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Principal Advisor
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Dear Sir/Madam

Submission: Review of PRRT Gas Transfer Pricing Arrangements

Please find attached suggested changes to design of the PRRT taxing point in response to the Consultation Paper on PRRT gas transfer pricing arrangements.

Each question posed in the Consultation Paper is not separately addressed, in part because discarding the Residual Price Method is suggested. Nevertheless, many of the questions posed are addressed in some form.

Transitional arrangements for the suggested design changes are not discussed.

Yours faithfully

Wayne Mayo
Tax Consultant

Residual price method is flawed

Liquefied natural gas (LNG) or electricity may be processed from gas feedstock sourced from petroleum resource projects subject to Petroleum Resource Rent Tax (PRRT).

PRRT gas transfer pricing arrangements determine the gas feedstock price at the PRRT taxing point indirectly from the price of product derived from that feedstock. That indirect price determination is used when the price of gas cannot be directly established at the PRRT taxing point. In these circumstances, available product pricing point is downstream of PRRT taxing point and specification of the gas transfer price sets the gross receipts from gas production upstream of the PRRT taxing point to be subject to the PRRT.

The residual price method (RPM) is currently used to determine the PRRT gas transfer price (and, thereby, gross receipts for PRRT purposes) at the PRRT taxing point. The RPM incorporates both *cost-plus* and *net-back* methodologies.

- The *net-back methodology* starts with gross receipts at product pricing point downstream of PRRT taxing point and subtracts a component of those receipts required to achieve a specified return (capital allowance rate) to downstream costs.
- The *cost-plus methodology* uses the same specified return but applies that to upstream costs to determine upstream gross receipts directly.

Both cost-plus and net-back methodologies use the same computational parameters to determine annual gross receipts associated with the specified return to upstream and downstream costs, respectively, as those costs evolve year by year.

If net-back were to apply alone, the gross receipts allocated upstream to be subject to PRRT would carry with them all the economic rent (beyond any included in downstream capital return) perceived by investors as being associated with both the upstream gas resource and downstream processing activities.

Under RPM, however, upstream gross receipts determined from the cost-plus methodology can act to reduce the gross receipts determined from the net-back methodology. That is because the average of the gross receipts (or prices) computed from the two methodologies is used when gross receipts from net-back are more than gross receipts from cost-plus.

Little principle would seem to be involved in RPM's use of cost-plus to reduce upstream gross receipts for PRRT purposes. First, the specified return to capital in the cost-plus methodology is necessarily arbitrary. And that arbitrarily-set return directly over-rides the actual profitability of the upstream petroleum resource thus undermining the integrity of the RPM method and consequently the PRRT itself. Secondly, the averaging of upstream price, or gross receipts, computed from the cost-plus and net-back methodologies would seem to have no sound conceptual underpinning.

Beyond these basic flaws, RPM arbitrarily applies the same capital allowance rate both upstream and downstream, excludes exploration expenditure employed in the discovery of the gas resource, as well as some other costs (adding to the lack of principle in the use of the cost-plus methodology) and depreciates upstream capital costs associated with projects' other petroleum products that are produced before sales gas is first produced. All of this adds to the subjective and opaque nature of RPM.

Stand-alone net-back methodology is preferred

As with the cost-plus methodology, the net-back methodology requires the apportionment of capital and operating costs upstream and downstream and imposes a return to downstream capital for use in complex calculations. But the net-back methodology applied alone would avoid the fundamental flaws of the cost-plus methodology, as well as the additional arbitrary and opaque features of RPM.

Particularly in circumstances where downstream activities are subject to increasing competitive pressures, net-back's required return to downstream costs may be able to be set less arbitrarily on the basis of the levels of return that might be expected from the more 'normal' types of downstream processing activity. Relevant in this regard is the Consultation Paper's reference[1] to increasing competition in LNG processing, including through tolling arrangements, leading to 'utility' pricing. Most importantly, the specified return would not be arbitrarily speculating directly on the profitability of the petroleum resource itself.

The strengths of the net-back methodology may then be appreciated by considering the situation where: first, net-back computations always produce *ex post* downstream gross receipts consistent with the specified *ex ante* pre-tax return to downstream capital; and, secondly, that specified 'normal' downstream return matches the pre-tax discount rate of the investor who is considering a prospective gas-to-liquids operation.

In these, admittedly restrictive, circumstances, the imposed downstream pre-tax return neatly excludes cash flows from the PRRT (including downstream gross receipts computed year-by-year) that, to the investor, have zero net present value (NPV). With downstream return matching investor discount (hurdle) rate, the investor perceives no economic rent in the excluded downstream activities of the planned operation. The application of the PRRT is neatly restricted to cash flows directly associated with any 'above-normal' profits of the upstream petroleum mineral resource perceived by the investor.

Such considerations suggest that, if a transfer pricing methodology is to be applied to determine upstream gross receipts, use of the net-back methodology alone would be preferable to having the cost-plus methodology constrain net-back outcomes within RPM.

But net-back methodology has disadvantages

Nevertheless, there are many disadvantages associated with the use of the net-back methodology.

- The selection of the return to downstream costs is still arbitrary. Investors will inevitably use discount rates that differ from the imposed downstream return. If the discount rate of an investor is higher than imposed downstream return, for example, the investor will consider that an insufficient proportion of overall gross receipts is being excluded from the upstream PRRT net.

[1] Australian Government, The Treasury, *Review of PRRT gas transfer pricing arrangements,* (April 2019), 15.

- There are various possible ways of netting back annual PRRT receipts and each method has its own advantages and disadvantages.
    - The PPRT regulations, for example, have net-back (and cost-plus) methodology jumping from one form of calculation (particularly for capital cost determination) to another depending on whether the 'effective life' of operations is more or less than 15 years. When less than 15 years, capital cost determination incorporates the complex but arbitrary formula for an annuity certain.
    - Mayo[2] specifies an alternative net-back computational method that might address some of the computational disadvantages of the PRRT regulations.
- Regardless of computational method, the downstream return specified for the net-back methodology will inevitably be different from the return actually achieved with gross downstream receipts having to be computed year by year as annual expenditures unfold. Mayo[3] shows the very different downstream returns that different net-back methodologies can produce when applied to a hypothetical petroleum operation with known 10% pa downstream pre-tax return.
    - A net-back methodology like that in the PRRT regulations results in a 11.1% pa return when applied on the basis of a 15-year effective life and 7.2% pa when applied on the basis of an effective life of greater than 15 years (assuming in both cases pre-production capital expenditure is uplifted annually at the 10% pa return specified for downstream capital).
    - The alternative computation method of Mayo[4] happens to produce a return of 10.0% pa for the particular hypothetical project used.
- Inevitably, different net-back methodologies would produce results that vary in different ways when applied to projects with differing characteristics.

Further complexity with accompanying varying impact on decision-making and on PRRT revenue is added by arbitrary uplift rates for capital expenditures under PRRT design.

Net-back methodology, too, can be avoided by aligning taxing point with pricing point

Even with vertically integrated LNG or electricity operations, use of the net-back methodology and its disadvantages could be avoided completely if PRRT were applied to aggregate upstream and downstream cash flows.

This would be achieved by giving primacy in the definition of PRRT taxing point for each marketable petroleum product (MPC) of a PRRT project to the first point at which the MPC can be valued (clear comparable uncontrolled price, CUP, determined) or is sold at arm's length. Use of a physical definition of the boundary line between the production and downstream processing stages – as under current PRRT design – would, nevertheless, be retained to simplify administration and compliance and minimise scope for dispute over which costs are included in the PRRT net.

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[2] W. Mayo, *Taxing Resource Rent: concepts, misconceptions and practical design* (2013 Kyscope Publishing: Canberra), 103.
[3] Ibid, 114.
[4] Ibid, 103.

The original specification of PRRT design[5] underpinning subsequent legislation and regulations included in the definition of PRRT taxing point both physical specification and first point at which product is saleable commercially. Giving primacy to valuation/pricing point over physical specification in establishing taxing point, however, would make a fundamental difference to the treatment for PRRT purposes of vertically integrated gas operations.

These integrated operations, including exploration activity leading to discovery of the associated petroleum resource, would be treated just like any other PRRT project. No longer would prices for PRRT MPCs in these operations be generated by separate complex and opaque mathematical formulae.

Consequently, if, say, in the case of vertically integrated LNG production of a taxpayer, no CUP is available for gas feedstock and the first point at which product can be valued is when the LNG is sold at arm's length, both upstream and downstream operations would be brought into the PRRT net – along with gross receipts from any non-gas MPCs produced. The entire integrated gas-to liquids operation would become a regular PRRT project.

As with RPM calculations, upstream and downstream operating and capital costs would be involved (though with particular differences relative to RPM, like the inclusion of exploration costs). Unlike RPM, however, upstream and downstream costs would be aggregated, avoiding all the complexities and arbitrary outcomes associated with upstream/downstream apportionment rules. And gross receipts at the valuation/price point(s) would be used directly, again with no requirement to split them upstream and downstream.

Aligning taxing with pricing point automatically accommodates tolling

Giving primacy to first pricing point over physical specification for determination of PRRT taxing point would see PRRT taxing point as the first point at which product in the gas-to-liquids stream can be valued (clear CUP established) or is priced directly in an arm's length sale.

Such an approach would deal flexibly with a wide range of circumstances in gas production.

An integrated gas-to-liquids operation with common ownership, for example, could see PRRT taxing point set at a point where a sound CUP can be established prior to gas entering the LNG plant. Absent such CUP, PRRT taxing point could be after gas is processed into LNG and a CUP or arm's length price for the LNG is first identifiable. Where gas is being processed into LNG by a third party (either independent of, or partly owned by, the owner of the gas resource), PRRT taxing point could be set at the point where a negotiated gas (tolling) price represents a genuine arm's length price.

Regardless of positioning of PRRT taxing point in the various circumstances, as now, eligible costs associated with all of a taxpayer's assets in a PRRT project employed in bringing PRRT MPCs to the taxing point would be included in the PRRT net.

Pricing problems aside, current physical specification of taxing point at least has the advantage of clarity for administration and compliance purposes. In contrast, suggested flexible design of taxing

[5] Australian Government, *Resource Rent Tax on "Greenfields" Offshore Petroleum Projects* (June 1984: Canberra), 8.

point as first pricing point raises the need to accommodate, with associated clearly specified PRRT treatment, a wide variety of changing circumstance.

- At one point in time, gas could be sold to a third party at an arm's length price for LNG conversion, with only costs associated with bringing gas to the tolling point then included in the PRRT net.
- Later, this tolling arrangement could be terminated and LNG conversion facilities constructed by the owner of at least some of the gas resource.
- In the event that a CUP could not be then set for the gas resource entering the new facilities, the taxing point would automatically move downstream where product could be valued or priced and, with that move, costs associated with the gas-to-liquids facilities would be included in the PRRT net.
- Similarly, the reverse could occur where a vertically integrated gas-to-liquids operation is transformed into a tolling arrangement with third party LNG processing.

PRRT treatment of such different circumstances would no doubt draw on other RRT design features like those dealing with changes in ownership, farm-ins and joint ventures, and possibly starting base arrangements for existing projects subjected to PRRT.

Aligning taxing with pricing point is not a strategy for increasing PRRT revenue

Aligning PRRT taxing point and MPC valuation/pricing point might seem simply to be a prescription for broadening the PRRT net and obtaining higher PRRT revenue from the downstream processing of LNG in circumstances where gas feedstock cannot be valued.

Certainly, downstream taxing point applying with an integrated gas-to-liquids operation would see PRRT applied to downstream LNG processing and the value added in that processing, including through innovation and special expertise. Well-designed PRRT, however, would not have a major impact on investment decisions down the chain of production. That should be the case regardless of what discount rates investors might use in their decision-making relating to the upstream gas resource, on the one hand, and downstream processing activities, on the other.[6]

In addition, there would likely not be a great difference in PRRT outcomes and impact with downstream taxing point operative relative to a net-back approach with upstream taxing point operative.[7] That is because a simple, uniform return to downstream capital under the net-back methodology cannot recognise returns to innovation and special expertise specific to particular operations. In any case, as noted, in a competitive processing environment, net-back's uniform

[6] See Mayo (2013), op cit, 104-106 where pure cash flow tax, rather than PRRT, is being applied at a downstream taxing point ('the port').

[7] There would be no difference at all for an investor with a common risk-weighted discount rate upstream and downstream which also matched net-back's downstream specified return. As explained, the net-back methodology would remove a stream of downstream cash flow with zero NPV from overall (upstream plus downstream) cash flow. Pre-PRRT NPV of upstream cash flows (upstream taxing point) would be the same as NPV of pre-PRRT upstream plus downstream flows (downstream taxing point). In these admittedly restrictive circumstances, net-back's specified return to downstream capital could be termed a *break-even return* for the investor. See Mayo (2013), op cit, 110 where pure cash flow tax is again being applied rather than PRRT and where a change in the investor's upstream discount rate under net-back with upstream taxing point ('the mine mouth') is shown not to affect investment decisions.

return to downstream capital would be set on the basis of 'normal' returns to processing-type activities. Generally, therefore, any economic rent perceived by the investor in downstream processing activities would be shifted by the net-back methodology upstream to be subject to PRRT.

In sum, when gas feedstock cannot be valued, movement of the PRRT taxing point to the end of integrated gas-to-liquids operations could see the impact of PRRT on investment decisions and tax revenue not greatly different to that under alternative design with physical upstream taxing point plus net-back methodology. But downstream taxing point would avoid all of the complexities and disadvantages of the net-back methodology. Simplicity and ease of compliance would be furthered if downstream taxing point were allowed to apply.

Taxing point re-design puts a focus on PRRT's impact on investment decisions

Aligning taxing point with first pricing point, and the associated potential application of PRRT to entire gas-to-liquids operations, puts particular focus on the neutrality properties of PRRT design. With profits from these operations potentially included in the PRRT net, there is a premium on PRRT design having as small as possible effect on investment decision-making – from initial decisions to explore for gas right through to decisions regarding the development of gas-to-liquids production facilities.

Neutral impact of the PRRT would see pre-PRRT NPV of prospective investments cut in proportion to the PRRT rate.

Such effect is associated with a pure cash flow tax (CFT) under which negative cash flow (loss) attracts a government cash rebate (loss times tax rate) and positive cash flow is taxed. NPV is then cut in proportion to the tax rate regardless of discount (hurdle) rate applied.[8]

PRRT design incorporates loss carry-forward instead of cash rebates with losses generally uplifted at rates higher than the government long-term bond rate (LTBR) to accommodate the risk that some carried-forward losses are never absorbed by positive cash flow.

However, the findings of the Callaghan Report[9] point to a low risk of losing PRRT deductions in the development/production phase of petroleum resource projects. The Callaghan review observes that:[10]

> "…. once developed, rare would be the (still risky) project that could not utilise PRRT deductions uplifted at LTBR".

Thus, the Callaghan review is suggesting that, if the PRRT uplift rate in in the development/production phase of petroleum resource projects were LTBR, it would invariably be just a matter of time before early PRRT losses (years of negative cash flow) – uplifted annually at LTBR – were completely absorbed by subsequent positive cash flow.

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[8] Ibid, 9.

[9] Petroleum Resource Rent Tax Review, *Final Report*, (Callaghan review) (M Callaghan AM PSM, Chairman) (April 2017 Australian Government: Canberra).

[10] Ibid, 72.

That situation suggests that aggregate post-PRRT flows in projects' production phase conflate two quite different assets: first, a risky asset comprising project cash flows as if a pure CFT applied (pre-tax cash flows cut by the CFT rate); and, an asset comprising implicit minimal-risk loans to government of amounts of cash rebates not paid immediately (as pure CFT would require) in years of negative cash flow[11].

Accepting the minimal risk of losing PRRT deductions (and implication of uplift at LTBR[12]) during the production phase of petroleum resource operations enables the cash flows of this phase's minimal-risk asset to be excised from the phase's aggregate post-PRRT cash flows. That separation is essential for sound investment analysis given the very different risk properties and the fact that the PRRT should only apply to the risky project asset, not at all to the implicit loan to government.

Once that separation is made, the effect of the PRRT on the risky asset of a prospective investment is clear. The PRRT cuts pre-PRRT NPV neatly in proportion to the PRRT rate (as with a pure CFT) regardless of the hurdle rate used by the potential investor, suggesting little impact of PRRT on investment decisions.[13] And, the PRRT has no impact on the minimal-risk asset.

Accepting the minimal risk of losing PRRT deductions in projects' production phase also brings into play the possibility of ideal design that assimilates PRRT and income taxation. Ideal assimilation would simply apply income tax to pre-tax flows (gross receipts, as well as costs) of the risky project asset cut by the PRRT rate.[14] That is consistent with the treatment for income tax purposes of payments and receipts subject to rebates and imposts, respectively, under Australia's GST. The income tax treatment of the production phase's minimal-risk asset, and its implications for PRRT uplift rate, are then able to be considered separately.[15]

Such treatment would remove the potential extra tax impost imposed by the current treatment of PRRT for income tax purposes (pre-tax cash flows subject to income tax with PRRT payments deductible). That extra tax impost arises because current treatment applies income tax to the minimal-risk asset not as a financial asset but as part of the associated petroleum resource project.

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[11] These implicit loans would carry risk commensurate with LTBR if government guaranteed delayed cash rebates, if necessary, for unutilised uplifted losses – see Mayo (2013), op cit, 44-49.

[12] A rate reflecting as close as practicable the risk of losing PRRT deductions, in line with the findings of the Callaghan review.

[13] The Callaghan review, op cit, p 73 (Box 4.1) shows before income taxation how discounting the cash flows of the minimal-risk loan at a rate commensurate with the risk of losing PRRT deductions (5% pa being used there rather than LTBR specifically) is required to maintain pre-PRRT investment decisions (there zero NPV pre-PRRT maintained post-PRRT) – regardless of whatever risk-weighted discount rate is applied by the investor to risky project cash flows (10% used there). W. Mayo expands on this type of analysis in his submission in response to Consultation Paper, 'Options to address design issues identified in the Petroleum Resource Rent Tax Review' (June 2017).

[14] This ideal income tax treatment is only possible because of the minimal risk of losing PRRT deductions. Investors would not accept up-front costs being cut by the PRRT rate for income tax purposes if there was significant risk that subsequent sufficient gross receipts, also to be cut by the PRRT rate, would not materialise.

[15] More details are provided (and the blending of projects' exploration and production phases is also discussed) in W. Mayo, 'Combining resource rent and income taxation for neutral impact', *Australian Tax Forum* (2019, forthcoming). Equivalent assimilation with income tax and CFT with delayed full loss offset is shown in Mayo (2013), op cit, 186-190, though delayed loss offset there comes from delayed write-off rather than delayed cash rebates.

Conclusion

The main change suggested in direct response to questions posed in the Consultation Paper is that:

- primacy be given to first pricing point (clearly established CUP or arm's length price) in defining PRRT taxing point of each PRRT MPC.
    - Integrated gas-to-liquids operations would become regular PRRT projects where no CUP can be established for sales gas being processed into LPG.
    - Tolling arrangements where sales gas is sold at arm's length for processing into LPG by third parties would be automatically accommodated.

In addition, while outside the scope of the Consultation Paper, acceptance of low risk of losing PRRT deductions in the production phase of PRRT projects brings with it the prospect of improving the neutrality properties of the PRRT – including through less arbitrary uplift rates and better design of PRRT's interface with income taxation.

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