

# **Submission to the Review of Commonwealth Petroleum Resource Taxes**



**AUSTRALIAN PETROLEUM PRODUCTION & EXPLORATION ASSOCIATION (APPEA) LTD**

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## Inquiry Terms of Reference

The Terms of Reference for the review, released by the Treasurer on 30 November 2016, are:

- The review will have regard to the need to provide an appropriate return to the community on Australia's finite oil and gas resources while supporting the development of those resources, including industry exploration, investment and growth.
  - The review will examine the design and operation of the PRRT, crude oil excise and associated Commonwealth royalties that apply to the onshore and offshore oil and gas industry, having regard to economic conditions in the industry and trends over time.
  - The review will also consider the impact of previous policy decisions on Commonwealth revenue.
  - Drawing on international experience, the review will make recommendations to the Government on future tax, excise and royalty arrangements having regard to revenue adequacy, efficiency, equity, complexity, regulatory costs and the impact on the industry generally.
  - The review will also examine other related matters.
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## Executive Summary

*“The Government believes that an RRT regime, which is related to achieved profits, is the most efficient mechanism for deriving for the community an appropriate share of the large returns that can be associated with the development of particularly rich mineral deposits. Alternative secondary taxing regimes, such as the excises and royalties applying in the petroleum sector, are often based on production and, as such, can both discourage marginal projects from getting underway and bring about the early termination of projects.”*

*“The Government believes that, seen in their totality, the arrangements decided upon represent a very reasonable balance between the objectives of satisfying the interests of the community as a whole in sharing in the benefits of very profitable offshore petroleum projects, and of providing companies with adequate rewards in return for the risks that they accept in undertaking offshore exploration and development activities.”*

The Hon Paul Keating MP and Senator The Hon Peter Walsh, 27 June 1984

The Australian Petroleum Production & Exploration Association (APPEA) is the peak national body that represents companies engaged in oil and gas exploration and production operations in Australia. APPEA’s members account for the vast majority of Australia’s oil and gas production and petroleum exploration.

The oil and gas industry is an integral part of the Australian economy, including through:

- the supply of reliable and competitively priced energy;
- the investment of hundreds of billions of dollars of capital;
- the payment of taxes and resource charges to governments;
- the direct employment of tens of thousands of Australians; and
- the generation of significant amounts of export earnings.

The industry is ending a decade of unprecedented capital investment, with potential to capture more opportunities in growing global and domestic gas markets.

The sector is truly global in nature and each Australian project must compete against other projects for investment from a limited pool of funds for both exploration and production activities. Oil and gas funding that is lost from the industry will not be spent in other parts of the Australian economy - it will be redirected to Australia’s overseas competitors. While the industry has committed to the development of a number of large scale gas projects over the last decade, the next generation of investments (and extensions to existing and committed projects) will be heavily dependent on the terms of the tax system, as it has an important impact on project economics and investor returns.

Any changes that lead to increased imposts under the resource taxation system will damage the ability of Australia to attract projects and thereby diminish the capacity to create sustainable taxation revenue streams for future generations.

The petroleum resource rent tax (PRRT) has operated in Australia since the mid 1980's, at first applying to new offshore projects, then extended to Bass Strait, and finally expanded in 2012 to cover all Australian petroleum operations. In some jurisdictions, it applies in conjunction with other resource taxes, however the existing PRRT provisions avoid the imposition of double taxation on the same production. The combined operation and relative stability of the resource and company tax systems have provided the certainty required to justify investments in very large projects.

The inquiry called by the Federal Treasurer on 30 November 2016 seeks to examine the design features and operation of the PRRT, with regard to the economic conditions that confront the industry and balancing the need to generate revenue, while continuing to support the development of the nation's resources.

**APPEA does not consider a case exists for any changes to be made to the existing PRRT provisions.**

The PRRT has been instrumental in promoting a long term and robust exploration effort in Australia to find and develop our oil and gas resources. It has also provided investors with an efficient taxation system that recognises the need for companies to achieve a return on invested funds before the imposition of a resource tax liability. Overall, PRRT has been critical to Australia's success as a global leader in the supply of gas to domestic and worldwide markets.

Critics of PRRT express concerns about its failure to collect revenue at all stages of the investment cycle. These views do not recognise the intense global competition for investment, the economy wide benefits of the industry, the risks undertaken by investors, the actual rent generated by projects, the timing of the investment cycle and more fundamentally, disregard the intentional design features of the PRRT.

Comparisons made with other countries ignore a range of significant factors that impact on project profitability – Australia remains a relatively high cost country and is still in the early stages of its development as a global energy producer (noting some projects have yet to commence production). Material compiled by Wood Mackenzie demonstrates the challenging cost framework within which the industry operates in Australia compared with other gas producing countries, and the benefits of a profits based resource taxation regime that is sensitive to movements in costs and prices.

The key parameters of PRRT remain as relevant today as they were at the time of their introduction. The provisions act as an integrated package of measures ensuring the risks associated with undertaking exploration and development activities in Australia are balanced against the rewards necessary to underpin the commitment of funds. The PRRT provides a balanced framework that imposes a high tax burden on investors after a modest return has been achieved from individual projects. It is essential that it continues to operate in this fashion.

The changes made to the tax since its introduction have been logical and have been mindful of the nation's energy policy objectives. Modifications have also been respectful of past investments and have attempted to ameliorate the retrospective impacts when it has been extended to new projects and areas.

It is important to note that taxation payments by the industry have remained robust despite a significant fall in the level of industry profitability and the abundance of projects in the early stages of their investment cycle. In the year 2014-15, despite the industry recording an overall net operating loss, tax payments of in excess of \$5 billion were made to governments across Australia.

For the industry to capture the next wave of developments in the sector, a stable and balanced fiscal framework is essential. Australia has a proven, successful model (including the PRRT) which should be retained.



## Section 1: The Australian Oil and Gas Industry

*“Australia’s continuing economic and social benefits resulting from its mineral and energy resource wealth is mostly the result of discoveries made decades ago and it is important to recognise that major discoveries have a long lead time to bring into production, commonly over a decade.*

*“Although the resources being mined currently are available to continue to support the country’s economy, new discoveries need to be made to replenish resources and ensure continuing supply and production into the future.”*

Dr Chris Pigram, CEO, Geoscience Australia, 19 September 2012

### 1.1. Introduction

Since the late 1960’s, oil and gas production has played a significant role in the Australian economy. The industry has been pivotal in the supply of energy to Australia and many of our key trading partners. The growth of the industry has provided many benefits to generations of Australians.

The position of the 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 important taxation settings. These have assisted investors to commit the vast sums of capital necessary to both find and develop the resource base. Importantly, they have created a relatively stable framework that has provided investors with the confidence to respond to the competition challenges from other countries.

Changes to cost structures and investor sentiment as a result of negative tax modifications can have significant implications in capital intensive projects with long lead times, impacting on exploration, development and production decisions. While investments in the industry have been significant to date, future decisions will be dependent on a taxation system that balances risk with reward. To capture future opportunities, it is critical that the resource taxation framework remains structured in a manner that does not discourage investments in risk taking and value adding activities.

The industry is approaching the end of a phase of investments in gas projects that has led to one of the largest commitments of risk capital in Australia’s history. Further investment in the oil and gas sector is within reach (including expansions to existing projects), however it is by no means assured. There are a number of national and state areas of policy in which complacency may threaten Australia’s attractiveness as a place to do business – tax is one of these areas.

The existing growth has been aided by Australia’s position at the cusp of a major shift in the world’s economic weight from west to east. Global growth has been driven by the rapid industrialisation of China and other large Asian economies, such as India. This has changed the dynamics of key international resource, product and capital markets. For Australia, this has translated into strong demand for our energy resources, particularly natural gas.

The economic advance of our region has been overwhelmingly positive for Australia. It plays to our comparative advantage as a secure and reliable energy exporter, our proximity to markets and being an open economy that encourages foreign investment. However, the continued growth of the oil and gas industry cannot be taken for granted as we are a relatively high cost investment destination compared to other oil and gas producing countries and we need to encourage future exploration activity.

## 1.2 Economic Contribution

A number studies and reports published over the last five years have confirmed the role that the oil and gas industry makes to Australia's economic prosperity. A brief sample are outlined below.

### *National Economic Benefits (Deloitte Access Economics 2012)*

Deloitte Access Economics (DAE) undertook an economic study of the sector, quantifying the output and how it will potentially grow over time. DAE also analysed the economic impact of the industry, recognising the level of capital investment committed and the value of increased production. This captures the industry's contribution over and above its significant production and export profile.

The analysis covered the economic contribution through the direct impact of oil and gas operations and the flow-on contribution of oil and gas projects. In 2011, the sector contributed \$28.3 billion to the economy – accounting for 2.0% of GDP. The extractive processes and related refining operations are highly capital intensive and value adding. Of this, \$4.3 billion was found to be flow on contributions distributed among supplying industries: exploration support and professional services, maintenance and construction, transport and storage and wholesale trade in Australia. The linkages between sectors have significant regional, interstate and international dimensions.

The future contribution is expected to be even more significant. The committed expansion is forecast to increase output by \$68 billion in 2020 and \$63 billion in 2025. The share of the oil and gas industry and associated exploration activities to GDP increases from 2.1% to 2.5 % in 2025 – peaking at 3.5% in 2020. The industry is forecast to make a substantive contribution to government revenues – \$93.6 billion in net present value terms (2011 dollars for the period 2011 to 2025).

(See [http://www.appea.com.au/wp-content/uploads/2013/04/120625\\_DAEreportAPPEAfinal.pdf](http://www.appea.com.au/wp-content/uploads/2013/04/120625_DAEreportAPPEAfinal.pdf) for more details.)

### *Australian Oil and Gas Industry Value-Adding (PwC 2014)*

The oil and gas industry has played an important role in underpinning much of Australia's economic prosperity and growth over the last decade. A 2014 PwC report, *Value Adding: Australian Oil and Gas Industry*, notes that:

- The oil and gas industry directly accounts for around 2 per cent of GDP, with value-added of about \$32 billion in 2012-13.
- The contribution of the oil and gas and exploration sectors is projected to double to about \$53 billion in 2019-20 and \$67 billion in 2029-30.

- The annual value of natural gas exports is expected to be in the range of \$60-70 billion by 2019.
- After accounting for its inter-linkages with the rest of the economy (businesses all over Australia supply goods and services to the oil and gas industry, and the use of fly-in, fly-out staff is spreading the benefits of the industry), the sector is projected to be around 3.5 per cent of national output in 2030.
- By 2020, the sector's economic contribution will more than double to \$70 billion and taxation paid will rise from \$8.8 billion in 2012 (\$4.9 billion in corporate taxes and \$3.8 billion in production taxes) to reach almost \$13 billion.

(See <http://www.appea.com.au/wp-content/uploads/2014/11/PwC-Report-Oil-and-Gas-Industry-Sept-2014-FINAL.pdf> for more details.)

#### *Economic Contribution of Gippsland Basin Joint Venture (ACIL Allen 2016)*

The Gippsland Basin Joint Venture was formed in 1964 between Esso and BHP Billiton. The project has operated successfully for nearly 50 years and made a significant and enduring contribution to Victoria and Australia. Direct impacts have included:

- In 2016 dollars, \$10.7 billion in capital works and more than \$12.9 billion in operating expenditures.
- Direct employment of around 1000 workers per year.
- Generation of gross revenues of over \$330 billion in 2016 dollars from 4.7 billion barrels of oil and 8 trillion cubic feet of gas production.
- Payment of over \$220 billion (2016 \$'s) in taxes, royalties and excise since the commencement of production.
- The production of 54 per cent of all of Australia's crude oil and liquids production and 40 per cent of Eastern Australia's gas production since the commencement of production.

The above are in addition to significant contributions to gross domestic and state products and the improvement in real incomes since production commenced.

(See [http://www.acilallen.com.au/cms\\_files/ACILAllen\\_GBJV\\_2016Factsheet.pdf](http://www.acilallen.com.au/cms_files/ACILAllen_GBJV_2016Factsheet.pdf) for more details.)

#### *The Queensland Coal Seam Gas Industry (ACIL Tasman 2014)*

The potential benefits of the growth of Queensland's coal seam gas sector were evaluated by ACIL Tasman in 2012. It was estimated that the expansion of the gas industry has the potential to increase Gross State Product in Queensland by half a trillion dollars in the coming decades, boosting employment, wages, and the state's reputation as an economic powerhouse.

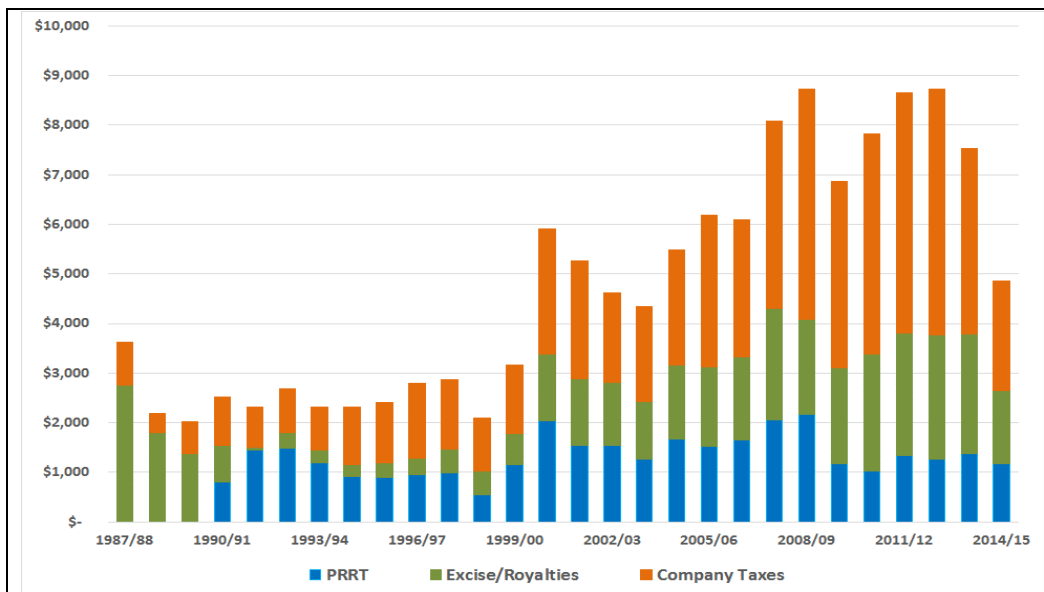
The industry's activities will be responsible for more than 20,000 full-time equivalent jobs each year by 2035. The report also finds in the years 2015 to 2035, the expansion of the Queensland CSG industry could place downward pressure on wholesale electricity prices, reducing prices by 10% and pay a further \$275 billion to governments in taxes and royalties.

(See [http://www.appea.com.au/wp-content/uploads/2013/05/120606\\_ACIL-qld-csg-final-report.pdf](http://www.appea.com.au/wp-content/uploads/2013/05/120606_ACIL-qld-csg-final-report.pdf) for more details).

### 1.3 Industry Tax Contribution and Profitability

The industry pays a variety of charges in relation to its activities, including resource taxes, company income tax and numerous other fees and charges ranging from import duties to state based licence fees and duties. The two main categories are company tax and resource taxes (petroleum resource rent tax, royalties and production excise).

Chart 1: Oil and Gas Industry Estimated Company and Resource Tax Payments (\$m)



Source: APPEA Financial Survey

Chart 1 outlines the estimated level of company and resource tax payments made by the Australia oil and gas industry based on financial survey data obtained from APPEA member companies. This information has been collected on an annual basis since 1987-88 and forms part of APPEA's annual industry financial survey.

In terms of the segmentation of the two primary forms of taxation paid by the industry (company tax and resource taxes), on average, around half has been attributable to each form of taxation over the period since data has been collected, although this will change with company tax receipts being expected to significantly increase in coming years as new large scale export gas projects reach plateau production.

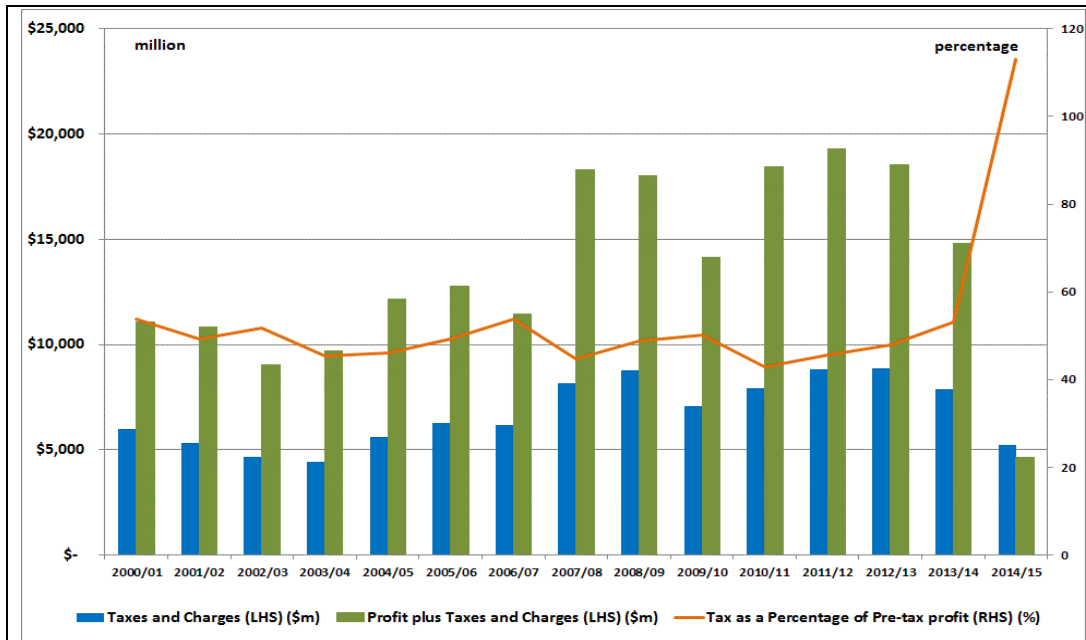
Overall, tax payments generally averaged between \$7 and \$8 billion per annum in the period 2007-08 to 2013-14, however this fell in 2014-15 in line with the significant reduction in commodity prices and the continued decline in petroleum liquids production in Australia (see Section 1.5).

Chart 2 presents total tax payments, industry pre-tax profit and total taxes as a percentage of pre-tax profit.



The industry's overall level of tax payments has, on average, been equal to industry net profit since 2000-01. This changed significantly in 2014-15, when a net loss was recorded for the first time since the survey has been conducted. In the same year, more than \$5 billion was paid in taxes.

Chart 2: Taxes Paid, Profit (before) Taxes and Tax Percentage

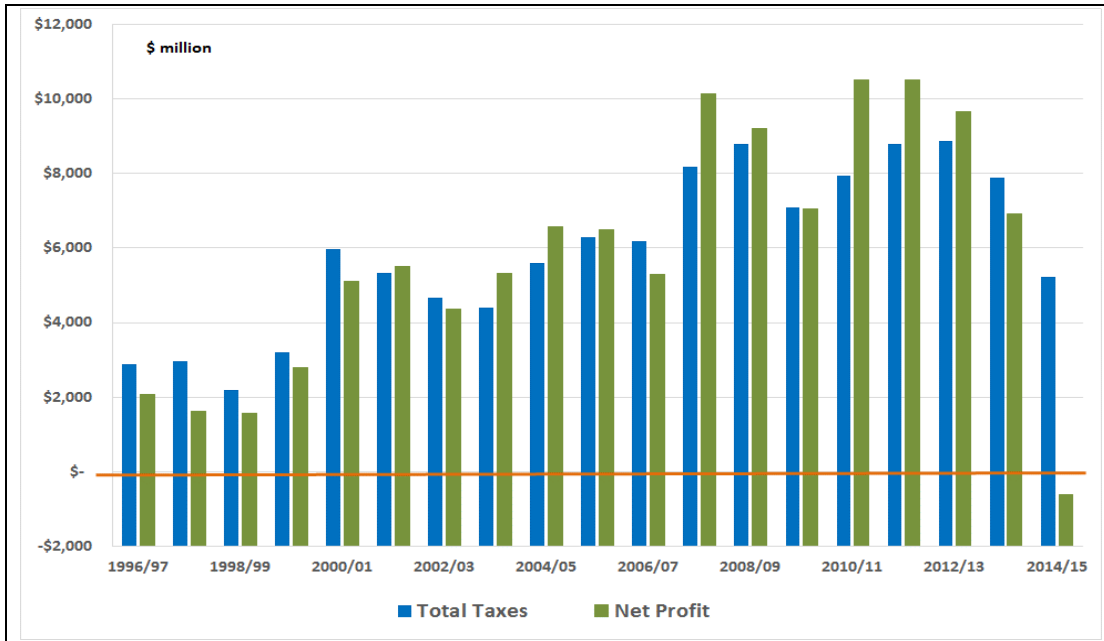


Source: APPEA Financial Survey

The fact that the industry incurs tax liabilities despite being in an overall loss position is explained by a number of factors. Firstly, deductions under the company tax and royalty regimes are limited by the application of depreciation provisions, while restrictions on deductible expenditure apply under most regimes. In addition, some individual projects have remained cash flow positive despite the fall in oil and gas prices, and therefore have continued to pay tax.

Chart 3 outlines taxes paid and net profit. As indicated above, the net loss recorded in 2014-15 is the first such result since the commencement of the survey in the mid-1980s.

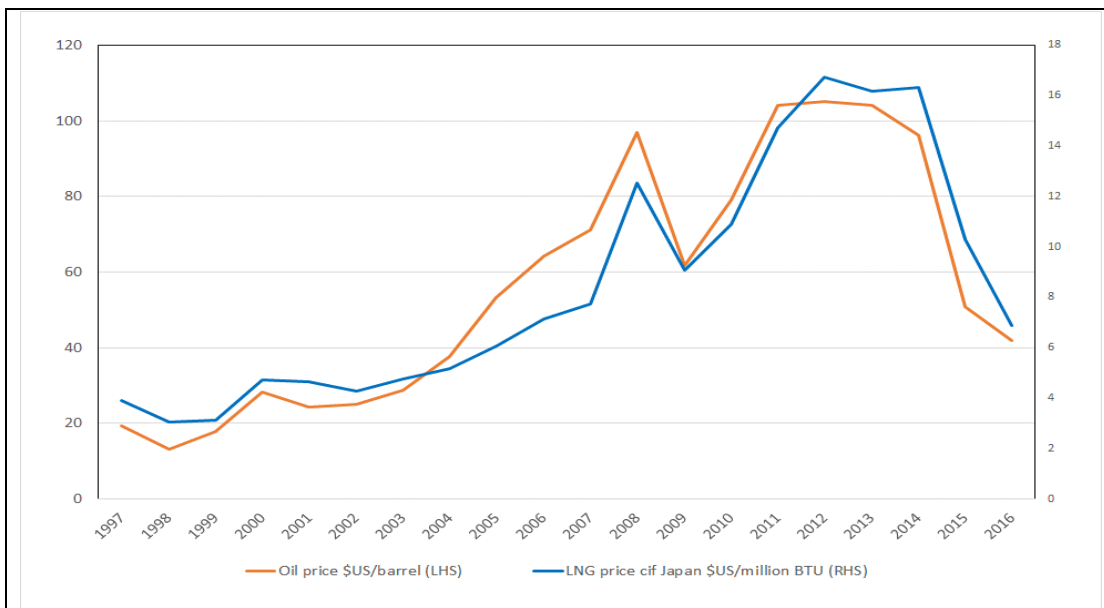
Chart 3: Oil and Gas Industry Tax Payments and Net Profit (\$m)



Source: APPEA Financial Survey

A major factor that impacts on profitability for projects in the oil and gas industry is the price of oil and gas (see Chart 4). The significant fall in both crude oil and liquefied natural gas prices over the last three years has dramatically impacted on industry profitability, and therefore the level of tax paid by the sector and the availability of funds for future exploration and production investments. The industry is also emerging from an unprecedented period of capital investment.

Chart 4: World Oil and LNG Prices (\$US)

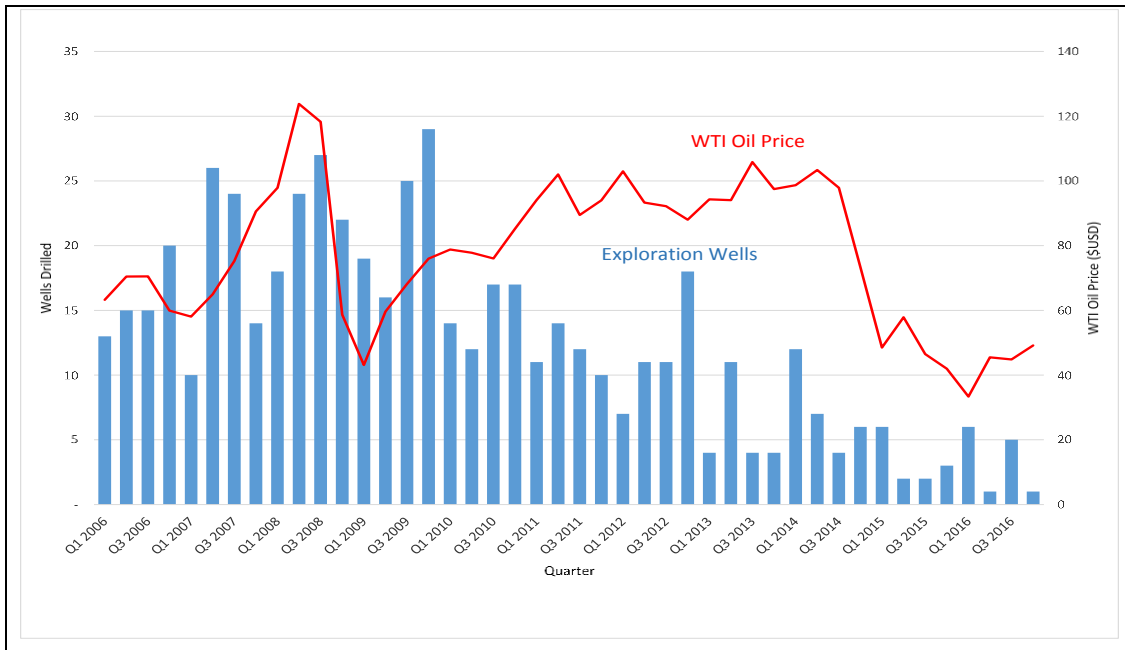


Source: BP Statistical Review of World Energy, IndexMundi, World Bank

### 1.4 Petroleum Exploration

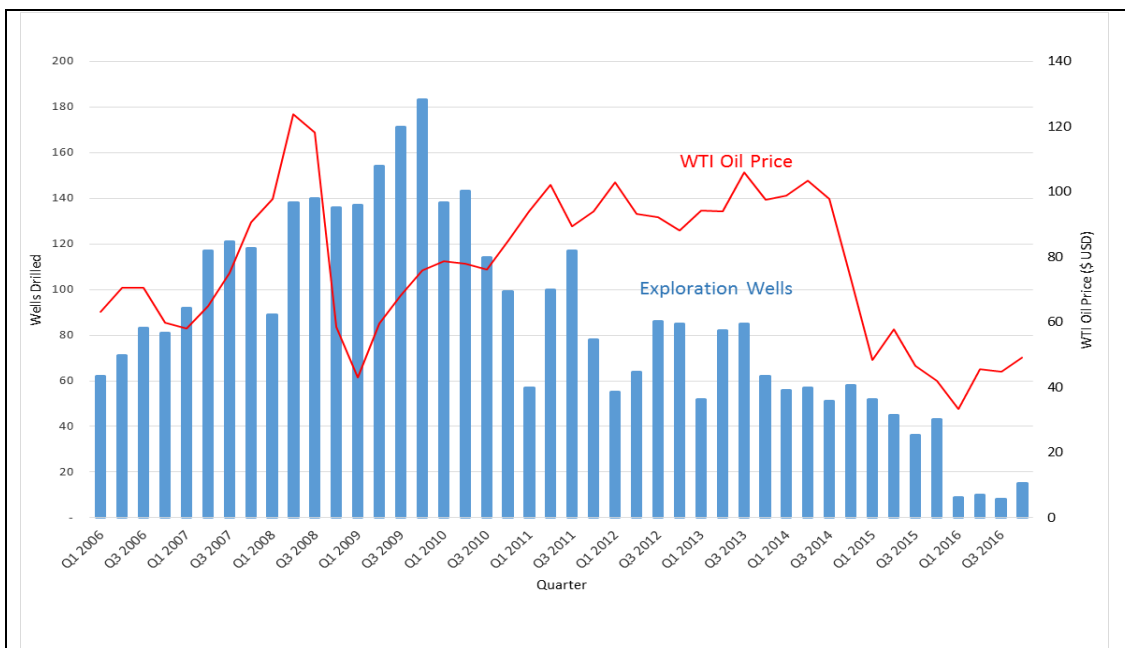
The long-term growth of the industry is dependent on exploration. Oil and gas cannot be produced without first locating commercially viable resources and these cannot be discovered without firstly undertaking exploration.

Chart 5: Offshore Exploration Wells Drilled and Oil Price



Source: APPEA, Federal Reserve Bank of St.Louis

Chart 6: Onshore Exploration Wells Drilled and Oil Price



Source: APPEA, Federal Reserve Bank of St.Louis

There are a number of indicators that can be used to measure the level of exploration activity. Charts 5 and 6 highlight exploration drilling in Australian offshore and onshore areas for the period 2006 to 2016, together with the oil price in \$US's.

As can be clearly noted, there has been a significant fall in the level of activity since the beginning of the decade. This fall is a consequence of a number of factors, including regulatory/access impediments, perceptions about the prospectivity of released acreage, oil and gas prices and business costs.

Australia is generally perceived to offer relatively low prospectivity for oil, with modest discovery rates and small average field sizes. Gas prospectivity is much better, however discoveries (both offshore and onshore) are often remote from markets and are becoming increasingly difficult to commercialise.

Petroleum exploration by its nature is a very high risk activity. This is 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 information across individual geological basins in Australia. Some key highlights are:

- 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 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, discovery rates and production, 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 wells drilled.

A summary of activities associated with exploration is at [Attachment 2](#).

The commitment to expend significant funds on exploration does not guarantee success. Even once a hydrocarbon discovery has been made, there is no guarantee of its commercial development. Significant funds are also invested in appraisal and feasibility activities to determine if discovered resources can be commercialised.

The transition to a greater exploration focus on offshore gas has meant that explorers are confronted with significantly higher risks as a result of factors including:

- Lower prospectivity driving attention to high risk high impact exploration targets.
- Significantly deeper water depths and challenging structures supporting by advanced, but costly technology.
- Longer lead times required to complete appraisal and feasibility (often multiple times).
- Longer payback periods.
- Large capital development costs beyond Australian capital market capacities.

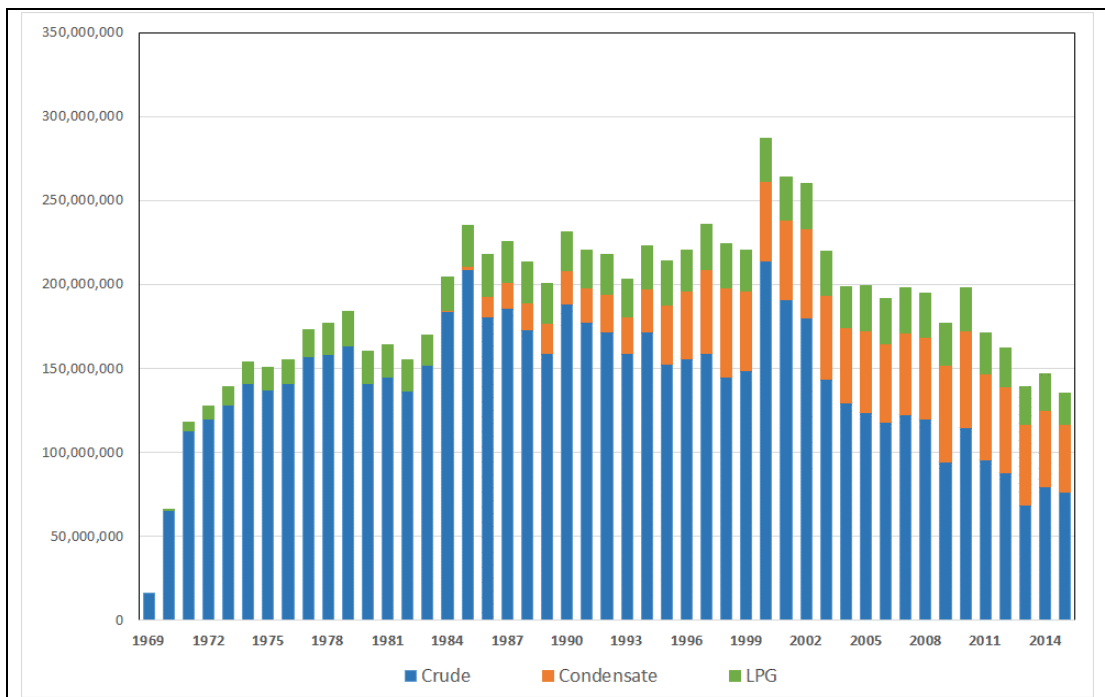
- The need for pipeline transportation from remote locations.

These higher risks also affect profitability and the time taken to recover costs. Overall, tens of billions of dollars of capital will be required over the coming decades if exploration is to continue at meaningful levels to underpin new oil and gas projects – there are major frontier basins that are explorable, but face risks due to the high cost to explore and develop.

### 1.5 Petroleum Production in Australia

Over the last four decades, there have been notable changes in the level and mix of petroleum liquids and gas production in Australia. Crude oil production reached peaks in the mid-1980's and again in 2000, but has steadily fallen over the last decade. The level of both condensate and liquefied petroleum gas production has also gradually fallen. These reductions in part account for the fall in taxation payments made by the industry, as liquids production has traditionally been of higher commercial value compared with gas production.

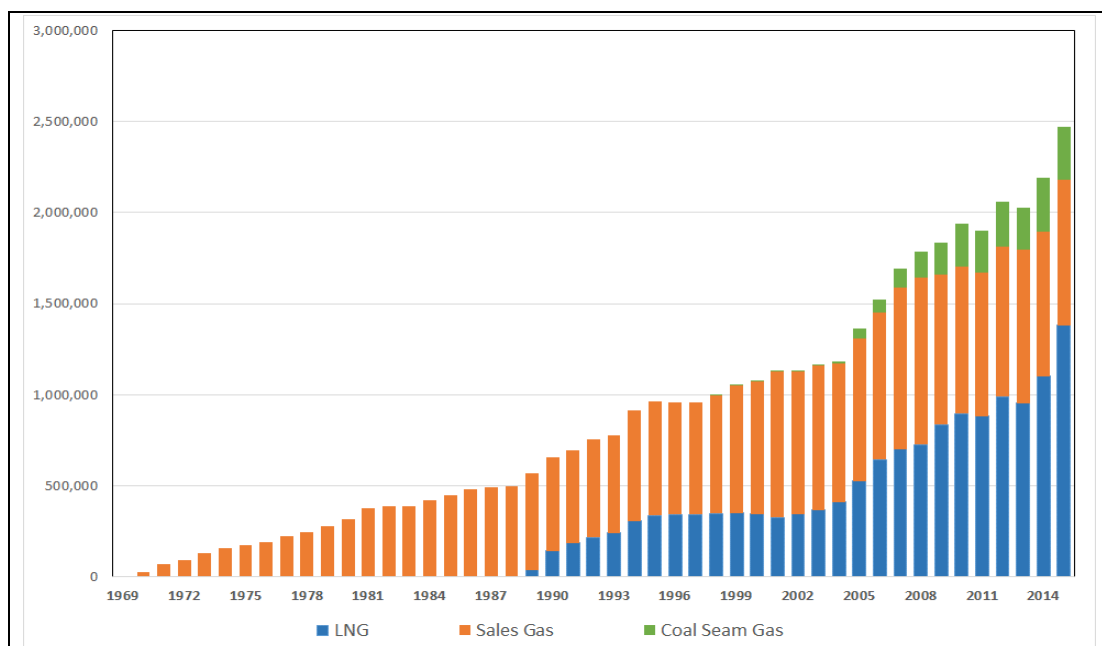
Chart 7: Australia Production of Petroleum Liquids (barrels)



Source: APPEA, ABARE, EnergyQuest

In contrast, gas production has been trending upwards as a result of both a growing demand for gas in domestic markets and the phased expansion of liquefied natural gas exports. The growth will continue over the next five years as a number of new projects come on stream.

Chart 8: Australia Production of Petroleum Gases (mmcf)



Source: APPEA, ABARE, EnergyQuest

## 1.6 Australian Gas Projects

Australia is approaching the end of an unprecedented first wave of investment in large scale gas projects, with estimated capital investment of in excess of \$200 billion over the last five years alone. A number of potentially new projects remain under constant review.

Table 1: Current and Prospective Large Scale Export Gas Projects

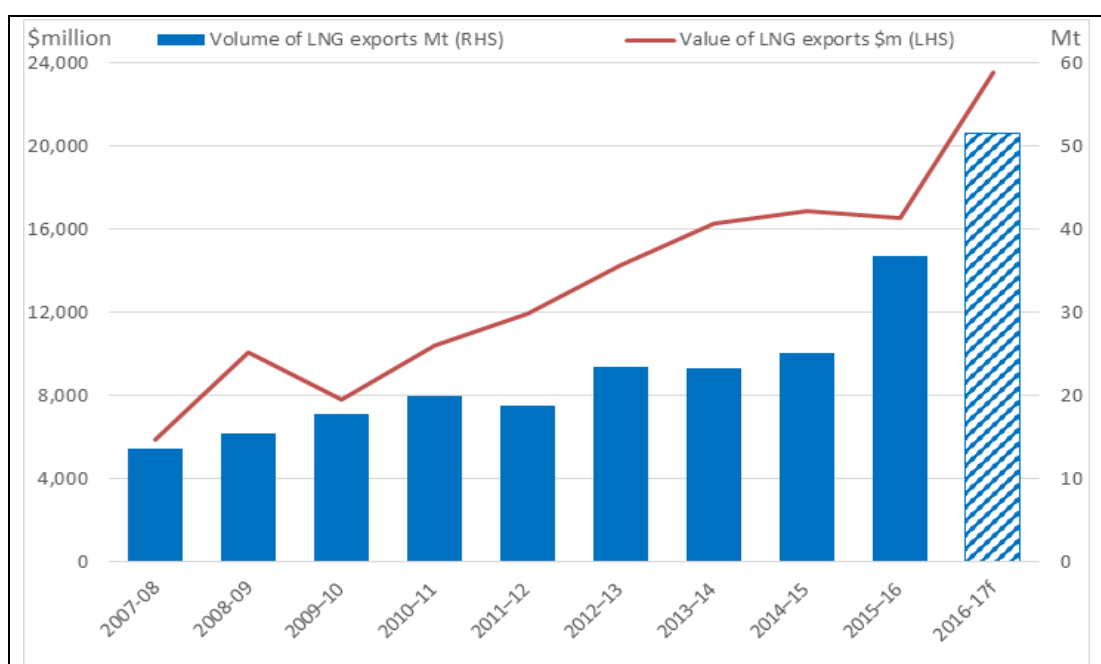
Name	Start-Up/Expected	Cost Estimate (A\$bn)	Annual capacity (Mt)
North West Shelf Venture	1989	33.5	16.3
Darwin LNG	2005	1.5	3.7
Pluto	2012	15.3	4.3
Queensland Curtis LNG	2014	23.7	8.5
Gladstone LNG	2015	21.6	7.8
Australia Pacific LNG	2015	24.7	9
Gorgon	2016	54.0	15
Wheatstone	2017	44.7	8.9
Ichthys	2017	42.5	8.9
Prelude FLNG	2017	12.6	3.6
Scarborough FLNG	2020+	15.0	6 - 7

<b>Browse FLNG</b>	2021+	40.0	12
<b>Crux LNG</b>	2021+	5.0	3
<b>Total</b>		334.1	

Source: Department of Industry, Innovation and Science, company reports, media reporting

The export value of the output of these projects has been trending upwards over the last decade, with the value being expected to further climb by the end of 2020. A number of significant gas discoveries have yet to be commercialised and will be impacted by any changes to fiscal terms.

Chart 9: Volume and Value of Australia's LNG Exports



Source: Department of Industry, Innovation and Science

### Challenges to Commercialising Gas Discoveries

The material that follows was provided by APPEA in 2012 to the Federal Government's Business Tax Working Group, chaired by the now Commissioner of Taxation, Mr Chris Jordan AO.

The BTWG examined key aspects of the business tax system in Australia. While it was company tax focussed, a number of important observations are relevant in a resource taxation context, particularly in relation to the long periods that exist prior to the generation of positive investor returns for gas projects.

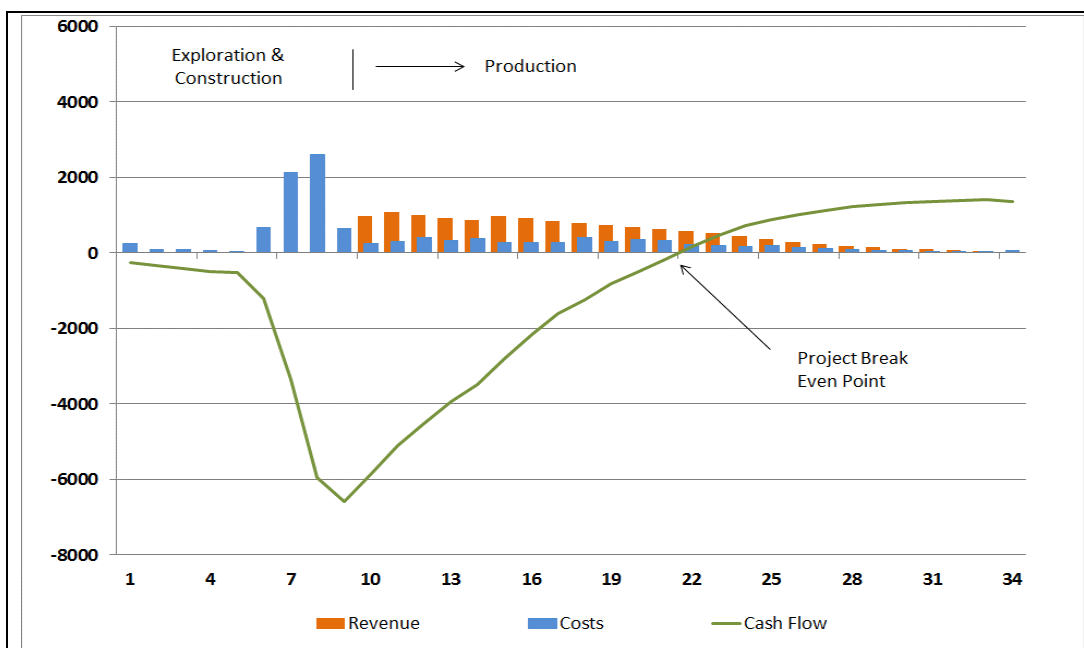
- Gas Project Economics

Some of the largest gas discoveries in the world have been made in Australia, yet significant quantities of discovered gas remains undeveloped. In 2005, Wood Mackenzie produced a report titled “Offshore Australia Economics – Gas is not Oil!”, which analysed why this was the case and why, at the same time, many oil discoveries in the same province had been developed.

Their conclusion was that the economics of gas exploration and development are generally less attractive than oil for the following principle reasons:

- Gas prices are generally lower than oil.
- Gas production profiles are flatter and longer than for oil developments (production from oil projects is generally front-end loaded).
- Gas discoveries take longer to develop than oil.

Chart 10: Indicative Large Gas Project Discount Cash Flows (\$ million)



Source: APPEA (Based on Unpublished Project Data)

The Wood Mackenzie Report stated that:

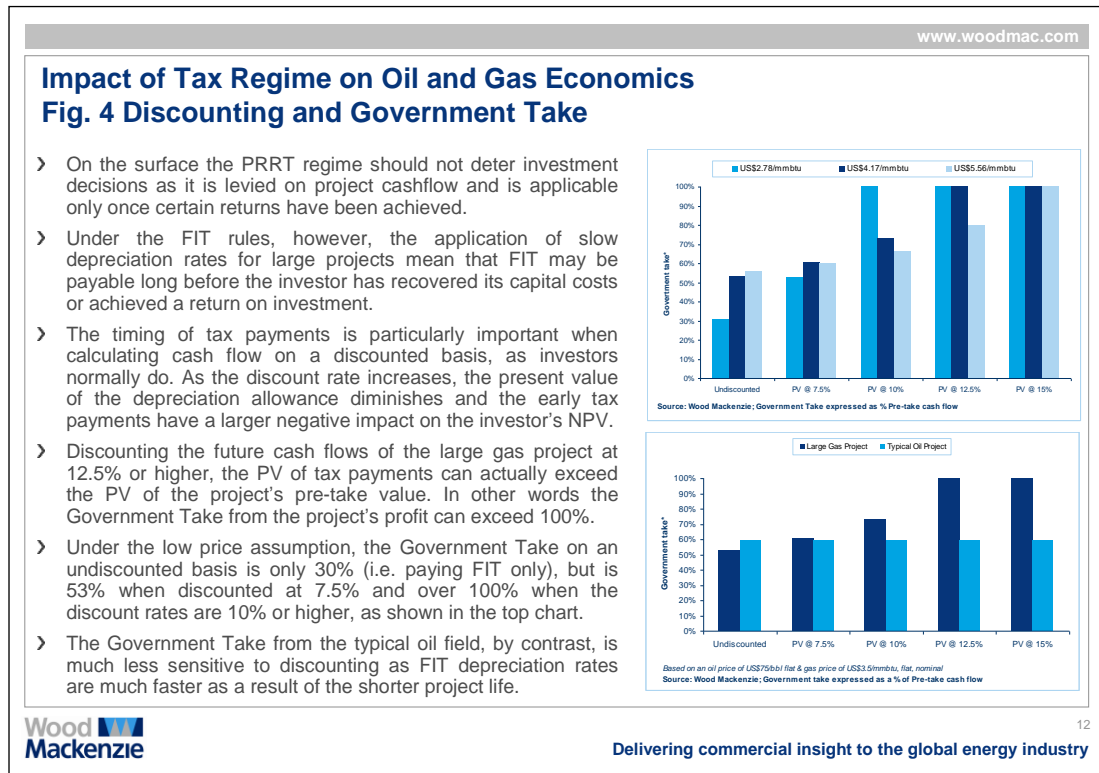
*“(f)or a number of reasons, the economics of large gas projects offshore Australia are fundamentally different from typical oil projects. While the PRRT regime is progressive, the very long depreciation schedule for federal income tax can create a very high government take, when considered on a discounted basis, as investors are likely to do. This has the effect of driving up the breakeven price for the large, stranded gas projects – making them potentially less attractive than other projects in the region.*

*With oil prices as high as they are, it may appear odd that investors in the petroleum industry could be seeking tax incentives. As this article demonstrates, however, gas is not oil, and the economics of the large gas discoveries continue to appear marginal to investors, even when oil prices are high. While securing a*



*high gas price will remain the investor’s primary objective, the Government may wish to consider reducing its take from large gas projects, if it wishes to stimulate development of its gas resources. The most obvious element to review would be the federal income tax depreciation schedule, which appears anomalously slow in comparison to fiscal regimes elsewhere.”*

An update of this report was commissioned by APPEA in late 2008 that provided a further snap shot of the impact of taxation on oil and gas economics in Australia. The key results were summarised as follows:



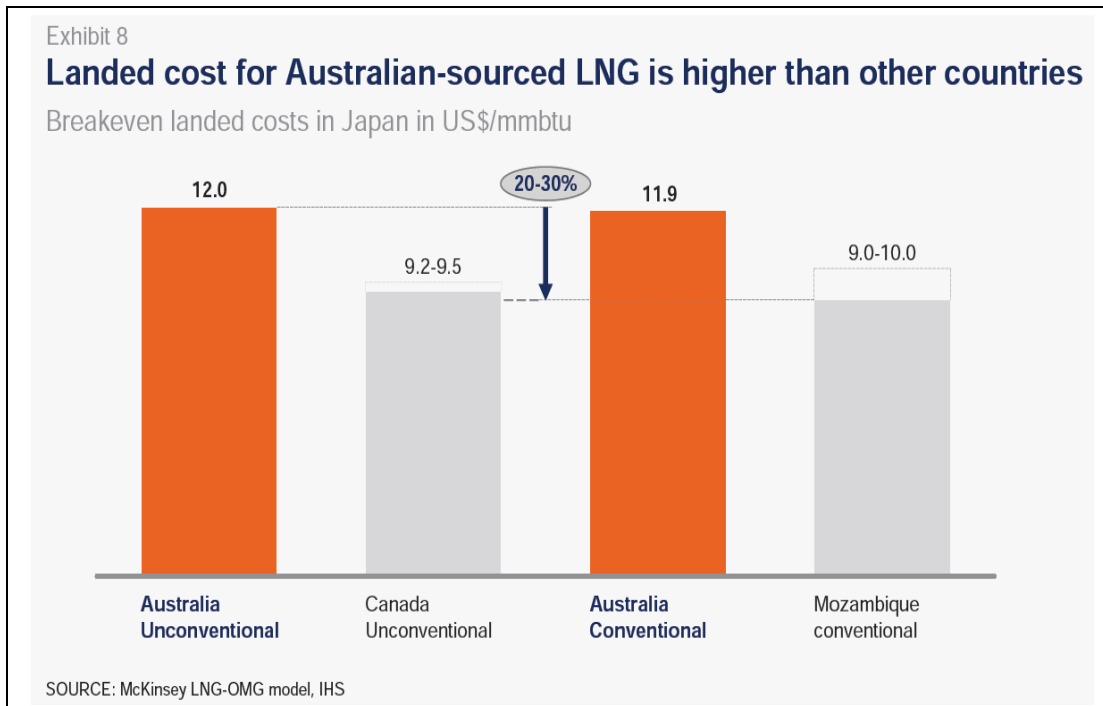
Source: Wood Mackenzie, 2008

The updated report confirmed the findings of the earlier study about the challenges that confront many gas projects. The commentary about the non-distortionary impact of PRRT is important to note.

A more recent report prepared in 2013 by McKinsey & Company in relation to extending the LNG boom in Australia highlighted the size of the potential prize for the country and the challenges of capturing that prize. In terms of costs, Australia faces significant challenges, as demonstrated by the comparison below.

Based on the data presented in the McKinsey report, Australia is up to 30 per cent more costly to produce and supply LNG compared with a number of potential competitor countries.

Chart 11: Australia's Cost Challenge - LNG



Source: McKinsey & Company, May 2013

(See [http://www.appea.com.au/wp-content/uploads/2013/07/Extending\\_LNG\\_boom\\_McKinsey.pdf](http://www.appea.com.au/wp-content/uploads/2013/07/Extending_LNG_boom_McKinsey.pdf) for more information.)

Wood Mackenzie also presented a report at the 2016 APPEA Conference and Exhibition that sought to identify the drivers and opportunities to improve the competitiveness of Australian LNG projects in the face of increasing global competition. It was noted in that report that while Australia had been somewhat successful in driving down costs in absolute terms, we had failed to keep pace with savings being achieved in other countries. Major savings in Australia had been achieved in areas such as drilling and onshore operations, however we had been less successful relative to competitors in other areas of the LNG chain.

Further opportunities exist to reduce costs, with a key area being debottlenecking of LNG plant – it is estimated that brownfield expansion trains can cost up to 30 per cent less than greenfield trains. However this is dependent on a range of important factors, including access to reliable future supplies of gas and extending the productive lives of existing projects. For many projects, backfill will be required to keep the plants operating at full or near maximum capacity. This has important consequences in terms of the ability of the industry to commercialise existing discoveries and stranded resources.

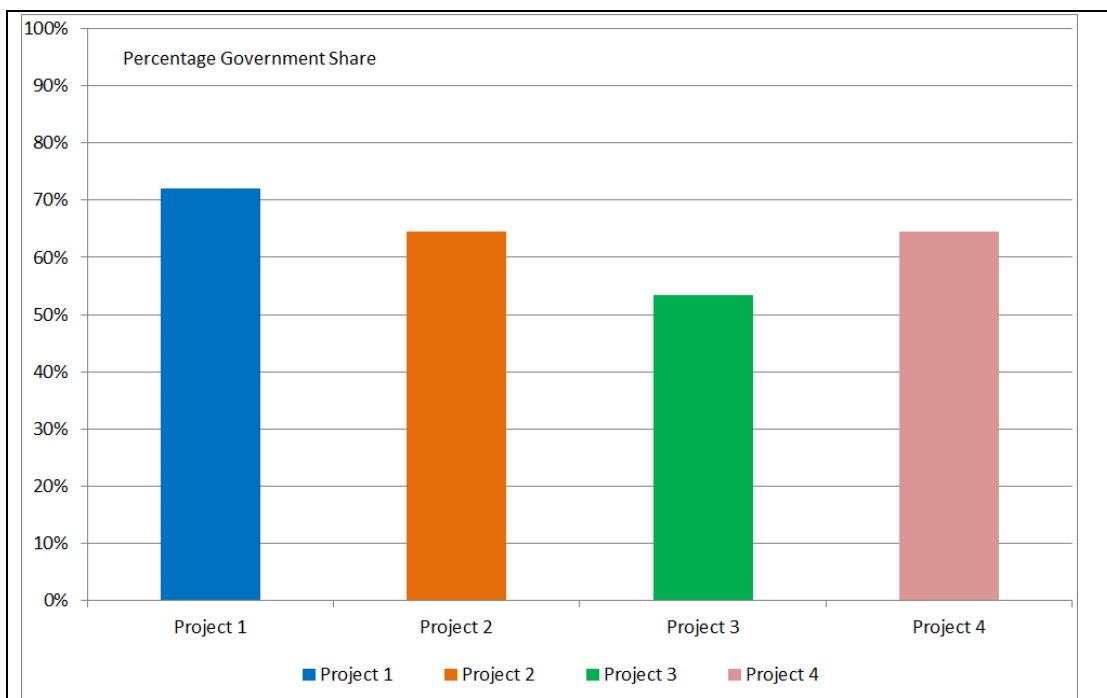
- Project Tax Take

In terms of the total tax attributable to individual projects, companies are best placed to inform the review taskforce of the specifics associated with individual projects.

Project estimates prepared by APPEA for the 2012 BTWG review highlighted the estimated share of net cash flows for governments and investors (see Chart 12).

In all cases, the government's share of the present value of net project cash flows exceeded the share for investors. The recent decline in prices and increase in project costs could be expected to further increase the governments share relative to that of the investor.

Chart 12: Estimated Government Share of Total Project Net Cash Flows - Net Present Value

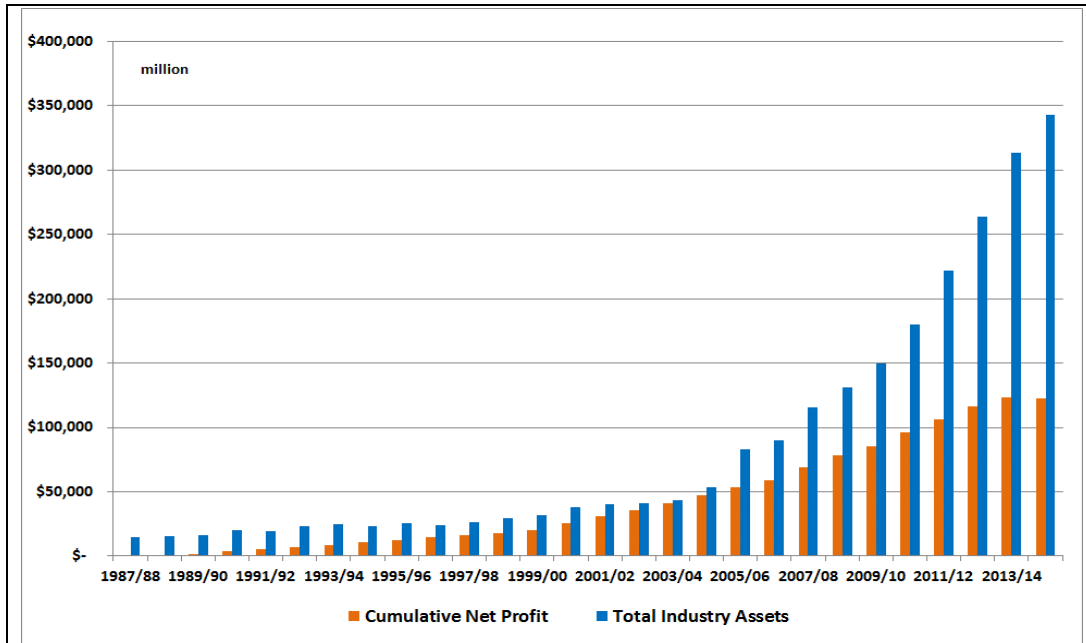


Source: APPEA

- Industry Investment

To demonstrate the level and scale of investment that has been required to fund the recent growth in the sector (particularly in the context of gas projects), Chart 13 compares cumulative industry profit for the period 1987-88 to 2014-15 with industry asset values (which can be used as a proxy for capital investment). It is estimated that invested funds have exceeded cumulative industry profits generated by the industry over the last three decade by a ratio of 2.15 to 1 over the period.

Chart 13: Industry Cumulative Profits and Asset Values (\$m)



Source: APPEA Financial Survey

## Section 2: Development of the Existing Resource Taxation Provisions

*“Shifting from the present output base royalty system to an economic rent base system for special taxation of the mining industry offers a number of advantages. Foremost, it would reduce efficiency losses by reducing distortions to the choice of mining investment and production decisions and by providing revenue from a relatively non-distorting tax on an immobile factor as part of a tax mix package which funds lower tax rates on more distorting taxes on internationally mobile factors, such as a lower corporate tax rate. A resource rent base tax provides the opportunity to collect in a less distorting way more of the returns on community owned natural resources than the corporate income tax and ad valorem royalties.”*

John Freebairn, John Quiggin, December 2010

Under the terms of the 1979 Offshore Constitutional Settlement (OCS) and the division of powers provided for under the Australian Constitution, the power to impose taxation and other charges on oil and gas production is divided between the Commonwealth and States/Territories. The Commonwealth holds title for all areas seawards of the outer boundary of the territorial sea (often termed ‘offshore waters’), while the States/Territories control areas landwards of this boundary.

In addition to income taxes, the resource (secondary) taxation framework that applies to petroleum production in Australia is broadly as follows:

- All projects are subject to the petroleum resource rent tax.
- Production sourced from licences derived from Offshore Exploration Permits WA-1-P and WA-28-P (the North West Shelf project) are subject to Commonwealth crude oil and condensate production excise and Commonwealth petroleum royalty.
- Onshore production and that sourced from projects located in submerged lands under state jurisdiction is subject to Commonwealth crude oil and production excise and royalty under the relevant state/territory jurisdiction.
- Production from the Barrow Island project in Western Australia is subject to a resource rent royalty.

Outlined below is a summary of the key provisions.

### 2.1 Petroleum Resource Rent Tax

#### *Design Features of PRRT*

The petroleum resource rent tax (PRRT) is a profits based resource tax that the Australian Government uses to tax profits from oil and gas projects in Australia. It is levied under the provisions of the Petroleum Resource Rent Tax Assessment Act 1987 (the PRRT Act). A liability to pay PRRT arises when a project has recovered all eligible outlays associated with a project (after deducting eligible exploration expenditure transferred from other projects), plus a threshold rate of return.

PRRT has the following basic features:

- It is assessed on an individual project basis. A project may be comprised of one or more petroleum production licences.
- Liability to pay PRRT is on a producer/company taxpayer basis (rather than a joint venture basis).
- It is assessed at a rate of 40 per cent.
- Is payable quarterly on an instalment basis.
- A liability is incurred when all allowable expenditures (including compounding) have been deducted from assessable receipts.
- Assessable receipts include the amounts received from the sale of all petroleum (based on the concept of a 'marketable petroleum commodity').
- Deductions include capital and operating costs that relate to the petroleum project, and are deductible in the year they are incurred. Deductible expenditures include those related to exploration (including eligible exploration costs incurred by a taxpayer in other areas), development, operating and closing down activities.
- Undeducted expenditures are compounded forward at a variety of set rates depending on the nature of those expenditures and the time that they are incurred prior to the application for a production licence. In general, undeducted exploration costs are augmented (compounded) at either the GDP factor rate or the long term bond rate (LTBR) plus 15 percentage points (subject to a five year timing condition), while other costs are augmented at the LTBR plus five percentage points.
- Other resource taxes and charges (production excise, royalties and RRR) incurred in relation to a project are rebateable against a PRRT liability for the project. This avoids the imposition of double taxation.
- Expenditures which are non-deductible include financing costs, some indirect administration costs, income tax and cash bidding payments.
- PRRT tax liabilities are deductible against income tax liabilities.

As PRRT is essentially an individual project based tax, excess undeducted expenditure may not generally be offset against income from other projects. The exception is exploration expenditure, which is transferable to other petroleum projects, subject to a number of transfer rules and integrity conditions.

PRRT differs from income tax in a number of important ways. Unlike income tax, where many costs are deductible over a defined life, all deductible expenditure for PRRT purposes is immediately and fully deductible at the time it is incurred, while only eligible exploration expenditure is transferrable between projects owned by a taxpayer. Project financing costs are not deductible. In addition, certain costs deductible for company tax purposes are not deductible for PRRT purposes.

#### *Introduction of the PRRT Regime*

In December 1983, the then Hawke Federal Government released a discussion paper that sought stakeholder comments in relation to the proposed introduction of a resource rent tax (RRT) for the petroleum sector in Australia. It was noted that such a system had been the official policy of the Australian Labor Party since 1977, and the intention was for the regime to be operative for year commencing 1 July 1984.

The Government noted at the time that the existing production excise and royalty regimes had a number of deficiencies, excise because it was production based and royalties because

it failed to respond to the individual characteristics of different projects. The specific details of a proposed RRT were not canvassed, but a range of options were presented to facilitate discussion with industry and the community.

In April 1984, the Treasurer (the Hon P.J. Keating MP) and Minister for Resources and Energy (Senator the Hon Peter Walsh) announced an intention to modify the proposed provisions as follows:

- The existing production excise arrangements would continue for 'old' oil produced from onshore and existing offshore projects, coupled with a lower rate of excise for 'new' oil from onshore projects and existing offshore projects.
- Offshore projects that had yet to reach the development stage would be subject to a new RRT and would be removed from the production excise and royalty systems.

At the time of the announcement, it was stated by the Government that there were economic efficiency advantages in applying a RRT type structure to new projects. A detailed discussion paper that canvassed a number of options was released at the time of the announcement that again sought the views of industry on the proposed changes.

A final announcement was made on 20 May 1985 by the Treasurer and Minister for Resources and Energy, Senator the Hon Gareth Evans, QC, on a number of the final details associated with the introduction of the RRT, including the treatment of exploration expenditure and closing down costs.

In summary, with effect from 1 July 1984, the new resource rent tax applied to all offshore petroleum projects (that is, projects under Commonwealth jurisdiction) with the exception of the Bass Strait and North West Shelf projects, where the existing production excise and Commonwealth royalty provisions continued to apply. This was in recognition of the significant expenditure commitments that had been made in relation to these projects.

#### *Key PRRT Modifications and Changes*

##### Bass Strait Extension, Wider Deductibility of Exploration and Reduction in the General Project Carry-Forward Rate (August 1990)

On 21 August 1990 (as part of the 1990-91 Federal Budget), the Government announced a number of significant changes to the operation of the regime. Specifically, it was announced that from 1 July 1990:

- The coverage of the tax would be extended to cover the Bass Strait project, replacing the then existing production excise and royalty provisions.
- Exploration costs incurred by a taxpayer in other projects covered by the regime would be deductible against an RRT liability of any projects held by the taxpayer, rather than being quarantined to within an individual permit area (subject to a number of rules and integrity provisions).
- The carry-forward threshold rate for development and operating (general project) expenses incurred after 1 July 1990 would be reduced from the long term bond rate plus 15 percentage points to the LTBR plus five (5) percentage points.

In recognition of the special circumstances associated with the North West Shelf project, the Government decided to retain the production excise and royalty provisions for that project.

The Government noted that decision “recognises that the current infrastructure involved vast sums of financing over very long lead times and that the liquefied natural gas export phase, which has just begun, involves major trade relations implications in a highly sensitive market.”

At the time of the decision, the Minister for Resources made the following observation:

*“The Government’s decision to fundamentally reform offshore petroleum production taxation has provided a taxation environment that:*

- *is economically efficient, ie the tax regime will not distort commercial decisions, which should be made in response to market signals;*
- *will provide equitable treatment between the community and resource developers, ie will provide the incentive for developers to invest in exploration and development, while ensuring the community a fair return for the exploitation of the community’s petroleum resources; and*
- *is administratively efficient and resilient to changes in market circumstances.”*

In addition, the Federal Treasurer noted that:

*“The RRT, as a profits-based tax, is more flexible and stable tax regime than a production-based excise. With the new arrangements being self-adaptive to market changes and because initial revenue cost from the announced changes will not be recovered until later years, it is the Government’s intention not to consider any further concessional changes to these taxation arrangements. This view was communicated to Bass Strait producers as part of the Commonwealth’s offer. Establishing a stable tax regime should promote investor confidence in a critical segment of Australia’s resources sector. In fact, the Government has received producer advice that the changes will lead to new developments in Bass Strait and increased exploration throughout Australia.”*

1990-91 Federal Budget (p4.7)

Mr Bob Alderson, Head of the Petroleum Policy Branch in the Department of Primary Industries and Energy presented a paper at the 1991 APEA Taxation and Accounting Seminar titled ‘Policy Issues and Application of PRRT Legislation’. The paper addressed a range of issues associated with the 1991 amendments, including the benefits of PRRT over the excise and royalty systems. He noted that “(t)he decision to replace excise and royalty with RRT in Bass Strait was taken because the latter is far more economically efficient” and “The RRT is a charge on net revenues and as such is fully sensitive to changes in prices and costs. It provides a uniform charge across the project and projects and thus does not serve to distort investment decisions within the Bass Strait or any other project. When prices are low and/or costs are high, a situation can be reached where no tax is paid. Therefore unlike the excise and royalty system RRT should not be a factor leading to premature abandonment of production.”

In addition, he made the following comment about the changes to the carry-forward rates.



*“The move to widen deductibility from a project to a company basis will reduce considerably the risk that exploration expenditure will not be recouped.*

*The former single carry-forward rate was set to allow companies to carry forward each year the real value of exploration and development costs. As wider deductibility reduces the relative risk of having unusable deductions, these relativities will now be reflected in a two tier rate of LTBR + 5 percentage points for general expenditure and LTBR + 15 percentage points for exploration expenditure. The lower premium for general expenditure will now reflect the lower risks associated with development relative to exploration. The new arrangements therefore recognise the characteristics of different stages of a petroleum project and the significant benefits to industry of company wide deductibility for exploration activity.”*

Following the enactment of the 1990 changes, the regime remained relatively unchanged until the mid-2000's, with the exception of a number of relatively technical amendments.

#### Designated Frontier Exploration Incentive (May 2004)

On 11 May 2004 (as part of the 2004-05 Federal Budget), the Government announced a targeted incentive to encourage petroleum exploration in Australia's remote offshore areas. The measure allowed for the uplift to 150 per cent on PRRT deductions for exploration incurred in designated offshore frontier areas.

The measure was limited to following:

- Offshore acreage releases in 2004 to 2008 (this was subsequently extended to include the 2009 release).
- Pre-appraisal exploration activity only (it did not cover activities associated with evaluating or delineating a petroleum pool which had been discovered).
- The initial term of an eligible exploration permit.
- Areas nominated by the Minister could not exceed 20 per cent of each year's offshore acreage release areas.
- Designated areas needed to be more than 100 kilometres away from an existing commercialised oil discovery and could not be adjacent to an area designated in the previous year's acreage release

The success of the measure was largely unquantifiable, however it is estimated that the number of permits released as 'designated offshore frontier areas' is less than 2 per cent of the total number of permits that have been issued in offshore Australia. Many of the permits have subsequently been relinquished and the level of deductible expenditure over and above normal exploration expenditure amounts would be modest. The provisions that apply to a company's ability to transfer exploration costs to another PRRT project restricted some entities from obtaining a benefit under the initiative.

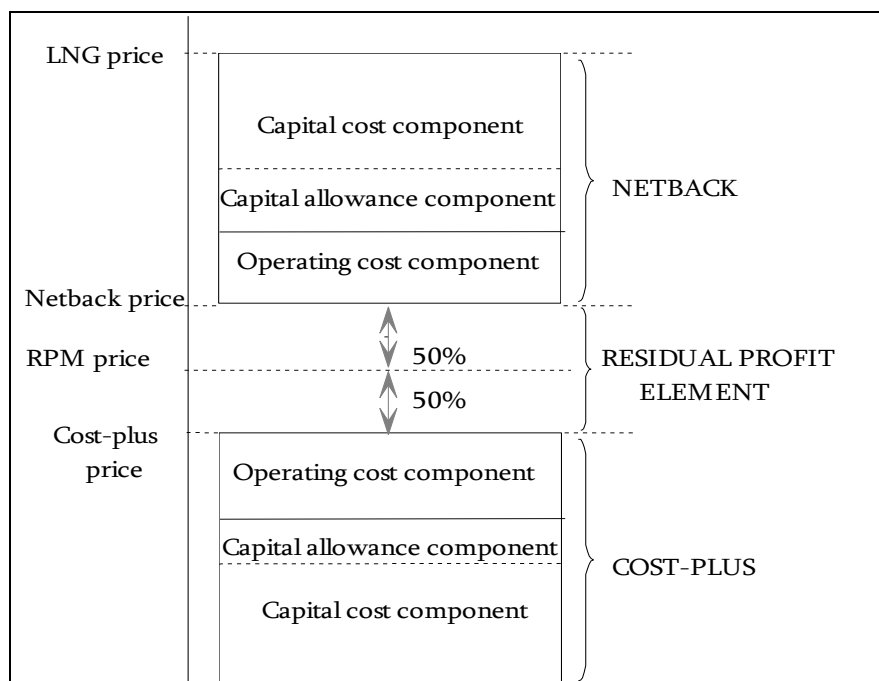
Gas Transfer Price Methodology (December 2005)

A regulation was released on 15 December 2005 that provides the basis for determining a gas transfer price for integrated gas to liquids projects under the PRRT regime. The policy objective of the Regulation was to provide a framework to determine a key component in the assessment of a liability to pay PRRT where an arm’s-length sale does not take place at the taxing point.

Assessable receipts for PRRT purposes are generally calculated at the point where a marketable petroleum commodity (MPC) exists. Sales gas is regarded as an MPC. In an integrated gas to liquids project, such as an LNG operation, the petroleum recovered from a project is processed into sales gas which is then processed into liquefied natural gas. There is often no arm’s length sale at the taxing point for the sales gas before it is processed and liquefied for transportation and sale, hence a methodology is required to value such gas. Costs incurred beyond the taxing point are not regarded as deductible expenditure for determining a PRRT liability.

Following lengthy consultations between government and industry, details were announced of the residual pricing methodology (RPM). A pictorial description as to how the RPM applies in practice is at Chart 14.

Chart 14: Stylised Residual Price Methodology



The cost-plus component is the minimum price at which the upstream stage of an integrated GTL operation would sell its gas to the downstream stage in order to cover its upstream costs, taking into account an allocation for its capital costs. The netback price is the maximum price the downstream stage of the integrated GTL operation would pay the upstream stage for sales gas, given the price obtained for or the value of project liquid

produced, in order to cover its costs including a proper allocation of capital invested. The difference between these prices identifies the residual profit for a project (if such a profit exist). The RPM price, for the purposes of the PRRT, is determined by allocating 50% of the residual profit to the upstream stage and 50% of the residual profit to the downstream stage of the project.

The cost-plus and netback calculations are two readily utilised and recognised kinds of arm's length transfer price methodologies. These types of methodologies are used across international jurisdictions in relation to petroleum and other transfer pricing issues.

#### Technical Enhancements and Amendments (2006)

A series of amendments were made to the regime in 2006 to address a range of issues that had been identified by industry and the Government over a number of years. While broadly technical in nature, the changes reflected a need to ensure the regime was operating in a manner that met the changing commercial framework within which the industry operates. The amendments covered the following aspects of the regime:

- The treatment of transferable exploration expenditure in remitting quarterly instalment payments of PRRT.
- Allowing internal corporate restructuring within company groups to occur without losing the ability to transfer exploration expenditure between the petroleum projects of group members.
- The treatment of closing down costs where a project transitions to an infrastructure licence.
- The application of a self-assessment regime in a manner consistent with that applying for income tax.
- A number of other technical matters, including the adoption of a transfer notice mechanism and a change to the lodgement of PRRT returns.

The changes, while generally modest in nature, positioned the regime to operate in a more efficient and administratively flexible manner.

#### Extension of PRRT to Onshore Areas and the North West Shelf Project (2011)

Following the decision of the Government in July 2010 to abandon the resource super profits tax that formed an element of the 2009 Henry Tax Review, amending legislation was introduced into Parliament in late 2011 to extend the PRRT to cover all petroleum exploration and production activities in Australia, with effect from 1 July 2012. This coincided with the introduction minerals resource rent tax.

The legislation was tabled following an extended period of consultations between government officials, industry and tax experts from legal and accounting advisory firms. In the Explanatory Memorandum to the Petroleum Resource Rent Tax Assessment Amendment Bill 2011 that extended the regime, it was stated in paragraph 1.13:

*“Unlike royalty and excise regimes, the PRRT applies to the profits derived from a petroleum project and not the volume or value of the petroleum produced. Through providing deductions for all allowable expenditure (whether capital or revenue in nature), together with uplifts for carry*

*forward expenditure, the PRRT taxes the economic rent generated from a petroleum project.”*

The decision required relatively complex amending legislation and transitional provisions, however the operation of the PRRT remained broadly unchanged. Changes that accompanied the decision included the following:

- The provision of a ‘starting-base’ for projects and licences entering the extending regime to recognise past investments and expenditures, and to prevent the retrospective application of PRRT.
- Modifications to the project combination provisions to allow for onshore projects with integrated downstream operations to be treated as a single project.
- Project expenditure related to the environment was made explicitly deductible.
- Deductible expenditure was expanded to include resource taxation expenditure to avoid the double taxation of petroleum projects also subject to production excise and petroleum royalties. This was necessary following the decision to fully retain all existing production excise and petroleum royalty provisions that applied at the time of the announcement.
- Onshore coal seam gas producers that are part of integrated gas to liquid operations were specifically recognised through ensuring that they are able to access the gas transfer pricing methodologies contained in the regulations.

As part of the consultations that took place in relation to extending the regime, a number of operational and compliance issues were also raised, including a recommendation that the test for deductibility be amended to one of expenditure necessarily incurred in carrying on activities in relation to a petroleum project (upstream of the taxing point) from July 2012. This recommendation reflected the ongoing uncertainty around the conditions which must be satisfied in order to qualify for expenditure to be deductible. The government deferred making a final decision, however it remains an issue to be revisited from a compliance perspective.

Overall, the 2011 amendments represented a fundamental change to the scope of the legislation that led to a nationally integrated PRRT regime. Many of changes were designed to explicitly address the implications arising from the effective retrospective application of an additional tax on existing activities and projects.

#### Factors Impacting on the Payment of PRRT

A range of factors must be considered in terms understanding the level of reported payments of PRRT by individual companies (and therefore projects), including the following:

- A tax liability under the PRRT regime is incurred at a time after a threshold return has been generated. This is a key design feature of the regime. PRRT will generally not be paid from a project until a number of years after the commencement of production.
- The imposition of a PRRT liability for a project may be deferred where eligible exploration expenditure incurred in other PRRT project areas held by the same taxpayer is deductible against PRRT income from the project (subject to the transferability rules).

- In connection with the above point, the timing of PRRT payments within a project are likely to vary across joint venture participants in a particular project due to the transferability of exploration costs from other projects, together with individual taxpayer operating cost structures.
- Other resource taxes and charges from a project (such as state and federal royalties and production excise) are rebatable against a PRRT liability from the same project. This is a design feature to avoid the double resource taxation of production from the same project.
- As PRRT is a profits based tax, a tax liability will be dependent on a range of factors, with commodity prices, foreign exchange rates and project costs being critical factors in determining project profitability.

## 2.2 Crude Oil and Condensate Production Excise

### *Development of the Regime*

The production excise regime has been in place since the mid-1970s, and applies in conjunction with the Commonwealth royalty and state/territory royalties, depending on the location and type of production.

Production excise is calculated as a percentage of the volume weighted average of realised f.o.b price (VOLWARE) made from a designated region. Crude oil and condensate production is subject to excise in a manner such that higher percentage rates apply to higher levels of production or liftings from each prescribed production area.

The excise scales that apply to production from each prescribed production area are dependent on the date of discovery and the commencement of production. The applicable excise scales and definitions that currently apply are outlined below.

EXCISE RATES ON CRUDE OIL & CONDENSATE PRODUCTION				
Annual Production		Excise Rates (% of VOLWARE Price) (1)		
Megalitres	'000's barrels	'old' oil (2)	'intermediate scale' oil (3)	'new' oil (4)
0 – 50	0 – 315	0	0	0
over 50 – 100	over 315 – 629	0	0	0
over 100 – 200	over 629 – 1259	0	0	0
over 200 – 300	over 1259 – 1888	20	0	0
over 300 – 400	over 1888 – 2517	30	15	0
over 400 – 500	over 2517 – 3146	40	30	0
over 500 – 600	over 3146 – 3776	50	50	10

over 600 – 700	over 3776 – 4405	55	55	15
over 700 – 800	over 4405 – 5034	55	55	20
over 800	over 5034	55	55	30
<p>(1) Volume weighted average realised price f.o.b of sales in a given calendar month  (2) Oil discovered before 18 September 1975  (3) Oil production from fields discovered before 18 September 1975 and undeveloped as of 23 October 1984  (4) 'New oil' is oil produced from naturally occurring discrete accumulations discovered on or after 18 September 1975</p>				

It is the most inefficient form of petroleum resource taxation, as it does not take into consideration any aspects of the cost of production. Implicit in its design is that there is a correlation between annual production rates and profitability and, to a lesser extent, field maturity and profitability. Such correlations often do not exist.

It was originally introduced as a levy on each barrel of production sold from eligible areas, and was then substantially modified in 1983 such that it applied at varying rates depending on the discovery and development date of the relevant prescribed production area. 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 encourage exploration and further stimulate the development of oil discoveries.

Prior to the mid-1980s, crude oil production excise applied to all petroleum projects in Australia. Following the introduction of PRRT, crude oil excise (and Commonwealth royalty) continued to apply to the Bass Strait project area and production licences derived from the NWS permit areas. Crude oil excise (and state/territory royalty) also continued to apply to production sourced from onshore projects and those in submerged lands under state/territory jurisdiction.

In 1990, when the PRRT was extended to cover the Bass Strait project, the crude oil excise only continued to apply to permits derived from the NWS project area and for onshore areas.

While production excise is paid, data is not separately recorded in the annual Federal Budget papers.

#### *Excise Treatment of Condensate*

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

*“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.”*

Source: Parliamentary Library, 27 May 2008

The decision did not provide a free rate of duty for condensate. Rather, it ensured that condensate was not covered by the provisions of the excise regime (that is, it was effectively exempted from the regime). The measure was aimed at assisting investment decisions in both the Cooper Basin and North West Shelf areas. Condensate and gas production remained subject to the normal state and Commonwealth petroleum royalty provisions.

A further adjustment was introduced in 1995 which allowed for condensate that was either produced or marketed separately from crude oil to be excise exempt. This ensured that condensate was not regarded as crude oil for the purposes of the excise regime merely because of the fact that it was commingled with crude oil post the point of production. This was a further reaffirmation of the exemption from condensate from the crude oil excise regime. Subsequent technical amendments were also made to the excise regime in 1997 and 2001.

Overall, the arrangement provided an important stimulus for companies with onshore and North West Shelf operations to explore for and make subsequent investment decisions to produce condensate that often occurs in association with natural gas. In many cases, the production of condensate has provided the economic underpinning for gas projects, including whether projects reach a final investment decision.

#### *The 2008/09 Budget Announcement*

In the 2008-09 Budget, 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”. The announcement also indicated that:

*“Condensate will be subject to the same excise rates as crude oil from petroleum fields discovered after 18 September 1975”*

and

*“The first 4,767.3 megalitres (or 30 million barrels) of crude oil produced from a field is excise exempt from Crude Oil Excise. Past production of condensate from a petroleum field will contribute towards meeting this threshold before the Crude Oil Excise becomes payable”.*

The Government subsequently introduced the Excise Tariff Amendment (Condensate) Bill 2008 and the Excise Legislation Amendment (Condensate) Bill 2008 to give legal effect to the changes.

### *Compliance Obligations and Impact on Producers*

All producers of crude oil excise and condensate covered by the regime are required to comply with the provisions of the legislation and any compliance/reporting obligations that may be imposed by the Australian Taxation Office.

APPEA understands that very few petroleum fields have (or will) 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 prescribed production areas will be insufficient to incur an excise liability (that is, combined crude oil and condensate production will be less than the annual 3.146 million barrels required before a liability is incurred).

Overall, there is not expected to be any duty incurred for onshore crude oil and/or condensate production in Australia. Despite this, producers are required to meet the verification, administrative and compliance obligations imposed by the regime.

The original decision to replace the crude oil excise/royalty systems for offshore areas was an explicit recognition by the Government of the economic efficiency benefits flowing from the PRRT regime. The 2008-09 Budget decision to extend the regime to cover condensate production represented a major retrospective imposition of excise (particularly as past production was counted towards the application of the 30 million barrel exemption) and was at odds with the stated principle of economic efficiency.

The potentially adverse impact of extending excise to condensate is compounded by the fact that condensate is generally produced in association with gas, the economics of which are generally more challenging than conventional oil projects. Such a situation was clearly part of the 1977 Budget decision not to include condensate as part of the excise system.

In addition to the compliance costs imposed 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 potential to be factored into the exploration decisions of investors. In particular, this may impact on 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 inefficient 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 largely be unworkable in the context of the different geological factors associated with unconventional resources.

In summary, as the Government has effectively accepted that PRRT is now its primary mechanism for the taxation of crude oil and condensate production, the continued application of production excise for areas that are unlikely to incur a liability should be revisited.



### Australian Oil Pricing and Excise Policy

For the five years beginning in September 1970, the price of Australian produced crude oil was set at the levels prevailing in 1968. Hence, the rapid increase in world oil prices of 1973-74 was not reflected in prices received by Australian producers until the end of this period. A levy (or excise) on Australian produced oil was introduced in August 1975, and was set at \$2 per barrel.

A month later the distinction between old and new oil was introduced; new oil received import parity prices (IPP) less the \$2 levy, while the price producers received for old oil was set by the Government at levels below IPP. Refiners paid this price plus the \$2 levy.

In August 1976, the Government announced that new oil, in addition to attracting IPP, would not be subject to the levy, as a further incentive to oil exploration.

In the 1977-78 Budget, the Government announced that it would increase the price paid by refiners for all domestic crude oil towards the import parity level. The price that producers received on old oil was increased so that a progressively increasing percentage of annual production attracted the IPP less \$3 per barrel. The remainder of production continued to attract a fixed price, plus the \$3 levy.

In the 1978-79 Budget, the Government increased the price for all "old" oil to IPP, by increasing the levy, ensuring that petroleum users paid the full world price and made realistic resource allocation decisions.

By 1983, the excise system had been further modified so that different sized production areas attracted different levies; a fixed levy, a levy which changed according to movements in either the import parity price or the Consumer Price Index, and a levy determined by the difference between the IPP and a fixed controlled price. This produced a number of anomalies. Under certain circumstances, increased production could reduce overall producer returns. In other situations, producer returns could increase even though the IPP had not changed or had fallen. On 1 July 1983, in response to this situation the Government introduced a new levy scale featuring progressively higher excise rates as annual production from each area increased. The highest excise rate was set at 87 per cent of the IPP.

In April 1984, the Government introduced a separate and lower excise scale for "new" oil. The size of the excise free tranche was increased significantly. Greenfields offshore petroleum projects were also made subject to RRT at this time.

In October 1984, the Government introduced the intermediate scale to encourage the development of a number of "old" oilfields which had not been developed due to inadequate returns under the "old" oil excise scale. The Government also modified the existing substantial new development policy to ensure that treatment of new projects within developed "old" oilfields was broadly consistent with the treatment of production from undeveloped fields under the intermediate scale.

In 1986 and 1987, in response to falling crude oil prices, the Government reduced the top marginal excise rate on "old" oil progressively from 87 per cent to 80 per cent and to 75 per cent by 1 July 1989.

In July 1987, again because of low oil prices, the Government introduced the 30 million barrel excise exemption and reaffirmed the exemption from excise for separately marketed condensate.

In January 1988, the Government, as part of moves deregulating the marketing of domestic crude oil, changed the basis of excise assessment to the VOLWARE price from the previous Government- determined import parity price.

Material sourced from the 1990 Background Report on Petroleum Production Taxation  
(Released by the Hon Alan Griffiths, Minister for Resources)

### 2.3 Petroleum Royalties

#### *Commonwealth Petroleum Royalty*

Under the Commonwealth's Offshore Petroleum and Greenhouse Gas Storage Act 2006 and Offshore Petroleum (Royalty) Act 2006, Commonwealth royalties are collected from certain offshore petroleum production. For the purpose of federal royalty collections, "offshore" refers to production licences derived from Exploration Permits WA-1-P and WA-28-P (or the North West Shelf project).

Under provisions of the legislation, royalty revenues are shared by the Commonwealth with Western Australia, with the WA Government receiving approximately two-thirds of gross payments. The administration of the royalty regime is undertaken by the WA Government on behalf of the Commonwealth. The total level of Commonwealth royalty payments is not recorded as a separate line item in the Federal Budget.

The method for determining the wellhead value of petroleum produced is as agreed between the Designated Authority (the relevant WA Minister) and the producer, following directions from the Joint Authority (the relevant Commonwealth Minister and WA Minister). If the Designated Authority and the producer are unable to reach agreement, then the Designated Authority can determine a wellhead value.

The wellhead value is generally calculated by subtracting from the sales receipts, certain deductions for costs incurred in bringing the petroleum from the wellhead to the point of sale. Deductions include production excise, allowances for a return on post-wellhead capital assets and for depreciation on post-wellhead capital assets, and operating expenses such as processing and transportation costs. Pre-wellhead costs are not deductible for royalty purposes.

By making allowance for certain costs, royalty is determined on a different basis to production excise, however it does not allow for the deductibility of all costs associated with production activities. In addition, as capital costs are depreciated (not immediately and fully deducted), the regime is effectively a hybrid of profits based and excise type regimes.

The rate of royalty payable is set by the Joint Authority under the provisions of the legislation.

### *State Royalty/Resource Rent Royalty*

In general, onshore mineral rights are vested with state and territory governments and the Commonwealth does not receive a share of royalty receipts in respect of those rights. A broadly similar methodology applies in determining royalties under state and territory jurisdictions, however the specific details vary on a state by state basis.

In addition to petroleum royalties, a mechanism was introduced in 1985 that provides state and territory governments with access to a profits-based regime (a resource rent royalty) to replace royalties and Commonwealth production excise for onshore petroleum production. The regime to date has been limited to the Barrow Island project under Western Australian jurisdiction, where future activity and production was potentially threatened by the continued imposition of then existing excise and royalty regimes.

The RRR is broadly similar to PRRT, however exploration costs are not transferable to other projects and the uplift rate for general project costs has remained at the long term bond rate plus 15 percentage points (as applied to PRRT prior to the 1990 changes).

### *Administration of Petroleum Royalties*

Contrary to some suggestions, the determination of a royalty liability and fulfilling compliance obligations can in some instances be complex, unclear and time consuming, as well as being subject to dispute and litigation. The industry would be concerned with any changes that would further increase the compliance burden on impacted projects.

## Section 3: Past Reviews of Petroleum Taxation in Australia

*When you look at the Petroleum Resource Rent Tax over its 25 year history, if you'd analysed the PRRT one year in, you would have said, "well this tax isn't raising what we wanted it to raise". But over the course of the last quarter century, the PRRT has brought in, I think, around \$25 billion. The Minerals Resource Rent Tax depends on commodity prices and it also depends on the deductions that mining companies are making, and that will change with the point of the cycle. But anyone who says going back to the old royalties regime is better than a profits based mining tax has got rocks in their head. There's no sensible economist that would argue that.*

The Hon Andrew Leigh MP, 15 May 2013

A number of reviews and inquiries have been undertaken in relation to the operation of the petroleum resource taxation provisions over the last three decades. These reviews have examined various aspects of the policy and technical settings, and have provided important background in terms of the development of the provisions and the strengths and weaknesses of the different taxing regimes.

### 3.1 Review into Petroleum Production Taxation (1990)

In August 1990, the Federal Government announced a number of significant reforms to the operation of petroleum taxation in Australia. Amongst these reforms were the decisions to extend the scope of the regime to cover production from the Bass Strait project, introduce the wider deductibility provisions for exploration and reduce the augmentation rate for development and general project costs from LTBR plus 15 percentage points to LTBR plus five (5) percentage points.

In the context of PRRT, the following comment was made:

*"The RRT is more efficient than the excise and royalty arrangements in Bass Strait. Because the tax is based on profits rather than production, it is sensitive to changes in prices and costs. This flexibility will remove the pressure for continuous changes in excise rates as production declines or market conditions vary. Unlike the existing excise system, the RRT will not be a factor inhibiting enhanced development of existing fields or create shut-ins at times of low prices. Moreover, as all production costs are deductible, it will not deter otherwise economic investment."*

Minister for Primary Industries and Energy and Minister for Resources  
21 August 1990

Underpinning this announcement was a comprehensive Federal Government review of the petroleum production taxation provisions, undertaken by the Department of Primary Industries and Energy. The terms of reference of review encompassed *"a fundamental, broad ranging examination of the principles of resource taxation as they apply to petroleum; consideration of the impact of varying structures and levels of resource taxation on the economy; a review of the existing taxation arrangements against the principles of resource taxation; and the development of options for the future taxation of petroleum resources."*

The review consulted widely and undertook extensive modelling to examine the implications of the various reform and taxing options. A key finding of the report was as follows:

*“On behalf of the community, governments, by virtue of their ownership of the resource and the conferring of exclusive rights to it, have a claim to at least some of the economic rent from resource developments. Economic rent is considered to be the surplus of revenue over all costs incurred in the extraction of the natural resource including a return on capital which recognises the risks taken. The report concludes that resource charges based on economic rents will be the most economically efficient. Attempts to obtain all economic rents will deter some risk averse investors and reduce efficiency. Hence resource charges should be below economic rents.”*

Background Report on Petroleum Production Taxation – 1990 (p.2)

The review and subsequent detailed report was arguably the most comprehensive of petroleum resource taxation undertaken in Australia, and was based on detailed data that was both held by the Government and that was provided to the review team.

Key findings and comments contained in the report included the following.

<p>Adoption of a ‘Brown Tax’</p>	<p>It has widely been held that a Brown tax, because it shares risk between developer and government in the same proportion as revenue shares, including full loss offsets, is neutral and would not distort investment either between the petroleum industry and other industries or within the petroleum industry. However, for a risk averse investor, a Brown tax may convert some sub-marginal projects into ones that would be undertaken.</p> <p>No governments have introduced a Brown tax. Partly, this is because they are reluctant to make this type of commitment involving payouts on negative cash flows at the time they are incurred because of the uncertainty this creates for planning Budget outlays.</p>
<p>Benefits of a RRT type system</p>	<p>A resource rent charge is more responsive to profitability than production based charges by virtue of levying a charge only on economic rents. The neutrality of a resource rent charge will depend partly upon the extent to which exploration costs for projects which fail can be recouped. In the absence of a mechanism for recouping the cost of failed exploration, a resource rent charge could alter the preferred ranking of projects for investment. It could also mean that some projects which would otherwise be undertaken would not be undertaken. This affects in particular high risk projects which rely on the low probability of very high returns to achieve positive expected net present values.</p> <p>Nonetheless, in its application a resource rent charge will be more economically efficient and have less impact on investment decisions than production based charges or excise/royalty provided that the key variables in the charging</p>

	<p>system are properly structured. These key variables are:</p> <ul style="list-style-type: none"> <li>▪ treatment of exploration expenditures;</li> <li>▪ the threshold rate; and</li> <li>▪ the rate of the charge.</li> </ul>
Treatment of Exploration	<p>The principal mechanism to allow for the effects on investment decisions of any inability to recoup a portion of expenditures on failed exploration would be to allow losses from a company's unsuccessful projects to be offset against its revenues from successful projects. If a company had no RRT liable projects, it could carry forward its exploration losses until it could deduct them against income from an RRT paying field. Some firms might never be in a position to claim their exploration credits. This risk is reflected in the threshold rate.</p>
Setting the 'threshold' (or augmentation) rates	<p>The threshold rate should be set at the level which just recognises an appropriate premium, adjusted for the risk that some costs may not be recoverable. Because exploration risk is greater than development risk it can be argued that different threshold rates should apply to expenditure under these two categories.</p>
The tax rate	<p>If the tax charge exceeded available rents, investment distortions would occur. Firms will be encouraged to reduce tax liability by padding the cost base. The lack of an appropriate return will also act as a disincentive to invest. A low tax rate, say 20 per cent, would be inequitable since returns to the community net of administrative costs would be inadequate.</p> <p>A flat 40 per cent charge based on cash flows net of capital and operating costs is more equitable than a production based tax because it extracts most rent from projects with the greatest capacity to pay while marginal fields may not be liable for secondary tax. RRT also provides the community with an equitable share of resource rents under fluctuating market conditions. Unlike product based taxes, RRT automatically adjusts for price changes.</p>
Treatment of 'gas'	<p>The inclusion of revenues from other product streams has implications for charges on gas vis-a-vis what it would pay under the existing excise/royalty regime. This arises because tax is payable on positive cash flows from gas whereas under the existing excise/royalty arrangements gas is exempt from excise. However, it would not be desirable in principle to exclude gas revenues from the basis for a rent charge and it would be very difficult in practice to allocate costs to gas production where gas and crude oil are produced from the same facilities.</p> <p>If all revenues and costs, including for gas, were not incorporated in a rent based system there would be significant investment distortions between the areas under reference and greenfields areas where the existing RRT regime provides for the inclusion of gas revenues.</p>

The report underpinned the decisions announced by the Government in August 1990 to introduce a range of reforms to the petroleum resource taxation system, and in particular,

the phased move away from the use of output based systems as a means of taxing many resource projects in Australia.

### 3.2 Federal Government Review into the Operation of the PRRT – 1992

As part of the legislation that implemented the 1990 reforms to the PRRT regime, the Minister for Resources was required to present a report on the operation of the regime by 30 November 1992. The report was required to include the following:

- Whether the PRRT Act had been effective in meeting its objectives.
- The impact on prices and on industry.
- The impact on the development of new offshore petroleum projects.

The review sought public submissions from interested parties, including state governments. The final report commented on numerous aspects of the PRRT, and couched the overall tax in following context:

*“The PRRT was implemented as it provides an efficient and equitable taxation regime with the objective of striking a reasonable balance between providing the private sector with adequate returns for the risks they take in investing in petroleum exploration and development, and providing the community with a fair return on the exploitation of its non-renewable resources.”*

Report on the Operation of the Petroleum Resource Rent Tax Assessment Act 1987 – November 1992 (p.2)

Specific issues addressed in the report are covered by the following extracts.

Company-wide Deductibility of Exploration	The introduction in 1990 of company-wide deductibility for exploration expenditures against the PRRT removed a significant impediment to efficient offshore petroleum exploration. It has equated after-tax costs for exploration in all PRRT-liable areas and therefore removed an incentive to concentrate exploration activity in developed areas. Previously, the after-tax cost of exploration differed in project and non-project areas. Within a project, the cost could be as low as 36.6 cents per dollar because the associated costs were deductible for PRRT (itself income tax deductible) and income tax. Elsewhere, exploration costs were 61 cents or more per dollar as these costs are only eligible for deductions for income tax. The reforms mean that new exploration decisions are driven by prospectivity and technical factors rather than by distortions in the taxation arrangements.
Application of PRRT to Gas Production	PRRT applies to profits from the project as a whole. It is not a product tax. At issue is the efficiency and integrity of the PRRT. Adopting the producers recommendation would introduce a concessional tax rate for some petroleum product streams. This would mirror the inefficiencies evident in the former excise and royalty regime. Effective tax rate differences between product streams could cause investment and consumption distortions.
Augmented Bond Rate	Submissions argue that the reduction of the augmented bond rate (ABA) for compounding of general project expenditures

	<p>from the long term bond rate (LTBR) plus 15 percentage points to LTBR plus five percentage points has an adverse impact on the economics of new gas developments, increasing the minimum gas price required to make a project economic. Submissions draw attention to the high capital costs, long lead times, flatter production profiles and longer payout periods that it is argued are associated with gas projects.</p> <p><u>Comment</u></p> <p>The carry forward rate provides a premium on outlays commensurate with the risk that the investment may never be recovered. A principal risk for gas projects is managed by establishing long term market commitments prior to construction at prices that reflect a market value. In those circumstances, the appropriate issue for the carry forward rate is determining a threshold rate that compensates for risk rather than providing for a reduced level of price.</p> <p>Project returns are dependent on a number of factors, including the market price negotiated for the gas. To this point, there has been no evidence presented to suggest that the carry forward rate of long term bond rate plus five percentage points will impede the development of commercial gas projects.</p> <p>The 15 per cent premium rate for exploration and five per cent rate for general expenditures was established to recognise the relative risk characteristics of the different stages of a petroleum project. It should also be recognised that the two tier threshold rates and the tax rate are part of a balanced and integrated package of petroleum taxation reforms which included the introduction of company wide deductibility for unsuccessful exploration expenditure.</p> <p>Any adjustment in the general expenditure carry forward rate would therefore need a corresponding adjustment elsewhere, eg, by increasing the tax rate or reducing the threshold rate for exploration, to restore the balance and preserve a fair community return.</p>
GDP Factor Expenditure	<p>All expenditures except those incurred more than five years before the production licence is granted are eligible for annual compounding at the rate of 15 percentage points above the Commonwealth long term bond rate (LTBR) for exploration expenditure, and five percentage points above the LTBR for general expenditures.</p> <p>Expenditures incurred more than five years before the production licence is granted are eligible for annual compounding at a rate that compensates for inflation, represented by the GDP factor.</p> <p>The application of the five year rule ensures that the generation of an equitable community return is protected.</p>



	<p>The GDP deflator maintains the real value of historical expenditures. There is no evidence that these arrangements will inhibit commercial gas developments in Australia.</p> <p>The reference date for determination of compounding will continue to be the date of issue of the production licence, to ensure in the community interests that applications are submitted with relevant supporting material in a timely fashion.</p> <p><i>(Note: The determination date for the application of the five year rule was subsequently changed to the application date for a production licence due to the significant time delays in obtain production licence approvals.)</i></p>
<p>Marketable Petroleum Commodity scope</p>	<p>The Act is based on the taxable profit of a petroleum project. A project consists of the production licence area as well as treatment facilities and other facilities and operations outside that area that are integral to the processes for production and initial on-site storage of an MPC. An MPC is produced from petroleum and includes stabilised crude oil, sales gas, condensate, liquefied petroleum gas and ethane. Expenditures on plant for use in treatment processes necessary to produce an MPC, including expenditure on a crude oil stabilisation plant and gas liquids fractionation plants, are allowable deductions.</p> <p>The PRRT is a resource tax and should not extend to secondary activities where the community has no proprietary interest. These should be evaluated solely on a commercial basis. Where an MPC is produced within a plant, the Act has provisions permitting the determination of a market value at the point of production (see section 3.6, market value).</p> <p>Extension of the ringfence to a point of sale would introduce a number of elements unrelated to resource recovery and create uncertainty about the extent and nature of eligible deductions for a broad range of expenditures associated with downstream activity. The appropriate taxation point for a resource tax is at the first point where there is a marketable product from the recovery of petroleum. Product-based definitions reflect the fundamental principle that the PRRT should not extend to manufacturing processes.</p> <p><i>(Note: The introduction of the gas transfer price methodology through the 2005 Regulations effectively confirmed the view expressed in the report).</i></p>

The final conclusions of the report indicated that:

- Insufficient time had elapsed to be completely definitive about the impact of the PRRT on the petroleum exploration and production industry, however there was no reason to conclude that the PRRT has inhibited development or is preventing the industry from achieving adequate returns for the risks taken in investing in

petroleum exploration and development activities. The PRRT is providing a competitive fiscal environment that takes account of changing cost structures and fluctuating prices.

- Early indications are that the PRRT is meeting its policy objectives. It is providing the community with a fair return for the use of its non-renewable petroleum resources within an efficient and equitable framework for investment in offshore petroleum exploration and development. There is no evidence to suggest that it is impacting adversely on gas projects.
- It is premature to fully assess the impact of broadening the deductibility for exploration expenditures under the PRRT from a project to a company-wide basis, however the incentive to explore on a tax-preferred basis in PRRT areas had been removed.

In tabling the report, the Minister made a number of observations about of the PRRT provisions that remain relevant in the context of the 2016 review.

#### *Augmentation Rate for General Project Costs*

A number of submissions to the review raised concerns about the decision to reduce the augmentation rate for general project costs to the long term bond rate plus five percentage points. The Minister noted that:

*“The reduction in the premium reflected the significant benefits to industry that derived from the introduction of company-wide deductibility for exploration, and the relative risks of the different stages of a petroleum project.*

*The carry forward rates and the tax rate for the PRRT are part of a balanced and integrated package that includes wider deductibility for exploration expenditures. To preserve the community return, any adjustment in the carry forward rate for general expenditure would require a corresponding adjustment elsewhere.”*

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*“In conclusion, Australia has a regulatory and taxation regime for petroleum exploration and development that makes us internationally competitive. This has been recognised internationally by respected, authoritative sources.*

*The report I table today shows that the Government’s package of reforms for the industry are working. New investments are going ahead in Bass Strait under the PRRT. The report also indicates that exploration activities in our offshore areas are no longer being affected by taxation that distinguishes between project and frontier areas.”*

*“Petroleum Resource Rent Tax is a key element of those reforms, providing a strong stimulus to the industry, while safeguarding the community’s return for the use of its non-renewable resources.*

*The PRRT is an excellent example of micro-economic reform introduced by this Government in the area of energy, and indeed the economy as a whole. It*

*demonstrates the Government commitment to policies that will ensure a strong, competitive petroleum industry into the 21<sup>st</sup> century.”*

### 3.3 Ministerial Council on Mineral and Petroleum Resources: Review of Australia’s Fiscal Regime (2006)

At its meeting in July 2004, the Ministerial Council on Mineral and Petroleum Resources directed its Standing Committee of Officials to examine and report on the fiscal environment in which Australia’s resources sector operates. The object of the review was to identify possible options to improve Australia’s overall fiscal competitiveness, while recognising the revenue impacts for state and territory budgets.

A working group of officials was convened and a workshop was held to facilitate discussions. A final report was completed in 2006, with a limited number of recommendations. The following comments were contained in the final report of officials.

*“At the same time, industry does not have a consensus view on a preferred royalty system. Views differ on the relative importance of the different criteria and, in the view of the MCMPR, trade-offs are necessary and even inevitable. For example, profit based taxes may be preferred for very large, long life projects such as gas projects. However, the administrative complexity of such regimes means that they are unlikely to be suitable for relatively small, low value projects such as quarrying. Profit related royalties have a number of efficiency benefits but also involve greater administrative costs and complexity and risk greater volatility to government revenues.*

*In contrast, an ad valorem royalty regime can be distorting because it does not respond to cost changes, while specific rate royalty, varying only with output, is the most distorting of all.”*

MCMPR Minerals and Resource Taxation Report (p.viii)

*“Resource rent tax is calculated as a percentage of the economic rent (the project’s net cash flow after accumulated exploration and production costs are deducted). Such taxes have rarely been used in other countries for minerals although they have a limited application for oil and gas. This form of tax makes allowance for the return on investment. Investments are less likely to be deterred, extraction is more efficient and premature project closures are less likely than under other resource tax regimes.”...*

*‘As a threshold return must be generated on capital invested before any resource rent tax is paid, government revenue from new projects may be delayed for some years especially for projects with high initial capital and exploration costs or long lead times prior to the commencement of production. At the project level, the revenue flow from a profit tax will be less stable and less predictable than from production-based royalties”*

MCMPR Minerals and Resource Taxation Report (p.34)

### 3.4 ABARE Report: Non-Renewable Resource Taxation in Australia (2010)

The Australian Bureau of Agricultural and Resource Economics (ABARE) prepared a submission for the 2008 review into Australia's tax system (*Australia's Future Tax System Review*). The submission reviewed aspects of the taxation of Australia's non-renewable resources, including making comparisons between alternative resource taxation systems.

A number of observations and comments were made about the relative merits of the different systems used both in Australia and overseas. In the context of the objective of resource taxation, it was noted that:

*"The economic rationale for resource taxation is based on the presence and size of resource rents. In practice, resource rent is difficult to estimate and is often approximated by the economic rent which is the excess profit or supernormal profit earned in the market (equal to revenue less costs where costs include normal profit or a 'normal' rate of return to capital). A resource tax is justified if the resource rents are sufficiently large to outweigh associated administrative and compliance costs."*

Non-Renewable Resource Taxation in Australia, ABARE, 2010 (p.2)

With respect to the use of royalty and excise based regimes:

*"Globally, ad valorem and specific royalties have been the traditional mechanisms applied by governments to collect resource revenue from mining projects. However, output based royalties are inefficient and regressive – these options tend to collect a higher share of resource rent for less profitable projects resulting in negative distortions to private investment and production decisions. While the government may collect royalty revenue throughout the production phase of a resource project, there may be significant lost revenue opportunities under an output based royalty, particularly during long periods of relatively high industry profitability."*

Non-Renewable Resource Taxation in Australia, ABARE, 2010 (p.3)

The report also noted the differing criteria that are relevant in assessing resource taxation options for investors and governments. For an investor, the criteria can be broadly categorised as:

- Neutrality (investment decisions should not be distorted).
- Project risk (taxation options may have significant impacts on individual projects and profitability assessment).
- Sovereign risk or stability (changes in fiscal settings over the life of a project can have a major impact on profitability).

From a government perspective, criteria encompass the following:

- Flexibility (the flexibility of fiscal instruments to changes in market conditions).
- Fiscal loss (the risk that the government doesn't collect a minimum return – this can in part be mitigated through a tax that is not responsive to market conditions, however this can lead to reduced revenue flows in strong market conditions).
- Revenue delay (revenue can be delayed until such time as an investor has generated a positive return on an investment).

The above criteria are important inasmuch as there is often a need to balance potentially competing objectives. Notwithstanding these concerns, rent or profits based charges more directly meet the objectives of industry and governments, and are less likely to discourage future investment decisions.

The report also noted a number of conclusions drawn from a resource taxation conference convened by the International Monetary Fund in 2008. Specifically, it was noted that:

***“Output based royalties are inefficient and regressive – under an output based royalty, government revenue varies with the volume of production (specific royalty) or the value of production (ad valorem royalty) but does not vary with project profitability. Under these options, a higher share of resource rent is collected for less profitable projects resulting in negative distortions to private investment and production decisions. For example, Hogan (2008) notes that an ad valorem royalty, levied at a constant rate, overtaxes low profit projects and under taxes high profit projects. Notably, some projects that were assessed to be economic before tax will become uneconomic or unprofitable under an output based royalty. While the government may collect royalty revenue throughout the production phase of a resource project, there may be significant lost revenue opportunities under an output based royalty, particularly during periods of relatively high industry profitability.***

***Rent and income based taxes and royalties are efficient policy options that allow the government to increase resource revenue during periods of high industry profitability – rent or income based taxes ensure government revenue varies with changes in economic conditions. Compared with the outcome under output based royalties, rent and income based taxes and royalties reduce investor risk and increase resource rent potential. For example, Land (2008, p.7) notes the ‘fiscal flexibility using progressive taxation removes the need to renegotiate periodically or override existing fiscal arrangements’ – under a progressive tax, a higher share of resource rent is collected for more profitable projects. Daniel et al. (2008, p.13) also note that ‘a system that responds flexibly to changes in circumstances may be perceived as more stable’.***

Non-Renewable Resource Taxation in Australia, ABARE, 2010 (p.22)

### 3.5 Policy Transition Group Report – New Resource Taxation Arrangements (2010)

On 2 July 2010, the Federal Government announced a range of new taxation arrangements for the resources sector in Australia, including a decision to extend the PRRT regime to cover exploration and production activities from state waters and onshore areas and the North West Shelf project. This decision followed the release on 2 May 2010 of the Government’s response to the recommendations of the review into Australia’s Future Tax System that was chaired by the Secretary to the Treasury, Dr Ken Henry (the Henry Report).

### *The Resource Super Profits Tax (RSPT)*

On 2 May 2010, the Federal Government indicated an intention to introduce the so-called resource super profits tax (RSPT). The RSPT was the subject of significant debate following its release, with a strong focus being placed on a number of key parameters that had the potential to both impose a significant retrospective tax change to projects in the mining and petroleum sectors, and at the same time apply a tax that had design features far removed from the commercial drivers that influence the decisions of investors in a globally competitive resources sector.

For example, the RSPT proposed to remove the allowance for an investor to achieve a risk adjusted return on investment (replacing it with an inadequate and risk free LTBR carry forward rate), introduced the concept of depreciation (similar to income tax) rather than allowing for the immediate and deductibility of costs, had numerous ill-defined concepts (including transitional provisions and what constituted a 'project') and vaguely promised the refundability of certain costs in a manner that was of limited use to producers.

In addition, the Henry proposal recommended the adoption of a cash bidding arrangement for the allocation of exploration rights – this was seen as a better basis for collecting upfront 'rent'. Subsequent to this proposal being released, the Federal Government has introduced cash bidding for selected prospective and high value offshore acreage. To date, this process has been unsuccessful in the awarding of acreage, and has failed to collect any revenue (or rent).

The Henry Report was particularly critical about output based taxes, including making the following comments:

*“By contrast, output-based royalties discourage investment and production because they are levied irrespective of the costs of production. Consequently, investors receive a lower post-tax return from a more expensive operation because costs are not recognised for tax purposes. This is particularly important for risky projects. Output-based royalties can therefore result in some economically viable projects not proceeding.”*

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*“The use of output-based royalties or an income-based tax can be expected to result in fewer discoveries, less output from discovered deposits and earlier closure of projects than otherwise. Therefore, they erode the value of resources for the community while still giving away a share of resource rent.”*

Australia's Future Tax System Report 2009 (p.222)

Overall, the RSPT model was highly theoretical in nature and fundamentally failed to understand the concepts of risk and reward in terms of resource investment decisions and the realities of global competition.

### *Extension of PRRT*

The Government revisited the RSPT proposal following widespread criticism of its details and inadequately thought through likely impacts on current and future investments in the resources industry. As a result of the review, it announced the introduction of a minerals resource rent tax for iron ore and coal production, and the extension of PRRT for oil and gas production.

To assist in implementing the decision, the Government established a Policy Transition Group (PTG) to advise on the technical design and policy issues that needed to be addressed. The PTG was headed by The Hon Martin Ferguson AM MP, Minister for Resources and Energy, and Mr Don Argus AC.

The PTG undertook a comprehensive consultation process with a range of stakeholders groups, including industry, major accounting firms and tax professionals. It received numerous submissions. While operating under a limited time-frame, it presented a detailed report that covered key matters relevant to the extension of the PRRT. One key recommendation was the formation of an implementation group to further develop the details of completing the PRRT transition process. The implementation group was made up of representatives from industry, advisory firms and officers from Treasury, the Australian Taxation Office and the Department of Resources, Energy and Tourism.

In terms of tax design guiding principles, it was noted that that the arrangements should include or address the following:

- Be neutral across resources.
- Minimise taxpayer uncertainty and compliance costs.
- Apply tax principles in a consistent fashion.
- Minimise incentives for tax avoidance and maintain the integrity of the tax base.
- The new arrangements should apply on a prospective basis.
- Minimise unintended distortionary impacts.

Specifically in the context of PRRT, the PTG noted that:

*“Consideration of the extension of the PRRT has been a markedly different exercise to designing the MRRT, with the key challenge being to identify a minimal set of changes to accommodate the transitioning projects within the existing PRRT. Minimising change to the existing provisions is important to avoid creating uncertainty or confusion over an established tax framework that is generally well understood and considered to function well.”*

Policy Transition Group Report 2010 (p.8)

While the report was primarily focused on design and implementation issues, the then existing PRRT parameters were broadly seen as being effective and transitional provisions were focused on maintaining the integrity of the underlying PRRT framework. The extended regime was introduced with effect from 1 July 2012, following Parliamentary review and debate.

## Section 4: Comments on the PRRT and the Core Provisions

*“Many people believe that the only important characteristic of a tax is how much it takes. This is far from true. The form of the tax may have extremely weighty effects in encouraging some activities or discouraging others. It is easy to assume, as governments often seem to have done in meeting the question of taxing mining companies, that there is a simple dilemma between heavy taxation, which discourages mining, and light taxation, which yields little in the way of revenue. On the contrary, provided that the form of the tax regime is chosen prudently, it is possible to improve the trade-off considerably...”*

*Ross Garnaut, 1983*

This section of the submission seeks to respond to assertions made about the operation of the PRRT, provide commentary on a range of issues associated with the appropriateness of using a profits based regime as the primary resource taxation for Australia and the case for the retention of the existing core provisions of the PRRT regime.

### 4.1 General Comments

#### *Tax Payments from Petroleum Projects*

Commentary was provided in Section 2 in relation to the factors that are relevant in determining the level of PRRT paid by individual companies. These factors can include:

- Oil and gas prices
- Exchange rate movements
- The level of production
- The output mix – oil, gas or the combination of products
- Expenditure – exploration, development, production and closing down
- Regulatory processes and obligations that impact on the timing and level of production (including lags between when funds are outlaid and when production commences)
- The quantum of creditable resource tax payments
- Time frames for undertaking projects

For petroleum resources to yield any return to the community, the fiscal conditions need to be conducive to bringing them to market. It is essential that the fiscal arrangements are sensitive to level of returns available for oil and gas investments and that certainty is provided as to how such investments are treated for tax purposes.

The level and mix of total tax paid by individual oil and gas projects will be determined by a range of factors. For example, the economics of gas projects are generally different to oil developments, with higher capital and operating costs and flatter production profiles. Oil projects can see the bulk of the reserves from a field or reservoir developed in the early years of a project life, while gas projects are often characterised by a slow ramp-up in production and more constant levels of production over a project life. This impacts on project economics and the likely mix of payments between resource taxes and company tax.



In 2007, APPEA released a detailed report that sought to identify the opportunities and challenges facing the industry with a view to promoting growth opportunities. The report was titled '*Platform for Prosperity – Australian Upstream Oil and Gas Industry Strategy*' and included long term projections about the possible taxation contributions from LNG projects.

The conclusion of the modelling was that the vast bulk of tax that would be paid by such projects would be through corporate taxation (up to 90 per cent of the total tax take), in large part due to the profits based nature of the PRRT regime and the modest returns generated by LNG projects.

Such an outcome was not surprising and is generally recognised by the industry as the norm for gas projects. It also demonstrates the strength of PRRT, inasmuch as the regime does not impede the timely development of gas resources.

#### *Application of PRRT to Gas Projects*

There have been views expressed by some observers that the PRRT regime was not intended to cover gas developments – this is simply incorrect and is not supported by the facts. The PRRT was designed to capture all oil and gas production, as referenced by the list of what represents a marketable petroleum commodity under the legislation (which includes a specific reference to sales gas).

Joint oil and gas developments have been treated as a single project for PRRT purposes as early as the decision to extend the regime to cover the Bass Strait project. The 1990 and 1992 reviews outlined in Section 3 of this submission both indicated the clear intention for the regime to cover oil and gas. In addition, as early as 1992, material presented by the ATO at an APEA Taxation Seminar raised the issue of how LNG projects were to be treated for PRRT purposes in the context of what represents a marketable petroleum commodity and the non-deductibility of LNG related processing costs.

There were no suggestions in any consultations or discussions that took place between the industry and government stakeholders during the negotiation of the gas transfer price provisions that the regime was either not intended or incapable of covering gas projects. Indeed amendments were made to the Act in 2001 to specifically address a technical issue that had the potential to cause anomalous outcomes following the announcement of the gas transfer price methodology.

As further evidence, the treatment of onshore gas to liquids projects was a detailed theme of discussions as part of the decision to extend the regime onshore from 1 July 2012.

In summary, the continued suggestion that PRRT is not intended to apply to gas production is rejected and seemingly represents a case of ideology over facts.

#### *Quantum of PRRT Deductible Expenditure*

Recent attention has been placed on the level of deductible expenditure that exists under the PRRT regime. Much of this commentary has been led by the industry's critics and some sections of the media. It is both ill-informed and fails to acknowledge the significant costs

incurred by the industry, the impact of the fall in prices and what the data actually measures.

The ATO publishes a range of taxation statistics covering the majority of taxes that are administered by the agency. Included in the data published are details on assessable receipts and deductible expenditure for PRRT purposes. A summary of the data for selected years is outlined below.

Table 2: Taxation Statistics – PRRT (\$m)

	2010-11	2012-13	2014-15
<b>PRRT returns (number)</b>	71	155	149
<b>Assessable Receipts</b>	12,049	26,326	25,524
Class 2 General Expenditure	15,062	63,276	94,820
Class 2 Exploration Expenditure	1,648	5,550	10,402
Resource Tax Expenditure	Na	6,241	5,942
Acquired Exploration Expenditure	Na	8,388	13,612
Starting Base Expenditure	Na	65,878	84,077
<b>Carry Forward Expenditure</b>	9,362	128,008	187,554
<b>Taxable Profits</b>	2,618	3,174	2,996
<b>PRRT Paid</b>	1,047	1,269	1,198

*Source: Australian Taxation Office*

It is clear from an informed reading of the data contained in the table that an important reason for the increase in deductions is as a direct result of the decision to extend the regime onshore and to the North West Shelf project. For the year 2014-15, nearly 50 per cent of the total carry forward expenditure related to starting base expenditure, while a large percentage of general expenditure will also be directly related to onshore deductions. These expenditures are not transferable to other projects held by a taxpayer.

In terms of deductions that relate to onshore projects and North West Shelf project, the retention of the existing royalty and production excise regimes means that these taxes will remain the primary resource taxes for these projects. PRRT was never intended to be the primary resource taxing tool for these projects. This has been recognised on a number of occasions, including the following:

*“There are numerous reasons the effects of extending the PRRT on Australian Government revenue are unknown and why any attempt to forecast revenue, especially over the long term would, at this stage, be speculative. The Australian Government will incur both revenue gains and losses. On the one hand, the Government will gain PRRT revenue from extending the PRRT to the North West Shelf and onshore projects. On the other hand, projects to which the PRRT will extend will continue to be subject to excise but the excise paid will be credited against the PRRT. The net effect on revenue is unknown.*

*A second reason long-term revenue effects are unknowable is that future developments in the shale oil and coal seam gas industries—both of which will be subject to the PRRT—are uncertain. The decision to establish an Independent Expert Scientific Committee to advise governments about the consequences for water resources of coal seam gas and large coal mining developments has added to this uncertainty.*

*Thirdly, the response of the states to the extension of the PRRT is unclear. Onshore projects are subject to state royalties. Under the Bill, resource tax expenditure—Commonwealth and state—will be deductible expenditure in certain circumstances. Deductibility provides the states with an incentive to increase petroleum and gas royalties.*

*Finally, revenue depends on the trajectory of future oil and gas prices and project costs that are uncertain.”*

Parliamentary Library, 22 December 2011 (p.8)

In addition, the following was noted in a Parliamentary report that addressed aspects of the legislation to extend the PRRT.

*“During informal discussions with industry, it appears that the amendments to the PRRT are less significant than the other Bills in the package because:*

- *the PRRT is already well known to industry; and*
- *the North West Shelf is unlikely to pay significant amounts of PRRT because the amount of royalties and excise paid will be taken into account in calculating PRRT. These royalties and excise are sufficiently high so as to preclude the PRRT being paid for these projects.*

House of Representatives Report on the MRRT and related Bills, 2011 (p16-17)

In addition, the regimes critics often make reference to the large amounts of exploration expenditure. Again, this is not supported by the facts, with exploration expenditure accounting for a relatively small proportion of total deductible expenditure.

Overall, the lack of understanding and an inaccurate representation by some parties of the data published by the ATO in relation to the levels of deductible expenditure undermines the claims made by some industry critics and opponents of the PRRT.

#### 4.2 20 December 2016 Treasury Issues Note

Dr Kraal said one way for the Australian people to get a return on their own assets, the natural gas, is for the Federal Government to levy a royalty at the start of production.

*"That is one option, another one is to use the status quo as the benchmark, then you would compare that benchmark against the current tax system," she said.*

*"Another is maybe a combination of a royalty with the PRRT, or a royalty and company tax alone.*

*"Or just totally redesign the PRRT with some measure of a royalty system in there.*

*"The gas belongs to the people, how long should they wait before they see a return on their own goods?"*

Dr Diane Kraal, 30 November 2016

APPEA understands that the Issues Note that was released on 20 December 2016 was intended to provide a snapshot of stakeholder commentary about petroleum resource taxation in Australia with a view to highlighting issues that interested parties may wish to focus upon in terms of the preparation of submissions to the review. The Note raises a number of important matters that are discussed in more detail in this submission, however APPEA would like to take the opportunity to formally respond to a number of comments that we consider to be either misleading or factually incorrect.

- General Comments

The economic and market circumstances the industry experiences has a significant impact on actual and projected PRRT collections. APPEA is of the view that the PRRT is operating in a manner that is entirely consistent with its design principles, and that the current projections reflect an outcome that is consistent with a period of very low prices, high project expenditures, the point in the production cycle of many large projects and a fall in petroleum liquids production in Australia.

The deductibility of expenditures is not an issue that affects the Review's terms of reference. The Issues Note is generally silent in commenting on the ATO's performance in monitoring and enforcing compliance with the legislation. This is regrettable as it is a criticism raised about the operation of the regime that is not supported by the facts. For example, the ATO has been successful in pursuing a number of important cases (reference the Woodside, Esso and ZZGN cases), conducts ongoing risk reviews and audits, conducts industry forums and is aware of topical and matters of importance to the industry. The industry experience is that the ATO has expanded both the number of resources and depth of industry experience in the context of administering PRRT. Any perceived lack of transparency should not be confused with a lack of compliance activity.

- Specific Comments

*The Revenue Raised from Oil and Gas Extraction Is Declining (p.6)*

As indicated earlier in this submission, care should be taken to distinguish deductible expenditure in relation to offshore projects from the deductible expenditure of onshore projects. As a result of extending PRRT to onshore projects, there are significant transitional expenditures included in "starting base," where the book value or the market value approach was chosen, and in "general expenditure" where the look-back approach was chosen.

For example, where the look-back approach was chosen, expenditure incurred between 1 July 2002 and 30 June 2012 is included as general expenditure. Whilst this will reduce any onshore PRRT otherwise collected, the collections from onshore PRRT (and the North West Shelf project) must be considered separately from offshore due to the onshore projects being subject to petroleum royalties and production excise before determining the PRRT position.

*Factors Influencing Revenue Collection (p.7)*

Foreign exchange rates also are an influence, affecting the Australian dollar value of oil linked revenue and the costs of project construction. Collections from taxpayers adopting a foreign currency will also be affected when the tax payable is converted to Australian dollars.

In addition, the Explanatory Memorandum to the legislation that gave effect to the extended PRRT noted that:

*“The revenue impact of the PRRT extension is unquantifiable, but it is unlikely to give rise to significant collections over the forward estimates. A key feature of the Main Bill is that transitioning projects are entitled to a starting base to shield a company’s historical investments and prevent the retrospective application of the extended PRRT. These transitional arrangements are the key reason why revenue is not expected to be collected from this measure over the forward estimates.”*

In addition to the above, resource taxation payments are also rebateable against a future PRRT liability on a project by project basis to avoid the imposition of double taxation.

*Carry Forward Losses and Uplift Rates (p.9)*

It is important to understand that these uplift rates are a key element of the conceptual model designed by Garnaut and Clunies Ross and are used to determine the rent generated by the project. This is a key object and intentional design feature of the tax.

*The Australia’s Future Tax System Review (p.10)*

The uplift rates are essential to measure the rent generated from each project. Investors should not be paying PRRT until rent is generated. Unless the risk returns that measure the rent are used to uplift undeducted expenditure, then investors will be paying PRRT before rent is earned.

The risk of not being able to utilise the value of a tax deduction to which the AFTSR report referred has some similarity to the risk used to determine the rent. It relates to the project and not to a simple time value of money or bond rate reflecting a company’s overall activities which may include non-PRRT activities or a range of PRRT projects at various stages of development and therefore risk. It must reflect the particular project.

*Comments Attributable to Dr Craig Emerson (p.9)*

The modification to the regime passed by the Government in the mid-2000s was, on APPEA’s analysis, limited to the former frontier exploration incentive. The frontier exploration incentive provided an additional fifty per cent deduction for exploration from designated frontier areas between 2004 and 2009. The concession has been discontinued and has no enduring impact on the integrity of the PRRT regime.

*Comments Attributed to Mr Ken Willett – ACIL Tasman 2012 (p.10)*

APPEA fundamentally rejects this comment. All practical experience would reject the purely theoretical view that the timing of generating revenue and incurring expenditure is manipulated to achieve better augmentation outcomes. Whilst petroleum projects are generally analysed on an after-tax basis, in practice there are more fundamental drivers of project schedule such as capital allocation amongst competing projects of an organisation, corporate strategies on reserves recognition, production and sales, engineering and construction logistics and marketing strategies and opportunities that over-ride any consideration of timing being driven by augmentation. Mr Willett's views do not seem to be supported by evidence.

The different rates on exploration augmentation arise because exploration expenditure incurred more than five years from a production licence is augmented at the GDP deflator. What the rate needs to measure is the rent being generated from the project, which in turn will reflect the risk undertaken by investors in a project. APPEA has previously raised with governments concerns about the GDP factor rate. Arguably, the PRRT system needs to adopt a common rate for all projects to provide certainty and simplicity. The use of a common rate does not indicate arbitrary selection. It is also the case that when incurring exploration, one of the risks is the time between discovery and an application for a production licence. This time is a function of the success of an initial discovery and the need to conduct additional exploration before sufficient certainty over the risks involved is obtained to make an investment decision. These time lags are not known when exploration commences.

In the final draft of the ACIL Tasman report (noting the report addressed exploration policy in Australia), a lengthy discussion was provided in relation to the relative merits of the resource and company tax provisions, including in the context of the recommendations of the 2009 Henry Tax Report and the subsequent decision of the Government to abandon the Henry proposals and extend the coverage of the PRRT regime. The discussion focuses on the theoretical purity of a cash flow based tax with full offsets for losses, but recognised the challenges of adopting such a model. The author noted the following in a draft provided to APPEA for comment:

*"...the petroleum resource rent tax is clearly superior to the company income tax system, and vastly superior to ad valorem, specific and hybrid ad valorem-specific royalty/regimes in terms of efficiency." (p.187)*

*"The United States and Australia ad valorem royalty and the Australian crude oil excise regimes ignores all costs upstream from the taxing point, and therefore, tax returns to all upstream inputs. These regimes tax poor outcomes relatively much more than superior outcomes. They effectively subsidise superior outcomes, because they capture a relatively small proportion of the resource rent. As a result, such systems increase the riskiness of cash flows to mining enterprises, discouraging exploration and other investments in relatively risky mining activities." (p.188)*

*Comments from the Policy Transition Group – Incurring of Expenditure (p.10)*

Subsequent to the PTG report, the Federal Court made findings in *Esso Australia Resources Pty Ltd v Commissioner of Taxation* [2012] FCAFC 5 which resulted in the enactment of the [Tax Laws Amendment \(2013 Measures No. 2\) Act 2013](#). This Act largely dealt with the deficiencies of the PRRT Act with which the PTG were concerned.

*PTG Comments – PRRT Meaning of Exploration (p.10)*

Subsequent to the PTG report, the ATO has conducted extensive consultation with industry and issued Taxation Ruling TR 2014/9 on the meaning of exploration for PRRT purposes which reflected the current case law and provides a more limited definition for PRRT purposes than for income tax purposes.

*Professor Michael Crommelin, University of Melbourne on the Starting Base (p.12)*

This commentary is directed principally at MRRT and in any event, deals with the difficult, but discrete and not-ongoing issue of providing transitional relief for the retrospective introduction of a new tax, which in the case of PRRT was imposed in addition to the existing royalties and production excise. Whilst relief is provided for royalties and production excise in the determination of PRRT, onshore projects continue to be subject to output-based royalties and production excise which can act to discourage investments.

*Growth in New Projects and Falling Revenue (p.13)*

This represents the point in the cycle of these projects, constructed at significant cost, in the early stages of a long production life over which the investment is recovered and in a time of low commodity prices. This lack of revenue reflects the operation of PRRT in accordance with its intended design.

*Dr Diane Kraal, Monash University on the Design of the Regime (p.13)*

The PRRT model seeks to measure and tax the rent generated from a project. The fact that gas is less profitable than oil reflects the reduced rent generated from gas rather than the inappropriate nature of a resource rent tax approach to generate a community return. The resource rent tax approach overcomes the limitations of output-based taxes and charges. The community is also deriving a return as a consequence of firms risking significant amounts of capital in projects that deliver growth from investment in construction, operation, export earnings and the payment of corporate tax. In addition, the return the community requires should also consider that the remote, technically demanding location of resources, the capital required (including from alternative investments proposals) and the long lead times for investment returns reduces the intrinsic value of the resources for secondary taxation purposes.

APPEA assumes that an output based model is Dr Kraal's preferred regime for these types of projects, with a preference for revenue collection over economic efficiency. It is also worthwhile noting the experience with respect to the application of petroleum royalties for some integrated gas to liquids projects onshore has been one of complexity due to royalties

being applied on a wellhead value basis. The PRRT has the considerable advantage of being assessed on a project basis.

*The Western Australian Government – Treatment of FLNG (p.14)*

Much of the discussion on PRRT in the quoted Report is directed at tensions between the federal and state revenues and it is not clear how the recommendation relates to the findings and text. The report notes: “FLNG projects represent a major benefit to the federal government. The lack of any onshore development means a much lower capital expenditure for the project. This results in higher profits, and, therefore, higher taxes, produced more quickly.” (paragraph 9.23). Arguably, the lower capital costs and flexibility of floating LNG will facilitate investment in the project that may not otherwise occur and produce a significant flow of PRRT.

Issues arise on the allocation of FLNG costs between the PRRT project and downstream operations, however this is simply an apportionment issue that does not affect the efficacy of the PRRT regime. This can be accommodated within the current provisions.

*The Australia’s Future Tax System Review – Gas Transfer Pricing Methodology (p.14)*

The design of the gas transfer price regulations was the subject of detailed discussion and independent studies, in particular in respect of the rate of return and the split between the upstream and downstream phases. The capital allowance is not arbitrary – a single rate of general application provides benefits of certainty and simplicity which is important in providing confidence on planning models.

*Dr Diane Kraal - Transparency in how GTP Methodology is Applied (p.14)*

The operation of the gas transfer price methodology is set out in significant detail in the Regulations and explanatory statements. In addition, the ATO understands the significance of the gas transfer price to PRRT liabilities and is able to thoroughly review calculations. Dr Kraal stated “I am advocating for a GTPM review that would require liaison with the Australian Taxation Office and corporate tax units to prepare a comparison of the current myriad of GTPM interpretations as provided for in the PRRT Regulations.” This, together with a call for greater transparency, say nothing about the appropriateness of the gas transfer price methodology. The ATO and taxpayers do engage in a review of the application of the gas transfer price regulations.

### 4.3 Australian Fiscal Regime in a Global Context

*"Comparing Qatar and Australian LNG taxes, and concluding Australia is not getting as much as it could, is akin to comparing a Landcruiser and Ferrari and concluding the Landcruiser isn't going as fast as it could,"*

*Saul Kavonic, Wood Mackenzie – Australian Financial Review, 1 December 2016.*

Considerable media attention has recently been given to comparing Australia’s fiscal regime to those applicable in other petroleum producing countries. This has been demonstrated by the incorporation of material in the published Issues Note quoting a report from the International Transport Workers’ Federation. In addition, APPEA understands that the Tax



Justice Network has written to a number of senior parliamentarians raising concerns with the forecast level of PRRT payments and making claims about the way the PRRT regime operates. It is essential that a debate of this importance be undertaken on a factual basis.

Rather than responding to individual issues, we have sought the input of Wood Mackenzie about key aspects of the fiscal framework that applies in Australia compared with other gas producing countries. A snapshot of the findings are outlined below, with the full report at [Attachment 3](#).

### Comparing Global LNG Projects

Wood Mackenzie notes that LNG developments represent some of the longest time horizon projects for companies, requiring substantial upfront capital investments. Many global projects have been producing for a number of years, while others are still under construction. The economics of LNG projects (including company returns and government revenues) are dictated by the performance of several stages in the production chain, ranging from the recovery of petroleum resources, to liquefaction and transportation.

The split of project profits between the host government and the investor is a function of the fiscal regime that is in place. A number of examples are provided in the report for comparative purposes.

Table 3: Project Returns and Estimated Profit Splits

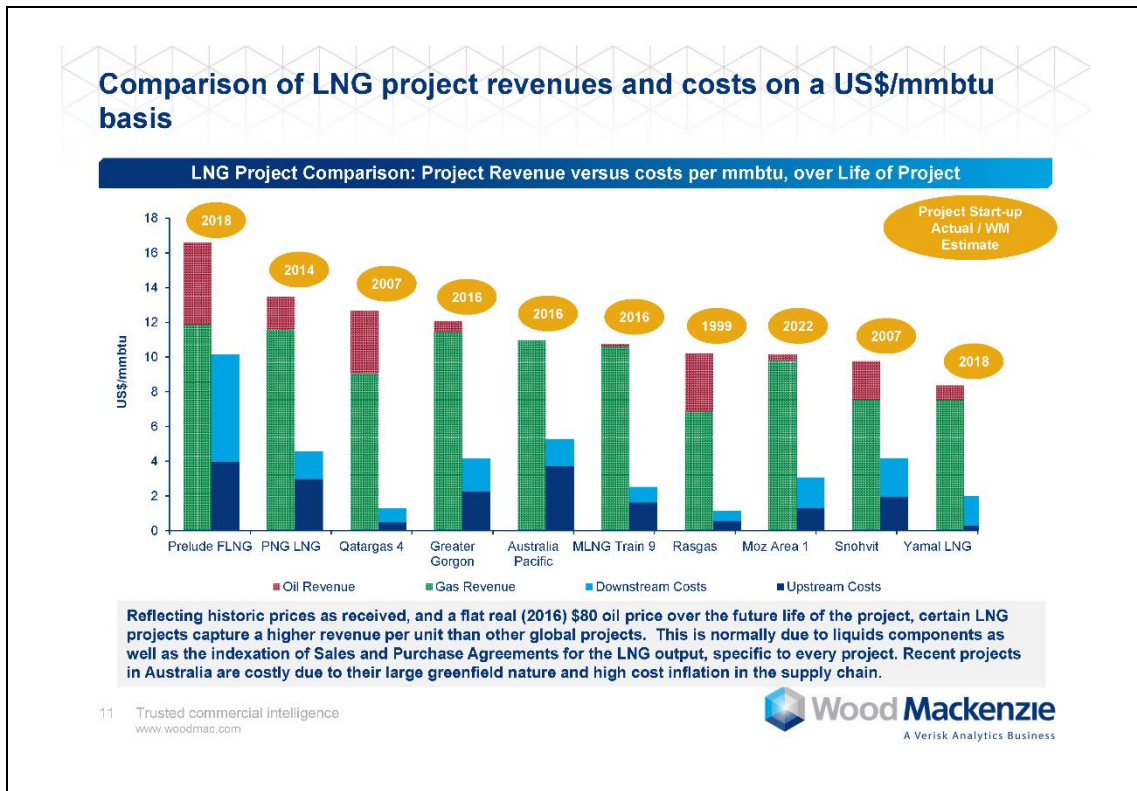
	<b>Gorgon (Australia)</b>	<b>Qatargas-4 (Qatar)</b>
Internal Rate of Return (post-tax full cycle)	7.0%	32.5%
On-stream Date	2016	2011
Government Share of Profits	44%	58%
Government Share (including equity)	44%	87%
Total Lifetime Capex (2016 real)	\$97bn	\$7bn
	<b>APLNG (Australia)</b>	<b>PNG LNG (PNG)</b>
Internal Rate of Return (post-tax full cycle)	7.3%	12.6%
On-stream Date	2016	2014
Government Share of Profits	44%	33%
Government Share (including equity)	44%	47%
Total Lifetime Capex (2016 real)	\$44bn	\$25bn

*Source: Wood Mackenzie 2017*

The Australian projects (Gorgon – Offshore, APLNG – Onshore) are high cost compared to peer projects overseas. In addition, project profitability, based on internal rates of return, are considerably lower for the Australian projects.

The Tax Justice Network has used project revenues as a simplified basis for comparing tax contributions for projects from different countries. This methodology is fundamentally flawed, as it implicitly assumes turnover is a proxy for profitability or capacity to pay. The failure of this approach is clear when a comparison of unit costs of production are made

between projects. Australian projects are significantly more expensive to operate compared with overseas competitor, a fact that is demonstrated by the slide below.



Source: Wood Mackenzie 2017

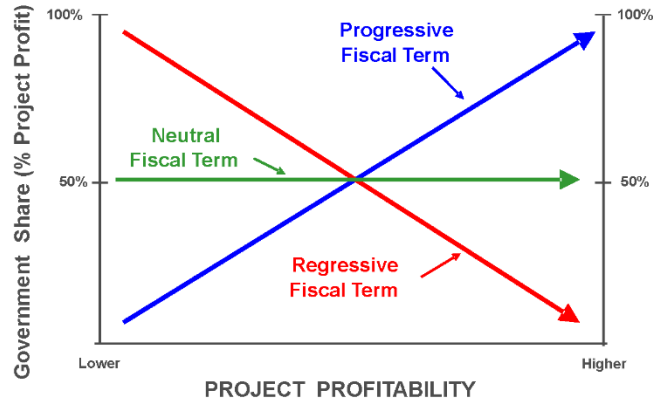
Overall, Australian LNG costs leave a smaller share of the profit to be split between the investor and government.

Government Share from LNG Projects

Comparisons of government revenue shares for the sample projects indicate the main differences are in the timing of payments, recognising differences in the taxation structures and the project cost profiles. The report notes the differences in the nature of global fiscal terms, with fiscal regimes being broadly divided into revenue, expenditure or profits based in nature. The type (and therefore the impact) of individual taxes will determine whether they are regressive or progressive in nature. This is consistent with the reviews undertaken since the inception of the PRRT regime, which have consistently highlighted the efficiency and progressive nature of PRRT.

## Progressive fiscal terms generate more government share as project profitability increases

Government Share Levels with changing Project Profitability



21 Trusted commercial intelligence  
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A Verisk Analytics Business

Source: Wood Mackenzie 2017

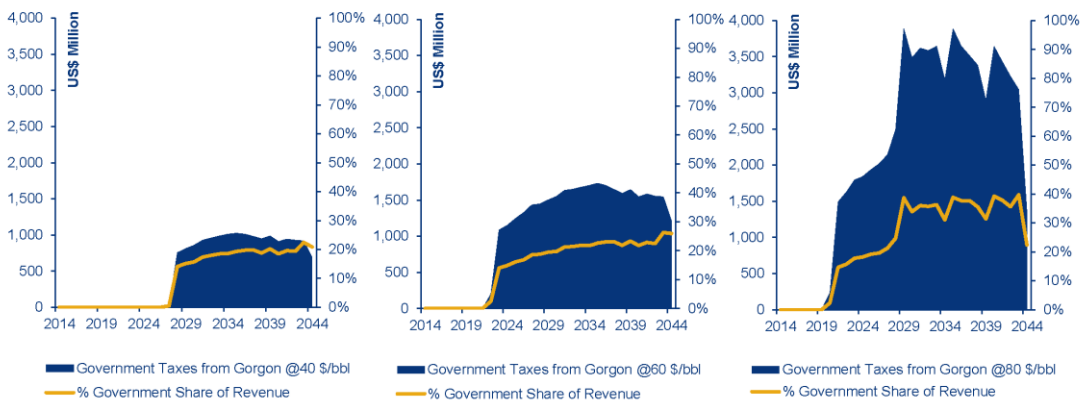
The level of the governments share will differ on a project by project basis over the life of individual projects, hence a one year comparison is not representative.

## With a progressive fiscal regime like PRRT, along with the absolute government revenue, the share government claims of the profit also increases with price increases

Gorgon (\$40 Real)

Gorgon (\$60 Real)

Gorgon (\$80 Real)



Note: Government Taxes are inclusive of any Royalties, PRRT and Corporate Taxes

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Source: Wood Mackenzie 2017

## Other Findings

### *Fiscal responses of governments*

The responses of different governments to the significant fall in oil and gas prices in 2014 has varied. Some sought to make their fiscal regime as attractive as possible, while others sought to increase their share of the remaining profits from projects. Some terms were only modified for the newly issued licences. There were a variety of responses in the Americas; in Europe, only Russia increased its government share; while in Asia, some governments lowered their share with a view to attracting increased investment. Australia has remained broadly stable.

### *Offshore Oil Projects*

Wood Mackenzie also analysed the fiscal terms applicable to offshore oil discoveries, noting that Australia's terms are both broadly competitive.

## 4.4 Comments on Key PRRT Provisions

*"It is an ambitious step in a long-term reform agenda that will provide all Australian oil and gas projects with a certain and consistent tax regime that takes account of the varying circumstances and profitability of individual projects."*

*"The bill before the House extends this efficient profit based tax to onshore oil and gas, including the growing onshore coal seam gas industry, while ensuring that the long-term attractiveness of investment in Australian oil and gas extraction is not impaired."*

*It was true back in 1987 and it is true now. I quote Hansard back when the PRRT was first introduced:*

*'Petroleum resources are, in their most basic sense, community property and the government believes that the community as a whole should share in the potentially high returns from the exploitation of these scarce, non-renewable resources.'*

....

*The government believes that a resource rent tax related to achieved profits is a more efficient and equitable secondary taxation regime....*

....

*In contrast to production-based secondary tax regimes, the petroleum resource rent tax will be payable only in respect of projects earning a high rate of return on outlays' "*

Second Reading Speech, Extension of the PRRT Regime  
The Hon Bill Shorten MP, Assistant Treasurer – November 2011

The discussion that follows seeks to focus on a number of specific provisions relevant to the effective operation of PRRT, with a view to demonstrating that the regime is operating as intended and that it remains fit for purpose in a globally competitive oil and gas industry.

While there are many provisions contained in the legislation that are important in determining a taxation liability, the settings discussed below are often the subject of specific

attention and as such, warrant both an explanation for their existence and commentary on why they are important for a well-functioning profits based regime.

### Guiding Principles

Overall, the petroleum taxation framework must attempt to balance a variety of objectives, ranging from the creation of an environment that does not discourage investment to ensuring that the community is adequately remunerated for the use of its scarce resources. Governments cannot expect industry to invest where rewards are inadequate, while the industry cannot assume that all rewards will accrue to investors.

The Explanatory Memorandum to the Bill extending the regime to onshore areas and the North West Shelf project noted that:

- “1.3 *The tax is designed to ensure that the Australian community receives an appropriate return from the development of its non-renewable petroleum resources located offshore. At the same time, it provides companies with an incentive to explore and develop resources by allowing a return to companies commensurate with the risks involved in petroleum exploration and development.*
- 1.4 *Unlike royalty and excise regimes, the PRRT applies to the profits derived from a petroleum project and not the volume or value of the petroleum produced. Through providing deductions for all allowable expenditure (whether capital or revenue in nature), together with uplifts for carry forward expenditure, the PRRT taxes the economic rent generated from a petroleum project.”*

A stable, fair and responsive taxation regime is essential in for planning and decision making processes. It represents one of the few factors under the direct control of governments. It is essential that both governments (on behalf of the community) and the industry take a long term view in the formulation of a coherent, equitable and robust secondary taxation structure. APPEA has emphasised in the past that without a fiscal regime that encourages both exploration and development activity, the benefits that can accrue will be not be maximised and indeed may be lost.

The success of the PRRT regime in assisting the nation to meet its broader energy policy and national income objectives must be viewed in a context that is much wider than secondary taxation collections alone. The then Minister for Resources and Energy made the following statement at the 1986 APEA Conference:

*“The resource rent tax, on ‘greenfields’ offshore production, has been designed to shift the focus of taxation from the quantity and value of petroleum produced, as is the case with excise and royalty, to project profitability.*

*Because it is profit related, the system will continue to encourage the development of marginal, relatively low profit petroleum resources even when oil prices are low.....A taxation system which encourages the development of marginal fields will continue to provide encouragement and incentive to explorers.*

Risk sharing between governments and industry must form the foundation for policy development in the petroleum exploration and development process. Without a recognition that risk must be shared, any policy framework will place an undue burden on one party in the overall process. While the risk may not be borne equally by all parties, it is essential that it is acknowledged and incorporated in policy settings.

It has been suggested by some observers that the PRRT does not work effectively for gas production and therefore a different system should apply that imposes a liability earlier in the production life of projects. Such a view demonstrates a lack of understanding of the design features of the PRRT regime. Specifically:

- A key objective of PRRT is to encourage investment
- PRRT was designed to apply to all petroleum production (oil and gas).
- Different projects have different levels of profitability
- Investors should be expected to earn a return on invested funds prior to the imposition of a tax liability under a profits based system

When PRRT becomes payable, the effective tax rate, in combination with company tax, can be as high as 58 cents in every dollar. It remains of concern to the industry that critics are supportive of the PRRT regime at times when a tax liability is incurred, however are willing to have a different position when projects are confronted with low commodity prices or prior to generating a return on invested funds.

#### Threshold (Augmentation) Rates

*“The reward required for the investment of capital must be treated as part of the cost of a project for purposes of determining the economic rent. The required reward is called the ‘supply price of the investment’. Since the cost of investment per unit is the cost of time, the supply price of the investment is often measured by the discount rate or interest rate for time which investor applies to future expected cash flows when assessing whether or not a project has a positive present value (and hence is worth undertaking).*

*The supply price of the investment, at least under competitive conditions, will not be less than the interest rate on riskless borrowing, but those who venture the capital on a mine will require an additional reward for the risk that they accept (since the risk naturally adds to the cost of the time for which they tie up their capital).”*

Garnaut & Clunies-Ross, “Taxation of Minerals Rents”, 1983, p.4

A key design feature of the PRRT regime is the principle that the risk borne by an investor should be reflected in the calculation of a taxpayer’s tax liability. As the regime does not have the full design features of a Brown Tax, where full and immediate tax offsets exist to share the risk between the industry and the community, the augmentation rates are critical to the efficient operation of the tax.

This was recognised as early as 1983 in the Federal Government’s discussion paper that sought to underpin discussions on the implementation of the regime. In discussing the question of risk, the following observation was made:

*“21. One means of attempting to take account of this risk would be to provide a loading for it in the threshold rate. In principle, this could involve either a single loading for all petroleum projects or different thresholds to take account*

*of different risks among projects or categories of expenditure. In practice, however, there are very significant difficulties in attempting to devise an objective test of the degrees of risk inherent in different projects or categories of expenditure and in translating such tests into particular threshold loadings. If an attempt were to be made to allow for the risk of having unrecouped expenditures through loading of the threshold rate, a uniform loading is clearly more straight forward than differential loadings.*

22. *The setting of the threshold and tax rates to apply to income above the threshold, will have implications not only for government revenues but also for investors' incentives. So far as the latter are concerned, the Government appreciates the need for after tax returns to be sufficiently high to justify the risks associated with petroleum exploration and development. An acceptable balance needs to be struck between these considerations. If the threshold rate were set too high, revenue would suffer because fewer projects would be taxable, and/or the consequent tax rate required to raise sufficient revenue would provide an incentive to over-invest in taxable projects. If the threshold rate were set too low, less profitable projects are likely to be deterred."*

Discussion Paper on RRT in the Petroleum Sector, 1983 (p.5)

In 1984, when the final design features of the regime were announced, the Treasurer and Minister for Resources indicated that:

*"The Government has given further consideration to the threshold and tax rate in the light of strong representations made by the industry. It has decided that the threshold should be set at the long-term bond rate (currently about 14 per cent) plus 15 percentage points. The tax rate is to be set at 40 per cent.*

*The linking of the threshold rate to movements in the Commonwealth long-term bond rate is intended to allow automatically for changes in inflation and movements in real interest rates.*

*The threshold and the tax rate have been set at levels which, in the Government's view, represent a reasonable balance between revenue and oil exploration objectives."*

Joint Press Statement, Treasurer and the Minister for Resources and Energy  
27 June 1984

The augmentation rates are not solely designed to keep expenditures constant in real terms. They are also designed to reflect the risk of the relevant activity that is undertaken by the investor. Such a distinction was misunderstood and represented one of the fundamental design flaws in the proposed resource super profits tax.

In 2010, Ross Garnaut, while recognising the theoretical basis of the design features of the RSPT (which was in part based on a modified version of a Brown Tax), highlighted a range of issues that would diminish its attractiveness to both government and industry. Commenting on a Brown Tax, Garnaut noted the following based on his work in 1983 with *Anthony Clunies Ross*:

*“A disadvantage of the Brown Tax (BT) is that... it entails the greatest risk to the government. On a very large project, this risk might be unacceptable... subsidising a project for making losses might also be difficult to “sell” politically, even though the subsidies would not in principle convert the losses into gains for the investor... A final possible disadvantage is on grounds of stability of the fiscal regime, as seen by the investor. It may be difficult for investors to be completely confident that subsidies to future capital outlays will continue to be paid at some very high rate. Thus investors may just possibly react to a BT system as one involving greater risk or a higher expected tax burden than its formal character justifies.”*

A strength of PRRT continues to be its recognition of risk (at the exploration, development and production stages of the investment cycle via the augmentation provisions), together with the balance it provides in terms of efficiency and not acting as an impediment to the development of marginal resources. Overall, the community is able to share in the benefits of petroleum activities, without having to carry the risks of incurring significant costs or providing full tax offsets.

#### *Types of Expenditure – Operation of the Augmentation Rates*

Where a person’s eligible real expenditure in relation to a project exceeds their assessable receipts in a year, the excess is ‘carried forward’ and augmented on a yearly basis until it can be absorbed against assessable receipts from the project, or if eligible, transferred to another project.

The uplift rate applied to augment undeducted expenditure depends on the nature of the expenditure and the time at which it is incurred. Outlined below are the classes of deductible expenditures.

#### Exploration Expenditure incurred prior to 30 June 1990

- Class 1 ABR Exploration Expenditure (LTBR plus 15 percentage points)
- Class 1 GDP Factor Expenditure (GDP Factor Rate)

#### Exploration Expenditure incurred from 1 July 1990

- Class 2 ABR Exploration Expenditure (LTBR plus 15 percentage points)
  - Class 2 GDP Factor Expenditure (GDP Factor Rate)
- (Note Class 2 expenditure can be transferred to another petroleum project)*

#### General Project Expenditure incurred prior to 1 July 1990

- Class 1 ABR General Expenditure (LTBR plus 15 percentage points)
- Class 1 GDP Factor Expenditure (GDP Factor Rate)

#### General Project Expenditure incurred from 1 July 1990 onwards

- Class 2 ABR General Expenditure (LTBR plus 5 percentage points)
  - Class 1 GDP Factor Expenditure (GDP Factor Rate)
- (Note General Project Expenditure is not transferable to another petroleum project)*

#### Closing Down Expenditure

- Closing down expenditure is not uplifted – instead, a taxpayer may be entitled to a tax credit. *(It is not transferable between petroleum projects).*

#### Resource Tax Expenditure

- Amounts are ‘grossed-up’ and augmented at LTBR plus 5 percentage points. *(It is not transferable between petroleum projects).*

#### Starting Base Expenditure



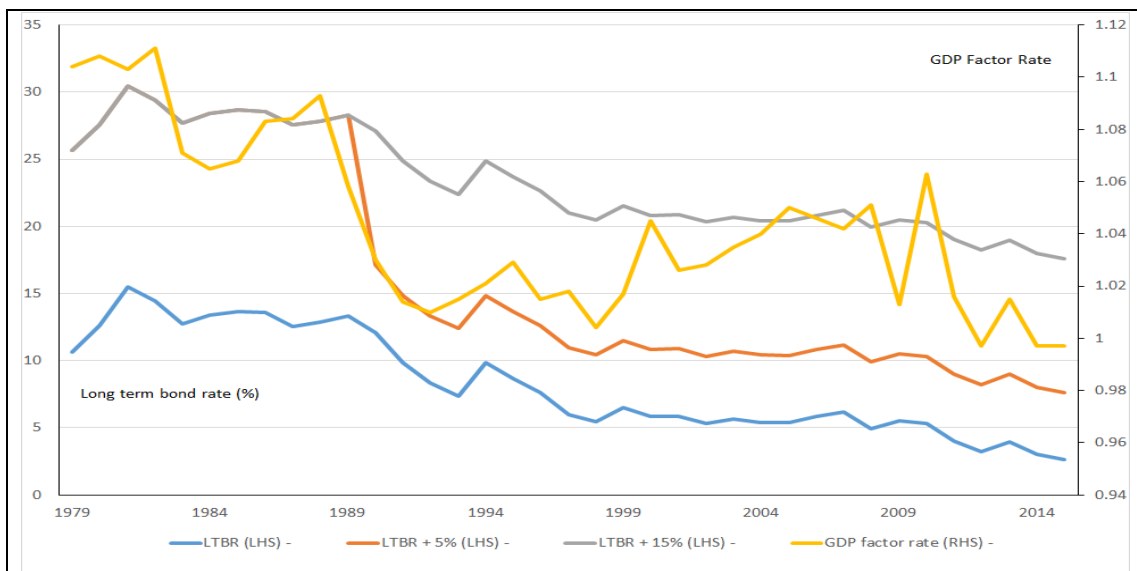
- Subject to the election of a starting base for an onshore project or the North West Shelf. Amounts are augmented at LTBR plus 5 percentage points. *(It is not transferable between petroleum projects).*

Acquired Exploration Expenditure

- Relates to the exploration component of the cost of acquiring an interest in a petroleum project, exploration permit or retention lease between 1 July 2007 and 2 May 2010. For the five years of tax between 30 June 2010 and 30 June 2014, the uplift rate is LTBR plus 15 percentage points. For all years starting 1 July 2014, the uplift is LTBR plus 5 percentage points. *(It is not transferable between petroleum projects).*

The movement in the respective augmentation rates is depicted in Chart X. Consistent with the broader movement in interest rates, there has been a steady fall since PRRT was first introduced in the mid 1980's.

Chart 15: PRRT Augmentation Rates



Source: Australian Taxation Office

The different rates reflect the different levels of risk associated with the different phases in the life cycle of a petroleum project.

Petroleum **exploration** is high risk in nature and is subject to different compounding rates depending on when it is incurred and when it is deducted. The applicable rate is either the long term bond rate plus 15 percentage points or the GDP factor rate. The five year rule that determines when expenditure moves from the higher rate to the GDP factor rate was modified in 1998 in recognition of the significant time lags that exist between incurring exploration costs and being granted a production licence. Many of the time delays are outside the control of an investor.

Originally, the five year rule was based on the granting of a production licence, however the rule was amended effective from 23 December 1998. Projects that applied for a production licence after 23 December 1998 measure the five year period from the date of notification from the Designated Authority that sufficient information has been received to determine an

application for a production licence. Much of the undeducted exploration expenditure that is carried forward under the regime incurs the lower (GDP factor) compounding rate.

The carry forward rate that applies to undeducted **general project costs** is another crucial parameter in the PRRT framework, as it has a significant impact on when a PRRT liability is first incurred for a developed project. The rate was originally set at the long term bond rate plus 15 percentage points when the regime was originally introduced in 1987, however this was significantly reduced in 1991 to the LTBR plus 5 percentage points. In a statement to Parliament announcing the reduction in the rate, the Minister for Resources noted that:

*“The reduction in the premium reflected the significant benefits to industry that derived from the introduction of the company-wide deductibility for exploration, and relative risks of the different stages of a petroleum project.*

*The carry forward rates and the tax rate for the PRRT are part of a balanced and integrated package that includes wider deductibility for exploration expenditures. To preserve the community return, any adjustment in the carry forward for general expenditure would require a corresponding adjustment elsewhere.”*

The carry forward rates remain a cornerstone of the PRRT system and ensures that it operates in a manner such that an initial tax liability is not incurred until such a time an entity has generated a risk adjusted return based on the modest rates contained in the legislation. **Any lowering of these rates would undermine a key design principle of the regime and fundamentally undermine the efficient operation of the tax.**

#### Wider Deductibility of Exploration

The 1991 amendments to the regime (that applied with effect from 1 July 1990) introduced a significant change in relation the treatment of exploration expenditures. The Minister for Resources indicated that:

*“The existing greenfields resource rent taxation arrangements will be amended to allow all exploration costs incurred by a company in areas where RRT applies, including Bass Strait, to be written off against company resource rent tax liability. This will widen exploration cost deductibility from a project to a company basis. Development costs will remain on a project basis.*

*Where no RRT liability exists, exploration costs will be able to be carried forward at a threshold rate of 15 percentage points above the long term bond rate. Currently, the threshold rate is about 28 per cent. Development costs will be eligible for carry forward at 5 percentage points above the long term bond rate. The lower threshold rate for development and production costs more clearly reflects the lower risk associated with development relative to exploration. Exploration and general project expenditures incurred more than 5 years before a production licence comes into force are compounded forward at the GDP factor until they can be written off.*

*The new arrangements for exploration expenditure will make the immediate after-tax cost to a company of exploration within RRT liable permits the same as the*

*cost outside those permits. Economic efficiency will therefore be improved by removing the current disincentive to explore in frontier areas."*

Minister for Resources, August 1990

In addition, the 1990-91 Federal Budget indicated a broader energy policy objective was also a key factor behind the decision.

*"The change to company wide deductibility of exploration costs will encourage the broadening of the exploration effort to frontier areas. There are largely unexplored basins where good prospects for major new oil finds exist. Previously, deductibility was limited to individual permit areas; as a result, for a company, after-tax exploration costs were lower in a RRT paying permit area than in prospective frontier areas. The change to a company wide system will equate a company's after-tax costs for exploration in all RRT offshore areas."*

1990-91 Federal Budget, (p4.6)

In terms of the detail of the measure, exploration expenditure incurred after 30 June 1990 is transferable to other petroleum projects of a taxpayer or to other petroleum projects within any wholly-owned group of companies to which the taxpayer belongs. The expenditure must be transferred where all conditions for transferability are satisfied.

The categories of expenditure transferable are class 2 ABR exploration expenditure (exploration expenditure incurred within 5 years of a production licence application) and class 2 GDP exploration expenditure (exploration expenditure incurred earlier than 5 years before a production licence application) in respect of petroleum projects and exploration expenditure in relation to a permit in relation to which no licence has been issued.

The amount transferred cannot exceed the taxable profit available to offset the transferable expenditure. Conditions for the transfer of expenditure are strict and include rigid ownership and timing tests. Specifically, as a general rule, for intra-company transfers, a taxpayer must hold an interest in both the transferring permit or project and the receiving project at all times from the beginning of the year in which the expenditure was incurred until the end of the year of transfer (with some specified modifications). The detailed conditions are within Schedule 1 to the PRRT Act.

The introduction of wider deductibility of exploration represented a major change to the operation of the regime in 1990, leading to a number of important consequential changes. In effect, the PRRT moved from being a project specific tax to one that is more dynamic in nature and that seeks to remove impediments to petroleum exploration in Australia.

While difficult to quantify, the advice from APPEA member companies indicates wider deductibility considerations form an important element in company exploration decisions. Any change to the current provisions would need to be mindful of the impact on exploration in Australia, particularly at a time of historically low levels of activity.

## Integrated Gas to Liquids Projects – The Gas Transfer Price Methodology

### *Background and Operation of the Gas Transfer Price Methodology*

Assessable receipts for PRRT purposes are determined with reference to a marketable petroleum commodity, or an MPC. For most activities, this point approximates the location where a sale takes place. At the time that PRRT was first introduced, the primary forms of petroleum sold as part of 'offshore' petroleum operations were crude oil, condensate, liquid petroleum gas and a range of gaseous products. The fact all forms of petroleum were listed as MPC's at the commencement of the legislation clearly indicates an intention for the regime to cover both oil and gas production.

Since that time, the nature of the petroleum industry's operations have expanded (both technically and commercially) and this has necessitated a series of enhancements to aspects of the regime. In the late 1990's, the industry raised with the Government the need for the incorporation of a mechanism or methodology to address circumstances where an MPC (or the taxing point) exists within an integrated project or process.

The impetus for this request was largely driven by the emergence of the liquefied natural gas industry and the need for taxpayers to understand the PRRT consequences for project decisions. For natural gas that is to be further processed in an integrated gas to liquids (GTL) project, the PRRT taxing point is where the commodity (sales gas) is first produced, not where the gas is liquefied. Consistent with the principles of the regime, the downstream portion of a GTL project is not subject to PRRT.

Following an extended period of review and consultations involving Treasury, the ATO, the industry department and APPEA, the Government announced the details of the so-called residual pricing methodology (RPM) that allows a taxpayer to estimate a value that can form one approach for calculating the value of assessable receipts within such projects.

The RPM is based on the relatively simple principle of allowing a return to both the upstream and downstream activities within a petroleum project, with the residual amount (the return above a defined rate) being split between the upstream and downstream segments of a project on a 50/50 basis. The calculation of the estimated price under the RPM for a project assists in the negotiations between a taxpayer and the ATO in relation to striking an advanced pricing agreement for a project.

In effect, the netback component of the RPM estimates the maximum price a downstream producer (liquefier) is willing to pay for feedstock natural gas to earn the minimum return necessary to continue production, while the cost plus component estimates the minimum price an upstream (natural gas) producer is willing to accept for natural gas product to earn the minimum return necessary to continue production.

Under the legislation, where an MPC is located within an integrated project and where an arm's length sale does not take place, a taxpayer is provided with the following options to determine assessable receipts:

- If an Advance Pricing Arrangement applies to the transaction — the amount calculated in accordance with the arrangement.

- If no APA applies to the transaction, but a comparable uncontrolled price exists for the transaction — the comparable uncontrolled price amount for the transaction.
- If no APA and no comparable uncontrolled price exist for the transaction — the RPM.

The methodology addresses the issue of how to value the gas when it is transferred to a related party and there is insufficient evidence of market value to determine an amount to be included as an assessable petroleum receipt under section 24 of the Act. The changes also deal with the issue of how to value the natural gas where there is a sale at the PRRT taxing point under a non arm's-length transaction. The provisions establish a clear and equitable methodology for the valuation of feedstock gas in a manner consistent with the current requirements of the Act.

Implementing the methodology involved a number of simple amendments to provisions of the Act that in effect provide the ATO with a process to determine an appropriate market value for the relevant gas. There are a number of important concepts that form part of the process.

An arm's-length transaction means a transaction where the parties to the transaction are dealing at arm's-length with each other in relation to the transaction. In determining whether an arm's-length transaction has occurred, regard is given to "any connection between" the parties to the transaction or to "any other relevant circumstances". In a project, there may be uncertainty or a dispute about whether an arm's-length transaction has occurred – in these circumstances, the Commissioner determines whether an arm's-length transaction has taken place.

A comparable uncontrolled price (or CUP) is a price that can be observed in a relevant market place for the sale of the commodity (sales gas) in an arm's-length transaction. When considering if the market place is relevant, both demand and supply side market characteristics are taken into account. This will include a consideration of the following:

- Product (similarities).
- Geographic differences between the production facilities and the product delivery point (limits on the degree to which customers will travel or products can be supplied).
- The end functional use of the product (retail, wholesale, manufacturing etc).

To determine whether a CUP exists, various comparability factors will also be taken into account. These factors will include, but not be limited to the following:

- Contract terms including volumes, discounts, exchange exposures and all other relevant conditions that would reasonably be considered to affect the price.
- Marketing strategies and spot sales above or below marginal cost such as market penetration sales or maximisation of profit sales.
- Technology used to produce the liquefied product and processing cost.
- Any other comparability factors that it would be reasonable to consider.

A CUP will not exist where:

- In all circumstances, including where there is insufficient information available to the Commissioner, it can be reasonably concluded a CUP does not exist.
- The adjustments required to be made would lead to an unreliable comparison.

Again, the Commissioner will determine whether a CUP exists.

#### *2012 Extension of the PRRT*

As part of the process of transitioning the onshore industry and the North West Shelf Project into the extended PRRT regime, consideration needed to be given to a number of aspects of the operation of PRRT for existing gas to liquids projects. In the context of the RPM, the Policy Transition Group provide the following recommendation:

*“To provide greater certainty and administrative simplicity to projects transitioning to the PRRT, the PTG recommends the following options:*

- *for on-shore integrated gas-to-liquids (such as liquefied natural gas) projects the RPM be provided as a default method that can be chosen by the taxpayer in place of the existing hierarchy;*
- *where a State or Commonwealth royalty determination that sets the value of the resource at the taxing point is in place, the taxpayer be able to seek a determination from the Minister for Resources and Energy to use that value in determining their PRRT receipts; and*
- *a simplified version of the RPM be developed in conjunction with industry that provides for a single agreed phase point and a capital base determined by an agreed valuation methodology for existing assets. Such an approach would retain the characteristics of the existing RPM but enable it to be applied with greater certainty to both the taxpayer and administrators.”*

Policy Transition Group Report 2010 (p.104)

The final changes were not entirely consistent with the Policy Transition Group recommendations, but have effectively allowed for the seamless transition of onshore integrated gas to liquids projects into the extended PRRT.

#### *Criticisms of the RPM*

APPEA notes that there has been some ill-informed criticism of the methodology for valuing gas within integrated projects. For example, we understand that Dr Diane Kraal has expressed a number of concerns about the operation of the price methodology for LNG developments.

Such comments are at odds with the operation of the current RPM (which has been specifically designed to provide an equitable and efficient mechanism that shares the risk between the different phases of a project), nor does it provide an explanation as to why it does not work. It seems to be based on a presumption the price being calculated is too low and that tax should be payable from the commencement of production.

The gas transfer price represents a key contemporary component of the PRRT regime and was developed following a period of collaborative discussions between government and industry to formulate both an efficient and equitable pricing mechanism. The mechanism is administered by the ATO in close collaboration with individual taxpayers to take into consideration the factors relevant to individual projects.

## Starting Base for Transitioning Projects

### *Background*

As part of the decision to extend the PRRT to cover onshore activities and the North West Shelf Project, special provisions were required to address the position of existing investments that were made prior to any thought being given to PRRT applying to such projects.

The Policy Transition Group noted that the diversity of the industry's operations onshore was more complex to that contemplated when the PRRT was originally introduced in 1987 and special consideration needed to be given to transitional arrangements that would not deter investments and growth in the industry. In the context of this recognition of existing investments, the following comment was made.

*“Unlike the MRRT, the PTG’s terms of reference were unclear as the treatment of the starting base for projects that are to transition to the PRRT. The PTG was mindful that the MRRT arrangements were the subject of a quite specific negotiation and the PRRT transitional arrangements were to be as consistent as possible with the current framework. Accordingly, the PTG has sought to identify relevant precedent which may apply to the treatment of the starting base.*

*There have been two occasions on which projects have been transitioned to the PRRT – at the commencement of the tax and with the extension of the PRRT to the mature Bass Strait project. The treatment of Bass Strait project reflected negotiations as part of an individual package within broader measures and as such is not considered an appropriate model by the PTG.*

*The recommended look-back arrangements reflects the provisions for existing tenements at the commencement of the PRRT with expenditure over the preceding eight years treated as if the tax had been in place for the existing uplift and immediate expensing.*

*The PTG considers a 1 May 2010 cut-off for being eligible for a starting base should include the value of potential projects that are yet to commence production. The PTG therefore recommends that all tenements in existence at 1 May 2010 be eligible for a starting base.*

*For each project, the taxpayer should be able to choose between a starting base comprised of:*

- *the market values of the project’s assets (including the resource); or*
- *the book value of the project’s assets (excluding the value of the resource); or*
- *actual expenditure over the eight year period from 1 July 2002 to 1 May 2010, under a look-back method.*

*Consistent with the features of the PRRT, the PTG recommends the starting base be immediately deductible and uplifted at the relevant rate where carried forward.*

*The uplift rate for a market value or book value starting base would be that applicable to general project expenditure. The uplift rate for a look-back starting base would be in accordance with the character of the expense.*

*As is the case with the MRRT, the PTG notes that market valuation of the starting base could have a significant bearing on taxpayer liabilities for PRRT and that different valuation methodologies and assumptions can produce quite different results. While taxpayers should be free to use a starting base valuation methodology that is appropriate for the specific circumstances of their project, it should be consistent with accepted methodologies, consistent with market expectations at 1 May 2010, transparent and defensible.*

Policy Transition Group Report 2010 (p.90-91)

In terms of the amending provisions, holders of interests in transitioning petroleum projects, exploration permits and retention leases existing as at 2 May 2010 were provided with an additional deductible expenditure amount (a starting base amount) or were able to take account of project expenditures incurred prior to 2 May 2010 in determining their PRRT liability.

These arrangements provided recognition of investments made prior to the Government's announcement of the extension of the regime. The provisions for determining starting base amounts were a key transitional feature of the PRRT and represent a key element that goes some way towards addressing the retrospective application of the tax on projects that remain covered by the scope of other taxes. The detailed provisions were included in a new Schedule to the legislation, while amendments were also made to the body of the Act to incorporate the starting base and look-back arrangements.

#### *Detailed Provisions*

Specifically, the holder of an interest in an onshore petroleum project or the North West Shelf project which had existed as at 2 May 2010, had the option to utilise either the market value or book value approach to determine a starting base amount in relation to their interest. Alternatively, they could instead choose to utilise the look-back approach, which allows expenditures incurred prior to the extension of the PRRT to be taken into account in the determination of PRRT liabilities.

Where the market value or book value approach was chosen, the starting base amount as at 1 July 2012 will comprise the sum of either:

- The market values of starting base assets (including rights to the resources) at 2 May 2010.
- The most recent audited accounting book values of starting base assets (not including rights to the resources) available at that time.
- Capital expenditure incurred in relation to the interest during the interim period between the time the starting base asset values were determined and 30 June 2012.

An alternative valuation method for determining the market value of the starting base assets was provided to interests that related to coal seam gas resources, in circumstances where the project to which that interest related had been the subject of a recent market transaction.



Where the book value approach is chosen, both the value of starting base assets and interim expenditure amounts are uplifted on 1 July 2012 for the total interim period during which the starting base assets were continuously held. The amount is uplifted by the long term bond rate plus 5 per cent (LTBR + 5 per cent) over the relevant period. Market value starting base amounts are not uplifted over the interim period.

Where the look-back approach is chosen in relation to a project interest, there is no starting base amount. Instead, expenditures incurred in relation to the project interest from 1 July 2002 will be able to be taken into account in determining PRRT liability, consistent with existing PRRT deductible expenditure provisions.

In addition, in cases where the project interest was directly acquired, or the company holding the interest was acquired during the period 1 July 2007 to 1 May 2010, the acquisition price may be taken into account via the look-back approach to the extent it relates to the project interest.

Starting base amounts are immediately deductible against assessable receipts following the extension of the PRRT where a production licence exists. This means that transitioning projects will be able to immediately deduct starting base or look-back amounts from 1 July 2012, with unused amounts uplifted by the LTBR + 5 percentage points each financial year. Importantly, starting base amounts relating to interests in petroleum exploration permits and retention leases will become deductible in the year a related production licence comes into force.

Starting base amounts are not transferable between projects. Similarly, exploration expenditure that is taken to be incurred by a project prior to 1 July 2012 under the look-back approach is not transferable.

The starting base provisions were an essential design feature of extending the PRRT to cover onshore projects and the North West Shelf project. Without a starting base, the transitioning projects and investors would have been significantly disadvantaged in terms of not receiving a recognition for past costs and the value of existing assets, which would have led the early (and premature) payment of PRRT. The PTG carefully considered a range of issues about extending the regime, including the significant retrospective aspect of the decision, and recommended an approach that has both logic and integrity.

#### Crediting of Non-PRRT Resource Tax Payments

As result of the decision to extend the PRRT regime with effect from 1 July 2012, the treatment of existing resource taxation provisions needed to be addressed to ensure that projects were not affected by the imposition of double taxation. The Policy Transition Group made the following observation.

*“To reflect the fact that existing Government resource taxes will apply alongside the extended PRRT, the resource taxes that entities pay are to be credited against the PRRT liability of a project.*”

*The recognition of Australian, State and Territory government resource taxes under the extended PRRT raises a number of important issues. Generally speaking, the current resource taxes are set at rates that industry can afford to pay, at least during normal times, and provide the governments with a relatively stable revenue stream. On the other hand, these existing regimes are less flexible during an industry downturn and can unnecessarily damage the industry and prevent optimal resource extraction. Further, by their nature, some existing resource taxation regimes do not capture the economic rents during a boom period.*

*Through the extension of the PRRT, Australia has the opportunity to substantially improve the overall outcome of resources taxation in this country. It provides a way to meet the needs of the States and Territories and captures more of the profits at the peak of the resources cycle, in a way royalties cannot, for the benefit of all Australians.*

*Recognising this objective as well as the importance of preserving Australia's international competitiveness, the PTG recommends that there be full crediting of all current and future resource taxes under the PRRT so as to provide certainty about the overall tax impost on the petroleum sector."*

Policy Transition Group Report 2010 (p.93)

Onshore petroleum projects are subject to royalties imposed by State and Territory governments, while Commonwealth production excise also applies to crude oil and condensate produced onshore. The North West Shelf project is subject to Commonwealth royalties and production excise, while a resource rent royalty is applied to petroleum production from the Barrow Island project.

Commonwealth, State and Territory resource tax expenditures are **creditable** against the liabilities of PRRT projects. As indicated above, this ensures that petroleum projects are not subject to double taxation. Resource tax expenditure is deductible if it is incurred in relation to the petroleum project or any pre-combination petroleum project in the financial year and it relates to petroleum recovered after 1 July 2012. This is consistent with the PRRT being a project based tax.

To ensure the appropriate treatment, these payments are grossed up and are deductible against the current and future PRRT liabilities of a petroleum project. The 'resource tax expenditure' is converted to a deduction equivalent by dividing the value of the expenditure by the PRRT rate. In circumstances where resource tax expenditures cannot be deducted against a petroleum project's assessable receipts in a financial year, the excess is carried forward and uplifted by the LTBR plus 5 percentage points. Undeducted amounts of resource tax expenditure are non-refundable and are non-transferrable to other petroleum projects.

A transitional provision was inserted into the legislation to ensure that refunds of resource taxes that relate to petroleum extracted prior to 1 July 2012 are not included as assessable receipts.

The current treatment appropriately addresses the direct impact of retaining the production excise, royalty and RRR provisions for production sourced from onshore areas and the North

West Shelf project. It would be inequitable to treat these resource tax payments in any other manner, as to do otherwise would be to suggest these taxes are not imposts associated with producing petroleum.

#### Designated Frontier Exploration Incentive

The Federal Government announced the introduction of a limited PRRT incentive for pre-appraisal expenditure in nominated frontier high risk areas as part of the 2004/05 Budget. The Explanatory Memorandum introducing the measure made the following observations:

*“5.5 The policy rationale is to encourage petroleum exploration in Australia's selected offshore areas in order to increase the chances of a new petroleum province being discovered. As exploration in frontier areas is often a high-cost and high-risk undertaking, an incentive is necessary to encourage exploration in these areas. Under the current provisions of the PRRTAA 1987, exploration expenditure is deductible against assessable receipts from petroleum production. Under the new law, 150 per cent of eligible exploration expenditure incurred in a designated frontier area will be deductible against the petroleum company's assessable receipts from petroleum production. Therefore, the 150 per cent uplift on eligible exploration expenditure will reduce petroleum resource rent tax payable.*

*5.6 Under the current law, undeducted exploration expenditure is augmented at a rate reflecting the period between the expenditure being incurred and when it is able to be deducted. The augmentation is at the annual rate of the long-term bond rate plus 15 percentage points or at the gross domestic product (GDP) factor rate depending on the time between when the expenditure was incurred and the time it is deducted. Under the new law, once an amount becomes uplifted frontier expenditure and is uplifted to 150 per cent of what it would otherwise be, it retains the same access to augmentation as all other exploration expenditure provided in the Schedule to the PRRTAA 1987. That is, the initial uplift is maintained as time passes and further augmentation applies to the uplifted amount.”*

*“5.15 Eligibility for the 150 per cent uplift depends on the purpose or intention of the exploration expenditure. If the purpose or intention of exploration expenditure is not evaluating or delineating a previously discovered petroleum pool, it will qualify for the 150 per cent uplift. Further, the outcome of the exploration activity does not change its eligibility for the 150 per cent uplift. That is, exploration expenditure on evaluating or delineating a petroleum discovery does not qualify for the 150 per cent uplift even if it happens to discover something new. Alternatively, exploration expenditure that is not evaluating or delineating an existing petroleum discovery qualifies for the 150 per cent uplift even if the results turn out to find something about an existing discovery.”*

This decision in part addressed a concern identified as part of the House of Representatives Inquiry into resources exploration impediments of the need for a broad reform package to encourage and stimulate exploration activity in high risk offshore and onshore areas in Australia.

The measure was discontinued following the release of permits following the 2009 round of offshore exploration acreage and is not relevant to any discussion on the present day operation of the regime.

#### Self-Assessment

In the 'Report on the Operation of the Petroleum Resource Rent Tax Assessment Act 1992', which was prepared by the then Federal Minister for Resources, it was indicated that in the context of self-assessment, the '*..Australian Taxation Office will consider the matter further in the context of the development and application of self-assessment principles generally*'. The introduction of a formal system of self-assessment was again raised by industry in April 2002, as part of a broader proposal to modernise key aspects of the regime.

The Federal Government announced in the 2005-06 Budget an intention to make a number of technical changes to the PRRT regime, including bringing PRRT under the scope of the self-assessment system. Prior to the change, the Act required that returns be assessed prior to the issuing of a final assessment. In addition, any challenge to an ATO technical interpretation could only have been made through the issue of an assessment and the challenge through the lodgement of an objection. Taxpayers did not have access to private binding rulings.

The Explanatory Memorandum to the legislation that extended the self-assessment provisions to over PRRT outlined the changes and obligations on taxpayers:

*“4.9 These amendments to the PRRT Act will bring the treatment of PRRT taxpayers in line with the treatment of income taxpayers in a number of respects. Firstly, under the new law, PRRT taxpayers will be subject to the self assessment regime as it generally applies within the income tax system. Under the self assessment system, a taxpayer's return is generally accepted at face value, subject to post-assessment audit or other verification by the ATO. Under this system, while a notice of assessment is issued (or taken to have issued) to create the formal obligation to pay tax, a taxpayer's statement in their return is taken to represent their view about how the taxation law applies to their circumstances.*

*4.10 Secondly, a four-year period of amendment of a PRRT assessment is introduced. The four-year period is the standard amendment period applied in the income tax context for businesses with more complex affairs. This case is applicable to PRRT taxpayers. The standard amendment period of two years in the income tax context for taxpayers with simple affairs (including most individuals and small business taxpayers) is not applicable in the PRRT context. The unlimited amendment period in the case of fraud or evasion and other limited circumstances remains.*

*4.11 Thirdly, the interest payment provisions in the PRRT Act will be aligned with those under income tax by incorporating the shortfall interest charge. Where a taxpayer's PRRT assessment is amended so as to increase their liability, the taxpayer is liable to pay the shortfall interest charge on the increase -- that is, on the shortfall amount. The shortfall interest charge replaces the current liability to*

*pay the general interest charge during the shortfall period. The general interest charge will continue to apply where tax or an interest charge remains unpaid.*

*4.12 Finally, PRRT taxpayers will be provided access to the provisions dealing with ATO advice in the same way as these provisions apply in the income tax context. Under income tax law, taxpayers may seek advice from the Commissioner as to how the taxation law applies in a particular circumstance. In the case of PRRT taxpayers, this advice may be provided in the form of a public and private ruling. Rulings are binding on the ATO in that it must accept a taxpayer's assessment which has been calculated in accordance with the ruling even if the ruling later turns out to be wrong."*

Petroleum Resource Rent Tax Amendment Bill 2006  
Explanatory Memorandum (p.49)

The decision to introduce self-assessment was a logical and considered decision that recognised the practical benefits of such a change, while ensuring that strong protections existed to maintain the integrity of the regime. It represented a natural progression in terms of the administration of PRRT.

#### Other Operational Issues

Outlined below are number of interpretative and operational issues associated with the PRRT that either remain unclear or need to be addressed as part of modernising the regime. In addition, a number of recommendations were contained in the 2010 PTG report that warrant further consideration.

#### *Partial Closing-Down Activities*

Potential uncertainty can arise in large or complex projects where, for instance, there are many production wells and/or complex facilities, some of which may be shut in, and abandoned or demolished, and environmental activity undertaken prior to the final phase of closing down the entire project. Projects that involve the drilling of many wells and/or the construction of numerous wellheads over the life of the project (such a coal seam gas developments), with the subsequent phased closing down of those wells or wellheads, are becoming more common in the industry.

Integrated petroleum projects that could involve either multiple offshore platforms or onshore wellheads linked to a single processing facility, could fall within the scope of such a scenario. In these cases, platforms or wells can be shut-in or shut-down without affecting the ongoing broader operations of a project.

The law is currently uncertain in the context of what represents closing down expenditure – is it the closure and or abandonment of any facility within a project area or the last production facility within a project area? To promote certainty for the large scale developments that are becoming more common (as opposed to the simpler offshore oil platform scenario), it would be helpful to remove this potential for ambiguity.

### *Regional and Social Infrastructure*

As part of any project, significant expenditures can be incurred in relation to the construction and maintenance of operational and social infrastructure. This can either be a specific element of a project approval or an expectation on the part of the local community and/or government in terms of the 'licence to operate'. Furthermore, some of this infrastructure may be necessary to make an area (often remote) more suitable for habitation of a workforce that will be relocated to work on a project. The deductibility of many such costs remains uncertain.

### *Advanced Pricing Agreements*

In some cases, the determination of the correct market value of assessable petroleum receipts where production becomes an excluded commodity other than by arm's length sale can be complex or resource intensive. In some situation, taxpayers are able to enter into an Advanced Pricing Agreement with the ATO to obtain some certainty.

However the process for obtaining an APA, and meeting annual compliance obligations, can be time consuming, expensive and administrative onerous. In addition, APA's are generally only binding for a period substantially less than a project's life and frequently a lesser period than the related commercial arrangements (for example, long term sales contracts). A simplified, fit for purpose process could be introduced, particularly for small producers, which enables certainty to be obtained more simply than an APA.

### *Joint Venture Operator Statements and Invoices*

One of the obligations assigned to an operator of a joint venture is to keep books of account. This is represented in the accounting principles that form part of the commercial agreement between the joint venture parties. The primary focus of the operator's accounting team is to produce joint venture statements that accurately represent the direct costs attributed to the joint operation. Depending on the nature of the joint venture, these can be a Joint Venture Billing statement (unincorporated) or a financial statement (incorporated).

Other documentation that supports these statements of accounts includes cash calls, authority for expenditure, and agreed supporting documentation. Non-operators do not have all the invoices nor do they have a complete record of all transactions undertaken by the operator. The statement of joint account is the main source of information for a non-operators recognition of expenditure. Non-operators do not usually have access to source documents (invoices, contracts etc) that are kept by operator of the joint venture. Non-operators rely on the joint venture billing statements, together with the audit rights, which are often limited to a defined number of years, to account for their share of joint venture expenditure.

A greater reliance on JV operator documents has been raised with the ATO as an area of cost saving and increased efficiency.

### *Record Retention Obligations*

Under the Act, a taxpayer is required to lodge a return where they derive assessable receipts in a year of tax. The Commissioner may amend that assessment within four (4) years after the day on which notice of the assessment was given.

Due to the long lead times of petroleum projects, expenditure is generally incurred for a number of years prior to the derivation of assessable receipts. In the absence of other mature petroleum projects to which exploration expenditure can be transferred, there can be a significant period between when expenditure is incurred and when assessable receipts are derived. In some cases, this period is 10 years or considerably more. In such scenarios, the 4 year amendment period permits the Commissioner to amend an assessment by, amongst other things, disallowing a deduction for expenditure incurred more than 10 years prior. This creates significant uncertainty for taxpayers and is inconsistent with record keeping requirements contained in income tax and corporation's legislation.

In addition, it is unclear as to what extent an assessment would be amended where records of expenditure are in a format that, for historical reasons, do not contain the level of detail that might otherwise be found had the expenditure been incurred more recently.

Consideration could be given to adopting a variety of measures that could simplify the existing obligations while retaining the integrity of the regime.

Attachment 1

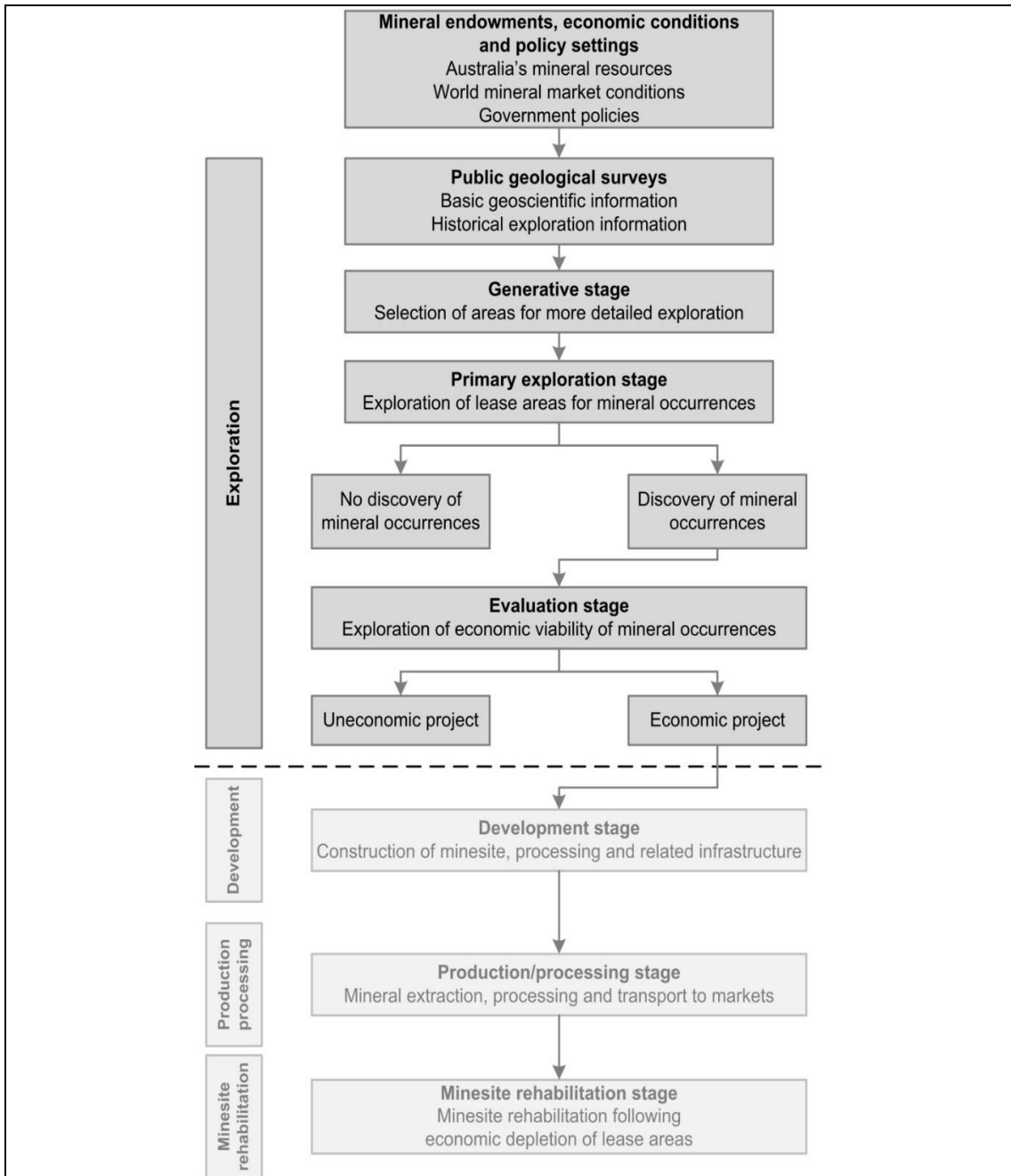
APPEA Full Member Companies

Arrow Energy Limited	Mitsubishi Australia Ltd
AWE Limited	Mitsui E&P Australia Pty Ltd
Beach Energy Limited	Murphy Australia Oil Pty Ltd
Benaris International Pty Ltd	Nido Petroleum Limited
BHP Billiton Petroleum Pty Ltd	Northern Oil & Gas Australia Pty Ltd
Bounty Oil & Gas NL	Norwest Energy N.L
BP Developments Australia Pty Ltd	OMV New Zealand Limited
Bridgeport Energy Ltd	Origin Energy Limited
Buru Energy Limited	Pangaea Resources
CalEnergy Resources (Australia) Ltd	Papuan Oil Search Limited
Carnarvon Petroleum Ltd	Petronas Australia Pty Ltd
Central Petroleum Limited	PTTEP Australasia
Chevron Australia Pty Ltd	Quadrant Energy Pty Ltd
Comet Ridge Limited	Roc Oil Company Limited
ConocoPhillips Australia Pty Ltd	Santos Limited
Cooper Energy Ltd	Senex Energy Limited
Cue Energy Resources Limited	Shell Australia Pty Ltd
Empire Oil & Gas NL	Statoil Australia Theta B.V
ENGIE Bonaparte Pty Ltd.	Strike Energy Limited
Eni Australia Limited	Tap Oil Limited
ExxonMobil Australia	Tokyo Timor Sea Resources Pty Ltd
FAR Limited	Total E&P Australia
Finder Exploration Pty Ltd	Tri-Star Petroleum Company
Hess Exploration Australia Pty Limited	Vermilion Oil & Gas Australia Pty Ltd
Icon Energy Limited	Woodside Energy Limited
Inpex Ichthys Pty Ltd	
ITOCHU Minerals & Energy of Australia Pty Ltd	
Japan Australia LNG (MIMI) Pty Ltd	
JX Nippon Oil and Gas Exploration Corporation	
Karoo Gas Australia Ltd	
KUFPEC Australia Pty Ltd	
Latent Petroleum Pty Ltd	
Melbana Energy Limited	



### What is Petroleum Exploration?

Prior to producing oil and gas, companies have to first search for and find hydrocarbon resources. This process involves a commitment to expend significant funds with no guarantee of success. Even once a hydrocarbon discovery has been made, there is no guarantee of its commercial development. Significant funds are also invested in appraisal and feasibility activities to determine if discovered resources can be commercialised.



Source: Productivity Commission

Searching for petroleum typically includes a ranges of activities:

- A regional geological assessment of an area is often required in order to determine its hydrocarbon bearing potential and to ascertain if there are areas that are prospective and over which exploration permits should be acquired.
- Competitive bidding on areas. Generally, governments will release exploration blocks and companies will bid a work program in order to secure a particular block.
- 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:
  - surface mapping (onshore);
  - 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;
  - 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. Often, exploration wells are not successful.

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. 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. Activities can involve:

- The acquisition of additional seismic data;
- 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;
- Studies and activities aimed at filling in the gaps between drilling locations.

The results of the feasibility studies will determine whether the resource is commercially viable and as whether to proceed with the proposed project.



# Independent Report on the PRRT Review in Australia

Prepared for APPEA  
February 2017

## Project Background

- In late 2016, the Australian Government announced a review into the operation of the Petroleum Resource Rent Tax (PRRT). As part of this process, the Department of the Treasury is soliciting comments from interested parties. APPEA has, in this regard, engaged Wood Mackenzie to provide an independent response
- PRRT was introduced in 1988 and is designed to capture the 'economic rent' associated with the development of petroleum projects. This report aims to compare the total Australian Government share with other producing provinces, highlighting the differences in operating environments and factors that influence what is distributed between the government and contractors
- In analyzing the fiscal systems (focusing on LNG regimes) this report highlights the strengths/weaknesses of profits-based taxation, comparing government share over the life cycle of a project, and fiscal stability in attracting large scale, long life LNG investment
- Through discussions on the likely time horizons required for investors in LNG projects to achieve a positive return on capital the report investigates the proposition that such projects will generate modest (if any) PRRT revenues in the early years of their production lives

## Executive Summary

- LNG projects have some of the longest investment horizons, requiring substantial upfront capital expenditure
- Different regime structures can have a material effect on the level of government share and accordingly the level of investment
- Progressive regimes, such as PRRT, result in higher levels of tax payments to the government as profitability increases
- By contrast, regressive regimes which feature a high level of non-profit related elements tax will result in a higher government share % as profitability declines
- Many countries have made changes to their fiscal terms over the past two years, some increasing and some reducing level of government share, although Australia has not made any changes since 2011/2
- Australia's government share for offshore oil projects are relatively stable across a range of prices with government share lying broadly in the middle of the pack

# Contents

## 1. Comparing global LNG projects

2. Evaluating government share from LNG projects

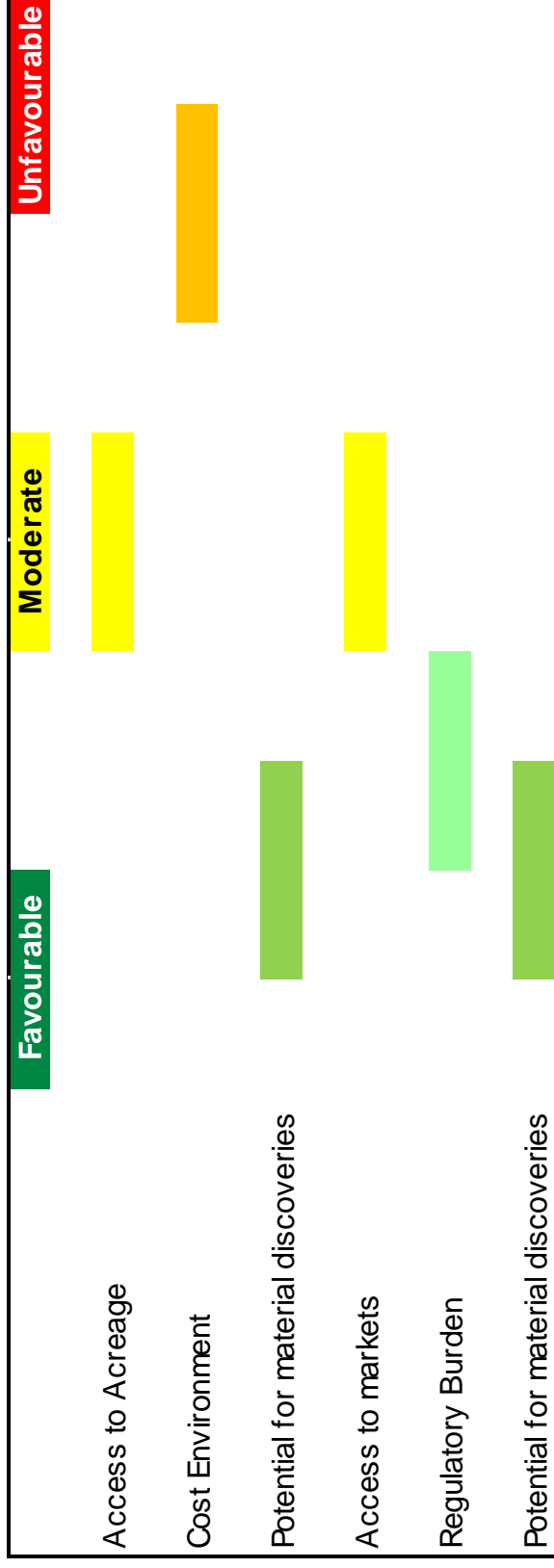
3. How different prices impact government share from LNG projects

4. Global overview of governments' fiscal response to low oil prices

5. Peer group comparison of government share on oil projects

# Investment in Australia

## Key Metrics



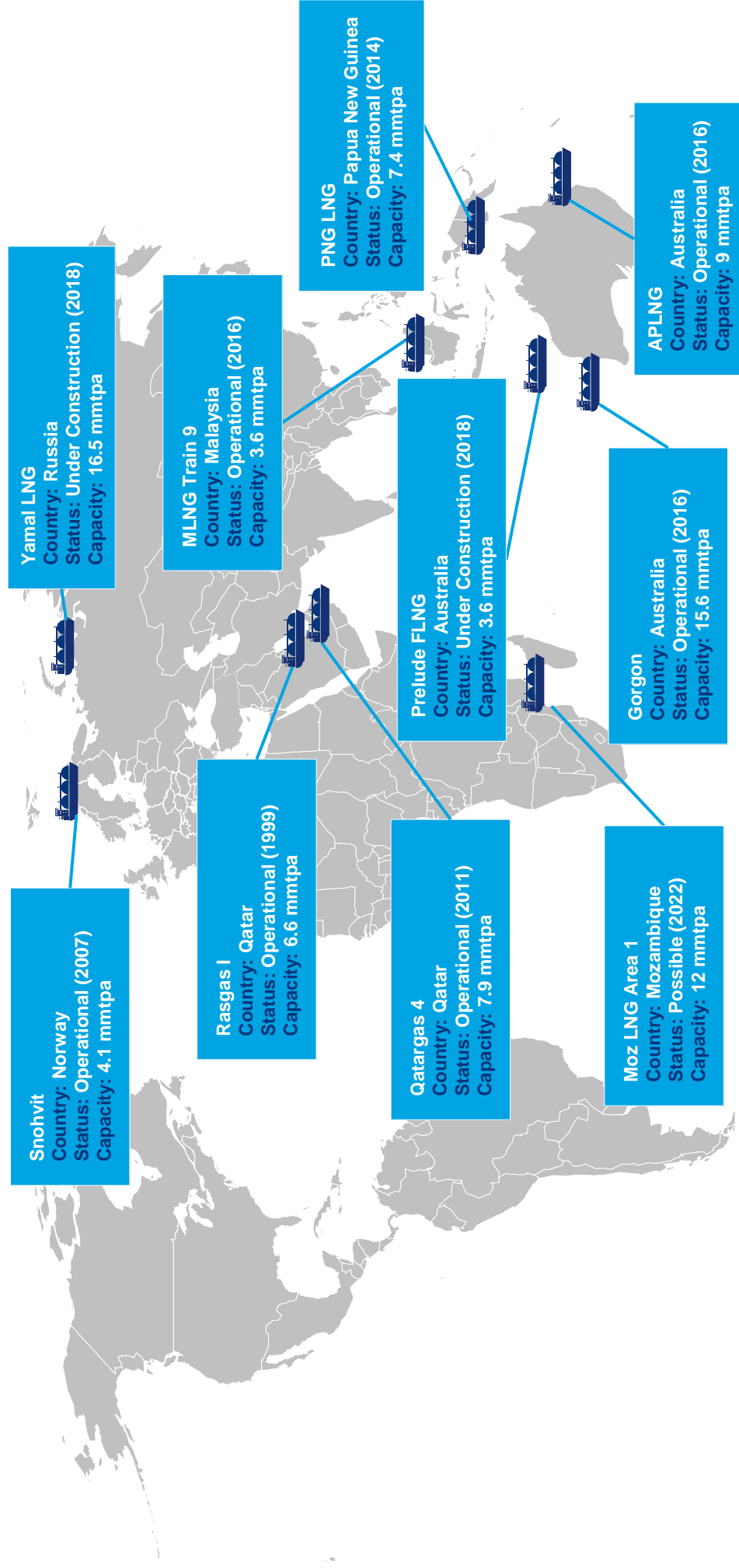
The above chart is based upon databases used in Wood Mackenzie's research products

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# LNG projects have some of the longest investment time horizons for companies, also requiring substantial upfront capital expenditure

## Selection of Global LNG Projects

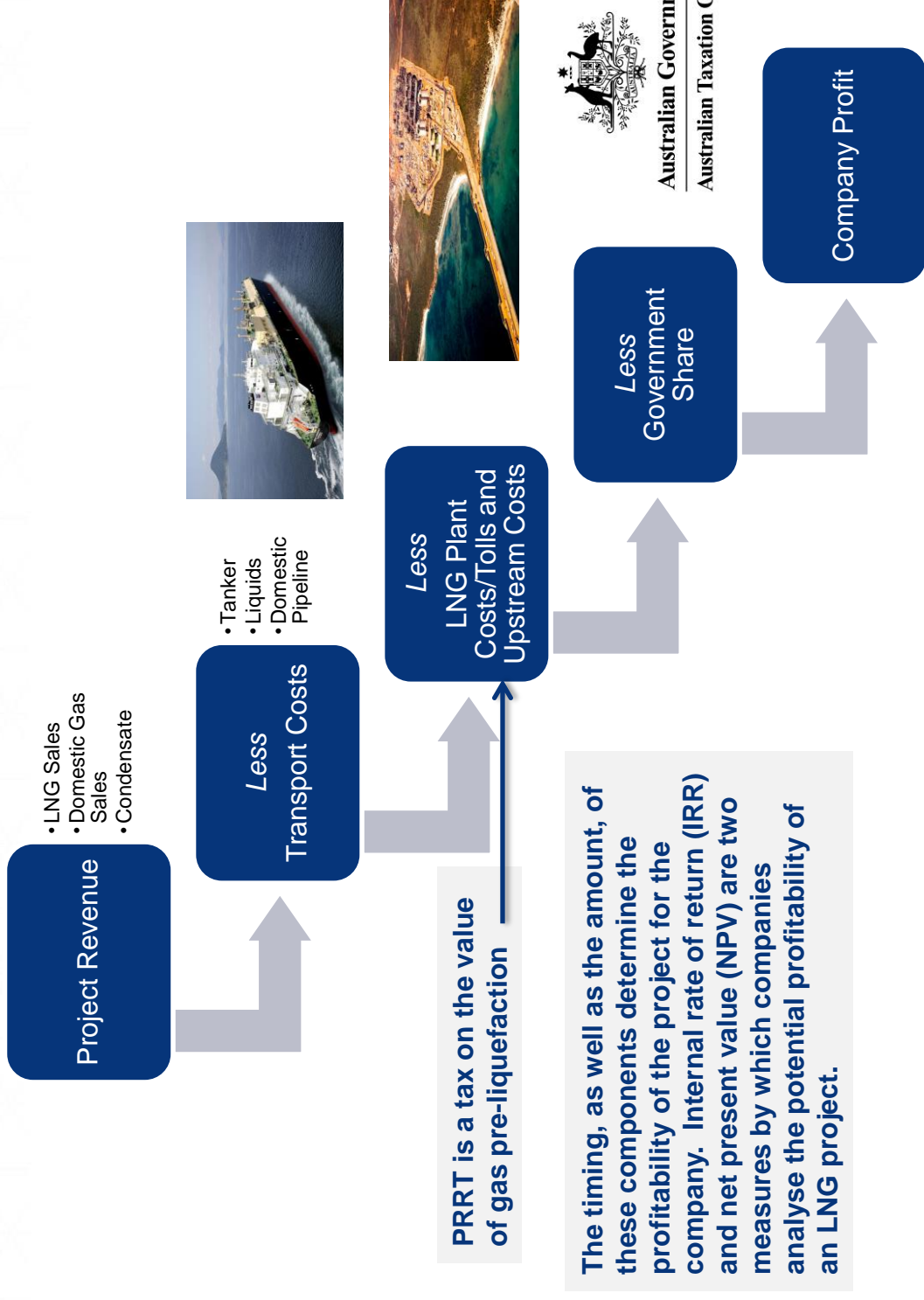


*An integrated LNG project is one in which the upstream and liquefaction elements are within a single tax ring fence.*



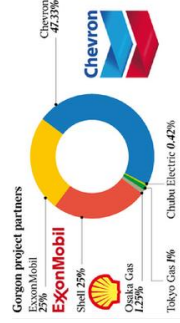


# LNG economics involves several steps between LNG sales revenue and the calculation of government share and finally, company profit



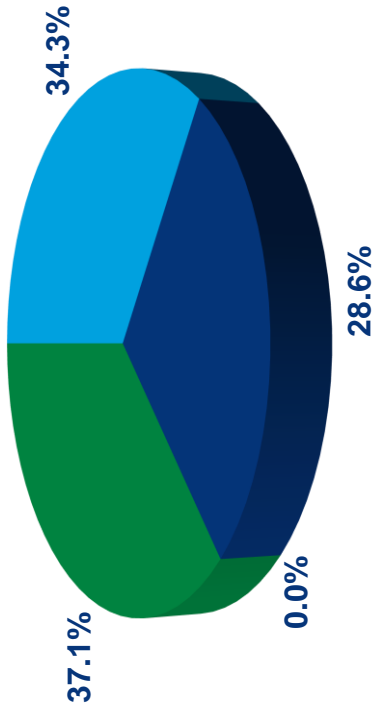
Australian Government  
Australian Taxation Office

The timing, as well as the amount, of these components determine the profitability of the project for the company. Internal rate of return (IRR) and net present value (NPV) are two measures by which companies analyse the potential profitability of an LNG project.



# The split of LNG project revenue between the government and the company is a function of the costs and the fiscal regime

## Gorgon, Australia



■ Total Costs  
■ NOC Equity

■ Taxes and Royalties  
■ Company Equity

IRR (post-tax full cycle)

7.0%

Total Lifetime Capex

\$97 bn (real 2016)

Government share of profit

44%

Government share of profit plus equity

44%

Onstream

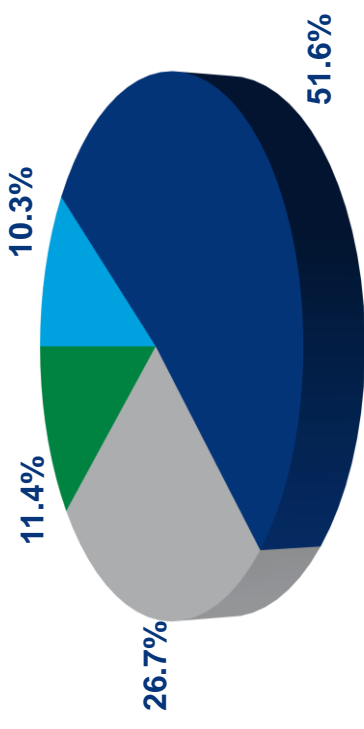
2016

Project Size

15.6 mmtpa

Government share of profit = (Government taxes and royalties) / (Revenue - Total Costs)  
 Government share of profit plus equity = (Government taxes and royalties + state equity share of profits) / (Revenue - Total Costs)  
 NOC: National Oil Company

## Qatargas-4, Qatar



■ Total Costs  
■ NOC Equity

■ Taxes and Royalties  
■ Company Equity

IRR (post-tax full cycle)

32.5%

Total Lifetime Capex

\$7 bn (real 2016)

Government share of profit

58%

Government share of profit plus equity

87%

Onstream

2011

Project Size

7.9 mmtpa

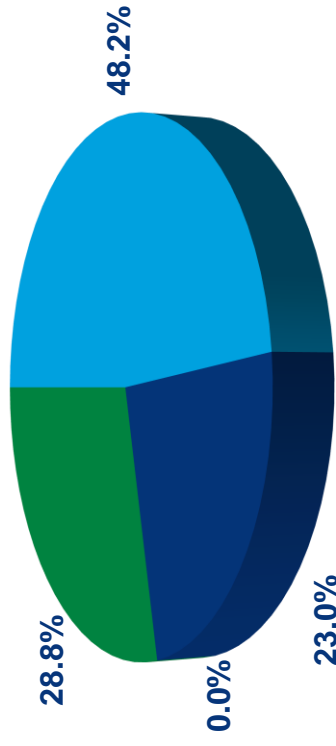


**Wood Mackenzie**

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... and reflects the conditions in which the project was developed

### APLNG, Australia



- Total Costs
- Taxes and Royalties
- NOC Equity
- Company Equity

IRR (post-tax full cycle) 7.3%

Total Lifetime Capex \$44 bn (real 2016)

Government share of profit 44%

Government share of profit plus equity 44%

Onstream 2016

Project Size 9.0 mmtpa

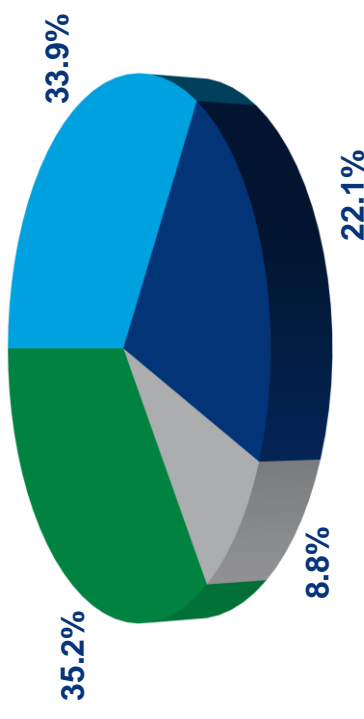
Government share of profit = (Government taxes and royalties) / (Revenue - Total Costs)  
 Government share of profit plus equity = (Government taxes and royalties + state equity share of profits) / (Revenue - Total Costs)

NOC: National Oil Company

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### PNG LNG, Papua New Guinea



- Total Costs
- Taxes and Royalties
- NOC Equity
- Company Equity

IRR (post-tax full cycle) 12.6%

Total Lifetime Capex \$25 bn (real 2016)

Government share of profit 33%

Government share of profit plus equity 47%

Onstream 2014

Project Size 7.4 mmtpa



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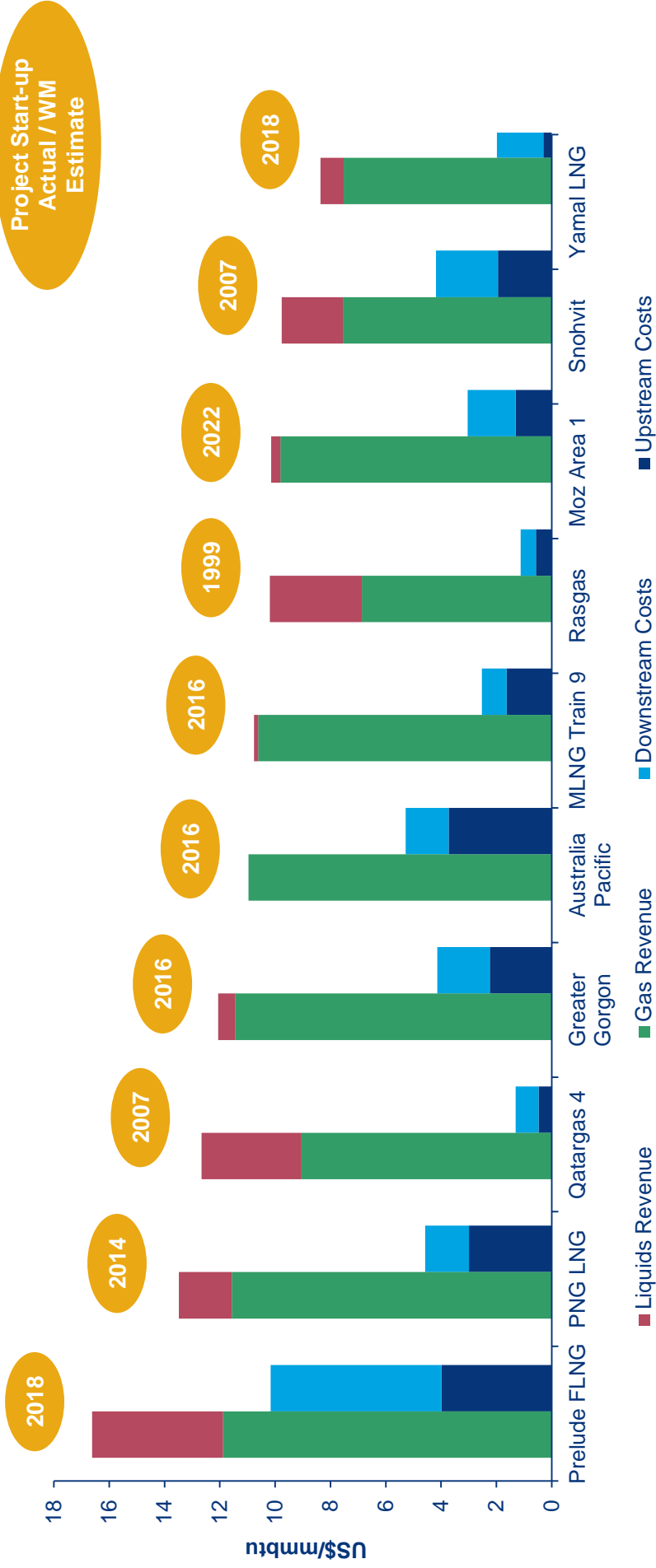
# Basis of Calculation of Government Share of Cash Flows

## Key Projects

	Gorgon	Qatargas-4	APLNG	PNG LNG
Revenues	100.0	100.0	100.0	100.0
Costs	34.3	10.3	48.2	33.9
Revenues less Costs	65.7	89.7	51.8	66.1
Taxes and Royalties	28.6	51.6	23.0	22.1
<b>Taxes and Royalties/ Revenues less Costs</b>	<b>44%</b>	<b>58%</b>	<b>44%</b>	<b>33%</b>
NOC Equity	-	26.7	-	8.8
Taxes and Royalties plus NOC Equity	28.6	78.3	23.0	30.9
<b>Taxes and Royalties plus NOC Equity/ Revenues less Costs</b>	<b>44%</b>	<b>87%</b>	<b>44%</b>	<b>47%</b>

# Comparison of LNG project revenues and costs on a US\$/mmbtu basis

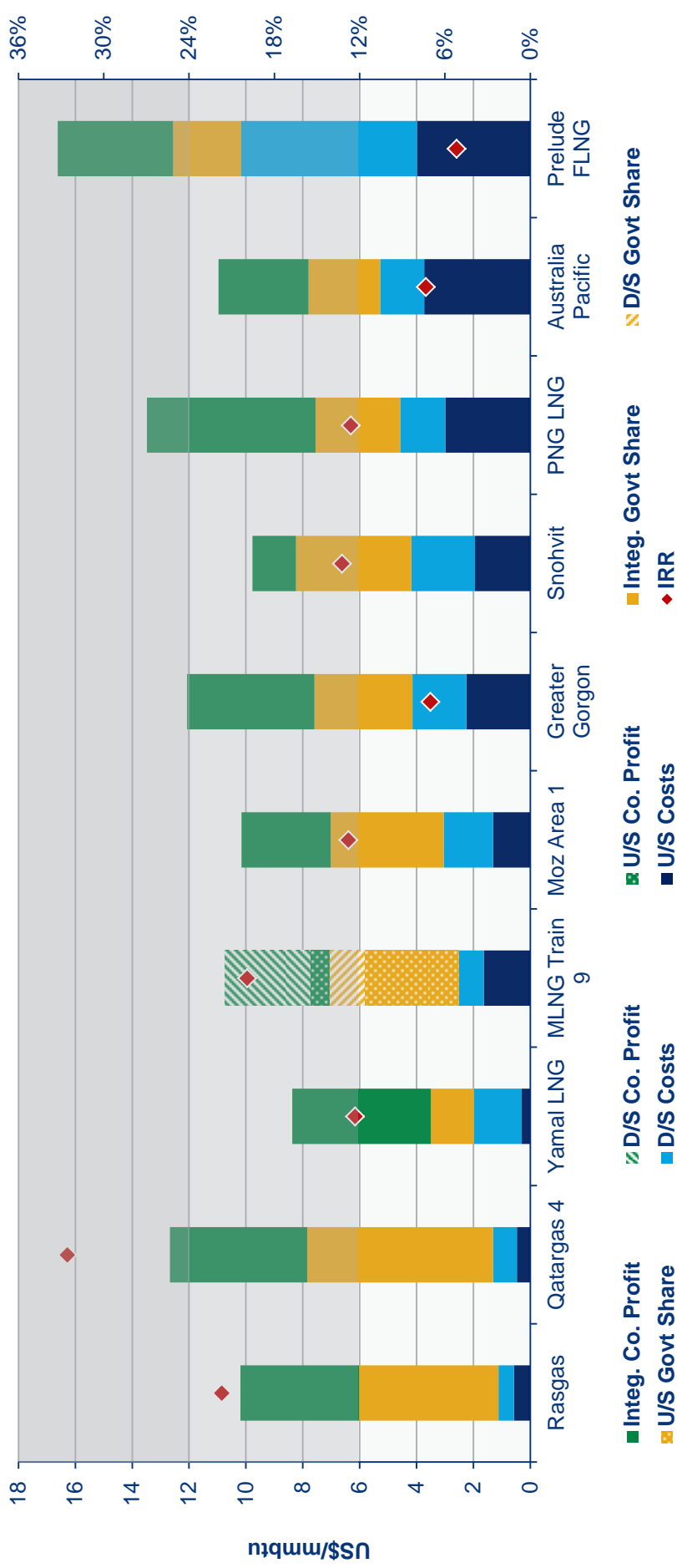
## LNG Project Comparison: Project Revenue versus costs per mmbtu, over Life of Project



Reflecting historic prices as received, and a flat real (2016) \$80 oil price over the future life of the project, certain LNG projects capture a higher revenue per unit than other global projects. This is normally due to liquids components as well as the indexation of Sales and Purchase Agreements for the LNG output, specific to every project. Recent projects in Australia are costly due to their large greenfield nature and high cost inflation in the supply chain.

# On US\$/mmbtu basis high costs for Australian LNG leave a smaller portion of revenue to be divided between the contractor and government

LNG Project Comparison: Split of Project Revenue over Life of Project (80 \$/bbl price case)



The Internal Rate of Return (IRR) is a measure of the profitability of the project; with a profit-based taxation system like PRRT, the government share is dependent not only on output and price but also profitability

U/S = Upstream, D/S = Downstream (plant), Integ. = Integrated project





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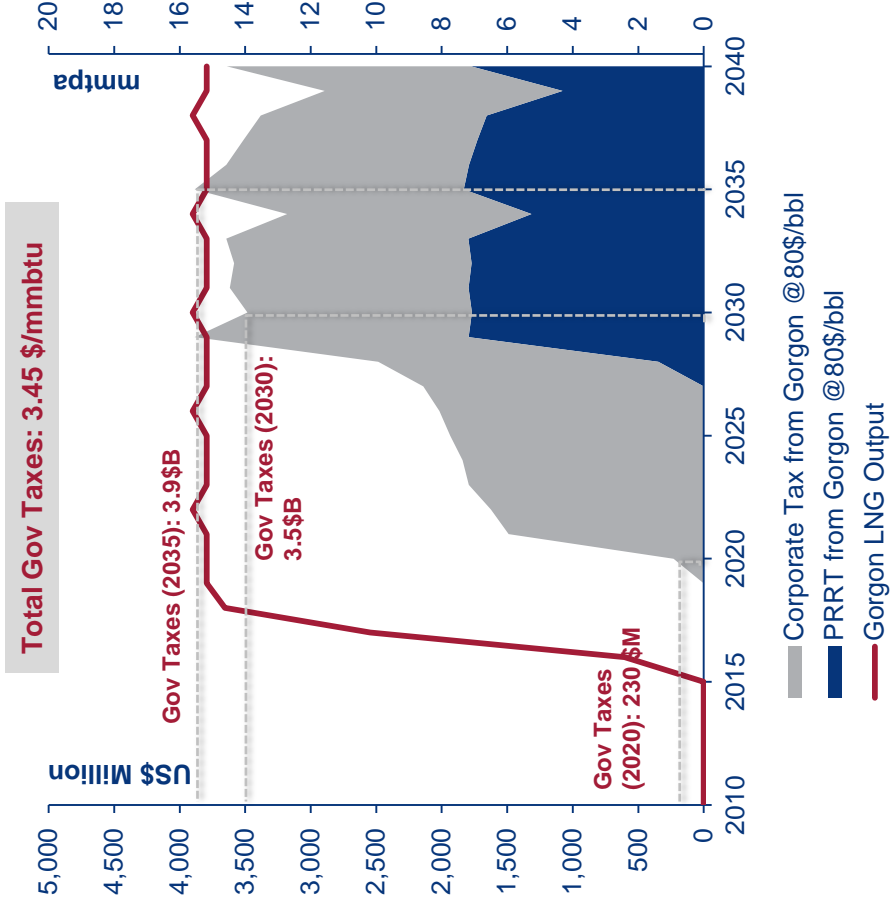
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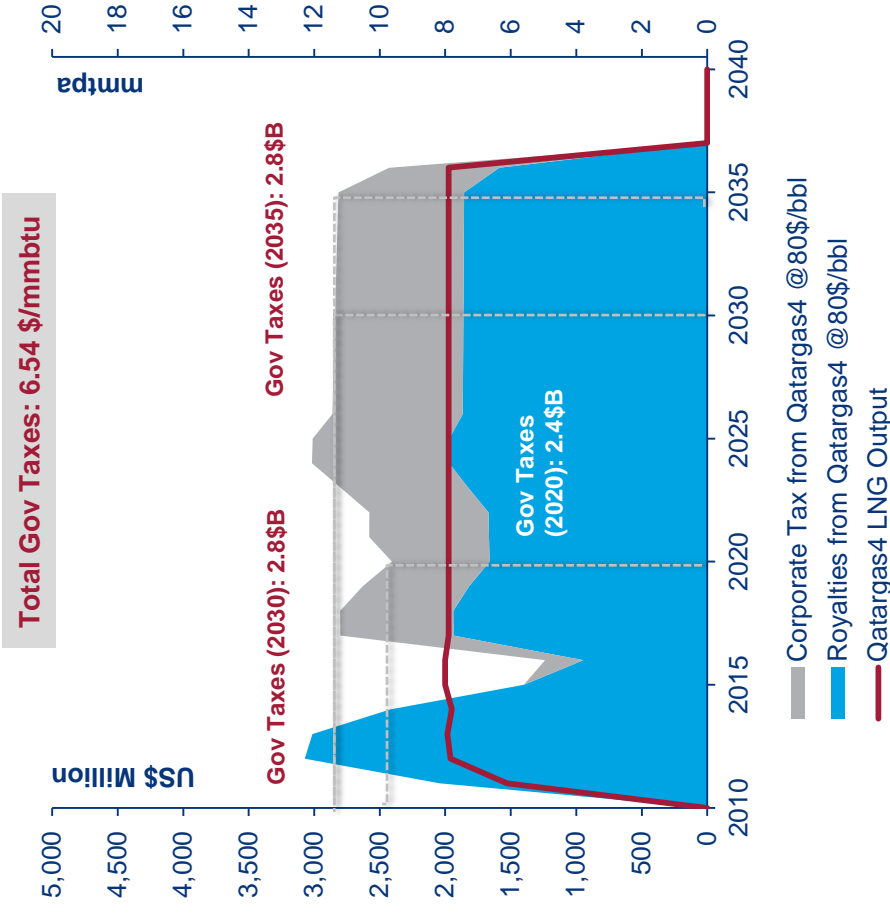
5. Peer group comparison of government share on oil projects

# The level of government taxes differs by project but also over the lifetime of the project; individual years are not representative

## Australia- Gorgon



## Qatar- Qatargas4

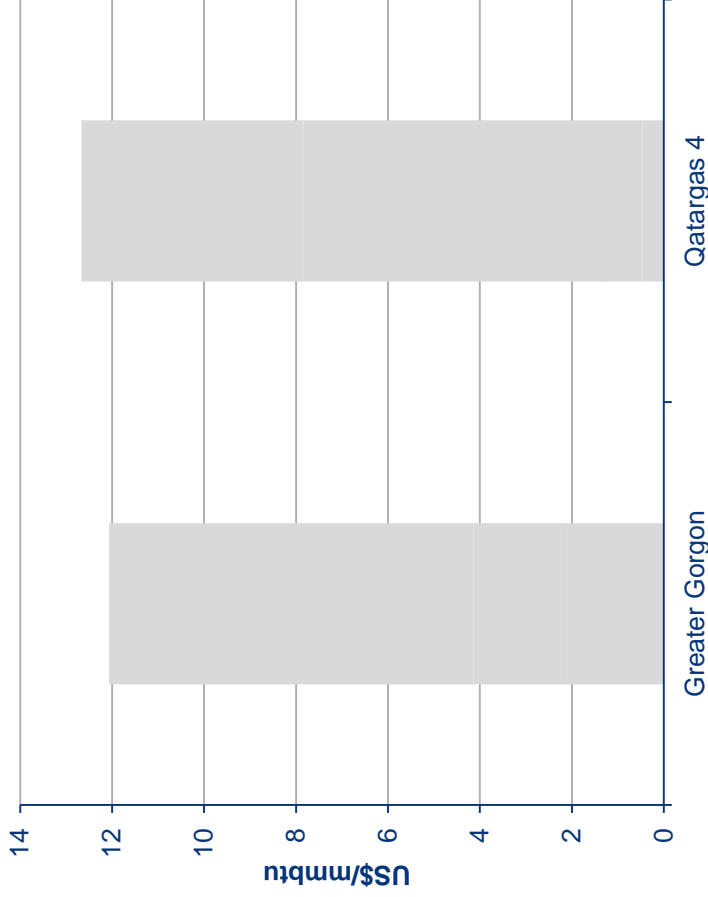


Note: Depending on the level of local content in projects, significant amounts of company tax will also be paid in the host country by local suppliers

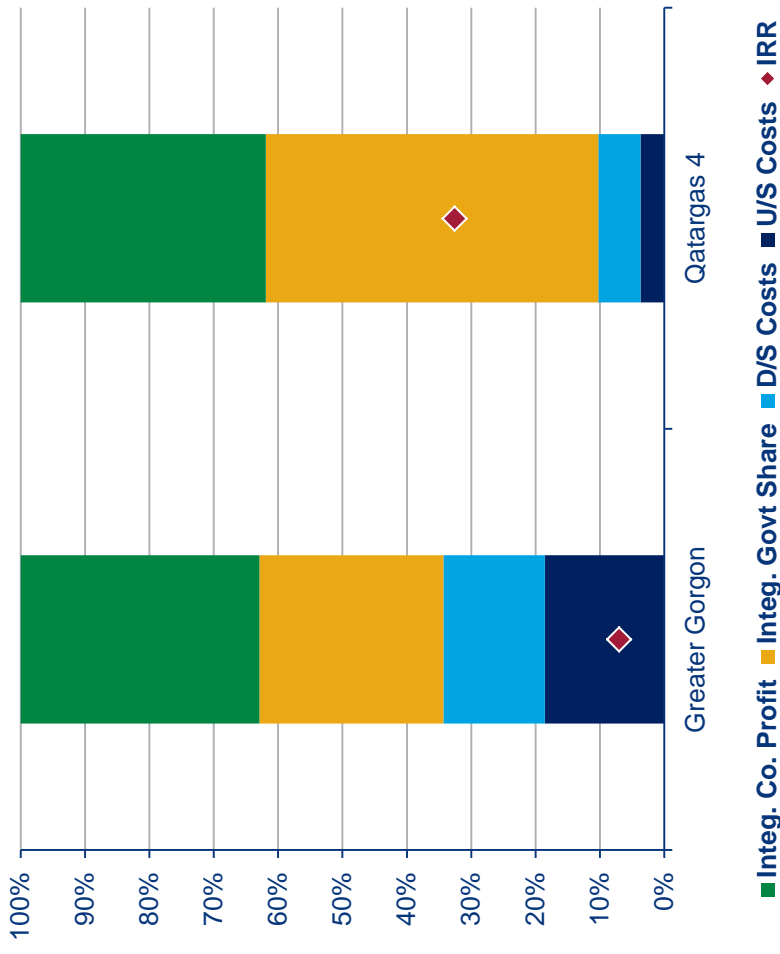


# Despite a similar per unit revenue, Gorgon's high cost base lowers the profitability to the contractor and the government

Gorgon vs. Qatargas - Revenue \$/mmbtu



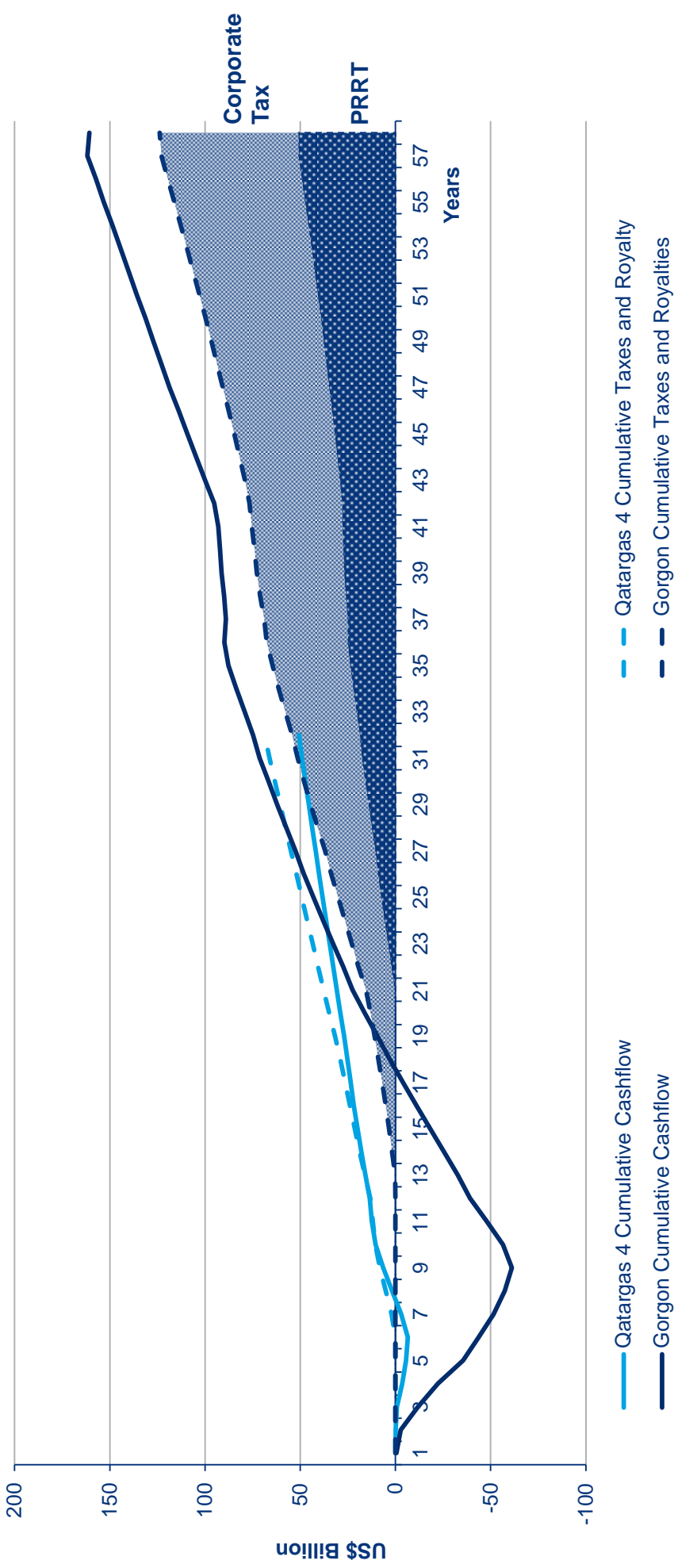
Gorgon vs. Qatargas - % Revenue Split



Higher costs at a project like Gorgon reduce the profit, thus reducing the government Taxes. However the profitability (as measured by IRR) is also low for the company—representing a borderline investment. In a project like Qatargas 4, the very low cost environment increases profitability for both the company (Qatar Petroleum) and the government.

# Gorgon's investment dwarfs Qatargas 4 in terms of amount and time to payback

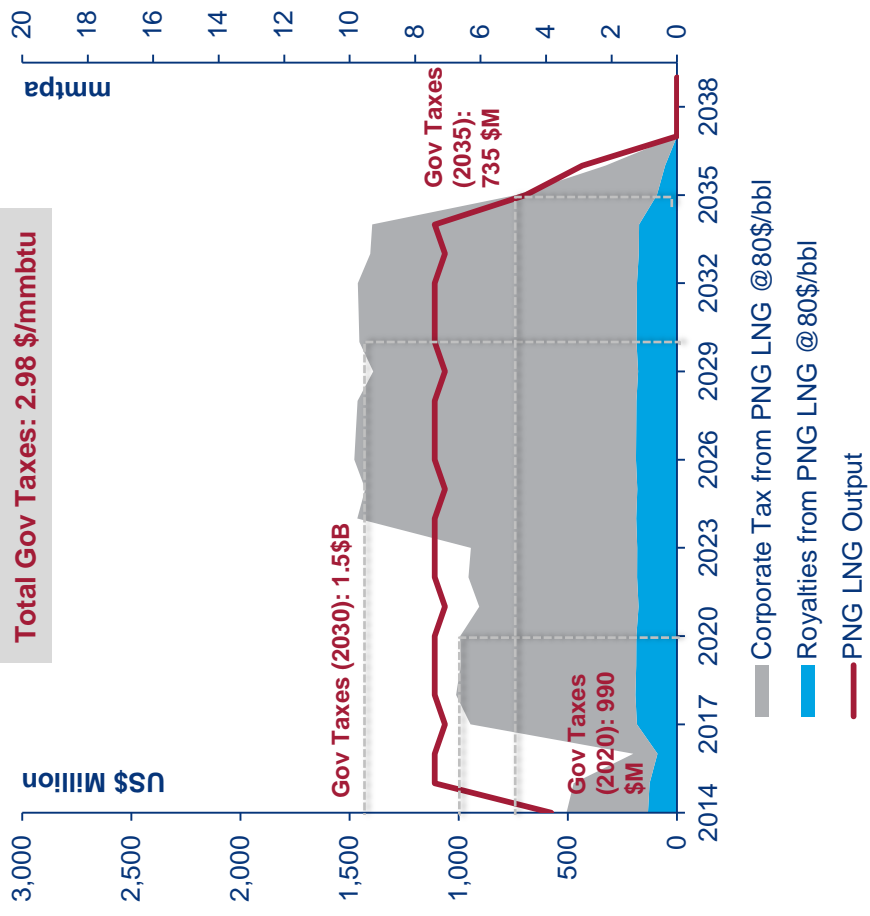
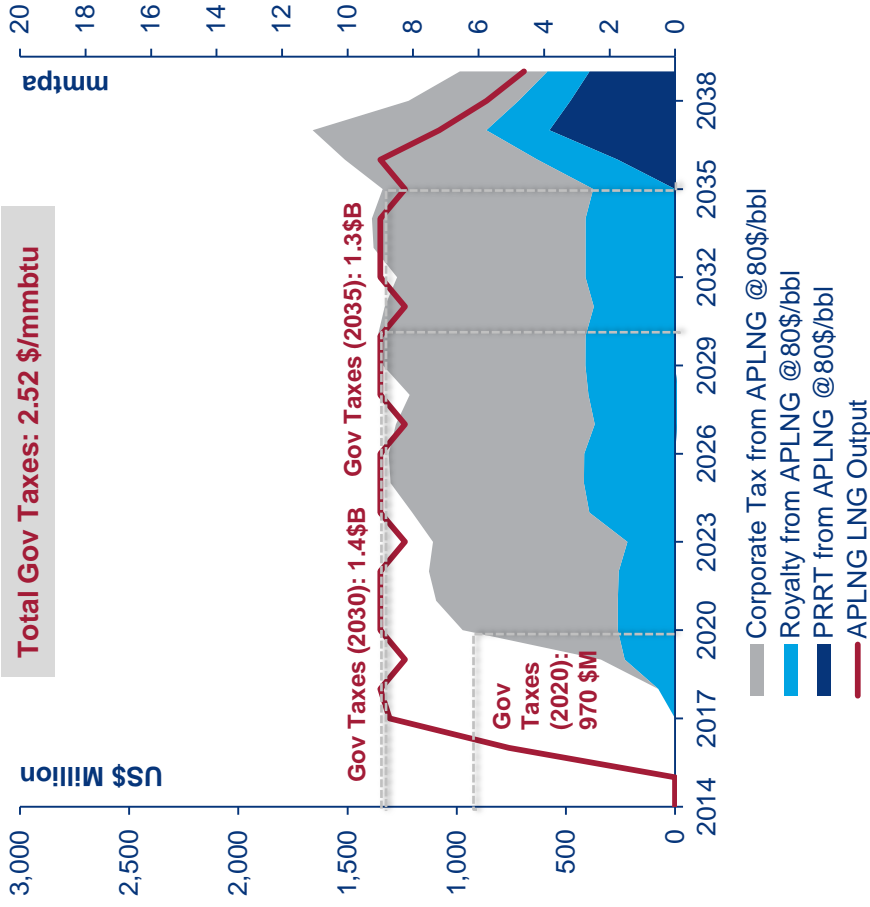
Gorgon vs. Qatargas 4: Cumulative Cashflow vs. Cumulative Government Tax and Royalty\*



Despite the fact that the government receives 44% of the profits at APLNG versus 33% at PNG LNG, the higher cost lowers the profit to be shared

### Australia- APLNG

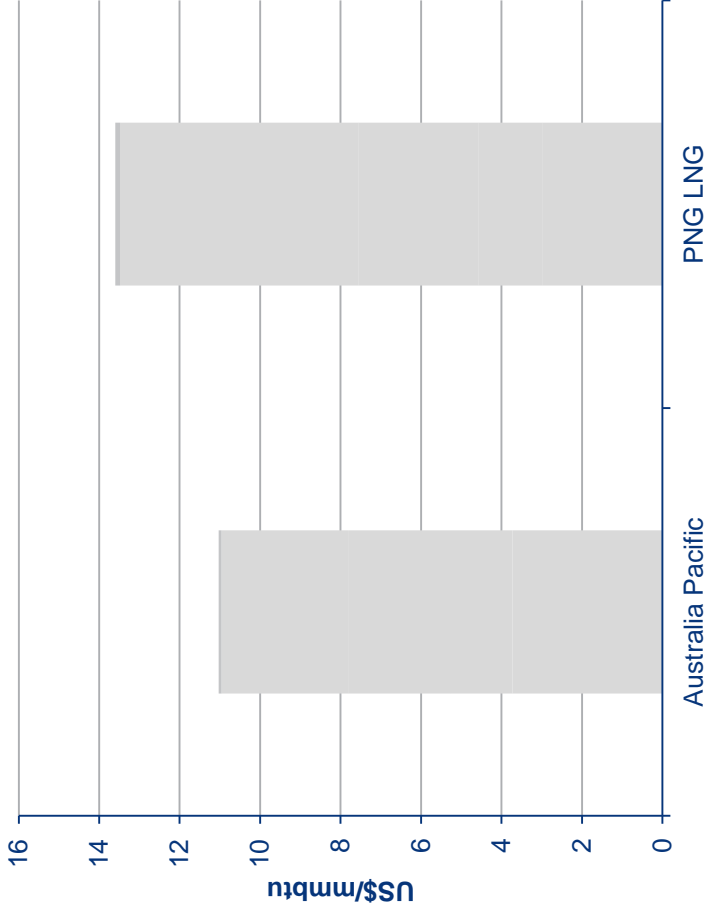
### PNG- PNG LNG



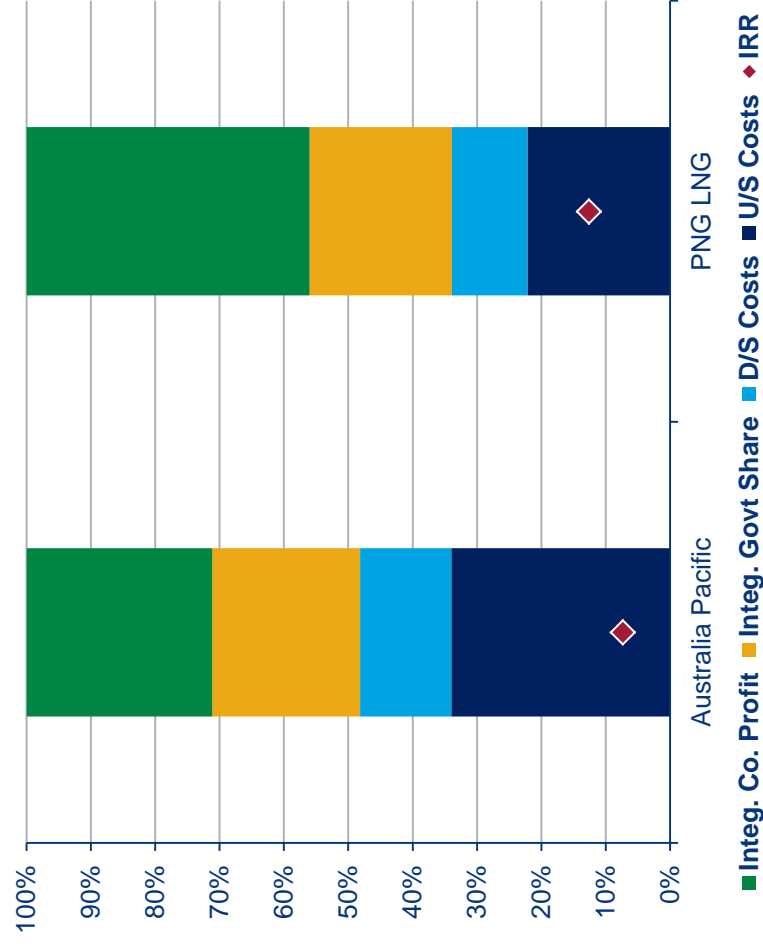
Note: Depending on the level of local content in projects, significant amounts of company tax will also be paid in the host country by local suppliers

# At APLNG, the profit split between the contractor and the government is roughly equal

APLNG vs. PNG LNG - Revenue \$/mmbtu



APLNG vs. PNG LNG - % Revenue Split



In a project like PNG LNG, the lower development cost increases the profitability of the project however, a greater part of it goes to the operator versus the government. In Australia, the impact of higher cost to development is, in effect borne equally by the government and the operator.

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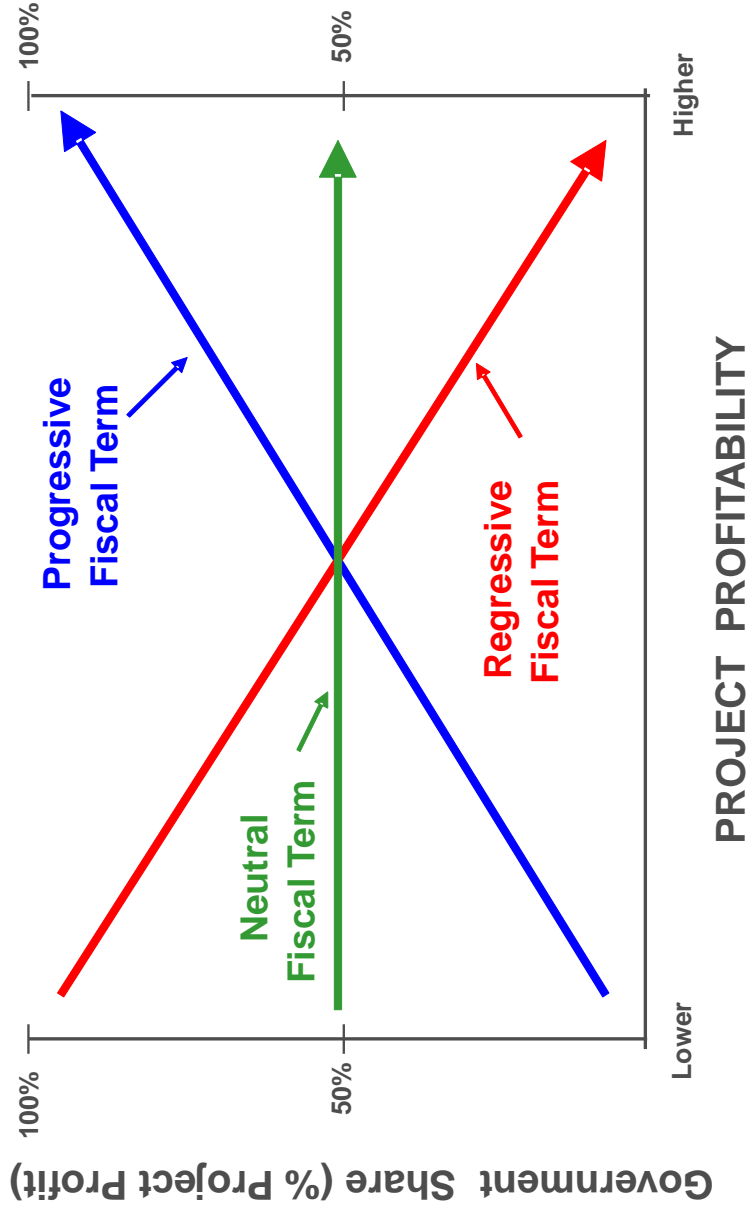
# Fiscal terms are a policy of the government that determine the level and type of government share from LNG projects

- Some fiscal terms are levied on **revenue**
  - » Examples: Royalty or Government Priority Oil (% of production or revenue); Cost Recovery Ceilings (% of revenue); Export Duties (\$/bbl or % of revenue); Domestic Supply Obligation (% of production at lower price)
- Some fiscal terms are levied on **expenditure**
  - » Examples: VAT; Import Duties; Social Development Funds; Property Tax; Exploration Tax (PSCs often exempt investors from liability to indirect taxes)
- Some fiscal terms are levied on **profits**
  - » Examples: PSC Production / Profit Share; Corporate Income Tax (CIT); Petroleum Profits Tax (PPT); Additional Profits Tax (APT); Dividend Withholding Taxes

This leads to some fiscal terms being categorized as 'regressive' or 'progressive' depending on how they react to sensitivity in price or cost

# Progressive fiscal terms generate more government share as project profitability increases

## Government Share Levels with changing Project Profitability

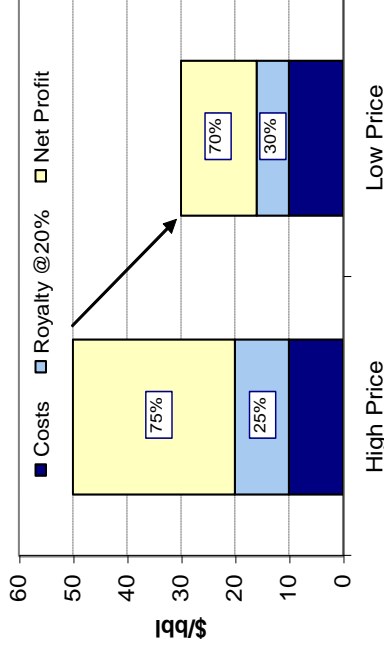




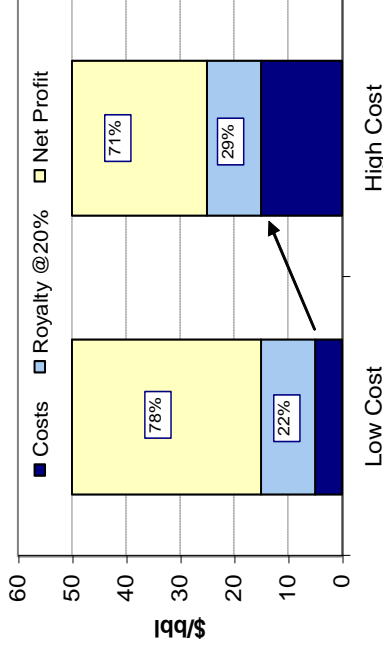
# Fiscal terms levied on revenue are often “regressive”—as project profit increases, government share may decrease

## Example 1: Royalty

Government share (as a % of project profit) increases as prices decrease



Government share (as a % of project profit) increases as expenditures increase



### Benefits of tax on revenue

- Generates revenue for the government as soon as production starts
- Do not have to wait until investor costs are recovered to generate tax

### Drawbacks of tax on revenue

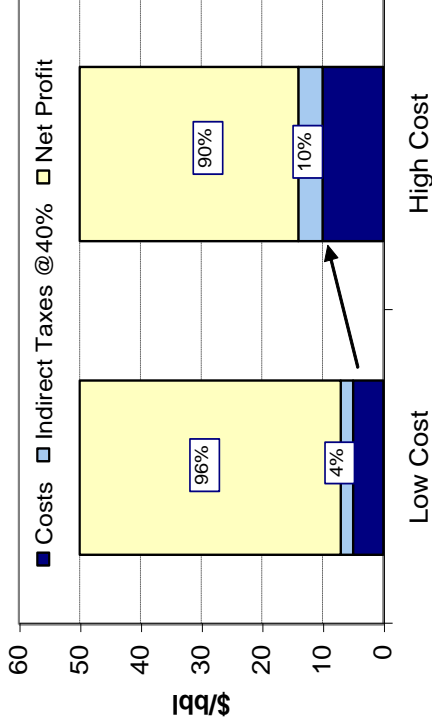
- Increases pre-share (pre-tax) returns required to pursue an investment opportunity
- Can deter development of marginal fields
- Can cause early abandonment as need more revenue to keep field onstream
- Increases the breakeven cost of project



# Fiscal terms levied on expenditure are “regressive” — government share decreases with increasing project profits

## Example 2: Indirect taxes

Government share (as a % of project profit) increases as expenditures increase



### Benefits of tax on expenditure

- Can generate revenue for government before any project revenue exists
- Guaranteed tax for government no matter if activity is successful or not
- Does not hinge on project FID
- Not impacted by growing project lead times between discovery and first oil/gas

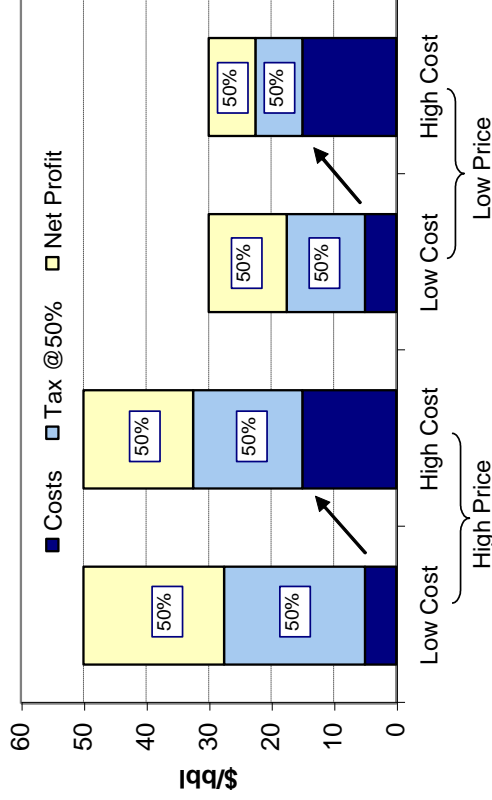
### Drawbacks of tax on expenditure

- Can add to the cost of an already expensive project, discouraging investment or eating into profit margins
- Can have a negative impact on key investor decision-making metrics (such as NPV, IRR, breakeven)
- Can deter development of marginal fields

# Fiscal terms based on profits are “neutral” or “progressive” —more project profit results in greater share of profit to the government

## Example 3: Special Petroleum Tax

Government share (as a % of project profit) stays the same when costs or prices change



Above: example of neutrality

Fiscal term is ‘progressive’ if rate increases when costs decrease or prices increase and decreases vice-versa (i.e. at higher price/profit range a higher tax rate is applied e.g. 70% instead of 50%)

### Benefits of tax on profits

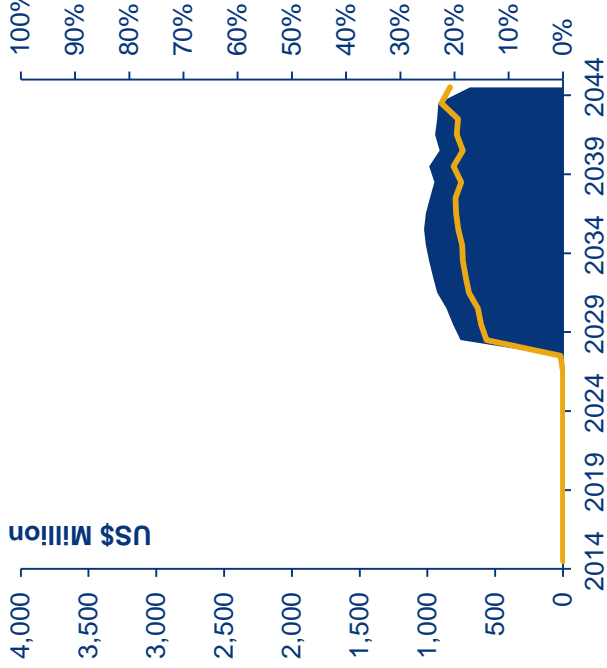
- Reduces risk to the investor, encouraging investment
- Lowers pre-share returns required to pursue an investment opportunity
- Depreciation is the main means of recovering costs and typically government receives revenue before full cost recovery

### Drawbacks of tax on profits

- From a government perspective the minimum level of receipts is zero
- Thus upfront spending can delay the start of tax payments for several years after the start of production

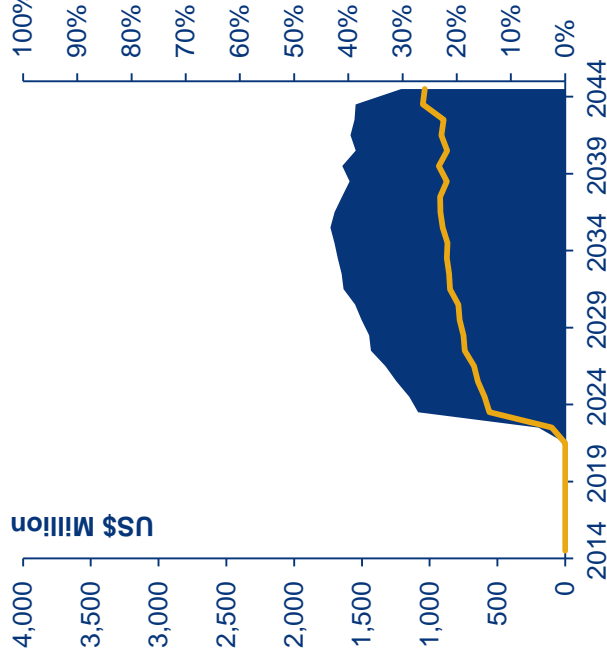
# With a progressive fiscal regime like PRRT, along with the absolute government revenue, the share government claims of the profit also increases with price increases

Gorgon (\$40 Real)



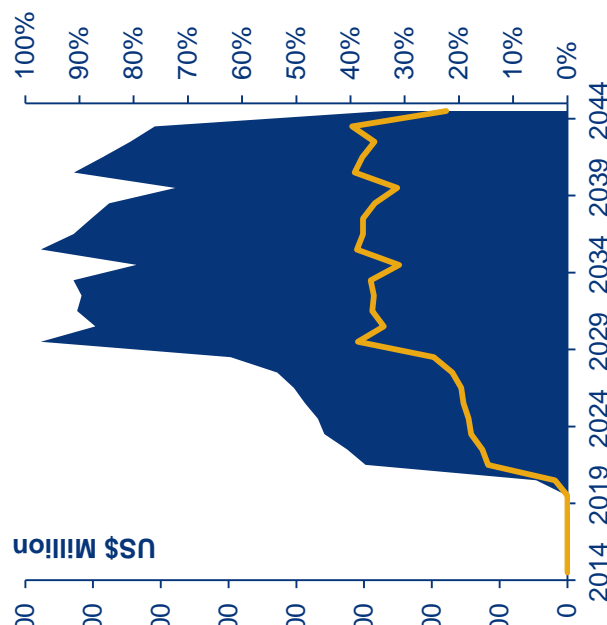
■ Government Taxes from Gorgon @40 \$/bbl  
 — % Government Share of Revenue

Gorgon (\$60 Real)



■ Government Taxes from Gorgon @60 \$/bbl  
 — % Government Share of Revenue

Gorgon (\$80 Real)



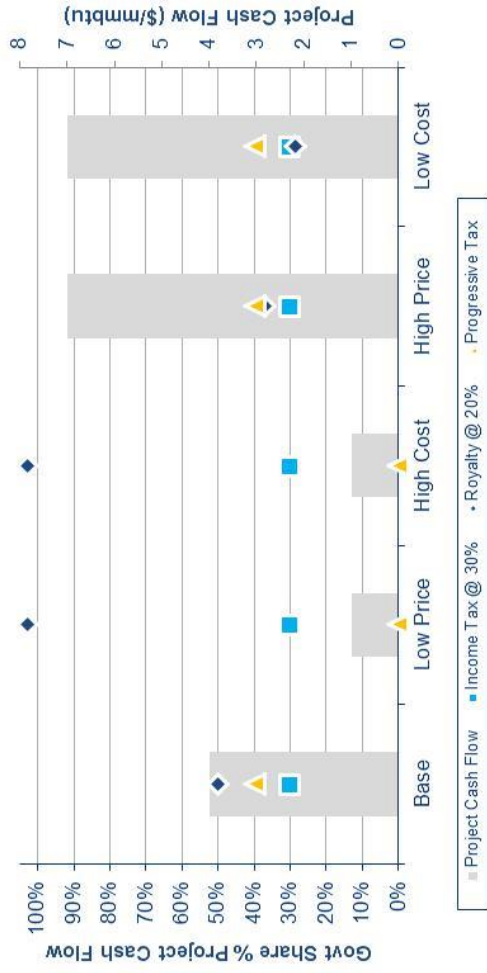
■ Government Taxes from Gorgon @80 \$/bbl  
 — % Government Share of Revenue

Note: Government Taxes are inclusive of any Royalties, PRRT and Corporate Taxes

# Progressive vs Regressive fiscal systems Impact on Government Share and Company Cash Flow

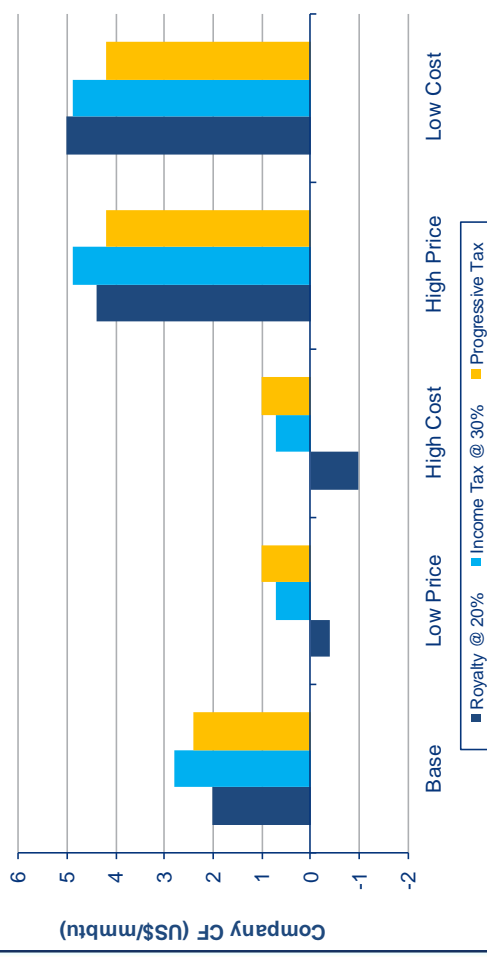
- Royalty is levied on revenue; Income Tax and Progressive Tax are levied on Project Cash Flow
- Royalty can make marginal projects uneconomic
- Income Tax is neutral, compared to project profitability
- Progressive Tax can be zero for marginal projects and apply at high rates for very profitable projects
- Many Progressive Tax systems include a sliding scale rate, not 'on or off', like PRRT

## Government Share as project profitability changes



Source: Wood Mackenzie; 'progressive tax' increases tax rate as cash flow increases

## Company Cash Flow as project profitability changes



Source: Wood Mackenzie; 'progressive tax' increases tax rate as cash flow increases

## Regressive / Progressive illustration: assumptions

US\$/mmbtu	Base	Low Price	High Price	High Cost	Low Cost	Progressive Tax Rate (proxy for PRRT)
Revenue	10.0	7.0	13.0	10.0	10.0	Project CF (US\$/mmbtu)
Costs	6.0	6.0	6.0	6.0	3.0	Tax Rate
<b>Project Cash Flow</b>	<b>4.0</b>	<b>1.0</b>	<b>7.0</b>	<b>1.0</b>	<b>7.0</b>	<b>0%</b>
						<b>40%</b>

# Progressive vs Regressive fiscal systems Impact on Government Share and Company Cash Flow

Regressive / Progressive illustration: assumptions						
US\$/mmbtu	Base	Low Price	High Price	High Cost	High Price	Low Cost
Revenue	10.0	7.0	13.0	10.0	13.0	10.0
Costs	6.0	6.0	6.0	9.0	6.0	3.0
<b>Project Cash Flow</b>	<b>4.0</b>	<b>1.0</b>	<b>7.0</b>	<b>1.0</b>	<b>7.0</b>	<b>7.0</b>
<b>Royalty system</b>						
Royalty @ 20%	2.00	1.40	2.00	2.00	2.60	2.00
Royalty % Project CF *	50%	103%	103%	103%	37%	29%
Company CF	2.00	-0.40	-1.00	-1.00	4.40	5.00
<b>Income Tax system</b>						
Income Tax @ 30%	1.20	0.30	0.30	0.30	2.10	2.10
Income Tax % Project CF	30%	30%	30%	30%	30%	30%
Company CF	2.80	0.70	0.70	0.70	4.90	4.90
<b>Progressive Tax system</b>						
Progressive Tax Rate	40%	0%	0%	0%	40%	40%
Progressive Tax	1.60	0.00	0.00	0.00	2.80	2.80
Progressive Tax % Project CF	40%	0%	0%	0%	40%	40%
Company CF	2.40	1.00	1.00	1.00	4.20	4.20

\* Government Share > 100% is shown as 103% to fit on the chart

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1. Comparing global LNG projects

2. Evaluating government share from LNG projects

3. How different prices impact government share from LNG projects

**4. Global overview of governments' fiscal response to low oil prices**

5. Peer group comparison of government share on oil projects



# In Asia, some governments lowered their share hoping to attract increased investment. Australia has remained stable with no changes since 2011/12



## China:

- ++** Threshold above which Special Oil Income Levy applies was increased from US\$55/bbl to US\$65/bbl in 2015.

## India:

- ++** CBM terms added for PSC
- CIT increased from 34% to 34.6%

- ~** New RSC introduced, no cost recovery.
- ~** Finance Bill 2016 updated royalty, cess and removed CIT holiday

## Japan:

- ++** CIT reduced from 35.6% to 33.1%.

## Indonesia:

- +** The 0.5% 'land and building tax' charged on exploration acreage was repealed in January 2015, to encourage exploration.
- Two new unconventional PSCs introduced Sliding Scale PSC and gross PSC.

**Key**

- ++** Better terms for investors for existing assets and new licences
- +** Better terms for investors for new licences only
- ~** Neutral
- Worse terms for investors for new licences only
- Worse terms for investors for existing assets & new licences

**Year:** 2015 2016

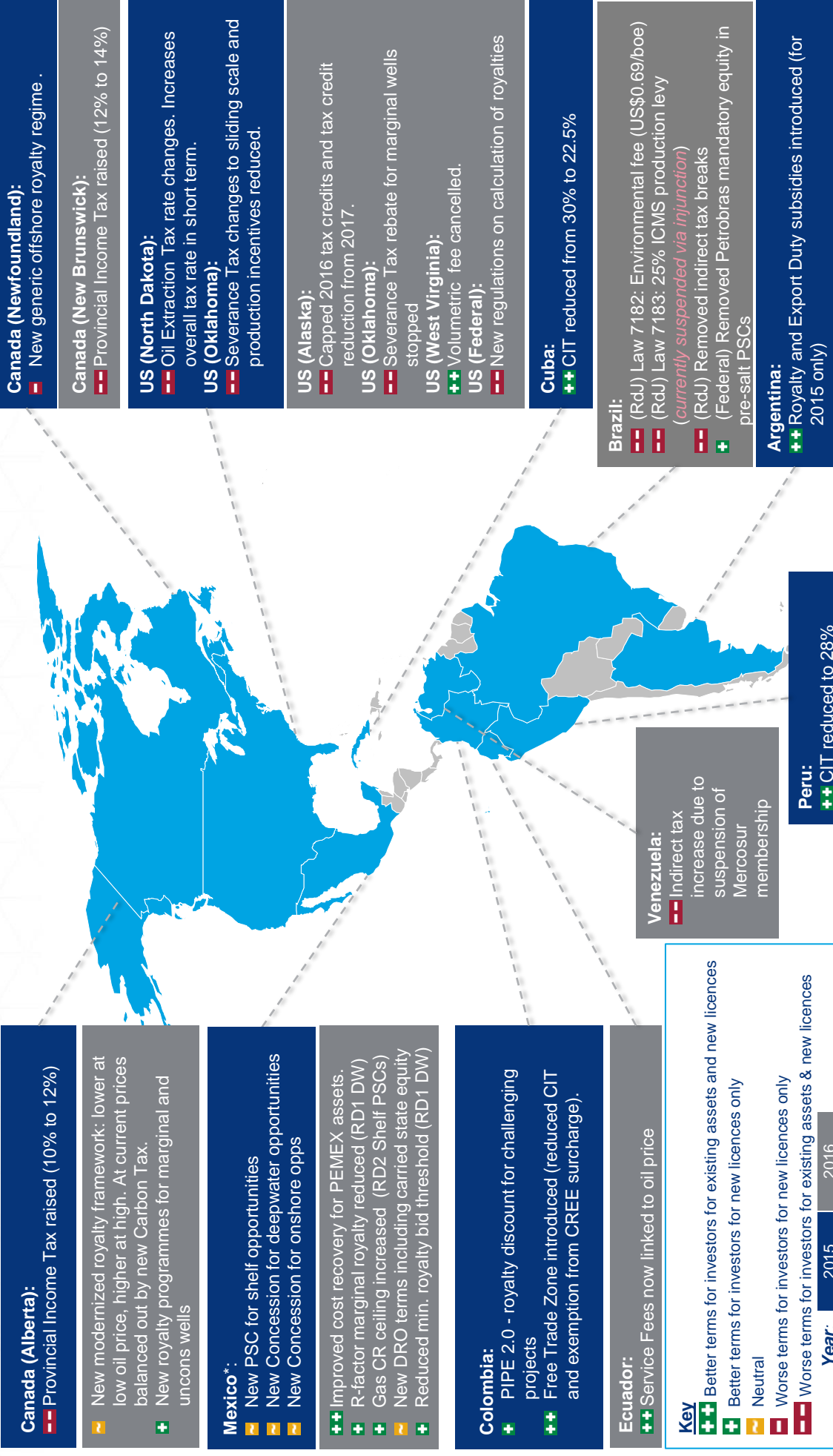
Note: There were no fiscal changes legislated in Australasia in 2015 and 2016



**Wood Mackenzie**

A Verisk Analytics Business

# The story in the Americas is mixed, with several large producers aiming to maintain government revenue with higher taxation



**Canada (Alberta):**  
 -- Provincial Income Tax raised (10% to 12%)

~ New modernized royalty framework: lower at low oil price, higher at high. At current prices balanced out by new Carbon Tax.  
 + New royalty programmes for marginal and unconcs wells

**Mexico\*:**  
 ~ New PSC for shelf opportunities  
 ~ New Concession for deepwater opportunities  
 ~ New Concession for onshore opps

++ Improved cost recovery for PEMEX assets.  
 + R-factor marginal royalty reduced (RD1 DW)  
 + Gas CR ceiling increased (RD2 Shelf PSCs)  
 ~ New DRO terms including carried state equity  
 + Reduced min. royalty bid threshold (RD1 DW)

**Colombia:**  
 + PIPE 2.0 - royalty discount for challenging projects  
 ++ Free Trade Zone introduced (reduced CIT and exemption from CREE surcharge).

**Ecuador:**  
 ++ Service Fees now linked to oil price

**Key**

- ++ Better terms for investors for existing assets and new licences
- + Better terms for investors for new licences only
- ~ Neutral
- Worse terms for investors for new licences only
- Worse terms for investors for existing assets & new licences

**Year:** 2015 2016

**Canada (Newfoundland):**  
 -- New generic offshore royalty regime .

**Canada (New Brunswick):**  
 -- Provincial Income Tax raised (12% to 14%)

**US (North Dakota):**  
 -- Oil Extraction Tax rate changes. Increases overall tax rate in short term.

**US (Oklahoma):**  
 -- Severance Tax changes to sliding scale and production incentives reduced.

**US (Alaska):**  
 -- Capped 2016 tax credits and tax credit reduction from 2017.

**US (Oklahoma):**  
 -- Severance Tax rebate for marginal wells stopped

**US (West Virginia):**  
 ++ Volumetric fee cancelled.

**US (Federal):**  
 -- New regulations on calculation of royalties

**Cuba:**  
 ++ CIT reduced from 30% to 22.5%

**Brazil:**  
 -- (RdJ) Law 7182: Environmental fee (US\$0.69/boe)  
 -- (RdJ) Law 7183: 25% ICMS production levy (currently suspended via *injunction*)  
 -- (RdJ) Removed indirect tax breaks (Federal) Removed Petrobras mandatory equity in pre-salt PSCs

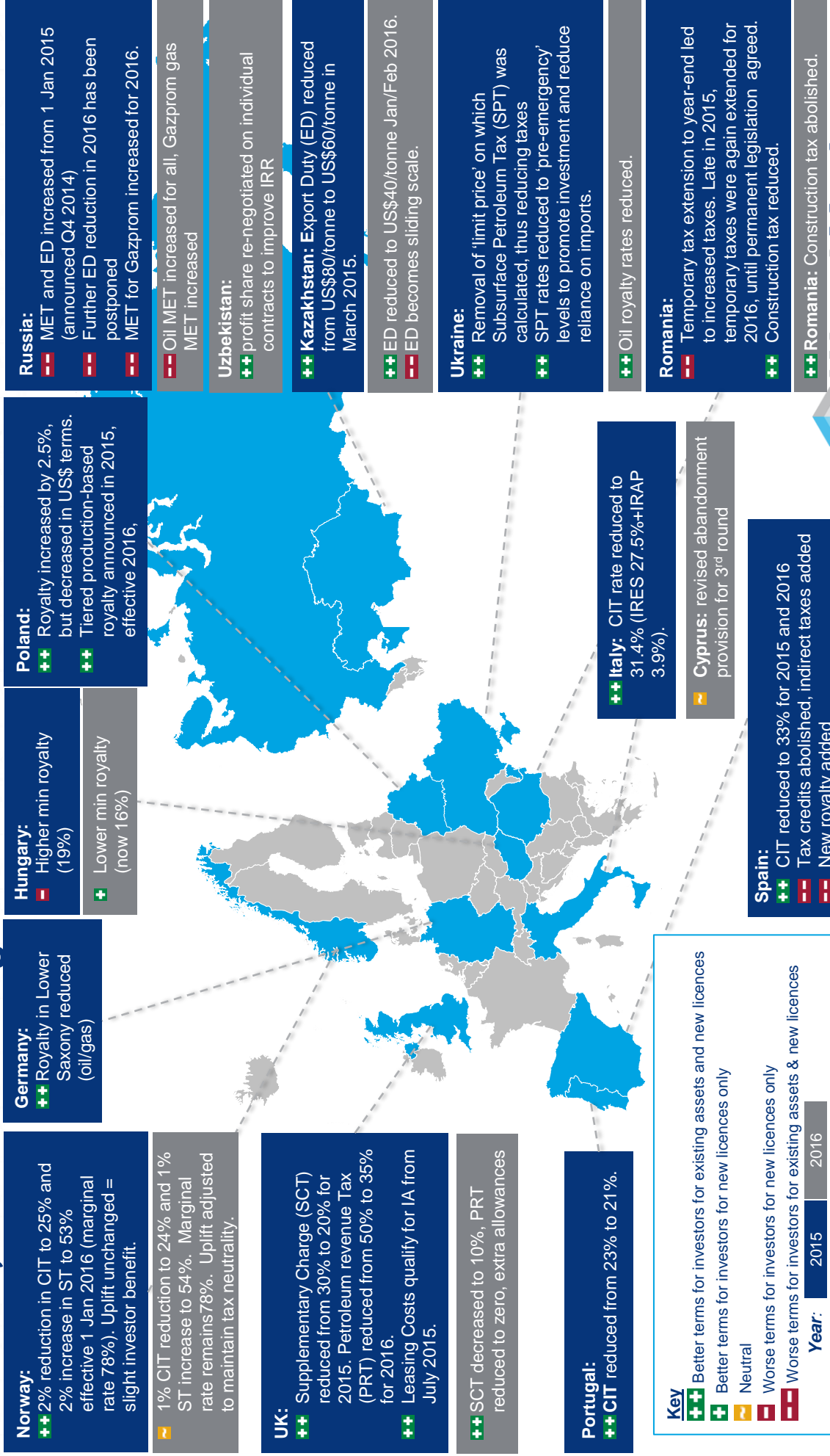
**Argentina:**  
 ++ Royalty and Export Duty subsidies introduced (for 2015 only)

**Peru:**  
 ++ CIT reduced to 28%

**Venezuela:**  
 -- Indirect tax increase due to suspension of Mercosur membership



# While in Europe and Russia, only Russia, with its dependence on oil revenue, increased its government share



**Key**

- ++ Better terms for investors for existing assets and new licences
- + Better terms for investors for new licences only
- Neutral
- Worse terms for investors for new licences only
- Worse terms for investors for existing assets & new licences

**Year:** 2015 2016

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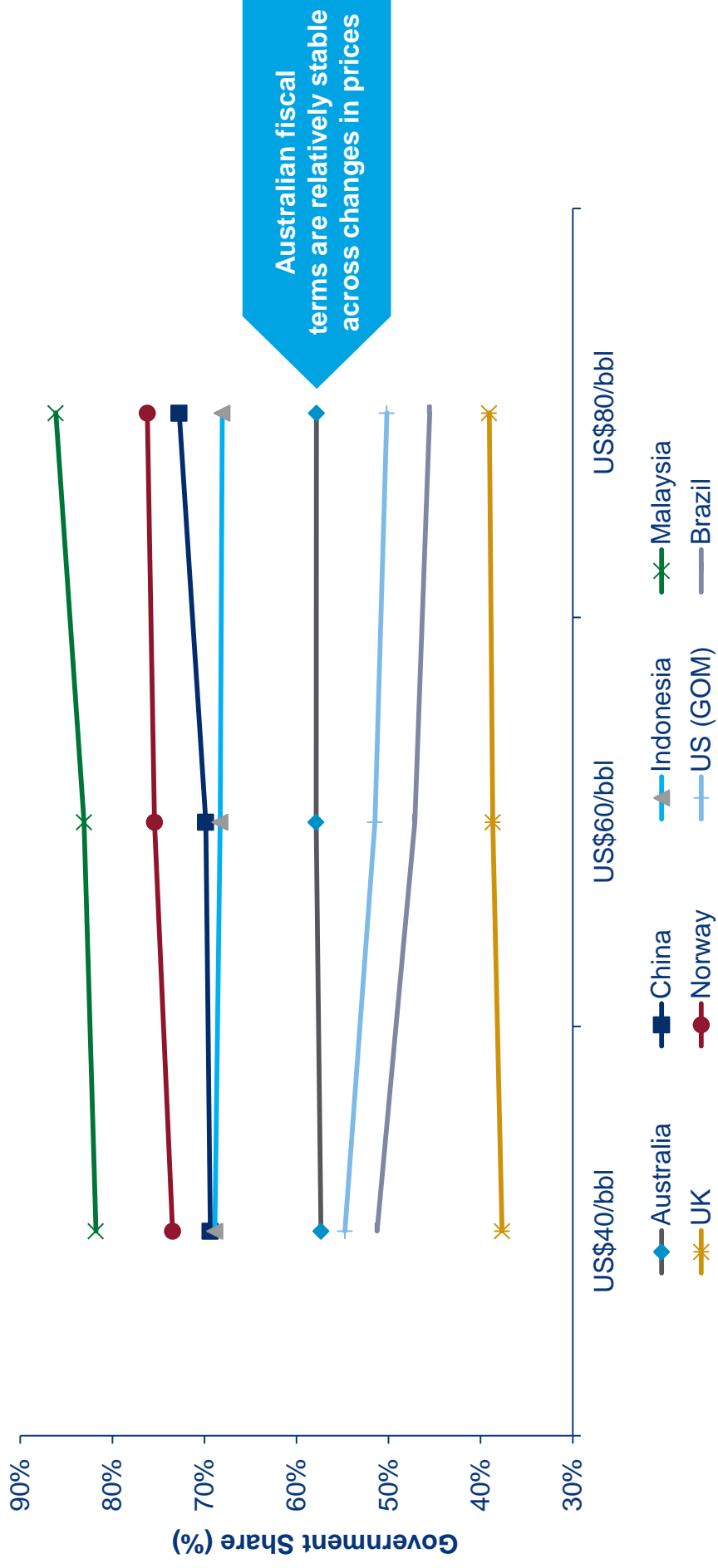
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# Overall, Australia's government share for offshore oil projects (example 100 mmbbl field) is competitive

## Sensitivity of fiscal terms to changing oil price on a theoretical discovery



Source: Wood Mackenzie Fiscal Benchmarking Tool (Q4 2016): Location – Shelf, Size -100 mmbbl oil field, Cost – medium, Discount Rate 0%

# Appendix

## Modelling Assumptions - Australian Projects

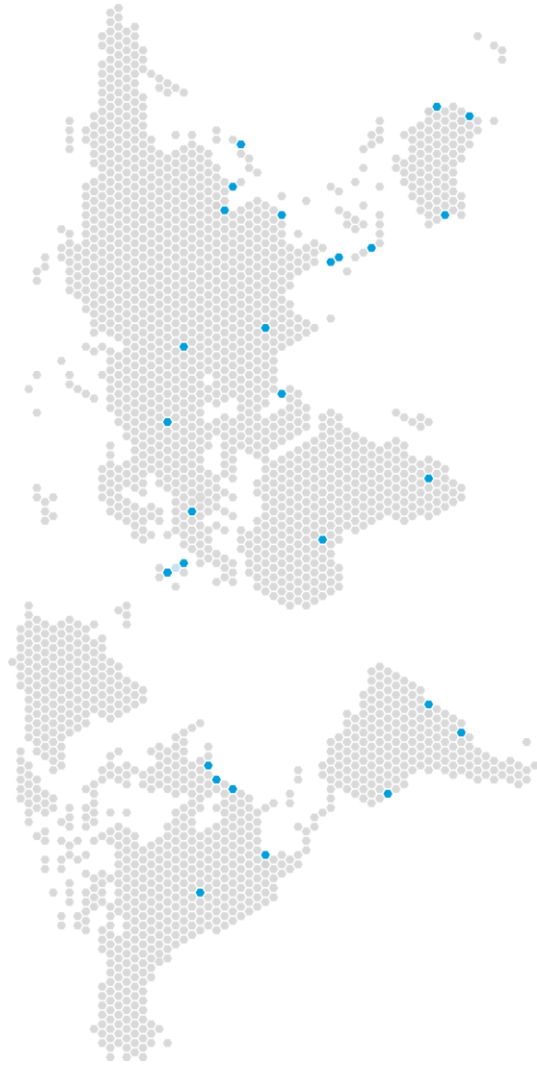
Australian LNG Projects			Total Recoverable Reserves	Total Costs			Total Revenue	
Name	Size of Project (mmtpa)	Lifetime of Project (years)	Liquids + Gas (mmboe)	Upstream Capex + Opex (\$B)	Plant Capex + Opex (\$B)	Liquids Revenue (\$B)	Gas Revenue (\$B)	
Gorgon*	15.6	>49	7,840	80	68	22	410	
APLNG	9.0	26	2,144	39	16	0	114	
Prelude FLNG	3.6	20	586	10	15	12	29	

Costs normalised to 2016; historical costs inflated to 2016 and future costs undiscounted  
\*Cost estimates for Gorgon include costs for assumed project extension through to 2064, which will require additional fields development and LNG plant refurbishment

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