The Tasmania Basin – Gondwanan Petroleum System

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TASMANIA BASIN – GONDWANAN SYSTEM

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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 other 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 (Fig. 1A) 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; Fig. 1B), with a high organic content, of coldwater environments (Domack *et al.*, 1993). The alga *Tasmanites* is common in these siltstones, and in the lower part is concentrated to form the *Tasmanites* 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 corresponding Source Potential Index (SPI), and in many areas is a mature or partially mature source rock for hydrocarbons. The remaining thick siltstones have dispersed *Tasmanites* and lower TOC and SPI values, 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. T_{max}, Hydrogen and Production Index values indicate source rock maturity over much of the basin.

Marine conditions continued with the deposition of generally highly fossiliferous siltstones and minor sandstones (Fig. 1C) as the Tasmania Basin was gradually filled (Banks, 1989; Clarke, 1989). In the Western Tiers region a quite 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.

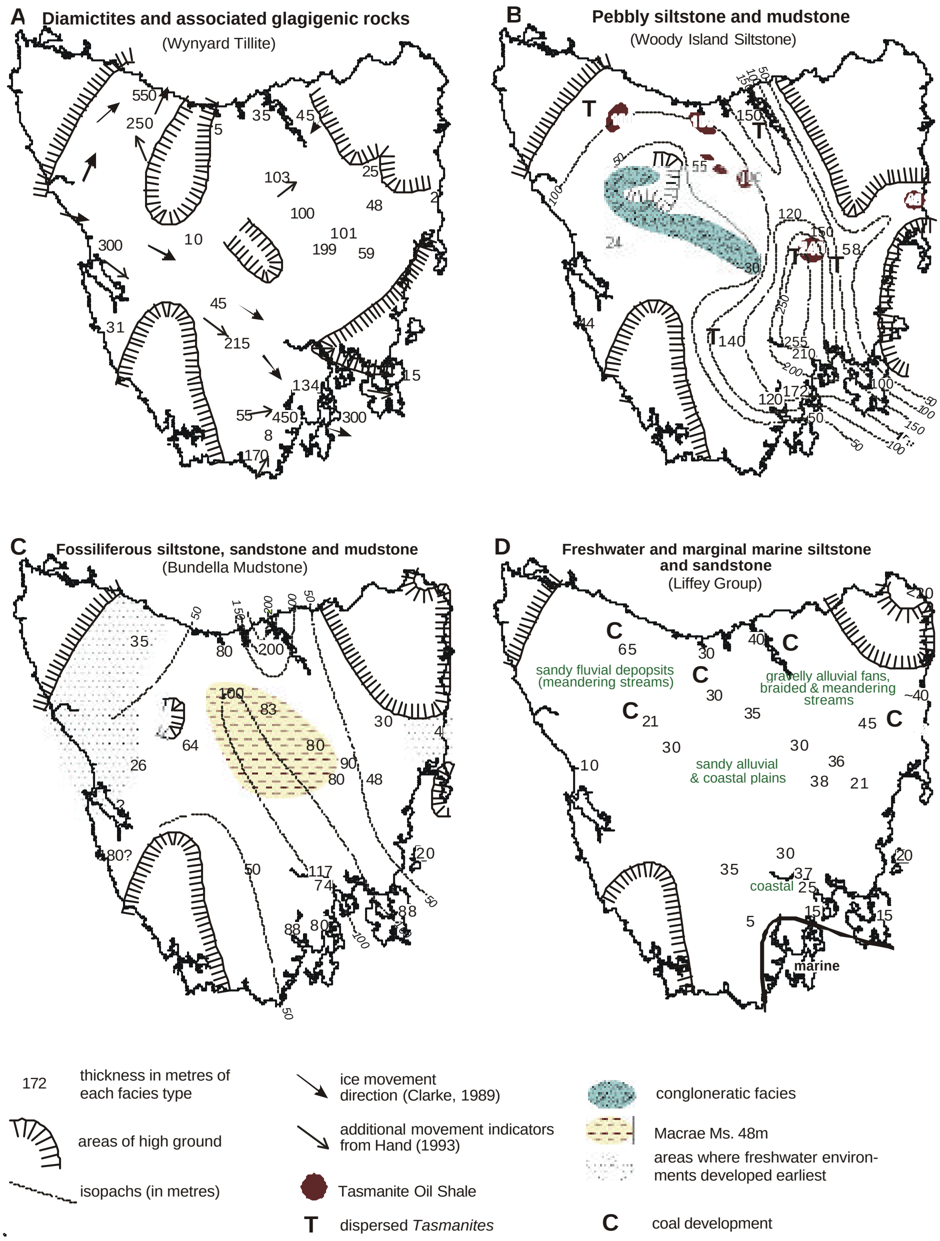


Figure 1 – Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – diamictites (Wynyard Tillite); B – pebbly siltstone (Woody Island Siltstone); C – fossiliferous siltstone (Bundella Mudstone; D – Freshwater sandstone and siltstone (Liffey Group).

Filling of the Tasmania Basin resulted in a relative regression of the shoreline southward and deposition of freshwater sandstones and carbonaceous siltstones (Fig. 1D). 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). Further work is continuing on the nature of porosity in these sandstone units and their lateral and vertical extent.

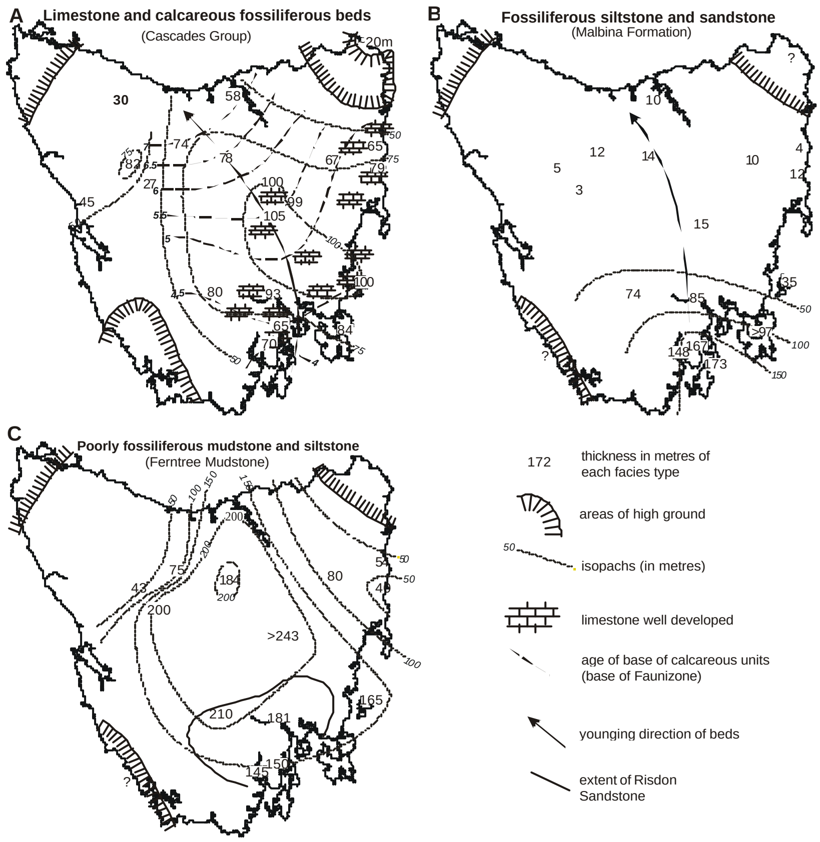


Figure 2 - Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – calcareous fossiliferous beds (Cascades Group); B – fossiliferous siltstone and sandstone (Malbina Fm and correlates); C – siltstone and mudstone (Ferntree Mudstone).

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; Fig. 2A). 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; Fig. 2B). 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 are also more 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 (Fig. 2C). 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.

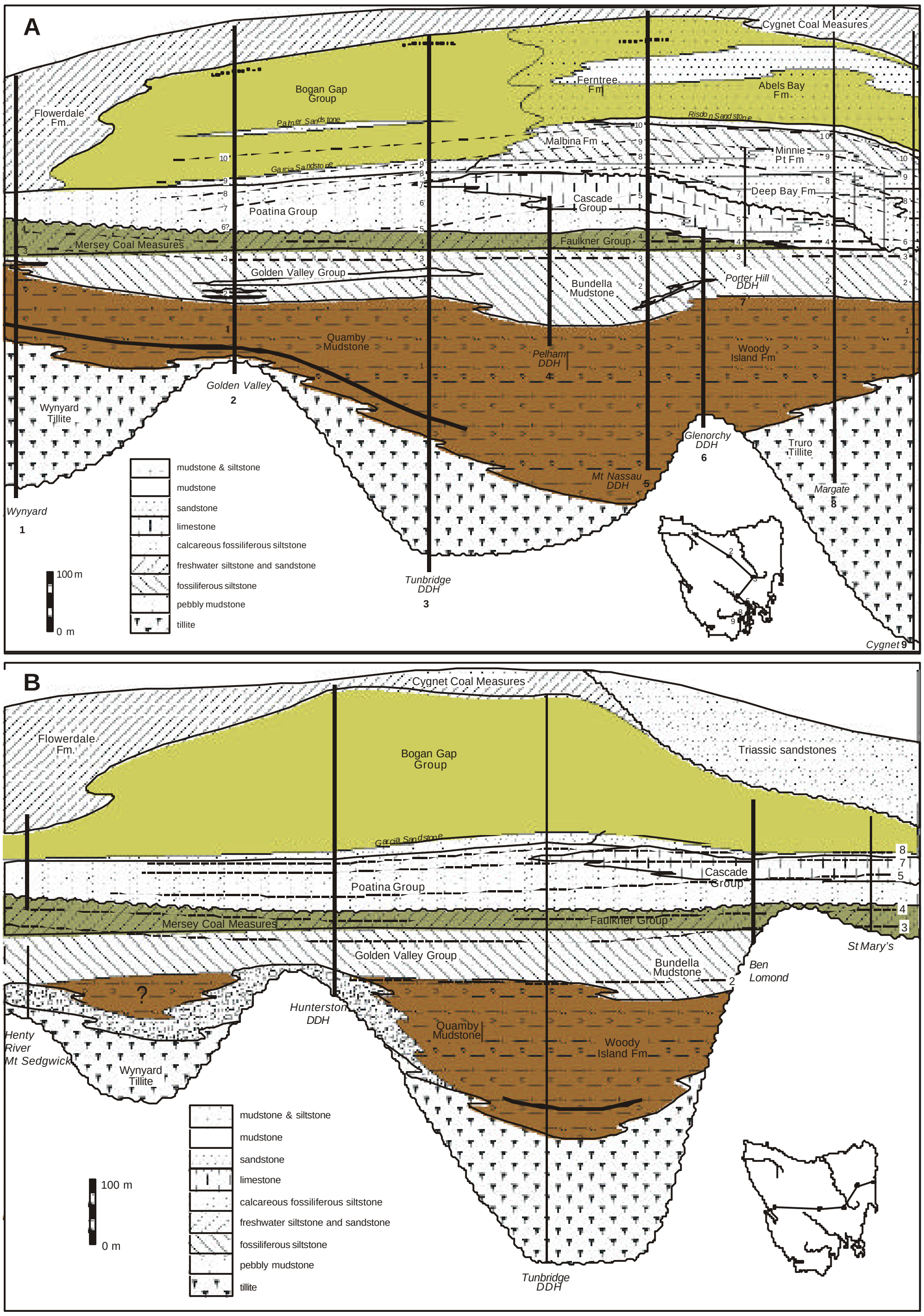


Figure 3 – Stratigraphic development of the Lower Parmeener Supergroup. A Section line from Wynyard to south of Hobart, B, Henty to St Marys. Potential source, reservoir and seal rocks are indicated.

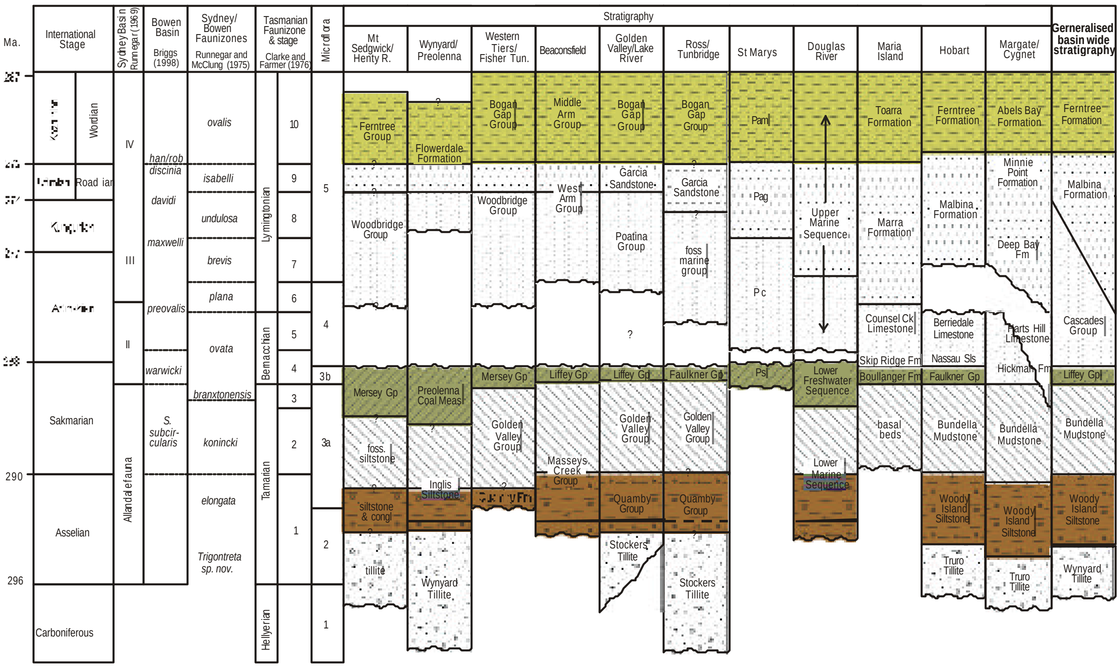


Figure 4 – Biostratigraphic correlation of the Lower Parmeener Supergroup.

The overall stratigraphy and general basin development are shown in Figs 3 and 4. Potential source reservoir and seal rocks are highlighted. These rocks will be discussed in detail later.

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 (Fig. 5A). 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; Fig. 5B). 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).

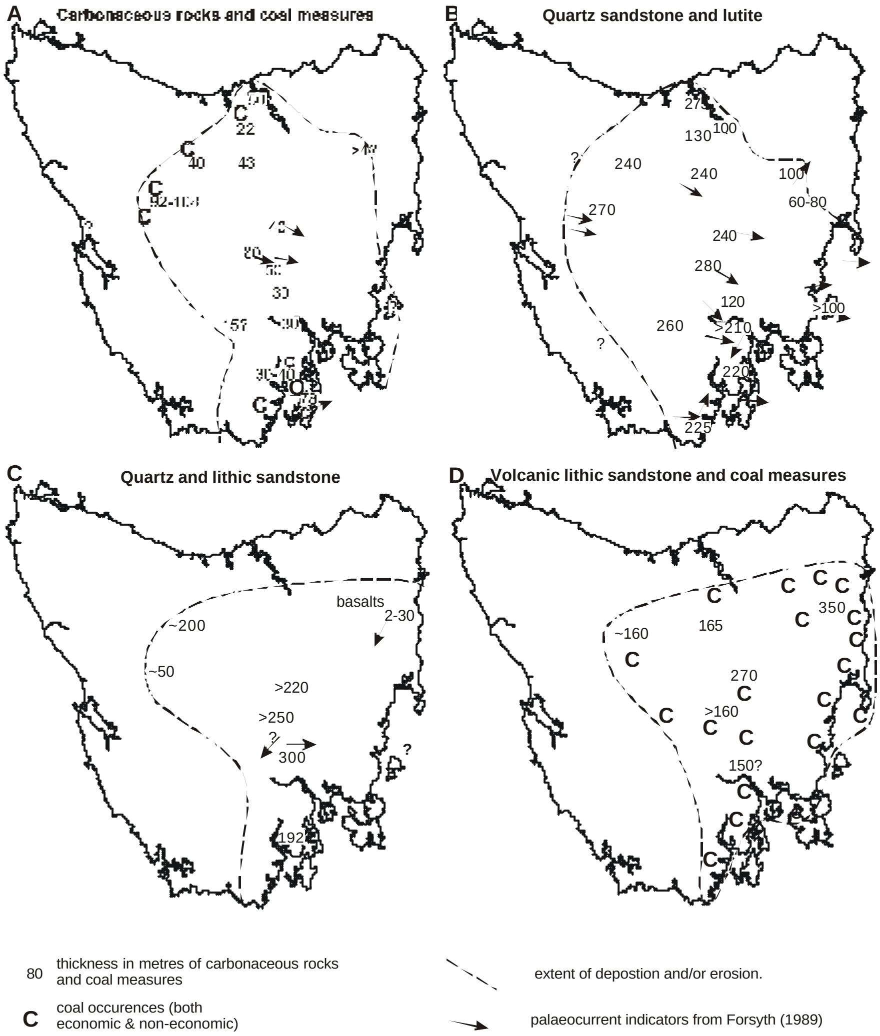


Figure 5 – Palaeogeography of the Upper Parmeener Supergroup. Isopachs of facies thicknesses in metres. Based on Forsyth (1989).

Following quartz sandstone and lutite deposition there is a broad basin wide change to lithic dominated sandstone with two prominent quartz sandstone intervals (Fig. 5C). 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 (Fig. 5D). 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 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 source rocks are contained within the Woody Island Siltstone, that 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.

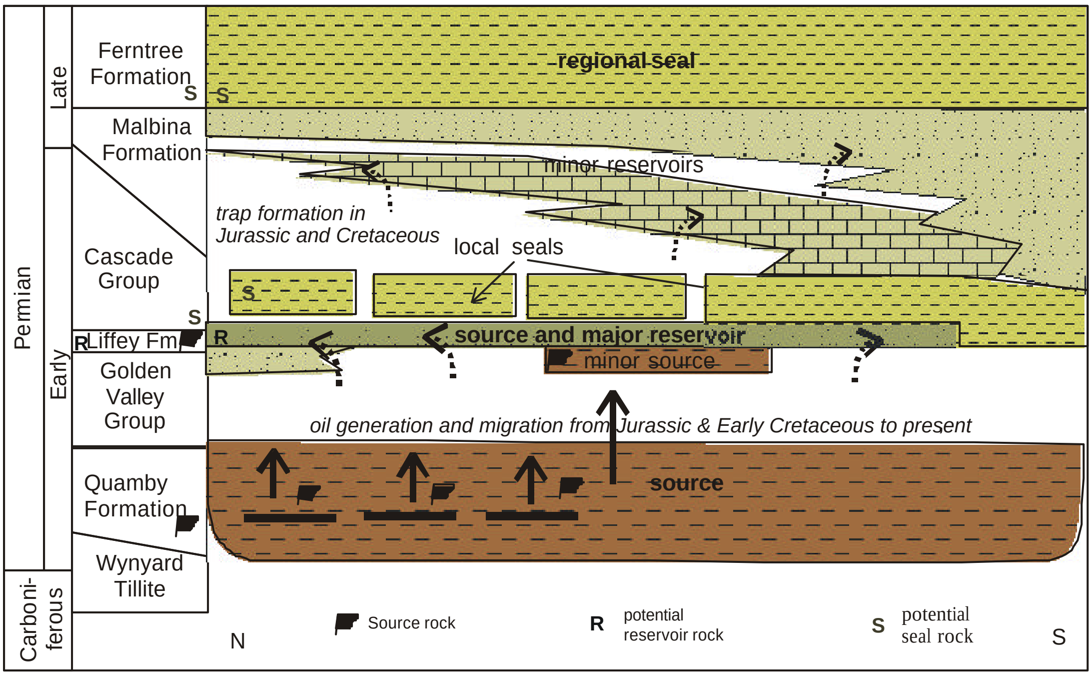


Figure 6 – Potential development of the Gondwanan petroleum system in the Tasmania Basin.

The basin maturity and source, reservoir and seal rocks are considered below, with a summary of basin stratigraphy and events shown in Fig. 6.

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 (Fig. 7A). 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 Fig. 7B.

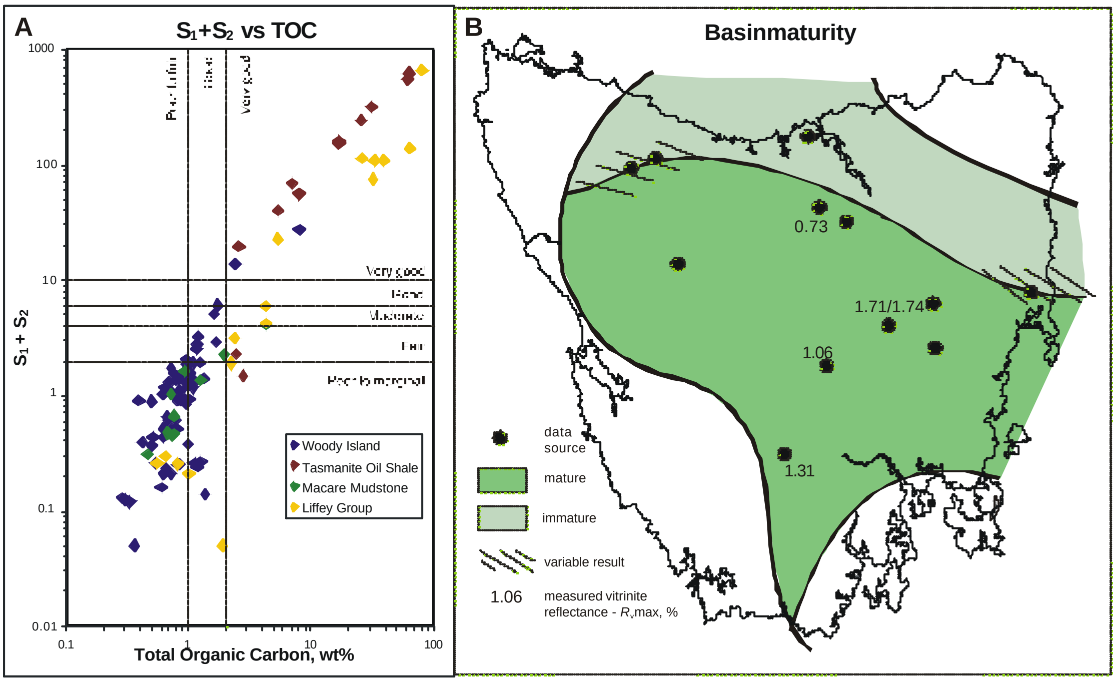


Figure 7 – A, Source rock potential of the Tasmania Basin. Data from Bacon et al. (2000) and new rock-eval analyses. B, Source rock maturity of the Gondwanan system in the Tasmania Basin. Maturity determined from T_{max}, Hydrogen Index, Production Index, and inferred and measured vitrinite reflectance.

Data indicators include T_{max}, Hydrogen Index (HI) and Production Index (PI) and inferred vitrinite reflectance (Fig. 8). The temperature range for generation of hydrocarbons is 430 – 465°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 Fig. 8 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 Fig. 8, for the most part indicate maturity. A limited number of samples have had vitrinite directly measured, and are included on Fig. 7B. 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 $R_v$max at Hunterston of 1.06%, is within 70m of a 600m thick dolerite sill, and is likely to have been elevated beyond regional non-dolerite values. 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.

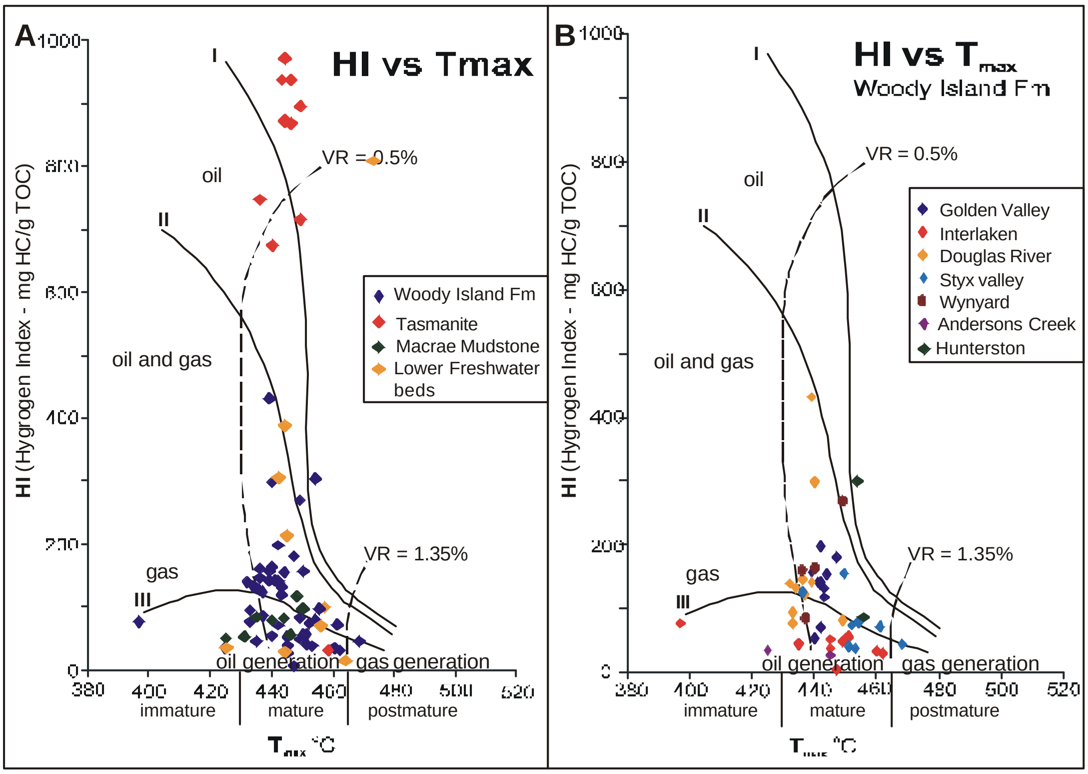


Figure 8 – HI vs T_{max} plots for source rocks in the Lower Parmeener Supergroup. A – HI vs T_{max} for all potential source rocks in the Lower Parmeener Supergroup. B – HI vs T_{max} for the Woody Island Formation, divided into geographic regions.

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 (Fig. 9A), 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 (Fig. 9B). 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 thickness 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.

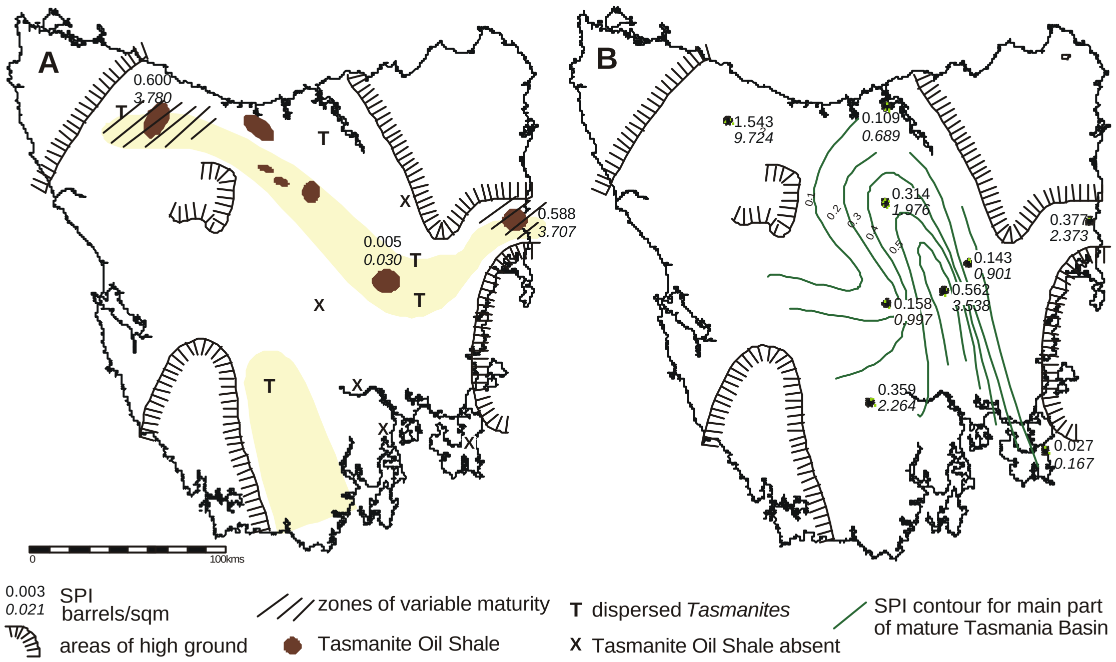


Figure 9 – A, Source Potential Index (SPI) data for the Tasmanite Oil Shale outcrops within the Tasmania Basin. Data available only for Wynyard, Douglas River and Tunbridge Tier DDH. B, Source Potential Index (SPI) data for the Woody Island Formation within the Tasmania Basin.

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 mariginal 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 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. 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 Muellers Rd 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 10A) shows that all source rocks contain an expected level of S_1 hydrocarbons for their given TOC.

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.

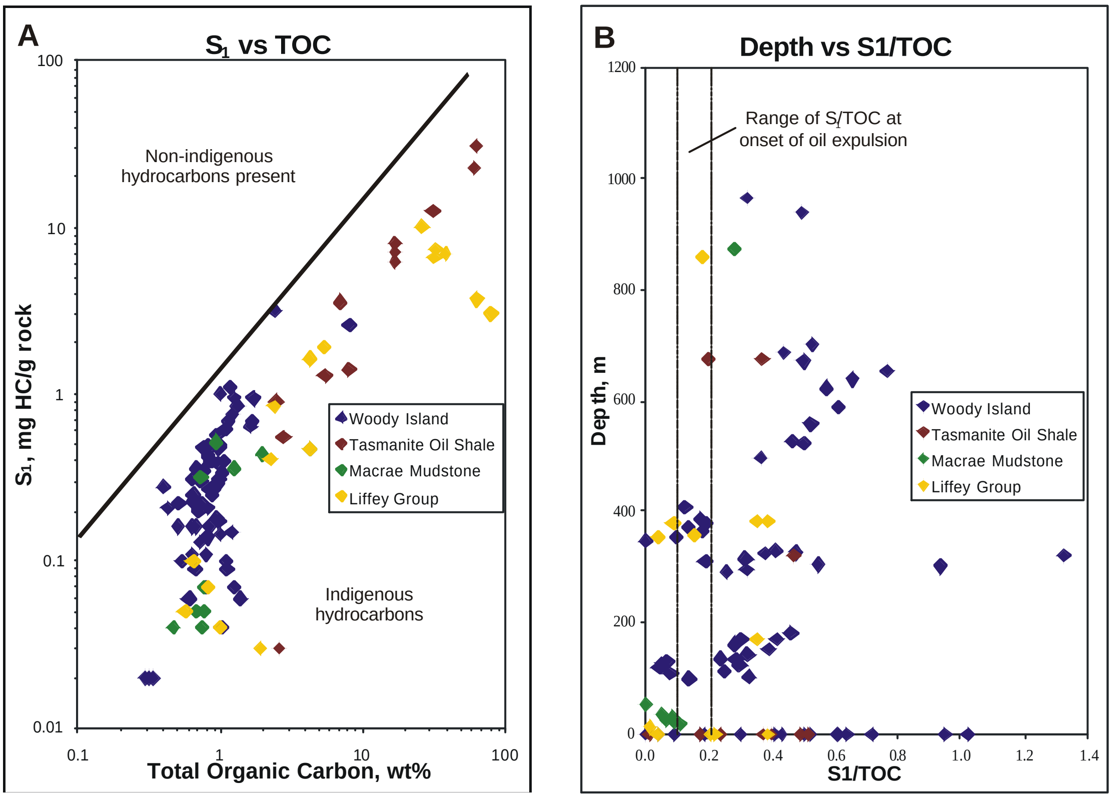


Figure 10 – Geochemical parameters and expulsion indicators of Tasmania Basin source rocks. A, S1 vs Total Organic Carbon (TOC), after ODP guidelines as an indicator of indigenous and non-indigenous hydrocarbons. B, S1 vs TOC ratio as an indicator of oil expulsion.

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 10B 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 11A) 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 quite 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.

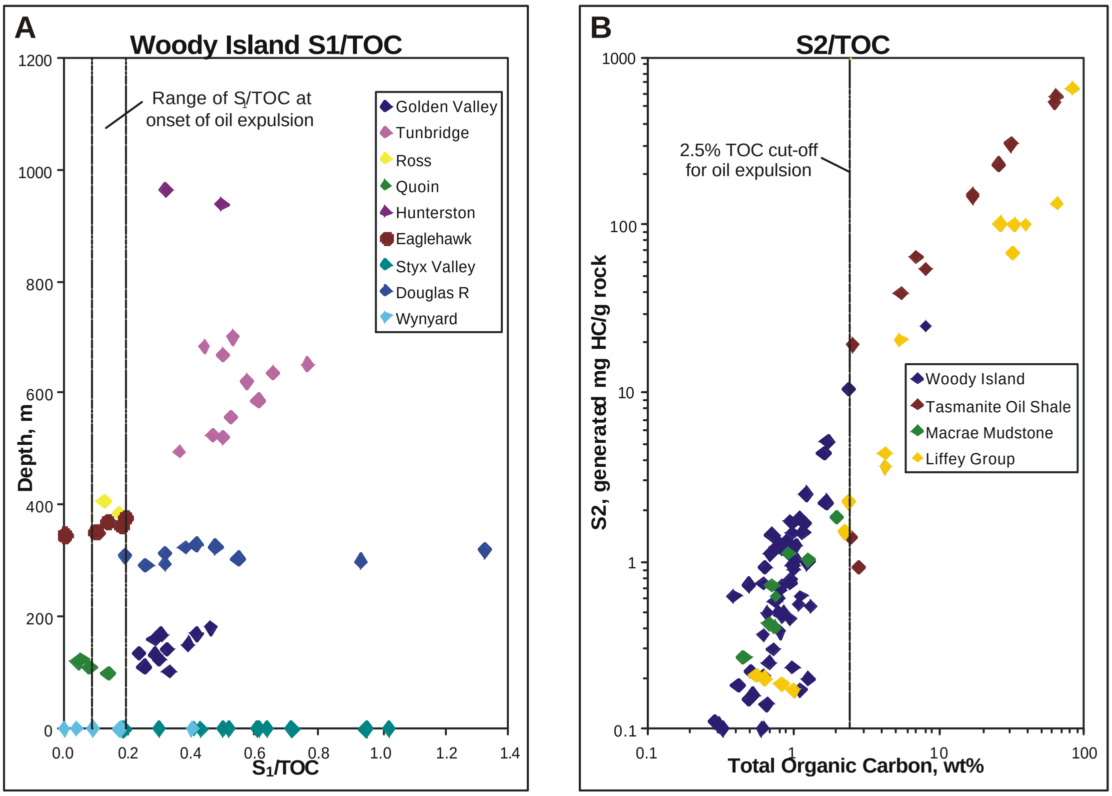


Figure 11 – Geochemical parameters and expulsion indicators of Tasmania Basin source rocks. A, S1 vs TOC ratio as an indicator of oil expulsion for the Woody Island Siltstone. B, Percentage TOC for Tasmania Basin potential source rocks.

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 expulsion. 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 11B). In consideration of gas generation and expulsion potential Figure 8 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.

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 to 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. Fig. 14 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).

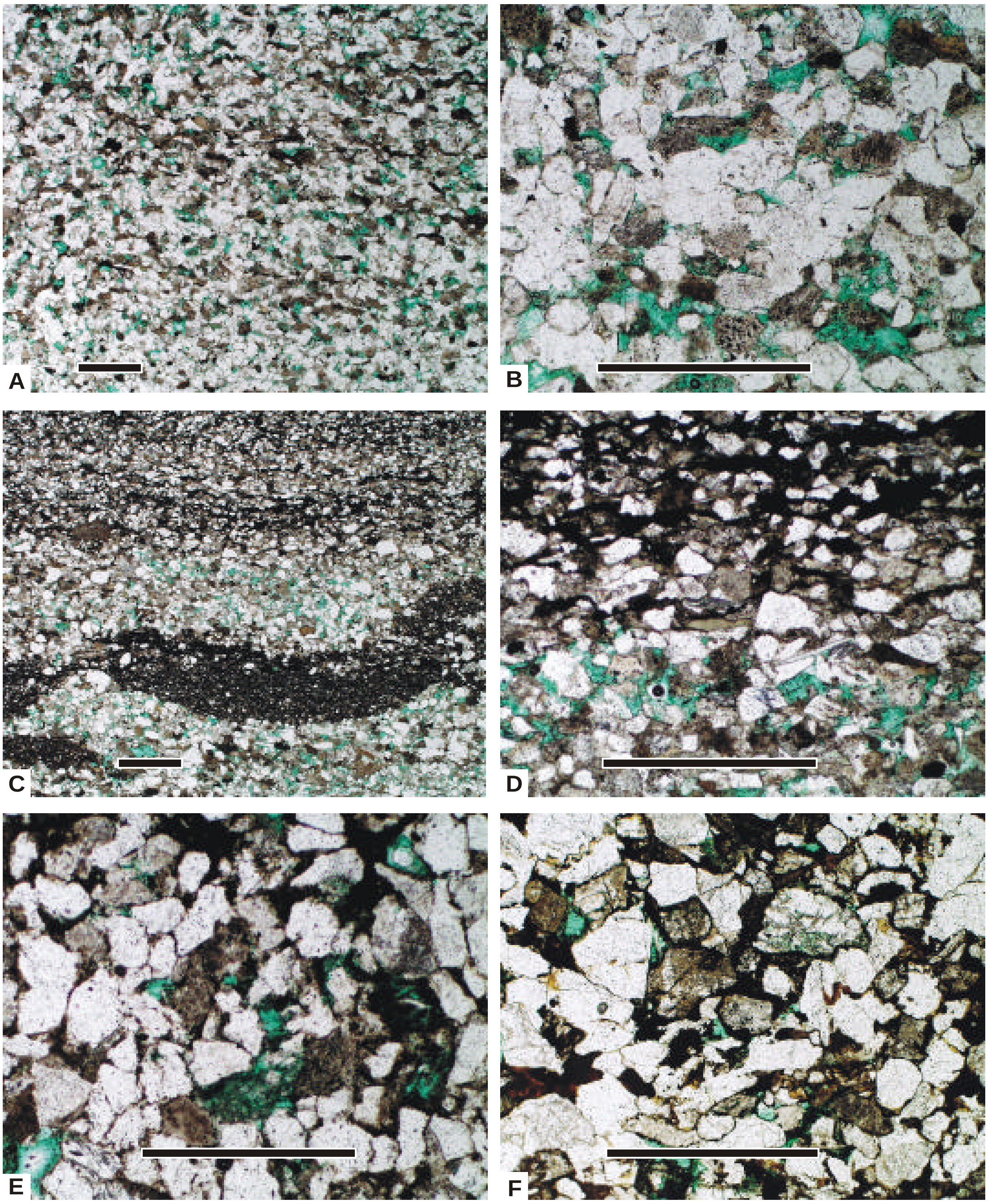


Figure 12 – Thin section porosity of potential reservoir rocks in the Lower Parmeener Supergroup. All scale bars 1mm. A-B – Ross DDH, 156.6m, Liffey Group sandstone, green material dyed araldite revealing pore space of 14.9% (Helium Injection). C-D – Granton DDH, 160.7m, Faulkner Group sandstone, C, 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%.

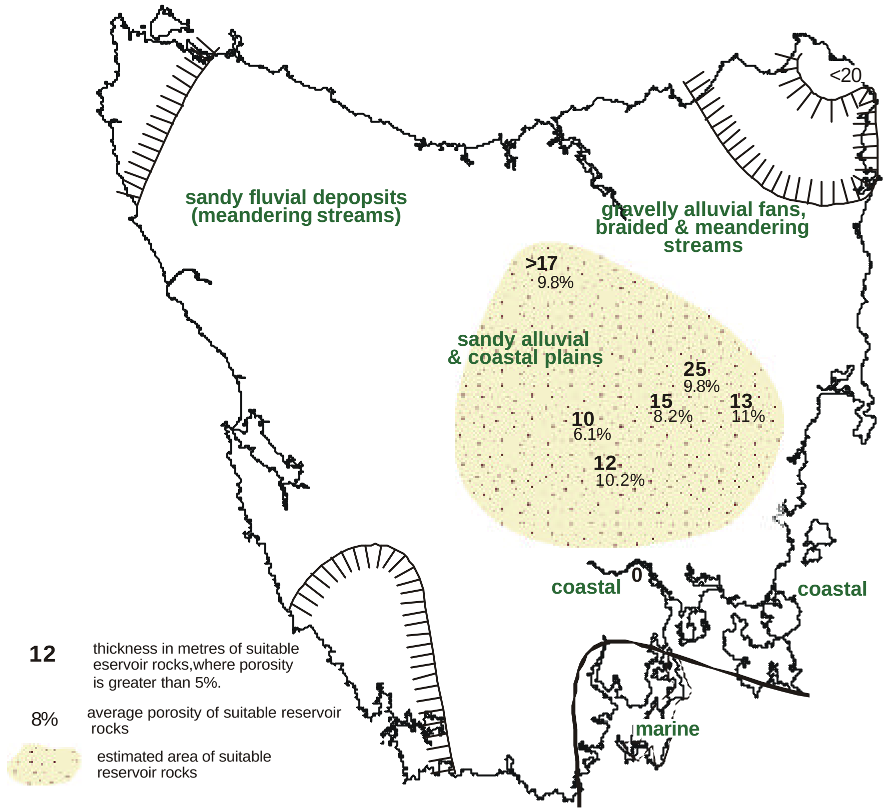


Figure 13 – Porosity distribution across the central Tasmania Basin, and total thickness of beds with porosity above 5%. Porosity data from Helium Injection and thin section point count.

In Fig. 13 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.

Reservoir diagenesis – Well sorted quartzose sandstones show clearly 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.

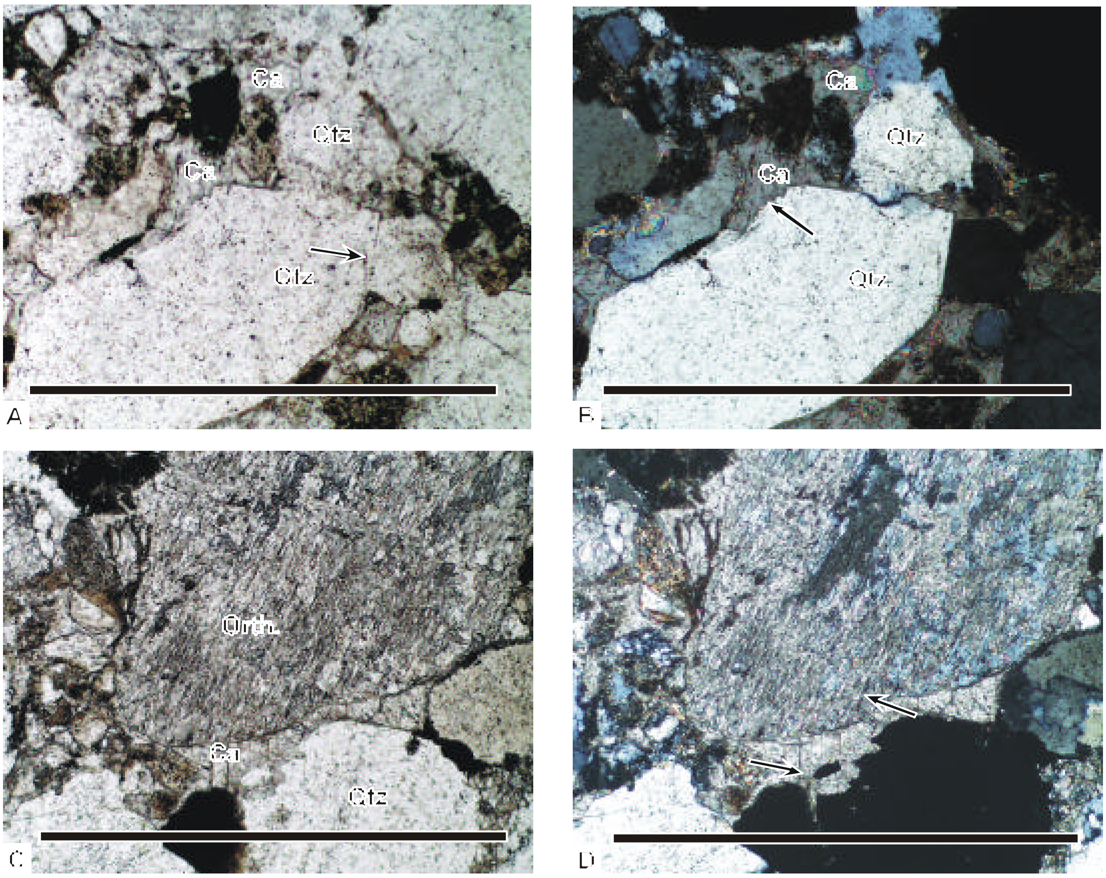


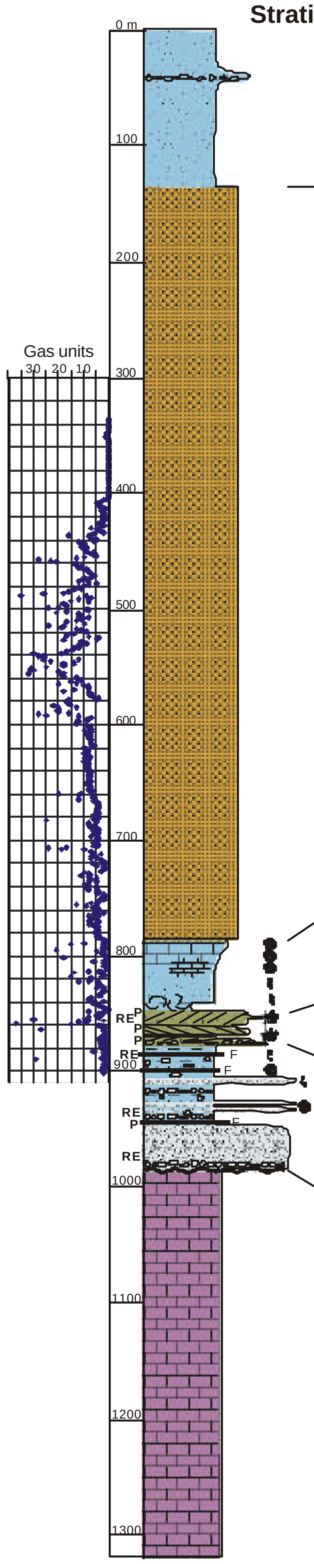
Figure 14 – Diagenetic features of Liffey Group sandstone in the Hunterston DDH, sample at 850.5m, all scale bars 1mm. A – plane light showing quartz overgrowths, with barely visible grain boundaries indicated by arrow. B – polarised light view of A, showing dissolution of quartz overgrowth and grains 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.

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 (Fig. 14). 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 (Claver & Forsyth, 2001; 2002) as intruding Upper Parmeener, and the Lower Parmeener Supergroup is apparently free pf pervasive dolerite intrusion. As discussed above suitable mature source rocks also exist in this area.

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

Limestone
Mudstone & siltstone
Siltstone
Sandstone
Tillite
Dolerite
Bioturbation
Carbonaceous material
Marine fossils
Calcareous beds
Unconformity

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 15 – Stratigraphic section of the Hunterston DDH.

Fault produced porosity

In the Hunterston DDH faults low in the Parmeener sequence were frequently seen to be brecciated (Fig. 15). 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 (Fig. 16).

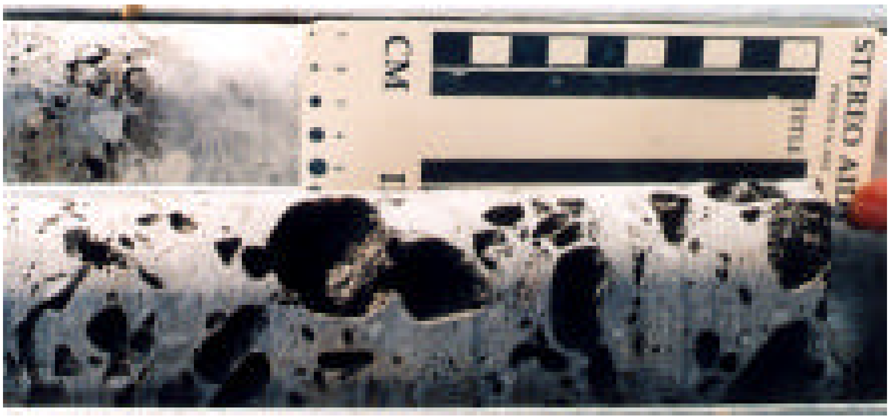


Figure 16 – Conglomeratic mudstone, from the Bundella Mudstone correlate, 957.5m depth Hunterston DDH. Cavities produced by dissolution of carbonate clasts and incomplete siliceous replacement.

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 traps.

Dolerite

As discussed earlier, the Parana Basin of Brazil is a unique petroleum system, in that instrusive 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 instrusive rocks, it is unclear at this stage at what depth fractures would be closed sufficient for seal properties to be formed.

However, the dolerite instrusions 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.

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