Australia’s petroleum resource rent tax
An economic assessment of fiscal settings
Australia’s petroleum resource rent tax
An economic assessment of fiscal settings

ABARE report for the Department of Industry, Tourism and Resources

Lindsay Hogan

January 2003
foreword

The petroleum resource rent tax was introduced by the Commonwealth government in 1987 and, together with other amendments, was extended in 1990 to cover the Bass Strait project. Further amendments were introduced in 1992 and 1993, and again in 2001. The petroleum resource rent tax is levied on net project income before company income tax is applied.

Overall, petroleum resource rent tax collections, in 2000-01 prices, have increased from A$52 million in 1989-90 to a peak of A$2.4 billion in 2000-01, and are estimated to have declined to A$1.4 billion in 2001-02.

It has recently been argued that Australia’s petroleum resource rent taxation arrangements need to be assessed taking into account the changing nature of offshore petroleum exploration and production activity, particularly the shift toward exploration in deepwater and frontier areas, and a greater emphasis on gas production.

The objective in this study is to examine the fiscal settings in Australia’s petroleum resource rent taxation arrangements taking into account historical and projected industry developments. The Australian government has stated that fiscal settings should ensure that the petroleum resource rent tax is competitive and efficient while also providing a reasonable return to the community from the production of community owned petroleum resources. Industry value added for Australia’s oil and gas extraction industry (onshore and offshore) was an estimated A$17 billion in 2000-01.

BRIAN S. FISHER
Executive Director

January 2003
This study was undertaken on behalf of the Commonwealth Department of Industry, Tourism and Resources.

The author wishes to thank Bill Layer, Chrys Papadopoulos, Matthew Paull and others from the Commonwealth Department of Industry, Tourism and Resources who provided information and helpful comments on previous drafts of this report.

The author also wishes to thank Paul Williamson, Denis Wright and Andrew Barrett from Geoscience Australia, and several industry representatives in Australia, including among others Noel Mullen and Barry Jones from APPEA.

Thanks also to Mike Hinchy from ABARE who reviewed this paper, and in particular provided very useful comments on the interaction between the petroleum resource rent tax and joint ventures.
# contents

Summary 1

1 Introduction 9

2 Petroleum resource taxation in Australia 11
   Overview 11
   Australia’s petroleum resource rent tax 12
   Key industry recommendations 14

3 Economic developments in Australia’s oil and gas extraction industry 15
   Oil and gas production 15
   Australia’s oil and gas resources 20
   Recent developments in offshore oil and gas exploration 21

4 Economic efficiency of resource taxation policy 26
   Economic rent and basic resource taxes 26
   Risk, attitudes toward risk and neutrality 30
   Brown tax 32
   Resource rent tax 38

5 Fiscal settings in Australia’s petroleum resource rent tax 42
   Some general comments relating to key industry recommendations 42
   Fiscal settings in Australia’s petroleum resource rent tax 47

References 63
Appendix

A Spreads of corporate bonds over government bonds 62

Boxes

1 Key options for fiscal settings in Australia’s petroleum resource rent tax 5
2 An algebraic representation of fiscal settings under the preferred option 57
3 An algebraic representation of fiscal settings under the alternative option 60

Figures

A Petroleum resource rent tax collections by the Australian government, and industry profitability 13
B Oil and gas production in Australia 16
C Oil and gas production in Australia, by major basin 17
D Australia’s economic demonstrated resources (EDR) and EDR/production ratios for oil and gas 20
E Exploration expenditure and activity indicators in Australia’s offshore oil and gas extraction industry 23
F Deepwater exploration wells, by country 25
G The concept of industry economic rent 27
H Basic resource taxes in a simplified framework 29
I Simplified decision tree for risky mineral or petroleum projects 31
J Probability distribution of the net present value (NPV) of a risky project before and after a Brown tax 34
K Probability distributions of profitability measures of risky projects with risk averse investors – certainty equivalent approach 36
L Expected utility theory – investor’s attitude toward risk and the shape of the utility function 37
M Number of exploration permits allocated by the Australian government, by field maturity 43
N Significant discoveries in Australia’s offshore petroleum industry, by leasing arrangements 45
O Threshold rates for general expenditure in Australia’s petroleum resource rent tax system 53
P Spreads of corporate bonds over government bonds 62
## Tables

1. Fiscal settings under alternative options  
2. Australia’s offshore production facilities, by basin  
3. Australia’s economic demonstrated resources for petroleum, by basin, as at 1 January 2001  
4. Number of petroleum exploration permits allocated by the Australian government, by maturity of field  
5. Significant discoveries in Australia’s offshore petroleum industry  
6. Significant discoveries in Australia’s offshore petroleum industry: duration from discovery to production commencement date or the year 2000  
7. Fiscal settings under alternative options
The objective in this study is to examine fiscal settings in Australia’s petroleum resource rent taxation arrangements. The Australian government has stated that fiscal settings should ensure that the petroleum resource rent tax is competitive and efficient while also providing a reasonable return to the community from the production of community owned petroleum resources.

The petroleum resource rent tax was introduced by the Commonwealth government in 1987 and, together with other amendments, extended in 1990 to cover the Bass Strait project. Further amendments were introduced in 1992 and 1993, and again in 2001.

In general terms, the petroleum resource rent tax is levied as a constant percentage of the project’s net cash flow whereby exploration and general project expenditures are accumulated at some threshold rate and offset against future revenues. The key fiscal settings are:

- the tax is levied at a rate of 40 per cent of net project income after the threshold rate of return is achieved (that is, after accumulated exploration and general project expenditures have been deducted);
- general expenditures are accumulated at the long term bond rate plus 5 percentage points;
- exploration expenditures are transferable between projects (within the same company);
- undeducted exploration expenditures are accumulated at the long term bond rate plus 15 percentage points if the expenditures are incurred within five years of the date of the lodgment of data required for the granting of the production licence; and
- undeducted exploration expenditures are maintained in real terms (that is, expenditures are accumulated at the gross domestic product (GDP) inflation factor) if the expenditures are incurred more than five years before the relevant lodgment date.

The petroleum resource rent tax is levied on net project income before company income tax is applied. Tax payments are deductible for company income tax purposes. Petroleum resource rent tax collections are significant, increasing from A$52 million in 1989-90 to a peak of A$2.4 billion
in 2000-01, and are estimated to have declined to A$1.4 billion in 2001-02 (values are in 2000-01 prices).

The Australian Petroleum Production and Exploration Association (APPEA), the national body representing companies involved in oil and gas exploration and production in Australia, has recommended several changes relating to the fiscal settings in Australia’s petroleum resource rent taxation arrangements. APPEA’s key recommendations relate to the identification of two specific risk categories in the petroleum resource rent taxation — deepwater projects and gas projects — and to the adjustment of the threshold rate for exploration expenditure by new investors to the long term bond rate in those years currently accumulated at the inflation rate (as measured by the GDP deflator). The approach taken in this study is to interpret these recommendations relatively broadly as signaling key areas of concern in the current petroleum resource rent tax system.

Given historical and prospective trends, it is certainly possible to argue that the current arrangements have performed well over several years and hence that the fiscal settings should not be altered. The industry arguments for identifying risk categories relating to deepwater activity and gas projects appear to be limited because the industry is already significantly engaging in frontier and deepwater exploration activities, and domestic and international gas markets are expected to develop significantly further over time.

However, an economic assessment of fiscal settings should also attempt to examine the scope for efficiency gains while also allowing the community to receive a reasonable return from the extraction of Australia’s offshore oil and gas resources under the jurisdiction of the system.

The key issue in the current fiscal settings of Australia’s petroleum resource rent tax is the economic incentives resulting from the current settings of the threshold rate for different expenditure categories — all of these rates vary from the long term government bond rate. Most importantly, the current system results in economic incentives to underinvest in higher risk wildcat exploration (although the signals are mixed for new investors), and to overinvest in the development phase (that is, over-invest in infrastructure for a given level of output) to take advantage of an annual rate of return that is significantly in excess of the long term bond rate.
There is a strong economic argument to set the threshold rate for all expenditures at the long term government bond rate since accumulated expenditures represent a reduction in future petroleum resource rent tax liabilities. It may be argued that the appropriate discount rate for a certain government payout (or reduced tax liability) is the risk free interest rate as measured by the long term government bond rate (although there will continue to be risks relating to the extent to which these reduced tax liabilities are fully utilised for any given project).

Assuming that the investor’s discount rate is equal to the risk free interest rate is consistent with a certainty equivalent approach to investment decisions (as opposed to a risk adjusted discount rate approach). A risk premium (if allowance is made for a risk premium) may be included in the size of the initial tax deduction — that is, allowing a tax deduction in excess of 100 per cent, referred to as an accelerated rate of deduction.

It is on this basis that two options are suggested here. Fiscal settings under each option — referred to as the preferred and alternative options — are presented in table 1 and box 1. In both options, all threshold rates are equal to the risk free interest rate as measured by the long term government bond rate.

- In the preferred option, to compensate investors for the lack of a risk premium, the tax rate is reduced from the current 40 per cent to a level that ensures reasonable returns for both the investor and the government (with the latter representing the return to the community from the extraction of the resource).

- In the alternative option, the tax rate is maintained at 40 per cent, while investors receive a risk premium through an accelerated rate of deduction (a tax deduction in excess of 100 per cent) at a sufficient level that ensures reasonable returns for both the investor and the government (with the latter representing the return to the community from the extraction of the resource).

It is assumed that the Commonwealth government chooses not to adopt a system of either cash rebates or transferable tax credits for unused tax credits at the end of a project life. The potential lack of full loss offset therefore remains an issue in the system and justifies a lower tax rate, or higher accelerated rate of deduction, than would otherwise be the case to target a given share of the industry’s economic rent.

Both options eliminate the current distortions caused by threshold rates that vary between expenditure categories, and differ from the long term...
The government bond rate. The preferred option also has the merit of simplicity and avoids the difficulties in specifying (typically on a relatively arbitrary basis) risk premiums for expenditure categories (single or multiple). The alternative option has the potential for a reduction in administrative costs compared with the current system (but this is dependent on the number of risk categories incorporated in the alternative system), and also has the major potential advantage of setting a higher accelerated rate of deduction for exploration expenditure associated with new field wildcat drilling to account for the significantly higher risks in this activity.

An assessment of specific settings for the actual and potential fiscal parameters in the petroleum resource rent tax is beyond the scope of the current study. It should also be recognised that, while both options attempt to increase the efficiency of the petroleum resource rent tax, there are potentially significant administrative costs involved in implementing each option.

### Fiscal settings under alternative options

<table>
<thead>
<tr>
<th>Notation</th>
<th>Tax rate</th>
<th>Threshold rate</th>
<th>Accelerated rate of deduction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( t^{PRRT} )</td>
<td>( i_{exp} )</td>
<td>( i_{gen} )</td>
</tr>
<tr>
<td>Unit</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td><strong>Current system</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>40</td>
<td>0</td>
<td>LTBR+5</td>
</tr>
<tr>
<td>New investors</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Threshold rate for exploration expenditure incurred:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>– within 5 year period</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>– outside 5 year period</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Other fiscal settings</td>
</tr>
<tr>
<td><strong>Preferred option</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>&lt;40</td>
<td>0</td>
<td>LTBR</td>
</tr>
<tr>
<td>New investors</td>
<td>&lt;40</td>
<td>LTBR</td>
<td>LTBR</td>
</tr>
<tr>
<td><strong>Alternative option</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>40</td>
<td>0</td>
<td>LTBR</td>
</tr>
<tr>
<td>New investors</td>
<td>40</td>
<td>LTBR</td>
<td>LTBR</td>
</tr>
</tbody>
</table>

\( a \) For ease of presentation, all fiscal settings are presented in percentage terms. However, it should be noted that the notation refers to a number whereby, for example, a tax rate of 40 per cent in the table is 0.40 in the equations in boxes 2 and 3.

LTBR refers to the long term government bond rate.
Box 1: Key options for fiscal settings in Australia’s petroleum resource rent tax

In this study, it is argued that all undeducted exploration and general project expenditures should be accumulated at the long term government bond rate and offset against future project revenue. Transfers of tax credits over time at the long term government bond rate reflect the assumption that the tax credit represents a certain reduction in future petroleum resource rent tax liabilities (if sufficient revenue is earned from the project).

This assumption is also consistent with a certainty equivalent approach to investment decisions rather than the current risk adjusted discount rate approach. A risk premium (if allowance is made for a risk premium) may be included in the size of the initial tax deduction — that is, allowing a tax deduction in excess of 100 per cent, referred to as an accelerated rate of deduction.

Two options for fiscal settings in Australia’s petroleum resource rent tax are suggested in this study.

Preferred option

Compared with the current system, the petroleum resource rent tax under the preferred option is triggered earlier for any given petroleum project — that is, when the investor obtains the risk free rate of return, as measured by the long term government bond rate. Under this option, the additional returns to the project, comprising the risk premium and resource rent components, are shared between the investor and the government. The tax rate must be reduced to ensure the government does not increase its share of the industry’s economic or resource rent.

The key features of the preferred option are:

- all exploration and general project expenditures are accumulated at the long term government bond rate;
- all exploration and general project expenditures receive a 100 per cent tax deduction; and
- the tax rate is reduced from its current level of 40 per cent to a level that ensures the government does not increase its share of the industry’s economic rent (assuming revenue neutrality, or the current share, is an appropriate and approximate benchmark).

The main advantages of the preferred option are:

- it eliminates the negative economic impacts of threshold rates that differ from the long term government bond rate;
- it is administratively simple, reducing three expenditure categories in the current system to a single expenditure category;
it avoids the need to estimate risk premiums for different expenditure categories (single or multiple), particularly given geological and economic environments that change over time;

- given a reduction in the tax rate, it reduces the negative impacts of the petroleum resource rent tax rate on economic incentives; and

- it eliminates different petroleum resource rent tax positions that may be an impediment to the formation of joint ventures (and hence risk spreading in the industry) and efficient decision making within a joint venture (noting that this ignores the ongoing influence of current arrangements following any reform).

The main disadvantages of this approach are:
- investors obtain only the risk free rate of return to expenditures before the petroleum resource rent tax is triggered, increasing uncertainty about the minimum rate of return that will be achieved on any given project.

**Alternative option**

Under the alternative option, the tax rate is maintained at its current level. The two threshold rates for exploration expenditure by new investors and the threshold rate for general project expenditure are all replaced by the long term government bond rate. However, a risk premium may be incorporated into the system through a single accelerated rate of deduction for all expenditure categories at a level that ensures that the government does not increase the share of the industry’s economic rent from what is currently paid through the petroleum resource rent tax system.

The key features of the alternative option are:
- all exploration and general project expenditures are accumulated at the long term government bond rate;
- all exploration and general project expenditures receive an accelerated rate of deduction (a tax deduction in excess of 100 per cent) at a level that ensures the government does not increase its share of the industry’s economic rent (assuming revenue neutrality, or the current share, is an appropriate and approximate benchmark); and
- the tax rate is maintained at its current level of 40 per cent.

The main advantages of the alternative option are:
- it eliminates the negative economic impacts of threshold rates that differ from the long term government bond rate;
- it is administratively simple compared with the current arrangements if the industry is treated as a single risk category since the three expenditure categories in the current system are reduced to a single expenditure category in the alternative option; and

Continued
it allows investors to obtain a risk premium in the return to expenditures before the petroleum resource rent tax is triggered, reducing uncertainty about the minimum rate of return that will be achieved on any given project.

The main disadvantages of this approach are:

- uncertainties about the appropriate size of any risk premium included as an accelerated rate of deduction, particularly given geological and economic environments that change over time; and
- compared with the preferred approach, the negative impact of a higher petroleum resource rent tax rate on economic incentives (although identical to the current rate).

The benefits of administrative simplicity under this system would be dissipated to some extent if multiple risk categories are identified and a different accelerated rate of deduction applies to each category. The strongest argument is for inclusion of a separate risk category for higher risk petroleum exploration that may be defined, for example, to include expenditure associated with drilling in a location that is no closer than 100 kilometres from a discovery well.

A critical direction for future research is to assess the implications of different fiscal settings in Australia’s petroleum resource rent tax for a range of feasible oil and gas projects over time, including exploration activity.

There are a number of possibilities in the scope of this research, including:

- simulating hypothetical oil and gas projects under a range of specific settings for policy parameters for the two options identified in this study, with the outcome under current settings included for comparison purposes;
- adopting a broader approach, and simulating hypothetical oil and gas projects for a range of assumptions for the tax rate and an accelerated rate of deduction, including both single and multiple expenditure categories based on risk profile; and
- undertaking more advanced research and examining the supply response from any change in fiscal settings in Australia’s petroleum resource rent tax, taking into account geological and economic risks, and investors’ attitudes toward those risks.

This research may be informed by government and industry about the range of assumptions for fiscal settings to be included in the simulations
of petroleum projects. Conversely, such research would clarify the nature of winners and losers from any change in the fiscal settings, and provide information to both government and industry that would facilitate the ranking of preferences for specific fiscal settings.

A further direction for economic research would be to examine the historical exploration decisions of new investors under the current petroleum resource rent taxation arrangements, and compare such decisions with those of old investors. This research would assist in clarifying the nature of the economic impacts of the various exploration expenditure categories in the petroleum resource rent tax.

In summary, Australia’s petroleum resource rent tax has performed well over a period in which there has been substantial change in geological and economic circumstances. On this basis, it may be argued that there is no imperative to alter current fiscal settings. However, if significant efficiency gains are desired, ABARE has identified two options that entail substantial reform to the petroleum resource rent tax.
introduction

The Barracouta oil and gas field in Bass Strait was the first significant offshore petroleum discovery in Australia (Geoscience Australia 2002). Barracouta was discovered by Esso in 1965 and production commenced in March 1969. By the end of the 1960s, Esso had made twelve further significant discoveries. Of these, ten fields in the Gippsland basin were subsequently developed, with production commencement dates ranging from November 1969 (Marlin) to January 1990 (Dolphin and Perch).

Six significant discoveries in a number of basins were made by other companies during the second half of the 1960s, including Shell (1967), Bocal (1967, 1968), Wapet (1969) and Arco (1969), although none of these has been developed for production to date. Since 1970, offshore petroleum exploration has been undertaken by a larger number of companies, including Ampolex, Apache, BHP Billiton (formerly BHP), Chevron, WMC, Woodside and more recently Santos, with significant discoveries made in several basins (Geoscience Australia 2002).

Overall, domestic production of crude oil, condensate and LPG increased from 2 gigalitres in 1968-69 to 41 gigalitres in 2001-02, and production of natural gas and ethane increased from 0.06 to 37 billion cubic metres (or Gm³) over the same time period (ABARE 2001, 2002a).

Notably, increased production of crude oil, condensate and LPG during the 1970s and early 1980s provided a major share of the domestic market’s oil requirements, resulting in a large decline in imports of crude oil and other refinery feedstocks from a peak of 24 gigalitres in 1968-69 to a low of 6 gigalitres in 1985-86. Since 1985-86, both exports and imports of crude oil and other refinery feedstocks have increased markedly, mainly reflecting the changing location and quality of production in Australia.

In 1998-99, the latest year for which historical energy consumption estimates are available, oil and natural gas accounted for 35 per cent and 18 per cent, respectively, of Australia’s primary energy consumption (Dickson, Thorpe, Harman, Donaldson and Tedesco 2001). Around 37 per cent of Australia’s primary consumption of oil was sourced from imports in 1998-99. In addition to servicing the domestic market, a major share of natural gas production is exported in the form of liquefied natural gas (LNG).

Industry value added for Australia’s oil and gas extraction industry (onshore and offshore) was an estimated A$17 billion in 2000-01 (ABS 2002a). Australia’s net petroleum exports in 2001-02 were valued at A$2.6 billion (ABARE 2002b). Petroleum exports were valued at A$11.7 billion, including, most importantly, exports of crude oil, condensate and other
refinery feedstock (A$6.1 billion) and LNG (A$2.6 billion). Petroleum imports totaled A$9.1 billion, mainly crude oil, condensate and other refinery feedstock (A$7.5 billion).

There are two key issues in the future exploration, development and production of Australia’s offshore petroleum resources.

- The share of natural gas in Australia’s total petroleum production is expected to increase significantly over the next two decades. The major share of future gas production is expected to be sourced from offshore gas projects. Compared with oil projects, gas projects tend to be long lived and are characterised by large capital costs, a relatively long payback period and lower profit rates.

- Future oil production will rely heavily on new discoveries from exploration in offshore frontier areas. Exploration, development and production tend to be higher cost and higher risk activities, particularly in deepwater frontier areas.

The objective in this study is to examine the fiscal settings in Australia’s petroleum resource rent taxation arrangements, taking into account historical and projected industry developments. With the exception of production licences drawn from the North West Shelf permit area and the Australia/East Timor Joint Petroleum Development Area, the Australian government applies the petroleum resource rent tax to all oil and gas projects seawards from three nautical miles to the outer limit of the territorial sea.

Several major petroleum companies have argued that the changing nature of offshore petroleum exploration and production activity needs to be taken into account when assessing Australia’s petroleum resource rent taxation arrangements (see, for example, Akehurst 2002; Bell 2002; Howarth 2002). Some of the industry arguments emphasise the implications of declining domestic oil production for oil self sufficiency and energy security in Australia — assessment of these particular issues is beyond the scope of this study.

The Australian Petroleum Production and Exploration Association (APPEA), the national body representing companies involved in oil and gas exploration and production in Australia, has provided extensive recommendations in its submission to the Council of Australian Governments’ Energy Market Review (APPEA 2002a). Of key importance to the current study, APPEA has recommended several changes relating to the fiscal settings in Australia’s petroleum resource rent taxation arrangements. A range of more technical amendments are proposed in APPEA (2002b).

In this study, the key APPEA recommendations are interpreted relatively broadly as signaling key areas of concern in the current petroleum resource rent tax system. While some general comments relating to the areas that APPEA has identified are provided, a more wide ranging assessment of fiscal settings in Australia’s petroleum resource rent tax is undertaken.
petroleum resource taxation in Australia

In Australia, petroleum resources are owned by the community. The government, on behalf of the community, transfers exploration and production rights to the private sector in return for some payment, usually collected in the form of a petroleum resource tax. In this chapter, some background information on petroleum resource taxation arrangements in Australia, and some key industry recommendations on directions for change in the petroleum resource rent tax, are provided.

Overview

Australia’s offshore petroleum jurisdiction, and the relevant legal framework, are outlined in Department of Industry, Science and Resources (1999). Australia has a 200 mile Exclusive Economic Zone (EEZ) around continental Australia and its territories in accordance with the United Nations Convention on the Law of the Sea (UNCLOS). Within this zone, the Commonwealth government is responsible for Australia’s offshore areas beyond three nautical miles. Coastal waters — areas in the zone within three nautical miles of the coast — are the responsibility of the corresponding state or territory government.

In general, resource taxation arrangements are either production or profit based, and include most importantly:

- **excise**, levied as a (dollar) amount per physical unit of production based on an increasing scale (that is, excise is levied at a higher rate for higher production levels);
- **specific royalty**, levied as a constant (dollar) amount per physical unit of production;
- **ad valorem royalty**, levied as a constant percentage of the value of production; and
- **resource rent royalty or tax**, levied as a constant percentage of the project’s net cash flow (whereby exploration and general expenditures are accumulated at some threshold rate and offset against future revenues).

With the exception of the North West Shelf project, production licence areas and the exploration permit areas from which they were derived, the petroleum resource rent tax currently applies to all oil and gas projects in offshore areas that are under the jurisdiction of the Commonwealth government.

Traditional volume based resource taxation arrangements — royalties and excise — apply onshore, in coastal waters and to the North West Shelf project area in Australia. Notably,
there is an exemption on the crude oil excise for the first 30 million barrels of production in new offshore projects where royalties and excise apply.

A mix of resource taxation arrangements applies in the former Australia–Indonesia Zone of Cooperation. These arrangements have been under review given the changed political status of East Timor. Projects within the Timor Gap Joint Petroleum Development Area (JPDA), previously referred to as the Zone of Cooperation Area A, are subject to the terms of a new treaty with, in general, revenue sharing between East Timor (90 per cent) and Australia (10 per cent) (see Geoscience Australia 2002).

**Australia’s petroleum resource rent tax**

Since the mid-1980s, the Commonwealth government has progressively shifted from traditional volume based royalty arrangements to the more efficient resource rent taxation system.

A resource rent royalty was introduced in Barrow Island in 1985. The petroleum resource rent tax (PRRT) was introduced by the Commonwealth government in 1987 to apply to all new offshore petroleum projects that were not already covered by pre-existing production licences and their associated permit areas. The petroleum resource rent tax is levied under the provisions of the *Petroleum Resource Rent Tax Assessment Act 1987*.

The petroleum resource rent tax was extended in 1990 to cover the Bass Strait project, defined to include all new developments and new discoveries made after 1990. Two further major amendments were introduced at that time. Undeducted exploration expenditures were allowed to be transferred to other projects — that is, exploration expenditures were made immediately deductible against companywide PRRT liabilities. The threshold rate at which undeducted general expenditures were carried forward was reduced from the long term bond rate plus 15 percentage points to the long term bond rate plus 5 percentage points.

APPEA (2002a,b) notes that a number of further amendments have since been made to the petroleum resource rent tax arrangements. In 1992 and 1993, the treatment of transferable expenditure and lodgment provisions were clarified. In 2000, a technical amendment was passed that addressed an uncertainty associated with the treatment of expenditures where a party ‘walks away’ from a continuing joint venture. In 2001, several changes announced by the Commonwealth government in 1998 were enacted — these changes related to the operation of the five year GDP rule and gas transfer pricing provisions.

The stated policy aim of the Commonwealth government, as given in the Minerals and Petroleum Resources Policy Statement, is to ‘continue to work with industry to ensure that Australia’s secondary tax and associated administrative arrangements, particularly in relation to Petroleum Resource Rent Tax, provide a fiscal regime which encourages the production of our oil and gas reserves while ensuring an adequate return on community-owned resources’ (Commonwealth Government 1998, Taxation section).
The key fiscal settings in the petroleum resource rent tax are:

- PRRT is levied at a rate of 40 per cent of net project income after the threshold rate of return is achieved (that is, after accumulated exploration and general project expenditures have been deducted);
- general expenditures are accumulated at the long term bond rate plus 5 percentage points;
- exploration expenditures are transferable between projects (within the same company);
- undeducted exploration expenditures are accumulated at the long term bond rate plus 15 percentage points if the expenditures are incurred within five years of the date of the lodgment of data required for the granting of the production licence; and
- undeducted exploration expenditures are maintained in real terms (that is, expenditures are accumulated at the GDP inflation factor) if the expenditures are incurred more than five years before the lodgment date of data for the production licence.

The petroleum resource rent tax is levied on net project income before company income tax is applied. PRRT payments are deductible for company income tax purposes. The company income tax rate is 30 per cent in 2001-02 and 2002-03 (CCH Australia 2002).

Overall, petroleum resource rent tax collections (in 2000-01 prices) increased from A$52 million in 1989-90 to a peak of A$2.4 billion in 2000-01, and are estimated to have declined to A$1.4 billion in 2001-02 (figure A).

Petroleum resource rent tax collections fluctuated substantially over this period. These fluctuations broadly reflect changes in industry profitability — the peaks in 1992-93 (A$1.6 billion), 1996-97 (A$1.4 billion) and 2000-01 (A$2.4 billion) correspond to years in which the real returns to assets and funds peaked or are likely to have peaked (figure A; ABS data after 2000-01 are not yet available).
Key industry recommendations

In APPEA’s submission to the Council of Australian Governments’ Energy Market Review, there are three specific recommendations for change to the petroleum resource rent tax (APPEA 2002a). These recommendations are as follows.

- For new gas projects, the carry forward rate for undeducted general project related expenditures should be increased from the long term bond rate plus 5 percentage points to the long term bond rate plus 10 percentage points.

- The PRRT Act should be amended to recognise the greater risks associated with deepwater exploration and production activity, possibly via the introduction of a barrel of oil equivalent exemption for deepwater oil and gas developments.

- The five year GDP factor for undeducted exploration expenditure should be modified for expenditure incurred more than five years prior to a company applying for an initial production licence. Such expenditure should be compounded forward at the augmented bond rate for the most recent five years, and for periods before this, compounded forward at the long term bond rate.

APPEA provided a further submission that contains several modernisation proposals and recommended technical amendments (APPEA 2002b). These latter recommendations are beyond the scope of the current study.
economic developments in Australia’s oil and gas extraction industry

In global terms, Australia is not highly prospective for oil and gas resources. At the end of 2001, Australia is estimated to have held around 0.3 per cent of the world’s proved reserves of oil and 1.6 per cent of the gas reserves (BP 2002). Future directions in Australia’s oil and gas extraction industry depend fundamentally on the extent to which discovered gas fields may be profitably developed and offshore exploration activity results in new economic discoveries of oil and gas fields.

Oil and gas production

Australia’s oil and gas production

Over the past thirty years, gas has become relatively more important in Australia’s total petroleum production, and this trend is expected to continue over the next twenty years. Australia’s upstream oil and gas production since 1965-66, including ABARE projections for the period to 2019-20, is shown in figure B.

Production of oil (including crude oil, condensate and LPG) increased rapidly in the late 1960s and early 1970s with the discovery and development of the Bass Strait fields. Oil production leveled off throughout much of the 1970s, increasing again in the early 1980s following the second oil price shock. Oil production increased further in 1999-2000 and 2000-01, reflecting both the commencement of production in a small number of new projects in the Bonaparte basin and the economic incentives resulting from higher world oil prices during this period.

Overall, oil production averaged 25 gigalitres in the period 1970-71 to 1982-83 and 36 gigalitres in the period 1983-84 to 2001-02 (peaking at 43 gigalitres in 2000-01). ABARE projections indicate that oil production will level off, averaging 37 gigalitres over the period 2002-03 to 2019-20.

Australian production of gas (including natural gas and ethane) has increased steadily since the early 1970s, from 3 billion cubic metres in 1971-72 to 12 billion cubic metres in 1981-82, 23 billion cubic metres in 1991-92, and 36 billion cubic metres in 2001-02. ABARE projections indicate that gas production will more than double, to 80 billion cubic metres in 2019-20 (Dickson et al. 2001).
In energy units, total oil and gas production in Australia has increased from 19 petajoules in 1965-66 to 2940 petajoules in 2001-02 and is projected by ABARE to reach 4610 petajoules in 2019-20. Reflecting the relatively steady historical and projected growth in gas production, the share of gas in Australia’s total petroleum production has increased from 1 per cent in 1965-66 to 50 per cent in 2001-02 and is projected by ABARE to reach 69 per cent in 2019-20.

Geoscience Australia (2002) provides forecasts for Australia’s crude oil and condensate production over the period 2001–15 at three cumulative probability levels (90, 50 and 10 per cent). Production is forecast to decline substantially from 2001 levels. ABARE forecasts are based in part on production forecasts by Geoscience Australia (Dickson et al. 2001).

**Oil and gas production, by major basin**

The changing location of Australia’s oil and gas production since 1983-84, particularly with declining oil production in the Gippsland basin and the emergence of oil and gas production in the Carnarvon basin in north west Australia, is indicated in figure C.

Between 1983-84 and 2001-02, there have been substantial changes in the location of oil production in Australia. Most notably, a large decline in oil production from the Gippsland basin (from 973 petajoules in 1983-84 to 370 petajoules in 2001-02) has been more than offset by an increase in the Carnarvon basin (46 petajoules; 784 petajoules). Production in the Bonaparte basin increased strongly in 1999-2000 and 2000-01 (221 petajoules in 2001-02). In the Cooper–Eromanga basin, the major onshore production area, oil production has increased slightly over the historical period, peaking in 1985-86 (52 petajoules in 1983-84; 168 petajoules in 1985-86; and 76 petajoules in 2001-02).

Overall, the share of the Gippsland basin in Australia’s oil production has declined markedly from 90 per cent in 1983-84 to 25 per cent in 2001-02. By contrast, the Carnarvon, Bonaparte
Oil and gas production in Australia, by major basin

<table>
<thead>
<tr>
<th>Oil - energy units</th>
<th>Oil - shares</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other</td>
<td>Cooper-Eromanga</td>
</tr>
<tr>
<td>1400</td>
<td>75</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Gas - energy units</th>
<th>Gas - shares</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other</td>
<td>Cooper-Eromanga</td>
</tr>
<tr>
<td>1250</td>
<td>75</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total oil and gas - energy units</th>
<th>Total oil and gas - shares</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other</td>
<td>Cooper-Eromanga</td>
</tr>
<tr>
<td>2500</td>
<td>75</td>
</tr>
</tbody>
</table>

There are some minor discrepancies between the aggregate of production by basin and the corresponding Australian production presented in figure B.

and Cooper–Eromanga basins accounted for 54 per cent, 15 per cent and 5 per cent respectively of Australia’s oil production in 2001-02.

Gas production in 1983-84 was sourced mainly from the Gippsland basin (239 petajoules or 49 per cent of total gas production) and the Cooper–Eromanga basin (194 petajoules; 40 per cent). In 2001-02, gas production was mainly located in the Carnarvon (735 petajoules; 56 per cent), Gippsland (254 petajoules; 19 per cent) and Cooper–Eromanga (252 petajoules; 19 per cent).

As a consequence of these changes, the location of total oil and gas production in Australia has become more diverse. In 1983-84, oil and gas production was mainly located in Gippsland (1212 petajoules; 77 per cent) and Cooper–Eromanga (246 petajoules; 16 per cent). In 2001-02, oil and gas production was mainly located in the Carnarvon (1519 petajoules; 55 per cent), Gippsland (624 petajoules; 22 per cent), Cooper–Eromanga (328 petajoules; 12 per cent) and Bonaparte (221 petajoules; 8 per cent).

An important aspect of the industry has been the adoption of new technologies to facilitate the profitable discovery and development of remote and smaller oil fields (table 2). Powell (2001) highlights the shift since 1985 from oil production in the giant fields in the Gippsland basin toward a larger number of relatively smaller oil fields in the north west (see also Akehurst 2002 and Bell 2002).

2 Australia’s offshore production facilities, by basin

<table>
<thead>
<tr>
<th>Gippsland</th>
<th>Production start date</th>
<th>Production end date</th>
<th>Resource</th>
<th>Production technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barracouta</td>
<td>March 1969</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Marlin</td>
<td>November 1969</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Halibut</td>
<td>March 1970</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Kingfish A</td>
<td>April 1971</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Kingfish B</td>
<td>November 1971</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Mackerel</td>
<td>December 1977</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Tuna</td>
<td>May 1979</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Snapper</td>
<td>July 1981</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>West Kingfish</td>
<td>December 1982</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Halibut–Cobia</td>
<td>April 1983</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Halibut–Fortescue</td>
<td>September 1983</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Flounder</td>
<td>December 1984</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Bream</td>
<td>March 1988</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Whiting</td>
<td>October 1989</td>
<td></td>
<td>Oil and gas</td>
<td>Miniplatform</td>
</tr>
<tr>
<td>Dolphin</td>
<td>January 1990</td>
<td></td>
<td>Oil</td>
<td>Monotower</td>
</tr>
<tr>
<td>Perch</td>
<td>January 1990</td>
<td></td>
<td>Oil</td>
<td>Monotower</td>
</tr>
<tr>
<td>Seahorse</td>
<td>January 1990</td>
<td></td>
<td>Oil</td>
<td>Subsea completion</td>
</tr>
<tr>
<td>Tarwhine</td>
<td>January 1990</td>
<td></td>
<td>Oil</td>
<td>Subsea completion</td>
</tr>
<tr>
<td>West Tuna</td>
<td>December 1996</td>
<td></td>
<td>Oil and gas</td>
<td>Concrete gravity platform</td>
</tr>
<tr>
<td>Bream B</td>
<td>January 1997</td>
<td></td>
<td>Oil and gas</td>
<td>Concrete gravity platform</td>
</tr>
<tr>
<td>Moonfish</td>
<td>July 1997</td>
<td></td>
<td>Oil</td>
<td>Platform wells</td>
</tr>
<tr>
<td>Blackback</td>
<td>June 1999</td>
<td></td>
<td>Oil</td>
<td>Subsea template</td>
</tr>
</tbody>
</table>

Continued ➸
## Australia’s offshore production facilities, by basin (continued)

<table>
<thead>
<tr>
<th>Basin</th>
<th>Production start date</th>
<th>Production end date</th>
<th>Resource</th>
<th>Production technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carnarvon</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Rankin</td>
<td>July 1984</td>
<td></td>
<td>Gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Harriet A</td>
<td>January 1986</td>
<td></td>
<td>Oil and gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Harriet B</td>
<td>January 1986</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Harriet C</td>
<td>January 1986</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>North Herald</td>
<td>December 1987</td>
<td>January 1997</td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>South Pepper</td>
<td>January 1988</td>
<td>January 1997</td>
<td>Oil</td>
<td>Tripod</td>
</tr>
<tr>
<td>Talisman</td>
<td>January 1989</td>
<td>August 1992</td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Chervil</td>
<td>August 1989</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Saladin A</td>
<td>November 1989</td>
<td></td>
<td>Oil</td>
<td>Miniplatform</td>
</tr>
<tr>
<td>Saladin B</td>
<td>November 1989</td>
<td></td>
<td>Oil</td>
<td>Miniplatform</td>
</tr>
<tr>
<td>Saladin C</td>
<td>November 1989</td>
<td></td>
<td>Oil</td>
<td>Miniplatform</td>
</tr>
<tr>
<td>Cowle</td>
<td>April 1991</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Saladin–Yammaderry</td>
<td>April 1991</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Campbell</td>
<td>October 1992</td>
<td></td>
<td>Gas</td>
<td>Monopod</td>
</tr>
<tr>
<td>Sinbad</td>
<td>October 1992</td>
<td></td>
<td>Gas</td>
<td>Monopod</td>
</tr>
<tr>
<td>Wando A</td>
<td>October 1993</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Scindian</td>
<td>January 1994</td>
<td></td>
<td>Oil and gas</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Roller A</td>
<td>March 1994</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Roller B</td>
<td>March 1994</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Roller C</td>
<td>March 1994</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Skate</td>
<td>March 1994</td>
<td></td>
<td>Oil</td>
<td>Monopod</td>
</tr>
<tr>
<td>Goodwyn</td>
<td>February 1995</td>
<td></td>
<td>Gas</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Lambert</td>
<td>November 1995</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Wanaea/Cossack</td>
<td>November 1995</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>East Spar</td>
<td>October 1996</td>
<td></td>
<td>Gas</td>
<td>Subsea</td>
</tr>
<tr>
<td>Wando B</td>
<td>March 1997</td>
<td></td>
<td>Oil</td>
<td>Concrete gravity</td>
</tr>
<tr>
<td>Agincourt</td>
<td>August 1997</td>
<td></td>
<td>Oil and gas</td>
<td>Monopod</td>
</tr>
<tr>
<td>Stag</td>
<td>May 1998</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Wonnich</td>
<td>July 1999</td>
<td></td>
<td>Oil and gas</td>
<td>Tripod</td>
</tr>
<tr>
<td>Ocean Legend</td>
<td>May 2001</td>
<td></td>
<td>Oil</td>
<td>Conventional steel</td>
</tr>
<tr>
<td>Karratha Spirit</td>
<td>May 2001</td>
<td></td>
<td>Oil</td>
<td>FSO</td>
</tr>
<tr>
<td>Simpson A</td>
<td>December 2001</td>
<td></td>
<td>Gas</td>
<td>Minopod</td>
</tr>
<tr>
<td>Simpson B</td>
<td>December 2001</td>
<td></td>
<td>Gas</td>
<td>Minopod</td>
</tr>
<tr>
<td>South Plato</td>
<td>June 2002</td>
<td></td>
<td>Oil</td>
<td>Minopod</td>
</tr>
<tr>
<td>Bonaparte</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jabiru</td>
<td>August 1986</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Challis</td>
<td>December 1989</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Skua</td>
<td>December 1991</td>
<td>January 1997</td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Elang/Kakatua</td>
<td>July 1998</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Laminaria/Corallina</td>
<td>November 1999</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
<tr>
<td>Buffalo</td>
<td>December 1999</td>
<td></td>
<td>Oil</td>
<td>Mini-platform</td>
</tr>
<tr>
<td>Buffalo FPSO</td>
<td>December 1999</td>
<td></td>
<td>Oil</td>
<td>Floating facility</td>
</tr>
</tbody>
</table>

*Source: Geoscience Australia (2002).*
Australia’s oil and gas resources

Over the past two decades, Australia’s economic demonstrated resources for oil and gas have increased substantially overall, although there is considerable variation between individual resources (figure D).

Geoscience Australia (2002) uses a McKelvey classification system to assess Australia’s oil and gas resources. Economic demonstrated resources are resources that are assessed to be economically extractable and for which the quantity and quality are computed partly from specific measurements, and partly from extrapolation for a reasonable distance on geological evidence. Subeconomic demonstrated resources are similar to economic demonstrated resources in terms of certainty of occurrence and are considered to be potentially economic in the foreseeable future, but are currently assessed to be subeconomic.

![Diagram showing Australian economic demonstrated resources (EDR) and EDR/productioin ratios for oil and gas.](chart.png)
These categories may be reconciled with the traditional petroleum industry classification (Geoscience Australia 2002). There are two categories in the petroleum industry classification:

- Category 1 comprises current reserves of fields that have been declared commercial, and includes both proved and probable reserves.
- Category 2 comprises estimates of recoverable reserves that have not yet been declared commercially viable; these reserves may be either geologically proved or are awaiting further appraisal.

Industry petroleum reserve estimates are equivalent to the sum of economic and subeconomic resources. Economic demonstrated resources includes category 1 reserves and some part of category 2 reserves, as assessed by Geoscience Australia. It should be noted that commercial reserves (category 1) are significantly more conservative estimates than economic demonstrated resources.

In energy units, Australia’s economic demonstrated resources of oil increased by 60 per cent between 1982 and 2001 (figure D). Over this period, economic demonstrated resources have declined significantly for crude oil (~28 per cent) and increased strongly for both condensate (254 per cent) and LPG (145 per cent). In 2001, crude oil, condensate and LPG accounted for 28 per cent, 42 per cent and 30 per cent, respectively, of Australia’s total economic demonstrated resources of oil.

The ratio of economic demonstrated resources to production (EDR/production ratio) provides some indication of the number of years that the resource would support production assuming current production levels are maintained. The EDR/production ratio has consistently been relatively low for crude oil, declining overall from twelve years in 1982-83 to six years in 2001-02 (figure D). By contrast, the EDR/production ratio for both condensate and LPG is relatively high, at 39 and 59 years respectively in 2001-02.

Consistent with the outcome for condensate, which is mainly located in gas fields, Australia’s economic demonstrated resources for gas recorded strong growth between 1982 and 2001 (259 per cent) (figure D). The EDR/production ratio for gas has increased from 53 years in 1982-83 to 61 years in 2001-02.

Australia’s total economic demonstrated resources for oil and gas have increased by 184 per cent from around 40 exajoules in 1982 to 114 exajoules in 2001. Over this period, the share of oil in economic demonstrated resources for oil and gas declined from 37 per cent in 1982 to 21 per cent in 2001. Australia’s economic demonstrated resources for oil and gas are mainly located in the Carnarvon (70 per cent), Bonaparte (17 per cent) and Gippsland basins (10 per cent) (table 3).

**Recent developments in offshore oil and gas exploration**

A major implication of Australia’s oil and gas resource estimates is that, to achieve the ABARE projections for oil production presented in figure B, substantial new discoveries of oil fields are required. Powell (2001) argues that future oil production can only be sustained if a significant new oil province is discovered, which is most likely to be located in an offshore frontier basin, and exploration in established areas continues.
Recent offshore exploration, development and production expenditure and drilling activity information is provided in figure E (see Geoscience Australia 2002, APPEA 2002c and ABS 2002c). Since 1988, both real exploration expenditure and new field wildcat wells drilled in offshore areas have at least doubled — exploration expenditure, in 2000 prices, increased from A$0.4 billion in 1988 to peaks of A$0.9 billion in 1998 and 2001; and new field wildcat wells drilled increased from 24 in 1988 to a peak of 57 in 1998, moderating to 49 in 2001.

The success rate of new field wildcat wells drilled is measured by Geoscience Australia (2002) as the ratio of the number of discoveries to the number of wells drilled, where a discovery is defined to be a well from which any measurable amount of oil or gas has been recovered. The success rate for the offshore new field wildcat wells drilled has fluctuated significantly over the period, declining overall from 33 per cent in 1988 and 1989 to 28 per cent in 2001. The average annual success rate for new field wildcat wells drilled offshore during this period is 28 per cent.

### Australia’s economic demonstrated resources for petroleum, by basin

<table>
<thead>
<tr>
<th>Basin</th>
<th>Crude oil</th>
<th>Condensate</th>
<th>LPG</th>
<th>Total</th>
<th>Sales gas</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GL</td>
<td>GL</td>
<td>GL</td>
<td></td>
<td>Gm³</td>
<td></td>
</tr>
<tr>
<td><strong>In physical units</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gippsland</td>
<td>68</td>
<td>18</td>
<td>31</td>
<td>–</td>
<td>175</td>
<td>–</td>
</tr>
<tr>
<td>Carnarvon</td>
<td>77</td>
<td>168</td>
<td>169</td>
<td>–</td>
<td>1 649</td>
<td>–</td>
</tr>
<tr>
<td>Bonaparte</td>
<td>25</td>
<td>82</td>
<td>65</td>
<td>–</td>
<td>332</td>
<td>–</td>
</tr>
<tr>
<td>Cooper–Eromanga</td>
<td>7</td>
<td>6</td>
<td>8</td>
<td>–</td>
<td>75</td>
<td>–</td>
</tr>
<tr>
<td>Other</td>
<td>3</td>
<td>2</td>
<td>1</td>
<td>–</td>
<td>25</td>
<td>–</td>
</tr>
<tr>
<td>Australia</td>
<td>180</td>
<td>276</td>
<td>274</td>
<td>–</td>
<td>2 256</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>PJ</td>
<td>PJ</td>
<td>PJ</td>
<td>PJ</td>
<td>PJ</td>
<td>PJ</td>
</tr>
<tr>
<td><strong>In energy units</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gippsland</td>
<td>2 516</td>
<td>666</td>
<td>822</td>
<td>4 004</td>
<td>7 000</td>
<td>11 004</td>
</tr>
<tr>
<td>Carnarvon</td>
<td>2 849</td>
<td>6 216</td>
<td>4 479</td>
<td>13 544</td>
<td>65 960</td>
<td>79 504</td>
</tr>
<tr>
<td>Bonaparte</td>
<td>925</td>
<td>3 034</td>
<td>1 723</td>
<td>5 682</td>
<td>13 280</td>
<td>18 962</td>
</tr>
<tr>
<td>Cooper–Eromanga</td>
<td>259</td>
<td>222</td>
<td>212</td>
<td>693</td>
<td>3 000</td>
<td>3 693</td>
</tr>
<tr>
<td>Other</td>
<td>111</td>
<td>74</td>
<td>27</td>
<td>212</td>
<td>1 000</td>
<td>1 212</td>
</tr>
<tr>
<td>Australia</td>
<td>6 660</td>
<td>10 212</td>
<td>7 261</td>
<td>24 133</td>
<td>90 240</td>
<td>114 373</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td><strong>Shares</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gippsland</td>
<td>37.8</td>
<td>6.5</td>
<td>11.3</td>
<td>16.6</td>
<td>7.8</td>
<td>9.6</td>
</tr>
<tr>
<td>Carnarvon</td>
<td>42.8</td>
<td>60.9</td>
<td>61.7</td>
<td>56.1</td>
<td>73.1</td>
<td>69.5</td>
</tr>
<tr>
<td>Bonaparte</td>
<td>13.9</td>
<td>29.7</td>
<td>23.7</td>
<td>23.5</td>
<td>14.7</td>
<td>16.6</td>
</tr>
<tr>
<td>Cooper–Eromanga</td>
<td>3.9</td>
<td>2.2</td>
<td>2.9</td>
<td>2.9</td>
<td>3.5</td>
<td>3.2</td>
</tr>
<tr>
<td>Other</td>
<td>1.7</td>
<td>0.7</td>
<td>0.4</td>
<td>0.9</td>
<td>1.1</td>
<td>1.1</td>
</tr>
<tr>
<td>Australia</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Source: Geoscience Australia (2002).
Exploration expenditure and activity indicators in Australia’s offshore oil and gas extraction industry

- Exploration expenditure
- Newfield wildcat wells drilled
- Newfield wildcat wells success rate
- Extension/appraisal wells drilled
- Development and production expenditure
- Development wells drilled
The number of extension/appraisal wells drilled increased in the mid-1990s. Offshore development and production expenditure, in 2000 prices, peaked at A$1.7 billion in 1996. The number of development wells drilled peaked in 1997. More detailed information on the timing and number of Australia’s significant offshore oil and gas discoveries is provided in chapter 5.

**Exploration by maturity of field**

The Australian government’s offshore exploration acreage release program is documented in Department of Industry, Science and Resources (1999). The Australian government releases a range of petroleum exploration areas for work program bidding by petroleum explorers. These areas are classified according to the level of exploration maturity.

### Number of petroleum exploration permits allocated by the Australian government, by maturity of field a

<table>
<thead>
<tr>
<th>Year</th>
<th>Mature</th>
<th>Submature</th>
<th>Immature</th>
<th>Frontier</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>4</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>12</td>
</tr>
<tr>
<td>1986</td>
<td>7</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>8</td>
</tr>
<tr>
<td>1987</td>
<td>3</td>
<td>0</td>
<td>5</td>
<td>3</td>
<td>11</td>
</tr>
<tr>
<td>1988</td>
<td>4</td>
<td>3</td>
<td>5</td>
<td>1</td>
<td>13</td>
</tr>
<tr>
<td>1989</td>
<td>0</td>
<td>1</td>
<td>7</td>
<td>2</td>
<td>10</td>
</tr>
<tr>
<td>1990</td>
<td>0</td>
<td>0</td>
<td>12</td>
<td>3</td>
<td>15</td>
</tr>
<tr>
<td>1991</td>
<td>4</td>
<td>1</td>
<td>7</td>
<td>3</td>
<td>15</td>
</tr>
<tr>
<td>1992</td>
<td>3</td>
<td>1</td>
<td>4</td>
<td>0</td>
<td>8</td>
</tr>
<tr>
<td>1993</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>0</td>
<td>7</td>
</tr>
<tr>
<td>1994</td>
<td>7</td>
<td>0</td>
<td>6</td>
<td>0</td>
<td>13</td>
</tr>
<tr>
<td>1995</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>1996</td>
<td>2</td>
<td>6</td>
<td>12</td>
<td>0</td>
<td>20</td>
</tr>
<tr>
<td>1997</td>
<td>3</td>
<td>4</td>
<td>19</td>
<td>0</td>
<td>26</td>
</tr>
<tr>
<td>1998</td>
<td>2</td>
<td>2</td>
<td>10</td>
<td>7</td>
<td>21</td>
</tr>
<tr>
<td>1999</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>8</td>
<td>14</td>
</tr>
<tr>
<td>2000</td>
<td>1</td>
<td>0</td>
<td>6</td>
<td>1</td>
<td>8</td>
</tr>
<tr>
<td>2001</td>
<td>0</td>
<td>0</td>
<td>14</td>
<td>0</td>
<td>14</td>
</tr>
</tbody>
</table>

**By time period**

**Full period**

<table>
<thead>
<tr>
<th>Year</th>
<th>Mature</th>
<th>Submature</th>
<th>Immature</th>
<th>Frontier</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985 – 2001</td>
<td>43</td>
<td>29</td>
<td>118</td>
<td>30</td>
<td>220</td>
</tr>
<tr>
<td>% of total</td>
<td>19.5</td>
<td>13.2</td>
<td>53.6</td>
<td>13.6</td>
<td>100.0</td>
</tr>
</tbody>
</table>

**Subperiods**

<table>
<thead>
<tr>
<th>Year</th>
<th>Mature</th>
<th>Submature</th>
<th>Immature</th>
<th>Frontier</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985 – 1989</td>
<td>18</td>
<td>7</td>
<td>21</td>
<td>8</td>
<td>54</td>
</tr>
<tr>
<td>% of total</td>
<td>33.3</td>
<td>13.0</td>
<td>38.9</td>
<td>14.8</td>
<td>100.0</td>
</tr>
<tr>
<td>1990 – 1995</td>
<td>16</td>
<td>8</td>
<td>33</td>
<td>6</td>
<td>63</td>
</tr>
<tr>
<td>% of total</td>
<td>25.4</td>
<td>12.7</td>
<td>52.4</td>
<td>9.5</td>
<td>100.0</td>
</tr>
<tr>
<td>1996 – 2001</td>
<td>9</td>
<td>14</td>
<td>64</td>
<td>16</td>
<td>103</td>
</tr>
<tr>
<td>% of total</td>
<td>8.7</td>
<td>13.6</td>
<td>62.1</td>
<td>15.5</td>
<td>100.0</td>
</tr>
</tbody>
</table>

---

a Includes permits allocated under cash bidding and work program bidding systems. This information was collected as part of an ABARE research project on Australia’s work program bidding system (see Maritz, Harman and Roberts 2002).
Mature regions are regions where there is a greater than 50 per cent probability that more than 50 per cent of the total petroleum in the region has been discovered.

Submature regions are regions where there is a greater than 50 per cent probability that 20–50 per cent of the total petroleum in the region has been discovered.

Immature regions are regions where there is a greater than 50 per cent probability that less than 20 per cent of the total petroleum in the region has been discovered.

Frontier regions are regions where no petroleum has been discovered.

The increase in the number of new field wildcat wells drilled offshore in the second half of the 1990s coincides with both an increase in the aggregate number of exploration permits allocated by the Australian government and a major shift by petroleum explorers toward immature and frontier areas (table 4).

Notably, increased interest by petroleum explorers in the higher cost and higher risk immature and frontier areas occurred during a period in which profit rates in the industry increased (see figure A).

Global rankings of deepwater exploration wells

Recent information on international oil and gas exploration activity in deepwater areas has been published by Wood Mackenzie. Using this information, Bell (2002) provided an international ranking of seventeen countries based on the number of deepwater exploration wells drilled by mid-2001. Deepwater is defined to be a water depth greater than 400 metres.

The US Gulf of Mexico accounts for half of all deepwater exploration activity to date, with 524 deepwater exploration wells drilled (figure F). This area is followed by Brazil (10.2 per cent of global deepwater exploration wells drilled), Indonesia (7.4 per cent), the United Kingdom (7.2 per cent) and Angola (5.5 per cent). Australia ranks sixth with 47 deepwater exploration wells drilled representing 4.5 per cent of the total.
economic efficiency of resource taxation policy

A resource rent tax was first proposed by Garnaut and Clunies Ross (1975) in the context of natural resource projects in developing countries to enable more of the economic benefits of these projects to accrue to the domestic economy. The second oil shock in the late 1970s and the associated anticipated resources boom generated substantial interest in the application of a resource rent tax to petroleum and mining projects in developed countries. Several papers were published in the economics literature in the late 1970s and early 1980s that examined the efficiency implications of resource taxation policy.

In this chapter, a review of the literature relating to the economic efficiency of resource taxation policy is provided, drawing on this and subsequent economic research, particularly Hinchy, Fisher and Wallace (1989), and Hogan and Thorpe (1990). The main objective in this chapter is to examine the efficiency (or neutrality) of rent based resource taxes, including both the Brown tax and the resource rent tax.

Economic rent and basic resource taxes

Economic rent

The economic rent of a mineral resource is the value of production when all necessary costs have been deducted (Garnaut and Clunies Ross 1983). Specifically, in a competitive market, the economic rent from resource exploration, development and extraction is the excess of revenue over costs where costs are defined to include a ‘normal’ rate of return on capital — that is, the minimum rate of return required to hold capital in the activity, including a risk premium where investors are risk averse (Hinchy, Fisher and Wallace 1989).

Under standard competitive conditions, the presence of economic rent signals the opportunity to gain supernormal profits that would attract new entrants and encourage investment in increased productive capacity by established firms. This would place downward pressure on commodity prices and upward pressure on the cost of fixed assets until economic rents were eliminated.

However, economic rent in a mineral resource industry, also referred to as mineral or resource rent, may persist in the long run owing to the quality or scarcity value of different ore deposits or fossil fuel fields. The quality rent is associated with the quality differential of fields. The marginal cost of extraction tends to be lower for higher quality (more productive) fields. For a given price, higher quality fields earn a larger excess of revenue over costs than marginal
fields. The scarcity value of the resource reflects the opportunity cost of future production forgone when the resource is extracted in the current period. That is, if investors choose to extract the resource now, the value of doing so must be at least equal to the value of choosing to extract in some future period.

The concept of economic rent in mineral resources therefore applies over the longer term, taking into account the following distinct economic activities:

- **production**: the cost of extracting resources from established resource developments (mines or petroleum projects);
- **new resource developments**: the cost of producing ore or petroleum from new resource developments based on mineral ore deposits or fossil fuel fields that are known; and
- **exploration**: the cost of finding new mineral ore deposits or fossil fuel fields.

A simplified representation of industry supply and economic rent is provided in figure G where price is assumed to be determined on world markets at $P^*$. The curve $SS'$ is the industry supply or long run marginal cost curve — this curve represents the total cost of resource production, including capital and exploration costs. Industry output is given by $Q^*$ and economic rent is the area where price exceeds long run marginal cost, given by the area $SP^*E$.

**Assigning property rights**

In Australia, as in most other countries, the mineral resource is owned by the community and the government assigns property rights to private companies for exploration, development and production activities. Property rights may be transferred using nonmarket or market mechanisms. The two main nonmarket mechanisms are the first come, first served and work program bidding systems, and cash bonus bidding is an important market mechanism:
in the first come, first served system, property rights are assigned to the first firm that applies for those rights;

in the work program bidding system, property rights are assigned to the firm with the bid that is judged to be the most likely to achieve the fullest assessment of the potential of the area; and

in the cash bonus bidding system, property rights are assigned to the firm that offers the highest cash bid.

In principle, in the cash bonus bidding system and under competitive conditions, firms would be prepared to bid up to the assessed value of the economic rent of the resource in the lease area. Under a work program bidding system, firms compete for the exploration lease by increasing the exploration work program, which results in higher exploration costs than would otherwise occur. In this case, some part of economic rent is transferred to exploration costs and hence is potentially dissipated by excess exploration. An assessment of the extent to which such a transfer may occur in practice in Australia is beyond the scope of this study. However, some indicative information on the number and value of winning bids is available.

In Australia, seven exploration permits in highly prospective areas were assigned on the basis of a cash bonus bid between 1985 and 1992. In 1999 prices, the value of the winning cash bid ranged from A$1 million (1992) to A$20 million (1985), with an average of A$9 million.

All other offshore petroleum exploration permits within the jurisdiction of the Australian government have been allocated on the basis of a competitive work program bid (Department of Industry, Sciences and Resources 1999).

Between 1985 and 1999, a total of 431 areas were released under a work program bidding system, with 238 (55 per cent) areas receiving no bids, and 94 (22 per cent) and 99 (23 per cent) areas receiving single and multiple bids respectively (Maritz, Harman and Roberts 2002). That is, close to half of the exploration permits (winning bids) during this period were assigned to a sole bidder. The average value of winning primary work program bids (the first three years of the proposed work program that is guaranteed to be undertaken by the company), in 1999 prices, ranged from A$2 million (1992) to A$32 million (1995).

Influences on the value of work program bids in offshore petroleum exploration between 1985 and 1999 are examined in Maritz, Harman and Roberts (2002). The design of auctions for offshore petroleum lease allocation is discussed for example in Sunnevag (2000).

Basic resource taxes
The economic rent, or resource rent, represents the value of (or return to) the mineral resource. The key objective in resource taxation is to enable the government to obtain some payment in return for the extraction of the community’s resources. Ideally, a resource tax system should be designed to ensure that the government receives through this mechanism no more than the value of the economic rent while minimising distortions to private decisions.
Basic resource taxes in a simplified framework

Specific royalty

Ad valorem royalty

Brown tax - a rent based resource tax

Economic rent to government as resource tax payments
Economic rent to investors
Economic rent dissipated from resource tax (deadweight loss)
The impacts of three alternative resource taxation systems in a simplified economic framework of certainty are presented in figure H. Two basic output based resource taxes often applied in practice are the specific and *ad valorem* royalty. An ideal rent based resource tax, the Brown tax, is also indicated in figure H. The resource rent tax is an approximation of the Brown tax that, most importantly, avoids the cash payments from the government to the private sector.

A specific royalty is levied as a constant (dollar) amount on per physical unit of output. The imposition of a specific royalty therefore is equivalent to an increase in the industry’s marginal cost curve which, for a given world price, reduces industry output. In the top panel of figure H, output falls from \( Q^* \) to \( Q^{SP} \), and the economic rent is either paid to the government in the form of a resource tax payment (indicated by the area \( SAFG \)), remains with private investors (area \( AP^*F \)) or is dissipated (that is, the area \( EFG \) is lost as a consequence of the resource tax — this is also referred to as the deadweight loss of the tax).

An *ad valorem* royalty is levied as a constant percentage of the value of output. The imposition of an *ad valorem* royalty is equivalent to a reduction in the price received at any given level of output. In the middle panel of figure H, output falls from \( Q^* \) to \( Q^{ADV} \), and the economic rent is again either paid to the government in the form of a resource tax payment (indicated by the area \( BP^*HI \)), remains with private investors (area \( SBI \)) or is dissipated (deadweight loss of the tax is indicated by the area \( EHI \)).

The Brown tax is levied as a constant percentage of the project’s net cash flow with cash payments made to private investors in years of negative net cash flow. In this simplified framework, the Brown tax takes a constant percentage of the economic rent and does not distort industry output. In the bottom panel of figure H, output remains at \( Q^* \) and the economic rent accrues to either the government (area \( CP^*E \)) or investors (area \( SCE \)).

Of the resource taxation systems considered here, the specific royalty is the most distorting because the resource tax payments vary only with changes in output. Resource taxation payments under the *ad valorem* royalty vary with changes in price and output, but are invariant to changes in costs. By contrast, rent based resource taxation systems are designed to be responsive to broadly based changes in economic conditions in the industry, including changes in price, output and cost.

### Risk, attitudes toward risk and neutrality

**Profitability assessments of risky projects and attitudes toward risk**

A simplified decision tree for risky mineral or petroleum projects is presented in figure I. At each stage of the decision tree — exploration, development, extraction and abandonment — there are a range of geological, economic and policy risks. These risks tend to be reduced as the investor gains information and proceeds through each stage for any given project.

In the exploration stage, it is assumed that an investor ranks alternative sites in order of preference based on the investor’s assessment of the profitability of each project. The profitability of a project is assumed to be assessed on the basis of a probability distribution of net present
values of possible outcomes. The net present value is the discounted net cash flow over the expected duration of the project. In these assessments, net present value is assumed to be discounted at the risk free interest rate.

An investor’s attitude toward risk taking may be characterised as:

- **risk neutral**, whereby the investor is indifferent to the risks that an outcome may be either worse or better than expected;
- **risk averse**, whereby the investor is relatively more concerned about the risk of unexpected losses than the risk of unexpected gains; or
- **risk taking**, whereby the investor values the risk of unexpected gains more highly than the risk of unexpected losses.

Although it is possible for investors to be risk taking (or risk preferring), this is typically not regarded as a realistic representation of the behavior of companies in practice.

If investors are neutral about risk, the profitability assessment for a project is based on its expected net present value (that is, the probability weighted sum of net present values). The project is assessed to be:

- **profitable** if the expected net present value is positive (where the economic rent is given by the expected net present value);
- **marginal** if the expected net present value is zero (where capital is expected to earn only normal profits at the risk free interest rate); and
- **uneconomic** if the expected net present value is negative (where the capital would be expected to earn a higher rate of return in an alternative investment).

If investors are risk averse, the profitability assessment for a project is based on its certainty equivalent value (that is, the value at which the investor would be indifferent between the risky project and a project with a certain return). The certainty equivalent value \(\text{CEV}\) is equal to the expected net present value \(\text{ENPV}\) less a risk premium \(\text{RP}\):

\[
\text{CEV} = \text{ENPV} - \text{RP}
\]
The risk premium represents the compensation that risk averse firms require for incurring risk. For risk averse investors, the project is assessed to be:

- **profitable** if the certainty equivalent value is positive (where the economic rent is now given by the certainty equivalent value);
- **marginal** if the certainty equivalent value is zero (where capital is expected to earn normal profits including a risk premium); and
- **uneconomic** if the certainty equivalent value is negative (where the capital would be expected to earn a higher risk adjusted rate of return in an alternative investment).

In practice, investors use a range of criteria to assess the viability of projects, including the internal rate of return, payback period and the net present value based on a risk adjusted discount rate. However, the net present value approach based on a risk free interest rate is a useful economic framework that highlights the efficiency implications of rent based taxes particularly under conditions of risk aversion — some further discussion on the inclusion of a risk premium in this approach is provided in the discussion on risk averse investors under a Brown tax.

**Neutrality of resource taxation policy**

In the following discussion, it is useful to distinguish two concepts of neutrality:

- a tax is **weakly neutral** if it does not alter the rankings of alternative risky projects for an investor; and
- a tax is **strongly neutral** if it satisfies weak neutrality and does not change the decisions of investors relating to which projects will proceed and which do not (that is, it does not change the cutoff point between those projects that would be undertaken and those that would not).

Hinchy, Fisher and Wallace (1989) discuss the issue of whether these criteria need to be modified in the presence of risk when there are imperfect risk markets (including futures, insurance, capital and equities markets). When investors are risk averse, there may be a suboptimal level of investment in higher risk projects (that is, risk averse investors may discriminate against higher risk projects). The efficiency of resource allocation may therefore be improved by changing the preference rankings by investors.

Any bias in policy, if at all appropriate, would be toward encouraging firms to undertake more risky activities. Nevertheless, the neutrality criteria are important benchmarks against which to assess alternative resource taxes, and the direction of any distortion in preference rankings.

**Brown tax**

**Risk neutral investors**

The Brown tax, named after a tax proposed by Brown (1948), is levied as a fixed proportion of the project’s net cash flow for each year. Net cash flow is measured by revenue less
costs, including all exploration and capital expenditure. In years where net cash flow is negative, the government pays the investor the Brown tax rate multiplied by the losses. In years where net cash flow is positive, the government receives the same fixed proportion of the profits.

If the Brown tax is levied at the rate, $t_{BT}$ (for $0 < t_{BT} < 1$) and the before and after tax net present value is given by $NPV$ and $NPV^{BT}$ respectively, it is relatively straightforward to demonstrate that, for any risky option, the net present value to the investor after the Brown tax is imposed would be equal to a fixed proportion of the before tax net present value:

$$NPV^{BT} = (1 - t_{BT}) NPV$$

The mean or expected net present value ($ENPV$) is correspondingly a fixed proportion of the before tax expected net present value:

$$ENPV^{BT} = (1 - t_{BT}) ENPV$$

As a consequence, the preference ranking of projects is unaltered and projects do not switch between economic, marginal and uneconomic assessments. That is, for risk neutral investors, the Brown tax is both weakly and strongly neutral.

The impact of a Brown tax on the probability distribution of the net present value of a risky project is indicated in figure J. For simplicity, the probability distribution of the net present values before tax is assumed to be symmetric (that is, not skewed) around a positive, zero and negative mean or expected net present value in the three parts of figure J.

The Brown tax reduces a positive expected net present value (top panel, figure J), does not alter a zero expected net present value (middle panel) and reduces the absolute value of a negative expected net present value (bottom panel).

In practice, it is likely that the probability distribution of the net present values is positively skewed such that there is a relatively high probability that exploration will not result in an economic discovery but there is a very small probability of making a highly valuable discovery. The assumption of symmetry does not alter the key result of the efficiency or neutrality of a Brown tax for risk neutral investors.

It is readily apparent from figure J that the variance of the probability distribution of the net present values is reduced by the Brown tax [in particular, $\text{var}(NPV^{BT}) = (1 - t_{BT})^2 \text{var}(NPV)$ where $0 < (1 - t_{BT})^2 < 1$].

In principle, for the government to collect the total economic rent from the resource industry under conditions of risk neutrality, the Brown tax rate would need to be set at 100 per cent and levied only on projects with a nonnegative mean or expected net present value (to avoid otherwise unprofitable projects from being undertaken). Under a 100 per cent Brown tax rate, the variance of the probability distribution of net present values would be reduced to zero and investors would be indifferent between all projects — the government bears the risk of all losses.
Probability distribution of the net present value (NPV) of a risky project before and after a Brown tax

Positive expected net present value (ENPV)

Zero expected net present value (ENPV)

Positive expected net present value (ENPV)

Net present value is discounted at the risk free interest rate
The optimal Brown tax would therefore be levied at some rate less than 100 per cent. The tax rate would need to provide private investors with significant economic incentives to better distinguish between projects (based on before tax profitability differentials) and provide a more balanced degree of risk sharing between government and investors. Issues relating to the Brown tax are discussed further in Hinchy, Fisher and Wallace (1989).

Risk averse investors
The implications of risk aversion on the investor’s profitability assessment of a risky project is indicated in figure K. The probability distributions of two profitability measures — the net present value and the corresponding internal rate of return — are given in figure K. The internal rate of return is the discount rate that would result in a zero net present value, noting that the figure is indicative only since the internal rate of return may not be well defined in some circumstances (see, for example, Brealey and Myers 1991 for a discussion of these issues). However, this comparison is useful for the following discussion on fiscal settings in a resource rent tax.

The investor is assumed to assess the risks inherent in the project and identifies the required risk premium and certainty equivalent value of the project. The risk premium in present value terms (top panel, figure J) has a corresponding risk premium in the internal rate of return (bottom panel). The profitability of the project is based on the certainty equivalent value.

The expected internal rate of return ($E_{irr}$) is the probability weighted sum of the internal rates of return for a given risky project (assumed to be well defined), and has three components:

$$E_{irr} = i^f + i^p + i^{rent}$$

where $i^f$ is the risk free interest rate, $i^p$ is the risk premium in the rate of return and $i^{rent}$ is the rate of return associated with the economic rent or supernormal profits (certainty equivalent value) of the project. The normal rate of return on the project is equal to $i^f + i^p$ and the excess rate of return is given by $i^{rent}$.

In the economics literature, expected utility theory is a commonly used approach to estimate the certainty equivalent value of a risky project (applications of expected utility theory in the resource taxation literature include, for example, Emerson and Garnaut 1984; Campbell and Lindner 1987; Fraser 1998, 2000). According to expected utility theory, the investor assesses the utility of the risky options and prefers the project with the highest expected utility. The investor’s utility curve is assumed to be a function of wealth and is illustrated in figure L under various attitudes toward risk.

As Hinchy, Fisher and Wallace (1989) note, the mean–variance framework is also often used in practice. In this approach, projects are ranked on the basis of the mean and variance of the probability distributions. The variance is a measure of the risk of the project. A probability distribution is strictly preferred to an alternative if it has a larger mean and smaller variance. In other cases, the investor needs to trade off the mean and variance by using some other approach.
Probability distributions of profitability measures of a risky project with risk averse investors - certainty equivalent approach

**Net present value (NPV)**

- **Economic rent**
- **Risk premium**
- **NPV probability distribution**

<table>
<thead>
<tr>
<th>Probability</th>
<th>Risk premium</th>
<th>NPV probability distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>Certainty equivalent value</td>
<td>Expected NPV</td>
</tr>
</tbody>
</table>

**Internal rate of return (irr)**

- **Risk free interest rate**
- **Risk premium in irr**
- **irr probability distribution**

<table>
<thead>
<tr>
<th>Probability</th>
<th>Risk premium in irr</th>
<th>irr probability distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>Certainty equivalent irr</td>
<td>Expected irr</td>
</tr>
</tbody>
</table>

**Net present value**, **NPV**, is discounted at the risk free interest rate.

**The internal rate of return** is the constant discount rate that makes the corresponding **NPV** equal to zero. If the **NPV** is zero, the internal rate of return will equal the risk free interest rate assuming the risk free interest rate is constant over time. Note that in some circumstances the internal rate of return may not be well defined. See, for example, Brealey and Myers (1991) for a discussion of these issues.

The mean and variance refer to the first and second moments of the probability distribution. Other theories refer to the role of skewness (the third moment of the probability distribution) in ranking projects. Skewness provides a measure of the lack of symmetry or the extent to which a probability distribution is positively or negatively skewed. The third moment will be positive if the distribution is positively skewed (as is likely to be the case in mineral or petroleum exploration). Kurtosis, given by the fourth moment, provides a measure of the extent to which a distribution is peaked or flat — this moment is not often used in practice.
Hinchy, Fisher and Wallace (1989) demonstrate that the Brown tax is weakly neutral under conditions of risk with risk averse investors (see appendix D). That is, the Brown tax does not alter the before tax preference rankings of projects. Using expected utility theory, however, they argue that the Brown tax does not satisfy the strong neutrality criterion.

This result occurs because the Brown tax reduces the variance of the probability distribution of the net present values, which would result in the investor requiring a smaller risk premium on the project — it is feasible for an uneconomic project before tax to be converted to a profitable project after tax.

A numerical example to illustrate this point is provided by Hinchy, Fisher and Wallace (1989, p. 17). Hogan and Thorpe (1990) simulated a wide range of hypothetical risky oil and gas projects assumed to be broadly relevant to the Australian industry under several alternative resource taxation arrangements. They found a significant proportion of projects switched from uneconomic before tax to economic after the Brown tax. The interaction of the risk averse attitude of investors and the risk sharing characteristics of the Brown tax resulted in higher economic rents than under alternative resource taxation arrangements (or no resource tax) with increased returns to both investors and the government. However, it is difficult to assess the extent to which such switching would occur in practice given the problems in identifying both the risks in any given project and the extent to which investors are risk averse.

Hogan and Thorpe (1990) identified a modified Brown tax (MBT) that is equal to a fixed proportion of the project’s before tax certainty equivalent value:

(5)  \[ CEV^{MBT} = (1 - p^{MBT}) CEV \]

They argued that this may provide a more neutral form of resource tax than the original Brown tax (although, as indicated above, this may not be the optimal policy outcome). Under this tax, the risk premium is also reduced by a fixed proportion [that is, \( RP^{MBT} = (1 - p^{MBT}) RP \)].

A key issue is how this tax would be implemented in practice since the information requirements are substantial — the government does not have information on each investor’s utility function and degree of risk aversion, or on the probability distribution of net present values for each risky project. Nevertheless, the concept is potentially useful in assessing the fiscal settings in a resource rent tax system.
Leland (1978) argued that, for risk averse investors, the optimal tax schedule in a Brown tax is likely to be progressive.

**Resource rent tax**

The resource rent tax is usually regarded as a practical alternative to the Brown tax where the government avoids the need for cash rebates. Under a resource rent tax, all losses (including exploration and capital costs) are accumulated at a threshold rate and offset against future revenues. The resource rent tax is a profit based tax that begins to be paid only when this threshold internal rate of return on total cash flow has been realised (Garnaut and Clunies Ross 1975).

There are three key fiscal settings in the resource rent tax:

- the setting of the threshold rate;
- the setting of the tax rate; and
- the treatment of projects that make losses.

Full loss offset occurs when all relevant expenditures in exploration, development and extraction are offset against revenue for resource rent tax purposes. With full loss offset, the main objectives in setting the threshold and tax rates are often argued to be to target efficient investment outcomes and to collect a share of the economic rent, respectively. However, it will be apparent from the following discussion that there remain significant unresolved issues, particularly in the setting of the threshold rate.

**The threshold rate**

**Risk premium in the threshold rate**

The risk free interest rate is typically assumed to be the long term government bond rate. In principle, if the threshold rate for a given project is set at the investor’s discount rate (comprising the risk free interest rate plus an appropriate risk premium), the remaining net cash flow represents the economic rent of the project — that is, the expected net present value for risk neutral investors and the certainty equivalent value for risk averse investors.

Garnaut and Clunies Ross (1979, 1983) among others have argued that if the threshold rate is set above the investor’s discount rate, there may potentially be an incentive for overinvestment in the activity. Conversely, if the threshold rate is set below the investor’s discount rate, the tax has the potential to deter some projects that would otherwise have proceeded.

According to this argument, the role of this threshold internal rate of return is to allow the investor to achieve a normal rate of return on a project before the resource rent tax is triggered. However, as indicated previously, this threshold rate is dependent on the riskiness of the project and the investor’s attitude toward risk. The investor’s risk premium may also be reduced to the extent that part of the risks are diversifiable. This is most likely to be the case with larger resource companies.
There are also likely to be substantial asymmetries in information between the government and the investor. The information requirements for setting the threshold rate on a project basis are therefore excessive. Given this, there may be a case for setting a threshold rate that is common to investments within an industry (or broad categories within that industry if well defined).

**Threshold rate set at the risk free interest rate**

A fundamental insight into the setting of the threshold rate in a resource rent tax was provided by Fane and Smith (1986). They argue that the threshold rate should be set equal to the risk free interest rate (the long term government bond rate) since, with full loss offset, the accumulated expenditures represent a certain reduction in future petroleum resource rent tax liabilities.

Fane and Smith argue that the future value of the tax reduction, where expenditure is accumulated at the long term government bond rate, is the same as a reduction in the company holdings of long term government bonds. That is, an investor has the option of reducing current holdings of long term government bonds to finance expenditure, forgoing the annual interest rate that would otherwise have accrued, to be compensated when the reduction in tax liabilities is triggered.

Alternatively, if the company does not hold long term government bonds, the expenditure may be financed through the release of corporate debentures with interest rates typically only marginally higher than the long term government bond rate (see appendix A).

**The tax rate**

There are a number of issues relating to the setting of the tax rate in either the Brown tax or the corresponding resource rent tax. Some of these were identified in the discussion above on the Brown tax. Most importantly, the tax rate needs to be sufficiently below 100 per cent to ensure that it does not seriously weaken efficiency incentives in the private sector.

Given these economic incentive issues, Garnaut and Clunies Ross (1979) discuss the possibility of jointly setting threshold and tax rates to increase the government’s share of the economic rent while minimising distortions to investment. (It should be noted however that the analysis by Garnaut and Clunies Ross was based on a project based system whereby most importantly the costs associated with failed exploration projects are not taken into account in any assessment of petroleum resource rent tax liabilities.) One implication of this discussion is to consider the use of a progressive tax scale for various threshold rates.

More generally, a tradeoff between government revenue and the efficiency of the tax system would involve a lower threshold rate to compensate the government for the lower tax rate required to maintain economic efficiencies in management and investment.

If the threshold rate is set equal to the long term government bond rate, either the tax rate would need to be reduced or an alternative mechanism would need to be introduced into the system to allow for the risks of resource projects — these issues are discussed further in chapter 5.
Fane and Smith (1986) argue that the difficulties in making any actual tax proposal approximate the theoretical concept of a pure rent tax provide a justification for choosing a fairly low rate of rent tax.

**Full loss offset**

The original design of the resource rent tax that was to be applied progressively to Australia’s petroleum and mineral industries was project based that did not allow for payments to be made to projects with negative net cash flows. The impact of this tax on the original probability distribution of the net present values (presented in figure 1) is to skew it negatively. Lack of full loss offset discriminates against risky projects. This variant of the resource rent tax is not characterised by either weak or strong neutrality (Hinchy, Fisher and Wallace 1989).

Papers that discussed the impact of the introduction of such a tax in Australia — noting the inefficiencies caused by the asymmetric resource rent tax or lack of full loss offset — include Mayo (1979); Emerson and Lloyd (1983), Ball and Bowers (1984), Emerson and Garnaut (1984), Swan (1984) and Fane and Smith (1986).

The project based resource rent tax was applied to Australia’s offshore petroleum industry in the mid-1980s. As indicated in chapter 2, Australia’s tax system was modified in 1990 to allow for companywide deductibility of expenditures. The threshold rate, which had been set at a relatively high level to compensate private investors for the lack of full loss offset, was reduced.

The options commonly identified in the literature to achieve full loss offset (assuming companywide deductibility is allowed, as is presently the case) are:

- to the extent that most losses are expected to occur in the exploration stage rather than the development/extraction stages, to provide the investor with a cash rebate on losses associated with exploration as they occur (see, for example, Emerson and Garnaut 1984);
- to provide the investor with a cash rebate at the mine or field closure stage if the project makes a final loss (see, for example, Emerson and Lloyd 1983; Ball and Bowers 1984; Emerson and Garnaut 1984; Hinchy, Fisher and Wallace 1989);
- to allow the sale of losses on unsuccessful projects to other companies with resource rent tax obligations (see, for example, Ball and Bowers 1984; Fane and Smith 1986; Hinchy, Fisher and Wallace 1989).

A major distinction in these options is the timing of the cash rebate or transferability of losses — they may be allowed on an annual basis (as the losses are incurred) or on an accumulated basis (at the end of a failed project, most likely to be at the end of the exploration stage).

Significant moral hazard problems may exist with a system of cash rebates or trade in losses (Hinchy, Fisher and Wallace 1989). Moral hazard problems arise when the incentive to avoid losses on a given project diminishes or when the incentives for falsifying accounting and taxation returns increases. Reflecting these problems, the government may choose to limit
its liability for cash payouts (under a cash rebate) or the amount that would be allowed to
be traded on any given project (under a tradable loss system). Any losses that are traded
would also need to be deducted from the net cash flow of the buyer in the tax year of the
trade to eliminate speculative trading in losses.

Lack of full loss offset remains an issue in the current design of Australia’s petroleum resource
rent tax.
Fiscal settings in Australia’s petroleum resource rent tax

Australia’s petroleum resource rent tax is a competitive and efficient resource taxation system that has provided the community with a direct return on the extraction of the petroleum resource. As indicated by historical and prospective developments (chapter 3), the capacity of the petroleum resource rent tax to be responsive to changing geological and economic circumstances is substantial.

Importantly, the petroleum resource rent tax represents a major advance over alternative production based royalties. In this chapter, some implications of the discussion on the efficiency of resource taxation policy (chapter 4) for fiscal settings in Australia’s petroleum resource rent tax are provided.

Some general comments relating to key industry recommendations

APPEA’s key recommendations, described in chapter 2, in essence relate to identifying two specific risk categories in the petroleum resource rent tax — deepwater projects and gas projects — and to adjusting the threshold rate for exploration expenditure by new investors to the long term bond rate in the years that are currently accumulated at the inflation rate (as measured by the GDP deflator).

Within the context of the design of a resource rent tax based on sound economic principles, it is valid to raise each of these points, at least in general terms, for consideration in any assessment of Australia’s specific arrangements. Each of these recommendations relates to key areas in either the future direction of the industry or in the current design of the petroleum resource rent tax.

The approach taken in this study is to interpret these recommendations relatively broadly as signaling key areas of concern in the current petroleum resource rent tax system. Fiscal settings in Australia’s petroleum resource rent tax are discussed in the next section. However, it may be useful to first provide some general comments on the areas that APPEA has identified.

Exploration – water depth and basin maturity

As discussed in chapter 3, oil production in Australia is projected by ABARE to be relatively steady over the period to 2019-20. Given current economic demonstrated resources...
for oil, this outlook requires continued exploration in established areas and more importantly the discovery of a significant new oil province, which is most likely to be located in an offshore frontier basin.

Notably, in the second half of the 1990s, there was a large increase in the number of exploration permits allocated in immature and frontier areas (figure M). During this period, industry profitability increased and there was a substantial rise in the number of new field wildcat wells drilled offshore (see figures A and E, respectively).

APPEA has argued that water depth should be the determining factor for a separate risk category in the petroleum resource rent tax system. While water depth is an important influence on project costs and risks, other variables related to the maturity of the basin (such as geological risk and proximity to infrastructure) are also important. Changes in the technology options available to the industry in recent decades are indicated in table 2, suggesting that project costs vary over time and depend on the particular attributes of the field.

As a consequence, basin maturity rather than water depth may be a more appropriate risk category for consideration in the petroleum resource rent tax.

Oil and gas discoveries - number, type and timing

Gas production, as a share of Australia’s total petroleum production, has increased steadily over the past three decades from 12 per cent in 1970-71 to 50 per cent in 2001-02 and is projected by ABARE to reach around 69 per cent in 2019-20. Reflecting relatively stronger growth in LNG exports compared with domestic gas consumption, the export share of gas production is projected by ABARE to increase from around a third in 1998-99 to 44 per cent in 2019-20 (Dickson et al. 2001).

Geoscience Australia (2001) provides information on the timing of significant oil, gas (including condensate), and oil and gas discoveries in Australia’s offshore petroleum industry, the corresponding lease arrangements and, where appropriate, production commencement dates. Based on this information, the number of significant gas, oil, and oil and gas discoveries for the years 1965 to 2000 is provided in table 5. Notably, since 1997 there has been a strong rise in the number of significant discoveries. This follows the increase in the number of exploration permits allocated.

Geoscience Australia notes that the listing of a significant discovery is based on a company classification and not a finalised Geoscience Australia classification. It should also be noted that a small number of these discoveries comprise multiple fields (see notes to appendix L)
Overall, there were 254 significant petroleum discoveries during the period 1965–2000, of which 112 (or 44 per cent) were classified as gas discoveries, 65 (26 per cent) were oil discoveries and 77 (30 per cent) were oil and gas discoveries. Over half of all significant discoveries were made in the period 1991–2000.

The number of significant discoveries, by lease and production arrangements, is indicated in figure N. The timing and number of discoveries that have subsequently been developed and produced are indicated in the left column of figure N for gas, oil, and oil and gas discoveries. The timing and number of significant discoveries that are either under a production lease (but not producing), retention lease or no lease are indicated in the right column.

Between 1965 and 2000, there were significantly more gas discoveries than either oil or oil and gas discoveries, but a relatively small number of gas discoveries had commenced production within the period.

By 2000, production had commenced on 19 per cent of significant discoveries — 35 per cent of oil discoveries and 30 per cent of oil and gas discoveries, but only 2 per cent of gas discoveries (table 6). There are relatively fewer oil discoveries that are either not producing (under a production licence) or are under a retention lease than for other discoveries.

Descriptive statistics for the time lag between discovery and production commencement for producing fields, and between discovery and the year 2000 (the latest year relevant to the data set) for other fields is provided in table 5. The time lag between discovery and project development can be substantial. The maximum number of years between discovery and production commencement is 24 years based on histor-

<table>
<thead>
<tr>
<th>Year</th>
<th>Gas no.</th>
<th>Oil no.</th>
<th>Gas and oil no.</th>
<th>Total no.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1965</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>1966</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>1967</td>
<td>3</td>
<td>3</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>1968</td>
<td>0</td>
<td>1</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>1969</td>
<td>1</td>
<td>3</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>1970</td>
<td>4</td>
<td>0</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>1971</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>6</td>
</tr>
<tr>
<td>1972</td>
<td>3</td>
<td>3</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>1973</td>
<td>4</td>
<td>2</td>
<td>1</td>
<td>7</td>
</tr>
<tr>
<td>1974</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>5</td>
</tr>
<tr>
<td>1975</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>1976</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>1977</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>1978</td>
<td>2</td>
<td>0</td>
<td>2</td>
<td>4</td>
</tr>
<tr>
<td>1979</td>
<td>6</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>1980</td>
<td>6</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>1981</td>
<td>2</td>
<td>1</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>1982</td>
<td>2</td>
<td>1</td>
<td>4</td>
<td>7</td>
</tr>
<tr>
<td>1983</td>
<td>3</td>
<td>2</td>
<td>10</td>
<td>15</td>
</tr>
<tr>
<td>1984</td>
<td>2</td>
<td>4</td>
<td>2</td>
<td>8</td>
</tr>
<tr>
<td>1985</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>9</td>
</tr>
<tr>
<td>1986</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>7</td>
</tr>
<tr>
<td>1987</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>1988</td>
<td>2</td>
<td>0</td>
<td>6</td>
<td>8</td>
</tr>
<tr>
<td>1989</td>
<td>3</td>
<td>2</td>
<td>4</td>
<td>9</td>
</tr>
<tr>
<td>1990</td>
<td>6</td>
<td>3</td>
<td>2</td>
<td>11</td>
</tr>
<tr>
<td>1991</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>5</td>
</tr>
<tr>
<td>1992</td>
<td>5</td>
<td>0</td>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>1993</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>10</td>
</tr>
<tr>
<td>1994</td>
<td>2</td>
<td>3</td>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>1995</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>9</td>
</tr>
<tr>
<td>1996</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>9</td>
</tr>
<tr>
<td>1997</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>8</td>
</tr>
<tr>
<td>1998</td>
<td>6</td>
<td>4</td>
<td>1</td>
<td>11</td>
</tr>
<tr>
<td>1999</td>
<td>7</td>
<td>6</td>
<td>3</td>
<td>16</td>
</tr>
<tr>
<td>2000</td>
<td>17</td>
<td>5</td>
<td>4</td>
<td>26</td>
</tr>
<tr>
<td>Total</td>
<td>112</td>
<td>65</td>
<td>77</td>
<td>254</td>
</tr>
</tbody>
</table>

*a* Condensate discoveries are listed under gas discoveries.

Significant discoveries in Australia's offshore petroleum industry, by leasing arrangements

<table>
<thead>
<tr>
<th>Gas - production</th>
<th>Gas - other</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>16</td>
</tr>
<tr>
<td>0.8</td>
<td>12</td>
</tr>
<tr>
<td>0.6</td>
<td>8</td>
</tr>
<tr>
<td>0.4</td>
<td>4</td>
</tr>
<tr>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td>no.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oil - production</th>
<th>Oil - other</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>no.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oil and gas - production</th>
<th>Oil and gas - other</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>no.</td>
<td></td>
</tr>
</tbody>
</table>

* Condensate discoveries are listed under gas discoveries.
### Significant discoveries in Australia’s offshore petroleum industry: duration from discovery to production commencement date or the year 2000

<table>
<thead>
<tr>
<th></th>
<th>Production leak: production commenced</th>
<th>Production lease: not producing</th>
<th>Other discoveries c</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Retention lease</td>
<td>No lease</td>
<td>Total other</td>
</tr>
<tr>
<td><strong>Gas</strong> (112 significant discoveries)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of discoveries</td>
<td>no.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0–10 years</td>
<td>2</td>
<td>12</td>
<td>16</td>
</tr>
<tr>
<td>11–20 years</td>
<td>0</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>over 20 years</td>
<td>0</td>
<td>2</td>
<td>8</td>
</tr>
<tr>
<td>Minimum</td>
<td>yrs</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>Maximum</td>
<td>yrs</td>
<td>3</td>
<td>33</td>
</tr>
<tr>
<td>Average</td>
<td>yrs</td>
<td>3</td>
<td>19</td>
</tr>
</tbody>
</table>

| **Oil** (65 significant discoveries) |                       |                      |                   |
| Number of discoveries   | no.               |                      |                   |
| 0–10 years              | 18                 | 6                   | 0                 |
| 11–20 years             | 1                  | 3                   | 2                 |
| over 20 years           | 4                  | 0                   | 1                 |
| Minimum                 | yrs                | 1                    | 11                |
| Maximum                 | yrs                | 24                   | 27                |
| Average                 | yrs                | 8                    | 18                |

| **Oil and gas** (77 significant discoveries) |                       |                      |                   |
| Number of discoveries   | no.               |                      |                   |
| 0–10 years              | 16                 | 10                  | 9                 |
| 11–20 years             | 4                  | 4                   | 4                 |
| over 20 years           | 1                  | 4                   | 1                 |
| Minimum                 | yrs                | 1                    | 0                 |
| Maximum                 | yrs                | 24                   | 31                |
| Average                 | yrs                | 8                    | 16                |

| **Total** (254 significant discoveries) |                       |                      |                   |
| Number of discoveries   | no.               |                      |                   |
| 0–10 years              | 36                 | 16                  | 7                 |
| 11–20 years             | 7                  | 16                  | 14                |
| over 20 years           | 5                  | 6                   | 12                |
| Minimum                 | yrs                | 1                    | 0                 |
| Maximum                 | yrs                | 24                   | 33                |
| Average                 | yrs                | 8                    | 12                |

- Condensate discoveries are listed under gas discoveries.
- Information relates to the number of years from discovery to production commencement date.
- Information relates to the number of years from discovery to the year 2000, the latest year in the data set.

ical experience. The maximum number of years that discoveries have been under a retention lease, which signals a significant probability of future development, is 33 years. Given these time lags, the treatment of exploration expenditure in Australia’s petroleum resource rent tax is an important issue, particularly for new investors.

It should be emphasised that the petroleum resource rent tax has been in place during a period in which there have been major changes within the industry and the prospect of further substantial change. Any consideration of gas projects as a separate risk category needs to take into account a range of issues.

Any separate risk category defined in Australia’s petroleum resource rent tax should be based on well defined projects within the industry that have markedly higher risks. Gas projects are often not well defined — nearly all offshore gas fields in Australia (all except three) have some oil associated with them (personal communication with Geoscience Australia). Snapper is an example of a gas project that subsequently became an oil producer.

A critical issue is that the smaller number of gas discoveries that have been developed to date may reflect the lower profitability of this type of discovery, and lack of markets, rather than any inherent additional riskiness. Indonesia is one of Australia’s major competitors in the Asia Pacific region. AUPEC (1998) found that Australia is competitive with Indonesia for gas, even allowing for higher gas prices in Indonesia. The government tax take tends to be considerably higher in Indonesia than in Australia.

Various strategies exist in the industry to reduce or diversify risk. LNG projects, for example, only commence when a long term contract is negotiated and signed with a buyer to reduce the risks for both buyers and sellers. The extent to which large resource companies are able to diversify the risks in any investment project is an important factor. In addition, joint ventures enable companies, particularly smaller companies, to spread risk by holding a diversified portfolio of projects — between 1985 and 1999, joint ventures accounted for 75 per cent of all work program bids placed and 65 per cent of all exploration permits awarded (Maritz, Harman and Roberts 2002).

**Fiscal settings in Australia’s petroleum resource rent tax**

The objective in this study is to examine the fiscal settings in Australia’s petroleum resource rent taxation arrangements taking into account historical and prospective industry developments. Given historical and prospective trends, as outlined in chapter 3, it is certainly possible to argue that the current arrangements have performed well over several years and hence the fiscal settings should not be altered. The industry arguments for identifying risk categories relating to deepwater activity and gas projects appear to be limited since the industry is already significantly engaging in frontier and deepwater exploration activities, and domestic and international gas markets are expected to develop significantly further over time.

However, an economic assessment of fiscal settings should also attempt to examine the scope for efficiency gains while also allowing the community to receive a reasonable return from the extraction of Australia’s offshore oil and gas resources under the jurisdiction of the system.
Based on the theoretical analysis in chapter 4, it is argued in this study that there is likely to be significant scope for efficiency gains through reform of the system. It is on this basis that two options are suggested in the current paper. The first option — referred to as the preferred option — has the merit of simplicity and is consistent with a partnership approach between industry and government (with government as a silent partner). The second option — referred to as the alternative option — is more administratively complex but raises the possibility of identifying key risk categories in the industry.

**Economic argument for a petroleum resource rent tax**

Before identifying key issues or distortions in the current fiscal settings and discussing the two options, it is useful to first summarise the fundamental economic argument for a petroleum resource rent tax. It is the existence of resource rents that justify royalty payments. Resource rents are the return to the oil and gas resource. Resource rents exist owing to quality differences in fields and the scarcity value of the resource.

In practical terms, however, it is difficult to measure resource rents in isolation from returns to other factors of production, particularly capital. Resource rent is typically assumed to be the economic rent from upstream oil and gas activity, defined to be the excess of revenue over the costs associated with resource exploration, development and extraction (including any rehabilitation requirements).

Costs include the minimum rate of return required to attract capital to the activity (including a risk premium for risk averse investors). It is also important to include costs that may not contribute to current production but are necessary for supply in the long run.

The concept of economic rent in oil and gas resources therefore applies over the longer term, including the following distinct economic activities:

- **production**: the cost of extracting oil and gas from established oil and gas resource projects;
- **new oil and gas resource developments**: the cost of producing oil and gas from new resource developments based on known petroleum fields; and
- **exploration**: the cost of finding new petroleum fields.

The key objective in the petroleum resource rent tax is to enable the government to obtain some payment in return for the extraction of the community’s resources, with smaller negative impacts on private sector exploration, development and production decisions compared with alternative volume based arrangements (such as the excise).

Ideally, the petroleum resource rent tax should be designed to ensure that the government receives through this mechanism no more than the value of the economic rent from the upstream oil and gas industry while minimising (negative) distortions to private decisions. In practice, given the difficulties inherent in measuring economic rent (the minimum return to capital) and taking into account the impacts of the tax on economic incentives, the government would aim to take some share of the industry’s economic rent.
Key issues in the current fiscal settings

There are three key elements in the current design of the petroleum resource rent tax system:

- **the threshold rate** — in the current system, the threshold rate represents the extent to which investors obtain a return to capital in excess of the risk free rate (long term government bond rate) before the tax applies;

- **the tax rate** — at 40 per cent, the current system recognises, first, the negative impacts that high tax rates have on economic incentives and, second, the possibility that some projects will not achieve their minimum rate of return before the petroleum resource rent tax is triggered; and

- **the treatment of projects that make losses** — in the current system, there is still some scope that not all relevant expenditures in exploration, development and extraction are offset against revenue for resource rent tax purposes.

The key issues associated with current fiscal settings in the petroleum resource rent tax are associated with:

- lack of full loss offset;

- the two settings of the threshold rate for exploration expenditures incurred by new investors that vary only according to the timing of those expenditures (the five year rule);

- the timing of the deductibility of accumulated exploration and general project expenditures for new investors; and

- the inclusion of a risk premium in the threshold rate for any expenditure category.

Each of these issues is discussed below.

**Lack of full loss offset**

Full loss offset occurs when all relevant expenditures in exploration, development and extraction are offset against revenue for petroleum resource rent tax purposes. The transferability of exploration expenditures between projects within the same company reduces the extent to which lack of full loss offset is an issue under the current system, but does not eliminate it.

In the current system, lack of full loss offset is an issue for:

- new investors if exploration is not followed by a successful project; and

- old investors in the case of a failed development project where such expenditures are not transferable to successful projects.

In this study, it is assumed that the Commonwealth government chooses not to adopt a system of either cash rebates or transferable tax credits. Issues associated with each of these systems were discussed in chapter 4. Hence, even under the two options presented below, it is assumed the petroleum resource rent tax will not achieve full loss offset.
The key implication of lack of full loss offset — that is, the potential for unutilised accumulated expenditures in any given exploration or development project — is that it may influence the assessed riskiness of petroleum projects and hence increase the risk premium associated with projects, particularly marginal projects.

**Threshold rates for exploration expenditures incurred by new investors**

As previously noted, two threshold rates apply to exploration expenditures by new investors where the relevant threshold rate is determined on the basis of the timing of the expenditure:

- Undeducted exploration expenditures are accumulated at the long term bond rate plus 15 percentage points if the expenditures are incurred within five years of the date of the lodgment of data required for the granting of the production licence; and
- Undeducted exploration expenditures are accumulated at the GDP inflation factor if the expenditures are incurred more than five years before the lodgment date of data for the production licence.

These arrangements appear to be the outcome of a compromise between limiting payouts for exploration expenditure that may be accumulated for a considerable period of time (although maintained in real terms) and compensating investors by providing a large premium in the threshold rate for more recent exploration expenditures (relative to the granting of a production licence).

One of the key problems is that the expenditure accumulated at the inflation rate (as measured by the GDP deflator) is most likely to be associated with higher risk exploration activity such as wildcat drilling. By contrast, exploration expenditure incurred within five years of the trigger date for the production licence is more likely to be associated with less risky (but still relatively high risk) appraisal drilling.

Taken in isolation, each threshold rate results in economic incentives that influences the investor’s assessment of the risk adjusted profitability of an exploration project.

- Exploration expenditure accumulated at the GDP deflator does not provide the investor with even the risk free rate of return (assuming positive real interest rates). If a new investor expects that exploration expenditure will be in this category (outside the five year period), there will be an underinvestment in such exploration projects. Once the exploration expenditure is incurred, the investor would prefer to obtain the deduction as soon as possible (all else constant).

- Exploration expenditure accumulated at the long term bond rate plus 15 percentage points provides the investor with a rate of return substantially above the risk free rate of return. If the investor expects the exploration expenditure will be in this category (within the five year period), there will be an overinvestment in such exploration projects. Once the exploration expenditure is incurred, there is an incentive for the investor to delay the timing of the deduction to maximise the benefits from such a high rate of return (all else constant).
The current fiscal settings increase the uncertainties of new investors in assessing the profitability of an exploration project. Risk averse investors demand a higher risk premium to compensate for higher risks, reducing the likelihood that a given exploration project will be undertaken.

An assessment of the extent to which these arrangements alter the ranking and economic viability of projects is beyond the scope of this study. As part of any such assessment, it would also be informative to examine the historical choices of new investors under these arrangements.

**Timing of the deductibility of accumulated exploration and general project expenditures for new investors**

When new investors move from the exploration phase (through successful exploration activity) into the development and production phase of a petroleum project, exploration expenditures continue to be accumulated and are deducted only after all accumulated general project expenditures have been deducted. The order of the deductibility of these expenditure categories has implications for project profitability and petroleum resource rent tax payments because of differences in threshold rates.

General project expenditures are accumulated at the long term bond rate plus 5 percentage points, while a significant part of exploration expenditure (including appraisal drilling) by new investors is accumulated at the long term bond rate plus 15 percentage points. The extent to which new investors accumulate older exploration expenditures at the GDP deflator depends on the success of past exploration projects — that is, the time period during which new investors commenced exploration and made an economic discovery that progressed within the five year period to the application of a production licence.

Reversing the order of the deductions — with exploration expenditures deducted before general project expenditures — would reduce, but not eliminate, the incentives for new investors to overinvest in appraisal exploration and reduce future petroleum resource rent tax payments. In each of the options presented below, these inconsistencies in the setting of the threshold rate for different expenditure categories are eliminated, making the order of the deductions over time irrelevant.

**Inclusion of a risk premium in the threshold rate**

The risk premium in the current system is given by the excess of the threshold rate over the long term government bond rate. There are two issues that merit some discussion:

- first, the rationale for the range of risk premiums in the current system; and
- second, the economic argument for setting all threshold rates at the risk free interest rate or the long term government bond rate.

In broad terms, there is some uncertainty about the rationale for the various risk premiums in the current system. It may be argued that the premium in each threshold rate represents:

- compensation for lack of full loss offset;
- allowance for a risk premium in the investor’s risk adjusted discount rate; or
some combination of these reasons.

The premium of 15 percentage points in the threshold rate for exploration expenditure incurred within the relevant five year period by new investors may represent, to some extent, compensation for lack of full loss offset since these investors only receive the loss offset when petroleum resource rent tax liabilities are incurred through successful offshore petroleum development projects. This premium also represents some compensation for the low threshold rate for exploration expenditures incurred outside the five year period.

Similarly, the premium of 5 percentage points in the threshold rate for general project expenditures may represent, to some extent, lack of full loss offset since these investors do not receive a loss offset in the event of a failed development project (or a development project with unutilised petroleum resource rent tax credits) — only exploration expenditures are deductible on a companywide basis.

It may be argued that in the current system without full loss offset, compensating investors in failed exploration projects (new investors) and failed development projects (old investors) through additional (and somewhat arbitrary) payments to investors in successful exploration and development projects is a poorly targeted outcome. As indicated previously, achieving full loss offset by providing those investors with either a cash rebate or the capacity to sell those losses to companies with petroleum resource rent tax liabilities would more closely target the value of those losses to both the specific investor and the industry in aggregate.

The premium in each threshold rate may also represent to some extent a risk premium, reflecting the concept that the government is more closely targeting the resource rent (or certainty equivalent value) in offshore petroleum production. An important issue with this interpretation is that exploration expenditure by old investors is an immediate 100 per cent tax deduction and does not receive any risk premium under current arrangements.

The long term government bond rate and current threshold rates — premiums of 5 and 15 percentage points — are given in figure O for the period 1989-90 to 2001-02. A premium of 5 percentage points, relative to the long term government bond rate, is significant in both nominal and real terms.

A further issue that has been reported by industry representatives is that the different taxation positions of member companies in a joint venture may result in conflicting goals in some investment and production decisions. It may be argued that forming joint ventures is one way of overcoming the lack of full loss offset. By increasing the number of joint ventures an investor is involved in, the probability is increased of achieving at least one successful project to offset losses on unsuccessful exploration projects. To the extent that the different taxation positions of investors is an impediment to forming joint ventures, it is also an impediment to the efficient spreading of risks. If the government sets risk premiums in the fiscal settings for different projects without sufficient information, it may reduce the efficiency of joint ventures as a market mechanism for spreading risks.

Regardless of the underlying rationale for the premium in each threshold rate, there is a strong argument to set the threshold rate equal to the long term government bond rate.
Fane and Smith (1986) argue that the value of any tax deduction over time is equivalent to a reduction in the company’s holdings of government bonds. If the company does not hold sufficient government bonds, Fane and Smith (1986) argue that the company may finance the expenditure through debt financing — the spread of corporate bonds over government bonds of a similar maturity since July 1997 (the earliest date available from the Reserve Bank of Australia) was less than 1.0 percentage point in nominal terms for each credit rating (see appendix A).

The accumulated expenditure represents a reduction in future petroleum resource rent tax liabilities. It may be argued that the appropriate discount rate for a certain government payout (or reduced tax liability) is the long term government bond rate (although there will continue to be risks relating to the extent to which these reduced tax liabilities are fully utilised for any given project).

Assuming that the investor’s discount rate is equal to the risk free interest rate is consistent with a certainty equivalent approach to investment decisions (as opposed to a risk adjusted discount rate approach). A risk premium (if allowance is made for a risk premium) may be included in the size of the initial tax deduction — that is, allowing a tax deduction in excess of 100 per cent, referred to as an accelerated rate of deduction.

A threshold rate that exceeds the long term government bond rate (particularly if it exceeds the cost of debt financing) results in economic incentives to overinvest in the corresponding activity. For example, the premium of 5 percentage points for general project expenditures provides investors with an economic incentive to overinvest in infrastructure for a given level of output to take advantage of an annual rate of return significantly in excess of the long term bond rate.

Options for fiscal settings in Australia’s petroleum resource rent tax
In each of the options presented below, the key change to the fiscal settings in Australia’s petroleum resource rent tax is to set the threshold rate equal to the long term government
bond rate (the risk free interest rate) for all expenditure categories (table 7). Potential changes in other fiscal settings follow from the assumption made about the extent to which investors receive a rate of return to their expenditures in excess of the risk free interest rate before the petroleum resource rent tax is triggered:

- the preferred option — investors receive a 100 per cent tax deduction, with expenditures accumulated at the long term government bond rate, as appropriate, before the petroleum resource rent tax is triggered but at a lower tax rate; and

- the alternative option — investors receive a risk premium through an accelerated rate of deduction, with expenditures accumulated at the long term government bond rate, as appropriate, before the petroleum resource rent tax is triggered at its current rate.

These options are discussed below.

**Preferred option**

The preferred option aims to approximate a Brown tax (see chapter 4) where in general no allowance is made for any risk premium to accrue to the investor before the resource rent tax is triggered. The Brown tax is levied as a constant percentage of the project’s net cash flow, with cash payments made to private investors in years of negative net cash flow (most importantly during the development phase of a petroleum project). Under a Brown tax, the government essentially acts as a silent partner to the private investor.

Resource rent taxes avoid the need for cash payments to private investors. Under the preferred option, the tax deduction is accumulated at the long term government bond rate and offset against future project revenue. Intertemporal transfers of tax credits at the long term government bond rate reflects the assumption that the tax credit represents a certain reduction in future petroleum resource rent tax liabilities (if sufficient revenue is earned from the project).

It is assumed that the Commonwealth government chooses not to adopt a system of either cash rebates or transferable tax credits for unutilised tax credits at the end of a project life. The potential lack of full loss offset therefore remains an issue in the system and justifies a lower tax rate than would otherwise be the case in an attempt to target a given share of the industry’s economic rent.

The key features of the preferred option, given in table 7, are:

- all exploration and general project expenditures are accumulated at the long term government bond rate;

- all exploration and general project expenditures receive a 100 per cent tax deduction; and

- the tax rate is reduced from its current level of 40 per cent to a level that ensures the government does not increase its share of the industry’s economic rent (assuming revenue neutrality, or the current share, is an appropriate and approximate benchmark).

Under the preferred option, the threshold rates for exploration expenditure by new investors (GDP deflator and the long term government bond rate plus 15 percentage points for expenditure incurred within and outside the five year rule period, respectively) and the threshold
rate for general project expenditure (long term government bond rate plus 5 percentage points) are all replaced by the long term government bond rate.

Compared with the current system, the petroleum resource rent tax under the preferred option is triggered earlier for any given petroleum project — that is, when the investor obtains the risk free rate of return as measured by the long term government bond rate. Under the preferred option, the additional returns to the project, comprising the risk premium and resource rent components, are shared between the investor and the government. The tax rate is reduced to a level that ensures reasonable returns for both the investor and government.

The main advantages of the preferred option are:

- it eliminates the negative economic impacts of threshold rates that differ from the long term government bond rate (discussed in the previous section);
- it is administratively simple, reducing three expenditure categories in the current system to a single expenditure category;
- it avoids the need to estimate the risk premium (or risk premiums if different risk categories are identified), particularly given geological and economic environments that change over time;
- given a reduction in the tax rate, it reduces the negative impact of the petroleum resource rent tax rate on economic incentives; and

7 Fiscal settings under alternative options

<table>
<thead>
<tr>
<th>Notation</th>
<th>Tax rate</th>
<th>Threshold rate</th>
<th>Accelerated rate of deduction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Exploration expenditure</td>
<td>General project expenditure</td>
<td>Exploration expenditure</td>
</tr>
<tr>
<td></td>
<td>$i_{PRT}$</td>
<td>$i_{exp}$</td>
<td>$i_{gen}$</td>
</tr>
<tr>
<td>Unit</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td><strong>Current system</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>40</td>
<td>0</td>
<td>LTBR+5</td>
</tr>
<tr>
<td>New investors</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Threshold rate for exploration expenditure incurred:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>– within 5 year period</td>
<td>LTBR+15</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>– outside 5 year period</td>
<td>GDP deflator</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Other fiscal settings</td>
<td>40</td>
<td>–</td>
<td>LTBR+5</td>
</tr>
<tr>
<td><strong>Preferred option</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>&lt;40</td>
<td>0</td>
<td>LTBR</td>
</tr>
<tr>
<td>New investors</td>
<td>&lt;40</td>
<td>LTBR</td>
<td>LTBR</td>
</tr>
<tr>
<td><strong>Alternative option</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old investors</td>
<td>40</td>
<td>0</td>
<td>LTBR</td>
</tr>
<tr>
<td>New investors</td>
<td>40</td>
<td>LTBR</td>
<td>LTBR</td>
</tr>
</tbody>
</table>

$^a$ For ease of presentation, all fiscal settings are presented in percentage terms. However, it should be noted that the notation refers to a number whereby, for example, a tax rate of 40 per cent in the table is 0.40 in the equations in boxes 2 and 3. LTBR refers to the long term government bond rate.
it eliminates different petroleum resource rent tax positions that may be an impediment to the formation of joint ventures (and hence risk spreading in the industry) and efficient decision making within a joint venture (noting that this ignores the ongoing influence of current arrangements following any reform).

The main disadvantages of this approach are:

- investors obtain the risk free rate of return to expenditures before the petroleum resource rent tax is triggered, increasing uncertainty about the minimum rate of return that will be achieved on any given project.

An algebraic representation of the accumulated tax deduction under the preferred approach is presented in box 2.

**Alternative option**

The aim in the alternative option is to approximate the theoretical concept of a modified Brown tax (see chapter 4) where some allowance is made for a risk premium to accrue to the investor before the resource rent tax is triggered.

In principle, the modified Brown tax is levied as a constant percentage of the project’s certainty equivalent value (or, ex post, the net cash flow after some allowance is made for a risk premium). That is, the risk premium is treated by government as a fixed assessable cost in a petroleum project which may be offset against net revenues.

Under the modified Brown tax, the government attempts to more accurately identify the industry’s resource rent and thereby would apply a higher tax rate (to achieve revenue neutrality between the Brown and modified Brown tax approaches). However, as previously discussed, the extent to which the tax rate may be increased is limited owing to the negative economic incentives created by a high tax rate.

A further key difficulty with the modified Brown tax is to estimate the risk premium for any given project (if projects are distinguished), for groups of projects (based on distinct risk categories within the industry) or even for the industry in aggregate. In particular, for an industry where there is substantial scope to diversify risk, attempting to estimate a risk premium on a project by project basis would be administratively complex and the accuracy of such an approach is highly likely to be spurious.

There would be substantial moral hazard issues under a modified Brown tax and, as a consequence, such an approach would not be implemented. However, the underlying concepts are useful in assessing the implications for the design of a resource rent tax. Consideration of this type of arrangement is particularly important given that the current fiscal settings in Australia’s petroleum resource rent tax incorporate risk premiums to some extent in the threshold rate.

In the alternative option, a risk premium (if allowance is made for a risk premium in all risk categories) may be included in the size of the initial tax deduction — that is, allowing a tax deduction in excess of 100 per cent, referred to as an accelerated rate of deduction.
Box 2: An algebraic representation of fiscal settings under the preferred option

In this box, an algebraic representation of fiscal settings under the preferred option for Australia’s petroleum resource rent tax is provided using a simple example. The accumulated value of the tax deduction of a single initial cost is presented under the assumptions of a constant threshold rate and a time varying threshold rate, respectively.

Accumulated value of a tax deduction: constant threshold rate

Assume, for simplicity, a given initial cost in year 0 is accumulated at a constant threshold rate. The value of the tax deduction in year \( s \) in simple algebraic terms is:

\[
V_s = \frac{tPRRT}{i} (1 + i)^s C_0
\]

where \( C_0 \) is the value of expenditure in year 0, \( V_s \) is the value of the tax deduction based on accumulated expenditure in year \( s \), \( tPRRT \) is the tax rate under the petroleum resource rent tax \( (0 < tPRRT < 1) \) and \( i \) is the threshold rate (assumed to be constant and where, for example, a threshold rate of 5 per cent is given as \( i = 0.05 \)).

That is, the accumulated value of the tax deduction in year \( s \) is the petroleum resource rent tax rate multiplied by the initial expenditure accumulated each year at the threshold rate.

Accumulated value of a tax deduction: time varying threshold rate

The relationship becomes slightly more complex when the threshold rate at which the initial expenditure is accumulated varies each year. The value of the tax deduction in year \( s \) is now given by:

\[
V_s = \frac{tPRRT}{i} \prod_{t=1}^{s} (1 + i_t) C_0
\]

where \( i_t \) is the threshold rate in year \( t \) \((t = 1, 2, ..., s)\) and \( \prod_{t=1}^{s} \) is the multiplication symbol for the period \( t = 1, 2, ..., s \) [for example, for \( s = 2 \), \( \prod_{t=1}^{2} (1 + i_t) = (1 + i_1)(1 + i_2) \)].

Fiscal settings under the preferred option

In general terms, the fiscal settings under the preferred option are:

\[
(8a) \quad tPRRT < 0.40
\]

\[
(8b) \quad i_t = i_{RF} = LTBR_t
\]

where \( i_{RF} \) is the risk free interest rate in year \( t \) \((t = 0, 1, ..., s)\), which is measured by \( LTBR_t \), the long term government bond rate in year \( t \) \((t = 0, 1, ..., s)\). That is, in the preferred option, all threshold rates are equal to the risk free interest rate as measured by the long term government bond rate. To compensate investors for the lack of a risk premium, the tax rate is reduced from the current 40 per cent to a level that ensures reasonable returns for both the investor and the government (with the latter representing the return to the community from the extraction of the resource).

The threshold rate for all exploration and general project expenditures is set equal to the long term government bond rate, consistent with the assumption that the tax credit represents a certain reduction in future petroleum resource rent tax liabilities (if sufficient revenue is earned from the project). That is, all tax deductions are accumulated at the long term government bond rate and offset against future project revenue. As under the preferred option, the potential lack of full loss offset remains an issue under the alternative option and in this case justifies a higher risk premium than would otherwise be the case.
Assuming the investor’s discount rate is equal to the risk free interest rate is also consistent with a certainty equivalent approach to investment decisions (as opposed to a risk adjusted discount rate approach).

The key features of the preferred option, given in table 7, are:

- all exploration and general project expenditures are accumulated at the long term government bond rate;
- all exploration and general project expenditures receive an accelerated rate of deduction (a tax deduction in excess of 100 per cent) at a level that ensures that the government does not increase its share of the industry’s economic rent (assuming revenue neutrality, or the current share, is an appropriate and approximate benchmark); and
- the tax rate is maintained at its current level of 40 per cent.

Under the alternative option, therefore, the two threshold rates for exploration expenditure by new investors and the threshold rate for general project expenditure are all replaced by the long term government bond rate. The tax rate is maintained at its current level. However, a risk premium is incorporated into the system through a single accelerated rate of deduction for all expenditure categories at a level that ensures reasonable returns for both the investor and government.

The main advantages of the alternative option are:

- it eliminates the negative economic impacts of threshold rates that differ from the long term government bond rate (discussed in the previous section);
- it is administratively simple compared with current arrangements if the industry is treated as a single risk category since the three expenditure categories in the current system are reduced to a single expenditure category in the alternative option; and
- it allows investors to obtain a risk premium in the return to expenditures before the petroleum resource rent tax is triggered, reducing uncertainty about the minimum rate of return that will be achieved on any given project.

The main disadvantages of this approach are:

- uncertainties about the appropriate size of any risk premium included as an accelerated rate of deduction, particularly given geological and economic environments that change over time; and
- compared with the preferred approach, the negative impact of a higher petroleum resource rent tax rate on economic incentives (although identical to the current tax rate).

The benefits of administrative simplicity under this system would be dissipated to some extent if multiple risk categories are identified and a different accelerated rate of deduction applies to each category. As indicated in the first section of this chapter, while industry has argued for separate risk categories for deepwater projects and gas projects, the strongest argument is for inclusion of a separate risk category for higher risk petroleum exploration that may be defined to include:
expenditure associated with wildcat drilling in frontier areas (or immature and frontier areas) where such areas are as defined by Geoscience Australia; or

more precisely, expenditure associated with drilling in a location that is no closer than 100 kilometres from a discovery well.

The second criterion for identifying a risk category is based on the criterion used in the Commonwealth government’s petroleum search subsidy scheme that operated in Australia between 1957 and 1974 (Powell, Wright and Nicholas 1990). This scheme encouraged exploration activity in previously unexplored areas and resulted in a wide distribution of wells. Most of Australia’s petroleum provinces were identified through exploration under this scheme.

An algebraic representation of the accumulated tax deduction under single and multiple risk categories in the alternative approach is presented in box 3.

Future directions for research

An assessment of specific settings for the actual and potential fiscal parameters in the petroleum resource rent tax is beyond the scope of the current study.

A critical direction for future research is to assess the implications of different fiscal settings in Australia’s petroleum resource rent tax for a range of feasible oil and gas projects over time, including exploration activity. Such research would clarify the nature of winners and losers from any change in the fiscal settings, and provide information to both government and industry that would facilitate the ranking of preferences for specific fiscal settings.

It should also be recognised that, while both options attempt to increase the efficiency of the petroleum resource rent tax, there are potentially significant administrative costs involved in implementing each option.

Further information on future research directions is provided in the summary to this report.

In summary, Australia’s petroleum resource rent tax has performed well over a period in which there has been substantial change in geological and economic circumstances. On this basis, it may be argued that there is no imperative to alter current fiscal settings. However, if significant efficiency gains are desired, ABARE has identified two options that entail substantial reform to the petroleum resource rent tax.
Box 3: An algebraic representation of fiscal settings under the alternative option

In this box, an algebraic representation of fiscal settings under the alternative option for Australia’s petroleum resource rent tax is provided using a similar approach to that introduced in box 2 for the preferred option. The accumulated value of the tax deduction is presented under the assumptions of a single risk category and multiple risk categories.

Single risk category
Assume a single accelerated rate of deduction under the alternative option for a given initial cost, $C_0$. The value of the tax deduction in year $s$, $V_s$, is:

$$V_s = t_{PRRT} (1+i)^s (1+a) C_0$$

where $a$ is the accelerated tax deduction (tax deduction above 100 per cent where $a > 0$) and other variables are as defined in box 2. In percentage terms, the premium in the tax deduction is equal to $a \times 100$ per cent, and the actual tax deduction is $(1+a)100$ per cent.

In this case, the accumulated value of the tax deduction in year $s$ is the petroleum resource rent tax rate multiplied by the initial expenditure, adjusted for the premium in the tax deduction, and accumulated each year at the threshold rate.

Multiple risk categories
In the simplest case, multiple risk categories may be defined such that the corresponding expenditure items are mutually exclusive — that is, an expenditure item is assigned to one risk category only. Differences in general categories of risk may be taken into account by allowing for different settings for the accelerated rate of deduction as follows:

$$V_s = t_{PRRT} (1+i)^s \left[ \sum_k (1+a_k) C_{k0} \right]$$

where $C_{k0}$ is the value of expenditure for risk category $k$ in year 0 (noting $\sum_k C_{k0} = C_0$), and $a_k$ is the accelerated rate of deduction for expenditure in risk category $k$ ($a_k > 0$ for all $k$). In general terms, a category with a higher level of risk corresponds to a higher accelerated rate of deduction.

The general specification when the threshold rate varies over time is:

$$V_s = t_{PRRT} \Pi_{t=1}^{s} (1+i_t) \left[ \sum_k (1+a_k) C_{k0} \right]$$

The additional risks associated with wildcat exploration may be recognised by allowing a higher premium in the tax deduction for this risk category. Most importantly, the additional risks associated with wildcat exploration (defined to be exploration no closer than 100 kilometres from a discovery well) may be recognised by allowing a higher premium in the tax deduction for this risk category.

Fiscal settings under the alternative option
The fiscal settings for the tax and threshold rates under the alternative option are:

$$t_{PRRT} = 0.40$$

$$i_t = \bar{i}_t = LTBR_t$$

The fiscal settings for the accelerated rate of deduction vary according to the number of risk categories identified in the system.

The accelerated rate of deduction for a single risk category is:

$$a = a_{exp} = a_{expo} = a_{gen} > 0$$

Continued →
where $a_{expw}$, $a_{expo}$, $a_{gen}$ are the accelerated rates of deduction for exploration expenditure on new field wildcat wells, other exploration expenditure and general project expenditure, respectively.

The accelerated rates of deduction for two risk categories where new field wildcat exploration is identified as a separate higher risk category than other expenditure categories are:

$$a_{expw} > a_{expo} = a_{gen} > 0$$

That is, in both the preferred and alternative options, all threshold rates are equal to the risk free interest rate as measured by the long term government bond rate. In the alternative option, however, the tax rate is maintained at 40 per cent, while investors receive a risk premium through an accelerated rate of deduction at a sufficient level that ensures reasonable returns for both the investor and the government (with the latter representing the return to the community from the extraction of the resource).
spreads of corporate bonds over government bonds

Fane and Smith (1986) argue that the value of any tax deduction over time is equivalent to a reduction in the company’s holdings of government bonds — this assumes full loss offset such that the future deduction is a certain outcome. This is discussed further in chapter 4.

Alternatively, if the company does not hold sufficient government bonds, Fane and Smith (1986) argue the company may finance the expenditure through debt financing. Risks relating to the future value of the deduction (among other risks) will be reflected in the interest paid on corporate debt.

Monthly data on the spread of corporate bonds over government bonds (of a similar maturity) is provided in figure P since July 1997 (the earliest date available from the Reserve Bank of Australia — see RBA 2002). Spreads are shown for corporate bonds that are in the three broad credit ratings as determined by Standard and Poor’s — AAA, AA and A.

During this period, the spread for each credit rating was less than 1.0 percentage point (in nominal terms).


—— 2002b, *Australian Commodities*, vol. 9, no. 3, Canberra.


—— 2002c, *Flowline*, Issue 13, Canberra, October.


RESEARCH FUNDING. ABARE relies on financial support from external organisations to complete its research program. As at the date of this publication, the following organisations have provided financial support for ABARE’s 2002-03 research program. We gratefully acknowledge this assistance.

Australian Bureau of Statistics
Australian Dairy Corporation
Australian Forest and Wood Products Research and Development Corporation
Australian National University
Australian Quarantine and Inspection Service
Australian Wool Innovation Limited
Bureau of Transport and Regional Economics
Dairy Research and Development Corporation
Department of Agriculture, Fisheries and Forestry – Australia
Department of Foreign Affairs and Trade
Department of Industry, Tourism and Resources
Environment Australia
Fisheries Research and Development Corporation
Fisheries Resources Research Fund
Fonterra Cooperative Group Ltd, New Zealand
Grains Research and Development Corporation
Grape and Wine Research and Development Corporation
Land and Water Australia
Meat and Livestock Australia
Murray–Darling Basin Commission
New Zealand Ministry of Agriculture and Fisheries
New Zealand Prime Minister and Cabinet
Office of Resource Development, Northern Territory
Productivity Commission
Rural Industries Research and Development Corporation
Snowy Mountains Engineering Corporation
Western Australian Chambers of Minerals and Energy
Woodside Australian Energy
World Bank