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

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Abstract

The glaciomarine Lower Parmeener Supergroup, onshore Tasmania Basin, is currently targeted in hydrocarbon exploration, and contains potential mature source, reservoir and seal rocks. Basal diamictites are overlain by carbonaceous and pyritic 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 freshwater sandstone and carbonaceous siltstone (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. Thick sequences of marginal marine and marine fossiliferous siltstone and sandstone follow, the siltstones forming potential local and regional seal units.

The Lower Parmeener Supergroup has been overlain by thick Triassic sequences, was intruded by thick dolerite sheets in the mid Jurassic, all overlain by a largely unknown thickness of Cretaceous and Tertiary sediments. Vitrinite reflectance analyses indicate maturity across much of the middle and southern Tasmania Basin, in respect to the Woody Island Formation and Liffey Group. Maximum burial over most of the basin is mid Cretaceous. The middle parts of the basin have been within the oil generation window, with entry into the gas window in the southwest. A hydrocarbon seep in the south of the basin has been linked to a *Tasmanites* source.

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 (Forsyth et al. 1974) into the glaciomarine Lower Parmeener, and terrestrial Upper Parmeener, Supergroups. The Parmeener Supergroup (Banks, 1973) was overlain by now largely eroded Jurassic and Cretaceous sediments, and Tertiary sediments, and is now shallowly buried. The thick Cretaceous and Tertiary sequences found in petroleum basins 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) presented the first modern review of the Parmeener Supergroup and other potential Tasmanian systems.

Interest in petroleum within Tasmania began in the late 1800's, with the Tasmanite Oil Shale later unsuccessfully commercially retorted for fuels and fuel products (Bacon et al. 2000). Exploration continued with shallow drilling and investigation of numerous coastal bitumen strandings. These bitumens are sourced from outside the onshore Tasmania Basin (Bacon et al. 2000), and their chemistry shows them to be of a variety of sources, with some also unrelated to oils from the adjacent Bass, Gippsland or Otway basins (Volkman et al. 1992; Currie et al. 1992). A recently discovered bitumen near the wharf on Bruny Island, southern Tasmania, is most likely a spill, by appearance, anecdotal evidence and the chemistry 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). Biomarkers from a bitumen seep in a dolerite quarry at Lonnavale, southern Tasmania, link it to a Tasmania Basin source of 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 1920's when there existed Federal Government incentives for the discovery of Australian reserves of oil and gas. These holes were all less than 360m, and oil or gas was not found. There was renewed activity in Tertiary rocks in the north of the state in the 1960's and 1970's, but drilling frequently intersected basalt and dolerite and was unsuccessful (Bacon et al. 2000). Exploration has been continuing since the 1980's, with exploration 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 deep holes, beyond 1000m, and has had limited gas reports from drilling in the south of the state. Thermogenic gas was reported from Jericho-1, at less than 100units (Tanner & Burrett 1997). In early 2001, 600km of seismic was shot through the middle area of the basin, and is the first such survey specifically run for hydrocarbon exploration. Drilling at Hunterston-1 in 2002, on a shot line of the 2001 survey, proved the presence of a thick dolerite intrusion in the area (Reid et al. 2003), and velocity details of lithologic units that could be applied to seismically acquired data. This paper combines this new data with stratigraphic data gathered by drilling programs run by Mineral Resources Tasmania, and petroleum data presented by Bacon et al. (2000). Bendall et al. (1991) reviewed exploration in the Tasmania Basin, up until that time, and Bendall et al. (2000) presented an overview of petroleum systems present in the Tasmania Basin. Bacon et al (2000) provided a more detailed review of the geology and potential of Ordovicain to Tertiary petroleum systems within the Tasmania Basin.

This paper presents the stratigraphy, and source 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) glaciomarine and terrestrial rocks of Late Carboniferous to Late Triassic age, unconformably overly Palaeozoic carbonates, siliciclastics and volcanics, and Precambrian dolomites. The topographic relief of the unconformity surface is in the order of 1000m, 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 central high through the centre of the basin (Reid et al. 2003). Thick diamictites, glacial outwash conglomerates and sandstones, and local mudstones and rhythmites (Clarke 1989; Hand 1993) were deposited as the Wynyard and Truro Formation. Total Organic Carbon (TOC) is low through these diamictites, usually less than 0.4% TOC (Domack et al. 1993).

The diamictites give way rapidly to marine pebbly siltstone and mudstone, the Woody Island Formation (Fig. 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 20-30m above the base of the unit algal tests are abundant, or accumulated to form the Tasmanite Oil Shale, which has TOC up to 63%. The oil shale is known in the northwest (Wynyard area) to the east (Bicheno-10), and in the central basin (Ross-2), with dispersed *Tasmanites* elsewhere. In the central Tasmania Basin (Reid et al. 2003), conglomerates and conglomeratic siltstone and sandstone exist in place of true Woody Island mudstone facies, and the Tasmanite Oil

Shale, or dispersed *Tasmanites* are absent. Topographic highs in the north and northwest also show conglomerates onlapping basement at this time. The oil shale does not occur everywhere, but its currently known distribution is in northern and nearshore localities. Banks & Clarke (1987) noted its distribution may be controlled by proximity to shorelines. Domack et al. (1993) suggested seasonal melting of sea ice creating a stable sea surface and allowing a photic zone for increased productivity within a stratigraphically restricted zone. This model seems the most likely, but so far the occurrence of tasmanite is not fully understood, and therefore predictions of its occurrence in the subsurface cannot be made.

The siltstone of the Woody Island Formation is up to 250m thick, has fewer *Tasmanites* cysts and TOC is usually less than 2%. Distribution of the Tasmanite Oil Shale and source facies of the Woody Island Formation are shown in Fig 3.

Marine conditions continued 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/Golden Valley Group) is a marginal marine, often organic siltstone. In the Western Tiers region quiet water organic siltstone (Macrae Formation) 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 freshwater sandstones and carbonaceous siltstones (Liffey Group). South of Hobart marine conditions persisted. Prominent coal beds were developed in northern parts of the basin, with sandier coastal deposits in central and southern areas. 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%. Distribution of Liffey Group, and sandstone component thickness are shown in Fig. 4.

A marine transgression saw deposition of marginal marine then shallow shelf marine fossiliferous siltstone, limestone and minor sandstone (Clarke 1989). The development of these fossiliferous beds (Cascades Group) was diachronous across the Tasmania Basin, with an apparent depositional hiatus before gradually younger and reduced carbonate deposition north and northeastward. Thick limestone was developed in the Hobart region. Volcanic ash horizons occur within this fossiliferous sequence and are recognised as thin clay layers that may or may not be bioturbated. The clay horizons and marginal marine siltstones of the Cascades Group may act as seal facies above the freshwater Liffey Group. The calcareous units were overstepped from the south by fossiliferous siltstone and sandstone (Farmer 1985) (Deep Bay Formation, Malbina Formation). 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 (Ferntree Formation) with minor sand and conglomerate horizons. These mudstones are thick and well developed and form the most obvious 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 carbonaceous sandstone and lutite of the basal Upper Parmeener Supergroup. The beds are carbonaceous with inter-bedded well sorted cross-bedded or ripple laminated sandstone and lutite, with a Permian flora. 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, 200-300 m thick (Forsyth 1989a). 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. Following quartz sandstone and lutite 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 lutite, with coal seams of economic grade, and rare tuff and conglomerate beds. The sequence is about 270m thick in the Midlands (Forsyth, 1984), and up to 350m 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 making them an obvious hydrocarbon source. However burial depths may be insufficient for source maturity. Repeated sandstones within the sequence may be suitable as reservoir rocks (Bedi 2003), with lutites forming seals, but burial depths are unlikely to be provide sufficient confining pressures.

Extensive sheets of tholeiitic dolerite were intruded into the Parmeener sequence during the mid Jurassic. There were several pulses of intrusion over a period of probably less than 20my, with a mean K-Ar age of 174 Ma (Schmidt & McDougall 1977). The dolerite preferentially intruded the then less than 130 my old Parmeener Supergroup, over older and harder basement rocks (Hergt et al. 1989). Dolerite occurs throughout the Tasmania Basin and at many levels, within the Parmeener Supergroup, and few regions are totally unaffected by dolerite intrusion. However the stratigraphic level at which the intrusions occur is important in understanding the Gondwana Petroleum System, and its effects on potential source, reservoir and seal rocks. The nature and quantity of Jurassic extrusive igneous ricks and any sedimentary succession 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 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. However the uplifted area of the Tasmania Basin, now eroded back to Jurassic dolerite and Parmeener Supergroup levels was buried by an unknown amount of Cretaceous and Tertiary sediment.

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.

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 to 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. 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 Fig. 3.

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, of hydrocarbons per square metre of oil shale. High HI and low Oxygen Index (OI) values indicate Type I kerogens in the oil shale, and low S1 and Tmax indicate 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 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.

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% (Figure 5). In addition HI values are low, indicating a Type III, gas and oil prone source, rather than the rich oil prone Type I source of the oil shale (Fig. 6). *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 on immature Woody Island Formation Siltstone indicate an average potential generation of 0.42 metric tons (~ 2.65 barrels/~ 538m^3 gas), of hydrocarbons per square metre.

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 because of the low hydrogen content generate 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. X). 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 to the elements 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.

Liffey Group

The freshwater Liffey Group contains carbonaceous siltstones and sandstones, 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. 5). 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. 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. Pelionite SPI calculations indicate 0.33 metric tons (2.1 barrels/422m^3 gas) per square metre, however exposures of this horizon are poor, and the region has not yet been drilled, so the distribution of this rich horizon is unknown.

Liffey Group source rocks display a range of kerogens types (Fig. 6). 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 Fig. 7, with maturity increasing in a southwesterly direction. Equivalent vitrinite reflectance is inferred from T_{max} and Hydrogen Index (HI) plots, (Fig. 6), Production Index (PI) and inferred (Bacon et al. 2000) and measured vitrinite reflectance (Fig. 7). The most reliable maturity data is from measured vitrinite reflectance, 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, 1995). In Fig. 7 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 Fig. 7, 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 inertinite 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). Data given in Fig. 7 are those not influenced by contact metamorphism, or an estimated pre-Tertiary basalt reflectance value.

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, a sheet of dolerite, up to 650m thick, and consisting of multiple intrusions, 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.

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 3km (Banks 1989b). O'Sullivan & Kohn (1997) assumed a geothermal gradient of 20-30^{o}C/km, however this seems low, given the current geothermal gradient in Tasmania of approximately 30-35^{o}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 had an effect on 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 to 70^{o}C/km, to their present day gradients of 30-40^{o}C/km (Duddy 1997). This implies that the geothermal gradient within Tasmania, before the late Cretaceous cooling, should also have been high.

Burial profiles

Bacon et al. (2000) and Reid et al. (2003) use a geothermal gradient of 35^{o}C/km, to determine theoretical hydrocarbon generation from burial profiles for Permian sediments. While it was shown hydrocarbons could have been generated in Tunbridge-1 and Hunterston-1 using this gradient, it is likely a conservative estimate, at the very least for Jurassic time. The generation potential for hydrocarbons will increase with increasing geothermal gradient. However, as the maximum burial temperature is constrained by known vitrinite reflectance values, gains in theoretical generation percentages are slight.

A burial profile for the Styx Valley region is shown in Fig. 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 freshwater Liffey Group. However in the Styx Valley, unweathered Liffey Group samples are not available 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 are complimentary to a late oil window maturity. A vitrinite reflectance of 1.31% correlates to a maximum burial temperature of 157^{o} (Barker and Pawlewicz 1994), and assuming a minimum geothermal gradient of 35^{o}km could have been buried to maximum depth of 4200m. Maximum burial is 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 28% of their kerogens to hydrocarbons, Type I up to 58% (Hunt, 1995). The Type I *Tasmanites* source is assumed exist in this southern region, as the *Tasmanites* linked Lonnavale bitumen seep is within close geographic proximity (see Fig. 1).

Reservoir rocks

As a potential reservoir, the freshwater sandstones of the Liffey Group and correlates are extensive, although with variable porosity. Through much of the central Tasmania Basin area sandstone porosities range from 4.1 to 14.9%, with an average of 9.6%. In the Golden Valley area porosities are up to 27% (Maynard, 1996), in medium to coarse quartzose sandstone. Sandstone beds within the Liffey Group occur as laminated well-sorted fine and medium sands, with rare coarse sand, and are generally 3 to 5m thick. The beds reflect an alluvial plane environment and sandstone beds are repeated and interbedded with carbonaceous siltstones. The carbonaceous siltstones have low porosity, as pore 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, an increased ratio of carbonaceous silt reduces the overall porosity and permeability.

Well-sorted quartzose sandstones show early stage silica cementation, clasts boundaries are indistinct as clay coatings have not been able to develop, and cementation may completely occlude porosity. Grain compaction is generally low, however where lithic clasts are common and soft they have been slightly distorted before silica cementation. Authigenic clay cement may be developed after silica cementation (Maynard 1996), and subsequent dissolution provides a secondary porosity. Where early stage clay coatings around quartz grains have prevented silica overgrowth, sandstone porosity is highest (Maynard 1996).

Carbonate cementation in some areas has reduced porosity, as seen in Hunterston-1 (Reid et al. 2003) and Bothwell-1 (Maynard 1996). Carbonate rich fluids have preferentially precipitated cements in sandstones previously exhibiting primary porosity. In Hunterston-1 there has been some dissolution of quartz and feldspar grains prior to carbonate cementation, and the low porosity and permeability these sandstones has been produced by further dissolution of the carbonate (Reid et al. 2003). Above the Liffey Group of Hunterston-1 there is a thick multiple dolerite intrusion into Cascades Group limestones, and the heating affects appear to be leaching carbonate into pore fluids (Reid et al. 2003).

As shown in Fig. 4 in the central area of the Tasmania Basin, individual sandstone beds or cycles form an accumulated thickness of up to 25m. Average porosities in localities vary from 6.1 in Hunterston-1 to 11% at Ross-1. In the Hobart region siltstone dominates over sandstone, that tends to be micaceous, and porosity is less than 5%. Porosity measurements in the Styx Valley region are absent, as here 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, varying from 0.03 to 8.8 mD. Only in Ross-1 and 2, and one Tunbridge-1 sample have permeabilities been recorded over 0.1mD, however at all other localities, permeabilities are mostly over 0.01mD. The reservoir unit at Hunterston has been affected by late diagenesis associated with intrusion of dolerite.

Oil Inclusions

Samples of Liffey Group sandstones from the Hunterston DDH contain rare oil inclusions, within both quartz 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)

Dolerite

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, creation of potential seals by clay alteration of contact lithologies.

As discussed above the direct heating halo associated with the dolerite may be limited to a narrow zone (Reid et al 2003), even where associated with thick multiple intrusions. But while effects of heating to maturation of source rock facies will likely be limited in extent, the intrusion of such a volume of igneous material into a sedimentary basin is significant

(Leaman 2003), and is likely to have contributed to higher heat flow within the Tasmania Basin.

As seen in Hunterston-1 intrusion of dolerite into carbonate facies overlying the potential reservoir sandstone of the Liffey Group has negative effects (Reid et al 2003), by mobilising carbonate and precipitation with porous sands. However, all rocks in contact with dolerite, and particularly the upper marine siltstones show clay alteration. 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.

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 is a very good source rock, of 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 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. 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 (fig 7). Maximum burial and maximum 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 permeability and porosity have been reduced by lithic compaction of less quartzose sand, silica and clay cementation, and by late stage carbonate cements associated with dolerite intrusion.

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 200m 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. Trap formation is associated with mid Jurassic dolerite intrusion and associated faulting, and Cretaceous extension. The later may 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.

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Figure captions

Fig 1 – Geology of the Tasmania Basin showing Parmeener Supergroup and Jurassic dolerite outcrop. Locations of diamond drill hole and outcrop sites discussed in the text are shown.

Fig 2 – 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.

Fig 3 – Thickness and distribution of Woody Island Formation source facies, and distribution of Tasmanite Oil Shale. Woody Island conglomeratic facies in the central Taasmania Basin is also shown. (After Reid et al 2003, Bacon et al 2000).

Fig 4 – Thickness and distribution of Liffey Group. Also shown are total thickness of sandstone beds and cycles, and the upper porosity value for some localities.

Fig 5 – 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).

Fig 6 – 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.

Fig 7 – 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).

Fig 8 – 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.

Fig 9 – 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.