**EXPLANATORY STATEMENT**

**Select Legislative Instrument 2013 No. 154**

**Issued by authority of the Assistant Treasurer**

 *Petroleum Resource Rent Tax Assessment Act 1987*

 *Petroleum Resource Rent Tax Assessment Amendment Regulation 2013 (No. 1)*

Section 114 of the *Petroleum Resource Rent Tax Assessment Act 1987* (the Act) provides that the Governor-General may make regulations prescribing matters required or permitted by the Act to be prescribed, or necessary or convenient to be prescribed for carrying out or giving effect to the Act.

Section 24 of the Act provides that regulations may specify the calculation method to determine the assessable petroleum receipts arising from sales gas in relation to a petroleum project. ‘Sales gas’ has a technical meaning as defined in the Act but essentially refers to natural gas that has had its impurities removed and has been sufficiently processed to be suitable for its intended purpose, which could be for sale into domestic gas markets, for use as raw material for conversion to another product, or for direct consumption as energy.

The *Petroleum Resource Rent Tax Assessment Regulations 2005* (the Principal Regulation) provides a framework for determining the value of sales gas where it is used as raw material for use in an integrated gas-to-liquid (GTL) operation. An integrated GTL operation is a coordinated operation involving the recovery of natural gas from a site which is processed into sales gas, where that sales gas is then further processed into a liquefied product, such as liquefied natural gas (LNG).

The framework in the Principal Regulation for determining the value of sales gas is required because there is often no observable market value for that gas prior to it being further processed into a liquefied product. The value, or ‘price’, of sales gas is required in order to determine the assessable petroleum receipts associated with the integrated operation for Petroleum Resource Rent Tax (PRRT) purposes. It is the profit resulting from the production of sales gas that is taxed under the PRRT.

Following the passage of the *Petroleum Resource Rent Tax Assessment (Amendment) Act 2012*, the application of the Act was extended from offshore petroleum projects to onshore petroleum projects, as well as the North West Shelf LNG project located off Western Australia, from 1 July 2012.

The purpose of the Regulation is to adapt and extend the existing framework set out in the Principal Regulation so that it can be appropriately applied to onshore integrated GTL operations and the North West Shelf LNG project, as well as to integrated gas-to-electricity (GTE) operations, following the extension of the scope of the Act in 2012.

In particular, the Regulation takes account of differences in the structure and operations of onshore integrated GTL and GTE operations relative to traditional offshore integrated operations upon which the existing framework in the Principal Regulation was based.

The Regulation amends the Principal regulation to:

* ensure that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation applies to onshore GTL operations, including those utilising coal seam gas, as well as the North West Shelf LNG project;
* ensure that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation is able to appropriately apply to integrated GTE projects;
* allow taxpayers to make an election to apply the Residual Pricing Method (RPM) in relation to onshore integrated GTL projects as the default method for determining assessable petroleum receipts;
* give taxpayers the option of using mass rather than volume measurements for project products to determine an RPM price, in order to reduce compliance costs for integrated operations who measure by mass; and
* provide taxpayers holding an interest in an integrated GTL project that existed prior to 2 May 2010 (that is, the North West Shelf project) with a simplified RPM for determining the value of project sales gas.

The Regulation provides the petroleum industry with certainty regarding the application of the Act to such operations, in particular to those taxpayers holding an interest in projects that are in the process of transitioning to the PRRT following the extension of the Act in 2012. The petroleum industry was consulted during the development of the Regulation.

The Regulation is consistent with the recommendations of the Policy Transition Group regarding the extension of the PRRT which followed extensive consultation with industry, and which were accepted by Government on 24 March 2011.

Details of the Regulation are set out in Attachment A.

A Statement of Compatibility with Human Rights has been completed for the Regulation, in accordance with the *Human Rights (Parliamentary Scrutiny) Act 2011*. The Statement’s assessment is that the measures in the Regulation are compatible with human rights. A copy of the Statement is at Attachment B.

The Regulation commenced on the day after registration.

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| Authority: | Section 114 of the *Petroleum Resource Rent Tax Assessment Act 1987* |

**ATTACHMENT A**

**Details of the *Petroleum Resource Rent Tax Assessment Amendment Regulation 2013 (No.*** *1****)***

## Part 1 – Preliminary

### Section 1 – Name of Regulation

This section names the Regulation the *Petroleum Resource Rent Tax Assessment Amendment Regulation 2013 (No. 1)* (the Regulation)*.*

### Section 2 – Commencement

Section 2 provides that the Regulation commences on the day after it is registered on the Federal Register of Legislative Instruments.

### Section 3 – Authority

This section notes that the Regulation is made under the *Petroleum Resource Rent Tax Assessment Act 1987* (the Act).

### Schedule – Amendments

This section provides that the amendments in Schedule 1 amend the *Petroleum Resource Rent Tax Regulations 2005* (the Principal Regulation).

## Part 2 – Background and Overview of the Regulation

### Background

#### The Petroleum Resource Rent Tax

The Petroleum Resource Rent Tax (PRRT) was enacted in 1987 through the *Petroleum Resource Rent Tax Act 1987* and the *Petroleum Resource Rent Tax Assessment Act 1987* (the PRRTAA), and is a profits-based tax applied to petroleum production from petroleum projects.

The PRRT is applied at a rate of 40 per cent on the ‘taxable profit’ of a project, calculated as assessable receipts less project related expenditures, including eligible exploration expenditures. Where project related expenditure is not able to be immediately deducted in the year incurred (due to expenditures being greater than receipts), it is carried forward and augmented by specific amounts dependent on the kind of expenditure, and is able to be deducted against receipts in future years. PRRT payments are income tax deductible.

Under the PRRTAA, assessable petroleum receipts are usually determined at the point where a marketable petroleum commodity (MPC) becomes an excluded commodity. An MPC, which is defined as including stabilised crude oil, condensate, LPG, shale oil, ethane, and sales gas, becomes an excluded commodity either by being sold, or by being further processed, or moved away from its place of production.

In most cases assessable petroleum receipts will reflect the consideration received from the sale of the MPC. However, in some cases, an MPC does not become an excluded commodity via a sale but rather undergoes further processing to another product as part of an integrated process. In that situation there is no observable
arm’s-length price for the MPC from which assessable petroleum receipts can be derived. Consequently, the PRRTAA normally requires that assessable receipts be based on the market value of the MPC.

However, this ‘market value’ method does not apply to the MPC, ‘sales gas’ in situations where it is used as feedstock in an integrated GTL operation, and becomes an excluded commodity other than by sale, or where it becomes an excluded commodity via a non-arm’s length transaction. Instead, the assessable receipts for the sales gas are calculated in accordance with the framework set out in the Principal Regulation.

#### Working out the value of sales gas under the Principal Regulation

The Principal Regulation provides a framework for determining a price for sales gas where it is used as feedstock in an integrated Gas-to-Liquid (GTL) operation and where there is no price, or a non-arm’s length price, for the gas.

Regulation 4 of the Principal Regulation defines an integrated GTL operation as an operation in which:

* + - * 1. petroleum is, or will be, recovered from a petroleum project; and
				2. sales gas is, or will be, produced from some or all of the petroleum; and
				3. some or all of the sales gas is, or will be, processed into a liquefied product.

The sales gas which is produced and then processed into a liquefied product is referred to in the Regulations as *project sales gas*.

The elements comprising an integrated GTL operation are also defined and divided into two stages, specifically:

* the *upstream stage*.
	+ This stage commences with the recovery of project natural gas (that is, the natural gas from which project sales gas will be produced and liquefied within the operation) and ends with the production of project sales gas; and
* the *downstream stage.*
	+ This stage commences with the transportation of project sales gas from the upstream stage for processing into project liquid and ends with the storage or loading of project liquid at an adjacent facility.

Where an integrated GTL operation exists, the Principal Regulation specifies that the gas transfer price (that is, the ‘price’ of the project sales gas used to determine assessable receipts for the purposes of the PRRTAA) is to be determined via the following hierarchy:

1. If an Advance Pricing Arrangement (APA) has been agreed between the taxpayer and the Commissioner, the amount calculated in accordance with the arrangement;
* APA’s are a well-established feature of Australian income tax administration of transfer pricing issues between related parties.
* The Principal Regulation allows for the Commissioner, at the request of the taxpayer, to enter into an APA specifying how the assessable receipts of the taxpayer will be determined. Any taxpayer may apply for an APA.
1. If there is no APA, but a comparable uncontrolled price (CUP) exists for the project sales gas, the CUP;
* A CUP refers to a price that can be observed in a relevant market place for the sale of the relevant commodity.
* Regulation 19 of the Principal Regulation defines CUP’s for the purposes of the regulations and the conditions under which a CUP can be observed.
1. If there is no APA and no CUP exists for the project sales gas, the price is determined in accordance with the Residual Pricing Method, which is set out in the Principal Regulations.

The Residual Pricing Method

The Residual Pricing Method (RPM) notionally treats the upstream and downstream stages of an integrated operation as separate arm’s-length businesses buying and selling the project sales gas in order to determine a gas transfer price.

The gas transfer price (for the purposes of the PRRTAA) that is determined via this method is referred to as the ‘RPM price’.

The RPM incorporates both a ‘cost-plus’ and ‘netback’ calculation.

* The cost-plus calculation is applied to the upstream stage to determine a ‘cost‑plus price’ for the project sales gas. The cost-plus price reflects the minimum price at which the upstream stage of the integrated operation would need to sell the project sales gas produced in order to cover its costs (including an allowance for capital investment).
* The netback calculation is applied to the downstream stage (netting off the downstream costs from the value of the final liquefied product) to determine a ‘netback price’ for the project sales gas. The netback price reflects the maximum price for project sales gas that would allow the downstream stage to recover its costs (including an allowance for capital investment) for a given sale price for the project liquid.

The ‘gap’ between the cost-plus and netback prices reflects the residual, or ‘excess’ profit of the integrated operation as a whole. This residual profit is divided equally between the upstream and downstream stages of the operation (implying an equal share of rents between the upstream and downstream stages of the operation) to determine the RPM price.

The operation of the RPM is graphically illustrated in Figure 1.

**Figure 1: Stylised representation of the RPM**



## The steps for determining the RPM price in relation to project sales gas of an integrated GTL operation are set out in Regulation 25 of the Principal Regulation.

#### The Policy Transition Group recommendations regarding the PRRT extension

On 2 July 2010, the Government announced the extension of the Petroleum Resource Rent Tax to onshore projects and the North West Shelf project, and established the Policy Transition Group (PTG) to provide advice regarding the details of the new arrangements.

The recommendations of the PTG, which were accepted by Government on 24 March 2011, included several recommendations related to the Principal Regulation. Specifically, the PTG recommended that the existing PRRT provisions for valuing gas at the taxing point should be applied to those projects transitioning into the PRRT, but that:

* taxpayers developing onshore gas resources within an integrated GTL project, such as liquefied natural gas, should have the option of using the existing RPM as a default methodology for calculating the value of the resource at the taxing point;
* taxpayers with existing integrated GTL projects, such as liquefied natural gas, at 1 May 2010 that are to transition to the PRRT should have access to a simplified RPM as a default methodology. This should provide a single agreed phase point and capital base determined by an agreed valuation methodology for existing assets; and
* the existing RPM provisions within the PRRT should be amended to provide for integrated GTE projects.

### Overview of the Regulation

The Regulation is consistent with the recommendations of the PTG regarding the extension of the PRRT and takes account of differences in the structure and operations of integrated onshore GTL and GTE operations relative to traditional offshore operations upon which the 2005 regulatory framework was based.

The Regulation:

* ensures that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation is adapted and extended to onshore GTL operations including those utilising coal seam gas, and the North West Shelf LNG operation;
* ensures that the framework in the Principal Regulation for determining assessable petroleum receipts in relation to an integrated GTL operation can be applied in the context of integrated GTE projects;
* allows taxpayers to make an election to apply the Residual Pricing Method (RPM) in relation to onshore integrated GTL projects as the default method for determining assessable petroleum receipts;
* gives taxpayers the option of using mass rather than volume measurements of project products to determine an RPM price, in order to reduce compliance costs for integrated operations who measure by mass; and
* provides those taxpayers holding an interest in an integrated GTL project which existed prior to 2 May 2010 with a simplified RPM as the default methodology for determining pricing, incorporating a single phase point and prescribed valuation method for determining the value of existing assets.

## PART 3 – CHANGES to the Concepts and Definitions Used in the existing Framework

To facilitate the extension of the existing framework in the Principal Regulation to onshore GTL and GTE operations, a number of amendments are made to the Principal Regulation to adjust the concepts and definitions used throughout the Regulation.

### Changes to certain core definitions

Regulation 3 of the Principal Regulation defines a number of terms that are specific to the Principal Regulation and apply in addition to the terms defined in the PRRTAA.

Items 1 to 26 of the Regulation amend regulation 3 of the Principal Regulation to incorporate new and amended definitions required to extend the regulatory framework to onshore integrated GTL and GTE operations.

New or amended definitions within regulation 3 include:

***Integrated operation*** is defined as meaning both integrated GTL and GTE operations. Defining this term allows for it to be used to apply the regulatory framework to both integrated GTL and GTE operations.

***Assessable gas*** is defined as meaningeither:

* in relation to calculating assessable petroleum receipts relating to sales gas – project sales gas; and
* in relation to calculating assessable petroleum receipts relating to natural gas – project natural gas.

The term is used throughout the Principal Regulation in cases where the relevant provision may apply to the determination of assessable receipts in relation to either project sales gas or project natural gas of an integrated operation.

***Taxpayer*** is more broadly defined as meaning an entity that is a participant in an integrated operation and whose assessable petroleum receipts in relation to either sales gas or natural gas from that operation are to be worked out under the Principal Regulation because of regulations 14, 15 or 16 of the Principal Regulation.

Regulations 14, 15 and 16 of the Principal Regulation set out the circumstances under which a taxpayer’s assessable petroleum receipts in relation to assessable gas are to be determined under the regulations.

Both ***actual mass of*** ***project natural gas*** and ***actual volume of project natural gas*** are defined in relation to an integrated operation and a year of tax. They mean the mass of project natural gas, or the volume of project natural gas, that was used to produce project liquid or project electricity.

The terms are used in regulation 10 and regulation 10A for calculating the volume coefficient or mass coefficient respectively. The relevant quantity coefficient is used in regulations 22 and 23 of the Principal Regulation to adjust the share of capital costs used in calculating the netback and cost-plus price in a year, according to the ratio of that year’s actual gas mass or volume and the estimated average volume, or, once actual annual mass or volume has exceeded the estimated average, the average gas mass or volume.

### Changes to other definitions in the Principal Regulation

There are also other terms of specific use that are included or amended by the Regulation and are discussed in further detail in the relevant sections below. The amendments made are minor and are required to adjust the terms to reflect the extension of the framework in the Principal Regulation to onshore integrated GTL and GTE operations.
A note is also be inserted at the end of regulation 3 of the Principal Regulation detailing those terms used which are defined in section 2 of the PRRTAA.

## PART 4 – Use of mass measurement

This Part explains the amendments in the Regulation that ensure that, when applying the RPM, a taxpayer may use the mass of petroleum products rather than their volume in determining the RPM price, noting that it delivers an identical RPM price outcome.

### Use of mass measurement

The volume of project natural gas and project sales gas are used in the Principal Regulation to determine the volume coefficient, which is used to weight upstream and downstream capital costs (under regulations 22 and 23) to ensure that capital costs are spread across years according to the volume of gas produced in each year of tax.

This ensures that an appropriate RPM price for the operation is determined during each year, which is not distorted by high or low production volumes in a given year of tax.

In practice, participants in an integrated operation may measure project product by volume or by mass. Whether project product is measured by volume or by mass has no effect on the calculations within the Principal Regulation provided that the same measure is used for all parts of each separate calculation.

The Regulation allows participants the option of using mass instead of volume by amending the Principal Regulation so that it accounts for both mass and volume measurement.

In relation to mass measurement, and consistent with the approach to volume measurement, the Regulation:

* requires participants in an integrated operation who measure by mass to give the Commissioner estimates of the total mass of project natural gas to be recovered during the life of the operation; and
* provides the formula for calculating the *estimated average annual mass of project natural gas* for an integrated operation in which natural gas will be measured by mass (using the estimates notified by the Commissioner).

All participants in an integrated operation must use the same measure (whether it is mass or volume).  Where participants have chosen to measure by mass, they will need to give the Commissioner estimates of the total mass of project product to be recovered during the life of the operation, and must continue to measure by mass.

It is not possible to switch from volume to mass and vice-versa.  Where a taxpayer has customers, some of whom buy by mass and some whom buy by volume, all quantities need to be converted to the measure that is being used by all participants in the integrated operation, being the same measure used in the estimates provided to the Commissioner.

Regulation 10 of the Principal Regulation defines the base year for an integrated operation and provides the formula for calculating the volume coefficient for a year of tax. The base year means the year of tax in which the actual volume of project natural gas first exceeds the estimated average volume of project natural gas for the integrated GTL operation.

The Regulation makes minor amendments to the definitions in the formula for calculating the volume coefficient where the current year is after the base year. The Regulation clarifies that the calculation only applies in relation to integrated operations measuring by volume; and that n represents a year of tax where the base year is year 1.

The Regulation also inserts an additional formula for calculating the ***mass coefficient*** for those integrated operations that measure project product by mass rather than volume. The new formula mirrors the existing formula in the Principal Regulation, except that all references to volume are replaced with references to mass.

The Regulation also makes minor amendments to the provisions of the Principal Regulation which define where a CUP may exist, so that it can apply regardless of whether an operation measures project product by mass or volume.

## Part 5 – Extension to INTEGRATED GTE operations

This Part details the amendments in the Regulation that adjust existing concepts and provisions that apply to integrated GTL operations to ensure that where an integrated GTE operation exists, the Principal Regulation, and in particular the RPM, will apply in a manner consistent with that applied to GTL operations.

### Extension to GTE operations

The generation of electricity generation from gas resources via an integrated operation can encounter similar issues to integrated GTL operations in determining an appropriate price for the gas feedstock in circumstances where no arm’s-length price exists.

To provide tax certainty, the Regulation amends the Principal Regulation, consistent with the PTG recommendation, to ensure that the Principal Regulation, including the RPM, is extended to also apply to integrated GTE operations.

### When an integrated GTE operation exists

Regulation 4 of the Principal Regulation defines when an integrated GTL operation exists, as well as detailing relevant aspects of such an operation.

The Regulation inserts regulation 4A into the Principal Regulation, which defines when anintegrated GTE operation exists.

Regulation 4A provides that an integrated GTE operation is an operation in which:

1. petroleum is, or will be, recovered from a petroleum project; and
2. sales gas is, or will be, produced from some or all of the petroleum; and
3. some or all of the sales gas is, or will be, consumed in the commercial production of electricity.

The requirement in paragraph 4A(1)(c) refers to an integrated GTE operation existing where, in addition to the requirements of the paragraphs 4A(1)(a) and 4A(1)(b) being met, some or all of the sales gas is, or will be, consumed in the commercial production of electricity.

The term ‘commercial production of electricity’ is not defined, but refers to the production of electricity for a commercial purpose, and would not include electricity that is used for project purposes within a petroleum project, for instance.

Example 1: Electricity used for commercial purposes

Plensue Petroleum Limited operates an integrated operation.  The sales gas produced by the operation is consumed in the production of electricity.  The majority of the electricity produced is sold to the national electricity market, with a small proportion of the electricity generated used to run the operation including employee accommodation and other amenities.

Plensue Petroleum Limited would be consuming sales gas in the commercial production of electricity for the purposes of paragraph 4A(1)(c).

Example 2: Electricity not used for commercial purposes, no assessable incidental receipts arising

Field Petroleum Limited operates an integrated GTL operation.  Some sales gas produced by the integrated GTL operation is used to generate electricity in an in‑house plant.  All of the electricity produced is used to run the entire operation including employee accommodation and other amenities.

Field Petroleum Limited would not be consuming sales gas in the commercial production of electricity for the purposes of paragraph 4A(1)(c).

Example 3: Electricity not used for commercial purposes, assessable incidental receipts arising

Nicolex Petroleum Limited operates an integrated GTL operation.  Nicolex Petroleum Limited has installed as part of the integrated GTL operation some electricity generation capacity that uses sales gas from the project as fuel.  While the electricity is generated for use by the operations and facilities of the petroleum project, at times excess electricity is produced to maintain security of supply because of fluctuating demand.  Any excess electricity produced is sold to the national electricity market and a local uranium mine operated by Annekene Limited.

The sale of excess electricity does not represent the commercial production of electricity for the purposes of paragraph 4A(1)(c).  However, the consideration received by Nicolex Petroleum Limited from the sale of the excess electricity would constitute assessable incidental production receipts under the PRRTAA.

### Changes to defined terms relating to GTE operations

Regulation 4A also defines a number of terms relevant to an integrated GTE operation.The definitions and their applications are similar to those for GTL operations under regulation 4 of the Principal Regulation, except that they relate to project electricity, rather than project liquid.

###### Project natural gas

The*project natural gas*of an integrated GTE operation is the petroleum from which sales gas will be produced and consumed to produce electricity. The term is primarily used in determining average volume or mass coefficient of an integrated GTE operation under regulations 9, 10 and 10A.

###### Project sales gas

The *project sales gas* for an integrated GTE operation is defined as that sales gas which is produced from project natural gas and is consumed by, or used in the production of electricity by the integrated GTE operation. Project sales gas is the marketable petroleum commodity which is normally being valued under the framework set out in the Principal Regulation.

###### Project electricity

###### *Project electricity* is the electricity produced through the consumption of project sales gas. The value of project electricity (normally determined by sale) is primarily used to determine the netback price under regulation 23 of the Principal Regulation. Project product and production year

###### The definitions of both *project product* and *production year* in relation to an integrated GTE operation mirror those for an integrated GTL operation, except that the definition substitutes project electricity in the place of project liquid.

###### Production date

The *production date* for an integrated GTE operation is 31 December of the production year, consistent with that for integrated GTL operations.

Both the production year and production date are used in relation to augmenting and reducing those costs incurred prior to the production year under Division 5.3 of the Principal Regulation.

###### Operating life

The *operating life* is a key concept in determining the estimated average and actual annual volume or mass of project natural gas for the volume or mass coefficient under regulations 9 and 10 of the Principal Regulation and regulation 10A, and is the basis of the estimated operating life for allocating direct capital costs across years of tax under regulation 36 of the Principal Regulation.

###### MPC production year

The *MPC production year* for an integrated GTE operation is the same as that for a GTL operation. It is defined as the year of tax in which an MPC, other than project sales gas, is first produced.

This definition has its main application where capital costs are augmented or reduced at Step 9 of the RPM, as set out in Division 5.3 (see regulations 34 and 35 of the Principal Regulation).

###### Upstream and downstream stages of integrated GTE operation

As explained earlier, both integrated GTL and GTE operations consist of an upstream stage and a downstream stage. The upstream stage, which usually involves the production of the marketable petroleum commodity ‘sales gas’, is comprised of the same activities and elements for both integrated GTL and GTE operations.

However, the downstream stage will differ due to the different processes involved in the production of electricity as opposed to project liquid.

Regulation 5 of the Principal Regulation currently defines the upstream and downstream stages of an integrated GTL operation. The Regulation amends regulation 5 so that it applies to both integrated GTL and GTE operations.

What constitutes the *upstream stage* of an integrated operation remains the same as in the Principal Regulation, and includes those processes necessary for the production of project sales gas and storage of that gas at or adjacent to the place it is produced. Similarly, the processes comprising the downstream stage of an integrated GTL operation also remain the same as under the Principal Regulation.

However, the Regulation amends the Principal Regulation to separately define the elements comprising the downstream stage of an integrated GTE operation.

Broadly, the Regulation specifies that the downstream stage of an integrated GTE operation comprises those processes which occur after the production of project sales gas and continue up to the point where project electricity is generated and sold or alternatively committed to some other use.

The costs of infrastructure after that point, such as those related to connecting the downstream electricity generator to the electricity grid, are outside the integrated GTE operation and are not considered part of the downstream stage.

### Changes to the core concepts of the Principal Regulation

#### Assessable petroleum receipts for sales gas

Regulations 14 to 17 of the Principal Regulation detail how assessable petroleum receipts for sales gas are to be worked out for an integrated GTL operation where the sales gas becomes excluded other than by sale, or alternatively by non-arm’s length sale. The Regulation consolidates the operations of those provisions while also broadening their scope to apply to ‘integrated operations’ (that is, integrated GTL and GTE operations) rather than only integrated GTL operations.

Regulation 14 applies in relation to calculating assessable petroleum receipts from project sales gas in circumstances where subparagraph 24(1)(d)(iii) of the PRRTAA applies – that is, where the project sales gas becomes an excluded commodity by virtue of being sold on a non-arm’s length basis.

Subregulations 14(2) to 14(6) set out how a taxpayer determines their assessable petroleum receipts depending on their circumstances, and mirrors the hierarchy detailed in regulation 16 of the Principal Regulation. This is summarised in Table 1 below.

Table 1.

|  |  |  |
| --- | --- | --- |
| Circumstance | Amount to be included in assessable petroleum receipts | Subregulation |
| An APA applies | The amount of assessable petroleum receipts calculated in accordance with the APA | 14(2) |
| An APA does not apply and:- no election has been made under regulation 42 or 43 of the Principal Regulation; and- a CUP exists | The higher of:* the consideration received or receivable, less any expenses payable, by the taxpayer in relation to the sale;
* the CUP multiplied by the volume or mass of project sales gas sold.
 | 14(3), (4) |
| An APA does not apply and:- no election has been made under regulation 42 or 43 of the Principal Regulation; and- a CUP does not exist | The higher of:* the consideration received or receivable, less any expenses payable, by the taxpayer in relation to the sale;
* the RPM price\* of the project sales gas multiplied by the volume or mass of project sales gas sold.
 | 14(5),(6) |

\*RPM price means the residual pricing method determined gas transfer price for the taxpayer in relation to the integrated operation in the year of tax in which the sale took place.

Similarly, regulation 15 applies in relation to calculating assessable petroleum receipts from project sales gas where paragraph 24(1)(e) of the PRRTAA applies – that is, where the project sales gas becomes an excluded commodity other than by being sold, such as where it is moved away from the place of its production for further processing as part of the integrated operation.

Subregulations 15(2), to 15(6) set out how a taxpayer calculates their assessable petroleum receipts depending on their circumstances and follows an identical hierarchy to that outlined above.

Consistent with the Principal Regulation, regulations 14 and 15 only apply to sales gas that is project sales gas of an integrated operation. Where this is not the case, assessable petroleum receipts for the sales gas will, depending on the circumstances, be determined under either paragraph 24(1)(b) or paragraph 24(1)(c) of the PRRTAA.

The Regulation also inserts regulation 16, which applies to calculating assessable petroleum receipts from project natural gas in cases where paragraph 24(1)(f) of the PRRTAA applies – that is, where project natural gas (i.e. the natural gas of the integrated operation from which sales gas will be produced and processed into liquefied product or electricity) is subject to a non-arm’s length sale prior to being processed into project sales gas. This is discussed further in Part 6, below.

The Regulation also makes consequential amendments to correctly refer to the new regulations, involving substituting references to regulations ‘14 or 15’ with references to regulations ‘14, 15 or 16’.

#### Cost-plus price

Regulation 22 of the Principal Regulation sets out the formula for determining the cost-plus price for taxpayers in an integrated GTL operation. The formula calculates the per unit price for sales gas for the year of tax by summing the share of all upstream capital costs allocated in the year of tax (including a capital allowance) with the upstream operating cost incurred, and dividing by the volume of project sales gas produced.

The Regulation amends this provision so that it operates in the same manner, but with an expanded scope to incorporate mass measurement and enable it to also apply to integrated GTE operations and to project natural gas.

Specifically, the amended regulation 22:

* refers to ‘integrated operations’ to ensure it operates in relation to integrated GTE operations as well as integrated GTL operations;
* uses theterm *quantity of assessable gas* (QAG) rather than the ‘volume of project sales gas’, and notes that quantity can be measured by either mass or volume; and
* refers to the term *quantity coefficient*rather than volume coefficient, which is defined as either a mass or volume coefficient depending on how project product is measured for the operation;

#### Netback price

Regulation 23 of the Principal Regulation sets out the formula for determining the netback pricefor taxpayers in an integrated GTL operation. This involves deducting from the market value of the project liquid produced, the sum of the downstream capital costs allocated and downstream operating costs incurred in the year of tax and dividing it by the volume of project sales gas produced by the operation to determine a cost per unit for the project sales gas. From this amount, each participant is also able to deduct their per unit selling and marketing costs (referred to as downstream personal costs) to arrive at their netback price.

The Regulation amends this provision to include a revised netback formula to encompass integrated GTE operations and allow for the use of mass measurement.

The amended regulation 23:

* substitutes *project liquid value* with *end product values* (EPV), as defined, reflecting that the end product may be either project liquid or project electricity depending on the nature of the integrated operation;
* uses *quantity of taxpayer’s downstream gas* (QTDG), rather than the ‘volume of taxpayer’s downstream gas’;
	+ QTDG is defined as being the quantity of assessable gas produced in the operation in the year of tax which was further processed into project liquid (in the case of an integrated GTL operation), or consumed in the production of project electricity (in the case of an integrated GTE operation) that the taxpayer was entitled to receive.
* recognises that project sales gas within an integrated GTE operation is consumed in the production of project electricity in comparison to an integrated GTL operation where it is processed into project liquid, and provides for those differences within the definition.

Generally the value of project electricity will be the consideration received by the taxpayer for the electricity sold. Where the electricity is sold into the national electricity market to meet a supply contract entered into with a third party, the price received under the contract will be the end product value for the project electricity irrespective of the market spot price.

 Example 4: End product value – project electricity

Biggen Co is a taxpayer participant in an integrated GTE operation. Biggen Co enters into a contract with Ismeltit Co to supply 100 MWh of electricity at a price of $50 per MWh. To meet the contract, Biggen dispatches 100 MWh into the National Electricity Market (NEM). Over the period the electricity is supplied, the NEM spot price averages $80 per MWh.

Biggen Co’s end product value for the project electricity supplied will be $5,000 ($50 x 100).

In relation to the value of project liquid, in cases where it is sold on a ‘delivered ex-ship’ or ‘delivered at terminal’ basis, the total amount received by the taxpayer will include not only the market value of the project liquid, but also an amount relating to shipping or delivery. In such cases the end product value will reflect the total amount received minus that portion that is reasonably attributable to the operations involved in delivering the project liquid.

The Regulation also makes a minor amendment to clarify that, where the value of QTDG is zero, the adjustment made to the netback cost to take account of personal costs is also zero. This ensures that the formula will not result in an infinity value where the downstream personal costs and quantity of taxpayers’ downstream gas are both zero values***.***

#### Residual Pricing Method (RPM)

The RPM is outlined in Part 5 of the Principal Regulation and in particular regulation 25 which sets out the necessary steps for calculating an RPM price in table form. There are a total of 14 steps to be carried out in determining an RPM price; however the Principal Regulations apply only to integrated GTL operations.

The steps involved in determining an RPM price for an integrated GTE operation are substantially the same as for an integrated GTL operation.

The Regulation amends the wording of the final paragraph of the explanation of what the method does within regulation 25 of the Principal Regulation, so that it includes reference to “project electricity” in addition to “project liquid”. This ensures that the costs of participants that are attributable to project electricity of an integrated GTE operation are included for the purposes of applying the RPM.

#### Identifying, classifying and allocating costs

Division 5.2 of the Principal Regulations provides for identifying and classifying the costs attributable to an integrated GTL operation which are to be included (or excluded) in the RPM calculations by a taxpayer.

In order to ensure that this Division applies appropriately to integrated GTE operations the Regulation makes a number of minor amendments as follows:

* the heading for regulation 26 is amended to refer to types of costs associated with an integrated operation, rather than an integrated GTL operation;
* the heading for regulation 27 is amended to refer to the exclusion of certain costs of an integrated operation; and
* the term “a integrated GTL” is omitted from subregulation 28(1) and replaced by “an integrated”.

The Regulation also amends to subregulation 35(3) to include a reference to the combustion of project sales gas to produce project electricity.

#### Notional tax amounts

Division 2 of Part VIII of the PRRTAA contains rules for the collection of PRRT by instalments. Section 96 of the PRRTAA specifies the amount that is payable by a taxpayer as an instalment of tax in relation to an instalment period. The amount is referred to as a ‘notional tax amount’ and is ascertained under section 97 of the PRRTAA.

Regulation 38 of the Principal Regulation applies in relation to determining the amount to be included in calculating a taxpayer’s current period liability under subsection 97(1A) of the PRRTAA where the RPM is not used to determine assessable petroleum receipts.

Where a participant of an integrated GTL operation uses an RPM price to determine their assessable petroleum receipts and they had an RPM price for the previous year of tax, regulation 39 of the Principal Regulation applies. Regulation 39 sets out a formula for calculating the taxpayers current period liability under subsection 97(1A) of the PRRTAA, and takes account of the participant’s RPM price in the previous year, as well as other factors including changes in the market value for project liquid and production levels, meaning the participant is not required to do a full reassessment of the RPM.

The Regulation replaces regulation 39 of the Principal Regulation with a new provision which includes a revised formula and definitions to ensure that the regulation applies to integrated GTE operations and those operations measuring by mass.

As with the formulas for determining netback and cost-plus prices, the new formula references the terms assessable gas, QAG and EPV so as to apply to integrated GTE and GTL operations, whether measuring project product by mass or volume.

The Regulation also amends subregulations 39(4) to 39(6) of the Principal Regulation, which deal with what is the appropriate end product value to be applied, in order to encompass both project liquid and project electricity.

Regulation 40 of the Principal Regulation applies in situations where a taxpayer of an integrated GTL operation uses the RPM price to determine their assessable petroleum receipts, but they do not have an RPM price for the previous year of tax. This is likely to occur when a new participant enters into the integrated GTL operation.

The Regulation amends the formula and definitions for subregulations 40(2) and 40(3) of the Principal Regulation to ensure that they apply to integrated GTE operations and to integrated operations that measure by mass as well as those that measure by volume, in a manner similar to the amendments to regulation 39.

Consistent with the operation of the Principal Regulations, the amendment to subregulation 40(2) will result in the amount to be included in calculating the current period liability under subsection 97(1A) of the PRRTAA being that amount determined as per the amended formula, unless the taxpayer makes an election under subregulation 40(3) of the Principal Regulation.

Subregulation 40(3) of the Principal Regulation applies where the taxpayer becomes a participant in the assessment year due to a transfer of interest, and allows them the choice of applying the formula in regulation 39 instead of using the previous participant’s outcomes in the previous year of tax.

## Part 6 – Integrated onshore operations and RPM election

This Part explains the amendments in the Regulation to ensure that:

* taxpayers with onshore integrated GTL operations have the option of making an irrevocable election to apply the RPM as a default methodology; and
* the RPM method is able to be applied to determine an appropriate RPM price in situations where project natural gas is sold by a participant via a non-arm’s length arrangement in the context of an integrated GTL operation.

### Election to use RPM – participant in onshore GTL operation

As outlined in Part 5, the Regulation consolidates regulations 14, 15, 16 and 17 of the Principal Regulation. The new regulations 14, 15 and 16 provide a hierarchy of methods for determining the assessable petroleum receipts of a taxpayer in an integrated operation in cases where a non-arm’s length sale, or alternatively where no sale occurs, in relation to the project sales gas produced in the operation.

As noted, the hierarchy is as follows:

1. If an APA applies, the amount calculated in accordance with the arrangement; and
2. If no APA applies to the sale, but a CUP exists for the sale – the CUP amount for the sale;
3. If no APA applies to the sale, and no CUP exists for the sale – the RPM amount for the sale.

However, the Regulation allows those taxpayers in an integrated GTL operation that recover petroleum from an onshore petroleum project and whose project gas is subject to a non-arm’s length sale, the option of using the RPM as the default methodology for calculating the value of the resource at the taxing point.

The Regulation inserts regulation 42 into the Principal Regulation to allow a participant in an integrated GTL operation that recovers petroleum from an onshore petroleum project to make an irrevocable election to use the RPM.

The election to use the RPM as the default methodology must be made in a form approved by the Commissioner and given to the Commissioner in the year of tax before the production year for the operation.

The practical effect of a taxpayer making an election under regulation 42 is that the RPM will be used to determine the assessable petroleum receipts of the taxpayer in relation to project product, irrespective of whether a CUP may exist.

Consistent with the operation of the Principal Regulation, where an election has been made and the RPM used, the assessable receipts of a taxpayer will be the higher of the consideration received, less any expenses payable in relation to the sale, and the RPM price multiplied by the volume or mass of the assessable gas sold.

### Assessable receipts where project natural gas is subject to non-arm’s length sale prior to becoming sales gas

The Principal Regulation was developed with traditional offshore integrated LNG operations in mind. Such operations are typically structured around one large natural gas project supplying gas to a liquefaction plant, with the majority of the project natural gas processed to project sales gas which is suitable for liquefaction.

The onshore integrated GTL operations currently being developed in Australia differ in a number of respects from this traditional structure. In particular, the gas to be used as liquefaction feedstock for these integrated operations will typically be supplied by a number of coal seam gas (CSG) projects, rather than a large single natural gas project, due to them generally having smaller gas reserves. As a consequence, these integrated operations may adopt a different structure to the traditional model.

This structure involves, in the first instance, a number of petroleum projects selling (potentially at non-arm’s length) natural gas (normally coal seam gas) to a special purpose entity referred to as an ‘aggregator’. The purpose of the aggregator is to source and aggregate volumes of CSG from the various coal seam gas projects sufficient to supply the downstream liquefaction facilities, as well as streamline gas processing services and transportation (see Figure 2).

**Figure 2: Structure of onshore GTL operation with an aggregator**

 

Applying the existing RPM method to an onshore integrated GTL operation with an aggregator structure where non-arm’s length sales of project natural gas occur could result in a misalignment between PRRT assessable receipts and deductible expenditures. This is because at the point of sale, the gas has generally not been processed or refined to the stage of being the marketable petroleum commodity ‘sales gas’ ready for liquefaction.

Section 24 of the PRRTAA makes clear that, in situations where petroleum is sold prior to a marketable petroleum commodity being produced from it, the point at which assessable petroleum receipts are to be determined (and the point up to which deductible expenditure can be incurred) is at the point of sale.

Paragraph 24(1)(f) of the PRRTAA was inserted by *Petroleum Resource Rent Tax Assessment (Amendment) Act 2012*. This paragraph allows for the assessable receipts arising from the sale of project natural gas to be determined in accordance with the regulations.

However, as the Principal Regulation currently only operates to determine an RPM price for project sales gas, applying them to integrated projects where project natural gas is subject to a non-arm’s length sale would result in the assessable receipts for the gas determined by the application of the RPM being too high.

The Regulation amends the Principal Regulation to ensure that it is able to apply, and that the RPM will determine an appropriate RPM price, in circumstances where project natural gas, rather than project sales gas, is subject to a non-arm’s length sale within an integrated operation.

This primarily involves adjusting what constitutes the upstream and downstream stages of the integrated GTL operation in such situations for the purposes of applying the RPM, as outlined below.

#### Non-arm’s length transactions

The Regulation inserts regulation 8A into the Principal Regulation which defines a non-arm’s length transaction*,* in order to clarify when a transaction is not considered to be at arm’s length for the purposes of determining assessable petroleum receipts.

A non-arm’s length transaction is defined as being one where the Commissioner, having regard to any connection between the parties to the transaction and any other relevant circumstances, is satisfied the parties are not dealing with each other at arm’s length; which mirrors section 57 of the PRRTAA.

In this context, a non-arm's length transaction normally involves a special price being negotiated because of a relationship between the parties involved, which is inconsistent with that which could be reasonably expected had the parties been dealing with each other at arm’s length. Whether parties are considered to be dealing with each other at arm’s length will depend on the facts and circumstances of the arrangements entered into. The mere fact that parties to an agreement are associated or related will not necessarily be determinative in concluding that they are not dealing at arm’s length with each other.

The decision of the Commissioner that a transaction is a non-arm’s length transaction is reviewable under Part IVC of the *Tax Administration Act* 1953, as set out in regulation 41 of the Principal Regulation. The Regulation makes a minor corresponding amendment to regulation 41 to correctly reference regulation 8A in this regard.

### Determining assessable petroleum receipts – project natural gas of onshore integrated operation with non-arm’s length sale

The Regulation substitutes a new regulation 16 into the Principal Regulation which provides the hierarchy of methods for calculating assessable petroleum receipts in cases where project natural gas produced from petroleum recovered from an onshore petroleum project is sold via a non-arm’s length transaction for the purposes paragraph 24(1)(f) of the PRRTAA.

The hierarchy that applies is the same as that which applies in in relation to project sales gas, unless the participants in the onshore integrated operation have made an election to use the RPM under regulation 42.

The hierarchy is:

1. If an APA applies, the amount calculated in accordance with the arrangement;
2. If no APA applies to the sale, and no election to use the RPM or modified RPM has been made (under regulations 42 or 43), but a CUP exists for the sale – the CUP amount for the sale; and
3. If no APA applies to the sale, and either no CUP exists for the sale or an election to use the RPM or modified RPM has been made (under regulations 42 or 43) – the RPM amount for the sale.

Consistent with this, the Regulation also makes additional minor amendments to regulations 18 and 19 of the Principal Regulations to:

* allow the Commissioner to enter into an advance pricing arrangement at the request of a participant in relation to project natural gas as well as project sales gas; and
* ensure that a CUP can be applied, where relevant, in relation to project natural gas.

### Upstream and downstream stages of an integrated operation where project natural gas is subject to non-arm’s length sale

Regulation 5 of the Principal Regulation defines the elements comprising both the upstream and downstream stages of an integrated GTL operation for the purposes of determining assessable petroleum receipts relating to project sales gas using the RPM.

What constitutes the upstream and downstream stages of an integrated operation determines what costs are taken into account in determining the cost-plus price (under regulation 22) and netback price (under regulation 23) of an integrated operation as part of the RPM calculation.

The Regulation amends regulation 5 of the Principal Regulation in order to redefine the scope of the upstream and downstream stages of an integrated operation where the project natural gas is subject to a non-arm’s length sale prior to project sales gas being produced.

The Regulation defines theupstream stage of an integrated operation involving the non-arm’s length sale of project natural gas as being comprised of those processes necessary to the production of project natural gas up to the point of sale. These processes include the recovery of project natural gas from the reservoir, and may, depending on the point at which it is sold, include the storage of project natural gas prior to use in the production of sales gas.

Similarly, the processes comprising the downstream stage of both integrated GTL and GTE operations where the project natural gas is sold prior to project sales gas being produced are expanded to recognise that the production of sales gas and related transportation and storage of sales gas will form part of the downstream stage for the purposes of determining the RPM price in such circumstances.

Defining what constitutes the upstream and downstream stages of onshore integrated operations involving a non-arm’s length sale of project natural gas as described ensures that the appropriate cost-plus and netback prices, and consequently the RPM, can be determined for such operations. In effect, this treatment will appropriately align the point at which assessable receipts are determined using the RPM under paragraph 24(1)(f) of the PRRTAA, with the point up to which project expenditures can be deducted under the PRRTAA (i.e. ‘the taxing point’).

### Amount and timing of included capital costs

Regulation 31 of the Principal Regulation defines what constitutes the capital costs and operating costs of an integrated operation for the purposes of a taxpayer determining the netback and cost-plus prices under the RPM. Depending on the time at which these costs are incurred, and the time at which project product is produced, they may be augmented or reduced consistent with the rules outlined in Division 5.3 of the Principal Regulation.

The Regulation amends regulation 31 of the Principal Regulation to ensure that included capital costs which are associated with an integrated operation, but which do not form part of the cost of a depreciating asset, are treated as capital costs (and not operating costs) for the purposes of applying the RPM.

The Regulation also inserts regulation 44 into the Principal Regulation which provides that participants in an integrated onshore operation may elect to use the depreciated replacement cost method to determine the included cost of units of property of the operation that were completed prior to 2 May 2010. This recognises that integrated onshore operations currently being developed may incorporate petroleum projects that have been operating for a significant period of time prior to becoming part of the integrated operation, and for which there are insufficient records to verify historic costs incurred.

Where an election has been made under regulation 44, regulation 31A will apply, which provides for the amount of included capital cost relating to property completed prior to 2 May 2010 to be taken to be the depreciated replacement cost of the unit at
1 July 2012. This is further discussed in Part 7 below.

## Part 7 – Arrangements for GTL operations existing before 2 May 2010

This Part explains the amendments in the Regulation to ensure that:

* taxpayers with integrated GTL operations existing at 1 May 2010 have the option to elect to use a modified RPM; and
* where an election to use the modified RPM has been made:
	+ a single phase point will apply for those integrated GTL operations; and
	+ capital assets existing prior to 2 May 2010 can be valued at depreciated replacement cost rather than on an historical cost basis.

### Election to use modified residual pricing method

The PTG recommended that taxpayers transitioning to the PRRT with existing integrated GTL projects as at 1 May 2010 should have access to a modified RPM as a default methodology to simplify the transition.

The modified RPM differs from the standard RPM method in two aspects. Firstly, the operation will be treated as having a single phase point occurring between upstream and downstream stages; and secondly, that the capital bases used for determining the netback and cost-plus prices of the operation, and consequently the RPM price, will be determined by using the depreciated replacement cost of assets existing as at
1 May 2010.

The Regulation inserts regulation 43 into the Principal Regulation, which allows participants in an integrated GTL that existed as at 1 May 2010 to make an irrevocable election to use the modified RPM.

An integrated GTL operation will, for the purposes of the Principal Regulation, be considered to have existed as at 1 May 2010 if it first processed project sales gas into project liquid prior to 2 May 2010. The North West Shelf LNG project in Western Australia was the only integrated GTL operation that existed at that time.

There are a number of requirements governing an election to use the modified RPM. Specifically, it must:

* be made by all participants in the operation jointly;
* be made in a form approved by the Commissioner; and
* be given to the Commissioner no later than the day on which the participants are required to give the Commissioner a starting base return under Schedule 2 of the Act.

The effect of making an election under regulation 43 is that the operation and/or application of a number aspects of the Principal Regulation are altered, including the production year; a reduction in the number of phases; and rules about capital costs, as outlined below.

### Production year for integrated GTL operations existing before 2 May 2010

Subregulation 4(6) of the Principal Regulation defines the production year for an integrated GTL operation as being the year of tax in which project sales gas is first converted into project liquid. The production year is used in the Principal Regulation in determining both the capital costs and the operating life of the project, which are used to determine the cost-plus and netback prices for the operation under the RPM.

Where participants in an operation elect to use the modified RPM method under regulation 43, the initial capital base for the upstream and downstream stages of their operation will be determined as at 2 May 2010.

The Regulation amends subregulation 4(6) of the Principal Regulation to provide that were an election is made under regulation 43, the production yearwill be the 2012-13 year of tax.

### A single phase point for integrated GTL operations existing before 2 May 2010

Regulation 6 of the Principal Regulation defines the phase points of an integrated GTL operation. Phase points are used to divide the integrated operation into a set of ‘phases’ which are used as a means of apportioning costs in cases where the multiple use of a phase occurs. Under this provision, a phase point always exists at the point where the upstream stage of the integrated operation ends and the downstream stage begins, with additional phase points existing at any point where the ratio of project product (that is, project natural gas, project sales gas and project liquid) to total product from the operation changes.

The Regulation amends regulation 6 of the Principal Regulation to provide that, where an election to use the modified RPM has been made under regulation 43, the integrated GTL operation will only have a single phase point - that being where the upstream stage ends and the downstream stage begins.

The Regulation also removes the requirement under subregulation 6(3) of the Principal Regulation for participants to notify the Commissioner of the phase points of the operation where such an election is made, given that there will only be one phase point.

### Estimated average annual volume or mass of project natural gas

Regulation 9 of the Principal Regulation sets out how the estimated average annual volume of project natural gas for an integrated GTL operation is calculated, as well as the requirement that the Commissioner be provided with estimates or revised estimates for the operating life of the operation and the total volume of gas to be recovered, which form the basis of the calculation. This estimate is necessary for determining the volume coefficient calculated under regulation 10 of the Principal Regulation.

As previously outlined, the Regulation replaces regulation 9 of the Principal Regulation with a new regulation to ensure it is applicable to integrated GTL and GTE operations and covers measurement by mass as well as volume. In addition, subregulation 9(2) provides for a revised timeframe in which estimates of the operating life and volume or mass of project natural gas to be recovered must be provided to the Commissioner in circumstances where an election under regulation 43 has been made. In such cases, estimates must be provided to the Commissioner no later than the date participants are required to provide their starting base return under Schedule 2 of the Act, or a later day agreed by the Commissioner.

The Regulation also replaces subregulation 10(1) of the Principal Regulation to include a new definition of “base year”, which is used in determining the volume coefficient of an integrated operation. The Regulation provides that, where an election has been made in relation to an integrated operation under regulation 43, the base year is the 2012-13 year of tax. The base year arrangements are mirrored in the new regulation 10A with regard to calculating mass coefficients for operations measuring by mass.

### Amount and timing of included capital costs

Regulation 31 of the Principal Regulation defines what constitutes the capital costs and operating costs of an integrated operation for the purposes of a taxpayer determining the netback and cost-plus prices under the RPM.

The Regulation inserts subregulation 31(1A) into the Principal Regulation, which excludes those costs incurred before 1 July 2012 as being capital costs for integrated GTL operations where an election has been made under regulations 43 or 44.

This is to prevent the double-counting of capital costs which could otherwise occur because, where an election is made under regulations 43 or 44, the capital costs incurred prior to the 2012-13 tax year used in the netback and cost-plus formulas will instead be determined using the specified approach set out in regulation 31A as outlined below.

The Regulation inserts regulation 31A into the Principal Regulation which provides for the amount and timing of included capital costs incurred before 1 July 2012 in relation to:

* integrated GTL operations which existed before 2 May 2010, and where an election has been made under regulation 43 to apply the modified RPM; and
* integrated onshore operations that made an election under regulation 44 to use the depreciated replacement cost method.

For integrated operations that existed prior to 2 May 2010 where an election has been made to apply the modified RPM method, and for integrated onshore operations where an election has been made to apply the depreciated replacement cost method, regulation 31A specifies that:

* capital costs incurred prior to 1 July 2012 will be taken to have been incurred on 1 July 2012 and not when they were actually incurred.
* where a capital cost was for a unit of property that was completed before
2 May 2010, the amount of the cost is taken to be the depreciated replacement cost of the unit as at 1 May 2010.
	+ The depreciated replacement cost is given the same meaning as in Accounting Standard *AASB 136 Impairment of Assets*.

The table in regulation 25 of the Principal Regulation sets out when the RPM can be used, as well as what the RPM does, and the steps involved in determining an RPM price.

The Regulation makes minor amendments to the table to clarify that, where an election has been made under regulations 43 or 44 in relation to an integrated operation, less information is needed about capital costs incurred before
2 May 2010 than would ordinarily be required for the RPM to be used. This is because of the modified method by which capital costs will be determined for such operations, as outlined above.

The Regulation also makes a minor amendment to step 6 of the RPM method statement in regulation 25 of the Principal Regulation, to clarify that, in circumstances where an election had been made under regulations 43 or 44, regulation 31A is to be applied to capital costs that were incurred before the 2012-13 year of tax.

## Part 8 – Technical Amendments

The Regulation makes a number of minor technical amendments to the Principal Regulation in order to improve consistency in the use of terminology and improve clarity in relation to their application as a consequence of other amendments made in the Regulation.

### ‘Financial year’

The terms, “year of tax”, and “financial year”, are used in various regulations. A “year of tax” is defined in section 2 of the PRRTAA as meaning the first and subsequent financial years in which assessable petroleum receipts are derived from the project.

Within the Principal Regulation, the term, “year of tax”, is used in some contexts which could potentially be interpreted as limiting the scope of a regulation only to those years following the derivation of assessable petroleum receipts, resulting in costs incurred in a financial year prior to the year of tax not being taken into account contrary to the original policy intent.

To address this ambiguity, the Regulation makes minor amendments to omit “year of tax” and substitute “financial year”, as detailed in Table 2 below.

**Table 2.**

|  |  |
| --- | --- |
| ***Regulation*** | ***Amendment*** |
| Regulation 3 (definition of *capital allowance*)  | Omit “year of tax”, substitute “financial year” |
| Regulation 3 (definition of *start date*)  | Omit “year of tax”, substitute “financial year” |
| Paragraph 6(3)(a)  | Omit “year of tax”, substitute “financial year” |
| Regulation 16 | Omit “year of tax”, substitute “financial year” |
| Subregulation 31(3) | Omit “the 1 January of the year of tax”, substitute “1 January in the financial year” |
| Subregulation 33(1) | Omit “year of tax”, substitute “financial year” |

### ‘GTE operations’

The Regulation includes a number of amendments to replace or omit references to ‘GTL’, wherever occurring within the Principal Regulation in order to expand the application of the regulations to include integrated GTE operations.

Similarly, a number of minor amendments are made to a number of regulations involving inserting ‘electricity’ after ‘petroleum product', and ‘project electricity’ after ‘project liquid’, so that they also apply in the context of integrated GTE operations. These amendments are summarised in Table 3.

**Table 3.**

|  |  |
| --- | --- |
| ***Regulation*** | ***Amendment*** |
| Regulation 8 (heading) | Repeal the heading, substitute:**8 Participants in integrated operation** |
| Regulation 8  | After “petroleum product”, insert “or electricity” |
| Subregulations 23(2), 23(3) and 23(4) | After “project liquid” insert “or project electricity” |
| Subregulation 28(6) | After “project liquid” insert “or project electricity” |
| Subregulations 39(4), 39(5) and 39(6) | After “project liquid” insert “or project electricity” |
| Paragraph 41(e) | After “project liquid” insert “or project electricity” |

Regulation 6 of the Principal Regulation, which deals with phase points of integrated GTL operations, is also renamed to refer to ‘Phase points of integrated operation’, rather than only of ‘integrated GTL operation’.

Subregulation 7(3) of the Principal Regulation outlines the circumstances where there will be multiple use of a phase in relation to the processing of project sales gas into project liquid in an integrated GTL operation. The Regulation inserts subregulation 7(3A) into the Principal Regulation, which indicates the multiple use of a phase in relation to the production of electricity from the combustion of sales gas as part of an integrated GTE operation will occur when sales gas produced outside the integrated operation is also combusted within the phase.

### ‘Natural gas’

To ensure that the Principal Regulation can be applied to onshore project natural gas as well as sales gas, the Regulation makes a number of minor technical amendments to refer to ‘natural gas’ in addition to ‘sales gas’; remove specific references to sales gas; or to refer to the new defined term, ‘assessable gas’. These amendments are summarised in Table 4.

**Table 4.**

|  |  |
| --- | --- |
| ***Regulation*** | ***amendment*** |
| Part 3 (heading ) | Omit “for sales gas” |
| Subregulation 4(1) | Omit “, with the elements described in regulation 5,”. |
| Subregulation 18(1) | Omit all the words after “sales gas”, substitute “or project natural gas to which paragraph 24(1)(d), (e) or (f) of the Act applies”. |
| Paragraphs 19(2)(a), (b) and (c) | After “sales gas”, insert “or natural gas”. |
| Regulation 20 (heading) | Repeal the heading, substitute **RPM price (transfer price using the residual pricing method)** |
| Regulation 20 | Omit “for a taxpayer in a year of tax is a price for project sales gas that”, substitute “of an assessable gas for a taxpayer in a year of tax”. |
| Paragraph 20(a) | After “cost-plus price”, insert “of the assessable gas”. |
| Regulation 20 | After “and the netback price”, insert “of the assessable gas”. |
| Subregulation 21(1) | After “RPM price”, insert “for an assessable gas”. |

### Other technical amendments

The Regulation also makes a number of other minor technical amendments to the Principal Regulation to correct or clarify terminology as follows:

* Correcting the reference to ‘RPM amount’ in example 1 under subregulation 21(4), pertaining to working out an RPM price where information is not available, by replacing it with ‘RPM price’.
* Amending subregulation 35(6) by inserting “as reduced” to clarify that capital costs reduced for the purposes of RPM calculations are also taken to be incurred in the production year. This correctly reflects that capital costs incurred before the production year can, in addition to being augmented, also be reduced, or augmented and then reduced under the RPM method.
* Amending regulation 41, which outlines reviewable decisions, to remove references to N or VNG as these acronyms will no longer referred to in the amended subregulation.

The Regulation also makes minor amendments to the examples included under regulation 6 to clarify where a phase point occurs within an integrated operation. Phase points divide an integrated operation into phases, allowing for the appropriate apportionment of costs where multiple use of a phase occurs. Only those costs that relate to the production and processing of project sales gas into project liquid are included in the RPM calculation.

**ATTACHMENT B**

**Statement of Compatibility with Human Rights**

Prepared in accordance with Part 3 of the *Human Rights (Parliamentary Scrutiny) Act 2011*

**Petroleum Resource Rent Tax Assessment Amendment Regulations 2013 (No. 1)**

This Legislative Instrument is compatible with the human rights and freedoms recognised or declared in the international instruments listed in section 3 of the Human Rights (Parliamentary Scrutiny) Act 2011.

**Overview**

The Regulation amends the *Petroleum Resource Rent Tax Assessment Regulations* 2005, which provide a framework for determining the value of project gas for Petroleum Resource Rent Tax (PRRT) purposes, in cases where it is used as feedstock in an integrated gas-to-liquids (GTL) operation, and where no arm’s length price for the gas exists.

The Regulation provides industry with certainty by extending the regulatory framework so that it can also be appropriately applied in relation to gas used in onshore integrated GTL and gas-to-electricity (GTE) operations, as well as the North West Shelf project, following the application of the PRRT being extended to onshore petroleum projects and the North West Shelf project from 1 July 2012.

**Human rights implications**

This Legislative Instrument does not engage any of the applicable rights or freedoms.

**Conclusion**

This Legislative Instrument is compatible with human rights as it does not raise any human rights issues.

**Assistant Treasurer, Hon David Bradbury**