DEPARTMENT OF MINES AND ENERGY

GEOLOGICAL SURVEY

SOUTH AUSTRALIA

REPORT BOOK 91/104

UNDISCOVERED PETROLEUM: Assessments of the potential of the Officer and Otway Basins in South Australia.

J G G MORTON

Oil, Gas & Coal Division

NOVEMBER, 1991 SR 28/1/112

F02625

CONTENTS PAGE

DEPARTMENT OF MINES AND ENERGY
GEOLOGICAL SURVEY
SOUTH AUSTRALIA

REPORT BOOK 91/104

SR 28/1/112
ENV. 6543

UNDISCOVERED PETROLEUM: ASSESSMENTS OF THE POTENTIAL OF THE OFFICER AND OTWAY BASINS IN SOUTH AUSTRALIA

J G G MORTON

Undiscovered (speculative and hypothetical) petroleum reserves and field sizes for sedimentary basins in South Australia have been estimated using methods that are appropriate to the level of previous exploration (and thus the data available). These methods range from extrapolation of discovery trends in the relatively mature Cooper Basin, to Monte Carlo probability simulation in the recently gas-proven Otway Basin, and in the underexplored Officer Basin. The results indicate that 1.7 TCF of sales gas is yet to be discovered in the South Australian portion of the Cooper Basin compared to 1.6 TCF of sales gas in the western onshore Otway Basin, and that in the Officer Basin there is a reasonable chance (50% probability) of finding 5 TCF of gas or 1.7 billion barrels of oil. This latter estimate gives considerable encouragement that a further petroleum producing basin may soon be discovered in South Australia.

INTRODUCTION

Estimating undiscovered petroleum reserves of sedimentary basins in South Australia (Figure 1) is of value in promoting exploration in those areas where little exploration is currently being undertaken, and in mature basins, such as the Cooper Basin, in planning for South Australia's future energy supplies.

The Cooper Basin in South Australia is a mature petroleum province, and undiscovered reserves of 1.7 TCF have been estimated using extrapolation of historical discovery trends (Morton, 1990a). Similar techniques are used by the BMR for other basins in Australia (Forman & Hinde, 1985, Forman, 1986), and are also commonly used overseas, particularly in the US (Crovelli, 1986) and the UK (Band, 1987). The model is used to estimate the exploration drilling effort required to meet future gas supply needs of South Australia.

The Otway Basin has recently been proven to contain commercial quantities of natural gas, while in the Officer basin, although no discoveries have been made, available data indicate that the basin has generated oil. These two basins are in a very early stage of exploration, and the estimation of the undiscovered potential by extrapolation of historical discovery trends is not possible. As a result a method has been developed that uses available geological data and Monte Carlo type statistical techniques to estimate, as a probability distribution, the undiscovered potential for these basins. Potential (undiscovered) reserves are classified as either "hypothetical" in basins with demonstrated commercial discoveries or "speculative" in basins with no discoveries; the latter are considered to have a lower confidence of existence (Laherrere,1990).

METHOD

For a commercial petroleum field to exist, four essential components are required:

1. A mature 'source rock' horizon; a rock unit that contains sufficient organic matter and which has been subjected to sufficient heat and pressure over time to have produced significant quantities of hydrocarbons, but not to have destroyed them through excessive heat and pressure.

2. A 'reservoir' horizon; a rock unit that accumulates the generated oil or gas. A reservoir rock must be porous, and have sufficient permeability to produce fluids economically.

3. A 'seal' horizon; a rock unit that traps the petroleum in the reservoir and prevents further migration.

4. A structure over the reservoir horizon that will concentrate the petroleum in economic quantities and that was present at the time of petroleum expulsion from the source rock. Usually this is an anticline, but stratigraphic traps can also be important.

When all four of these occur in a basin, a petroleum 'play' or a potential target for explorationists exists. More than one play may exist in a basin and a single exploration wildcat well may address more than one at several stratigraphic levels.

The method of estimating undiscovered reserves in unexplored or underexplored basins consists of identifying all of the 'plays' that may exist, either by discoveries made so far, or by analysis of the available data (e.g drillhole, geophysical, outcrop). The oil *or* gas potential for each play is then calculated by the following formula:

$P_t = A_p \times AB \times ER \times h \times NG \times FF \times Por \times S_h \times FVF \times SR \times RS$

Where:

- P_t = Total potential recoverable reserves (oil or gas) of the play
- A_p = Prospective area of the basin
- AB = Anticline to total basin area ratio
- ER = Reduction factor to reduce AB to account for anticlines that are too small to be economic.
- h = Average gross reservoir thickness.
- NG = Net to gross pay ratio
- FF = Anticline fill factor
- Por = Porosity (fraction)
- S_h = Hydrocarbon saturation (1 - water saturation).
- FVF = Formation volume factor
- SR = Exploration drilling success ratio
- RS = Recovery x shrinkage factors.

None of the above parameters is known with certainty, but most can be estimated from available data to within at least broad limits. The problem then arises as to how to multiply these factors together to produce an estimate of the petroleum potential of the 'play'. The most common method of combining and expressing the uncertainty associated with this type of equation is to use Monte Carlo simulation techniques (White and Gehman,1979). A frequency distribution for each parameter is assumed, converted to a cumulative probability distribution, and a random number between 0 and 1 (corresponding to 0 to 100% probability) is used to sample each of the distributions, which are combined as in the equation above to give one estimate of the potential of the play. The process is repeated many times (in this case at least 1000 times). to produce multiple estimates of the potential of each play. These are then used to produce a probability versus petroleum potential distribution for each play and for the basin as a whole. Because this is computationally intensive, the calculation is carried out by computer using a commercially available simulator ("RISK", a LOTUS 1-2-3 add in). This uses a more advanced stratified sampling technique called "Latin Hypercube" that will converge in fewer iterations than with the traditional "Monte Carlo" technique.

DISCUSSION OF PARAMETERS

Prospective area (A_p):

This is the area of the basin that is believed to contain the three essential components of source, reservoir and seal, and where the reservoir is at an economically drillable depth (assumed to be less than 4500 metres). This is the most critical factor in determining the potential of the basin but can be mapped with reasonable accuracy from available drillhole and seismic data (figures 6 to 8 and 12 to 13), and these maps are useful to potential explorers in assessing the relative prospectivity of different areas of a basin. It is entered as a Triangular distribution (minimum, most likely, maximum).

Anticline to basin area ratio (AB):

This is the proportion of the prospective area that is within an anticlinal trap. It is extrapolated from detailed seismic maps of the particular reservoir horizon that are available for limited areas of the basin. Regional seismic maps are not adequate as they tend to map only the very large structures and result in very conservative estimates of the anticline/basin area ratio. In practice as many detailed maps as possible are used to gain an understanding of the range of possible values, or if none is available, substitutes are extrapolated from other producing horizons. An example of one of these detailed maps for the Officer Basin is shown in figure 2. This parameter is also entered as a Triangular distribution.

Economic reduction factor (ER):

The purpose of this factor is to reduce the anticline to basin area ratio to exclude anticlines that are considered too small to contain potentially economic hydrocarbon volumes. The limiting anticline area is determined from the smallest economic field (assumed to be a minimum of 2 BCF sales gas or 44 MSTB oil at 100% success ratio for onshore fields), and is dependent on the success ratio. This is particularly critical for assessing gas potential, and while relatively constant onshore, the ER is very variable and relatively unknown offshore. This parameter is entered as a Truncated Normal distribution (mean, standard deviation, minimum=0, maximum=1.0)

Maximum reservoir thickness (h):

This is the maximum reservoir thickness or the maximum anticline vertical closure, whichever is the lesser. If for the particular play, the anticline height is the lesser, then the reservoir is modeled as a cone and h is reduced to a third (volume of a cone = 1/3 x area x height). If the reservoir thickness is less than the anticline closure, then the reservoir is modeled as a slab, and h is not reduced (Figure 3). The parameter is modelled as a Truncated Lognormal distribution (mean, standard deviation, minimum, maximum).

Net to gross pay ratio (NG):

The net to gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. This can be determined with good accuracy from drillhole data. A Truncated Normal distribution is used.

Anticline fill factor (FF):

In oil or gas basins with commercial fields, anticlines can range from filled to spill to near 0% fill (0% = dry wells). The average fill is therefore less than one, and it is assumed that the richer the source rock the greater the average fill. This critical parameter is very subjective even when some fields have already been discovered due to the normally wide range of values found. Conservative estimates are made based on the relative richness of the source rocks compared to known producing basins, the estimated timing of anticline formation relative to petroleum generation and the nature of the petroleum (the fill factor for gas will be greater than for oil). A Triangular distribution is used.

Porosity (Por):

The average porosity of the reservoir can be reliably estimated from available drillhole data. A Triangular distribution is used.

Hydrocarbon saturation (S_h):

The average hydrocarbon saturation is partly dependent on the average porosity, and the two distributions are linked in the Monte Carlo simulator so that when a low value of porosity is chosen a low hydrocarbon saturation is also chosen. The range is determined from known porosity/hydrocarbon saturation relationships in other basins. A Truncated Normal distribution is normally used, although a uniform distribution is used in the Otway Basin, where porosity/hydrocarbon saturation relationships are unusual.

Formation volume factor (FVF):

The volume of gas in a reservoir increases when brought to the surface due to the drop in pressure, and oil decreases in volume due to loss of volatiles. The value for these factors is determined from existing fields in the basin or from other analogous basins with known fields at a similar depth to the potential plays.

Success ratio (SR):

This is an estimate of the proportion of exploration wells to be drilled that will find an oil or gas field. Like the fill factor (FF) above this ratio is related in part to the richness of the source rocks, but other factors such as the degree of structural complexity, and quality of seismic data are also important. Values are conservatively estimated from analogous basins or recent drilling results.

Recovery and Shrinkage factors (RS):

The recovery factor converts petroleum in-place reserves to sales gas or recoverable oil, and is dependent on composition of the petroleum,depth of the reservoir and the degree of mobility of the underlying aquifer. Recovery factors range up to 85% for gas reservoirs with negligible water drives, to less than 25% for oil reservoirs. The shrinkage factor, which applies only to gas, reflects impurities that may be found in natural gas; in South Australia this is commonly carbon dioxide. Carbon dioxide content is dependent on temperature and pressure in the reservoir and proximity to igneous rocks. A Triangular distribution is used.

ESTIMATING THE LARGEST FIELD TO BE DISCOVERED

An extension of the estimate of the undiscovered potential for the basin is an order of magnitude estimate of the largest field likely to be discovered. This is useful for planning exploration strategies. It is an established fact from well explored and developed oil and gas provinces that fields of a given structural type (e.g. anticlines), when ranked in discovery order, follow a consistent mathematical decline. As the sum of all the fields to be discovered equals the total potential of the basin, this mathematical relationship can be used to estimate the largest field likely to be discovered if an estimate of the number of fields can be made. A number of mathematical relationships have been used to describe the distribution in field sizes but the following simple relationship has been shown to work well in the Cooper Basin and elsewhere:

$F_s = C/(1 + N)$

Where:

F_s = field reserves
C = a constant for each play
N = discovery number

This relationship is illustrated in figure 4.
The total potential (P_t), can be related to N and C (as an approximation at large N) by integrating the equation above:

$P_t = C \times \ln(1 + N_{max})$

and where the total number of fields to be discovered (N_{max}):

$N_{max} = A_p \times A_{den} \times SR$

These equations can be combined to estimate the maximum field size:

$F_{max} = [P_t/(\ln(1 + (A_p \times A_{den} \times SR)))]/2$

Where:

F_{max} = Largest field likely to be discovered
P_t = Total potential recoverable reserves (oil or gas) of the play.
A_p = Prospective area of the basin
A_{den} = Density of anticlines (number per unit area)
SR = Exploration drilling success ratio

This equation is also evaluated using Monte Carlo simulation techniques to give the probabilities of various maximum field sizes. The density of anticlines (A_{den}) is estimated from the same detailed seismic maps that the anticline to prospective area ratio (AB) is estimated (figure 2). A Triangular distribution is used.

A TEST OF THE METHOD ON THE COOPER BASIN

The Cooper Basin provides an ideal test of the method, as this is a relatively mature largely gas prone petroleum province, with most of parameters required for the method being accurately known from the 98 discovered fields and 194 wildcat exploration wells drilled to 1990. The remaining potential has been independently determined with a high confidence by both extrapolation of discovery trends (Morton,1990a) and by an alternate Monte Carlo simulation technique that also relies on extrapolation of discovery trends (D. Forman,BMR, pers comm, 1989).

Estimates by these techniques for the total sales gas potential of the Cooper Basin in South Australia range from 6.2 TCF to 6.9 TCF, of which about 1.7 TCF are still to be discovered. The largest field discovered is Big Lake with sales gas reserves of over 500 BCF. Estimates of the parameters used in the simulation of the Cooper Basin, using the new methods described above, are summarised in appendix A. The results indicate a total potential ranging from 5 TCF to 8.6 TCF, but is likely to be more or less 6.6 TCF (50% probability), and that the largest field is likely to be more or less 580 BCF.

This result gives confidence to apply the method to other less well known basins.

ASSESSMENT OF THE OFFICER BASIN, SOUTH AUSTRALIA

The Officer Basin covers large areas of north western South Australia, but is poorly explored for petroleum in spite of widespread oil shows indicating that petroleum has been generated. The geology of this basin has been described by Brewer *et al* (1987), Gravestock (1990) and Gravestock and Hibburt (1991). There are significant geological similarities with the Amadeus Basin in the Northern Territory, where both gas and oil fields have been discovered, and with the Lena-Tunguska oil and gas province in Siberia (USSR). This latter basin is one of the larger petroleum provinces in the world with an estimated potential of 200 TCF of gas and 100 billion barrels of oil (Meyerhoff, 1980). A speculative assessment of the potential of the Officer Basin is warranted, as the most prospective areas are currently available for application for petroleum exploration licences.
Within the basin, three potential plays have been identified (figure 5):

1. Murnaroo Sandstone

Reservoir:	Murnaroo Sandstone
Seal:	lower Rodda Beds
Source:	lower Rodda Beds

2. Relief Sandstone

Reservoir:	Relief Sandstone
Seal:	Observatory Hill Formation
Source:	Ouldburra Formation/Rodda Beds

3. Observatory Hill (Playa Lake) facies

Reservoir:	Observatory Hill Formation (Moyles Chert)
Seal:	Observatory Hill Formation (Oolarinna Member and equivalents)
Source:	Observatory Hill Formation (Moyles Chert and Parakeelya Alkali Member)

Parameters for the assessment were estimated from available data (appendix B), and maps of the prospective areas are shown in figures 6 to 8. Specific information on the distribution, thickness and source rock richness was derived mainly from 60 to 70 drillholes, of which only 12 were drilled as petroleum exploration wells. Some of the others were drilled by SADME for the purpose of gathering data on the potential of the area, (Pitt *et al.*, 1980) and others were drilled by the private sector to explore for minerals other than petroleum. Structural parameters were estimated from 3000 km of fair to good quality seismic data (figure 2), which was recently re-interpreted by SADME (Thomas, 1990).

Table 1 summarises the results of the assessment of the undiscovered potential of the basin at various probability levels, and figure 9 shows the full probability curve for the total of all plays. Reserves are given for both oil and gas, but these represent the extreme alternate endpoints of a continuum; the basin is likely to contain both oil and gas but it is not possible to estimate the relative proportions. Potential reserves at 90% probability level should be regarded as conservative; this means that there is a 9 in 10 chance the ultimate petroleum potential in the basin will be larger than 523 BCF of sales gas *or* 451 Million barrels of recoverable oil. The 10% probability level, in contrast, would be regarded as very optimistic, and there is only a 1 in 10 chance that the basin hydrocarbon potential is bigger than 18 TCF of sales gas *or* 5 Billion barrels of recoverable oil. The 50% probability level is regarded as a "reasonable" mid point, i.e. there is a 50/50 chance that the basin will be more or less than 5 TCF of sales gas *or* 1.7 Billion barrels of recoverable oil.

The largest field size assessment is summarised in table 2. At the 50% probability level, the largest field is of the order of 500 BCF of sales gas or 200 million barrels of recoverable oil. The 50% probability results suggest that there is a reasonable chance that, if gas-prone, the basin could be as large as the Cooper Basin, or if oil-prone, about half as large as the Gippsland Basin (Bass Strait oil fields). These estimates use conservative success ratios (only 1 in 10, compared to 1 in 2 for the Cooper Basin), and conservative fill factors (only 10 to 50%) to reflect the relatively low organic content of the source rocks. However, although they are based on very limited data, the results are encouraging for future exploration in this basin.

ASSESSMENT OF THE OTWAY BASIN, SOUTH AUSTRALIA

The Otway basin comprises the central to eastern portion of a series of basins formed during the rifting of Australia from Antarctica during the Early Cretaceous, and is related to the Bight-Duntroon basins to the west, and to the Bass-Gippsland Basins to the east. The stratigraphy of the basin has been recently revised by Kopsen and Scholefield(1990), and Morton(1991). A summary of the structure and geology is described in Gravestock, Hill and Morton (1986), and a summary of an early estimate of the undiscovered potential in Morton, (1990b). Prior to the discovery of gas at Katnook in 1987, the basin in South Australia had been extensively explored, with nearly 18000 km of seismic data and 26 wells. The only gas discovery was the Caroline carbon dioxide gas field. However since the early 1980's, seismic data quality dramatically improved, and this led to the discovery of the Katnook and Ladbroke Grove gas fields. The Katnook Field is now contracted to supply Mount Gambier, the APCEL paper mill at Snuggery, (near Millicent), and the SAFRIES plant south of Penola with gas over the next 15 years.

The basin is also believed to have generated oil as evidenced by the numerous strandings of oil which occur on the south eastern beaches and Kangaroo Island, and which have been shown compositionally to have probably been generated within the Otway Basin (McKirdy,1985). Exploration effort within the basin in South Australia is at record levels with 10 Petroleum Exploration Licences (PELs), and 2 Petroleum Production Licences (PPLs) current. There exists a ready market for any further gas discoveries locally and especially in Adelaide. An assessment of the hypothetical gas potential and a speculative assessment of the oil potential is of interest to both explorers active in the basin and to the residents of the south east region of the State.

There are 3 plays that have proven gas reservoirs (Figure, 10, 11):

1. Pretty Hill Sandstone

Reservoir: Pretty Hill Sandstone
Seal: Laira Formation
Source: Laira Formation

2. Katnook/Windermere Sandstone

Reservoir: Windermere Sandstone Member, Katnook Sandstone, Pretty Hill Sandstone
Seal: Eumeralla Formation
Source: Laira Formation

3. Waarre/Flaxmans Formations

Reservoir: Waarre Formation, Flaxman Formation
Seal: Belfast Mudstone
Source:Eumeralla Formation, Laira Formation

These plays are in anticlines or faulted anticlines, but additional potential could exist in stratigraphic traps, in reservoirs of the basal tertiary sequence, or in isolated sands of the Belfast Mudstone or Eumeralla Formation, however, as these units have no source potential onshore, their potential is already included in the other plays. Data for the assessment (appendix C) are derived from the existing gas fields, the 40 petroleum exploration wells, and recent detailed seismic interpretation carried out by exploration companies. Figures 12 to 13 map the prospective areas for each play. Only the onshore portion of the basin is assessed as economic factors differ (and are less accurately known) offshore.

Table 3 summarises the results of the assessment of the undiscovered potential of the onshore basin at various probability levels, and figure 14 shows the full probability curve for the total of all plays. The results indicate that at the 50% probability level, the potential of the onshore basin is 1600 BCF of sales gas or 760 million barrels of recoverable oil. The estimates for the largest field size (160 BCF of sales gas or 70 million barrels of recoverable oil) are interesting (table 4), as they indicate that the reserves are likely to be in relatively small fields. In particular they emphasise the need for high resolution seismic on a closely spaced grid (about 0.5 km) to ensure drilling success.

REFERENCES

Band, G.C. 1987. UK North Sea production prospects to the year 2000 Journal of Petroleum Technology, 39(1):64-70

Brewer, A.M., Dunster, J.N., Gatehouse, C.G., Henry, R.L. and Weste, G., 1987. A revision of the stratigraphy of the Eastern Officer Basin South Australia. Geology Survey, Quarterly Geological Notes, 102.

Crovelli, R.A. 1986 USGS Quantitative petroleum resource appraisal methodologies pp 769-776 in "Oil and Gas assessment", AAPG Studies in Geology #11

Forman, D.J. 1986 Australia's potential for further petroleum discoveries (from May, 1986) BMR Record 1986/34 (Unpublished)

Forman, D.J. and Hinde, A.L. 1985 Improved statistical method for assessment of undiscovered petroleum resources. AAPG Bulletin 69(1):106-118

Gravestock, D.I. 1990 Officer Basin petroleum potential pp 29-32 in "South Australia-Towards 2000, Extended Abstracts", compiled by A.J.Parker, SADME unpublished Report Book no 90/78

Gravestock, D.I. and Hibburt, J.E. 1991 Sequence stratigraphy of the Eastern Officer and Arrowie Basins: A framework for Cambrian oil search. APEA Journal 31:in press.

Gravestock, D.I., Hill, A.J. and Morton, J.G.G. 1986 A review of the structure, geology, and hydrocarbon potential of the Otway Basin in South Australia. SADME Report Book 86/77 (unpublished)

Kopsen, E. and Scholefield, T. 1990 Prospectivity of the Otway Supergroup in the central and western Otway Basin. APEA Journal 30:263-279

Laherrere, J. 1990 Hydrocarbon classification rules proposed Oil and Gas Journal,August 13, 1990:62

McKirdy, D.M. 1985 Coorongite, coastal bitumen and their origins from the lacustrine alga Botryococcus in the western Otway Basin. In Geological Society of Australia (SA and Vic. Divisions) Otway 85:Earth resources of the Otway Basin Summary Papers.

Meyerhoff, A.A. 1980 Geology and petroleum fields in Proterozoic and Lower Cambrian strata, Lena-Tunguska petroleum province, eastern Siberia, USSR pp225-252 in "Giant oil and gas fields of the decade:1968-1978", AAPG Memoir 30

Morton, J.G.G. 1990a Future oil and gas potential pp 9.1-9.23 in "Petroleum Reserves of South Australia as at 1st January, 1990" Unpublished confidential report, prepared by Oil Gas and Coal Division, SADME.

Morton, J.G.G. 1990b Otway Basin petroleum potential: An update of stratigraphy and discoveries, and an assessment of undiscovered oil and gas potential. pp 23- 27 in "South Australia- Towards 2000, Extended Abstracts", compiled by A.J.Parker, SADME unpublished Report Book no 90/78

Morton, J.G.G. 1991 Revised stratigraphic nomenclature for the Otway Basin in South Australia. Quart. Geol. Notes, SADME, no. 116: 2-19.

Pitt, G.M., Benbow, M.C. and Youngs, B.C., 1980. A review of recent geological work in the Officer Basin, South Australia. APEA Journal 20: 209-220.

Thomas, B. 1990 Summary of seismic interpretation in the eastern Officer Basin, South Australia. SADME Report Book 90/58. (unpublished)

White, D.A. and Gehman, H.M. 1979 Methods of estimating oil and gas resources. AAPG Bulletin 63:2183-2192

APPENDIX A

Assumptions for Monte Carlo Simulation, Cooper Basin

PLAY: Permian (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 20,000	Av: 22,500		Max: 25,000
AB	Triangular	Min: 0.4	Av: 0.45		Max: 0.5
ER	Triangular	Min: 1	Av: 1		Max: 1
h	Trunc. Log normal	Av: 150	SD: 10	Min: 0	Max: 200
NG	Trunc. Normal	Av: 0.15	SD: 0.02	Min: 0	Max: 0.2
Por	Triangular	10%: 0.1	Av: 0.11		90%: 0.12
$S_w(1-S_h)$	Trunc. Normal	Av: 0.3	SD: 0.05	Min: 0.1	Max: 0.5
FVF	Trunc. Normal	Av: 185	SD: 10	Min: 170	Max: 200
SR	Triangular	Min: 0.45	Av: 0.48		Max: 0.5
FF	Triangular	Min: 0.6	Av: 0.70		Max: 0.8
RS	Triangular	Min: 0.52	Av: 0.53		Max: 0.54
A_{den} (per km^2	Triangular	Min: 0.01	Av: 0.015		Max: 0.02

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.8 km^2

APPENDIX B

Assumptions for Monte Carlo Simulation, Officer Basin

PLAY: Murnaroo (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 12,786	Av: 62,760		Max: 119,245
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 0.8	Av: 0.85		Max: 0.90
h	Trunc. Log normal	Av: 100	SD: 10	Min: 0	Max: 250
NG	Trunc. Normal	Av: 0.6	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: 0.1	Av: 0.15		90%: 0.20
$S_w(1-S_h)$	Trunc. Normal	Av: 0.30	SD: 0.05	Min: 0.1	Max: 0.50
FVF	Trunc. Normal	Av: 160	SD: 10	Min: 150	Max: 220
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.5		Max: 1.0
RS	Triangular	Min: 0.5	Av: 0.70		Max: 0.75
A_{den} (per km^2)	Triangular	Min: 0.05	Av: 0.04		Max: 0.1

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.2 km^2

PLAY: Murnaroo (OIL)

PARAMETER	DISTRIBUTION		ASSUMED VALUES		
A_p (km^2)	Triangular	Min: 12,786	Av: 62,760		Max: 119,245
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 1	Av: 1		Max: 1
h	Trunc. Log normal	Av: 100	SD: 10	Min: 0	Max: 250
NG	Trunc. Normal	Av: 0.6	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: 0.10	Av: 0.15		90%: 0.2
$S_w(1-S_h)$	Trunc. Normal	Av: 0.30	SD: 0.05	Min: 0.1	Max: 0.5
FVF	Trunc. Normal	Av: 0.8	SD: 0.05	Min: 0.75	Max: 1
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.1		Max: 1
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.08		Max: 0.15

PLAY: Relief (GAS)

PARAMETER	DISTRIBUTION		ASSUMED VALUES		
A_p (km^2)	Triangular	Min: 5,372	Av: 14,752		Max: 96,501
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 0	Av: 0.85		Max: 1.0
h	Trunc. Log normal	Av: 100	SD: 10	Min: 0	Max: 250
NG	Trunc. Normal	Av: 0.9	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: 14	Av: .20		90%: .26
$S_w(1-S_h)$	Trunc. Normal	Av: 0.30	SD: 0.05	Min: 0.1	Max: 0.5
FVF	Trunc. Normal	Av: 160	SD: 10	Min: 150	Max: 220
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.5		Max: 1
RS	Triangular	Min: 0.5	Av: 0.7		Max: 0.75
A_{den} (per km^2)	Triangular	Min: 0.05	Av: 0.04		Max: 0.1

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.2 km^2

PLAY: Relief (OIL)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 5,372	Av: 14,752		Max: 96,501
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 1	Av: 1		Max: 1
h	Trunc. Log normal	Av: 100	SD: 10	Min: 0	Max: 250
NG	Trunc. Normal	Av: 0.9	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: .14	Av: 0.2		90%: 0.26
$S_w(1-S_b)$	Trunc. Normal	Av: 0.30	SD: 0.05	Min: 0.1	Max: 0.5
FVF	Trunc. Normal	Av: 0.8	SD: 0.05	Min: 0.75	Max: 1
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.1		Max: 1
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.05		Max: 0.15

PLAY: Observatory Hill (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 3,373	Av: 5,248		Max: 22,824
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 0.0	Av: 0.85		Max: 1
h	Trunc. Log normal	Av: 40	SD: 10	Min: 8	Max: 60
NG	Trunc. Normal	Av: 1	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: 0.01	Av: 0.05		90%: 0.12
$S_w(1-S_b)$	Trunc. Normal	Av: 0.50	SD: 0.05	Min: 0.1	Max: 0.75
FVF	Trunc. Normal	Av: 160	SD: 10	Min: 150	Max: 220
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.5		Max: 1.0
RS	Triangular	Min: 0.5	Av: 0.7		Max: 0.75
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.08		Max: 0.15

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.2 km^2

PLAY: Observatory Hill (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 3,373	Av: 5,248		Max: 22,824
AB	Triangular	Min: 0.1	Av: 0.17		Max: 0.25
ER	Triangular	Min: 1	Av: 1		Max: 1
h	Trunc. Log normal	Av: 40	SD: 10	Min: 8	Max: 60
NG	Trunc. Normal	Av: 1	SD: 0.1	Min: 0	Max: 1
Por	Triangular	10%: 0.01	Av: 0.05		90%: 0.12
$S_w(1-S_h)$	Trunc. Normal	Av: 0.50	SD: 0.05	Min: 0.1	Max: 0.75
FVF	Trunc. Normal	Av: 0.8	SD: 0.05	Min: 0.75	Max: 1
SR	Triangular	Min: 0	Av: 0.1		Max: 0.25
FF	Triangular	Min: 0	Av: 0.1		Max: 1
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.005	Av: 0.04		Max: 0.1

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 0.35 km^2

APPENDIX C

Assumptions for Monte Carlo Simulation, Otway Basin

PLAY: Pretty Hill (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 2,306	3,203,		Max: 5,043
AB	Triangular	Min: 0.2	Av: 0.25		Max: 0.28
ER	Triangular	Min: 0.5	Av: 0.75		Max: 1
h	Trunc. Log normal	Av: 110	SD: 10	Min: 0	Max: 220
NG	Trunc. Normal	Av: 0.35	SD: 0.15	Min: 0	Max: 1
Por	Triangular	10%: 0.115	Av: 0.14		90%: 0.152
$S_w(1-S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 210.8	SD: 10	Min: 150	Max: 250
SR	Triangular	Min: 0.25	Av: 0.75		Max: 1
FF	Triangular	Min: 0.5	Av: 1		Max: 1
RS	Triangular	Min: 0.3	Av: 0.5		Max: 0.7
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.034		Max: 0.04

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.8 km^2

PLAY: Pretty Hill (OIL)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 2,306	Av: 3,203		Max: 5,043
AB	Triangular	Min: 0.2	Av: 0.25		Max: 0.28
ER	Triangular	Min: 0.5	Av: 1		Max: 1
h	Trunc. Log normal	Av: 110	SD: 10	Min: 0	Max: 220
NG	Trunc. Normal	Av: 0.35	SD: 0.15	Min: 0	Max: 1.0
Por	Triangular	10%: 0.115	Av: 0.140		90%: 0.152
$S_w(1-S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 0.8	SD: 0.05	Min: 0.75	Max: 1.0
SR	Triangular	Min: 0.25	Av: 0.75		Max: 1.0
FF	Triangular	Min: 0.5	Av: 1		Max: 1
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.034		Max: 0.04

PLAY: Katnook/Windermere (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 2,306	Av: 3,203		Max: 5,043
AB	Triangular	Min: 0.24	Av: 0.5		Max: 0.8
ER	Triangular	Min: 0	Av: 0.93		Max: 1.0
h	Trunc. Log normal	Av: 10	SD: 5	Min: 0	Max: 20
NG	Trunc. Normal	Av: 0.98	SD: 0.01	Min: 0	Max: 1.0
Por	Triangular	10%: 0.14	Av: 0.163		90%: 0.18
$S_w(1-S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 164.6	SD: 10	Min: 150	Max: 220
SR	Triangular	Min: 0.1	Av: 0.25		Max: 1.0
FF	Triangular	Min: 0.5	Av: 1		Max: 1
RS	Triangular	Min: 0.3	Av: 0.5		Max: 0.7
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.12		Max: 0.4

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.8 km^2

PLAY: Katnook/Windermere (OIL)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 2,306	Av: 3,203		Max: 5,043
AB	Triangular	Min: 0.24	Av: 0.5		Max: 0.8
ER	Triangular	Min: 1	Av: 1		Max: 1
h	Trunc. Log normal	Av: 10	SD: 5	Min: 0	Max: 20
NG	Trunc. Normal	Av: 0.98	SD: 0.01	Min: 0	Max: 1
Por	Triangular	10%: 0.14	Av: 0.163		90%: 0.18
$S_w(1\text{-}S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 0.8	SD: 0.05	Min: 0.75	Max: 1
SR	Triangular	Min: 0.1	Av: 0.25		Max: 1
FF	Triangular	Min: 0.5	Av: 1		Max: 1
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.2		Max: 0.4

PLAY: Waarre/Flaxman (GAS)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 540	Av: 897		Max: 1,250
AB	Triangular	Min: 0.2	Av: 0.25		Max: 0.28
ER	Triangular	Min: 0.5	Av: 0.75		Max: 1.0
h	Trunc. Log normal	Av: 110	SD: 10	Min: 0	Max: 220
NG	Trunc. Normal	Av: 0.5	SD: 0.15	Min: 0	Max: 1
Por	Triangular	10%: 0.115	Av: 0.14		90%: 0.152
$S_w(1\text{-}S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 210.8	SD: 10	Min: 150	Max: 250
SR	Triangular	Min: 0.1	Av: 0.5		Max: 1
FF	Triangular	Min: 0.1	Av: 0.5		Max: 1
RS	Triangular	Min: 0	Av: 0.5		Max: 0.7
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.12		Max: 0.4

Minimum Field size: 3BCF OGIP
equivalent minimum closure area: 1.8 km^2

PLAY: Waarre/Flaxmans (OIL)

PARAMETER	DISTRIBUTION	ASSUMED VALUES			
A_p (km^2)	Triangular	Min: 0	Av: 897		Max: 1,250
AB	Triangular	Min: 0.2	Av: 0.25		Max: 0.28
ER	Triangular	Min: 6.5	Av: 1		Max: 1
h	Trunc. Log normal	Av: 110	SD: 10	Min: 0	Max: 220
NG	Trunc. Normal	Av: 0.5	SD: 0.15	Min: 0	Max: 1
Por	Triangular	10%: 0.115	Av: 0.14		90%: 0.152
$S_w(1-S_h)$	Uniform			Min: 0.25	Max: 0.65
FVF	Trunc. Normal	Av: 0.8	SD: 0.8	Min: 0.75	Max: 1
SR	Triangular	Min: 0	Av: 0.5		Max: 1.0
FF	Triangular	Min: 0	Av: 0.5		Max: 1.0
RS	Triangular	Min: 0	Av: 0.25		Max: 0.5
A_{den} (per km^2)	Triangular	Min: 0.01	Av: 0.2		Max: 0.4

Table 1

UNDISCOVERED (SPECULATIVE) RESERVES
EASTERN OFFICER BASIN

Play	Probability that the basin reserves will exceed the stated value.		
	90%	50%	10%
OBSERVATORY HILL (Molyes Chert)			
Sales Gas (BCF)	6	61	243
Recov. Oil (MMSTB)	4	20	67
RELIEF SANDSTONE			
Sales Gas (BCF)	294	2699	9268
Recov. Oil (MMSTB)	189	883	2480
MURNAROO SANDSTONE			
Sales Gas (BCF)	249	2425	8774
Recov. Oil (MMSTB)	173	805	2546
*TOTAL Sales Gas (BCF)	523	5152	18459
*TOTAL Recov. Oil (MMSTB)	451	1823	4896

* Note:

Totals are not arithmetic additions of individual plays, as they are the subject of an independent Monte Carlo simulation.

Table 2

UNDISCOVERED (SPECULATIVE) MAXIMUM FIELD SIZES EASTERN OFFICER BASIN

Play	Probability that the reserves of the largest field will exceed the stated value.		
	90%	50%	10%
OBSERVATORY HILL (Molyes Chert)			
OGIP (BCF)	1	12	45
OOIP (MMSTB)	2	10	29
RELIEF SANDSTONE			
OGIP (BCF)	53	398	1293
OOIP (MMSTB)	108	343	763
MURNAROO SANDSTONE			
OGIP (BCF)	38	329	1107
OOIP (MMSTB)	74	295	726
TOTAL OGIP (BCF)	87	766	2506
TOTAL OOIP (MMSTB)	189	674	1567

Table 3

ONSHORE S.A. OTWAY BASIN

Undiscovered Potential

Play	Probability that the ultimate potential will exceed the stated value.		
	90%	50%	10%
WAARRE/FLAXMAN			
Sales Gas (BCF)	24	158	571
Recov. Oil (MMSTB)	.4	48	212
WINDERMERE/KATNOOK			
Sales Gas (BCF)	17	276	1660
Recov. Oil (MMSTB)	16	164	877
PRETTY HILL			
Sales Gas (BCF)	206	1031	3031
Recov. Oil (MMSTB)	61	377	1208
TOTAL Sales Gas (BCF)	303	1610	4905
TOTAL Recov. Oil (MMSTB)	242	762	1878

Table 4

ONSHORE S.A. OTWAY BASIN

Maximum Field Sizes

Play	Probability that the largest field is greater than the stated value		
	90%	50%	10%
WAARRE/FLAXMAN			
Sales Gas (BCF)	3	19	64
Recov. Oil (MMSTB)	1	6	23
WINDERMERE/KATNOOK			
Sales Gas (BCF)	12	26	141
Recov. Oil (MMSTB)	2	15	72
PRETTY HILL			
Sales Gas (BCF)	28	123	348
Recov. Oil (MMSTB)	8	45	138
TOTAL Sales Gas (BCF)	32	159	469
TOTAL Recov. Oil (MMSTB)	22	74	179

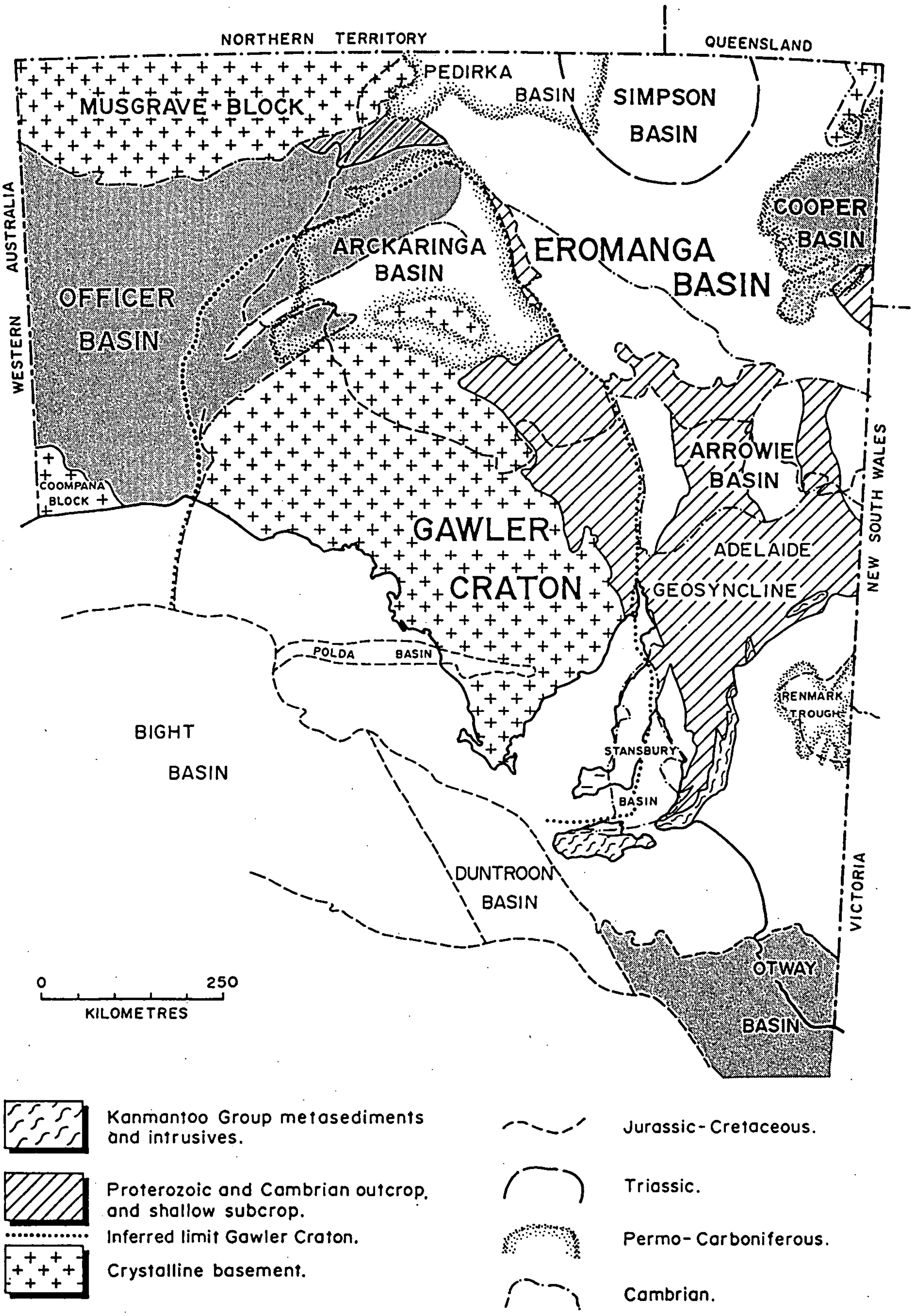
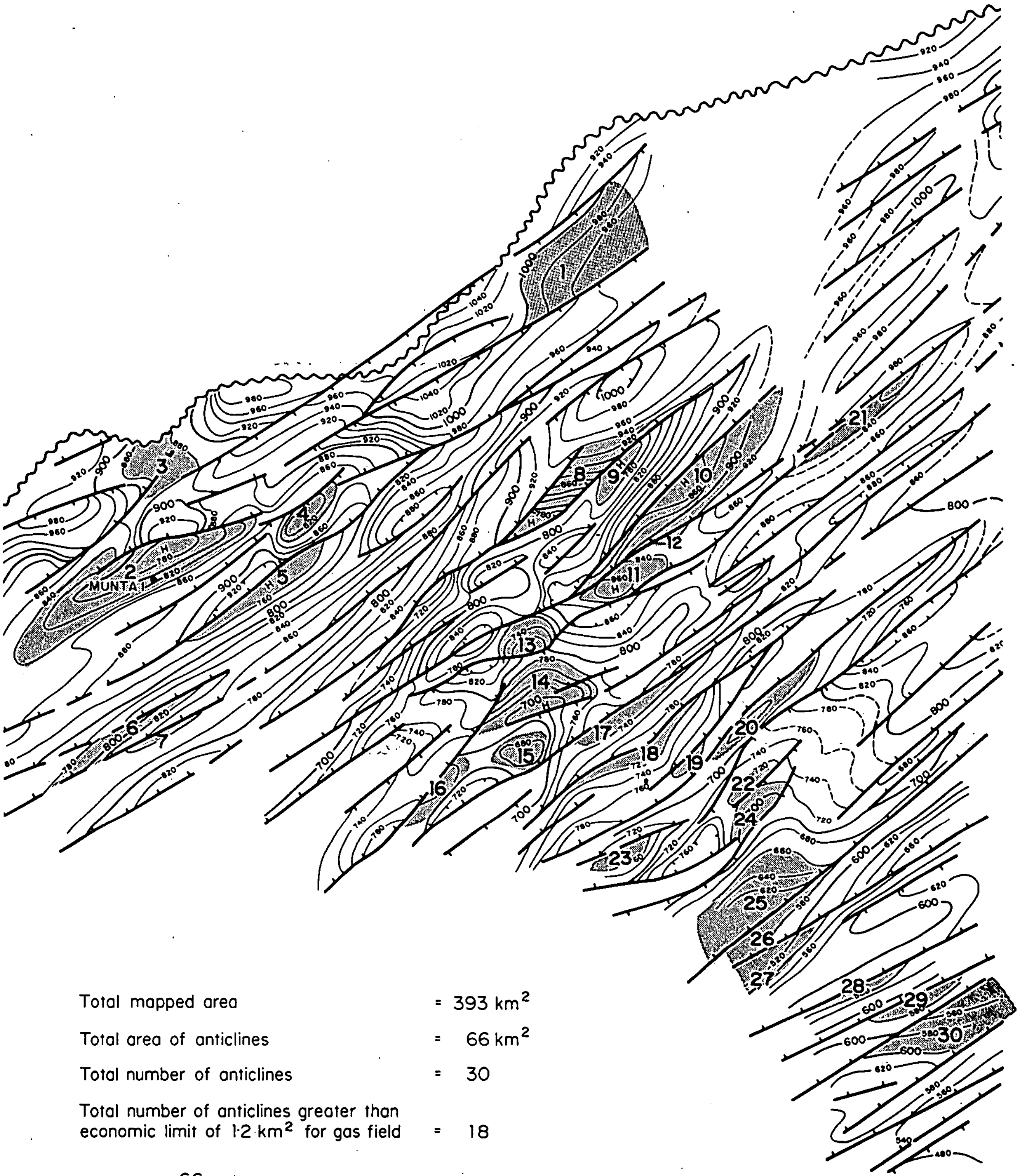


Figure 1 Location of sedimentary basins in South Australia



Total mapped area	=	393 km^2
Total area of anticlines	=	66 km^2
Total number of anticlines	=	30
Total number of anticlines greater than economic limit of 1·2 km^2 for gas field	=	18

$$AB = \frac{66}{393} = 0{\cdot}17$$

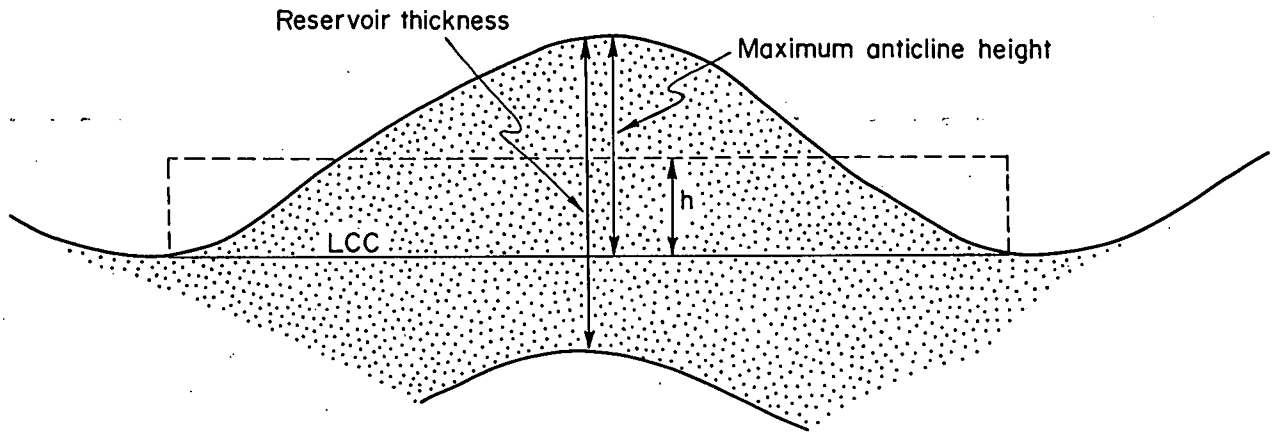
$$ER = \frac{18}{30} = 0{\cdot}60$$

$$A_{den} = \frac{18}{393} = 0{\cdot}05 \text{ prospects per } km^2$$

0 2 4 6 8 10
KILOMETRES

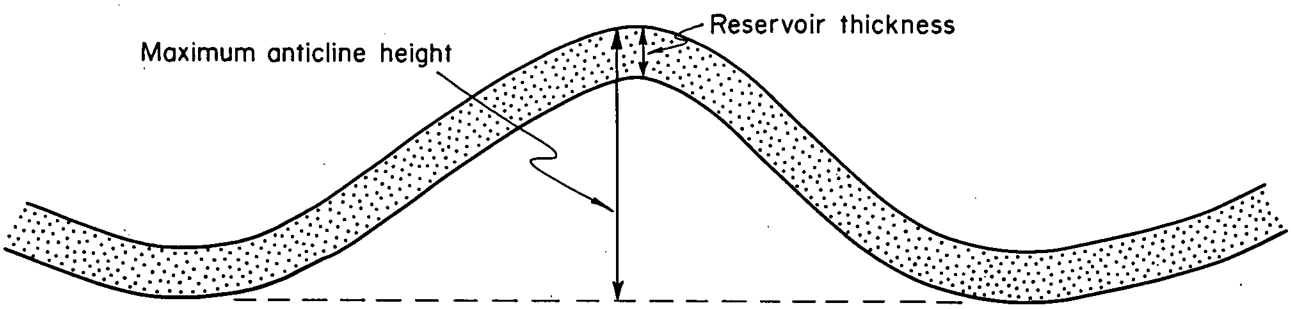
Figure 2 Seismic interpretation of F5 Horizon (Intra Rodda Beds) Officer Basin (after Thomas, 1990)

Case 1 : Reservoir thickness > anticline height



$$h = \frac{\text{Maximum anticline height}}{3}$$

Case 2 : Reservoir thickness < anticline height



h = Reservoir thickness

Figure 3 Models of reservoir volumes

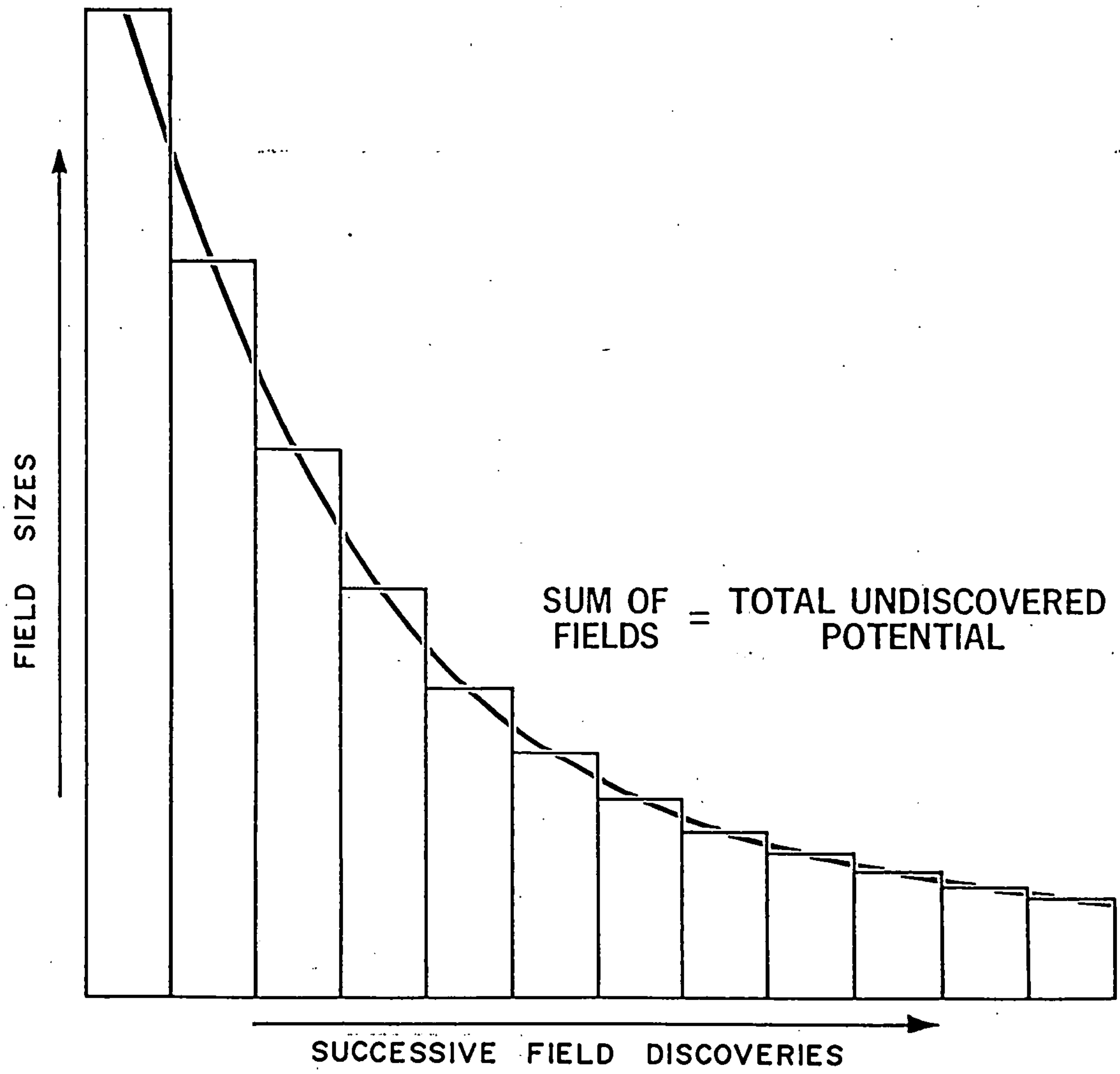


Figure 4 Field size decline model

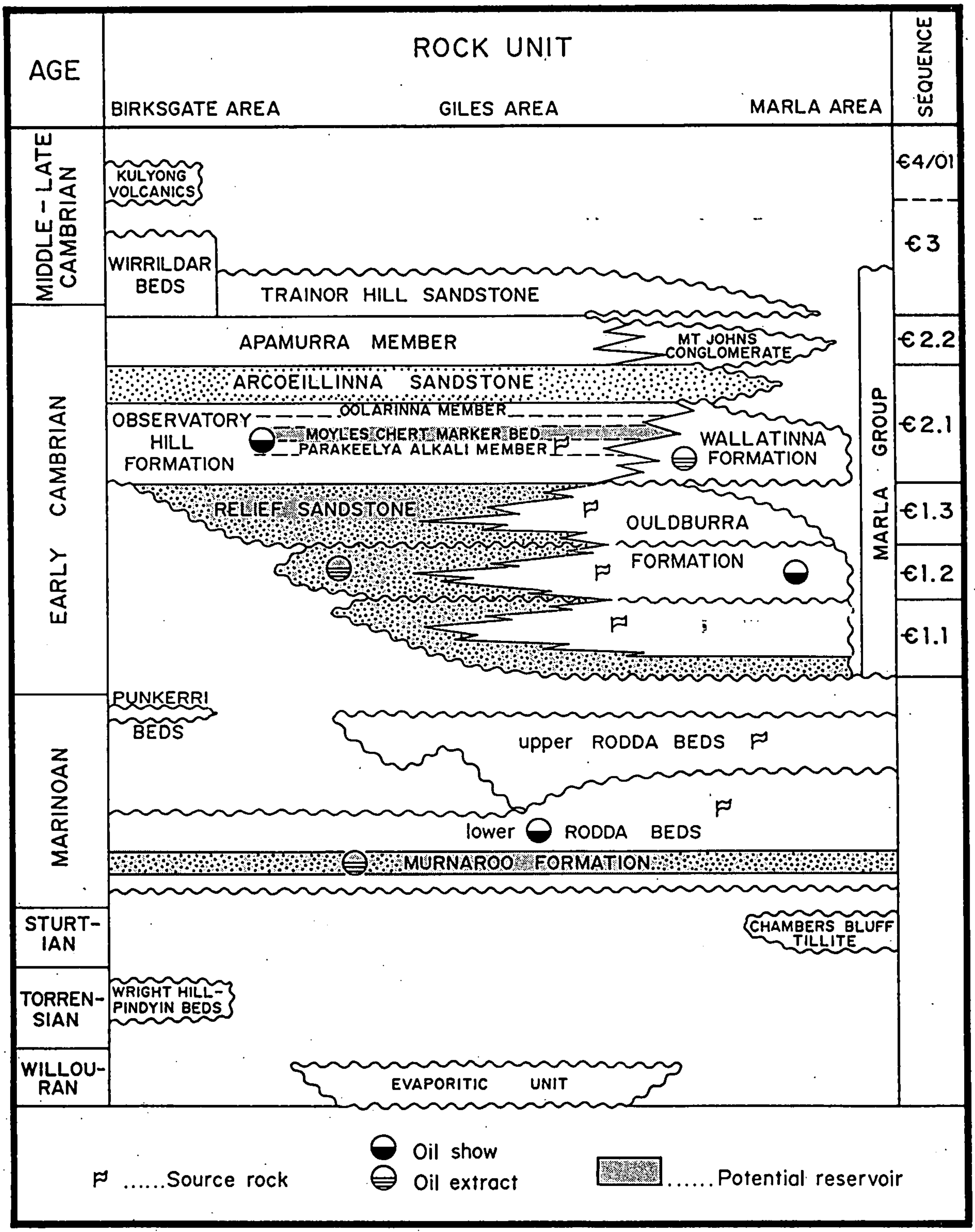
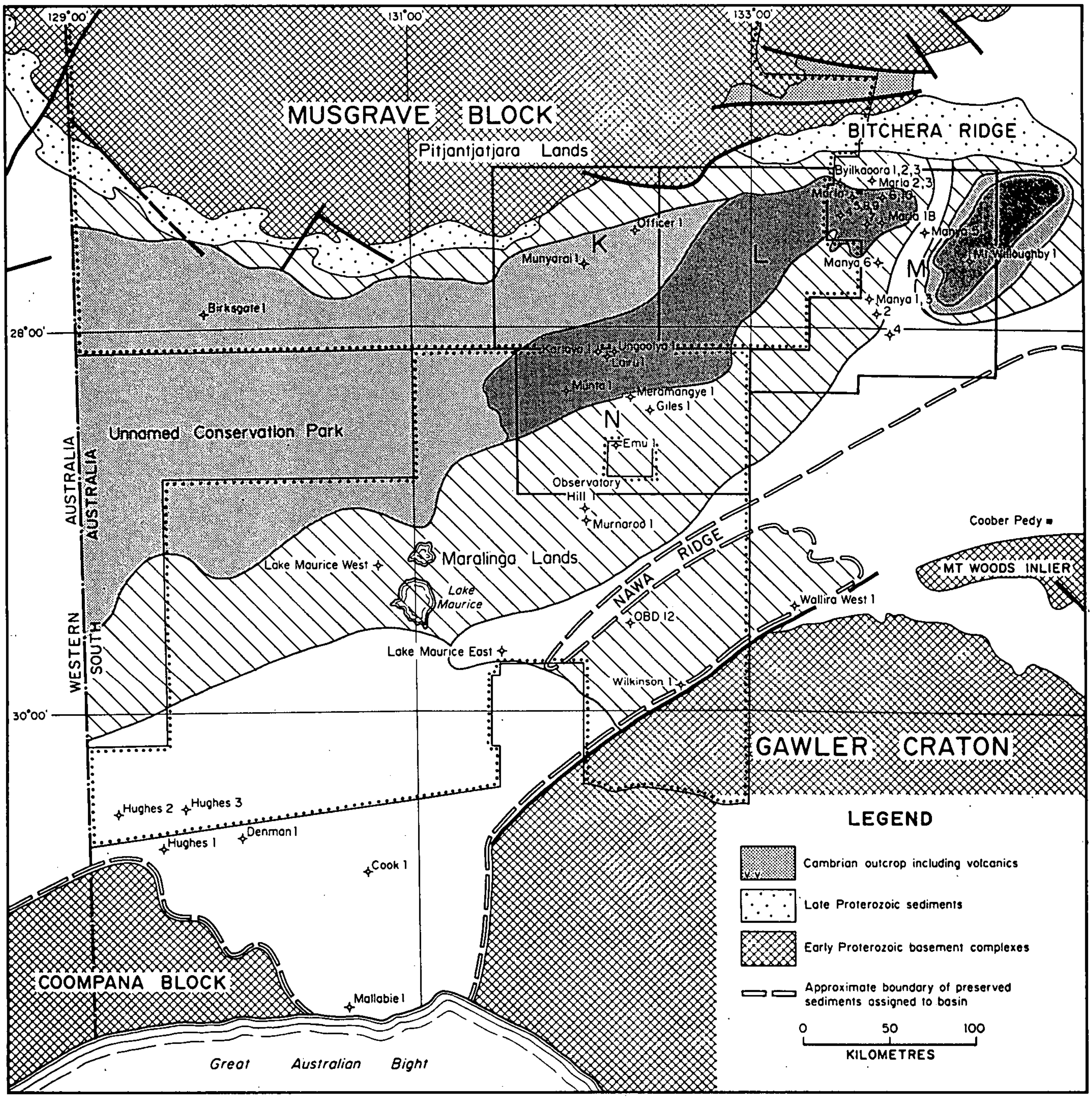
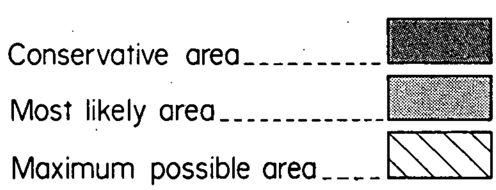


Figure 5 Neoproterozoic and Early Proterozoic stratigraphy in the Eastern Officer Basin S. A. (after Gravestock, 1990) showing potential reservoirs



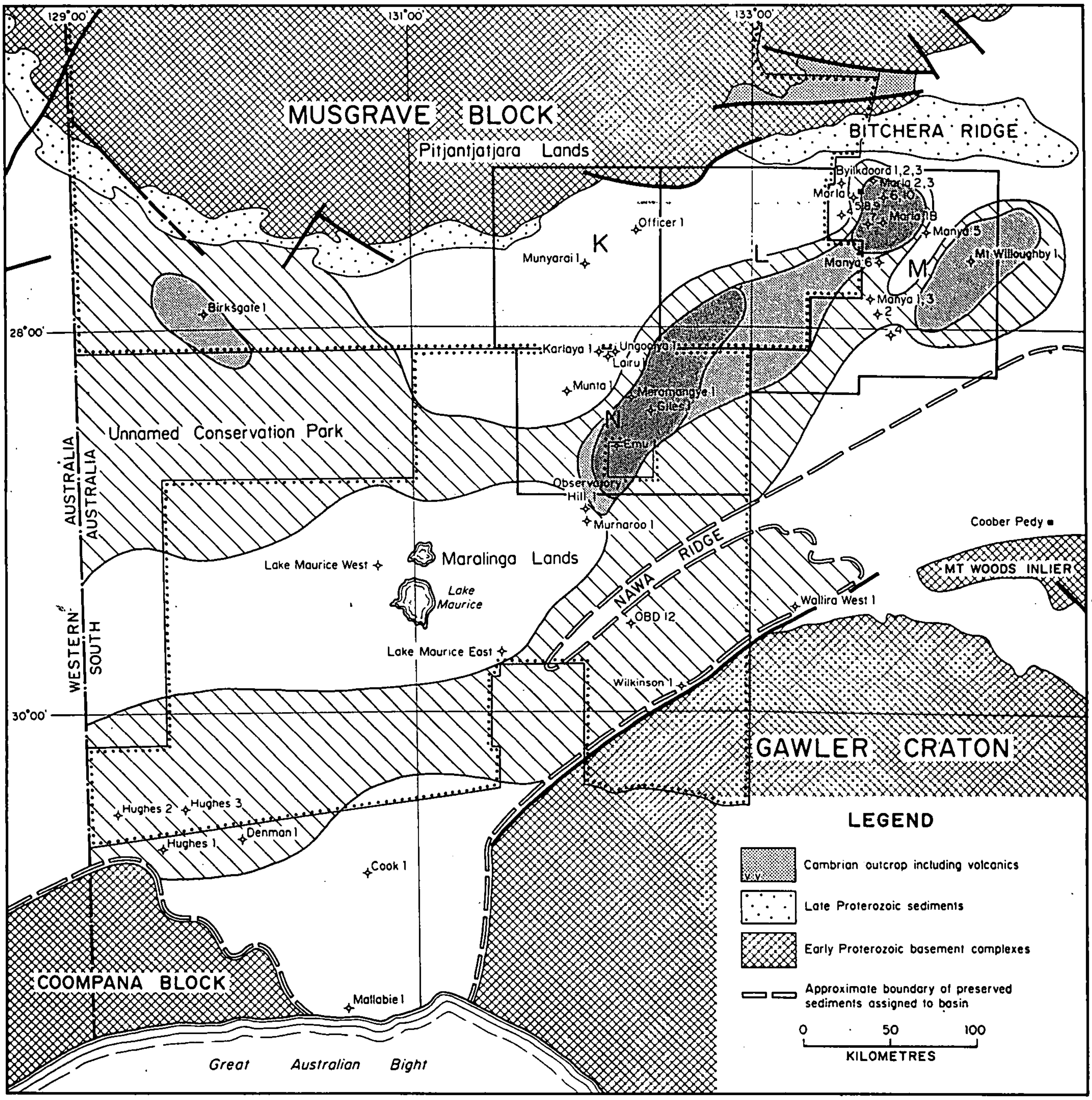


OFFICER BASIN

MURNAROO FORMATION PROSPECTIVE AREAS

Figure 6

S 22598



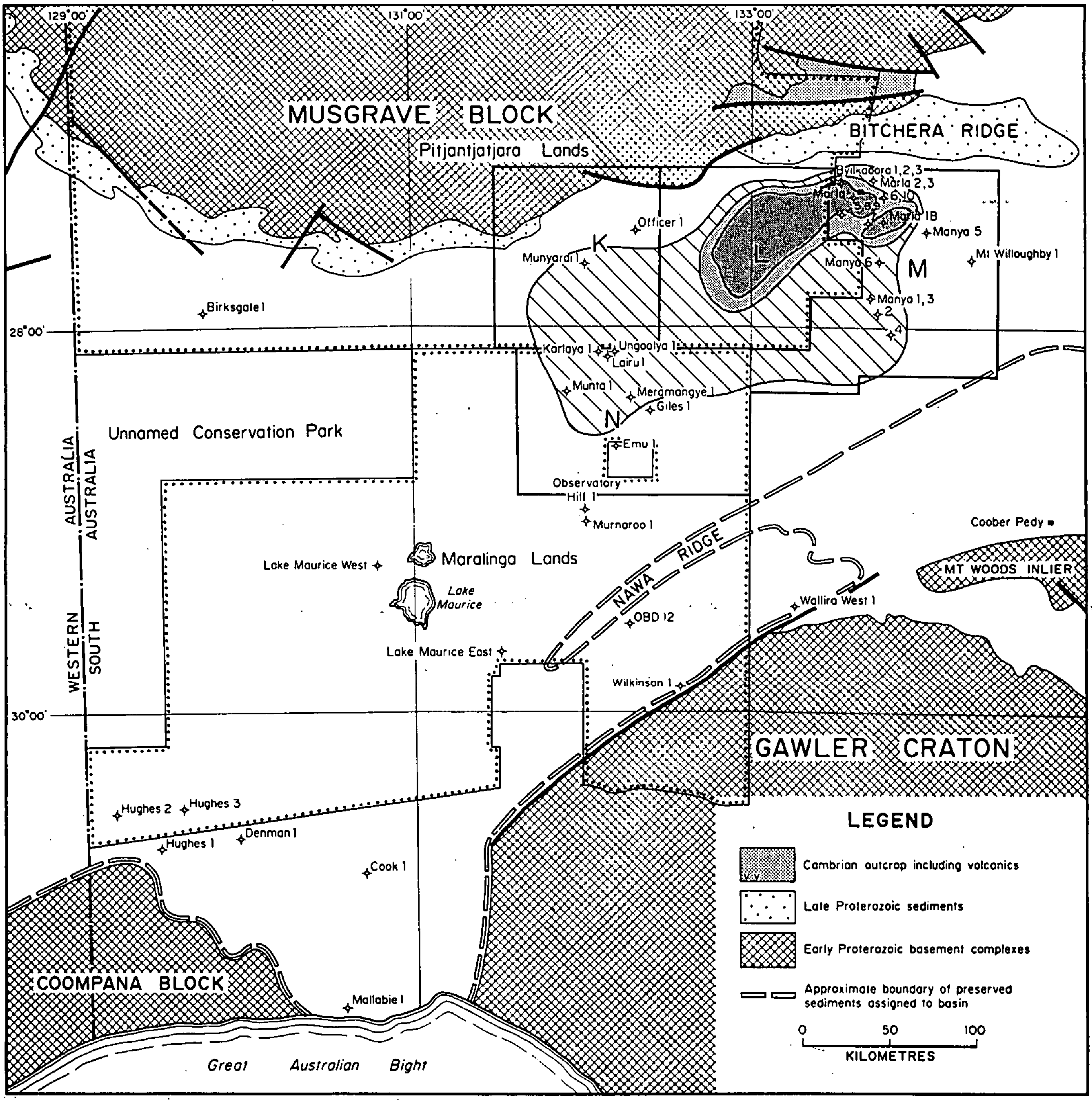
Conservative area
Most likely area
Maximum possible area

OFFICER BASIN

RELIEF SANDSTONE PLAY
PROSPECTIVE AREAS

Figure 7

S 22599



Conservative area

Most likely area

Maximum possible area

OFFICER BASIN

OBSERVATORY HILL FORMATION

(PLAYA LAKE FACIES PLAY)

PROSPECTIVE AREAS

Figure 8

S 22600

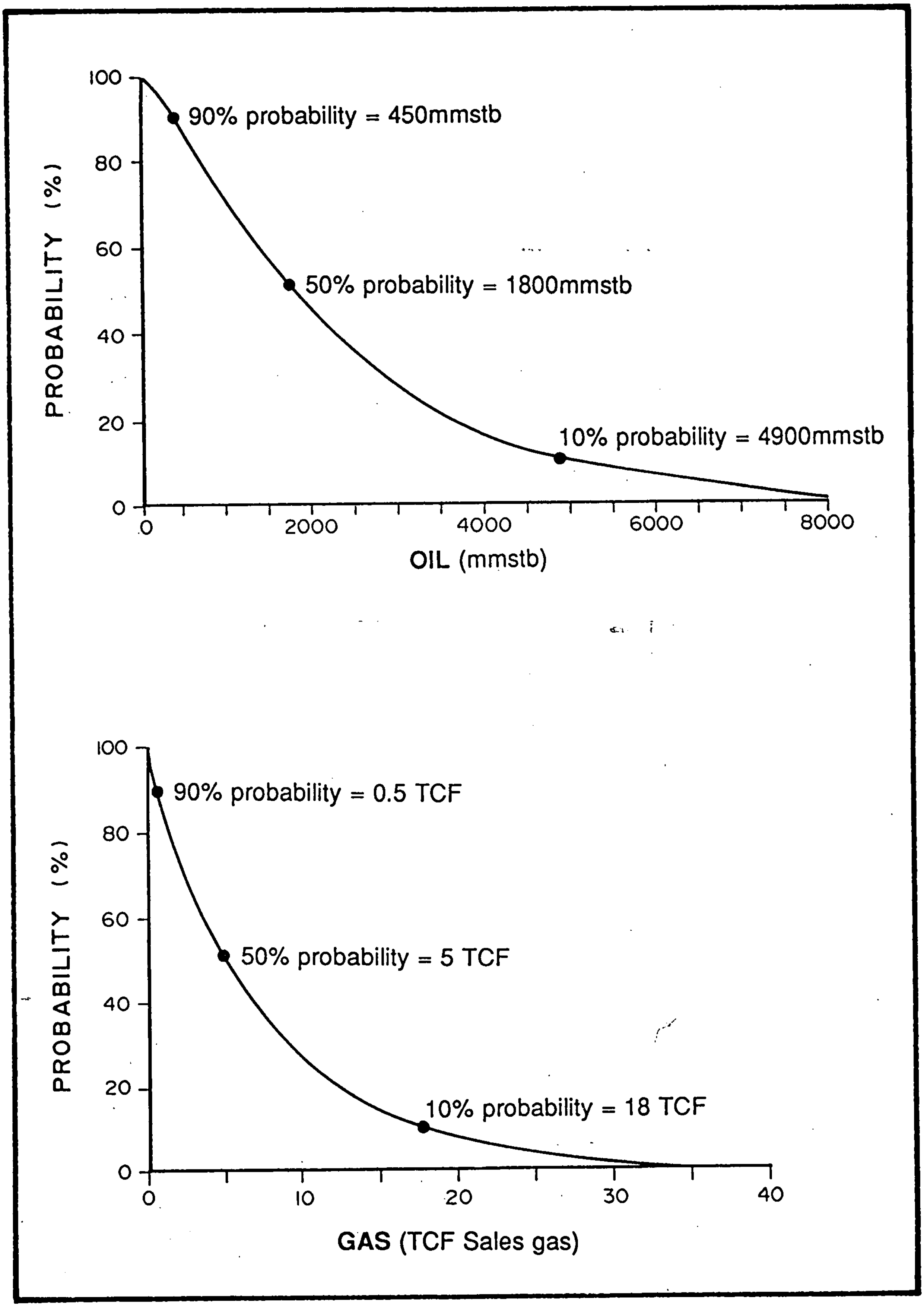
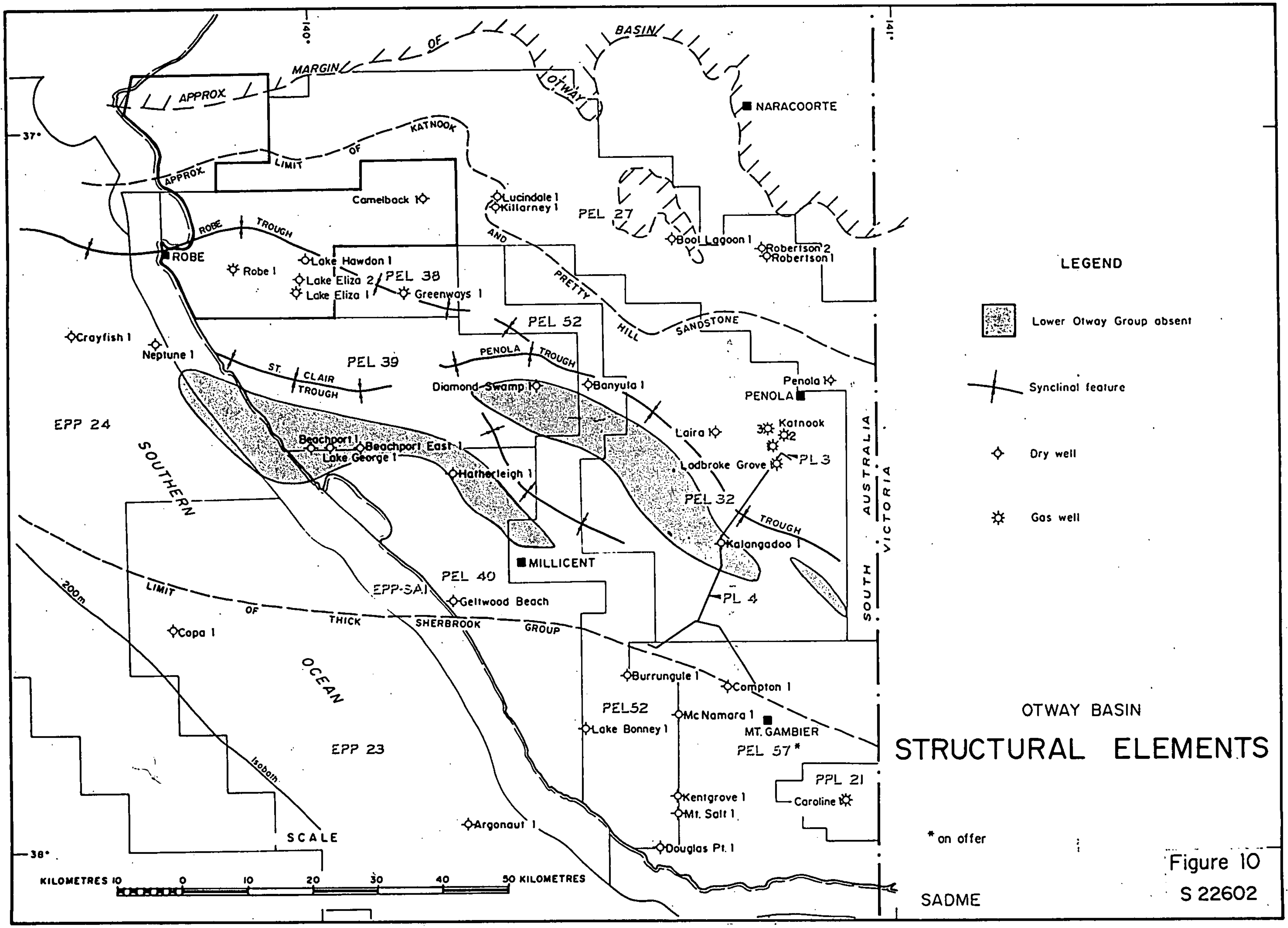


Figure 9 Cumulative probability curves for undiscovered reserves of the Officer Basin S.A.

5487



OTWAY BASIN

STRUCTURAL ELEMENTS

Figure 10

S 22602

SADME

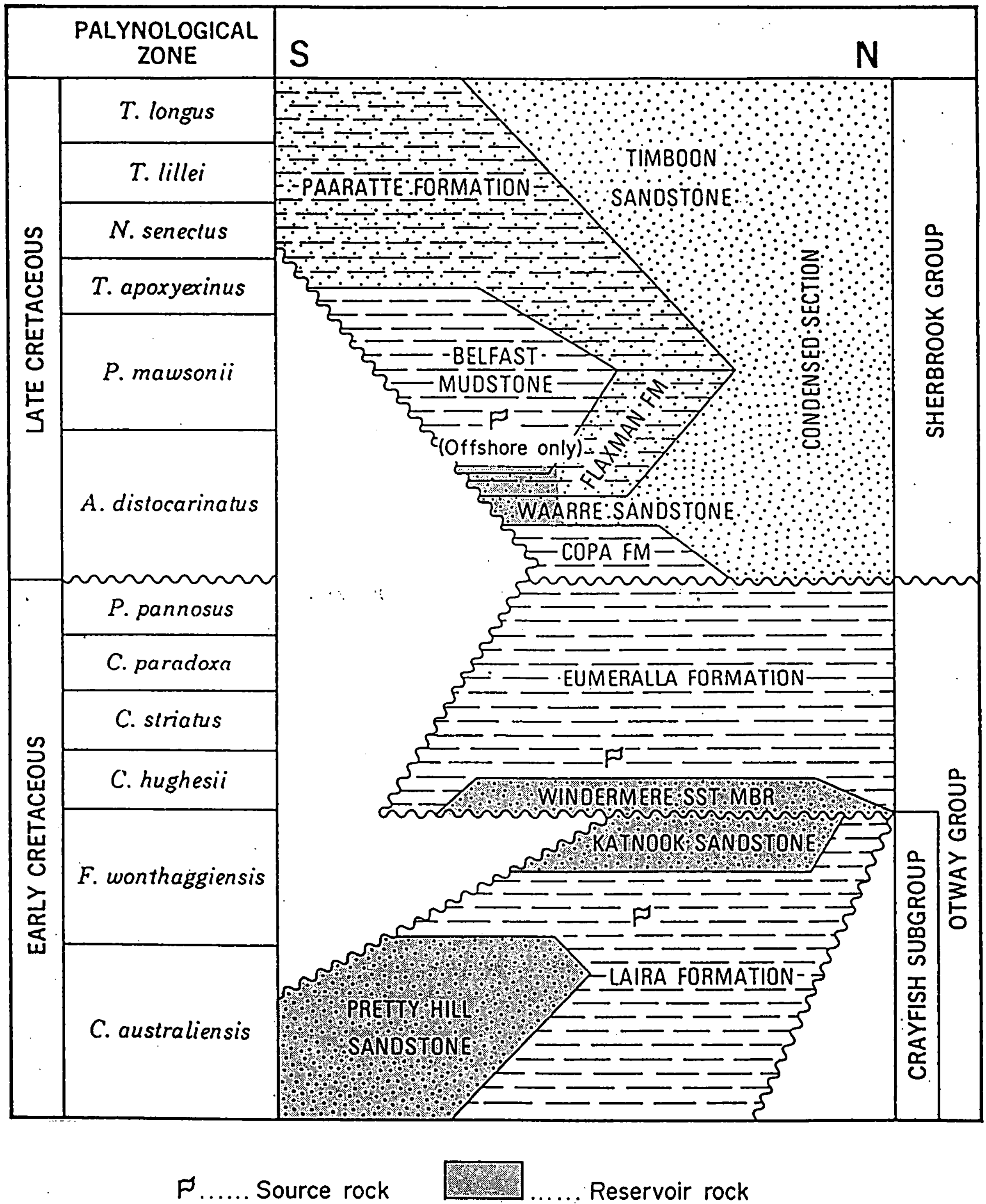
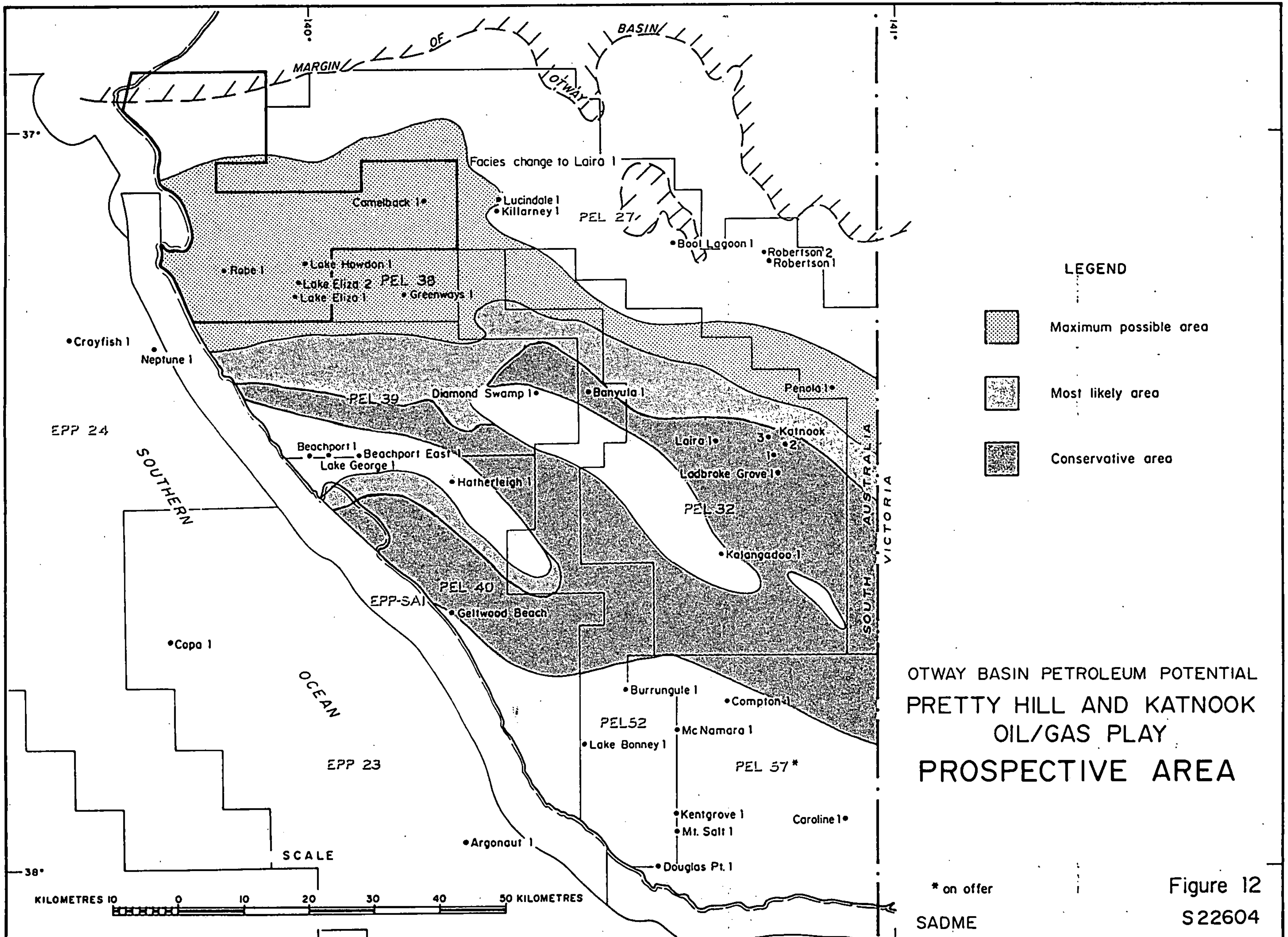


Figure 11 Stratigraphic nomenclature and petroleum potential of the Otway Basin

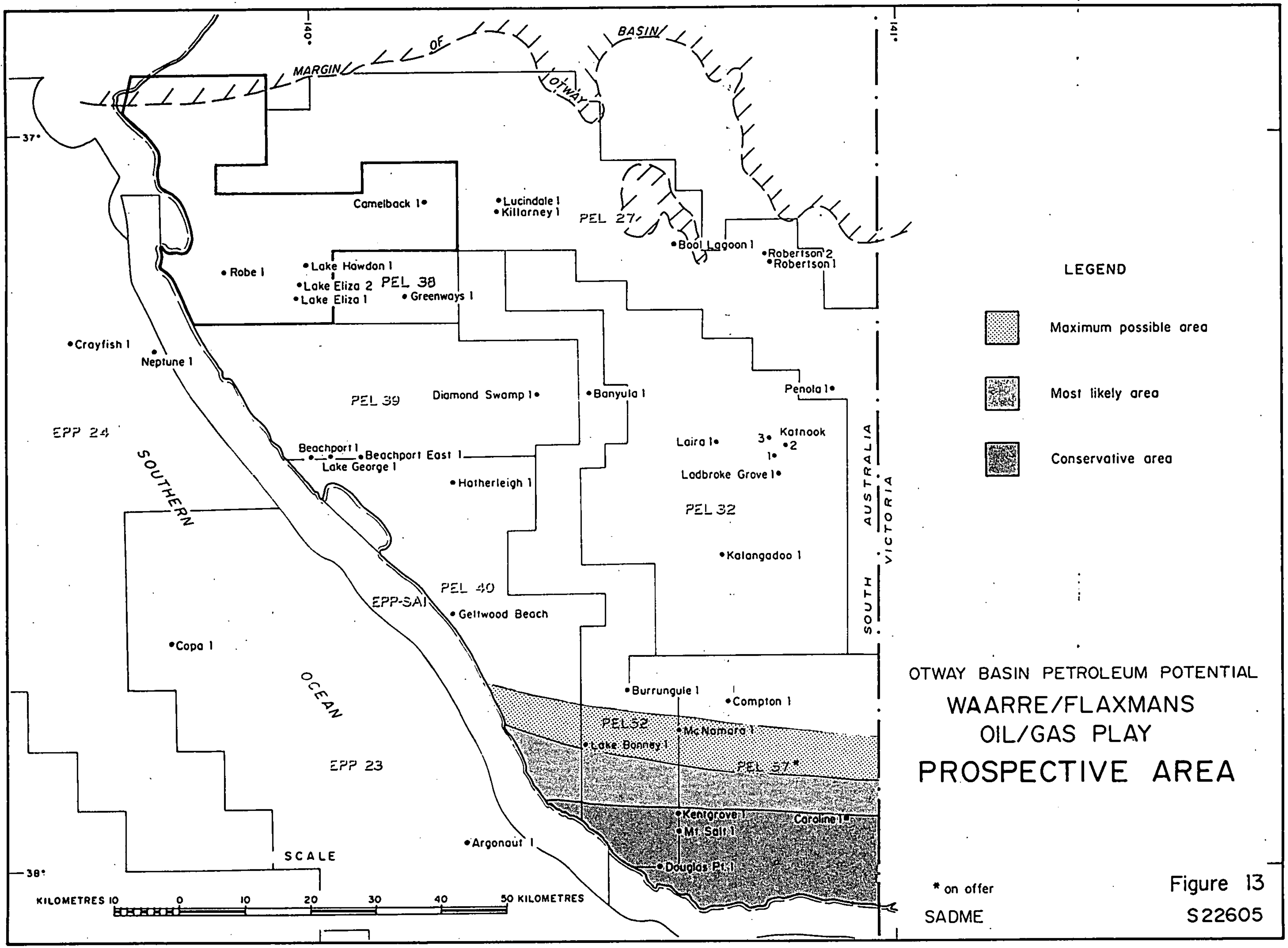
5487

5437



MARGIN OF OTWAY BASIN
140°
141°
37°
38°
Facies change to Laira 1
Camelback 1
Lucindale 1
Killarney 1
PEL 27
Bool Lagoon 1
Robertson 2
Robertson 1
Robe 1
Lake Howdon 1
Lake Eliza 2
PEL 38
Lake Eliza 1
Greenways 1
Crayfish 1
Neptune 1
PEL 39
Diamond Swamp 1
Banyula 1
Penola 1
EPP 24
SOUTHERN
Beachport 1
Beachport East 1
Lake George 1
Hatherleigh 1
Laira 1
Katnook
Ladbroke Grove 1
PEL 32
Kalangadoo 1
PEL 40
EPP-SA1
Geltwood Beach
Copa 1
OCEAN
Burrungule 1
Compton 1
PEL52
Mc Namara 1
Lake Bonney 1
EPP 23
PEL 57*
Kentgrove 1
Mt. Salt 1
Caroline 1
Argonaut 1
Douglas Pt. 1
SOUTH AUSTRALIA
VICTORIA
SCALE
KILOMETRES 10 0 10 20 30 40 50 KILOMETRES
LEGEND
Maximum possible area
Most likely area
Conservative area
OTWAY BASIN PETROLEUM POTENTIAL
PRETTY HILL AND KATNOOK OIL/GAS PLAY
PROSPECTIVE AREA
* on offer
SADME
Figure 12
S22604

3487



OTWAY BASIN PETROLEUM POTENTIAL

WAARRE/FLAXMANS OIL/GAS PLAY

PROSPECTIVE AREA

Figure 13

S22605

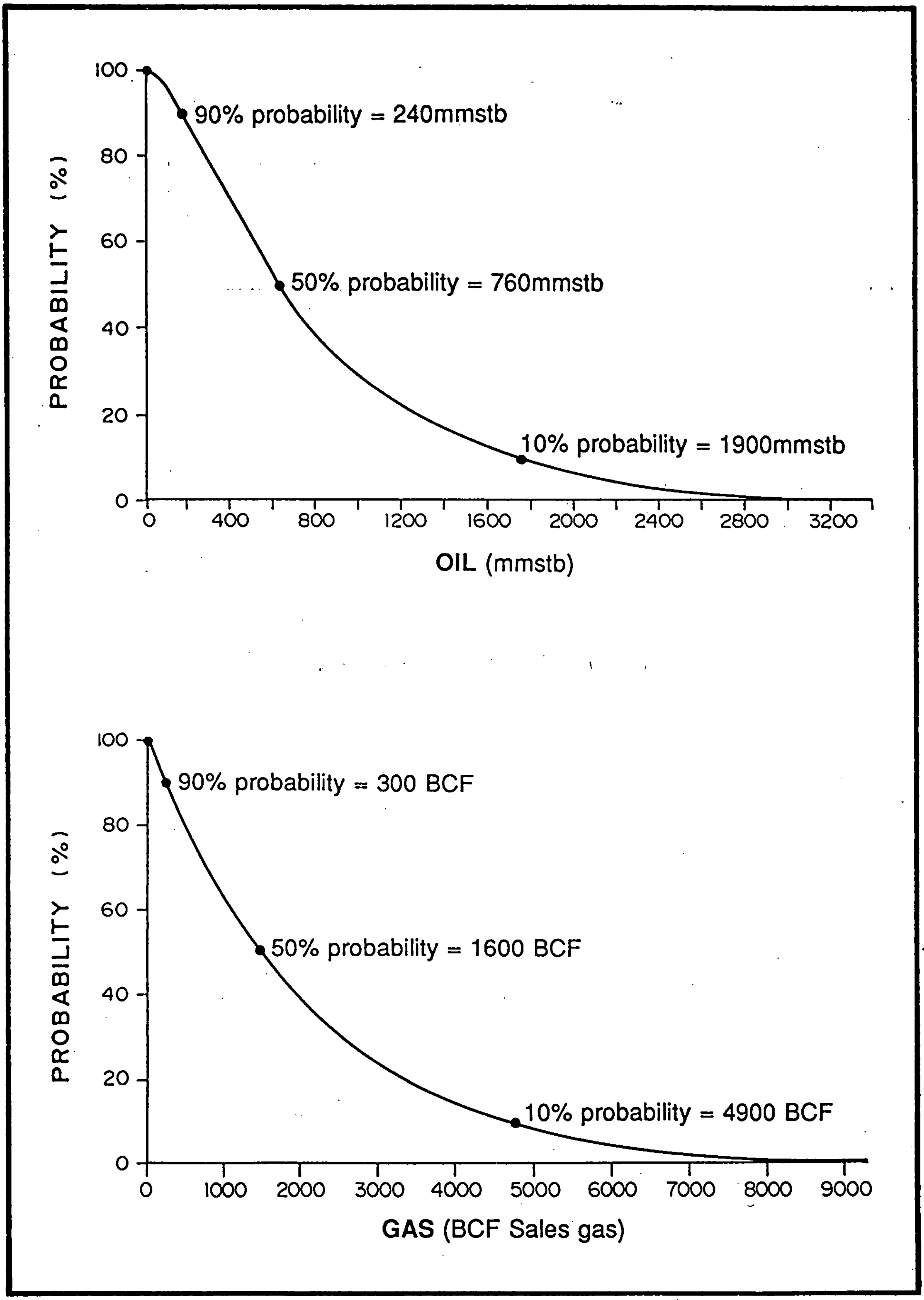


Figure 14 Cumulative probability curves for undiscovered reserves of the onshore Otway Basin S.A.