225001

TPR
OR-210

T/19P Part 7.

Permit T-19-P

Bass Basin
Tasmania, Australia
Quarterly Report

Second Quarter Report
June 27th to September 27th, 1984

Year 4

Submitted by:

Perthshire Petroleum, Ltd.

14141 Southwest Freeway

Houston, Texas USA

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225002

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Submitted by:

Perthshire Petroleum, Ltd.

14141 Southwest Freeway

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225003

Summary

No well was drilled and no new geophysical data was acquired during this quarter.

The results of a regional seismic data acquisition program carried in the Bass Basin by the Bureau of Mineral Resources has been intregrated with the well data and the most recent seismic data acquired by the current permit holder. These results have been presented by the BMR in the form of seismic time structure maps, representative segments of seismic lines, models, etc. New exploration concepts are presented and illustrated.

The reservoir potential of the Paleocene/Cretaceons objective section has been evaluated. The sandstone porosity and permeability determinations from whole core and plug samples are listed. Cross-plots of porosity versus depth indicate that reservoir deterioration does not seem to be controlled to any significant extent by present day depths of burial. The main controlling factor appears to be the nature and amount of the matrix component and to a lesser extent the amount and nature of the cement component. These are not so much related to depths of burial as they are to the environment at time of deposition where low energy levels did not promote the removal of the fine fraction or when differential settling of the fine fraction took place and choked the pore throats of the sandstone. The analysed core intervals indicate that substantial thicknesses of excellent reservoir quality sandstone are present throughout the Eastern View Coal Measures.

The regional seismic mapping of Permit T-19-P area has revealed the presence of several prospects and leads. These have previously been described and illustrated by seismic time structure maps, isochron maps and representative seismic lines. Additional prospect definition seismic data acquisition has been recommended on the most promising leads. It is expected

that data acquisition will take place in the second quarter of 1985 in order to take advantage of the best weather window.

All the published data and studies relevant to source-rock evaluation of the Paleocene and Cretaceous found in the Bass Basin wells has been assembled and reviewed. These indicate that the objective section contain shale, coal, and fine clastics of source rock quality and that they are rich enough and locally mature enough to have generated significant quantities of hydrocarbons. Some analysis indicate the possibility of an early marine ingression from the northwest and southwest, around King Island.

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Introduction

This quarterly report introduces a new exploration concept whereby the Paleocene and Cretaceous sandstone, coal, and shale sequence constitutes the objective section of major tilted fault blocks located in the northwest corner of the Bass Basin.

Conventional cores of the Paleocene and Cretaceous objective section, taken in various wells of the basin, are described as to their lithology, reservoir potential and preservation of reservoir potential with increasing depth.

The source rock potential of the Paleocene and Cretaceous objective section is summarized.

Play Concept

The whole of Exploration Permit T-19-P area has been remapped at several stratigraphic levels. The seismic horizons are tied as well as can be to the Konkon #1 and Cormorant #1 well, as they are the nearest in this general area of the basin.

Several prospects and leads have been identified. These consist of tilted fault blocks located below, or related to a very major unconformity, or unconformities.

The play concept calls for a thick reservoir sandstone and a mature coal and shale source-rock package to be present within the Eastern View Coal Measures in areas of the basin where the section is greatly expanded by contemporaneous down faulting and rotation and where prospective structure were sealed in a timely manner by interbedded and surrounding shales. Figure 2. Available data indicate that these requirements are present in certain areas of Permit T-19-P.

225008

NEW PALEOCENE/CRETACEOUS PLAYS IN THE BASS BASIN - A 'BRIGHT SPOT' IN SOUTHEAST AUSTRALIA?

J.C.Branson, M.A. Etheridge, D.A. Falvey, K.L. Lockwood, A.S. Scherl and P.G. Stuart-Smith

The Cretaceous to Recent Bass, Gippsland and Otway Basins lie predominantly offshore in the Bass Strait region between southeast mainland Australia and Tasmania (see map). The Gippsland Basin is responsible for more than 90% of domestic crude oil production, but the Bass and Otway Basins have yet to yield a commercial hydrocarbon discovery, despite superficial similarities of stratigraphy and evolution.

In the Gippsland Basin, hydrocarbons are largely trapped in anticlinal and fault-related structures at a Late Eocene unconformity. Structures of this age are poorly developed in the Bass Basin. However, a recent review of hydrocarbon potential by BMR scientists, had demonstrated that suitable source rocks and maturation conditions existed in the Late Cretaceous to Paleocene sequence, and that plays could be developed at that level which may justify further examination.

Exploration of this deeper portion of the Bass Basin was previously hampered by relatively poor quality of seismic data generated at and below highly reflective and reverberant Eocene coal measures. In 1982, the Bureau of Mineral Resources, Geology and Geophysics (BMR) conducted a contract seismic survey using a high energy airgun source and a 3200 metre long streamer (96 channel, 48 fold). Over

3200 kilometres of regional lines covering the whole basin with ties to wells and adjacent basins (Gippsland and Otway) were collected along with gravity and magnetic data. These data have opened up the deeper basin beneath the Eocene coal measures and revealed new and exciting hydrocarbon plays, as well as providing a sounder basis for understanding basin formation mechanisms.

STRATIGRAPHY

Early Cretaceous deposition filled graben and half-graben with volcanogenic detritus under fluviatile and alluvial conditions. These sediments are at least 6 km thick in the depocentres and thin to a few hundred metres or less over horst blocks and near basin margins. Seismic interval velocities and well data together with the volcanogenic nature of sediment indicate low porosity and low permeability. Slower basin subsidence prevailed in the Late Cretaceous with sediment derived from eroded Palaeozoic and Proterozoic highland regions, as well as elevated portions of horst blocks. These sediments were deposited under fluvial and lacustrine conditions. Minor marine ingressions may have occured as these are known to occur in the Otway Basin to the west. During the Paleocene-Eocene, coal deposition was widespread in what appears to have been a dominantly alluvial basin. In the latest Eocene a barrier to the northwest was over stepped by the sea. At the same time the marine influence was increasing in the Otway and Gippsland Basins. Widespread marine marls, limestones and clays were deposited in the Oligocene and Miocene. Marine carbonate shelf conditions prevail to the present day. Volcanism in the latest Tertiary gave rise to intrusives and extrusives in the upper section.

STRUCTURE

The Early Cretaceous fault geometry recognized from the BMR data demands significant crustal extension, in contrast to the largely vertical movements previously proposed. The faults are planar, with shallow to moderate dips (generally to SSW), and they produce tilts of the basement surface of up to 40 degrees. This "domino-style" rotational faulting resulted from a SSW-NNE upper crustal extension of 50% to 70%. The section shows the tilt blocks and their associated half-graben. The map illustrates the short strike extent of the normal faults, due to disruption along NNE-trending, dextral transverse faults. There is not necessarily a simple strike-slip displacement across these transverse faults (the heavily drawn fault near the basin centre is a good example), and they may therefore have essentially the same kinematic style and geometry as oceanic transform faults. In the southeastern extremity of the basin, a near symmetrical Early Cretaceous graben is overprinted by northwest trending, Late Cretaceous tilt blocks . This episode of faulting may be related to Tasman Sea spreading.

The Early Cretaceous fault and tilt blocks play a key role in the development of hydrocarbon plays. Much of the structuring in the more prospective overlying rocks results from differential compaction over and/or rejuvenation of these deep structures. Anticlinal closures over buried tilt block corners have been extensively explored along the basin margin (e.g. Dondu-1,Bass-3). However the major hydrocarbon indications have been found closer to the basin depocentre. The Pelican gas field is located in just such a mid-basin structure. Whereas previous interpretations have correlated the Pelican structures with those along the southwest margin of the basin, this new structural model correlates them across transform-like faults with the major tilt block near Aroo-1 and Bass-1, in the basin centre. The coincidence of an Early Cretaceous tilt block with a thick Late Cretaceous to Paleocene source section is now regarded as being highly prospective, and play concepts have been developed accordingly.

PLAY CONCEPTS

One example of a number of such new, tilt-block related Paleocene/Late Cretaceous plays in the vicinity of Bass-1 is illustrated. The uppermost play (1) is associated with differential compaction over the basement high and occurs in Eocene, Paleocene and Late Cretaceous sediments. In this particlar example, direct hydrocarbon indicators (D.H.I's) are observed on the synthetic sonic log/seismic trace inversion record section. They occur at multiple depths over the structure as both velocity anomalies and 'flat spots'. The origin of such D.H.I's in this basin has not been previously tested. A deeper play (2) is related to sand aprons of Late Cretaceous age associated with the horst block. Such locally elevated areas should give rise to reworked sands during horst block erosion. The global sealevel highstand in the Late Cretaceous could provide a lateral regional seal through deposition of marine ingressive clays, particularly towards the centre of the basin. A play related to possible shale diapirism (3) in the thickest parts of the Late Cretaceous section occurs on the downthrown sides of horst blocks. The Cretaceous paleolatitudes of the region argue against evaporites, whereas overpressuring, related to shale mobilisation is known to occur around Pelican-2.

SUBSIDENCE AND MATURATION HISTORY

The subsidence and thermal maturation history ('geohistory') of such a new Bass Basin play have been synthesized using the seismic stratigraphy, well data from Bass-1 and an anomalous paleo-heatflow predicted by a lithospheric extension model developed by Garry Karner (now at Durham University,U.K.)

The computer generated thermal geohistory shown, was prepared for BMR by Ian Deighton (Paltech Pty. Ltd., Sydney) The analysis indicates that the entire Paleocene/ Cretaceous section falls precisely within the oil window (Ro = 0.6 to 1.3%). This is consistent with observed Eocene to Recent maturation levels in adjacent wells. Late Cretaceous and Paleocene source rocks are predicted to have commenced generation in the Miocene, after structural development of the trap. The presence of D.H.I.'s at a depth of 2 kms and above the top of the present oil window implies migration and is consistent with shows of oil observed at similar levels in Cormorant-1.

STUDIES CONTINUE

This represents just the preliminary results from BMR's Bass

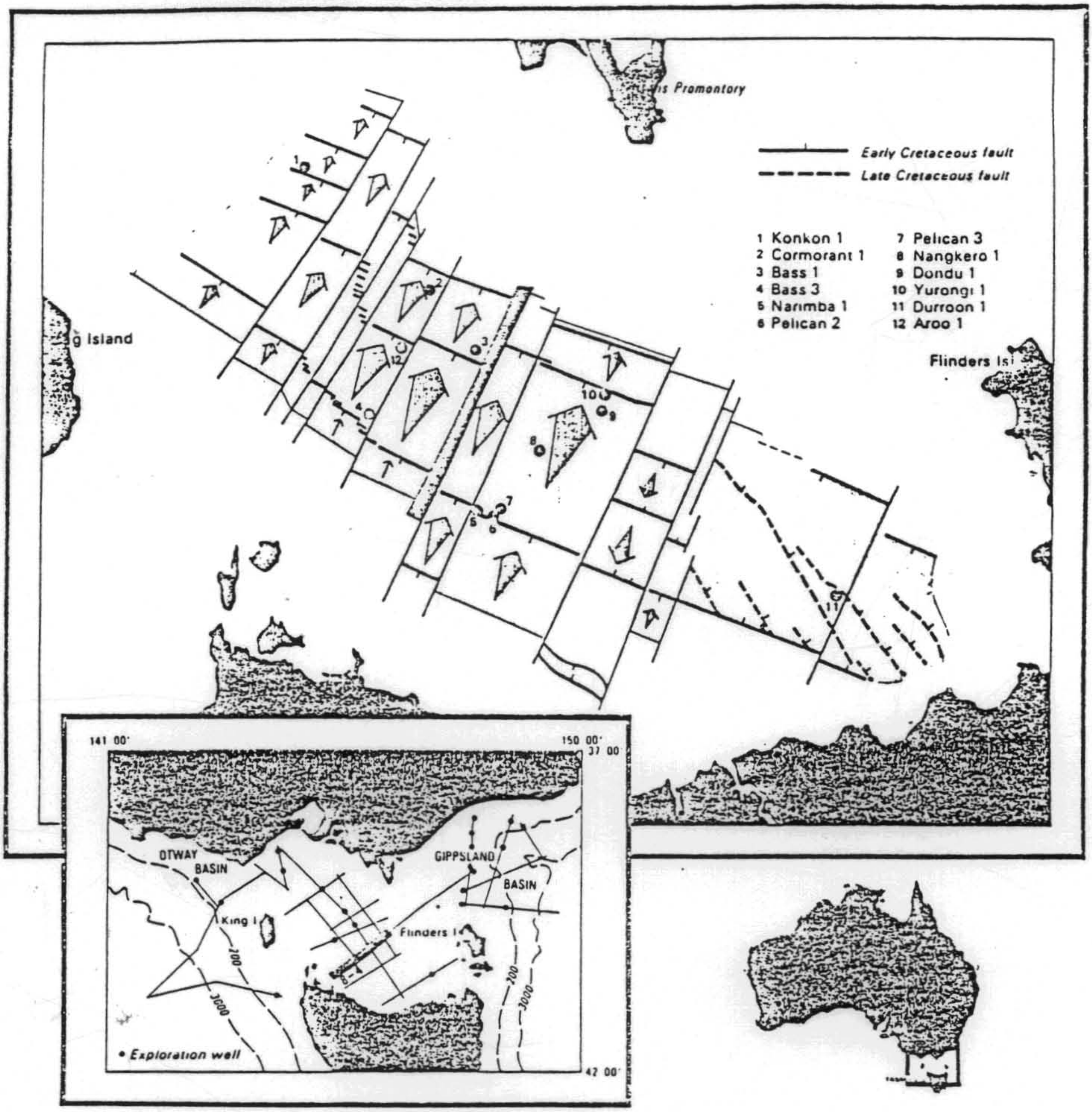
Basin Study. Work is continuing on other aspects of the new seismic data: a complete structural and stratigraphic synthesis of the Bass Basin; Otway and Gippsland Basin correlations; deepwater Otway and Gippsland Basin studies; and a sedimentological study including work on diagenetic processes being conducted by Monash University (Melbourne).

The majority of this survey data, including the seismic inversion sections, were released to the public between October 1983 and February 1984. The open file data includes processed record sections, digital field tapes and digital stack tapes. The total cost of this survey was $3 million.

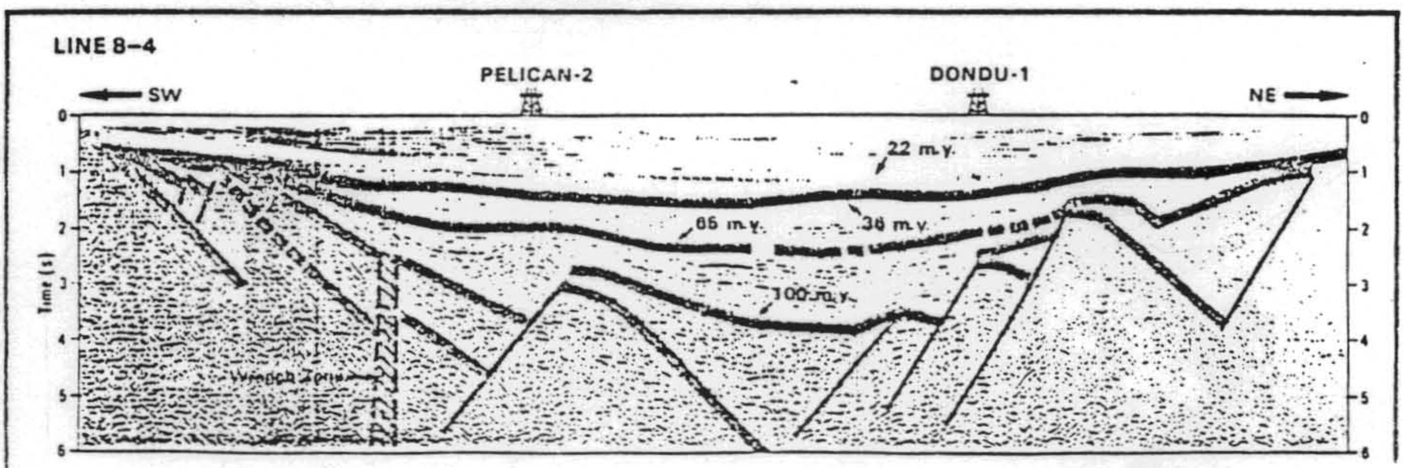
FIGURES

5 cm

FIGURE 1



...s Promontory
Early Cretaceous fault
Late Cretaceous fault
1 Konkon 1
2 Cormorant 1
3 Bass 1
4 Bass 3
5 Narimba 1
6 Pelican 2
7 Pelican 3
8 Nangkero 1
9 Dondu 1
10 Yurongi 1
11 Durroon 1
12 Aroo 1
...g Island
Flinders Is
141 00'
150 00'
37 00'
42 00'
OTWAY
BASIN
GIPPSLAND
BASIN
King I
Flinders I
200
3000
• Exploration well



LINE 8-4
SW
PELICAN-2
DONDU-1
NE
Time (s)
22 m.y.
65 m.y.
38 m.y.
100 m.y.
Wrench Zone

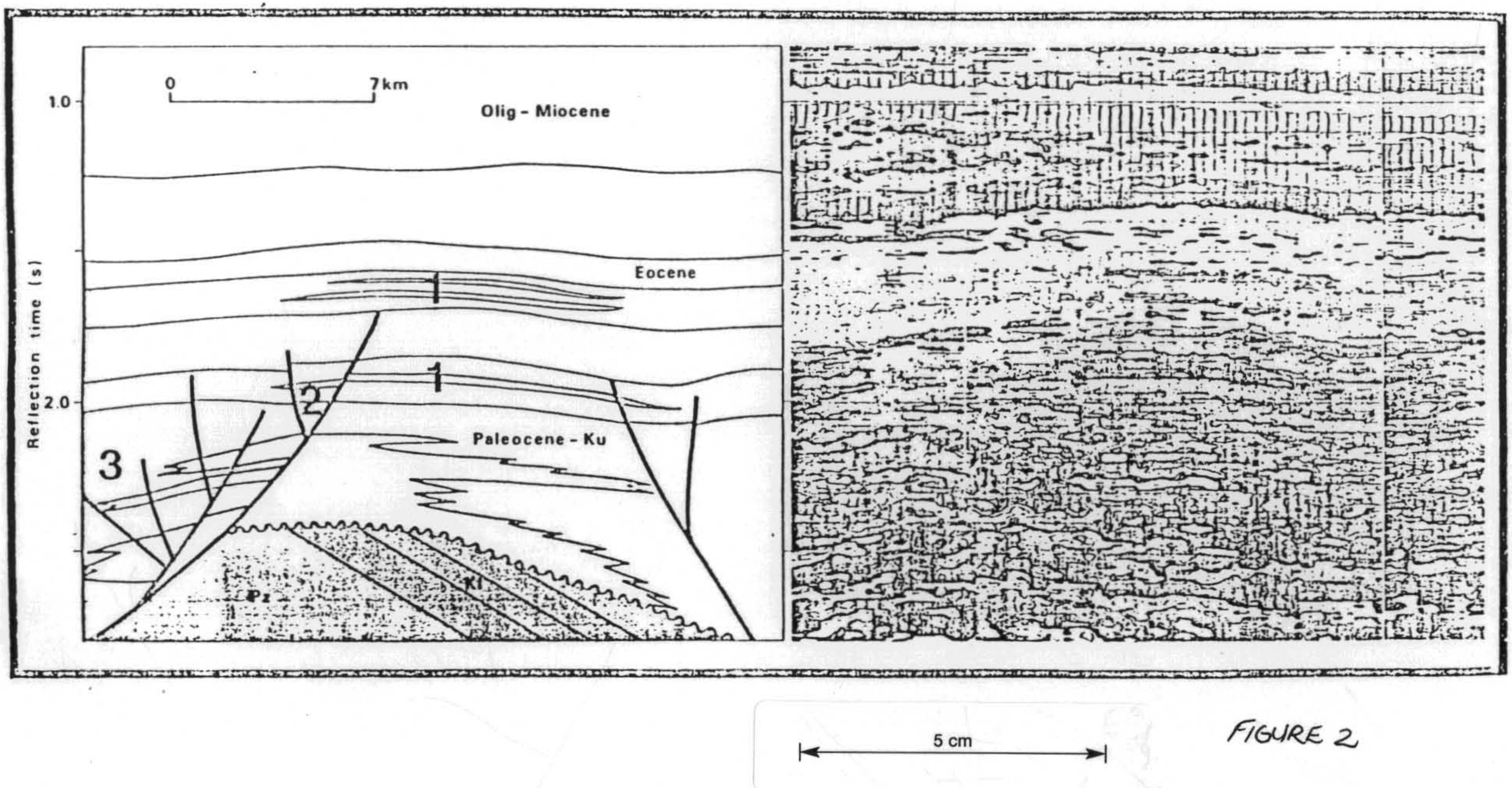


FIGURE 2

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FIGURE 3

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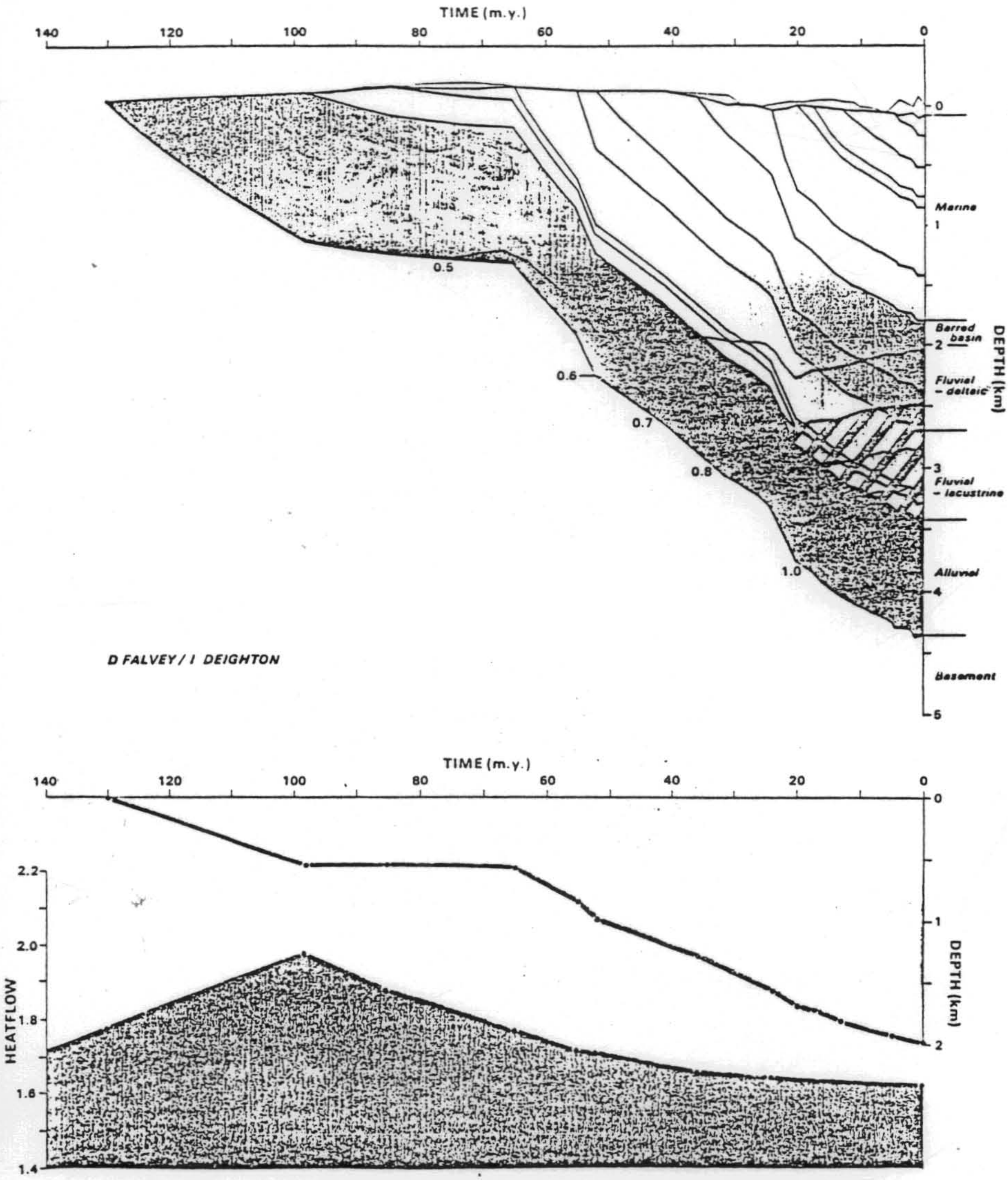

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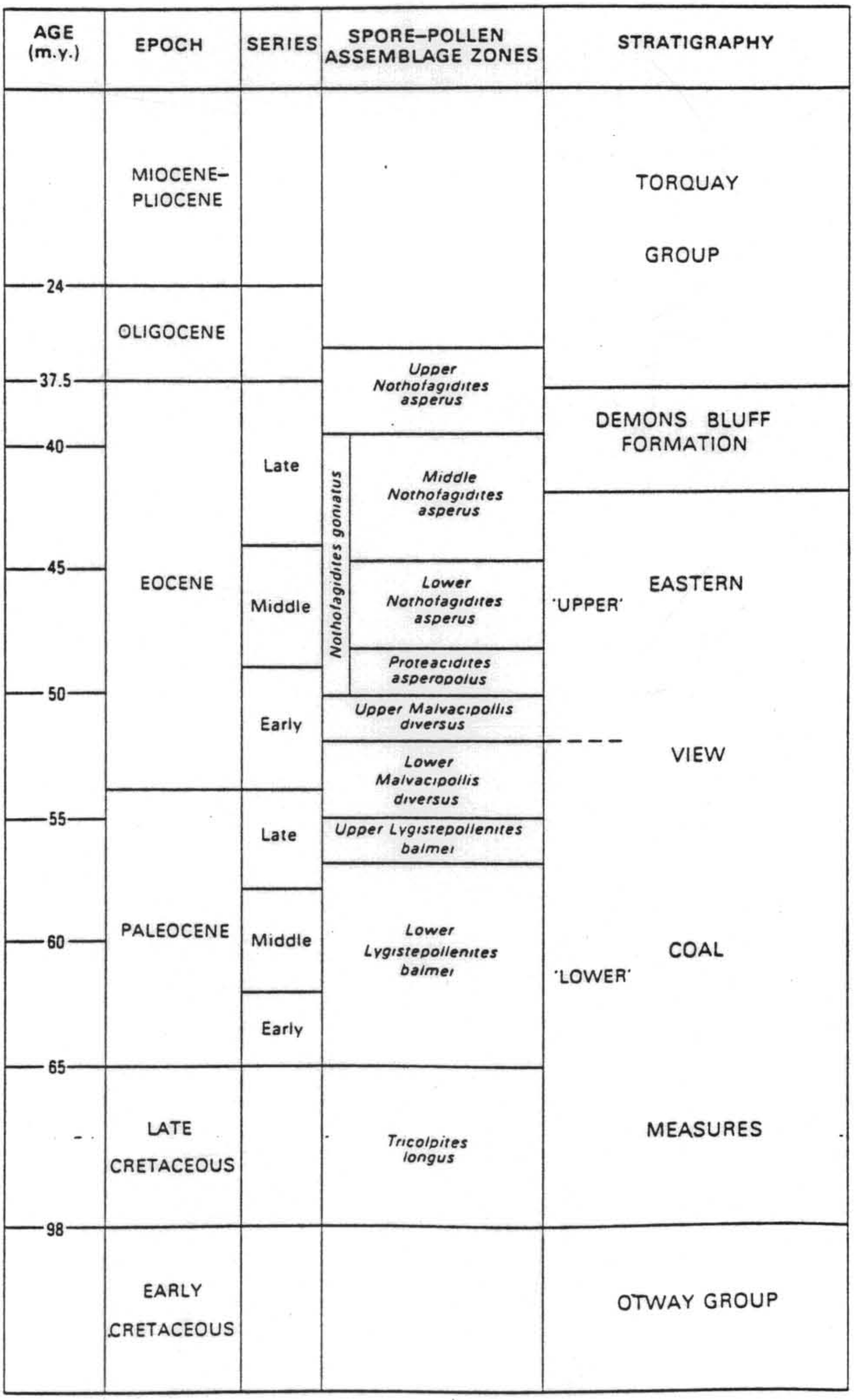
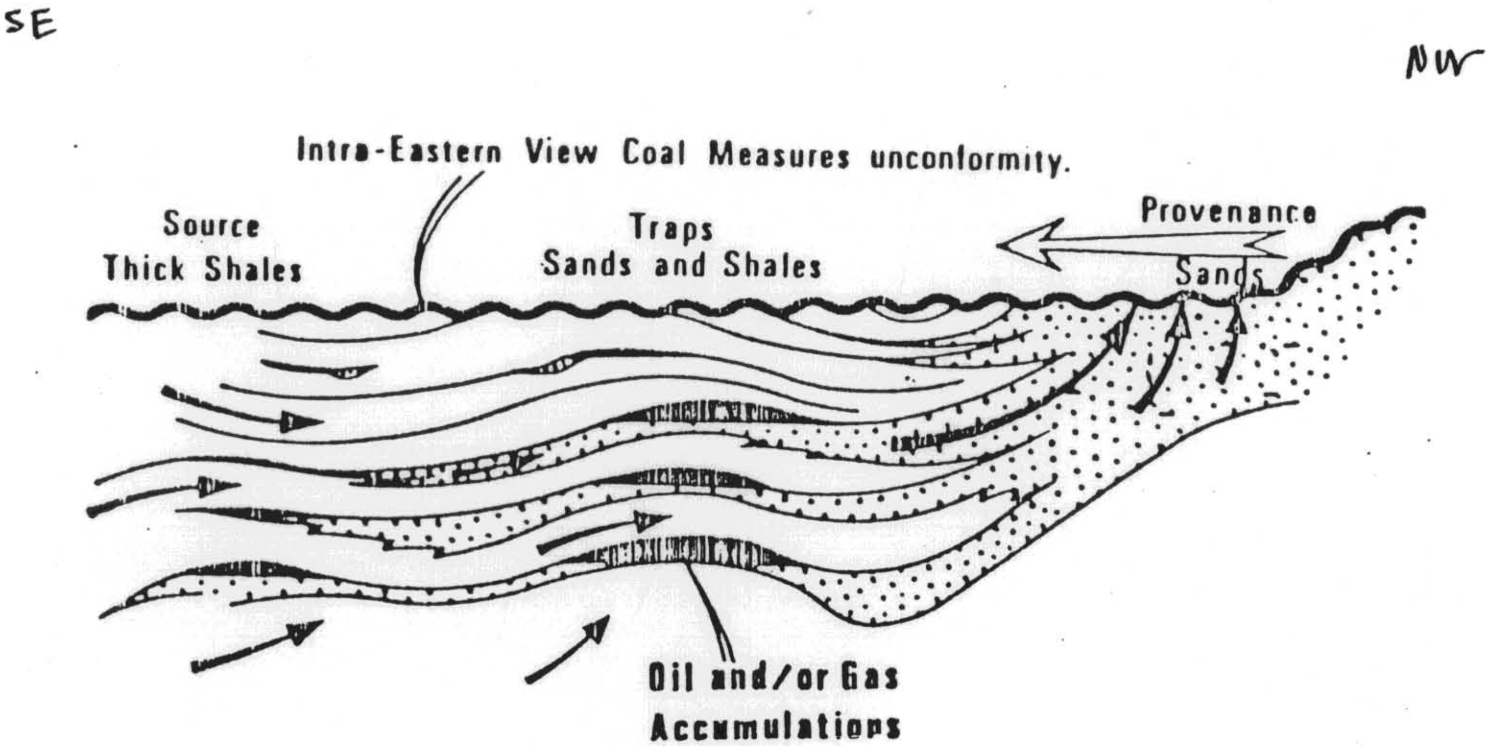


Stratigraphy of the Bass Basin

FIGURE 1

FIGURE 2



Suggested hydrocarbon migration.

5 cm

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Potential Reservoir

Measurements of porosity and permeability in conventional cores and sidewall cores reported in well completion reports indicate that potential reservoirs exist both in the Eastern View Coal Measures and lower Cretaceous or Otway Group of the Bass Basin. Figure 3 shows the ranges of the measured porosity and permeability as well as the average values.

Data on the Paleocene and Cretaceous conventional core intervals of the Bass Basin wells has been assembled. The core intervals are listed in Figure 4. Following are the core descriptions and measurements of porosity and permeability.

INTERVAL	POROSITY (%)			PERMEABILITY (md)		
	Samples	Range	Average	Samples	Range	Average
Upper EVCM (*N. asperus + P. asperopolus*)	24	3.1–30.2	19.0	24	0.1–9200	776
Middle EVCM (*M. diversus*)	112	10.5–26.9	19.6	113	0.0–1600	64
Lower EVCM (*L. balmei + T. longus*)	75	3.7–37.4	17.3	76	0.0–1230	68
Otway Group	29	8.0–35.6	20.0	29	0–710	63

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Porosity and permeability data for the Bass Basin.

FIGURE 3

Well Name Total Depth	Paleocene		Upper Cretaceous				Lower Cretaceous			
	U.L. balmei	L.L. balmei	T. longus	T. lilliei	N. senectus	C. triplex	T. pannosus	C. paradoxus	C. striatus	F. asymetricus (U.C. Hughesii)
Aroo #1 12122'	8900'	9100' *								
Bass #2 5910'	4913' *	5350' *	5511'± *							
Bass #3 7978'	6490'	6685' *	7248' *							
Dondu #1 9603'	7446' *	8713'								
Durroon #1 9922'		2070'	3156'±	3715'±	4360'±	4495'±	5500'± *	5900'±	7927'± *	9650'± *
Konkon #1 5013'	4490'	4648'	4894'							
Nangkero #1 9440'	8552'									
Pelican #1 10428'	10339' *									
Pelican #3 9537'	7935'	8300' *								
Poonboon #1 10715'	8788' *	9028' *	10632' *							
Squid #1										
Yurongi #1 8000'	6488' *	7302'								

FIGURE 4

Palynological Zonation, Paleocene and Cretaceous section only
* Conventional Core

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CONVENTIONAL CORES

In the Aroo #1 well, two conventional cores were cut in the Lower L. balmei palynologic zone of the basal-most Paleocene section.

Core number one is over the interval 9515' to 9545', while core number two is over the interval 9545' to 9570'.

9515-9527' Sandstone; white, fine to medium, well sorted, sub-angular to rounded, quartz overgrowth, minor coal beds. Bright yellow fluorescent, strong fast cut.

9527'-9529' 4" Coal and shale; brown, carbonaceous, hard, fractured. Fluorescense and cut.

9529'4"-9534' Sandstone; white, carbonaceous, firm, moderately well cemented, medium grained, minor coal stringers, greenish-white fluoresense, good cut.

9534'-9539' 6" Sandstone; white, fine, clean, thinly interbedded with light to dark grey siltstone, tight, carbonaceous, micaceous, cross-bedded, Dull golden or red fluorescense, very slow weak cut or no cut.

9539' 6"-9545' Sandstone; fine to medium grained to very coarse at top, minor siltstone and shale. Sandstone is white, firm, hard, sub to well rounded, micaceous. Yellow-green, yellow and golden, dull golden fluorescense,

9545'-9551' Sandstone; buff to light grey, firm, medium grained, slightly calcareous toward top. Quartz overgrowth, carbonaceous, micaceous, plant debris. Dull gold fluorescense, slow weak cut.

9551'-9555'6" Shale; light grey, silty, hard, thinly bedded, slow weak cut. Thin fine sandstone interbeds with dull gold fluorescense.

9555'6"-9560' Shale; medium grey, very thinly bedded, hard, slightly carbonaceous, slightly micaceous, slow weak cut.

9560'-9570' Mudstone; shaly, grey to brown, massive, hard, slow weak cut.

Depth(ft)	Effective Porosity(%)	Permeability(md) Vert.	Hor.	Oil Saturation(%)
9516'	17.6	0.80	2.0	2.4
9520'4"- 9520'8"	15.0		3.281	3.075
9521'	18.6	2.3	0.76	0.84
9524'	21.2	11.0	14.0	5.9
9530'	20.8	113	53	3.8
9544'	17.3	0.55	0.78	tr
9546'	11.7	0.26	0.11	nil
9552'	14.3	0.15	0.15	2.4

A formation interval test was conducted at a depth of 9530 feet. The test recovered 1.4 cubic foot of gas, a trace of oil, and 1900 cubic centimeter of water. The final shut-in pressure was 4444 psi. A low permeability is indicated.

The sample studies indicate that the general cored interval consist of interbedded sandstone, siltstone, mudstone and coal. The sandstone is described as cream to brown, soft to firm, medium to fine, carbonaceous in part, micaceous, clay choked in part, well cemented in part, slightly calcareous, with pale blue to bright yellow fluorescense, weak to strong fast cut. The siltstone is grey to light brown, firm, slightly carbonaceous. The mudstone is grey to chocolate brown. soft to hard. The coal is black, hard to friable, waxy.

The gas detector and chromatographer indicate the presence of C_1 to C_{5+} over this interval.

In the Bass #2 well, a conventional core was cut within the upper L. balmei palynological zone of the lower Paleocene. The cored interval is 5062' to 5092', fourteen feet were recovered.

5062'-5066.5' Sandstone; quartz, light grey, very fine to silty, sub-angular, fair sorting, slightly calcareous, very argillaceous, coal grains, this laminae of carbonaceous material, tight.

5066.5'-67' Dolomite; mottled, medium dark grey-light brown, micritic, argillaceous, pyritic.

5067'-5072' Sandstone as above.

5072'-5075' Shale; medium grey, carbonaceous, sandy in patches. Slightly petroliferous odor on fresh surface.

5075'-5076' Sandstone; quartz, light grey, very fine, subrounded to sub-angular, fairly well sorted with common carbonaceous grains, non calcareous clay matrix, micaceous, carbonaceous.

According to the gamma ray and spontaneous potential curves, the interval 5062' to 5092' should have recovered a very argillaceous, non reservoir, sandstone down to approximately 5065', or so, then a shale interval from 5065' to 5072' or 5075, then a clean sandstone from 5072'/5075' to 5083', then a dirty sandstone to 5092', the end of the cored interval. It appears that the clean sandstone interval was not recovered possibly because it is friable and has washed out.

Depth (ft)	Porosity (%)	Permeability (md)
5063'	20.8	1.1
5064'	19.3	1.0
5065'	20.1	0.6
5066'	20.6	0.8
5067'	18.3	0.5
5069	14.4	0.1

A conventional core was cut within an undifferentiated zone of the Mensozoic. The cored interval is 5508' to 5521', eleven feet were recovered.

5508'-5509' Siltstone; dark reddish brown, very carbonaceous, sandy.

5509'-5510' Sandstone; dark tannish grey, friable, fine grained and very silty, carbonaceous.

5510'-5511' Siltstone; as above

5511' Basal breccia;chips of underlying greenstone in carbonaceous siltstone matrix.

5511'-5519' Greenstone; orthoclase porphyry or altered trachytic rock, brecciated near top and weathered throughout.

A second conventional core was cut within an undifferentiated zone of the Mesozoic. The cored interval is 5900'-5910', nine feet were recovered.

It is described as altered tuffaceous mudstone; medium greyish blue-green, faintly banded, highly fractured, pyritic. A hand speciman is described as bedded tuff. A thin section of the same mentions the presence of glass shards, abundant feldspar, chlorite grains and concludes that this rock was originally a fine-grained vitric-crystal tuff. A second hand specimen is also descirbed as a bedded tuff; hard, tough, grey-green with dark green chlorite bands, grading rapidly into a greyish white quartzitic mudstone. Secondary pyrite is common. A thin section of this specimen describes it as: extremely fine-grained mass of pale green chlorite. This chloritic tuff grades rapidly into a recrystallized mudstone.

7433'-7438' Thinly interbedded shale and sandstone. The shale in medium grey, in part silty to very finely sandy, micaceous, pyritic with fine carbonaceous streaks. The sandstone is grey white to buff, coarse grained to granular, subangular to rounded, fairly well sorted with scattered pebbles, grey shale and carbonaceous grains, micaceous, clay matrix.

7438'-7442' Sandstone; grey white to buff, coarse grained to granular with fine pebbles towards the base, clay matrix.

7442'-7450' Shale; medium grey, silty, sandy, conglomeratic, micaceous, with white clay grains, sparsely carbonaceous.

7450'-7450'3" Conglomerate; subangular to subrounded pebbles in poorly sorted light brown, agillaceous, silty, sandy, micaceous, carbonaceous matrix pebbles include quartz, feldspar, dark grey shale, volcanics, tourmaline.

7450'3"-7452'6" Sandstone; as 7442'-7450' with breccia and finely banded shale and coarse grain to granular quartz sandstone.

7452'6"-7453' Sandstone; grey white to buff, coarse grained to granular.

Depth (ft)	Porosity (%)	Permeability (md)
7433	28	19.3
7438	26	19.5
7439	24	20
7441	5	18.9

A conventional core was cut over the interval 7877' to 7892'. Nothing was recovered. On logs this interval appears to be within the so-called basement section.

A conventional core was cut over the interval 7903' to 7914', five feet was recovered.

The core interval appears to consist of a thinly banded and laminated sequence of quartzite, shale and sandstone.

The quartzite,or chert,is light to dark grey to black, very fine grained sparsely pyritic. The shale is dark grey to black, in part silty, carbonaceous, very finely sandy, dense, moderately hard. The sandstone is light to dark grey, argillaceous, fine to very fine grained,in part silica cemented, vuggy

A conventional core was cut over the interval 7974' to 7978', four feet were recovered. The core interval is described or metamorphosed shale with recrystallised segregations of quartz-calcite-biotite and irregular bodies of light to dark grey quartzite. Irregular veins of quartz-calcite and mica, minor pyrite.

In the Bass #3 well, a conventional core was cut within the lower L. balmei palynological zone of the basal Paleocene. The core interval is 6903' to 6933', thirty feet were recovered.

6903'-6905.5' Shale; light grey to light brown, micaceous carbonaceous, slightly dolomitic.

6905.5' - 6906' Shale; brown to black, micaceous, carbonaceous.

6906'-6920' Shale, light grey, micaceous carbonaceous.

6920' - 6922' Sandstone; mottled black, light grey to white, very fine to medium to coarse grained, subrounded to sub-angular, poor sorting, coal grains, micaceous, carbonaceous, clay matrix.

6922'-6923' Sandstone; as above with carbonaceous laminae.

6923'-6924' Sandstone; as 6920'6922'.

6924'-6926' Shale; light brown, micaceous, carbonaceous.

6926'-6930' Sandstone; light grey, fine to coarse grained, subrounded to sub-angular,coal and shale grains, clay matrix, slightly calcareous.

6930' - 6931'Shale; light grey, micaceous, carbonaceous, silty.

6931' - 6932.5' Shale, brown, micaceous, carbonaceous.

6932.5' - 6933' Sandstone; light grey, fine to medium grained, subrounded to sub-angular, fair sorting,micaceous,clay matrix, slightly calcareous.

Depth (ft)	Porosity (%)	Permeability (md)
6921	22.2	10.28
6922	16.3	0.45
6925	16.0	28.39
6926	22.3	18.24
6928	18.9	42.10
6929	25.8	0.45
6930	15.5	2.30
6932	15.4	1.30

A formation interval test was conducted at 6740 feet. It recovered 29 cubic feet of gas along with 800 cubic centimeter of condensate, or light oil, and 12,500 cubic centimeters of discolored water which upon analyses appears to be mud filtrate. Sampling pressure during the test was 3025 psi and the final shut-in pressure was 3125 psi.

A conventional core was cut within the T. longus palynological zone of the Upper Cretaceous. The core interval is 7433' to 7453', twenty feet were recovered.

A conventional core was cut over the interval 7674' to 7733' in the Dondu #1 well, This interval is assigned to the upper L. balmei palynological zone of the basal Paleocene.

7674'-7683' Shale; dark brownish grey, silty, micaceous.

7683'-7686' Siltstone; tan-white, hard, micaceous, carbonaceous, sandy towards the base.

7686'-7689' Sandstone; clear and frosty with subangular to subrounded unconsolidated coarse to very coarse quartz grains, moderately well sorted.

7689'-7691' Shale; dark brownish grey, silty, hard, indurated.

7691'-7696' Sandstone; unconsolidated, as 7686'-7689.

7696'-7701' Sandstone; tan, white, fine grained, sub-angular to subrounded quartz grain, very silty, firm, consolidated, carbonaceous bands.

7701'-7703' Sandstone; white, fine to very coarse, predominately medium grained, firm, consolidated, poorly sorted.

7703' - 7706' Sandstone; white, fine to very coarse, predominantly medium grained, firm, consolidated, poorly sorted.

7706'-7713' Sandstone; white, fine to medium grained, very silty, carbonaceous bands.

7713-7717' Sandstone; white, very fine grained with abundant horizontal carbonaceous laminae.

7717'-7721' Siltstone; light grey, very micaceous and sandy, abundant horizontial carbonaceous laminae.

7721'-7725' Sandstone; white , very fine to fine grained, very micaceous, silty, horizontal carbonaceous laminae.

7725'-7730' Siltstone; light grey, very micaceous, abundant horizontal carbonaceous laminae, layers of mica, few thin coals.

7730'-7733' Sandstone; white, very fine to fine to very coarse grained, silty, poorly sorted, carbonaceous laminae.

Depth(ft)	Permeability (md)	Porosity (%)	Gas (%)
7689	356	17	6
7706	25	21	7
7721	11	18	7

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A conventional core was cut over the interval 8373' to 8425'. This interval is assigned to the C. striatus palynological zone of the Lower Cretaceous.

8373'-8385' Sandstone; apple green, fine to medium with many coarse grains, subrounded to subangular, poorly sorted, well indurated, abundant lithic grains 8385'-8387' Conglomerate; well rounded pebbles of chert(?) and quartzite in very fine to very coarse grain matrix of sandstone.

8387'-8396' Sandstone; light green, very fine to coarse, sub-angular to subrounded, poorly sorted, very hard, indurated, massive, non calcareous.

8396'-8412' Sandstone; grey-white with few green grains, increasing amounts of very fine to very coarse lithic, poorly sorted, cleavage fracture at 30 degrees. Few thin carbonaceous laminae dipping at 15 degrees are present in the bottom one foot of this interval.

8412'-8422' Sandstone; grey-green, fine to coarse, silty, sub-angular, micaceous, abundant lithic, very hard,

8422'-8423' Shale; dark brown, very carbonaceous, firm, indurated.

8423'-8424.5' Coal; black, brittle, fractured.

8424.5'-8425' Shale; dark grey, very silty, sandy, very carbonaceous, hard, indurated with scattered wood fragments.

A petrographic description at 8374' refers to a lithic sandstone, cemented with silica-chlorite and by the break down or distortion of lithic fragments, well sorted, angular to sub-rounded. At 8376' the rock is described as lithic pebbly sandstone or conglomeratic greywacke with igneous, sedimentary and metamorphic components.

Depth (ft)	Lithology	Porosity (%)	Permeability(md)
8380	Sand	16.0	0
8387	Sand	16.0	0
8394	Sand	11.0	0
8401	Sand	12.0	0
8408	Sand	15.0	0
8415	Sand	15.0	0
8422	Sand	8.0	0

225033

In the Durroon #1 well, a conventional core was cut over the interval 5547' to 5566'. This interval is assigned to the T. pannosus palynological zone which straddles the Upper versus Lower Cretaceous boundary.

5547'-5548.5' Sandstone; very fine to fine grained, grey-green, silty, glauconitic, poorly sorted, sub-angular, firm occasional shale clasts

5548.5'-5553.5' Shale; grey black, fissile, carbonaceous, with stringer beds of sandstone; grey, glauconitic. Siltstone grey, firm to friable.

5553.5'-5565.5' Sandstone; grey, medium-fine grained, sub-angular, moderately sorted, quartzose, carbonaceous, well cemented, grey-white clay matrix.

5565.5'-5566' Shale; grey-brown, fissile, firm, micaceous.

Dip throughout this core is 30° approximately. A hand specimen taken from this core at 5599' is described as lithic sandstone; friable, with rare patches of hydrocarbons or coal. The lithic fraction consist of siltstone and represent 85-90% of the grain population.

Depth (ft)	Lithology	Porosity(%)	Permeability(md)
5548'	sand	16.9	0
5548'	sand	22.0	0.45
5554'	sand	26.9	52
5555'	sand	21.1	310
5556'	sand	18.0	6.2
5557'	sand	18.4	82
5558'	sand	22.6	29
5559'	sand	17.3	4.4
5560'	sand	17.0	11
5561'	sand	19.0	3.6
5562'	sand	24.0	9.1
5563'	sand	15.2	7.1
5563'	sand	14.0	3.4
5564'	sand	18.0	9.8
5565'	sand	13.3	2.6

A conventional core was cut over the interval 9905' to 9922'. This interval is assigned to the upper L. hughesii palynological zone of the lower Cretaceous.

9905'-9913.5' Sandstone, grey-green, fine grained, silty, agillaceous with calcareous matrix.Quartzone with some overgrowth, common brown and green lithic grains, mica and carbonaceous streaks, poor to moderate sorting, sub-angular to subrounded, hard, massive bedding with dip at 20 to 30 degrees.

9913.5'-9915' Conglomerate; elongated shale and sandstone pebbles and cobbles in grey-green sandstone matrix, very argillaceous and shaly at base. Minor gypsum and calcareous pebbles, as well as a coal band at the top.

9915'-9922' Sandstone; massive and dipping at 20 to 30 degrees. Thin carbonaceous streaks.

Depth (ft)	Lithology	Porosity (%)	Permeability(md)
9905	Sand	10	0
9911	Sand	10	0
9918	Sand	10	0

A conventional core was cut over the interval 10,386' to 10,398' in the Pelican #1 well. This interval is assigned to the upper L. balmei palynological zone of the Paleocene.

10,386'-10,393.375' Siltstone; light grey-light brown, well indurated, interbedded with dark grey-black, micaceous, hard carbonaceous shale.

10,393,375'-10,398' Shale; dark grey-black, generally massive, carbonaceous, more coaly toward the base.

Depth	Lithology	Effective Porosity	Permeability
10387'1"-10387'1"	SLTST	8.5%	0.1 md

The interval 9351' to 9521' was continously cored in the Pelican #3 well. This interval is assigned to the undifferentiated L. balmei palynological zone of the Paleocene.

9351'- 9361'Shale; gray, silty, laminated, carbonaceous.

9352'-9353.5' Sandstone; medium to very coarse grained, quartz, feldspar, possibly chert, in shaly carbonaceous matrix with shale and coal laminae.

9353.5'-9361' Sandstone; light grey, clay matrix, sub-angular to subrounded quartz, very fine to fine grains, slight to fair odor with dull gold brown fluroescense, no visible cut. Minor cross bedding, generally massive with some carbonaceous material, minor shaly streak.

9361'-9364' Interbedded sandstone as above and shale as above.

9364'-9366' Shale; with thin silty sandstone laminae.

9366'-9373.5' Thinly interbedded sandstone and shale as above.

9373.5'-9376' Sandstone; light grey, subangular to subrounded quartz grains, fine to very fine, with minor shale partings. Dull gold brown fluorescense, no cut, odor present but not strong.

9376'-9378.5' Laminate sandstone and shale.

9378.5'-9397' Shale; dark grey, very carbonaceous.

9397'-9418' Sandstone; light grey to white, fine to medium grained, hard massive, with very minor carbonaceous shale streaks and coaly wood fragments.

Sub-angular to subrounded, well sorted, some overgrowth on quartz. White clay matrix. Dull gold-brown fluorecense , weak, pale cream cut with blue-white residue, evidence of deep drilling mud invasion.

Depth(ft)	Porosity(%)	Permeability(md)
9406'	22.3	10
9415.5'	22.9	157

9418'-9419.5' Shale; dark grey, carbonaceous with thin interbeds of very fine sandstone.

9419.5'-9425.5' Sandstone; as above. Dull gold-brown fluorescense, weak cut and residue.

9425.5'-9428.5' Shale; dark grey, carbonaceous with minor sandstone interbeds.

9428.5'-9430' Sandstone; fine grained, hard with shale streaks.

9430'- 9431.5' Shale; dark grey to black, fissile,hard, carbonaceous and micaceous.

9431.5'-9433' Sandstone; grey-white, fine grained, hard with shaly streaks.

9433'-9438' Shale; dark grey to black, fissile,hard, carbonaceous with sandstone interbeds.

9438'-9440.5' Sandstone; very fine grained, silty, clay matrix, shaly and coaly streaks.

9440.5'-9442' Shale; as above.

9442'-9448' Sandstone; clay matrix, fine to medium, sub-angular to sub-rounded grains, micaceous, carbonaceous, with minor shale and coaly streaks.

9448'-9460' Interbedded sandstone, siltstone and shale. The sandstone is light grey-white, very fine to fine grained, angular to sub-rounded.

9460'9464' Shale; dark grey, fissile, with minor interbedded thin sandstone.

9464'-9467' Thinly interbedded sandstone and shale.

9467'-9477' Sandstone; light grey, very fine to fine, silty,clay matrix, very slightly calcareous, sub-angular, fair to well sorted, carbonaceous. Gold brown fluorescense, slow weak pale yellow cut fluorescense, blue with white fluorescense cut residue, slight odor,

Depth (ft)	Porosity (%)	Permeability (md)	% Gas Bulk Vol.
9472	18.5	1.	7.4

9477'-9479' Interbedded sandstone and shale.

9479'-9486.5' Shale; with some thin sandstone and siltstone laminae.

9486.5'-9504.5' Sandstone; with shale laminae, silty in part, very fine to medium grained, rare quartz overgrowth carbonaceous, clay and fine quartz grains matrix. Gold brown fluorescense, slow weak cut, fair odor.

Depth (ft)	Porosity (%)	Permeability (md)	%Gas Bulk Vol.
9492'	13.2	1:	4.5

9504.5'-9509' Thinly interbedded sandstone and shale.

9509'-9518' Shale with sandstone interbedded.

9518'-9521' Shale, dark grey, fissile.

Three conventional cores have been cut in the Paleocene and Upper Cretaceous section penetrated by the Poonboon #1 well.

The 8802' to 8827' core interval is assigned to the upper L. balmei palynological zone of the Paleocene.

8814' - 8815' Sandstone; as above, with abundant coarse grains to pebbles, poorly sorted, carbonaceous stringers.

8815' - 8817' Sandstone; silty to very fine grained.

8817' - 8822' Interbedded siltstone and shale.

Siltstone is grey to grey brown, firm to hard, carbonaceous. Shale is dark gray.

8822' - 8827' Siltstone; grey-green, shaly, firm.

The core interval 9954' to 9982' is assigned to the lower L. balmei palynological zone of the Paleocene.

9954' - 9959' Shale; dark brown grey, carbonaceous, coal streaks.

9959' - 9974' Sandstone; light grey to grey, very fine to medium, silty in part, subangular to subrounded, moderate sorting, firm. Clay matrix, quartz overgrowth, carbonaceous, trace mica, chlorite, lithic grains. Minor spotty dull gold mineral fluorescense.

9974' - 9982' Shale; dark grey, hard, carbonaceous. This section is over-pressured.

The core interval 10,691' to 10,715' is assigned to the T. longus palynological zone of the Upper Cretaceous.

10,691' - 10691.5' Sandstone; tan, white, medium grained, friable, well sorted, subangular to subrounded, clean.

10,691.5' - 10,715' Shale; dark grey, silty, micaceous, carbonaceous.

A hand specimen at 10,691' is described as fine grained agillaceous sandstone. The clay fraction is kaolinite with moderate amounts of chlorite and mica, Quartz represents roughly 10% of the total.

This section is overpressured.

The interval 10,444' to 10,450' is considered to be gas bearing. It was not cored.

Depth(ft)	Porosity(%)	Permeability(md)	% Gas Bulk Vol
8803	18	1230	30
8804	29	40	56
8805	16	313	25
8806	18	142	29
8807.5	18	150	29
8808.5	18	105	29
8809.5	16	367	22
8810	14	67	-
8810.5	14	98	22
8811.5	14	39	26
8812.5	16	100	36
8813	12	50	25
8814	15	88	26
8814	19.7	19	-
8815	17	122	28
8816	15	16	37
9960	16.9	2.1	6.9
9960	16.3	4.2	-
9961	13.8	2.9	4.2
9962	16.8	-	5.2
9963	14.7		4.3
9964	22.3	3.5	10.9
9965	16.2		6.06
9965	18.2	14.1	-
9966	21.2	48	9.9
9967	18.9	6.8	8.2
9968	11.5	14.5	0.5
9969	17.9	20	7.0
9970	15.0	1.5	5.1
9971	17.9		7.9
9971.5	3.7	0.99	-
9972	9.8		4.8
9973	16.9		6.6
10691	9	276	9.8

The interval 7045' to 7075' was cored in the Yurongi #1 well. This interval is assigned to the upper L. balmei palynological zone of the Paleocene.

7045'-7075' Sandstone; light grey, fine grained, sub-rounded to angular, poorly sorted, calcareous matrix, abundant muscovite, few fine lithic grains, coal fragments, massive with local faint lamination.

Depth(ft)	Porosity(%)	Permeability(md)	% Gas Bulk Vol.
7045	19.1	1.62	8.8
7054	21.2	2.5	-
7056	16.6	1.51	5.4
7067	16.9	-	6.6

Plots

The Paleocene and Cretaceous cored intervals of the Bass Basin wells have been described in the preceding Conventional Core section and the values for the porosity and permeability determined from whole core or plug samples have been listed.

Figure 5. is a plot of porosity versus depth for each core interval. Since the core intervals are relatively thin when plotted at this scale, each core generates a range of porosities which plot as a straight line on the depth scale. It should be noted that individual cores contain porosity ranges up to 17 percent points, thus an appreciable scatter of points is generated for each depth analysed. A best fit line is shown in an attempt to illustrate the deterioration of porosity with increasing depth. The slope of this line is so slight that it leads to the conclusion that porosity preservation is mostly not controlled by depth. Porosities in excess of 20 percent are found at 10,000 feet just as at 5,000 feet.

Figure 6. is a plot of porosity versus depth for the Paleocene upper L. balmei palynologic zone only. The name of the wells in which each core was cut is indicated. A best fit line indicates that porosity decreases with depth, from 5000 feet to 9000 feet, at a rate of one porosity percent point per 1700 feet, or so. This is considered non diagnostic of reservoir deterioration with depth. The range of porosities within one core interval is again up to 17 percent points.

Figure 7. is a plot of porosity versus depth for the Paleocene lower L. balmei palynologic zone. The name of the wells in which each core was cut is indicated. A best fit line indicates that porosity decreases with depth, from 7000 feet to 10,000 feet, at a rate of one porosity percent point per 2000 feet. This is considered non diagnostic of reservoir deterioration with depth. The range of porosities within are core interval is up to almost 13 percent points.

Figure 8. is a plot of porosity for the T. longus palynologic zone of the Upper Cretaceous in the Bass #3 well conventional core. The average porosity of this core interval is 26 percent and the range is 4 porosity percent points. A porosity versus depth decline curve is not generated since this palynological zone has only been cored once in the Bass Basin wells. This core interval indicates excellent reservoir conditions in the Upper Cretaceous section of the Bass #3 well.

Figure 9. is a plot of porosity for the T. pannosus palynologic zone of the Upper and Lower Cretaceous section found in a core interval of the Durroon #1 well. The porosity range is almost 14 percent and the mean porosity is 19 percent.

A porosity versus depth decline curve is not generated since this palynologic zone has only been cored once in the Bass basin wells. This core interval indicates excellent reservoir conditions for the basal Upper Cretaceous and upper-most Lower Cretaceous section found in the Durron #1 well.

Figure 10, is a plot of porosity for the C. striatus palynological zone of the Lower Cretaceous section cored in the Durroon #1 well. The porosity range is 8.5 percent and the mean porosity is approximately 14 percent. This palynological zone has only been cored once in the Bass basin wells. This core interval indicates moderate reservoir conditions for this zone of the Lower Cretaceous.

Figure 11, is a plot of porosity for the L. hughesii palynological zone of the Lower Cretaceous section cored in the Durroon #1 well. A single figure of 10 porosity percent point is indicated.

Figure 12. is a cross-plot on three cycle log paper of porosity determinations measured in percent point versus permeability measured in millidarcies as generated from all the analysed core intervals of the Paleocene and Cretaceous sections available in the Bass basin.

A wide scatter of points is generated. It should be noted that permeabilities of one or less millidarcies are measured in samples with porosities ranging from 6 to 26 percent points. No clear pattern of decreasing permeability associated with decreasing porosity is recognized.

A series of parallel curves have been generated. These curves indicate that for a specific group of porosity determinations, a trend of permeabilities is indicated. It therefore appears that in specific cases, the permeability does decrease with the porosity. Since all the curves generated are parallel it may be concluded that a single reservoir deterioration mechanism is present.

Two rather well defined parallel trends are recognized. As porosity decreases from 28 percent down to 10 percent, the permeability decreases from 1000 millidarcies down to 320 millidarcies. The second trend indicate that as porosity decreases from 29 percent down to 9 percent, the permeability decreases from 400 millidarcies down to one or less millidarcy.

An effective reservoir area is defined by two lines with porosity in excess or 10 percent point and permeability in excess of 10 millidarcies. Half or more of the points fall within this area.

Since plots of porosity versus depth taken collectively, or individually on the basis of palynologic zone, indicate that relatively thin core intervals show very wide ranges of porosity, from poor resevoir conditions to excellent reservoir conditions, and no significant reduction of porosity with depth, it may be concluded that the series of parallel curves generated by the porosity versus permeability cross-plot indicate the presence of individual genetic units, or correlatable groups of genetic units, within which the porosity and permeability vary widely and are related to one another. This relationship may be seen in core descriptions which indicate that permeability is much more sensitive than porosity and is controlled by the amount of clay matrix and calcite or silica cement. Depth is not a significant factor, however age may be a significant factor as the older sediments were deposited in a low energy environment, therefore are less mature and more likely to have a significant matrix component.

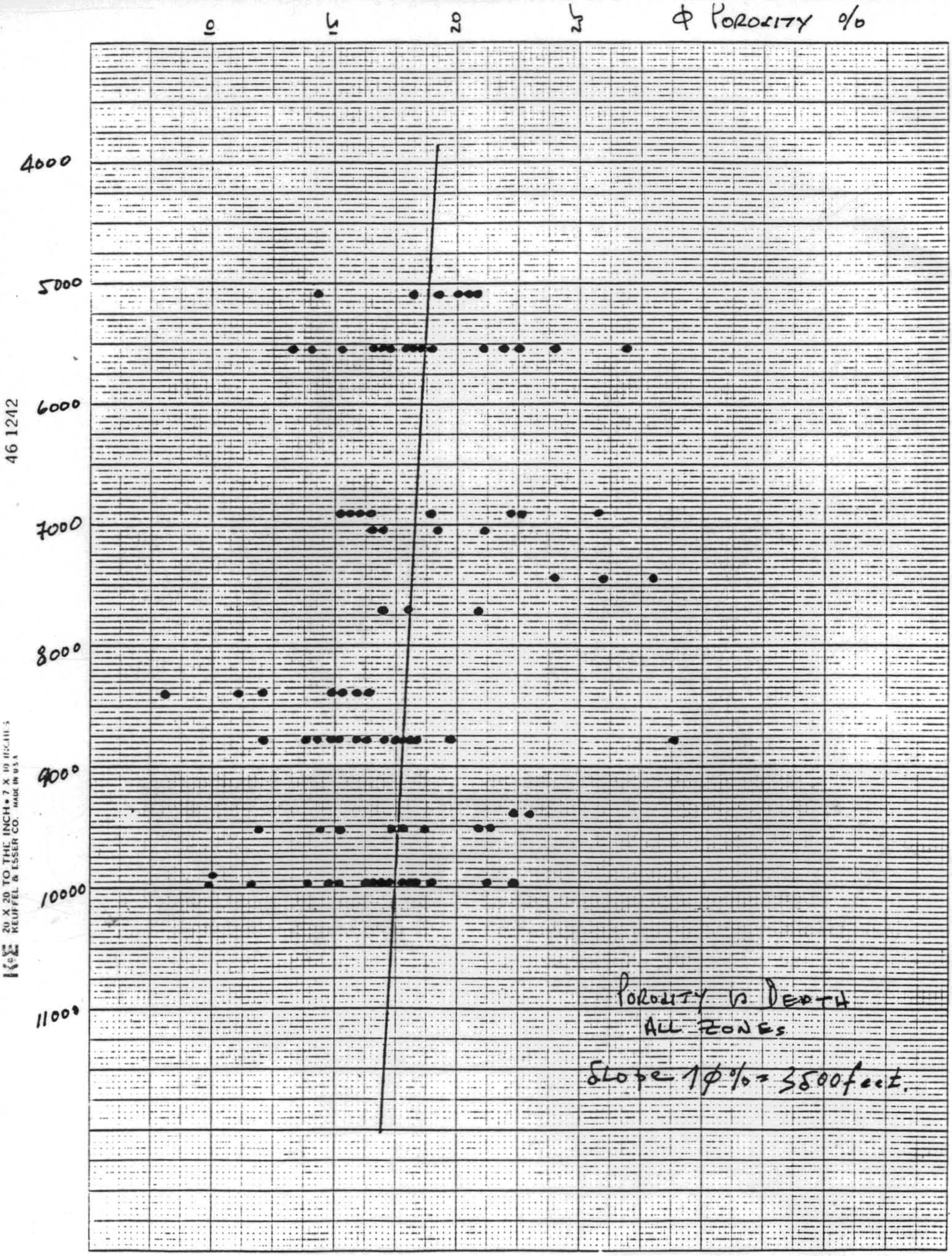
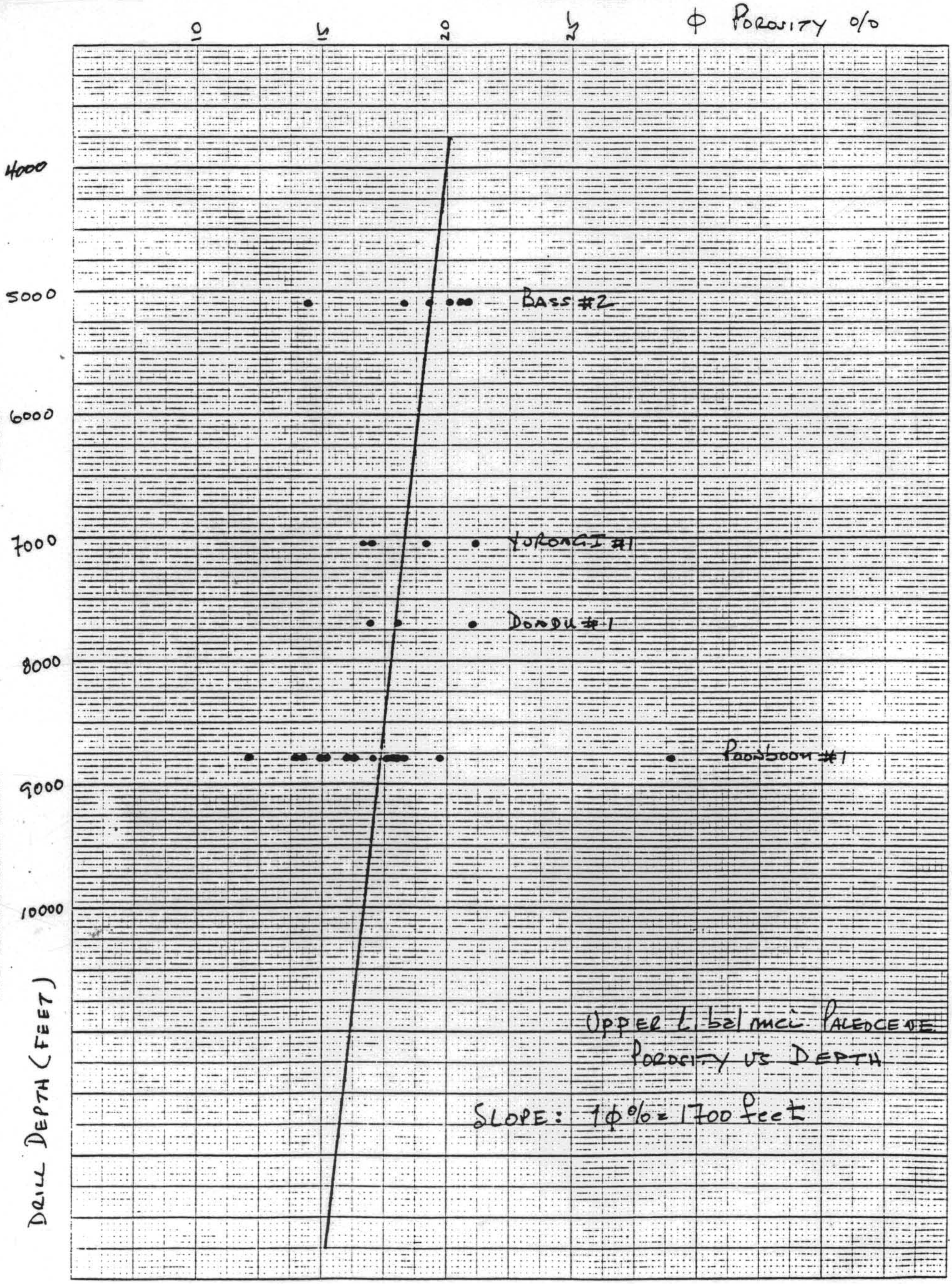


FIGURE 5

225043

5 cm



225044 FIGURE 6

5 cm

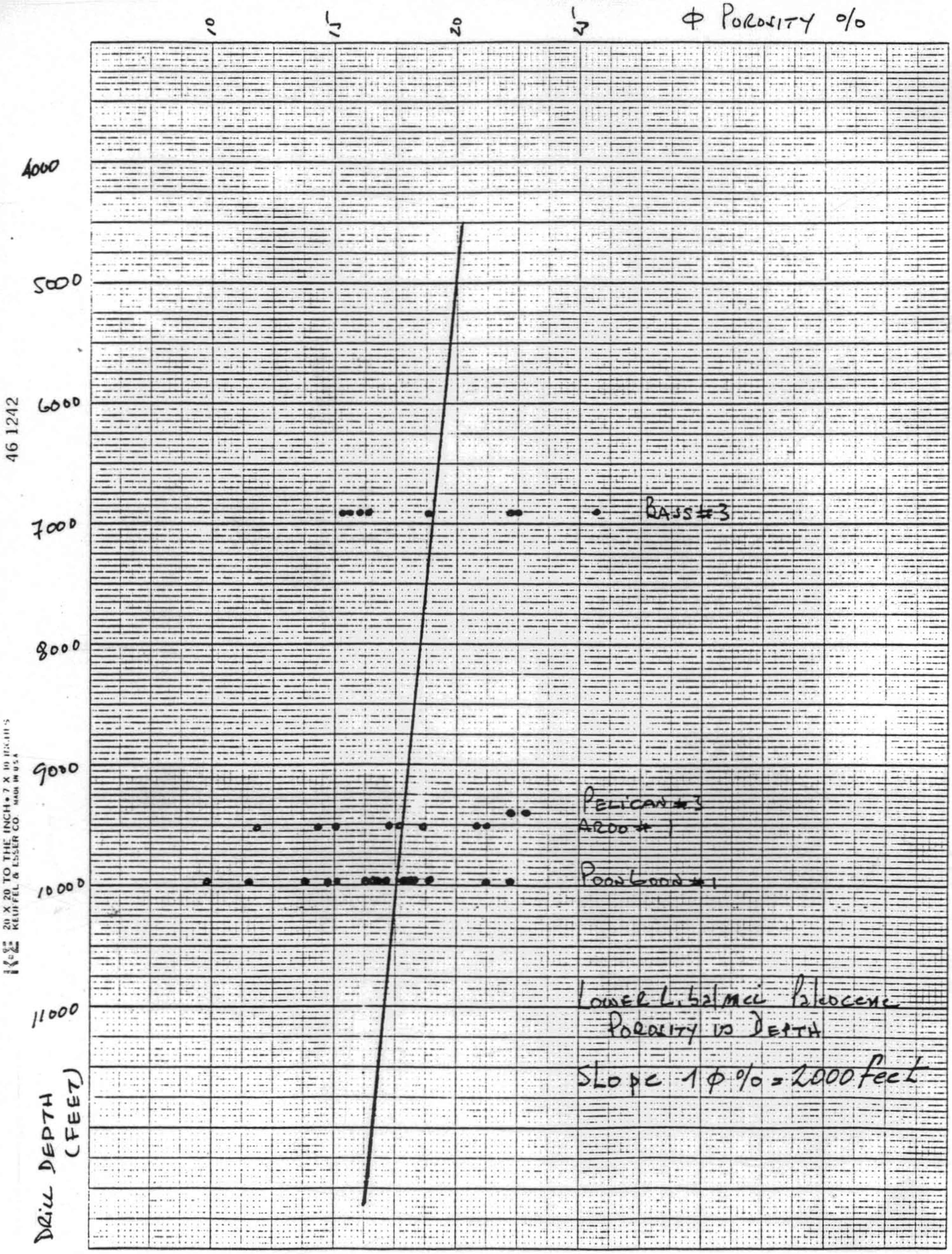


FIGURE 7

225045

5 cm

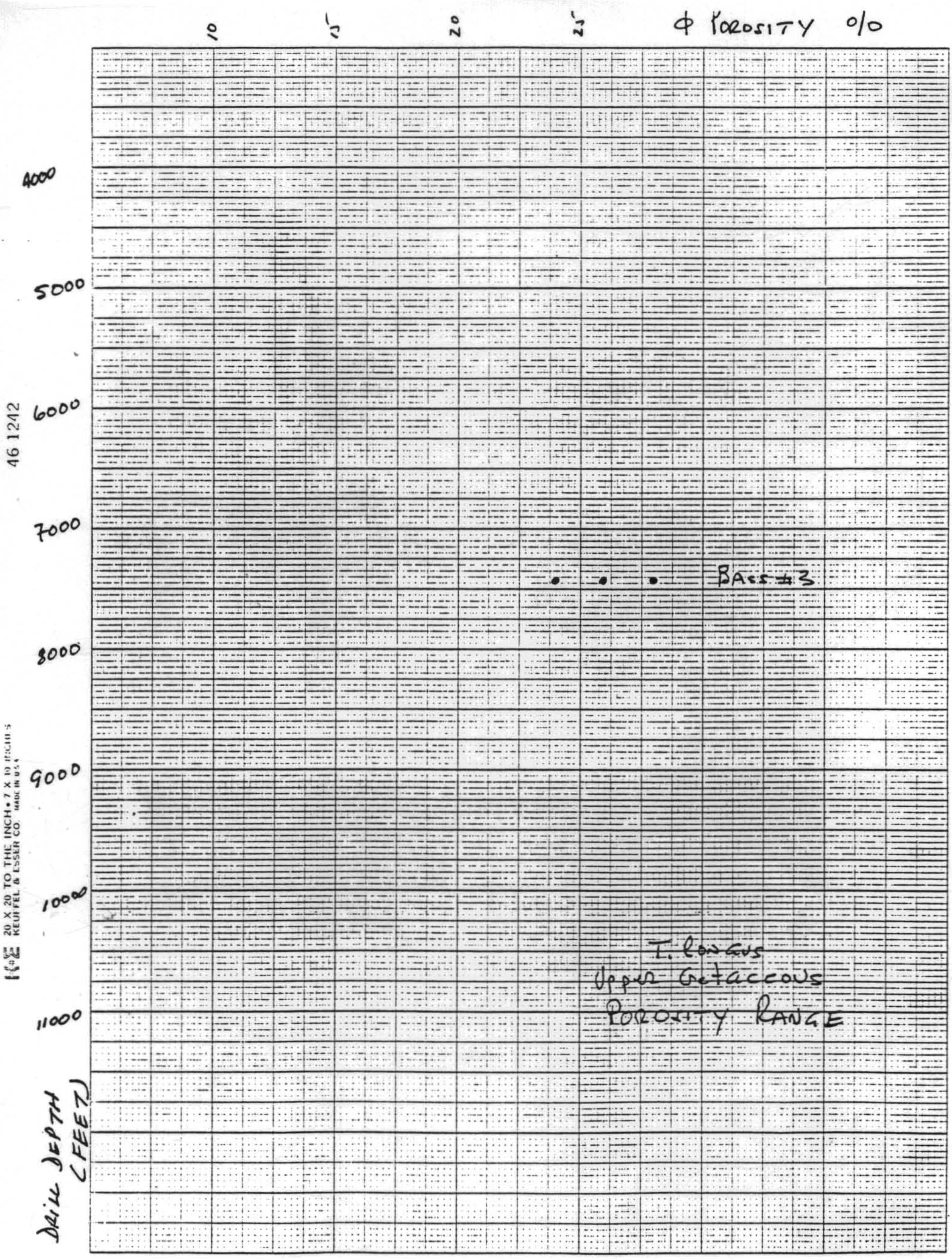
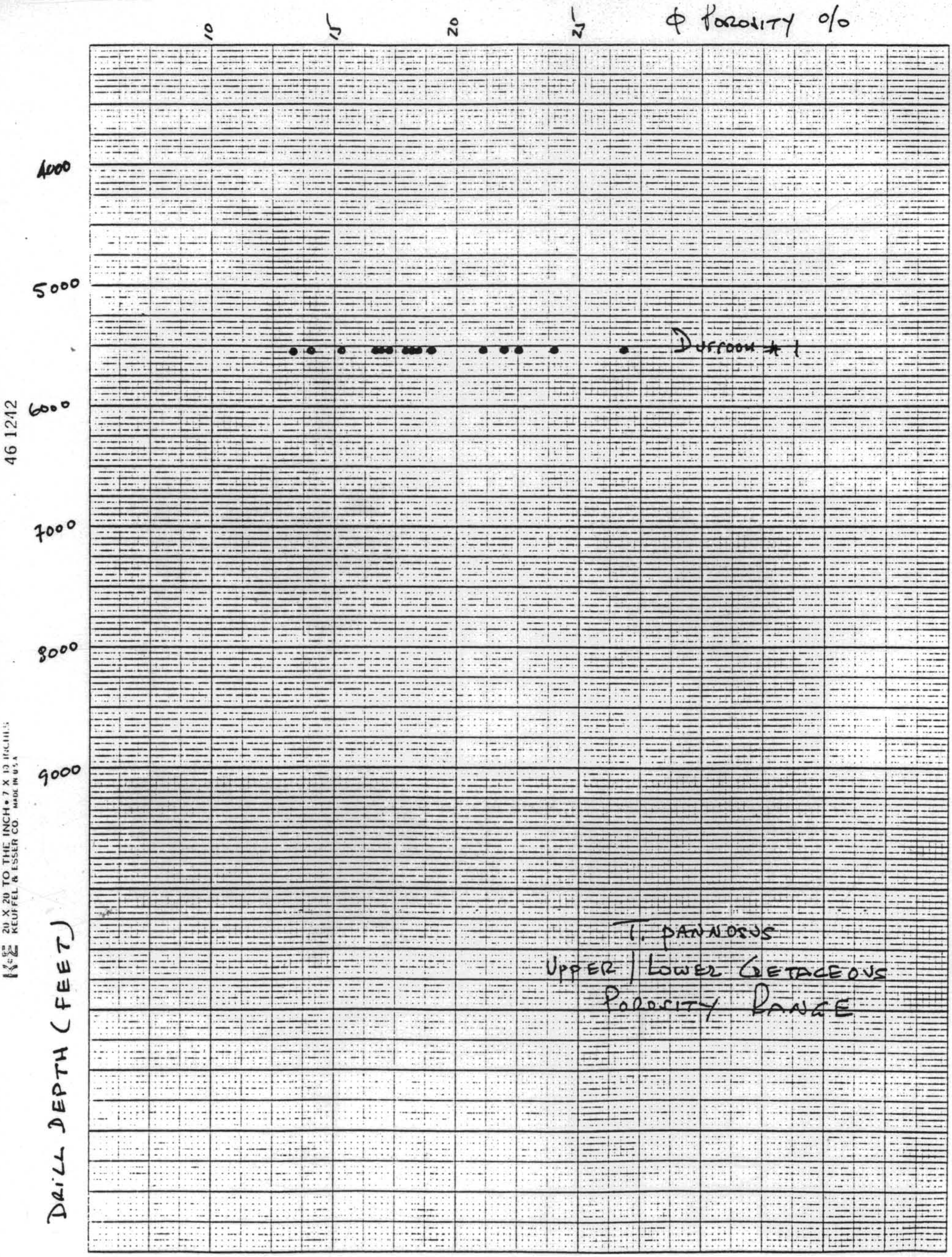


FIGURE 8

225046

5 cm

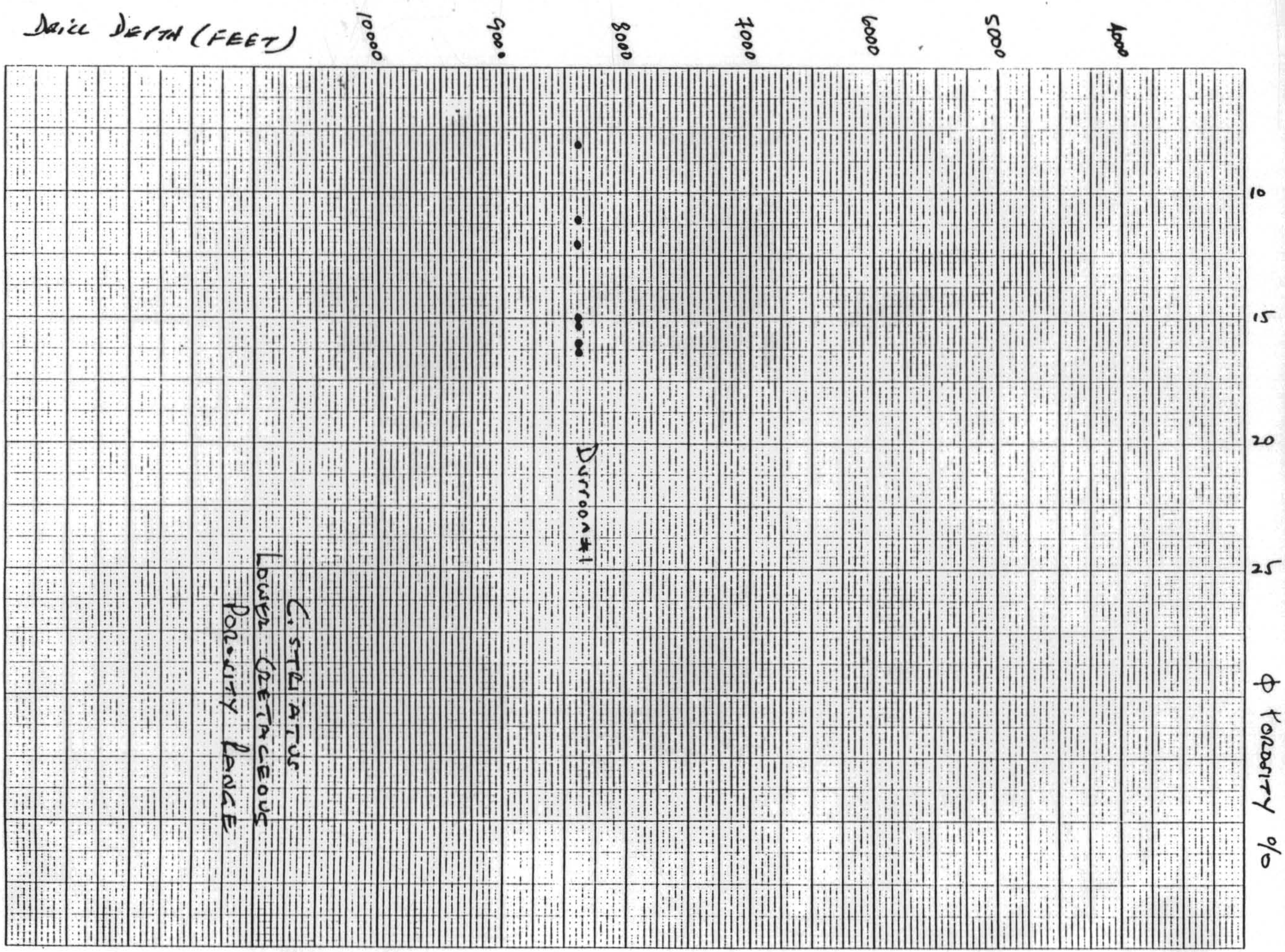


225047

FIGURE 9

5 cm

K&E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A. 46 1242



225048

FIGURE 10

5 cm

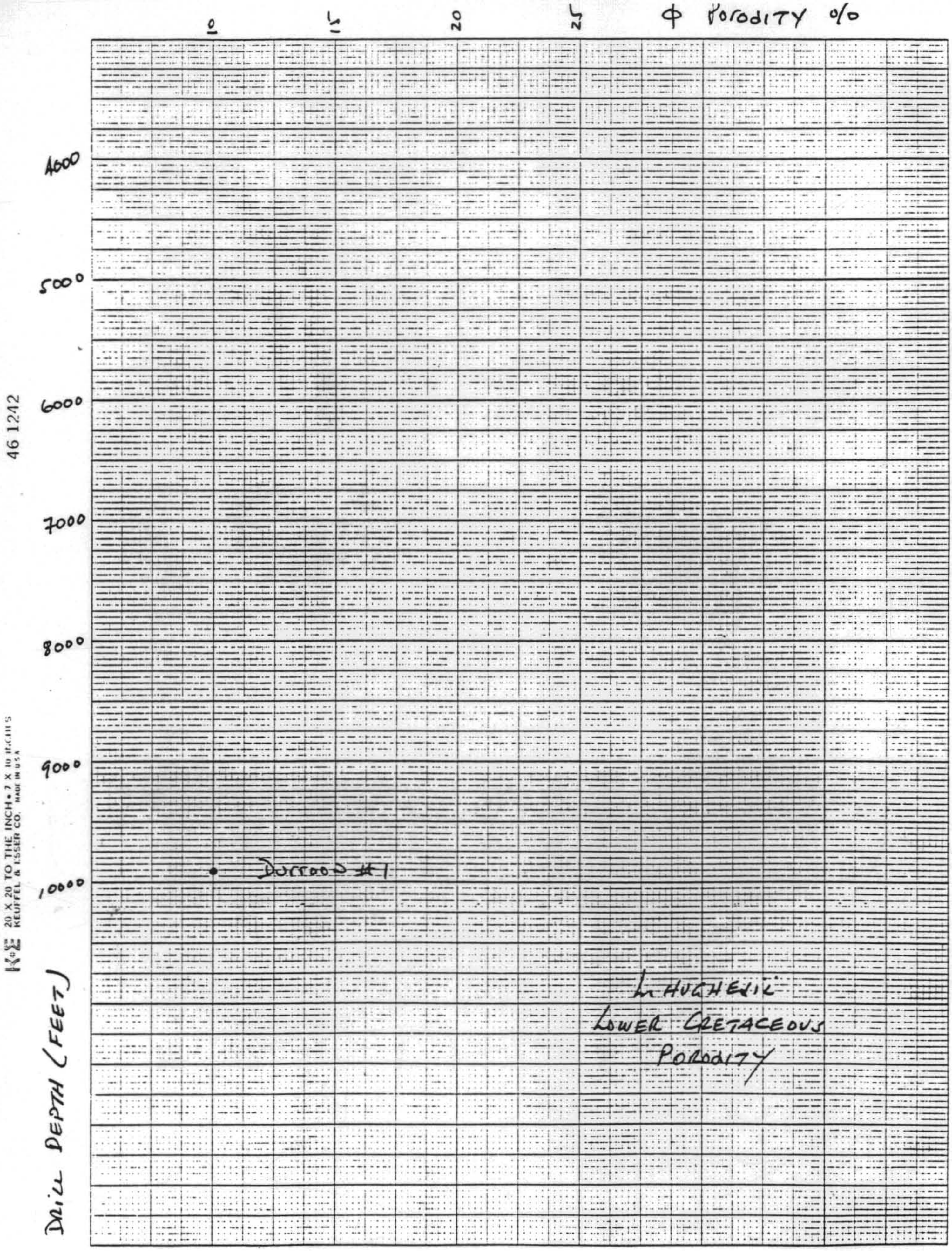
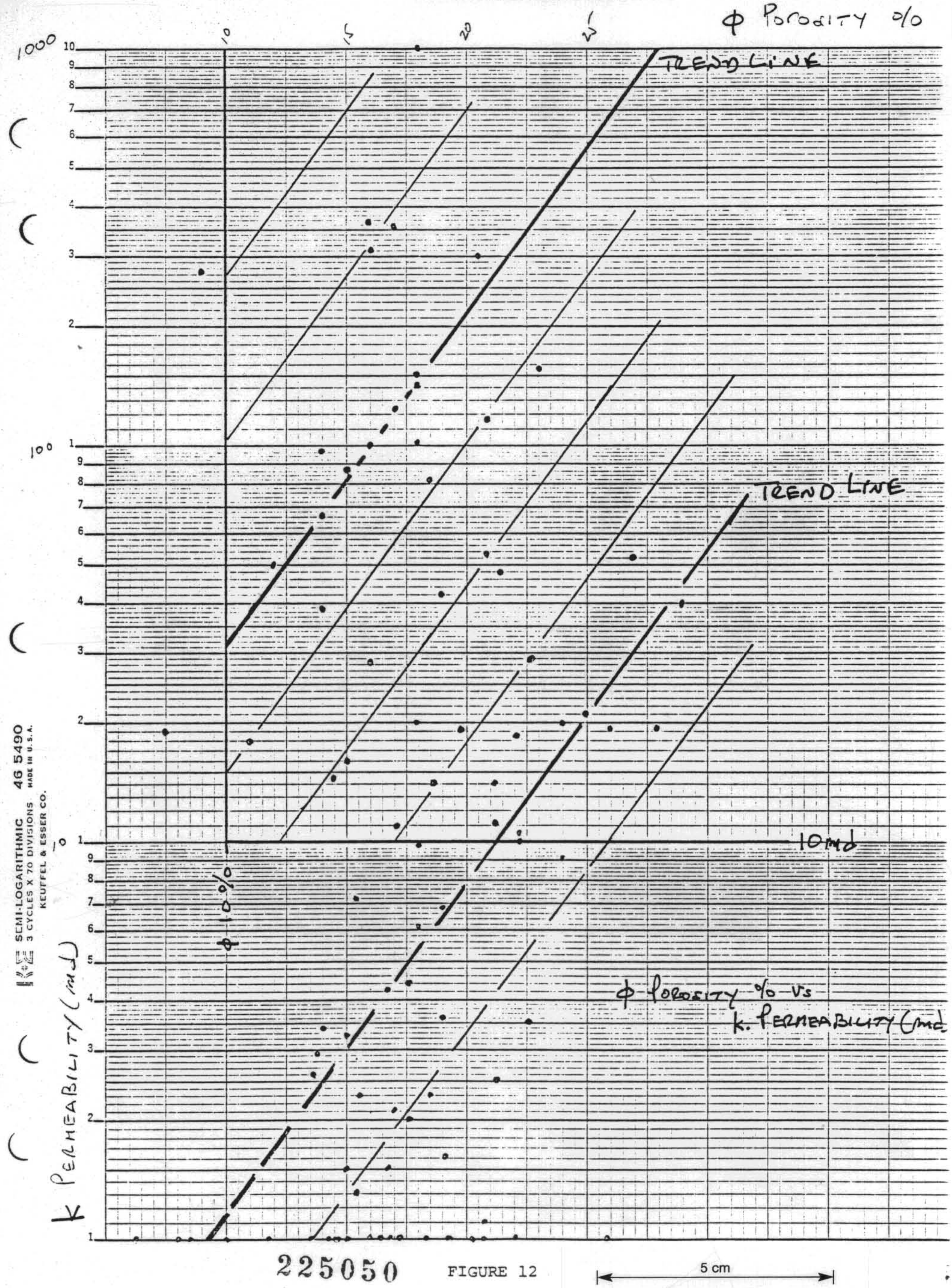


FIGURE 11

225049

5 cm



225050 FIGURE 12

5 cm

Reprocessed Seismic Lines (BMR)

The Bureau of Mineral Resource (BMR) has reprocessed certain seismic lines originally acquired by Heamatite Petroleum Party Limited in the course of their HB-75A survey conducted in 1975 in the Bass Basin. The reprocessing was done by GSI in Perth, Western Australia, in 1983. It consist of using a sliding gate AGC program to enhance the deep reflector. Some of the lines were also restacked and migated.

Seismic lines HB-75-A-185/186/174 are located close but outside Permit T-19-P. Line HB-75A-185/186 is a northeast trending, or dip line, located close to the Bass #3 well. It has been migated. A prominent reflector associated with a major unconformity is shown. Seismic events above this unconformity shown mostly regional dip.

Seismic line HB-75A-174 is a northwest trading, or strike, line which goes through the Bass #3 well. A prominent "Basement" reflector associated with a major unconformity is shown. Seismic events above this unconformity show regional dip, convergence and termination against the flank of the basement high. The gas/condensate or light oil tested in this well is shown to be located below an unconformity of local extent associated with structural readjustment of this feature.

Source-Rock Evaluation

Introduction

The lower Eastern View Coal Measures contain Late Cretaceous, Paleocene and Early Eocene sediments. On the basin margin the sequence is unconformable on the Early Cretaceous, the mid-Cretaceous unconformity, or on Paleozoic basement. Relationship with older units are unknown over large area of the basin. The Durroon #1 well is the only well to have penetrated a significant thickness of Late Cretaceous sediments. It comprises a sequence of coarse grained sandstone with thin shale intervals unconformably overlaying a massive carbonaceous shale. The Early Cretaceous sequence also consists of interbedded sandstone and shale. The Paleocene to Early Eocene section comprises a sequence of interbedded sandstone, siltstone, shale and thin coal seams, which exhibit a broad facies change, being dominantly arenaceous in the south and southwest, and becoming more argillaceous towards the north.

Types of Organic Matter

Figure 13 contains descriptions of organic types in samples from the Bass Basin that were submitted for microscopic examination. For each well, the stratigraphic unit has been interpreted as gas-prone or oil-prone, depending on whether the dominate organic types are of the humic vitrinite type, or the exinite type. There are too few samples from which to draw definite conclusion about each unit. Figures 14, 15.

Source-Rock Chemistry

Core samples have been analysed for total organic carbon (TOC) and total extractable organic matter (EOM). The EOM was subdivided by liquid chromatography into three fractions: saturated hydrocarbons (SATS); aromatic hydrocarbons (AROM); and polar organic compounds.

Gas chromatograms were recorded for the saturated fraction only. The results are given in Figure 16. Comparative analysis were also made by pyrolysis, using the Rock-Eval method. Using the generally accepted criteria that a minimum TOC content of 0.5 percent is necessary for a clastic rock to have hydrocarbon source potential, it is readily apparent that since all the samples reach and exceed this value, the lower Eastern View Coal Measures and Early Cretaceous section does have source potential. Disregarding the coal sample, the highest value of 20.10 percent is from a carbonaceous shale of Paleocene age.

225053

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson

Unit	Well name	Core No.	Depth m	% of organic types 1	2	3	4	5	Comments on exinites	Fluorescence
L. EVCM	Bass 3	11	2265.6	58	33	3	3	3	C	Very dull orange
L. EVCM	Aroo 1	1	2903.8	>99	>1	—	—	<1	C	None
L. EVCM	Poonboon 1	4	3034.0	63	30	—	4	3	C. A. S	Moderate to dull orange

Organic types
1. Vitrinite
2. Semifusinite
3. Fusinite
4. Inertodetrinite
5. Exinite

Abbreviations of exinites
A = Alginite
C = Cutinite
LD = Liptodetrinite
R = Resinite
S = Sporinite

EVCM = Eastern View Coal Measures

Types of organic matter

FIGURE 13

KONKON-1

DESCRIPTIONS OF KEROGEN ALTERATION

FROM "PICKED" CUTTINGS

Description by J.L. Morgan

Depth Feet	Sample Type	Kerogen Alteration	TYPES OF KEROGEN ** Predominant	Secondary	Other	Remarks
3500		1+	W	N	C	
3700		1+	W	N	C	
4000		2-	Al?	W	C	
4300		2-	W	- Al?	C	
4500		1+	W-	- Al,A	C	
4800		2-	W	H	- Al,C	
4900		2-	W	- Al?	H,C	
5000		2-	- Al?	W,H	C	
5043		2-	W	H	- Al,C	

** H - Herbaceous
W - Woody
C - Coaly

A - Amorphous
Al- Algal
N - Nonfilamentous Algal

FIGURE 14

225055

<u>POONBOON - 1</u>

DESCRIPTION OF KEROGEN ALTERATION

FROM "PICKED" CUTTINGS

Description by J.L. Morgan

Depth Feet	Sample Type	Kerogen Alteration	TYPES OF KEROGEN ** Predominant	Secondary	Other	Remarks
6500		2	N?	W	F	
6600		2+	N?	W,C	H	
6900		2	W	-	N?	
7300		2+	W	N?	H	
7500		2+	N?	N	N	
7600		2	W	-	N?	
8100		2+	~Al	W	~ A,C	
8300		2	W	-	N?	
8900		2+	C	N?	~A,H	
9200		2+	W	~ Al	H,C	
9400		2+	W	~ Al	H,C	
9500		2+	W	-	~Al	
9700		2+	~Al	W	C	
9900		2+	~Al	W	C	
10200		2+	~Al	W	H	
10400		2+	W	~ Al	C	
10600		2+	~ Al	W	H,C	

** H - Herbaceous
W - Woody
C - Coaly

A - Amorphous
Al - Algal
N - Nonfilamentous Algal
F - Finely Disseminated.

FIGURE 15

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson

Unit/zone *	*Index No.*	*Well name*	*Core No.*	*Depth (m)*	*Lithology*	*TOC %*	*EOM ppm*	*SATS ppm*	*AROM ppm*	*POLAR ppm*	*Vitr. R. Ro mean max.* †	*Source rating.*
L. EVCM *L. balmei*	3	Aroo 1	1	2 903.8	Shale	6.05	5 020	608	1 450	486	0.65	Good
L. EVCM *L. balmei*	11	Bass 2	9	1 679.0	Siltstone	2.40	2 360	765	484	672	0.35	Very good
L. EVCM *L. balmei*	13	Bass 3	10	2 104.6	Shale	20.10	11 500	1 100	5 460	1 410	0.63	Good
L. EVCM *L. balmei*	14	Bass 3	11	2 265.6	Sandstone	2.40	1 530	129	684	353	0.56	Good
L. EVCM *T. longus*	15	Bass 3	13	2 408.8	Siltstone	0.60	152	57	52	54	—	Fair
L. EVCM Lower *M. diversus*	19	Narimba 1	1	2 833.6	Shale	7.10	12 300	6 250	3 300	1 140	0.67	Very good
L. EVCM Lower *M. diversus*	20.	Narimba 1	2	2 912.3	Shale, siltstone	0.85	1 680	29	353	586	0.62	Good
L. EVCM Lower *M. diversus*	21	Narimba 1	3	2 972.3	Shale	1.85	2 600	193	1 220	533	0.56	Very good
L. EVCM Lower *M. diversus*	22	Poonboon 1	2	2 472.8	Coal	65.80	39 930	3 270	4 820	10 290	0.60	Fair
L. EVCM *L. balmei*	23	Poonboon 1	4	3 034.0	Shale	1.75	1 030	176	324	231	0.70	Good
L. EVCM *T. longus*	24	Poonboon 1	5	3 258.6	Siltstone	1.20	809	79	250	202	0.66	Good
Otway Group	27	Durroon 1	3	1 695.9	Sandstone	1.80	988	66	127	595	0.38	Fair
Otway Group	28	Durroon 1	4	2 567.0	Siltstone	4.50	1 200	13	633	319	(0.54)	Fair
Otway Group	29	Durroon 1	5	3 024.2	Sandstone	3.75	2 500	43	1 020	539	0.69	Good

† Values in parenthesis are uncertain, too few determinations having been made to give a reliable mean.

Source rock chemistry

FIGURE 16

225056

A plot of total hydrocarbon content, SATS plus AROM against TOC gives a better rating of source-rock potential, Figure 17. The higher hydrocarbon to TOC ratios observed in the three categories, fair, good, very good, is suggestive of a more oil-prone than gas-prone source. Overall, the results indicate that the lower Eastern View Coal Measures contains rocks with good to very good source potential. The early Cretaceous Otway group has been rated as having fair to good source potential.

Maturation of Organic Matter

Vitrinite reflectance measurements in the range of 0.6 to 0.7 percent indicate close approach to maturation or maturation levels at which point hydrocarbons may be generated, Figure 18 and 19.

A later study, Figure 20 and 21, indicate that mature,, above 0.6 percent, source rock are present and capable of hydrocarbon generation.

Microscopic examination of kerogen color, in transmitted light, are in broad agreement with those indicated by vitrinite reflectance data, showing that the lower Eastern View Coal Measures have reached marginal maturity, and are within the hydrocarbon generation zone at the deepest levels tested.

Geothermal Gradient

Reported geothermal gradients in the Bass Basin tend to be relatively lower in the central parts of the basin than on the flanks. The northeast flank having higher gradient than the southwest.

Initial gradients are determined between the surface and the bottom of each well. The underlying assumption is that the logged temperature is equivalent to the formation temperature after correction for time since drilling mud circulation stopped.

The geothermal gradients in the Bass Basin vary between 29°c/km and 37°c/km. The average geothermal gradient in the basin is approximately 35° c/km or 1.92°F/100 feet to 2.0°F/100 feet. Figure 22.

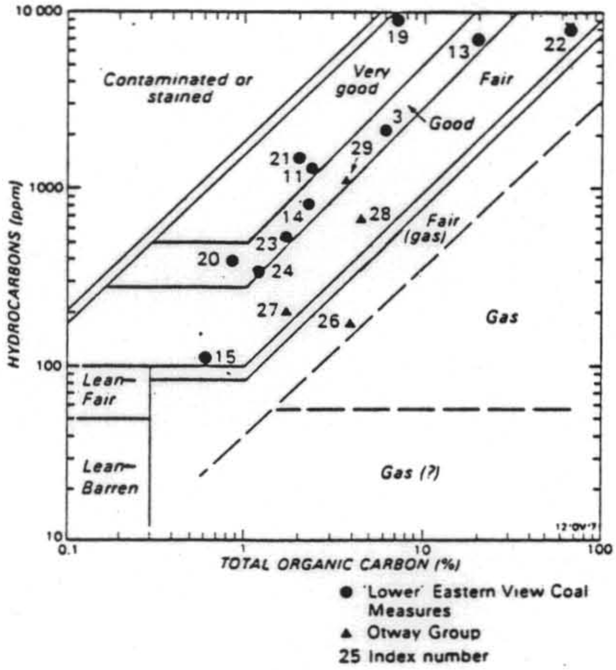
High values of vitrinite reflectance at depths of 3 kilometers are consistent with localized heating. It can be concluded that laterally intensive sources of heat within the basin basement locally affected the deeper basin sediments. Sediments shallower than 2 kilometers remain unaffected.

225058

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson



Source-rock richness

FIGURE 17

5 cm

225059

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson

Well	'Lower' Eastern View Coal Measures (71 samples)		Otway Gp (9 samples)	
	T.A.I.	Source type	T.A.I.	Source type
Bass No. 2	1 to 1.5	Gas		
Bass No. 3	1.5 to 2	Oil & gas		
Cormorant No. 1	2 to 3	Gas & some oil		
Durroon No. 1	1 to 2	Gas	2 to 2.5	Gas
Konkon No. 1	1 to 2	Gas	1.5 to 2	Gas
Narimba No. 1	1 to 1.5	Gas		
Pelican No. 1	1.5 to 2.5	Gas		
Pelican No. 3	2 to 2.5	Oil & gas		
Poonboon No. 1	2 to 2.5	Oil & gas		
Tarook No. 1	2 to 2.5	Gas		
Dondu No. 1	2 to 2.5	Gas & some oil		

Thermal alteration index (based on spore and pollen colouration): 1 to 2, immature
2 to 2.5, transitionally mature
2.5 to 3, mature
3 to 4, increasingly overmature

Maturation and interpreted hydrocarbon (oil or gas) source type

FIGURE 18

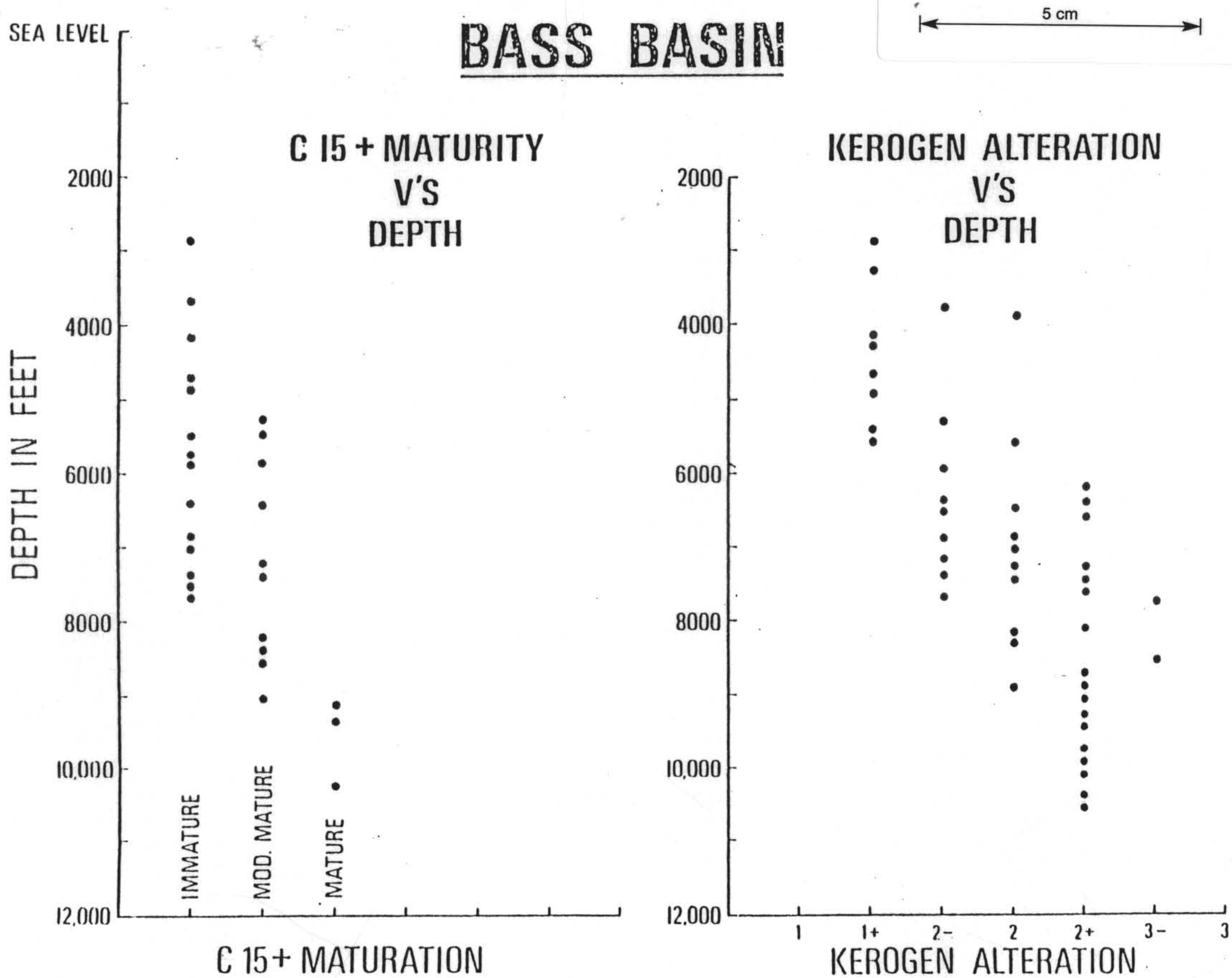

BASS BASIN
SEA LEVEL
2000
4000
6000
8000
10,000
12,000
DEPTH IN FEET
C 15 + MATURITY
V'S
DEPTH
IMMATURE
MOD. MATURE
MATURE
C 15+ MATURATION
KEROGEN ALTERATION
V'S
DEPTH
1
1+
2-
2
2+
3-
3
KEROGEN ALTERATION

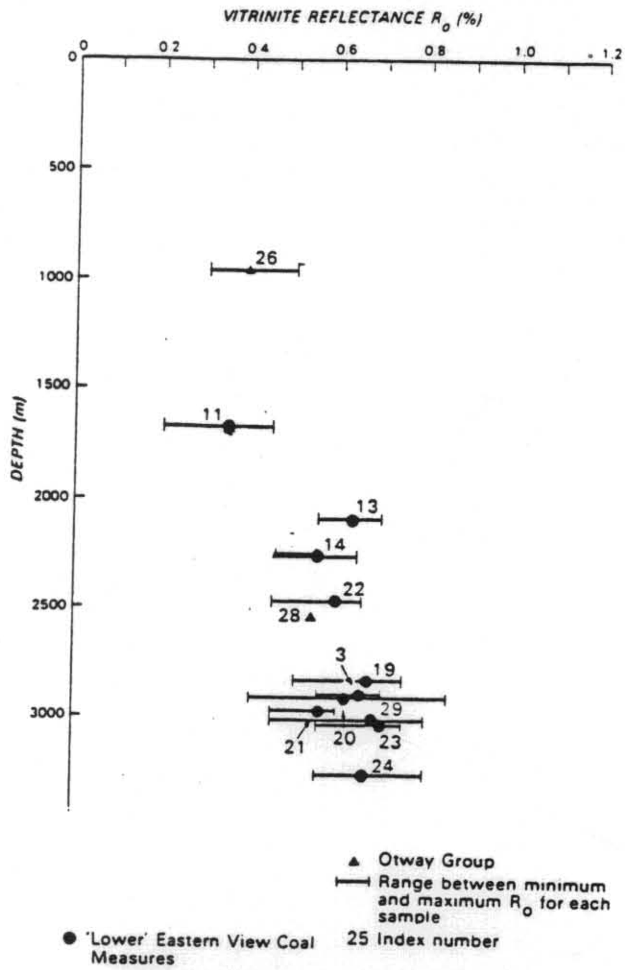
FIGURE 19

225061

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson



Vitrinite reflectance plotted against depth in Bass Basin.

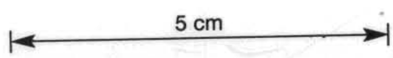


FIGURE 20

225062

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Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson

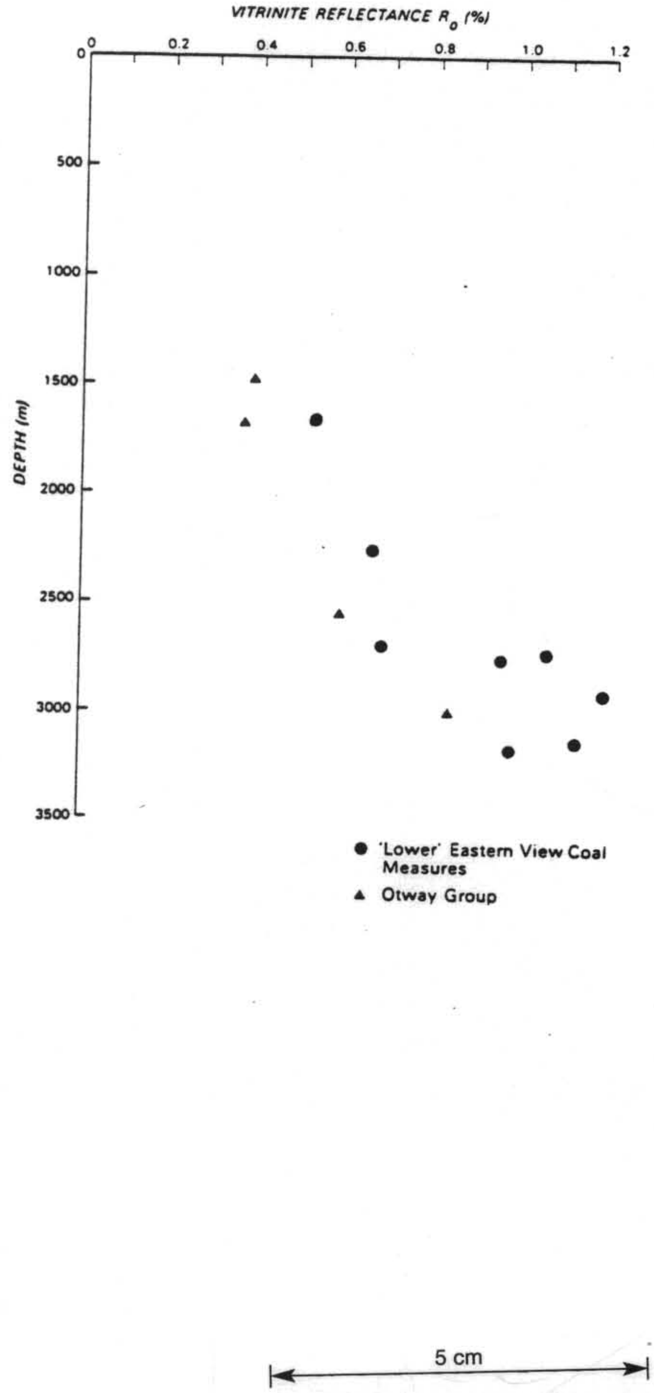


FIGURE 21

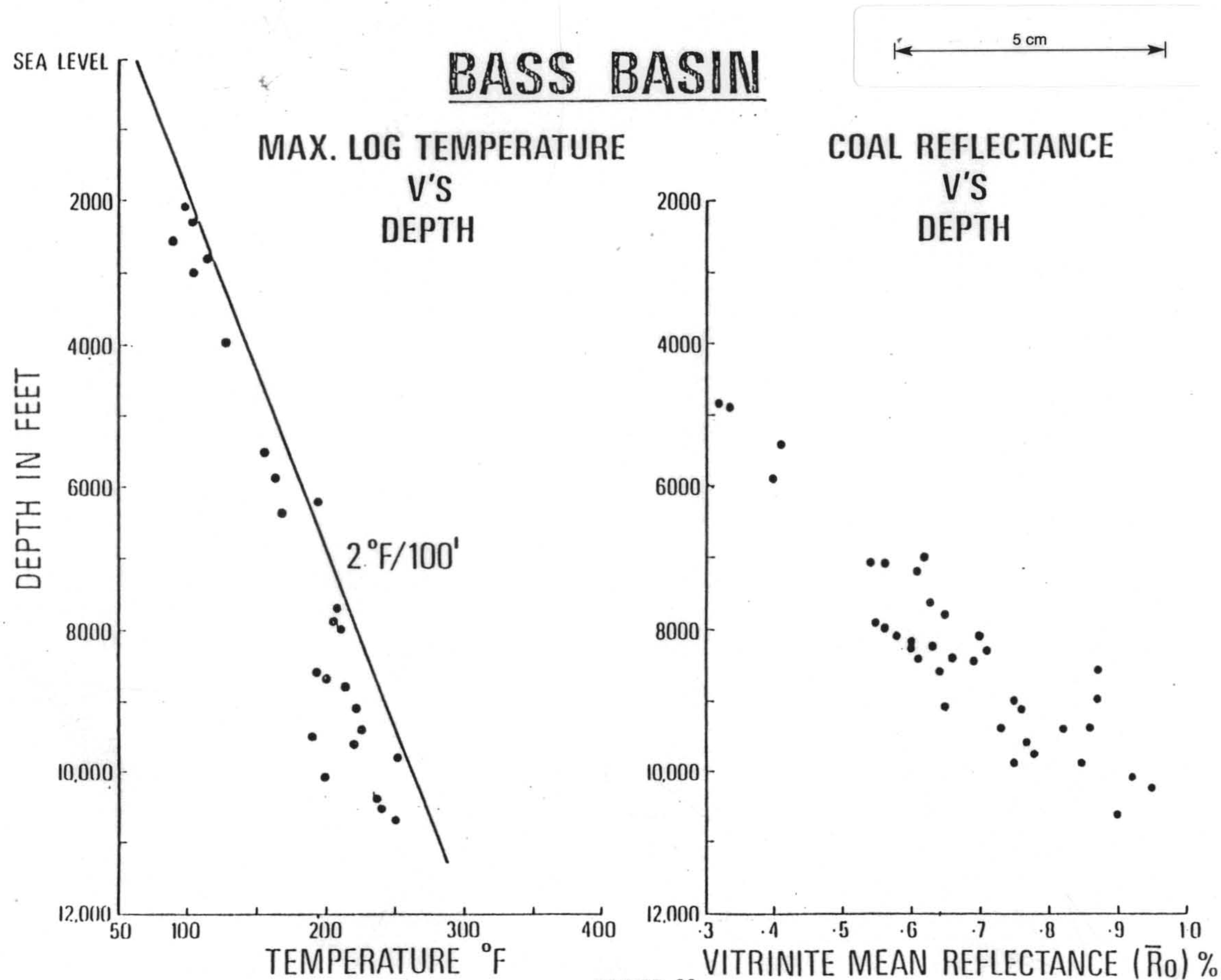


FIGURE 22

225063

Cases of significant divergence between reflectance gradient and thermal gradient have been reported. Though unexplained at this stage, it should be recognized that such cases of low reflectance gradients and apparent lagging of maturation increase behind temperature increase also are reported in the Gippsland basin.

Pyrolysis

Core samples have been analysed by pyrolysis, using the Rock-Eval methods. Published results are summarized in Figure 23.

The samples from the lower Eastern View Coal Measures are rated as good to very good in regard to petroleum potential. This is in general agreement with source ratings obtained from other methods.

Gippsland Basin Comparison

Results of several published studies on the subject of source rock and maturation in the Gippsland basin are summarized.

The main source rock for the extensive oil and gas deposits so far discovered in the Gippsland basin appear to be at depths greater than those reached by any of the exploratory wells.

Chromatographic analysis of Gippsland crudes suggest that the oil originated in solid organic matter derived from algae and land plants, the latter contributing to the higher than usual wax content.

Microscopic characterization of carbonaceous material reveals high contents of vitrinite and exinite. A typical composition of coal being vitrinite 84%, exinite 12% and inertite, mostly fusinite, 4%.

Studies of the exinite indicate that the upper part of the Latrobe group, time equivalent to the upper Eastern View Coal Measures, is above the maturation level, Figure 24. Therefore, it appears that the major oil, condensate and gas accumulations of the Gippsland basin have not been sourced by in-situ mature source rock, but are the results of long range migration along fault planes, bedding planes and unconformity surfaces. Figure 25. Figure 26 shows that vitrinite reflectance versus depth increases at comparable rates in the Bass Basin as in the Gippsland basin.

BMR Journal of Australian Geology & Geophysics, 6, 1981, 199-212

Petroleum potential of the Bass Basin

E. Nicholas, K. L. Lockwood, A. R. Martin[1], & K. S. Jackson

Well name	*Unit*	*Core No.*	*Total organic carbon (TOC) (%)*	*Oil & gas content S_1 (mg hydro-carbon/g rock)*	*Petroleum potential S_1+S_2 (mg hydro-carbon/g rock)*	*Production index $S_1/(S_1+S_2)$*	*Hydrogen index S_2/TOC (mg hydro-carbon/ g TOC)*	*Oxygen index S_3/TOC (mg CO_2/ g TOC)*	*Hydrogen: oxygen ratio (H/O)*
Aroo No. 1	L. EVCM	1	6.05	0.82	22.80	0.04	365	10	37
Bass No. 2									
	L. EVCM	9	2.40	0.21	10.00	0.02	409	29	14
Bass No. 3	L. EVCM	10	20.10	1.21	46.70	0.03	226	10	23
	L. EVCM	11	2.40	0.13	4.74	0.03	192	11	18
	L. EVCM	13	0.60	0.02	0.03	0.67	2	18	0.1
Narimba No. 1	L. EVCM	1	7.10	1.81	17.70	0.10	223	9	24
	L. EVCM	2	0.85	0.09	0.73	0.12	76	271	0.3
	L. EVCM	3	1.85	0.19	1.72	0.11	83	148	0.6
Poonboon No. 1	L. EVCM	2	65.80*	19.60	160	0.12	213	13	16
	L. EVCM	4	1.75	0.11	1.49	0.07	79	132	0.6
	L. EVCM	5	1.20	0.13	0.88	0.15	63	100	0.6
	Otway Gp	3	4.15	3.03	3.14	0.96	3	150	0.02
Durroon No. 1	Otway Gp	3	1.80	0.01	0.60	0.02	33	69	0.5
	Otway Gp	4	4.50	0.17	0.98	0.17	18	9	2.0
	Otway Gp	5	3.75	0.23	2.28	0.10	55	9	5.9

* Coal

Rock-Eval pyrolysis data for some Bass Basin source rocks

FIGURE 23

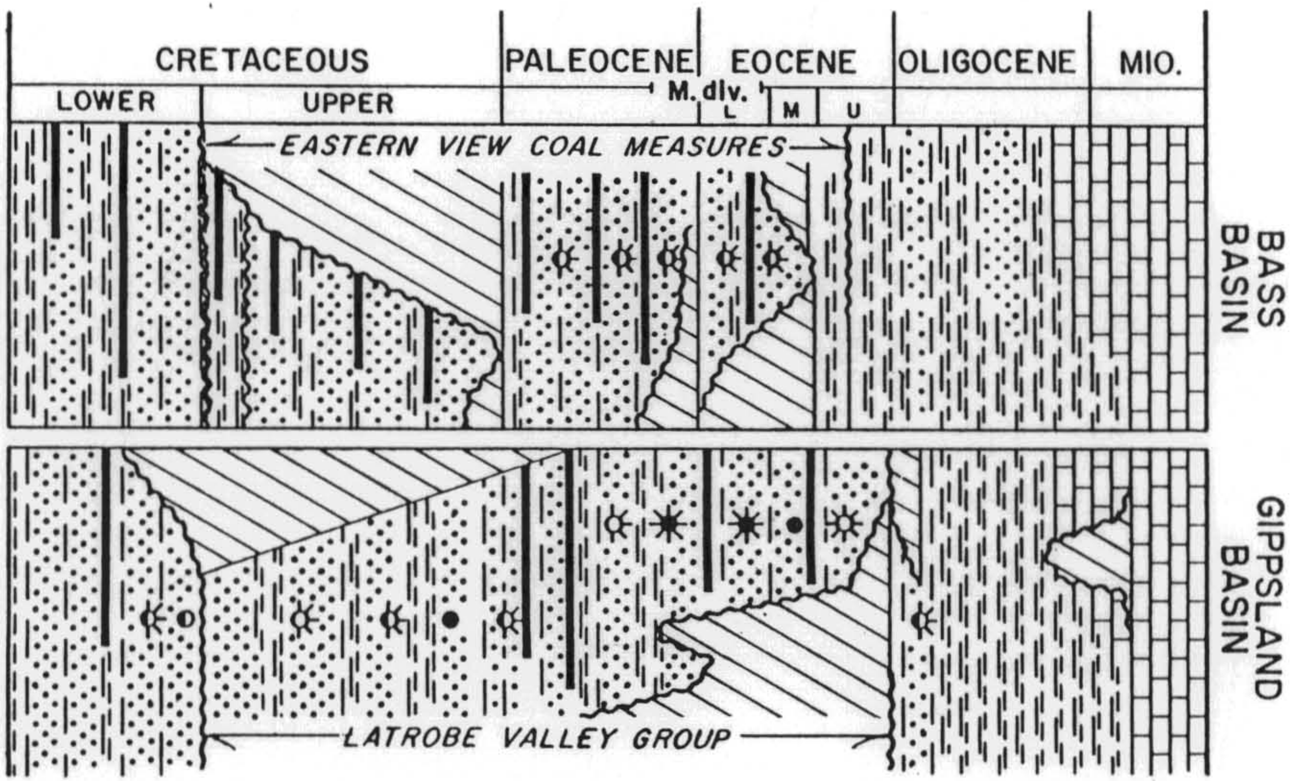
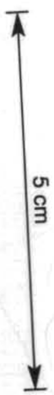
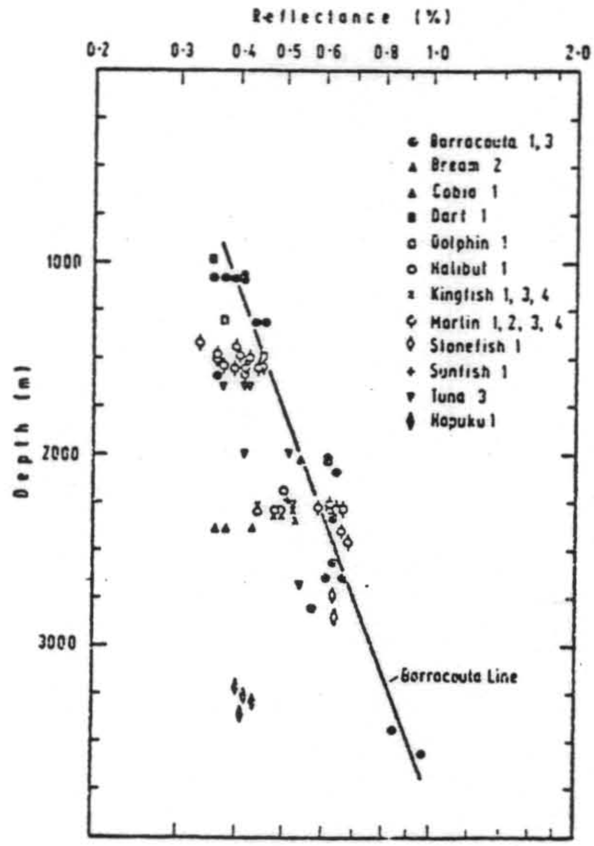


FIGURE 24



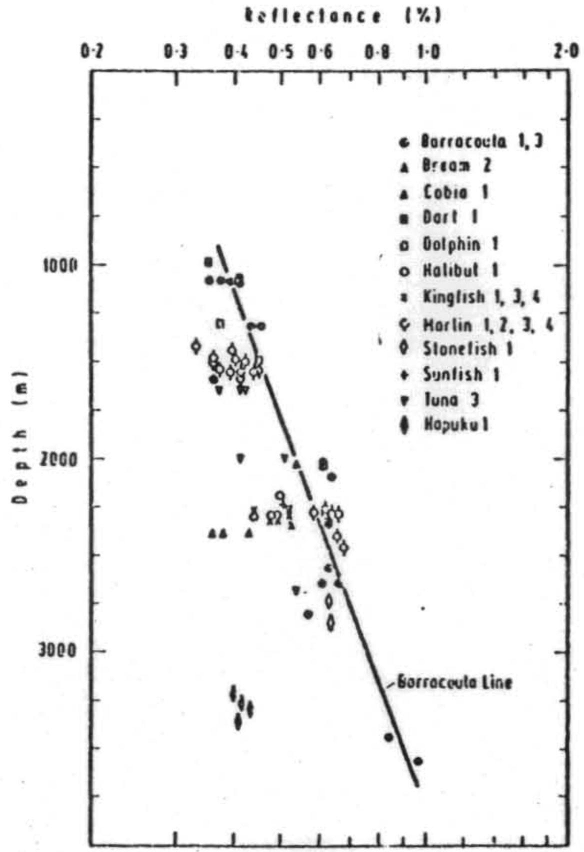
225066



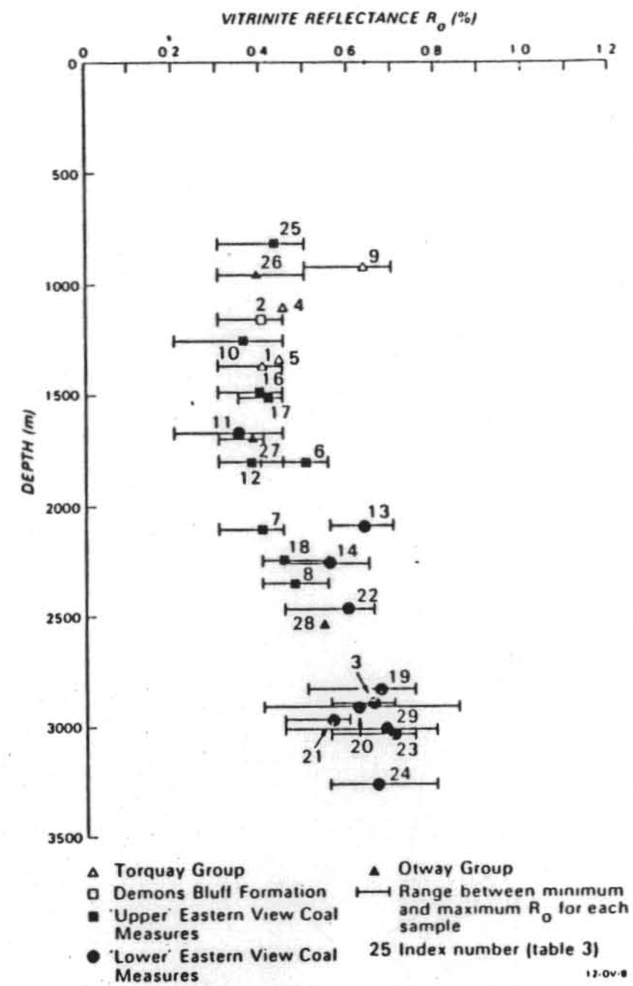
Reflectance of vitrinite in offshore wells in the Gippsland Basin

5 cm

FIGURE 25



Reflectance of vitrinite in offshore wells in the Gippsland Basin



Vitrinite reflectance plotted against depth in Bass Basin.

5 cm

FIGURE 26

Conclusions

The published source rock studies confirm the hydrocarbon source potential of the Eastern View Coal Measures, especially its lower portion which is rated as having good to very good potential. The presence of vitrinitic kerogen indicates generally gas-prone source rocks, but the exinitic kerogen content in samples from some wells is sufficient to warrant an oil-prone and gas-prone rating.

Thermal maturation indicators show the at the deepest levels tested, the source rocks in the lower Eastern View Coal Measures are within the mature zone for hydrocarbon generation.

Studies of the kerogen types in the Konkon, Cormorant and Poonboon wells indicate the presence of algal remains or algeanite possibly associated with marine incursion of the basin.