Freehold Mineral Tax 2009 Unit Value Submission Guide

General Information

- Freehold Mineral Rights Tax is calculated annually on calendar year wellhead production of petroleum and natural gas. The tax on production is allocated to the mineral rights' owners of each tract within a production entity. This guide describes the calculation of a Unit Value (UV) of wellhead freehold production using the revenue and allowable costs of the production entity.
- The Department of Energy (the department) calculates a default unit value for gas at 80% of the weighted average Crown gas reference prices. The default unit value for oil is calculated on the APMC average oil prices.

For 2009, the default price for GAS is $143.00/$10^3m^3$ **and the default price for OIL is $355.00/** m^3**.**

- If no unit value is submitted for a production entity, the department will use the default values to calculate the tax payable. If you choose to report unit values for the 2009 tax year, the submission is due by **January 27, 2010**. The method of calculating a Unit Value for Freehold Mineral Tax must be consistent for all properties and all years. To request a change in UV calculation method, contact the department, Freehold Mineral Tax, 9th Floor, 9945 – 108 St., Edmonton, AB T5K 2G6.
- The reporting period for capturing production, revenue and allowable costs for the 2009 unit value calculation is the production months from October 2008 to September 2009 (3+9 months).
- When reporting a working interest ownership percentage (WIO%), use the same WIO% to determine revenue, costs and production. Allowable costs are recognized for a reporting period. Any costs exceeding gross revenues cannot be carried forward to a future reporting period.
- For additional information access our website http://www.energy.alberta.ca/Tenure/605.asp

  or contact the Freehold Mineral Tax unit at 780-427-6000 (310-0000 Alberta Toll Free) or e-mail Mintax.Energy@gov.ab.ca

Submitting Unit Values

- The 2009 unit value submission document is available through the department's Electronic Transfer System (ETS) - Freehold Mineral Tax – Download Unit Values. It will list single well and multiple well production entities producing from freehold mineral titles where you have a declared interest. Refer to the Download Unit Value section of the FMT On-line Learning on our website ETS FMT Online Learning
- If the UV submission document does not include all of your production entities, refer to the Add Lessee section of the On-line Learning to establish a linkage. The Department will only accept unit values submitted by a lessee who has declared an interest and has established a lessee role to the PE and titles. See Delete Lessee section of on-line learning to remove yourself from a PE.
- Record the unit values for the products and submit. See the Submit Unit Value section of the On-line Learning.
- A value of $0.00 is acceptable for PE/products where costs exceed revenues, or all gas was flared or used for lease fuel. Only submit a value of $0.00 if the unit value calculation is $0.00.
  Do not submit $0.00 value if you have no interest in the PE.

Calculation of Unit Value for Crude Oil and Gas Well Condensate

1. Unit Value ($) = $\dfrac{\text{Revenues (2) - Allowable Costs (3)}}{\text{Oil or Condensate Production (4)}}$

   Several Production Entities can be grouped at a battery to calculate a common unit value for all wells that contributed to the calculated revenues.

2. Revenues:
   Determine the gross revenue ($) from the sale of crude oil or gas well condensate from a production entity or group for the reporting period October 2008 to September 2009 (3+9).

3. Allowable Costs:
   Determine the allowable costs ($) for the (3+9) reporting period. Allowable costs are the actual costs incurred for transportation from the point of first measurement of the clean oil or gas well condensate to the first point of sale.

4. Production:
   Determine the total oil or condensate production (m^3) at the wellhead for the (3+9) reporting period. The well volumes are those reported to the Energy Resources Conservation Board (ERCB) through the Petroleum Registry of Alberta (PRA).

5. Calculate the Unit Value ($ per m^3 of wellhead production):
   Deduct any allowable costs (3) from total gross revenues (2) and divide by oil or condensate production (4) to determine the wellhead unit value.

6. Record the unit value for OIL or CON of the production entities in the space on the Unit Value Submission spreadsheet.

Calculation of Unit Value for Field Gas or Solution Gas

A. Standard Gas Unit Value Calculation Method A (A): Using Crown Gas Royalty Information

Method A **(A)** is the Department's preferred method for calculating a gas and/or solution gas unit value. This standard method uses Crown Gas Royalty reporting, specifically Crown Gas Invoice Volume, Crown Gas Invoice Valuation Pricing, Crown Unit Operating Cost Rates (UOCR), Capital Cost Allowances and actual Custom Processing Fees reported to the Crown. Refer to the Department's Gas Royalty Guidelines (2006) at http://www.energy.gov.ab.ca/NaturalGas/941.asp

Wells and production entities can be grouped by processing facility for gas and solution gas unit value calculations. Revenues, Costs and Production must then all be grouped at the same facility.

1. Unit Value ($) =

   $$\frac{\text{Revenues } \mathbf{(2A)} \text{ – Allowable Costs } \mathbf{(3A)}}{\text{Gas or Solution Gas Production } \mathbf{(4A)}}$$

2. Revenues **(A)**:
   Determine revenues ($) for the production of gas and/or solution gas using the Crown Gas Royalty Detail invoice valuation prices for the reporting period production months October 1, 2008 to September 30, 2009 (3+9). The valuation prices are multiplied by the Client Volumetric Totals (Quantity/Heat) for all product types (e.g. gas, ethane, propane, butane, pentanes and sulfur) from the production entity processed at each facility. Valuation prices already incorporate gas in-stream Facility Average Prices (FAP), raw gas sales, transportation and fractionation adjustments.

3. Allowable Costs **(A)**:

Allowable costs for processing, gathering and compressing natural gas are operating costs, capital costs and custom processing fees. Determine the allowable costs for processing, gathering and compression for the October 1, 2008 to September 30, 2009 (3+9) reporting period by using:

- The department's posted UOCR for the 2008 previous calendar year **and** applicable capital costs for the 2008 previous calendar year, **or**
- The actual custom processing fees for October 1, 2008 to September 30, 2009 (3+9), **or**
- The applicable de-layered UOCR, custom fees and capital costs for facilities where you do not have ownership in the entire gathering, compressing and processing functions.

You cannot claim both the de-layered UOCR and custom fees for the same activity.

For example: If you have ownership in the compression and processing facilities and also in two of the four gathering systems used by the well or production entity. Eligible costs are:

the de-layered UOCR for the compressing and processing functions, **and**

the operating costs for the gathering function, which is either:

- The de-layered UOCR for the gathering function, **or**
- The custom fees incurred for the gathering system when you have no ownership.

For excess capacity at a facility (i.e. processed volumes exceed the proprietary share), the custom fees charged are intended to cover the capital and profit portion of custom processing and therefore operating costs or UOCR can be claimed for the excess volume.

Raw gas sold prior to processing and which is subsequently processed at a gas plant before delivery to a sales pipeline is valued at 80% of the gas reference price. Costs cannot be claimed for such raw gas sales. Raw gas sold and delivered to a sales pipeline without processing at a gas plant is valued at the Facility Average Price.

UNIT OPERATING COST RATES (UOCR)

UOCR is stated in dollars per 10^3m^3 of energy-adjusted gas equivalent volumes (EAGEV). The volumes used for revenue in Method **A (2)** or **B (2)** for gas and by-products are converted to energy adjusted gas equivalent volumes (EAGEV) by the following factors. The EAGEV is then multiplied by the UOCR to obtain allowable operating cost.

GAS	in 10^3m^3	x	1.00000
ETHANE	in m^3	x	0.28132
PROPANE	in m^3	x	0.65554
BUTANE	in m^3	x	0.72793
PENTANES-PLUS	in m^3	x	0.78783
SULPHUR	in tonnes	x	0.73750

CAPITAL COST ALLOCATION, use either:

- The production entities grouped by processing facility. This avoids the complexity of allocating capital costs at a well level. A unit value for the group is calculated using total revenues, costs and production for all of the streams in the group. Capital costs associated with the gathering, compression and processing of non-Alberta volumes and volumes purchased from a third party are not eligible. Capital costs incurred in the fractionation of proprietary NGL mix products from other gas plants into specification products are also ineligible. **or**

- Allocate capital costs using the percentage of gas equivalent volumes (GEV) of the stream compared to the total GEV processed at the plant. Using the EAGEV of the stream compared to that of the plant is also acceptable. The GEV or EAGEV volumes used should be from the same calendar year as the capital costs. Facilities that handle out of province volumes exclusively are not eligible costs..

Only use your WIO% share of allocated capital costs, not the total facility capital costs.

4. Production **(A)**:
   Determine the total gas or solution gas production (10^3m^3) at the wellhead using the (3+9) reporting period for all wells that contributed to the calculated revenues **(2).** The volumes are those reported to the ERCB through the PRA.

5. Deduct allowable costs **(3),** if any, from total revenues **(2)** and divide by gas and/or solution gas production **(4)** to calculate the unit value.

6. Record the unit value of the GAS or SOL for production entities on the UV submission spreadsheet.

B. Alternate Gas UV Calculation Method B (B): Actual Gross Revenues minus Crown Allowable Costs and Rates

1. Unit Value ($) = Actual Gross Revenues **(2B)** **-** Crown Allowable Costs **(3A)** / Field Gas or Solution Gas Production **(4A)**

2. Actual Gross Revenues:
   Determine the actual gross revenues ($) on the sale of gas or solution gas from each production entity for the reporting period October 1, 2008 through September 30, 2009 (3+9). Include revenues from all by-products e.g. gas, ethane, propane, butane, pentanes and sulfur. Gas Valuation: Where freehold gas is commingled with other sources (Crown volumes, third party purchases, out of province volumes or other non Crown volumes) before it is sold, the gross revenues attributable to freehold gas and by-product sales must be valued using the pooling concept. The revenue realized from the sale of all sources should be distributed proportionately to the ratio of volumes in the sales pool.

3. Crown Allowable Costs:
   Use the Crown's Allowable Cost rates for Capital Cost Allowances, Unit Operating Cost Rates (UOCR), or, Actual Custom Fees for costs as in Standard Method A.

C. Alternate Gas UV Calculation Method C (C): Actual Gross Revenues minus Actual Allowable Costs

1. Unit Value ($) = Actual Gross Revenues **(2C)** **-** Actual Allowable Costs **(3C)** / Field Gas or Solution Gas Production **(4A)**

2. Actual Revenues:
   Determine gross revenues ($) on the sale of gas or solution gas from each production entity for the reporting period October 1, 2008 through September 30, 2009 (3+9). Include revenues from all by-products e.g. gas, ethane, propane, butane, pentanes and sulfur. Gas Valuation: Where freehold gas is commingled with other sources (Crown volumes, third party purchases, out of province volumes or other non Crown volumes) before it is sold, the gross revenues attributable to freehold gas and by-product sales must be valued using the pooling concept. The revenue realized from the sale of all sources should be distributed proportionately to the ratio of volumes in the sales pool.

3. Actual Allowable Costs:
   Determine allowable costs of the production ($) using the (3+9) reporting period. Allowable costs are the actual custom processing fees or capital and operating costs incurred for, gathering, compressing, processing field gas or solution gas from the production entity. Allocate actual capital costs by tracking the actual flow for each well/unit and prorate the costs in each facility by throughput volume. Detailed schematic records must be kept.

Flared or Lease Fuel Gas

1. Calculate a unit value for flared or lease fuel gas the same as field or solution gas.

2. The unit value will be $0.00 when the total volume of the gas produced in the (3+9) reporting period has been flared or used as lease fuel as there are no revenues or deemed sales.

3. When only a portion of the gas produced was flared or used as lease fuel and the remaining portion was sold, the sales portion revenues are used in the unit value calculation. Dividing the revenues by the total production will result in a lower unit value. This will compensate for the portion of the gas flared or used as lease fuel.

4. Record the unit value for the production entities on the submission document

Injected Gas

Injection of Taxable Gas or Products; a unit value is required for production entities when all or part of the production was injected.

All operating and capital costs for gathering, compressing and processing of production, whether sold or re-injected, are considered to be allowable costs. Allowable costs are recognized before any Crown Enhanced Oil Recovery (EOR) recapture adjustments. For companies that extract Capital and Custom Processing costs from the Capital Cost Recapture Summary and Custom Processing Fee Recapture Summary portion of the Crown Gas Royalty Invoice, the costs prior to EOR – Recapture should be used.

1. If all gas and liquids from the production entity are injected into the same field and pool where they were originally produced, there is no change in ownership and no revenue is recognized. The resulting unit value is $0.00.

2. If gas and liquids are injected into a different field or pool than where they were originally produced, the gas and products injected are considered to undergo a change in ownership, are deemed sold and are taxable. Revenue is determined similar to actual sales transactions.

3. When part of the gas and liquids production is sold and part is injected into the same field and pool, revenue is recognized only on the gas and liquids sold.

   When part of the gas and liquids production is injected into the same field and pool and part is injected into a different field or pool, the latter volumes are deemed to be sold and revenue is recognized.

   To ensure that revenue for products injected into the same field and pool is not recognized, companies using invoice client volumes in revenue calculations should reduce the relevant Crown Royalty (CR) charge type volumes by the related Injection Credit (IC) charge type volumes. Companies should retain documentation to substantiate the sources of the Injection Credit (IC) charge type volumes.

4. When part of the gas and liquids production is sold and part is injected into a different field or pool, revenue is recognized on all of the gas and liquids, whether sold or injected.

Injection of Tax Paid Products (Mineral Tax Paid Bank)

5. When both taxable and tax paid products are injected, only the revenue and costs associated with the taxable products are recognized in the unit value calculation. As the net revenue is divided by the total production (which includes tax payable and tax paid volumes), the resulting reduction in unit value compensates for levying tax on the tax paid volume.

6. It is the responsibility of companies to maintain detailed records of the volumes of injected taxable and tax paid products and reproduced products. Companies should also retain documentation to substantiate the sources of any tax paid products or non-native products injected.

7. Record the unit value on the submission spreadsheet for all production entities with injected production.

New Wells, Significant Production or Capital Changes

Unit values should be calculated over the balance of the reporting period when a new well starts production during the reporting period. Use the same calculation method as in Gas Unit Value Calculation Method (revenue and allowable costs).

For example: A unit value for a new well placed on production in July would use the following information (Method A):

- For the reporting period use July 2009 – September 2009 (3 months instead of 12)
- For the revenue use the Valuation price, by product, using Client Volumetric Totals (Quantity/Heat).
- For allowable costs use an estimated portion of current year's allowable capital costs for the reporting period and applicable previous year's UOCR using energy-adjusted gas equivalent Crown Client Volumetric Quantities/Heat from July 2009 – September 2009 and/or
- Actual custom fees for July 2009 – September 2009 for volumes when the UOCR does not apply.
- Use production volumes for July 2009 – September 2009.

To calculate a UV for wells that start production after the 3+9 reporting period but before the end of the taxation year, use the actual production volumes and estimated revenue and allowable cost estimates for the balance of the taxation year.

The next year's unit value calculation will follow the standard reporting period and methodology used by your company. Some of the same information will be re-used in the next year's unit value calculations.

Capital costs corresponding to the reporting period should be used when significant production or capital changes occur (e.g. new well, sales of properties, shut-in or major capital additions). This may involve the use of a portion the previous year's actual capital costs and an estimated portion of the current year's capital costs. The estimate can then be adjusted to actual in the following year. The previous year's capital costs should be used in the following year (i.e. the same capital costs would be used in two consecutive years).

Prior Period UV Adjustments, Amendments, Appeals and Audits

Adjustments for Prior Period UV submissions

Production, revenue, UOCR, operating cost, capital cost and custom processing fee changes identified after a tax year unit value filing deadline can be included as adjustments to subsequent years' unit value filings as prior year adjustments (PPA).
Include PPA for all non-statute barred years in your next unit value submission. e.g. Include any changes of the components of your original 2006, 2007 or 2008 tax year unit value calculation in the calculation of your 2009 unit value. Identify each PPA year and component separately. Detailed documentation of any prior period adjustments must be kept for audit purposes. For material adjustments, approval must be obtained from the department.

Amendments

To amend a unit value, submit a new unit value for the specific production entity on ETS – Freehold Mineral Tax - Submit Unit Value. Amendments can be filed for up to two years after the initial annual tax statement.

Appeals

A notice of formal appeal of the tax assessment for the 2009 tax year may be submitted as specified in the *Freehold Mineral Rights Tax Act*. The requirements include a written appeal notification and copies of all supporting information. Pursuant to section 11(2) of the Freehold Mineral Rights Tax Regulation the deadlines for formal appeals are July 15, 2010 for 2009 tax statements or 90 days after the date of issue for any new or corrected tax statements.

Audits

All unit value submissions are subject to audit by the Department's Compliance and Assurance Branch. Records of the production, revenue and costs of 2009 Freehold production entities can be reviewed until December 31, 2013 and must be made available within 30 days of request. The department may revise the original tax or may recommend an adjustment to the next year's unit value calculation.