Tax Justice Network – Australia
Submission to Treasury
In response to
Consultation Paper from 30 June 2017
"Options to address the design issues identified in the Petroleum Resource Rent Tax Review"

The Tax Justice Network – Australia (referred to here after as TJN) appreciates the quality of the analysis in the Callaghan Review of the Petroleum Rent Resource Tax (PRRT) but strongly rejects the notion that obviously need changes to the PRRT regime should not be applied to existing projects. The Callaghan Review clearly prioritised the interests of largely foreign multinational oil companies over ensuring that Australians receive a fair return for the exploitation of their finite natural resources. No credible evidence was provided that fair and modest proposed changes to the PRRT regime would significantly harm the long term returns of existing projects or deter future investment.

The massive wave of new investment in Australia's offshore gas resources has largely come and gone. In refusing to make changes now as these projects enter production, the Australian government is acknowledging and accepting that there will very likely be no direct economic return from the five new offshore LNG projects for several decades, if ever. Future investment is likely to expand into adjacent gas fields to maximise the returns, and extend the productive life, of existing investments. These investments will not be deterred by fair and reasonable changes to the PRRT regime. Given current market conditions, low oil prices and a global glut of LNG, it is not in the interests of investors or the Australian people to overly incentivise further gas production in the near term. While there is a need to ensure domestic gas supply as Australian becomes the world's largest exporter of LNG, that is not a subject of this review.

Concerns of sovereign risk have been trumped by the industry, and now repeated by government, to preserve a fiscal regime for offshore gas that is incredibly generous by global standards. The PRRT has been changed at least 9 times already, each time to the benefit of the industry, and no concerns of sovereign risk were raised before. The inaction to fix a clearly broken system will deprive Australians of not only a fair share of revenue, but very likely any revenue whatsoever.

In a complete contradiction, the government's proposal to introduce a levy on the largest domestic banks, who already pay significantly more corporate tax, did not raise any concerns of sovereign risk. Rather than make policy changes to fix a tax regime which is clearly broken and in a sector that is dominated by foreign multinationals with a proven record of corporate tax avoidance, the government choose to make a populist ploy by whacking banks.

TJN supports a bank levy that does not create a competitive disadvantage for domestic banks, but strongly believes that foreign multinationals should not be getting our gas for free. The revenue from the bank levy is modest in comparison to the potential and promised revenues from the booming offshore LNG industry, which is 87 per cent foreign owned.

In contrast to the Australian banks, which are deeply connected to the economy through employment, financial services, shareholdings, etc., the Reserve Bank of Australia has stated that the economic benefit to Australia of the LNG boom will be limited due to the high levels of foreign ownership, low levels of employment once production starts, and the massive amount of tax deductions and credits.[1]

At today's oil prices, or at any price below $60/ barrel, the Callaghan review confirms that no PRRT payments are likely to ever be made over the entire 40-year project life from any of the five new offshore LNG projects that are catapulting Australia to be the world's largest exporter. As the pace of renewable energy production continues to surpass expectations, there is an increasing possibility that oil prices will remain low indefinitely. It is increasingly recognized that the global demand for gas -and therefore price- is also being curtailed as well. Bloomberg reporters recently wrote that "with the cost of renewable technologies falling sharply, some are warning that the outlook [for gas] may not be so rosy."[2]

The expected profits -due to the decline in global oil prices and increasing global LNG supply- are far below what was anticipated when investment decisions were made. Government approvals were granted based on promises of huge revenues. While the expectation of government revenues has disappeared, these projects will still generate significant profits after recouping investment costs. TJN estimates that the value of production from these 5 projects at $60/barrel is $33 billion per year. Other estimates of projected revenue from these projects are significantly higher.

This means:

- ***$33 billion in sales per year for 40 years for which the Australian people may not receive any direct payment.***
- ***$1.3 trillion in revenue for the world's largest oil companies and no direct payment to the Australian people.***

This cannot be considered a fair return!

As stated above, TJN rejects the notion in the Callaghan Review, and discussed in the Consultation Paper, that the majority of PRRT reform recommendations should only be applied to new projects. However, if this is to be the case then -as suggested in the Consultation Paper and consistent with the PRRT legislation- a project must be considered new when a production licence comes into force. As suggested in Option 2, the new PRRT regime should apply when existing projects are combined with new projects or significantly changed based on new production licenses. However, having two sets of PRRT regulations for new and old projects will only add additional complications, uncertainties and further reduce transparency. The far better option is to make reasonable and modest PRRT changes for all existing and new projects, with some consideration and allowances for any unintended consequences. Two sets of regulations will further distort the market and provide unfair advantages to existing projects and corporations that have accrued vast numbers of PRRT credits.

TJN Recommendations

TJN believes there are four simple and fair measures that should be accepted by the industry to restore integrity and public confidence to the tax regime for offshore gas. If these measures are not introduced it will create uncertainty about possible, more comprehensive changes, in the future. Even with these changes applying to existing and new projects Australia's fiscal regime for oil and gas production will continue to be one of the world's most favourable.[3]

1. Level the playing field and guarantee minimum payment for resources

The distinct possibility that Australia, as it becomes the world's largest exporter of LNG, may never collect any direct payments from its natural resources was never intended by government, has been obfuscated by industry and now needs to be urgently addressed in a fair and reasonable manner.

To guarantee that Australians receive some benefit, a minimum price, for our resources a 10% royalty needs to apply to offshore gas that is currently only covered by PRRT. The royalty is necessary given the possibility of oil prices remaining below $60 per barrel and the PRRT failing to collect any revenue ever. The royalty would level the playing field for all oil and gas projects, such as the North West Shelf and the Queensland CSG to LNG, that already pay a 10% royalty. Given the predominance of foreign multinationals in new offshore gas projects and their large and growing volume of PRRT credits, the current system puts smaller domestic companies at a significant competitive disadvantage.

Modelling by the McKell Institute suggests annual revenues of $2.8 billion for a 10% royalty on the five offshore LNG projects. It is crucial to note that a ***royalty does not fundamentally change the economics, or projected returns to the companies, over the long timeframes of these projects***. The royalty merely guarantees that some modest revenue is collected and brings payments forward. Even the modelling commissioned by APPEA of the impact a 10% royalty showed modest impacts on the internal rate of return for the projects. It is also worth noting that the ***royalty proposal would level the playing field across the sector and not have any impact on the majority of existing oil and gas projects and/or corporations that are already paying other forms of royalties or already making significant PRRT payments.***

The decrease in the global price of oil has been the key driver in lowering expecting returns from these offshore gas projects and partially responsible for undermining the functionality of the PRRT to capture any revenue. However, even with lower oil prices, these projects will generate significant returns for the shareholders of these companies over the life of the projects. Despite statements to the Australian government and the general public, Chevron continues to highlight the Gorgon and Wheatstone projects as key future drivers of global profitability.

The modelling of the 10% royalty by the Callaghan Review suggested that it may collect less revenue over the life of the projects than the PRRT in its current form. If that is the case, ***why is this proposal not embraced by the industry as being the most beneficial outcome for the long-term interests of shareholders?***

This estimate is dependent on higher oil prices but also because royalty payments are currently deductible from PRRT and given an uplift of the Long Term Bond Rate (LTBR) +5% which compounds annually. ***Royalty payments should be deductible from PRRT, but not given any uplift.*** As noted in the Callaghan Review and the Consultation Paper, uplifts of the LTBR +5% double after nine years of compounding and uplifts of LTBR +15% double every four years.

2. Gas Transfer Pricing Mechanism

As discussed in the Consultation Paper and the Callaghan Review, the method to measure the value at which the PRRT applies, the gas transfer price mechanism, needs to be simplified and made more transparent. This is an opportunity for the government to cut red tape by altering the regulation, consistent with the principles they were designed around, to apply to all existing and future LNG projects. The PRRT regulations currently allow for multiple methods to determine the value of gas to which the PRRT is applied. There is ample opportunity for transfer pricing to reduce tax payments. Many of the companies involved in LNG projects have a long and documented history of transfer pricing in relation to corporate income tax payments.

The PRRT Review modelled the difference between using the current default method of determining value, the Residual Price Mechanism, and the net-back method. By making the net-back method the standard for determining value there could be an extra $89 billion in PRRT revenue. ***The net-back method should be adopted as the default method for pricing gas on all integrated LNG projects.*** This is suggested in Option 2 in the Consultation Paper, but only applying to new projects. Regulatory changes are needed to simplify and update the way the value of gas is determined. The rationale for this reasonable, common-sense reform are described in greater detail below.

The Consultation Paper also has an Option 3 of moving the taxing point to the end of LNG production. This is an option that should be considered further, but would be complicated in terms of the interaction with other components of the PRRT regime.

3. Simplify and Reform Uplift Rates

Consistent with the discussion in the Callaghan Review and the Consultation Paper, overly generous uplift rates must be scaled back. However, these reforms must be applied to existing and future credits moving forward. The current value of existing PRRT credits would not be changed retrospectively.

The consequences of compounding uplift rates on the existing PRRT credits, and those that have been generated but are yet to enter the system, will continue to provide a massive tax shelter for the corporations that have accrued them. This was not the intent and should have never been allowed. As acknowledged in the Callaghan Review, the PRRT was designed to stimulate oil exploration and has not been sufficiently changes to suit the current boom in offshore LNG production which has significantly higher upfront capital costs, longer start-up periods and longer-term production.

Companies are not required submit PRRT filings to the ATO until after production starts. This means that on top of the $238 billion in PRRT credits that have been reported by the ATO, there are potentially hundreds of billions in additional exploration credits that have yet to reported. ***TJN strongly supports the recommendation in the Consultation Report to require all PRRT taxpayers to lodge annual returns after they start holding an interest in an exploration permit, retention lease or production lease.***

Exploration expenditure should be reduced to uplifts of LTBR +5% and general expenditure reduced to merely the LTBR. This is considered as Option 1 in the Consultation Paper, but only applying to new projects. As mentioned above, ***royalty payments should remain 100% deductable from PRRT but with no uplift***. The Consultation Paper suggests that the “uplift factor for resource tax expenditure could be reduced to the LTBR” and the “Commonwealth should not be providing an uplift rate for resource tax expenditure credits higher than its cost of borrowing.”

If the uplift rates are not reduced than it is paramount that the PRRT must be returned to the initial design intent which the Consultation Paper confirms was to have the "expenditure attracting the higher uplift rates deducted first." There must be a requirement that existing credits with uplifts of the LTBR +15% be used first. In this context, the proposed dual principal for the order of deductions is appropriate in acknowledging the impact of high uplifts and transferability. The Consultation Paper acknowledges that uplifted expenditures could grow "so large that it effectively shields profitable projects from tax."

The existing interaction between high uplifts and transferability create unintended consequences which potentially result in unfair competition and barriers to entry for new market participants.

The proposed reforms to uplift rates are reasonable and common-sense reforms. No other industry is entitled to uplifts like these. The overly generous uplifts are likely to distort investment decisions and how they are used cannot be forecast by governments. If the uplifts are not reduced on all PRRT credits than it is imperative that changes are made to require that PRRT credits with the highest uplifts are required to be used first, as originally intended.

4. Mandatory public disclosure

There must be requirements for mandatory public disclosure of production levels by project and estimates of known reserves. Some of this data is available from various sources, particularly disclosure by listed companies. However, this data is not easily accessible or comparable. This reform is in line with emerging globally standards for transparency in the resource sector. Australia is far behind in this area and its ability to join the global Extractive Industries Transparency Initiative (EITI) process is jeopardised by the lack of existing public disclosure.

These resources belong to the Australian people and the public right to know what is being extracted should outweigh any concerns of corporate privacy or commercial confidence. It is impossible for governments to make informed public policy decisions without having public, accessible, comparable and verifiable information about resource production levels and estimated reserves.

A key flaw of the Callaghan Review was the lack of reliable data. The data that was used was obtained from Wood MacKenzie because the government itself does not have data. There are obvious biases of Wood MacKenzie as a contractor for APPEA and many companies in the industry. Additionally, and more problematic, is that Treasury allowed the companies to manipulate the Wood McKenzie data - inconsistent with Wood MacKenzie's own analysis- in a way that suggested companies would utilise the transfer of credits to make higher PRRT payments. The notion that multinational oil companies will voluntarily structure their tax credits to make more tax payments and not less is not believable and potentially in violation of their obligations to shareholders. It is hard to understand why Treasury would accept this notion.

Currently, the level of disclosure and public information on the resource sector in Australia is not only far behind most OECD countries, but behind many resource rich countries in the developing world as well. Australia needs to have better disclosure and transparency for domestic policy concerns, but also to set a positive example for other resource countries rather than lowering global standards.

It is likely that many Australian-based companies would support requirements for mandatory disclosure. The largest Australian-based resource companies have been global leaders in voluntary reporting of payments to governments. Those payments to government reports are now mandatory in Canada, the United Kingdom and the European Union. It is worth noting that BHP Billiton, advocated for enhanced disclosure for resource companies (Dodd-Frank Rule 1504) in the United States, which was vehemently opposed by Chevron, Exxon and the American Petroleum Institute.

Transfer pricing in Integrated LNG projects: Why the Netback approach should be adopted

The PRRT is intended to collect a share of the windfall profits resulting from the extraction of oil and gas. It does not apply to the profits resulting from the transformation of these natural resources into "manufactured" products including LNG.

The transformation of the Australian petroleum industry into one dominated by integrated LNG projects means that a robust, trusted methodology for allocating profits between upstream and downstream segments is critical to the integrity of the PRRT and its ability to raise revenues from the sale of Australia's commonly-owned natural resources.

Existing PRRT regulations frame this as a problem of transfer pricing. In this model, the upstream business "sells" the project sales gas to the downstream business at a price that at a minimum covers the costs of production; and at a maximum is the highest the "market" for such wholesale, unprocessed gas can bear, in order to capture the greatest profits possible. In the case of an integrated LNG project, the price of project sales gas is set internally to the LNG project operator. The "sale" between upstream and downstream components is never at arm's length, and does not necessarily reflect market forces. There is a hierarchy of methodologies set out in the PRRT regulations to determine assessable receipts in this case.

- The first option is for the taxpayer to make an advance pricing arrangement (APA) with the ATO.
- The second – and intended 'default' – method is to apply a comparable uncontrolled price (CUP) to the relevant volume of project sales gas.
- Where there is no APA and no CUP can be established, then a price is determined using the residual pricing method (RPM).[4]

The Callaghan Review argues that although the default method was intended to be the CUP, under the status quo it has become the Residual Price Method (RPM). Some taxpayers may have an Advance Pricing Arrangement with the ATO.

The RPM is derived using both Net Back and Cost Plus methods, dividing the difference by two.[5] This is a fairly unique feature of the Australian system. Individually, the two methods are widely used internationally in relation to petroleum and other transfer pricing issues; but it is unusual for the price of sales gas to be based on a 50-50 split between the results of the two methods.[6] The "netback" value represents the costs of the upstream component, the "cost plus" values the costs of the downstream component, and the difference between them the "residual profit element". Under this method, residual profits are assumed to be split evenly between upstream and downstream.

Cost to taxpayers is at least $89 billion to 2050 or approximately $3 billion annually

Modelling for the Callaghan Review found that by using the Net Back method alone – instead of the RPM as is currently used – the Government would raise around $89 billion more in PRRT revenue between 2023 and 2050. Projects that already pay PRRT would pay more, sooner; projects that otherwise would never pay PRRT would start paying PRRT.[7]

Review's proposal is to wait for a CUP

The Callaghan Review argues that the existing method of 50-50 profit-splitting between upstream and downstream components of integrated LNG projects fails to satisfy the six principles for establishing the gas transfer price that were agreed between industry and government in the late 1990s. The evidence in the Review that the use of the RPM results in a loss of government revenue of around $89 billion compared to the netback only methodology supports the Review's finding that "there is not a consensus on whether the GTP regulations are delivering a transfer price that is transparent, equitable, auditable and simple to administer [one of the six principles]."[8] Moreover, the Review argues that the 50:50 split of profits "results in outcomes that are inconsistent with the intent of properly capturing the upstream rents within the PRRT ring fence." (p94)

The Review concludes that "the established principles may need to be revised so that a method for valuing sales gas can be identified that balances the need for certainty in investment with a fair return to the community." (p93).

The Review argues that the preferred approach to arm's length pricing would be to establish an industry wide Comparable Uncontrolled Price, in line with OECD recommendations on transfer pricing, replacing the RPM as default methodology. However, the Review itself notes the difficulty of establishing a CUP (p90).

OECD member countries' agreement on transfer pricing is founded on the arm's length principle. The OECD Transfer Pricing Guidelines state that the CUP method is one of the "most direct" ways to establish arm's length conditions, by "directly substituting the price in the comparable uncontrolled transaction for the price on the controlled transaction." The CUP is the preferred transfer pricing method, if there is a choice between the CUP and an alternative that can be applied in an equally reliable manner.[9]

However, the OECD recognises that comparable data can be very difficult, even impossible, to obtain. In these cases, alternative methodologies are needed. In January 2017, the Platform for Collaboration on Tax – a collaboration between the IMF, the OECD, the UN and the World Bank Group – issued a draft "toolkit for addressing difficulties in accessing comparables data for transfer pricing analyses".[10]

The Platform for Collaboration on Tax states that "application of the arm's length principle is heavily reliant in practice on external comparables" (i.e. a transaction that looks like the "controlled" one we are interested in, but between two independent companies – and not those involved in the controlled transaction) (p22). Typically, this data is sourced from commercial databases, including specialised databases and publications that publish information on market conditions and prices, trading terms and industry developments for commodities. The availability of information in individual transactions varies significantly between markets; and publishers adjust raw trade data in a variety of ways (pp24-25).

According to the 2013 UN Practical Manual on Transfer Pricing, "it is often in practice extremely difficult, especially in some developing countries, to obtain adequate information to apply the arm's length principle."[11] According to the Platform for Collaboration on Tax, "it is only rarely that data is available to provide a well-defined measure of the arm's length price or result."[12]

A lack of data can be addressed by strengthening requirements for companies to publish their financial accounts; using other data; using safe harbours or other prescriptive rules; using the transactional profit split method; using anti-avoidance measures.[13]

CUP doesn't exist

The relevant data for a CUP methodology for calculating PRRT payable by LNG projects is the price of sales gas. Australia's gas is increasingly produced for export in the form of LNG instead of domestic consumption, with Australia set to become the world's largest LNG producer. The majority of LNG will be sold under long-term contracts with consumers in Japan, followed by other Asian countries.

An ATO ruling found that for offshore LNG projects, it is very difficult to identify a comparable uncontrolled price. Adjustment is needed if there are material differences between product, contract terms and economic/market conditions (ATO Taxation Ruling TR 97/20 paragraph 3.14, cited in Callaghan Review p138).

The Callaghan Review considered the possibility that a CUP be established based on Australian domestic gas prices. The Review says that there is evidence of a "link between the price of gas in the domestic market and the price of sales gas being used for export on the East Coast", suggesting that it may be possible to establish a CUP for operations in the East Coast gas market. However, the Review stops short of explicitly recommending that this be done. The difficulty establishing a CUP is still greater in the case of the LNG projects in North West Australia. Here, sales gas prices are either not observable at all, in the case of projects that do not sell to the domestic market; or are not comparable, due to the impact on prices of WA's domestic gas reservation policy (p90).

Australian wholesale gas markets

There are two key, not physically interconnected markets – east and west coast. Most sales are in the context of gas supply agreements between wholesale suppliers and buyers which specify the sales price over an agreed term. There is little transparency as there is no managed market place or exchange; instead the market is "contractually driven" with "contractual confidentiality … a cornerstone of the market". However, there are some gas spot markets (Short Term Trading Markets) and other exceptions.[14]

In some cases, LNG producers had a surplus of gas produced before the commissioning of the LNG plants, and sold instead into the domestic market, both in Queensland and in WA. The result was a fall in domestic gas prices.[15] In Queensland, "rapid and massive increase in gas demand" from LNG projects has created a scarcity of supply and increased domestic gas prices substantially. As most LNG exported from Queensland will be sold on an oil linked basis, east coast gas supply agreements have also been increasingly linked to oil prices, with producers "seeking LNG netback pricing" (LNG export prices minus the costs of transportation and liquefaction).

This has been particularly important in Queensland but had an effect across the east coast. Prices in the south-east have "lagged those in Queensland and prices have been mitigated by distances and underlying contractual positions of retailers and large industrial customers and greater competition for customers … Victoria is best served in terms of price mitigation as the available supply is very close to the market but it is also starting to experience rising prices as Sydney sets the clearing prices for Bass Strait gas sales [because NSW relies on gas from out of state]".[16] However, since international oil (and LNG) prices have fallen, gas supply negotiations are instead more likely to revolve around "cost of new supply" arguments.[17] The use of unconventional gas sources means that new gas is likely to be relatively expensive.[18]

An alternative would be to consider the price of gas internationally. It is common to rely on data from other markets, but there is no guidance about when this is appropriate.[19] There is no widely accepted method for making adjustments to eliminate differences in country conditions (whether economic or otherwise).[20] The price of gas still varies significantly by region. The two most important spot prices for natural gas are the Henry Hub (a physical trading location and gas futures market in the US) and the National Balancing Point (a virtual trading and gas futures market in the UK). There have been periods of significant divergence between the two, and movements aren't necessarily correlated with each other.[21]

There is also no transparent wholesale gas market at the point of consumption of the majority of Australia's LNG in Japan. The Japanese government has indicated an interest in establishing a more transparent wholesale gas market, but has not yet taken the necessary actions such as liberalising access to pipelines and other infrastructure. The price of LNG imports to Japan is currently set in long-term contracts that cover the vast majority of expected supply to at least 2025. The majority of these contracts link prices to the oil price via the JCC ("Japanese customs-cleared crude oil") price, although from about 2018 imports from the US will be linked to the Henry Hub gas price. Research suggests that there is unlikely to be a suitably liquid Asian gas "hub" for use as a price index for years or decades. Even if a sales gas price could be identified, substantial adjustments would be required to transform this price into a CUP.[22]

Waiting for a CUP a weak response

Despite these problems, the Callaghan Review concludes that "it would be appropriate to continue to pursue the option of establishing a shadow price or CUP across the LNG projects and align the approach to establishing a CUP to the latest OECD recommendations and approaches on transfer pricing." (p90)

There are certain types of transactions that are better suited to the CUP method. Two typical scenarios for its use are where an internal comparable is available; or "for commodities, particularly those with deep, liquid markets, which tend to equalise price differentials based on the circumstances". Even in this latter case, "adjustments may be necessary".[23]

In fact, research shows the use of comparable uncontrolled prices for transfer pricing purposes in commodity transactions is difficult as "wholesale hydrocarbon distribution margins are thin and difficult to find comparables for". There can be large transfer pricing adjustments as a result, depending on the method used. Tax authorities have in some cases ignored the CUP based on indices such as NYMEX prices and instead use a "broad set of wholesale distributors of all sorts of products" to establish a benchmark; or they have rejected the various adjustments to the CUP that the taxpayer has used to try and increase comparability, adjusting for shipping, location, quality, volume, etc.[24]

While some argue that the CUP be the preferred method, "projects in Norway, Australia and other key LNG exporters have had very limited success when trying to apply to CUP method." The hierarchy in Canada is CUP, the netback or cost-plus.[25] If using the latter options, the acceptable rate of return to be used in calculations must be prescribed (to maintain public confidence in the calculation). Australia does this for midstream investments within the RPM framework by adding a constant 7% premium to the LTBR yield.[26]

The PRRT's RPM is an example of a "transactional profit split method". This is considered to be potentially more appropriate than a CUP in situations including cases where parties are highly integrated; and cases where "both make unique and valuable contributions".[27] According to the Platform for Collaboration on Tax, the division of profits between the parties should be determined with reference to the split that would be expected if the parties were unrelated. They warn that ***"the selection of a profit split method purely on***

the basis of a lack of data … risks leading to a significant departure from the arm's length outcome." (p60). In this method, the profits should be split "on an economically valid basis" (OECD Transfer Pricing Guidelines 2010 p93). In particular, the profit split should reflect the allocation of risks among the parties (p95).

Recommended 'best practice': don't let perfect be the enemy of the good

The Platform for Collaboration on Tax argues that "there is no hierarchy in the selection of transfer pricing methods."[28] Instead, the emphasis is placed on the selection of a method that applies the arm's length principle "in a workable and efficient way". The January 2017 discussion paper argues that further work must be done to facilitate this process, especially in the natural resources and other commodities sectors. They propose the development of a framework for adjustments such as those based on **netback approaches** (p68).

The Australian Government should be prepared to regularly review its transfer pricing methodology as this international work proceeds; and to keep up to date with changing conditions in the Australian petroleum industry. ***The principles and methodologies determined in the 1990s pre-date the massive LNG developments that now dominate the industry. The application of the arm's length principle requires that these methodologies be regularly revisited to ensure that the basis for the application of the PRRT continues to be appropriate given contemporary market conditions.***

The modelling presented in the Callaghan Review shows that there is no reason to believe that the RPM's 50-50 profit split genuinely reflects an economically valid allocation of risks between upstream and downstream business units. The Government should continue to monitor international developments and pursue the development of a CUP. In doing this, it should consider ways to increase transparency, for example drawing lessons from Norway's Petroleum Price Council.

Norway's Petroleum Price Council

> A model for the implementation of a transfer price methodology that meets the principle that it be "transparent, equitable, auditable and simple to administer" is the Norwegian Petroleum Price Board. This is a government institution that meets quarterly to set "norm prices", the reference prices for taxation purposes. These are published online and can be appealed by the companies, a privilege which should be extended to civil society.[29]
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> The "norm price" approach in Norway resembles a CUP but is more accurately an example of what the OECD refers to as "the sixth method", meaning that quoted prices from commodities markets are used to determine the price.[30] In Norway, information provided by companies is also used. The advantage of these approaches is in their simplicity and the greater certainty provided. These factors are often important for governments in relation to industries "which are very significant to the economy, which may be complex, and for which necessary information may be scarce."[31] Effective implementation may require a simplified approach to comparability adjustments.[32]

In the meantime, the Government should revert to the netback only approach. This would help ensure that Australians receive a fairer share of the profits from the extraction of commonly owned natural resources. Companies should be required to disclose (to government) actual LNG sales prices, which can form the basis of the netback value. If this disclosure is not already in place, it could be implemented as part of the Government's proposed Australian Domestic Gas Security Mechanism.

Netback only

A netback approach is used "where there is a known arm's length or market price downstream of the relevant valuation point". This downstream price is adjusted by identifying relevant costs between the valuation point and the market pricing point, including an allowance for capital expenditure. The adjustment is more complicated if the downstream price is for a product with different physical characteristics, such as being more or less processed.[33]

The Callaghan Review argues that netback only "would mean that project risks are no longer equitably reflected on all costs centres [one of the principles set out when the RPM was developed in the late 1990s] … any rents attributable to the downstream would be captured in the upstream and subject to PRRT." (p92) Note that these principles were developed before the existence of integrated LNG projects, and "it is timely to consider whether they are still fit for purpose." (p93). None of the options canvassed by the Review (including status quo) meet all the principles.

The Government's proposed Australian Domestic Gas Security Mechanism may be an opportunity for the Government to collect sufficient information from participants in the domestic gas industry as well as LNG exporters to enable it to establish an industry-wide CUP – or at least to reduce the estimation required in applying the netback approach. According to the proposed "stepped process" for determining whether a domestic shortfall is likely, the Minister will make this decision based on advice from AEMO, information from the ACCC, sales gas forecasts from gas producers, production forecasts from major industrial consumers, and others.[34]

Conclusion

In conclusion, these are simple, reasonable, common sense reform proposals that will not have any impact on future investment decisions. The unsubstantiated threats of "sovereign risk" from companies who reap unparalleled benefits from the existing system need to be critically analysed in context. If these reforms are not enacted, it will further undermine public confidence in the integrity of the PRRT system. Ultimately, it would be far better for the industry to accept these modest reforms now and secure a stable fiscal regime for the oil and gas industry into the future. Without sufficient change the demands for reform from the public will only continue and increase the risk of more substantial changes in the future. We hope that this government -or future governments- will take responsible measures to protect the interests of the Australian people.

It is politically untenable that Australia's vast offshore gas resources are being given away for free to the world's largest multinational oil companies while structural budget deficits continue to grow and domestic gas price increases are severely impacting industry and consumers. The current policy frameworks are badly broken on all sides and in urgent need of meaningful common-sense reform.

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Background on the Tax Justice Network Australia

The Tax Justice Network Australia is the Australian branch of the Tax Justice Network (TJN) and the Global Alliance for Tax Justice. TJN is an independent organisation launched in the British Houses of Parliament in March 2003. It is dedicated to high-level research, analysis and advocacy in the field of tax and regulation. TJN works to map, analyse and explain the role of taxation and the harmful impacts of tax evasion, tax avoidance, tax competition and tax havens. TJN's objective is to encourage reform at the global and national levels.

The Tax Justice Network aims to:
(a) promote sustainable finance for development;
(b) promote international co-operation on tax regulation and tax related crimes;
(c) oppose tax havens;
(d) promote progressive and equitable taxation;
(e) promote corporate responsibility and accountability; and
(f) promote tax compliance and a culture of responsibility.

In Australia the current members of TJN-Aus are:

- ActionAid Australia
- Aid/Watch
- Australian Council for International Development (ACFID)
- Australian Council of Social Service (ACOSS)
- Australian Council of Trade Unions (ACTU)
- Australian Education Union (AEU)
- Australian Services Union (ASU)
- Anglican Overseas Aid
- Baptist World Aid
- Caritas Australia
- Columban Mission Institute, Centre for Peace Ecology and Justice
- Community and Public Service Union (CPSU)
- Evatt Foundation
- Friends of the Earth
- GetUp!
- Global Poverty Project
- Greenpeace Australia Pacific
- International Transport Workers' Federation (ITF)
- Jubilee Australia
- Maritime Union of Australia (MUA)
- National Tertiary Education Union (NTEU)
- New South Wales Nurses and Midwives' Association (NSWNMA)
- Oaktree Foundation
- Oxfam Australia
- Save the Children Australia
- Save Our Schools
- SEARCH Foundation
- SJ around the Bay
- Social Policy Connections
- Synod of Victoria and Tasmania, Uniting Church in Australia
- TEAR Australia
- The Australia Institute
- Union Aid Abroad – APHEDA
- United Voice
- UnitingWorld
- UnitingJustice
- Victorian Trades Hall Council
- World Vision Australia

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