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BASS BASIN TECHNICAL ASSESSMENT

by:

South Australian Oil & Gas Corporation Pty. Ltd.
Basin Assessment Group

March 1984.

OR - 245

IMPORTANT NOTICE

REVIEW

This report provides a technical basis for SAOGC corporate decision-making related to the Bass Basin.

The Bass Basin is situated offshore in the Bass Strait between Tasmania and Victoria in water depths of 30 to 90 metres. The most prospective permits lie within the area of Tasmanian state administration. The Basin has an area of approximately 12 million acres. A Vacant Area of 52 blocks comprising 760,000 acres has been gazetted by the Federal and Tasmanian Governments for tenders by March 23, 1984. The area includes Pelican gas field which is currently assessed as subeconomic with 1.5 TCF of gas reserves (75% confidence level).

Most of the central Bass Basin area is covered by Exploration Permits T14P and T18P held by a group of small companies headed by Bass Strait Oil and Gas N.L. and Cue Minerals N.L. These companies are interrelated and are controlled by E.G. Albers, a Melbourne attorney.

The basin margins and part of the southeast central portion are covered by T15P, T16P and T19P held by Weaver Oil and Gas of Houston, Texas.

Nineteen wells were drilled by the Hematite/Esso partnership in the Bass Basin during the period 1965 to 1982 and over 12,000 kilometres of seismic was shot. The seismic data is of variable quality. Most wells tested objectives at the top of the Eastern View Coal Measures (EVCM) where a regional shale seal provided a Gippsland Basin prospect analogue. Testing of this concept by Hematite and Esso was unsuccessful.

Drilling established that all major shows, as well as the Pelican Field gas reserves, occur deeper within the EVCM section and pointed to the potential for deeper plays of a type different from those producing in the Gippsland Basin.

The Bass Basin was formed by extensional tectonics associated with the rift separation of the Australian and Antarctic continents. Initial rift phase sedimentation during the late Jurassic consisted of fluvio-lacustrine sediments of Otway Group equivalence. Actual separation of the two continents corresponded with major tilting of fault blocks in the Basin. Deposition of the Eastern View Coal Measures in this setting produced up to 15,000 feet of fluvio-lacustrine sediments ranging in age from late Cretaceous to Eocene.

The late Eocene Demons Bluff Formation shales and fine grained clastics form a regional seal over the EVCM and are marine in origin. The younger Tertiary (Oligocene to Pliocene) section consists of marine shales and limestones.

The primary prospects are in the Eastern View Coal Measures, below the level of the Early Eocene M. diversus unconformity. Source rocks are present in all stratigraphic intervals, but only those below the M. diversus unconformity are mature in depocentre areas. In general, EVCM sediments below 9,000 feet are mature, becoming supermature below 18,000 feet. The existence of Pelican Field pay zones within this interval and numerous shows confirm that maturation, hydrocarbon generation and some entrapment have occurred.

The structural style of the Bass Basin is in the form of major and minor tilted blocks generated by extensional normal faults. The block tilting controls sedimentation geometry, with depocentre trends following major structural lows . Episodes of recurrent movement on large, normal faults produced rapid thickness changes in various sedimentary units, particularly across faults.

Facies analysis and sand percentages in the EVCM indicate that the Bass Basin largely was more fluvial around the shallow margins, and more lacustrine towards deeper, central depocentres. This simple type of basin fill geometry creates few facies-controlled barriers to the migration of hydrocarbons from the basin, but intraformational seals appear to have confined the migration of hydrocarbons within the zone from which they were generated.

However, trapping of hydrocarbons has occurred at Pelican Field, and the involvement of faults in the trapping mechanism is demonstrated by the sealing of three distinct gas/condensate pools from each other, and the isolation of an overpressured zone beneath the field. The overpressure zone may also indicate additional potential for sealing of deeper hydrocarbon reservoirs.

The lower part of the EVCM is considered to have generated hydrocarbons from Paleocene time through until the Present, so the timing of fault movement is extremely important in the formation of a hydrocarbon trap. The percentage of sand present in the section intersected by the fault is the other important element in trapping. At Pelican Field, the faults seal 50% of the reservoir sands at a sand percentage of 40%. The dependence of traps on fault sealing is risky, and it is likely that major volumes of hydrocarbons have escaped from the basin since their generation. However it is also likely that a significant volume still remains in fault-sealed traps.

Play types interpreted in the Bass Basin are:

1) **Pelican-type play:** fault-sealed traps. Hydrocarbons are confined by faults and intraformational seals within a mature interval in the EVCM, below the *M. diversus* Unconformity. Pelican field has liquids-rich gas reserves of 1.5 TCF in place, but the same play type in an oil prone location may have 400 million barrels of oil in place. Prospects of Pelican type may exist along the eastern bounding fault of the main Cormorant-Narimba depocentre trend, and have a cumulative reserves potential of 3 TCF of gas and 1150 million barrels of oil in place.

2) **Pipipa-type play:** fault sealed traps formed by recurrent movement of tilted blocks along the southwest margin of the basin. Sand percentages similar to or lower than Pelican Field are required for fault sealing of the EVCM interval below the *M. diversus* unconformity. The Pipipa 1 well did not penetrate this interval. The Pipipa prospect has liquids-rich gas potential reserves of 900 BCF in place. This type of prospect may occur along a facies trend which generates fault sealing sand percentage values through the reservoir interval. This play type is assigned a cumulative potential of 1.7 TCF gas and 450 million barrels of oil in place.

3) **Variations of the Pelican and Pipipa type plays** exist, with higher risk derived from either the difficulty in defining the appropriate facies requirements, or the effectiveness of major recurrent faults as reservoir seals. These are assigned cumulative potential reserves of 350 million barrels of oil in place at a high risk level.

4) **Structural Culminations at the top of EVCM** have been tested sufficiently in the basin to prevent significant reserves from being assigned to this play. However, the "Yolla" prospect is untested and may be the exception. Reserves potential is estimated at 1 TCF gas in place.

Deep, structurally high features in the lower EVCM section exist in the basin. These are untested and have unknown potential.

Based on a detailed analysis of the development potential of Pelican Field, commercial viability of the Bass Basin depends on high initial production rates and the production of either oil, or gas which has a very high liquids component.

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BASS BASIN TECHNICAL ASSESSMENT

(i) PREFACE

This report documents a technical assessment of the Bass Basin by the SAOGC Basin Assessment Group [1] in early 1984.

The purpose of the report is to provide a basis for corporate decisions by SAOGC management, and allow the development of future exploration strategies.

The report is in two parts:

PART 1 evaluates the prospectivity of the Bass Basin in general terms, outlining specific play areas and high risk prospects.

PART 2 evaluates the Vacant Area in terms of:

(i) Pelican Field and

(ii) Other prospects.

Interests in the entire Bass Basin are currently available either by Vacant Area application or farmin negotiation.

It is recommended that the entire basin should be explored as an entity, since proper integration of results is required to assess particular areas of prospectivity. This can only be done within the framework of a considered, sequential work programme which investigates sufficient high risk aspects to properly determine the petroleum potential of this basin.

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[1] SAOGC Basin Assessment Group

P.S. Moignard	:	Supervisor
K.S. Glenday	:	Team Leader
R. Smit	:	Geophysicist
L.K. Spencer	:	Geologist

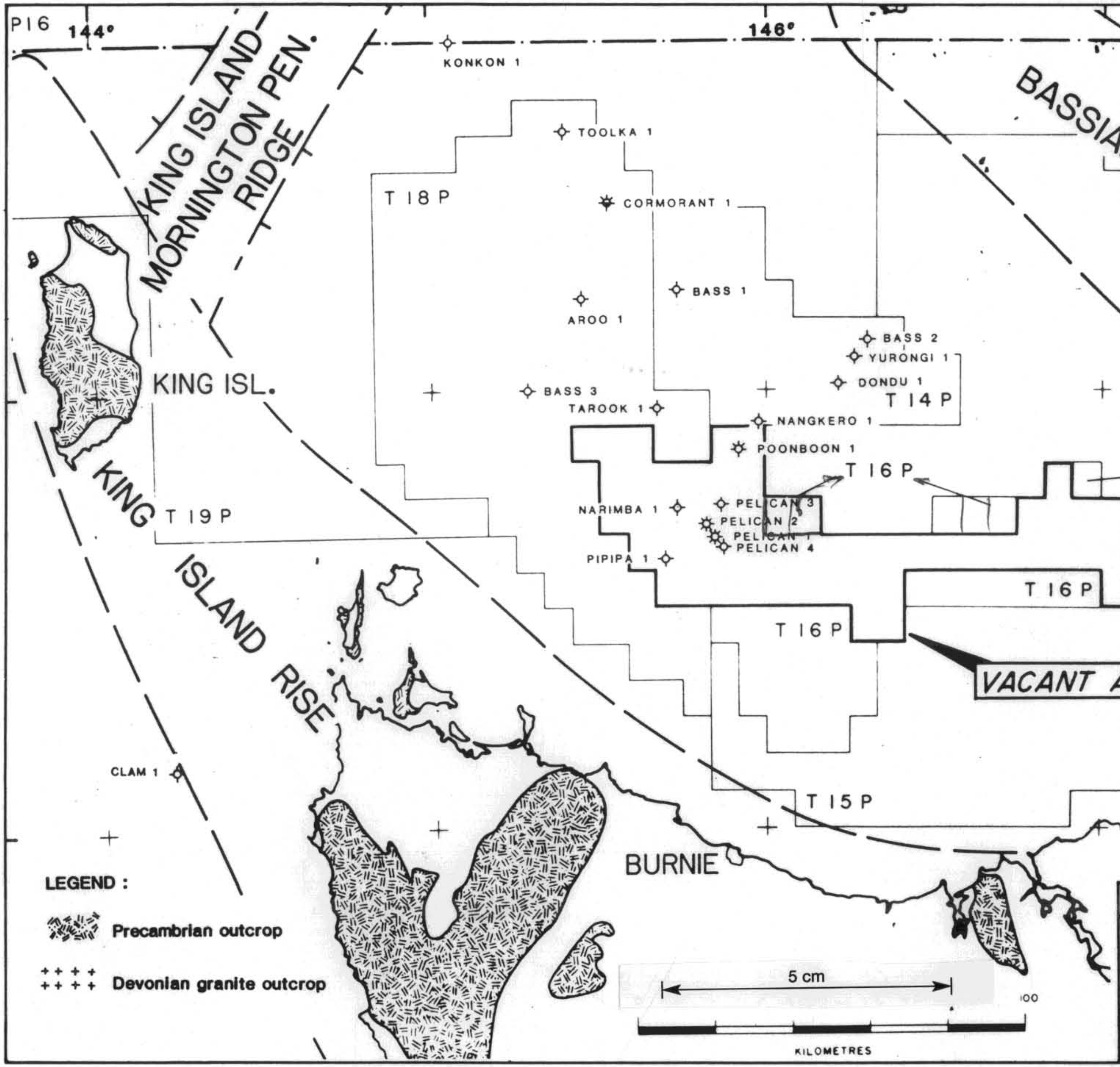
PART 1. BASS BASIN OVERVIEW

1.0 INTRODUCTION

The Bass Basin is located in the Bass Strait between Tasmania and Victoria (see Figure 1.1). It is a northwest-southeast trending oval-shaped basin approximately 250 kilometres long by 125 kilometres wide and consists of Early Cretaceous to Late Tertiary age sediments. It is separated from the Gippsland Basin by Devonian age granitic rocks of the Bassian Rise and from the Torquay Embayment of the Otway Basin by the late uplifted (Miocene ?) King Island - Mornington Peninsula Ridge. To the southwest it is bounded by Precambrian rocks of the King Island Rise.

The basin lies wholly on the continental shelf in water depths ranging from 30 to 90 metres (Aquing, 1980).

The Bass Basin appears to have been first developed towards the close of the Late Jurassic during rift development which preceded continental separation. Sediments of the Otway Group were deposited during Early Cretaceous time within the early rift basin. Initiation of continental separation at the end of Early Cretaceous time resulted in a phase of crustal thinning and extensional normal block faulting (Fig. 1.2). Falvey's model (1974) of Atlantic-type continental margins suggests that during breakup, a pulse of uplift resulted in the development of an unconformity which is referred to as the "breakup uncon-



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN PERMIT MAP		
INT: K.S.G.	DATE: MAR. 84	NO: BASOO.3297
DRN: C.K.	SC: AS SHOWN	Fig. 1.1

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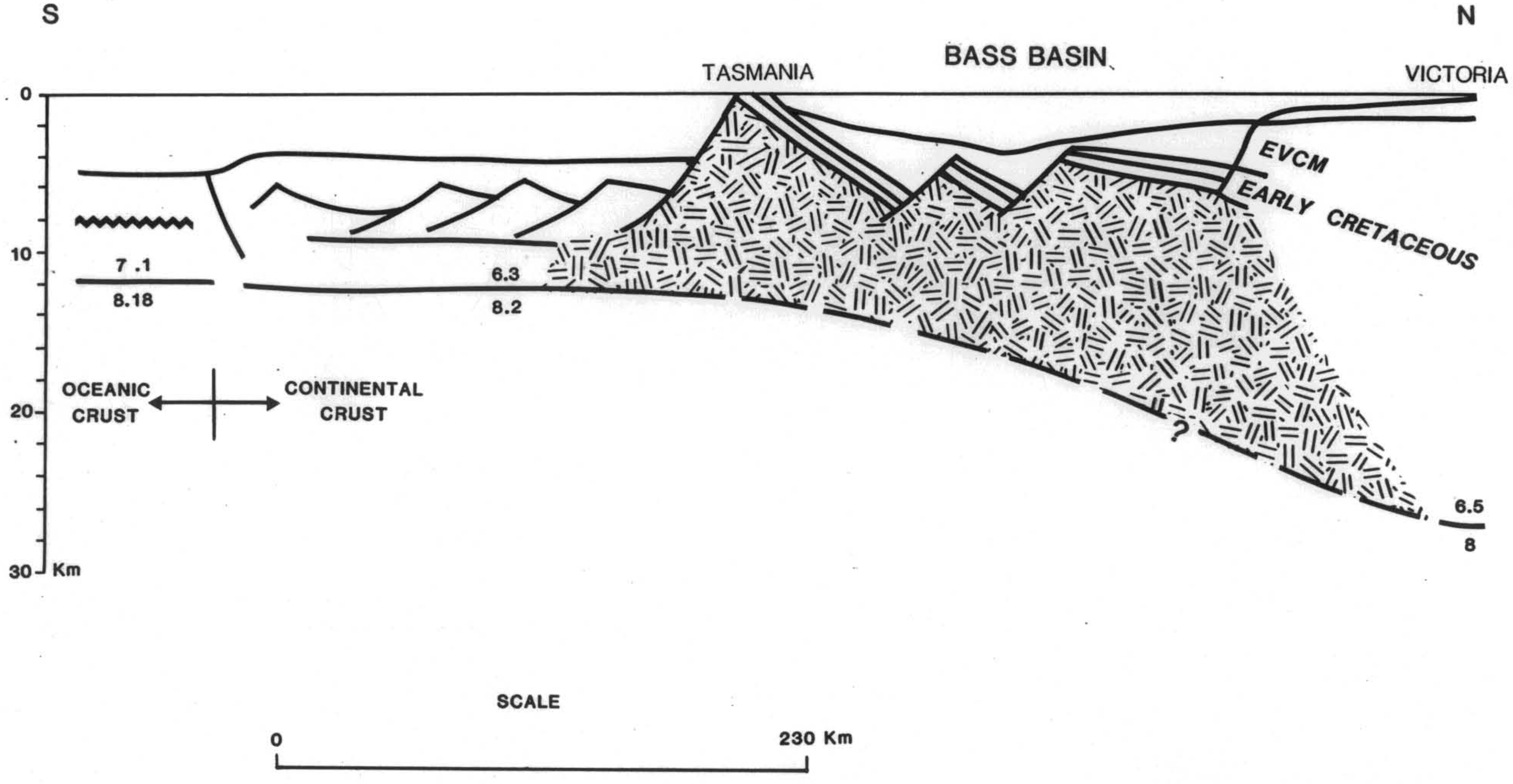

(Modified after Montadert et al 1979)

SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.		
SCEMATIC CROSS SECTION OF BASS BASIN		
Interp K.GLENDAY	Date MAR 84	Drg.No. BASOO.3298
Drawn A.B-M	Scale AS SHOWN	FIG. 1.2

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TABLE 1.1

BASS BASIN WELLS

YEAR DRILLED	STATE	WELL	LATITUDE (SOUTH)	LONGITUDE (EAST)	TD	LOWERMOST INTERVAL PENETRATED
1965	TAS	BASS -1	40 16 18.000	145 44 03.000	7717	Upper M.diversus (E.Eocene)
1966	TAS	BASS -2	39 53 09.000	146 18 15.000	5910	Lower L.balmei(E.to M.Paleocene)
1967	TAS	BASS -3	39 59 51.000	145 16 57.000	7978	T.longus (L.Cretaceous)
1970	TAS	CORMORANT-1	39 34 22.800	145 31 35.700	9845	Lower M.diversus (E.Eocene)
1970	TAS	PELICAN -1	40 20 21.720	145 50 36.920	10248	Upper L.balmei (L.Paleocene)
1972	TAS	POONBOON -1	40 08 15.190	145 55 01.280	10715	T.longus (L.Cretaceous)
1972	TAS	PELICAN -2	40 18 30.200	145 49 11.590	10066	Lower M.diversus (E.Eocene)
1972	TAS	PELICAN -3	40 15 44.990	145 51 50.600	9521	Lower L.balmei(E.to M.Paleocene)
1972	TAS	TAROOK -1	40 02 36.950	145 40 28.560	9100	Middle M.diversus (E.Eocene)
1973	VIC	KONKON -1	39 12 19.580	145 03 39.720	5043	T.longus (L.Cretaceous)
1973	TAS	DURROON -1	40 32 02.940	147 12 48.480	9922	C.paradoxa (E.Cretaceous)
1973	TAS	DONDU -1	39 59 12.520	146 13 02.600	9603	Lower L.balmei(E.to M.Paleocene)
1973	TAS	YURONGI -1	39 55 29.936	146 15 58.866	8000	Lower L.balmei(E.to M.Paleocene)
1973	TAS	NARIMBA -1	40 16 18.080	145 43 53.581	11003	Lower M.diversus (E.Eocene)
1974	TAS	TOOLKA -1	39 24 35.678	145 23 45.108	8907	Lower M.diversus (E.Eocene)
1974	TAS	AROO -1	39 47 30.325	145 26 47.976	12112	Lower L.balmei (E.to M.Eocene)
1974	TAS	NANGKERO -1	40 04 24.161	145 58 41.952	9440	Upper L.balmei (L.Paleocene)
1979	TAS	PELICAN -4	40 21 40.020	145 52 15.360	10017	Lower M.diversus (E.Eocene)
1982	TAS	PIPIPA -1	40 23 14.000	145 41 45.000	6939	M.diversus (E.Eocene)

formity". This is interpreted here to correspond with the hiatus observed between Early and Late Cretaceous sedimentation. Late Cretaceous to Late Eocene sediments of the EVCM were subsequently deposited in this extensional basin.

After continental break-up, interpreted to be between 110 and 90 mmybp, (Cande & Mutter, 1982), tensional forces between Tasmania and Australia diminished with time and faulting became associated with reactivation of pre-existing basement faults and igneous activity.

1.1 Exploration History

An aeromagnetic survey was flown in 1961 and the first seismic survey was shot in 1962-63. A total of 19 wells (Figure 1.1 and Table 1.1) have been drilled to date and approximately 12000 kilometres of seismic has been shot. Three thousand one hundred kilometres of seismic was interpreted for the present study.

Drilling commenced in 1965 with Bass 1 and continued until 1982 when Pipipa 1 was drilled. Of the nineteen wells drilled, five encountered significant hydrocarbons. Gas and condensate were recovered in Bass 3, Pelican 1, 2, and 4, and Cormorant 1. At Cormorant 1, 22 litres of oil was also recovered on a Formation Interval Test (FIT). Pelican 1,2, and 4 define the sub-economic Pelican gas/condensate field which contains an estimated 1.5 TCF of gas-in-place (reserves based on the present study). In addition, encouraging oil and/or gas shows have been encountered in Toolka 1, Bass 1, Pipipa 1, Narimba 1, Pelican 3, and Dondu 1 (Table 1.2).

A more detailed exploration history may be found in Brown (1976).

2.0 STRATIGRAPHY

2.1 General Stratigraphy

Sediments within the Bass Basin range in age from Early Cretaceous to Late Tertiary (Fig. 2.1). The Lower Cretaceous (Otway Group equivalent) comprise the oldest sediments within the Basin and rest unconformably on Mesozoic and Palaeozoic "basement" rocks. They consist of fluvio-deltaic sands, silts, shales, and coals. Durroon 1 is the only well to have penetrated the Otway Group and 4000' was drilled before total depth was reached.

The Upper Cretaceous to Late Eocene EVCM is a sequence of sands, silts, shales, and coals deposited in a dominantly fluvial system comprised of high and low sinuosity streams. Seismic data indicates that the EVCM attains thicknessess as great as 15000' in the vicinity of Cormorant 1 and Toolka 1. Cormorant 1 intersected 5625' of this interval before reaching total depth.

Overlying the EVCM is the Late Eocene Demons Bluff Formation (also referred to as the Upper Eocene Shale in some studies). It consists of fine grained marine clastics and has an average

TABLE 1.2

HYDROCARBON SHOWS AND RECOVERIES

WELL	SHOWS	RECOVERIES	INTERVAL
Aroo 1		-1.4 to 1.9 ft^3 gas,	-Paleocene
	-fluorescence with crush cut -gas show on gas detector -fluorescence with crush cut		-"Upper" EVCM -"Upper" EVCM -M.diversus Uncon. to L.balmei
Bass 1	-fluorescence, no cut		-"Upper" EVCM
Bass 3		-29 ft^3 gas, 800cc condensate	-Paleocene
Cormorant 1		-22 litres 22^0 API oil -1000cc condensate -condensate recovery (no volumes available)	-"Upper" EVCM -"Upper" EVCM -M.diversus Uncon. to L.balmei
Dondu 1	-fluorescence with crush cut -gas show on gas detector		-M.diversus Uncon. to L.balmei -Paleocene
Narimba 1	-fluorescence with crush cut -fluorescence with crush cut		-"Upper"EVCM -M.diversus Uncon. to L. balmei
Pelican 1		-six gas recoveries up to 129ft^3 with up to 3200cc condensate -110ft^3 gas 2500cc condensate	-M.diversus Uncon. to L.balmei -Paleocene

TABLE 1.2 Cont'd

HYDROCARBON SHOWS AND RECOVERIES

WELL	SHOWS	RECOVERIES	INTERVAL
Pelican 2		-seven gas recoveries up to 39ft^3 with up to 750 cc condensate	-M.diversus Uncon. to L.balmei
Pelican 3		-GTSTSTM on cased hole test	-Paleocene
Pelican 4		-seven gas recoveries up to 69ft^3 with up to 1500cc condensate	-M.diversus Uncon. to L.balmei
Pipipa 1	-fluorescence with crush cut		-"Upper" EVCM
Poonboon 1	-gas kick		-Paleocene
Toolka 1	-gas show on detector and fluorescence with crush cut		-M.diversus Uncon. to L.balmei

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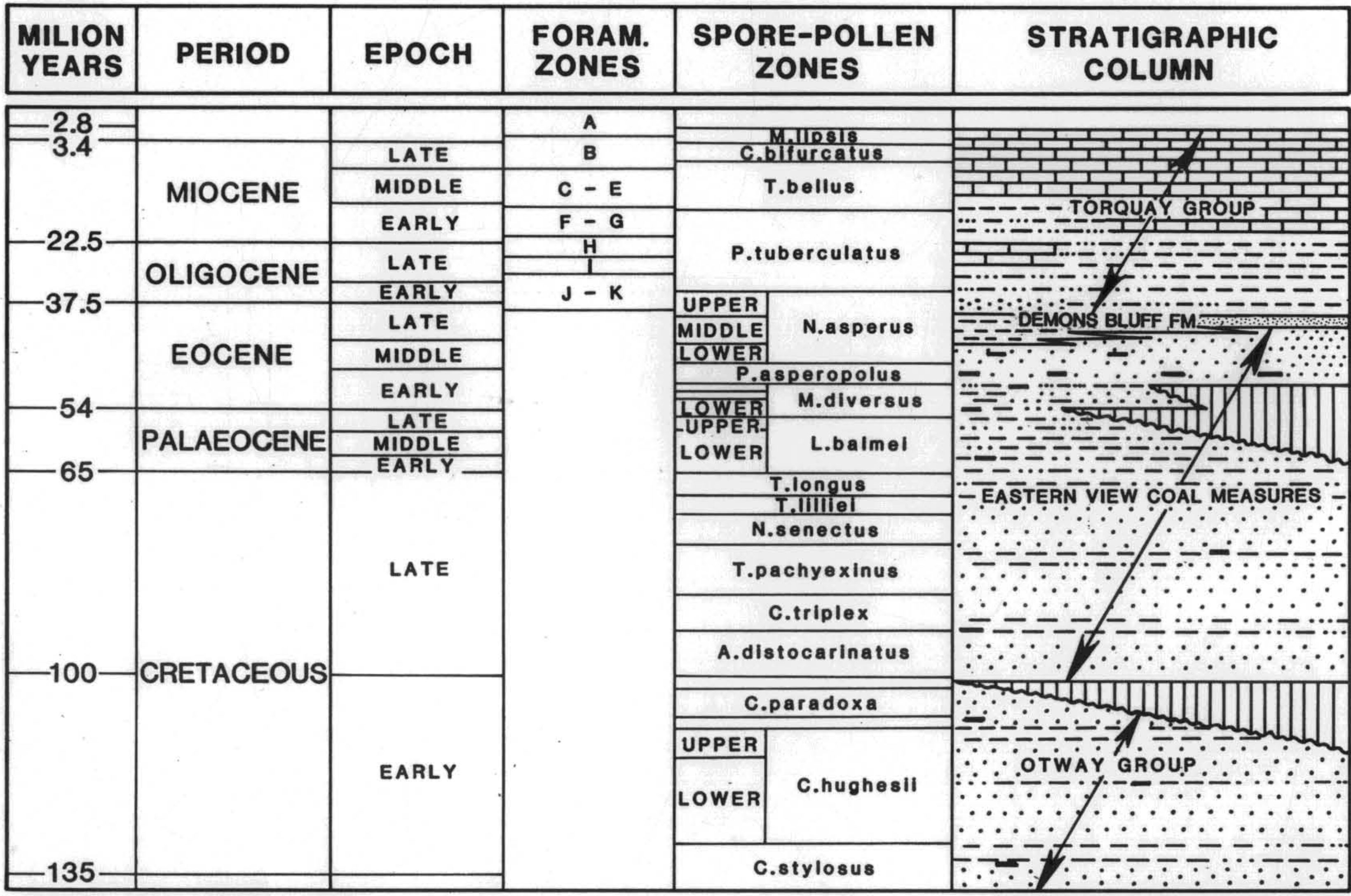

(Modified after Aquing, 1980)

5 cm

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN **STRATIGRAPHIC CHART**		
INT. K.G.	DATE.: FEB'84	BASOO. 3299
DRN. J.D.	Sc. AS SHOWN	FIG.2.1

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thickness over the basin of approximately 400' but thins to approximately 50' at the basin margins.

The Demons Bluff Formation is overlain by the Oligocene to Pliocene age Torquay Group which consists of interbedded limestones, marls, and shales of marine origin. The Torquay Group ranges in thickness from approximately 1500' around the basin margins to about 5500' at Pelican 2.

Both intrusive and extrusive igneous rocks of Eocene to Miocene age have been recognised within the basin. Earlier igneous activity possibly occurred but age dating is not available.

2.2 Eastern View Coal Measures Stratigraphy

The EVCM is an extremely thick stratigraphic unit spanning some 60 million years from the Late Cretaceous to the Late Eocene and is the approximate stratigraphic equivalent of the Latrobe Valley Group in the Gippsland Basin. The stratigraphic subdivision of the EVCM is based on microfossil and palynological assemblages from adjacent onshore areas, as well as the Otway and Gippsland Basins. The palynologic zonation used by Aquing (1980) is adopted here.

The greatest thickness of EVCM penetrated to date is 5625' at Cormorant 1. In the Toolka-Cormorant area of the basin, seismic data indicates a thickness of greater than 15000'. The unit thins to zero at the basin margins (see Encl. 4.1) and exhibits both onlap onto the basement and uplift with erosional truncation.

The present study was limited mainly to the uppermost EVCM (predominantly Eocene age), in particular the base of the Lower M. diversus zone to the top of the EVCM. The top of the EVCM may occur anywhere within the Middle N. asperus zone. The main reason for limiting the study to this interval is the low quantity and quality of data below the Eocene.

Wells that have penetrated the Paleocene (defined here as being approximately the top of the L. balmei zone) or deeper are Pelican 3, Poonboon 1, Dondu 1, Yurongi 1, Bass 2 and 3, Nangkero 1, Konkonl, Durroon 1, and Aroo 1. Of these ten wells, Pelican 3, Dondu 1, Aroo 1, and Bass 3 had encouraging gas shows within the Paleocene section and Bass 3 recovered condensate as well as gas on a formation interval test (Table 1.2).

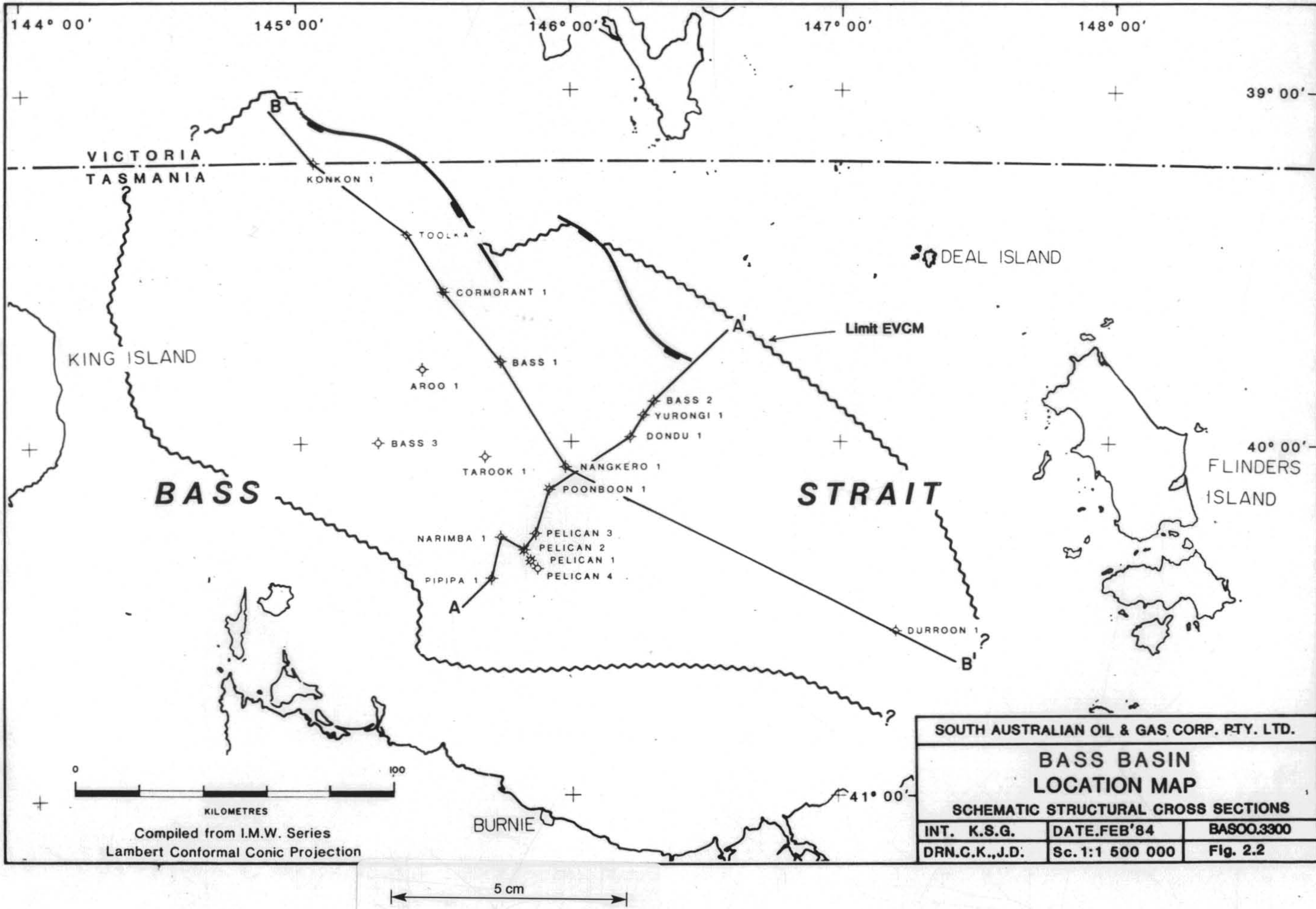
The most prospective intervals within the EVCM to date based on occurrence of shows, availability of data, and cost of drilling appear to be of Eocene age. It is possible, using seismic data, to divide this interval into two thinner, genetically related intervals separated by an unconformity towards the base of the Upper M. diversus zone. This unconformity will be referred to as the M. diversus Unconformity in this report. The two intervals separated by this unconformity will be referred to as: 1) the "Upper" EVCM, which encompasses the interval from the top of the EVCM to the M. diversus Unconformity and 2) the M. diversus Unconformity to the top of the L. balmei interval.

Of the two intervals, the M. diversus Unconformity to Top of L. balmei is the most prospective based on the occurrence of hydrocarbon shows and levels of thermal maturation history. The Pelican Field gas/condensate reservoirs occur within this interval and encouraging oil and gas shows from this interval have been encountered in Narimba 1, Dondu 1, Toolka 1, and Cormorant 1.

The "Upper" EVCM interval appears somewhat less prospective due to the relative paucity and quality of hydrocarbon shows and its immature thermal maturity levels. Due to its low degree of thermal maturity, hydrocarbon accumulations within the "Upper" EVCM must rely on sourcing from deeper strata and significant migration distances both laterally and vertically. Within this interval, however, hydrocarbon shows were encountered at Narimba 1, Pipipa 1, Bass 1, and Aroo 1. Also, 22 litres of 22^{o} API oil were recovered from this interval at Cormorant 1.

Both these intervals have been mapped utilizing seismic data and well control (see Encl. 4.1 to 4.5). Regional schematic cross-sections (Figure 2.2), running across the basin from the southwest to the northeast (Figure 2.3 and Encl. 2.3) and the length of the basin from the northwest to the southeast (Figure 2.4 and Encl. 2.4) have been constructed to show the distribution and relative thicknesses of the two intervals. Hydrocarbon shows and recoveries are also shown on the cross sections.

Aquing (1980) analysed the depositional environment of the sands within the EVCM using available core and logs. He divided the sands within each palynologic zone into either upper alluvial plain or lower alluvial plain. Sands of the upper



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BASS BASIN LOCATION MAP SCHEMATIC STRUCTURAL CROSS SECTIONS		
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DRN.C.K.,J.D.	Sc. 1:1 500 000	Fig. 2.2

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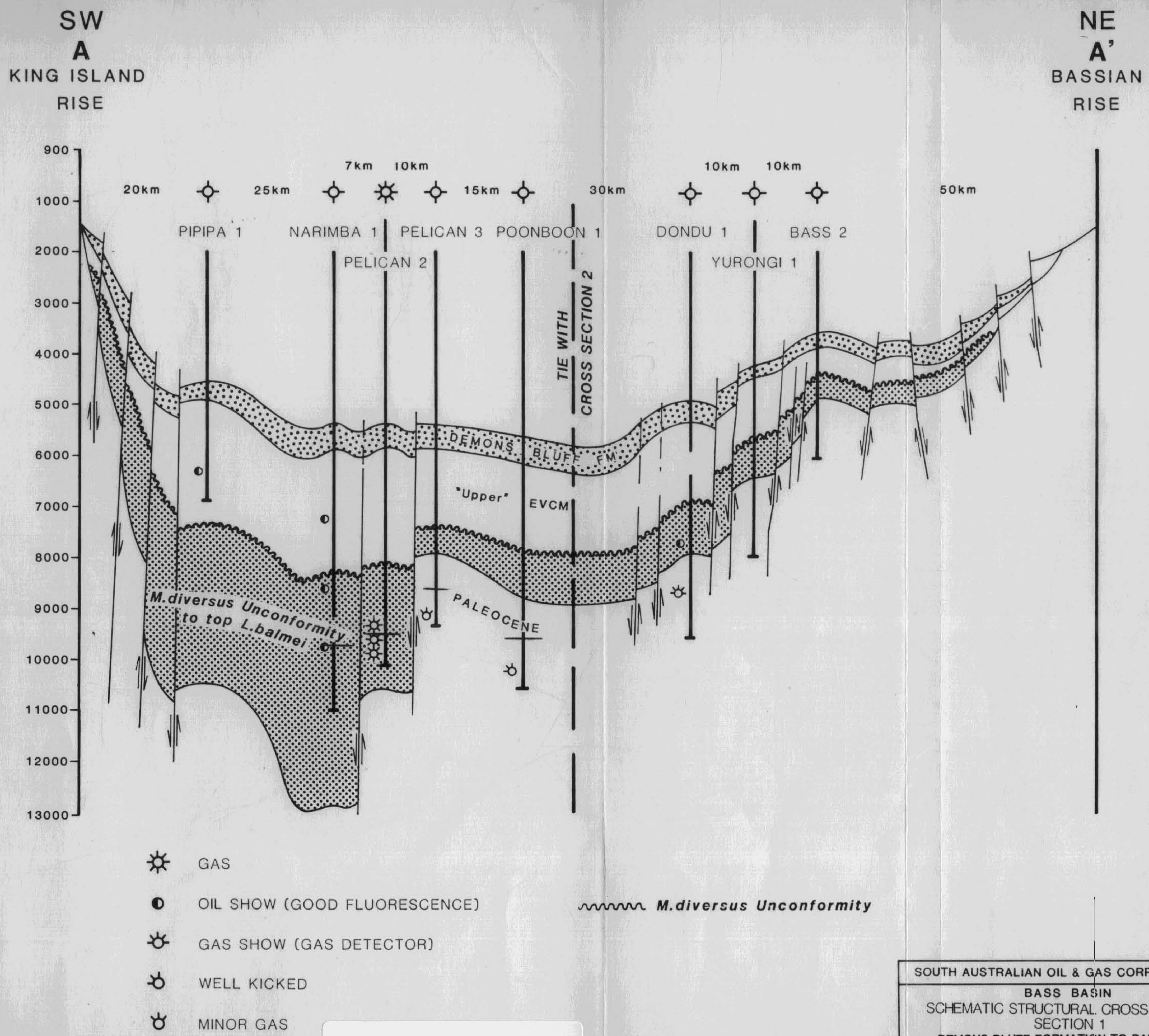

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SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN SCHEMATIC STRUCTURAL CROSS SECTION SECTION 1 DEMONS BLUFF FORMATION TO PALEOCENE		
INT. K.G.	DATE. FEB'84	BASOO.3301
DRN. J.D.	Sc. AS SHOWN	FIG. 2.3

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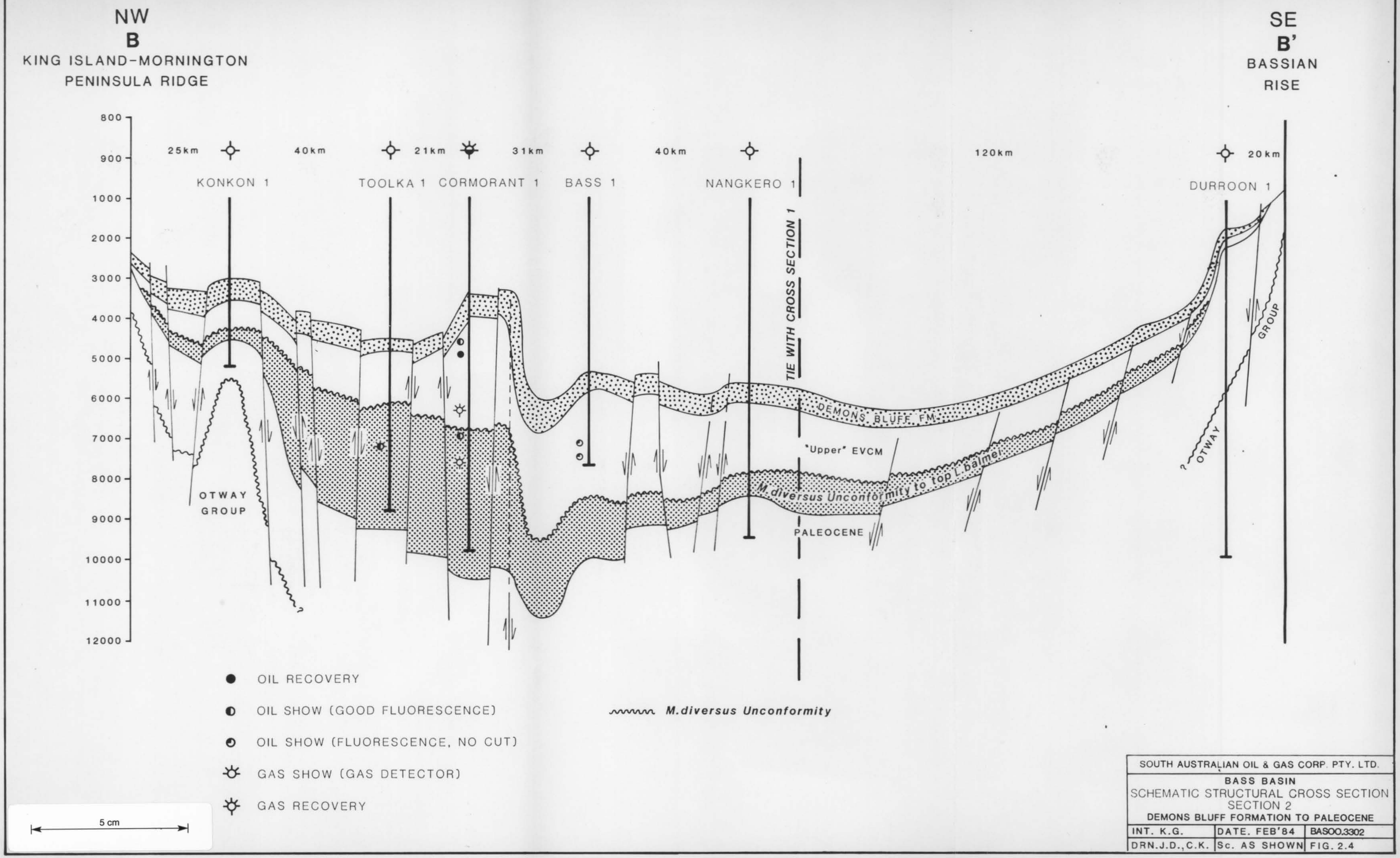


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN SCHEMATIC STRUCTURAL CROSS SECTION SECTION 2 DEMONS BLUFF FORMATION TO PALEOCENE		
INT. K.G.	DATE. FEB'84	BASOO.3302
DRN.J.D., C.K.	Sc. AS SHOWN	FIG. 2.4

alluvial plain are interpreted as having been deposited in low sinuosity, predominantly bed-load streams whereas sands of the lower alluvial plain are interpreted as having been deposited on point bars within high sinuosity streams. In this study, Aquing's data was used in a modified form to be compatible with the two intervals being mapped. The following two sections will discuss the distribution of depositional facies associated with the two mapped intervals of the EVCM.

2.3 M. diversus Unconformity to Top of the L. balmei Zone

As mentioned in the previous section, this interval is considered the most prospective for hydrocarbons. Table 2.1 lists the thicknesses of this interval, or if it is not completely penetrated, the thickness of the interval penetrated for each well. Thicknesses range from 0' at Durroon 1 to 2616' at Narimba 1 and seismic indicates this interval may be as thick as 4500' in the Narimba area. Table 2.2 lists the net sand thicknesses and percent sand for the interval between the M. diversus Unconformity to the top of the L. balmei zone in each well. Sand percentages range from as low as 3 percent in Cormorant 1 to as high as 50 percent in Bass 2 and Pelican 2. In general, the sand percentages decrease away from the basin margins towards the basin centre (Figure 2.5). Table 2.3 lists the thickness of coal and the percentage of coal within the interval. As with the sand percent, the percentage of coal depends on position within the basin and Figure 2.6 shows the percentage of coal

TABLE 2.1 ZONE THICKNESS

	Top of EVCM to Upper M. diversus Unconformity ("Upper" EVCM)	M. diversus unconformity to Top of L. balmei
Aroo 1	2378'	223'
Bass 1	1960'*	TS
Bass 2	660'	417'
Bass 3	1172'	NP'
Cormorant 1	2700'	2427'*
Dondu 1	1546'	1022'
Durroon 1	167'	NP
Konkon 1	755'	131'*
Nangkero 1	1680'	679'
Narimba 1	2432'	2616'*
Pelican 1	2260'	2230'
Pelican 2	2426'	1710'*
Pelican 3	1647'	445'
Pelican 4	2273'	2000'*
Pipipa 1	1910'*	TS
Poonboon 1	1662'	902'
Tarook 1	2530'	405'*
Toolka 1	1371'	2195'*
Yurongi 1	1200'	695'

* INTERVAL NOT COMPLETELY PENETRATED

TABLE 2.2

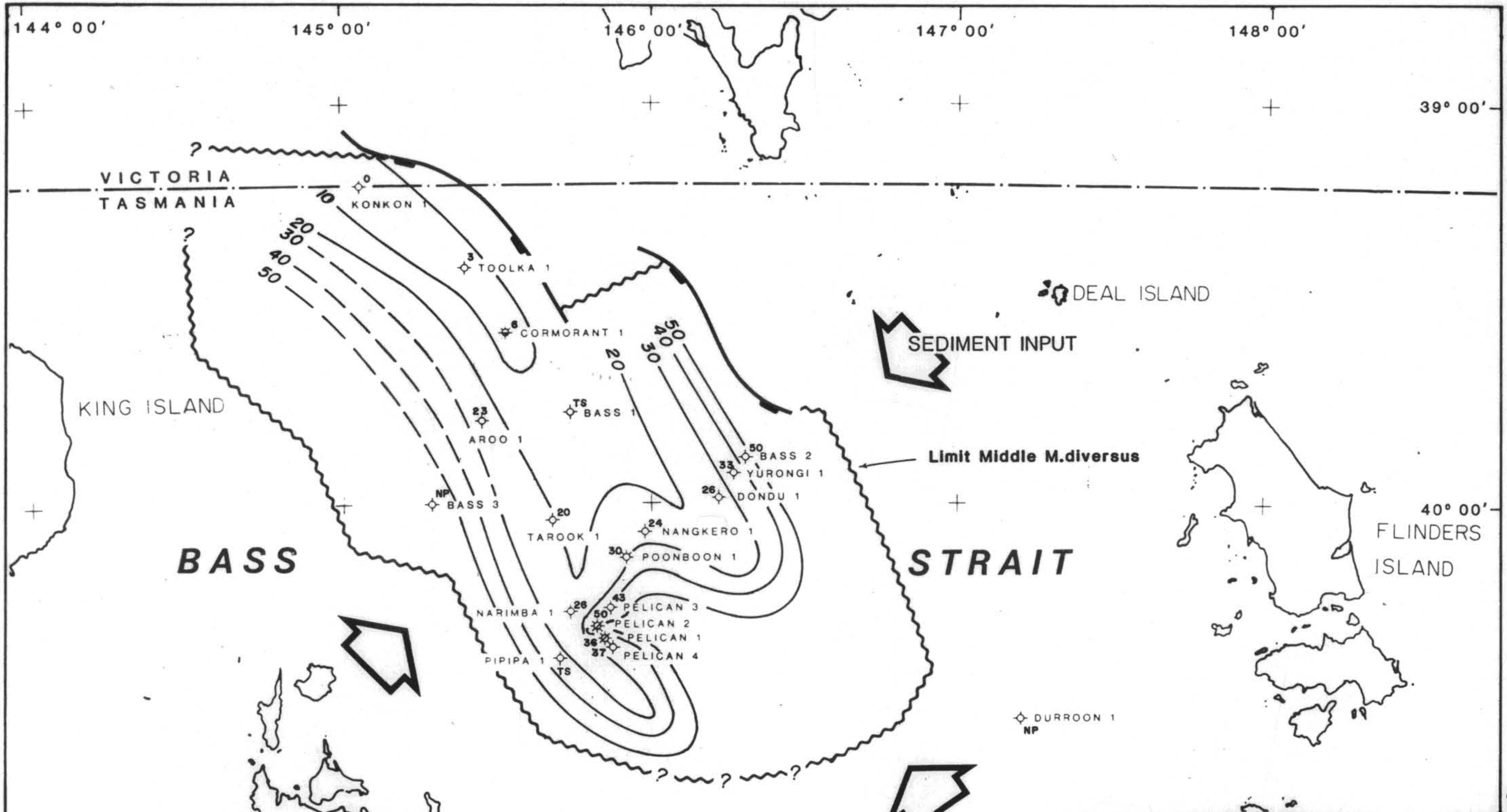
	NET SAND		% SAND (NET SAND/GROSS THICKNESS)	
	"Upper" EVCM	M.diversus Unconformity to Top of L.balmei	"Upper" EVCM	M.diversus Unconformit to Top of L.balmei
Aroo 1	641'	51'	27	23
Bass 1	+595'	TS	30	TS
Bass 2	343'	209'	52	50
Bass 3	700'	NP	60	NP
Cormorant 1	653'	150'	24	6
Dondu 1	530'	267'	34	26
Durroon 1	167'	NP	100	NP
Konkon 1	395'	0'	52	0
Nangkero 1	520'	161'	31	24
Narimba 1	1070'	674'	44	26
Pelican 1	1285'	795'	57	36
Pelican 2	1350'	850'	56	50
Pelican 3	585'	190'	36	43
Pelican 4	1210'	735'	53	37
Pipipa 1	848'	TS	44	TS
Poonboon 1	535'	275'	32	30
Tarook 1	722'	83'	29	20
Toolka 1	118'	70'	9	3
Yurongi 1	663'	229'	55	33

TABLE 2.3

MARSH/LAKE : COAL (TOTAL THICKNESS COAL AND % OF TOTAL INTERVAL)

(modified after Aquing, 1980)

	"Upper" EVCM"		M.diversus Unconformity to Top of L.balmei		
	Thickness	% Coal	Thickness	% Coal	
Aroo 1	235'	1%	2'	1%	0
Bass 1	97'	6.2%	TS	TS	
Bass 2	43'	8.3%	13.5'	3.2%	-
Bass 3	10'	1.2%	1'	1.2%	0
Cormorant 1	252'	8.7%	110.5'	4.6%	-
Dondu 1	308.5'	25%	52'	5.1%	-
Durroon 1	-----	----	-----	----	
Konkon 1	46.5'	7.9%	38'	29%	4
Nangkero 1	174'	12.7%	49'	7.2%	-
Narimba 1	78'	3%	585'	2.2%	-
Pelican 1	149'	7%	96.5'	4.3%	-
Pelican 2	153.5'	7.2%	52'	3%	-
Pelican 3	75'	6%	3'	1%	
Pelican 4	165'	7%	135'	7%	
Pipipa 1	153'	8%	TS	TS	
Poonboon 1	112.5'	8.4%	18'	2%	
Tarook 1	90'	3.9%	9'	2.2%	
Toolka 1	138'	5.9%	75'	3.4%	
Yurongi 1	107'	12%	28.5'	4.1%	



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN

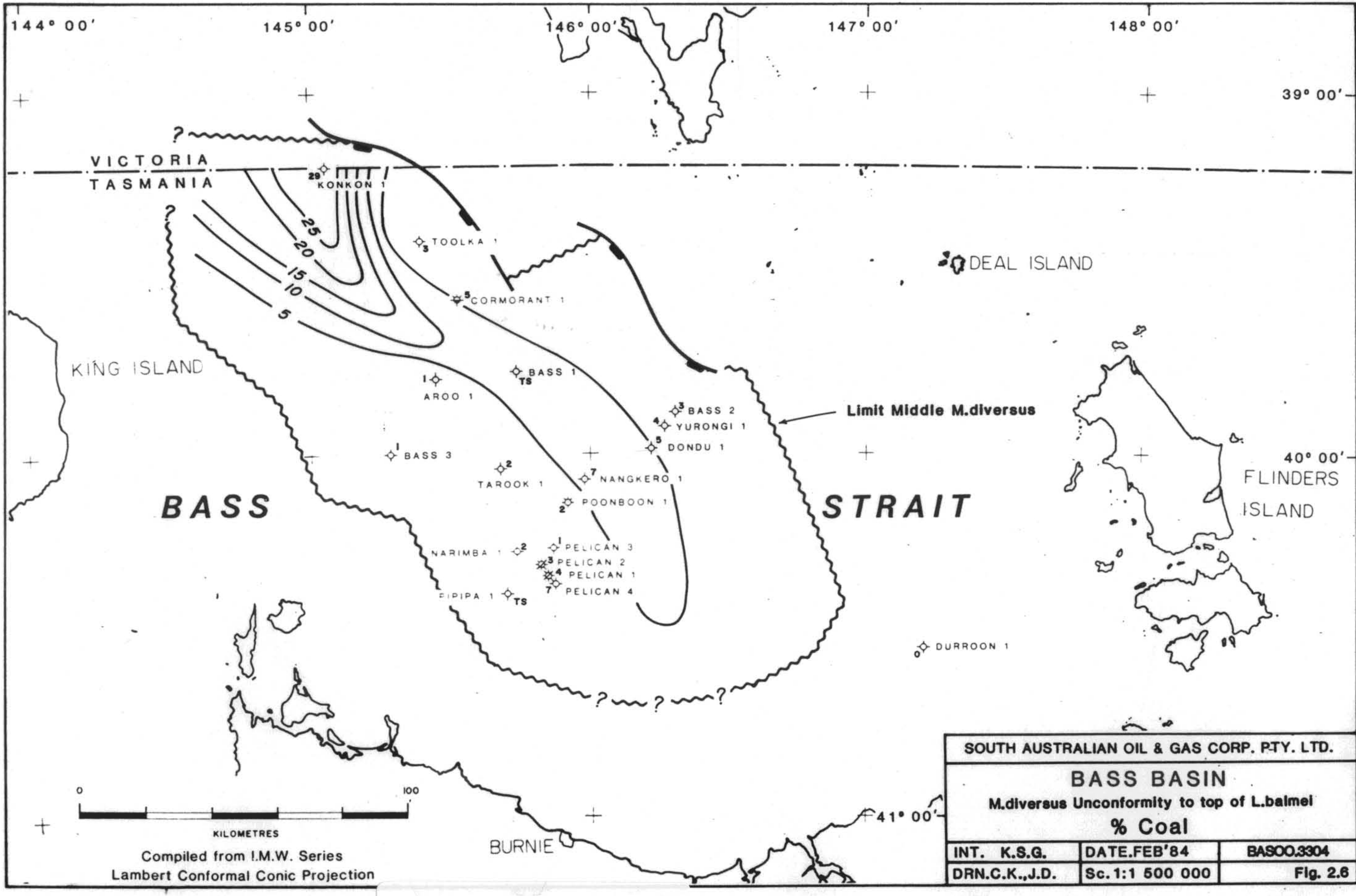
M.diversus Unconformity to top of L.balmei

% Sand Map

INT. K.S.G.	DATE.FEB'84	BASOO.3303
DRN.C.K.,J.D.	Sc.1:1 500 000	Fig. 2.5

5 cm

636038



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN M.diversus Unconformity to top of L.balmei % Coal		
INT. K.S.G.	DATE.FEB'84	BASOO.3304
DRN.C.K.,J.D.	Sc.1:1 500 000	Fig. 2.6

63039

increasing away from the basin margins towards the basin depocentres.

Tables 2.4 and 2.5 list the percentage of sand which is interpreted by Aquing (1980) as having been deposited in an upper or lower alluvial plain environment respectively and Figures 2.7 and 2.8 show the distribution of these facies. In general, the percentage of lower alluvial plain sands increases towards the centre of the basin whereas the percentage sands of the upper alluvial plain increases towards the basin margins. These trends are consistent with seismic mapping, which shows an isopach thick trending roughly through Toolka 1, Cormorant 1, and the Pelican Field (Encl. 4.5). This thick represents a depocentre which should contain low energy, high sinuosity fluvial channels characteristic of the lower alluvial plain. Bass 2, however, presents a problem with facies interpretation over this interval. Aquing (1980) has interpreted the sands at Bass 2 to be one hundred percent lower alluvial plain, whereas, the regional mapping of this study indicates that the sands should be predominantly upper alluvial plain. It is possible that either Aquing's interpretation is incorrect or a local anomaly exists which is not reflected in the regional trends.

2.4 "Upper" EVCM

Tables 2.1 to 2.5 list interval thickness and sand and coal data for this interval and Figures 2.9 and 2.10 are maps showing sand and coal distributions. The trends for this interval are similar to those for the interval between the *M. diversus*

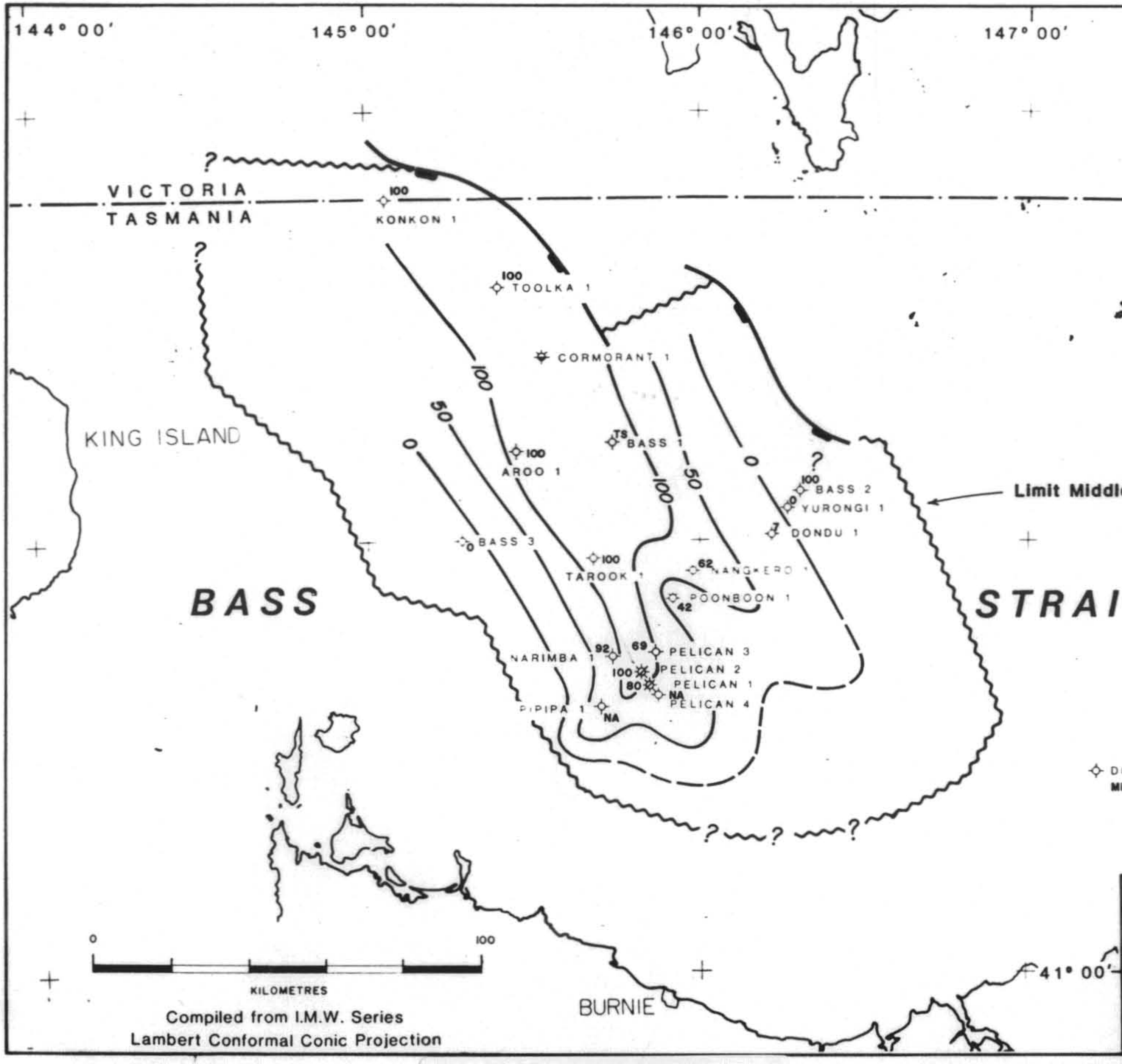
TABLE 2.4 UPPER ALLUVIAL PLAIN (% OF TOTAL SAND)
(modified after Aquing, 1980)

	"Upper" EVCM	M.diversus Unconformity to Top of L.balmei
Aroo 1	26	0
Bass 1	20	TS
Bass 2	46	0
Bass 3	65	100
Cormorant 1	25	0
Dondu 1	51	93
Durroon 1	-	NP
Konkon	65	0
Nangkero	47	38
Narimba 1	27	8
Pelican 1	20	20
Pelican 2	8	0
Pelican 3	10	31
Pelican 4	no data	no data
Pipipa 1	no data	no data
Poonboon 1	18	58
Tarook 1	30	0
Toolka 1	36	0
Yurongi 1	82	100

TABLE 2.5 LOWER ALLUVIAL PLAN (% OF TOTAL SAND)

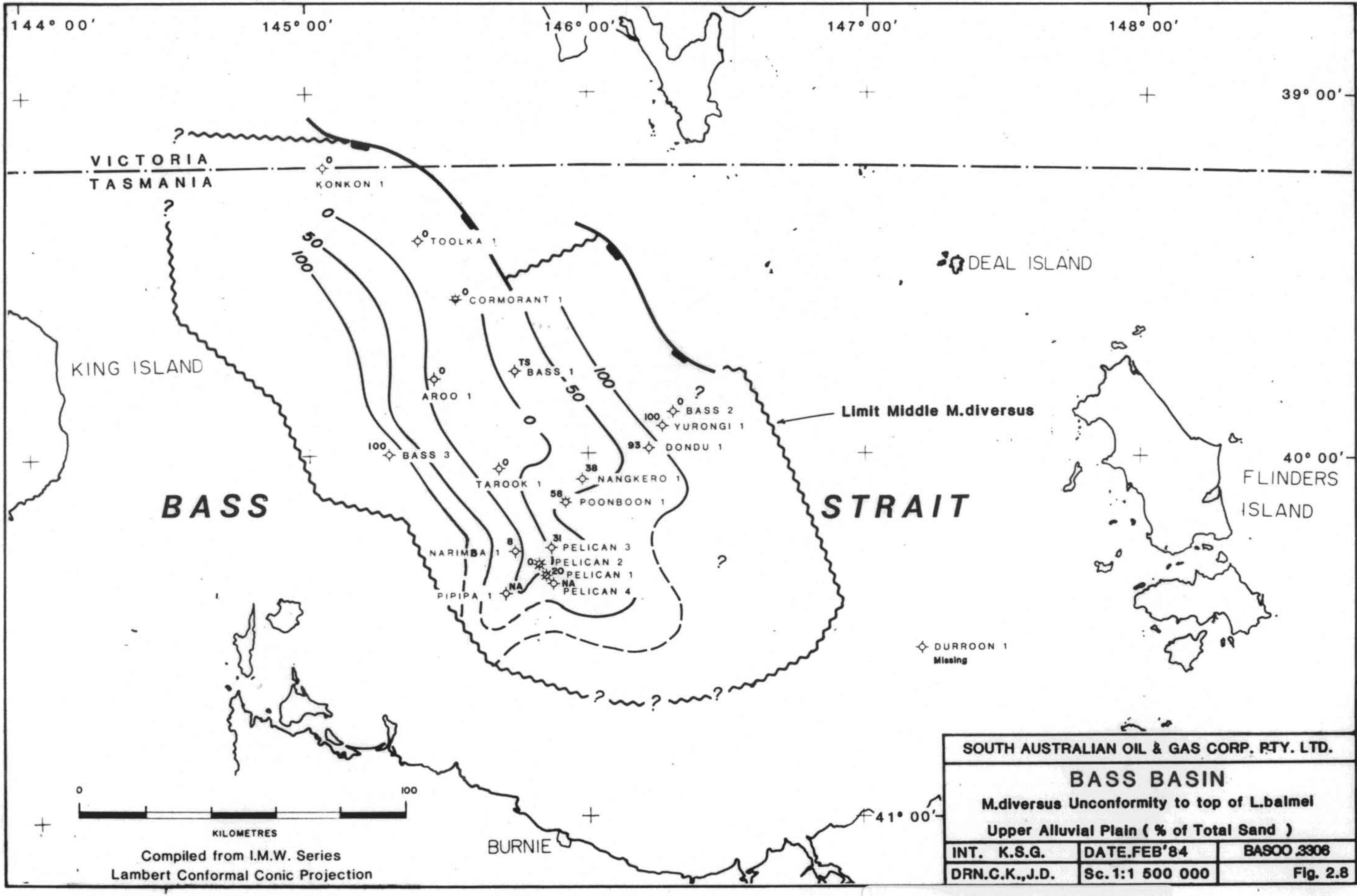
(modified after Aquing, 1980)

	"Upper" EVCM	M.diversus Unconformity to Top of L.balmei
Aroo 1	74	100
Bass 1	80	TS
Bass 2	54	100
Bass 3	35	0
Cormorant 1	75	100
Dondu 1	49	7
Durroon 1	--	NP
Konkon 1	35	100
Nangkero 1	53	62
Narimba 1	73	92
Pelican 1	80	80
Pelican 2	92	100
Pelican 3	90	69
Pelican 4	no data	no data
Pipipa 1	no data	no data
Poonboon 1	82	42
Tarook 1	70	100
Toolka 1	64	100
Yurongi 1	18	0



SOUTH AUSTRALIAN OIL & GAS CORP. P.TY. LTD.		
BASS BASIN M.diversus Unconformity to top of L.balmei Lower Alluvial Plain (% Total Sand)		
INT. K.S.G.	DATE.FEB'84	BASOO.3305
DRN.C.K.,J.D.	Sc. 1:1 500 000	Fig. 2.7

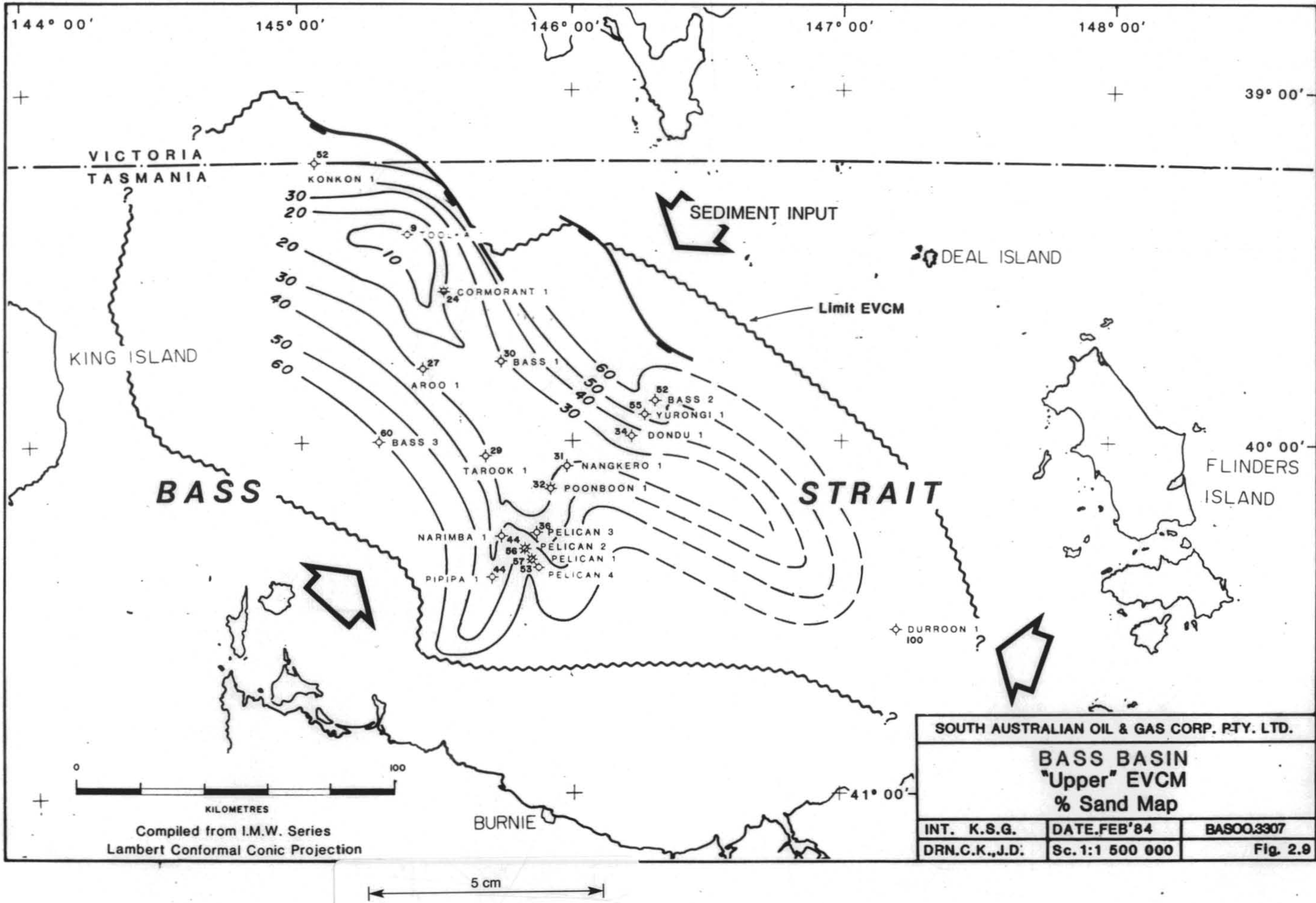
63643



144° 00'
145° 00'
146° 00'
147° 00'
148° 00'
39° 00'
40° 00'
41° 00'
VICTORIA
TASMANIA
KONKON 1
TOOLKA 1
CORMORANT 1
DEAL ISLAND
KING ISLAND
BASS 1
AROO 1
BASS 2
YURONGI 1
DONDU 1
Limit Middle M.diversus
BASS 3
TAROOK 1
NANGKERO 1
POONBOON 1
FLINDERS
ISLAND
BASS
STRAIT
PELICAN 3
NARIMBA 1
PELICAN 2
PELICAN 1
PELICAN 4
PIPIPA 1
DURROON 1
Missing
0
50
100
TS
38
58
31
8
20
NA
93
?
0
100
KILOMETRES
Compiled from I.M.W. Series
Lambert Conformal Conic Projection
BURNIE
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
M.diversus Unconformity to top of L.balmei
Upper Alluvial Plain (% of Total Sand)
INT. K.S.G.
DATE.FEB'84
BASOO .3306
DRN.C.K.,J.D.
Sc.1:1 500 000
Fig. 2.8

63644

5 cm

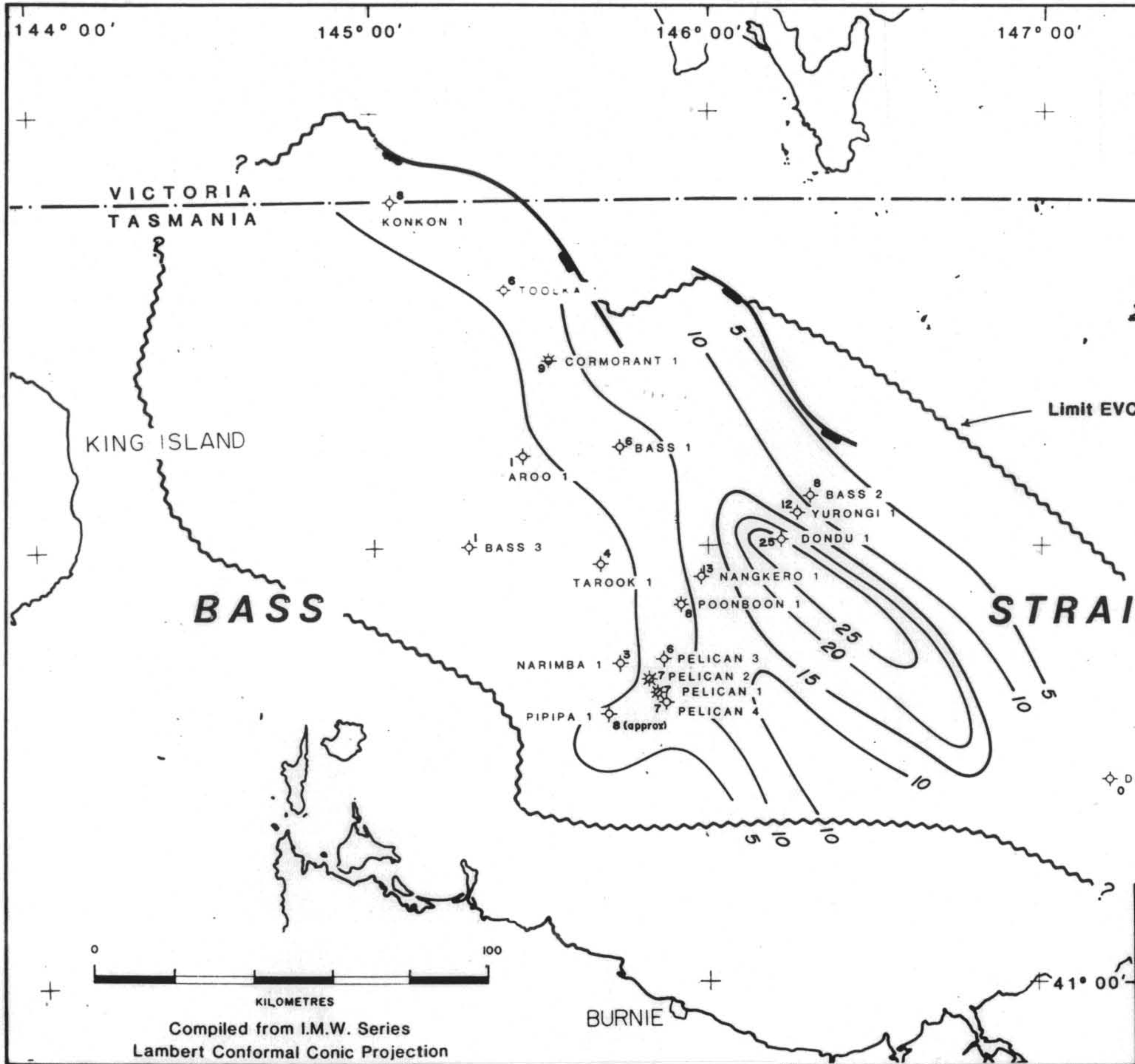


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN
"Upper" EVCM
% Sand Map

INT. K.S.G.	DATE.FEB'84	BASOO.3307
DRN.C.K.,J.D.	Sc. 1:1 500 000	Fig. 2.9

6360



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN
"Upper" EVCM
% Coal

INT. K.S.G.	DATE.FEB'84	BASOO.3308
DRN.C.K.,J.D.	Sc.1:1 500 000	Fig. 2.10

5 cm

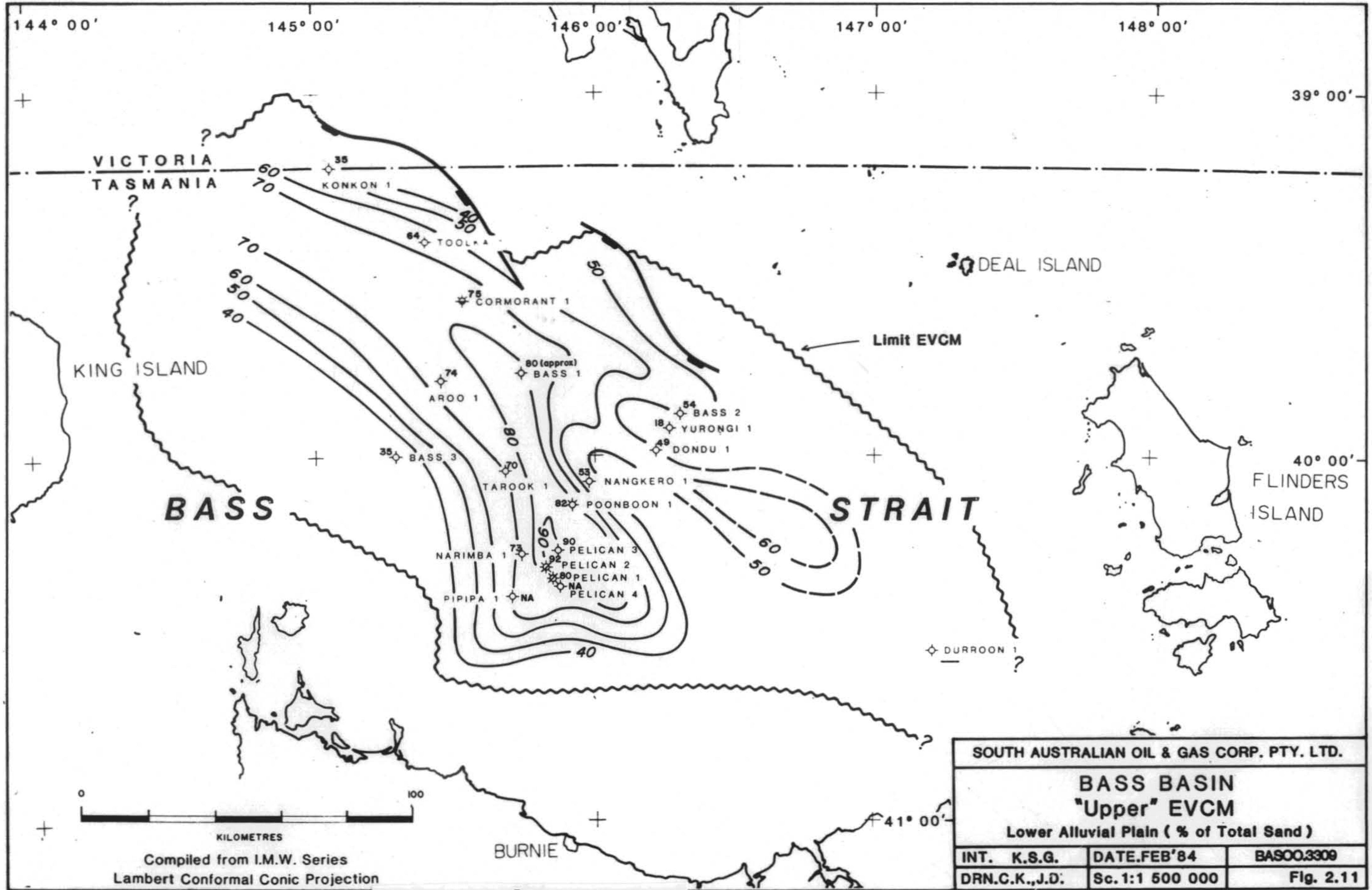
63604C

Unconformity and the top of the L. balmei zone. Again, seismic interval mapping (Encl. 4.4) shows a thick trending through the Toolka, Cormorant, and Pelican areas, but in addition, another thick is present between Dondu 1 and Durroon 1. Sand mapping shows that in general, sand percentages decrease away from the basin margins towards the interval thicks which are interpreted to be basin depocentres. Sand facies mapping (Figures 2.11 and 2.12) indicates that upper alluvial plain sands occur around the margins of the basin and lower alluvial plain sands predominate within the thicker parts of the centre of the basin. In general, the same conclusions regarding facies distribution within the interval between the M. diversus Unconformity and the top of the L. balmei zone can also be made for the "Upper" EVCM interval.

3.0 RESERVOIR QUALITY

3.1 Introduction

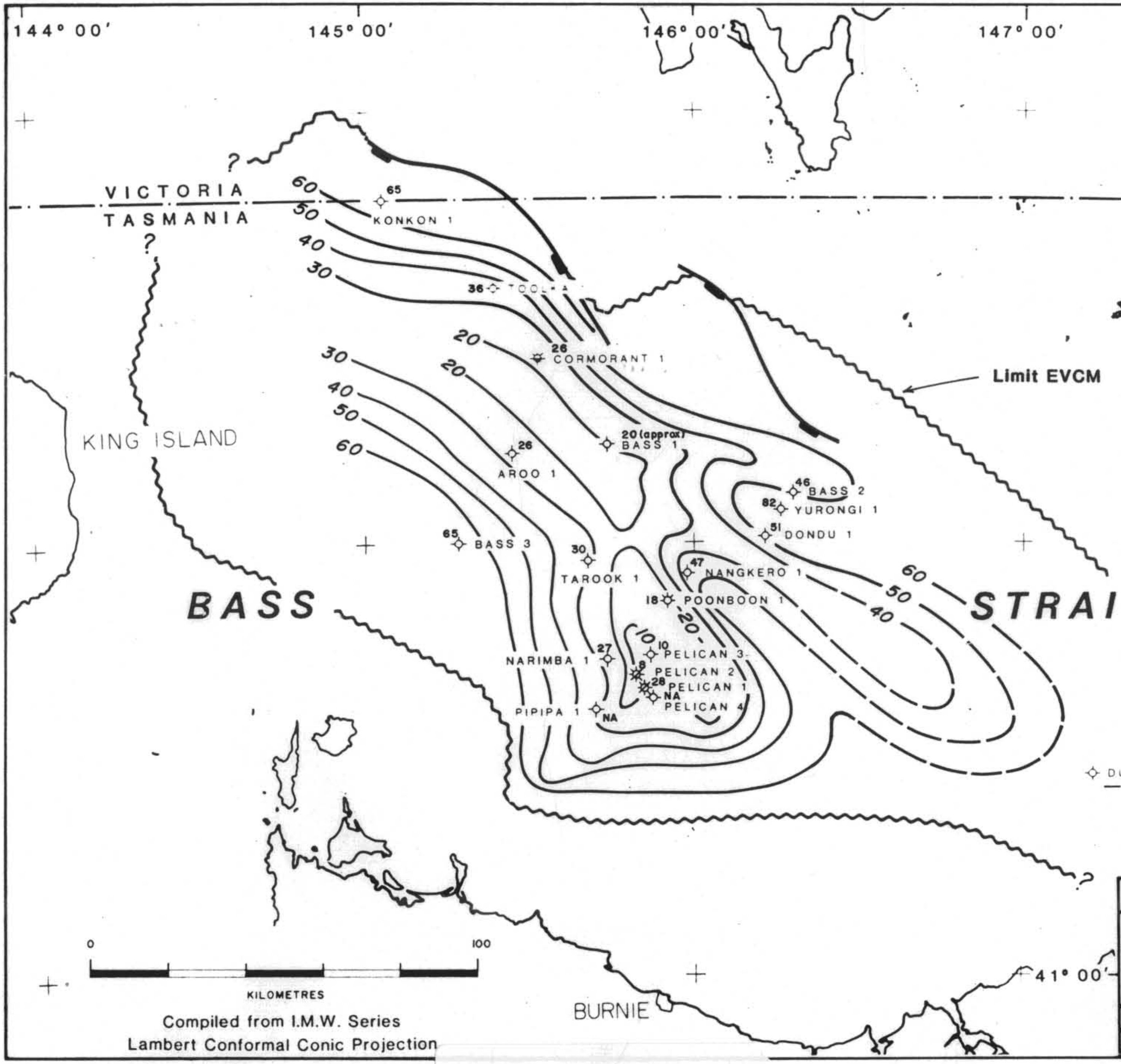
No drill stem tests or production tests have been carried out in the Bass Basin. All interpretations of reservoir quality rely on the results of FITs, RFTs and laboratory derived core data. The former provide questionable estimates of permeability due to the small sample area and possible formation damage adjacent to the well bore. Results of core studies are always suspect unless the actual core sample is available to the interpreter to determine if fracturing has contributed to the results. The following discussion of reservoir quality acknowledges these



Compiled from I.M.W. Series
Lambert Conformal Conic Projection

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN "Upper" EVCM Lower Alluvial Plain (% of Total Sand)		
INT. K.S.G.	DATE.FEB'84	BASOO.3309
DRN.C.K.,J.D.	Sc. 1:1 500 000	Fig. 2.11

63604S



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN "Upper" EVCM Upper Alluvial Plain (% of Total Sand)		
INT. K.S.G.	DATE.FEB'84	BASOO.3310
DRN.C.K.,J.D.	Sc.1:1 500 000	Fig. 2.12

636049

limitations on the reliability of any conclusions.

Only the EVCM are considered as reservoirs here, based on available data.

3.2 Depositional Environment

The Eastern View Coal Measures are interpreted as having been deposited in an upper and lower alluvial plain environment with large areas of lacustrine development.

Minor paralic sands may have been deposited and reworked along the margins of large lakes towards the northwest portions of the basin.

Dinoflagellates and microplankton occur sporadically through the upper part of the EVCM in Dondu 1, Nangkero 1, Toolka 1, and Konkon 2. These occurrences indicate limited marine incursions at least into the depocentre areas of the basin.

Within this framework potential reservoir type sands were deposited in the sub-environments listed in Table 3.1.

TABLE 3.1 CLASSIFICTION OF DOMINANT RESERVOIR SAND DEPOSITIONAL ENVIRONMENTS

(AQUING, 1980)

ENVIRONMENT	RESERVOIR SAND SUB ENVIRONMENT	GENERAL LITHOLOGICAL CHARACTERISTICS
Upper Alluvial Plain	Braided River	Cross-bedded coarse to pebbly quartz arenite and greywacke.
Lower Alluvial Plain	Point bar	Cross-bedded, fining upward coarse to fine grain quartz arenite to greywacke.
	Crevase play	Laminated current bedded quartz arenite.
	Distributory Mouth Bar	Laminated current rippled quartz arenite better sorted towards top.
	Lacustrine Delta mouth bar	Rippled laminated coarsening up (fine to pebble grade) quartz arenite and greywacke.
Nearshore/Shallow Marine	Beach/Offshore bar	Glauconite calcareous quartz arenite with common forminifera and bryozoan fragments.

3.3 Provenance

Sediment transport distances were not great. The main source was from the south (Tasmania) and the northeast (Bassian Rise) and southwest (King Island) with some minor local intrabasin sources generated by uplift and volcanism. Mainland Australia is not considered a significant source area, unlike the Gippsland Basin.

Metasediments in the south and southwest and granites in the northeast are the main sediment source types.

During deposition of the EVCM the Australian/Antarctic plate was at high latitudes and glacial action within the source areas may have played an important part in the sediment transport history.

3.4 Lithological Variations

Descriptions of the various sandstone types encountered suggest a high variability of lithological types.

Generally the dominant sandstone type appears to be an off white (light brown to light grey) fine to medium grained, poor to moderately sorted, angular to subrounded quartz arenite with lesser but significant amounts of plagioclose feldspar and muscovite. Traces of tourmaline and zircon are the main heavy mineral components. Depending on the depositional environment, this dominant sandstone type is variously modified.

The coarser grained sandstones, or pebbly conglomerates, generally have up to 80 percent lithic material, of argillaceous derivation. Grains are generally subrounded to well rounded.

The finer grained end members grade into carbonaceous siltstone has abundant micaeous material which is generally clear crystals of muscovite.

All of the sandstones have an argillaceous content. In the cleaner varieties this is dominantly kaolinitic (with minor illite or mixed layer clays) occurring as an authigenic interstitial pore infill. Most sands have a significant percentage of primary matrix material as well as the authigenic component.

Carbonate and glauconite are locally important constituents probably reflecting marine/paralic conditions.

3.5 Diagenesis

These submature sandstones have been significantly modified by compaction and diagenesis. Although friable sandstones are found in shallower sections of the EVCM the majority of sandstones are well consolidated. Quartz grains are generally sutured and silica remobilisation and recrystallisation has often removed all primary grain shapes. Highly deformed muscovite is evidence of strong compaction effects. In some samples, quartz grains are often rimmed by limonite, and styolitic surfaces are not uncommon.

At depths below approximately 7000' MSL dolomite may replace quartz to the extent that loss of porosity is complete.

3.6 Porosity and Permeability

Porosities, as measured on cores, range from essentially zero (in dolomitised sandstones) to 30 percent, but are generally between 15 and 25 percent. The dominant range appears to be 17-19 percent.

Measured permeabilities average in the tens of millidarcies but can be as high as 1000 md. It is not known, however, if very high permeability values are due to fracturing of the core sample. RFT results suggest permeabilities in the 1-2 md range but this may be due to severe formation damage and inadequate testing. Limited core data correlations suggests that very low permeability does occur when porosity falls below 13 percent.

3.7 Discussion

There is conflicting evidence from core data versus Formation Interval Test (FIT) results on the permeability of reservoir sands. This is a most critical factor in estimating deliverability and hence commercial viability of prospects.

FIT's can be easily influenced by formation damage as they only sample an area within a few centimetres of the borehole. Hence results are questionable, particularly when they conflict with core data.

Prior to any future drilling programme it is recommended that tests are made for sensitivity to drill fluids in an effort to reduce potential formation damage.

Only extended production testing seems likely to resolve the uncertainity of present estimates of permeability.

3.8 Conclusion

The data suggest that reservoir sands with good porosities and permeabilities exist at the level of the interpreted mature section. However productivity may be reduced by migrating fines, clay plugging or formation damage caused by drilling.

No detailed correlation of lithology, porosity, permeability and diagensis has been undertaken, however, such a study could improve play concepts and drilling practice.

4.0 BASS BASIN STRUCTURE

4.1 Structural Maps

The high quality widely spaced regional seismic lines recorded for the BMR in 1982 plus the data recorded for the partners in T-14-P and T-18-P during 1981 and 1982 forms the basis of the preliminary regional interpretation (Appendix 4.1). Approximately 3100 km of seismic data has been interpreted. Another 9000 kms of older less reliable seismic data available was not examined due to time constraints.

The seismic data was tied to a geological interpretation of the 19 wells in the Basin. A synthetic seismograph was produced for wells in which a sonic log was available to SAOGC.

Three seismic horizons were mapped at a scale of 1:250,000. These were 1) the top of the Eastern View Coal Measures,

2) the Upper M. diversus unconformity and

3) the top of the L. balmei zone (approximate top of the Paleocene).

Towards the margins of the Basin and beneath structural highs, reflections associated with the highly characteristic steeply dipping Otway Group were observed. A regional map of this reflector was not produced due to the lack of seismic energy penetration in the central portions of the basin. An estimation of the maximum thickness of EVCM sediments which occur in the vicinity of the Cormorant 1 structure is 15,000 ft.

The study of the Pelican field (Part 2, Fig. 2.3) indicated that faults are en echelon and vary considerably in throw, even over a short distance. The seismic line spacing used in this regional study is large compared with the variability of faults, thus only the very large faults could confidently be correlated between lines.

4.1.1 EVCM Horizon (Encl. 4.1)

The boundary between the Demons Bluff Formation and the top of the EVCM is generally marked by a strong seismic reflection associated with a large increase in velocity. To the northeast of the Basin, however, the reflection strength and character of this boundary is reduced. This event can generally be mapped with a high degree of confidence.

4.1.2 Upper M. diversus Unconformity (Encl. 4.2)

This mapped event varies from an erosional unconformity primarily associated with fault reactivation on early highs and basin margins to an hiatus in the low lying area. The unconformity (or hiatus) is generally associated with a velocity shift apparent on sonic logs and is seismically represented by a change in interval reflectance character. The correlation of this event across faults, due to seismic character variations, is particularly difficult and relies heavily on the palynological interpretation of well data.

4.1.3 Top of L. balmei Horizon (Encl. 4.3)

This event, which approximates the Paleocene-Eocene time boundary, is characterised by a slight velocity shift, notable on sonic log data, and a bland reflectance character beneath it. The reduced seismic energy penetration and the increased presence of misleading multiple energy hampers the mapping of this horizon.

4.2 Isopach Maps

In addition to the three seismic horizon maps enclosed in this report, two isopach maps are included: top EVCM to M. diversus Unconformity and M. diversus to top L. balmei.

Faults presented on these isopach maps represent a change in thickness and can be used as an indication of early structural development.

4.2.1 Top EVCM to M. diversus Unconformity (Encl. 4.4)

With the exception of the margins of the basin where the top of the EVCM is an erosional unconformity, this isopach represents the shape and amount of structural development of the basin during the upper portion of the EVCM.

Two main depositional trends are obvious. One, with a north-south orientation stretching from the Toolka feature to the Pelican feature, is dominated by a major recurrent fault east of Toolka 1. The second has a southeast-northwest orientation passing approximately 10 kilometres south of Dondu 1 and Aroo 1. The southeast depocentre is dominated by fluvial sands, and appears to trend into the postulated northwest marine outlet of the basin.

4.2.2 Upper M. diversus to top L. balmei (Enc. 4.5)

The upper limit of this isopach is an unconformity and thus, within the basin, it can be used to estimate the amount of fault movement and/or erosion associated with early structuring. The thick preserved section has a north south orientation and is dominated by the major northwest-southeast trending recurrent fault northeast of Cormorant 1 and Toolka 1.

4.3 Structural Controls and Development

The initiation of the development of the Bass Basin appears to be coincident with the onset of rifting between the Australian and Antarctic continents. The Early Cretaceous Otway Group sediments were deposited in the early rift valley. The Durroon 1 well penetrated Early Cretaceous Otway Group sediments which underlie the unconformity associated with the break-up. At Durroon 1 and along the margins of the basin, major tilted fault blocks and the unconformity associated with break-up are seismically recognisable (Figure 4.1).

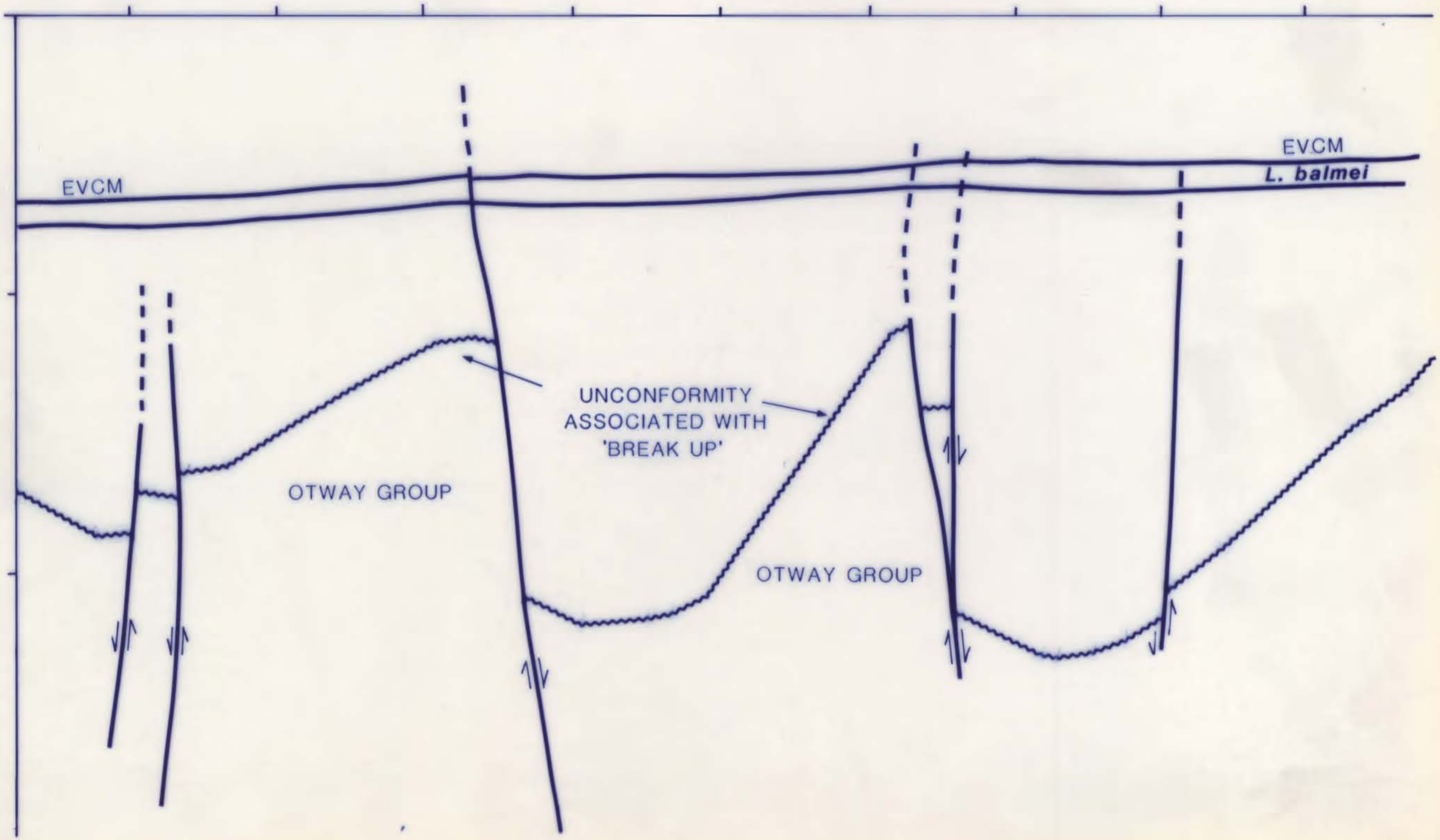
Downwarping and recurrent faulting occurred during the Late Cretaceous and throughout the Tertiary with the north-west Tasmania - King Island ridge to the west, Tasmania to the south and the Bassian Rise to the east, provenancing sediment.

Two major episodes of Tertiary faulting are evident. The M. diversus unconformity is associated with one of these episodes. This unconformity is recognisable from seismic data in the Pelican area (Figure 4.2). The interval velocity G-log of this data also clearly indicates the presence and extent faulting prior to the deposition of the Lower N. asperus sediments (Figure 4.3). Interval velocity G-log's of data from portions of other lines would aid in determining the throw of faults associated with this unconformity.

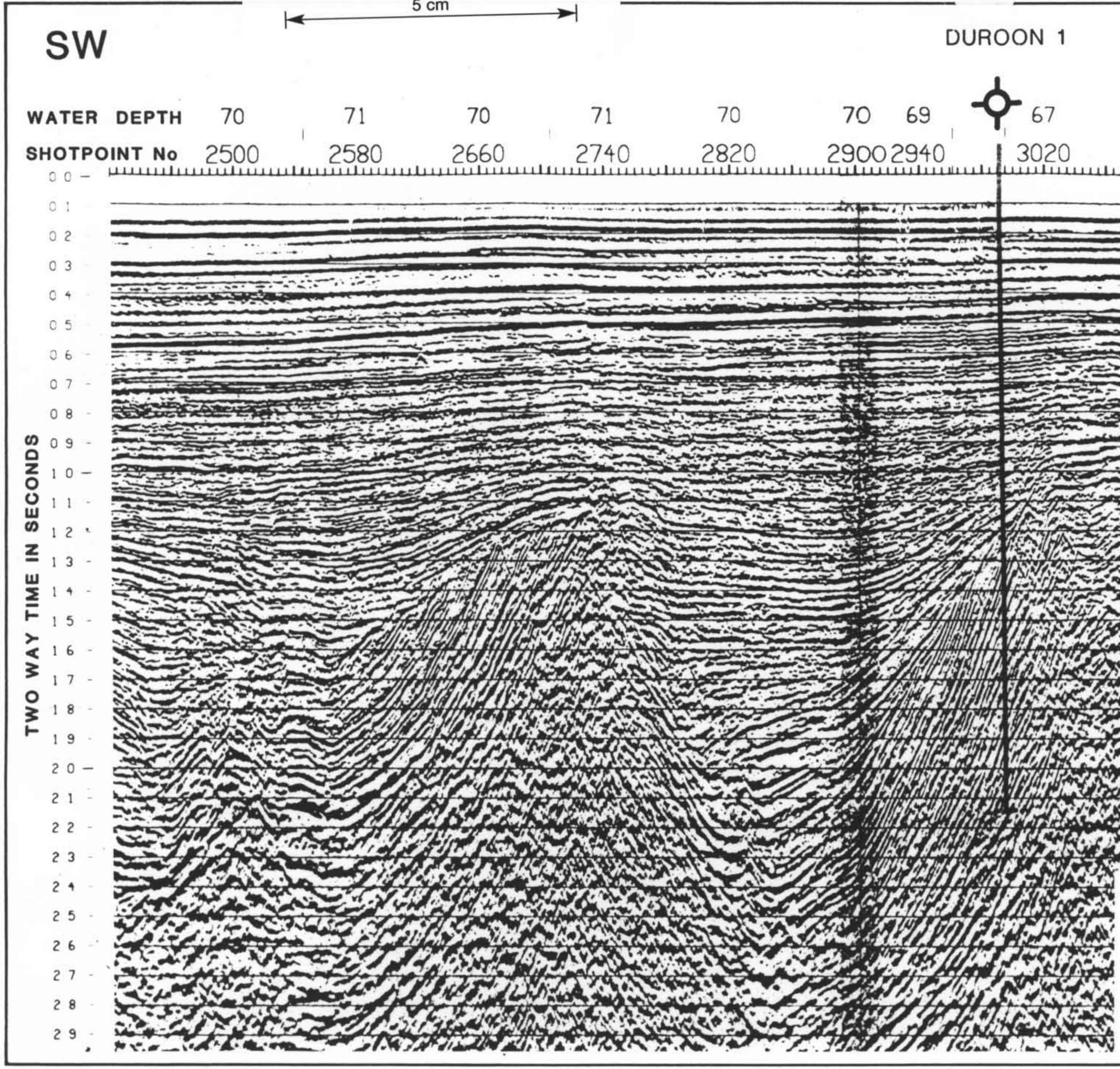
The second major Tertiary episode of faulting occurred during the Miocene. Reactivation of earlier basement features occurred (Figures 4.4, 4.5, 4.6) and faults with a northeast-southwest orientation were created (Figure 4.7). Volcanic lavas and tuffs related to this episode of faulting are readily recognisable on seismic sections (Figure 4.8).

636060

5 cm


EVCM
EVCM
L. balmei
UNCONFORMITY
ASSOCIATED WITH
'BREAK UP'
OTWAY GROUP
OTWAY GROUP

062

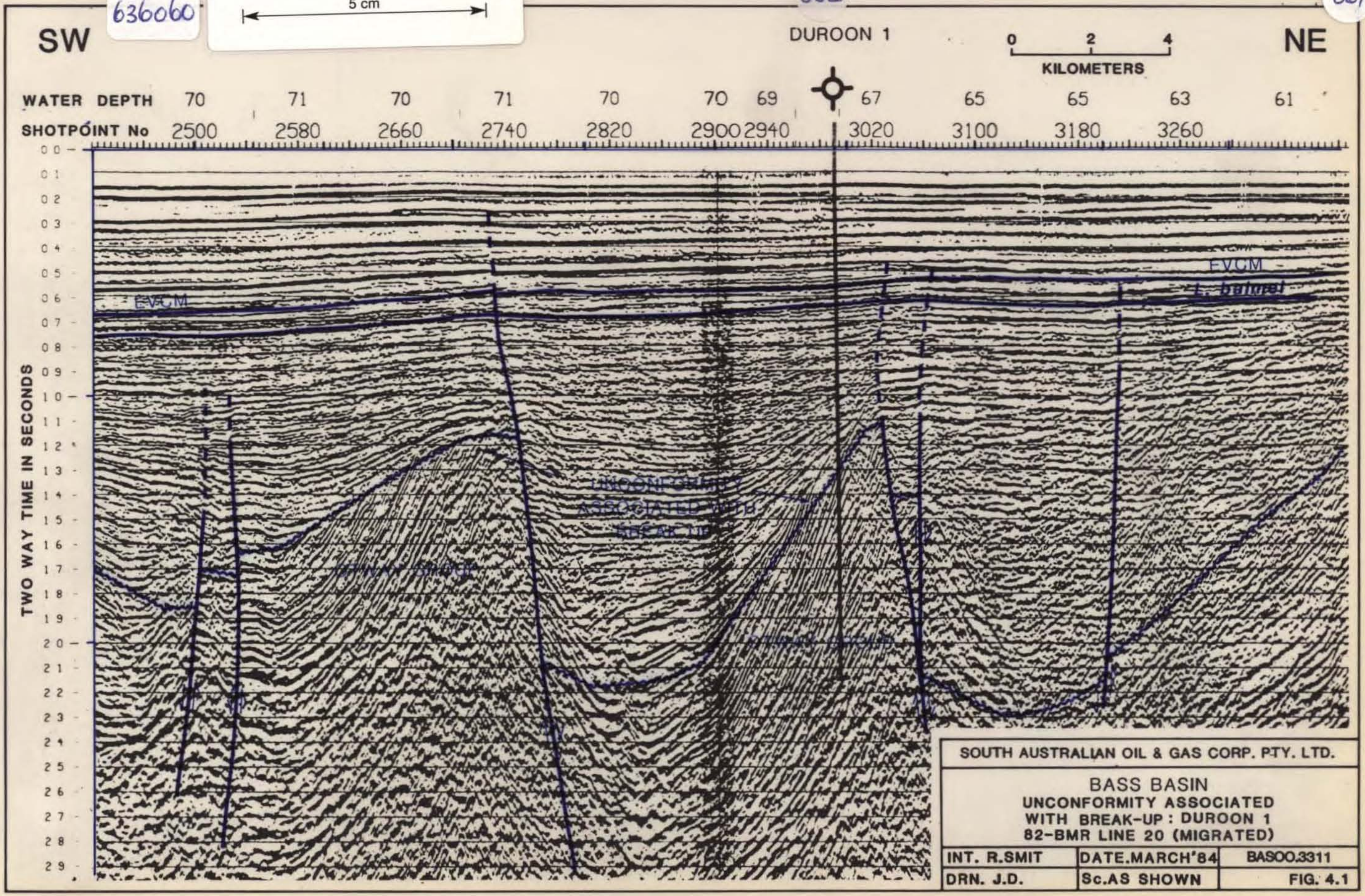


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN UNCONFORMITY ASSOCIATED WITH BREAK-UP : DUROON 1 82-BMR LINE 20 (MIGRATED)		
INT. R.SMIT	DATE.MARCH'84	BASOO.3311
DRN. J.D.	Sc.AS SHOWN	FIG. 4.1

636060

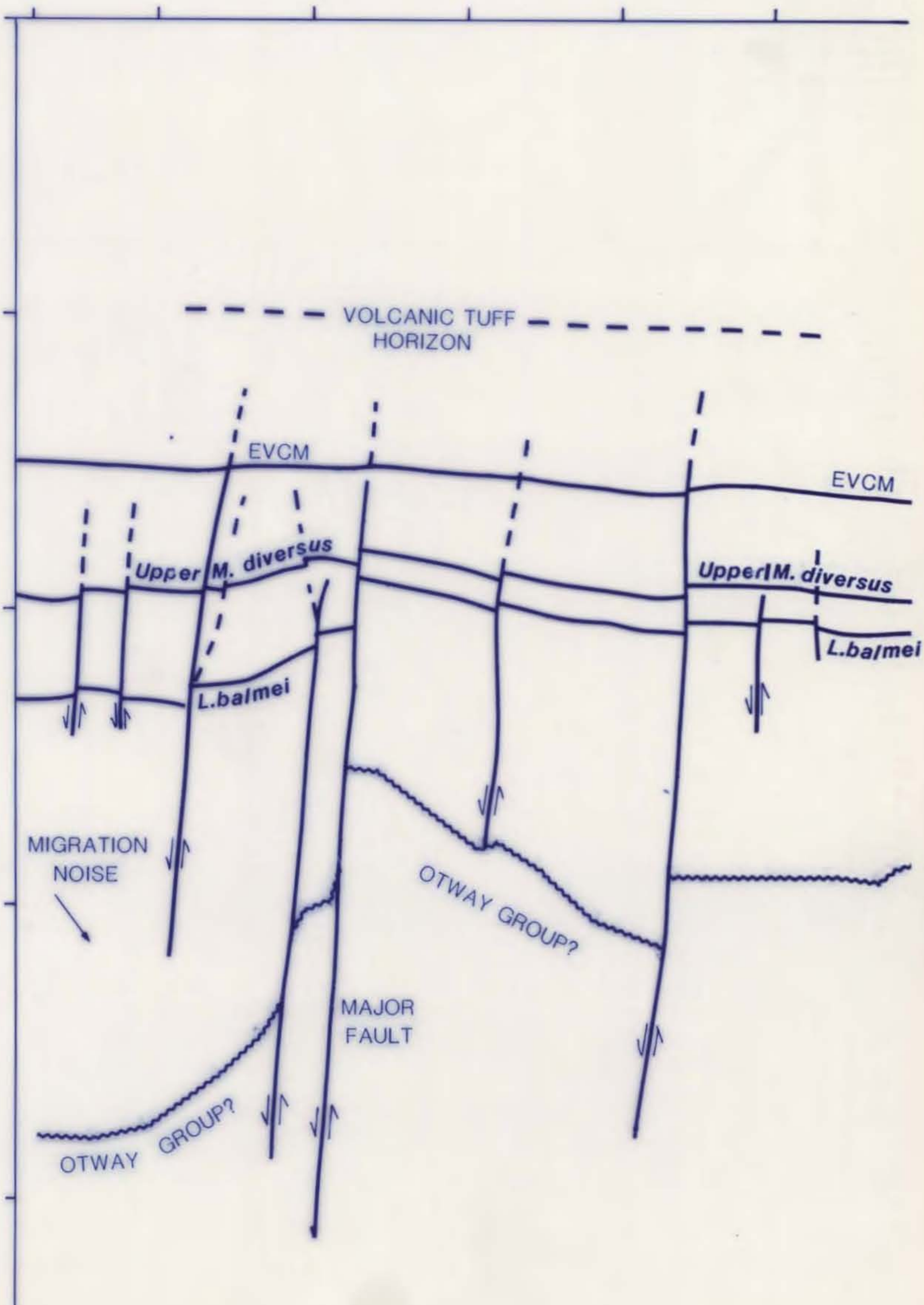
062

061

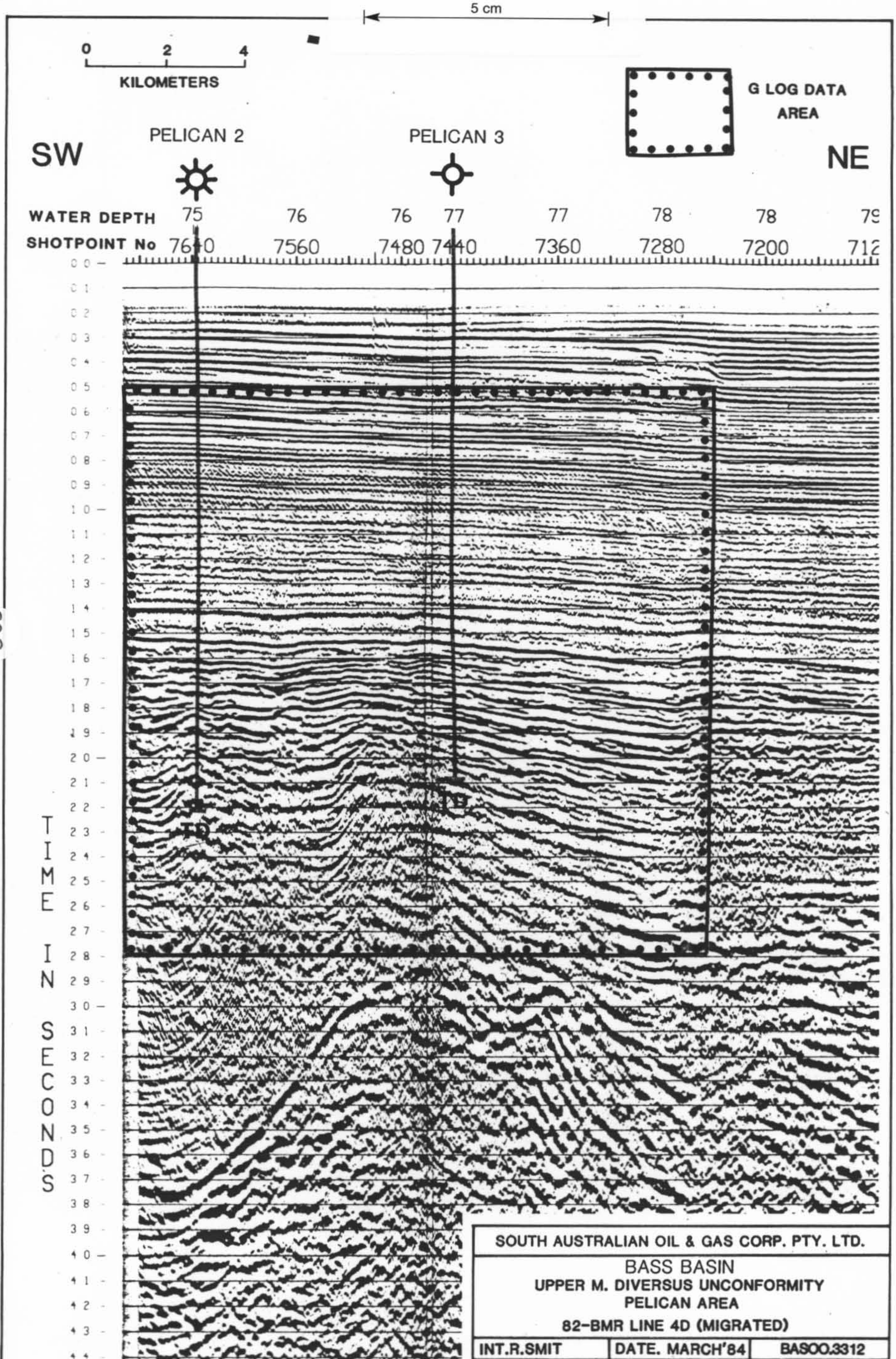


064

5 cm

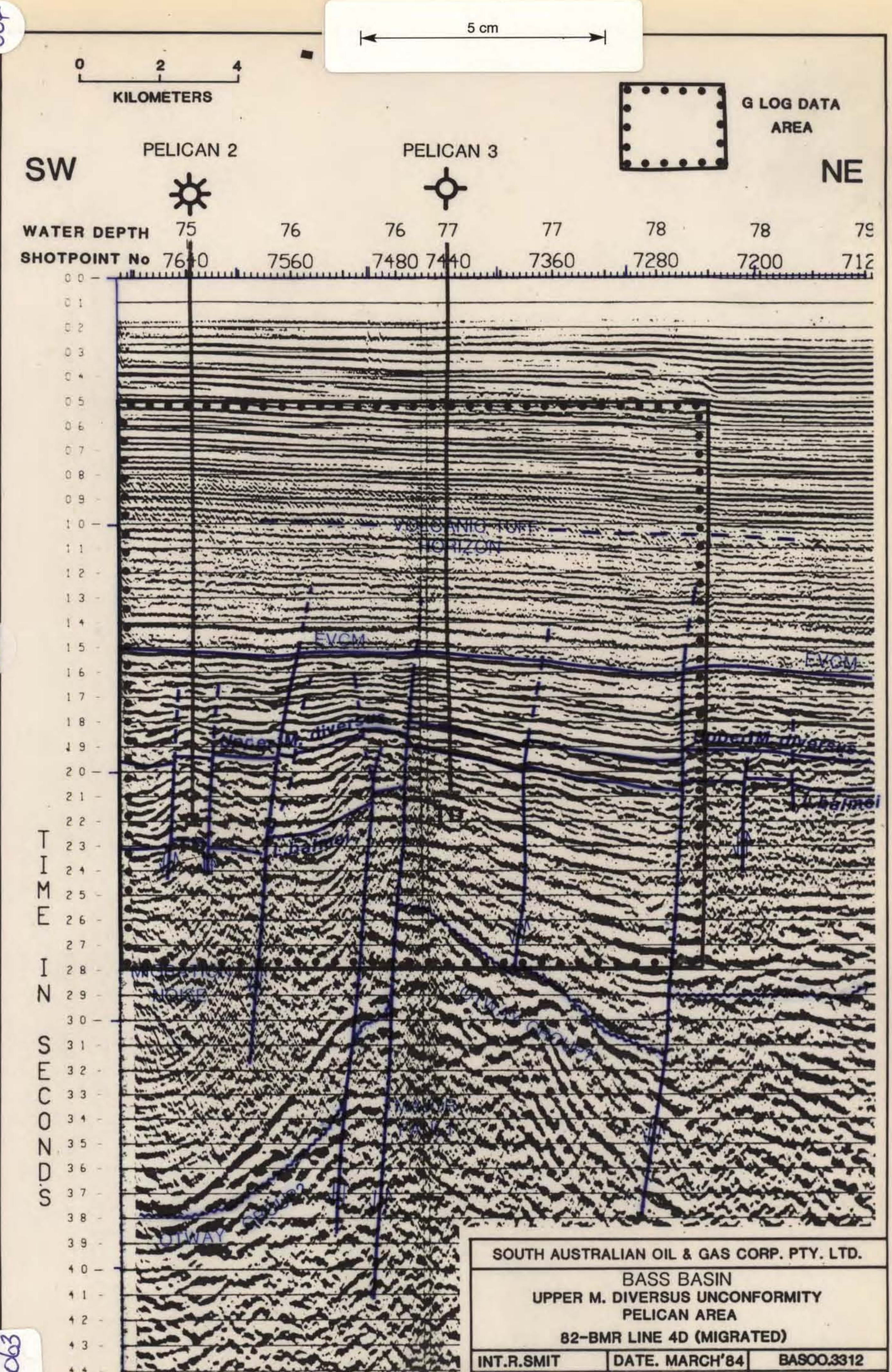


636063



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN UPPER M. DIVERSUS UNCONFORMITY PELICAN AREA 82-BMR LINE 4D (MIGRATED)		
INT.R.SMIT	DATE. MARCH'84	BAS00.3312
DRN. J.D.	Sc. AS SHOWN	FIG. 4.2

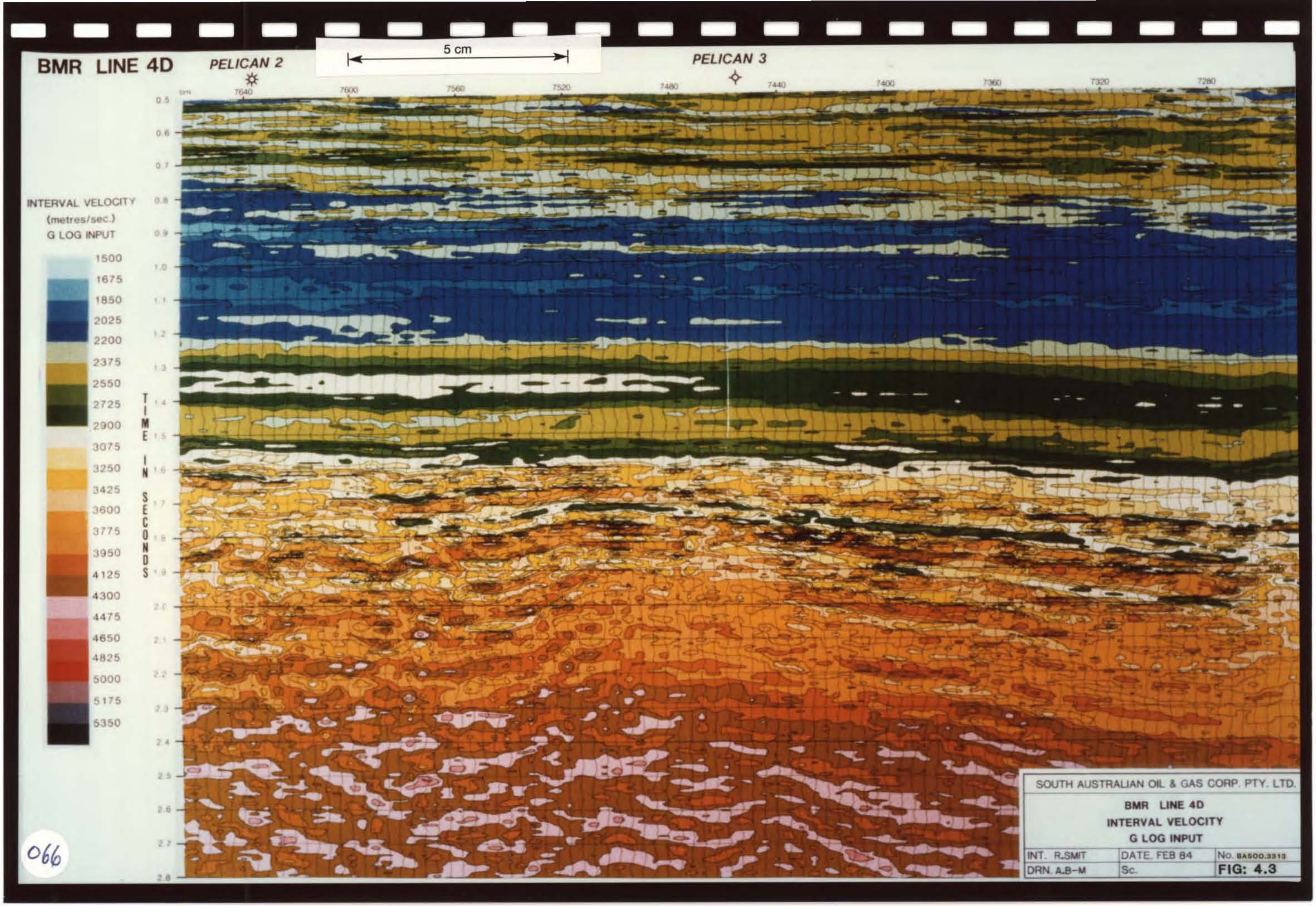
064

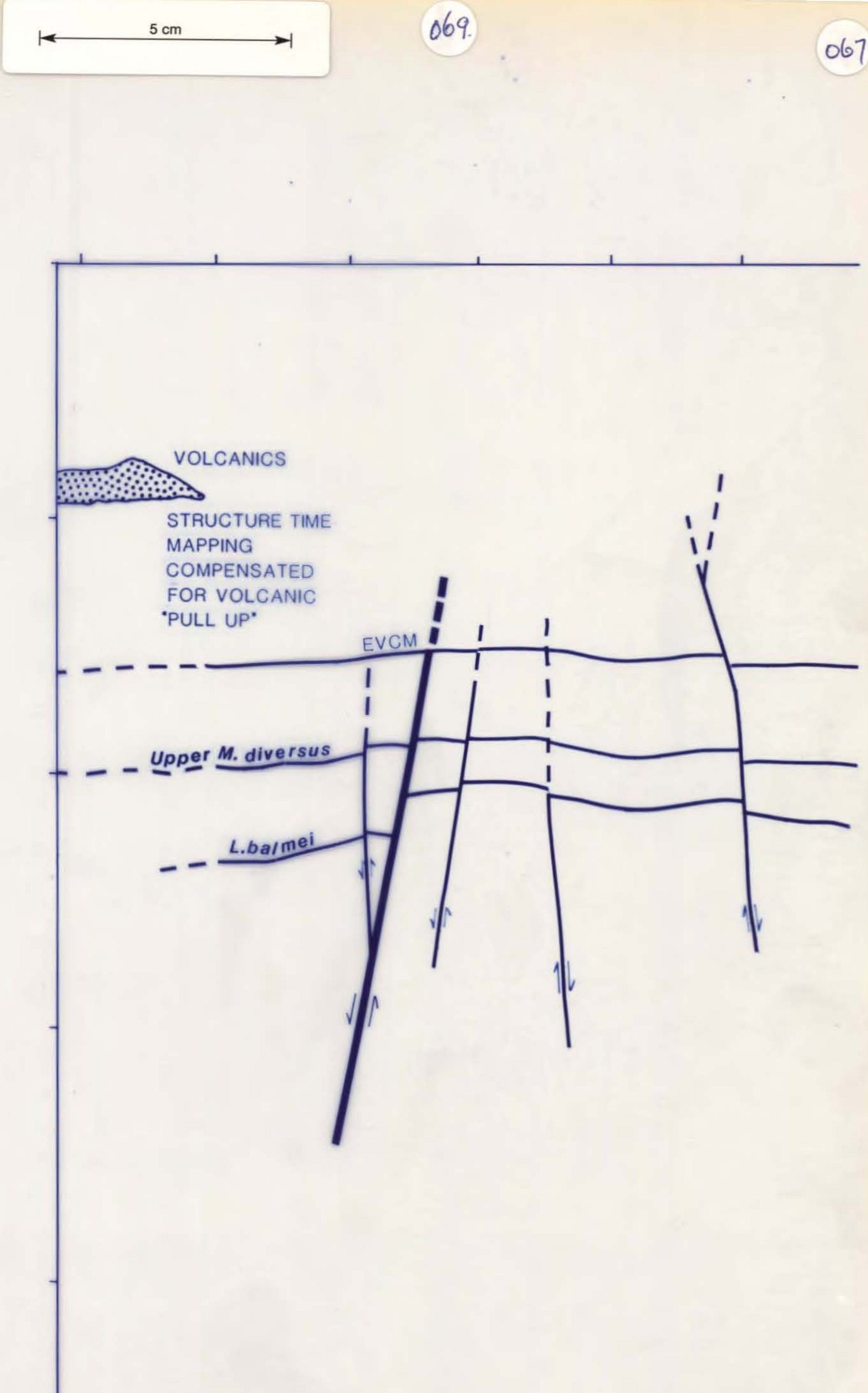


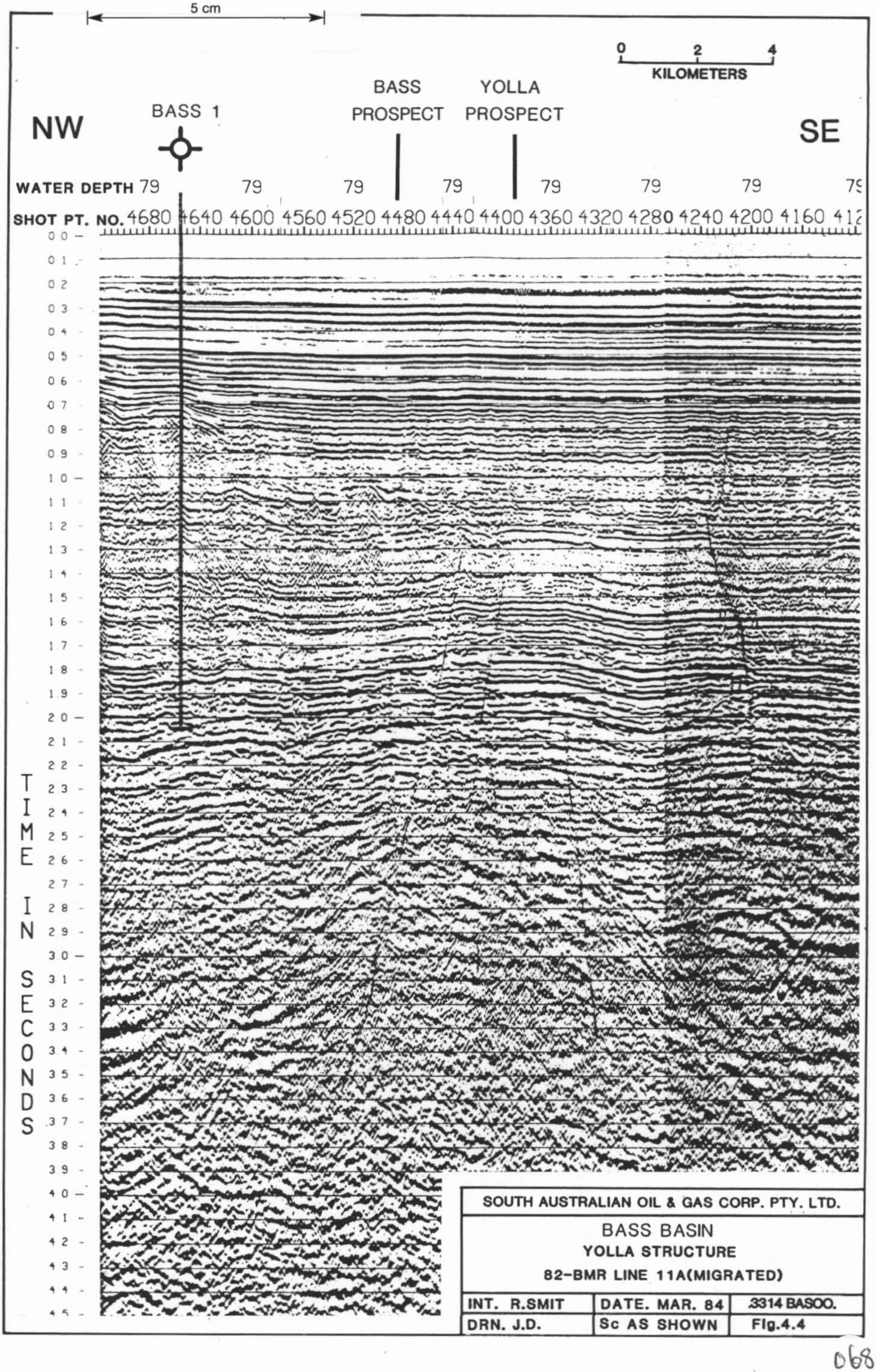
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN UPPER M. DIVERSUS UNCONFORMITY PELICAN AREA 82-BMR LINE 4D (MIGRATED)		
INT.R.SMIT	DATE. MARCH'84	BAS00.3312
DRN. J.D.	Sc. AS SHOWN	FIG. 4.2

065

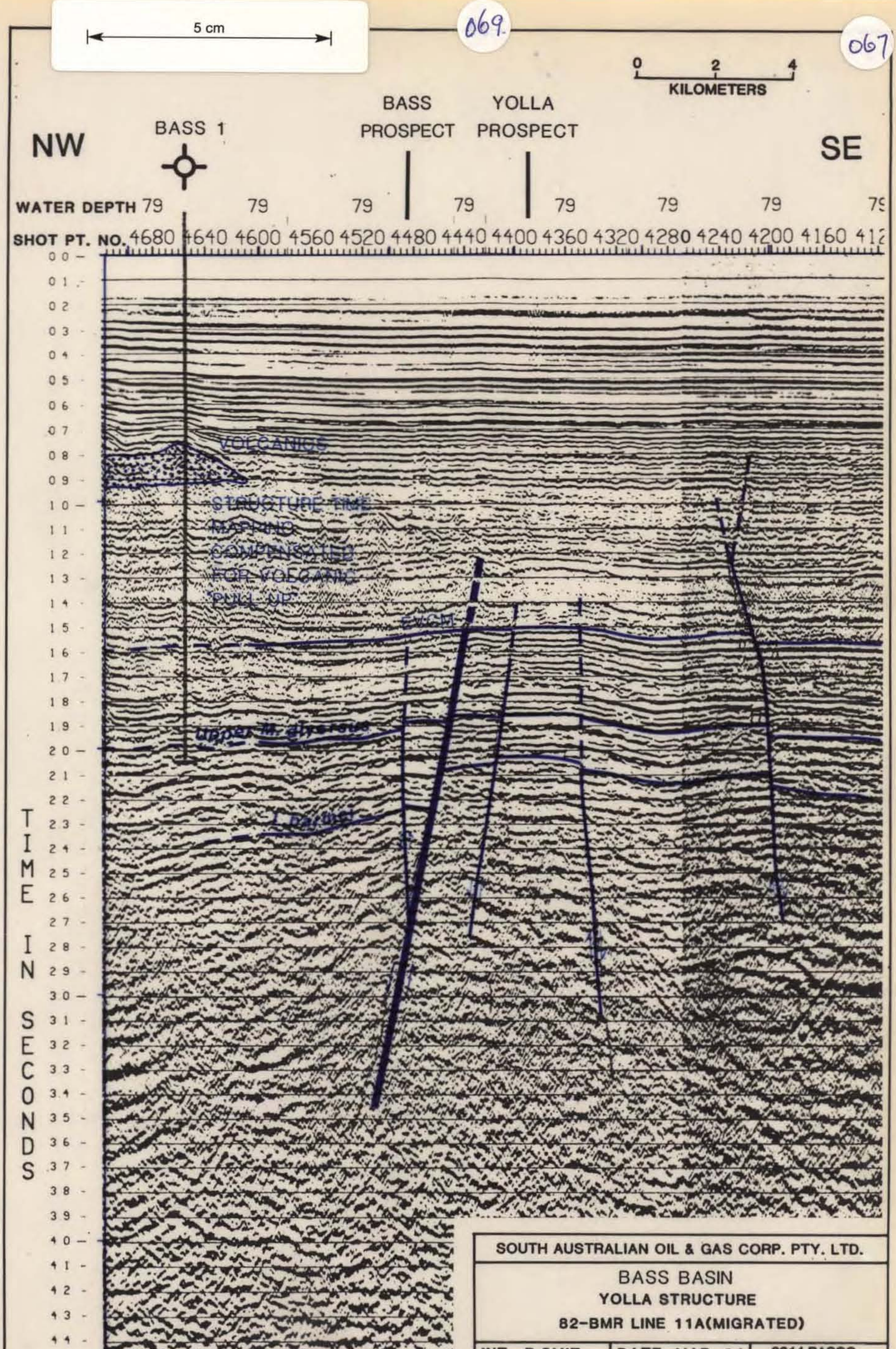
636063


BMR LINE 4D
PELICAN 2
5 cm
PELICAN 3
7640
7600
7560
7520
7480
7440
7400
7360
7320
7280
INTERVAL VELOCITY
(metres/sec.)
G LOG INPUT
1500
1675
1850
2025
2200
2375
2550
2725
2900
3075
3250
3425
3600
3775
3950
4125
4300
4475
4650
4825
5000
5175
5350
TIME IN SECONDS
0.5
0.6
0.7
0.8
0.9
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
2.2
2.3
2.4
2.5
2.6
2.7
2.8
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BMR LINE 4D
INTERVAL VELOCITY
G LOG INPUT
INT. R.SMIT
DATE. FEB 84
No. BAS00.3313
DRN. A.B-M
Sc.
FIG: 4.3
066

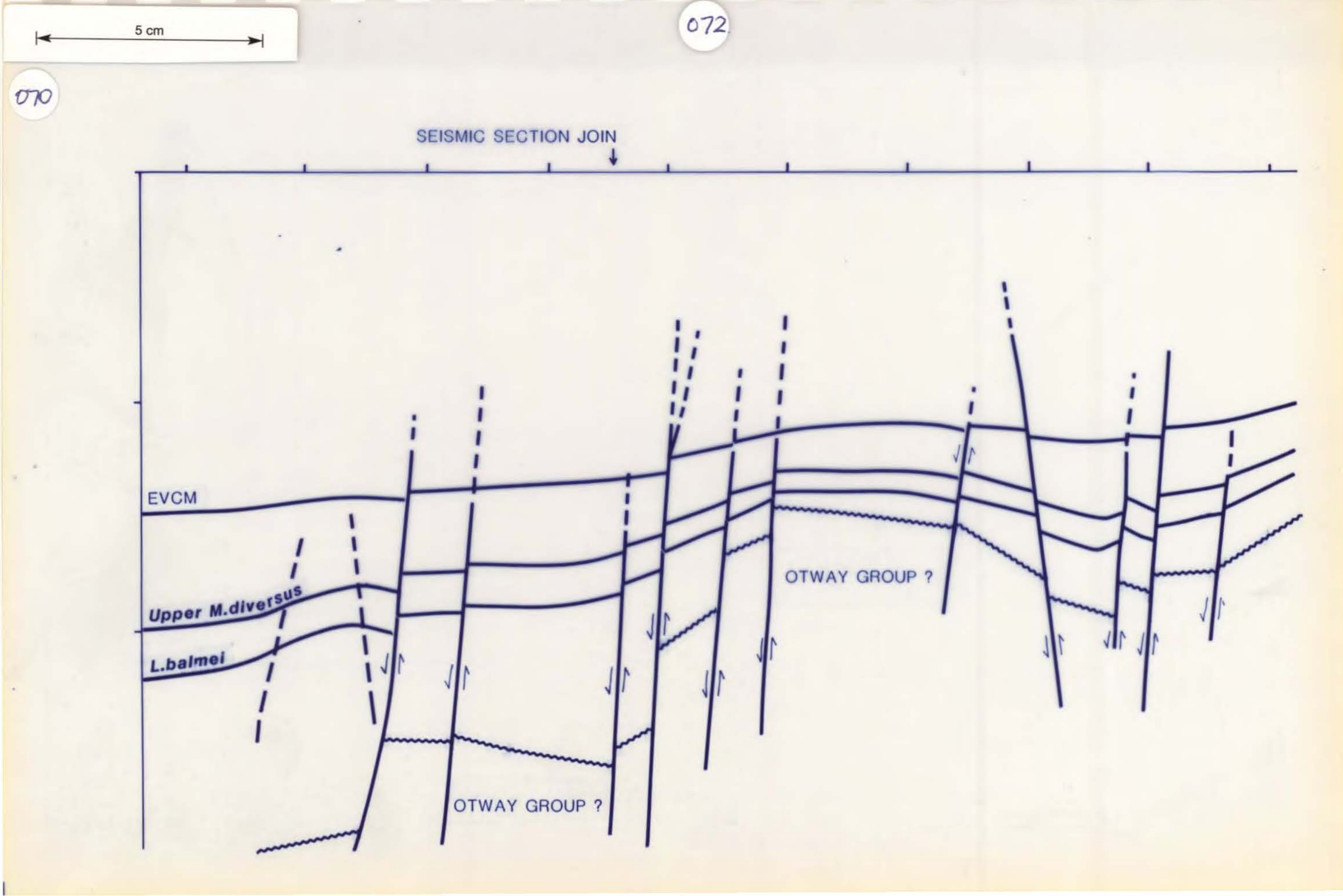

5 cm
VOLCANICS
STRUCTURE TIME
MAPPING
COMPENSATED
FOR VOLCANIC
"PULL UP"
EVCM
Upper M. diversus
L.balmei


5 cm
0 2 4
KILOMETERS
NW
SE
BASS 1
BASS PROSPECT
YOLLA PROSPECT
WATER DEPTH 79 79 79 79 79 79 79
SHOT PT. NO. 4680 4640 4600 4560 4520 4480 4440 4400 4360 4320 4280 4240 4200 4160
0.0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0 1.1 1.2 1.3 1.4 1.5 1.6 1.7 1.8 1.9 2.0 2.1 2.2 2.3 2.4 2.5 2.6 2.7 2.8 2.9 3.0 3.1 3.2 3.3 3.4 3.5 3.6 3.7 3.8 3.9 4.0 4.1 4.2 4.3 4.4 4.5
TIME IN SECONDS
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
YOLLA STRUCTURE
82-BMR LINE 11A(MIGRATED)
INT. R.SMIT
DATE. MAR. 84
3314 BASOO.
DRN. J.D.
Sc AS SHOWN
Fig.4.4

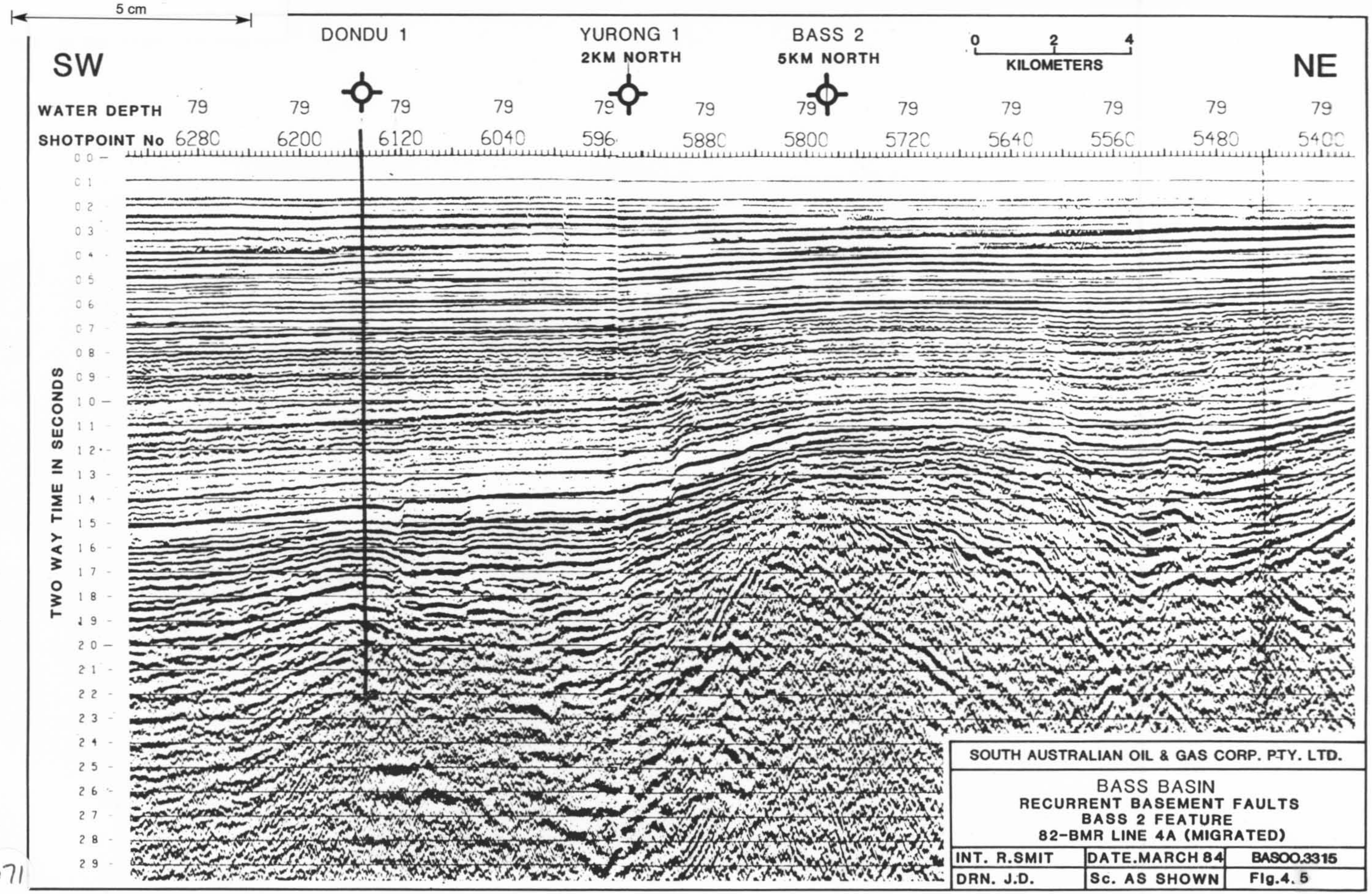
067


5 cm
069
0 2 4
KILOMETERS
NW
BASS 1
BASS PROSPECT
YOLLA PROSPECT
SE
WATER DEPTH 79 79 79 79 79 79 79 79
SHOT PT. NO. 4680 4640 4600 4560 4520 4480 4440 4400 4360 4320 4280 4240 4200 4160
VOLCANICS
STRUCTURE TIME MAPPING COMPENSATED FOR VOLCANIC 'PULL UP'
upper M. diversus
TIME IN SECONDS
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
YOLLA STRUCTURE
82-BMR LINE 11A(MIGRATED)
INT. R.SMIT
DATE. MAR. 84
3314 BASOO.
DRN. J.D.
Sc AS SHOWN
Fig.4.4

068

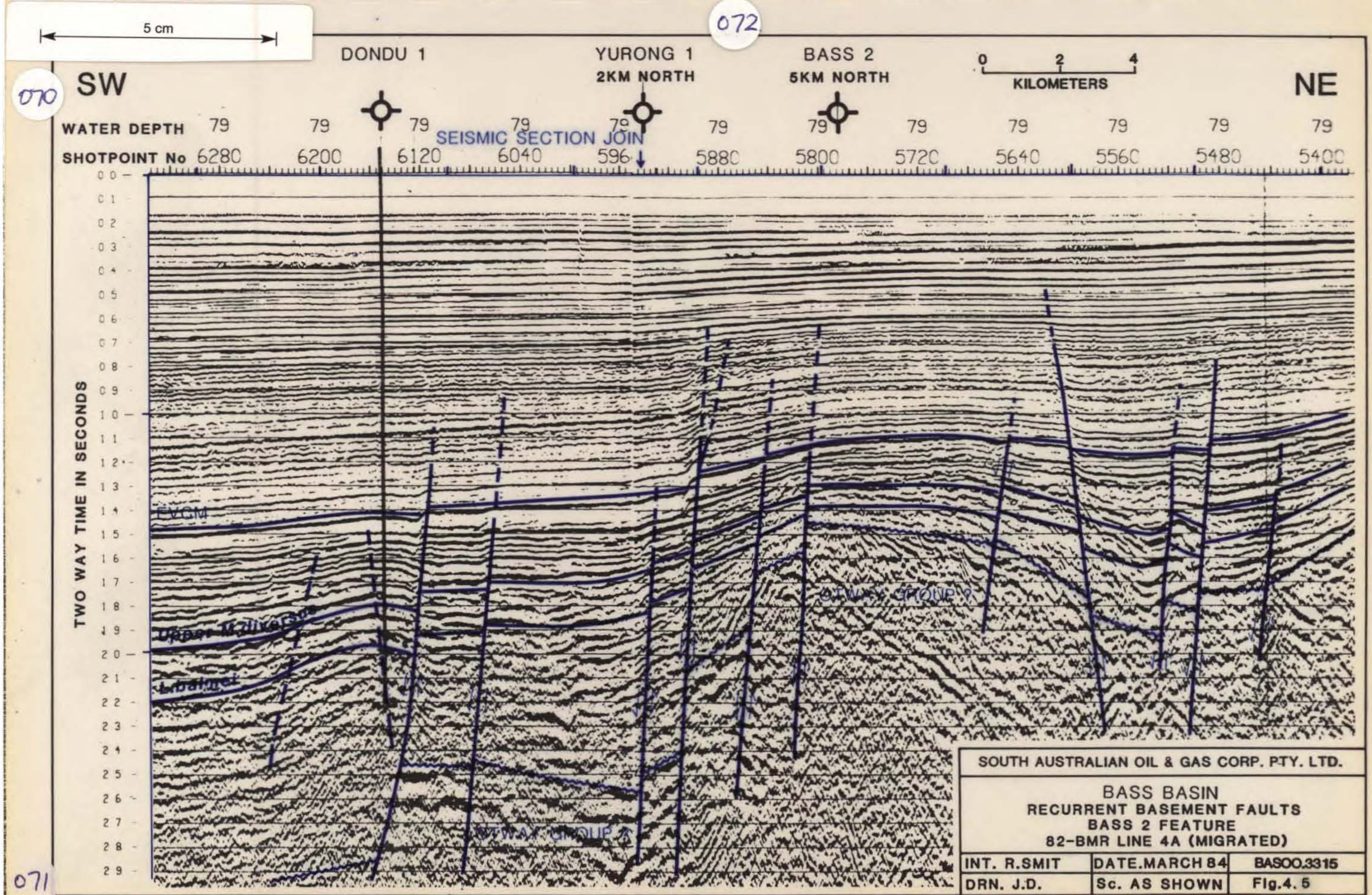


5 cm
070
072
SEISMIC SECTION JOIN
EVCM
Upper M.diversus
L.balmei
OTWAY GROUP ?
OTWAY GROUP ?


5 cm
DONDU 1
YURONG 1
2KM NORTH
BASS 2
5KM NORTH
0 2 4
KILOMETERS
SW
NE
WATER DEPTH 79 79 79 79 79 79 79 79 79 79 79 79
SHOTPOINT No 6280 6200 6120 6040 596 5880 5800 5720 5640 5560 5480 5400
TWO WAY TIME IN SECONDS
0 0
1 0
2 0
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
RECURRENT BASEMENT FAULTS
BASS 2 FEATURE
82-BMR LINE 4A (MIGRATED)
INT. R.SMIT
DATE.MARCH 84
BASOO.3315
DRN. J.D.
Sc. AS SHOWN
Fig.4. 5

071

070

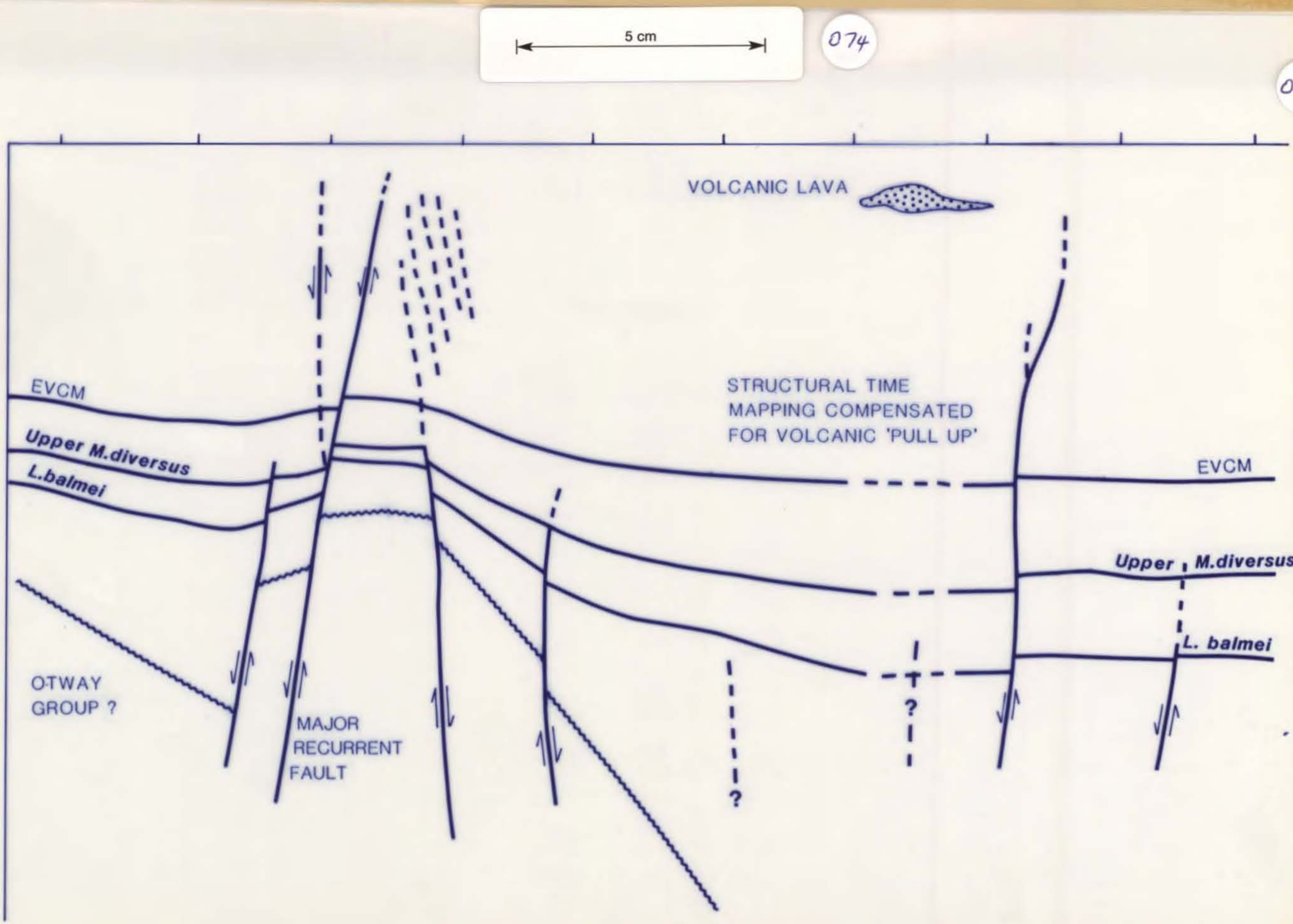


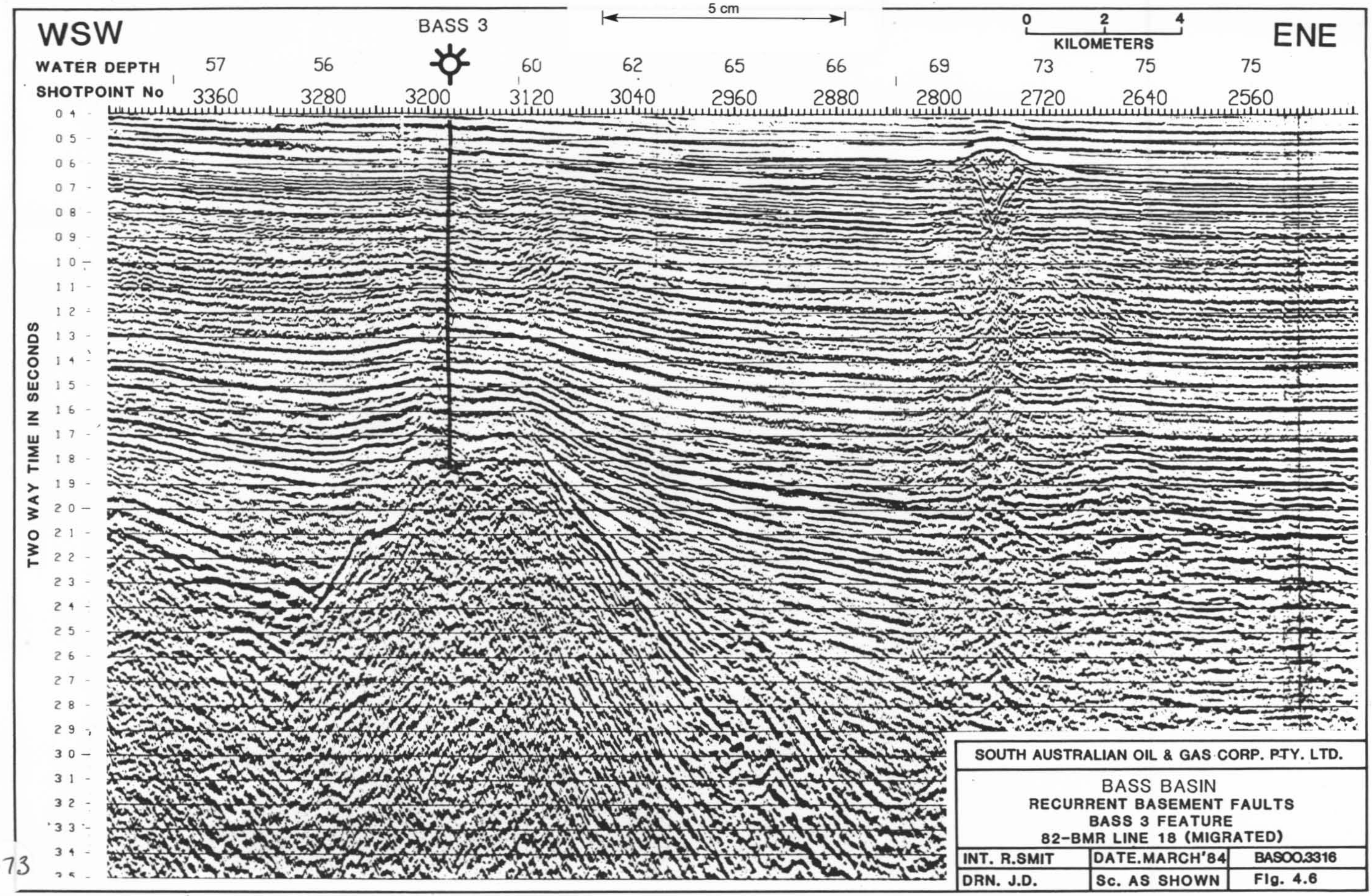
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN RECURRENT BASEMENT FAULTS BASS 2 FEATURE 82-BMR LINE 4A (MIGRATED)		
INT. R.SMIT	DATE.MARCH 84	BASOO.3315
DRN. J.D.	Sc. AS SHOWN	Fig.4.5

071

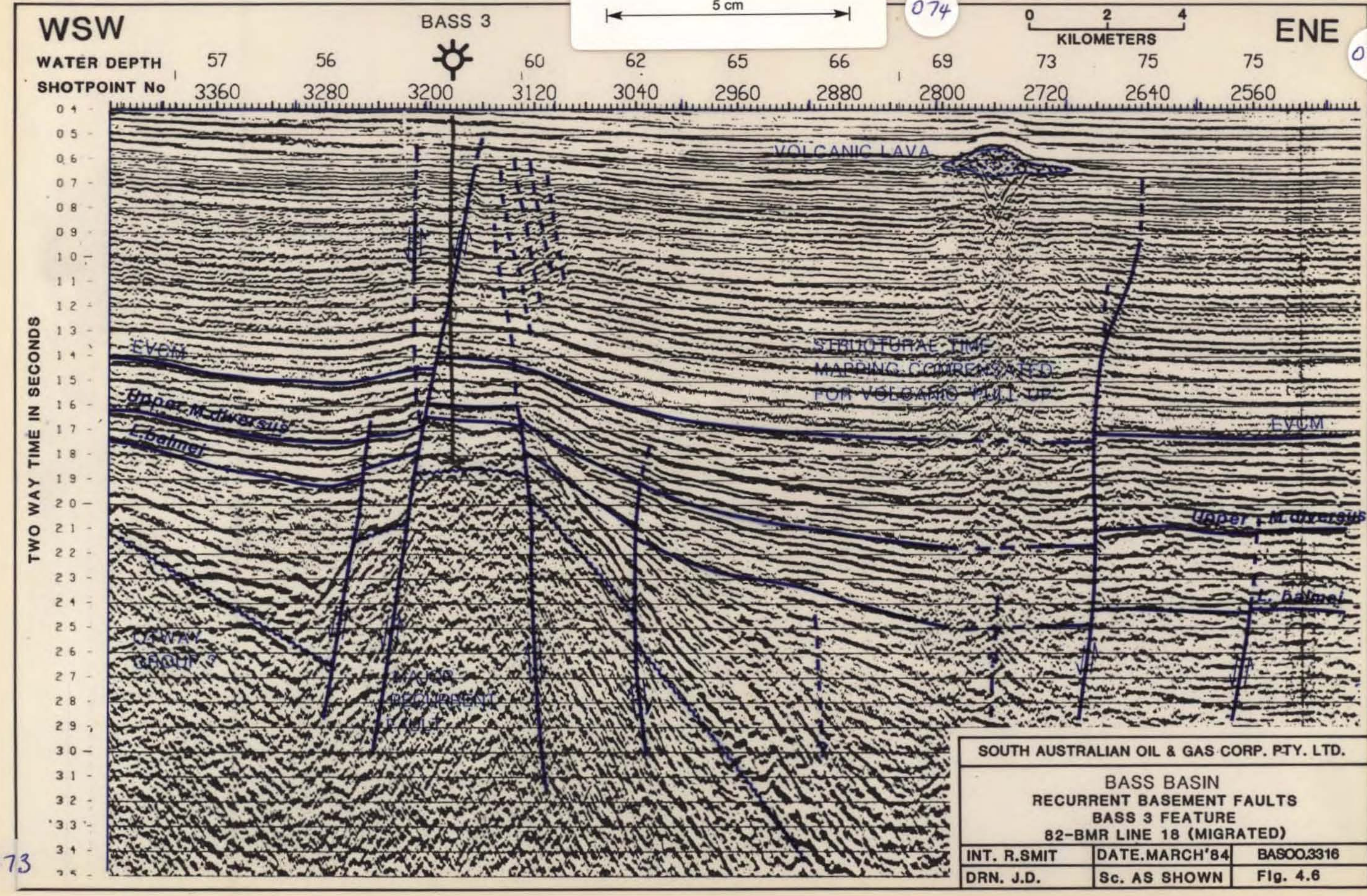
074

072


5 cm
VOLCANIC LAVA
STRUCTURAL TIME
MAPPING COMPENSATED
FOR VOLCANIC 'PULL UP'
EVCM
Upper M.diversus
L.balmei
EVCM
Upper M.diversus
L. balmei
OTWAY
GROUP ?
MAJOR
RECURRENT
FAULT
?
?


WSW
ENE
BASS 3
5 cm
0 2 4
KILOMETERS
WATER DEPTH
57 56 60 62 65 66 69 73 75 75
SHOTPOINT No
3360 3280 3200 3120 3040 2960 2880 2800 2720 2640 2560
TWO WAY TIME IN SECONDS
0 4
0 5
0 6
0 7
0 8
0 9
1 0
1 1
1 2
1 3
1 4
1 5
1 6
1 7
1 8
1 9
2 0
2 1
2 2
2 3
2 4
2 5
2 6
2 7
2 8
2 9
3 0
3 1
3 2
3 3
3 4
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
RECURRENT BASEMENT FAULTS
BASS 3 FEATURE
82-BMR LINE 18 (MIGRATED)
INT. R.SMIT
DATE.MARCH'84
BAS00.3316
DRN. J.D.
Sc. AS SHOWN
Fig. 4.6

073

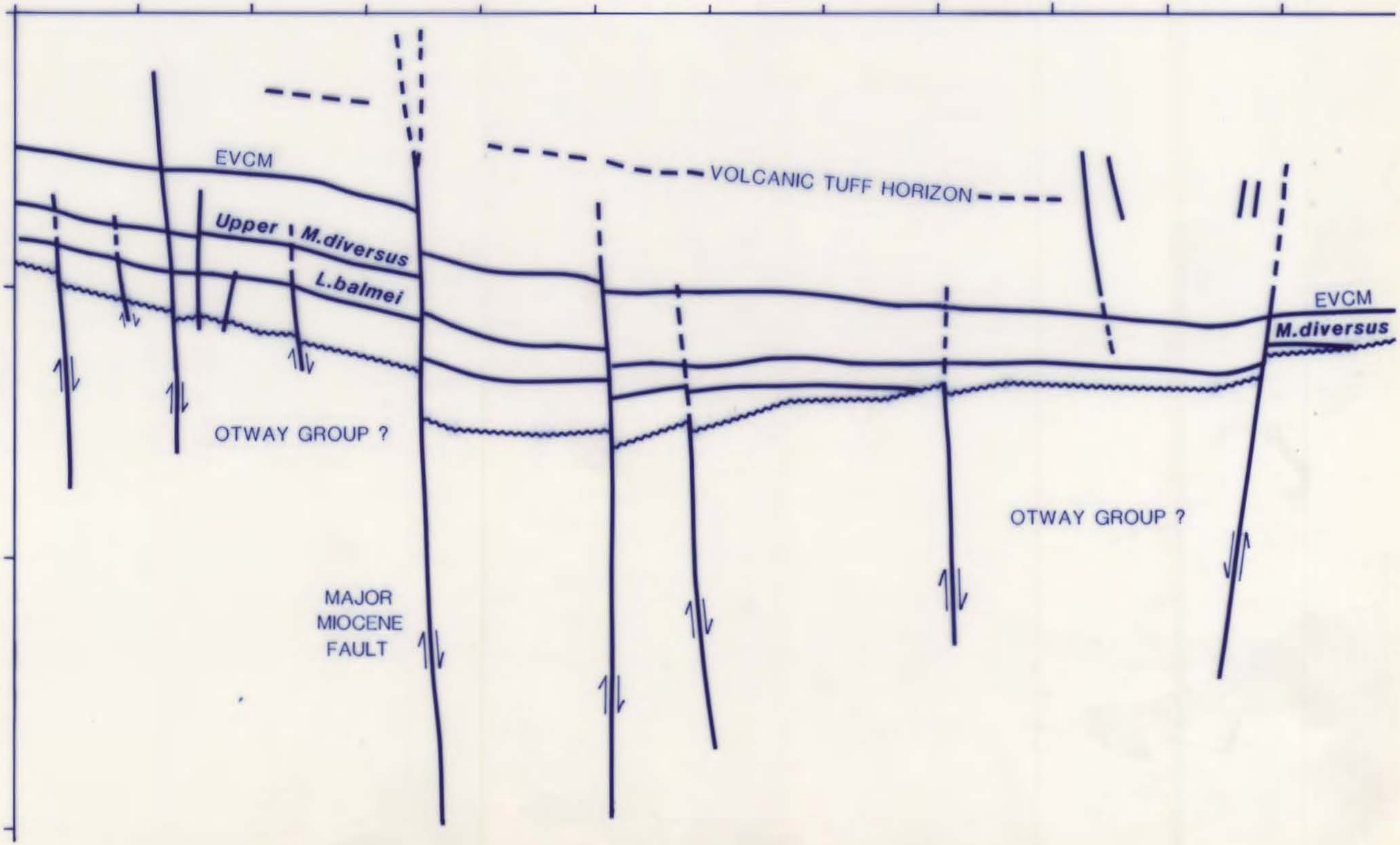


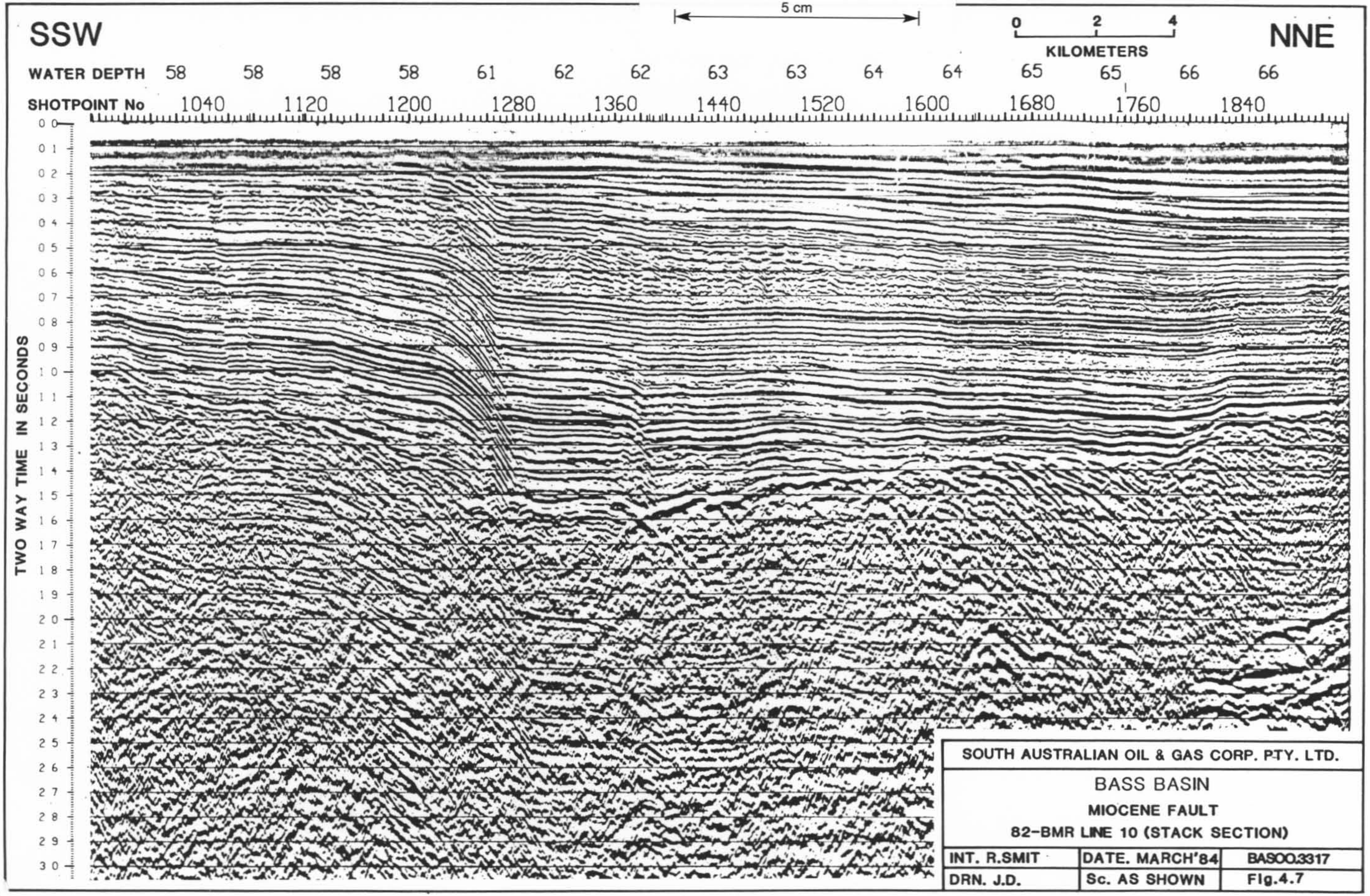
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN RECURRENT BASEMENT FAULTS BASS 3 FEATURE 82-BMR LINE 18 (MIGRATED)		
INT. R.SMIT	DATE.MARCH'84	BASOO.3316
DRN. J.D.	Sc. AS SHOWN	Fig. 4.6

077

5 cm

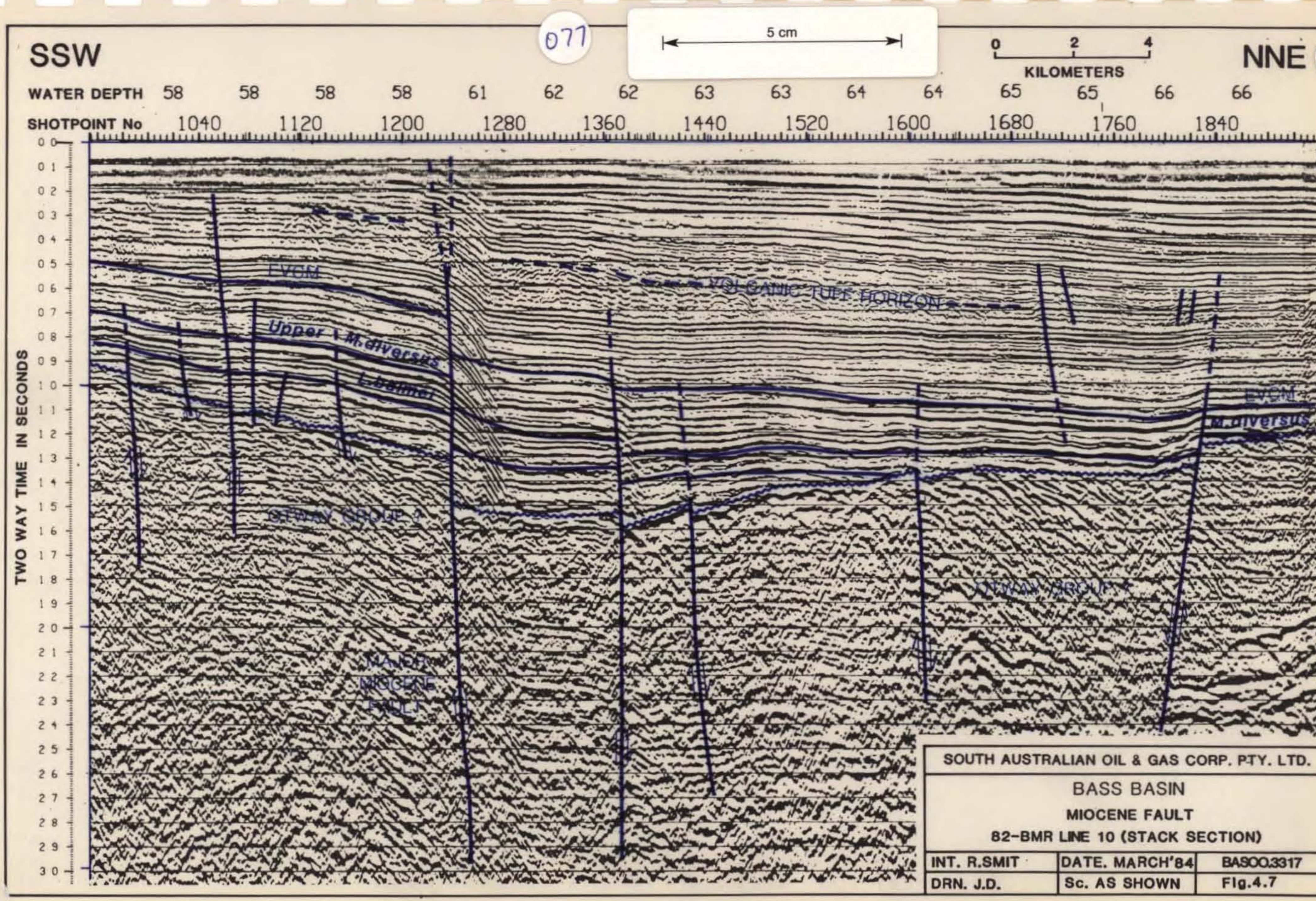
075


EVCM
Upper M.diversus
L.balmei
VOLCANIC TUFF HORIZON
EVCM
M.diversus
OTWAY GROUP ?
OTWAY GROUP ?
MAJOR
MIOCENE
FAULT



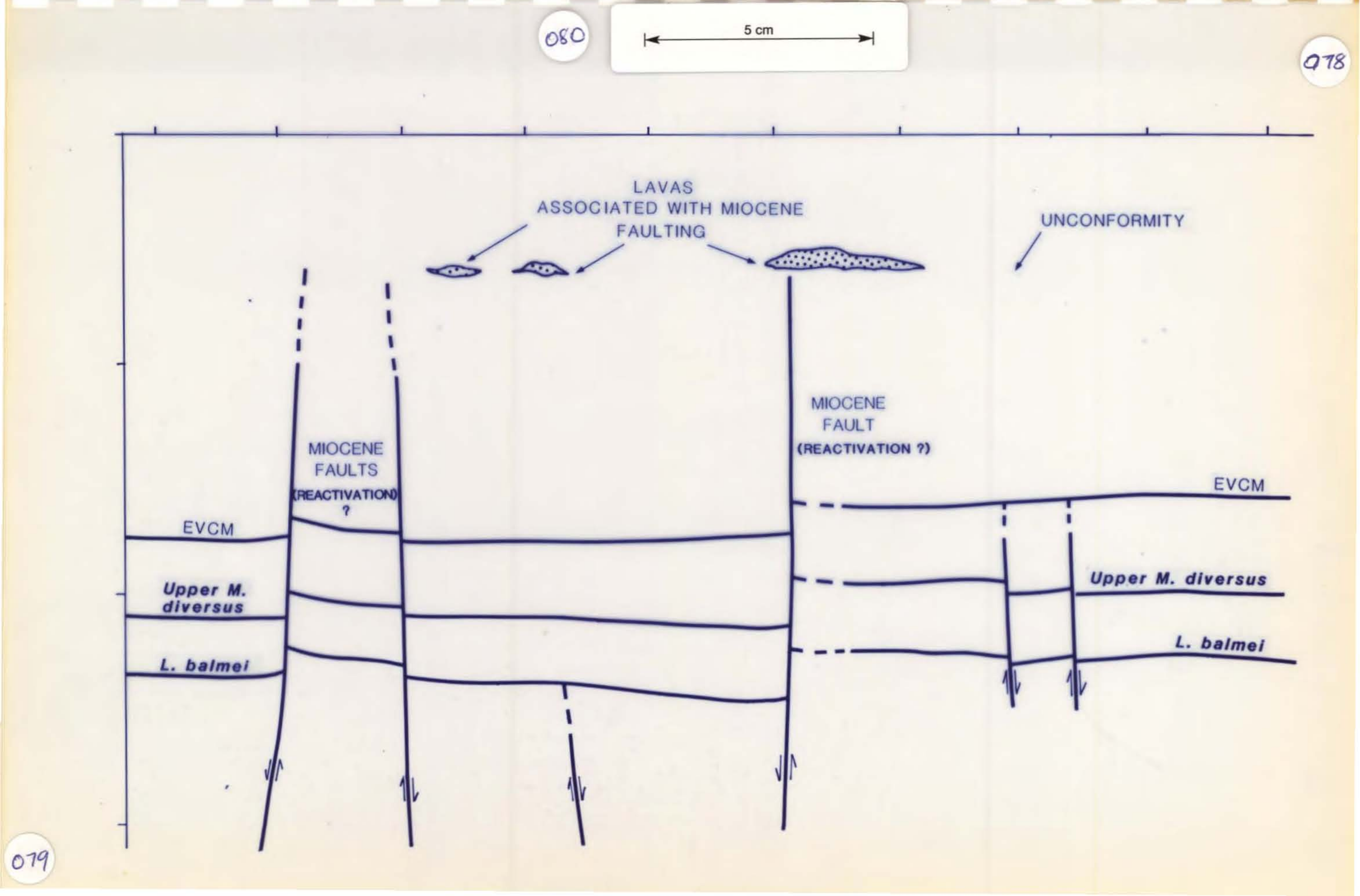
SSW
NNE
5 cm
0 2 4
KILOMETERS
WATER DEPTH 58 58 58 58 61 62 62 63 63 64 64 65 65 66 66
SHOTPOINT No 1040 1120 1200 1280 1360 1440 1520 1600 1680 1760 1840
TWO WAY TIME IN SECONDS
0 0
0 1
0 2
0 3
0 4
0 5
0 6
0 7
0 8
0 9
1 0
1 1
1 2
1 3
1 4
1 5
1 6
1 7
1 8
1 9
2 0
2 1
2 2
2 3
2 4
2 5
2 6
2 7
2 8
2 9
3 0
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
MIOCENE FAULT
82-BMR LINE 10 (STACK SECTION)
INT. R.SMIT
DATE. MARCH'84
BASOO.3317
DRN. J.D.
Sc. AS SHOWN
Fig.4.7

077 075

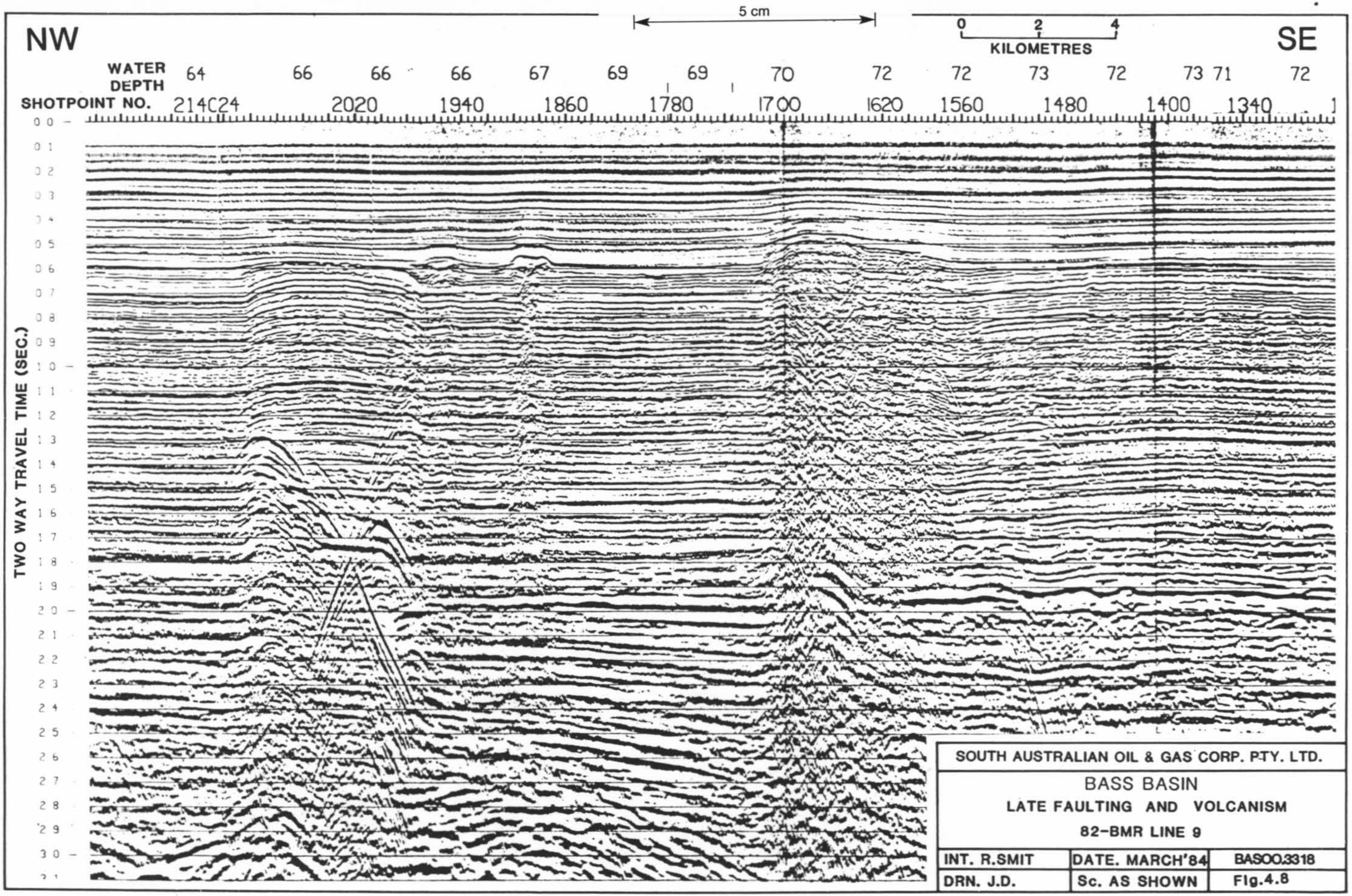


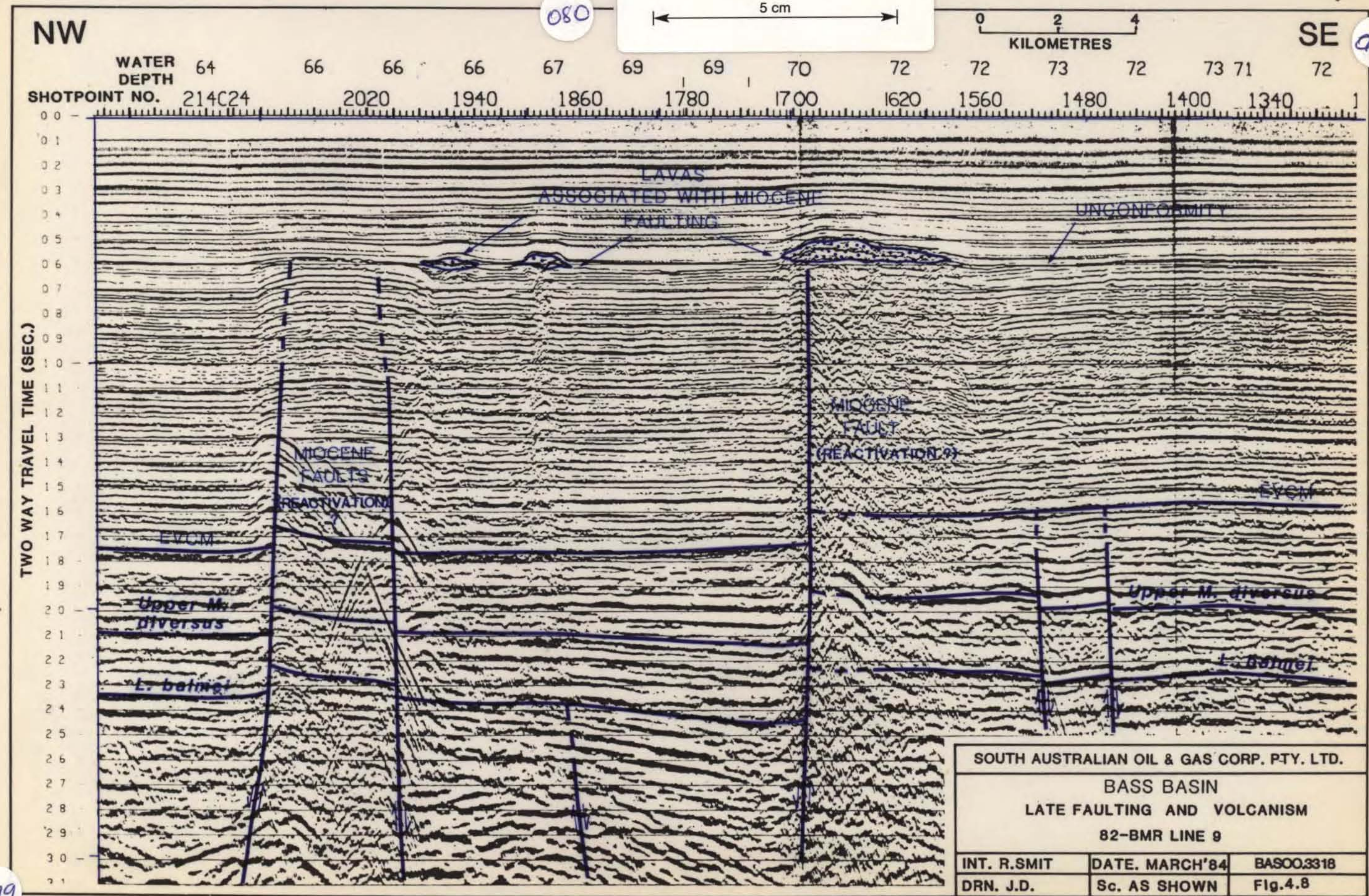
5 cm
SSW
NNE
0 2 4
KILOMETERS
WATER DEPTH 58 58 58 58 61 62 62 63 63 64 64 65 65 66 66
SHOTPOINT No 1040 1120 1200 1280 1360 1440 1520 1600 1680 1760 1840
TWO WAY TIME IN SECONDS
0 0
0 1
0 2
0 3
0 4
0 5
0 6
0 7
0 8
0 9
1 0
1 1
1 2
1 3
1 4
1 5
1 6
1 7
1 8
1 9
2 0
2 1
2 2
2 3
2 4
2 5
2 6
2 7
2 8
2 9
3 0
EVCM
VOLCANIC TUFF HORIZON
Upper M.diversus
L.balmei
OTWAY GROUP
MAJOR MIOCENE FAULT
OTWAY GROUP
EVCM
M.diversus
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
MIOCENE FAULT
82-BMR LINE 10 (STACK SECTION)
INT. R.SMIT
DATE. MARCH'84
BASOO.3317
DRN. J.D.
Sc. AS SHOWN
Fig.4.7

076



080
5 cm
078
LAVAS
ASSOCIATED WITH MIOCENE
FAULTING
UNCONFORMITY
MIOCENE
FAULT
(REACTIVATION ?)
MIOCENE
FAULTS
(REACTIVATION)
?
EVCM
EVCM
Upper M. diversus
Upper M.
diversus
L. balmei
L. balmei
079


NW
SE
5 cm
0 2 4
KILOMETRES
WATER DEPTH
64 66 66 66 67 69 69 70 72 72 73 72 73 71 72
SHOTPOINT NO.
2140 2020 1940 1860 1780 1700 1620 1560 1480 1400 1340
TWO WAY TRAVEL TIME (SEC.)
0.0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0 1.1 1.2 1.3 1.4 1.5 1.6 1.7 1.8 1.9 2.0 2.1 2.2 2.3 2.4 2.5 2.6 2.7 2.8 2.9 3.0
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
LATE FAULTING AND VOLCANISM
82-BMR LINE 9
INT. R.SMIT
DATE. MARCH'84
BASOO.3318
DRN. J.D.
Sc. AS SHOWN
Fig.4.8


NW
SE
5 cm
0 2 4
KILOMETRES
WATER DEPTH 64 66 66 66 67 69 69 70 72 72 73 72 73 71 72
SHOTPOINT NO. 2140 24 2020 1940 1860 1780 1700 1620 1560 1480 1400 1340
TWO WAY TRAVEL TIME (SEC.)
LAVAS ASSOCIATED WITH MIOCENE FAULTING
UNCONFORMITY
MIOCENE FAULTS (REACTIVATION ?)
MIOCENE FAULT (REACTIVATION ?)
EVCM
Upper M. diversus
L. balmei
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
LATE FAULTING AND VOLCANISM
82-BMR LINE 9
INT. R.SMIT
DATE. MARCH'84
BASOO.3318
DRN. J.D.
Sc. AS SHOWN
Fig.4.8
080
078
079

5.0 SOURCE ROCK, THERMAL HISTORY AND MATURATION

5.1 INTRODUCTION

Oil has been recovered from Cormorant 1 and gas-condensate from Bass 3, Pelicans 1, 2, 3 and 4 (See Table 2.1). There are also numerous good shows from other wells in the basin. Pipipa 1, which reached total depth prior to encountering the main reservoir section of the adjacent Pelican Field, had particularly strong shows. Hence, the generation of hydrocarbons within of the Bass Basin has been empirically established.

The lack of success in finding a commercial-sized petroleum accumulation within the Basin, despite the encouraging indications, requires a more detailed evaluation of the source rock type, maturation history and volume and timing of generation. This would ensure that future targets are optimised for these factors.

Nineteen wells have been drilled in the basin, but data is relatively sparse for an area of about 12 million acres. In addition, much of the primary data has not been readily available to SAOGC for this study.

The discussion which follows is based on the primary source rock maturation investigations of Kantsler and others (1978) and Nicholas and others (1981). It was considered that a complete re-evaluation of the heat flow data was required. That work has been integrated with all of the above information (via Lopatin Time-Temperature Maturation Plots) into a preliminary regional assessment of the hydrocarbon generative potential of the basin.

5.2 HYDROCARBON GENERATIVE POTENTIAL

5.2.1 Source Rock Richness

Nicholas and others (1981) analysed 27 core samples from the basin, including the Otway Group. The highest recorded value is 20.1 percent TOC in the EVCM (coals excluded) with an average of 3.51 percent overall. The average for the EVCM is 4.0 percent T.O.C. All stratigraphic intervals (Torquay Group, Demons Bluff Formation, EVCM and the Otway Group) contain greater than 0.5 percent T.O.C. and can be considered as potential source rocks.

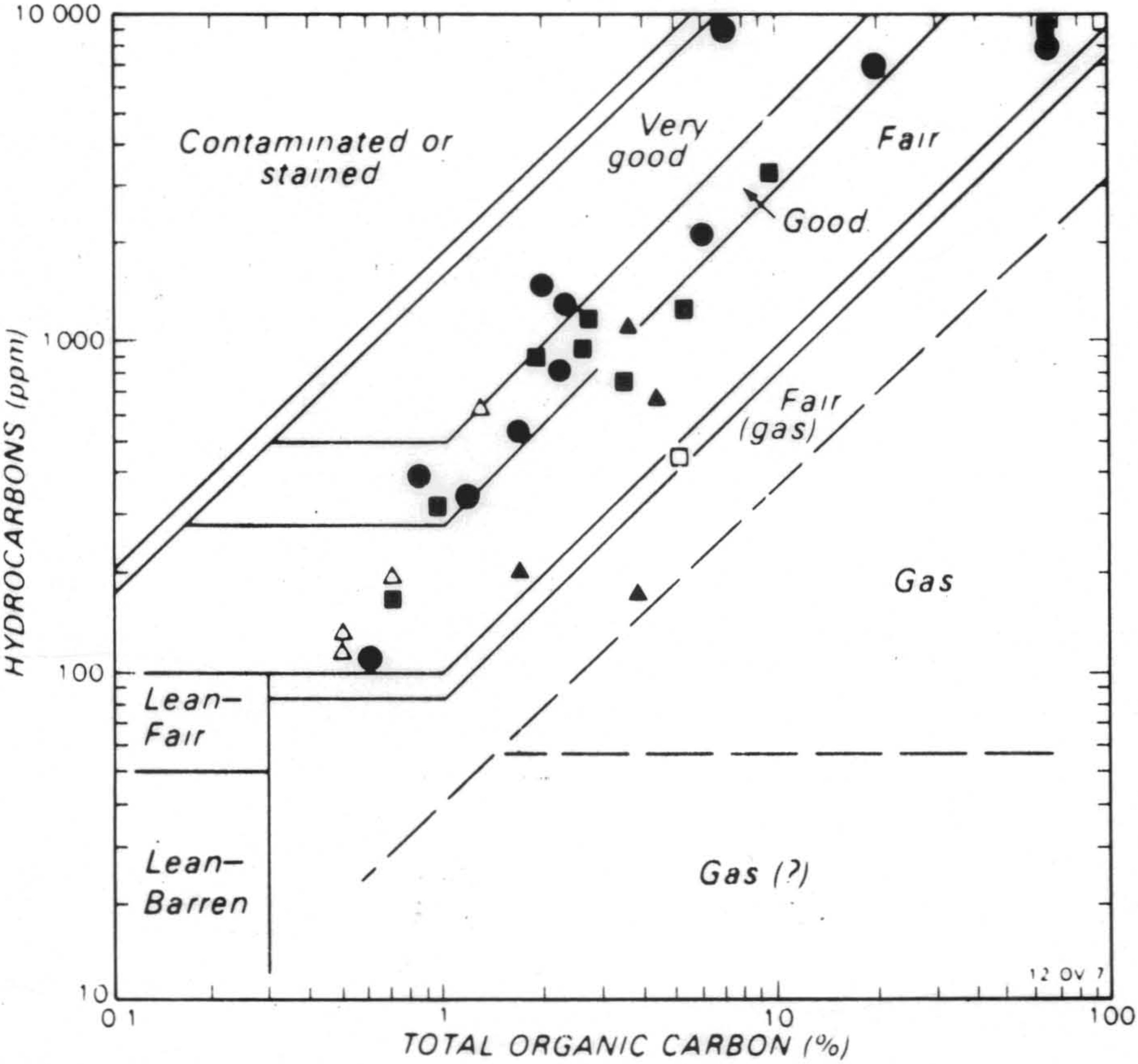
Based on the samples studied, the EVCM (below the Lower *M. diversus* zone) are ranked as good to very good source rocks whilst the EVCM above the *M. diversus* Unconformity are ranked as fair to good source rocks.

A cross-plot of total hydrocarbon content against total organic carbon content shows the overall source rock quality of measured formation samples (See Figure 5.1).

5.2.2 Source Rock Quality

Different source rock types are prone to produce different hydrocarbons. Table 5.2 simplifies the general conclusions of Nicholas and others (1981) concerning the type of hydrocarbons which would be produced by each formation.

636083



△ Torquay Group
□ Demons Bluff Formation
■ 'Upper' Eastern View Coal Measures
● 'Lower' Eastern View Coal Measures
▲ Otway Group

5 cm

(Modified after Nicholas et. al. 1981)

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN SOURCE ROCK RICHNESS		
INT. L.S.	DATE.MAR. 84	BASOO.3319
DRN: B.D.W.	Sc.AS SHOWN	FIG. 5.1

TABLE 5.1: INTERPRETED HYDROCARBON (OIL OR GAS) SOURCE TYPE

Formation	Source Potential	Source Type	RO
Torquay Group	Fair	Oil and Gas	Immature
Demons Bluff Fm	Fair	Oil and Gas	Immature
U. E.V.C.M.	Fair-Good	Gas and Oil	Marginal
L. E.V.C.M.	Good-V.Good	Gas, some Oil	Mature
Otway Group	Fair-Good	Gas	Mature

TABLE 5.2 ESTIMATED PRESENT DAY TEMPERATURE GRADIENT

WELL	$^{o}C/km.$ This author (X^{i})	Nicholas & Others 1981	z^{i}	ESTIMATE RELIABILITY
AROO-1	39.1	30.7	0.21	GOOD
BASS-1	42.0	34.7	1.05	POOR
2	41.1	31.8	0.80	POOR
3	41.5	34.1	0.90	POOR
CORMORANT-1	41.5	30.6*	0.90	POOR
DONDU-1	40.1	41.7*	0.51	FAIR
DURROON-1	36.1	28.4*	-0.68	GOOD
KONKON-1	42.0	46.2*	1.05	POOR
NANGKERO-1	32.5	30.6*	-1.72	FAIR
NARIMBA-1	38.6	34.0	0.06	GOOD
PELICAN-1	35.7	32.5*	-0.78	FAIR
2	33.4	26.7*	-1.47	POOR
3	32.2	28	-1.82	FAIR
4	40.5	NA	0.60	GOOD
PIPIPA-1	41.0	NA	0.74	FAIR
POONBOON-1	34.9	27	-1.03	FAIR
TAROOK-1	40.1	30.6*	0.51	FAIR
TOOLKA-1	35.7	34.6*	-0.78	FAIR
YURONGI-1	41.6	40.6*	0.93	GOOD
MEAN ($\bar{x}$)	38.4	33.1		X
S.D. (s)	3.4	5.4		

$z_i = (X_i - \bar{X})/S$

ESTIMATED SURFACE TEMPERATURE = $40^{o}F = 4.44^{o}C$.

NA = Not available

* = Extrapolated from Horner plot method.

5.2.3 Discussion

In the different stratigraphic intervals, source rock quantity and type directly reflect the depositional environment. The Otway Group is believed to be entirely a continental depositional system. The EVCM are predominantly continental, but with marine ingressions of increasing frequency through time in the north. The Demons Bluff and Torquay Group are totally marine. Likewise, the general trend of source type through time is from gas prone, typical of continental sediments, to more oil prone, typical of marine sediments. The system has also evolved from a predominantly sandstone/siltstone dominated clastic system in the Otway Group, through to a shale dominated system during Demons Bluff Formation deposition. Hence, as a general feature, the relative quantity of oil prone source rock per unit of section has increased through time.

5.3 MATURATION

5.3.1 Introduction

The degree of maturation of a section can be estimated by a variety of methods, either by direct measurement,e.g. vitrinite reflectance, or by modelling, e.g. Lopatin Time Temperature Maturation Plots. The application of these techniques is discussed in the following sections.

5.3.2 <u>Vitrinite Reflectance and Thermal Alteration Index</u>

Tissot and Welte (1978, p. 451) make the following correlation of vitrinite reflectance (R_O) with source rock maturity, emphasising that there are no definite rules and that the general scheme should be fine-tuned to a particular basin.

(i) R_O < 0.5 to 0.7%: diagenesis stage, source rock is immature,

(ii) 0.5 to 0.7% < R_O < 1.3%: catagenesis stage, main zone of oil generation, also referred to as the "oil window",

(iii) 1.3% < R_O < 2%: catagenesis stage, zone of wet gas and condensate,

(iv) R_O > 2%: metagenesis stage; methane remains as the only hydrocarbon (dry gas zone).

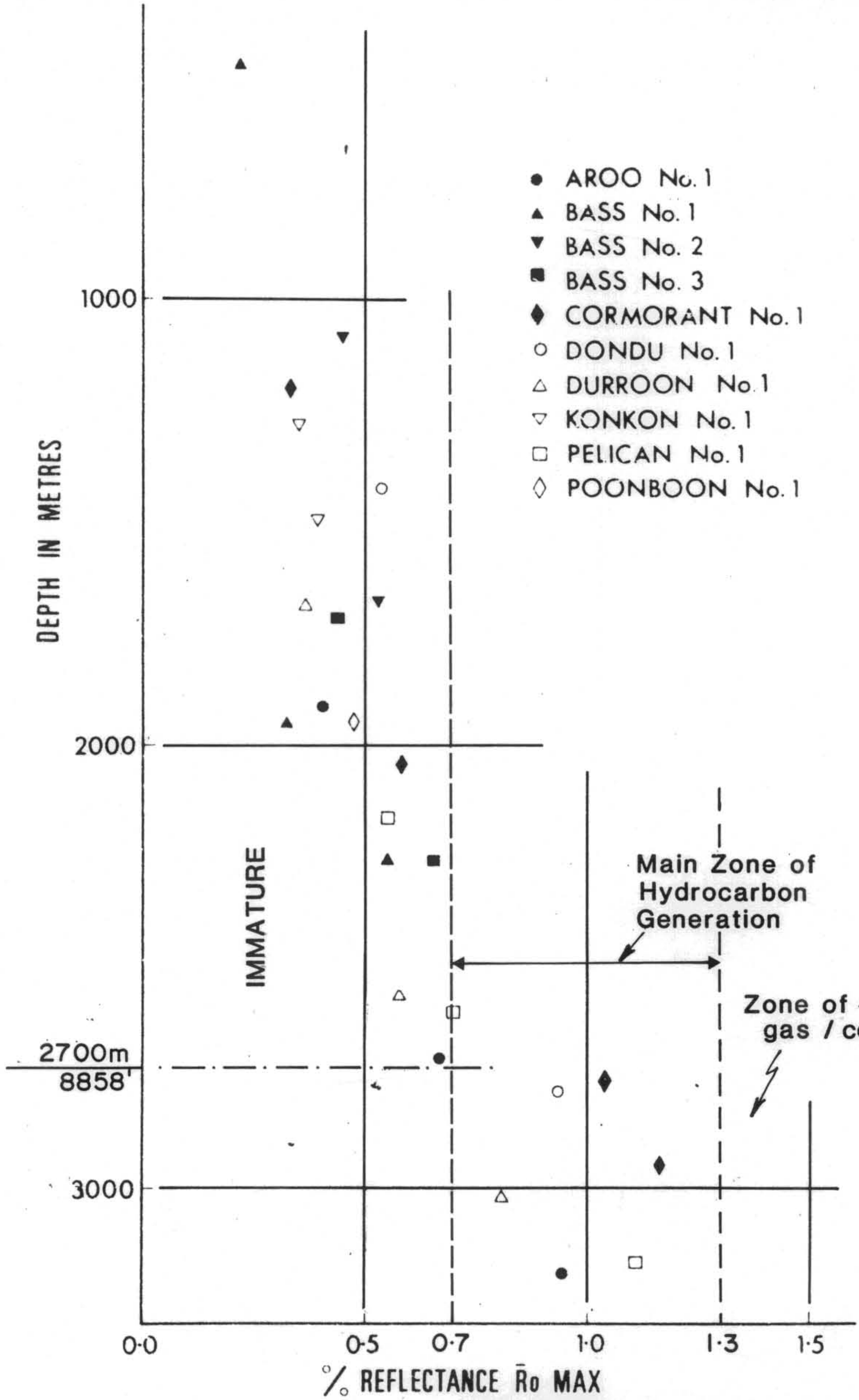
R_O values from 0.36 - 1.2% have been obtained from the Bass Basin. In general all units above the lower EVCM have R_O values indicating immaturity. However the lower EVCM have reached marginal maturity, a result consistent with independent spore/pollen thermal alteration index studies. This marginal maturity is reached only in deeper levels of the Bass Basin. Figure 5.2 modified from Nicholas and others (1981) summarises the vitrinite reflectance data.

5.3.3. <u>Geothermal Gradient Review</u>

(i) <u>General Heat Flow Data</u>

The following data from Tissot and Welte (1978, p. 512-518) is relevant to the general geological evolution of the Bass

636088



5 cm

(After Nicholas et. al. 1981)

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN RELATIONSHIP BETWEEN VITRINITE REFLECTANCE (% R̄ max) AND DEPTH IN BASS BASIN WELLS		
INT. L.S.	DATE. MAR.84	BASOO.3320
DRN: B.D.W.	Sc.AS SHOWN	FIG.5.2

Basin.

Highest present day heat flows occur over mid-oceanic ridge crests and in rift valley grabens with up to 8 Heat Flow Units (HFU see equation (1) below) and average values of 4 HFU. This is 2 to 3 times the average heat flow of stable areas. It has been established that heat flow drops to < 3.0 HFU within 150km of the rift centre. This equates to a rapid drop in heat flow within 5 MMY following plate separation and to 1.28 HFU within 15-20 MMY. Most basins do not drop as low as 1.28 HFU, which is a characteristic of mid-oceanic basins. The average is higher at 1.9 HFU. It is emphasised that in areas of Tertiary volcanics, higher values of 2.2 HFU are common.

The geothermal gradient at any location is given by:

$$G = \Phi\xi \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where Φ = heat flow(1 micro cal cm^{-2} sec^{-1})
= 1 Heat Flow unit
= HFU
ξ = thermal conductivity
G = Geothermal gradient $^{o}C/km$

It should be noted that both coal and shale have relatively low thermal conductivity compared with sandstone. The thermal conductivity of volcanics and intrusives can range from poor to very poor. Porous but low permeability tuffs can act as thermal blankets. Overpressured sections also tend to act as areas of low thermal conductivity.

(ii) Method of Estimation of Present Geothermal Gradient

Lopatin Time Temperature Maturation Plots (LTTMP) require input of the best available data on the present temperature gradient. SAOGC uses a new method for estimating static formation temperature from bore hole temperature data and since maturation history depends strongly on temperature history, it was important to thoroughly reappraise the temperature data.

Several methods of estimating the true static formation temperature from time sequentially collected bore hole temperature measurements are available. The most common method is the Horner plot which requires knowledge of the time spent circulating the bore hole fluids prior to running the temperature logs. This method was used by Nicholas and others (1981 p. 208). Unfortunately the raw data required to accurately use this method is rarely considered worthy of systematic or reliable operational procedures, since temperature measurement is secondary to the prime aim of well logging. In the Bass Basin, temperature data is invariably incomplete or inconsistantly reported, so only a small percentage of the available data can be used. In particular, knowledge of the time spent circulating prior to logging is difficult to ascertain from either the log headers or from the well completion reports available to SAOGC.

To partly overcome this problem, SAOGC has used the method described by Middleton (1979) and modified by Leblanc and others (1982). This method has the advantage that the circulation time prior to logging need not be known.

The static formation temperature estimates derived from the available data have been ranked into GOOD/FAIR/POOR categories, generally on the basis of the number of data points available for calculation, as follows:

1-2 POOR

2-3 FAIR

> 3 or other additional information GOOD

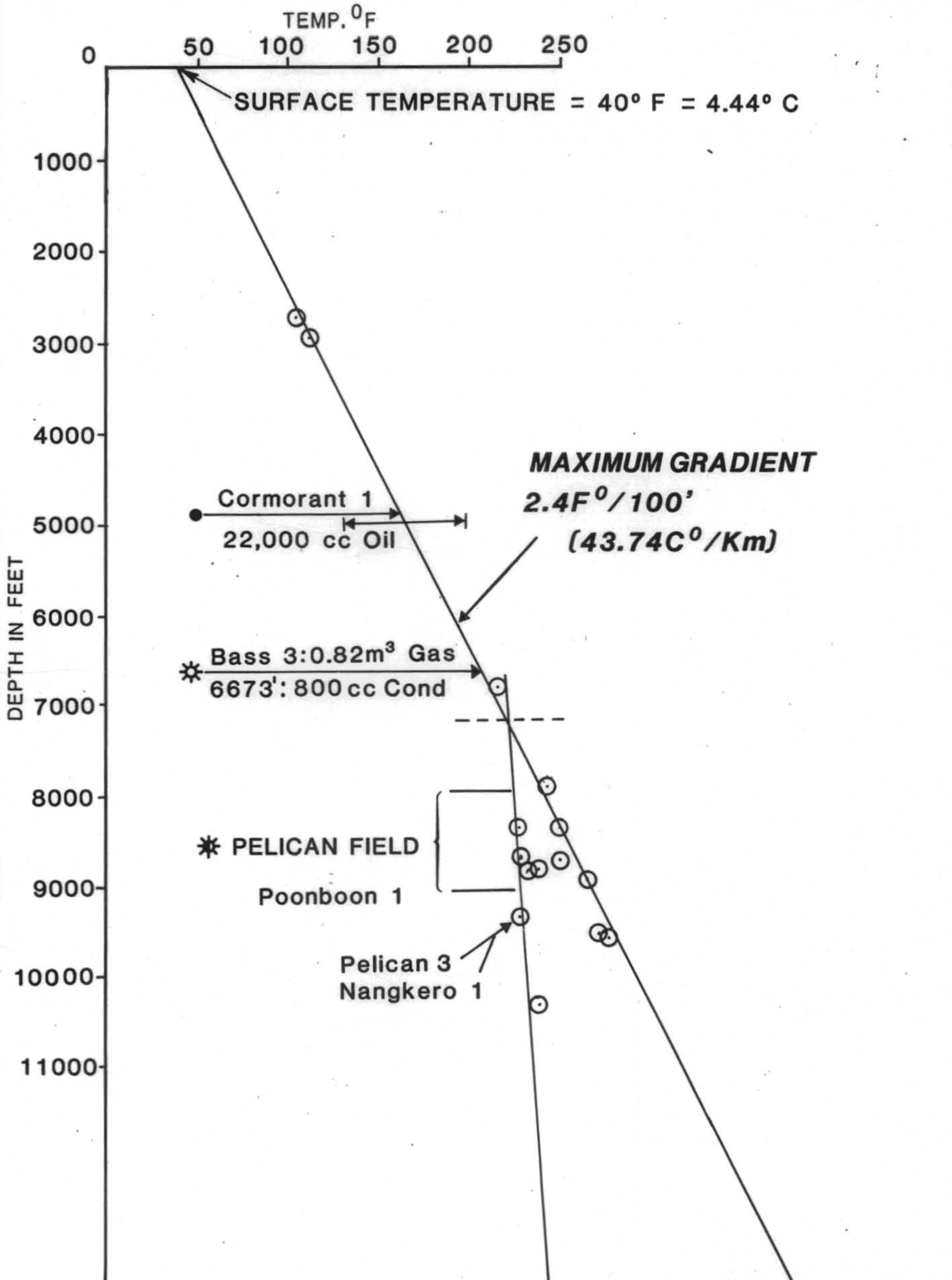
The results are tabulated in Table 5.2.

(iii)Discussion of Results

The data is of poor quality overall and the extrapolated temperatures can only be as reliable as the input data. A plot of all estimated static formation temperatures is given in Figure 5.3. This graph suggests a mean annual surface temperature of 40°F (4.44°C) and this value has been used in estimating the gradient. Nicholas and others (1981) do not specify which surface temperature they assumed, and this could have a bearing on their calculated gradient.

The new results indicate an average increase of 5°C/km in the estimated gradients over those calculated by Nicholas and others (1981) (see Table 5.2). The composite plot tends to suggest that there is a distinct break in gradient with depth, at least in some parts of the basin. However, in view of the quality of the initial data, it is also likely that these results represent underestimations of the actual gradient (see Table 5.2 and Figure 5.3).

The data group form a single normal distribution which



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN PLOT OF ESTIMATED STATIC FORMATION TEMPERATURE Vs SUBSEA DEPTH FOR ALL BASS BASIN WELLS		
INT. L.S.	DATE. MAR.84	BASOO.3321
DRN: B.D.W.	Sc. AS SHOWN	FIG. 5.3

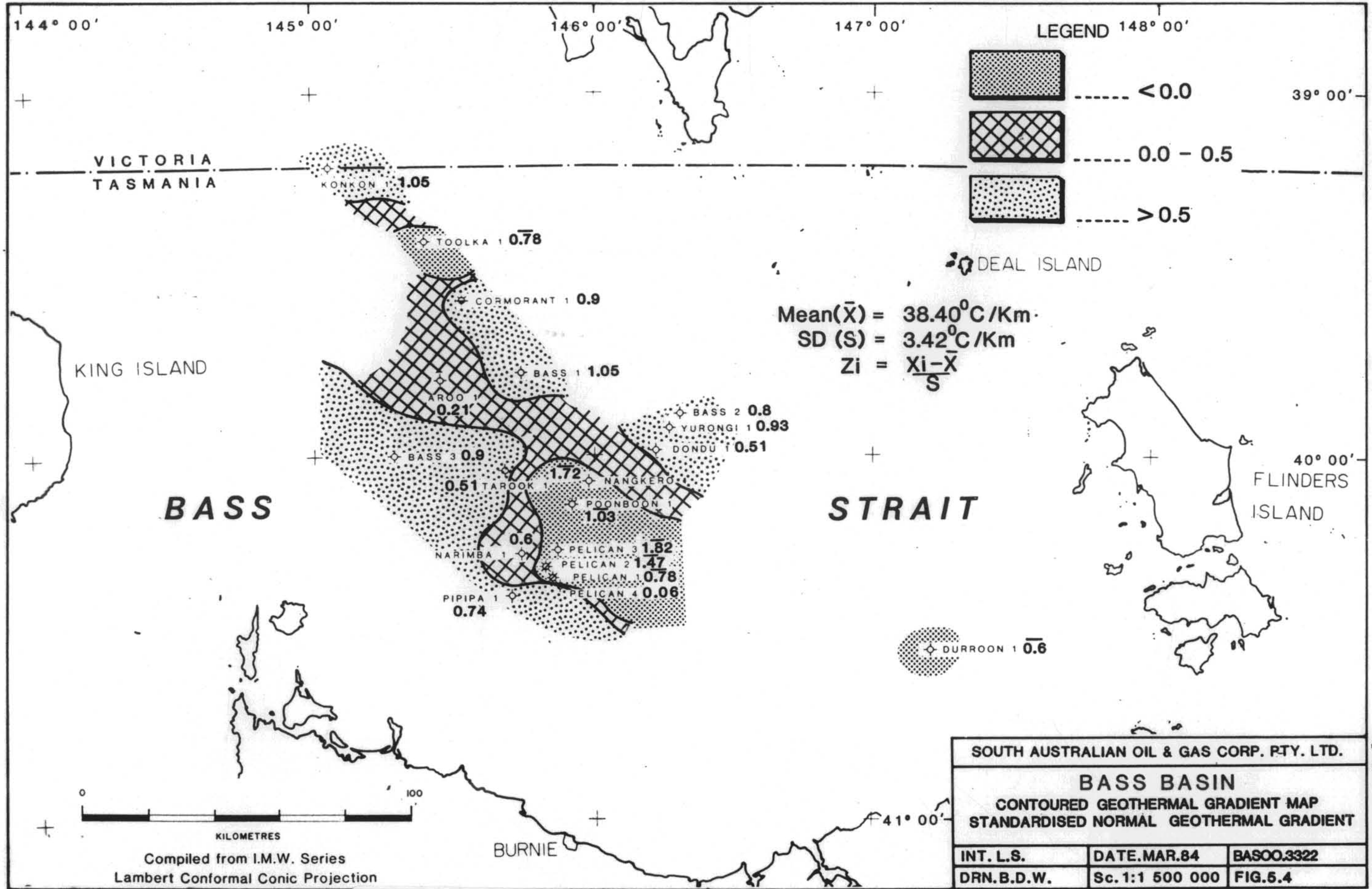
can be analysed with simple statistics. As shown on Table 5.2 the gradient has a mean of 38.4°C/km and a standard deviation of 3.4°C/km. No well has a temperature gradient which is in excess of 2 standard deviations from the mean. This latter value is a rule of thumb for detecting possibly anomalous values within a normal population. Although no anomalous values are found this does not mean that there is no real spatial variation in the gradient within the Bass Basin. However the above results, when taken in conjunction with the low quality of the original data, imply that any interpretations of contoured data should be treated with a high degree of caution. Results have been contoured as standardised normal values, Z_i, and the contouring interval is in units of standard deviations from the mean value (see Figures 5.4 & 5.6).

In summary, the results are consistent with a linear gradient throughout the basin, up to a maximum 43.74°C/ km, at least within the post Otway Group sediments.

(iv) Interpretation of Results

It is possible to provide at least three conceptual models to account for the spatial variations of the temperature gradients:

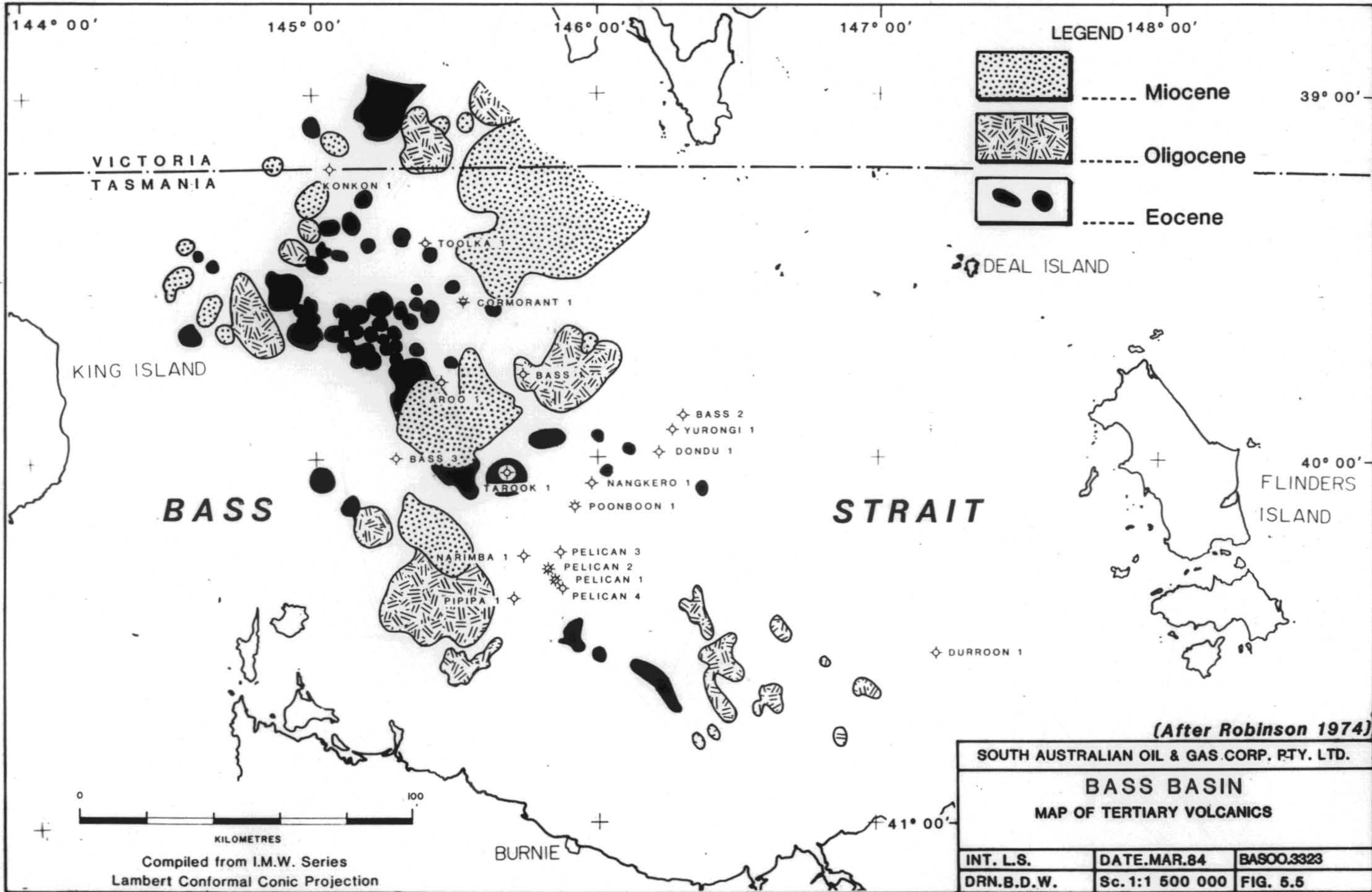
1) The first model is that of Kantsler and others (1978) which shows that gradients in the Bass Basin tend to be relatively lower in the deeper parts of the basin and higher on the flanks, the northeast flank being higher than the southwest flank. It is noted here that the proposed cooler gradient



144° 00'
145° 00'
146° 00'
147° 00'
148° 00'
39° 00'
40° 00'
41° 00'
LEGEND
<0.0
0.0 - 0.5
>0.5
VICTORIA
TASMANIA
KONKON 1 1.05
TOOLKA 1 0.78
CORMORANT 1 0.9
BASS 1 1.05
AROO 1 0.21
BASS 2 0.8
YURONGI 1 0.93
DONDU 1 0.51
BASS 3 0.9
0.51 TAROOK 1
1.72 NANGKERO
POONBOON 1 1.03
0.6 NARIMBA 1
PELICAN 3 1.82
PELICAN 2 1.47
PELICAN 1 0.78
PELICAN 4 0.06
PIPIPA 1 0.74
DURROON 1 0.6
DEAL ISLAND
KING ISLAND
FLINDERS ISLAND
BASS
STRAIT
BURNIE
Mean($\bar{X}$) = 38.40^{0}C /Km
SD (S) = 3.42^{0}C /Km
Zi = $\frac{Xi-\bar{X}}{S}$
0
100
KILOMETRES
Compiled from I.M.W. Series
Lambert Conformal Conic Projection
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
CONTOURED GEOTHERMAL GRADIENT MAP
STANDARDISED NORMAL GEOTHERMAL GRADIENT
INT. L.S.
DATE.MAR.84
BASOO.3322
DRN.B.D.W.
Sc. 1:1 500 000
FIG.5.4

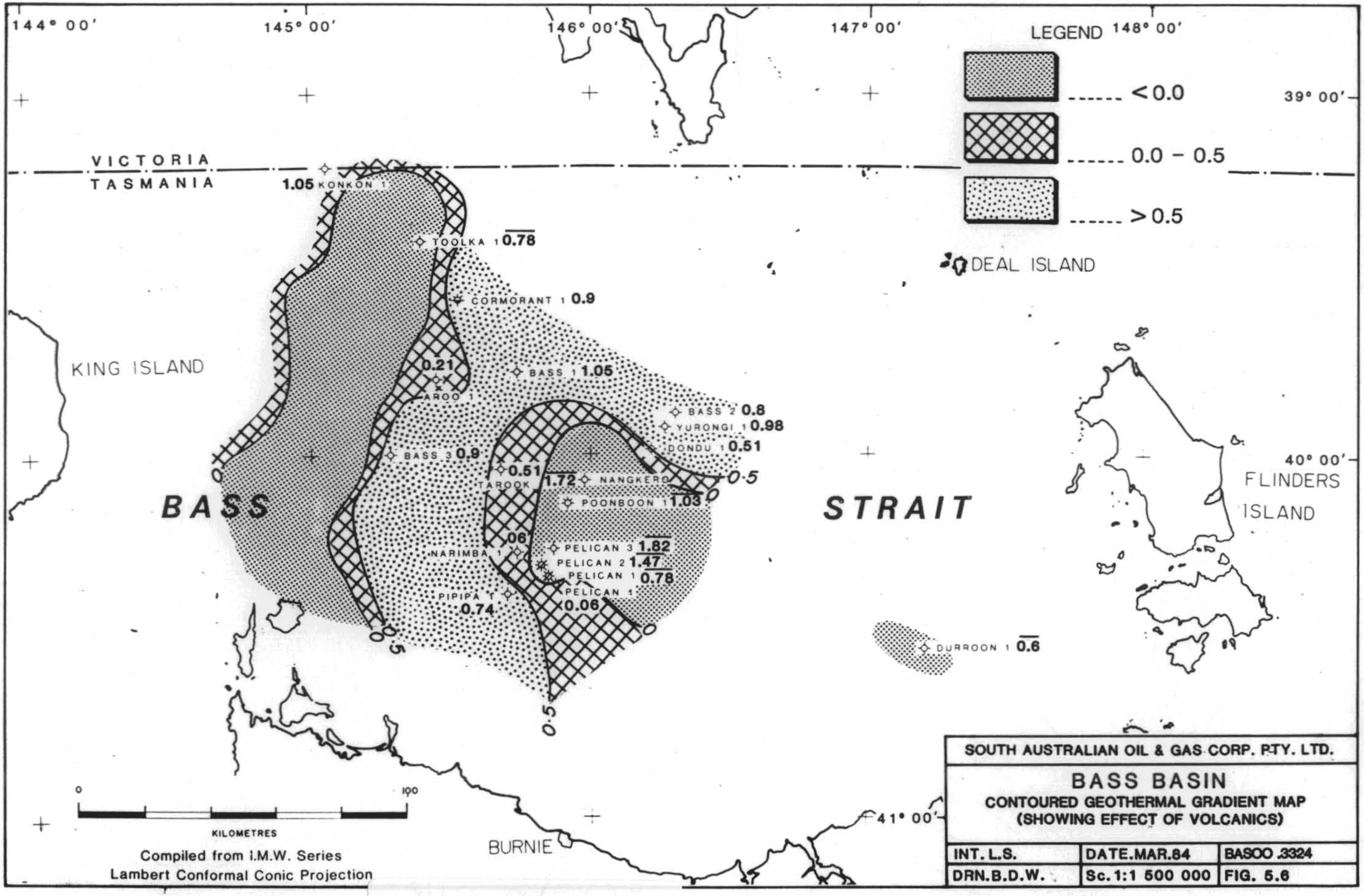
63609 4

5 cm


144° 00'
145° 00'
146° 00'
147° 00'
148° 00'
39° 00'
40° 00'
41° 00'
LEGEND
Miocene
Oligocene
Eocene
VICTORIA
TASMANIA
KONKON 1
TOOLKA 1
CORMORANT 1
KING ISLAND
BASS 1
AROO 1
BASS 2
YURONGI 1
DONDU 1
BASS 3
TAROOK 1
NANGKERO 1
POONBOON 1
BASS
STRAIT
DEAL ISLAND
FLINDERS ISLAND
NARIMBA 1
PELICAN 3
PELICAN 2
PELICAN 1
PELICAN 4
PIPIPA 1
DURROON 1
BURNIE
0
100
KILOMETRES
Compiled from I.M.W. Series
Lambert Conformal Conic Projection
(After Robinson 1974)
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
MAP OF TERTIARY VOLCANICS
INT. L.S.
DATE.MAR.84
BASOO.3323
DRN.B.D.W.
Sc. 1:1 500 000
FIG. 5.5

5 cm

636095



144° 00'
145° 00'
146° 00'
147° 00'
148° 00'
39° 00'
40° 00'
41° 00'
LEGEND
<0.0
0.0 – 0.5
>0.5
VICTORIA
TASMANIA
1.05 KONKON 1
TOOLKA 1 0.78
CORMORANT 1 0.9
0.21
AROO 1
BASS 1 1.05
BASS 2 0.8
YURONGI 1 0.98
DONDU 1 0.51
BASS 3 0.9
0.51
TAROOK
1.72 NANGKERO
POONBOON 1 1.03
.06
PELICAN 3 1.82
PELICAN 2 1.47
PELICAN 1 0.78
PELICAN 1
0.06
NARIMBA 1
PIPIPA 1
0.74
DURROON 1 0.6
DEAL ISLAND
KING ISLAND
FLINDERS ISLAND
BASS
STRAIT
BURNIE
0
0.5
0
100
KILOMETRES
Compiled from I.M.W. Series
Lambert Conformal Conic Projection
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
CONTOURED GEOTHERMAL GRADIENT MAP
(SHOWING EFFECT OF VOLCANICS)
INT. L.S.
DATE.MAR.84
BASOO .3324
DRN.B.D.W.
Sc. 1:1 500 000
FIG. 5.6

5 cm

on the southeastern flank could be simply a function of the distribution of the data points (see figure 5.4).

2) The second model relies on data estimate inaccuracies and localised phenomena to explain the variations seen. The disposition of faulting and pay within the Pelican Field suggests that the gas accumulations may be the result of vertical migration. The expansion of gas as it migrates vertically may cause a local decrease in the temperature gradient.

None of the lower gradients over Pelican field area are ranked as good estimates (see Table 5.2). Further, there is difficulty in establishing an explanation of why Pelican 4 (GOOD ESTIMATE OF RELIABILITY) has a gradient of 40.47^{o}C/km only a few kilometers away from Pelican 1 (FAIR ESTIMATE OF RELIABILITY) with a gradient of 35.73^{o}C/km. It is possible that all the wells in the apparently cooler area may have temperature gradients higher than calculated and similarly quite a few of the wells in the apparently hotter zones may be overestimates due to measurement reliability.

Also, Pelican Field is over an overpressured zone, which normally reduces thermal conductivity.

Considering data reliability, the basin can be modelled as having a moderately cooler northwest trending deeper zone, and flanked to the southwest, northeast and north west by slightly higher gradients.

(3) The data can also be contoured to reflect the major north

south trend of Oligocene-Miocene volcanics which extend from south of Pipipa 1 to north of Cormorant 1 in a belt 20-30 kilometres wide (See Figure 5.5). Such volcanics may be evidence for a thin lithosphere above a thermally domed mantle. In addition, the tuffs and flows may act as thermal blankets, as they have lower thermal conductivities than surrounding adjacent sediments, hence, both effects may act to increase the local temperature gradient for the EVCM.

It may be postulated that the area of maximum volcanic activity is likely to coincide with the area of maximum intrusive activity. In Cormorant 1, 248' of syenite was intersected and in the Toolka 1 well, 345' were penetrated. These intrusive intersections may possibly indicate a single, laterally continuous body. A thermal pulse associated with such an event probably would have a significant effect on local maturation.

The above distribution in time and space of volcanic activity leads to the following model.

a) surface temperature is 4.44°C.

b) In the basin centre the temperature gradient is approximately 37°C/km rising along the north-eastern and southwestern flanks to values in the vicinity of 40-41°C/km.

c) In parts of the northwestern end of the basin igneous intrusive and extrusive events may have been significant in terms of both heat input and thermal blanketing. In these areas, in particular a 25 kilometre wide belt running N-S from Cormorant 1 to Pipipa 1, the temperature gradient is elevated above the basin average, possibly up to 43^{o}C/km (see Figure 5.6).

d) Paleoheat flow (and hence geothermal gradient) is most likely to have been higher in the past, particularly immediately prior to Australia/Antarctica breakup at approximately 97.5 MMYBP.(Cande and Mutter,1982).

5.4 BURIAL HISTORY: LOPATIN TIME-TEMPERATURE MATURATION PLOTS

5.4.1 Introduction

The construction of Lopatin Time Temperature Maturation Plots (LTTMP), or geohistory analysis models, is discussed fully in Waples (1981, p. 95-106). Waples Table 8.3 (p. 102) is reproduced here (Table 5.3) to illustrate the range of Time-Temperature Index (T.T.I.) values versus hydrocarbon generation and preservation. Advanced techniques of generating Lopatin diagrams are described by Falvey and Deighton (1982).

Three wells were chosen for initial geohistory analysis: Pelican 1, Narimba 1 and Cormorant 1. Pelican 1 was chosen because of its association with a known gas field, Narimba 1 as an adjacent but dry well and Cormorant 1 because it has the

TABLE 5.3 CORRELATION OF TTI WITH SEVERAL IMPORTANT STAGES OF OIL GENERATION AND PRESERVATION

Stage	TTI	Ro	TAI
Onset of oil generation	15	0.65	2.65
Peak oil generation	75	1.00	2.9
End of oil generation	160	1.30	3.2
Upper TTI limit for occurrence of oil with API gravity 40°	500	1.75	3.6
Upper TTI limit for occurrence of oil with API gravity 50°	1,000	2.0	3.7
Upper TTI limit for occurrence of wet gas	1,500	2.2	3.75
Last known occurrence of dry gas	65,000	-	-
Liquid Sulfur in Lone Star Baden #1 (Below dry gas limit)	972,000	5.0	4.0

only oil recovery in the basin. Also, Cormorant 1 intersected 248' of a late Tertiary igneous intrusive and the possible effects of this on maturity required modelling.

Few wells have penetrated the upper Cretaceous section, and only one has intersected the Otway Group. Hence the earliest (pre-Tertiary) basin history remains highly speculative within a framework that deposition probably commenced no earlier than the upper Jurassic (160 MMYBP).

Geohistory models for a frontier area can be extremely simple or become more complex when more variables are included. The available data limits the accuracy of geohistory analysis for the Bass Basin. For example, variables such as sea level change and compaction have not been incorporated. The models produced here should be used as a guide only.

5.4.2 Paleotemperature Model

As previously discussed (5.3.2), one of the major potential sources of error in geohistory analysis is in estimating the paleotemperature history. The models presented here are considered as preliminary and experimental. The following simplified and general geological model is assumed as a basis for paleotemperature gradients.

(a) Break up of the Australian/Antarctic plates occurred between 90-110 MMYBP (taken for convenience at 97.5 MMYBP, which is the Upper Cretaceous-Lower Cretaceous boundary). At this time the paleolatitude was high and the surface temperature is therefore assumed to be zero.

(b) At least 50 MMY before breakup, thermal doming and rifting occurred. It was under these conditions that the Otway Group was deposited. During this period high heat flows are expected. A high heat flow value of 65^{o}C/km, estimated from high Cooper Basin gradients, was used to model pre-breakup conditions. This gradient may require refinement in future detailed modelling.

In the Otway Basin at least 11,000' of Otway Group sediments have been deposited locally. Preserved thickness in the Bass Basin is uncertain, but possibly of the same magnitude. Two models of possible Otway Group burial history have been generated to test how tectonic evolution might affect the Otway Group's maturation history. As the boundary between the overlying EVCM and the Otway Group is an unconformity, only the TTI values for the unconformity surface need be calculated. In the first model, at Pelican 1, the break-up unconformity was buried to approximately 2000' at 120 MMYBP then uplifted and eroded between 120 MMYBP and 97.5 MMYBP. In the Narimba 1 model, the depth of burial was increased to 5500' prior to uplift and erosion to provide a contrast to Pelican 1. An examination of the diagrams (see Figures 5.7 & 5.8) shows the effect to be slight

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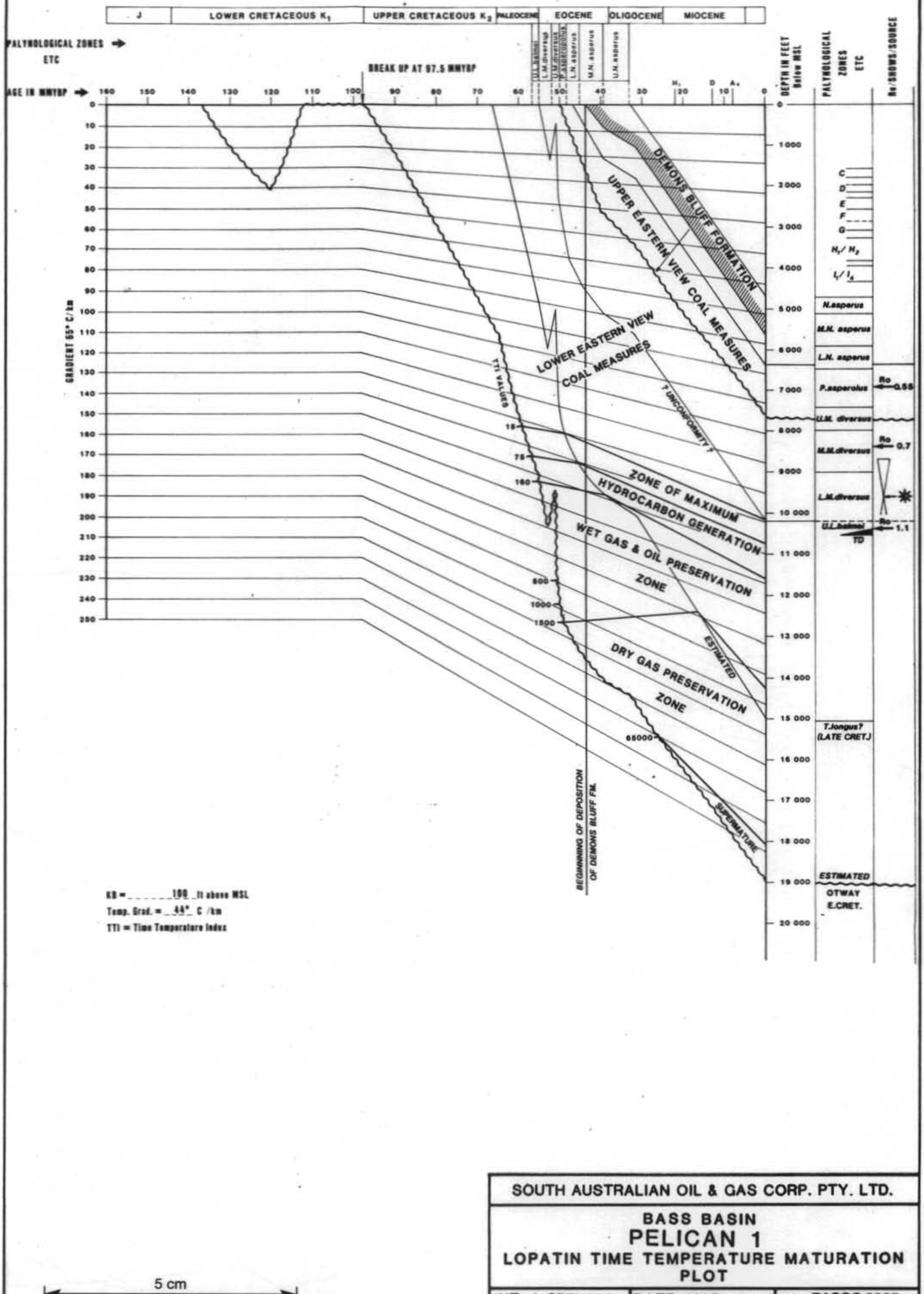
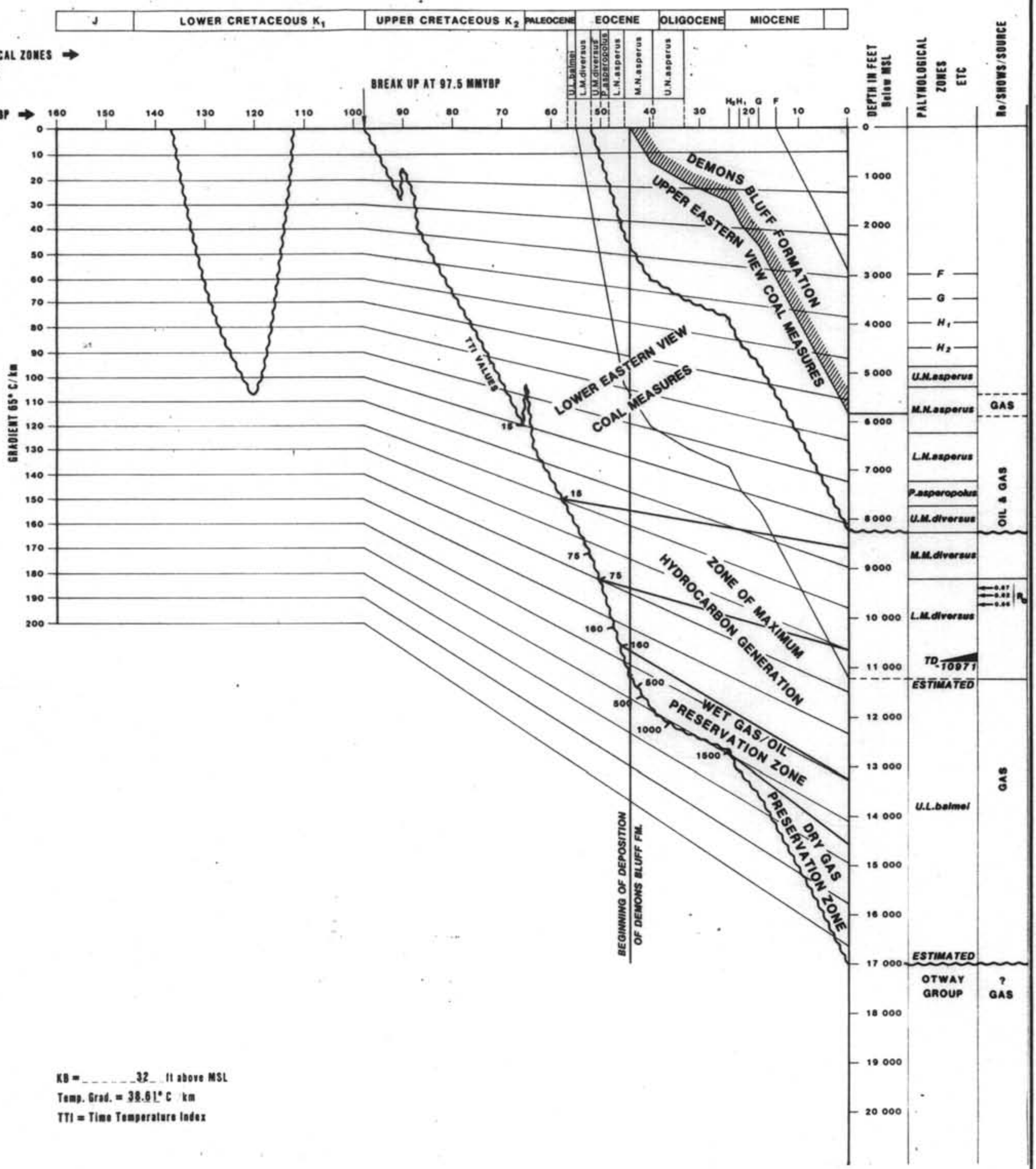


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN
PELICAN 1
LOPATIN TIME TEMPERATURE MATURATION PLOT

INT: L.SPENCER	DATE: MAR. 84	NO: BASOO.3325
DRN: J.D	SC: AS SHOWN	FIG: 5.7

636104



5 cm

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN NARIMBA 1 LOPATIN TIME TEMPERATURE MATURATION PLOT		
INT: L.SPENCER	DATE: MAR. 84	NO: BASOO.3326
DRN: J.D	SC: AS SHOWN	FIG: 5.8

on final results. It is apparent that significant generation of hydrocarbons only occurs, within the constraints of these models, once the sediments have spent considerable time at temperatures in excess of 110°C.

(c) The remainder of the temperature history input has been simplified. It is assumed that the post break up (97.5 MMYBP) temperature gradient fell linearly to the present values.

Although a rapid drop in temperature gradient normally occurs within 5 MMY of break-up, the Bass Basin differs sufficiently from other Australian southern margin basins to warrant this simplification.

Sufficient palynological control is available to allow post Lower Cretaceous burial history to be plotted with a reasonable level of confidence.

(d) To assess the heating effect that may result from intrusive activity a thermal pulse, modelled as a post intrusive maintenance of higher thermal gradient, was incorporated into the Cormorant 1 model (see Figure 5.9).

5.4.3 <u>Details of Lopatin Time Temperature Maturation Plots</u>

(a) <u>Pelican 1</u> (Figure 5.7)

The plot indicates that for the upper Otway Group peak hydrocarbon generation took place during the Paleocene. As the Otway Group has a source rock which is considered to be gas prone, requiring slightly higher temperatures for rock peak generation, actual peak generation may have occurred slightly later than noted values. Maturation was complete, or well advanced, prior to the M. diversus unconformity. The Otway Group appears to be supermature. Any hydrocarbons generated within the Otway Group sediments require migration, either laterally into the basins cooler flanks or vertically into the overlying sediments, to be preserved.

The entire lowermost EVCM, (pre-Lower M. diversus) is presently within the generative-preservation TTI zone. It is worth noting that the Pelican field gas-condensate accumulation occurs immediately above the mature section. Pelican wells reached total depth prior to entering this zone.

(b) Narimba 1 (See Figure 5.8)

In this model the upper Otway Group was buried to 5500' with a higher geothermal gradient prior to uplift and erosion. Compared to the Pelican 1 model it can be seen that this has two effects. The time interval of generation is expanded and onset of maturation is earlier. However, the TTI values on both sides of the break-up unconformity are comparable to those calculated in the Pelican 1 model. The present day upper Otway Group is in the dry gas preservation zone.

The maturation plot of the EVCM at Narimba 1 is similar to the maturation plot of these sediments in Pelican 1. Note, Narimba 1 also reached total depth prior to reaching the zone of maximum hydrocarbon generation (TTI = 75).

(c) Cormorant 1 (See Figure 5.9)

As for Pelican 1 and Narimba 1 the Otway Group sediments are supermature.

The maturation plot of the lower EVCM is similar to the maturation plot of those sediments in Narimba 1 and Pelican 1 and fall in the zone of hydrocarbon generation-preservation.

Cormorant 1 was used as a model for examining the potential influence of intrusives on thermal maturation. The model assumes that the intrusive will decrease the rate of thermal cooling between the pre-breakup gradient and present day gradient. Cormorant 1 is the only well studied in which the source rock data (Nicholas and others, 1981) suggests that the lower EVCM are both oil and gas prone rather than gas prone only. The thermal effect of the thick intrusive may have marginally maturated the upper EVCM. These sediments are also oil and gas prone. The oil recovered from Cormorant 1, 22° API gravity and probably derived from continental source material (Aquing 1980 p73), may have migrated vertically from an earlier mature source. However, this recovery of heavy oil could also be a characteristic of very early generation. As this oil recovery overlies a good oil prone source rock this latter explanation is favoured.

5.4.4 Discussion of Results

If the Otway Group had an early high thermal event, as proposed, then over most of the basin the lower Otway Group

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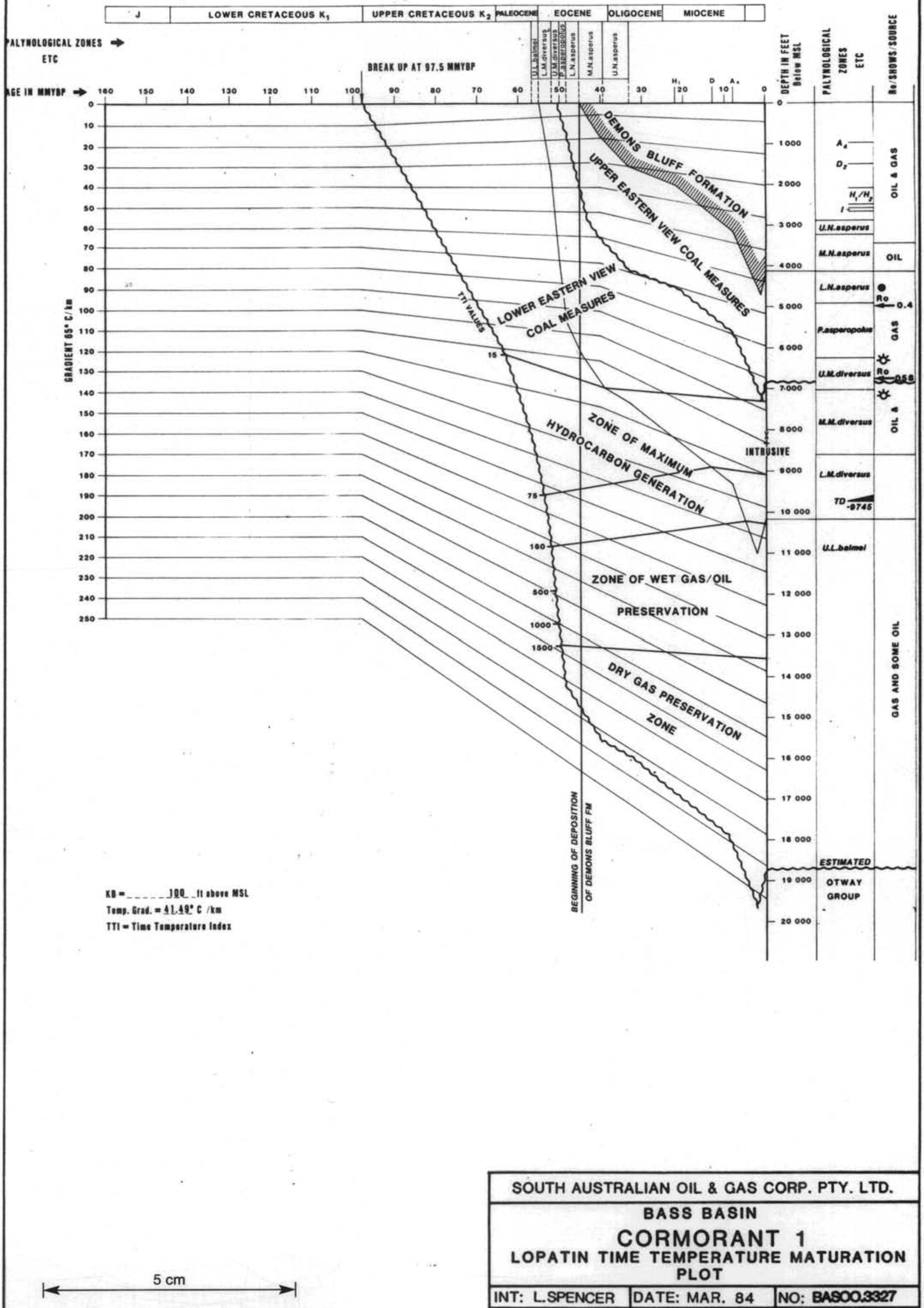

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN

CORMORANT 1

LOPATIN TIME TEMPERATURE MATURATION PLOT

INT: L.SPENCER	DATE: MAR. 84	NO: BASOO.3327
DRN: J.D	SC: AS SHOWN	FIG: 5.9

will be super-mature and hydrocarbon generation would have ceased in the middle Eocene prior to deposition of the Demons Bluff Formation.

The present model illustrates that at the modelled sites the Otway Group is overmature and cannot be considered a target at any depth in excess of 17-18,000' BMSL.

Finally it is noted that in Pelican 1, 5000' feet of gas prone source rock of lower EVCM age entered the maturation/preservation zone following deposition of the regional shale seal, ie. the Demons Bluff Formation. The corresponding figures are 3,000' and 2,500' for Narimba 1 and Cormorant 1 respectively.

5.4.5. Requirements of Basin Wide Maturation Study

1. In future wells a serious attempt should be made to collect valid, interpretable temperature data to enable a static formation temperature profile from surface to T.D to be determined. This could be accomplished by running three or four temperature survey logs at different times in a well. This information would be extrapolated to obtain a static formation temperature profile. One reliable set of temperature data would aid in assessing the reliability of the data already collected.

2. A study needs to be carried out to ascertain the impact of intrusives on heat flow, both regionally and locally.

Information gained should then be integrated into maturation levels via maturation modelling. Radiometric age dating of any intrusives intersected would then be necessary for input into thermal maturation models.

3. If the study outlined in recommendation 2 results in the identification of specific maturation anomalies associated with intrusives then geophysical detection of intrusives would be important. Seismic acquisition and processing may be optimised to enhance intrusive bodies.

4. Thorough source rock studies should be related to wireline geophysical logs so that future source rock work can be minimised. Entire well sections should then be evaluated for source rock quality from the wireline logs.

5. As part of an exploration program, expand and elaborate on geohistory analysis both in terms of "what if" modelling and sensitivity studies which encompass the entire basin. The results of the geohistory analysis and the understanding obtained from it can be fedback into the geological understanding to enhance exploration concepts and hopefully play quality and finally play ranking. The previous recommendations are essentially

aimed towards fulfilling this general objective.

5.5 CONCLUSIONS

The results of the present models appear to confirm the following.

(1) The lowermost EVCM is in the zone of maximum generation-preservation of hydrocarbons. This zone has rarely been penetrated, as most wells were terminated in the upper EVCM.

(2) The mature section is probably wet gas to slightly oil prone. All the more oil prone sections tend to be immature. The deeper sections are dry gas prone.

(3) The upper EVCM are only marginally mature, and younger sediments are all immature.

(4) Below 18,000 the sediments are super-mature (mainly Otway Group sediments) and above 9,000' they are immature.

(5) Igneous intrusives have the potential to significantly affect the local maturation history. This aspect of maturation in the Bass Basin is difficult to quantify. Local maturation may be accelerated adjacent to intrusives and thermal blanket effects of igneous bodies may retard maturation of source rocks above them.

(6) An average increase of 5°C/km in the geothermal gradient over those calculated previously by Nicholas and others (1981) is likely. Available data indicates that the deeper central basin has a cooler gradient (37°C/km)

compared with the northeastern and southwestern flanks (40-41°C/km). The northern end of the basin may have a gradient as high as 43°C/km. This high gradient may be associated with Tertiary igneous activity. The northern half of the basin is therefore more prospective than the southern half, due to shallower depths of maturity.

(7) Lopatin Time - Temperature Maturation plots require the input of additional and refined data to show the effects of burial compaction and detailed paleoheat flow. Although such changes could upgrade areas, which based on present assumptions are only marginally mature, basic levels of maturity are unlikely to change significantly.

(8) If it is assumed that the marine transgressive shales of the Demons Bluff Fm. are a regional seal then the maturation period of the underlying section is the most important aspect in considering generation and migration. The LTTMP shows that the following approximate thicknesses of lowermost EVCM entered the hydrocarbon generation-preservation zone following deposition of the Demons Bluff Fm.

Pelican 1	5,000'
Narimba 1	3,000'
Cormorant 1	2,500'

6.0 GENERATION AND MIGRATION

6.1 Introduction

Although the results of the Lopatin Time-Temperature Maturation plots are approximate (refer section 5.4), the plots can be used as a guide to the timing of onset of maturity, peak generation and preservation phases for each stratigraphic level. These factors are indicated in Tables 6.1 & 6.2.

The Cormorant and Narimba depocentre areas were developed in asymmetric basins controlled by extensional normal tilted fault-blocks. The data available suggests these areas have higher maturity. Spore colouration indicates that Tarook 1 and Poonboon 1 also encountered mature section in the EVCM, and maturity/generation/expulsion windows may therefore be similar to the Cormorant and Narimba area examples.

The eastern basin area near Poonboon 1 and Tarook 1 has not been examined further because of interpreted poor trap conditions.

6.2 Interpretation of Generative History and Migration

6.2.1 EVCM Below the Upper L. balmei Zone

a) In depocentres with similar maturation history to the Cormorant and Narimba areas the late Cretaceous (*T. longus* zone) and lower Paleocene (lower *L. balmei* zone) reached peak

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CORMORANT AREA TABLE 6.1

AGE (m.y.)	EPOCH	SERIES	SPORE-POLLEN ASSEMBLAGE ZONES	STRATIGRAPHY	SOURCE ROCK RICHNESS	THERMAL ALTERATION INDEX (COAL)	T.T.I. (LOPATIN) GENERATION	INTERVAL THICKNESS	MIGRAT-ION PERIOD	POTENTIAL TRAPS PRIMARY MIGRATION	POTENTIAL TRAPS SECONDARY MIGRATION
	MIOCENE–PLIOCENE			TORQUAY GROUP						YOUNG STRUCTURES LATE FAULTS (SAND %) FAULT OFFSETS	YOUNG STRUCTURES (LATERAL REMIGRATION) REMIGRATION UP FAULTS
24	OLIGOCENE										
37.5			Upper *Nothofagidites asperus*	DEMONS BLUFF FORMATION							
40	EOCENE	Late	*Nothofagidites goniatus* / Middle *Nothofagidites asperus*		FAIR-LEAN (OIL)	IMMATURE				↑ DEMONS BLUFF FORMS REGIONAL SEAL	
45		Middle	Lower *Nothofagidites asperus*	UPPER EASTERN	GOOD (GAS & OIL)	IMMATURE				INTRA FORMATIONAL SEALS REQUIRED ↓ EARLY STRUCTURES STRAT TRAPS EARLY FAULTS	
			Proteacidites asperopolus								
50		Early	Upper *Malvacipollis diversus*		FAIR (GAS & OIL)	IMMATURE		~ 1000'		SAND OFFSETS AT FAULTS	
			Lower *Malvacipollis diversus*	VIEW	V. GOOD (GAS & OIL)	TRANSITION MATURE	PEAK	> 2000'			
55	PALEOCENE	Late	Upper *Lygistepollenites balmei*		GOOD TO VERY GOOD (GAS & OIL)	TRANSITION MATURE TO MATURE		NP			
60		Middle	Lower *Lygistepollenites balmei*	LOWER COAL				NP		NOTE: ALL TRAPS MUST BE BELOW DEMONS BLUFF FM.	
		Early					ONSET				
65	LATE CRETACEOUS		*Tricolpites longus*	MEASURES	FAIR (BASS 3)	MATURE TO OVERMATURE (DRY GAS)		NP			
98	EARLY CRETACEOUS			OTWAY GROUP	FAIR TO GOOD (DURROON)	OVERMATURE					

T.T.I. (LOPATIN) GENERATION: DRY GAS PRESERVATION; WET GAS PRESERVATION; PEAK; ONSET; DRY GAS PRESERVATION; PEAK; ONSET; GAS & OIL PRESERVATION; PEAK; ONSET

MIGRATION PERIOD: PROGRESSIVE PEAK MATURITY PERIOD OF EXPULSION

NARIMBA AREA TABLE 6.2

AGE (m.y.)	EPOCH	SERIES	SPORE-POLLEN ASSEMBLAGE ZONES	STRATIGRAPHY	SOURCE ROCK RICHNESS	THERMAL ALTERATION INDEX (COAL)	T.T.I. (LOPATIN) GENERATION	INTERVAL THICKNESS	MIGRAT-ION PERIOD	POTENTIAL TRAPS PRIMARY MIGRATION	POTENTIAL TRAPS SECONDARY MIGRATION
	MIOCENE–PLIOCENE			TORQUAY GROUP			DRY GAS PRESERVATION; WET GAS PRESERVATION; DRY GAS PRESERVATION; WET GAS PRESERVATION; ONSET			YOUNG STRUCTURES LATE FAULTS (SAND %) FAULT OFFSETS	YOUNG STRUCTURES (LATERAL REMIGRATION) REMIGRATION UP FAULTS
24	OLIGOCENE										
37.5	EOCENE	Late	Upper *Nothofagidites asperus*	DEMONS BLUFF FORMATION	FAIR-LEAN (OIL)	IMMATURE	PEAK		PROGRESSIVE PEAK MATURITY PERIOD OF EXPULSION	DEMONS BLUFF FORMS REGIONAL SEAL	
40			*Nothofagidites goniatus*: Middle *Nothofagidites asperus*	UPPER EASTERN	GOOD (GAS & OIL)	IMMATURE	WET GAS			INTRAFORMATIONAL SEALS REQUIRED	
45		Middle	Lower *Nothofagidites asperus*							EARLY STRUCTURES STRAT TRAPS EARLY FAULTS	
			Proteacidites asperopolus							SAND OFFSETS AT FAULTS	
50		Early	Upper *Malvacipollis diversus*		FAIR (GAS & OIL)	IMMATURE	PEAK	~ 800'			
			Lower *Malvacipollis diversus*	VIEW	V. GOOD (GAS & OIL)	MATURE		> 2000'			
55	PALEOCENE	Late	Upper *Lygistepollenites balmei*		GOOD TO VERY GOOD (GAS & OIL)	MATURE	ONSET	NP			
60		Middle	Lower *Lygistepollenites balmei*	LOWER COAL						NOTE: ALL TRAPS MUST BE BELOW DEMONS BLUFF FM.	
		Early									
65	LATE CRETACEOUS		*Tricolpites longus*	MEASURES	FAIR (BASS 3)	MATURE TO OVERMATURE (DRY GAS)					
98	EARLY CRETACEOUS			OTWAY GROUP	FAIR TO GOOD (DURROON)	OVERMATURE					

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maturity for gas and oil prior to deposition of the Demon's Bluff Formation. The Demons Bluff Formation transgressive marine shales are considered to provide a general shale seal for the complete EVCM section, although Miocene uplift and erosion at the basin perimeter may reduce the continuity of the seal in some areas.

b) The lower part of the lower EVCM generally reached peak maturity and expelled generated hydrocarbons during the period of upper EVCM deposition (post M. diversus unconformity).

c) Lateral updip migration probably occurred out of EVCM depocentres (eg. Cormorant, Narimba areas) toward the south-western basin margins, and also updip toward faults along the eastern sides of the asymmetric depocentre areas. Intermittent leakage up these faults may also have occurred.

d) Intraformational seals are required for confinement of hydrocarbons generated at this time, since no regional seal was developed.

e) Sand percentages in intervals above the lower L.balmei level generally increase toward the basin margins. It is expected that this would also be true for the EVCM sediments in general. The total sand percentage for this interval would also be expected to be high at this active stage of basin fill. The bulk of hydrocarbons generated from this interval is likely to have been expelled from the basin centre along increasingly sandy conduits out towards the margins and escaped.

f) Structural closures and areas of primary accumulation existing during the time of generation should be reflected by mapping of the upper EVCM interval. (ie. Top EVCM to M. diversus unconformity isochron Encl. 4.4).

Based on the Top EVCM to M. diversus isochron map, these areas are:

(i) a subtle thin area 40 kilometres south of Cormorant 1, which represents early block faulting of the lower EVCM interval and is reflected in Pipipa-type plays (see 8.4).

(ii) the axis of a thin interval through Poonboon 1 and Nangkero 1 towards Bass 1. The northern extent of this axis has a lower sand percentage in lower EVCM units. Migration from generative areas across faults onto this structurally higher area may have been inhibited by fault seals. However, some vertical migration up faults may have occurred episodically with recurrent movement. This axis generally tends to nose to the north. Once hydrocarbons entered this structural trend, migration to the southeast, updip from lower to higher sand percentages, would have been likely. Hydrocarbons are likely to have left the basin as no cross-fault barriers exist along a southeast migration pathway.

g) In depocentres, the EVCM section up to the top of the L. balmei zone has matured through to the overmature gas phase at the present day, and may always have been more gas prone due to the facies type of the source rock.

6.2.2. M diversus Unconformity to top L. balmei

The interval including upper L. balmei and lower M. diversus zones has been rated as "very good" source rock in Narimba 1 (see Table 6.1).

a) For depocentre areas similar to Cormorant and Narimba, this interval, the upper part of which includes the pay zone at Pelican Field, reached peak generation for gas and oil approximately 12 m.y. ago (Miocene) and is probably still generating. However, a small error in the maturation TTI plot (Figure 5.7) could easily retard or advance the peak generation stage of this interval.

b) Hydrocarbons generated from this interval and expelled up early faults would be vertically sealed by the Demons Bluff Formation.

c) Based on evidence from existing shows and hydrocarbon distribution at Pelican Field it is likely that most migration has occurred laterally, and was confined to mature intervals by intraformational seals.

d) Transgression of the marine Demons Bluff Formation shales over the EVCM sand units may also provide the ultimate updip seal for laterally migrating hydrocarbons.

e) Fault seals to lateral migration occur at Pelican Field in this interval, probably because interval sand percentages allow fault displacement seals to be effective.

6.2.3 Upper EVCM (post M.diversus Unconformity)

Although this interval has good source rock potential, it has never reached maturity or generated significant hydrocarbon volumes. Support of this is provided by the absence of gas from this interval in the Pelican Field. Narimba 1, Pipipa 1, Cormorant 1 and Bass 1 all have weak shows and some fluorescence over the upper EVCM interval, but it is likely that this represents either fault migration (vertical leakage from the lower EVCM) or the weak onset of marginal maturity locally. (Oil recovered from the M. asperopolus zone at Cormorant 1 may have been locally generated by volcanic intrusives into immature source rocks.)

7.0 SEALS AND TRAPS

7.1 Introduction

Previous exploration objectives in the Bass Basin have mainly been structural culminations. Tests of these were unsuccessful. Vertical migration into structural highs may have occurred but subsequent migration out of present day highs, or timing of the structural development, has made these traps ineffective.

Therefore, a different approach to trap type is required for the Bass Basin to sustain further exploration effort.

7.2 Important Factors To Consider

(a) Vertical migration to structural closures under the Demons Bluff Formation seal has either:
a) occurred, but structural closure was ineffective,
b) not occurred, and migration was laterally confined within the generative interval.

(b) Normal faulting has been an effective seal confining both overpressure and hydrocarbon accumulations at Pelican Field.

(c) Interval sand percentages probably play a key role in the sealing effectiveness of faults. Sand percentage values in the 20-40 range are generally considered as effective in a marine shale/delta front sand environment. In the sand and silt dominated fluvial-lacustrine environment represented in the Bass Basin, this percentage range may be different. However, sand percentages of about 40 percent are associated with effective seals at Pelican Field.

7.3. Overpressure: Implications for Sealing

Overpressure below 9800 ft (subsea) in the Pelican Field indicates that undercompaction relative to depth of burial exists in these sediments. The overpressure is interpreted as being related to compression along the basin axis associated with late (Miocene) fauling. The overpressure is a significant feature to consider since it occurs in conjunction with the only known petroleum accumulation in the basin.

Observations

(1) Both overpressure and hydrocarbons occur on the downthrown and depocentre side of the major normal fault between Pelican 3 and Pelican 1, 2, and 4.

(2) Since overpressure has not equilibrated, possibly since Miocene time, fault sealing on the major normal fault bounding the depocentre appears to be effective.

(3) Pelican Field pay distribution and apparent gas pool isolation within fault blocks further confirms that fault seals are effective in the Pelican area.

7.4 Results

(a) Lateral migration along generative intervals appears to be the dominant migration pathway, generally towards the steeply dipping southwestern basin flank, with intraformational seals and faults largely confining migrating hydrocarbons within the generative intervals.

(b) The percentage of sand in the interval from Top EVCM to the *M. diversus* Unconformity is generally high around the periphery of the basin, with depocentre areas showing values below 40 percent. The lowest values of less than 20 percent occur in the Cormorant depocentre. Fault sealing within this section is likely where less than 40 percent sand occurs. The immaturity of the section probably explains the absence of hydrocarbon accumulations in this interval.

(c) The percentage of sand in the interval from the M. diversus Unconformity to the top of the L. balmei zone is low in the depocentre area around Cormorant 1 and seals approximately half the reservoir sands at Pelican Field where the sand percentage is approximately 40 percent. A trend of sand percentage values less than 40 percent in this interval along the southwest dipslope of the basin provides good sealing potential for normal faults and a trap mechanism for migrating hydrocarbons.

(d) Traps appear to depend on:

1) sand offsets at faults eg. Pelican Field and Pipipa 1. This is considered to be the most important trap element in the Bass Basin, or

2) abutment of sands up against basement /Otway Group tight sands eg. Bass 3 (downdip) where the upper part of the T. Longus zone abuts the basement.

(e) Large scale, continuous fault seals are unlikely, and most traps will be small in size, since fault correlations between seismic lines 15 kilometres apart are generally not possible in the area of the basin flanks. However, many sands may produce multiple pay zones in lower EVCM intervals, and reserves estimates are high due to thick cumulative net pay.

Traps significantly larger in size than Pelican Field appear unlikely, since Pelican Field as presently defined is approximately 15 kilometres long. However, extension of Pelican Field to the northwest and southeast along the fault trend may be possible.

(f) The sand percentage map for the M.diversus unconformity to base of M.diversus interval indicates that a more shaly section existed in the Cormorant-Tarook area depocentre. This interval may also include a proportion of shales from periodic marine ingressions. This section could generate a much higher proportion of liquids than exists in Pelican Field. The greatest proportion of this potential oil would be expected to have migrated laterally within its source interval - probably up dipslope towards Bass 3 and also toward the normal bounding fault adjacent Bass 1. The latter fault had little major recurrent movement after the M. diversus Unconformity.

(g) Early faults appear to be involved in effective traps. Faults developed before the M.diversus unconformity and not recurrent significantly after that event provide an effective mechanism for hydrocarbon accumulation at Pelican Field. Early faults tend to trend along the eastern margin of the M. diversus Unconformity to L. balmei depositional thicks. Pelican 1,2 and 4 (field wells) are the only ones which test section sealed by these early faults.

(h) Remigration to young structural culminations may be inhibited in areas where sand percentages are low and early fault seals remain effective.

8.0 HYDROCARBON POTENTIAL

Five play types have been interpreted for the Bass Basin. These are outlined on the Prospect Map (Encl. 8.1). The plays are described in order of prospectivity.

8.1 The Pelican-Type Play

Key elements of the Pelican gas/condensate field are:

(a) Reserves are confined by intraformational seals.

(b) Fault separation of the field into discrete pools indicates fault sealing is effective for pay intervals.

(c) Ratio of wet sands to gas sands probably correlates with percentage of sand in gross reservoir interval.

(d) The overall trapping of hydrocarbons in Pelican Field may be due to either:

i) fault juxtaposition of the gross reservoir interval against tight sands below the *L. balmei* zone, or

ii) sealing of the interval by tight unsorted alluvial fan complexes adjacent to the major bounding fault.

(e) The interval from the *M. diversus* Unconformity to the *L. balmei* zone increases in thickness by approximately

2000' across the bounding fault from Pelican 3 toward the Pelican Field. This dramatic interval change is largely produced by differential rates of subsidence and deposition across the fault.

A similar thickening is common across extensional normal faults in the Cooper Basin during deposition of the Patchawarra Formation.

At Pelican Field, the major episode of faulting which commenced during Lower EVCM deposition and bounded the Pelican - Narimba - Cormorant depocentre trend was largely active up until M. diversus time. Little further recurrent faulting occurs after the M. diversus Unconformity. Therefore, the fault trend is early relative to the hydrocarbon generation period (probable Miocene period).

(f) Regional erosion at the level of the M. diversus Unconformity to the east of Pelican 3 is considered insufficient to explain the extreme difference in thickness. The change is mainly depositional. This is considered important since erosion of local highs at the M. diversus unconformity level is evident at the Bass 3 structure. This structure has a long history of recurrent normal movement on its bounding fault and is not productive.

(g) Minor thickening in the Top EVCM to M. diversus unconformity interval is largely due to differential compaction on the downside of the fault, again supporting the absence of later fault movement within that interval.

(h) Late Miocene structure at the Top of EVCM level is evident on the eastern side of the bounding fault, and may have allowed an episode of late hydrocarbon migration.

8.1.1 Reserves

Gas Reserves for Pelican Field assessed by SAOGC are based on the following assumptions:

Area (total)	:	28 sq km (6900 acres) average
Pay (average)	:	167 ft
Porosity	:	0.18
Hydrocarbon Saturation	:	0.68
1/BG	:	245

Based on the above

Initial Gas in Place = 1.5 TCF

If source rock type is oil-prone, using same assumptions for oil equivalent and FVF = 2.86, then

Potential Initial Oil in Place = 383 MM bbl.

8.2 Trend of the Pelican-Type Play

The fault system which defines the downdip eastern extremity of the western depocentre trend is readily identified on the *M. diversus* Unconformity to *L. balmei* isochron (Prospect map, Encl. 8.1). Pelican field wells are the only tests of the prospective mature zone in this setting. Tarook 1 and Bass 1 were both drilled in locations suitable to test a Pelican field - type play, but terminated prior to entering the interval equivalent to the Pelican field pay zone.

Seismic data over the Pelican Field area and Bass 1 area are compared in Figures 8.1 and 8.2 and the high potential for a Pelican look-alike field near the Bass 1 location is evident. All aspects of the prospects appear to be similar, although it should be noted that these two comparative lines cross the bounding fault at different angles. In addition, detailed mapping of migrated seismic data is required to identify prospective areas for Pelican-type plays and some additional shooting would also be required.

Tarook 1 was drilled through the M. diversus Unconformity but terminated before encountering the Pelican Field pay zone. This well also is in a location with similar potential to Pelican field but the limited seismic data examined to date in the area is insufficient to develop a prospect.

Similar normal fault geometry into a tilted block west of Aroo 1 is evident on regional BMR line 17. Proximity of this tilted block to the probable northwest inlet area for episodic marine ingressions into the Bass Basin during the later part of the EVCM makes this an oil prospect with high potential.

Wherever flexural dip up to the bounding fault exists at the M. diversus Unconformity to L. balmei interval, a Pelican type accumulation appears to be possible.

Structural and interval mapping of reprocessed data along

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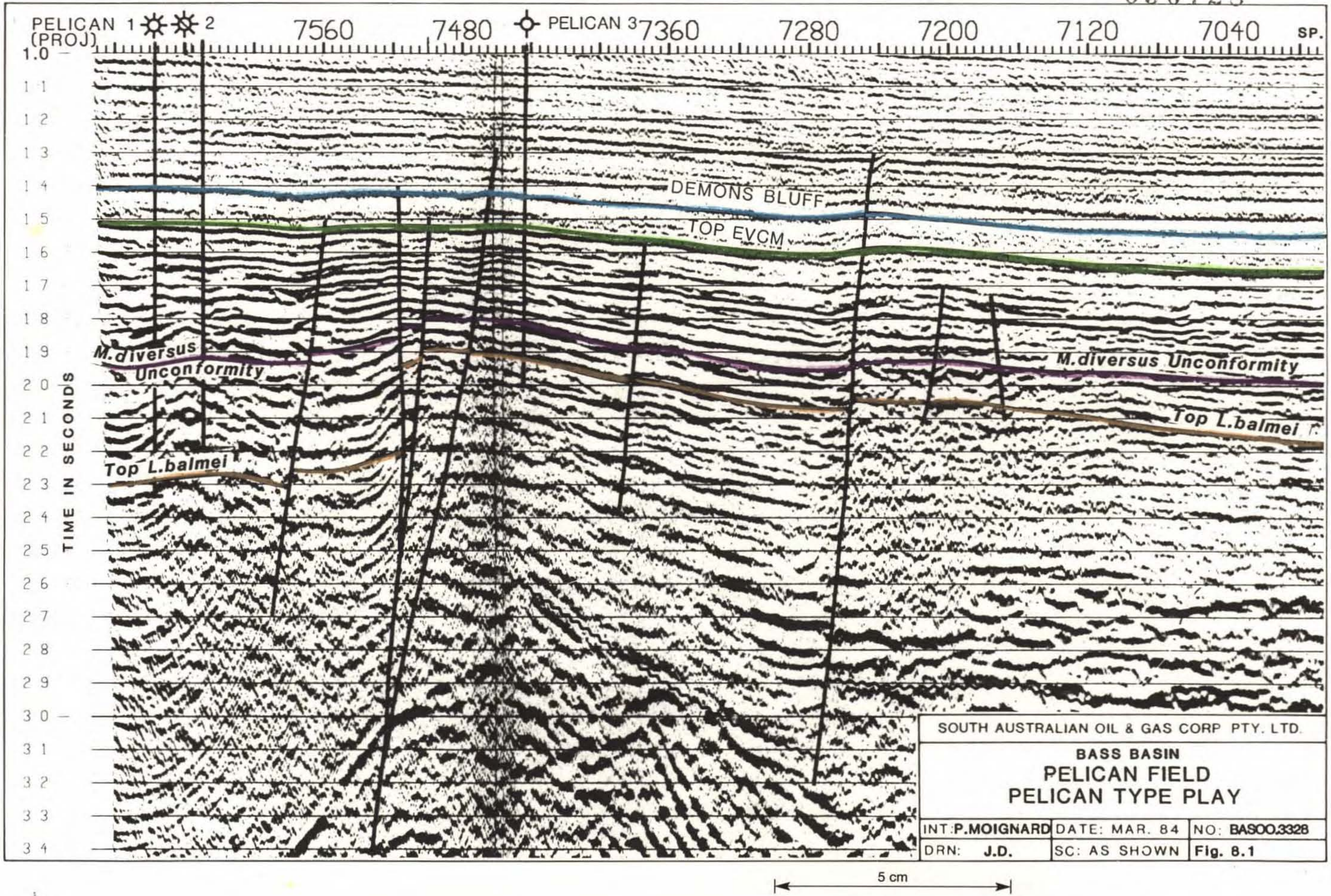
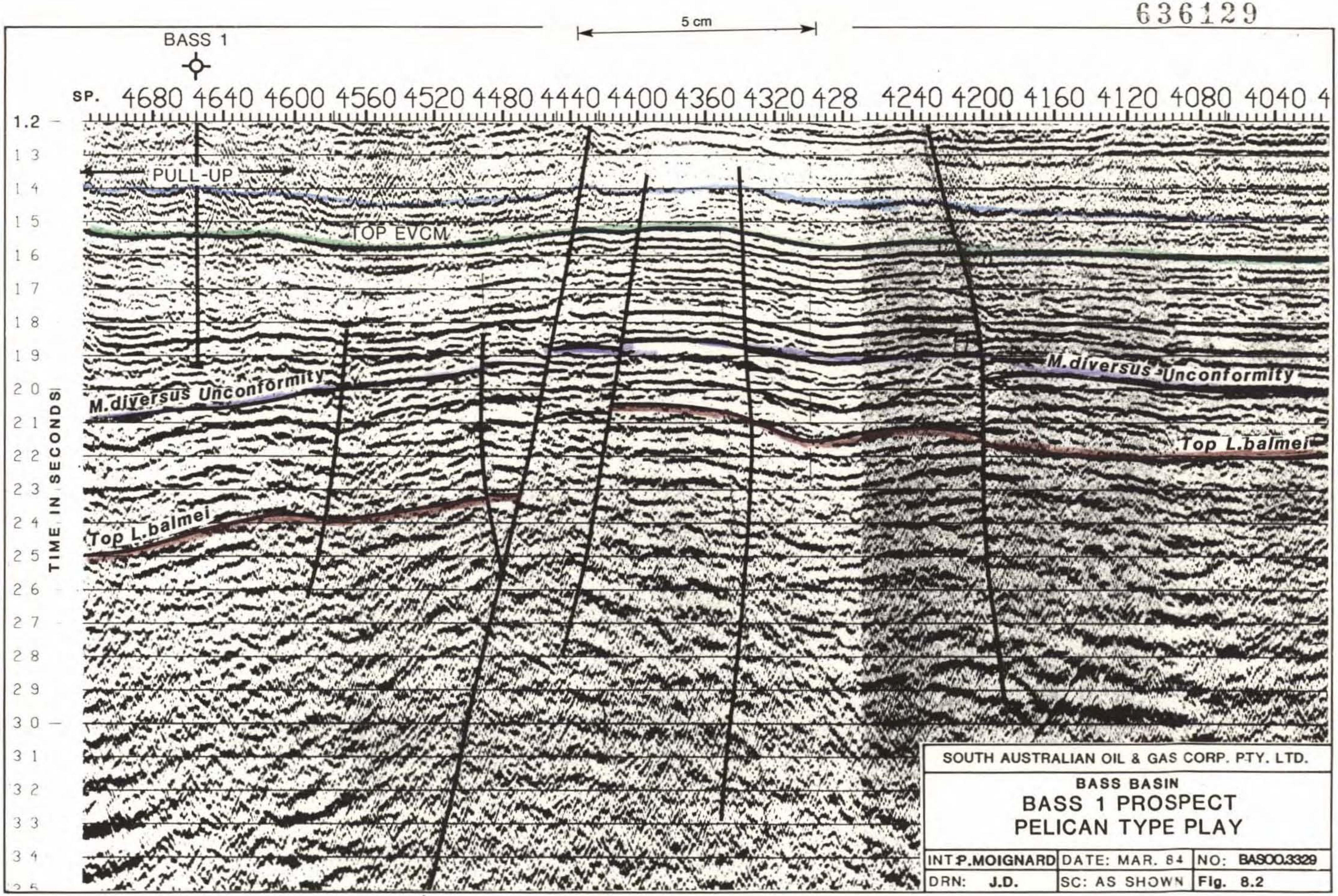


SOUTH AUSTRALIAN OIL & GAS CORP PTY. LTD.		
BASS BASIN PELICAN FIELD PELICAN TYPE PLAY		
INT: P.MOIGNARD	DATE: MAR. 84	NO: BASOO.3328
DRN: J.D.	SC: AS SHOWN	Fig. 8.1

636129



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN BASS 1 PROSPECT PELICAN TYPE PLAY		
INT: P.MOIGNARD	DATE: MAR. 84	NO: BASOO.3329
DRN: J.D.	SC: AS SHOWN	Fig. 8.2

the trend, particularly over Pelican field, may establish a relationship which could define the conditions for accumulation of hydrocarbons. Detailed definition of early structure through interval mapping using reprocessed seismic data at the Pelican Field may aid in defining a prospect.

8.2.1 Potential Reserves

Prospects of the Pelican-type probably exist along the eastern, fault bounded edge of the depocentre trend and it is possible that an additional gas/condensate field of Pelican size exists in this setting. Three oil prone fields, including the Bass 1 prospect, may be present in a setting closer to the shale prone depocentre of the Cormorant area.

Total Potential Reserves (in place) : 3 TCF gas and
1150 MM bbl oil

8.3 The Pipipa - Type Play

Fault-sealed plays exist within the 20 to 40 percent sand zone on the dipslope of the southwest tilted basin margin. The type play appears likely to be developed at the Pipipa 1 location. This well reached total depth well above the Pelican field pay zone (*M. diversus* Unconformity to top *L. balmei*). The Pipipa prospect is described in detail in Part 2 of this report, but generally takes the form of a fault-sealed trap on the dipslope from the Narimba depocentre axis source area toward the western updip termination of the tilted block. At

Pipipa, a minor tilted fault block developed prior to L. balmei time. Most reactivation of the normal fault at Pipipa occurred during the Miocene. Hydrocarbons were generating in the M. diversus Unconformity to L. balmei zone later than this episode of major movement on the normal fault. Fault seals are required at the updip and northeast boundaries of the prospect, so it is important to attempt to predict whether sand percentage values at the Pipipa location are likely to allow fault sealings. Table 8.3 indicates comparative isochron values versus sand percentages for Pelican 1, Narimba 1 and Pipipa 1 wells.

At Pipipa 1, a sand percentage value of about 30 between Narimba 1 and Pelican 1 is estimated for the M. diversus Unconformity to L. balmei interval, although higher values are possible if more fluvial facies are developed towards the basin margin. If a sand percentage less than or equal to Pelican 1 exists, by analogy fault seals are likely to be effective over the potential pay zone at the Pipipa prospect.

Reserves in the Pipipa prospect and Pelican field are likely to be generated from a common source type, and therefore should be similar in composition. However, other prospects of this type close to more shale-prone sources in the Cormorant area may tend to reservoir oil.

Reserves : Estimated potential for Pipipa prospect (see Part 2 of this report for details) based on:

Area : 20 sq km (4940 acres)

Pay : 150 ft (similar to Pelican field producable

TABLE 8.3: ISOCHRON VALUES VERSUS SAND PERCENTAGES

Well	Interval: Top EVCM to *M. diversus* unconf.		Interval: *M. diversus* unconf. to top *L. balmei*	
	Isochron	Sand %	Isochron	Sand %
Pelican 1	420 ms	57	380 ms	36
Narimba 1	450 ms	44	470 ms	26
Pipipa 1	440 ms	44	390 ms	estimated 30

zones)

Porosity: 0.16

Hydrocarbon Saturation: 0.7

$1/B_G$: 245

Potential IGIP = 890 BCF

Alternatively using FVF : 2.86

Potential Oil in Place = 225 MM bbl

8.4 Trend of the Pipipa-type Play

The setting of the Pipipa prospect is a rejuvenated tilted block fault structure adjacent the Narimba depocentre area. Similar prospects are expected to occur along a trend of reactivated faults adjacent to the asymmentric depocentre trend. (see Prospect map, Encl. 8.1). These take the form of readjusted small tilt blocks with thick potential pay zones in the *M. diversus* unconformity to top *L. balmei* interval.

One prospect additional to Pipipa is shown on Fig. 8.3 (BMR line 18) where updip diplacement occurs on a small normal tilt-block fault. Alternative interpretations of this line which reposition the top *L. balmei* are possible, but line and well ties in the area are poor and require further work for resolution.

Towards the Cormorant depocentre, this play is likely to become oil prone. A total of four fields are considered likely (including Pipipa), each of similar size. Two of these are given oil reserves.

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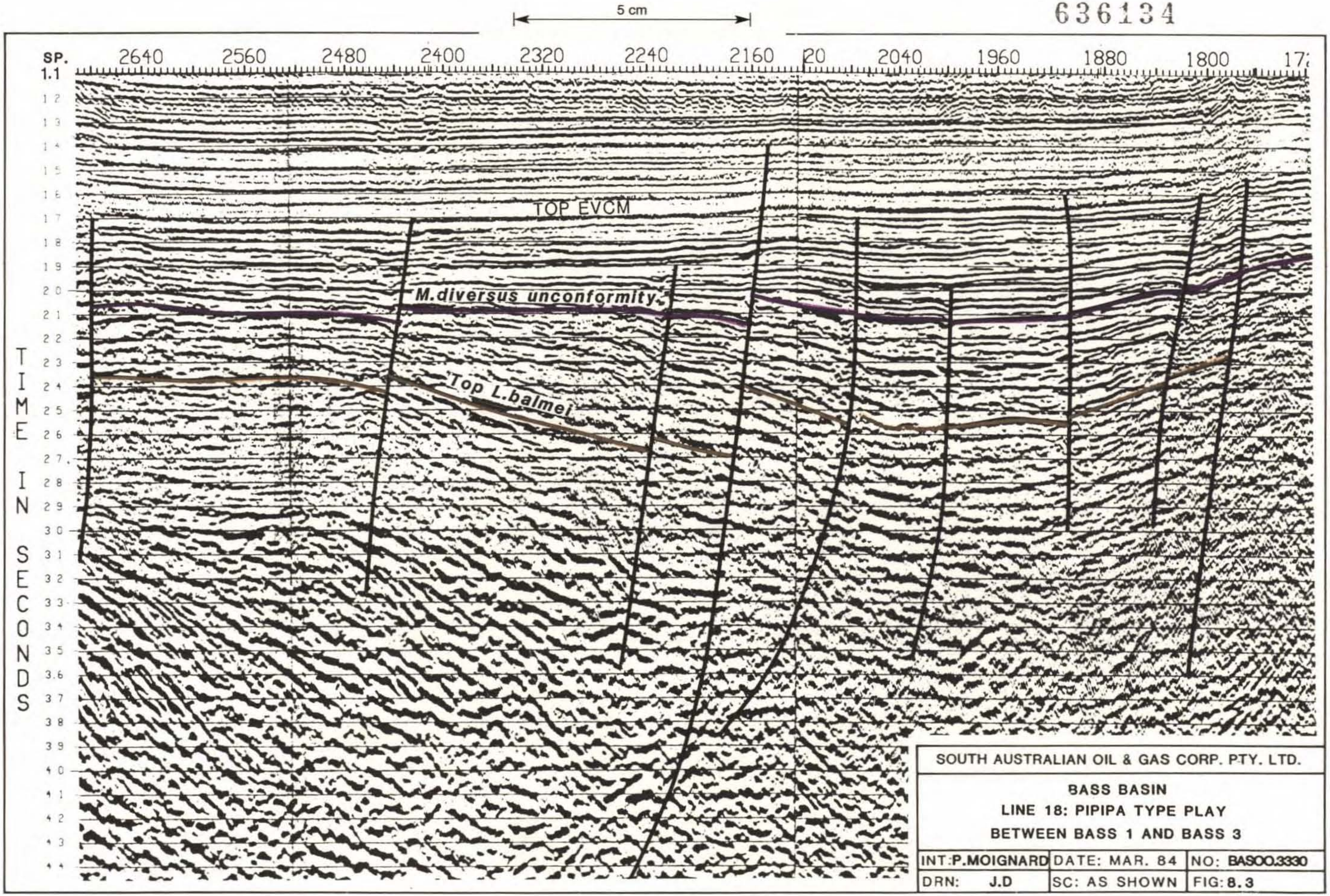


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN
LINE 18: PIPIPA TYPE PLAY
BETWEEN BASS 1 AND BASS 3

INT: P.MOIGNARD	DATE: MAR. 84	NO: BASOO.3330
DRN: J.D	SC: AS SHOWN	FIG: 8.3

Total Reserves Potential (in place) : 1700 BCF gas and 450 MM bbl oil

8.5 Pipipa-type play, with Facies Controlled Seal to Northwest

West of the Toolka-Cormorant shaly depocentre, a single field of the Pipipa type is considered possible. Dipslope small normal faults provide the seal toward the basin margin, and north-northwest trapping is by facies change of sand to shale. The presence of lower sand percentage and thinner sands in such a location may be offset by improved reservoir permabilities due to lacustrine wave reworking.

This play is considered to be oil prone, but difficult to assess in terms of risk.

Total Reserves (in place) : 100 - 200 MM bbl oil

8.6 Pelican-type with Large Recurrent Sealing Faults

Several major NNW-SSE trending fault systems east of Cormorant 1 have potential for early fault sealing of upturned intervals.

This play may occur in a trend east of Toolka 1, Cormorant 1 and Bass 1, and southeast towards Dondu 1. Insufficient seismic detail exists in this area to define this concept, or determine whether any areas of closure along the faults exist. The prospectivity of the downthrown side of faults and fault sealing is supported by the description of Pelican-type plays (see section 8.2). However, this play must be considered to be a much higher risk play since the major sealing faults in this area have been recurrent until recent time. Episodes of fault movement and escape of hydrocarbons may have prevented any accumulations.

Potential Reserves of 200 MM bbl are arbitrarily assigned based on a single accumulation with thin sands, similar to Play Type 8.5.

Some small rollover closures may exist in areas of complex faulting in an area of offset or en echelon small scale basin-boundary faulting southeast of Cormorant 1 and around Dondu 1.

These features may be uneconomic in size and their age in relation to migration is not known. No reserves are assigned.

8.7 Structural Culminations

Although some structural closures have not been tested at culmination, Bass 2, Bass 3 and Cormorant 1 appear to be close to their optimal location for an economic-sized reserve. These wells were unsuccessful at the top of EVCM level. The potential for reserves associated with structural crests with the Demons Bluff Formation providing the seal appears to be limited. Stepout on existing wells to test higher closure at this level would be unlikely to produce sufficient reserves to be economically viable for most prospects drilled to date.

The structure updip from Bass 1 appears to be the exception to this generalization, since Bass 1 was drilled to test a "reef" anomaly. The feature was found to be volcanics associated with one of the major faults bounding the high and the well did not test any closure.

This prospect (termed "Yolla" by Petrecon Pty. Ltd.) may have up to 40 square kilometres of closure, and have the potential for significant gas/liquids reserves. The risk in this structure is that early faults sealed migration pathways from generative areas to the structure and that the structure itself is relatively late (Miocene) in age. Since other Miocene and younger structural crests have been barren, this prospect must be considered high risk. However, an additional well is required updip from Bass 1 to test the "Yolla" feature.

Potential Reserves ("Yolla")

Based on 30 square kilometres of closure and the other parametres used for Pelican Field, reserves would be in the order of 1 TCF. Gas liquids content may be higher than at Pelican Field due to the proximity of the Bass 1 area to more lacustrine, shaly source rocks in the Cormorant depocentre.

8.8 Play and Reserves Summary

Table 8.4 details the Play types and summarises reserves.

TABLE 8.4: PLAY TYPES AND RESERVES SUMMARY

Play	No. of Prospects	Potential Reserves Gas in Place (some liquids)	 Oil in Place (some gas)
8.2 Pelican Type	4 (excluding Pelican Field)	3 TCF	1150 MM bbl
8.4 Pipipa Type	3 (including Pipipa)	1.7 TCF	450 MM bbl
8.5 Pipipa-Type, with facies controlled seal to N.W.	1	-	150 MM bbl
8.6 Pelican-Type with large recurrent sealing faults	1	-	200 M bbl
8.7 Structural Culminations	1 ("Yolla")	1 TCF	
Pelican Field	existing reserves	1.5 TCF	
BASIN POTENTIAL		7.2 TCF	1950 MM bbl

PART 2 VACANT AREA

1.0 INTRODUCTION

The Vacant Area (Figure 2.1) of 52 contiguous blocks (760,000 acres) in the central portion of the Bass Basin was gazetted by the Tasmanian and Australian Governments in November, 1983. Bids in the form of work programmes may be lodged up until March 23, 1984.

An early vintage regional seismic grid was shot over the area between 1961 and 1964. More regional data was shot in 1970-71. More detailed grids were shot in 1975, 1979 and 1981 over structural leads delineated by the early surveys. A total of six wells has been drilled in the Vacant Area.

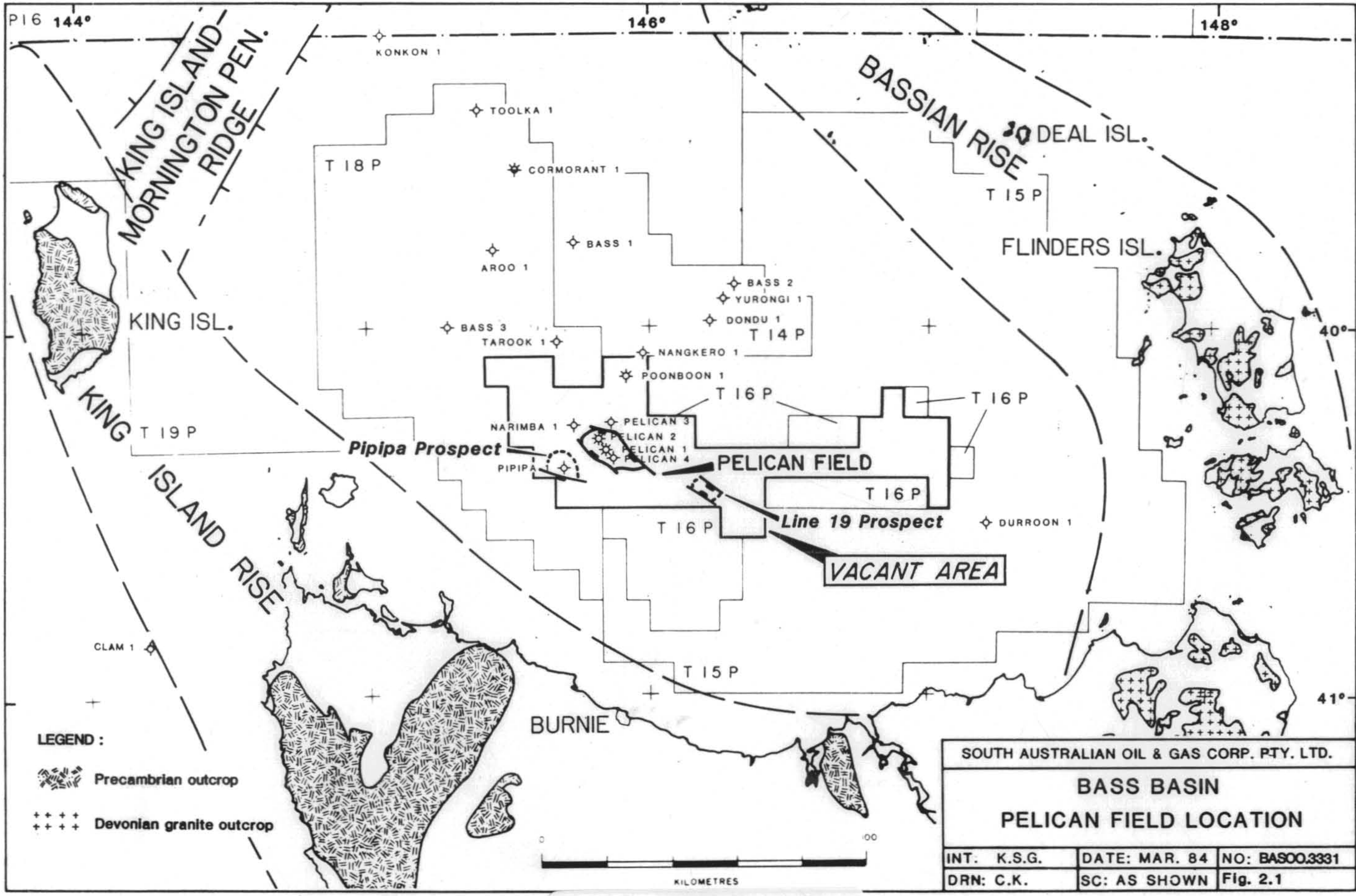
Three of the six wells, Pelican 1,2, and 4 define the sub-economic Pelican gas/condensate field. Two of the remaining three wells, Pipipa 1 and Narimba 1, encountered significant oil shows during drilling. The third well, Pelican 3, recorded a gas show on the gas detector.

The following sections will discuss the Pelican Field and other prospects within the vacant area.

2.0 PELICAN FIELD REVIEW

2.1 Introduction

The Pelican Field is a gas/condensate accumulation situated near the centre and deepest part of the Bass Basin approximately


P16
144°
146°
148°
40°
41°
KING ISLAND-MORNINGTON PEN. RIDGE
BASSIAN RISE
KING ISLAND RISE
KONKON 1
TOOLKA 1
CORMORANT 1
BASS 1
AROO 1
BASS 2
YURONGI 1
DONDU 1
BASS 3
TAROOK 1
NANGKERO 1
POONBOON 1
NARIMBA 1
PELICAN 3
PELICAN 2
PELICAN 1
PELICAN 4
PIPIPA 1
CLAM 1
DURROON 1
T18P
T14P
T15P
T16P
T19P
DEAL ISL.
FLINDERS ISL.
KING ISL.
BURNIE
Pipipa Prospect
PELICAN FIELD
Line 19 Prospect
VACANT AREA
LEGEND :
Precambrian outcrop
Devonian granite outcrop
0
100
KILOMETRES
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
PELICAN FIELD LOCATION
INT: K.S.G.
DATE: MAR. 84
NO: BASOO.3331
DRN: C.K.
SC: AS SHOWN
Fig. 2.1
636140
5 cm

80 kilometres north of Burnie, Tasmania (Figure 2.1). Water depth is about 80 metres. The field is located in the Vacant Area and straddles the boundary between the old T-5-P and T-6-P permits held by Hematite and Esso during the period 1961-1978, and by Hematite alone from 1978-1982.

The field is estimated in this report to contain approximately 1.5 TCF of gas-in-place (75% confidence level).

2.2 Pelican Field Stratigraphy

Three wells have been drilled in the Pelican Field. They are Pelican 1,2 and 4. Pelican 3, to the northeast, was located in a separate structural setting.

All three of the wells penetrated thick sections of EVCM (Eastern View Coal Measures) but none is interpreted to have penetrated the upper Cretaceous portion of the EVCM. Total thickness of EVCM encountered in Pelican 1,2 and 4 is 4640', 4150' and 4210' respectively. The upper 2200' of this section ie. from the top of the EVCM to the M. diversus Unconformity is characterised by abundant, thick coals in which no significant hydrocarbon shows were encountered.

Significant gas shows (confirmed by RFT and FIT tests) were encountered in the lower 2200' of section ie. the interval from the M. diversus Unconformity to the top of the L. balmei zone (Figure 2.2). Pay sands and potential pay sands occur throughout this interval. It has been subdivided into Units A through F and each unit contains one or more pay sands within

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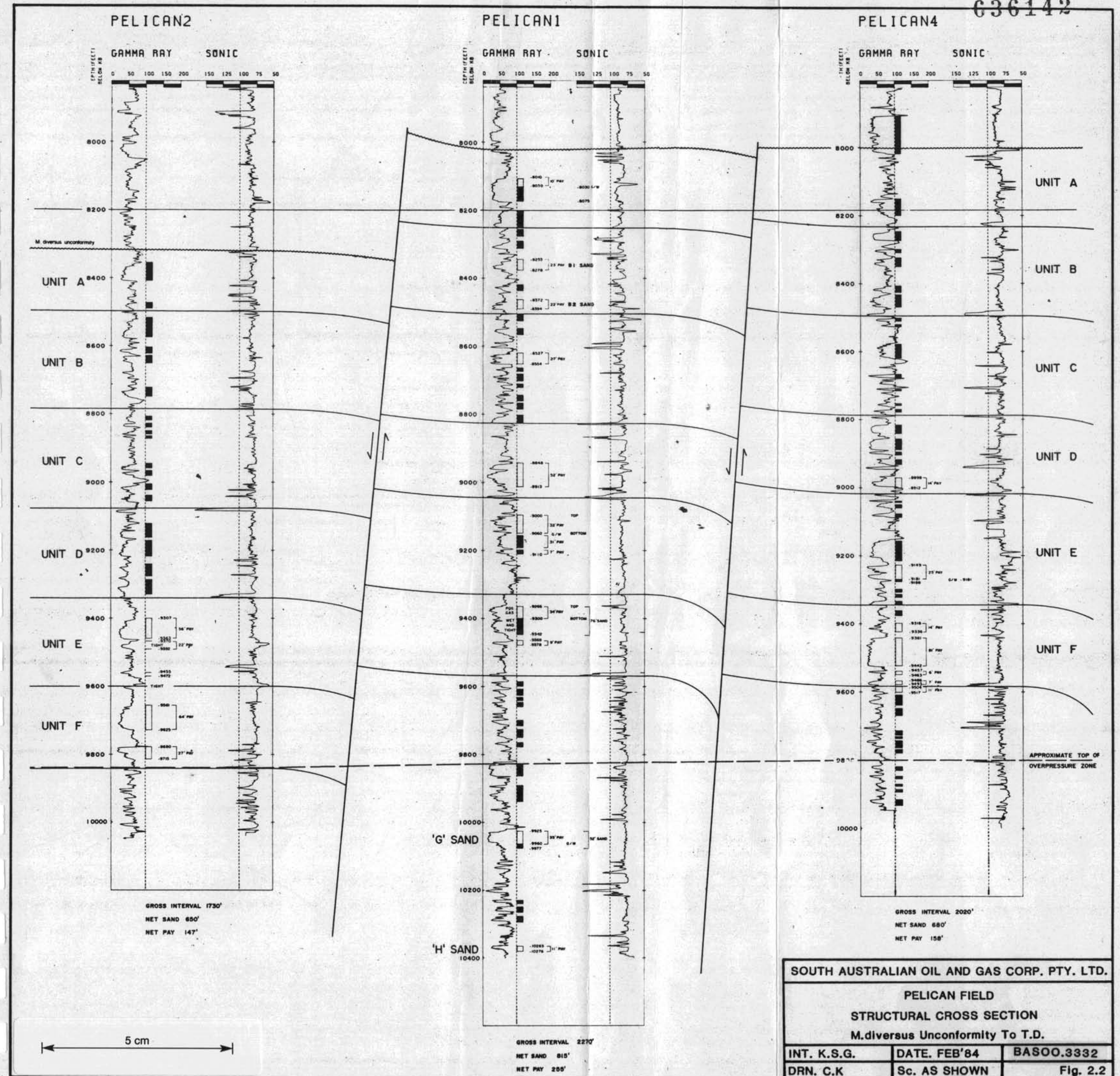

SOUTH AUSTRALIAN OIL AND GAS CORP. PTY. LTD.

PELICAN FIELD

STRUCTURAL CROSS SECTION

M.diversus Unconformity To T.D.

INT. K.S.G.	DATE. FEB'84	BASOO.3332
DRN. C.K	Sc. AS SHOWN	Fig. 2.2

it. At Pelican 1, two pay sands were encountered (termed "G" and "H" Sands) below Unit F at a stratigraphic level not penetrated in either of the other two wells.

2.3 Pelican Field Structure

The Pelican Field is located on a northwest-southeast trending anticline situated within a graben feature (Fig. 2.3). Faulting is dominantly northwest-southeast but minor cross-cutting faults can be interpreted as dividing the field into three separate structures with different gas/water contacts. Each structure has been penetrated by a well and has been mapped separately (Fig. 2.4).

Doming within the graben is considered to be related to Miocene faulting which was possibly initiated by a compressional event. Further tilting of fault blocks during this period resulted in compression in the centre of the graben and overpressuring of the deep section. This late movement has resulted in many smaller faults within the field, increasing the complexity of the reservoir. Two interpreted seismic sections are shown in Figures 2.5 and 2.6 to illustrate this structural analysis.

2.4 Reservoir Parameters

As mentioned previously, the Paleocene section of the EVCM was divided into six zones, Units A through F. These six zones contain a total of seven pay sands. Two additional pay sands were mapped in Pelican 1 below Unit F for a total of nine pay

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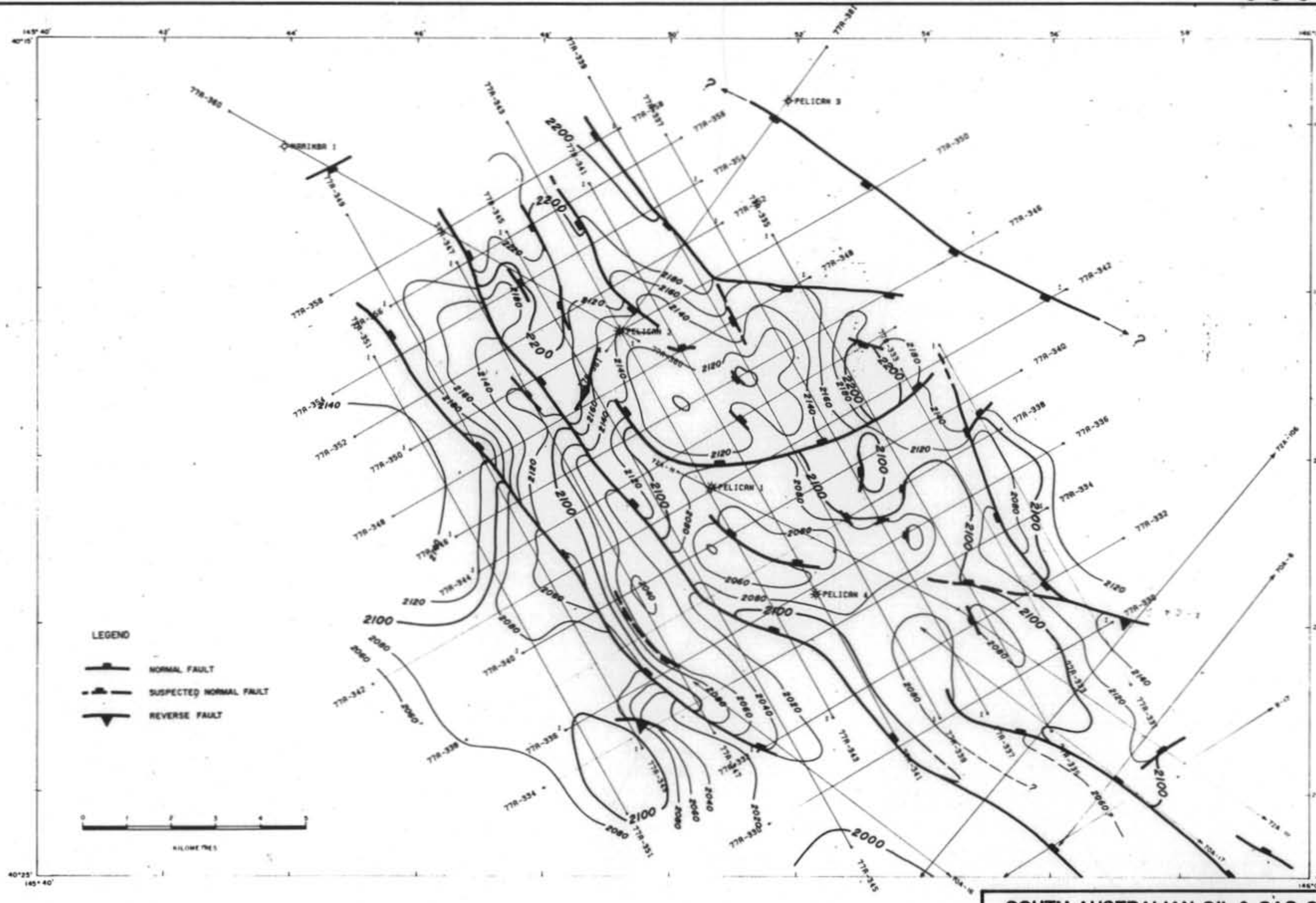
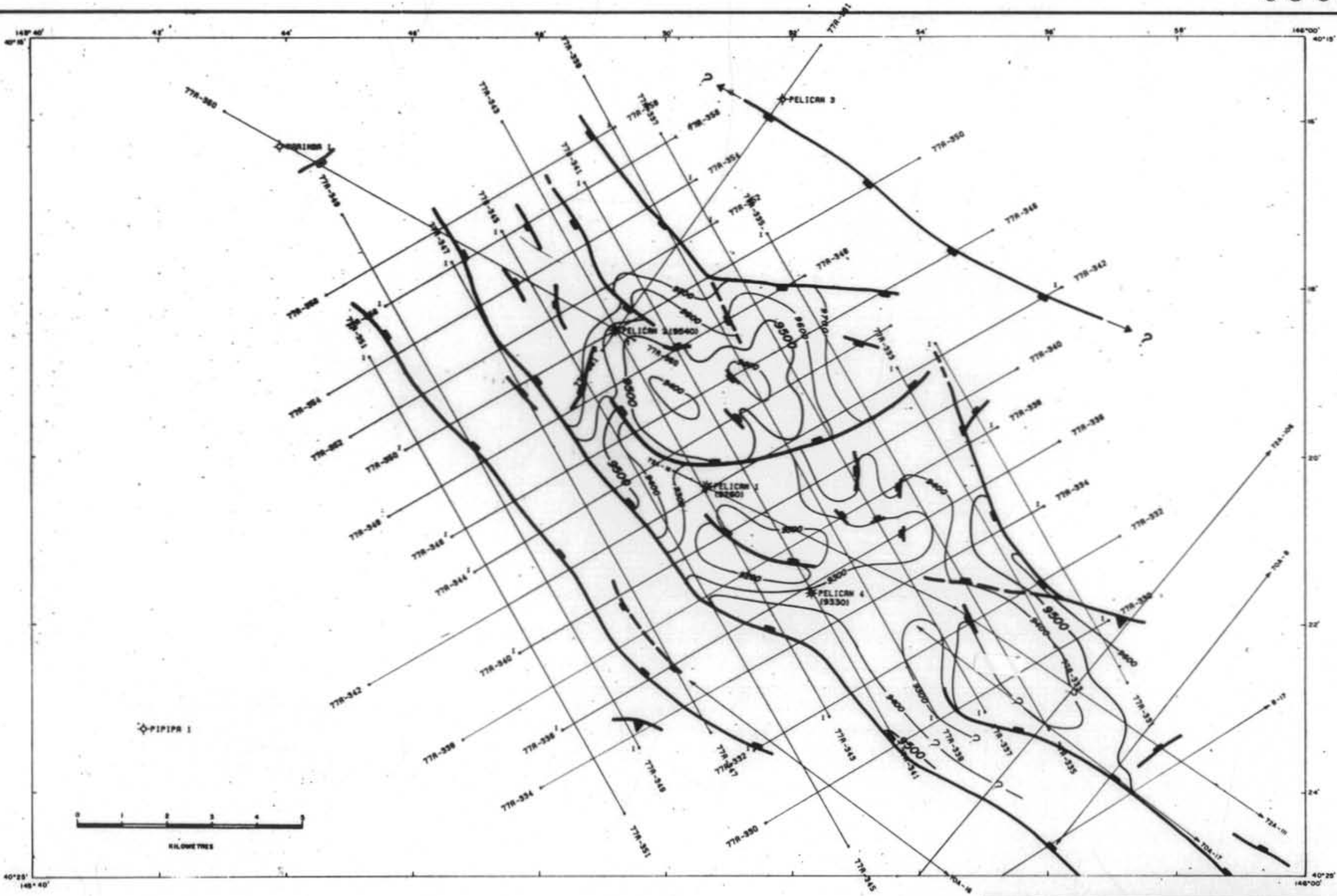


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD TWO WAY TIME STRUCTURE 'E' ZONE		
INT: R.SMIT	DATE: MAR. 84	NO: BASOO.3333
DRN: C.K.	SC: AS SHOWN	FIG: 2.3

5 cm

636145



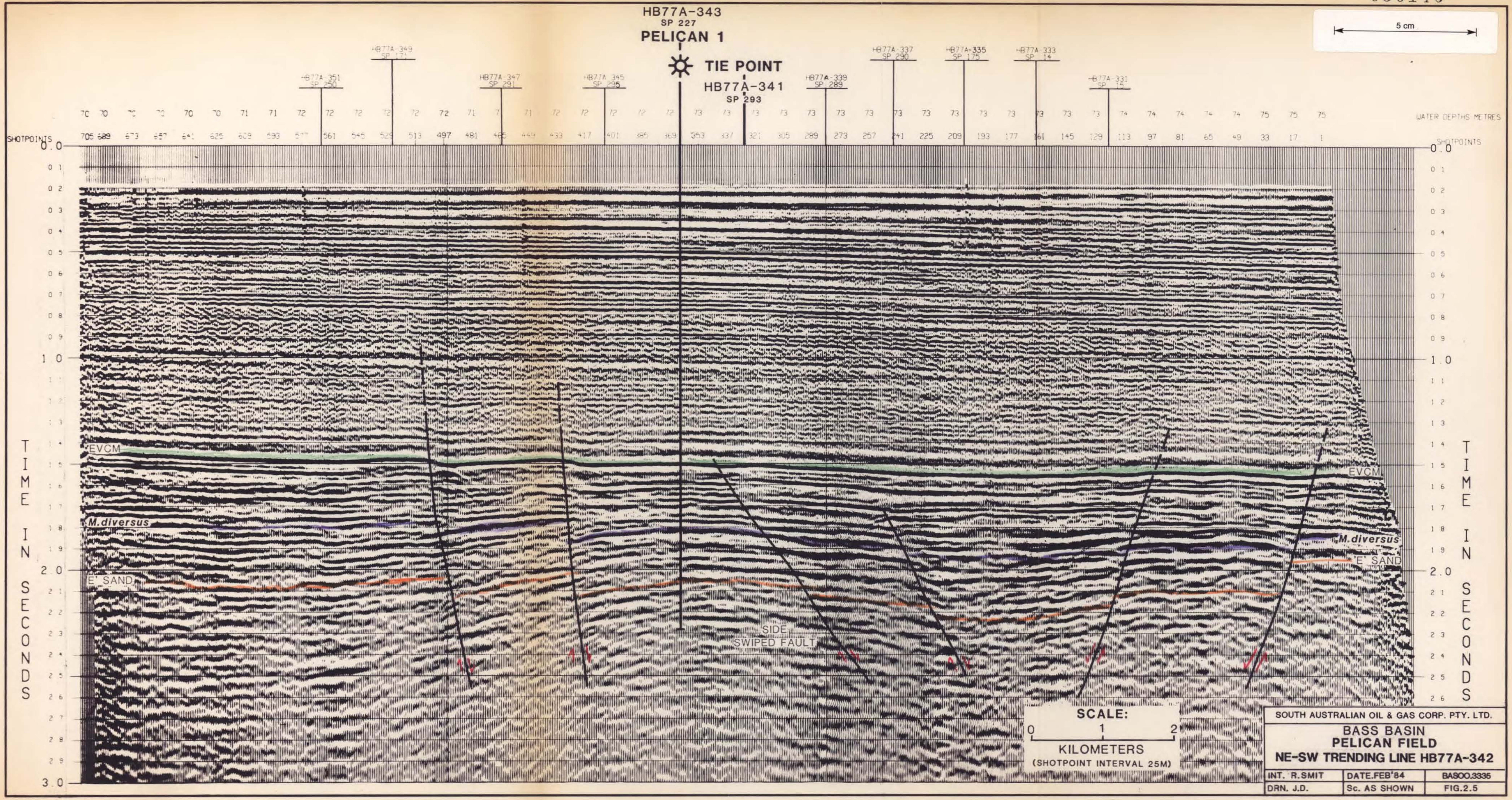
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

PELICAN FIELD
STRUCTURE 'F' SAND
(PHANTOMED FROM 'E' ZONE
TIME STRUCTURE)

INT: R.SMIT	DATE: MAR. 84	NO: BASOO.3334
DRN: C.K.	SC: AS SHOWN	FIG: 2.4

5 cm

636146

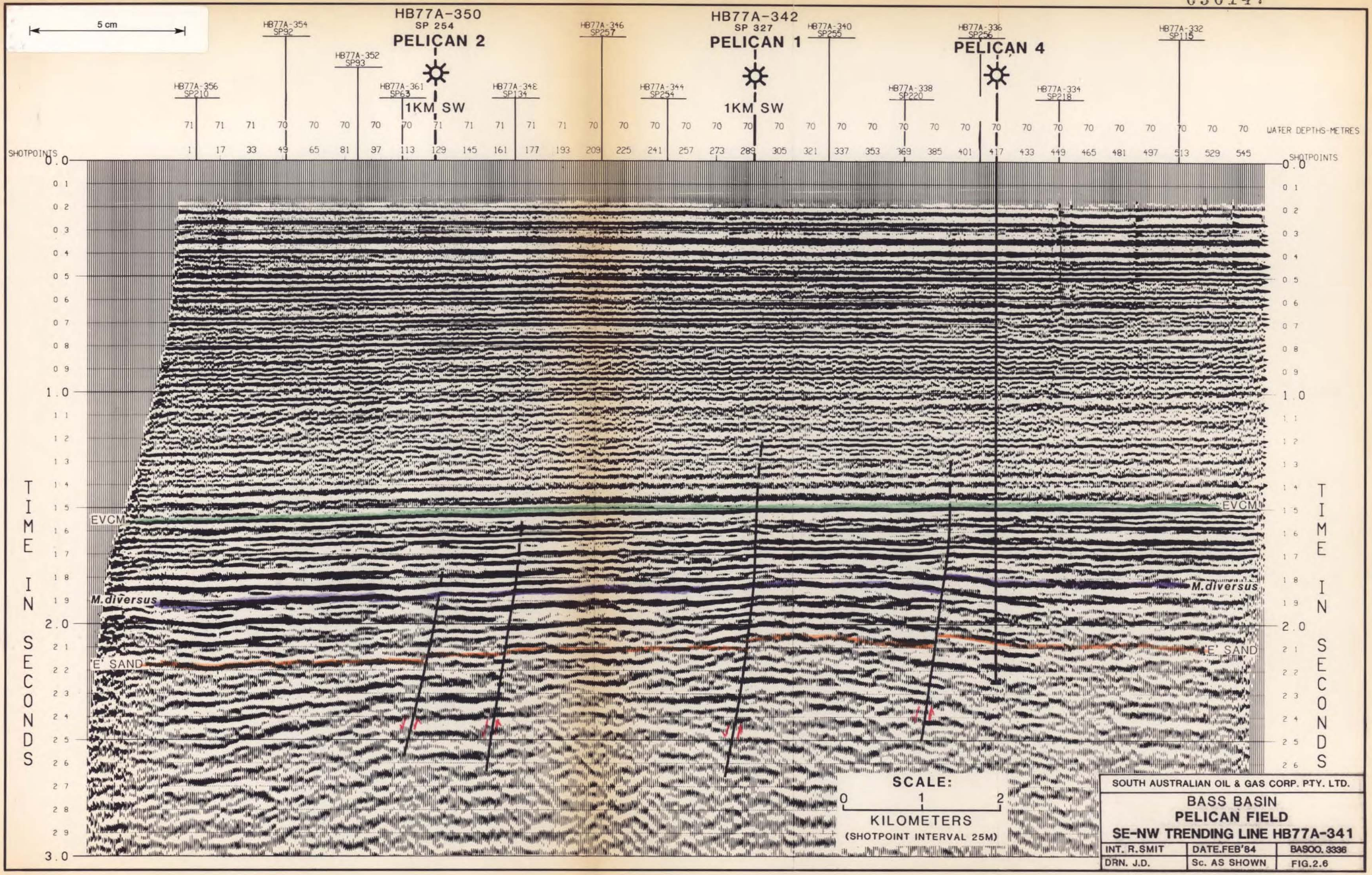


SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

BASS BASIN
PELICAN FIELD
NE-SW TRENDING LINE HB77A-342

INT. R.SMIT	DATE.FEB'84	BASOO.3335
DRN. J.D.	Sc. AS SHOWN	FIG.2.5

636147


5 cm
HB77A-350
SP 254
PELICAN 2
1KM SW
HB77A-342
SP 327
PELICAN 1
1KM SW
PELICAN 4
HB77A-354 SP92
HB77A-352 SP93
HB77A-356 SP210
HB77A-361 SP63
HB77A-348 SP134
HB77A-346 SP257
HB77A-344 SP254
HB77A-340 SP255
HB77A-338 SP220
HB77A-336 SP256
HB77A-334 SP218
HB77A-332 SP115
WATER DEPTHS-METRES
SHOTPOINTS
1 17 33 49 65 81 97 113 129 145 161 177 193 209 225 241 257 273 289 305 321 337 353 369 385 401 417 433 449 465 481 497 513 529 545
TIME IN SECONDS
0.0 1.0 2.0 3.0
EVCM
M.diversus
'E' SAND
SCALE:
0 1 2
KILOMETERS
(SHOTPOINT INTERVAL 25M)
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
PELICAN FIELD
SE-NW TRENDING LINE HB77A-341
INT. R.SMIT
DATE.FEB'84
BASOO. 3336
DRN. J.D.
Sc. AS SHOWN
FIG.2.6

sands.

2.4.1 Log Analysis

Log analysis was attempted on Pelican 1, 2 and 4 but results were inconclusive. This is due to poor log quality and insufficient data, such as reliable formation water resistivities. The poor log quality is largely a function of bad hole conditions. Also, the poor quality copies available to SAOGC were impossible to read in many instances.

In the final analysis, reservoir parameters were determined by a compilation of results from reports by Schlumberger, Esso, BHP, BMR, and from SAOGC hand calculated estimates.

2.4.2 Pay Thickness, Net Pay Maps and Field Limits

Net gas pay for Pelican 1, 2 and 4 is 255', 147' and 158' respectively. Individual pay thicknesses on a sand by sand basis are listed in Table 2.1.

Net gas pay isopachs for each sand were constructed in order to determine reserves (see Figures 2.7-2.15). Gas/water contacts were recognized in only three of the nine sands and these only on the Pelican 1 structure. The sands with recognisable gas/water contacts occur in units A,E, and F. The field limits for the remaining sands in Pelican 1 and all sands in Pelican 2 and 4 were determined by extending the pay downdip to a point midway between the Lowest Known Gas (LKG) and the High Known Water (HKW) or simply to the LKG. In all cases, the HKW was in a different sand to that containing the gas, so conceivably

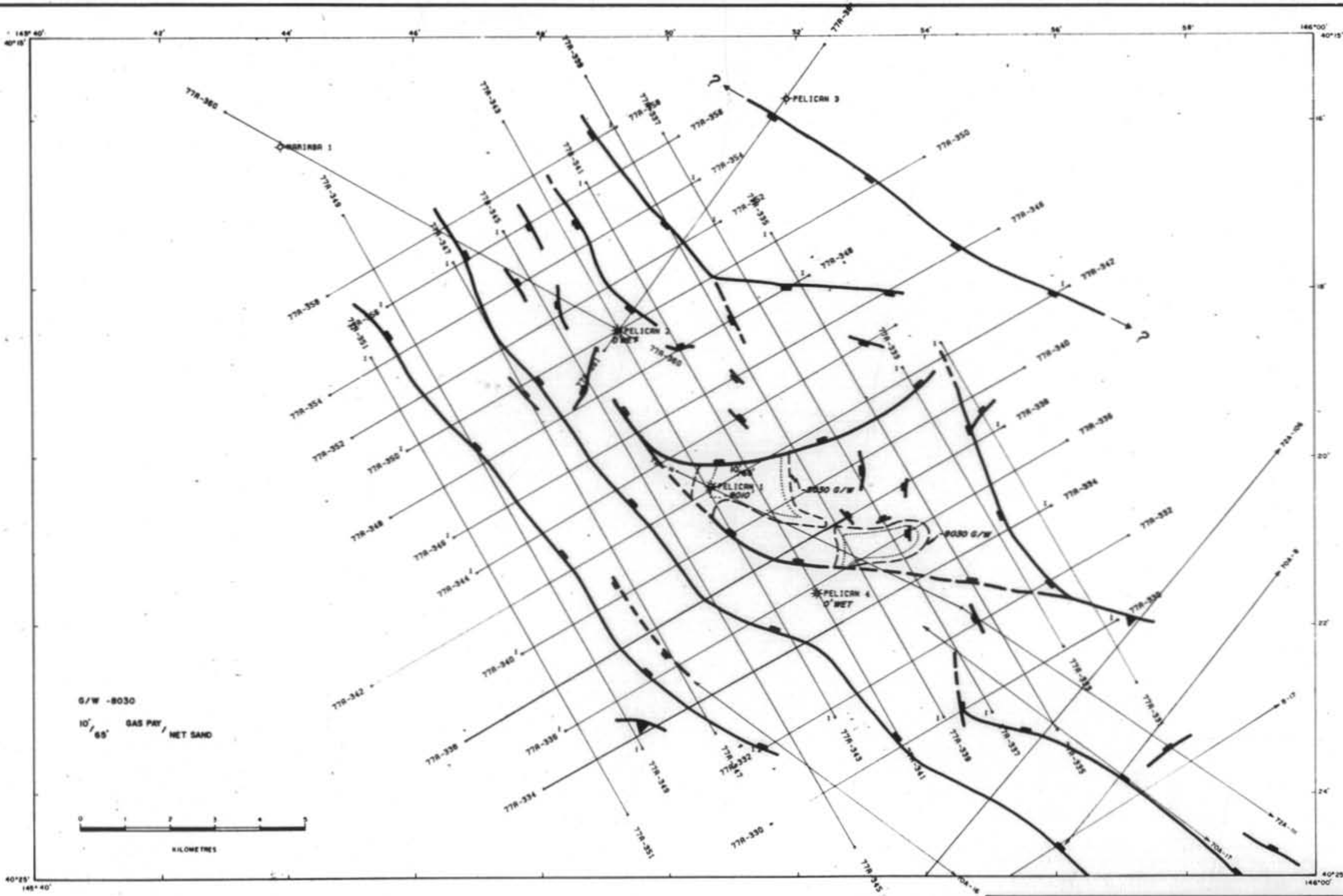
636149

TABLE 2.1 PELICAN FIELD - BASS BASIN RESERVOIR DATA AND RESERVES

SAND	WELL NUMBER	PAY THICKNESS (FT.)	BRV ac-ft	Ø	Sg	1/Bg	GIP (BCF)	
A	1	10	8,000	16	74	249	10.300	
B1	1	23	21,000	20	50	248	23.151	
B2	1	22	21,979	20	50	248	23.719	
C	1	27	33,124	18	60	246	38.476	
D	1	52	79,107	19	68	245	109.171)	
D	4	14	28,293	17	70	245	35.963)	145.134
E	1	32	49,085	13	50	245	33.997)	
E	2	56	168,135	18	75	243	240.494)	317.037
E	4	25	57,023	13	54	243	42.546)	
F	1	34	77,590	23	70	247	134.615)	
F	2	64	275,180	17	70	246	350.940)	866.672
F	4	81	377,830	14	67	246	381.117)	
G	1	52	67,376	21	60	266	98.454	
H	1	11	9,417	20	60	270	13.316	

1.536 TCF IGIP

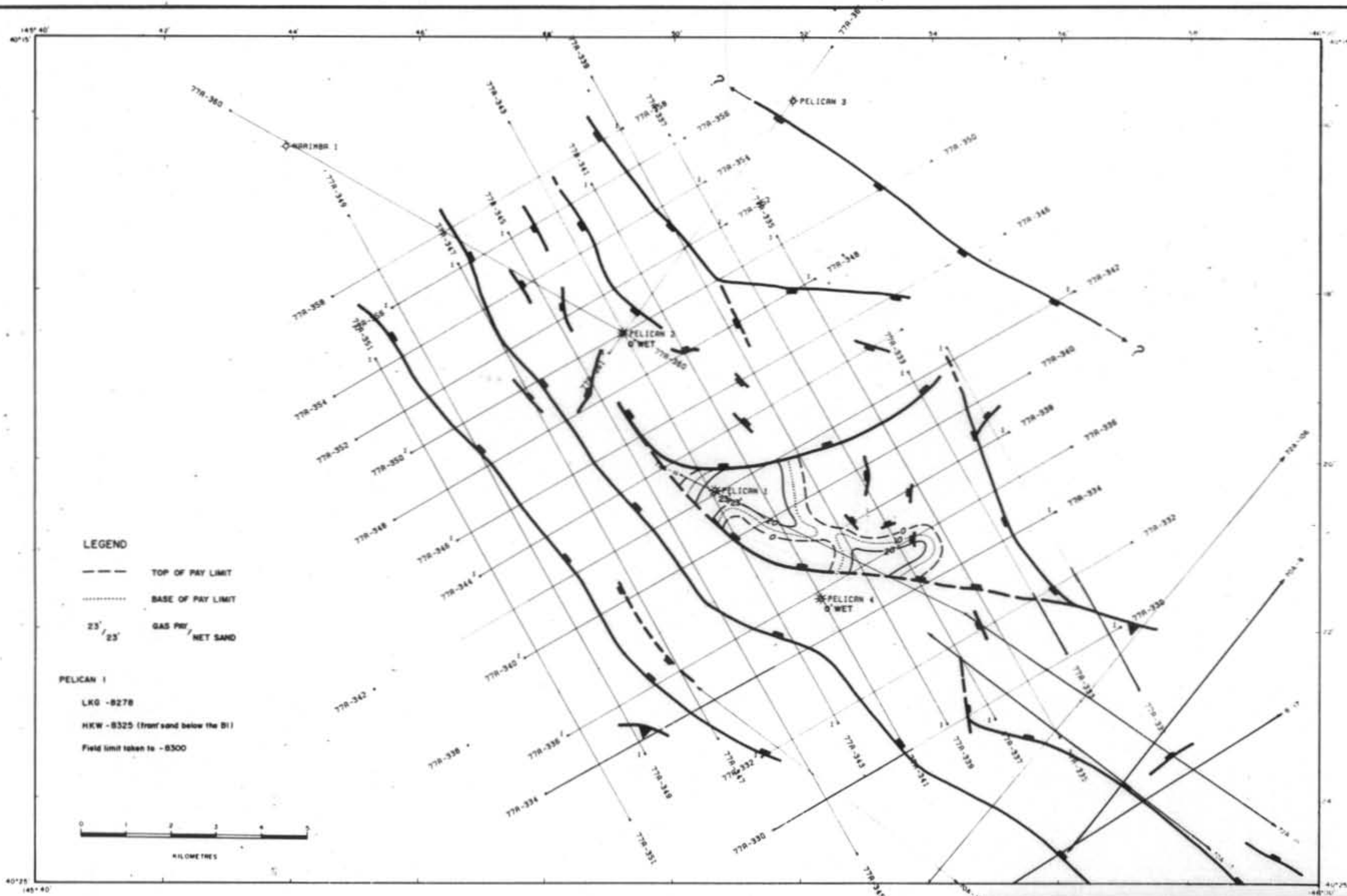
636150



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD		
UNIT 'A' NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3337
DRN: C.K.	SC: AS SHOWN	FIG: 2.7

5 cm

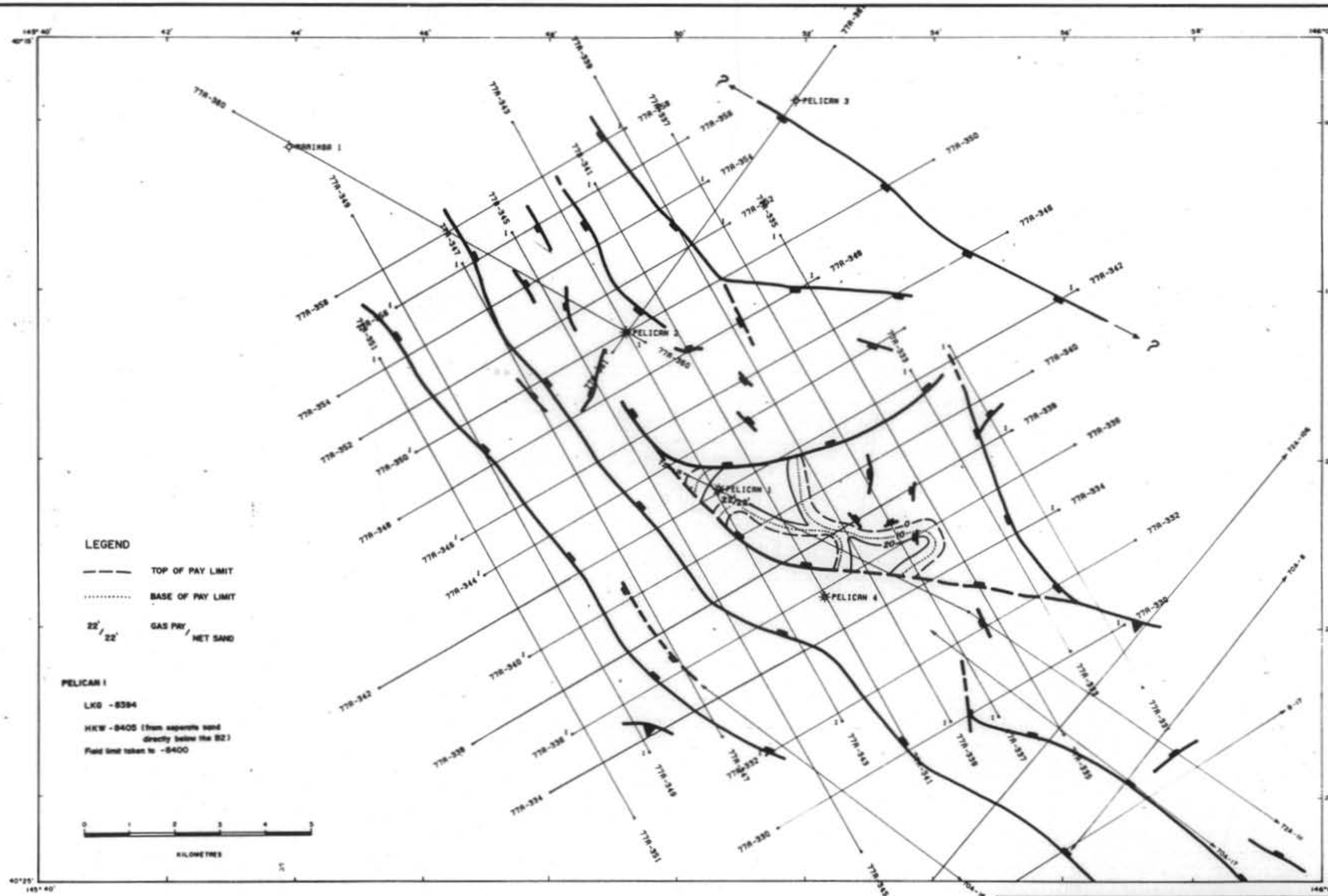
636151



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD UNIT 'B',B1'SAND NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3338
DRN: C.K.	SC: AS SHOWN	FIG: 2.8

5 cm

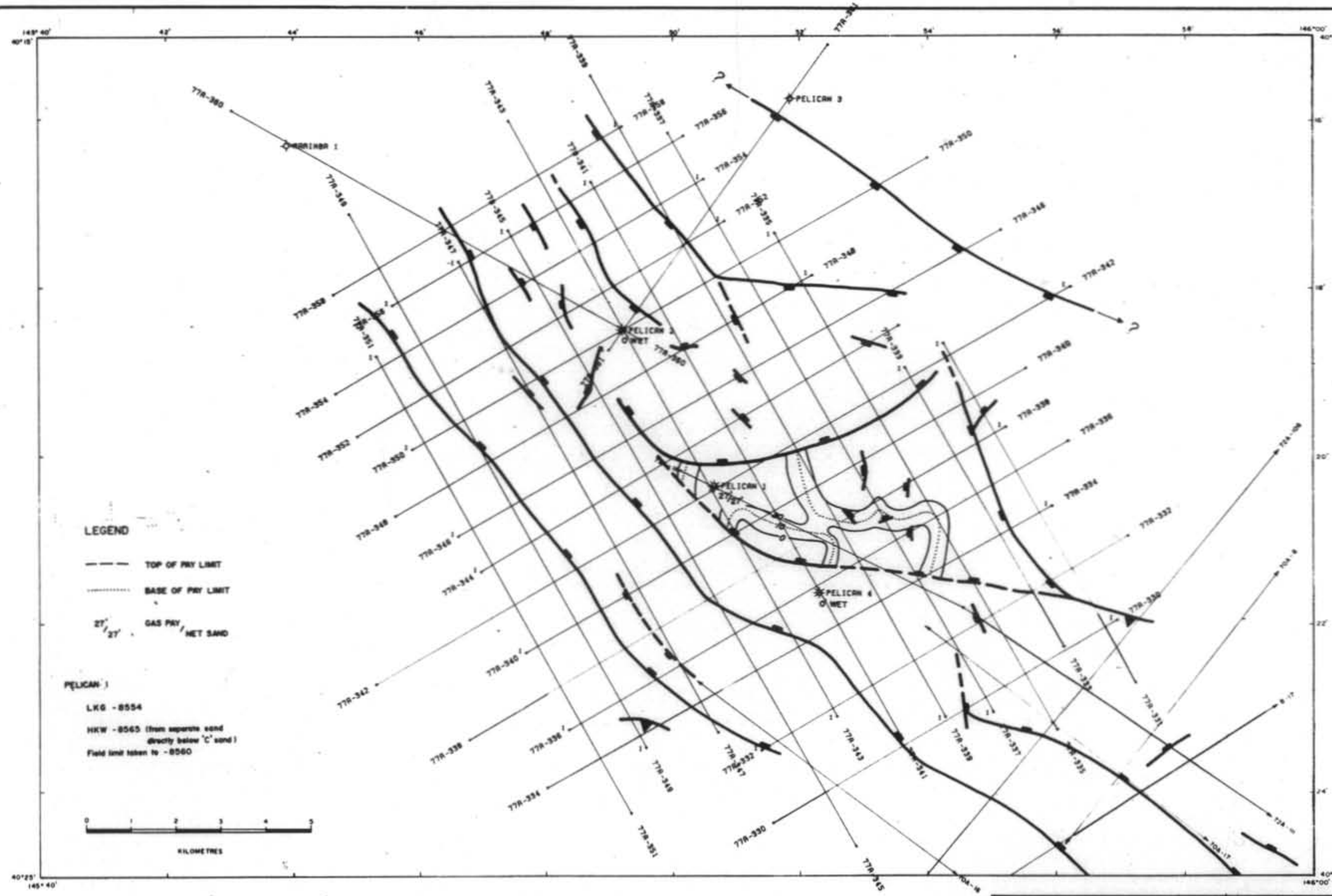
636152



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD UNIT 'B','B2' SAND NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3339
DRN: C.K.	SC: AS SHOWN	FIG: 2.9

5 cm

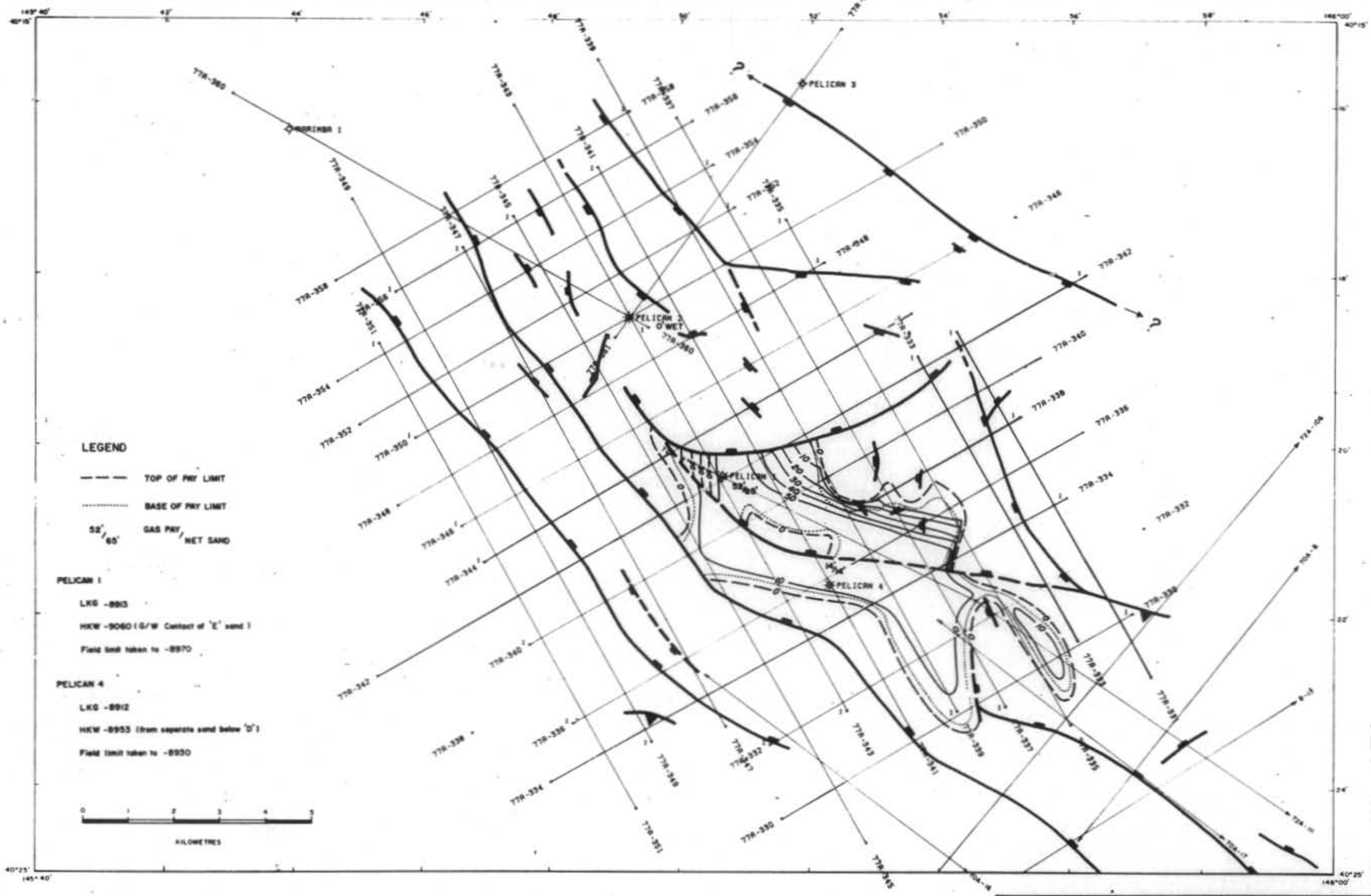
636153



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD UNIT 'C' NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR.84	BASOO.3340
DRN: C.K.	SC.: AS SHOWN	FIG: 2.10

5 cm

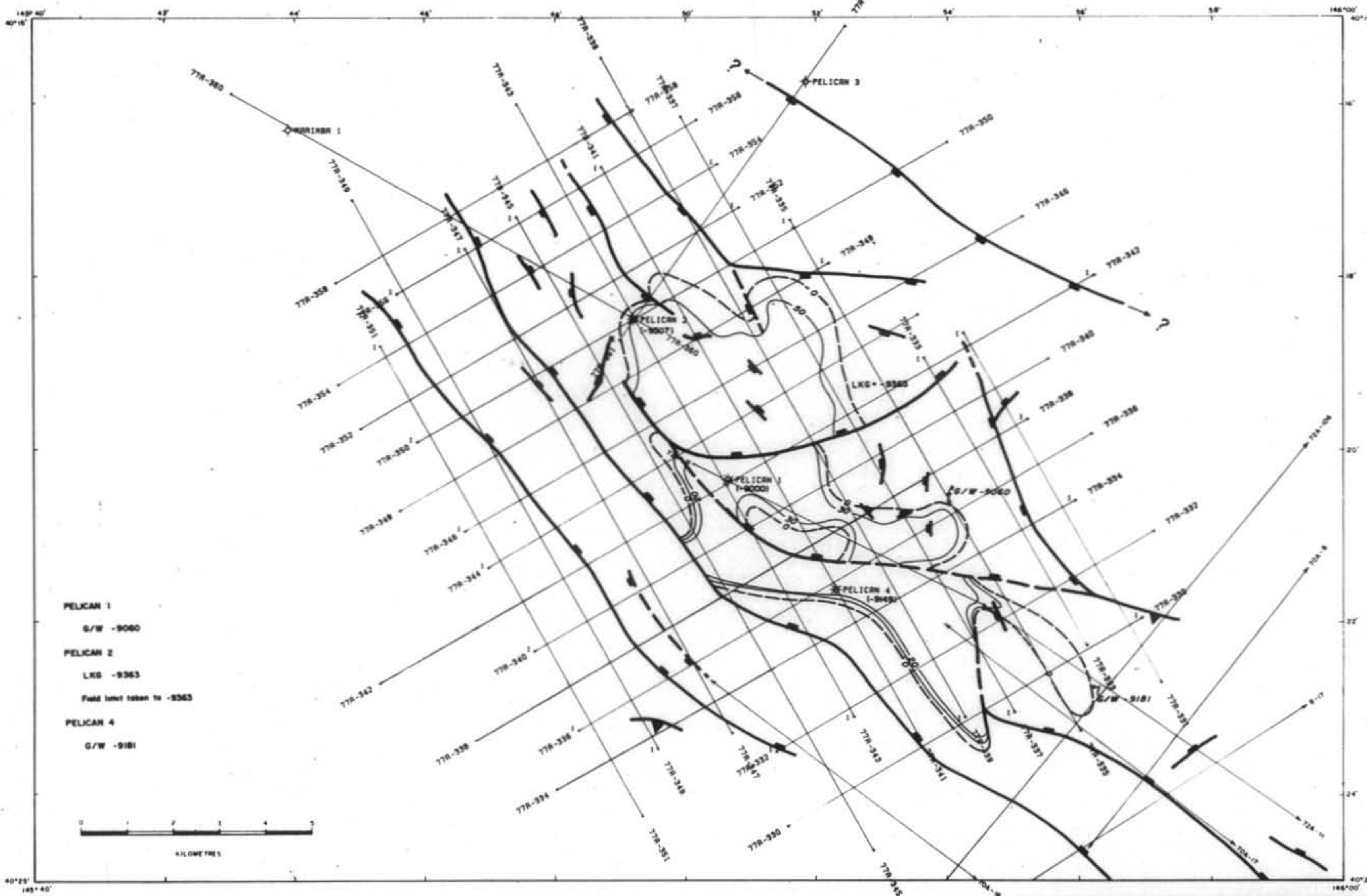
636154



5 cm

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD		
UNIT 'D' NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3341
DRN: C.K.	SC: AS SHOWN	FIG: 2.11

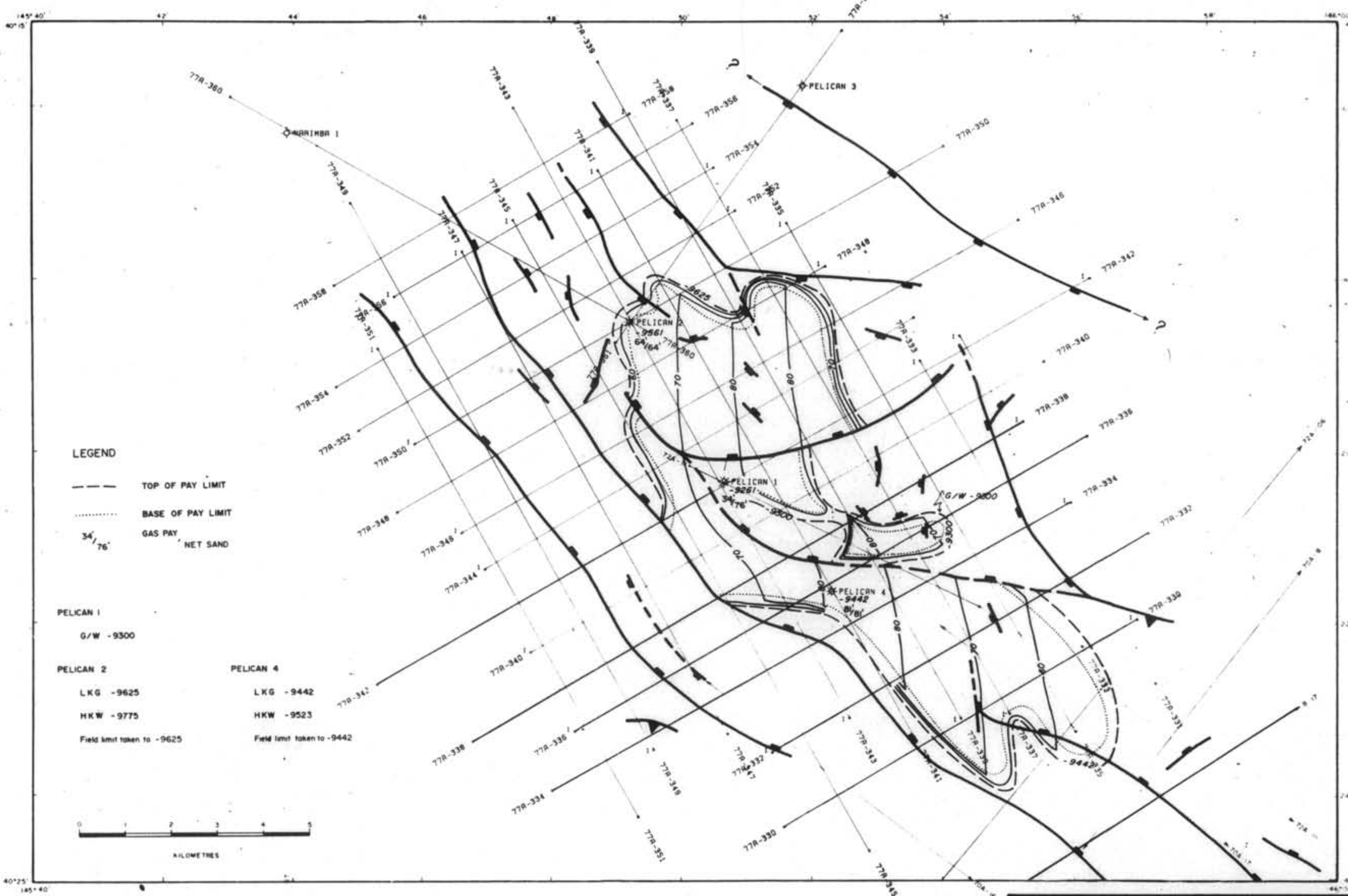
636155



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD **UNIT 'E' NET GAS ISOPACH**		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3342
DRN: C.K.	SC: AS SHOWN	FIG: 2.12

5 cm

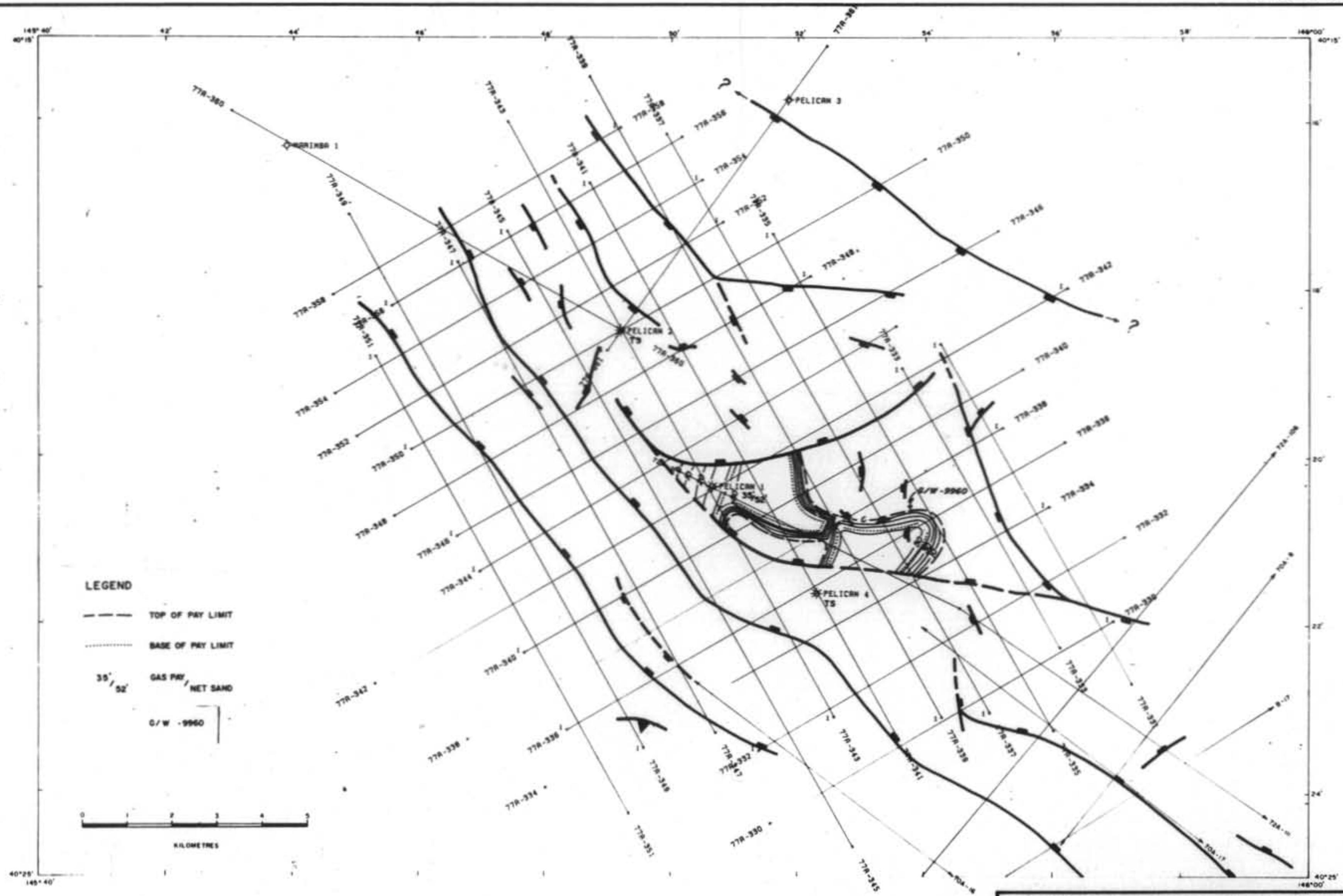
636156



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
PELICAN FIELD		
UNIT 'F' NET GAS ISOPACH		
INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3343
DRN: C.K.	SC: AS SHOWN	FIG: 2.13

5 cm

636157



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

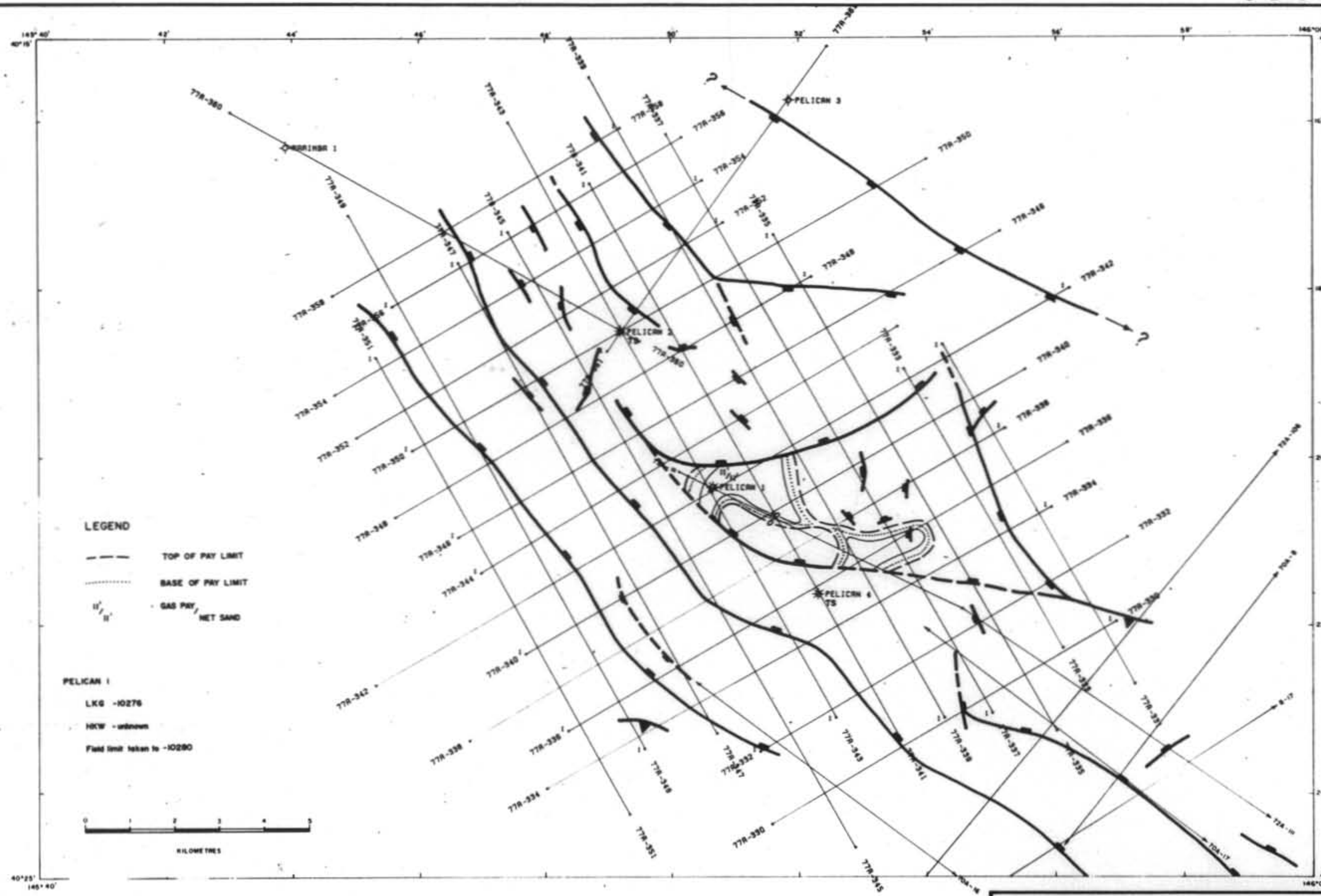
PELICAN FIELD

'G' SAND NET GAS ISOPACH

INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3344
DRN: C.K.	SC: AS SHOWN	FIG: 2.14

5 cm

636158



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

PELICAN FIELD

'H' SAND NET GAS ISOPACH

INT: K.GLENDAY	DATE: MAR. 84	NO: BASOO.3345
DRN: C.K.	SC: AS SHOWN	FIG: 2.15

5 cm

gas pay could extend beyond the arbitrary limit assigned on the pay maps.

2.4.3 Porosity, Gas Saturations, and Permeabilities

The available logs are inadequate to run a valid quantitative log analysis, hence, porosities and water saturations can only be roughly calculated. In general, the values tabled in the 1980 BMR report were used. The assumed error associated with these estimates varies for different sands depending on whether core data was available or not. In some cases, core data was available and in the absence of BMR estimates these were used.

BMR estimates of water saturation were generally used as they appeared to be reasonable values ie. in the 50 to 75 percent range. When a BMR estimate was not available, a conservative 50 to 65 percent value was assigned based on a rough estimate of the logs.

Porosities in cores range from measured values of 4 to 29 percent with the average over the more prospective sand zones being 19 to 21 percent. It is probable that under reservoir conditions this would actually be reduced to approximately 17 to 19 percent.

Some permeabilities from core analysis are quite high, in the 400 md range, and average values are in the tens of millidarcies. Although RFT results suggest lower permeabilities (1 to 2 md range), formation damage caused during drilling may be responsible for misleading RFT pressures and recoveries.

Correlations from limited core suggest that very low permeability occurs when porosity falls below 13 percent.

Based on the best core data available, reservoir sands with good porosities and permeabilities exist. However, low production rates may because of migrating fines, clay plugging or formation damage caused by drilling.

2.4.4 Formation Pressures and Over Pressures

Drilling and development problems associated with overpressure may be significant in determining the economic prospects of deeper plays in the Bass Basin.

Drilling has been stopped in several wells, notably Pelican 1, 2 & 4 and Poonboon 1, when a 500 psi overbalance between formation pressure and bore hole pressure could no longer be maintained with a 12 ppg mud weight. Good hydrocarbon shows, however, were still being encountered within the overpressured zone in Pelican 4.

Figure 2.16 plots <u>RFT</u> shut in pressure versus depth below MSL. In Pelican 4 it shows:

* that normal hydrostatic pressure gradient exists to -8800' MSL, ie. 0.44 psi/ft which is typical of brackish water depositional environments
* a lithostatic pressure gradient exists between -8800 and -9800 MSL (1.02 psi/ft)
* a zone of significant overpressure exists below -9800' MSL

The top of the lithostatic zone gradient coincides with

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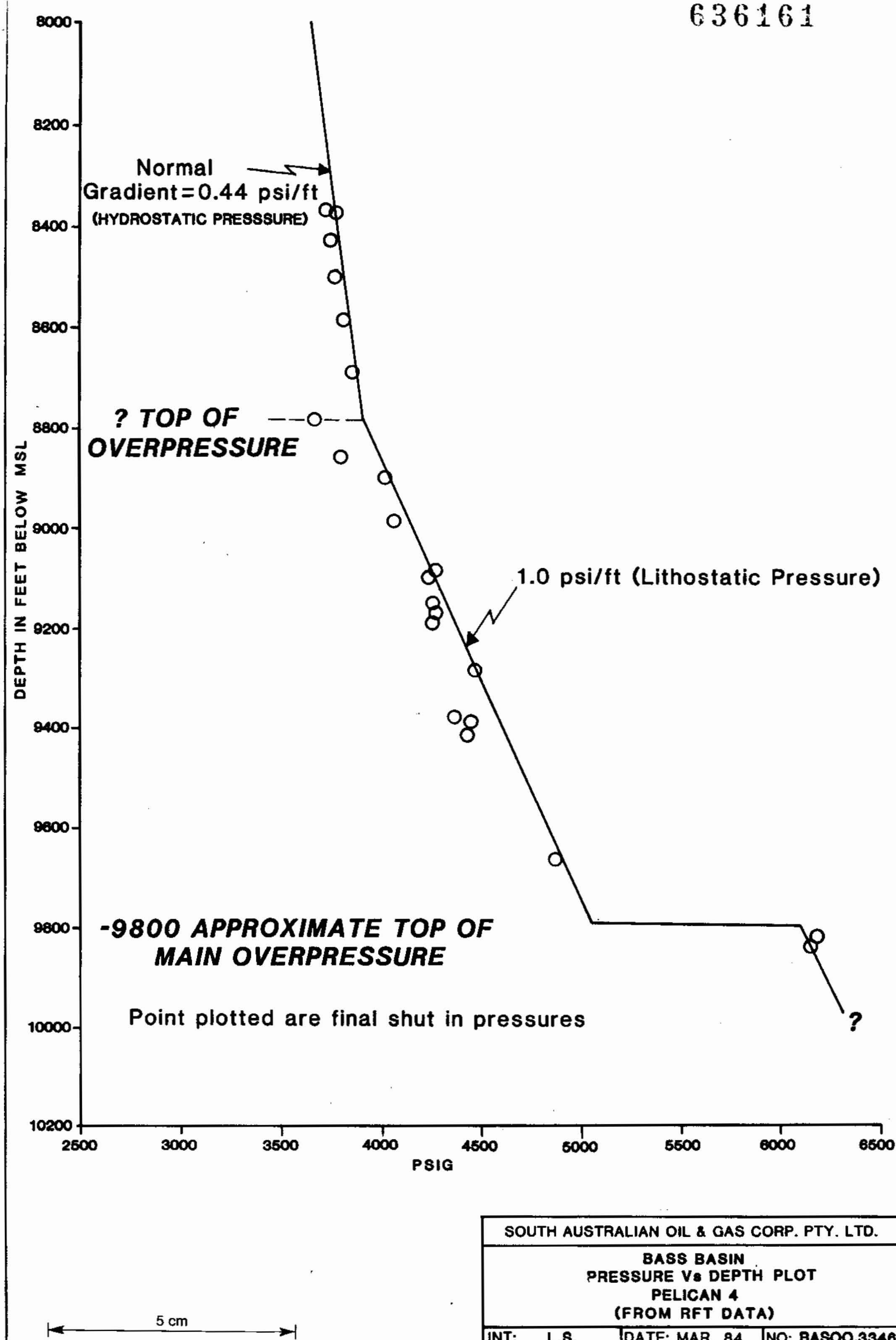

SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN PRESSURE Vs DEPTH PLOT PELICAN 4 (FROM RFT DATA)		
INT: L.S.	DATE: MAR. 84	NO: BASOO.3346
DRN: J.D.	SC: AS SHOWN	FIG: 2.16

a correlatable horizon in Pelican 1, 2 and 4 which may be a local unconformity surface. The main E & F pay sands also occur in this zone.

The relationships between overpressuring and Pelican Field hydrocarbon accumulation is not understood, but the overpressure maintenance indicates that faults are sealing. The existence of overpressuring also implies that a valid seal exists for sediments beneath it.

The following points taken from Fertl (1976) require consideration in any future play concepts involving potential overpressure zones:

* Lower temperature gradients exist within an overpressure zone due to the insulating effect associated with increased shale porosity.
* Overpressure may retard oil destruction (Fertl, 1976 p. 305).
* When an index ((R_{Sh} (normal) / R_{Sh} (observed) calculated from the short normal electrical log (Fertl, 1976, p. 178)) exceeds 3.5, it has been established from the US Gulf Coast and elsewhere, that no matter what other indications there are, including log results and mud logging, the zone will be non-commercial. This is normally associated with where the formation pressure exceeds overburden pressure ie. superpressure zones.
* In some cases overpressure zones can be determined prior to drilling from seismic data. There are numerous methods

available to monitor for overpressure during drilling.

In conclusion, any drilling programme should monitor for overpressure below depths of -8000' MSL.

2.5 Reserves

Reserves for the Pelican Field were calculated using the volumetric formula:

$$GIP = 43560 \times BRV \times \emptyset \times Sg \times 1/Bg$$

It is estimated at the 75 percent probability level that the total gas-in-place reserves for the Pelican Field based on available data is 1.536 TCF. Table 2.1 lists in-place reserves for each sand. The field is liquids-rich, but reliable figures for recovery factors and liquids production are not available. Previous reports indicate that the field may be a retrograde condensate reservoir which would result in very poor liquids recoveries but data to support this conclusion are not reliable. Indirect evidence from logs indicate that reserves may already exist in the liquid state within the "F" Sand Reservoir at Pelican 4.

2.6 Monte Carlo Simulation of Field Size

A Monte Carlo computer simulation was run to determine a field size probability distribution of the Pelican Field reserves. The variables which were taken into account and assigned probability distributions based on geological interpretation and intuition are reservoir area, thickness, gas saturation, porosity, and gas expansion.

The resulting field size - probability distribution (see Table 2.2) indicate a 90 percent chance of the Pelican Field containing greater than 1.18 TCF, a 70 percent chance of greater than 1.73 TCF, and a 50 percent chance of greater than 2.15 TCF and so on.

2.7 Problems and Recommendations

Problems associated with the present study are:

1) poor quality logs result in unreliable estimate of reservoir parameters,
2) insufficient fluid recoveries from the reservoir result in unreliable values for gas composition and formation water resistivities,
3) insufficient seismic coverage prevents closure of the reservoir to the southeast, and
4) the quality of seismic data available is too low for detailed mapping of this complex reservoir.
5) Faulting and facies changes combine to prevent reliable sand correlations.

Problems associated with producing the field are:

1) the highly faulted nature of the reservoir may reduce sand continuity,

TABLE 2.2

MONTE CARLO SIMULATION RESULTS

FREQUENCY TABLE

	PROBABILITY OF VALUE BEING GREATER THAN INDICATED								
	90	80	70	60	50	40	30	20	10
AREA	352513	374305	393701	414871	433823	452147	479318	510430	545837*1000
THICKNESS	98.8	121.0	136.8	150.7	165.4	177.8	194.5	214.8	241.0
EXPANSION	244.1	246.0	247.9	249.6	251.3	253.2	255.1	257.5	261.4
POROSITY	.137	.151	.163	.174	.182	.189	.198	.208	.221
GAS	.582	.619	.645	.669	.688	.705	.724	.749	.775
RECOVERY FACTOR	.466	.489	.506	.526	.550	.575	.608	.643	.688
OGIP	1180	1431	1733	1944	2147	2414	2657	3069	3530

2) The sands are fluvial in nature and likely to be relatively discontinuous over even short distances,

3) several gas/water contacts appear to be present, increasing the complexity of the reservoir and causing completion problems, and

4) if it is a retrograde condensate reservoir, poor liquids recovery would result.

Recommendations are:

1) the first well should be located to maximise intersection with gas pay, cased, and have extensive production testing carried out to determine potential deliverabilities,

2) prior to any further assessment drilling in the field, existing seismic should be reprocessed and migrated and the field remapped,

3) three further wells are considered necessary to prove up the reserves as presently mapped and one well should be drilled (assuming deliverabilities prove to be economic) on each of the Pelican structures and

4) seismic coverage should be extended at the southern end of the field to map closure.

2.8 Engineering and Economic Evaluation of Pelican Field [2]

2.8.1 Introduction

The BMR Record of the Pelican Field (Kurlowicz and Ellis 1980) indicated that "the initial production rate is only 3.27 MMCFD/well of raw gas.... thus the field will be less economic to develop than previously envisaged."

Most certainly, if the actual performance of the reservoirs is as described above, then any appraisal or development expenditure will be uneconomical. Massive front end development expenditure could only be supported by well deliverabilities considerably in excess of this BMR estimate.

Flow rates and gas composition are critical to the economic evaluation for the Pelican Field appraisal programme. These parameters are reviewed and Field economic evaluation developed using a number of simplifying assumptions.

2.8.2 Well Deliverability

Core analysis conducted by the BMR on 13 samples from two conventional cores in Pelican 4 yielded an average permeability of 1.7 md with a range from 0.1 to 4.8 md. In the subsurface, under overburden pressure, effective permeability would be less than indicated by these numbers. As the two cores were cut on either side of the major "F" reservoir it is questioned whether

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[2] Engineering and Economic Evaluation by SAOGC Engineering Department
D.J. Stanley - Manager
G. Halliday - Engineer

the core analysis data are representative of the better developed sandstone sections.

Analysis of RFT results provided calculated permeabilities from 0.3 to 3.7 md (average 1.4 md) which the BMR found to support the conventional core analysis. The one RFT pressure build up analysis which was considered reliable, took place in the 'F' reservoir unit and resulted in a calculated permeability of 0.16 md.

The BMR recognised the limitations of the RFT analysis which is greatly affected by skin damage, variations in vertical permeability and relative permeability effects. In the thick homogenous sandstone reservoirs of the Gippsland Basin the RFT has proven performance and provides an efficient method to evaluate the reservoir performance. However, in the Cooper Basin, where the sedimentary environment is similar to the Bass Basin, the tool has proved unreliable. Under a fluvio-deltaic sedimentary environment, the average reservoir permeability cannot be determined from the results of one RFT which examines one half inch of the pay interval.

The BMR Report based their total Pelican Field analysis on the limited results of Pelican 4 well. In earlier wells higher permeabilities were reported in the 400 md range and an average of tens of millidarcies (Glenday et al 1984).

It is concluded that the BMR assessment of the deliverability of the Field could be pessimistic:-

- conventional core permeability results from thin, shaley "ratty" sands were allocated to the major 'F' sandstone unit.

- RFT analysis, which is ineffective for determining permeability data in the Bass Basin sedimentary environment, was used to "confirm" low permeability in the 'F' reservoir.

For the 72 feet of log interpreted net pay in the 'F' reservoir unit (Ø .131; Sw.41) to be allocated a theoretical deliverability of 3.27 MMCFD appears conservative and can only be confirmed by flow tests on appraisal wells. Production rates in excess of 3.27 MMCFD could be expected.

2.8.3 Gas Composition

The BMR Report uses the gas composition (Table 2.3) presented in an earlier study (Ozimic and Donald 1977).
The source of that information is unstated.

There is no question that the gas is rich in liquids but the field average composition remains unknown. In multiple reservoir sands it is highly likely that the composition will vary between the sandstone units. This is even more complicated in the Pelican Field which is subdivided into independent fault blocks where compositions are likely to vary significantly in the one sand, between each of the fault blocks.

To obtain representative samples of the reservoir fluid is difficult, particularly in a retrograde condensate field where changes of state occur with changes of temperature and

Table 2.3

GAS COMPOSITION

Component	Md Fraction
Methane	.5488
Ethane	.0944
Propane	.0947
iso-Butane	.0336
n-Butane	.0452
iso-Pentane	.0144
n-Pentane	.0182
Heranes	.0208
Heptanes plus	.0723
Hydrogen Sulphide	
Carbon Dioxide	.0510
Nitrogen	.0066
	1.0000

LPG	124.9 Bbls/MMCF Raw Gas
Condensate	136.4 Bbls/MMCF Raw Gas
GOR	7331 Cubic Feet/Barrel Condensate

Source: BMR Record 1978/26

pressure. The RFT or FIT samples would provide only an approximation of the reservoir fluid.

The conclusion is that the reservoir composition is rich in gas liquids but detailed information can only be obtained by production testing an appraisal well and collecting representative samples of the reservoir fluid. Laboratory PVT work is essential to examine the changes of state of the reservoir fluid at different temperatures and pressures.

2.8.4 Economic Evaluation

The development of an isolated field in Bass Strait requires a major front-end investment. This could only proceed after defining with precision the characteristics of the reservoir, in particular the well deliverability and gas compositions. The project has been analysed on the basis of constant costs and prices. Thus it is assumed that the selling price for products will vary in harmony with the inflation of investment and operating costs. For further simplification, the 10% royalty has been incorporated in the discount factor.

2.8.5 Development Options

Two development options have been selected as a simplified "first-look" evaluation. These are:

	Option 1	Option 2
Initial Well Deliverability (MMCFD)	5	10
Platforms	3	2
No. of Wells	80	40

Gas Market (BCF/a x 20 yrs)	34
Subsea line (inches)	22
Process Plant	CO2,LRP(C3+)
Prices:	
Sales Gas ($ MCF)	2
Condensate ($/Bbl)	33
LPG ($/Tonne)	260
Reservoir depletion (1.5 TCF)	72%

(a) Initial Well Deliverability

The BMR estimate of 3.27 MMCFD is considered conservative and further appraisal of the field cannot be economically justified unless initial well deliverability approximates 5 MMCFD. A production decline curve (Table 2.4), similar to the BMR Record has been used with initial deliverability per well assumed at 5 MMCFD and 10 MMCFD.

These production profits do not fully recognise the effects of retrograde condensation occurring in the reservoir with depletion. This effect has been discounted since the influence of the retrograde condensation on the relative permeability of the formation to gas can be overcome by limited fracture treatments to increase conductivity in the vicinity of the well bore.

(b) Platforms

The configuration of the field, together with its independent fault block segments, dictates multiple platforms for the field development. In both options, a primary platform

Table 2.4

DELIVERABILITY DECLINE CURVES (MMCFD)

Year	Option 1	Option 2
1	5.0	10.0
2	5.0	10.0
3	5.0	10.0
4	5.0	10.0
5	4.25	8.5
6	3.85	7.7
7	3.48	7.0
8	3.21	6.4
9	2.90	5.8
10	2.67	5.3
11	2.52	5.0
12	2.32	4.6
13	2.14	4.3
14	1.97	3.9
15	1.82	3.6
16	1.75	3.5
17	1.65	3.3
18	1.55	3.1
19	1.46	2.9
20	1.34	2.7

Source: BMR Record 1981/81

is established with field processing facilities (separation/dehydration). Secondary platforms, connected by sub-sea lines, supply raw well production to these field facilities.

(c) Number of Wells

Option 1 is based on an 80 well programme, while Option 2 has 40 wells. It is assumed that the full compliment of wells are drilled as each platform is completed. Delayed investment could be achieved by mobilising the rig at various intervals during the life of the field.

(d) Gas Market

A limiting assumption is that the gas market must be supplied with a constant volume of gas over a twenty year period. Under each option, 34 BCF/a sales specification gas is supplied to the market.

The requirement for supplying a constant gas market is realistic from a contract point of view, however restricts the project from maximising gas liquids production during the early pay-back period. The possibility of "cycling" wells not required for immediate deliverability, could be examined once the reservoir parameters, gas composition, well completion timing and costs have been defined.

(e) Subsea Pipeline

The primary platform is connected by subsea line to the shore plant. It will carry the combined gas liquids stream for the 270 kms. The shore base is assumed to be south-west of Geelong, on the Victorian coast.

Advantages do occur in developing facilities on the Tasmanian coast as this limits the length of the two phase (gas and liquids) line, and a smaller single phase gas line could be used to connect to the Australian mainland. A location near Burnie would provide an integrated operation and processing base. This option should be evaluated in subsequent appraisals.

(f) Process Plant

The gas composition of 5% CO_2 will require CO_2 removal trains to meet a sales gas specification of less than 3%, and the high LPG content justifies a liquids recovery plant. The LPG's would be recovered by investment in packaged units rather than custom build plant.

It is assumed that condensate is pumped directly to the Shell Geelong Refinery, while LPG's are stored and loaded out over a wharf and suitable shipping facilities.

(g) Prices

Sales gas is sold at $2.0/MCF at the Victorian plant gate, while other products, condensate and LPG are sold at $33/Bbl and $260/tonne respectively.

(h) Depletion

Assuming the gas-in-place reserves are 1.536 BCF (Glenday et al 1984) then a depletion of 72% is achieved during the 20 year project. This depletion is high, however Glenday gives a 50% probability that gas-in-place exceeds 2 TCF.

2.8.6 Investment

Table 2.5 details estimated investment expenditure for the two options. The total investment cost ranges from $980,000 (Option 2) to $1,300,000 (Option 1).

The timing of investment expenditure is based on a four year design, construct and drill initial development wells to commence sales gas production from the commencement of year five. The commissioning of the second and third platforms (Option 2 and 1 respectively), are timed to maintain the constant 34 BCF sales gas to market. The investment schedules are presented in Table 2.6 and 2.7.

2.8.7 Operating Costs

The operating costs included have been restricted to direct costs only with limited allowance for overheads (Head Office, reservoir engineering, development geology, accounting etc.).

The principle cost centres are:-

Lifting (workovers, clean-outs, treatments)

Offshore Production:

Operating of gas processing facilities

Maintenance of platforms

Table 2.5

INVESTMENT EXPENDITURE

($ x 10^3)	Option 1	Option 2
Platforms (number)	520 (3)	360 (2)
Wells (number)	320 (80)	160 (40)
Subsea Line	230	230
Shore Plant:		
Infrastructure	30	30
CO_2 trains	40	40
LRP & storage, wharf	150	150
Line to refinery	10	10
	1300	980

Table 2.6

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OPTION 1
INVESTMENT TIMING, OPERATING COSTS AND PRODUCTION

Year	Investment ($ x 10^6)	No. of Wells *		Operating Costs ($ x 10^6)				Product Sales		
		Comp.	Prod.	Lifting	Offshore	Pipeline	Onshore	Gas (BCF)	LPG (M.Tonnes)	Condensat (M.Bbls)
1	40									
2	130									
3	440									
4	240									
5	210	48	30	4	6	1	4	34	574	6660
6		48	30	4	6	1	4	34	574	5730
7		48	30	4	6	1	4	34	574	5010
8	10	48	30	4	6	1	4	34	564	4410
9	40	48	33	4	9	1	4	36	538	3936
10	90	48	36	4	9	1	4	35	547	4149
11	50	56	39	5	9	1	4	35	561	4320
12	50	68	39	5	9	1	5	34	530	3885
13		80	42	5	9	1	5	34	543	4035
14		80	45	5	9	1	5	34	565	4218
15		80	48	5	9	1	5	34	527	3750
16		80	48	6	8	1	5	34	549	4044
17		80	51	6	9	1	5	36	516	4212
18		80	51	6	9	1	5	36	624	3711
19		80	54	6	9	1	6	35	546	4029
20		80	57	6	9	1	6	36	573	4269
21		80	57	6	9	1	6	34	537	3774
22		80	60	6	10	1	6	36	560	4092
23		80	63	6	10	1	6	35	581	4311
24		80	66	6	10	1	6	35	597	3786

* Comp. is wells completed; Prod. is well producing

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Table 2.7

OPTION 2
INVESTMENT TIMING, OPERATING COSTS AND PRODUCTION

Year	Investment ($ x 10^6)	No. of Wells *		Operating Costs ($ x 10^6)				Product Sales		
		Comp.	Prod.	Lifting	Offshore	Pipeline	Onshore	Gas (BCF)	LPG (M.Tonnes)	Condensa (M.Bbl
1	40									
2	130									
3	280									
4	140									
5	150	20	15	2	3	1	4	34	574	6660
6		20	15	2	3	1	4	34	574	5730
7		20	15	2	3	1	4	34	574	5010
8	10	20	15	2	3	1	4	34	564	4410
9	40	20	17	2	3	1	4	36	538	3936
10	100	48	18	2	3	1	4	35	547	4149
11	50	28	20	3	6	1	4	35	561	4320
12	40	34	20	3	6	1	5	34	530	3885
13		40	21	3	6	1	5	34	543	4035
14		40	23	3	6	1	5	34	565	4218
15		40	24	3	6	1	5	34	527	3750
16		40	24	3	6	1	5	34	549	4044
17		40	26	3	6	1	5	36	516	4212
18		40	26	3	6	1	5	36	624	3711
19		40	27	4	6	1	6	35	546	4029
20		40	29	4	6	1	6	36	573	4269
21		40	29	4	6	1	6	34	573	3774
22		40	30	4	8	1	6	36	560	4092
23		40	32	4	8	1	6	35	581	4311
24		40	33	4	8	1	6	35	597	3786

* Comp. is wells completed; Prod. is well producing

Submarine Pipeline

Onshore Process Plant:

Operating plant

Maintenance

Estimated costs for each classification are included in Tables 2.6 and 2.7.

2.8.8 Production

The product streams derived from supplying a constant gas market are included in Tables 2.6 and 2.7. The sales gas is shrunk by 7% as allowance for fuel gas while other product streams relate to the BMR Record and the timing of well commissioning.

2.8.9 Net Present Values

The pre-tax Net Present Value resulting from the investment schedules and production profits of Tables 2.6 and 2.7 are:-

($ x 10^6) Discount Rate *	Option 1	Option 2
22%	+ 146.5	+ 312.7
27-1/2%	+ 2.6	+ 142.6
33%	- 73.5	+ 45.9

* The discount rates correspond approximately to 20%, 25% and 30% before 10% royalty.

Under the assumptions of an initial well deliverability of 5 MMCFD and an investment of $1,300,000, the Option 1 indicates marginal profitability. With increased well deliverability, the investment cost in platforms and wells is decreased and the project is profitable.

Well deliverability appears to be the single most important element in the evaluation - and this can only be determined by testing of appraisal wells.

The economic evaluation presented stands on the development of the Pelican Field in isolation. Should the investment costs in sub-sea lines and process plant be supported by cross-subsidisation through the development of another field in the same general area of the Bass Basin - then the economic viability would be further enhanced.

2.8.10 Conclusions

1. Well deliverability is uncertain, however it is considered that the BMR analysis is very conservative.
2. The average field fluid composition is unknown, other than it is a liquids rich gas.
3. Well deliverability and gas composition can only be confirmed by the drilling and testing of appraisal wells.
4. The field configuration is such that multiple platform development is required.
5. Advantages in siting the process plant and operational base on the Tasmanian coast should be reviewed.
6. The possibility of "cycling" gas to increase early condensate production should be examined.
7. Under the assumptions, the project is marginally profitable with initial well deliverability rates of 5 MMCFD meeting

a sales gas market of 34 BCF per annum.

8. The discovery and development of a field in the same general area of Bass Basin would cross-subsidise development costs, enhance viability and reduce risks.

3.0 OTHER PROSPECTS

3.1 Introduction

Other prospects located within the Vacant Area include the Pipipa prospect and two potential prospects (or leads) which exhibit overpressure and characteristics similar to those evident on seismic data over Pelican Field. Each of these leads are only intersected by one line.

The Pipipa prospect, located at Pipipa 1, was mapped using the 1980 seismic detail grid.

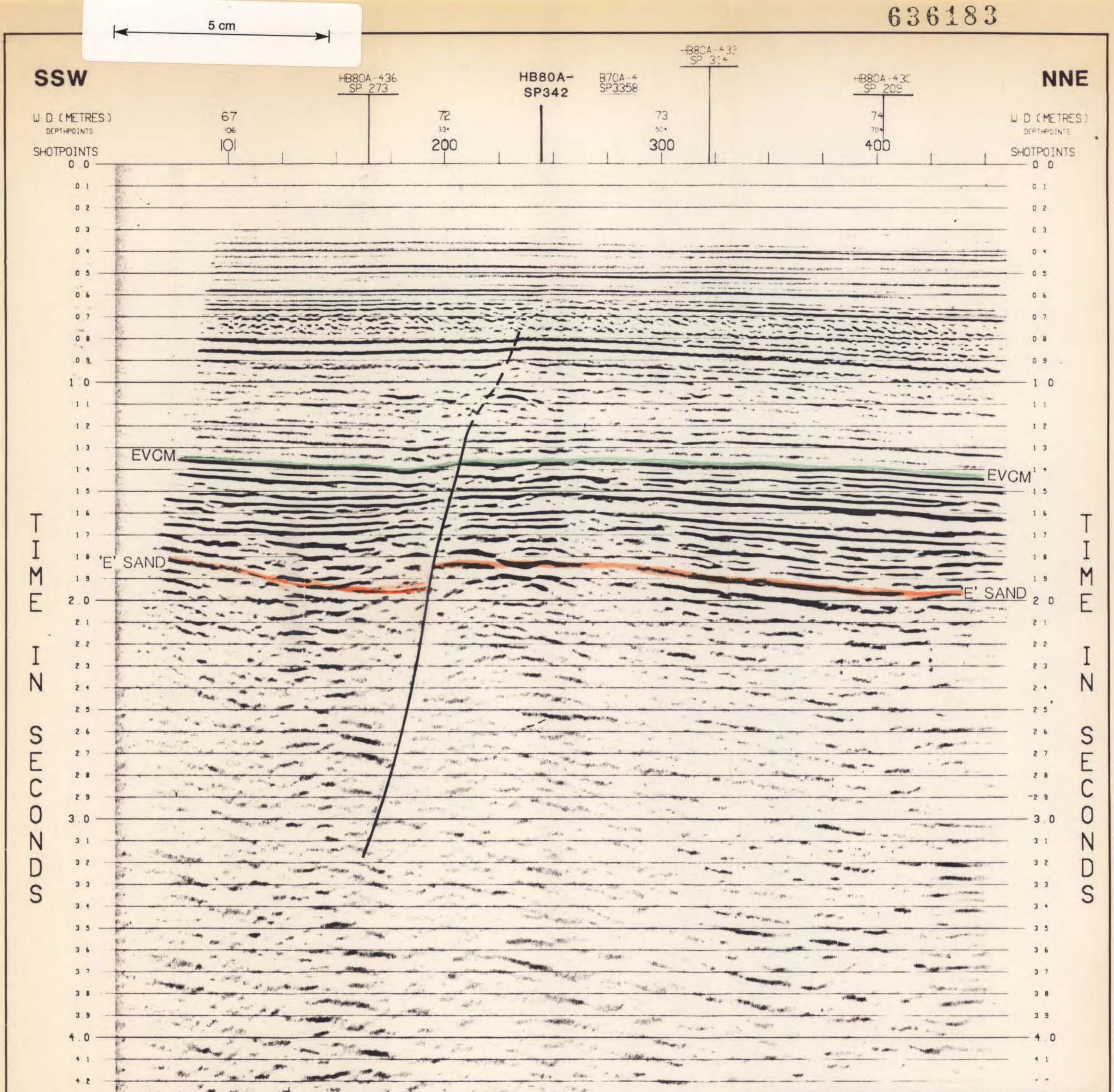
3.2 Pipipa Prospect

3.2.1 Structure

BHP drilled a well on this structure in 1982. The well reached total depth above the zone which contains pay in the Pelican field 12 kilometres to the north-east. Therefore the Upper *M. diversus* Unconformity to *L. balmei* interval must still be considered prospective on this structure. Two interpreted seismic sections are presented (Figures 3.1 and 3.2).

Two time structure maps have been produced for the Pipipa

636183



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.

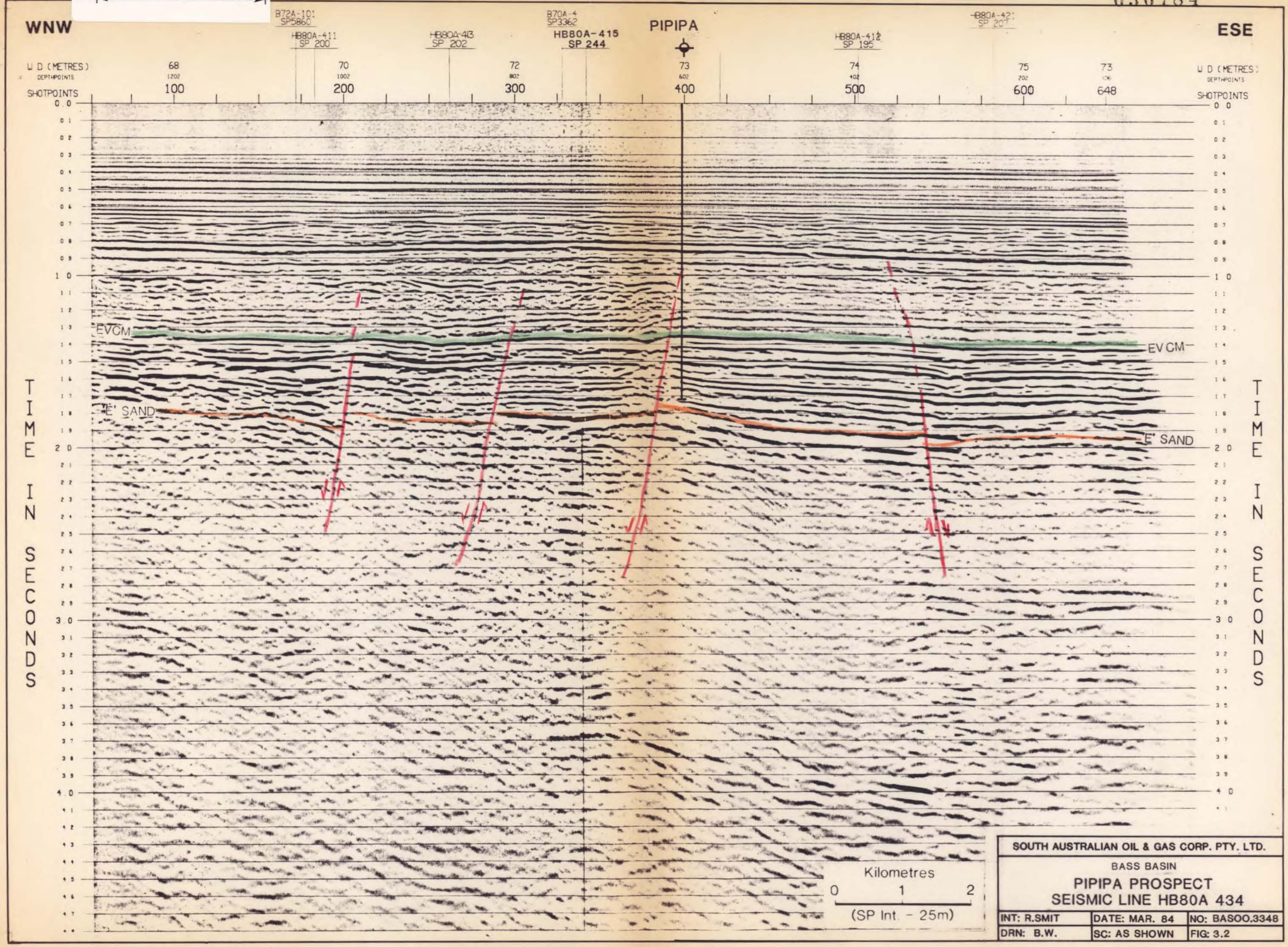
BASS BASIN

PIPIPA PROSPECT

SEISMIC LINE HB80A-415

INT: R.SMIT	DATE: MAR. 84	NO: BASOO.3347
DRN: B.W.	SC: AS SHOWN	FIG: 3.1

636184


5 cm
WNW
ESE
PIPIPA
B72A-101 SP5860
HB80A-411 SP 200
HB80A-413 SP 202
B70A-4 SP3362
HB80A-415 SP 244
HB80A-412 SP 195
HB80A-421 SP 207
W.D (METRES)
DEPTHPOINTS
SHOTPOINTS
EVCM
'E' SAND
TIME IN SECONDS
Kilometres
0 1 2
(SP Int. - 25m)
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
PIPIPA PROSPECT
SEISMIC LINE HB80A 434
INT: R.SMIT
DATE: MAR. 84
NO: BASOO.3348
DRN: B.W.
SC: AS SHOWN
FIG: 3.2

prospect: 1) top EVCM and

2) slightly above Pelican field 'E' zone. These time structure maps are considered to reflect depth structure, as stacking velocities do not indicate any significant velocity anomalies.

3.2.2 Top EVCM Structure Map (Figure 3.3)

The main feature of this mapping is the northwest-southeast trending fault, reactivated during the Miocene, which occurs 1 kilometre southwest of Pipipa 1. The Pipipa 1 well tested the structural closure at this level.

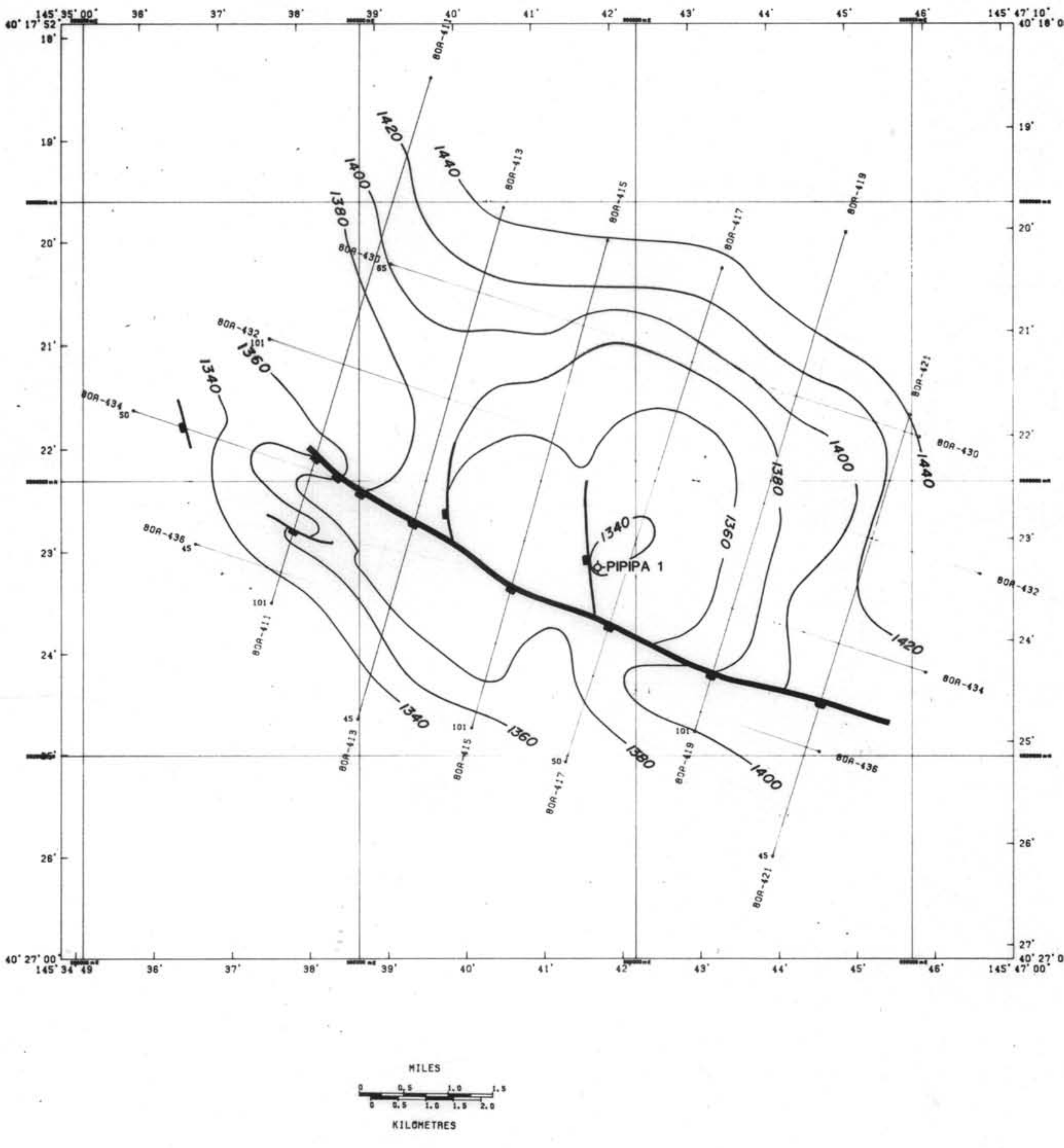
3.2.3 Slightly Above Pelican Field 'E' Zone Structure Map (Figure 3.4)

This mapping is an approximation of the structure at the 'E' and 'F' zones which encountered gas and condensate pay in the Pelican Field.

3.3 Overpressure Zone Leads

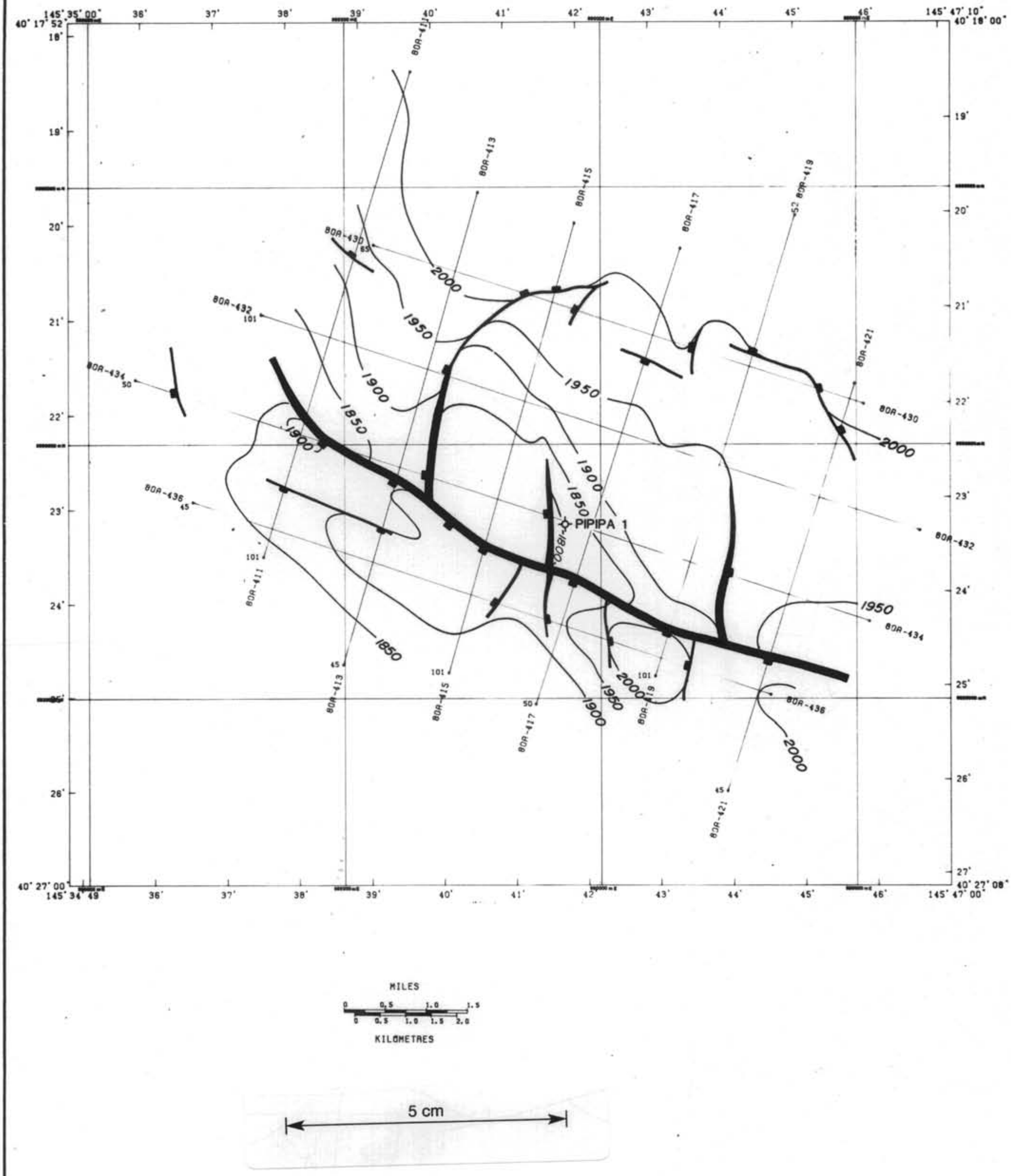
Two areas, one located approximately between shot points 1900 and 2000 on BMR line 19, the other located approximately between shot points 800-1050 on BMR line 9 are interpreted as zones of overpressuring below the top of the Paleocene (*L. balmei* zone). These areas have similar characteristics to those observed at Pelican Field (see Figure 3.5). These anomalies occur in a fault bounded graben which trends approximately northwest-

636186



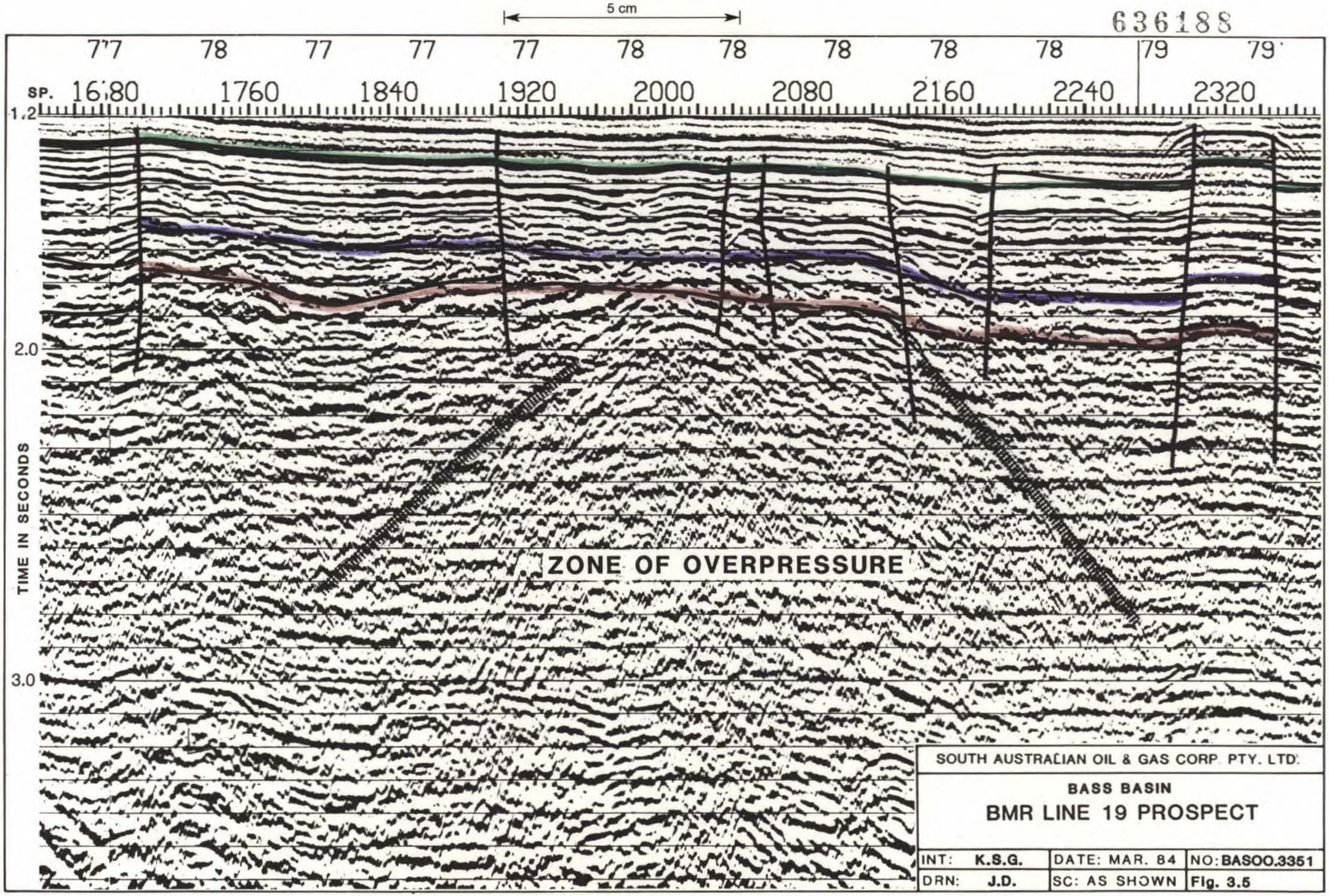
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN PIPIPA PROSPECT TWO WAY TIME STRUCTURE TOP EVCM		
INT: R.SMIT	DATE: MAR. 84	NO: BASOO.3349
DRN: B.W.	SC: AS SHOWN	FIG: 3.3

636187



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.		
BASS BASIN PIPIPA PROSPECT TWO WAY TIME STRUCTURE SLIGHTLY ABOVE PELICAN FIELD 'E' ZONE		
INT: R.SMIT	DATE: MAR. 84	NO: BASOO. 3350
DRN: B.W.	SC: AS SHOWN	FIG: 3.4

636188



SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.			
BASS BASIN BMR LINE 19 PROSPECT			
INT:	K.S.G.	DATE: MAR. 84	NO: BASOO.3351
DRN:	J.D.	SC: AS SHOWN	Fig. 3.5

southeast along the same trend as the Pelican Field.

As well as being in a similar structural setting as the Pelican field, these leads are located along the same depositional trend and sand percentages and sand types are likely to be similar. These prospects require further seismic detailing to be matured for drilling, and would best be followed up after a deeper test at Pelican Field investigated the potential of the section beneath the overpressured zone.

3.4 Other Play Concepts

There is still untested for Pipipa-type plays northwest of Pipipa 1 along the same depositional and structural trend (Encl. 8.1). Hydrocarbons being sourced from the deeper portions of the basin in the vicinity of Narimba 1 have a relatively short migration path updip before they are trapped against possible sealing faults similar to those postulated for the Pipipa prospect.

Further potential also exists to extend the Pelican Field, particularly to the northwest (Encl. 8.1). As at Pelican Field, hydrocarbons sourced in the Narimba 1 area may have had a short distance to migrate updip to the northeast and be trapped against the extension of major fault system separating the Pelican Field from Pelican 3.

Both of these concepts would be clarified by results obtained from appraisal wells at the Pelican Field and exploration wells on more mature prospects.

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NW
KING ISLAND MORNINGTON PENINSULA RIDGE
SE
KONKON 1
CORMORANT 1
TOOLKA 1A
GAMMA RAY
SONIC
BASS 1
NANGKERO 1
TIE WITH CROSS SECTION 1
DEMONS BLUFF FORMATION
"UPPER" EVCM
M.DIVERSUS UNCONFORMITY TO TOP OF L.BALMEI INTERVAL
PALEOCENE
OTWAY GROUP
NO SHOWS
EVEN FAIR YELLOW FLUORESCENCE GOOD CUT
EVEN STRONG GOLDEN YELLOW FLUORESCENCE GOOD CUT
REC. 22000 cm³ 22° API OIL
REC. 1000 cm³ CONDENSATE
EVEN GOOD YELLOW FLUORESCENCE GOOD CUT
FLUORESCENCE FAIR TO GOOD CUT BLEEDING GAS,OIL SHOW UP TO C4 RECORDED
AS BELOW
AS BELOW
AS BELOW
FAINT DULL YELLOW FLUORESCENCE (NO CUT)
NO SHOWS
636197
5 cm
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
SCHEMATIC STRUCTURAL CROSS SECTION
SECTION 1
DEMONS BLUFF FORMATION TO PALEOCENE
INT. K.G.
DATE. MAR'84
No. BASOO.3352
DRN. S.M & L.S
Sc. AS SHOWN
ENCL. 2.3
OR-245


SW
NE
TIE WITH CROSS SECTION 2
PIPIPA 1
NARIMBA 1
PELICAN2
PELICAN3
POONBOON1
DONDU1
YORONGI1
BASS2
DEMONS BLUFF FORMATION
"UPPER" EVCM
M.DIVERSUS UNCONFORMITY TO TOP OF L.BALMEI INTERVAL
PALEOCENE
-GOOD FLUORESCENCE
-METHANE TO HEXANE GAS PEAKS
TRACE DULL YELLOW FLUORESCENCE
AS ABOVE
STRONG BLUISH FLUORESCENCE WITH VERY WEAK BLUISH - WHITE CUT (RESIDUAL OIL)
BLUE WHITE AND BLUE YELLOW FLUORESCENCE
FAIR BLUE-YELLOW CUT
GOOD SHOW ON GAS DETECTOR
SPOTTY BLUE - WHITE FLUORESCENCE FAIR CUT
SPOTTY BRIGHT YELLOW FLUORESCENCE FAIR TO GOOD
TRACE FLUORESCENCE
MINOR GAS SHOW (TIGHT SAND)
PROD. TEST MINOR GAS
WELL KICKED WITH 10.2PPG MUD
FLUORESCENCE
FLUORESCENCE
FLUORESCENCE
MINOR C5's FLUORESCENCE RECORDED
MINOR C5's
MINOR FLUORESCENCE
NO SHOWS
NO SHOWS
5 cm
SOUTH AUSTRALIAN OIL & GAS CORP. PTY. LTD.
BASS BASIN
SCHEMATIC STRUCTURAL CROSS SECTION
SECTION 2
DEMONS BLUFF FORMATION TO PALEOCENE
INT. K.G
DATE. MAR'84
No. BASOO.3353
DRN. S.M & L.S
Sc. AS SHOWN
ENCL. 2.4
OR-245
636198

SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.

BASS BASIN

TIME STRUCTURE TOP OF EASTERN VIEW COAL MEASURES

636199

INTERP.:	R. SMIT	DATE:	MAR '84	ENCLOSURE 4.1
DRAWN:	SAOGC	SCALE:	1:250,000	BASOO.3354

OR_245

SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.

BASS BASIN
TIME STRUCTURE
TOP OF M. DIVERSUS UNCONFORMITY

636200

INTERP.: R.SMIT	DATE: MAR '84	ENCLOSURE 4.2
DRAWN: SAOGC	SCALE: 1:250,000	BASOO.3355

OR-245

636201

SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.

BASS BASIN
TIME STRUCTURE
TOP OF L. BALMEI
(PALEOCENE)

INTERP.:	R. SMIT	DATE:	MAR '84	ENCLOSURE 4.3
DRAWN:	SAOGC	SCALE:	1:250 000	BASOO.3356

OR-245

WILSON'S PROMONTORY
VICTORIA
TASMANIA
VIC P16
VIC P13
VIC P12
T-19-P
T-18-P
T-15-P
T-14-P
T-16-P
T-16-P
T-16-P
T-16-P
T-16-P
T-16-P
T-15-P
T-19-P
VACANT
AREA
DEAL ISLAND
KING ISLAND
FLINDERS ISLAND
THREE HUMMOCK IS.
HUNTER IS.
TASMANIA
KONKON 1
TOOLKA
CORMORANT 1
BASS 1
AROO 1
BASS 2
YURONG
DONDU 1
BASS 3
TAROOK 1
NANGKERO 1
POONBOON 1
NARIMBA 1
PELICAN 3
PELICAN 2
PELICAN 1
PELICAN 4
PIPIPA
DURROON 1
100
200
300
400
500
SCALE:
KILOMETRES
0 5 10 15 20 25 30 35
1:250 000
5 cm
636202
SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.
BASS BASIN
ISOCHRON: TOP OF EVCM
TO TOP M. DIVERSUS UNCONFORMITY
INTERP.: R. SMIT
DATE: MAR.'84
ENCLOSURE 4.4
DRAWN: SAOGC
SCALE: 1:250,000
BASOO.3357
OR_245

636203

SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.

BASS BASIN
ISOCHRON
M. DIVERSUS UNCONFORMITY
TO TOP L.BALMEI

INTERP.: R. SMIT	DATE: MAR '84	ENCLOSURE 4.5
DRAWN: SAOGC	SCALE: 1:250 000	BASOO.3358

OR-245

VIC P16
VICTORIA
TASMANIA
T-19-P
WILSON'S PROMONTORY
VIC P13
VIC P12
KONKON 1
TOOLKA 1
T-15-P
DEAL ISLAND
T-18-P
CORMORANT 1
BASS 1
AROO 1
KING ISLAND
T-14-P
BASS 2
YURONG 1
DONDU 1
FLINDERS ISLAND
TAROOK 1
APPEARS ON SEISMIC SECTION TO BE OVERPRESSURED BENEATH L. BALMEI
NANGKERO 1
POONBOON 1
T-16-P
NARIMBA 1
PELICAN 3
PELICAN 2
PELICAN 1
PELICAN 4
PIPIPA 1
VACANT
AREA
T-19-P
THREE HUMMOCK IS.
HUNTER IS
APPEARS ON SEISMIC SECTION TO BE OVERPRESSURED BENEATH L. BALMEI
T-15-P
DURROON 1
TASMANIA
PLAY TYPES
REF.
TYPE
SYMBOL
8. 2
PELICAN
TOP EVCM
M. DIVERSUS
M. DIVERSUS
THIN
THICK
L. BALMEI
L. BALMEI
8.3
PIPIPA
TOP EVCM
M. DIVERSUS
M. DIVERSUS
L. BALMEI
L. BALMEI
8.5
PIPIPA N.W. FACIES SEAL
8.6
PELICAN LARGE RECURRENT FAULT SEAL
8.7
STRUCTUAL CULMINATIONS
SCALE:
KILOMETRES
0 5 10 15 20 25 30 35
1:250 000
5 cm
636204
SOUTH AUSTRALIAN OIL & GAS CORPORATION PTY. LTD.
BASS BASIN
PROSPECT MAP
(BASE : ISOCHRON M. DIVERSUS
UNCONFORMITY TO TOP L. BALMEI)
INTERP.: P. MOIGNARD
DATE: MAR '84
ENCLOSURE 8.1
DRAWN: SAOGC
SCALE: 1:250 000
BASOO.3359

OR_245