Bureau of Mineral Resources, Geology & Geophysics

R E C O R D

Record 1990/32

PETROLEUM EXPLORATION AND DEVELOPMENT IN AUSTRALIA:

A BMR DISCUSSION PAPER

by

T.G. Powell, D.J. Wright and E. Nicholas

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CONTENTS

SUMMARY

Over the last 20 years, Australia has enjoyed a high level of oil production, thus reducing the need for oil imports. Decline in Bass Strait (Gippsland Basin) production has now commenced and other Australian areas are becoming increasingly important in their contribution to the national supply picture for liquid fuels. Remaining commercial oil and condensate reserves of 1676 million barrels represent only 8.5 years production at current rates. In contrast, remaining commercial gas reserves are currently estimated to be 16 trillion cubic feet, representing 30 years' production at current rates. There are also non-commercial (undeveloped) gas reserves of 55 trillion cubic feet. The amount of new oil reserves discovered by wildcat drilling dropped dramatically after 1970. In contrast, additions to gas reserves have consistently exceeded gas production, with several giant fields being discovered in the 1970s.

While it is important to recognise the potential for a rapid and imminent decline in the rate of Australian oil production, this decline has not yet commenced. Largely as a result of extremely high flow rates from some recent discoveries, 1990 is likely to be a near-record year for Australian oil production. These high flow rates will rapidly deplete these fields unless additions to reserves are made, so that decline when it does occur will be steep.

Policies and decisions involved in the stewardship of the nation's petroleum resources must be based on the best possible information regarding their distribution in nature. However, there is no unique answer to the question, 'What is the petroleum prospectivity of Australia?'. The answer depends on current geological knowledge, perceptions, technical capability, and geological ingenuity and environment of opinion. Detailed resource assessments, such as those produced by BMR, address these uncertainties by integrating the current state of knowledge, together with objective and subjective opinions as to the favourability for petroleum occurrence, into probabilistic distributions of petroleum resources through computer modelling procedures. However, resource assessments are dynamic, reflecting changing perceptions in the light of new knowledge, and are therefore inherently uncertain.

Australia's undiscovered oil resources are considered to lie between 1000 (95% probability) and 5000 (5% probability) million barrels, with an average estimate of 2400 million barrels. Undiscovered sales gas

resources are considered to lie between 10 (95% probability) and 45 (5% probability) trillion cubic feet, with an average estimate of 23 trillion cubic feet. Undiscovered condensate resources are considered to lie between 250 (95% probability) and 800 (5% probability) million barrels, with an average estimate of 500 million barrels. These figures place Australia as a nation in the middle to low rank of prospective areas on an international basis. Upwards revision of oil reserves in discovered fields is also a major source for future supply.

At the average expectation level these estimates represent a realistic lower limit of the petroleum potential of the continent. In any given basin, however, there is a small but significant chance of a very much larger speculative potential that is expressed at the 5% probability level which is the target for exploration. That this large speculative potential exists in several regions reflects our uncertainty and lack of knowledge in unexplored or partially explored basins. It is unlikely that such speculative potential will be realised in all basins, but there is a chance it may be achieved or exceeded in one or more basins. The most prospective basins are considered to be the Bonaparte and Carnarvon Basins in which some exploration success has been achieved but which are far from completely explored. The most extensively explored basins (offshore Gippsland, Eromanga, Cooper and Surat) are not considered to have a large speculative potential and are ranked behind less well explored basins at the 5% probability level. There are additional areas where there is insufficient information to allow a meaningful quantitative assessment. Only sustained exploration will resolve the question of Australia's oil potential.

The petroleum exploration industry differs from many other forms of business enterprise in the inherent uncertainty as to the outcome of exploration ventures and the long lead times involved. Given a typical success rate of a 1 in 10 chance of discovering an oil accumulation, the exploration effort represents a large sunk cost before the financial rewards of any discovery can be defined. Individual companies attempt to maintain a balanced portfolio of ventures that covers all risk/reward scenarios commensurate with the objectives of the enterprise, but does not leave the particular company unnecessarily exposed to high risk. The risk in petroleum exploration and development incorporates geological, economic, political and technological elements.

- Geological risk incorporates all the elements of uncertainty related to prospectivity.

- Economic risk incorporates uncertainty related to the price of oil, exploration and development costs and the general economic climate in which petroleum products are sold.

- Political risk incorporates elements of political stability but also includes perceptions of the stability of the licensing or taxation regime under which oil is produced.

- Technological risk incorporates uncertainty regarding the ability to effectively explore for and exploit resources in an area because of technological factors, for example water depth, seismic resolution, drilling difficulties, weather and ocean conditions, or measures to protect the environment.

An exploration venture is in essence a carefully planned series of activities to determine whether or not petroleum accumulations are present, and if present whether they are likely to be of commercial value. The exploration program is designed to gather information in order to minimise the risk of unsuccessful expensive wells. At all stages of exploration and development there is considerable uncertainty as to the final outcome of the venture.

The effectiveness of the exploration effort in the development of the national resource base is also affected by the legislative framework, fiscal regime and lease administration under which companies operate. Optimisation of the regulations under which exploration leases and production licences are granted can lead to improvements in the effectiveness of exploration and development nationally. However, the lack of knowledge in Australia's less well explored areas is the single most important impediment to companies devoting exploration effort in those areas.

The Commonwealth Government operated a petroleum search subsidy scheme from 1957 to 1974. Most of Australia's petroleum provinces were identified by activity occurring under this scheme, which clearly stimulated activity in previously unexplored areas. The wide distribution of wells that resulted from the activity, the rapid release of data, and the success engendered during the scheme and immediately thereafter illustrates the importance in immature exploration areas such as Australia of the development of an infrastructure of geological knowledge upon which ongoing exploration success may be based.

It appears that the effect of the petroleum taxation regime operating in Australia compares favourably with that operating in other countries in the region.

Steps to increase the knowledge base and thus reduce the perceived level of geological risk represent the single most effective way of encouraging effective exploration for Australia's undoubted endowment of oil resources.

1. INTRODUCTION

Over the last 20 years Australia has enjoyed a high level of oil self-sufficiency mainly as a result of the large oil fields discovered in Bass Strait in the 1960s. However, Bass Strait production has begun to decline and other producing areas are becoming more important in their contribution to national supply. Australia's reserves of natural gas will continue to exceed its immediate requirements, but access may well be restricted by remoteness from the main markets. The changing balance in the supply of liquid fuels from Australian fields requires that policies for optimal petroleum exploration and development be maintained.

The purpose of this paper is to discuss the availability of oil and natural gas in Australia and the activities of the petroleum exploration and development industry in Australia. These are considered in the context of the potential to discover additional petroleum reserves in Australia and with special reference to elements of government policy that would encourage the discovery and development of new oil and gas fields and ensure that Australia's undiscovered petroleum resources are in fact discovered and produced in an optimal way.

Fundamental factors which affect the search for oil and gas in Australia include:

- the geographical distribution of oil and gas resources
- large size of Australia relative to its population
- the remoteness of many producing and prospective areas from population centres
- the various policies of State and Federal governments
- the small size of the petroleum industry relative to the size of the continent

This paper attempts to answer the following questions.

- What is the current status and distribution of Australia's oil and gas reserves?
- How good is the information that is needed to assess Australia's prospectivity?
- What is Australia's prospectivity for further oil and gas discoveries?
- How does industry use assessments of prospectivity in decision making?
- What are the requirements for a balanced exploration strategy from the national viewpoint?

- What government policies in relation to exploration and development affect the direction of industry's search for oil and gas?

The second question is critically important. Because of Australia's size, and the relatively low level of exploration, in many basins there is simply not enough geological information to allow a consistent assessment of prospectivity. The assessments that have been made necessarily concentrate on areas where there is geological information. There are large areas of sedimentary basins where data are still so sparse that they do not allow for a quantitative assessment. It is crucially important to recognise this in developing government policies for the petroleum industry.

2. AUSTRALIA'S IDENTIFIED PETROLEUM RESOURCES

2.1 Introduction

For simplicity, petroleum resources can be considered to fall into four categories (Fig. 2.1):

1. **Crude oil** (a mixture of intermediate and heavy liquid hydrocarbons, usually processed in the field to remove gases).

2. **Condensate** (an oil-like substance consisting of hydrocarbons heavier than butane which condenses from the natural gas produced from gas fields).

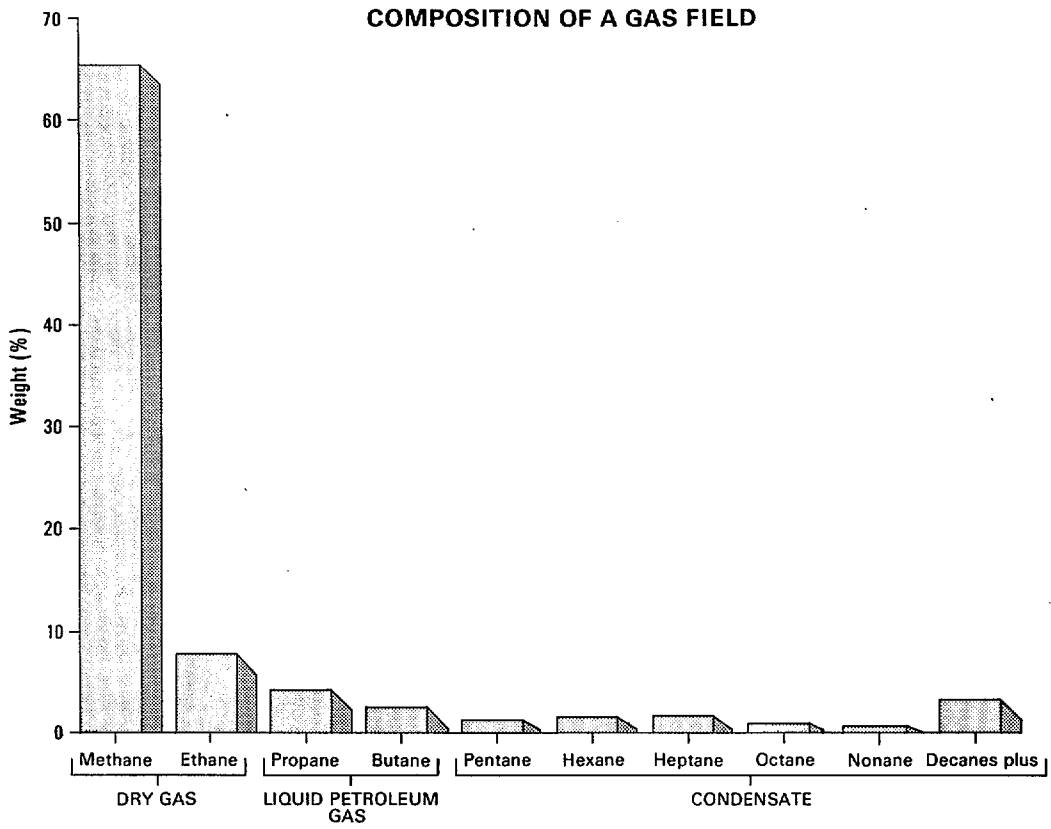
3. **Liquefied petroleum gas** (essentially the light hydrocarbons, propane and butane, which are a small fraction of the oil produced from oil fields, and are also a small fraction of the gas produced from gas fields).

4. **Natural gas** (mainly methane and some ethane) which is produced from gas fields, and produced or flared from oil fields. Ethane is sometimes sold separately for petrochemical uses. Liquefied natural gas is now being exported from the North West Shelf.

2.2 Current estimates of reserves

Australia's remaining reserves of these four basic categories of petroleum - crude oil, condensate, liquefied petroleum gas and natural gas - are shown in Table 2.1. The reserves shown are in commercial fields (those which are producing, or have firm commitments to commence production), and non-commercial fields (discoveries for which there are, at present, no firm commitments to commence production).

Australia's reserves of crude oil and condensate are limited. Remaining commercial reserves of 1676 million barrels represent only 8.5 years production at current rates. Australia's 49 sedimentary basins are shown in Figure 3.1. As at June 1988, 69% of remaining commercial oil and condensate reserves were located in the Gippsland Basin, 17% in the Carnarvon Basin, and 5% in the Bonaparte Basin (Timor Sea) (Fig. 2.2). Production from the Bonaparte Basin has recently increased and this will continue as the recent discoveries become fully delineated and are



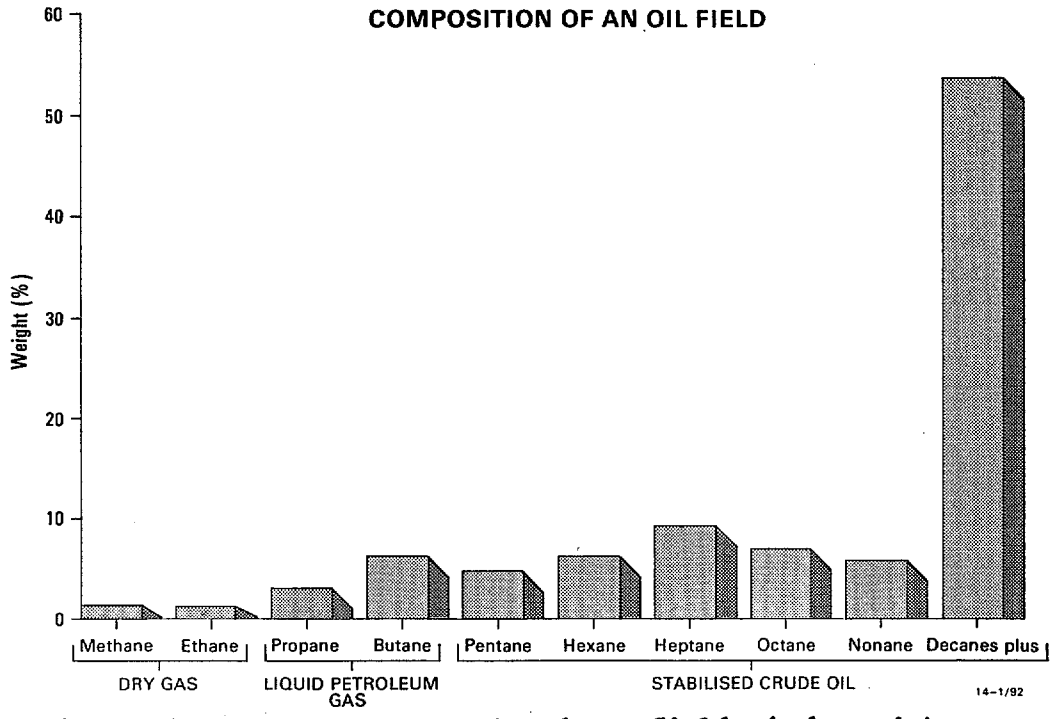


Figure 2.1 The composition of oil and gas fields (schematic).

Gas reservoirs contain predominantly methane, together with 8 ethane, LPG and some condensate.

Oil reservoirs contain predominantly pentanes and heavier components, but also contain significant amounts of the gas and LPG products. Australian oils are generally deficient in heavy ends, so some products (lubricant, fuel oil, bitumen) are mainly produced from imported crude.

Often, oil reservoirs lie directly beneath a gas cap. Other reservoirs contain oil or gas only.

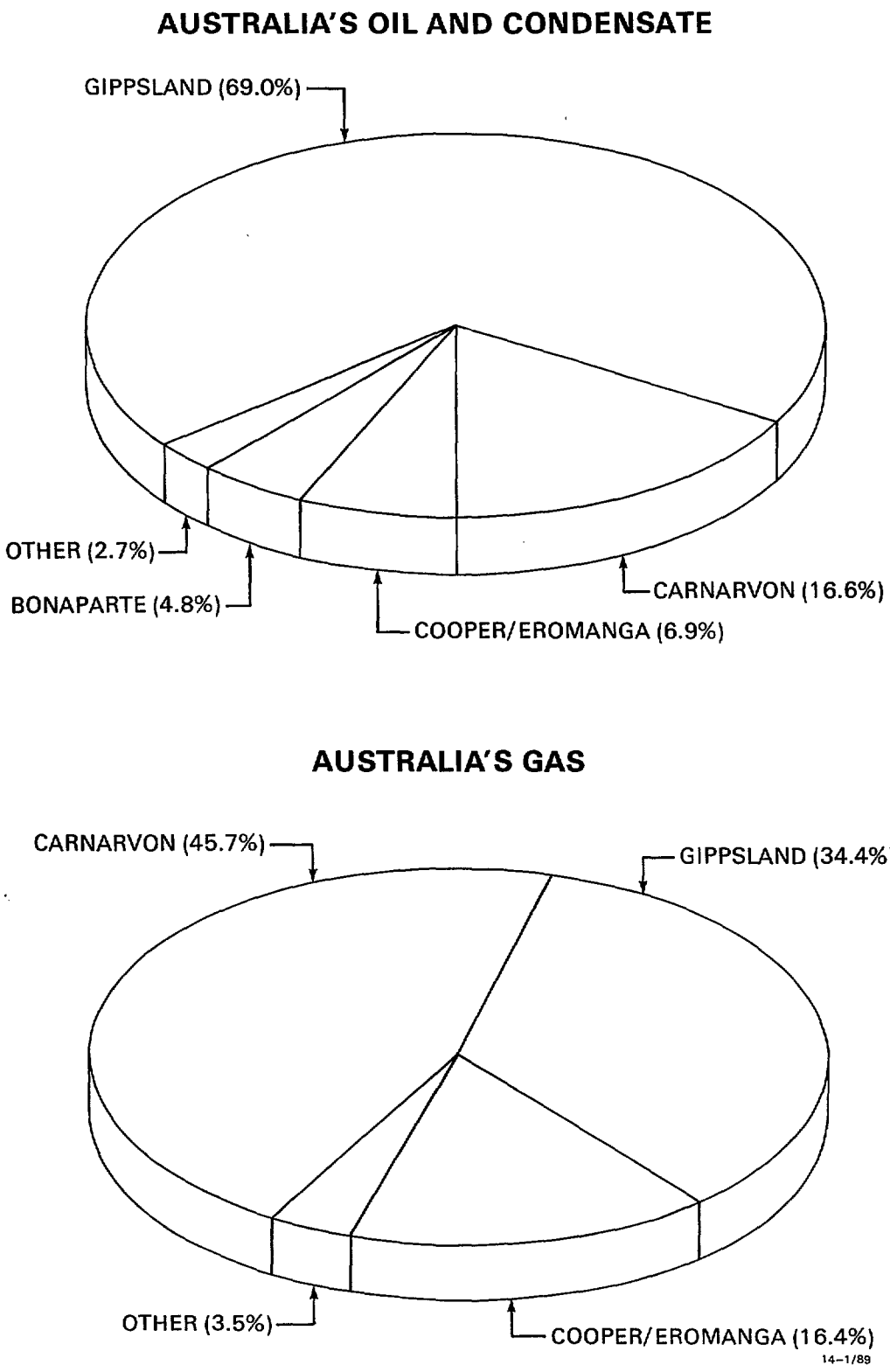


Figure 2.2 Australia's remaining commercial reserves of crude oil, condensate and natural gas, by sedimentary basin.

developed. All the other basins contribute only about 10% of crude oil and condensate reserves.

Table 2.1 Australia's commercial petroleum reserves (a)

	Crude oil (million barrels)	Condensate (million barrels)	Liquid petroleum gas (million barrels)	Natural gas (billion cubic feet)
Initial reserves	4093	441	807	22160
Cumulative Production to mid-1988	2747	111	331	5694
Remaining reserves as at mid-1988	1346	330	476	16466

Australia's non-commercial petroleum reserves (b)

Crude oil (million barrels)	Condensate (million barrels)	Liquid petroleum gas (million barrels)	Natural gas (billion cubic feet)
338	714	147	55096

(a) 'Commercial' fields are those which are producing and have commitments to start production.

(b) 'Non-commercial' fields are discoveries for which there are, at present, no commitments to start production.

By contrast, Australia has very large reserves of gas and liquefied petroleum gas (Table 2.1). Remaining commercial gas reserves are currently estimated as 16 trillion cubic feet which represents 30 years' production at current rates. The economic viability of gas fields is closely linked to the availability of markets. Given markets and pipelines, some of the non-commercial gas reserves of 55 trillion cubic feet could become commercial.*

* These figures do not include very large amounts of gas in coal seams. Trial production of gas in the Bowen Basin coal fields has commenced recently.

As at June 1988, 46% of remaining commercial gas reserves were in the Carnarvon Basin, 34% were in the Gippsland Basin (Fig. 2.2) and 16% were in the Cooper/Eromanga Basins.

Nearly all Australia's oil reserves, and most its gas reserves, are offshore (see Fig. 2.3). Figures for total reserves (including currently non-commercial fields) are shown in Figure 2.4. The main difference is due to the important Browse Basin fields which contribute significantly to both gas and condensate reserves. Most oil fields are small (Fig. 2.5): only a few fields exceed 100 million barrels. Table 2.2 shows the development of first commercial petroleum production from each basin with time.

Table 2.2 First development of Australian commercial petroleum by basin

	Crude oil	Gas
1960s	Carnarvon (Barrow Island) Perth (Dongara) Surat(Moonie)	Perth (Dongara) Cooper (Gidgealpa) Surat (Roma Shelf) Gippsland (Barracouta) Bowen (Roma Shelf)
1970s	Cooper (Tirrawarra) Gippsland (Halibut) Bowen (Cabawin, Kincora)	
1980s	Canning (Blina) Bonaparte (Jabiru) Amadeus (Mereenie) Eromanga (Jackson, Strzelecki)	Carnarvon (North Rankin) Amadeus (Palm Valley) Otway (North Paaratte)

2.3 Reserves trends

Australia's total (commercial plus non-commercial) remaining reserves of oil have increased marginally over the last 20 years in the face of increasing production rates (Fig. 2.6). Since 1973, upward revisions of reserves have been keeping pace with production of oil and condensate in Australia. Most of the revisions have been due to increases in reserves in previously known fields - this appreciation of reserves is commonly

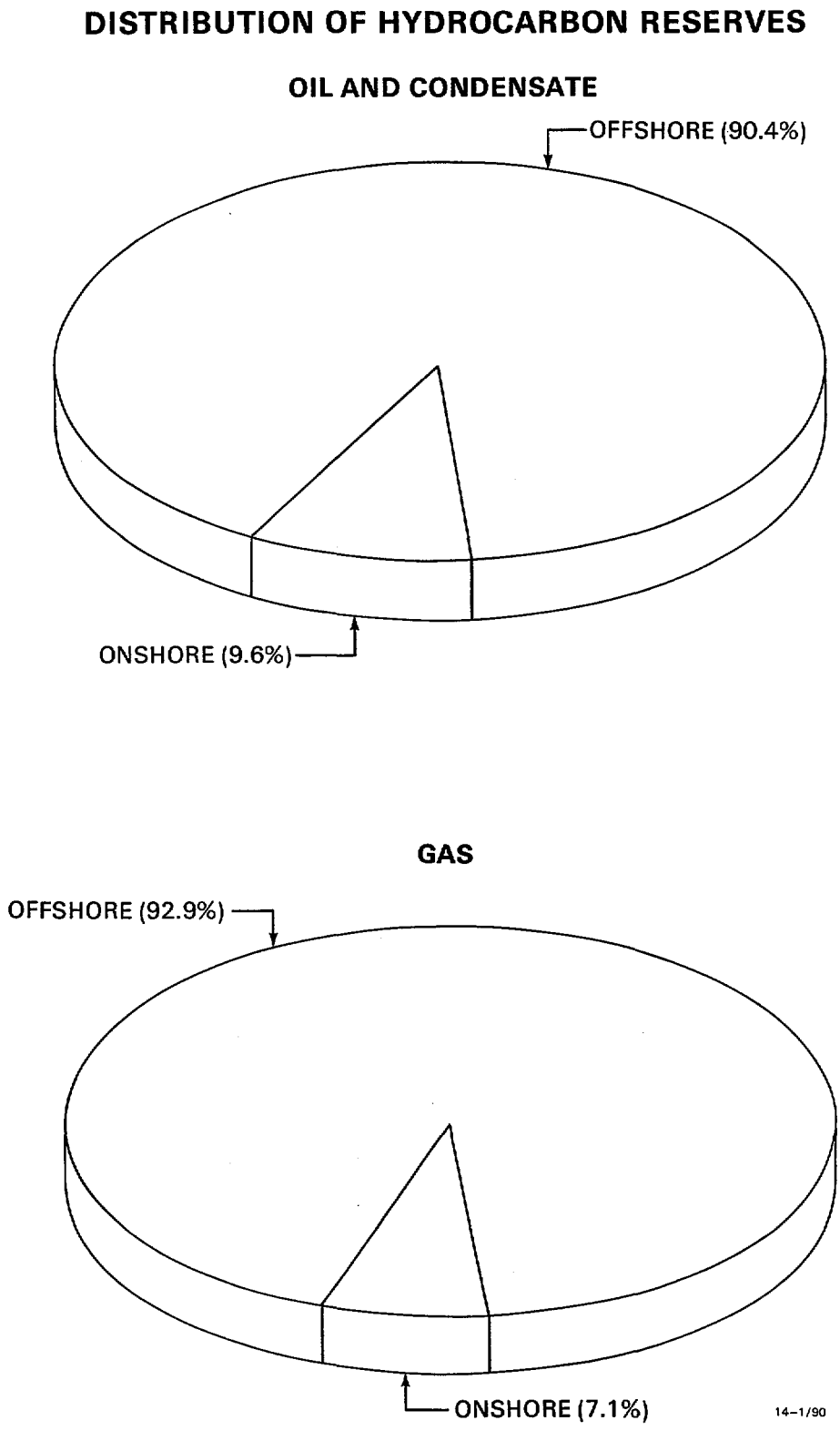


Figure 2.3 Distribution of commercial and non-commercial hydrocarbon reserves - onshore and offshore.

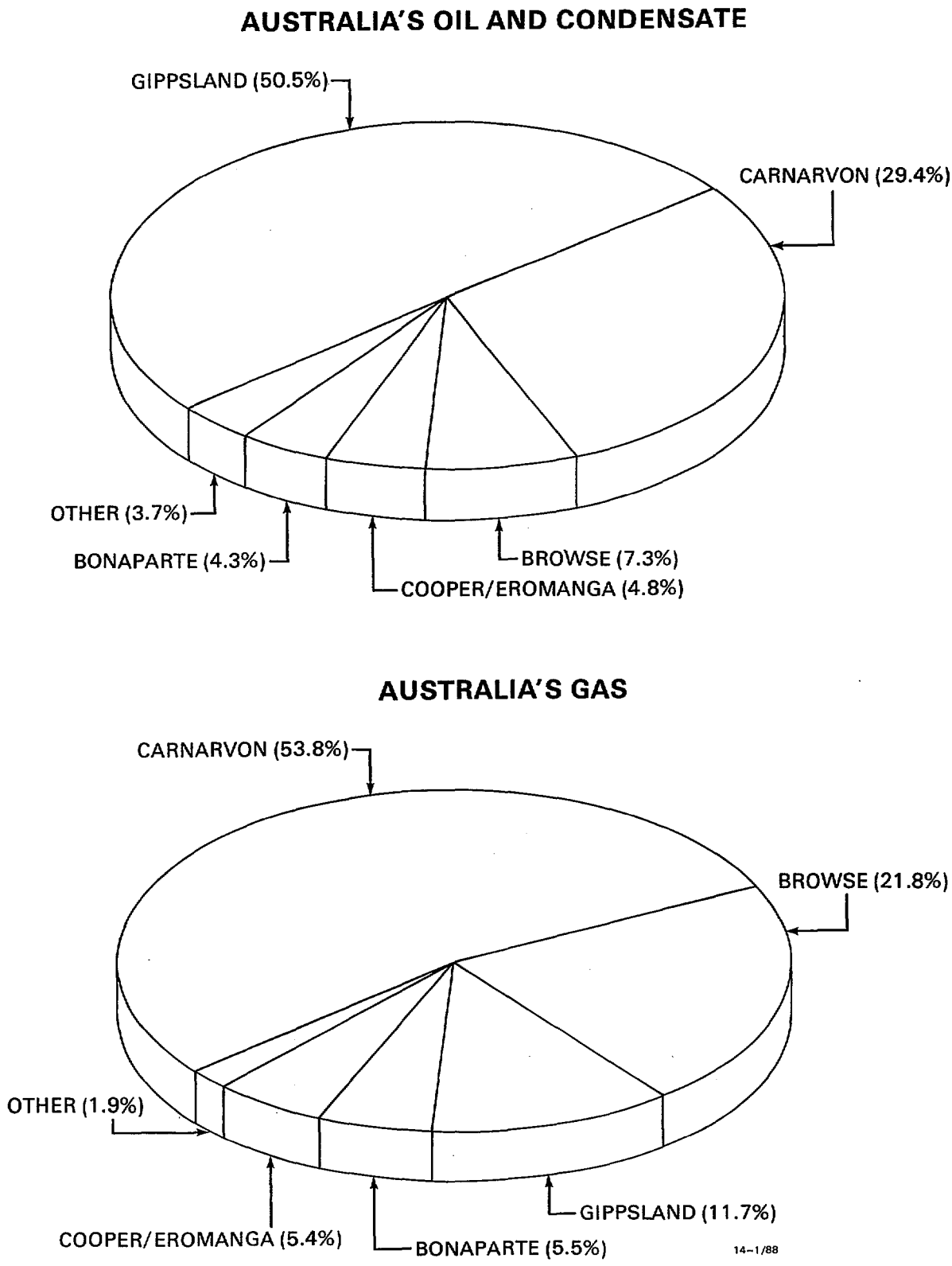


Figure 2.4 **Commercial plus non-commercial oil and gas reserves by basin.**

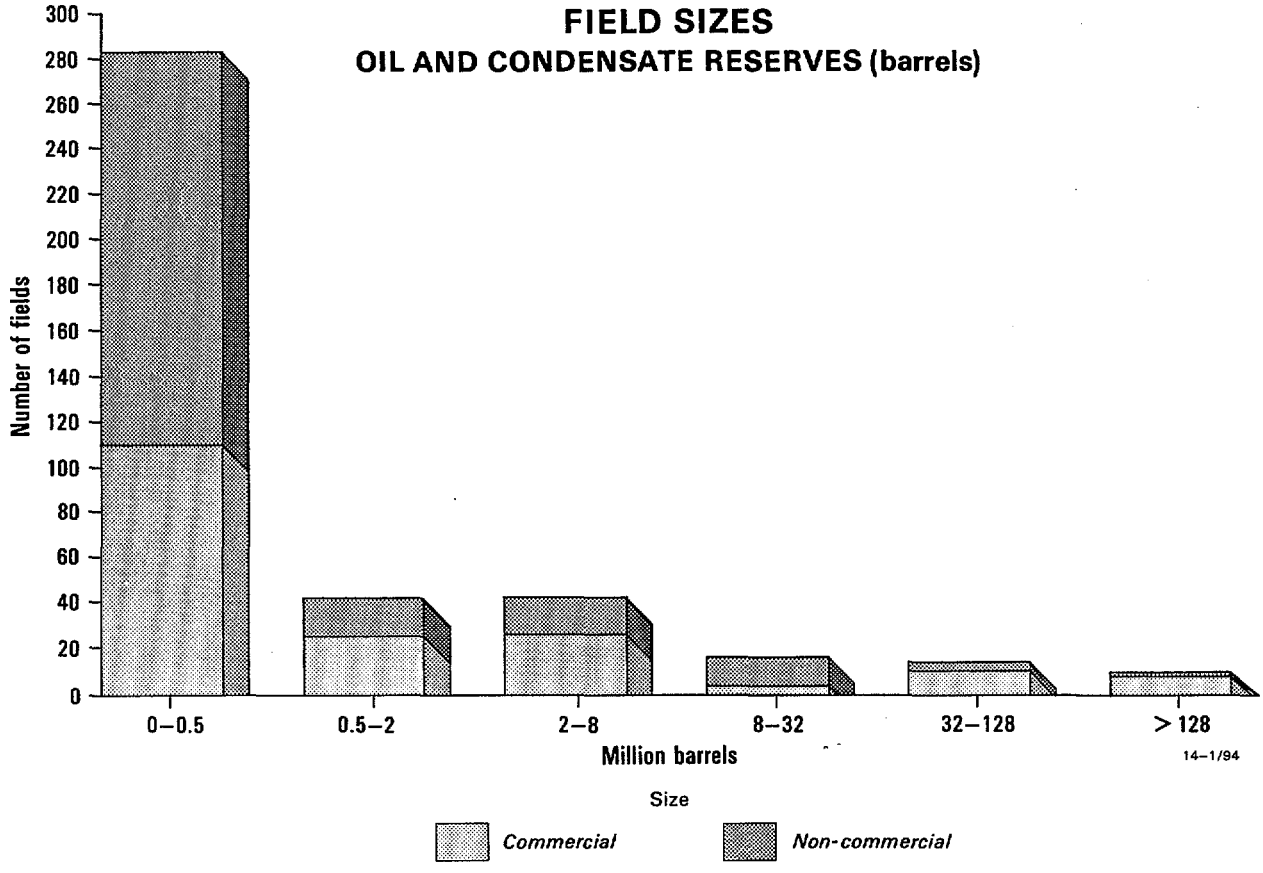
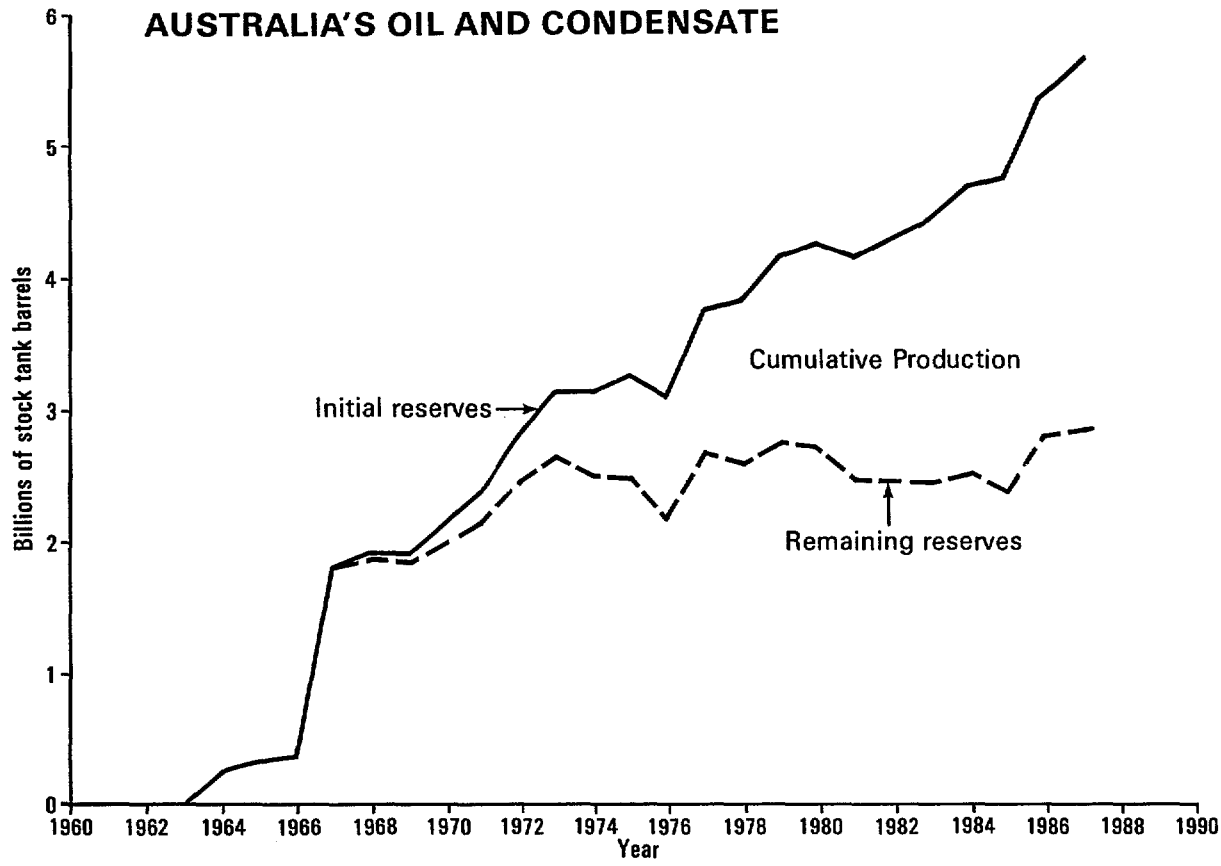


Figure 2.5 Size distribution of Australian oil and condensate field (barrels).



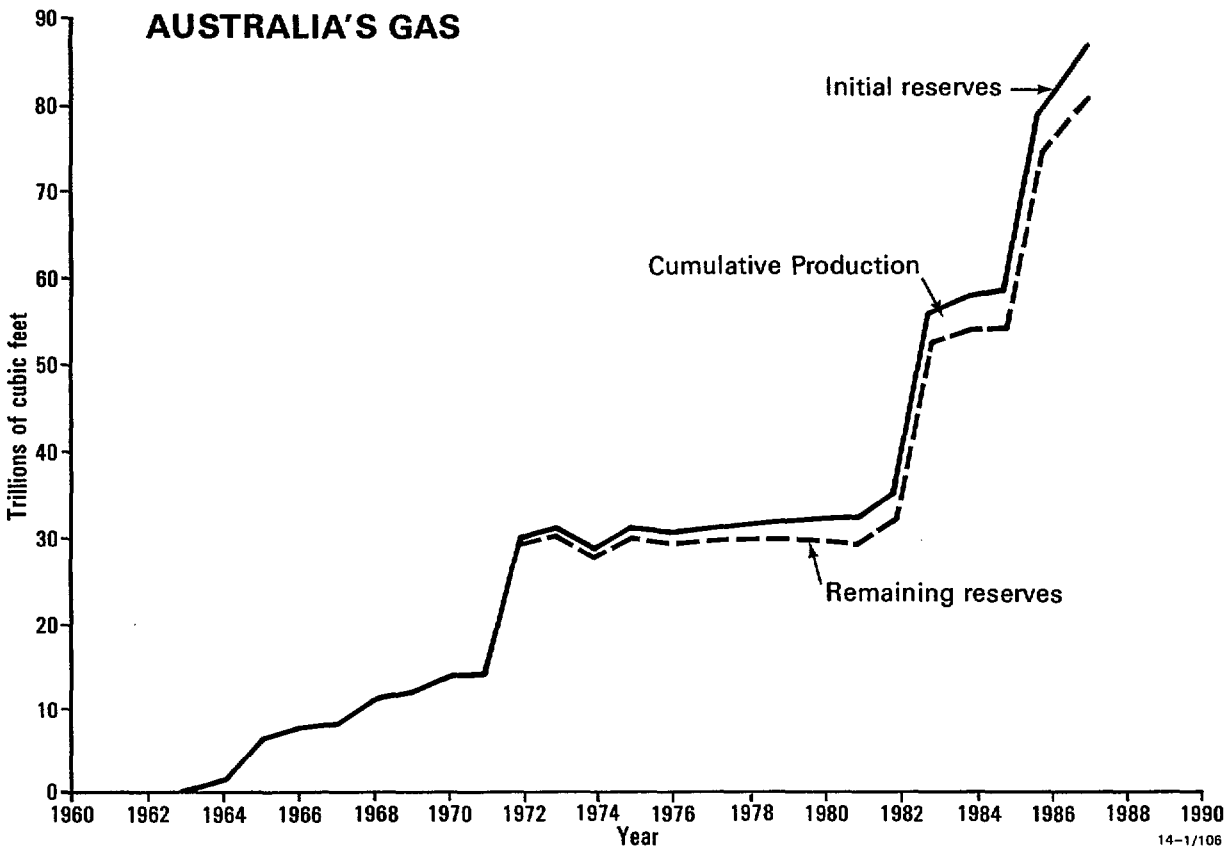


Figure 2.6 Trends with time in total (commercial plus non-commercial) reserves of oil, condensate and gas. Figures show resources as perceived at the year given.

observed in the development of new fields. During the last 20 years, the actual amount of new oil reserves discovered by wildcat drilling has dropped dramatically (Fig. 2.7). This has occurred in spite of the fact that the number of new field discoveries (mainly small onshore gas and oil fields) has increased (Fig. 2.8).

The total reserves (commercial plus non-commercial) of oil and condensate discovered since 1972 represent 55 percent of remaining total reserves, but only 17 percent of total initial commercial and non-commercial oil and condensate reserves discovered to date. Thus the incremental addition to new reserves from newly discovered fields has been modest compared with the reserves discovered in the Gippsland Basin in the 1960s and the additional reserves proved up by subsequent appraisal and development drilling of these discoveries.

As for gas, several giant fields were discovered in the 1970s, and additions to gas reserves (Fig. 2.6) have consistently exceeded gas production. However, development of gas fields can be delayed because of a lack of pipelines to connect markets with existing fields. This was highlighted in the recent Australian Gas Association study (AGA, 1988) and is a significant issue in energy supply. The largest reserves of gas are in Western Australia, remote from the major domestic markets on the east coast.

2.4 Oil and condensate production history and outlook

Figure 2.9a shows the daily rate of production of crude oil and condensate in Australia, since the beginning of significant oil production in 1964. Oil production commenced from Moonie in 1964 and Barrow Island in 1967. The substantial increase which occurred in 1970 represents the beginning of production from the major Gippsland Basin fields - Halibut, Kingfish, Mackerel, and other large discoveries. Since 1974, production of oil and condensate has remained at levels above 400 000 barrels a day. In August 1983 the ban on exports of Australian crude oil was removed. Since 1984 production has exceeded 500 000 barrels a day.

Some possibly large oil fields were discovered in 1988-89. However, it is important to recognise the potential for an early and rapid decline in Australia's oil output even though such a decline has not yet actually eventuated. Despite the decline in recent years in production from Bass Strait (Gippsland Basin), 1990 overall is likely to be a near-record year for Australian output, largely as a result of the extremely high flow rates of some recent developments (Fig. 2.9a). These flow rates will of course more rapidly deplete these fields, so that the decline, when it

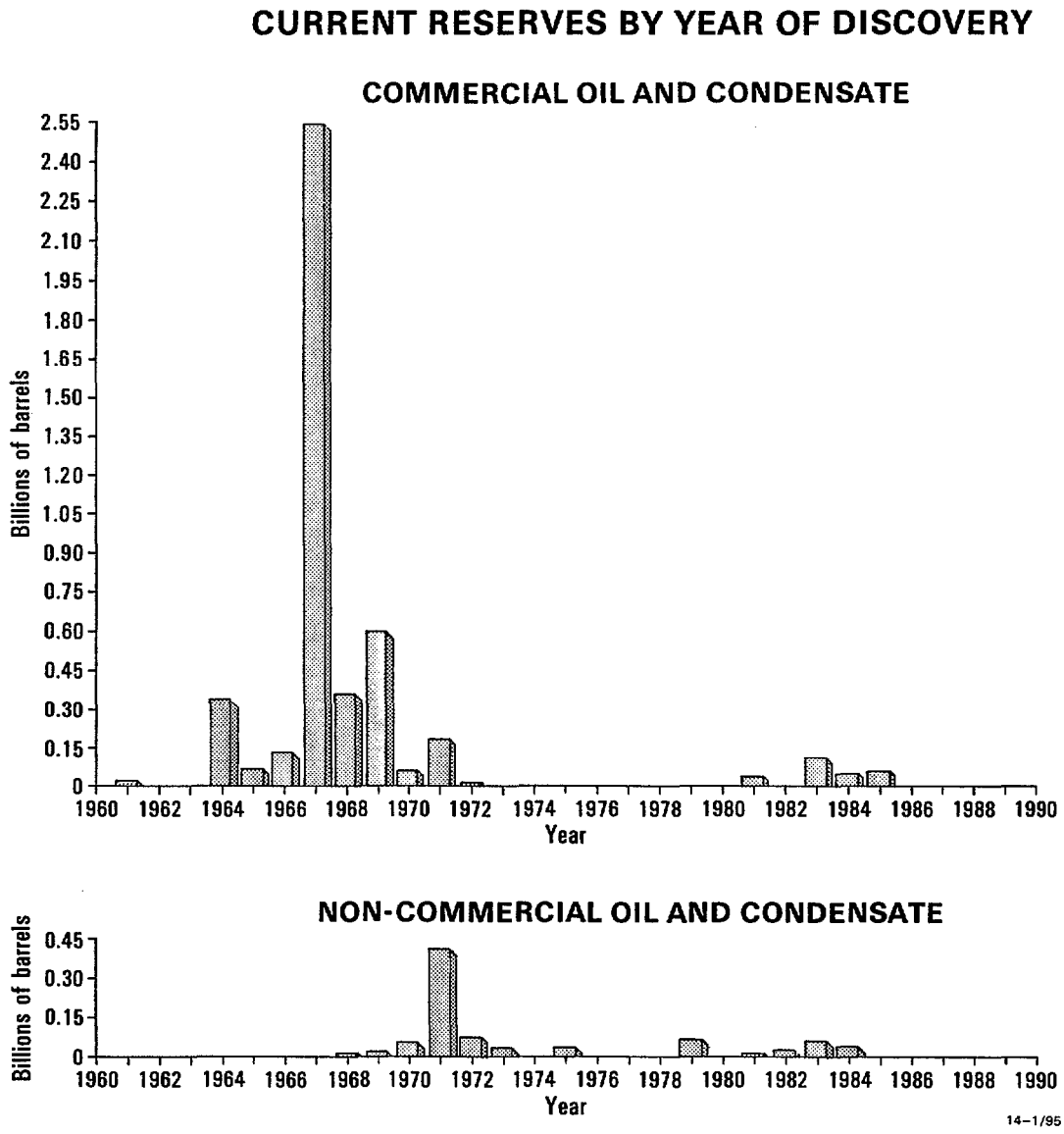


Figure 2.7 Amounts of liquid hydrocarbons (oil plus condensate) discovered per year in Australia.

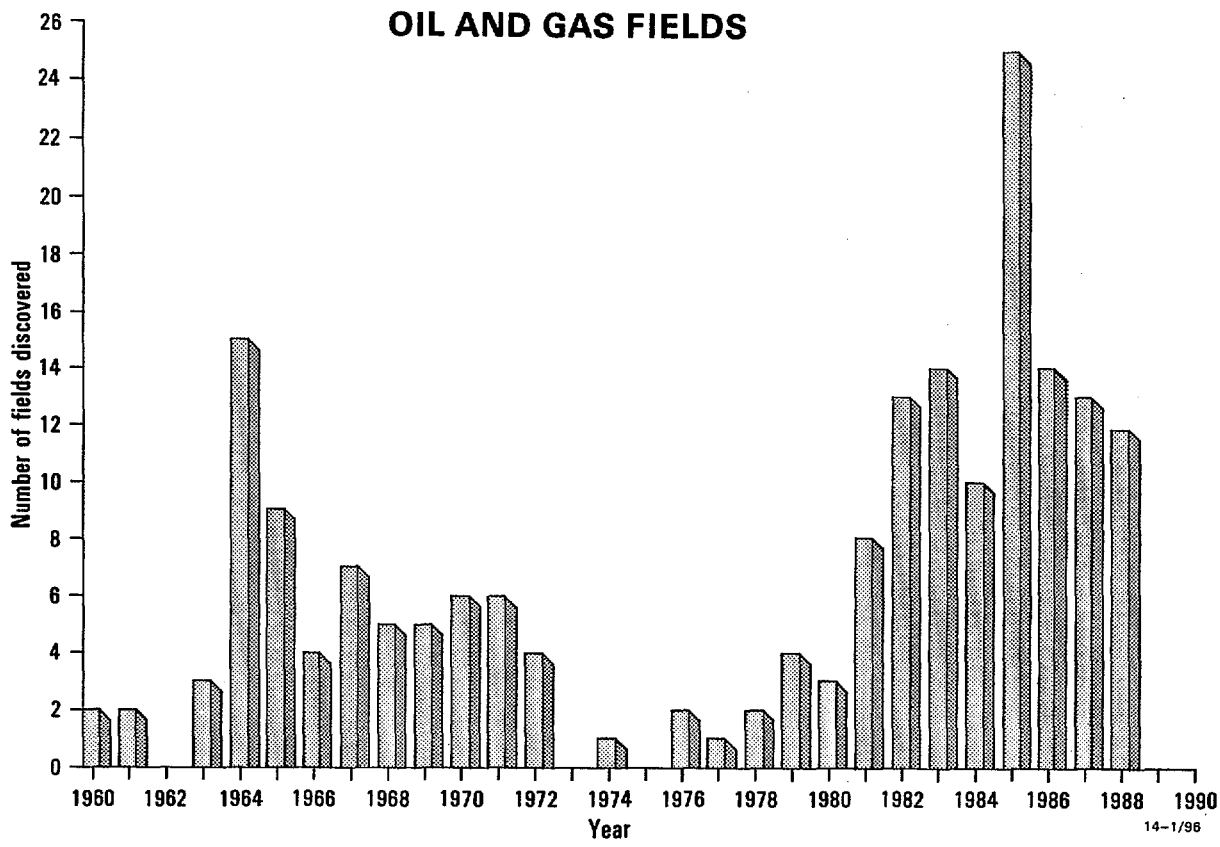


Figure 2.8 Number of commercial field discoveries each year in Australia.

Note: this diagram shows numbers only, not size, e.g. the 1960s discoveries include the large fields in Bass Strait, whereas almost all the fields discovered in the 1980s were small.

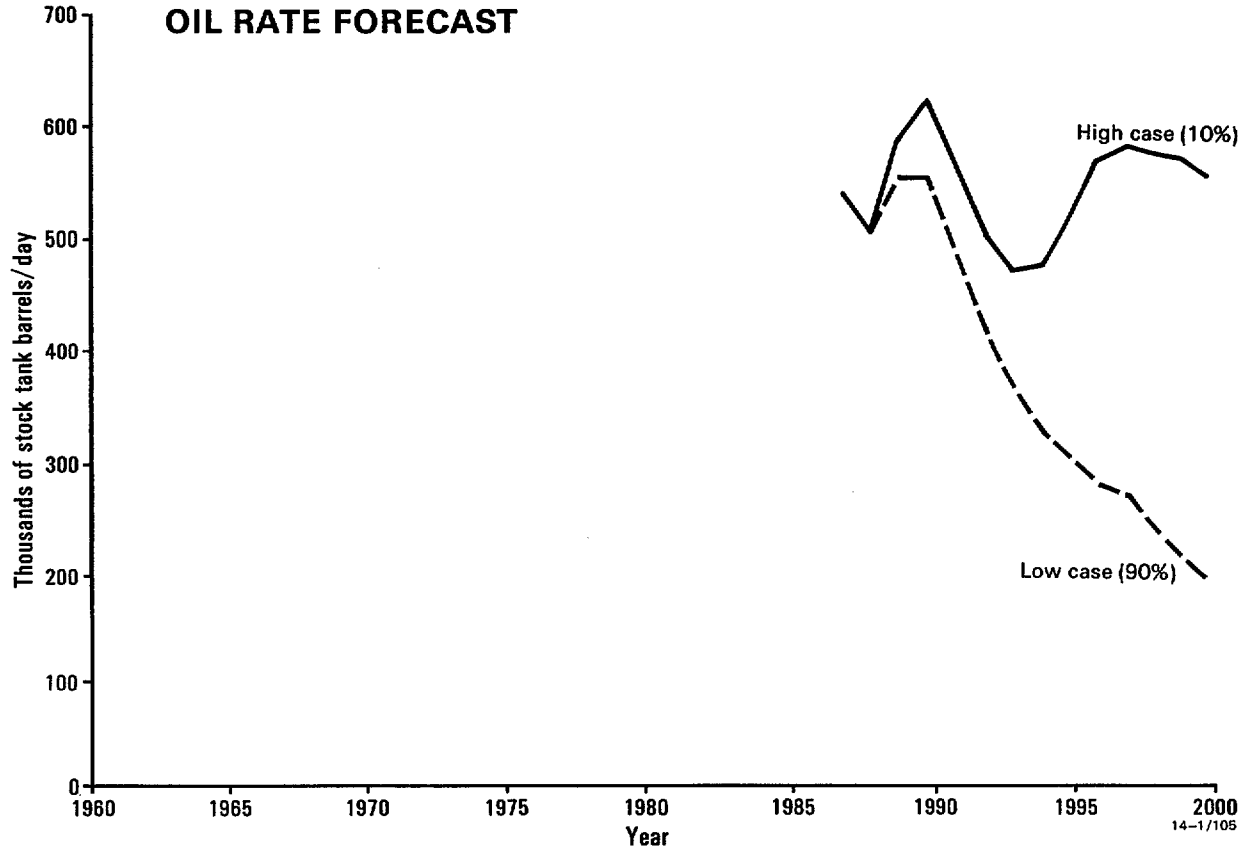


Figure 2.9 Australia's annual rate of oil and condensate production.
(a) Historical rates.
(b) Projected rates based on 10% and 90% probability levels.

does occur, will be steep, unless additions to reserves are made (Fig. 2.9b).

The importance of the present reserves situation is illustrated by the ratio of oil and condensate reserves to production (R/P ratio). The R/P ratio represents years of production from known sources at current depletion rates, and is a relevant measurement of long-term economic outlook for a non-renewable resource. Using five-year averages of commercial plus non-commercial reserves, the R/P ratio was about 20 years in the early 1970s; steady at 17 years in the late 1970s and early 1980s, and has further decreased to 14 years in the mid-1980s to the present day. Based on commercial reserves, the current ratio is only 8.5 years. Clearly this is a non-sustainable pattern of resource usage.

If oil production declines, condensate associated with Australia's abundant gas reserves will assume increasing importance as a source of liquid hydrocarbons. Several important condensate projects are envisaged in the near future. Now it is possible to develop condensate-only projects where, after condensate removal, the gas is reinjected into the reservoir. The Brae B development in the UK North Sea is an example.

Australia is self-sufficient in both liquefied petroleum gas and natural gas (as liquefied natural gas) and exports substantial quantities of both, but is currently a net importer of crude oil. This reflects the relative abundance of gas reserves compared with oil reserves in Australia.

2.5 Potential production from currently non-commercial reserves

By definition, production from present non-commercial reserves awaits a significant change in economic or technical factors. Currently non-commercial gas reserves, particularly in Western Australia, could potentially contribute to energy supply in Australia. The condensate associated with these reserves total 714 million barrels which is equivalent to an additional 3.5 years production of crude oil and condensate for Australia as a whole at current rates.

Non-commercial oil reserves are concentrated in the Gippsland and Carnarvon Basins. It is estimated that over 100 000 barrels a day of production are potentially available from these reserves. Most of the oil is in thin columns underlying gas caps. The technology for production of such reservoirs has advanced in recent years and could be a source of future production.

Apart from production from non-commercial reserves which are recoverable with existing technology, there is also some scope for enhanced oil recovery (recovery of oil in addition to that recoverable by conventional technology). A detailed NERDDC report on the potential for enhanced oil recovery in Australia will be published shortly. The availability of oil production by enhanced recovery techniques is critically dependent on the life of current infrastructure - platforms, well bores and pipelines.

REFERENCE

Australian Gas Association, 1988 - Gas supply and demand study to 2030, Second Report, October 1988.

3. PRINCIPLES OF OIL OCCURRENCE AND PROSPECTIVITY

3.1. Introduction

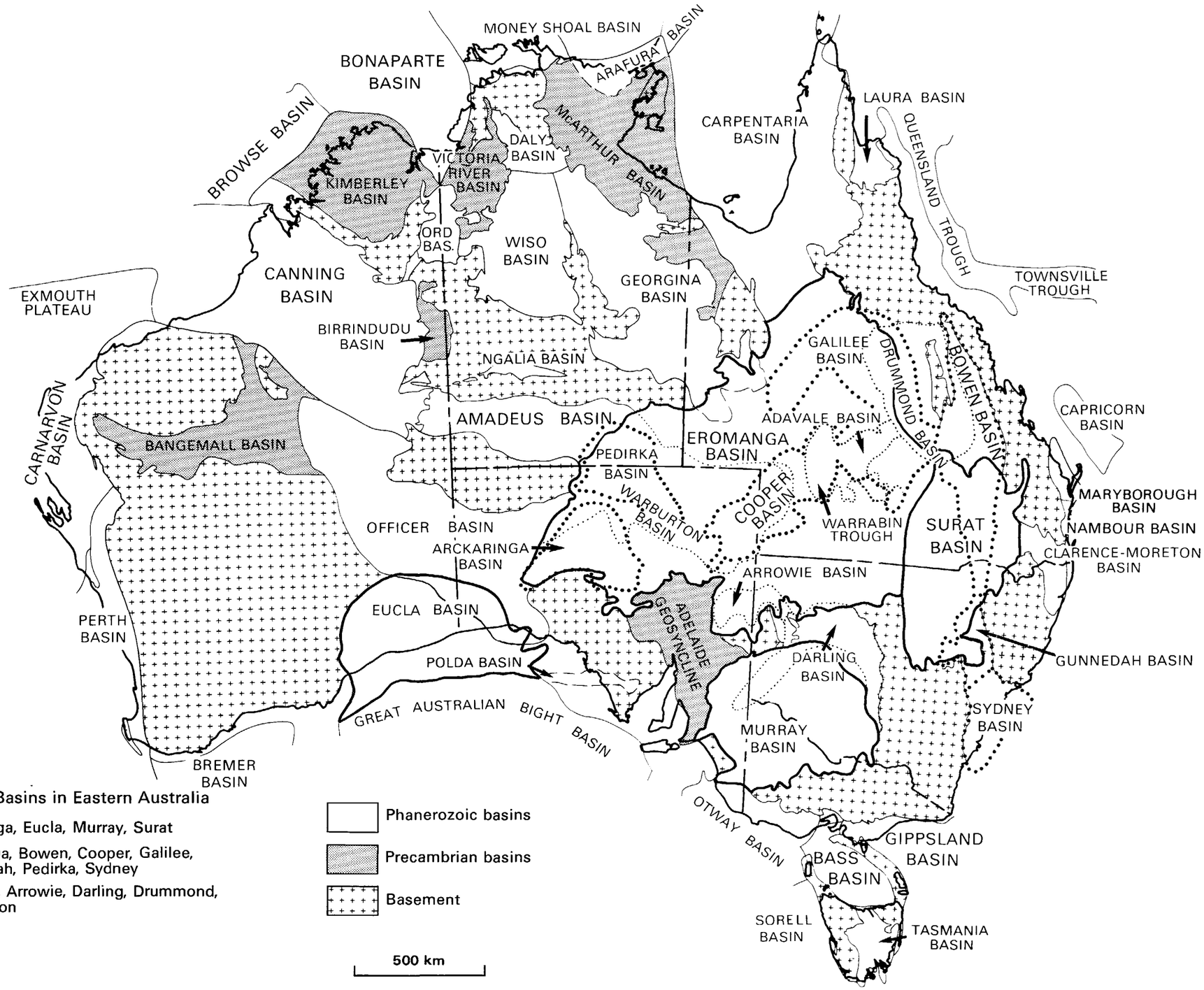
Policies and decisions involved in the stewardship of a nation's petroleum resources must be based on the best possible knowledge of the distribution of these resources in nature. However, there is no unique answer to the question 'What is the petroleum prospectivity of Australia?' (i.e. the potential for exploration success. The answer depends on:

- the current state of geological knowledge and the quality, extent and density of geological and geophysical surveying
- current perceptions of the favourability of the geological factors that contribute to the occurrence of petroleum
- the ingenuity of geoscientists in conceiving circumstances in which petroleum might occur, given the known geological constraints
- the environment of opinion at the time of the assessment, which is frequently related to the cyclicity of the petroleum exploration business
- the technical ability to develop petroleum fields of a given size in a given area at a given time

These uncertainties influence the assessment of petroleum prospectivity. It is important that the existence of uncertainty, and its degree, be recognised, and the policy implications of resource estimates be considered in the context of this uncertainty.

3.2 Petroleum occurrence

Petroleum occurs in sedimentary basins, but is not evenly distributed between basins either on the basis of size or volume of sediment. Many basins are barren of hydrocarbons, whereas in others hydrocarbons are relatively abundant. Of the world's 800 sedimentary basins, some 260 are producing, 210 have apparent potential and 330 have little recognised potential (White, 1987). In Australia there are 49 sedimentary basins, of which 11 are producing oil or gas and a further four have non-commercial reserves (Figs. 3.1, 3.2, and 3.3, and Table 3.1).



EON	ERA	PERIOD	EPOCH	AGE
PHANEROZOIC	CAINOZOIC	Quaternary	Recent	0.01
			Pleistocene	1.8
		Tertiary	Pliocene	5.0
			Miocene	23.5
			Oligocene	37.0
			Eocene	58.0
			Paleocene	65.0
	MESOZOIC	Cretaceous		130
		Jurassic		204
		Triassic		250
	PALAEOZOIC	Permian		295
		Carboniferous		354
		Devonian		408
		Silurian		434
		Ordovician		500
		Cambrian		580
PRECAMBRIAN	PROTEROZOIC	Late		1000
		Middle		1600
		Early		2500
	ARCHAEAN			3960 (greatest age so far measured)

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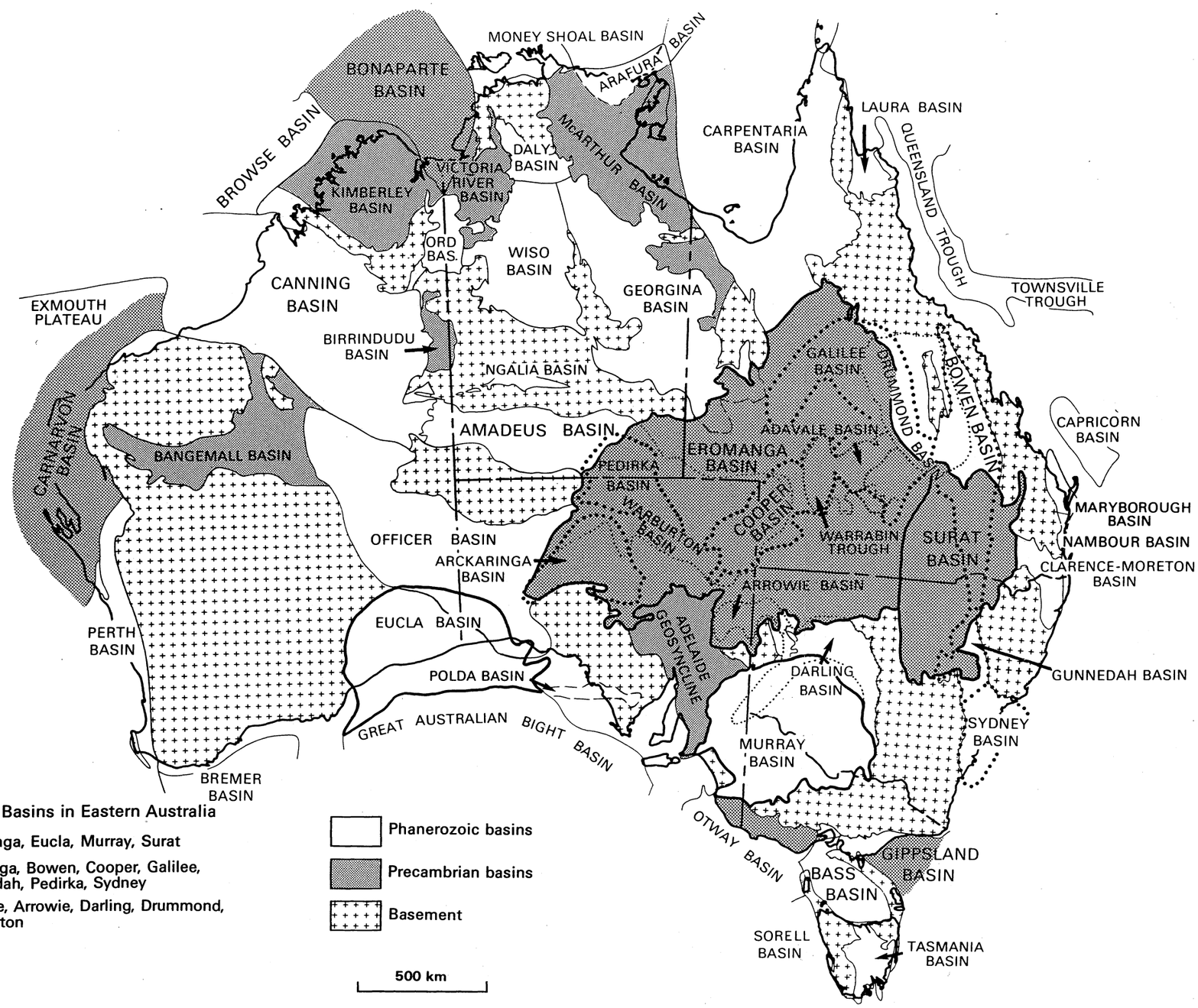
Figure 3.1 Australia's sedimentary basins. Basement denotes regions generally unprospective for petroleum—mainly areas underlain by crystalline rocks or by tightly folded or metamorphosed strata. Locally relationships are complex, eg: the Galilee Basin overlies the Adavale Basin and underlies the Eromanga Basin



EON	ERA	PERIOD	EPOCH	AGE	
PHANEROZOIC	CAINOZOIC	Quaternary	Recent	0.01	
			Pleistocene	1.8	
		Tertiary	Pliocene	5.0	
			Miocene	23.5	
			Oligocene	37.0	
			Eocene	58.0	Gippsland
			Paleocene	65.0	Gippsland
	MESOZOIC	Cretaceous		130	Gippsland, Otway, Carnarvon, Eromanga, Surat
		Jurassic		204	Bonaparte, Carnarvon, Eromanga, Surat
		Triassic		250	
	PALAEOZOIC	Permian		295	
		Carboniferous		354	
		Devonian		408	
		Silurian		434	
		Ordovician		500	
		Cambrian		580	
PRECAMBRIAN	PROTEROZOIC	Late		1000	
		Middle		1600	
		Early		2500	
	ARCHAEAN			3960 (greatest age so far measured)	

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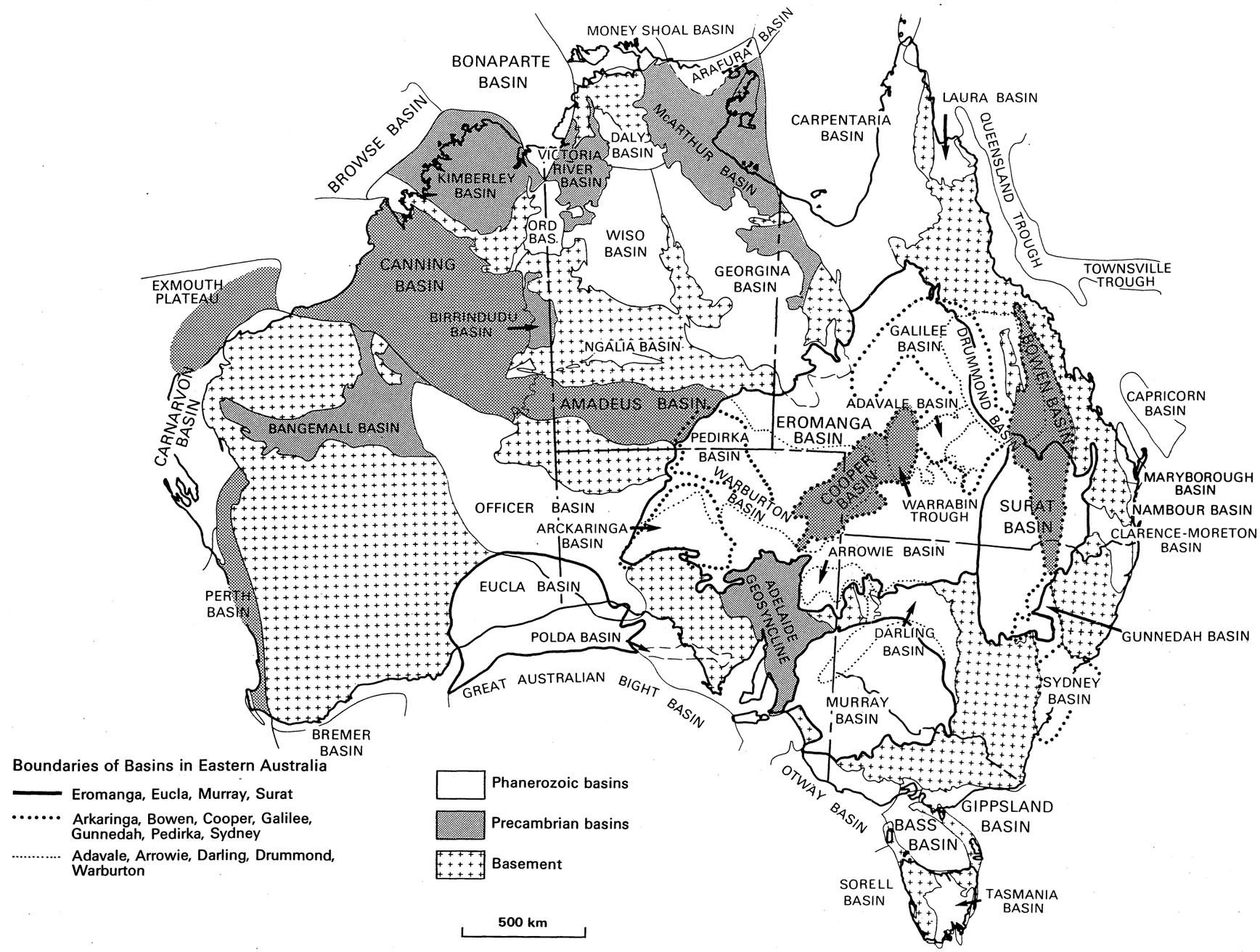
Figure 3.2 Sedimentary basins with production from Jurassic and/or younger sediments



EON	ERA	PERIOD	EPOCH	AGE	
PHANEROZOIC	CAINOZOIC	Quaternary	Recent	0.01	
			Pleistocene	1.8	
		Tertiary	Pliocene	5.0	
			Miocene	23.5	
			Oligocene	37.0	
			Eocene	58.0	
			Paleocene	65.0	
	MESOZOIC	Cretaceous		130	
		Jurassic		204	
		Triassic		250	**Perth, Bowen, Cooper, Carnarvon**
	PALAEOZOIC	Permian		295	**Bowen, Canning, Cooper**
		Carboniferous		354	
		Devonian		408	**Canning**
		Silurian		434	
		Ordovician		500	**Amadeus**
		Cambrian		580	
PRECAMBRIAN	PROTEROZOIC	Late		1000	
		Middle		1600	
		Early		2500	
	ARCHAEAN			3960 (greatest age so far measured)	

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Figure 3.3 Sedimentary basins with production from Triassic and/or older sediments

Table 3.1 **Hydrocarbon status of Australia's sedimentary basins**

Basins with commercial oil of gas reserves (11)
Amadeus, Bonaparte, Bowen, Canning, Carnarvon, Cooper, Eromanga, Gippsland, Otway, Perth, Surat

Basins with currently non-commercial oil or gas reserves (4)
Adavale, Bass, Browse, Money Shoal

Other basins with significant discoveries (3)
Clarence-Moreton, Gunnedah, Sydney

Basins with minor or no discoveries (31)

Arckaringa	Eucla	Ngalia
Arafura	Galilee	Officer
Arrowie	Georgina	Ord
Bangemall	Great Australian Bight	Pedirka
Birrindudu	Kimberley	Polda
Bremer	Laura	Sorell
Capricorn	Maryborough	Tasmania
Carpenteria	McArthur	Victoria River
Daly	Murray	Warburton
Darling	Nambour	Wiso
Drummond		

The occurrence of hydrocarbons in sedimentary basins is a consequence of a number of geological circumstances and events, the absence or the failure in timing of any one of which will result in failure to produce a hydrocarbon accumulation (Appendix A). The required circumstances are understood from the study of well known regions:

- **Source rock** (a rock layer or layers containing abundant organic material derived from algae, bacteria and parts of plants)

- **Generation** (conversion of source to hydrocarbons by heat during burial)

- **Migration** (movement of hydrocarbons from source to reservoir)

- **Reservoir** (porous rock able to contain hydrocarbons)

- **Trap** (appropriate geometric configuration of reservoir unit in which hydrocarbons accumulate)

- **Seal** (barriers preventing upward escape of hydrocarbons)

- **Preservation** of hydrocarbons from destruction by excessive heat or alternatively by invasion of the reservoir by groundwater and degradation by bacteria

Among hydrocarbon-bearing basins there is much variation in richness and distribution of hydrocarbon types (oil or gas)

- A disproportionate amount of the world's petroleum resources is distributed in relatively few basins and indicates that richness is dependent on the efficiency of hydrocarbon generation and subsequent migration and accumulation. Only in a relatively few basins does the ideal combination of events and circumstances occur. Of the world's 260 producing basins, the top five (Arabian-Zagros-Middle East, West Siberia-USSR, Gulf of Mexico-Mexico, Volga-Ural-USSR and Maracaibo-Venezuela) contain 65% of all ultimately recoverable hydrocarbons (White, 1987). In Australia, the total commercial oil reserves found in the Gippsland Basin are more than 15 times larger than those in the Cooper, Eromanga, Bowen, Surat, Amadeus and Canning Basins combined.

- Many basins, though rich in petroleum, have a predominance of natural gas, which again reflects the geological history of the basin. In the Cooper Basin the nature of the source rock and the thermal conditions of petroleum generation favour the formation of gas.

In any given hydrocarbon basin, most of the reserves are contained in a few major fields

- The sizes of fields within a given hydrocarbon-bearing basin approximate a doubly truncated log-normal distribution. In the Gippsland Basin, the Halibut/Cobia/Fortescue and Kingfish fields are much larger than the other fields. Similarly in the Eromanga Basin, although the resources are not large in comparison with the Gippsland Basin, the Jackson Field is much larger than the next largest field.

Thus bulk of the world's petroleum is derived from a relatively small number of large fields in a few rich provinces. More than 70% of the world's known recoverable petroleum occurs in only 500 giant fields,

representing less than 2% of the total number of fields (White, 1987). The same general principles apply in Australia.

3.3 Availability of resources

The various categories of petroleum resources can be shown in a modified McKelvey diagram (Fig. 3.4). This diagram uses scales of increasing geological assurance and increasing economic feasibility to separate various categories of reserves from the resource base. The system shown has loosely defined boundaries, but it does provide a framework for classification.

Petroleum resources can be divided into identified and undiscovered resources. As geological knowledge improves and exploration is successful, resources 'move' from the undiscovered to the identified category. Identified resources can be sub-divided into commercial reserves (which are currently being produced, or for which firm plans for production exist) and non-commercial reserves. As economic conditions or technology improve, reserves can move from the non-commercial to the commercial category. Some non-commercial reserves are in fields, particularly gas fields, which are undeveloped at present but which would be developed if the markets existed; other commercial reserves are being evaluated and are likely to be brought into production in the foreseeable future. These reserves and the commercial reserves are together sometimes referred to as 'economic demonstrated resources'.

Exploration geoscientists can identify areas where undiscovered fields might occur and then can give informed opinions about how many of these fields might exist and their possible sizes. These represent the undiscovered resources that we have the potential to discover and exploit them with current techniques. Nearly all of our known petroleum fields were once classified as undiscovered resources.

- There is no way in which the ultimate amount of undiscovered resources can be determined, even though some portions of the ultimate amount can be estimated. We can predict a discoverable portion using well supported hypotheses as well as an additional discoverable portion using poorly supported speculations. These make up the hypothetical and speculative categories.

- There is an additional unknown potential, which cannot be defined because the geological circumstances for occurrence are not known from any existing data. It becomes possible to add resources to the speculative category from this area of unknown potential as geological

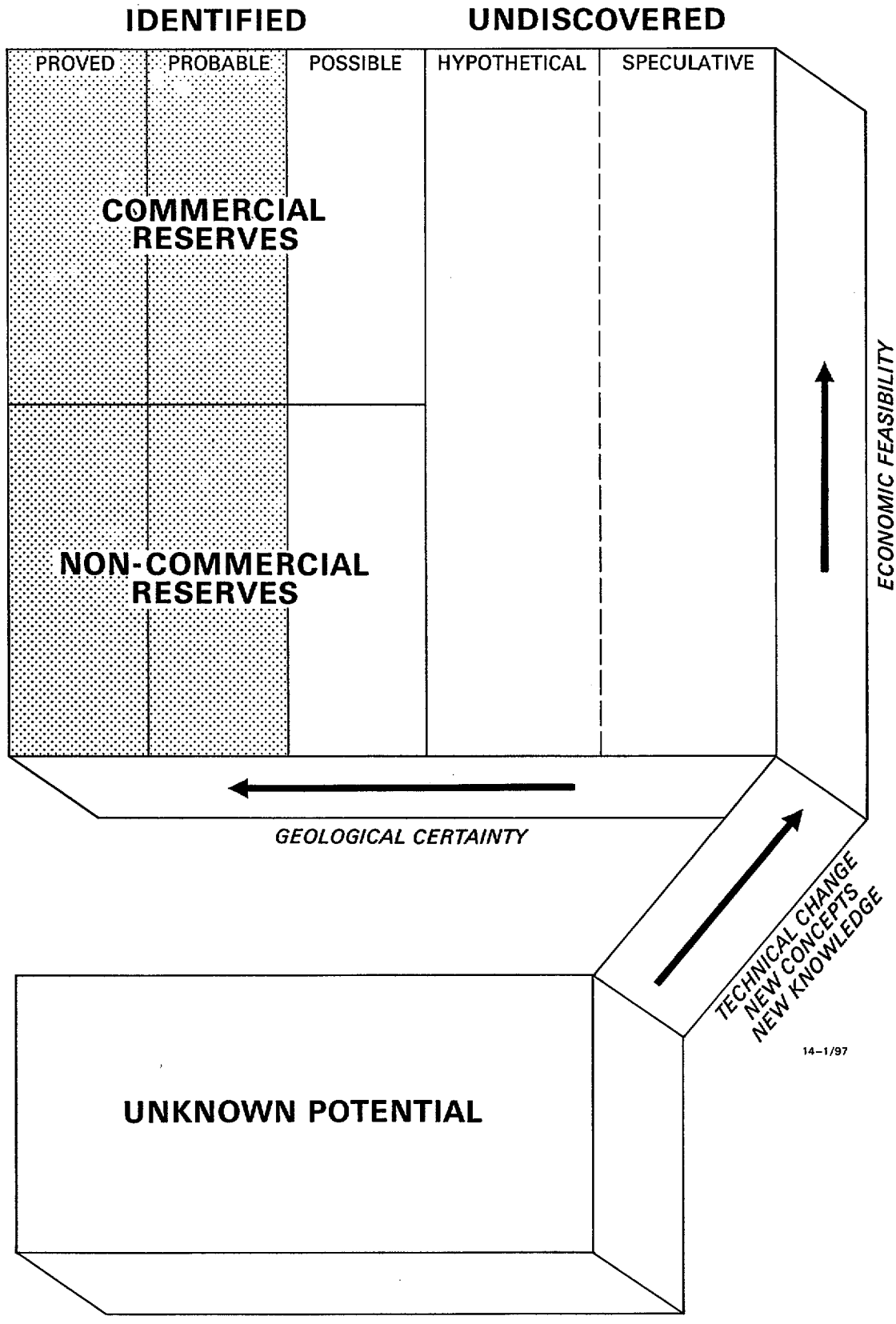

Figure 3.4 Modified McKelvey diagram showing conceptual framework for identified, undiscovered and unknown petroleum resources.

research, exploration and technological developments add to the geological knowledge of poorly-known areas.

3.4 The concept of prospectivity

The concept of prospectivity relates to the qualitative or quantitative opinion of a geoscientist or a group of geoscientists on the chances of finding a commercial petroleum field in a given area. To be useful for planning, the opinions should answer the following questions:

- How large is the resource and where is it located?
- In what size fields does it exist?
- How certain are we of these opinions?

Precise answers can be obtained only after the resource is depleted. In the early stages of exploration there is enormous uncertainty, but even then finite limits can be set on the possible range of answers. As exploration proceeds and knowledge accrues, the range will narrow, rapidly at first, then more slowly. Because absolute answers are not attainable, they must be estimated indirectly using whatever information is available. Decisions under uncertainty are inescapable. The important thing is to quantify the uncertainty and make it explicit.

- The issue of uncertainty can be divided into two parts. Firstly, what is the probability that petroleum occurs in an area, i.e. are the conditions favourable for petroleum generation, and preservation entrapment? Secondly, given that petroleum may occur, how much is this likely to be present?

Numerical assessments of petroleum prospectivity (i.e. <u>resource assessment</u>) integrate the current state of knowledge, together with objective and subjective opinions as to the favourability for petroleum occurrence (and their uncertainty), into probability-based distributions of petroleum resources by computer modelling (Appendix B). This resource assessment will only ever be an informed 'opinion' as to whether petroleum resources of the specified range of magnitude actually exist.

- Undiscovered resources exist only at a stated probability level and are not a certain part of a resource inventory until they are identified and demonstrated by drilling.

- Estimates of undiscovered resources (whether quantitative, qualitative or intuitive) provide part of the framework within which exploration

companies evaluate relative investment risks in different areas of exploration potential.

Various factors influence the resource assesment and the way in which results should be interpreted. The state of knowledge of the petroleum geology is an important constraint on the degree of certainty associated with the resource assessment of a given basin or region.

- In regions or basins where resources have already been identified, much of the uncertainty has been removed and resources can be predicted in the established style of occurrence with some level of confidence. However, preconceived or entrenched ideas, even about established areas, can markedly affect the assessment, and can result in failure to identify a new style of accumulation. However, the large fields tend to be discovered early in the exploration of a province, so any future discoveries will probably be smaller.

- In poorly explored regions, little is known about the petroleum geology, and there is a wide range of possible sizes for any petroleum occurrence, ranging from very small at a high level of probability to very large at a low level of probability. There is a chance that in one such region a large resource may exist. Before exploring, it will be uncertain as to which region this may be. Many of Australia's basins fall into this category and in some cases the uncertainty is so high as to make a quantitative assessment relatively meaningless. This should not be construed as indicating that resources will never be found, and indeed an increase in the geological knowledge of a region may eventually allow petroleum potential to be quantitatively assessed and additional resources recognised.

New concepts in either established or poorly explored regions can increase resource estimates. Similarly, new technology, such as advances in seismic acquisition and processing, may lead to the assessment of resources that were not previously known. Conversely, exploration drilling may negate some concepts and thus decrease resource estimates. However, given the complexity of most geological situations, a single dry well need not downgrade the prospectivity of the remaining exploration targets.

The importance of innovative thinking in resource exploration and assessment cannot be overemphasised if the nation's resource potential is to be recognised.

- Oil may be found in well-explored basins with new ideas, in poorly-explored basins with old ideas, or in poorly-explored basins with new ideas, but it is unlikely that it will continue to be found in well-explored basins with old ideas.

REFERENCE

White, D.A., 1987 - Continental oil and gas resources. In D.J. McLaren and B.S. Skinner, (Editors), Resources and world development. Wiley & Sons, 113-128.

4. AUSTRALIA'S PROSPECTIVITY

4.1 Reserves appreciation

Most of the oil produced in Australia so far has been from fields that were discovered before 1970. Furthermore, most of the growth in Australia's oil reserves since 1970 has come through identifying additional reserves in established fields rather than from new discoveries.

Thus, failure to predict such increases in reserves in existing commercial fields can therefore lead to unduly pessimistic forecasts of production. For example (see Adelman, 1988), in 1944 an expert estimated that the reserves of Persian Gulf fields as 16 billion barrels proved and 5 billion barrels probable. By 1975, the same fields had already produced 43 billion barrels and the remaining oil was estimated as 74 billion barrels. Similar observations can be made for the Prudhoe Bay and Kern River fields in the US as follows:

Field	Reserves Estimate (bbls)	Year of Estimate	Production to 1987 (bbls)	Remaining in 1987 (bbls)
Prudhoe Bay	9.6 billion	1969	4.6 billion	8.2 billion
Kern River	54 million	1942	781 million	877 million

As Adelman (1988) points out, the additional reserves in old fields were neither a gift of nature, nor an outcome of the geologists' supposed 'conservatism'. They simply reflect the increase in knowledge, and the recognition of additional opportunities as a result of the intensive activity accompanying development and production.

Factors contributing to an upgrading of reserves in an oil field include:

- Increases in the known volume of discovered pools (from drilling and geophysical data)
- New pool discoveries (often by development wells)
- Improved development technology, allowing a greater proportion of in-place oil to be produced
- Revised assessments of reservoir and fluid properties, leading to higher recovery factors than those originally calculated

It is hard to quantitatively predict the growth in reserves in existing fields. Estimates of 'possible reserves' indicate potential for an increase in 'proved and probable' reserves, but, historically, in many cases the predicted 'possible' reserves did not cover the eventual increase in 'proved and probable' reserves.

Major increases in reserves are generally less likely in onshore fields than in offshore fields, where well control is more limited, and there is more uncertainty as to the possible range of outcomes.

Advances in technology are impossible to predict. Enhanced oil recovery (recovery of some of the oil that normally remains in the ground after conventional reserves are depleted) has been developed in the last 20-30 years and is now being applied in the Cooper Basin. Similarly, horizontal drilling in reservoirs is a new technology now being introduced to Australia that has the potential to increase recovery by allowing more effective drainage of reservoirs.

With the benefit of 'hindsight', it can be seen how the magnitude of reserves in identified fields changes with time. Figure 4.1 shows the magnitude of the year-by-year increase in Australian oil and condensate reserves due to revision. It shows annual current estimates of remaining commercial reserves contrasted with estimates of the actual reserves in these fields, calculated in 1989.

The scope for an increase in reserves is highest in the early years of field development and is only tenuously linked to the size of the field, as the above examples show. Increases in reserves occur mainly in producing fields, where development drilling and the reservoir's response to production rapidly improve knowledge of the field. The reserves of nearly every North Sea field have increased after production began. Thus, reserves of non-producing fields are often understated, especially where the significance of an apparently minor discovery is not perceived until a stepout well is drilled, often years later. Figure 4.1 indicates, for example, that the 'true reserves' discovered in fields declared commercial before 1972 were underestimated in 1972 by 42% (about 1.5 billion barrels).

The possibility of revisions to reserves varies throughout the life of the field.

It has recently been suggested that the percentage of uncertainty in remaining reserves is relatively constant throughout the life of a field.

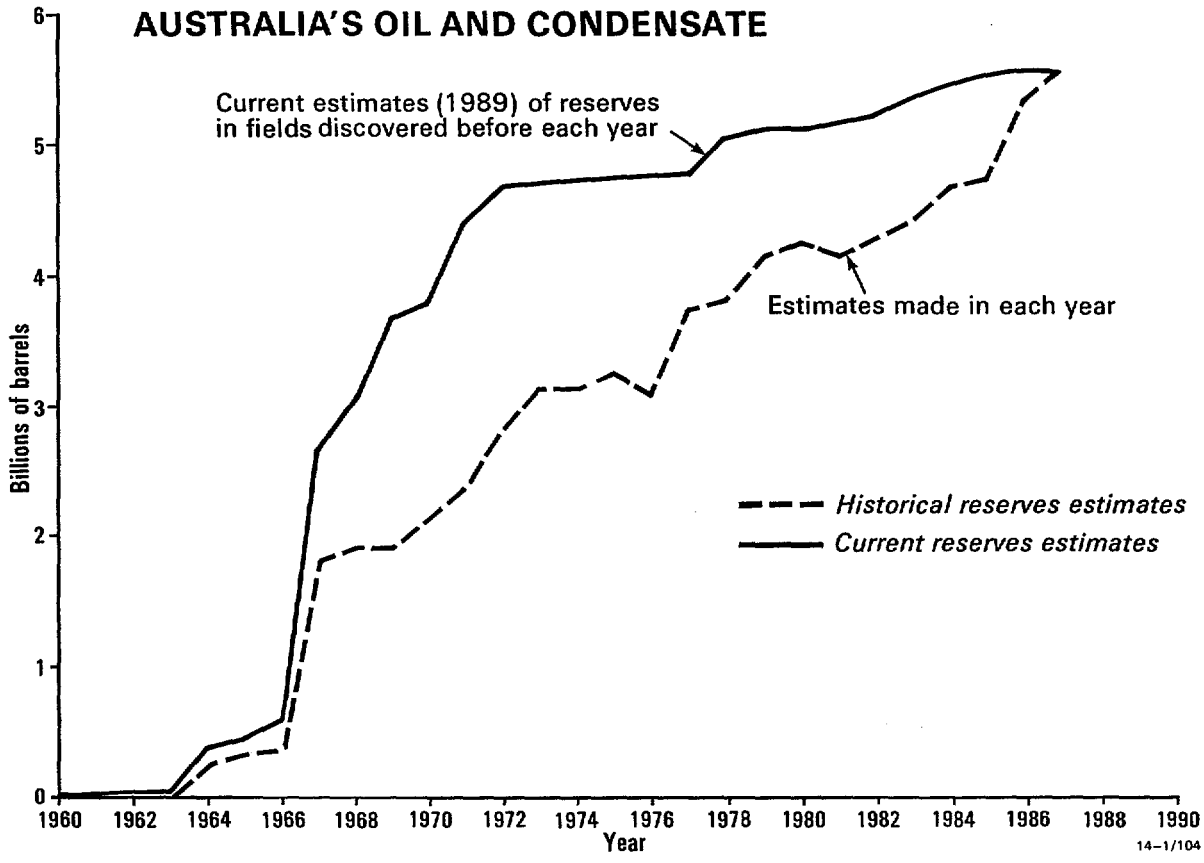

Figure 4.1 Australia's oil and condensate: initial commercial and non-commercial reserves estimated each year.

4.2 Undiscovered resources

Australia's undiscovered petroleum resources have been assessed using a methodology developed in BMR and described in Appendix B. The assessment refers to conventional oil and gas accumulations that may occur in recognised geological circumstances and could be brought into production within the next 20-25 years. It excludes new pool discoveries that may be made in known fields, accumulations that may occur in deep water and remote areas, and accumulations that may occur in presently unknown circumstances.

- Undiscovered petroleum resources are assessable at specified probability levels, because the geological circumstances for occurrence are regionally known, or reasonable analogies exist.

- It is impossible to provide a quantitative informed assessment of Australia's unknown petroleum resources because the geological circumstances for occurrence are not defined by existing data.

The national assessment of Australia's undiscovered petroleum resources is summarised by region in Table 4.1. It indicates that there is the potential to find the following resources in Australia, (the range of figures quoted is from 95%-5% probability levels):

- Oil. 1000-5000 million barrels (average 2400 million barrels).

- Sales gas. 10-45 trillion cubic feet (average 23 trillion cubic feet).

- Condensate. 250-880 million barrels (average 500 million barrels).

At the average expectation level these estimates represent a conservative but realistic view of petroleum potential based on current scientific concepts and survey data. They constitute a reasonable expectation over the next 25 years and are therefore probably appropriate for 'base case' planning purposes.

At first glance these estimates might also lead to the conclusion that Australia's prospectivity is not particularly high. However, in any given basin there is a small but significant chance of a very much larger speculative potential that is expressed at the 5% probability level (Table 4.1). This is the target for innovative scientific exploration. The fact that this large, speculative potential reflects our uncertainty and lack of knowledge in unexplored or partially explored basins. It is highly unlikely that this potential will be realised in all basins, but

Table 4.1 Estimates of Australia's undiscovered petroleum resources by region, and at various probability levels

	Crude oil (million barrels)			Condensate (million barrels)			Sales gas (trillion (10^{12}) cu ft)		
	95%	Average	5%	95%	Average	5%	95%	Average	5%
Eastern Australian onshore basins (a)	60	200	500	25	50	100	1.8	1.8	3.3
Southern coastal margin basins (b)	140	560	1340	15	70	170	0.4	1.3	2.6
Central Australian basins (c)	1	60	250	1	8	25	0.03	0.3	1
Northeastern margin basins (d)	0	320	1000	0	20	70	0	0.3	1
Northern & western margin basins (e)	280	1540	3200	350	1200	2800	8	23	45

(a) Carpentaria, Eromanga, Surat, Bowen, Clarence-Moreton, Karumba, Laura, Cooper, Galilee, Arkaringa, Pedirka, Sydney, Gunnedah, Adavale, Warburton, Drummond, Maryborough, Murray and associated infrabasins.
(b) Gippsland, Bass, Otway, Sorell, Great Australian Bight, Bremer, Eucla, Polda.
(c) Amadeus, Ngalia, Daly River, Wiso, Georgina, Officer, Arrowie, Ord, and Precambrian basins.
(d) Papuan, Torres Shelf, Bligh Trough, Queensland Trough, Townsville, Capricorn.
(e) Perth, Carnarvon, Canning, Browse, Bonaparte, Arafura, Money Shoal.

there is a chance it may be achieved in one or more. There have been many spectacular successes in the history of petroleum exploration where this has proved to be the case (e.g. Pratt, 1952). Clearly a low average potential should not by itself inhibit exploration. Development of new geological concepts resulting from research and exploration may well result in the discovery of resources that were conceived previously at the 5% probability level or lower.

Figure 4.2 ranks Australian sedimentary basins according to their potential. The most prospective are considered to be the Bonaparte and Carnarvon Basins ('Northern and Western Margins' group) in which some exploration success has been achieved but which are far from completely explored. The most extensively explored basins (offshore, Gippsland; onshore Eromanga, Cooper and Surat) have ralatively small speculative potential at the 5% probability level, and are ranked behind less well explored basins. Except for the offshore Gippsland Basin, they retain the same rankings at the average probability levels. At the average probability level the oil-rich Gippsland Basin ranks equal third, reflecting the high degree of certainty that further oil accumulations exist. In contrast, the basins of the Northeastern Margin have hardly been explored at all; despite the considerable risk, at the average probability level their resource potential equals that of the Gippsland Basin, but at the 5% (speculative) level it far exceeds that of the Gippsland Basin.

Based on current assessments, although there is a high degree of certainty that small oil pools will continue to be found in the well explored areas, the significant oil potential lies in the partly explored, or poorly explored, regions offshore (Bonaparte, Carnarvon and northeastern Australian Basins).

Figure 4.3 shows a range of possible production scenarios incorporating present commercial reserves, non-commercial reserves derived from modelling of discovery rates and estimates of undiscovered resources at various probability levels. The graph shows that, at the 10% probability level, the possibility exists that current production levels can be broadly maintained. However, this could happen only if a vigorous exploration program is maintained.

4.3 Impact of future developments

'Perceptions of Australia's petroleum prospects have been and are of critical importance to the nation's petroleum exploration industry. Although other factors are certainly involved, perceptions of petroleum

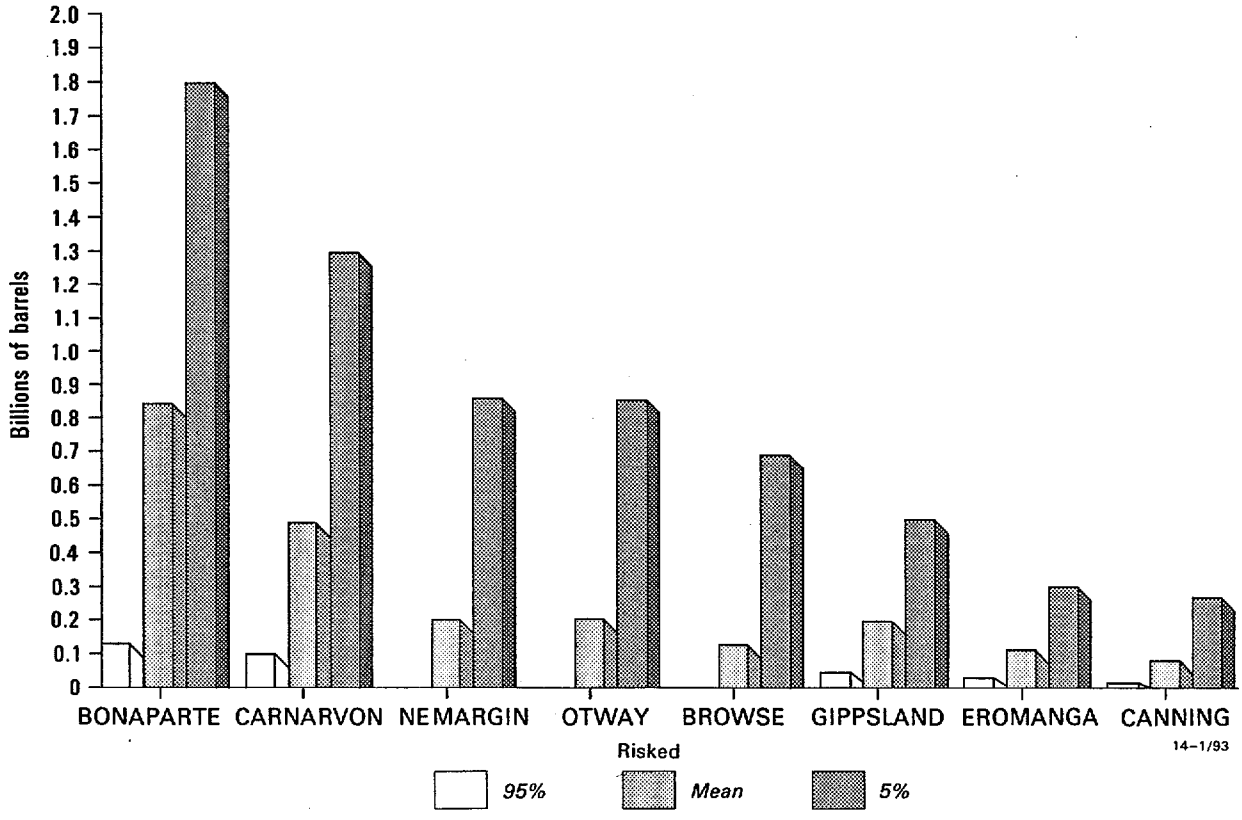

Figure 4.2 Undiscovered oil: estimates of undiscovered oil resources in the most prospective sedimentary basins.

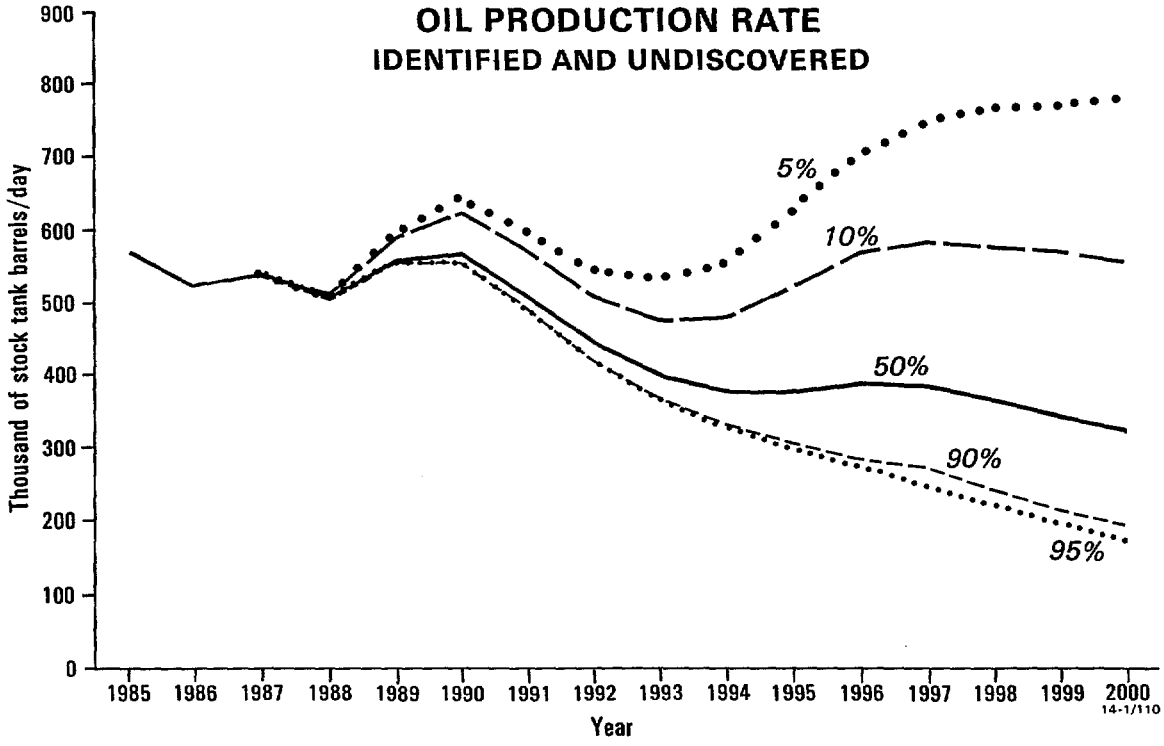

Figure 4.3 Possible future production rates derived from identified and undiscovered resources at various probability levels.

prospectivity play a large part in determining the amount of exploration activity at any time, and the amount of activity has in turn a significant effect on the likelihood of success' (Robertson, 1988).

In a country as underexplored as Australia the results of a single well may significantly change perceptions of the prospectivity of a region. Two cases in point are the discoveries of the Fortescue oil accumulation in the Gippsland Basin in 1978 and the Jabiru oil field in the Bonaparte Basin in 1983; these finds significantly upgraded industry perceptions of the oil prospects of those basins and resulted in surges in exploration in them (Robertson, 1988). Again, as late as 1977, the Eromanga Basin (onshore, mainly Queensland) was not widely regarded as having significant petroleum potential but since that time it has become Australia's largest onshore producing region (Paten, 1989). These observations emphasise the importance of tangible positive results, obtained by exploration drilling, to industry's perceptions of petroleum prospectivity.

Changes in geological knowledge and exploration technology, and the identification of new prospects, may result in the recognition of new resource potential.

- A recent scientific well (Site 764, Fig. 4.4), drilled as part of the Ocean Drilling Program (ODP), encountered Late Triassic reefs beneath Wombat Plateau at the northern edge of the Exmouth Plateau, offshore WA (Williamson & others, 1989). These are the first such reefs documented near the North West Shelf, a region already known to have excellent petroleum potential. Palaeogeographic reconstructions suggest that the reefs could be distributed widely along Australia's northwestern continental margin. Fossil reefs can be excellent petroleum reservoirs and are the main productive reservoirs in many major petroleum provinces (e.g. Golden Lane Province, Mexico, and Western Canada). These Late Triassic reefs may therefore constitute a new exploration target along Australia's northwestern margin. At this stage there is obviously a high degree of uncertainty as to whether these fossil reefs contain petroleum. A preliminary risked assessment suggests an additional resource potential of 50 million barrels.

- Most of the world's petroleum is located in relatively young rocks - Mesozoic and younger. The abundance of petroleum diminishes substantially as the age of the host rocks increases, reflecting the diminished chances of preservation of petroleum with advancing geological age. However, in two exceptional circumstances (Oman and the Siberian Platform), large reserves of indigenous petroleum occur in Proterozoic, i.e. comparatively old rocks. Several of Australia's

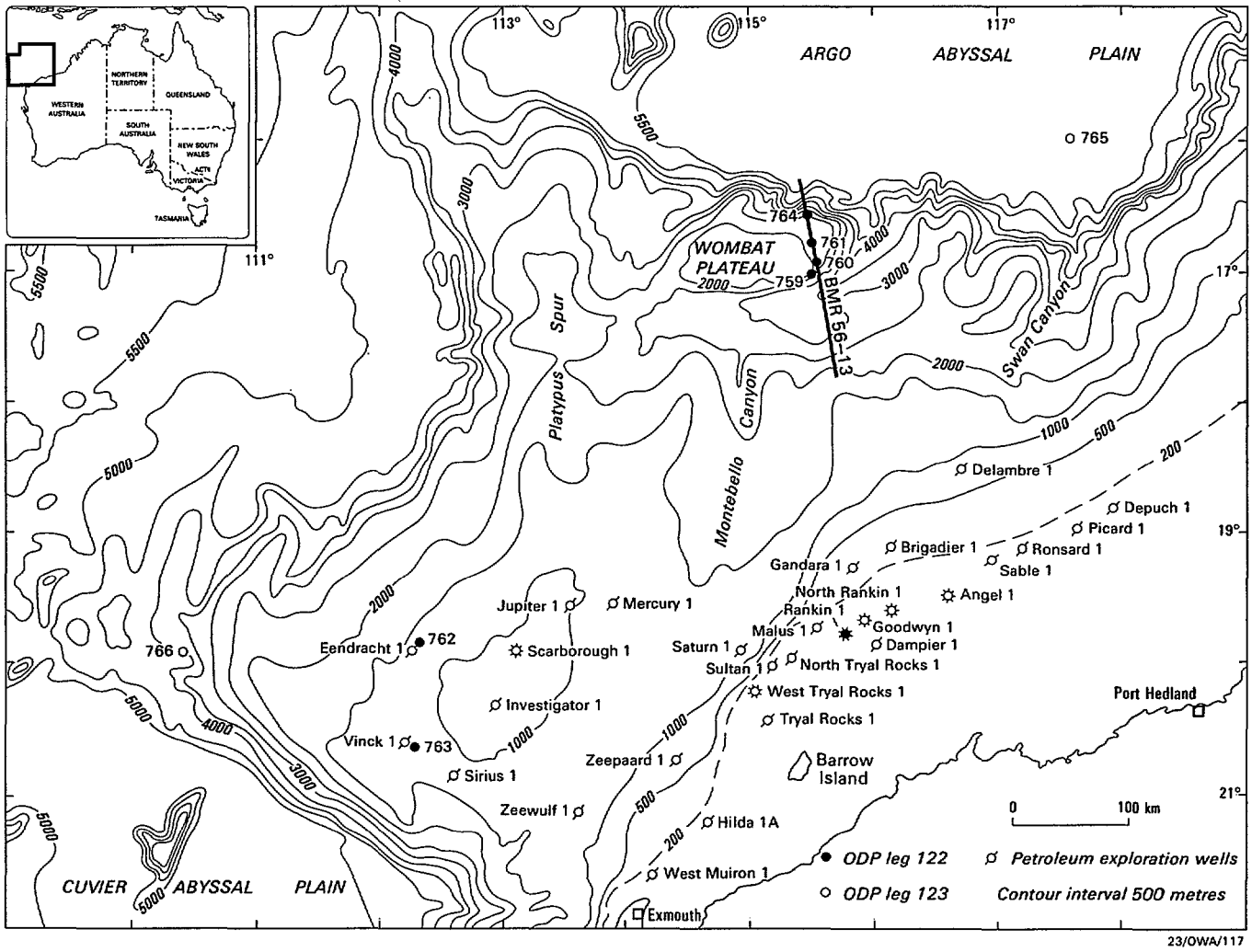

Figure 4.4 Location of ODP Leg 122 sites (including Site 764) on the Exmouth and Wombat Plateaus, northwestern Australia (Williamson & others, 1989).

onshore basins contain Proterozic strata. Also, these basins have been exceptionally stable over long periods of time, thus enhancing the chances of preservation of any petroleum that might have been formed. In fact, a small gas accumulation has been found in Proterozoic rocks of the Amadeus Basin in central Australia. Recent research in the Proterozoic McArthur Basin (Fig. 4.5) has established the presence of abundant petroleum source rocks and associated reservoir rocks, with the correct levels of thermal alteration for the generation and preservation of petroleum (Jackson & others, 1988). 'Live' oil shows have been encountered in stratigraphic drilling in the basin (Fig. 4.5). At this stage there is too little data on the size distribution of potential targets in the McArthur Basin to allow a quantitative assessment of resource potential and there remains considerable uncertainty over whether petroleum accumulations exist. Nonetheless, in a qualitative sense, new petroleum resource potential has been recognised, albeit of high risk.

The following observations by Paten (1989) show that at the low levels of geological exploration current in Australia, there is considerable scope for recognition of new petroleum resources.

. In 1977, at the First Queensland Exploration & Development Symposium, the following basins were identified as having perceived prospectivity: Surat/Bowen, Cooper, Georgina, Galilee, Adavale, Pedirka.

  Thus, Eromanga Basin, which has since been found to contain 70.3% of known initial commercial oil and condensate reserves in Queensland, was not identified as a prospective basin. The Georgina, Galilee, Adavale, and Pedirka Basins do not yet have commercial oil or condensate reserves.

. The current size distribution of Authorities to Prospect in Queensland is as follows:

Number	Area (km^2)
26	less than 1000
33	1000-4000
26	4000-16 000
5	16 000-32 000
6	greater than 32 000

Paten considers that although some of these larger areas contain several operating blocks, they are too large to be fully explored and properly evaluated.

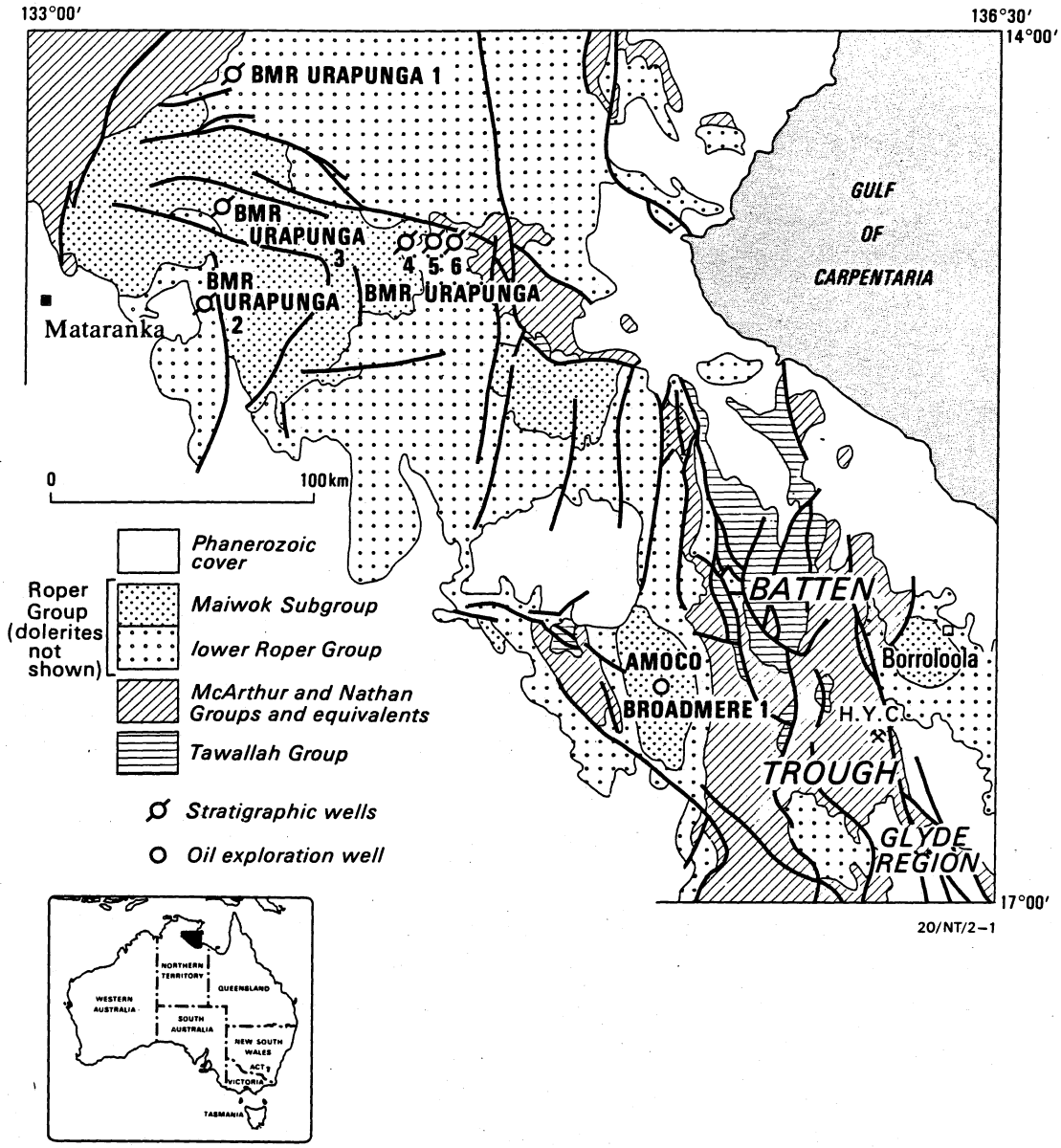

Figure 4.5 Simplified geology and locations of some stratigraphic and petroleum exploration wells in southern McArthur Basin (Jackson & others, 1988).

In Australia there has been too short a history of petroleum exploration and production to determine how estimates of prospectivity and production may turn out in practice. However, in the United States, where there has been a long history of petroleum exploration and production, estimates of ultimately recoverable oil have been consistently exceeded by actual production within about two decades of the estimate being made (Table 4.2). Although modern techniques of resource assessment are undoubtedly far superior to those used in the past, our state of knowledge is incomplete and necessarily leads to estimates on the conservative side.

Table 4.2 Estimates of US ultimately recoverable oil reserves vs actual production

Year	Estimate (billion barrels)	Cumulative production (billion barrels)	Year estimate exceeded
1909	10	5	1919
1921	18	15	1922
1941	100	50	1961
1947	110	60	1964
1949	100	65	1961
1955	155	80	1978
1961	175	100	1987
1965	200	114	
1967	203	121	
1969	205	127	
1973	225	139	
1980	245	159	
1982	250	164	
1984	235	168	

Data courtesy of BHP Petroleum Pty Ltd

4.4 Australia's prospectivity in world context

It is difficult to obtain a universal view of the prospectivity of Australia relative to other countries. The assessment presented in this paper suggests that there is a speculative potential for up to 5000 million barrels of oil to be found in Australia. This is in essential agreement with opinions published by Conoco (Patterson, 1985) and Esso Australia (1984). Patterson (1985) has ranked countries on the basis of total undiscovered reserves of oil (Table 4.3). Of the 15 countries considered to have a resource potential in excess of 15 000 million barrels, only one (Indonesia) is in the southern hemisphere. Among the 16 countries considered to have a resource potential of 3000-15 000 million barrels, Australia is ranked 7, i.e. 22 overall. A similar view of Australia's relative prospectivity was given by Riva (1988) (Table 4.4).

Table 4.3 Ranking of countries on basis of total undiscovered reserves (TUR) of oil in billions (10^9) of barrels (Patterson, 1985).

TUR > 15 billion barrels		TUR = 3-15 billion barrels		TUR = 1-3 billion barrels	
Rank	Country	Rank	Country	Rank	Country
1	USSR	16	Kuwait	32	Ivory Coast
2	Saudi Arabia	17	Angola	33	Guatemala
3	Iran	18	India	34	Spain
4	USA	19	Brazil	35	Chad
5	China	20	Oman	36	Colombia
6	Mexico	21	Egypt	37	Peru
7	Norway	22	**Australia**	38	Gabon
8	Iraq	23	Malaysia	39	Dubai
9	Indonesia	24	Div. Neut Zone	40	Sudan
10	Abu Dhabi	25	Argentina	41	Italy
11	Libya	26	Tunisia	42	Philippines
12	Canada	27	Qatar	43	Congo Republic
13	Venezuela	28	Syria	44	Ras-al-Khaimah
14	UK	29	Algeria	45	Afghanistan
15	Nigeria	30	Sharjah	46	Trinadad-Tobago
		31	Ecuador	47	Romania

Based on the estimates of Patterson (1985), Australia falls in the middle of the range of prospectivity, although it must be emphasised that the most highly ranked countries have a disproportionate share of the world's remaining oil resources (White, 1987) (see also Table 4.4).

Drilling density and prospectivity

The density of exploration drilling is sometimes used to demonstrate the degree of exploration maturity of a region. A low drilling density suggests that opportunities for discovery of new fields remain and, insofar as opportunities for petroleum occurrence remain untested, this is true. Conversely, a high drilling density can be used to suggest that many opportunities for petroleum occurrence are known and thought to exist. In practice, however, a high drilling density is typical of areas where incremental amounts of low-cost production can be identified, i.e. the probability of occurrence is high but the rewards are low.

Table 4.4 Oil Distribution of World Oil Reserves and Undiscovered Oil Resources (Riva, 1988)

Country	Cumulative production	1986 production	Proved reserves	R/P	Inferred reserves	Undiscovered resources	Total oil
	(In billion barrels of recoverable conventional oil)						
1. Saudi Arabia*	54.5	1.78	169.2	95/1	3.4	36.0	263.3
2. Soviet Union	94.5	4.49	59.0	13/1	22.0	77.0	252.5
3. United States	141.7	2.99	27.3	9/1	20.1	37.0	226.1
4. Kuwait*	24.3	.50	79.2	158/1	15.0	3.0	121.5
5. Iran*	35.0	.66	48.8	74/1	11.3	19.0	114.1
6. Iraq*	18.1	.65	47.1	72/1	3.6	35.0	103.8
7. Venezuela* & Trinidad	42.2	.67	25.6	38/1	14.1	15.0	96.9
8. China 12.6	12.6	.95	18.4	19/1	5.2	35.0	71.2
9. Mexico	13.7	.90	26.5	29/1	3.5	25.0	68.7
10. United Arab Emirates*	10.0	.50	33.0	66/1	12.7	5.0	60.7
11. Libya*	15.7	.38	21.3	56/1	4.6	6.0	47.6
12. Canada	12.5	.54	6.0	11/1	.8	27.3	46.6
13. Nigeria*	11.3	.53	16.0	30/1	3.2	7.0	37.5
14. Norway	2.4	.30	10.5	35/1	.2	17.0	30.1
15. Indonesia*	11.9	.45	8.3	18/1	.5	7.9	28.6
16. United Kingdom	6.8	.95	9.0	9/1	9.2	2.3	27.3
17. Algeria*	7.3	.22	8.8	40/1	2.5	1.5	20.1
18. Malaysia & Brunei	3.4	.25	4.1	16/1	.1	4.5	12.1
19. Egypt	3.9	.28	3.6	13/1	1.1	2.0	10.6
20. India	1.9	.23	4.2	18/1	2.0	2.5	10.6
21. Australia & New Zealand	2.6	.18	1.7	9/1	.3	4.0	8.6
22. Oman	2.4	.20	4.0	20/1	1.1	1.0	8.5
23. Brazil	2.0	.21	2.2	10/1	1.3	3.0	8.5
24. Argentina	4.2	.16	1.8	11/1	.5	1.7	8.2
25. Qatar*	3.9	.12	3.2	27/1	.4	0	7.5
26. Colombia	2.6	.12	1.3	11/1	1.2	1.5	6.6
27. Ecuador*	1.2	.10	1.7	17/1	.8	2.0	5.7
28. Peru	1.6	.07	.6	9/1	1.3	2.0	5.5
29. Tunisia	.7	.04	1.3	33/1	.5	2.0	4.5

* OPEC countries
Source: Oil & Gas Journal, 181/88, p. 59

In the US, about 3.3 million wells have been drilled. In Australia, which has a similar area, only 5400 wells have been drilled (the US surpassed this number in 1867). The Australian well database, on which geological knowledge is strongly dependent, is thus much smaller than that in the US. However, as indicated above, there is no direct correlation between number of wells drilled and petroleum prospectivity. The relation between the number of producing wells, reserves and production rate are illustrated for Australia, Saudi Arabi and the US in Table 4.5. In the US many oil pools are quite small and individual wells are not especially productive, and thus a large number of wells have to be drilled to discover the pools and effectively exploit them. In contrast, in Saudi Arabia, the wells are extremely productive and the fields are large.

Clearly, there is no simple relation between maturity of exploration, drilling density, prospectivity and level of production. Although Australia's prospectivity ranks behind that of the United States, the well density in Australia is still substantially lower than that required to properly address the issue of Australia's prospectivity.

Table 4.5 Comparison of production rate and well density in Australia, Saudi Arabia and USA

	Wells producing	Reserves	Production rate	Average rate per well
		billion barrels	million barrels per day	barrels per day
Australia	926	1.7	0.6	648
Saudi Arabia	588	170	4.7	7 993
USA	613 430	26.5	8.2	13

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5. RISK IN PETROLEUM EXPLORATION AND DEVELOPMENT

5.1 Introduction

The petroleum exploration industry differs from many other forms of business enterprise in the inherent uncertainty as to the outcome of exploration ventures. Given typical success rates of a 1-in-10 chance of discovering an oil pool, the exploration effort represents a large sunk cost before the financial rewards of any discovery can be defined. Further, exploration costs are extremely variable depending on whether exploration is offshore or onshore and whether in remote or established exploration areas. As a result of this inherent uncertainty, the oil industry has evolved sophisticated quantitative procedures for comparing the risk, potential returns and cost of exploration ventures. Of course the degree of sophistication which is applied to this analysis varies enormously within the oil exploration industry.

Exploration ventures are usually assessed on the basis of risked net return measured against the cost of an unsuccessful outcome. Concepts of Net Percent Value (NPV), Rate of Return (ROR) and Profit to Investment (P to I) are all used. The relative risks of projects do not directly affect the ranking, which is measured by the expected (risked) outcome of possible alternative activities which may be exploration ventures or other business opportunities.

A portfolio of exploration ventures reduces the overall risk of total failure when compared with the risk of any particular venture. The overall risk of unsuccessful results is reduced by spreading risk (diversification) over a variety of opportunities. The relative chance of overall failure is likely to fall as a greater number of separate ventures are undertaken. Management of risk can therefore be regarded as a strategic consideration related to the financial goals of the exploration enterprise itself. For an exploration enterprise, therefore, there is a requirement to maintain a balanced portfolio of ventures that covers all risk/reward scenarios commensurate with the objectives of the enterprise, but does not leave the particular company unnecessarily exposed to high risk. Companies may therefore seek partners to explore a particular region (farm out) in order to reduce their exposure to risk. They may also participate in other companies' projects (farm in) in order to increase their overall chance of success. As a result of this requirement large petroleum companies operate world-wide whilst smaller companies may attempt to diversify by not confining their activities to a particular region. For example, Patterson (1985) has outlined the evaluation process

used by Conoco Inc on a world-wide basis, to assist in the development of an international investment portfolio. The basic objective of the process is to 'evaluate continually new opportunities for international exploration in a systematic manner'. The analysis focuses on a comparison of the technical merits, cost environment, political/economic environment and contract terms for every area of interest. Whereas many large companies set about risk assessment in a sophisticated manner, many smaller companies do not explicitly analyse risks.

5.2 Sources and Nature of Risk

The risk in petroleum exploration and development incorporates geological, economic, political and technological elements.

. **Geological risk** incorporates all the elements of uncertainty related to prospectivity. It can only be fully assessed by acquiring a detailed scientific understanding of the factors which affect the generation, migration, entrapment and preservation of petroleum in the target area. In turn this influences the process of petroleum exploration and the discovery of accumulations. If the geoscientific understanding of a region is poor the risk associated with petroleum exploration is large.

  Historically in Australia, the chance of an exploration well discovering a commercial field has been around 10%, although it is highly variable from region to region (Forman, 1988). The success rate (proportion of wells discovering petroleum) is often used as a measure of the geological risk in an exploration region. This may be a distortion of the risk if exploration is concentrated in a region where resources are already identified. Large fields tend to be found first (Meisner & Demirmen, 1981). Because oil fields occur in clusters, locating the first field focuses attention and makes others in the cluster easier to find. Continued exploration eventually yields diminishing returns (Meisner & Demirmen, 1981; Amensen 1988). The success rate may be high but the number of barrels of oil reserves discovered per well is generally low. Conversely if exploration expands to less well explored regions the success rate may decrease, but in the event of a discovery there is a significant chance that the barrels of reserves discovered per well will be substantially higher.

  Any process which concentrates exploration in low risk areas will enhance success rate, but may not encourage optimal exploration for the large resources.

Success rate is only a measure of the effectiveness of exploration and the geological risk if it is considered in the context of the target resource for exploration. It is therefore more appropriate for analysis to consider risked reserves, the product of the probability of successful exploration and projected reserves, i.e. the discovery rate.

- **Economic risk** incorporates uncertainty related to the price of oil, exploration and development costs and the general economic climate in which the petroleum products are sold. This is usually expressed in terms of the 'finding cost per barrel of oil' and the 'development cost per barrel of oil' (McCammon, 1988). Figure 5.1 describes the relationship between 'finding' and 'development' costs and investment returns for a hypothetical offshore oil discovery. There is a risk of enhanced costs over those projected.

From the point of view of the exploration company, there is an additional risk of finding gas rather than oil. Discovery of gas elicits an economic penalty because of constraints in development and marketing of gas rather than high producing oil fields. Thus the North West Shelf Gas Project took some 15 years to bring to fruition compared with only a couple of years for production from the Jabiru Oil Field in the northwest offshore. In addition, in order to realise a profit from gas development, lower finding and development costs have to be achieved than for an oil field of similar size (McCammon, 1988). This arises from the fact that in Australia, gas commands a lower price per calorific value than oil. Further, gas production is market limited and so production levels as a percentage of reserves are low in the early years when compared with oil. Oil which can be readily sold is produced more quickly and the return of funds is consequently earlier than in the case of gas.

- **Political risk** incorporates elements of political stability, but also includes perceptions of the stability of the licensing or taxation regime under which the oil is produced (McCammon, 1988).

  Frequent changes in policy, or unusual policies, lead to enhanced risk because of the long lead times involved in petroleum exploration or development. These not only relate to financial matters, but also may relate to environmental issues wherein development of a discovery may be delayed or deferred indefinitely. In circumstances of high political risk, rapid development of resources in a non-optimum way is encouraged and/or only projects with short payout periods may be undertaken.

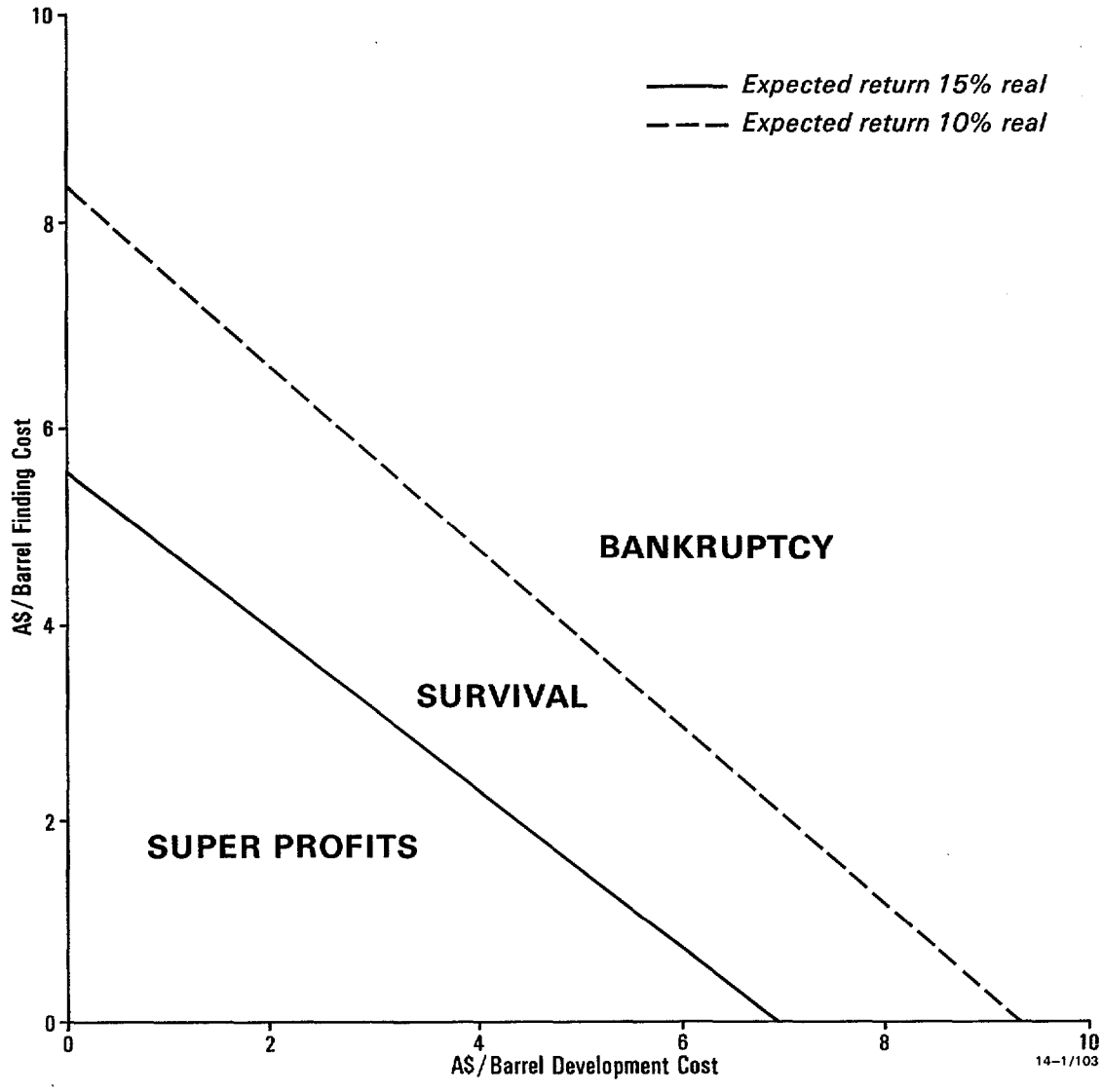

Figure 5.1 Relationship between finding and development costs and investor returns: offshore oil discovery (McCammon, 1988). The curves show the point of indifference for the investor who has decided that an expected rate of return of (i) 15% and (ii) 10% on funds is necessary to compensate for the risk involved. In this case, the assumptions are an oil prise of US$20.00 per barrel, a nominal 50 million barrels recoverable find and no secondary tax applicable at the point of indifference. If finding costs of $3.00 per barrel are realised, the development costs would have to be held below $3.00 per barrel to achieve a 15% return, but could drift as high as $6.00 per barrel if only a 10% return were required. (Reproduced with permission of the Australian Petroleum Exploration Association.)

- Canadian exploration underwent a significant downturn in the early eighties as a result of a period of change in government policies which resulted in changes in perceived political risk.

. **Technological risk** incorporates uncertainty regarding the ability to effectively explore for and exploit resources in a particular area because of technological factors, for example water depth, seismic resolution, drilling difficulties, weather and ocean conditions or measures to protect the environment.

5.3 The exploration and development process

'Successful exploration of a likely part of the earth for its content of petroleum relies on knowledge of the geological history of the sedimentary basins of that area. Armed with that knowledge, it is usually possible to identify particular parts of a basin where conditions for the processes of petroleum generation, migration, and entrapment appear to be right. But Nature never reveals all her secrets at once. Earth scientists improve their understanding of the earth's history by successive approximations. Ideas are drawn from the available data and eventually tested by the drill. The results obtained most likely show how inadequate or incomplete were the original notions. Of vital importance to exploration nevertheless, those results are assimilated into the general body of knowledge to produce a new and more accurate idea of where to look next. Such has been the story of exploration for oil and gas throughout the world' (Evans, 1988).

The demonstrated success of geoscientific concepts in reducing the risk associated with costly exploration ventures underlies the modus operandi of the exploration industry, although it is important not to underrate the role of serendipity in many exploration successes. Exploration is often unsuccessful in the early stages, and it may require numerous attempts by several operating groups before the key to exploration success in a potential region is found. Over 100 wells were drilled in the North Sea before oil was found.

An exploration venture is in essence a carefully planned series of activities to determine whether petroleum accumulations are present in an area and whether they are productive enough to be of commercial value (Fig. 5.2). The program is designed to gather information in order minimise risk of unsuccessful expensive wells. Thus in order to adequately explore an area, an exploration budget needs to be allocated usually to carry out a sustained seismic and drilling program over a number of years. Exploration, including the drilling of new wells, is

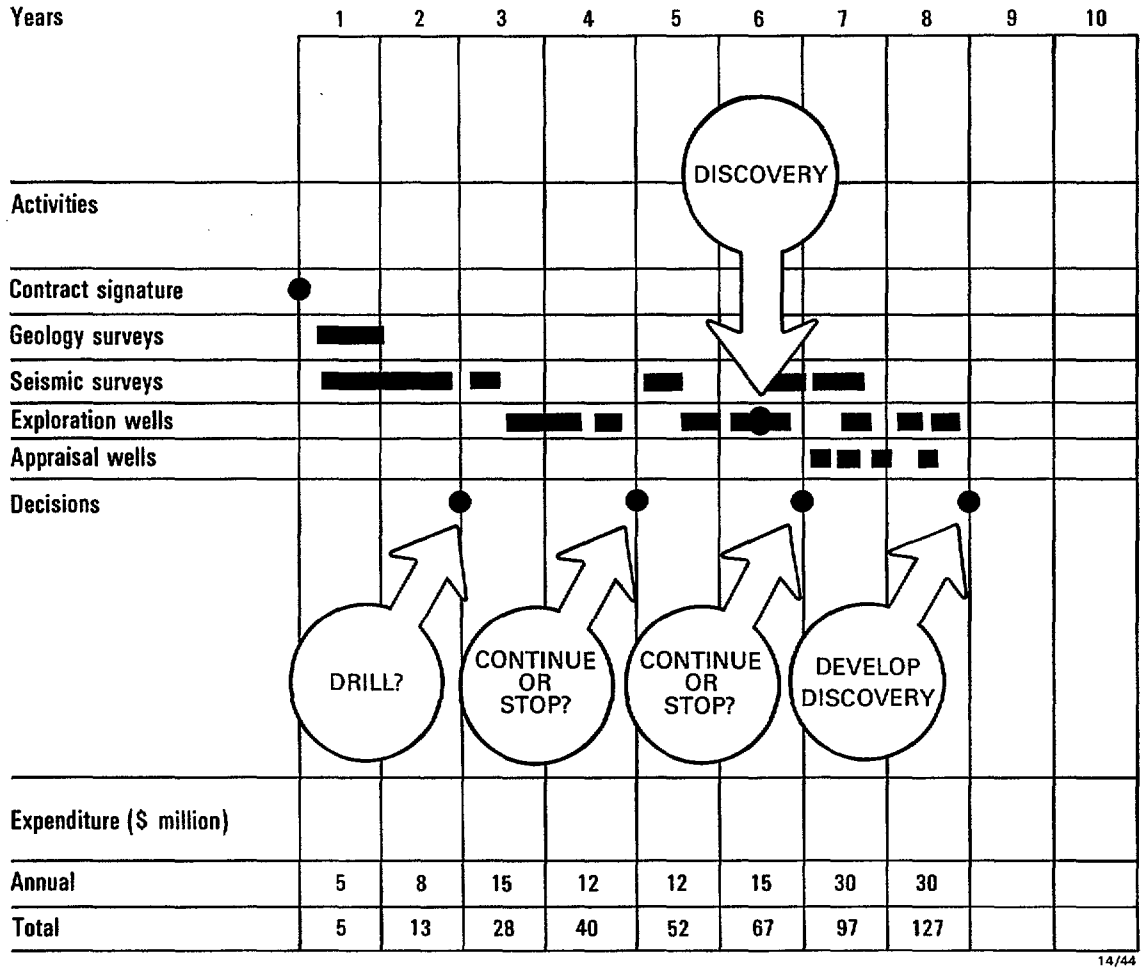

Figure 5.2 A typical exploration programme (Kessler, 1984; reproduced with permission of St. Martins Press).

funded from revenue raised by the exploration group either from the sale of hydrocarbons or from funds injected from outside.

- Initial activities typically involve consideration of available geoscientific data on the likely potential of areas that might be petroleum-bearing. Additional geological and geophysical surveys are then conducted to determine whether there are large enough prospects to contain a significant volume of petroleum. The assessment of possible petroleum potential is strongly focused on deciding whether a particular prospect could contain a sufficient volume of hydrocarbons to warrant drilling. Geological considerations include prospect size, appropriate geological history and presence of associated source, seal and reservoir facies. Ideally the sequence in which prospects are drilled also contributes incrementally to the geological knowledge base and the evaluation of the area. A typical exploration scenario is illustrated in Figure 5.2. The chances of success in drilling a prospect are typically estimated from available geoscientific data as well as the use of subjective estimates of unknown variables. Simulation techniques are often employed to assess the likely outcome of the various geological processes which might lead to the accumulation and preservation of a major petroleum accumulation (White, 1987).

A constraint on the level of exploration is the availability of exploration funds, which reflects in part the economic climate for exploration. The effect of a shortage of exploration funds is to lower the general level of exploration and to concentrate efforts in low risk-lower return prospects rather than the higher risk, frontier areas where returns are potentially high.

- In established companies revenue from production is used to fund exploration. The profitability of production including the tax regime thus has a direct bearing on the availability of funds for exploration. The cost of exploration is nonetheless relatively small compared to the gross revenue from a commercial field.

- The cost of maintaining a sustained exploration programme to ensure future discovery and consequently future production income is, nonetheless, a factor in setting the required target rate of return on a field. Its effect as a percentage will thus relate to the cost of the exploration programme compared with the net capital expenditure in developing the field. Thus if mainly smaller fields are discovered this percentage will be higher unless distorted by the tax regime.

- Frequently the source of funds for exploration in a given area is derived from income which has its origins outside of that area or even country. Consequently any constraints on the use of exploration funds may inhibit effective exploration of a region or group of regions

  - The Resource Rent Tax regime, for example, encourages a company to explore for new fields in the same permit area in which it has production because of deductibility considerations, even though such fields may be marginal outside of the RRT area.

When a discovery is made the well control and seismic data are used to estimate the reserves of the field on the basis of proven and possible reserves. If the reserves could be high enough to support commercial development, additional seismic analysis may be carried out and appraisal wells drilled to establish that a sufficient hydrocarbon accumulation is present.

- At this stage there can be considerable uncertainty as to the reserves and productivity of a field. This uncertainty can continue well into field development and production since reserve figures frequently vary as operating data are collected, altering the original estimate (McCammon, 1988; Fig. 5.1). Thus it is difficult to derive a unique number for reserves of a field in the early stages of development. Whilst project economics require that proven reserves exceed a certain threshold, the total potential for a field may be presented as a probability curve (McKay & Taylor, 1979; Fig. 5.3), although many companies use only single number estimates. The fluctuating reserve estimates of fields at various stages of their appraisal and development has been illustrated recently in Australia by the history of published reserves estimates for the Jabiru Field which have varied widely at various stages of field appraisal and development.

After appraisal, the economic viability of a field is established by forward looking project economics. Critical factors include projected production rates, sale price of hydrocarbons, capital expenditure, operating expenses and tax regime.

- The decision to develop a field depends on a number of criteria including the rate of return meeting a target rate of return on forward investment. This is normally a discounted rate of return between 15% and 25%. Other procedures used in determining the financial viability of a field include discounted Net Present Value, Payback Time and undiscounted cash flow.

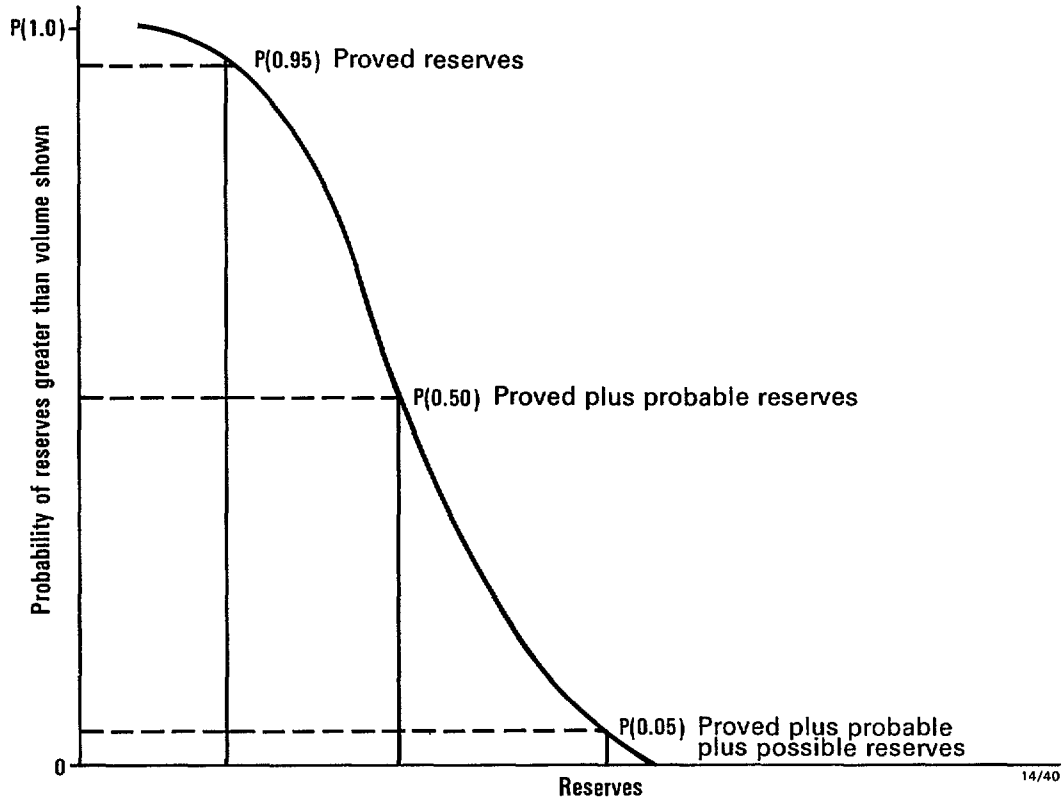

Figure 5.3 Typical probability distribution curve indicating potential for use in defining 'Proved', 'Proved Plus Probable' and 'Proved Plus Possible' reserves (McKay & Taylor, 1979; reproduced with permission of the Australian Petroleum Exploration Association).

- In general the most economically favourable fields in a company's portfolio will be developed first. Pressure from operators of jointly-held acreage can cause some modification to this premise.

  - The ability to develop a field also depends on the cash flow of the company and its ability to raise funds.

- The costs incurred during exploration do not enter directly into the decision to develop a field unless it impacts the cash flow from production of the field, for example in a positive way as an expense for tax purposes. If it is profitable to complete a well and put it on production on a 'money forward' basis, this will be done even if the drilling cost renders the entire venture unprofitable.

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6. LEGISLATION FOR EXPLORATION AND DEVELOPMENT

6.1 Introduction

Optimal exploration occurs where a wide diversity of exploring companies is encouraged and new ideas and capabilities are continuously brought to bear on the search for, and the development of, petroleum resources. Consequently, the manner in which governments control the activities involved in exploration and development is of critical importance to the achievement of this optimal situation.

In Australia, petroleum exploration and development, both onshore and offshore, was controlled by the Petroleum Acts and Ordinances of the individual States and Territories until November 1967, when joint Commonwealth/State legislation (Petroleum (Submerged Lands) Act) governing the offshore* area came into force. Onshore activity continued to be controlled by the individual States. A Commonwealth-funded subsidy scheme, for both onshore and offshore operations, operated from 1957 to 1974.

This chapter examines the effectiveness of the subsidy scheme, and of the current joint Commonwealth/State offshore legislation in helping to promote an optimal level of exploration and development since the late 1950s. It also refers to certain recent State initiatives in legislative systems, and draws some comparisons between Australian policies for the offshore area and those adopted to manage the resources of the North Sea UK Continental Shelf.

The distribution of exploration wells drilled prior to the introduction of the subsidy scheme is shown in Figure 6.1, and of wells drilled with subsidy, in Figure 6.2. Subsidised and other exploration wells drilled since 1957 are shown in Figure 6.3.

6.2 The Subsidy Scheme 1957-1974

The introduction by the Commonwealth Government of the Petroleum Search Subsidy Act (PSSA) in 1957 marked the beginning of the 'modern' phase of petroleum exploration in Australia. Before the introduction of subsidy

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* The offshore area covered by Commonwealth legislation does not include areas within the Territorial Sea (i.e. within three nautical miles from the coast). It does not include Barrow Island, Harriet, Saladin and some other offshore oilfields in Western Australia.

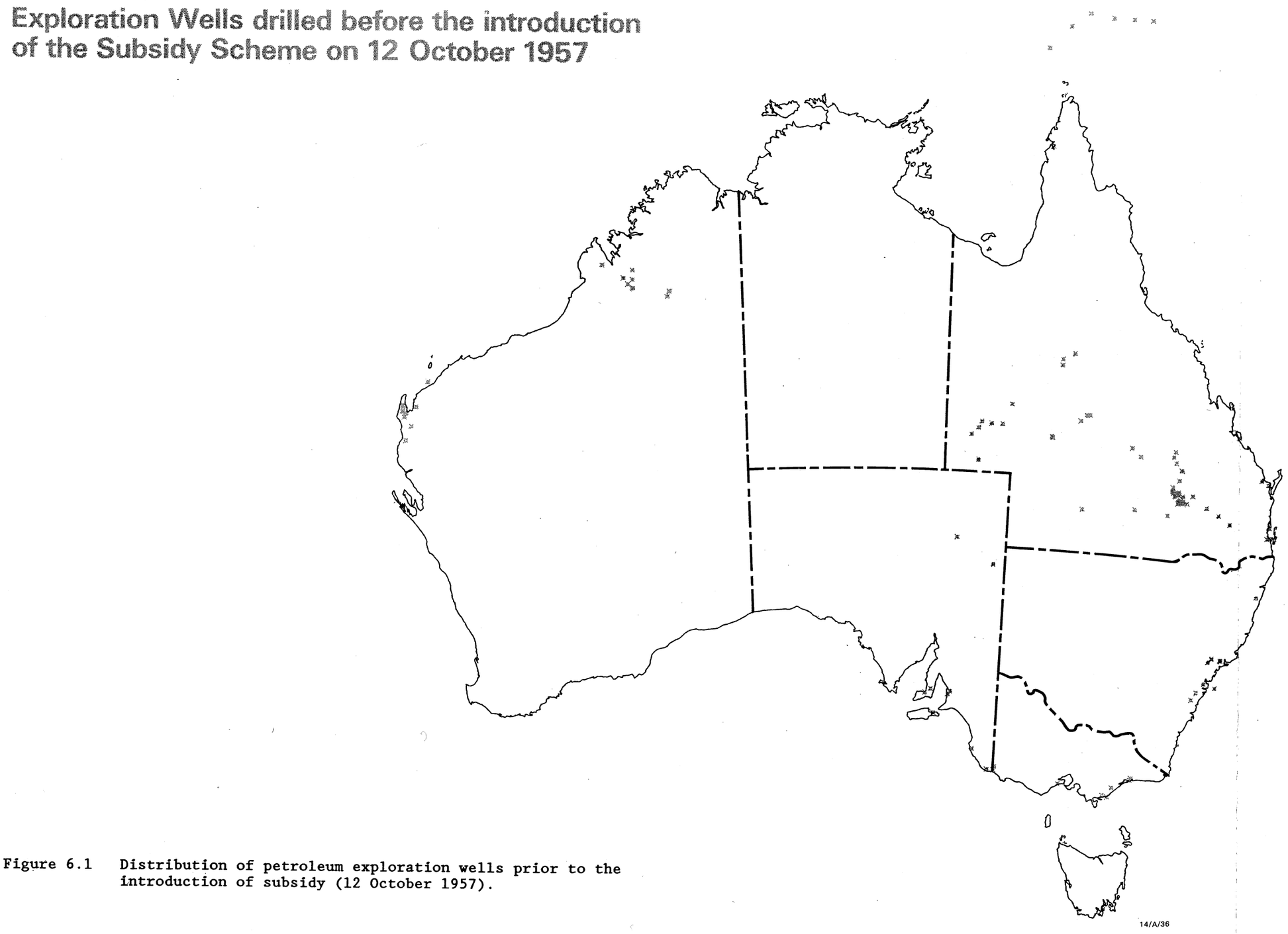


Figure 6.1 Distribution of petroleum exploration wells prior to the introduction of subsidy (12 October 1957).

Subsidised Wells 1957–1974

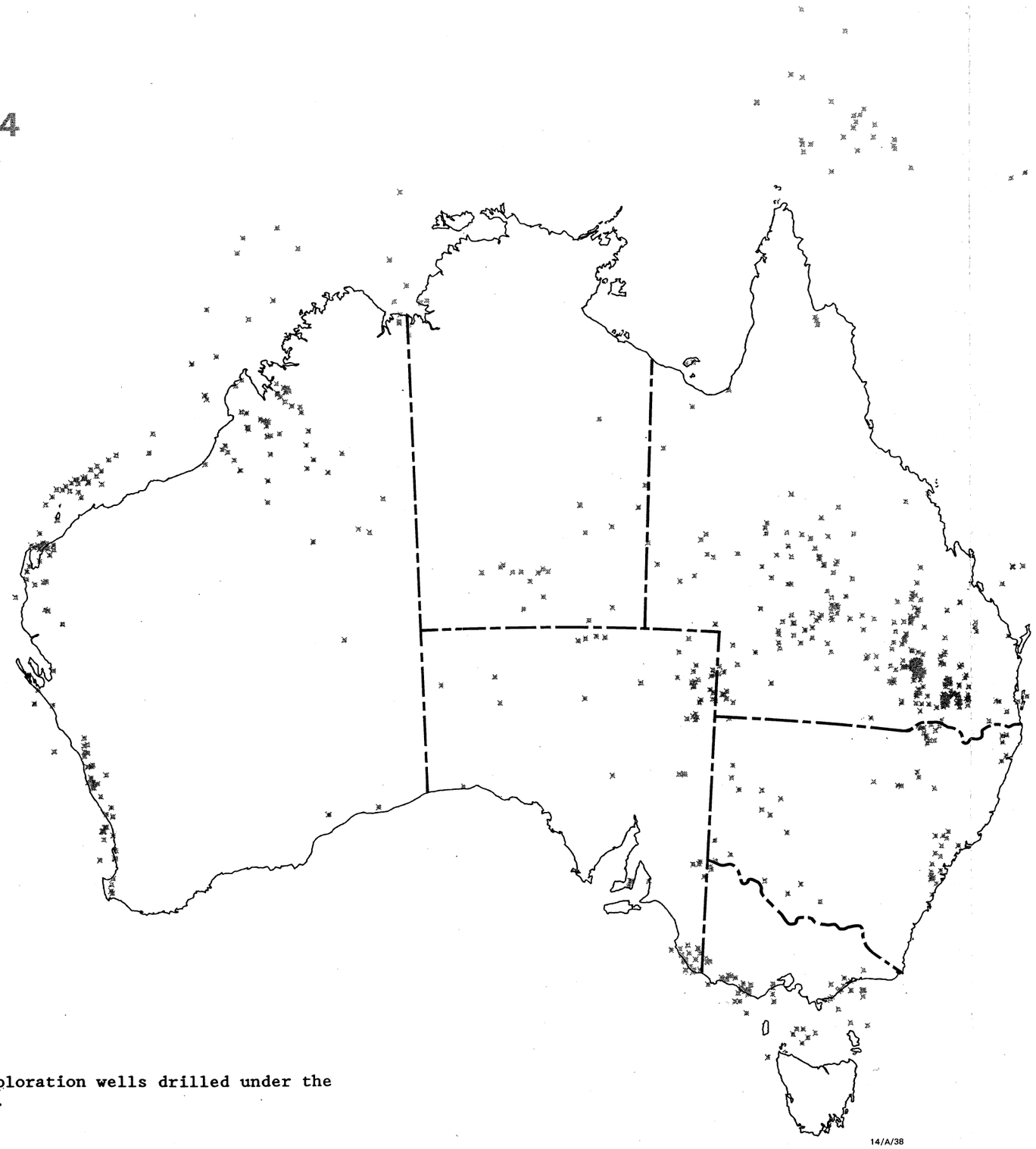


Figure 6.2 Distribution of petroleum exploration wells drilled under the Petroleum Search Subsidy Act.

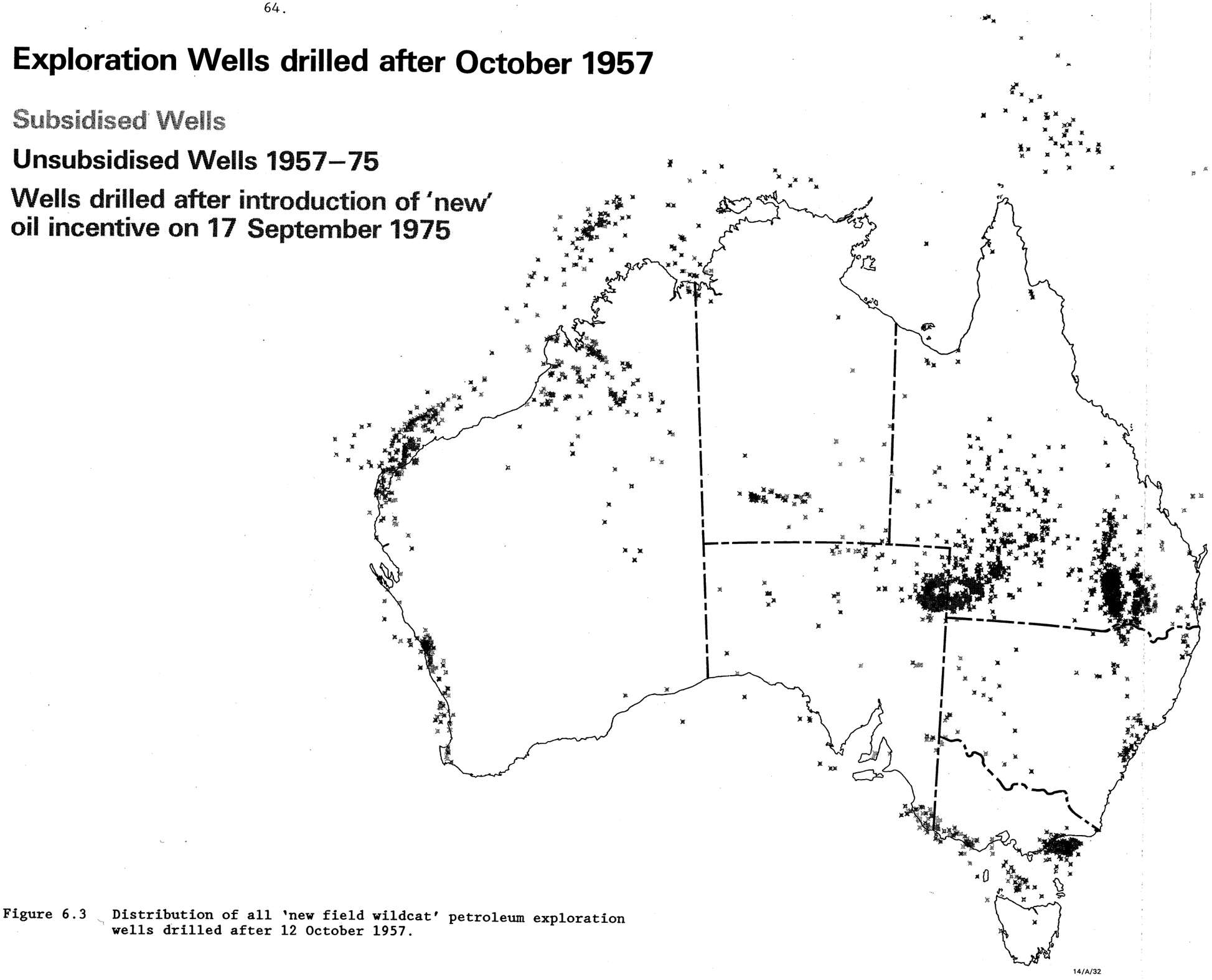


Figure 6.3 Distribution of all 'new field wildcat' petroleum exploration wells drilled after 12 October 1957.

the most encouraging event had been the discovery of oil in the Rough Range-1 well in the Carnarvon Basin, Western Australia in 1953. This event initially produced a dramatic increase in the total level of exploration in Australia (Fig. 6.4). However, activity soon declined when there were no further discoveries, and by 1957 interest in Australia's petroleum prospectivity was waning and money for exploration was difficult to raise. The Government sought to rekindle interest and stimulate exploration by providing financial assistance to exploration companies through the subsidy legislation, and by increasing the basic geological and geophysical work being carried out by the Bureau of Mineral Resources. The distinguished American consultant geologist, Dr A.I. Levorsen, together with Dr Harold Raggatt, then Director of the BMR, played a significant role in encouraging the Government to develop a subsidy scheme, believing it would speed both the discovery of petroleum, and the accumulation of publicly available geological information on Australia's sedimentary basins (Sprigg, 1975). Details of the development of the scheme are outlined in Appendix C.

The introduction of subsidy did not produce an immediate increase in the level of drilling activity (Fig 6.4). The breakthrough came in 1961 with the discovery of oil in the Cabawin-1 and Moonie-1 wells, south of Roma in Queensland - Moonie becoming Australia's first producing oil field in 1964. In South Australia, the first of the major Cooper Basin gas discoveries was made in 1963 by the Gidgealpa-2 well, and in the same year, the Mereenie gas and oil field was discovered in the Amadeus Basin in the Northern Territory. In mid-1964, Western Australia's first commercial oil field was discovered on Barrow Island. At the end of 1964 came a milestone in Australia's exploration history with the spudding of the first offshore well, East Gippsland Shelf-1 (re-named Barracouta 1), in Victorian waters in the Gippsland Basin. In January 1965 the well made a gas discovery of 'giant' size by world standards. Discovery of a second 'giant' gas accumulation, the Marlin field, followed a year later. Small oil accumulations were also found in these fields. The major Halibut and Kingfish oil fields were discovered in 1967.

Opinions expressed at the time indicate that the subsidy scheme was widely considered to have made a major contribution to the level and quality of petroleum exploration in Australia (Traves, 1962; Rudd, 1966; Rayner, 1969; Williams, 1974; Sprigg, 1975). The financial assistance greatly increased the work capacity of the companies, particularly of the smaller ones, and the administrative requirements of the legislation had the

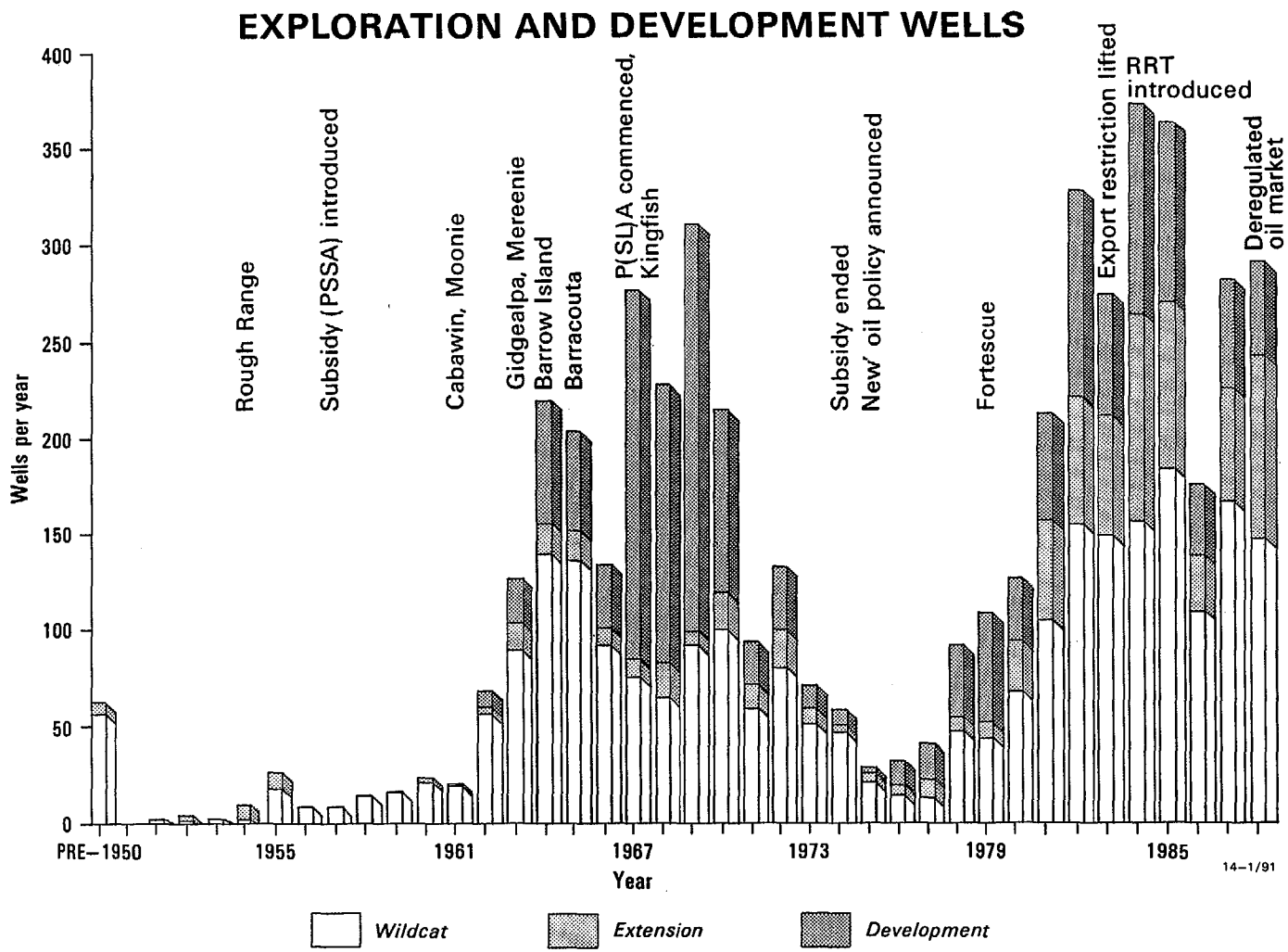


Figure 6.4 Distribution of exploration and development wells through time.

effect of raising the technical standard of exploration operations in Australia, and helped to promote the drilling of wells to depths adequate to fully test the prospective section. The public availability of properly documented data, including cores and cuttings, six months after completion of the operations was also a major factor in encouraging companies to explore in Australia.

Fifteen years after the end of subsidy, it is possible to speculate, with the benefit of hindsight, on the effects of the scheme.

Reviewing the effects of subsidy in the Cooper/Eromanga Basins, Lavering & others (1986), point out that all the petroleum exploration carried out in these basins from 1959 to 1964 was subsidised, and that the scheme 'critically influenced the decision by Delhi-Santos to initiate major exploration work in the region and the subsequent course of those activities.'

Falvey (1990) provides a very recent comment on the effects of the scheme stating that 'Whilst it is perhaps difficult to conclusively draw a causative relationship, certain technical and commercial attitudes clearly changed between the 1950's (when drilling levels were around 10 wells per year) and the early 1960's (when they were around 150 wells per year). Perceptions of Australia's prospectivity before subsidy were of a geologically ancient continent with little or no subsurface data from its then known sedimentary basins to suggest any significant oil generation or preservation. The assigned risk in exploration ventures at the time was, therefore, very high. Subsidy helped reduce the sunk cost of initial exploration on any given prospect and thus effectively helped spread the investment risk. The outcome was more geographically widespread drilling, leading to more openfile data on the subsurface geology of a wide range of Australia's sedimentary basins. The availability of such data further encouraged more scientifically based exploration. BMR's view is that the Scheme was, at least in part, responsible for initiating the current and so far successful phase of Australian exploration and development.'

The wide distribution of wells drilled under the subsidy scheme (Figs. 6.2 & 6.3) contrasts with the 'clustering' of wells drilled after the subsidy scheme was discontinued (Figs. 6.1 & 6.3). This suggests that some form of incentive may be the only way to encourage wildcat exploration in frontier areas and areas where little information is available.

6.3 The Petroleum (Submerged Lands) Act

Award of Exploration Permits and Production Licences

Exploration Permits

From 1967 to 1985 the work program bidding system was used as a basis for the award of Exploration Permits. It incorporated a commitment to the monetary value of the proposed exploration program, but did not commit the permittee to a guaranteed work program. This led to frequent failure on the part of the successful bidders to carry out the programs proposed in their applications, as illustrated by the following examples.

- Two permits were awarded in the Gippsland Basin in 1979 covering together 64 blocks (about 4288 km^2); only one well of the combined total of four initially proposed, was drilled during the six-year permit terms.

- In the Bass Basin, three permits were awarded in 1980/81 covering a collective area of 292 blocks (about 19 564 km^2). Each were held for the full six-year permit terms with only three wells drilled of the combined total of eight originally proposed.

- The Otway Basin and Great Australian Bight Basin (GAB) provide the most striking examples. In the Otway Basin, seven permits awarded between 1980 and 1985 and covering collectively 395 blocks (about 26 465 km^2) were relinquished before the end of the permit terms; only two wells were drilled of the total of 18 initially offered. Six permits in the GAB Basin awarded between 1979 and 1982 and covering a total of 1847 blocks (about 123 750 km^2), were relinquished with only two wells drilled of the total of 17 initially offered.

Details of the modifications made to the system in 1985 are given in Appendix C. Briefly, under the modified system, permits are awarded on the basis of a minimum work program which must be guaranteed for the first three years of the six-year permit term. The program for the second three years is, to some extent, negotiable.

As under the previous system, the permittee may renew the permit at the end of the initial six-year term. The first, and subsequent renewals are for five years, and half the area must usually be relinquished on each renewal.

The modified system appears to be a more satisfactory way of ensuring reasonable yet realistic bids for Exploration Permits. There has been a good response from industry, with only a small number of areas attracting no applicants. The following are two examples of awards made under the modified system. The marked contrast between the minimum work program commitments in the two examples reflects differences in the level of previous exploration activity and the amount of information available.

- In 1987, eight permits covering about 12 470 km^2 were awarded in the Gippsland Basin. This was the first release in this relatively mature basin since 1981. The successful applicants collectively committed to carry out a minimum 7020 km of seismic surveying and drill 16 wells in the first three years of the permit terms.

- Also in 1987, five permits, two in the Otway Basin, one in the Carpentaria Basin, and two in the Browse Basin, were awarded, covering a much larger (about 52 460 km^2) total area than the Gippsland Basin permits. The more cautious attitude of the explorers in these immature areas is reflected in the guaranteed minimum work programs offered: a collective guaranteed minimum seismic commitment of 6000 km, and one well.

Another Government initiative in 1985 was the introduction of a cash bidding system for certain areas considered to be highly prospective. Permits are awarded for six years to the highest cash bidder, provided they satisfy criteria of technical competence and financial viability.

- There has been only one release to date of vacant areas under the cash bidding scheme. In 1985, five areas were offered in the Territory of Ashmore and Cartier Islands in the Timor Sea (Bonaparte Basin). The areas were close to the Jabiru and Challis fields, and three of them were awarded to the highest bidders in April 1986.

  During the four years since the permits were awarded, the consortium which holds two of the areas (covering a total of 47 blocks (about 3900 km^2)) has carried out in excess of 4300 km of seismic survey, a geochemical 'Sniffer' survey of some 100 km and has drilled six wells. In the third area, which covers 17 blocks (about 1400 km^2), the permittees have carried out some 800 km of seismic survey and drilled one well.

Although it is encouraging that the permittees have not delayed embarking on active exploration of the cash bidding areas, the level of activity is

probably no greater than would have been expected in these areas under the modified work program bidding system.

This is illustrated by the guaranteed minimum work program commitments made for the first three years in three permits awarded more recently (February 1989) in the Timor Sea. In the first three years, permittees have committed to the following programs.

- 6000 km of seismic survey and four wells in a 46 block permit.
- 4325 km of seismic survey and four wells in a 30 block permit.
- 1000 km of seismic survey and six wells in an 18 block permit.

The latter two permits substantially cover the two areas that were not awarded in the cash bidding release because of the unsatisfactory level of the bids.

Production Licences/Retention Leases

Production Licences are awarded over discoveries that can be developed in the short term, and Retention Leases over discoveries which are non-commercial at the time of application, but which are expected to become commercial within 15 years.

The acquisition of a licence/lease requires an initial nomination by the permittee of an area around the discovery referred to as a 'location'. The permittee then has up to two years (which may be extended for a further two years) in which to apply for either a Retention Lease or a Production Licence (see Appendix C). The term of a Production Licence is for 21 years and the Licence can be renewed for a further 21-year period.

Under the regulations governing the award of locations prior to 1987, there was the potential for a Production Licence to extend significantly beyond the area of the discovered field. The regulations normally required a location to contain nine graticular blocks, and all nine blocks could potentially be included in the subsequent Production Licence.

As Production Licences, unlike Exploration Permits, are not reduced in area with time, and do not require guaranteed exploration commitments, they can have the effect of reducing wildcat exploration relative to the level expected in a competitive situation, and of 'sterilising' large areas for very long periods (42 years) from activity and new ideas in exploration and development. The following examples of licences awarded before 1987 illustrate the point.

- In the Gippsland Basin, an area of 3380 km^2 is held under 14 Production Licences (at 1 January 1989). Four of these licences held since 1967, and four held since 1968, cover together an area of 2340 km^2, and have recently been renewed for a further 21 years.

- The major Northwest Shelf natural gas project in the Carnarvon Basin involved the granting of Production Licences in 1980 covering a total area of some 2240 km^2.

- In the Timor Sea, Production Licences granted in 1985 for the development of the Jabiru and Challis fields cover a total area of some 1160 km^2.

Under the amended regulations introduced in 1987, the Joint Authority must be satisfied that the graticular blocks nominated for inclusion in a location do not extend beyond the known extent of the pool(s) discovered.

The absence of competitive development opportunities in Production Licences means that if a licence holder does not wish to develop additional discoveries within the licence area, in particular smaller or more complex accumulations, alternative operators who may be willing and capable of developing them are excluded. As innovative ideas for development (particularly low cost development) have arisen from smaller or independent operators, this can restrict development and delay production of known resources.

One way of avoiding this situation is to limit the term of production licences (e.g. to 20 years, as in Malaysia). Another is to allow other operators to develop accumulations not considered economic by the licence holder.

The Retention Lease option is another relatively recent innovation introduced in 1984 to enable a permit holder to maintain tenure over a non-commercial discovery, other than by retaining the permit indefinitely or taking out a Production Licence with immediate development obligations. Leases are awarded for five years with renewal options, and are intended for discoveries which are not commercial but with a reasonable probability of becoming commercial within fifteen years (see Appendix C). To date, the only Retention Lease awarded is over the giant remote deep water Scarborough gas field on the Exmouth Plateau, Western Australia.

Release of data

One of the most important contributing factors to successful exploration activity is the public availability of data from wells and geophysical surveys. Recent amendments (1985, 1987) to the offshore legislation, detailed in Appendix C, have greatly improved the situation in this regard. Previously, basic data were kept confidential for five years, unless the permit became vacant, and interpretive data could only be made public by the permit holder. As a result of the amendments, basic data can now be released after two years, and interpretive data after five years subject to certain safeguards.

6.4 Special provisions for exploration

Certain special provisions in the Petroleum (Submerged Lands) Act can also assist in promoting exploration activity.

Special Prospecting Authorities (SPA's) allow petroleum exploration activities other than the drilling of wells, to be undertaken by companies in vacant areas as a preliminary means of assessment prior to a more permanent exploration title being applied for. The SPAs are restricted in time to six months, and an important feature of them is that several can be granted over the same area at the same time, thus increasing the number of operators with access to new data. SPAs can also be used by commercial services to acquire data on a speculative basis, a common practice overseas but less so in Australia.

Organisations engaged in scientific research into the physical or biological characteristics of the continental shelf may be given approval to carry out Scientific Investigations related to petroleum explorations in both vacant areas and areas covered by title. The investigations may include the drilling of stratigraphic holes, but not of petroleum exploration wells. The details and results of Scientific Investigations must be openly published. In this respect they differ from SPA's which are covered by the conditions governing the release of data in exploration permits.

Access Authorities allow titleholders to undertake petroleum exploration or development work (except drilling) in areas immediately adjacent to their title area. Access Authorities may be issued for a vacant area, or for an area covered by a title with the concurrence of the titleholder. In the latter case, the holder of the Authority must provide the titleholder with a full report of the activities and data acquired within the area accessed.

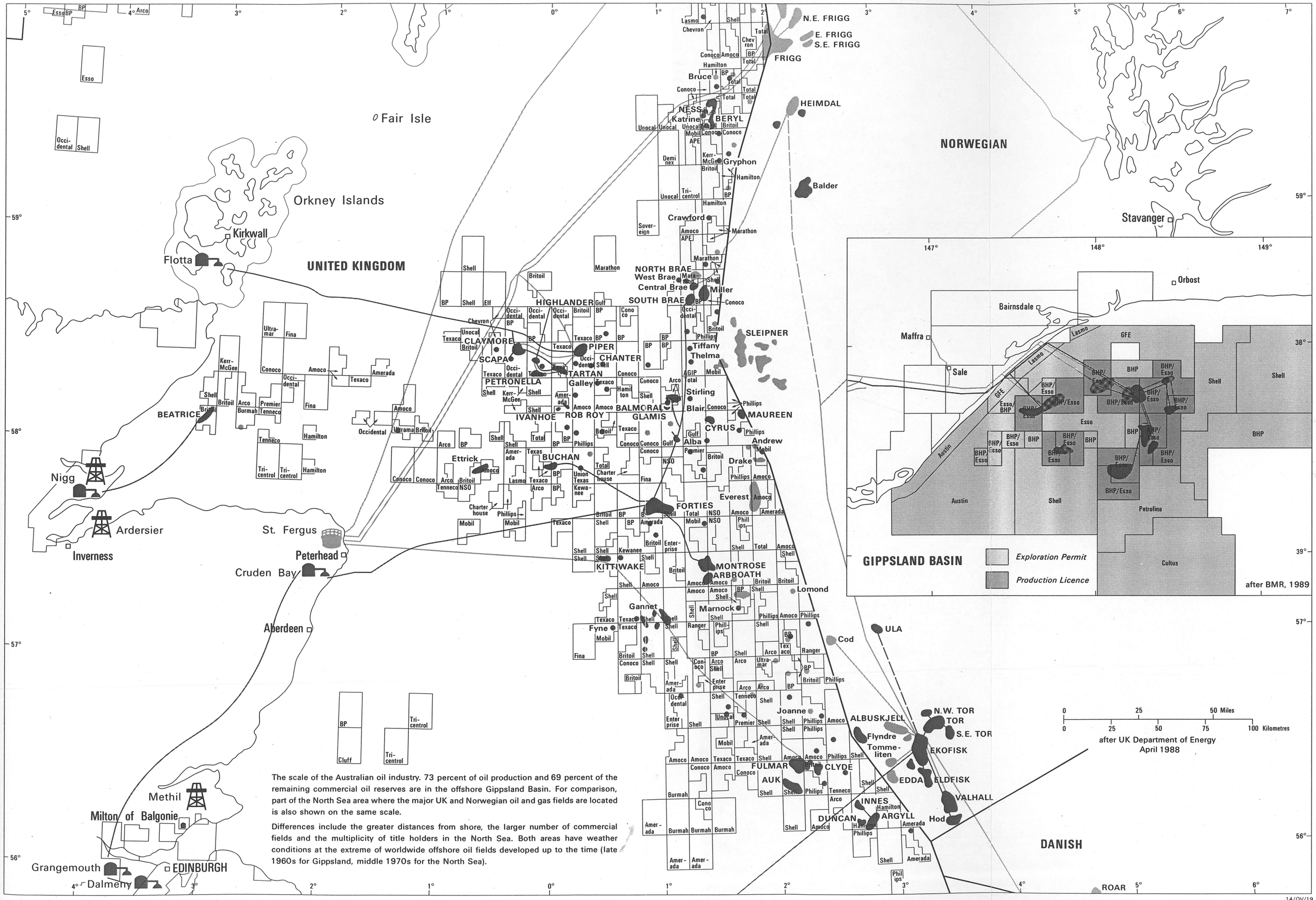
A Drilling Reservation system is currently in the process of being introduced into the Western Australian legislation (onshore and Territorial Sea). The system, adapted from one in existence in Canada, will allow an explorer to apply for an area restricted to the size of an identified prospect, in order to drill a well. The Drilling Reservations will be issued for a period of twelve months, and prospects may be identified either from open file data, or by the holder of an SPA. In the event of a discovery, Reservations will be eligible for conversion to Production Licences. This system will greatly benefit the smaller exploration companies, because of the much smaller financial commitment involved than that required in the acquisition of an exploration permit.

6.5 Comparison with North Sea (UK Continental Shelf) licensing system

As on the Australian continental shelf, vacant offshore areas under United Kingdom (UK) jurisdiction are offered to the petroleum industry in licensing rounds for competitive bidding (see Figure 6.5). However, the licences awarded (Production Licences) give both exploration and production rights to the licensee with the initial award, which differs from the two-stage system under P(SL)A. The UK system also offers Exploration Licences which can be applied for at any time, and gives the licensee the right to explore anywhere on the UK Continental Shelf not covered by Production Licences. These are comparable to Special Prospecting Authorities issued under P(SL)A.

Vacant areas ('blocks') offered in recent UK licensing rounds have been advertised according to their exploration maturity as Mature, Intermediate, Deep Water Frontier or Other Frontier, areas. In Australian releases, areas have not been formally categorised in this way.

The UK Production Licences have mainly been awarded on the basis of a 'discretionary' system broadly comparable in terms of award criteria with the work program bidding system under P(SL)A. A point of difference is that in assessing applicants for mature areas, the extent to which they also show willingness to explore in the frontier areas is taken into account. Although a similar criterion may be applied in the Australian system, it is only one of a number of secondary criteria (see Appendix C) which may be used in the event that applicants cannot be separated on the basis of the work programs offered. In addition to the discretionary



The scale of the Australian oil industry. 73 percent of oil production and 69 percent of the remaining commercial oil reserves are in the offshore Gippsland Basin. For comparison, part of the North Sea area where the major UK and Norwegian oil and gas fields are located is also shown on the same scale.

Differences include the greater distances from shore, the larger number of commercial fields and the multiplicity of title holders in the North Sea. Both areas have weather conditions at the extreme of worldwide offshore oil fields developed up to the time (late 1960s for Gippsland, middle 1970s for the North Sea).

Figure 6.5 Comparison of size of exploration and production licences in the UK North Sea (UK Department of Energy, May 1987) and Gippsland Basin, Bass Strait. Oil fields, etc are denoted by a dark screen, and gas fields, etc by a medium screen.

system, a small number of blocks have also been offered on a cash tender basis in several UK licensing rounds.

Blocks offered in the recent rounds average 250 km^2 in area (larger in the Deep Water Frontier Areas), which is significantly smaller than most areas released under P(SL)A. A comparison of Gippsland Basin permits and UK licence areas (Fig 6.5) illustrates this difference in size.

The UK Production Licences are awarded for an initial term of six years with a renewal option for a further 30 years, in all except the Deep Water Frontier areas where the initial term is for eight years with a renewal option for a further 40 years. In both cases there are relinquishment options at the end of the initial terms.

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7. RESOURCE TAXATION FOR PETROLEUM EXPLORATION AND DEVELOPMENT

7.1 Introduction

Resource taxation in the form of royalty, excise and resource rent tax (RRT) has effects on the level and direction of petroleum exploration, and the balance between exploration and development. This chapter summarises some features of the secondary taxation systems in Commonwealth administered areas which have been in place at various times and comments briefly on the impact of the systems on exploration and development.

7.2 'New' and 'old' oil

Before 1975, there were only small differences in the prices received for crude oil produced from different fields in Australia. The price of crude oil produced in Australia was subject to Government control from the commencement of production in 1964 until deregulation of crude oil pricing in 1988. In September 1975 a policy was announced (DNDE, 1982) which meant that, for the first time, there would be substantially different prices paid for oil from different accumulations. Under the policy, oil from newly discovered fields or pools ('new' oil) was to be differentiated from oil from previously discovered fields or pools. The policy applied only to fields discovered by exploration wells, both onshore and offshore. A special levy initially of $2 per barrel was applied to all production. 'New' oil was to attract a price at the nearest refinery port equivalent to the landed cost of imported crude minus the levy. Producers of 'old' oil (discovered before September 1975) received a price equivalent to 1968 world price levels, while the refiners effectively paid the levy on this oil.

In August 1976, as a further incentive to exploration and in recognition of the higher costs associated with developing new oil, the excise levy was removed from 'new' oil so that producers would thereafter receive the equivalent of full import parity.

The oil pricing arrangements which were introduced to apply from 1 July 1979 resulted in all oil attracting the import parity price, but different net excise rates for 'old' oil varied for areas with different annual production rates (the excise rate for areas with high production volume areas being higher than that for areas with smaller production volume areas). 'New' oil remained free of excise.

In June 1983, the 'new' oil excise policy was extended to accumulations discovered by development wells. The 'old' oil excise regime was revised to a progressive scale in which successive 'tranches' or increments of annual production attracted higher rates of excise, the highest marginal rate being 87%.

In July 1984, excise was applied to 'new' oil production onshore and offshore, scaled according to production. Areas producing less than 500 megalitres per year (3.1 million barrels per year) were free of excise. Resource Rent Tax (RRT) was also introduced to greenfields offshore areas, and replaced excise/royalty in these areas.

In October 1984, the 'intermediate' excise category was introduced for 'old' oilfields that had not been developed as at 23 October 1984.

In November 1986, the 'old' oil excise (top marginal rate) was reduced from 87% to 80% of the import parity price. In July 1987, it was announced that the 'old' oil 80% excise (top marginal rate) was to remain, but with progressive lowering in future years to 75% by 1989-90. The first 30 million barrels of crude oil produced from new offshore projects and from all onshore fields were made exempt from excise.

Comments

The effect of the 'new' oil pricing and excise arrangements has been to encourage the search for 'new' oil pools in previously discovered 'old' oil fields. As a result, the focus has been on 'new pool' discoveries rather than 'new field' discoveries. Pools intersected in 101 individual wells in 'old' fields have received 'new' oil pricing compared with only 26 new field discoveries.

One minor effect of the changes in 1983 appears to be the diversion of considerable effort to construct 'new' oil cases for new pools in development wells in developed fields, where the distinction between 'new' and 'old' oil is sometimes not clear.

Another effect of different pricing and excise arrangements (including different levels of royalty) for different accumulations in the same area, is to create the need for detailed metering arrangements for each source of oil, in order to correctly determine how much oil comes from each individual accumulation into a common pipeline. In offshore areas metering equipment is expensive and space-consuming, and adds complexity to the design of facilities. The calculation of excise is also very complex and time-consuming in this arrangement.

A beneficial result of the 'tranche' system is that no excise is paid at the end of a field's life, when oil production rates are very low and operating costs per barrel increase. This has the effect of delaying the abandonment of the field and significantly increasing the oil recovery of the field.

7.3 Substantial new developments

In order to facilitate costly new developments (e.g. new platforms or additional drilling) in the known 'old' oil fields, provision was made in 1977 for the Commonwealth Government to recognise areas which may qualify for an additional allowance of higher priced crude. Part of the production of 'old' oil is treated for excise as if it were derived from a separate 'old' oil area. These additional areas are referred to as Substantial New Developments. Because of the increasing marginal excise rates on 'old' oil, less excise would be payable on a separate basis than would otherwise be the case.

In October 1984, the policy was modified to provide consistency with the 'intermediate' excise scale.

Comments

Substantial New Development status has assisted innovative projects such as the South Mackerel wells (record-breaking highly deviated wells) and encouraged the extension of drilling activities in marginal projects. The reserves attributed to some of these projects would not have been recovered otherwise. In recent years in Australia, new but initially high risk technology has played an important part in lowering the cost of development and allowing production of resources in previously non-commercial fields.

7.4 Royalty

Royalty is a more or less uniform taxation on every barrel of crude produced, regardless of the field size, and whether the oil is 'new' or 'old'. Costs of production are recognised to the extent that some deductions may be made from the sales receipts for excise, allowances for a return on post-wellhead capital assets and for depreciation on post-wellhead capital assets, and operating expenses such as processing and transportation.

Currently royalty arrangements differ only slightly from State to State. In Commonwealth administered areas, the rate of royalty paid may vary from field to field and within a field, depending on whether the production licence is primary or secondary.

Comments

From a national point of view, with an extraordinarily small number of exploration wells drilled to date (see Chapter 4.4), it is clearly important at present to encourage drilling in such a way as to increase the information available to the industry, and thus promote efficient development. It is also important to ensure that the incentive for large discoveries (which contribute nearly all our oil reserves) is not reduced.

Most of Australia's reserves are in very large fields (91% of reserves are in the largest 10% of fields). It is important to encourage explorers to look in immature areas - where the information already available does not preclude discovery of large new fields (as it often does in densely drilled areas). Discrimination in favour of small fields by excise exemptions does not achieve this objective. Against this may be balanced the fact that many large fields have been discovered (often many years later) following encouraging shows of oil or gas in nearby, smaller fields.

7.5 Resource Rent Tax

Resource Rent Tax applies to petroleum projects in the majority of Australia's offshore areas beyond the territorial seas. The areas excluded are the Bass Strait and North West Shelf production licence areas and associated exploration permits (Vic-P-1, WA-1-P and WA-28-P). Where RRT applies, it replaces excise and royalties which would otherwise have been levied. Currently RRT applies only to the Jabiru and Challis/Cassini oil fields. No RRT has yet been paid.

Resource Rent Tax applies at the rate of 40% to net cash flows after returns on project-related expenditures exceed the specified threshold limit. In respect of exploration expenditures, only the expenditures within the original permit area are deductible.

Comments

Resource Rent Tax is applied on a profits basis (in this respect similar to the implicit profits basis of the 'old' oil excise range). The unique features of the tax that relate to exploration and development are:

(i) At present, all exploration expenditure within the permit area is deductible. This can lead to over-drilling in the permit area at the expense of other prospective areas, and accelerated drilling early in the life of a project to obtain the maximum deductions before the project reaches the threshold level of profitability. The evidence to date does not show conclusively that this is occurring. There is a natural 'clustering' of wells near a commercial discovery.

(ii) The tax discriminates in favour of small and low risk projects, where exploration is more likely to be deductible against a discovery.

(iii) The tax does not distinguish between high risk expenditures (wildcat exploration) and low risk expenditures (appraisal and development wells and production infrastructure). This has potential implications for future petroleum supplies, which are likely to be dependent on large new field discoveries rather than appraisal drilling in known fields.

These features can lead to a distortion of the optimal exploration and development process.

7.6 Resource taxation and prospectivity

The impact of RRT has been discussed by Falvey (1990). Figure 7.1 (after Allinson, 1989a and b) shows the estimated minimum prospect sizes which can be economically drilled in different countries.

For the range of probabilities of drilling success shown, RRT and excise arrangements currently in place give a smaller required prospect size than for all the other countries shown except New Zealand.

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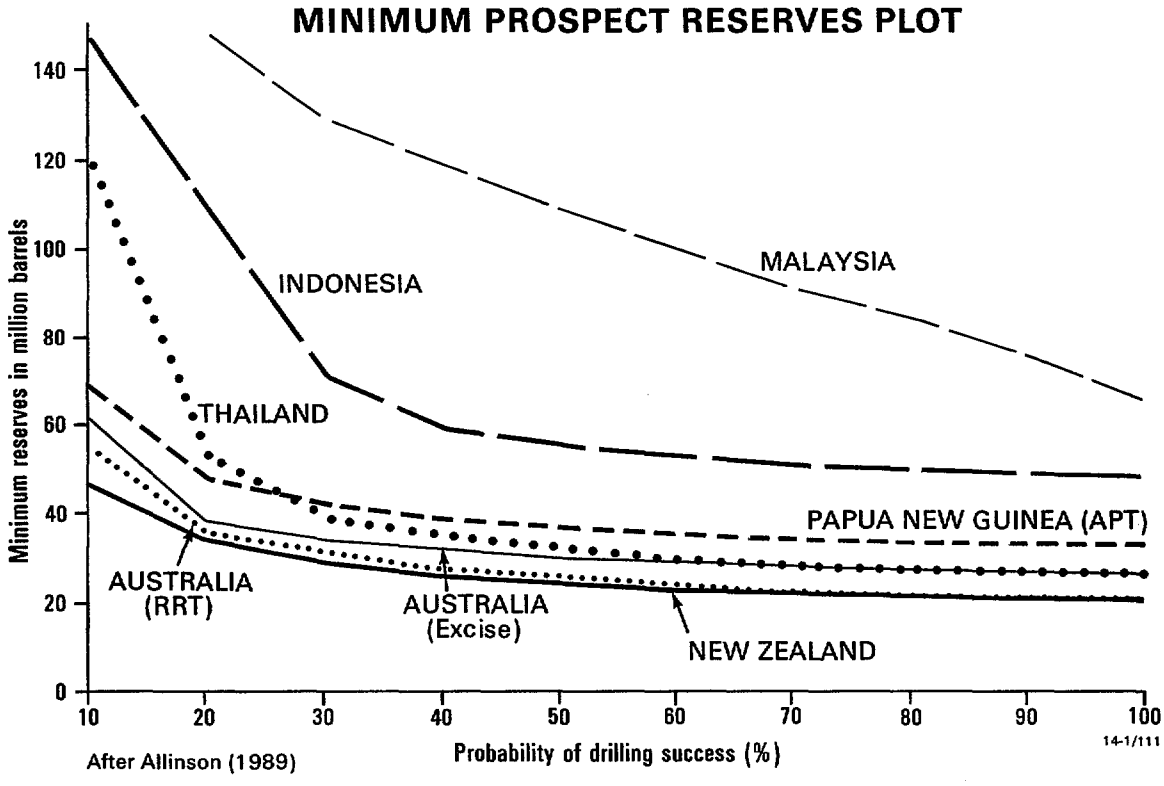

Figure 7.1 Minimum economic reserve size of prospects assuming various probabilities of drilling success in different countries (after Allinson, 1989a and b).

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APPENDIX A

How petroleum is formed

Oil and gas (petroleum) are found in sedimentary basins, in porous and permeable rock strata, or 'reservoirs', that exist in particular geometrical configurations, or 'traps' (Fig. 1). The traps may be near the surface but more commonly lie at depths of several thousand metres. Geological research has shown that petroleum actually takes millions of years to form in geological strata and for oil or gas fields to occur, the following natural conditions or requirements must have existed in a sedimentary basin:

(1) Abundant, organic-rich source beds

When mud is deposited in seas, lakes and flood plains, the overlying water may become depleted in oxygen, and a complex mixture of partly decayed organic remains of algae, bacteria, and plants become incorporated in the mud instead of being destroyed by oxidation. With continued burial by other sediments over long periods of geological time (millions of years), the organic-rich mud becomes compacted and hardened, to form shale. The complex mixture of organic material is termed 'kerogen'. Kerogen is believed to be the source material for petroleum. The host rock in which the kerogen resides is termed the 'source rock'.

In geological strata, the occurrence of organic-rich shale is a relatively rare event in comparison with the volume of organic-poor sediment that is deposited and preserved. Also, not all preserved organic material is suitable for petroleum generation. Only the remains of algae, bacteria and certain parts of land plants (e.g. leaf cuticles) are relatively rich in hydrogen and yield liquid hydrocarbons (kerogen types I to II, Fig. 2b). In contrast, the woody parts of the land plants are depleted in hydrogen and do not yield significant amounts of liquid hydrocarbons (kerogen type III, Fig. 2b). Particular shales (oil shales) that contain large amounts of hydrogen-rich kerogen may be mined and used to produce liquid hydrocarbons by retorting.

(2) Suitable temperatures for the conversion of kerogen to hydrocarbons

As the source rock is progressively buried, its temperature rises in proportion to the depth. The rate of temperature increase or geothermal gradient varies from place to place around the world. The increase in

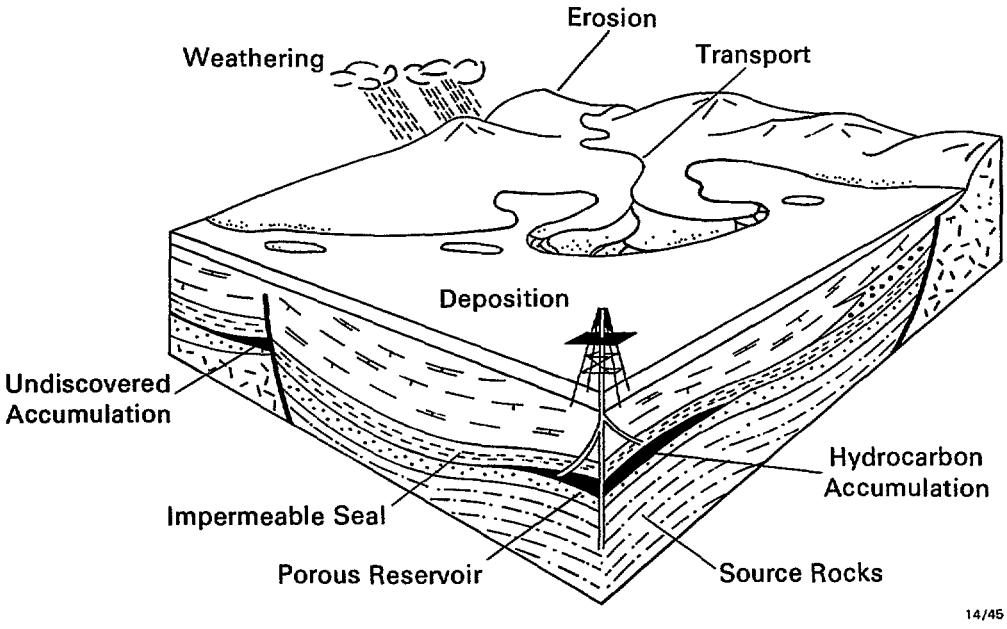

Figure 1 Schematic diagram illustrating two possible modes of structural petroleum accumulation in a sedimentary basin showing a possible relationship of source, seal and reservoir. (After Evans, 1988; reproduced with permission of the Australian Petroleum Exploration Association.)

temperature induces thermal breakdown or 'cracking' of the kerogen to produce liquid hydrocarbons (crude oil, Fig. 2a). If burial continues, thermal alteration intensifies and both kerogen and oil are further broken down to form gas. Inherent in this concept is the notion of an immature (shallow) zone where no hydrocarbons have been generated, a mature (deeper) zone mainly of oil generation, and an overmature (deep) zone, primarily of gas generation. It therefore becomes possible to define in a sedimentary basin the concept of a 'liquid window', denoting those parts of the basin within which oil can be expected to have formed. However, this oil 'window' is not only a simple function merely of depth and geothermal gradient but also of the time that the source interval has spent at a given temperature, because organic reactions are a function of both time and temperature. Thus, theoretically, a rock 'progresses' into and through the oil window as burial occurs. Studies have indicated that, typically, petroleum is generated from kerogen at temperatures of 100-150°C over a period of 20-50 million years.

(3) A source rock efficiently drained by carrier beds

Although most kerogen generates hydrocarbons, the crucial question is whether or not the hydrocarbons are free to migrate to a reservoir. For migration to occur, enough hydrocarbons must be generated first to overcome the absorptive capacity of the source rock, then to saturate the pore space and move out of the source rock as a discrete liquid or gas. So, the potential of a source rock to yield oil to a porous carrier bed in economic amounts depends on the ability of the kerogen to yield hydrocarbons of the right type, and the amount of kerogen in the rock. The best oil source rocks contain above-average concentrations of hydrogen-rich kerogen - typically more than 3% of type II kerogen (Fig. 2b).

Hydrocarbons are typically expelled from the source bed into an adjacent porous conduit or carrier such as a sandstone or a fault zone. The efficiency of expulsion depends on the richness of the source bed, the contact area of the conduit with the source rock and the speed of generation, i.e. intense thermal alteration results in rapid saturation of pore space, facilitating oil expulsion.

(4) For a productive oil basin, reservoir rocks that are voluminous and of high quality, and (5) suitable traps created before the oil is formed and starts to migrate

The conduit bed is porous and permeable and is generally saturated with brine. Oil and gas are immiscible with, and less dense than, the brine,

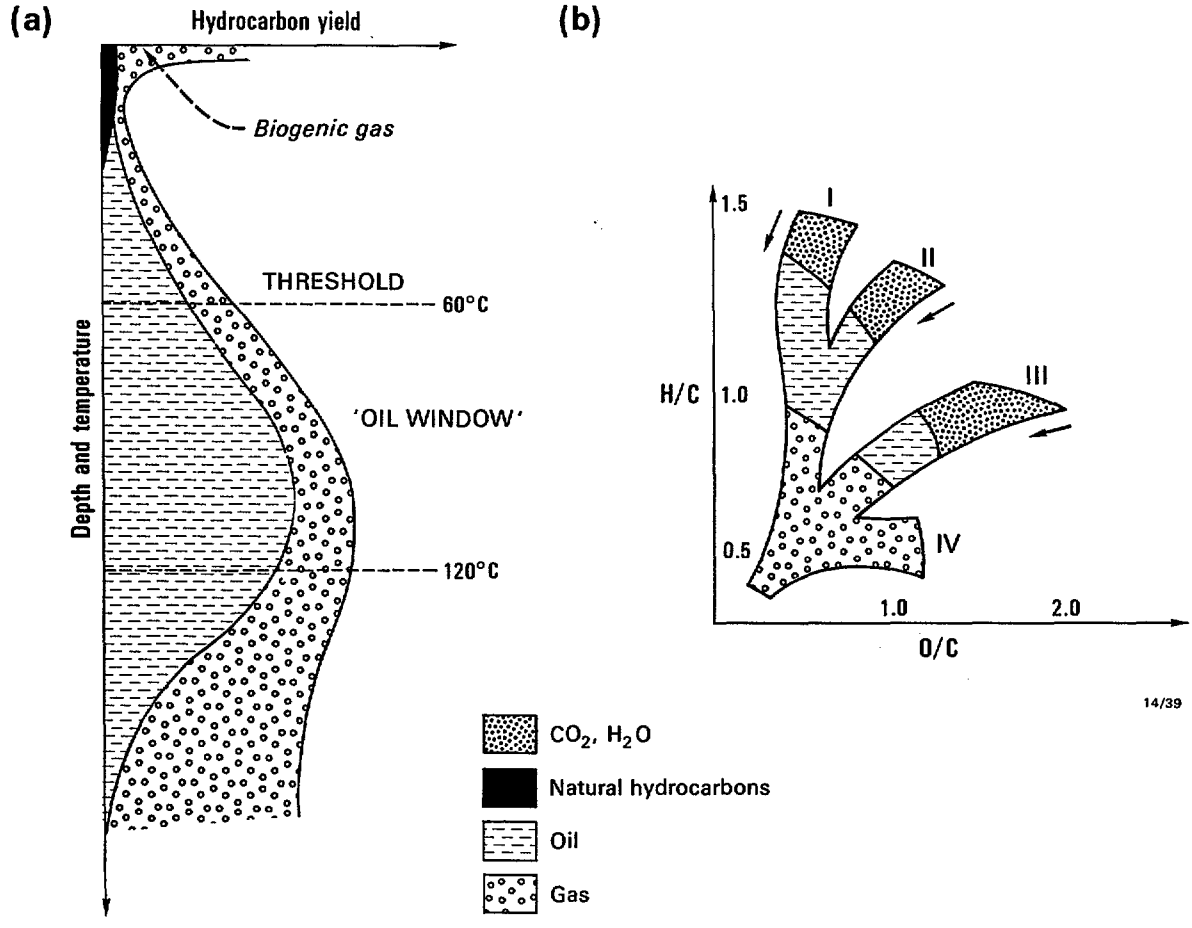

Figure 2a Schematic representation of the oil window in a sedimentary basin. The 'oil window' is the zone in which kerogen yields its maximum amount of liquid hydrocarbons. The depth of the oil window varies from location to location depending on geothermal gradient and length of exposure to maximum temperature. (Evans, 1988; reproduced with permission of the Australian Petroleum Exploration Association.)

Figure 2b The types and quantities of petroleum generated depend on the origins of the kerogen from which the hydrocarbons have been cracked. As kerogen undergoes thermal alteration it loses carbon (C), hydrogen (H) and oxygen (O/C) and the ratios of H/C and O/C decrease as hydrocarbons and carbon dioxide are generated. Types I and II kerogens are enriched in hydrogen (high H/C ratios) initially and hence yield more liquid hydrocarbons on maturation. Kerogens depleted in hydrogen (Types III and IV) yield lesser amounts of hydrocarbons and generally do not generate sufficient liquids for the formation of accumulations. (Evans, 1988; reproduced with permission of the Australian Petroleum Exploration Association.)

and rise through the conduit by buoyancy. The carrier bed may actually constitute the reservoir, or a carrier fault may intersect a porous carrier bed, leading to the eventual reservoir.

The oil and gas will continue to rise by buoyancy until their progress is halted at a trap. A trap is formed where the carrier bed is overlain by an impermeable barrier such as shale or salt, termed the seal, such that the oil and gas are prevented from moving upwards and to the side: this may be as a result of doming of the reservoir and seal beds or by the creation of a fault, placing the reservoir bed adjacent to an impermeable bed. These are termed structural traps and form by deformation of the earth's crust during the basin's geological history. It is crucially important that the structural trap be formed before the oil migrates.

Alternatively, stratigraphic traps may be formed where sandstone gives way to shale laterally or where porous fossil reefs are encased in shale. Stratigraphic traps have excellent trapping potential because they form while the sediments are being deposited (syn-depositional). The petroleum accumulates in the porous bed (reservoir) within the trap, and the best reservoirs are highly permeable, allowing high production rates and high recovery rates of oil.

(6) Accumulations must be preserved intact during later structural movements and other processes that could lead to degradation and/or escape of hydrocarbons

Once the petroleum has accumulated, the traps have to have remained intact to the present day. Structural movements may allow the seals to leak, and the accumulated petroleum to dissipate. Alternatively, the sedimentary basin may be uplifted, resulting in erosion of the covering strata and bringing the reservoir within reach of circulating groundwater. Should this happen, the oil may degrade by bacterial action, forming a non-producible tar. The major tar deposits of the world (e.g. the Athabasca Tar Sands in Canada) are the result of bacterial degradation at shallow depth.

Questions for the explorationist

In petroleum exploration much effort is devoted to identifying potential reservoirs and traps, but if a source is absent or, if present, it does not have the appropriate burial history, then there will be no hydrocarbons to charge the reservoir. Therefore, to assess prospectivity adequately, several questions must be asked:

- Between which depths could hydrocarbons have been generated?
- Where and what are the possible source beds?
- What will the hydrocarbon product be?
- What has been the relative timing of hydrocarbon generation and trap formation?
- Was the source capable of yielding hydrocarbons to the target reservoir?
- Are there any deleterious reservoir alteration effects?

In new exploration areas there is always a high degree of uncertainty on these points. The objective of the exploration process is to successively identify suitable targets and to succeed in answering these questions, thereby systematically reducing the risk of failure.

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APPENDIX B

BMR's procedure for assessment of undiscovered petroleum resources

D.J. Forman, A.L. Hinde, & A.P. Radlinski

ABSTRACT

Petroleum resource assessment begins with geological study of sedimentary basins and the subdivision of the sedimentary sequence and petroleum prospects into plays. Next, data are gathered about the traps that have been tested, the accumulations discovered, and the traps that remain to be tested in each play. Some data are sorted, plotted, and analysed by computer. All data are then examined by specialist geoscientists. These specialists interpret the historic data, select analogues, make direct theoretical calculations, and make subjective judgements in order to determine the information to be used in the assessment.

Quantitative assessment is carried out using a computer program that simulates drilling each trap in each play. It estimates the size of each potential discovery by multiplying together estimates of the area of closure of the trap and the resources per unit area of closure which are input as loglinear models. The program also uses other types of information such as existence risk, success rate, the proportion of oil to oil and gas, and the smallest size of field to be included as a resource. Assessments of undiscovered oil and gas resources are given as cumulative probability distributions.

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INTRODUCTION

The total amount of oil and gas that occurs throughout Australia may be thought of as an ultimate endowment; the amount of which is presumed finite, non-renewable, and exhaustible at present and projected rates of demand. There is no method for assessing all of this ultimate endowment and the Bureau of Mineral Resources, Geology and Geophysics (BMR), in company with other organisations, assesses only that part of the total that is classified as resources, that is recoverable petroleum that is surmised to exist on the basis of present geological knowledge and that could be brought into production within the next 20 to 25 years.

Government needs to know not only the petroleum resources that occur in known oil and gas fields throughout Australia but also the resources in fields that remain to be discovered, so that decisions can be made on energy policy, energy management, and land use. Indications that the amount of the undiscovered resource is large or small will satisfy some of these purposes but quantitative assessments are required for other purposes, particularly discovery rate and production forecasting as is carried out using BMR's SEAPUP program (Forman & Hinde, 1989).

This paper outlines the method that has been developed at BMR for the assessment of undiscovered petroleum resources. Application of the method requires using a series of computer programs in conjunction with a database containing information on petroleum plays, the size and geometry of the petroleum traps in them, and the sizes of the petroleum accumulations that they are known to contain.

Delineation of plays

The quantitative assessment of the undiscovered petroleum resources in a region begins by dividing the sedimentary rocks into a number of distinct assessment units. The type of unit selected will depend on the detail of the information that is available and the amount of time and effort that can be put into the assessment and will vary from one area to another across Australia.

A well-known method of assessing entire, unexplored sedimentary basins uses a yield factor expressed in cubic metres of oil or gas per cubic kilometre of sedimentary rock or per square kilometre of surface area selected from one or more geologically analogous basins. A number of authors (Hedberg, 1975; Jones, 1975; Bultman, 1986; Resnick; 1986; and Ulmishek, 1986) have raised objections to this method. For instance, petroleum occurs in a variety of habitats which would be unlikely to match

from one basin to another. There is no proven statistical relationship between basin type and petroleum yield. There is doubtful scientific basis, therefore, for use of the basin as an assessment unit. Furthermore, the method provides little information on the distribution and sizes of the fields in which the petroleum might occur.

These problems may be reduced by subdividing the sedimentary rocks and the petroleum prospects in a basin into a number of smaller assessment units, such as the play or the closely related petroleum zone (Bois, 1975). Assessment units such as these contain a small number of closely related petroleum habitats.

Where little is known about a basin the sedimentary rocks may be subdivided into megasequences (Porter & McCrossan, 1975). According to Ulmishek (1986), such units are often unsuitable for resource assessment. A better unit is a type of superplay which may be thought of as a laterally extensive sequence of reservoir rocks bounded by shales. In many cases the superplay is identical to the independent petroliferous system of Ulmishek (1986), which he defined as a body of rocks separated from surrounding rocks by regional barriers to lateral and vertical migration of fluids including oil and gas.

Later, as more is known about a region and more resources are available for assessment, it is possible to recognise individual reservoir/seal pairs within the stratigraphic sequences and to delineate individual traps, each of which could contain a petroleum accumulation. The traps, or prospects, may then be grouped into more closely defined assessment units, normally referred to as plays. According to Baker & others (1986), a play is a group of prospects with geologically similar source, reservoir, and trap controls on oil and gas occurrence.

We believe that this definition should be expanded to include consideration of the geometry of the reservoir/seal contact. For instance, a play is better defined as a system or branching system of traps that is separated from adjacent systems by barriers to lateral migration of petroleum, such as synclines or faults. Such a play will have one spill-point from which petroleum can escape laterally, although, there may be several entry points through which petroleum may enter laterally from adjacent plays. Unlike a prospect, a closing contour can never be drawn around a play or any grouping of traps within the play.

Plays that match this definition can be outlined by drawing regional drainage divides onto structure contour maps of the reservoir/seal contact. The systems of traps are outlined by drawing on the areas of

closure and drainage of each trap and the likely migration paths from one trap to another (Fig. 1). Particularly if the present geometry is a reasonable match to the geometry at the time of migration, the major drainage divides will outline plays, within each of which petroleum generation, migration, and entrapment are to some degree different. These differences occur partly because of differences in geometry and partly because of differences in source richness, migration efficiency, and seal capacity.

Such a petroleum play can be further subdivided. Forman & others (1989a) and Forman & others (in prep.) found that a proportion of the traps in the Cooper Basin of South Australia are complex, which means that they contain two or more culminations. In these circumstances, the enclosing trap belongs to one play and the culminations within it belong to another. The contact between the reservoir and cap rocks in the play may be a fractal surface (Mandelbrot, 1983), suggesting that there could be a series of fractal plays within plays. Each significant play should be assessed separately.

Risking of plays

Any assessment of undiscovered petroleum resources comprises two major tasks. One is to calculate the probability that significant petroleum occurs in at least one trap in the play. The other is to calculate how much petroleum, if any, the play may contain.

The first task, that of probability of occurrence, is solved by risk analysis (Gehman & others, 1981; Baker & others, 1986), often on a rather subjective (intuitive) basis. For instance, a play must have potential source rocks, reservoir rocks, and migration paths from source to reservoir. The probability that petroleum has been generated and has migrated within the play is estimated by determining the individual probability that each of these critical factors is favourable and then by multiplying the individual probabilities together.

Where there are few traps, the probability of occurrence will also depend on the success rate. Success rate depends on a variety of factors that may affect each trap differently, such as adequacy of reservoir and seal, sequence of trap development with respect to maturation, and protection of accumulated petroleum from breaching or biodegradation. Success rate and, therefore, the overall probability that at least one trap will contain significant hydrocarbons are also affected by the sizes of the potential accumulations in comparison to the magnitude of the smallest size of accumulation to be included as a resource.

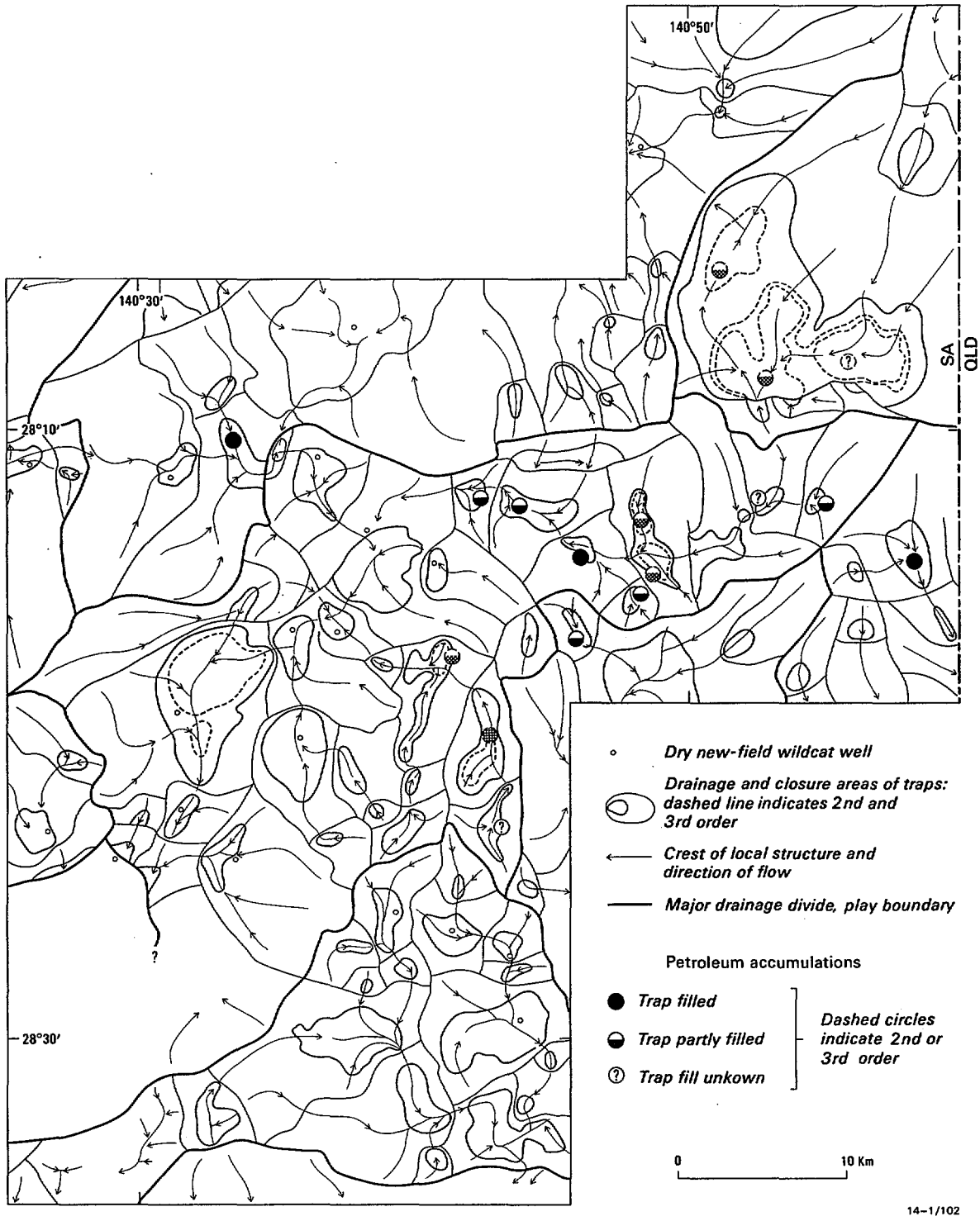

Figure 1. Map showing areas of closure, areas of drainage, and drainage paths of structural traps and petroleum accumulations within a Permian sequence in a part of the Cooper Basin in South Australia. Major drainage divides, which are shown as solid lines, have been selected as the boundaries of plays.

Assessment of plays

A wide variety of methods is available for carrying out the second task, that of assessing how much conventional oil and gas remains to be discovered in a play. Some are geological and some statistical. They vary according to the purpose and scale of the assessment, the amount and type of data available, and the resources that are available to the assessor.

BMR has developed a geological method (BMR, 1988) that simulates drilling all of the prospects in each play and calculates the amount of petroleum in each undiscovered accumulation (V) using the equation

$$V = A_{clos} \cdot V_{Aclos} \qquad (1)$$

where A_{clos} is the area of closure of the trap and V_{Aclos} is the resources per unit area of closure. The computer program that performs the task also uses other types of information such as existence risk, success rate, the proportion of oil to oil and gas, and the smallest size of accumulation to be included as a resource. Apart from assessing the undiscovered petroleum resources throughout Australia, the method has the potential to also estimate the sizes of the individual accumulations in which the petroleum may occur and their likely distribution by basin, sequence, drainage area, trap type, order, or fractal play.

The determination of a range of values for each factor begins with systematically gathering information about the traps and the petroleum accumulations known in each play and recording this information in a confidential computer-based data storage and retrieval system. Preliminary processing, sorting, plotting, and statistical analysis of each factor in each play are then carried out by computer. The resultant information is then examined in confidence by groups of geoscientists who use their specialist knowledge in combination with the historic data to select the values likely to apply during further exploration ready for entry to the assessment program.

The method can be adapted to almost any level of knowledge about an area, but the reliability of the assessment and frequently the magnitude of the assessment increase with the level of knowledge and the manner in which the plays have been delineated. Where exploration data are lacking, plays must be loosely defined and the specialists may need to select analogues, or make direct theoretical calculations, or make subjective judgements of the values that apply to each factor. Their ability to determine these values without serious under- or over-estimation is in direct proportion

to the availability of geological information and to their understanding of the geology of the locations in which the oil and gas accumulations may occur and of the ways in which they might have originated. The better assessments are carried out knowing the kitchen areas in which the petroleum may be generated, the pathways along which it could have migrated, and the reservoirs and traps in which it might occur.

Statistical analysis is used throughout the program to keep track of the probabilities involved. The resulting assessment of the play or of the whole continent is presented as a cumulative probability distribution (Fig. 2) that indicates both the probability that the answer will lie in a certain range and that the answer will be larger than a particular value.

TRAP TYPES

Different degrees of exploration risk and different drainage ratios (area of drainage/area of closure) may be associated with different types of traps. Also, traps can form at different times and can receive and retain different amounts of petroleum. For these reasons the traps in each region are classified according to their type, in case each type is to be assessed as a separate play.

The type of trap at any specific locality should be determined by reference to the most recent structure contour or prospect map available. The types of traps that occur most commonly are shown in Figure 3, simply classified as anticlines, faulted anticlines, faults, diapirs, palaeotopographic highs, pinchouts, fans, and reefs. Additional types of traps should be recognised as exploration proceeds. In some cases the effective trap type is uncertain. It could, for example, be either anticline or fault, anticline or pinchout, or palaeotopographic high or pinchout. In these cases both types are recorded in the data storage and retrieval system.

LOGLINEAR MODELS

It has been observed many times that the sizes of the identified petroleum accumulations in plays approximate lognormal distributions that are truncated at each end and that there is a tendency to discover the large accumulations early. These two observations have led to the hypothesis that the order in which the accumulations are discovered corresponds to a scheme called successive sampling (Kaufman & others, 1975; Barouch & Kaufman, 1976; O'Carrol & Smith, 1980; Kaufman, 1986).

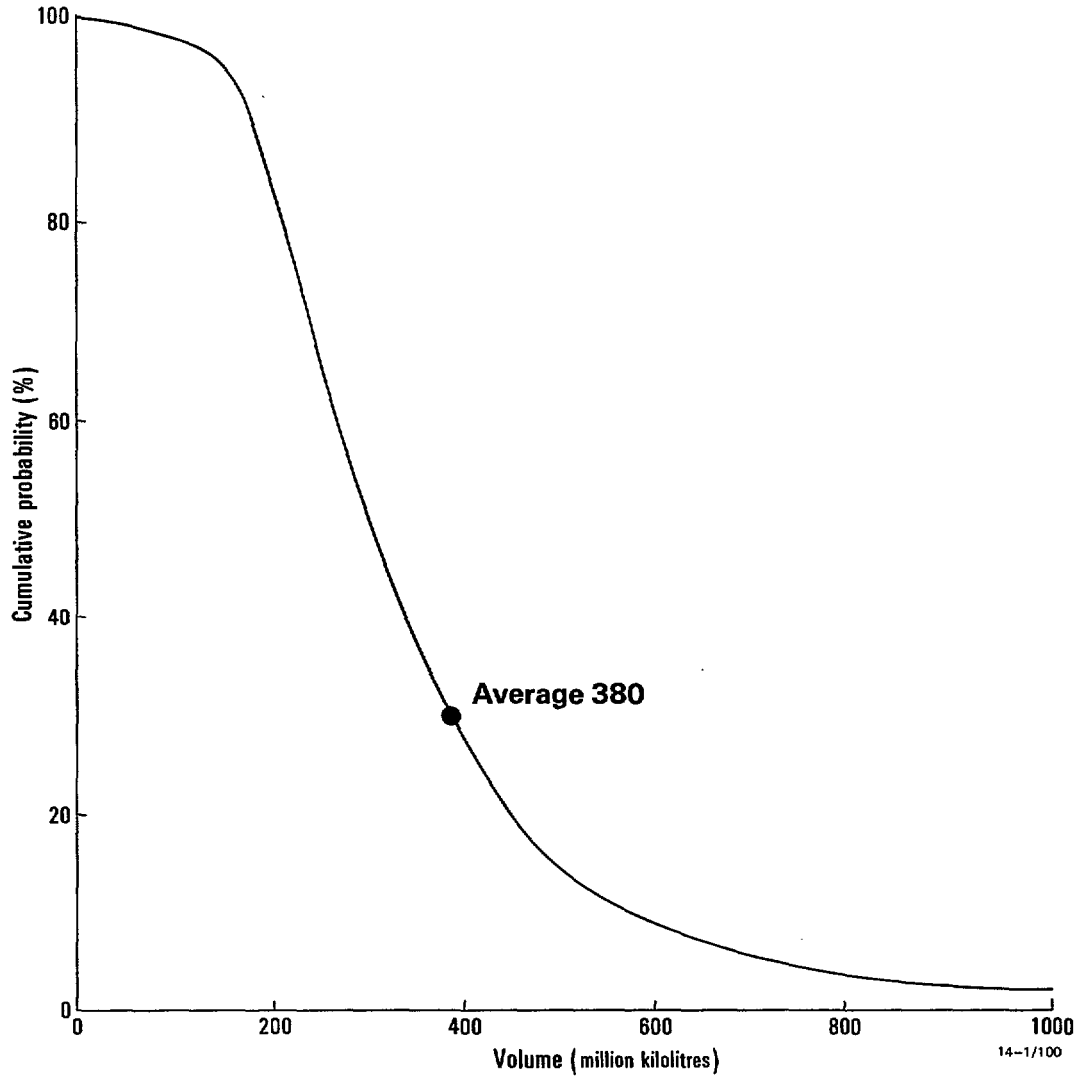

Figure 2. Cumulative probability distribution showing Australia's undiscovered crude oil resources, as at June 1989.

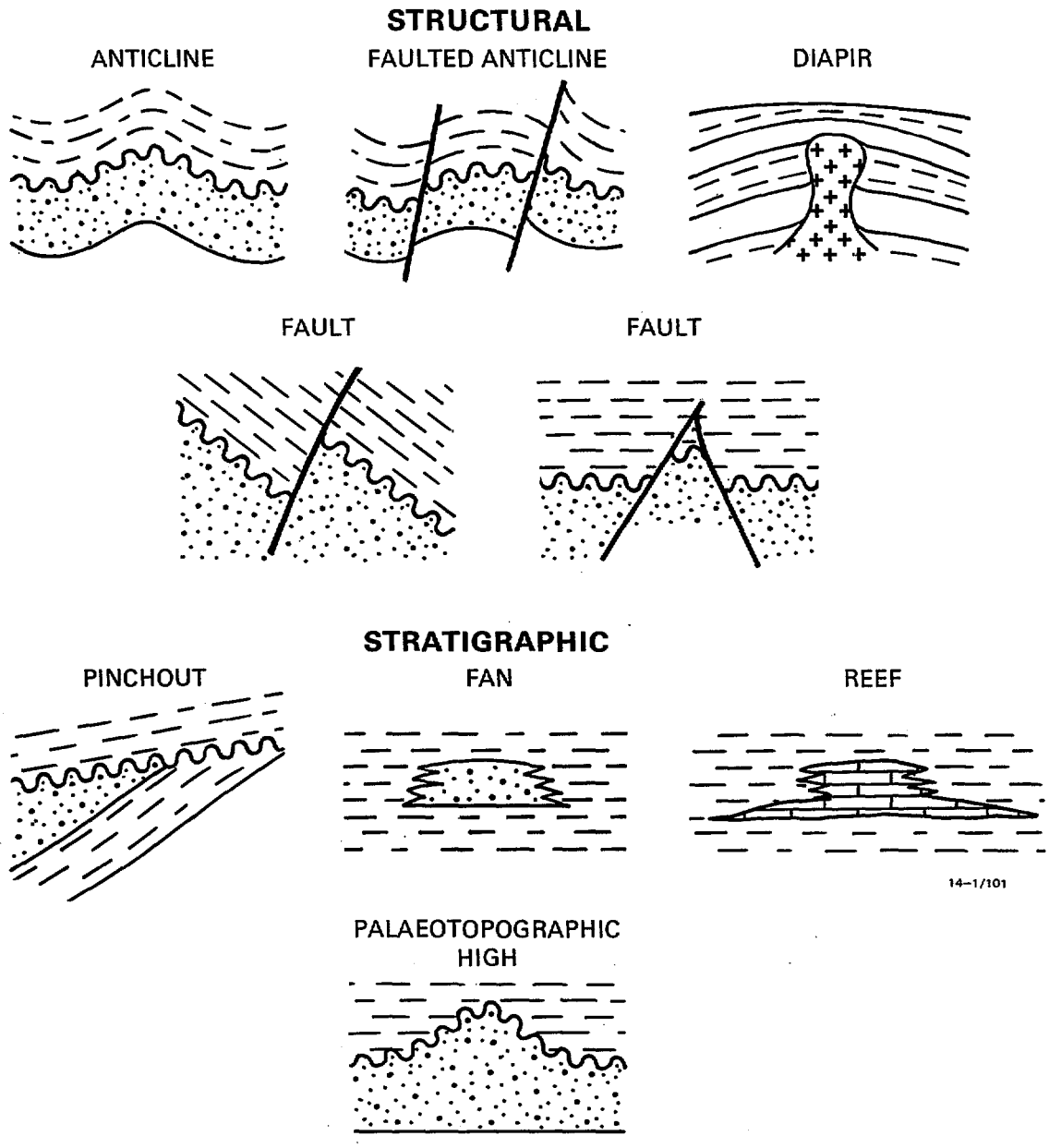

Figure 3. Simple classification of the structural and stratigraphic trap types (anticline, faulted anticline, diapir, palaeotopographic high, fault, pinchout, fan, and reef) that have been identified in Australia's sedimentary basins.

Forman & Hinde (1985, 1986) and Forman & others (1989b) found that the same observations apply to the areas of closure of the traps in a play and their order of drilling and to the resources per unit area of closure of the accumulations and their order of discovery. They also showed that the order in which the traps are drilled is close to that in a successive sampling model in which the probability of drilling a trap next is proportional to its area of closure raised to the power lambda (λ).

Repeated simulations of a computer model incorporating this hypothesis showed that there is a regularity inherent in the model. The simulations yielded plots in which the average values of log A_{clos} versus drilling sequence number are approximately linear, particularly when the value of lambda is low. Also, the distributions of possible values for log A_{clos} for each drilling sequence number are approximately normal and have a similar standard deviation.

Lambda is called the creaming factor (Forman & Hinde, 1986) and is a measure of the tendency to drill the areally larger traps early. Its value has a theoretical range from 0 to infinity, but typically is about one. When lambda equals infinity, the traps will be drilled in the order of their areas of closure. When lambda equals 0, the order of drilling will be random and independent of area.

The simulations also showed that there is a dependent relationship among the slope and intercept of the fitted line, the standard deviation of the residuals, and the value of lambda. While the distributions of the values of slope, intercept, and standard deviation of the residuals that correspond to particular values of lambda cannot be calculated, the average values of each distribution are given to within about five percent by the linear least-squares equations in conjunction with the empirical equation:

$$\bar{B} = B_{max}(1 - e^{-s\lambda}), \qquad \lambda > 0 \qquad (2)$$

where $\bar{B}$ is the average slope for a given value of lambda, B_{max} is the slope of the fitted line when $\lambda = \infty$, and s is the standard deviation of the logarithms of the closure areas of the traps that have been drilled and is in turn dependent on the number of traps that have been drilled.

The model can be fitted to actual data (Fig. 4a). Values for the intercept and slope of the average straight line and the standard deviation of the residuals are determined using the linear least-squares equations. The average and standard deviation of the normal distribution of the value of lambda (Fig. 4b) are determined using the maximum likelihood method.

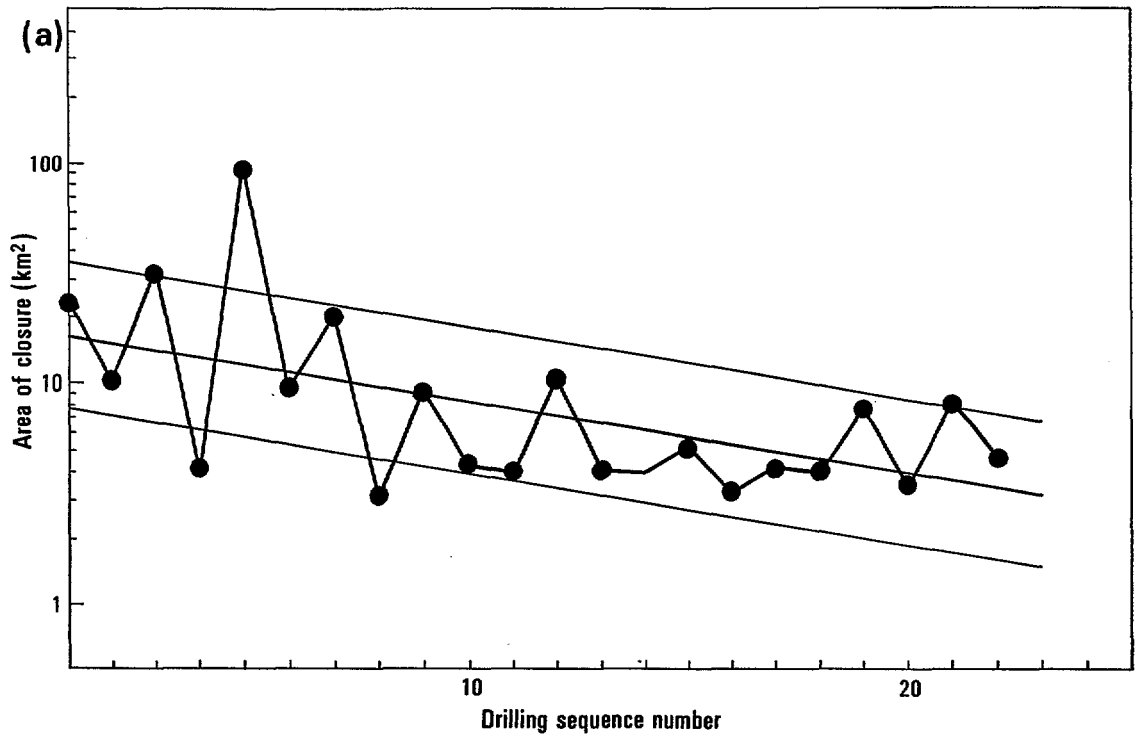

Figure 4a. Areas of closure (A_{clos}) of the first order traps from a Permian play in part of the Cooper Basin plotted on a logarithmic scale in order of drilling. The average straight line has been fitted by the method of least squares and the two flanking lines show plus and minus one standard deviation of the residuals.

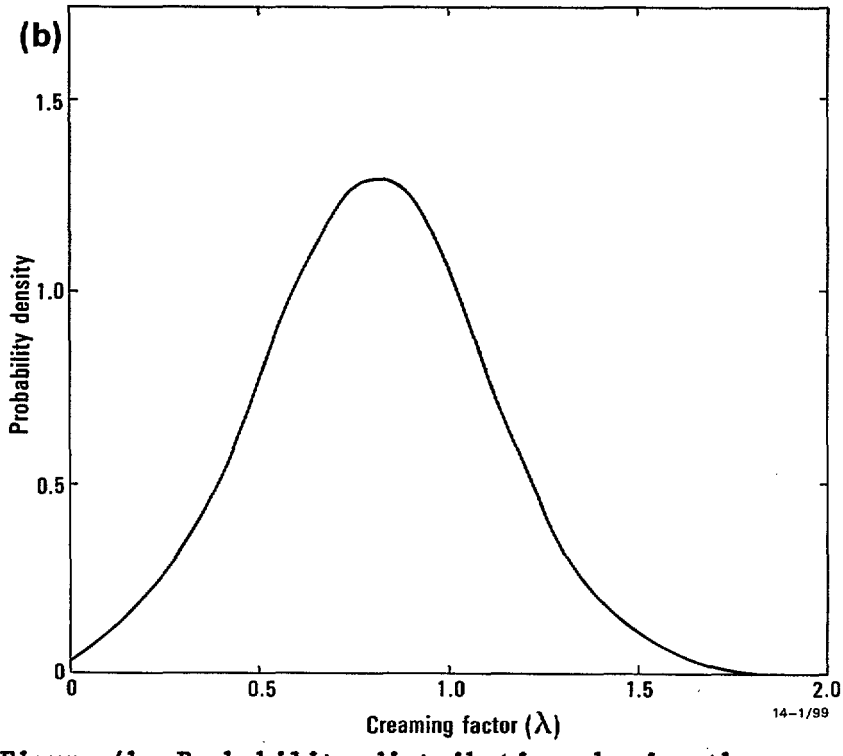

Figure 4b. Probability distribution showing the normal distribution of the value of lambda, determined by the maximum likelihood method, for the order of drilling of the first order traps shown in Figure 4a.

A maximum cut-off for the area of closure of the first of the undrilled traps is determined after examining a plot of log A versus drilling sequence number for all the traps for which information is available. The cut-off values for subsequent traps are determined by the program so that they decline with drilling sequence number in parallel with the average slope ($\bar{B}$) of the linear model selected for the iteration.

The resources per unit area of closure (V_{Aclos}) of the accumulations may be modelled in order of discovery in the same way as the areas of closure in order of drilling. A maximum cut-off value for the resources per unit area of closure of the first of the simulated discoveries is best determined after examining a plot of the logarithms of the values versus their discovery sequence numbers. Where historic data are not available the cut-off value may be estimated either by analogy or by using the principle that the retention factor (V/A_{clos}) can not exceed the capacity factor (V/A_{acc}).

AREAS OF CLOSURE AND DRAINAGE

The areas of closure of the traps that remain to be tested are input to the computer program as a loglinear model of area of closure versus drilling sequence number. In plays with abundant data, the model is built up by specialist geoscientists after examining a plot of log A_{clos} versus drilling sequence number for the traps that have already been tested together with the traps that remain to be tested. In plays with few data, the model may be built up using additional types of information, such as density of structuring and analogy with other plays that are outlined in Baker & others (1986).

Area of closure (A_{clos}) is outlined by the lowest closing contour of the trap and area of drainage (A_{drain}) is outlined by a drainage divide (Fig. 5a). In an anticlinal trap the lowest closing contour and the drainage divide coincide at one point called the spill-point of the trap while in a fault trap they will coincide along the line of the sealing fault or faults. Whereas there is only one lateral exit point from a well-sealed trap, there may be any number of entry points, each of which is the spill-point of an adjacent trap.

Areas of closure, and drainage if required, should always be measured on the map that best depicts the trap. In plays with a history of drilling for petroleum, the areas of the traps that have already been drilled may be measured either on the pre-drill structure contour maps contained in the drilling proposals prepared for each new-field wildcat well by the

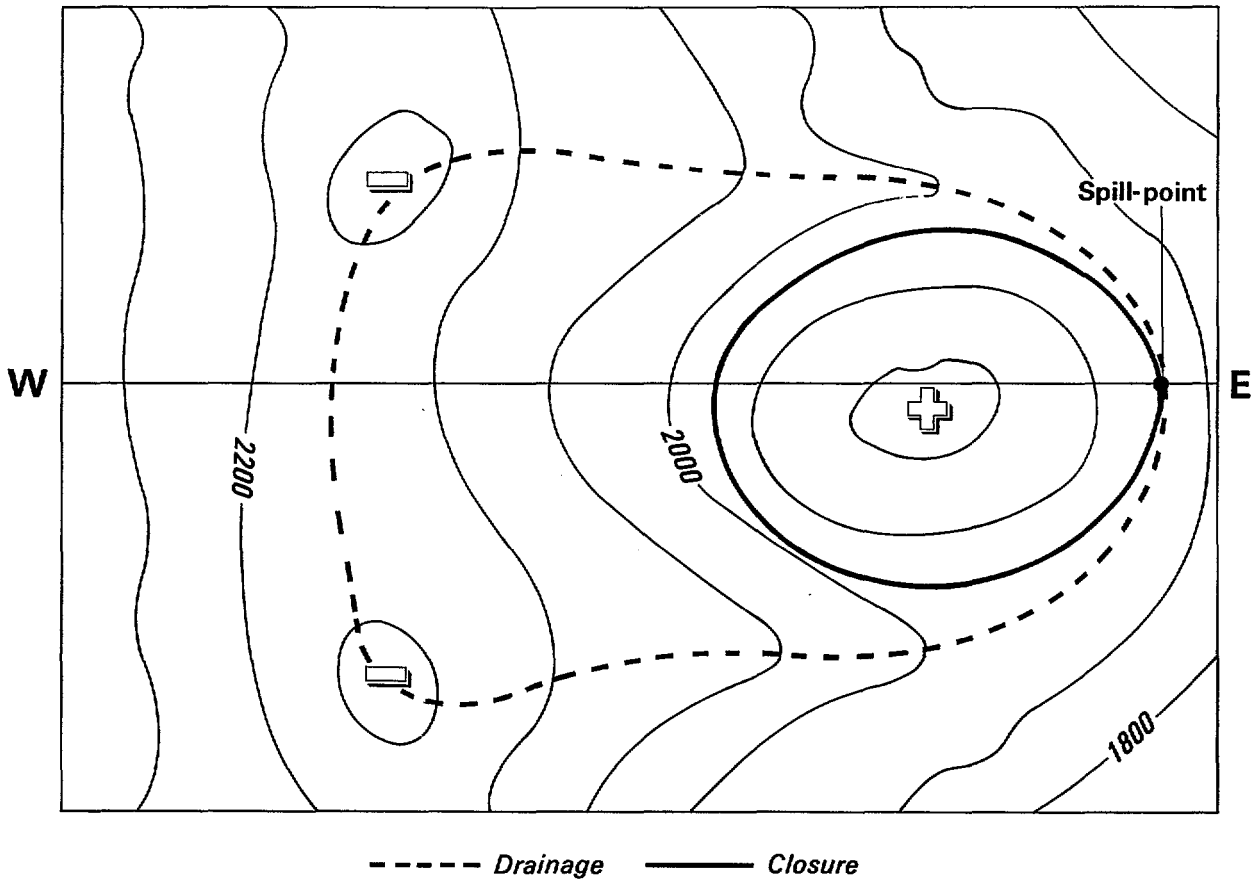

Figure 5a. Two way time contour map of a simple anticlinal trap showing drainage area (dashed line), closure area (solid line), and spill-point.

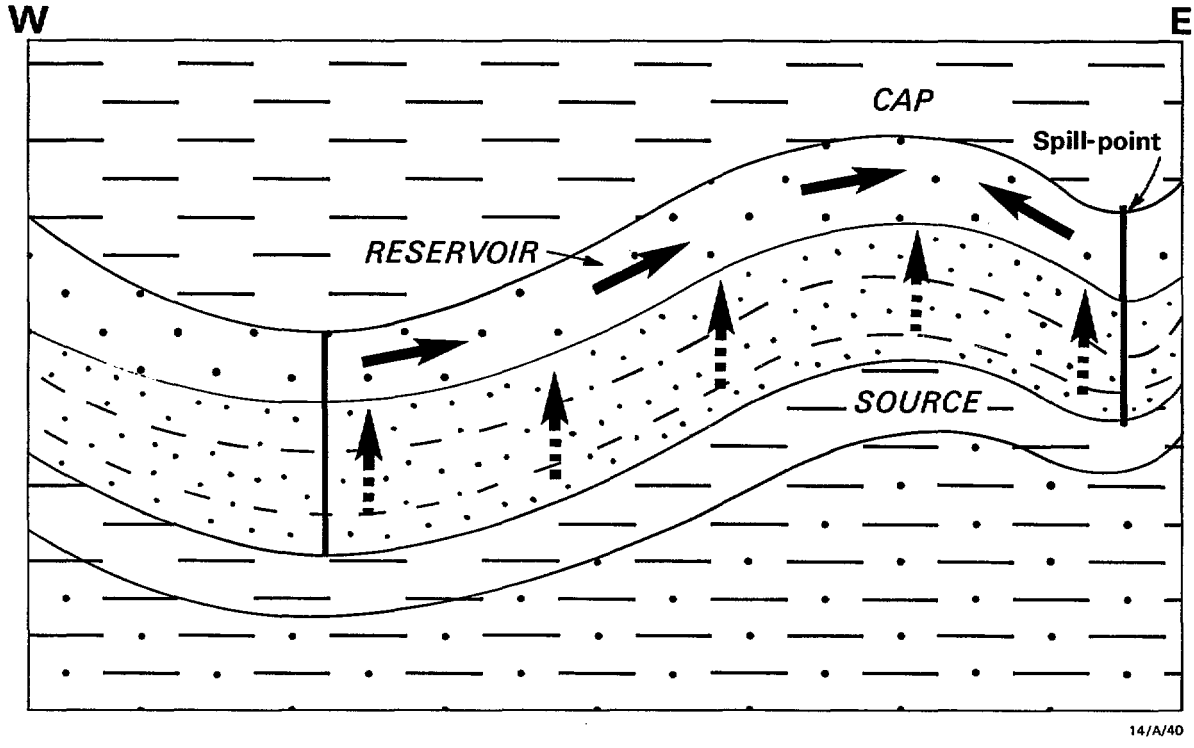

Figure 5b. Cross-section of the anticlinal trap along E-W showing possible migration paths of petroleum from source to reservoir rocks and into trap.

operating company (e.g. Fig. 5a) or, preferably, on post-drill maps. Where a detailed structure contour map of the play is available, the areas of closure of the traps that remain to be drilled can be measured directly and then arranged into their likely order of drilling. Where the effective trap type is unknown, the areas of closure and drainage corresponding to each trap type are measured and are all recorded in a confidential section of BMR's well data storage and retrieval system (PEDIN).

The procedure is more difficult where complex traps are involved. Figure 6 is an example of a complex trap; in which the lowest closing contour outlines an anticline with five culminations. Consideration of the geometry indicates eight possible traps (areas of closure) and leads to the concept of an order (Forman & others, 1989a) for each of them. The largest trap, which forms no part of any other trap, is classified as first order. The two smaller traps that it incorporates are classified as second order. Similarly, the two traps incorporated within one of the second order traps are classified as third order, and the three traps incorporated within one of the third order traps are classified as fourth order. There is an area of drainage corresponding to each area of closure and these are also classified as first order, second order, and so on.

If a play contains complex traps, the areas of closure in their order of drilling (Fig. 4a) must be determined for each order of traps. Where a large body of historical data is available, the structure contour maps should be examined to determine the type, order, and area of each trap tested. Where few historic data are available, the areas of closure must be determined using available geological information, subjective judgement, and analogy. If analogue data from another area are to be used, care must be taken to select a play with a similar proportion of complex traps.

DRAINAGE RATIO AND TILT OF TRAPS

Drainage ratio is the ratio between the areas of drainage and closure (DR = A_{drain}/A_{clos}) of a trap. In some plays (Forman & others, in prep.), average DR will increase with decreasing average A_{clos}. The major cause of this relationship is the various amount of tilt of the sedimentary rocks containing the traps. Tilting of a few degrees has little effect on A_{drain}, but it substantially reduces A_{clos}, thus increasing DR. To a lesser degree DR also depends on the type of trap and its shape.

Hence, a play with a variable degree of regional dip may be expected to have some traps, large and small, which are nearly horizontal and have low

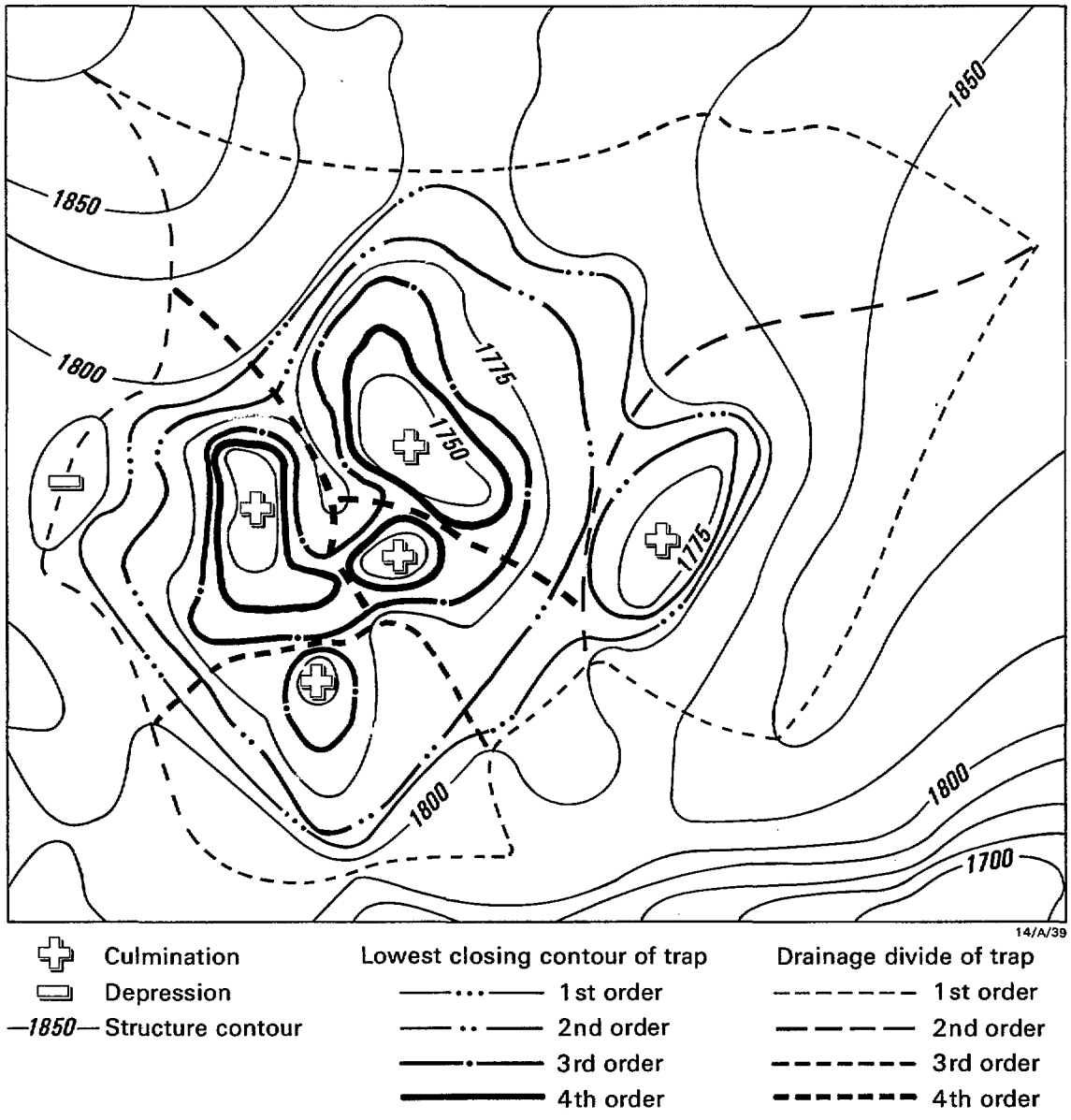

Figure 6. Two way time contour map of a complex anticlinal trap from the Cooper Basin showing areas of closure and drainage for eight possible traps belonging to four orders.

drainage ratios and a proportion of smaller traps which are tilted and have higher drainage ratios. Because of the tendency to drill the areally larger traps early, DR in such a play will tend to increase with drilling sequence number (Fig. 7a). Average DR will remain constant with drilling sequence number, however, in a play with consistent regional dip throughout (Fig. 7b).

In a complex anticlinal trap (Fig. 6), the areas of closure of higher order traps must add up to a lower value than that of the lower order trap that contains them, while their areas of drainage must add up to the same value. It follows that the average DR for each order of traps will increase with trap order.

It also follows that the average angle of tilt of the traps in each order will increase with trap order, until the tilt becomes too steep for anticlinal traps to exist. There is a theoretical limit, therefore, to the number of orders of anticlinal traps and therefore to the number of effectively fractal plays. The magnitude of this theoretical limit depends on the shape of the traps and the overall tilt of the complex trap. It will decrease from a maximum value at zero tilt, through to a value of one at the tilt angle at which the trap regresses from complex to simple, and finally to a value of zero when the tilt is too high for a trap to exist.

RESOURCES PER UNIT AREA OF CLOSURE

The resources per unit area of closure of the undiscovered accumulations are estimated by the computer program using loglinear models of V_{Aclos} versus discovery sequence number that correspond to the successive sampling scheme and have been built up either from plots of the resources per unit area of closure of the identified accumulations in their order of discovery (Fig. 8), or by analogy with better explored plays, or by direct theoretical calculations such as those outlined by Bishop & others (1983) and Sluik & Nederlof (1984).

Determination of V_{Aclos} using historic data

The petroleum in each accumulation can be classified as conventional and unconventional. Conventional petroleum is contained in reservoirs capable of flowing the petroleum at an economic rate. Unconventional petroleum is contained in thin or tight reservoirs which would flow the petroleum at uneconomic rates and is not classified as a resource. In practice, there are few estimates of the unconventional petroleum in accumulations and it is usually necessary to ignore this amount. The identified resource (V)

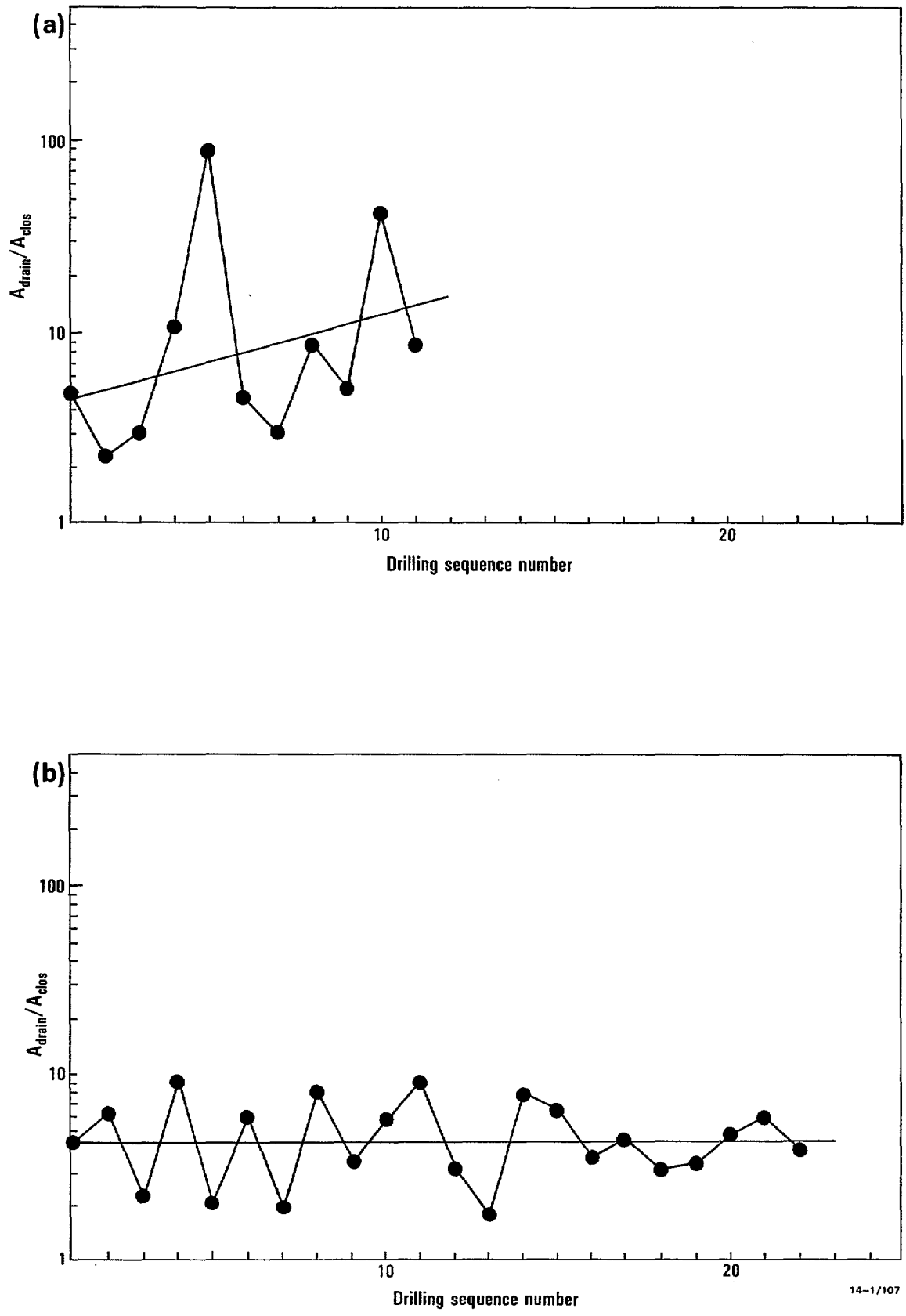

Figure 7. (a,b) Drainage ratios (A_{drain}/A_{clos}) for the first order structural traps in two Permian plays within the Cooper Basin, both plotted on a logarithmic scale in order of drilling. The straight lines have been fitted by the method of least squares.

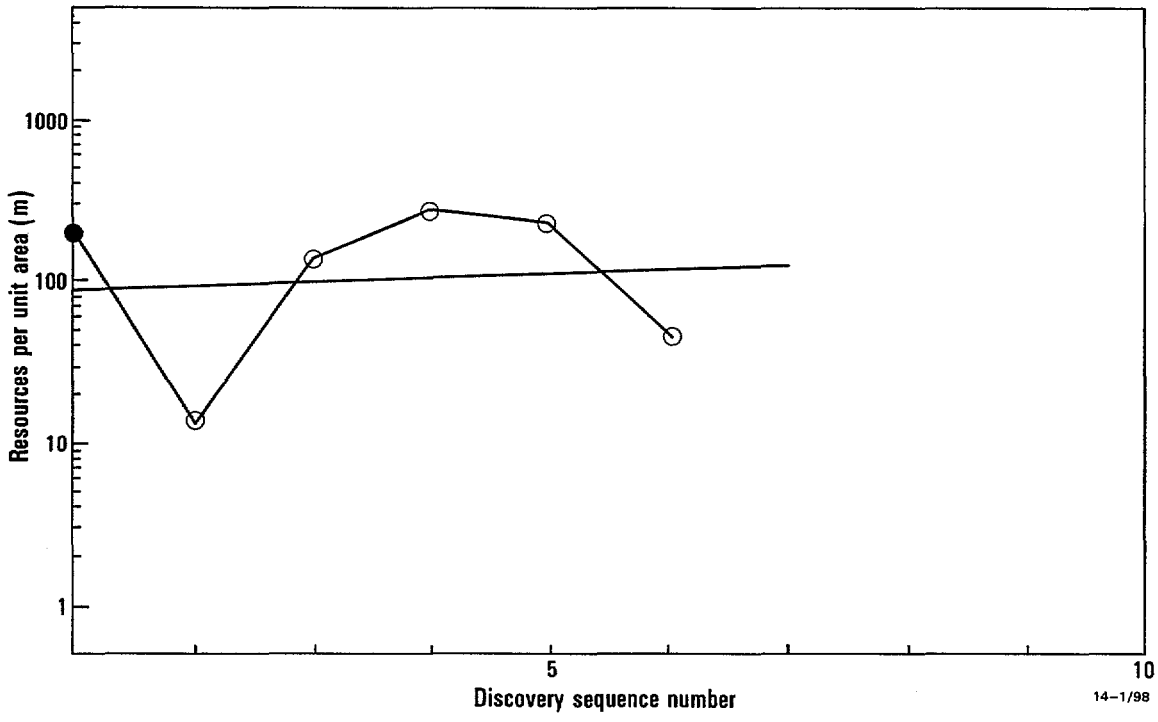

Figure 8. Recoverable sales gas resources per unit area of closure (V_{Aclos}) of the identified accumulations within first order traps in a Permian play in part of the Cooper Basin plotted on a logarithmic scale in order of discovery. Solid circles show traps that are known to be filled to their spill points. The straight line has been fitted by the method of least squares.

in each accumulation is, therefore, taken to equal the demonstrated resource plus some, unknown, part of the inferred resource. The total, demonstrated plus inferred resources, commonly equals the amount of petroleum that the trap would contain if it was filled to spill-point.

It is necessary, therefore, to record the initial, in-place and recoverable demonstrated and inferred resources of crude oil and sales gas in the confidential data storage and retrieval system. Sales gas, where it is present, is converted to crude oil equivalents using the conversion factor:

$$O_{ge} = RF_{oil}.GVF/RF_{gas}.FVF \qquad (3)$$

where RF is the recovery factor and FVF and GVF are the formation volume factor and the gas volume factor.

The resources per unit area of closure of each identified accumulation are calculated by dividing its estimated recoverable resource of petroleum (V) by the area of closure (A_{clos}) of the trap in which it occurs. Where a trap is only partly filled the value of V_{Aclos} is referred to as the retention factor; where a trap is filled to the structural spill-point of the main seal the value of V_{Aclos} is called the capacity factor (V_{Acap}).

If a trap is only partly filled, the value of V_{Acap} may be approximated by dividing the identified resources in the accumulation by the area of the accumulation (i.e. $V_{Acap} = V/A_{acc}$). In some cases, V_{Acap} may also be calculated by dividing the demonstrated plus inferred resources in the accumulation by the area of closure of the trap. Where a trap is filled to capacity, the actual value of V_{Acap} will depend on the thickness and quality of the reservoirs, the geometry of the trap, the temperature and pressure, and the holding capacity of any individual seals that occur within the reservoir sequence.

Where complex traps are involved, the resources per unit area of closure and the order of discovery for each accumulation must be determined separately for each order of traps. The accumulation maps should be examined to determine the order of the trap in which each identified accumulation occurs.

It is important to consider the part played by migration in charging a trap with petroleum. For instance, a trap filled to spill-point has probably spilled some petroleum into the adjacent, downstream trap, increasing the value of V_{Aclos} in the downstream trap. Hence, the

downstream trap can only be used as an analogue for traps that are likely to occur downstream from a filled trap.

Determination of V_{Aclos} by calculation or analogy

In a simple case, where all the petroleum in a trap has originated in its adjacent drainage area, the amount of petroleum and, therefore, the value of V_{Aclos} for a trap that is underfilled depend on the richness and maturity of the source rocks, the efficiency of migration from source to reservoir, the drainage ratio of the trap, and the holding capacity of the cap rocks. It is important to note, however, that the effective drainage area may be difficult to determine and may depend on the adequacy of the lateral seals in possible down-dip fault and stratigraphic traps as well as the tendency for petroleum to overflow from down-dip traps.

In these cases where some of the petroleum in a trap has migrated in from outside, the value of V_{Aclos} in the trap also depends on the geometry of the interface between trap and seal in the vicinity of the trap. Assuming that the resources that enter the trap per unit area of drainage (V_{Adrain}) can be calculated, the assessor then needs to determine: the geometry of the trap itself, whether it is simple or complex; the geometrical relationships and migration paths from neighbouring traps; the drainage ratios of the traps; and their capacity factors. The importance of these geometrical factors is demonstrated by looking at the different relationships that arise between trap geometry and petroleum charge in four separate models.

Model one - a simple trap with no migration

Model one (Forman & others, 1989b) incorporates two genetic assumptions: (1) that all the petroleum within a trap has originated within the immediate drainage area (A_{drain}) of the trap and (2) that the area of closure (A_{clos}) of the trap has only one culmination. The cumulative amounts of oil and oil-equivalent gas that are expelled from the source rocks and may migrate into a unit area of the reservoir rocks (V_{Adrain}; Fig. 5b) may be expressed as a vertical height in metres, measured at surface temperature and pressure. Providing that all this petroleum migrates into the trap, that the trap is only partly filled, that no petroleum is lost during migration in the reservoir, and that there has been no leakage through the cap rocks, the amount of petroleum that it contains is:

$$V = V_{Adrain} \cdot A_{drain} = V_{Adrain} \cdot A_{clos} \cdot DR \qquad (4)$$

where $DR = A_{drain}/A_{clos}$.

The resources per unit area of closure or retention factor,

$$V_{Aclos} = V/A_{clos} = V_{Adrain}.DR \qquad (5)$$

The capacity factor may be calculated by the equation

$$V_{Acap} = h.\phi.HS.RF/HVF \qquad (6)$$

where h is the thickness of the reservoir, ϕ is the average porosity, HS is the hydrocarbon saturation, RF is the recovery factor, and HVF is the hydrocarbon volume factor.

Model two - a complex trap with internal migration

Model two (Forman & others, 1989a) incorporates the assumptions (1) that several culminations occur within the area of closure of the trap (Fig. 6) and (2) that all the petroleum within the trap has originated within its immediate drainage area. If nearly filled with petroleum, such a complex trap would contain a single accumulation within its overall area of closure. If partly filled with petroleum, the same complex trap may contain several accumulations, each within a separate area of closure. The amount of petroleum and therefore the value of V_{Aclos} in each trap within the complex depends on the amount of petroleum that was generated in the trap itself, the amounts that spilled into it from other traps that are filled to spill-point, and its capacity factor.

Where the loglinear models of V_{Aclos} versus discovery sequence number for each order must be built up by calculation it is necessary to allow for the possibility of secondary migration within the complex trap and the additional drilling needed to identify all the resources. If analogue data from another area are to be used, care must be taken to select a play with a similar proportion of complex traps with similar resources per unit area of closure. A complete methodology is still being developed.

Model three - a group of traps with migration

Model three recognises that there may be extensive secondary migration within a play, in many cases through a string of traps (fairway) into a trap that might otherwise contain no petroleum because it is underlain by immature source rocks (Fig. 1). Such migration is a result of spilling from filled traps. Assuming no leakage from or into the play, the amount of petroleum in each trap and therefore the value of V_{Aclos} is equal to the amount of petroleum, if any, that has been generated in its drainage area, plus the amounts that have been spilled into it from adjacent traps, less the amount that is spilled from the accumulation into adjacent traps.

Hence, accumulations formed according to model three include one or more that are filled to spill-point and an adjacent trap that is only partly filled. A variety of equations may be written for the resources per unit area of closure in model three traps, depending on the resources per unit area of drainage in individual traps in the fairway.

If values of V_{Aclos} or V_{Adrain} for traps that contain migrated petroleum are to be determined by analogy, they should only be chosen from other traps containing migrated petroleum.

Model four - traps with leaky cap rocks

The concept that some, or even most, traps may be filled with petroleum to a leak-point (rather than a spill-point) complicates the interpretation of the genesis of the accumulations in terms of the preceding models and makes selection of analogues and interpretation of data trends particularly difficult, indicating a vital area for further study. There are two possible, but not necessarily exclusive, models for a leaking cap rock: in one the leakage occurs at a specific location in the cap rock, such as along a fault; in the other the leakage is more diffuse and may occur more or less uniformly across the area of the cap rock.

Some preliminary studies of traps which appear to have leaked petroleum (Radlinski & others, 1988; Nederlof; 1981) indicate that, within restricted depth ranges, there may be a correlation between the thickness of the shale cap rocks and the buoyancy pressures exerted on them by the underlying hydrocarbon columns. Further work is needed to develop the method in case it can be used to predict the amount of leakage through specific cap rocks.

PREDICTION OF FUTURE TRENDS

Forman & others (1989b) indicated a number of reasons why extrapolation of past trends may underestimate future trends. These included future revisions to estimates of identified resources, insufficient exploration history, variation in economic factors, and future changes in economics, data quantity and quality, or geological interpretation.

The interaction between trap geometry and petroleum charge can also affect future trends. For example, different trap types, such as isolated stratigraphic fans, faults, and anticlines can be logically expected to have systematically different values for DR and therefore for V_{Aclos}. Hence a plot of the log V_{Aclos} versus discovery sequence number for accumulations within all three trap types might be expected to show a

declining trend as anticlinal traps tend to be drilled early and fans tend to be drilled late.

Another example occurs in plays (Fig. 7a) where, as discussed previously, the average value of DR increases with drilling sequence number and with decreasing average A_{clos}. A proportion of the smaller traps, which are drilled later, are tilted and have high DR's, high values for V_{Aclos}, and high values for fraction trap fill ($TF = V_{Aclos}/V_{Acap} = A_{acc}/A_{clos}$). Where this occurs the plot of log V_{Aclos} versus discovery sequence number should show a gentle incline. Once the traps are filled to spill-point, however, and there is a correlation between log V_A and discovery sequence number (as a consequence of the well-known positive correlation between the area of the accumulation (A_{acc}) and net pay thickness (Masters & others, 1986)), the plot of log V_{Aclos} versus discovery sequence number should show a declining trend (Fig. 8).

Where there is little variability in the degree of tilting of the traps in a play (Fig. 7b), the plot of log V_{Aclos} versus discovery sequence number (Fig. 8) is likely to have either a horizontal or a negative slope, rather than a positive slope.

In the event that traps have leaked through specific, randomly distributed locations in the cap rock, the plot of log V_{Aclos} versus discovery sequence number should have gentle negative slope. If, on the other hand, leakage is more uniform and relates to the thickness of the cap rock, the loglinear plot could be expected to have a positive slope for the larger traps which are only part filled and a negative slope for the smaller traps which are filled to spill-point.

SUCCESS RATE

The historic success rate of a play is the slope of the plot showing the discovery sequence number of each petroleum accumulation versus its drilling sequence number. Where complex traps are involved, a separate plot may be drawn for each order of traps (Fig. 9). A triangular distribution of linear success rates that covers the likely range for future drilling may be estimated either from these plots or after analysis of the trap risks involved as described by Baker & others (1986).

PROPORTION OF OIL TO OIL AND GAS

The proportion of recoverable oil to oil and gas in a play is expressed both as the proportion by number of the oil, gas, and oil and gas accumulations and as the proportion by volume of the oil in the oil and

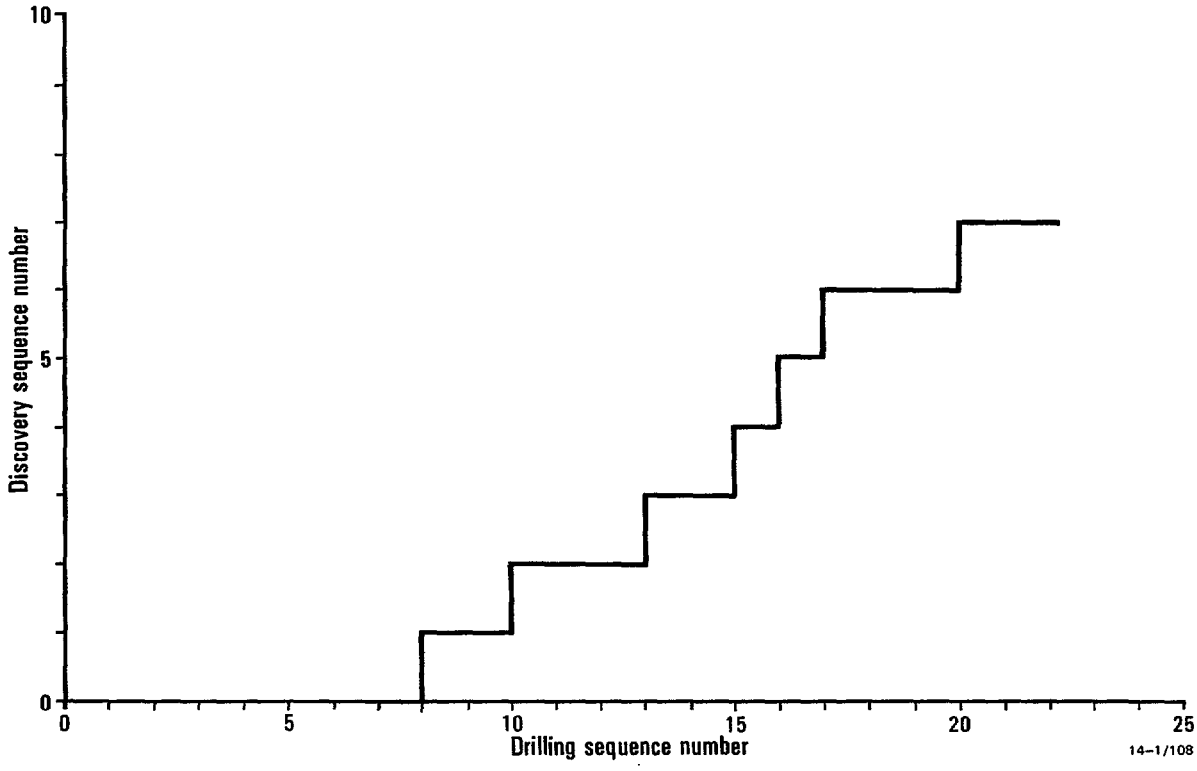

Figure 9. Drilling sequence number plotted against discovery sequence number for first order traps in a Permian play within part of the Cooper Basin. The slope of the plot is the historic success rate.

gas accumulations. Where historic data are lacking, the proportions may be determined by analogy with a similar play, preferably within an adjacent area.

SMALLEST SIZE OF ACCUMULATION

For each play it is necessary to estimate the smallest size of accumulation that could be brought into economic production during the next 20 to 25 years. Determination of the size requires consideration of many engineering and economic factors some of which are uncertain at this time. An econometric analysis would be difficult to make and subjective estimation by specialists appears the best approach. The smallest size of accumulation to be included as a resource is considerably smaller than the minimum economic reservoir size required under present day economics.

ASSESSMENT OF UNDISCOVERED PETROLEUM RESOURCES

The computer program for assessing undiscovered petroleum resources (Hinde, 1986; Forman & Hinde, 1986; Forman & others, 1989b) simulates drilling every trap in the play during each iteration. The undiscovered petroleum resources in a trap (j) are calculated probabilistically using the equation

$$V_{ij} = A_{clos,ij} \cdot V_{Aclos,ij} \cdot d_{ij} \cdot c_{ij} \qquad (7)$$

where V_{ij} is the simulated volume of crude oil in trap j during iteration i; $A_{clos,ij}$ is the area of closure of the trap; $V_{Aclos,ij}$ is the resources per unit area of closure; d_{ij} is either 0 or 1 depending on whether a random number is greater or less than a random value chosen for iteration i from the distribution for the success rate; and c_{ij} is either 0 or 1 depending on whether V_{ij} is smaller or larger than the random value chosen for iteration i from the distribution for the smallest size of accumulation to be included as a resource.

The computer program chooses a linear model of log A_{clos} versus drilling sequence number for each iteration by selecting a random value of lambda from the normal distribution and by determining the corresponding values for the average slope, intercept, and standard deviation from the linear least-squares regression equations in conjunction with equation 2.

A corresponding model of log V_{Aclos} versus discovery sequence number for each iteration is chosen in a different way to that for the log A_{clos} model. In cases where the same distribution of log V_{Aclos} applies to all discovery sequence numbers, a distribution is chosen by selecting random values of the average and standard deviation of the normal

distribution of log V_{Aclos}. In cases where log V_{Aclos} correlates with discovery sequence number, there must also be a correlation between log A_{clos} and log V_{Aclos} so that the slope of the log V_{Aclos} model has to be determined using the value selected for the slope of the log A_{clos} model and the equation for the correlation coefficient between log A_{clos} and log V_{Aclos}.

Discoveries are simulated during each iteration by comparing a random value of the success rate with a random number selected for each trap. The values of A_{clos} and V_{Aclos} for each simulated discovery are then chosen by extrapolation and random sampling of the linear models. The amount of petroleum in each accumulation is estimated in oil equivalents. Provided that this amount exceeds the minimum to be included as a resource, the oil resources in the trap equal $V_{ij}.P_{o,ij}$ and the gas resources equal $V_{ij}.(1-P_{o,ij})$, where $P_{o,ij}$ is a random value chosen from a distribution of possible values for the proportion of oil to oil plus gas. The oil and gas resources are then totalled separately for each iteration using the equation

$$V_{tot,i} = E_i \sum_{j=1}^{n} V_{ij}. \qquad (8)$$

where $V_{tot,i}$ is the total undiscovered oil or gas resource simulated during an iteration, E_i is either 0 or 1 depending on whether a random number is greater or less than the existence risk, and n is the number of traps. The total undiscovered oil and gas resources simulated during each iteration are then accumulated into histograms of undiscovered resources.

Another computer program (Hinde, 1986) is used to add up the histograms of the undiscovered petroleum resources in each play, taking into account the dependent risks for fractal plays and any dependence that may be perceived in the risks between laterally and vertically adjacent plays. The assessment of the region is given as two cumulative probability distributions, one of which indicates the probabilities of finding more than certain amounts of oil and the other indicates the probabilities of finding more than certain amounts of gas, as a consequence of drilling a specified number of new-field wildcat wells.

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APPENDIX C

Summary of the Petroleum Search Subsidy Scheme, 1957-1974 and Title award systems For Australia's offshore Areas

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CONTENTS

The Petroleum Search Subsidy Act

Legislation to implement a subsidy scheme for petroleum exploration was introduced by the Commonwealth Government in 1957. The following brief summary of the legislation is based on a detailed review by Williams (1974).

The 1957 Act provided subsidy only for stratigraphic drilling. By 1959 it appeared that this was tending to encourage drilling based on inadequate preliminary work and a new Act was passed to extend subsidy to regional geophysical surveys and electric logging of wells.

The 1959 Act was amended in 1961 to include detailed geophysical work, and wells drilled to test structural prospects, in recognition of the fact that in some areas, sufficient information had been acquired for exploration to proceed to a more detailed stage. In addition, the required period of confidentiality for the information obtained by the subsidised operations was reduced from twelve months to six.

Amendments in 1962 and 1964 were designed to limit the increasing financial burden to the public purse of the subsidy scheme. In 1962 the maximum subsidy of 50% was reduced to 30%. By 1964, discoveries had been made in Queensland, South Australia, Northern Territory and Western Australia, and exploration was moving into the higher cost offshore areas. Operations within certain defined areas ('excluded areas') around discovery wells and developed fields, were excluded from subsidy. A

further amendment in 1969 excluded offshore operations from subsidy if there was no Australian contribution to their cost.

A final amendment in 1972 restored the maximum level of subsidy for onshore operations to 50%, and the 'excluded areas' restriction was removed for both onshore and offshore operations.

A cross-section of opinion expressed at the time is indicative of the success of the subsidy scheme (see Chapter 6 for References).

Traves (1962) (then Exploration Manager, Mines Administration Pty Ltd) commented that 'There is no doubt that Commonwealth subsidy increased oil exploration in Australia. With companies on a limited budget it probably doubled their work capacity ... .'

Rudd (1966) (then University of Adelaide) stated that 'There is little doubt that the Petroleum Search Subsidy Act was one of the major factors which led to success in the search for petroleum, both oil and gas, in this country'.

Rayner (1969) (then Director, BMR) commenting on the financial contribution of the scheme, stated that 'the financial contribution is no doubt particularly important to those companies which finance their exploration from capital. Not only does it help them directly to finance their exploration but it helps them to raise capital through demonstrating the Government's confidence in the ultimate success of the search'.

Williams (op. cit.) (then Assistant Director, Petroleum Branch, BMR) considered that the most important result was probably the release to the public of properly documented data, including cores and cuttings, at an early date after the completion of each operation, and that this availability of information was a major factor in encouraging companies to explore in Australia. Although he recognised the financial assistance provided as a major factor in encouraging Australian and some of the smaller overseas companies, he thought it probable that the major companies would have carried out similar programs, at least since the mid-sixties, even without the subsidy*. (* This may be true, but the data would probably not have been made public (authors' comment).)

Sprigg (1975) (then Geosurveys of Australia Pty Ltd, also Foundation Chairman of APEA) speaking on the role of Government in petroleum exploration, stated that the 'imaginative subsidy scheme ... offered the greatest incentive to serious exploration yet devised'.

The subsidy scheme was in force from 12 December 1957 to 30 June 1974. Subsidy paid for Australian operations amounted to $119 707 242, and for operations in Papua New Guinea (PNG), $19 781 330. The number of subsidised wells drilled totalled 659 of which 24 were in PNG. There were 973 subsidised geophysical operations (55 in PNG).

Figure 1 relates annual subsidy payments to the effects of the various changes as the legislation was amended (Williams, op. cit.). The most marked break in the curve occurred in 1969, reflecting the effect of the restrictions placed on subsidy for offshore operations. The introduction of the 'excluded areas' was followed by a period of fairly constant payments. The increase in 1973 followed the removal of the excluded areas and an increase in the rate for offshore geophysics in 1972, plus the announcement of the termination date for the subsidy scheme. Figure 2 showing subsidy payments for onshore and offshore, clearly demonstrates that the sharp increase in payments from 1967 to 1969, and the subsequent decline, is related to the level of subsidised offshore activity. Annual subsidy payments on a State or Territory basis are shown in Figure 3. Payments were mainly in Queensland in the early 1960s, and in Western Australia and PNG in the late 1960s and early 1970s. In Queensland, payments were predominantly for onshore operations due to the curtailment of offshore work by the Barrier Reef moratorium imposed in the early 1970s. Payments in South Australia were also predominantly for onshore exploration. Offshore payments predominated in Victoria from 1965 to 1970, and in Western Australia from 1969 to 1971.

The Petroleum (Submerged Lands) Act 1967

The Petroleum (Submerged Lands) Act (P(SL)A) came into force on 22 November 1967 as mirror legislation of the Commonwealth and the States (the Joint Authority) to regulate the search for and production of petroleum in Australia's offshore areas. Starkey (1983) gives a detailed discussion of subsequent development of P(SL)A and associated offshore petroleum legislation. Commonwealth legislation applies beyond the three nautical mile Territorial Sea, where the administration and supervision of exploration and development activity is the joint responsibility of the Commonwealth and the States (the Joint Authority). The Joint Authority determines important matters relating to title, and day-to-day administration is carried out by the States (the Designated Authority).

Within the Territorial Sea the States have the sole responsibility for the administration and supervision of exploration and development

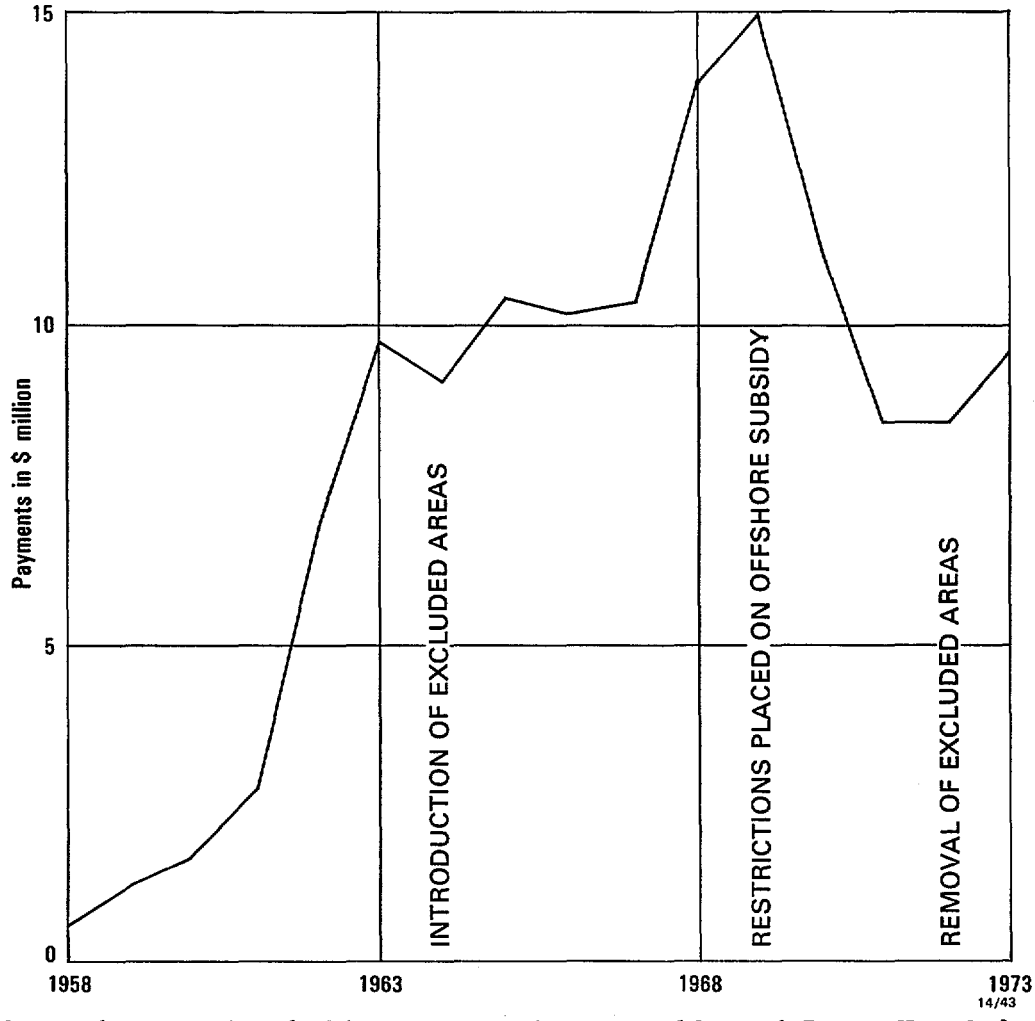

Figure 1 Annual subsidy payments in Australia and Papua New Guinea (1958-1974) (Williams, 1974).

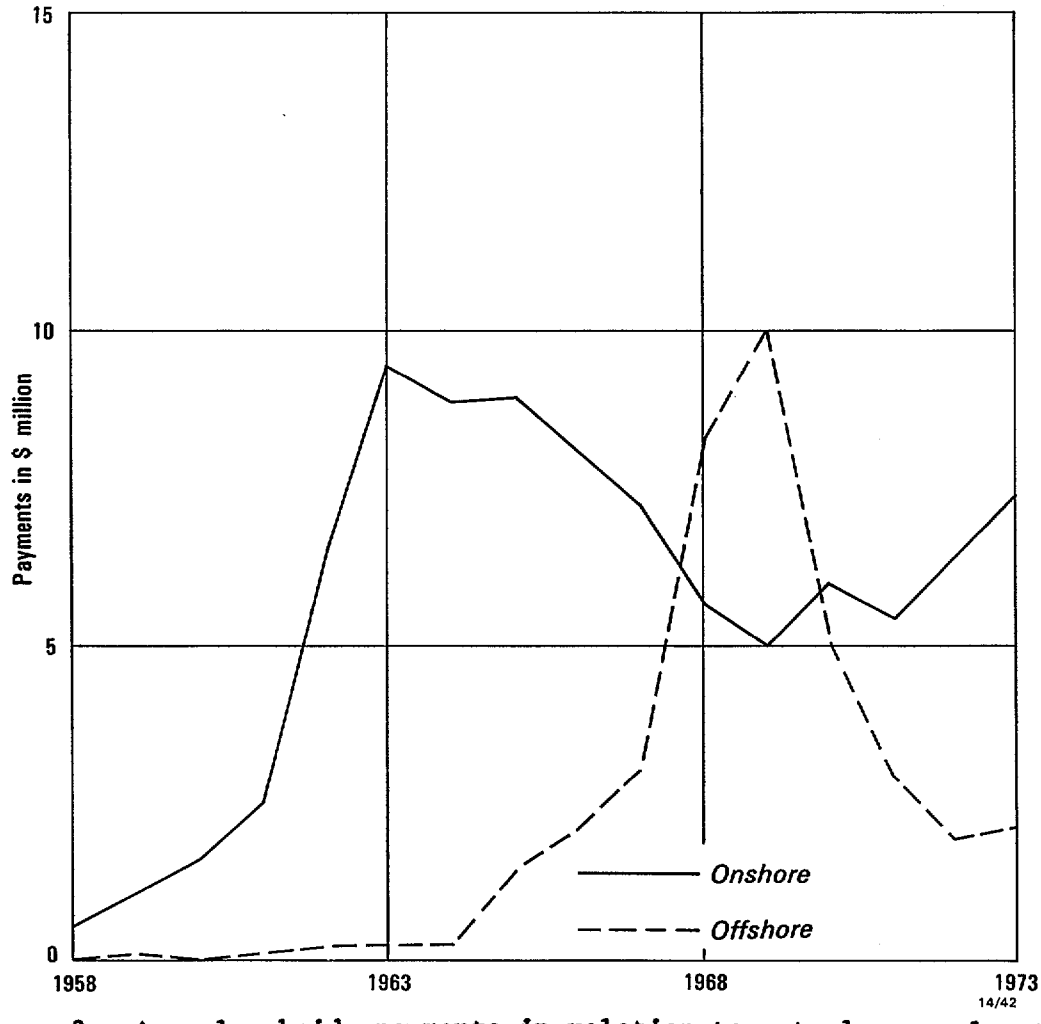

Figure 2 Annual subsidy payments in relation to petroleum exploration activity onshore and offshore (1958-1974) (Williams, 1974).

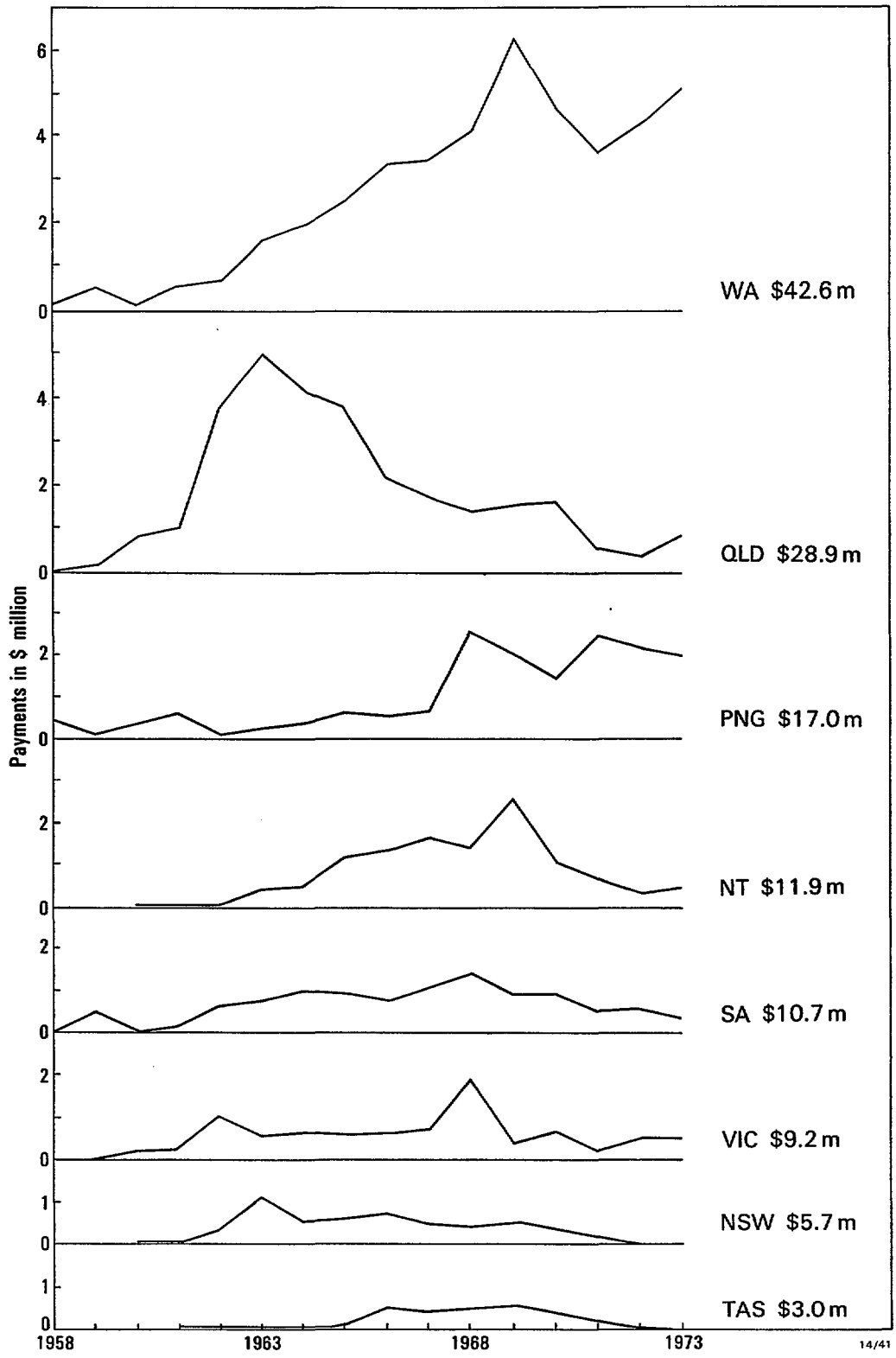

Figure 3 Annual subsidy payments in relation to petroleum exploration activity in each State (1958-1974) (Williams, 1974).

activity as an extension of their responsibilities for activities in the onshore areas.

Exploration permits

For the purpose of Title awards (Exploration Permits, Production Licences, etc.) the offshore area is divided into graticular blocks of five minutes Latitude by five minutes Longitude.

The maximum area for an exploration permit is 400 graticular blocks (between 25 900 and 31 100 sq km), and there is no limit to the number of permits that may be held by any one company.

Work program bidding system

From 1967 to 1985 exploration permits were awarded under a work program bidding system in which the monetary value of the work program constituted a basic condition of the permit award, but a guaranteed commitment to undertake the proposed work program did not. In practice, this arrangement had the potential to encourage companies to propose unrealistically high level work programs to obtain the permits, resulting, in some areas, in frequent requests for variations of permit conditions, early permit relinquishments, and less than optimum levels of exploration activity, particularly drilling.

Modified work program bidding system

The system was modified in 1985 to address these problems. Under the modified system, permits are awarded primarily on the basis of a minimum guaranteed 'dry hole' work program commitment for the first three years of the initial six year permit term.

The primary criteria for the awards (Commonwealth of Australia, 1988a) are:

. 'the number of wells to be drilled on a minimum guaranteed 'dry hole' basis, in each of the first three permit years;* and

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* 'Applications proposing equal numbers of wells on a minimum guaranteed 'dry hole' basis in the initial three year period will not be assessed on the basis of data evaluation and geophysical surveying activities alone, but will also be assessed against the other primary and, if necessary, secondary criteria. A similar assessment process will apply to competing applications in which no wells are proposed in the initial three year period.'

- the extent to which the minimum guaranteed 'dry hole' program, including the drilling program, data evaluation and geophysical surveying activities, reflects the available technical information on exploration prospects in the area, seeks to follow up existing leads, and seeks to identify and assess new exploration prospects in previously unexplored parts of the area - to be assessed on the basis of a detailed review of the objectives of the individual items of work proposed.'

The technical and financial capacity of the applicant to undertake the proposed work programs are also considered.

In cases where competing applicants cannot be separated on the basis of the above criteria, the following additional criteria are used collectively (in no priority order):

- 'in the interest of diversifying exploration activity in Australia and introducing fresh exploration approaches to a particular petroleum province, consortia which include new explorers to the petroleum province in question with a significant percentage participating interest, whether Australian or foreign owned, may be given preference;

- consistent with the Government's wish to see a continuing and significant level of Australian involvement in petroleum exploration, preference may be given to consortia with high levels of Australian participation;

- consideration will be given to the intent of consortia members (including past performance) to source goods and services in Australia, including willingness of foreign companies to transfer technology and skills to Australians;

- consideration will be given to the intent of consortia members (including past performance) to undertake research into exploration techniques and technology in Australia; and

- where the permit under consideration is in a highly prospective area, preference may be given to applicants that have demonstrated a recent willingness to apply for permits in less prospective or 'frontier' areas.

In the event that the best applicant cannot be chosen on the basis of these criteria, consideration will be given to the amount and timing of work proposed under the 'secondary' program.'

Failure of a permittee to undertake each component of the minimum guaranteed work program in the designated year results in cancellation of the permit unless conditions of 'force majeure' apply.

The work program commitments for Years 4 to 6 of the permit term secondary work program) may be revised under certain conditions. The applicant may submit a revised secondary work program no earlier than six months, and no later than three months, before the end of Year 3, for consideration by the Joint Authority. If the revised program is considered to be of lower quality than the original, and no agreement can be reached on a mutually acceptable program, the permittee may surrender the permit in good standing or continue with the original program.

At the beginning of Year 4 the secondary work program becomes guaranteed on a year by year basis, and each component must be undertaken in the designated year or the permit is cancelled, unless conditions of 'force majeure' apply. Surrender of the permit in good standing may only be agreed in a permit year if the permittee has completed the guaranteed work for that year.

The permittee has the option to renew the permit at the end of the initial six year term. The first and subsequent renewals are for five year terms, and usually half the area held must be relinquished on each renewal. The conditions of the modified work program bidding system continue to apply in the granting of renewals.

Cash bidding system

A cash bidding system was introduced in 1985 for certain areas considered to be highly prospective. Permits are awarded to the highest cash bidder provided they satisfy criteria of technical competence and financial viability.

The permits are awarded for a six year term, but are not renewable unless a renewal option is included in the award negotiations.

Only three areas, located in the Territory of Ashmore and Cartier Islands in the Timor Sea, have been awarded under the cash bidding system. Details of the release are given in Chapter 6.

Production Licences/Retention Leases

Production Licences are awarded over discoveries that can be developed in the short or medium term, and Retention Leases over discoveries considered non-commercial because of a lack of markets, necessary technology or insufficient reserves at current petroleum prices. Permit holders have a preferential right to licences.

The acquisition of a licence/lease requires an initial nomination by the permittee of an area around the discovery referred to as a 'location'. The permittee then has up to two years in which to apply for either a Retention Lease or a Production Licence.

Prior to the amendment of the legislation in 1987, a location was normally required to contain nine graticular blocks. Under the amended regulations a permittee

> 'may nominate the block in which the pool is situated, or the blocks (being blocks within the permit area) to which the pool extends, for declaration as a location' or

> 'where 2 or more petroleum pools are identified in a permit area, the permittee may, ... nominate all of the blocks to which the pools extend, or to which any 2 or more of the pools extend, for declaration as a single location.'

A location may not be nominated unless petroleum has been recovered from the pool(s) (whether within or outside the permit area) to which the nomination relates, and the Joint Authority must be satisfied that the number of blocks nominated do not extend beyond the area of the known extent of the pool(s). There is also provision in the Act for blocks to be added or removed from the location as new data become available.

A Production Licence granted before the 1987 amendments could include up to five graticular blocks (about 325 sq km (125 sq miles)) of the nine block 'location' (Primary Licence). The permittee also had the option of taking up all or some of the remaining four blocks as a Secondary Production Licence. Any blocks not taken up reverted to the Crown.

Under the amended legislation, one type of Production Licence is granted, and there is no fixed limit on the number of blocks it may contain.

There has been no change to the length of the licence term, which is for 21 years with a renewal option of a further 21 years. The award of a

licence involves immediate development obligations, but no guaranteed exploration work program commitments.

The Retention Lease option was introduced in 1984 to enable a permit holder to maintain tenure over a non-commercial discovery other than by retaining the permit indefinitely, or taking out a Production Licence involving immediate development obligations. Neither of the alternatives encouraged exploration in areas where development was likely to be a long term prospect for technical or commercial reasons.

A Retention Lease is only intended to be used to allow tenure over significant discoveries, and there is no reduction in the work program commitments applicable to the permit from which the lease is drawn.

In assessing an application for a Retention Lease, the criteria which are taken into account (Commonwealth of Australia, 1988b) are:

- there is no doubt that the discovery is not currently commercially viable;
- there is a reasonable probability that the discovery could become commercially viable within fifteen years.

An applicant must provide work plans to continue to assess the commercial viability of the discovery in the area covered by the application.

Release of data

The regulations governing the release of data obtained under P(SL)A have undergone several amendments since the legislation was introduced.

The initial conditions were that basic data could be released five years after they were lodged with the Designated Authority or immediately the permit was surrendered, cancelled, or expired. Interpretive data could not be released unless already made public by the permit holder or permission obtained by the Designated Authority.

The first amendment was made in 1985 and provided for basic data lodged on or after 22 July 1985 to be released after two years or on surrender, cancelling or expiry of the permit. Interpretive data lodged on or after this date could be released after five years subject to safeguards. The companies involved can lodge an objection on publication of a notice of intent by the Designated Authority. A further amendment which came into effect on 13 November 1987 makes the July 1985 amendment retrospective.

The Regulations are the same for Exploration Permits and Retention Leases. For Production Licences the Regulations are the same with respect to interpretive data, but basic data may be released one year after lodgement with the Designated Authority.

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