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MINIMUM ECONOMIC RESERVOIR SIZE PROJECT

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LIST OF TABLES & FIGURES

ABSTRACT

The Minimum Economic Reservoir Size (MERS) Project was established to estimate the smallest undiscovered oil or gas reservoir that could be developed economically in seven separate locations, onshore and offshore Australia. This was achieved by deriving from estimated physical characteristics of the undiscovered reservoirs, the most likely systems for production and transport of hydrocarbons, and the timing and magnitude of the costs involved as a basis for a discounted cash flow analysis using a computer program. The MERS program uses current (March 1980) Federal and State royalty and taxes. Other required input information on well producibility, production build-up, maximum production rates, decline rates, etc., as well as capital and operating costs, are easily modified. This enables the user to interact with the computer to examine the effect of changes in one or more variables. The results are shown both on a year by year forecast and in terms of the discounted cash flow rate of return commonly used in the petroleum industry.

Representative costs (late 1979) for all aspects of capital development, operation, and product transportation have been assembled for use with the program.

The prospects analysed comprise examples from a range of petroleum exploration frontiers in Australia: onshore prospects include the Eromanga and Amadeus Basins in the interior, and the Canning Basin in the northwest. Offshore prospects include a range of water depths: the Carnarvon Basin prospect is in conventional water depths; the Bonaparte Gulf Basin prospect is in moderate water depths; the Browse basin and Exmouth Plateau prospects are in water depths beyond existing production experience.

As would be expected from such a wide range of production requirements, the Minimum Economic Reservoir Size varied for oil, from 2.2 Gl for the onshore Eromanga Basin to 148.4 Gl for the offshore Exmouth Basin, and for gas, from 4.7 billion cubic metres for the Amadeus Basin to in excess of 40 billion cubic metres for the Carnarvon Basin.

REPORT ON MINIMUM ECONOMIC RESERVOIR SIZE

1. INTRODUCTION

The Bureau of Mineral Resources, Geology and Geophysics (BMR) applied to the National Energy Research, Development and Demonstration Council in October 1978 for a grant for a Minimum Economic Reservoir Size project. The grant was approved in January 1979. Macdonald Wagner & Priddle Pty Ltd and Purvin & Gertz, Inc. (MWP/P & G), in association, submitted a proposal in competition with other firms who had prequalified. The above association of companies was awarded the consultant contract for the project in May, 1979.

2. SCOPE OF WORK

The aim of the project is to determine for seven localities, onshore and offshore Australia, the smallest petroleum field that, if discovered, would be economic to produce under current prices and costs and with current technology. Two phases were contemplated: the identification, collection, and collation of all costs that affect the production of hydrocarbons; and the development, testing, and running of a computer program to determine the smallest petroleum reservoir necessary to support commercial development at various locations throughout Australia. The purpose in hiring consultants was to supplement BMR's expertise in resource assessment with expertise in financial analysis and cost estimating.

An initial series of discussions was held between the consultants and BMR to establish a basis for the evaluation of the minimum economic reservoir size and to assess the cost data available to BMR and the consultants. These discussions were followed by gathering further information, collating data, preparing a detailed computer program algorithm and flow chart, and initial programming. Thereafter, final programming and testing of selected prospects was completed, which was followed by documentation and program testing.

3. DETERMINATION OF ECONOMIC FEASIBILITY

The parameter used to assess the financial performance of an oil or gas field is the discounted cash flow rate of return (DCF ROR) over the life of the field.

Corporate criteria for rate of return vary with the project and the company. The risks involved in petroleum production generally demand a greater return than other enterprises such as utility pipelines/ refining.

Most firms require a DCF ROR in excess of 20 percent to develop and produce a petroleum field, even in an established petroleum province. A minimum return of 25 percent after taxes is commensurate with commercial practice in Australia and is taken as the minimum for an economic petroleum field in this study.

A discount rate of twenty five percent per annum is applicable to a cash flow in constant dollars. It would need to be increased by an amount approximately equal to the annual rate of inflation in the industry if actual cash flow is treated.

4. DISCOUNTED CASH FLOW RATE OF RETURN

DCF ROR is a commonly used criterion for the economic evaluation of capital projects. Mathematically, DCF ROR is that interest rate which - when applied to calculate the present value of all cash outlays and incomes related to the project - yields a net present value of zero. Present value recognises the time value of money and is defined as the amount of money today which, when invested at a compound interest rate to a future date, will have a particular value at that date. Net present value is the algebraic sum of the present values of all cash outflows and incomes related to the project. Thus when the net present values of all outflows and income are equal - i.e. the sum = zero - the money invested can be said to have earned the computed interest rate that satisfies the equation.

The DCF ROR criterion used for the MERS program is for income continuously received and continuously discounted. Other choices are available and are used by companies and financial institutions. Commonly used methods include those where the incomes and outflows are assumed to be received at year-end or mid-year. These bases for present value would yield different answers. A detailed discussion of various discounting techniques is given by Essley (1965.)

Continuous receipt and expenditure and hence continuous discounting most closely approximates the actual model of the financial operation of petroleum production, and is the preferred model for most commercial economic calculations. The DCF ROR derived is the nominal interest rate which, when compounded continuously derives the same result.

The present value, PV, of a future cash flow, CF, received during a future year, n, is defined as follows:

$$PV = PW_1 \times CF$$

$$PW_1 = \frac{(e^j - 1)\, e^{-jn}}{j}$$

where PW_1 = present worth factor, e is the base of natural logarithms, 2.718282..., and j is the nominal fractional interest rate.

By contrast year-end discounting uses present worth factors computed as follows:

$$PW_1 = \frac{1}{(1 + i)^n}$$

where i is the effective fractional interest rate.

The two methods give similar results for rates less than 10 percent, but diverge as DCF ROR increases. A 25 percent nominal rate is equivalent to 28.4 percent effective rate. Because petroleum development is a high risk business, i.e. it has high discount factors and because continuous discounting approaches the real world, the nominal rate has been chosen over year-end discounting.

5. THE FINANCIAL MODEL OF THE RESERVOIR

5.1 Overview

The computer program is set up as a financial model of the cash flow history of a field for a period of 30 years after the year of discovery, or where the field starts to return a negative cash flow if this is less than 30 years. The model incorporates:

- physical data for the reservoir
- capital expenditure to delineate and develop the field to full production
- production profiles
- operating costs
- capital and operating costs for transport of the products to market
- income from sales
- royalties due to governments
- taxation benefits available for exploration expenses and investment allowances
- depreciation
- Australian company tax

Application fees, rents, securities, etc. are not treated in the model.

5.2 Assumptions

The range of possible situations encountered in practice has made it necessary for some assumptions in this study. These are:

1. In accordance with the aims of the project, initial exploration costs are excluded from consideration, but delineation wells - if they are to be used for production - are included.

2. Crude oil of Bass Strait quality.

3. Natural gas has a specific energy of 38-39 MJ/m^3.

4. A market is available within Australia at the nearest major population centre.

5. Export markets are not considered.

6. Existing oil and gas pipelines are available, and in addition it is assumed that a liquids pipeline will be built from Moomba to Redcliff and a gas pipeline will be built from Dampier to Perth.

7. Where possible, existing technology is assumed, with no allowance made for future advances; exceptions are the production systems assumed for the Exmouth Plateau and Browse Basin prospects.

8. The economics of each undiscovered field are considered apart from those of other undiscovered fields, and sequential development is not considered.

9. Exploration will be undertaken by an existing company that can benefit from tax credits in early years.

10. The minimum acceptable DCF ROR is based on the assumption that cash flow occurs continuously throughout each annual period, rather than at year end.

11. No debt capital has been used.

12. All income and expenditure are in constant dollar values, with no provision for inflation, because we assume that future cost and price increases will be more or less equal.

Provision is made in the computer program to allow the study of the effects of exploration costs and debt capital, should these be required. All of the above assumptions can be varied by modifying entered data, except for 10. which has a predetermined computer algorithm.

5.3 Method of use

The number of interdependent variables involved in the assessment means that the program does not produce a unique minimum reservoir size from one calculation run. The procedure for finding the minimum economic reservoir size is iterative: it has been designed to require a high level of user intervention - so that the interaction of variables can be assessed, and the relative sensitivity of the financial response to these variables determined.

This procedure is as follows:

1. Select a field size for initial economic analysis.

2. Assess probable well productivity from geological data.

3. Define a field production profile.

4. Define the nature and size of development, production, transportation, and support facilities necessary for the assumed field characteristics.

5. Define a field development schedule.

6. Build cost estimates and cash flow data for the assumed field.

7. Enter the calculated data into the computer.

8. Run the program to determine its DCF ROR.

9. If DCF ROR differs from the rate set for minimum economic acceptability, interactions are made by changing any or all of the following parameters:

    1. Percentage royalty
    2. Percentage tax
    3. Taxation benefits available according to company type
    4. Price
    5. Annual production
    6. Per well production
    7. Number of wells

The order of magnitude of change must be reviewed carefully to ensure that the assumptions in determining the data have remained valid (e.g., if the number of wells is doubled it may be necessary to increase the size, and hence cost, of support facilities and to change the production profile by extending the period required to bring the field to full production.)

It is recommended that only one parameter be changed at a time in order to gain a feel for sensitivities, before finally determining the combination most likely to give the desired result.

10. If the desired DCF ROR cannot be achieved by such adjustments, the remaining parameters are reviewed to assess one which may, reasonably, be adjusted for the defined field.

    If this is not successful the initial assumption must be modified and the development schedule re-evaluated. In this eventuality the data file will have to be modified.

11. The results of each (DCF ROR case) run may be saved in an output file. This enables all runs to be compared later. These files can also be accessed for producing output in graphical form or for statistical analysis.

12. Several hard-copy reports of the cash flows and financial evaluation are available as described in the program manual.

5.4 Detailed discussion

The following is a detailed description of how the cash flow model is structured and the parameters incorporated into it.

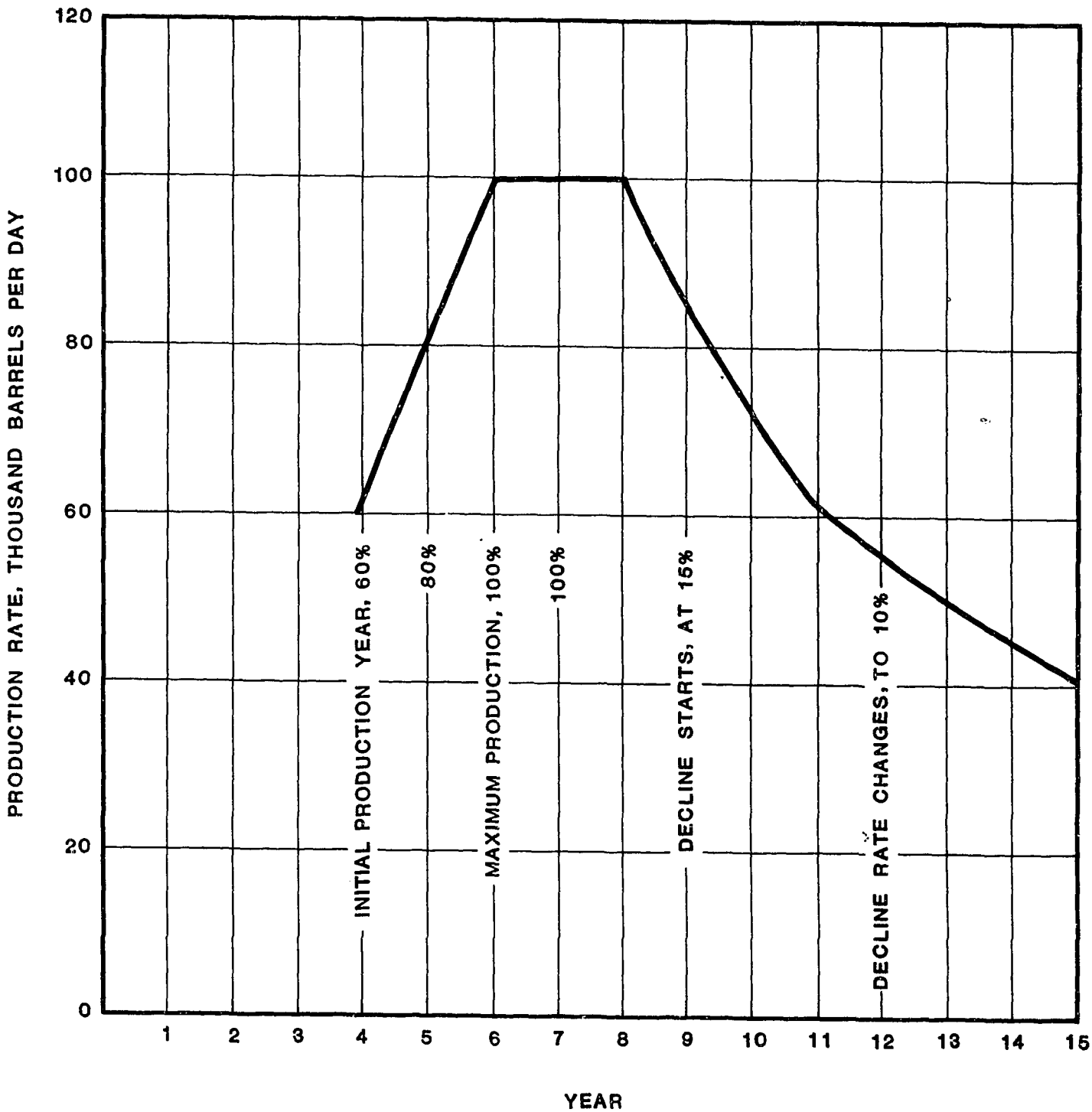
(a) Production rate

The production rate of a petroleum resource is a function of the physical parameters of the reservoir and the development schedule for drilling wells and installing other necessary facilities. There are two ways to establish production rates in the model.

The user specifies the initial year of production, which is determined by the time necessary to complete field delineation wells, development wells, production facilities, and the availability of a means of delivering the resource to market. Annual production rates, based on a specified maximum production rate per well can then be generated by the program. In the early years of production, the field may still be under development, therefore the production rate during the first years of production is specified by the number of operating wells in these years. Production decline after the initial period is then determined by specifying the first year and annual percentage decline rate for either one or two different decline rates. Figure 1 is an illustration of a field-production profile specified in this way.

FIGURE I

EXAMPLE FIELD PRODUCTION PROFILE



Alternatively, if the per well production rate is entered as zero in the program input, the user can supply annual production data. This is a useful feature where production rate is not expected to follo a regular pattern.

(b) Field revenue

Annual revenues are calculated using the average daily production rates generated by the production profile multiplied by 365 times the unit price of the resource

A single unit price can be specified for the life of the field. Alternatively, a price forecast can be entered for each year.

(c) Royalties

Royalty payable on petroleum produced onshore in Australia is under State Government jurisdiction. Royalty rates are summarised below:

New South Wales -	10 percent of wellhead value. Rate after renewal of lease is variable at Ministerial discretion.
Queensland -	10 percent of wellhead value.
South Australia -	10 percent of wellhead value.
Tasmania -	10 percent of wellhead value afte first 227 kilolitres.

Victoria - 10 percent of value of petroleum produced. No royalty when average production per well is less than 15.9 kilolitres/day.

Western Australia - 10 percent of wellhead value while testing; Primary license - 10 percent of wellhead value; Primary plus secondary license - 10 percent to 12.5 percent of wellhead value as determined by Minister; during initial term 5 percent - 12.5 percent as determined by Minister.

Northern Territory - 10 percent of wellhead value.

Royalty on petroleum produced offshore is 10 percent of wellhead value on primary license and, as determined by the Minister, 11 percent - 12.5 percent on primary plus secondary license.

Costs for surface processing and transporation by the producer can generally be deducted from the royalty. For instance, an offshore gas field where the gas is sold f.o.b. pipeline ashore would incur royalty based on the sale price, less amortisation of pipeline to shore, offshore processing facilities, and a portion of production platform investment. Amortisation is either taken over 20 years or linearly against reserves.

The ten percent royalty rate was selected for all MERS calculations.

(d) Operating expenses

Operating expenses for the production of petroleum generally fall into the following categories: maintaining facilities and paying the salaries of operating personnel; maintenance and monitoring of wells and production facilities; operating materials, fuel, chemicals; and home-office expenses required to support field operations.

The model accepts expenses either fixed annually or that vary either with the production rate or the number of wells in operation, or on a combination of fixed and variable rates. After a base-operating budget for a particular prospective field has been developed, variations in expenses for other circumstances are easily prepared for input to the model.

Home-office expense is determined by the required skills and numbers of individuals required to support field operations. A basic home-office contingent, with specific additions for multi-field operations, can usually support more than one field operation, therefore a fraction of a full home-office budget should be assigned to a prospective field development. The annual cost is input as a single number representing thousands of dollars of home-office or general and administration expense.

Additional provision is made for injection expenses required for secondary recovery on a fixed annual basis and/or per unit of production.

(e) Capital depreciation and allowances

Australian law provides for deduction of depreciation, and other allowances for investment in petroleum production. Three principal categories of investment are involved; they are treated in different ways.

Exploration expenditure, which includes discovery well cost, geological and geophysical expense, and delineation well cost, can be deducted from any income in the year incurred. If income cannot accommodate accumulated exploration expenditure in any year, the balance can be carried forward indefinitely.

Capital expenditure for pipelines, terminals, and other oil movement facilities can be depreciated on a straight line basis over either ten or twenty years. A seven-year loss carry-forward limitation applies after start of income if such depreciation yields a negative taxable income thereafter. In the program, a ten-year period is used because it maximises early cash income by deferring taxable income to a later date. This depreciation deduction is used preferentially to other deductions that do not have the time limitation and is, therefore, taken first by the model. In the model it is taken in the year in which it is incurred. (See Section 5.2.9).

The largest investment is generally for production facilities, which include:

a. petroleum drilling plant, including offshore platforms and cost of wells, except for discovery and appraisal drilling.

b. pumping equipment and gas/oil separators at wellhead.

c. gathering lines and field storage tanks.

The cost of any of these facilities, installed ready for use by 30 June 1986, qualifies for a 20 percent investment allowance, which is deductible in addition to depreciation allowances for the full cost of the facilities. The investment allowance can be carried forward for seven years.

Production facilities can be written down for tax purposes on a five-year declining-balance basis. Twenty percent of the remaining balance can be written off each year, and a switch to a straight-line depreciation is permitted during the last five years of operation. If the amount permitted is greater than remaining taxable income after other allowances, only enough is taken to make taxable income zero, the remainder of the permitted amount is then offset against other income.

(f) Income tax and cash flow calculation

Corporate income tax is levied at the present rate of 46 percent of taxable income. Taxable income is defined as field revenue, less royalty, less operating expenses, less exploration expenditures, less oil-movement facility depreciation, less investment allowance, less production facility depreciation. Net income is taxable income less income tax. As indicated previously in this report, exploration costs are excluded. However, exploration costs may be included in the program should the user need them.

Cash flow is net income, plus non-cash deductions used to arrive at taxable income, less cash paid for the capital investment in any given year. It is calculated in the program as field revenue less operating cost, royalties, and income taxes, less capital expenditure for any given year.

6. CAPITAL REQUIREMENTS

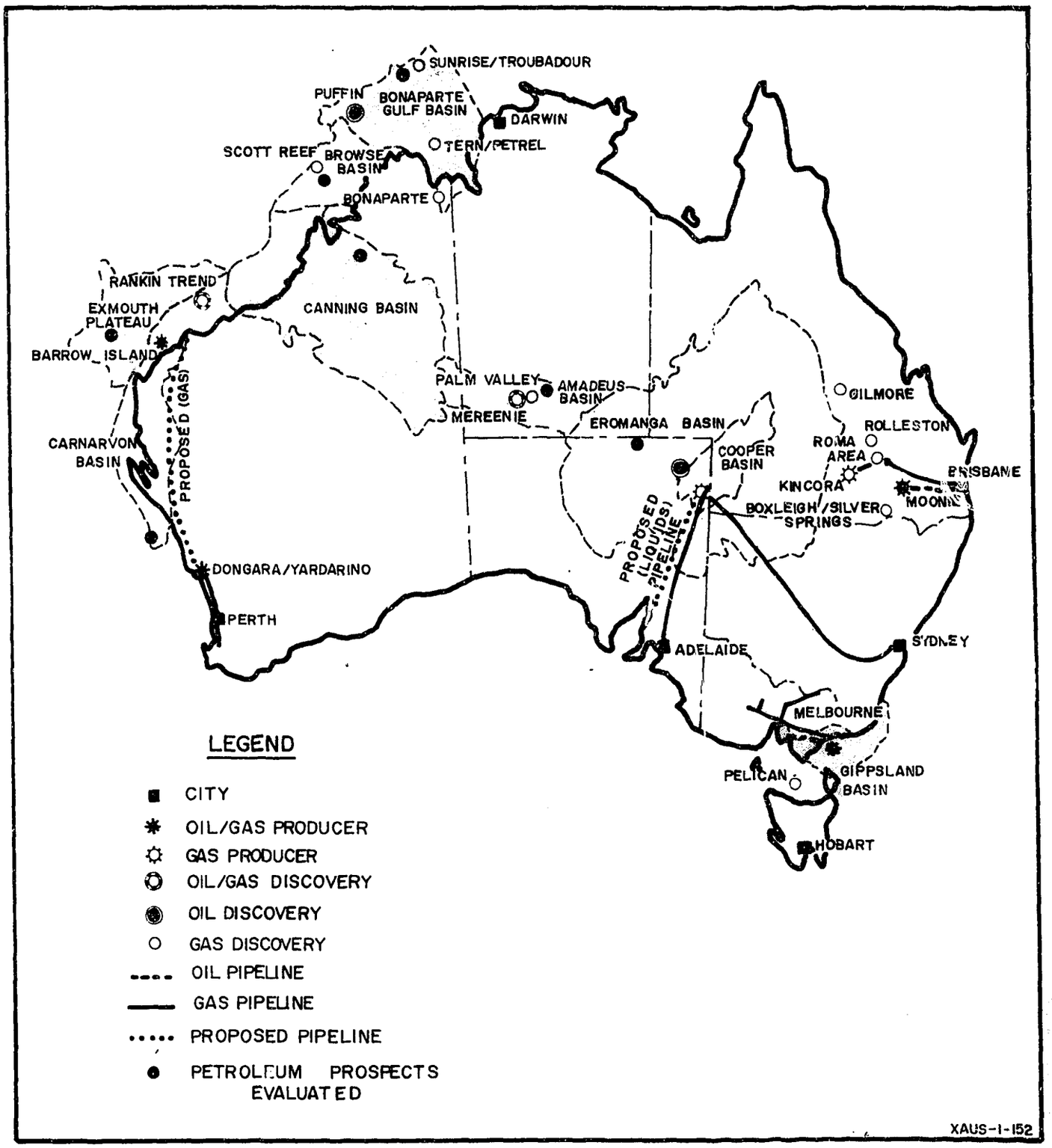
The prospects analysed comprise examples from a range of petroleum exploration frontiers in Australia: onshore prospects include the Eromanga and Amadeus Basins in the interior, and the Canning Basin in the northwest. Offshore prospects include a range of water depths: the Carnarvon Basin prospect is in conventional water depths; the Bonaparte Gulf Basin prospect is in moderate water depths; the Browse Basin and Exmouth Plateau prospects are in water depths beyond existing production experience.

The locations of the prospects for which test data was formulated are shown in Figure 2. Future facilities in various stages of consideration include a gas pipeline from Dampier to Perth and a liquids pipeline from Moomba to Redcliff in South Australia.

The key factors in the determination of MERS over and above the physical characteristics of a prospective reservoir are the size and timing of the capital investments required to explore for, develop, and transport the petroleum. In various areas of the world where operating environment, reservoir characteristics, and logistics are relatively homogeneous it is possible to develop a set of algebraic equations which provide a reasonable estimate of development capital requirements. The range of petroleum resource prospects scattered throughout the Australian continent, onshore and offshore, does not lend itself to such a reduction of variables.

FIGURE 2

LOCATION OF PETROLEUM RESOURCES



The project is further complicated by the absence of good historical cost data. BMR has good records of exploration costs, but these data do not extend to the cost of delineation and development of drilling. The various state Departments of Mines have more complete records but, in all instances, the details necessary for a sound estimate of costs in specific areas are confidential.

Private industry data on costs are closely held. Most companies with successful exploration efforts do not wish to divulge information useful to their competitors. In addition, the basis for royalty payments and other tax matters is a subject to be resolved with the appropriate State and Commonwealth government agencies - an attributed statement of costs which does not properly or completely represent the facts could be economically damaging to the party making the statement, or could violate confidentiality requirements with exploration venture partners.

Faced with these limitations MWP/P & G solicited such information as was available. Reasonably complete cost data for some specific prospects were provided by three operating companies, (and a limited amount of data was provided by other companies). With general and detailed cost data obtained for the United States, the North Sea, and Southeast Asia, these data provide the basis for estimated development schedules, as discussed later.

6.1 Exploration costs

NEAC (1979) reported that petroleum exploration costs in Australia are among the highest in the world. The report cited high labour costs, inhospitable terrain, a general lack of service and supply companies, and long distances from supply bases as factors contributing to such costs. Seismic costs were reported to be over 150 percent of world averages in 1975. Onshore drilling costs per metre increased from 150 percent in 1972 to 220 percent of United States average in 1975.

Onshore exploration carried out typically with one or two-well programs in remote areas is penalised in every aspect of cost. Expenses to move in, rig up, rig down, and move out in a remote area are often two-thirds as much as all other costs. Such costs are in addition to the extra costs incurred for equipment rentals, well-logging services, road-building, and personnel. However, costs decline somewhat for delineation and development wells where personnel and equipment are used continuously. Australian costs are likely to remain higher than in most other areas.

6.2 Field development capital requirements (onshore)

Well drilling costs are a significant component of field development capital requirements. Other costs are for gathering and processing facilities, living support facilities, and for operation and maintenance.

Table 1 is a set of costs that have been estimated for a 48-well onshore field with a peak production rate of about 30 000 barrels of oil per day. It is assumed to be in a remote location, to which the principal access is by air.

These estimates include generous amounts for field staff living facilities. It is important to provide such facilities to attract and keep the required skilled workers. Locations close to population centres would require less elaborate facilities because of shorter tours of duty at the field, smaller airstrip requirements, and other considerations. A camp as outlined is more likely to be the norm for most prospects. Specific assumptions for development costs are discussed in the review of examples. These costs are considered to be accurate within a range of -15 percent to +25 percent.

Table 2 is a set of equations by which the cost of field development (Table 1) can be adjusted to allow for different field capacity and development plans. Exponents for capacity ratios are those frequently used by engineers to adjust cost estimates for similar facilities.

Tables 4, 5, and 6 are the field-staff requirements and costs, field maintenance costs, and home-office requirements, respectively, for the 48-well remote field.

6.3 Field development capital requirements (offshore)

The technology of steel or concrete platforms for offshore oil and gas development and production is well established. Numbers of these structures are operating in the North Sea, the Gulf of Mexico, and southeast Asian waters. The most important variables in offshore platform costs are water depth and supported platform weight. Beyond these factors, wind and wave conditions and sea bottom conditions also have a significant effect on platform costs.

The deepest water in which a bottom-supported platform is presently operating is at the Cognac field, offshore Louisiana, where a steel platform was installed in 312 m (1025 ft) of water in 1978. This is about the practical limit of water depth for operation of bottom-supported platforms. For deeper waters new technologies must be applied. Among the systems suggested for deeper operation are the following:

1. Submerged production system - subsea completion template, with maintenance support vessel and manipulator, separate production riser with processing and storage tanker.

2. Floating and subsea system - subsea template with drilling and production risers. Floating concrete caisson structure with drilling, production, processing, storage, and loading facilities.

3. Vertically moored platform - subsea template; floating production drilling facility similar to semi-submersible drilling vessel vertically moored to template.

4. Tension leg platform - subsea template; semi-submersible type drilling and production platform moored vertically to deadweight anchors and kept in tension by vessel buoyancy.

5. One-atmosphere subsea system - well manifold centre and satellite wells serviced by service unit for installation and servicing at one-atmosphere pressure; floating production platform operating from separate riser.

Some of these systems are scheduled to be tested in shallower waters. Most of the components have been tested in actual use. Actual installation in very deep water awaits a field discovery of sufficient size and per well productivity to justify the cost. The system eventually chosen in Australia will depend on a number of factors, which can only be evaluated at the time a discovery is made.

Construction and transport of large floating or gravity-type concrete structures will be a problem in Australia. There are very few locations in the Pacific region where water is deep enough to accommodate floating structures during construction. Moving the structures to their locations is another problem. Gravity-type structures are being used in several North Sea locations; they were built in the fjords of Norway close to their final location. Rapidly escalating costs for concrete systems have dictated that most of the producing structures that have been announced recently are to be either conventional steel leg platforms, or variations of the very deep water systems.

For small reservoirs in the North Sea, British Petroleum Ltd has recently announced a system using a super tanker as processing and storage vessel. When the tanks are full the vessel would retrieve its production riser and steam to port for unloading. A prototype is planned. Such a system might be considered for small offshore oil fields in Australia.

For this project offshore platform costs were analysed as follows: detailed costs or estimates of costs for platforms in the North Sea, southeast Asia, and the US Gulf Coast were escalated to a late 1979 basis and plotted against the water depth and the number of wells for which they were designed. A fair correlation was obtained of cost against water depths in the range 50 to 300 m; a factor serves to adjust base cost for the number of wells the platform can carry.

The following equation was chosen as representative of conventional platform cost for a 24-well platform, in late 1979:

$$\text{Cost} = 27.108\ e^{.00895D}$$

with Cost = millions of dollars installed cost

D = water depth, metres

This equation plots as a straight line on semi-logarithmic graph paper.

Cost for 36-well platforms were about 2.26 times the cost determined above, and a factor of 0.61 times the formula cost is representative of 15-well platforms. In the absence of better data, this equation was used as a starting point for offshore conventional platform.

6.4 Onshore gas pipeline costs

It is assumed that gas will be transported to market in pipelines provided by a government authority.

The Pipeline Authority provided a generalised empirical relation for the transport cost via onshore pipeline versus distance based on their calculations in October 1979. This formula is as follows:

$$\text{Transport cost, } \$/\text{GJ} = 0.30 + .02 \frac{(\text{design flow rate})(\text{line length})}{(\text{present value of demand})}$$

where

design flow rate is in cubic metres per hour

and line length is in metres

Present value of demand is in cubic metres. The recommended discount rate was 10.8 percent, the recent rate on private semi-governmental loans. Discount factors for this rate for twenty years are included in Table 3. The sum of annual production in cubic metres times the appropriate discount factor over the life of the field - for which the initial production year is year one - was used to calculate the present value of demand. The cumulative present value figures in Table 3 are useful for periods of constant annual production. For instance, the present value of demand for 15 years of constant production is 7.4269 times annual production. Present values for other interest rates can be computed using the nominal present value

formula which was discussed along with DCF ROR. The values obtained are represented as having an accuracy of about 20 percent.

6.5 Onshore oil pipeline capital requirements

Crude oil will probably be transported in pipelines provided by the producer. However, in some instances, it may be possible to use pipelines provided by other producers. For instance it has been assumed that any crude oil produced from the prospects in the Eromanga and Amadeus Basins will be transported by the producer company's pipeline to Moomba in the Cooper Basin and by another company's pipeline that has been proposed from Moomba to Redcliff on the Spencer Gulf. A fixed annual charge for dedicated capacity in this proposed pipeline was charged as an expense against any crude oil produced from prospects in the Eromanga and Amadeus Basins.

For estimating purposes in the United States, pipeline costs are frequently based on a dollars per inch-diameter per mile basis. Recent averages in the United States are about U.S. $12 000 to $15 000 per inch-mile. Australia does not have a well-established pipeline contracting industry, and the prospective locations are remote. As a base estimate a value of $18 500 per inch-mile was used for this study. In SI units this is approximately $420 per mm-diameter per km.

6.6 Offshore pipeline capital requirements

Offshore pipeline costs are often double or triple the onshore cost. A value of double the onshore cost was used for the examples.

7. OPERATING EXPENSES

A limited amount of data on Australian operating expenses was obtained and has been used to develop the operating expense assumptions for the examples. Field expenses are divided into four main categories: manpower; maintenance materials and services; operating materials; and outside transportation. In addition, there are appreciable general and administrative or home office expenses necessary to develop, manage, and support field operations.

7.1 Field expenses

Manpower expense is a major part of any field operation. In a remote location the field personnel must be fed and housed at a self-sufficient camp as described in onshore capital costs. They must be rotated periodically to spend time with their families. Table 4 shows the development of personnel-related costs for a 48-well field. The total estimate of 74 field personnel includes 10 food service personnel paid by an outside caterer. Of these 74 personnel, 41 would be required in camp at any one time to maintain operations.

The 74 operating company personnel would incur an annual cost of about $1 350 000, which includes a 30 percent payroll burden to cover company-paid benefits and other oncosts. Accommodation costs are based on each employee being present in the camp 18 days a month, plus an average of five visitors a

week each staying two days. The daily accommodation cost is assumed to be $20 per man. Air transport costs vary with distance; for this field complement, 1148 return trips per year are required.

Maintenance other than of routine items is assumed to be covered by contract with outside service companies. For the basic 48-well onshore field the maintenance cost assumptions in Table 5 were used. These costs were varied in the examples to account for differences in number of wells and other development as dictated by the circumstances.

Some oil and gas produced would be carried to a coastal location in an existing or planned pipeline. Adjustments for transportation costs were made as described in the various examples.

7.2 Home-office expenses

Discovery, development, and operation of a petroleum field requires a home-office staff with a full complement of personnel to undertake the necessary tasks of management, engineering, accounting, purchasing, and planning. Table 6 outlines a basic home-office complement of 28 personnel required for full-fledged operations. The total estimated annual cost of $1 745 000 includes salaries and 30 percent oncosts, office rentals and other office costs, and insurance.

With minor additions, the home-office complement could manage two or more field operations. In an operating company it is very likely that more than one producing field operation or exploration operation would be carried on simultaneously. Therefore, for the examples, one-half the estimated home-office expense was assigned to the prospective resource discovery.

7.3 Offshore expenses

The principal reason for the difference between expenses for offshore and onshore operations is the additional maintenance necessary for offshore platforms and structures. After accounting for the difference in operation of offshore fields, then the additional maintenance expenses for the marine structures and equipment envisaged in the examples were estimated.

8. PRICES

It was assumed that oil would be priced at $25.00/Bbl at the nearest metropolitan centre or offshore loading terminal, and that natural gas would be priced at $3.00/GJ at the nearest metropolitan centre.

It is not certain that producers of newly discovered gas could earn a gas sales value similar to this price. This price may not take into account the impediments to substitution imposed by costs of conversion from competitive energy sources or high natural gas distribution costs. Except in Queensland, existing and short-term natural gas demand is expected to be satisfied either by producing gas fields or by those scheduled for production.

The Pipeline Authority estimated the following demand for natural gas which cannot be satisfied by supply from demonstrated economic resources:

Brisbane - Currently 5 petajoules per year rising to 20 petajoules in 1985.

Adelaide - Beginning in 1988 at about 140 petajoules per year.

Sydney - Beginning in 1988 and rising from zero to approximately 50 petajoules in 1995.

Adelaide and Sydney combined - about 300 petajoules in 1994.

For the prospects in the Eromanga and Amadeus Basins, field values for gas were computed by calculating pipeline cost to Moomba, SA, adding an approximate Moomba-Sydney pipeline cost of $0.36/GJ, and deducting these costs from $3.00/GJ. For the Canning Basin prospect, delivered value at Dampier was estimated to be $2.00/GJ.

In practice, the economic evaluation of a crude oil or natural-gas discovery encompasses a thorough and detailed evaluation of all the elements of transportation required to deliver the resource to market, and the price to be realised from its sale. Quality of crude oil is an important part of these computations. Port charges and tanker costs are other elements of these costs. A detailed analysis of such costs is beyond the scope of this study.

9. EXAMPLES

A discounted cash flow analysis was carried out on each of the seven prospects located in Figure 2. All seven were analysed assuming that they contained oil and four of them were analysed again on the assumption that they contained gas.

The initial analysis used the technical information on the potential oil and gas reservoirs (as provided by BMR) and the exploration, appraisal, development, and transport cost data that are summarised in Tables 7 and 8. In each instance development was scheduled to proceed as rapidly as thought practicable.

The results of these initial calculations are summarised as follows:

Prospect		Case Series number	Reservoir size assumed Gl or $m^3 x 10^9$	Calculated DCF ROR (%)
Eromanga	oil	1000	6.87	48.08
"	gas	2000	4.80	27.49
Amadeus	oil	1100	7.71	24.42
"	gas	2100	12.57	45.72
Canning	oil	1200	3.66	32.38
"	gas	2200	12.33	19.54
Bonaparte Gulf	oil	1300	11.88	6.80
Carnarvon	oil	1400	32.88	44.84
"	gas	2400	12.01	.00
Exmouth Plateau	oil	1500	77.96	14.18
Browse	oil	1600	22.71	2.60

It can be seen - as was expected - that the initial calculations resulted in a wide range of DCF ROR.

In the sections that follow the reservoir size and the associated investment and operating costs for each prospect were adjusted to determine the (minimum economic) reservoir size which will yield a 25 percent DCF ROR.

These adjustments have been made mainly by using the formulae in Table 2. Experience indicates that for adjustments of plus or minus 50 percent these formulae give reasonable results. Care is required, however, when the extrapolation exceeds a 50 percent change. It

is suggested therefore that any such adjusted minimum economic reservoir sizes be investigated further to test whether the investment required is reasonable.

The results of the final calculations made to approach the 25 percent DCF ROR are summarised in the following table.

Prospect	Adjustment	Reservoir Size* Gl or $m^3 x 10^9$ Calc'd	Calculated DCF ROR
Eromanga oil	Reduced wells etc.	2.10	23.41
Eromanga gas	Reduced productivity	4.32	25.08
Amadeus oil	No adjustment necessary	7.71	24.42
Amadeus gas	Wells and productivity decreased	4.82	24.97
Canning oil	Reduced wells and productivity	2.56	24.71
Canning gas	Wells and productivity increased	19.28	25.26
Bonaparte Gulf oil	Productivity increased	36.74	25.83
Carnarvon oil	Wells and productivity decreased	10.67	25.07
Carnarvon gas		38.19	12.27
Exmouth oil	Well productivity increased	160.42	25.18
Browse oil	Well productivity increased	72.98	24.41

* In those cases where a DCF ROR close to 25 percent is obtained, the calculated reservoir size is our estimate of the MERS for the hypothetical reservoir.

Each of these prospects is discussed individually in the following section of the report.

9.1 Series 1000 - Eromanga Basin (Pedirka) oil

Reservoir data for this prospect are summarised in Table 7. This table also shows exploration costs, appraisal costs, and development costs. (Exploration costs have not been included in the calculations, but have been retained in this table for completeness). The rig which drills the discovery well is assumed to continue drilling to complete four appraisal wells during the ensuing year.

Camp, infrastructure, and production equipment are scheduled for purchase and installation during the second year. Costs for these were developed by scaling the cost data in Table 1 to fit the circumstances of the initial data (Case 1001) shown below in thousands of dollars.

	48-well field (Table 1)		22-well field (Case 1001)	
Infrastructure	$ 9 800		$ 9 800	
Utilities	2 400		2 400	
Camp	1 360		1 360	
Vehicles & miscellaneous	1 790		1 790	
Subtotal	15 350		15 350	
Flowlines	6 000	(@ 640 BOPD/ well)	3 260	(@ 900 BOPD/ well)
Separators	6 200		4 810	(77% + test)
Tanks	250	(9540 kl)	250	(9540 kl)
Oil washing	250		250	
Gas dehydrational reinjector	5 650		4 340	
Oil pump for Moomba line	-		1 500	
Subtotal	18 350		14 410	
TOTAL	$33 700		$29 760	

Development drilling was scheduled at a rate of six wells per year over a three-year period; one-third of field flowlines were installed during each of these years. $230/m is the industry estimate of costs for 2500 m development wells; each well is estimated to cost $575 000. With one of the development wells assumed to be dry, the result is 22 producing wells including the discovery well. (See Table 9.)

To deliver the oil to market a 400-km pipeline to Moomba was assumed, which then connects with the projected liquids line to Redcliff. The 10" diameter line, at $18 500 per inch-diameter/mile, would cost $46 250 000, with an additional $1 500 000 for pumping facilities. This expenditure was spread evenly over the second and third years of development. The full schedule of capital expenditures for the initial run is detailed in Table 9.

Production was scheduled to start on the completion of the pipeline at the beginning of year 4, at which stage 16 producing wells would have been completed - 4 appraisal and 12 production. It is assumed that production from the final six development wells, to be drilled sequentially in the fourth year, will be equivalent to the annual production of three producing wells. Hence the total annual production for the fourth year would be 19/22 or 0.863 of the full anticipated production rate.

Operating expenditures for the 22-well field (Table 10) were derived by scaling down the estimated costs for the 48-well field listed in Table 1 and detailed in Tables 4 and 5. Manpower costs are the same, as no difference in staffing requirement from the 48 well field is anticipated. Maintenance and outside service costs are roughly proportional to the number of operating wells; therefore these items are reduced by one-half. Other costs remain the same. $8 400 000 per year is the estimated cost of dedicated capacity in a Moomba-Redcliff projected liquids pipeline.

The total annual operating expense of $12 365 000 divided by the number of producing wells, was input to the program as the per well producing cost for the base case.

Home-office costs, at half the full costs detailed in Table 6, amount to $872 500 annually.

Using the foregoing information the program calculates the DCF ROR, and generates substantial amounts of data which can be printed in one of several tables; these can be examined on the screen or printed. The following tabulated data show the economic forecast.

MINIMUM ECONOMIC RESERVOIR SIZE PROJECT

PROSPECTIVE AREA : EROMANGA BASIN (PEDIRKA)

SUMMARY REPORT

OIL CASES

Case	Max No. Wells	Reservoir Size (Gl)	Reservoir Size (MBbl)	Cap Inv (M$)	Op Cost (M$)	DCF ROR (%)	Nett...Present..Value 10%	15%	25%
1001	22	6.87	43.20	90.81	185.35	48.08	175.43	119.68	80.90
1011	19	5.97	37.53	87.91	155.62	46.06	151.43	102.93	69.07
1021	16	5.03	31.60	84.97	138.88	41.07	119.62	79.44	51.49
1031	13	4.08	25.68	82.38	122.41	35.35	87.68	55.91	33.92
1041	10	3.08	19.37	79.79	97.62	28.42	55.65	32.38	16.42
1051	7	2.10	13.23	76.25	75.54	23.41	29.54	15.27	5.15

This table has been designed to give the program user a concise but complete forecast. The key production factors and dates are shown in a logical format. The resultants are the reservoir size and the DCF ROR. (A much more detailed line-by-line, year-by-year table is available for inspection at BMR. It will be helpful when a more intensive examination of the physical and economic factors is needed.)

It would only be coincidental if the assumed data yielded a DCF ROR of about 25 percent. A mechanism has been devised for varying the investment and producing rates to attempt to yield a 25 percent return. These variations must be made judiciously, because the method is valid only over a limited range. Experience indicates that adjustments using Table 2 are probabl valid for changes -50 percent or +50 percent from t detailed estimate of Table 1.

These techniques have been used to adjust the Eromanga prospect to reach a roughly 25 percent DCF ROR. The following table shows the iterations used. The resultant wells and investments are shown in Table 9 under the columns labelled 'Final'. Similarly, the adjusted operating costs are shown under the 'Final' sub-heading of the column labelled 'Eromanga' in Table 10.

MINIMUM ECONOMIC RESERVOIR SIZE PROJECT

PROSPECTIVE AREA : EROMANGA BASIN (PEDIRKA)

CASE 1001 OIL PRODUCTION

Year of initial production	1983	
Year of maximum production	1984	
Field life	17 years	
Reservoir size	6.9 Gl	(43.2 MBbl)
Maximum production rate	140. kl/d	(880.5 Bbl/d)
Government royalty	10.0%	
Corporate tax	46.0%	
DCF Rate of Return	48.08% p.a.	

Year	Well Nos.	Cap. Invest. (M$)	Prodn Rate (kl/d)	Oil Price ($/Bbl)	Oper. Cost (M$)	Income (M$)	Tax (M$)	Nett Profit (M$)
1980	0	2.840	0.000	0.000	0.000	0.000	0.000	-1.534
1981	0	55.686	0.000	0.000	0.000	0.000	0.000	-48.734
1982	0	28.077	0.000	0.000	0.000	0.000	0.000	-22.765
1983	19	4.207	2660.000	25.000	13.244	139.426	51.960	67.992
1984	22	0.000	3080.000	25.000	13.239	163.536	62.843	83.016
1985	22	0.000	2541.000	25.000	13.239	132.601	50.447	67.570
1986	22	0.000	2096.325	25.000	13.239	107.079	40.210	54.837
1987	22	0.000	1729.469	25.000	13.239	86.023	31.756	44.341
1988	22	0.000	1426.812	25.000	13.239	68.652	24.775	35.688
1989	22	0.000	1177.120	25.000	13.239	54.321	19.010	28.555
1990	22	0.000	971.124	25.000	13.239	42.498	14.250	22.674
1991	22	0.000	801.177	25.000	13.239	32.744	11.418	16.728
1992	22	0.000	660.971	25.000	13.239	24.697	9.271	11.633
1993	22	0.000	545.301	25.000	13.239	18.058	6.522	8.187
1994	22	0.000	449.874	25.000	13.239	12.581	4.255	5.350
1995	22	0.000	371.146	25.000	13.239	8.063	2.384	3.014
1996	22	0.000	306.195	25.000	13.239	4.335	.841	1.090
		90.810			185.351		329.942	377.644

Because the 48.1 percent DCF ROR for the Eromanga initial run (Case 1001) is much higher than the 25 percent target, and large adjustments in investments and numbers of wells are required, the resultant changes must be critically evaluated.

An examination of the above tables reveals that the number of wells required in the final calculation is only about 30 percent (7 vs. 22) of those needed in the initial run. If individual well productivity is constant, the field should produce at a lower rate. There are reductions in well costs and the costs of related facilities, but it has been assumed that the same pipeline would be installed. The adjusted values are shown in Table 9.

Likewise the operating expenses (Table 10) have been reduced only in those areas directly affected by the number of wells or the throughput. For example, the share of the cost for the outside pipeline has been reduced proportionately, although salaries and wages have been held constant.

It is beyond the scope of this study to develop the 25 percent DCF ROR in detail. It is believed that the adjustments made are reasonable for first passes. However, should more precise figures be needed, item-by-item cost estimates should be prepared following the form of Tables 1, 4, 5, and 6.

The format of the tables in this report differs somewhat from the format required for input to the computer. For example, the operating cost data in Table 10 is converted into a per-well annual cost as input. However, the overhead cost, which is virtually independent of the number of wells, is entered as an annual figure. Similarly the information in Table 9 is used both as a fixed investment independent of wells and also on a per-well basis. The user manual, which is a separate document, details the form of the input.

The Eromanga oil prospect has been discussed in detail to develop an understanding of what the program does and detail how the costs were derived and used. In the following sections the program costing descriptions will be minimised; special requirements will, however, be described in detail.

9.2 Series 1100 - Amadeus Basin oil

The prospect in the Amadeus Basin is assumed to produce at the rate of 115 BOPD per well. For a 15 percent annual decline in this rate, 160 producing wells are required to produce an estimated 70 million barrels of recoverable reserves. After an appraisal and drilling program, similar in cost to the Eromanga program, full development and construction of field facilities is assumed to start in the second year. The costs are summarised in Table 11. The development cost of $384 000 for each 1800 m well is $213.25 per m ($65/ft).

Field flowlines for 115 BOPD per well are estimated to cost 35 percent of per well cost for the 900 BOPD wells in the Eromanga Basin, or $43 750 each, a total of $7 000 000 for the field. Camp facilities and other development costs are assumed to be the same.

With a 40 well/year development program, field development is spread over four years (Table 11).

Construction of a 10-inch diameter pipeline 550 miles to Moomba is estimated to cost $105 050 000 and take two years to build. Production would begin in year 4.

Amadeus Basin operating costs are based on similar staffing to that used for the Eromanga prospect; differences are given in Table 10.

The cost of well maintenance materials is scaled to the number of wells and well cost; there are 160 wells, compared with 48 for the field in Table 1. The wells cost $384 000 each compared to $575 000 each for the Eromanga prospect. The estimated annual cost of maintenance materials for wells is $1 113 000.

Similarly, cost of outside services is based on three times as many workovers and other activities scaled to well cost.

Air transport cost is based on Alice Springs as the operational base. Material transport cost is estimated to be one-third more than the base estimate.

Expenses were increased to the maximum $11 787 000 when development is complete in year 6. Half of home-office expense, or $872 500 annually, was assigned to the prospect.

The DCF ROR for the Amadeus oil prospect is very close to the target 25 percent and no adjustment of data was necessary.

The minimum economic reservoir size is estimated at about 7.7 gigalitres (48.5 million barrels).

9.3 Series 1200 - Canning Basin oil

The Canning Basin prospect is based on a 24 million barrel oil reservoir with productivity per well of 1400 BOPD. With a predicted 10 percent annual production decline only five producing wells are required in the initial run to produce the basic anticipated reserves.

A four-well appraisal drilling program with one dry hole would result in four producing wells. Therefore the additional development well was assumed to be drilled as a continuation of the appraisal drilling program, at a cost of $1.80 million.

The smaller scale of operations requires fewer personnel and camp facilities. A total field complement of 43 is estimated. Camp facilities and infrastructure are estimated at $12.87 million.

To deliver the oil to market an 8-inch pipeline 220 km to the coast was included. An offshore 10-km double line to a single point mooring (SPM) facility is included. Costs were as follows:

	$/million
Pipeline to coast	20.72
Pumps	1.50
Pipeline to SPM	3.55
SPM	6.00
Total	31.77

Field production facilities required were estimated as follows:

	$/million
Flowlines	1.20
Separators	3.20
Tanks	0.25
Other	0.25

Table 12 shows the capital investment program.

With a two-year construction period for the pipeline and offshore loading facilities, production could start in year 4. Because all wells could produce from the start of production a simple 10 percent per year decline describes the production schedule.

Operating salaries and wages in Table 10 include a 20 percent additional cost reflecting the very remote location. Maintenance and outside service expense has been scaled down to reflect the five producing wells and 7000 BOPD production rate. The costs shown in Table 10 are not directly proportional, and in most instances reflect a judgment of minimum annual costs and scale of operations. An annual SPM maintenance cost of $1.128 million was included to reflect industry experience. Annual operating expenses were rounded off to $4 million. Additional home-office expenses of $875 000 per year were included.

The initial run shows a 32.4 percent DCF ROR, which drops to 25 percent by changing from five wells to four. The adjustments to investments resulting from the deletion of a well are shown in Table 12. The anticipated operating costs are shown in Table 10.

The minimum economic reservoir size is estimated at about 2.6 gigalitres (16.1 million barrels) of oil.

9.4 Series 1300 - Bonaparte Gulf Basin oil (offshore)

Technical data for a hypothetical oil reservoir in the Bonaparte Gulf Basin suggest 400 BOPD from a well depth of 2350 m. The prospect is located in a water depth of 200 m. The estimated costs are - for the discovery well $5 million, and appraisal wells $4.5 million each. The combination of well and water depth imposes a practical maximum of 36-wells per platform. A two-platform development program was used in the example to

realise economies of scale from the use of common tanker loading facilities and personnel. Even so only 73 million barrels of oil could be produced from the estimated 500 million barrel probable reservoir.

The development plan includes adapting an idle tanker to serve as a storage vessel, and loading tankers from an SPM.

Drilling costs for the development wells are based on similar southeast Asia cost estimates of $280 per foot or $920 per metre, which is $2.16 million for each hole.

The drilling/production platform cost is estimated at $368 million each. Other facilities required were estimated as follows:

	$/million
Storage vessel	11.00
SPM, 28 000 B/D capacity	40.28
Risers	4.63
Connecting pipelines	10.50

Schedule of development capital outlays is included in Table 13. Production could start in year six, when all but 20 of the 70 development wells are complete, peaking in year seven at 28 000 BOPD, and declining thereafter at 15 percent per year.

The operating costs that have been estimated for the offshore oil production cases are listed in Table 14. Offshore salaries and wages should cost the same as for the 48-well onshore field. The costs of well-maintenance materials and contract services are scaled up from the estimates for a 48-well field. A platform maintenance cost equal to about 1 percent of investment is added. Air transport cost is increased by $200 000.

The Bonaparte Gulf oil prospect has a marginal rate of return at the assumed well productivity. To test the possibility of reaching an acceptable rate of return the well productivity was increased by 100 percent and then by 200 percent. At the higher rate (195 kl/d) and with no adjustments in costs the return was just over 25 percent. It would appear that unless a very large and prolific reserve is found or the price increases substantially relative to inflation the 25 percent target will be difficult to obtain.

The minimum economic reservoir size is in excess of 36.7 gigalitres (226 million barrels) and individual well productivity would need to exceed 195 kl/d (1230 BOPD).

9.5 Series 1400 - Carnarvon Basin oil (offshore)

The technical data for the Carnarvon Basin oil prospect suggests 6500 BOPD maximum well productivity, a water depth of 125 m, and a field of about 30 Gl for the base case. With a 15 percent production decline rate, 12 wells could produce over 30 Gl of oil over a 30-year period.

In this prospect, the cost of a 12-well platform was estimated at $83 million. Discovery and appraisal well costs of $5 million and $4 million each, respectively, were used. For a well depth of 3000 m at a cost of $920/m ($280/ft) the cost per well is $2.76 million. Other development capital includes the following:

	$/million
Storage vessel	11.0
SPM	91.8
Riser	3.6
Connecting pipeline	6.0
Total	$112.4

Development capital expenditures are scheduled in Table 15.

Operating costs (Table 14) include salaries and wages, air transport, and accommodation costs at 70 percent of the cost for a 48-well field. Contract services of $975 000 per year reflect the fewer workovers and well logs required for a 12-well field. An allowance of $4 000 000 per year covers maintenance on the platform, SPM, and storage vessel. Maximum production rate of 78 000 BOPD against the 48-well field estimate of 30 500 BOPD is the basis for increased operating chemical costs totalling $1 250 000 per year.

The Carnarvon prospect yielded a 45 percent DCF ROR. By reducing the number of wells from 12 to 8, and reducing the well productivity by 50 percent, a 25.07 percent DCF ROR was obtained. For this first pass only the investments related to the wells were reduced as shown in Table 15 under the column labelled 'Final'. The appraisal well costs have not been included, because the wells are not used for production. It should be noted that these reductions reduce the required reservoir to 10.67 Gl (67.1 million barrels).

9.6 Series 1500 and 1600 - Exmouth Plateau and Browse Basins

These prospects involve production in water depths where conventional fixed platforms are impractical. Because no production presently comes from similar depths (1000 m for Exmouth and 400 m for Browse) only an educated guess can be made of development costs.

Physical and cost data for the hypothetical reservoir beneath the Exmouth Plateau are included in Table 7. The cost of the 3500 and 4000 m development wells for the Exmouth Plateau and Browse Basin prospects were assumed to be double the unit depth cost for the fixed platform prospects, or $560 per foot.

For the Exmouth Plateau a production facility cost of $3000 million was assumed for a 32-well development program. Discovery well and three appraisal wells drilled from a dynamically positioned drilling vessel are estimated to cost $12.5 million each. These wells would be plugged and abandoned after testing. Development drilling would start only after the production facility was in place and would cost $6.43 million per well. Capital expenditure schedule is included in Table 16.

An annual platform and production-facility maintenance cost of 2.5 percent of the $3000 million investment was assumed. This is the main difference in operating cost to those of moderate depth offshore (Table 14).

The 400 m water depth and 13-well program for the Browse Basin prospect would require less elaborate production platform facilities. A cost of $2000 million was assumed for the base case. Well cost of $10.0 million for discovery well, $9.5 million for each appraisal well, and $7.35 million for each development well was used. Capital development program is included in Table 17. With platform and delivery system maintenance cost estimated to be $56.39 million, annual operating expense totals $61.615 million for the initial run.

In both of these prospects the DCF ROR is substantially below the target 25 percent. To test the possibility of the areas meeting the target the well productivity was increased with no increase in cost. A per-well increase of 100 percent for the Exmouth Plateau shows an indicated 25 percent DCF ROR but would require nearly 160 Gl of reserves against 78 Gl in the initial data. For the Browse Basin, a trebling of the productivity yields a 25 percent DCF ROR, and the required reserves increase from 23 to 73 Gl. These adjustments require a close review, before the estimates can be accepted as reasonable.

9.7 Series 2000 - Eromanga Basin (Pedirka) gas

Initial calculations were carried out assuming a gas field of about 5.1 billion cubic metres (180 billion cubic feet). This could be developed with five wells yielding 6.7 billion cubic feet of gas per year, and no decline in production until after 16 years.

Field development costs identical to those for the Eromanga Basin oil prospect were used, with the following exceptions (Table 8). Production equipment requires smaller separators and gas dehydration costing only $3.43 million. Flowlines to gather gas from 15 producing wells are estimated to cost a total of $1 875 000 or $125 000 per well. A schedule of capital expenditure is included in Table 18.

It has been assumed that the Government will provide a pipeline to connect to the gas pipelines at Moomba. For the run, the $0.77/GJ delivery cost is based on the Pipeline Authority formula cost to Moomba of $0.41/GJ, and Moomba-Sydney pipeline cost of $0.36/GJ. This $0.77/GJ was subtracted from the $3.00/GJ market price, to yield a $2.23/GJ field price. A figure of $2.23/MCF (thousand cubic feet) was used.

Operating expense assumptions for the gas prospects are given in Table 19. For the Eromanga Basin, expenditure related to personnel is based on the same assumptions as were used for the oil prospect. Maintenance materials, outside services, and operating chemicals are, however, lower with 15 wells operating versus 48 wells in the example used for Table 5. The initial run yielded a DCF ROR of about 27 percent. The production was reduced by 10 percent which gave a DCF ROR of 25 percent and a minimum economic reservoir size of 4.3 million cubic metres of gas.

9.8 Series 2100 - Amadeus Basin gas

The initial calculation was carried out for a 12.8 billion cubic metres (0.45 TCF) reservoir. A production rate of about 700 000 cubic metres per year, from 40 wells, with a decline starting after 16 years, was used for the initial data.

Field development cost was based on the data in Table 19, and an expenditure schedule is included in Table 20.

The operating expenses detailed in Table 19 were used for the initial data. With delivery to Moomba* estimated to cost $0.55/GJ, total delivery costs of $0.91/GJ were deducted from the conceptual Sydney market price for a field price of $2.09/GJ. $2.09/MCF was used.

The initial data yielded a DCF ROR of 45.7 percent. A DCF ROR close to 25 percent was attained by reducing the number of wells to 30 and per well productivity to 25.6 thousand cubic metres per day, declining after 16 years. Minimum economic reservoir size was estimated at 4.8 billion cubic metres (0.17 TCF).

*Although there are proposals to develop previously discovered Amadeus Basin gas for use in Alice Springs and other Northern Territory centres, example economics are based on delivery to major metropolitan markets.

9.9 Series 2200 - Canning Basin gas

The initial calculation was carried out assuming a 12.7 billion cubic metres (0.45 TCF) reservoir. A production rate of about 700 billion cubic metres per year, from 38 wells with a decline starting after 17 years, was used for the base case.

Field development cost was based on the data in Table 19, and an expenditure schedule is included in Table 21.

Total delivery costs of $1.58 were subtracted from a conceptual Perth market price of $3, to arrive at a well head price of $1.42 per thousand cubic feet.

The initial run yielded a DCF ROR of 19.5 percent. A DCF ROR of about 25 percent was attained by increasing the number of wells to 46 and per well productivity to 64 thousand cubic metres per day. Minimum economic reservoir size was estimated at 19.3 billion cubic metres (0.68 TCF), an increase of about 50% over the size determined from the initial data analysed.

Increased well productivity may be sufficient to raise the DCF ROR to the 25 percent mark.

9.10 Series 2300 - Bonaparte Gulf gas

An examination of the Bonaparte gas prospect indicated that production is uneconomic under the parameters set. The principal reason is the remote location, thus the costs. It is possible that, given enough reserves, the gas could be liquefied or converted to methanol. Both of these processes, however, are beyond the scope of this report.

9.11 Series 2400 - Carnarvon Basin gas

An examination of Carnarvon gas production indicated it is uneconomic under the parameters set. The principal reason is the remote location, and thus the costs. As in the Bonaparte Gulf it is possible that, given enough reserves, the gas could be liquefied or converted to methanol. These possibilities are, however, beyond the scope of this report.

10. REFERENCES

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TABLE 1

FIELD DEVELOPMENT CAPITAL REQUIREMENTS - ONSHORE
(Thousands of dollars)

Facility	Description	1979 Cost
Gathering and processing		
Flowlines	To connect 48 wells on a 3-mile by 4-mile grid	6 000
Separators	Two trains with 2-stage separation	6 000
Test separator		200
Stock tanks	9540 kl capacity	250
Oilwashing facilities		250
Gas dehydrator	1.7×10^6 m^3/day	650
Gas reinjection compressor	2 units	5 000
Subtotal		18 350
Infrastructure		
Road	300 km for rig and major equipment access	2 500
Airfield	1.8 km sealed airstrip	1 000
Water supply	568 m^3/day, 1 200 m bore	300
Water purification	Flash evaporator and storage 454 m^3/day	2 000
Communications	Radio, telephone and telex	4 000
Subtotal		9 800
Utilities		
Fuel gas system		50
Power generation	2 x 1-1/2 MW gas turbines	2 100
Control room and laboratory		250
Subtotal		2 400
Camp facilities		
Housing for workers	4 x 19-man units	500
Supervision and visitors	2 x 6-man units	100
Dining room and kitchen	50-men	60
Recreation unit	50-men	40
Other recreation and furnishings		200
Combination office, workshop and warehouse		250
Vehicle workshop		50
Workshop equipment		100
Office furniture and equipment		60
Subtotal		1 036
Vehicles		
Four-wheel drive	10	100
Service trucks	4	175
Cranes and earthmovers	4	315
Subtotal		590
Miscellaneous		
Spares including tubular goods		1 000
Mobile field equipment and test equipment		200
Subtotal		1 200

TABLE 2

GUIDELINES FOR VARIATION OF ONSHORE FIELD CAPITAL REQUIREMENTS

Flowlines	Cost ($ thousands) = $6\ 000 \left(\frac{N}{48}\right) \left(\frac{P}{100}\right)^{0.5}$ N = number of wells P = well production rate, kl/d
Separators	Cost ($ thousands) = $6\ 000 \left(\frac{F}{4800}\right)^{0.6}$ F = field maximum production rate, kl/d
Stock tanks	Cost ($ thousands) = $250 \left(\frac{C}{9600}\right)$ C = capacity, kl
Gas dehydration and reinjection	Cost ($ thousands) = $5\ 650 \left(\frac{F}{4800}\right)^{0.6}$ F =field maximum production rate
Road	Cost ($ thousands) = 8.33 L L = length, km
Power generation	Cost ($ thousands) = $2\ 100 \left(\frac{K}{3}\right)^{0.6}$ K = capacity, megawatts

TABLE 3

PRESENT VALUES AT 10.8% FOR GAS PIPELINE COST FORMULA

Year	Present value of 1	Cumulative present value
1	0.9479	0.9479
2	0.8509	1.7987
3	0.7638	2.5625
4	0.6856	3.2481
5	0.6154	3.8634
6	0.5524	4.4158
7	0.4958	4.9117
8	0.4451	5.3567
9	0.3995	5.7562
10	0.3586	6.1149
11	0.3219	6.4368
12	0.2889	6.7257
13	0.2594	6.9851
14	0.2328	7.2179
15	0.2090	7.4269
16	0.1876	7.6145
18	0.1511	7.9340
19	0.1357	8.0697
20	0.1218	8.1914

TABLE 4

ONSHORE FIELD STAFF REQUIREMENTS

Personnel		Number required
Field staff superintendent		1
Deputy field superintendent		1
Control room operator		5
Pumping plant operator		5
Field operators		4
Laboratory and testing		4
Field maintenance		14
Plant and workshop maintenance		10
Maintenance supervisor		2
Storemen		4
Mechanics		5
Clerk		2
Camp supervisor		2
Food service personnel (by outside caterer)		10
Drivers and machine operators		5
Total[1]		74
Costs		**$/year**
Salaries and 30% oncost		1 350 000
Accommodation costs	330 080	
Air transport 1148 return trips per year based on once a month for field personnel and 5 visitors per week.	230 000	
Accommodation plus air transport, say		560 000

Note: [1] Covers rotation to city. Forty-one in camp at any one time.

TABLE 5

ONSHORE OIL FIELD MAINTENANCE COST BASIS
(Thousands of dollars)

MAINTENANCE MATERIALS	Annual cost
Wells	500
Field production equipment	250
Plant equipment	250
Vehicles	50
Total materials	1 050
Outside service contracts	
Workovers - 10/year	500
Production logging	250
Well stimulation	125
Wireline testing	100
Contract maintenance	200
Total contracts	1 175
Operating chemicals	500
Vehicle fuel	50
Transport operating materials	125

TABLE 6

HOME-OFFICE STAFF REQUIREMENTS

Personnel	Number required
Manager	1
Production manager	1
Production engineer	1
Plant engineer	1
Reservoir engineer	1
Assistant reservoir engineer	1
Accountant	2
Clerk	2
Purchasing officer	2
Personnel officer	2
Aircraft dispatch clerk	1
Warehouseman	2
Draughtsman	2
Secretary/typist	5
Receptionist/telephonist	1
Engineering assistant	1
Computer operator	1
Drilling supervisor	1
Total	28

	$/year
Salaries and wages with 30% oncost	595 000
Office rental and other office costs	400 000
Insurance for all facilities	750 000
Total	1 745 000

TABLE 7

CRUDE OIL PROSPECT DATA
BASE CASES

Case series:	1000	1100	1200	1300	1400	1500	1600
Prospect:	Eromanga	Amadeus	Canning	Bonaparte	Carnarvon	Exmouth	Browse
Reservoir characteristics							
Probable recoverable oil million barrels	40	40	20	500	180	500	150
Gl (millions of kl)	6.4	6.4	3.2	79.5	28.6	79.5	23.8
Depth, m	2 500	1 800	2 500	2 350	3 000	3 500	4 000
Water depth, m	-	-	-	200	125	1 000	400
Productivity, B/D/well	900	115	1 400	400	6 500	6 500	5 000
Annual productivity decline, percent	17.5	15.0	10.0	15.0	15.0	15.0	15.0
Distance to terminal, km	400	880	225	470	20	-	-
Exploration costs							
Discovery well, $M	1.81	1.81	2.00	5.00	5.00	12.50	10.00
Seismic, km	300	200	400	600	200	200	600
$/km	2 500	2 500	2 500	600	600	600	600
$/m	0.75	0.50	1.00	0.36	0.12	0.12	0.36
Appraisal costs							
Wells, no.	4	4	4	6	4	3	4
dry	1	1	1	-	-	-	-
Cost each, $M	0.71	0.71	1.80	4.50	4.00	12.50	9.50
Development costs							
Development wells, no.	18	156	1	60	12	32	13
Cost, $M	0.575	0.384	1.80	2.16	2.76	6.43	7.35
Camp and infrastructure or platform, $M	15.45	15.45	12.87	736.00(1)	83.0	3 000.(3)	2 000.(3)
Production equipment, $M	14.41	19.60	4.90	66.41(2)	112.4(2)	-	-
Pipeline, $M	47.75	105.05	31.77	-	-	-	-

Notes: (1) 2 - 36-well platforms with processing
(2) Storage, risers, loading facilities
(3) Includes all facilities

TABLE 8

NATURAL GAS PROSPECT DATA
BASE CASES

Case series:	2000	2100	2200	2300	2400
Prospect:	Eromanga	Amadeus	Canning	Bonaparte	Carnarvon
Reservoir characteristics					
Probable recoverable gas, TCF	0.18	0.45	0.5	4.00	3.00
$m^3 \times 10^9$	5	12.8	14.2	113	85
Depth, m	2 500	1 800	2 500	2 350	3 000
Water depth, m	-	-	-	200	125
Productivity, million SCFD/well	1.836	1.71	1.808	2.800	2.00
Annual productivity decline, percent	(1)	(1)	(1)	(2)	(3)
Distance to terminal, km	400	900	1 018	470	20
Exploration costs					
Discovery well, $M	1.81	1.81	2.00	4.80	5.00
Seismic, km	300	200	400	600	200
$/km	2 500	2 500	2 500	600	600
$/M	0.75	0.50	1.00	0.36	0.12
Appraisal costs					
Wells, no.	4	4	4	4	4
dry	1	1	1	-	-
Cost each, $M	0.71	0.71	0.72	4.50	4.00
Development costs					
Development wells, no.	11	36	34		36
Cost, $M	0.575	0.384	1.80		2.76
Camp and infrastructure or platform, $M	15.45	15.45	12.87		350.0
Production equipment, $M	3.43	5.64	5.55		3.89
Pipeline, $/GJ	0.77	0.91	0.58		-

Notes: (1) Starts after 17 years
(2) Starts after 17 years
(3) Starts after 14 years

TABLE 9

EROMANGA BASIN (PEDIRKA) - OIL
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

		Development capital		Pipeline capital		Exploration costs
Case number:		Base case 1001	Final 1051	Base case 1001	Final 1041	All cases
Year	Description					
1	Discovery well, seismic					2.56
	Appraisal wells (number)					4
	Appraisal wells					2.84
2	Development wells (number)	6	3			
	Development wells, camp, vehicles, 1/3 flowlines, tanks, separators, gas dehydration	31.81	28.10			
	1/2 pipeline			23.87	47.75	
3	Development wells (number)	6				
	Development wells, 1/3 flowlines	4.20				
	1/2 pipeline			23.88		
4	Development wells (number)	6				
	Development wells, 1/3 flowlines	4.20				

Note: The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 10

ONSHORE OIL FIELD MAINTENANCE COST BASIS
(Thousands of dollars/annum)

Case series:		1000 Eromanga		1100 Amadeus	1200 Canning	
Prospect:	48-well field	Base case 1001	Final 1051	Base case 1101	Base case 1201	Final 1221
Case number:						
Salaries and wages						
Direct(1)	1 040	1 040	1 040	1 040	858	858
30 percent oncost	310	310	310	310	258	258
Maintenance materials						
Wells	500	250	80	1 113	100	80
Field production equipment	250	250	250	250	150	120
Plant equipment	250	250	250	250	150	150
Vehicles	50	50	50	50	60	60
Service companies						
Workovers	500	250	80	1 002	120	96
Production logging	250	125	40	501	50	40
Well stimulation	125	65	20	375	20	16
Wireline testing	100	50	16	200	50	40
Contract maintenance	200	100	32	400	100	80
Single point mooring maintenance	-	-	-	-	1 078	1 078
Transport operating materials	125	125	100	166	125	125
Operating chemicals	500	500	451	500	300	240
Fuel	50	50	50	50	50	50
Air transport and accommodation	560	550	550	400	531	531
Outside pipeline	8 400	8 400	2 673	5 180	-	-
Total	13 210	12 365	5 992	11 787	4 000	3 822

(1) General administration is a separate computer input. See text.

TABLE 11

AMADEUS BASIN - OIL
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital	Pipeline capital	Exploration costs
		Base case 1101	Base case 1101	All cases
Year	Description			
1	Discovery well, seismic			2.31
	Appraisal wells (number)			4
	Appraisal wells			2.84
2	Development wells (number)	40		
	Development wells, camp, vehicles,	30.81		
	1/2 pipeline		52.53	
3	Development wells (number)	40		
	Development wells, 1/2 flowlines, tanks, separators, dehydrators	31.46		
	1/2 pipeline and loading		52.53	
4	Development wells (number)	40		
	Development wells, 1/4 flowlines	17.11		
5	Development wells (number)	36		
	Development wells, 1/4 flowlines	15.57		

Note: The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 12

CANNING BASIN - OIL
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital		Pipeline capital		Exploration costs
		Base case 1201	Final 1231	Base case 1201	Final 1231	All cases
Year	Description					
1	Discovery well, seismic					3.00
	Appraisal wells (number)					4
	Appraisal wells					7.20
2	Development wells (number)	1	0			
	Flowlines, camp, vehicles	16.67	14.87			
	1/2 pipeline			10.36	10.36	
3	Flowlines and production facilities	4.90	3.99			
	1/2 pipeline			10.36	10.36	
	Offshore line and loading			11.05	11.05	

Note: The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 13

BONAPARTE GULF BASIN - OIL
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital Base case 1301	Pipeline capital	Exploration costs All cases
Year	Description			
1	Discovery well, seismic			5.36
	Appraisal wells (number)			4
	Appraisal wells			18.00
2	Engineering and materials, 20 percent of one platform	73.60		
	Appraisal wells (number)	4		
	Appraisal wells			9.00
3	60 percent of first platform and 40 percent of second	368.00		
4	Finish first platform and 40 percent of second platform	220.80		
	Drill 12 wells	25.92		
5	Finish platform 2	73.60		
	Storage vessel, SPM, connections	61.90		
	Drill 28 wells	60.48		
6	Drill 18 wells	38.88		
	Connections	4.50		
7	Drill 2 wells	4.32		

Notes: No change in investment for increase in productivity used to approach 25% DCF ROR.
The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 14

OFFSHORE OIL FIELD MAINTENANCE COST BASIS
(Thousands of dollars/annum)

Case series:		1300	1400		1500	1600
Prospect:		Bonaparte	Carnarvon		Exmouth	Browse
Case number:	48-well field	Base case 1301	Base case 1401	Final 1412	Base case 1501	Base case 1601
Salaries and wages	1 040	1 040	728		728	728
Oncosts	310	310	218		218	218
Maintenance materials						
Wells	500	729	729		729	729
Other production equipment	500	500	500		500	500
Platforms	-	7 000	4 000		75 000	56 390
Contract services	1 175	1 575	975		975	975
Operating chemicals	500	500	1 250		1 250	1 250
Fuel	50	50	50		50	50
Air transport and accommodation	550	750	525		525	525
Operating material transport	125	250	250		250	250
Total	-	12 704	9 225		80 225	61 615

TABLE 15

CARNARVON BASIN
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital		Pipeline capital	Exploration costs
		Base case 1401	Final 1412		All cases
Year	Description				
1	Discovery well, seismic				5.12
	Appraisal wells (number)				4
	Appraisal wells				16.00
2	20 percent of platform	16.60	16.60		
3	60 percent of platform	49.80	49.80		
	50 percent of SPM	45.90	45.90		
4	20 percent of platform	16.60	16.60		
	50 percent of SPM	45.90	45.90		
	Connectors	6.00	6.00		
5	Storage vessel	11.00	11.00		
	Riser	3.60	3.60		
	Development wells (number)	6	4		
	Development wells	16.56	11.04		
6	Development wells (number)	6	4		
	Development wells	16.56	11.04		

Note: Discovery and appraisal wells are abandoned and are not used in the prospect evaluation.

TABLE 16

EXMOUTH PLATEAU
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital	Pipeline capital	Exploration costs
		Base case 1501		All cases
Year	Description			
1	Discovery well, seismic			12.62
	Appraisal wells (number)			4
	Appraisal wells			25.00
2	1 appraisal well			12.50
	10 percent of platform and facilities	300.00		
3	30 percent of platform and facilities	900.00		
4	30 percent of platform and facilities	900.00		
5	Finish, move and install platform	900.00		
	6 development wells	38.58		
6	12 development wells	77.16		
7	12 development wells	77.16		
8	2 development wells	12.86		

Notes: No change in investment or operating costs owing to increased production per well.
Discovery and appraisal wells are abandoned and are not used in the prospect evaluation.

TABLE 17

BROWSE BASIN
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital	Pipeline capital	Exploration costs
		Base case 1601		All cases
Year	Description			
1	Discovery well, seismic			10.36
	Appraisal wells (number)			4
	Appraisal wells			38.00
2	Engineering and bottom template	300.00		
3	Install template	50.00		
	Start platform	200.00		
	Development wells (number)	4		
	Development wells	29.40		
4	Platform and equipment	1050.00		
	Development wells (number)	6		
	Development wells	44.10		
5	Install platform	400.00		
	Development wells (number)	3		
	Development wells	22.05		

Notes: No change in investment or operating costs owing to increased production per well.
Discovery and appraisal wells are abandoned and are not used in the prospect evaluation.

TABLE 18

EROMANGA BASIN (PEDIRKA) - GAS
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital		Pipeline capital	Exploration costs
		Base case 2001	Final 2011		All cases
Year	Description				
1	Discovery well, seismic				2.56
	Appraisal wells (number)				4
	Appraisal wells				2.84
2	Development wells (number)	6	6		
	Development wells, camp, vehicles, 1/2 flowlines, tanks, separators, gas dehydration	23.267	23.267		
3	Development wells (number)	5	6		
	Development wells, 1/2 flowlines	3.812	4.512		

Note: Discovery and appraisal wells are abandoned and are not used in the prospect evaluation.

TABLE 19

ONSHORE GAS FIELD MAINTENANCE COST BASIS
(Thousands of dollars/annum)

Case series:		2000		2100		2200	
Prospect:		Eromanga		Amadeus		Canning	
Case number:	48-well field	Base Case 2001	Final 2011	Base Case 2101	Final 2141	Base Case 2201	Final 2231
Salaries and wages							
Salaries and wages	1 040	1 040		1 040		1 040	1 040
Oncosts	310	310		310		310	
Maintenance materials							
Wells	500	156		417		398	
Other production equipment	250	250		250		250	
Plant equipment	250	250		250		250	
Vehicles	50	50		50		50	
Service companies							
Workovers	500	150		400		400	
Production logging	250	75		200		200	
Well stimulation	125	38		100		100	
Wireline testing	100	30		80		80	
Contract maintenance	200	60		160		160	
Transport operating materials	125	125		166		125	
Operating chemicals	500	100		250		250	
Fuel	50	50		50		50	
Air transport and accommodation	550	550		400		531	
Total	4 800	3 234		4 123		4 194	

TABLE 20

AMADEUS BASIN - GAS
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

		Development capital		Pipeline capital	Exploration costs
Case number:		Base case 2101	Final 2141		All cases
Year	Description				
1	Discovery well, seismic				2.31
	Appraisal wells (number)				4
	Appraisal wells				2.84
2	Development wells (number)	20	15		
	Development wells, camp, vehicles	23.13	23.13		
3	Development wells (number)	20	15		
	Development wells, 1/2 flowlines, separators, dehydrators	11.781	5.959		

Note: The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 21

CANNING BASIN - GAS
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital		Pipeline capital	Exploration costs
		Base case 2201	Final 2221		All cases
Year	Description				
1	Discovery well, seismic				3.00
	Appraisal wells (number)				4
	Appraisal wells				7.20
2	Development wells (number)	20	20		
	Camp	48.87	48.87		
3	Development wells (number)	14	22		
	Flowlines and production facilities	30.75	45.97		

Note: The discovery well is abandoned and is not used in the prospect evaluation.

TABLE 22

CARNARVON BASIN
CAPITAL DEVELOPMENT PROGRAM
(Millions of dollars unless noted)

Case number:		Development capital	Pipeline capital	Exploration costs
		Base case 2401		All cases
Year	Description			
1	Discovery well, seismic			5.12
	Appraisal wells (number)			4
	Appraisal wells			16.60
2	20 percent of platform	70.00		
3	60 percent of platform	210.00		
4	20 percent of platform	70.00		
	Development wells (number)	12		
	Development wells	33.12		
	Separators	2.6		
5	Development wells (number)	24		
	Development wells	66.24		
	Dehydration	1.29		

Notes: No change in investment or operating costs due to increased production per well.
Discovery and appraisal wells are abandoned and are not used in the prospect evaluation.