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The Committee Secretary
Senate Economics References Committee
PO Box 6100
Parliament House
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Dear Committee Secretary

Senate Economics References Committee Inquiry into Corporate Tax Avoidance and Minimisation

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 majority of Australia's oil and gas production and exploration.

APPEA welcomes the opportunity to provide comments to the Committee on the recently announced expanded terms of reference of the inquiry. We refer the Committee to the Association's submission lodged with the Treasury Taskforce that is examining aspects of the federal petroleum resource taxation provisions – the Treasury review has a reporting date of April 2017. A copy of APPEA's submission to that review can be found **here**. Please note that some of the material outlined below is sourced from the APPEA's Treasury submission. In addition, the comments in this submission are focused on petroleum resource taxation, noting that a number of APPEA members have previously appeared before the Committee with respect to income tax related matters.

The Legislative and Taxation Framework

Under the terms of the 1979 Offshore Constitutional Settlement and the division of powers 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 company tax, resource taxes that apply to petroleum production in Australia are broadly as follows:

- All projects are subject to the petroleum resource rent tax.
- Production sourced from production 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 petroleum production and that sourced from projects located in submerged lands under state/territory jurisdiction is subject to Commonwealth crude oil and condensate 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.

The petroleum taxes that are the focus of this submission are the petroleum resource rent tax and offshore petroleum royalties.

Industry Taxation Contribution

Chart 1 below 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. 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 reported period.

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

<u>Chart 1: Oil and Gas Industry Estimated Company and Resource Tax Payments ($m)</u>

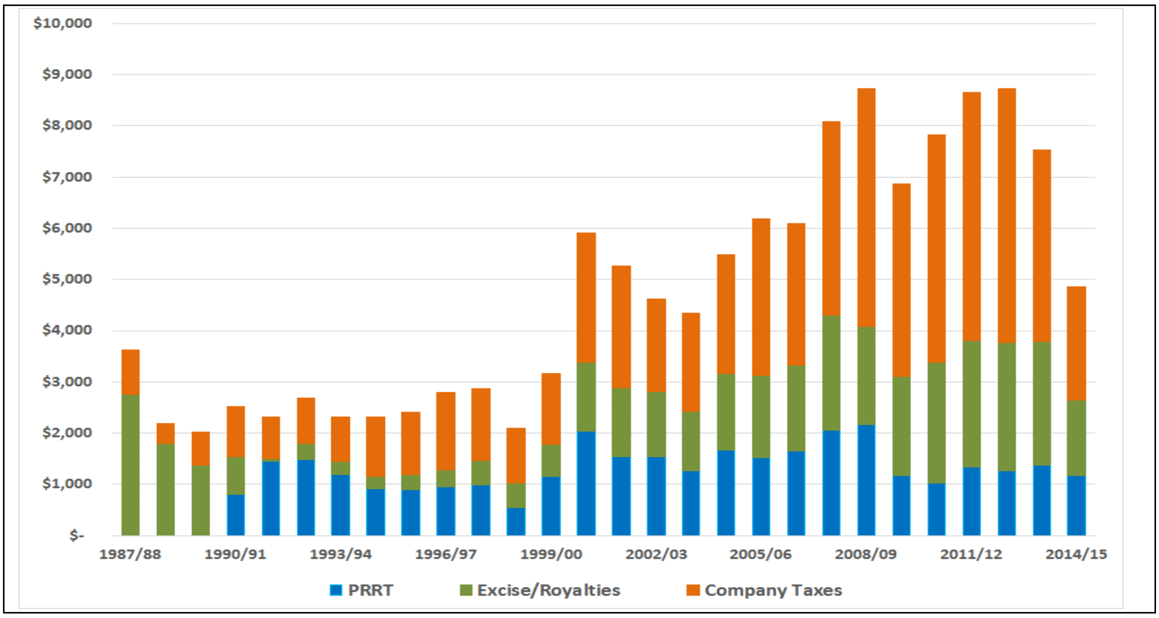
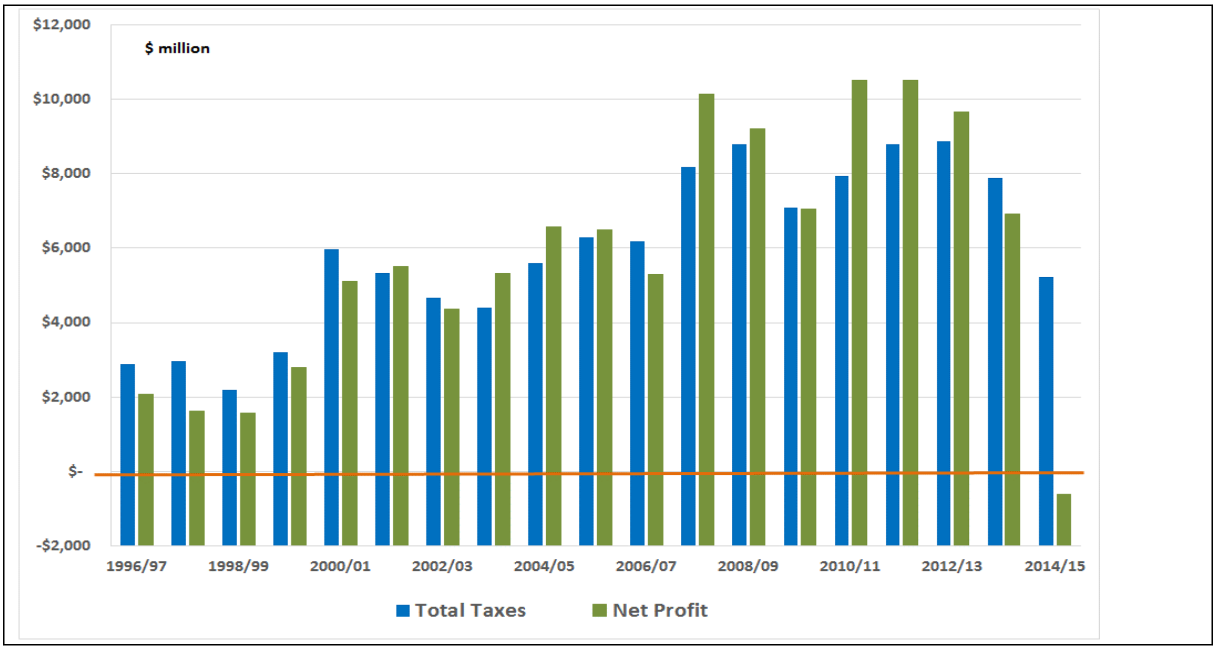


Chart 2 presents total tax payments and industry profit. The industry's overall level of tax payments has, on average, been broadly equal to industry net profit since the mid 1990's. This changed significantly in 2014-15, when a net loss was recorded for the first time since the survey has been conducted. In the same year, more than $5 billion was still paid in taxes by the industry.

The fact that the industry incurs tax liabilities despite being in an overall loss position is explained by the design features of a number of taxes. Firstly, deductions under the company tax and royalty regimes are limited by the application of depreciation provisions, while restrictions on deductible expenditure also 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 incur tax liabilities.

Chart 2: Oil and Gas Industry Tax Payments and Net Profit ($m)



Petroleum Resource Rent Tax

The petroleum resource rent tax (PRRT) is a super profits tax that the Commonwealth Government uses to tax economic rent from oil and gas projects in Australia. It is levied under 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 the project (including after deducting eligible exploration expenditure transferred from other projects), with an allowance for a threshold rate of return. It 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).
- As PRRT is a 'resource' tax, it does not seek to tax downstream processing and/or liquefaction activities.
- 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 generally 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 to avoid 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 payments are deductible against income tax.

As PRRT is essentially a project based tax, excess undeducted expenditures from one project cannot generally be offset against income from other projects held by a taxpayer. The exception is exploration expenditure, which is transferable to other petroleum projects, subject to a number of strict transfer rules.

Selected Features of PRRT

PRRT differs from income tax in a number of 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. Project financing costs are not deductible. In addition, certain other costs deductible for company tax purposes are not deductible for PRRT purposes.

An important aspect of the design of the PRRT is the specific allowance for risk – without such an allowance, tax would be payable prior to an investor achieving a return on capital (a core principle of the regime). This is provided for under the augmentation provisions (as outlined above). In commenting on the threshold or augmentation rates in 1975 (during the early design phase of resource rent taxes in Australia), Professor Ross Garnaut noted the following in the setting of the risk adjusted rates for the petroleum industry:

> *"There is, however, a case for separate, higher threshold rates in industries, such as petroleum and natural gas, in which investment in exploration is both highly risky and a high proportion of total investment."*

Augmentation (Carry-Forward) Rates

A number of points are relevant in understanding aspects of the augmentation rates.

For exploration expenditure, undeducted amounts are carried forward at either the GDP factor rate **or** the long term bond rate plus 15 percentage points. The relevant rate is dependent on the timing of the exploration expenditure relative to the lodgment of an application for a production licence - five (5) years is the relevant time horizon. As a result of this condition, a large proportion of exploration expenditure is carried forward at the GDP factor, not the higher rate of LTBR plus 15 percentage points. The annual GDP factor rate has averaged less than one (1) per cent over the last five years.

The augmentation rate for general project costs (development and operating costs) is the LTBR plus five (5) percentage points. This is a rate broadly equivalent to that applying to regulated utilities, noting that oil and gas projects are, by their very nature, high risk undertakings. In this context, a case could be made that the augmentation rate for general project costs should be higher than presently applies.

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There have been some suggestions (including as part of the proposed 2010 Resource Super Profits Tax) that the risk adjusted rate of return allowable on resource projects should be limited to the long term bond rate. This approach fundamentally misunderstands the principle underpinning the notion of a tax on super profits. The RSPT was based on the presumption the investment risk for projects would be shared by both the investor and government, including the repayment of a refund by the government for companies unable to recoup an investment in a project. As such an arrangement does not apply for PRRT purposes, the use of such an augmentation rate would fundamentally undermine the design of PRRT. Even if full refunds were available, such a low rate would still not reflect the risks inherent in petroleum exploration and development activities.

Transferability (Wider-Deductibility) of Exploration Expenditure

A key amendment to the PRRT was made from 1 July 1990 covering the treatment of exploration expenditures. In August 1990, 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."*
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> ++++++
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> *"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."*

Exploration expenditure incurred after 30 June 1990 is transferable to other petroleum projects held by a taxpayer or to other petroleum projects within any wholly-owned group of companies to which the taxpayer belongs. The expenditure must and can only be transferred where a series of conditions for transferability are fully satisfied.

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.

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. The most significant of these changes was a reduction in the carry forward rate for development and operating costs from LTBR plus 15 percentage points to LTBR plus 5 percentage points. 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.

Any restrictions to the present wider deductibility provisions would negatively impact on the overall exploration effort in Australia at a time of historically low levels of activity.

Determination of a Gas Transfer Price

Revenue for PRRT purposes is determined with reference to a marketable petroleum commodity (MPC). For most activities, this is the location where a sale takes place. 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 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 (for example, cost incurred post the taxing point are not deductible for PRRT purposes).

The Government announced the introduction of the so-called 'residual pricing methodology' (or 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 principle of allowing a return to both the upstream and downstream phases of an integrated petroleum project, with the residual amount (the return above a defined rate) being split between the upstream and downstream segments on a 50/50 basis.

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.

The calculation of the price under the RPM provides an equitable basis for determining the value of petroleum produced at the taxing point, recognising the inherent risks associated with the different elements of an integrated gas to liquids project and the close connection between the upstream and downstream phases of the project.

Application of PRRT to Gas Projects

Some observers have stated that that the regime was not intended to cover gas developments. This 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 from as early as the decision to extend the regime to cover the Bass Strait project in 1990, while a 1992 review into the operation of the tax indicated a clear intention for the regime to cover both oil and gas. There have been no suggestions in any consultations or discussions that took place between the industry and departmental officials during the development 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 PRRT 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 PRRT onshore from 1 July 2012.

ATO Taxpayer Data

Attention has been placed on the level of deductible expenditure accruing under the PRRT regime. Some of the public commentary has been ill-informed and fails to acknowledge the significant costs incurred by the industry, the impact of the fall in commodity prices and what the data actually measures.

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

Taxation Statistics – PRRT ($m)

	2010-11	**2012-13**	**2015-16**
PRRT returns (number)	71	155	148
Assessable Receipts	12,049	26,326	20,111
Class 2 General Expenditure	15,062	63,276	124,597
Class 2 Exploration Expenditure	1,648	5,550	17,121
Resource Tax Expenditure	Na	6,241	5,062
Acquired Exploration Expenditure	Na	8,388	15,213
Starting Base Expenditure	Na	65,878	91,447
Carry Forward Expenditure	9,362	127,987	237,867
Taxable Profits	2,618	3,203	2,114
PRRT Paid	1,047	1,281	845

Source: Australian Taxation Office

A simple explanation for the increase in deductions is the decision to extend the PRRT onshore and to the North West Shelf project from 1 July 2012. For the year 2015-16, nearly 40 per cent of the total carry forward expenditure relates to starting base expenditure. Starting bases amounts were explicitly provided to onshore projects and the North West Shelf to avoid significant retrospective impacts, including sovereign risk, on past investments.

Furthermore, 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 tax to apply to these projects. For example, a House of Representative report into the MRRT and PRRT Bills in 2011 noted that the following:

"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."*

In addition, it is realistic to expect that a significant percentage of general expenditure will also be directly related to these onshore projects. These expenditures are not transferable to other projects held by a taxpayer. Industry critics also often make reference to the large amounts of exploration expenditure. Again, this is not supported by the facts. As can be noted in the table, exploration expenditure accounts for a relatively small proportion of total deductible expenditure.

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 an integral design feature of the regime. In practice, PRRT will generally not be paid from a project until a number of years after the commencement of production. This will be longer for some projects compared with others.
- 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 deducted against PRRT income from the project (this is subject to the transferability rules). This is a design feature introduced in the 1990 amendments to improve economic efficiency by removing disincentives to explore in frontier areas.
- In connection with the above, the timing of when a PRRT liability will first be incurred within a project is likely to vary across joint venture participants in a particular project. This is due to the ability of individual participants to transfer exploration costs to or 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 fully rebatable against a PRRT liability from the same project. This is a design feature to avoid the imposition of double resource taxation of production from the same project.
- As PRRT is a profits based taxed, 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.

Suggestion of the Introduction of a New Offshore Petroleum Royalty

Some critics of the industry and the PRRT regime have advocated for the introduction of a royalty (which would apply in addition to PRRT). The PRRT is a super profits tax which is intended to encourage investment by allowing an investor a return on a project prior to the payment of tax – it takes into consideration prices and the vast majority of project costs. Petroleum royalties are effectively a hybrid between a cash flow tax and accounting profits based tax. Royalties have frequently been criticised as being an inefficient resource charging mechanism that can deter investment in marginally economic projects.

While the proponents of such a new cash flow tax have not provided detailed information on how such a new regime would be applied in practice, its introduction would effectively impose an additional cost on both existing and future offshore oil and gas investments in Australia.

Royalty regimes in Australia do not allow for the deduction of all costs (exploration and all pre-wellhead costs are not deductible), while many other costs are only deductible over extended periods of times. In practice, its main objective in the present petroleum taxation debate seems to bring forward the payment of tax at the expense of project profitability and future investment. This is the type of offshore resource taxation regime has been rejected by past federal governments, as it was considered to be inconsistent with encouraging the identification and development of the nation's offshore petroleum resources.

Preliminary analysis undertaken by APPEA of such a proposal has identified numerous technical, administrative and transitional issues that would need to be addressed for the more than 60 individual royalty agreements that would need to be negotiated for such a proposal to be implemented. Examples of the types of issues that would need to be addressed include:

- Breadth of coverage.
- How it would be applied to mature developments or projects already in production (including those already paying PRRT), including where records or information does not exist in a form consistent with established royalty regimes.
- The full suite of transitional provisions, including the treatment of past costs.
- The detailed form of the royalty calculation process, including deductibility percentages for capital equipment.
- Treatment of tolling and jointly used facilities.
- Interaction with the PRRT regime, including avoidance of double taxation.
- Revenue sharing arrangements with adjacent states/territories.
- Determining the administering agency.

Overall, the introduction of such a proposal would likely see some future projects either being delayed or abandoned and lead to an increase in the already significant compliance and administrative burden through a tax that is fundamentally different to both PRRT and company tax. It would also increase the uncertainty that confronts investors in the context of long term investments that take many years before positive returns are achieved.

Offshore Petroleum Royalty – North West Shelf

Background

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 areas. 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).

The North West Shelf (NWS) project was quarantined from the changes made to the offshore petroleum resource taxation regime in 1987 and 1990. While PRRT was applied to all other offshore projects (it was extended to cover the Bass Strait project with effect from 1 July 1990), the NWS continued to be covered by the Commonwealth royalty and production excise systems (PRRT was not applied to the project, while the royalty and excise provisions did not apply to other offshore projects). This decision was the result of a number of factors, including the significant level of funding associated with financing the project, the complexity in transitioning the project into the

PRRT system and the need to avoid a major retrospective changes to what represented one of Australia's major investment projects.

Under the 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. While the total level of Commonwealth royalty payments is not recorded as a separate line item in the Federal Budget, it is estimated that the project has made royalty payments in excess of $17 billion since the project first commenced in 1985.

APPEA notes that the North West Shelf Joint Venture made a submission to the Treasury petroleum taxation inquiry, a copy of which is available on the **Treasury website**.

Method of Calculation

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, 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, which is calculated on a volumetric basis. Unlike PRRT, royalty 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 is lower than the tax rate under the PRRT, with the royalty rate being set by the Joint Authority under the provisions of the legislation.

Australian National Audit Review

In 2016, the Australian National Audit Office (ANAO) completed a performance audit into the collection of North West Shelf petroleum royalties. The final report was presented to Parliament on 28 November 2016. The objective of the audit "… *was to assess whether the Department of Industry, Innovation and Science had effectively and efficiently administered the collection of NWS royalty revenue*".

The report made a number of findings dealing with the legal form and quantum of deductible expenditure (see attached). In one example, the report highlighted a technical deficiency with the existing royalty schedule in that is does not specifically reference excise paid on condensate production as being deductible expenditure. The ANAO acknowledges that this is despite there being a clear policy position that such costs should be deductible in the ascertainment of the wellhead value. A further example is cited that deals with the failure to incorporate a provision in a 2006 consolidation of the project royalty schedule dealing with deductions for the cost of debt and equity funded capital. In both cases, there was no suggestion that the costs were not deductible, but rather, it deals with the specific legal form of the royalty agreement.

The report highlighted a number of areas of administration and monitoring of the project operators control procedures. There was no suggestion in the report of any systemic concerns – rather, the ANAO focused on the procedures and processes implemented by the Department of Industry, Innovation and Science and the WA Department of Mines of Petroleum (DMP) to correctly calculate the wellhead value.

The response from DMP (dated 8 November 2016) was critical of the processes implemented by the ANAO in the conduct of the audit, including the failure of the ANAO to adequately engage with DMP to prepare and contribute towards the audit. DMP considered that there was insufficient evidence provided by the ANAO to support the critical conclusions contained in the report. APPEA notes that a copy of the response is available on the DMP website.

The experience of APPEA in dealings with federal and state government agencies across multiple jurisdictions in Australia is that DMP undertakes its royalty activities in a professional, comprehensive and consultative manner. It effectively balances the need for a detailed compliance program with an operational approach in determining royalty deductions in areas where considerable levels of judgement are required.

The media reporting that accompanied the release of the report was seemingly inconsistent with the findings and recommendations made by the ANAO. Headlines such as 'Gas giants reap tax bonanza', (The Age, 29 November 2016) were accompanied by comments such as "*A damning investigation has found multinational companies are claiming billions of dollars in questionable deductions while exploiting the nation's natural riches, an accounting trick allowed to flourish under a hands-off government approach that is dudding Australian taxpayers*." APPEA is not aware of the ANAO report making any comments or findings that could support such headlines or comments. Indeed the report has highlighted instances where the project participants had under-claimed deductions.

While APPEA is not in a position to comment on the processes in place between DIIS and DMP to provide conformation on the level of veracity of royalties paid by the NWS project participants, an implication of the ANAO report will be a possible increase in both the complexity and administrative costs for all parties in the operation of the regime. This is despite according to the DMP "the Department's processes are robust and comprehensive, and the Australian and Western Australian Governments can be confident that royalties are being accurately calculated and collected".

Concluding Comments

The oil and gas industry is an integral part of the Australian economy, including through the supply of energy to households and industry, the investment of hundreds of billions of dollars of capital (including during the global financial crisis), the payment of vast sums of taxes 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 further potential to capture more opportunities in growing global and domestic gas markets. Extending the operational lives of existing infrastructure (including liquefied nature gas plants) will be dependent on commercialising discovered and undiscovered gas resources

While the industry 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 tax burdens will damage the ability of Australia to attract projects and thereby diminish the capacity to create sustainable taxation revenue streams for future generations.

In terms of PRRT, it has operated in Australia since the mid 1980's and 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 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.

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. Overall, the PRRT is operating as originally intended.

Changes made to the tax since its introduction have been logical and have been mindful of the nation's broader 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.

Any increased tax burden (whether that be through modifying the terms of the PRRT or applying a new layer of taxation) will present hurdles to future investments in the industry. APPEA proposes that the Committee recommends the retention of the existing provisions.

Yours sincerely

[redacted]

Malcolm Roberts
Chief Executive

Enclosed: Australian National Audit Office NWS Royalty Audit: Summary and Recommendations

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Attachment

Extract from the Australian Audit Office Report into the NWS Royalty Administration: ANAO Report No.28, 2016-17

"Summary and recommendations

Background

1. Most natural resources in Australia are publicly owned. The Australian, state and territory governments collect royalties levied on petroleum extraction to ensure that the community receives a benefit from their development.
2. The Department of Industry, Innovation and Science (DIIS) is responsible for the collection of royalties levied on off-shore petroleum operations from the North West Shelf (NWS) project located in Australian Government regulated waters off the Western Australian coast. NWS petroleum products include: crude oil, condensate, natural gas, liquefied natural gas and liquefied petroleum gas (both propane and butane).
3. Revenue reported by producers from NWS petroleum sales between July 2014 and December 2015 was $19.7 billion. From this, $1.9 billion in royalties was collected. The Australian Government retained $0.6 billion (32.3 per cent) and the remaining $1.3 billion (67.7 per cent) was paid to Western Australia.

Audit objective and criteria

4. The audit objective was to assess whether the Department of Industry, Innovation and Science had effectively and efficiently administered the collection of NWS royalty revenue.
5. To form a conclusion against the audit objective, the ANAO assessed whether:
   - the royalty collection framework, including the agreed administrative arrangements between the Australian Government and Western Australia, enabled efficient and effective administration;
   - an adequate framework was in place for accurately calculating NWS petroleum production and sales; and
   - the amounts subtracted from sales receipts to calculate the amounts of royalty payable were likely to be accurate and valid.

Conclusion

6. The administration of the collection of NWS petroleum royalties by DIIS has not been sufficiently efficient or effective as the existing assurance arrangements do not effectively address key risks to the accurate calculation of royalty payable.
7. NWS royalties are a considerable revenue source each year for both the Australian and Western Australian governments. But there is no formal agreement outlining the day-to-day roles and responsibilities of the respective departments involved in the collection of NWS royalty revenue. The DIIS also does not have a comprehensive procedure manual in place.

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8. There are some significant shortcomings in the framework for calculating NWS royalties. The consolidated Royalty Schedule, which governs those calculations, has not been updated in the last 10 years. In addition, the testing of the meters that are relied upon to identify production and allocate it to the appropriate field for royalty calculation purposes has not been sufficiently comprehensive or frequent.

9. The amount of royalty paid is reduced by producers being permitted to claim significant deductions in areas such as operating costs and the depreciation of capital assets.1 There has been limited scrutiny of the claimed deductions. Some errors in the claiming of deductions have been identified, but the available evidence indicates that the problems are much greater than has yet been quantified.

Supporting findings

Administrative arrangements

10. The division of roles and responsibilities between DIIS, on behalf of the Australian Government, and the Western Australian Department of Mines and Petroleum (DMP) has not been adequately set out. In particular, DIIS has not set out the level of assurance it requires for royalty collections or agreed with DMP the specific administrative arrangements that would support a conclusion that the correct amount of royalty is being collected.

Calculating petroleum production and sales

11. The royalty calculation has not been adequately defined and kept up to date.2 An external review prepared for DMP in October 2015 highlighted insufficient detail in the Schedule about deductible expenditure, leading to incorrect claiming.3

12. At the start of this ANAO performance audit there were gaps in records relating to the titles on which royalties should be charged, and the relevant royalty rate. DIIS and DMP have addressed this situation. As a result, DIIS has now developed a good understanding of the titles on which royalties should be charged, and the royalty rates that are to be charged.

13. The current administrative arrangements provide insufficient assurance that production is being fully identified and accurately allocated to fields for royalty calculation purposes. The key shortcoming relates to testing of metering. There is sporadic testing by DMP of metering on-shore; no equivalent meter testing off-shore; and there is limited testing of the NWS operator’s production accounting system.

Costs deducted from the gross well-head value

14. More than $5 billion worth of deductions were claimed against petroleum revenues in the 18 months to December 2015. These deductions were claimed under the broad categories of: operating costs; depreciation; cost of capital; depreciated asset disposal; crude oil excise; condensate excise; processing tariffs and joint venture participant costs.

15. Any costs that are claimed as deductions by NWS producers reduce the royalty amount that is payable. DIIS relies on DMP’s compliance work and does not undertake any further activities to gain assurance that only eligible deductions have been claimed. DIIS has not agreed with DMP the deductions data that DMP should obtain and the information obtained is not sufficiently detailed to be adequately assured that only valid deductions are being claimed.

16. The Royalty Schedule does not permit all the deductions currently being claimed. On this basis, the ANAO has doubts about the eligibility of deductions claimed for the cost of debt and equity funded capital, excise paid on crude oil and excise paid on condensate.
17. There has not been adequate scrutiny of claimed deductions. Of note:
- it has been 17 years since there has been an audit of the NWS operator's control procedures for royalty calculations;
- there have been recent annual reviews by DMP of cost deductions, but this work has involved quite limited testing and there has been no major, comprehensive examination since 2006. The limited work that has been undertaken has, nevertheless, highlighted potential problem areas. But little action has been taken in response to those findings; and
- more recently, the Western Australian Government commissioned consultants to undertake some data analytic procedures on capital and operating expenditure items claimed by NWS producers. That work, although quite limited in scope, has provided some valuable insights. The report's findings indicate that there is a risk of significant errors in the claiming of deductions. To date, there has been agreement that a net amount of $8.6 million in royalties has been underpaid requiring adjustments, but many matters identified by the consultants have not yet been addressed, and a comprehensive review of claimed deductions has not been commissioned, such that the full extent of any errors in the calculation and payment of royalties has not been quantified.

Recommendations

Recommendation No.1

Paragraph 2.26

The Department of Industry, Innovation and Science improve governance over the administration of the royalty calculation and collection function by:

a. implementing an appropriate accountability framework with the Western Australian Department of Mines and Petroleum that clearly sets out the roles and responsibilities of each party; and
b. developing a procedure manual that covers all aspects of its responsibilities in relation to the collection of North West Shelf royalties. This should include identifying the activities undertaken by the Western Australian Government that the department relies upon, and the compliance and reporting procedures that are to be employed to oversee and be assured about the conduct of those activities.

Department of Industry, Innovation and Science's response: *Agreed*.

Recommendation No.2

Paragraph 3.15

The Department of Industry, Innovation and Science, through the Joint Authority, set a timeline and regularly review progress against this timeline so as to expedite changes to the Royalty Schedule aimed at updating and improving the clarity of descriptions relating to deductible expenditure, and incorporating expenditure relating to new fields.

Department of Industry, Innovation and Science's response: Agreed.

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Recommendation No.3

Paragraph 3.41

The Department of Industry, Innovation and Science work with the Western Australian Department of Mines and Petroleum to implement improved controls for the verification of North West Shelf petroleum production and sales to provide increased assurance that the approach taken when allocating production to fields is complete and accurate.

Department of Industry, Innovation and Science's response: Agreed.

Recommendation No.4.

Paragraph 4.33

The Department of Industry, Innovation and Science work with the Western Australian Department of Mines and Petroleum to:

c. verify the validity of deductions claimed prior to 2014; and
d. develop and implement a comprehensive strategy for gaining a reasonable level of assurance that deductions claimed by the North West Shelf producers in 2015 and later years are valid and calculated in accordance with the Royalty Schedule.

Department of Industry, Innovation and Science's response: Agreed.

Summary of entity responses

18. The proposed audit report issued under section 19 of the Auditor-General Act 1997 was provided to the Department of Industry, Innovation and Science and was also provided to the Western Australian Department of Mines and Petroleum. The Department of Industry, Innovation and Science and the Western Australian Department of Mines and Petroleum summary responses are provided below, while their full responses are provided at Appendix 1.

Department of Industry, Innovation and Science

The department welcomes the audit by the ANAO and acknowledges the areas for improvement identified in the Proposed Report. The department agrees the accountability and assurance frameworks over the administration of collection of North West Shelf (NWS) petroleum royalties can be improved, in particular to ensure they are appropriately documented and that the operational responsibilities of the Australian and Western Australian Governments are clearly articulated. This is reflected in the department's agreement with all four recommendations of the audit report.

The department believes the current processes over royalty collection are robust and provide for the accurate, efficient and comprehensive collection of NWS royalty payments. The department will confirm their reliability in partnership with the Western Australia Government and the NWS joint venture participants in actioning the report's recommendations.

Western Australian Department of Mines and Petroleum

The Department of Mines and Petroleum's (DMP's) North West Shelf royalty revenue verification processes are robust and adequate, and the Commonwealth and State Governments can be confident that royalties are being accurately assessed and collected.

The DMP looks forward to working with the Department of Industry, Innovation and Science (DNS) to implement its responses to the ANAO audit.

DMP notes that the ANAO was auditing DIIS, and not DMP, and therefore does not accept or support many of the comments in the report relating to DMP's processes."