1 June 2015

Tax White Paper Task Force
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Tax White Paper – Submission from the Australian Petroleum Production & Exploration Association

Please find attached a submission from the Australian Petroleum Production & Exploration Association in relation to the Tax White Paper process. Should you wish to discuss any of the matters raised in the submission, please contact Noel Mullen, Deputy Chief Executive, on tel 02-62670904 or email nmullen@appea.com.au

Yours sincerely

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SUBMISSION TO THE TAX WHITE PAPER TASK FORCE

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June 2015

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KEY POINTS

The Australian Petroleum Production & Exploration Association Ltd (APPEA) is the peak national body representing the oil and gas exploration, development and production industry in Australia. The Association's membership comprises companies that account for an estimated 98 per cent of Australia's petroleum production and the vast majority of exploration. APPEA's membership also includes many companies that provide services to the industry.

Petroleum is crucial to Australia's economic prosperity. For the foreseeable future, oil and gas will continue to account for well in excess of 50 per cent of our primary energy needs and has the potential to make a material difference to the energy security of our region. The future health of the industry is integrally tied to investment in both exploration and development activities.

The oil and gas industry is truly global in nature, and must compete for a limited pool of international investment capital. Oil and gas funding that is lost from the domestic oil and gas industry will not be spent in other parts of the Australian economy. It will be redirected to our overseas competitors. While the industry has committed to the development of a number of large scale projects over the last decade, the new generation of investments (and extensions to existing and committed projects) will be heavily dependent on the fiscal system, as it is a key factor that determines the economics of projects.

A key objective of tax reform is to position the Australian economy to achieve sustainable economic growth and improve productivity. Tax reform that merely leads to a redistribution of wealth without the economy wide benefits will represent a major lost opportunity (and a deadweight loss to the economy). A strong and growing oil and gas industry can create enduring wealth for the Australian community both through economic growth and long term revenue streams for governments. Successfully meeting the long terms challenges outlined in the Intergenerational Report will be dependent on robust private sector investment.

The tax system plays a key role in influencing investment decisions in the Australian petroleum exploration and production industry and Australia's ability to compete for international investment funds. The immediate deductibility of exploration costs remains a cornerstone of the tax system for the resources sector, while the treatment of capital under the income tax regime has a significant impact on the decisions of companies to develop discovered resources. It is also important that the tax system supports the efficient use of Australia's existing oil and gas infrastructure through provisions which encourage sharing or realignment of ownership of infrastructure assets to encourage future project developments. In addition, a reduction in the company tax rate also has the potential to improve the overall competitiveness of Australia's business taxation system.

APPEA and its member companies support genuine tax reform. The industry has been an active participant in numerous reviews of aspects of the fiscal system since the 1970's, and have taken a constructive and transparent position in examining reform options, including assessing the potential impact on investments in the industry. For Australia's oil and gas industry's perspective, a number of important questions must be addressed in the context of the Review.

What features should the fiscal system have in order to promote growth in the oil and gas industry?

- Recognition of the economic challenges that confront long life capital intensive projects in Australia and the need for a sustained exploration effort in Australia's under-explored basins.
- International competitiveness to attract investment in the industry to meet local and international energy needs.
- Stability and certainty for long term investments.

What are the problems with the current system?

- Tax distortions biasing against investment in capital intensive activities – depreciation terms are critical to achieving a sustained level of investment.
- Inadequate incentives for exploration –the immediate deductibility of exploration remains essential.
- Inconsistent resource taxation administration across jurisdictions and fees and charges on transactions.
- Tax complexity that places 'form' over 'substance'.

In terms of the current review, APPEA's recommends:

- The retention of the income tax treatment of exploration that allows for **the immediate deductibility of exploration expenditures**.
- **Improved capital depreciation provisions** for oil and gas capital assets to allow Australia to more effectively compete with other countries in future gas export growth.

The combination of these factors has played an important role in Australia's success in being a leader in the growth of the global gas industry. Any changes that tilt the company income tax system against the capital intensive activities will fundamentally impact on the ability of Australia to construct legacy projects and to create sustainable taxation revenue streams for future generations of Australians. Australia needs a balanced economy, not one that simply rewards industry's that provide services to other industries. Consideration should also be given to fiscal measures which could support the sharing or realignment of ownership of infrastructure assets to encourage future project developments.

Further commentary on the options canvassed in the discussions paper, details of the nature of oil and gas industry operations and international competitiveness issues are outlined in more detail in this submission.

The key consultation questions addressed in this submission are as follows:

24: How important is Australia's corporate tax rate in attracting foreign investment? How should Australia respond to the global trend of reduced corporate tax rates?

27: To what extent does the tax treatment of capital assets affect the level or composition of investment? Would alternative approaches be preferable and, if so, why?

28: How complex is the tax treatment of capital assets and are the costs of compliance significant?

38: In what circumstances is it appropriate for certain types of businesses to be subject to special provisions? How can special treatment be balanced with the goal of a fair and simple tax system

52:	What are the relative priorities for state and local tax reform and why? In considering reform opportunities for particular state taxes, what are the broader considerations that need to be taken into account to balance equity, efficiency and transitional costs
56:	What parts of Australia's tax system, and which groups of taxpayers, are most affected by complexity? What are the main causes of complexity?

RECOMMENDATIONS

1. The **immediate deductibility of exploration** related costs that has shaped the historical taxation treatment of such expenditures must be maintained. It reflects the nature of such costs and that the future development of the nation's petroleum resources is dependent on a continued and robust exploration effort.
2. The existing **depreciation provisions** have been an important factor that has allowed Australia to attract the investment funds necessary to expand our natural gas export capability to a world class scale. Not only do these provisions need to be retained, they arguably need to be further shortened if Australia is to attract the next wave of investment in this critical export industry.
3. **Crude oil and condensate production excise be abolished** for all onshore and state waters production areas.
4. A **simplification to the CGT provisions** associated with the creation and cancellation of income rights to reduce complexity and uncertainty and eliminate double taxation.
5. In order to reduce the **GST compliance burden** and risks associated with transactions between joint venture participants, it is recommended that revenue neutral amendments be introduced to sub-division 51-B of the GST Act.
6. Governments consider the **harmonisation of the administration of the petroleum royalty regimes (and other imposts)** in Australia and that measures be considered to provide royalty relief for the production of hydrocarbons from projects that require the adoption of new technologies.
7. All governments move to **abolish transfer fees and duties on farm-in transactions or commercial realignments** in the petroleum industry.

SECTION 1: INDUSTRY BACKGROUND

1.1 The Australian Oil and Gas Industry

Since the late 1960's, oil and gas exploration and production has been playing an increasingly significant role in the Australian economy. From the discovery of gas in central Australia to the oil and gas fields in the Gippsland Basin and in the north-west region of Australia, the industry has been pivotal in the supply of energy to Australia and many of our key trading partners. The emergence of gas sourced from coal seams and the potential of shale gas presents Australia with a unique opportunity to be a world leader in the supply of energy.

The growth of the industry has provided many benefits to Australia, including:

- the supply of reliable and competitively priced energy;
- investment of hundreds of billions of dollars in exploration and development activities;
- employment (both directly and indirectly) of hundreds of thousands of Australians;
- payment of hundreds of billions of dollars in taxes and charges to governments since production commenced in the late 1960's; and
- the generation of export income and the replacement of costly imports of petroleum.

The position of the Australian oil and gas industry today as an emerging global leader in the supply of natural gas to the world has to a large part been underpinned by the application of a range of targeted fiscal settings. The fiscal framework has assisted investors to commit the vast sums of risk capital necessary to both find and develop the resource base.

While investments in the industry have been significant to date, future development decisions will be dependent on a fiscal regime that balances risk with reward. To capture the opportunities, it is critical that the overall tax regime remains structured in a manner that does not impede positive investment decisions.

1.2 Economic Contribution

Our abundant natural gas resources place Australia in an enviable position to maintain long-term, cleaner energy security domestically and internationally. Natural gas makes it possible for Australia to meet the world's growing energy needs over the coming decades while incorporating a strategy to curb emissions and address the risks posed by climate change.

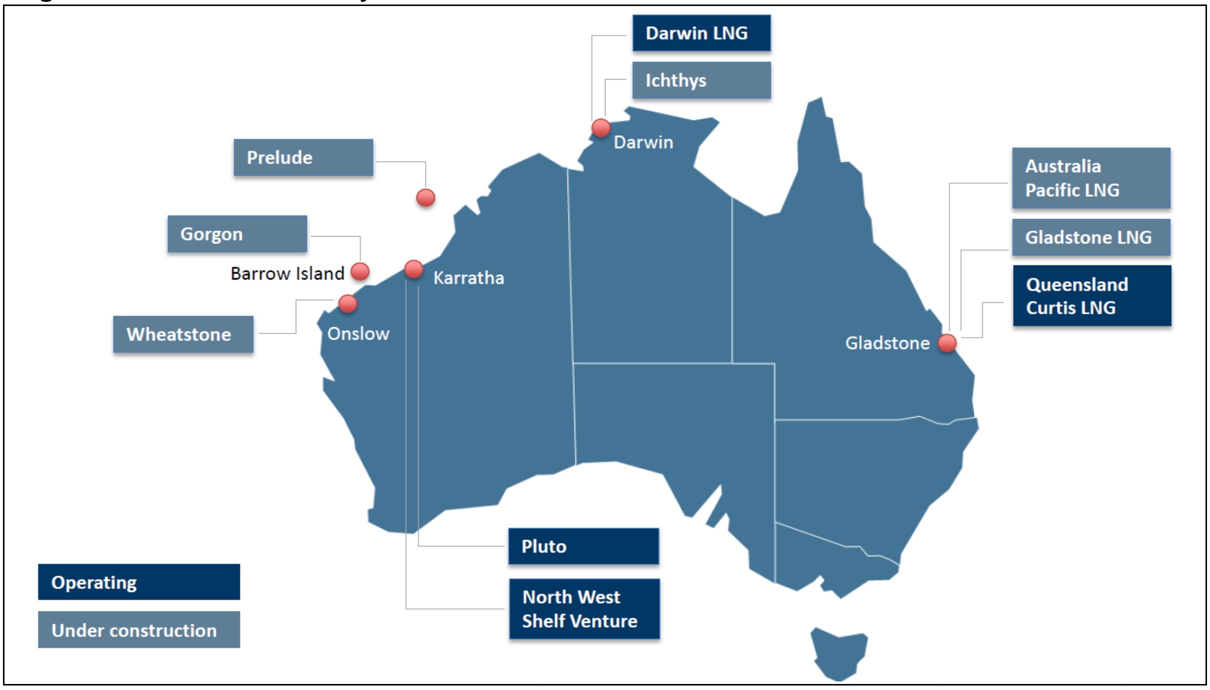
Just as importantly, the industry creates significant wealth for the country, including through the employment of many Australians, underpinning the revenue collections of governments and generating valuable export revenue for the Australian economy. Almost $180 billion is currently being invested in oil and gas projects, including major liquefied natural gas (LNG) export projects that will add to the four LNG projects under operation.

Australia's oil and gas industry has underpinned much of Australia's economic prosperity and growth since at least the early 1960s. A recent PwC report, *Value Adding: Australian Oil and Gas Industry*, shows that:

- The oil and gas industry's production profile directly represents around 2 per cent of current GDP, with value-added of approximately $32 billion in 2012-13.

- At current projected investment levels, the total forward contribution of the combined oil and gas and exploration sectors is projected to double to approximately $53 billion in 2019-20 and $67 billion in 2029-30.
- Driving strong value-add from the industry is an increase in gas exports over the next decade. The value of natural gas exports (already Australia's third largest export, after iron ore and coal) is expected to reach around $60-70 billion by the middle of 2019 and production is expected to double over the next five years.
- In 2030, when production (on the basis of current and forthcoming capacity) and prices are expected to stabilise, the oil and gas industry's total economic contribution is projected to be around 2.6 per cent of the Australian economy.
- After accounting for its inter-linkages with the rest of the economy (companies all over Australia supply goods and services to the oil and gas industry, and the use of fly-in, fly-out staffing is spreading the benefits of the industry) the sector is projected to be around 3.5 per cent of national output.

Figure 1: Australian LNG Projects



Source: Department of Industry (2014).

By 2020, the sector's economic contribution to the national economy will more than double to $65 billion and taxation paid is expected to rise from $8.8 billion in 2012 to reach almost $13 billion per year.

1.3 Achieving Future Growth

A key challenge in achieving future growth in the industry is maintaining Australia's international competitiveness in the face of a rapidly changing global energy sector. A high-cost local environment, a complex domestic regulatory framework and the potential for other countries to capture market opportunities will continue to make it challenging for Australia to benefit from the next wave of global investment in the industry. To harness these potential gains, there will need to be further adjustment in the allocation of resources within the economy and a tax reform agenda that does not adversely impact production or future investment decisions.

A challenge facing the industry in the medium-term is the downward pressure on prices that impact on project economics (see Figure 2). While the industry is experienced in managing this type of scenario, governments have an important role in influencing the broader investment framework.

Figure 2: The Price of Oil (real terms)

* Crude oil (WTI), global spot, close, USD/US CPI, all urban consumers, all items
Source: CEIC, GaveKal data

For Australian export gas projects, the price for LNG is often linked to crude prices under long-term contracts. A major price correction of the kind now being experienced is a sharp reminder of the need to keep a tight hold on costs.

Companies in the oil and gas industry operate in timeframes of a decade or more, taking into account a wide range of possible price, economic and policy scenarios. Short-term fluctuations are managed as part of the broader planning process. In terms of LNG projects, where Australia is an emerging world leader, petroleum project prospects are coming under renewed scrutiny all round the world. For industry, the price change means a return to business fundamentals: watching cash flow; scrutinising investment proposals anew and keeping an eye open for opportunities.

Commodity price fluctuations may be a factor that is largely beyond the control of government, but there are areas where governments can assist in mitigating risk. Tax competitiveness is one such area. While the Australian economy has benefited (and will continue to benefit significantly) from LNG investments committed to in the past, there are potentially more projects that could see a second wave of investment in the industry. There is scope for Australia's LNG exports to expand further through expansion of existing fields, new discoveries and the adoption of new technologies.

The upstream oil and gas industry is integrated into the global trading system and is one of Australia's most globalised and trade-exposed industries. Investment in the development of Australia's oil and gas resources will depend on the commercial attractiveness of the operating environment. The last decade has been characterised by an increase in the cost of projects. This has now been further complicated by a fall in key commodity prices together with a projected decline in global economic growth.

The bottom line for commercial attractiveness is project economics – costs relative to output prices. There are many determinants of profitability – resource quality, infrastructure cost, taxation policy, labour costs, location issues through freight costs, fuel and energy costs, communication costs and imposts associated with meeting government regulations. Countries largely compete for a share of global investment on the basis of how potential investors consider domestic policies and the social environment contribute to prospective profitability.

Commitments to new resource developments in Australia have slowed markedly over the last year. As the International Energy Agency (IEA) recently noted, the prospects for another round of major Australian projects will depend heavily on how costs evolve, on the deployment of new technologies (such as floating LNG (FLNG) and hydraulic fracturing) and on competition from other regions, notably North America and East Africa. If not addressed, these cost and productivity challenges threaten to hold back plans for additional export projects.

1.4 Maintaining a Competitive Fiscal Framework

In the context of any discussion in relation to possible reforms to the Australian taxation system, it is important that core principles are established by which specific taxation settings can be judged. It is generally accepted that the following three criteria should be used.

Equity - those in relatively similar economic positions should be treated equally, while those in different circumstances should be treated in proportion with their ability to pay.

Efficiency -the distortionary impact of taxes, or the likelihood that taxes may alter investment decisions (both in domestic and international contexts), should be minimised.

Administrative Simplicity -the cost of complying with, or collecting taxes, should be kept to a minimum. A tax system should also be as simple as possible so ensuring that its meaning is clearly conveyed.

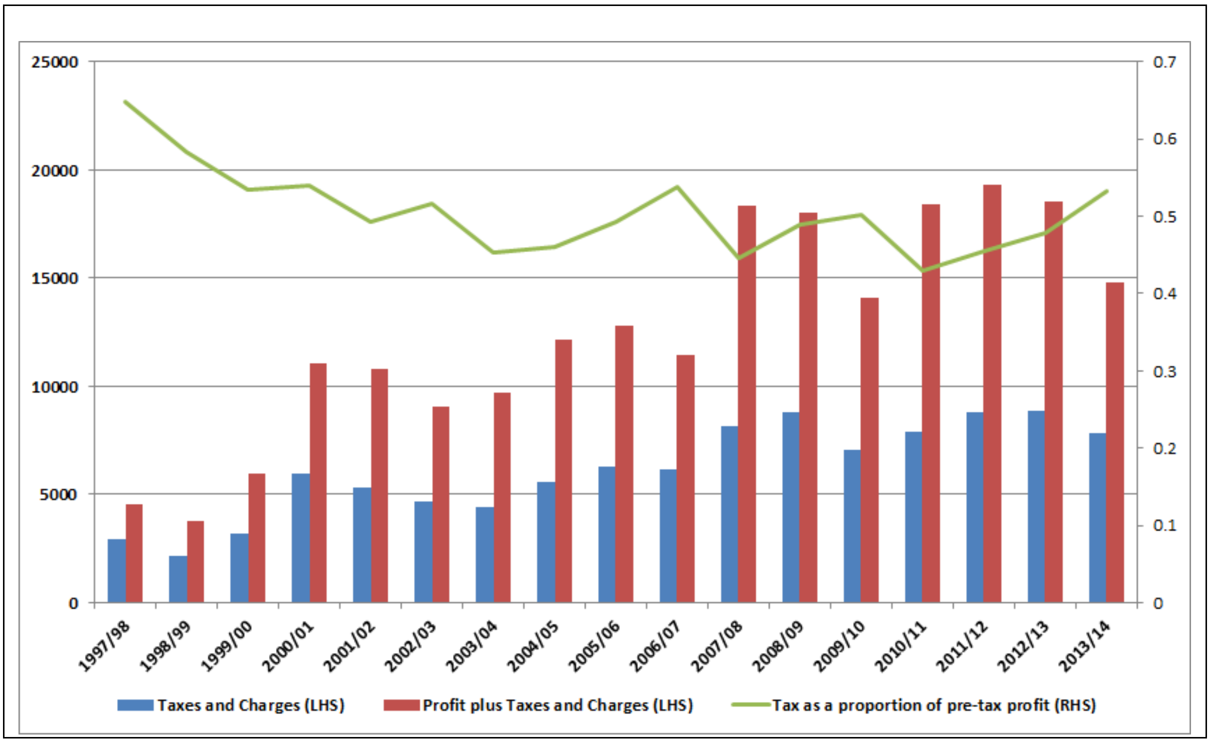
In addition to the above, the increasing mobility of capital and funds between nations dictates that the question of the international competitiveness of the taxation framework must also be considered. A further defining feature is stability. While industry fully recognises the rights of governments to set and adjust fiscal settings, it is nonetheless important that investments that have long lags between outlays (which can often involve billions of dollars) and project returns are provided with a taxation framework that respects the long term commitment of such investments.

It is inevitable that variations in the tax mix will lead to outcomes that will at least (to some extent) conflict with the above principles. It is therefore important that outcomes are pursued that attempt to minimise distortions.

While the petroleum exploration and production industry is subject to normal company , indirect taxes and duties, it is also subject to a range of special taxes and charges (such as the petroleum resource rent tax, production excise and petroleum royalties) which are resource taxation instruments used by various governments in Australia. These charges add an additional layer of complexity in terms of assessing the impact of the overall framework using the above criteria, as well as the fact that they directly impact on the profitability and investment decisions. Fuels that compete for similar markets in Australia are generally not subject to this suite of imposts.

Data compiled by APPEA indicates that on average, taxes and resource charges account for around half of the industry's overall level of pre-tax profit (See Figure 3).

Figure 3: Estimated Petroleum Industry Profit Before Tax and Taxation Contributions ($m)



Source: APPEA Financial Survey (various years)

Total payments have averaged around $8 billion per year over the last five years. Subject to movements in oil and gas prices, total payments are expected to increase in the coming years as a number of projects currently under construction commence production.

In terms of resource taxation, as indicated above, a variety of regimes apply:

- the petroleum resource rent tax (PRRT) applies to all projects (both 'onshore and 'offshore');
- production sourced from licences derived from Exploration Permits WA-1-P and WA-28-P (including the North West Project) are subject to Commonwealth crude oil and condensate production excise and Commonwealth petroleum royalty; and
- onshore production and that sourced from projects located in submerged lands (including coastal waters) under state/territory jurisdiction is subject to Commonwealth crude oil and condensate production excise and royalties levied under the relevant state/territory jurisdiction. The royalty provisions for each jurisdiction are broadly similar in principle but are administered in a variety of different manners.

The layered nature of the taxation structure (resource, income and indirect) and the involvement of multiple jurisdictions creates considerable complexity and compliance costs for the industry.

One of the most recent reforms was announced in 2010. The then Federal Government announced that modified fiscal terms would apply to petroleum production sourced from areas not then subject to the PRRT. This covered all onshore areas in Australia and the North West Shelf project. In addition to the existing royalty and production excise regimes, the PRRT was extended to cover production not then subject to PRRT, with effect from 1 July 2012.

A range of technical and administrative details are the subject of discussion between industry, the Australian Taxation Office and policy agencies for the purposes of the operation of the PRRT regime. The extension of the PRRT imposes an additional layer of compliance costs on companies (as well as potentially complicating future investment decisions), while uncertainties associated with aspects of the various royalty regimes is creating unnecessary inefficiencies and administrative burdens on companies.

Key Consultation Question

24. How important is Australia's corporate tax rate in attracting foreign investment? How should Australia respond to the global trend of reduced corporate tax rates?

For the reasons discussed in this submission, continued investment in the Australian petroleum industry requires a tax system that is internationally competitive. For income tax, this is achieved through the combination of tax rate and deduction allowances which in tandem encourage future investment and provide a stable regime over time. APPEA broadly supports the existing deduction regime (subject to a number enhancements), while international competitiveness would be enhanced (and additional foreign investment attracted) by any reduction in the tax rate.

SECTION 2: EXPLORATION – THE BASIC BUILDING BLOCK

2.1 What is Exploration?

Prior to any consideration of production, companies have to first search for and find hydrocarbon resources. This process involves a commitment to expend significant funds with no guarantee of success. If a hydrocarbon discovery has been made, there is no guarantee of its commercial development. Significant resources are ordinarily invested in appraisal and feasibility activities to determine if the field can be commercially exploited.

Searching for petroleum typically includes the following activities (some of which will be undertaken prior to obtaining an interest in a permit or licence):

- A regional geological assessment of an area in order to determine its hydrocarbon bearing potential and to determine if there are areas that are prospective and over which exploration permits should be acquired.
- Competitive bidding on areas. Generally the government will release exploration blocks and companies will bid an indicative work program in order to secure a particular block, although some areas are subject to cash bidding arrangements.
- If a company is awarded an exploration permit over an area, it will then conduct activities with the objective of determining the likely location of a hydrocarbon resource. Activities may include:
  - Geological surface mapping (onshore);
  - Geological studies looking to confirm the presence of a hydrocarbon system, presence of suitable source, reservoir and seal rocks, and does the timing of hydrocarbon generation post date that of trap formation;
  - Geophysical surveys such as gravity surveys or magnetic surveys (usually as recognisance tools);
  - Geophysical surveys such as 2D and 3D seismic with the objective of trying to define a suitable trap.
- Drilling only occurs once a suitable target has been identified. More often than not exploration wells are not successful. The drilling results are then fed back into the search process and the process repeated.

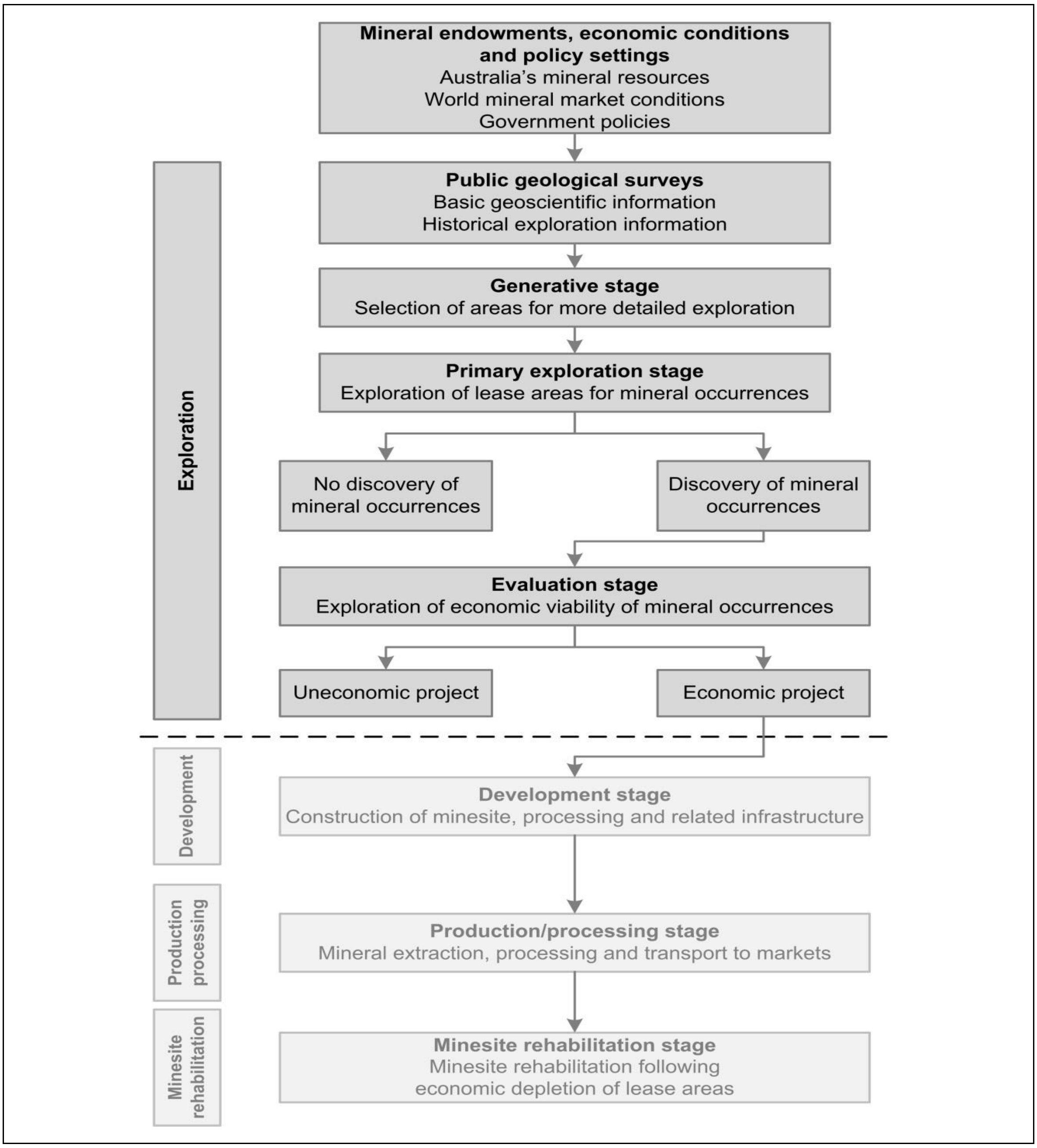
If a hydrocarbon deposit is discovered it then needs to be appraised. Appraisal is the process of acquiring data on the field to assist with determining its potential for commercial development. Appraisal is not about determining everything there is to know about a field. It is often said that the day you know exactly how much will be produced from a particular field is the day you stop producing from it. Appraisal is about collecting enough data to have an appropriate level of confidence about the resource when undertaking feasibility studies and determining whether the resource is commercially viable.

Appraisal activities are usually focused around the area of the discovery (or nearby if it is hoped that additional fields may be located that might become part of a potential development) and involve:

- The acquisition of additional seismic data;

- Usually a lot more drilling to determine the geographic extent of the field, the ability of the field to produce and how uniform the properties of the field are (how the field varies from one end to the other);
- Often appraisal wells are flowed in order to confirm the fields productivity; and
- Numerous studies aimed at filling in the gaps between the drilling locations.

Figure 4: Petroleum Activity Cycle



Source: Productivity Commission (2012)

It is only once the parties have some confidence in the possible size of the resource that the process for determining potential development options and evaluating commercial viability of the resource can commence through feasibility studies. The results of the feasibility studies will determine whether the resource is commercially viable and as such, whether to proceed with the proposed project.

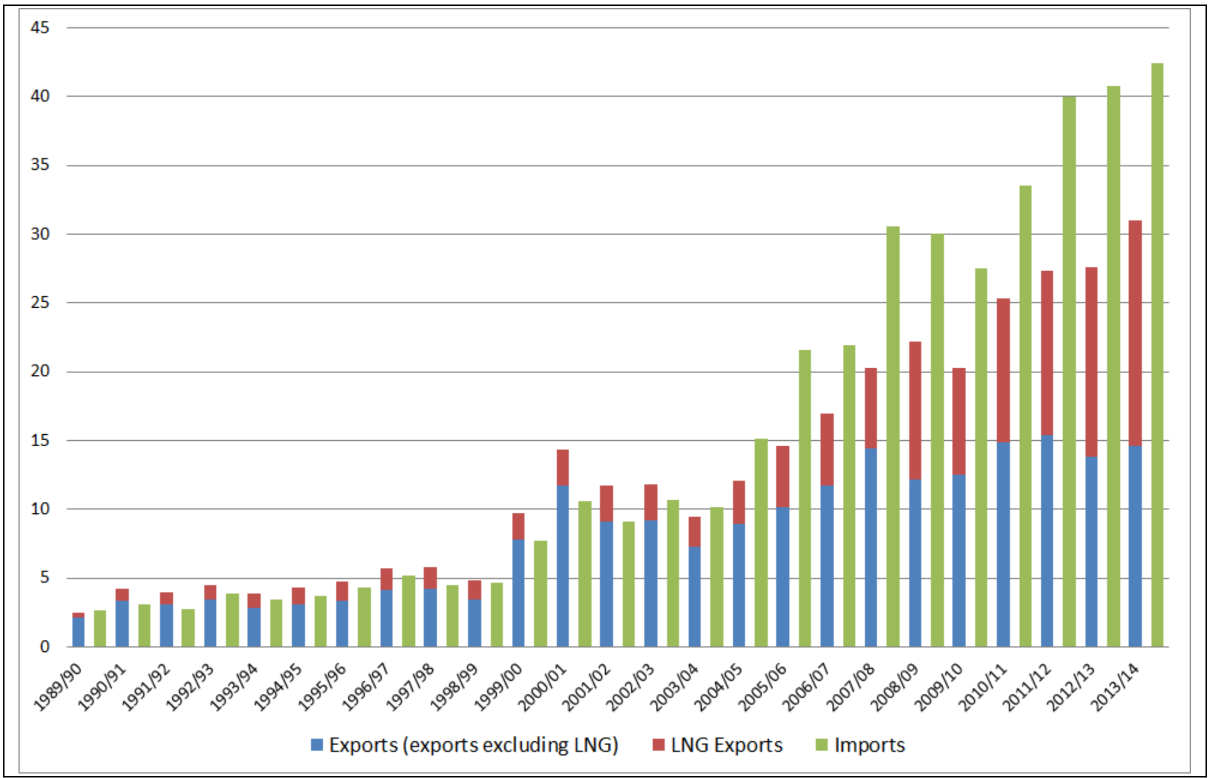
Figure 4 depicts the typical activities in the exploration, development, production and decommissioning cycle.

2.2 The Value of Exploration to the Australian Economy

Exploration provides greater certainty about Australia's available petroleum resources. This creates option value for industry and the wider community and economy. It creates options in the form of expanded identification of high prospect petroleum targets, better information on where, whether and when to proceed to production drilling, and ultimately project implementation. The importance and value at any point in time of undertaking exploration for future production is highly dependent on the current level of identified reserves and the economics of tapping those reserves.

Australia is currently rich in identified gas resources, however its position in the case of petroleum liquids (crude oil and condensate) is somewhat different. After enjoying a significant period of self-sufficiency in crude oil and condensate during much of the later part of the last century, Australia is now in a position where it is no longer self-sufficient.

Figure 5: Australian Trade in Petroleum and Petroleum Products ($b)



Source: Department of Industry and Science

Australia is now a net importer of crude oil and oil products (see Figure 5), with the imported share continuing to trend upwards. Major uncertainties around indigenous oil supply include the success of efforts exploring frontier basins, a costly and risky endeavour, and whether these efforts are commercialised.

While exploration can be considered as a means to an end, it creates economic activity in its own right. A large percentage of the expenditure on petroleum exploration comes from overseas sources. Australia competes with other countries for these exploration funds that can have beneficial effects for the economy ahead of successful commercialisation. This includes exploration investments that do not lead to the identification of commercial reserves.

The impacts of ceasing exploration were analysed for the period of 2003-04 to 2024-25 by ACIL Tasman in 2010. As a result of the cessation of exploration activity, there is a consequent reduction in field development and production. A conservative assumption was made given Australia's extensive gas reserves that a cessation of exploration would not affect gas development to 2025.

Table 1 - Overview of Exploration Model Results – Loss of Exploration

	Real GNP (2004 $ million)			Real GDP (2004 $ million)			Real Private Consumption (2004 $ million)			Employment at 2025 (number workers)
	4 % NPV	7% NPV	10% NPV	4 % NPV	7% NPV	10% NPV	4 % NPV	7% NPV	10% NPV	
QLD	-1132	-885	-713	-1274	-979	-777	-552	-430	-346	-121
SA	-538	-430	-355	-610	-486	-400	-329	-263	-218	-43
WA	-502	-404	-333	-332	-253	-199	-125	-106	-91	-88
Aust	-2581	-2031	-1648	-2712	-2101	-1681	-1432	-1131	-920	-362

ACIL Tasman (2010)

The outcomes of the loss of the oil and gas exploration industry are significant, resulting in reductions (at the 4 per cent discount rate) of more than $2.7 billion of GDP, $2.5 billion of GNP and $1.4 billion of private consumption expenditure for the nation as a whole over the course of the twenty-year time horizon examined. There is a smaller impact in WA than there is in Queensland, despite the former accounting for some 70 per cent of exploration expenditure in Australia. The reason for this is that most of WA's exploration is offshore, whilst most of Queensland's (and South Australia's) is onshore. A higher proportion of costs in offshore exploration are rig costs compared to onshore exploration.

2.3 Exploration Trends in Australia

The oil and gas industry is highly funds intensive. Tens of billions of dollars of capital is required over the coming decades if exploration is to continue and new oil and gas projects are to be developed. Australia is generally perceived to offer low prospectivity for oil, with relatively low discovery rates and small average field sizes. Gas prospectivity is generally good, but Australia already has many large undeveloped gas fields. New discoveries are often remote from markets and are becoming increasingly difficult to commercialise.

It is important to understand that petroleum exploration is a very high risk activity. This is best demonstrated by comparing the number of exploration wells drilled with both discoveries and the percentage of discoveries that are subsequently converted to production. Geoscience Australia maintains a detailed petroleum database that records the above information across individual geological basins in Australia. Some of the key trends are as follows:

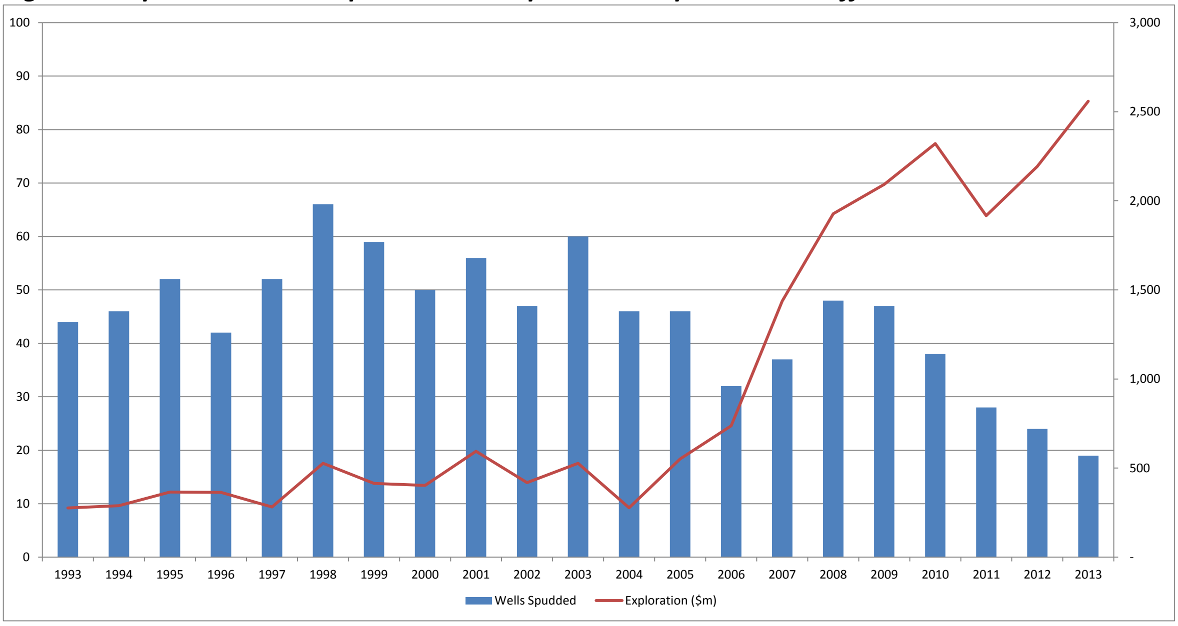
- In the period 1955 to 2011, a total of 4,248 conventional exploration wells were drilled in onshore and offshore Australia.

- Of the 4,248 wells drilled, 1,200 were considered by Geoscience Australia as being 'discoveries'. (A discovery well is defined as a well that recovers petroleum or encounters a producible log pay zone.) This represented a 28 per cent success rate as a percentage of the number of exploration wells drilled.
- Of the 1,200 discovery wells, 585 had led to production. This represented a 14 per cent success rate as a percentage of total wells drilled.
- If the two most successful basins are excluded from the data set in terms of exploration wells drilled, the discovery success rate falls to 20 per cent, while the production success rate falls to slightly less than 9 per cent. For this latter scenario, this means that the success rate is around one in eleven.

This data highlights some very important trends and has significant implications for how such activities need to be recognised within the income tax system. Specifically, such activities are often unsuccessful, they more often than not do not generate petroleum reserves, and many decades can pass before a company is aware as to whether a discovery can ultimately be converted into production (see further comments in Section 3).

There has been a gradual decline in recent years in the overall exploration effort. While many factors influence exploration decisions, ensuring that taxes operate as an effective tool in achieving comprehensive energy policy outcomes will remain a key to our future successes.

Figure 6: Exploration Wells Spudded and Exploration Expenditure – Offshore Areas



Source: APPEA and ABS

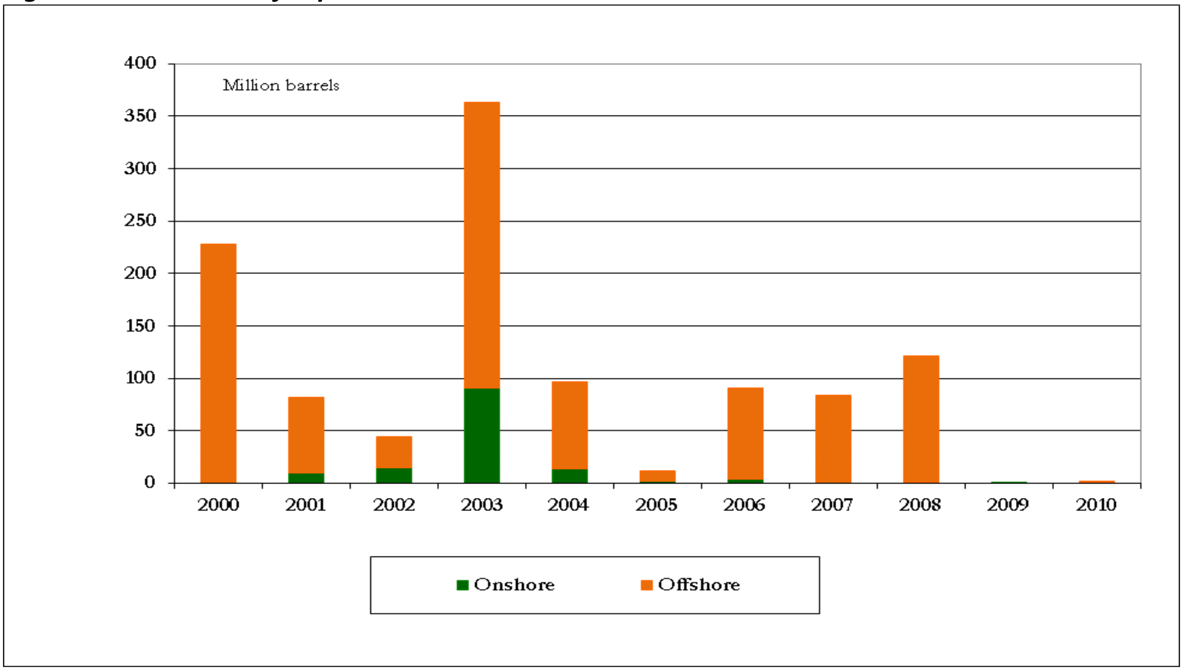
The long term growth in the Australian oil and gas industry is dependent on the level of exploration. Oil and gas cannot be produced without first locating new resources and these cannot be discovered without undertaking exploration activity. A rising cost of exploration has coincided with a reduction in the number of offshore exploration wells drilled, which have fallen by more than two thirds since the peak in 1998. There has also been an increase in the overall level of regulation imposed on the industry that impacts on both the timing and quantum of exploration.

Figure 6 plots the levels of exploration expenditure in offshore areas with the number of wells spudded in the same area. The divergence in the number of wells drilled (which has dramatically fallen) with the increase in the cost of exploration (which has significantly risen) represents a disturbing trend. While anecdotal information suggests that will there has been a cooling-off in the contracting costs of rigs that are critical component of offshore exploration, the declining trend in exploration is nonetheless continuing.

This decline has also corresponded with the introduction of cash bidding for selected offshore acreage (that was introduced by the Federal Government in 2014). The first round of bidding for such acreage failed to attract any successful bids. The Federal Government has now released a further six areas in the second round of cash bidding acreage.

Over the five years from 2006 to 2010, less than 300 million barrels of liquid petroleum was discovered (Figure 7), whereas Australia's consumption of refined petroleum products totalled more than 1,500 million barrels over the same period.

Figure 7: Discoveries of Liquid Petroleum – 2000 to 2010



Source: Geoscience Australia

2.4 Company Tax Treatment of Exploration – Previous Reviews

Key Consultation Question
38. In what circumstances is it appropriate for certain types of businesses to be subject to special provisions? How can special treatment be balanced with the goal of a fair and simple tax system?

The immediate deductibility of the majority of exploration related costs has been a central feature of the income tax provisions for many decades. This treatment reflects the nature of such activities.

The first major review of how exploration costs should be considered in an income tax context was considered as part of the Asprey Taxation Review in 1975. In that inquiry, it was recognised that the immediate deductibility of such costs was appropriate. Specifically, it was stated that:

> *"19.19….. Expenditure on exploration, which is a necessary and continuing part of a mining company's operations, should be treated consistently, whether successful or not. The Committee favours the approach that would make all exploration and prospecting expenditure immediately deductible against assessable income derived from any source. The availability of a deduction upon the lines suggested would constitute an acknowledgement that exploration expenditure is a normal operating expense of a mining enterprise and should be treated as such. This recommendation also answers the submission made to the Committee by a number of mining companies to the effect that, under the present system, when funds awaiting expenditure on exploration are invested by the mining enterprise, any deduction entitlement in respect of exploration expenditure cannot be set off against the income from those invested funds."* Asprey Tax Review, 1975 (p293/4)

The Asprey Review (which had a strong economy-wide taxation focus) was followed shortly thereafter by a major review into effects of taxation measures on the mining and petroleum industries in Australia. The Industries Assistance Commission Report, *Petroleum and Mining Industries*, released in 1976, examined numerous aspects of the taxation system as it applied to activities in the resources sector. The Commission confirmed support for the immediate deductibility of exploration related expenditures, and made the following observation:

> *"Since expenditure on both exploration and R and D represents a necessary operating expense, the criterion of neutrality requires that the manner in which it is allowed as a deduction for tax purposes should be similar in both cases."*
>
> *"Many witnesses expressed the view that expenditure on exploration and prospecting represents a necessary and continuing operating expense of a mining company and should be treated consistently whether successful or not. The Commission accepts this view and believes that companies should have greater opportunity to recoup the full costs of exploration."* Industries Assistance Commission Report, Petroleum and Mining Industries, 28 May 1976 (p19)

The Industry Commission undertook a further review into the Mining and Minerals Processing Industries in 1991 (Report 02/1991). While recognising that the issues surrounding the treatment of exploration related costs can be complex, the income tax treatment whereby costs are immediately deductible was again considered to be the most appropriate treatment of such costs. In addition to highlighting that exploration expenditure is an expense unique to mining industries:

> *"The Commission concludes that although immediate deductibility of exploration expenditure may involve an element of assistance, this 'concession' is the least distorting tax treatment in terms of the efficient allocation of resources."* Industry Commission Inquiry, Mining and Minerals Processing, 1991 (p335)

In 1999, arguably the most comprehensive review of the business taxation system was undertaken since the 1975 Asprey Review. The Review of Business Taxation, or the so-called 'Ralph Review', examined a wide range of business related taxes, and again addressed the treatment of exploration related costs. It came to the same broad conclusion as the earlier reviews.

> *"243 Expenditure on exploration and prospecting will continue to be immediately deductible under the Review's proposals. The strict logic of the generalised approach would suggest that expenditure on unsuccessful exploration and prospecting would be immediately deductible, while successful expenditure would be written off over the life of the resulting asset. However, in many cases there may be significant delays before it is known whether the activity has been successful or before a mine is established. It is largely on the grounds of practicality that the current treatment is proposed to be retained."* Review of Business Taxation, A Tax System Redesigned, Report, July 1999 (p55)
>
> *"**Mining and quarrying exploration and prospecting expenditure***
>
> *Applying the recommended treatment of expenditure and assets without recognising the valuation difficulties associated with the results of exploration and prospecting expenditure would mean that the tax treatment of this expenditure would depend on the results of the exploration or prospecting activity. Unsuccessful expenditure would be deductible at the time the activity was abandoned, while successful expenditure would enter the cost base of the project. That is the accounting approach.*
>
> *It has been a longstanding feature of the current law to allow an immediate deduction for exploration and prospecting expenditure. Allowing continuation of immediate deductibility is justified on the basis that the value of the associated asset cannot be reliably measured.* Review of Business Taxation, A Tax System Redesigned, Report, July 1999 (p167)

As evidenced in the outcomes of a number of independent reviews, a consistent series of conclusions have been drawn that have broadly confirmed the current treatment that exploration related costs should be immediately deductible.

2.5 May 2013 Budget Changes

In the 2013-14 Budget, the Government indicated that it would restrict the immediate deduction for the cost of assets first used for exploration, by excluding certain petroleum (mining) rights and information. It was announced that the following would continue to be immediately deductible:

- costs of mining rights obtained from a relevant government issuing authority;
- costs of mining information from a relevant government authority;
- costs incurred by a taxpayer itself in generating new information or improving existing information; and
- mining rights acquired by a farmee under a recognised 'farm-in/ farm-out' arrangement.

By media release on 14 May 2013, the Assistant Treasurer indicated that:

> *"The Government will better target the immediate deduction for expenditure on depreciating assets first used for exploration so that it supports genuine exploration activity.*

This change will address situations where the immediate deduction is being claimed for the costs of acquiring an interest in natural resources that have effectively already been discovered. This will help ensure the sustainability of this important concession for the resources industry.

The overwhelming majority of exploration expenditure will continue to benefit from an immediate deduction, maintaining support for genuine exploration activity."

Accompanying the decision in the Budget, the Government released a proposal paper (*Targeting the immediate deduction for mining rights and information first used for exploration*) that sought comments on the detailed application of the announced measure. That paper made a number of observations about the overall treatment of exploration for income tax purposes:

1. *Australia's income tax system supports the exploration for resources by allowing an immediate deduction for the cost of depreciating assets that are first used in exploration. This is an important concession, which recognises resources exploration is a vital activity that has spill over benefits to the economy.* (page 2)

****

6. *The immediate deduction for depreciating assets first used for exploration is a concessional treatment that is designed to encourage exploration, which is a particularly risky activity. The concession is appropriate because the amount of investment in exploration affects the ability of the resources sector to continue to grow and support the nation's growth into the future.*

7. *The knowledge that exploration generates has value, even when the resources discovered are unable to be immediately developed. This is because future changes in market conditions and technology may make a currently uneconomic resource viable, and because the benefits of that knowledge may flow beyond the businesses undertaking the exploration activity. In addition, information about one exploration lease may provide information about resources that may be available in nearby areas.* (page 3)

While the measure applied from the night of the Budget in 2013, the first tranche of legislation to enact the measure was not passed until mid-2014. Further aspects of the reform package are currently being developed by the Government.

Recommendation

The immediate deductibility of exploration related costs that has shaped the historical taxation treatment of such expenditures must be maintained. It reflects the nature of such costs and that the future development of the nation's petroleum resources is dependent on a continued and robust exploration effort.

SECTION 3: DEVELOPMENT OF DISCOVERED RESOURCES

3.1 Transitioning from Exploration to Production

As outlined in Section 2, discovery rates associated with exploration wells are quite low in Australia. As part of the exploration dataset maintained by Geoscience Australia, information is also available in relation to the time between when a discovery is made and when production commences. This is relevant in the context of understanding the uncertainties associated with converting a discovery into production, the lengthy time lags that can exist between those decisions and therefore the complexities associated with any income treatment of both exploration and development expenditures.

Table 2 outlines both the length of time it has taken for discoveries to reach production, together with the number of discoveries that have yet to lead to production. (For illustrative purposes, the analysis below has been limited to petroleum basins in offshore focus based on data as at 2012.)

Table 2: Discovery to Production – Key Timelines: Australian Offshore Basins

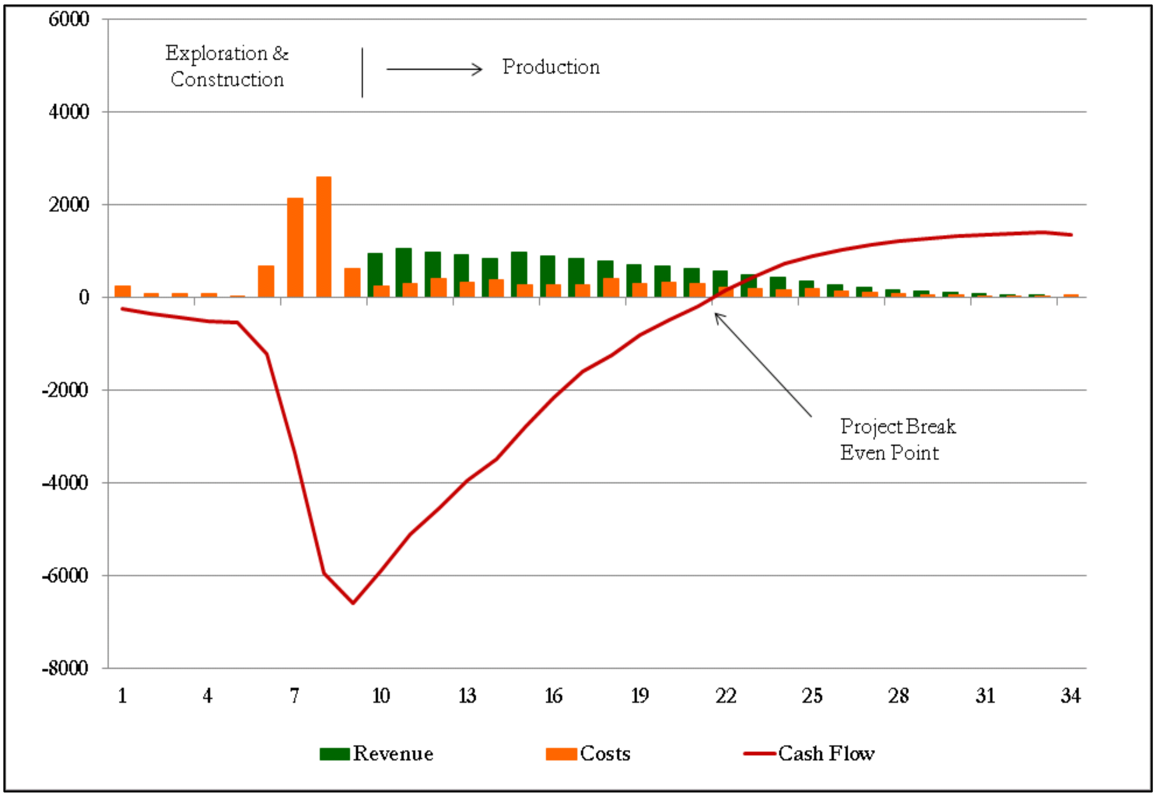
Length of time between initial discovery and production	**Number**
▪ Greater than 20 years	16
▪ Greater than 10 years	32
▪ Greater than 5 years	59
Past petroleum discoveries not yet produced	
▪ Pre 1960	2
▪ 1960 to 1970	20
▪ 1970 to 1980	33
▪ 1980 to 1990	66
▪ 1990 to 2000	89
▪ 2001 onwards	107

Source: Geoscience Australia (unpublished data - 2012)

This data demonstrates the considerable uncertainties that are associated with exploration activity. Notwithstanding the generally poor success rates associated with petroleum exploration (reflecting the high risk nature of the activity), the lengthy time periods between discoveries and a decision to produce highlights both the commercial and technical challenges that confront final investment decisions.

Figure 8 displays the profile of costs and revenues for what could be considered to be a representative large scale gas to liquids project. The results are presented on a discounted cash flow basis. As can be noted, significant costs are incurred prior to the commencement of production (both construction and exploration), while it takes many years before an investor achieves an overall positive cash flow from the project. In this example, the development costs are incurred four years prior to the commencement of production, and therefore four years prior to when depreciation can be claimed for income purposes (see further comments below).

Figure 8: Indicative Project Discount Cash Flows ($ million)



Source: APPEA

In the example above, the project does not generate a positive discounted cash flow until year 22, or more than a decade after the project has commenced production. Income tax would however be payable almost immediately from the time that production commences from the project. For the purposes of the analysis, taxation payments are factored into the project costs.

3.2 Recent and Current Australian Projects

The petroleum industry is at the forefront of globalisation. Capital is mobile and the majority is obtained from foreign sources. It is a reality that the future development of the nation's petroleum resources will be heavily reliant on foreign capital and expertise. Table 3 outlines the size of the capital commitments that have been required to construct Australia's recent expansion in LNG developments.

Table 3: Project Capital Costs (as at September 2014) - $A

Operating LNG projects

PROJECT	PRODUCTION CAPACITY	CAPITAL EXPENDITURE	START DATE	PARTNERS
North West Shelf	16.3 million tonnes per annum (mtpa)	$50B-plus (in 2012 dollars)	1989	Woodside, BHP Billiton, BP Chevron, Shell, MIMI
Darwin LNG	3.7mtpa	$1.5B (in 2005 dollars)	2005	ConocoPhillips, Inpex, Eni, Santos, Tokyo Electric, Tokyo Gas
Pluto	4.3mtpa	$15.3B	2012	Woodside, Kansai Electric, Tokyo Gas

Committed / Under construction

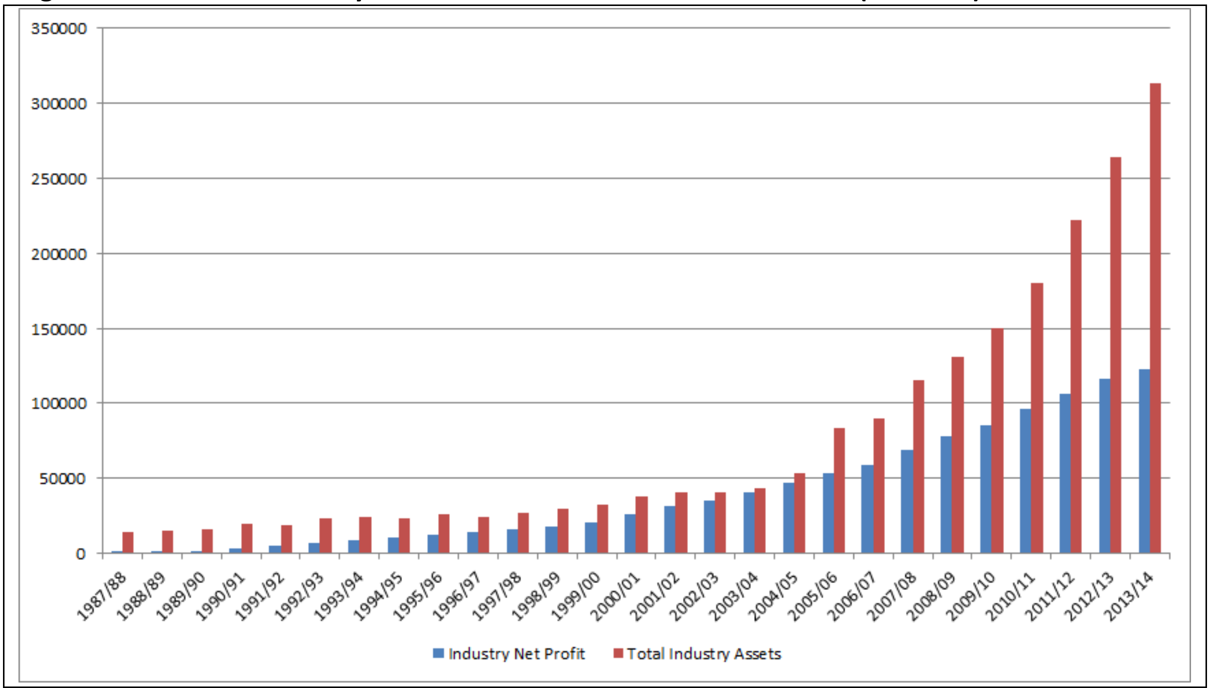
PROJECT	PRODUCTION CAPACITY	CAPITAL EXPENDITURE	START DATE	PARTNERS
Queensland Curtis LNG	8.5mtpa	$20.4B	2014	BG Group, CNOOC
Gladstone LNG	7.8mtpa	$18.5B	2015	Santos, Petronas, Total, Kogas
Australia Pacific LNG 1	9mtpa	$24.7B	2015	Origin Energy, ConocoPhillips
Gorgon	15mtpa	$54B	2015	Chevron, ExxonMobil, Shell
Ichthys	8.4mtpa	$34B	2016	Inpex, Total, CPC, Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas
Wheatstone	8.9mtpa	$29B	2016	Chevron, Apache, KUFPEC, Shell, Kyushu Electric Power Company, PE Wheatstone Pty Ltd
Prelude Floating LNG	3.5mtpa	$13B	2017	Shell Partners, Inpex, Kogas, CPC

Source: APPEA

Figure 9 compares the industry's estimated asset base value (a conservative measure of capital invested) with the sectors cumulative profits over the period commencing in the mid 1980's. The difference between asset values and cumulative profitability is a simple proxy for the level of expenditure that has been committed by the industry over and above the level of profitability during the same period.

The data highlights the significant injection of funds that have been required to fund the expansion of the industry in Australia. The data suggests that for every dollar of profit that is generated by the industry in profit, an additional $1.50 is required just to meet the cost of new projects.

Figure 9: Petroleum Industry Asset Value and Cumulative Net Profits ($ million)



Source: APPEA Annual Financial Survey

3.3 Taxation of Resource Projects

Fiscal terms that apply to oil and gas projects are one of the few mechanisms available to governments to improve project economics. Tax system settings needs to be competitive in order to attract the risk capital required to develop discovered resources. Oil and gas projects in Australia are subject to a range of taxes, fees and charges. Two of the major mechanisms are company tax and resource taxes. The resource taxation provisions were briefly outlined in Section 1.

Income (or company) tax is levied uniformly across corporate activities at a general rate of 30 per cent (a lower rate applies for small business), with most income being assessable and the majority of costs being deductible. Costs are generally broken into two categories - those that are immediately deductible (such as operating or administrative costs) and those that are depreciated over a defined period or the life of a project (capital costs).

The treatment of capital costs largely accounts for the variable impact of income tax between different business activities in the Australian economy. Costs incurred within the non-capital intensive sectors (for example, those associated within the finance, retail or services-related sectors) are generally capable of being deducted relatively quickly, while those that are more capital intensive in nature (such as within the infrastructure and resource development sectors) are generally deductible over extended periods.

A bias is inherent in the current system in that the net present value of costs which can be immediately deducted (for example, operating costs) are usually greater than the net present value of plant and equipment costs which are generally depreciated at historical cost over longer periods of time. The result is that a dollar spent on operating related activities can be more tax effective than a dollar spent on capital. This treatment favours industries which are non-capital intensive in nature. The accelerated depreciation provisions that were previously in place were an attempt to address this bias by allowing depreciation deductions above the rate that would otherwise apply based on an assets engineering or effective life.

Australia's company tax rate is relatively high by international standards. In addition, the average period over which much of the capital invested in oil and gas projects can be written off for depreciation purposes in Australia is between 15 and 20 years. This is much longer than the three-to-ten year write-off periods available to gas projects in other jurisdictions that compete with Australian projects for investment capital.

The negative impacts associated with the use of long write-off periods for plant and equipment is further exacerbated by the significant misalignment in timing between when expenditures are incurred and when a tax deduction can be claimed. While the general principle of 'first use' or 'installed ready for use' forms the basis as to when depreciation can be claimed on eligible plant and equipment, it is relevant in an economic context to recognise that the value of plant can start to diminish prior to commencement of production. In the case of large projects (such as those associated with gas developments), development expenditures can be (and often are) incurred up to five years prior to the commencement of physical production.

Overall, the company tax system plays a key role in shaping the framework within which investment decisions are made in the petroleum exploration and production industry. In simple terms, it fundamentally influences Australia's ability to compete for international investment funds.

3.4 The Current Capital Allowance Provisions

Key Consultation Question

27. To what extent does the tax treatment of capital assets affect the level or composition of investment? Would alternative approaches be preferable and, if so, why?

In 2002, the Federal Government introduced statutory caps for income tax purposes on certain classes of assets, including those assets used in the oil and gas industry. Specifically, the current caps are:

- 20 years for gas supply (transmission and distribution assets) and oil and gas extraction (offshore platforms); and
- 15 years for oil and gas extraction (oil and gas production assets other than an electricity generation assets or an offshore platform) and petroleum refining.

The result is that a taxpayer is able to bring forward a deduction to earlier income years than if a longer life applied (assuming the life of the equipment is greater than 15 or 20 years). The overall deduction over the life of the asset is unchanged. <u>The introduction of the caps has been one of the primary reasons why companies have been prepared to commit the enormous level of funding required to unlock the nation's gas resources. The slight deferment in the timing of the payment of income tax that results can significantly improve the economics of long term capital intensive gas projects.</u> The current provisions still remain well outside the shorter periods over which similar assets can be depreciated in other countries that produce oil and gas.

In the 2006-07 Federal Budget, the Government announced a modification to the depreciation arrangements with a view to ensuring that Australian businesses are able 'to stay up to date with new technology'. The decision changed the diminishing value rate under the capital allowance regime for determining depreciation deductions from 150 to 200 per cent for all eligible assets. The measures were also designed to ensure that businesses remained competitive. Significantly, it was stated by the Federal Treasurer in May 2006 that:

> *"The measure encourages efficient investment by ensuring that depreciation deductions for income tax purposes more closely reflect an asset's actual decline in value. This will enhance productivity and help sustain strong economic growth."*

Box 1: Design Life versus Operating Life for Oil and Gas Industry Capital Assets

The Commissioner in issuing effective life determinations for assets will often place a very strong emphasis on the engineering life of equipment. This can generate anomalous outcomes. The high safety standards that the industry must operate within makes it essential that much of the equipment used must have an engineering life considerably greater than the periods for which it is to be physically used. As would be expected, highly controlled conditions must be established to meet the highly volatile operating environment to ensure the highest standards in equipment reliability. While a piece of equipment may have 'theoretical design life' of a certain number of years, to suggest that this would be the period for which it is actually used would be misleading.

In the context of gas production, sales are often contracted under extremely rigid delivery terms. It is prudent to ensure that equipment is replaced well within design tolerances to ensure a continuity of supply to meet contract terms. The potential impact on customers of delivery disruptions often necessitates a very conservative equipment replacement strategy. For a variety of reasons, plant for gas projects will generally be constructed with a physical life exceeding the term of the initial or foundation contract. Again, the physical life of an asset will not necessarily be a reliable guide as to the economic life of equipment.

For example, a fifteen year gas supply contract may require construction of a fixed offshore production facility and gas gathering pipeline network to service the contract. It is a requirement that the facility operate reliably and safely throughout the 15 year contract given the worst possible operating conditions. As a result, the facility must operate at a design capacity beyond the 15 year period to ensure that it remains in a safe and reliable order for the duration of the project. A sales contract between the buyer and seller may specifically refer to this requirement. In reality, it is possible that the facility may have no economic use beyond this point unless certain specific conditions exist, including:

- a market exists beyond the original contract;
- additional hydrocarbon reserves are recoverable; and
- the price for the product makes it economic to continue production.

In addition, government regulation may also necessitate design lives well in excess of the economic life of the project. In offshore locations, it is necessary to engineer plant to withstand the worst of statistically possible weather conditions, for example 100 year storms, cyclones or wave heights. At remote onshore locations, the extremes of hot and cold temperatures also present significant engineering challenges. Safety of the industry's workforce and environmental considerations also require plant to meet the highest standards integrity standards.

The actual life extending over an extended period further reduces the correlation between the rate of deduction and the actual rate of production of petroleum, which generally commences at peak rates and declines rapidly then slowly over an extended period.

Key Consultation Questions

28. How complex is the tax treatment of capital assets and are the costs of compliance significant?

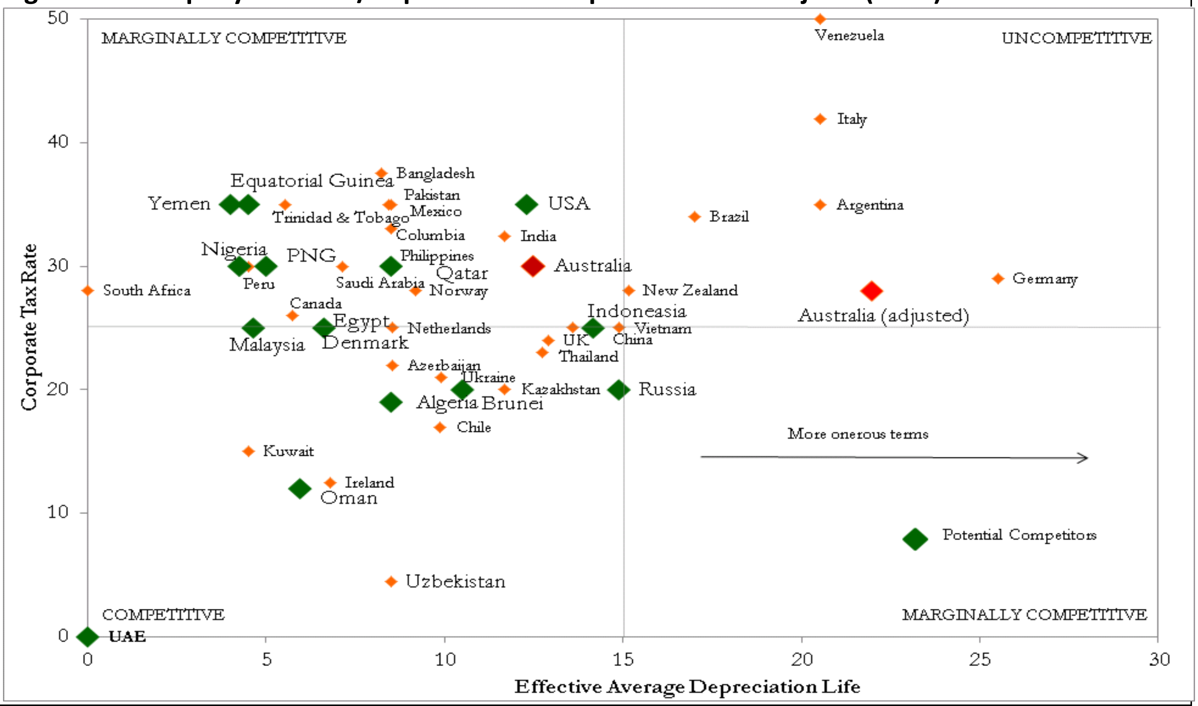
On balance, APPEA members are satisfied that the tax treatment of capital assets is not unnecessarily complex. The capped effective life of oil and gas industry assets is also an important component to reducing the compliance costs of capital allowance by reducing the need to analysis and categorise the effective life in detail.

3.5 A Global Comparison of Income Tax Terms – Gas Projects

APPEA first commissioned a study in 2006 to compare key company tax provisions for gas projects across a number of competing jurisdictions – this analysis was undated at the beginning of the decade. The analysis compares the company tax rate that applies in a range of energy producing exporting countries with the estimated periods over which capital can be written-off for depreciation purposes under the income tax systems. The results are highlighted in Figure 10.

The depreciation write-off scale attempts to factor in the special incentives that have been introduced by some countries, including investment allowances or accelerated depreciation (or both) to encourage investment in gas plant and equipment. It is clear that Australian developers face a challenging framework compared to our competitors.

Figure 10: Company Tax Rate/Depreciation Comparison – Gas Projects (2012)



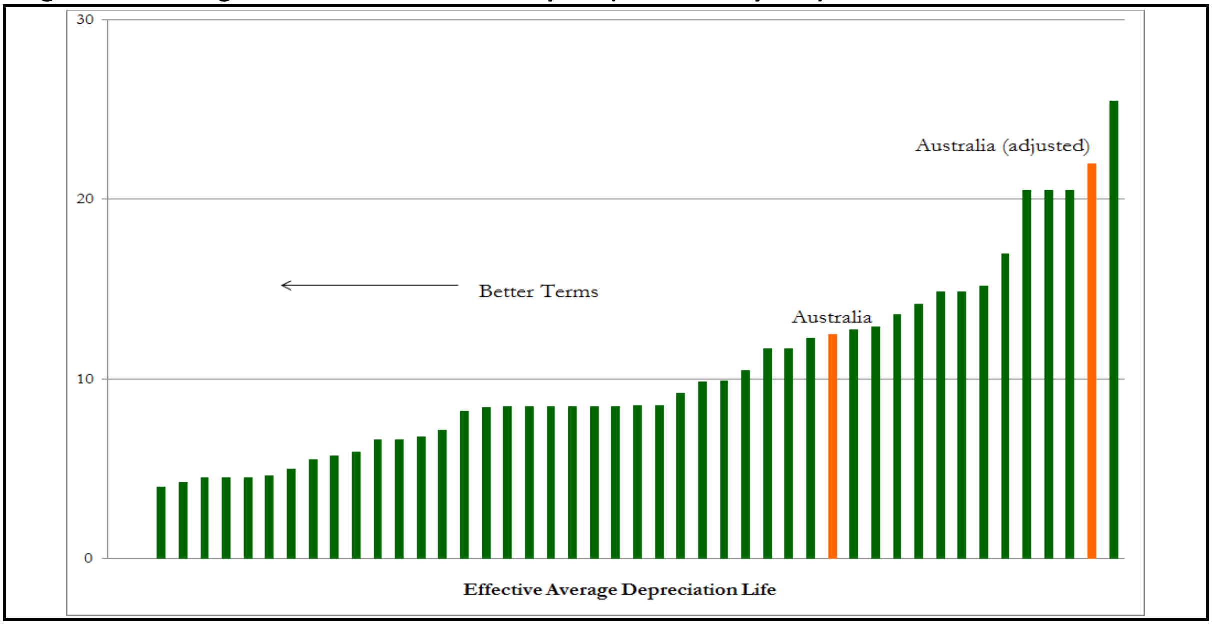
Source: APPEA (based on data supplied by KPMG)

Any decision to extend the write-off periods that currently apply (as highlighted in the chart) will further disadvantage Australian producers compared with other jurisdictions. In reality, a modest reduction in the company tax rate would only partially ameliorate the impact of more onerous depreciation terms because of the highly capital intensive nature of the oil and gas industry.

In drawing conclusions about Australia's relative competitive tax position with countries seeking to commercialise gas projects, it is clearly important to recognise that other taxes and/or fiscal systems can exist. Different resource taxation provisions and income tax parameters apply in different countries. Notwithstanding these differences, it is still illustrative to make the above comparison.

Figure 11 isolates the analysis to depreciation terms only. It demonstrates the average period over which plant can be depreciated for gas related activities. It is clear that Australia already ranks relatively poorly with the 15 year write-off terms. Any move to lengthen this period (as indicated in the 'Australia adjusted' bar which is based on a hypothetical engineering design life) will further disadvantage companies making new or incremental investment decisions in Australia.

Figure 11: Average Write-Off Periods for Capital (number of years)



Source: APPEA (based on data supplied by KPMG)

Overall, the accelerated depreciation provisions that were in place up until the end of the 1990's helped mitigate against the above position, while the 15/20 year effective life caps introduced in 2002 go some way to addressing the competitive disadvantage. As noted previously, the negative impacts associated with the use of long write-off periods for plant and equipment are further exacerbated by the mismatch in timing between when expenditures are incurred and when a tax deduction can first be claimed.

In summary, the comparison shows that most current and prospective gas exporting countries enjoy low effective company tax rates and allow project proponents to depreciate capital over periods considerably less than ten years.

The tax discussion paper sought commentary as to what the extent does the tax treatment of capital assets affect the level or composition of investment and whether alternative approaches would be preferable? The advice from APPEA member companies is that the current provisions have been a key factor that has allowed Australia to become a world leader in the export of natural gas to global markets.

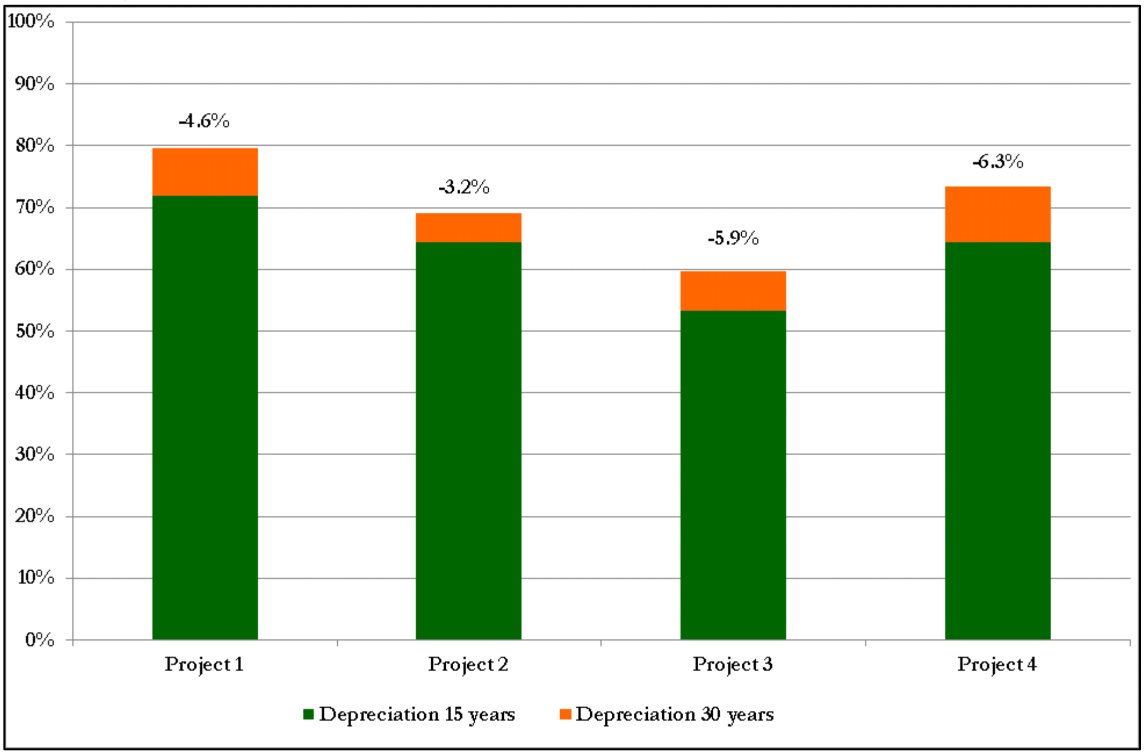
3.6 The Tax-Base/Tax-Rate Trade-Off

Much discussion in the context of tax reform has surrounded the argument that a reduction in the company tax rate would be of benefit to the overall business community. Such a reduction would improve Australia's relative ranking in terms of the baseline tax rate with competitor nations. In the context of the broader reform agenda, modifications to the taxation base that are introduced to fund a reduction in the tax rate must be viewed in a wider context.

It is important to understand the potential impacts associated with offsetting changes to key company tax settings. An illustrative example is the impact associated with a change to the depreciation terms and the tax rate. APPEA undertook such an analysis in 2012 as part of the information submitted to the Business Tax Working Group. That Group was tasked with considering a cut to the company tax rate accompanied by measures that fully offset the cost of such a rate reduction (such as depreciation terms).

As indicated above, the average period over which much of the capital invested in gas projects may be written off is between 15 and 20 years. This is much longer than the three-to-ten year write-off periods available to gas projects overseas that compete with Australian projects for investment capital and gas customers. The existence of the 15/20 year statutory caps for oil and gas assets is to address both competitiveness issues and a range of other factors (including energy policy objectives) that would otherwise act to discourage investments in such projects.

Figure 12: Estimated Government Tax Take of Total Project Cash Flows - Net Present Value (Percentage Take)



Source: APPEA

APPEA modelled a range of hypothetical projects to examine both the governments tax take from the respective projects (on a net present value basis), as well as the quantum of a reduction that would be required in the company tax rate to compensate for depreciation lives shifting from 15 years to 30 years. Figure 12 outlines the results.

Not only is the government's share of project returns high (between 54 and 72 per cent), the importance of the depreciation terms is clearly demonstrated as reductions in the company tax rate of between 3.2 to 6.3 percentage points would be required to offset against the removal of the existing depreciation provisions.

Recommendation

The existing depreciation provisions have been an important factor that has allowed Australia to attract the investment funds necessary to expand our natural gas export capability to a world class scale. Not only do these provisions need to be retained, they arguably need to be further shortened if Australia is to attract the next wave of investment in this critical export industry.

3.7 Other Comments

Key Consultation Questions

29. To what extent does the tax treatment of losses discourage risk-taking and innovation and hinder business restructuring? Would alternative approaches be preferable and, if so, why?

36. Should the tax system provide a more neutral treatment of income earned on revenue account and capital account? Does the distinction create significant compliance costs for business and, if so, how could it be simplified?

Australia has some of the world's most complicated loss integrity rules, many of which were put in place prior to tax consolidation provisions and deal with rare or hypothetical scenarios. These rules need to be considered during any corporate restructure and can impede potential efficiency driven restructures.

The current distinction between revenue and capital makes little sense for large corporate taxpayers. Capital gains are taxed at the same rate as revenue gains and receive no indexation benefit yet capital losses are quarantined. In capital intensive depletive industries such as mining and petroleum, where capital gains can be rare, this can mean that no tax benefit is received for legitimate economic losses which are classified as capital losses.

Consideration should also be given to identifying measures which could support the sharing or realignment of ownership of infrastructure assets to encourage the efficient development of Australia's resources. Experience in the past is that fiscal settings can impede such activities.

SECTION 4: OTHER ISSUES

Outlined below are a range of issues and examples of how the existing taxation imposes complexities and/or rigidities on the operations of companies.

4.1 Tax Complexity

Key Consultation Question
56. What parts of Australia's tax system, and which groups of taxpayers, are most affected by complexity? What are the main causes of complexity?

4.1.1 Production Excise

The crude oil excise regime has been in place since the mid-1970s. As outlined above, it applies in conjunction with the Commonwealth royalty or state/territory royalties (depending on the location of a project). With the exception of the NWS Project, no other offshore projects are subject to production excise or royalties.

It was originally introduced as a levy on each barrel of oil production sold from eligible areas, and was then substantially modified in 1983 such that it then applied at varying rates depending on the discovery and development date of the relevant producing field or project. In April 1984, the 'new oil' excise scale was introduced, while the 'intermediate scale' was introduced at the end of 1984 to encourage the development of satellite fields that had become uneconomic under the 'old oil' scale. In July 1987, a 30 million barrel excise exemption for each field was introduced to further stimulate the development of oil discoveries.

In the 1977/78 Federal Budget, a number of announcements were made covering the operation of the excise regime. In relation to condensate, the following was announced:

> *The levy will not apply to condensate marketed separately from a crude oil stream; such condensate may now be sold at commercially negotiated prices. Nor will the levy apply to liquefied petroleum gas fields yet in production. This will assist the marketing of LPG and condensate from fields already discovered but not yet developed in the North West Shelf and Cooper Basin. Condensate sold commingled in a crude oil stream will continue to be treated as crude oil for pricing and levy purposes.*

On 13 May 2008, the Federal Government announced an intention to remove the exemption of condensate from the crude oil excise regime. The Treasurer stated that the "… *measure will increase the return to the Australian community from allowing private interests to extract non-renewable energy resources located in the North West Shelf project area and onshore*".

Information currently available to APPEA in relation to onshore production indicates that very few petroleum fields have or will ever exceed the 30 million barrel excise free allowance threshold. Even in the very limited cases where this threshold may be passed, the annual levels of production that will apply to the relevant taxable areas will most likely be insufficient to incur an actual excise liability. In effect, there is not expected to be any duty incurred for onshore crude oil and/or condensate production in Australia. Despite this, all onshore producers are required to meet the on-going verification, administrative and compliance obligations imposed by the excise regime.

In addition to the compliance obligation on companies, the imposition of a potential excise liability on onshore crude oil and condensate production (in the event of a future discovery) has the real potential to discourage future exploration decisions. In particular, this may have implications for exploration in frontier onshore areas where the risk/reward balance can be different to more traditionally explored regions. High risk frontier exploration requires a fiscal framework that provides an incentive for risk capital to be directed towards these areas – the imposition of a potential excise liability on future discoveries clearly sends a negative fiscal signal. The imposition of this form of taxation will be even more complex in the event that liquids production is generated from unconventional sources. For example, the definition of a 'field' that currently exists will be challenging in the context of the different geological factors associated with unconventional resources.

Perhaps more importantly, the Government has also effectively recognised that PRRT is now its primary mechanism for the taxation of crude oil and condensate and therefore the continued application of excise for areas that are unlikely to incur a liability is inconsistent with established benchmarks.

APPEA considers that crude oil and condensate excise should be abolished for all onshore areas in recognition that:

- production excise duty is unlikely to be payable on current onshore discoveries;
- there are ongoing reporting and compliance burdens being placed on many onshore producers;
- the Commonwealth now applies PRRT to all onshore petroleum production; and
- the potentially negative impact that production excise can have on onshore exploration decisions.

Recommendation

Crude oil and condensate production excise be abolished for all onshore and state waters production areas.

4.1.2 Dealings and transactions in permits and interests

The taxation of the acquisition and disposal of interests in a petroleum project can be complex because of the interaction of capital gains tax and income tax provisions. The trading in petroleum assets is important to the activity of the sector to spread risk of projects and to allow projects to be undertaken by the investor best suited to maximise the returns from the project. For example, large projects require the capital and technical expertise of large companies, which because of their scale of operation, may not be the optimal investor in depleting assets sensitive to costs or assets with high risk. The nature of a project changes over time and can require a re-alignment of investors.

The recent proposals in relation to farm-outs and interest realignments reduced the uncertainty and complexity associated with those particular type of transactions but further complexities remain.

Complexity also arises through the capital gains tax provisions, in particular from the bi-furcation of rights to receive proceeds from the proceeds themselves (such as in the earn-out ruling), the CGT consequences of CGT event C2 arising on cancellations and capital gains arising from CGT event D1 for which there is some evidence that it is applied in inconsistent ways.

In addition, a common industry practice to deal with uncertainty in valuations is for a purchaser to grant a seller a royalty, which will provide the seller with that uncertain value if it arises. The generally accepted view is that receipt of the right to a royalty by the seller is a capital gain and that the future royalty is also subject to tax as it is received, representing double taxation. The cancellation of the royalty, which may be required to affect a future sale, may also give rise to a CGT event C2 gain.

Recommendation

A simplification to the CGT provisions associated with the creation and cancellation of income rights to reduce complexity and uncertainty and eliminate double taxation.

4.1.3 Goods and Services Tax

Since its introduction, the GST legislation has largely remained unchanged and has consistently been overlook or excluded from the various major tax reviews that have been initiated by successive Federal Governments. However during the 15 years since its inception, the world and business practices have evolved such that embedded gaps, unintended consequences or blind spots in the original legislation have been amplified creating enhanced risk and complexity. The GST legislation needs modernisation and clear administrative principles to provide business surety when managing this real time tax.

Increased GST complexity affects many entities (including APPEA members) and typically results in higher administrative costs as increased time is required to manage GST obligations. All of this, notwithstanding that typically there is no loss of revenue as the transactions are generally revenue neutral.

Whilst there are numerous areas of the legislation ripe for improvement including, cross border transaction (exports and imports of non-goods; and dealings with non-residents), two particular areas of interest to APPEA members are the GST joint venture provisions and the treatment of non-cash transactions (barters).

The high cost and technical complexity of developing oil and gas projects has led to large projects in the industry increasingly being undertaken by multiple parties within common project developments. The use of common project developments is also being promoted by State Governments.

While a common project development can be structured in different ways, in broad terms, it involves the construction and operation of infrastructure that is made available to parties other than those who constructed it. The aim being to eliminate the need to developing duplicate infrastructure and thus enabling third parties to develop new projects by utilising the common infrastructure without incurring high capital costs of their own.

However, when the existing GST law is applied to these common project developments, a number of complex GST issues emerge from the need to identify GST taxable supplies between the common project development participants. The difficulty is compounded if there is no monetary consideration for the supply as non-monetary consideration is difficult to identify and value. As transactions may not always be recognised for accounting, this leads to not only a high compliance cost being imposed on the common project development participants to identify, value and account for these supplies, but a risk of penalties being imposed as whatever view the parties take is open to challenge by the Commissioner of Taxation. This is despite the fact these transactions generate no net GST revenue as any GST paid is claimed as a credit by the recipient party.

Recommendation

In order to reduce the GST compliance burden and risks associated with transactions between joint venture participants, it is recommended that revenue neutral amendments be introduced to sub-division 51-B of the GST Act.

4.2 Royalties and Transfer Duties

Key Consultation Question

52. What are the relative priorities for state and local tax reform and why? In considering reform opportunities for particular state taxes, what are the broader considerations that need to be taken into account to balance equity, efficiency and transitional costs?

4.2.1 Petroleum Royalties

Royalty Administration

Each state and territory jurisdiction in Australia has relatively well established mining and petroleum royalty regimes. For petroleum, most apply royalties at a rate of ten per cent of the wellhead value of production. While these regimes have provided stable revenue bases, companies with petroleum operations in some states are experiencing increased complexity and uncertainty in terms of the application of the royalty provisions.

Companies operating in more than one state or territory invariably need to develop separate systems and compliance processes to meet different obligations that regulators are placing in determining royalty liabilities. The industry considers that a move to harmonise the determination and administration of royalties across state/territory jurisdictions should be considered. In fact, this should occur with respect to all state/territory imposts such as land taxes, stamp duties, carbon certificate schemes etc. Such an outcome would both provide certainty for companies in understanding the operation of the relevant impost provisions, and avoid the need for the introduction of costly and complex compliance systems for individual jurisdictions.

Royalty Framework

The industry recognises the merits of profits based taxes, such as the petroleum resource rent tax, however the introduction of profits-based systems under state and territory jurisdictions would need to be very carefully considered. This is particularly the case for a sector that has been operating for many decades and where companies have mature operations in place.

The experience associated with extending the PRRT to onshore areas in 2012 provides lessons for both the complexity of any change and the need for provisions not to lead to unintended outcomes. Issues such as establishing the 'tax position' of existing projects, determining the treatment of past expenditures and agreeing on the categories of deductible costs would all require close attention. Furthermore, the application of a risk premium on expenditures to ensure projects do not incur a tax liability prior to generating a risk adjusted return is also an important factor. Overall, APPEA does not consider that a compelling case exists for the states and territories to move to profits based systems.

Royalty Incentives

APPEA supports consideration being given to the implementation of targeted incentives within the royalty framework to cover petroleum production from sources that require the development and adoption of new technologies. Such projects invariably involve high degrees of risk. Incentives could be provided by using a number of mechanisms, including through a reduction in the rate of royalty or a royalty holiday period.

Recommendation

Governments consider the harmonisation of the administration of the petroleum royalty regimes (and other imposts) in Australia and that measures be considered to provide royalty relief for the production of hydrocarbons from projects that require the adoption of new technologies.

4.2.2 Duties and Licence Fees

APPEA recommends that consideration be given to the abolition of duties on business transactions. While a number of states have moved to reduce duties on a range of activities, some still have wide bases that can impede business decisions and investments.

The efficient development (and exploration) of Australia's resource base is dependent on the ability of companies to realign interests or to engage in farm-in transactions. Such transactions are often necessary so that commercial interests can be aligned or new parties are brought into projects to provide the technical and/or financial resources necessary for ongoing investment activity. Such transactions can be discouraged (or indeed abandoned) purely as the result of the imposition of duties or licence fees. While some targeted exemptions currently exist, it is recommended that the Government considers exempting all dealings in exploration and petroleum licences and permits.

Recommendation

All government move to abolish transfer fees and duties on farm-in transactions or commercial realignments in the petroleum industry.