# Undiscovered resource assessment methodologies and application to the Bonaparte Basin

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## Abstract

**A medium-term forecast of undiscovered hydrocarbon resources for the Mesozoic and Palaeozoic petroleum systems of the Bonaparte Basin has been generated by Geoscience Australia. It concludes that there is a mean expectation that 56 gigalitres (350 million barrels) of oil, 82 billion cubic metres (2.9 trillion cubic feet) of gas, and 18 gigalitres (115 million barrels) of condensate are likely to be discovered in the next ten to fifteen years. This assessment is highly sensitive to the modelled number of wildcat wells to be drilled and is based on historical drilling rates. The assessment process only assesses existing play types and cannot account for new or unconceived plays.**

**This assessment is significantly smaller than the US Geological Survey assessment released in 2000, and the difference is mainly attributable to the timeframe being addressed by the two different assessment processes and the level to which reserves growth (sometimes referred to as field growth) is modelled. The Geoscience Australia forecast is for the medium term with no reserves growth modelled, whereas the US Geological Survey forecast approximates an ultimate discovery assessment with reserves growth incorporated.**

**An appropriate assessment methodology is critical when attempting to undertake an assessment and should be selected to answer specific questions. The Geoscience Australia methodology is a discovery-process (or creaming curve) model and the assessment results are primarily used for input into production forecasts. The assessment process has been revised with this new assessment being a petroleum system approach, which is more suitable than the migration fairway approach used in the previous resource estimations.**

**Reserves growth has been identified by the US Geological Survey as a critical element in estimating future hydrocarbon supply. Research is being directed within Geoscience Australia to determine its effect on its resource assessments.**

## Introduction

### *Why do we make assessments?*

"Governments need to know not only the petroleum resources that occur in identified oil and gas fields 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 …"

Forman, Hinde and Radlinski (1992)

This statement succinctly enunciates the need for assessments, especially now that social, economic and environmental pressures are increasingly leading to more competition between overlapping land and offshore uses.

### *What question is being asked – what assumptions have been made?*

When undertaking an assessment, it is critical that both the assessor and the user understand the purpose of the assessment and the assumptions that have been made. Does the assessment seek to determine the ultimate potential or is it restricted to the discovery potential within a specified time range? The answers to these two questions will most likely produce two very different answers.

One of the many problems assessors experience is to convey the meaning of the assessment result. It is very easy for the numerical result to become separated from the assumptions and input data, and be taken as gospel. This can lead to confusing interpretations and misconceptions that can degrade the value of the assessment. The potential for myths and misunderstandings abounds.

As an example, Drew (1997) related the controversy associated with the release of the US Geological Survey natural gas assessment in 1988. The Secretary of the US Department of the Interior, Donald Hodel, thought the assessment to be very pessimistic. This was at a time when the US gas industry was promoting the benefits of gas as a cleaner fuel compared to oil. The controversy arose because Hodel and his staff thought the assessment was for all types of gas (both conventional and unconventional), whereas the assessment was only for conventional resources. This fact got lost along the way. Who was to blame? Do you blame the assessors for not making it clear, or the users of the results for not reading the fine print carefully? The outcome shows that there has to be a clear understanding of all aspects of the assessment, both by users and assessors. Accordingly, this paper documents the methods and assumptions used in this assessment.

## Resource assessment methodologies

Numerous qualitative and quantitative methodologies have been devised to assess undiscovered resources. Qualitative methods have been superseded, with both companies and governments preferring a quantitative approach.

Today, the quantitative methodologies generally produce results in terms of ranges of values, with probabilities and risks attached. Single number assessments are no longer adequate.

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White and Gehman (1979), from the Exxon oil and gas assessment group, identified eight categories of assessment methodology as follows:

1. **Geologic analogy** basically says that if area A looks geologically similar to area B, then it must have a similar hydrocarbon content. Some scaling factors are usually applied to account for differences between the two areas.

2. The **Delphi** method takes the average of several experts' opinions of the probability distribution of potential resources. A group of experts review all the available geological data and then determines the critical factors. From this review, each expert constructs a probability distribution curve of potential resources. The group then reviews the assessments and modifications are made as necessary. The set of probability distribution curves are then averaged.

   This method has several advantages including ease of application, but several disadvantages exist, including lack of documentation of the input parameters. As White and Gehman (1979) stated, "One has to know how expert are the experts in order to assess the assessment".

3. The **areal yield** methodology is based on the equation:

   *Yield = (basin area) x (% potentially productive) x (yield factor)*

   Yield factor is expressed in units such as volume/unit area, and is traditionally expressed as barrels/acre.

   Areal yield assessments can be obtained relatively rapidly, but there is no account made of the third (vertical) dimension; thickness.

4. The **volumetric yield** method is the most widely used, especially for individual prospect assessments. The method can be used at prospect, play and basin scales. For a prospect assessment:

   *Yield = (potentially productive area)* x *(estimated net pay thickness)* x *(yield factor)*

   The yield factor is commonly expressed in terms of barrels/acre foot.

   For prospect assessment, the advantages are that all key volume factors are presented. While it may be difficult to determine the appropriate factors prior to drilling, probabilistic estimates of the range of values can be made using analogues.

   For play assessments:

   *Yield = (trap closure area) x (% potentially productive) x (average net pay thickness) x (yield factor)*

   This play assessment has the advantage that it can be used to estimate the size and number of potential prospects/traps. The main disadvantage is that a great deal of information is required for an assessment to be undertaken.

   For basin assessment:

   *Yield = (basin area) x (average total sediment thickness) x (potential yield factor)*

   The main advantage of this method is that it can be applied to poorly explored areas or basins where data are scarce. Proper risking is essential for this type of assessment to be credible. A large basin may have an enormous potential even with only a small potential yield factor, but if inadequate source rocks are present, the potential yield would be very small. White and Gehman (1979) quoted yields for explored basins varying between 0 to 4 million barrels/mile$^3$.

5. The **geochemical material balance** method is a special case of the volumetric yield method that deals with petroleum generation, migration and entrapment. The equation for this method is much more complex:

   *Yield = (drainage area) x (source thickness)* x *(% organic content)* x *(% generated into hydrocarbons)* x *(% migrated)* x *(% trapped)* x *(% potentially recoverable)*

   This method has the advantage of addressing all the key genetic factors for the occurrence of hydrocarbons, but it also highlights areas of little knowledge. The drainage area needs to be determined for the time that migration occurred, which may not necessarily reflect today's structural configuration. Also, migration and entrapment efficiencies are often contentious.

6. The **field number and size** method has a straightforward equation:

   *Yield = (number of prospects) x (success ratio) x (potential field size)*

   The success ratio may have to be taken from an analogue, if there is insufficient data to determine it for the area in question. This method is relatively simple and considers the fundamental units of exploration, namely prospects and fields. The main disadvantage is the requirement for good seismic control.

   The US Geological Survey World Petroleum Assessment (USGS, 2000) essentially falls in this category. The methodology and results of this assessment are discussed in a later section.

7. The **summation of prospects and plays** methodology is used to sum the results obtained from assessments produced by any of the previously described methods to produce a broader assessment. The process, however, is not as simple as adding two or more probability distribution curves together; only the means can be added. The main characteristic of this method is that the probability distributions of the contributing parts are maintained in the final output.

8. **Extrapolation of discovery rates** has been used extensively to make assessments. This method, sometimes referred to as discovery-process modelling, has been very popular, because it is directly related to previous exploration activity.

   White and Gehman (1979) clearly outlined the disadvantages for this type of method:

   "Like other methods, however, extrapolations have limitations. There is always some ambiguity about exactly what areas and drilling depths are represented. Presumably, frontier areas without either drilling or discoveries are not included. A vast array of accurate historical data is required. Extrapolations can be very sensitive to small variations in data points, particularly the recent ones. Changing economic, political, and regulatory conditions may alter the curves. …The study area must be in a relatively mature stage of exploration in which the discovery rates are declining; if discoveries are on the increase, an uncontrolled extrapolation would go to infinity."

   White and Gehman (1979)

   It is important to note that White and Gehman (1979) advocated that this method should only be used in mature areas. In previous years, Geoscience Australia and its predecessors have used this approach to provide numeric assessments of frontier, immature and mature exploration areas. A decision has now been made by Geoscience Australia to discontinue numerical assessments of frontier exploration areas, as they are highly debateable and their value questionable, for the reasons outlined above. For frontier exploration areas, Geoscience Australia now prefers to evaluate scientific evidence of active petroleum systems, rather than undertake numerical assessments.

Some methodologies are only applicable in certain circumstances depending upon whether a prospect, a play or a basin is being assessed. Some methodologies are applicable across a broad range of assessment requirements. There is certainly no single methodology that stands out above the others.

What type of methodology should we use in Australia? All recent Geoscience Australia undiscovered resource assessments have used a discovery-process method. Geoscience Australia undertook a review of its methodology in 2001 and, after internal and external consultations, has decided to retain the discovery-process methodology, but to incorporate some modifications.

### *Resource assessment at Geoscience Australia*

AUSTPLAY is Geoscience Australia's in-house software for conducting assessments of undiscovered petroleum resources. The program can be used to determine either in-place resources or recoverable reserves; for the Bonaparte Basin assessment discussed in this paper, all calculated volumes are for potential reserves. Technically, the yet-to-be discovered hydrocarbons can not be called reserves as their commerciality has not been determined; a more correct title may be technically recoverable resources.

Hinde *et al.* (1991) and Forman *et al.* (1992) described the fundamentals of the AUSTPLAY modelling program. AUSTPLAY attempts to model explorers' ability to discover the large accumulations early in the exploration cycle, and to forecast future drilling activity and discoveries. It is very much constrained by previous exploration activities, with future behaviour modelled on past behaviour. The AUSTPLAY assessment process can only assess already identified play types and cannot assess new or unconceived plays.

AUSTPLAY simulates drilling each untested trap within each assessment unit (Hinde *et al*., 1991). It estimates the size of each simulated discovery, using estimates of the area of closure and of the reserves per unit area for each trap. These estimates are recorded in drilling and discovery order as loglinear models. The program also uses other information such as chance of a viable hydrocarbon system (generation and migration of hydrocarbons), success rate, the proportion of oil to gas, and the smallest size of accumulation to be included as a resource. Undiscovered resources are presented as cumulative probability distribution curves. The average size and standard deviation of modelled accumulation sizes are also calculated.

### Assessment Units

The first step in any petroleum resource assessment is the division of the area to be assessed into distinctive assessment units. The amount of information and time available to the assessor will control the type of assessment unit chosen. In previous assessments undertaken with the AUSTPLAY methodology, the fundamental assessment unit was a migration fairway. Forman *et al.* (1992) described a migration fairway to be:

"… a system or branching system of traps that is contained within a sequence of source, reservoir, and cap rocks and is separated from adjacent systems by barriers to tertiary migration of petroleum, such as synclines, faults, or stratigraphic pinchouts. … It will have one spill point from which petroleum can escape laterally, but could have several lateral entry points from adjacent fairways."

Forman *et al.* (1992) went a step further where data were available and introduced the concept of complex traps, where closures could be sub-divided into two or more smaller structures, each with its own closure area. For each complex trap, the enclosing trap belonged to one trap order and the separate culminations belonged to others.

This is a very detailed way of conducting an assessment, but requires a large amount of data, which is frequently not available, to be able to construct a description of a migration fairway. Detailed knowledge of structure through time is necessary to understand migration pathways.

For the current AUSTPLAY assessment of the Bonaparte Basin (Fig. 1), an alternative approach was adopted, with the fundamental assessment unit being a petroleum system as defined by Magoon and Dow (1994). The reasons for adopting a petroleum systems approach are:

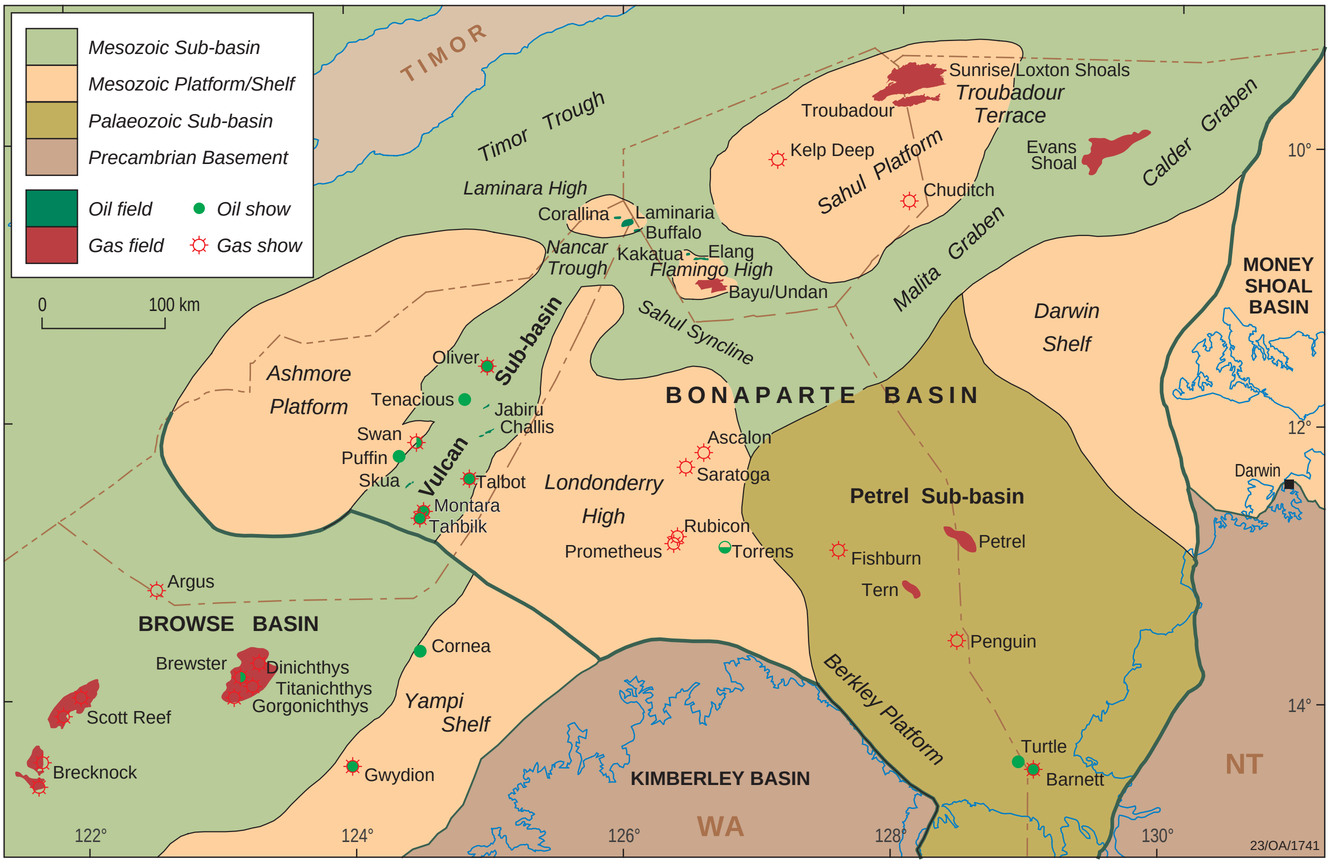


**Figure 1**. Bonaparte Basin location.

- the exploration industry is familiar with the concept of petroleum systems;
- assessments are conducted elsewhere using petroleum systems as assessment units; and
- less data and information is required to define the assessment units, but arguably, provides an equally reasonable result.

It is important to understand that the purpose of government assessments is to obtain a regional estimate of the petroleum potential that can be obtained by an exploration program over the medium term. It is not an unconstrained estimate of petroleum potential.

## Required input parameters

AUSTPLAY divides data into well data and petroleum system data. Well data contains data pertinent to individual wells. Wells are then assigned to a petroleum system that is described by specific characteristics. In some cases, a well may be assigned to more than one petroleum system where two or more identified petroleum systems spatially overlap.

Input data required for wells consists of name, location, date, type and volume of discovered hydrocarbons and, most importantly, the pre-drill area of closure tested by each wildcat well. The pre-drill area of closure is used as a proxy for trap volume since it is usually easier to obtain the area of closure than a volume-related parameter. The pre-drill area of closure is used in preference to the post-drill area, as the pre-drill area reflected the explorer's thinking at the time of drilling.

The petroleum system parameters used are as follows:

*Petroleum system name*

The construction of the petroleum system name, according to Magoon and Dow (1994), contains the volumetrically important source, followed (and separated by a dash '-') by the volumetrically important reservoir, with the punctuation in parentheses giving an indication of the degree of certainty of the source: (!) indicates a known system with oil-source rock or gas-source rock correlation established; (.) indicates a hypothetical system where there is geochemical evidence to suggest the origin for the hydrocarbons; (?) indicates a speculative system where there is lack of direct evidence for the active source rock. For example, "Vulcan-Plover(!)" signifies a petroleum system known to be sourced from the Vulcan Formation and primarily reservoired within the Plover Formation.

Where no one particular source or reservoir can be clearly identified as the most volumetrically significant, a second name can be added such as "Hyland Bay/Keyling-Hyland Bay(.)". If two names are used, they do not necessarily indicate a time range of possible formations.

The petroleum system name also allows for structured data management.

*Number of traps to be drilled*

This parameter is the number of wildcat wells that are expected to be drilled during the timeframe of the assessment, being ten to fifteen years in this assessment of the Bonaparte Basin. Past drilling rates are a starting point, but consideration is also made of the number of wells that have been committed to be drilled in each extant exploration permit. The latter sets a minimum number of wells that will be drilled over the life of the current permits.

The number of wells to be drilled is currently defined by a single value but the software is being developed to allow a triangular distribution for a low, medium and high set of input values.

The assessment result has proved to be extremely sensitive to the number of wells to be drilled. Figure 2 shows how the assessment outcome is determined by the number of wells being drilled where a creaming curve is in operation. The slope of the curve is the instantaneous rate of volumes of hydrocarbon being discovered per well, and as one would expect, this rate will decline over time. At position $X_w$, a small change in the modelled number of wells will produce a significant change in the assessment outcome, whereas at position $X_e$, the assessment will be less sensitive. It can be argued that where this curve becomes flat the ultimate potential is represented, but exploration will stop at some point prior to this where the perceived rate of discovery becomes uneconomic, such as at position $X_e$. This will be when the rate of discovered volumes per additional wildcat well falls below a commercially determined threshold.

The 2002 AUSTPLAY Bonaparte Basin assessment tends to lie on the steep part of the curves for the individual petroleum systems, reflecting their underexplored nature. This makes the assessment outcome highly sensitive to the number of wells to be drilled.

*Drilling success rate*

Past success is the main indicator of what is likely to happen in the future unless there is some knowledge that would suggest a higher success rate. This parameter equates closely to prospect success rate used by industry and is defined by a triangular distribution.

*Probability of hydrocarbons being generated and migrated*

There are two separate parameters for this category in AUSTPLAY; one for generation and the other for migration. These parameters are distinct from the success rates and equate with play chances used in industry, and a single value is input for each parameter.

For all the established Bonaparte Basin petroleum systems, these parameters had a value of 1, as hydrocarbons had been discovered in each petroleum system. Potential petroleum systems would have a value less than one.

*Minimum and maximum accumulation sizes*

The minimum accumulation size is an estimate of the minimum economic size; explorers will not explore for accumulations smaller than this economic cut-off, but will often find an accumulation smaller than the economic minimum. One could attempt to make a sophisticated model by dividing assessment units into various categories, based upon water depth and proximity to production facilities, but this has not been attempted for the 2002 AUSTPLAY assessment.

The maximum size is not a compulsory data entry, but can be used to ensure that no very large fields are 'discovered' by the model. In a mature exploration area, one would expect that the largest field has already been discovered.

*Proportion of oil, gas and oil plus gas accumulations*

This parameter is self-explanatory. It is based upon known values for the petroleum system.

*Proportion of oil/oil + gas*

This parameter determines the amount of oil and gas within each modelled discovery that contains both oil and gas, and is defined by a triangular distribution.

*Condensate-gas ratio*

This ratio is used to determine the amount of condensate that occurs in gas accumulations. This parameter is defined by a triangular distribution.

*Oil to gas or gas to oil conversion factor*

The current structure of AUSTPLAY requires assessments to be calculated in either oil or gas volumetric units. The conversion factor allows for the conversion from either oil to gas units or gas to oil units of measurement and takes the depth of the reservoir into account.

*Log Area and Log Volume/Area models*

Historical wildcat well data is used to construct a Log Area and a Log Volume/Area model, which form the key part of the assessment.

A Log Area (or Log A) plot is used to model the size of future drilling targets. The model is created by plotting the logarithm of the pre-drill area of closure for each wildcat well against the drilling sequence number. All wildcat wells for a petroleum system are ordered by the date the wells reached total depth. Figure 3

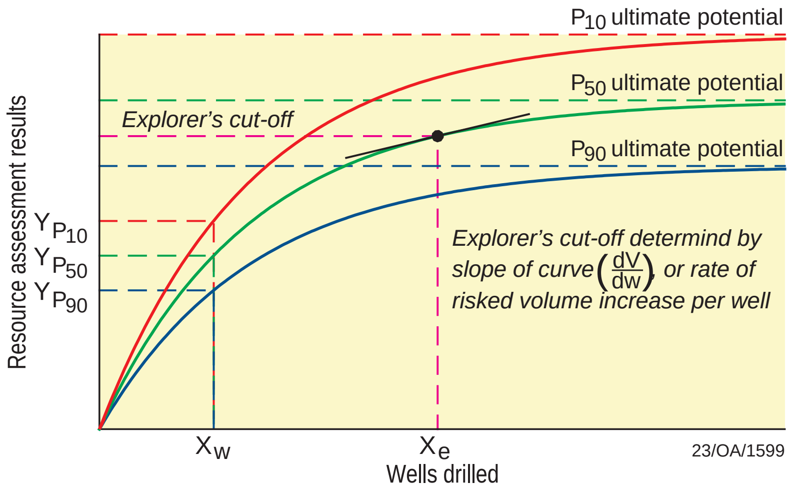


**Figure 2**. Assessment outcome as a function of wells to be drilled.

shows an example of this type of plot. One would expect explorers to drill the larger structures prior to drilling smaller structures, so that the Log A plot will usually have a negative slope.

The order in which traps are drilled can be modelled by assuming that the probability explorers will drill a trap is proportional to trap area raised to a constant power, lambda ($\lambda$). Lambda is also known as the creaming factor. When $\lambda$ has a value of infinity, fields will be drilled exactly in order of their trap area and if $\lambda$ is zero, the order of drilling is random. Lambda is typically less than one.

A Log Volume/Area (or Log V/A) plot is used to create a model for the volume of hydrocarbons to be discovered if the modelled well is a success. By its very nature, this model has less data points defining the line of best fit than the Log A plot.

The AUSTPLAY software provides the line of best fit of the Log A and Log V/A plots, but the user is given the option of modifying this result. The model is created on the assumption that the drilling to date reflects the explorers' learning process and that they have had access to all areas for exploration at all times. The quarantining of exploration in the Zone of Co-operation (subsequently the Joint Petroleum Development Area – JDPA) is an example of where access was restricted for a long period of time, and it can be argued that the Log A and Log V/A plots need to reflect this situation. Statistical parameters for the line of best fit are recorded and subsequently used to define the forecast model.

Stacked reservoirs may appear to complicate this process, but they can be viewed as a single area of closure with all volumes attributed to a single reservoir with a larger V/A value.

## Planned AUSTPLAY developments

The AUSTPLAY software is continually being modified to make it more functional. Major efforts are being directed to improve the database aspects of the program, with links to all other necessary databases within Geoscience Australia.

The user interface is also receiving attention. Business rules and guidelines are being incorporated into data tables, so that the user is aware of the basis of the assessment process. Tables are being designed to allow the rapid comparison of parameters between the various petroleum systems. This should lead to a greater consistency in how assessments are undertaken.

Perhaps the most important improvement is in relation to reserves growth, which is expected to have a significant effect on future assessments. The US Geological Survey World Petroleum Assessment team analysed the effect of reserves or field growth. As stated in the Introduction to the Reserves Growth section of the report (USGS, 2000),

"In the United States and Canada, experience shows that estimates of the sizes (cumulative production plus remaining reserves) of oil and gas fields made at any particular point in time are commonly too low. As years pass, successive size estimates of groups of fields usually increase in a collective sense, even though the size changes of individual fields through time are extremely variable. … Although only remaining reserves increase in volume, this increase is generally considered to be proportional to the total size of the field."

p. RG-1, USGS (2000)

Reserves growth is attributable to factors such as infill drilling, technological improvements and advancements, as well as cumulative production experience.

"Reserves growth is a major component – perhaps the major component – of remaining US oil and natural gas resources."

USGS (2000)

Reserves growth is also apparent in many Australian fields, but we do not currently have the ability to model this growth using the AUSTPLAY program. The experience in the US indicates that there is a necessity to do so.

The US Geological Survey (2000) report used two different reserves growth curves, depending upon the perceived situation. The report, however, only details one of the reserves growth curves, based upon reserves growth observed onshore in the lower 48 states (see Chapter RG – Estimating potential reserve growth of known (discovered) fields: a

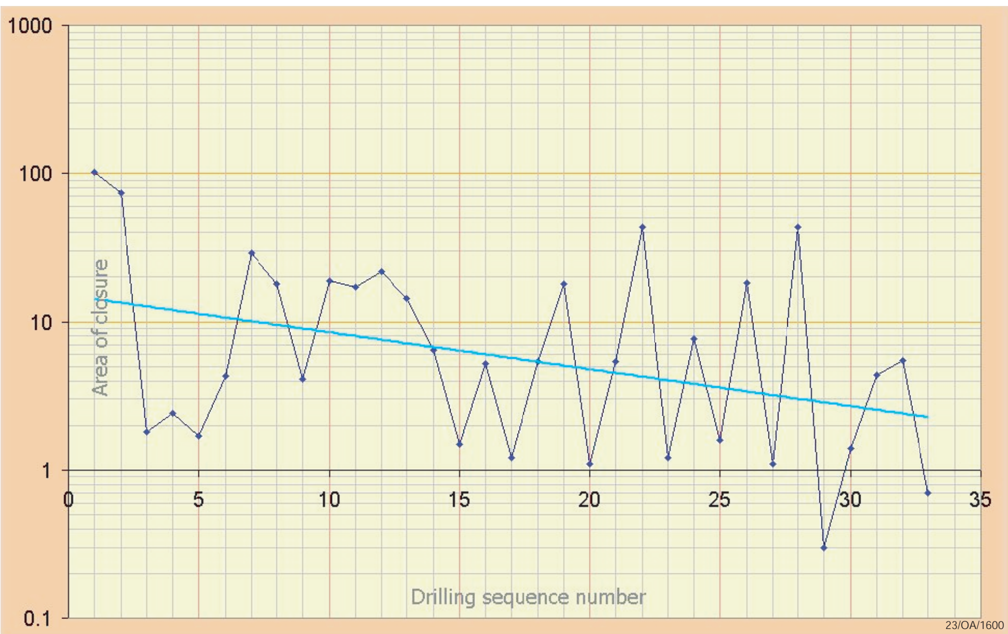


**Figure 3**. Example of a Log Area (Log A) plot from AUSTPLAY. Area of closure is given in square kilometres.

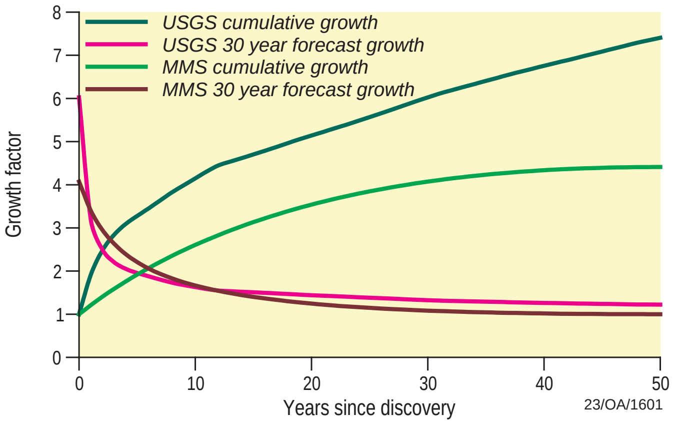


**Figure 4**. Reserves growth factor curves from the US Geological Survey (USGS, 2000) and the Minerals Management Service (MMS, 1999).

component of the US Geological Survey World Petroleum Assessment 2000). The other curve was developed by the Minerals Management Service (MMS, 1999) and this is the one that has been applied to the Australian component of the US Geological Survey report.

These two curves apply a relatively high growth factor to discoveries made just prior to the assessment cut-off date; 6.02 for the lower 48 states and 4.07 for the Minerals Management Service curve. Figure 4 shows how these two factors vary with age of discovery and are utilised for reserves growth over a thirty year timeframe. These high factors do not appear to have adversely affected the US Geological Survey (2000) Bonaparte Basin assessment, even though the Laminaria oil field would appear to "grow" to a reserve of about 800 million barrels. Such a volume does not appear consistent with the field production history. The US Geological Survey (2000) assessment has used the medians of distributions to model future field size distributions, so that wayward endpoints from any particular field size do not adversely affect the results.

It is anticipated that reserves growth will be incorporated in future versions of the AUSTPLAY software. However, the nature of how reserves are originally reported can influence the outcome on reserves growth factors. It is important to understand how our reserves are reported before we adopt a reserves growth function. It may well be inappropriate for Geoscience Australia to adopt the growth functions used by the US Geological Survey. Preliminary data from Australian reserves indicates that it is unlikely that the high initial reserves growth factors seen with US data will generally be observed with Australian data (D. Wright, pers. comm.).

One aspect that is currently being investigated is whether the reserves growth factor should be related to time since discovery, or time since start-up of production. Geoscience Australia's preference is to use the start-up date, as there can be very long delays between discovery and production, during which time very little work is done on defining the reserves. Reserves' reporting activity increases just prior to the decision to commence production.

## Bonaparte Basin assessment

### *Exploration history of the Bonaparte Basin*

To the end of 2001, a total of 384 wells had been drilled in the Bonaparte Basin. Of these, some 251 are classified as New Field Wildcats for the purpose of assessment. Figure 5 shows the number of wells drilled on a year by year basis, while Figure 6 shows the breakdown by petroleum system. Figure 7 shows cumulative discovered reserves from 1966 to January 2002.

The most significant point on Figure 5 is the discovery of the Jabiru oil field in 1983, which kick-started a greater exploration

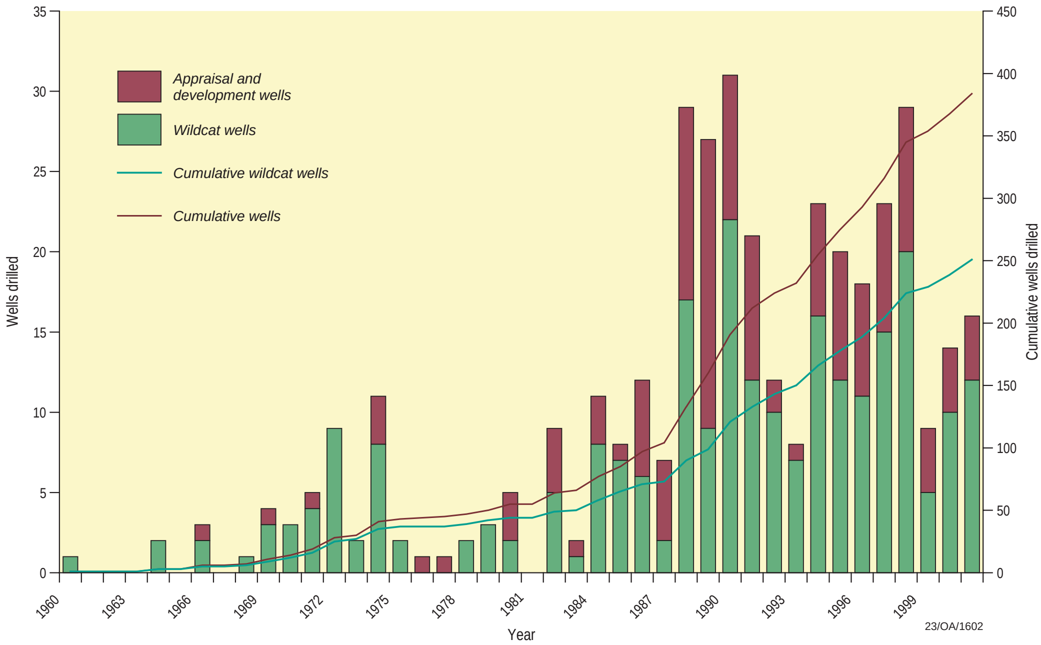


**Figure 5**. Bonaparte Basin drilling activity.

effort in the Bonaparte Basin in 1988–91. This represented the first substantial oil discovery in the basin. The opening up of the Zone of Co-operation to exploration in the 1990s provided the impetus to maintain a high level of exploration activity.

### *Petroleum systems in the Bonaparte Basin*

Seven petroleum systems have been defined in the Bonaparte Basin. Descriptions of the regional geology of the basin are provided by Mory (1988) and Mory (1991) and the stratigraphy is illustrated in Figures 8 and 9.

The starting point for the definition of the petroleum systems was a review of data held in the various Geoscience Australia databases. The definition of the petroleum systems has followed closely the guidelines of Magoon and Dow (1994). The seven petroleum systems can be considered as three Jurassic systems, three Permian systems and one Permo-Carboniferous system. The petroleum systems are:

*Jurassic*

- Elang-Elang(!) (Sahul Syncline, Flamingo High);
- Plover-Plover(.) (Malita Graben, Sahul Platform);
- Vulcan-Plover(!) (Vulcan Sub-basin).

*Permian*

- Hyland Bay-Hyland Bay(?) (Kelp High);
- Hyland Bay/Keyling-Hyland Bay(.) (Central Petrel Sub-basin);
- Permian-Hyland Bay(?) (Londonderry High).

*Permo-Carboniferous*

- Milligans-Kuriyippi/Milligans(!) (Southern Petrel Sub-basin).

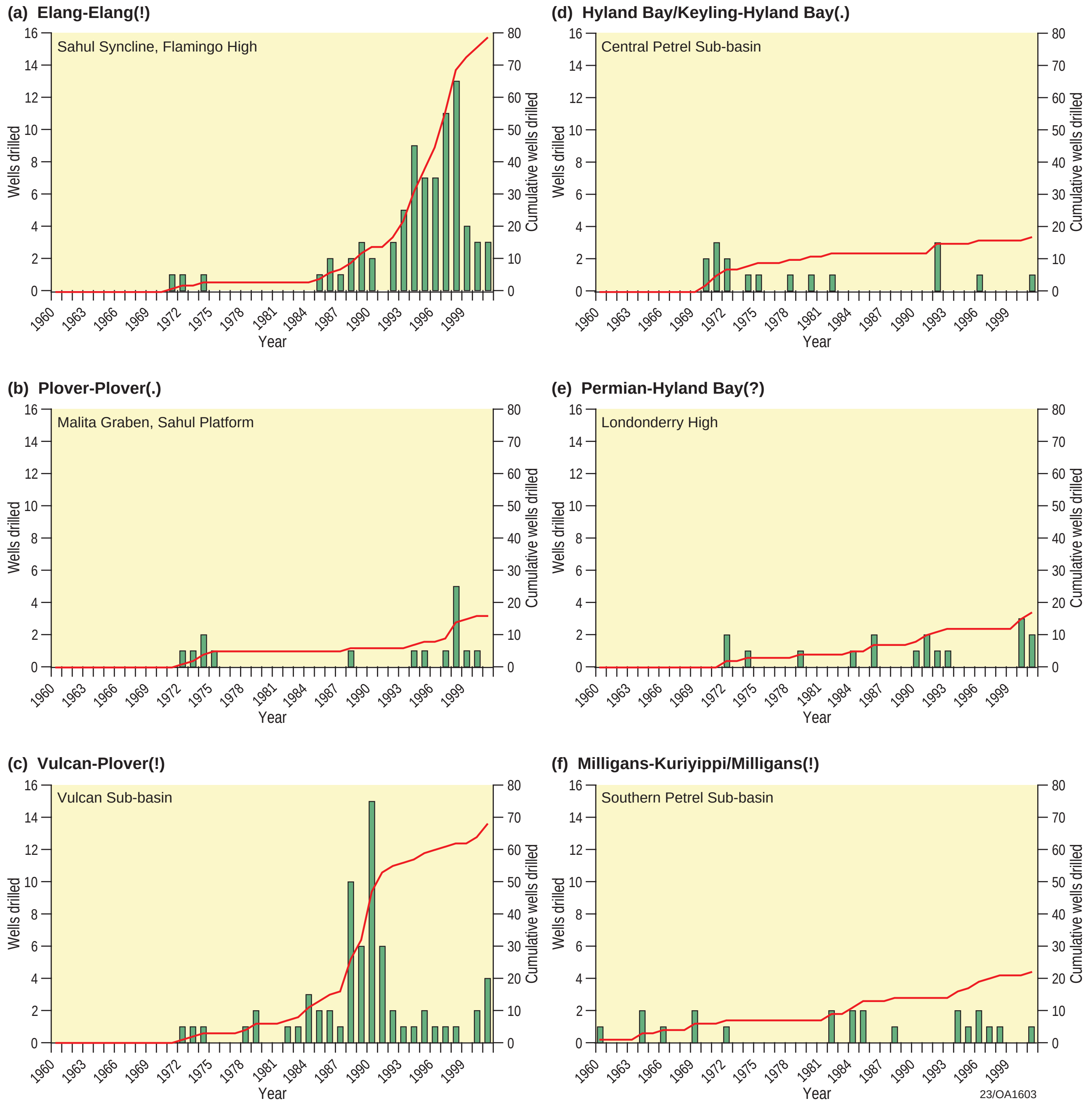


**Figure 6**. Wildcat drilling activity by petroleum system.

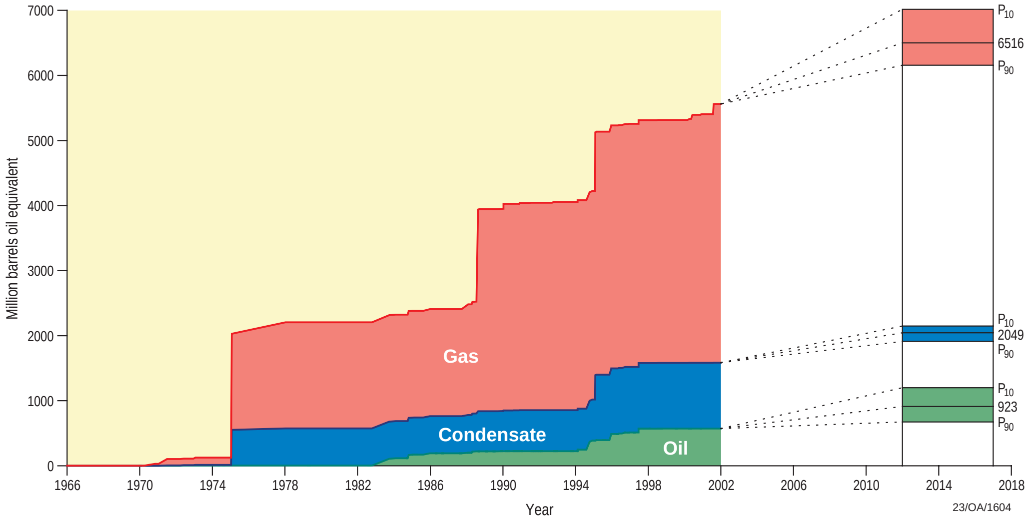


**Figure 7**. Cumulative discovered hydrocarbon volumes in the Bonaparte Basin, with forecast from the 2002 AUSTPLAY assessment.

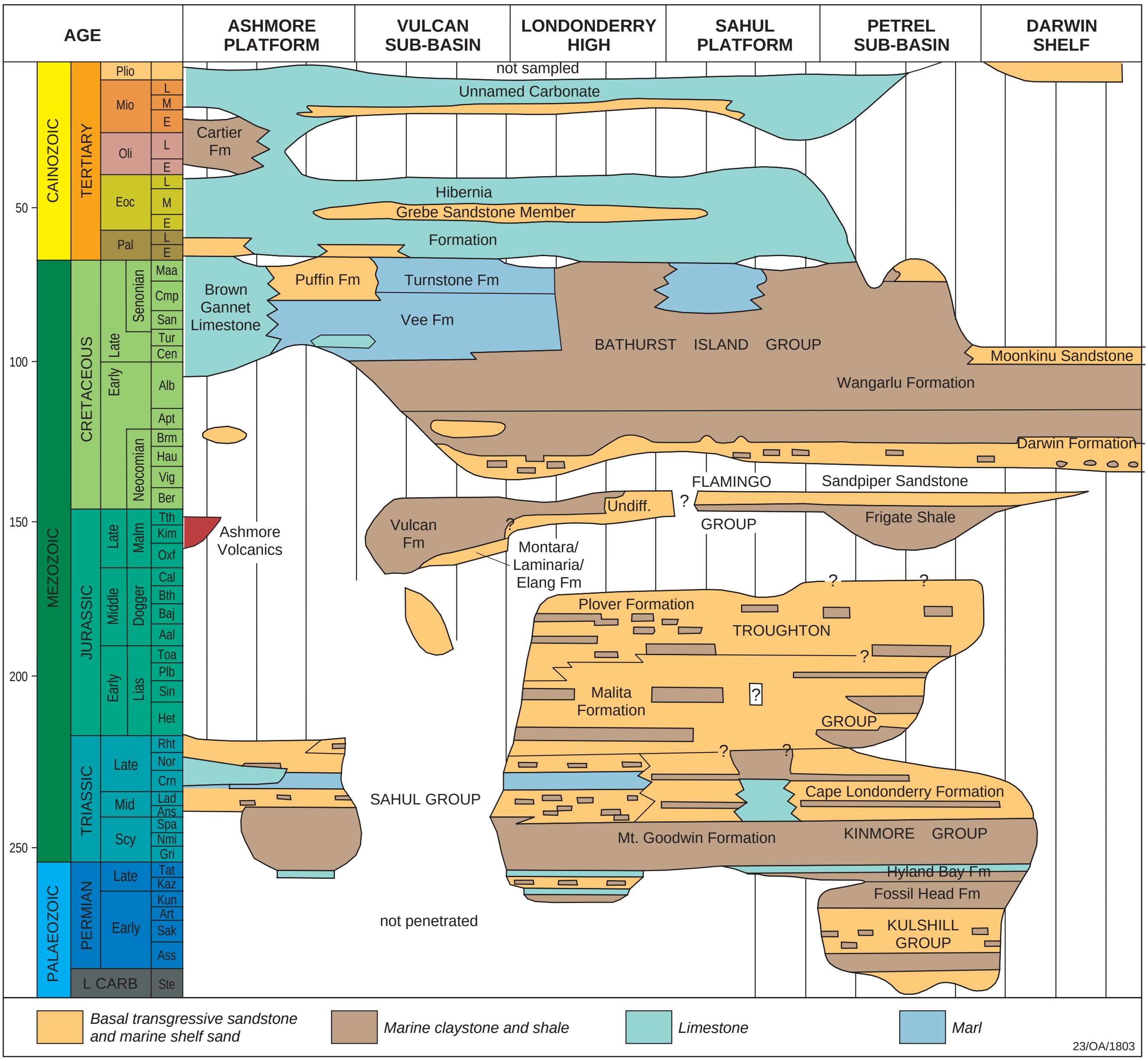


**Figure 8**. Stratigraphy of the Bonaparte Basin.

The structural elements of the Bonaparte Basin have recently been redefined at Geoscience Australia. These elements were used to initially define which wells should be considered for the assessment process. As obvious as it sounds, the correct location for all data is essential for assessment.

Hydrocarbon show data from the Geoscience Australia RESFACS database were analysed primarily to determine the spatial distribution of shows. Significant shows were extracted and their distribution is shown in Figure 10. The distribution of interpreted oil slicks derived from Synthetic Aperture Radar (SAR) data (O'Brien *et al*., 2001; Nigel Press Associates, 2001) and migration and entrapment indications derived from analysis of fluid inclusions (Grains containing Oil Inclusions; GOI) (CSIRO, 2002) are also shown on Figure 10. The SAR and GOI provide a bias to the data as they have been studied in certain areas only, whereas the conventional show data is provided for all wells.

These data by themselves do not define petroleum systems. Geochemical data, including interpreted hydrocarbon families and oil-source correlations (Preston and Edwards, 2000; Edwards *et al*., 2000; Edwards *et al*., 2004), together with geohistory modelling (Kennard *et al*., 1999; 2002), have all been incorporated in defining the petroleum systems.

For each petroleum system, two regions were defined; the limit of the source pod and the limit of the petroleum system. The source pod refers to the area from which modelling suggests hydrocarbons have been expelled. The limit of the petroleum system, by definition, fully encloses the source pod plus all the hydrocarbon shows thought to have been generated from the source pod. The certainty with which both the source pod and petroleum system boundaries are defined varies from tightly controlled to relatively arbitrary, often changing from one to the other over short distances.

Figure 11 shows the location and limits of all the petroleum systems. Note that there is some overlap between the petroleum systems.

### Jurassic Elang-Elang(!) Petroleum System (Sahul Syncline, Flamingo High)

*Definition of limits of petroleum system*

The Bayu-Undan, Buffalo, Corallina, Elang, Kakatua and Laminaria commercial discoveries are attributed to this Jurassic petroleum system. Other small non-commercial discoveries include Ascalon-1A, Avocet-1A, Bluff-1, Buller-1, Coleraine-1, Flamingo-1, Fohn-1, Jahal-1, Krill-1, Kuda Tasi-1, Minotaur-1, Rambler-1 and Saratoga-1 (Fig. 12). The petroleum system extends across the Sahul Syncline, Flamingo High and Flamingo Syncline.

The discoveries consist of oil, gas or oil plus gas accumulations. For the purposes of assessment modelling, the ratio of oil/gas/oil + gas is 0.3/0.3/0.4.

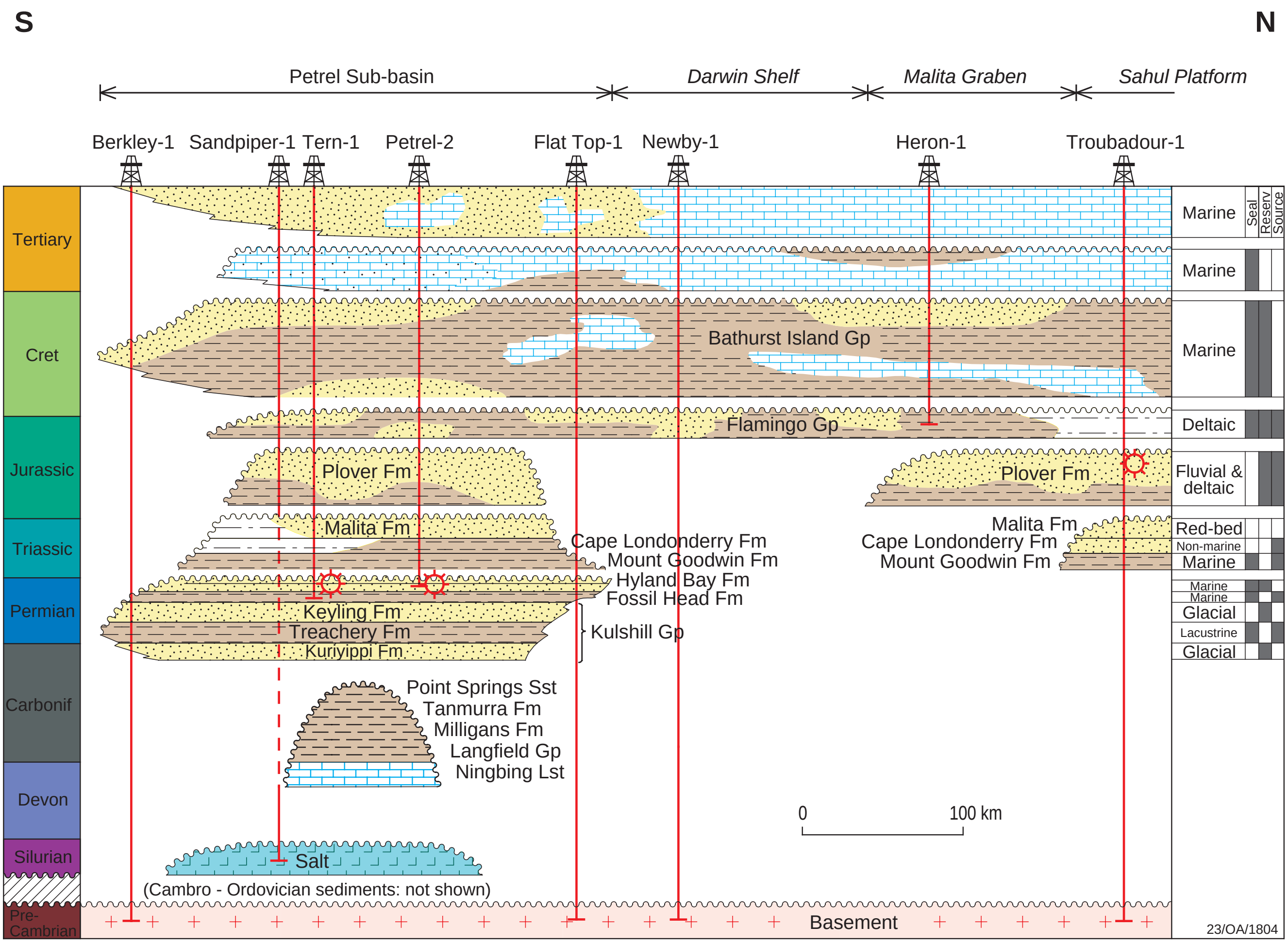


**Figure 9**. Chronostratigraphy: Petrel Sub-basin – Darwin Shelf – Malita Graben – Sahul Platform.

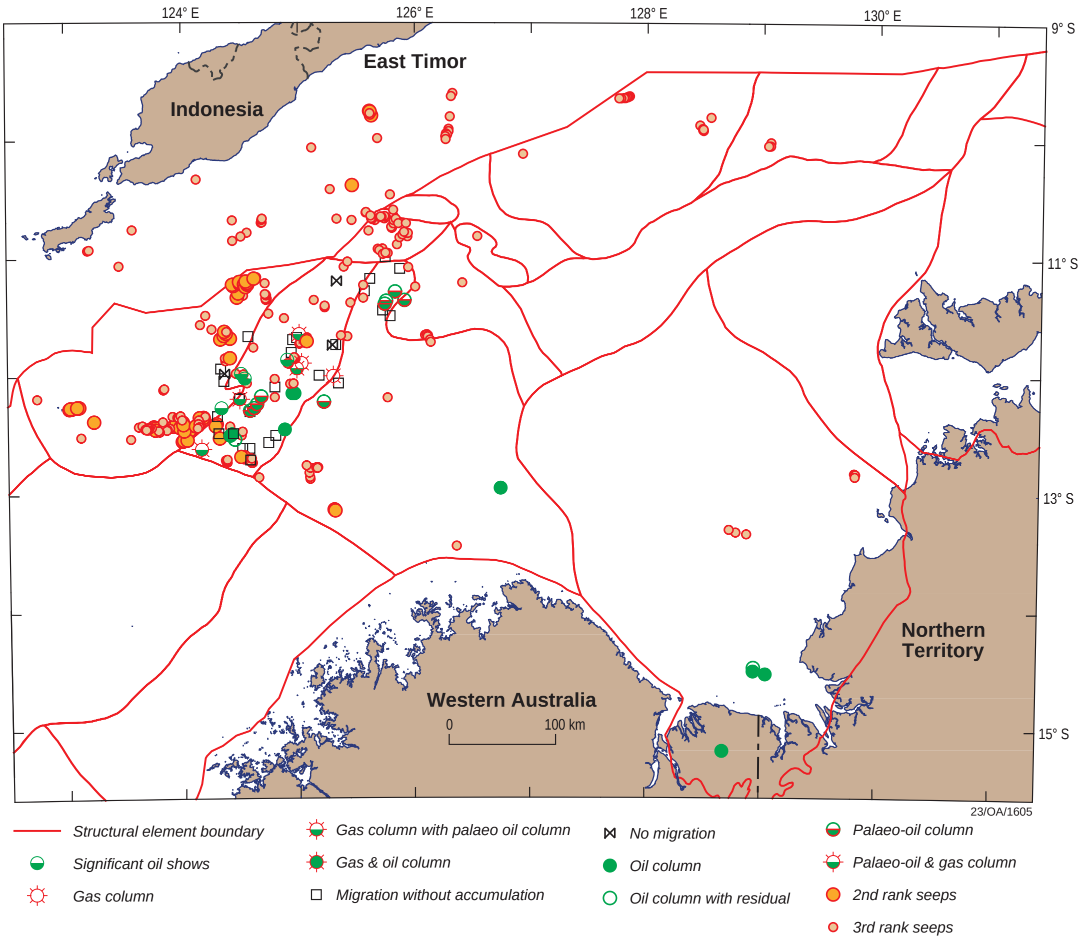


**Figure 10**. Significant oil shows, oil slicks derived from SAR data and migration indicators from GOI data.

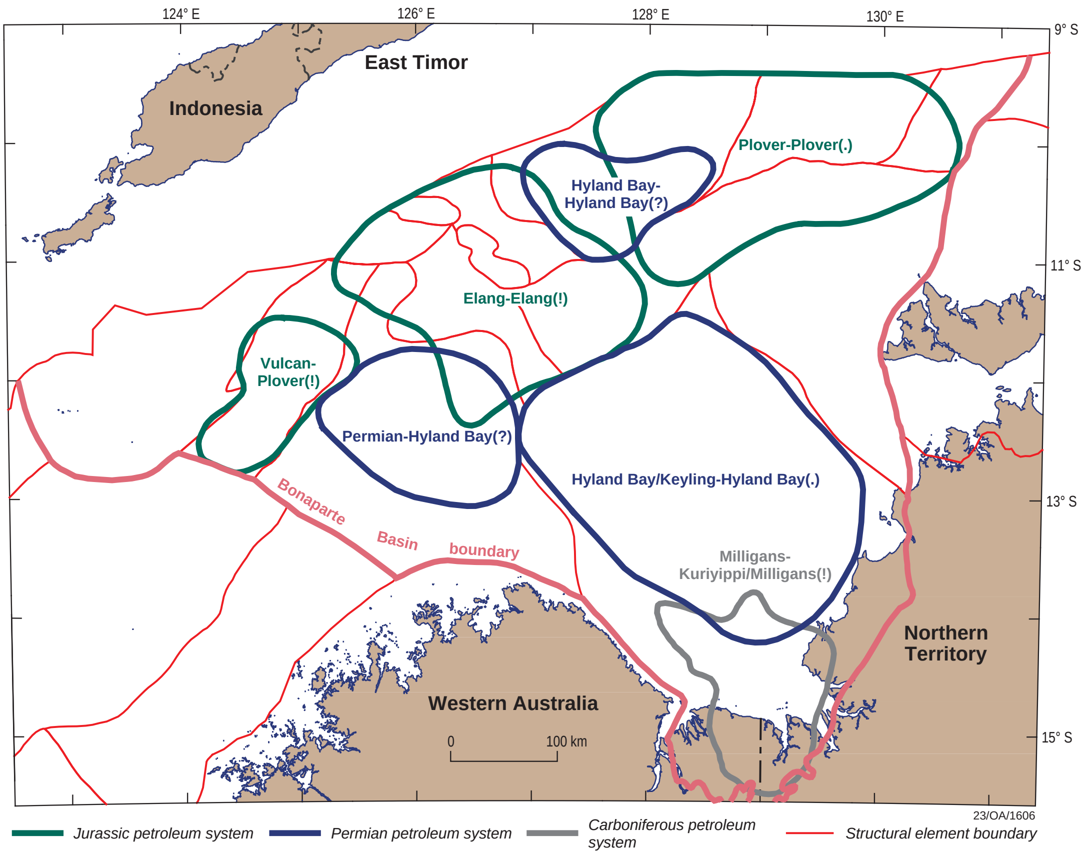


**Figure 11**. The seven petroleum systems of the Bonaparte Basin.

Seventy-nine wildcat wells have been drilled in the petroleum system. Drilling activity increased markedly after the lifting of the quarantine to exploration in the Zone of Cooperation in the early 1990s. Peak wildcat drilling activity was reached in 1998, when thirteen wildcat wells were drilled. Recent activity has been significantly lower with only three wildcat wells drilled in each of 2000 and 2001.

Preston and Edwards (2000) presented thermal history models for part of this petroleum system and their work has been used to help define the limit of the main Elang Formation source pod. In their paper, they presented a temperature map on the Top Elang surface. The 140°C contour has been used to define the limit of the mature source pod within the central area (see box marked in Figure 12), with the remainder of the boundary being defined by regional structural trends.

*Assessment input parameters*

Figure 6 shows that a total of 65 wildcat wells have been drilled in this petroleum system in the last ten years and a further eight were drilled in the preceding five years. It is anticipated that wildcat drilling activity will continue at a relatively high level for the Bonaparte Basin and it is estimated 30 wells will be drilled over the next ten to fifteen years.

A minimum oil field size of one million cubic metres (6.3 million barrels) has been selected. It is expected that relatively small discoveries close to producing facilities should be economic. The maximum oil field size selected was 30 million cubic metres (190 million barrels). Discoveries larger than this have already been found, but the most obvious structures have now been drilled and future discoveries are unlikely to be as large.

A success rate distribution of 5% (minimum), 15% (most likely) and 25% (maximum) closely reflects success to date. Only 6% of wildcat discoveries have been commercialised, although this will rise when production at Bayu-Undan commences. If all commercial and non-commercial discoveries are included, the success rate increases to about 15%. It is anticipated that previous experience in the petroleum system may lead to higher success rates in the future.

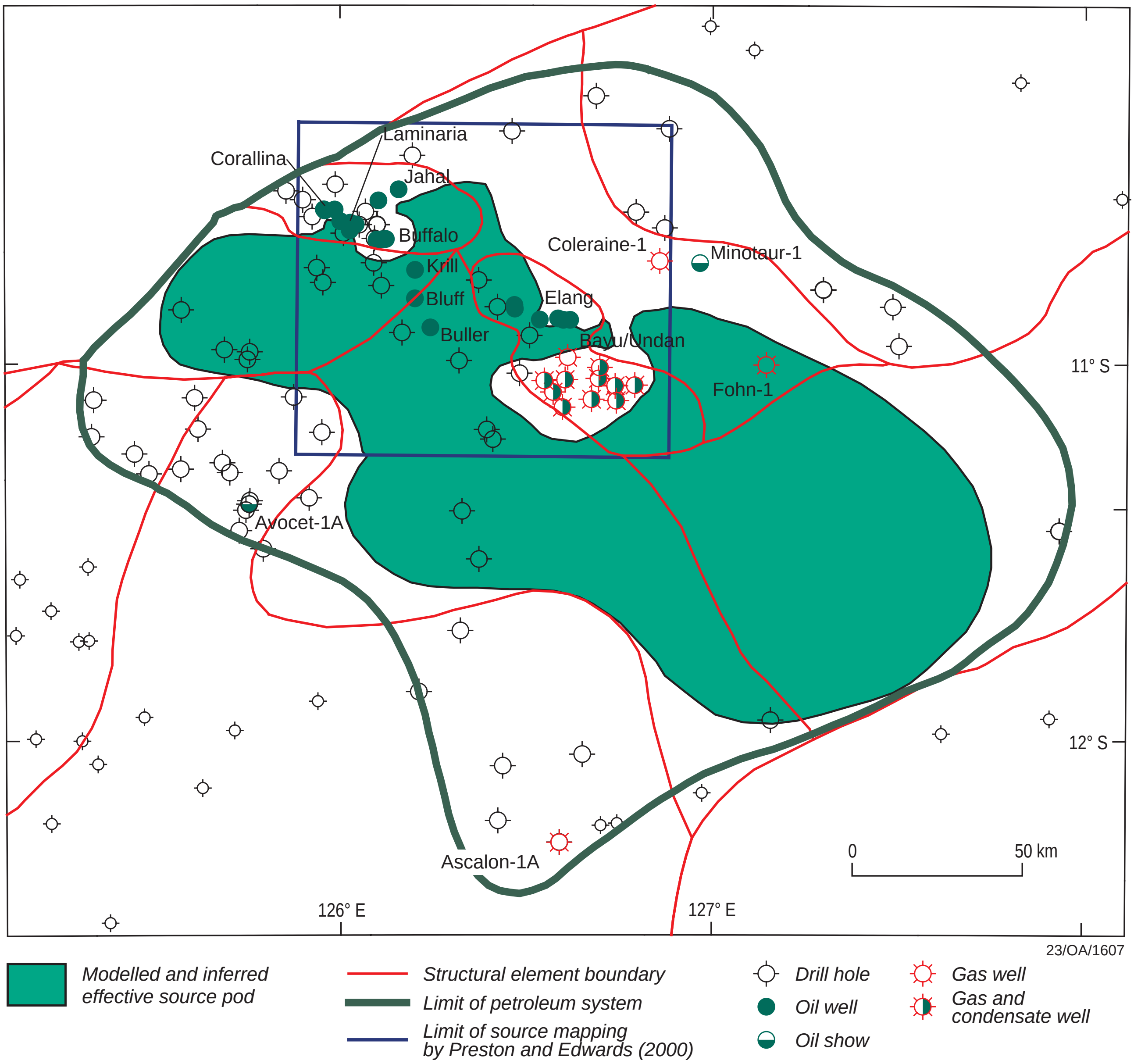


**Figure 12**. The Jurassic Elang-Elang(!) petroleum system, with wells attributed to the petroleum system shown in large symbols. Limit of source mapping by Preston and Edwards (2000) shown by box.

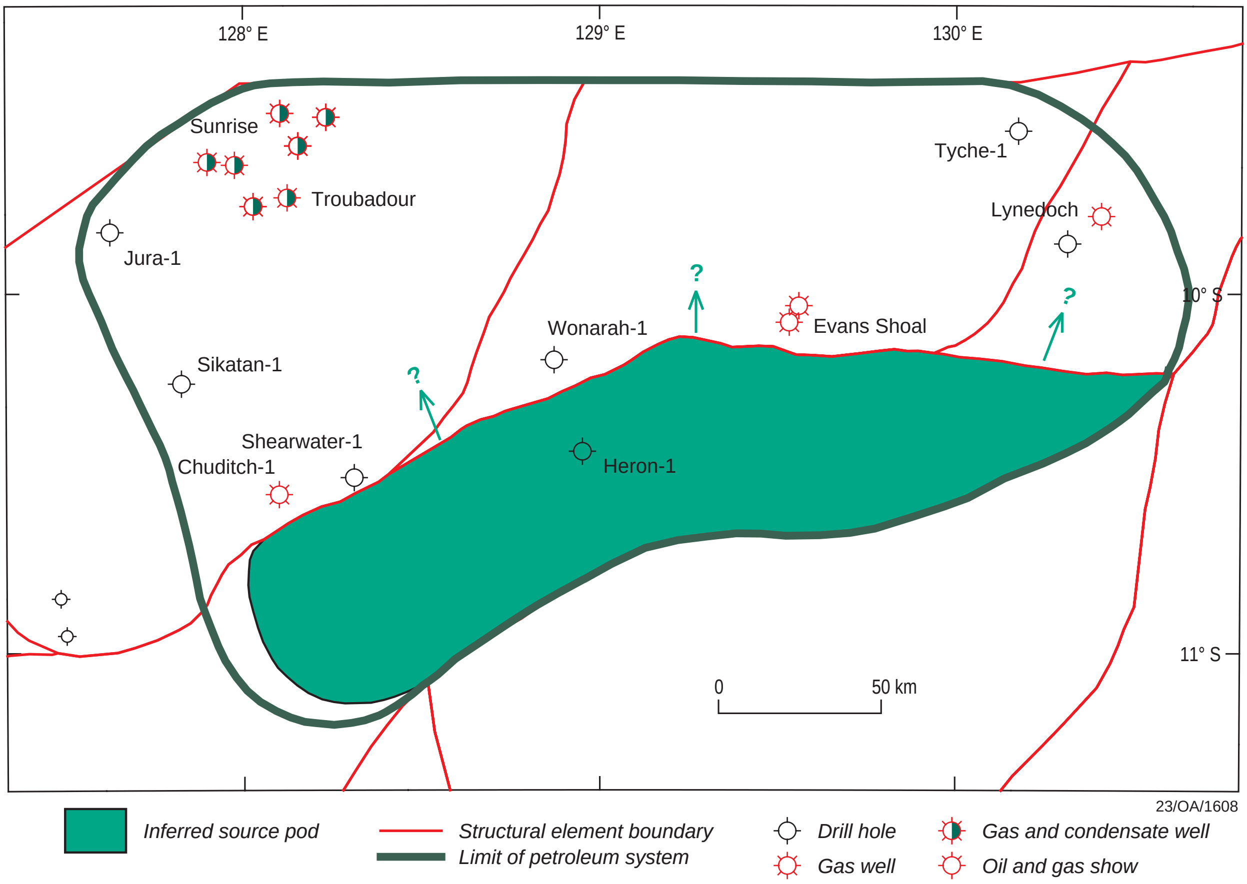


**Figure 13**. The Jurassic Plover-Plover(.) petroleum system, with wells attributed to the petroleum system shown in large symbols.

## Jurassic Plover-Plover(.) Petroleum System (Malita Graben, Sahul Platform)

*Definition of limits of petroleum system*

Five gas discoveries have been made from the 16 wildcat wells in this petroleum system: Chuditch-1, Evans Shoal, Lynedoch, Sunrise and Troubadour (Fig. 13). In only two years has there been more than one wildcat well drilled: 1974 with two and 1998 with five. The initial success of Sunrise-Troubadour did not generate immediate follow-up activity and a drilling time gap of thirteen years was experienced from the late 1970s until very late in the 1980s.There has been no modelling of the source pod undertaken by Geoscience Australia, but based upon regional structural settings, the active source is anticipated to extend throughout the Malita Graben (Whittam *et al*., 1996) and perhaps parts of the Sahul Platform, Troubadour Terrace and Calder Graben. The petroleum system extends north from the Malita Graben extending across the Sahul Platform and the Troubadour Terrace with the northern limit being defined politically by the boundary with Indonesia. The Abadi gas discovery in Indonesian waters is most likely part of the northern extension of this petroleum system. The petroleum system also extends into the Calder Graben.

This petroleum system has been modelled as gas-prone (with moderate liquids), but with little or no oil potential.

*Assessment input parameters*

This petroleum system is underexplored, but is dominated by the giant Sunrise-Troubadour gas accumulation. Ten wildcat wells have been drilled in the last ten years, with only one in the previous five years. Ten wells have been modelled for the next ten to fifteen years, with commitment drilling representing only a small proportion of this estimate. The assessment outcome is very sensitive to the number of modelled wells and any reduction below ten wells will have a significant effect on the forecast of gas and condensate to be discovered.

The modelled minimum pool size is 5 billion cubic metres of gas (175 billion cubic feet). Again, this is a small volume, but any pool of this magnitude close to facilities could potentially be economic. A maximum field size of 100 billion cubic metres (3.5 trillion cubic feet) has been selected. It is considered unlikely that a discovery greater than this size will be made in the next ten to fifteen years.

The distribution of success rates used for this petroleum system is 10% (minimum), 25% (most likely) and 45% maximum.

## Jurassic Vulcan-Plover(!) Petroleum System (Vulcan Sub-basin)

*Definition of limits of petroleum system*

The Vulcan-Plover(!) petroleum system is primarily restricted to the Vulcan Sub-basin, but extends a short distance onto the Ashmore Platform to the west and the Londonderry High on the east (Fig. 14). This system has been tested by 70 wildcat wells with 24 discoveries, including four commercial discoveries; Cassini, Challis, Jabiru and Skua (now abandoned). The non-commercial discoveries are Audacious, Bilyara-1, Birch-1, Delamere-1, East Swan, Eclipse-2, Halcyon-1, Keeling-1, Maple-1, Maret-1, Montara, Oliver-1, Padthaway-1, Pengana–1, Puffin, Swan, Swift-1, Tahbilk-1, Talbot and Tenacious.

These discoveries are a mixture of oil, gas and oil + gas and the assessment has used proportions of oil/gas/oil + gas as 0.6/0.2/0.2.

Drilling activity has been episodic, with the Jabiru and Challis discoveries encouraging companies to commit to large drilling campaigns. The peak of drilling activity was reached in 1990, when fifteen wildcat wells were drilled. Unfortunately no commercial discoveries arose from this activity and drilling efforts soon declined to one or two wells per year.

Kennard *et al.* (1999) have modelled the extent of the Late Jurassic Lower Vulcan Formation source pod. Two Upper Jurassic source pods that have expelled hydrocarbons have been identified within the Swan and Paqualin grabens. Hydrocarbons may have migrated onto the Ashmore Platform, but there is little evidence of hydrocarbons being trapped; the retention efficiency of most traps is very low.

*Assessment input parameters*

This petroleum system has had extensive exploration activity since the discovery of the Jabiru oil accumulation. Of the 70 wildcats drilled, 38 were drilled in the last ten years with a further 17 drilled in the previous five years. A total of twenty new wells have been modelled in the assessment. This is a lower level of activity than seen in the last ten years, but reflects the reduction in drilling activity since 1990.

The minimum oil field size selected for this system is 0.1 million cubic metres (approximately 600,000 barrels). This would only be applicable to pools accessible from current infrastructure. A maximum field size has been set at 30 million cubic metres (190 million barrels) and is similar to that for the Elang-Elang(!) petroleum system.

A total of 24 discoveries has been made and this represents a success rate of 34%, but many of these are very small. The current commercial success rate is much smaller at 6%. The success rate distribution was modelled to be 1% (minimum), 10% (most likely) and 25% (maximum). Improvements in seismic technology and improved geological understanding may have a positive impact on future success rates and discovery sizes.

**Permian Hyland Bay-Hyland Bay(?) Petroleum System (Kelp High)**

*Definition of limits of petroleum system*

This petroleum system is defined by only one gas discovery well; Kelp Deep-1, drilled in 1997. Gas was encountered at numerous stratigraphic levels, but resulted in only non-commercial flows from tight reservoirs (Bint *et al.*, 1998). The petroleum system is viewed to be gas-prone, with no oil potential.

There are few constraints on the limits of the petroleum system. To the south and east, the boundary is defined by the southern boundary of the Sahul Platform, while the northern boundary is related to the interpreted depositional limit of the Permian (Fig. 15).

Given the disappointing results of Kelp Deep-1, no further exploration is anticipated in this petroleum system over the

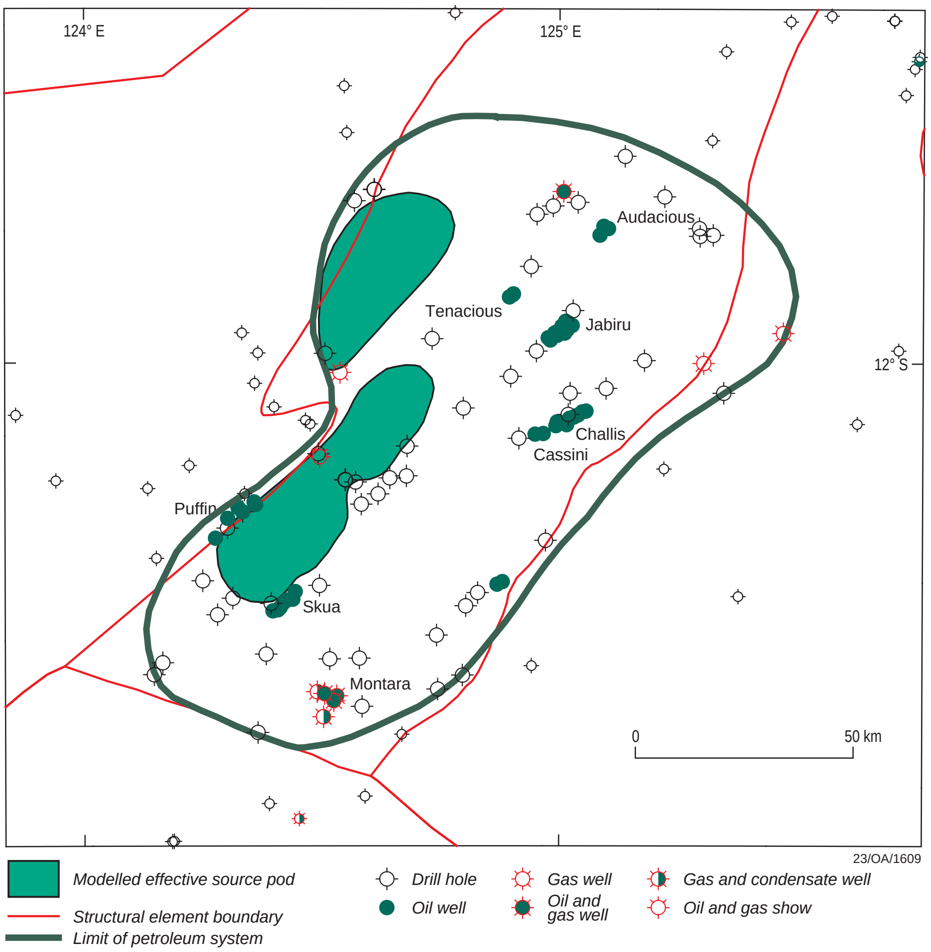


**Figure 14**. The Jurassic Vulcan-Plover(!) petroleum system, with wells attributed to the petroleum system shown in large symbols. Extent of source pod mapped by Kennard *et al*. (1999).

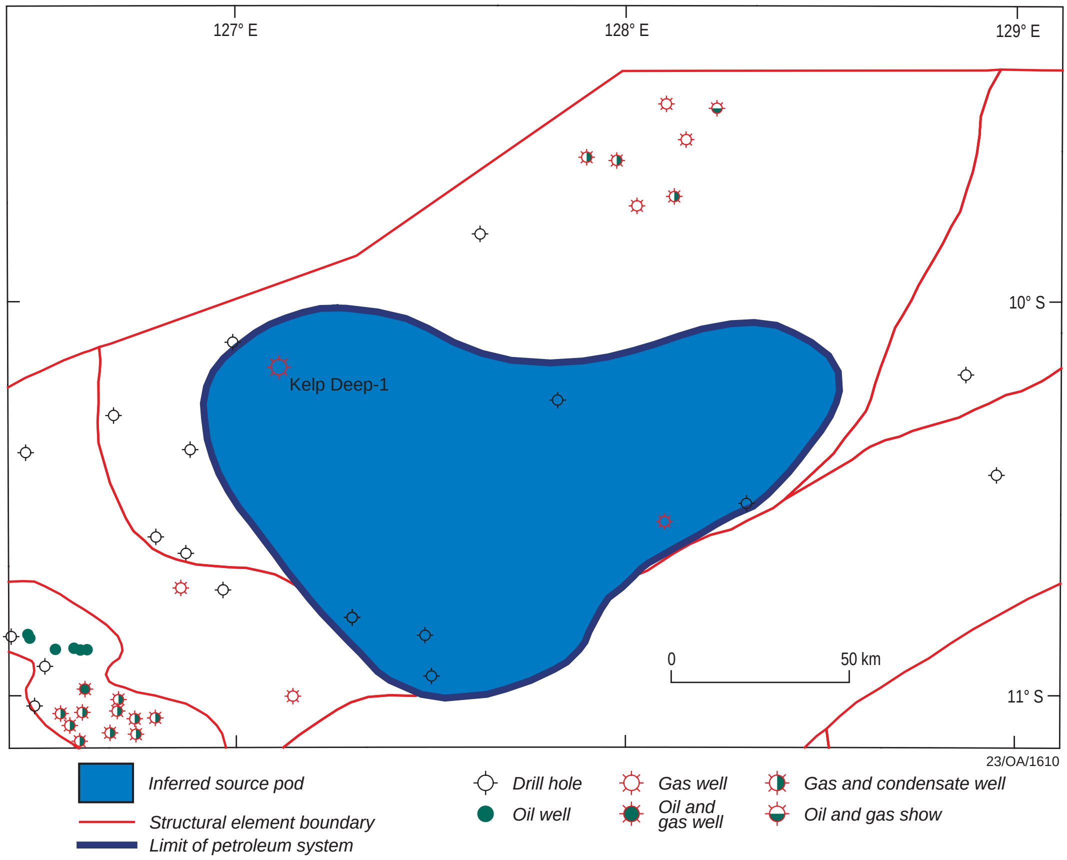


**Figure 15**. The Permian Hyland Bay-Hyland Bay(?) petroleum system, with Kelp Deep–1 the only well attributed to the petroleum system.

next ten to fifteen years. Although there is undoubtedly remaining potential for this play, no hydrocarbons are anticipated to be discovered in this petroleum system in the medium term.

**Permian Hyland Bay/Keyling-Hyland Bay(.) Petroleum System (Central Petrel Sub-basin)**

*Definition of limits of petroleum system*

Sixteen wildcat wells are attributed to this petroleum system in the Petrel Sub-basin. A total of four gas discoveries have been made; Fishburn-1, Penguin-1, Petrel and Tern, and the recent Blacktip-1 discovery is also tentatively assigned to this system (Fig. 16). Drilling activity had been low for many years prior to the drilling of Blacktip-1. The Blacktip gas field is anticipated to provide the first commercial producer for this petroleum system.

The Hyland Bay/Keyling-Hyland Bay(.) petroleum system is restricted to the Petrel Sub-basin. Geohistory modelling by Kennard *et al.* (2002) has defined the source pod. Kennard *et al.* (2002) show data for Upper and Lower Permian source units (Hyland Bay and Keyling formations, respectively) but as it is difficult to ascribe discoveries to either source, a single Permian petroleum system has been defined for assessment purposes.

The outer boundary for the petroleum system is constrained by regional structural trends but is considered to be limited to the Petrel Sub-basin. There is a possibility that the Permian-Hyland Bay(?) Londonderry High petroleum system is a part of the Hyland Bay/Keyling-Hyland Bay(.) Petrel Sub-basin petroleum system, but an analysis of the areas of closure of the prospects shows a completely different size grouping, associated with a very different structural style.

*Assessment input parameters*

The recent Blacktip-1 gas discovery is expected to increase medium-term exploration activity. Only five wildcat wells have been drilled in the last ten years (none in the five years prior to that), but commitment drilling is expected to underpin an increase to ten wells in the next ten to fifteen years.

This petroleum system is gas-dominated, but geochemical data indicate that the coaly shales of the Lower Permian Keyling Formation have some oil potential and, although no oil accumulations have been discovered to date, a small proportion (20%) of future discoveries are modelled to be oil discoveries. The remaining 80% are modelled to be gas discoveries.

A minimum gas field size of one billion cubic metres (35 billion cubic feet) has been selected on the basis that fields of this size could be economic close to a stand-alone commercial discovery.

The drilling success rate to date is 35% (commercial success rate is zero to date) and this is reflected in a modelled success rate of 1% (minimum), 33% (most likely) and 50% (maximum). The relatively simple structural style and good rock properties, allowing hydrocarbon effects to be observed on seismic, should contribute to a relatively high success rate in the future.

**Permian-Hyland Bay(?) Petroleum System (Londonderry High)**

*Definition of limits of petroleum system*

Seventeen wildcat wells have been assigned to this petroleum system (Fig. 17). Two gas discoveries have been made; Prometheus-1 and Rubicon-1. The oil shows in

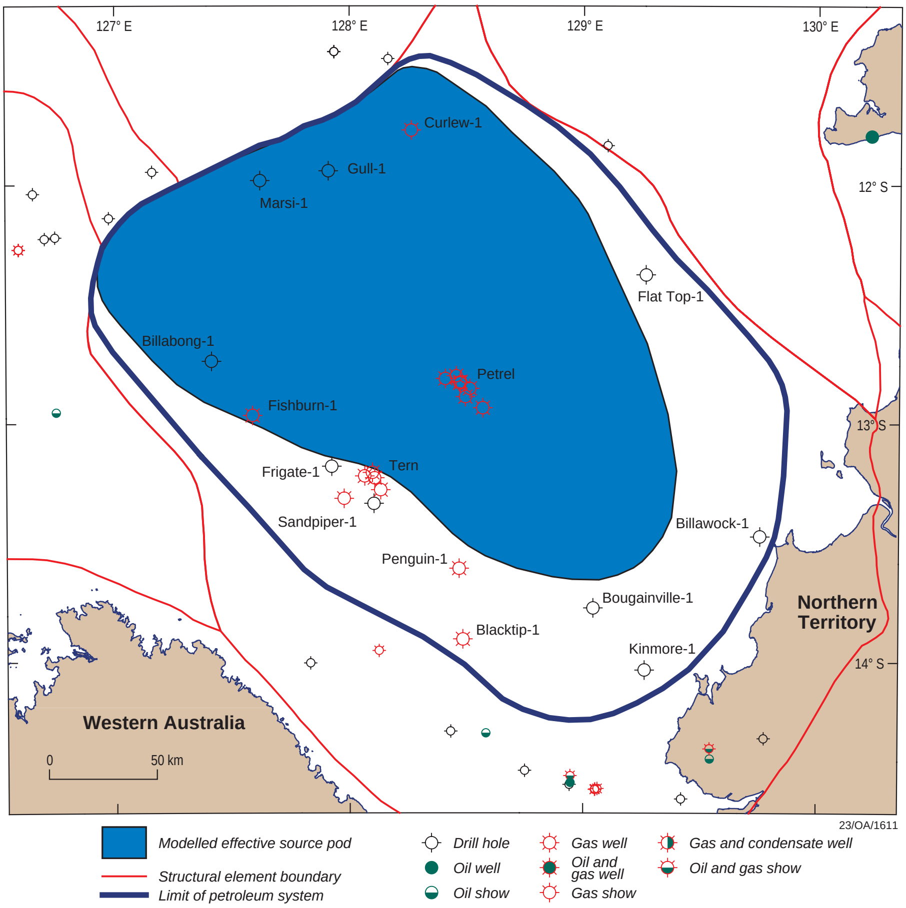


**Figure 16**. The Permian Hyland Bay/Keyling-Hyland Bay(.) petroleum system, with wells attributed to the petroleum system shown in large symbols. Source pod modelled by Kennard *et al*. (2002).

Torrens–1 provide encouragement for oil targets. Drilling in this petroleum system commenced in 1972 with Osprey-1. Exploration activity has been very sporadic, with gaps in drilling activity of up to six years. The most active and successful year was 2000, when three wells (Prometheus-1, Intrepid-1 and Rubicon-1) were drilled.

A Permian source is considered for this petroleum system; oil shows in Torrens-1 have been correlated in part with the early Permian Keyling Formation (Kennard *et al*., 2000; Ruble *et al*., 2000). No detailed modelling has been published to help define the source pod. This petroleum system is restricted to the Londonderry High structural element, but is poorly constrained.

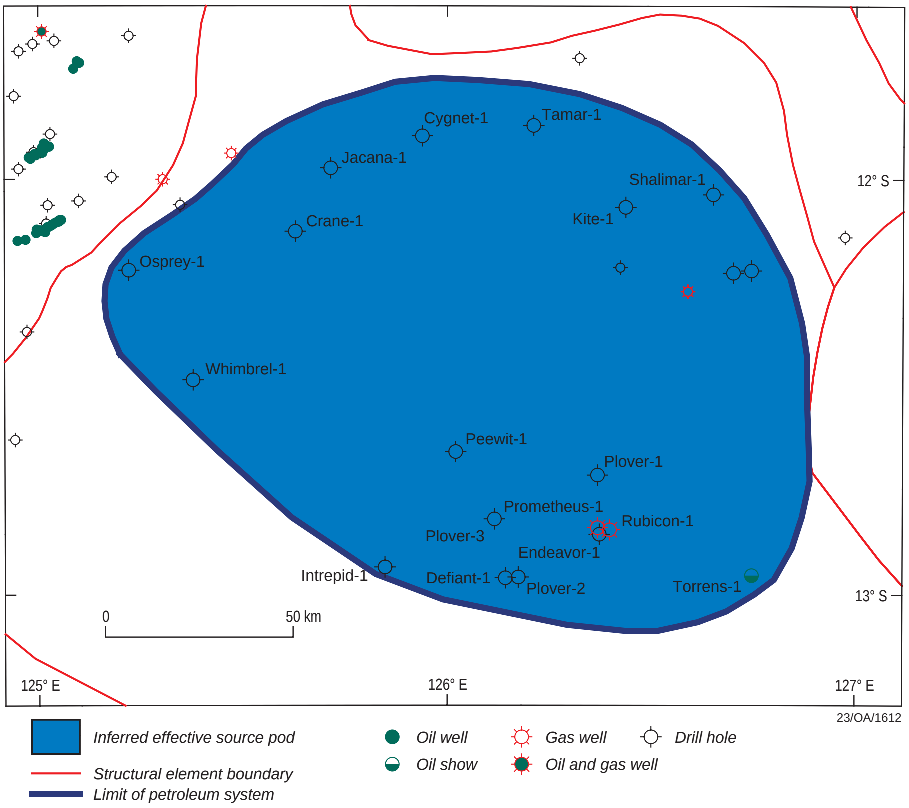


**Figure 17**. The Permian-Hyland Bay(?) petroleum system, with wells attributed to the petroleum system shown in large symbols.

*Assessment input parameters*

Although only seven wildcat wells have been drilled in the last ten years, with three in the previous five years, the Prometheus and Rubicon gas discoveries, and a potential commercial development in the Petrel Sub-basin, are anticipated to encourage further drilling activity in the Permian-Hyland Bay(?) petroleum system. Eight wells are modelled in the assessment.

The oil shows in Torrens-1 indicate some oil potential. Hence, 20% of future discoveries have been modelled as oil discoveries with the remainder as gas discoveries.

Both the Prometheus and Rubicon discoveries are relatively small and future discoveries are anticipated to be similar. The maximum gas field size of 30 billion cubic metres (about one trillion cubic feet) allows for a significant discovery to be made.

A success rate distribution of 0% (minimum), 10% (most likely) and 30% (maximum) reflects the relatively low success rate to date; two discoveries from 17 wildcat wells. The maximum value allows for the fact that early wildcat wells were poorly sited and targeted concepts which are now outdated.

**Carboniferous Milligans-Kuriyippi/Milligans(!) Petroleum System (Southern Petrel Sub-basin)**

*Definition of limits of petroleum system*

This is the only petroleum system that extends onshore and the exploration activity reflects this, with numerous small targets having been drilled. Twenty-two wildcat wells have been drilled and eleven non-commercial discoveries have been made: Barnett and Turtle offshore; Bonaparte, Garimala-1, Kulshill, Ningbing, Pelican Island-1, Spirit Hill-1, Vienta-1, Waggon Creek-1A and Weaber, either onshore or on islands (Fig. 18). This petroleum system has been explored for longer than all other petroleum systems in the Bonaparte Basin, commencing with the drilling of Spirit Hill-1 in 1960. The oil discoveries at Turtle and Barnett did little to encourage increased drilling activity and no more than two wells have been drilled in any one year. No commercial discoveries have been made to date.

Kennard *et al*. (2002) has defined a Carboniferous petroleum system, probably sourced from marine mudstones of the Milligans Formation. The limit of the petroleum system has been defined as an envelope around the shows attributed to the source pods.

*Assessment input parameters*

With an onshore component to this petroleum system, it is not surprising that small onshore targets have been drilled. Seven wildcat wells have been drilled in the last ten years, with only one in the five years prior. It is expected that drilling activity will be similar in the medium term, especially as any commercial development in the Petrel Sub-basin will bring infrastructure close to the petroleum system.

With both oil and gas already discovered in this petroleum system, future discoveries have been modelled on the basis of 30% oil, 30% gas and 40% oil and gas.

The modelled minimum field size is 0.1 million cubic metres of oil (600,000 barrels) with a maximum of 30 million cubic

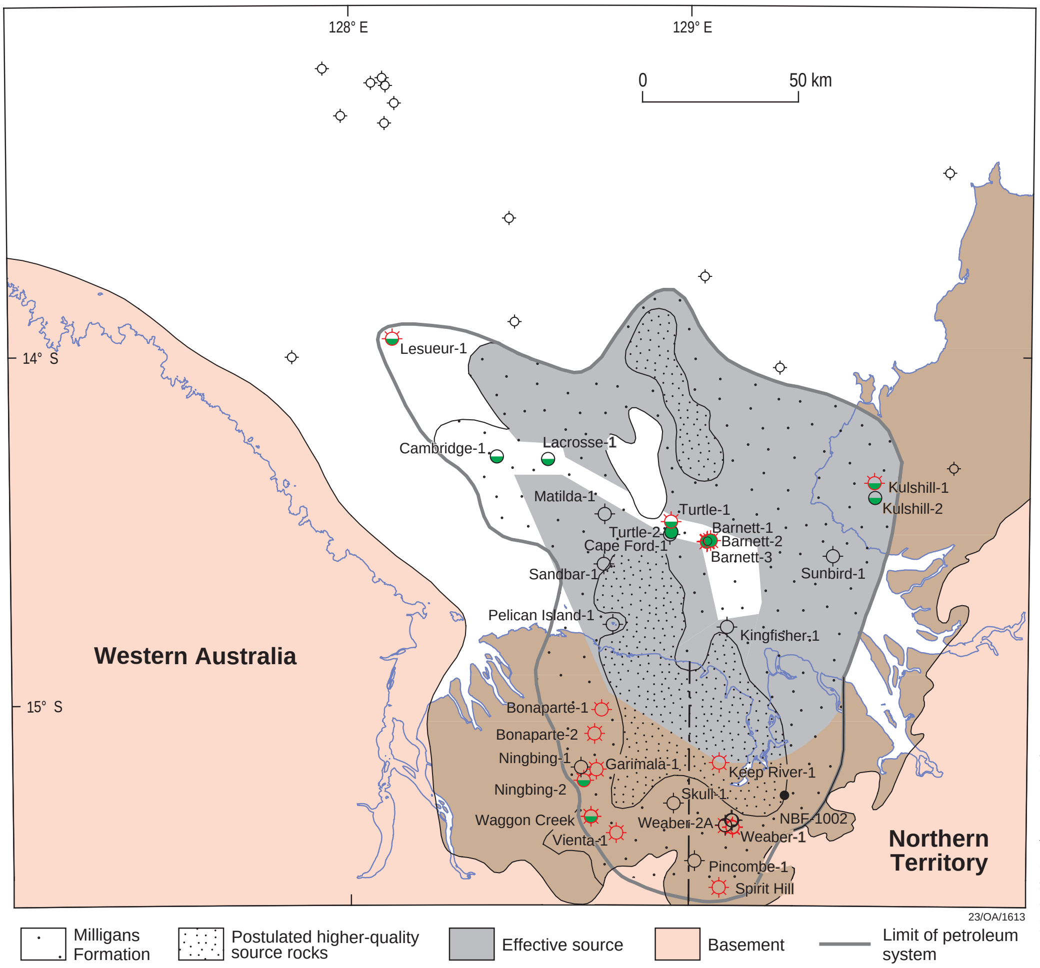


**Figure 18**. The Carboniferous Milligans-Kuriyippi/Milligans(!) petroleum system, with wells attributed to the petroleum system shown in large symbols. Source pod modelled by Kennard *et al*. (2002).

| | | $P_{90}$ | Mean | $P_{10}$ |
|---|---|---|---|---|
| Oil | Million barrels (MMBBL) | 122 | 350 | 626 |
| | Gigalitres (GL) | 19 | 57 | 100 |
| Gas | Trillion cubic feet (TCF) | 0.9 | 2.9 | 6.0 |
| | Billion cubic metres (BCM) | 24 | 82 | 169 |
| Condensate | Million barrels (MMBBL) | 26 | 115 | 246 |
| | Gigalitres (GL) | 4 | 18 | 39 |

**Table 1**. Probability distribution of undiscovered petroleum reserves in the Bonaparte Basin.

metres (190 million barrels). The maximum size is significantly larger than both the Turtle and Barnett discoveries, but with submarine fans mapped around the Turtle-Barnett High, the potential for a large discovery remains.

The commercial success rate is zero, but one in two wells have discovered hydrocarbons. A success rate distribution of 1% (minimum), 5% (most likely) and 10% (maximum) reflects the low commercial success rate.

### *A new Bonaparte Basin assessment*

The new medium-term assessment of the undiscovered petroleum resources of the Bonaparte Basin reveals that there is a mean expectation that 56 gigalitres (350 million barrels) of oil, 82 billion cubic metres (2.9 trillion cubic feet) of gas, and 18 gigalitres (115 million barrels) of condensate are likely to be discovered in the next ten to fifteen years. Table 1 shows the results in more detail.

A total of seven petroleum systems have been defined in the Bonaparte Basin and the assessment results for each petroleum system are given in Table 2. Details of the individual petroleum system results are discussed earlier in this paper.

The previous assessment of the Bonaparte Basin undertaken by Geoscience Australia was released in 1998 and Table 3 shows a comparison of the two assessments. The two assessments are fundamentally different, as the 1998 assessment was an assessment of the ultimate potential, while the new 2002 assessment is a medium-term discovery forecast. Furthermore, the 1998 assessment was based on the concept of migration fairways, whereas the 2002 assessment uses the petroleum system as the basic assessment unit. The latest assessment shows a higher gas assessment but a lower oil assessment.

It is interesting to note that since the 1998 assessment, the Blacktip-1 discovery has accounted for about one third of the gas in that assessment. Rather than reducing the gas assessment, the reverse appears to have happened, with the Blacktip-1 discovery encouraging further exploration and, hopefully, greater success.

The US Geological Survey (2000) has also released an assessment of the undiscovered hydrocarbon resources of the Bonaparte Basin as part of its World Petroleum Assessment. The results of that assessment, based on exploration results to the end of 1995, are shown in Table 4.

The US Geological Survey mean assessment for oil is about 3.7 times that modelled by AUSTPLAY, while gas and condensate are eight to nine times the AUSTPLAY volumes. On first inspection, there is a significant difference between the two assessed volumes, but it is very important to understand that the US Geological Survey (2000) assessment spans about thirty years whereas the AUSTPLAY assessment is a ten to fifteen year projection. In this respect, the AUSTPLAY assessment could be considered as a subset of the US Geological Survey assessment, as shown in Figure 19.

There are differences between the two assessments worth noting. Firstly, the US Geological Survey methodology is very different to AUSTPLAY and secondly, the area assessed by the US Geological Survey is slightly different, with the southern part of the Vulcan Sub-basin included in the Browse Basin.

Despite the rigour of the US Geological Survey (2000) assessment process, there is inevitably some debate about the input parameters used for the assessment, but the overall assessment ranking tables provide a basis for comparing the Bonaparte Basin with other basins around the world.

### Summary and conclusions

The 2002 Geoscience Australia AUSTPLAY assessment is a medium-term discovery assessment and not an ultimate potential one. The US Geological Survey World Petroleum Assessment (USGS, 2000) provides a current estimate of the ultimate potential of the basin.

| Petroleum System | Oil | | Gas | | Condensate | |
|---|---|---|---|---|---|---|
| | GL | MMBBL | BCM | BCF | GL | MMBBL |
| **Jurassic petroleum systems** | | | | | | |
| Elang-Elang(!) (Sahul Syncline, Flamingo High) | 30 | 188 | 15 | 530 | 4 | 26 |
| Plover-Plover(.) (Malita Graben, Sahul Platform) | 0 | 0 | 48 | 1,700 | 12 | 74 |
| Vulcan-Plover(!) (Vulcan Sub-basin) | 19 | 121 | 8 | 280 | 1 | 9 |
| **Permian petroleum systems** | | | | | | |
| Hyland Bay-Hyland Bay(?) (Kelp High) | 0 | 0 | 0 | 0 | 0 | 0 |
| Hyland Bay/Keyling-Hyland Bay(.) (Central Petrel Sub-basin) | 3 | 20 | 9 | 320 | 1 | 4 |
| Permian-Hyland Bay(?) (Londonderry High) | 3 | 16 | 2 | 80 | 1 | 3 |
| **Carboniferous petroleum system** | | | | | | |
| Milligans-Kuriyippi/Milligans(!) (Southern Petrel Sub-basin) | 1 | 6 | 1 | 10 | 0 | 0 |
| **Total** | **57** | **350** | **82** | **2,920** | **18** | **115** |

**Table 2**. Bonaparte Basin Assessment – summary of mean results for petroleum systems.

| | 2002 | 1998 | % difference |
|---|---|---|---|
| Oil (MMBBL) | 351 | 567 | -38% |
| Gas (TCF) | 2.92 | 2.27 | +29% |
| Condensate (MMBBL) | 115 | ? | ? |

**Table 3**. Comparison of mean results for Geoscience Australia's 2002 and 1998 Bonaparte Basins Assessments (AGSO, 1998).

The Bonaparte Basin still has the potential for significant hydrocarbon discoveries. Some petroleum systems are oil-prone, but collectively, the Bonaparte Basin is gas-dominated. The addition of undiscovered hydrocarbon volumes to the cumulative volumes shown in Figure 7 suggests that there will be a steady increase in reserves over the next ten to fifteen years. The AUSTPLAY assessment for the Bonaparte Basin does not expect any dramatic change in the rate at which hydrocarbons will be discovered. However, the development of a pipeline network in the basin may well change the outcome.

The assessment result is highly sensitive to the modelled number of wells anticipated to be drilled. The total number of wells expected/modelled to be drilled in the Bonaparte Basin the next ten to fifteen years is 86; more than two thirds of these wells will target the three Jurassic petroleum systems.

Reserves growth has proved to be an important component of the US Geological Survey World Petroleum Assessment (USGS, 2000). It should be emphasised that the current Geoscience Australia assessment does not allow for reserves growth and will be updated once the appropriate model for Australia is known.

## Acknowledgments

A great deal of the raw data for assessments such as this has been provided by both government and company sources.

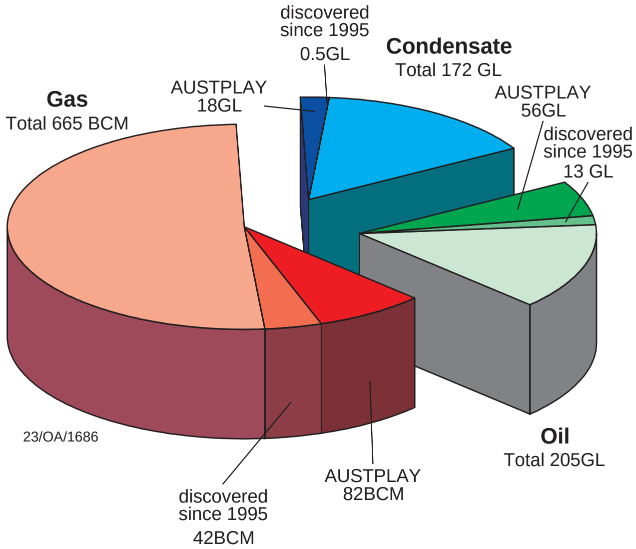


**Figure 19**. US Geological Survey Bonaparte Basin assessment results (USGS, 2000), showing proportions of resources in oil-equivalent units. Dark portions are the Geoscience Australia assessment results, showing how much is likely to be discovered in the next ten to fifteen years. Intermediate portions are hydrocarbons discovered since 1995; the effective date of the USGS assessment.

| | | $P_{95}$ | Mean | $P_{05}$ |
|---|---|---|---|---|
| **Oil** | Gigalitres | 61 | 204 | 414 |
| | Million barrels | 383 | 1286 | 2605 |
| **Gas** | Billion cubic metres | 159 | 674 | 1406 |
| | Trillion cubic feet | 6 | 24 | 50 |
| **Condensate** | Gigalitres | 42 | 172 | 382 |
| | Million barrels | 266 | 1079 | 2402 |

**Table 4**. Summary of US Geological Survey Bonaparte Basin assessment (USGS, 2000).

The data is often confidential and the authors wish to thank these people for their time and assistance.

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