Review of the PRRT Gas Transfer Pricing arrangements

Consultation paper

April 2019

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| Notes to participantsThe Government has asked Treasury to provide advice on the gas transfer pricing arrangements of the petroleum resource rent tax as part of its response to the Callaghan Review of the Petroleum Resource Rent Tax released 2 November 2018.The issues canvassed in this paper are intended to facilitate consultation by Treasury and have not been endorsed by the Australian Government. |

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# Consultation process

## Request for feedback and comments

Interested parties are invited to comment on the issues raised in this note by 14 June 2019.

While submissions may be lodged electronically or by post, electronic lodgement is preferred.

Closing date for submissions: 14 June 2019

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## Providing a confidential response

It is our intention to publish non-confidential submissions on the Australian Treasury website after the closing date for submissions has passed.

If you would like all or part of your submission to remain confidential, you should indicate this at the time of lodging your submission together with reasons as to why you are requesting that the information be accepted on a confidential basis. Automatically generated confidentiality statements in emails do not suffice for this purpose.

Respondents who would like part of their submission to remain confidential should provide a version that ‘blacks out’ or specifically identifies the confidential information as well as a separate complete version.

A request made under the *Freedom of Information Act 1982* (Cth) to have access to submissions marked ‘confidential’ will be determined in accordance with that Act.

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# Review of the PRRT gas transfer pricing arrangements

# 1. Objectives

1. On 2 November 2018, the Government announced its final response to the Callaghan Review of the Petroleum Resource Rent Tax (PRRT). As part of its response, the Government asked Treasury to lead a review of the gas transfer pricing (GTP) arrangements of the PRRT, to consult and report back within 12 to 18 months.
2. Treasury has been asked to provide advice to Government on:
* options to reflect an appropriate distribution of rents, including when resource prices are high
* ensuring the regulations are fit for purpose into the future and compatible with emerging developments in the industry, such as liquefied natural gas (LNG) tolling arrangements and third party processing
* whether the evidence of how the regulations are applied in practice reflects an appropriate arm’s length price for gas at the taxing point, including in situations where prices and resource rents are high
* ensuring commercial transactions for parts of the LNG production chain are used as far as possible as a reference for establishing a gas transfer price
* ensuring that the regulations are neutral as far as possible between operations where the owners (or part owners) of gas process their own gas and where gas is processed by third parties
* options to improve transparency and reduce complexity in the way in which the rules operate, and
* any other related matters.
1. The GTP review will have regard to the need to ensure the community receives a fair return for its oil and gas resources, while not discouraging investment in the industry.

## 1.1 Next steps

1. Information obtained in this consultation, in conjunction with expertise from the Australian Taxation Office (ATO) and the Department of Industry, Innovation and Science, will be used in advising the Government about options to modify the GTP arrangements.

# 2. Issues identified by the Callaghan Review

1. The Callaghan Review identified that the current GTP regulations likely undervalue gas that is used in vertically integrated LNG or electricity generation projects compared to what an arm’s length market price for sales gas would be. This undervaluation reduces the assessable receipts of integrated projects for PRRT purposes.
2. The Callaghan Review recommended that the current GTP regulations be examined to identify changes that would achieve greater simplicity and transparency, ease of compliance and fair treatment of the economic rent from each stage of an integrated petroleum operation.
3. The Callaghan Review considered the further examination should particularly consider:
* ‘strengthening the scope to use a CUP [comparable uncontrolled price] as the primary method of setting the gas transfer price in line with international best practice and recent work by the Organisation for Economic Co-operation and Development (OECD); and
* where a CUP is not available, examining the appropriateness of the asymmetric treatment of upstream and downstream operations, the way profits are split between the upstream and downstream, and the rate of the capital allowance in the RPM [Residual Pricing Method].’ p. 14.

# 3. Gas transfer pricing regulations

1. The role of the *Petroleum Resource Rent Tax Assessment Regulation 2015* (Cth) (the regulations) is to establish the price of the feedstock gas that is used in vertically integrated operations, as there is no arm’s length sale at the taxing point from the ‘upstream’ feedstock gas used to make LNG (which is subject to PRRT) to the ‘downstream’ liquefaction facility or electricity project (which is outside the PRRT ring-fence).[[1]](#footnote-2)
2. By setting a price for feedstock, the regulations enable the PRRT liability for LNG projects, or gas to electricity projects to be calculated.
3. After the PRRT was extended to include onshore projects and the North West Shelf project in 2012, the regulations were revised in 2013 to adapt the regulations to apply to these areas as well as gas to electricity operations.
4. In 2015, the regulations were remade as they were due to sunset on 1 April 2016. The updated regulations incorporated minor revisions that modernised the drafting style and, consistent with the Government’s deregulation agenda, reduced compliance costs for industry. The process of remaking the regulations did not consider whether the methods set out in the regulations collected an appropriate return for the Australian community.

## 3.1 Development of the regulations

1. Prior to the original regulations being developed in 2005, Industry and Government agreed on a set of principles which would underpin the formation of the GTP. In summary, these were:
* only upstream activities would be liable for PRRT
* outcomes should be assessed against economic efficiency criteria
* GTP methodology should apply to all integrated gas to electricity and LNG projects
* project risks should be equitably reflected on all cost centres
* the transfer price should reference the first commercial third party price for derivative products
* the transfer price should be transparent, equitable, auditable and simple to administer.
1. The Government commissioned a report from Arthur Andersen[[2]](#footnote-3) to perform an analysis of the industry and recommend a pricing methodology.
2. One of the central features of the analysis of the Arthur Andersen report is that in determining an arm’s length price, the model chosen assumes that:
* the LNG integrated project is run as a single project
* the LNG project is already integrated when the price for the gas is being determined
* the risks associated with exploration activities are not a relevant concern for the upstream business
* the upstream and downstream businesses carry the same level of risk and expect the same level of returns
* the upstream entity would consider that the resource rents inherent in the resource as well as the rents attributable to the upstream entities’ know how etc. are together equivalent to rents attributable to the downstream entities’ know how for marketing, shipping and liquefaction of LNG.
1. The Arthur Andersen report included the caveat that the arm’s length price established according to the legislation will always dominate the residual price approach. In doing so, the report acknowledged that the methodology developed for projects that were just commencing may not be suitable once more specific information was available.
2. The assumptions made in the Arthur Andersen report were built off the principles developed between Industry and Government in the 1990s. The Government has decided to re-test the assumptions underlying those principles, to question whether they were appropriate for the original development phase of the industry and whether they reflect commercial practice for the next wave of development.
3. The construction of LNG operations in Australia and the lack of third parties developing downstream facilities during the development phase suggest that it was important to maintain control of the whole value chain. Further, the way in which companies with upstream interests only are proposing to develop their fields suggests that assumptions previously adopted may not accurately reflect the arm’s length price today.
4. The purpose of determining the arm’s length price in the legislation is to be able to determine the assessable receipts of the upstream project. In the PRRT, the assessable receipts provisions and the deductible expenditure provisions are finely balanced to ensure that it is the rents that are calculated. The PRRT will not effectively tax resource rents, to the extent that the arm’s length methodology chosen changes the balance between the assessable receipts provisions and the deductible expenditure provisions.

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| Questions1. What principles should underpin the price of feedstock gas in vertically integrated operations going forward?
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## 3.2 The GTP regulations contain three methods

1. The GTP regulations provide three methods for calculating the transfer price, together with the conditions for each approach and the order in which they apply. The methods are:
* Comparable uncontrolled price (CUP) – a shadow pricing method in which the transfer price is determined by finding a comparable ‘uncontrolled’ transaction in similar circumstances.
* Residual pricing method (RPM) – which allocates part of the price received for LNG to the upstream (PRRT project) and part to the downstream (liquefaction plant). It does this by providing a return on capital to each component, an allowance for operating costs, and if there is any residual value, it is typically allocated equally between the two sides.
* Advance pricing arrangement (APA) – an agreed method between the Commissioner of Taxation and a taxpayer for calculating an arm’s length price.
1. For offshore projects, the RPM applies if the alternatives of an APA or CUP are not available.
2. The GTP framework is easiest to apply in circumstances where there is common ownership across all stages of an integrated project. The existing methods may not suit circumstances where there is separate ownership of the upstream and downstream stages.
3. In considering whether changes should be made to the existing methods to accommodate new arrangements, it is important that the regulations enable developments to go ahead in the most economically efficient way without resulting in different tax outcomes.
4. Further details on each of the methods follow.

# 4. Comparable uncontrolled price

1. A CUP is generally considered the most direct and reliable way to apply the arm’s length principle and to determine the prices for related party transactions. Difficulties in finding suitable information can make the method difficult to apply in practice.
2. The 1998 Arthur Andersen report that informed the development of the regulations noted that while there were no comparable transactions for LNG projects at that time, conditions to support a comparable price method may exist in the future.
3. At the time the regulations were developed, there was no competitive market in Australia for the LNG feedstock gas which meant that a CUP was not likely to be available. Despite this, the option of determining a CUP was included in the regulations to reflect its advantages and the power to determine the existence of a CUP was given to the Commissioner of Taxation.
4. The following is from the explanatory materials for the 2001 amendments introducing the arm’s length test:

‘The preferred option for implementing the policy objective is to include a methodology to determine a GTP. The shadow pricing methodology can only be used where there is an observable comparable arm’s length price. It is not expected that the shadow pricing method could be reliably applied in the foreseeable future’ (Explanatory Memorandum, Taxation Laws Amendment Bill (No. 6) 2001 (Cth), p. 18, [1.34]).

1. However, market conditions and sales arrangements should be reviewed periodically to determine whether changes have occurred that would justify establishing an industry wide CUP.
2. At the current time, it appears there are practical challenges with applying the CUP rules for two reasons:
* Under the existing industry conditions there is no realistic scenario under which an observable third party price for sale of gas would be identifiable at the taxing point. Some LNG operations in North West Australia do not sell gas to the domestic market, meaning the price of sales gas is not observable. Further, where sales gas is sold, this is under Western Australia’s domestic gas reservation policy, making the resulting price incomparable.
* Even if there were observable third party prices, there may be issues with applying the CUP rules as currently drafted, given the focus of the analysis is on the market in which the sales gas is sold to, that is, the notional LNG plant operator at the taxing point. The rules for determining a CUP are in section 23 of the regulations. Details are contained in Appendix A.
1. Consequently, it may be desirable to review the CUP rules to ensure that if data informing the identification of an arm’s length price for sales gas in integrated offshore operations becomes available, the rules do not unnecessarily restrict the application of the CUP method to inferring a gas transfer price.

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| Questions1. Are the CUP rules too restrictive, even if there was a scenario where a CUP is identifiable?
2. In what way could the CUP rules be revised in order to provide greater flexibility to use arm’s length prices to derive a CUP as new commercial arrangements arise?
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## 4.1 The OECD Guidelines

1. The Callaghan Review noted that:

‘…it would be appropriate to…align the approach to establishing a CUP to the latest OECD recommendations and approaches on transfer pricing. The market conditions and project structures could be regularly reviewed to determine whether it is appropriate to establish an industry wide CUP that would take the place of the RPM as the main GTP methodology for LNG projects.’ p. 90.

1. The OECD’s approach to the application of the arm’s length principle to evaluate the transfer pricing of associated entities is set out in the *OECD Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations 2017* (the OECD Guidelines). The OECD has adopted the ‘separate entity’ approach to intra-group transactions as the most reasonable means for achieving equitable results and minimising the risk of unrelieved double taxation in the international tax framework. This treats each enterprise within the multinational group as a separate entity. Application of the arm’s length principle in this context seeks to achieve parity between associated and independent enterprises for tax purposes.
2. While the OECD Guidelines are not intended to consider domestic transfer pricing issues, they contain useful principles and methods to test consideration received or receivable and the attribution of economic value created or added in a transaction in which the parties are not dealing at arm’s length.
3. There may be practical limitations on the extent to which the outcomes of the gas transfer pricing regime in the PRRT can achieve the principles set out in the OECD Guidelines. For example, as the current taxing point for PRRT purposes is likely to differ from the point at which independent enterprises would transact for the sale of feedstock gas, it may be difficult to identify transactions between independent enterprises that provide a high level of comparability for the purposes of pricing sales gas at the taxing point. It may also be difficult to make reasonable adjustments to pricing data that does emerge to determine a sufficiently certain arm’s length price.
4. Despite these difficulties, ultimately, the overall objective of the gas transfer pricing regime should be to find a reasonable estimate of an arm’s length outcome based on the most reliable information available.

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| Questions1. How could the OECD Guidelines be best used to inform an arm’s length outcome in the gas transfer pricing regime?
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## 4.2 Are tolling arrangements likely to be more common?

1. In circumstances where gas is processed into LNG by a third party through a partly owned processing facility via a tolling arrangement, there will be observable negotiated prices for a part of the value chain. Depending on the ownership of upstream and downstream facilities in these arrangements, negotiated prices might be considered to represent an arm’s length price for tolling.
2. Currently, the regulations do not allow this observable tolling fee to be used as a basis for, or to otherwise inform, calculating the gas transfer price at the PRRT taxing point.
3. In most offshore projects there will be a difference between the taxing point for PRRT purposes and the tolling point that is used for commercial purposes. For example, as reflected in the diagram below, in many projects, the taxing point is inside the LNG plant and is at the point immediately before the sales gas gets liquefied, whereas the tolling point would be at or prior to the gas entering the LNG facility. There are also other project structures, however, where the tolling point may be prior to processing of the gas, whereas the taxing point is likely to be at or prior to the gas entering the LNG facility.



1. There is also a difference in what is being calculated. The PRRT requires an arm’s length price to be calculated as if the gas were sold at the taxing point. By comparison, the tolling fee may represent the value of the processing of the natural gas into LNG (and perhaps storage and handling), and not the risks associated with the transfer of ownership of the gas, marketing or commodity pricing.
2. Nevertheless, an observable arm’s length price for tolling arrangements is useful in testing the commerciality of outcomes under the RPM. This is particularly the case where there are additional observable prices for other parts of the downstream value chain.
3. Whether an observable arm’s length price for tolling can inform the calculation of the gas transfer price may depend on the specific arrangements and whether reasonably scientific adjustments can be made to the observed prices to account for any material differences in the functions performed, assets used, or risks assumed.

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| QuestionsWhile there are no CUPs at the current time in offshore projects, these questions are focused on developing the right settings for when observable third party prices in the LNG value chain become available.1. How might the regulations be amended to allow for an observable tolling fee to be used as a basis for, or to inform, the calculation of the price of gas at the PRRT taxing point? What kind of adjustments might be required?
2. If the LNG sales price minus the arm’s length prices for marketing, shipping and tolling (if paid for by the seller) were higher than the RPM price for the same project, would it be an indication that RPM was delivering too high a return to the downstream? Could a comparison be incorporated into the regulations?
3. Are there future projects which rely upon third party access to existing infrastructure in order to be commercial? How is a tolling fee for the use of existing infrastructure likely to be negotiated?
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# 5. Residual pricing method

1. The RPM calculates the price for gas at the PRRT taxing point using a 14 step process.
2. This method involves creating a notional integrated operation consisting of an upstream and a downstream entity. A prescribed ‘minimum return’ for each entity to invest capital and run the business is then calculated. For the upstream entity, the cost-plus price reflects the minimum price they would sell feedstock gas from the PRRT project. For the downstream entity, the netback price reflects the maximum price they would be willing to pay for the feedstock gas.
3. Where the netback price exceeds the cost-plus price and the notional project is ‘profitable’, the RPM price is their mid-point. Where the cost-plus price exceeds the netback price and the notional project is in a loss situation, the netback price is the RPM price, which imposes an asymmetric risk on the notional upstream entity.
4. The calculations for both the cost-plus and netback prices involve determining the capital invested in each respective business and provides a rate on return on these capital costs. The regulations specify eligible capital and operational costs attributable to upstream and downstream entities as well as excluded costs.
5. A stylised representation of the RPM, where the integrated project is in a profit situation is below:



1. The main design features in the RPM which allocate value to the upstream or downstream include:
* Capital cost allocation
* Capital allowance rate
* Division of the residual profit element (‘residual profit split’), and
* Asymmetric treatment in loss situations.

Each is considered in more detail in the sections that follow.

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| Questions1. Are there other sensitivities in addition to capital allocation, capital allowance rate, profit split and asymmetric treatment that impact the RPM?
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## 5.1 Capital cost allocation

1. The purpose of the capital allocation process under the RPM is to determine the minimum return required to reward the capital invested. The regulations specify the capital and operational costs that can contribute to the upstream and downstream entities. There are also apportionment rules so that only costs relating to the production and processing of sales gas are included in the RPM.
2. The RPM price is most sensitive to the amount of capital allocated to the upstream and downstream entities. Relatively, changes to the upstream or downstream capital impact the RPM price more than either a change in LNG price or the capital allowance rate. This is because an increase in LNG prices operates through the netback equation. While a higher netback price widens the residual profit element to be split, the subsequent 50:50 apportionment means any increase in the RPM price is proportionately lower.
3. In applying a rent tax to upstream operations, the Government accepts the risk that companies may spend more than is optimally required (because of unforeseen events) to extract the resource and in doing so may reduce the rents available for taxation. The PRRT operates in a way that if the price of oil and gas suddenly makes the project highly profitable despite these increased costs, then the additional profits will be taxed at the PRRT rate.
4. However, the capital cost application of the RPM means that cost over runs in the downstream will also reduce the rents available for upstream taxation. When coupled with the other features of the RPM, particularly the 50:50 profit split, the result is that even if the price of the final product increases significantly, this will not translate to higher profitability in the upstream.
5. In addition, as the capital allowance rate (the rate of reward for the capital invested) is the same for the upstream and downstream, a change to the rate typically results in more or less weight on the residual split. Sensitivities related to the capital allowance rate are explored in section 5.2 below.
6. Overall, capital costs of the upstream and downstream entities are the primary determinant of whether or not an integrated project realises a notional profit.

### 5.1.1 Exploration costs

1. There are a number of potentially sizable costs that are excluded from upstream or downstream capital. This includes exploration costs and early stage expenses incurred to get the project to a final investment decision stage. Section 32 of the regulations contains the excluded costs.
2. The Callaghan Review identified that:

‘As these costs are more likely to be recognised for PRRT purposes in the upstream and uplifted over several years, the failure to include these costs in the RPM potentially undervalues the return to the upstream business. The reasoning provided in the explanatory statement for the exclusion of these costs is not compelling. The effect of the exclusion of these costs is a potential asymmetry in how development costs for the upstream and downstream are reflected in the RPM.’ p. 159.

1. Businesses that have explored in a particular area are able to develop these rights as well as sell them to another party. Like the onshore minerals industry, the offshore petroleum sector may have established methods for determining the value of underdeveloped petroleum resources. Alternatively, a specific method might be designed to determine how exploration expenditure and early stage final investment decision costs should be recognised in upstream capital. Given the potential long periods of time between when a resource is discovered and it is developed, a historical cost approach may not be the best basis to recognise exploration expenditure.

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| Questions1. Comments are invited regarding whether exploration costs and a broader range of costs to develop a project to final investment decision should be included in upstream capital, and how this is best achieved to properly value the return to the upstream business.
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### 5.1.2 Capital allocations where other products are produced in years before sales gas

1. Section 41 of the regulations deals with circumstances under which other petroleum products are produced from an integrated LNG facility before the year that sales gas first starts to be produced from that same facility. Relevant capital costs associated with the production of the other marketable petroleum commodities (MPCs) are depreciated at the Long Term Bond Rate (LTBR)+7 percentage point capital allocation rate each year before the project sales gas is produced. This is to account for the use of the capital assets in producing the other MPCs. An example of a circumstance where this arises is if the gas is reinjected during oil production for later extraction.
2. The Callaghan Review identified that:

‘The practical effect of this in a LNG operation where other MPCs are produced first is that the capital costs for much of the upstream infrastructure will be reduced over the period in which the other MPCs are produced before the production of sales gas **while the capital costs for the downstream infrastructure will continue to be uplifted**.’ p. 160 (emphasis added)

1. Overall, this treatment results in a lower cost-plus price and consequently, potentially undervalues the RPM price.

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| Questions1. Arguably, the depreciation of capital costs where other products are produced in reporting periods before sales gas starts to be produced is asymmetric. Are there better options that can be used in the RPM?
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## 5.2 Capital allowance rate

1. The capital allowance rate is used to augment capital costs incurred in the notional upstream or downstream projects. The capital allowance rate is LTBR+7 percentage points for both the upstream and downstream. There does not appear to be a stated reason for this symmetrical capital allowance rate. The Arthur Andersen report provides one possible explanation, as it uses the assumption that upstream and downstream projects carry the same level of risk and so expect the same level of returns.
2. The explanatory statement outlines that it represents a proxy for the cost of equity, but does not articulate why this is the best representation of the minimum return required to sustain reward for the capital invested. Generally, a weighted average cost of capital (WACC) approach is preferred to determine the minimum required rate of return. However, in trying to set a single representative number across an industry, there will always be projects that are inherently risker and therefore have a higher cost of capital than other projects.
3. The rate is not the key element that determines how value is allocated between the upstream and the downstream – rather it is the interaction of the capital allowance rate with both the profit split and capital allocation rules that determines the value allocation.
4. Changing the capital allowance rate on its own can lead to unintended consequences. By increasing the role of the profit split and placing less reliance on the return on capital, the existing weaknesses in the profit split and capital allocation settings are augmented.
5. For example, if the capital allowance rate is increased, it could result in a lower netback price and a higher cost-plus price, other factors remaining the same. If the netback price is lower than the cost‑plus price, the current rules result in the netback price being used. This asymmetry in loss situations is considered in section 5.4 below.
6. On the other hand, if the capital allowance rate is decreased, the netback price would increase and the cost-plus price decrease, other factors remaining the same. This would result in a greater residual profit element to be split to determine the RPM price. How the profit split could be changed is considered in section 5.3 below.
7. These scenarios assume that upstream and downstream projects share the same level of risk and should carry the same levels of returns for the capital invested. There is also the assumption that the rate should only reflect the minimum return to justify a capital investment. These assumptions are worth examining given the important role they play within the existing method.

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| Questions1. What is the right proxy for determining a capital allowance rate?
2. How is this best calculated, reflecting that some PRRT projects may be more risky than others?
3. Does this differ for the upstream and downstream?
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## 5.3 Division of the residual profit element

1. The current regulations split any residual profit in the overall project equally between the upstream and downstream components.
2. The 50:50 profit split is an arbitrary allocation and is not based on any economic or theoretical reason. It reflected that when the regulations were developed, there was little prior experience to draw from, and an equal split seemed a good starting point for allocating the profits.
3. The regulation impact statement, included in the Explanatory Statement to the 2005 regulations stated that:

‘Although the application of the netback and cost-plus formula define the residual profit in a project, no theoretical basis exists for determining how the residual profit should be split between the netback and cost-plus prices to arrive at a single price. Consequently, the RPM splits this differential equally. This split reflects the integrated and interdependent nature of an integrated GTL operation. It is also the most appropriate and equitable solution to split the difference between the netback and cost-plus price to arrive at the project’s gas transfer price’. p. iii

1. When considering the same issue, the Callaghan Review stated:

‘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. Where resource rents are high, allocating the higher profits of the whole operations equally will result in the PRRT upstream project being undertaxed. Correspondingly, when downstream rents are high, the equal allocation of residual profits may result in the upstream PRRT project being overtaxed. The 50:50 split assumes that project rents are just as likely to be attributable to the downstream as the resource’ p. 94.

1. A key policy question is the appropriateness of the current 50:50 profit split. It may be that at a low LNG price or profitability level, the 50:50 split may not result in a particularly different outcome compared to different methods. However, if the price of LNG increases and results in a large profit margin, an alternate profit split may more appropriately capture the rents that are attributable to the resource.

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| Questions1. How can the current profit split be changed to better allocate returns in circumstances where the price of the LNG resource is high?
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### 5.3.1 Utility returns

1. Another option is to replace the profit split rather than change it.
2. The RPM assumes that the downstream entity undertakes the processing, marketing, shipping and sale of the LNG product while the upstream entity provides sales gas to the downstream entity. The assumed relationship between them is that the upstream entity has a ‘take or pay’ style arrangement with the downstream entity for the sales gas.
3. Since enactment of the regulations, technology and industry developments have changed the landscape of LNG extraction and processing in Australia. Existing processing facilities are no longer likely to remain standalone, integrated projects. The expectation is that existing infrastructure will be used to process gas from new PRRT projects in preference to constructing new facilities. Increased use and consideration of tolling arrangements supports this view – for example, the North West Shelf venture recently reached preliminary agreement to process gas from Woodside Petroleum’s Browse venture and from a separate Chevron venture.[[3]](#footnote-4)
4. Further, comments by major industry players reflect that increasingly LNG processing facilities compete to achieve ‘utility’ returns. This suggests that, compared to the volatile changes in resource price, changes in the efficiency and operation of LNG processing facilities have relatively small impacts on the level of overall profits achieved.
5. Guidance from the OECD on application of the transactional profit split notes that a high degree of integration means that the way in which one party to the transaction performs functions, uses assets and assumes risks is interlinked with, and cannot reliably be evaluated in isolation from the way in which another party to the transaction performs functions, uses assets and assumes risks. This contrasts the situation in which the contribution of one party to the transaction can be reliably evaluated to comparable uncontrolled transactions.[[4]](#footnote-5)
6. While the underlying assumption at the time the regulations were developed was that the upstream and downstream were highly interdependent, with the benefit of experience, it is not clear that the downstream liquefaction contribution is so integrated in terms of functions performed, assets used and risks assumed that it is impossible to evaluate its respective contribution in isolation of the upstream.
7. Reflecting this, the RPM may no longer be the most appropriate approach to determine the value of gas at the taxing point.
8. It may be more appropriate to use a netback only approach for the downstream operation. Adopting this approach would effectively fix the level of return the downstream entity achieves.
9. Any replacement or update to the RPM should better reflect current and evolving commercial situations. Additionally, it needs to better reflect movements in the sales gas price, given the PRRT is intended to provide the community a return for the upstream gas resource.

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| Questions1. Why did resource owners choose to build and own downstream liquefaction plants rather than enter into arrangements where third parties would provide these facilities?
2. To the extent that future tolling arrangements emerge, are downstream operators likely to assume the risks associated with the underlying LNG market or are tolling arrangements more likely to reflect cost-plus approaches to recovering costs?
3. How can the RPM be altered to better reflect movements in gas price that also takes into account the risk of selling LNG into market?
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## 5.4 Asymmetric treatment in situations of profit or loss

1. The Callaghan Review identified the downstream and upstream capital allocations are treated differently in situations where the notional project was in a profit or loss situation and recommended reviewing this treatment.
2. As noted earlier, where an integrated project is profitable the RPM price is the mid-point of the cost-plus price (the minimum price a producer will sell its gas) and the netback price (the maximum price a processor will purchase the gas). However, if the project is in a notional loss situation, that is where the maximum price a processor is willing to purchase gas for is below the price a gas producer is willing to sell it then a 50:50 residual profit allocation is not used. Instead, all the losses are attributed to the upstream (gas) resource.
3. The example given in the Callaghan Review is, ‘if an LNG producer used the RPM and worked out that the netback price was $6 per unit, and the price cost-plus price was $4 per unit, the RPM price would be $5 per unit. If, however the netback price was $4 per unit, and the cost-plus price was $6 per unit, the RPM price would be $4 per unit because the cost-plus price was higher than the netback price.’ p.159
4. This setting means the Australian community bears a disproportionately large share of downside risk from an integrated project if it makes a loss – whether as a result of low amounts of revenue due to a lower than expected gas price or high costs in the downstream operations. Under a 50:50 residual profit allocation, the expectation would be for equal treatment in both the upside and downside scenarios.
5. The key policy question for focus here is whether there are compelling reasons for maintaining a different treatment of upstream and downstream capital allocations.

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| Questions1. Are there any reasons for retaining a differential treatment between the upstream and downstream in determining the RPM price?
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# 6. Advance pricing arrangements

1. An APA is an agreement between the Commissioner of Taxation and a taxpayer on the future application of the arm’s length principle to the taxpayer’s dealings with related parties.
2. An APA is not an agreed price; instead, it is an agreed method of calculating an arm’s length price.
3. APAs are typically used in cross-border international dealings to manage transfer pricing risks for taxpayers and the Commissioner of Taxation. In the PRRT context the transfer pricing risk is not limited to, or focused on, cross border international dealings. The main aim of the APA is to find agreement on the appropriate method, assumptions and information to calculate the price at the PRRT taxing point.

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| Questions1. Comments are invited on any revisions that would be beneficial to consider with regard to APAs.
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# 7. Transparency and ease of compliance

1. In addition to identifying changes that would result in fair treatment of economic rent from each stage of an integrated petroleum production, the Callaghan Review recommended changes that achieve greater simplicity, transparency and ease of compliance be examined.
2. The current regulations provide three methods for calculating the price of gas at the taxing point. Each involves varying levels of complexity, both for administrators and businesses.
3. Currently, appropriate information with respect to complying with the regulations may be exchanged between industry participants and the ATO. For example, there are provisions in the *Petroleum Resource Rent Tax Assessment Act 1987* (Cth) that require the disclosure of certain information from a vendor to the purchaser in respect of a transaction.
4. However, the regulations were developed on the basis that did not explicitly consider third party processing arrangements. Currently, to calculate a price using the RPM approach, a project participant needs to obtain capital cost information for downstream infrastructure. In future arrangements such as tolling where a participant does not have an interest, there may need to be a way of exchanging appropriate information to undertake calculations for the cost of gas at the taxing point.
5. Additionally, public confidence in the PRRT may be assisted by greater public accountability. The ATO currently publishes information on entities that have PRRT payable through the annual Report on Entity Tax Information, as well as data on PRRT as part of the ATO’s annual *Taxation Statistics* publication. There is no public information available, however, on the price of gas at the taxing point.

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| Questions1. Comments are invited on the ease of complying with each of the methods in the regulations, and any changes that should be considered that achieve greater public transparency or greater simplicity.
2. Comments are invited on whether the regulations provide adequate sharing of information between project participants in order to calculate their respective gas transfer prices for future arrangements and whether legislation or other methods best address any identified gaps.
3. Should businesses be required to publicly report on the price of gas at the taxing point? What other practical options are there to improve transparency that the PRRT is delivering a fair return on resources to the Australian community?
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# Appendix APRRT CUP rules and OECD Guidelines

## A.1 The PRRT CUP rules

1. The rules for determining a CUP are in section 23 of the the *Petroleum Resource Rent Tax Assessment Regulation 2015* (the regulations).
2. In respect of a transaction for sales gas, the CUP is defined as the price from a sale in a market that the Commissioner of Taxation (the Commissioner) is satisfied as being a market relevant to the transaction and that the Commissioner is satisfied with an observable arm’s length price.
3. With respect to the latter requirement, an arm’s length price is defined in the regulations as the consideration received or receivable in relation to a transaction in which the parties are dealing with each other at arm’s length.[[5]](#footnote-6)
4. The Commissioner must take into account a number of factors to determine whether a market is relevant. These include:
* the demand and supply characteristics of the market
* the usual contractual terms in the market, including volumes, discounts, exchange exposures, and other relevant conditions that would reasonably be considered to affect the price
* market strategies
* the existence of spot sales (including market penetration sales) below or above marginal cost
* processing costs, and
* technology used in processing.
1. The Commissioner must also take into account any other factors that it would be reasonable to consider.
2. The Commissioner’s considerations of the demand and supply characteristics of the market explicitly include:
* the composition of gas sold in the market
* geographic differences between the production facilities and the product delivery point of the gas sold in the market, and
* the end use for the gas sold in the market.

## A.2 OECD Guidelines

1. The *OECD Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations 2017* (the OECD Guidelines)[[6]](#footnote-7) outlines the OECD’s approach to application of the arm’s length principle to evaluate the transfer pricing of associated entities. Under the OECD Guidelines, there are two key aspects when applying the arm’s length principle:
* identifying the commercial or financial relations between the associated parties and the conditions and circumstances relevant to the controlled transaction, and
* comparing the identified conditions and circumstances of the controlled transaction with the conditions and circumstances of comparable transactions between independent parties.
1. The OECD Guidelines analyse the methods for evaluating whether the conditions of commercial and financial relations within a multinational enterprise satisfy the arm’s length principle and discuss the practical application of those methods.

### Application of the arm’s length principle

1. The identification of commercial and financial relations between associated enterprises and relevant conditions and circumstances requires an understanding of the industry relevant to the multinational group as a whole in the controlled transaction and factors affecting commercial performance in that industry. This is derived from an overview of how the group responds to factors affecting its performance in the industry, including its business strategies, markets, products, supply chain, and the key functions performed, material assets used and important risks assumed.
2. It further requires an understanding of how each party in the group operates and identification of the conditions and economically relevant characteristics of the transaction. Application of the arm’s length principle depends on determining the conditions that independent parties would have agreed to in comparable transactions in comparable circumstances.
3. The economically relevant characteristics that need to be identified are broadly characterised in the OECD Guidelines as:
* the contractual terms of the transaction
* the functions performed by each of the parties to the transaction, taking into account assets used and risks assumed
* the characteristics of property transferred or services provided
* the economic circumstances of the parties and of the market in which the parties operate, and
* business strategies of the parties.
1. Other circumstances that may also be relevant in a transfer pricing analysis include features of the local market and the workforce.
2. The second aspect of the arm’s length principle involves applying the most appropriate transfer pricing method to compare the controlled transaction with the uncontrolled comparable transaction, which would include analysis of the above factors.
3. An uncontrolled transaction is comparable to a controlled transaction where either:
* there are no material differences between the situations, or
* reasonably accurate adjustments can be made to eliminate the material effects of any such differences.

### The CUP method in the OECD Guidelines

1. CUPs are recognised internationally as the most appropriate transfer pricing valuation method.
2. When available, a CUP represents an objective arm’s length price that is relevant and comparable to the circumstances of the transfer to which it is applied. The OECD Guidelines noted:

‘Where it is possible to locate comparable uncontrolled transactions, the CUP method is the most direct and reliable way to apply the arm's length principle. Consequently, in such cases the CUP method is preferable over all other methods.’ p. 101, [ 2.15]

1. The CUP method compares the price charged for property or services transferred in a controlled transaction to the price charged for property or services transferred in a comparable uncontrolled transaction in comparable circumstances. Differences between the two prices may indicate that the conditions of the transaction are not arm’s length, and that the price in the controlled transaction may need to be used instead.
2. Given the difficulties involved in identifying controlled and uncontrolled comparable transactions, the OECD Guidelines allow adjustments to be made to the relevant factors to eliminate the material effect of differences on price. In some cases, consideration may be given to applying a more flexible approach to enable the CUP method to be used and be supplemented as necessary by other appropriate methods. The difficulties in making reasonably accurate adjustments should not preclude the possible application of the CUP method.
3. The OECD Guidelines note that the CUP method would generally be an appropriate transfer pricing method for establishing the arm’s length price for the transfer of commodities between associated enterprises. However, the reference to commodities in this context encompasses physical products for which a quoted price is used as a reference by independent parties in the industry to set prices in uncontrolled transactions, with a quoted price being the price of the commodity in the relevant period, obtained in an international or domestic commodity market.

### Other methods in the OECD Guidelines

1. The OECD Guidelines detail other methods to establish an arm’s length price. These include:
* The resale price method: based on the price resulting from a resale to an independent party, reduced by a gross margin that is representative of selling and other operating expenses that still allows an appropriate profit in light of the functions performed, assets used and risks assumed (and after adjustment for other relevant costs).
* The cost plus method: the arm’s length price is derived by adding an appropriate cost plus mark-up that reflects the functions performed, assets used, risks assumed and the market conditions to the costs incurred by the supplier in the transaction between associated parties.
* The transactional net margin method: analyses the net profit relative to an appropriate base in a controlled transaction for the taxpayer, established by reference to the net profit in a comparable uncontrolled transaction and in the context of the functions performed, assets used and risks assumed.
* The transactional profit split method: determines the division of profits that would have been expected between independent parties in the transaction.

### OECD guidance on the profit split method

1. The OECD issued revised guidance on the application of the transactional profit split method in June 2018[[7]](#footnote-8) which clarifies and specifically expands the guidance on when a profit split method may be the most appropriate method.[[8]](#footnote-9) It describes the presence of one or more of the following indicators as being relevant:
* Each party makes unique and valuable contributions (functions performed or assets used are considered unique and valuable in cases where they are not comparable to contributions made by uncontrolled parties in comparable circumstances and they represent a key source of actual or potential economic benefits in the business operations).
* The business operations are highly integrated such that the contributions of the parties cannot be reliably evaluated in isolation from each other.
* The parties share the assumption of economically significant risks or separately assume closely related risks
1. The guidance makes clear that while a lack of comparables is, by itself, insufficient to warrant the use of the profit split method, if, conversely, reliable comparables are available it is unlikely that the method will be the most appropriate.
2. In addition, the guidance outlines that

‘References to “profits” in this section should generally be taken as applying equally to losses. Where a transactional profit split method is determined to be the most appropriate method, it should generally also apply, and apply in the same way, regardless of whether the transaction(s) result in a relevant profit or loss.’ p. 12, [2.115]

1. Under the PRRT, the taxing point is where the gas is processed sufficiently to be a marketable petroleum product. [↑](#footnote-ref-2)
2. A copy of the Arthur Andersen report, which reported in 1998, is at Attachment B. [↑](#footnote-ref-3)
3. Angela Macdonald-Smith, ‘North West Shelf strikes deal for processing Browse gas’, Australian Financial Review published 7 November 2018. Link: <https://www.afr.com/business/energy/gas/north-west-shelf-strikes-deal-for-processing-browse-gas-20181107-h17lpr> [↑](#footnote-ref-4)
4. OECD (2018), Revised Guidance on the Application of the Transactional Profit Split Method: Inclusive Framework on BEPS: Action 10, OECD/G20 Base Erosion and Profit Shifting Project, OECD Paris. [↑](#footnote-ref-5)
5. *Petroleum Resource Rent Tax Assessment Regulation 2015*(Cth),s 5. [↑](#footnote-ref-6)
6. Since the approval in their original version by the Committee on Fiscal Affairs and by the OECD Council for publication in 1995, the Guidelines have been supplemented and modified by developments that have been adopted by the Committee on Fiscal Affairs and approved by the OECD Council. The OECD has stated that the Guidelines will continue to be supplemented with additional guidance and will be periodically reviewed and revised on an ongoing basis. [↑](#footnote-ref-7)
7. OECD (2018), Revised Guidance on the Application of the Transactional Profit Split Method: Inclusive Framework on BEPS: Action 10, OECD/G20 Base Erosion and Profit Shifting Project, OECD Paris. [↑](#footnote-ref-8)
8. The OECD Guidelines have included guidance on the transaction method since their first iteration in 1995. Since the revision to the Guidelines in 2010, the transactional profit split method has been applicable where it is found to be the most appropriate method to the case at hand. [↑](#footnote-ref-9)