# The geology and hydrocarbon potential of the glaciomarine Lower Parmeener Supergroup, Tasmania Basin

C.M. Reid and C.F. Burrett

## Abstract

The glaciomarine Lower Parmeener Supergroup, onshore Tasmania Basin, is currently targeted by hydrocarbon exploration and contains mature potential source, reservoir and seal rocks. Basal diamictites are overlain by organic siltstone of the Woody Island Formation, containing the alga *Tasmanites*, in places accumulated as the Tasmanite Oil Shale. The siltstone has low TOC and type III kerogens, the oil shale 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. Thick sequences of marginal marine and marine fossiliferous siltstone and sandstone superpose these, the siltstones forming potential local and regional seal units.

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.

Vitrinite reflectance analyses indicate the Woody Island Formation and Liffey Group are within the oil generation window in the central basin, with entry into the gas window in the south and southwest. Maximum burial occurred during the mid Cretaceous. A hydrocarbon seep in the south of the basin has been linked to a *Tasmanites* source. Structural traps probably exist within the Tasmania Basin but need to be seismically defined.

Keywords: Parmeener Supergroup, Permian, Tasmania Basin, glaciomarine, Tasmanite Oil Shale.

## Introduction

The onshore Tasmania Basin contains a glaciomarine to terrestrial sequence of Late Carboniferous to Late Triassic age (Fig. 1). It is divided into the glaciomarine Lower Parmeener, and terrestrial Upper Parmeener, Supergroups (Forsyth et al. 1974) (Fig. 2). The Parmeener Supergroup (Banks 1973) was overlain by now largely eroded Jurassic, Cretaceous, and Tertiary sediments, and is shallowly buried. 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 paper. The source and reservoir potential of the terrestrial Upper Parmeener Supergroup are discussed in Bedi (2003) and Eggert (1983). Bacon et al. (2000) and Bendall et al. (2000) presented the first modern reviews of the Parmeener Supergroup and other potential Tasmanian systems.

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). Exploration continued with shallow drilling and investigation of numerous coastal bitumen strandings. These coastal bitumens originate from sources outside the onshore Tasmania Basin (Volkman et al. 1992; Bacon et al. 2000), recent work showing them to be unrelated to known oils from the adjacent Bass, Gippsland or Otway basins (Volkman et al. 1992). Although not biodegraded, as might be expected after long distance transport (Volkman et al. 1992), the bitumens show relationships with known oil from southeast Asia (Currie et al. 1992), but a more local source cannot be ruled out (Volkman et al. 1992). A recently discovered bitumen near the wharf on Bruny Island, southern Tasmania, is most likely a spill, based on the appearance, anecdotal evidence and chemistry (Bacon et al. 2000) of the bitumen. Numerous 'oil seeps' and 'oily waters' have been reported, and all but one are unrelated to occurrences of petroleum (Bacon et al. 2000). The exception is a bitumen seep in a dolerite quarry at Lonnavale, southern Tasmania, where 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. Activity was most intense in the 1920s when there were Federal Government incentives for the discovery of oil and gas. These holes were all less than 360 m deep, 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 glaciomarine 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 with limited gas shows reported from drilling in the south of the state. Thermogenic gas was reported from Jericho-1, at less than 100 units (Tanner & Burrett 1997). In early 2001, 600 km of seismic was recorded through the central basin, specifically for hydrocarbon exploration. Drilling at Hunterston-1 in 2002, on a 2001 survey seismic line, proved the presence of a thick dolerite intrusion in the area (Reid et al. 2003), and provided velocity details of lithologic units that could be applied to seismically acquired data.

School of Earth Sciences, University of Tasmania, Private Bag 252-79, Hobart, TAS 7001.
C.Reid@utas.edu.au

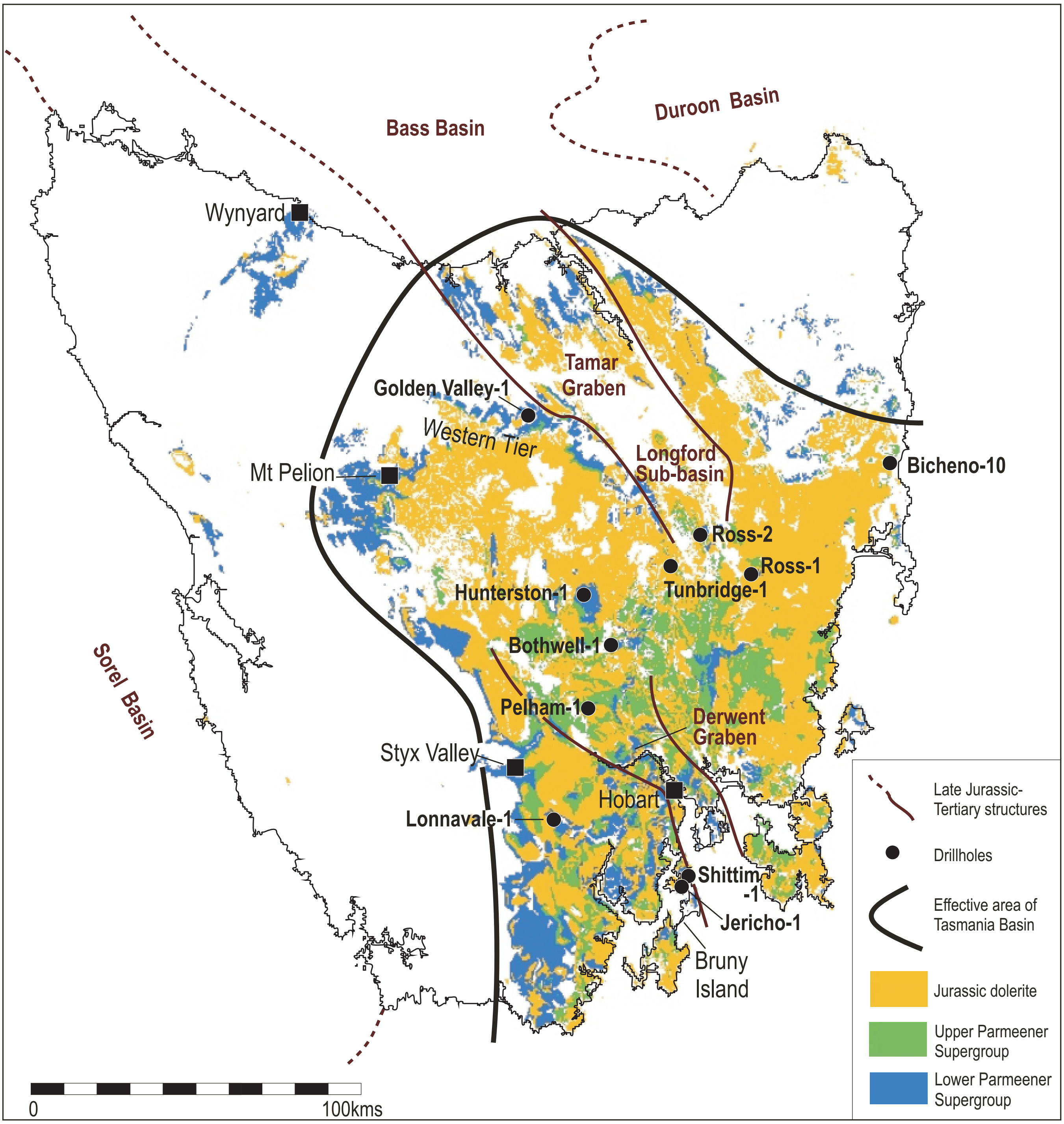


**Figure 1.** Geology of the Tasmania Basin showing Parmeener Supergroup and Jurassic dolerite outcrop, and major post-Parmeener structural features. Locations of diamond drill hole and outcrop sites discussed in the text are shown.

This paper combines new drilling and rock analyses with stratigraphic data gathered by Mineral Resources Tasmania drilling programs, and petroleum data presented by Bacon et al. (2000). Bendall et al. (1991) reviewed exploration in the Tasmania Basin, and Bendall et al. (2000) presented an overview of petroleum systems in the Tasmania Basin. Bacon et al. (2000) provided a more detailed review of the geology and potential of Ordovician to Tertiary petroleum systems within the Tasmania Basin.

This paper presents the stratigraphy, source, seal and reservoir potential of the glaciomarine Lower Parmeener Supergroup, or Gondwana 1 petroleum system of Bendall et al. (2000). Structure and seismic details are presented in Stacey and Berry (this volume).

## Stratigraphy

The Parmeener Supergroup (Banks 1973) consists of Late Carboniferous to Late Triassic glaciomarine and terrestrial rocks, which unconformably overlie Palaeozoic carbonates, siliciclastics and volcanics, and Precambrian dolomites. The topographic relief of the unconformity surface is in the order of 1000 m, carved during Carboniferous glaciation. Glacial retreat in the Late Carboniferous led to deposition of the basal Lower Parmeener Supergroup, of mostly glaciomarine origin (Hand 1993). Regional highs existed in the northwest, northeast, east and southwest, with a high through the centre of the basin (Reid et al. 2003). Thick

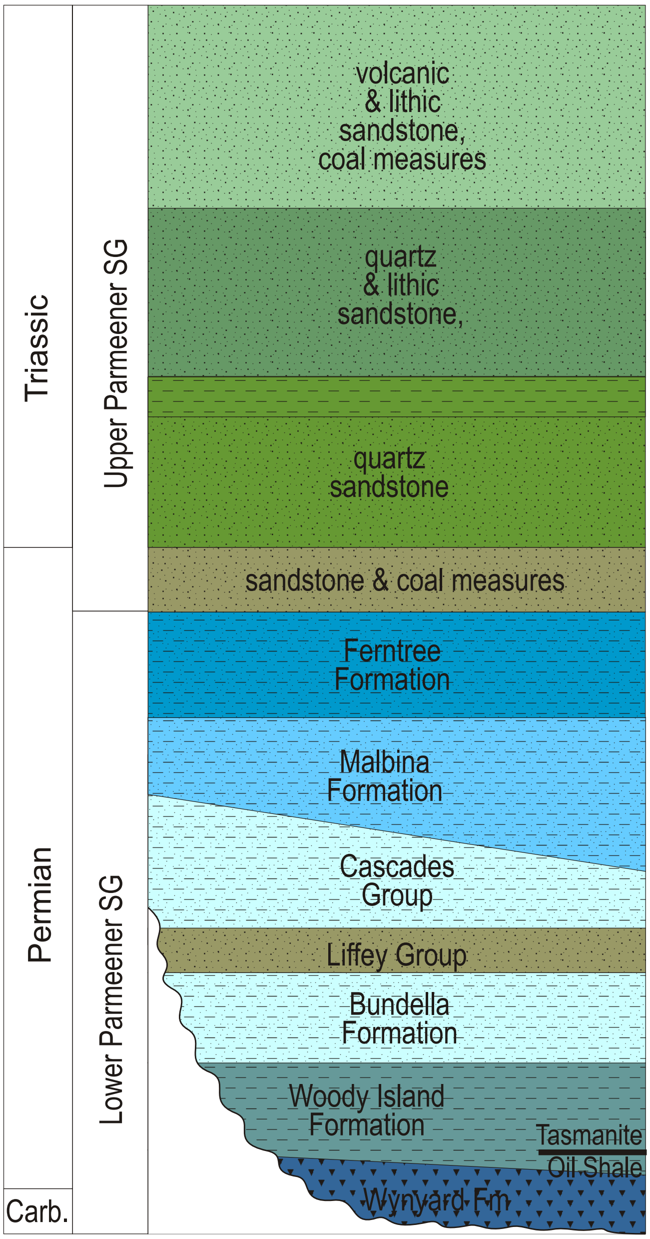


**Figure 2.** A generalised stratigraphic column and nomenclature for the Parmeener Supergroup. The Lower Parmeener Supergroup is divided into many local units (see Clarke, 1989), but is simplified here to broad units recognisable basin wide. The Upper Parmeener Supergroup nomenclature follows Forsyth (1989).

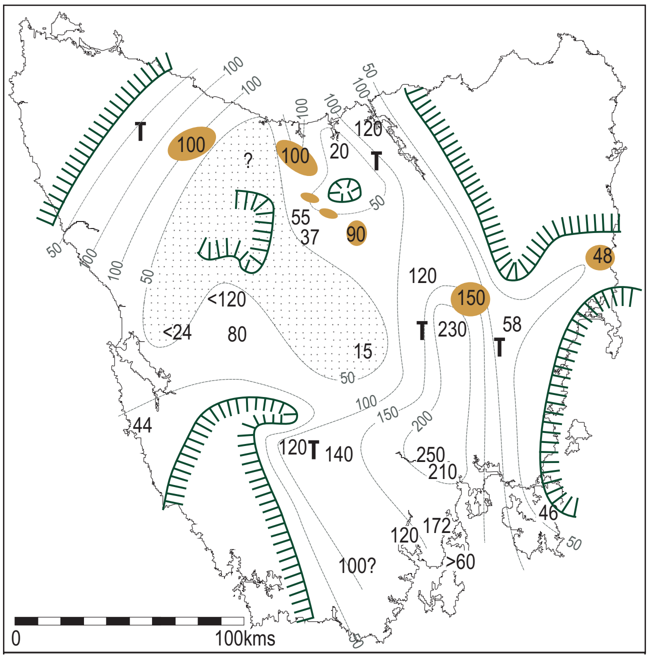


**Figure 4.** Thickness and distribution of Woody Island Formation source facies, and distribution of Tasmanite Oil Shale. Woody Island conglomeratic facies in the central Tasmania Basin is also shown. (After Reid et al. 2003; Bacon et al 2000).

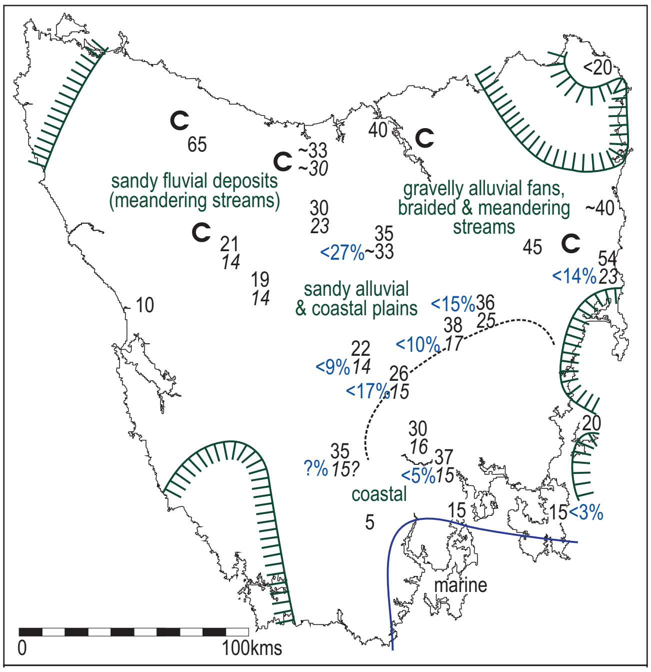


**Figure 5.** Thickness and distribution of Liffey Group. Also shown are total thickness of sandstone beds and cycles, and the upper porosity value for some localities (after Clarke 1989; Martini & Banks 1989; with additional data from this study).

diamictites, glacial outwash conglomerates and sandstones, and local mudstones and rhythmites (Clarke 1989; Hand 1993) were deposited as the Wynyard Formation. Total Organic Carbon (TOC) is low through these diamictites, at less than 0.4% (Domack et al. 1993).

The diamictites rapidly give way upwards to marine pebbly siltstone and mudstone, of the Woody Island Formation (Fig. 2,3). Environments of deposition were glacial, with glendonites and scattered ice rafted pebbles common (Domack et al. 1993; Clarke 1989). The green alga *Tasmanites punctatus* is dispersed throughout the Woody Island Formation, and 20–30 m above the base of the unit algal tests are abundant, and in places are accumulated to form the Tasmanite Oil Shale, which has TOC up to 63%. The oil shale occurs in the northwest (Wynyard area) to the east (Bicheno-10), and in the central basin (Ross-2), with dispersed *Tasmanites* elsewhere (Fig. 4). In the central Tasmania Basin (Reid et al. 2003), conglomerates and conglomeratic siltstone and sandstone facies associated with topographic highs, occur in place of typical Woody Island mudstone facies, and the Tasmanite Oil Shale and dispersed *Tasmanites* are absent. Conglomerates also onlap basement highs in the north and northwest at this time. Banks & Clarke (1987) noted Tasmanite Oil Shale distribution may be controlled by proximity to palaeo-shorelines. Domack et al. (1993) suggested seasonal melting of sea ice created a stable sea surface and allowed a photic zone with increased productivity within a stratigraphically restricted zone. As yet the distribution

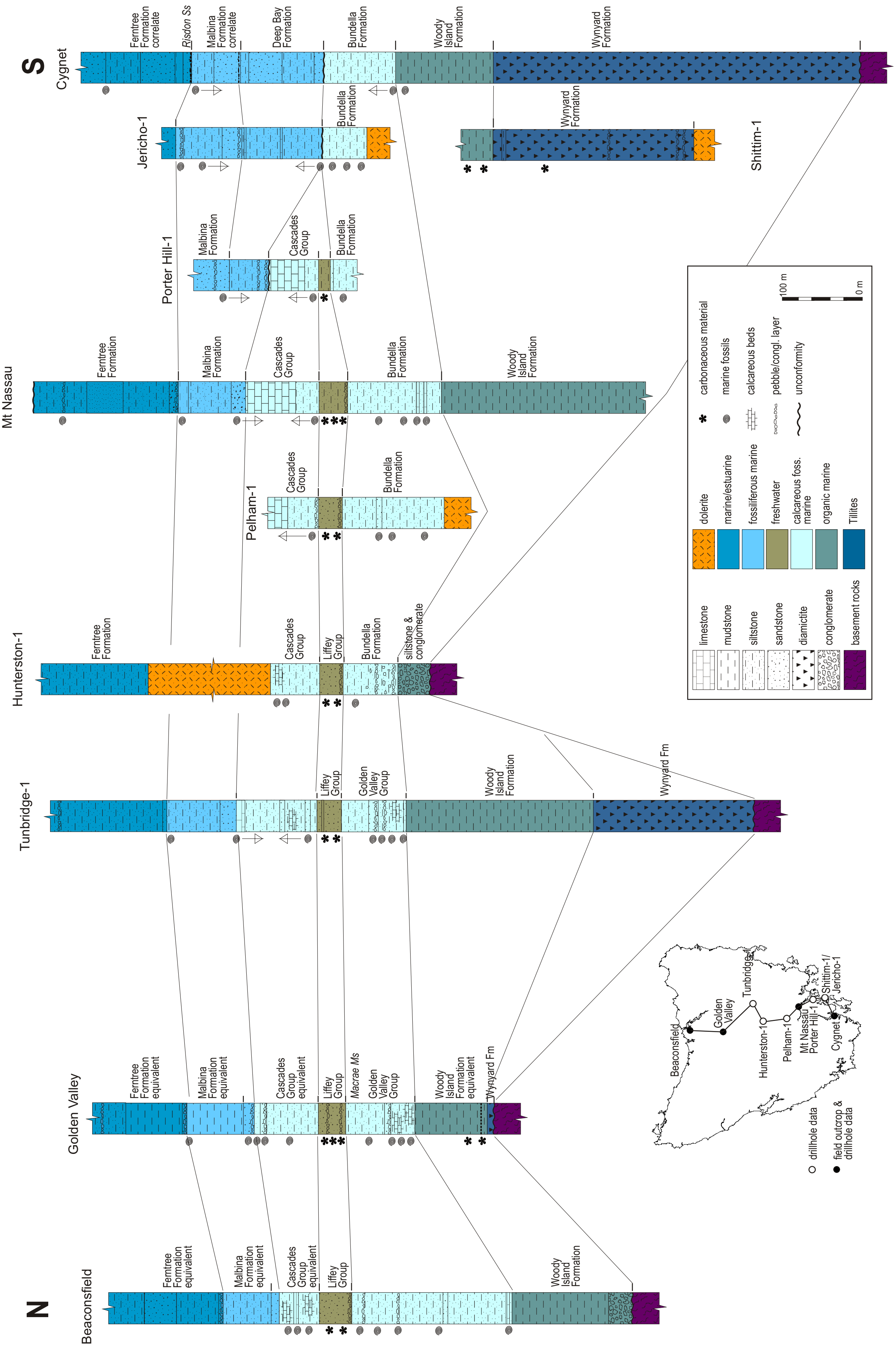


**Figure 3.** Lower Parmeener Supergroup stratigraphy across the Tasmania Basin. Location of drill hole and outcrop shown, inset. The base of the Cascades Group, recording a basin wide marine transgression, is taken as a level palaeosurface for the purposes of correlation.

and depositional environment of the Tasmanite Oil Shale is not fully understood, and therefore reliable predictions of its occurrence in the subsurface cannot be made. The siltstone source facies of the Woody Island Formation is up to 250 m thick (Fig. 4) and has fewer *Tasmanites* cysts and TOC is usually less than 2%.

Marine conditions continued during the Early Permian (Sakmarian) with the deposition of fossiliferous siltstones and minor sandstones as the Tasmania Basin was gradually filled (Banks 1989; Clarke 1989). At the top of this fossiliferous marine interval (Bundella Formation) is a marginal marine and often organic rich siltstone, that in the Western Tiers region (Macrae Mudstone) has TOC up to 4.25% (Bacon et al. 2000), though usually less than 1% and is of limited vertical and lateral extent.

Filling of the Tasmania Basin resulted in a relative regression of the shoreline southward and deposition of Liffey Group non-marine sandstones and carbonaceous siltstones. South of Hobart, marine conditions persisted. Coal beds were deposited in northern parts of the basin, with sandier coastal deposits in central and southern areas. In the Western Tiers and central basin regions the sandstones are medium to coarse-grained and well sorted.

Sandstone beds within the Liffey Group occur as laminated well-sorted fine and medium sands, with rare coarse sand, and beds generally 3–5 m 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 space is filled by fine material and locally may act as seals. Where sandstone and carbonaceous silt are interbedded, or carbonaceous material defines laminations within sandstones, overall porosity is reduced. In the southeast, in coastal environments, carbonaceous siltstone is common, and sandstone beds are micaceous. Distribution of the Liffey Group, and sandstone bed thicknesses are shown in Figure 5.

Marginal marine then shallow shelf marine fossiliferous siltstone, limestone and minor sandstone were deposited following marine transgression in the mid Early Permian (Artinskian) (Clarke 1989). The development of these fossiliferous beds (Cascades Group) was diachronous across the Tasmania Basin, with an apparent depositional hiatus followed by progressively younger deposits and reduced carbonate deposition to the north and northeast. Thick limestone was developed in the Hobart region to the south. Volcanic ash horizons occur within this fossiliferous sequence and are recognised as thin clay layers that are bioturbated in places. Cascades Group clay horizons and marginal marine siltstones may act as seal facies above Liffey Group sandstones. The calcareous units were overstepped from the south by fossiliferous siltstone and sandstone of the Deep Bay and Malbina Formations (Farmer 1985). The sandstone sequences are thickest in the south and thin northward.

Continued deposition led to an almost filled basin by the early Late Permian, leading to deposition of poorly fossiliferous mudstone and siltstone in a shallow marine to estuarine environment (Ferntree Formation) with minor sand and conglomerate horizons. The mudstones are thick and well developed and form the most obvious potential regional hydrocarbon seal in the Tasmania Basin.

In the Late Permian the marginal marine beds of the uppermost Lower Parmeener Supergroup were progressively overlain by the Upper Parmeener Supergroup. Nomenclature for the Upper Parmeener Supergroup is varied with numerous local formation names and the facies based nomenclature of Forsyth (1984, 1989a) has been followed here, and summarised in Figure 2. Basal units consist of inter-bedded, well-sorted, cross-bedded or ripple-laminated carbonaceous sandstone and mudstone, with a Permian flora. The Permo-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 quartz sandstone and feldspathic quartz sandstone with siltstone and mudstone, 200–300 m thick (Forsyth 1989a). Sandstone beds form fining-upwards cycles, or eroded cycles, of coarse to medium sandstone at the base, to finer sandstone or siltstone at the top. Mudstone occurs throughout as finer beds in the cycles, as isolated lenticular beds or interbedded with sandstone. Following quartz sandstone and mudstone deposition there is a broad basin-wide change to lithic-dominated sandstone with two prominent quartz sandstone intervals. The uppermost sequence in the Upper Parmeener Supergroup consists of predominantly volcanic lithic sandstone and mudstone, with coal seams of economic grade, and rare tuff and conglomerate beds. The volcanic sandstone sequence is about 270 m thick in the Midlands (Forsyth 1984), and up to 350 m in the northeast where it is mined for coal.

Within the Upper Parmeener Supergroup, high TOC levels are associated with the coals and carbonaceous beds, which are sufficient to act as an obvious hydrocarbon source. However, burial depths may be insufficient for source maturity. Sandstone within the sequence may be suitable as reservoirs (Bedi 2003), with mudstone forming seals, but burial depths are unlikely to provide sufficient confining pressures.

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 my, with a mean K-Ar age of 174 Ma (Brauns et al. 2000), a recalculation of Schmidt & McDougalls' 1977 data. The dolerite preferentially intruded the Parmeener Supergroup (then less than 130 my old), 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, 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.

# Source rocks

There are several potential 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 carbonaceous Liffey Group.

## Tasmanite Oil Shale

The Tasmanite Oil Shale is a rich accumulation of tests of the green alga *Tasmanites punctatus* (Clarke 1989). 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 TOC contents between 2.58 and 63%, making this a rich potential source rock. As discussed above, distribution of the Tasmanite Oil Shale is limited and it is only known from diamond drill core or surface outcrop in the northern and eastern basin, as shown in Figure 4.

RockEval 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 (SPI) (Demaison & Huizinga 1991) calculations for immature Tasmanite Oil Shale indicate up to 0.6 metric tons, or 3.7 barrels, 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, and low $S_1$ and $T_{max}$ show the currently known outcrop in northern and eastern areas is immature or marginally mature. However the seep at Lonnavale is most likely derived from a *Tasmanites* rich source (Wythe & Watson 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 $R_c$ 0.8–1.0%.

## Woody Island Formation

The Woody Island Formation has low TOC values mostly between 0.5 and 2% (Fig. 6), excluding the Tasmanite Oil Shale. In addition HI values are low, indicating a Type III gas and oil prone source, rather than the rich oil prone Type I source in the oil shale (Fig. 7). *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 layers.

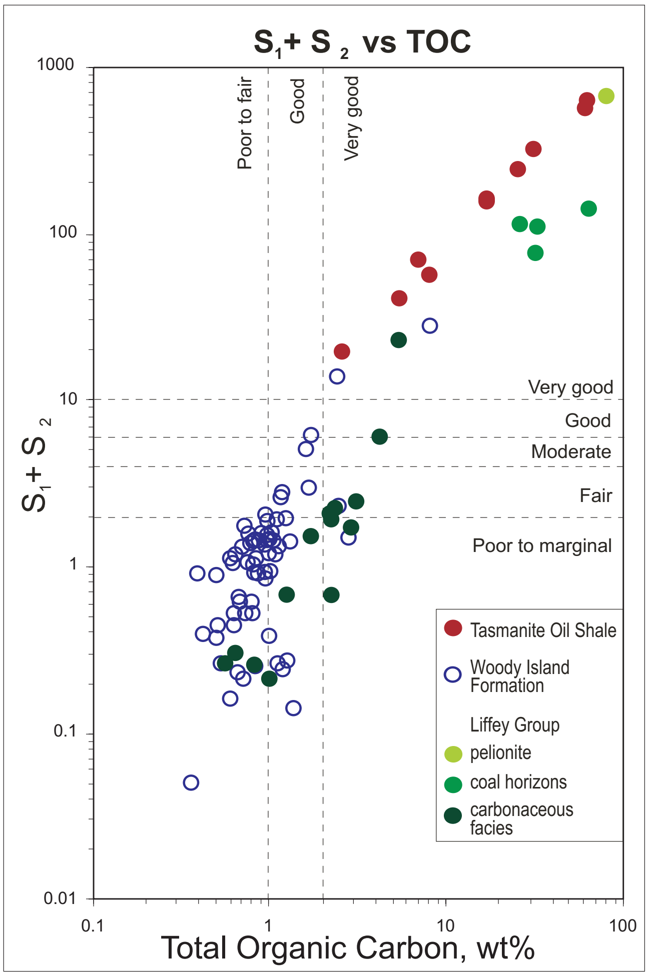


**Figure 6.** Tasmania Basin source rock quality, as expressed by a plot of $S_1$ + $S_2$ and Total Organic Carbon. Data, from this study and Bacon et al. (2000).

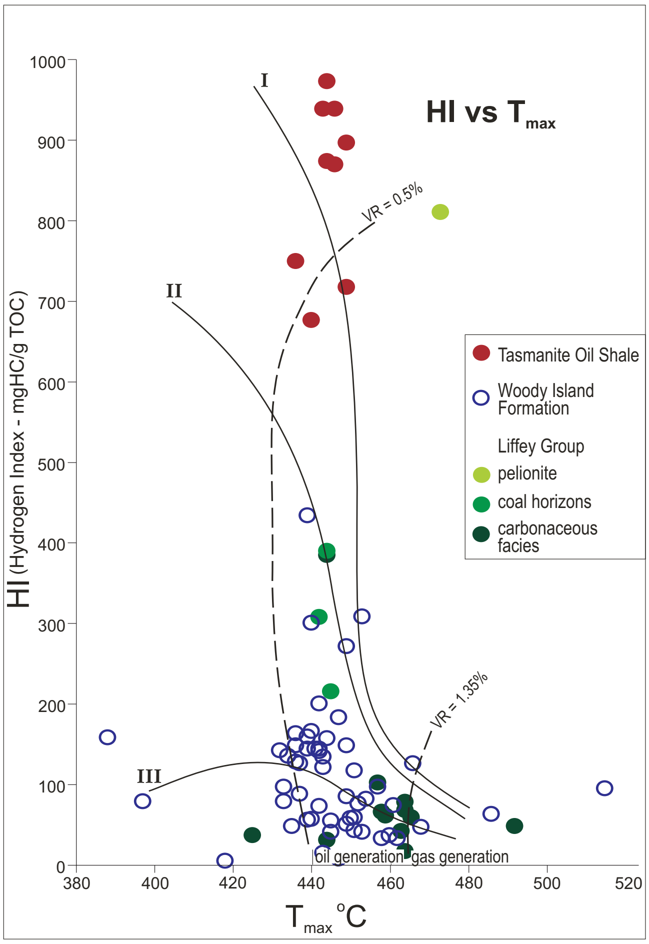


**Figure 7.** Hydrogen Index vs Temperature Maximum plot for Tasmania Basin source rocks. Tasmanite Oil Shale samples are from immature parts of the basin in the far northwest. Woody Island Formation samples predominantly show Type III kerogens, from disseminated organic matter. Those plotting as Type I and II kerogens are sampled in close stratigraphic proximity to the Tasmanite Oil Shale.

Siltstone adjacent to the oil shale, or between oil shale seams, shows a slightly higher TOC (~2.5%), and higher HI values (up to 440). Over most of the Woody Island Formation, siltstone RockEval parameters $S_1$ and $S_2$, are low, but its thickness (up to 250 m, see Fig. 4) makes it a potential hydrocarbon source rock. SPI calculations on immature Woody Island Formation siltstone indicate a mean potential generation of 0.42 metric tons (~ 2.65 barrels oil/~ 538$m^3$ 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 25.2% of their volume to petroleum (Hunt 1995), and generate less gas than Type II oil and gas prone kerogens. The low TOC levels of the Woody Island Formation siltstone (0.5–2%) are above the minimum experimental TOC of 0.5% required to generate gas, but below the minimum experimental TOC of 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 central part of the basin has been within the oil window, and the southern part is within the gas generation window (Fig. 8). Outcrop of the Woody Island Formation in the Styx Valley region, exhibits a petroliferous odour upon breakage of fresh rock surfaces. Weathered surfaces and outcrop exposed for several years do not exhibit any petroliferous odour, indicating rapid loss of the volatiles which cause this phenomenon.

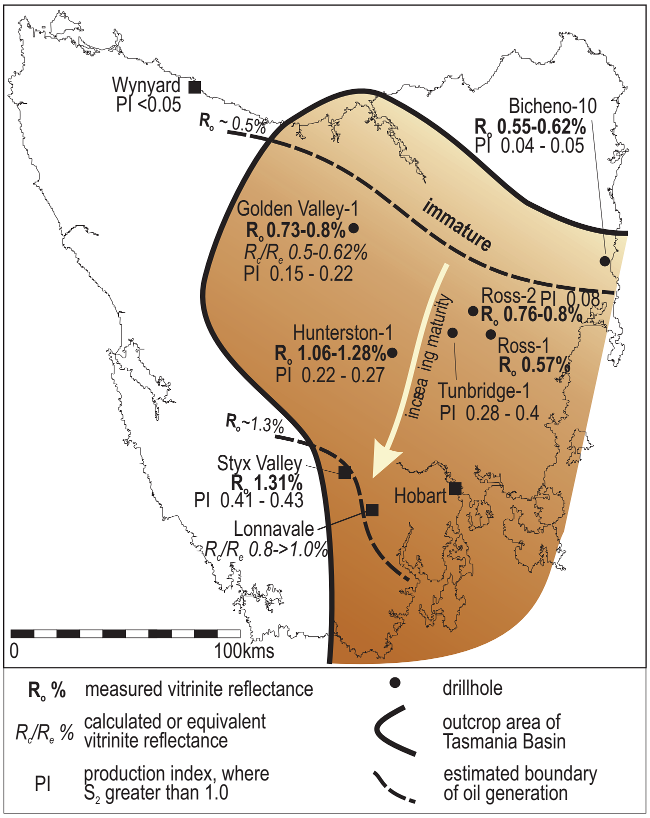


**Figure 8.** Maturity of Tasmania Basin source rocks, increasing towards the southwest. Measured vitrinite reflectance from Liffey Group and Woody Island Formation (Cook 2003) and equivalent reflectance data from Bacon et al (2000).

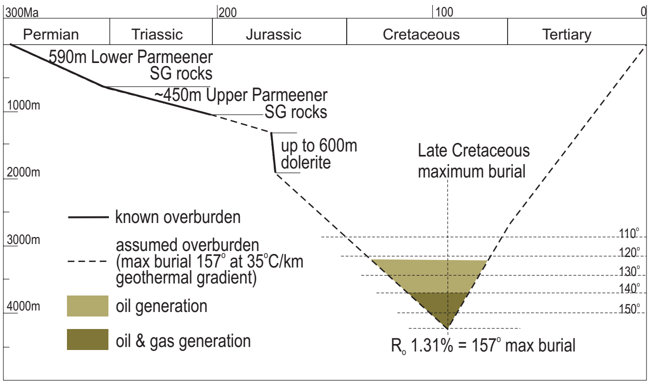


**Figure 9.** Theoretical burial profile for Woody Island Formation siltstone and Tasmanite Oil Shale in the Styx Valley region. Late Cretaceous maximum burial indicated from apatite fission track data (O'Sullivan & Kohn 1997; Kohn et al. 2002). Maximum burial temperature from comparative charts of Barker & Pawlewicz (1994). Maximum burial temperature and assumed 35ºC/km geothermal gradient define total burial depth, actual Jurassic to Cretaceous overburden unknown.

## Liffey Group

The non-marine Liffey Group consists of carbonaceous siltstone and sandstone, with coal horizons developed in the northern Tasmania Basin. Plant fragments are common in the Liffey Group through the central part of the basin, where it was deposited in a coastal plain environment by meandering streams. Coal horizons exhibit TOC levels up to 65%, with most carbonaceous siltstone less than 5% TOC (Fig. 6). SPI calculations from coaly units indicate 0.27 metric tons (1.7 barrels/345 $m^3$ gas) per square metre and 0.14 metric tons (0.87 barrels/179$m^3$ gas) per square metre in carbonaceous siltstone (without consideration of maturation or efficiency of kerogen type). A pelionite (a sapropelic coal or carbonaceous oil shale) sample from Mt Pelion (Fig. 1) has source quality parameters equalling that of the Tasmanite Oil Shale—HI at 800 and $T_{max}$ of 473—indicating it has just entered the oil window. However, this horizon is poorly exposed, and this part of the basin has not yet been drilled, so the distribution of this rich horizon is unknown.

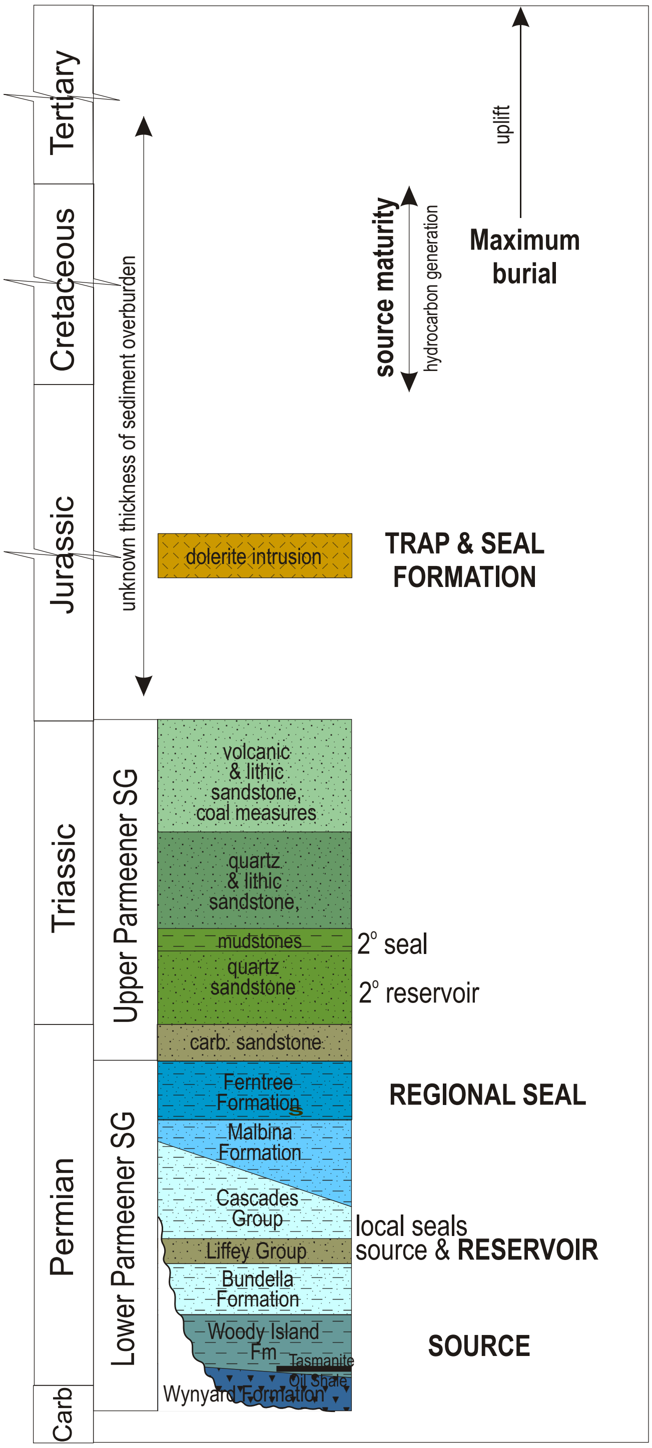


**Figure 10.** Stratigraphic events chart for the Gondwana 1 petroleum system. Source rocks are marked in the Woody Island Formation and Liffey Group, reservoir in the Liffey Group, and seals in the Cascade and Ferntree Formation and Jurassic dolerite.

Liffey Group source rocks display a range of kerogen types (Fig. 7). 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 laminae within sandstone units. These disseminated samples contain Type III kerogens, with a low hydrogen to carbon ratio, and are gas and oil prone.

## Basin maturity

RockEval pyrolysis of Woody Island Formation, Tasmanite Oil Shale and Liffey Group rocks has revealed all of these units have source potential. Maturity data indicate the basin is immature in the north, but mature through the central part of the basin with maturity increasing in a southwesterly direction (Fig. 8). Equivalent vitrinite reflectance, inferred from $T_{max}$ and Hydrogen Index (HI) plots, (Fig. 7), Production Index (PI) (Bacon et al. 2000), and measured vitrinite reflectance are used to determine basin maturity. The most reliable maturity data is from measured vitrinite reflectance, but inferred data have been used to determine maturity trends across the basin. A Production Index of 0.1 is considered 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 1995). In Figure 8, PI values are taken from Tasmanite Oil Shale 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 8, but in the Golden Valley, Styx and Tunbridge-Ross regions, HI versus $T_{max}$ plots for the Woody Island Siltstone indicate maturity from equivalent vitrinite reflectance. Samples from Bicheno-10 have low equivalent vitrinite reflectance and are immature to mature.

Vitrinite reflectance has been measured in carbonaceous units of the Liffey Group and some siltstones of the Woody Island Formation, by Cook (2003). Vitrinite is rare in the Woody Island Formation, but its presence indicates a component of terrestrially-sourced dispersed organic matter that has been recycled into these marine siltstones (Hunt 1995). In Liffey Group samples, inertinite is nearly always dominant over vitrinite, with liptinite rare or absent (Cook 2003), indicating a dominantly terrestrial humic source of kerogens (Hunt 1995). Vitrinite reflectance mean range is 0.57–1.74%, but the higher values are from samples affected by contact metamorphism (Cook 2003), caused by intrusion with Jurassic dolerite or Tertiary basalt. Samples showing coking, indicating contact metamorphism (Cook 2003) are not shown in Figure 8.

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

Accurate determination of the geothermal gradient of the Tasmania Basin is not possible using the currently available vitrinite reflectance data. Vitrinite is rare in Woody Island Formation marine siltstones and is largely confined to the non-marine 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 erosion 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 thickness to the Parmeener Supergroup has produced results varying from 0.5–3 km (Hergt et al. 1989). O'Sullivan & Kohn (1997) assumed a geothermal gradient of 20–30ºC/km. However, this seems low, given the current geothermal gradient in Tasmania is approximately 30–35ºC/km (calculated from heat flow data given in Cull & Denham 1979; Cull 1991). Geothermal gradients in the Otway Basin to the north of Tasmania are known to have cooled in the Late Cretaceous, from 50 –70ºC/km, to 30–40ºC/km in the present day (Duddy 1997). This implies that the Tasmanian geothermal gradient should also have been high before Late Cretaceous cooling.

## Burial profiles

Bacon et al. (2000) and Reid et al. (2003) use a geothermal gradient of 35ºC/km, to determine theoretical hydrocarbon generation from burial profiles of Permian sediments. While it was shown hydrocarbons could have been generated in Tunbridge-1 and Hunterston-1 using this gradient, it is likely to be a conservative estimate, at the very least for the Jurassic. The generation potential for hydrocarbons increases with increasing geothermal gradient. While the actual geothermal gradient and overburden thickness is unknown, measured vitrinite reflectance values constrain the maximum burial temperature (Barker & Pawlewicz 1994), and therefore maximum burial depth for an assumed gradient of 35ºC/km. Changes to this gradient do not result in significant gains in theoretical generation percentages.

A burial profile for the Styx Valley region is shown in Figure 8, profiles for Hunterston-1 and Tunbridge-1 are shown in Reid et al. (2003) and Bacon et al. (2000) respectively. In the Styx Valley region potential source rocks exist in Woody Island Formation siltstone, and in the non-marine Liffey Group. However, in the Styx Valley, available Liffey Group samples are from weathered outcrop and are not suitable for Rock-Eval pyrolysis. The following TTI calculations are based on the Woody Island Formation. As discussed above, Woody Island Formation organic matter is disseminated and gas prone type III kerogen. A single measured vitrinite reflectance value of 1.31% exists for a Woody Island sample; $T_{max}$ values indicate a late oil window maturity. The vitrinite reflectance of 1.31% correlates to a maximum burial temperature of 157ºC (Barker & Pawlewicz 1994), and assuming a minimum geothermal gradient of 35ºC/km, the sample could have been buried to a maximum depth of 4,200 m in the Late Cretaceous (O'Sullivan & Kohn 1997). TTI calculations based on this burial profile, indicate that 96% of the Type III kerogens capacity, and 100% of Type I capacity, could have been converted to oil given this profile, and 20% cracked to gas. Total capacity is that amount considered from SPI calculations and rate of conversion to hydrocarbons. Type III kerogens convert only up to 25.2% of their kerogens to hydrocarbons and Type I up to 58% (Hunt 1995). The Type I *Tasmanites* source is assumed exist in the south, as the *Tasmanites*-linked Lonnavale bitumen seep is within close geographic proximity (see Fig. 1).

# Reservoir rocks

Non-marine sandstones of the Liffey Group are extensive and constitute a potential reservoir, although with variable porosity. Porosity values range up to 27% (Maynard 1996) in outcrop material of coarse sandstone. This same sandstone is not seen in drillhole material for comparison. In the Golden Valley area porosities are up to 18% (Maynard 1996) in drillhole medium to coarse quartzose sandstone beds 3–5m thick, while through much of the central Tasmania Basin area sandstone porosities range from

4.1–14.9%, with an average of 9.6%. Interbedded carbonaceous siltstone beds, or laminations defined by carbonaceous material, have low vertical porosity, and may form local seals. In the Hobart region, an increased ratio of carbonaceous silt reduces the overall porosity and permeability.

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 have been slightly deformed before silica cementation. Authigenic clay cement may develop after silica cementation (Maynard 1996), and subsequent dissolution provides a secondary porosity. Sandstone porosity is highest in the few samples where early-stage clay coatings around quartz grains have prevented silica overgrowth (Maynard 1996).

Calcite cementation in some areas has reduced porosity, as seen in Hunterston-1 (Reid et al. 2003) and Bothwell-1 (Maynard 1996). In Hunterston-1 dolerite intrusion occurs in Cascades Group limestones, that overlie the Liffey Group, and the heating effects appear to be leaching carbonate into pore fluids (Reid et al. 2003). Carbonate-rich fluids have preferentially precipitated calcite cements in porous sandstone and in Hunterston-1 some dissolution of quartz and feldspar grains occurred prior to carbonate cementation. Secondary porosity was developed in these sandstones by dissolution of the carbonate cement (Reid et al. 2003).

As shown in Figure 5 the central Tasmania Basin contains sandstone beds forming an accumulated thickness of up to 25 metres. 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 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.

### Oil Inclusions

Liffey Group sandstone samples from Hunterston-1 contain rare oil inclusions, within both quartz grains and carbonate cement (Cook 2003). Inclusions are also found within microfractures in quartz grains in Liffey Group sandstone from Styx Valley outcrop and Tunbridge-1. Oil inclusions form during crystallisation of diagenetic minerals and brittle deformation and fracturing of detrital and diagenetic grains during burial (George et al. 1996). The inclusions within detrital Liffey Group quartz grains are most commonly found within microfractures, 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% Grains with Oil Inclusions (GOI). Extraction and geochemical analyses to determine oil source are not possible. Less than 5% GOI indicates that migrated hydrocarbons have not previously been trapped (Eadington et al. 1996).

## Seals

Potential seal units occur above the Liffey Group sandstones, as siltstone in the lower part of the Cascades Group and as 1–5cm 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 seals at shallower depths than that otherwise 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 this volume), 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 this volume for further discussion), 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.

## Conclusions

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

Marine organic siltstones and Tasmanite Oil Shale of the Woody Island Formation, and carbonaceous units within the non-marine Liffey Group form potential source rocks. The Tasmanite Oil Shale is potentially a very good source rock, with oil-prone Type I kerogens, but is thin and of limited areal distribution. 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 contains potential sandstone reservoirs. The Woody Island Formation contains gas and oil-prone Type III kerogens, and is widespread across the basin. The Tasmania Basin is within the oil generation window, except in northern and northeastern 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.

Sandstones of the Liffey Group form potential poor to good reservoirs, with some good porosity developed, but generally 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. Some sandstone beds have fair to good porosity combined with fair permeability. Sandstone porosity is typically secondary; primary porosity and permeability have been reduced by lithic compaction, silica and clay cementation, and by late stage calcite cements associated with dolerite intrusion.

Siltstone and mudstone lenses within the Liffey Group form local potential seals, as do siltstone containing volcanic clay horizons in the overlying Cascades Group. The extensive and thick Ferntree Formation forms a potential regional seal in the Tasmania Basin. Contact metamorphism and clay alteration associated with dolerite intrusion in the Jurassic may also form potential localised 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, this volume). The latter may have been detrimental to trap integrity.

The intrusion of extensive dolerite sheets into the Parmeener Supergroup in the mid Jurassic is a significant factor in the understanding and exploration of the Tasmania Basin as a petroleum system (see also Stacey & Berry this volume). Dolerite intrusion is pervasive and occurs at all levels in the stratigraphy of the Parmeener Supergroup. Possible geologic effects include direct heating of source rock, elevation of basin geothermal gradient, diagenetic alteration of reservoir facies, disruption or creation of potential traps and creation of potential seals by clay alteration of contact lithologies.

## Acknowledgements

The authors thank Great South Land Minerals for access to drill core and seismic data. The project is funded by the Strategic Partnerships with Industry - Research and Training Scheme (SPIRT), jointly funded by the Australian Research Council and Great South Land Minerals. Alan Chester, Andrew Stacey and Jubo Liu are thanked for discussions of Tasmanian geology, seismic and structure, and petroleum system modelling. Constructive review was received from Elinor Alexander and Bob Laws.

## References

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, 93.

BANKS, M.R., 1973. General geology. *In:* Banks, M.R. (Ed.), The Lake Country of Tasmania., Royal Society of Tasmania, 25–33.

BANKS, M.R. and CLARKE, M.J., 1987. Changes in the geography of the Tasmania Basin in the Late Paleozoic. *In:* McKenzie, G.D. (Ed), Gondwana Six: Stratigraphy, Sedimentology and Paleontology, Geophysical Monograph 41, 1–14.

BANKS, M.R., 1989. Summary and structural development. *In:* Burrett, C.F. and Martin, E.L. (Eds), Geology and mineral resources of Tasmania, Special Publication 15, Geological Society of Australia, 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:* Mukhopadhyay, P.K. and Dow, W.G. (Eds), Vitrinite reflectance as a maturity parameter. Applications and limitations. ACS Symposium Series 570, American Chemical Society, 216–229.

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

BENDALL, M.R., VOLKMAN, J.K., LEAMAN, D.E. and BURRETT, C.F., 1991. Recent developments in exploration for oil in Tasmania. APEA Journal, v. 31, 74–84.

BENDALL, M.R., BURRETT, C.F. and ASKIN, H.J., 2000. Petroleum systems in Tasmania's frontier onshore basins. APPEA Journal, v. 40, 26–38.

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.

CLARKE, M.J., 1989. Lower Parmeener Supergroup. *In:* Burrett, C.F. and Martin, E.L. (Eds), Geology and mineral resources of Tasmania, Special Publication 15, Geological Society of Australia, 295–309.

COOK, A.C., 2003. Organic petrology of some core samples from the Permian of Tasmania. Unpublished report, Keiraville Konsultants Pty Ltd.

CULL, J.P., and DENHAM, D., 1979. Regional variations in Australian heat flow. BMR Journal of Australian geology and geophysics, v. 4, 1–13.

CULL, J.P., 1991. Geothermal Gradients in Australia. *In:* Drummond, B. (Ed), The Australian lithosphere. Geological Society of Australia Special Publication 17, 147–156.

CURRIE, T.J., ALEXANDER, R. and KAGI, R.I., 1992. Coastal bitumens from Western Australia- long distance transport by ocean currents. Organic Geochemistry, 18, 595–601.

DEMAISON, G. and HUIZINGA, B.J., 1991. Genetic classification of petroleum systems. AAPG Bulletin, v. 75, 1,626–1,643.

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:* Findlay, R.H., Unrug, R., Banks, M.R. and Veevers, J.J. (Eds), Assembly, evolution and dispersal; proceedings of the Gondwana eight symposium, International Gondwana Symposium 8, 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.

EGGERT, J.T., 1983. Petrology, provenance and diagenesis of quartzose and volcanic lithic Triassic fluvial sandstones, Tasmania, Australia. Unpublished M.Sc. Thesis, Ohio State University.

FARMER, N., 1985. Kingborough. Geological Survey explanatory report, Tasmania Department of Mines, Geological Atlas 1:50,000 Series, Sheet 88 (8311N).

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, v. 108, 107–109.

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., 1989a. Upper Parmeener Supergroup. *In:* Burrett, C.F. and Martin, E.L. (Eds), Geology and mineral resources of Tasmania, Special publication 15, Geological Society of Australia, 309–338.

FORSYTH, S.M., 1989b. The Tamar Graben. *In:* Burrett, C.F. and Martin, E.L. (Eds), Geology and mineral resources of Tasmania, Special publication 15, Geological Society of Australia, 358–361.

GEORGE, S.C., LISK, M., EADINGTON, P.J., QUEZADA, R.A., KRIEGER, F.W. and 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.

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:* Findlay, R.H., Unrug, R., Banks, M.R. and Veevers, J.J. (Eds), Assembly, evolution and dispersal; proceedings of the Gondwana eight symposium, International Gondwana Symposium 8, 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.

HUNT, J.M., 1995. Petroleum geochemistry and geology. W.H. Freeman and Company, New York, 743 p.

KOHN, B.P., GLEADOW, A.J.W., BROWN, R.W., GALLAGHER, K., O'SULLIVAN, P.B. and 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.

LEWAN, M.D., 1987. Petrographic study of primary petroleum migration in the Woodford Shale and related rock units. *In:* Doligez, B. (Ed), Migration of hydrocarbons in sedimentary basins. Paris, Editions technip, 113–130.

MARTINI, I.P. and BANKS, M.R., 1989. Sedimentology of the cold-climate, coal-bearing, Lower Permian 'Lower Freshwater Sequence' of Tasmania. Sedimentary Geology, v. 64, 25–41.

MAYNARD, B.R., 1996. Reservoir characterisation of the Liffey/Faulkner Group, Tasmania. Unpublished honours thesis, University of Tasmania.

O'SULLIVAN, P.B. and KOHN, B.P., 1997. Apatite fission track thermochronology of Tasmania. Record Australian Geological Survey Organisation, 1997/35.

REID, C.M., CHESTER, A.D., STACEY, A.R., and BURRETT, C.F., 2003. Stratigraphic results of diamond drilling of the Hunterston Dome, Tasmania: implications for palaeogeography and hydrocarbon potential. Papers & proceedings of the Royal Society of Tasmania, v. 137, 87–94.

REVILL, A.T., 1996. Hydrocarbons isolated from Lanna Vale (Lonnavale) seep. Swab and bitumen samples. Report CSIRO Division of Oceanography, TDR-1.

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.

STACEY, A.R. and BERRY, R.F., this volume. The structural history of Tasmania.

TANNER, D. and BURRETT, C.F., 1997. Annual exploration report. Great South Land Minerals Pty Ltd, unpublished.

VOLKMAN, J.K., O'LEARY, T., SUMMONS, R.E. and BENDALL, M.R., 1992. Biomarker composition of some asphaltic coastal bitumens from Tasmania, Australia. Organic Geochemistry, v. 18, 669–682.

WHYTHE, S. and WATSON, B., 1996. Geochemical evaluation of an oil seep sample from Lonnavale, Tasmania. Unpublished Amdel Limited Petroleum Services Report LQ4496.