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Great South Land
Minerals Limited

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Estimating the Undiscovered Petroleum Resources of The Tasmania Basin

By Tony Collings: Geologist, Great South Land Minerals Ltd.
June, 2008.

Summary:

Past estimates of the undiscovered prospective petroleum resources onshore Tasmania have indicated that up to 2.6 MMM bbl's could have been generated, with estimates based on the generative potential of source rocks (SPI method) (see table 1). Monte Carlo simulations of reservoir volumes within leads and plays are widely used in the hydrocarbon exploration industry. In this report we have used Monte Carlo simulations to generate cumulative frequency plots and to estimate the undiscovered resource potential of the basin.

Introduction:

The **undiscovered, estimated prospective** oil resource potential of the Tasmania Basin will be calculated using standard oil industry quantitative methods (adapted from: Morton, 1996b). The Tasmania Basin is a potential on-shore oil and gas producing province located in the south-eastern corner of the Australian continent. The Tasmania Basin covers an area in excess of 30,000 km^2 and is clearly oil prone due to the presence of independently verified seeps. The Tasmania Basin and specifically Great South Land's oil exploration tenement SEL 13/1998, has had over 1300 line kilometres of 2D seismic shot and processed with detailed interpretations completed. In addition to the seismic acquisition program: regional/local magnetic and gravity surveys have been performed.

Many recent studies have estimated the in-situ, recoverable oil potential of the Tasmania Basin based on the generative potential of source rocks (table1). Burrett (2004) used the Source Potential Index method (or Cumulative Hydrocarbon Potential) based on rock-eval and thickness data (Hunt, 1996), SPI= thickness (S1 & S2) x density divided by 1000. SPI calculations for the Early Permian Tasmanite Oil Shale and *Tasmanites*- rich horizons have been estimated as 2.5 bbl's m^2 (Bacon et al 2000, p. 48), and 3.78 bbl's m^2 (Reid 2003). The remainder of the Early Permian Woody Island - Quamby Formation (excluding the Tasmanite) has an SPI of 7 bbl's m^2 (Bacon et al. 2000. p48) and 6 bbl's m^2 (Reid, 2003). The Liffey Group has a calculated SPI of 1.1366 bbl's m^2 (Reid, 2003).

Author	Method	Petroleum System	Estimated Recoverable
Bacon, 2000. p48.	SPI	Gondwanan (including tasmanite)	9.5 bbl/m^2 or (2.97 MMM bbl's)
Burrett, 2004.	SPI	Gondwanan	2.6 MMM bbl's
Collings, 2008 [1].	ZETAWARE	Gondwanan & Larapintine	346.4 MM bbl's (oil) or 6 T scf (gas)
Collings, 2008 [2].	Monte Carlo	Gondwanan & Larapintine	594 MM bbl's (P90) (total of 17 drill-sites)
Guise, 2007.	Monte Carlo	Larapintine (Bellevue #1 site only)	118.5 MM bbl's or 219 MMM cf (gas)
Reid, 2003.	SPI	Gondwanan (including tasmanite)	9.78 bbl/m^2 or (3.01 MMM bbl's)

Table 1. Petroleum Estimates, Summary Table.

Method

Taking the variables such as source type, maturity, trap geometry, seal and reservoir characteristics into consideration, we have based our resource estimates on extensive geological data and a statistical technique based on the oil industry preferred Monte Carlo method. Guise (2007) used a similar version of the Monte Carlo statistical technique to calculate the petroleum potential of two structures in the Tasmania Basin.

The two petroleum systems present onshore Tasmania are: The Permian-Triassic, Gondwanan system (the Tasmania Basin) (figures 1 and 2), and the Ordovician-Devonian, Larapintine 2 petroleum system (figure 3). Each system is potentially prospective for oil and gas and has similar features and age respectively to the producing Cooper Basin in South Australia, and the Tarim Basin in China. In contrast; The Tasmania Basin Gondwanan source rock is much more prospective for oil, as it contains bands of type 1 kerogen containing the alga *Tasmanites* oil shale, which is commonly up to a metre thick. 1,127,948 litres of oil were produced by distillation of the oil shale between 1910 and 1932 (James, 1950. p21). The Larapintine 2 system also has a marine algal source and fresh samples in outcrop have a strong petroliferous odour (Chester, 2006). When age and maturity factors are considered, the Larapintine source rocks are interpreted to have the potential for generating wet and dry gas. See **tables 2-5** for source rock and reservoir statistics used in calculations.

If commercial quantities of oil and gas were to be discovered in The Tasmania Basin, four essential components must be present in the geology:

- Mature source rocks containing sufficient organic matter, which has been subjected to sufficient heat, time and pressure to generate large quantities of oil or gas. In order to preserve the resource, the original source must not be destroyed by either over-temperature or over-pressure conditions.
- A reservoir horizon or rock unit that has the potential to store the migrated hydrocarbons. The reservoir rock must have sufficient porosity and permeability to allow the storage of fluids, and then allow the economic removal and flow of fluids to the surface once discovered.
- An effective/impermeable sealing horizon that traps the hydrocarbons within the reservoir, preventing further migration out of the reservoir or loss to the surface (seep).
- A suitable structure over the reservoir and seal that concentrates the hydrocarbons in economic quantities. There are many types of stratigraphic traps described in oil producing provinces, and structures can take the form of an anticline, dome, or well-sealed fault blocks.
- The trap should be present before migration to prevent hydrocarbons seeping to the surface.

The method for estimating undiscovered resources from individual variables within the basin 'plays', is calculated by analysing the existing/available data. Once this information is calculated, the result is then multiplied by the other variables, leading to the calculation of the Total Potential Recoverable amount (P_t).

Using this method as a guide, the oil potential of The Tasmania Basin has been calculated using the following Monte Carlo formula parameters:

Where:
P_t is the Undiscovered Prospective Resource Estimate.
A_p is the Prospective Area of the basin.
G is the geometry correction.
h is the Gross reservoir thickness.
ff is the Trap fill factor, or Nett/Gross.
Por is the Porosity (fraction, expressed as percentage).
S_h is the Hydrocarbon saturation (water saturation %).
FVF is the Formation Volume Factor.
RF is the Recovery Factor.

Note: None of the above parameters are certainties, but can be estimated from easily available data within broad limits (see Morton, 1996b).

The Monte Carlo simulation is the most commonly used method for combining and expressing the uncertainties of the individual plays. By generating a frequency distribution curve for each parameter, then converting the result to a probability distribution, a random number between 0 and 1 is generated (0-100% probability). Combining the results of the probability distribution for each play into the formula gives an estimate of the petroleum potential of a specific site, or for the whole basin (see XCEL generated attachments). As each equation is computationally intensive; each play within the Tasmania Basin will be discussed individually and then combined to give a total oil potential (P_t).

Discussion of Plays:

The Tasmania Basin has many sites which contain all four of the essential components necessary for the accumulation of economic quantities of oil. So far, over 20 leads and prospects (well locations) have been identified onshore Tasmania

Prospective Area (A_p).
This is the area of the basin which is believed to contain all of the essential elements of a hydrocarbon play (and is also economically drillable). Seismic interpretation has been combined with local/regional mapping of the geology to high accuracy, including play and site specific thickness and lithology interpretation down to basement level. Using these constraints as a guide, a conservative 10% of basin area has been used for this calculation (see figures 1-3).

Geometry Correction (G).
This is the shape correction used for the potential reservoir, expressed as a percentage. For example: a triangular distribution (1/2 base x height = 50%), or 40/60/80% for other shapes which are used to calculate the reservoir geometry.

Gross Reservoir Thickness (h).
This measurement is the maximum vertical closure of the reservoir measured in metres (m). The thickness has been calculated from either measured (known outcrop thickness), or by calculating the two-way seismic profile at specific sites.

Trap Fill Factor (ff), or **Nett/Gross**.
As reservoirs in commercial basins can range in fill from 0% (dry well), to full at 100%. It is assumed that rich source rocks will lead to 100% fill.

Porosity (Por).
Average porosity for each reservoir is based on the available, independently verified studies of the measured in-situ reservoir rock characteristics of Tasmania.

Hydrocarbon Saturation (water content) (S_h).
The amount of oil within a reservoir depends on the porosity, but often not all of the reservoir contains oil and can contain large amounts of water. The Australian oil industry range of 30-70% water saturation is assumed for this calculation.

Formation Volume Factor (FVF)
As oil is brought to the surface, the drop in pressure changes the volume and causes the loss of volatiles (lighter fractions). For this calculation, an oil industry typical calculation of 76.9-90.9% has been used to compensate for the volume loss.

Recovery Factor (RF)
This factor converts petroleum in-place estimates to recoverable oil, and is mostly dependant on the mobility of the underlying aquifer and height of the oil column. Recovery Factor is based on production averages in the Cooper Basin (SA). Up to 75% of resource is assumed to be unrecoverable, unless expensive/complex recovery methods are employed (10-40% used).

Potential Plays: 1. Permian-Triassic (Gondwanan Petroleum System).

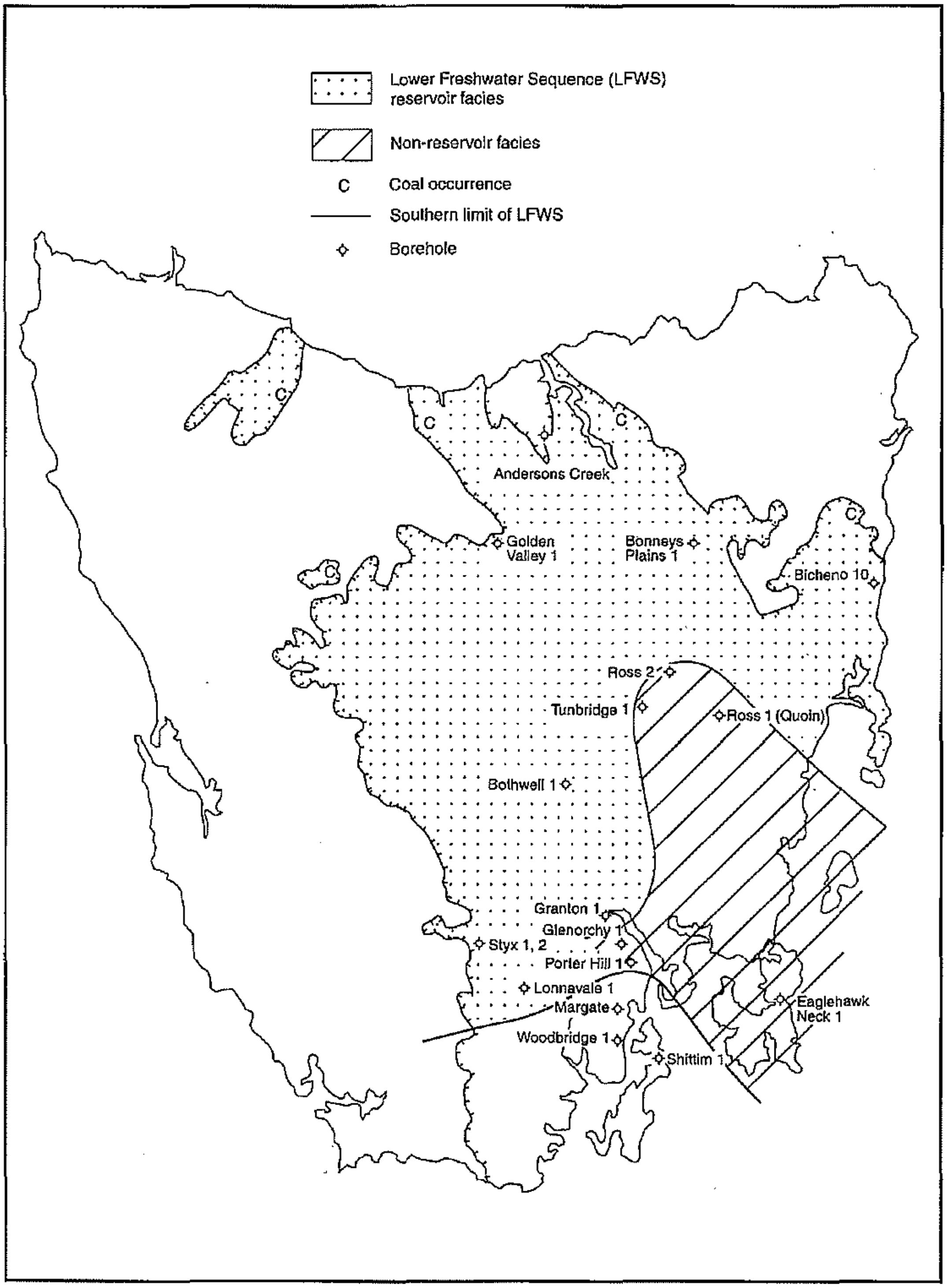

Figure1. Mapped extent of Permian, Lower Freshwater Sequence.
Coverage Area ~ 30,000km^2.
(Source: Bacon, 2000. p35).

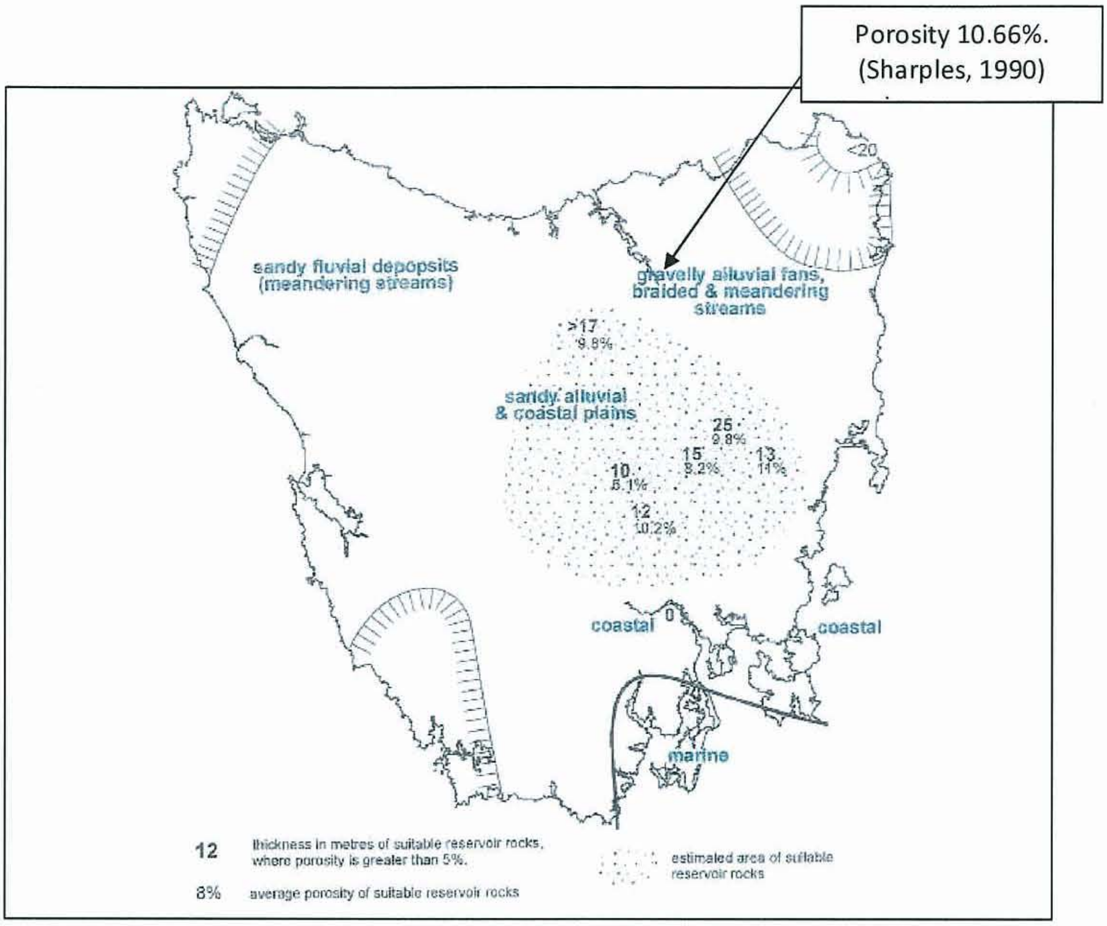

Figure 2. Mid-Permian freshwater sandstone reservoir area/thickness distribution (Liffey Group).
(source: Reid, 2003. p44).

2. Ordovician-Devonian (Larapintine 2 Petroleum System).

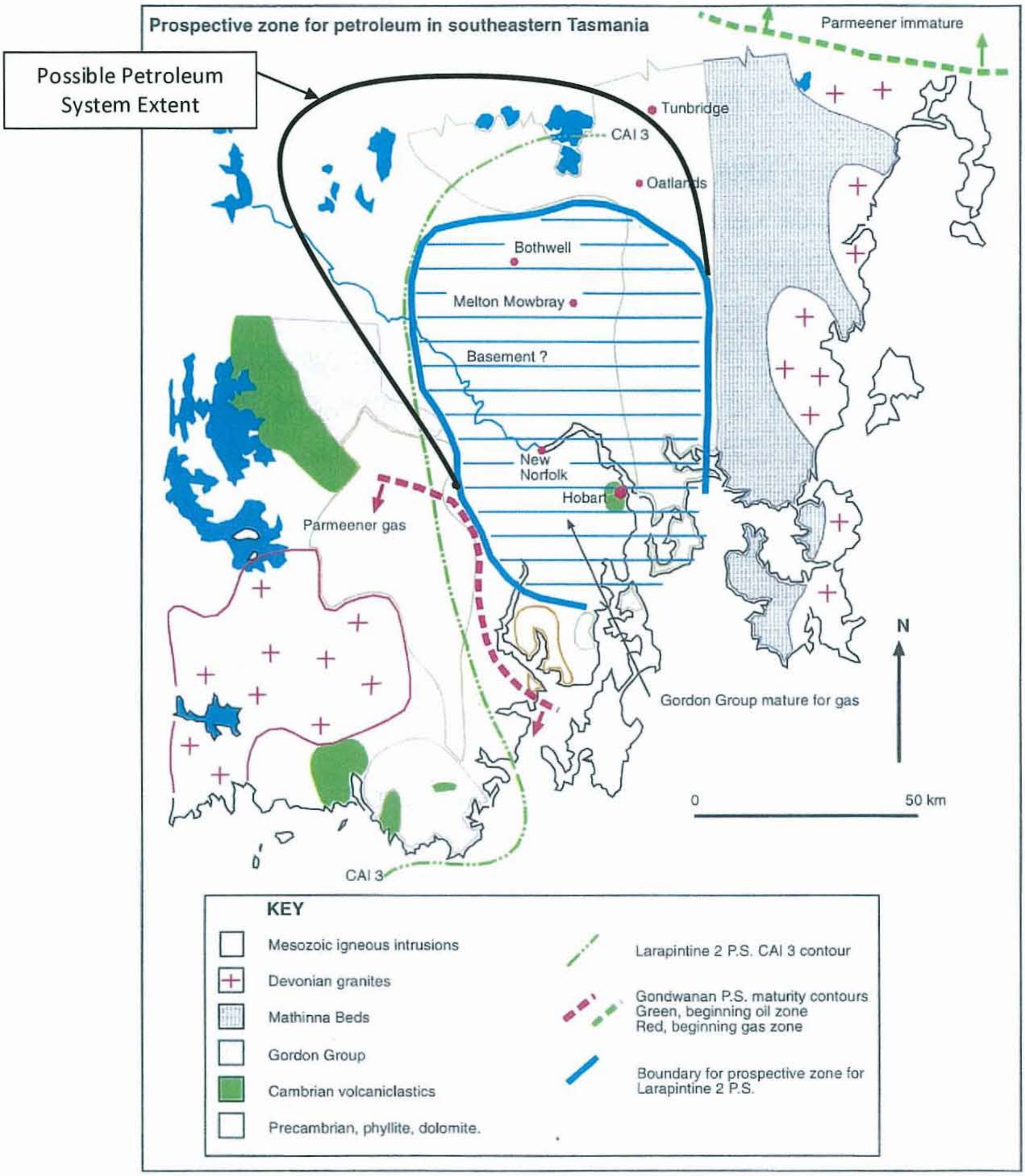

Figure 3. Most likely basin area, for Larapintine 2 Petroleum System.
Coverage Area ~ 11,500km^2.
(source: Chester, 2006. p136).

Gondwanan Petroleum System

Table 2. Mid-Permian - Mersey/Liffey/Faulkner Group.

Reservoir: Terrestrial sandstone (see Figure 1and 2). **Seal:** Mudstone and dolerite. **Source:** Either: Tasmanite oil shale, Woody Island Fm, Macrae Mudstone, Liffey Group (coal/torbanite). Or: singularly or a combination of these.

Summary of Monte Carlo parameters used.

Variable	Minimum	Likely	Maximum
Prospective Area of Basin #	1,000 km^2	1,500 km^2	2,500 km^2
Geometry Correction	0.4	0.6	0.8
Average Reservoir Thickness *	6m	25m	50m
Trap Fill Factor (Nett/Gross)	1%	50%	100%
Reservoir Porosity *	4.1%	9.6%	27%
Hydrocarbon Saturation (water)	30%	50%	70%
Formation Volume Factor	76.9%	83.3%	90.9%
Recovery Factor	10%	25%	40%

Source: #Reid, 2003. *Maynard, 1996.

Table3. Triassic - Sandstone (primarily unit 2).

Reservoir: Terrestrial sandstone. **Seal:** Mudstone and dolerite.
Source: Either: Tasmanite oil shale, Woody Island Fm, Macrae Mudstone, Liffey Group (coal/torbanite) or Upper Permian carbonaceous shales and Cygnet Coal Measures (unit 1). Or: singularly or a combination of these.

Summary of Monte Carlo parameters.

Variable	Minimum	Likely	Maximum
Prospective Area of Basin #	1,000 km^2	1,500 km^2	2,500 km^2
Geometry Correction	0.4	0.6	0.8
Average Reservoir Thickness #	10m	50m	120m
Trap Fill Factor (Nett/Gross)	1%	50%	100%
Reservoir Porosity *	5%	10%	20%
Hydrocarbon Saturation (water)	30%	50%	70%
Formation Volume Factor	76.9%	83.3%	90.9%
Recovery Factor	5%	10%	20%

Source: #Reid, 2003. *Bedi, 2003 and Sharples, 1990.

Larapintine 2 Petroleum System

Table 4. Silurian-Devonian - High Porosity Estimate.

Reservoir: Limestone (possible paleokarst), sandstone (see Figure 2). **Seal:** Mudstone/siltstone. **Source:** Upper Limestone Member of the Benjamin Limestone (marine carbonates) ^.

Summary of Monte Carlo parameters.

Variable	Minimum	Likely	Maximum
Prospective Area of Basin #	250 km^2	558 km^2	1,150 km^2
Geometry Correction	0.4	0.6	0.8
Average Reservoir Thickness *	50m	100m	200m
Trap Fill Factor (Nett/Gross)	1%	50%	100%
Reservoir Porosity *^	1%	5%	12%
Hydrocarbon Saturation (water)	30%	50%	70%
Formation Volume Factor	76.9%	83.3%	90.9%
Recovery Factor	10%	25%	40%

Source: #Burrett, 1996. *Maynard, 1996. ^Chester, 2006.

Table 5. Silurian-Devonian - Low Porosity Estimate.

Reservoir: Limestone (possible paleokarst), sandstone (see Figure 2). **Seal:** Mudstone/siltstone. **Source:** Upper Limestone Member of the Benjamin Limestone (marine carbonates) ^.

Summary of Monte Carlo parameters.

Variable	Minimum	Likely	Maximum
Prospective Area of Basin #	250 km^2	558 km^2	1,150 km^2
Geometry Correction	0.4	0.6	0.8
Average Reservoir Thickness *	50m	100m	200m
Trap Fill Factor (Nett/Gross)	1%	50%	100%
Reservoir Porosity *^	1%	3%	5%
Hydrocarbon Saturation (water)	30%	50%	70%
Formation Volume Factor	76.9%	83.3%	90.9%
Recovery Factor	10%	25%	40%

Source: #Burrett, 1996. *Maynard, 1996. ^Chester, 2006.

Discussion of Results

By applying the statistical Monte Carlo method to the measured variables associated with the Tasmania Basin, a range of possible petroleum generation scenarios were found. When all of the measured variables (such as basin area, porosity, trap fill factor ect) were taken into consideration for the modelling parameters: it became apparent that although the reservoir rocks have the necessary storage qualities, it could only be assumed that a small area of the basin would have the necessary trap and sealing structures to contain any generated hydrocarbons. For example: if we choose the total basin area without adjusting for structures, then a high probability for possible petroleum generation (P90) was found to be in the order of 8.1 MMM bbl's, which is 2 to 3 times greater than any amount calculated in previous studies and therefore this figure would be considered unlikely (see table 1).

A more realistic method for modelling the Tasmania Basin was therefore chosen, which assumed that only discrete locations in the basin, or approximately 10% of the available reservoirs would be capable of having the structure qualities to trap hydrocarbons. By choosing a conservative figure of 10% of the total reservoir area, the results obtained were not only found to be similar to previous study estimates, but also generated a more realistic P90 value of 786 MM bbl's (see attached Monte Carlo tables).

Conclusion of Play Analysis

This report has used the quantitative Monte Carlo method as the industry accepted tool for assessing the undiscovered petroleum potential of the Tasmania Basin (Morton, 1996b). The adapted Monte Carlo method has highlighted the undiscovered potential of the Tasmania Basin, where a conservative estimate (P90 low/conservative) indicates the prospective resource (P_t) could be 786 MM bbl's (or BOE) (Gondwanan+Larapintine 2). The attached XCEL table/graph of each play shows the calculations in detail, and provides a graphical representation of how the prospective resource estimate figures were attained.

While the estimates obtained are encouraging, the oil and gas potential of The Tasmania Basin highlighted in this report will require further geological investigation. Also note that all Potential (undiscovered) resource estimates should not be compared to traditional Proved, Probable and Possible reserves of known discoveries. With this in mind; the undiscovered estimates have been calculated to provide a quantitative indication or estimate of the basin potential, and therefore the basin will still require significant and continued exploration to establish the existence of commercial quantities of oil or gas.

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Table 1. Initial 15 Candidate Sites - Resource Estimates

Candidate Site Name		System (Age)	Estimated Target Surface Area (km^2)	Reservoir Estimated Net Pay Thickness (m)	Reservoir Estimated Volume (m^3) (80% geometry correction)	Reservoir Average Porosity (%) (see table below)	Reservoir Volume as US Barrels (bbl)	Reservoir Volume: Minus water/gas Saturation (bbl)	Possible Potential Recoverable Estimate (75% lost) (bbl)
Bellevue #1	BV #1	L + G	90 (6 X 15)	361*	25,992,000	10	1,634,846,895	1,164,828,413	291,207,103
Thunderbolt #1	TB #1	L + G	35 (10 X 3.5)	350*	9,800,000	10	616,401,184	439,185,844	109,796,461
Interlaken #1	IL #1	G (P)	28 (7 X 4)	100	2,240,000	15	211,337,549	150,578,004	37,644,501
Bracknell #1	BN #1	G (Tr-P)	20 (8 X 2.5)	100	1,600,000	12.5	125,796,160	89,629,764	22,407,441
Butlers Rise #1	BR #1	G (P)	24 (6 X 4)	100	1,920,000	15	181,146,470	129,066,860	32,266,715
Stockwell #1	SW #1	G (Tr-P)	16 (4x4)	100	1,280,000	12.5	100,636,928	71,703,811	17,925,953
Cressy #1	CR #1	G (Tr-P)	9 (3 X 3)	80	576,000	12.5	45,286,618	32,266,715	8,066,679
Hunterston #2	HS #1	G (P)	20 (8x2.5)	100	1,600,000	15	150,955,392	107,555,717	26,888,929
Bellevue #2	BV #2	L + G	90 (6 X 15)	361*	25,992,000	10	1,634,846,895	1,164,828,413	291,207,103
Hummocky #2	HH #1	G (Tr-P)	9 (3 X 3)	80	576,000	12.5	45,286,618	32,266,715	8,066,679
Scotts #1	ST #1	G (P)	28 (7x4)	100	2,240,000	15	211,337,549	150,578,004	37,644,501
Cressy #2	CR #2	G (Tr-P)	20 (8x2.5)	100	1,600,000	12.5	125,796,160	89,629,764	22,407,441
Lonnavale #2	LV #2	G (P)	28 (7x4)	100	2,240,000	15	211,337,549	150,578,004	37,644,501
Macquarie #1	MR #1	G (Tr-P)	20 (8x2.5)	100	1,600,000	12.5	125,796,160	89,629,764	22,407,441
Quamby #1	QY #1	G (P)	9 (3 X 3)	80	576,000	15	54,343,941	38,720,058	9,680,015
						Totals	**4,147,247,803**	**2,954,914,060**	**738,728,515**

G = Gondwanan - Permo-Triassic Petroleum System.

L = Larapintine - Ordovician - Silurian Petroleum System.

Water Saturation: 25%

***Based on Seismic 'Bright Spots'**

Gas Saturation: 5%

Note: calculation assumes API of 20 (therefore the metric 6.289808 conversion factor is used)

Ranking (Risk)	Average Porosity Calculation Used				
Age	Tertiary	Triassic	Permian	Paleokarst	Ordovician
High	20%	20%	27%	3%	12%
Best	10%	10%	15%	2%	8%
Low	5%	5%	2%	1%	3%

June 2008 (prepared by Tony Collings)

Table 2. Risk Analysis_ 8 Initial Candidate Well

Candidate Name	Abbreviated Name	Petroleum System	Risk Factors						Success Ratio (%)	Depth (m)	Time (days)	Start Day	Finish Day
			Source	Maturity Migration	Reservoir	Seal	Trap	Timing					
Rig Mobilisation												60	531
Bracknell #1	BN #1	G	9	8	9	8	9	8	85	1450	45	171	216
Butlers Rise #1	BR #1	G	9	8	8	8	8	7	80	1050	40	226	271
Bellevue #1	BV #1	L	7	8	6	7	9	6	72	3500	70	286	356
Thunderbolt #1	TB #1	L	7	9	7	7	8	4	70	3250	60	371	431
Interlaken #1	IL #1	G	7	7	7	7	7	7	70	1000	30	446	476
Cressy #1	CR #1	G	8	7	8	7	7	2	65	1500	45	61	106
Hummocky Hills #1	HH #1	G	8	7	8	8	8	2	68	1500	45	116	161
Quamby #1	QB #1	G	7	7	6	7	7	8	70	1000	30	491	531
									TD=	14250			

G = Gondwanan - Permo-Triassic Petroleum System.

L = Larapintine - Ordovician - Silurian Petroleum System.

Source -Larapintine PS, Ordovician - Silurian carbonates and shales; Gondwanan PS, Early Permian shales and oil shales (including tasmanite), mid-late Permian coals and shales.

Maturity/Migration - Larapintine PS, dry-wet gas window in central Tasmania, overmature in north and west; Gondwanan PS, immature for oil in northern Tasmania, mature in central and south.

Reservoir - Larapintine PS, paleokarst with primary and secondary porosity in carbonates (basin margin reefs); Gondwanan PS, Permian and Triassic sandstones, fractured and weathered dolerite beneath Tertiary sediments.

Seal - Larapintine PS, Early Devonian shales; Gondwanan PS, Permian shales and Jurassic dolerite.

Trap - Larapintine PS, Ordovician - Devonian folding and faulting; Gondwanan PS, Jurassic and Tertiary faults and anticlines.

Timing - Larapintine PS, oil/gas generation from Devonian - Cretaceous; Gondwanan PS, oil/gas generation from Cretaceous to Tertiary.

Time - From spud date to TD, including well testing.

Estimated Cost - Based on complete turnkey approach, with remote site risk (approx US $1000/1m drilled).

Table 3. Calculated Generative Potential and Resource Estimates: Larapintine and Gondwanan Petroleum Systems

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
Formation	TOC	H Index	Kerogen Type	Thickness (m)	Tasmania Basin % (mature area km²)	Gas Volume Trillion (T scf)	Gas Volume assuming 95% lost G/20 (T scf)	Gas volume assuming 67% of H H*0.67 (T scf)	Gas Energy remaining (P joules)	Oil Volume (MMbbl)	Oil Volume assuming 95% lost (MM bbl)	Oil Volume assuming 25% of L (MM bbl)	Gross Gas Value recovered J*4.5 (millions US $)	Gas E@P costs (12 %) million US $	Gas Royalty (12%) million US $	Net Gas Value after royalty and E@P costs (millions US $) Pre-tax	Oil Value recovered M x $130 (millions US $)	Oil E@P costs (15 %) million US $	Oil Royalty (12%) million US $	Net Oil Value after royalty and E@P costs (millions US $) Pre-tax
Gondwanan: Tasmanite Horizons (average)#	16.9	748	I	*1.3	16.66 (5,000)	12	1	0	443	7423.76	371.188	92.797	1,995	239.373	210.648	1,545	12,064	1809.54	1230.49	9,024
Woody Island/Quamby #	1	100	II/III	150	40 (12,000)	29	1	1	1,071	83.7	4.185	1.04625	4,817	578.085	508.715	3,731	136	20.4019	13.8733	102
Liffey Group # (carbonaceous sediments)	81	809	II/III	0.2	40 (12,000)	30	1	1	1,081	19522.7	976.1352	244.0338	4,863	583.553	513.527	3,766	31,724	4758.66	3235.89	23,730
Cygnet Coal Measures ^	47.8	45	III	1	16.66 (5,000)	38	2	1	1,393	55.57	2.7785	0.694625	6,267	752.083	661.833	4853.443658	90	13.5452	9.21073	67.545335
Torbanite: Lower Freshwater Sequence ^	72.6	398	III	0.2	3.33 (1,000)	4	0	0	127	580.998	29.0499	7.262475	574	68.8361	60.5757	444.2220922	944	141.618	96.3004	706.203069
Macrae Mudstone #	1.97	105	II/III	2	26.66 (8,000)	3	0	0	105	14.952	0.7476	0.1869	472	56.607	49.8142	365.3040011	24	3.64455	2.47829	18.174156
Larapintine: Gordon Group Limestone *	0.78	50	II/III	150	10 (3000)	63	3	2	2,313	30.753	1.53765	0.384413	10,407	1248.83	1098.97	8059.143195	50	7.49604	5.09731	37.3802715
Totals (rounded)						179	9	6	6,532	27,712.44	1,385.62	346.4055	29,395	3,527.37	3,104.09	22,763	45,032.71	6,754.91	4,593.34	33,684

Tasmania consumes 115 Petajoules of energy per-annum (115,000,000 GJ).

Tasmania consumes 32.2 PJ (28%), of its annual energy budget in fossil fuels.

Oil/gas volume calculated using ZetaWare source rock potential calculator (www.zetaware.com).

1 GJ = 10^9 Joules

Gas volume converted to energy using www.onlineconversion.com.

1 PJ = 10^{15} Joules

^ Chester, 2004.

Predicted Total net value of Larapintine and Gondwanan Petroleum Systems (millions US $) = 56,448

*Burrett and Martin (eds), 1989.

Gross value before E@P and Royalties (millions US $) = 74,427

Comparison of Tasmania gas total: Santos estimates 126 trillion scf of natural gas as total WA reserve (Australian, 10/07/07).

Tasmania Basin: 30,000 km² (#Reid, 2004)

Density of shale: 2.3 g/cc. (www.zetaware.com).

Density of tasmanite: 1.76-1.77 g/cc. From James, 1950. p63.

Predicted Gas Reserve in Petajoules (10^{15} J) = 6,532

Density of *Tasmanites* derived oil: 0.97 g/cc. From James, 1950. table 3, p159.

Number of years supply of all Tasmania's energy = 42.14302432

Density of gas: LNG (methane) 0.41-0.5 g/cc (www.wikipedia.com)

Gas market price: $4.50 US/GJ (Australian, 10/7/07)(column **N**).

Oil market price per barrel: $130 US/bbl (www.wtrg.com)

Gas price per GJ: $5.75 US MM BTU (GJ) (www.wtrg.com)

Average oil price for previous 12 months: $85 US/bbl.

Density of oil: 0.8-0.97 g/cc (API 25=0.904, API 42=0.816)

June 2008 (prepared by Tony Collings).

Table 4. Well Costing Proposal

Well Site Name	Depth (m)	Days (inc move)	Cost P&A	C&S
Bellevue 1	2600	43	$4,400,000	$4,754,000
Thunderbolt 1	3250	43	$5,547,000	$5,835,000
Interlaken 1	1000	22	$2,803,000	$2,964,000
Bracknell 1	1450	28	$2,930,000	$3,100,000
Butlers Rise 1	1050	28	$3,298,000	$3,489,000
Stockwell 1	1600	21	$2,371,000	$2,556,000
Cressy 1	1500	21	$3,084,000	$3,260,000
Hunterston 2	1050	18	$3,084,000	$3,260,000
Mobilization/Demobilization				$2,000,000
	Total (with 10% contingency		$14,767,000	$17,665,000
	Total (with no contingency)		$13,290,300	$15,898,500
Core Office				$10,000,000
Totals				$29,665,000
NOTE: Costs are ESTIMATES only based on current data and program NOTE: All costs include a 10% contingency. NOTE:: P&A (Plug and abandon) costs apply to dry wells NOTE: C&S costs (Case and suspend) costs apply to successful wells				

Note: well site order may change without notice (depending on geological/logistical constraints)

Table 5. Estimated Reservoir Depth/Volume/Value - 15 Sites

Drillsite (Top 15)	Reservoir/Structure Depth (m)				Structure Volume Estimate (m^3) (80% volume corrected)	Structure Volume Estimate (cf)	Oil Estimate P90 (barrels - BBL)	Resource Value $US (@ $120/BBL)
	Triassic	Permian	Paleokarst Siluro-Devonian Carboniferous	Ordovician				
BV #1	300	400/550/650/820	2200	2425/3570	25,992,000	917,907,480	283,000,000	$33,960,000,000
Bellevue (NE)				(4440m basement)				
TB #1	500	775/1275	1800	2550	9,800,000	346,087,000	116,000,000	$13,920,000,000
Thunderbolt (S)				(3250m basement)				
BN #1	350/750	1200/1350/1400			1,600,000	56,504,000	49,000,000	$5,880,000,000
Bracknell		(1700m basement)						
BR #1		150/200/1050			1,920,000	67,804,800	18,000,000	$2,160,000,000
Butlers Rise		(1700m basement)						
IL #1		550/650/700			2,240,000	79,105,600	21,000,000	$2,520,000,000
Interlaken		(1400m basement)						
CR #1	700	800			576,000	20,341,440	8,000,000	$960,000,000
Cressy		(1600m basement)						
SW #1	550/700	800/875/1050			1,280,000	45,203,200	4,000,000	$480,000,000
Stockwell		(1600m basement)						
HS #2		850	950		1,600,000	56,504,000	6,000,000	$720,000,000
Hunterston			(1050m basement)					
BV #2	375/425	550/575/750	2250	2950	25,992,000	917,907,480	285,000,000	$34,200,000,000
Bellevue (NW)				(4440m basement)				
HH #1	400	800/875/1050			576,000	20,341,440	8,000,000	$960,000,000
Hummocky		(1500m basement)						
ST #1		400/475/550			2,240,000	79,105,600	4,000,000	$480,000,000
Scotts Tier		(1300m basement)						
CR #2	600/675	850/875/1000			1,600,000	56,504,000	8,000,000	$960,000,000
Cressy		(1550m basement)						
LV #2	300?	900			2,240,000	79,105,600	3,000,000	$360,000,000
Lonnavale		(UK basement)						
MR #1	900	1200/1325/1450			1,600,000	56,504,000	5,000,000	$600,000,000
Macquarie		(2100m basement)						
QY #1		100/175/250/525			576,000	20,341,440	2,000,000	$240,000,000
Quamby		(950m basement)						
Totals					79,832,000	2,819,267,080	820,000,000	$98,400,000,000

P 90 STOOIP calculation based on Monte Carlo Method.

Note: Reservoir/Structure Volume Based on Table 1 Calculations

UK = unknown

June 2008 (prepared by tony Collings)

Table 6 Undiscovered Prospective Resources - Volume Ranking of 17 Sites.

Ranking	Monte Carlo Estimate*	P90 (mmbbl's)	P50 (mmbbl's)	P10 (mmbbl's)
1	Bellevue #1	283	620	1,256
2	Thunderbolt #1	116	243	468
3	Bracknell #1	49	100	194
4	Derwent Bridge #1	36	87	199
5	Interlaken #1	21	45	92
6	Nile River #1	20	45	92
7	Butlers Rise #1	18	40	79
8	Cressy #1	8	16	29
9	Hummocky #1	8	16	30
10	Cressy #2	8	16	30
11	Hunterston #2	6	12	23
12	Macquarie #1	5	12	24
13	Stockwell #1	4	11	25
14	Scotts #1	4	8	15
15	Lonnavale #2	3	7	16
16	Steppes #1	3	7	16
17	Quamby #1	2	5	10
Totals		594	1,290	2,598

*Monte Carlo calculations are based on Table 1 and 5 values.

mmbbl's = million US barrels (or BOE)

June 2008 (prepared by Tony Collings)

On and Offshore Oil/Gas Production in Australia

GSLM Internal Report – Compiled by Tony Collings, October 2007.

Onshore - Cooper/Eromanga Basin

The Cooper/Eromanga Basin covers an area of approximately 75,000 km^2, and is currently the largest producing oil and gas field within onshore Australia (figure 1). Current annual production is approximately 20 Bcf of gas and 1.6 million barrels of oil. The Cooper/Eromanga Basin is estimated to contain approximately 3,720 Bcf of gas and 700 million barrels of oil (3P Santos, 2007).

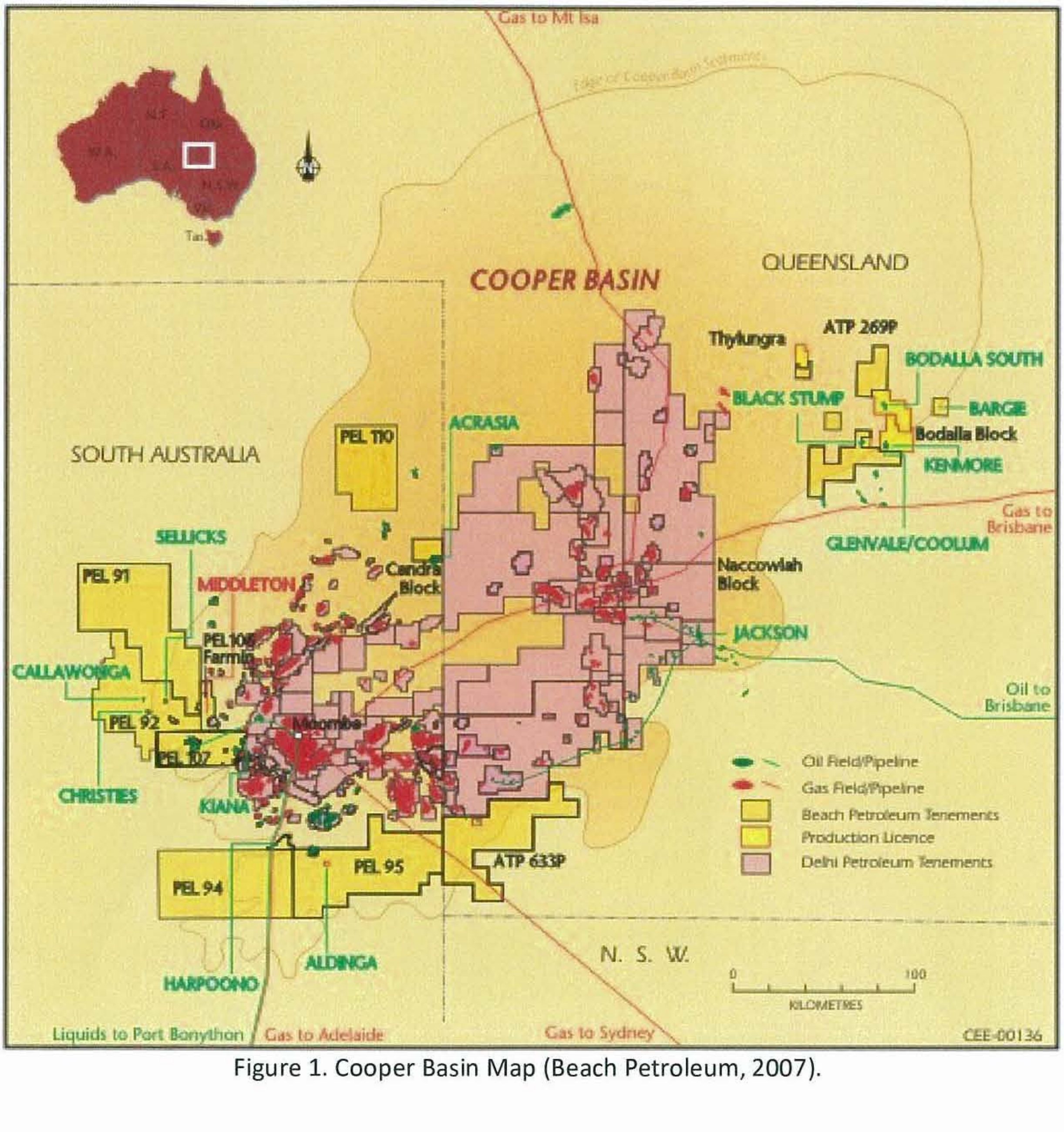

Figure 1. Cooper Basin Map (Beach Petroleum, 2007).

The Cooper basin of N/E South Australia, S/W Queensland was originally explored for oil and gas by the geologist Dr Reg Sprigg. Several surveys of the area were conducted and Dr Sprigg was awarded leases in the late 1950's and 1960's. The first commercial gas discovery was made at the Gidgealpa field in 1963. With the first Permian (Cooper) oil discovery made at the Tirrawarra field in 1970, and the first Jurassic (Eromanga) oil discovery made at the Strzelecki field in 1978.
Oil production from the Jackson field commenced in 1981, and the Jackson-Moonie pipeline opened in 1984. To date, approximately 340 oil wells have been drilled in the Cooper Basin and just over 100 million barrels of oil have been removed. In addition: over 1400 gas exploration wells have been drilled, with 630 of these wells currently in production.

Offshore - Bass Strait

Currently there are 4 offshore oil and gas production basins within the S/E Australian Bass Strait region (figure 2). These are the Gippsland, Otway, Bass and Sorell Basins. The Gippsland and Otway Basins are the most productive, with over 70% of the total Australian offshore production coming from Gippsland (Calver, 1998).

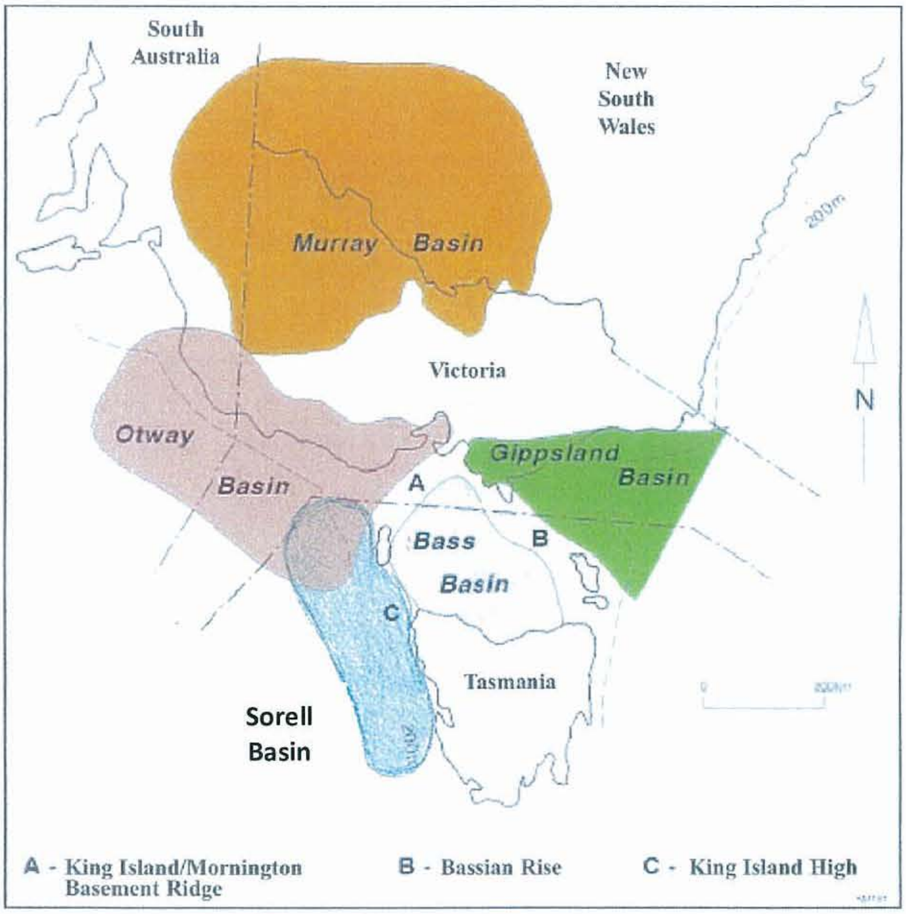

Figure 2. Offshore Basin Map (Victorian Government).

Gippsland Basin

The offshore Gippsland Basin covers an area of approximately 41,000 km^2, and is situated in the S/E corner of mainland Australia, off the coast of Victoria (eastern Bass Strait). The first commercial oil/gas discovery was made in 1964 at Barracouta 1.
Current annual production is 3446.5 million barrels of oil and 4779.5 trillion cubic of gas. Identified commercial reserves (2P) have been estimated at 4073.5 million barrels of oil and 9617.6 billion cubic feet of gas (Geoscience Australia, 2004).

Otway Basin

The offshore Otway Basin covers an area of approximately 150,000 km^2, and is situated off the southern mainland coast of Victoria and South Australia (western Bass Strait). The first commercial oil/gas discoveries occurred in 1979 (Victoria) and 1987 (SA). With the first commercial Otway Basin gas supplied to the processing plant in 1986.
Current production is 0.72 million barrels of oil equivalent, with identified gas reserves estimated to be 1,775 billion cubic feet (2P. Geoscience Australia, 2004).

Bass Basin

The offshore Bass Basin covers an area of approximately 42,000 km^2, and is situated between the south coast of Victoria and north coast of Tasmania, in the central region of Bass Strait. The basin has a drilling density of approximately 35 wells per 1,200 km^2, similar to other basins along the southern margin of Australia (Victorian Government).
Exploration of the Bass Basin commenced in the early 1960's and 15 wells were drilled between 1966 and 1974. The first commercial test well: Yolla 1 was drilled in 1985 by Amoco and is sited on the crest of a four-way dip and fault closure. Later; the Yolla 2 and White Ibis wells identified the Bass Basin resource to contain 450-600 billion cubic feet of gas and 70 million barrels of oil. Yolla 3 and 4 were drilled in 2004 by Origin Energy and partners, which resulted in the Yolla field being upgraded to a 2P reserve of 422 billion cubic feet of gas (Origin, 2007).

Sorell Basin

The offshore Sorell Basin currently has 8 tenements, and is situated off the west coast of Tasmania. Exploration of the basin commenced in the late 1960's, with a seismic survey conducted by Esso. Two exploration wells have since been been drilled; Clam 1 near King Island in 1967 and Sorell 1 near Strahan in 1981. Since exploration began in the 1960's, extensive 2D seismic , aeromagnetic and swath mapping of the basin has continued. Additional sedimentary and structural data has since been gathered with a deep ocean well drilled to the west of Cape Sorell 1 in 1973 (DSDP, Leg 29).

Shale Smear in Tasmanian Faults: Providing an effective seal for hydrocarbons; linked to Conductivity Anomalies and Iodine Occurrences.

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Introduction:

The Tasmania Basin has experienced many periods of active faulting which have occurred well into the Tertiary. Much of the faulting in Tasmania is complex and often associated with movement along existing lineaments following trends within the underlying basement structure. The faulting history of Tasmania is reasonably well understood and has been documented in many past and recent structural surveys (Stacey, 2007).

In response to such a complex tectonic history, many researchers have the opinion when looking at the oil and gas prospectivity of the basin; that recent faulting events in The Tasmania Basin have reduced the hydrocarbon trap potential, by allowing oil and gas to escape through potential sealing structures. Unfortunately, negative opinions of The Tasmania Basin do not take into account the growing international research indicating that fault smear sealing of hydrocarbon reservoirs occurs in many types of hydrocarbon plays.

The existence of effective hydrocarbon traps created by fault sealing within The Tasmania Basin can also be studied through the use of conductivity anomalies and iodine measurements. The high conductivity anomaly associated with the Tamar Lineament shows that the Tasmania Basin has oilfield potential and should be explored for its hydrocarbon potential. Natural iodine occurrences and saline lakes along The Tamar Lineament also indicate the potential for the existence of hydrocarbons. Iodine and brine are often used as effective oil indicators.

1.1. How Does Fault Smear Work?

Fault smear is a natural process where a layer of shale or similar sediments are trapped within a fault and then act as a seal, thus preventing fluid flow across the faulted surface. This process is similar to what we see in the wet areas of our homes, where grout or silicon can form a seal across a joint between two surfaces, thereby preventing unwanted fluid flow.

Effective seals across faults are often created by a shale, coal or sandstone layer being trapped within a fault zone (figure 1). Research indicates that the effectiveness of the seal is strongly dependent on the fault offset and the thickness of the smear layer, and is not necessarily dependant on the age of faulting. "Where a shale layer is offset by a fault with throw greater than the vertical thickness of the layer, a shale smear may be entrained into the fault zone" (Faerseth, 2006. p741).

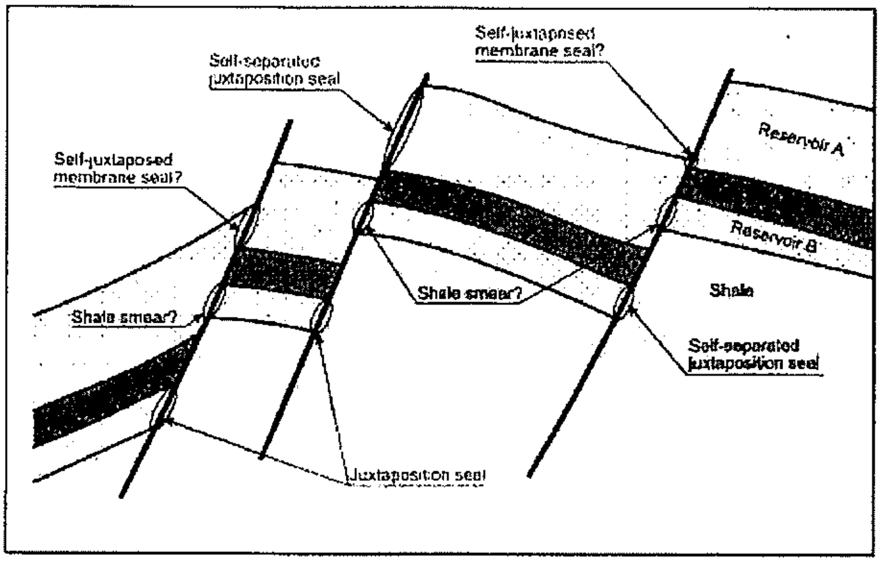

Fig. 1. Schematic illustration showing potential hydrocarbon traps (fault-blocks) resulting from normal faults that offset a sand–shale sequence. Juxtaposition of sedimentary units across the large faults introduces a number of potential seal types. Where reservoir A and reservoir B are juxtaposed across faults, the shale interval that is stratigraphically situated between the two reservoirs may be smeared along faults to form a seal that hydraulically separates the sandstones.

(Source: Faerseth, 2006)

Current research on fault smear properties indicate that normal and reverse faults, regardless of age, can maintain an effective seal for hydrocarbons when the necessary conditions are present. The Tertiary age faulting within the Tasmania Basin has often been given as a reason for the basin being un-prospective for oil and gas. Unfortunately, this opinion does not follow the current research into shale smear; which has found that fault sealing is not dependent on the age of the structure; but is primarily dependent on whether an effective seal has been created during the faulting process.

Studies of well known petroleum basins in Asia and Europe, have shown that the sealing of faults with a shale smear works most effectively when the ratio between the throw of the fault and the thickness of the sealing sediment is below a factor of 4. In effect; this means that when the throw of the fault is equal to or less than 4 times the thickness of the sealing bed, an effective seal across the fault can be formed. Alternatively, if the throw of the fault is higher than 4 times the bed thickness, there is less chance of seal preservation as the smear may become too thin and allow fluid to pass (figure 2).

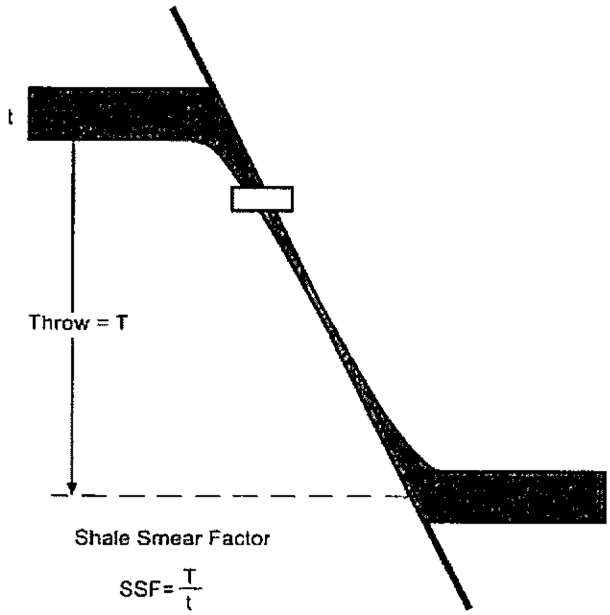

Fig. 2. The shale smear factor (SSF) (Lindsay *et al.* 1993) is given by the fault throw divided by the vertical thickness of the offset shale source layer. Smears may have a significant thickness in exposures and wells, and the point at which smears become discontinuous is generally not exposed. Based on the measured smear thickness at the study location (light grey box) and assuming a gradual thinning of the smear away from this location, a shale smear factor has been calculated for throw values for which the smear is assumed to become discontinuous.

(Source: Faerseth, 2006)

In Tasmania, there are many sites where mature hydrocarbon source and reservoir rocks are common and the fault offset has been measured to be at or below the SSF of 4. By analysing the existing data that shows local fault offsets and bed-thickness using 2D seismic and field observations, it is possible to conclude: that fault smear could provide an effective seal above the known source and reservoir rocks in Tasmania.

1.2. Testing Shale Smear

Shale smear sealing of hydrocarbon reservoirs is often observed in the field.either by measuring the differential pressure across fault zones, or by measuring outcrop/drill-core lithology and thickness. A differential pressure of 7 atmospheres is typical of a well sealed fault zone that has previously been measured in The North Sea (figure 3). "Where normal faults offset sand-shale sequences, shale smear along faults is commonly involved in hydrocarbon exploration a likely membrane seal, assumed to prevent leakage across large faults and thereby to seal potential traps" (Faerseth, 2006. p741).

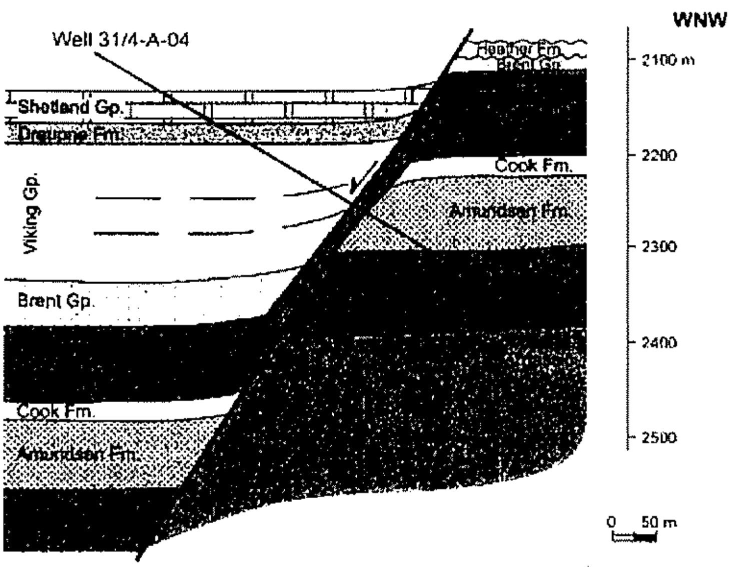

Fig. 3. A normal fault with a throw of 200–250 m at reservoir level delineates the Brage Field in the northern North Sea. Between the two slip zones that have accommodated the displacement, shale-dominated lithologies of the Lower Jurassic (Toarcian) Drake Formation provide a 20 m thick smear at the well location about 50 m below the footwall cutoff. The fault juxtaposes oil-bearing sandstones of the Lower Jurassic Statfjord Formation in the footwall (Brage Field) against water-bearing sandstones of the Middle Jurassic Brent Group in the hanging wall. The fault is a major seal and a pressure difference of 7 bars was recorded across the fault zone.

(Source: Faerseth, 2006)

2D Seismic surveys are also used to test and provide valuable information about fault offset and bed thickness at local sites. The seismic information; when applied to a fault sealing system, can often be used to predict the existence of any fault smear sealing at a particular site. Armed with a detailed knowledge of 2D seismic, plus outcrop and drill-core lithology, an interpretation of the existence of a fault smear can often be determined by using standard geophysical methods.

1.2. The Probability of Shale Smear in Tasmania

In the Tasmanian basin, thick sequences of sedimentary shale and sandstone are known to be abundant within the Permian and Triassic sequences. Although the local lithology has not been tested for specific fault sealing qualities, the possibility of shale smear within local faults is considered likely as the local shale qualities are similar to those outlined in the Faerseth study. It is observed that many Tasmanian faults of Tertiary age are full of fine grained mudstones.

An extensive program of 2D seismic acquisition has been acquired within the Tasmania Basin since 2001. As a result of the previous seismic surveys, approximately 1,350 line kilometres of data has been collected and processed since 2001. At Tunbridge to the southeast and Bracknell in the north of the basin, preliminary seismic interpretation has shown that shale smear sealing of many faults is possible.

The Tunbridge area of the Tasmania Basin is of particular interest, as it has many fault and sedimentary features similar to those identified for fault smear qualities. Through detailed interpretation of the Tunbridge seismic data (TB 01-ST), it has been found that fault smear would be less likely to occur within the 'flower structure' west of Tunbridge, as it is bounded by the Tamar Lineament has an observed fault throw of approximately 1000m west of Tunbridge.

The Late Permian, Ferntree Fm has a measured thickness of approximately 250m in a nearby drill-hole (Tunbridge #1), which would give a SSF value of 4 for this location (fig 3a). This SSF result is close to the cut-off point for reliable sealing (Faerseth, 2006). Therefore, a fault offset of this magnitude may have breached the shale smear sealing capabilities of the Permian sediments (SSF = to or >4). Imperfect fault sealing at this site may be indicated by the high iodine levels found in the surface water at Tunbridge (see 3).

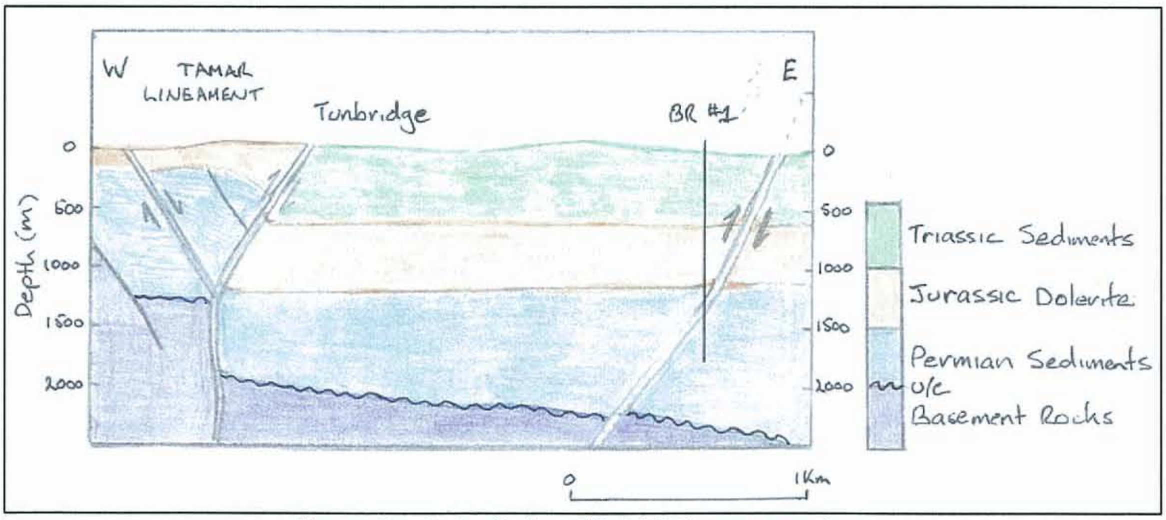

Figure 3a. Seismic line TB-01ST interpretation.

To the east of Tunbridge however, the fault offset observed in the TB01-ST seismic section is interpreted to be in the order of 100 metres or less and the Ferntree Fm is approximately 250m thick (SSF 0.4). The low offset and thick shale sequence observed presents a good case for fault smear sealing of the reservoir to have occurred at this site (fig 3a).

At Bracknell, in the north of The Tasmania basin, another promising case for shale smear may exist. The interpreted seismic line TB-01 SA indicates an anticline structure in contact with the Tamar Lineament (fig 3b). After interpretation of seismic line TB-01SA, it has been found that the Permian shales would have sealed the faults to the east, and could possibly seal The Tamar Lineament to the west. An SSF of 0.5 in predicted at the eastern end of TB-01 SA, and an SSF of 4.0 is predicted on the western end (Tamar Lineament).

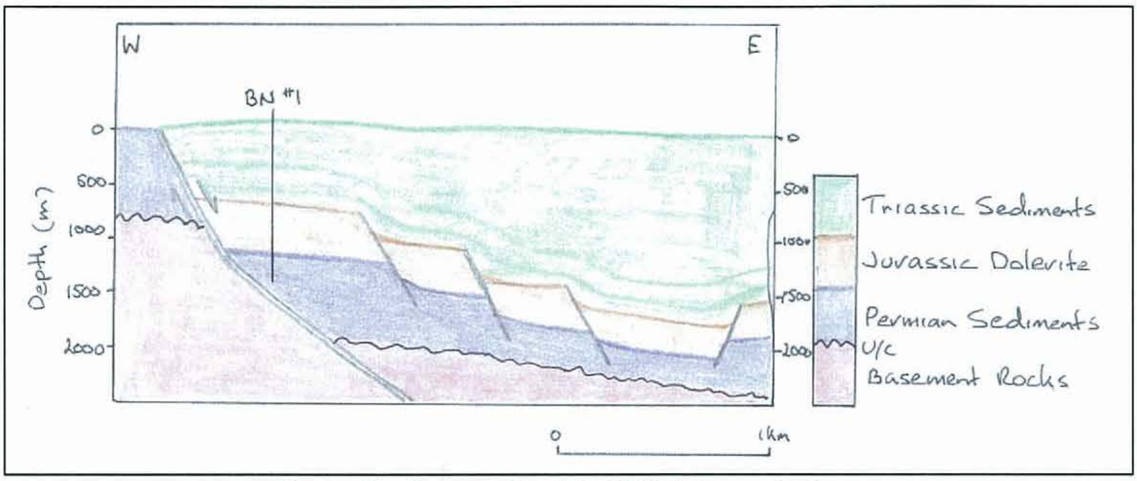

Figure 3b. Seismic line TB-01SA interpretation.

By using the examples form Tunbridge and Bracknell, the conditions for fault sealing can be demonstrated and shale smear is therefore considered possible. Tasmania has several analogous sedimentary sequences which also contain suitable attributes for SSF to occur, similar to those studied in other hydrocarbon basins.

2. High Conductivity Anomalies

In addition to the use of 2D seismic and lithology studies, the presence of effective fault sealing for hydrocarbons can also be confirmed using additional geophysical methods such as gravity, magnetic and conductivity analyses. Gravity and magnetic methods are generally useful for determining the local and regional trends of ore-bodies, faults and lineaments, but they poorly depict any dip trends occurring within the underlying structure.

By using a fluxgate magnetometer; the dip and direction of the local magnetic field can be plotted on a map. The map can then be used to show the local and regional gradient or dip of subsurface conductivity. The 'induction arrow' indicated on the following map, is created by plotting the magnetometer measurements taken from the field which depicts the plane of dip towards the better conductor; with the arrow length showing the angle of tilt (figure 4).

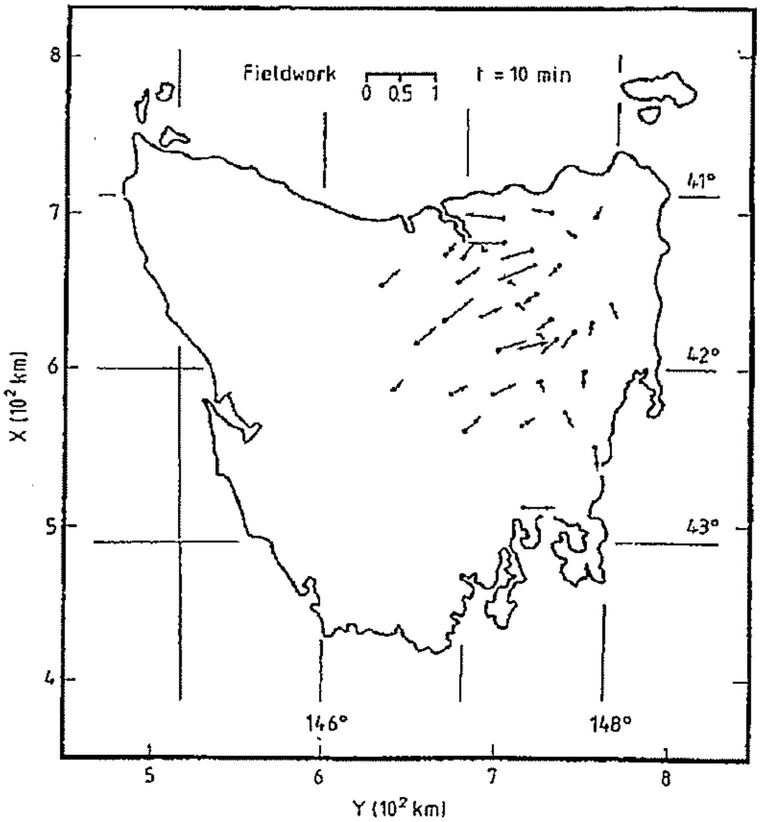

Fig 4, Induction arrows for north-east Tasmania showing the presence of the Tamar conductivity anomaly. The arrows indicate the directions of horizontal magnetic field change which cause maximum vertical magnetic field change at each site. The lengths of the arrows indicate the effectiveness of the process. The arrows point towards a zone of high electrical conductivity.

(Source: Parkinson and Hermanto, 1986)

Shallow depth conductivity anomalies can often indicate semi-conductors such as graphite or hydrocarbons which are present in the subsurface. As there is an absence of a significant magnetic anomaly associated with the measured conductivity anomaly in The Tamar Lineament, graphite can be ruled out as a likely cause and either oil or basinal brines can be assumed. Parkinson and Hermanto, 1986 concluded from their study of the Tamar Lineament that:

> The shallow depth makes the presence of graphite unlikely and a sufficiently high temperature out of the question. The most likely cause seems to be fractured rock saturated with highly conducting fluids. Archies Law suggests that a porosity of 20-40% is necessary with a fluid conductivity of the order of 10 Sm^{-1}. Fluids with such a high conductivity have been reported, but are generally confined to oilfields.

3. Iodine Occurrences

As the natural concentration of iodine is generally low in areas isolated from oceanic sources, it is most unusual that the Tamar Lineament was found to have very high concentrations of iodine and several brine lakes located over 100 km from the nearest sea. This discovery was made when Dr Paul Richards found high iodine concentrations in surface waters during his survey of inland eastern Tasmania (fig 5, Jo Zantuck, 2007. Surfer plot of Richards, 2005 data). The observations found in the Richards survey are unusual, as high iodine concentrations and subsurface brines are often associated with petroleum-bearing basins "About 26% of annual USA production of iodine is from sodium iodide in deep subsurface brines..." (Burrett et al, 2007).

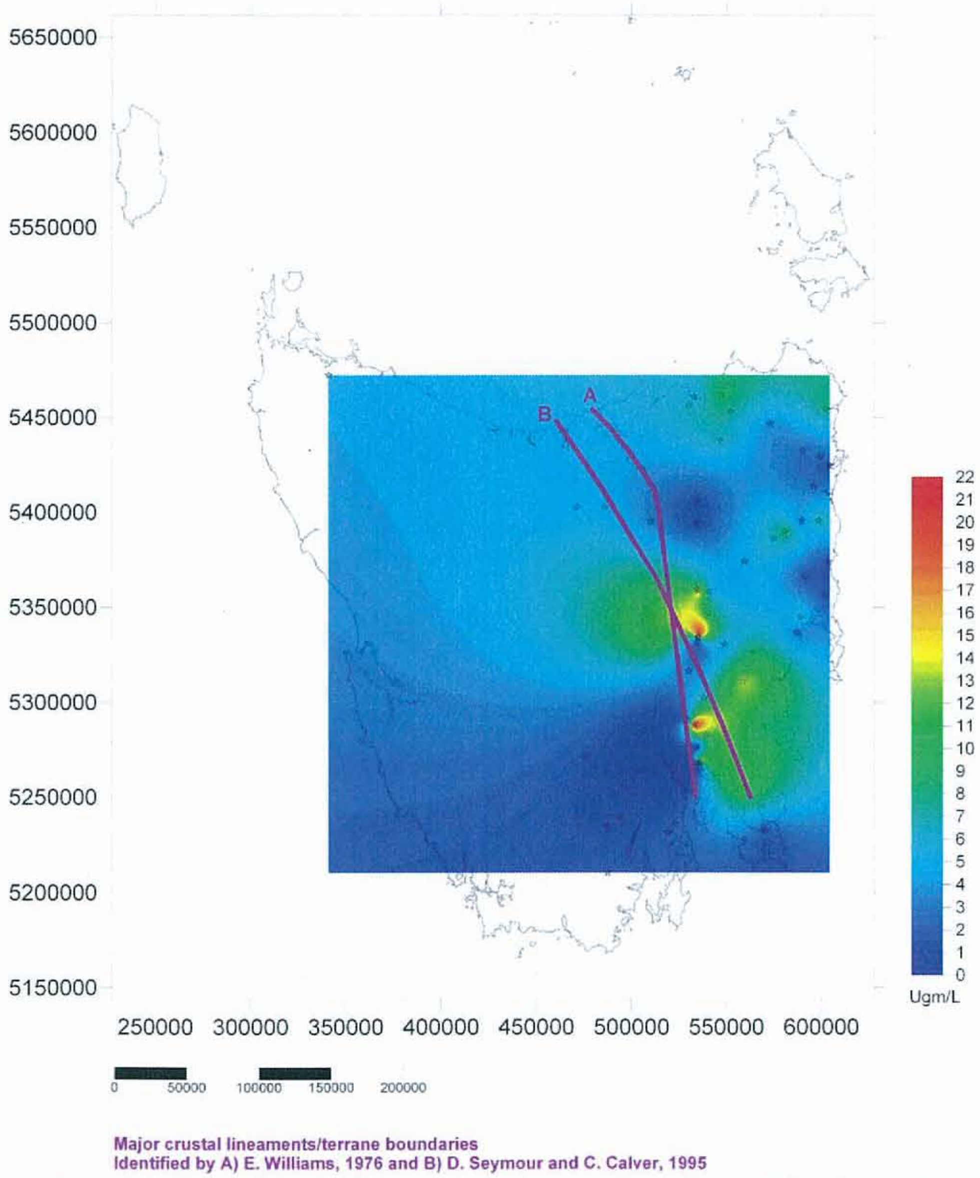

Figure 5. Iodine/crustal lineaments, data average from Richards, 2005. Zantuck, 2007.

Iodine and brine seepages along the Tamar Lineament could be interpreted individually as evidence for the presence hydrocarbons. As the high iodine data is also confirmed by the presence of a high conductivity anomaly associated with hydrocarbons along the Tamar Lineament, the only reasonable conclusion which could be made of the combined evidence is that a connection to a common oil source must exist.

Conclusion

After an interpretation of the all the seismic and geological data collected in The Tasmania Basin, it is considered likely that fault sealing has occurred in many locations. This interpretation is considered likely for two reasons: 1, The Tasmania Basin contains up to 800m of sedimentary source and reservoir rocks, many of which occur within the potential oil producing Permian succession. 2, The Tasmania Basin contains similar lithology and fault structures to those studied in other countries.

The presence of high subsurface conductivity anomalies, indicate the presence of either oil or gas in The Onshore Tasmania Basin. Shows of iodine and brine along the Tamar Lineament, suggest that trapped hydrocarbon reservoirs may be leaking in some locations where known faults occur.

Shale smear sealing of faults above hydrocarbon reservoirs and in areas with an SSF below 4, should be further explored for evidence of sealing. By looking at all of the evidence which has been presented a conclusion can be reached: that effective fault seal qualities can be assumed to exist above many of the potential oil and gas reservoirs in The Tasmania Basin.

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IODINE IN TASMANIAN SURFACE WATERS - PETROLEUM EXPLORATION SIGNIFICANCE

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Natural iodine concentrations are generally low in rocks, soil and surface water but are high in subsurface brines associated with petroleum-bearing basins. About 26% of annual USA production of iodine is from sodium iodide in deep subsurface brines pumped from the Paleozoic rocks of the Anadarko Basin, Oklahoma (Johnson & Gerber 1999). Surface and subsurface analyses of iodine in water, sediments and soil have been used as geochemical indicators of subsurface petroleum accumulations in Ukraine , Russia , USA and Japan (e.g. Leaver & Thomasson 2003; Gallagher 1983; Gordon, 1992; Kudelskiy 1976: Moody & Ervin 2001; Kunisue, et al., 2002 & Tedesco 1993, 1997,1998).

Unpolluted freshwater has values of 1.5 -2.5 ug L. (Whitehead 1984).

In 2005, Dr Paul Richards organized, through the state government of Tasmania , an analytical program for measuring iodine in surface waters in eastern Tasmania. These data were published as part of a larger project on iodine deficiency in Tasmania (Richards & Stewart, 2007).

We have contoured the data using the program SURFER and presented these as three maps (Figs 1-3). Some differences between samples collected at different times of year are apparent and may be due to a variety of factors which need to be explored. Contouring may be skewed by a lack of data from central and western Tasmania.

The results show near normal values over most of eastern Tasmania with highs at the Coal River, Tunbridge, Macquarie River and Carlton River sites. Several of the iodine anomalies lay above or near major faults and could be interpreted as leaking basinal brine. Interestingly, these anomalies are close to the NNW-SSE Tamar Fracture System which was first identified by Parkinson et al. (1988) on the basis of induced electromagnetism. A very pronounced conductivity maximum point to a highly conductive fluid at depth which Parkinson suggested is brine.

These anomalies are unlikely to be the result of iodine in rainfall or in soil, as modeling by Butler et al. (2007,Fig. 8) shows that most of the anomalously high values fall within their predicted iodine deficient area.

Clearly more analyses are needed but the high iodine values which are up to ten times what might be expected are encouraging for petroleum exploration. For soil surveys, Tedesco (1997) recommends a general geochemical survey using existing road networks followed by a detailed survey at a grid distance of 350m in order to define areas of leakage. He shows that combining seismic and iodine surveys substantially increases the chances of exploration success.

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The Directors
Great South Land Minerals Limited
Level 1, 199 Macquarie St.
Hobart, Tasmania 7000

23rd August, 2007

Gentlemen,

Independent Evaluation of Special Exploration License SEL 13/98

Great South Land Minerals Limited (GSLM), a wholly owned subsidiary of Empire Energy Corporation, requested that RPS Energy (RPS) provide an independent evaluation of Special Exploration License SEL 13/98 as a part of their application for admission to trade on the Alternative Investment Market of the London Stock Exchange Plc (AIM).

GSLM holds 100% interest in the Special Exploration License SEL 13/98 which covers the potential prospective portion of the Tasmania Basin. The permit area is approximately 30,000 square kilometres and covers approximately half the island of Tasmania. The permit expires on 1 October, 2009. No petroleum wells have been drilled in the permit area to date.

The oldest basement consists of Proterozoic rocks which are exposed on the western half of Tasmania. Later basement rocks of Cambrian to Early Devonian age are known as the Wurawina Supergroup. All of these rocks were deformed by the mid Devonian tectonic event called the Tabberabberan Orogeny, a major pan Australian event.

Seismic coverage is approximately 950 kilometres of 2D (TB01-2001; 775 km and TB02-2006; 175 km). To date, only stratigraphic tests and mineral holes have been drilled in the Tasmania Basin. Drilling between 1997 and 2001 was conducted by GSLM using diamond coring mineral exploration rigs to establish stratigraphy. No borehole has been drilled on a structure as yet.

A seismic exploration progress report provided by GSLM in June, 2007, states that the 2001, 2006 and 2007 seismic programs have helped to identify several major and many minor structures. Further seismic work is planned for November, 2007, to February, 2008. To date, interpretation of the acquired seismic data has identified several fault block traps and small anticlines with shallow targets in the Gondwana Petroleum System. Deeper targets have been identified by GSLM in the Larapintine Petroleum System, mainly Ordovician in the Central Highlands. An extensive drilling program is planned by GSLM for late 2007.

To date, there have been no oil or gas fields discovered in the Tasmania Basin although several oil seeps have been reported in Tasmania. Oil seeps can be valuable in signifying the occurrence of mature source rocks in frontier exploration. In order for a seep to be authentic and considered part of a petroleum system, it is required to be correlated to a source rock. Currently, the seeps reported in the Tasmania Basin have had limited correlations made to petroleum systems, however, there is a seep in a recently used quarry at Lonnavale, to the southwest of Hobart, that has been correlated with the Permian Tasmanite Oil Shale and is the best indication yet that an active and significant petroleum system may exist in the Tasmania Basin. Two potential petroleum systems could be present in the Tasmania Basin, these are the Pre-Carboniferous system (Larapintine) and the Permian System (Gondwana).

The first petroleum system is referred to in this document as the Pre-Carboniferous System and is based on an Ordovician source. Structures formed in the Tabberabberan Orogeny have the potential to form large traps. Seismic coverage is not yet dense enough to fully define such traps. The Ordovician Limestone and Silurian siliciclastic formations are suggested reservoirs. The reservoir quality of these formations is not known. Gas and/or oil are possible but, given the expected low permeability, gas is more likely to be economic.

The second possible petroleum system is the Permian system, the source of which is expected to be the Early Permian Woody Island Formation and its member the Tasmanites Oil Shale. The potential reservoir for the system is a relatively well understood fluvial formation called the Liffey/Faulkner Group. This formation has modest permeability in most locations (<10 mD). It is hoped that the intra formational seals in the Liffey Group can either provide seal for structural traps or set up stratigraphic traps. The play has good source rock presence as evidenced by the Tasmanite Oil Shale, which has been typed to the Lonnavale seep. The maturity level and, therefore, the timing of expulsion, is not well understood. The source rocks are the most encouraging aspect of this play but a high confidence trap has yet to be defined so that their effectiveness can be tested.

Stratigraphic plays and traps are a theoretical possibility at any level but pursuit of them is currently impractical, given the limited 2D seismic coverage and variable seismic image quality. Typically, good 3D seismic data is required to successfully pursue such play types.

The Prospective Resources for SEL 13/98 are summarised in Table 1 and Table 2. "Risk Factor" for Prospective Resources means the chance or probability of discovering hydrocarbons in a sufficient quantity for them to be tested to the surface.

	Prospective Oil Resources			
Feature	**Low (MMstb)**	**Best (MMstb)**	**High (MMstb)**	**Risk Factor (%)**
Interlaken	1	4	12	1.26
Bellevue – Level 1	9	35	95	0.40
Bellevue – Level 2 (Fault Independent Closure)	5	20	54	0.40
Bellevue – Level 2 (Fault Dependent Closure)	10	70	396	0.40
Bellevue – Level 3 (Fault Independent Closure)	2	8	21	0.40
Bellevue – Level 3 (Fault Dependent Closure)	4	36	271	0.40

Table 1 – SEL 13/98 Prospective Oil Resources

	Prospective Gas Resources			
Feature	**Low (Bcf)**	**Best (Bcf)**	**High (Bcf)**	**Risk Factor (%)**
Interlaken	8	21	48	1.26
Bellevue – Level 1	65	164	339	0.40
Bellevue – Level 2 (Fault Independent Closure)	40	110	215	0.40
Bellevue – Level 2 (Fault Dependent Closure)	68	374	1815	0.40
Bellevue – Level 3 (Fault Independent Closure)	19	52	107	0.40
Bellevue – Level 3 (Fault Dependent Closure)	33	240	1598	0.40

Table 2 – SEL 13/98 Prospective Gas Resources

Because of the nature of prospect analysis and evaluation, it is not appropriate to add the prospective gas and oil resources. The hydrocarbon discovery would be gas or oil at any particular reservoir level. The risk factor in this case remains the same for oil or gas because of the large uncertainty on source rock distribution, quality, maturation and timing.

The Tasmania Basin is a challenging frontier basin due to the presence of dolerite. Rocks with good source potential do exist in the Permian section but their efficacy is unclear. The Pre-Carboniferous is poorly explored in the sub-surface with a potential for large structures. Both plays offer potential oil and gas in reservoirs which will probably be of modest production in the case of oil. To increase knowledge of the Pre-Carboniferous, GSLM propose to drill a deep (1,965 m) stratigraphic well in the Bellevue area in 2007, using a conventional petroleum drilling rig. Other proposed stratigraphic wells are to be drilled to the north of SEL 13/98 at the Bracknell Feature location and to the west of SEL 13/98 at the Thunderbolt Feature location (Figure 18).

Qualifications

RPS Energy is an independent consultancy specialising in petroleum reservoir evaluation and petroleum geology. Except for the provision of professional services on a fee basis, RPS Energy does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report. David R. Guise, Director - Consulting at RPS Energy, has supervised the evaluation.

David is a registered Professional Engineer with over 30 years of domestic and international experience in both onshore and offshore operating environments. He has substantial experience and knowledge of field development planning, optimization and reserve estimating as well as new venture identification and evaluation. David has also acquired significant commercial and team management skills in an operating production environment. Operating companies that he has worked for as an employee include Nexen Australia, Gulf Indonesia, Energy Equity, Asamera Oil, Delhi Petroleum and Texaco Canada. He also worked in a consulting role as an independent consultant for several companies in Australia and Indonesia prior to joining RPS Energy as Petroleum Engineering Manager in January, 2006. He was appointed to the position of Director – Consulting, Australia and South East Asia in November, 2006.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property.

It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Yours faithfully,

David R. Guise
(Director - Consulting, Australia and South East Asia)

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DATE:	23 August 2007	PROJECT REFERENCE:	GSL – 1047
	PREPARED:	**CHECKED:**	**APPROVED:**
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19/12/2006	REV.E.	Draft	For Internal Review
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1. PERMIT DESCRIPTION

The Tasmania Basin is a frontier basin which covers around half of the island of Tasmania, a state of the Commonwealth of Australia. GSLM holds 100% interest in the Special Exploration License SEL 13/98 which covers the potential prospective portion of the basin. The permit expires on 1 October, 2009. The permit area is approximately 30,000 square kilometres and covers most of the basin as illustrated in Figure 1.

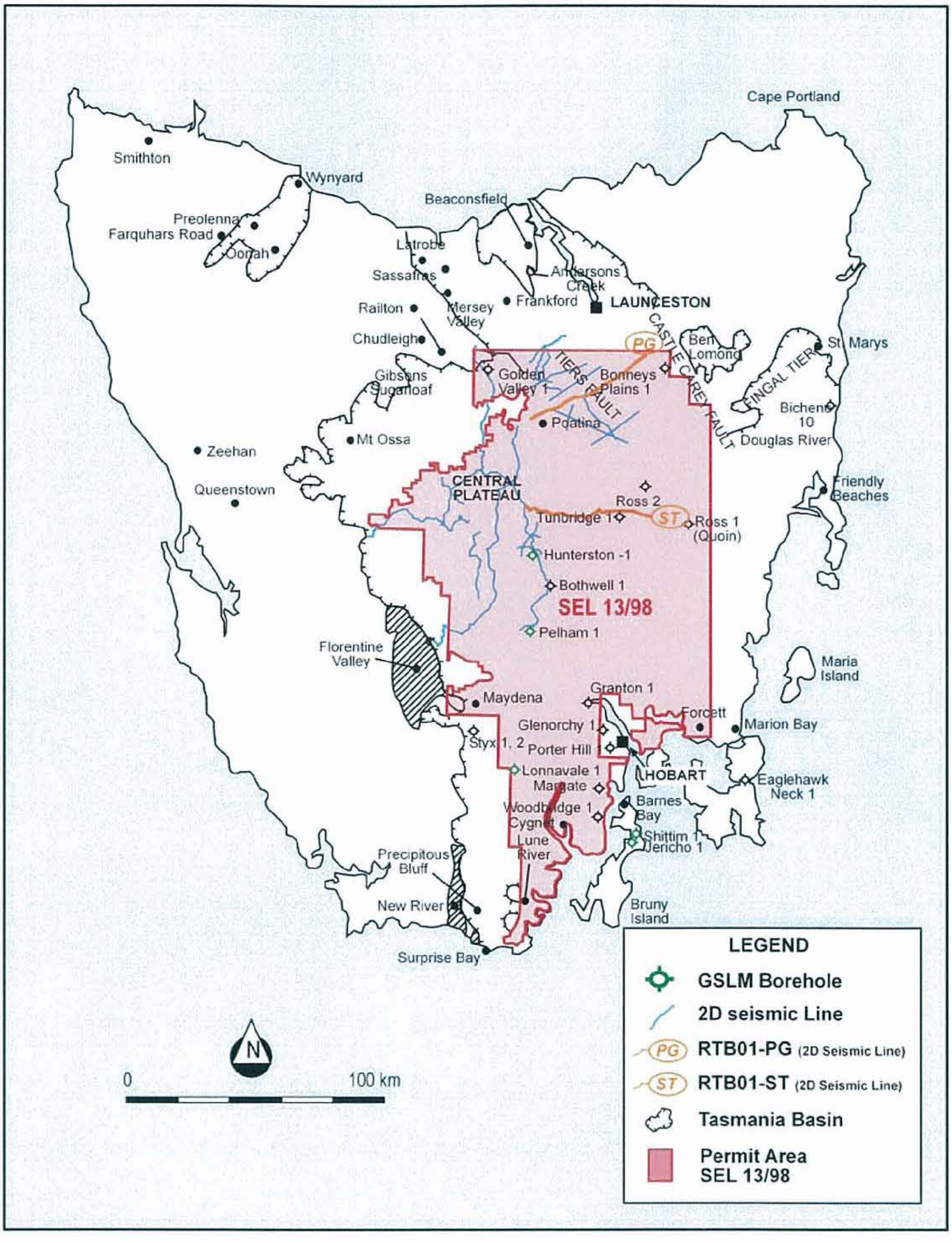

Figure 1 – Permit location, major boreholes and 2D seismic lines

Onshore petroleum permits are administered by the relevant state government. In general, Australian petroleum permits of any jurisdiction are governed by an agreed work programme system with terms of five "permit" years. The anniversary of the permit year is usually the formal award date. The Tasmanian State Government has chosen to define the agreed work programme for Special Exploration Licence SEL 13/98 in terms of mandatory expenditure targets. The proposed and mandatory expenditure per year is shown in Table 3 and the respective activities in Table 4.

Permit Year Ending	Expenditure Proposed by GSLM	Cumulative Expenditure Proposed by GSLM	Mandatory Expenditure (80%)* (AUD)
1/10/2005	$5,341,000	$5,341,000	$4,272,800
1/10/2006	$3,020,000	$8,361,000	$2,416,000
1/10/2007	$4,799,000	$13,160,000	$3,839,200
1/10/2008	$6,530,000	$19,630,000	$5,224,000
1/10/2009	$1,810,000	$21,500,000	$1,448,000

*The mandatory spend is 80% of the value of the programme proposed by the operator

Table 3 – SEL 13/98 expenditure-based programme agreed with regulator

Year Ending	Activity	Status
1/10/2005	2D seismic survey TB02, seismic interpretation, drilling	TB02 suspended (175 km acquired and processed)
1/10/2006	152 km 2D seismic	Completed
1/10/2007	270.5 km 2D seismic. Interpretation and integration of seismic. Extensive gravity survey	Completed
1/10/2008	6 – 10 targeted wells	Planned
1/10/2009	To be determined	To be determined

Table 4 – SEL 13/98 planned activities

2. REGIONAL OVERVIEW, TASMANIA BASIN

2.1 Exploration Drilling History

No petroleum wells have been drilled in the permit area. To date, only stratigraphic tests and mineral holes have been drilled in the Tasmania Basin. Between 1997 and 2002, GSLM drilled five stratigraphic tests, all with hard rock diamond core rigs. None of these wells were drilled on a defined structure. The results of these wells are summarised in Table 5.

Borehole	Operator	Type	Spud Year	Total Depth (mKB)	Purpose	Hydrocarbon Indications (gas % corrected for air, nitrogen and CO_2 contamination)[2]	Formation at TD	Age
Shittim-1	GSLM	Diamond core	1997	1751	Stratigraphic Test	Methane max. 31%, ethane max. 2.12% traces C3-C6. Helium up to 4.8 %	Phyllite and quartzite	Proterozoic
Jericho-1[1]	GSLM	Diamond core	1997	640	Stratigraphic Test	Methane max. 10%, ethane max 1.26% traces C3-C6. Helium detected	Bundella Fm	Permian
Lonnavale-1	GSLM	Diamond core	1997	557	Stratigraphic Test	Methane max. 1.8% ethane max. 0.35 % traces C3-C6	Ferntree Fm	Permian
Pelham-1	GSLM	Diamond core	1997	503	Stratigraphic Test	Methane max. 1%	Bundella Fm	Permian
Hunterston-1[3]	GSLM	Diamond core	2002	1324	Stratigraphic Test	Methane and ethane and traces C3-C6	Dolomitic siltstone	Precambrian

Table 5 – GSLM stratigraphic boreholes

1 Isotopic analysis of the methane at Jericho-1 showed it to be thermagenic in origin.

2 All gas measurements are air, nitrogen and CO_2 corrected. The estimation of CO_2 content may result in error. Samples were collected in various ways and sent to a laboratory for gas chromatograph analysis. The amounts above are subject to error and should be treated as qualitative.

3 No mud log is available for any well except Hunterston-1. It is, therefore, difficult to assess the exact depth origin of the maximum gas values. Operations such as reaming and tripping all result in anomalously high gas readings. Repeated swabbing was noted on the Hunterston-1 mud log.

2.2 Seismic Data

GSLM acquired 659 line kilometres of seismic reflection data across the Central Highlands and in the Northern Midlands areas of Tasmania (Figure 1). The data was acquired in March, 2001, by Trace Terracorp using Vibroseis. The grid is somewhat random as it was acquired mainly along roads (Stacey, 2003). Processing was done by Robertson Research.

The random grid was acquired in order to maximize regional coverage within a limited budget. However, because of poor data resolution and sparse coverage, interpretation of the regional structural elements was not achieved, although a very limited number of leads were recognized.

The presence of extensive Jurassic dolerite has a major impact on the seismic data resolution. At or near the surface, dolerite is generally highly diffusive resulting in poor resolution of underlying events. At depth, the dolerite is characterized by a strong positive event at its top and base and by weak and scattered events in between. Seismic events beneath the dolerite at depth are in general, better resolved.

The quality of the seismic data set is highly variable and coherent events across sections are rare. Previous interpretation efforts were focused on lines where there was well control and there are clear coherent events to correlate wells to seismic. Recent work has concentrated on the Tasmania Basin sequences, especially in areas of better data quality where there is no dolerite.

In 2006, GSLM recorded 152 kilometres of 2d seismic data and in 2007, 270.5 kilometres of 2d seismic data was completed, interpreted and integrated into the seismic database.

A seismic exploration progress report provided by GSLM in June, 2007, states that the 2001, 2006 and 2007 seismic program identified several major and many minor structures. Further seismic work is planned for November, 2007, to February, 2008. An extensive drilling program is planned by GSLM for late 2007.

2.3 Structural Setting

The island of Tasmania is situated off the southeast coast of the Australian continent. The Tasmania Basin is an erosional remnant of an epicratonic basin (Bacon *et al,* 2000) that covers most of central and eastern Tasmania. Regional seismic lines through the northern and central part of the Tasmania Basin are shown in Figure 2 and Figure 3.

The oldest basement consists of Proterozoic rocks which are exposed on the western half of Tasmania. Later basement rocks of Cambrian to Early Devonian age are known as the Wurawina Supergroup. All of these rocks were deformed by the mid Devonian tectonic event called the Tabberabberan Orogeny, a major pan Australian event.

Following a long hiatus, a succession of predominantly flat lying sedimentary rocks of Carboniferous to Late Triassic age was deposited (Bacon *et al*, 2000). In the Jurassic, dolerite intruded this succession as thick sheets, resulting in bodies with thicknesses of up to 600 metres. The total known maximum thickness of the Carboniferous to Late Triassic succession (excluding the dolerite) is 1.7 kilometres (Bacon *et al*, 2000). No well has drilled a section this thick. It is assumed that this estimate is based on the integration of drilling and outcrop data. The present boundaries of the basin are erosional and the original basin extent was probably much greater (Bacon *et al*, 2000).

This basin is an epicratonic skin of sediment and there is no strongly defined depocentre in the rocks preserved onshore today. The basin was uplifted at the end of the Cretaceous, probably associated with the Australian-Antarctic plate margin break-up. Erosion of approximately two kilometres of sediment is interpreted to have occurred. No further sediment was deposited until the Tertiary. Tertiary deposits are only a few hundred metres thick.

The Tasmania Basin can be divided into three major structural elements (Figure 4). The Longford Sub-basin (onshore extension of the Bass Basin) effectively divides the rest of the basin into a large western half called the Central Lakes-Huon Block, and an eastern half called the Douglas River Block (block names modified after Wakefield, 2000). All of these areas are underlain by folded Palaeozoic rocks of Cambrian to Devonian age.

Over much of the basin, the Earlier Palaeozoic is covered by generally flat-lying Permian to Triassic sediments and Jurassic Dolerite. The Longford Sub-basin is evident at the surface as a region called the "Lowlands". It formed due to extension in the Latest Cretaceous to Early Tertiary (Stacey and Berry, 2004) but contains only a few hundred metres of Tertiary sediments. A densely faulted zone, which may be a wrench zone, lies between the Longford Sub-basin and the Highlands (Blackburn, 2004). The Tiers Fault, an obvious cliff at the present day, delineates the western edge of this zone (Figure 4).

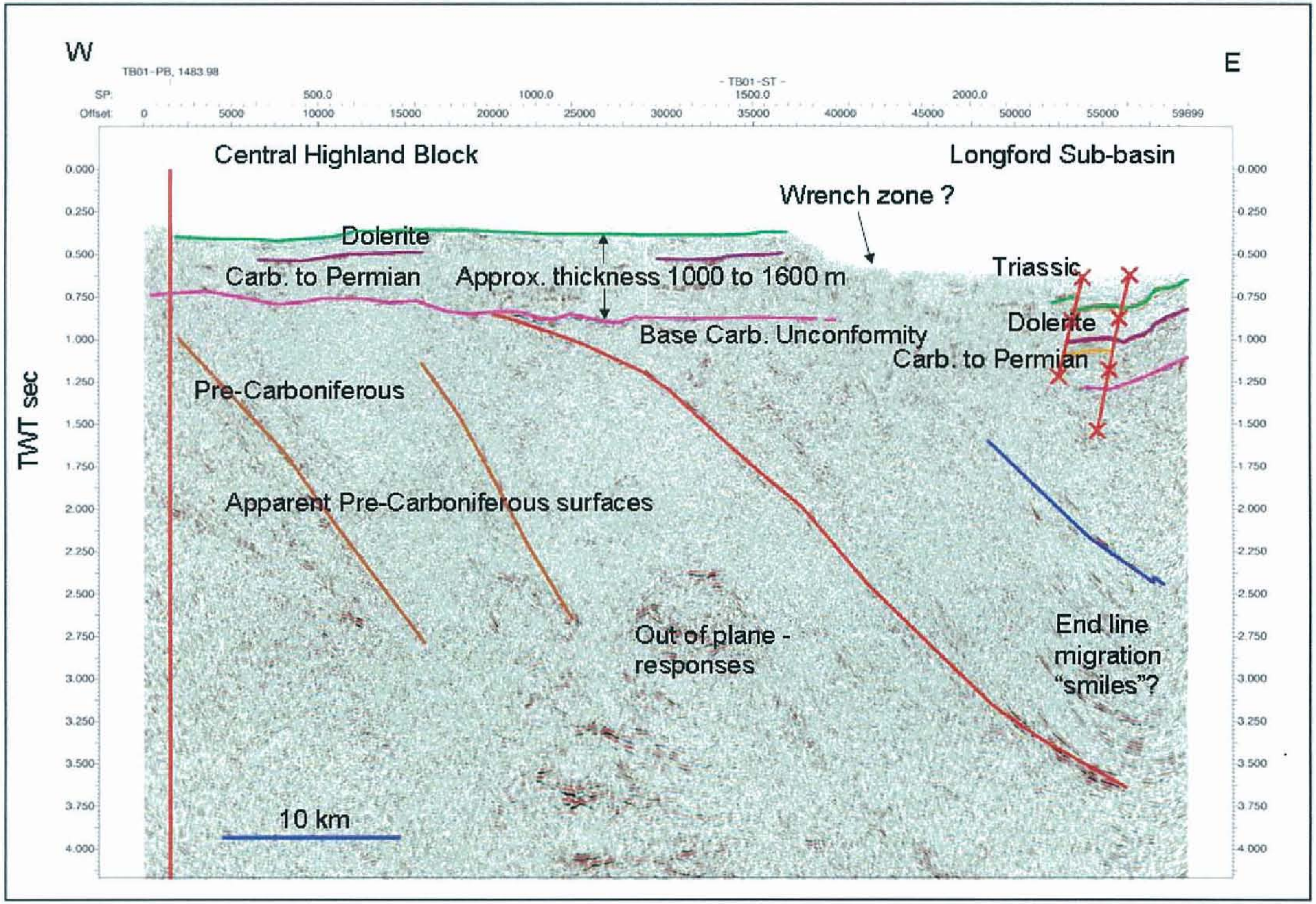

Figure 2 – Regional seismic line RTB01-ST through the central part of the Tasmania Basin. For line location, see Figure 1

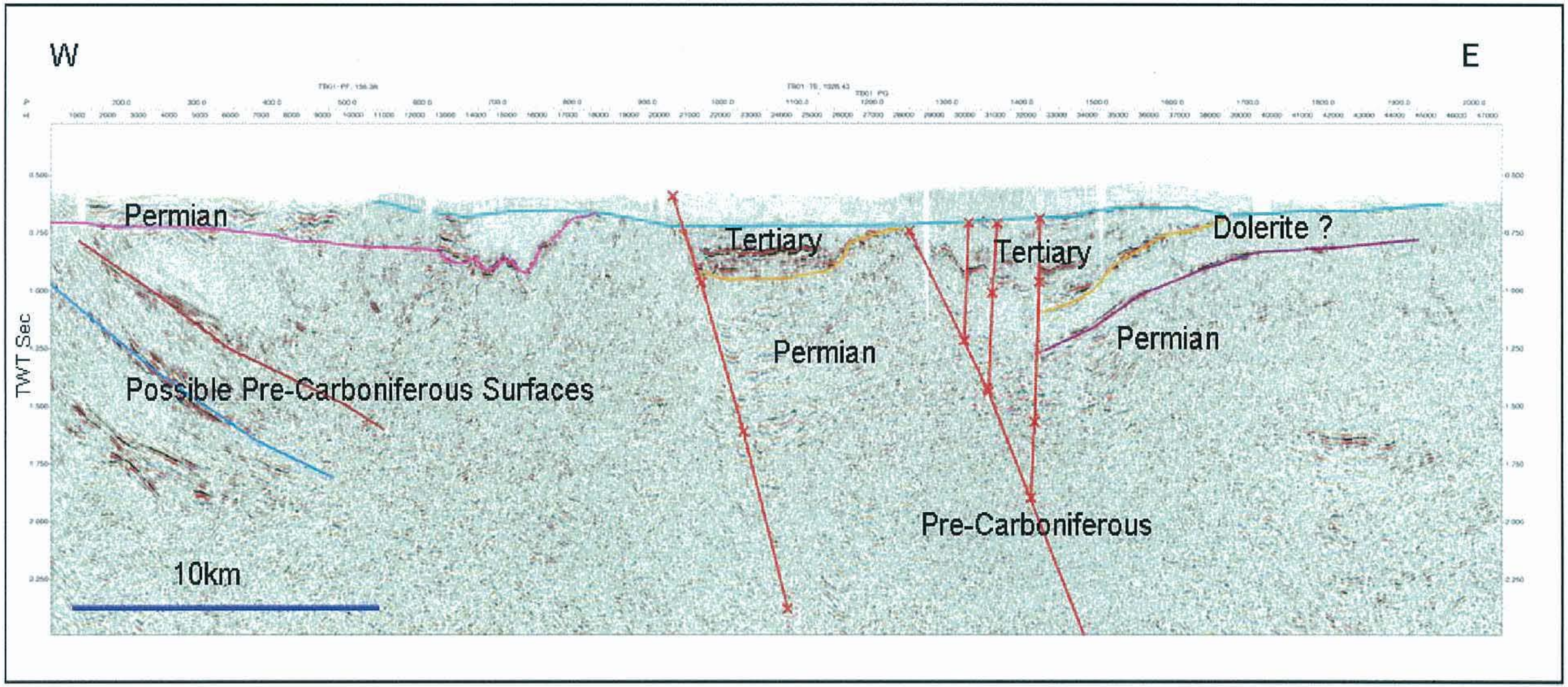

Figure 3 – Regional seismic line RTB01-PG through the northern part of the Tasmania Basin. For line location, see Figure 1

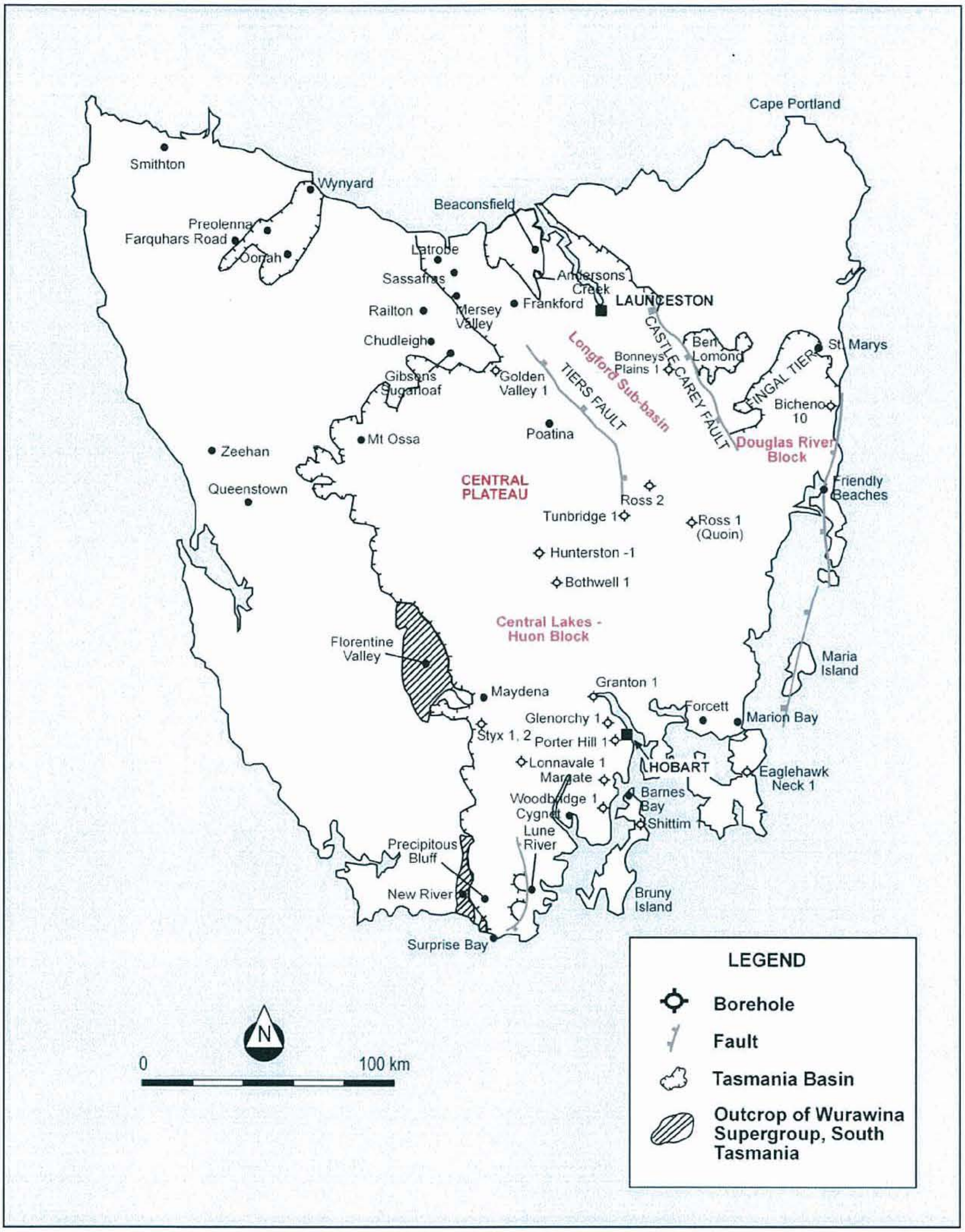

Figure 4 – Tasmania Basin major structural elements (modified from Seymour and Calver 1995a, and Wakefield, 2000)

2.4 Stratigraphy

The generalised stratigraphy of the Tasmania Basin is summarised in Figure 5. The stratigraphy of the basin is known mainly from outcrop and the stratigraphic diamond bore holes (Table 5). The following stratigraphic summary is based on Bacon *et al*, (2000). A more detailed discussion can be found in Clarke and Forsyth (1989).

The sediments are separated into two supergroups; the Wurawina Supergroup of Early Palaeozoic age and the Parmeener Supergroup of Late Palaeozoic to Early Mesozoic age. These are separated by a major angular unconformity, associated with the Tabberabberan Orogeny. Each of the supergroups are sub-divided into a number of lower rank lithostratigraphic units (Figure 5).

The Wurawina Supergroup is a Late Cambrian to Early Devonian shelf carbonate and clastic succession (Bacon *et al,* 2000). The supergroup consists of Late Cambrian to Early Ordovician, shallow marine to fluvial siliciclastic rocks (Denison Group) overlain by 1.5 kilometres of predominantly micritic, shallow marine, warm water Ordovician limestone (Gordon Group), then up to 5 kilometres of shallow marine Silurian to Early Devonian siliciclastic rocks (Eldon Group) (Bacon *et al*, 2000).

Results from a regional conodont alteration index (CAI) study on the Gordon Group carbonates, performed by Burrett, (1992), indicate that these rocks are mature for hydrocarbon generation in southern Tasmania, showing a CAI typically between 1.5 and 4 (Bacon *et al*, 2000). The results of this work are summarised in Figure 6.

A major orogenic event occurred in the Devonian. This resulted in considerable folding of the Early Palaeozoic strata and was followed by a long hiatus, lasting approximately 80 million years (Figure 5).

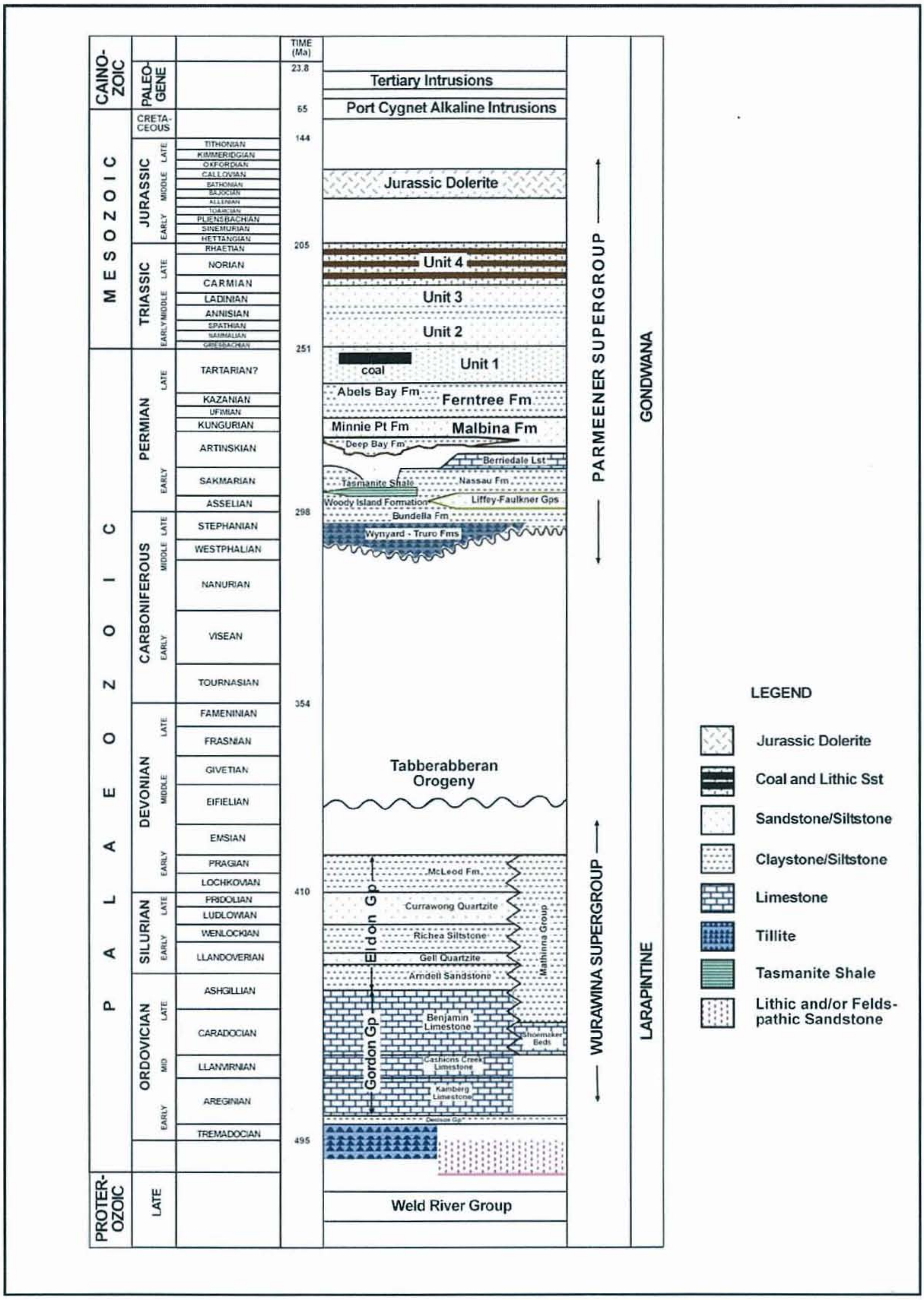

Figure 5 – Stratigraphy detail of the Tasmania Basin (modified from Seymour and Calver 1995b)

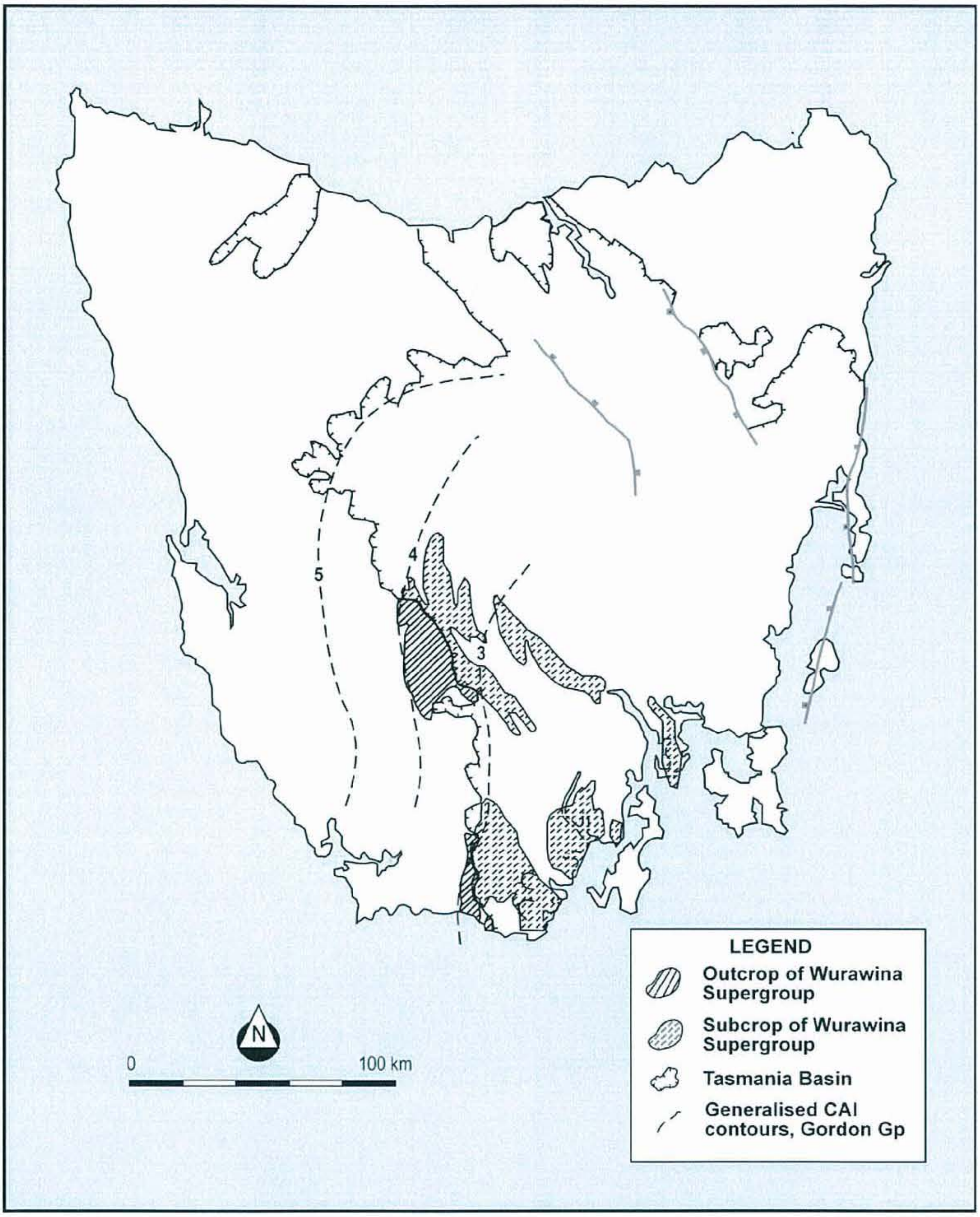

Figure 6 - Generalised CAI contours (modified from Burrett, 1992) with outcrop and inferred subsurface extent of Ordovician - Devonian basement rocks that may be mature for oil and gas generation (Leaman, 1996b)

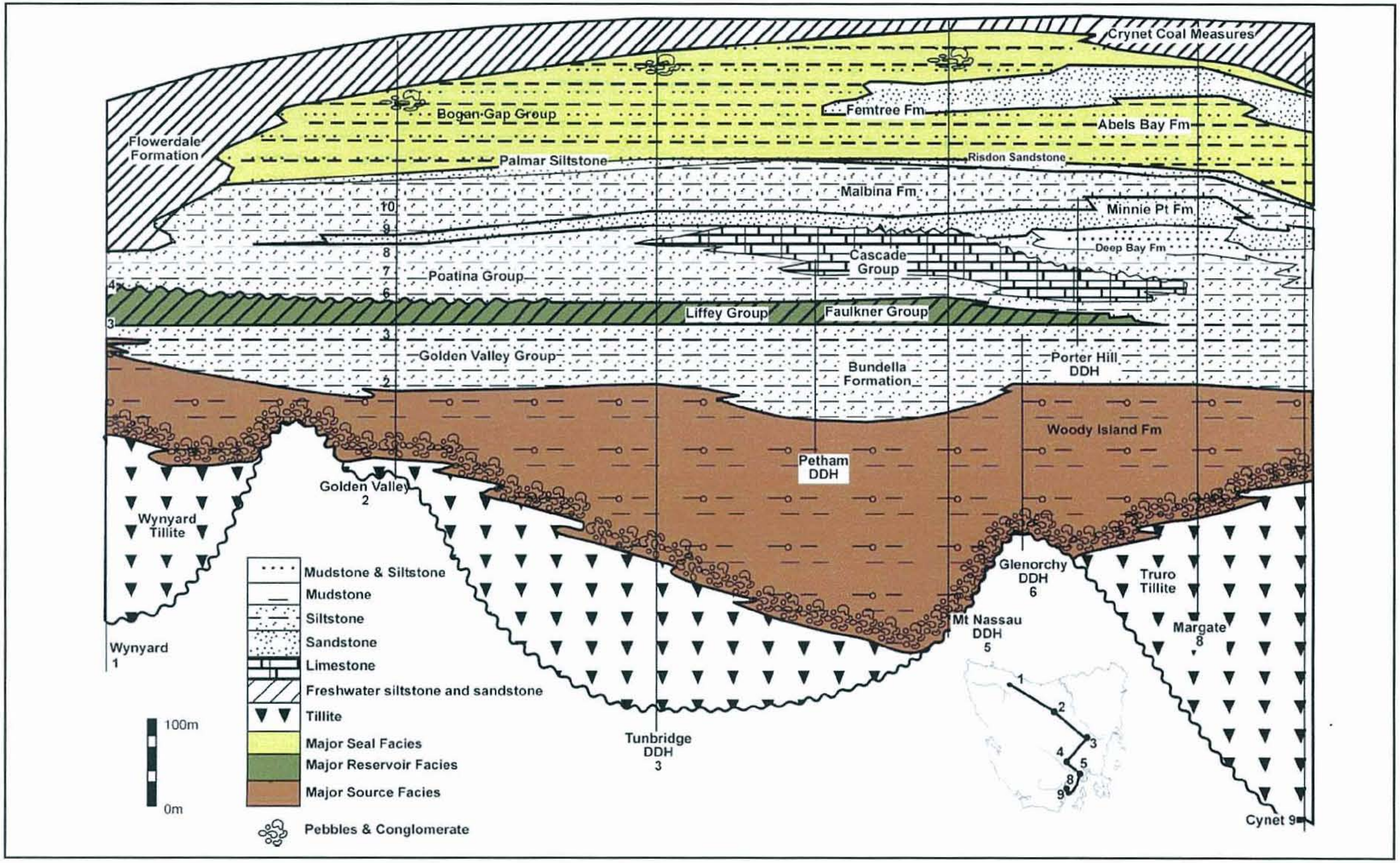

Figure 7 – Time-space diagram of the Lower Parmeener Supergroup (modified from Reid, 2004)

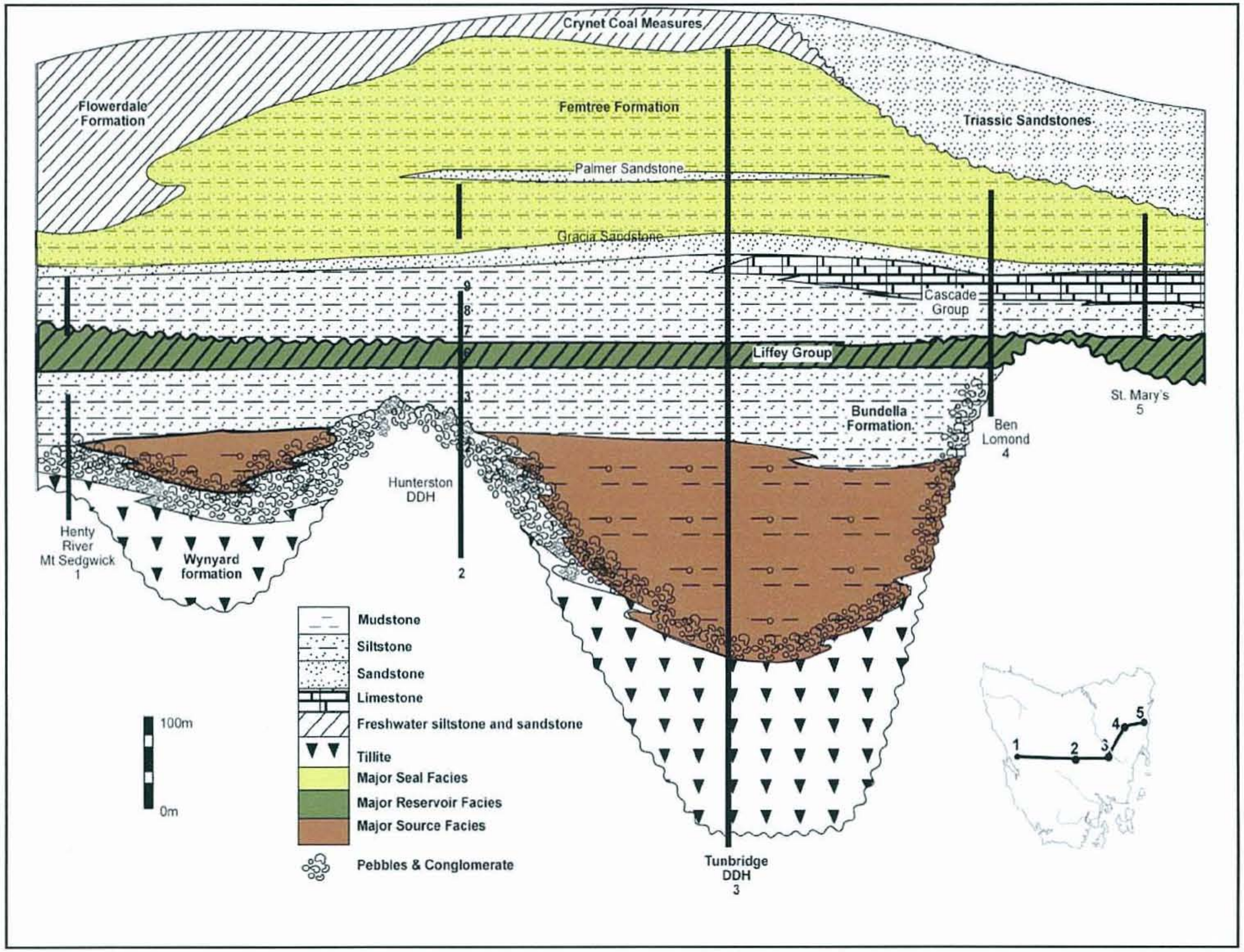

Figure 8 – Time-space diagram of the Lower Parmeener Supergroup (modified from Reid, 2004)

Deposition recommenced in the Carboniferous and the sediments of the Parmeener Supergroup were accumulated (Figure 5, Figure 7 and Figure 8). A flattened stratigraphic section comprising well and outcrop data provides an indication of formation thicknesses and depths (Figure 9).

Carboniferous to Permian tillite deposits occur at the base of the supergroup and are widespread throughout the entire basin (Stockers, Wynyard and Truro Tillites, see Figure 5). These are followed by the Woody Island Formation, a 100 to 200 metre thick dark grey monotonous siltstone. In the base of this formation, beds of the alga *Tasmanites punctatus* occur. The Woody Island Formation and the *Tasmanites* Oil Shale beds are the main potential source rocks and are discussed in Section 3. The distribution of the Woody Island Formation source facies and Tasmanite Oil Shale distribution is shown in Figure 10.

The Woody Island Formation is overlain by the Bundella Formation, a muddy siltstone with little potential as a source rock. These are overlain by the Liffey Group, consisting of well sorted, laminated, fine to medium sands (Reid and Burrett, 2004). The sandstone beds are generally 3-5 metres thick and are interbedded with carbonaceous siltstones.

Permian palaeogeography of the Tasmania Basin is presented in Figure 11, and has been modified from Clarke, (1989). The thickness and distribution of the Liffey Group is shown in Figure 12. The facies become more marine to the south, suggesting regression in that direction. Recent work has identified a zero edge near Cygnet, which was established by Mineral Resources Tasmania (MRT) from outcrop and several stratigraphic diamond core holes.

The Liffey Group is overlain by silt/clay marginal marine to marine formations; the Malbina and Ferntree Formations.

Terrestrial environment of deposition becomes dominant around the end of the Permian. The Lower Parmeneer Supergroup was deposited from the Late Carboniferous to Late Permian. The Upper Parmeener Supergroup was deposited from the Late Permian to Late Triassic, in a non marine environment (Bacon *et al*, 2000). Within the Late Permian to Late Triassic sequence, four stratigraphic units have been defined (Leaman, 1971, and Forsyth, 1989). The following summary is derived from Bacon *et al,* (2000).

Unit 1 is dominantly felspathic and micaceous sandstones. Thin coal is seen in the south on Bruny Island and at Cygnet, and is known as the Cygnet Coal Measures. The entire section is generally 50 metres thick.

Unit 2 is 200 to 300 metres thick and was deposited by a fluvial system which flowed the north-west to the south-east.

Unit 3 is generally 80 metres thick and consists mainly of sandstones with minor conglomerates and rare thin coals.

Unit 4 is mainly lithic sandstone with minor claystone and contains most of Tasmania's economic coal reserves, located mainly in the north-east.

The Upper Parmeener Supergroup (mainly Triassic in age) appears to be a series of fluvial deposition cycles. There is no major marine influence on this group or in the time following, so a widespread regional seal for these sediments seems unlikely.

In the Early Jurassic, 400 to 600 metre thick intrusions of dolerite were emplaced into the existing Permo-Triassic sequences, essentially parallel to bedding. In any given section of the basin, one to three of these bodies may be present. Outcrop observations indicate that each of these bodies is a composite emplacement consisting of several sheets (Burrett, 1992).

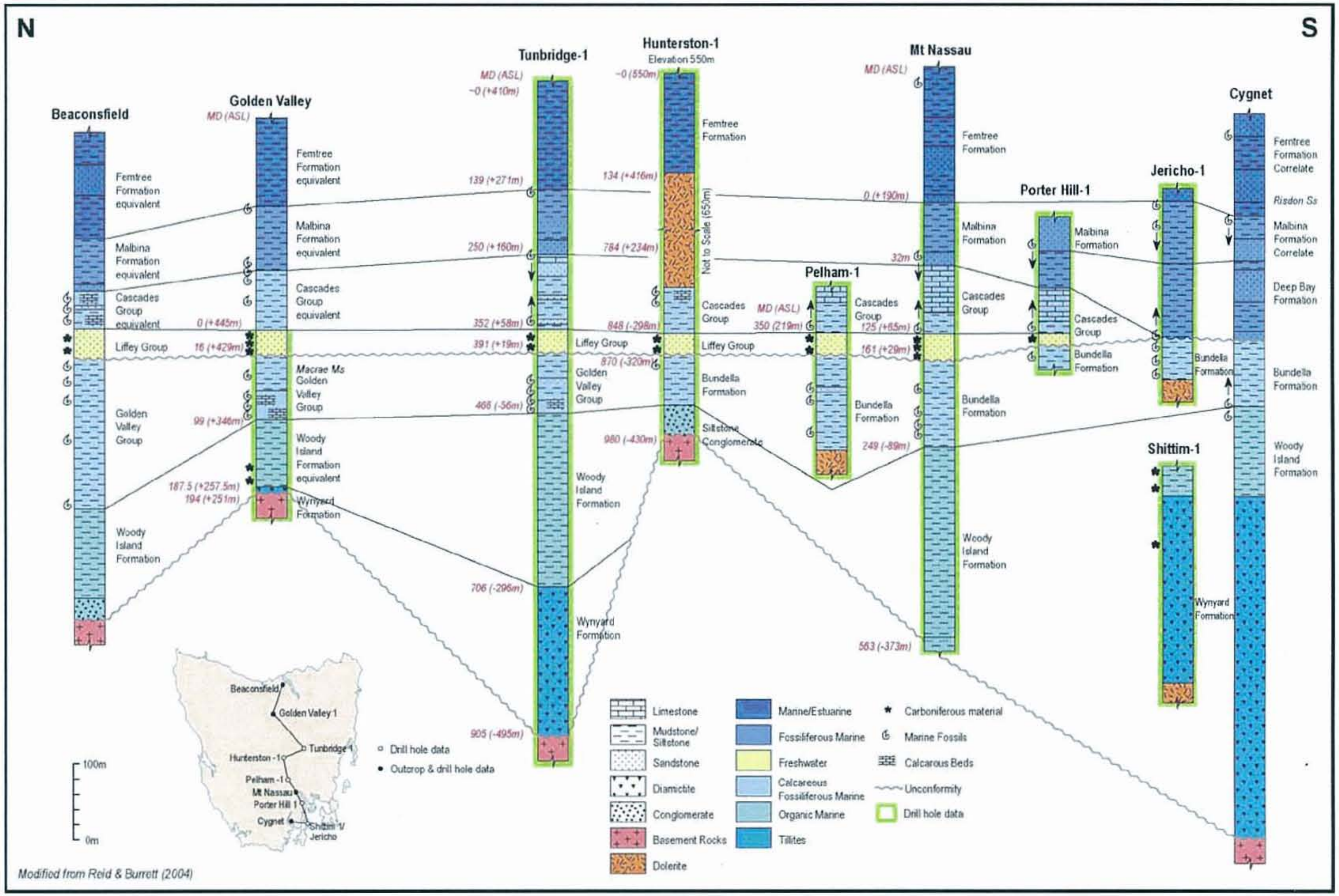

Figure 9 – Stratigraphic cross-section of the Tasmania Basin (modified from Reid and Burrett, 2004)

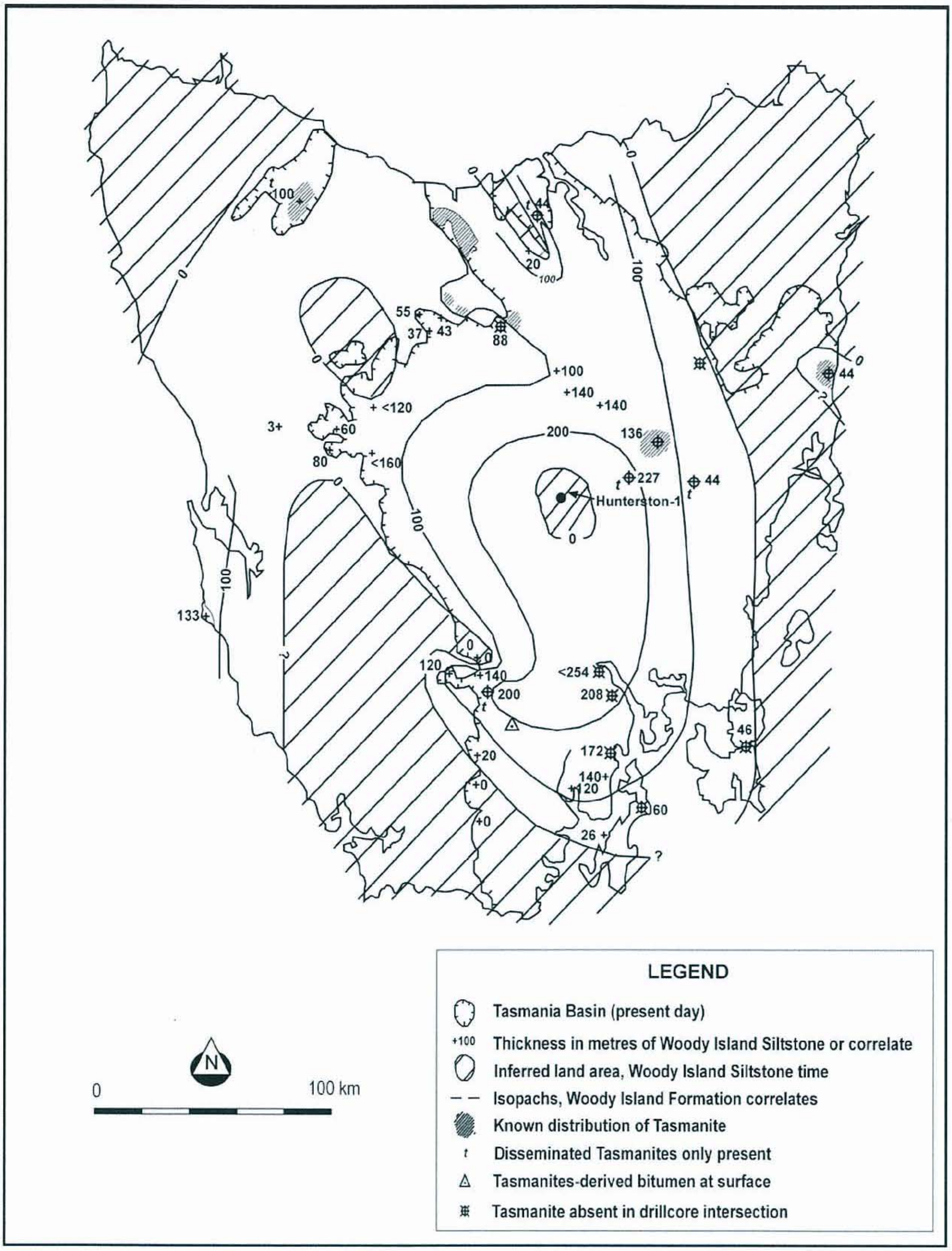

Figure 10 – Known distribution of the Tasmanite Oil Shale with an isopach of the Woody Island Formation (modified from Bacon *et al*, 2000)

The dolerite presents several challenges for petroleum exploration, including the reduction of seismic signal, variations in seismic velocity, hard drilling, localised over-maturation of vitrinite and source rocks, and possibly the reduction of reservoir quality.

At the present day, there are no Cretaceous sedimentary rocks of note in the basin. An apatite fission track study (O'Sullivan and Kohn, 1995) suggests that the basin was uplifted somewhere between 100 and 50 Ma (Late Cretaceous to Early Tertiary), and approximately 3 to 4 kilometres of previously deposited Jurassic to Middle Cretaceous rocks were completely eroded. Bacon *et al* (2000), suggest 2 kilometres of section is more likely, and points out the work of Sutherland (1977) who suggested that zeolites within the Jurassic dolerite indicated a possible burial depth of 2 kilometres.

Bacon *et al* (2000) suggest that the Mesozoic sediments of the Tasmania Basin were once more widespread. The western margin of the basin is defined by Permian formations truncated by outcrop. This erosion and reduction in basin sediments is inferred to have occurred between Late Cretaceous and Middle Tertiary time.

Some minor Tertiary deposition of some hundreds of metres occurred in the Longford Sub-basin. This deposition has negligible impact on the burial history and, therefore, thermal history of the basin. This section will be penetrated during a stratigraphic test of the Bracknell Dome area (see Section 3.6).

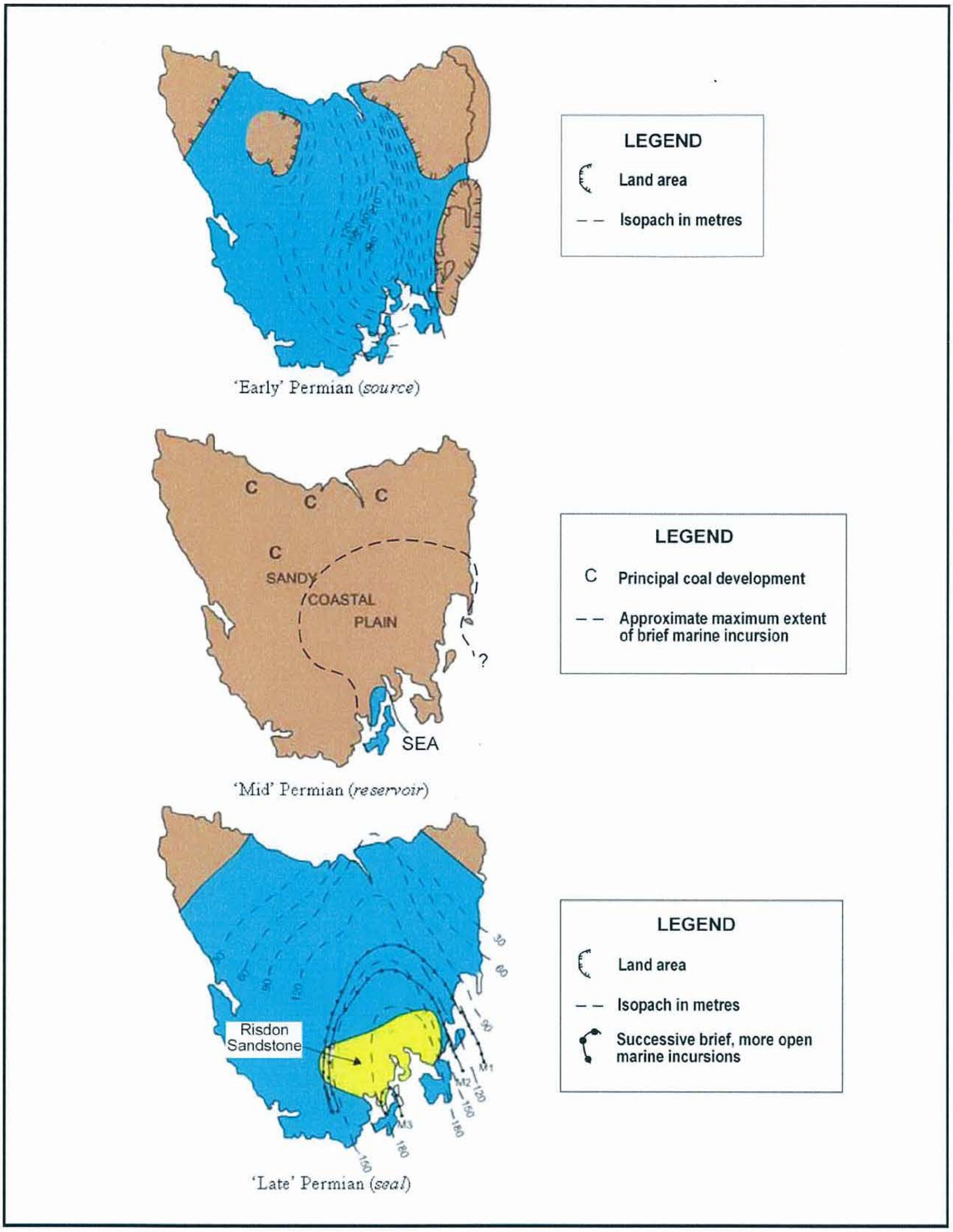

Figure 11 – Permian palaeogeography development of the Tasmania Basin (modified from Clarke, 1989)

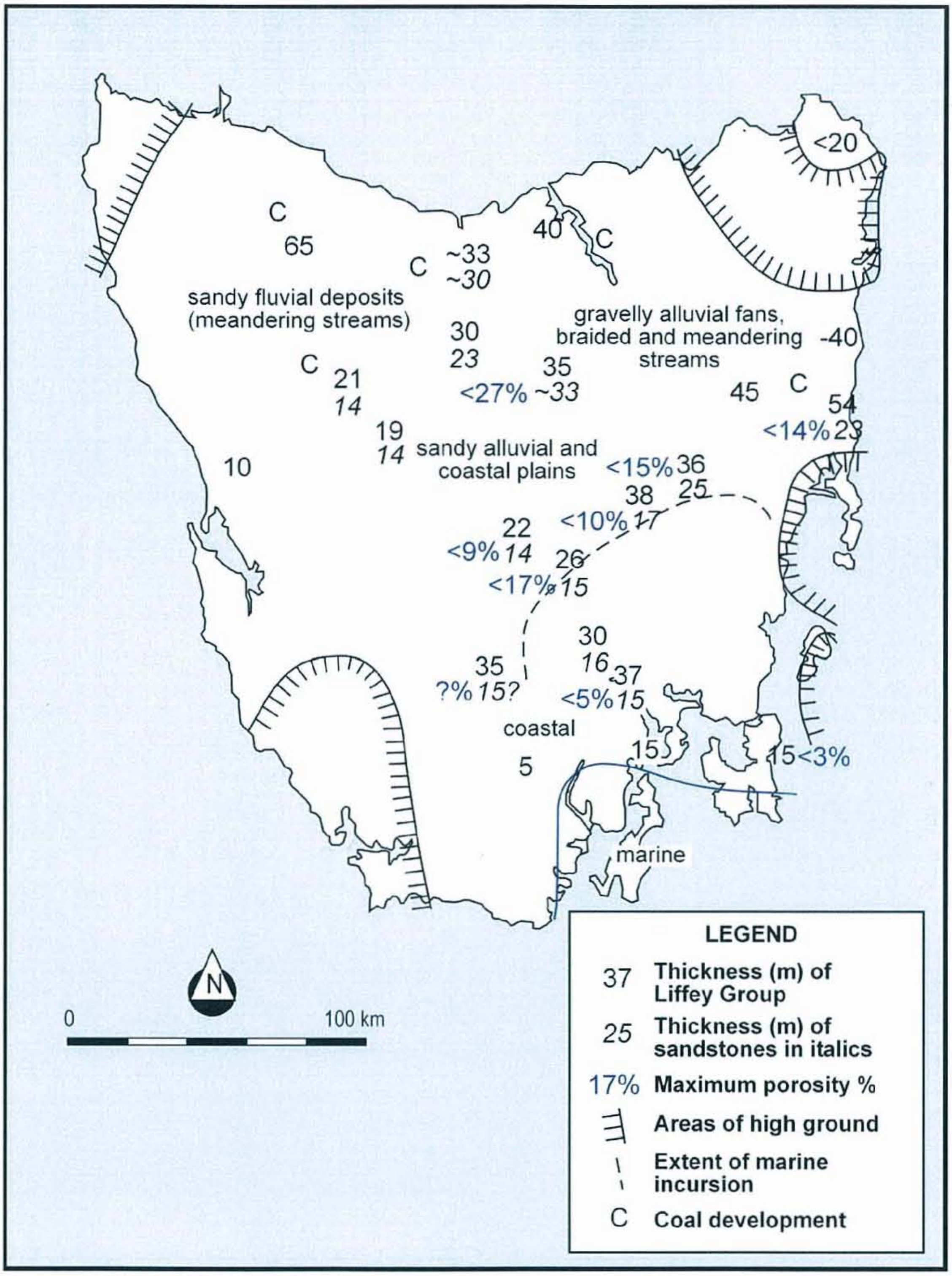

Figure 12 – Thickness and distribution of the Liffey Group. Total thickness of sandstone beds and cycles (black) and some upper porosity values (blue) are also shown (modified from Reid and Burrett, 2004, after Clarke 1989 and Martin and Banks, 1989).

3. PETROLEUM SYSTEM ANALYSIS

To date, there have been no oil or gas fields discovered in the Tasmania Basin although several oil seeps have been reported in Tasmania. Oil seeps can be valuable in signifying the occurrence of mature source rocks in frontier exploration. Currently, the seeps reported in the Tasmania Basin have had limited correlations made to petroleum systems, however, there is a seep in a recently used quarry at Lonnavale, to the southwest of Hobart, that has been correlated with the Permian Tasmanite Oil Shale and is the best indication yet that a significant petroleum system possibly exists in the basin. Two potential petroleum systems could be present, these are the Pre-Carboniferous system (Larapintine) and the Permian System (Gondwana). These two systems are discussed below and schematics are provided in Figure 13 and Figure 14.

3.1 Hydrocarbon Occurrences

Hydrocarbon indications have been reported to the Tasmanian government over the past century. A tabulation of all of these shows and their assessments are provided in Bacon *et al* (2000).

According to Wakefield (2000), over 130 reports of oil and gas seeps have been registered with Mineral Resources Tasmania (MRT). Approximately 10% of these reports have confirmed the presence of naturally occurring hydrocarbons in the form of seeps, tars and bitumens. To date, no bore hole has ever yielded core or cuttings that contained macroscopic hydrocarbon fluorescence although very few wells have been drilled to specifically explore for oil and gas. Of these wells, including those drilled since 1997 by GSLM, none have been drilled on a trap defined by modern seismic.

Mud gas was detected in several of the GSLM wells (Table 1). Most samples were contaminated with significant amounts of air but, after adjusting for this, levels of C6 up to 50 ppm were detected in Shittim-1 and Jericho-1. Isotopic analysis of the gas at Jericho-1 shows it is thermogenic. Results at Shittim-1 range from biogenic to possible mixed biogenic/thermogenic. However, traces of C3-C6 are encouraging and indicate that there are rocks with the capacity to produce wet gas in the basin.

Low yields of hydrocarbon extracted from a Proterozoic core sample from 1,676 metres in Shittim-1 on Bruny Island and a hydrocarbon extract from a Gordon Group limestone from a quarry were compared by Burrett (1997). The Gordon Group traces are similar in the dominance of n-C18 alkane. The pristane to phytane ratios are reported to be approximately 1 in both (Bacon *et al,* 2000). The Shittim-1 sample seems biodegraded or water washed but, surprisingly, the quarry sample does not appear biodegraded. It has been interpreted that this extracted hydrocarbon probably originated in Ordovician rocks down dip.

Oil and bitumen in Permian sandstone outcrops near Zeehan, Tasmania, have been reported by Cook (2003). The author examined samples from these Permian outcrops, one sample of a carbonaceous shale grading to a shaly coal and two sandy samples thought to have contained possible bitumens. The silty sandstone contains prominent oil inclusions within the sand grains and abundant brightly fluorescing oil, presumably being originally part of the same petroleum system as the bitumens (Cook, 2003).

Cook (2003) also observed that the presence of gas bubbles indicates that the oil to gas ratio of the system was originally relatively high. The Permian sandstones' maturation level is best estimated at 0.7% and may be as high as 0.8% (Cook, 2003) which is consistent with the findings from the previous geochemical reports. Another study by Revill *et al*, (1994), which represented the first organic geochemical comparison of thermally mature and immature Tasmanite Oil Shale samples in relation with a geological evaluation of the sedimentary setting, concluded that at least some deposits of the Tasmanite Oil Shale in Tasmania are near the "oil window".

Rare (< 0.1%) microscopic oil inclusions, in fractures in samples from Hunterston-1, were also observed by Cook (2003). These inclusions appear apparently on fractures through cements in the Liffey Group. They could have emplaced at any point post deposition (i.e. post-Permian). No inclusions have been extracted to determine their source (Reid 2004). An occurrence of oil inclusions < 0.1% does not indicate a breached oil column or migration.

This assessment is based on empirical limits developed by CSIRO in their oil inclusion counting studies GOI™ (Eadington *et al*, 1996). The very low occurrence of inclusions (<0.1%) and the proximity to an intrusion suggests localised maturation of a very small amount of organic matter to the point of expulsion. Oil inclusions of <2% were also observed in samples of the Liffey Group from Ross-1 where maturity is VR% 0.57 (Reid, 2004).

Rare oil inclusions were also observed in Liffey Group samples from Douglas River with a mean maturity of VR% 0.55 (range VR% 0.48-0.64) – just barely at the oil window.

3.1.1 The Lonnavale Seep

The hydrocarbon show at the Lonnavale quarry is a bitumen found within Jurassic dolerite joints. The quarry is based on a Jurassic dolerite deposit which has a possible contact with a Permian mudstone, exposed in a nearby older quarry, and is known, in other areas of Tasmania, to contain the Tasmanite Oil Shale (Revill, 1996). Geochemical studies were undertaken at the request of Tasmanian Development and Resources (TDR) in 1996. Two samples of possible hydrocarbons were studied. One sample was a swab of what appeared to be hydrocarbon staining and the second was a bitumen from within a fracture in the dolerite.

Seeps were examined at a quarry in Lonnavale (personal observation by P. Vytopil, 2007). The rock was a fractured dolerite, with one section of the quarry showing good oil shows with strong petroliferous odour along fracture planes. The oil effortlessly smeared when samples were handled and left a dark reddish streak. In areas where samples were not fresh, there was a dark bituminous stain and some samples had a faint odour of H_2S.

The presence of oil shows at Lonnavale has been previously recorded by numerous authors. Bottrill (1996) provides a detailed description of oil shows along two generations of fractures within the dolerite. These factures were filled with calcite and minor globules and flecks of bitumen. The bitumen was dark brown to black, vitreous, soft and sticky on fresh surfaces, as well as hardened and dark on exposed surfaces.

Geochemical analysis indicates that the n-alkane profile from the swab sample is characteristic of a light oil or petroleum fraction such as diesel. The sample was a stain and had a more liquid character than the bitumen sample taken (Revill, 1996). There are maturity differences between the liquid (oil) and solid (bitumen) although hydrocarbons in both samples share a similar source (Revill, 1996).

Conclusions from the geochemical reports indicate that the seep appears to have been subjected to light biodegradation and the samples taken are likely to have undergone some migration since generation from the source rock. Aromatic maturity indicators indicate that the seep was generated and expelled from a moderately mature source interval (Vitrinite Reflectance (VR_{equiv} = 0.80%) and saturated biomarker maturity indicators support this level of maturity (Wythe and Watson, 1996). Revill (1996) classifies maturity of between 0.57–0.62% for the swab sample and 0.61-0.70% for the bitumen sample.

Revill (1996) states that the source is likely to be Permian mudstone containing Tasmanites Oil Shale and Wythe and Watson (1996) indicate that the oil seep is likely to have been derived from a mixed algal/terrestrial source containing abundant Tasmanites Oil Shale alga deposited in an anoxic, marine environment.

The value of VR_{equiv} = 0.80% given by Wythe and Watson (1996) is not anomolous and does fit the regional maturity trend. However, it is still difficult to assess whether this hydrocarbon was expelled as a result of localised heat from dolerite emplacement or of more widespread burial maturation.

The models put forward above by Wythe and Watson (1996) and Revill (1996) that the oil seep, consisting of a migrated, low sulphur oil derived from a moderately mature Tasmanites-rich source rock, was migrated into the late stage dolerite joints when they were open, can be supported by the data.

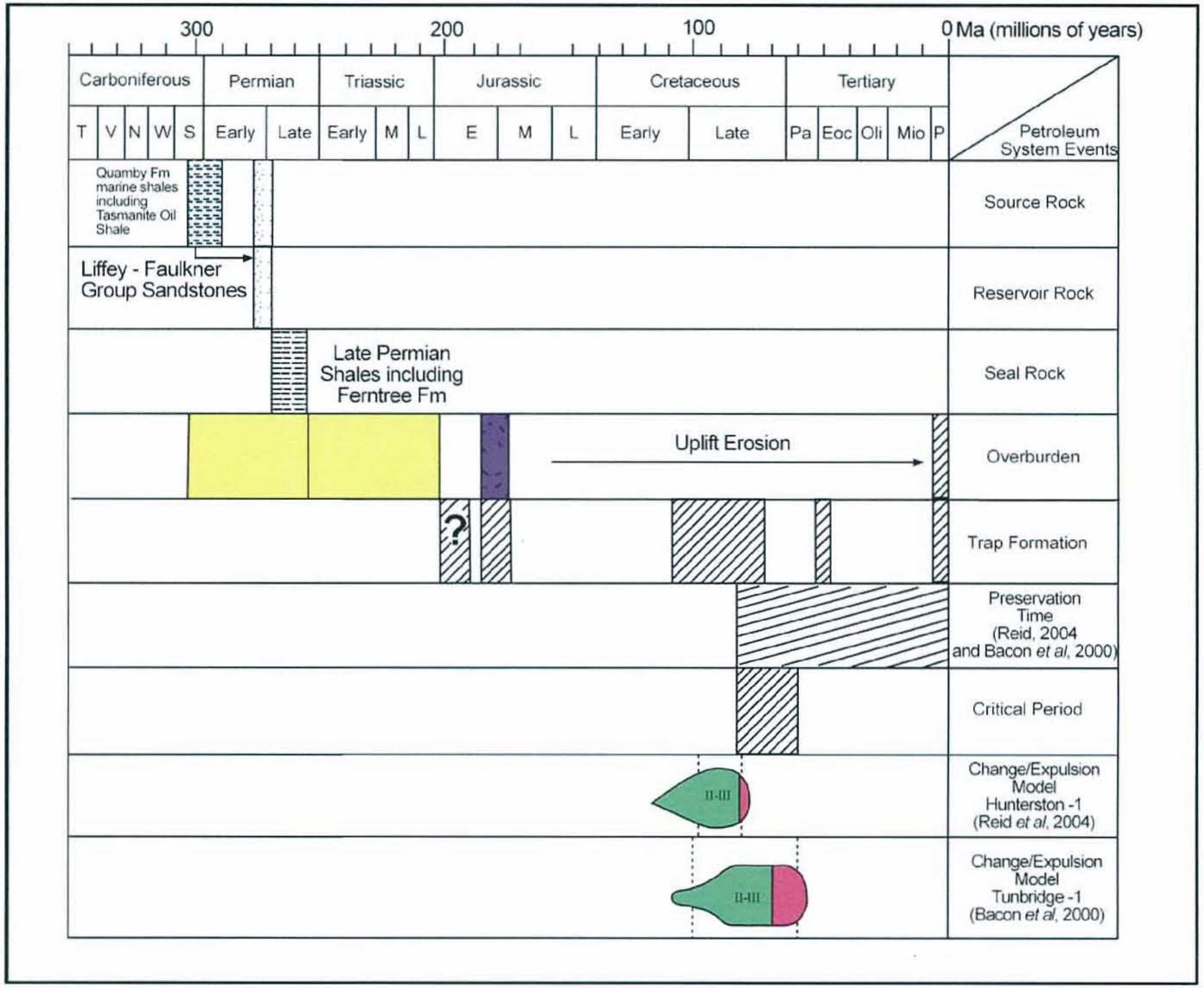

Figure 13 – Hypothetical Pre-Carboniferous Petroleum System (modified from Wakefield, 2000)

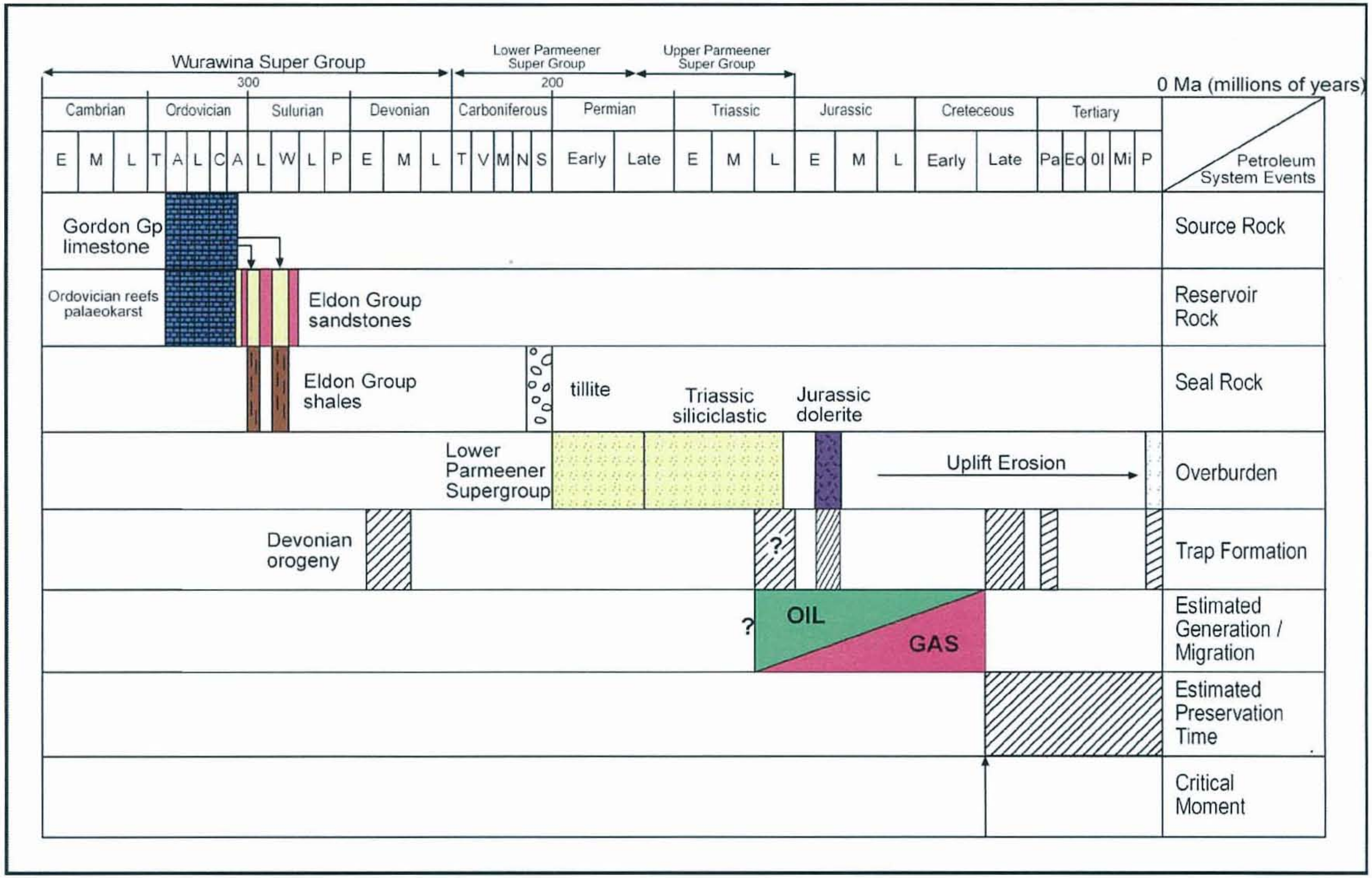

Figure 14 – Hypothetical Permian Petroleum System (modified from Wakefield, 2000)

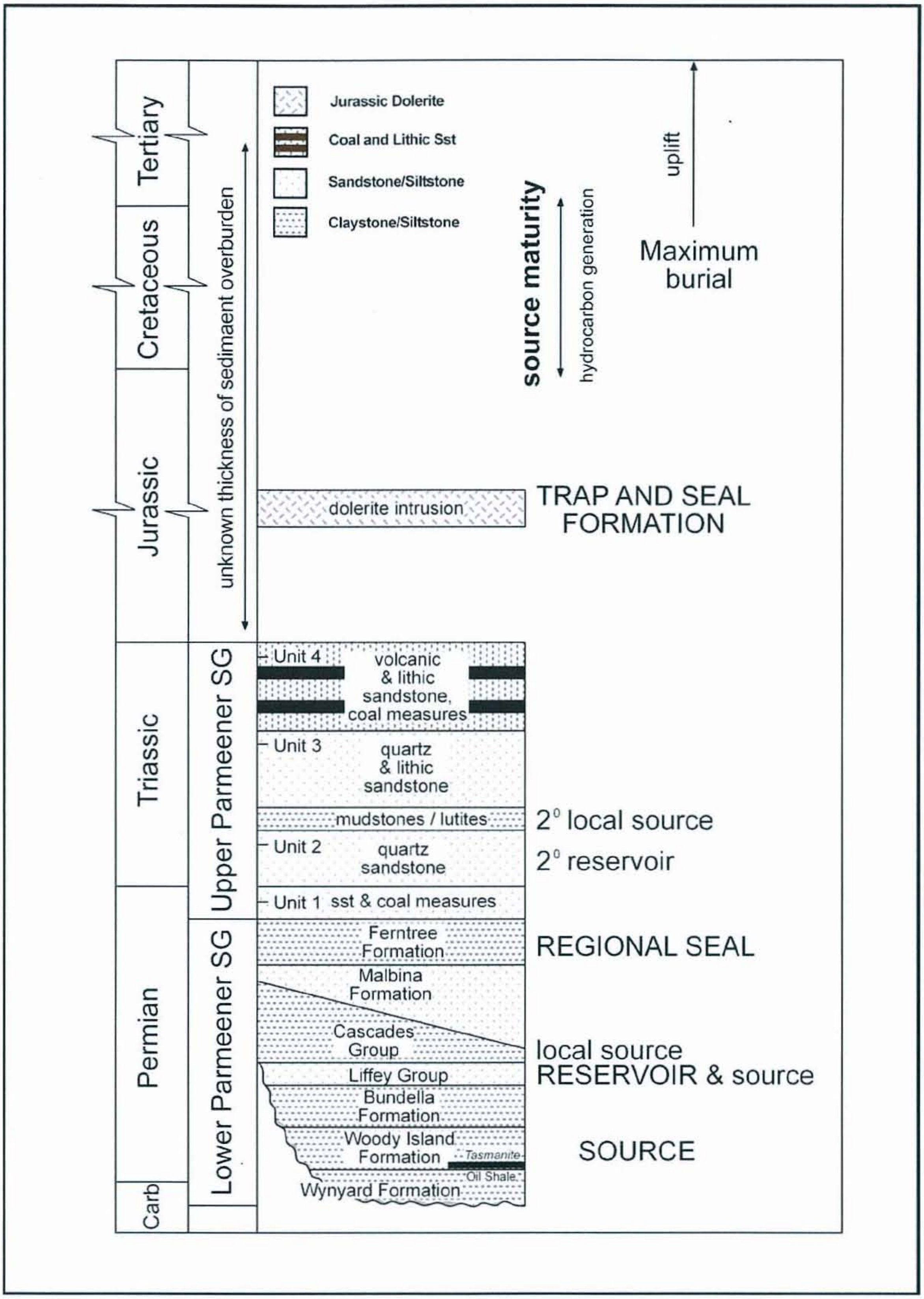

Figure 15 – Stratigraphic model of Permian plays (modified from Reid and Burrett, 2004)

3.2 Source Rocks

3.2.1 Pre-Carboniferous (Larapintine) Source Rocks

The oldest potential source in the Tasmania Basin is Ordovician, however, organic richness data has yet to be adequately verified. Measurements of total organic carbon (TOC) and Rock-Eval (RE) have previously been made on a few samples of limestones within the Gordon Group but these data do not indicate that these limestones have any viable source potential (Reed and Beauchamp, 2001). However, more recent analyses of the shalier Gordon Group facies indicates higher TOC values, some above 1.0%, suggesting the possibility of source rocks in this interval.

Two samples, one from Queenstown and one from Ida Bay (Volkman ,1989; Bendall *et al,* 1991), were analysed and the distribution of n-alkanes was typical of mature hydrocarbon (Bacon *et al*, 2000). Ordovician aged rocks provide a source in other parts of Australia (Amadeus and Canning Basins) and other parts of the world.

Sediments in the Gordon Group are reported to have a petroliferous odour when struck by a hammer, and bituminous films have been seen along stylolites, providing evidence of generation and migration (Chester, 2003). Further occurrences of pyrobitumen have been sighted at road cuttings within and proximal to the limestones east of Queenstown. A sample of upper Gordon Limestone from Florentine Valley liberated gas on crushing.

Black shales of the Benjamin Formation have poor to good source potential. TOC in these rocks ranged from 0.43 to 1.83 (poor to fair), averaging 0.78%, with 80% of the samples below 1%. T_{max} ranged from 439° to 546° and averaged 490°. Most of these samples (66%) were in the oil window and the remainder were in the gas generation window (Chester, 2003).

3.2.2 Permian (Gondwana) Source Rocks

3.2.2.1 Early Permian Tasmanite Oil Shale (Basal Woody Island Formation)

The Permian aged Tasmanite Oil Shale is the most well known source rock in Tasmania. It has been previously documented as having TOC content ranges from good to very good, containing from 2.5% to over 60% (Burrett and Reid, 2004) and a hydrogen index between 700-1000mgHC/gTOC. These high measurements come from thermally immature sediments and represent the hydrocarbon potential of *Tasmanites*-rich source rock within Tasmania.

S_1+S_2 levels are high (from 10 to 900 mg/gm of rock) and although these bands are thin they can produce up to 3.7 bbls/m² (Demaison and Huizinga, 1991).

The distribution of the Tasmanite Oil Shale, as known at present, is shown in Figure 10. It is only known to occur in the north and eastern areas of the basin. The Tasmanite Oil Shale was not present in several wells in the south of the Tasmania Basin. It appears that several parts of the basin were sufficiently low in oxygen for some algal beds to be preserved.

The Tasmanite Oil Shale is a rich concentration of alga type kerogens present in the lower part of the Woody Island Formation. The individual algal bands range from 3 to 30 centimetres thick.

3.2.2.2 Early Permian Woody Island Formation Siltstone

The Woody Island Formation is present over a wide area as shown in Figure 10. Most of the Woody Island Formation is a carboniferous siltstone, deposited in proximity of retreating glaciers and is characterised by glacial peddle dropstones. The formation has poor to fair source potential with TOC values of 0.5 to 2% and contain Type III gas prone kerogens. Most of the siltstones have a low to fair S_1+S_2 (0.2 to 2) (Reid, 2004).

Organic rich shale show a higher TOC of >2 to over 10, with HI correspondingly higher (Reid and Burrett, 2004).

In Bicheno 10, ten source rock quality samples have been tested. Of the ten samples, three rank as good potential (TOC 1-2 %) Type III source rock, one ranks as good potential Type II/III (TOC 1.72%, HI 300) and one ranks as very good potential Type II (TOC 2.42%, HI 433). Another four samples rank as fair (0.5 -1% TOC) Type III. This implies a mixed gas/oil source with a generally higher proportion of gas-prone source.

It is clear that the basin produced marine organic matter and it was preserved in thin highly concentrated beds, eg. Tasmanite Oil Shale beds. The quality of the Woody Island siltstone at Bicheno 10 and other locations suggest that the basin had favorable conditions for the preservation of other organic matter.

T_{max} for the majority of the Woody Island Formation samples analysed varies from approximately 430°, which is below the oil window, and up to 465° and well within the oil window. Similarly, vitrinite reflectance is shown to range from Ro=0.55% (marginal) in the north east at Bicheno, to Ro=0.8% at Lonnavale and Ro=1.3% (gas and condensates) at Styx Valley in the southwest (Reid, 2004).

3.2.2.3 Permian Liffey Group

The Liffey Group is a non marine sequence within the overall marine sequences of the Lower Parmeener Supergroup. It consists of carbonaceous siltstone and sandstones and also included coal horizon in northern Tasmania.

The carbonaceous siltstones have less than 5% TOC, whereas the coal horizons have up to 65% TOC. The majority of the disseminated organic matter contains Type III kerogens. The disseminated carbonaceous material shows a similar characteristic and level of maturity to the underlying Woody Island Formation. However, the calculated yield from this potential source is three times lower at 0.87 bbls/m², primarily due to the thinner interval (Reid and Burrett, 2004).

A study of the Liffey Group samples from Hunterston-1 showed the presence of total organic matter of 0.22 to 2.9%. Some coal is present. The HI (hydrogen index) is < 78 in all cases, indicating that there is gas potential only. As the Liffey Group at Hunterston-1 has been over matured by contact metamorphism and perhaps burial maturation, the full potential of these rocks may not be indicated by these results.

3.2.2.4 Late Permian to Triassic Coal Measures

The Upper Parmeener Subgroup contains up to 600 metres of fluvial sandstone, including significant coal measures. These include the Cygnet Coal Measures in the northeast, and equivalents (Unit 1), and the Late Triassic lithic sandstones and coal measures (Unit 4).

The Cygnet interval comprises carbonaceous sandstones with interbedded cross bedded and ripple laminated channel sands and lie between the underlying Lower Parmeener Supergroup and the overlying massive sandstones of Triassic age. In southern Tasmania, the sandstones are feldspathic and grade into mudstones and thin coal seams. The interval varies in thickness and is restricted in extent, but is reported to be up to 100 metres thick.

The upper most Triassic coal measures are up to 300 metres thick and are dominated by volcanic lithic sandstones, minor claystones and also contain commercial coal reserves in north eastern Tasmania.

The following results are extracts from Bedi (2003). Five samples were taken from drill cores from Unit 4. Three were from the northeast of which one was a carbonaceous sandstone (Dalmayne); two were from 2 metre thick coal seams (Mt. Nicholas and Dalmayne) and two samples were of carbonaceous sandstone and siltstone from the south (Catamaran).

The TOC values are good to high ranging from 1.28 and 3.70 to 27.40 in the clastics and 25 and 63 in the coal seams. HI values are generally very low, below 100, but with one of the samples it is up to 188. This indicates Type III kerogens with a dominance of inertinite, a deficient gas prone marcel.

Vitrinite Reflectance from Catamaran, in the south, are in the wet gas to dry gas window ranging from 1.18% to 1.41%. T_{max} values of 523° and 535° show that these are over-mature for oil generation.

Vitrinite Reflectance from the samples taken in the northeast have Rv_{max} ranging from 0.59 to 0.93 and corresponding T_{max} values from 438° to 491°. The high valves are from one of the coal samples and represent maturity within the transition from the oil to wet gas window.

3.3 Maturity Indicators and Burial History

In summary, understanding the maturity and expulsion timing of the basin is difficult due to the influence of dolerite on vitrinite maturity, the scarcity of easily identified vitrinite, the mixture of maturity indicators and the apparent major uplift and erosion or "unroofing" across the basin.

3.3.1 Permian Maturity Indicators

Bacon *et al*, 2000, observe an obvious bimodal distribution in VR data due to over maturity of many samples due to heat from Jurassic intrusions. Reid (2004) produced a basin-wide maturity map (Figure 16). The main feature of this map is the lower maturity in the north of the basin and the very reliable low maturity in the east at Douglas River. Confidence in the maturity of samples at Hunterson-1 and Styx Valley is qualified due the presence of dolerite at these locations.

3.3.2 Timing of Maturity

Bacon *et al* (2000), following on from the apatite fission track (AFT) work of O'Sullivan and Kohn (1997) and Sutherland (1977), suggest the maximum burial of the basin occurred just before 100 Ma. This puts useful constraints on any attempt to model the burial history and the maturity of the source rocks.

The burial history was modelled at Tunbridge-1 and Douglas River (Bacon *et al*, 2000) and at Hunterston-1 and the Styx Valley (Reid, 2004). In the Tunbridge-1, Hunterston-1 and Styx Valley models, it was suggested that a peak maturity of 1.2 to 1.3 VR% was reached during the second half of the Cretaceous. In all models, a constant 35 degrees C/km has been assumed from the Permian to the present, for useful simplification. Models presented in Reid *et al* (2004) were described by the author as "best case" and were similar to those in Bacon *et al*, (2000) but indicating a charge later in the Cretaceous. The timing of both models is illustrated in Figure 14.

The fundamental feature of these models is the maximum burial in the Cretaceous, which is constrained by the AFT data. This implies expulsion at around the Middle Cretaceous just before the entire basin begins to uplift and perhaps tilt in various directions while expulsion was occurring. This timing implies the risk that hydrocarbons formed before traps or before traps were stabilised. However, the uplift may have been very gentle, preserving the existing traps. The very limited structuring of the Carboniferous to Jurassic seems to give support to this idea. Extension in the Middle Tertiary and compression at the close of the Tertiary presents some trap preservation risk. Long preservation times are of course possible in Palaeozoic basins (eg. Amadeus Basin in Central Australia, Appalachian Basin in the USA).

3.3.3 Pre-Carboniferous

Not all of the Pre-Carboniferous section in southern Tasmania is over matured at the present day (Burrett, 1992) (Figure 6). However, there is still a risk that Pre-Carboniferous rocks were expelled before the stabilisation of traps during the Tabberabberan Orogeny.

No models of this concept have been made because there is not enough constraining data available. However, we can infer from the burial models of Bacon *et al* (2000) in Figure 17 and Reid (2004) that these rocks (lying some kilometres deeper than the Permian) could have re-entered the oil gas window in the Mesozoic to Tertiary. Under this scenario the most likely charge phase would be gas from an already partly depleted hypothetical Ordovician source.

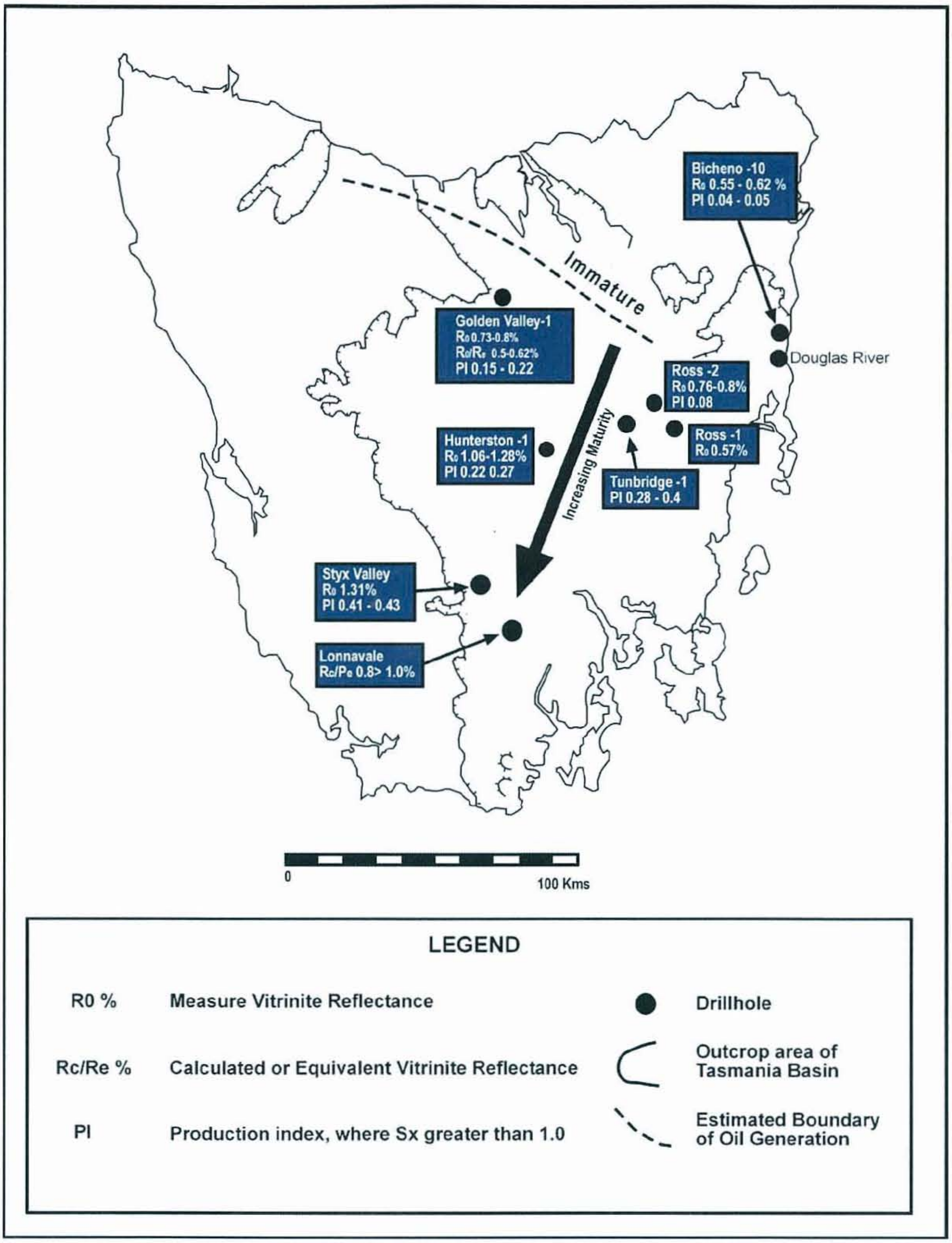

Figure 16 – Maturity of the Lower Parmeener Super Group (modified from Reid, 2004)

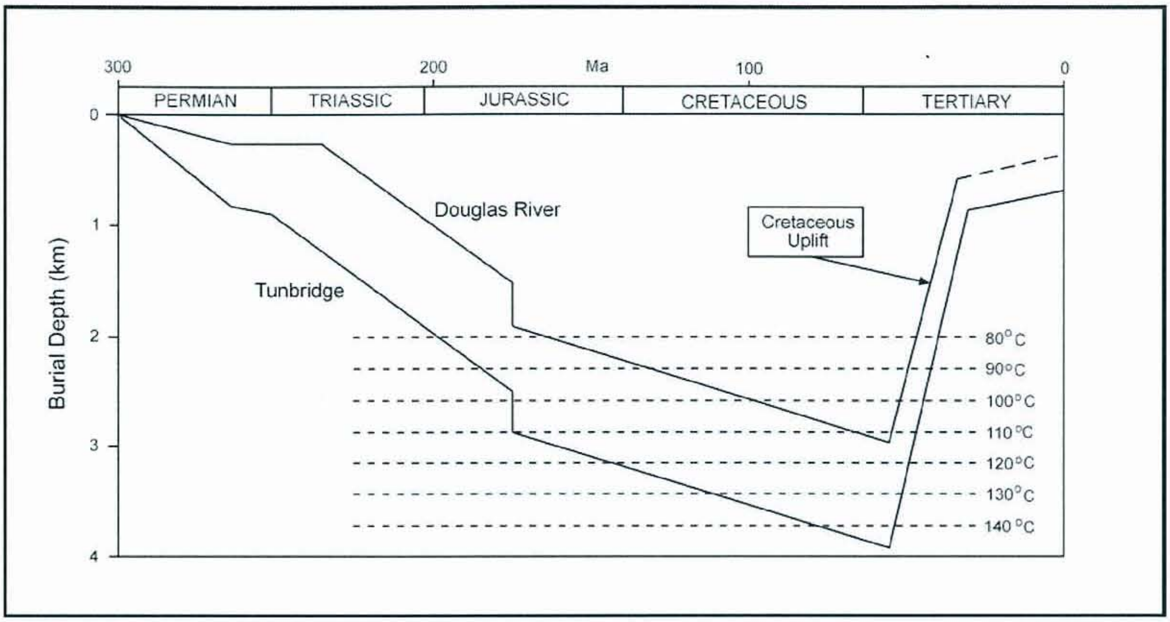

Figure 17 – Burial model modified (from Bacon *et al*, 2000)

3.4 Reservoirs

3.4.1 Pre-Carboniferous (Larapintine) Reservoirs

The primary reservoirs within the Larapintine Petroleum System are carbonates of the Gordon Group. Leached and dolomitized limestones, reefal and fractured reservoirs could be anticipated but not much is known about these sequences. Likewise, the overlying sandstones of lower Eldon Group are potential reservoirs but, to date, no accurately documented information is available.

Palaeokarst features have been reported within Gordon Group at various location including Eugenana, Florentine Valley, Tyerma, Ida Bay, Lake Sydney and Moina. This implies that any Gordon Group limestone sub-aerially exposed before Parmeener Supergroup deposition may also have developed karst features. An Ordovician carbonate reservoir perhaps karstified with cavernous porosity and enhanced with fractures is also a Pre-Carboniferous reservoir possibility. However, palaeokarst has not been intersected by drilling but it is in outcrops. There is no porosity/permeability data on such a rock in the Tasmania Basin. The notion of a karst reservoir preserved "at depth" is speculative at this stage. However, GSLM is proposing to drill one or two stratigraphic wells in 2007 which could greatly improve knowledge of the Pre-Carboniferous. This is discussed in Section 3.4.

The Arndell Sandstone conformably overlies the Gordon Group limestone, in the Tiger Range area. The sandstone sequence is approximately 250 metres thick, but is a very fine-grained sandstone with a poor porosity of only 5%.

The expected depths of burial and temperatures in the Pre-Carboniferous section would severely reduce porosity and permeability in any siliciclastic reservoir (eg. Eldon Group). Given the deformation of the section during the Devonian, it is reasonable to postulate that fractures are present and could enhance reservoir quality and aid hydrocarbon recovery. Recovery from such a reservoir, typically, will not exceed 25%. Gas recovery would be much higher. To date, there is no core or log from these intervals "at depth" to support these ideas.

3.4.2 Permian to Triassic (Gondwana) Reservoirs

3.4.2.1 Lower Parmeener Supergroup "Freshwater Facies"

Within the Lower Parmeneer Supergroup, there are a number of sandstone intervals with good reservoir characteristics. These sandstones are considered to be extensive and porosities vary, but range to over 20%.

The potential reservoirs in the Lower Parmeneer Supergroup are summarised in Table 6.

	Formation	Porosity (%)	Thickness (m)	Environment
Lower Parmeener Supergroup	Risdon Sandstone	13.7- 14.7 2.1	4 - 8	barrier complex shallow. marine shelf
	Minnie Point Formation	14.1- 16.6	?	shallow marine shelf
	Rayner Sandstone	3.97	?	? basal conglomerate
	Liffey / Faulkner Group	12.8	?	coastal channel
	Bundella Formation	7.4- 22.3	?	shallow, marine shelf

Table 6 - Porosity of sandstone units within the Lower Parmeener Supergroup (modified from Woods, 1995)

The Risdon Sandstone is prevalent throughout the study area, with a thickness of usually 4 metres to 8 metres. The Rayner Sandstone and Malbina Formation samples exhibit a relatively immature mineralogy compared to the more porous samples. The Rayner Sandstone is highly bioturbated and poorly sorted in comparison to the very well sorted, channel facies of the Faulkner Group.

The Minnie Point and Malbina Formations are also extensive throughout the south east of the study area, but become much thinner further to the south. Well to moderately sorted sandstone units occur at the base and top of the formation. Porosity varies markedly between sandstone units, which are up to several metres in thickness.

The Permian Liffey/Faulkner Group reservoirs are widespread. The depositional environment of the Liffey/Faulkner Group (Maynard, 1996) includes glacial, fluvial, coastal and marine depositional environments. The section is about 30 metres thick within the basin. In southern Tasmania around Granton, it exceeds 40 metres. In central Tasmania, it is divided into 7 units of an average thickness of 20-35 metres, with varying reservoir porosity (Table 7). Continuity is undetermined and the reservoir potential is poorer for the deeper parts of the basin.

The mature mineralogy of the high energy channel sand facies occurs with coastal plain facies and consists primarily of very well sorted, fine to medium-grained sandstone. Good primary porosity and permeability may be expected. Reid and Burrett (2004) report that porosity for the Liffey Group ranges up to 27%. The sandstones are often laterally extensive point bars within a braided stream environment. These facies often grade or pinch-out into well consolidated siltstone and shale, thus providing stratigraphic traps for the accumulation of hydrocarbons (North, 1985).

The available permeability data (Reid, 2004), suggests Permian formations are very marginal as oil reservoirs. In several wells, namely Hunterston-1 and Shittim-1 this may be attributed (in some part) to the influence of intrusions. Petrography at Hunterston-1 indicates the presence of silica overgrowth and secondary carbonate cement. Wells without obvious influence from intrusions on reservoir quality are Ross-1 and Tunbridge-1 (Reid, 2004, and Maynard, 1996). These wells do not show very high permeability either. It is very likely that the reservoir is generally poor to fair quality and the presence of dolerite can reduce it even further. The best permeability by far, of 166 mD, is from the far eastern side of the onshore basin at shallow depth in the Douglas River area. The next highest permeability is 8.8 mD at Ross-1. This suggests that low permeability (1 to 10 mD) is quite likely. Data from Hunterston-1 suggests the presence of intrusions can take permeability below 1 mD. The Permian sequence does not represent a very effective oil reservoir.

This poor reservoir quality is consistent with the explanation for the AFT measurements that suggest kilometres of overburden were eroded between 100 and 50 Ma. The models of Reid (2004) and Bacon *et al* (2000) suggest the Permian reservoirs are buried to a depth of 4,000 plus kilometres and exposed to temperatures over 100 degrees C for almost 100 Ma. Silica overgrowth occurs at temperatures over 100 degrees C. This aside, there is the risk of direct and/or indirect reduction of reservoir quality by intrusions. There may be a higher risk in areas where carbonate is present in the Ordovician as a thin section examination of the Liffey Group from Hunterston-1 indicated carbonate cements. The source of this carbonate is thought to be the carbonates intersected in the Precambrian section of the well.

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7
Lithology	white-grey sandstone	interbedded white-grey sandstone, dark grey mudstone	white-grey sandstone	heavily bioturbated sandstone to mudstone	white-grey sandstone	interbedded white-grey sandstone, and dk grey mudstone	heavily bioturbated sandstone
Composition	qtz (75%), feldspar, mica, clay		qtz (>75%), feldspar mica, clay	qtz (70%), feldspar mica, clay	qtz (>70%), feldspar mica, clay		qtz (70%), feldspar mica, clay
Grain Size	medium to very fine	medium to silt	fine to very fine	medium to very fine	coarse to very fine	medium to silt	medium to very fine
Grain Morphology	sub-angular to sub-rounded		sub-angular to sub-rounded	sub-angular to sub-rounded	sub-angular to sub-rounded		sub-angular to sub-rounded
Sorting	well sorted		well sorted	Mod- poorly sorted	well sorted		Mod.-poorly sorted
Framework	close packed		close packed	relatively open	close packed		relatively open
Cement	minor silica		minor silica	minor silica (mainly clay matrix)	minor silica & some carbonate		minor silica (mainly clay 1 matrix)
Porosity	**10 -15%** (1-5% at Poatina)	variable	2 -5% at Poatina, up to 25% at Ross	**9 -27%**	**10 -25%**	variable	5-7%
Thickness	10m (Golden V.) to 1m	1 to 11m	5 to11 m	3 to9m	ave 11 m	I to 3m	3 to >7m

Table 7 - Summary of the characteristics of units in the Liffey/Faulker Group reservoirs (modified from Maynard, 1996)

In central Tasmania, the Liffey/Faulkner Group was intersected in several drill holes around central Tasmania near the axis of Tiers Fault including Golden Valley, Great Lake Tail Race Tunnel, Great Lake Penstock at Poatina, Ross, Tunbridge Tier and Bothwell.

Fissile and non-fissile siltstones comprise the Bundella Formation. These have a consistent thicknesses and the sandstones exhibit fair to good porosity. The Bundella Formation was deposited on a shallow, low energy marine shelf.

3.4.2.2 Upper Parmeener Supergroup "Fluvial Sequences"

The Upper Parmeener Supergroup contains up to 600 metres of terrestrial fluvial sandstones. Substantial coal measures occur within Upper Triassic sandstones in the northeast of the basin and the Cygnet Coal Measure of late Permian age.

The Upper Parmeener Supergroup has been divided into four potential reservoir units. The Upper Permian carbonaceous sandstone, Unit 1 (equivalent to Cygnet Coal Measures), is up to 50 metres thick and has poor to moderate porosity (10%) (Bedi, 2003).

The Triassic quartzose sandstone, Unit 2, has the best potential reservoir. It is up to 250 metres thick and has excellent porosity (23%) but only fair permeability (9.8 mD). These quartzose sandstones are characterized by authigenic quartz overgrowths with reduced porosity and lowered permeabilities. The sandstones were deposited in a braid plain environment resulting in thickly bedded clean sandstones, largely free of heterogeneities (Bedi, 2003).

The volcanic lithic sandstones with coal measures, Units 3 and 4 have poor porosity and permeability (0.08mD). Sandstones in these units are characterized by mechanical compaction and alteration of lithic grains to clay matrix. The volcanic lithic sandstones were deposited in a meandering fluvial environment resulting in abundant lutite intervals, which may act as seals (Bedi, 2003).

3.5 Seals

3.5.1 Jurassic

By the early Jurassic the Parmeener Supergroup formed in a shallow syncline, plunging towards the south-southeast, with possibly some gentle folding in an otherwise sub-horizontal succession (Hergt *et al*,. 1989). Large volumes of tholeiitic dolerite intruded as sills into the Tasmanian crust during the Middle Jurassic.

The dolerite is exposed over an area of 30,000 square kilometres and has an estimated average thickness of 500 metres (Hergt *et al,* 1989). Most dolerite intrusions have the form of a flattened cone connected to a source or sources at the deepest point, the limbs are concordant or approximately concordant with abrupt transgressions when rising to higher levels (Leaman, 1976). The metamorphic effects resulting from dolerite intrusion are usually confined to within a few metres of the intrusion margin, the effect being more severe at the roof of the intrusions.

In the Hobart area, two or three dolerite sheets are commonly present. These sheets are either less than 1 metre, or 300 to 400 metres thick. The thicker sheets in middle or lower Permian rocks are typically 30 square kilometres in area, while in Triassic rocks, they are more extensive (Leaman, 1975). In contrast, only a single sill, intruding the Upper Parmeener Supergroup, has been recognized in the northern part of the basin (Central Plateau, Ben Lomond and the Fingal Tier, Figure 6) (Bacon *et al*, 2000). A single, 650 metre thick dolerite sheet was intersected near the Upper-Lower Parmeener Supergroup boundary in Hunterston-1 (Reid *et al*, 2003). From the interpreted seismic this sheet appears to cover many hundreds of square kilometres.

There is limited well data, fault and fracture information at depth to ascertain whether the dolerite can be classed as a regional seal. At depth, in areas away from major faults where significant fractures are not expected and the dolerite is tight, it would be a considered to be a reasonable seal. Jurassic dolerite intrusive sheets can also be classed as effective seals based on their very high velocities of approximately 6500 m/s.

3.5.2 Permian

There is no quantitative seal data, such as Mercury Capillary Injection Pressure (MCIP), for any formation. Bacon *et al* (2000) observed that "muddy lithologies" dominate the Lower Parmeener Group. The Liffey Group is generally described as a non-marine sand in a dominantly muddy marine section. This implies a basin-wide low stand event. In a study of Liffey Group cores, Maynard (1996) interprets inter-bedded sandstone and silt/mudstone.

Intra-formational seals are likely to be present. Like any intra-formational seal in a fluvial section, it is moderately high-risk due to limited lateral extent. The Malbina and Cascades Group Formations are also marine mudstone formations (Figure 5 and Figure 15). Potential seal units occur above the Liffey Group sandstones as siltstone in the lower part of the Cascades Group as 1-5 centimetre thick volcanic ash layers within this group (Burrett and Reid, 2004).

These Permian formations are not homogeneous and there is the possibility they are waste zones (non-commercial, extremely low permeability reservoirs). The potential for waste zones could not be assessed from the current data available. The Ferntree Formation is the result of widespread marine conditions that mark the top of the Lower Parmeener Group. It is not composed of a highly plastic clay but it seems to be a reasonable candidate for a regional seal. Unfortunately, it does not directly overlie the targeted Liffey Group (Figure 15).

3.5.3 Pre-Carboniferous

Currently, there is no quantitative data on seal quality. In deformed Palaeozoic rocks such as these, it is expected that permeability will be quite low in general.

Effective fine-grained seal lithologies are possible in the marine Gordon Group limestones. As discussed previously, some form of intra-formational seal would need to be invoked in the Tiger Range Group for the Eldon Formation.

Early Permian Tillites were widely deposited on the Devonian unconformity of the Tabberabberan Orogeny. If a Mesozoic to Tertiary charge from hypothetical Ordovician sources is supposed, the Stockers Tillite could provide a seal to sub unconformity traps.

3.6 Play Types

Due to the very early stage in exploration, to date, no wells have been drilled to test structural closures in the Tasmania Basin. The limited seismic data, of poor to fair quality, does not allow structural traps to be accurately defined within the Lower Parmeener Supergroup. The seismic survey, acquired in 2001, would need to be extended by further seismic surveys and drilling programs to identify more potential traps.

As discussed in Section 2.2, the seismic exploration progress report provided to RPS by GSLM in June, 2007, states that the 2001, 2006 and 2007 seismic program identified and clarified several major and additionally, many minor structures. To date, interpretation of the acquired seismic data has identified several fault block traps and small anticlines with shallow targets in the Gondwana Petroleum System. Deeper targets have been identified by GSLM in the Larapintine Petroleum System, mainly Ordovician in the Central Highlands. Further seismic work is planned by GSLM for November, 2007, to February, 2008. An extensive drilling program is also planned by GSLM for 2007.

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 (Reid and Burrett, 2004). Mid Cretaceous to Early Tertiary faulting was dominantly extensional (Stacey and Berry, 2004) and may have compromised traps formed in the

Jurassic, prior to maximum burial and maturation of the Lower Parmeener Supergroup in the Cretaceous.

Two main plays have been identified in the Tasmania Basin. These are the Permian and the Pre–Carboniferous. The Pre-Carboniferous play is an immature concept. There are few boreholes that have intersected more than a few hundred metres past the Devonian Unconformity. The seismic resolution is very poor at this level. Reservoirs rely on fracture porosity to be present to enhance either the Eldon Group sandstone or karstified Ordovician limestones.

The potential source rocks would be Ordovician algal-rich sediments, capable of producing oil and gas. GSLM have proposed a 1,965 metre stratigraphic well (Gezer-1) for 2007 in the Bellevue area (Figure 18) which would certainly increase the understanding of reservoirs, seal, source rock potential and maturity of the Pre-Carboniferous section. A stratigraphic well (to be named) is also proposed in the Thunderbolt area (Figure 18), sited on topographic indications of a possible Pre-Carboniferous structured basement. Understanding of the Pre-Carboniferous play elements in the Longford Sub-basin will be enhanced by the planned Lachish-1 and Hebron-1 stratigraphic wells (Figure 18).

The play elements of the Permian play are better defined. The section seems to be quite unstructured in a regional sense and bedding has quite low dips. This lack of structure supports the idea that the regional Cretaceous uplift was gentle, thus preserving any hydrocarbon accumulations existing at the time. However, the basin is quite flat-lying, so identifying the location of a high confidence closure on the existing sparse 2D seismic data in the Carboniferous to Jurassic section is quite difficult.

Normal faults are more prominent in the Longford Sub-basin. These could represent Tertiary extension which post dates the expected Mid Cretaceous charge event. Regardless of this issue, the visible faults run right to the surface, indicating recent movement, and suggesting that the fault dependent closures have a risk of being breached. Some of these normal faults appear to have undergone reverse re-activation supporting the Late Tertiary compressional event suggested by Stacey and Berry (2004). If fault independent closure can be located on some large fault blocks, these could form exploration targets. However, the timing of trap formation and possible hydrocarbon expulsion would still be an issue.

GSLM are proposing a stratigraphic borehole (Eglon-1) on a small anticlinal feature called the Bracknell Dome probably formed by the draping of Tertiary sediments over earlier rocks enhanced by the late Tertiary compressional event.

The Bracknell Dome and other features of interest are displayed in Figure 18. Dolerite may lie at 600 metres, however, the proposed Eglon-1 well is intended to test this interpretation. Seal and charge are extremely risky in this area and the well is considered to be stratigraphic.

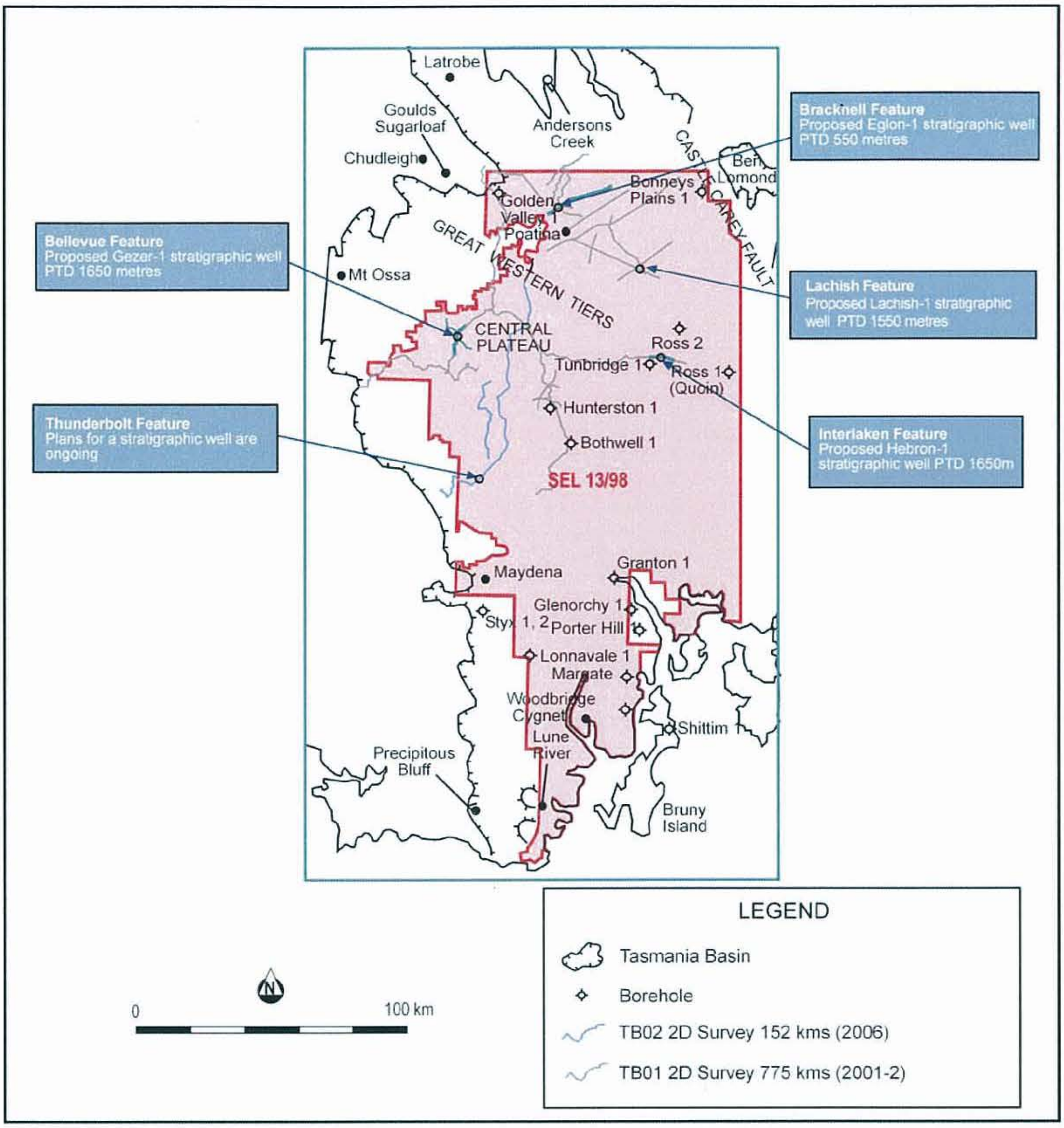

Figure 18 – Locations of features of interest

The Bracknell Dome feature has also been identified on a gravity map of the Longford Sub-basin (Figure 19).

Figure 20 shows a location map of the Longford Sub-basin, highlighting seismic lines TB-01-SA and TB01-PM. Figure 21 shows seismic line TB01-SA and the location of the Bracknell Dome, which is also the general location of the proposed Eglon-1 stratigraphic well. Figure 27 shows seismic line TB01-PM with structural and stratigraphic interpretations. Figure 23 shows a TWT contour map of a package interpreted on the TB01-SA and TB01-PM seismic lines.

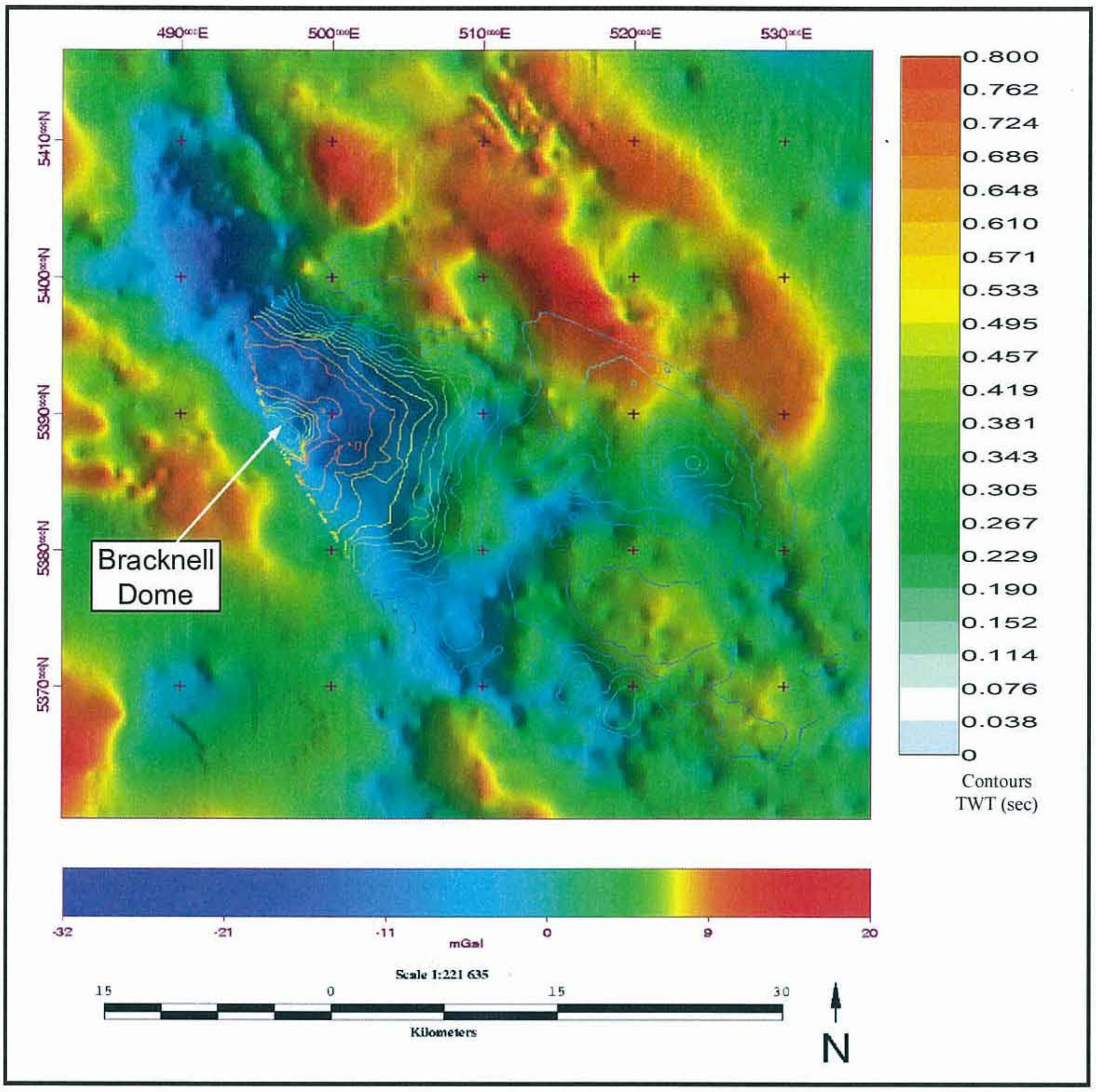

Figure 19 – Gravity map of the Longford Sub-basin highlighting the Bracknell Dome feature (modified after Heath, 2004)

Another stratigraphic test is planned in the Longford Sub-basin at Lachish-1 which will investigate expected Permian stratigraphy below a poorly-defined, possibly domal dolerite feature. This well has a planned TD of 1,550 metres which, it is hoped, will take the well into the Pre-Carboniferous. The dolerite sheets may have formed structural highs after erosion. This play concept has several risks. On the Hunterston-1 mud log, the background gas in the dolerite seems similar to the sedimentary sections. Natural fractures in dolerite are described on the Hunterston-1 mud log. Regardless of this issue, Hunterston-1 shows that proximity to a dolerite body may reduce reservoir quality to <1 mD. Hunterston-1 was not drilled at the crest of the so-called Hunterston Dome and so the well is a stratigraphic test.

A potential Triassic play has been proposed by Reid (2004) (Figure 15). There is no porosity, permeability or seal integrity data published. Coals are proposed as the source. There is minor coal stratigraphically low in the Upper Parmeener Group (Cygnet and Adventure Bay Coal Measures) occurring in the south-eastern, western and northern edges of the basin (Anon, 2005). The Coal Measures generally contain two seals less than 1 metre thick, with ash contents of 25 to 30% (Anon, 2005). The invoking of a wide spread "lutite" seal in the Mid Upper Parmeener (Figure 14) seems to be difficult to justify in a supergroup which consists of four cycles of fluvial to minor swamp deposition.

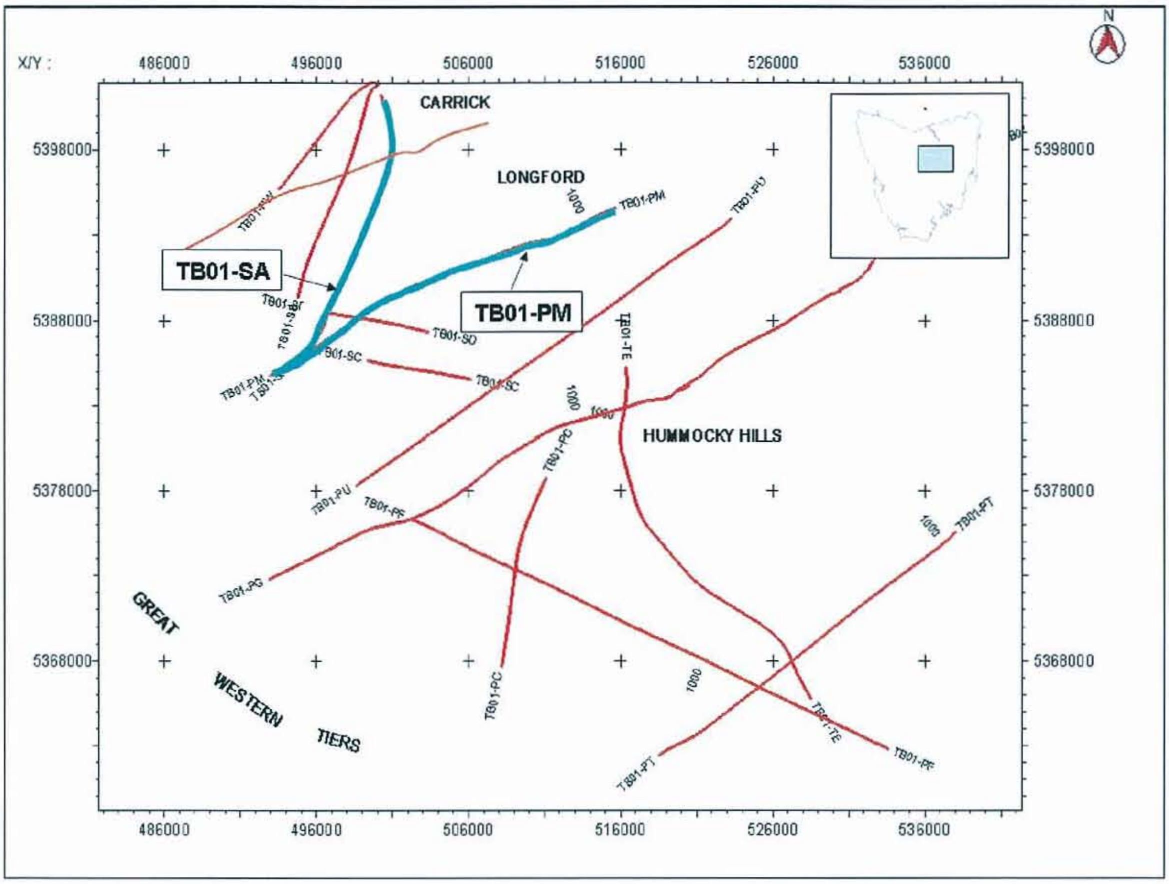

Figure 20 - Longford Sub-basin location map highlighting seismic lines TB01-SA and TB-01 PM (modified after Heath, 2004)

The best developed coal by far is at the top of the Triassic (Anon, 2005 and Bacon *et al*, 2000), making charge and seal problematic (Figure 14). As noted earlier, if the Ferntree Formation is an effective regional seal then Permian charge will not reach the Triassic. A Triassic play would rely on fluvial intra-formational seals with their intrinsic risk.

3.6.1 Stratigraphic Plays

Stratigraphic plays and traps are a theoretical possibility at any level but pursuit of them is impractical, given the limited 2D seismic coverage and variable seismic image quality.

Larger scale stratigraphic plays/traps (i.e. zero edge traps) are limited. The southern zero edge of the Liffey/Faulkner Group has been defined by MRT to be in the Cygnet area. It appears that no indications of hydrocarbons were located in any of the several bore holes drilled. The zero edge of the Liffey Group is eroded in the west and probably in the east. The proximal portion of the Liffey Group in the north of the basin does not present a viable zero edge play, being very likely to have poor top seal. Once again, such plays are inherently high risk, and require a very sharp transition from reservoir to good seal rock. Helium was detected in the Jericho-1 and Shittim-1 wells. There is no known structure at either of these wells. It is assumed this gas has made its way, along with hydrocarbon gases, from Pre-Carboniferous rocks down dip.

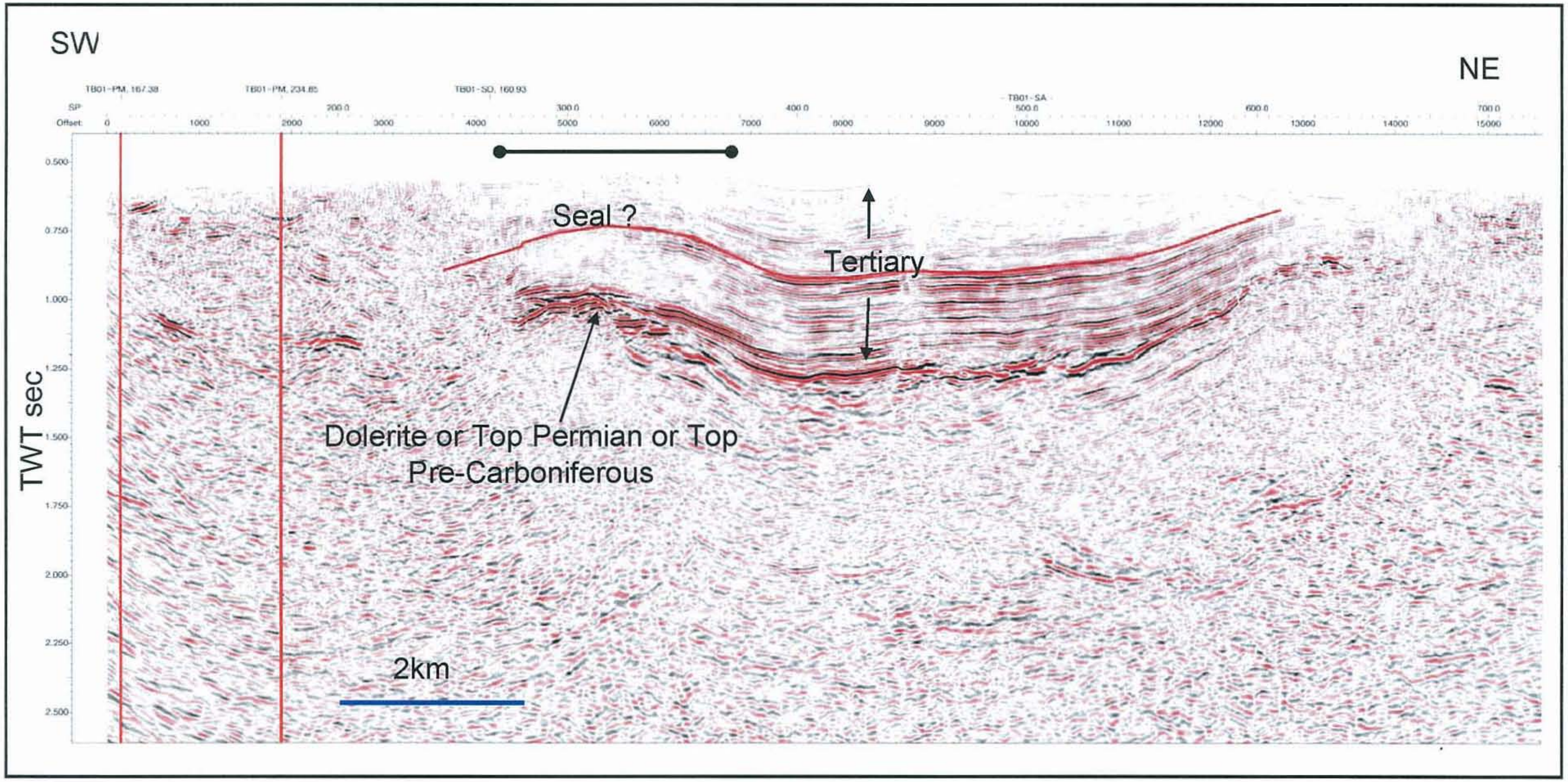

Figure 21 – Seismic line TB01-SA showing Bracknell Dome (proposed location of Eglon-1 stratigraphic well). Line location shown on Figure 20

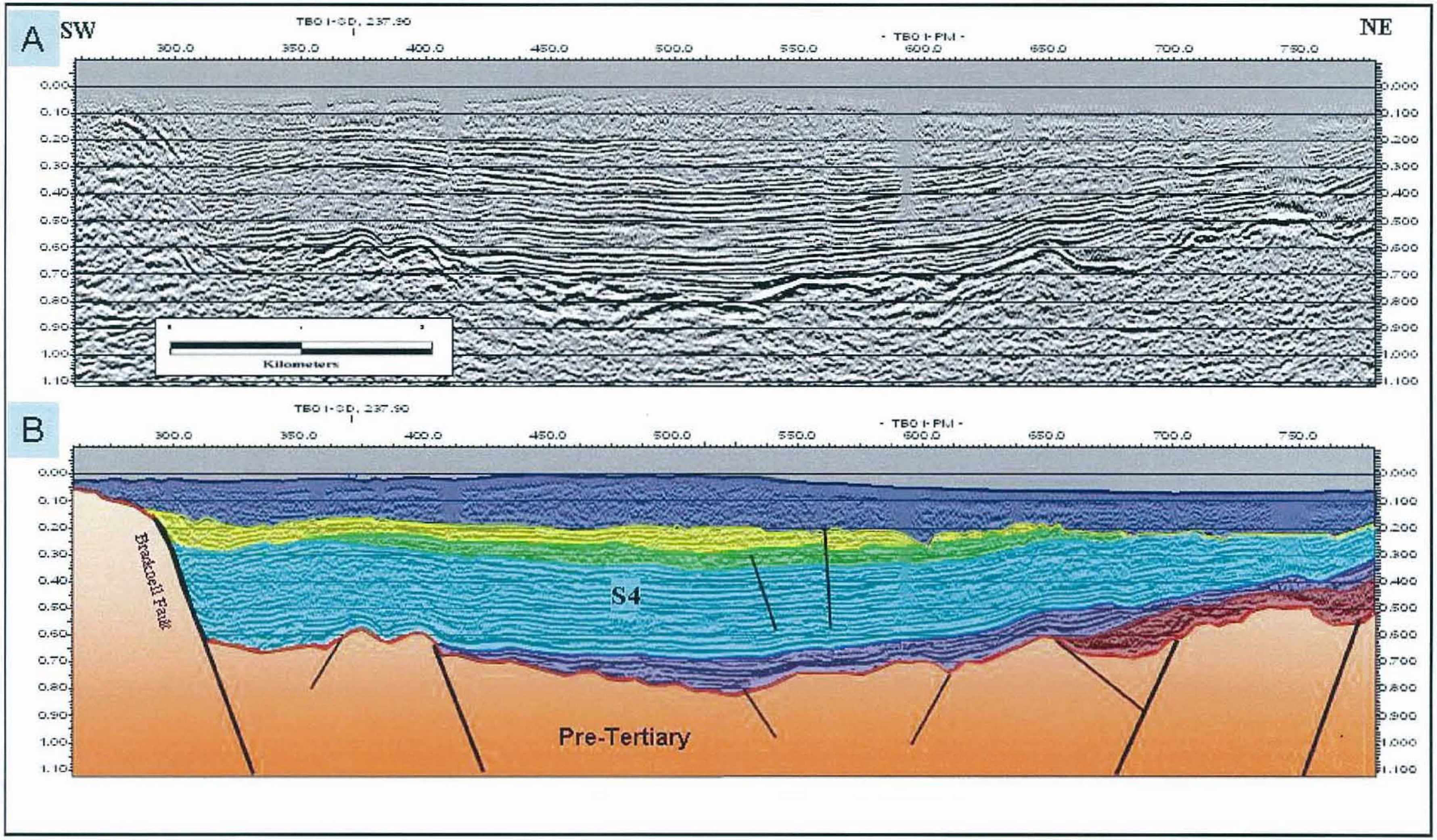

Figure 22 – Seismic line TB01-PM. "A" is non-interpreted and "B" is interpreted. Line location is shown on Figure 20 (modified after Lane, 2003)

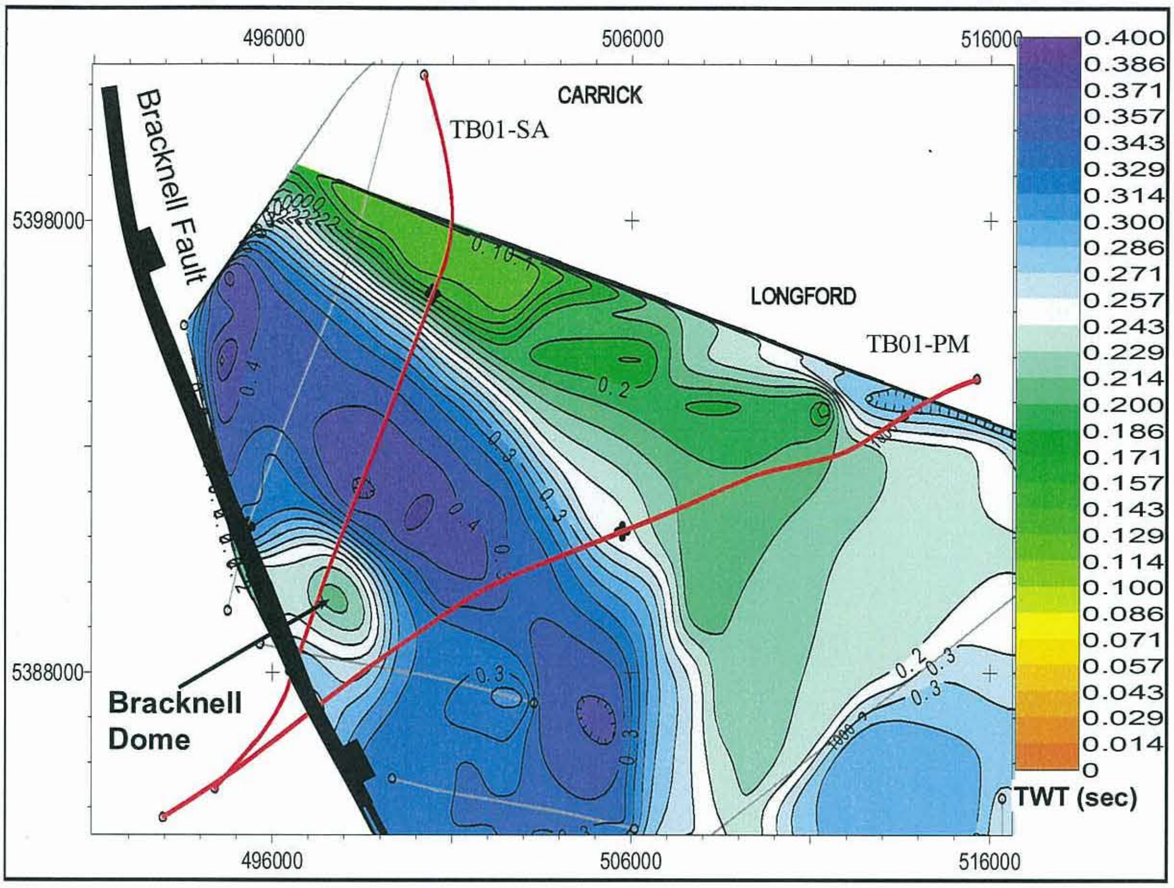

Figure 23 – TWT map of the top of the S4 package (modified after Lane, 2003)

3.7 Petroleum Prospectivity

There is limited seismic in the area because of hilly, treed terrain. The imaging is poor on much of the 2001 data though this might be improved by reprocessing with velocity data from Hunterston-1. In 2006, GSLM recorded 152 kilometres of 2d seismic data and in 2007, 270.5 kilometres of 2d seismic data was completed, interpreted and integrated into the seismic database. Further seismic work is planned by GSLM for November, 2007, to February, 2008. To date, interpretation of the acquired seismic data has identified several fault block traps and small anticlines with shallow targets in the Gondwana Petroleum System. Deeper targets have been identified by GSLM in the Larapintine Petroleum System, mainly Ordovician in the Central Highlands. The data gained from the extensive drilling program, planned by GSLM for 2007, and the further seismic work will give rise to further understanding of the potential prospectivity of the permit area.

On the available data, there are only two features that can be identified with any confidence, the Bellevue Feature and the Interlaken Feature. Both of these are very high-risk due to lack of seismic and well control.

All resources are classified as Prospective Resources under the SPE/WPC/AAPG/SPEE resources classification system (Figure 24) taken from the Petroleum Resources Management System document (2007).

The risks discussed throughout this document are geological risks only.

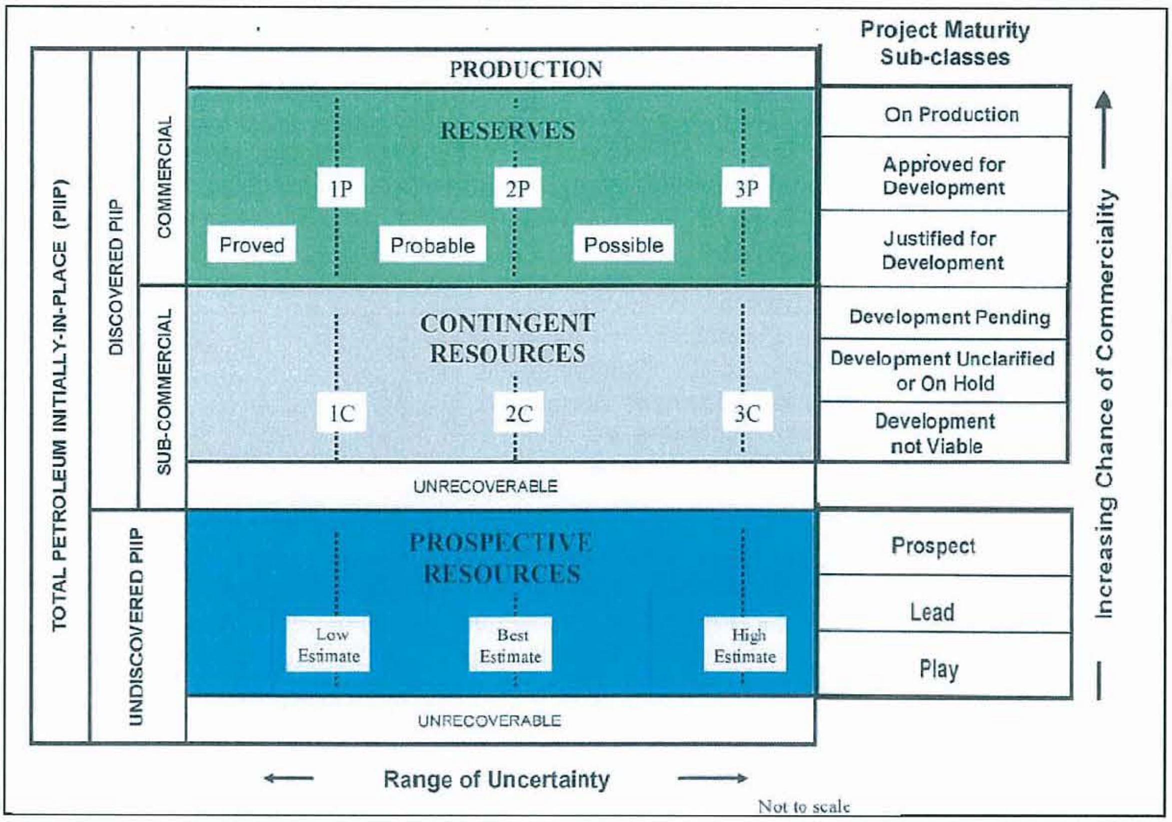

Figure 24 – SPE/WPC/AAPG/SPEE resources classification system

3.7.1 SEL 13/98 Leads Volumetrics and Risk Analysis

3.7.1.1 Interlaken Feature – Permian (proposed stratigraphic well Hebron-1)

The Interlaken Feature is located to the east of the permit area (Figure 18). It is a tilted fault block with dolerite, probably intruding above the Liffey Group reservoir. The feature is immature and poorly defined on a single seismic line which crosses the feature (Figure 25).

A number of assumptions have been made in order to develop an indicative, prospective volume. There is no strike line to constrain the fault block size. Some modest assumptions have been made regarding strike dimension. All volumetric inputs are shown in Appendix B.

Faults go to the surface, so the volumetric case being risked constitutes sufficient fault independent closure to contain the Liffey Reservoir at around 38 metres thick. An oil and gas case was run using a probabilistic method. While the source may well be present, the maturity and timing of the trap formation increases the overall charge risk.

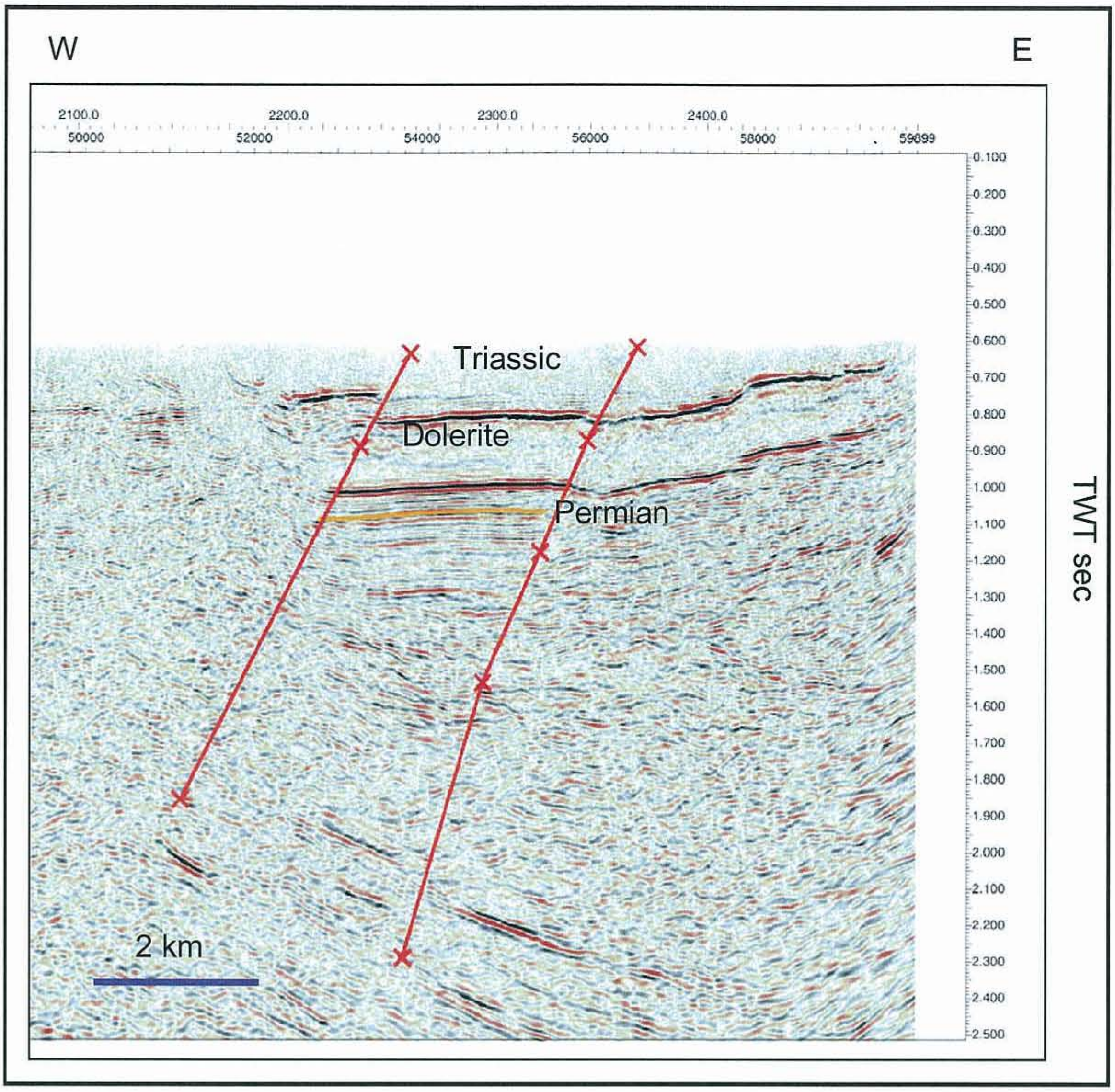

Figure 25 – Seismic line TB01-ST through the Interlaken Feature. Line location shown on Figure 18

The chances of success of the Interlaken Feature are presented in Table 8, and unrisked volumes of oil and gas are tabulated in Table 9.

Risk Factor	Percent
Charge	30
Reservoir	70
Seal	60
Trap	10
Chance of Success	**1.26**

Table 8 – Chance of success of Interlaken Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	10	27	65	33
Prospective Resource (MMbbls)	1	4	12	6
GAS CASE				
Undiscovered Gas Initially-in-Place (Bcf)	11	30	69	36
Prospective Resource (Bcf)	8	21	48	25

Table 9 – Unrisked oil and gas volumes of the Interlaken Feature

3.7.1.2 Bellevue Feature – Pre-Carboniferous (proposed stratigraphic well Gezer-1)

The Bellevue Feature is located in the Central Plateau in central Tasmania (Figure 18). It is identified on two seismic lines, TB01-PB and TB01-TD (Figure 26, Figure 27 and Figure 28).

The crest of the structure is offset from these interpreted seismic lines and extends to outside the range of the lines displayed. It is assumed, optimistically, that the amplitude of the fold seen in Figure 27 is representative of the actual crest which may lie to the north.

There are three potential reservoirs in the feature. The deeper two are suggested by higher amplitudes. There is no well control for this interpretation and the higher amplitudes are inferred to result from karst porosity in the Ordovician limestone.

The upper level (Level 1), without amplitude, is interpreted to be siliciclastic Eldon Formation reservoirs. At Levels 2 and 3, fault dependent and fault independent closures have been estimated. The chances of success for each level of the Bellevue Feature is presented in Table 10. Because of the large uncertainties of each element and the poor definition of the feature at each level, the chance of success is considered the same at each level. The volumes of unrisked oil and gas for each level are presented in Table 11 to Table 15.

Risk Factor	Percent
Charge	20
Reservoir	40
Seal	50
Trap	10
Chance of Success	**0.40**

Table 10 – Chance of success of the Bellevue Feature

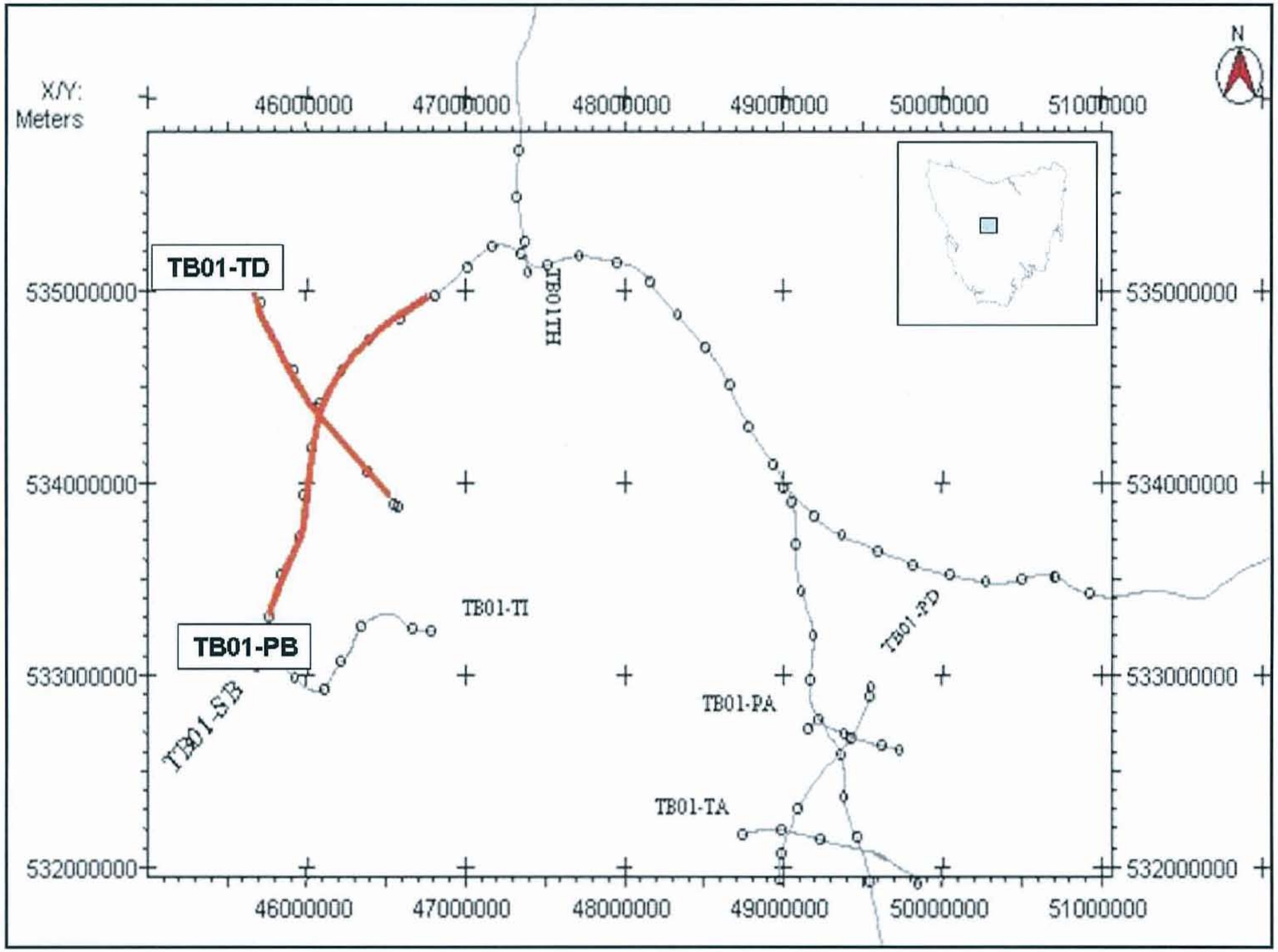

Figure 26 – Locations of seismic lines TB01-PB and TB01-TD

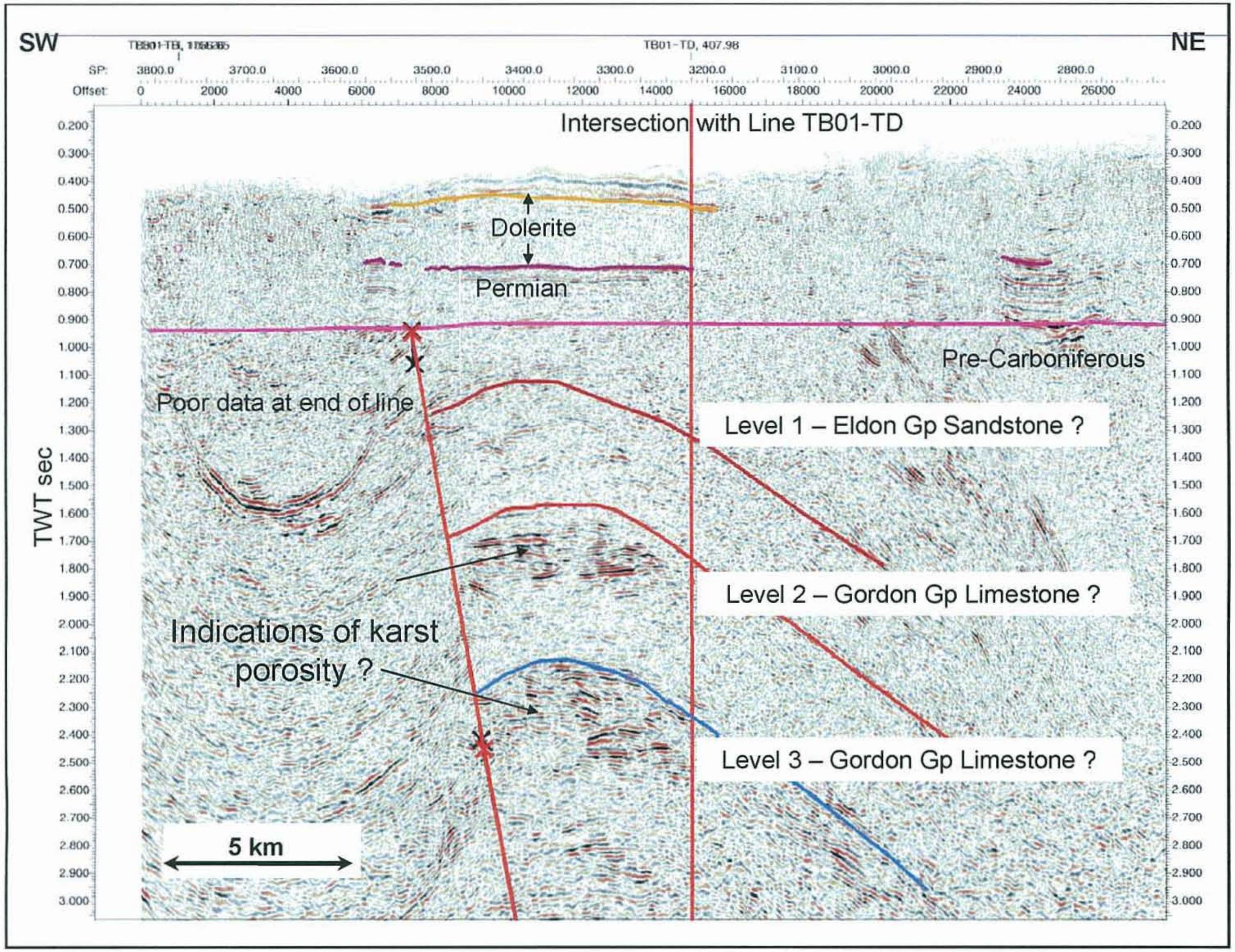

Figure 27 – Seismic line TB01-PB through the Bellevue Feature (proposed location of Gezer-1 stratigraphic well). Line location shown on Figure 26

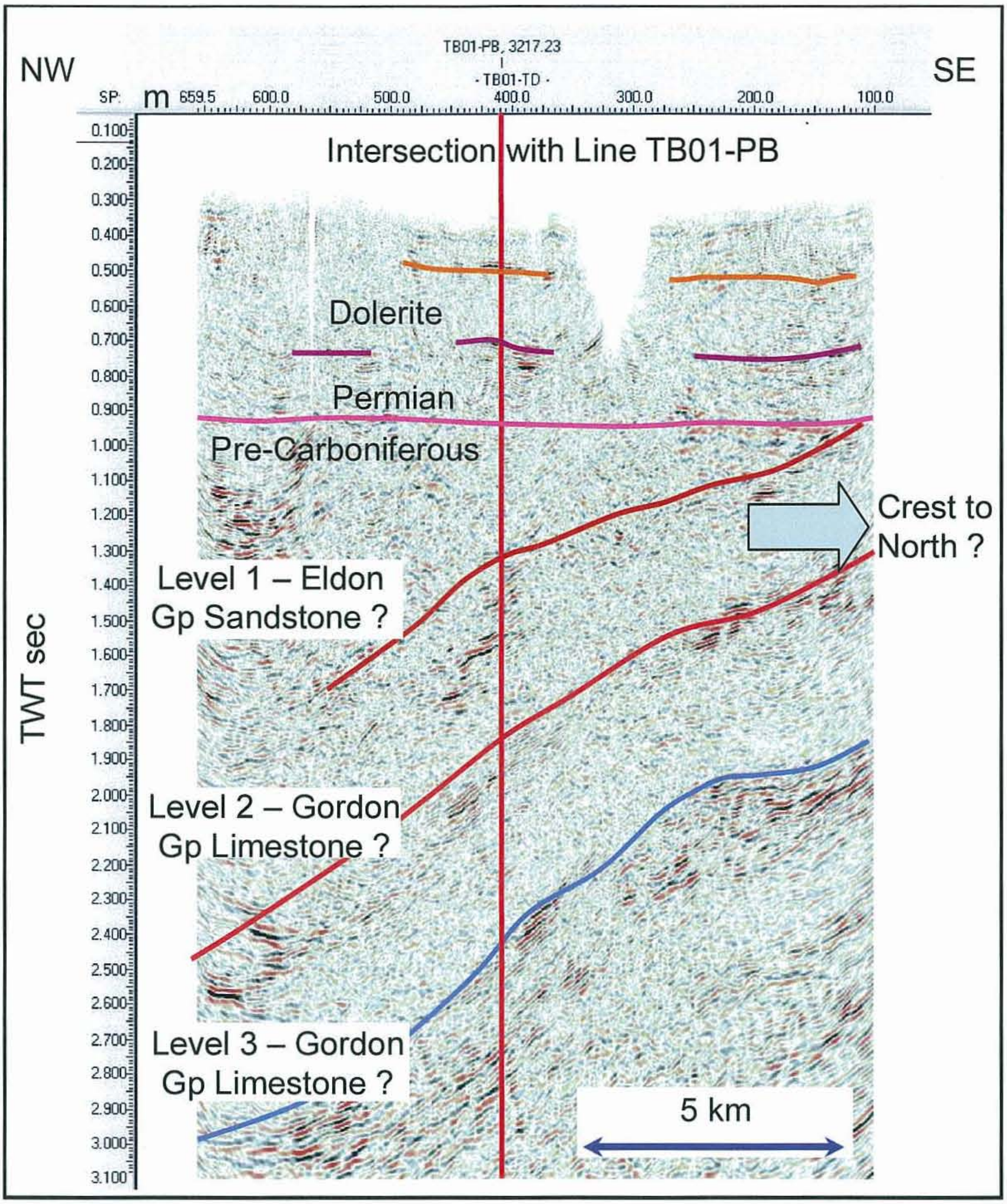

Figure 28 – Seismic line TB01-TD through the Bellevue Feature (proposed location of Gezer-1 stratigraphic well). Line location shown on Figure 26

3.7.1.3 Level 1 of the Bellevue Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	55	152	337	180
Prospective Resource (MMbbls)	9	35	95	46
GAS CASE				
Undiscovered Gas Initially-in-Place (Bcf)	94	235	479	268
Prospective Resource (Bcf)	65	164	339	188

Table 11 – Unrisked oil and gas volumes of Level 1 of the Bellevue Feature

3.7.1.4 Level 2 of the Bellevue Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	29	88	187	101
Prospective Resource (MMbbls)	5	20	54	26
GAS CASE				
Undiscovered Gas Initially-in-Place (Bcf)	58	158	304	173
Prospective Resource (Bcf)	40	110	215	121

Table 12 – Unrisked oil and gas volumes of Level 2 (independent closure) of the Bellevue Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	52	302	1521	643
Prospective Resource (MMbbls)	10	70	396	164
GAS CASE				
Undiscovered Gas Initially-in-Place (Bcf)	98	536	2608	1104
Prospective Resource (Bcf)	68	374	1815	772

Table 13 – Unrisked oil and gas volumes of Level 2 (upside fault dependent closure) of the Bellevue Feature

3.7.1.5 Level 3 of the Bellevue Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	11	33	74	39
Prospective Resource (MMbbls)	2	8	21	10
GAS CASE				
Undiscovered Gas Initially-in-Place (Bcf)	27	75	151	84
Prospective Resource (Bcf)	19	52	107	59

Table 14 – Unrisked oil and gas volumes of Level 3 (fault independent) of the Bellevue Feature

	Low Estimate	Best Estimate	High Estimate	Mean
OIL CASE				
Undiscovered Oil Initially-in-Place (MMbbls)	20	154	1058	449
Prospective Resource (MMbbls)	4	36	271	114
GAS CASE				
Undiscovered Gas initially-in-place (Bcf)	47	346	2280	969
Prospective Resource (Bcf)	33	240	1598	677

Table 15 – Unrisked oil and gas volumes of Level 3 (upside fault dependent) of the Bellevue Feature

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5. APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

AAPG	American Association of Petroleum Geologists
AFT	apatite fission track
API	American Petroleum Institute
asl	above sea level
B	billion
bbl(s)	barrels
bbls/d	barrels per day
Bcm	billion cubic metres
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
B_w	water volume factor
bopd	barrels of oil per day
Bscf	billions of standard cubic feet
bwpd	barrels of water per day
CO_2	Carbon dioxide
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
ft	feet
ftSS	depth in feet below sea level
GRV	gross rock volume
H_2S	hydrogen sulphide
KB	Kelly Bushing
km	kilometres
km^2	square kilometres
LNG	liquefied natural gases
LPG	liquefied petroleum gases
Ma	Million years ago
M	thousand
MM	million
MD	measured depth
mD	permeability in millidarcies
m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day

m/s	metres per second
msec	milliseconds
NTG	net to gross ratio
P_c	capillary pressure
Petroleum	A naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.
phi	porosity fraction
ppm	parts per million
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.
PVT	pressure volume temperature
rb	barrel(s) of oil at reservoir conditions
rcf	reservoir cubic feet
RFT	repeat formation tester
RKB	relative to Kelly Bushing
rm^3	reservoir cubic metres
SCAL	special core analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	stock tank barrels per day
STOIIP	stock tank oil initially-in-place
S_w	water saturation
t	tonnes
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness

TWT	two-way time
Undiscovered Petroleum initially-in-place	That quantity of petroleum which is estimated, as of a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum initially-in-place is classified as Prospective Resources, as defined below.
V_{sh}	shale volume
WPC	World Petroleum Council
ϕ	porosity

6. APPENDIX B: PROBABILISTIC RESERVES INPUT DATA

Prospect/Field Recoverable Oil

LOCICOM

Country:	Australia	Name:	Interlaken Level 1
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	3.00	5.48	10.0
Thickness	m	Lognor	25.0	31.6	40.0
Shape factor	%	Single	90.0	90.0	90.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Normal	50.0	65.0	80.0
Porosity	%	Normal	5.00	10.0	15.0
Sw	%	Normal	30.0	45.0	60.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	17.5	25.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

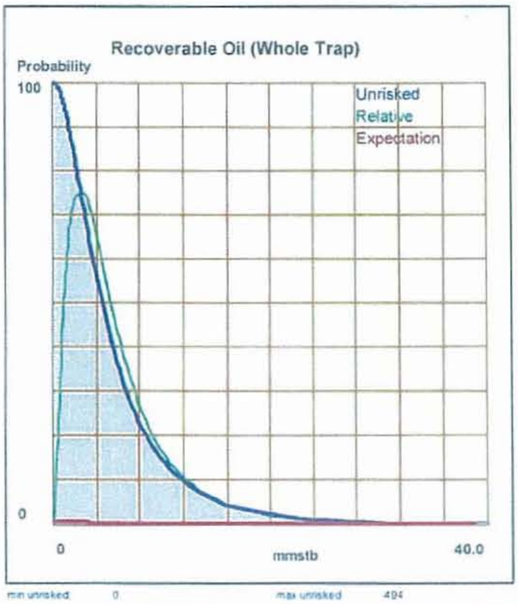
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	1.26%	
Trap	10%	Very unlikel
Reservoir	70%	Probable
Seal	60%	Probable
Charge	30%	Possible
Geological Chance of Success GPOS:	1.26%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked mmstb	Oil-in-Place Whole Trap	Recoverable Oil Whole Trap	Recoverable Oil Net Share
P90:	9.87	1.40	1.40
P50:	27.0	4.44	4.44
P10:	64.6	11.9	11.9
Mean:	33.4	5.84	5.84



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: Interlaken level 1 oil
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Gas

LOGICOM

Country:	Australia	Name:	InterlakenLevel 1
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	3.00	5.48	10.0
Thickness	m	Lognor	25.0	31.6	40.0
Shape factor	%	Single	90.0	90.0	90.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Normal	80.0	82.5	85.0
Porosity	%	Normal	5.00	10.0	15.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	100	108	115
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore:	Onshore	
Facilities @:		km
Terrain:		
Target depth:		m
Operator:		

Risk Factors

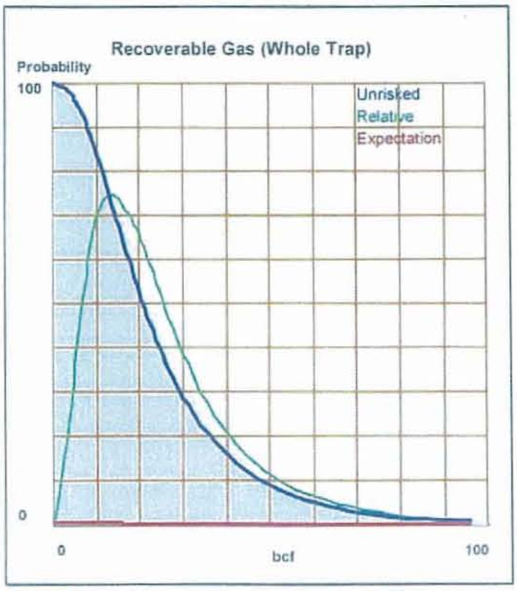
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	1.26%	
Trap	10%	Very unlikel
Reservoir	70%	Probable
Seal	60%	Probable
Charge	30%	Possible
Geological Chance of Success GPOS:	1.26%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Gas-in-Place	Recoverable Gas	
bcf	Whole Trap	Whole Trap	Net Share
P90:	11.5	7.90	7.90
P50:	29.9	20.8	20.8
P10:	68.8	48.3	48.3
Mean:	36.2	25.3	25.3



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: Interlaken level 1 gas
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Oil

LOGICOM

Country:	Australia	Name:	Bellevue Level 1
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	54.0	76.4	108
Thickness	m	Lognor	34.0	37.3	41.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Normal	30.0	55.0	80.0
Porosity	%	Normal	5.00	8.50	12.0
Sw	%	Normal	30.0	50.0	70.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	25.0	40.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

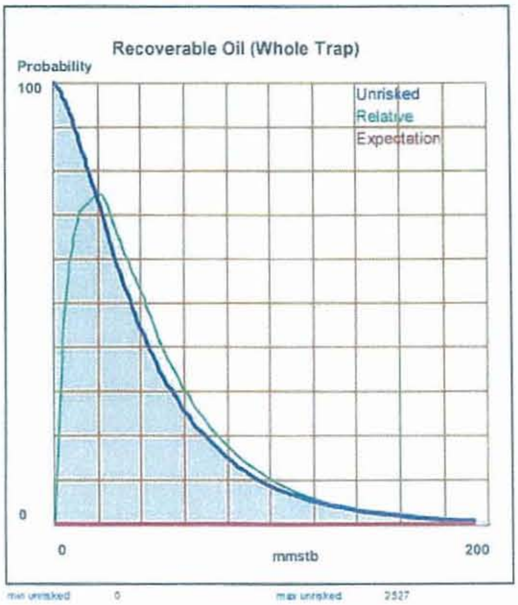
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked mmstb	Oil-in-Place Whole Trap	Recoverable Oil Whole Trap	Recoverable Oil Net Share
P90:	55.0	9.34	9.34
P50:	152	35.3	35.3
P10:	337	95.4	95.4
Mean:	179	46.0	46.0



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 1 oil
Author:
Date: 06/12/06

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Prospect/Field Recoverable Gas

LOCICOM

Country:	Australia	Name:	Bellevue Level 1
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	54.0	76.4	108
Thickness	m	Lognor	34.0	37.3	41.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Normal	30.0	55.0	80.0
Porosity	%	Normal	5.00	8.50	12.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	160	170	180
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m

Operator:

Risk Factors

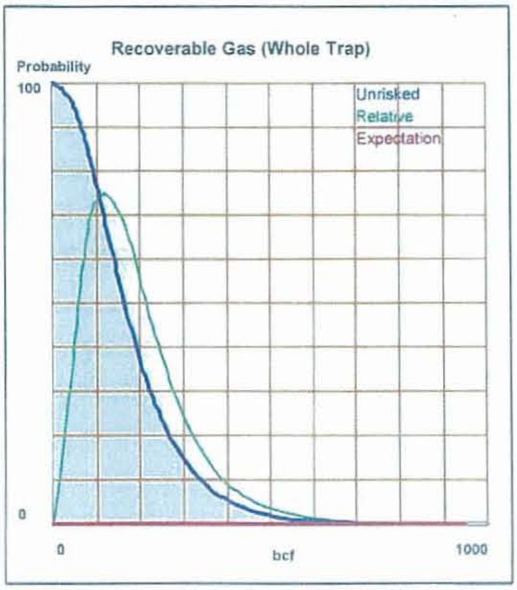
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Gas-in-Place	Recoverable Gas	
bcf	Whole Trap	Whole Trap	Net Share
P90:	94.0	64.9	64.9
P50:	235	164	164
P10:	479	339	339
Mean:	268	188	188



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 1 gas
Author:
Date: 06/12/06

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Prospect/Field Recoverable Oil

LOGICOM

Country:	Australia	Name:	Bellevue Level 2
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	13.0	17.7	24.0
Thickness	m	Lognor	25.0	27.4	30.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	30.0	50.0	70.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	25.0	40.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

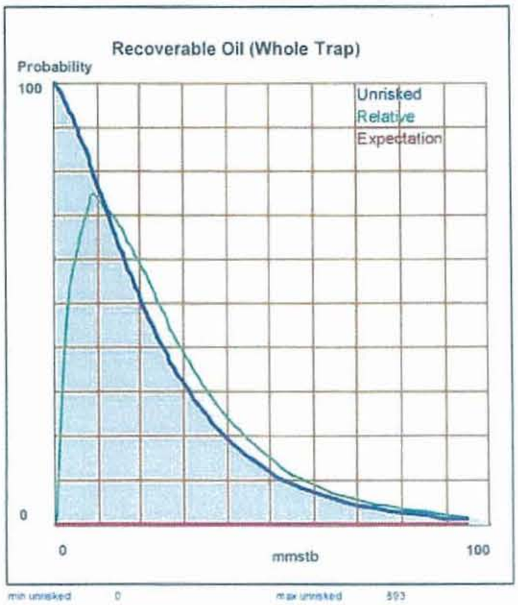
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Oil-in-Place	Recoverable Oil	
mmstb	Whole Trap	Whole Trap	Net Share
P90:	29.5	5.07	5.07
P50:	88.6	20.3	20.3
P10:	187	53.7	53.7
Mean:	101	25.9	25.9



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 2 oil lowside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Gas

LOCICOM

Country:	Australia	Name:	Bellevue Level 2
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	13.0	17.7	24.0
Thickness	m	Lognor	25.0	27.4	30.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	190	195	200
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

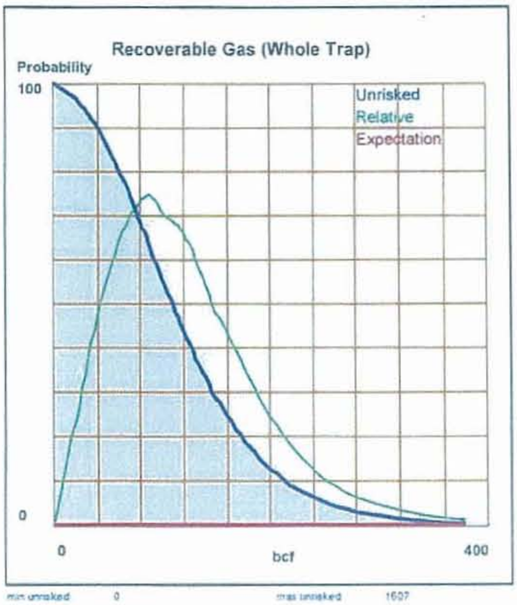
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked bcf	Gas-in-Place Whole Trap	Recoverable Gas Whole Trap	Recoverable Gas Net Share
P90:	58.4	40.5	40.5
P50:	158	110	110
P10:	304	215	215
Mean:	173	121	121



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 2 gas lowside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Oil

LOGICOM

Country:	Australia	Name:	Bellevue Level 2
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	13.0	17.7	24.0
Thickness	m	Lognor	25.0	101	405
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	30.0	50.0	70.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	25.0	40.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

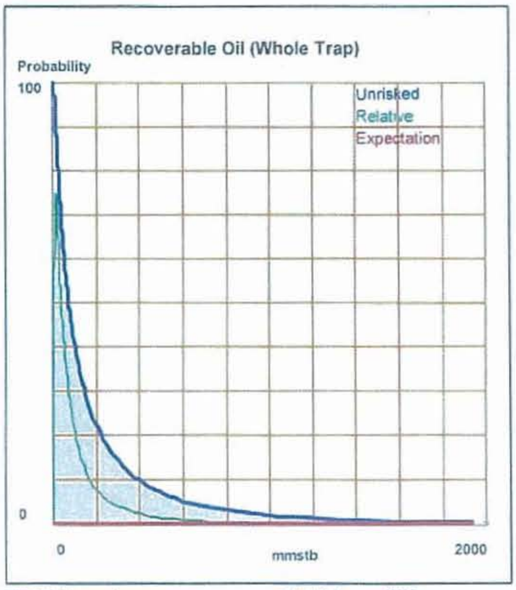
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked mmstb	Oil-in-Place Whole Trap	Recoverable Oil Whole Trap	Recoverable Oil Net Share
P90:	52.6	10.0	10.0
P50:	302	69.4	69.4
P10:	1521	396	396
Mean:	643	164	164



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 2 oil upside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Gas

LOGICOM

Country:	Australia	Name:	Bellevue Level 2
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	13.0	17.7	24.0
Thickness	m	Lognor	25.0	101	405
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	190	195	200
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m

Operator:

Risk Factors

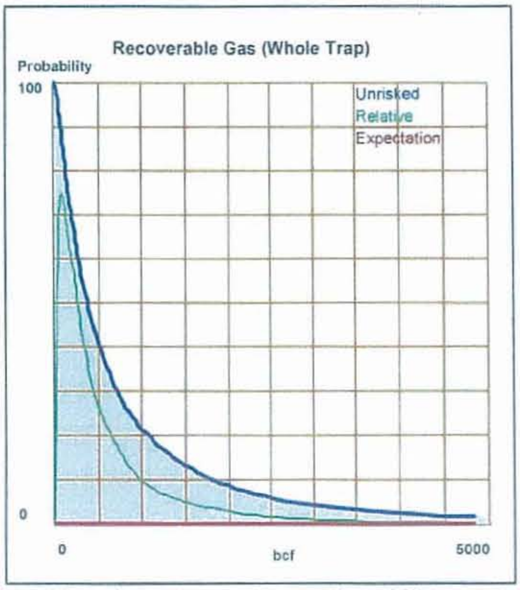
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Gas-in-Place	Recoverable Gas	
bcf	Whole Trap	Whole Trap	Net Share
P90:	98.0	68.1	68.1
P50:	536	374	374
P10:	2608	1815	1815
Mean:	1104	772	772



min unrisked 0 max unrisked 124203

Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 2 gas upside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Oil

LOGICOM

Country:	Australia	Name:	Bellevue Level 3
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	7.00	10.2	15.0
Thickness	m	Lognor	16.0	17.9	20.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	30.0	50.0	70.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	25.0	40.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

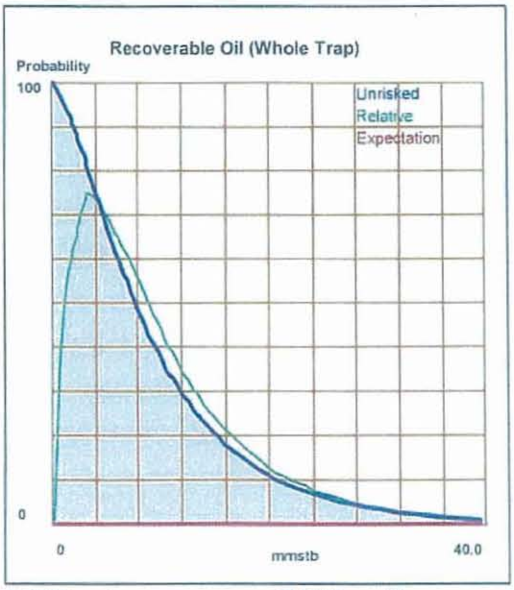
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked mmstb	Oil-in-Place Whole Trap	Recoverable Oil Whole Trap	Recoverable Oil Net Share
P90:	10.9	1.88	1.88
P50:	33.3	7.65	7.65
P10:	73.7	20.9	20.9
Mean:	39.0	9.97	9.97



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 3 oil lowside
Author:
Date: 06/12/06
5.05a1

Prospect/Field Recoverable Gas

LOCICOM

Country:	Australia	Name:	Bellevue Level 3
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	7.00	10.2	15.0
Thickness	m	Lognor	16.0	17.9	20.0
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	240	245	250
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

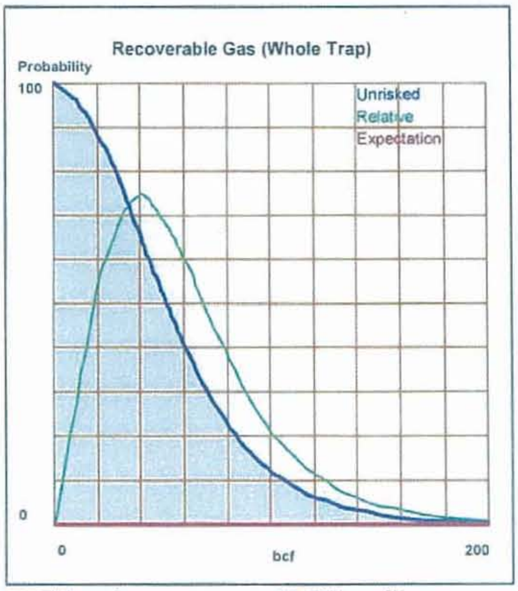
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Gas-in-Place	Recoverable Gas	
bcf	Whole Trap	Whole Trap	Net Share
P90:	27.0	18.8	18.8
P50:	74.7	51.9	51.9
P10:	151	107	107
Mean:	83.7	58.6	58.6



min unrisked 0 max unrisked 944

Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 3 gas lowside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Oil

LOGICOM

Country:	Australia	Name:	Bellevue Level 3
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Oil

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	7.00	10.2	15.0
Thickness	m	Lognor	16.0	89.4	500
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	30.0	50.0	70.0
FVF (Bo)	vol/vol	Normal	1.10	1.20	1.30
Oil rec fac	%	Normal	10.0	25.0	40.0

On/offshore: Onshore
Facilities @: km
Terrain:
Target depth: m
Operator:

Risk Factors

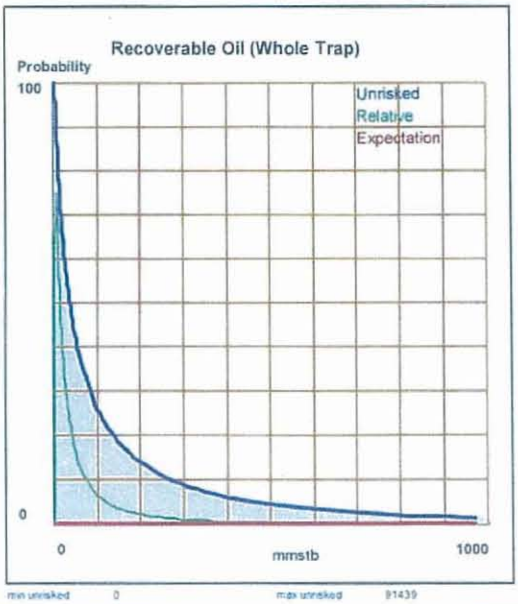
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked mmstb	Oil-in-Place Whole Trap	Recoverable Oil Whole Trap	Recoverable Oil Net Share
P90:	20.2	3.97	3.97
P50:	154	35.3	35.3
P10:	1058	271	271
Mean:	449	114	114



Production Working Interest: 100.00
Exploration Working Interest: 100.00
Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 3 oil upside
Author:
Date: 06/12/06

5.05a1

Prospect/Field Recoverable Gas

LOGICOM

Country:	Australia	Name:	Bellevue Level 3
Block:	SEL 13/98	Segment:	
Classification:	Unspecified	Hydrocarbons:	Gas

Input Data

Variable	Unit	Shape	P90	P50	P10
Area	km2	Lognor	7.00	10.2	15.0
Thickness	m	Lognor	16.0	89.4	500
Shape factor	%	Single	50.0	50.0	50.0
Deg. of fill	%	Single	100	100	100
Net-to-gross	%	Single	100	100	100
Porosity	%	Normal	5.00	15.0	25.0
Sw	%	Normal	20.0	35.0	50.0
FVF (1/Bg)	vol/vol	Normal	240	245	250
Gas rec fac	%	Normal	60.0	70.0	80.0

On/offshore:	Onshore
Facilities @:	km
Terrain:	
Target depth:	m
Operator:	

Risk Factors

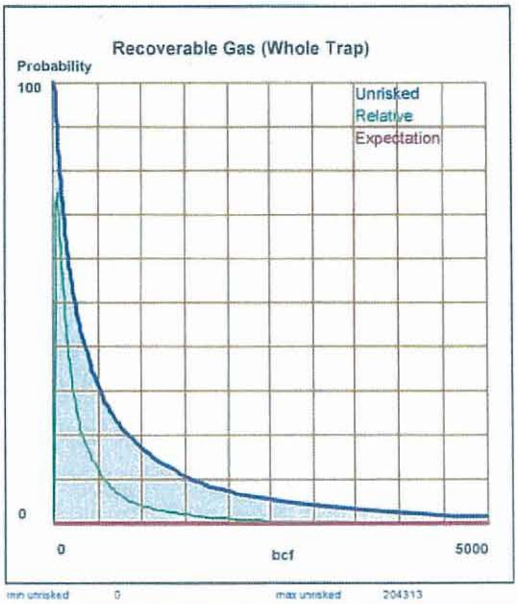
Play Chance:	100%	
Reservoir	100%	Very likely
Source	100%	Very likely
Seal	100%	Very likely
Prospect Specific Chance:	0.400%	
Trap	10%	Very unlikel
Reservoir	40%	Possible
Seal	50%	Possible
Charge	20%	Unlikely
Geological Chance of Success GPOS:	0.400%	

Economic Criteria

No economic minima applied

Summary of Results

Unrisked	Gas-in-Place	Recoverable Gas	
bcf	Whole Trap	Whole Trap	Net Share
P90:	47.0	32.6	32.6
P50:	346	240	240
P10:	2280	1598	1598
Mean:	969	677	677



Production Working Interest: 100.00

Exploration Working Interest: 100.00

Production Working Interest is used to calculate net volumes

Comments:

REP file: bellevue level 3 gas upside

Author:

Date: 06/12/06

5.05a1

Mosaics

As a way of demonstrating our choice of drill site, GSLM have put all available information in the form of maps, charts, tables and seismic sections in each mosaic. The location of each drill sites mosaic is shown in general Geology of the Tasmania basin (Reid and Burrett, 2004). A geological map of the proposed drill site depicts the local geology of the area. A topographic map demonstrates the elevation of each drill site. Two Way Time and seismic maps, gravity, depict every possible reservoir. Gravity maps described by Residual Bouguer Anomaly of the local area. The map of Tasmania identifies each drill site in relation to the GSLM Special Exploration Licence.

Stratigraphy prognoses for well sites are based on existing information written about the stratigraphy of the region and our expectation of finding hydrocarbons with regard to the suggested petroleum systems present in Tasmania. The thickness of each formation is calculated by measuring seismic sections and seismic velocities for each local formation. The Monte-Carlo Table illustrates the potential of the undiscovered petroleum system in each site. Seismic sections are selected from close seismic lines to the proposed drill sites. Each seismic line is also presented with and without structural and stratigraphic interpretation. The Gondwanan and Larapintine systems are the two petroleum systems proposed for the Tasmania basin.

The Gondwanan system is of Permo-Triassic age. Potential developments of the Gondowanan petroleum system are shown in greater detail in the mosaics. Major and minor potential sources, reservoirs and seals, along with timing of trap formation and source rock maturity are also presented.

The Pre-Carboniferous Larapintine petroleum system is targeted in two well sites in the Tasmania Basin. Not all of the pre-Carboniferous sections in Southern Tasmania are suggested to be over matured (Burrett, 1992) and this will be examined in Thunderbolt #1 and Bellevue #1 drill sites. The burial models of Bacon et al. (2000) and Reid (2004) suggest that rocks lying some kilometres deeper than the Permian could have re-entered the oil gas window in the Mesozoic to Cainozoic periods.

In 2008, GSLM have presented 15 mosaics. The "Bellevue #1 and Thunderbolt # 1" sites are actively in preparation to be drilled by early October. Bracknell #1, Derwent Bridge #1, Interlaken #1, Nile River #1, Butlers Rise #1, Cressy #1, Hummocky Hills Fault Block #1, Macquarie River #1, Stockwell #1, Scotts Tier #1, Lonnavale #1, Stepps #1 and Quamby #1. Other are other undiscovered prospective drilling sites named in order of volume ranking will be proposed by GSLM for the future drilling activities.

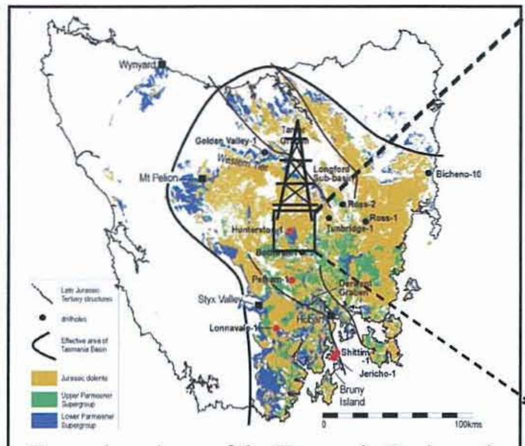
EMPIRE Energy

Great South Land Minerals

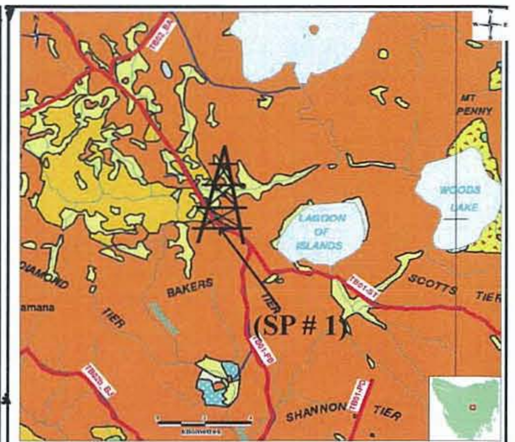
Steppes Anticline

(SP # 1) June 2008

Compiled by Dr. Zohreh Amini

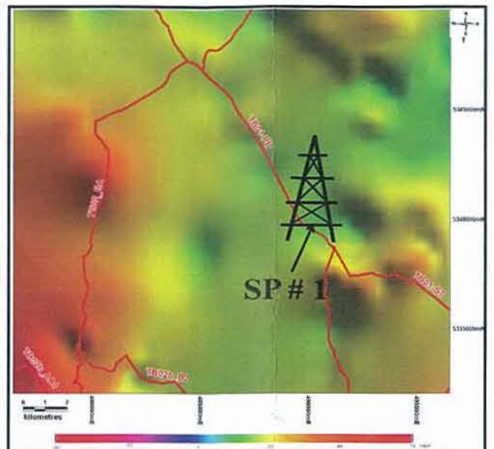


General geology of the Tasmania Basin and location of drill site on the Steppes Anticline

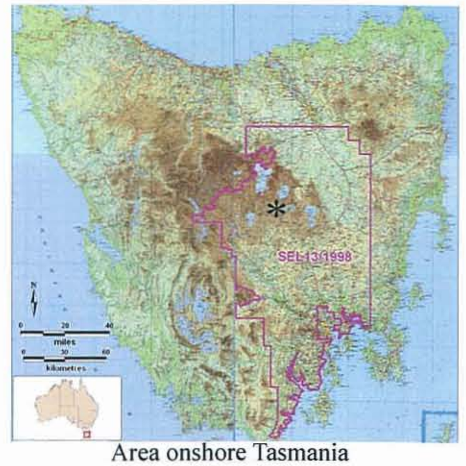


Geology map of the Steppes Anticline and location of proposed drill site (SP # 1)

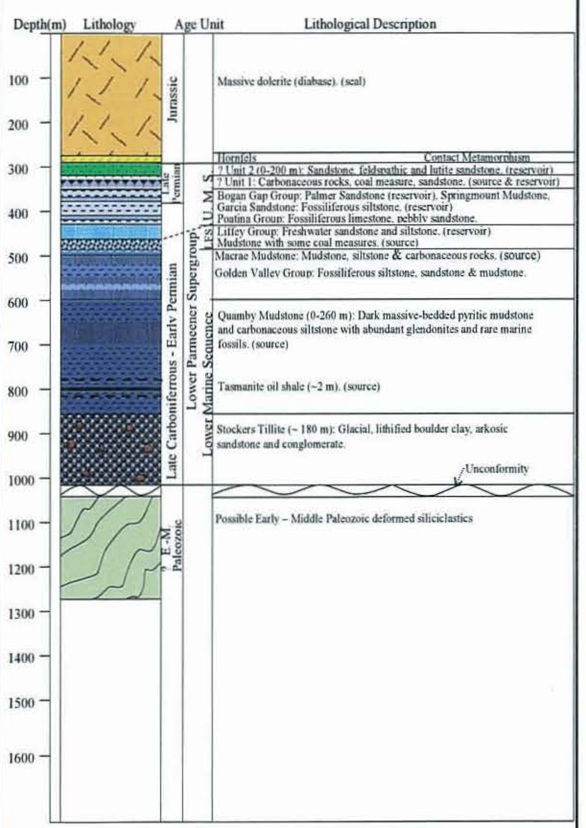
Topographic map of the Steppes Anticline (SP# 2)



Gravity Map (Residual Bouguer Anomaly) of the Steppes Anticline (SP # 1)



Area onshore Tasmania Special Exploration Licence 13/98



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

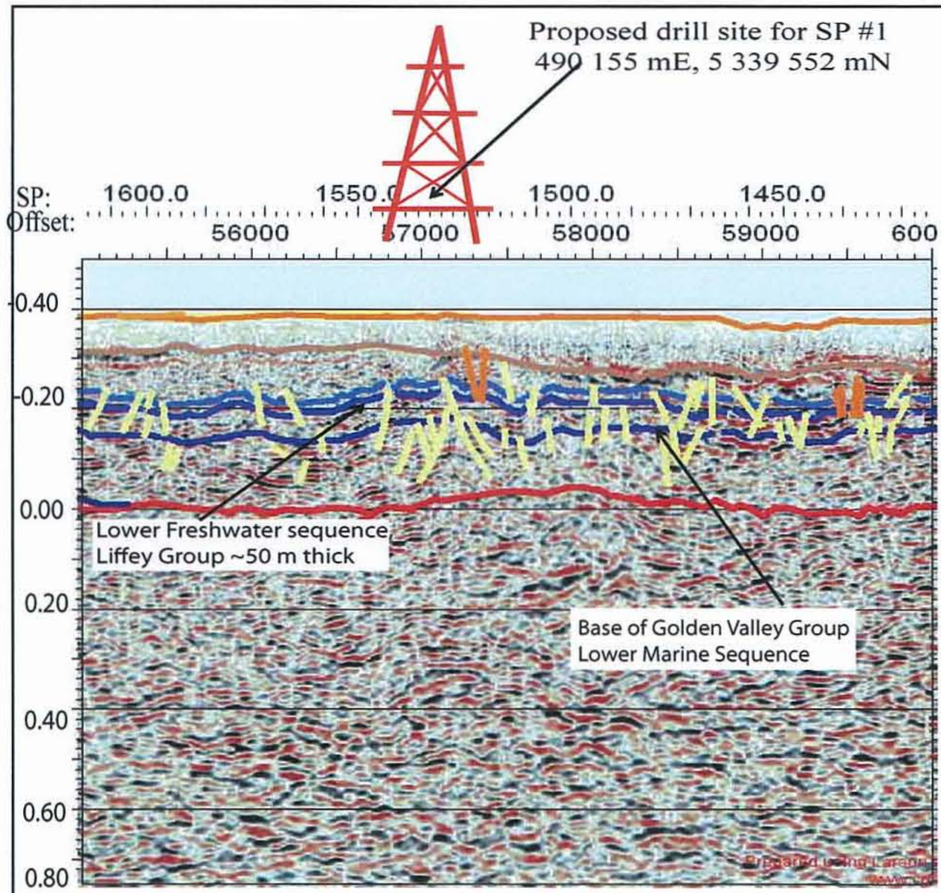
Prediction of Stratigraphy at the Steppes Anticline (SP # 1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	3	-	3
(P50)	7	-	7
(P10)	16	-	16

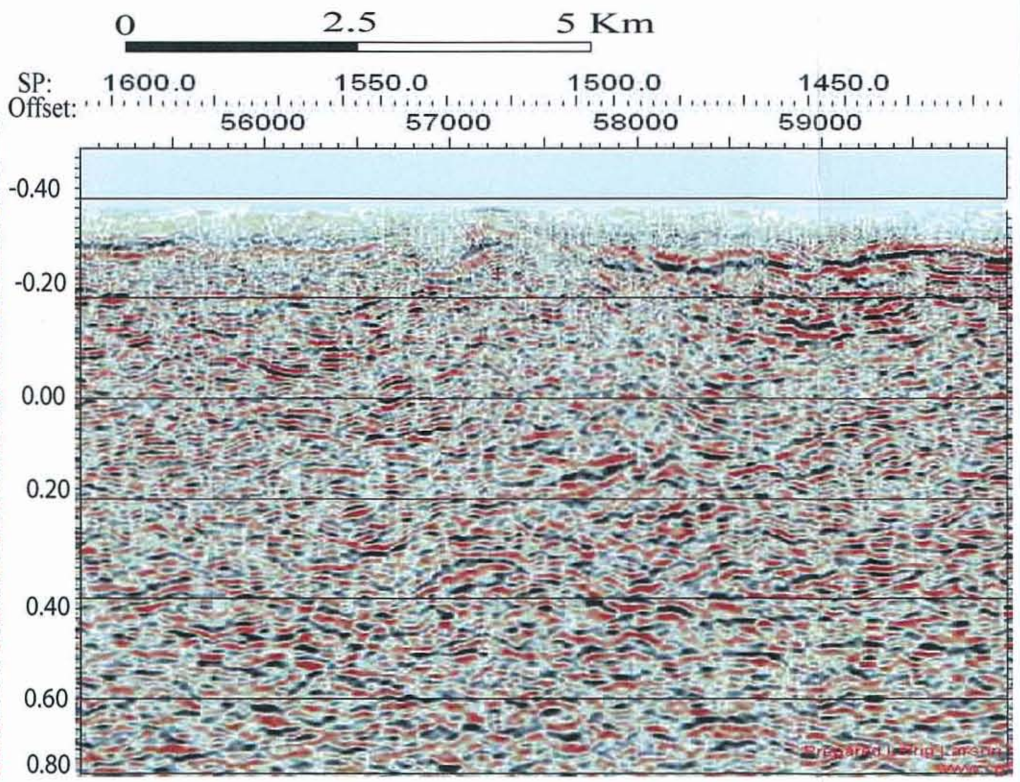
Monte – Carlo simulations of potential, undiscovered petroleum at Steppes #1 in million barrels

Petroleum System Characteristics of the Steppes Anticline (based on seismic line TB01-SP)

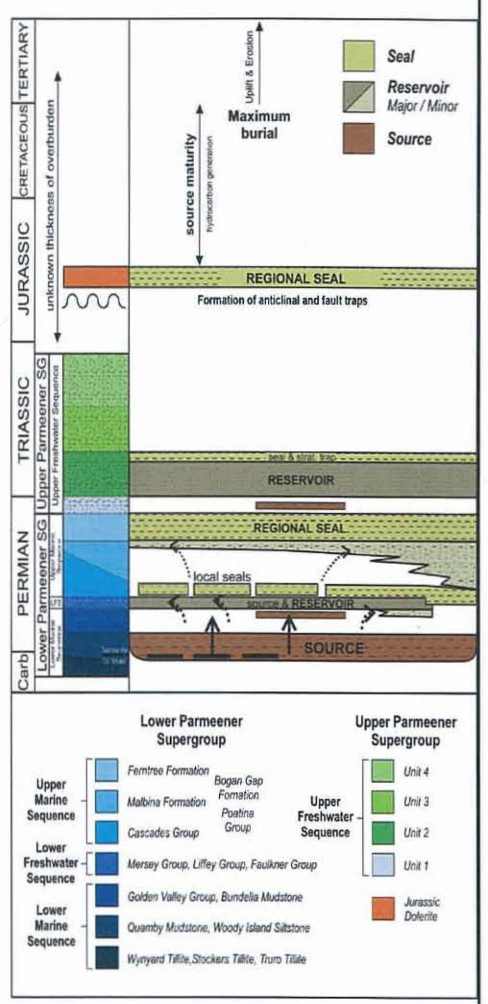
Target:	Triassic, Early to Late Permian in Anticline
Source:	Unit 1, Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2, (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = 295 m, Unit 1 =320 m, Palmer Sandstone = ~370 m, Garcia Sandstone = ~ 410 m, Liffey Group = ~ 470 m.
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Anticline
Risk:	Timing of trap formation is favorable. occuring prior to predicted generation. The Bogan Gap Group and Jurassic Dolerite are thought to provide excelent seals.



Seismic line TB01-SP with structural and stratigraphic interpretations



Seismic line TB01-SPwithout interpretations



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. 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.

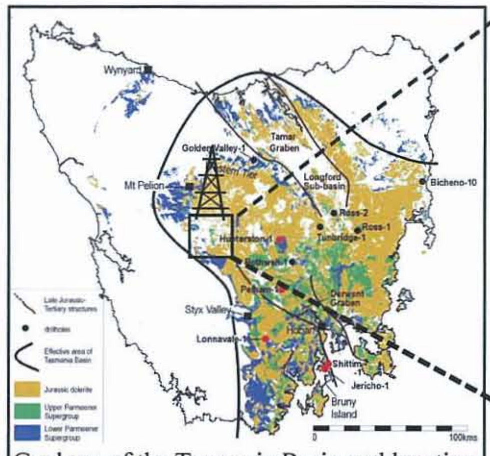
EMPIRE Energy

Great South Land Minerals

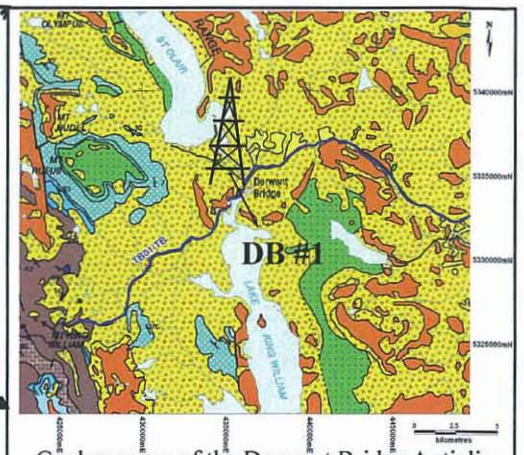
Derwent Bridge Anticline

(DB # 1) May 2008

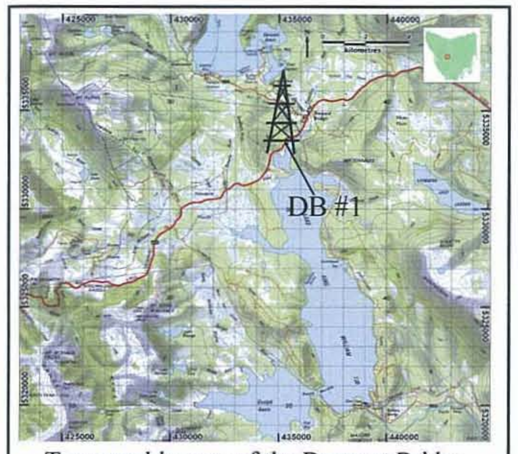
Compiled by Dr. Zohreh Amini



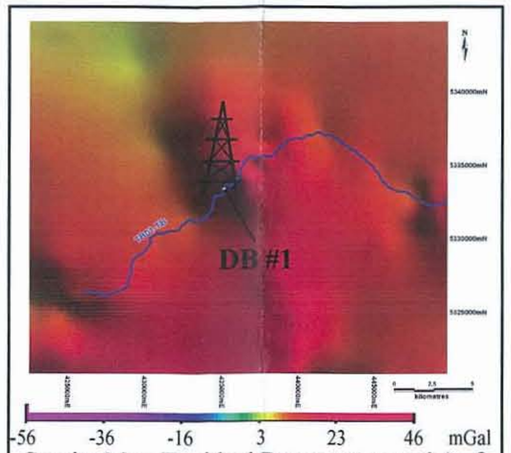
Geology of the Tasmania Basin and location of drill site on the Derwent Bridge Anticline



Geology map of the Derwent Bridge Anticline and location of proposed drill site (DB # 1)

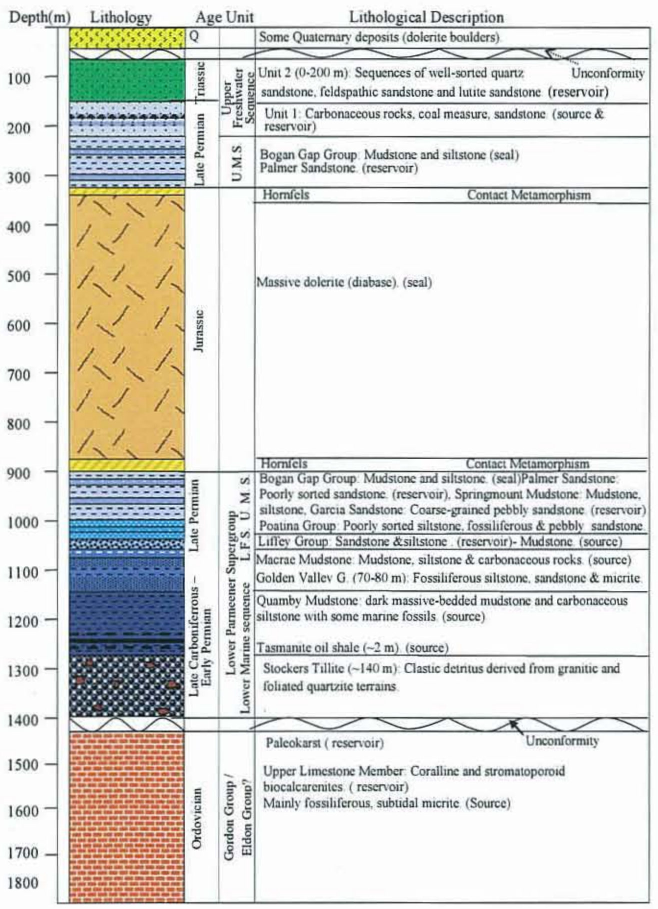


Topographic map of the Derwent Bridge Anticline (DB # 1)



Gravity Map (Residual Bouguer Anomaly) of the Derwent Bridge (DB # 1)

Area onshore Tasmania Special Exploration Licence 13/98



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

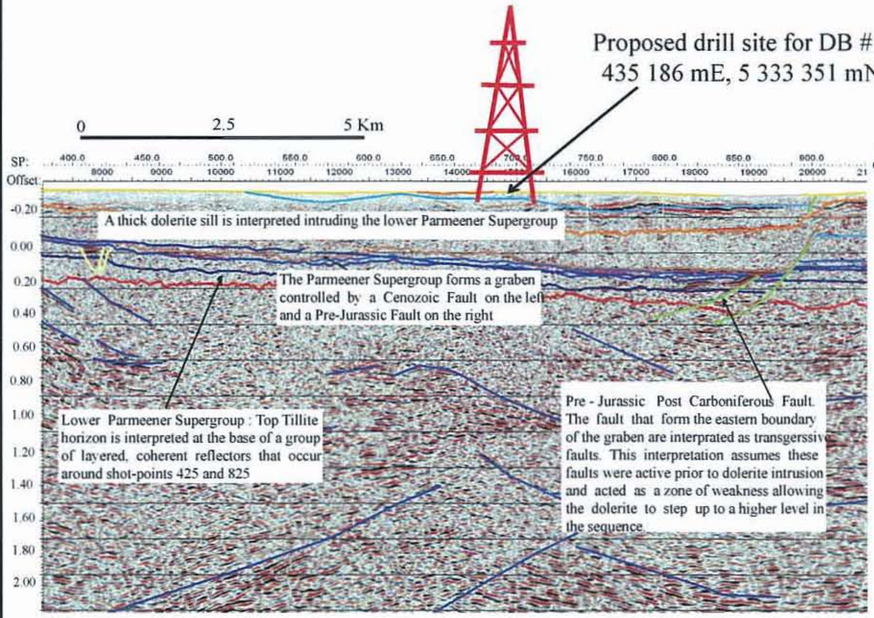
Prediction of Stratigraphy at the Derwent Bridge Anticline (DB #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	36	-	36
(P50)	87	-	87
(P10)	199	-	199

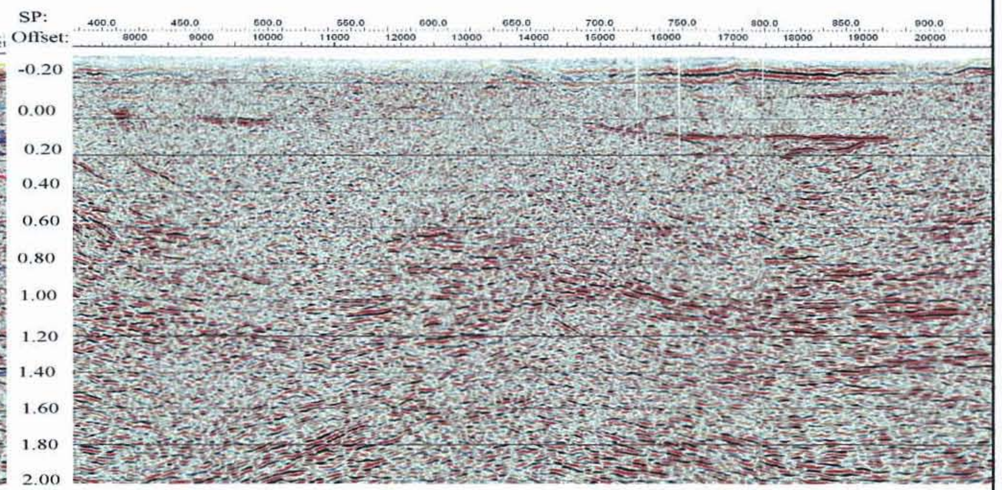
Monte – Carlo simulations of potential, undiscovered petroleum at Derwent Bridge #1 in million barrels

Petroleum System Characteristics of the Derwent Bridge Anticline (based on seismic line TB01-TB):

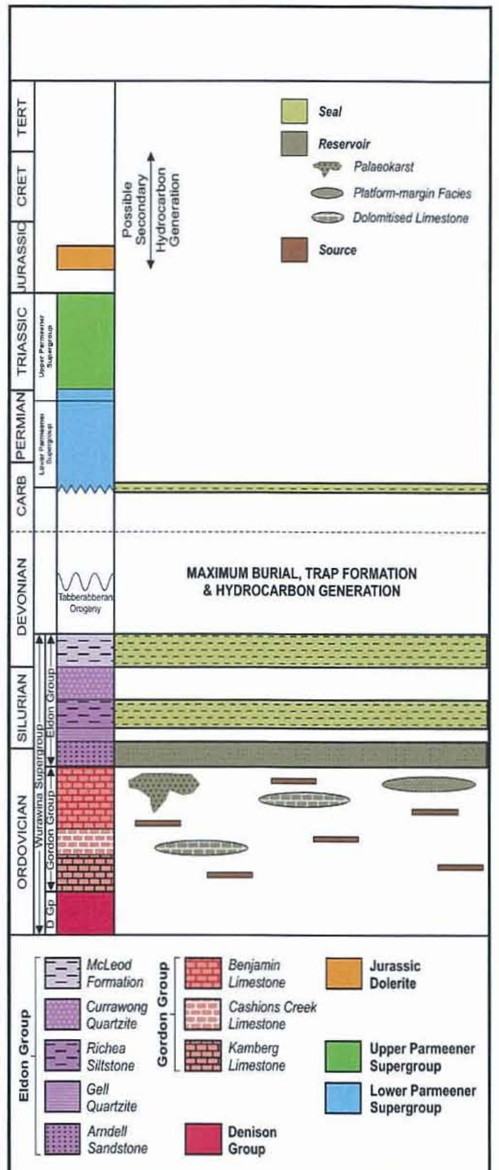
Target:	Triassic, Permian, Gordon Group Upper Limestone Member of Ordovician
Source:	Unit 1, Quamby mudstone (Tasmanite oil shale), Upper Limestone Members
Reservoir:	Unit 2, Unit 1, Palmer Sandstone, Garcia sandstone, Liffey Group, Upper Limestone Member (Ordovician).
Depth to top of reservoir:	Unit 2= 50 m, Unit 1 = 150 m, Palmer Sandstone = 230 m and 910 m, Garcia sandstone = 300 m and 950 m, Liffey Group = ~1030 m, Upper Limestone Member = ~ 1420 m.
Seal:	Jurassic Dolerite, Ferntree Formation
Trap:	Anticline
Risk:	This structure is currently poorly defined. If the rocks belong to the Eldon and Gordon Groups, they are prospective for hydrocarbons. Potential source rocks are also present in the Woody Island Siltstone.



Seismic line TB01-TB with structural and stratigraphic interpretations



Seismic line TB01-TB without interpretations



Stratigraphic events chart for the Larapintine petroleum system in Tasmania. Source rocks are marked in the Gordon Group, reservoir in the Gordon Group and Eldon Group and seals in the Eldon Group and Lower Parmeener Supergroup.

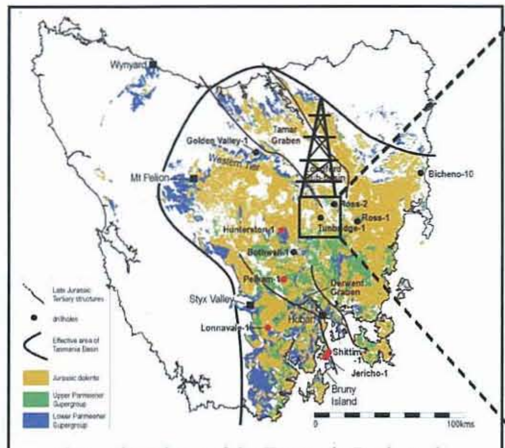
EMPIRE Energy

Great South Land Minerals

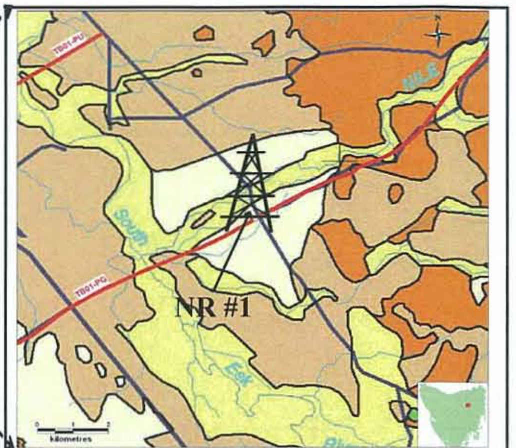
Nile River Fault Block

(NR #1) May 2008

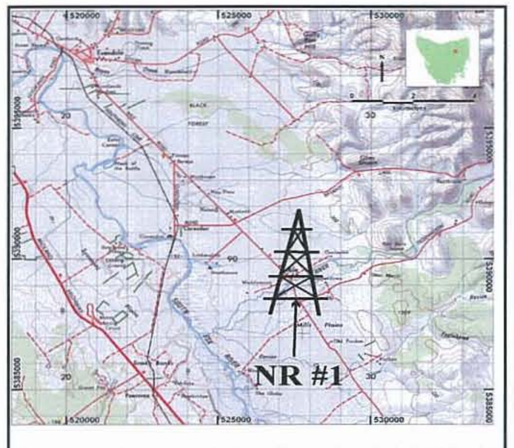
Compiled by Dr. Zohreh Amini



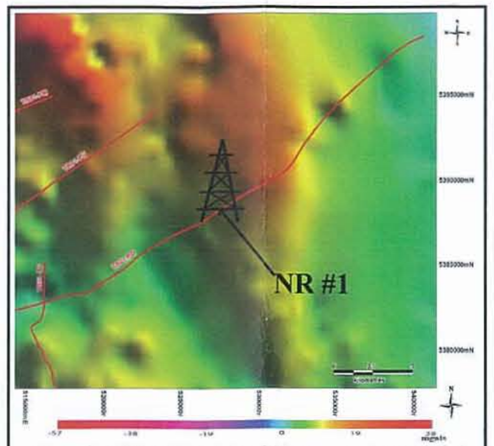
General geology of the Tasmania Basin and location of drill site on the Nile River Fault Block



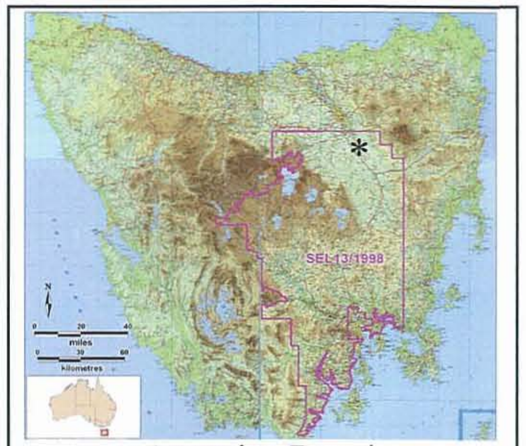
Geology map of the Nile River Fault Block and location of proposed drill site (NR #1)



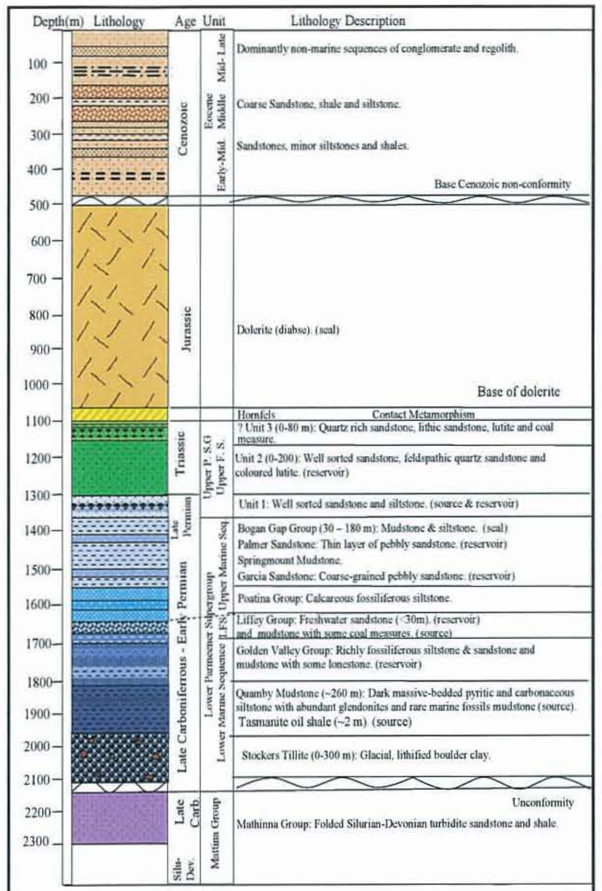
Topographic map of the Nile River Fault Block (NR #1)



Gravity Map (Residual Bouguer Anomaly) of the Nile River Fault Block (NR#1)



Area onshore Tasmania Special Exploration Licence 13/98



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

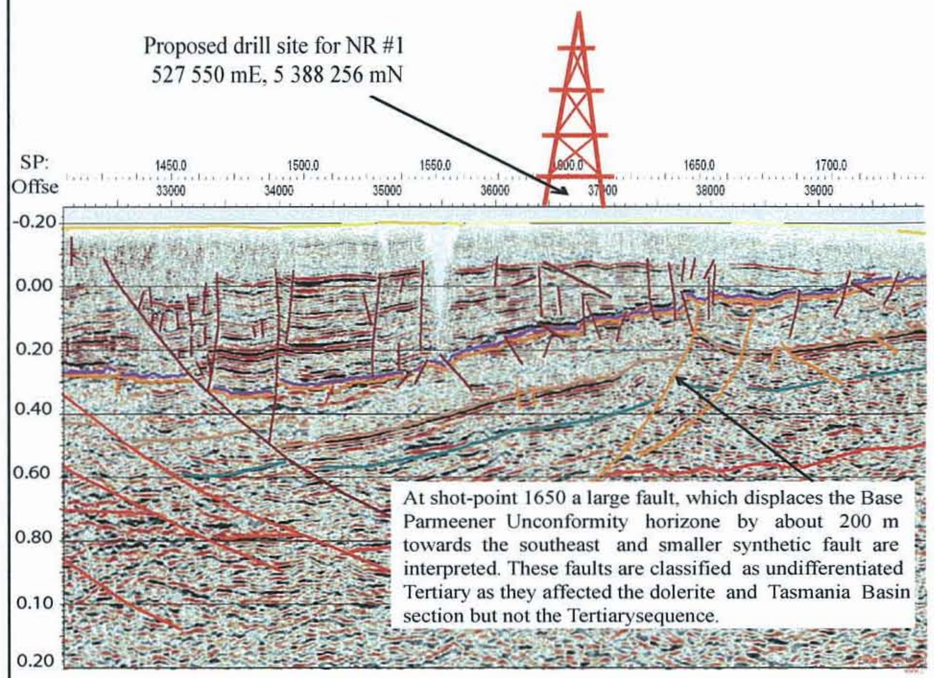
Prediction of Stratigraphy at Nile River Fault Block (NR #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	20	-	20
(P50)	45	-	45
(P10)	92	-	92

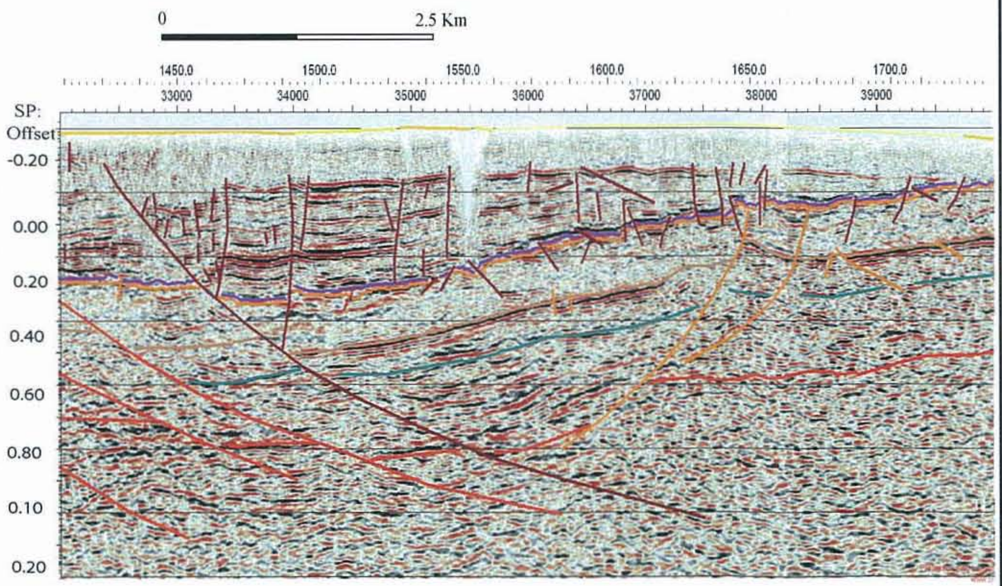
Monte – Carlo simulations of potential, undiscovered petroleum at Nile River #1 in million barrels.

Petroleum System Characteristics of the Nile River Anticline (based on seismic line TB01- PG)

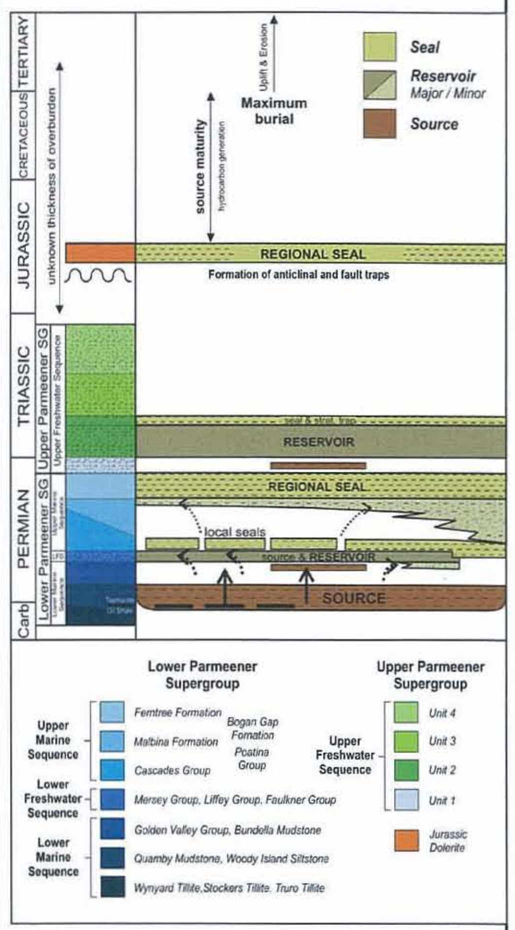
Target:	Triassic, Early to Late Permian.
Source:	Unit 1, Liffey Group, Quamby Mudstone, Tasmanite oil shale.
Reservoir:	Unit 2- (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = ~ 1150 m , Unit 1 = 1300 m, Palmer Sandstone= ~ 1410 m , Garcia Sandstone= ~1500 m , Liffey Group= ~1650 m
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Fault Block
Risk:	Timing, maturation and migration in the mid Jurassic to Cretaceous.Traps were formed in early Cenozoic. Burial in the Cenozoic, plus an elevated geothermal gradient.



Seismic line TB01-PG with structural and stratigraphic interpretations



Seismic line TB01-PG without interpretations



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. 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.

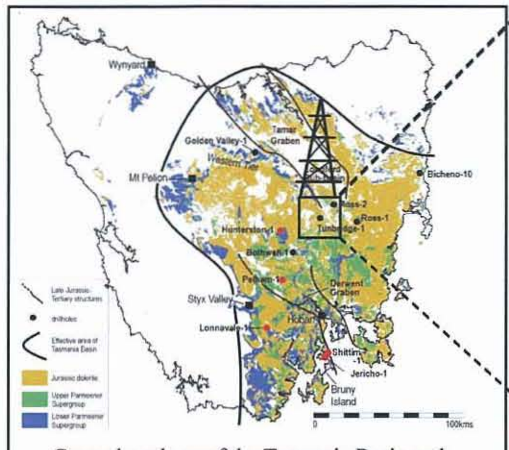
EMPIRE Energy

Great South Land Minerals

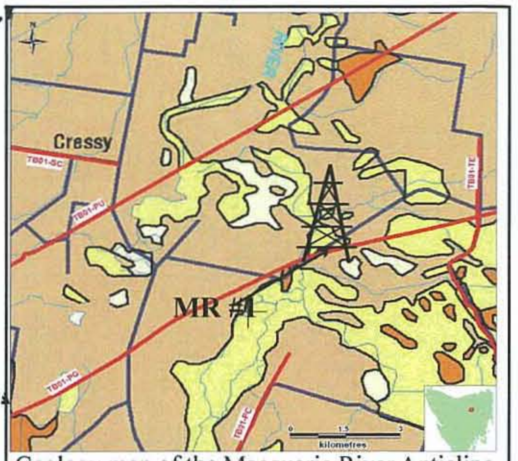
Macquarie River Anticline

(MR #1) May 2008

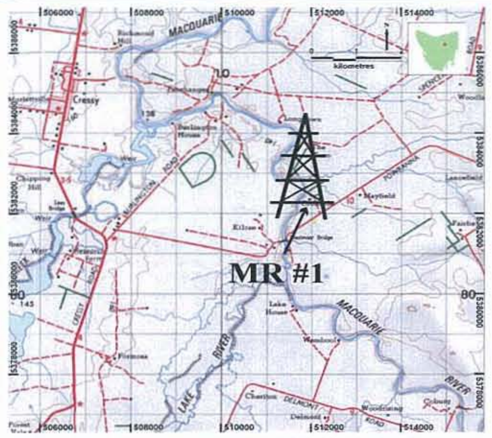
Compiled by Dr. Zohreh Amini



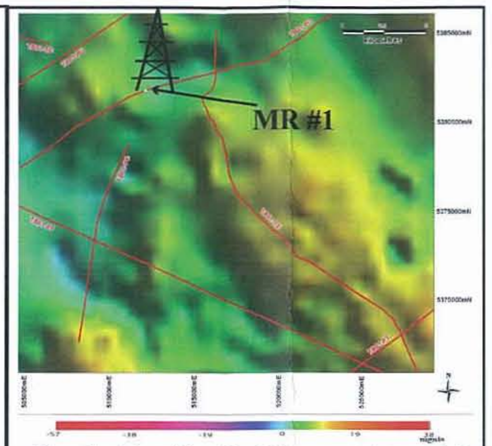
General geology of the Tasmania Basin and location of drill site on Macquarie River Anticline



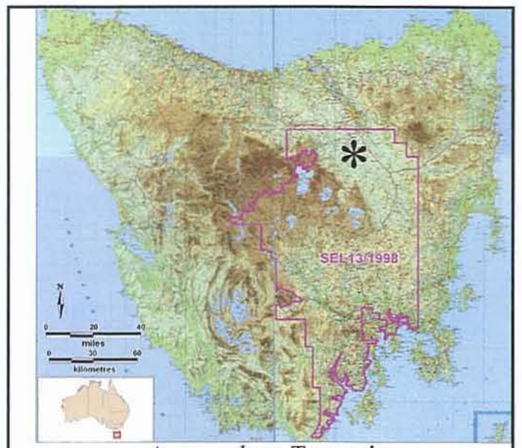
Geology map of the Macquarie River Anticline and location of proposed drill site (MR #1)



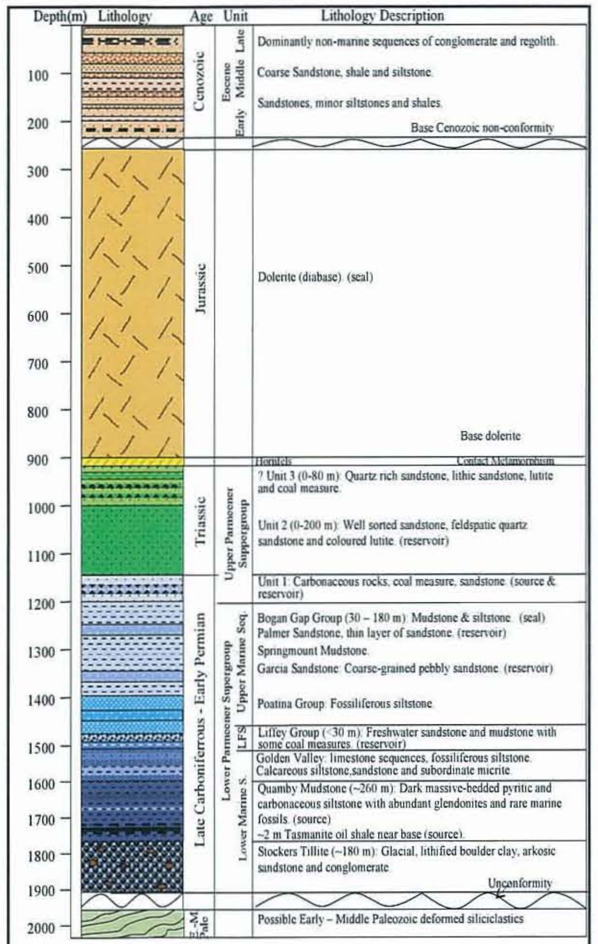
Topographic map of the Macquarie River Anticline (MR #1)



Gravity Map (Residual Bouguer Anomaly) of the Macquarie River Anticline (MR#1)



Area onshore Tasmania Special Exploration Licence 13/98



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

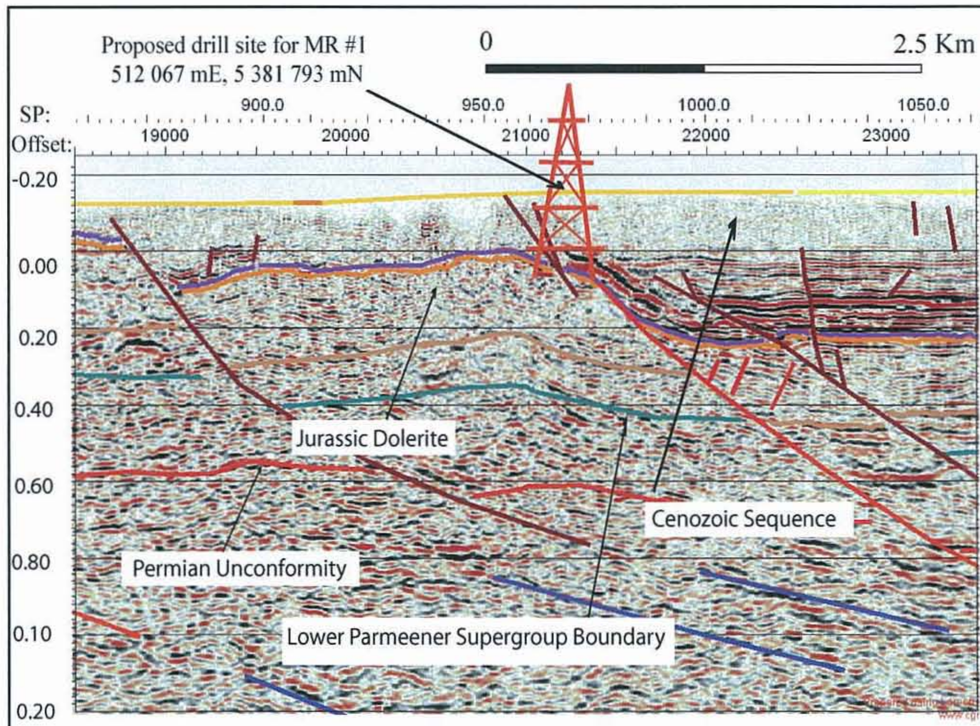
Prediction of Stratigraphy at Macquarie River Anticline (MR #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	5	-	5
(P50)	12	-	12
(P10)	24	-	24

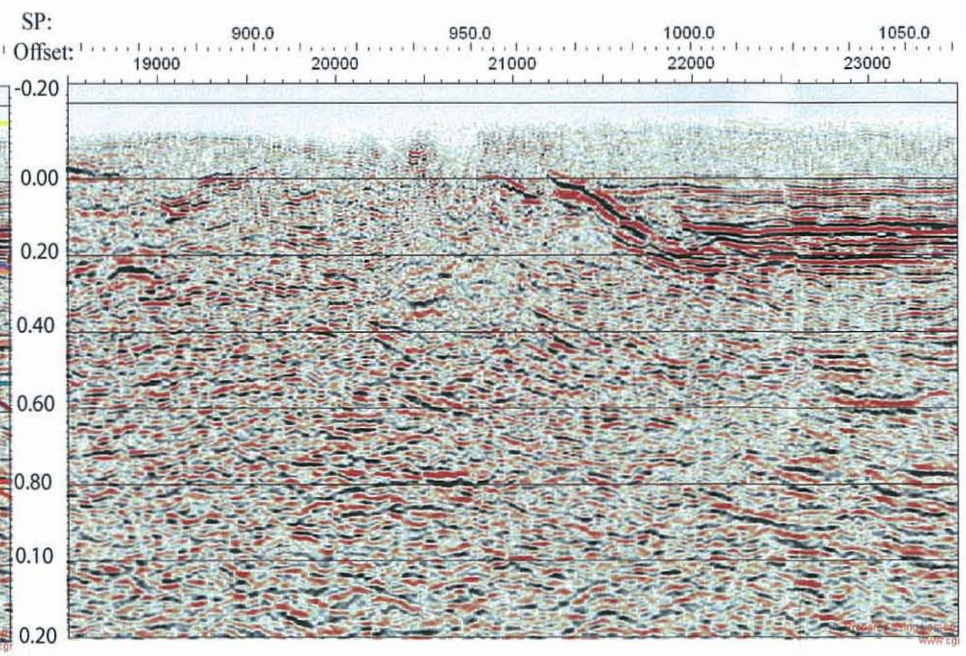
Monte – Carlo simulations of potential, undiscovered petroleum at Macquarie River #1 in million barrels.

Petroleum System Characteristics of the Macquarie River Anticline (based on seismic line TB01- PG)

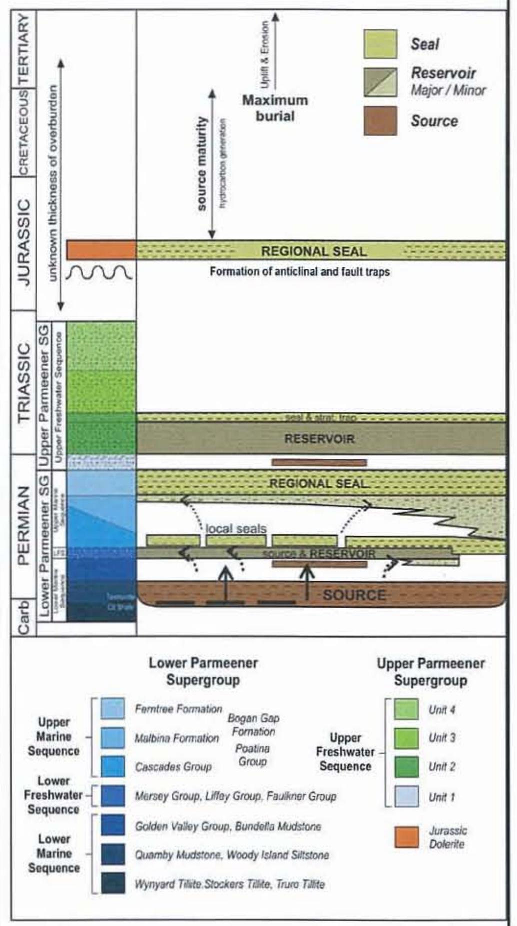
Target:	Triassic, Early to Late Permian
Source:	Unit 1, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = ~1000 m, Unit 1 = ~1050, Palmer Sandstone= ~1250 m, Garcia Sandstone= ~1350 m, Liffey Group= ~1480 m
Seal:	Jurassic Dolerite, Bogan Gap Group Mudstone
Trap:	Anticline
Risk:	Timing, maturation and migration in the mid Jurassic to Cretaceous.Traps were formed in early Cenozoic. Burial in the Cenozoic, plus an elevated geothermal gradient.



Seismic line TB01-PG with structural and stratigraphic interpretations



Seismic line TB01-PG without interpretations



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. 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.

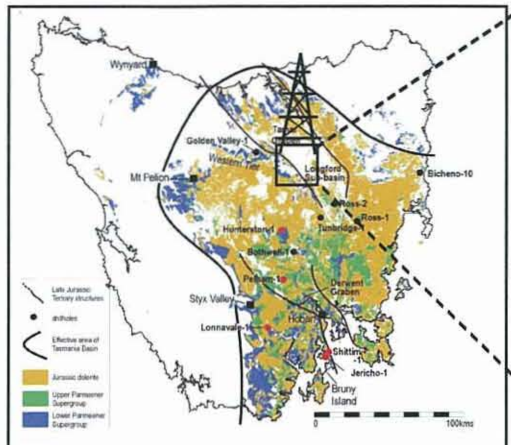
EMPIRE Energy

Great South Land Minerals

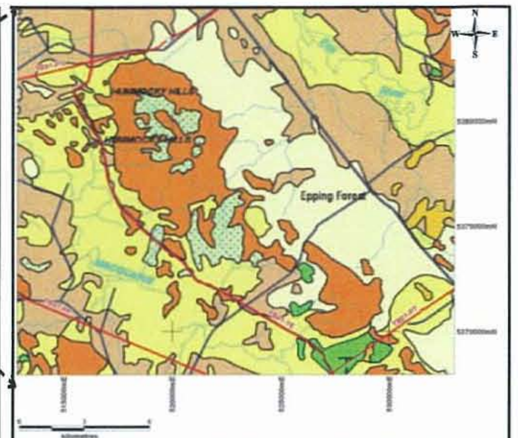
Hummocky Hills Fault Block

(HH #1) May 2008

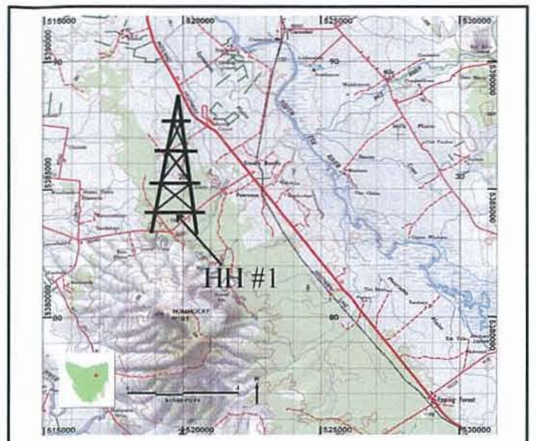
Compiled by Dr. Zohreh Amini



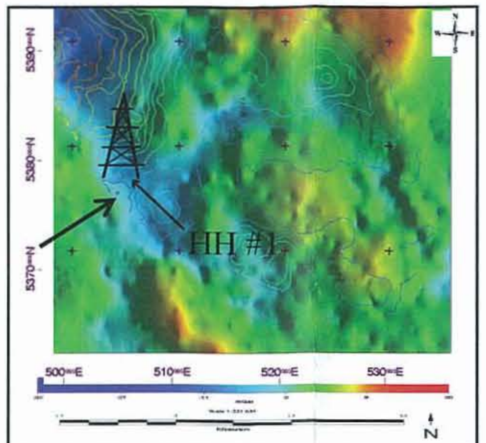
Geology of the Tasmania Basin and location of drill site on Hummocky Hills Fault Block.



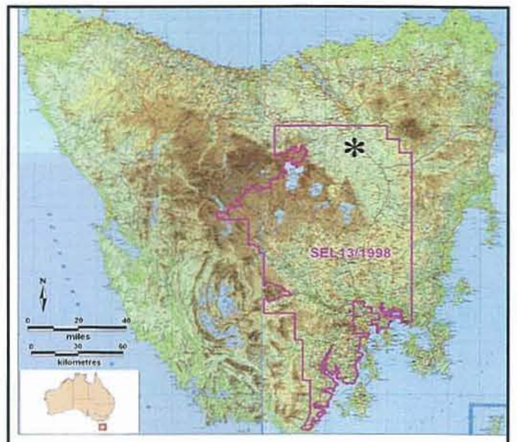
Geology map of the Hummocky Hills Fault Block and location of proposed drill site.



Topographic map of the Hummocky Hills Fault Block (HH#1)



Gravity Map (Residual Bouguer Anomaly) of the Hummocky Hills Fault Block (HH#1)



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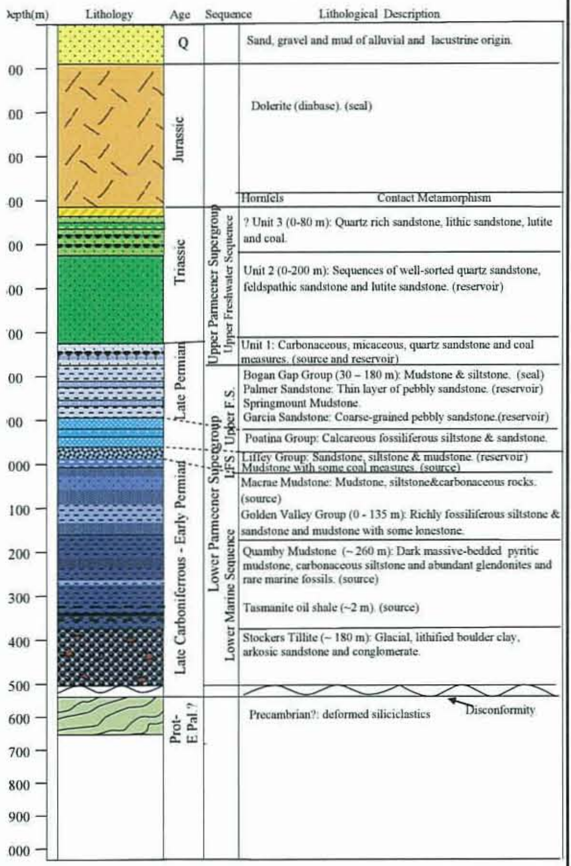


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

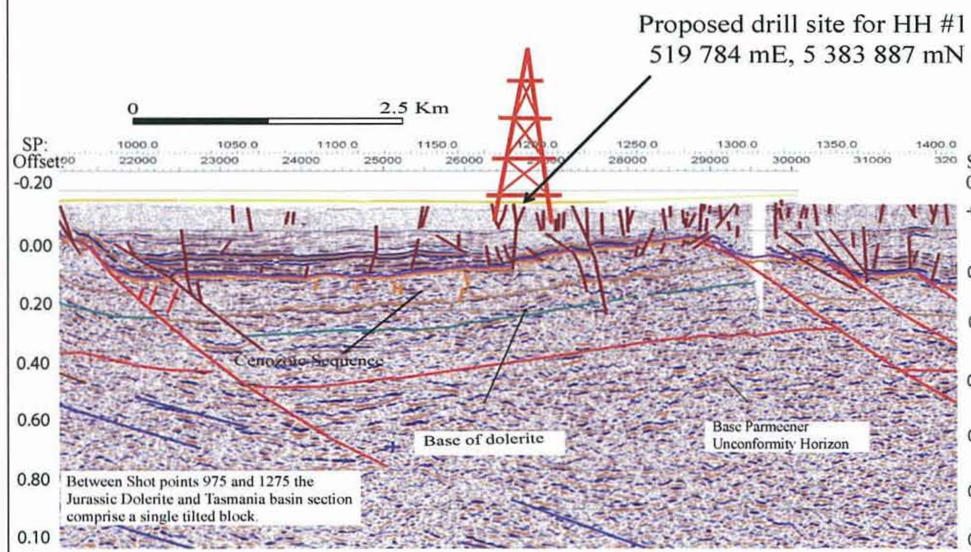
Prediction of Stratigraphy at Hummocky Hills Fault Block (HH #1).

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	8	-	8
(P50)	16	-	16
(P10)	30	-	30

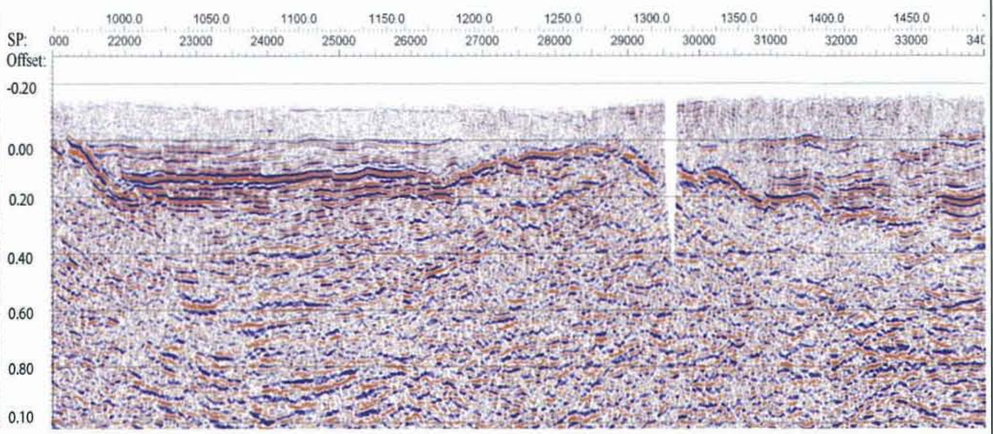
Monte – Carlo simulations of potential, undiscovered petroleum at Hummocky Hills # 1 in million barrels.

Petroleum System Characteristics of the Hummocky Hills Half Graben (based on seismic line TB01- PG)

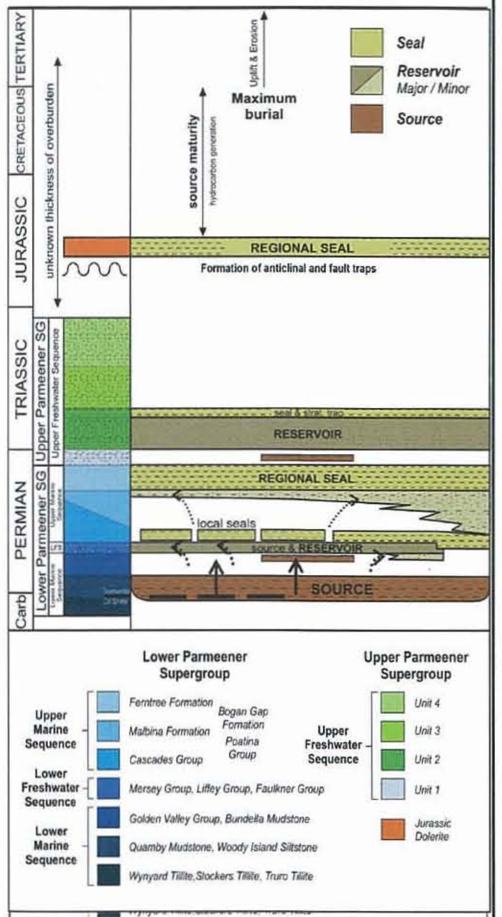
Target:	Triassic, Early to Late Permian
Source:	Unit 1, Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite Oil Shale
Reservoir:	Unit 2 (Triassic), unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = 510 m, Unit 1 =~710 m, Palmer Sandstone=~ 810 m, Garcia Sandstone=~ 860 m, Liffey Group=~960 m.
Seal:	Jurassic Dolerite
Trap:	Half Graben
Risk:	Timing, maturation and migration in the Mid-Jurassic to the Cretaceous - traps were formed in the early Cenozoic. Burial in the Cenozoic, plus an elevated geothermal gradient may result in generation of late hydrocarbons.



Seismic line TB01-PG with structural and stratigraphic interpretations



Seismic line TB01-PG without interpretations



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. 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.

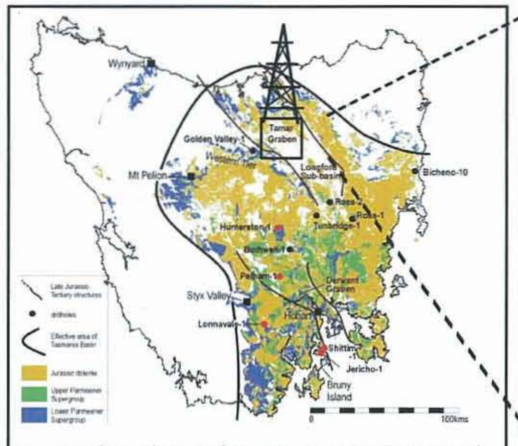
EMPIRE Energy

Great South Land Minerals

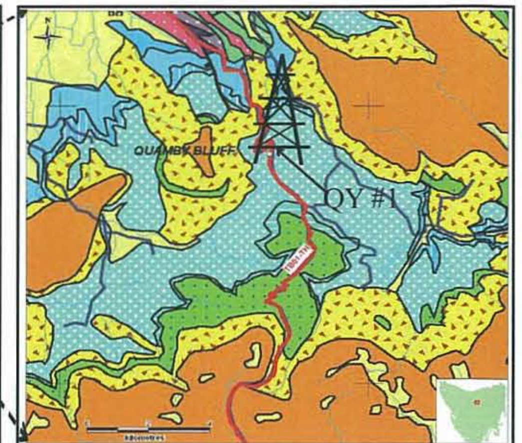
Quamby Fault Block

(QY #1) May 2008

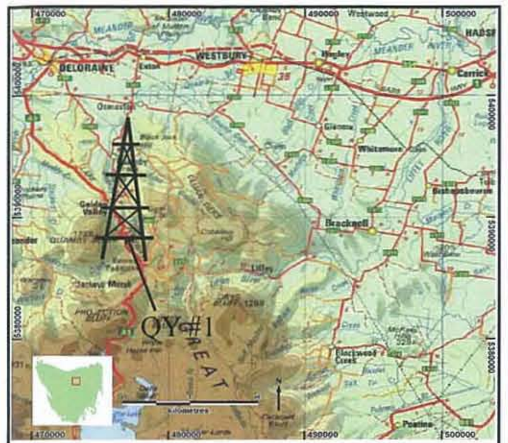
Compiled by Dr. Zohreh Amini



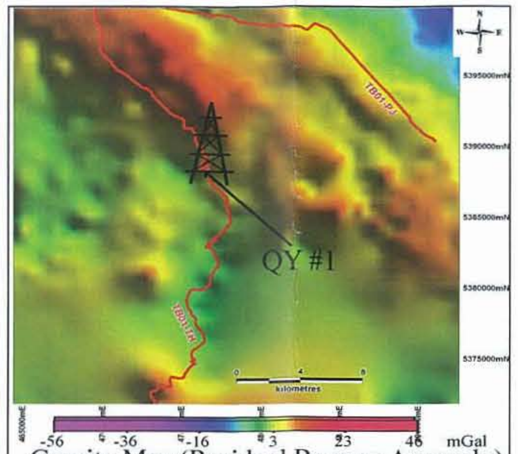
General geology of the Tasmania Basin and location of drill site on the Quamby Fault Block



Geology map of the Quamby Fault Block and location of proposed drill site (QY #1)



Topographic map of the Quamby Fault Block (QY#1)



Gravity Map (Residual Borguer Anomaly) of the Quamby Fault Block (QY#1)

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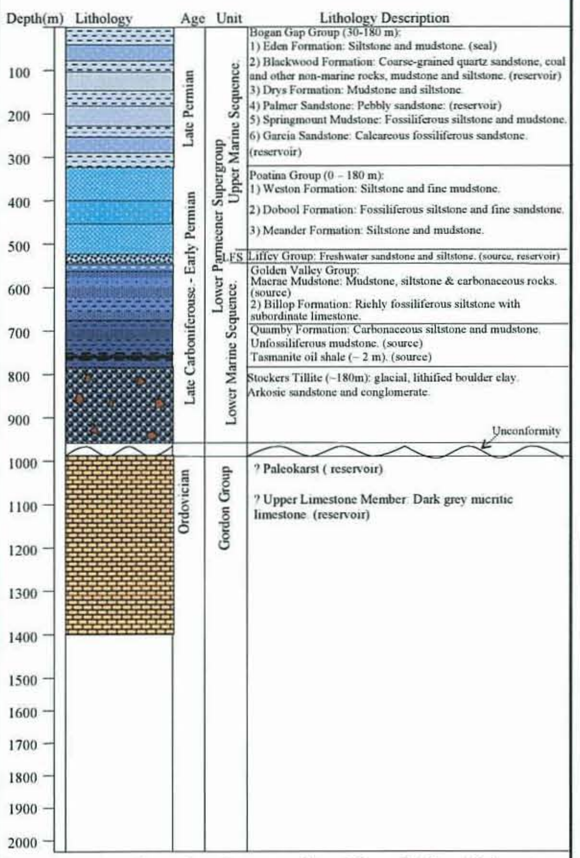


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

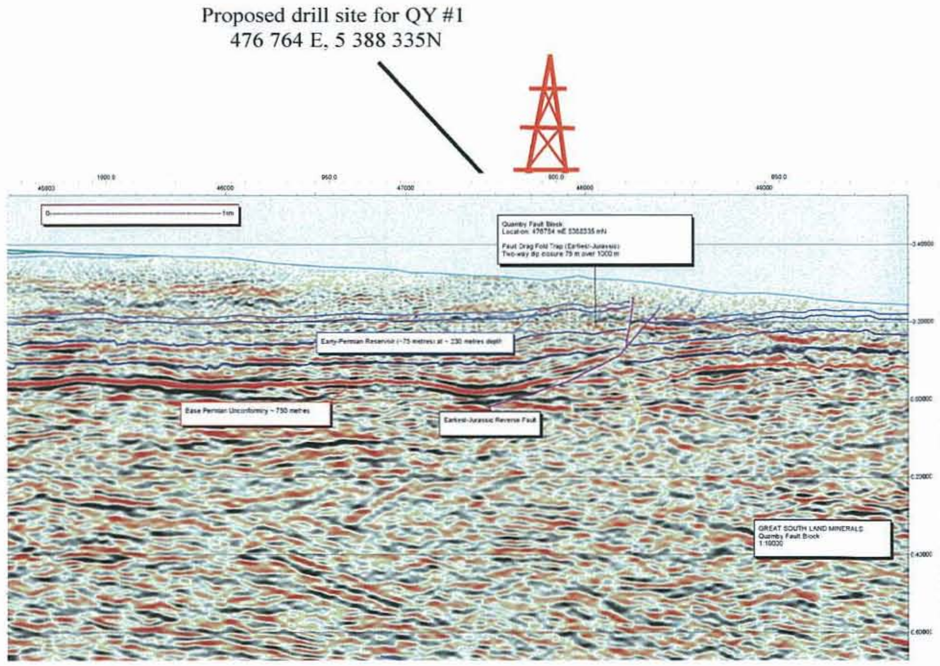
Prediction of Stratigraphy at the Quamby Fault Block (QY #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	2	-	2
(P50)	5	-	5
(P10)	10	-	10

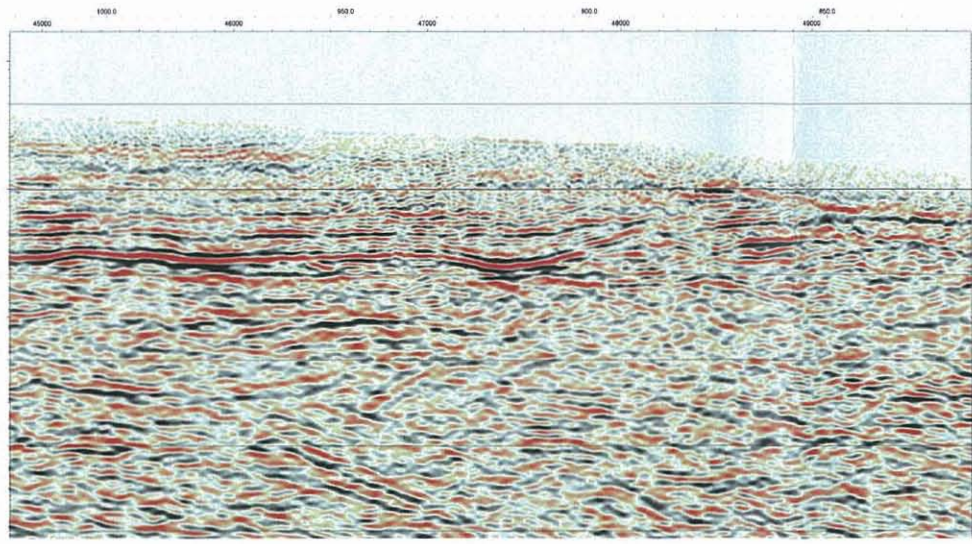
Monte – Carlo simulations of potential, undiscovered petroleum at Quamby #1 in million barrels.

Petroleum System Characteristics of the Quamby Fault Block (based on seismic line TB01-TH)

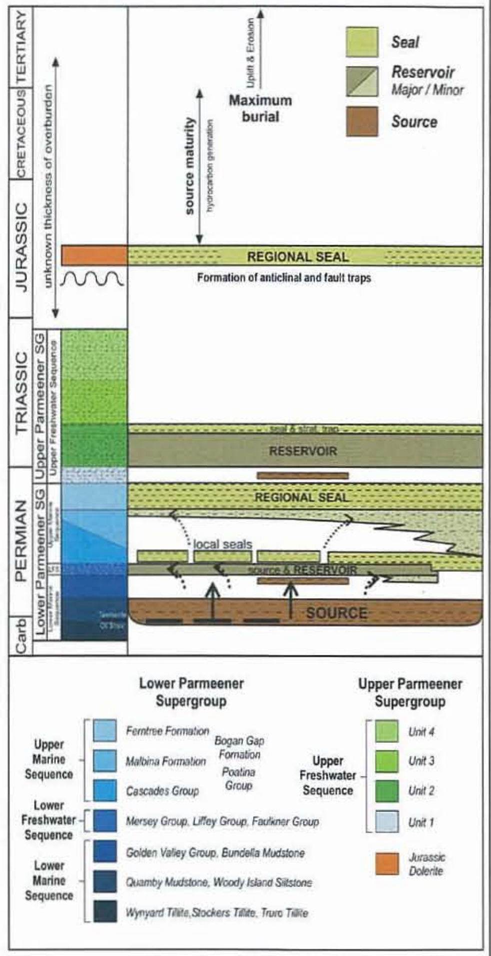
Target:	Permian reservoirs in Jurassic age fault block.
Source:	Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale.
Reservoir:	Blackwood Fm, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian), Gordon Group (Ordovician).
Depth to top of reservoir:	Blackwood Fm = ~200 m, Palmer Sandstone = ~120 m, Garcia Sandstone = ~250 m, Liffey Group = ~ 510 m, Gordon Group = ~990 m.
Thickness of reservoir:	Sandstones in Bogan Gap Group = ~ 20 m in total, Liffey Group = ~ 30 m, Gordon Group = ~ 400 m.
Seal:	Latest Bogan Gap Group Mudstones
Trap:	Fault Block
Risk:	Timing of structuring (Jurassic) is pre-generation and is therefore excellent.



Seismic line TB01-TH with structural and stratigraphic interpretations



Seismic line TB01-TH without interpretations



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. 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.

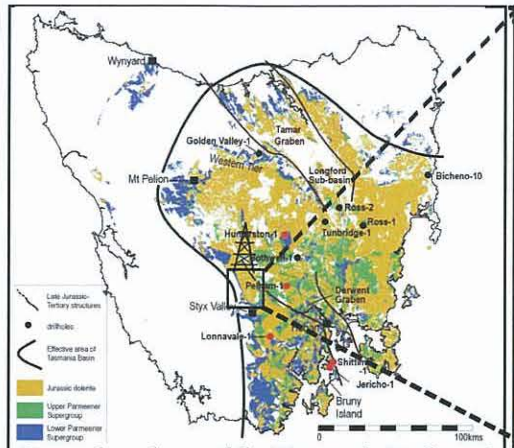
EMPIRE Energy

Great South Land Minerals

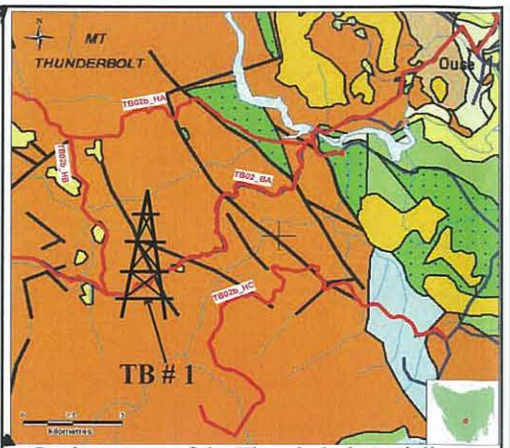
Thunderbolt Anticline

(TB # 1) May 2008

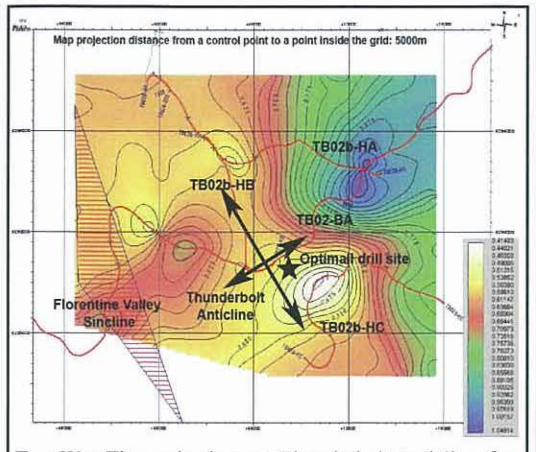
Compiled by Dr. Zohreh Amini



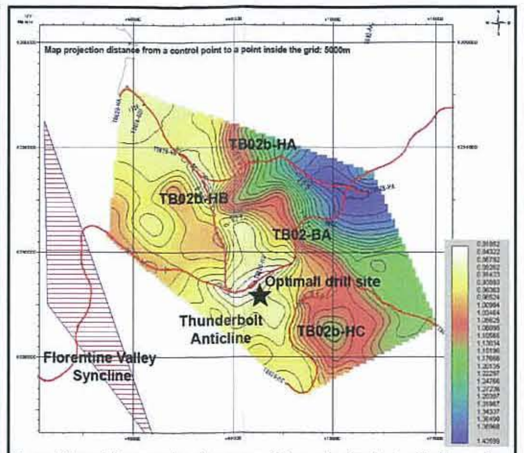
General geology of the Tasmania Basin and location of drill site on Thunderbolt Anticline



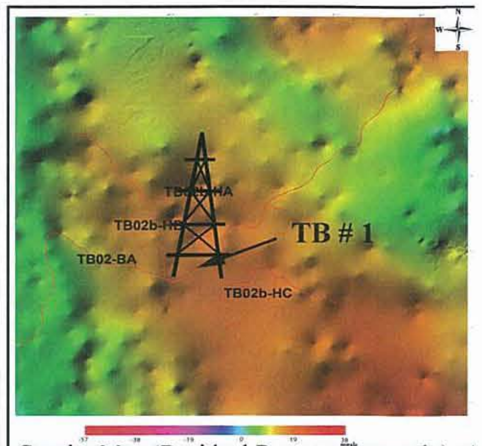
Geology map of the Thunderbolt Anticline and location of proposed drill site (TB # 1)



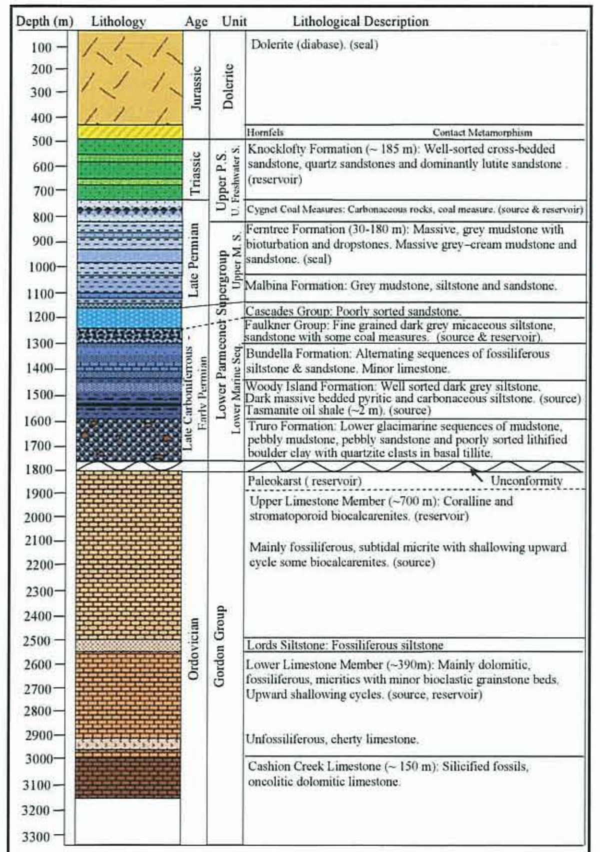
Two Way Time seismic map, Thunderbolt Anticline, for Upper Limestone Member of Gordon Group (Late Ord.)



Two Way Time seismic map, Thunderbolt Anticline, for Lower Limestone Member of Gordon Group (Mid. Ord.)



Gravity Map (Residual Bouguer Anomaly) of the Thunderbolt Anticline South (TB # 1)



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

Prediction of Stratigraphy at Thunderbolt Anticline (TB # 1)

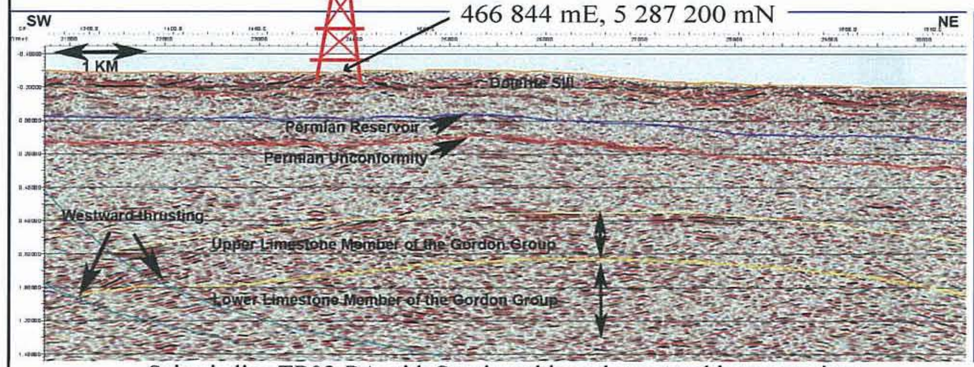
	Permo-Triassic	Ordovician -Devonian	Total
(P90)	60	56	116
(P50)	126	117	243
(P10)	246	222	468

Monte – Carlo simulations of potential, undiscovered petroleum at Thunderbolt in million barrels.

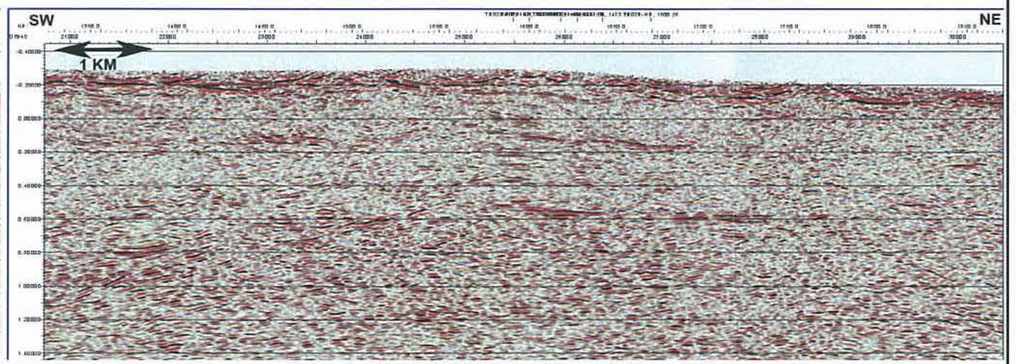
Petroleum System Characteristics for Thunderbolt Anticline (based on seismic line TB02-BA):

Target:	Permo- Triassic of Gondwanan system and Gordon Group Upper Limestone Member of Ordovician age
Source:	Faulkner Group, Woody Island, Tasmanite oil shale, Upper Limestone Member, Lower Limestone Member
Reservoir:	Knocklofty Formation (Triassic), Cygnet Coal Measures, Faulkner Group (Permian), Upper Limestone Members, Lower Limestone Members, (Ordovician)
Depth to top of reservoir:	Knocklofty Formation, =~500 m, Cygnet Coal Measures,= ~750 m, Faulkner Group =~1250 m, Upper Limestone Member =~1800 m, Lower L.M. =~2500 m
Thickness of reservoir:	Knocklofty Formation, = ~220 m, Cygnet Coal Measures,= ~60 m, Faulkner Group = ~30 m, Upper Limestone Member = ~ 700 m, Lower L.M. = ~ 350 m
Seal:	Jurassic Dolerite, Ferntree Formation,
Trap:	Anticline
Risk:	Source, quality and maturation. Recent work indicates the Gordon Group may be prospective for hydrocarbons. Potential source rocks are also present in Woody Island Siltstone.

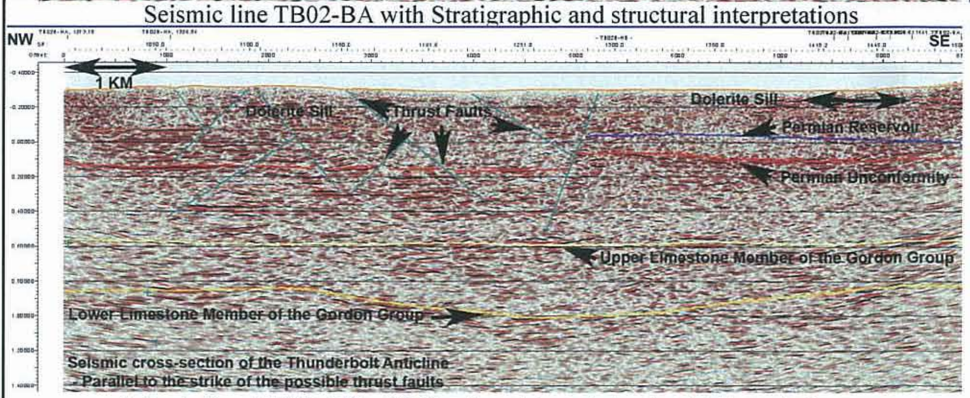
Proposed drill site for TB # 1
466 844 mE, 5 287 200 mN



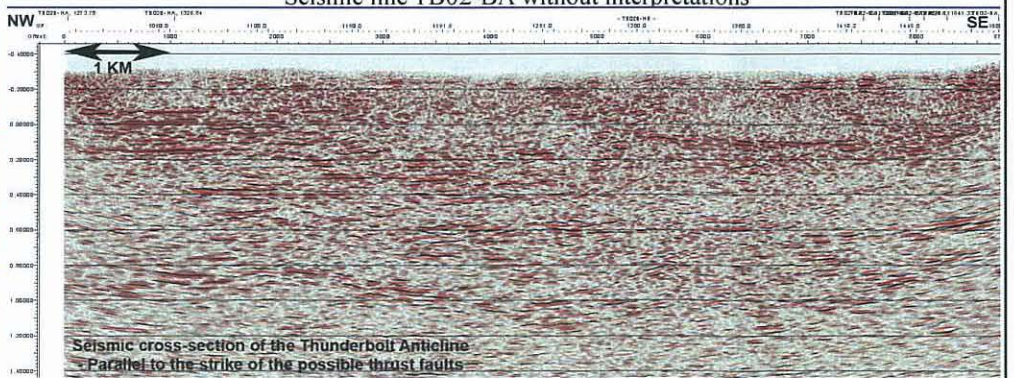
Seismic line TB02-BA with Stratigraphic and structural interpretations



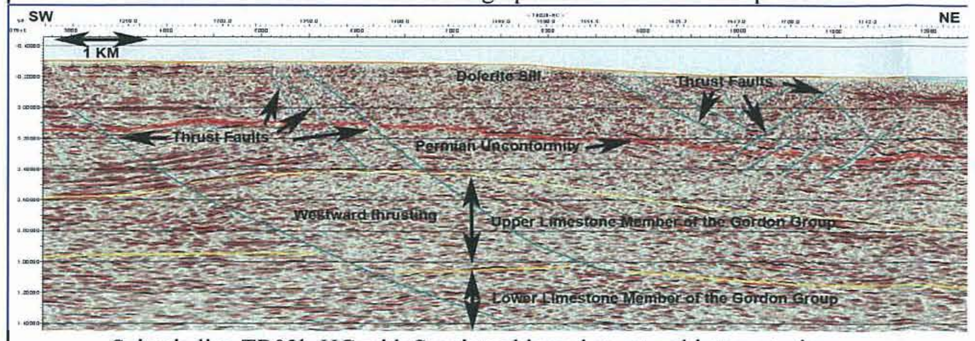
Seismic line TB02-BA without interpretations



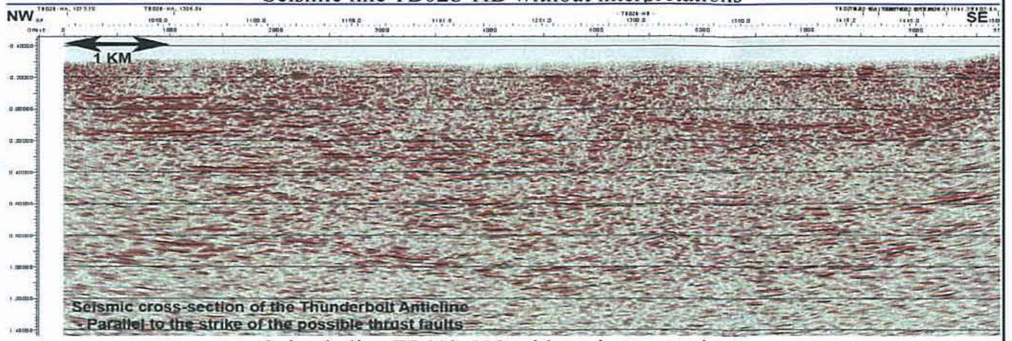
Seismic line TB02b-HB with Stratigraphic and structural interpretations



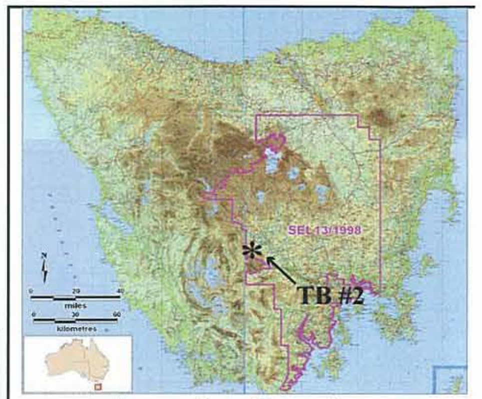
Seismic line TB02b-HB without interpretations



Seismic line TB02b-HC with Stratigraphic and structural interpretations



Seismic line TB02b-HC without interpretations



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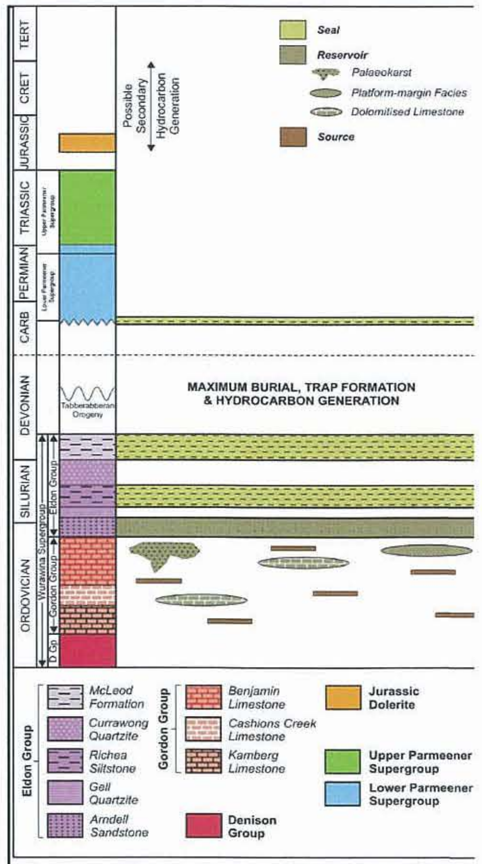


Stratigraphic events chart for the Larapintine petroleum system in Tasmania. Source rocks are marked in the Gordon Group, reservoir in the Gordon Group and Eldon Group and seal in the Eldon Group and Lower Parmeene Supergroup.

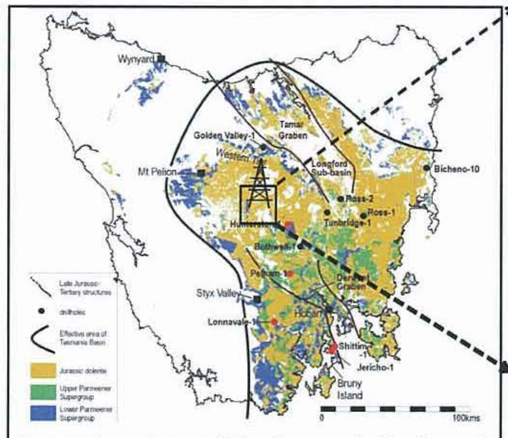
EMPIRE Energy

Great South Land Minerals

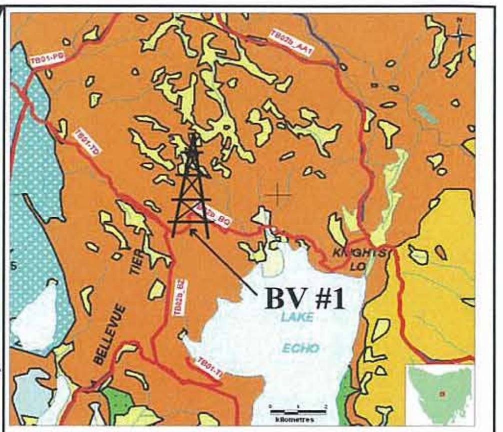
Bellevue Anticline

(BV #1) May 2008

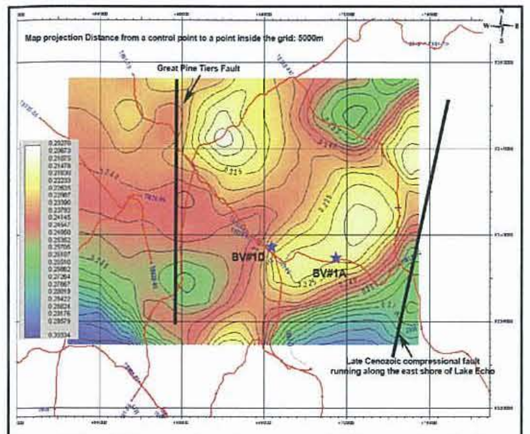
Compiled by Dr. Zohreh Amini



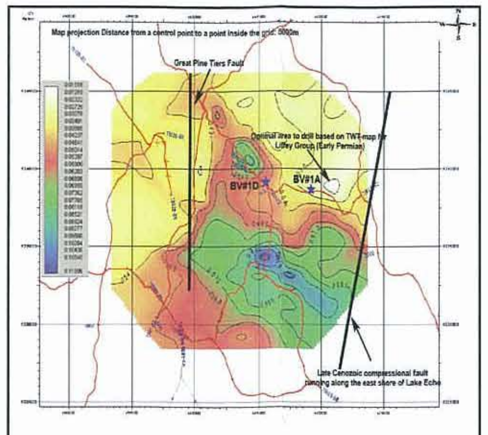
General geology of the Tasmania Basin and location of drill site on Bellevue Anticline



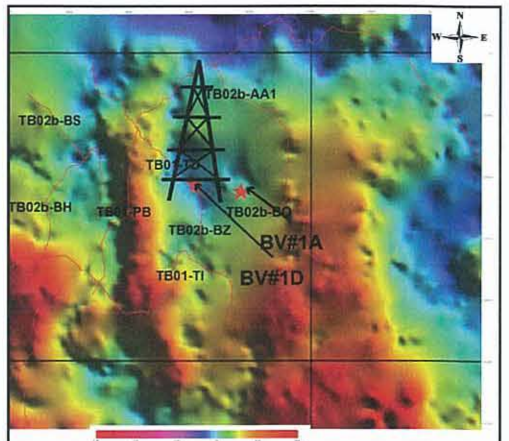
Geology map of the Bellevue Anticline and location of proposed drill site (BV #1)



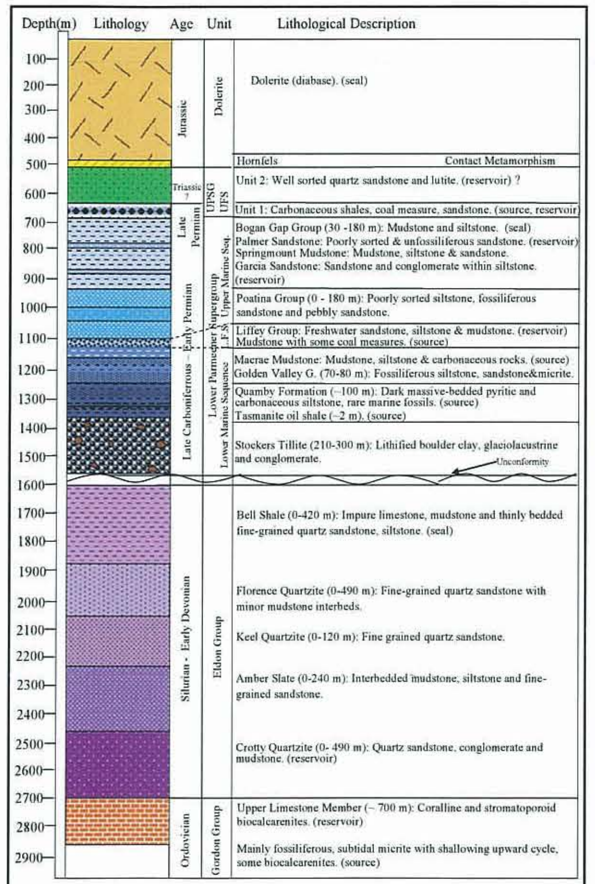
Two Way Time seismic map, Bellevue Anticline, for Upper Limestone Member of Gordon Group



Two Way Time seismic map, Bellevue Anticline, for Liffey Group



Gravity Map (Residual Bouguer Anomaly) of the Bellevue Anticline (BV # 1).



Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

Prediction of Stratigraphy at Bellevue Anticline (BV #1)

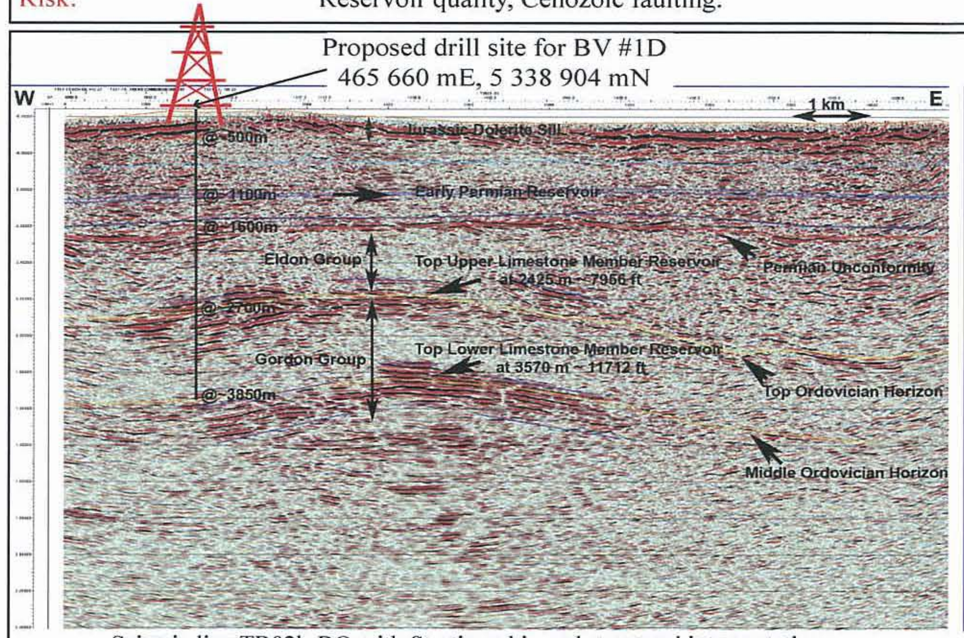
	Permo-Triassic	Ordovician -Devonian	Total
(P90)	134	149	283
(P50)	295	325	620
(P10)	599	657	1256

Monte – Carlo simulations of potential, undiscovered petroleum at Bellevue in million barrels.

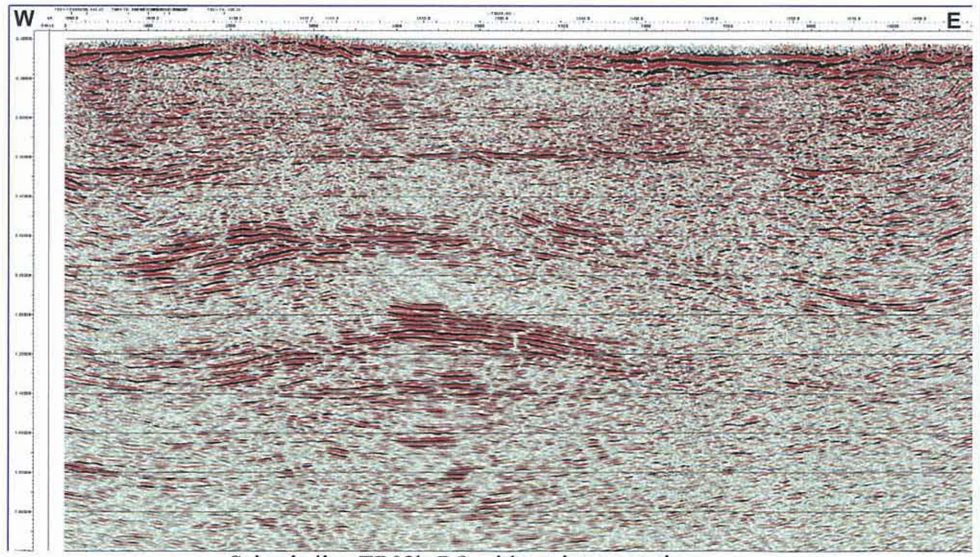
Petroleum System Characteristics for Bellevue Anticline (based on seismic line TB02b-BQ):

Target:	Triassic, Permian, Silurian - Devonian, Ordovician.
Source:	Unit 1, Liffey Group, Quamby Formation, Tasmanite oil shale, Upper Limestone Member.
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer & Garcia Sandstone, Liffey Group (Permian), Crotty Quartzite (Sil-Dev.), Gordon Group limestone (Ordovician).
Depth to top of Reservoir:	Unit 2 = 500 m, Unit 1 = 630 m, Palmer Sandstone = 780 m, Garcia Sandstone = 890 m, Liffey Group = 1100 m, Crotty Quartzite = 2450 m, Upper Limestone Member = 2700 m.
Pay Zone:	Unit 2 = ~25 m, Unit 1= ~10 m, Palmer & Garcia Sandstones = ~3 m in total, Liffey Group = ~30 m, Crotty Quartzite = ~20 m, Upper Limestone Member = ~250 m, Lower Limestone Member = ~250 m.
Seal:	Dolerite, Permian mudstone, Bell Shale, Lords Siltstone.
Trap:	Anticline.
Risk:	Reservoir quality, Cenozoic faulting.

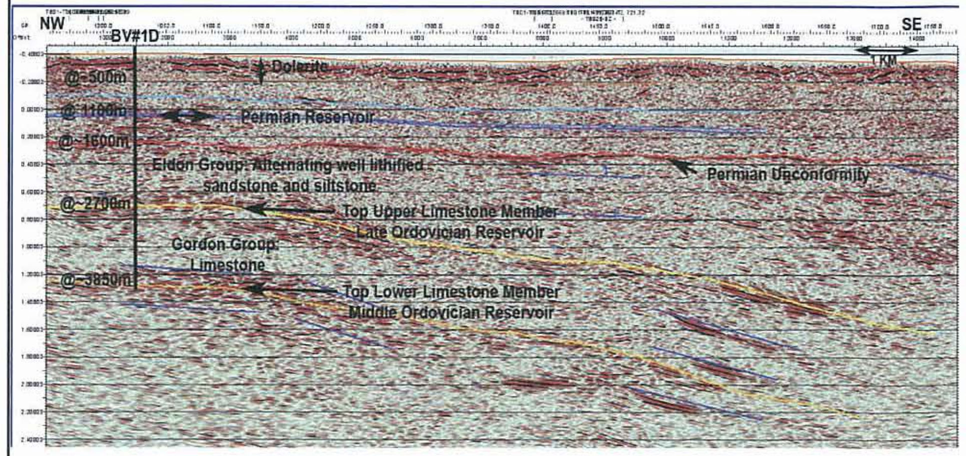
Proposed drill site for BV #1D
465 660 mE, 5 338 904 mN



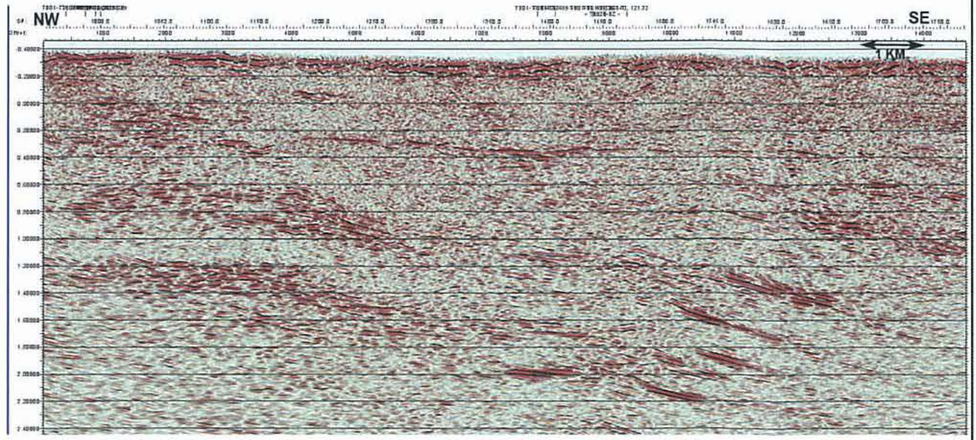
Seismic line TB02b-BQ with Stratigraphic and structural interpretations



Seismic line TB02b-BQ without interpretations



Seismic line TB02b-BZ with Stratigraphic and structural interpretations



Seismic line TB02b-BZ without interpretations

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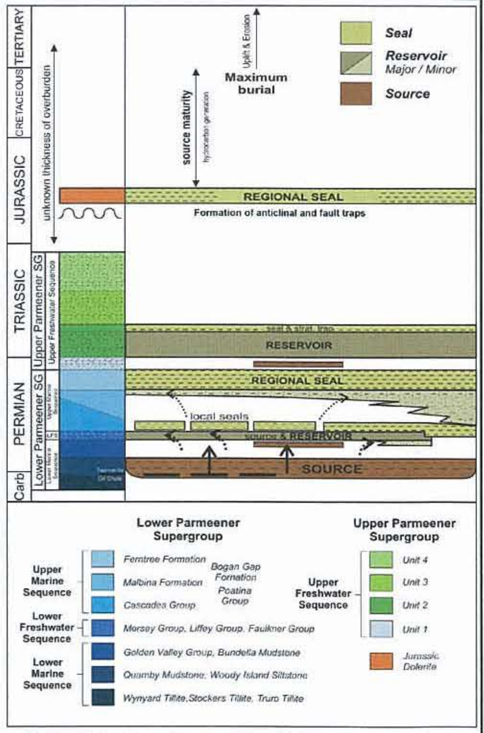


Potential development of the Gondwanan petroleum system in the Tasmania Basin. Major and minor potential source, reservoir and seal facies are indicated, along with timing of trap formation and source maturity. Source rocks are marked in the Woody Island Formation and Liffey Group, reservoir in the Liffey Group, and seals in the Cascade and Ferntree Formation and Jurassic dolerite.

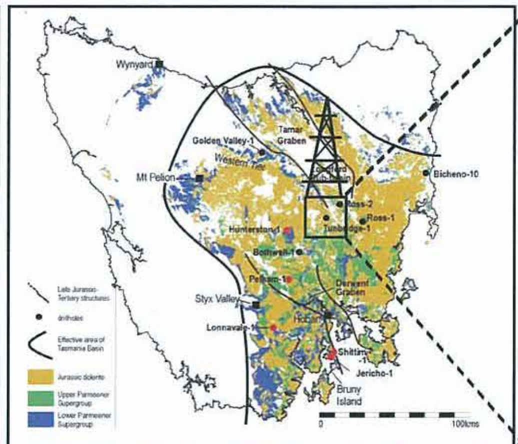
EMPIRE Energy

Great South Land Minerals

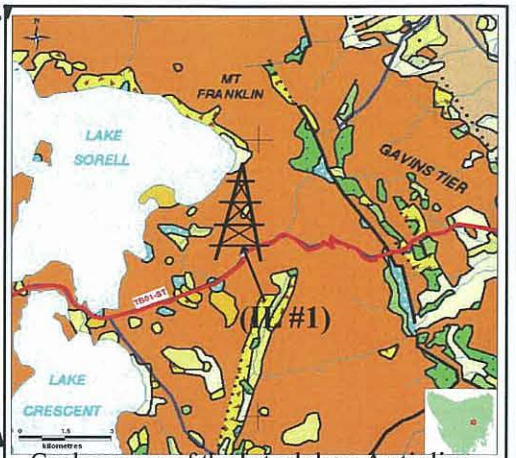
Interlaken Anticline

(IL #1) May 2008

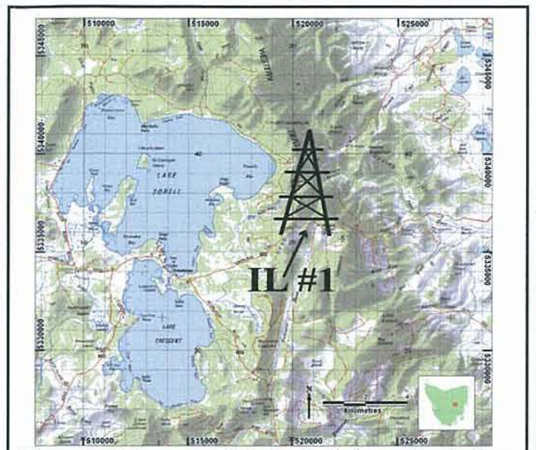
Compiled by Dr. Zohreh Amini



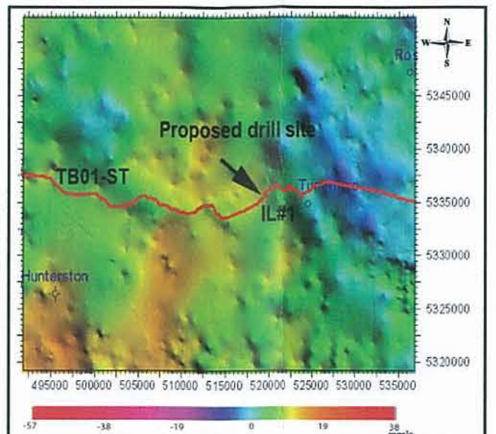
General geology of the Tasmania Basin and location of drill site on the Interlaken Anticline



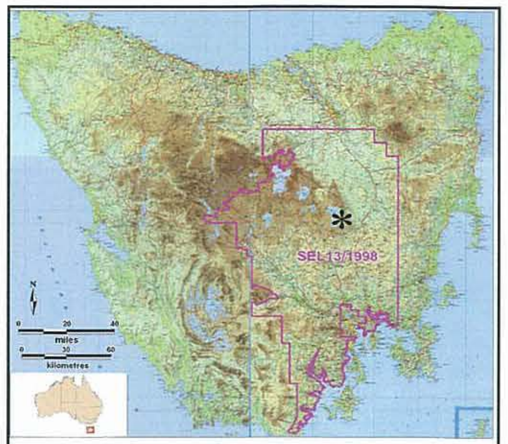
Geology map of the Interlaken Anticline and location of proposed drill site (IL #1)



Topographic map of the Interlaken Anticline (IL #1)



Gravity Map (Residual Bouguer Anomaly) of the Interlaken Anticline (IL#1)



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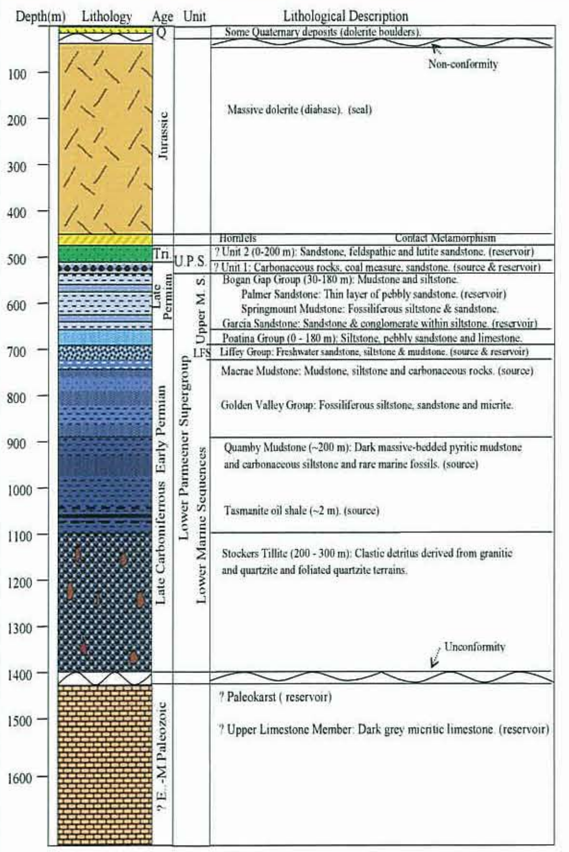


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

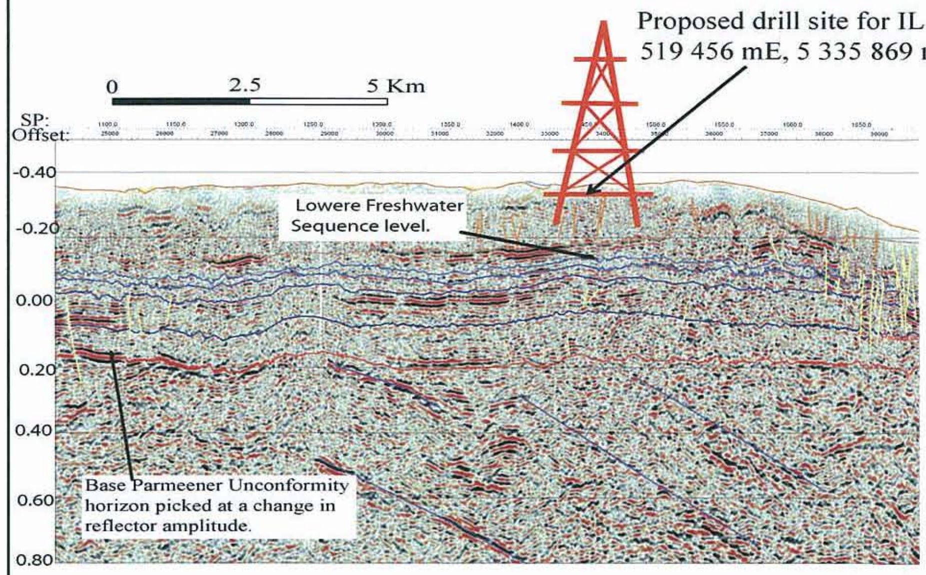
Prediction of Stratigraphy at the Interlaken Anticline (IL #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	21	-	21
(P50)	45	-	45
(P10)	92	-	92

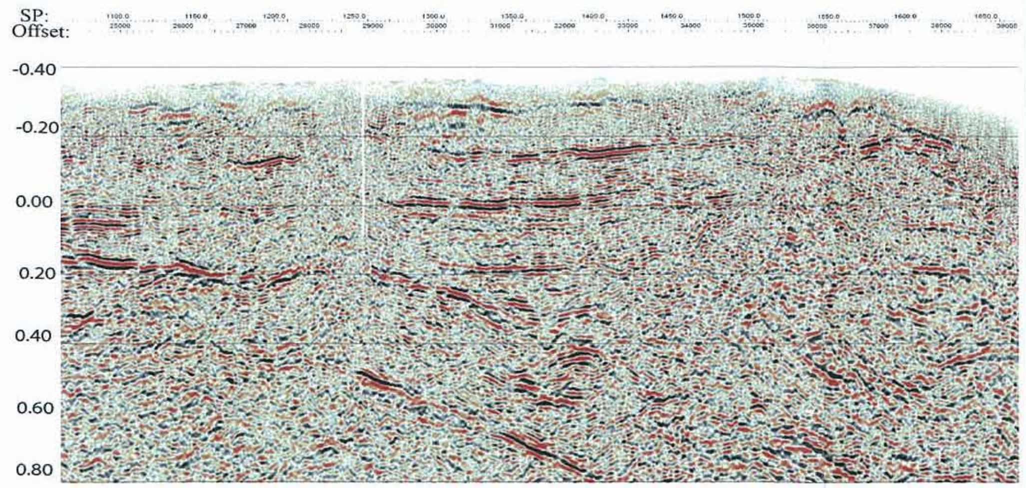
Monte – Carlo simulations of potential, undiscovered petroleum at Interlaken in million barrels.

Petroleum System Characteristics of the Interlaken Anticline (based on seismic line TB01-ST)

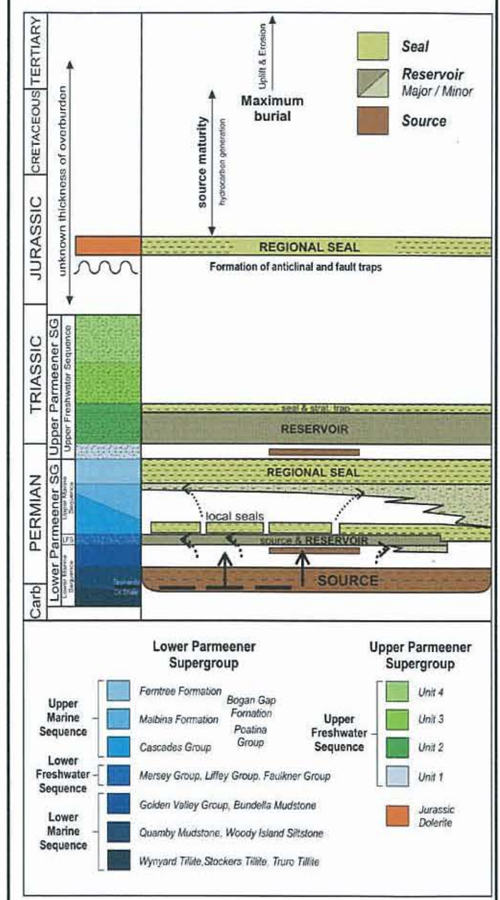
Target:	Triassic, Early to Late Permian
Source:	Unit 1, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2, (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = 480 m, Unit 1 =510 m, Palmer Sandstone = ~560 m, Garcia Sandstone= ~ 630 m, Liffey Group = ~ 700 m,
Pay zone:	100 m
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Anticline
Risk:	Timing - maturation and migration in Mid-Jurassic to the Cretaceous - traps were formed in the early Cenozoic, plus an elevated geothermal gradient may result in generation of late hydrocarbons.



Seismic line TB01-ST with structural and stratigraphic interpretations



Seismic line TB01-ST without interpretations



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. 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.

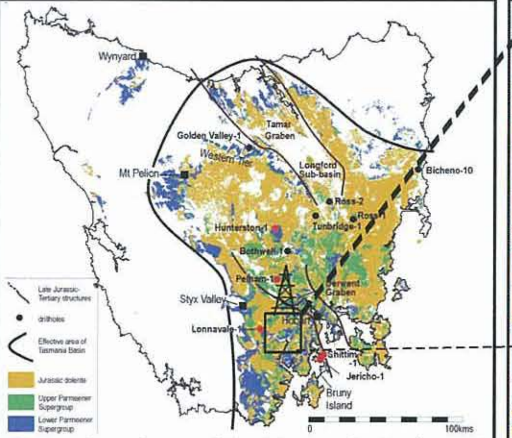
EMPIRE Energy

Great South Land Minerals

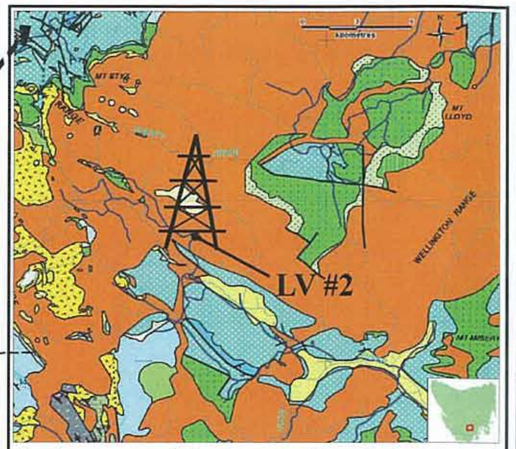
Lonnavale

LV # 2 May 2008

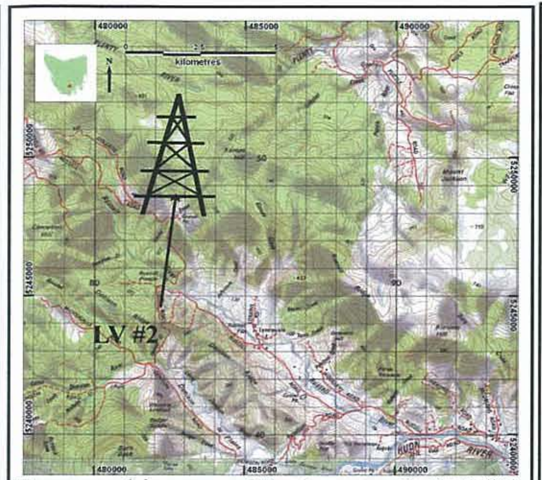
Compiled by Dr. Zohreh Amini



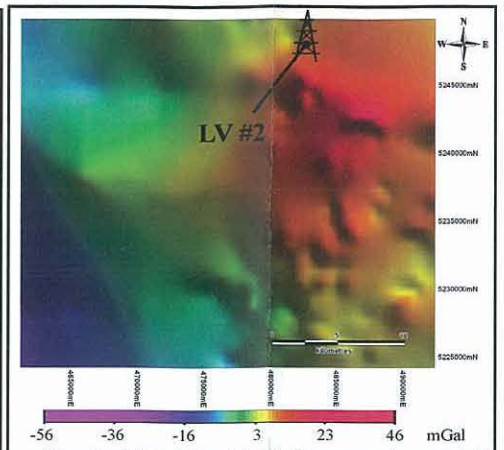
General geology of the Tasmania Basin and location of drill site on the Lonnavale area



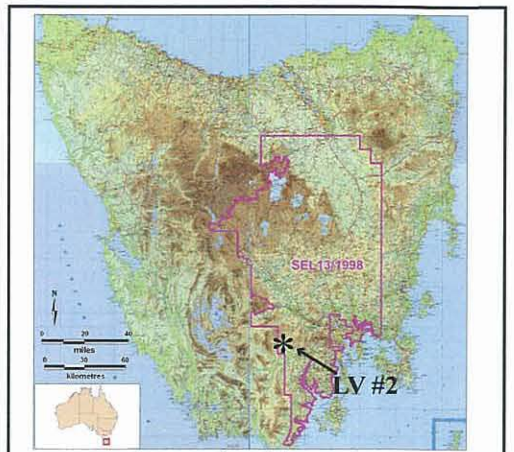
Geology map of the Lonnavale and location of proposed drill site (LV # 2)



Topographic map of the Lonnavale (LV #2)



Gravity Map (Residual Bouguer Anomaly) of the Lonnavale (LV#2)



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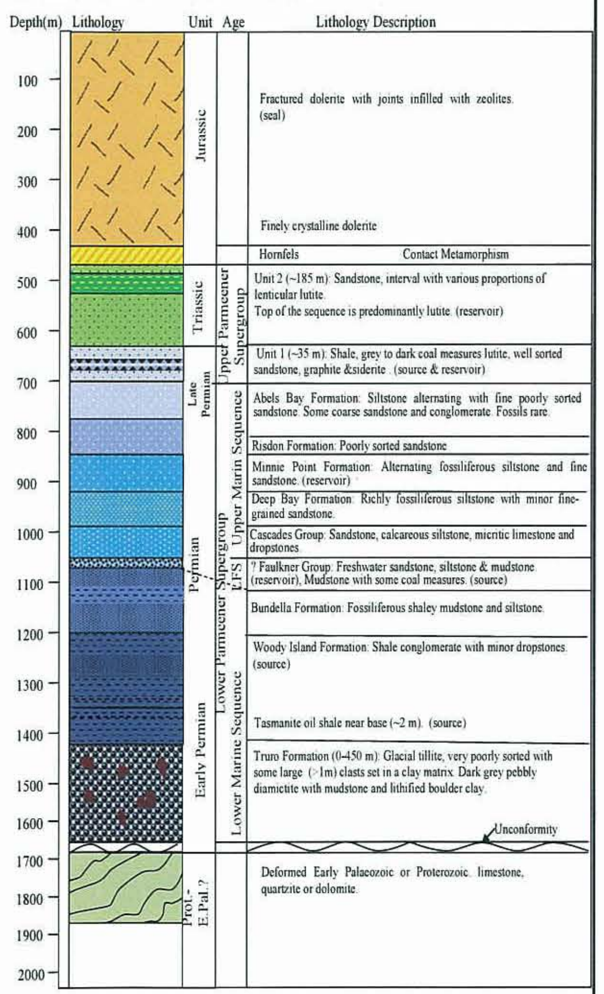
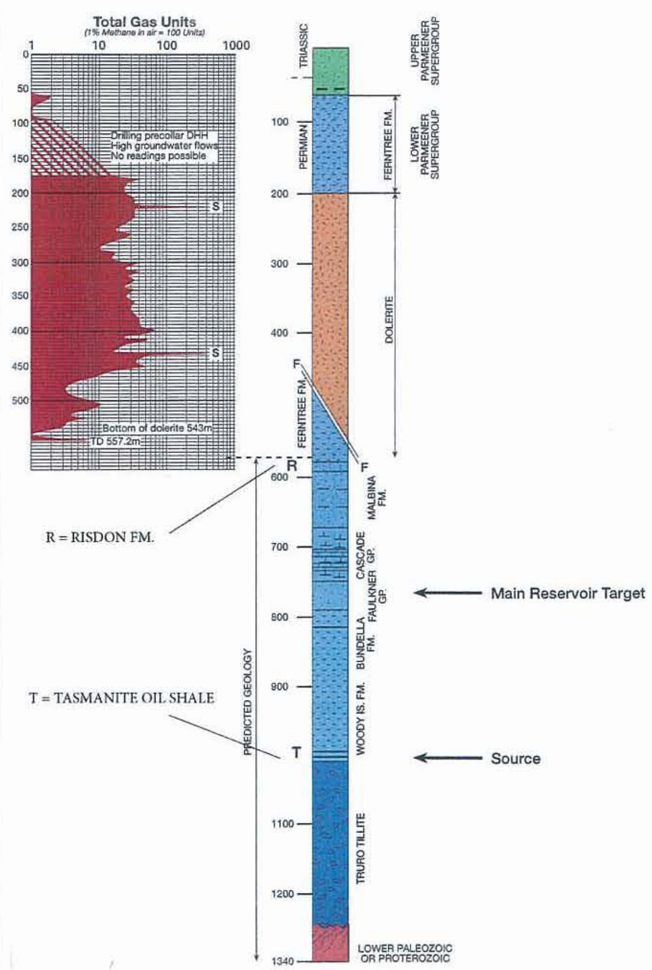


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

Prediction of Stratigraphy at Lonnavale (LV # 2)

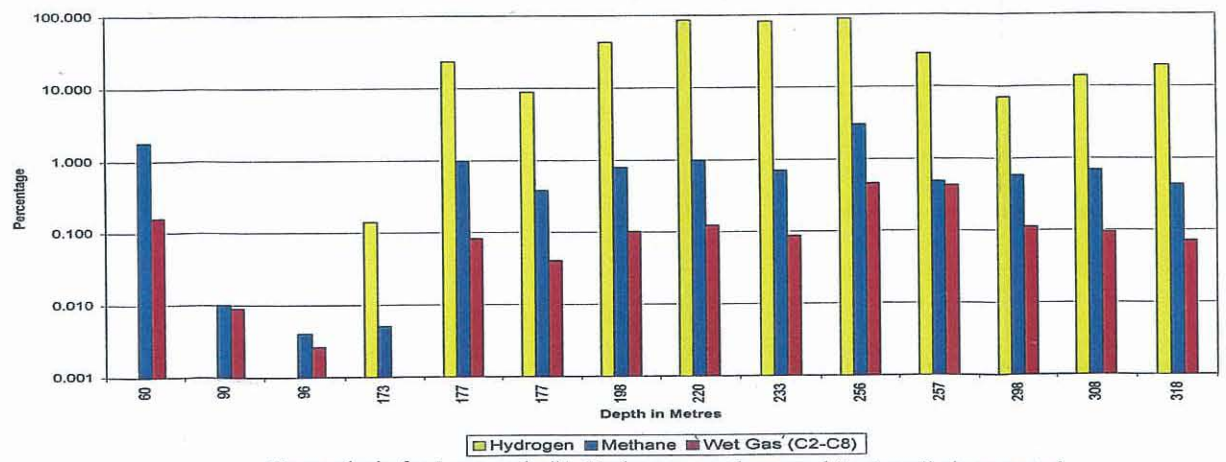
Petroleum System Characteristics of the Lonnavale #2 (based on stratigraphy prediction):

Target:	Triassic, Early to Late Permian.
Source:	Unit 1, Faulkner Group, Woody Island Formation, Tasmanite oil shale.
Reservoir:	Unit 2 (Triassic), Unit 1, Minie Point Formation, Faulkner Group (Permian).
Depth to top of Reservoir:	Unit 2 = 470 m, Unit 1 = 630 m, Minie Point Formation = 830 m, Faulkner Group = 1050 m.
Seal:	Dolerite

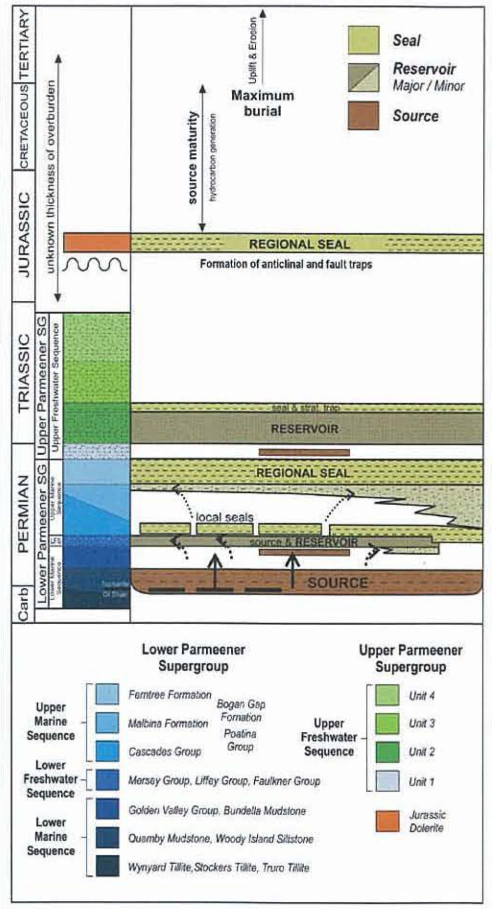


Lonnavale #1 lithology and total gas units


Tasmanite derived oil seep within joints in dolerite



Gas analysis for Lonnavale #1. Hydrogen, methane and "wet gas" air corrected



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. 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.

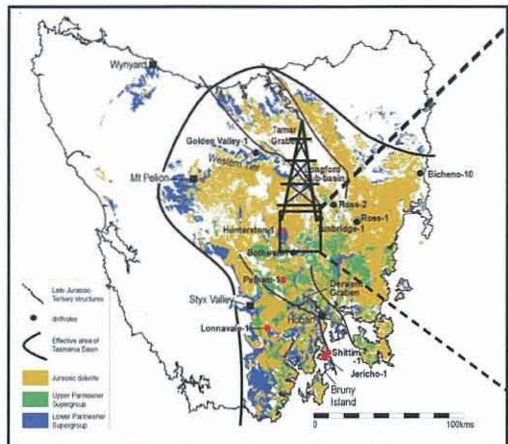
EMPIRE Energy

Great South Land Minerals

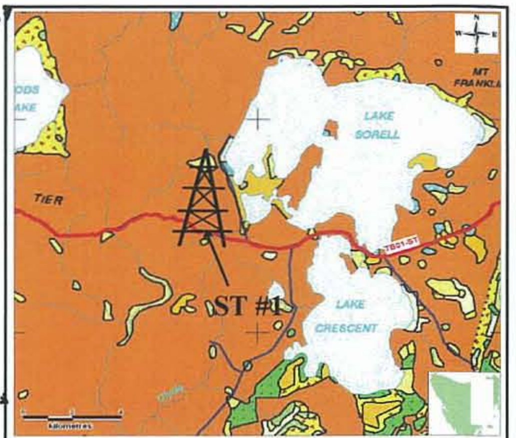
Scotts Tier Anticline

(ST #1) May 2008

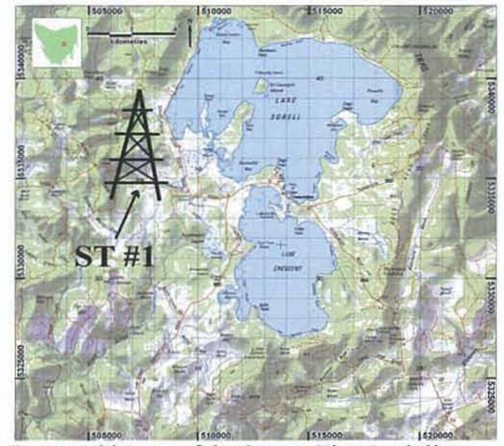
Compiled by Dr. Zohreh Amini



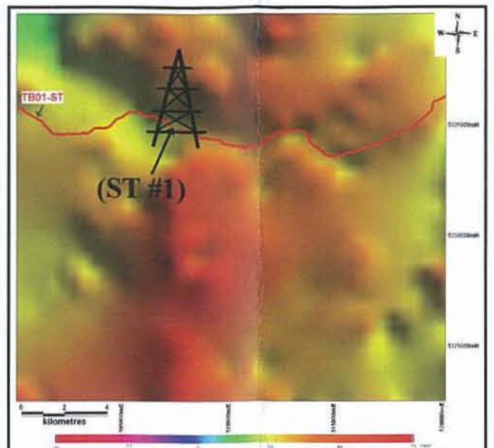
Geology of the Tasmania Basin and location of drill site on the Scotts Tier Anticline (ST #1)



Geology map of the Scotts Tier Anticline and location of proposed drill site (ST #1)



Topographic map of the Scotts Tier Anticline (ST#1)



Gravity Map (Residual Bouguer Anomaly) of the Scotts Tier Anticline (ST#1)

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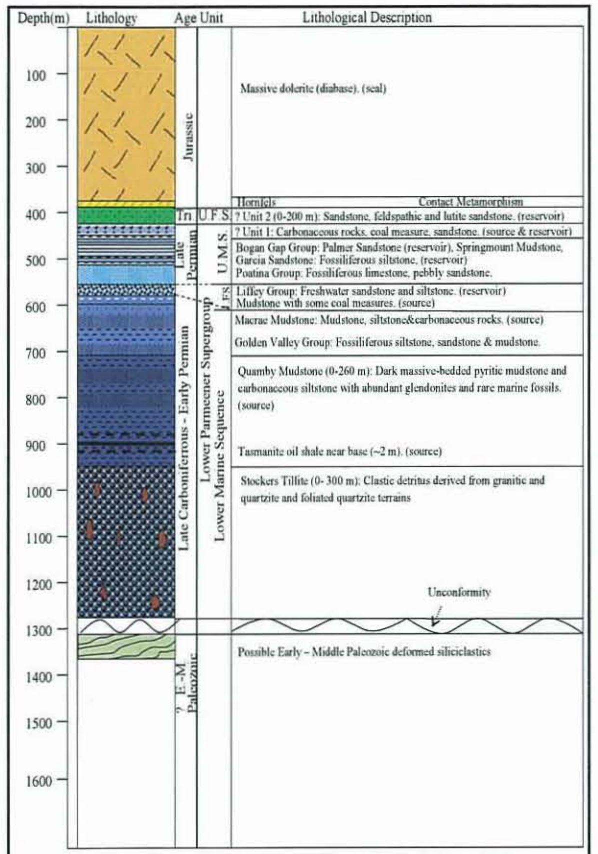


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

Prediction of Stratigraphy at the Scotts Tier Anticline (ST #1)

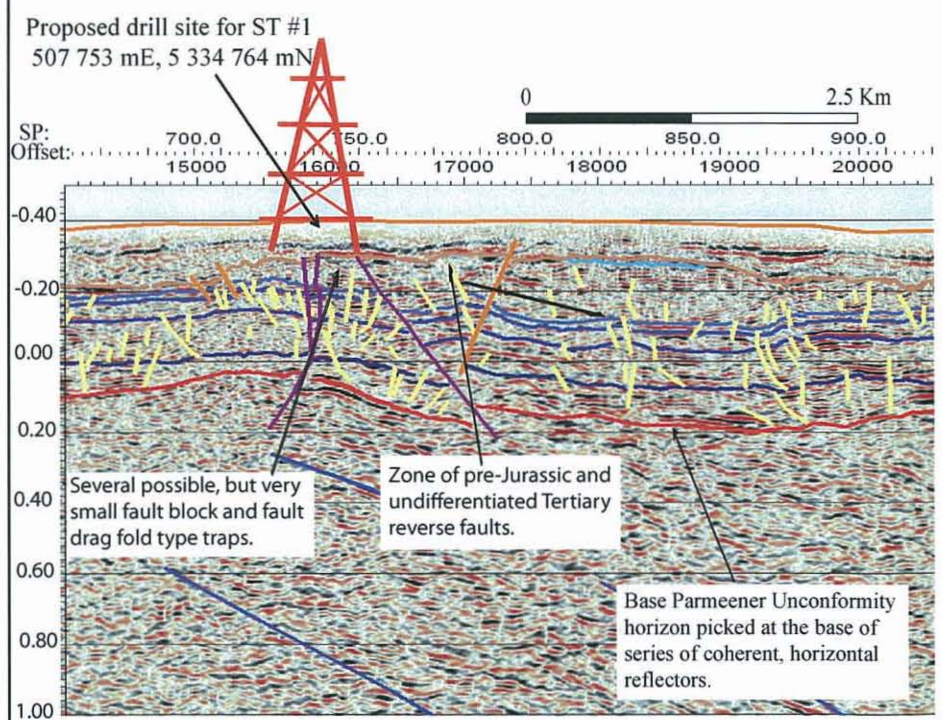
ST #1

	Permo-Triassic	Ordovician-Devonian	Total
(P90)	4	-	4
(P50)	8	-	8
(P10)	15	-	15

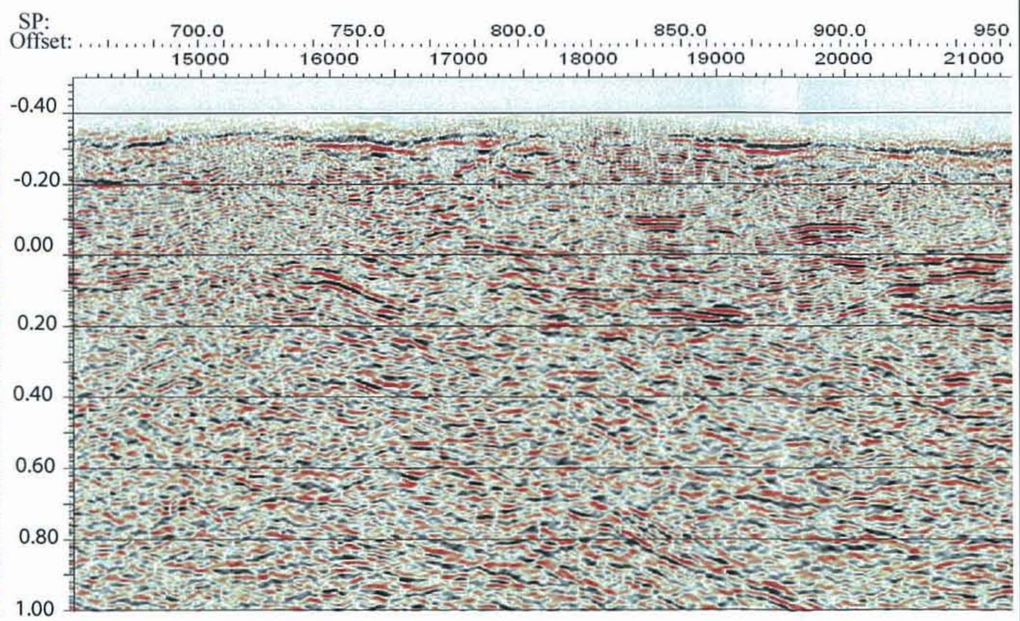
Monte – Carlo simulations of potential, undiscovered petroleum at Scotts Tier#1 in million barrels.

Petroleum System Characteristics of the Scotts Tier Anticline (based on seismic line TB01-ST)

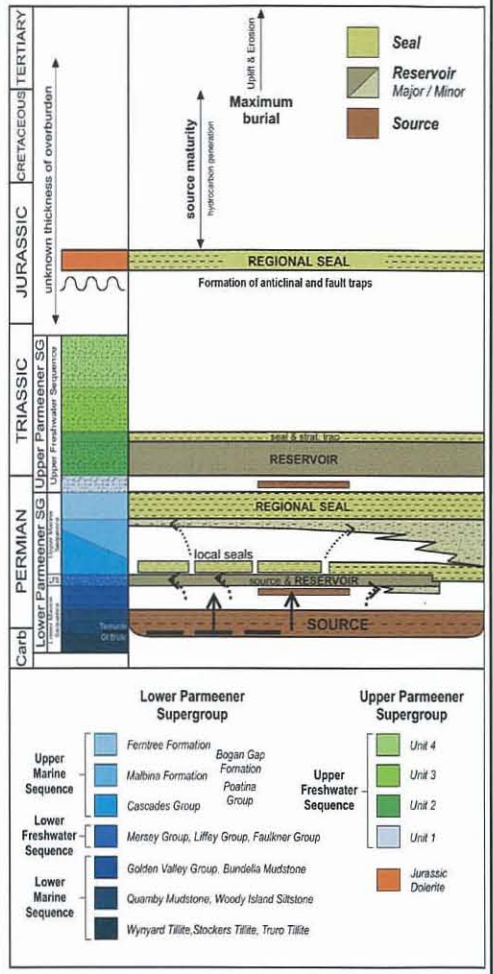
Target:	Early to Late Permian in Anticline
Source:	Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2, (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = 400, Unit 1 = 430 m, Palmer Sandstone = ~450 m, Garcia Sandstone= ~ 500 m, Liffey Group = ~ 550 m.
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Anticline
Risk:	Although timing of structuring (Jurassic) is pre-generation and therefore excellent, integrity of trap may have been compromised by Cenozoic



Seismic line TB01-ST with structural and stratigraphic interpretations



Seismic line TB01-ST without interpretations



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. 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.

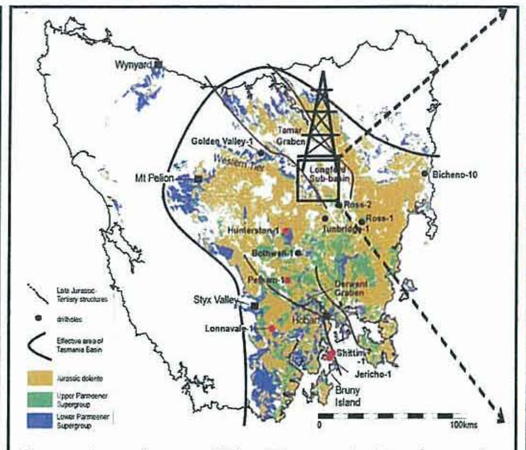
EMPIRE Energy

Great South Land Minerals

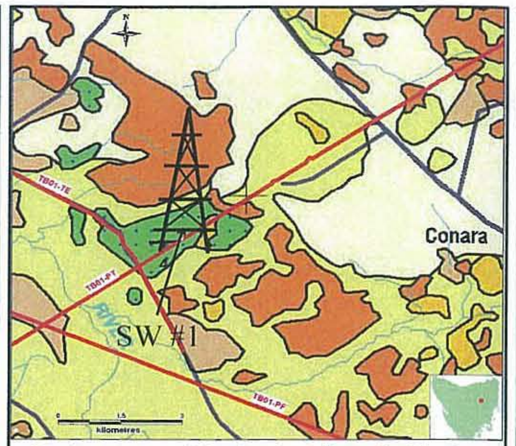
Stockwell Fault Block

(SW #1) May 2008

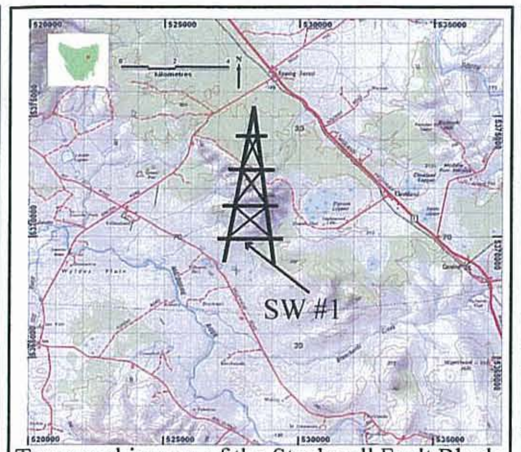
Compiled by Dr. Zohreh Amini



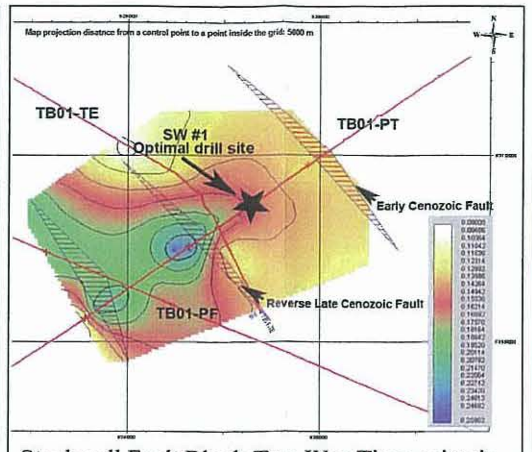
General geology of the Tasmania Basin and location of drill site on Stockwell Fault Block



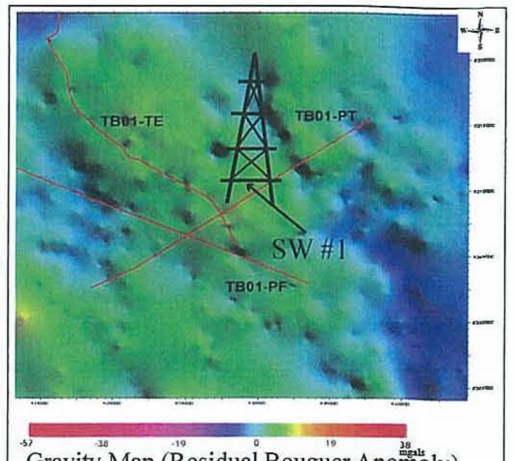
Geology map of the Stockwell Fault Block and location of proposed drill site (SW #1)



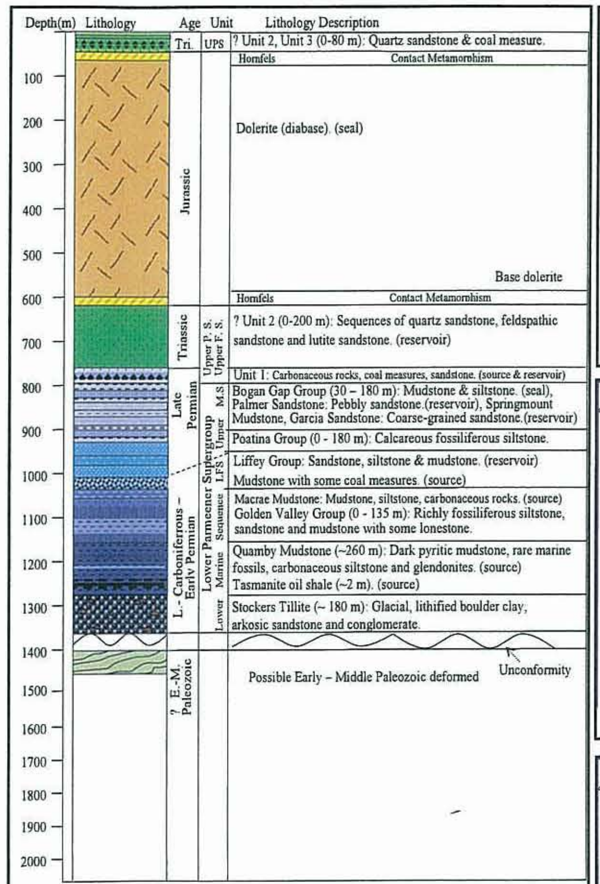
Topographic map of the Stockwell Fault Block (SW #1)



Stockwell Fault Block Two Way Time seismic map for the base of the dolerite (Early Jurassic)



Gravity Map (Residual Bouguer Anomaly) of the Stockwell Fault Block (SW # 1)

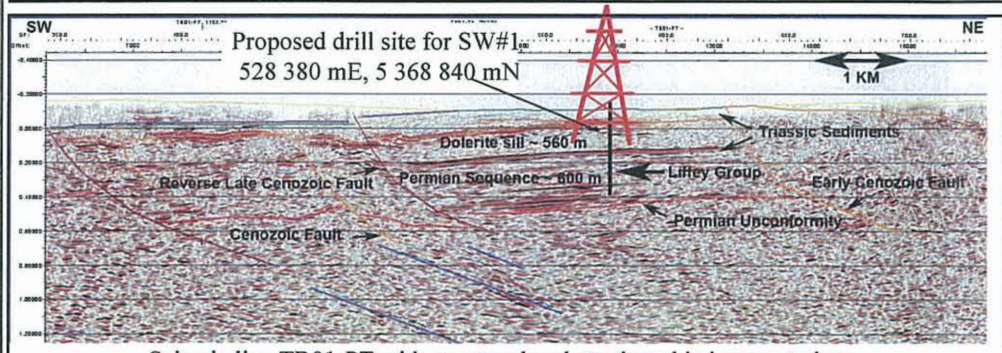


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

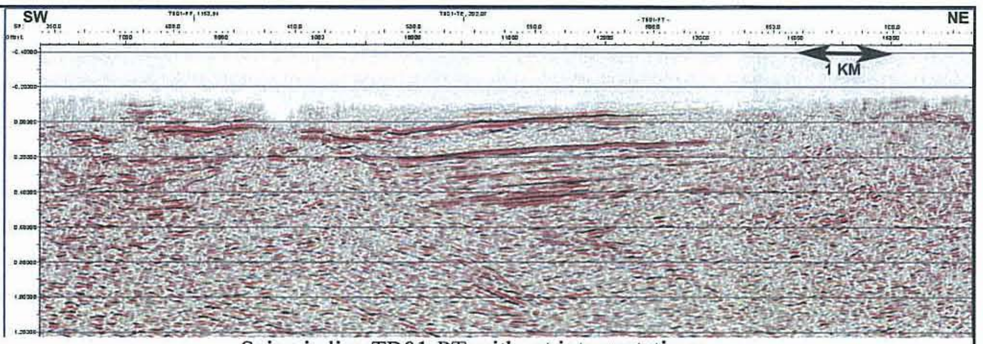
Prediction of Stratigraphy at Stockwell Fault Block (SW#1)

Petroleum System Characteristics of Stockwell Anticline (based on seismic line TB01-PT)

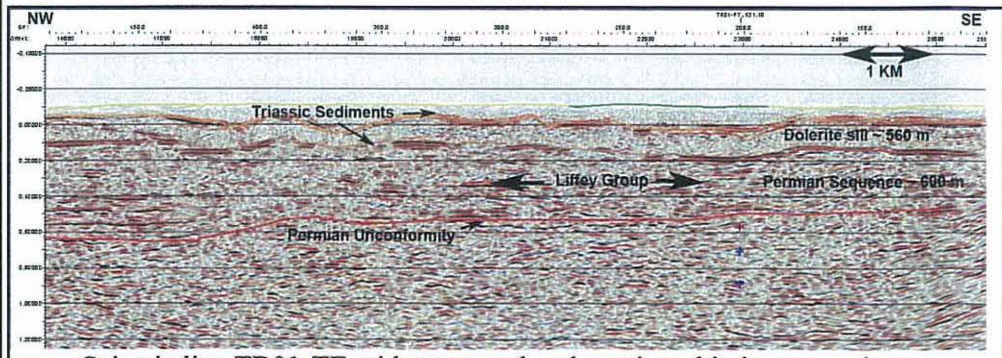
Target:	Permo-Triassic Gondwanan system in Fault Block
Source:	Unit 1, Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = 610 m, Unit 1= 760 m, Palmer Sandstone= ~ 810 m, Garcia Sandstone= ~ 890 m, Liffey Group= ~1010 m,
Pay Zone	Unit 2 = ~ 50 m, Palmer Sandstone = ~ ? m, Garcia Sandstone= ~ ? m, Liffey Group= ~ 15 m,
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Fault Block
Risk:	Timing, maturation and migration in the Mid- Jurassic to the Cretaceous. Traps were formed in the early Cenozoic to the Miocene.Burial in the Cenozoic, plus an elevated geothermal gradiant may result in generation of late hydrocarbons.



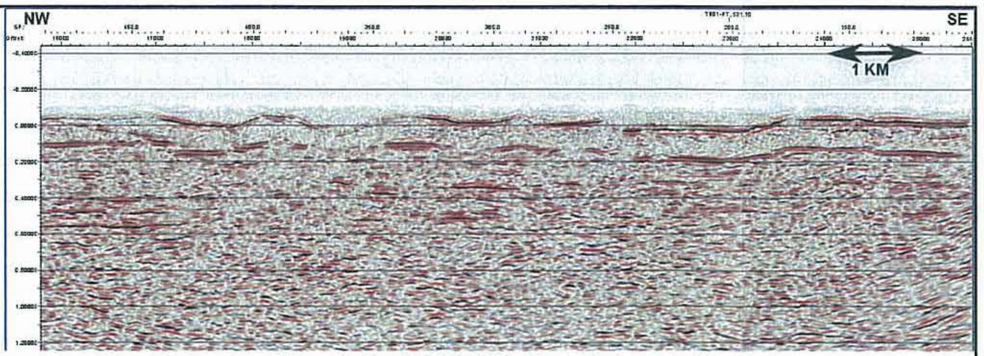
Seismic line TB01-PT with structural and stratigraphic interpretations



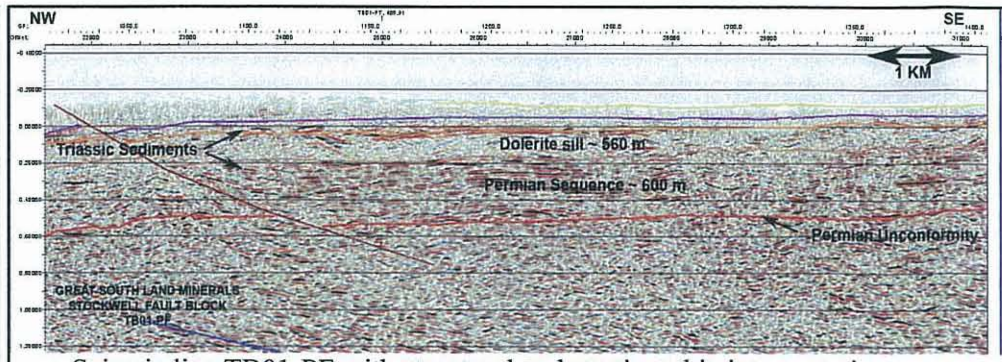
Seismic line TB01-PT without interpretations



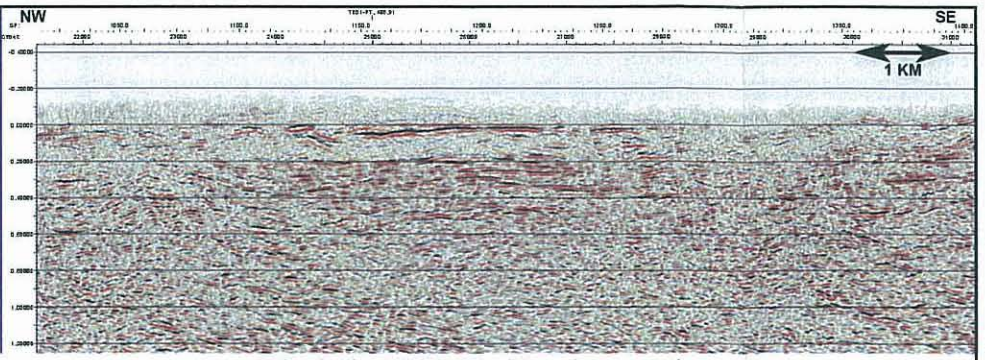
Seismic line TB01-TE with structural and stratigraphic interpretations



Seismic line TB01-TE without interpretations



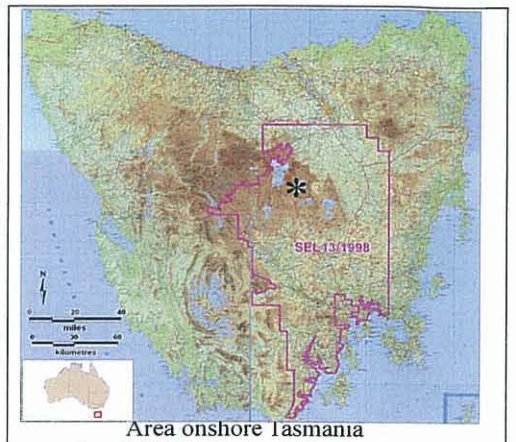
Seismic line TB01-PF with structural and stratigraphic interpretations



Seismic line TB01-PF without interpretations

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	4	-	4
(P50)	11	-	11
(P10)	25	-	25

Monte – Carlo simulations of potential, undiscovered petroleum at Stockwell in million barrels.



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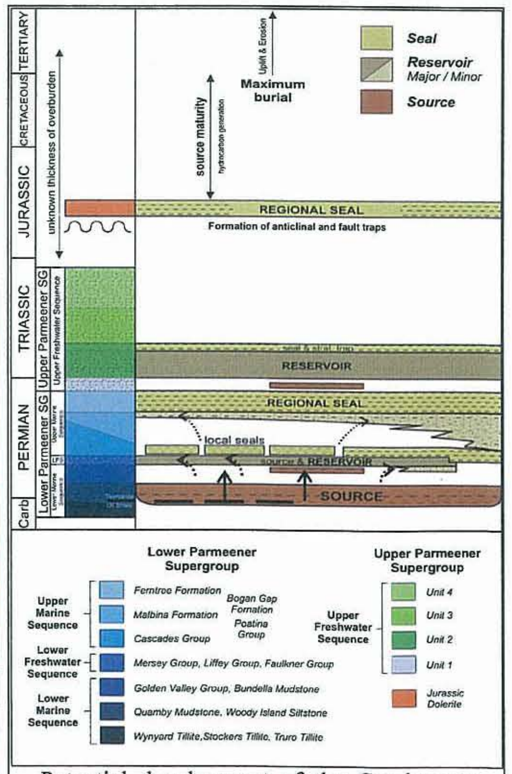


Potential development of the Gondwanan petroleum system in the Tasmania Basin. Major and minor potential source, reservoir and seal facies are indicated, along with timing of trap formation and source maturity. Source rocks are marked in the Woody Island Formation and Liffey Group, reservoir in the Liffey Group, and seals in the Cascade and Ferntree Formation and Jurassic dolerite.

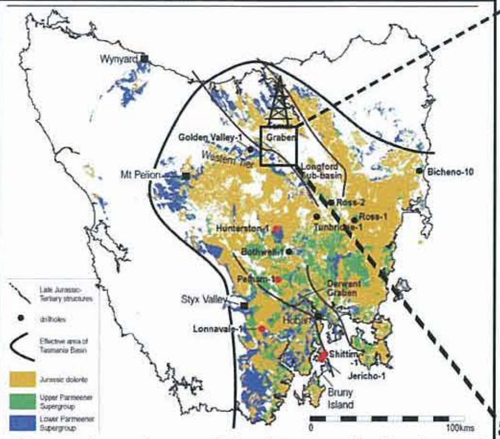
EMPIRE Energy

Great South Land Minerals

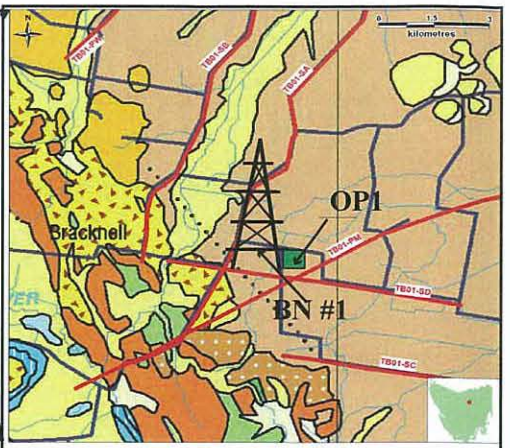
Bracknell Dome

BN #1 May 2008

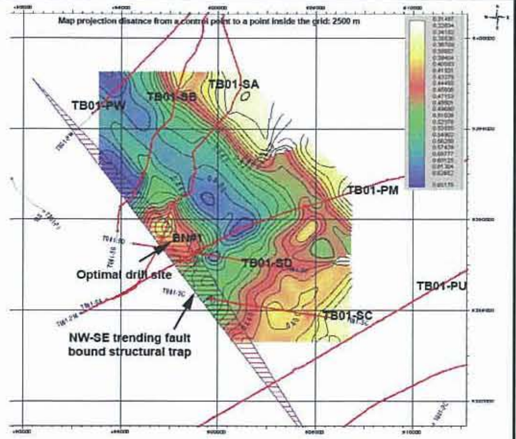
Compiled by Dr. Zohreh Amini



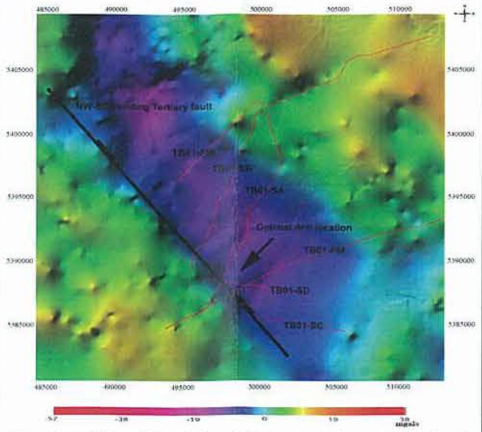
General geology of the Tasmania Basin and location of drill site on Bracknell Dome

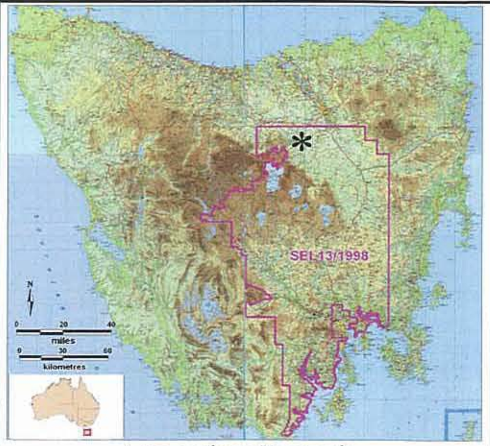


Geology map of the Bracknell Dome and location of proposed drill site (BN #1)

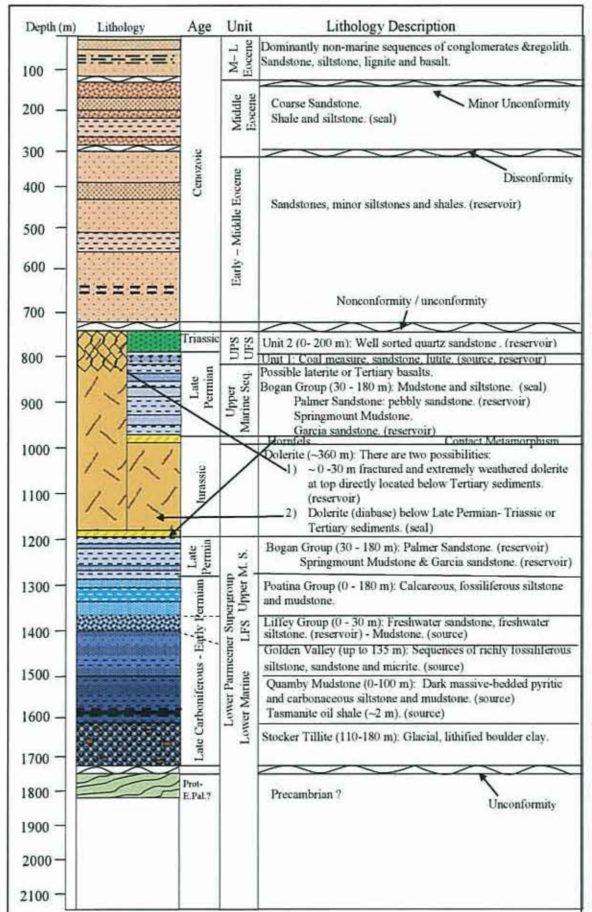


Two Way Time contour map of top of the SA and PM package on the Bracknell Dome


Gravity Map (Residual Bouguer Anomaly) of the Bracknell Dome (BN# 1)



Area onshore Tasmania Special Exploration License 13/98

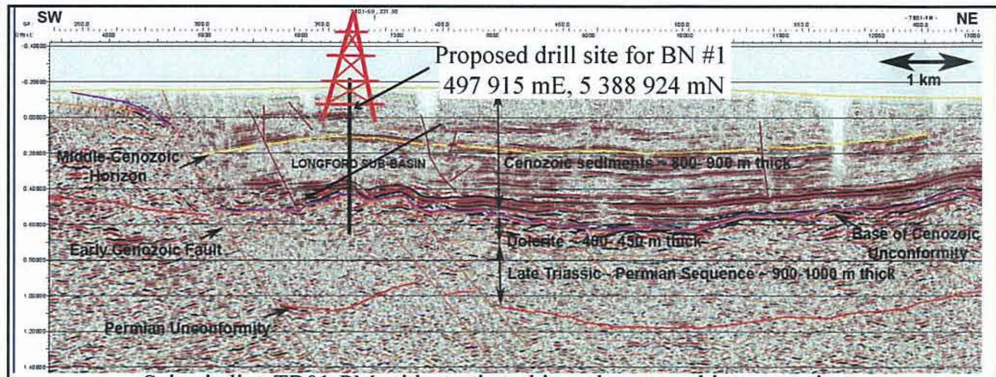


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

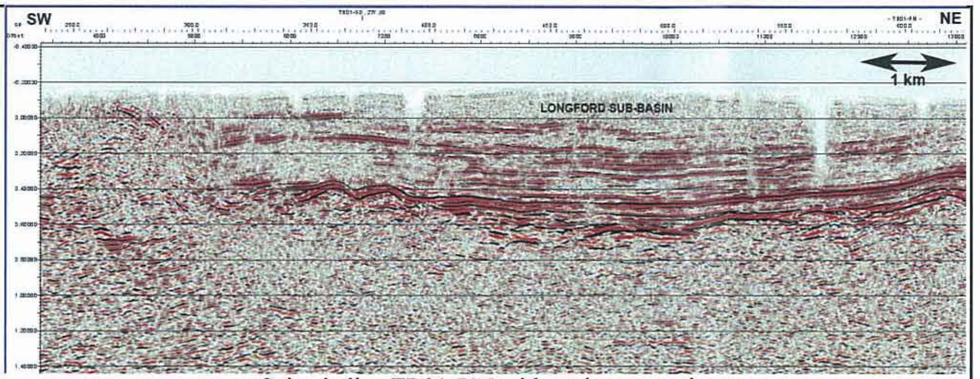
Prediction of Stratigraphy at Bracknell Dome (BN #1)

Petroleum System Characteristics of Bracknell Dome (based on seismic line TB01_PM)

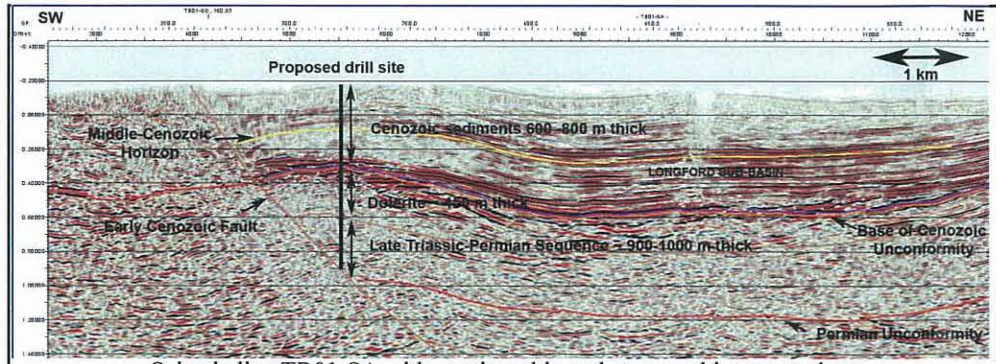
Target:	Early - Middle Eocene, Triassic, Early to Late Permian.
Source:	Unit 1, Liffey Group, Quamby Formation, Tasmanite oil shale.
Reservoir:	E - M Eocene (Cenozoic), Fractured Dolerite (Jurassic), Unit 2 (Triassic), Unit 1, Palmer and Garcia Sandstone, Liffey Group,(Permian).
Depth to top of Reservoir:	Early - Middle Eocene = 300 m, Fractured Dolerite = 740 m, Unit 2 = 740 m, Unit 1 = 790 m, Palmer Sandstone = 830 m or 1210 m, Garcia Sandstone = 950 m or 1280 m, Liffey Group = 1370 m.
Seal:	Dolerite, Cenozoic mudstone.
Trap:	Dome
Risk:	Timing - maturation and migration in Mid-Jurassic to the Cretaceous - traps were formed in the early Cenozoic. Burial in the Cenozoic, plus an elevated geothermal gradient may result in generation of late hydrocarbons.



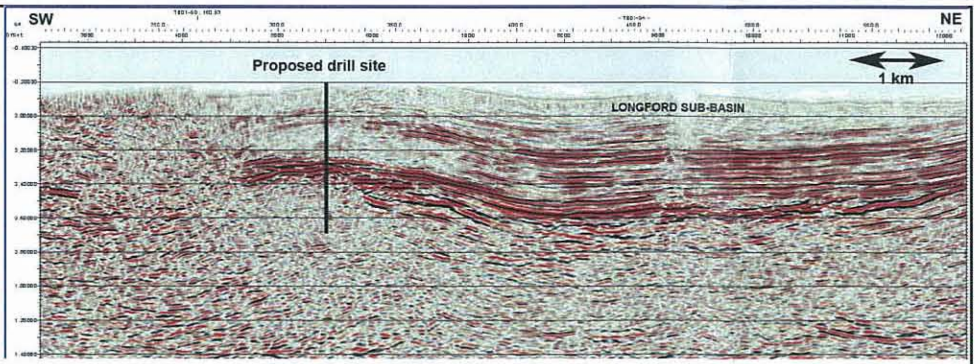
Seismic line TB01-PM with stratigraphic and structural interpretations



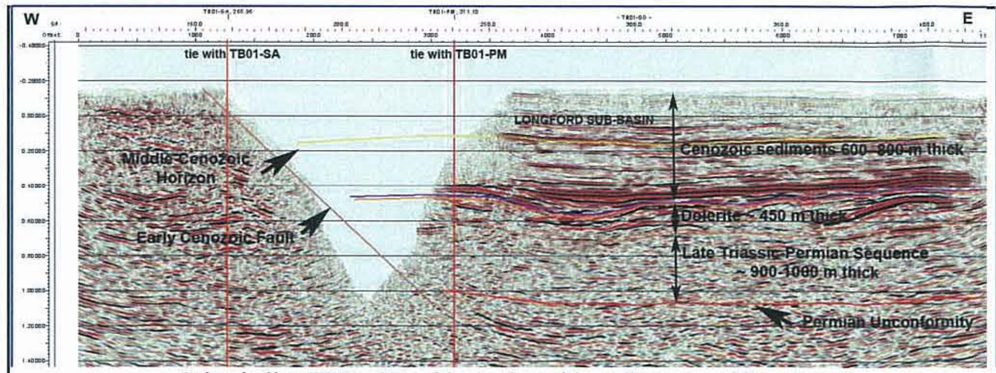
Seismic line TB01-PM without interpretatios



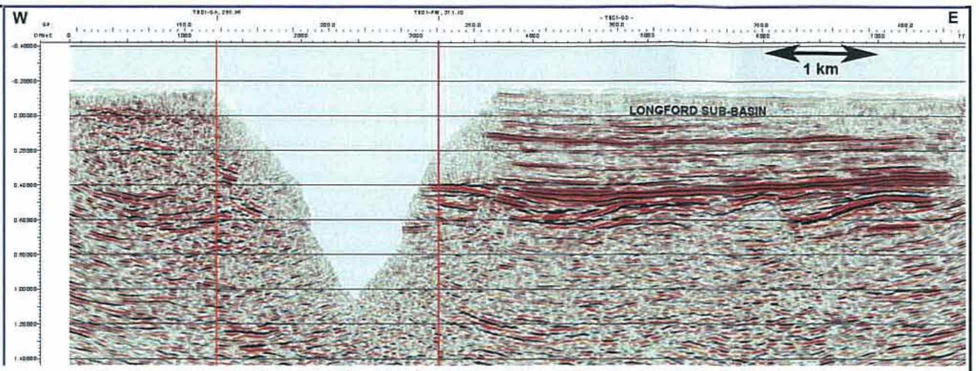
Seismic line TB01-SA with stratigraphic and structural interpretations



Seismic line TB01-SA without interpretatios



Seismic line TB01-SD with stratigraphic and structural interpretations

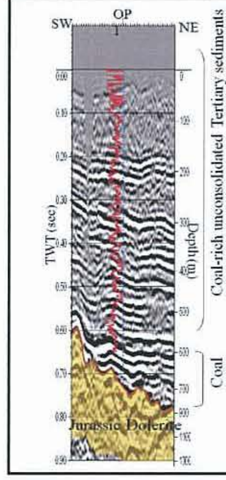


Seismic line TB01-SD without interpretatios

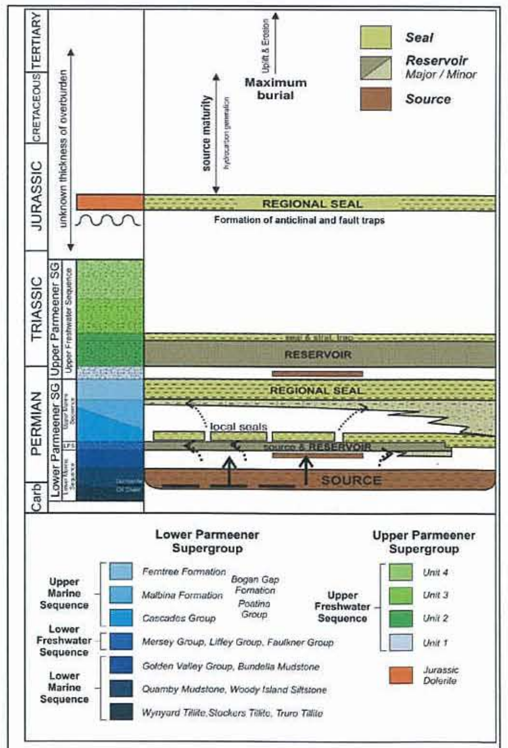
BN #1

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	49	-	49
(P50)	100	-	100
(P10)	194	-	194

Monte – Carlo simulations of potential, undiscovered petroleum at Bracknell in million barrels.



Gamma - ray log of OP1placed over line TB01- PM and used to calibrate the seismic data.



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. 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.

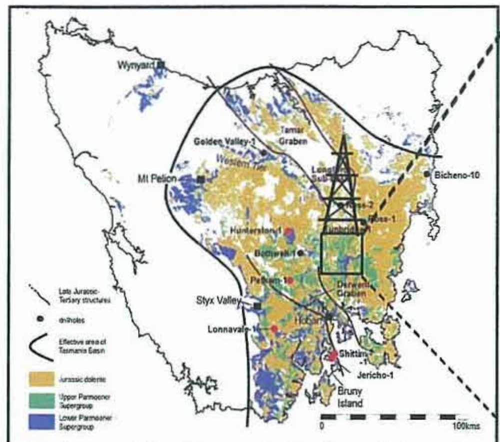
EMPIRE Energy

Great South Land Minerals

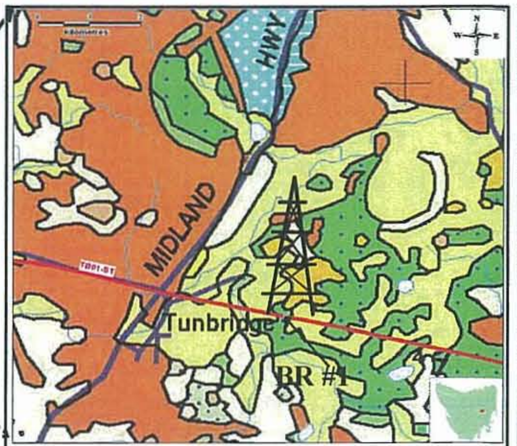
Butlers Rise Fault Block

(BR #1) May 2008

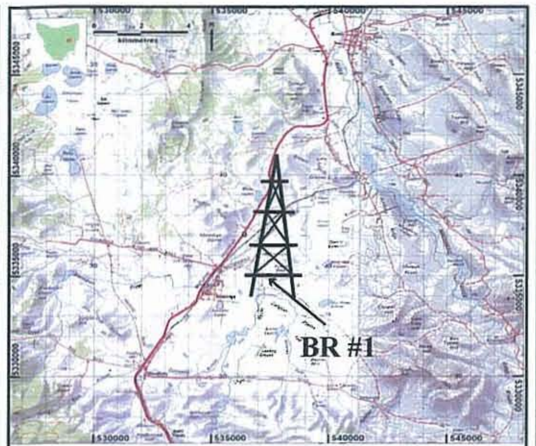
Compiled by Dr. Zohreh Amini



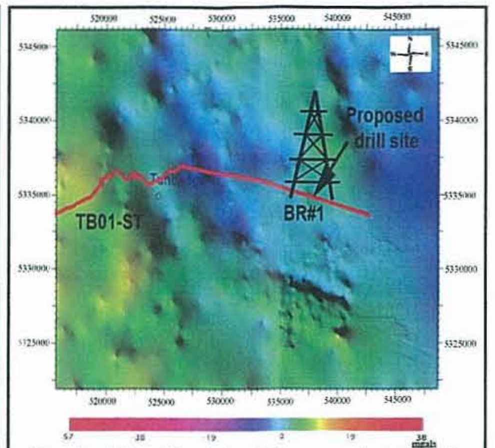
Geology of the Tasmania Basin and location of drill site on the Butlers Rise Fault Block



Geology map of the Butlers Rise Fault Block and location of proposed drill site (BR #1)



Topographic map of the Butlers Rise Fault Block (BR #1)



Gravity Map (Residual Bouguer Anomaly) of the Butlers Rise Fault Block (BR # 1)

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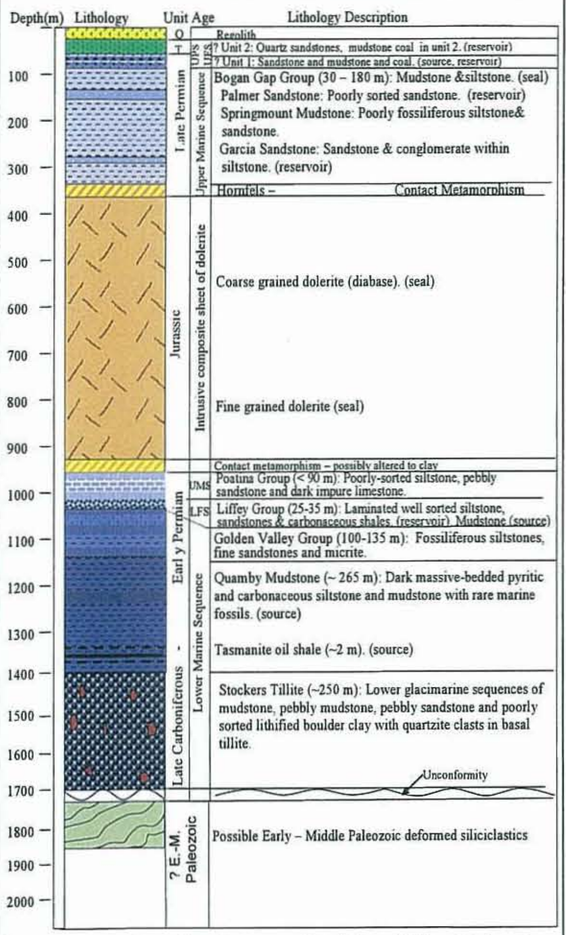


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

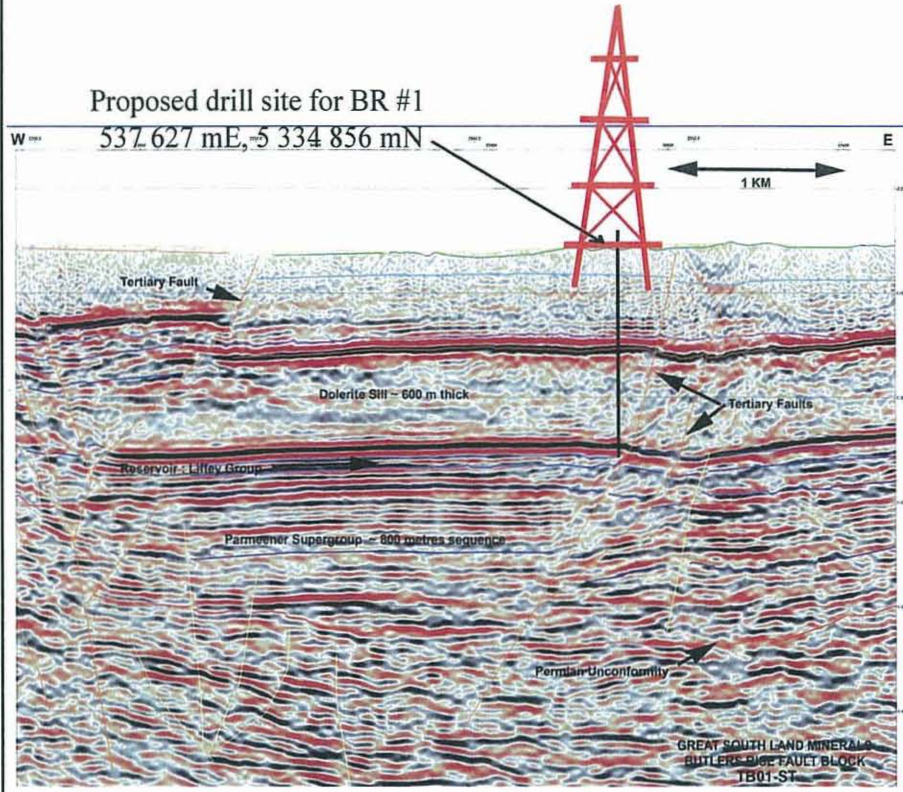
Prediction of Stratigraphy at ButlersRise Fault Block (BR #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	18	-	18
(P50)	40	-	40
(P10)	79	-	79

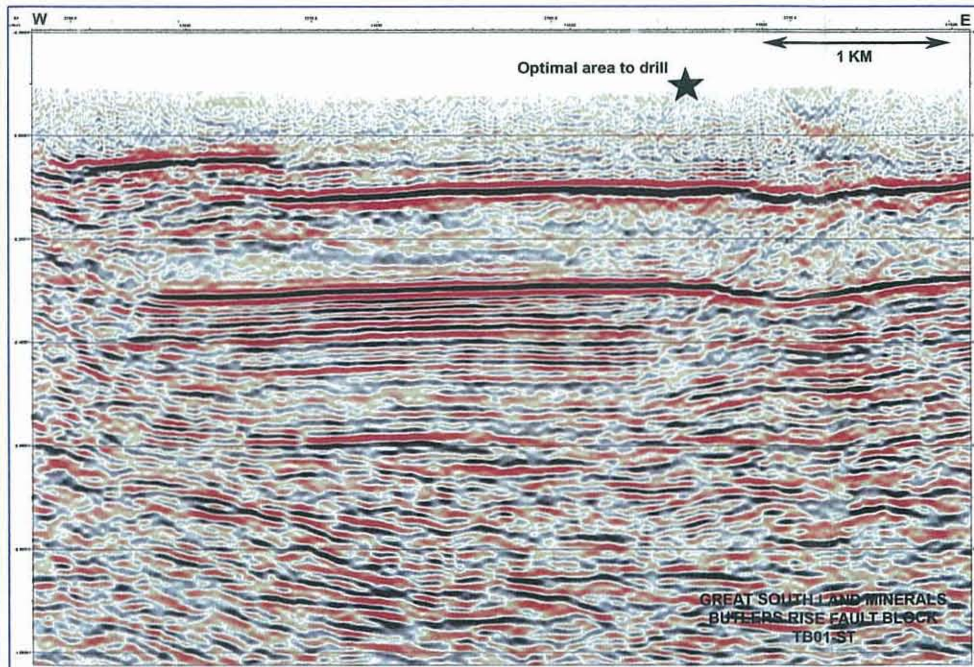
Monte – Carlo simulations of potential, undiscovered petroleum at Butlers Rise in million barrels.

Petroleum System Characteristics of the Butlers Rise Fault Block (based on shot point ~2335 on seismic line TB01-ST)

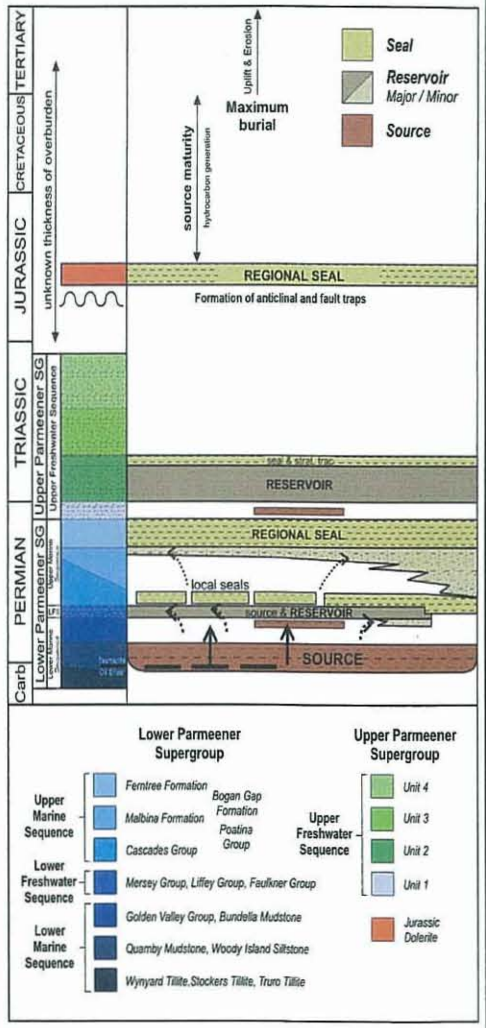
Target:	Triassic, Early to Late Permian Fault Block
Source:	Unit 1, Liffey Group, Quamby Formation, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to reservoir:	Unit 2 = 20 m, Unit 1= 70 m, Palmer Sandstone = 130 m, Garcia Sandstone = 270, Liffey Group = ~ 1010 m
Seal:	Dolerite, latest Bogan Gap group
Trap:	Fault Block
Risk:	Timing - maturation and migration in Mid-Jurassic to the Cretaceous - traps were formed in the early Cenozoic, plus an elevated geothermal gradient may result in generation of late hydrocarbons.



Seismic line TB01-ST with structural and stratigraphic interpretations



Seismic line TB01-ST without interpretations



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. 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.

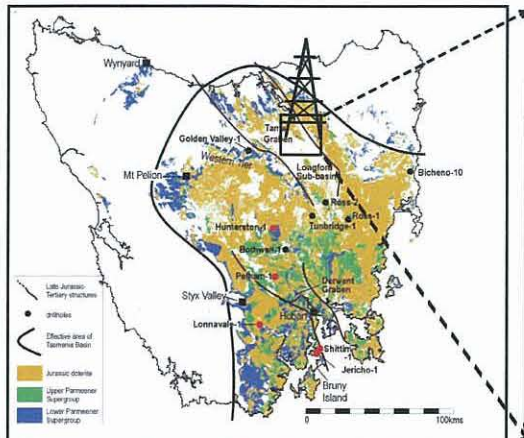
EMPIRE Energy

Great South Land Minerals

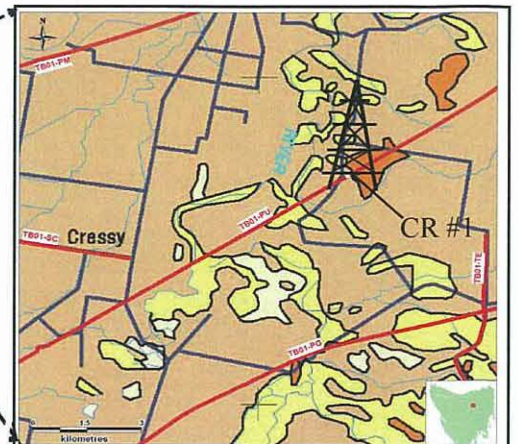
Cressy Anticline

(CR #1) May 2008

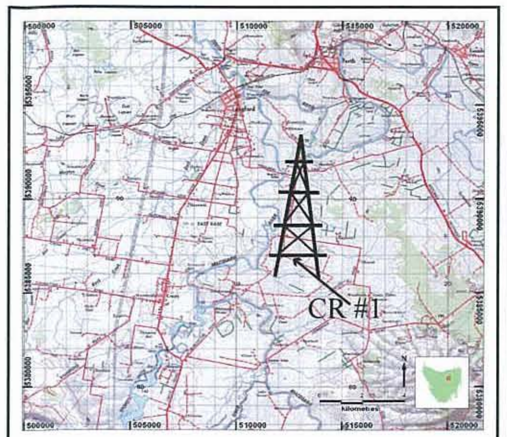
Compiled by Dr. Zohreh Amini



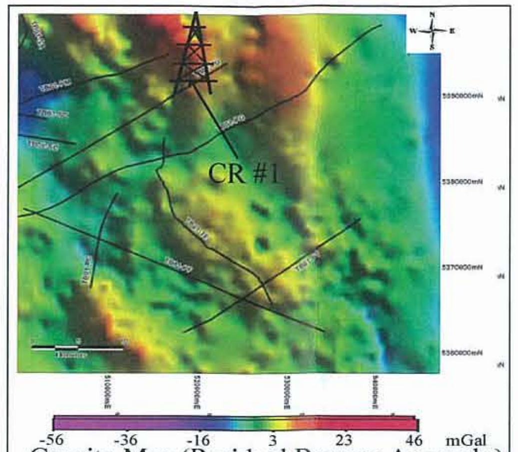
General geology of the Tasmania Basin and location of drill site on the Cressy Anticline



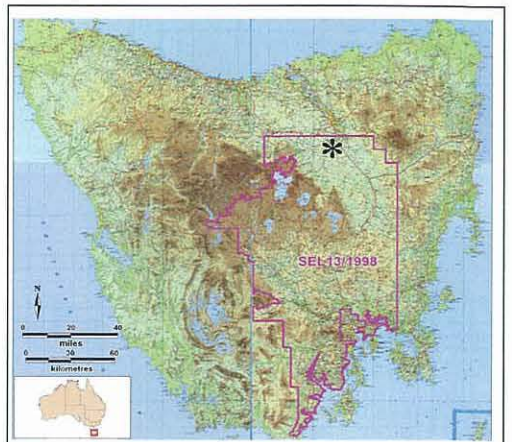
Geology map of the Cressy Anticline and location of proposed drill site (CR #1)



Topographic map of the Cressy Anticline (CR#1)



Gravity Map (Residual Borguer Anomaly) of the Cressy Anticline (CR#1)



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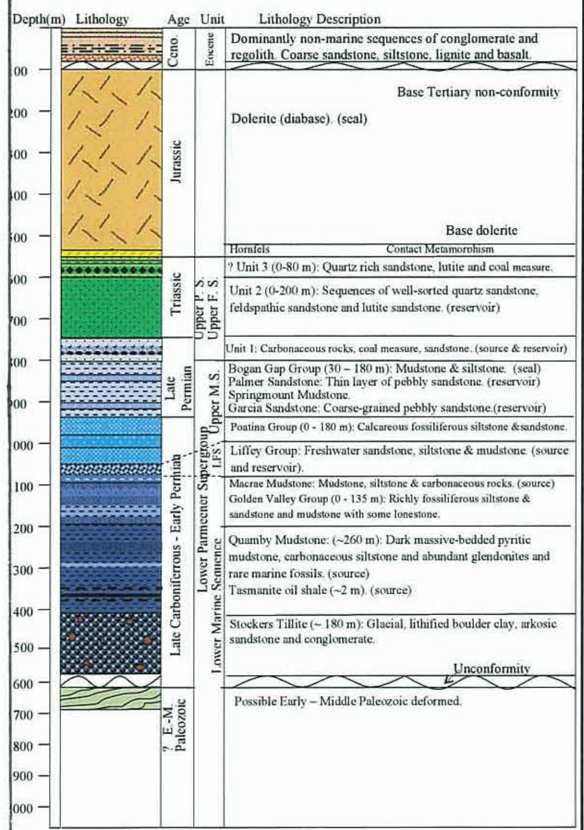


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

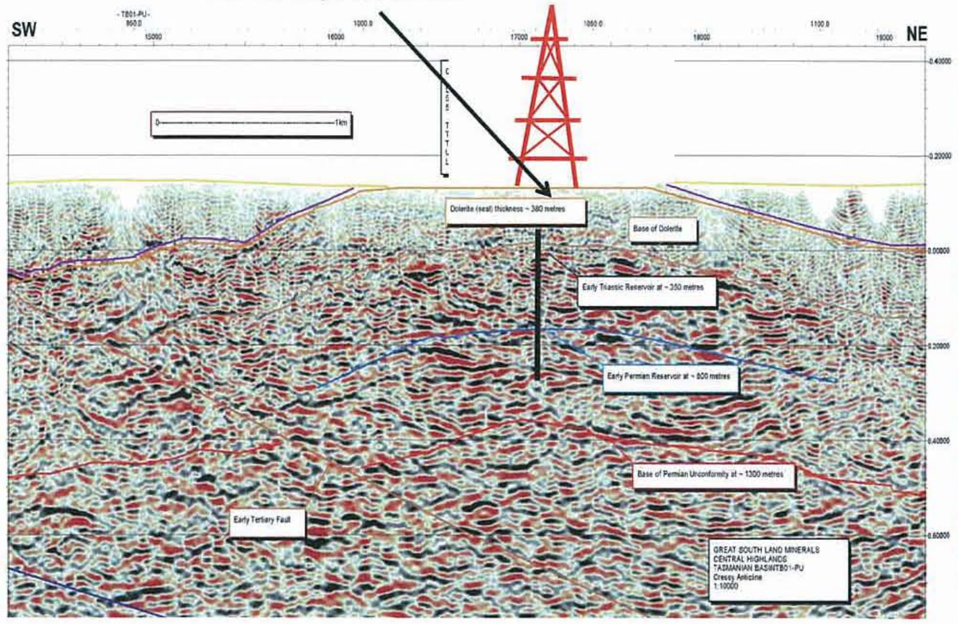
Prediction of Stratigraphy at the Cressy Anticline (CR #1)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	8	-	8
(P50)	16	-	16
(P10)	29	-	29

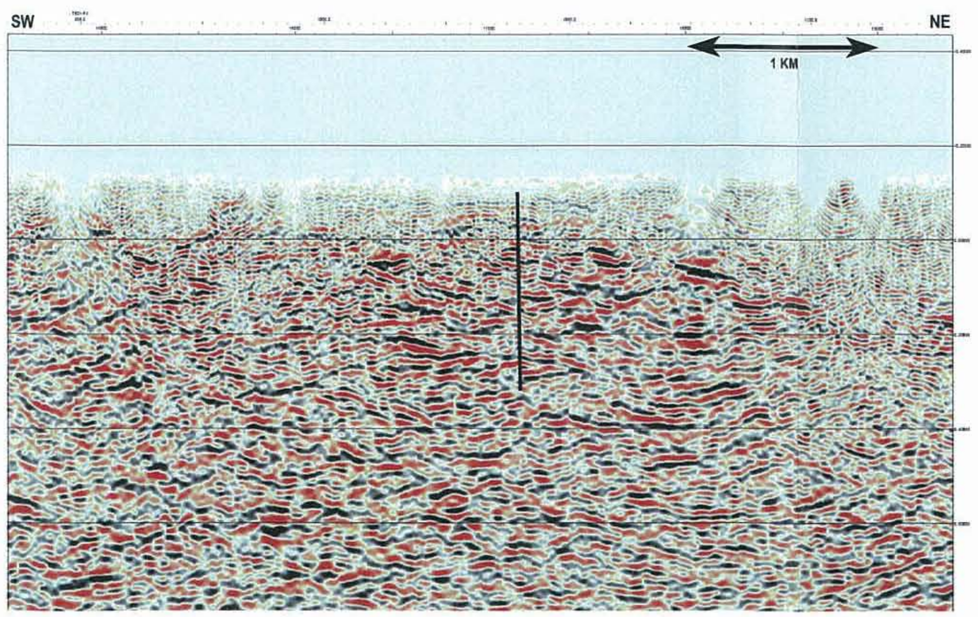
Monte – Carlo simulations of potential, undiscovered petroleum at Cressy #1 in million barrels.

Petroleum System Characteristics of the Cressy Anticline (based on seismic line TB01-PU)

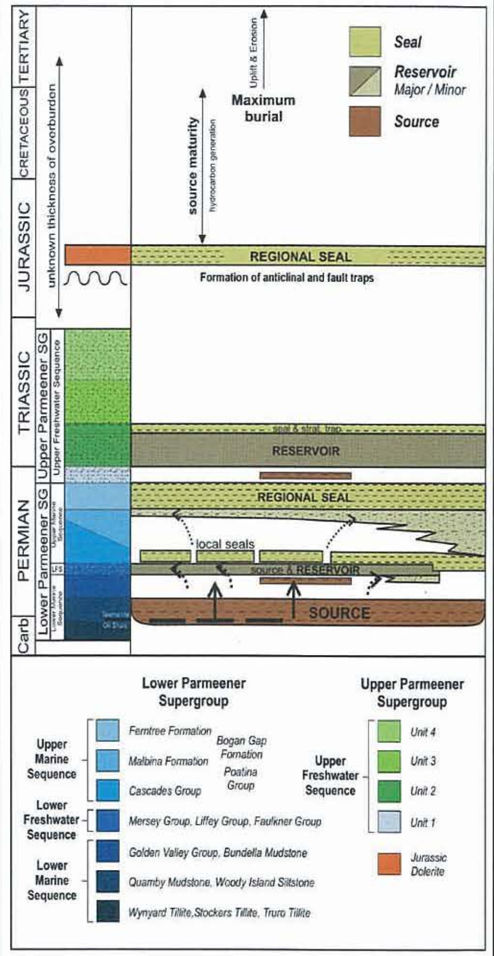
Target:	Triassic, Early to Late Permian.
Source:	Unit 1, Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = ~ 600 m, Unit 1 = 750 m, Palmer Sandstone= ~ 830 m, Garcia Sandstone= ~ 900 m, Liffey Group= ~1070 m,
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Anticline
Risk:	Timing, maturation and migration from Jurassic to Cenozoic. Traps were formed in Cretaceous or earliest Cenozoic. Note major compressional fault does not cut Eocene and younger sediments.



Seismic line TB01-PU with structural and stratigraphic interpretations



Seismic line TB01-PU without interpretations



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. 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.

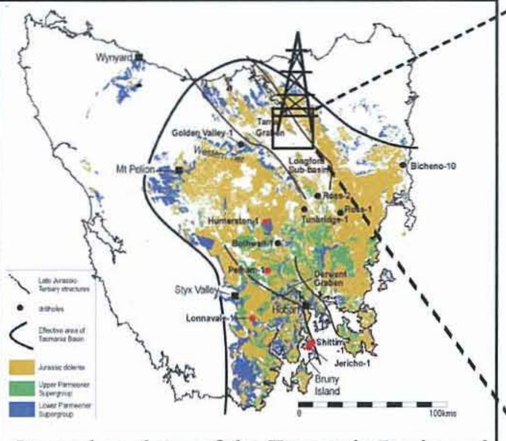
EMPIRE Energy

Great South Land Minerals

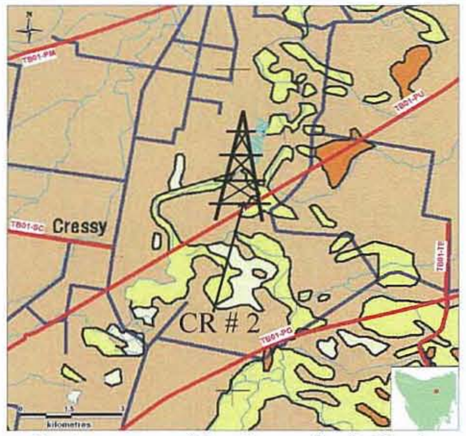
Cressy Fault Bolck

(CR # 2) May 2008

Compiled by Dr. Zohreh Amini

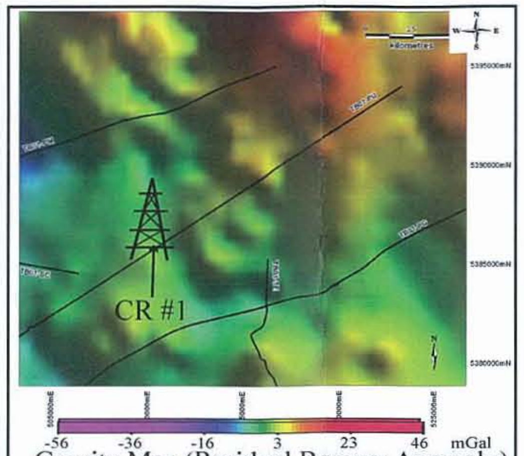


General geology of the Tasmania Basin and location of drill site on the Cressy Fault Block

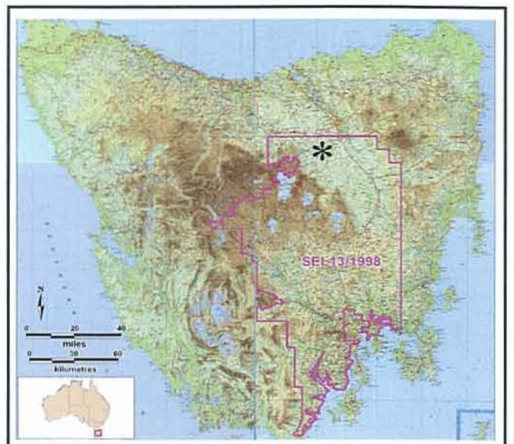


Geology map of the Cressy Fault Block and location of proposed drill site (CR #2)

Topographic map of the Cressy Fault Block (CR # 2)



Gravity Map (Residual Borguer Anomaly) of the Cressy Fault Block (CR# 2)



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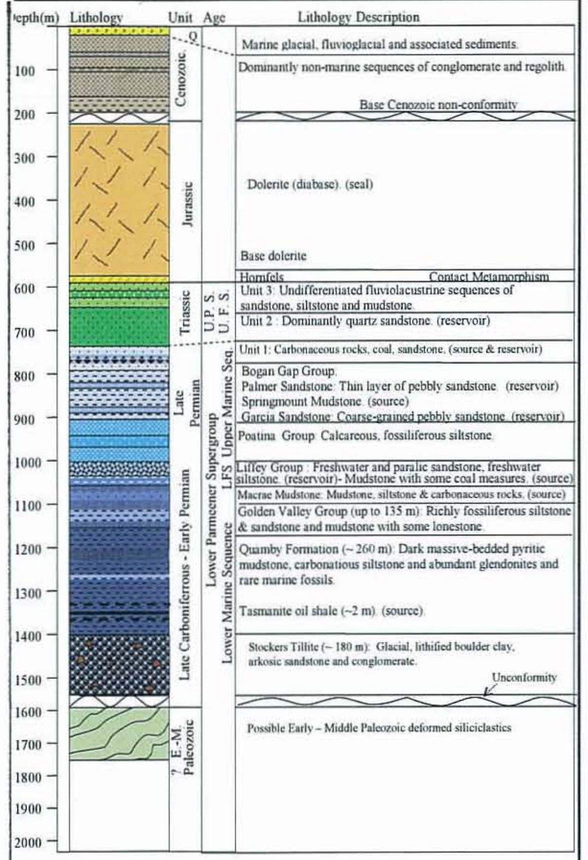


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

Prediction of Stratigraphy at the Cressy Fault Block (CR # 2)

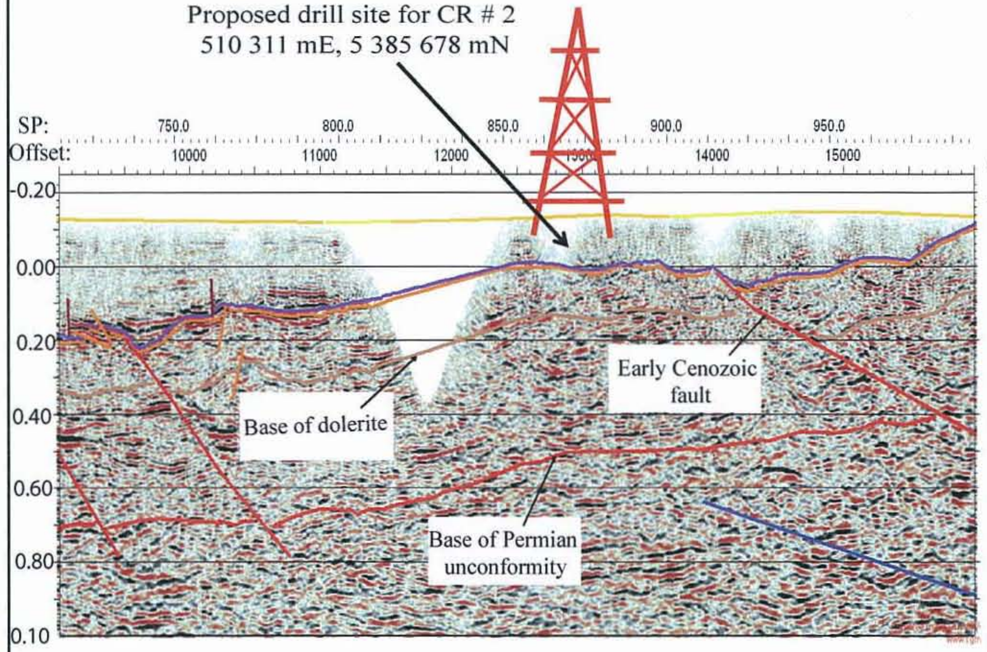
	Permo-Triassic	Ordovician -Devonian	Total
(P90)	8	-	8
(P50)	16	-	16
(P10)	30	-	30

Monte – Carlo simulations of potential, undiscovered petroleum at Cressy #2 in million barrels.

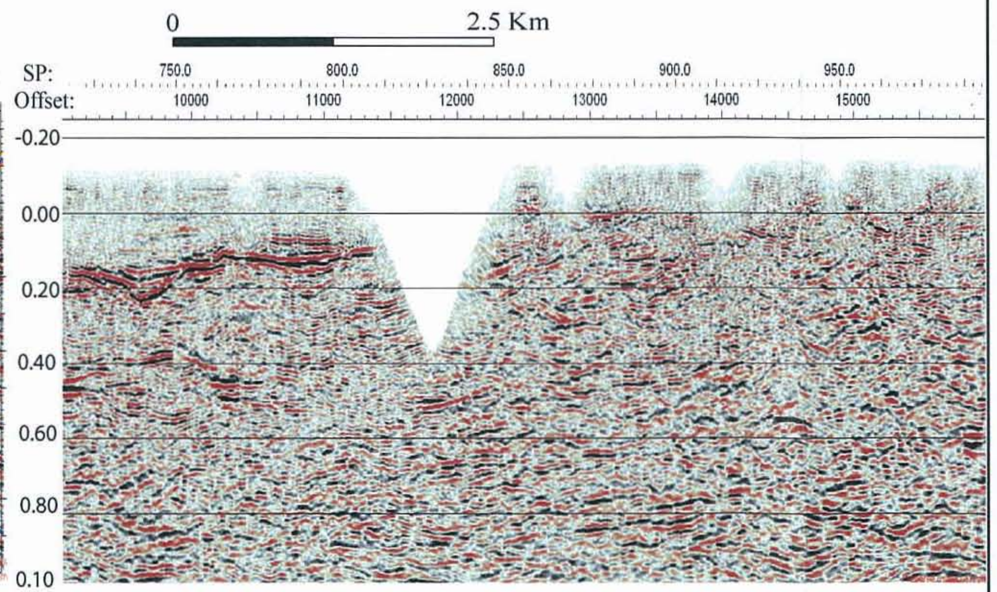
Petroleum System Characteristics of the Cressy Fault Block (based on seismic line TB01-PU)

Target:	Triassic, Early to Late Permian.
Source:	Unit 1, Liffey Group, Macrae Mudstone, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = ~ 630 m, Unit 1 = 740 m, Palmer Sandstone= ~ 820 m, Garcia Sandstone= ~ 890 m, Liffey Group= ~1000 m,
Seal:	Jurassic Dolerite, Latest Permian mudstone
Trap:	Fault Block
Risk:	Timing, maturation and migration from Jurassic to Tertiary. Traps were formed in Cretaceous or earliest Cenozoic. Note major compressional fault does not cut Eocene and younger sediments.

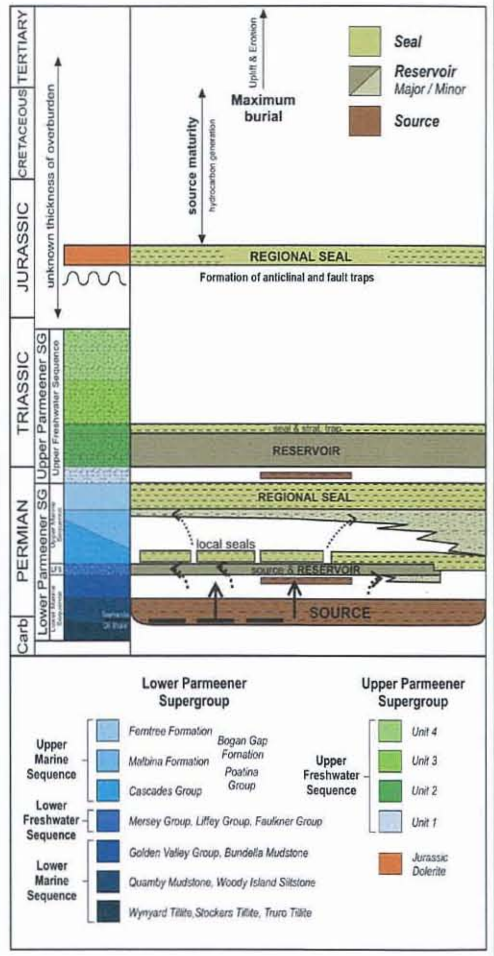
Proposed drill site for CR # 2
510 311 mE, 5 385 678 mN



Seismic line TB01-PU with structural and stratigraphic interpretations



Seismic line TB01-PU without interpretations



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. 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.

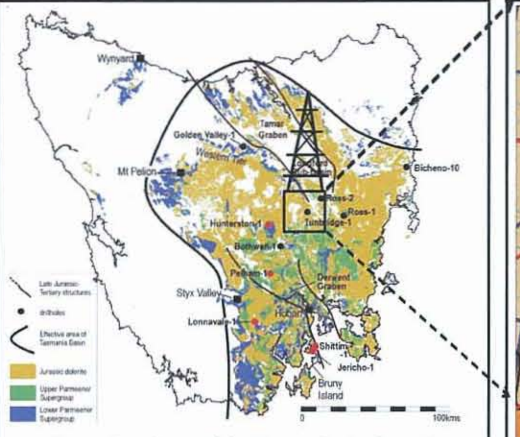
EMPIRE Energy

Great South Land Minerals

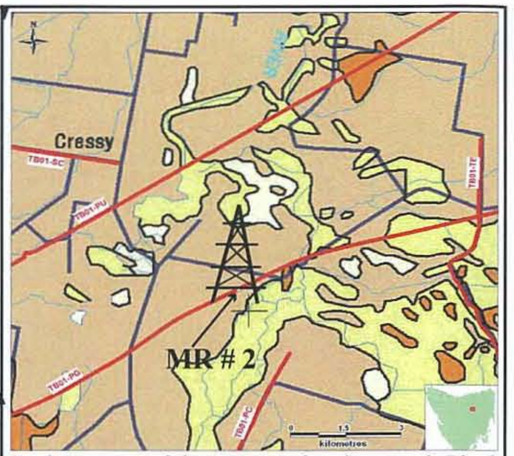
Macquarie River Fault Block

(MR # 2) May 2008

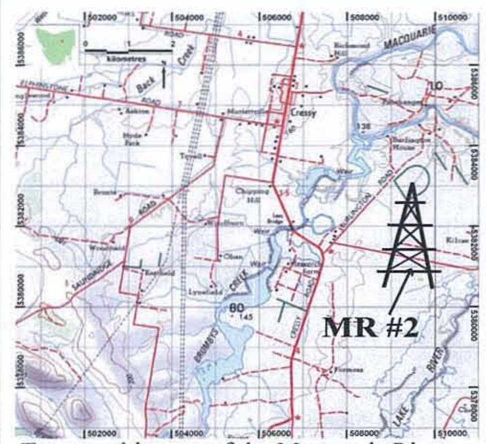
Compiled by Dr. Zohreh Amini



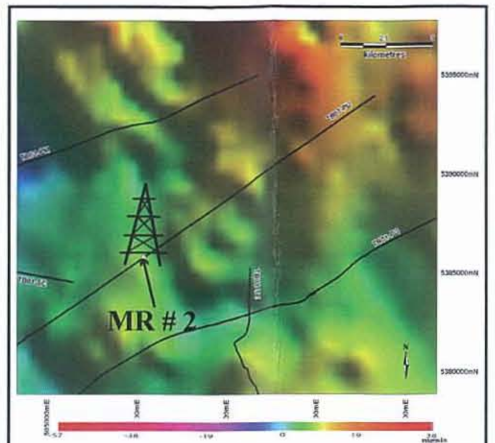
General geology of the Tasmania Basin and location of drill site on Macquarie River Fault Block



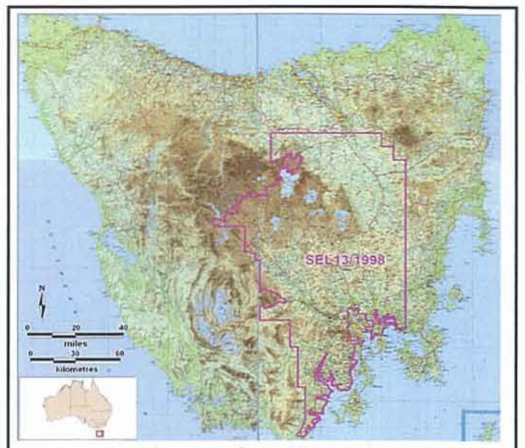
Geology map of the Macquarie River Fault Block and location of proposed drill site (MR #2)



Topographic map of the Macquarie River Fault Block (MR # 2)



Gravity Map (Residual Bouguer Anomaly) of the Macquarie River Fault Block (MR# 2)



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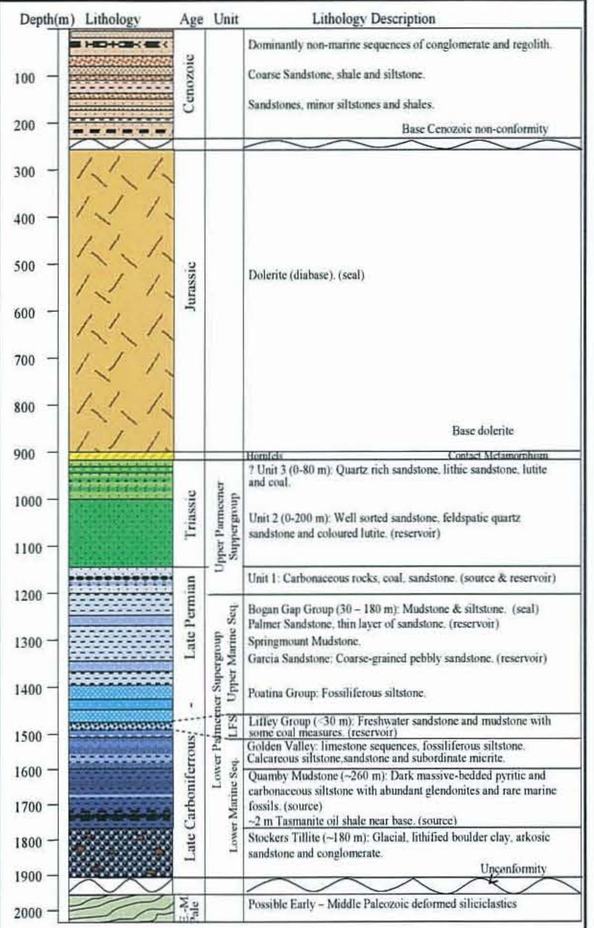


Sources, reservoirs and seals are predicted from field and laboratory work. All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork.

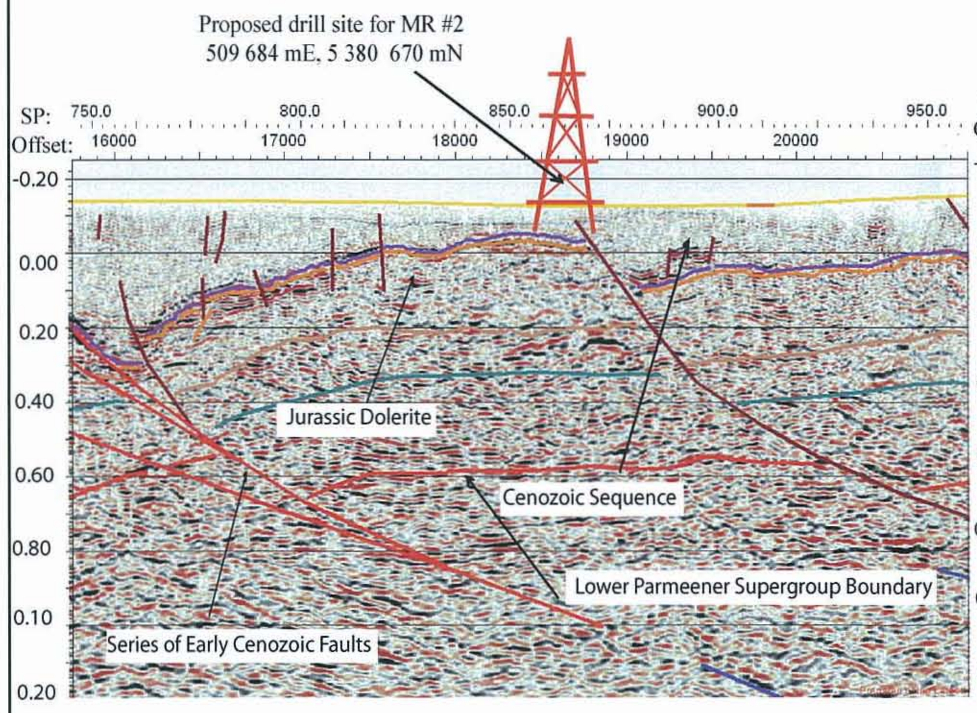
Prediction of Stratigraphy at Macquarie River Fault Block (MR # 2)

	Permo-Triassic	Ordovician -Devonian	Total
(P90)	5	-	5
(P50)	12	-	12
(P10)	24	-	24

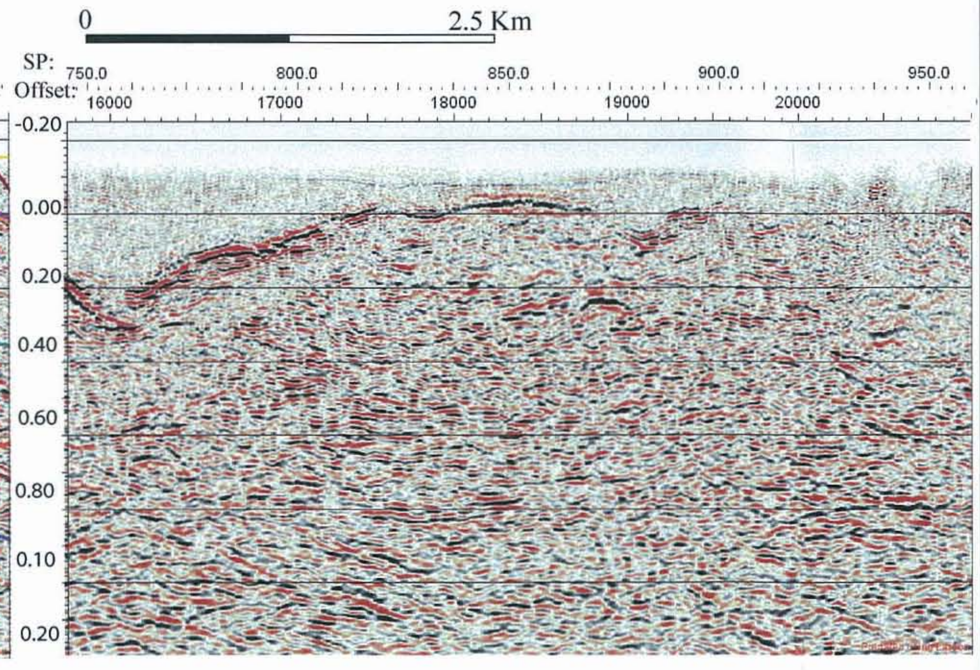
Monte – Carlo simulations of potential, undiscovered petroleum at Macquarie River #2 in million barrels

Petroleum System Characteristics of the Macquarie Fault Block (based on seismic line TB01- PG)

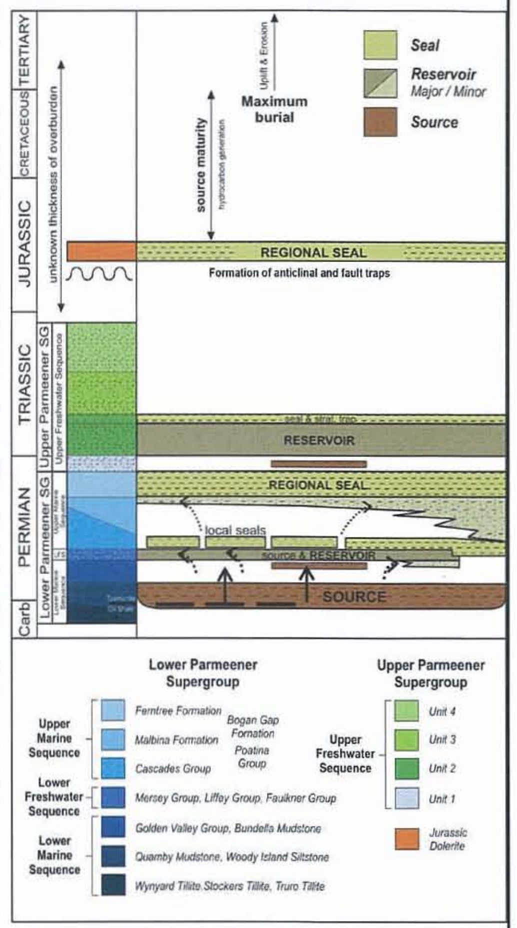
Target:	Triassic, Early to Late Permian
Source:	Unit 1, Quamby Mudstone, Tasmanite oil shale
Reservoir:	Unit 2 (Triassic), Unit 1, Palmer Sandstone, Garcia Sandstone, Liffey Group (Permian)
Depth to top of reservoir:	Unit 2 = ~1000 m, Unit 1 = ~1050, Palmer Sandstone= ~1250 m, Garcia Sandstone= ~1350 m, Liffey Group= ~1480 m
Seal:	Jurassic Dolerite, Bogan Gap Group Mudstone
Trap:	Fault Block
Risk:	Timing, maturation and migration in the mid Jurassic to Cretaceous.Traps were formed in early Cenozoic. Burial in the Cenozoic, plus an elevated geothermal gradient.



Seismic line TB01-PG with structural and stratigraphic interpretations



Seismic line TB01-PG without interpretations



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. 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.

Stratigrayphy Prognoses

Stratigraphy prognoses for well sites are based on data gathered from existing and recent papers. In addition to and reports from different formations on each region with regard to the expectation of finding hydrocarbons, the prognoses are based on the suggested petroleum systems. Two petroleum system models are suggested for Tasmania basin (Gondwanan and Larapintine), which show potential development for sources, reservoirs and seals in different formations.

In the Gondwanan system; source rocks have been identified in Unit 1 (Permian) as Upper Parmeener Supergroup, Liffey Group (Faulkner Group in south), Macrae Mudstone, Woody Island Formation (Quamby Formation in south) and Tasmanite Oil Shale (Permian, Lower Parmeener Supergroup).

Reservoirs are recognized in Eocene-Oligocene (Cainozoic); Unit 2 (Triassic); Unit 1, Palmer Sandstone (Risdon Sandstone in the South), Garcia Sandstone (Mini Point and Deep Bay formations in the South) and Liffey Group (Faulkner Group in the South, Permian). In some cases highly fractured dolerite could be assumed to be a good underground reservoir for oil or gas.

Seal formations that have been identified include the diabasic dolerite (Jurassic), and the latest formation of the Bogan Gap Group (Ferntree Mudstone in the South, Permian). Liffey Group, Cascade Group clay and marginal marine siltstone may also act as seals locally (Burrett and Reid 2004).

In the Larapintine system; source rock is identified in Upper Limestone Member (Gordon Group).

Reservoirs are recognized in Crotty Quartzite (Eldon Group), Palaokarst, Upper Limestone Member and Lower Limestone Member of Gordon Group.

Seal formations are identified as Bell Shale impure Limestone and thinly bedded fine-grained quartz siltstone of Eldon Group and fossiliferous, subtidal micrite with shallowing upward cycle of biocalcarenite of upper Limestone Member also act as seals.

The thickness of each formation have been calculated by measuring the Two Way Time on the seismic section of the particular line close to the drill sites, with respect to seismic velocities proposed by Burrett (2002) and Stacy (2004). Plus using known thicknesses from field observations.

Stratigraphical columns listed below are in order of volume ranking, proposed by GSLM for the future drilling activities.

Bellevue Anticline BV#1D

Thunderbolt Anticline # 1

Bracknell Dome # 1

Derwent Bridge Anticline # 1

Interlaken Anticline# 1

Nile River Fault Block#1

Butler Rise Fault Block #1

Cressy Anticline #1

Hummocky Hills Fault B# 1

Cressy Anticline #2

Macquarie R. Anticline # 1

Stockwell Fault Block # 1

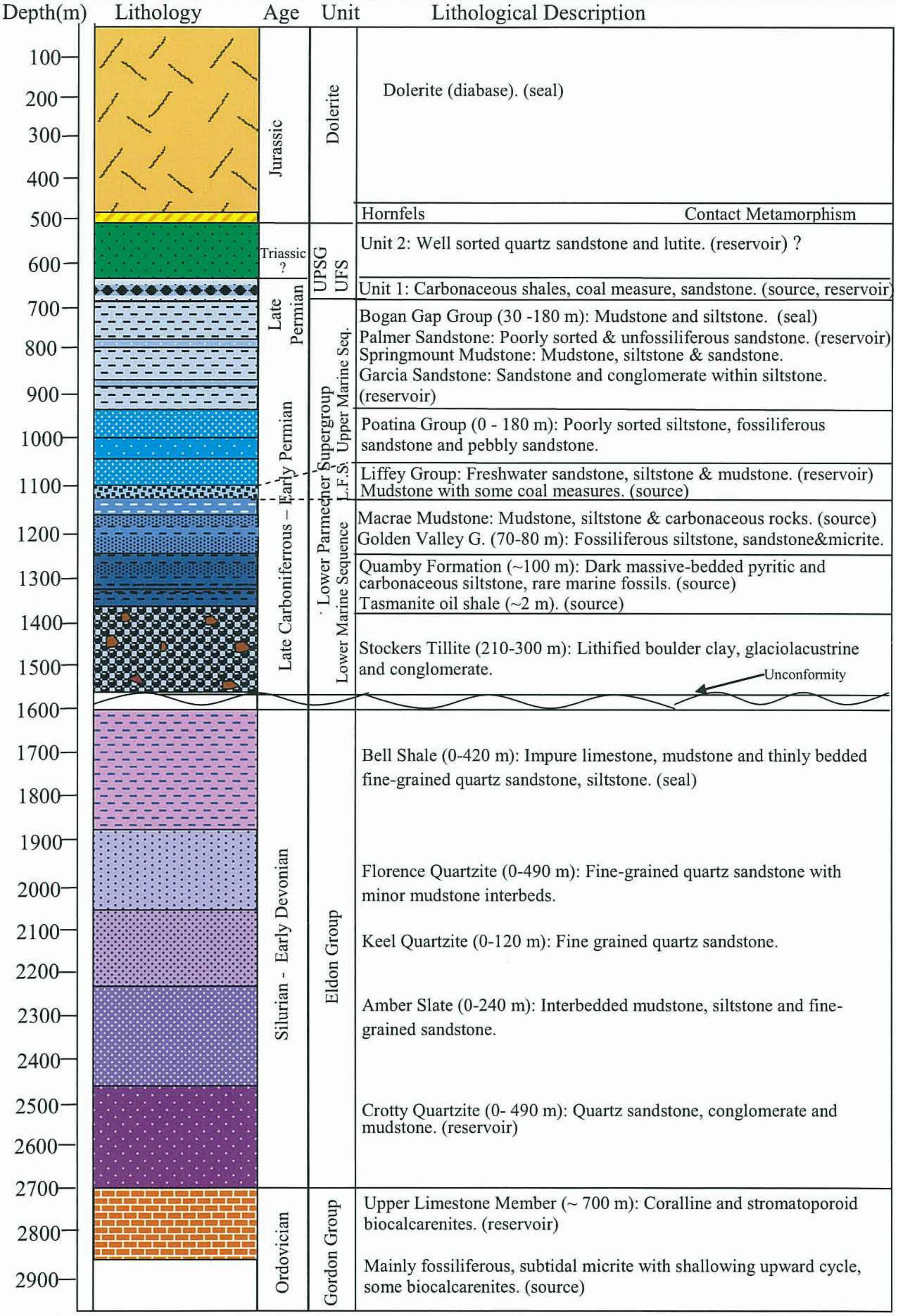
Scotts Tier Fault Block # 1

Lonnavale # 2

Steppes Anticline # 1

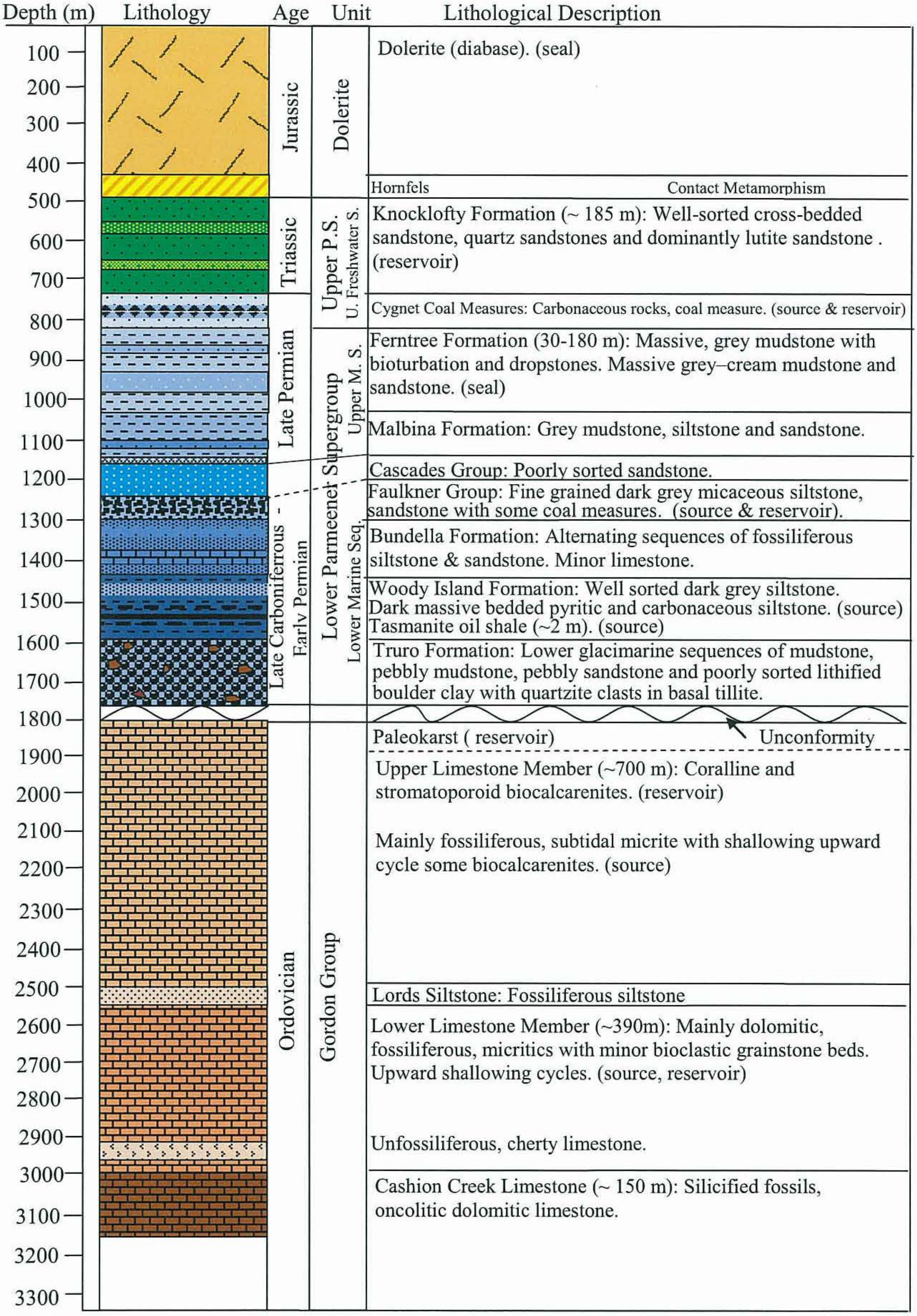
Quamby Fault Block # 1

Bellevue Lake Echo (BV#1)- Predicted- SectionAMG 66- Coordinates: 465 660mE, 5 338 904mN



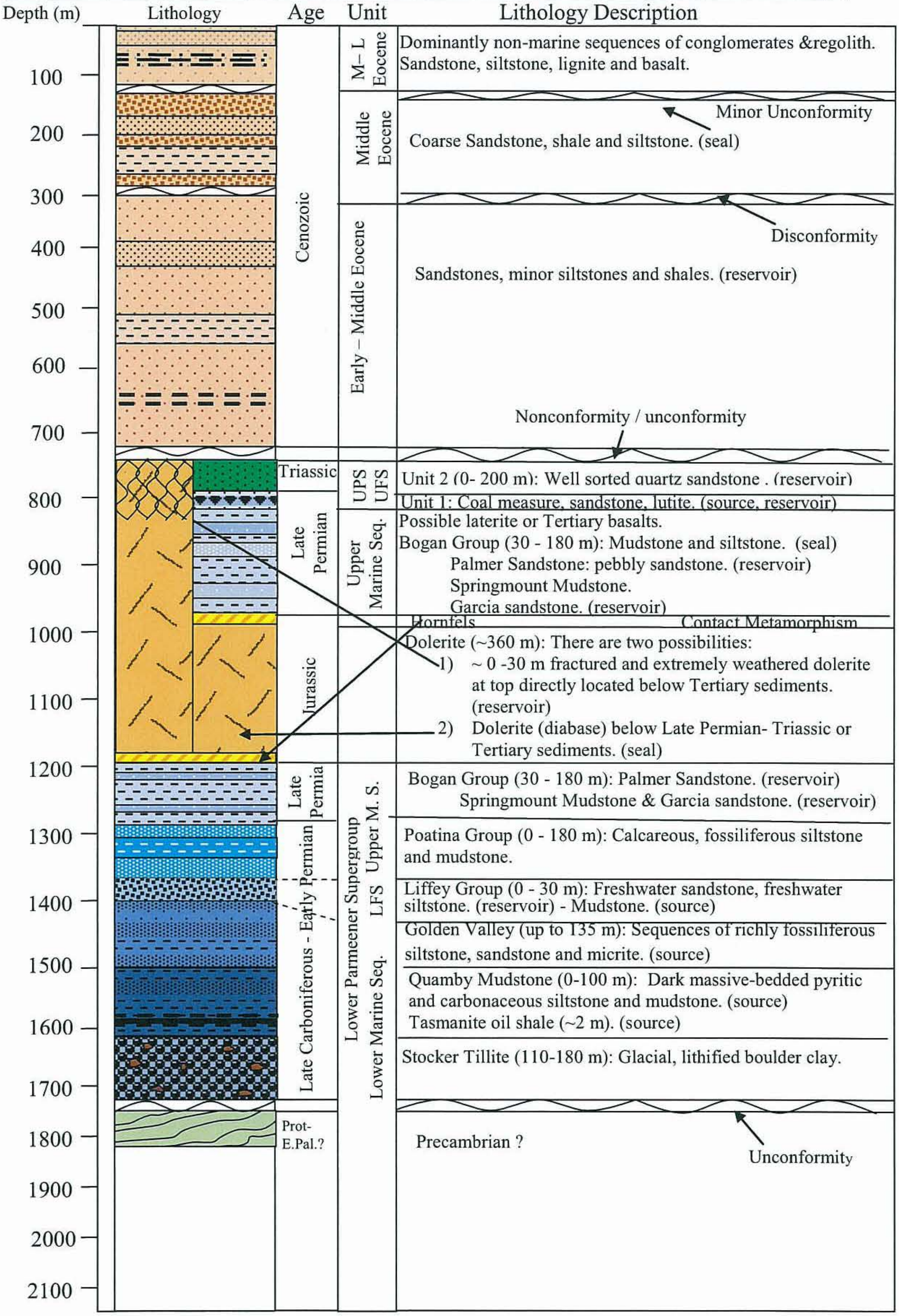
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Thunderbolt (TB #1)- Predicted Section AMG 66 Coordinates:465 931 mE, 5 287 859 mN



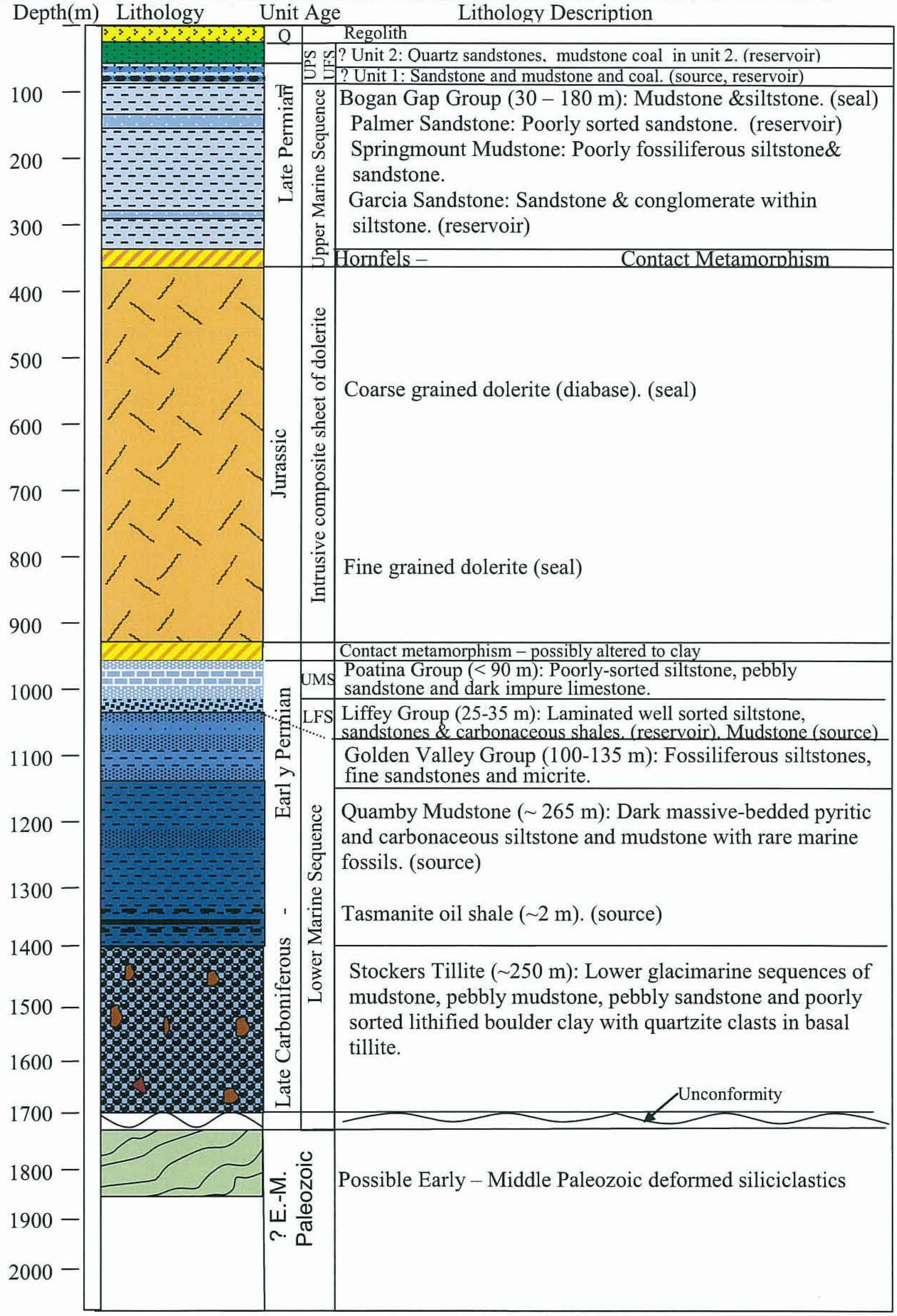
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Bracknell (BN#1)- Predicted- SectionAMG 66- Coordinates: 497 915 mE, 5 388 924 mN



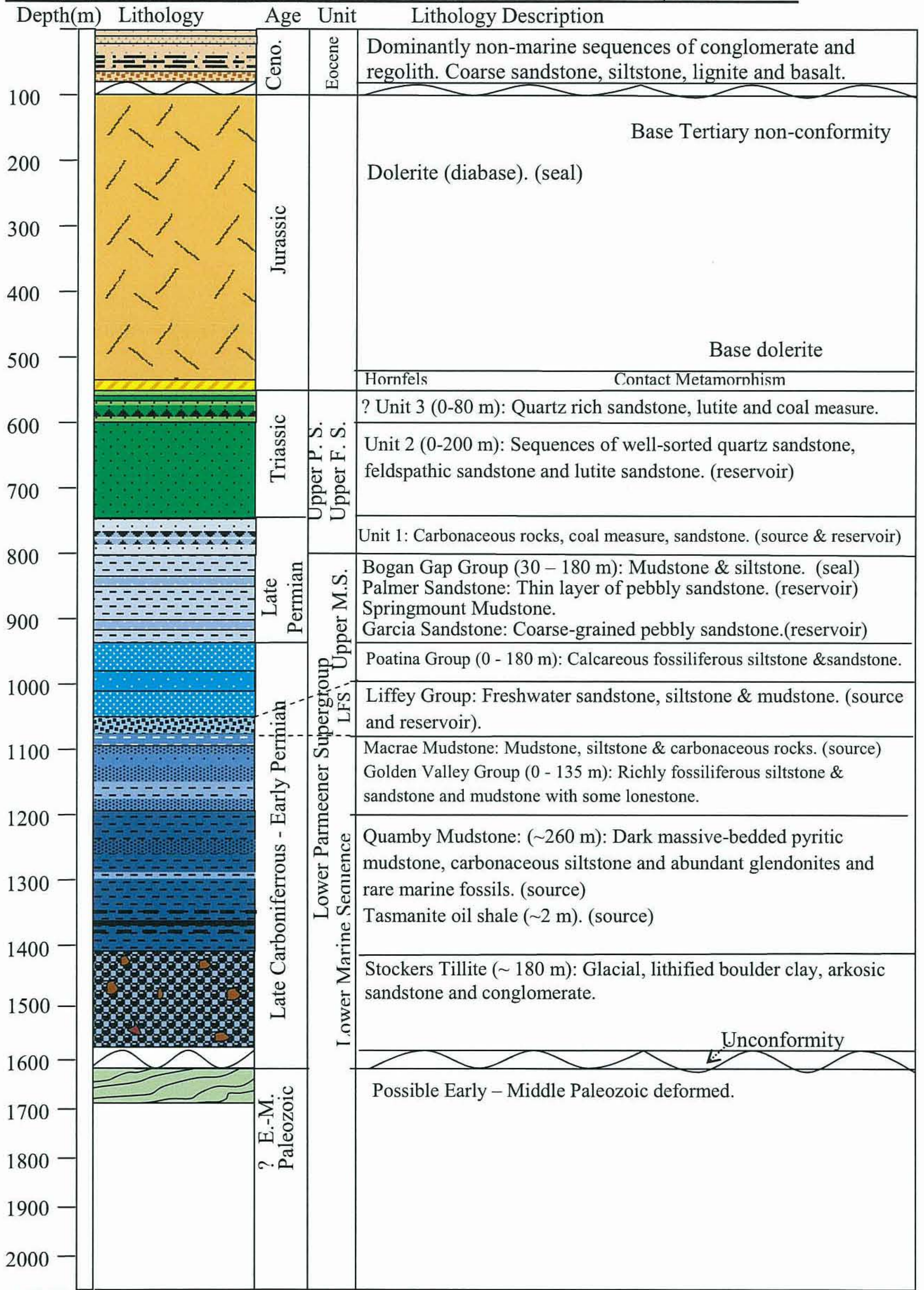
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Butlers Rise (BR#1)– Predicted Section-AMG66 Coordinates:537 627 mE, 5 334 856 mN



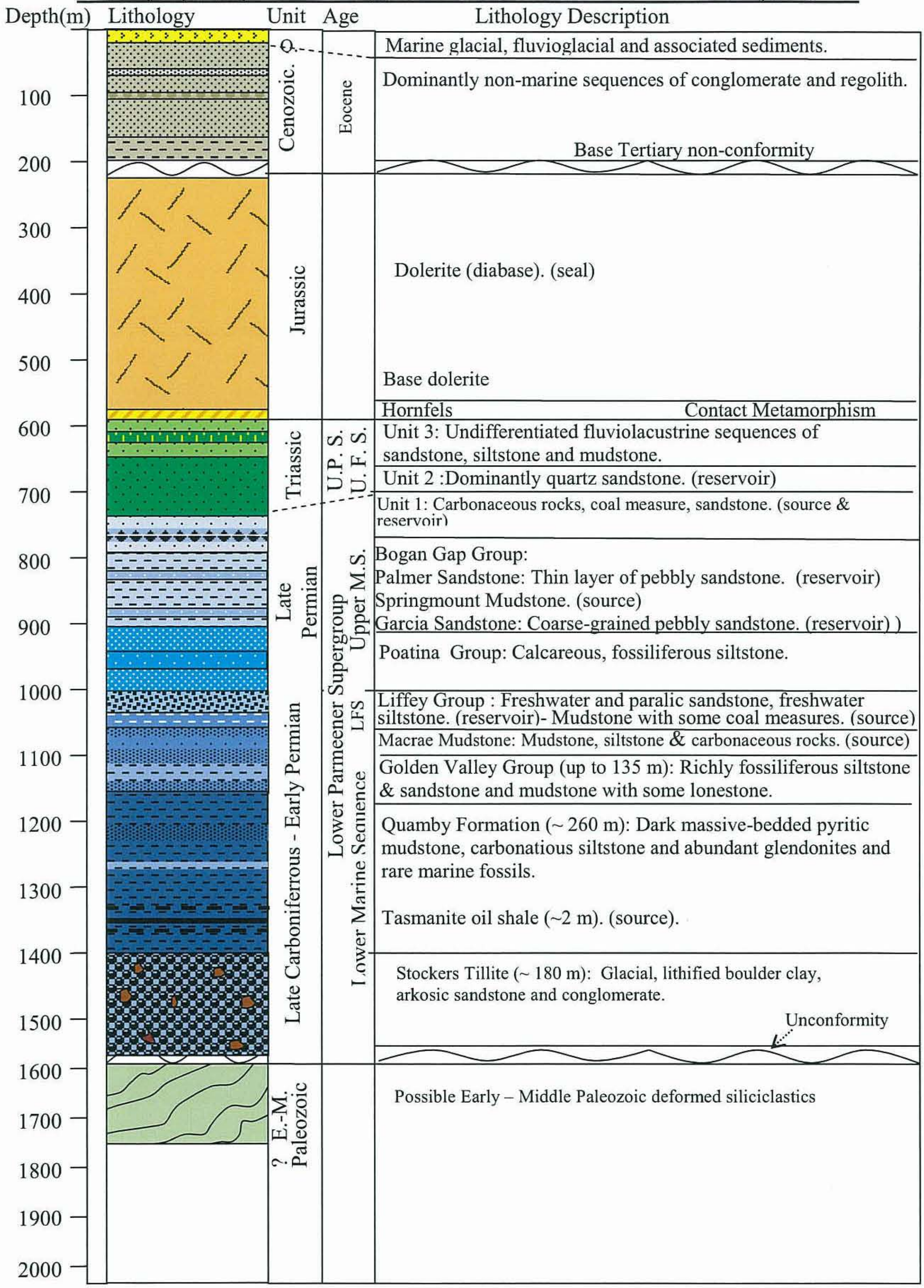
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Cressy 1(CR#1)– Predicted Section AMG66 Coordinates: 512 450 mE, 5 387 021 mN



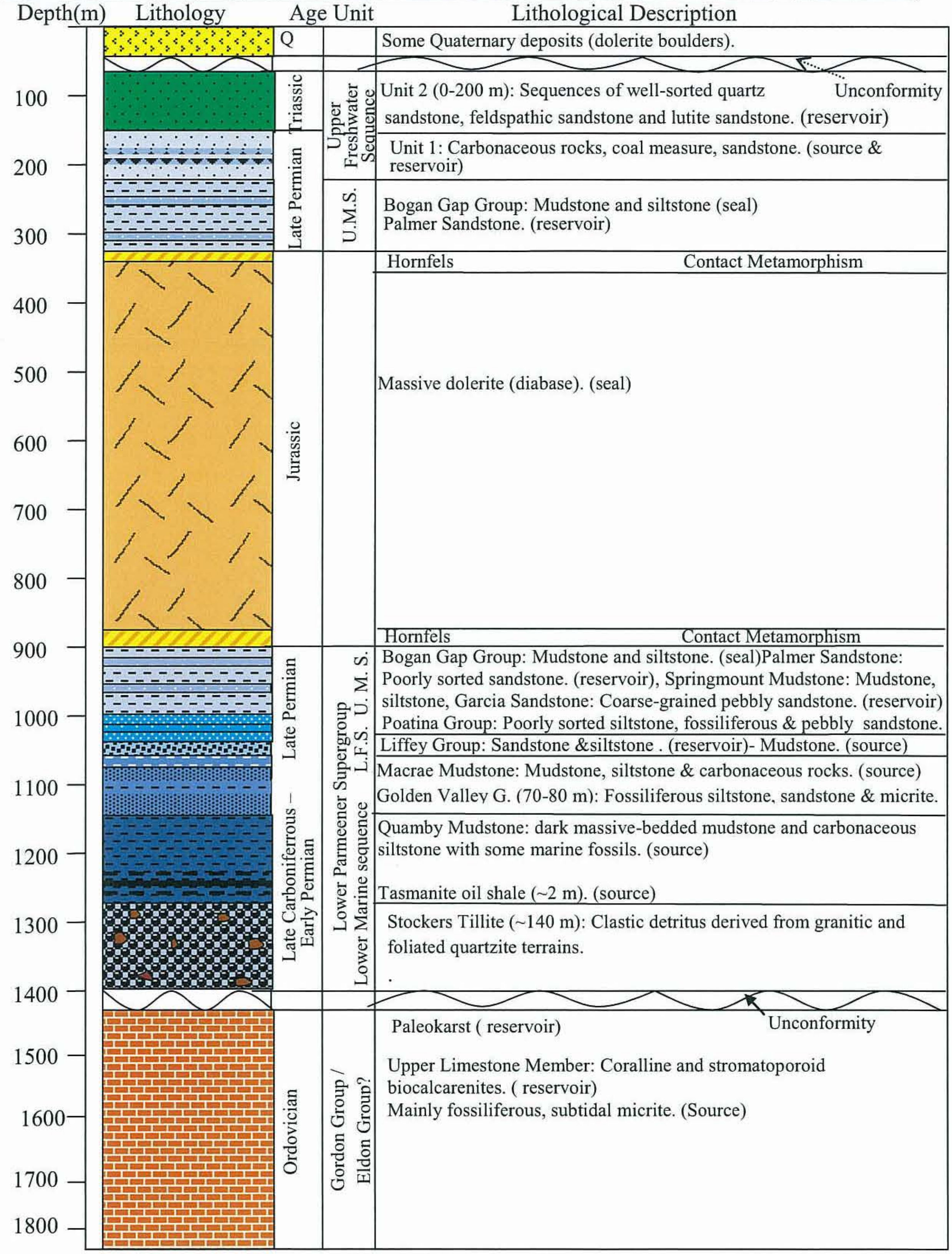
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Cressy 2 (CR#2) – Predicted Section AMG66 Coordinates:510 311 mE, 5 385 678



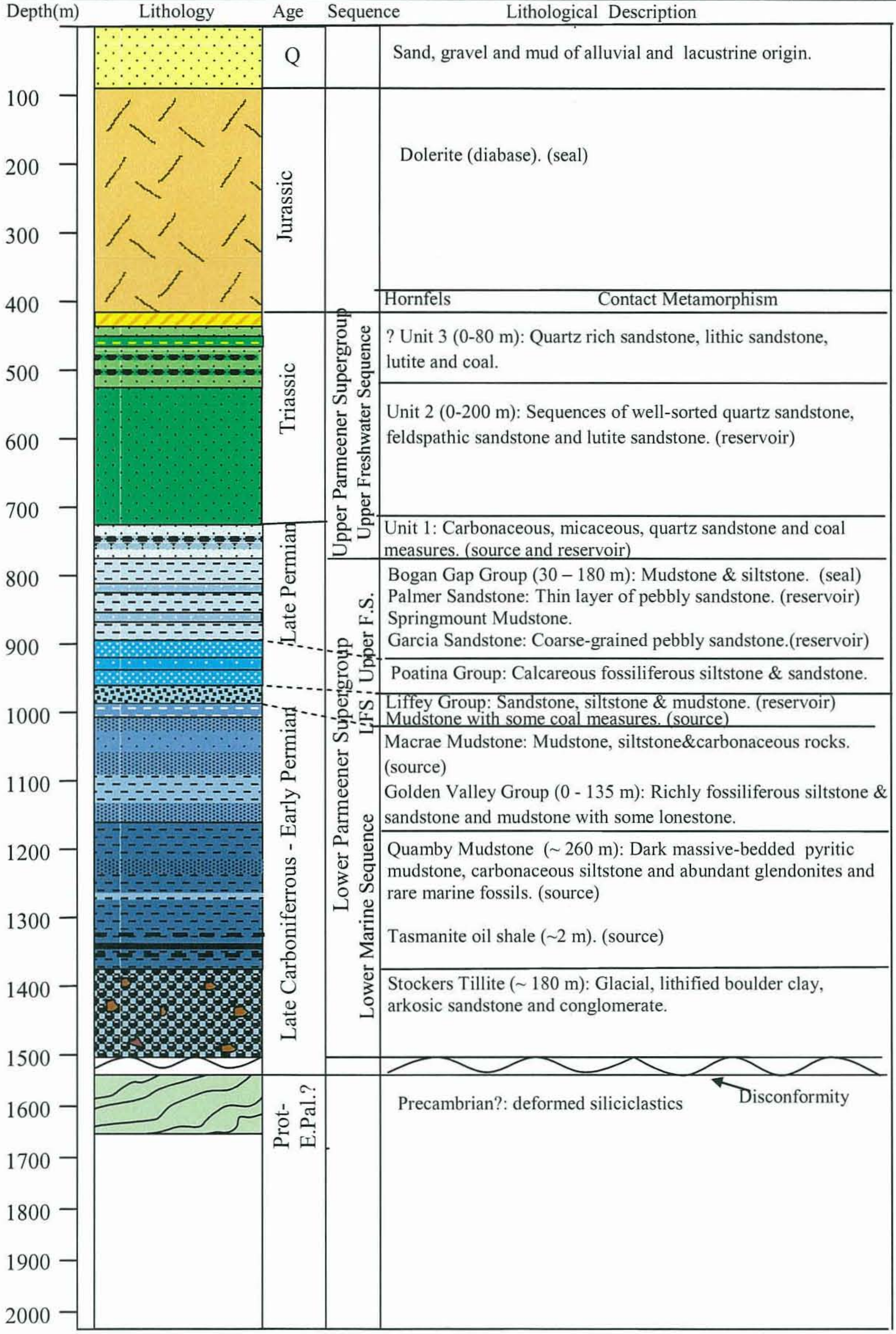
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Derwent Bridge (DB#1)- Predicted Section AMG66 Coordinates: 435 186 mE, 5 333 351 mN



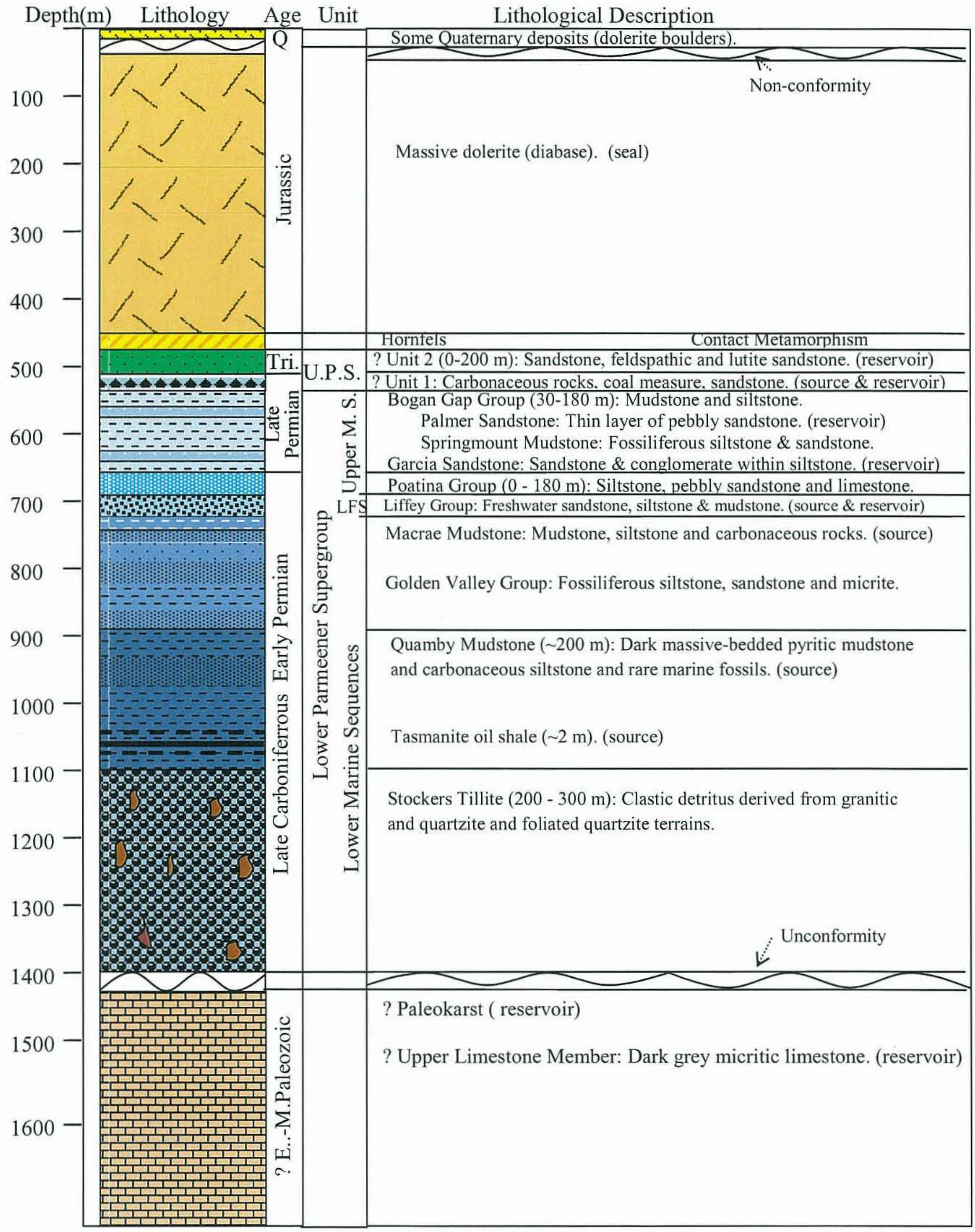
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Hummocky Hills (HH #1)- Predicted Section AMG66 Coordinates: 519 784 mE, 5 383 887 mN



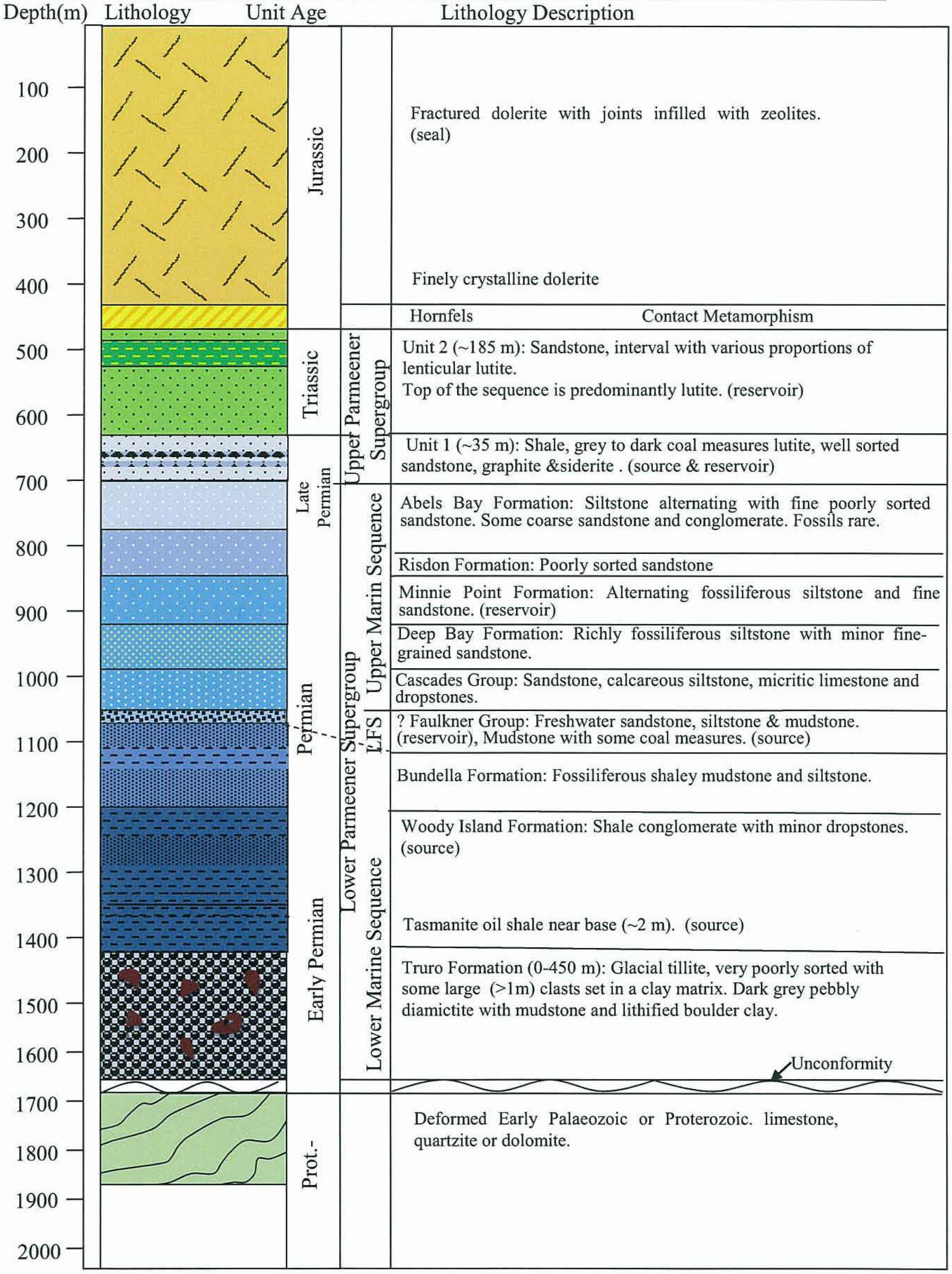
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Interlaken (IL #1)- Predicted Section AMG 66 Coordinates: 519 456 mE, 5 335 869 mN



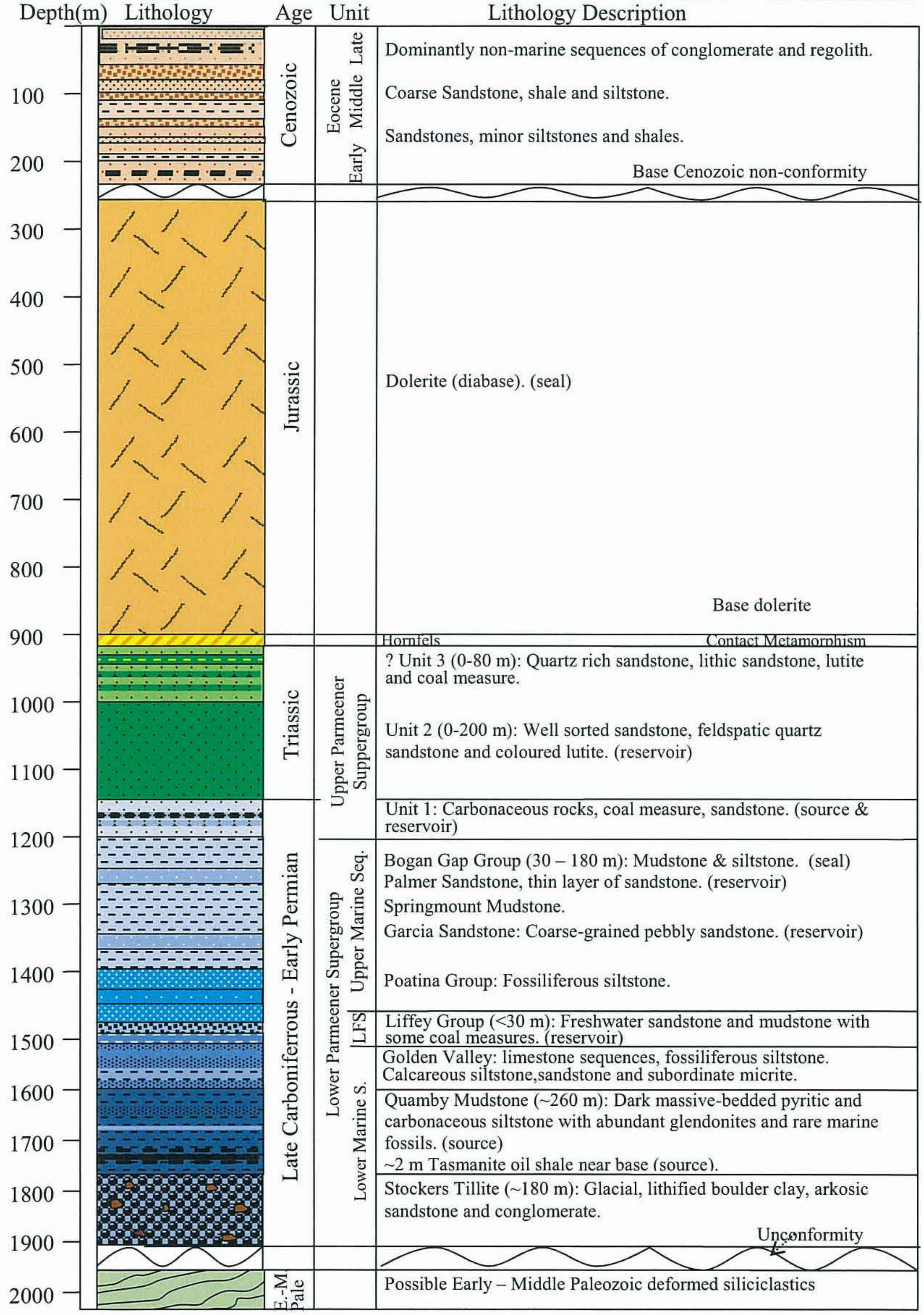
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Lonnavale # 2 (LV #2) Predicted Section AMG66 Coordinates: 482 665mE, 5 247 967 mN



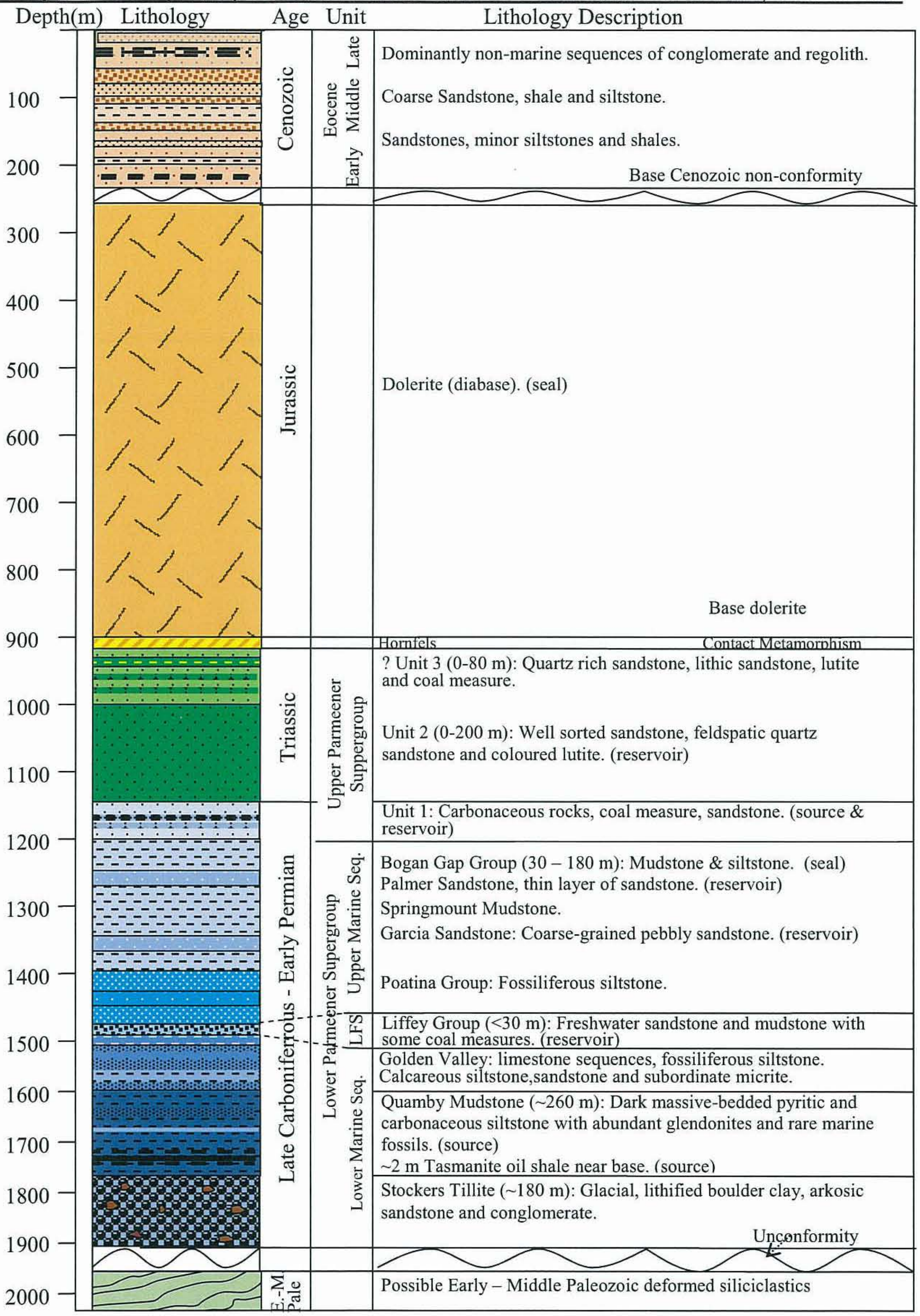
All thicknesses are approximate and are based on data from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Macquarie River (MR#1)– Predicted Section AMG66 Coordinates: 512 067 mE, 5 381 794 mN



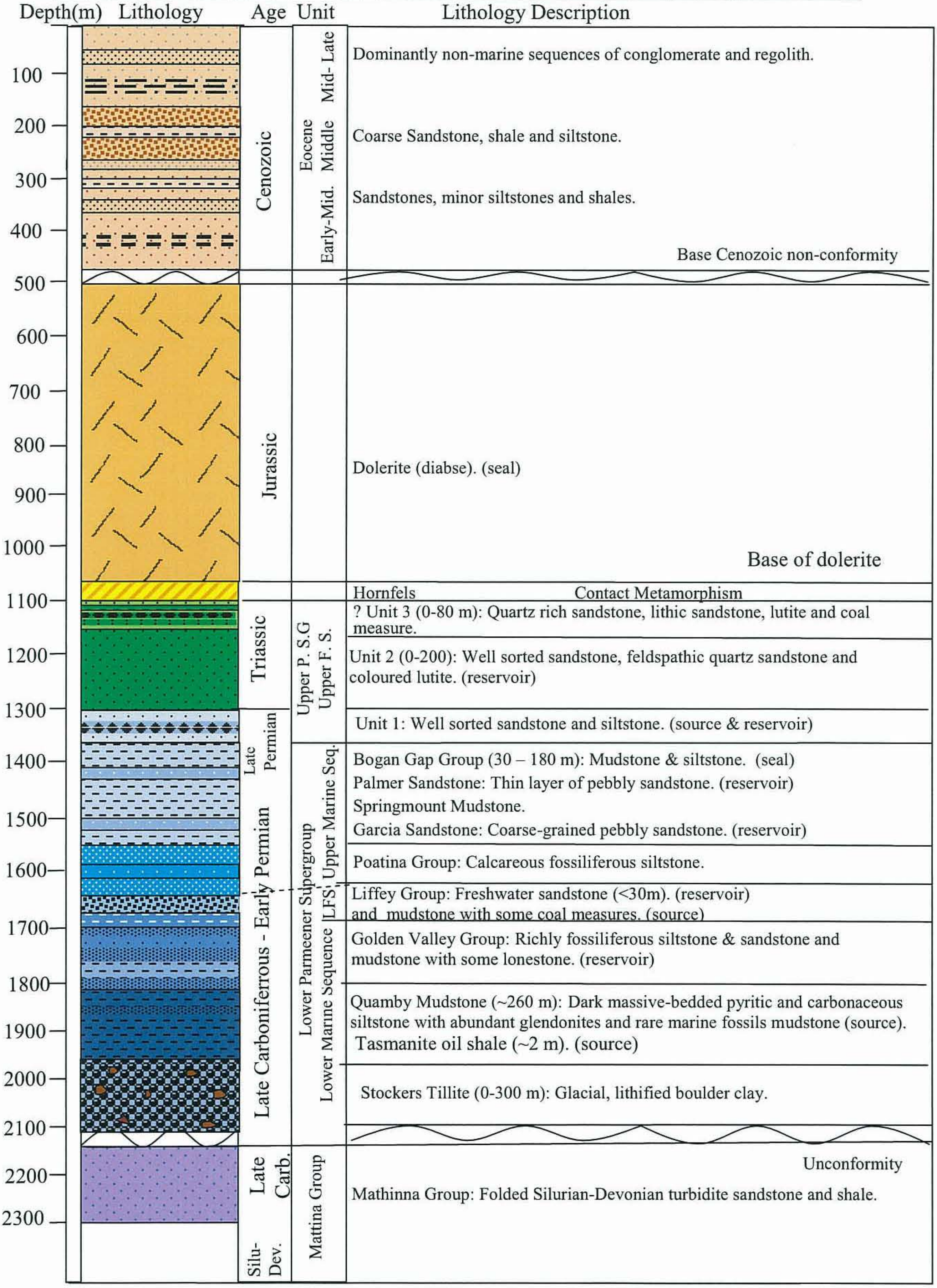
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Macquarie River (MR#2)– Predicted Section AMG66 Coordinates: 509 684 mE, 5 380 670 mN



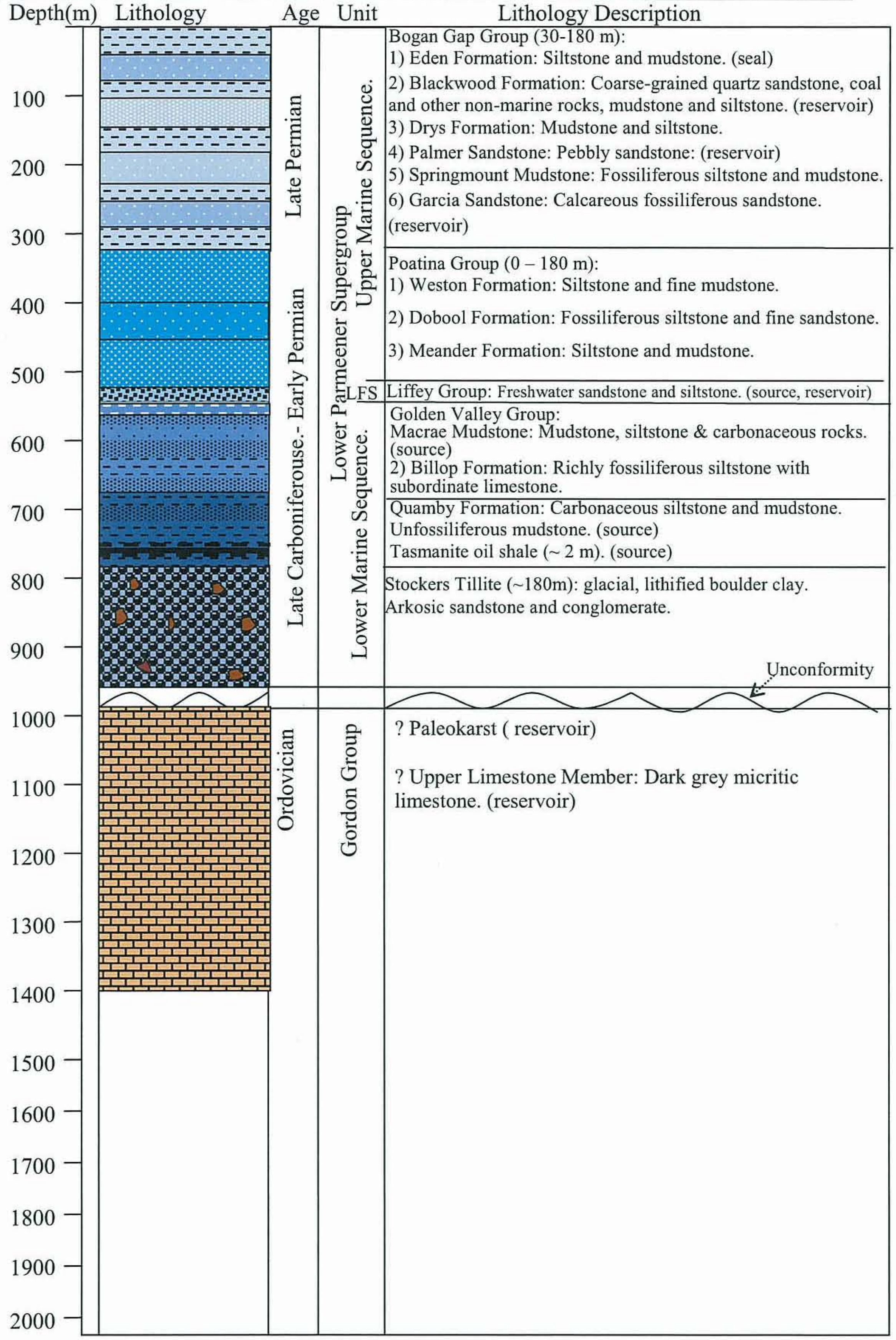
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Nile River (NR #1)– Predicted Section AMG66 Coordinates:527 550 mE, 5 388 256 mN



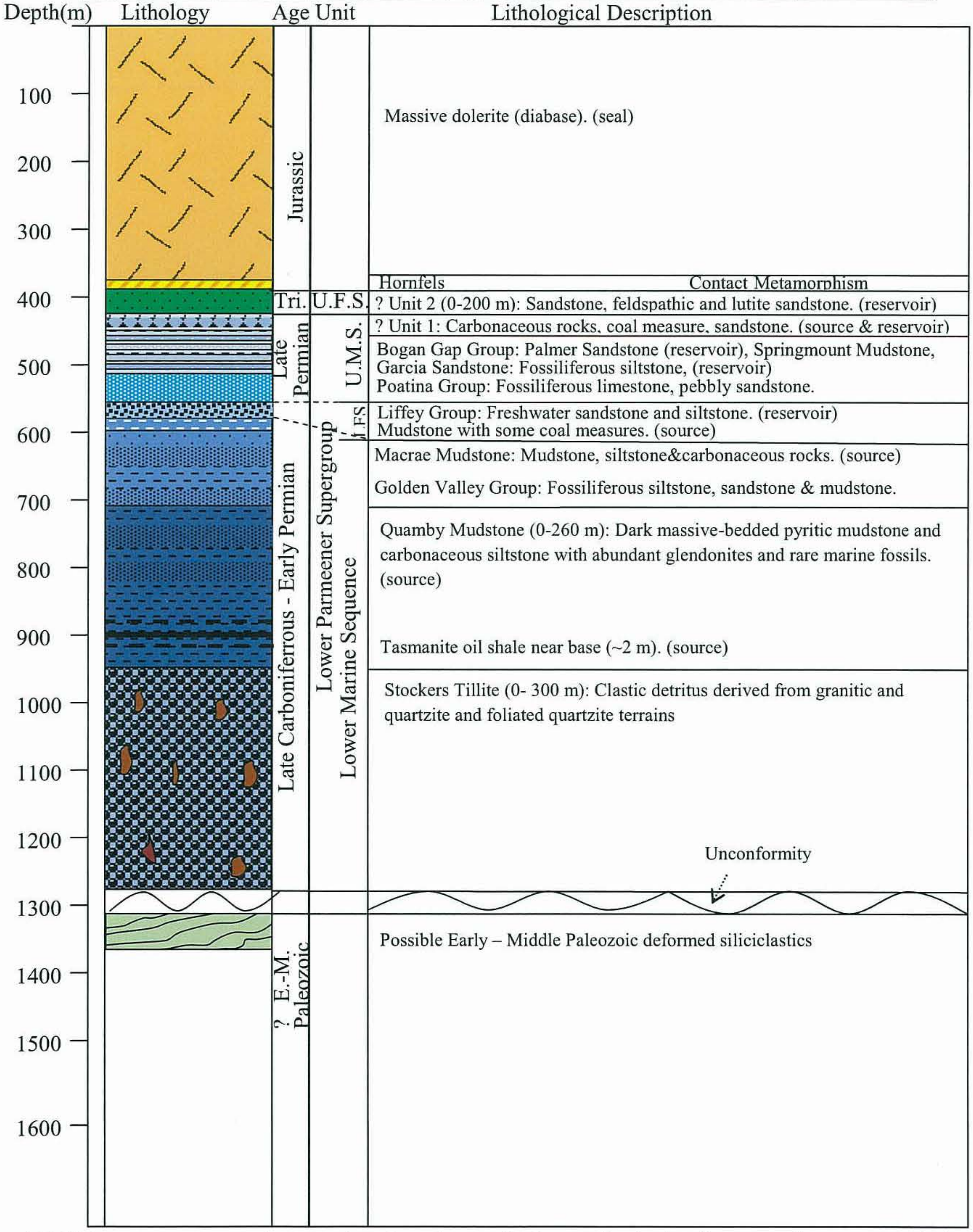
All thicknesses are approximate and are based on preliminary seismic data interpretation

Quamby (QY #1))– Predicted Section AMG66 Coordinates: 476 764 mE, 5 388 335 mN



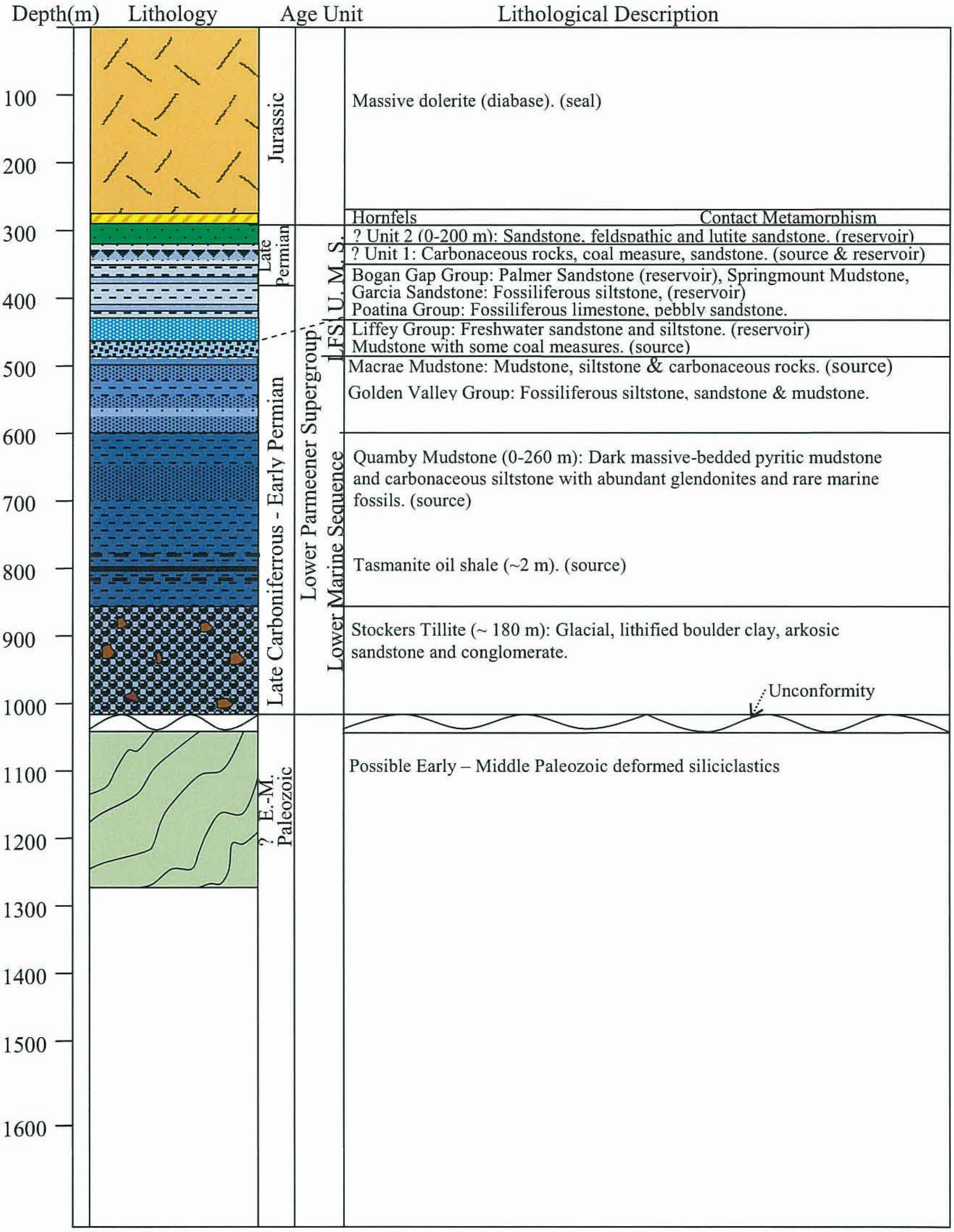
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Scotts Tier#1 (ST#1)- Predicted Section AMG66 Coordinates: 507 753 mE, 5 334 764 mN



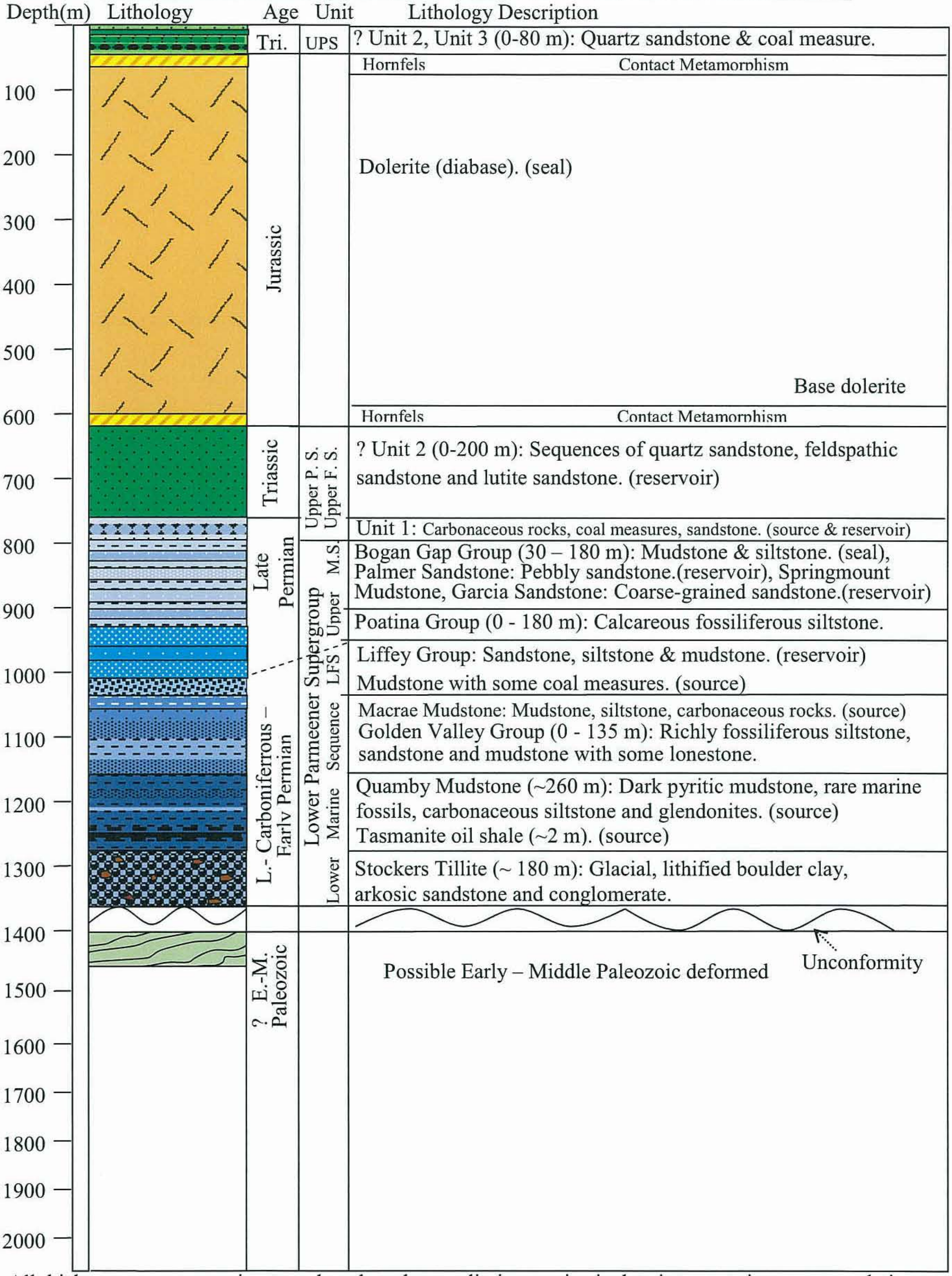
All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Steppes (SP#1)- Predicted Section AMG66 Coordinates: 490 155 mE, 5 339 552 mN



All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.

Stockwell #1 – Predicted Section AMG66 Coordinates: 528 380 mE 5 368 840 mN



All thicknesses are approximate and are based on preliminary seismic data interpretation or extrapolation from fieldwork. Sources, reservoirs and seals are predicted from field work and laboratory data.