SHELL AUSTRALIA

Response to Treasury's Petroleum Resource Rent Tax consultation paper

July 2017

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Glossary

ATO	Australian Taxation Office
CSG	Coal seam gas
Consultation Paper	Treasury's PRRT consultation paper of 30 June 2017
IRR	Internal rate of return
LNG	Liquefied natural gas
LTBR	Long-term bond rate as defined by the PRRTAA
NWS	The North West Shelf joint venture
PRRT	Petroleum Resource Rent Tax
RPM	Residual pricing method as defined by the PRRTAA
The Review	The PRRT review lead by Michael Callaghan AM PSM
WACC	Weighted average cost of capital
Shell Australia	The Australian operations and interests of Shell Energy Holdings Australia Limited (SEHAL) and BG International (Aus) Pty Limited (members of the Shell Group of Companies)

Executive summary

1. Shell appreciates the opportunity to comment on the Consultation Paper.

2. Australia has enjoyed an absolute advantage from its historically stable fiscal and regulatory settings relative to other countries. Changes to fiscal settings erode investor confidence and increase the supply price of investment. Similarly, retrospective taxation policy changes undercut investor confidence after expenditure has been committed based on forecast after-tax returns over the life of the investment.

3. In the case of the oil and gas industry, over $200 billion has been invested during the last decade or so to develop several large projects with long lives. That expenditure mainly represents investment in the foundation phase of these projects. A significant amount of additional expenditure will be required over the coming decades to sustain production. However, no future investment or operations are guaranteed and will be highly dependent on the oil price and other external factors.

4. An important principle in the design of PRRT was that it recognises the volatility (and inherent investment risk) in monetizing natural resources. The largest factor in determining the level of PRRT revenue collection is the oil price. At a time of structurally soft oil pricing, following unprecedented capital investment in the sector and consequential PRRT deductions, it follows that PRRT revenues will be suppressed until projects return to threshold levels of profitability.

5. Shell's position is that the PRRT is operating as designed and intended and provides an appropriate balance of economic rent to resource holders and risk incentives for investors. The PRRT as a secondary tax does not discourage investment because it is designed to tax oil and gas resources once they reach a reasonable threshold profit. Once projects have reached threshold returns, which reflect an appropriate balance of risk and reward, PRRT applies, albeit at a relatively high rate of 40%.

6. The current design features of the PRRT work in addition to the existing company income tax regime to ensure a fair return to Australia for its finite oil and gas resources, while supporting ongoing investment for continuation of existing and new projects. Oil and gas projects have typically required a forecast risk-adjusted after-tax IRR of around 15% to attract investment in a globally competitive market. This investment expectation applies across the investor portfolio, meaning investments in unsuccessful exploration or projects are taken into account with successful projects. The combination of the PRRT augmentation rates and transferability of exploration expenditure ensures that the PRRT profit threshold is in line with threshold returns that are required to attract investment.

7. It is critical that Australia maintains a globally competitive fiscal regime that encourages future investment. Fiscal competitiveness is influenced by the combined impact of corporate income tax and resources taxation, including the timing of tax payments compared to the timing of returns to investors. Recently announced or enacted reductions in taxation in a number of countries, including the United Kingdom and the United States, will erode the competitiveness of Australia as an investment destination.

8. The PRRT design aspects in scope of the Part A recommendation (broadly, uplift rates, the RPM and deduction ordering and transfers) have been stable and functional for over 30 years as an integrated taxation framework. Shell Australia believes that the interdependence of key mechanisms in the PRRT regime make it difficult to consider issues such as uplift rates, ordering, transferability and gas transfer pricing separately. The potential impacts of altering one or more of these elements are difficult to forecast and could produce negative, distortionary and unintended economic consequences.

9. It is also important to consider the historic policy intent for the legislation as a whole. The legislation is designed to "strike a reasonable balance between the objectives of satisfying the right of the community as a whole to share in the benefits of profitable offshore petroleum projects, and of providing the

participants with adequate returns for the risks they accept in undertaking offshore exploration and development activities".[1]

10. Consistent with the original and consistent policy intent of the PRRT Act, Shell believes that augmentation rates were included not just to ensure an appropriate level of deductions are brought forward, but as a mechanism to lessen the likelihood of overestimating economic rent of oil and gas resources.

11. The PRRT treatment of "new" projects is of fundamental concern for Shell Australia, and the definition of "new" should be carefully and clearly articulated. In considering options for reform, Government should be mindful of the potential for unintended economic consequences. In particular, the PRRT treatment of "new" projects in the onshore sector would require careful design and further consultation. The technical and economic profiles of onshore gas projects are fundamentally different to conventional offshore petroleum projects, with differences in reserves, and the timing of exploration, development and production. The application, as proposed, of a new PRRT regime to future production licences would substantially impair the economics of existing projects where titles are held at either exploration or retention lease stage.

12. Overall, Shell Australia is confident that the PRRT is working as originally designed and intended, and that it is being administered well in line with the objectives of the Act. Furthermore, changes to the PRRT at a time when the industry is under considerable pressure from a depressed global market may be detrimental to existing and future projects, and will undermine Australia's global competitiveness if not carefully considered in the context of the operation of the broader taxation framework.

[1] Hansard, Minister's 2nd Reading Speech, 28 April 1987.

1. Introduction

Shell Australia welcomes the opportunity to participate in this consultation with Treasury as part of the Australian Government's review of PRRT. A fact-based consultation process is an important step in maintaining community confidence in the PRRT and broader resource taxation framework.

In this response to Treasury's Consultation Paper, we have outlined Shell's position in relation to the Review recommendations generally. We have not sought to address in detail all options in the Consultation Paper that relate to the Part A Recommendation of the Review. Instead this response focuses on addressing the concerns of the Review that influenced the Part A Recommendation, as well as options put forward in the Consultation Paper that could have significant negative, distortionary, or unintended consequences.

In addition to this submission, Shell Australia has contributed to and supports the response to the Consultation Paper from the Australian Petroleum Production & Exploration Association. Further, this submission supports the positions put forward in Shell Australia's submission to the Review in February 2017.

2. Part A Recommendation

2.1 Uplift rates

A fundamental premise in the Consultation Paper is that the purpose of the uplift rate is to maintain the value of deductible expenditure in real terms and take into account the risk that the project will not produce sufficient returns to utilise its deductible expenditure. This assertion is not supported by the broader historic policy framework enunciated at the time the Act was designed and legislated, and does not reflect the consistent policy framework that has since underpinned the Act.

The PRRT derives from a modified version of a cash-flow tax (i.e. Brown tax) that was put forward by Ross Garnaut and Anthony Clunies Ross in 1975. The original design intent was to allow taxpayers to carry negative cash flows forward with an annual uplift, rather than providing a cash refund to taxpayers during negative cash flow years. The primary purpose of the annual uplift is not to preserve the value of deductions, but to maximise government revenue by "balancing the possibility of revenue loss [to the government] on highly profitable projects through an over-liberal approach against the possibility of setting rent charges so high that there is revenue loss through deterrence of projects which are [marginal]".[2]

Achieving the theoretical balance between a fair return to government and not discouraging greenfields or ongoing investment for existing operations is regarded as efficient taxation. Garnaut and Clunies Ross recognised that investor behavior is critical and an efficient resource rent tax should therefore account for the "supply price of investment";[3] the minimum expected rate of return consistent with a decision to invest. They considered the profit left over after subtracting the supply price of investment was the economic rent associated with the natural resource.

The supply price of investment (i.e. financing costs) is not deductible for PRRT purposes. Instead, "negative cash flows are carried forward at an interest rate that is judged to correspond appropriately to the return on capital thought to be required *ex ante* by a mining company in considering an investment".[4] Key features of the current PRRT system such as uplift rates, deduction ordering and exploration transferability work together to allow this required return on capital to be realised before the PRRT (the secondary tax) applies.

The Review was critical of the "almost unanimous view"[5] of the petroleum industry that the uplift rate equates with the typical overall risk of a petroleum project measured by weighted average cost of capital or investors'

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[2] Ross Garnaut & Anthony Clunies Ross, *Uncertainty, Risk Aversion and the Taxing of Natural Resource Projects* (1975), The Economic Journal, vol. *85*, no. 338, 1975, p. 273, available at http://www.jstor.org/stable/2230992.
[3] Ibid.
[4] Ibid.
[5] Australian Government, the Treasury, *Petroleum Resource Rent Tax Review Final Report* (2017), pg. 71.

risk-weighted hurdle rates. But this criticism is at odds with the policy intent of the Act, based as it is on resource rent tax principles of Garnaut and Clunies Ross as outlined above. Since the introduction of the original Act in 1987, and during the decades since, it has been consistent Government policy that the PRRT is intended to tax only profits and to operate as neutrally as possible in securing both investment and returns to Government. As a secondary tax, it is intended to capture an equitable share of economic rent, or profit upside, over and above the corporate income tax rate (noting that Australia's tax rate has been higher than the OECD average for nearly all years since the announcement of the PRRT in 1984[6]), but not deter new or sustaining investment in marginal projects. Consistent with the policy design as a profit based tax, PRRT uplift rates can only be considered concessionary if they exceed the supply price of investment.

These taxation principles were also endorsed in the Henry Review:

> A well-designed rent-based resource tax is less likely to distort investment and production decisions. This is because rent-based taxes do not apply to the normal rate of return to investment in projects. The government achieves this by effectively contributing to costs at the same rate as it shares in receipts from resource production.[7]

It is clear that the purpose of the PRRT uplift rates is not just to take into account the risk of losing deductions, but to approximate the supply price of investment, or the normal return that should be allowed for the purpose of taxation neutrality before the secondary tax applies. As noted in the Henry Review, there are difficulties in determining the supply price of investment because the cost of capital of each investor differs, as do the risk characteristics of each project. There are also difficulties in assessing the current uplift rates due to the integration with the expenditure ordering and transfer rules, as well as the relatively high 40% headline tax rate. However, Shell's position is that the current PRRT uplift rates do not exceed the average industry supply price of investment.

As submitted to the Review, oil and gas projects have typically required a forecast risk-adjusted after-tax IRR of around 15% to attract investment in a globally competitive market. This investment expectation will generally apply across the investor portfolio, meaning investments in unsuccessful exploration or projects are taken into account along with successful projects. Further, the supply price of investment for Australia's oil and gas industry will be no less than the WACC of the companies that have the capacity and expertise to invest in and operate the petroleum projects. Investment will not occur if the forecast after-tax returns are considered unlikely to exceed the WACC. The combination of the PRRT augmentation rates, deduction ordering and transferability of exploration expenditure ensures that PRRT should not apply before investors realise returns exceeding their WACC.

2.1.1 Assessing the rates of uplift

In evaluating the PRRT uplift rates, it is critical to consider how they apply in practice. LTBR+5% and LTBR+15% only apply to expenditure incurred up to five years before the PRRT project's first petroleum production licence comes into force. A production licence is typically granted almost immediately before a final investment decision is made for the project. In practice, this means only a part of feasibility and exploration spend receives these higher uplift rates. This is because it takes decades to develop hydrocarbons, and expenditure incurred more than 5 years prior to the first production licence application only receives the much lower GDP factor uplift. In fact, the GDP factor has deflated the value of carried forward deductions in three of the last four PRRT years.

LTBR+5% is mainly applicable to expenditure relating to the engineering and construction of the upstream infrastructure. For the 2016 PRRT year, LTBR+5% was equal to 7.61% and has averaged around 8.4% during the last 5 years. This uplift rate has been less than industry WACC. For example, the global average WACC for the industry's exploration and production segment was around 10% for 2016.[8] The highest augmentation rate, LTBR+15%, is applicable only to expenditure on activities directed at discovering and appraising the

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[6] James Kelly and Robert Graziani, *International trends in company tax rates — implications for Australia's company income tax* (2004), Australian Government, the Treasury, https://archive.treasury.gov.au/documents/930/PDF/02_International.pdf.
[7] Australian Government, *Australia's Future Tax System* (2010), pt. 2, c1-1.
[8] See e.g. *Costs of Capital by Industry Sector* (Global), available at: http://people.stern.nyu.edu/adamodar/New_Home_Page/datacurrent.html

petroleum resources, such as drilling exploration wells and undertaking seismic surveys. Shell believes that this higher rate is at an appropriate level for two reasons.

Firstly, the larger the petroleum project, the less likely it is that exploration expenditure will be incurred within the 5-year pre-FID period such to receive the LTBR+15% uplift rate. This is because larger projects typically take longer to commercialise once the resources have been discovered and appraised. LNG projects are especially unlikely to incur much exploration expenditure during the 5-year pre-FID period because they typically have much longer lead times than oil projects. For example, more than 5 years elapsed between the appraisal of the foundation fields and the FIDs for the Gorgon and QGC LNG projects. Further, there are several large gas fields discovered significantly longer than 5 years ago for which FIDs have not been taken (e.g. the Browse project).

Secondly, we consider LTBR+15% is a policy setting that gives appropriate recognition of investor risk / revenue return in the policy context of approximating the supply price of investment in exploration activities. Petroleum exploration is a high cost, high risk activity with "explorers increasingly seeing low returns, low value and slow progress".[9] It was for this reason that Garnaut and Clunies Ross noted there "is a case for separate, higher [resource rent tax] threshold rates for industries, such as petroleum and natural gas".[10] In recent years, less than one in every ten exploration wells have revealed petroleum thought to be commercially recoverable.[11] In addition to the nature of petroleum exploration investment, any assessment of the LTBR+15% should account for the low GDP factor uplift, the high 40% headline tax rate, the 15% after-tax IRR benchmark and an upstream industry WACC of at least 10%.

As we noted in Shell's submission to the Review, indicative after-tax yields for infrastructure investments of around 5.5% are forecast over the next 5 years.[12] This average is based on estimates of around 3% for airports to 9% for social infrastructure. The indicative after-tax IRRs required for these projects to support those yields are between 7% and 15%. Considering that the majority of PRRT project expenditure is augmented at LTBR+5% (i.e. currently around 7.6%), the profit threshold set by the current augmentation rates is reasonable relative to other capital intensive sectors, including Australian infrastructure, which are lower risk investments.

We emphasise that the purpose of the PRRT uplift rates is to approximate the supply price of investment for Australia's oil and gas industry. This is a critical design feature of the PRRT aimed at ensuring this secondary tax is neutral to investment and production decisions. It is Shell's position that the current uplift rates achieve their purpose because they do not exceed the supply price of investment.

2.2 Gas transfer pricing regulations

The concerns raised about the gas transfer pricing regulations relate primarily to the RPM, which is the most common method for determining a transfer price where no independent sale has occurred, or readily observable and comparable sales price exists, at or before the PRRT taxing point. There is apparently concern that the RPM is not transparent and/or well-understood, and questions regarding whether the RPM in practice allocates rent between the upstream and downstream as intended. From a tax policy perspective, the RPM is the transfer pricing method that is most consistent with the principles of a resource rent tax. As previously noted, the key principle of a resource rent tax is that the economic rent of the resource is what is left after subtracting the supply price of investment from upstream profits. The purpose of the RPM is to determine the supply price of investment in the upstream and downstream components of integrated LNG projects. The supply price of investment is subtracted from the LNG sales price, and the residual profit, the economic rent, is split evenly between the upstream and downstream.

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[9] Wood Mackenzie, *Global exploration trends*, May 2016, https://www.woodmac.com/reports/oil-and-gas-exploration-global-exploration-trends-38729753.

[10] Ross Garnaut & Anthony Clunies Ross, *Uncertainty, Risk Aversion and the Taxing of Natural Resource Projects* (1975), The Economic Journal, vol. *85*, no. 338, 1975, p. 284.

[11] See e.g. Wood Mackenzie, *Global exploration trends*, June 2017, https://www.woodmac.com/reports/oil-and-gas-exploration-global-exploration-trends-47672439.

[12] Dr. Shane Oliver, *Infrastructure investing in a world of low interest rates* (2016), AMP Capital http://www.ampcapital.com.au/article-detail?alias=%2Folivers-insights%2Faugust-2016%2Finfrastructure-investing-low-interest-rates.

The RPM is complex mainly because it is designed to allocate the supply price of investment for an integrated LNG project between the upstream and downstream infrastructure and processes as precisely and prescriptively as possible. The need for the RPM arises because the pricing of Australian sales and/or feed gas is not readily observable. The domestic gas market is not sufficiently deep and integrated to produce an industry benchmark price that fairly represents the cost of feed gas for the large integrated LNG projects, particularly in the case of Western Australia. As noted in the Discussion Paper, Australia is yet to develop independent gas hubs or multi-user downstream facilities such as those in the United States. Similarly, the Asia-Pacific spot market for LNG is reasonably immature, with long-term supply contracts still prevalent. Due to the nature of Australia's gas markets, and the quantum of investment in the large Australian LNG projects, most pricing information is commercially sensitive.

The confidentiality provisions in Australia's taxation laws enable taxpayers such as Shell Australia to provide commercially sensitive information to the administrators. This information sharing may otherwise be prohibited. The lack of detail concerning the RPM process and outcomes is not driven by unwillingness to explain the RPM calculations, but rather the implications of revealing commercially sensitive pricing information used for the calculations. This is not an issue that is unique to the gas industry, the PRRT or the RPM. The complexity of the RPM is not the reason for the lack of transparency of gas transfer pricing.

The RPM is well-understood by those in the industry and at the ATO involved with PRRT matters. There are a limited number of PRRT taxpayers, and a smaller number again who use the RPM. Further, the cost elements of the RPM calculation will be consistent across taxpayers involved in the same LNG project. It follows that there are a small number of tax experts that understand how to apply the RPM in practice. However, the ATO closely reviews the pricing outcomes for the small number of taxpayers using the RPM. We do not think the administration and compliance with the RPM should be called into question based solely on a perceived transparency issue.

The most complex aspect of the RPM is calculating the initial parameters such as the costs of each functional infrastructure unit, phase points and energy coefficients. This does create a significant upfront taxation compliance burden preceding the generation of the first PRRT assessable receipts of the project. Taxpayers will typically seek a review by the ATO on the establishment of these initial RPM parameters, prior to lodgement of the first PRRT return for the project, with the aim of administrative certainty going forward. Once the initial RPM parameters are established, the ongoing application of the RPM is straight-forward.

Shell does not support the differential allocation of economic rent between the upstream and downstream, as proposed in the Consultation Paper. In our view there are equally significant risks in the upstream and downstream enterprises, so it is Shell's position that an even split is entirely appropriate and equitable. The LNG plants are not low-risk infrastructure projects and it is therefore not appropriate to allocate all of the economic rent to the upstream. There is a significant amount of capital, intellectual property and risk that is associated with the complex LNG processing and liquefaction infrastructure and operations.

3. Application of Part A changes

The Review recommended that any changes to the PRRT relating to the Part A recommendation should only apply to new projects (as defined in the PRRT legislation) after a date to be specified. The Part A recommendation and related options put forward in the Consultation Paper could produce materially different PRRT outcomes for projects and taxpayers.

Given the potentially material implications of any Part A changes, it is entirely appropriate as a matter of policy that these changes should not apply on a retrospective basis. However, Shell is concerned that using the proposed "new project" definition will not achieve the desired outcome of non-retrospectivity and will give rise to investment disincentives, as well as significant administrative issues, especially for onshore projects. As proposed in the Consultation Paper, the application of a new PRRT framework to new production licences could, especially in the onshore sector, see projects with existing exploration licences and retention leases become uneconomic. For this reason and those discussed below, Shell does not support using the new project definition as the basis for ensuring any Part A changes are not retrospective.

3.1 Project definition

As explained in the Consultation Paper, the definition of a project for PRRT purposes is linked to a production licence. A new PRRT project arises when a new production licence comes into force, unless that new production licence is combined with one or more other production licences (in which case the project is defined by the combination certificate in force).

A critical implication of the PRRT legislation being framed around this project definition is taxpayers generally have notional or quasi-projects if they hold interests in petroleum exploration licences or retention leases. That is, deductible PRRT expenditure can be incurred in relation to these licence or lease areas despite that they are not "PRRT projects". In the case of exploration expenditure, the transfer rules may require the expenditure to be deducted against assessable receipts arising from production licences held by the same taxpayer group. Otherwise, undeducted expenditure relating to an exploration licence or retention lease area will transfer to the new PRRT project that arises when the first production licence deriving from that area comes into force. In other words, how and when pre-production licence expenditure is deducted is subject to geographical and common ownership tests, as well as the deduction ordering and transferability rules.

Production licence boundaries are set based on the petroleum resource that is sought to be extracted, which is typically a fraction of the geographical area of the underlying exploration licence or retention lease area from which the production licence derives. Hence it is common, particularly for onshore projects, that multiple production licences will derive from the same exploration licence or retention lease. When the first production licence is issued, a new PRRT project arises that inherits any undeducted PRRT expenditure relating to the underlying exploration licence or retention lease area. If a second production licence is issued, a second PRRT project arises that only inherits any undeducted expenditure relating to the underlying exploration licence or retention lease incurred after the first production licence was issued. This may result in the first PRRT project accumulating expenditure that actually relates to the second PRRT project on a geographical basis. That is, the two PRRT projects may have deductible expenditure balances that do not reflect the geographical reality of the activities that gave rise to that expenditure. PRRT would in these circumstances have an unintended distortional effect on the economics of the projects.

The PRRT combination rules address the above potential distortion and simplify the PRRT administration and compliance. Production licences deriving from the same underlying exploration licence or retention lease will typically meet the criteria to be combined as a single PRRT project. In particular, it is likely that petroleum from all production wells in the multiple production licence areas will be processed through common infrastructure. In this case, all deductible expenditure relating to the common geographical area will be available to the same PRRT project. This is appropriate because it reflects the integrated commercial, economic and operational nature of these petroleum projects.

Set out below are issues that, due to the PRRT design features discussed above, may arise from using the new project definition as the enabler of any Part A changes to the PRRT.

3.2 Projects with starting base

The PRRT was extended to apply to onshore petroleum projects and the NWS from 1 July 2012. A policy decision was made at the time that the extension should not have retrospective impact on investment made prior to its announcement:

> Holders of interests in transitioning petroleum projects, exploration permits and retention leases existing as at 2 May 2010 are provided with an additional deductible expenditure amount (a starting base amount), or alternatively are able to take account of project expenditures incurred prior to 2 May 2010 in determining their PRRT liability. These arrangements are provided in recognition of investment made prior to the Government's announcement of the extension of the [PRRT].[13]
>
> The revenue impact of the PRRT extension is unquantifiable, but it is unlikely to give rise to significant collections over the forward estimates. A key feature of the Main Bill is that transitioning projects are entitled to a starting base to shield a company's historical investments and prevent the retrospective application of the extended

[13] Explanatory Memorandum, Petroleum Resource Rent Tax Assessment Amendment Bill 2011 (Cth), 5.3, pg. 67

PRRT. These transitional arrangements are the key reason why revenue is not expected to be collected from this measure over the forward estimates.[14]

It is important to note that to achieve the intended policy outcome of non-retrospectivity, it was necessary to provide recognition of the historical investment in relation to exploration permits and retention leases (i.e. future PRRT projects), rather than just the production licences (i.e. current PRRT projects) that existed at the time of the Government's announcement. This was primarily achieved by allowing a deduction for the market value of the transitioning interests/projects as at 2 May 2010, informed by either a valuation undertaken for this purpose or a previous acquisition of the interest/project (i.e. acquired exploration expenditure).

The Review noted two potential policy integrity issues where starting base amounts might benefit petroleum interests/projects other than those that transitioned into the PRRT from 1 July 2012. The first situation is where post-30 June 2012 exploration expenditure incurred in relation to a transitioned project is compulsorily transferred to (and utilised by) a non-transitional project (i.e. an offshore project other than the NWS, or an onshore project that does not derive from an interest that existed as at 2 May 2010). In our view, this situation is unlikely to occur due to the deduction ordering rules and common ownership rules. A transitioned project is required to utilise its general and exploration project expenditure before it utilises its resource tax and starting base expenditure. Further, only post-30 June 2012 exploration expenditure is transferrable to another project.

In practice, the circumstance that could give rise to this potential integrity issue is where a taxpayer group has continuously held a transitioned onshore project carried forward post-30 June 2012 exploration expenditure and a profitable offshore project with no carried forward project expenditure (i.e. the assessable receipts of the offshore project exceed current year expenditures). In that circumstance, the exploration expenditure may be compulsorily transferred from the transitioned onshore project to the profitable offshore project with no carried forward expenditure. Shell Australia is one of the few taxpayer groups that have significant interests in offshore and transitioned onshore PRRT projects. However, the deduction ordering rules will result in our transitioned project interests (NWS and QGC) utilising their own exploration expenditure before the circumstance for a compulsory transfer to another of Shell's project interests could occur.

The second situation is where onshore interests that existed at 2 May 2010 are combined with onshore interests that did not exist as at 2 May 2010. In this case starting base relating to the former could theoretically benefit the latter. In our view, there is a low likelihood of tenures with material production value (i.e. highly profitable onshore permit areas that have no starting base) being combined with large onshore projects with starting base. Most of the transitioned onshore permits are concentrated in two Australian states and three basins, and cover most known petroleum reserves in those basins. It follows that, in our view, the proposed measure will not result in any material PRRT revenues, but will significantly increase the administrative complexity.

Onshore CSG-LNG operations require thousands of wells, drilled over vast geographic areas to sustain the volume requirements of the LNG Plants and to meet domestic gas supply commitments. When PRRT was introduced to the onshore petroleum projects in 2012, it was framed in such a way that tenures supplying to integrated gas supply networks (i.e. CSG-LNG operations) were treated as holistic 'projects' for the purposes of PRRT. This was achieved via the combination rules, and allowed petroleum producers administrative simplicity and certainty with respect to operations and economic outcomes. As stated in the Department of Industry and Innovation's Issue of Combination Certificate Guidelines, "[t]he intent of combination certificates is to reduce administrative burden and compliance costs for the industry by avoiding costs and revenues being apportioned to individual production licences".[15]

The proposal to exclude new projects from combining with existing combined projects will create administrative and apportionment complexities that the combination rules sought to eliminate. Shell Australia holds interests in 42 production licences in southern Queensland that have been combined into a single project for PRRT purposes. These tenures are integrated, and ultimately supply gas to the LNG facilities and the domestic gas market. To sustain volume requirements, new production areas will need to be progressively developed over the life of the project and new production licences will be sought. In this regard, the proposal

[14] Ibid, pg. 3
[15] Department of Industry and Innovation, *Issue of Combination Certificate Guidelines* (2012), Australian Government, 1.3-1.4, https://industry.gov.au/resource/Documents/upstream-petroleum/offshore-petroleum-environment/Issue-of-Combination-Certificates-Guideline.pdf.

to create a new regime for new projects will result in isolated PRRT projects that are factually the same as the combined tenures, feed the same LNG facilities, and are geographically aligned, but would be separated for PRRT purposes. This could result in a scenario of having two (or many) separate PRRT projects within one commercially, economically and operationally integrated project. This would create issues with regards to revenue/expenditure apportionment, inter-project tolling and tariff charges, and administrative complexity.

For the reasons outlined above, it is Shell's position that the low likelihood of the two potential integrity issues identified in relation to the 2012 transitional arrangements does not warrant an approach that prevents onshore production licences issued after a certain date from being combined with those issued prior. This proposal is at odds with an intention of not imposing significant retrospective changes, does not suit the characteristics of these projects, and could have significant distortionary effects on future investment and production decisions.

3.3 General project implications

As with transitioned PRRT projects, applying any Part A changes to production licences issued after a certain date may have an adverse distortionary impact on future investment and production decisions for large gas projects that are currently or soon to be producing. Most of these projects are in their foundation phase, meaning that the basic processing infrastructure is in place but only a fraction of the petroleum fields that underwrote these large investments are currently tied-in and supplying the processing plants with feed gas. Significant future investment will be required to sustain production, tie-in additional fields to keep plants running at full capacity, and to potentially expand processing capacity.

An adverse distortionary impact would arise if Part A changes applied to production licences issued after a certain date. Such changes would increase the incremental costs to investors to develop the new production areas and have the overall impact of reducing the after-tax returns to investors. This would likely encourage investors to prioritise investment in and production from existing licences, and defer development of new production areas. This could occur even if the pre-tax forecast returns from new production areas are higher than those of existing/old areas. Further, if the changes have a significant impact on forecast after-tax returns, marginal projects are likely to deferred indefinitely pending improvements in oil price outlook and reduction of project development costs.

In this regard, we consider it is important to emphasise that the PRRT is just one of the ways the oil and gas industry provides benefits to the Australian community. The other taxes paid by the industry (e.g. at least 30% of the profits from even marginal projects) are significant. The economic benefits associated with the employment, and the goods and services demand created by the industry are even more significant than the taxation revenues. Under current fiscal settings, the Australian economy benefits significantly when marginal petroleum projects are developed rather than the resources left in the ground, even without taking into account any PRRT paid (as a secondary tax) in relation to those projects.

4. Part B recommendations

We have set out above Shell's position on Recommendation 2, which we are concerned could have a significant distortionary impact on the industry. Shell supports in-principle the remainder of the Part B recommendations. We are supportive of common sense measures that improve and simplify the administration of PRRT and improve transparency.

However, the legislative detail and implementation of these recommendations is critical. Further consultation to ensure effective implementation will help simplify administrative complexity and avoid unintended consequences. We look forward to working with Treasury to further explore the design and implementation of these measures.