PETROLEUM SYSTEM MODELLING ONSHORE TASMANIA

The Tasmania Basin–Gondwanan Petroleum System

Final Report June 2004

Catherine Reid
School of Earth Sciences
University of Tasmania

Part of the SPIRT project "Petroleum System Modelling Onshore Tasmania", jointed funded by the Australian Research Council and Great South Land Minerals Limited.

This is a final report for research conducted in conjunction with the SPIRT project "Petroleum System Modelling Onshore Tasmania", joint funded by the Australian Research Council, and the Industry Partner Great South Land Minerals.

This section of research covers the potential source, reservoir and seal facies within the Tasmania Basin, along with basin development and stratigraphic review. Data was obtained from existing stratigraphic drill holes, with the addition of one new site drilled during the term of this project. Older Tasmanian petroleum systems, seismic, basin structure and basin modelling have been studied by other members of the research team.

The report is broken into two sections. This first is a brief review of Gondwanan glacial petroleum systems, in particular those of south Oman and the Parana Basin, Brazil, and an overview of late Palaeozoic glacial petroleum basins within Tasmania. The second section deals directly with the Tasmania Basin Gondwanan Petroleum System.

INTRODUCTION

The onshore Tasmania Basin Parmeener Supergroup is a glaciomarine to terrestrial sequence of Late Carboniferous to Late Triassic age overlain by now largely eroded Jurassic, Cretaceous, and Tertiary sediments. Thick Cretaceous and Tertiary sequences, which occur offshore, are not found in the onshore Tasmania Basin. The Lower Parmeener Supergroup of Late Carboniferous to Late Permian age is the focus of this report.

Interest in petroleum within Tasmania began in the late 1800s, with the Tasmanite Oil Shale unsuccessfully commercially retorted for fuel and fuel products (Bacon et al., 2000). There have been numerous reports of oil seeps and other phenomena (Bacon et al., 2000), but only a bitumen seep in a dolerite quarry at Lonnavale, southern Tasmania, is proven to be related to Tasmanian sourced hydrocarbons. Here biomarkers link it to a Tasmania Basin source containing abundant Tasmanites (Wythe & Watson 1996; Revill 1996).

Numerous shallow holes have been drilled targeting Tertiary to Permian rocks in various locations around Tasmania, but these holes were all shallow, and oil and gas were not found. There was renewed exploration activity in Tertiary rocks in the north of the state in the 1960s and 1970s, but drilling frequently intersected basalt and dolerite and was unsuccessful (Bacon et al., 2000).

Exploration has been continuing since the 1980s, focussing on the Parmeener Supergroup, with additional interest in the underlying Precambrian and Ordovician sequences and overlying Tertiary. This program has only produced two holes deeper than 1000 m, both drilled by Great South Land Minerals, with limited gas shows reported from drilling in the south of the state. In early 2001, Great South Land Minerals recorded 600 km of seismic through the central basin, specifically for hydrocarbon exploration, along with drilling at Hunterston-1 in 2002, on a 2001 survey seismic line (Reid & Burrett, in press).

The glaciomarine Lower Parmeener Supergroup, onshore Tasmania Basin contains mature potential source, reservoir and seal rocks. The Woody Island Formation has low TOC and type III kerogens, and contains the alga Tasmanites, that is in places accumulated as the Tasmanite Oil Shale, of high TOC and type I kerogens. Fossiliferous marine siltstone and sandstone follow, before widespread deposition of carbonaceous siltstone and sandstone (Liffey Group). The Liffey Group has good TOC and type II and III kerogens. Porosity in sandstone is fair to good, but permeability is limited by quartz and carbonate cements. Oil filled inclusions are present in some Liffey Group sandstone beds, but in low quantities, and do not yet indicate palaeo accumulations or migration paths. Potential local and regional seal units are found thick sequences of marginal marine and marine fossiliferous siltstone and sandstone. The Lower Parmeener Supergroup is succeeded by the thick non-marine Upper Parmeener Supergroup, and intruded by thick dolerite sheets in the mid Jurassic. The latest Carboniferous to Triassic Parmeener Supergroup is overlain by an unknown thickness of Jurassic to Cretaceous, now much eroded, plus Tertiary sediments.

The Lower Parmeener Supergroup has entered the oil window through the central basin, and the gas window in the far south. Maximum burial occurred during the mid Cretaceous, after intrusion of dolerite sheets that may form traps and seals. Further work is required to seismically define the presence or absence of structural traps within the Tasmania Basin.

GLACIAL PETROLEUM SYSTEMS IN GONDWANA

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. Figure 1 shows the distribution of glacial basins during the Late Carboniferous, when the Tasmania Basin was close to the magnetic South Pole.

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 places 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 of 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 1970s 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.

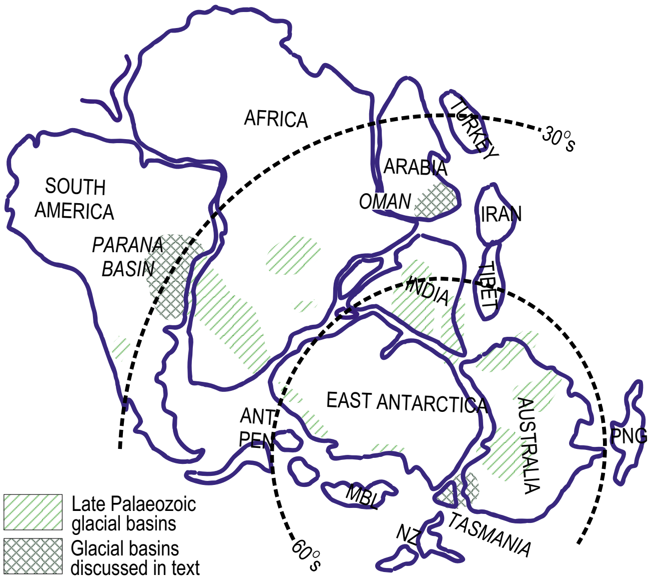


Figure 1 - Reconstruction of Gondwana during the Late Carboniferous, with glacial basins highlighted. After Lawver and Scotese (1987).

Glacial deposits are found in the lower part of the Haushi Group, in the Al Khlata Formation and Rahab Shale (Fig. 2). The upper parts of the Haushi Group, the Gharif and Khuff Formations, are not of glacial origin.

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 1-3000 mD (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.

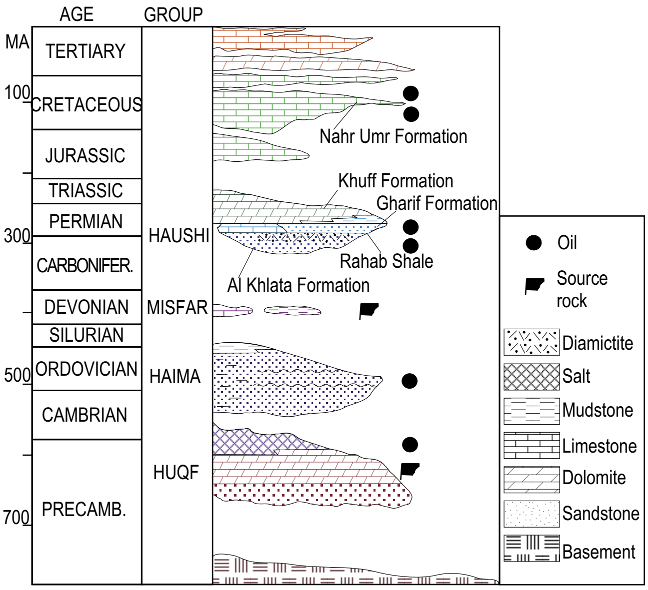


Figure 2 - Stratigraphic column for south Oman, showing major depositional phases, source and reservoir rocks. After Levell et al. (1988).

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 (Araujo 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 (Fig. 3).

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 & 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 & Catto, 1998).

The second hydrocarbon system has an upper Permian

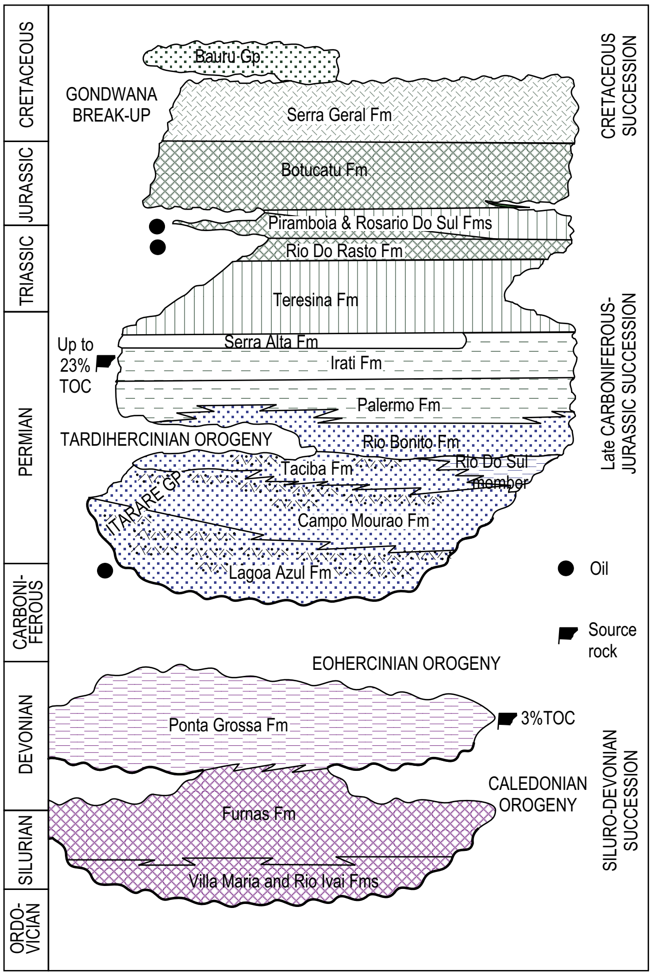


Figure 3 - Stratigraphic column for the Parana Basin, showing source and reservoir rocks. After Eyles et al. (1993).

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 & Catto, 1998). Oils have again been generated by heating from the Cretaceous intrusives, and the thick accumulation and overburden of up to 2 km of volcanic extrusives (Milani & 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 instrusive 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.

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 1 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 in the Tasmania Basin. The igneous instrusive 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.

Additionally Benelmouloud & Zhuravlev (1989) have reported on the trapping of hydrocarbons beneath plateau basalts in Algeria, which form effective seals to Palaeozoic sourced hydrocarbons.

AUSTRALIAN GONDWANAN PETROLEUM SYSTEMS

Exploration for hydrocarbons within onshore Australian basins has been occurring since the early 20th century. Exploration accelerated in the 1950s, 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 (Fig. 4).

Permian sequences are commonly form rich source rocks supplying 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.

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.

Table 1 - 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	Permian siltstones
Reservoir rock	Sands interbedded with diamictites	Sands interbedded with diamictites, and fluvial sands	Fluvial sandstones
Seal rocks	Diamictites & and shales	Diamictites, shales & igneous intrusives	Shales, siltstones and igneous instrusives

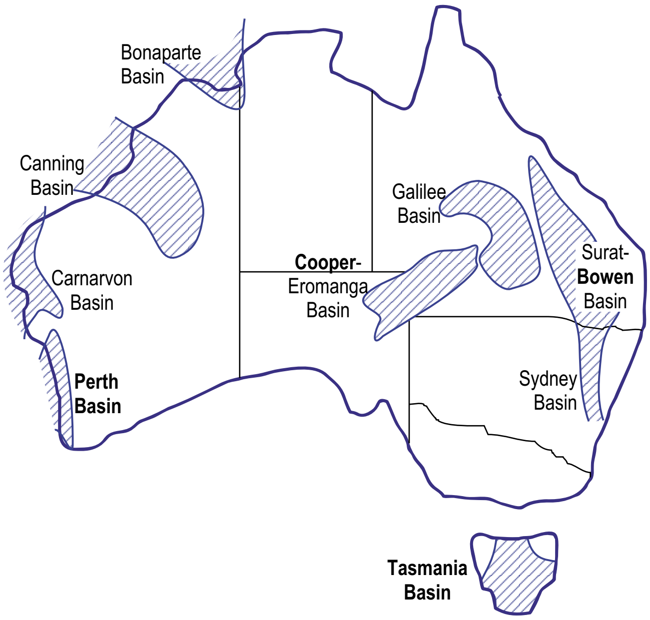


Figure 4 - Australian basins containing Permian petroleum systems. Those in bold are discussed in the text.

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 and average TOC of 5% (Schwebel et al., 1980). The Toolachee and Patchawarra Coal Measures comprise narrow sandy fluvial distributary 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 (Fig. 5).

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

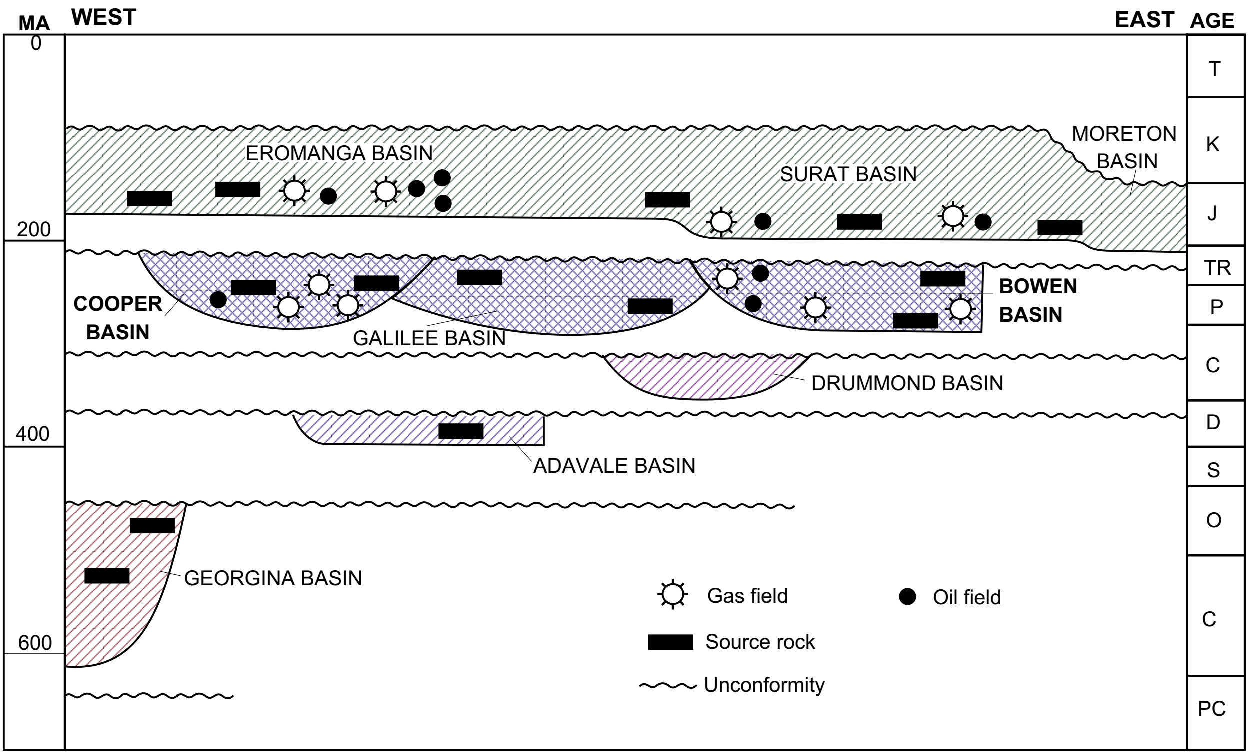


Figure 5 - Schematic cross-section through central Australia and Queensland showing the stratigraphic distribution of the petroleum basins of this region. From Randal (1984).

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).

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

The Tasmania Basin Parmeener Supergroup (Banks, 1973) contains both marine and terrestrial rocks ranging in age from Late Carboniferous to Late Triassic (Fig. 6). 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.

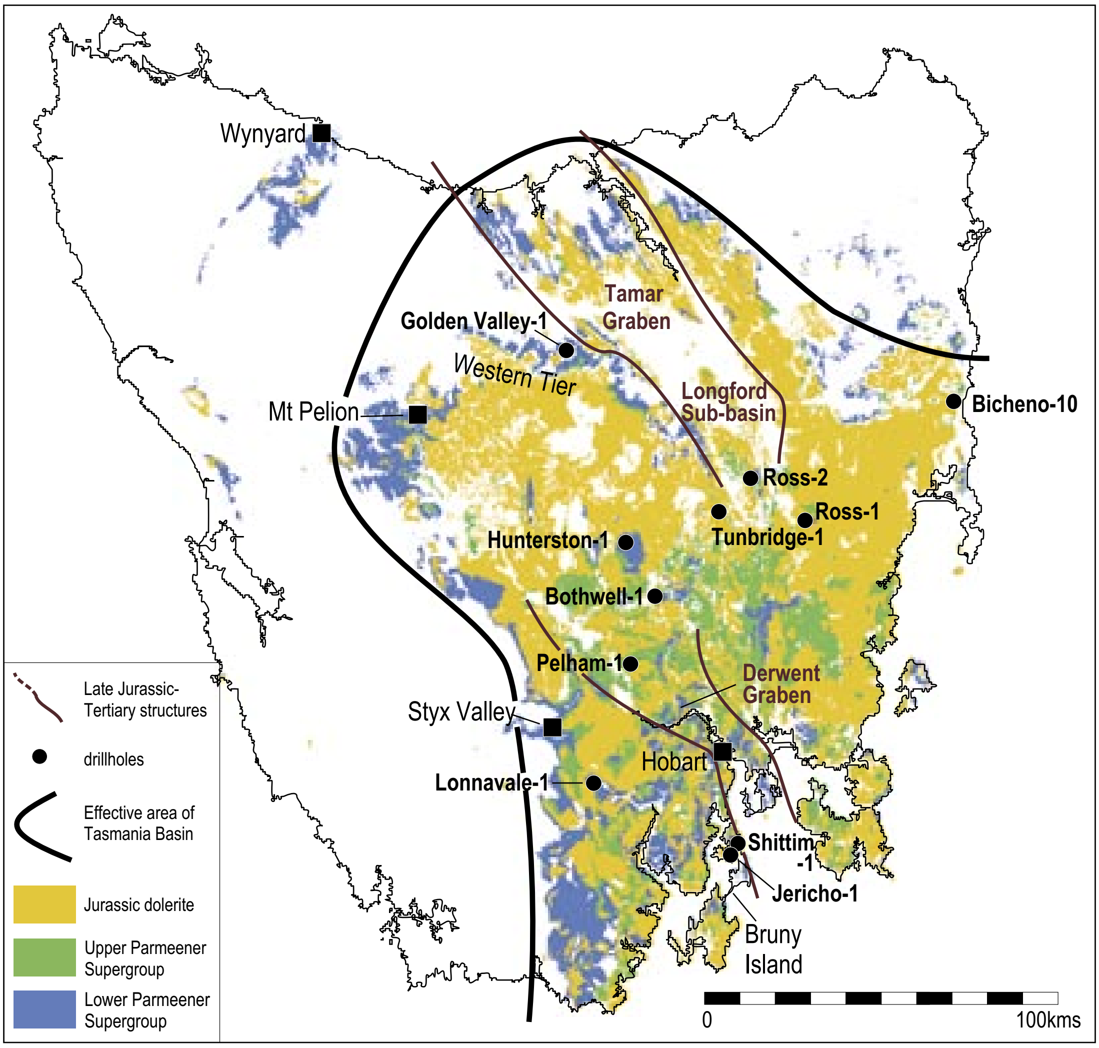


Figure 6 – General geology and areal extent of the Tasmania Basin. Locations of drill-holes and field sites discussed in the text are shown (after Reid & Burrett, in press)

The Lower Parmeener Supergroup

The Lower 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. 7A) 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 Formation; Fig. 7B), 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 (Fig. 7B). 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 siltstone has dispersed Tasmanites and lower TOC, but their great thickness (100-250m) increases their source potential. The Woody Island Formation is thickest in the middle of the Tasmania Basin.

Marine conditions continued with the deposition of fossiliferous siltstone and minor sandstone (Fig. 7C) 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.

Filling of the Tasmania Basin resulted in a relative regression of the shoreline southward and deposition of freshwater sandstones and carbonaceous siltstones (Fig. 7D). 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%.

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. 8A). 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. 8B). 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.

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. 8C). 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 Ferntree Formation 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 9 and 10. 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. 11A). 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

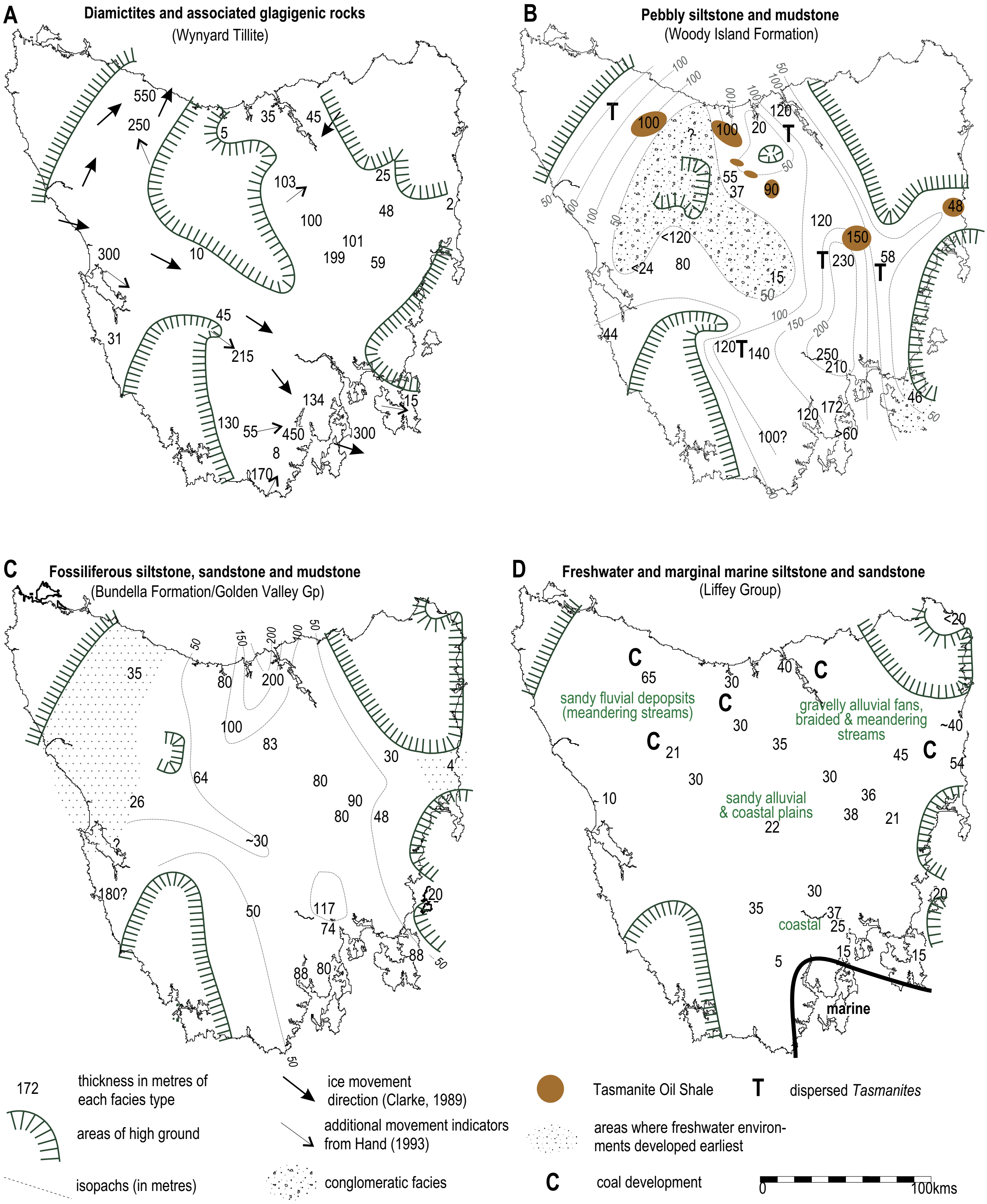


Figure 7 – Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – diamictites (Wynyard Tillite); B – pebbly siltstone (Woody Island Formation); C – fossiliferous siltstone (Bundella Formation; D – Freshwater sandstone and siltstone (Liffey Group) (after Reid et al. in prep).

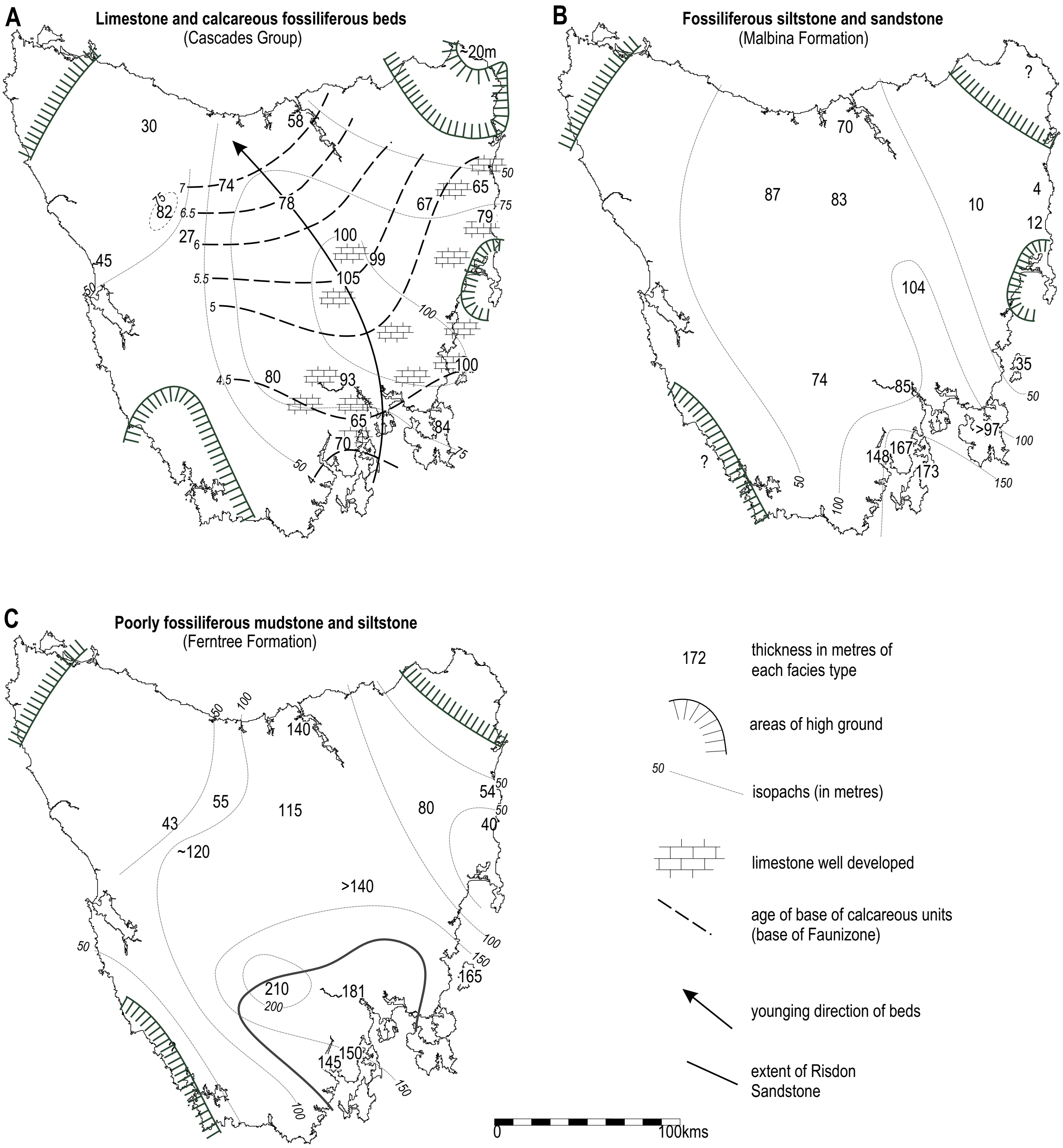


Figure 8 - Palaeogeography of the Lower Parmeener Supergroup. Isopachs of facies thickness in metres. A – calcareous fossiliferous beds (Cascades Group); B – fossiliferous siltstone and sandstone (Deep Bay and Malbina Formations); C – siltstone and mudstone (Ferntree Formation) (after Reid et al., in prep).

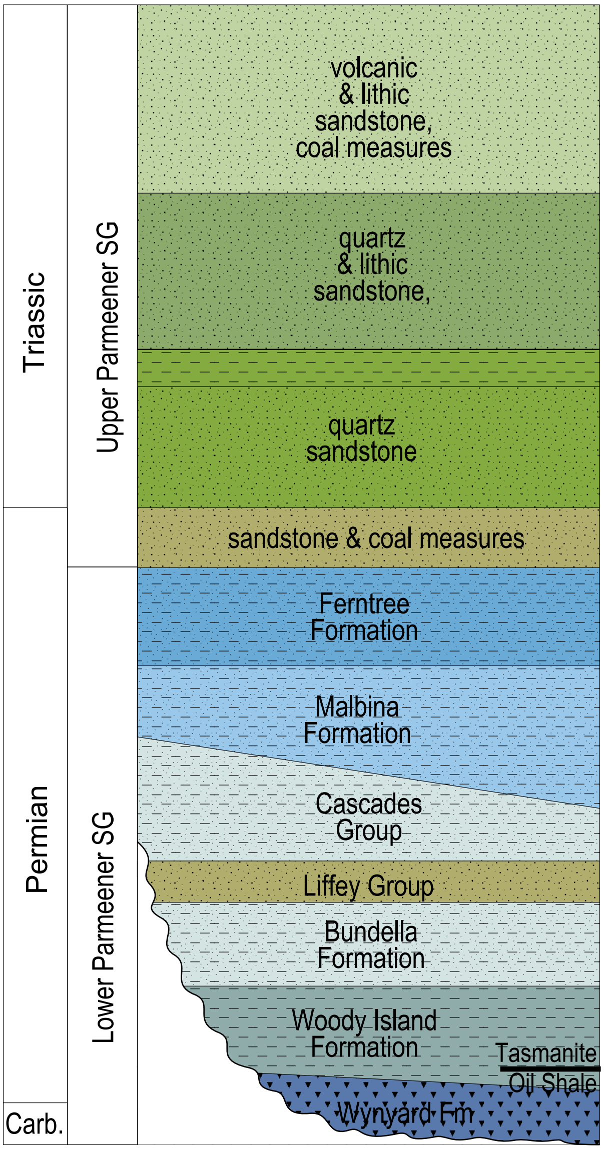


Figure 9 – A generalised stratigraphic column and nomenclature for the Parmeener Supergroup. The Lower Parmeener Supergroup is divided into many local units (see Clarke, 1989), but is simplified here to broad units recognisable basin wide. The Upper Parmeener Supergroup nomenclature follows Forsyth (1989). (after Reid & Burrett, in press).

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. 11B). 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 230 m 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 60 m 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).

Following quartz sandstone and lutite deposition there is a broad basin wide change to lithic dominated sandstone with two prominent quartz sandstone intervals (Fig. 11C). 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. 11D). The sequence is about 270 m thick in the Midlands (Forsyth, 1984), and up to 350 m 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 220 m 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).

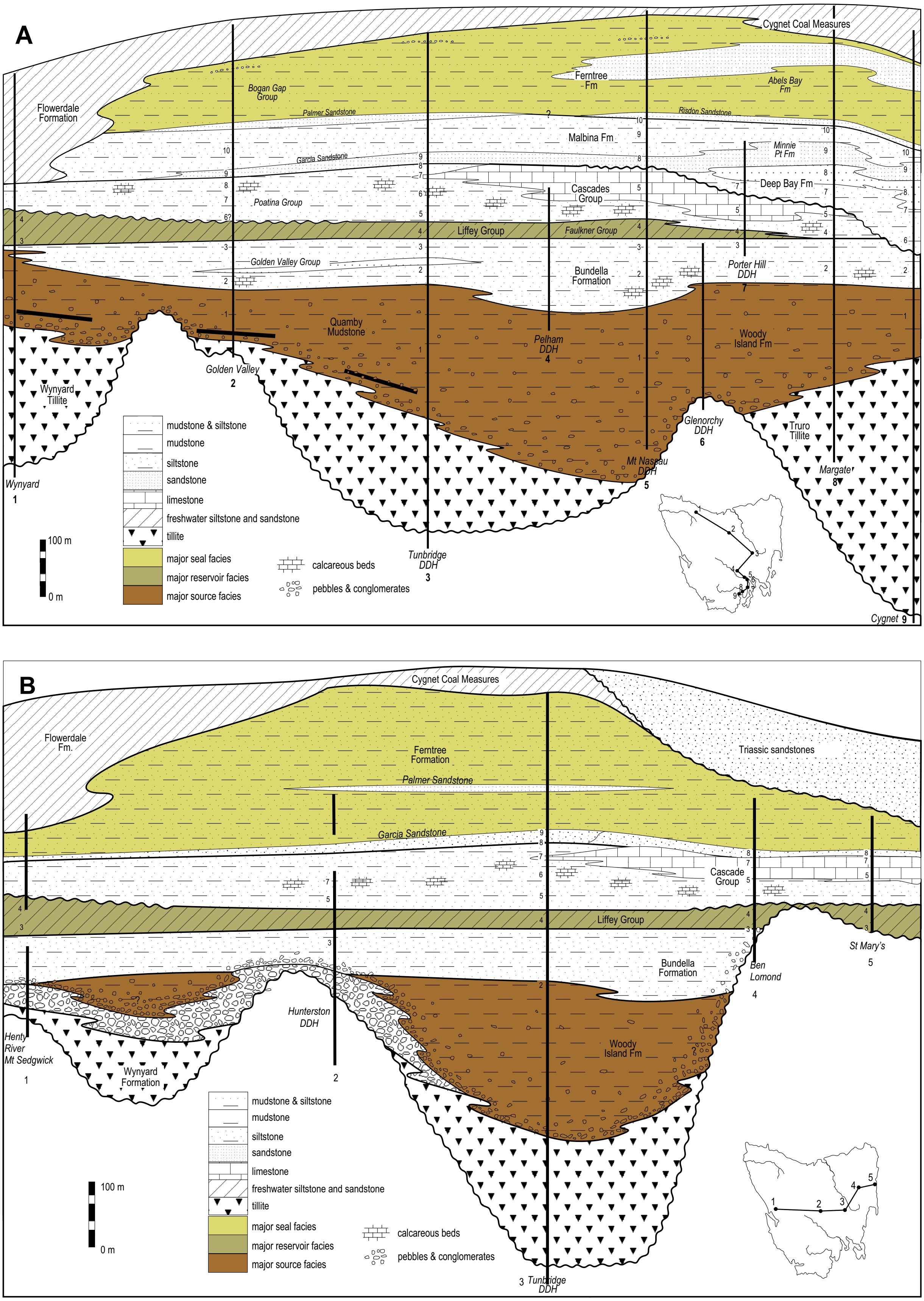


Figure 10 – Lithostratigraphic development of the Tasmania Basin, Lower Parmeener Supergroup. A Section line orientation north-south, B, Section line orientation west-east. Basinwide stratigraphic nomenclature is applied with limited local stratigraphic names shown in italics. Potential source, reservoir and seal rocks are indicated.

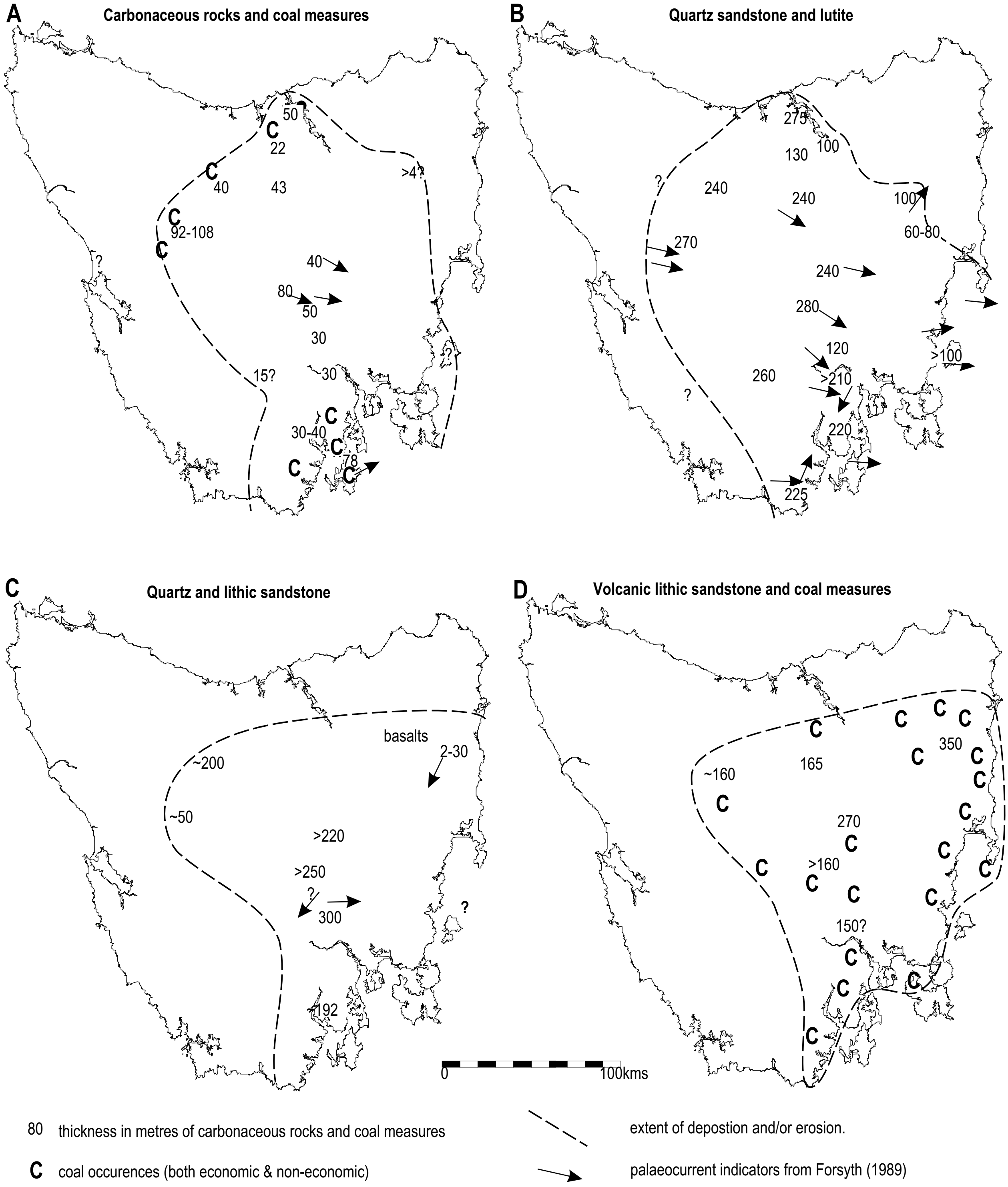


Figure 11 – Palaeogeography of the Upper Parmeener Supergroup. Isopachs of facies thicknesses in metres. Based on Forsyth (1989).

Within the Upper Parmeener Supergroup high TOC levels will be associated with the coals and carbonaceous beds making them an obvious hydrocarbon source. However burial depths are insufficient for source maturity across most of the Tasmania Basin, with the exception areas in the far south (Bedi, 2003), where Upper Parmeener beds are exposed at or near the surface, with little or no existing overburden. Repeated sandstones within the sequence may be suitable as reservoir rocks, with lutites forming seals (Bedi, 2003), and again burial depths are unlikely to produce sufficient confining pressures. For these reasons research efforts are concentrated on the deeper buried Lower Parmeener Supergroup.

Extensive sheets of tholeiitic dolerite were intruded into the Parmeener Supergroup during the mid Jurassic. There were several pulses of intrusion over a period of less than 20 myr, with a mean K-Ar age of 174 Ma (Brauns et al. (2000); recalculation of Schmidt & McDougall (1977) data). The dolerite preferentially intruded the then less than 130 my old Parmeener Supergroup, rather than older and more indurated basement rocks (Hergt et al., 1989). Dolerite occurs throughout the Tasmania Basin and at many levels within the Parmeener Supergroup. Few regions are unaffected by dolerite intrusion. However the stratigraphic level at which the intrusions occur is important in understanding the Gondwana Petroleum System, and their effect on potential source, reservoir and seal rocks. The nature and volume of Jurassic extrusive igneous, and sedimentary, rocks are unknown, but a limited record of Jurassic sediments and plant fossils exists in southern Tasmania (Hergt et al., 1989).

Cretaceous sedimentary rocks are not exposed onshore Tasmania, although they do occur at depth in the Tamar Graben of northern Tasmania (Forsyth 1989b). Tertiary sediments are well exposed at the surface within the Derwent Graben and Longford Sub-basin, and are known at depth within Tertiary grabens of onshore Tasmania. An unknown amount of Cretaceous and Tertiary sediment was eroded from uplifted areas of the Tasmania Basin, exposing Jurassic dolerite and 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 Formation, 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 Formation 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 may 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 12.

Source Rocks

There are several suitable source rock units within the Lower Parmeener Supergroup. The high grade Tasmanite Oil Shale is contained within the low grade Woody Island Formation, with further source rock facies in the freshwater carbonaceous Liffey Group. Rock eval data, from this study and Bacon et al. (2000), is shown in Appendix 1.

Tasmanite Oil Shale

The Tasmanite Oil Shale is a rich accumulation of tests of the green alga Tasmanites punctatus. The bands of discrete oil shale are 2-30 cm thick and may be repeated over a few metres of Woody Island Formation siltstone. The bands are thin but have total organic carbon (TOC) contents between 2.58 and 63%, making this a rich potential source rock (Fig. 13). As discussed above distribution of the Tasmanite Oil Shale is limited, and is only known from diamond drill core or surface outcrop in northern and eastern areas, as shown in Figure 2B.

Rock eval pyrolysis shows Hydrogen Index levels above 675, variable S_1 (hydrocarbons contained within matrix) and very high S_2 (hydrocarbons generated during pyrolysis) values. Source Potential Index (Demaison & Huizinga, 1991) calculations for immature Tasmanite Oil Shale indicate up to 0.6 metric tons, or 3.7 barrels (Fig. 14), of hydrocarbons per square metre of oil shale (without consideration of maturation or efficiency of kerogen type). High HI and low Oxygen Index (OI) values indicate Type I kerogens in the oil shale (Fig. 15), and low S_1 and T_{max} show the currently known outcropping material in northern and eastern areas is immature or marginally mature. However a bitumen seep at Lonnavale is most likely derived from a Tasmanites rich source (Wythe & Watson

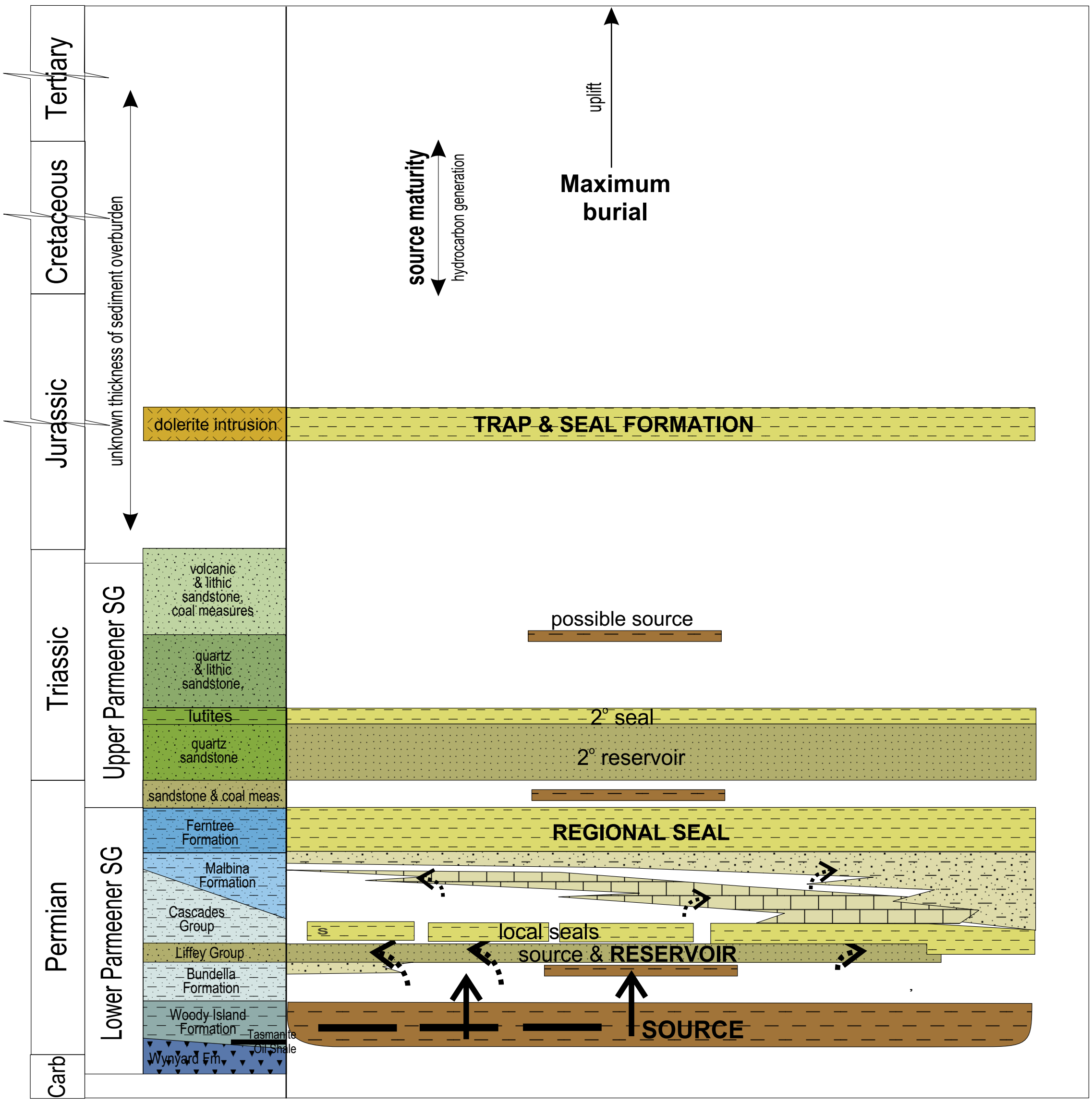


Figure 12 – Potential development of the Gondwanan petroleum system in the Tasmania Basin. Major and minor potential source, reservoir and seal facies are indicated, along with timing of trap formation and source maturity.

1996; Revill 1996), indicating the presence of the oil shale in the subsurface in the southern part of the basin (Bacon et al., 2000). The bitumen is dominated by tricyclic terpanes (Wythe & Watson 1996), which are associated with Tasmanites source rocks (Greenwood et al., 2000). Maturity parameters from the Lonnavale bitumen are variable, but all indicate derivation from a mature source rock well within the oil generation window at R_e 0.8–1.0%.

Woody Island Formation

The Woody Island Formation, while containing the Tasmanite Oil Shale in its lower part, has low TOC values mostly between 0.5 and 1.5% (Fig. 13). In addition HI values are low, indicating a Type III, gas and oil prone source (Fig. 10), rather than the rich oil prone Type I source of the oil shale. Tasmanites tests are dispersed within the Woody Island Formation siltstone, but the bulk of the organic material is derived from disseminated matter, rather than discrete algal sources. Siltstone closely associated with the oil shale, or between oil shale seams, show a slightly higher TOC (~2.5%), and higher HI values (up to 440). For the majority of the Woody Island Formation siltstone rock eval parameters S_1 and S_2, are low, but the great thickness of this unit makes it a prospect for hydrocarbons. SPI calculations (Fig. 14) on immature Woody Island Formation siltstone indicate a mean potential generation of 0.42 metric tons (~2.65 barrels/~538m^3 gas), of hydrocarbons per square metre (without consideration of maturation or efficiency of kerogen type).

Type III kerogens are gas and oil prone, but because they have a low hydrogen to carbon ratio, they may only convert 25% organic matter to petroleum (Hunt, 1995), and generate

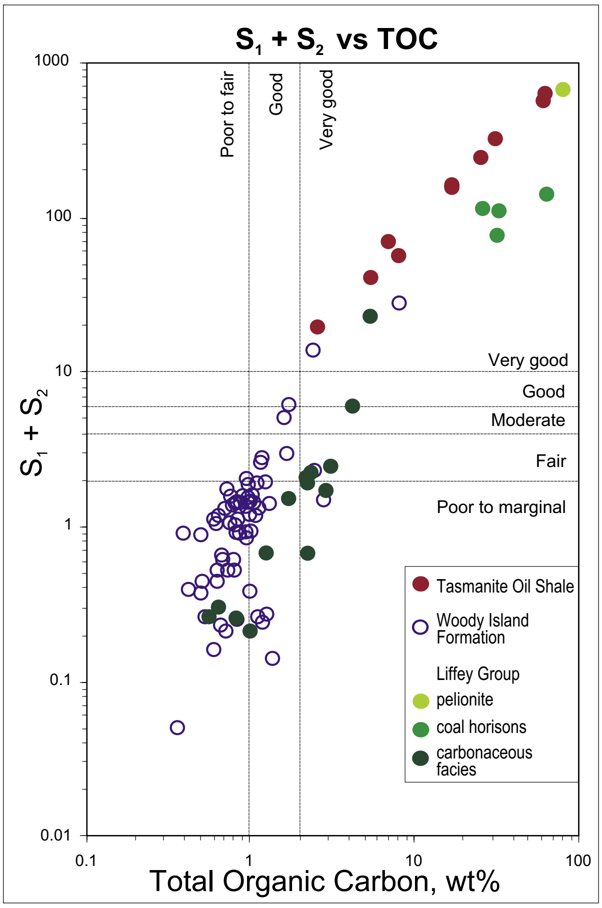


Figure 13 – Potential source rock quality in the Tasmania Basin determined from Total Organic Carbon, and S1+S2. Additional data from Bacon et al. (2000).

less gas than Type II, oil and gas prone, kerogens. The low TOC levels of the Woody Island Formation siltstone, 0.5 to 1.5%, are above the minimum experimental TOC (0.5%) required to generate gas, but below the minimum experimental TOC (2.5%) required to generate oil, by formation of a bitumen network (Lewan 1987).

The Woody Island Formation is immature in the north and northeast, but shows increasing maturity towards the southwest. Much of the middle part of the basin is within the oil window, and the southern part entering the gas generation window (Fig. 16). The Woody Island Formation in the Styx River region, southern Tasmania Basin, exhibits a petroliferous odour upon breakage of fresh rock surfaces. Weathered surfaces, and outcrop exposed for several years do not exhibit this petroliferous odour. This rapid loss of this petroliferous odour suggests that it may be a more common phenomenon, but is not being recognised in weathered exposures.

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, 1996). While

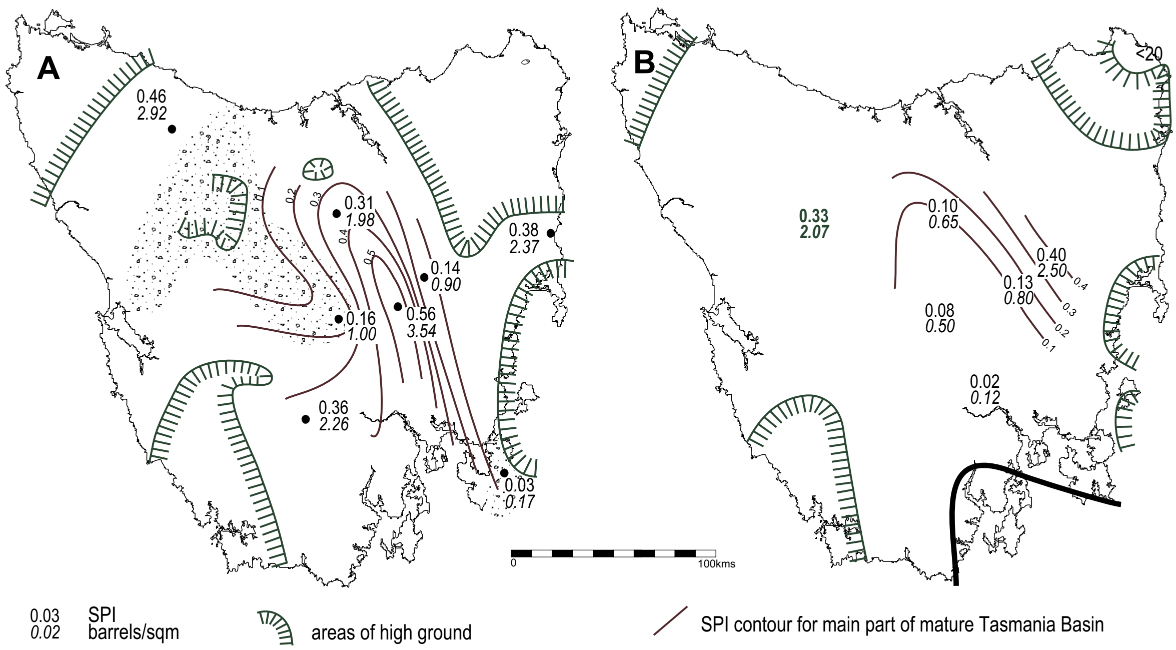


Figure 14 – A, Source Potential Index (SPI) data variation for the Woody Island Formation within the Tasmania Basin B, SPI data for Liffey Group carbonaceous facies, single pelionite value shown in green text.

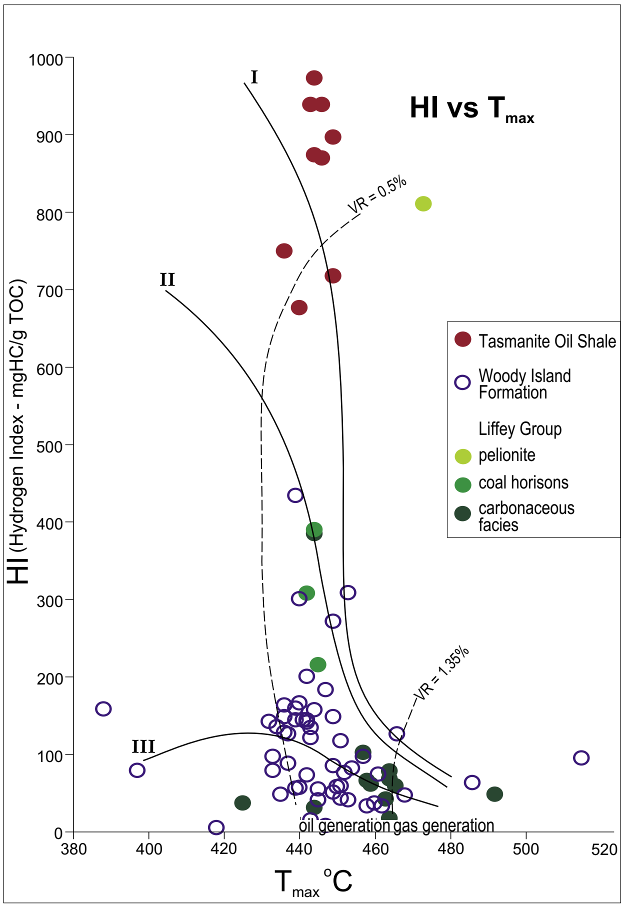


Figure 15 – HI vs Tmax plot for potential source rocks in the Lower Parmeener Supergroup. Divided into Tasmanite Oil Shale, Woody Island Formation and Liffey Group, subdivided into pelionite, coal and carbonaceous facies.

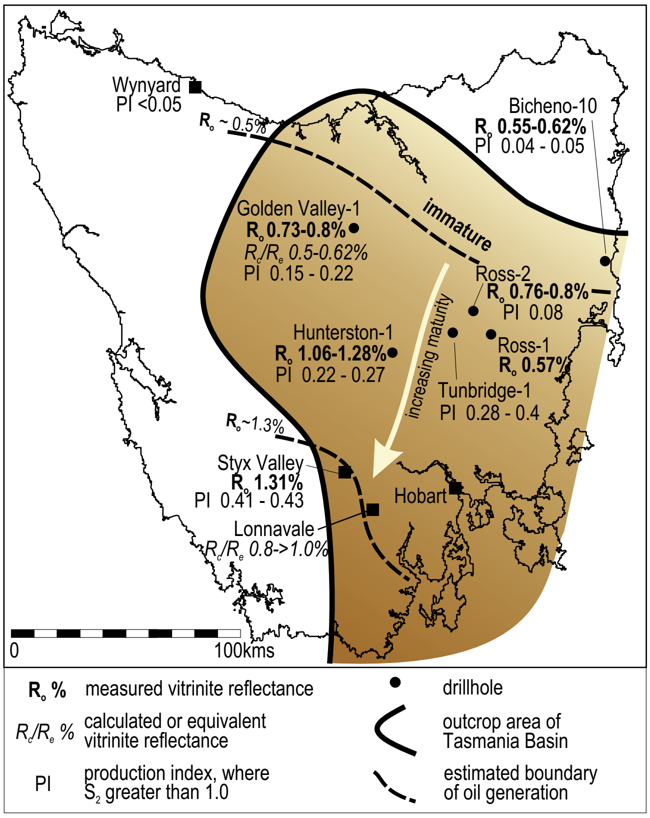


Figure 16 - Maturity of Tasmania Basin source rocks, increasing towards the southwest. Measured vitrinite reflectance from Liffey Group and Woody Island Formation (Cook 2003) and equivalent reflectance data from Bacon et al (2000) Production Index (PI) data from this study and Bacon et al. (2000).

this in itself is not significant, the Tasmania Basin data (Fig. 17A) shows that all source rocks contain an expected level of S_1 hydrocarbons for their given TOC. However the Liffey Group, both source and reservoir, is not showing migrated hydrocarbon levels.

Smith (1994) determined, from Shell Oil's data base, that the S_1/TOC ratio 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 17B 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, indicating that hydrocarbons produced are not being released, particularly from the Woody Island Formation, that whilst not a rich source, its bulk provides the majority of the calculated potential hydrocarbons for the Tasmania Basin.

In addition 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, 1996). All but one of the Woody Island Formation samples have TOC wt % below 2.5%, most below 1.5% (Fig. 13). While the above restriction does not apply to gas expulsion the Woody Island Formation, of type III kerogens, is gas and oil prone but over most of the basin is not yet mature for gas. In the absence of fracturing or faulting to release hydrocarbons, the Woody Island Formation may therefore act as a seal as well as source. The Woody Island Fm as a unit is characteristically massive without fracturing, and may be sealing hydrocarbons produced both within itself, and from the Tasmanite Oil Shale.

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, and/or regions where gas maturity is reached for the Woody Island Formation. Suitable areas for this are the Golden Valley/Longford Basin

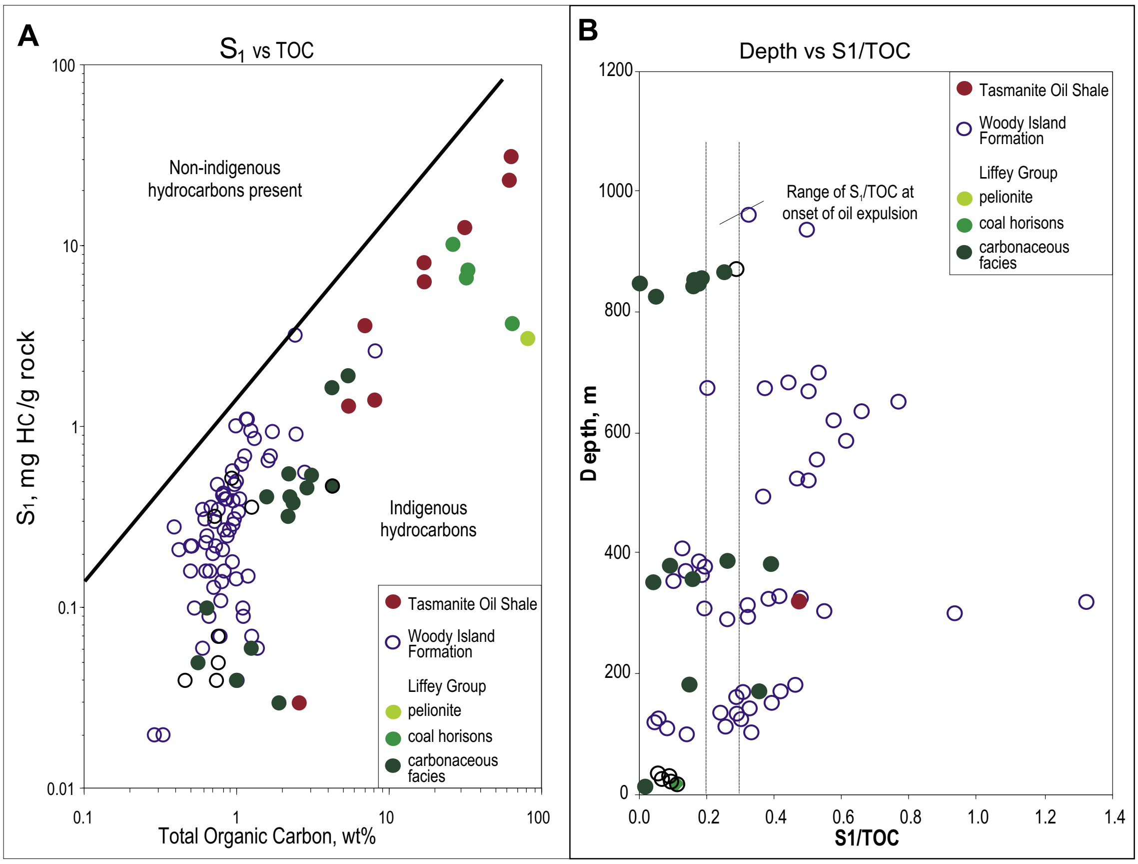


Figure 17 – Geochemical parameters and expulsion indicators of Tasmania Basin source rocks. A, S1 vs Total Organic Carbon (TOC), after ODP guidelines as an indicator of indigenous and non-indigenous hydrocarbons. B, Depth vs S1/TOC ratio as an indicator of oil expulsion, theoretical expulsion onset at 0.2-0.3 S1/TOC.

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.

Liffey Group

The freshwater Liffey Group contains carbonaceous siltstone and sandstone, with coal horizons in the north of the state. Plant fragments are common through the middle part of the basin, where the unit reflects a coastal plain with meandering streams. Coal horizons exhibit TOC levels up to 65%, with most carbonaceous layers at less than 5% TOC (Fig. 13). Coal unit SPI calculations indicate 0.27 metric tons (1.7 barrels/ 345m^3 gas) per square metre, and the carbonaceous layers 0.14 metric tons (0.87 barrels/179m^3 gas) per square metre (without consideration of maturation or efficiency of kerogen type). A pelionite sample from Mt Pelion in the north-west, has source quality parameters (Bacon et al., 2000) equalling that of the Tasmanite Oil Shale, HI at 800, and T_{max} indicating it has just entered the oil window (Fig. 15). However exposures of this horizon are poor, and this northwest region of the basin has not yet been drilled, and the distribution of this rich horizon is unknown.

Liffey Group source rocks display a range of kerogens types (Fig. 15). The pelionite sample contains Type I kerogens, and is oil prone with a high hydrogen to carbon ratio allowing significant conversion to hydrocarbons. Coal horizons and samples rich in plant material generally display Type II kerogens, which have a moderate hydrogen to carbon ratio, and are oil and gas prone. The majority of the Liffey group source rocks contain organic carbon as disseminated organic matter within carbonaceous siltstones, or as carbonaceous silt lamination within sandstone units. These disseminated samples display Type III kerogens, with a low hydrogen to carbon ratio and are gas and oil prone.

Basin Maturity

Rock-Eval pyrolysis of Woody Island Formation, Tasmanite Oil Shale and Liffey Group rocks has revealed source potential for all of these units, as discussed above.

Source rocks exist across the basin, and maturity data indicates the basin is immature in the north, but mature through the main body of the basin as indicated in Figure 16, with maturity increasing in a southwesterly direction. Equivalent vitrinite reflectance is inferred from T_{max} and Hydrogen Index (HI) plots, (Fig. 15), Production Index (PI) and inferred (Bacon et al., 2000) and measured vitrinite reflectance. The most reliable maturity data is from measured vitrinite reflectance (shown in Appendix 2), but the additional data is used to determine maturity trends across the basin. A Production Index of 0.1 is equivalent to the start of the oil generation window and 0.4 the end, however the calculation of PI (S_1/S_1+S_2) is prone to error where S_2 is low (Hunt, 1996). In Figure 16 PI values are taken from Tasmanite and Liffey Group samples which have high S_2, or, where these data are not available, from the low TOC Woody island Formation where S_2 is greater than 1.

T_{max} and HI data are not shown in Figure 16, but in the Golden Valley, Styx and Interlaken regions, T_{max} versus HI plots for the Woody Island Siltstone indicate maturity from equivalent vitrinite reflectance. Samples from Douglas River have low equivalent vitrinite reflectance and are immature to mature.

Actual vitrinite reflectance has been measured (Cook 2003) in carbonaceous units of the freshwater Liffey Group, and some siltstones of the Woody Island Formation. Vitrinite is rare in the Woody Island Formation, and is indicating a component of terrestrially sourced dispersed organic matter that has been recycled. In Liffey Group samples, inertinite is nearly always dominant over vitrinite, with liptinite occurring in some but not all samples (Cook 2003), indicating a dominantly terrestrial humic source, with some sapropelic terrestrial or lacustrine sources of kerogens. Vitrinite reflectance total range is 0.57 to 1.74%, but some samples have been influenced by contact metamorphism (Cook 2003) with Jurassic dolerite or Tertiary basaltic intrusions. Data influenced by contact metamorphism is not shown in Figure 16.

Intrusion of thick dolerite sheets in the Jurassic has locally baked and contact metamorphosed potential source units. However direct heating effects do not extend for great distances beneath intrusions. In the central Tasmania Basin, multiple dolerite intrusions, resulting in a 650m thick sheet, occurs in the Lower Parmeener Supergroup sequence. In Hunterston-1, coking effects, and elevation of measured vitrinite reflectance were not seen (Cook 2003) within 45m of the intrusion (Reid et al., 2003). The geothermal gradient of the Tasmania Basin may have been raised by this extensive Jurassic intrusive episode, but direct contact with source beds has limited effect.

Tasmanian Geothermal Gradient

Accurate determination of the geothermal gradient of the Tasmania Basin is not possible on the currently available vitrinite reflectance data. Vitrinite is rare in Woody Island Formation marine siltstones, and is largely confined to the freshwater Liffey Group. Apatite fission track data has determined a major cooling event beginning in the Late Cretaceous (Kohn et al., 2002; O'Sullivan & Kohn 1997), reflecting widespread denudation of cover rocks. The record of Cretaceous, and younger, rocks in the onshore Tasmania Basin is poor, despite thick Cretaceous sequences in offshore basins. Calculation of overburden rocks to the Parmeener Supergroup has produced results varying from 0.5 to 3 km (Hergt et al., 1989). O'Sullivan & Kohn (1997) assumed a geothermal gradient of 20-30˚C/km, however this seems low, given the current geothermal gradient in Tasmania of approximately 30-35˚C/km (calculated from heat flow data given in Cull & Denham 1979; Cull 1991). The intrusion of thick dolerite sheets in the Jurassic represents a major igneous period that would have influenced regional thermal characters (Leaman 2003). Geothermal gradients in the Otway Basin to the north of Tasmania are known to have cooled in the Late Cretaceous, from gradients of 50°-70˚C/km, to their present day gradients of 30°-40°C/km (Duddy 1997). This implies that the geothermal gradient within Tasmania, before the late Cretaceous cooling, should also have been high.

RESERVOIR ROCKS

Liffey Group

As a potential reservoir the freshwater sandstones of the Liffey Group and correlates are extensive, although with variable porosity (Porosity and permeability data is shown in Appendix 3). Through much of the central Tasmania Basin area sandstone porosities range from 4 to 15%, 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 3-5m 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 18 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).

As shown in Figure 19 the central Tasmania Basin contains sandstone beds forming an accumulated thickness of up to 25 m. Porosities vary from 4-9% in Hunterston-1, from 1-15% in Ross-1, and 2-18% in Golden Valley-1 (a shallow level sample

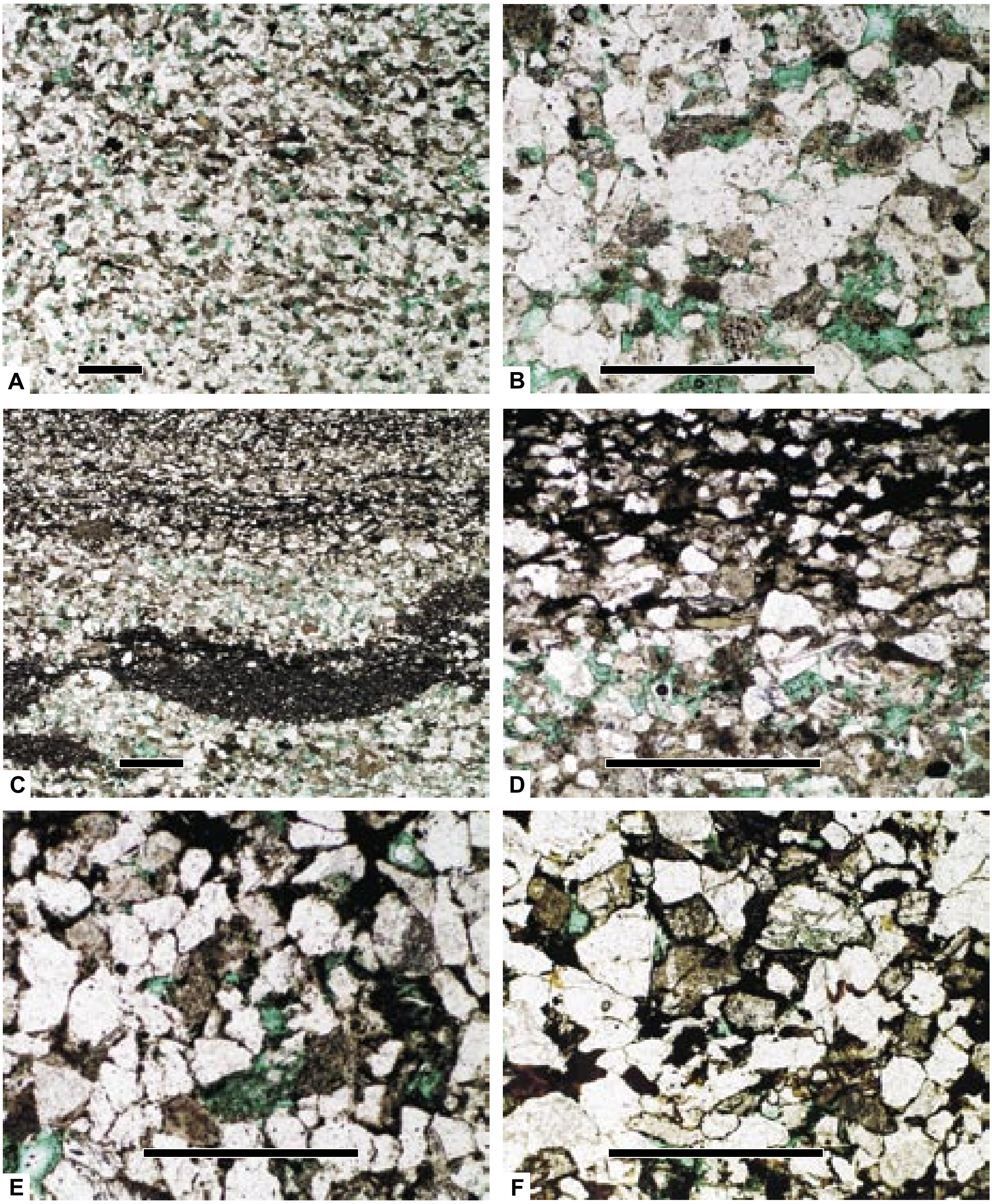


Figure 18 – Thin section porosity of potential reservoir rocks in the Lower Parmeener Supergroup. All scale bars 1mm. A-B – Ross DDH, 156.6m, Liffey Group sandstone, green material dyed araldite revealing pore space of 14.9% (Helium Injection). C-D – Granton DDH, 160.7m, Faulkner Group sandstone, C, 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%.

from Golden Valley shows higher porosity but this is probably enhanced by weathering effects). In the Hobart region, siltstone dominates over micaceous sandstone, and porosity is less than 5%. There are no porosity measurements in the Styx Valley region where the Liffey Group is only sampled from partially weathered surface outcrop, there being no subsurface material available.

Permeability of the Liffey Group across the basin is generally poor, most samples being 0.01-0.1 mD. In Ross-1, permeabilities are 0.2-1.8 mD, 0.2-8.8 in Ross-2 and one sample in Bicheno-10 is 166 mD. The reservoir unit at Hunterston-1 and Bothwell-1 has been affected by late diagenesis associated with intrusion of dolerite.

Correlations between sections of Liffey Group can be made, with fining upward sandstone cycles broadly recognisable across the central Tasmania Basin, as shown in Figure 20. Each sandstone sequence is generally finer grained in southern regions, and coarsens northward.

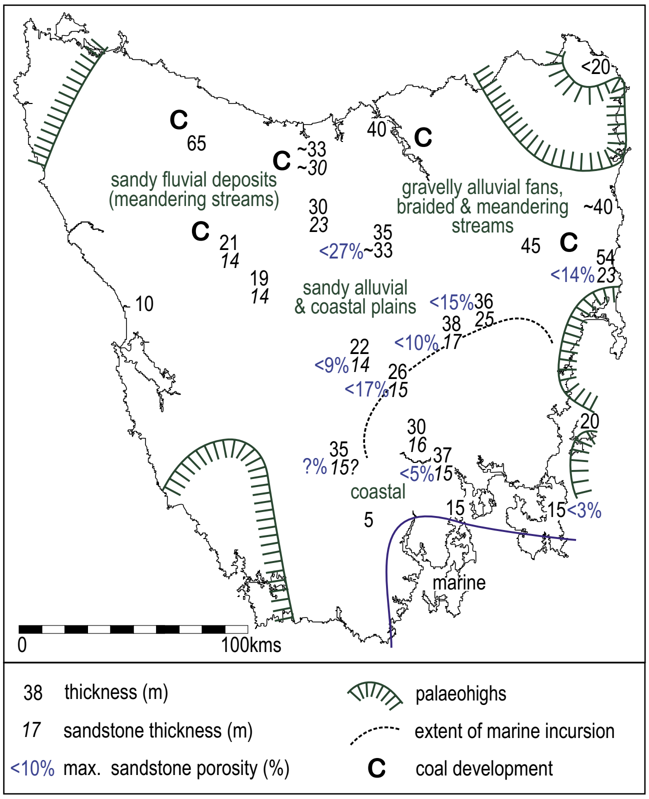


Figure 19 – Thickness and distribution of Liffey Group. Also shown are total thickness of sandstone beds and cycles, and the upper porosity value for some localities. (After Clarke 1989; Martini & Banks 1989; with additional data from this study).

Reservoir Diagenesis

Well-sorted quartzose sandstones show early stage silica cementation; individual grain boundaries are indistinct and overgrowths may completely occlude porosity. 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 (Reid et al., 2003). Carbonate cementation is later than both silica and clay, but may destroy both (Fig. 21). 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 (Reid et al., 2003), as in the Bothwell DDH (Maynard, 1996), however it is the late dissolution of carbonate that produces a thin-section secondary porosity.

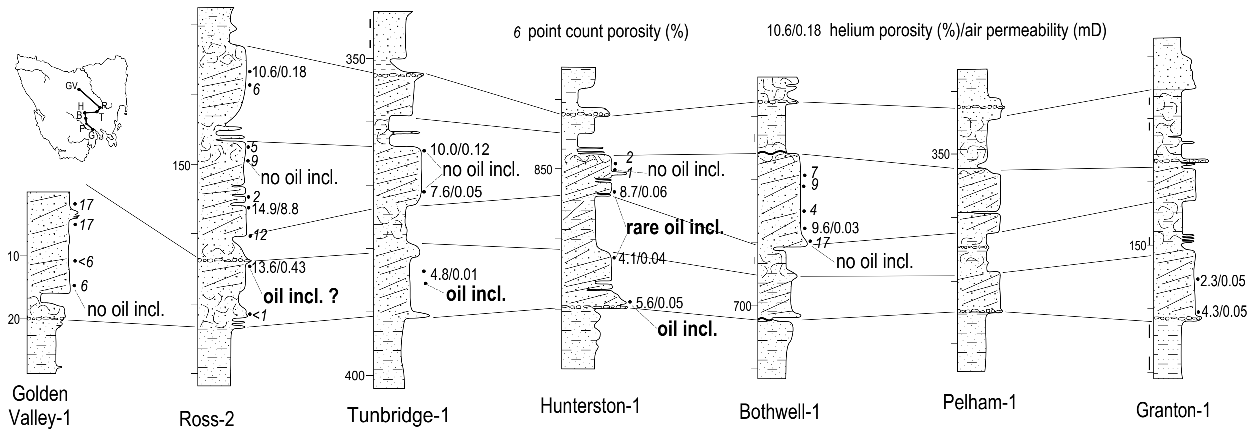


Figure 20 – Correlation of cycles within the Liffey Group across the Tasmania Basin. Cycles are correlated according to lithologic relationships and do not represent time slices. Occurrence of oil inclusions indicated, note inclusions predominantly occur in lowest cycle.

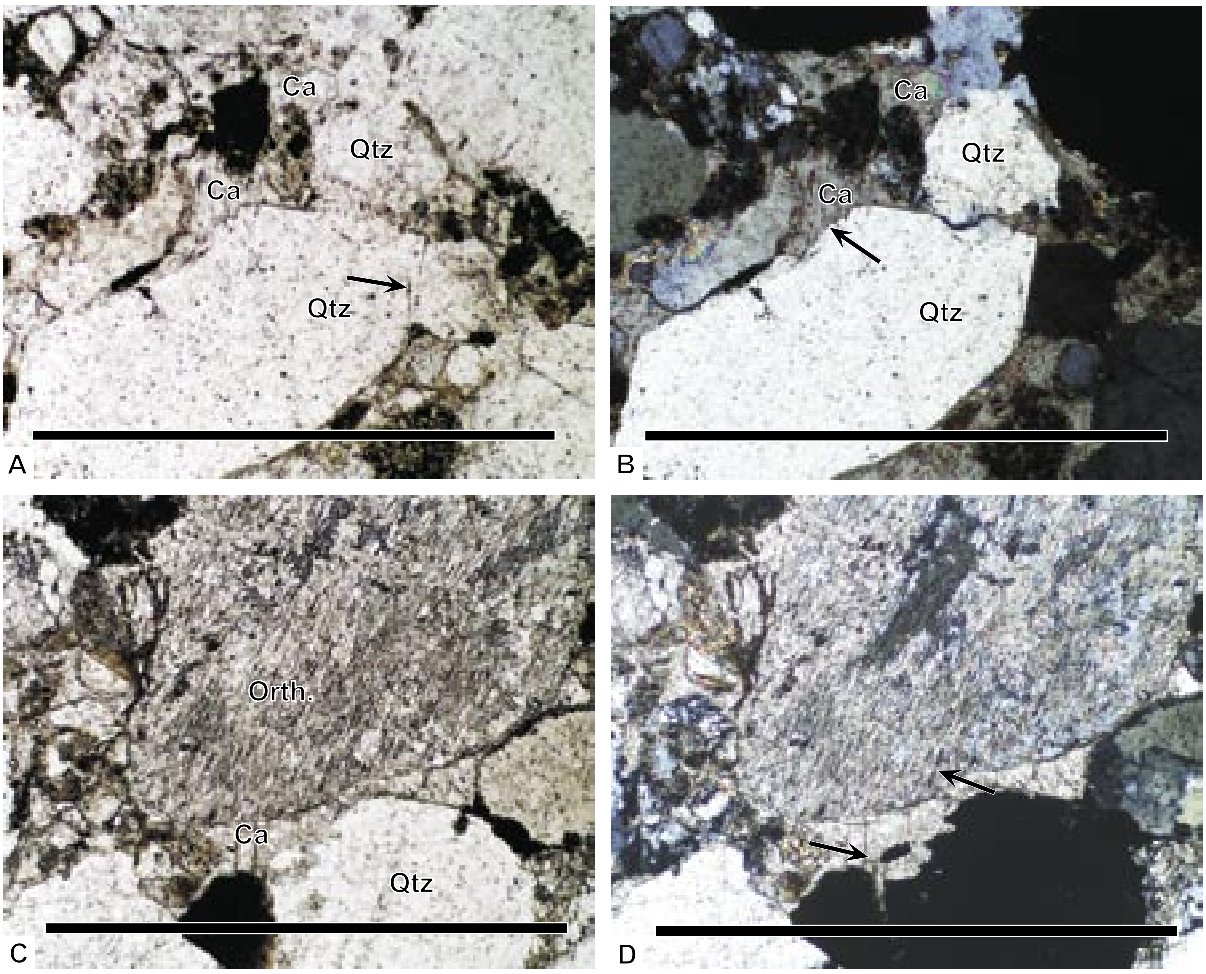


Figure 21 – Diagenetic features of Liffey Group sandstone in the Hunterston DDH, sample at 850.5m, all scale bars 1mm. A – plane light showing quartz overgrowths, with barely visible grain boundaries indicated by arrow. B – polarised light view of A, showing dissolution of quartz overgrowth and grains 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.

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.

Oil Inclusions

Samples of Liffey Group sandstones from Hunterston-1 contain rare oil inclusions, within both quartz (Fig. 22) and carbonate (Cook, 2003), and are also found within microfractures of quartz grains in Liffey Group sandstone from Styx Valley outcrop and Tunbridge-1. 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 are most commonly found within quartz grain microfractures, and typically in the lowermost sandstone sequence. Some inclusions show small dark gas bubbles. The total proportion of oil inclusions in quartz grains is less than 1%, and they are not been able to be extracted and geochemically examined to determine oil source. However, the proportion of inclusions is less than 5% GOI, indicating that migrated hydrocarbons have not previously been contained in Hunterston-1 Liffey Group (Eadington et al., 1996), and at less than 2% may not yet indicate hydrocarbon migration (Eadington et al., 1996)

Fault Produced Porosity

In Hunterston-1 faults low in the Parmeener sequence are brecciated. Also associated with these brecciated fault zones is dissolution of fossil material and carbonate clasts within the Bundella mudstones and conglomeratic facies. Several of

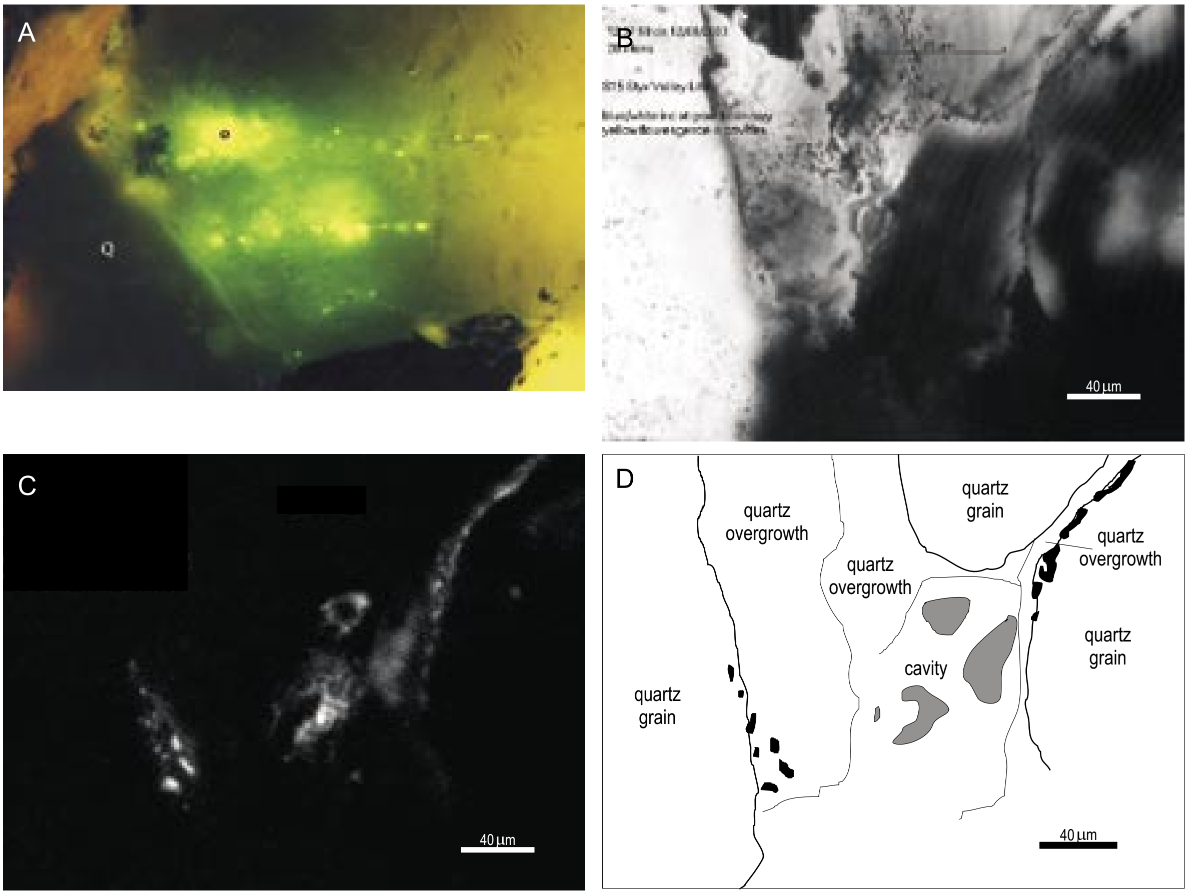


Figure 22 – A, Hunterston-1, Liffey Group, depth 869.5m. Quartz grains lacking fluorescence (Q) and strongly fluorescing with abundant inclusions of oil (O). The oil inclusions occur along microfractures within quartz grains. vmax 1.23%. Fluorescence-mode, width of field 0.22mm. (Plate 3 Cook 2003). B-D, Liffey Group, outcrop sample Styx Valley, B, transmitted light showing grain boundaries, C, fluorescence mode showing oil inclusions, D, Schematic interpretation. Oil inclusions present in boundary between detrital quartz grains and diagenetic quartz overgrowths. Flourescence in central cavity may be organic contamination of outcrop sample. Inclusions can only be conformed in grain boundaries.

these brecciated zones occur around 900 m depth, each with an associated "hallow" of carbonate dissolution, and replacement by silica, ranging from 0.5 to 10 m 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.

SEAL ROCKS

Potential seal units occur above the Liffey Group sandstones, as siltstone in the lower part of, and 1-5 cm thick volcanic ash layers within, the Cascades Group. The siltstone and mudstone of the Ferntree Formation are thick and occur across the Tasmania Basin. Potential localised seal rocks also occur within the Liffey Group, in the interbedded carbonaceous siltstones.

While there are potential seal rocks throughout the basin the most significant factor in assessing their suitability lies in their depth of burial. The Ferntree Formation has a high silt content, lowering its plasticity, and it is always strongly fractured in outcrop. The Ferntree Formation is high in the Permian stratigraphy, and is often exposed or only buried to depths of a few hundred metres, beneath Triassic sandstones, increasing the possibility of seal failure by fracture permeability. The siltstones of the lower Cascades Group are more deeply buried, and the volcanic horizons within the same unit, while being laterally discontinuous, are rich in clay minerals making them a potential seal.

All rocks in contact with dolerite, and particularly the upper marine siltstones, show clay alteration that has the potential to form a seals at shallower depths that may otherwise be required for a given seal facies. While the dolerite itself displays columnar jointing at shallow depths the contacts of the dolerite and country rocks may form clay seal facies throughout the basin.

TRAPS

The Lower Parmeener Supergroup shows steep folding and faulting in the Maydena-National Park corridor (Stacey & Berry in press), adjacent to the Styx Valley region, but otherwise is almost flat-lying and any folding is generally broad and open.

Potential traps may have been created by faulting in the Early to Middle Jurassic and associated with dolerite intrusion in the Middle Jurassic, and Cretaceous to Tertiary faulting. Mid Cretaceous to Early Tertiary faulting was dominantly extensional (see Stacey & Berry in press), and may have compromised traps formed in the Jurassic, prior to maximum burial and maturation of the Lower Parmeener Supergroup in the Cretaceous.

To date trap structures have not been accurately defined within the Lower Parmeener Supergroup. The seismic survey run in 2001 needs to be extended by further surveys and drilling programs to identify potential traps.

CASE STUDIES

Hunterston-1

Drilling of the Hunterston Dome in 2002 (Fig. 23) proved the presence of a thick dolerite multiple intrusion, and the continuation of the Lower Parmeener Supergroup into the subsurface (Reid et al., 2003). The basement of the Tasmania Basin is locally high, and the lowermost rocks were conglomerates of a probable equivalent age to the Woody Island Formation. The organic siltstone facies typical of the Woody Island Formation were absent, along with any possible occurrence of the Tasmanite Oil Shale.

Appropriate source rocks in the Hunterston-1 are confined to the freshwater Liffey Group. The bulk of the organic matter is confined to carbonaceous siltstones, and its fine disseminated nature yields Type III kerogens., which are gas prone, but require greater burial temperatures before they begin to generate hydrocarbons. Total organic carbon (TOC) percentages in the Hunterston beds are less than 3.1%. Source bed thickness is mostly less than 5 m, and total SPI is 0.08, calculated to a potential hydrocarbon generation of 0.498 barrels/m^2 (of oil equivalent). The absence of the Woody Island organic siltstone facies and the Tasmanite Oil Shale in the area reduces the overall source potential.

Vitrinite reflectance mean values range between 1.06 to 1.28%, mean 1.19%. From data in Barker & Pawlewicz (1994) V_r of 1.19% is equivalent to a maximum burial temperature of 151°. As a best case scenario, assuming source maturity to 1.19 had not been influenced by dolerite intrusion (Cook, 2003), TTI calculations for type III kerogen (Fig. 24) indicates 94% of the potential maximum hydrocarbons could have been generated given the burial profile shown (94% of 0.498 barrels/m^2), and 20% petroleum may have cracked to gas (94% x 20% x 45 m^3 gas/m^2). Of SPI calculations however, type III kerogens generally only generate 25.2 % of carbon in their total TOC to oil and gas as the quantity of petroleum generated is determined by the hydrogen content of the kerogen (Hunt, 1996), and type III have a low H:C ratio (see Hunt, 1996, pages 212-213, and 23). In this instance the kerogen type reduces the overall potential productivity of the system, despite an otherwise favourable burial curve.

Reduction of reservoir rock quality by carbonate fluids associated with dolerite intrusion into the overlying limestones, is seen at Hunterston-1 (Reid et al., 2003), and in nearby Bothwell-1 drillhole (Maynard, 1996). Maximum burial, and therefore hydrocarbon generation is postulated to be in the Cretaceous, however if reservoir quality was reduced in the Jurassic, then any generated hydrocarbons would not have found a suitable reservoir in this region. The heating effects associated with the dolerite intrusion itself may have generated hydrocarbons, but it is difficult to calculate any hypothetical quantities. The effect of dolerite intrusion is figured into TTI calculations by assuming geothermal gradient of 35°km, however the actual geothermal gradient is not able to be measured but may have been higher, by analogy with Bass Strait basin gradients.

In summary, the negatives effects of carbonate cementation on reservoir facies in the Hunterston Bothwell region, before source maturity, suggest that the immediate region is not the most suitable target for future exploration.

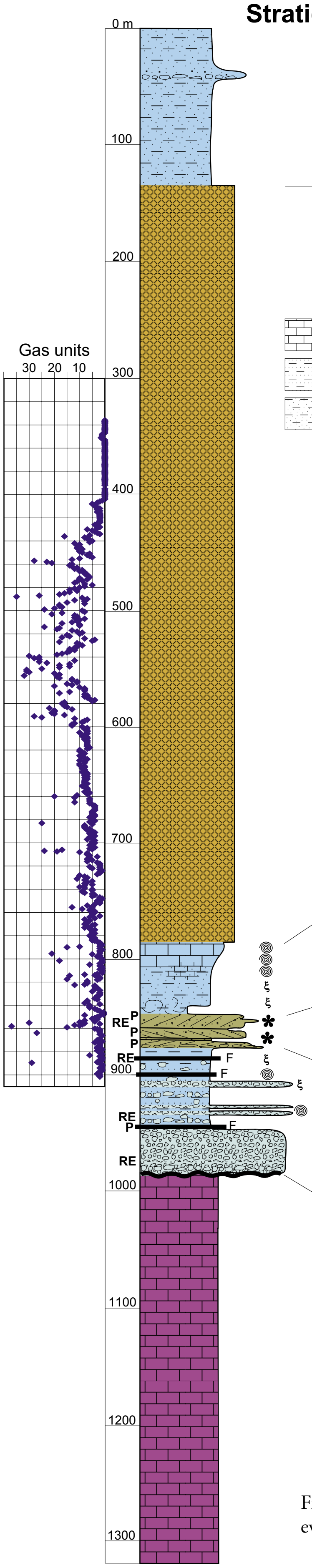
Tunbridge-1

Appropriate source rocks in Tunbridge-1 exist in the Woody Island Siltstone, and the Tasmanite Oil Shale near the base of this unit, and the Liffey freshwater beds. The Liffey and Woody Island siltstone both contain organic matter of type III kerogen, and the Tasmanite Oil Shale type I kerogen.

Bacon et al. (2000) constructed a burial profile on sediment thickness and AFT data alone, and calculated 100% oil generation from Type I kerogens (Tasmanite Oil Shale) and 70% generation from type III kerogen (Woody Island Formation siltstone), with only 10% cracked to gas. Measured vitrinite reflectance data obtained during this study does not enhance this estimation of generation potential. Again, type III kerogens may only generate 25.2 % of carbon in their total TOC to oil and gas (Hunt, 1996).

Liffey Group sandstone in the Tunbridge Ross region is fine to medium grained, with porosities ranging up to 10% at Tunbridge-1 and 15% in Ross-1. Permeabilities are low in Tunbridge-1, at less than 0.12mD. In Ross-1 permeabilities range up to 8.8mD (Fig. 20). Oil inclusions occur in both

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

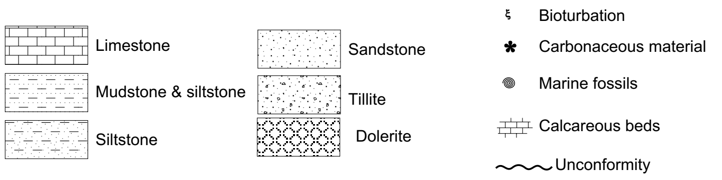


Ferntree Formation- to 134m

Generally monotonous sequence of bioturbated siltstone, with dispersed granules and

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)

Depth	T_{max}	PI	S1	S2	TOC
828.5	492	0.09	0.06	0.61	1.25
845.6	463	0.27	0.46	1.24	2.9
850.15	459	0.22	0.54	1.9	3.1
856.5	464	0.17	0.38	1.84	2.35
859.2	458	0.22	0.41	1.49	2.24
869.5	464	0.27	0.55	1.51	2.2
874.4	447	0.260	0.36	1.01	1.26

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

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

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.

Figure 23 – Stratigraphic section of the Hunterston DDH, including porosity/permeability and rock eval data, and gas units measured during drilling.

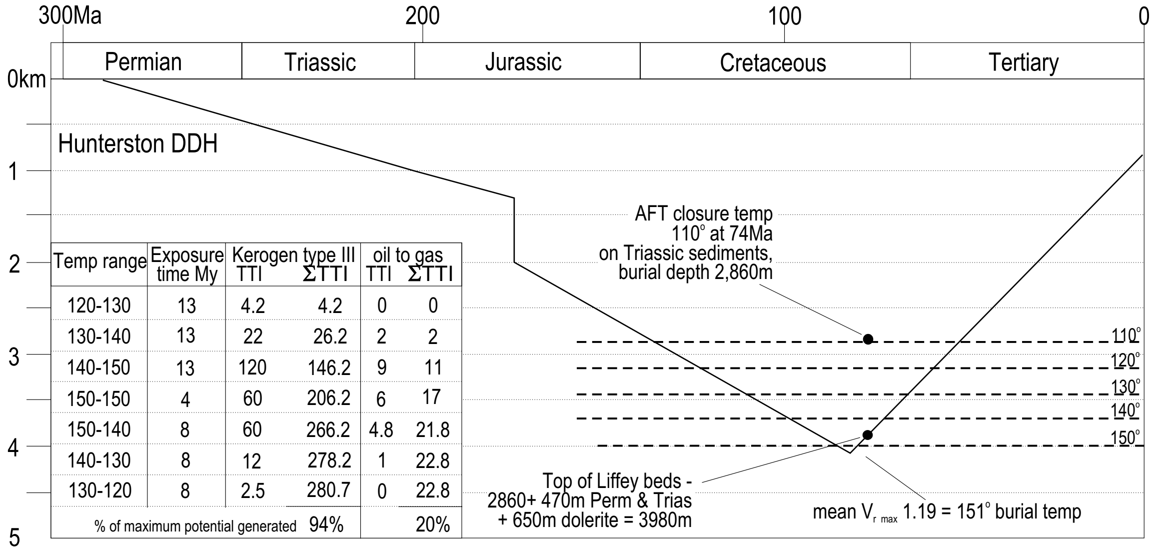


Figure 24 –Theoretical burial profile and calculated hydrocarbon generation for Liffey Group beds, based on Time Temperature Index (TTIARR). Constraints on the burial profile are the known thickness of Permian sediments and Jurassic dolerite, and assumed thickness of Triassic sediments. Maximum burial depth plotted according to mean vitrinite reflectance maximum (Barker & Pawlewicz 1994) and assumed geothermal gradient of 35o/km. Time of maximum burial based on AFT closure temperature of 110oC in Triassic sediments (O'Sullivan & Kohn 1997). (from Reid et al., 2003)

Tunbridge-1 and Ross-1, but at less than 2% GOI, and therefore may not represent hydrocarbon migration (Eadington et al., 1996), beyond what might be expected for a sedimentary basin.

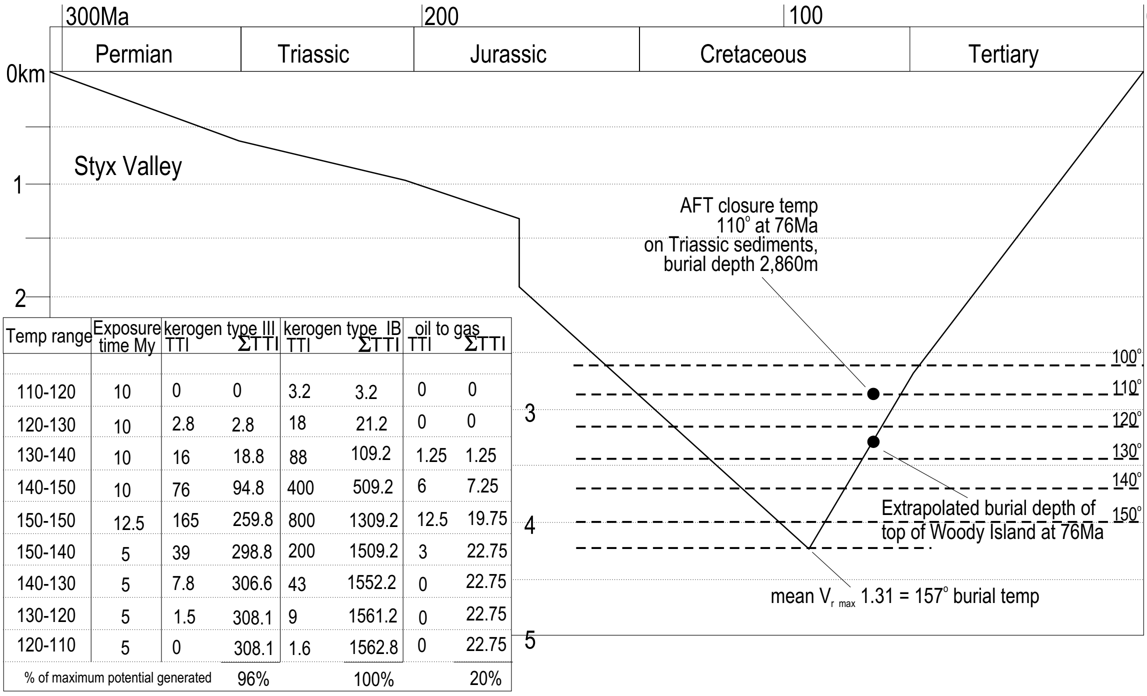
The Lower Parmeener sequence is, in this region, currently buried beneath a thick dolerite sheet and the Upper Parmeener Supergroup sediments. All petroleum system facies, of source, reservoir and seal are present in the region. Source rocks exist in the form of the Tasmanite Oil Shale, Woody Island Formation siltstone and Liffey Group carbonaceous units. Maturity data indicates entry into the oil window (Fig. 16), and the Ross Tunbridge region may be suitable for future exploration. Traps and seals may exist in the area as fault blocks and dolerite intrusions but are yet to be defined.

Styx Valley

Outcrops of Woody Island Formation 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 Formation in the Styx River region, while not containing the oil shale itself, has dispersed Tasmanites in its lower part. New forestry roads and quarries, some 7-8 km 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) and in a quarry near the junction of Muellers and Styx Rd exhibit a petroliferous odour when fresh surfaces of Woody Island Formation are exposed. However the odour is absent in weathered rocks that have been exposed for some time. The loss of odour suggests that it may be a more common phenomenon, but is not being recognised in weathered exposures.

Appropriate source rocks in the Styx Valley region exist in the low TOC but extensive Woody Island Formation, and in disseminated Tasmanites within the lower part of the same unit. The freshwater Liffey Group would also be a favourable source rock given its carbonaceous nature, however no fresh samples are available for rock eval pyrolysis. The following TTI calculations are therefore based on the Woody Island and disseminated Tasmanites only.

In the Woody Island Formation, organic matter is disseminated and of predominantly gas prone type III kerogen. A single measured vitrinite reflectance value of 1.31% exists for a Woody Island sample (Cook, 2003), subsequent sampling has not yielded vitrinite. Elevated inertinite values in all samples indicate the vitrinite value of 1.31% is representative. This vitrinite value correlates to a peak burial temperature of 157° (Barker and Pawlewicz 1994), and assuming a geothermal gradient of 35°km the Woody Island Formation would have been buried to 4200m maximum depth. TTI calculations based on this maximum burial profile, and an AFT age, on 110° closure, of 74Ma on a Triassic sample NE of Westerway, indicate that 96% of the maximum potential hydrocarbons could have been generated given this profile (Fig. 25). Mean



Temp range	Exposure time My	kerogen type III TTI	kerogen type III ΣTTI	kerogen type IB TTI	kerogen type IB ΣTTI	oil to gas TTI	oil to gas ΣTTI
110-120	10	0	0	3.2	3.2	0	0
120-130	10	2.8	2.8	18	21.2	0	0
130-140	10	16	18.8	88	109.2	1.25	1.25
140-150	10	76	94.8	400	509.2	6	7.25
150-150	12.5	165	259.8	800	1309.2	12.5	19.75
150-140	5	39	298.8	200	1509.2	3	22.75
140-130	5	7.8	306.6	43	1552.2	0	22.75
130-120	5	1.5	308.1	9	1561.2	0	22.75
120-110	5	0	308.1	1.6	1562.8	0	22.75
% of maximum potential generated			96%		100%		20%

Figure 25 – Theoretical burial profile for Woody Island Formation siltstone and Tasmanite Oil Shale in the Styx Valley region. Late Cretaceous maximum burial indicated from apatite fission track data (O'Sullivan & Kohn 1997; Kohn et al. 2002). Maximum burial temperature from comparative charts of Barker & Pawlewicz (1994). Maximum burial temperature and assumed 35oC/km geothermal gradient define total burial depth, actual Jurassic to Cretaceous overburden unknown (from Reid & Burret in press).

SPI for Styx Valley samples, that have TOC's ranging up to only 1.16%, is 0.359 metric tons, or 2.264 barrels/m^2. Again with type III kerogens only 25.2% of total SPI may be converted to hydrocarbons, so total potential SPI is 25.2% x 2.264 = 0.570 barrels/m^2. As discussed above there may be problems with the expulsion of oil from source rocks with such low TOC values. Gas may not experience these problems, but at the burial profile shown for TTI calculations, only 20% hydrocarbons may have been converted to gas (20% x 25.2% x 2.264 = 0.114 barrels or 19.5m^3 gas/m^2). So despite being mature for gas generation, the burial profile does not allow significant time inside the gas generation window.

The disseminated Tasmanites material in the lower part of the Woody Island Siltstone is of type I kerogen, and oil prone. The H:C ratio in type I kerogens allow for up to 58% (Hunt, 1996) TOC to be converted to hydrocarbons, and type I kerogens begin to convert to hydrocarbons at shallower depths than type III. For the same burial profile as used above for Woody Island Siltstone TTI calculations indicate up to 100% of maximum potential may be converted to hydrocarbons. SPI values for disseminated Tasmanites are not available for the Styx Valley, however the Lonnavale oil seep, within close geographical proximity has been positively linked to a Tasmanites type source (Revill et al., 1996, Whythe and Watson 1996).

Outcrops of the potential reservoir Liffey Group in the Styx Valley are poor, all showing weathered outcrop. Facies seen are dominated by carbonaceous siltstones, but some fine to medium grained sandstones are present. Outcrop silicification and weathering mean that porosity and permeability cannot be measured, but similar facies elsewhere are suitable reservoirs.

Rare oil inclusions occur in Styx Valley Liffey Group samples, at <2% GOI (Grains with Oil Inclusions). A GOI of >5% would indicate a palaeo reservoir, and >2% a palaeo migration path (Eadington et al., 1996). The rarity of oil inclusions suggests neither has occurred, and that the inclusions present are no more than could be expected in a sedimentary basin, however due to poor outcrop preservation this data is not conclusive.

In summary, the maturity of source beds in the region in association with potential reservoir and seal facies suggest the Styx region may be suitable for future exploration. Current drilling data is limited, and the reservoir facies need to be examined subsurface. Seismic data is absent, and while acquisition may be problematic because of dolerite intrusion into the overlying Upper Parmeener sequence, a seismic survey is essential to identify potential trap structures.

Lonnavale Geology and Lonnavale Oil Seep

The local geology at Lonnavale is dominated by dolerite with windows into upper marine Permian sequences and Triassic sandstone (Fig. 26). A prominent feature of dolerite geology

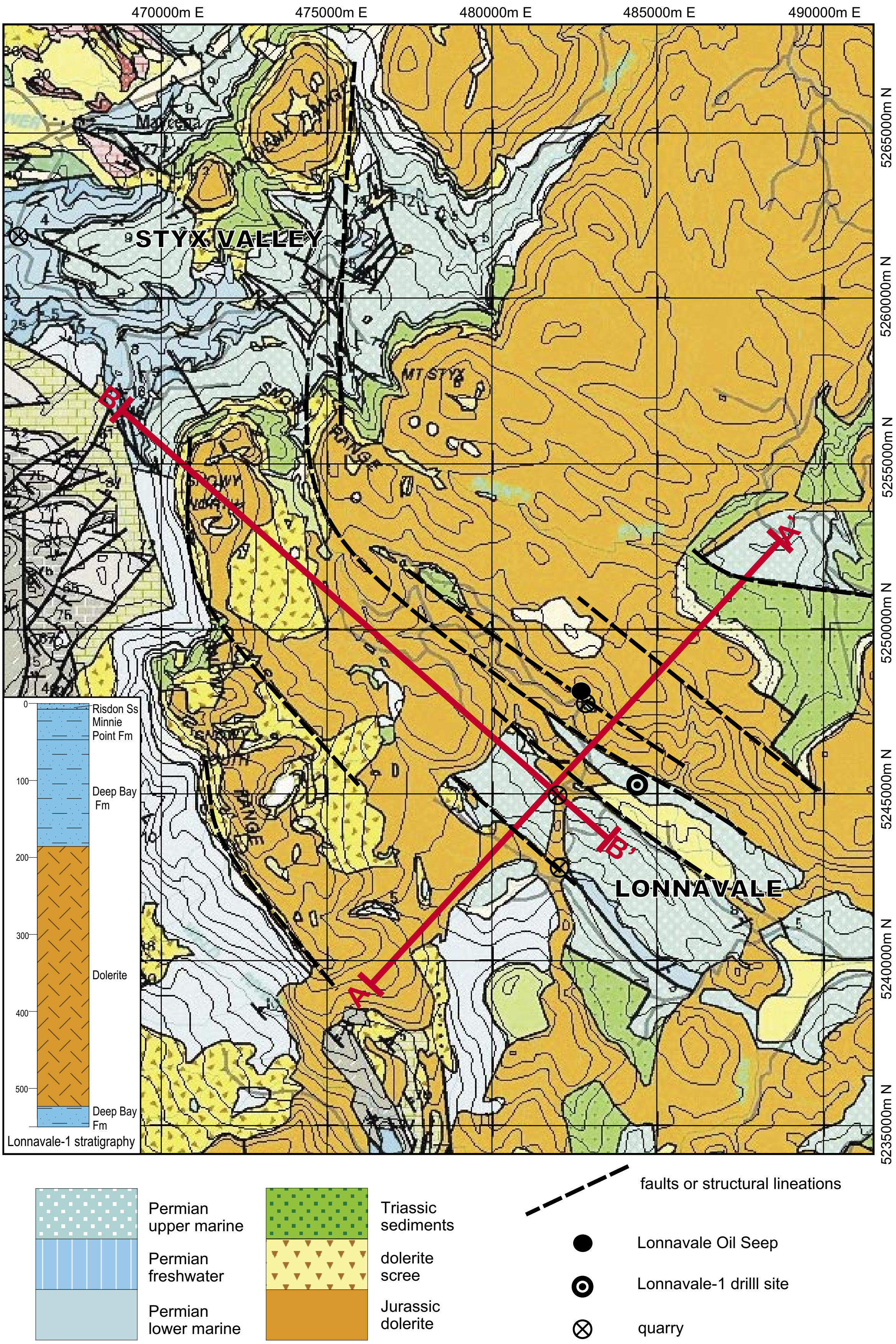


Figure 26 – Geology of the Styx–Lonnavale region, based on 1:125,000 digital geology map series, with fault structures highlighted. Cross section lines A–A' and B–B' marked and shown in Fig. 27.

at Lonnavale is a large north-south striking feeder zone. Two small probable feeder pipes are also present. The feeder zones are intruding dolerite into the Parmeener Supergroup in the uppermost Permian and lower Triassic stratigraphy. NW/SE trending exposures of dolerite, cross cutting the stratigraphy are assumed to be associated with a second intrusive phase. On a regional scale, a prominent north south trending fault is evident in the Styx Valley, and sweeps south and southeast to Lonnavale (Fig. 26). The Lonnavale portion of this fault or fault set is in the vicinity of the oil seep, and matches a NW/SE structural trend, and second phase of dolerite intrusion. A second large quarry at the southern end of Link Road shows a prominent 300˚ quartz filled fracture set. In the base of the quarry wall one such fracture shows fine-grained secondary intrusion into the main body of medium to coarse dolerite. Thrust faulting occurs along the same NW/SE strike and may be coincident with dolerite intrusion. In the area of McDougalls and Links Rd junction dolerite exposure sweeps SE crosscutting stratigraphy, and merges with outcrop of a north-south trending dolerite feeder.

Bitumens collected from an oil seep in a dolerite quarry northeast of Lonnavale are positively linked to a Tasmanites source (Revill et al., 1996, Whythe & Watson, 1996). Seepage in the quarry is via two fractures sets. One strikes 300-330˚, the other strikes approx 50˚. The 50˚,NE, strike is approximately parallel to the faulted dolerite boundary at the eastern edge of the quarry. The 300-330˚ set is repeated elsewhere in the Lonnavale district.

The drillhole Lonnavale-1 was located to the east of the feeder zone, and encountered dolerite and Permian sediment thrust packages (Fig. 27 A-A'), in the upper Lower Parmeener Supergroup. The reservoir target, Liffey Group was not reached. A cross section of inferred geology from Lonnavale to the Styx Valley in the NW is shown in Figure 27 B-B', and assumes the presence of reservoir and source facies in the subsurface by extrapolation of known geology. However, without acquisition of seismic data, predictions of geology likely to be encountered by further drilling in the Lonnavale Styx area are speculative.

Regionally dolerite sills are currently known high in the stratigraphy, with the possibility that only feeders will be found

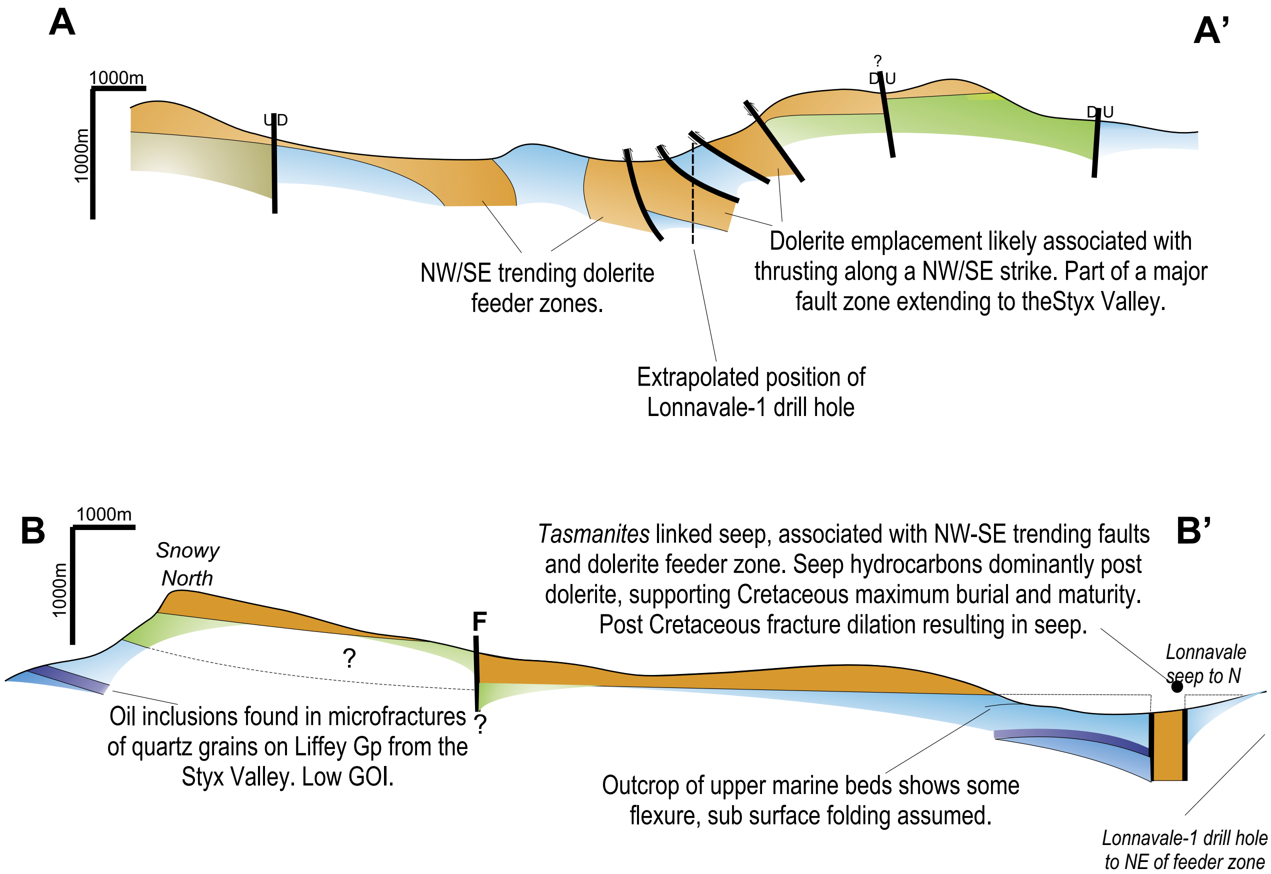


Figure 27 – Geological cross sections A-A' and B-B' as marked on Fig. 26. A-A' showing thrusting and dolerite feeder zones, with extrapolated position of Lonnavale-1 marked. B-B' showing inferred geology between Lonnavale and Styx Valley. Much of this region is covered by forest and structures within dolerite outcrop are not mappable.

in lower sediments. Therefore the reservoir target, Liffey Group, may be unaffected. Thrusting, and associated trap formation appears to have been during the Jurassic, before peak source maturation. But, it is the opening or reactivation, probably in the Tertiary, of these Jurassic NW/SE thrusts that has probably led to the seep northwest of the drill site.

Despite limited exploration in the Lonnavale area, with only one short drill hole, source rocks are known to have reached maturity in southern Tasmania, and the seep at Lonnavale is linked to a Tasmanites source. This, and the general geology of the region between the Styx Valley and Lonnavale, suggests the area may be suitable for further exploration to determine reservoir potential and search for the existence of traps.

CONCLUSIONS

The glaciomarine Lower Parmeener Supergroup contains suitable potential source, reservoir and seal lithologies. Additional reservoir and seal facies may be contained within the overlying Upper Parmeener Supergroup.

Potential source rocks are within the organic siltstones and Tasmanite Oil Shale of the Woody Island Formation, and within the carbonaceous units of the freshwater Liffey Group. The Tasmanite Oil Shale contains oil prone Type I kerogens and is a high quality source rock, but is thin and of limited areal distribution. In many of its occurrences in northern and northeastern areas it is immature or marginally mature. The Liffey Group contains Type II, oil and gas prone kerogens, as well as gas and oil prone Type III kerogens and is distributed across most of the Tasmania Basin. This unit also forms the reservoir facies within the Lower Parmeener Supergroup. The Woody Island Formation contains gas and oil prone Type III kerogens, and is widespread across the basin, although drilling at Hunterston revealed a conglomeratic facies in central western areas, in place of typical organic siltstone. The Tasmania Basin is within the oil generation window, except in northern and north-eastern areas, and has entered the gas window in the far south. Maximum burial and maturity occurred in the late Cretaceous. Jurassic dolerite intrusion has had limited local contact maturation effect, but may have acted to raise the overall geothermal gradient of the Tasmania Basin.

Potential reservoir rocks exist in the sandstone of the Liffey Group, and have poor to fair, occasionally good porosity, and poor permeability. Liffey Group permeability is generally more suitable for gas than for oil, although the Tasmania Basin is only mature for significant gas generation in southern areas. There are however some sandstone beds with fair to good porosity combined with fair permeability. Sandstone porosity is secondary, and primary porosity and permeability have been reduced by lithic compaction of less quartzose sand, silica and clay cementation, and by late stage carbonate cements associated with dolerite intrusion. This carbonate cementation is particularly evident in the Hunterston–Bothwell region.

Seal rocks of low permeability and local extent are found as siltstone and mudstone lenses within the Liffey Group, and as thicker siltstone with volcanic clay horizons in overlying Cascades Group. Regionally the Tasmania Basin is sealed by the extensive and up to 200 m thick Ferntree Formation. Contact metamorphism and clay alteration associated with dolerite intrusion in the Jurassic also provides potential local seals.

The Tasmania Basin Lower Parmeener Supergroup shows generally broad open folding, and may be considered almost flat lying. Likely trap formation is associated with mid Jurassic dolerite intrusion and associated faulting, and latest Jurassic to early Tertiary extension (Stacey and Berry, in press). The later may also have been detrimental to trap integrity. Faulting and contact metamorphism during dolerite intrusion has the potential to form both traps and seals, prior to late Cretaceous thermal maturity.

Future exploration programs need to target areas within the central and southern mature part of the Tasmania Basin, as shown in Figure 16, where Lower Parmeener Supergroup rocks are extensive and capped by sufficient overburden to provide suitable confining pressures. Source rocks are present throughout the basin, although of varying quality, as are reservoir facies.

ACKNOWLEDGEMENTS

The author has been funded as an Australian Postdoctoral Research Fellowship by the Strategic Partnerships with Industry - Research and Training Scheme (SPIRT) Project, joint funded by the Australian Research Council, and the industry partner Great South Land Minerals. Discussion and interaction with project PhD students Alan Chester, Andrew Stacey and Jubo Liu, and chief investigator Clive Burrett are greatly appreciated.

REFERENCES

Alsharhan, A. S., Nairn, A. E. M. and Mohammed, A. A., (1993): Late Palaeozoic glacial sediments of the southern Arabian Peninsula: their lithofacies and hydrocarbon potential. Marine and Petroleum Geology, 10: 71-78.

Araujo, L. M., Triguis, J. A., Cerqueira, J. R., da Silva Freitas, L. C., (2000): The atypical Permian petroleum system of the Parana Basin, Brazil. In Petroleum systems of South Atlantic margins. (eds) Mello, M.R., Katz, B. J., AAPG Memoir, 73: 377-402.

Bacon, C. A., Calver, C. R., Boreham, C. J., Leaman, D. E., Morrison, K. C., Revill, A. T. and Volkman, J. K., (2000): The petroleum potential of onshore Tasmania: a review. Mineral Resources Tasmania, Geological Survey Bulletin, 71: 93p.

Bacon, C. A. and Green, D. C., (1984): A radiometric age for a Triassic tuff from eastern Tasmania. Tasmania Department of Mines Unpublished Report, 1984/29.

Banks, M. R., (1973): General geology., in M. R. Banks, ed., The Lake Country of Tasmania., Royal Society of Tasmania., p. 25-33.

Banks, M. R., (1989): Summary and structural development., in C. F. Burret and E. L. Martin, eds., Geology and mineral resources of Tasmania.,15, Geological Society of Australia special publication, p. 293-294.

Barker, C. E. and Pawlewicz, M. J., (1994): Calculation of Vitrinite Reflectance from Thermal Histories and Peak Temperatures, a comparison of methods., in P. K. Mukhopadhyay and W. G. Dow, eds., Vitrinite Reflectance as a Maturity Parameter. Applications and Limitations. ACS Symposium Series 570: 216-229. American Chemical Society.

Bedi, J.C.S., (2003): Reservoir and source rock potential of the Upper Parmeener Supergroup, Tasmania Basin. Unpublished Honours Thesis University of Tasmania, 116.

Benelmouloud, M., Zhuravlev, E., (1989): Problems of petroleum exploration under plateau basalts. In Origin and evolution of sedimentary basins and their energy and mineral resources. (Ed.) Price, R. A. Geophysical Monograph, 48: 197-202.

Brauns C.M., Hergt, J.M., Woodhead, J.D and Maas, R., (2000): Os isotopes and the origin of the Tasmanian dolerites. Journal of Petrology, v. 41, 905-918.

Calver, C. R. and Castleden, R. H., (1981): Triassic basalt in Tasmania. Search, 12: 92-103.

Calver, C. R. and Forsyth, S. M., (2001): Skeleton, Sheet 4625. Tasmanian Geological Survey Digital Geological Atlas 1:25,000 Series.

Calver, C. R. and Forsyth, S. M., (2002): Maydena, Sheet 4626. Tasmanian Geological Survey Digital Geological Atlas 1:25,000 Series.

Clarke, M. J., (1989): Lower Parmeener Supergroup., in C. F. Burrett and E. L. Martine, eds., Geology and Mineral Resources of Tasmania.,Special Publication 15, Geological Society of Australia., p. 295-309.

Cook, A.C., (2003): Organic petrology of some core samples from the Permian of Tasmania. Unpublished report, Keiraville Konsultants PTY LTD.

Crowell, J. C. and Frakes, L. A., (1975): The Late Palaeozoic glaciation., in K. S. W. Campbell, ed., Gondwana Geology: Proceedings of the 3rd Gondwana Symposium, Canberra 1973.,3, International Gondwana Symposium, p. 313-331.

Delaney, P. J. V., (1998): The Pilar Basin; a new prospect in Paraguay. AAPG Bulletin, 82: 1908.

Demaison, G. and Huizinga, B. J., (1991): Genetic Classification of Petroleum Systems. American Association of Petroleum Geologists Bulletin, 75: 1626-1643.

Domack, E. W., Burkley, L. A., Domack, C. R. and Banks, M. R., (1993): Facies analysis of glacial marine pebbly mudstones in the Tasmania Basin: implications for regional paleoclimates during the late Paleozoic., in R. H. Findlay, R. Unrug, M. R. Banks and J. J. Veevers, eds., Assembly, evolution and dispersal; proceedings of the Gondwana eight symposium.,8, International Gondwana Symposium, p. 471-484.

Duddy, I.R., (1997): Focusing exploration in the Otway Basin: understanding timing of source rock maturation. APPEA Journal, v. 37, 178-191.

Eadington, P.J., Lisk, M. and Krieger, F.W., (1996): Identifying oil well sites. United States Patent Number 5,543,616.

Edwards, D., Kennard, J. M., Colwell, J. B. and Jones, P. J., (1996): Source and generation history of Palaeozoic hydrocarbons, Petrel Sub-basin. AGSO Research Newsletter, 25: 24.

Eyles, C. H., Eyles, N. and Franca, A. B., (1993): Glaciation and tectonics in an active intracratonic basin: the Late Palaeozoic Itarare Group, Parana Basin, Brazil. Sedimentology, 40: 1-25.

Farmer, N., (1985): Kingborough. Geological Survey Explanatory Report, Tasmania Department of Mines, Geological Atlas 1:50,000 Series, Sheet 88 (8311N): 105 p.

Forsyth, S. M., (1989): Upper Parmeener Supergroup., in C. F. Burrett and E. L. Martin, eds., Geology and mineral resources of Tasmania, Geological Society of Australia special publication 15: 309-338.

Forsyth, S.M., 1984. Oatlands. Geological Survey Explanatory Report, Tasmania Department of Mines, Geological Atlas 1:50,000 Series, Sheet 68 (8313S).

Forsyth, S. M., Farmer, N., Gulline, A. B., Banks, M. R., Williams, E., and Clarke, M. J., (1974): Status and subdivision of the Parmeener Super-Group. Papers and Proceedings of the Royal Society of Tasmania, 108: 107-109.

Gee, R. D. and Legge, P. J., (1974): Beaconsfield. Geological Survey Explanatory Report, Tasmania Department of Mines, Geological Atlas 1 Mile Series, Sheet 30 (8215N): 121 p.

George, S.C., Lisk, M, Eadington, P.J., Quezada, R.A, Krieger, F.W. & Greenwood, P.F. (1996): Comparison of palaeo oil charges with currently reservoired hydrocarbons using the geochemistry of oil-bearing fluid inclusions. SPE paper 36980, Society of Petroleum Engineers, Asia Pacific Oil and Gas Conference, 28-31 October 1996, Adelaide, 159-171.

Grantham, P. J., Lijmach, G. W. M., Posthuma, J., Hughes Clarke, M. W. and Willink, R. J., (1988): Origin of crude oils in Oman. Journal of Petroleum Geology, 11: 61-80.

Greenwood, P.F., Arouri, K.R. and George, S.C., (2000): Tricyclic terpenoid composition of Tasmanites kerogen as determined by pyrolysis GC-MS. Geochimica et Cosmochimica Acta, v. 64, 1249-1263.

Hand, S. J., (1993): Palaeogeography of Tasmania's Permo-Carboniferous glacigenic sediments., in R. H. Findlay,

R. Unrug, M. R. Banks and J. J. Veevers, eds., Assembly, evolution and dispersal; proceedings of the Gondwana eight symposium.,8, International Gondwana Symposium, p. 459-469.

Hergt, J.M., McDougall, I., Banks, M.R. and Green, D.H., (1989): Jurassic Dolerite. In: Burrett, C.F. and Martin, E.L. (Eds), Geology and Mineral Resources of Tasmania, Special Publication 15, Geological Society of Australia, 375-381.

Hughes, T., Lang, S. C. and Hall, N., (2000): Integration of sequence stratigraphy and sedimentology in an intracratonic setting; Tartulla Field, Cooper Basin, Australia. AAPG Bulletin, 84: 1440.

Hunt, J. M., (1996): Petroleum geochemistry and geology, second edition., W.H. Freeman and Company, New York., p. 743 p.

Kohn, B.P., Gleadow, A.J.W., Brown, R.W., Gallagher, K., O'Sullivan, P.B. & Foster, D.A., (2002): Shaping the Australian crust over the last 300 million years: Insights from fission track thermotectonic imaging and denudation studies of key terranes. Australian Journal of Earth Sciences, v. 49, 697-717.

Leaman, D.E., (2003): Discussion. Shaping the Australian crust over the last 300 million years: insights from fission track thermal imaging and denudation studies of key terranes. Australian Journal of Earth Sciences, v. 50, 645-646.

Levell, B. K., Braakman, J. H. and Rutten, K. W., (1988): Oil-bearing sediments of Gondwana glaciation in Oman. AAPG Bulletin, 72: 775-796.

Lewan, M. D., (1987): Petrographic study of primary petroleum migration in the Woodford Shale and related rock units., in B. Doligez, ed., Migration of hydrocarbons in sedimentary basins.: Paris, Editions technip, p. 113-130.

Lowe-Young, B. S., Mackie, S. I., Heath, R. S., (1998) The Cooper-Eromanga petroleum system, Australia; investigation of essential elements and processes. Annual Meeting Expanded Abstracts - American Association of Petroleum Geologists, 1998

Maynard, B. R., (1996): Reservoir characterisation of the Liffey/Faulkner Group, Tasmania., Unpublished B.Sc. Honours thesis, Univeristy of Tasmania., 80 p.

Milani, E. J. and Catto, A. J., (1998): Petroleum geology of theParana Basin, Brazil. AAPG Bulletin, 82: 1944.

O'Sullivan, P. B. and Kohn, B. P., (1997): Apatite fission track thermochronology of Tasmania. Record Australian Geological Survey Organisation, 1997/35: 61p.

Philp, R. P. and Gilbert, T. D., (1986): A geochemical investigation of oils and source rocks from the Surat Basin. The APEA Journal, 26: 172-186.

Pike, G. P., (1973): Quamby. Geological Survey Explanatory Report, Tasmania Department of Mines, Geological Atlas 1 Mile Series, Sheet 46 (8219N): 56 p.

Randal, M. A., (1982): Petroleum exploration in Permian basins - history and future trends. Queensland Government Mining Journal, 971: 411-420.

Randal, M. A., (1984): Review of petroleum exploration and potential in Queensland. Queensland Government Mining Journal, 998: 435-447.

Revill, A., (1996): Hydrocarbons isolated from Lonnavale, Seep, swab and bitumen samples. CSIRO Report, TDR-1: unpublished.

Reid, C. M. & Burrett, C. F., (in press): The geology and hydrocarbon potential of the glaciomarine Lower Parmeener Supergroup, Tasmania Basin. Proceedings of the East Australian Basin Symposium II, Adelaide, September 2004.

Schmidt, P.W. and McDougall, I., 1977. Palaeomagnetic and potassium-argon dating studies of the Tasmanian dolerites. Journal of the Geological Society of Australia, v. 25, 321-328.

Schwebel, D. A., Devine, S. B. and Riley, M., (1980): Source, maturity and gas composition relationships in the southern Cooper Basin. The APEA Journal, 20: 191-200.

Shaw, R. D., Korsch, R. J., Boreham, C. J., Totterdell, J. M., Lelbach, C. and Nicoll, M. G., (1999): Evaluation of the undiscovered hydrocarbon resources of the Bowen and Surat Basins, south Queensland. AGSO Journal of Geology and Geophysics, 17: 43-65.

Stacey, A. R. and Berry, R. F., (in press). The structural history of Tasmania. Proceedings of the East Australian Basin Symposium II, Adelaide, September 2004.

Turner, N. J. and Calver, C. R., (1987): St Marys. Geological Survey Explanatory Report, Tasmania Department of Mines, Geological Atlas 1:50,000 Series, Sheet 49 (8514N):

Warris, B. J., (1993): The hydrocarbon potential of the Palaeozoic basins of Western Australia. The APEA Journal, 33: 123-137.

Wythe, S. and Watson, M., (1996): Geochemical evaluation of an oil seep from Lonnavale Tasmania. AMDEL Report, unpublished.

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total SPI	mean SPI	barrels m2
Woody Island siltstone															
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			
5802	Tunbridge DDH	458	0	33	0.38	1	676.4	0.56	0.92	1.48	2.8	0.004			
T676.3	Tunbridge DDH	439	6	56	0.4	1	676.3	0.91	1.38	2.29	2.46	0.006			
total													0.572		3.606
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
Q3	Quoin DDH	542	17	15	0.27	6.4	126.4	0.07	0.2	0.27	1.26	0.004			
Q4	Quoin DDH	418	14	5	0.43	10	120	0.06	0.08	0.14	1.37	0.004			
Q5	Quoin DDH	443	18	15	0.35	10	110	0.09	0.17	0.26	1.11	0.007			
Q6	Quoin DDH	486	36	63	0.18	32	100	0.11	0.5	0.61	0.79	0.049			
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				
average					0.5075	50		0.11	0.1025	0.2125	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	road cut	449	18	148	0.41		oc	1.01	1.47	1.19	0.99				
S4b	road cut	388	56	158	0.31		oc	0.28	0.62	0.9	0.39				
S5b	Styx Road quarry	515	7	95	0.35		oc	0.5	0.95	1.45	1				
"S8"	Styx Road quarry	466	36	126	0.32		oc	0.35	0.76	1.11	0.6				
average		453	8.429	74.33	0.433	140.000		0.501	0.669	1.027	0.819			0.359	2.264
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

Sample	Location	T_{max}	OI	HI	PI	Thickness	Depth	S1	S2	S1+S2	TOC	SPI	Total SPI	mean SPI	barrels m2
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	100		0.172	1.682	1.854	0.972	0.464		0.464	2.920

Tasmanite Oil Shale

Immature Oil Shale															
1995	Mersey Gt Bend	444	18	971	0.04	0.45	oc	12.5	304	316.5	31.3	0.356			
1996	Hellyer Gorge	449	46	716	0.03	0.45	oc	1.3	38.9	40.2	5.43	0.045			
1	Oonah	446	3	937	0.05	0.45	oc	30.8	590.8	621.6	63.05	0.699			
2	Oonah	443	4	937	0.05	0.45	oc	3.6	65.2	68.8	6.96	0.077			
5	Oonah	440	27	675	0.03	0.45	oc	1.4	54.4	55.8	8.06	0.063			
6	Oonah	444	5	872	0.04	0.45	oc	22.8	535	557.8	61.35	0.628			
8	Mersey Gt Bend	436	11	748	0.002	0.45	oc	0.03	19.3	19.33	2.58	0.022			
	average					1			230	240	26			0.600	3.780
	Bicheno 10 DDH	446	1	868	0.04			6.28	147.5	153.78	17				
5800	Bicheno 10 DDH	449	0	895	0.05		321.05	8.01	152	160.01	16.99				
	average					1.5		7.145	150	157	17			0.588	3.707
	basin average													0.594	3.743

Macrae Mudstone

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

Liffey Group

coaly horizons															
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						1		6.925	101.73	108.65	38.875		0.272		1.711
Carbonaceous siltstone															
1999	Musselroe BH 1A	277	4	1	0.6	35	12.8	0.03	0.02	0.05	1.9				
2000	Golden Valley DDI	435				10		0.47	3.64	4.11	4.25		0.103		0.647
P1	Pelham DDH	444	0	31	0.33	6.5	358.45	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	5	383.6	1.64	4.32	5.96	4.22	0.075			
T2	Tunbridge DDH	425	10	37	0.19	23	380.7	0.05	0.21	0.26	0.56	0.015			
T3	Tunbridge DDH	465	2	63	0.29	10	388.5	0.41	1.01	1.42	1.58	0.036	0.125		0.787
R1	Ross DDH	444	4	384	0.08	7	171.5	1.91	20.75	22.66	5.4		0.397		2.498
H10	Hunterston DDH	492	30	48	0.09		828.5	0.06	0.61	0.67	1.25				
H7	Hunterston DDH	463	8	42	0.27	3.5	845.6	0.46	1.24	1.7	2.9	0.015			
H5	Hunterston DDH	459	10	61	0.22	5.1	850.15	0.54	1.9	2.44	3.1	0.031			
H6	Hunterston DDH					0.25	850.5				0.22				
H8	Hunterston DDH	464	3	78	0.17	3.4	856.5	0.38	1.84	2.22	2.35	0.019			
H1	Hunterston DDH	458	4	66	0.22	3	859.2	0.41	1.49	1.9	2.24	0.014			
H9	Hunterston DDH	464	2	68	0.27	0.01	869.5	0.55	1.51	2.06	2.2				
total													0.079		0.498
												total		0.145	0.911
Pelionite															
62373	Pelionite, Mt Pelio	473	2	809	0	0.2	oc	3.06	655	658	81		0.329		2.073

Appendix 2 – Vitrinite reflectance analyses Alan Cook, Keiraville Konsultants.

KK # Ref #.	Depth (m) /Type	$\bar{R}_{vmax}$	Range	N	**DRILLHOLE H, p 1** Sample description including liptinite fluorescence, maceral abundances, mineral fluorescence
					CASCADE GROUP
T8898	828.5	-	-	-	Fluorescing liptinite absent. (Siltstone with minor silty claystone. Dom common, I. Inertinite common, vitrinite and liptinite absent. Mineral fluorescence pervasive moderate orange. Iron oxides rare. Pyrite abundant.)
Core	$\bar{R}_{Imax}$	2.09	1.54-3.46	25	
					LIFFEY GROUP
T8899	856.5	1.06	0.94-1.26	9	Fluorescing liptinite absent. (Siltstone. Dom abundant, I>>V. Inertinite abundant, vitrinite rare, liptinite absent. Diffuse organic matter common. Mineral fluorescence patchy moderate orange. Iron oxides rare. Pyrite rare.)
Core	$\bar{R}_{Imax}$	2.10	1.62-2.72	25	
					BUNDELLA MUDSTONE
T8900	874.4	-	-	-	Fluorescing liptinite absent. (Argillaceous siltstone with minor sandstone. Dom common, I. Inertinite common, vitrinite and liptinite absent. Sparse foraminiferal tests. Mineral fluorescence patchy weak orange. Iron oxides rare. Pyrite abundant.)
Core	$\bar{R}_{Imax}$	2.02	1.56-2.84	25	

The shallowest sample appears to contain only inertinite. Identification of vitrinite in dispersed organic matter (dom) is difficult at vitrinite reflectance levels between about 1.0% and 2.0% and it is possible that the lower part of the range reported as inertinite includes some vitrinite. However, the vitrinite present within the second sample was relatively easy to distinguish, suggesting that the other two samples do not contain vitrinite.

No evidence was found of carbonized organic matter, but the level of vitrinite reflectance may have been elevated by the doleritic intrusions near the horizons sampled. Small amounts of oil droplets are present in the two deeper samples. The oil is occluded within mineral grains.

KK # Ref #.	Depth (m) /Type	$\bar{R}_{vmax}$	Range	N	**DRILLHOLE GV, p 1** Sample description including liptinite fluorescence, maceral abundances, mineral fluorescence
					BUNDELLA MUDSTONE
T8901	34.8	0.80	0.66-0.92	4	Sparse lamalginite and liptodetrinite, orange to dull orange, rare sporinite, orange to dull orange, rare *Botryococcus*-related telalginite, bright orange. (Sandy siltstone. Dom common, I>L>V. Inertinite and liptinite common, vitrinite rare. Sparse foraminiferal tests. Mineral fluorescence weak dull orange. Iron oxides rare. Pyrite sparse.)
Core	$\bar{R}_{Imax}$	1.88	1.26-2.62	25	
					WOODY ISLAND SILTSTONE
T8902	142.4	0.73	0.68-0.77	2	Abundant lamalginite and sparse liptodetrinite, orange to dull orange, sparse sporinite, orange to dull orange, rare *Botryococcus*-related telalginite, bright orange. (Argillaceous siltstone. Dom abundant, L>I>V. Liptinite abundant, inertinite sparse to common, vitrinite rare. Mineral fluorescence weak dull orange. Iron oxides rare. Pyrite abundant.)
Core	$\bar{R}_{Imax}$	1.72	1.28-2.40	25	

Small populations of vitrinite are present in both the samples and fluorescing liptinite is also present. Mineral fluorescence is very weak in the shallower of the two samples. More normal mineral fluorescence is present in the deeper sample

Lamalginite is present in both samples and a small colony of *Botryococcus*-type telalginite was noted in T8901. Both samples also contain moderate-sized thin-walled palynomorphs that may be small tasmanitid cysts.

KK # Ref #.	Depth (m) /Type	$\bar{R}_{vmax}$	Range	N	**DRILLHOLE T, p 1** Sample description including liptinite fluorescence, maceral abundances, mineral fluorescence

					LIFFEY GROUP
T8903	383.6	1.71	1.45-1.94	25	Fluorescing liptinite absent. (Sandy siltstone. Dom common, I>V. Inertinite common, vitrinite sparse, liptinite absent. Diffuse organic matter abundant. Sparse yellow fluorescing specks in the fractures in some quartz grain, probably from oil. Mineral fluorescence patchy weak orange. Iron oxides rare. Pyrite common.)
Core	$\overline{R}_{I}max$	2.77	2.26-4.54	10	
					WOODY ISLAND SILTSTONE
T8904	676.3	1.74	1.53-1.87	10	Fluorescing liptinite absent. (Claystone. Dom sparse, I>V. Inertinite sparse, vitrinite rare, liptinite absent. Coke rare, fine mosaic. Diffuse organic matter abundant. Mineral fluorescence patchy weak orange. Iron oxides rare. Pyrite abundant.)
Core	$\overline{R}_{I}max$	2.61	2.14-4.70	20	

The fields reported as vitrinite show relatively angular outlines and the vitrinite populations are not well-defined. The restricted ranges of reflectance found suggest that the material is vitrinite but it is possible that they represent low reflecting inertinite. The deeper of the samples contains one larger phytoclast that shows semicoke textures, with a fine coke mosaic. The reflectance of the semicoke is about 1.33% but with fine mosaics it is difficult to measure the maximum reflectance. The deeper sample clearly has been affected by contact metamorphism and it is likely that its vitrinite reflectance was about 0.6% or 0.7% at the time when the contact alteration occurred.

KK # Ref #.	Depth (m) /Type	$\overline{R}_{v}max$	Range	N	**OUTCROP SAMPLE, p 1** Sample description including liptinite fluorescence, maceral abundances, mineral fluorescence
					WOODY ISLAND SILTSTONE
T8905	-	1.31	1.16-1.45	5	Fluorescing liptinite absent. (Argillaceous siltstone. Dom sparse, I>V. Inertinite sparse, vitrinite rare, liptinite absent. Mineral fluorescence pervasive dull orange with bright orange patches. Most of the bright areas seem to represent oil inclusions but some could be liptodetrinite. If they do represent liptodetrinite, the values reported as vitrinite may represent low reflectance inertinite. Iron oxides rare. Pyrite sparse, locally abundant.)
Outcrop	$\overline{R}_{I}max$	2.28	1.62-4.74	25	

A small population is present that is similar morphologically to the populations reported as vitrinite for the samples from Drillhole T. Again, it is possible that the material reported as vitrinite is a low reflecting inertinite population but the relatively small range is more consistent with it representing vitrinite. The presence of occluded oil is possible at a vitrinite reflectance of about 1.3%. However, if the more elongate fluorescing areas are liptodetrinite, then the vitrinite reflectance reported is too high.

Second suite of samples

KK # Ref #.	40772 Depth (m)	$R_v$max Mean	Range	SD	N	UNIVERSITY OF TASMANIA Sample description including liptinite fluorescence maceral abundances, mineral fluorescence
						H - Liffey Group
T9028 Core	850.5 $\overline{R}_{I}$max	1.28* 2.10	0.90-1.55 1.54-2.72	0.195 0.456	17 5	Fluorescing liptinite absent. (Sandstone with abundant fossils, ?fish. Dom common, "V">I, L absent. *The material included within the reported vitrinite population includes some telovitrinite, some detrovitrinite and some material that appears to represent bitumen inclusions within ?fish bones. Some of the bitumen occurrences show fine coke mosaic. Rare bright yellow oil drops within ?carbonate. Mineral fluorescence patchy, bright orange to weak dull orange. Pyrite abundant.)
T9029 Ctgs	869.5	1.23	1.11-1.31	0.061	25	Fluorescing liptinite absent. (Sandstone. Dom abundant, V>I, L absent. Vitrinite abundant, inertinite common and liptinite absent. A high proportion of the vitrinite is present as thick layers of telovitrinite with common to abundant pyrite. Oil drops common, small to moderate in size, within quartz grains and probably within overgrowths, but overgrowth boundaries are not clearly defined. Some of the oil inclusions show prominent gas bubbles. Mineral fluorescence patchy, moderate orange to weak dull orange. Pyrite common to abundant.)
						R - Liffey Group
T9030 Ctgs	138.4 $\overline{R}_{I}$max	0.80 1.46	0.60-0.94 1.04-2.78	0.099 0.461	24 11	Rare cutinite dull orange, rare sporinite orange to dull orange. (Silty sandstone. Dom abundant, I>V>L. Inertinite abundant, vitrinite common and liptinite rare. A small proportion of the vitrinite is present as thin layers of telovitrinite. Mineral fluorescence weakly patchy, moderate to weak dull orange. Pyrite common to abundant.)
T9031 Ctgs	171.5 $\overline{R}_{I}$max	0.76	0.61-0.93	0..111	17	Common sporinite yellowish orange to dull orange, sparse telalginite yellowish orange to dull orange, rare resinite dull orange. (Sandy siltstone. Dom abundant, I>L>V. Inertinite abundant, liptinite common, vitrinite rare to sparse. The telalginite is derived from *Reinschia sp.* and shows well preserved cell structures. The presence of telalginite may be the cause of the lower reflectances in this sample compared with T9030 rather than a lower level of rank. Rare thucholitic bitumens, too poorly developed for reflectances to be measured but appear to be about 0.6%. Mineral fluorescence weakly patchy, moderate to weak dull orange. Iron oxides sparse to common. Pyrite sparse to common.)
						Q - Liffey Group
T9032 Ctgs	20.4 $\overline{R}_{I}$max	0.57	0.42-0.71	0.084	25	Rare cutinite dull orange. (Silty micaceous sandstone. Dom abundant, I>V>L. Inertinite abundant, vitrinite sparse, liptinite rare. The inertinite is dominated by large phytoclasts of fusinite and semifusinite. Most of the vitrinite appears to be either from root tissues or more rarely leaves. Mineral fluorescence weak dull orange. Pyrite sparse.)

The organic matter assemblages in most of the samples are dominated by inertinite, mainly semifusinite and fusinite. T9031 contains sparse telalginite that is fresh-water in origin. Oil inclusions are prominent in T9028. In T9031 the presence of thucholitic bitumen on a small grain of zircon indicates some migration of hydrocarbons through the section.

Most of the samples show prominent populations of relatively massive low reflecting inertinite. This makes determination of vitrinite reflectance relatively difficult. However, the determination for T9028 is the only one that is problematical.

ACC 31 March 2003

	48503		$R_v$max			**UNIVERSITY OF TASMANIA**
KK # Ref #.	Depth (m)	Mean	Range	SD	N	Sample description including liptinite fluorescence maceral abundances, mineral fluorescence
						DRILLHOLE DR - LIFFEY GROUP
T9668 Core	234	0.55	0.48-0.64	0.039	33	Sparse sporinite yellowish orange, rare cutinite orange, rare telalginite yellow to yellowish orange. (Sandstone, with localised coal scares. Within selected parts of the core, dom abundant, I>V>L. Inertinite and vitrinite abundant, liptinite sparse. Most of the coaly inclusions represent inertinite or vitrinite layers, but some represent redeposited peat fragments with layers containing detrovitrinite, inertinite and liptinite. The telalginite is derived from very small colonies of *Botryococcus spp.* Rare oil inclusions within quartz grains. Mineral fluorescence patchy, bright orange to weak dull orange. Pyrite abundant.)
T9669 Core	246	0.62	0.51-0.68	0.050	27	Sparse sporinite yellowish orange. (Sandstone, with localised coal scares. Within selected parts of the core, dom abundant, I>V>L. Inertinite and vitrinite abundant, liptinite sparse. Most of the coaly inclusions represent inertinite or vitrinite layers, but some represent redeposited peat fragments with layers containing detrovitrinite, inertinite and liptinite and some of the inertinite and telovitrinite layers represent reworked peat rather than single phytoclasts. Large sporangium present. Mineral fluorescence patchy, bright orange to weak dull orange. Pyrite abundant.)
						DRILLHOLE T - LIFFEY GROUP
T9670 Core	384.5 $\overline{R}_I$max	- 2.67	- 1.24-5.12	- 0.849	- 26	Fluorescing liptinite absent. (Siltstone, carbonaceous. Dom abundant, I, V and L absent. The inertinite grains appear corroded and include a number of very highly reflecting lenses. Rare to sparse oil inclusions within quartz grains, and some gas bubbles present within the oil inclusions. Mineral fluorescence patchy, bright orange to weak dull orange. Pyrite abundant.)
						OUTCROP - WOODY ISLAND FORMATION
T9670 Core	O/C $\overline{R}_I$max	- 3.52	- -	- -	- 1	Rare liptodetrinite orange, probably includes some poorly preserved sporinite. (Mudstone, calcareous. Dom rare, L>I, V absent. Liptinite and inertinite rare, vitrinite absent. Sparse yellow oil inclusions within quartz grains. Mineral fluorescence mostly very weak dull orange locally brighter near oil inclusions. Pyrite abundant.)

The DR sample contain common to abundant vitrinite that yields excellent quality vitrinite reflectance data. Small amounts of telalginite are present in the shallower of the two samples.

The sample from Drillhole T represents a facies present in many Gondwana sequences where silty lithologies contain abundant inertinite but no other macerals. The mean inertinite reflectance is very high but the lower reflecting fields are undoubtedly inertinite and are not vitrinite. Thus, the vitrinite reflectance must be below 1.24% and this is consistent with the patchy mineral fluorescence that was found.

The outcrop sample also does not contain any vitrinite and even inertinite is rare. The reason for the dark colouration is not clear. Oil inclusions are present and indicate that the oil was gassy as free gas bubbles are present. The liptinite that is present would be consistent with a vitrinite reflectance of about 0.75% to 0.85%.

ACC 5 May 2004

APPENDIX 3

sample	Location	unit	depth	He porosity (%)	point count porosity (%)	Air perm. mD	density g/cm3
G1	Granton	Liffey	154.6	2.3		0.05	2.66
G2	Granton	Liffey	160.7	4.3	7.6 to 0	0.05	2.68
R1	Ross	Liffey	136.9	10.6	10	0.18	2.67
R149.5	Ross	Liffey	149.5		9.2		
R154.6	Ross	Liffey	154.6		2.5		
R3	Ross	Liffey	156.6	14.9	14.3	8.8	2.66
R2	Ross	Liffey	165.6	13.6	6	0.43	2.66
R171.5	Ross	Liffey	171.5		0.4		
T1	Tunbridge	Liffey	364.50	10.0		0.12	2.64
T2	Tunbridge	Liffey	370.70	7.6		0.05	2.68
T3	Tunbridge	Liffey	370.75	7.0		0.05	2.67
	Tunbridge	Liffey	383.6	4.8		<0.01	2.59
Q6.4	Quoin DDH	Liffey	6.4	14.7		1.8	2.66
Q14.9	Quoin DDH	Liffey	14.9	9.9		0.21	2.7
Q19.4	Quoin DDH	Liffey	19.4	8.5		0.21	2.57
B681.2	Bothwell	Liffey	681.2		8.9		
B685.4	Bothwell	Liffey	685.4		4.2		
B687.9	Bothwell	Liffey	687.9	9.6	13.9	0.03	2.66
B690	Bothwell	Liffey	690		17		
H849.2	Hunterston	Liffey	849.2		1.8		
H850.5	Hunterston	Liffey	850.5		0.9		
H853.25	Hunterston	Liffey	853.25	8.7	10.4	0.06	2.68
H862.5	Hunterston	Liffey	862.5	4.1	2.6	0.04	2.68
H869.3	Hunterston	Liffey	869.3	5.6	6.5	0.05	2.67
H957.5	Hunterston	Bundella	957.5	7.5		0.03	2.62
	Hunterston	Bundella		31.3		15916.00	2.64
	Hunterston	Bundella		11.8		3053.00	2.63
H957.5 mean	Hunterston	Bundella		16.9		6323.0	2.6
EN182.8	Eaglehawk	Liffey	182.8	3.2		<0.01	2.67
EN307	Eaglehawk	Wl congl	307	15.2		3987.0	2.6
DR263.8	Douglas River	Liffey	263.8	13.4		166.0	2.64
DR256.85	Douglas River	Liffey	256.85	11.4		-	2.65
DR246	Douglas River	Liffey	246	14.0		1.06	2.64