Petroleum Royalty Act 2023 – Petroleum royalty overview

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| Acronyms | Full form |
| CoTR | Commissioner of Territory Revenue |
| PRA | *Petroleum Royalty Act 2023* (NT) |
| TRO | Territory Revenue Office |

# Purpose

1. This Overview outlines the administrative arrangements relating to the establishment, calculation and collection of petroleum royalties under the *Petroleum Royalty Act 2023* (NT)(PRA)*.*
2. This Overview is for general guidance purposes only.

# Introduction

1. The Department of Industry, Tourism and Trade issues titles under the *Petroleum Act 1984* (NT) for the right to enter land, explore, produce and dispose of petroleum. When petroleum interest holders obtain a title they are required to pay royalties as a condition of that petroleum interest.
2. Royalties are payments made to the Territory as the owner of the resources, in consideration of a right granted to extract and remove petroleum and are calculated in respect of the gross value at the wellhead of petroleum taken or produced. In this respect, royalties differ to taxes.
3. The *Petroleum Act 1984* (NT) provides that ownership of petroleum produced in the Territory passes to the holder of a petroleum interest at the wellhead[[1]](#footnote-2) and as such, the wellhead is the trigger point and valuation point for royalty purposes.
4. Royalties are collected under the PRA for all petroleum produced in a royalty year and compensate the Territory community for allowing the private extraction of the Territory’s non‑renewable resources.
5. This Overview outlines the royalty requirements and sets out the obligations of the petroleum interest holders.
6. The royalty return required to be lodged under section 24 of the PRA provides the Commissioner of Territory Revenue (CoTR) with information to enable calculation of the royalty, including the value of the petroleum disposed, sold or processed beyond its first saleable point, the basis for valuation and any deductible expenditure incurred after the wellhead to the first saleable point.
7. The licensee(s) and permittee(s) is/ are responsible for the lodgement of royalty returns and payment of royalties. Royalties are calculated on a self-assessment basis and all interest holders are joint and severally liable for the royalty due under the PRA.

# Petroleum subject to royalty

1. All licensees and permittees for a project area are liable to pay royalty to the Territory on petroleum produced from a project area in a royalty year.
2. Under the *Petroleum Act 1984* (NT), petroleum is defined as:
   1. Any naturally occurring hydrocarbon, whether in gaseous, liquid or solid state
   2. Any naturally occurring mixture of hydrocarbons, whether in gaseous, liquid or solid state
   3. Any naturally occurring mixture of one or more hydrocarbons, whether in gaseous, liquid or solid state, and one or more of, hydrogen sulphide, nitrogen, hydrogen, helium, carbon dioxide or any combination of these.
3. Pursuant to the *Petroleum Act 1984* (NT), produced in relation to petroleum, means to recover or release the petroleum from a petroleum pool in the course, or as a result, of any operations on a production licence, retention licence or exploration permit.
4. For the purposes of the PRA, petroleum produced includes petroleum that is used or lost due to venting, flaring or other means, and are subject to royalty under this Act, but only where this occurs on a production project area.

# Petroleum not subject to royalty

1. The measurement and valuation of petroleum used for the purpose of processing or preparing petroleum for sale, or for incidental purposes is not required. Incidental purposes includes such things as the heating and lighting of employee accommodation or other employee social amenities. However, the use of petroleum outside the project area for these specified purposes is subject to royalty under the PRA.
2. Petroleum is also not subject to royalty if it is returned or reinjected into the natural reservoir in accordance with good oilfield practice.
3. Petroleum that is used or lost through venting, flaring or other means is also not taken to be produced provided this occurs on an exploration project area. Holders of exploration permits and retention licences may be approved by the Minister as a condition of those titles the ability to sell or use appraisal petroleum that would otherwise have been vented or flared. Where appraisal petroleum is sold, or used outside the project area, it would not be subject to exclusion and would therefore be subject to royalty.

# Meaning of project area

1. A production project areais comprised of one or more licence areas being operated by, or on behalf of, one or more licensees as a single integrated operation, or one or more licences together with one or more exploration permits, by or on behalf of one or more licensees together with one or more permittees as a single integrated project. The concept of a single integrated operation means that the operation of the licences and exploration permits must be functionally integrated and interdependent to the production of petroleum to be considered a single production project area.
2. A exploration project areais one or more exploration permits being operated by, or on behalf of, one or more permittees as a single integrated operation. The concept of a single integrated operation means that the operation of the exploration permits must be functionally integrated and interdependent to the exploration for, and production of, petroleum*.*
3. A project area under the PRA refers to either an exploration project area or a production project area and is used where a particular provision applies in the circumstances described by either definition.

## Meaning of single integrated project

1. For royalty purposes, each petroleum field, or project area, is treated independently from other project areas. Ring-fencing principles apply and each of the functionally integrated operations are treated independently, for royalty purposes, from all of the other operations (including operations on distinct and separate licence areas), even if operated by the same licensee or permittee.
2. For royalty purposes, each petroleum field, or project area, is treated independently from other project areas. The accounts from the individual field or project area may not be mixed with the accounts for activities outside the field or project. There is no ability to aggregate income or revenue and expenses from all operations carried on by the licensee or permittee within the Northern Territory.

# Calculation of royalties

1. Royalties on petroleum are charged on the gross value at the wellhead of petroleum production from a project area. However, as petroleum is not usually sold at the wellhead, a netback methodology is used to recognise the costs incurred after the wellhead to the point of sale. Only those expenditures essential to produce the petroleum are allowable as deductions against the value of the saleable mineral commodity sold or removed without sale from a production unit.
2. Royalty is payable at a rate of 10 percent of the gross value at the wellhead of all petroleum produced from a project area.

## Gross value at the wellhead

1. The gross value at the wellhead is calculated by taking the sales value of petroleum and reducing it by the lesser of:
   1. The deductible costs (refer paragraphs 43 to 46) of the petroleum in the royalty year.
   2. The deduction cap (refer paragraphs 76 to 78) for the petroleum for the royalty year.

### Sales value

1. The sales value of petroleum produced is the revenue received or receivable net of shipping costs of the petroleum.
2. The sales value is the market value where:
   1. No revenue is received or receivable for the petroleum, including where it is vented or flared on a production project area.
   2. The petroleum is not sold.
   3. The petroleum is sold as a petroleum product that was further refined or processed past its first saleable point.
   4. The sale is not on arm’s length terms.
3. Revenue also includes the proceeds received from an insurer for the loss or damage to petroleum, net of any excess paid in relation to the claim.

### Market value

1. The market value of petroleum produced from the project area is the price in Australian dollars that would be negotiated on the basis that it was sold at the first saleable point in an open commercial market between knowledgeable, willing but not anxious buyers and sellers, acting severally and independently, having regard to:
   1. The price of other petroleum sold to a third party on arm’s length terms and that is substantially similar to the petroleum being valued in time of delivery, kind, quality and composition.
   2. A price agreed in an advance pricing arrangement with the Commonwealth Commissioner of Taxation.
   3. A price audited and approved by the Commonwealth Commissioner of Taxation.
   4. Any applicable benchmark prices published by a recognised commodities exchange or index that the CoTR accepts.
   5. Any other matter the CoTR considers relevant.
2. Some of the above circumstances, particularly the methodologies accepted by the Commonwealth Commissioner of Taxation may not be in line with the provisions of the PRA (for example, the scope of deductions that may be entertained by the Commonwealth Commissioner of Taxation in arriving at a value, including marketing fees, which are excluded costs). While regard would be given to these circumstances, they would not be applied rigidly in all circumstances. A recognised commodities exchange price may not be appropriate to apply directly to petroleum produced in the Territory in all circumstances.
3. An advance pricing arrangement is an arrangement made with the Commonwealth Commissioner of Taxation under which a transfer pricing methodology is agreed to be used in accounting for dealings with petroleum for the purposes of the *Income Tax Assessment Act 1997* (Cth).
4. Other matters the CoTR may consider includes any other available information from any source that is considered relevant in determining the market value of petroleum produced from a project area. This may include (but is not limited to) sales of comparable petroleum made in the Territory over a particular reporting period, the applicability of a benchmark price used to the petroleum produced in the Territory in terms of time of delivery, kind, quality and composition, or sales agreements and arrangements for on-sales to an unrelated third party where the initial sale was made a related party.
5. Where petroleum is not sold, the CoTR may have regard to the average sales value obtained for other arm’s length petroleum sales made in the relevant reporting period from the same project area.

### Meaning of first saleable point

1. The first saleable point is the point at which petroleum is either sold, or disposed of, or the point at which the petroleum is processed into a petroleum product, and is usually the point where the value of the petroleum can be independently established. This concept makes clear that the sales value of petroleum is the market value if the petroleum is sold as a petroleum product that was processed beyond its first saleable point.
2. Deductible costs incurred in relation to an activity after the first saleable point are excluded costs for the purposes of calculating gross value at the wellhead of petroleum. No royalty is imposed on value adding or conversion of petroleum beyond its first saleable point.

### Australian dollar or equivalent

1. The revenue received or receivable for petroleum should be converted to Australian dollars by converting foreign currency at the exchange rate applying at the time the foreign currency was received, receivable or incurred. The rates that may be used for this purpose includes:
   1. The closing daily representative rate for the relevant day, as published by the Reserve Bank of Australia.
   2. The buy rate for the foreign currency, as quoted by a major Australian trading bank.
   3. Another rate agreed in writing between the licensee or permittee and the CoTR.
2. The exchange rate selected by a licensee or permittee to be applied for royalty purposes should be selected in good faith and on a consistent basis.
3. An application may be made to the CoTR in writing to use an alternative exchange rate for royalty purposes to ensure administrative ease in circumstances where a reasonable alternative rate is used by a licensee or permittee, and the use of the prescribed rates would result in additional administrative burden.

### Valuation of vented or flared petroleum

1. Petroleum that is used or lost through venting, flaring or other means on a production project area is subject to royalty. As vented or flared petroleum is not sold, it is to be valued at the market value of the petroleum produced under the PRA.
2. Refer to paragraphs 28 to 32 for details regarding the factors that the CoTR may consider in establishing the market value of petroleum produced.

### Shipping costs

1. Shipping costs in relation to the calculation of sales value is:
2. Where petroleum is exported, all freight charges, dead freight costs and marine insurance costs
3. Where petroleum is not exported, but sold into the Australian market, the freight and insurance costs incurred in delivering the petroleum to the point of sale or transfer.
4. Shipping costs do not include costs for which reimbursement or compensation is received, or where the costs are charged to another person, to ensure that the sales value is not reduced for costs for which no net expense has been incurred. Costs that are excluded costs are not shipping costs.
5. Shipping costs included in the calculation of sales value, must be incurred by the licensee, permittee or operator of the project directly in relation to the sale of petroleum or be incurred by a related party of the licensee, permittee or operator in relation to the sale of the petroleum on arm’s length terms. Where the shipping costs have been incurred by a related party, no mark up is permitted on the price charged by the third party.

### Deductible costs

1. As the royalties on petroleum are charged on an ad valorem basis (not a profit-based or net value approach), deductible costs able to be reflected in the calculation of gross value at the wellhead is limited to 75% of the sales value of petroleum produced from a project area. This limitation acknowledges the inherent nature of the ad valorem scheme ensures that deductions will never exceed sales value and that the Territory will always receive a royalty for petroleum under the ad valorem scheme.
2. The formula for determining the amount of deductible costs is:

**DC = AC + CFD – R**

Where:

**DC** is the amount of the deductible costs.

**AC** is the amount of the allowable costs calculated in accordance with section 18.

**CFD** is the amount of the balance of any carry forward deductions that are unable to be used in the royalty calculation as a result of the deduction cap.

**R** is the amount of any allowable costs the licensee, permittee or operator has received as reimbursement or compensation.

1. An amount cannot be claimed more than once, either in the same or different royalty year, regardless of whether it could fall under more than one heading of deduction or is capable of being reflected in the financial accounts of a licensee or permittee in more than one form. This is to prevent the double deduction of costs as both capital and expense.
2. For the purposes of calculating sales value or gross value at the wellhead, where an item of revenue or expenditure could technically fall under more than one definition, it must be classified under the most appropriate category, even if it could also be classified under another category.

### Allowable costs

1. For a cost to be an allowable cost it must be:
   1. Incurred by a licensee, permittee or operator, or a related party.
   2. Incurred in relation to the petroleum produced in the royalty year.
   3. Not a shipping cost or an excluded cost.
   4. Directly related to a post-wellhead activity.
   5. Incurred on arm’s length terms.
2. The allowable costs that may be included in the calculation of deductible costs in relation to petroleum produced from a project area, includes:
3. A pipeline tariff for transporting petroleum from the project area through a pipeline to the first saleable point. Pipeline tariffs beyond the first saleable point are not allowable costs.
4. The cost of a processing plant toll or other charge for processing the petroleum before its first saleable point. Costs for further processing of the petroleum past its first saleable point are not allowable costs.
5. Field gathering costs to transport the petroleum from the wellhead to processing or storage facilities.
6. Operating costs of a post-wellhead activity that is directly related to the treatment, processing, refining, storage or transportation of the petroleum.
7. A capital allowance deduction, in accordance with Australian income tax.
8. Costs directly related to a post-wellhead activity that are directly incurred for operating or maintaining an office in the Territory, fees for management services performed wholly in the Territory, or labour, employee or personnel costs (including travel and ancillary costs) only where work is performed solely in the Territory. For labour, employee and personnel costs to meet this provision, the worker must be working solely in the Territory for the entire period to which the cost relates, and for the period the worker was remunerated.

#### Capital allowance deductions

1. A capital allowance deduction, calculated in accordance with Australian income tax treatment, in relation to a post-wellhead facility. Where no Australian income tax treatment applies to the post-wellhead facility, a deduction may be calculated in accordance with a method approved in writing by the CoTR.
2. As a project area may be operated by a joint venture under a joint venture arrangement, there may be circumstances where each joint venture party lodges income tax returns accounting for its own proportionate interest in the assets of the joint venture. In these circumstances, different income tax treatments may be adopted for the same assets, depending on the treatment approved by the Commonwealth Commissioner of Taxation for each joint venture party.
3. Methodologies that may be considered in the above circumstances include:
   1. Applying a consistent and appropriate income tax treatment to the relevant assets that complies with Australian income tax laws.
   2. The sum of the capital allowance deduction claimed for income tax purposes by all joint venture parties in relation to the relevant assets.

#### Office expenses for NT-based offices

1. Office expenses relating to the general day-to-day running of an office are allowable operating costs if they:
2. relate to an office of the licensee or permittee that is located within the Territory
3. are directly attributable to the operation of the project area
4. in the case of work or services, the work or services are performed solely in the Territory.
5. Office expenses are administrative and corporate expenses relating to an office of the licensee or permittee within the Territory. This includes a wide variety of expenditure of which it is not possible to provide a comprehensive or exhaustive list. As a general guide, the expenses that would ordinarily fall within this category include:
6. running costs in respect of land and buildings where an office is located
7. utilities expenses
8. telecommunications and internet expenses
9. office equipment and stationery expenses
10. administrative, human resources and information technology expenses
11. expenses for the in-house provision of accounting and legal services.

For any of the above expenses to be allowable operating costs they must satisfy the criteria in paragraph 47.

1. Office expenses often include costs that are not directly attributable to the operation of a project area. For example, an office of a licensee or permittee can also incur costs in respect of another project that does not form part of the project area, or for other activities not directly attributable to the operation of the project area (such as exploration). In such instances, an apportionment of the costs may be required.

#### Fees for management services

1. Management connotes direction or control. Fees for management services which are performed or incurred solely within the Territory and are directly attributable to the operation of the project area are allowable costs. Fees for services performed or incurred by a person that was not physically present in the Territory during the entire time that service was performed are not allowable costs.
2. Fees for management services that are directly attributable to the operation of a project area may include, but are not limited to, fees for services in respect of the control, direction, influence or strategic management of a project area.
3. Fees for management services often include costs that are not incurred solely in respect of one project. Also, such fees can relate to activities of a licensee or permittee that are not directly attributable to the operation of a project area (for example, exploration activities). In either case, an apportionment of the costs may be required.
4. The requirement that the fees are directly attributable to the operation of the project area means that fees relating to strategic or higher level policy management may not be allowable.

### Non-deductible costs

1. The PRA specifically excludes certain costs for the purposes of calculating shipping costs or deductible costs from a project area. The nature of an ad valorem royalty scheme is such that royalty is imposed on the gross value of petroleum at the wellhead, with only those costs necessarily incurred after the wellhead to the point of sale or first saleable point being deducted from the sales value of petroleum.
2. Although for a cost to be included as a shipping cost or deductible cost it must fall within the meaning of those terms under separate provisions, for the avoidance of doubt a list is provided of costs that are specifically excluded from either allowable costs or shipping costs. The following costs are specifically excluded from the calculation of gross value at the wellhead:

#### Exploration and other pre-wellhead costs

1. Exploration or discovering petroleum that are in the nature of pre-wellhead costs (i.e. costs incurred in exploring and prospecting for petroleum and outlays on plant and other items of capital equipment required to develop petroleum from a well), lifting costs (being the costs of bringing petroleum to the surface), reservoir maintenance costs and overhead costs relating to pre-wellhead activities.

#### Marketing and selling costs

1. Marketing or selling petroleum, including fees, commissions, brokerage, or an amount paid to a distributor or agent. This also prevents the inclusion of any marketing costs included in any transfer pricing arrangement with a related party.

#### Care and maintenance costs

1. Maintaining a petroleum facility during an extended or permanent shutdown of the facility. An extended or permanent shutdown does not include shutdowns for the repairs and maintenance in the ordinary course of operations of the project area. Where a field or project ceases production as a result of a permanent shut down or a field or project ceases production and its operation is placed in care and maintenance for an indefinite period, mothballing costs, care and maintenance or abandonment costs are excluded for royalty purposes. This includes circumstances where those costs are necessarily incurred to maintain plant and gathering systems to facilitate the safe re‑commencement of production at some future period of time.

#### Decommissioning or rehabilitation costs

1. Decommissioning, rehabilitation or abandonment of the project area or a petroleum facility. Deferred or post-production rehabilitation expenditure (i.e. expenditure incurred subsequent to the cessation of production and not directly attributable to the production of petroleum from the field) is not eligible to be claimed as allowable costs.

#### Guarantees, security and insurance required by law

1. Complying with a law of the Territory, the Commonwealth, a State or another Territory, including costs and expenses related to any guarantees, securities or insurance imposed under law. This includes costs associated with complying with requirements for environmental bonds or other required securities.

#### Costs for non-NT resident employees

1. Salaries, allowance termination payments, other similar payments or benefits, superannuation payments and wages for any pay periods where the worker to which the payment relates did not work solely in the Territory, or was not engaged primarily in work that was directly attributable to petroleum produced in the Territory. This exclusion aligns with the allowable cost described at paragraph 48(f) to make clear that only wages and other employee related remuneration costs may be claimed as a for royalty calculation purposes where the work is carried out solely in the Territory.

#### Costs for interstate offices

1. Office expenses that do not relate to an office in the Territory, or are not for work services performed in the Territory. In order to incentivise the establishment of offices in the Territory, this exclusion aligns with the allowable cost described at paragraph 52 to 54 to make clear that only costs office costs may be claimed as a deductible cost where an office is located in the Territory and the services are performed solely in the Territory.

#### Costs for management fees

1. Fees for management services that are not performed solely in the Territory, or are not directly attributable to the production of petroleum in the Territory. This exclusion aligns with the allowable cost described at paragraph 55 to 58 to make clear that only fees for management services may be claimed as a deductible cost where the services to which the services related are performed solely in the Territory.

#### Travel costs for non-NT resident employees

1. Travel or ancillary costs in relation to an employee, contractor or other worker whose principal place of residence is outside the Territory. In order to incentivise the employment of local workers, this exclusion aligns with the allowable cost described at paragraph 48(f) to make clear that only travel and ancillary costs for resident employees is claimable for royalty deduction calculation purposes.

#### Interest and financing costs, foreign exchange and other financing arrangements

1. Interest and financing costs, foreign exchange gains or losses, hedging costs, costs associated with bad debts, asset revaluation gains or losses, are specifically excluded are not allowable costs for the purposes of the royalty calculation.

#### Royalties and payments in the nature of royalties

1. Payments in the nature of royalties cannot be claimed as allowable costs. Examples of such payments include:
   1. Payments made to an owner or occupier of private land or a lessee of Crown land (such as a pastoral lease) calculated on an ad valorem or profit basis.
   2. Negotiated payments calculated on an ad valorem or profit basis made to traditional Aboriginal owners or representatives of such owners.
2. Costs in relation to negotiating with, or compensation payments to, land holders or persons related to native title under an access agreement or native title agreement under the *Native Title Act 1993* are not allowable costs.

#### Taxes levies and fees

1. Taxes, levies or fees imposed or payable under a law of the Territory, the Commonwealth or a state or another Territory. This includes any licence, application or licence fees imposed under the *Petroleum Act 1984* (NT) and any levies imposed as a condition of the licence or exploration permit imposed under thelaw, including the monitoring and compliance or orphan well levies.
2. Amounts paid or payable for breaches of a legal or statutory obligation, including a penalty or damages for breach of contract are not allowable costs.

#### Costs incurred beyond the first saleable point

1. Any costs incurred beyond or after the first saleable point of the petroleum are not to be included in calculation of royalty.

### Deduction cap

1. The deduction cap limits the extent to which the sales value of petroleum is reduced by deductible costs to 75%.
2. All deductible costs are able to be claimed by a licensee or permittee, by providing that where deductible costs incurred in a royalty year are unable to be claimed in full in that royalty year due to application of the deduction cap, the balance of any deductible costs that exceed the deduction cap in a royalty year are able to be carried forward to a later royalty year.
3. Any deductible costs carried forward to the next royalty period must not be inflated or adjusted in any way, including for inflation.

# Payment of royalty

1. All licensees and permittees for a project area must pay the royalty for a royalty year by quarterly payments within 30 days after the end of each quarter on the following basis:

|  |  |
| --- | --- |
| Quarter period | Payment due |
| 1 July – 30 September | 30 October |
| 1 October – 31 December | 30 January |
| 1 January – 31 March | 30 April |
| 1 April – 30 June | 30 July |

1. CoTR may approve an alternative arrangement to the above payment dates, upon request by a licensee or permittee, if required. An application for an alternative arrangement needs to be made in writing and include details regarding why the alternative arrangement is required.

# Registration and information requirements

## Requirement to register

1. A licensee or permittee must register with the CoTR within 30 days after the commencement of petroleum production under a licence or permit.
2. A licensee or permittee must also notify CoTR within 30 days of certain events, including:
3. Petroleum production ends during an extended or permanent shutdown of a project area. This does not include a temporary shutdown of operations for the purposes of repairs and maintenance
4. Petroleum production restarts after a period of cessation. This would not include a restart after a temporary shutdown unless notification had been provided that the shutdown would be extended or permanent
5. There is a full or partial change in ownership of a licence or permit.
6. Registration or notification under this clause must be made to the CoTR in the approved form.

## Cancellation of registration

1. CoTR may cancel the registration of a licensee or permittee, where:
2. Petroleum production ceases following a permanent shutdown of operations under a licence or permit in a project area.
3. A licensee or permittee transfers its interest in a licence or permit to another person.
4. The registration is not required for any other reason.

# Lodgement of royalty returns

1. A single royalty return is required to be lodged for each project area. Where there is more than one licensee or permittee, the licensees or permittees may authorise a person to lodge the royalty return on behalf of all interest holders.
2. Annual royalty returns are required to be lodged in circumstances where the production of petroleum has commenced. The royalty return is due to be lodged and the final quarterly payment made within 30 days of the end of the royalty year.
3. The licensee(s) or permittee(s) must ensure that:
   1. Information relating to its field or project is accurate and up to date.
   2. The submitted royalty return is in the approved form, covering all details set out in the return together with working papers supporting the royalty calculations.
4. For convenience, a template royalty return is available on the Territory Revenue Office website at <https://treasury.nt.gov.au/dtf/territory-revenue-office/publications>.



Sarah Rummery

Commissioner of Territory Revenue

Date of Issue: 1 July 2023

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1. Section 6 of the *Petroleum Act 1984* (NT) [↑](#footnote-ref-2)