rock Eval Pyrolysis (Amdel Laboratories)

RE	Depth	OI	HI	PI	Tmax	S1	S2	S1+S2	TOC
Liffey	859.2	4	66	0.22	458	0.41	1.49	1.9	2.24
Bundella	874.4	15	80	0.260	447	0.36	1.01	1.37	1.26
Bundella	940	37	97	0.34	457	0.48	0.95	1.43	0.97
Bundella	964.9	9	308	0.09	453	2.61	24.97	27.58	8.1

Cascades Group - from 784.4m

Upper part richly fossiliferous, fossiis becoming rarer and thin shelled downwards from approx 800m. Lower part poorly to non fossiliferous bioturbated siltstone, base of pyritic bioturbated black mudstone.

Liffey Group - from 848.6m

Laminated micaceous fine grained sandstone, with carbonaceous lamination and plant material. Thin coarse sandstone and carbonaceous siltstone/mudstone indicated.

Bundella correlate - from 870.1m

Grey pebbly siltstone, conglomeratic siltstone and conglomerate. Isolated fossil horisons. Conglomeratic beds increasing in frequency from 950m. Siltstone, grey to dark grey, bioturbated and sparsely fossiliferous. Wispy carbonaceous lamination in lower part.Woody Island organic facies probably present in lower part of unit, as organic silt matrix in conglomeratic beds.

Precambrian dolomite - from 980m (Alan Chester)

Dolomitic siltstone and thin sandstone unit. Soft sediment deformation prominent, along with later brittle deformation. Banded siltstone prominent in upper part, becoming coarser from 1180m.

Pyritic partings common, with oolitic section at 1036m that is similar to the Black River Dolomite. Voids at 1213m, possibly from dissolution of calcite.

Bedding vertical between 1130-1190. Greenish chert band at 1300.

Figure 39. Stratigraphic section of the Hunterston DDH.

Figure 40. Conglomeratic mudstone, from the Bundella Mudstone correlate, 957.5m depth Hunterston DDH. Cavities produced by dissolution of carbonate clasts and incomplete siliceous replacement.
Porosity = 16.9%, permeability = 6323mD

Dolerite

As discussed earlier, the Parana Basin of Brazil is a unique petroleum system, in that intrusive rocks serve both to provide heat for source maturation, and seals and traps by the arrangement of sills and dykes.

While in the Tasmania Basin much of the dolerite may be too shallowly buried to maintain closure of the cooling fractures seen in intrusive rocks, it is unclear at this stage, at what depth fractures would be closed sufficient for seal properties to be formed.

However, the dolerite intrusions cause an alteration hallow within the enclosing sediments. When intruded into the upper marine sequence of the Lower Parmeener Supergroup clay minerals are commonly formed up to 30m from the intrusion, with often a very conspicuous clay horizon immediately beneath. This alteration zone forms a potentially effective seal that is not as limited by depth of burial as the closure of dolerite fractures, and may be found in all areas of the basin.

STRUCTURAL HISTORY OF TASMANIA FROM THE DEVONIAN – RECENT (Andrew Stacey)

Introduction

The main aim of this project is to establish the geometry and timing of structures affecting all the sedimentary sequences in and underlying the Tasmania Basin from the early Palaeozoic through to the Tertiary. The exact timing of folding and faulting in the Tasmania Basin is critical in the assessment of the Gondwana Petroleum System and its relationship to hydrocarbon maturation, migration and trap formation. The geometry of folds and faults within the Lower-Middle Palaeozoic's is critical to understanding the Larapintine Petroleum System.

This study will provide structural input into the ARC SPIRT project: *Petroleum Systems Modelling Onshore Tasmania.* The structural history, especially the definition of hydrocarbon traps, migration fairways, palinspastic restorations of source kitchens and uplift and thermal history will be integrated into a three dimensional model of onshore petroleum systems in Tasmania, this work performed in close association with other project team members.

Thus far, the structural history project has concentrated mainly on the interpretation of seismic data provided by Great South Land Minerals (GSLM).

Seismic Data

Introduction

In March 2001 GSLM acquired 659 line kilometres of seismic reflection data across the Central Highlands and in the Northern Midlands areas (Tasmania Basin Seismic Survey – TB-01) (Figure 41). The data was acquired for GSLM by Trace Terracorp using the vibroseis method and "crooked line" type grid (shot mainly along roads), processing of the data is by Robertson Research and the subsequent interpretations have been made utilising The Kingdom Suite™ seismic interpretation software.

Seismic Data Quality

The quality of the seismic data set is highly variable, individual sections contain zones of strongly coherent events as well as zones of noise; consequently coherent events across sections are rare. The variability in the data are likely to result from the "crooked-line" grid employed during acquisition, outcropping dolerite and from the velocity picks applied during processing.

The use a "crooked line" grid (shooting along existing roads) and the vibroseis method has enabled GSLM to acquire an extensive regional data set whilst minimising the expense. However, seismic data acquired along straight lines is more easily ascribed to geologic rather than acquisition changes. Processing techniques generally assume a straight line profile with uniform fold and even offsets, crooked line acquisition results in variable fold and uneven offsets (Wu, 1996). Specialised processing with careful initial and residual statics corrections and frequent velocity analysis are required, and even with crooked line processing methods applied, problems such as seismic transparent zones and coherent noise can still result where there are changes in survey line direction (Wu, 1996).

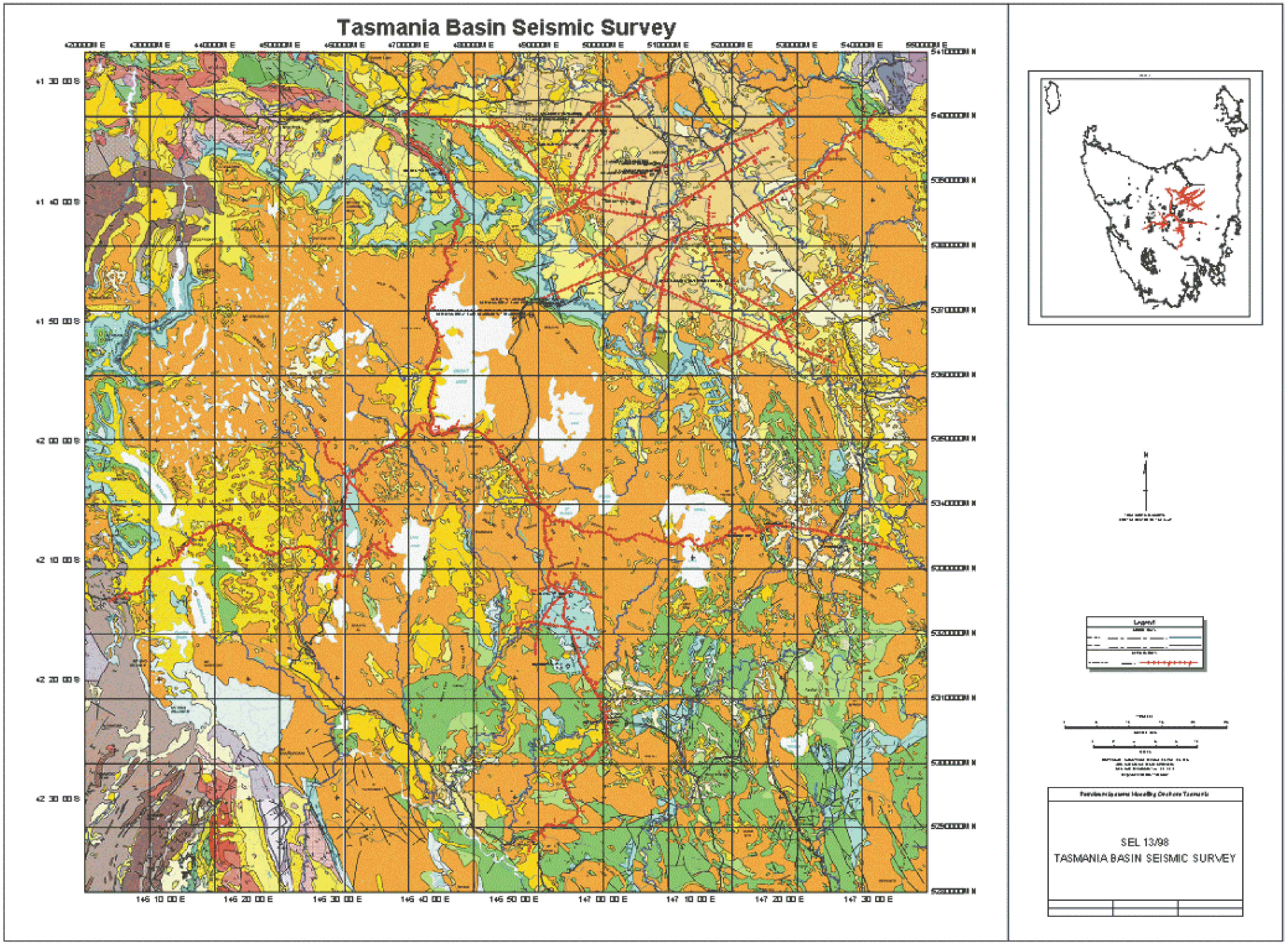


Figure 41. Tasmania Basin Seismic Survey (TB-01) line location map.

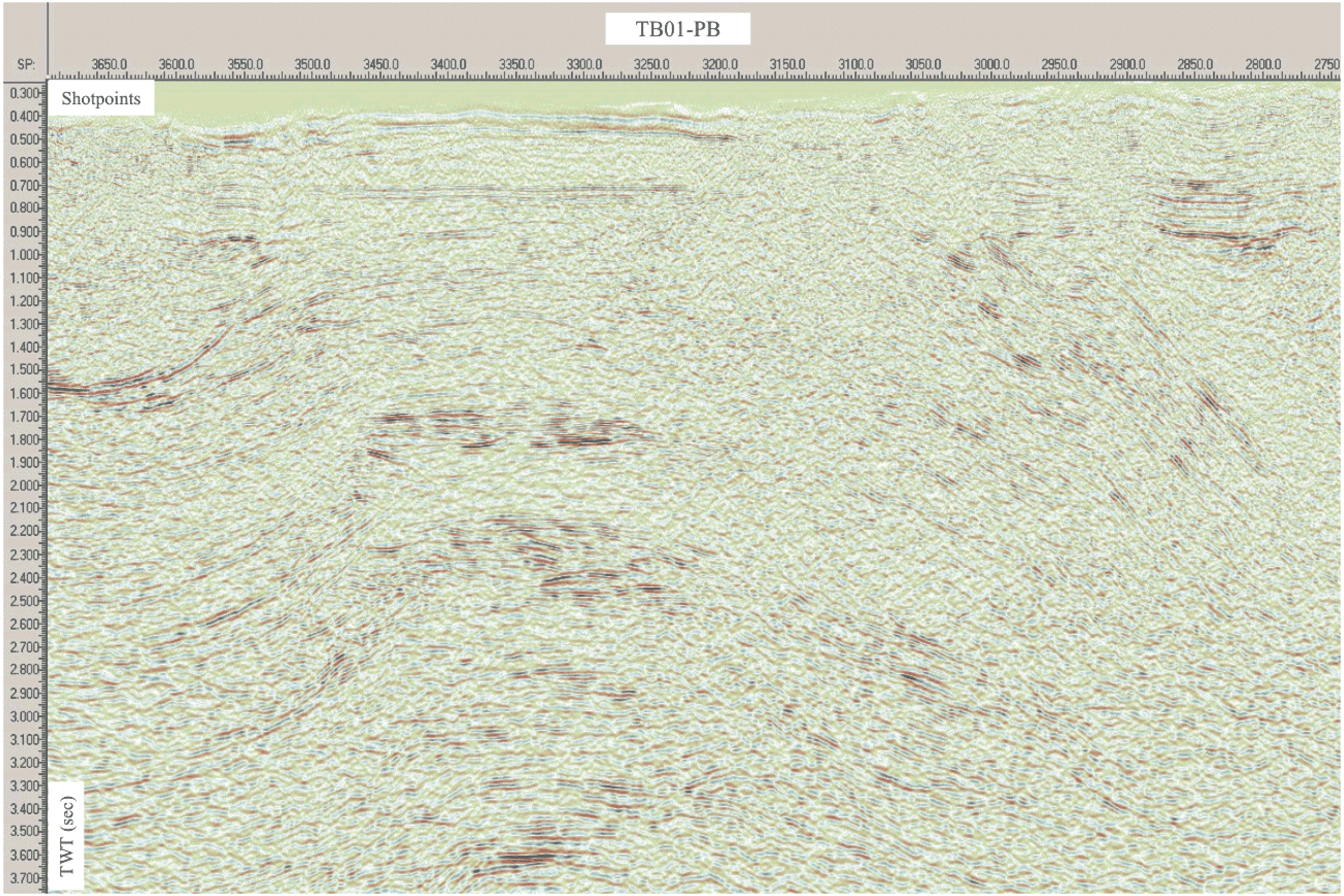


Figure 42. Resolution of shallow and deep structure at a window in the dolerite, line TB-01 PB, SP 3185-3470.

The best resolution of seismic data in the TB-01 survey occurs where the dolerite is covered by sediment. This is seen in the Longford Sub-Basin where up to several hundred metres of Tertiary rock overlie dolerite (Lane, 2002). In the Central Highlands the best resolution occurs where there are “windows” in the outcropping dolerite, where the dolerite underlies 100-200m of Parmeener Supergroup strata eg Line TB-01 PB (Figure 41) between shotpoints (SP) 3185 and 3470 flat lying events in the Parmeener Supergroup above and below dolerite and an antiform deeper in the section are resolved by the seismic data (Figure 42).

Geologic Controls on Seismic Data

The control provided by wells of seismic data is essential in relating seismic events to stratigraphy. There are very few deep wells i.e. wells that sample rocks from below the Parmeener Supergroup in the survey area and those that are available are not always on or adjacent to a seismic line (Figure 41).

There are 2 methods used to tie geologic controls to seismic data: 1) using a time depth function calculated from checkshot data, or 2) tying into the seismic data using a synthetic seismogram (Tearpock and Bische, 2003).

Synthetic seismograms are the preferred method as they provide the best results, their generation requires the combination of sonic and density data logs and checkshot surveys from wells. Unfortunately there are no drillholes in the survey area that have had these logs recorded and therefore tying seismic data to well data cannot be achieved using this method.

A simple but less accurate method is to conduct a checkshot survey and use the measured velocities to convert formation tops in the drillholes from depth to time, which can then be plotted on to a seismic section. The only checkshot survey conducted in Tasmania (to my knowledge) was on Bruny Island in the Shittim #1 drillhole. Patrick Fournier performed the survey where he measured the velocity of the dolerite found in the hole and the temperature gradient as part an honours thesis at the University of Tasmania (Fournier, 2000). The velocity estimates being used here to convert between depth and time are those published in “Processing of the AGSO T4 and T5 seismic lines” (Leaman, 1996).

The sonde, trailer and equipment (Figures 43 and 44) used by Fournier are still available at the University of Tasmania and have been modified by extending the range of the communications and strength cables to 1000m for use in the Hunterston #1 DDH. Changes to the temperature circuit have also been made to improve its stability and operation. A checkshot survey will be carried out in the Hunterston #1 DDH when the hole becomes available.

Figure 43. Sonde for measuring downhole velocity and temperature.

Figure 44. Trailer rig and seismic recorder for sonde.

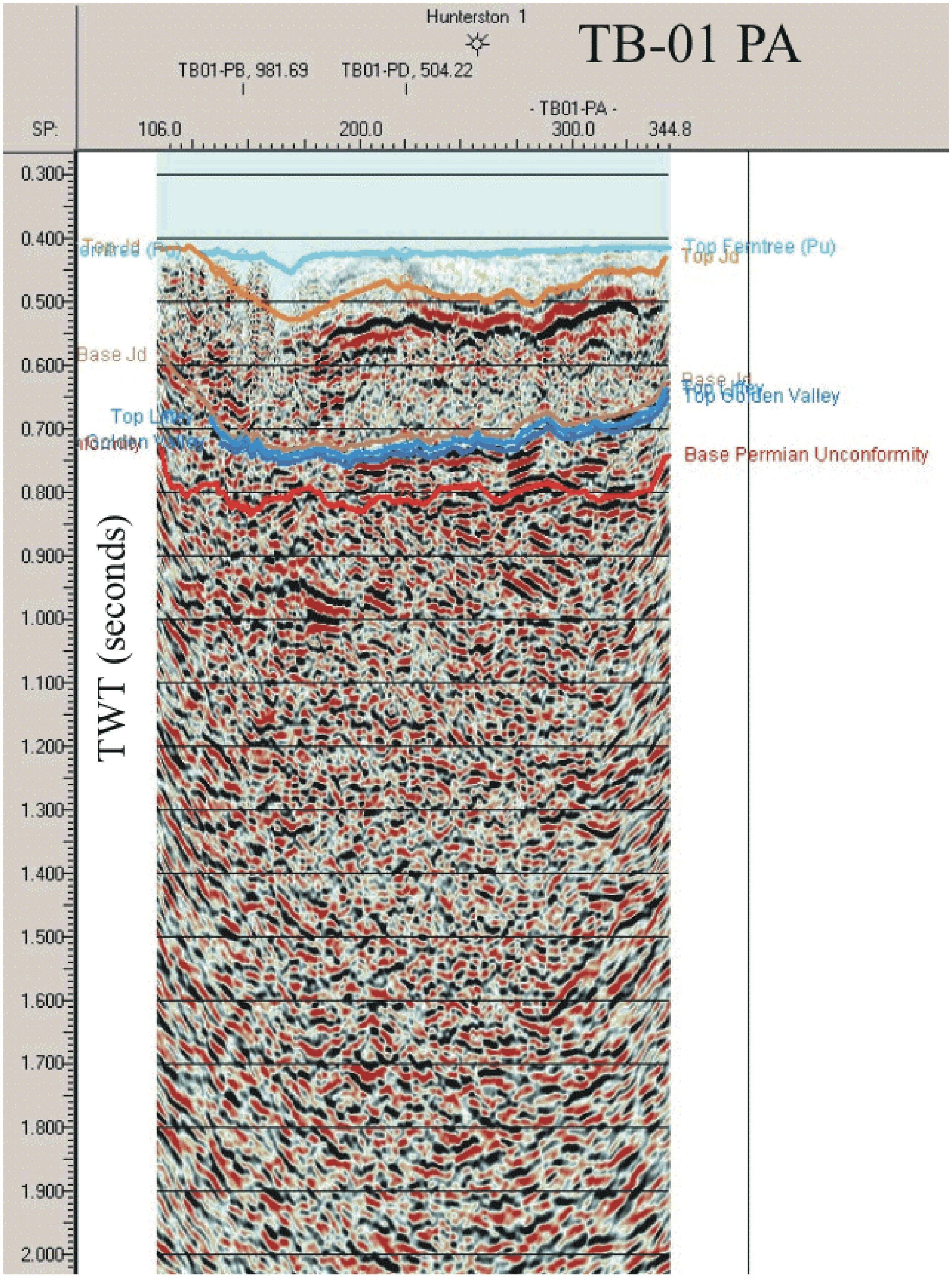


Figure 45. Interpretation of seismic lines across the Hunterston prospect.

Seismic Data Interpretation

The interpretation of the data from the TB-01 Seismic Survey is the cornerstone of the Structural History project. The interpretation process has been an iterative one, with improvements to the interpretation being continually made as new data becomes available. Recent advances have resulted from control provided by the incorporation of well logs and well data into the seismic data set (especially the Hunterston #1 DDH).

All the survey lines have been interpreted, although some have been the subject of greater effort then others depending upon the availability of other data to constrain the interpretation and/or the needs of the current drilling program. The interpretation of the lines acquired over the Longford Sub-Basin is the subject of an honours thesis at the University of Tasmania (Lane, 2002).

The interpretation effort is currently being focused on lines where there is well control and there are clear coherent events to correlate wells to seismic. Later interpretation of data on lines and zones in lines where the data quality is poor will be based on these better-constrained lines. Therefore recent work has been on the Tasmania Basin sequences, especially those cropping out through “windows” in the dolerite, these are the Hunterston and Bronte/Bellevue prospects and the end of line TB-01 ST.

Hunterston

The Hunterston prospect is at the northern end of one such window (490000mE, 5320000mN). Fairbridge (Fairbridge, 1949) was the first to notice the gently dipping Permian strata of the area formed a domal structure (Hunterston Dome), which he thought had lost their dolerite capping and had been eroded out into physiographic basin because of their elevation. The Hunterston #1 DDH was pre-collared in August 1997to a depth of 336m intersecting dolerite at 134m (Tanner and Burrett, 1997). Fairbridge’s interpretation was revised by GSLM geologists to include a second dolerite sill (Tanner and Burrett, 1997). Interpretation of seismic lines TB-01 PA, PB, PD and TA with the control from the Hunterston #1 DDH has revealed that a single, bowl shaped dolerite sill underlies the Permian strata and that the Hunterston Dome has been created by a small, higher relief area on the northeastern edge of the intrusion (Figure 46).

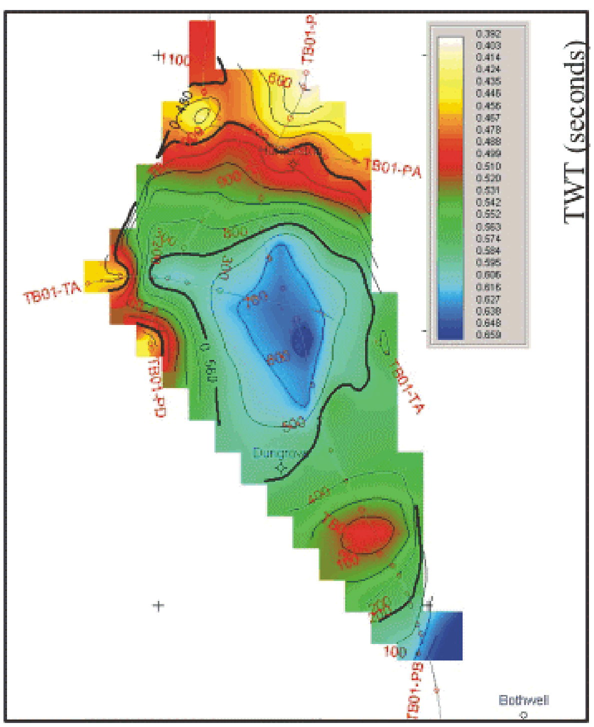


Figure 46. Two-way time structure map of the top dolerite horizon, Hunterston prospect

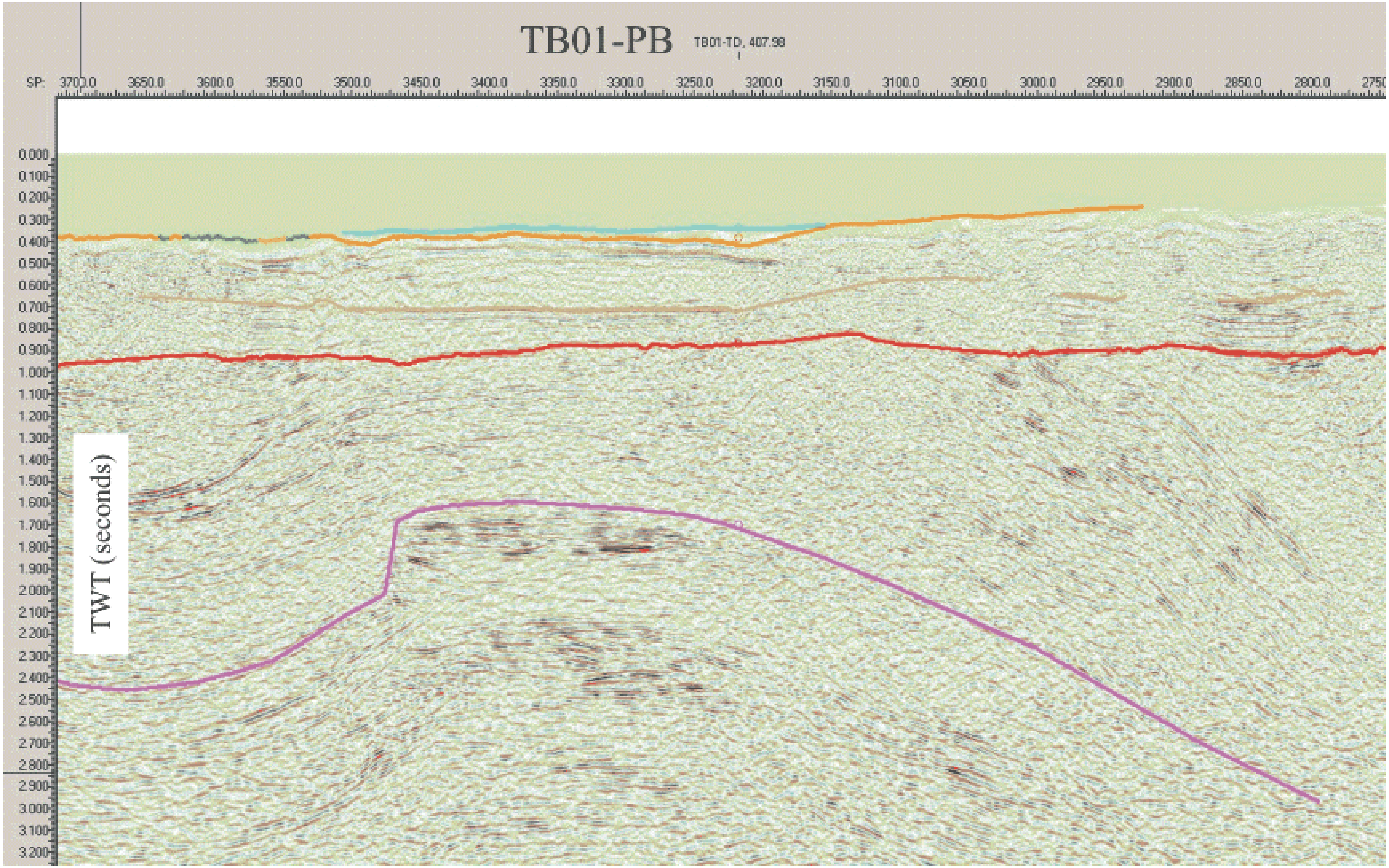


Figure 47A. Interpretation of the Permian section, Bronte/Bellevue prospect.

Bronte/Bellevue

The Bronte/Bellevue prospect is located in another Permian window between the village of Bronte Park and the Bellevue Tier (460000mE, 5330000mN). Seismic lines TB-01 PB, and TD resolve events particularly well here, except in those areas where there are bends in the roads along which the data was acquired. Interpretation of the seismic data for the Permian section predicts a ~100m veneer of the upper glaciomarine sequence of the Parmeener Supergroup followed by a ~800m thick dolerite sill with a further 400-450m of Permian rocks to the predicted base Parmeener unconformity (Figure 47A & B).

Deeper structures are resolved by seismic lines TB-01 PB, TB, TD and TI, however it is unclear what rock units form these structures. The structure has been interpreted as northwesterly plunging antiform (Figure 48), the strike of which would appear to be a continuation of the northwesterly striking Deloraine/Railton trend (Williams *et al.*, 1989).

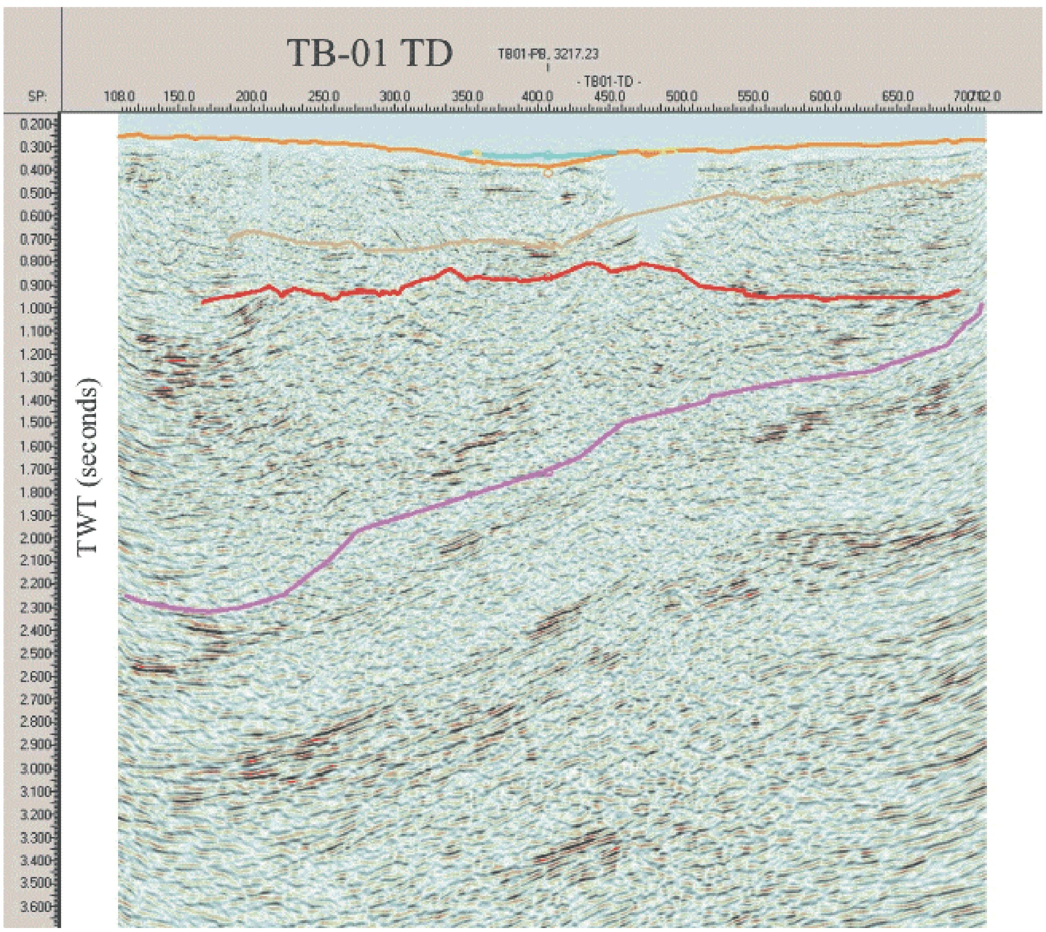


Figure 47B. Interpretation of the Permian section, Bronte/Bellevue prospect.

Eastern end of Seismic Line TB-01 ST

The eastern end of line TB-01 ST is constrained by the deep drillholes Tunbridge RG145, Ross 1 (Quoin) and Ross RG146 (Ross 1) and by the shallower drillholes Annandale 1 and Woodbury 11 (Figure 41). The relatively flat lying Permian sequence is dissected by a complex series of faults most of which appear to postdate the intrusion of a 300m thick dolerite sill. Deeper structures are less well resolved, although steep events and vergence folds indicate the basement is a series of thrusts (Figure 49).

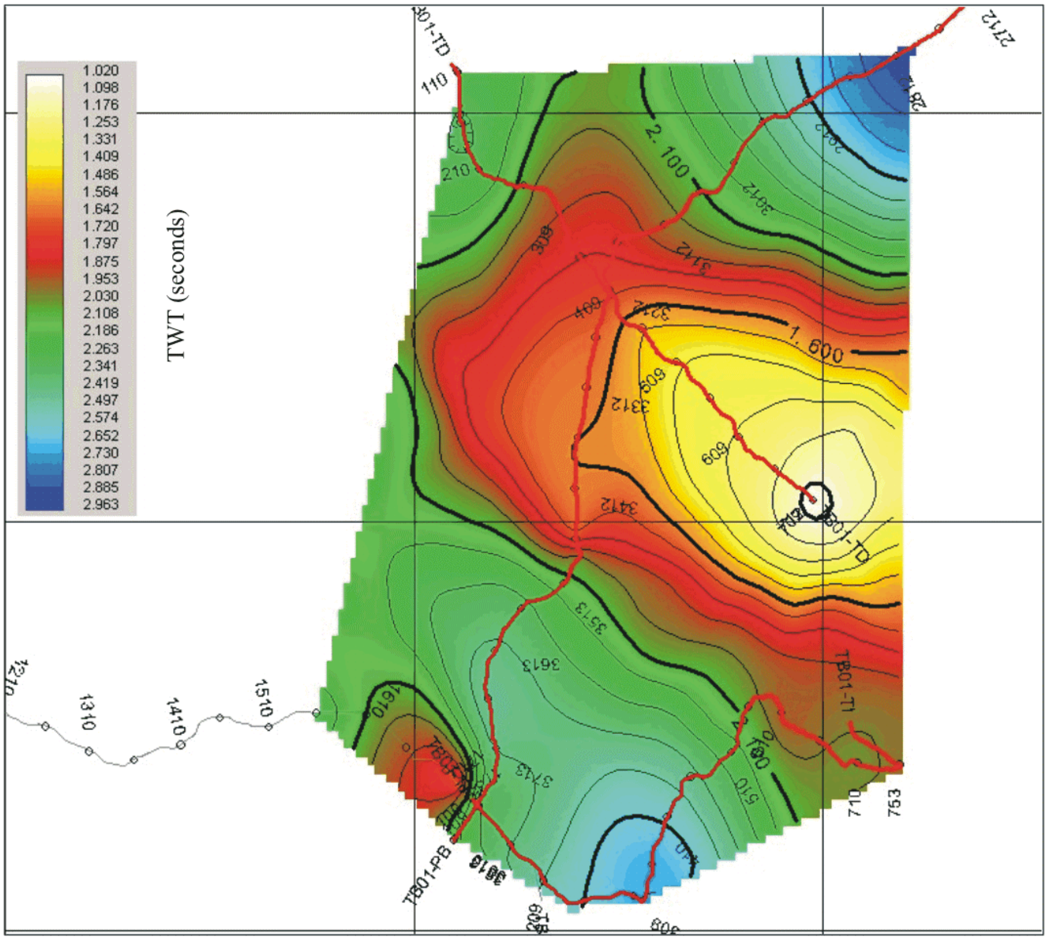


Figure 48. Two-way time structure map of the basement structure, Bronte/Bellevue prospect

Other Work

To complement the seismic interpretation a parallel study has been undertaken to map the extent of surfaces within the Parmeener Supergroup over the entire Tasmania Basin. This analysis aims to combine assessments of the modern DEM, extant geological mapping, fission track data, fault striation data and other data sets to generate maps of fault patterns, and a history of fault formation and reactivation which will assist in understanding petroleum migration and trap formation (Figure 50).

Table 3. Seismic velocities and two-way travel times for different units if the Tasmania Basin (Leaman, 1996)

Geology	Velocity	Two-way Time/100m
Permian Rocks	4000-4500 m/s	50 ms
Triassic Rocks	3500-4200 m/s	56 ms
Jurassic Dolerite	5000-6000 m/s	35 ms
Recent Sediments	1750-2000m/s	100ms

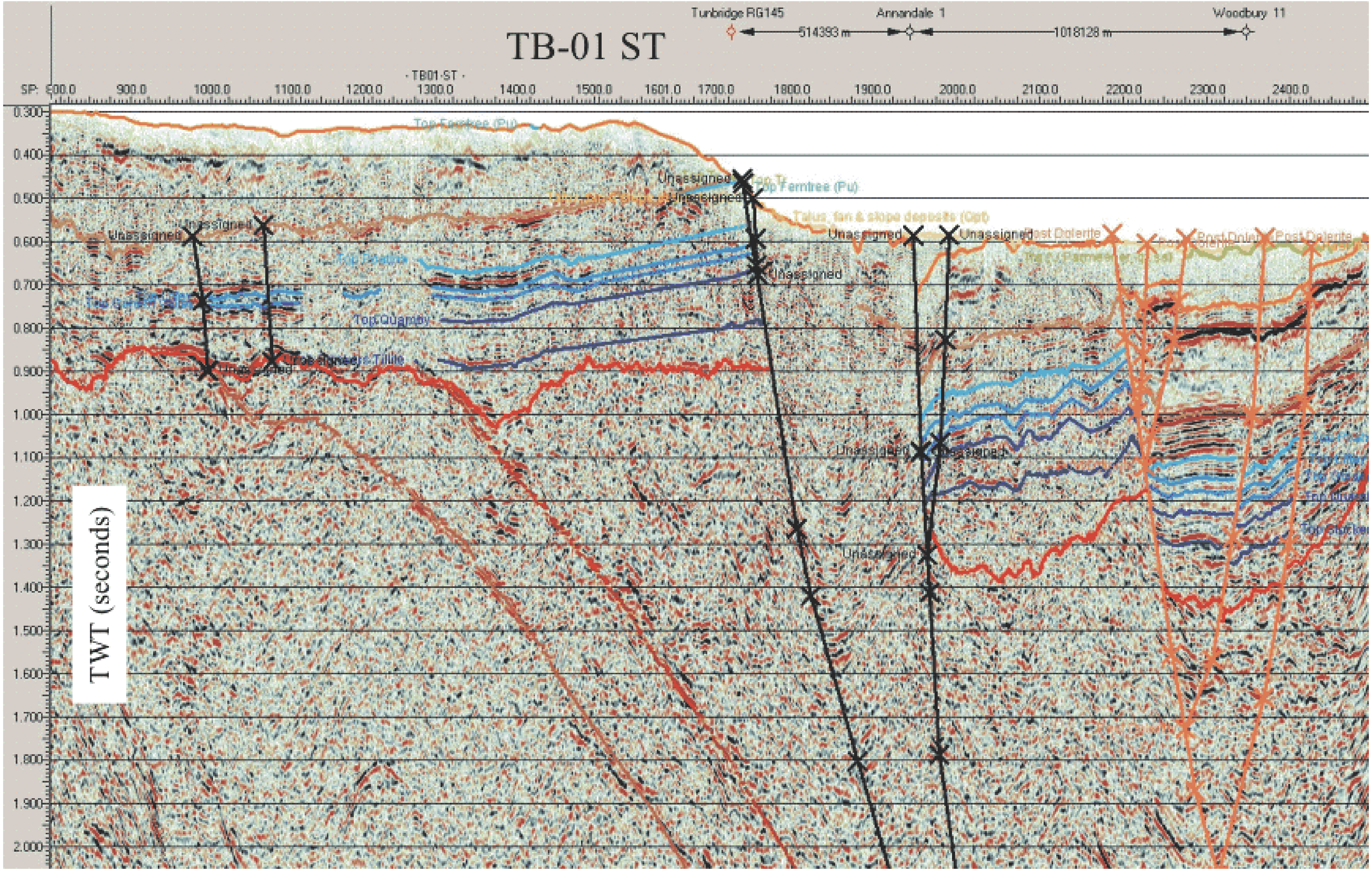


Figure 49. Interpretation of the eastern end of seismic line TB-01 ST.

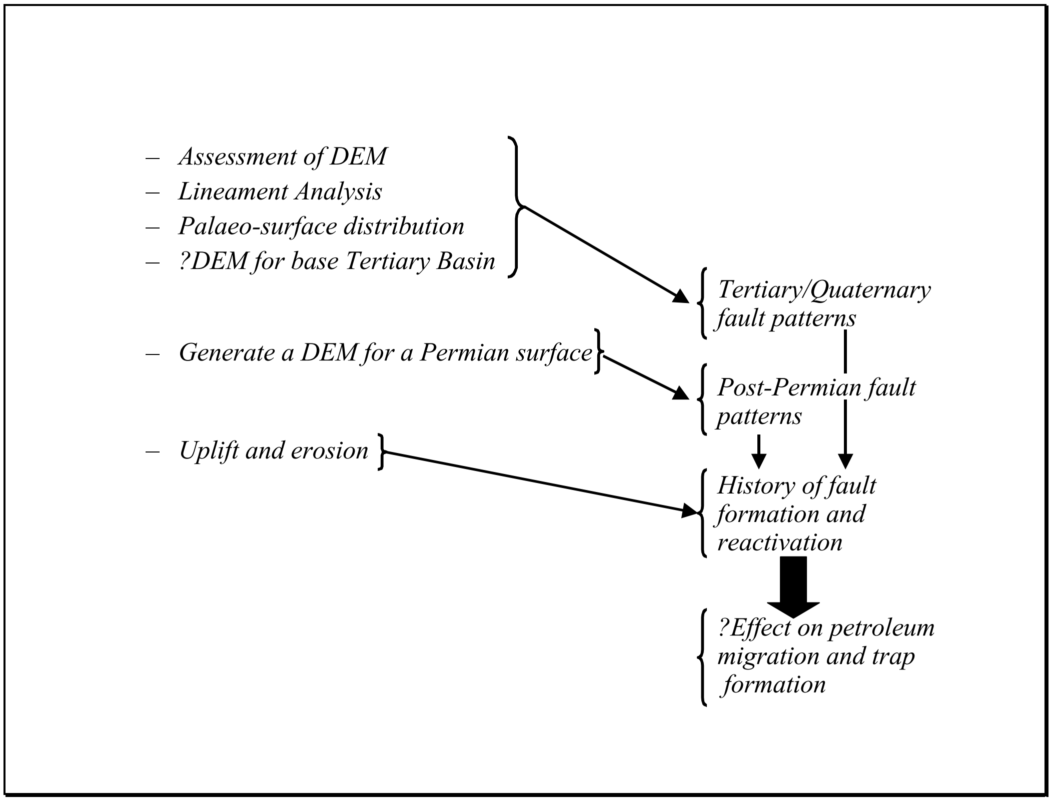


Figure 50. Processes and predicted outputs for Permian surface analysis.

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Appendix 1

Hydrocarbon Potential Parameters

***(Macrae Mudstone, Liffey Group,
Woody Island Siltstones, Tasmanite Oil Shale)***

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
Woody Island Siltstone													**SPI**	**SPI**	**sq metre**
G1	Golden Vly DDH	439	11	159	0.22	11.1	182.5	0.35	1.21	1.56	0.76	0.043			
G2	Golden Vly DDH	442	7	200	0.17	9.6	171.4	0.3	1.44	1.74	0.72	0.042			
G3	Golden Vly DDH	444	1	157	0.15	9.5	161.8	0.2	1.1	1.3	0.7	0.031			
G4	Golden Vly DDH	441	2	144	0.21	9.1	152.3	0.25	0.92	1.17	0.64	0.027			
G5	Golden Vly DDH	442	0	141	0.19	9	143.2	0.27	1.17	1.44	0.83	0.032			
G6	Golden Vly DDH	443	6	134	0.18	8.9	134.2	0.25	1.17	1.42	0.87	0.032			
G7	Golden Vly DDH	442	1	144	0.17	12.7	125.3	0.27	1.3	1.57	0.9	0.050			
G8	Golden Vly DDH	440	13	57	0.31	9.3	112.6	0.16	0.36	0.52	0.63	0.012			
G9	Golden Vly DDH	443	8	121	0.21	6	103.3	0.34	1.25	1.59	1.03	0.024			
total													0.292		
1990	Golden Valley	442	7	73	0.25	*50*	135.9	0.16	0.49	0.65	0.67	0.081			
1991	Golden Valley	447	7	183	0.14	*50*	170.4	0.29	1.74	2.03	0.95	0.254			
total													0.335		
average														0.314	1.976
T1	Tunbridge DDH	460	1	37	0.59	16.1	702	0.36	0.25	0.61	0.68	0.025			
T2	Tunbridge DDH		0	30	0.59	14.9	685.9	0.22	0.15	0.37	0.5	0.014			
T3	Tunbridge DDH		7	43	0.54	17.3	671	0.21	0.18	0.39	0.42	0.017			
T4	Tunbridge DDH	397	1	79	0.49	16.1	653.7	0.95	0.98	1.93	1.24	0.078			
T5	Tunbridge DDH	445	2	41	0.61	15.2	637.6	0.86	0.54	1.4	1.31	0.053			
T6	Tunbridge DDH	449	3	51	0.53	33.9	622.4	0.62	0.55	1.17	1.08	0.099			
T8	Tunbridge DDH	445	2	55	0.53	31	588.5	0.69	0.62	1.31	1.13	0.102			
T10	Tunbridge DDH	451	4	59	0.47	31.7	557.5	0.43	0.48	0.91	0.82	0.072			
T12	Tunbridge DDH	450	2	58	0.44	3.3	525.8	0.4	0.5	0.9	0.86	0.007			
T522.5	Tunbridge DDH	451	16	117	0.3	26.7	522.5	0.31	0.73	1.04	0.62	0.069			
T14	Tunbridge DDH	462	2	33	0.52	24.8	495.8	0.23	0.21	0.44	0.63	0.027			
total													0.563		
average					0.51	236		0.48	0.472	0.952	0.845			0.562	3.538
5801	Ross DDH	447	0	8	0.63	*75*	409.3	0.15	0.09	0.24	1.19	0.045			
8480	Ross DDH	435	0	48	0.27	*75*	388	0.14	0.38	0.52	0.8	0.098			
total													0.143		
average						150		0.145	0.235	0.38	0.995			0.143	0.898
H3	Hunterston DDH	457	37	97	0.34	25	940	0.48	0.95	1.43	0.97	0.089			
H4	Hunterston DDH	453	9	308	0.09	1	964.9	2.61	24.97	27.58	8.1	0.069			
													0.158	0.158	0.997
E1	Eaglehawk DDH		1	11		6.9	378.9	0.16	0.09	0.25	0.83	0.004			
E2	Eaglehawk DDH		5	21	0.64	6.9	372	0.09	0.14	0.23	0.66	0.004			
E3	Eaglehawk DDH		1	11	0.39	9.9	365.1	0.13	0.08	0.21	0.71	0.005			
E4	Eaglehawk DDH		5	17	0.62	6.9	355.2	0.06	0.1	0.16	0.6	0.003			
E5	Eaglehawk DDH				0.38	13.3	348.3				0.35				
total													0.016		
average					0.508	50		0.11	0.103	0.213	0.63				
S3	Styx Valley	454	1	82	0.43		oc	0.57	0.77	1.34	0.94				
S5	Styx Valley	453	19	41	0.42		oc	0.22	0.3	0.52	0.73				
S6	Styx Valley	461	2	74	0.41		oc	0.42	0.6	1.02	0.81				
S7	Styx Valley	468	4	47	0.46		oc	0.39	0.45	0.84	0.95				
S8	Styx Valley		11	30	0.38		oc	0.1	0.16	0.26	0.53				
S10	Styx Valley	452		76	0.46		oc	0.48	0.57	1.05	0.75				
S11	Styx Valley	436	4	128	0.43		oc	1.1	1.48	2.58	1.16				
S13	Styx Valley	451		43	0.5		oc	0.22	0.22	0.44	0.51				
S3b	Styx Road quarry	449	18	148	0.41		oc	1.01	1.47	1.19	0.99				
average		453	8.429	74.33	0.433	140.000		0.501	0.669	1.027	0.819			0.359	2.264

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
Immature Woody Island Siltstone															
D1	Bicheno 10 DDH	434	3	135	0.23	3	330	0.69	2.25	2.94	1.67	0.022			
8481	Bicheno 10 DDH	449	1	85	0.36	1.7	327	0.4	0.71	1.11	0.84	0.005			
D2	Bicheno 10 DDH	433	7	97	0.28	5	325.3	0.4	1.02	1.42	1.05	0.018			
D3	Bicheno 10 DDH	439	4	433	0.23	5.1	320.3	3.2	10.48	13.68	2.42	0.174			
D4	Bicheno 10 DDH	437	6	126	0.2	5.9	315.2	0.31	1.22	1.53	0.97	0.023			
D5	Bicheno 10 DDH	433	9	79	0.2	4.4	309.3	0.18	0.74	0.92	0.94	0.010			
D6	Bicheno 10 DDH	440	1	300	0.15	3.6	304.9	0.94	5.16	6.1	1.72	0.055			
D7	Bicheno 10 DDH	432	9	142	0.4	5.7	301.3	1.1	1.67	2.77	1.18	0.039			
D8	Bicheno 10 DDH	439	10	144	0.18	4	295.6	0.16	0.72	0.88	0.5	0.009			
D9	Bicheno 10 DDH	436	2	148	0.15	5.3	291.6	0.21	1.2	1.41	0.81	0.019			
total													0.373		
average		437			0.238	46		0.759	2.517	3.276	1.21			0.377	2.373
1992	Andersons Ck BH	445	24	30	0.17		124.4	0.02	0.1	0.12	0.33				
1993	Andersons Ck BH	425	31	38	0.15		129.5	0.02	0.11	0.13	0.29				
average		435			0.16	350		0.02	0.105	0.125	0.31				
1994	Hellyer Gorge	363	92	14	0		oc	0	0.05	0.05	0.36	0.000			
1997	Relapse Creek	449	19	271	0.13		float	0.65	4.37	5.02	1.61	0.000			
3	Oonah	437	72	88	0.04		oc	0.04	0.89	0.93	1.01	0.000			
4	Oonah	440	43	166	0.05		oc	0.07	1.3	1.37	0.78	0.000			
7	Oonah	436	54	163	0.05		oc	0.1	1.8	1.9	1.1	0.000			
average		425			0.054	333		0.172	1.682	1.854	0.972	1.543		1.543	9.724
average SPI and barrels sq/m for mature Woody Island Siltstone														0.307	1.935
average SPI and barrels sq/m for immature Woody Island Siltstone														0.960	6.049

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
													SPI	SPI	sq metre
Tasmanite Oil Shale															
Immature Oil Shale															
1995	Mersey Gt Bend	18	444	971	0.04	0.45	oc	12.5	304	316.5	31.3	0.356			
1996	Hellyer Gorge	46	449	716	0.03	0.45	oc	1.3	38.9	40.2	5.43	0.045			
1	Oonah	3	446	937	0.05	0.45	oc	30.8	590.8	621.6	63.05	0.699			
2	Oonah	4	443	937	0.05	0.45	oc	3.6	65.2	68.8	6.96	0.077			
5	Oonah	27	440	675	0.03	0.45	oc	1.4	54.4	55.8	8.06	0.063			
6	Oonah	5	444	872	0.04	0.45	oc	22.8	535	557.8	61.35	0.628			
8	Mersey Gt Bend	11	436	748	0.002	0.45	oc	0.03	19.3	19.33	2.58	0.022			
	total												1.890		
	average					1			230	240	26			0.600	3.780
	Bicheno 10 DDH	1	446	868	0.04			6.28	147.5	153.8	17				
5800	Bicheno 10 DDH	0	449	895	0.05		321.1	8.01	152	160	16.99				
	average					1.5		7.145	150	157	17			0.588	3.707
	basin average													0.594	3.743
Mature Oil Shale															
5802	Tunbridge DDH	0	458	33	0.38	1	676.4	0.56	0.92	1.48	2.8	0.004			0.023
T676.3	Tunbridge DDH	6	439	56	0.4	1	676.3	0.91	1.38	2.29	2.46	0.006			0.036

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
Macrae Mudstone													SPI	SPI	sq metre
2000	Golden Vly DDH	435	3	86	0.11		16.6	0.47	3.64	4.11	4.25				
5727	Golden Vly DDH	448	0	119	0.32			0.52	1.11	1.63	0.93				
5728	Golden Vly DDH	450	0	99	0.31			0.32	0.71	1.03	0.72				
average		444.3			0.247	2		0.437	1.820	2.257	1.967			0.011	0.071
GV2	Golden Vly DDH	425	28	52	0.15	4	21.2	0.07	0.4	0.47	0.76	0.005			
GV3	Golden Vly DDH	440	10	81	0.08	4.5	25.7	0.05	0.62	0.67	0.76	0.008			
GV4	Golden Vly DDH	446	45	58	0.13	4.7	30.3	0.04	0.27	0.31	0.46	0.004			
GV5	Golden Vly DDH	431	33	55	0.09	4.5	34.8	0.04	0.41	0.45	0.74	0.005			
GV1	Golden Vly DDH						53				0.3		0.021		
average		435.5			0.113	49		0.05	0.425	0.475	0.68			0.058	0.367
H2	Hunterston DDH	447	15	80	0.260	6	874.4	0.36	1.01	1.37	1.26			0.021	0.129
B1	Bothwell DDH										0.38				
average														0.030	0.189

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total	Average	barrels
Liffey Group													SPI	SPI	sq metre
1999	Musselroe BH 1A	277	4	1	0.6	35	12.8	0.03	0.02	0.05	1.9	0.004			
2000	Golden Valley DDI	435				35		0.47	3.64	4.11	4.25	0.360		0.182	2.266
average															
2002	Relapse Creek	442	16	307	0.07		oc	7.3	101	108.3	32.9				
2003	Relapse Creek	444	20	389	0.09		oc	10.1	102	112.1	26.2				
2004	Relapse Creek	445	15	215	0.09		oc	6.6	68.9	75.5	32.1				
	Preolenna Coal	438						3.7	135	138.7	64.3				
average						0.4		6.925	101.7	108.7	38.88			0.109	0.684
62373	Pelionite, Mt Pelior	473	2	809	0	0.2	62373	3.06	655	658	81			0.329	2.073
P1	Pelham DDH	444	0	31	0.33	6.5	358.5	0.1	0.2	0.3	0.64	0.005			
P2	Pelham DDH	464	4	17	0.2	6.5	353.2	0.04	0.17	0.21	1	0.003			
average					0.265	30.5		0.07	0.185	0.255	0.82			0.019	0.122
T1	Tunbridge DDH	457	3	102	0.28	1	383.6	1.64	4.32	5.96	4.22	0.015			
T2	Tunbridge DDH	425	10	37	0.19	3	380.7	0.05	0.21	0.26	0.56	0.002			
average						38.5	382.2	0.845	2.265	3.11	2.39			0.299	1.886
R1	Ross DDH	444	4	384	0.08	2	171.5	1.91	20.75	22.66	5.4	0.113		0.113	0.712
H1	Hunterston DDH	458	4	66	0.22	7	859.2	0.41	1.49	1.9	2.24			0.033	0.209
basin average														0.155	1.136

Appendix 2

Porosity, Density, Permeability Parameters

Sample number	Region	DDH depth	TS	Lab	Helium porosity %	Point count porosity %	Grain density g/cm3	Permeability mD
G1	Granton DDH	154.6		acs	2.3		2.66	0.05
G2	Granton DDH	160.7	x	acs	4.3	7.6 to 0	2.68	0.05
R1	Ross DDH	136.9	x	acs	10.6	10	2.67	0.18
R149.5	Ross DDH	149.5	x			9.2		
R154.6	Ross DDH	154.6	x			2.5		
R3	Ross DDH	156.6	x	acs	14.9	14.3	2.66	8.8
R2	Ross DDH	165.6	x	acs	13.6	6	2.66	0.43
R171.5	Ross DDH	171.5	x			0.4		
Q6.4	Quoin DDH	6.4		acs	14.7		2.66	1.8
Q14.9	Quoin DDH	14.9		acs	9.9		2.7	0.21
Q19.4	Quoin DDH	19.4		acs	8.5		2.57	0.21
B681.2	Bothwell DDH	681.2	x			8.9		
B685.4	Bothwell DDH	685.4	x			4.2		
B687.9	Bothwell DDH	687.9	x			13.9		
B690	Bothwell DDH	690	x			17		
H849.2	Hunterston DDH	849.2	x			1.8		
H850.5	Hunterston DDH	850.5	x			0.9		
H853.25	Hunterston DDH	853.25	x	acs	8.7	10.4	2.68	0.06
H862.5	Hunterston DDH	862.5	x	acs	4.1	2.6	2.68	0.04
H869.3	Hunterston DDH	869.3	x	acs	5.6	6.5	2.67	0.05
UTGD 132524	Bothwell DDH	677	BM			3.6		
UTGD 132525	Bothwell DDH	679.7	BM			7		
UTGD 132500	GV Glencoe DDH	3.48	BM			17.6		
UTGD 132501	GV Glencoe DDH	4.27	BM			17.6		
UTGD 132502	GV Glencoe DDH	5.19	BM			2.2		
UTGD 132503	GV Glencoe DDH	6.22	BM			6.2		
UTGD 132504	GV Glencoe DDH	7.32	BM			2		
UTGD 132505	GV Glencoe DDH	15.5	BM			6.2		
UTGD 132506	Great Lake 5113	12.81	BM			2.1		
UTGD 132507	Great Lake 5113	14.94	BM			6.3		
UTGD 132508	Great Lake 5113	35.38	BM			1.8		
UTGD 132509	Great Lake 5005	46.06	BM			2.1		
UTGD 132514	Ross RG146	136	BM			2.3		
UTGD 132516	Ross RG146	137.1	BM			1		
UTGD 132517	Ross RG146	137	BM			5.9		
UTGD 132518	Ross RG146	148.8	BM			4.9		
UTGD 132519	Ross RG146	160.8	BM			11.9		
UTGD 132520	Tunbridge RG145	366	BM			0		
UTGD 132521	Tunbridge RG145	369.5	BM			2.7		
UTGD 132522	Tunbridge RG145	370	BM			0		
UTGD 132523	Tunbridge RG145	378.5	BM			15 ?		
T1	Tunbridge RG145	364.50	x	acs	10.0		2.64	0.12
T2	Tunbridge RG145	370.70	x	acs	7.6		2.68	0.05
T3	Tunbridge RG145	370.75	x	acs	7.0		2.67	0.05

Appendix 3

'Stratigraphic results of diamond drilling of the Hunterston dome,Tasmania: Implications for palaeography and hydrocarbon potential'

STRATIGRAPHIC RESULTS OF DIAMOND DRILLING OF THE HUNTERSTON DOME, TASMANIA: IMPLICATIONS FOR PALAEOGEOGRAPHY AND HYDROCARBON POTENTIAL.

Reid C.M., Chester A.D, Stacey A.R. and Burrett C.F. (in prep)

(with x figures tables etc)

REID, C.M., CHESTER, A.D., STACEY, A.R. and BURRETT, C.F., 2003: Stratigraphic results of diamond drilling of the Hunterston Dome, Tasmania: implications for hydrocarbon potential. *Papers & Proceedings of the Royal Society of Tasmania*, XXX: XXXISSN 0080-4703. School of Earth Sciences, University of Tasmania, GPO Box 252-79, Hobart, TAS 7001.

ABSTRACT

The structure known as the Hunterston Dome, in central Tasmania, was drilled to a depth of 1324m, through Jurassic Dolerite, Lower Parmeener Supergroup and into Precambrian dolomite basement. This paper describes the stratigraphy encountered, revises the basement palaeogeography of central Tasmania, and discusses the implications for hydrocarbon potential of the Tasmania Basin. The base of Lower Parmeener Supergroup does not outcrop in the area, and drilling proved the absence of the extensive glacial diamictites present elsewhere in the Tasmania Basin, and a conglomeratic facies in place of Bundella Mudstone and Woody Island Siltstone. Basement to the Lower Parmeener Supergroup is proven to be Precambrian dolomite, similar to the Black River Dolomite of northwestern Tasmania.

Hydrocarbons of significance were not encountered during drilling, however stratigraphic drilling proved the maturity of potential source beds in the region and the nature of potential reservoir rocks, where they are found in close association with dolerite intrusion.

Keywords – Lower Parmeener Supergroup, Hunterston, dolomite, hydrocarbons, palaeogeography, stratigraphy, dolerite.

INTRODUCTION

The geology of this region of Central Tasmania was first described in any conclusive detail by Fairbridge (1949), after regional mapping work for the Hydro-Electric Commission. Fairbridge described the Permian and Triassic rocks of the area and their structural relationship with Jurassic dolerite intrusives, and was the first to note the presence of a domal structure southeast of Lake Echo. This structure was named the Hunterston Dome, after the pastoral property which covers this area. Fairbridge gave an accurate description of the local Permian geology and gentle dip of the strata. However the “sandy facies” of Fairbridge (1949), outcropping on the eastern and north-eastern limb of the dome, is in fact the lower part of the freshwater Triassic.

The Hunterston area provides some of the only Permian (Lower Parmeener Supergroup) outcrop through the central Highlands region, however only the marine series above the freshwater interval is exposed (Fig. 1). The nature of the lower marine interval of the Lower Parmeener Supergroup is unknown, although extensive tillites and pyritic mudstones are known to the east (Forsyth 1989) and southwest (Jago 1971). However, to the northwest in the Du Cane mapsheet (MacLeod *et al.* 1961), and Mackintosh mapsheet (Collins, *et al.* 1981) conglomerates and siltstones are present in place of the pyritic mudstones of the Quamby Mudstone and Woody Island Siltstone known from elsewhere in the Tasmania Basin. The nature of the pre-Parmeener basement is unknown in the region from the Florentine Valley to the southwest and Western Tiers to the north.

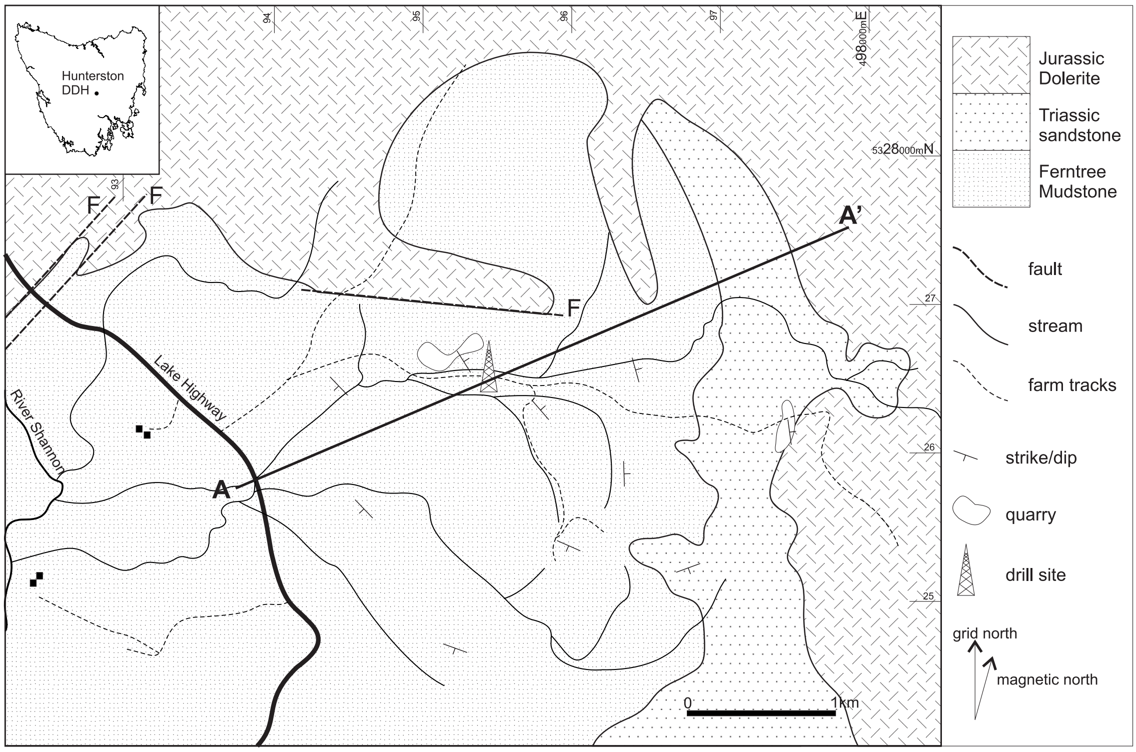


FIG. 1 – Locality map and geology in the immediate vicinity of the Hunterston DDH.

The Hunterston dome is of interest in hydrocarbon exploration within the Tasmania Basin, and was first drilled in August 1997 for Great South Land Minerals. The initial method was of 6 inch down hole hammer drilling to a depth of 336m. In July 2002 drilling recommenced with diamond core drilling (HQ, 63 mm diameter to 974m and NQ, 45 mm diameter to base) to a total depth of 1324m, drilling through Parmeener sediments into a Precambrian basement. The drill core is stored at Mineral Resources Tasmania, Mornington Store.

STRATIGRAPHY

Upper marine sequence

Ferntree Mudstone correlate 0-134m

This section of the hole was produced by hammer drill and the resultant chip material shows little about this monotonous sequence of predominantly mudstone. Because of the lack of stratigraphic detail in this section it is unknown if and how much of the sequence has been displaced by movement associated with dolerite intrusion.

Dolerite

Dolerite was encountered in the Hunterston DDH from 134 to 784.4m, totalling 650m thickness, and represents multiple intrusive events (Leaman, *pers. comm.*). The dolerite is massive and generally fine to medium grained. Baking effects on underlying Parmeener sediments are readily visible in core sample for approximately 20m beneath the margin of the dolerite. Vitrinite reflectance values of samples 65-85 m beneath the dolerite do not indicate significantly elevated temperatures.

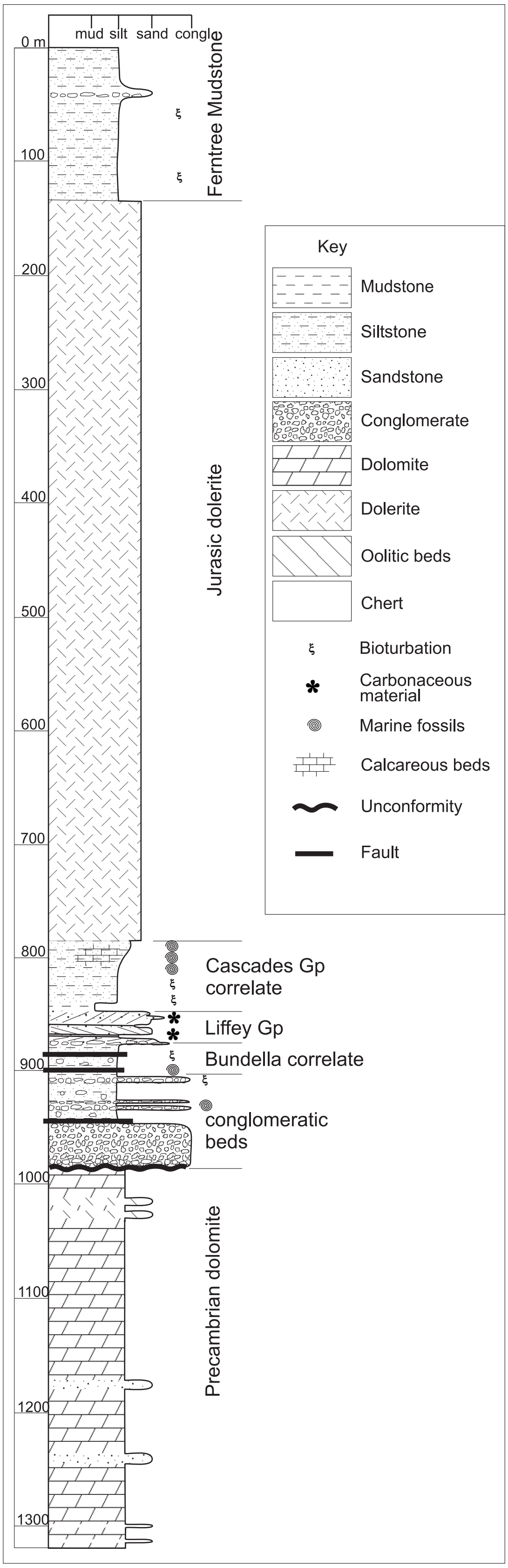


FIG. 2 – Schematic stratigraphic column of the Hunterston DDH.

Upper marine sequence

Cascades Group correlate 784.4 – 848.5m

The lower margin of the dolerite contacts directly with fossiliferous siltstones of the Cascades Group. From 784.4 – 811.5m, is a baked fossiliferous siltstone, baking effects decreasing downward into grey bioturbated fossiliferous siltstone. Fossils are abundant, of brachiopods, molluscs and bryozoans, with fenestellid dominant horizons. Fossils become thin shelled and less common from 798m. Weathered and bioturbated clay horizons are present at 801m and 811m. From 811.5 – 838.8m, bioturbated siltstone and sandy siltstone with scattered fossils in upper part, and granules and scattered pebbles throughout. From 838.8m – 848.5m, bioturbated pyritic mudstone and siltstone, with bioturbated sandstone and a prominent pebble horizon at 842.5m. The lowermost part of this sequence, immediately above the Liffey Group, is of black mudstone with wispy bioturbation and heavy pyritisation.

The effects of contact metamorphism associated with the dolerite have destroyed much of the skeletal detail of the bryozoans, however a Bernacchian age is indicated by the presence of *Levifenestella expansa* in the richly fossiliferous siltstones at 797.5m. The presence of Bernacchian species is in keeping with the Cascades Group in the Tunbridge Tier DDH where a probable Bernacchian age is indicated for the lower 45m of Cascades beds (Reid, *in press*). This age and the thinness of the fossiliferous sequence indicates some loss of Parmeener Supergroup section in association with dolerite intrusion, given that the base of the Ferntree Mudstone in the region is upper Lymingtonian in age.

Freshwater beds

Liffey Group 848.5 – 870.1m

The Liffey Group is divided into three units, upper carbonaceous fine sand, middle sandy siltstone and lower carbonaceous fine sand. The uppermost unit, from 848.5 to 853.6m, is of carbonaceous, silt laminated and cross-bedded, fine micaceous sand. The sandstone is bioturbated at its upper boundary with the overlying marine unit. Thin carbonaceous siltstone bands occur in the lower part, and a prominent coarse sandstone with plant fragments at 850.45-850.7m. The middle unit, from 853.6 to 862m, is of thinly laminated carbonaceous sandy siltstone. Soft sediment deformation and pyritisation are common. Soft sediment deformation is intense at 855.5m. The siltstone becomes gritty at 860m and grades in the lower unit, from 862-870.1m. The lower unit is similar to the uppermost and is of carbonaceous, laminated, micaceous, fine sand, with minor soft carbonaceous silt horizons. The grain-size increases downward with medium to coarse sand over the last two metres. The base of the Liffey Group is sharp and conglomeratic at 870.1m.

Lower marine sequence

Bundella Mudstone correlate 870.1-900m

The top of the Bundella Mudstone is bioturbated silty pebbly sandstone, fining rapidly to a dark grey-black foraminiferal siltstone. Black siltstone grades to a grey bioturbated siltstone, typical of the Bundella Mudstone, by 876m. The main body of the Bundella Mudstone correlate is of grey siltstone, that becomes increasingly pebbly downwards. Fossils are not common, with only rare horizons containing brachiopods and trepostome bryozoa.

Conglomeratic beds 900-980m

The typical fossiliferous lower Bundella Mudstone facies and Woody Island Siltstone are absent from the drillcore, and are replaced by conglomerates, conglomeratic siltstones and pebbly siltstone. From 900 to 908.5m are poorly sorted silty conglomerates and pebbly siltstones. Clasts are generally rounded, up to 7cm in diameter, and of dolomite, chert and limestone, volcanic clasts are rare. From 908.5 to 949m pebbly siltstone predominates, with isolated bands of conglomerate and conglomeratic siltstone. The siltstone becomes better sorted and darker from 924m to 944m. Bands of silty conglomerate and conglomeratic siltstone are common from 944 to 949m. From 949m, to the base of the Parmeener sequence at 980m, conglomerates and conglomeratic sandstone dominate. Clasts are of mostly dolomite, with some sandstone and metamorphic clasts occurring. Rounding is variably subangular to well rounded, with some well-sorted well-rounded conglomerate beds, within poorly sorted subangular to rounded conglomeratic sandstones. Poorly sorted conglomeratic sandstones, with wispy carbonaceous silt bands, dominate the lowermost 18m. The basal beds are of dolomitic conglomerate with a sharp and steep erosional contact to a dolomite basement.

The lowermost conglomerates are poorly sorted and may be termed diamictites, however they are not the tillites typical to the Tasmania Basin. Their glacial origin cannot be proven, and they are conglomeratic rather than the silty diamictites of the Wynyard Tillite.

Basement

Precambrian Dolomite 980.5-1323.6.

Dolomite colour varies from grey to black, the darker materials generally being finer grained. Interbeds of greenish sandstone, and red and green chert, also occur. Sandstone interbeds occur at 1173-1180m, 1253-1266m, 1318m and 1320m and thin chert beds occur at 1015m and 1300m. Two small intervals at 1025m and 1036m have dark coloured oolites approximately 5mm across in a lighter grey matrix.

Bedding planes vary from near horizontal to vertical and are rarely consistent for more than 500mm. In most cases bedding is convoluted and in places shows slump structures. Stylolites were observed in a number of places outlined by graphitic material.

Much of the core is broken and crumbly but competent sections show complex calcite veining patterns, many veins having breaks and displacements due to minor faulting. Two veins sets occur, fine and generally less than 1mm thick, and larger 10-20mm, both cross cut each other and the bedding. The larger calcite veins are more common below 1250m.

The dolomite sequence is non-fossiliferous except at 1180m where remnants of stromatolites occur. Poor preservation does not allow closer identification. At 1170m a 50mm section appears to be algal laminated. In a number of places core breakage may have occurred along algal laminated layers.

Pyrite occurs as fine disseminations and as crystals on partings from 1041m, becoming more prevalent between 1235-1247m. Where pyrite is prominent fine dissolution cavities are present, particularly in thicker calcite veins. Decomposed black clay occurs towards the bottom of the hole.

Textures become schistose from 1240m. A black sheen is visible on bedding surfaces and this became pervasive towards the bottom of the hole. Cleavage becomes crenulated and from 1320m the core can be described as schist. The last two metres were partly decomposed and pyrite crystals up to 1mm across were present in this section.

The dolomite intersected at Hunterston can be lithologically correlated to the Black River Dolomite of northwestern Tasmania. The interbeds of green coloured basaltic sandstone, small oolitic intervals, and chert within the Hunterston core are similar to the Black River Dolomite (pers. comm. Calver, 2002). The Black River Dolomite has been correlated with the Crimson Creek Formation of western Tasmania (Adabi 1997; Calver 1998) and the Weld River Group of south-central Tasmania (Calver 1989). All these groups are recognised as Neoproterozoic (~750-650 Ma) (Calver 1998). Widespread distribution of these similar aged dolomites may indicate that a possible Neoproterozoic carbonate platform existed.

The stromatolites within the Hunterston core are not identifiable, however Calver (1998) mentions the occurrence of Baicalia burra in clasts within diamictite at the top of the Black River Dolomite in northwestern Tasmania, and Adabi (1997) also recorded Baicalia burra within Crimson Creek Formation at Renison. Griffin and Preiss (1976) described the occurrence of Baicalia burra from diamictite overlying the Smithton Dolomite and made a comparison with the Skillogalee Dolomite in South Australia. It is possible the remnants of stromatolites in the Hunterston core are also *Baicalia burra* and thus could provide a means of correlation with other Tasmanian, and possibly mainland, Precambrian dolomites.

PALAEOGEOGRAPHY

The freshwater beds and upper marine sequence encountered in the Hunterston DDH are similar to these units elsewhere and are not of significant palaeogeographic interest. However the absence of Wynyard Tillite and the prominence of conglomerates in the lower marine sequence are of interest. To the east in the Tunbridge and Ross DDHs are thick sequences of tillite (Wynyard Tillite) followed by pyritic pebbly mudstone and siltstone (Woody Island Siltstone). These areas are in closer proximity to Hunterston than the thick conglomeratic deposits in the Mackintosh mapsheet (Collins *et al.* 1981), or the thinner but significant conglomerates in the Du Cane area (MacLeod 1961). The absence of thick diamictites or identifiable tillite signifies a regional high to the northwest, as outlined by Collins et al. (1981). The absence of true tillite, and the presence of conglomeratic sequences at Hunterston in place of the Woody Island Siltstone shows this regional high extends southeastward. Whether the high is a series of peaks or a continuous southeast trending mountain range is unknown. However the change in relief to the east and northeast is significant, with thick sequences of tillite deposited in the Golden Valley to Tunbridge area (Fig. 3).

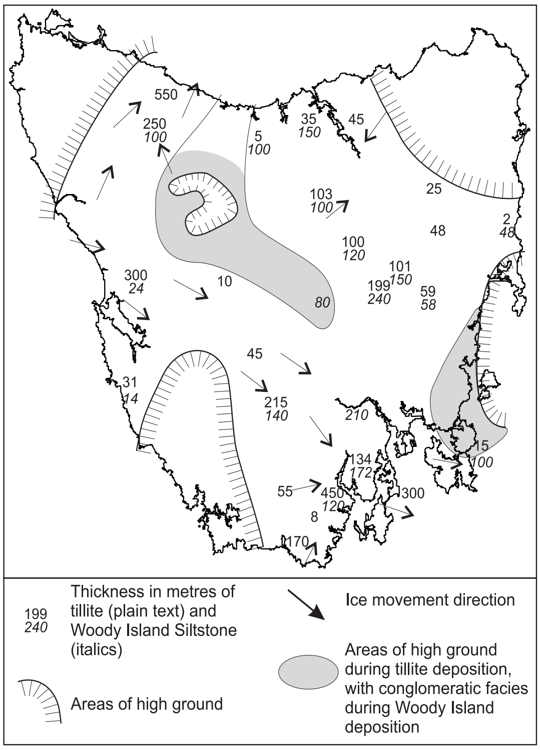


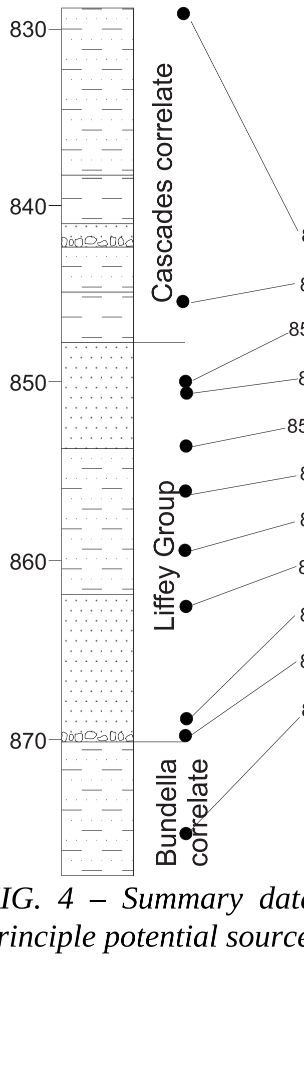
FIG. 3 – Palaeogeography of the Tasmania Basin, during deposition of the Wynyard Tillite and Woody Island Siltstone. Updated from Clarke (1989), with additional ice movement indicators from Hand (1993). Extension of Mt Inglis area conglomerates into central area of basin based on drilling results of Hunterston DDH.

HYDROCARBON PROSPECTIVITY

Source rock

The Woody Island Siltstone, which is regionally extensive across the Tasmania Basin, and may be considered an appropriate potential source rock, is absent in the Hunterston DDH. The conglomeratic mudstones at this stratigraphic level, whilst often having a dark mud matrix are not of source quality. Toward the base of the conglomeratic beds wispy carbonaceous mud lenses appear in the matrix, with moderate TOC and Type I kerogens, however these are too thin and discontinuous to be of significance. The Tasmanite Oil Shale, or abundant *Tasmanites* are absent.

However, potential hydrocarbon source rocks are contained within the carbonaceous siltstones and sandstones of the Liffey Group. Discrete coal beds are not developed but the quantity of plant fragments and carbonaceous mud show TOC levels up to 3.1% (Figure 4), comparable to non-coal beds in this unit elsewhere in the Tasmania Basin. Kerogen types are dominantly type III, as characterised by Hydrogen Index versus Tmax. Type III kerogens are gas prone, and their low atomic hydrogen to carbon ratio means they generate and expel less petroleum products than other kerogen types (Hunt, 1995).

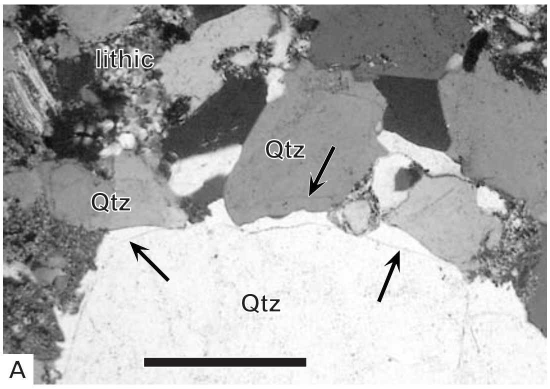


	Reservoir porosity %	Reservoir perm. mD	VR	Rock Eval TOC	Rock Eval Tmax	Rock Eval S1/S2	Comments
828.5				1.25	492	0.6/.61	
845.6				2.9	463	.46/1.24	
850.15				3.1	459	.54/1.9	
850.5	0.9		1.28				oil inclusions
853.25	8.7	0.06					
856.5			1.06	2.35	464	.38/1.84	oil inclusions
859.2				2.24	458	.41/1.49	
862.9	4.1	0.04					
869.3	5.6	0.05	1.23				oil inclusions
869.5				2.2	464	.55/1.51	
874.4				1.26	447	.36/1.01	oil inclusions

FIG. 4 – Summary data for the Liffey Group and adjacent rocks. Data given for principle potential source and reservoir rocks.

Samples from the Liffey Group, and underlying and overlying marginal marine beds of the Bundella Mudstone and Cascades Group were analysed for vitrinite reflectance. Only the Liffey Group samples actually contained vitrinite in the dispersed organic matter (Cook, 2003), all samples contained inertinite, liptinite is absent. The contact to the base of the dolerite sill complex is at 784.4m, 44.1m above the Cascades sample, 66.1, 72.1 and 84.9m above the Liffey Group samples and 90m above the Bundella sample. The relative consistency in the reflectance of inertinite and vitrinite material indicates that heating effects of contact metamorphism are negligible at this distance from the dolerite intrusion. The nature of the vitrinite also indicates that any alteration from contact metamorphism is mild, as carbonised organic matter is not present (Cook, 2003).

Calculated petroleum generation, using time-temperature index graphs based on the Arrhenius equation (TTI_{ARR}), is difficult to determine, as the total sedimentary overburden in the Hunterston region is not known. The thickness of Triassic sediments can be roughly assumed, but there is an unknown amount of Cretaceous and Tertiary sedimentation. Burial profiles based on the known Permian to Jurassic overburden do not bury the Liffey Group to depths great enough for hydrocarbon generation. Yet the vitrinite reflectance values indicate maturity was achieved, with probably only a small increase from dolerite effects. However as the source is a type III kerogen, initial generation temperatures required are higher, than for say type I (*Tasmanites*), few hydrocarbons were generated despite the source rocks being within the maturity window. Given a maximum vitrinite reflectance value of 1.28%, the corresponding temperature (from Hunt, 1995, p. 389) would be approximately 115^{o}C. Assuming maximum burial was reached in the mid-Cretaceous, from maximum fission track data (O'Sullivan & Kohn 1997), and constructing a theoretical burial curve to match a temperature maximum of 115^{o}C, type III kerogens would have generated less than 4.3 unit TTI, or less than 5% of maximum potential hydrocarbon generation. Had the kerogen type been type II, as is seen elsewhere in the basin, up to 65% of maximum potential hydrocarbon generation may have occurred.



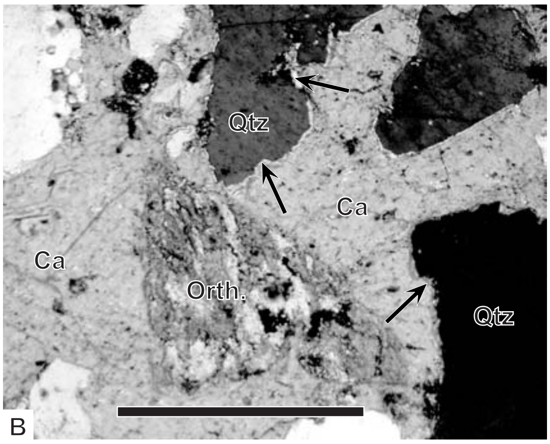


FIG. 5 - Diagenetic features of Liffey Group sandstone in the Hunterston DDH, all scale bars 0.5mm. A,869.3m polarised light view showing quartz overgrowths, with grain boundaries indicated by arrows. B, 850.5m polarised light view showing perthitic dissolution of orthoclase feldspar and dissolution of quartz cement and grains, and replacement with calcite cement, arrows. Qtz = quartz, Ca = calcite, Orth = orthoclase feldspar, lithic = lithic clast.

Reservoir rock

Traditional potential hydrocarbon reservoir rocks exist within the sandstones of the Liffey Group, as they do across much of the Tasmania Basin. However in the Hunterston DDH, the negative effect of proximity to dolerite intrusions is shown. The overlying limestones have contributed carbonate to the pore fluids, increasing pH, with temperature elevated from the intrusion. Carbonate cementation is later than both silica and clay, but may destroy both (Fig. 5). In many samples original quartz clasts have been eroded, and orthoclase feldspar has been pervasively replaced by calcite. In the Hunterston DDH carbonate cement is well developed, and it is the late dissolution of carbonate that produces a secondary porosity. However connectivity of pore spaces is low, and hence permeability is low. Permeability in potential reservoir beds ranges between 0.04 –0.06mD, suitable for gas (threshold 0.01mD) but not oil (threshold 0.1mD).

Some Liffey Group sandstones contain oil inclusions, within both quartz and carbonate (Cook, 2003). Oil inclusions form during crystallisation of diagenetic minerals, and through brittle deformation and fracturing of detrital and diagenetic grains during burial (George *et al.* (1996). The inclusions within detrital Liffey quartz grains could have formed by fracturing at any time in their diagenetic history. As the timing of precipitation of the carbonate is known to be associated with Jurassic dolerite, the presence of oil inclusions is important. While they may also have formed by fracturing at any given time, they may have been directly included during crystallisation of the carbonate cement in the Jurassic.

Down hole fault zones

There is potential for localised reservoirs within the brecciated fault zones in the lower marine sequence. Several of these brecciated zones occur around 900m depth, each with an associated “halo” of carbonate dissolution, and replacement by silica, ranging from 0.5 to 10m in thickness. The dissolution of carbonate material is assumed to be by fluids introduced along fault structures. The degree of brecciation is severe, and the high porosity and permeability led to loss of drilling pressure, indicating such horizons would be highly suitable reservoirs, providing there is a suitable seal on the fault away from the zone of dissolution.

Near the base of the Lower Parmeener Supergroup in the Hunterston DDH at 957m, one such dissolution horizon, involving strong carbonate dissolution and siliceous replacement of a conglomerate, over 3m, has not been brecciated and mean porosity is 16.9% and mean permeability 6323mD.

Gas

The drilling program of July 2002 included gas measurement during drilling by OME Resources. Background levels of gas remained low, with a maximum of 40 units (0.4 % by volume in air) encountered in the sandstones of the Liffey Group. However as the hole was diamond drilled the volume of cuttings from which gas could be measured and/or collected is small and is not a definitive indicator of true gas content.

Hydrocarbon summary

Thick source rocks are absent from the Hunterston DDH, although thin beds exist in the Liffey Group. While the porosity and permeability of potential reservoir sandstones in the Liffey Group are poor, destroyed by diagenetic effects associated with dolerite intrusion, there are indications of the presence of oil. Oil inclusions within both silica and carbonate in the sandstones, indicates generation and/or trapping of hydrocarbons before the final diagenetic phase. A possible scenario is of hydrocarbons generated before dolerite intrusions that have been locally expelled by carbonate fluids.

Structure

Figure 1 shows the local strike and dip of beds that form a dome like structure. The drillhole was placed to be at the estimated central position of this domal structure. The Hunterston Dome, is reflected at the surface in Permian and Triassic sediments, and was assumed to continue as a subsurface feature. The seismic data is not at a scale appropriate to determine the subsurface dip of the Parmeener beds, showing them as regionally flat lying, however a broad domal structure is seen in the underlying Precambrian dolomites. However the seismic data does prove the continuity of the eastern outcropping dolerite with the intrusion encountered between 134m and 784m in the hole. On a regional scale it appears there is only one major dolerite body across the central Midlands, and in the local Hunterston area forms a shallow dipping basin, as partly shown in Fig. 6. The deformation of Triassic sandstones and the upper marine beds of the Parmeener Supergroup, producing the Hunterston Dome, either preceded or was coincident with dolerite intrusion. Dips adjacent to the dolerite contact east of the DDH site steepen towards the boundary, and may indicate bed drag effects.

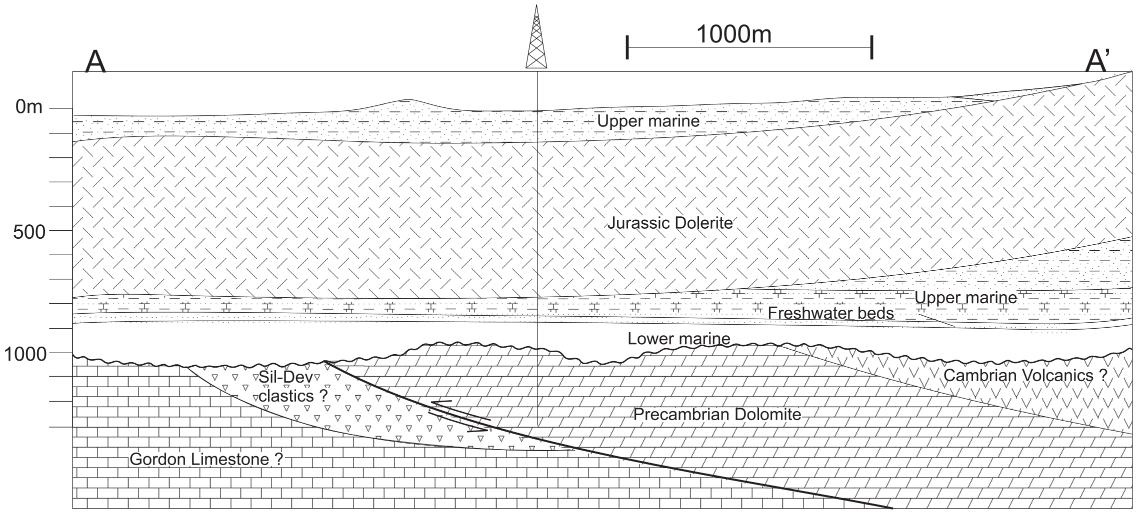


FIG. 6 – Schematic cross section along the line A-A' (location shown in Fig. 1). The vertical to horizontal exaggeration is 1:1. Data from drilled section, and interpretation of seismic survey.

Within the basement Precambrian dolomite complex minor faulting and intersecting veining patterns noted in the core indicate a complex tectonic history and a number of episodes of movement. Bedding directions, where visible, repeatedly vary between near horizontal to vertical indicating that the drilled section passed through multiple folds. The extremely contorted bedding near the bottom of the hole may indicate proximity to a thrust plane, contortions being due to drag folding. The presence of black clay, evidence of decomposition of the dolomite, in this region may have been due to fluids introduced along a permeable thrust plane. Disseminated pyrite also noted in this region may have been precipitated from introduced fluids.

Permo-Carboniferous glacial erosion and retreat has produced conglomeratic beds of rounded pebbles of Precambrian dolomite, supported in a silty matrix, immediately on top of the massive Precambrian dolomite. It is hard to conceive that all of the sedimentation from Cambrian to Carboniferous could have been eroded when nearby thousands of metres of deposition from this time interval can be observed. It is likely that the Permian deposits lie over the end of a thrust sheet of Precambrian dolomite as shown in Figure 6. A series of thrusts can be traced in Fossey Mountains region of northern Tasmania (Woodward et al. 1993) and the existence of stacked thrusts in the area drilled has been interpreted from geophysical data (Leaman et al. 1973; Leaman 1989; Leaman 2001). In the Hunterston area the geology of associated thrust blocks is unknown. The closest outcrops of Precambrian dolomite occur near Hastings Caves, in southern Tasmania, where it is in fault contact with Ordovician Gordon Limestone, hence the thrust contact of Precambrian dolomite and Gordon Limestone are inferred in Figure 6. Cambrian volcanics are inferred to overly Precambrian dolomite by superposition.

CONCLUSIONS

The Parmeener stratigraphy in the Hunterston DDH includes the Ferntree Mudstone, in part, the Cascades Group, freshwater Liffey Group and Bundella Mudstone as expected. A thick, 650m, multiple dolerite intrusion is present between the Ferntree and Cascades Group. A portion of Parmeener sediments have been lost in this interval, although it is unknown whether this is associated with faulting before, or events during, intrusion. The presence of basal conglomerates in place of Woody Island Siltstone, and Wynyard Tillite, proved the extension of Mackintosh – Du Cane regional high to the northwest through this central part of the Tasmania Basin. Basement to the Parmeener Supergroup is Precambrain dolomite, with its closest lithological correlate near Smithton in far northwest Tasmania.

The absence of the Woody Island Siltstone, a potential hydrocarbon source rock, and dispersed or concentrated Tasmanites commonly contained within it, reduces the previously assumed distribution of this unit. Potential hydrocarbon source rocks exist within the freshwater Liffey Group, but rock eval pyrolysis shows them to be type III kerogens, one of the last groups of kerogens to generate hydrocarbons within the oil window (Hunt 1995). However oil inclusions reported within reservoir sandstones indicate that hydrocarbons have probably migrated through the section.

Dolerite intrusion has mobilised carbonate, and reduced reservoir quality within the Liffey Group, however direct heating effects are not seen. Measured vitrinite reflectances within the Liffey Group show close to background maturity of organic matter (Cook 2003), indicating the central Tasmania Basin is mature for hydrocarbons.

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