

Options to address the design issues identified in the Petroleum Resource Rent Tax Review

Consultation Paper
30 June 2017

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| Notes to participantsThe Government has asked Treasury to provide advice on the design of the Petroleum Resource Rent Tax, following the review led by Michael Callaghan AM PSM which was released on 28 April 2017. The options 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 and options raised in this paper by Friday, 28 July 2017.

Submissions may be lodged electronically or by post.

#### Providing a confidential response

All information (including name and address details) contained in formal submissions will be made available to the public on the Australian Treasury website, unless it is indicated that you would like all or part of your submission to remain confidential. 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 this information marked in a separate document.

A request made under the *Freedom of Information Act 1982* for a submission marked ‘confidential’ to be made available will be determined in accordance with that Act.

#### Closing date for submissions: Friday, 28 July 2017

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# Purpose of this consultation

On 30 November 2016 the Australian Government announced a review into the operation of the Petroleum Resource Rent Tax (PRRT), crude oil excise and associated Commonwealth royalties (the Review). The Review was chaired by expert economist Michael Callaghan AM PSM. The Review reported to the Treasurer, the Hon Scott Morrison MP in April 2017 and was publicly released on 28 April 2017.

The Treasurer released the Government’s interim response to the Review on 30 June 2017. The Treasurer has requested that Treasury undertake further consultation and provide advice to Government on options to address the PRRT design issues raised in the Review. The Government will then consider its final response to the Review.

The Review made recommendations in two parts:

* Part A recommends that a process be established, involving full consultation with industry and the community, to update PRRT arrangements so that they are more appropriate to the current Australian oil and gas industry, with changes from this process only applying to new projects, as defined in PRRT legislation, from a date to be specified.
* Part B contains an additional 11 recommendations focused on the integrity and administration of the PRRT, which should apply to existing and new projects.

Treasury is seeking feedback in relation to both Parts A and B of the Review recommendations.

In relation to the Part A recommendation, Mr Callaghan identified four aspects of the PRRT for consideration:

* changing the arrangements for the uplift rates for all deductible expenditures so that they are more commensurate with the risk of losing PRRT deductions, taking into account transferability and that this risk will vary over the life of a project;
* ensuring that classes of expenditure with the highest uplifts are deducted first having regard to how deductions can compound in large, long life projects;
* examining the rules for the transferability of deductions between projects in a company to ensure they produce a consistent set of outcomes; and
* examining the gas transfer pricing arrangements to identify possible 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.

This consultation is intended to address PRRT design issues identified in the Review. It is not intended to revisit the question of whether the PRRT should be replaced with alternative forms of taxation.

This paper seeks comments on each of the issues identified by the Review in turn. However, the integrated nature of the PRRT means that all options need to be considered as a package in order to ascertain the interactions between changes to different elements of the PRRT and the effect on both PRRT payers and Government revenues.

Part B of the Review recommendations outlines specific changes dealing with administration and integrity of the PRRT. Alternative options are not suggested in this paper but views are sought on these recommendations.

#### Next steps

The information obtained through this consultation process will be used to develop more refined and integrated design options for reforming the PRRT.

It is envisaged that further consultation will occur following the development of detailed options with the consultation process concluding at the end of August. The Government has asked Treasury to report back by the end of September 2017.

# Options to address the design issues raised in the Review

## 1. Uplift rates

#### Summary of current rules

Under the PRRT, uplift rates (sometimes referred to as augmentation rates or threshold rates) are applied to eligible project expenditure which cannot be fully utilised in the income year in which it is incurred.

Uplift rates vary according to the type of expenditure and the time the expenditure was incurred (see Table 1). Currently, the uplift rate for general expenditure is the long term bond rate (LTBR) plus 5 percentage points, however this rate applies only to general expenditure incurred no earlier than 5 years before the year in which a production licence is applied for while general expenditure outside this period is uplifted by the GDP deflator. The uplift for exploration expenditure is the LTBR plus 15 percentage points, however this rate applies only to exploration expenditure incurred no earlier than 5 years before the year in which a production licence is applied for while exploration expenditure outside this period is uplifted by the GDP deflator.

The uplift rates have been changed on one occasion since the PRRT commenced in 1988. The uplift rate for general expenditure was reduced from LTBR plus 15 percentage points to LTBR plus 5 percentage points for general expenditure after 1 July 1990 when transferability of exploration expenditure was introduced into the PRRT (see section 3).

#### Issues identified in the Review

##### The purpose of uplift rates

The PRRT is intended to operate as a modified cash flow tax where, instead of providing immediate cash rebates for tax losses (negative cash flows), unutilised expenditure is carried forward with an uplift to be offset against future positive cash flows from the project.

The Review noted there was a difference of view between industry and the academic literature and previous reviews as to the purpose of the uplift, with industry arguing the uplift was intended to represent an appropriate rate of return for the risk borne in carrying on a petroleum project, while Government statements at the time of the PRRT design, the academic literature and previous reviews suggest the uplift should maintain the value of deductible expenditure and take into account the risk that the project will not produce sufficient returns to utilise its deductible expenditure.

The Review concluded that:

…a PRRT design that sets uplift rates on the basis of investors’ risk-weighted hurdle rates is likely to underestimate the levels of economic rent and therefore collect lower levels of PRRT. In contrast, uplifting PRRT losses at a rate commensurate with the risk of unutilised PRRT deductions would further tax neutrality and tax revenue objectives. (Callaghan Review, p. 72)

The Review considered that uplifts should be changed for all deductible expenditure such that they are more commensurate with the risk of losing PRRT deductions, taking into account transferability and that this risk will vary over the life of a project.

In determining the correct uplift rates it is important to consider how uplift rates interact with other parts of the PRRT, including the transferability of exploration expenditure.

##### What should the uplift rates be?

As noted in the Review, the risk of losing PRRT deductions is significantly different from the overall risk of a project:

Risk of a prospective petroleum project is reflected in the wide range of possible realised outcomes arising from changes in prices, costs and other events; outcomes spanning from very high profitability, moderate/marginal profitability and a spread of losses… The risk of losing PRRT deductions also depends on changes in the same myriad of prices, costs and events. But this risk is only reflected in the spread of possible outcomes where uplifted expenditures exceed revenue. (Callaghan Review, p. 71)

The risk of losing deductions varies substantially throughout the lifecycle of a project. Exploration expenditure carries the highest risk, but the risk of losing exploration deductions is significantly reduced due to the introduction of transferability of exploration expenditure in 1991. General expenditure carries a lower risk and the risk of losing deductions falls substantially once a project is in the production phase.

##### The effect of uplift rates in the current PRRT system

The industry transformation to one that is now dominated by gas has changed the timeframes over which projects are developed and taxpayers recoup their costs and become PRRT payers. This has amplified the effect of the uplift rates as deductible expenditure is uplifted for years, and sometimes decades, allowing very large compounding to occur. For example, exploration expenditure uplifted at an LTBR of 3 per cent plus 15 percentage points almost doubles in value every four years. Expenditure uplifted at an LTBR of 3 per cent plus 5 percentage points doubles after nine years of compounding.

This highlights that the risk of losing deductions is not just a function of project risk but also the design of the PRRT. Long timeframes exacerbate the circularity between the size of the uplift and the risk that deductions will not be utilised. To the extent that a large uplift compounded over a number of years generates an outsized pool of deductible expenditure, it becomes less likely that deductions will be utilised.

#### Options for consideration

The options put forward in this paper reflect the principles that uplift rates are intended to preserve the real value of undeducted expenditure, while providing a premium for the risk that some expenditure may never be utilised, taking into account transferability and that risk will vary over the life of a project.

Reflecting these principles, options for reform could include:

* Option 1: Reduce uplift rates to better reflect the risk of losing deductions.
* Option 2: Limit the number of years for which a high uplift rate applies.
* Option 3: Provide an investment allowance (a deduction in excess of 100 per cent) for the initial expenditure, with a low uplift applied thereafter.

There are a number of variants to these options, and options could be considered separately or in combination. The details of each option (for example the uplift rate, the number of years for which uplifts apply and the level of the investment allowance) will depend on the specifics of each option or combination of options.

##### Option 1: Reducing the uplift rates for exploration and general expenditure

The uplift on exploration expenditure could be reduced, for example, to the LTBR plus 5 percentage points. This would reflect the fact that while exploration is more risky than general development, the current uplift rate is too high.

The uplift rate on general expenditure could be reduced to a level that proxies the corporate bond rate, as suggested by the Australia’s Future Tax System Review[[1]](#footnote-2), or the LTBR to reflect the low risk that deductions will not be realised once a project is in the production phase.

An alternative option could be to align the exploration and general uplift rates, recognising that allowing exploration expenditure to be transferable substantially reduces the risk of trapped deductions.

##### Option 2: Capping the number of years for which the uplift rate applies

A higher uplift could be maintained, but applied only for a set number of years, with a lower uplift rate applying thereafter. For example, the current uplift rates of the LTBR plus 15 percentage points for exploration expenditure and the LTBR plus 5 percentage points for general expenditure could apply for five years from the date of expenditure with the LTBR or the GDP factor applying thereafter.

This option would still provide a premium above the LTBR for the risk that expenditure is not ultimately able to be used, but would prevent the scenario where deductions compound to very high levels over many years (noting that an uplift even at LTBR does more than simply maintain the real value of the deductions).

A variation on this option is to reduce uplift rates when a project starts producing (or after a set number of years following first assessable receipts). This would more accurately align the uplift factors with the risk at each stage of a project.

Once in the production phase, the risk that deductions will not be recouped is small. For this reason, a high uplift could apply until a project starts producing, with only the LTBR or the GDP factor applying thereafter.

##### Option 3: An investment allowance

An investment allowance would provide an additional deduction in the year in which the expenditure is incurred, with a lower uplift applied thereafter. For example, companies could deduct 110 per cent of their expenditure, with this amount uplifted at the LTBR thereafter.

This approach was suggested in the 2003 report ‘Australia’s petroleum resource rent tax – An economic assessment of fiscal settings’ by Lindsay Hogan. Hogan proposed the option of an investment allowance approach, which has a number of advantages including:

* it eliminates the negative economic impacts of threshold rates that differ from the long term government bond rate;
* it is administratively simple compared with the current arrangements if the industry is treated as a single risk category since the three expenditure categories (ABR exploration, ABR general and GDP expenditure) in the current system are reduced to a single expenditure category; and
* it allows investors to obtain a risk premium in the return to expenditures before the PRRT is triggered, reducing uncertainty about the minimum rate of return that will be achieved on any given project.

This approach would recognise the risk of projects by allowing a higher deduction upfront, but would prevent the extreme outcomes that can occur when deductions are able to compound at a high uplift rate for an unlimited amount of time.

##### Resource tax expenditure

In addition to any of the three options outlined above, the uplift factor for resource tax expenditure could be reduced to the LTBR.

Resource tax expenditures (state royalties, Commonwealth royalties and excise) are deductible for PRRT purposes, and are uplifted at the LTBR plus 5 percentage points. In this sense, resource tax expenditures can be seen as a pre-payment of PRRT. The 5 percentage point uplift loading on these credits is designed to recognise the risk to the investor that uplifted credits will never be offset against future PRRT payments.

However, as the Review observed, from the Commonwealth’s perspective there is no difference between providing the value of a credit up front or later if the uplift rate on the credit carried forward matches the Commonwealth’s cost of borrowing or LTBR. This may suggest that the Commonwealth should not be providing an uplift rate for resource tax expenditure credits higher than its cost of borrowing.

#### Questions for consultation

1. Of the options outlined above, which option, or combination is preferred? What are the advantages and disadvantages of each option? Which options could be considered in combination?

2. Given that transferability provisions have been inserted in the system, should exploration expenditure continue to attract a higher uplift rate (or larger investment allowance) relative to general expenditure?

3. If exploration expenditure continues to attract a higher uplift (or larger investment allowance) than general expenditure, what is the appropriate differential?

4. If the uplift rates are lowered, what would be the appropriate rates for exploration, and general expenditure?

5. Which option is likely to be the most robust to changes in the industry (for example, infrastructure sharing, future oil and gas discoveries)?

6. If deductions were to be uplifted for a set number of years, what would the appropriate time period be? When would be the most appropriate time to apply this limit from (for example, from the time expenditure is incurred or from the time a project obtains a production licence or starts producing)?

7. If an investment allowance was introduced, what would be the appropriate amount for the initial deduction? What would the appropriate uplift be thereafter?

8. What is the appropriate uplift rate for resource tax expenditure?

## 2. Changes to the order of deductions

The *Petroleum Resource Rent Tax Assessment Act 1987* (PRRT Act) prescribes the order in which deductible expenditure is to be applied against assessable receipts. Given the current diversity of uplift rates that apply to different categories of expenditure (ranging from GDP factor to LTBR plus 15 percentage points), the order in which deductions are applied has a significant impact on ultimate PRRT liabilities.

#### Summary of the current rules

Under the PRRT, assessable receipts are reduced by eligible deductible expenditure in accordance with ordering rules to determine the PRRT taxable profit. Initially, the order of deductible expenditure in the PRRT regime operated under a ‘highest uplift first principle’, with expenditure attracting higher uplift rates deducted first. This was contradicted with the introduction of the categories of transferable exploration expenditure in 1991, as general expenditure (LTBR plus 5 percentage points) was deducted before more mobile, transferable exploration expenditure (LTBR plus 15 percentage points). This ‘project first principle’ was itself contradicted in 2012, when the PRRT was expanded to include onshore and North West Shelf projects. Here, starting base and resource tax expenditure categories introduced at this time recognised project-based historical expenditure and project-based royalties and excises paid to states or the Commonwealth respectively, and were placed lower in the order of deductions. Table 1 outlines the different categories of currently applicable deductible expenditure, the order in which they must be deducted and the uplift rates that apply.

#### Table 1 – Order of deductible expenditure in the PRRT

|  |  |  |
| --- | --- | --- |
| Category of Deductible Expenditure | Description | Uplift Rate |
| Class 1 ABR general expenditure | General expenditure before 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 1 ABR exploration expenditure | Exploration expenditure before 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 2 ABR general expenditure | General expenditure after 1 July 1990, less than 5 years before production licence came into effect. | LTBR + 5% |
| Class 1 GDP factor expenditure | General expenditure and exploration expenditure (before 1990) incurred more than 5 years before production licence came into effect.  | GDP deflator |
| Class 2 ABR exploration expenditure**TRANSFERABLE** | Exploration expenditure incurred after 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 2 GDP factor expenditure**TRANSFERABLE** | Exploration expenditure incurred after 1 July 1990, more than 5 years before production licence came into effect. | GDP deflator |
| Resource tax expenditure | Commonwealth, state and territory imposed resource taxes, divided by 40 per cent. | LTBR + 5% |
| Acquired exploration expenditure | The exploration component of the ‘look back’ method of determining the starting base. | LTBR + 15% for 5 years following May 2010, LTBR + 5% thereafter |
| Starting base expenditure | Recognising the value of projects brought into the PRRT regime in 2012. | LTBR + 5% in most cases |
| Closing-down expenditure | Eligible undeducted payments to close operations are credited. | ‑ |

#### Issues identified in the Review

The Review comments that the current ordering of PRRT deductions is complex with no consistent rationale. This largely reflects the aforementioned changes to the PRRT over time which introduced more categories of expenditure that tried to accommodate varying underlying principles. This diminishes the integrity of the PRRT and may also significantly impact revenue.

The Review drew particular attention to the impact of having Class 2 ABR general expenditure (which has an uplift rate of LTBR plus 5 percentage points and is not transferrable) appearing higher in the order of deductions than transferable expenditure, including Class 2 ABR exploration expenditure that attracts the highest uplift factor of LTBR plus 15 percentage points. The result is that if the exploration expenditure is not transferred, it can accumulate and compound substantially before a project’s pool of general expenditure deductions is exhausted. This delays the time from when a project starts paying tax than if these expenditures were deducted first, and makes some deductions more valuable than others. This is exacerbated where projects are expected to have a long period elapsing between the incurring of expenditure and the offsetting against assessable receipts, as is the case with many of Australia’s LNG operations.

This was illustrated in the Review through a hypothetical 40 year gas project, where establishing an order that deducted expenditure with the highest uplift first resulted in PRRT starting to be collected in half the time than if the current ordering rules were maintained (18 years after production commenced rather than 36 years).

To further complicate outcomes, the revenue treatment when exploration expenditure is transferred is not predictable (see section 3).

#### Options for consideration

Where uplift rates differ between categories of deductible expenditure, the order of deductions will always have an important impact on the amount of PRRT a project pays over its lifetime. The greater the variation in uplift rates between categories of deductible expenditure, the more important it becomes that the order be based on a coherent approach which takes into account transferability.

Only one option for deduction ordering is canvassed in this paper and it is applicable to a situation where varying uplift rates for different categories of expenditure continues to be a feature of the PRRT. Any change to the order of deductions would need to take account of changes to the uplift rates discussed in section 1. For example, if uplift rates were made uniform the order of deductions would cease to be a material issue.

The Review recommended that the sequence of deductible expenditure be based on the dual ordering principle of:

(1) expenditure with higher uplift before expenditure with lower uplift; and

(2) transferable expenditure before project‑specific expenditure.

Starting base expenditures, which were introduced for transitioning projects in 2012, were excluded from this principle. These were placed last in the order as the starting base largely eliminated the possibility that these projects would pay PRRT. As such, it was not considered appropriate that significant amounts of exploration expenditure be transferred to other projects, which would lower PRRT payable in receiving projects.

Table 2 details an amended order of deductions that incorporates the dual ordering principles proposed by the Review together with the other categories of deductible expenditure. This order is based on the assumption that all else in the regime, for example current uplift rates and transferability rules, remains unchanged.

#### Table 2 – Amended order of deductions proposed in the Review

|  |  |  |
| --- | --- | --- |
| Category of Deductible Expenditure | Description | Uplift Rate |
| Class 2 ABR exploration expenditure**TRANSFERABLE** | Exploration expenditure incurred after 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 1 ABR general expenditure | General expenditure before 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 1 ABR exploration expenditure | Exploration expenditure before 1 July 1990, less than 5 years before production licence came into effect. | LTBR +15% |
| Class 2 GDP factor expenditure**TRANSFERABLE** | Exploration expenditure incurred after 1 July 1990, more than 5 years before production licence came into effect. | GDP deflator |
| Class 2 ABR general expenditure | General expenditure after 1 July 1990, less than 5 years before production licence came into effect. | LTBR + 5% |
| Class 1 GDP factor expenditure | General expenditure and exploration expenditure (before 1990) incurred more than 5 years before production licence came into effect.  | GDP deflator |
| Resource tax expenditure | Commonwealth, state and territory imposed resource taxes, divided by 40 per cent. | LTBR + 5% |
| Acquired exploration expenditure | The exploration component of the ‘look back’ method of determining the starting base. | LTBR + 15% for 5 years following May 2010, LTBR + 5% thereafter |
| Starting base expenditure | Recognising the value of projects brought into the PRRT regime in 2012. | LTBR + 5% in most cases |
| Closing-down expenditure | Eligible undeducted payments to close operations are credited. | ‑ |

#### Questions for consultation

9. Is the proposed dual principle appropriate?

10. How material is the impact of changing the order of deductions as compared to other options (such as changing the uplift rate for exploration expenditure)?

## 3. Transferability

In 1991, amendments to the PRRT Act were made to allow exploration expenditure to be transferred between different production licence areas that have common ownership. This reduced the risk that exploration expenditure in an unprofitable project would never be able to be deducted.

#### Summary of current rules

Exploration expenditure incurred on or after 1 July 1990 is able to be transferred to other petroleum projects that the company either owns or that is within the company’s wholly owned group.

The uplift rate that applies depends on whether the exploration expenditure is before or after 5 years before the year in which a production licence of the receiving project was applied for. This results in two categories of transferable deductible expenditure, tabulated below. No other deductible expenditure is able to be transferred.

|  |  |  |
| --- | --- | --- |
| **Category of Deductible Expenditure** | **Description** | **Uplift Rate** |
| Class 2 augmented bond rate exploration expenditure  | Exploration expenditure incurred after 1 July 1990, less than 5 years before production licence came into effect. | LTBR + 15% |
| Class 2 GDP factor expenditure  | Exploration expenditure incurred after 1 July 1990, more than 5 years before production licence came into effect. | GDP deflator |

In addition to the ordering rules (see section 2), transfers of eligible transferable exploration expenditure must meet certain conditions and must be made in a specific order. These the rules are outlined in Schedule 1 of the PRRT Act. In brief, the conditions that must be met are:

* the receiving project needs to have a PRRT taxable profit;
* a common ownership test must be satisfied, generally requiring a company or group company to have an interest in both the transferring and receiving project from the start of the year in which the expenditure is incurred until the end of the year in which the expenditure is transferred;
* the amount of expenditure transferred can only be so much as sufficient, with appropriate uplifts to reduce the PRRT profit of the receiving project to zero.

The specific order that transfers are to be made is first, to other petroleum projects that the company owns in the order:

* Transfers are made to the petroleum project with the most recent production licence first.
* Class 2 ABR exploration expenditure (which attracts the LTBR plus 15 percentage points uplift rate) is to be transferred before Class 2 GDP factor expenditure (which has an uplift rate of the GDP deflator). The uplift rate applied to the transferred expenditure is determined by reference to the receiving project.
* The oldest eligible expenditures are to be transferred first. Put another way, the expenditure is transferred on a first-in-first-out (FIFO) basis.

After transfers are made to projects that the company owns, transfers may then be made to other companies within a wholly owned group. The same order (for transfers to other projects that the company owns) is maintained.

As all transferrable expenditure that satisfies the rules must be transferred, companies generally have no choice with respect to which expenditure is transferred from a project or the receiving petroleum projects that this expenditure is transferred to. Companies also have no choice with respect to the final tax treatment that results from the transfer, as the uplift rate applied depends on the characteristics of the receiving project. Industry representations to the Review reinforced this ̶ outlining that exploration was rarely carried forward at the LTBR plus 15 percentage point uplift rate for long periods and that it was hard to predict what uplift exploration expenditure would get as a result of the transfer rules.

#### Issues identified in the Review

The Review identified that the order in which eligible expenditure is deducted and the transferability of certain types of expenditure can have an important impact on the amount of PRRT a project pays over its lifetime. In some cases, the compulsory transfers reduce the chance that uplifted exploration expenditure grows so large that it effectively shields profitable projects from tax. However, whether this outcome is achieved depends on each company’s portfolio of projects and when they earn revenue. An illustration of how the exploration expenditure for several participants in the same project could receive different treatment is outlined in more detail in Box 1.

In this example four participants each have an equal interest in a project. The first participant, Company A, also had an interest in a profitable project. As a result, Company A’s exploration interest was transferred immediately without any uplift. Companies B and C had interests in other (separate) projects which became profitable a number of years after the exploration expenditure was incurred. At that later time, both Company B and C transferred exploration expenditure based on the facts of their respective receiving projects. As the receiving projects had different characteristics, the exploration expenditure received different treatment when transferred. The fourth participant, Company D, did not have an interest in another profitable project. It was therefore not able to transfer the expenditure to another project. In this case, Company D’s exploration expenditure was carried forward and deducted against its future assessable receipts in the project.

Overall, under the current rules, it is difficult to predict what revenue treatment will result from the application of transferability. The factor that determines the final tax treatment seems arbitrary. It is based on whether the receiving project had satisfactorily applied for its production licence within five years of the time the expenditure (that is to be transferred) is incurred.

Combined with the wide difference in the uplift rates that can apply, this means very different tax outcomes can result from the same interest in a project. This is further exacerbated by the ordering rules (see section 2) which deducts Class 2 general expenditure (which has an uplift rate of LTBR plus 5 percentage points) before Class 2 exploration expenditure (which has the highest uplift rate of LTBR plus 15 percentage points).

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| **Box 1 – An illustration of the arbitrary outcomes from the current transferability rules**Project Green has four participants: companies A, B, C and D, each with an equal interest. Project Green applied for and obtains a production licence in 2019-20, starts production in 2025-26 and is first profitable in 2036-37. For illustrative purposes, we assume that the only exploration expenditure incurred in respect of the project is $400 million in 2017-18. We also assume there is no other expenditure higher in the order of deductions that needs to be taken into account. This provides each participant with $100 million of transferable exploration expenditure from its interest. Some companies have interests in other petroleum projects:

|  |  |  |  |
| --- | --- | --- | --- |
|  | Other project interests  | Production licence applied for and granted | Profitable from  |
| Company A | White  | 1999-20 | 2015-16 |
| Company B | Blue | 2024-25 | 2027-28 |
| Company C | Red | 2009-10 | 2027-28 |
| Company D | - | n/a | 2036-37 |

The treatment of the transferable interest for each participating company follows:**Company A**Company A has an interest in Project White which in 2017-18 had a PRRT notional taxable profit of $1000 million. Company A must transfer its 2017-18 exploration expenditure in Project Green to Project White. This amount is not uplifted (given this is a current year transfer). Following the transfer, the 2017-18 taxable income in Project White is reduced from $1000 million to $900 million. **This reduces Company A’s PRRT liability with respect to Project White by $40 million** (from $400 million to $360 million) in the 2017-18 income year. There is no balance of Company A’s interest in Project Green’s 2017-18 exploration expenditure to carry forward as the full amount was transferred to Project White.**Company B**Company B’s interest in Project Blue starts to become profitable in 2027-28 with a notional taxable income of $1000 million in that financial year. As a result, in 2027-28, Company B is required to transfer some of its exploration expenditure from Project Green to Project Blue. As the uplift rate that applies is determined with reference to the receiving project, this is the GDP deflator (given the 2017‑18 expenditure was incurred after 1 July 1990 but more than 5 years before the production licence for Project Blue was applied for and granted in 2024‑25).

|  |  |  |  |
| --- | --- | --- | --- |
| Year | Uplifted exploration ($ million) | Year | Uplifted exploration ($ million) |
| 2017-18 | 100 |  |  |
| 2018-19 | 100 x (1.0+0.05)= 105 | 2023-24 | 134 |
| 2019-20 | 110 | 2024-25 | 141 |
| 2020-21 | 116 | 2025-26 | 148 |
| 2021-22 | 122 | 2026-27 | 155 |
| 2022-23 | 128 | 2027-28 | **163** |

(The GDP deflator is assumed to be constant at 5 per cent.)Project Blue’s 2027-28 notional taxable income is reduced from $1000 million by $163 million to $837 million. **This reduces Company B’s PRRT liability with respect to Project Blue by $65 million** (from $400 million to $335 million) in the 2027-28 income year. There is no balance of Company B’s exploration expenditure to carry forward as the full amount was transferred to Project Blue.**Company C****C**ompany C’s interest in Red also starts becoming profitable in 2027-28 with a notional taxable profit of $1000 million. However, Red applied for and received its production licence in 2009-10. This means that while Company C must also transfer some of its exploration expenditure interest from Project Green to Red, the uplift rate that applies is LTBR plus 15 percentage points (as 2017-18 expenditure is incurred no earlier than five years before Red’s production licence was applied for and granted in 2009-10).

|  |  |  |  |
| --- | --- | --- | --- |
| Year | Uplifted exploration ($ million) | Year | Uplifted exploration ($ million) |
| 2017-18 | 100 |  |  |
| 2018-19 | 100 x (1.15+0.05)= 120 | 2023-24 | 299 |
| 2019-20 | 144 | 2024-25 | 358 |
| 2020-21 | 173 | 2025-26 | 430 |
| 2021-22 | 207 | 2026-27 | 516 |
| 2022-23 | 249 | 2027-28 | **619** |

(The LTBR is assumed to be constant at 5 per cent.)Project Red’s 2027-28 notional taxable income is reduced from $1000 million by $619 million to $381 million. **This reduces Company C’s PRRT liability with respect to Project Red by $248 million** (from $400 million to $152 million) in the 2027-28 year. There is no balance of Company C’s exploration expenditure to carry forward as the full amount is transferred to Project Red. While both Company B and C’s interests in their respective projects start to become profitable in the same year and with the same notional taxable profit, the tax outcomes as a result of transferability are different.**Company D**Company D does not have any other petroleum project interests. Its exploration expenditure from the 2017-18 year is considered Class 2 ABR exploration expenditure. Accordingly, it is uplifted at the rate of LTBR plus 15 percentage points and carried forward until the 2036-37 financial year when Project Green is in a cash flow positive situation. In 2036-37, the uplifted exploration expenditure that is able to be deducted is $3195 million.

|  |  |  |  |
| --- | --- | --- | --- |
| Year | Uplifted exploration ($ million) | Year | Uplifted exploration ($ million) |
| 2017-18 | 100 | 2027-28 | 619 |
| 2018-19 | 100 x (1.15+0.05)= 120 | 2028-29 | 743 |
| 2019-20 | 144 | 2029-30 | 892 |
| 2020-21 | 173 | 2030-31 | 1070 |
| 2021-22 | 207 | 2031-32 | 1284 |
| 2022-23 | 249 | 2032-33 | 1541 |
| 2023-24 | 299 | 2033-34 | 1849 |
| 2024-25 | 358 | 2034-35 | 2219 |
| 2025-26 | 430 | 2035-36 | 2662 |
| 2026-27 | 516 | **2036-37** | **3195** |

(The LTBR is assumed to be constant at 5 per cent.) |

#### Options for consideration

The Review recommended that the rules for transferability of expenditure be examined to ensure they produce a consistent set of outcomes. The Review did not explicitly raise whether the design feature of transferability should be revisited. Transferability provides investors with an incentive to undertake exploration and to maintain a portfolio of interests that move to a production phase. It does this by reducing the risk that unprofitable exploration expenditure will not be able to be offset against assessable revenue (or be a stranded expense). For the Australian community, transferability offers the prospect of helping ensure an equitable return while not discouraging petroleum investment. This is because it helps offset lengthy periods where exploration expenditure is uplifted at a relatively high rate. In addition, maintaining a setting that did not discourage investment was considered appropriate.

Within this context, the objective of this consultation is to consider options that increase the predictability and consistency in revenue outcomes resulting from transferability.

Options that increase consistency in outcomes could do so by decreasing the difference in the uplift rates that apply at the time of the transfer and/or when exploration expenditure becomes deductible against future receipts. These include:

* Option 1: apply a uniform uplift rate to all expenditure that is transferred.
* Option 2: revise the exploration uplift setting and have this treatment apply for transfers and deductible expenditure.
* Option 3: working within the existing regime and changing the uplift factors and ordering rules so these better take transferability into account.

Options 2 and 3 above rely on changes resulting from consideration of sections 2 and 3 of this consultation paper. Further, the example outlined in Box 1 on Project Green illustrates the importance of setting an appropriate exploration uplift rate. The current uplift rate for Class 2 ABR exploration expenditure of LTBR plus 15 percentage points is particularly generous (see section 1). In cases where projects can expect to have a long period between incurring expenditure and deriving assessable receipts, as is the case with the LNG operations that have recently or will soon move into the production phase this magnifies the design weakness of having a very generous uplift rate by further eroding the PRRT tax base. A key consideration under each option is that an appropriate exploration uplift setting also applies. The issues outlined in section 1 should be considered together with these transferability options.

In exploring these options, it is acknowledged that some variation in revenue outcomes can be expected. This reflects that different PRRT taxpayers will have different ownership interest in production licences. The ability to transfer expenditure also introduces additional variability. While increased consistency may be a desirable goal, a uniform outcome will not necessarily be the end point.

##### Option 1: Apply the same uplift to expenditure that is transferred

Under this option, a single uplift rate would apply to expenditure that is transferred.

This approach captures all exploration expenditure that is able to be transferred but that is not immediately deductible (at level). This option would replace the rule that the uplift rate be determined by reference to the receiving project with a rule that sets a single uplift rate that would apply when expenditure is transferred.

The uplift rate set would need to be considered together with the proposals outlined in section 1. It would also need to take into account the uplift rate that applies where the exploration expenditure is to be carried forward and deducted against future assessable receipts in the project – ideally the difference in treatment between expenditure that is held for either future deductibility or to be transferred should not be significant.

By way of illustration, if the Box 1 Project Green example were subject to this option, Companies B and C would now receive the same deductible expenditure (where currently Company B receives a reduction in Project Blue’s PRRT liability of $65 million and Company C receives a reduction in Project Red’s PRRT liability of $248 million). The outcomes of Companies A and D, however, would remain the same.

##### Option 2: Revise exploration uplifts and have the same treatment apply for both transfers and within‑project deductions

This option consists of two related components.

* The first component involves replacing the current rule which determines the uplift rate by reference to the receiving project with a rule that determines the uplift by reference to the transferring project.
* The second component would be to revise the exploration expenditure uplifts and to have this revised treatment apply universally – whether the exploration is carried forward for later deduction when the project starts becoming profitable or whether it is transferred to another project at the time.

Key to this option will be ensuring the exploration uplift rate is set appropriately.

One benefit of this approach is that regardless of the year in which the transfer occurs, or whether a transfer occurs, the revenue treatment would be predictable and uniform. If the Project Green example in Box 1 were applied here, Companies A, B, C and D would now receive the same uplift.

##### Option 3: Change the uplift factors and ordering rules so these better take transferability into account

This approach would work within the existing parameters on the regime and focus on:

* ensuring the uplift rate for each category of deductible expenditure is set appropriately and is not overly generous (see section 1);
* reducing the variations between the uplift rates, where appropriate; and
* giving transferability greater consideration in the ordering rules.

Should the uplift rates become more uniform, then transferability (together with the order of deductible expenditures) becomes less material. If, however, there continues to be a difference in uplift rates between categories of deductible expenditure, then the order of deductible expenditure will become more important in impacting revenue outcomes.

In the case where there is a high variation in uplift rates between categories of deductible expenditure, transferable exploration expenditure should be deducted first (with transferable expenditure with higher uplift rates deducted first, if there are differences). After transferable expenditure is deducted, other categories of expenditure should be deducted in the order of those with the highest uplift rate to the lowest uplift rate.

#### Questions for consultation

11. Is a consistent set of outcomes for PRRT taxpayers desirable or should the focus be on rewarding companies that have multiple projects underway?

12. Should transferability remain part of the PRRT or should the risk of never being able to offset some deductible expenditure against revenue be accounted for in some other way?

13. Treasury is interested in views on these options – the positives and negatives – and the reasons why one approach may be favoured above others. Are there other approaches that could be considered?

## 4. Gas Transfer Pricing

The problem the *Petroleum Resource Rent Tax Assessment Regulations 2015* (the Regulations), were created to solve is how the value received for the sale of LNG should be distributed across the LNG value chain in situations where there is no arm’s length sale of the petroleum between extraction and liquefaction (in order to determine the value of sales gas at the taxing point for PRRT). The Regulations do this by providing a framework for assigning a value to the feedstock gas of the LNG operation at the taxing point.

For PRRT purposes an amount is included in assessable petroleum receipts at the point where a Marketable Petroleum Commodity (MPC) becomes an ‘excluded commodity’. MPC is a defined term and includes ‘sales gas’. An MPC becomes an excluded commodity by being sold, further processed or moved away from its place of production.

Where sales gas recovered from a PRRT project is used as feedstock in LNG production, it becomes an excluded commodity at the point it is sold by the gas producer to be used in the LNG project. Where that sale is an arm’s length transaction the amount received for the sale of the sales gas becomes the assessable receipts of the PRRT project.

In circumstances where the sales gas is sold and becomes an excluded commodity by a non‑arm’s length transaction or where it becomes an excluded commodity other than by sale (is used in an integrated operation) the Regulations provide the framework for determining the value of assessable receipts.

In other circumstances, such as where the project’s natural gas is sold prior to the production of an MPC, general valuation principles are used to determine the value of the project gas at the taxing point.[[2]](#footnote-3)

The existing design of the PRRT is that in an integrated operation where there is no sale of sales gas prior to LNG being produced, the project to which the PRRT applies only exists up to the point where initial processing of ‘sales gas’ is complete. The PRRT project does not extend to the subsequent processing of the gas into LNG. The role of the Regulations is to determine how much of the value received for the final LNG product should be allocated to the PRRT project up to the taxing point and how much should be allocated to the liquefaction operations.

#### Summary of existing rules

There are three options provided in the Regulations for calculating the value of assessable receipts:

* The first is an agreed approach with the Commissioner through an advance pricing arrangement (APA).
* The second is the use of a comparable uncontrolled price (CUP).
* The third is the use of the Residual Pricing Method (RPM).

The Regulations set out the conditions required for each approach to apply and the order in which they apply. Generally, if an APA has been agreed it applies. In the absence of an APA, if a CUP can be established it will apply. If there is no APA and no CUP then the RPM will apply as the default methodology. Onshore integrated LNG operations can also elect to use the RPM, even if a CUP is available. Because the RPM is a default method it effectively acts as a safe-harbour approach for the purposes of both planning and calculating assessable receipts for integrated LNG operations. Although there are three options, the practical outcome is that the RPM predominates, unless the particular circumstances of an operation mean that it does not apply.

#### Issues identified in the Review

The Review established that the design of the existing framework was a result of a number of policy and tax design decisions, but that there are genuine concerns about whether the outcome of those decisions has resulted in a fair distribution of the rents of LNG projects. In particular the Review found that the current system is a result of:

* The decision that the PRRT would apply only to the production of feedstock gas and not to the whole LNG project.
* The decision that the preferred approach to valuing the feedstock gas in an integrated operation is by using the arm’s length principle.
* That the preferred methodology for determining the arm’s length value is by using comparable transactions or through an industry based pricing mechanism, however at the time the Regulations were introduced foreseeable market conditions would not support the implementation of such an approach.
* The RPM was developed through a lengthy consultation approach with industry using independent experts to assist.
* Design decisions in the implementation of the RPM favoured the allocation of capital and distribution of capital in the downstream operation at the expense of the upstream operation.

Submissions to the Review suggested a range of ways in which the arrangements could be changed. Any change however, will need to be done in a way that can apply across a range of very different LNG operations factoring in:

* That each operation has unique geographical, logistical and engineering challenges that require a unique process design.
* Differences in the chemical composition and specification of the feed gas mean different process requirements.
* The high technological and cost barriers to entry result in the need to integrate upstream and downstream operations and infrastructure to ensure that the gas produced has a market.
* Presently, Australian LNG producers often substantially or exclusively use their own gas or gas from projects owned by related entities for LNG production.
* That unlike some other jurisdictions the Australian Government does not take a share in petroleum projects or generally contribute to the costs of gas processing or liquefaction facilities.
* The distance between different gas projects and between those gas projects and intended markets has meant that Australia has not yet developed the same independent hubs or multi-user downstream facilities that other jurisdictions have developed.

The Review noted that developments and changes in the gas industry in Australia since the development of the Regulations mean that it is appropriate to review whether the option of establishing a shadow price or CUP is now possible. In particular the review noted increased competition for gas between domestic and export uses on the East Coast. LNG facilities completed or under construction in North Western Australia are expected to eventually process third party gas.

A review of the approach to gas transfer pricing is an opportunity to ensure that the PRRT works in the Australian context and that it results in a fair distribution of the economic rents from LNG production for integrated projects but also produces similar and appropriate PRRT outcomes for those entities selling third party gas to an LNG producer as for those LNG producers who produce LNG with their own or a related entity’s sales gas.

The Review concluded that:

* The RPM is complex, opaque and raises issues as to whether the Australian community is receiving an equitable share from the gas used in LNG projects.
* An in depth examination of the gas transfer pricing arrangements should be undertaken.
* The option of using the CUP as the primary method should be explored.
* The RPM should be further reviewed to assess whether the design features, including the way profits are split, the capital allowance rates and asymmetries in the model are appropriate.

The Review recommended changes be considered that would achieve greater simplicity and transparency, ease of compliance, and fair treatment of economic rent from each stage of an integrated petroleum operation.

The modelling undertaken by the Review indicated that the gas transfer pricing arrangements ‘are a very significant factor influencing PRRT revenue’.

##### Simplicity and transparency

The existing framework in the Regulations is complex and lacks transparency. The method chosen for the way assessable receipts are calculated is confidential between the Commissioner of Taxation and the taxpayer, as is the result of the calculations, consistent with other taxation provisions.

An APA can take 18 months to negotiate at significant cost to the taxpayer and the ATO. The term of the APA is generally then confined to a period of three to five years. The selection of methodology and inputs for calculating the transfer price require expert analysis. There is no transparency for the community, because APA’s are confidential between the taxpayer and the Commissioner.

The approach for calculating a CUP requires a detailed assessment of the relevant markets for the transactions being compared. Under the existing test, a CUP would be very difficult to establish especially in wholly integrated offshore operations. The result is that establishing a CUP under the existing framework is complex and unlikely, involves detailed analysis and is not transparent for the community.

The RPM is also detailed and complex with multiple steps and sub steps in the calculation. Although prescriptive in the inputs for the calculations expert knowledge and judgment is required as well as complex apportionment, volumetric measurement and analysis. The result is that although the methodology is transparent and consistent because the detailed steps are publicly available, the complexity, expert judgment and project knowledge required means that there is very little transparency about the results the method produces.

The Review noted that the current system is highly complex and that the complexity, particularly of the RPM, means that there is no transparency about how the gas transfer price is calculated.

##### Ease of compliance

The existing framework requires high upfront costs and ongoing monitoring to ensure compliance either through an APA, CUP or the RPM.

The Review noted that the RPM and APA were considered beneficial from a project planning perspective as they allowed companies to model the impact of the PRRT on the project. However, the application of the RPM to new technologies, new project configurations and new fields will result in uncertainty and complexity in appropriately allocating, uplifting and apportioning expenditure across LNG operations.

##### Fair treatment of economic rent

The Review noted that in practice the RPM would be used directly or as the basis for an APA unless it produced an outcome that was anomalous. The Review found that a CUP was unlikely to be established for offshore operations and that onshore entities are able to avoid a CUP by electing to prioritise the RPM. Consequently ensuring that the RPM appropriately distributes value and associated economic rents between the upstream and downstream components of integrated operations is essential to ensure that the Australian community receives an equitable return from the recovery of petroleum while also recognising and appropriately rewarding the downstream investment.

In particular the Review noted that the existing design of the RPM was not consistent with the intent of properly reflecting all upstream rents within the PRRT ring-fence. Asymmetric treatment of the upstream and downstream operations, the capital allowance rate and equal residual profit split all had an impact on the allocation of rents. For example, in relation to the way residual profits are split, the Review found that when resource rents are high, that the RPM results in the PRRT project being undertaxed, while when downstream rents are high the PRRT project will be overtaxed.

The significance of the gas transfer pricing arrangements on overall PRRT revenue means that if the safe harbour or default methodology settings are not balanced and appropriate, then there is the risk of a material transfer of value from the PRRT project to downstream operations.

#### Options for consideration

#### There are three main options for reforming the way assessable receipts are calculated for feedstock gas in integrated LNG projects:

* The first option is to work within the existing framework in the Regulations but consider changes to improve that framework, by bringing the CUP rules up to date with international best practice and reviewing the RPM method to achieve a greater proportion and distribution of rents to the upstream operations. The existing framework can also be improved by prioritising a CUP for both onshore and offshore operations.
* The second option is to retain the approach of determining a transfer price at the taxing point but to use a different transfer pricing approach such as a netback.
* The third option would be to remove the need for valuation of the feedstock gas at the taxing point prior to liquefaction by moving the taxing point for integrated LNG operations to the end of the liquefaction process.

Changes for each of these options will also have ramifications for integrated operations where project gas is sold prior to processing into sales gas or prior to the taxing point. These impacts will be considered as part of the detailed design phase of any of the proposed options.

##### Option 1A: Modify the CUP method

The Review noted that it was always the intention that if a shadow price methodology or CUP methodology could be established that this would be the preferred method of determining the arm’s length price. At the time the legislation was introduced in 2001 it was not expected that such an approach could be established. At the time the legislation was introduced there was only one LNG production facility in Australia, the North West Shelf project, and at that time it was not part of the PRRT regime.

In 2017, 16 years after the introduction of the legislative framework for gas transfer pricing, there are now 10 LNG production facilities in operation or under construction. There has also been extensive work in recent years focused by the OECD on the CUP methodology as it applies to commodity transactions.

The Regulations currently specify that a price is a CUP only if it is a price obtained for sale in a market that is relevant to the assessable gas transaction that is being priced and the price is an observable arm’s length price. It then outlines a range of factors to be taken into account in determining whether a market is relevant.

Given the changes to the Australian industry context and global transfer pricing best practice it is timely to reconsider whether a CUP or shadow price could be established as the preferred method of calculating the transfer price. Consideration will be given to whether the existing CUP rules in the Regulations should be changed or modified to:

* Prioritise a CUP over the other methods of determine the gas transfer price (an APA or the RPM).
* Review the current way the CUP rule is designed to determine whether it now reflects international best practice, and assess whether changes to the CUP rule can be made to make it more likely that a CUP can be established without undermining important, globally recognised comparability factors.
* Replace the existing CUP rule and determine a notional or proxy CUP for gas traded though a hub, within a geographical region or across the industry by reference to an appropriate market based gas price index (or volume weighted average of a basket of gas market price indices).

If a CUP or shadow price was established for an integrated LNG operation, then the transfer price of the feedstock gas will no longer be determined by reference to the price received by the LNG operation. Assessable receipts would no longer be linked to the LNG price that participants receive under long term contracts. Instead assessable receipts for PRRT purposes will be driven by the market for sales gas or the relevant price indices that are used to determine the CUP price. Deductible expenditure would be unaffected.

Such an approach would improve both the simplicity and transparency of the gas transfer price. It would improve the ease of compliance, as PRRT taxpayers using a CUP would not be required to go through the complicated steps in the RPM. It would also provide a stronger correlation between gas prices and the economic rents attributed to the feedstock gas under the PRRT, resulting in a more appropriate distribution of rents between the upstream and downstream phases. The price would be more consistent across industry and across projects, particularly those projects using the same LNG processing facility, meaning a more level playing field for PRRT purposes.

There is a risk that for some taxpayers, the CUP price may exceed the price at which the LNG is sold under contract. In such circumstances, the assessable receipts of a PRRT project would exceed the cash flows of the integrated LNG operation. Measures could be considered to ensure that taxpayers are not placed in this position or to reflect a minimum cost for LNG production.

##### Questions for consultation

1. What approach to reforming the CUP rules in the Regulations are the most appropriate in terms of meeting the outcomes identified in the Review of fair distribution of rents, simplicity and transparency and ease of compliance?
2. What, if any, are appropriate combinations of gas market price indices on which to build a notional or proxy CUP?
3. What safeguards may need to be put in place to ensure that the CUP price does not exceed the proceeds of the LNG operation?
4. What safeguards may be needed to ensure that liquefaction operations are able to cover costs, and if so what is an appropriate way to recognise this amount?

##### Option 1B: Modify the RPM

The Review analysed the RPM and noted that particular features of the design and implementation of the RPM were not consistent with the intent of the methodology.

In particular the Review raised concerns and recommended further review of:

* The way capital is allocated, augmented and rewarded in the methodology and in particular whether the treatment of capital is consistent and appropriately represents the respective costs of investment.
* The interaction between the capital allowance rate and the residual profit split and in particular whether the way value is distributed between the upstream and downstream phases gives an appropriate reflection of the respective economic rents.

Particular features of the RPM that were identified in the Review as inconsistent or asymmetric were the way the RPM price is calculated when the overall operation is in a notional loss, the exclusion of exploration expenditure from the upstream capital allocation rules and the application of the augmentation and depreciation rules to assets. Each of these rules operates to potentially undervalue the capital contribution of the upstream project to the overall LNG operation.

The interaction between the capital allowance rate and the 50:50 residual profit split currently result in a methodology that is driven by the amount of capital that is allocated to the upstream and downstream. Changes to the LNG price have a direct impact on the netback price in the methodology but not a corresponding impact on the cost-plus price or the RPM price.

One of the issues impacting the methodology is that both the capital allowance rate and the residual profit 50:50 allocations were numbers that were selected without any appropriate justification being put forward. The capital allowance rate (LTBR plus 7 percentage points), was chosen as a proxy for the cost of equity for the projects, but there is no explanation about why the cost of equity is appropriate. The 50:50 residual profit split justification was that there was no available allocation key that worked and so 50:50 was the only way to allocate the profits. In each case the number chosen is explained but there is no information to suggest it is the right number.

In examining the results of the methodology however, the overall effect of the capital allocation asymmetries, the capital allowance rate and 50:50 split, is a methodology that is driven primarily by the weight of capital spent on the upstream and downstream components, with asymmetric treatment advantages given to the downstream capital. For the RPM to remain the default methodology there must be confidence that the capital driven model, gives an appropriate return to both the upstream and downstream investments and that increases in the price of LNG are appropriately distributed across the value chain.

Under this option the RPM could be modified to:

* Remove the rule that the RPM price is the netback price in situations where the cost‑plus price exceeds the netback price; this will ensure the rules operate consistently across the years of the LNG operation including notional loss years.
* Include exploration costs and other development costs in both the upstream and downstream capital allocation, this would ensure that a return on the costs of finding and developing the resource is recognised in the methodology, consistent with the fact that these costs are also deductible under the PRRT.
* Review the apportionment, augmentation, depreciation and allocation rules to ensure that upstream capital is not reduced both by depreciation and apportionment in circumstances where the project produces other MPCs prior to LNG production commencing.
* Develop and apply an allocation key for an appropriate split of the residual profits. One possible approach is to use an allocation key based on capital allocation, this would effectively remove the interaction between the capital allowance rate and the residual profit split. A second approach is to compare the value of the unique intangibles that contribute to the residual profits, for example, the costs of finding and developing the resource for the upstream and the cost of accessing the liquefaction technology for the downstream.
* Review the capital allowance rate to consider changes to ensure that it reflects the weighted average cost of capital for integrated LNG operations rather than the cost of equity.

##### Questions for consultation

1. What, if any, unintended consequences may arise from removing the asymmetric treatment of the upstream and downstream businesses?
2. What would be an appropriate allocation key within the context of the RPM, to appropriately attribute residual profits upstream and downstream so that they more appropriately reflect the respective economic rents of each operation?
3. Are there any other aspects of the RPM that result in asymmetric treatment of upstream capital? Are there any aspects of the RPM that result in asymmetric treatment of downstream capital?
4. Are there reasons that the capital allowance rate in the RPM should reflect the cost of equity rather than the lower weighted average cost of capital?

##### Option 2: Use a new transfer pricing approach to determine the transfer price

In the event that a satisfactory CUP or proxy CUP cannot be established and it is considered that the RPM cannot be modified to achieve an appropriate distribution of value across the LNG production process, other options may be considered.

One such option is to develop an alternative transfer pricing model to act as the default methodology in place of the RPM. A common approach to determine the value of a commodity at a specific point within an integrated operation is to use a netback methodology.

The key design feature that the RPM currently offers that most netback methods do not accommodate is the ability to allocate a proportion of profits to the downstream operation rather than allocating a fixed return. This reflects the principle agreed between industry and government that the transfer price methodology would reflect project risks equitably on all cost centres.

Consistent with the design of the RPM, any new transfer price methodology would need to take into account the project’s capital costs, operational costs, and the return on capital required to sustain investment. The key question is whether a transfer pricing methodology should also allocate a return for any unique and valuable assets possessed by the downstream operation.

The explanatory statement introducing the 2005 version of the Regulations recognised that the companies bring intellectual property and know-how related to gas production, processes and marketing.

##### Questions for consultation

1. As the global LNG market grows and LNG facilities proliferate, what are the unique and valuable assets that are used in the downstream operation?
2. How are intellectual property and know-how generally rewarded in arm’s length arrangements, for example third party tolling arrangements?
3. For PRRT purposes, should the design of a netback methodology result in downstream liquefaction facilities sharing in the upside of increases in the LNG price above that necessary to sustain investment and to what extent?
4. What transfer pricing methodology and what features of that methodology would ensure an appropriate distribution of any rents to the upstream and downstream business in a way that would truly reflect an arm’s length agreement?

##### Option 3: Move the taxing point to the end of the LNG production

The other option to be considered in the event that a CUP or proxy CUP cannot be established and it is considered that the RPM cannot be modified to achieve an appropriate distribution of value across the LNG production process is to move the taxing point to the end of the liquefaction process.

Moving the taxing point would involve a major change to the design of the PRRT and may have implications for other products. Part of the rationale for the design of the existing taxing point was separating the first produced product from products that further altered the chemical or physical properties of the petroleum.

Although the LNG process alters the physical properties of the sales gas, it does not do so permanently; regasification processes return the gas to a form suitable for use in destination markets. There is merit to the argument that the LNG process is simply part of the process of producing a marketable product.

The advantage of moving the taxing point is that it would align the arm’s length sales point for the operation with the PRRT project ring-fence. The effect of such changes on the way the PRRT works would be significant.

Assessable receipts for PRRT purposes would increase from the transfer price or market value of sales gas to the sales price for the project LNG. Deductible expenditure would increase to take into account downstream liquefaction, storage and loading facilities.

The PRRT ‘payback period’ would be changed to the extent that it changes the ratio of general expenditure to assessable receipts. The ‘payback period’ will also be affected if there are large amounts of expenditure attracting the higher exploration uplift in the project.

Once the project participants became profitable for PRRT purposes, the PRRT would be taxing higher cash flows; the return to the liquefaction business would no longer be quarantined from the 40 per cent tax rate.

The measure would simplify the PRRT regime and would remove any uncertainty about how the assessable receipts for a project should be calculated. It aligns the regime to the way projects generally operate and to observable transactions.

It would mean that the actual downstream expenditure is deductible once upfront rather than having ongoing value allocated across the life of LNG operations. Once the investment in the LNG plant had been recouped the government and the taxpayer would share in the profits of the overall operation via the PRRT tax rate.

Moving the taxing point without adjusting other parts of the PRRT regime could involve a substantial increase in PRRT revenue and have a corresponding impact on the cash flows of LNG operations, particularly once a project became PRRT profitable. Moving the taxing point would change the scope of the PRRT project from a tax on production and initial processing to a tax on a broader range of operations. Any rents from the downstream liquefaction business would be shared in the same manner between the producer and the government as upstream rents. Without some other adjustments to the PRRT regime it is not clear that simply moving the taxing point would result in an appropriate distribution of rents.

##### Questions for consultation

1. If the taxing point were moved to the end of LNG production, what other adjustments should be considered to ensure an appropriate recognition of rents?
2. How should the PRRT account for rents in the liquefaction business to the extent they exist in any given project?
3. How would moving the taxing point for LNG impact on other petroleum products?

## 5. What is a new project?

The Review recommended that major changes apply only to new projects, as defined in the PRRT legislation.

Part IV (section 19) of the PRRT Act provides a definition for a petroleum project which is linked to having a production licence in force. A production licence provides the licensee with the right to recover petroleum from a licence area and is typically obtained at the stage where investors have determined that that they will move to a recovery phase (from an exploration phase). In many cases this occurs close to the time that final investment decisions are made in respect of the project.

#### Questions for consultation

1. Are there any unintended consequences from having the new regime apply only to projects that have their production licence come into force after any amendments to the PRRT regime commence?
2. Should there be a delay between when the new changes are announced and when the new regime comes into effect?

#### Combinations of new with existing projects

Part IV of the PRRT Act also provides that petroleum projects can be combined, subject to being issued a combination certificate from the Resources Minister. Certain criteria that must be met are outlined in the legislation. This raises the question whether petroleum projects subject to an amended PRRT regime in future should be able to be combined with projects covered by the current regime, and if so, what arrangements would apply.

##### Option 1: Exclude existing projects from combining with projects subject to the new regime

As noted in the Review, when the scope of the PRRT was expanded in 2012 to include the North West Shelf and onshore projects, an integrity measure applied which specifically excluded transitioning projects from combining with offshore projects. This provision was inserted because there was an expectation that transitioning projects would be heavily shielded from PRRT liabilities and could shield offshore projects if they were allowed to combine. A similar arrangement could apply.

##### Option 2: New PRRT regime to apply where projects combine

Alternatively, the legislation could dictate that where projects are issued a combination certificate by the Resources Minister, and one of the production licences comes into force after the date of commencement of the new PRRT regime, the tax arrangements for the new regime should apply to the combined project.

#### Questions for consultation

31. Interested parties are encouraged to make comments on how the integrity of the new regime should be maintained where the opportunity exists for combinations to occur between projects within the new and existing regime.

#### Transfers between new and existing projects

Consideration will also need to be given to whether transfers of exploration expenditures should apply between new projects and existing projects, and if so what these arrangements would be.

The key issue to be managed would be to ensure integrity within the new regime, so that new projects are prevented from receiving more generous treatment after a transfer, than if the exploration expenditure had not been transferred. There are two broad options:

##### Option 1: Prevent existing projects from being able to transfer exploration expenditure to new projects (and vice-versa)

This option would ensure integrity by providing a clear ring-fence between the new regime and the existing regime with respect to transfers. New projects would only be able to transfer exploration expenditure to other new projects. Similarly, projects within the existing regime would be prevented from transferring exploration expenditure to projects that fall within the new regime.

##### Option 2: New legislation to outline rules for treatment of transferred expenditure where this is between new and existing projects

Under this option, eligible exploration expenditure incurred in new projects would be able to be transferred to projects encompassed by the new regime as well as existing projects, subject to rules. Exploration expenditure incurred in existing projects could also be transferred to new projects. Clear rules would need to be established that outline how transfers would occur and whether these rules would differ where transfers occur in the directions from new projects to existing projects, existing projects to new projects, between new projects (and potentially between existing projects). Section 3 contains different options on transferability.

The option that is most appropriate will depend on transfer arrangements chosen for the new regime, although working through implementation issues could mean that one option is preferred.

#### Questions for consultation

32. Interested parties are encouraged to make comments on how the integrity of the new regime should be maintained where the opportunity exists for transfers to occur between projects within the new and existing regime.

# Changes recommended by the Review to improve the integrity, efficiency and administration of the PRRT

The Review made a number of recommendations to improve the integrity, efficiency and administration of the PRRT (Part B recommendations 2 to 12). The Review recommended that each of these changes should be applied to existing as well as new projects on the grounds that they are not major changes that would significantly increase the PRRT paid on existing projects.

Recommendation 3 of the Review related to matters to be considered in a separate review process, rather than recommendations for changes to the PRRT and is not dealt with in this consultation paper. For ease of reference, the relevant recommendations of the Review are replicated below.

#### Prohibit new onshore projects from combining with onshore projects that have a starting base (Recommendation 2 of the Review)

When the PRRT was extended to onshore projects and the North West Shelf project in 2012, to facilitate the transition of these projects they were provided with an additional amount of deductible expenditure called a starting base. The integrity measure introduced at that time, which excluded transitioning projects with a starting base from combining with offshore projects, should be extended to include a prohibition between transitioning projects with a starting base combining with future onshore projects without a starting base. This will avoid the revenue risk posed by transitioning projects with a starting base combining with other projects without a starting base to form a single PRRT project that would use the starting base amount as a tax shield for the whole project.

#### Recognition of partial closing down expenditure as a legitimate general project expense (Recommendation 4 of the Review)

The PRRT has a linear, or cradle‑to‑the grave, treatment of the phases involved in a petroleum project’s operational life. This no longer captures the characteristics of multi‑stage projects that have become a common feature of the industry. Projects are now designed to operate for upwards of 40 years, although parts of the project will be closed over that time. The ATO is currently undertaking consultations to clarify the treatment of closing down expenditure within the meaning of the legislation. If this review does not provide sufficient clarity to deal with partial closing down situations, the legislation should be amended to recognise partial closing down expenditure as a legitimate general project expense. There is no reason why expenditure that is deductible when a project is completely closing down should not be deductible because the project is partially closing down.

#### PRRT taxpayers to lodge annual returns after they start holding an interest in an exploration permit, retention lease or production lease (Recommendation 5 of the Review)

Under current PRRT arrangements, a PRRT taxpayer is only required to lodge an annual return with the ATO when a project starts producing assessable receipts. It is only at this point that a PRRT taxpayer is required to disclose the carried forward deductible expenditure for the project to the ATO. Given the long lead times for some projects, this expenditure may have occurred many years prior to a return being lodged, which can result in considerable uncertainty for PRRT taxpayers and significantly restricts the ATO’s ability to undertake compliance activity. This also affects the ATO’s ability to provide reliable data to Treasury for revenue forecasting purposes. To deal with this, the PRRT arrangements should be amended such that PRRT taxpayers are required to lodge annual returns after they start holding an interest in an exploration permit, retention lease or production licence rather than having to wait until they receive assessable receipts from the project.

#### Provide the Commissioner of Taxation with power to treat a new project as a continuation of an earlier project (Recommendation 6 of the Review)

The PRRT design feature which links a project to a production licence does not align with current commercial practice whereby a production licence may revert to a retention lease. The Commissioner of Taxation should be given the power to treat a new project as a continuation of an earlier project, where it would be reasonable to do so.

#### Provide the Commissioner of Taxation with the discretion to recognise more than one project from a production licence area where there are genuinely separate and independent petroleum operations in the licence area (Recommendation 7 of the Review)

The structure of ownership interests used by the industry is becoming more diverse and fragmented and less likely to remain constant through the life of a project. To deal with these increasingly complex structures that were not envisaged when the PRRT was introduced, the Commissioner of Taxation should be given the discretion to recognise more than one project from a production licence area for genuinely separate and independent petroleum operations in the licence area.

#### Extend to offshore projects the option of having all interests held within a group to be reported as a single PRRT return (Recommendation 8 of the Review)

Entities within a wholly owned group currently have the option to have all the interests held by the group in an onshore project taken together and reported as a single PRRT return (without affecting the project‑based nature of the tax). This compliance cost saving measure should be extended to offshore projects.

#### Provide taxpayers the ability to adopt a substituted accounting period (Recommendation 9 of the Review)

Currently all PRRT tax payers must prepare their PRRT return on a 30 June year end, which is out of step with income tax and accounting rules. The PRRT arrangements should be amended such that PRRT taxpayers can chose to adopt a substituted accounting period for PRRT so it can align with their choice to use a substituted accounting period for income tax.

#### Provide choice of functional currency to taxpayers operating with a Multiple Entry Consolidated (MEC) group (Recommendation 10 of the Review)

The functional currency rules for PRRT are out of step with those for income tax as they do not recognise a functional currency choice by a ‘Multiple Entry Consolidated (MEC) group’. A MEC group is an income tax consolidated group of Australian entities that are wholly foreign‑owned and do not have a common Australian head company. The PRRT arrangements should be amended so that PRRT taxpayers operating with a MEC group can make a functional currency choice for PRRT purposes that aligns with the functional currency choice made for income tax purposes.

#### Provide the Commissioner the ability to administratively exempt projects from PRRT obligations (Recommendation 11 of the Review)

Given that some PRRT projects are unlikely to ever pay PRRT (such as the oil project on Barrow Island), in order toreduce compliance costs for taxpayers and administrative costs for the ATO, the Commissioner of Taxation should be given the power to administratively exempt projects from lodging PRRT returns where they are clearly unlikely to pay PRRT in the foreseeable future.

#### Make PRRT anti-avoidance rules consistent with those applying to income tax (Recommendation 12 of the Review)

Amendments were made to the income tax anti‑avoidance rules in 2013 to ensure they operated as intended after a number of Federal court cases suggested there were deficiencies in identifying a ‘tax benefit’. The PRRT anti‑avoidance rules should be amended in line with the amendments to the income tax rules.

#### Questions for consultation

33. Are there any unforeseen consequences of implementing recommendations 2 through 12 (excluding recommendation 3) of the Review?

34. For recommendations that affect the ATO’s administrative powers, are there any specific safeguards that should apply to the exercise of powers by the Commissioner of Taxation?

35. How significant are the compliance cost savings and/or transitioning compliance costs/burden associated with these recommendations?

1. Australia’s Future Tax System, Final Report December 2009, page 227. [↑](#footnote-ref-2)
2. Onshore PRRT projects that sell project gas prior to processing into ‘sales gas’ are able to access the Regulations and apply the RPM, this option is not available for offshore projects. [↑](#footnote-ref-3)