UNDISCOVERED PETROLEUM RESOURCES

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Chapter 13

INTRODUCTION

Estimating undiscovered petroleum resources of the Eromanga 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. As the basin is clearly oil prone, only undiscovered oil resources are calculated, however gas discoveries are known from the Cooper region. The gas in these fields is likely to have been sourced from the underlying Permo-Carboniferous Cooper Basin. In the western Eromanga Basin, gas discoveries are possible, particularly in areas overlying the older infrabasins (Pedirka and Simpson Basins), but it is unlikely that small gas discoveries in this area would be economic.

Petroleum exploration in the Eromanga Basin in South Australia has traditionally concentrated in the portion underlain by the highly productive Cooper Basin, a relatively mature area. In addition, there is the likelihood that a significant amount of the oil found in this area has been sourced from the underlying Cooper Basin. For these reasons, undiscovered oil resources are best estimated using methods that extrapolate discovery trends.

Areas to the west have had minimal exploration effort, with only one sub-economic discovery. Oil found here will probably be sourced from the Poolowanna and Birkhead Formations or the underlying Pedirka and Simpson Basins. Estimates of undiscovered resources in the western Eromanga are best carried out by a method that uses available geological data and Monte Carlo type statistical techniques to calculate, as a probability distribution, the undiscovered resources for each play (Morton, 1992, 1995).

The average estimate of the remaining potential in the Eromanga Basin in South Australia (both the Cooper region and western Eromanga Basin) is 11 x 10^6 kL of recoverable oil.

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.

WESTERN EROMANGA BASIN

METHOD

For a commercial petroleum field to exist in the western Eromanga Basin, four essential components are required:

- A mature 'source'; a rock unit that contains sufficient organic matter and which has been subjected to sufficient heat and pressure over time to have produced significant quantities of hydrocarbons, but not to have destroyed them through excessive heat and pressure.
- A 'reservoir' horizon; a rock unit that accumulates the generated oil or gas. A reservoir rock must be porous, and have sufficient permeability to produce fluids economically.
- A 'seal' horizon; a rock unit that traps the petroleum in the reservoir and prevents further migration.
- A structure over the reservoir horizon that will concentrate the petroleum in economic quantities and that was present at the time of petroleum expulsion from the source rock. Usually this is an anticline, but stratigraphic traps can also be important.

When all four of these occur together, a petroleum 'play' or a potential target for exploration exists.

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

$$P_t = A_p \text{ x } AB \text{ x } h \text{ x } NG \text{ x } FF \text{ x } Por \text{ x } S_h \text{ x } FVF \text{ x } SR \text{ x } RF$$

P_t	total undiscovered recoverable oil resources of the play
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
FF	anticline fill factor
Por	porosity (fraction)
S_h	hydrocarbon saturation (1 - water saturation)
FVF	formation volume factor
SR	exploration drilling success ratio
RF	recovery factor

None of the above parameters are known with certainty, but most can be estimated from available data to within at least broad limits. The most common method of combining and expressing the uncertainty associated with this type of equation is to use Monte Carlo simulation techniques (White and Gehman, 1979). A frequency distribution for each parameter is assumed, converted to a cumulative probability distribution, and a random number between 0 and 1 (corresponding to 0–100% probability) is used to sample each of the distributions, which are combined as in the equation above to give one estimate of the potential of the play. The

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process is repeated many times (in this case at least 1000 times) to produce multiple estimates of the potential of each play. These are then used to produce a probability versus petroleum potential distribution for each play and for the basin as a whole. This calculation is carried out by computer using a commercially available simulator ('RISK', a LOTUS 1-2-3 add-in). This uses an advanced stratified sampling technique, 'Latin Hypercube', that converges in fewer iterations than with the traditional Monte Carlo method.

Discussion of parameters

Prospective area

This is the area of the basin that is believed to contain the three essential components of source, reservoir and seal, and where the reservoir is at an economically drillable depth (assumed to be *4500 m). This is a critical factor in determining the potential of the basin but can be mapped with reasonable accuracy from the available drillhole and seismic data. It is entered as a triangular distribution (minimum, most likely, maximum). E.M. Alexander (MESA) constructed maps for each play, taking into account distribution of source, seal and reservoir. Figures 13.1–13.3 summarise these for the Poolowanna Formation, Hutton Sandstone and Namur–Algebuckina Sandstones plays respectively.

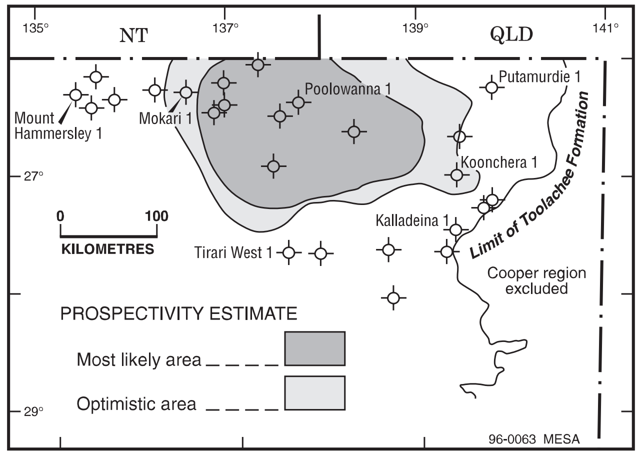

Fig. 13.1 Poolowanna Formation prospectivity, western Eromanga Basin. Based on distribution of mature intra-Poolowanna Formation and underlying Peera Peera Formation.

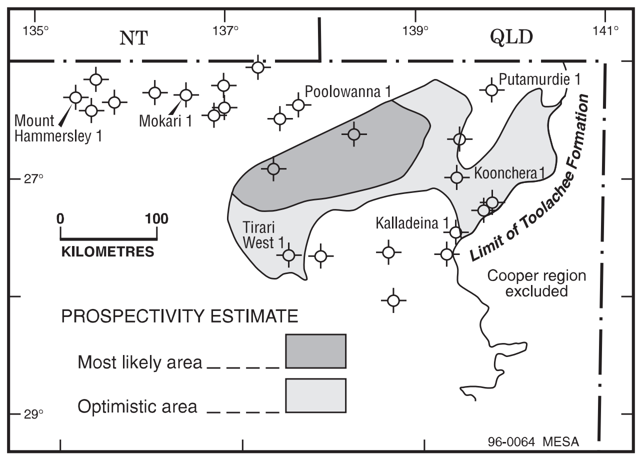

Fig. 13.2 Hutton Sandstone prospectivity, western Eromanga Basin. Based on distribution of mature Birkhead, Poolowanna and Peera Peera Formations.

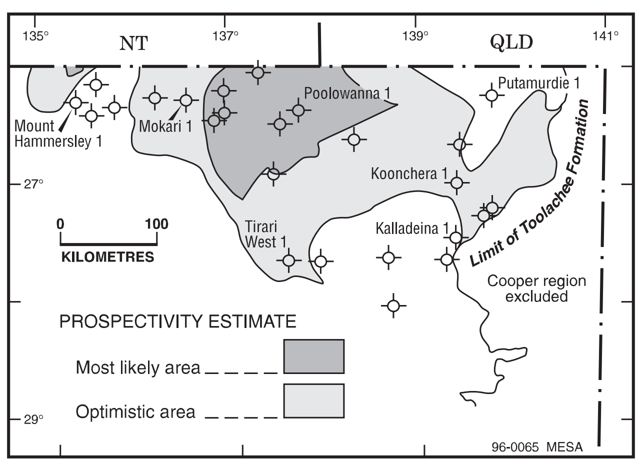

Fig. 13.3 Namur–Algebuckina Sandstones prospectivity, western Eromanga Basin. Based on distribution of mature Birkhead, Poolowanna, Peera Peera and Purni Formations.

Anticline to basin area ratio

This is the proportion of the prospective area that is within an anticlinal trap. It was extrapolated from a depth structure map of the base of the Eromanga Basin over the eastern part of the basin (near the Cooper region; Figure 11.1). This area was selected because it has the greatest seismic density and the structuring is most likely to reflect the overlying plays. However, the seismic coverage is still poor compared to that required in the Cooper region to identify all of the smaller prospects, hence the values used in this assessment may be conservative. This parameter is also entered as a triangular distribution.

Gross reservoir thickness

This is the maximum vertical closure of the trap. The reservoir is modelled as a cone and h is reduced to a third (volume of a cone = 1/3 x area x height). The parameter is modelled as a truncated lognormal distribution (mean, standard deviation, minimum, maximum).

Net to gross pay ratio

The net to gross ratio reduces the maximum reservoir thickness to the anticipated pay (permeable reservoir) thickness. This has been estimated using data from the Strzelecki Field for the Hutton Sandstone and Namur–Algebuckina Sandstone plays. For the Poolowanna Formation play, data from Poolowanna 3 was used. A truncated normal distribution is used.

Anticline fill factor

In oil or gas basins with commercial fields, anticlines can range from filled to spill to near 0% fill (0% = dry wells). The average fill is therefore less than one, and it is assumed that the richer the source rock the greater the average fill. This critical parameter is subjective for the western Eromanga Basin, as fill factors may be expected to be less than for the Cooper region, where the underlying Cooper Basin is likely to have resulted in greater charge volumes. No data on fill factors for the Cooper region was available for this study, instead this parameter was adjusted to give pay thicknesses in the range 5–10 m, which is comparable with discovered oilfields in the Cooper region. A triangular distribution is used. This distribution is linked to gross reservoir thickness, so that low fill factors are chosen by the model for large reservoir thicknesses.

Porosity

The average porosity of the reservoir was estimated from available core data (Table 10.1). A triangular distribution is used.

Hydrocarbon saturation

The average hydrocarbon saturation is partly dependent on the average porosity and the pay thickness, and the distributions are linked in the Monte Carlo simulator so that when a low value of porosity and/or pay thickness is chosen a low hydrocarbon saturation is also chosen. The range was determined from water saturation data in the Strzelecki Field. A truncated normal distribution is usually used.

Formation volume factor

The volume of oil in a reservoir decreases when brought to the surface due to the drop in pressure, and consequent loss of volatiles. The value for these factors was averaged from existing fields in the Cooper region.

Success ratio

This is an estimate of the proportion of exploration wells to be drilled that will find an oil or gas field. Like the fill factor this ratio is related in part to the richness of the source rocks, but other influences such as the degree of structural complexity, and quality of seismic data are important. Values were estimated from past drilling results in both the Cooper region and in the western Eromanga Basin.

Recovery factor

The recovery factor converts petroleum in-place resources to recoverable oil, and is mostly dependent on the degree of mobility of the underlying aquifer and the height of the oil column. Estimates were derived from averages in the Cooper region. A triangular distribution is used.

POTENTIAL PLAYS

There are three major plays that have potential for discoveries.

Poolowanna Formation

Reservoir: sands of the Poolowanna Formation (Fig. 13.1). **Seal:** intra-Poolowanna Formation shales.
Source: intra-Poolowanna Formation, or underlying Triassic Peera Peera Formation.

Summary of Monte Carlo input parameters:

	Minimum	Average	Maximum
Prospective area of the basin (km^2)	0	27 910	42 540
Anticline to total basin area ratio	0.005	0.0328	0.1
Average gross reservoir thickness (m)	7	72	225
Net to gross pay ratio	0.1	0.19	0.25
Anticline fill factor	0.07	0.17	0.33
Porosity (fraction)	0.10	0.12	0.15
Water saturation	0.3	0.5	0.6
Formation volume factor	0.85	0.89	0.91
Exploration drilling success ratio	0.03	0.07	0.2
Recovery factor	0	0.3	0.67

Hutton Sandstone

Reservoir: top Hutton Sandstone (Fig. 13.2). **Seal:** Birkhead Formation.
Source: Birkhead Formation, Poolowanna Formation or underlying Triassic Peera Peera Formation.

Summary of Monte Carlo input parameters:

	Minimum	Average	Maximum
Prospective area of the basin (km^2)	0	12 810	32 590
Anticline to total basin area ratio	0.005	0.038	0.1
Average gross reservoir thickness (m)	7	72	225
Net to gross pay ratio	0.5	0.75	1.0
Anticline fill factor	0.07	0.17	0.33
Porosity (fraction)	0.15	0.19	0.21
Water saturation	0.25	0.3	0.6
Formation volume factor	0.87	0.89	0.91
Exploration drilling success ratio	0.03	0.07	0.2
Recovery factor	0	0.32	0.6

Namur–Algebuckina Sandstones

Reservoir: top Namur Sandstone or Algebuckina Sandstone (Fig. 13.3). **Seal:** Murta or Cadna-owie Formations, or Bulldog Shale.
Source: Birkhead Formation, Poolowanna Formation or underlying Triassic Peera Peera Formation and Permian Purni Formation.

Summary of Monte Carlo input parameters:

	Minimum	Average	Maximum
Prospective area of the basin (km^2)	0	16 040	61 180
Anticline to total basin area ratio	0.005	0.0328	0.1
Average gross reservoir thickness (m)	7	72	225
Net to gross pay ratio	0.5	0.75	1.0
Anticline fill factor	0.07	0.17	0.33
Porosity (fraction)	0.15	0.19	0.21
Water saturation	0.25	0.3	0.6
Formation volume factor	0.86	0.9	0.93
Exploration drilling success ratio	0.003	0.07	0.2
Recovery factor	0	0.27	0.78

Additional potential could exist in reservoirs of the Birkhead Formation, Murta Formation McKinlay Member and in reservoirs of the Permian and Triassic infrabasins. In addition, lateral migration is possible from Permian sources in the Cooper region.

Table 13.1 summarises the results of the assessment of the undiscovered resources of the western Eromanga Basin at various probability levels.

Table 13.1 *Undiscovered recoverable oil resources.*

Play	Probability that the ultimate potential will exceed the stated value (10^6 kL)		
	90%	50%	10%
Poolowanna Formation	0.2	0.6	1.9
Hutton Sandstone	0.6	2.4	7.6
Namur–Algebuckina Sandstones	1.0	4.1	13.0
Total	**3.5**	**8.4**	**18.6**

COOPER REGION

METHOD

The method is 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 types of models used to describe observed field size distributions, either lognormal type distributions, or J-shaped (Pareto) type distributions. The major difference between them 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 the parameter 'l', the creaming factor, is used as a measure of exploration efficiency, which the Bureau of Resource Sciences (Forman and Hinde, 1985, 1986) use in conjunction with the lognormal model.

The Pareto model (Zipf type) used in this paper to describe the parent population is:

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

F_s field size (10^6 m^3)
N_d field discovery number
a an empirically determined constant

In practice, the discovery rate model is applied by matching to the historical data so that the historical discovery rate is equal to or less than the model. If cumulative discoveries are made faster than predicted by the model the model is by definition, too pessimistic and is modified. In contrast to the method used by the Bureau of Resource Sciences, the model is deterministic, in that only one estimate of undiscovered resources is calculated. This is assumed to be an average or 50% probability estimate.

Once an equation has been developed that models exploration, the ultimate potential or the total remaining to be discovered can be determined if the smallest economic field size is known i.e. the point beyond which it would be uneconomic to continue exploration. This is broadly a combination of two factors: the cost of exploration (dry wells and seismic acquisition), and the cost of development of a new discovery. The smallest developed oilfield in the Eromanga Basin in South Australia is of the order of 3 x 10^3 kL. This would be too small however, to pay for all exploration and development costs, and the true limiting field size would be larger, estimated to be about 69 x 10^3 kL, assuming 130 km of 2D seismic per prospect is required, and the success ratio is 1:10.

SUCCESS RATIO

The historical success ratio for the Eromanga Basin in South Australia has decreased from an initial 1:5 to close to 1:10 (Figure 13.4), but this assumes that all Cooper Basin exploration (including successful wells) are unsuccessful Eromanga Basin oil exploration wells. The historical success rate has been variable, from a low of 1:30 (1990–91; 29 successive wildcats without a discovery), to a high of close to 1:1 (1983; inception of the liquids scheme). A success ratio of 1:10 is assumed for the future, although if wells were specifically targeted at the Eromanga Basin, the success ratio could improve.

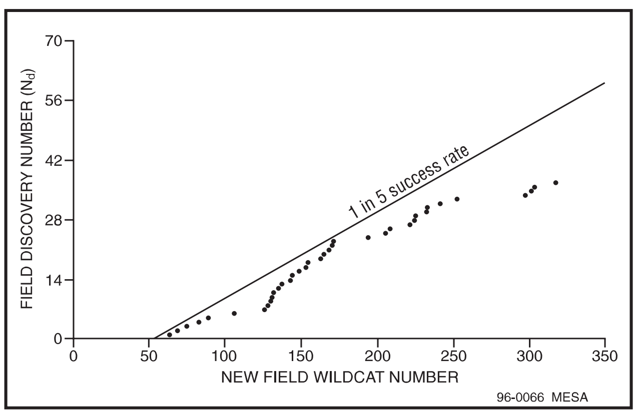

Fig. 13.4 *Success ratios for the Eromanga Basin in South Australia, using data to 1.1.96.*

SUMMARY OF RESULTS

There have been 33 discovered Eromanga oilfields in South Australia up to 1.1.93 from 293 new field wildcats. Since the beginning of 1993 a further four oilfields have been discovered in the Eromanga Basin.

The model of exploration is (Fig. 13.5):

$$F_s\ (10^3\,m^3) = \frac{3980.7}{N_d + 1}$$

Assuming a field size limit to exploration of 69 x 10^3 kL, the number of new field discoveries expected in the Cooper region is 57. This would give a remaining potential (from

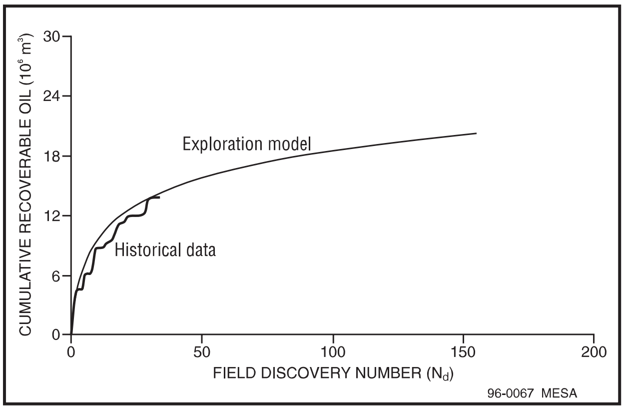

***Fig. 13.5** Exploration discovery model for the Cooper region, 1978–93.*

1.1.93) of 2.4 x 10^6 kL of recoverable oil. Discovery sizes would range from 69 x 10^3 to 111 x 10^3 kL recoverable oil.

For comparison, Bureau of Resource Sciences's (1986) undiscovered recoverable Eromanga Basin oil estimates for South Australia range from 1.1 x 10^6 to 6.4 x 10^6 kL, with an average estimate of 3.2 x 10^6 kL.