UNDISCOVERED PETROLEUM RESOURCES

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Chapter 14

INTRODUCTION

Estimating undiscovered petroleum resources of the Cooper Basin in South Australia is of value in that it gives some quantitative expression of the potential, and some basis for comparison with other basins. The potential for oil discoveries in the overlying Eromanga Basin has been reviewed previously (Morton, 1996). Some oil in Eromanga fields may have been sourced from the underlying Cooper Basin, and the estimate given here for undiscovered oil potential in the Cooper Basin may, in fact include some of the oil already discovered in the Eromanga Basin.

The present discovered recoverable raw gas reserves (at 1.1.98) of the Cooper Basin are 229 x 10^9 m^3 (8.2 tcf) comprising 129 x 10^9 m^3 (4.6 tcf) of produced gas and 101 x 10^9 m^3 (3.6 tcf) of gas yet to be produced from known discoveries. The average recovery factor for gas fields is 64%. The present discovered recoverable oil reserves (at 1.1.98) of the basin are 6.9 x 10^6 kL (43.9 mmstb) comprising 4.6 x 10^6 kL (29.1 mmstb) of produced oil and 2.3 x 10^6 kL (14.8 mmstb) of oil yet to be produced from known discoveries. The combined average primary and secondary recovery factor for oil fields is 21%. More than 80% of the oil reserves are contained in the Tirrawarra Field.

The potential undiscovered petroleum resources of the Cooper Basin have been assessed using a variety of methods, most of which have been summarised by Griffiths (1997). All of these methods may have biases that produce either optimistic or conservative estimates, but if broadly coincidental, give confidence in forecasting the potential of the basin. The methods are described briefly below.

Potential undiscovered resources should not be compared to traditional proved, probable and possible reserves in known discoveries. Undiscovered resources are calculated to give a quantitative indication of the potential of the basin, and require considerable exploration to establish their existence.

METHODS

BASIN ANALOGUE

The simplest method of estimating the undiscovered petroleum potential of a basin is to find a geological analogue that has been sufficiently explored that the resource potential has been fully realised. This method has limited reliability — no two basins are geologically alike, there are few basins where it is certain that all the resources have been identified, and the method ignores nearly all known information about the basin to be assessed. It may be of most use in a basin with little available geological information. Griffiths (1997) estimated the potential of the Cooper Basin using the Oligocene fluvial play in the Texas Gulf Coast Basin (Frio Formation) in the United States as an analogue. This basin has discovered reserves of 1.27x 10^{12} m^3 (45 tcf) of gas and 1.25 x 10^9 kL (7.86 x 10^9 bbl) of oil, and it is estimated that a further 0.327 x 10^{12} m^3 (11.6 tcf) of gas and 0.215 x 10^9 kL (1.35 x 10^9 bbl) of oil are still to be discovered (Galloway *et al.,* 1982). The total rock volume of the basin is 175 227 km^3. The total volume of the Cooper Basin is about 21 000 km^3 (Griffiths, 1997) which, by comparison with the Frio Formation, would give the potential of the Cooper Basin as between 154.3 x 10^9 and 193.5 x 10^9 m^3 (5.5–6.9 tcf) of gas and between 157 x 10^6 and 176 x 10^6 kL (1003–1123 mmstb) of oil. As the present discovered gas reserves of the basin are in excess of these estimates this model (method 1) is regarded as very unreliable.

A second approach (method 2) using the analogue approach and some discovery information is that of Klemme (1984), who used worldwide statistics to suggest that an intracratonic basin would have 20–30% of the total resources in the five largest fields. In the Cooper Basin the five largest gas fields are (in decreasing order) Big Lake, Moomba Central, Della, Toolachee West, and Tirrawarra, with combined raw gas reserves of 101.2 x 10^9 m^3 (3.6 tcf). This would give an ultimate basin gas potential of between 337.3 x 10^9 and 506 x 10^9 m^3 (12–18 tcf). The five largest oil fields are (in decreasing order) Tirrawarra, Moorari, Fly Lake, Telopea, and Brolga, with combined recoverable oil reserves of 6.5 x 10^6 kL (41.3 mmstb). This would give a total basin oil potential of between 21.7 x 10^6 and 32.5 x 10^6 kL (137.7–206.5 mmstb). Klemme's (1984) method is somewhat crude, as it is heavily dependent on the assumptions that the five largest fields have been discovered and that their reserves are accurately known. In addition the definition of a 'field' is subjective, and the above estimate would have been increased if the original field definitions of Moomba and Toolachee were used. Chen and Sinding-Larsen (1994) further refined this method using an underlying Pareto distribution to estimate the number of fields likely to be discovered and their size distribution.

BASIN PLAYS

This method of estimating undiscovered resources consists of identifying all of the petroleum 'plays' that may exist, either by discoveries made so far, or by analysis of the available data (e.g. drillhole, geophysical). The oil or gas potential of a basin is calculated by the following formula:

$$P_t = A_p \times AB \times h \times NG \times NR \times Por \times S_h \times FVF \times SR \times RF$$

P_t total potential recoverable oil or gas reserves of the basin

A_p prospective area of the basin

AB	anticline to total basin area ratio
h	average gross reservoir thickness
NG	net to gross pay ratio
NR	average number of reservoirs per field
Por	porosity (fraction)
S_h	hydrocarbon saturation (1 - water saturation)
FVF	formation volume factor
SR	exploration drilling success ratio
RF	recovery factor

A range of values is attributed to each parameter based on the available data, and these are combined using Monte Carlo techniques. The method uses much more of the known geological information of a basin, but does not use discovery information, therefore is better suited to basins with limited exploration and few discoveries (Morton, 1995, 1996, 1997). Where large amounts of data are available, as in the Cooper Basin, the method should at least predict the same order of magnitude of reserves as are currently identified.

There are many plays that have proven potential for discoveries in the Cooper Basin, mostly as individual high sinuosity fluvial sands within the major formations of the Gidgealpa and Nappamerri Groups, although the Tirrawarra Sandstone has more massive low-sinuosity braided fluvial sands, and bar sands are known from the upper Patchawarra and Epsilon Formations. As these are too numerous (and to a certain extent are co-dependent) to model independently, an 'average' field has been modelled using the input parameters in Table 14.1, and the results are summarised in Table 14.2.

SOURCE GENERATION

This method estimates the amount of hydrocarbon that may have been generated from the known source rocks. The amount is then modified to an estimate of the trapped resources (i.e. in fields, discovered and undiscovered) by expulsion efficiency, migration timing, seal potential and retention factor. As these factors are very subjective, this method is not often used to estimate the undiscovered potential of an area, but it is useful in providing an upper constraint to other methods. Griffiths (1997), using data compiled by Apak (1994), estimated that the Malabine Coal of the Patchawarra Formation (the major coal seam up to 30 m thick) may have generated between 5600 x 10^9 and 27 200 x 10^9 m^3 (198–961 tcf) of original gas-in-place. The modal estimate was 10 300 x 10^9 m^3 (364 tcf) of original gas-in-place.

The main hydrocarbon source for the Cooper Basin fields is considered to be the coals and shales of the Toolachee, Daralingie, Epsilon, and Patchawarra Formations.

At minimum maturity, one tonne (0.625 m^3) of Cooper Basin coal would contain a carbon content of 830 kg (i.e. a total organic carbon (TOC) content of 83%) and have a hydrogen index of 200 mg/g (C.J. Boreham, AGSO, pers. comm., 1998). At maximum maturity , this coal could be expected to generate between 38.2 and 76.4 kg of gas (57–114 m^3 (2–4 cf) at standard conditions) and up to 127.8 kg of oil (0.161 kL (1 bbl)). The total volume of mature coal for the basin is 688 km^3 (Toolachee 213 km^3, Daralingie 20 km^3, Epsilon 52 km^3, Patchawarra 403 km^3).

The shales of the major formations have varying organic contents and hydrogen indices (Table 14.3). Assuming the shales have an average density of 2.7 tonnes/m^3, the sum of the coal and shale data would give the total generative potential of the basin as indicated in Table 14.4.

Clearly, source is not a constraint on the ultimate producible reserves from the basin. However, the trapping efficiency, in either the Cooper Basin itself, the underlying Warburton Basin or the overlying Eromanga Basin is the critical factor. McDowell (1975) concluded that the amount of hydrocarbon that resides in reservoirs is between 0 and 25% of the total hydrocarbon generated. This would suggest

Table 14.1 *Input parameters for estimating undiscovered petroleum resources in the Cooper Basin, basin plays method.*

	Minimum	Mean	Maximum
Gas			
Prospective area of the basin (km^2)	24 664	29 059	33 459
Anticline to total basin area ratio	0.1	0.27	0.45
Average gross reservoir thickness (m)	2.9	4.6	7.3
Net to gross pay ratio	0.64	0.8	0.96
Number of reservoirs per field	1	3	6
Porosity (fraction)	0.08	0.1	0.11
Water saturation (fraction)	0.35	0.45	0.55
Formation volume factor	179	185	192
Exploration drilling success ratio	0.27	0.41	0.56
Recovery factor	0.58	0.64	0.71
Oil			
Prospective area of the basin (km^2)	24 664	29 059	33 459
Anticline to total basin area ratio	0.1	0.27	0.45
Average gross reservoir thickness (m)	2.9	4.6	7.3
Net to gross pay ratio	0.64	0.8	0.96
Number of reservoirs per field	0	1	2
Porosity (fraction)	0.08	0.1	0.11
Water saturation (fraction)	0.35	0.45	0.55
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.06	0.08	0.1
Recovery factor	0.14	0.21	0.28

Table 14.2 *Potential undiscovered petroleum resources in the Cooper Basin (for all plays), basin plays method.*

	Probability that the ultimate potential will exceed the stated value					
	90%		50%		10%	
Gas *10^6 m^3 (bcf)*	0	(0)	25 000	(900)	215 000	(7700)
Oil *10^3 kL (mmstb)*	0	(0)	13 700	(87)	41 500	(264)

Table 14.3 *Shale source rock characteristics of the Cooper Basin.*

Formation	Total shale volume (km^3)	Total organic carbon (initial) (%)	Hydrogen index (initial) (kg hydrocarbon/ tonne TOC)
Toolachee	579	5.35	203
Daralingie	369	5.26	230
Epsilon	906	4.44	162
Patchawarra	2735	6.6	198

Table 14.4 *Potential hydrocarbon generation from source rocks of the Cooper Basin.*

Formation	Coal source			Shale source			Total		
	Minimum gas 10^9 m^3 (tcf)	Maximum gas 10^9 m^3 (tcf)	Oil 10^9 kL (10^9 bbl)	Minimum gas 10^9 m^3 (tcf)	Maximum gas 10^9 m^3 (tcf)	Oil 10^9 kL (10^9 bbl)	Minimum gas 10^9 m^3 (tcf)	Maximum gas 10^9 m^3 (tcf)	Oil 10^9 kL (10^9 bbl)
Toolachee	19 426 (699)	38 851 (1399)	54.9 (347)	5827 (210)	11 654 (420)	16.5 (104)	25 253 (909)	50 505 (1818)	71.4 (451)
Daralingie	1824 (66)	3648 (131)	5.2 (33)	4136 (149)	8273 (298)	11.7 (74)	5960 (215)	11 921 (429)	16.9 (107)
Epsilon	4742 (171)	9485 (342)	13.4 (85)	6045 (218)	12 090 (435)	17.1 (108)	10 787 (388)	21 575 (777)	30.5 (193)
Patchawarra	36 754 (1323)	73 507 (2646)	103.8 (656)	33 118 (1192)	66 237 (2385)	93.6 (591)	69 872 (2515)	139 744 (5031)	197.4 (1247)
						Total	**111 872 (4027)**	**223 745 (8055)**	**316.2 (1997)**

that, unless the Cooper Basin has a particularly low rate of retention of hydrocarbons, the total potential of the basin may be ~5000 x 10^9 m^3 (180 tcf) of recoverable gas or 9.5 x 10^9 m^3 (60 000 mmbbl) of recoverable oil — assuming a 3% retention rate in reservoirs (as found in the west Texas Permian Basin by McDowell, 1975). Although this figure indicates a potential considerably above even the most optimistic of other methods, this figure may give a hint as to the potential of currently poorly explored play types (e.g. Warburton Basin, low-permeability reservoirs, stratigraphic traps, coal seam methane). Alternatively, these figures suggest that seal integrity is a key parameter in the Cooper Basin.

DISCOVERY TREND

Discovery trend methods are based on the generally observed phenomenon in other exploration areas worldwide that exploration effectiveness (both field size and success rate) decline with advancing exploration effort.

There are two broad methods used to describe observed field size distributions, either lognormal type, or Pareto (J-shaped) type. The major difference between these is that the Pareto distribution predicts a very large number of very small undiscovered fields. The lognormal distribution was first used by Arps and Roberts (1958) and has been used to model discovered field sizes in western Canada (Lee and Wang, 1985, 1986), the North Sea (Band, 1987), the southern United States (Davis and Chang, 1989) and Australia (Forman and Hinde, 1985, 1986). Schuenemeyer and Drew (1983) and Attanasi and Drew (1985) suggested that the lognormal distribution may describe the sampled distribution, but did not adequately describe the parent population due to economic truncation of the data set and/or sampling bias (large fields tend to be discovered early). This sampling bias has been called the 'creaming' phenomenon and is a measure of exploration efficiency, which the Australian Bureau of Resource Sciences (Forman and Hinde 1985, 1986) uses in conjunction with the lognormal model.

The Pareto equation (Zipf-type) used here to describe the parent population is:

$$F_s = \frac{a}{N_d + 1}$$

F_s field size

N_d field discovery number

a an empirically determined constant

In contrast to the method used by the Bureau of Resource Sciences, the model is deterministic. However, minimum (most pessimistic), average and maximum (most optimistic) models can be developed for the data.

Success ratio — Pareto models

The historical overall success ratio for both oil (including Eromanga discoveries) and gas in Cooper Basin targeted wells in South Australia has recently declined from 1:1.7 to 1:3.7. This success ratio is dominated by gas discoveries (Fig. 14.1). If Cooper oil discoveries are considered alone, the success rate has been relatively constant at about 1:12 (Fig. 14.2). For future exploration, it is assumed that the gas success rate will drive exploration, (i.e. a future success rate of 1:4 exploration wells) and that oil discoveries will be made in the ratio of one oil discovery per five gas discoveries.

Limiting discovery

As the Pareto distribution predicts a large number of small fields to be discovered, it is sensitive to the limiting field size chosen, i.e. the point beyond which it would be uneconomic to continue exploration. This is broadly a

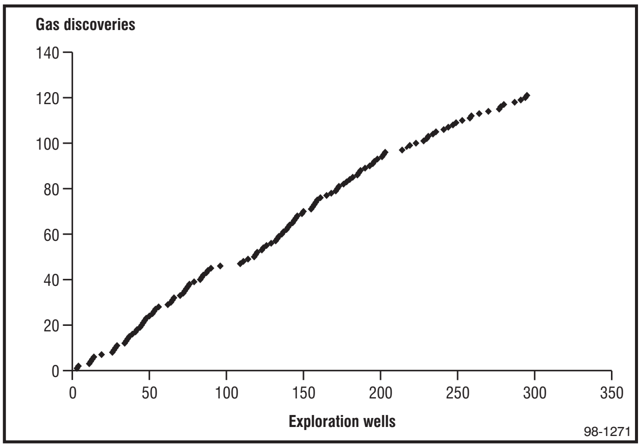

Fig. 14.1 *Success ratios for gas fields in the Cooper Basin.*

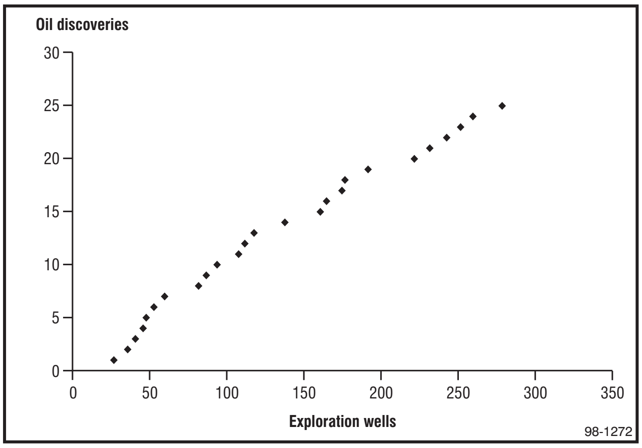

Fig. 14.2 *Success ratios for oil fields in the Cooper Basin.*

combination of two factors; the cost of exploration (dry wells and seismic acquisition), and the cost of development of a new discovery. The amount of seismic acquired compared to prospects drilled is shown in Figure 14.3. Historically, seismic acquisition has averaged 283 km of 2D seismic per exploration well. However, a significant part of this acquisition is attributable to development of newly discovered fields. For the purposes of determining the limiting field size, it is assumed that at the limit no further exploration seismic will be acquired per exploration well.

An economic model has been developed that is simpler than the one used in Chapter 13. It assumes:

- an average gas composition
- no seismic acquisition per exploration well
- three dry wells will be drilled for each discovery
- 5 km of flowline to connect the gas discovery to existing facilities
- marginal operating costs
- 1/5 of an average oil field (60 900 kL (383 000 bbl) recoverable, excluding Tirrawarra Field) will also be discovered for each gas field discovered.

Using this model, the limiting economic field size is ~104.2 x 10^6 m^3 (3.7 bcf) of gas.

Gas

There have been 121 discovered Cooper Basin gas fields in South Australia up to 1.1.98 from 298 new field wildcats.

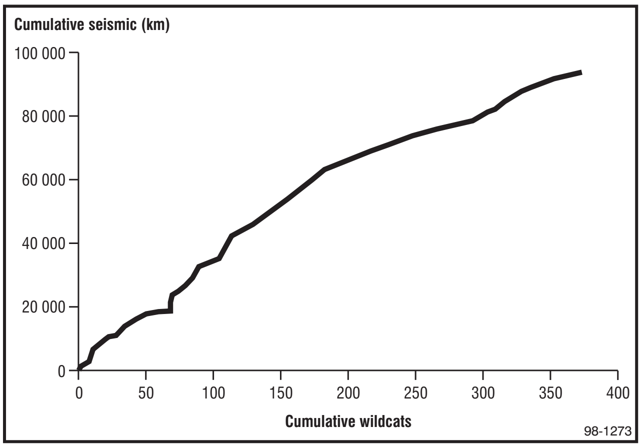

Fig. 14.3 *Seismic acquisition versus exploration wells in the Cooper and Eromanga Basins.*

The models based on the historical data (recoverable raw gas) are:

Minimum

$$F_s\ (10^6\ m^3) = \frac{37\ 765}{N_d + 1}$$

Most likely

$$F_s\ (10^6\ m^3) = \frac{40\ 527}{N_d + 1}$$

Maximum

$$F_s\ (10^6\ m^3) = \frac{43\ 811}{N_d + 1}$$

The models are shown graphically against the historical data in Figure 14.4 and summarised in Table 14.5.

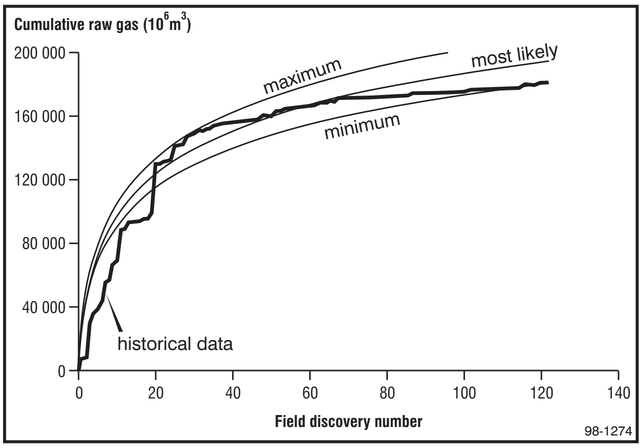

Fig. 14.4 *Pareto models against historical gas discoveries in the Cooper Basin.*

Table 14.5 Potential undiscovered recoverable petroleum resources in the Cooper Basin, Pareto method.

Model	Number of fields to be discovered	Undiscovered recoverable resource	
Gas		10^6 m^3 (bcf)	
minimum	240	41 072	(1458)
most likely	267	60 260	(2139)
maximum	298	83 204	(2954)
Oil		10^3 kL (mmstb)	
minimum	48	2049	(12.9)
most likely	53	5453	(34.3)
maximum	60	20 294	(127.6)

Oil

There have been 25 Cooper Basin oil fields discovered in South Australia up to 1.1.98 from 297 new field wildcats.

The models based on the historical data (recoverable oil) are:

Minimum

$$F_s\ (10^3\ kL) = \frac{2100.4}{N_d + 1}$$

Most likely

$$F_s\ (10^3\ kL) = \frac{2848.0}{N_d + 1}$$

Maximum

$$F_s\ (10^3\ kL) = \frac{6125.5}{N_d + 1}$$

The models are shown graphically against the historical data in Figure 14.5 and summarised in Table 14.5.

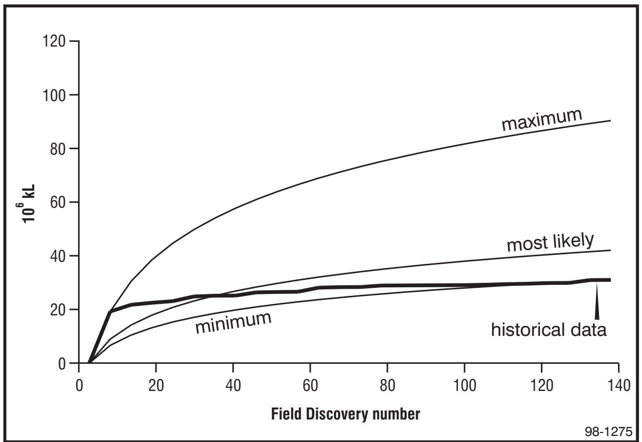

Fig. 14.5 *Pareto models against historical oil discoveries in the Cooper Basin.*

Although for gas at least, the number of fields to be discovered would appear to be excessive, this must be viewed in the context that the Cooper Basin is not yet fully explored when compared to similar basins in mature exploration areas. For example, Figure 14.6a (after Caldwell, 1994) shows the gas field discoveries in Texas District 3, United States, from 1932 to 1991. In total there are over 900 gas pool discoveries, with the largest pools of the order of 28 x 10^9 m^3 (1000 bcf) in size. Significantly, the rate of pool size decline is reduced after the first 100 to 200 discoveries, and large fields (over 2.8 x 10^9 m^3 (100 bcf)) were being discovered beyond discovery number 800. Figure 14.6b shows the South Australian Cooper Basin gas field data at a similar scale, which suggests that it is underexplored by comparison.

Field size profile

Using the Pareto models above, field size profiles can be generated for the Cooper Basin (Figs 14.7, 14.8). These indicate the likelihood of discovering fields of various sizes assuming efficient exploration. In all cases fields smaller than those predicted by the models have been found, and this risk has not been factored into the probabilities summarised in Table 14.6.

Lognormal model

The Bureau of Resource Sciences has used the lognormal model for many years, however the assessments for gas are considered here to be pessimistic. The most recent gas assessment for the South Australian part of the Cooper Basin (Bureau of Resource Sciences, 1996) ranges from 7155 x 10^6 to 19 071 x 10^6 m^3 (254–677 bcf), with an average estimate of 11 916 x 10^6 m^3 (423 bcf).

Bradshaw *et al.* (1998) recently published an estimate using similar techniques based on a 1988 database of reserves for the whole of the Cooper and Eromanga Basins (South Australia and Queensland). They concluded that from 1988, a further 60 fields would be discovered with a potential of 16 200 x 10^6 m^3 (576 bcf) of recoverable gas. Since 1988, in the South Australian portion of the basin alone, there have been 35 discoveries with total recoverable reserves attributed of 7 200 x 10^6 m^3 (254 bcf). Significant discoveries have also been made in the Queensland portion of the basin in that time, and this suggests that the Bradshaw *et al.* estimate is also pessimistic.

The Bureau of Resource Sciences' (1996) undiscovered recoverable oil estimates for the Cooper Basin, South Australia range from 0.32 x 10^6 to 4.29 x 10^6 kL (2–27 mmbbl), with an average estimate of 1.59 x 10^6 kL (10 mmbbl).

ANALYTICAL PETROLEUM RESOURCE APPRAISAL SYSTEM (APRAS)

The Analytical Petroleum Resource Appraisal System (APRAS) was developed by the United States Geological

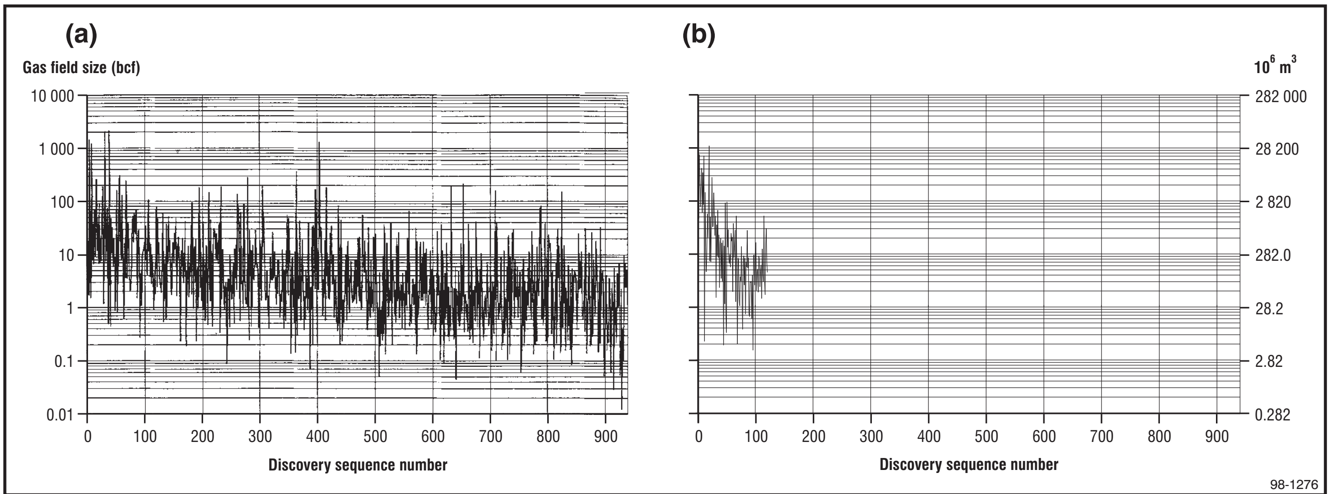

Fig. 14.6 *Discovery sequence plots.* ***(a)*** *Texas District 3 gas pools, 1932–91 (from Caldwell, 1994).* ***(b)*** *Cooper Basin gas fields, 1963–97 (at same scale to Fig. 6a).*

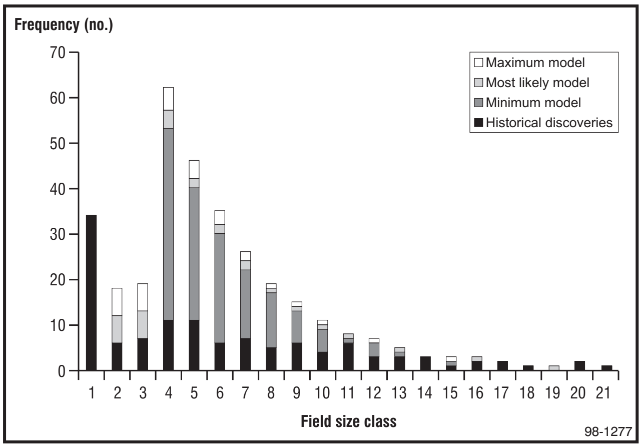

Fig. 14.7 Gas field size profile. Field size classes are given in Table 14.6 and are logarithmic.

Survey. It is similar to the basin play method in that it uses Monte Carlo simulation to manipulate probabilities. However, APRAS uses an analytical combination of five fractiles of the observed distribution (usually lognormal) for each parameter, which makes it faster to run. Each play to be assessed is assigned a set of distributions which model oil and gas accumulation sizes, reservoir depths and number of accumulations. In addition, the probabilities for source, timing, migration, reservoir facies, marginal play probability and conditional probability of at least one undiscovered accumulation in the play are provided. The methodology is summarised in Crovelli and Balay (1988, 1992) and Griffiths (1997). Griffiths (1997) developed two models for the Cooper Basin — a pessimistic and an optimistic case that differed in the number of large accumulations that are still to be found.

The result of Griffiths' assessment is summarised in Table 14.7 (converted from his original gas-in-place and original oil-in-place to remaining recoverable raw gas and recoverable oil). He concluded that most of the gas potential was in the Patchawarra Formation, and most of the oil potential in the Tirrawarra Sandstone. The assessment did not predict the volume of resources already discovered at some probability levels (the zero estimates in Table 14.7).

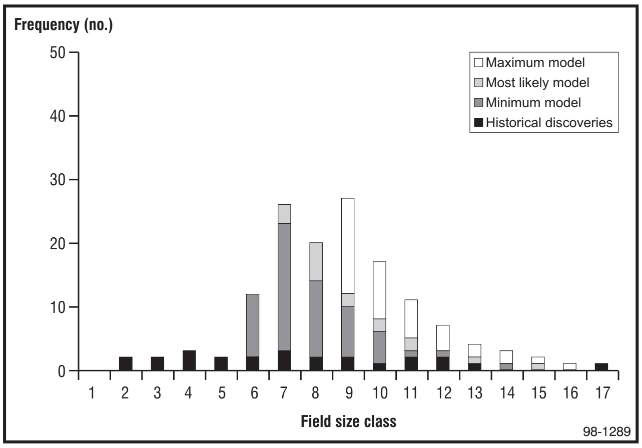

Fig. 14.8 Oil field size profile. Field size classes are given in Table 14.6 and are logarithmic.

***Table 14.6** Potential undiscovered petroleum fields in the Cooper Basin, Pareto method.*

Field size			**Probability of finding a field in this size class** (%)		
Class	Range		Minimum	Most likely	Maximum
Recoverable gas *10^6 m^3 (bcf)*					
1	75–100	(3–4)	–	–	–
2	100–133	(4–5)	26	26	25
3	133–178	(5–6)	23	23	23
4	178–237	(6–8)	15	15	15
5	237–316	(8–11)	10	10	10
6	316–422	(11–15)	9	9	9
7	422–562	(15–20)	5	6	6
8	562–750	(20–27)	4	4	4
9	750–1000	(27–35)	3	3	3
10	1000–1334	(35–47)	2	2	2
11	1334–1778	(47–63)	0	1	1
12	1778–2371	(63–84)	1	1	1
13	2371–3162	(84–112)	0	1	1
14	3162–4217	(112–150)	0	0	0
15	4217–5623	(150–200)	0	0	1
16	5623–7499	(200–266)	0	0	0
17	7499 – 10 000	(266–355)	0	0	0
18	10 000 – 13 335	(355–473)	0	0	0
19	13 335 – 17 783	(473–631)	0	0	0
20	17 783 – 23 714	(631–842)	0	0	0
21	23 714 – 31 623	(842–1123)	0	0	0
Oil-in-place *10^3 kL (mmbbl)*					
1	10–16	(0.06–0.10)	–	–	–
2	16–25	(0.10–0.16)	–	–	–
3	25–40	(0.16–0.25)	–	–	–
4	40–63	(0.25–0.40)	–	–	–
5	63–100	(0.40–0.63)	–	–	–
6	100–159	(0.63–1.00)	17	0	0
7	159–252	(1.00–1.59)	34	35	0
8	252–399	(1.59–2.51)	21	28	15
9	399–633	(2.51–3.98)	14	15	33
10	633–1003	(3.98–6.31)	9	11	21
11	1003–1590	(6.31–10.00)	2	5	12
12	1590–2520	(10.00–15.85)	2	2	7
13	2520–3994	(15.85–25.12)	0	2	4
14	3994–6329	(25.12–39.81)	2	2	4
15	6329 – 10 031	(39.81–63.10)	0	2	3
16	10 031 – 15 899	(63.10–100.00)	0	0	1
17	15 899 – 25 198	(100.00–158.49)	0	0	0

***Table 14.7** Potential undiscovered recoverable petroleum resources in the Cooper Basin, APRAS method.*

	Probability that the ultimate potential will exceed the stated value					
	95%		50%		5%	
Low estimate						
Gas *10^6 m^3 (bcf)*	0	(0)	123 600	(3481)	628 000	(17 688)
Oil *10^3 kL (mmstb)*	0	(0)	0	(0)	3218	(20.2)
High estimate						
Gas *10^6 m^3 (bcf)*	96 000	(2704)	332 500	(9365)	747 600	(21 056)
Oil *10^3 kL (mmstb)*	0	(0)	0	(0)	5 460	(34.3)

SUMMARY

The results of reasonably reliable methods for calculating potential undiscovered petroleum resources are summarised in Table 14.8. Basin analogue (method 1) and source generation are considered unreliable. Some of the potential attributed to the Cooper Basin may have already been discovered in the Eromanga Basin. The current discovered recoverable oil reserves of the Eromanga Basin in the Cooper Basin region are 14.5 x 10^6 kL (92.5 mmstb). If most of the oil in the Eromanga is Cooper Basin sourced (see Chs 8 and 10 for a discussion on this), then the remaining oil potential for the Cooper Basin may be quite limited.

Table 14.8 *Comparison of potential undiscovered recoverable petroleum resources in the Cooper Basin. Results are presented in decreasing order of the average estimate.*

Method	**Estimate[1]**					
	Low		Average		High	
Gas *10^9 m^3 (tcf)*						
Basin analogue[2]	108	(3.8)	193	(6.8)	277	(9.8)
APRAS (average)	39	(1.4)	228	(6)	688	(19)
Pareto	41	(1.5)	60	(2)	83	(3)
Basin plays	0	(0)	25	(1)	215	(8)
Lognormal	7	(0.3)	12	(0.4)	19	(0.7)
Oil *10^6 kL (mmstb)*						
Basin analogue[2]	15	(94)	20	(300)	26	(163)
Basin plays	0	(0)	14	(87)	42	(264)
Pareto	2.0	(13)	6	(34)	20	(128)
Lognormal	0.3	(2)	2	(10)	4	(27)
APRAS (average)	0	(0)	0	(0)	4	(27)

[1] Estimate categories are generalised — refer to tables above for detail.
[2] Method 2