UPDATE: February 2021
This handbook is still being updated. Thank you for your patience.

Due to ongoing operational changes, employee organization charts have been removed from this handbook.

For current reporting and invoicing information visit our website (gov.bc.ca/oilandnaturalgastaxes). Petrinex reporting information is also available on the Petrinex website (www.petrinex.ca).

MINISTRY OF FINANCE

OIL AND GAS ROYALTY HANDBOOK

July 2014

1.0 LEGISLATIVE AND HANDBOOK OBJECTIVES

1.1 Introduction

Legislative provisions with respect to petroleum and natural gas royalties and freehold production tax in British Columbia are in several acts and regulations. Acts express the general policy and intent of the Legislative Assembly. Regulations provide the detailed administrative procedures and practices to be followed.

HANDBOOK OBJECTIVES

The objectives of this Handbook are to assist producers and operators in meeting their royalty and tax reporting and payment obligations by:

- explaining the relevant provisions of Acts and Regulations that apply to oil and gas activities in British Columbia
- providing the ministry's interpretation where meaning is not clear, and
- illustrating and explaining the prescribed reporting forms.

As well as assisting producers and operators, this Handbook is designed to support the royalty management system used in the Mineral, Oil and Gas Revenue Branch of the Ministry of Finance.

If this Handbook is found to be inconsistent with the legislation or prescribed forms in any respect, the Handbook should be considered to be in error.

PETROLEUM AND NATURAL GAS ACT

Parts 10 and 11 of the *Petroleum and Natural Gas Act* contain the primary legislative provisions for royalties and freehold production taxes on oil and gas.

Section 73(1) provides that the Crown in the Right of the Province shall receive a royalty on oil and gas production from Crown land permitted, licensed or leased under that Act.

Section 73(2) gives the Lieutenant Governor in Council authority to prescribe by regulation the amount of royalty, who must pay it, when it must be paid, penalties for late or non-payment, and any other considerations.

Section 73(3) allows the Lieutenant Governor in Council to delegate powers to, and confer discretionary powers on, an employee of the Ministry of Energy, Mines and Natural Gas appointed Royalty Administrator and an employee of the Ministry of Finance appointed Royalty Collector.

Section 74 requires every person who is required to pay royalty to pay it and to file and complete reports in the form and manner required by the Director of Titles on or before the date prescribed in the Regulation. Section 74 also requires payment of interest if royalty is not paid when it is due and provides for refunds of overpayments of royalty with interest. An important objective of this handbook is to explain how to complete the forms required by the Director.

PETROLEUM AND NATURAL GAS ACT cont'd

Sections 75, 76 and 77 provide for various powers of enforcement and requirements for creation and retention of adequate records relating to royalty calculations.

Section 78 allows the Minister of Energy, Mines and Natural Gas to make an agreement establishing the amount of royalty on petroleum and natural gas produced from a unitized operation or as the result of a conservation plan, scheme or project, including injection or pressurization schemes.

Section 80(1) requires every owner of freehold land to pay a production tax calculated as a percentage of the value of the petroleum and natural gas produced and disposed of from freehold land.

Section 80(2) allows the Lieutenant Governor in Council to make regulations prescribing the percentage freehold production tax rate, but limits the percentage to less than 30%. Section 81 applies the administrative and enforcement provisions of sections 73 to 77 respecting royalties in the same manner and to the same extent to the freehold production tax.

PETROLEUM AND NATURAL GAS ROYALTY AND FREEHOLD PRODUCTION TAX REGULATION

The matters that section 73 of the *Petroleum and Natural Gas Act* leaves to the Lieutenant Governor in Council for all oil and gas production except from net profit royalty projects are prescribed in the *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation* (B.C. Reg. 495/92). Provisions with respect to the freehold production tax have also been included in this Regulation.

The calculation of royalty and freehold production tax payable for different classes of petroleum and natural gas and most of the practices and procedures to be followed are set out in this Regulation. A primary objective of this handbook is to explain its provisions.

This regulation is usually referred to as the Royalty Regulation in this Handbook.

NET PROFIT ROYALTY REGULATION

The matters that section 73 of the *Petroleum and Natural Gas Act* leaves to the Lieutenant Governor in Council that are related to oil and gas production from net profit royalty projects are prescribed in the Net Profit Royalty Regulation (B.C. Reg. 98/2008).

This regulation outlines the calculation of the net profit royalty for approved net profit royalty projects. An important provision of the regulation is the power given to the administrator to approve projects and the power given to the administrator and collector to set royalty provisions, practices and procedures as they relate to net profit royalty administration. These provisions apply to production from net profit royalty projects on both freehold and Crown land. This Handbook provides more details and examples of these royalty provisions, practices and procedures.

This regulation is usually referred to as the NPR Regulation in this Handbook.

DRILLING AND PRODUCTION REGULATION

The *Petroleum and Natural Gas Act* contains many provisions with respect to exploration for and production of British Columbia's oil and natural gas resources. Many of the detailed practices and procedures with respect to drilling, operating and reporting oil and gas wells are set out in the *Drilling and Production Regulation* (B.C. Reg. 362/98).

The Drilling and Production Regulation is relevant for royalty purposes because some terms that are used in the *Royalty and Freehold Production Tax Regulation* are defined in the *Drilling and Production Regulation*. The *Drilling and Production Regulation* also requires certain reports that are used for royalty and tax purposes.

OBTAINING REFERENCE MATERIALS

This Handbook is produced and maintained by the Ministry of Finance. It is available along with Information Letters and Bulletins on the Government of British Columbia website at www.gov.bc.ca/sbr. This website allows users to subscribe to receive notification if particular Information Letters or Bulletins are updated. If the subscription service is used, subscribers are notified of change by way of the email address they provide at the time of subscription.

Any questions regarding this Handbook may be made to:

Mineral, Oil and Gas Revenue Branch
Ministry of Finance
P.O. Box 9328 Stn Prov Gov't
Victoria, British Columbia V8W 9N3
Phone: 250 952-0192
Fax: 250 952-0191
Toll Free: 1-800-667-1182

Acts and Regulations are available on the Government of British Columbia website at www.gov.bc.ca under Statutes and Regulations.

Copies of Acts and Regulations with unconsolidated amendments may be purchased by contacting:

Crown Publications Bookstore
563 Superior Street
Victoria, British Columbia V8V 1T7
Phone: 250 387-6409 or 1-800-663-6105
Fax: 250 387-1120
Website: www.crownpub.bc.ca

2.0 INTRODUCTION

2.1 Administrative Organization Charts

MINISTRY OF FINANCE

The Ministry of Finance has been assigned the responsibility of administering the provisions of sections 73 to 81 of the *Petroleum and Natural Gas Act* in so far as they relate to the collection of public money. The Executive Director of the Mineral, Oil and Gas Revenue Branch, part of the Revenue Programs Division of the Ministry has been appointed Royalty Collector.

MINERAL, OIL AND GAS REVENUE BRANCH

The Mineral, Oil and Gas Revenue Branch of the Ministry of Finance has been assigned the responsibility for administering parts of the *Petroleum and Natural Gas Act* that cover royalties and freehold production tax. The Branch also administers the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation and the parts of the Net Profit Royalty Regulation insofar as they relate to the collection of royalties and freehold production tax.

[Due to ongoing operational changes, the organization chart previously included on this page has been removed.]

MINISTRY OF NATURAL GAS DEVELOPMENT

The Policy and Royalty Branch of the Ministry of Natural Gas Development has been assigned responsibility for calculating prices that are used in royalty calculations for each producer, including Producer Prices and Posted Minimum Prices. This Branch also has responsibility for assisting the Administrator in setting the Select Price in some gas royalty rate formulas and the Threshold Prices in Third Tier and Heavy Oil rate formulas, and certain other determinations.

[Due to ongoing operational changes, the organization chart previously included on this page has been removed.]

2.2 Directory of Contacts

CONTACTS

Mineral, Oil and Gas Revenue Branch
Revenue Programs Division
PO Box 9328 Stn Prov Gov't
Victoria, B.C. V8W 9N3
Telephone: 250 952-0192 or 1-800-667-1182
Facsimile: 250 952-0191
Website: gov.bc.ca/oilandnaturalgastaxes

[Due to ongoing operational changes, the organization chart previously included on this page has been removed.]

3.0 REPORTING PROCESS

3.1 System Overview

SELF ASSESSMENT

The Royalty Regulation and the NPR Regulation and their administration is based in part on the principle of self assessment. Facility operators are required to provide oil and natural gas production and disposition reports. Producers or their designates are required to report their shares of production and sales values for oil, marketable gas and natural gas by-products in accordance with the regulation and forms prescribed by the Director of Titles. The reports must be filed and payments made by the specified due dates. Producers must ensure they maintain adequate personnel, data processing and other resources to meet the reporting obligations.

To facilitate electronic exchange of information and administrative efficiencies, the Ministry has relied less heavily on self-assessment in recent years. The Ministry now invoices producers for the amount of oil and gas royalties payable based on production and sales information provided by producers.

EXAMINATION OF RETURNS AND ASSESSMENT OF ROYALTY OR TAX

Section 9 of the Royalty Regulation and section 16 of the NPR Regulation allows the Royalty Collector to examine reports that have been filed and if the Collector disagrees with information in a report, the Collector may request an amended report or assess royalty or tax payable based on information the Collector believes to be correct.

The Collector may make an assessment or reassessment not more than 72 months after the last day of the producing month to which the assessment or reassessment is based, or at any time if the producer has made a misrepresentation or committed fraud in filing a report or supplying information.

When the Collector issues an assessment or reassessment, the producer must pay any additional royalty or tax owing within 60 days after the date of the notice of assessment. If there is an overpayment, the producer may deduct it from royalty or tax due after the notice, or may request a refund.

The Mineral, Oil and Gas Revenue Branch assists the Collector with these responsibilities. The Petroleum Operations Section of the Branch uses a royalty management system to process the production, disposition, and remittance reports filed by producers and to produce royalty invoices. The section maintains a database of factors related to the calculation of royalties and taxes. These factors include royalty payors and their account information, exemptions and allowances, and classification of wells.

The Validations and Audit Section of the Branch verifies the data submitted by producers against information available from other sources in a post transaction review. The primary focus of this section is the verification of reported volumes and values and royalty allowance claims.

APPEALS

If a producer does not agree with an assessment issued by the Collector and states their objection in writing to the Collector, the Collector may change the assessment.

If the Collector decides not to change the assessment, the producer may appeal the Collector's decision to the Minister of Finance by mailing by registered mail a notice of appeal addressed to the Minister of Finance. The notice of appeal must state the name and address of the producer, the date of the Collector's decision, the amount assessed, reasons for the appeal and the facts on which it is based.

No further recourse beyond the decision of the Minister of Finance is available.

WHO IS LIABLE

In this Handbook and in the Regulations the term "producer" is synonymous with "royalty payer". Section 4 of the the Regulation requires that a "producer" must pay the required royalty/tax by specified dates. The Regulation defines a "producer" to be,

(a) a holder of a location who markets or otherwise disposes of oil, natural gas or both, that has been produced by
  (i) the holder of the location, or
  (ii) a person authorized to do so by the holder of the location, and

(b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder's behalf, oil, natural gas or both;

The NPR Regulation has a similar definition for a producer in a Net Profit Royalty project.

The Petroleum and Natural Gas Act defines "holder of a location" to be a permittee, licensee or lessee in accordance with the context. A "permittee", "licensee" or "lessee", is the person whose name is recorded in the appropriate Ministry of Energy, Mines and Natural Gas' oil and gas titles records.

Where a holder of a permit, license or lease fails to comply with a provision of the *Petroleum and Natural Gas Act* or its regulations, section 135 of the Act allows the Minister to cancel the permit, license or lease after giving 60 days notice to the holder of the location.

Although the Branch will accept any designation of persons as royalty or tax payor, if royalties or taxes are not paid, the Branch will only recognize the name of the person(s) on the titles records as the person(s) liable for paying royalties. If the holder of a location sells, assigns or otherwise disposes of their rights to oil or gas at a location, the Branch will not recognize this transfer until it is reported to the Ministry of Energy, Mines and Natural Gas and changed in the Ministry's titles records. If a transfer of rights is not reported to the Ministry until after the effective date of the agreement or other document giving effect to the transfer, the Branch will not amend its record of liabilities for royalties in the intervening period.

Purchasers of oil and gas properties should ensure that royalties have been paid up to the date of purchase and should take measures to protect themselves against assessments and reassessments subsequent to the purchase for periods prior to the purchase. Failure to take such precautions could result in a purchaser having to pay royalties relating to periods prior to their gaining title in order to retain their title.

REPORTING ENTITIES

Starting with production in August 2005 for oil and in March 2006 for gas, the meaning of royalty Reporting Entities was changed. Starting with these months, Reporting Entities are used only for grouping wells and Production Entities (PE's) on royalty invoices and numerical references to invoices on client statements and Remittance Advices. Reporting Entity Numbers (REN's) refer to groups of well events or PE's as follows:

- gas produced from oil wells that are in PE's, REN = 5 + client code
- gas produced from gas wells: 6 + client code, REN = 6 + client code
- oil produced from oil wells that are in PE's, REN = 7 + client code
- oil produced from oil wells that are not in PE' s, REN = 8 + client code

Amendments to royalties and taxes for production periods prior to August 2005 for oil and March 2006 for gas must be done using Reporting Entities that were in effect at that time. These were consolidations of a producer's ownership of wells connected to a facility. Each of the wells in a Reporting Entity must have shared the following attributes:

(1) Connected to the same facility
(2) Type of land (either Crown land or freehold land)
(3) Processing Plant for gas.

A producer may have had more than one gas Reporting Entity at a facility, but was not allowed to have a Reporting Entity that included interests in gas wells that are connected to different facilities. Producers are required to report amendments to their shares of marketable gas production and by-product sales for each Reporting Entity, and the amended royalty/tax share is calculated for the Reporting Entity.

REFUNDS

If a producer pays more than the required amount of royalty under the regulations, the Ministry will refund the overpayment upon written request from the producer.

However, if a transfer in title at a location is reported to the Ministry after the effective date of the agreement between two parties, the Ministry will not refund royalties paid by one party in the intervening periods that, according to their agreement, should have been paid by the other party. Such errors in payment must be settled between the two parties.

3.2 Summary of Reports

FROM PRODUCERS TO THE MINERAL, OIL AND GAS REVENUE BRANCH

The following reports are required under section 8(1) of the Royalty Regulation, section 43(1) of the Drilling and Production Regulation, or section 5 of the *Natural Gas Price Act*. Where the stated due date falls on a weekend or holiday, reports are due on the next business day.

	Activity	Name of Required Form	Due Date
1	When commencing, suspending or resuming production, injection or disposal activities, when testing a completed gas well	Notice of Suspension or Commencement of Operations **(BC11)**	20th day of the month after the month in which the well status changes.
2	To establish or change a royalty/tax payment responsibility	Reporting Interest Statement **(BC12)**	20th day of the month after the month in which the change is to take effect.
3	To establish an entitlement to a deduction for costs of gathering, dehydration, compression and field processing of gas upstream of a processing plant	Application for Producer Cost of Service **(BC22)**	Prior to the production month in which a PCOS status is to be effective.
	To establish an entitlement to a deduction for costs of processing gas in a producer-owned plant	Application for Gas Cost Allowance **(BC23)**	March 15 each year for actual or estimated costs.
	To establish an entitlement to a credit for a portion of costs of drilling wells in the summer	Application for Summer Drilling Credit **(BC25)**	June 30 of the year following the year in which the well was spud.
	To report actual costs incurred in each calendar year and to apply for an estimated Coalbed Methane Producer Cost of Service for the next calendar year	Coalbed Methane Producer Cost of Service **(BC26)**	March 15 of the following year for actual operations.
4	To report oil, gas, condensate and water production from a well	Monthly Production Statement **(BCS1)**	25th day of the month following the month of production.
5	To report disposition of oil, gas, condensate and water production	Monthly Disposition Statement **(BCS2)**	25th day of the month following the month of production.
6	To report natural gas sales data used in the determination of Producer Prices for the purpose of calculating gas royalties and taxes	Gas Sales Invoices	10th day of the 2nd month after the month of production.
		Gas Sales Contracts	Upon request.
7	To report sales values for oil for periods after July 2005	Monthly Oil Sales Statement **(BC09)**	Last day of the month following the month of production.
	To report amendments to oil royalties for periods before August 2005	Monthly Oil Royalty Statement **(BC13)**	Not applicable
	To report marketable gas and natural gas by-product volumes and by-product sales values for periods after February 2006	Natural Gas and By-Product Producer Allocations Report **(BC08)**	Last day of 2nd month following production

FROM PRODUCERS TO THE MINERAL, OIL AND GAS REVENUE BRANCH cont'd

8	To report amendments to marketable gas volumes and natural gas by-product volumes and by-product sales values for periods before March 2006	Natural Gas and By-Product Volumes and Value Report **(BC10)**	Not applicable.
9	To report how payments are to be allocated between assessments and accounts	Petroleum and Natural Gas Remittance Advice **(BC15)**	Last day of the calendar month in which the payment is made.
10	For producers of natural gas to provide a summary of natural gas sales contracts	Gas Sales Contract Summary **(BC40)**	Yearly by November 30 for the current contract year beginning November 1.

FROM THIRD PARTIES TO THE MINERAL, OIL AND GAS REVENUE BRANCH

The following reports are required under sections 8(1) of the Royalty Regulation:

	Activity	Name of Required Form	Due Date
2	For operators of gas storage projects to report receipts and withdrawals	Monthly Gas Injections Operations Report **(Form 15A)**	25th day of the month following the reported month.
4	The BC19 replaces the BC16 and BC17 reporting forms and is to be used by operators of gas plants and dry gas sources	Monthly Natural Gas Plant and Processing Statement *(effective December 2009)* **(BC19)**	25th day of the month following the calendar month in which the gas was processed
5	For purchasers of oil to report all purchases and subsequent dispositions	Monthly Crude Oil and Condensate/Pentanes Plus Purchaser's Statement **(Form 20)**	25th day of the month following the month of purchase.
6	For purchasers of LPG's to report supply and disposition	Monthly Liquefied Petroleum Gas Purchaser's Statement **(Form 21)**	25th day of the month following the month of purchase.
7	For purchasers to report purchases of oil and condensate at each sales meter	Oil Purchasers Summary **(BC30)**	Last day of the month following the month in which the purchase was made.
8	For operators of oil pipelines to report oil shipments	Crude Oil and Condensate Monthly Pipeline Statement **(BC35)**	25th day of the month following the month of receipt of the oil.
9	For operators of oil treatment plants to report oil receipts and treatment activity	Central Treating Plant Statement **(BC36)**	25th day of the month following the month of receipt of oil.

FROM PRODUCERS TO THE OIL AND GAS COMMISSION

The following reports are required under the Drilling and Production Regulation:

	Activity	Name of Required Form	Due Date
1	For facility operators to obtain approval to construct a faciltiy	Application for Production Facility **(BC20)**	
2	For operators to provide notification of a connection between a well and a facility, or between two facilities	Application for a Well or Facility to Facility Linkage **(BC21)**	

3.3 Electronic Submissions

Facility operators who are reporting on 20 or more wells are required to submit BC-S1 and BC-S2 reports on electronic media. The easiest and most reliable form of electronic media is an attachment to an electronic mail message. See BC-S1 Monthly Production Statement Guidelines for a description of the electronic formats for the BC-S1 and BC-S2 reports.

BC-09 reports may be submitted in electronic form as attachments to electronic mail. See BC-09 Monthly Oil Sales Statement Guidelines for specification of the electronic BC-09 file format. The electronic BC09 file may be easily created using the BC09 Excel file that is available from the Ministry website. BC-09 reports may also be submitted through our Ministry internet at www.fin.gov.bc.ca/rev.htm, or by paper copy to the Mineral, Oil and Gas Revenue Branch.

BC-08 reports may be submitted in electronic form as attachments to electronic mail. See BC-08 Marketable Gas & By-product Allocations Report Guidelines for specification of the electronic BC-08 format. The electronic BC08 file may be easily created using the BC08 Excel file that is available from the Ministry website. BC-08 reports may also be submitted through our Ministry internet at www.fin.gov.bc.ca/rev.htm. BC-08 reports may not be submitted on paper.

BC-10 reports may be submitted in electronic form as attachments to electronic mail. See BC-10 Marketable Gas & By-product Volumes & Values Report Guidelines for specification of the electronic BC-10 file format. BC-10 reports may also be submitted through our Ministry internet at www.fin.gov.bc.ca/rev.htm, or by paper copy to the Mineral, Oil and Gas Revenue Branch.

BC-11 reports may be submitted through our Ministry internet at www.fin.gov.bc.ca/rev.htm. Submission of BC-11 reports through the Ministry internet site is much easier than paper reports because the internet site will bring up information on a BC-11 already in the Ministry's records and only data that has changed need to be entered. See BC-11 Notice of Suspension or Commencement of Operations Guidelines for an explanation of how to file BC-11 reports through our Ministry internet site.

BC-25 reports may be submitted through our Ministry internet site at www.fin.gov.bc.ca/rev.htm. The BC-25 report can also be submitted by paper copy to the Mineral, Oil and Gas Revenue Branch.

The Ministry encourages submission of reports on electronic media by all producers regardless of the number of wells being reported.

Any questions regarding electronic filings should be addressed to Mineral, Oil and Gas Revenue Branch at 250 952-0192 or e-mail at oil&gasroyaltyquestions@gov.bc.ca.

3.4 Use of Custom Forms

Producers must report to the Mineral, Oil and Gas Revenue Branch in the form and manner required by the Director of Titles. All reporting forms are available from the Ministry of Finance website, but the Branch recognizes that current technology may make it easier and more convenient for many producers to generate their own versions. Custom forms will be accepted by the Branch, but they must be approved by the Branch prior to their use.

In designing a custom form, the following guidelines should be followed to expedite approval:

(1) All fields shown on the Ministry issued forms must appear on the custom form.

(2) Quality, density and clarity of type should be similar to the type on Ministry forms.

(3) Identification information, line description and column headings should be in the same order as they appear on Ministry forms.

(4) Areas that are for Ministry use should be in exactly the same size and configuration.

(5) Paper size should be the same as the Ministry forms.

3.5 Submission of Reports

Producers may deliver the required reports and payments to either of the two locations listed below. Reports and payments can be made on any business day. Cheques should be made payable to the “Minister of Finance”.

Calgary

P3 Deposit, Lower Level
Canadian Imperial Bank of Commerce
C.I.B.C. Place
309 - 8th Avenue S.W.
Calgary, Alberta T2P 2P2

Victoria

Mineral, Oil and Gas Revenue Branch
Revenue Programs Division
Ministry of Finance
PO Box 9328 Stn Prov Gov’t
Victoria, B.C. V8W 9N3

To be considered as received by the due date, reports must be received in Calgary no later than 3:00 p.m. or in Victoria, no later than 4:30 p.m. on the due date. Reports received after the specified times are considered received the next business day.

Royalty payors are requested to place ALL cheques on top of the report packages submitted to the Canadian Imperial Bank of Commerce so they can be easily identified.

3.6 Penalty and Interest Policies

GENERAL

The Royalty Collector's authority to assess reporting penalties and to charge interest is given in section 74 of the *Petroleum and Natural Gas Act*. Subsection 74(1) states,

"every person who is required to pay royalty must, on or before a prescribed date

(a) pay any royalty due; and
(b) file and complete a report in the form and manner required by the director"

Section 74(2) states,

"A person required to pay royalty who fails to pay royalty when it is due must pay interest on the amount of the unpaid royalty as prescribed by the Lieutenant Governor in Council."

Section 74(5) states that if a person who is required to pay royalty fails to file and complete a report in the form and manner required, the person shall, in addition to any royalty payable, pay the prescribed penalty.

PENALTIES

The penalty is prescribed in section 13(4) and section 13(5) of the Royalty Regulation and section 13 of the NPR Regulation.

Section 8(1) of the Royalty Regulation and section 9 of the NPR Regulation specify the reports that are required for the purposes of section 74(1) of the Act and therefore subject to penalty provisions. The following reports are subject to penalties of $20 per day to a maximum of $6,000:

- Monthly Production Statement (BCS1)
- Monthly Disposition Statement (BCS2)
- Natural Gas and By-Product Producer Allocations Report (BC08)
- Notice of Commencement or Suspension of Operations (BC11)
- Reporting Interest Statement if one or more interests in oil production are reported (BC12)
- Monthly Crown Royalty/Freehold Tax Statement - Oil (BC09)
- Petroleum and Natural Gas Remittance Advice (BC15)
- Application for Gas Cost Allowance (BC23)
- Gas sales invoices and purchases and sales of gathering, processing and transportation services

PENALTIES cont'd

The following reports are subject to penalties of $100 per month up to a maximum of $6,000:

- Reporting Interest Statement if no interests in oil production are reported (BC12)
- Crude Oil and Condensate Monthly Pipeline Statement (BC35)
- Central Treating Plant Statement (BC36)
- Monthly Natural Gas Plant Statement (BC16)
- Monthly Natural Gas Processing Statement (BC17)
- Monthly Natural Gas Plant and Processing Statement (BC19)
- Net Profit Monthly Allowable Capital and Operating Costs (BC50)

A report referred to in section 9(2)(a) of the Royalty Regulation or section 16(2)(a) is an amended report requested by the Mineral, Oil and Gas Revenue Branch. An amended report is due within 60 days from the date of the request.

Section 9(8) of the Royalty Regulation allows the Royalty Collector the choice of varying or not assessing penalties referred to in section 13(4).

The Mineral, Oil and Gas Revenue Branch issues this Handbook and Information Bulletins to instruct industry on completion and filing of all reports. All producers should ensure that they are on the mailing lists for these publications and that the material is being directed to the appropriate person(s) within their organization.

This Handbook, Reporting Forms and Information Bulletins are available on our Ministry internet sites at www.fin.gov.bc.ca/rev.htm.

Photocopies and faxes of forms must be legible and must reproduce the entire form, not just segments. If copy quality is becoming poor, please obtain new copies from the ministry's website. Forms that cannot be read easily may be subject to penalty.

INTEREST ON OVERDUE ROYALTY/TAX PAYMENTS

The manner in which interest on overdue payments is calculated is prescribed in section 13 of the Royalty Regulation. As with penalties, section 9(8) of the Regulation allows the Royalty Collector discretion over when interest will be assessed.

The annual rate at which interest is calculated is fixed for each quarterly period commencing on January 1, April 1, July 1 and October 1 of each calendar year. The rate during each quarter is 3% above the prime lending rate of the principal banker to the Province on the 15th day of the month immediately preceding the beginning of the quarter.

No interest shall be charged if the charge is less than $5.

Section 13(2) requires interest to be calculated on the following balances:

(a) the royalties and taxes due on a producer's account on the last day of each month, and

(b) the difference between the balance in a producer's estimate account at the end of a month and the sum of

- royalty and tax due on oil that was produced in the month before that month and.
- royalty and tax due on natural gas and gas by-products that were produced in the month that was two months before that month.

INTEREST cont'd

The Royalty Collector's policy is to assess interest in three situations:

(1) there is an adjusted net balance owing in specified royalty/tax payor accounts as of the last day of a month;
(2) the estimate account balance is less than 90% of actual oil and natural gas royalties/taxes for the required months, and
(3) there is an adjustment to royalties for a previous month resulting from an amended report being filed or an assessment resulting from validation or audit by the Ministry.

When there is an adjusted net balance owing in specified royalty/tax payor accounts as of the last day of a month,

(i) specified interest bearing accounts include,

- Oil Royalty/Tax (OR)
- Natural Gas Royalty/Tax (GR)
- Cash Suspense (CS)

(ii) the adjusted net balance is calculated as follows:

Sum of the closing balances for all Royalty and Tax accounts +
Closing balance of the Cash Suspense account

(iii) the number of days for which interest is calculated is the number of days from the start of the statement period to the statement date (i.e. the number of days in that month).

When the estimate account balance is less than 90% of actual royalties/taxes for the required months, interest will be charged on the difference between the estimate account balance and the actual amount for one month.

When there is an adjustment to royalties for a previous month, the number of days for which interest will be calculated for each royalty charge is the number of days from the initial due date of the royalty payment to the start of the statement period.

All payments of interest should be shown on line 47 of the Petroleum and Natural Gas Remittance Advice (BC-15).

INTEREST ON OVERPAYMENTS OF ROYALTY/TAX

Section 9(8) of the Royalty Regulation allows the Royalty Collector discretion over when interest will be paid on royalty/tax overpayments.

The methodology for calculating the amount of interest to be paid on royalty overpayments is the same as the methodology used to calculate interest assessments on royalty, underpayments except for the following:

(i) interest is paid at the prime lending rate of the principal banker to the Province on the quarterly dates as for royalty underpayments.

(ii) interest is paid when the estimate account balance is greater 110% of actual royalties/taxes for the required months on the difference between the estimate account balance and the actual amount for one month.

3.7 Reporting Standards

As a general guideline, the following standards apply to the reports that must be filed for royalty and tax purposes.

VOLUMES AND VALUES

All physical volumes should be reported to one decimal place.

Oil, natural gas liquids, condensate and pentanes plus must be reported in cubic metres (m^3) at 101.325 kPa and 15^0C.

Natural gas must be reported in thousand cubic metres (10^3m^3) at 101.325 kPa and 15^0C.

Sulphur must be reported in tonnes.

All dollar values should be reported to 2 decimal places.

REPORTING INTERESTS

When a well or a tract in a unitized operation has more than one owner, the reporting interest of each owner must be reported as a percentage to seven decimal places. When establishing or changing well or tract reporting interests, the sum of reporting interests for each well or tract must be equal to 100%.

Any adjustment to reporting interests for a gas well or an oil well to ensure that they total 100% will be made to the interest of one of the producers.

Example: If three producers each have a 1/3 interest in a gas well, the following adjustment may be made to ensure that the sum of all interests is exactly 100%:

Producer	Actual Interests	Adjusted Interests
1	33.3333333%	33.3333333 %
2	33.3333333%	33.3333333 %
3	33.3333333%	33.3333334 %
Total	99.9999999%	100.0000000 %

The participation of each tract in a unitized operation must be reported as a percentage to seven decimal places. When establishing or changing reporting interests in tracts, the sum of reporting interests for each tract must be equal to 100%. Any adjustment to reporting interests to ensure that they total 100%, if necessary, will be made to the highest numbered tract.

When allocating:

- oil production to tracts in a Production Entity
- oil Royalty/Tax Shares from wells or tracts to producers,

total allocated volumes must equal total actual volumes. Any adjustment that may be required to ensure that reported volume is equal to actual volume will be made to the tract with the highest number or to any one of the producers.

4.0 OIL ROYALTY AND TAX CALCULATION

4.1 Oil Royalty and Tax Calculation

OVERVIEW

The calculation of oil royalty and tax payable is based on prescribed royalty rate formulas, sales values reported by producers on Monthly Oil Sales Statements (BC-09) and production volumes reported by facility operators on Monthly Production Statements (BC-S1). The production volumes used in the calculation are either of:

(a) actual production from a well, or
(b) production allocated to tracts under the terms of a unitization agreement.

When royalty/tax is based on production from a well, a Royalty or Tax Share of oil in kind is calculated for each well directly from production reported on the Monthly Production Statement (BC-S1). This share is assigned to each producer with an interest in the well in proportion to their reporting interest as reported on Reporting Interest Statement (BC-12).

The Ministry uses information from these sources to determine the royalty or tax payable by each producer for each well in which they have an interest and invoices producers on a monthly basis.

OIL UNITIZATION AGREEMENTS

Section 114 of the *Petroleum and Natural Gas Act* allows the Crown to enter into a unitization agreement for the unitized operation of a field or pool or a part thereof. “Unitized operation” means coordinated management of development, production, and conservation of oil and gas in an area by all owners of interests in the area. Usually this means production from wells in the unitized area is allocated to tracts of land within the unitized area.

Section 78 of the *Petroleum and Natural Gas Act* allows the Crown to enter into royalty agreements for unitized operations. There are royalty agreements for all unitized operations in British Columbia prior to April 1, 1993. Under the terms of these agreements, royalty and tax rates are based on production allocated to each tract, instead of production from each well.

The Ministry’s policy since April 1993 is to not have royalty or tax agreements for any new unitized operations. For new unitized operations, royalty/tax rates will be based on production from each well and the resulting Royalty/Tax Share for each well will be allocated to each tract in accordance with the terms of the unitization agreement.

When royalty is based on allocation of production to tracts in a unitized operation, it is referred to in this Handbook as a Production Entity. Oil production reported on the Monthly Production Statement (BC-S1) for each well in the unitized area is allocated to tracts in accordance with the participation factors in the unitization agreement. The Royalty/Tax Share of oil is calculated for each tract using the volume of oil allocated to the tract in the month. The Royalty/Tax Share for the tract is then assigned to each producer with a reporting interest in the tract in proportion to their interest.

SUMMARY OF CALCULATION AND REPORTING

For oil produced before August 2005, the Crown oil royalty payable by a Reporting Entity was reported on the "Monthly Crown Royalty Statement, Oil", (BC-13). The freehold production tax for oil was reported separately on the "Monthly Freehold Tax Statement, Oil" (BC-13).

For production in August 2005 and after, BC-13 reports have been replaced by BC-09 reports. BC-09 reports are listings of oil sales information and do not require the producer's calculation of royalty share or royalty payable. The Ministry uses the reported sales, S1 production data and well and tract ownership interests to calculate oil royalties payable and to invoice producers.

Calculation of the royalty or tax due is done in the following five steps:

(1) The Royalty/Tax rate for a month is calculated for each well and producer or for each tract in a Production Entity.

(2) The full Royalty/Tax Share for a month is calculated for each well that has production or for each tract in a Production Entity that has production allocated to it in the month.

(3) Each producer's share of the Royalty/Tax Share is calculated for each well that has production or tract in a Production Entity that has production allocated to it in the month. This is determined in accordance with each producer's ownership of production from each well or production allocated to each tract.

(4) Each producer's portion of the Royalty/Tax Shares is valued using the weighted average net selling price at the point of production from all sales during the month by that producer to determine the gross royalty/tax payable.

(5) The gross royalty/tax payable is reduced by any exemptions that the producer is entitled to claim.

Step 1 - Calculating the Royalty/Tax Rate

The royalty and tax rates are calculated in accordance with section 5(1) of the Royalty Regulation. The applicable rate may vary from 0 to 40% depending upon:

- the volume of oil produced by the well or allocated to the tract,
- whether the oil is produced from Crown land or freehold land,
- if produced from Crown land, whether the oil is New Oil, Old Oil, Third Tier Oil or Heavy Oil, and
- if oil is Third Tier Oil or Heavy Oil, the net sales price at which the oil was sold for.

If more than one producer has an interest in a Heavy or Tier 3 well, the sales price and therefore the royalty rate may be different for each producer.

See section 4.2 for an explanation of terms and the formulae for calculating the royalty and tax rates.

SUMMARY OF CALCULATION AND REPORTING cont'd

Step 2 - Calculating the Full Royalty/Tax Share for a Well or Tract

The Royalty/Tax Share is a volumetric representation of the royalty due to the Crown from a particular well or tract. The Royalty/Tax Share for a well or tract is calculated by multiplying the royalty/tax rate applicable to the well or tract by that volume produced from the well or allocated to the tract for the month. If more than one producer has an interest in a Heavy or Third Tier well, the Royalty/Tax Share for the well, i.e. the full Royalty/Tax Share, may be different for each producer.

If oil is produced from a Production Entity, Royalty/Tax Share is determined for each tract according to production volumes allocated to the tract under the unitization agreement.

- For tracts on Crown land, the Royalty Share for a tract for a month is that volume of oil that is the sum of:

  (i) a volume of Old Oil, calculated as: $V \times RO \times (1 - P)$, and
  (ii) a volume of New Oil, calculated as: $V \times RN \times P$

  where,

  V = the total volume of oil allocated to the tract in the month
  RO = the Royalty Rate for Old Oil
  RN = the Royalty Rate for New Oil
  P = the ratio of New Oil production to the total volume of oil production from the unitized operation.

- For tracts on freehold land, the Tax Share for a month is that volume of oil that is allocated to the tract during the month times the tax rate for freehold oil.

If oil is not produced from a Production Entity, the Royalty/Tax Share is determined for each well according to actual production from the well.

- For wells on Crown land, the Royalty Share for a well for a month is that volume of oil that is the sum of:

  (i) a volume of Old Oil, calculated as: $V \times RO \times (1 - P_N - P_T)$, and
  (ii) a volume of New Oil, calculated as: $V \times RN \times P_N$
  (iii) a volume of Third Tier Oil, calculated as: $V \times RE \times P_T$
  (iv) a volume of Heavy Oil, calculated as: $V \times RH$

  where,

  V = the total volume of oil produced from the well in the month
  RO = the Royalty Rate for Old Oil
  RN = the Royalty Rate for New Oil
  RE = the Royalty Rate for Third Tier Oil
  RH = the Royalty Rate for Heavy Oil
  P_N = the ratio of New Oil production from the well to the total volume of oil produced from the well
  P_T = the ratio of Third Tier Oil production from the well to the total volume of oil produced from the well

SUMMARY OF CALCULATION AND REPORTING cont'd

- For wells on freehold land, the Tax Share for a well for a month is that volume of oil that is produced from the well during the month times the tax rate for freehold oil.

Step 3 - Calculating Producers' Shares of the Royalty or Tax Share
Each producer's share of the Royalty or Tax Share for a well or tract is determined by multiplying the producer's reporting interest in the well or tract by the full Royalty or Tax Share for a well or tract.

Step 4 - Valuation of the Royalty or Tax Share
The first sale of oil by a producer is deemed to include the entire Royalty/Tax Share. The actual selling prices are used to derive a value for a producer's Royalty/Tax Share for a well or tract at the point of production. This value is the net weighted average selling price for all sales by the producer at the facility.

Each producer must therefore report their sales of oil at each facility during the production month on a BC-09 report. The BC-09 report required the volume of oil sold, the sales value and transportation costs at each facility.

The sales reported must be the first arms-length transfers of title. The value of each sale is based on the actual selling price at the point of sale plus or minus equalization penalties or credits from a pipeline company and transportation costs that are already included in determination of the selling price. Adjustments in the sales value for marketing fees and administrative overhead are not allowable.

Transportation costs on the BC-09 are from the point of production to the point of sale and are deducted from the sales value provided that:

(i) they are not used in the determination of the selling price, and
(ii) they relate only to clean oil volumes.

The point of production is the point at which clean oil is available for shipping, which is usually at a battery outlet.

An Average Net Value is calculated for each producer's sales of oil at each facility as follows:

(Sales Values – Transportation Costs) / Volume Sold

The Average Net Value at each facility is used to value the Royalty/Tax Share for each well connected to the facility. The product of the Average Net Value and the producer's Royalty/Tax Share is the "Gross Royalty/Tax Payable".

Step 5 - Determining the Royalty Exempt Value
For wells with production that is exempt from payment of royalty/tax, the Gross Royalty/Tax is a notional amount that would have been payable without the exemption. For discovery oil from a discovery well`, the notional royalty/tax share is calculated by applying the appropriate royalty/tax rate to production from the well.

SUMMARY OF CALCULATION AND REPORTING cont'd

After the Gross Royalty/Tax has been determined, the Net Royalty/Tax Payable is reduced to zero for exempt wells, except in the month in which the maximum exempt volume is reached, in which case the Net royalty/Tax Payable is the production in the month that is not exempt times the Average Net Value.

See section 4.3 for more detailed information about exemptions.

4.2 Oil Royalty and Tax Rates

Royalty/Tax rates for oil are calculated in accordance with section 5(1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation (B.C. Reg. 495/92)(the Regulation). The applicable rate depends upon:

- the volume of oil produced by the well or allocated to the tract,
- whether the oil is produced from Crown land or freehold land, and
- if produced from Crown land, whether the oil is classified as New Oil, Old Oil, Third Tier Oil or Heavy Oil,
- if produced from freehold land, whether the oil is classified as Heavy Oil.

"Crown land" is land where the Crown has retained ownership of underlying oil and natural gas rights. Production of oil and natural gas from Crown lands requires a lease under the *Petroleum and Natural Gas Act*.

"Freehold land" is land where the Crown has granted ownership of underlying oil and natural gas rights to a person. Production of oil and natural gas from freehold lands does not require a lease under the *Petroleum and Natural Gas Act*.

"Heavy Oil" means oil, produced from an oil well, with a density of at least 890 kilograms per cubic meter.

"New Oil" means:

(a) oil, other than heavy oil or third tier oil from an oil well event that
  (i) draws from an oil pool having on October 31, 1975 no completed well, or
  (ii) is outside the outline, shown in each plat in Schedule A, of the surface area of the oil pool named on the plat,

(b) incremental oil other than incremental oil that qualifies as third tier oil under paragraph (b) of the definition of "third tier oil",

(c) oil, from an oil well event, that received the new oil reference price under the National Energy Program, or

(d) oil from an oil well event that is completed within the outline referred to in paragraph (a) (ii) if the oil well event
  (i) resumed production on or after January 1, 1981 and had not produced oil for a period of at least 36 months immediately preceding that date, and
  (ii) was not an injection, pressure maintenance or observation well event during the period referred to in subparagraph (i), whether or not the period was more than 36 months.

"Incremental oil" means oil that the administrator considers would not have been recovered without a new pressure maintenance scheme, improved pressure maintenance scheme or other enhanced oil recovery scheme methods, but does not include heavy oil.

Schedule A consists of plats dated December 31, 1976 describing areas in the Peace River District. These plats have been exempted from publication in the Regulation, but are available from the Mineral, Oil and Gas Revenue Branch of the Ministry upon request.

OIL ROYALTY AND TAX CALCULATIONS cont'd

"Old Oil" means oil other than new oil, heavy oil or third tier oil;

"Third Tier Oil" means

(a) oil, other than revenue sharing oil and heavy oil, produced from oil well events that draw from an oil pool having, on June 1, 1998, no completed well, or

(b) oil produced from an oil well event that is incremental oil, other than revenue sharing oil, that is derived from a pressure maintenance scheme, or an enhanced oil recovery scheme, that was approved after December 31, 1999 under section 100 of the Act as it read immediately before its repeal or that is designated as a special project under section 75 of the *Oil and Gas Activities Act*.

The formulae for calculating the royalty or tax rate in their simplest forms are described below. In the royalty regulation the formulae for Old Oil and New Oil are stated in a more complex form. However, they are mathematically equivalent to the formulae below.

In the following formulae,

- Q is production from the well or allocated to the tract during the month
- R is the royalty/tax rate as a percentage to three decimal places.

1. For oil produced from Crown land except Heavy Oil:

Old Oil: (i) if $Q \leq 95m^3$, $R\% = \dfrac{Q}{7.92}$

(ii) if $Q > 95m^3$, $R\% = \dfrac{1140 + 40(Q - 95)}{Q}$

New Oil: (i) if $Q \leq 159m^3$, $R\% = \dfrac{Q}{10.58}$

(ii) if $Q > 159m^3$, $R\% = \dfrac{2390 + 30(Q - 159)}{Q}$

Third Tier Oil, effective June 1998 to December 31, 1999:

(i) if $Q \leq 159m^3$, $R\% = \dfrac{Q}{13.225}$

(ii) if $Q > 159m^3$, $R\% = \dfrac{1912 + 24(Q - 159)}{Q}$

Third Tier Oil, effective January 1, 2000:

(i) if $Q \leq 159m^3$, $R\% = \dfrac{\text{Price Factor} \times Q}{26.45}$

(ii) if $Q > 159m^3$, $R\% = \dfrac{\text{Price Factor} \times (956 + 12\,(Q - 159))}{Q}$

OIL ROYALTY AND TAX CALCULATIONS cont'd

The Price Factor for Third Tier oil is equal to the lesser of:

(a) $1 + \dfrac{3.5 \times (\text{Wellhead Price - Threshold Price for Third Tier oil})}{\text{Wellhead Price}}$, and

(b) a factor of 2.

The Threshold Price for Third Tier oil is established by order of the Administrator. As of September 1, 2002 it was set at $125 per m^3. As of February 2010, it remains at this value.

The Wellhead Price is the greater of:

(a) the average net value of that oil at the wellhead determined in accordance with Section 7(3)(b) of the Regulation, and
(b) the Threshold Price.

2. Heavy oil:

(i) if $Q \leq 20m^3$, $R\% = 0$

(ii) if $20\ m^3 < Q \leq 200\ m^3 Q > 20\ m^3 \leq 200\ m^3$ $R\% = \dfrac{\text{Price Factor} \times (Q - 20)^2}{24 \times Q}$

(iii) if $Q > 200\ m^3$ $R\% = \dfrac{\text{Price Factor} \times ((Q - 200) \times 11 + 1350)}{Q}$

The Price Factor for Heavy oil is equal to:

$$1 + \frac{2.5 \times (\text{Wellhead Price - Threshold Price for Heavy oil})}{\text{Wellhead Price}}$$

The Threshold Price for Heavy oil is established by order of the Administrator. As of September 1, 2002 it was set at $110 per m^3. As of February 2010, it remains at this value.

The Wellhead Price is the greater of:

(a) the average net value of that oil at the wellhead determined in accordance with Section 7(3)(b) of the Regulation, and
(b) the Threshold Price.

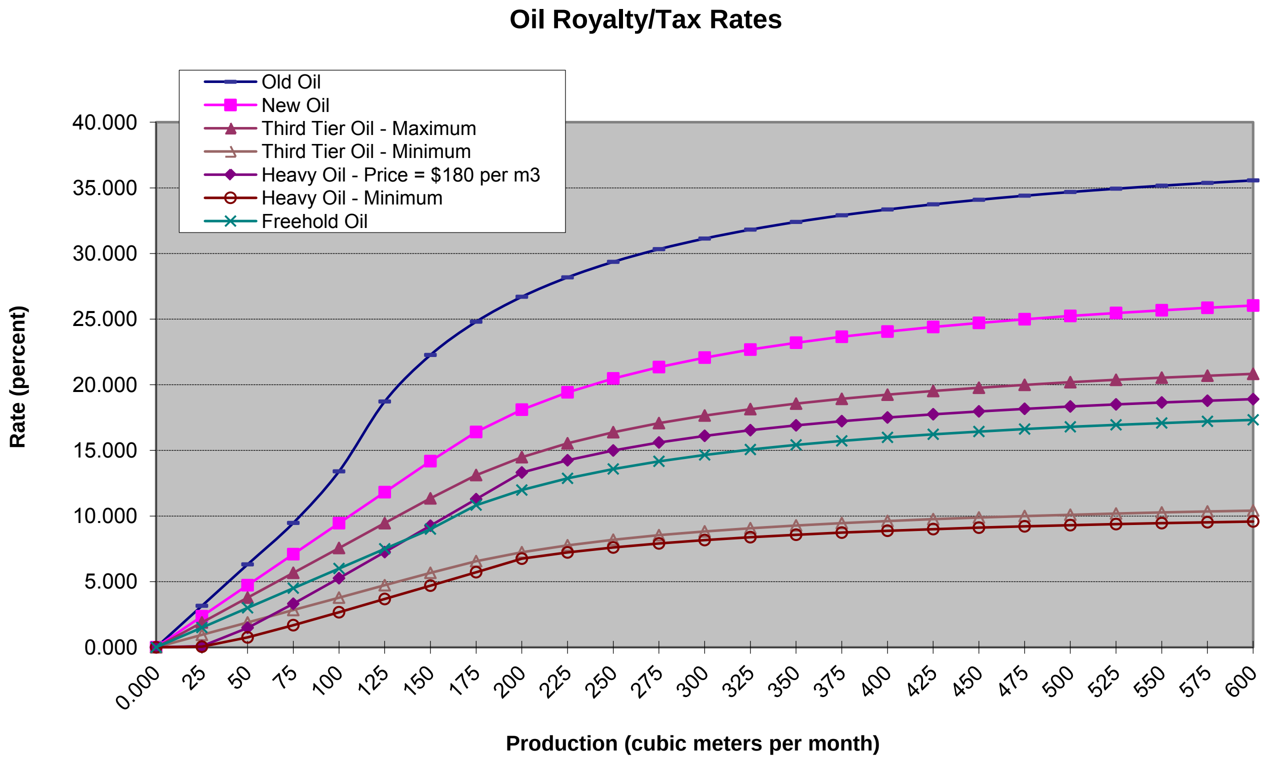
3. For all oil produced from freehold land, except Heavy oil:

(i) if $Q \leq 159m^3$, $R\% = .06 \times Q$

(ii) if $Q > 159\ m^3$, $R\% = \dfrac{1575 + 20(Q - 159)}{Q}$

OIL ROYALTY AND TAX CALCULATIONS cont'd

The following graph illustrates the relationship between oil royalty and tax rates and production for each classification of oil.



4.3 Oil Royalty/Tax Exemptions

The following production is exempt from payment of royalty and tax:

(a) oil that, in the opinion of the royalty administrator, was lost without fault on the part of the producer and for which the producer received no compensation,

(b) discovery oil that is produced in the first 36 producing months and which is not in excess of:

  (i) the monthly allowable production multiplied by 36, or
  (ii) 11,450 cubic metres.

"Discovery oil" means oil discovered in a new pool discovery well completed after June 30, 1974.

"Discovery well" means a well from which, in the opinion of an authorized commission employee, sufficient information has been obtained to determine that the well has encountered a previously undiscovered pool.

A Notice of Exemption Termination will be sent to the facility or unit operator upon termination of the exempt status of a well. This notice is not sent to individual producers.

If a discovery well is converted to an injection well as part of a pressure maintenance scheme prior to the well producing its maximum exempt volume, the royalty administrator, on application, may approve a transfer of the unused portion of the exempt volume to another well that produces from the same pool. Application should be made by letter to the Royalty Collector.

5.0 GAS ROYALTY AND TAX CALCULATIONS

5.1 Natural Gas Royalty/Tax Calculation Summary

OVERVIEW

Starting with gas produced in March 2006 the method for calculating royalty/tax on natural gas and its by-products was changed. Net royalty/tax payable on gas produced in March 2006 and after is calculated for each well event, except for gas produced from oil wells that are in Production Entities. This has simplified the calculation of gas royalties, particularly when marginal, ultra-marginal and low productivity royalty rate reductions apply.

For periods before March 2006, production from facilities was assigned to facility-based Reporting Entities for a producer in proportion to the producer's interest. See section 3.1 for a description of facility-based Reporting Entities. The Royalty/Tax Share of the production and the royalty/tax payable was then calculated for each Reporting Entity. This method is still used for amendments to periods before March 2006.

The following section describes the calculation of royalty and tax payable for gas produced in March 2006 and after. The calculation for periods before March 2006 is described in for BC-10 Natural Gas and By-Products Volumes & Values Report Guidelines.

ROYALTY AND TAX CALCULATION

Starting with production in April 2001, the Government of BC has been invoicing producers for natural gas royalties. Producers are only required to provide volumes of marketable gas available for sale and by-product sales volumes and values. Starting with production in March 2006, this information is provided for each well event and Production Entity (PE) on Natural Gas and By-Product Producer Allocations Reports (BC-08). The ministry uses this data and other information to calculate natural gas royalty and freehold production tax for each well event and PE and sends two monthly invoices to each produce: one for gas produced from oil wells in PE's and one for gas produced from all other well events. See section 7.1 for a detailed description of these invoices.

Calculation of the royalty or tax payable is done in the following 7 steps:

(1) Royalty/tax rates are determined for each well event and PE using certain attributes of the well event, average sales prices (Reference Prices) and average daily rates of raw gas production for some well events.

(2) Gross royalty/tax for the month is calculated for marketable gas produced from each well event and PE by multiplying the Reference Price times the volumes of marketable gas times the royalty/tax rate for the well event or PE.

(3) Gross royalty/tax for the month is calculated for by-products produced from each well event and PE by multiplying the sales value times the royalty/tax rate for each by-product and totaling them for the well event or PE.

ROYALTY AND TAX CALCULATION cont'd

(4) A weighted average royalty/tax rate is calculated for each well event and PE by dividing the sum of the gross royalty/tax for marketable gas and by-products produced from the well event or PE by the sum of the marketable gas volume produced from the well event or PE times the Reference Price plus the sales value of all by-products produced from the well event or PE.

(5) Gross royalty/tax is reduced by a Producer Cost of Service (PCOS) allowance for the producers' field costs for gathering, dehydration and compression of the royalty/tax share. The PCOS allowance is calculated for each well event and PE by multiplying the volume of raw gas produced from the well event or PE times the weighted average royalty rate for the well event or PE times the PCOS rate for the facility to which the well is connected or PE.

(6) The gross royalty on exempt volumes and credits available to deep well events and deep re-entry well events are calculated and deducted to get Net Royalty/Tax Payable. If the available deep well credit for a well event is greater than the gross marketable gas and by-product royalty less the PCOS allowance, net royalty payable is reduced to zero. The deep well bank for each eligible well is reduced by the amount deducted from royalties payable on production from deep well events in the well.

(7) Net Royalty/Tax Payable for a producer's interests in all PE's are added together in a separate invoice for PE's. Net royalty/tax payable for a producer's shares of production from all other well events are added together in an invoice for all other well events.

Marketable Gas Volume by Well Event or PE

The **marketable gas** volume is the volume of marketable gas available for sale based on the volume of raw gas processed during the production month and raw gas that may be used as fuel. This may not be the same as actual volumes delivered to buyers.

Royalty and Tax Rates

The royalty/tax rate is calculated in accordance with section 6(1) of the Royalty Regulation. The applicable rate for gas is dependent upon:

- whether the gas is produced from Crown land or freehold land, whether the gas is classified as Conservation gas or Non-conservation gas,
- if it is Non-conservation gas from Crown land, whether the gas is Base 15, Base 12 or Base 9,
- the Reference Price when it exceeds the Select Price for Base 9 or Base 12 Non-conservation gas or when it exceeds $50 per thousand cubic metres for any other gas, and
- the average daily rate of raw gas production.

See section 5.2 for the meaning of important terms and the formulae for calculating royalty and tax rates on marketable gas and by-products.

ROYALTY AND TAX CALCULATION cont'd

Reference Price

The Reference Price is used to calculate the gross royalty/tax for marketable gas. The Reference Price is the greater of the Producer Price and the Posted Minimum Price.

A Producer Price is determined monthly for each producer at each gas processing plant at which the producer has production for the month. Producer prices are calculated as follows:

- Producers are required to submit invoices for all their sales of marketable gas in a given month to the Ministry of Energy, Mines and Natural Gas.
- An average sales price for all plant outlet and downstream sales made by a producer is calculated at a common pricing point.
- The average price is then netted back to the outlet of each processing plant using transportation charges actually incurred by the producer.
- For gas that is processed through producer-owned plants, the Gas Cost Allowance (GCA) is deducted to get an average value at the inlet of the plant. See Section 5.6 and BC-23 Application for Gas Cost Allowance Guidelines for a more detailed discussion of GCA. For gas that is processed through plants that are not owned by producers, i.e. custom processing plants, processing charges are deducted as invoiced.
- A weighted average of the resulting inlet values and prices for sales by the producer at the plant inlet is the Producer Price at that plant.
- If Duke Energy Inc. is the custom processor and the producer uses Duke Energy's raw gas gathering system, the average plant inlet value is reduced by Duke Energy's raw gas gathering charges. The Producer Price is a weighted average of the resulting value and the prices for sales by the producer at the inlet to the Duke Energy system.

Producer Price calculations are described in more detail in section 5.3.

The Ministry of Energy, Mines and Natural Gas calculates and publishes a Posted Minimum Price (PMP) each month for each processing plant. The PMP is used as a price floor in calculating the royalty/tax rate and gross royalty/tax for a well event or PE. See section 5.4 for a complete description of how the PMP is calculated.

By-Product Sales Value

For natural gas by-products, the sales volume is the actual amount disposed of. Natural gas by-product sales volumes at the plant outlet should be allocated to each well event or PE in proportion to the liquid content of the gas stream. The Sales Value for natural gas by-products is,

(i) the consideration received or receivable by the producer for their disposition less actual approved costs for processing and transporting the by-products from the point of production to the point of sale, or

(ii) if there is no actual sales price or if the sales price is in the opinion of the Administrator less than fair market value, a deemed value.

See section 5.7 for more details on natural gas by-products.

ROYALTY AND TAX CALCULATION cont'd

Producer Cost of Service (PCOS) Allowance

The PCOS allowance is an allowance of such amounts to cover a producer's cost of:

(a) field gathering, dehydration and compression of Non-conservation gas,
(b) conserving conservation gas, and
(c) processing natural gas in the field for use as fuel in the field.

The PCOS allowance is deducted from the Gross Royalty/Tax. This allowance is allocated to the Royalty/Tax Share using the Weighted Average Royalty/Tax Rate which is the proportion of Total Gross Royalty/Tax to total sales value.

All producers are eligible for a PCOS deduction. PCOS rates are established for each reporting facility and depend upon:

(a) the equipment that is in place and in use in the field,
(b) the average costs of field equipment as determined by annual engineering studies and
(c) the volume of raw gas that is produced from well events delivering to the reporting facility.

A PCOS deduction is calculated for each well event. The amount of the deduction is equal to the PCOS rate per 10^3m^3 of raw gas times the well event's share of raw gas production times the Weighted Average Royalty/Tax Rate to get the PCOS allowance that may be deducted from the Total Gross Royalty/Tax for the well event. The PCOS Allowance may not exceed 95 per cent of the Total Gross Royalty/Tax.

Coalbed methane projects are also eligible for a PCOS allowance for producers' costs of handling water. If the water handling allowance is greater that the royalty on production of gas from the project in a month, the difference may be carried forward for deduction in future months.

See section 5.5 for a more detailed discussion of the PCOS allowance.

Determining the Royalty Exempt Value

In rare circumstances gas may be exempt from royalty. See section 5.9 for a complete description of gas that is exempt from royalty.

Credits for Deep Gas Wells

To encourage greater exploration for and development of deep gas resources, deep gas royalty incentives were introduced on July 1, 2003. These are intended to encourage exploration for deep reserves of natural gas by offsetting the higher drilling costs. These incentives were introduced on July 1, 2003 and modified on December 1, 2003.

ROYALTY AND TAX CALCULATION cont'd

There are different incentives for three types of deep gas wells: Deep Discovery Wells, Deep Wells and Deep Re-entry Well Events. The Deep Discovery Well incentive is an exemption from payment of royalties. The Deep Well incentive is a deduction from royalties that is based on the depth and type of well. The Deep Re-entry incentive is also a deduction from royalties, which is based on well event depth and amount of incremental drilling that is done. Tables that correlate well depths to drilling costs have been developed to provide royalty and tax incentives that are related to higher drilling and completion costs.

A well can only qualify for one of the Deep Well or Deep Re-entry incentives. However, a well may qualify for the Deep Discovery Well and either the Deep Well or Deep Re entry incentives. Producers are entitled to the incentive that is of the greater benefit. Since well events on Crown or freehold land are eligible, the benefits are available against both royalties and freehold production taxes.

5.2 Gas and Gas By-Products Royalty Tax Rates

BASIC RATES

The royalty/tax rate is calculated in accordance with section 6(1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation (B.C. Reg. 495/92). The applicable rate for gas is dependent upon:

- whether it is produced from Crown land or freehold land
- whether it is classified as Conservation gas or Non-conservation gas,
- if it is Non-conservation gas from Crown land, whether it is Base 15, Base 12 or Base 9,
- its Reference Price, and
- the Select Price

"Crown land" is land where the Crown has retained ownership of underlying oil and natural gas. Production of oil and natural gas from Crown lands requires a lease under the *Petroleum and Natural Gas Act*.

"Freehold land" is land where the Crown has granted ownership of underlying oil and natural gas to a person. Production of oil and natural gas from freehold lands does not require a lease under the *Petroleum and Natural Gas Act*.

"Conservation Gas" is gas produced from an oil well where the marketable gas is conserved, but does not include gas from an oil well granted concurrent production status under section 97 of the *Petroleum and Natural Gas Act*.

"Non-conservation Gas" is gas other than Conservation Gas and is classified into Base 15, Base 12 and Base 9. These classifications are defined as follows:

Base 15 / Freehold: Non-conservation gas that is produced from well events in a well having a spud date before June 1, 1998, or is revenue sharing gas.

Base 12: Non-conservation gas, other than revenue sharing gas, produced from well events that are not Non-Conservation Gas, Base 15 or Non-Conservation Gas, Base 9.

Base 9: Non-conservation gas, other than revenue sharing gas, produced from well events

(a) for which the entire spacing area is
  (i) in a lease that was disposed of under section 71 of the Act after May 1998, or
  (ii) in a lease that was issued from a permit or license that was disposed of under section 71 of the Act after May 1998
(b) which have a completion date not more than 60 months after the disposition date of the lease in paragraph (a) (i) or the disposition date of the permit or license in paragraph (a) (ii), as the case may be

"Revenue Sharing Gas" means gas the royalties from which are to be shared under the terms of a revenue sharing agreement applicable to that gas.

BASIC RATES cont'd

"Reference Price" for a producer's gas is the greater of:

(i) the Producer Price for the producer's gas in the month, and

(ii) the Posted Minimum Price for the month in which it is available for disposition.

"Producer Price" is an average sales price for all of the gas sold by a producer netted back to the plant at which the marketable gas volume is available for sale. The Ministry of Energy, Mines and Natural Gas calculates Producer Prices monthly for each producer at each plant based on each producer's sales invoices and transportation and treatment costs (see section 5.3).

"Select Price" is a price set by Order of the Administrator for each calendar year. It is a mechanism by which the Reference Price at which the minimum royalty rate takes effect can be adjusted for inflation. It is currently \$50 per 10^3m^3 until further notice.

The formulae for calculating the royalty and tax rates are as follows:

(1) For marketable gas and by-products produced from Crown land:

Conservation Gas:	(i) if $RP \leq 50$,	$R\% = 8$
	(ii) if $RP > 50$,	$R\% = \frac{400 + 15(RP - 50)}{RP}$
Non-Conservation Gas, Base 15:	(i) if $RP \leq 50$,	$R\% = 15$
	(ii) if $RP > 50$,	$R\% = \frac{750 + 25(RP - 50)}{RP}$
Non-Conservation Gas, Base 12:	(i) if $RP \leq SP$,	$R\% = 12$
	(ii) if $RP > SP$,	$R\% = \frac{12 \times SP + 40(RP - SP)}{RP}$
	(iii) if $RP/SP \geq 28/13$,	$R\% = 27$
Non-Conservation Gas, Base 9:	(i) if $RP \leq SP$,	$R\% = 9$
	(ii) if $RP > SP$,	$R\% = \frac{9 \times SP + 40(RP - SP)}{RP}$
	(iii) if $RP/SP \geq 31/13$,	$R\% = 27$
Natural Gas Liquids		$R\% = 20$
Sulphur		$R\% = 16.667$

where, RP is the Reference Price in \$ per 10^3m^3,
SP is the Select Price in \$ per 10^3m^3, and
R is the royalty rate as a percentage.

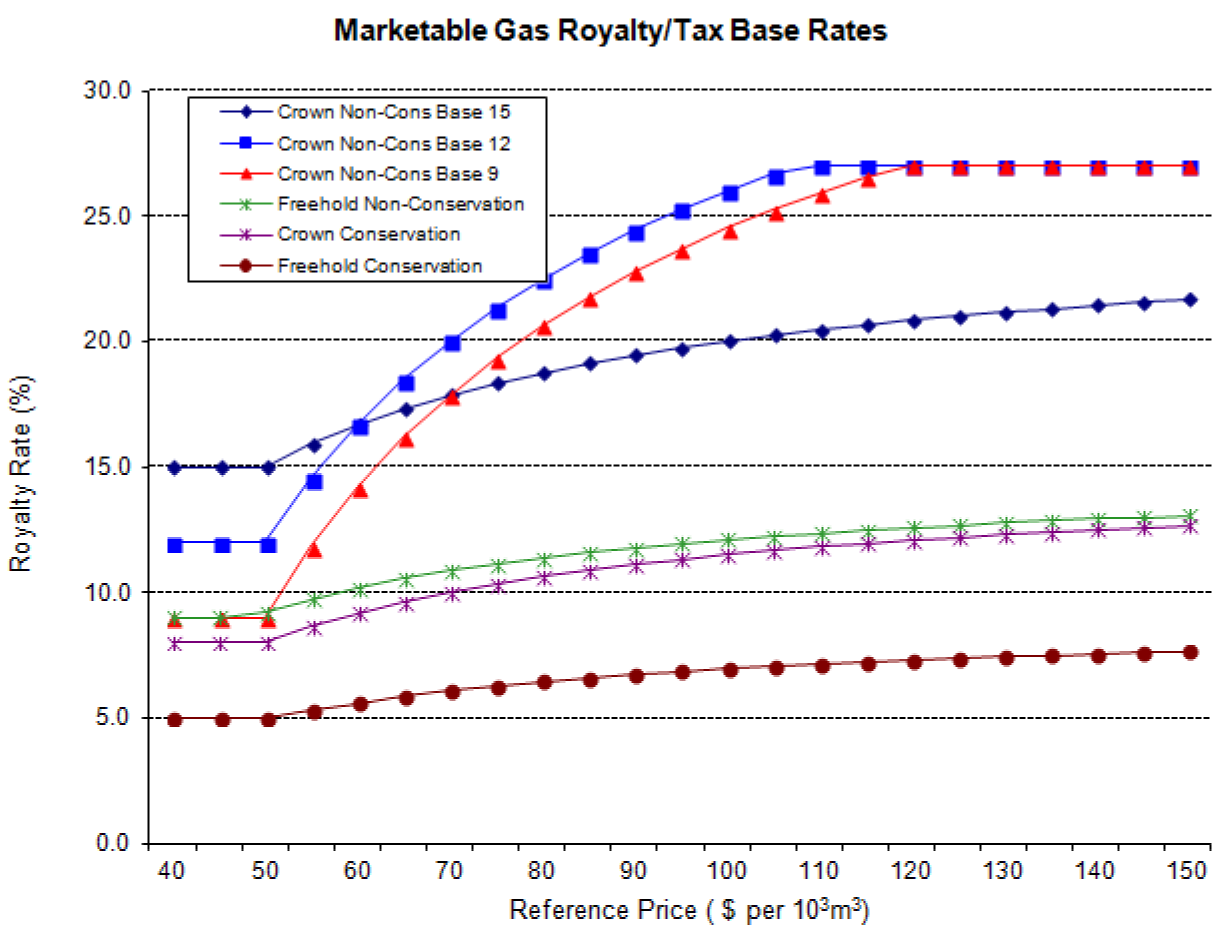
BASIC RATES cont'd

(2) For all marketable gas and by-products produced from freehold land:

Conservation Gas:	(i) if RP $\leq$ 50, (ii) if RP > 50,	R% = 5 R% = $\frac{245 + 9(RP - 50)}{RP}$
Non-Conservation Gas:	(i) if RP $\leq$ 50, (ii) if RP > 50,	R% = 9 R% = $\frac{460 + 15(RP - 50)}{RP}$
Natural Gas Liquids		R% = 12.25
Sulphur		R% = 10.25

where, RP is the Reference Price in \$ per 10^3m^3, and
R is the royalty rate as a percentage.

The following graph illustrates the royalty curves for gas:



PRODUCTION RELATED REDUCTIONS IN BASE RATES

For certain types of gas well events, base royalty and tax rates are reduced by factors related to the average daily rate of production from the well event. The types of well events that qualify for production-related rate reductions are low productivity, coalbed methane, marginal and ultramarginal well events.

1. Definition of Low Productivity Well Events

A reduction in royalty shares for low productivity gas wells was introduced in 2001 to prevent the government's royalty from causing gas wells to be shut in when they reached rates of production that are too low to cover their operating costs.

Low productivity wells are well events with average raw gas production less than 5000 m^3 per day during a month and are not marginal, ultra-marginal or coalbed methane well events. The royalty/tax reduction applies to all non-conservation gas, which is gas produced from gas well events or from oil well events that are part of an approved concurrent production scheme. The reduction applies to all Crown and freehold well events regardless of when they were drilled or completed. A well event means all completions in a well in the same zone.

The reduction does not apply to conservation gas, which is gas from oil wells that are not part of an approved concurrent production scheme.

2. Definition of Coalbed Methane Well Events

Special royalty provisions were introduced in March 2002 to encourage development of British Columbia's reserves of coalbed methane. These included a reduction in the royalty rate that is dependent on the rate of production from a well event, additional Producer Cost of Service Allowance provisions (see section 5.5) and credits for each coalbed methane well drilled.

A coalbed methane well event is a well event that is part of a coalbed methane project. A coalbed methane project is one or more wells that have been approved as a scheme under section 100 (1) (a) or (b) of the *Petroleum and Natural Gas Act* and are capable of producing natural gas from a geological stratum or strata containing mainly coal. Projects requiring approval under section 100 (1)(a) of the *Act* include repressuring, recycling, pressure maintenance or any other enhanced recovery technique. Projects requiring approval under section 100 (1)(b) are experimental applications of oilfield technology.

A coalbed methane well event cannot also be a low productivity well event.

PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont'd

3. Definition of Marginal Well Events

A reduction in royalty shares for marginal gas wells was introduced on July 1, 2003 to encourage development of gas reserves that are marginally economic because of depth and flow rates (pressure and permeability). Whereas the low productivity reduction is intended to keep existing wells from being shut in, the marginal well reduction is intended to encourage decisions to drill new gas wells.

A well event qualifies for the marginal well royalty rate reduction if it meets the following criteria:

(a) The primary product is natural gas.

(b) It is not part of a coalbed methane project.

(c) The spud date of the well is after May 31, 1998, i.e. it is subject to Base 9 and 12 royalty rates, unless it is on land that is subject to a revenue sharing agreement with the Fort Nelson, Blueberry or Doig First Nations in which case it may be subject to the Base 15 royalty rate.

(d) The first month in which marketable gas is produced from the well event is after June 2003, or it was suspended as of June 30, 2003 and reactivated after June 2003.

(e) The average daily production of natural gas per metre of depth in the 12-month period that begins with the first month in which the well event produces marketable gas is less than 23. This is calculated using the following formula:

$$\frac{(TP / TPH) \times 24}{MWD}$$

TP = total production of natural gas from the well event in the 12 consecutive calendar months starting with the month in which marketable gas is first produced from the well event, or, in the case of a reactivated well event, the month in which marketable gas is first produced after reactivation.

TPH = the total number of hours of production during the months referred to in the meaning of TP.

MWD = the marginal well depth of the well event. This depends on the type of well, as follows.

(i) For a well event in a vertical well, MWD is the true vertical depth to the top of pay, which is the distance from the intersection of the well bore with the pay of the well event to the point directly above that intersection that is the same elevation as the kelly bushing used in drilling the well.

(ii) For a well event in a horizontal well, MWD is the total measured depth of the well event, which is the length of the well bores from the surface to the well event. Since all well events in the same geological zone are considered for royalty purposes to be one well event, if a horizontal well has more than one lateral extension to well events in same zone, MWD includes the length of all of the lateral extensions.

PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont'd

4. Definition of Ultra-marginal Well Events

A reduction in royalty shares for ultramarginal gas wells was introduced on March 1, 2006 to encourage development of shallow gas reserves with low rates of production. The new incentive is similar to existing incentives for marginal and low productivity gas wells which progressively reduce the royalty rate when the average daily rate of natural gas production is below prescribed amounts. The ultra-marginal rate reduction is more significant than the rate reduction for marginal wells because it takes effect at higher rates of production. However, the conditions for a well to qualify for the ultra-marginal reduction are more stringent.

Only one of the production-based royalty reductions (low productivity, marginal and ultramarginal) can be applied to the same well event. Wells that satisfy the qualifying criteria for both marginal and ultra-marginal reductions will be given ultramarginal status.

A well event qualifies for the ultramarginal well royalty reduction if it meets the following criteria:

(a) Its primary product is natural gas, but it is not part of a coalbed methane project. The ultramarginal royalty reduction does not apply to conservation gas or non-conservation gas produced from an oil well event.

(b) The well event is in a well with a spud date after December 31, 2005, or it is a reactivated well event with a re-entry date after December 31, 2005 in a well with a spud date after May 1998.

(c) The well event is in a vertical well with a true vertical depth that is less than 2,500 meters or in a horizontal well with a true vertical depth of less than 2 300 metres. This limits the ultra-marginal rate reduction to wells that do not qualify for a deep well credit. Effective April 1, 2014, there are two changes to the qualifications for the ultra-marginal program. Horizontal gas wells with a spud date on or after April 1, 2014 are not eligible for the ultra-marginal royalty program. Vertical wells with a spud date on or after April 1, 2014 must have a completion point that has a true vertical depth equal to or less than 2,500 metres. This is in addition to the qualification that all vertical gas wells must have a true vertical depth to the top of the pay of the well event of less than 2,500 metres.

PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont'd

(d) If the well event is in an exploratory wildcat well, its average daily rate of production per metre of depth in the 12 month period that begins with the first month in which it produces marketable gas is less than 17. If the well event is in an exploratory outpost well or a development well, its average daily rate of production per metre of depth in the 12-month period that begins with the first month in which it produces marketable gas is less than 11. The average daily rate of production per metre of depth is calculated using the following formula:

$$\frac{(TP / TPH) \times 24}{UWD}$$

TP = the total natural gas production from the well event in the 12 consecutive calendar months starting with the month in which marketable gas is first produced from the well event. In the case of a reactivated well event, the 12 consecutive calendar months start with the month in which marketable gas is first produced following reactivation.

TPH = the total number of hours during which the well event produced marketable gas over the 12-month test period.

UWD = the Ultra-marginal Well Depth of the well event. This depends on the type of well, as follows.

(i) For a well event in a vertical well, UWD is the true vertical depth to the top of pay. This is the distance between the well bore's intersection with the pay of the well event to the point, directly above that intersection point, that is the same elevation as the Kelly bushing used in drilling that well.

(ii) For a well event in a horizontal well,

- if the total measured depth (TMD) less the measured depth to the top of pay (MDTP) is less than 1,000 meters, UWD = TMD
- if TMD less MDTP is equal to or greater than 1,000 meters, UWD = MDTP + 1,000 + (TMD – (MDTP + 1,000)) / 2

For a well event in a horizontal well, TMD is the length of all of the vertically and horizontally oriented well bores that constitute the well event.

(e) The 12-month test period in which gas production is measured to determine whether a well event qualifies for ultra-marginal status must end after January 2007.

5. Royalty/Tax Rate Reduction Factors

The production related reduction factors reduce royalty/tax rates by the basic royalty/tax rate multiplied by the reduction factor. The basic royalty/tax rates are the rates prescribed in section 6(1) of the Royalty Regulation and described in the previous section of this Handbook. The reduction factors are as follows:

(a) for low productivity well events: $((5{,}000 - ADV) / 5{,}000)^2$

(b) for coalbed methane well events: $((17{,}000 - ADV) / 17{,}000)^2$

(c) marginal well events: $((25{,}000 - ADV) / 25{,}000)^2$

PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont'd

(d) ultra-marginal well events $((60{,}000 - ADV) / 60{,}000)^{1.5}$

In these formulas, ADV = the average daily natural gas production volume from the well event during the month in cubic meters. It is calculated as follows,

$$ADV = (TP / TPH) \times 24$$

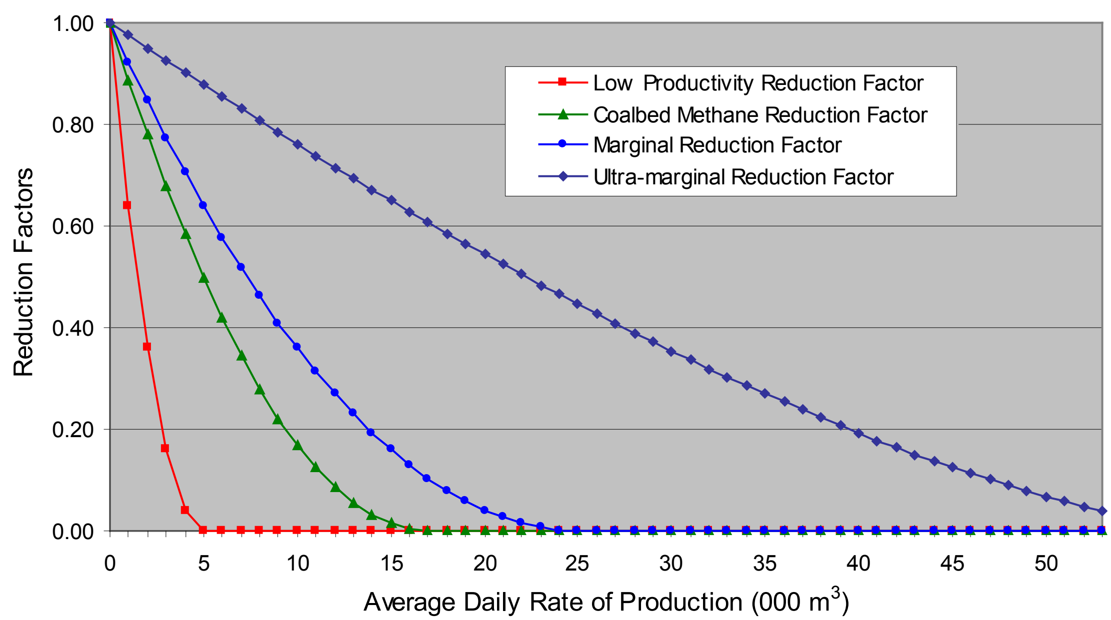
TP = total natural gas production from the well event during the month, as reported on *Monthly Production Statements* (BCS1).

TPH = the total measured and prorated number of hours during which the well event produced natural gas during the month, as reported on BCS1'S.

For low productivity well events, if ADV is greater than 5,000 m^3, the reduction factor is zero. For coalbed methane well events, if ADV is greater than 17,000 m^3, the reduction factor is zero. For marginal well events, if ADV is greater than 25,000 m^3, the reduction factor is zero. For ultra-marginal well events, if ADV is greater than 60,000 m^3, the reduction factor is zero.

The following graph illustrates how reduction factors for low productivity, coalbed methane and marginal well events increase as the rate of production declines below 5,000, 17,000, 25,000 and 60,000 m^3 per day, respectively.

Production Related Gas Royalty Reduction Factors



PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont'd

6. Royalty Rate Reductions

The low productivity, coalbed methane, marginal and ultra-marginal royalty rate reductions that are related to the rate of production from individual well events result in royalty/tax rates that are unique to the well event.

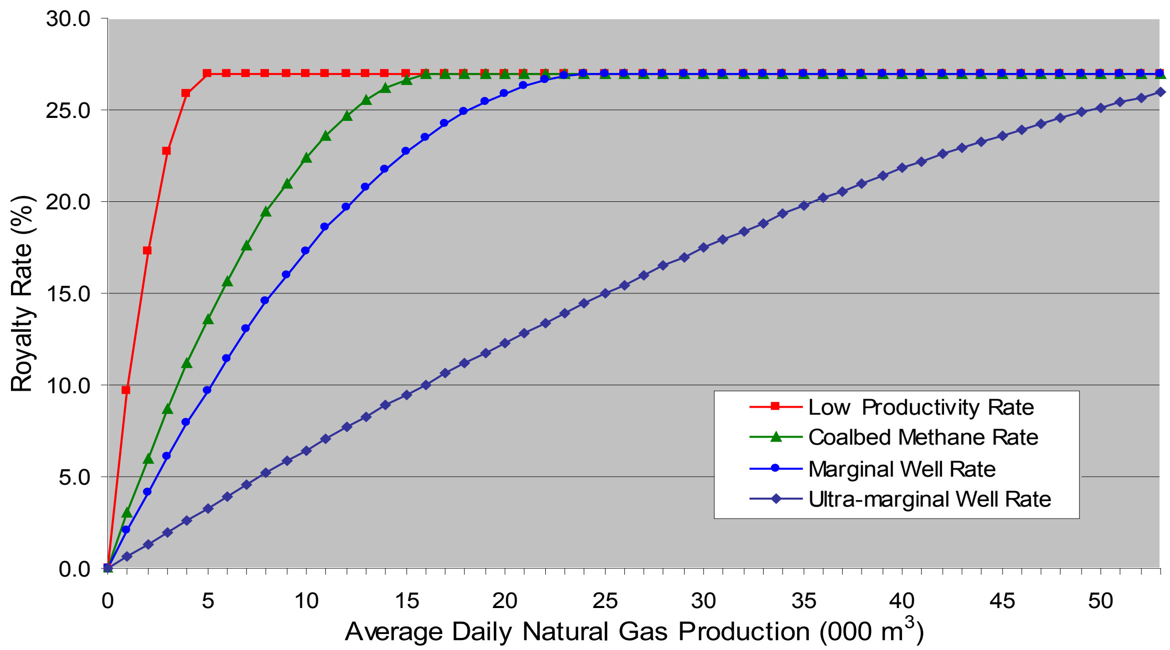
The production related reduction factors reduce royalty/tax rates by the basic royalty/tax rate multiplied by the reduction factor, as follows:

Royalty/Tax Rate = Basic Rate - Basic Rate x Reduction Factor

The following graph illustrates how the royalty rate for Base 9 and 12 well events that are low productivity, coalbed methane, marginal and ultra-marginal well events decrease as the rate of production declines below 5,000, 17,000, 25,000 and 60,000 m^3 per day, respectively.

Production Related Gas Royalty Rate Reductions

[Base 9 and 12 well events, Select Price = $50 / m3,
Reference Price > $120 / m^3]



To realize the benefit of a royalty rate reduction, a producer must report the marketable gas volumes that were produced from the qualifying well event on the BC08 Marketable Gas and By-Product Producer Allocations Report. The monthly crown invoice will then calculate a royalty rate reduction for the qualifying well event and apply the reduction to the marketable gas volume reported on the BC08.

RECALCULATIONS FOR FIRST 12 MONTHS OF PRODUCTION

For every new and reactivated well event with an initial production month after June 2003, the ministry will review the marginal well eligibility after the well event's first 12 months of production. If the well event is eligible for the marginal well reduction, the ministry will notify each producer with an ownership interest in the well event that it is a marginal well event. The ministry will recalculate royalties for those months in which average daily production from the well event is less than 25,000 m^3/day, and will issue revised invoices for the well event for those months.

For every new and reactivated well event with an initial production month after January 2006, the ministry will review the ultra-marginal well eligibility after the well event's first 12 months of production. If the well event is eligible for the ultra-marginal reduction, the ministry will notify each producer with an ownership interest in the well event that it is an ultra-marginal well event. The ministry will recalculate royalties for those months in which average daily production from the well event is less than 60,000 m^3/day, and will issue revised invoices for the well event for those months.

5.3 Gas Sales Contract Summary and Pricing for Marketable Gas

OVERVIEW

In British Columbia, a royalty is paid by a producer on its marketable gas sales volumes that have been allocated to a well event. The determination of a marketable gas royalty rate used in determining the Crown royalty share and the valuation of this Crown royalty share are dependant on the marketable gas reference price for the well event. The reference price is equal to the greater of the Producer Price and the Posted Minimum Price. The Ministry of Energy, Mines and Natural Gas (MEM) calculates both the Producer Price and the Posted Minimum Price on a monthly basis for use on the Crown invoice that is issued by the Ministry of Finance to each natural gas producer.

PRODUCER PRICE

The *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation* (the royalty regulation) provides the authority for the Royalty Administrator to set out the “rules” that will be applied in determining a Producer Price. These rules are set out in Order of the Administrator 2008-3. A Producer Price is determined for each producer delivering natural gas to a natural gas processing plant or dry gas source. The royalty regulation defines a “producer” as:

(a) "a holder of a location who markets or otherwise disposes of oil, natural gas or both, that has been produced by

  (i) the holder of the location, or

  (ii) a person authorized to do so by the holder of the location, and

(b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder’s behalf, oil, natural gas or both”.

For administrative purposes, the producer is identified using the following rules:

(a) for marketable gas delivered to the Spectra Energy Westcoast transportation system, a producer is identified as the party appearing on Spectra Energy’s Determination of Production report unless the producer, or production source operator, has notified the Ministry of Energy, Mines and Natural Gas in writing.

(b) for marketable gas delivered to the TransCanada transportation system, Alliance transportation system or any other transportation systems other than a Spectra Westcoast transportation system, a producer is identified from plant split information provided to the Ministry of Finance by plant operators on the BC-19 Monthly Natural Gas Plant and Processing Statement.

Producer Prices will only be calculated for producers identified as above.

The methodology for calculating a Producer Price is based on the following procedure.

PRODUCER PRICE cont'd

For each producer, a volume weighted average sales price is determined based on all of a producer's sales, other than plant inlet sales, at a common pricing point. The common pricing point is Station 2 on the Spectra transportation system or at the inlet to the TransCanada or Alliance transportation systems. The price at the common pricing point is then netted back to the inlet of each plant at which the producer has production using producer and plant specific transportation charges and processing fees (custom processing fees, or Gas Cost Allowances). A weighted average of this "netback price" and the prices of any sales made by the producer at the inlet of each plant are blended to determine a Producer Price for each plant that a producer has production behind.

Order of the Administrator 2008-3 also specifies the following rules:

(i) When gas is disposed of and there is no arm's length sale (e.g. transferred into storage, intra-company sales or swapped), the price is deemed to be the net selling price of all other sales for the producer in the region in which the disposition takes place,

(ii) Energy based prices will be converted to volumetric prices using the average heating value of the producer's gas at a plant; and,

(iii) The value of fuel consumed in the transportation of a producer's gas, where the producer has not received consideration for the fuel, is factored into the calculation of a Producer Price by including the fuel gas volume in the volume delivered to a buyer when calculating the per unit sales price. Producers wishing to have fuel costs factored in must submit supporting documentation showing fuel volumes.

REPORTING

Producer Prices are determined monthly in the 2nd month after the gas is produced, when a producer's actual sales information is available. On a monthly basis producers must submit to the MEM copies of all sales invoices showing actual sales volumes and values. For gas sold into a producer's pool, the producer must submit a summary outlining all buyers from the pool, sales revenue (excluding marketing, administration and financial hedging transactions), sales volumes and transportation costs. Note that gas purchases are not included in the calculation of the Producer Prices. The sales information submitted by the producer will be used to verify the resale price and, in combination with cost of service information, determine the Producer Price.

A Plant operator is a primary source of information used for calculating Producer Prices. Spectra Energy provides the MEM with a monthly summary of production by producer and a statement of deliveries and cost of service invoices for each producer with service on the Spectra Westcoast transportation system. Other plant operators provide marketable gas volumetric splits for each producer delivering natural gas to their gas plants.

REPORTING cont'd

Producers are required to submit sales and cost of service invoices to the MEM by the 11th day of the 2nd month after the month in which gas has been produced. Producers invoiced by a party other than Spectra Energy for processing or transmission service must provide the MEM with the appropriate invoices (this includes Spectra Energy Midstream's processing invoices) to ensure that these costs are factored into the Producer Price calculation. Failure to submit this information will result in the costs not being deducted in the calculation of Producer Prices. The MEM may also request that producers submit third party processing contracts.

Late invoices may result in a Producer Price not being issued in time to be used for the royalty estimate. Insufficient royalty estimates may be subject to interest charges.

Producers are notified of Producer Price calculations through a *Producer Price* report. A *Summary of Sales* report and, if applicable, a *Cost of Service* report is also provided to the producer. These reports provide the details of sales revenue and costs used in the calculation of Producer Prices.

The MEM may request documentation to support the calculation of a producer's Producer Price throughout a calendar year. Examples of supporting documentation that may be requested are as follows:

- Contracts supporting marketable gas sales volumes and values.
- Processing and transportation contracts.
- Documentation supporting non-arms length or sales with unusual pricing provisions.
- Summary of Sales' pricing formulas.

GAS ROYALTY PRODUCER PRICE EXAMPLE

This example (TABLE 1) outlines a scenario where a producer has production behind two Spectra processing plants and multiple sales (Sales A to E) at various points off the Spectra transportation system.

Provision of Data

For Sales A to D the producer must submit copies of sales invoices. For Sale E, (Alberta Pool sales), the producer must submit a summary outlining all buyers in the pool, sales revenue (excluding marketing, administration and hedging transactions), sales volume and transportation costs.

Step 1 - Sales Prices (Order 2008-3, section A, B, C4, C5)

The producer has four arm's length sales (Sales A to D) and one non-arm's length transaction (Sale E) for a total disposition volume of 324,000 GJ. Because of gas purchases and line pack, production and sales volumes may not equal each other.

Per unit sales prices are determined at the title transfer points for Sales A to D using invoices provided by the producer. Sale E will be valued at the producer's average Alberta sales price.

GAS ROYALTY PRODUCER PRICE EXAMPLE cont'd

Step 2 - Cost of Service (Order 2008-3, section C7, C8) In this example, eligible deductions are calculated using the Spectra cost of service data as well as data for transportation costs on the TransCanada or Alliance transportation systems. Any invoices submitted by the producer for custom processing fees other than Spectra's or brokered Spectra service would also be factored in. The costs are applied over total volumes transported on that service type to determine a $/GJ rate.

Step 3 - Weighted average price at a common pricing point (Order 2008-3, section C3)

Once the sales price has been determined, all sales, except inlet sales, are netted forward or back using actual transportation costs, to the common pricing point (equivalent to Station #2 on the Spectra transportation system or the inlet to TransCanada or Alliance Pipelines). For example, Sale B at the outlet of Spectra Plant #2, is netted forward to Station 2 using T-North charges of $0.14/GJ. Sale C at Sumas is netted back using T-South charges of $0.40/GJ. Once these prices are calculated for each sale a weighted average price for all sales is determined at the common pricing point ($3.41/GJ in this example).

Step 4 - Determine plant production and heating values

The producer's plant production volumes and heating values are obtained directly from Spectra's Determination of Production report, or data provided by the operators of non-Spectra plants as reported on the Form BC-19 Monthly Natural Gas Plant and Processing Statement, if applicable.

Step 5 - Determine Producer Price (see Order 2008-3; sections A, B, C2)

From the average price at the common pricing point for the producer ($3.41/GJ), actual transportation and gathering and processing charges ($.14/GJ and $.45/GJ, respectively, for Plant #1) are deducted, to provide an average inlet price for downstream sales for each plant at which the producer has production ($2.82 at Plant #1). As there is an inlet sale, a weighted average of this price and the average inlet sale price ($2.15/GJ) results in an average plant inlet price ($2.60/GJ). The average inlet price is multiplied by the average heat content of the producer's gas at the plant (42.356 GJ/m^3 at Plant #1) to obtain the Producer Price ($110.13/10^{3}m^3). This price will be used on the crown invoice issued by the Ministry of Finance to value marketable gas volumes allocated to the producer's well events delivering natural gas to Plant #1.

GAS ROYALTY PRODUCER PRICE EXAMPLE cont'd

TABLE 1

Step 1. Determine Sales Price and Title Transfer Point (from Producer Invoices)

Sale #	Title Transfer Point	Sale Volume (GJ)	Sale Value ($CDN)	Sale Price ($/GJ)
A	Inlet to Spectra Plant #1	50,000	107,500.00	2.15
B	Outlet of Spectra Plant #2	75,000	243,750.00	3.25
C	Sumas	100,000	400,000.00	4.00
D	Station #2	27,000	91,800.00	3.40
E	Alberta Pool	72,000	241,200.00	3.35
	TOTAL	**324,000**		

Step 2. Determine Costs (Spectra, Custom Processing, Third Party Brokering)

Plant	Service	Rate ($/GJ)
Spectra Plant #1	Gathering and Processing	0.45
Spectra Plant #2	Gathering and Processing	0.50
TNorth Long Haul (TNLH)	Transportation	0.14
TSouth (TS)	Transportation	0.40
Miscellaneous (MISC)	Transportation on NOVA	0.18

Step 3. Determine Average Price at Common Pricing Point (equivalent to Station #2/NOVA Inlet)

Sale #	Title Transfer Point	Sale Volume (GJ)	Sale Price ($/GJ)	TNLH ($/GJ)	TS ($/GJ)	MISC ($/GJ)	Average Price ($/GJ)
A	Inlet to Spectra Plant #1	50,000	2.15				n/a
B	Outlet of Spectra Plant #2	75,000	3.25	0.14			3.39
C	Sumas	100,000	4.00		(0.40)		3.60
D	Station #2	27,000	3.40				3.40
E	Alberta Pool	72,000	3.35			(0.18)	3.17
		324,000					**$ 3.41/GJ**

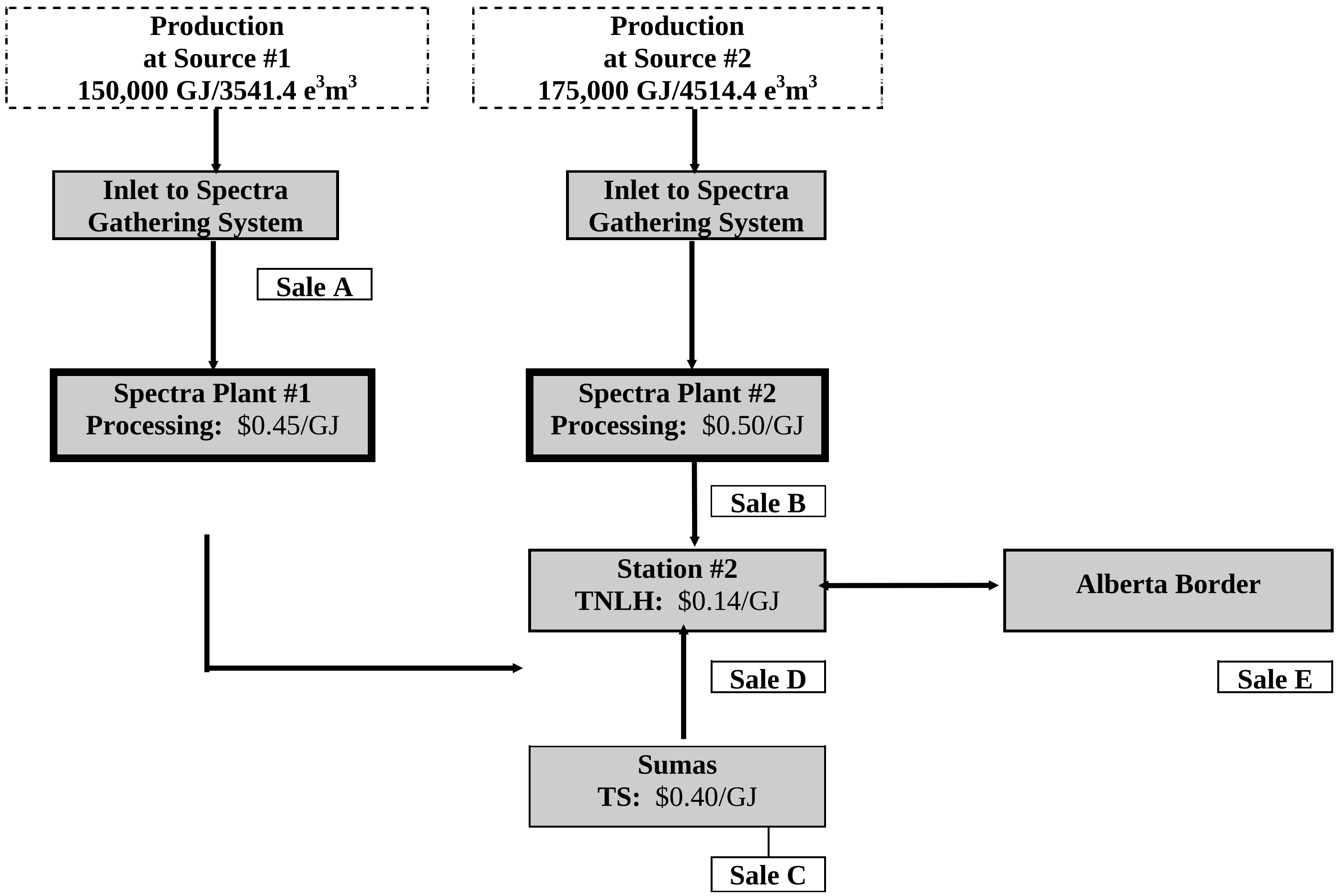
Step 4. Determine Plant Production and Heating Values

Plant	Production (GJ)	Heating Value (GJ/e3m3)
Spectra Plant #1	150,000	42.356
Spectra Plant #2	175,000	38.765
	325,000	

Step 5. Determine 'Producer Prices'

Plant	Sale Type	Volume (GJ)	Avg. Price ($/GJ)	TNLH ($/GJ)	Gathering and Processing ($/GJ)	Inlet ($/GJ)	Heat Value	Producer Price
Spectra Plant #1	Inlet	50,000	n/a			2.15		
	Blended Sales	100,000	3.41	($0.14)	($0.45)	2.82		
		150,000				**2.60**	**42.356**	**$ 110.13 /e^3m^3 Spectra Plant #1**
Spectra Plant #2								
	Blended Sales	175,000	3.41	($0.14)	($0.50)	**2.77**	**38.765**	**$107.38/ e^3m^3 Spectra Plant #2**

GAS ROYALTY PRODUCER PRICE EXAMPLE cont'd



5.4 Posted Minimum Price for Marketable Gas

OVERVIEW

The Posted Minimum Price (PMP) at a gas processing plant sets a minimum value for Reference Prices that are used to calculate royalty on gas produced at the plant. If the Producer Price for a producer at a plant is less than the PMP for the plant, the PMP must be used for royalty purposes.

The PMP is equal to 80% of an estimated average sales price for gas produced during each month. On about the 20th day of the 2nd month after the production month, the Ministry of Energy, Mines and Natural Gas calculates and publishes PMP's for five groupings of plants.

PLANT GROUPINGS

Since Producer Prices are values at the inlet of processing plants, they will vary from plant to plant because of differences in transportation and processing costs. To make the PMP test sensitive to these differences, separate PMP's are calculated for 5 groups of plants. These plant groups were defined with considerations to plant size, gas quality and market access. Each processing plant is assigned to one of the groups by Order of the Administrator. As of August 2006, the plant groups were as follows.

Plant Group	Plant Group Description	Facility Code
Group 1	Fort Nelson	0437
Group 2	McMahon	0439
Group 3	Pine River	0442
Group 4	Plants Delivering Gas to the Duke Transportation System	Various
Group 5	Plants Delivering Gas to TransCanada & Alliance Transportation Systems	Various

PMP CALCULATIONS

PMP values are 80% of estimated volume weighted average prices of all natural gas sales (domestic and export; spot, short-term and long-term, firm and interruptible) net of applicable gathering, processing, and transportation charges.

PMP values are calculated monthly using information provided by producers, aggregators, custom processors, pipeline companies, and independent publications. The Natural Gas Market Report, Inside FERC, and the Daily Oil Bulletin are examples of sources used for gas prices. Duke Energy provides cost of service data relating to the majority of gas gathered, processed and transported in the province. Several aggregators and distributors are contacted monthly to obtain current gas sales contract prices. The Administrator has set a minimum price for the PMP of $10 per 1000 cubic metres.

PMP EXEMPTIONS

The Order of the Administrator 98-3 designates certain wells as being PMP exempt. Prior to February 1, 1998, these wells received an exemption from PMP due to their high H_2S content. When the wells identified in the Order no longer produce, there will be no PMP exemptions.

USE OF THE PMP IN THE NATURAL GAS ROYALTY/TAX CALCULATION

The PMP is applied in both the determination of the royalty/tax rate and the valuation of the royalty/tax share of marketable gas. The PMP does not apply to by-products. See section 5.1 for further details of the use of the PMP in the royalty calculation.

PUBLICATION OF THE POSTED MINIMUM PRICE

The five plant group PMP values are issued by approximately the middle of the month following the production month. Notification will be made to industry by the Ministry of Energy, Mines and Natural Gas via Information Letters, which are available on our ministry website at: http://www.sbr.gov.bc.ca/business/Natural_Resources/Oil_and_gas_royalties/bulletins_PMP.htm.

5.5 Producer Cost of Service Allowance

GENERAL DESCRIPTION

Producer Cost of Service (PCOS) is an allowance for the cost of moving the Royalty/Tax Share of raw gas from the wellhead to the inlet of a gas processing plant. The PCOS allowance is intended to cover the Crown's share of costs for gathering, dehydration and compression of raw gas and in some cases processing gas that is used as fuel in these activities. It does not include processing costs for the gathered gas as these costs are included in either the Gas Cost Allowance for producer-owned plants or processing tolls at third party processing plants, which are deducted in the determination of the Producer Prices.

Prior to April 2005, PCOS rates were calculated for the following four categories:

1. Gathering and Dehydration
2. Compression
3. Field Processing
4. Conservation of Conservation Gas

Separate rates per 10^3m^3 of raw gas were periodically set for each PCOS category at each gas processing plant except for Conservation of Conservation Gas, which received the same rate for all plants.

Effective April 2005, the methodology for calculating PCOS rates was changed. PCOS rates are now calculated on an annual basis in accordance with procedures established under the PCOS Order of the Administrator 2008-01. PCOS rates are calculated for each reporting facility (rather than plant) producing Non-Conservation Gas. The PCOS rate for reporting facilities producing Conservation Gas remains at $16.00.

INDUSTRY INPUT

The primary mechanism for industry input is the BC-22 form "Application for Producer Cost of Service". The Ministry encourages all facility operators to submit this form for new facilities or whenever changes are made to equipment at an existing facility. The submission of a BC-22 for a new reporting facility will trigger the calculation of a new PCOS rate. A BC-22 submission for an existing facility will not trigger a new PCOS rate recalculation but will be included in the next annual PCOS rate recalculation. Failure to submit the BC-22 form for equipment additions will result in the value of the equipment not being included in future rate calculations.

PCOS RATES

Up-to-date PCOS rates are available on the Ministry website at:
www.sbr.gov.bc.ca/business/Natural_Resources/Oil_and_gas_royalties/Oil_and_gas_ONLINE.htm.

X-REFERENCE

Refer to BC-22 Application for Producer Cost of Service Guidelines.

5.6 Gas Cost Allowance

OVERVIEW

The Gas Cost Allowance (GCA) is a rate per 10^3m^3 of raw gas approved by the Royalty Administrator to offset the capital and operating costs associated with:

(1) processing the Crown's share of raw gas at a producer-owned gas plant, and

(2) transmission of the Crown's share of residue gas through a producer-owned sales line.

A producer-owned gas plant or sales line may be for a producer's own use, or for the use of another producer who pays to use the plant. Producers who pay a custom-processing fee to process and/or transport their gas at a producer-owned plant will only receive the approved GCA rate for that calendar period for that plant.

GCA rates are deducted from average sales values in Producer Price calculations for marketable gas at producer-owned plants. (refer to section 5.3 for further information). The approved GCA rates per 10^3m^3 of raw gas are converted to a rate per GJ of marketable gas at the average shrinkage rate and heat content for the plant.

The GCA rate flows from the application of the actual allowable capital and operating costs incurred at a processing plant against the volumes of gas processed through the plant.

ALLOWABLE EXPENDITURES

Allowable costs of a processing plant for a calendar year are the following:

(1) **Allowable direct operating costs.**

Allowable direct operating costs include an overhead allowance equal to 10% of total direct operating costs incurred during the year. Actual overhead and indirect charges are not allowed. See Schedule III in BC-23 Application for Gas Cost Allowance Guidelines for a list of allowable direct operating costs and Schedule IV in BC-23 Application for Gas Cost Allowance Guidelines for a list of expenses that are not allowable.

(2) **A provision for depreciation of allowable capital expenditures.**

The depreciation provision is equal to 5% of the undepreciated cost of depreciable assets. The undepreciated cost of depreciable assets is the net balance at the end of the previous year plus the cost of additions in the year less the net undepreciated cost of disposals in the year. See Schedule I in BC-23 Application for Gas Cost Allowance Guidelines for a list of allowable capital expenditures and Schedule II in BC-23 Application for Gas Cost Allowance Guidelines for a list of capital expenditures that are not allowable.

ALLOWABLE EXPENDITURES cont'd

(3) **A return of 15.0% on invested capital.**

Invested capital consists of:

- the average undepreciated cost of depreciable assets between the beginning and the end of the year,
- the cost of land on which the facility is located, and
- an allowance for working capital equal to 1/6 of allowable direct operating costs incurred in the year.

In determining what costs are allowable for GCA purposes it is important to distinguish between expenditures related to producing gas and delivering it to the plant (the "production function") and expenditures related to processing the gas in the plant. The production function includes extraction, gathering, field compression, field dehydration, conservation, injection and activity related to oil production. Gathering, field compression and field dehydration costs are allowed for by the Producer Cost of Service allowance (PCOS). PCOS is based on standard costs for installed equipment and does not require reporting of actual costs incurred. Inclusion of costs related to the production function for GCA purposes will result in deduction of these costs twice.

X-REFERENCE

BC-23 Application for Gas Cost Allowance Guidelines.

5.7 Natural Gas By-Products

Natural gas by-products means natural gas liquids, sulphur and substances other than marketable gas which are recovered from raw natural gas by processing or normal two phase field separation. Natural gas liquids means ethane, propane, butanes, pentanes or pentanes plus and any other condensates, or any combination of them, recovered from natural gas.

Royalty or tax is payable on natural gas by-products when they are sold. The royalty or tax share of natural gas liquids is valued at the sales value.

Where gas is processed in a plant, the sales value is the consideration received or receivable by the producer less actual costs incurred by the producer for transporting and processing the by-products from the point of production to the point of sale. By-product processing costs include the cost of stabilization and fractionation of an LPG mix into propane, butane and pentanes plus.

Costs incurred are subject to approval by the Administrator. Approved costs for sulphur include costs of storage, remelting, prilling, slating, cleaning, forming and freight to the point of sale. Costs that will not be approved are marketing fees, sales commissions, and administration costs, and any costs for processing or transportation after the point of sale.

X-REFERENCE

Specific details of the natural gas royalty calculation may be obtained by referring to section 5.1, 5.2 and 7.0.

5.8 Raw Gas Sales

A relatively small volume of natural gas is sold for consumption in the field without being processed though a gas plant.

Section 4 of the royalty regulation states that royalty and tax must be paid on the value of 'marketable gas'. Marketable gas means natural gas that is available for sale for direct consumption as a domestic, commercial or industrial fuel, or as an industrial raw material, whether it occurs naturally or results from the processing of natural gas. Raw gas that is sold in the field falls within this definition.

The determination of royalty or tax due on sales of raw gas is essentially the same as for residue gas. Volumes of raw gas sales are reported on a Marketable Gas and By-product Volumes and Values Report (BC08) for the well event that produced the raw gas for sale. The Ministry will issue a crown invoice to the producer, which calculates the royalty due on the BC08 raw gas sales volume using the royalty calculation procedures outlined in section 5.1.

5.9 Credits and Exemptions from Natural Gas Royalty/Tax

OVERVIEW

The following volumes are exempt from royalty and tax:

(1) Natural gas and natural gas by-products that, in the opinion of the royalty administrator, were lost without fault on the part of the producer and for which the producer received no compensation. In the case of gas or gas by-products that were lost, any compensation that is received for the loss, such as insurance proceeds, will be subject to royalty or tax.

(2) Natural gas or natural gas by-products used for oil and natural gas production, for drilling purposes or for injection into the formation from which they were produced.

(3) Volumes from wells meeting conditions of discontinued incentive programs.

(4) Natural gas and natural gas by-products produced from a deep discovery well event. A deep discovery well event is a gas well event that
 (a) is in a discovery well,
 (b) has a pay the top of which has a true vertical depth deeper than 4 000 metres,
 (c) is in a well that has a spud date after November 30, 2003, and,
 (d) is in a well that has a surface location at least 20 kilometres away from the surface location of any well in a recognized pool of the same formation;

DEEP WELLS

Do you drill or have an ownership interest in deep gas wells?

Do you need to know how the deep well and deep re-entry credits apply to royalties on production from gas wells?
This section provides specific information on the deep well credit, the deep re-entry credit and the deep discovery well exemption for natural gas producers. The credits and exemption are earned by drilling on both Crown and freehold lands, and may be applied against either gas royalties or freehold production taxes.

Obtaining a Credit or Exemption

The ministry determines eligibility of a well, which credits apply and the amount of the credits or exemption. Eligibility is based on the information provided by the well operator on drilling and completion reports, and on the *Notice of Suspension or Commencement of Operations* (BC11). It is important to note that the Oil and Gas Commission verifies the depths to top of pay provided on the BC11, but is not able to do so right away. Consequently, adjustments to credits may be made a few months after the initial calculation.

DEEP WELLS cont'd

The ministry allocates the deep well credits for a qualifying well between each producer having a reporting interest in the deepest deep well event, based on the information provided on the *Reporting Interest Statement* (BC12). The ministry allocates the deep re-entry credit for a deep re-entry well event based on the ownership interests in that well event provided on the BC12.

A well can qualify for both the deep well and deep re-entry credits; however, for royalty purposes, a gas well event consists of all completions in a geological zone. Consequently, if a deep re-entry well event is in the same zone as a deep well event, the deep re-entry credit will displace any unused balance of the deep well credit. A well event may qualify for the deep discovery well exemption and either the deep well or deep re-entry credit. Producers are entitled to the exemption or credit that provides the greatest benefit.

A deep well credit is deducted from royalties on production from all deep well events within the same well. Each producer's share of the credit will be based on their ownership interest in the deepest deep well event. A deep re-entry credit is deducted from royalties on production from the qualifying deep re-entry well event.

Applying the Credit to Net Royalties

When marketable gas volumes are reported on the *Marketable Gas and By-Product Allocations Report* (BC08).

The ministry subtracts enough of a credit from the net royalty payable on production from the deep well event each month to reduce the royalty payable for the well event to zero. The ministry continues to subtract portions of the credit from net royalties for the well event until the full amount of the credit has been used.

The ministry's monthly invoice to a producer will show the unused balance left in each of the producer's deep well credits and deep re-entry credits. If the unused balance of the credit for a well event is less than net royalty payable for the well event, the invoice will show the net royalty payable after deducting the unused balance.

For wells with spud dates **after** August 31, 2009, and **before** July 31, 2010, a temporary 2% gas royalty is in effect for 12 months, beginning with the month the well event began continuous production. If a well that is eligible for the 2% royalty is also eligible to receive a deep well credit, the amount of the credit that is deducted from royalties will not be the same as the amount that is deducted from the unused balance of the credit. The ministry subtracts enough of the deep well credit from the 2% net royalty on production from the deep well event to reduce the royalty payable for the well event to zero. However, the amount that is deducted from the unused balance of the credit will be that amount that would have been deducted if the 2% royalty had not been introduced.

For more information on the 2% gas royalty, please see Bulletin PNG 007, Temporary 2% Gas Royalty to Stimulate Drilling**.**

If the reporting interests in the deepest well event are changed, the ministry transfers a portion of any unused balance in the deep well credit to the purchaser based on the new reporting interests.

The sections below explain how the ministry calculates the deep well credit, the deep re-entry credit and the deep discovery well exemption.

DEEP WELL CREDIT

Effective April 1, 2014, deep gas wells are classified as either tier 1 or 2. The tier of the well depends on the type of deep gas well and the well spud date. Shallow gas wells with long horizontal segments that have a spud date on or after April 1, 2014 are classified as tier 1. All other wells that qualify or have qualified for deep well credits are classified as tier 2.

Qualifying Criteria for the Tier 1 deep well credit are as follows:

- the well is a horizontal well,
- the well has a spud date on or after April 1, 2014,
- the deepest productive well event in the well has a TVD to a completion point in the well of 1,900 metres or less, and
- the deepest productive well event in the well has a deep well depth greater than 2,500 metres.

Qualifying Criteria for the Tier 2 deep well credit are as follows for vertical wells:

- the well has a spud date on or after January 1, 2009, and
- the deepest productive well event in the well has a TVD to a completion point in the well greater than 2,500 metres.

For horizontal well, the qualifying criteria are as follows:

- the well has a spud date on or after September 1, 2009,
- the deepest productive well event in the well has a TVD to a completion point in the well greater than 1,900 metres, and
- the deepest productive well event in the well has a deep well depth greater than 2,500 metres.

Effective September 1, 2009, the Deep Well Credit Program has been changed to reflect increases in drilling costs, enhance British Columbia's competitive business climate, and encourage activity and investment. The original and modified deep well credits are explained below.

Qualifying Criteria
To earn a deep well credit, a well must be a gas well, but may not be part of a coalbed methane project. In addition, the deepest productive well event in the well is used to determine the true vertical depth (TVD).

For horizontal wells with spud dates **after** August 31, 2009, the minimum true vertical depth (TVD) to completion point (CP) to qualify for a deep well credit is reduced to 1,900 meters (from 2,300 metres for wells with spud dates **before** September 1, 2009). However, horizontal wells with spud dates **after** August 31, 2009 must also have a deep well depth greater than 2,500 metres to qualify for a deep well credit.

DEEP WELL CREDIT cont'd

A gas well event in a well with a spud date **after** August 31, 2009, will not receive a deep well credit if the well event is ultra-marginal (it may be marginal). For example, if a horizontal well event with a spud date **after** August 31, 2009 is ultra-marginal and has a TVD to top of pay and TVD to CP between 1,900 and 2,300 metres, it does not qualify as a deep well event. Well events in wells spud **before** September 1, 2009, are virtually prevented from having both the ultra-marginal and deep statuses by the depth requirements, i.e. ultra-marginal well events must have TVD to top of pay less than 2,500 metres in vertical wells or 2,300 metres in horizontal wells, and deep well events must have TVD to CP greater than 2,500 metres in vertical wells or 2,300 metres in horizontal wells.

A well event is given deep status at the time the BC11 is recorded; this is normally done before production is recorded for that well event. Under current processing rules, determination of ultra-marginal status is done after the first 12 months of production. If a well event is found to be ultra-marginal, the ultra-marginal reduction is given on amended invoices dating to the first production month and the deep credit is reversed on the amended invoices.

Spud date on, or after, January 1, 2009
For wells with spud dates **on or after, January 1, 2009 (but before September 1, 2009)**, the eligibility for deep well credits is based on the true vertical depth (TVD) to a completion point in the well. TVD to the completion point is the distance from the completion point to a point directly above the completion point that is at the same elevation as the kelly bushing used in drilling the well. The completion point depends on the type of well, as follows.

- For vertical wells with open hole completions, the completion point is the bottom of the casing.
- For vertical wells that do not have open hole completions, the completion point is the bottom of the deepest perforations in the casing.
- For horizontal wells, the completion point is the point in the well bore at which the angle of the well bore first exceeds 80 degrees from vertical.

Horizontal wells are wells with a wellbore that is:

- drilled at an angle of at least 80 degrees from the vertical, where the angle is measured for a line connecting the wellbore's initial point of penetration into a productive zone to the end point in that zone, and
- at least 100 metres in length from point of penetration into the productive zone to the end point in that zone.

A vertical well is any well, including a directional well, that **does not** qualify as a horizontal well.

DEEP WELL CREDIT cont'd

Producers qualify for the deep well credit if the well meets the following qualifying criteria:

- the well has a spud date on, or after, January 1, 2009, and
- the deepest productive well event in the well has a TVD to a completion point in the well greater than:
- 2,500 metres if it is in a vertical well, and
- 2,300 metres if it is in a horizontal well.

The ministry obtains TVD to completion point information from drilling and completion data that is provided by the industry to the Oil and Gas Commission.

Spud date before January 1, 2009
For wells with spud dates **before January 1, 2009,** the eligibility for deep well credits continues to be based on TVD to top of pay. The ministry will continue to obtain TVD to top of pay information from well operators for these wells from the *Notice of Commencement or Suspension of Operations* (BC11).

Producers qualify for the deep well credit if the well meets the following qualifying criteria:

- the well has a spud date **after June 30, 2003**,
- if the well has a spud date **after June 30, 2003 and before December 1, 2003**, for both vertical and horizontal wells, the deepest productive well event in the well has a true vertical depth (TVD) to the top of pay of at least 2,500 metres, and
- if the well has a spud date **after November 30, 2003**, the deepest productive well event in the well has a TVD to the top of pay greater than:
- 2,500 metres for vertical wells, and
- 2,300 metres for horizontal wells.

TVD to the top of pay is the distance between the point of intersection of the wellbore with the top of the well event's pay and a point directly above the point of intersection that is at the same elevation as the kelly bushing used in drilling the well. The pay is the part of the producing zone where there is sufficient gas, pressure and permeability to justify commercial production.

Calculating the Credit
The value of the tier1 deep well credit is designed to reflect higher drilling and completion costs for shallow wells with long horizontal segments. The ministry calculates the credit amount using Table 3 below and the appropriate formula.

The value of tier 2 deep well credit is designed to reflect higher drilling and completion costs that relate to factors, such as bottom hole location, the hydrogen sulphide (H_2S) content and the depth of the well. The ministry categorizes the well type, determines which of the four deep well credit tables apply and then calculates the credit amount using the appropriate formula. Each of these steps are explained further in the sections and in the examples provided below.

DEEP WELL CREDIT cont'd

Well Type
There are two variables for determining the well type:

1. bottom hole location
2. H_2S content

Bottom hole location (east or west)
To recognize the higher costs associated with drilling in specific underdeveloped areas of the province, there are two bottom hole location categories: east and west.

Schedule 1 describes the locations within the east area for wells with spud dates **before January 1, 2009**. Schedule 1b describes the locations within the east area for wells with spud dates **on, or after January 1, 2009**. Locations that are not on these schedules are considered to be in the west areas. Figure 1 is a map of the east/west lines for wells with spud dates **before January 1, 2009** and **on or after January 1, 2009**.

H_2S content (special sour or sweet)
To recognize the higher costs associated with sour gas, there are two categories based on H_2S content: special sour and sweet. Deep wells classified as special sour are eligible for a greater credit than wells classified as sweet.

For a well to be classified as special sour, it must meet the required distance from an urban centre and the corresponding maximum potential H_2S release rate as outlined below.

Distance from the Well to the Corporate Boundaries of an Urban Centre	Maximum Potential H_2S Release Rate From the Well
Within 500 metres	0.01 m^3/s or greater and less than 0.1 m^3/s
Within 1.5 kilometres	0.1 m^3/s or greater and less than 0.3 m^3/s
Within 5 kilometres	0.3 m^3/s or greater and less than 2.0 m^3/s
5 kilometres or greater	2.0 m^3/s or greater

All deep wells that do not meet the above criteria are classified as sweet.

Deep Well Credit Tables
Based on the well type, the ministry determines which of the tables below to use for calculating the credit. Wells with spud dates after August 31, 2009 receive a credit that is 15% higher than wells with spud dates on or before August 31, 2009. The higher credit is reflected in the Cumulative and Incremental Value columns in Tables 1 and 2 below.

DEEP WELL CREDIT cont'd

Table 1

(For qualifying wells with spud dates on, or before, August 31, 2009)

West Special Sour			East Special Sour		
Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)	Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)
2500	0	4200	2500	0	1500
3000	2100	600	3000	750	650
3500	2400	700	3500	1075	750
4000	2750	800	4000	1450	850
4500	3150	900	4500	1875	1000
5000	3600	1000	5000	2375	1100
5500	4100		5500	2925	
West Sweet			**East Sweet**		
Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)	Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)
2500	0	3800	2500	0	1400
3000	1900	550	3000	700	600
3500	2175	600	3500	1000	700
4000	2475	700	4000	1350	800
4500	2825	800	4500	1750	900
5000	3225	900	5000	2200	1000
5500	3675		5500	2700	

DEEP WELL CREDIT cont'd

Table 2
(For qualifying wells with spud dates after August 31, 2009)

West Special Sour			**East Special Sour**		
Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)	Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)
2500	0	4830	2500	0	1725
3000	2415	690	3000	863	748
3500	2760	805	3500	1236	863
4000	3163	920	4000	1668	978
4500	3623	1035	4500	2156	1150
5000	4140	1150	5000	2731	1265
5500	4715		5500	3364	
West Sweet			**East Sweet**		
Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)	Table Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)
2500	0	4370	2500	0	1610
3000	2185	633	3000	805	690
3500	2501	690	3500	1150	805
4000	2846	805	4000	1553	920
4500	3249	920	4500	2013	1035
5000	3709	1035	5000	2530	1150
5500	4226		5500	3105	

DEEP WELL CREDIT cont'd

Table 3

(For **qualifying Tier 1** wells with spud dates after March 31, 2014)

Deep Well Depth (Metres)	Cumulative Value ($000)	Incremental Value ($/Metre)
2500	445	430
3000	660	720
3500	1020	980
4000	1510	1 006
4500	2013	974
5000	2500	622
5500	2811	

The Formula

Based on one of the tables above, the ministry calculates a producer's deep well credit for a qualifying well as follows:

[cumulative value + incremental value X (deep well depth of the deepest well event – table depth)] x producer's share

Deep well depth on, or after, January 1, 2009

For well events in wells with spud dates **on or after, January 1, 2009**, deep well depth is calculated in the following ways.

- In a vertical well, deep well depth is the measured depth to the completion point (MDCP). For a well event that is in a vertical well and is **not** an open hole completion, this is the distance along the well bore from the kelly bushing of the rig used to drill the well to the bottom of the deepest perforation in the well event. For a well event that is in a vertical well and **is** an open hole completion, this is the distance along the well bore to the bottom of the casing.
- In a horizontal well, deep well depth is MDCP plus the horizontal length factor (HLF) multiplied by the positive difference between total measured depth and MDCP, as follows:

MDCP + [HLF X (total measured depth – MDCP)]

DEEP WELL CREDIT cont'd

The HLF is calculated as follows:

- for a well event in a well that has a spud date on or before August 31, 2009, and a MDCP of between 2,300 metres and 2,875 metres, the HLF is:

  [60 – 0.035 x (MDCP – 2,300)]/100

- for a well event in a well that has a spud date after August 31, 2009, and a MDCP equal to or less than 2,875 metres, the HLF is the lesser of:
  - 1, or
  - [60-0.035 x (MDCP – 2,300)]/100

For a well event with a MDCP deeper than 2,875 metres, the HLF is 0.4.

This formula will give a result that is greater than .6 for well events with spud dates after August 31, 2009 and MDCP less than 2,300 metres. For example, if MDCP is 1,900 meters, the horizontal length factor is .74. For well events with spud dates on or before August 31, 2009, the horizontal length factor cannot be more than .6 because MDCP may not be less than 2,300 metres.

The ministry obtains MDCP information from drilling and completion data provided by the industry to the Oil and Gas Commission.

Deep well depth before January 1, 2009
For well events in wells with a spud date **after June 30, 2003 and before December 1, 2003**, the deep well depth is the TVD to the top of pay of the well event.

For well events in vertical wells with a spud date **on or after, December 1, 2003**, the deep well depth is the measured depth to top of pay (MDTP). MDTP is the distance along the wellbore from the intersection with the top of the pay of the well event to the kelly bushing used in drilling the well.

For well events in horizontal wells with a spud date on or after, December 1, 2003, the deep well depth is MDTP plus the horizontal length factor (HLF) multiplied by the positive difference between total measured depth and MDTP, as follows:

MDTP + [HLF X (total measured depth – MDTP)]

The HLF is calculated as follows:

- for well events with MDTP greater than 2,300 metres and less than 2,875 metres, the HLF is:

  [30 - .035 X (MDTP - 2,300)] / 100, and

- for well events with MDTP greater than 2,875 metres, the HLF is 0.1.

DEEP WELL CREDIT cont'd

Table depth
The table depth for a well is the deep well depth of the deepest well event rounded down to the nearest 500 metres. For example, if the deepest well event has a deep well depth of 3,785 metres, the table depth is 3,500. Possible table depths are listed in the tables above.

Cumulative value
The cumulative value for a well is the amount in the cumulative value column and the same row as the table depth for the well in the appropriate table above. For example, for a west special sour well with a spud date on, or before, August 31, 2009, in which the deep well depth of the deepest well event is 3,785 metres, the cumulative value is $2,400,000, as shown in the 3,500 metre row of the West Special Sour table in Table 1 above.

Incremental value
The incremental value for a well is the amount in the incremental value column and the same row as the table depth for the well in the appropriate table above. It is the additional credit per metre of depth in excess of the table depth. For example, for a west special sour well with a spud date on, or before, August 31, 2009, in which the deep well depth of the deepest well event is 3,785 metres, the incremental value is $700 per metre, as in the 3,500 metre row of the West Special Sour in Table 1 above.

Producer's share
The producer's share is the producer's proportionate interest in the deepest well event in that well. If there is more than one producer with an ownership interest in production from the deepest well event, each producer will be allocated a portion of the deep well credit based on their ownership share.

DEEP WELL CREDIT cont'd

Example 1

Spud date:	November 2007
Type of well:	vertical
H_2S content:	special sour
Location:	west
MDTP:	3,785 metres
Producer's share:	producer A owns 60% and producer B owns 40%

The deep well credit is calculated using the West Special Sour in Table 1 above. Each value and the amount of the deep well credit are determined as follows:

Deep well depth	= the MDTP (vertical well) = 3,785 metres
Table depth	= deep well depth rounded down to the nearest 500 metres = 3,500 metres
Cumulative value	= amount in 3,500 row = $2,400,000
Incremental value	= amount in 3,500 row = $700 per metre
Deep well credit	= cumulative value + [incremental value x (deep well depth – table depth)] = $2,400,000 + [$700 X (3,785 – 3,500)] **= $2,599,500**
Producer A	= $2,599,500 X 60% **= $1,599,700**
Producer B	= $2,599,500 X 40% **= $1,039,800**

Example 2

Spud date:	November 2007
Type of well:	horizontal
H_2S content:	sweet
Location:	east
MDTP:	2,655 metres
Total measured depth:	2,910 metres
Producer's share:	producer A owns 50% and producer B owns 50%

DEEP WELL CREDIT cont'd

The deep well credit is calculated using the East Sweet table in Table 1 above. Each value and the amount of the deep well credit are determined as follows:

Horizontal length factor (HLF)	= [30 - 0.035 X (MDTP – 2,300)] / 100 = [30 - 0.035 X (2,655 – 2,300)] / 100 = 0.17575
Deep well depth	= MDTP + [HLF X (total measured depth - MDTP)] = 2,655 + [0.17575 X (2,910 - 2,655)] = 2,699 metres
Table depth	= deep well depth rounded down to the nearest 500 metres = 2,500 metres
Cumulative value	= amount in 2,500 row = $0
Incremental value	= amount in 2,500 row = $1,400 per metre
Deep well credit	= cumulative value + [incremental value X (deep well depth - table depth)] = $0 + [$1,400 X (2,699 – 2,500)] = **$278,600**
Producer A	= $278,600 X 50% = **$139,300**
Producer B	= $278,600 X 50% = **$139,300**

Deep Re-Entry Credit
The deep re-entry credit was introduced to maximize the development of known resources by encouraging producers to re-enter previously drilled wells and drill deeper.

Qualifying Criteria
For well events in wells with spud dates **on or after January 1, 2009**, top of pay is replaced by the completion point in the well event. All other criteria for the credit remain the same, except that well events that are eligible for the deep re-entry credit may not be part of a coalbed methane project.

DEEP WELL CREDIT cont'd

Producers qualify for the deep re-entry credit if the well event meets all of the following qualifying criteria:

- the well has a re-entry date after November 30, 2003,
- an application to alter the well has been submitted and approved before re-entry,
- if the well has a spud date before January 1, 2009, the TVD to the top of pay of the re-entry well event is greater than 2,300 metres, and
- if the well has a spud date on, or after, January 1, 2009, the TVD to the completion point of the re-entry well event is greater than 2,300 metres.

Calculating the Credit

The value of the deep re-entry credit is designed to reflect higher drilling and completion costs related to the location of the well and the additional amount of drilling that is done (incremental drilled distance).

The ministry determines a deep re-entry credit for each deep re-entry well event using the values in one of the two tables below and the incremental drilled distance.

Bottom hole location (east or west)

Similar to the deep well credit, there are two bottom hole location categories: east and west. The east and west areas for deep re-entry credits are the same as the areas used for deep well credits. Schedule 1 describes locations in the east area for re-entries with re-entry dates **before January 1, 2009**. Schedule 1b describes locations within the east area for re-entries with a re-entry date **on or after January 1, 2009.** Locations that are not on these schedules are considered to be in the west area. Figure 1 is a map of the lines between the east and west areas for re-entries.

Deep Re-entry Credit Tables

West			**East**		
Table Distance (metres)	Cumulative Value ($)	Incremental Value ($/Metre)	Table Distance (metres)	Cumulative Value ($)	Incremental Value ($/Metre)
100	0	750	100	0	450
300	150,000	500	300	90,000	300
1,500	750,000		1,500	450,000	

DEEP WELL CREDIT cont'd

The Formula

Based on the two tables above, the ministry calculates the deep re-entry credit using the following formula.

[cumulative value + incremental value x (incremental drilled distance – table distance)] x producer's share

Incremental drilled distance

This is the difference between the total measured depth (TMD) of the well after the well has been altered and the TMD before the well was altered. The TMD is the sum of the lengths of all the vertical and horizontal wellbores in the well.

Table distance

The table distance for a deep re-entry well event is the incremental drilled distance rounded down to the nearest value in the table distance column in the appropriate table above. For example, if a re-entered well had a TMD of 5,000 metres before alteration and 5,450 metres after alteration, the incremental drilled distance would be 450 metres and the table distance would be 300 metres.

Cumulative value

The cumulative value for a deep re-entry well event is in the cumulative value column and the same row as the table distance for the well event in the appropriate table above. For example, for a deep re-entry well event in the west with a table distance of 300 metres, the cumulative value is $150,000, as shown in the 300 metre row of the West table above.

Incremental value

The incremental value for a deep re-entry well event is the value in the incremental value column and the same row as the table distance for the well event in the appropriate table above. It is the additional credit per metre of incremental distance in excess of the table distance. For example, for a deep re-entry well event in the west with an incremental distance of 450 metres, the incremental value is $500 per metre, as in the 300 metre row of the West table above.

Producer's share

This is the producer's proportionate interest in the deep re-entry well event. If there is more than one producer with an ownership interest in production from the well event, each producer will be allocated a portion of the deep re-entry credit based on their ownership share.

DEEP WELL CREDIT cont'd

Example

Re-entry date:	November 2007
Location:	east
TMD before alteration:	1,800 metres
TMD after alteration:	2,900 metres
Producer's share:	producer A owns 60% and producer B owns 40%

The deep re-entry credit is calculated using the East table above. Each value and the amount of the deep re-entry credit are determined as follows:

Incremental distance	= 2,900 – 1,800 = 1,100 metres
Table distance	= the incremental distance rounded down to the nearest amount in the table distance column = 300 metres
Cumulative value	= amount in 300 row = $90,000
Incremental value	= amount in 300 row = $300 per metre
Deep re-entry credit	= cumulative value + [incremental value x (incremental distance – table distance)] = $90,000 + [$300 X (1,100 – 300)] **= $330,000**
Producer A	= $330,000 X 60% = **$198,000**
Producer B	= $330,000 X 40% = **$132,000**

Deep Discovery Well Exemption

The deep discovery well exemption was introduced to stimulate growth in areas that are beyond existing infrastructure and to provide additional relief for extremely high risk drilling.

DEEP WELL CREDIT cont'd

Qualifying Criteria

For well events in wells with spud dates **on or after January 1, 2009**, top of pay is replaced by the completion point in the well event.

All other criteria for the exemption remain the same, except that well events that are eligible for the exemption may not be part of a coalbed methane project.

Producers are eligible for the deep discovery well exemption for a well event that meets all of the following criteria:

- the well event discovers a new gas pool,
- the spud date is after November 30, 2003,
- if it is in a well with a spud date before January 1, 2009, the well event has a TVD to the top of the pay that is deeper than 4,000 metres,
- if it is in a well with a spud date on, or after, January 1, 2009, the well event has a TVD to the completion point that is deeper than 4,000 metres, and
- the surface location of the well is at least 20 kilometres away from the surface location of any well in a recognized pool of the same formation.

The Oil and Gas Commission will determine if a well event discovers a new gas pool and will provide the producer with written notification that the well event qualifies for the deep discovery well exemption.

Calculating the Exemption

Natural gas produced from a deep discovery well event is exempt from payment of royalties for the first 36 producing months or 283,000,000 m^3 of raw gas, whichever comes first.

The ministry's monthly royalty invoices will include a statement showing the number of months at zero royalty and the royalty exempt gas totals.

If a deep discovery well event also qualifies for a deep well credit or a deep re-entry credit, producers are entitled to the exemption or credit, whichever one provides the greatest benefit. To ensure maximum benefit, the ministry calculates the value of the exemption each month and the cumulative value. When the end of the 36-month exemption or the maximum exempt volume has been reached, the ministry compares the cumulative value to the deep well credit or deep re-entry credit. If the deep well credit or deep re-entry credit is greater, the additional amount will be deducted from future royalties.

Schedule 1

East Area for Wells with Spud Dates Before January 1, 2009

For the purposes of determining which table to use for bottom hole location, well events in any of the following locations are in the East. Areas in subparagraphs (i) to (xvi) are described in accordance with the petroleum and natural gas grid established under the Petroleum and Natural Gas Grid Regulation, BC Reg. 321/93. Areas in subparagraph (xvii) to (xxi) are described in accordance with the Dominion Land Survey System.

(i) The portion of Group 095-A-01 to Group 095-A-04 (inclusive) that is located within British Columbia
(ii) The portion of Group 095-B-01 to Group 095-B-04 (inclusive) that is located within British Columbia
(iii) Group 094-O-01 to Group 094-O-16 (inclusive)
(iv) Group 094-P-01 to Group 094-P-16 (inclusive)
(v) Group 094-I-01 to Group 094-I-16 (inclusive)
(vi) Group 094-J-01 to Group 094-J-16 (inclusive)
(vii) Group 094-G-01 to Group 094-G-16 (inclusive)
(viii) Group 094-H-01 to Group 094-H-16 (inclusive)
(ix) The portion of Group 094-A-01 to Group 094-A-16 (inclusive) that is located outside the Peace River Block
(x) The portion of Group 093-P-09 that is located outside the Peace River Block
(xi) The portion of Group 093-P-10 that is located outside the Peace River Block
(xii) Groups 093-P-01, 093-P-02, 093-P-07 and 093-P-08
(xiii) Group 093-I-16
(xiv) Blocks A and G to K of Group 093-I-15
(xv) Blocks A, B and F to K of Group 093-I-09
(xvi) Block I of Group 093-I-08
(xvii) The portion of the Peace River Block within Township 076 east of Range 20 W6M that is within British Columbia
(xviii) The portion of the Peace River Block within Township 077 east of Range 20 W6M that is within British Columbia
(xix) The portion of the Peace River Block within Township 078 east of Range 20 W6M that is within British Columbia
(xx) The portion of the Peace River Block within Township 079 east of Range 20 W6M that is within British Columbia
(xxi) The portion of the Peace River Block within Township 080 to Township 088 and Range 13 to Range 26 W6M that is within British Columbia

For all other well events located in British Columbia, the West tables apply.

Schedule 1b
East Area for Wells with Spud Dates on, or After, January 1, 2009

East deep well and deep re-entry credit tables apply to well events that have spud dates on, or after, January 1, 2009, and are located in any of the areas listed below. The areas referred to in (i) to (xxxvi) and (lxiv) to (lxxiii) are described in accordance with the National Topographical Survey. The areas referred to in (xxxvii) to (lxiii), are described in accordance with the Dominion Land Survey System.

(i) The portion of Group 095-A-01 to Group 095-A-04 (inclusive) that is located within British Columbia
(ii) The portion of Group 095-B-01 to Group 095-B-04 (inclusive) that is located within British Columbia
(iii) The portion of Group 095-C-01 that is located within British Columbia
(iv) Group 094-P-01 to Group 094-P-16 (inclusive)
(v) Group 094-O-01 to Group 094-O-3 (inclusive)
(vi) Blocks A to C, Units 1-7 and 11-100 of Block D, and Blocks E to L of Group 094-O-04
(vii) Group 094-O-05 to Group 094-O-16 (inclusive)
(viii) Units 11-100 of Block A, Units 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block B, Units 71-77, 81-87, 91-97 of Block E, Units 71-100 of Block F, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-100 of Block G, Blocks H to K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-N-01
(ix) Units 71-77, 81-87, 91-97 of Block G, Units 71-100 of Block H, Block I, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block J of Group 094-N-07
(x) Blocks A to C (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-100 of Block E, Blocks F to L (inclusive) of Group 094-N-08
(xi) Blocks A-D, Units 1-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block E, Blocks F-K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-N-09
(xii) Block A, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block B, Units 1-7, 11-17, 21-27 of Block G, Units 1-30 of Block H of Group 094-N-10
(xiii) Block A, Units 1-73, 81-83, 91-93 of Block B, Units 1-70 of Block C, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67 of Block D, Units 1-3, 11-13, 21-23, 31-33, 41-43, 51-53, 61-63, 71-73, 81-83, 91-93 of Block G, Block H and I, Units 1-3, 11-13, 21-23, 31-33, 41-43, 51-53, 61-63, 71-73, 81-83, 91-93 of Block J of Group 094-N-16
(xiv) Group 094-J-01 to Group 094-J-03 (inclusive)
(xv) Blocks A to C (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block E, Blocks F to K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-J-04
(xvi) Blocks A to C (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block E, Blocks F to K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-J-05
(xvii) Group 094-J-06 to 094-J-11 (inclusive)

(xviii) Blocks A to C (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block E, Blocks F to K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-J-12

(xix) Blocks A to C (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block E, Blocks F to K (inclusive), Units 1-7, 11-17, 21-27, 31-37, 41-47, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-J-13

(xx) Group 094-J-14 to Group 094-J-16 (inclusive)

(xxi) Group 094-I-01 to Group 094-I-16 (inclusive)

(xxii) Group 094-H-01 to Group 094-H-16 (inclusive)

(xxiii) Block A, Units 1-3, 11-13, 21-23, 31-37, 41-47, 51-57, 61-67, 71-100 of Block B, Units 71, 81, 91 of Block C, Unit 91 of Block E, Units 1, 11-15, 21-25, 31-35, 41-45, 51-59, 61-69, 71-79, 81-89, 91-100 of Block F, Blocks G to K (inclusive), Units 1, 11, 21, 31-33, 41-43, 51-55, 61-65, 71-75, 81-85, 91-97 of Block L of Group 094-G-01

(xxiv) Units 31, 41, 51-53, 61-63, 71-73, 81-83, 91-95 of Block A, Units 51, 61, 71-73, 81-83, 91-95 of Block G, Units 1-5, 11-17, 21-27, 31-39, 41-49, 51-100 of Block H, Block I, Units 1-5, 11-15, 21-25, 31-37, 41-47, 51-59, 61-69, 71-79, 81-89, 91-100 of Block J, Unit 91 of Block K of Group 094-G-07

(xxv) Block A to Block C (inclusive), Units 1-7, 11-19, 21-29, 31-100 of Block D, Blocks E to L of Group 094-G-08

(xxvi) Group 094-G-09

(xxvii) Block A and B, Units 1, 11-13, 21-23, 31-33, 41-43, 51-55, 61-65, 71-77, 81-87, 91-100 of Block C, Unit 91 of Block D, Units 1, 11-13, 21-23, 31-37, 41-47, 51-100 of Block E, Blocks F to L (inclusive) of Group 094-G-10

(xxviii) Units 51, 61, 71-75, 81-85, 91-99 of Block H, Units 1-9, 11-100 of Block I, Units 11-13, 21-23, 31-37, 41-47, 51-100 of Block J, Units 51, 61, 71-73, 81-83, 91-97 of Block K of Group 094-G-11

(xxix) Units 71-73, 81-83, 91-97 of Block A, Units 71, 81, 91-95 of Block F, Units 31-35, 41-45, 51-59, 61-69, 71-100 of Block G, Units 1-7, 11-19, 21-29, 31-100 of Block H, Blocks I and J, Units 1-5, 11-19, 21-29, 31-100 of Block K, Units 31-33, 41-43, 51-57, 61-67, 71-77, 81-87, 91-97 of Block L of Group 094-G-13

(xxx) Blocks A and B, Units 1-7, 11-100 of Block C, Units 11, 21, 31-33, 41-43, 51-59, 61-69, 71-100 of Block D, Blocks E to L (inclusive) of Group 094-G-14

(xxxi) Group 094-G-15 and Group 094-G-16

(xxxii) Unit 91 of Block H, Units 1, 11-13, 21-23, 31-37, 41-47, 51-57, 61-67, 71-79, 81-89, 91-100 of Block I, Units 91-93 of Block J of Group 094-B-16

(xxxiii) The portion of Group 094-A-09 to Group 094-A-11 that is located outside the Peace River Block

(xxxiv) The portion of Block I, Units 1, 11-15, 21-25, 31-35, 41-45, 51-57, 61-67, 71-100 of Block J, Units 71, 81, 91 of Block K of Group 094-A-12 that is located outside the Peace River Block

(xxxv) Blocks A and B, Units 1, 11-13, 21-23, 31-35, 41-45, 51-55, 61-65, 71-77, 81-87, 91-99 of Block C, Units 11-13, 21-23, 31-35, 41-45, 51-57, 61-67, 71-79, 81-89, 91-100 of Block E, Units 1-9, 11-100 of Block F, Blocks G to L (inclusive) of Group 094-A-13

(xxxvi) Group 094-A-14 to Group 094-A-16 (inclusive)

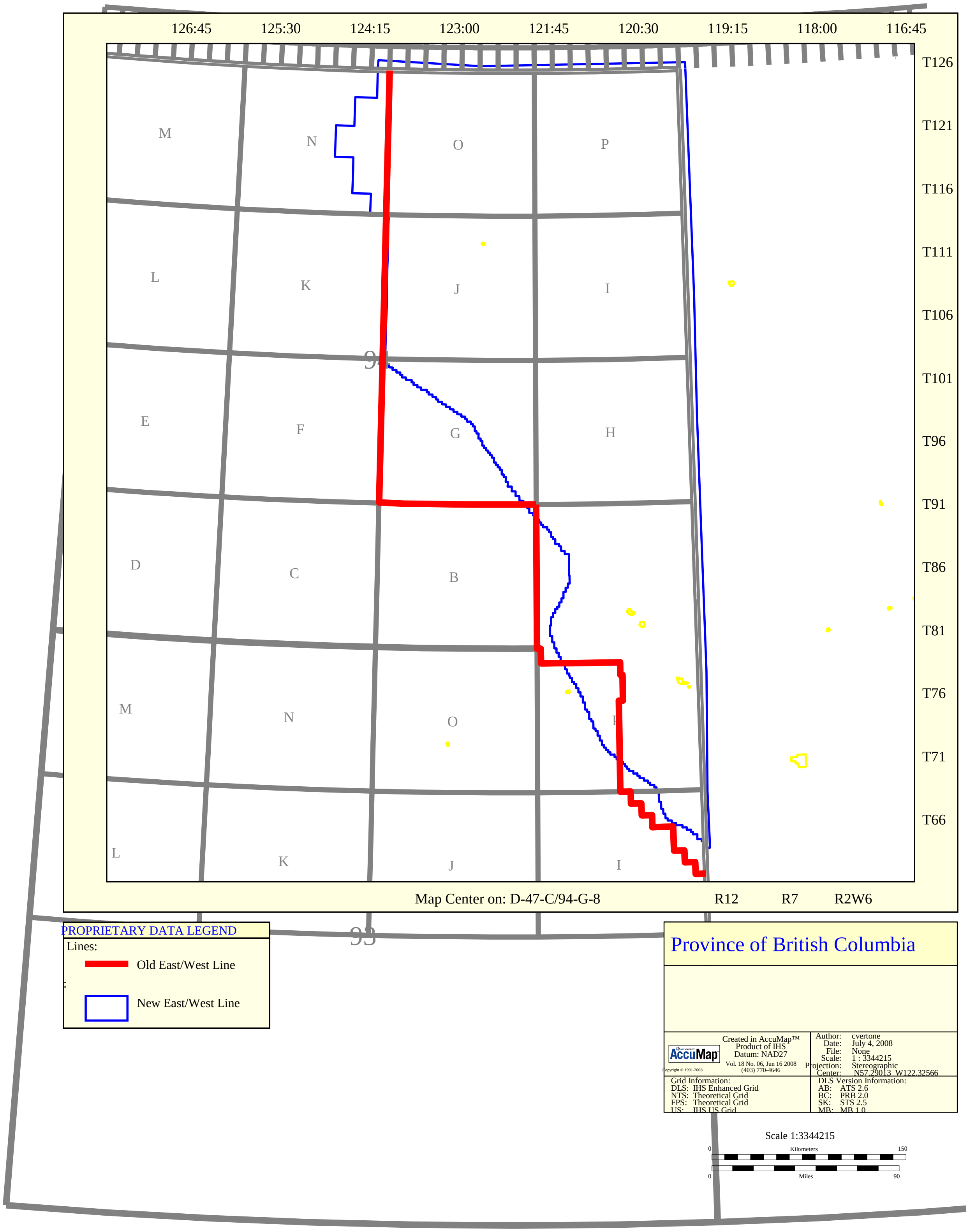
(xxxvii) The portion of the Peace River Block within Sections 1-3, 10-15, 22-29, 2-36 of Township 88 Range 23 W6M

(xxxviii) The portion of the Peace River Block with Township 88 east of Range 23 W6M within British Columbia
(xxxix) Sections 1-3, 10-15, 22-27, 34-36 of Township 87 Range 23 W6M
(xl) Township 87 east of Range 23 W6M within British Columbia
(xli) Sections 1-5, 8-16, 21-28, 33-36 of Township 86 Range 23 W6M
(xlii) Township 86 east of Range 23 W6M within British Columbia
(xliii) Sections 1, 2, 12, 13, 24 of Township 85 Range 24 W6M
(xliv) Township 85 east of Range 24 W6M within British Columbia
(xlv) Sections 1-5, 8-16, 22-27, 35, 36 of Township 84 Range 24 W6M
(xlvi) Township 84 east of Range 24 W6M within British Columbia
(xlvii) Sections 1, 12, 13, 24 of Township 83 Range 25 W6M
(xlviii) Township 83 east of Range 25 W6M within British Columbia
(xlix) Sections 1, 2, 10-15, 22-27, 34-36 of Township 82 Range 25 W6M
(l) Township 82 east of Range 25 W6M within British Columbia
(li) Sections 12, 13, 24-26, 35, 36 of Township 81 Range 25 W6M
(lii) Township 81 east of Range 25 W6M within British Columbia
(liii) Sections 1-3, 9-16, 20-29, 31-36 of Township 80 Range 24 W6M
(liv) Township 80 east of Range 24 W6M within British Columbia
(lv) Sections 12, 13, 23-26, 34-36 of Township 79 Range 24 W6M
(lvi) Township 79 east of Range 24 W6M within British Columbia
(lvii) Section 36 of Township 78 Range 24 W6M
(lviii) Sections 1-4, 9-17, 19-36 of Township 78 Range 23 W6M
(lix) Township 78 east of Range 23 W6M within British Columbia
(lx) Sections 1, 12-14, 23-27, 34-36 of Township 77 Range 23 W6M
(lxi) Township 77 east of Range 23 W6M within British Columbia
(lxii) The portion of the Peace River Block within Section 36 of Township 76 Range 23 W6M
(lxiii) The portion of the Peace River Block within Township 76 east of Range 23 W6M within British Columbia
(lxiv) Group 093-P-01
(lxv) Units 1-5, 11-15, 21-25, 31-37, 41-47, 51-100 of Block A, Units 51, 61,71-73, 81-83, 91-97 of Block B, Units 71, 81, 91-93 of Block E, Units 11, 21, 31-33, 41-43, 51-57, 61-67, 71-100 of Block F, Units 1-7, 11-100 of Block G, Blocks H to K (inclusive), Units 1-3, 11-15, 21-25, 31-37, 41-47, 51-100 of Block L of Group 093-P-02
(lxvi) Units 51, 61, 71-73, 81-83, 91-95 of Block I of Group 093-P-03
(lxvii) Units 1-5, 11-19, 21-29, 31-100 of Block A, Units 31, 41, 51-53, 61-63, 71-75, 81-85, 91-97 of Block B, Units 71, 81, 91 of Block F, Units 1-7, 11-17, 21-27, 31-39, 41-49, 51-59, 61-69, 71-100 of Block G, Blocks H to J (inclusive), Units 1, 11-13, 21-23, 31-35, 41-45, 51-55, 61-65, 71-75, 81-85, 91-97 of Block K of Group 093-P-06
(lxviii) Group 093-P-07 and Group 093-P-08
(lxix) The portion of Group 093-P-09 and Group 093-P-10 that is located outside of the Peace River Block
(lxx) The portion of Blocks A, B, Units 1-7, 11-19, 21-29, 31-39, 41-49, 51-59, 61-69, 71-100 of Block C, Units 71, 81, 91-93 of Block D, Units 1-3, 11-13, 21-23, 31-33, 41-43, 51-55 of Block E, Blocks F to H (inclusive) of Group 093-P-11 that is located outside of the Peace River Block
(lxxi) Units 51, 61, 71-73, 81-83, 91-97 of Block H, Units 1-7, 11-17, 21-27, 31-100 of Block I, Units 31, 41, 51-53, 61-63, 71-77, 81-87, 91-100 of Block J, Unit 91 of Block K of Group 093-I-09

(lxxii) Units 51, 61, 71, 81, 91 of Block H, Units 1, 11-13, 21-23, 31-33, 41-43, 51-53, 61-63, 71-73, 81-83, 91-95 of Block I of Group 093-I-15

(lxxiii) Blocks A, B, Units 1, 11-17, 21-27, 31-100 of Block C, Units 31, 41, 51-55, 61-65, 71-77, 81-87, 91-97 of Block D, Units 1-7, 11-19, 21-29, 31-39, 41-49, 51-100 of Block E, and Blocks F to L (inclusive) of Group 093-I-16

Figure 1: Old and New East/West Lines



5.10 Minimum Natural Gas Royalty Program (for production periods after March 2013)

*For minimum royalty invoice sample go to Sample 7.1(3a)
*For minimum royalty deep deduction sample go to Sample 7.1(6a)

On the monthly royalty invoice, the minimum royalty is calculated separately from the calculation of natural gas and by-product royalties. The minimum royalty amount will not be taken from the deep well credit bank in that production month, thereby lengthening the time the deep well credit bank is drawn down. The minimum royalty is based on gross revenues for royalty purposes and is computed as follows:

Minimum Royalty Formula = [Gross Revenue] x Minimum Royalty Rate
= [(Marketable Gas Volume x Reference Price) + (Natural Gas Liquids Sales Value*) + (Sulphur Sales Value*)] x Minimum Royalty Rate

Sales Value from the BC08

Example 1: Deep Well Credit Bank is Greater than Gross Royalty Less PCOS; *the 3% minimum royalty applies in this example as the net royalty calculation would have equaled zero ,Tier 2 well*

Opening Deep Credit Balance (A):	$444,265.57
Gross Royalty owed less PCOS (B):	$25,252.00
Marketable Gas Volume:	887.0 10^3m^3
Natural Gas Reference Price:	$110.41 /$10^3m^3$
Natural Gas Liquids Sales Value:	$11,812.40
Sulphur Sales Value:	$0.00

Using the example values above the first step is to determine if the net royalty payable would have been equal to zero.

Determine if Net Royalty would have equalled zero = (Gross Royalty less PCOS) – (Available Credits to Bring Royalties to zero)
= $25,252.00 - $25,252.00
= $0

Since the net royalty calculation would have equalled zero, the 3% Minimum Royalty Program applies. The second step is to determine the 3% minimum royalty payable. This is done by calculating the gross revenue using the example's sales volumes and reference prices, then multiplying the gross revenue by 3%.

3% Minimum Royalty Calculation = [(887.0 x $110.41) + $11,812.40 + $0.00] x 3%
= [$97,930.12 + $11,812.40 + $0.00] x 3%
= $109,742.52 x 3%
= $3,292.28 (C)

In summary, the 3% minimum royalty (C) is payable. The resulting closing deep well credit bank balance (D) is then available to be deducted against gross royalties payable in future production months either in part with the 3% minimum royalty calculation or deducted in full in the last production month in which the deep well credit bank is extinguished.

Cont'd

Deep Well Credit Bank Monthly Transaction

Opening Deep Well Credit Balance	Gross Royalty less PCOS	3% Minimum Royalty	Closing Deep Well Credit Balance	Total Deep Well Credits Used
$444,265.57	$25,252.00	$3,292.28	$422,305.85	$21,959.72
A -	B +	C =	D	

Example 2: Production period 2014/04, Tier 1 well

Deep Well Credit Bank is Greater than Gross Royalty Less PCOS <u>and</u> the Calculated 6% Minimum Royalty is Greater than the Original Gross Royalty Owed Less PCOS; *the 6% minimum royalty applies in this example as the net royalty calculation would have equalled zero.*

Opening Deep Credit Balance (A): $1,162,876.12
Gross Royalty owed less PCOS (B): $4,899.48

Marketable Gas Volume: 2559.7 10^3m^3
Natural Gas Reference Price: $110.41 /$10^3m^3$

Natural Gas Liquids Sales Value: $0.00
Sulphur Sales Values: $0.00

The first step is to determine if the net royalty payable would have equalled zero.

Determine if Net Royalty would have equalled zero = (Gross Royalty less PCOS) – (Available Deep Well Credits to Bring Royalties to zero)
= $4,899.48 - $4,899.48
= $0

Since the net royalty calculation would have equalled zero and the well is a tier 1 well, the 6% Minimum Royalty Program applies. The second step is to determine the minimum royalty payable. This is done by calculating the gross revenue using the example's sales volumes and reference prices, then multiplying the gross revenue by 6%.

6% Minimum Royalty Calculation = [(2559.7 x $110.41) + $0.00 + $0.00] x 6%
= [$282,606.24 + $0.00 + $0.00] x 6%
= $282,606.24 x 6%
= $16,956,37 (C)

In summary, the 6% minimum royalty (C) is payable although it is greater than the original gross royalty less PCOS (B). As a result, the opening deep well credit balance (A) will increase by the difference (E) between the gross royalty less PCOS (B) and the 6% minimum royalty (C).

Cont'd

The resulting closing deep well credit balance (D) is then available to be deducted against gross royalties payable in future production months either in part with the 6% minimum royalty calculation or deducted in full in the last production month in which the deep well credit bank is extinguished.

Deep Well Credit Bank Monthly Transaction

Opening Deep Well Credit Balance	Gross Royalty less PCOS	6% Minimum Royalty	Closing Deep Well Credit Balance	Total Deep Well Credits Used
$1,162,876.12	$4,899.48	$16,956.37	$1,174,933.01	$12,056.89
A -	B +	C =	D	E

6.0 REPORT COMPLETION GUIDELINES

The guidelines provide a detailed explanation of the form and the fields to be filled in.

Form Name	Printable (PDF)	Download (Excel)	Online	Guidelines
BC-S1 Monthly Production Statement	Yes	Yes	No	Yes
BC-S2 Monthly Disposition Statement	Yes	Yes	No	Yes
BC-08 Marketable Gas and By-product Producer Allocations Report (*Required for reporting production after February 2006*)	No	Yes	Yes	Yes
BC-09 Monthly Oil Sales Statement	Yes	Yes	Yes	Yes
BC-11 Notice of Commencement or Suspension of Operations	No	No	Yes	Yes
BC12 Reporting Interest Statement	Yes	Yes	No	Yes
BC-15 Petroleum & Natural Gas Remittance Advice	Yes	Yes	Yes	Yes
BC19 Monthly Natural Gas Plant and Processing Statement *(effective December 2009)*	Yes	No	Yes	Yes
Facility Schedule 1 Well or Facility to Facility Linkage	Yes (MS Word)	No	No	No
BC-22 Application for Producer Cost of Service	No	Yes	No	Yes
BC-23 Application for Gas Cost Allowance	Yes	Yes	No	Yes
BC-25 Summer Drilling Credit Application	Yes	No	Yes	Yes
BC-26 Coalbed Methane Producer Cost of Service	Yes	Yes	No	Yes
BC-30 Oil Purchasers Summary	No	No	No	No
BC-35 Crude Oil and Condensate Monthly Pipeline Statement	Yes	Yes	No	Yes
BC-36 Central Treating Plant Statement	Yes	Yes	No	Yes
BC-50 Net Profit Historical Allowable Costs	No	No	No	No
BC-51 Net Profit Monthly Allowable Capital and Operating Costs	No	No	Yes	Yes
Form 15A Monthly Gas Injection Operations Report	Yes	No	No	Yes
Form 20 Monthly Crude Oil and Condensate/Pentanes Plus Purchasers' Statement	No	No	No	No

*** *The BC-20 is an Oil and Gas Commission form and must be sent to the Oil and Gas Commission in Fort St. John.*

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GOVERNMENT OF BRITISH COLUMBIA OIL ROYALTY/TAX INVOICE

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Original Oil Royalty/Tax Invoice - Non-PE Operations

Royalty/Tax Payor: 0999 ABC Company
REN: 80999 Production Period: 2005/09 BC09 Received Date: 2005/10/31 Invoice Number: 8-0999-200509-001
Invoice Date: 2005/11/17 Payment Due Date: 2005/11/30

Reporting Facility	UWI	Vintage Type	Vintage Percent	Production Volume	Exempt Percent	Price Factor	Roy/Tax Rate	Reporting Interest	Payor Roy/Tax Share	Ave Net Value$	Gross Payable$	Net Payable$
00008888	100100808517W6-00	New	100.0000000	25.2			2.382	93.2600000	.6	426.928	256.16	256.16
00004444	100053208417W6-02	New	100.0000000	84.1			7.949	93.2600000	6.2	426.928	2,646.95	2,646.95
00007111	200D073G094H01-00	Tr3	100.0000000	170.7	100.0000000	2.00000	12.846	100.0000000	22.0	448.729	9,872.04	0.00
00007222	200D095B094H02-02	Tr3	100.0000000	37.2	100.0000000	2.00000	2.813	100.0000000	1.0	456.298	456.30	0.00
00007333	202D003I094A15-00	New	100.0000000	615.1	100.0000000		26.131	15.0000000	24.1	479.580	11,557.88	0.00
00007444	200B020B094H02-00	New	100.0000000	323.4			22.641	62.5000000	45.8	465.369	21,313.90	21,313.90
00007444	200D011C094H02-00	New	100.0000000	114.5			10.822	75.0000000	9.3	465.369	4,327.93	4,327.93
00008111	200D081K094A11-00	Tr3	100.0000000	706.9		2.00000	21.307	25.0000000	37.7	462.196	17,424.79	17,424.79
00009333	200A011G094A15-00	New	100.0000000	64.9			6.134	100.0000000	4.0	455.747	1,822.99	1,822.99
00009333	200B002G094A15-00	Old	100.0000000	184.8			25.606	100.0000000	47.3	455.747	21,556.83	21,556.83
00009333	200B032G094A15-00	New	100.0000000	127.0			12.004	100.0000000	15.2	455.747	6,927.35	6,927.35
00009333	200B043G094A15-00	New	100.0000000	76.0			7.183	100.0000000	5.5	455.747	2,506.61	2,506.61
00009333	200B064G094A15-00	Old	100.0000000	306.0			31.307	100.0000000	95.8	455.747	43,660.56	43,660.56
00009333	200B092B094A15-00	Old	100.0000000	16.7			2.109	100.0000000	.4	455.747	182.30	182.30
00009333	200C020H094A15-00	New	100.0000000	102.9			9.726	100.0000000	10.0	455.747	4,557.47	4,557.47
00009333	200C032G094A15-00	New	100.0000000	407.2			24.155	100.0000000	98.4	455.747	44,845.50	44,845.50
00009333	200D022G094A15-00	New	100.0000000	103.5			9.783	100.0000000	10.1	455.747	4,603.04	4,603.04
00009333	200D054G094A15-00	Old	100.0000000	698.4			36.191	100.0000000	252.8	455.747	115,212.84	115,212.84
00009333	200D093B094A15-00	Old	100.0000000	8.0			1.010	100.0000000	.1	455.747	45.57	45.57
00009555	200A028A094A15-00	New	100.0000000	114.1			10.784	100.0000000	12.3	479.578	5,898.81	5,898.81
00009555	200B068A094A15-00	New	100.0000000	9.9			.936	80.0000000	.1	479.578	47.96	47.96
00009555	200C039A094A15-00	New	100.0000000	168.5			15.875	100.0000000	26.8	479.578	12,852.69	12,852.69
				4,465.0					725.5		332,576.47	310,690.25

Total Royalty/Tax Payable: 310,690.25

Notes:
* - Royalty payable will be calculated with prices in a future month or an amended BC09 for this month.
I - Price is taken from a future month because no price was available for the facility for the producing month.

Sample 7.0(1)

GOVERNMENT OF BRITISH COLUMBIA OIL ROYALTY/TAX INVOICE

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Original Oil Royalty/Tax Invoice - PE Operations

Royalty/Tax Payor: 0999 ABC Company
REN: 70999 Production Period: 2005/09 BC09 Received Date: 2005/10/31 Invoice Number: 7-0999-200509-001
Invoice Date: 2005/11/17 Payment Due Date: 2005/11/30

PE Code	Tract Number	Vintage Type	Vintage Percent	PE Production Volume	Tract Interest	Allocated Tract Volume	Roy/Tax Rate	Reporting Interest	Payor Roy/Tax Share	Ave Net Value$	Net Payable$
0007	0009	New	100.0000000	743.9	3.9960000	29.7	2.807	62.6940000	.5	453.402	226.70
0007	0010	New	100.0000000	743.9	3.5730000	26.6	2.514	62.6940000	.4	453.402	181.36
0007	0011	New	100.0000000	743.9	5.6620000	42.1	3.979	62.9590000	1.1	453.402	498.74
0007	0012	New	100.0000000	743.9	4.3600000	32.4	3.062	69.1406250	.7	453.402	317.38
0007	0013	New	100.0000000	743.9	2.8460000	21.2	2.004	67.1875000	.3	453.402	136.02
0007	0014	New	100.0000000	743.9	4.2690000	31.8	3.006	62.6940000	.6	453.402	272.04
0011	0001	Old	100.0000000	466.8	2.8488900	13.3	1.679	100.0000000	.2	479.578	95.92
0011	0002	Old	100.0000000	466.8	3.0542100	14.3	1.806	100.0000000	.3	479.578	143.87
0011	0003	Old	100.0000000	466.8	1.7731700	8.3	1.048	100.0000000	.1	479.578	47.96
0011	0004	Old	100.0000000	466.8	6.5702400	30.7	3.876	100.0000000	1.2	479.578	575.49
0011	0005	Old	100.0000000	466.8	2.8898400	13.5	1.705	100.0000000	.2	479.578	95.92
0011	0006	Old	100.0000000	466.8	4.1976000	19.6	2.475	100.0000000	.5	479.578	239.79
0023	0001	New	100.0000000	856.4	7.7069900	66.0	6.238	62.5000000	2.6	477.293	1,240.96
0023	0002	New	100.0000000	856.4	39.8140700	341.0	23.021	62.5000000	49.1	477.293	23,435.09
0023	0003	New	100.0000000	856.4	30.9678400	265.2	21.026	61.9777630	34.6	477.293	16,514.34
0023	0004	New	100.0000000	856.4	4.8792500	41.8	3.951	64.0000000	1.1	477.293	525.02
0023	0005	New	100.0000000	856.4	12.4766300	106.8	10.095	63.9593190	6.9	477.293	3,293.32
0026	0011	New	48.0000000	1,236.6	3.8811000	48.0	4.537	100.0000000	1.0	479.578	479.58
0026	0011	Old	52.0000000	1,236.6	3.8811000	48.0	6.061	100.0000000	1.5	479.578	719.37
0026	0033	New	48.0000000	1,236.6	30.4631000	376.7	23.682	100.0000000	42.8	479.578	20,525.94
0026	0033	Old	52.0000000	1,236.6	30.4631000	376.7	32.939	100.0000000	64.5	479.578	30,932.78
0026	0044	New	48.0000000	1,236.6	11.7282000	145.0	13.705	100.0000000	9.5	479.578	4,555.99
0026	0044	Old	52.0000000	1,236.6	11.7282000	145.0	21.655	100.0000000	16.3	479.578	7,817.12
									236.0		112,870.70

Total Royalty/Tax Payable: 112,870.70

Notes:
* - Royalty payable will be calculated with prices in a future month or an amended BC09 for this month.
I - Price is taken from a future month because no price was available for the facility for the producing month.

Sample 7.0 (2)

GOVERNMENT OF BRITISH COLUMBIA OIL ROYALTY/TAX INVOICE

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Amended Oil Royalty/Tax Invoice - Non-PE Operations

Royalty/Tax Payor: 0999 ABC Company
REN: 80999 Production Period: 2005/08 BC09 Received Date: 2005/10/31 Invoice Number: 8-0999-200508-002
Assessment Notice Date: 2005/09/26 Payment Due Date: 60 days after Assessment Notice Date

Reporting Facility	UWI	Vintage Type	Vintage Percent	Production Volume	Exempt Percent	Price Factor	Roy/Tax Rate	Reporting Interest	Payor Roy/Tax Share	Ave Net Value$	Gross Payable$		Net Payable$
00000001	200D068K094H02-00	New	100.0000000	305.5			22.209	100.0000000	67.9	455.249	30,911.41	Now:	30,911.41
[00000001	200D068K094H02-00	New	100.0000000	305.5			22.209	100.0000000	67.8	455.249	30,865.88	Was:	30,865.88]
00000055	200B041H094A15-00	Old	100.0000000	24.5			3.093	100.0000000	.8	470.802	376.64	Now:	376.64
[00000055	200B041H094A15-00	Old	100.0000000	44.0			5.556	100.0000000	2.4	470.802	1,129.92	Was:	1,129.92]
00000111	200B042H094A15-00	Old	100.0000000	47.0			5.934	100.0000000	2.8	470.802	1,318.25	Now:	1,318.25
[00000111	200B042H094A15-00	Old	100.0000000	47.0			5.934	100.0000000	2.8	Missing *		Was:	0.00]
00000111	200D043H094A15-00	Old	100.0000000	75.0			9.470	100.0000000	7.1	470.802	3,342.69	Now:	3,342.69
[00000111	200D043H094A15-00	Old	100.0000000	75.0			9.470	100.0000000	7.1	Missing *		Was:	0.00]
00000333	200D038I094A11-00	New	100.0000000	296.5			21.973	100.0000000	65.2	466.695	30,428.51	Now:	30,428.51
[00000333	200D038I094A11-00	New	100.0000000	262.5			20.933	100.0000000	54.9	466.695	25,621.56	Was:	25,621.56]
00000666	200C027A094H02-00	New	100.0000000	33.9			3.204	100.0000000	1.1	429.193	472.11	Now:	472.11
[00000666	200C027A094H02-00	New	100.0000000	33.9			3.204	100.0000000	1.1	459.199	505.12	Was:	505.12]
00000666	200C063I094A15-00	New	100.0000000	106.7			10.085	100.0000000	10.8	429.193	4,635.28	Now:	4,635.28
[00000666	200C063I094A15-00	New	100.0000000	106.7			10.085	100.0000000	10.8	459.199	4,959.35	Was:	4,959.35]
00000777	100061808416W6-00	New	100.0000000	62.7			5.926	25.0000000	.9	481.484	433.34	Now:	433.34
[00000777	100061808416W6-00	New	100.0000000	62.7			5.926	25.0000000	.9	459.199	413.28	Was:	413.28]

Net Change of Royalty: 8,423.12

Total Previous Royalty: 63,495.11

Total Current Royalty: 71,918.23
=============

Notes:
* - Royalty payable will be calculated with prices in a future month or an amended BC09 for this month.
I - Price is taken from a future month because no price was available for the facility for the producing month.

Sample 7.0 (3)

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GOVERNMENT OF BRITISH COLUMBIA OIL ROYALTY/TAX INVOICE

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Amended Oil Royalty/Tax Invoice - PE Operations

Royalty/Tax Payor: 0999 ABC Company
REN: 70999 Production Period: 2005/08 BC09 Received Date: 2005/10/31 Invoice Number: 7-0999-200508-002
Assessment Notice Date: 2005/09/26 Payment Due Date: 60 days after Assessment Notice Date

PE Code	Tract Number	Vintage Type	Vintage Percent	PE Production Volume	Tract Interest	Allocated Tract Volume	Roy/Tax Rate	Reporting Interest	Payor Roy/Tax Share	Ave Net Value$		Net Payable$
0007	0041	New	100.0000000	643.7	1.9380000	12.5	1.181	62.6940000	.1	475.983	Now:	47.60
[0007	0041	New	100.0000000	643.7	1.9380000	12.5	1.181	62.6940000	.1	Missing *	Was:	0.00]
0011	0031	Old	100.0000000	430.5	4.8669600	21.0	2.652	100.0000000	.6	451.110	Now:	270.67
[0011	0031	Old	100.0000000	430.5	4.8669600	21.0	2.652	100.0000000	.6	470.808	Was:	282.48]
0023	0002	New	100.0000000	610.5	39.8140700	243.1	20.210	25.0000000	12.3	470.303	Now:	5,784.73
[0023	0002	New	100.0000000	610.5	39.8140700	243.1	20.210	62.5000000	30.7	470.303	Was:	14,438.30]
0033	0005	New	100.0000000	551.7	12.4766300	68.8	6.503	63.9593190	2.9	477.293 I	Now:	1,384.15
[0033	0005	New	100.0000000	551.7	12.4766300	68.8	6.503	63.9593190	2.9	Missing *	Was:	0.00]

Net Change of Royalty: -7,233.63

Total Previous Royalty: 14,720.78

Total Current Royalty: 7,487.15
=============

Notes:
* - Royalty payable will be calculated with prices in a future month or an amended BC09 for this month.
I - Price is taken from a future month because no price was available for the facility for the producing month.

Sample 7.0 (4)

GOVERNMENT OF BRITISH COLUMBIA OIL ROYALTY/TAX INVOICE
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch

Oil Royalty/Tax Invoice Summary

Royalty/Tax Payor: 0999 ABC Company

REN	Prod Period	Invoice Number	Current Invoice Amount	Previous Invoice Amount	Difference
70999	2005/08	7-0999-200508-002	7,487.15	14,720.78	-7,233.63
80999	2005/08	8-0999-200508-002	71,918.23	63,495.11	8,423.12
70999	2005/09	7-0999-200509-001	112,870.70	.00	112,870.70
80999	2005/09	8-0999-200509-001	310,690.25	.00	310,690.25
			-------------	-------------	-------------
Total of 4 invoices generated.		Total amount of invoices:	502,966.33	78,215.89	424,750.44
			=============		

Sample 7.0 (5)

7.0 OIL ROYALTY AND TAX INVOICING

For production months before August 2005, oil producers were required to submit BC13 “Monthly Oil Royalty/Tax Statements” to show their calculation of oil royalties payable for each reporting entity. BC13 reports are still required for amendments to royalties payable for those production months. BC13 reports and related reports are described in section 8.

For oil produced in August 2005 and later, producers are not required to submit their calculation of royalties or taxes payable. The Ministry calculates the royalty or tax payable for each producer’s share of production from each well event and issues monthly invoices to each producer. The Ministry’s calculations of royalties payable are based on the following sources of information:

1. Reporting Entity Structure Statements (BC12), which provide producers’ ownership interests in each well event
2. Monthly Production Statements (BCS1), which provide volumes of oil produced from each well event, and
3. Monthly Oil Sales Statements (BC09), which provide values received by producers for sales of oil at each production facility.

BC12 reports are due by the 20th day of the month following the month in which an ownership interest is to be effective. BCS1 reports are due by the 25th day and BC09 reports by the end of the month following the month in which oil is produced.

The ministry issues oil royalty and tax invoices to producers on about the 10th day of the second month following the month in which oil is produced. For each production month the ministry issues two invoices to each producer: one for oil produced from oil wells that are included in Production Entities (PE’s) and one for oil produced from all other oil wells.

The invoice for oil royalty or tax on oil produced from wells that are not included in PE’s is illustrated in Sample 7.0(1). Sample 7.0(2) illustrates the invoice for oil produced from PE’s. Samples 7.0(3) and 7.0(4) illustrate amended oil royalty invoices for oil produced from wells that are not included in PE’s and for oil produced from PE’s, respectively. Sample 7.0(5) illustrates an Oil Royalty/Tax Invoice Summary for a producer and month.

OIL ROYALTY OR TAX INVOICE

The following is an explanation of information displayed on a Oil Royalty Invoice and how it is derived using an example of one producer with oil production from 22 oil wells at 9 different facilities and 23 tracts in 4 Production Entities. Background data that is not provided on the invoice in this example is as follows:

- Threshold Price for Third Tier oil — $**125.00** / m^3
- Threshold Price for Heavy oil — $**110.00** / m^3

OIL ROYALTY OR TAX INVOICE cont'd

The top of every oil royalty or tax invoice, whether for oil produced from PE's or from wells that are not in PE's, includes the following information.

Royalty/Tax Payor:	This is the ministry's 4-digit client code for the producer of the oil.
REN:	This is a reference number that indicates whether the invoice is for oil produced from PE's or from wells that are not in PE's. For oil produced from PE's, it will consist of a '7' followed by the ministry's client code for the producer. For oil produced from wells that are not in PE's, it will consist of an '8' followed by the ministry's client code.
Production Period:	This is the month in which the oil was produced.
BC09 Received Date:	This is the date on which the ministry received the Monthly Oil Sales Statement (BC09) y for the production period.
Invoice Number:	This is an identifying number for the invoice, consisting of the 5-digit REN, 6-digit production period, and the number of invoices that have been issued for the REN and production period.
Invoice Date:	This is the date on which the invoice is sent to the producer by the ministry.
Payment Due Date:	This is the later of 15 days after the Invoice Date or the 25^{th} of the 2^{nd} month after the Production Period.

Invoices for oil produced from wells that are not in PE's consist of a list of the royalty or tax payable on the producer's share of oil produced from each well event. The following 13 items of information are shown for each well event, if applicable.

Reporting Facility:	This is the ministry's 4-digit code for each reporting facility through which oil from each well event is produced.
UWI:	This is the Unique Well ID for each well event. If the classification of the oil for royalty purposes (vintage) is split between two classes, the UWI for the well event will be listed twice.
Vintage Type:	This is the royalty classification of oil produced from each well event. Possible classifications are: **New** for New Oil from Crown land **Tr3** for Third Tier Oil from Crown land **Hvy** for Heavy Oil from Crown land **Old** for Old Oil from Crown land **Fre** for oil produced from freehold land See section 4.2 of this Handbook for a description of each of these classes.
Vintage Percent:	This is the percentage of production from each well event that is of the specified vintage.

OIL ROYALTY OR TAX INVOICE cont'd

Production Volume:	This is the volume of oil produced from each well event during the production period, as reported on the Monthly Production Statement (S1) for the reporting facility.
Exempt Percent:	This is the percentage of production from each well event that is not subject to royalties. The only exemption that is currently available is for discovery wells, which are exempt for the lesser of 36 months or 11,450 m^3 of oil. For almost all well events the Exempt Percent will be either 0 or 100%. It will only be something other than 0 or 100% when cumulative production from a discovery well reaches 11,450 m^3 during the production period.
Price Factor:	There are factors that are used in calculating some royalty rates. Royalty rates for Third Tier and Heavy oil are base royalty rates multiplied by a Price Factor. The Price Factor for Heavy oil is the lesser of 2.0 and the amount determined from the following formula: $1 + 2.5 \times \frac{\text{Wellhead Price – Threshold Price for Heavy oil}}{\text{Wellhead Price}}$ The Price Factor for Third Tier oil is the lesser of 2.0 and the amount determined from the following formula: $1 + 3.5 \times \frac{\text{Wellhead Price – Threshold Price for Third Tier oil}}{\text{Wellhead Price}}$ The Wellhead Price is the Average Net Value for the facility as shown in the Ave Net Value column. The Threshold Prices have been set at \$110 per m^3 for Heavy oil and \$125 per m^3 for Third Tier oil.

OIL ROYALTY OR TAX INVOICE cont'd

Roy/Tax Rate:	The amounts in this column are the royalty or tax rates that were calculated for each well event. The rates for Heavy and Third Tier oil are a base rate multiplied by a Price Factor. For Old, New and Freehold oil there is only a base rate with no Price Factor. Base rates are derived from the following formulas: Crown Land: Old If Production $\le 95\ m^3$, Production / 7.92 If Production $> 95\ m^3$, $\frac{(11.4 + .4\ (\text{Production} - 95)) \times 100}{\text{Production}}$ Crown Land: New If Production $\le 159\ m^3$, Production / 10.58 If Production $> 159\ m^3$, $\frac{(23.9 + .3\ (\text{Production} - 159)) \times 100}{\text{Production}}$ Crown Land: Third Tier If Production $\le 159\ m^3$, Price Factor x Production / 26.45 If Production $> 159\ m^3$, Price Factor x $\frac{(956 + 12\ (\text{Production} - 159))}{\text{Production}}$ Crown Land: Heavy If Production $\le 20\ m^3$, 0 If Production > 20 and $\le 200\ m^3$, Price Factor x $\frac{(\text{Production} - 20)^2}{24 \times \text{Production}}$ If Production $> 200\ m^3$, Price Factor x $\frac{11 \times (\text{Production} - 200) + 1350}{\text{Production}}$ Freehold Land If Production $\le 159\ m^3$, .06 x Production If Production $> 159\ m^3$, $\frac{1575 + 20\ (\text{Production} - 159))}{\text{Production}}$ In these formulas, Production is the Production Volume for the well event during the production period, as shown in the Production Volume column.
Reporting Interest:	This is the percentage of production from each well event for which the producer is responsible for paying royalties. In most cases this is the proportion that the producer takes in kind.
Payor Roy/Tax Share:	This is the producer's royalty or tax share in m^3 for each well event. For each well event this is equal to, **Production Volume x Roy/Tax Rate x Reporting Interest**
Ave Net Value:	The amounts in this column are the average price for the producer's sales of oil at each reporting facility as reported on the producer's Monthly Oil Sales Statement (BC09).
Gross Payable:	The amounts in this column are the royalty or tax payable before taking exemptions into account. They are equal to, **Payor Roy/Tax Share x Ave Net Value**

OIL ROYALTY OR TAX INVOICE cont'd

Net Payable:	The amounts in this column are the royalty or tax payable after taking exemptions into account. They are equal to, **Gross Payable x (1 - Exempt Percent / 100)**

Invoices for oil produced from wells that are in PE's consist of a list of the royalty or tax payable on the producer's share of oil produced from each well event. The following 12 items of information are shown for each tract, if applicable.

PE Code:	These are the ministry's 4-digit codes for the Production Entities from which the producer receives production of oil. A Production Entity is a unitized operation for which royalty rates are based on volumes of oil allocated to each tract, rather than volumes produced from wells.
Tract Number:	These are the numbers of the tracts in each Production Entity. Some Tract Numbers can be expected to appear more than once since they may be used for different PE's. If the classification of oil allocated to the tract for royalty purposes is split between two classes, the tract number will be listed once for each class.
Vintage Type:	These are the royalty classifications of the oil allocated to each tract. Possible classifications are: New for New Oil from Crown land Tr3 for Third Tier Oil from Crown land Hvy for Heavy Oil from Crown land Old for Old Oil from Crown land Fre for oil produced from freehold land See section 4.2 of this Handbook for a description of each of these classes.
Vintage Percent:	For each tract, this is the percentage of production allocated to the tract that is of the specified vintage.
PE Production Volume:	These are the volumes of oil produced during the Production Period by each unitized operation in which the producer has an interest. These are allocated to tracts in accordance with the Tract Interest.
Tract Interest:	These are the percentages of production by the unitized operation that are allocated to each tract.
Allocated Tract Volume:	These are the volumes of oil production that have been allocated to each tract during the Production Period. For each well event this is equal to, **PE Production Volume x Tract Interest / 100**

OIL ROYALTY OR TAX INVOICE cont'd

Roy/Tax Rate:	These are the royalty or tax rates that were calculated for each class of oil in each tract. The classes of oil and the formulas for each rate are the same as for non-PE wells, except the Production volume used in each formula is the volume allocated to the tract during the Production Period, as shown in the Allocated Tract Volume column.
Reporting Interest:	These are the percentages of production allocated to each tract for which the producer is responsible for paying royalties. In most cases, this is the proportion that the producer takes in kind.
Payor Roy/Tax Share:	These are the producer's royalty or tax shares in m^3 for each tract. For each tract this is equal to, **Allocated Tract Volume x Roy/Tax Rate x Reporting Interest**
Ave Net Value:	These are the average prices for the producer's sales of oil from each Production Entity as reported on the producer's Monthly Oil Sales Statement (BC09).
Net Payable:	These are the royalty or tax payable on the producer's share of oil allocated to each tract. They are equal to, **Payor Roy/Tax Share x Ave Net Value**

RMS98521

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch

Gas Royalty/Tax Invoice - PE Operations

PE - Gas Details

Invoice Date: 2006/08/14 Payment Due Date: 2006/08/29 Invoice:50440-200605-1

To Royalty Payor ABC Company REN: 50999

Royalty Payor Code: 0999 Production Period: 2006/05

PE	Plant	Gas Type	Marketable Gas Volume (1000m3)	Reference Price	Marketable Gas Royalty Rate(%)	Marketable Gas Royalty($)	By-Product Royalties ($)	Weighted Average Royalty Rate(%)	Raw Gas Volume (1000 m3)	PCOS Rate ($)	PCOS Allowance ($)	Gas and By-Product Royalty less PCOS($)	Net Royalty Payable($)	Previous Royalty Payable($)
0006	46	CONS-C	26.8	154.724	12.73791	528.19	1.272.53	17.13462	26.8	16.00	73.47	1,727.25	1,727.25	0.00
0016	439	CONS-C	1,199.3	187.237	13.13071	29,485.45	5.437.78	13.87261	1,236.5	16.00	2,744.56	32,178.67	32,178.67	0.00
0017	439	CONS-C	290.8	187.237	13.13071	7,149.48	1.401.65	13.91405	303.7	16.00	676.11	7,875.02	7,875.02	0.00
0017	439	CONS-F	211.3	187.237	7.90513	3,127.52	623.80	8.40060	220.6	16.00	296.51	3,454.81	3,454.81	0.00
0019	46	CONS-C	12.6	154.724	12.73791	248.33	673.21	17.33662	12.6	16.00	34.95	886.59	886.59	0.00
													==============	========
											Totals for 2006/05		46,122.34	0.00
												Difference:	46,122.34	

Sample 7.1(1)

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch

Gas Royalty/Tax Invoice - PE Operations

PE - Gas By-Product Details

Invoice Date: 2006/08/14 Payment Due Date: 2006/08/29 Invoice:50440-200605-1

To Royalty Payor Devon Canada Corporation REN: 50440
Royalty Payor Code: 0440 Production Period: 2006/05

PE	Plant	Gas Type	-Ethane- Sales Volume	-Ethane- Sales Value($)	-Propane- Sales Volume	-Propane- Sales Value($)	-Butane- Sales Volume	-Butane- Sales Value($)	-Plant Pentanes- Sales Volume	-Plant Pentanes- Sales Value($)	-Field Cond- Sales Volume	-Field Cond- Sales Value($)	Nat. Gas Liquid Sales Value($)	Natural Gas Liquid Royalty($)	- Sulphur- Sales Volume	- Sulphur- Sales Value($)	Sulphur Royalty($)	Total By-Product Royalty($)
0006	46	CONS-C	0.0	0.00	10.9	2810.90	6.7	2256.49	2.4	1295.26	0.0	0.00	6362.65	1272.53	0.0	0.00	0.00	1272.53
0016	439	CONS-C	0.0	0.00	4.4	1164.64	19.1	6919.93	38.8	19104.35	0.0	0.00	27188.92	5437.78	0.0	0.00	0.00	5437.78
0017	439	CONS-C	0.0	0.00	4.9	1287.71	7.8	2811.78	5.9	2908.77	0.0	0.00	7008.26	1401.65	0.0	0.00	0.00	1401.65
0017	439	CONS-F	0.0	0.00	3.5	935.66	5.6	2043.04	4.3	2113.51	0.0	0.00	5092.21	623.80	0.0	0.00	0.00	623.80
0019	46	CONS-C	0.0	0.00	5.5	1418.34	3.7	1246.12	1.3	701.59	0.0	0.00	3366.05	673.21	0.0	0.00	0.00	673.21
																		============
															Totals for	2006/05		9,408.97

Sample 7.1(2)

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RMS98511

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - Non-PE Operations
Non-PE - Gas Details
Invoice Date: 2006/08/14 Payment Due Date: 2006/08/29 Invoice:60999-200605-001

To Royalty Payor ABC Company REN: 60999
Royalty Payor Code: 0999 Production Period: 2006/05

WA#	Unique Well Identifier	Plant	Reporting Facility	Marketable Gas Volume (1000m3)	Reference Price	Net Marketable Gas Royalty Rate(%)	Net Marketable Gas Royalty($)	By-Product Royalties ($)	Weighted Average Royalty Rate(%)	Raw Gas Volume (1000 m3)	PCOS Rate ($)	PCOS Allowance ($)	Gas and By-Product Royalty less PCOS($)	Deep Well Deduction($)	Net Royalty Payable($)	Previous Royalty Payable($)
00129	200A049B094H16-00	2766	2766	629.3	184.211	22.28572	25,834.49	0.00	22.28572	814.3	6.29	1,141.46	24,693.03	0.00	24,693.03	0.00
04263	200B022A094H16-00	921	921	36.1	238.611	20.31037	1,749.51	340.08	20.25919	38.3	10.78	83.64	2,005.95	0.00	2,005.95	0.00
04646	200B062I094H09-00	921	921	86.8	238.611	22.90454	4,743.86	1,176.52	22.26207	92.8	10.78	222.71	5,697.67	0.00	5,697.67	0.00
04815	200A001G093I16-04	204	9102	2.4	203.829	27.00000	132.08	14.62	26.09020	2.5	17.56	11.45	135.25	0.00	135.25	0.00
04838	200C098A093P01-02	204	204	349.5	203.829	22.54696	16,062.06	2,643.47	22.14836	372.1	22.58	1,860.91	16,844.62	0.00	16,844.62	0.00
05053	200C012L093P01-03	205	205	5.6	215.834	4.30985	52.09	0.00	4.30970	9.4	5.90	2.39	49.70	0.00	49.70	0.00
05096	200D097I093P07-02	205	205	122.6	215.834	22.68340	6,002.31	19.86	22.67335	132.6	5.90	177.38	5,844.79	0.00	5,844.79	0.00
05107	200B042H094H16-00	921	921	25.2	238.611	16.20954	974.68	546.54	17.39390	27.1	10.78	50.81	1,470.41	0.00	1,470.41	0.00
05189	200D099E093I15-00	8382	8382	25.6	.000	.00000	0.00	14.81	16.66479	35.2	4.04	14.07	0.74	0.00	0.74	0.00
05277	200C019G094H16-00	921	921	114.3	238.611	22.90454	6,246.81	1,644.25	22.23178	120.6	10.78	289.03	7,602.03	0.00	7,602.03	0.00
06590	200A089C093P07-03	205	205	355.7	215.834	22.68340	17,414.53	119.11	22.66274	374.5	5.90	500.74	17,032.90	0.00	17,032.90	0.00
06598	200D055D093P08-00	205	205	35.6	215.834	12.70248	976.02	9.93	12.74933	40.4	5.90	30.39	955.56	0.00	955.56	0.00
06599	200A009D093P08-00	205	205	196.1	215.834	22.68340	9,600.76	49.65	22.66774	233.2	5.90	311.88	9,338.53	0.00	9,338.53	0.00
06599	200A009D093P08-02	205	205	10.3	215.834	3.53929	78.68	0.00	3.53922	12.3	5.90	2.57	76.11	0.00	76.11	0.00
06636	200D051D093P08-02	205	205	337.3	215.834	22.68340	16,513.70	377.18	22.61564	347.8	5.90	464.08	16,426.80	0.00	16,426.80	0.00
06637	200A067I093P02-00	205	205	52.1	215.834	15.71279	1,766.90	9.93	15.73166	55.8	5.90	51.79	1,725.04	0.00	1,725.04	0.00
07236	200D011E093P08-02	205	205	0.0	215.834	22.68340	0.00	0.00	0.00000	0.0	5.90	0.00	0.00	0.00	0.00	0.00
07386	100150108719W6-00	745	745	62.9	.000	.00000	0.00	211.50	19.99962	75.9	27.21	200.93	10.57	0.00	10.57	0.00
16635	200B026G093I16-00	204	9102	15.5	203.829	27.00000	853.02	175.09	25.48094	19.2	17.56	85.91	942.20	0.00	942.20	0.00
16715	200B018H093I16-00	204	9102	115.3	203.829	22.45779	5,277.91	3,708.11	21.37390	134.2	17.56	503.69	8,482.33	8,482.33	0.00	0.00
16715	200B018H093I16-02	204	9102	31.6	203.829	7.43391	478.82	85.53	8.21629	33.9	17.56	48.91	515.44	0.00	515.44	0.00
16906	200B013G093I16-00	204	9102	554.6	203.829	27.00000	30,521.76	1,160.42	26.65825	591.6	17.56	2,769.39	28,912.79	0.00	28,912.79	0.00
16929	200B029F093I16-02	204	9102	220.0	203.829	23.75865	10,653.94	52.80	23.73665	235.2	17.56	980.35	9,726.39	9,726.39	0.00	0.00
16929	200B029F093I16-05	204	9102	696.2	203.829	27.00000	38,314.55	467.91	26.88646	743.9	17.56	3,512.15	35,270.31	0.00	35,270.31	0.00
16968	200A081D093P10-00	205	7382	30.2	215.834	10.81755	705.11	0.00	10.81757	31.9	5.11	17.63	687.48	0.00	687.48	0.00
16989	200C058C093P10-00	205	7382	34.6	215.834	8.57223	640.16	9.87	8.64725	38.7	5.11	17.10	632.93	0.00	632.93	0.00
16989	200C058C093P10-02	205	7382	29.8	215.834	27.00000	1,736.60	9.87	26.94679	29.0	5.11	39.93	1,706.54	0.00	1,706.54	0.00
16996	200C089H093P07-00	205	205	395.2	215.834	27.00000	23,030.35	1,637.76	26.38684	411.5	5.90	640.63	24,027.48	0.00	24,027.48	0.00
17828	200B068C093P10-00	205	7382	93.8	215.834	12.39813	2,510.03	29.60	12.45331	101.8	5.11	64.78	2,474.85	0.00	2,474.85	0.00
17866	200D033I093P07-00	205	205	7,834.8	215.834	27.00000	456,574.38	15,305.81	26.69692	7,365.3	5.90	11,601.22	460,278.97	0.00	460,278.97	0.00
18677	200A063F094H16-00	921	921	14.4	238.611	3.27537	112.54	236.71	7.56026	15.5	10.78	12.63	336.62	0.00	336.62	0.00
18692	200C084B094H16-00	921	921	63.5	238.611	10.94067	1,657.71	924.04	13.05761	67.4	10.78	94.87	2,486.88	0.00	2,486.88	0.00
18985	200C021B093P10-00	205	205	97.5	215.834	26.32851	5,540.52	19.86	26.29876	110.5	5.90	171.45	5,388.93	0.00	5,388.93	0.00
19521	202D015G093I16-00	204	9102	698.5	203.829	27.00000	38,441.13	296.70	26.92781	760.4	17.56	3,595.57	35,142.26	35,142.26	0.00	0.00
													Totals for 2006/05		673,571.12	0.00

Difference: 673,571.12

* Facility reported on the BC08 is different than the facility recorded on RMS
X Exemption from Gas Royalty used this month
N means UWI does not receive the compression component of the PCOS, even though its linked facility does have compression

Sample 7.1(3)

RMS98511_DEFT ** UAT ** GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE ** UAT ** 2014/07/10

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch

Gas Royalty/Tax Invoice - Non-PE Operations

Non-PE - Gas Details

Minimum Royalty Sample

Invoice Date: 2014/07/10 Payment Due Date: 2014/07/25 Invoice:60999-201404-001

To Royalty Payor ABC Company REN: 60999

Royalty Payor Code: 0955 Production Period: 2014/04

WA#	Unique Well Identifier	Plant	Reporting Facility	Marketable Gas Volume (1000m3)	Reference Price	Net Marketable Gas Royalty Rate(%)	Net Marketable Gas Royalty($)	By-Product Royalties ($)	Weighted Average Royalty Rate(%)	Raw Gas Volume (1000 m3)	PCOS Rate ($)		PCOS Allowance ($)	[1] Gas and By-Product Royalty less PCOS($)	CBM(C) or Deep Well Deduction($) For Royalty Purposes	[2] Net Royalty Payable($)	Previous Royalty Payable($)	[3] Net Effect of Min Royalty on Deep Bank		Tier
29071	200C058G094G01-02	437	7908	713.6	172.227	26.94762	33,118.95	5,239.02	25.72698	740.9	3.02	N	575.65	37,782.32	33,309.43	4,472.89	0.00	33,309.43	d	
29092	202C058G094G01-00	437	7908	632.4	172.227	26.41572	28,771.04	5,550.66	25.11289	661.0	3.02	N	501.31	33,820.39	0.00	33,820.39	0.00			
29327	200D088A094G01-02	437	7961	2,422.4	172.227	27.00000	112,644.72	39,904.85	24.73535	2,598.9	19.11	N	12,284.81	140,264.76	121,762.95	18,501.81	0.00	121,762.95	d	
29510	200D021G094G01-00	437	7961	744.4	172.227	27.00000	34,615.56	8,367.51	25.27772	798.7	19.11	N	3,858.18	39,124.89	34,023.59	5,101.30	0.00	34,023.59	d	
30610	200E004H094G01-00	437	7961	1,260.1	172.227	27.00000	58,596.27	26,680.22	24.33521	1,355.3	19.11	N	6,302.77	78,973.72	68,460.99	10,512.73	0.00	68,460.99	d	
31299	200E098A094G01-00	437	7961	2,839.6	172.227	27.00000	132,045.06	45,979.81	24.76162	3,046.5	19.11	N	14,415.87	163,609.00	0.00	163,609.00	0.00			
31439	200E098A094G01-00	437	7961	3,683.0	172.227	27.00000	171,264.25	41,166.92	25.28501	3,951.3	19.11	N	19,092.54	193,338.63	142,929.83	50,408.80	0.00	142,929.83	d	1

Sum of Changes for REN 60999 for 2014/04: 286,426.92 0.00

Difference of Changes for REN 60999 for 2014/04: 286,426.92

Invoice Totals for REN 60999 for 2014/04: 286,426.92 0.00

Difference of Invoices for REN 60999 for 2014/04: 286,426.92

- * At the right of an item indicates its value has changed since the last invoice.
- V BC08 Gas Validations Amendment
- F Facility reported on the BC08 is different than the facility recorded on PRMS - PRMS facility is shown here.
- ^ Plant reported on the BC08 is different than the plant recorded on PRMS - plant reported on the BC08 is shown here.
- X Exemption from Gas Royalty used this month
- N Means UWI does not receive the compression component of the PCOS, even though its linked facility does have compression.
- d/a/z Means that the minimum royalty rate for a deep well was used, calculated by the following using items from this and from the accompanying By-Product Details report:

  [(Marketable_Gas_Volume x Reference_Price) + Natural_Gas_Liquids_Sales_Value + Sulphur_Sales_Value] x Minimum_Royalty_Percent

  where for prod_period 201404, the Minimum_Royalty_Percent is:

  3.000% for Tier 2

  3.000% for Tier B - Tier B means a Tier 1 UWI drawing from a Tier 2 well bank

  6.000% for Tier 1
- d Means, further, that the minimum royalty calculated is smaller than Gross-Royalty-Less-PCOS, so the net effect to the deep bank is to decrease it.
- a Means, further, that the minimum royalty calculated is greater than Gross-Royalty-Less-PCOS, so the net effect to the deep bank is to add to it.
- z Means, further, that the minimum royalty calculated is equal to than Gross-Royalty-Less-PCOS, so the net effect to the deep bank is nil.

Note that for the (last) column labeled “Tier” only a “1” or “B” will show, as all other deep wells are by definition Tier 2 wells

Sample 7.1(3a)

RMS98512 GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch

Gas Royalty/Tax Invoice - Non-PE Operations

Non-PE By-Product Details

Invoice Date: 2006/08/14 Payment Due Date: 2006/08/29 Invoice:60999-200605-1

To Royalty Payor ABC Company REN: 60999

Royalty Payor Code: 0999 Production Period: 2006/05

WA	Unique Well Indentifier	Plant	Class Base Rate	-Ethane- Sales Volume	-Ethane- Sales Value($)	-Propane- Sales Volume	-Propane- Sales Value($)	-Butane- Sales Volume	-Butane- Sales Value($)	-Plant Pentanes- Sales Volume	-Plant Pentanes- Sales Value($)	-Field Cond- Sales Volume	-Field Cond- Sales Value($)	Nat. Gas Liquid Sales Value($)	Natural Gas Liquid Royalty($)	- Sulphur- Sales Volume	- Sulphur- Sales Value($)	Sulphur Royalty($)	Total By-Product Royalty($)
00129	200A049B094H16-00	2766	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.00	0.00
04263	200B022A094H16-00	921	15-C	0.0	0.00	1.4	361.42	1.4	450.58	1.7	888.42	0.0	0.00	1,700.42	340.08	0.0	0.00	0.00	340.08
04646	200B062I094H09-00	921	15-C	0.0	0.00	4.5	1,112.70	4.1	1,319.54	6.6	3,450.35	0.0	0.00	5,882.59	1,176.52	0.0	0.00	0.00	1,176.52
04815	200A001G093I16-04	204	12-C	0.2	21.69	0.0	0.00	0.0	0.00	0.1	51.40	0.0	0.00	73.09	14.62	0.0	0.00	0.00	14.62
04838	200C098A093P01-02	204	15-C	51.7	5,596.15	15.7	3,512.63	5.9	1,898.41	4.5	2,210.16	0.0	0.00	13,217.35	2,643.47	0.0	0.00	0.00	2,643.47
05053	200C012L093P01-03	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.00	0.00
05096	200D097I093P07-02	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.2	99.31	0.0	0.00	99.31	19.86	0.0	0.00	0.00	19.86
05107	200B042H094H16-00	921	15-C	0.0	0.00	1.4	361.42	1.2	386.21	3.8	1,985.08	0.0	0.00	2,732.71	546.54	0.0	0.00	0.00	546.54
05189	200D099E093I15-00	8382	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	4.9	88.87	14.81	14.81
05277	200C019G094H16-00	921	15-C	0.0	0.00	5.7	1,405.11	5.1	1,641.38	9.9	5,174.77	0.0	0.00	8,221.26	1,644.25	0.0	0.00	0.00	1,644.25
06590	200A089C093P07-03	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	1.2	595.54	0.0	0.00	595.54	119.11	0.0	0.00	0.00	119.11
06598	200D055D093P08-00	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.1	49.66	0.0	0.00	49.66	9.93	0.0	0.00	0.00	9.93
06599	200A009D093P08-00	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.5	248.27	0.0	0.00	248.27	49.65	0.0	0.00	0.00	49.65
06599	200A009D093P08-02	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.00	0.00
06636	200D051D093P08-02	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	3.8	1,885.90	0.0	0.00	1,885.90	377.18	0.0	0.00	0.00	377.18
06637	200A067I093P02-00	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.1	49.66	0.0	0.00	49.66	9.93	0.0	0.00	0.00	9.93
07236	200D011E093P08-02	205	15-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.00	0.00
07386	100150108719W6-00	745	15-C	0.0	0.00	0.7	190.46	1.3	438.52	0.8	428.54	0.0	0.00	1,057.52	211.50	0.0	0.00	0.00	211.50
16635	200B026G093I16-00	204	09-C	0.0	0.00	1.5	335.60	0.4	128.70	0.8	411.17	0.0	0.00	875.47	175.09	0.0	0.00	0.00	175.09
16715	200B018H093I16-00	204	09-C	22.5	2,437.20	14.6	3,266.52	9.8	3,153.23	19.7	9,683.60	0.0	0.00	18,540.55	3,708.11	0.0	0.00	0.00	3,708.11
16715	200B018H093I16-02	204	09-C	2.5	271.06	0.7	156.61	0.0	0.00	0.0	0.00	0.0	0.00	427.67	85.53	0.0	0.00	0.00	85.53
16906	200B013G093I16-00	204	09-C	36.5	3,941.01	5.5	1,230.54	1.8	579.17	0.1	51.40	0.0	0.00	5,802.12	1,160.42	0.0	0.00	0.00	1,160.42
16929	200B029F093I16-02	204	12-C	2.5	263.99	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	263.99	52.80	0.0	0.00	0.00	52.80
16929	200B029F093I16-05	204	12-C	18.7	2,003.96	1.5	335.60	0.0	0.00	0.0	0.00	0.0	0.00	2,339.56	467.91	0.0	0.00	0.00	467.91
16968	200A081D093P10-00	205	09-C	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.00	0.00
16989	200C058C093P10-00	205	12-C	0.0	0.00	0.0	0.00	0.0	0.00	0.1	49.33	0.0	0.00	49.33	9.87	0.0	0.00	0.00	9.87
16989	200C058C093P10-02	205	12-C	0.0	0.00	0.0	0.00	0.0	0.00	0.1	49.33	0.0	0.00	49.33	9.87	0.0	0.00	0.00	9.87
16996	200C089H093P07-00	205	09-C	0.0	0.00	0.0	0.00	0.0	0.00	16.5	8,188.82	0.0	0.00	8,188.82	1,637.76	0.0	0.00	0.00	1,637.76
17828	200B068C093P10-00	205	12-C	0.0	0.00	0.0	0.00	0.0	0.00	0.3	147.98	0.0	0.00	147.98	29.60	0.0	0.00	0.00	29.60
17866	200D033I093P07-00	205	12-C	0.0	0.00	0.0	0.00	0.0	0.00	154.2	76,529.03	0.0	0.00	76,529.03	15,305.81	0.0	0.00	0.00	15,305.81
18677	200A063F094H16-00	921	12-C	0.0	0.00	0.8	215.23	0.9	289.66	1.3	678.66	0.0	0.00	1,183.55	236.71	0.0	0.00	0.00	236.71
18692	200C084B094H16-00	921	12-C	0.0	0.00	3.5	848.74	3.6	1,158.62	5.0	2,612.84	0.0	0.00	4,620.20	924.04	0.0	0.00	0.00	924.04
18985	200C021B093P10-00	205	12-C	0.0	0.00	0.0	0.00	0.0	0.00	0.2	99.31	0.0	0.00	99.31	19.86	0.0	0.00	0.00	19.86
19521	202D015G093I16-00	204	09-C	13.9	1,483.52	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	1,483.52	296.70	0.0	0.00	0.00	296.70
																			============
																Totals for	2006/05		31,294.53

Sample 7.1(4)

RMS98513 GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - Non-PE Operations
Non-PE - Incentive Deduction Details
Invoice Date: 2006/08/14 Payment Due Date: 2006/08/29 Invoice:60999-200605-1

To Royalty Payor ABC Company REN: 60999
Royalty Payor Code: 0999 Production Period: 2006/05

WA #	Unique Well Indentifier	Plant	Reference Price	Class Base Rate	BCS1 Volume	Hours of Production BCS1	Average Daily Production	Daily Volume Cutoff	Base Royalty Rate(%)	Royalty Rate Reduction Factor	Royalty Rate Reduction(%)	Net Royalty Rate(%)	Batch Number	Entry Date-Time
00129	200A049B094H16-00	2766	184.211	15-C	1,131.3	695	39.0664748	5.0	22.28572	0.00000	0.00000	22.28572	U-2006-07-21	20060725-09122700
04263	200B022A094H16-00	921	238.611	15-C	100.9	730	3.3172603	5.0	22.90454	0.11326	2.59417	20.31037	U-2006-07-21	20060725-09122700
04646	200B062I094H09-00	921	238.611	15-C	244.2	710	8.2546479	5.0	22.90454	0.00000	0.00000	22.90454	U-2006-07-21	20060725-09122700
04815	200A001G093I16-04	204	203.829	12-C	5.1	1	122.4000000	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
04838	200C098A093P01-02	204	203.829	15-C	372.1	744	12.0032258	5.0	22.54696	0.00000	0.00000	22.54696	U-2006-07-21	20060725-09122700
05053	200C012L093P01-03	205	215.834	15-C	13.5	648	0.5000000	5.0	22.68340	0.81000	18.37355	4.30985	U-2006-07-21	20060725-09122700
05096	200D097I093P07-02	205	215.834	15-C	132.6	430	7.4009302	5.0	22.68340	0.00000	0.00000	22.68340	U-2006-07-21	20060725-09122700
05107	200B042H094H16-00	921	238.611	15-C	71.2	744	2.2967742	5.0	22.90454	0.29230	6.69500	16.20954	U-2006-07-21	20060725-09122700
05189	200D099E093I15-00	8382	0.000	15-C	529.3	651	19.5133641	5.0	0000	0.00000	0.00000	0.00000	U-2006-07-21	20060725-09122700
05277	200C019G094H16-00	921	238.611	15-C	317.2	740	10.2875676	5.0	22.90454	0.00000	0.00000	22.90454	U-2006-07-21	20060725-09122700
06590	200A089C093P07-03	205	215.834	15-C	374.5	743	12.0969044	5.0	22.68340	0.00000	0.00000	22.68340	U-2006-07-21	20060725-09122700
06598	200D055D093P08-00	205	215.834	15-C	40.4	576	1.6833333	5.0	22.68340	0.44001	9.98092	12.70248	U-2006-07-21	20060725-09122700
06599	200A009D093P08-00	205	215.834	15-C	233.2	726	7.7090909	5.0	22.68340	0.00000	0.00000	22.68340	U-2006-07-21	20060725-09122700
06599	200A009D093P08-02	205	215.834	15-C	12.3	726	0.4066116	5.0	22.68340	0.84397	19.14411	3.53929	U-2006-07-21	20060725-09122700
06636	200D051D093P08-02	205	215.834	15-C	347.8	741	11.2647773	5.0	22.68340	0.00000	0.00000	22.68340	U-2006-07-21	20060725-09122700
06637	200A067I093P02-00	205	215.834	15-C	55.8	601	2.2282862	5.0	22.68340	0.30730	6.97061	15.71279	U-2006-07-21	20060725-09122700
07236	200D011E093P08-02	205	215.834	15-C	0.0	0	0.0000000	0.0	22.68340	0.00000	0.00000	22.68340	U-2006-07-21	20060725-09122700
07386	100150108719W6-00	745	0.000	15-C	74.6	744	2.4064516	5.0	0000	0.26906	0.00000	0.00000	U-2006-07-21	20060725-09122700
16635	200B026G093I16-00	204	203.829	09-C	38.3	1	919.2000000	25.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
16715	200B018H093I16-00	204	203.829	09-C	268.5	437	14.7459954	25.0	27.00000	0.16823	4.54221	22.45779	U-2006-07-21	20060725-09122700
16715	200B018H093I16-02	204	203.829	09-C	67.7	437	3.7180778	25.0	27.00000	0.72467	19.56609	7.43391	U-2006-07-21	20060725-09122700
16906	200B013G093I16-00	204	203.829	09-C	1,183.2	737	38.5302578	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
16929	200B029F093I16-02	204	203.829	12-C	470.4	691	16.3380608	25.0	27.00000	0.12005	3.24135	23.75865	U-2006-07-21	20060725-09122700
16929	200B029F093I16-05	204	203.829	12-C	1,487.9	692	51.6034682	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
16968	200A081D093P10-00	205	215.834	09-C	66.1	281	5.6455516	25.0	27.00000	0.59935	16.18245	10.81755	U-2006-07-21	20060725-09122700
16989	200C058C093P10-00	205	215.834	12-C	46.0	254	4.3464567	25.0	27.00000	0.68251	18.42777	8.57223	U-2006-07-21	20060725-09122700
16989	200C058C093P10-02	205	215.834	12-C	34.5	39	21.2307692	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
16996	200C089H093P07-00	205	215.834	09-C	411.5	596	16.5704698	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
17828	200B068C093P10-00	205	215.834	12-C	121.0	439	6.6150342	25.0	27.00000	0.54081	14.60187	12.39813	U-2006-07-21	20060725-09122700
17866	200D033I093P07-00	205	215.834	12-C	7,365.3	734	240.8272480	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700
18677	200A063F094H16-00	921	238.611	12-C	40.7	624	1.5653846	25.0	27.00000	0.87869	23.72463	3.27537	U-2006-07-21	20060725-09122700
18692	200C084B094H16-00	921	238.611	12-C	177.3	744	5.7193548	25.0	27.00000	0.59479	16.05933	10.94067	U-2006-07-21	20060725-09122700
18985	200C021B093P10-00	205	215.834	12-C	128.1	730	4.2115068	5.0	27.00000	0.02487	0.67149	26.32851	U-2006-07-21	20060725-09122700
19521	202D015G093I16-00	204	203.829	09-C	1,520.8	709	51.4798307	5.0	27.00000	0.00000	0.00000	27.00000	U-2006-07-21	20060725-09122700

End of schedule for period 2006/05

Sample 7.1(5)

RMS98526_DEEP GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - Non-PE Operations
Deep Well Bank Calculation

To Royalty Payor: ABC Company Royalty Payor Code: 0999

WA Number	Unique Well Identifier	Initial WA-Bank	Payor % Interest	Initial Client-Bank	Prodn Period	Opening Balance	Transfers In	Transfers Out	Deep Deduction	Closing Balance
16715	200B018H093I16-00	561,400.00	50.0000000	280,700.00						
					2005/10	90,507.48	0.00	0.00	18,829.01	71,678.47
					2005/11	71,678.47	0.00	0.00	13,095.22	58,583.25
					2005/12	58,583.25	0.00	0.00	11,808.38	46,774.87
					2006/01	46,774.87	0.00	0.00	12,101.25	34,673.62
					2006/02	34,673.62	0.00	0.00	8,649.25	26,024.37
					2006/03	26,024.37	0.00	0.00	8,903.03	17,121.34
					2006/04	17,121.34	0.00	0.00	5,476.12	11,645.22
					2006/05	11,645.22	0.00	0.00	8,482.33	3,162.89
16929	200B029F093I16-02	781,600.00	50.0000000	390,800.00						
					2005/10	107,819.91	0.00	0.00	0.00	107,819.91
					2005/11	107,819.91	0.00	0.00	0.00	107,819.91
					2005/12	107,819.91	0.00	0.00	0.00	107,819.91
					2006/01	107,819.91	0.00	0.00	0.00	107,819.91
					2006/02	107,819.91	0.00	0.00	0.00	107,819.91
					2006/03	107,819.91	0.00	0.00	12,652.77	95,167.14
					2006/04	95,167.14	0.00	0.00	7,959.58	87,207.56
					2006/05	87,207.56	0.00	0.00	9,726.39	77,481.17
19521	202D015G093I16-00	969,400.00	50.0000000	484,700.00						
					2006/01	484,700.00	0.00	0.00	48,911.09	435,788.91
					2006/02	435,788.91	0.00	0.00	46,874.28	388,914.63
					2006/03	388,914.63	0.00	0.00	45,413.04	343,501.59
					2006/04	343,501.59	0.00	0.00	36,614.80	306,886.79
					2006/05	306,886.79	0.00	0.00	35,142.26	271,744.53

Sample 7.1(6)

3% Minimum Royalty Deep Deduction Sample

Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - Non-PE Operations
Deep Well Bank Calculation

To Royalty Payor: ABC Compamy Royalty Payor Code: 0999

WA Number	Unique Well Identifier	Initial WA-Bank	Payor % Interest	Initial Client-Bank	Prodn Period	Opening Balance	Transfers In	Transfers Out	[1] Potential Deep Deduction	[2] Deferred Deep Deduction	[3] Actual Deep Deduction	Closing Balance
28586	200C064I094B09-00	2,351,479.00	20.0000000	470,295.80								
					2013/02	470,295.80	0.00	0.00	6,056.97		6,056.97	464,238.83
					2013/03	464,238.83	0.00	0.00	19,973.26		19,973.26	444,265.57
					2013/04	444,265.57	0.00	0 00	25,252.00	3,292.28	21,959.72 d	422,305.85
28618	200C065B094B16-00	2,443,897.00	50.0000000	1,221,948.50								
					2013/01	1,221,948.50	0.00	0.00	1,684.46		1,684.46	1,220,264.04
					2013/02	1,220,264.04	0.00	0.00	0.00		0.00	1,220,264.04
					2013/03	1,220,264.04	0.00	0.00	57,387.92		57,387.92	1,162,876.12
					2013/04	1,162,876.12	0.00	0.00	4,899.48	8,478.19	- 3,578.71 a	1,166,454.83

Sample 7.1(6a)

RMS98521

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - PE Operations
PE - Gas Details
Assessment Notice Date: 2006/04/26 Payment Due Date: 60 days after Assessment Notice Date Invoice:50440-200603-3

To Royalty Payor ABC Company REN: 50999
Royalty Payor Code: 0999 Production Period: 2006/03

PE	Plant	Gas Type	Marketable Gas Volume (1000m3)	Reference Price	Marketable Gas Royalty Rate(%)	Marketable Gas Royalty($)	By-Product Royalties ($)	Weighted Average Royalty Rate(%)	Raw Gas Volume (1000 m3)	PCOS Rate ($)	PCOS Allowance ($)	Gas and By-Product Royalty less PCOS($)	Net Royalty Payable($)	Previous Royalty Payable($)
0016	439	CONS-C	1,033.7	217.031	13.38733	30,033.80	4.874.07	14.03527	1,070.8	16.00	2,404.63	32,503.24	32,503.24	18,740.07
													==============	==============
												Totals for 2006/03	32,503.24	18,740.07
												Difference:	13,763.17	

Sample 7.1(7)

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice - Non-PE Operations
Non-PE - Gas Details
Assessment Notice Date: 2006/04/26 Payment Due Date: 60 days after Assessment Notice Date Invoice:60999-200603-003

To Royalty Payor ABC Company REN: 60999
Royalty Payor Code: 0999 Production Period: 2006/03

WA#	Unique Well Identifier	Plant	Reporting Facility	Marketable Gas Volume (1000m3)	Reference Price	Net Marketable Gas Royalty Rate(%)	Net Marketable Gas Royalty($)	By-Product Royalties ($)	Weighted Average Royalty Rate(%)	Raw Gas Volume (1000 m3)	PCOS Rate ($)	PCOS Allowance ($)	Gas and By-Product Royalty less PCOS($)	Deep Well Deduction($)	Net Royalty Payable($)	Previous Royalty Payable($)
17237	200D055I093P07-00	205	205	52.3	238.724	7.46793	932.39	0.00	7.46792	56.1	5.90	24.72	907.67	0.00	907.67	3,072.16
18573	200B005E093P10-00	205	7382	61.7	238.724	21.24225	3,128.83	0.00	21.24226	67.9	5.11	73.70	3,055.13	0.00	3,055.13	3,883.22
19185	200D005E093P10-00	205	7382	65.6	238.724	20.21760	3,166.13	0.00	20.21757	72.2	5.11	74.59	3,091.54	0.00	3,091.54	4,128.67
19258	200C035B093P10-00	205	205	211.0	238.724	22.16754	11,165.96	25.77	22.16201	229.4	5.90	299.95	10,891.78	0.00	10,891.78	13,260.69
19355	200A035B093P10-00	205	205	93.1	238.724	17.66961	3,927.11	159.18	17.75021	103.9	5.90	108.81	3,977.48	0.00	3,977.48	5,995.95
19356	200A044B093P10-00	205	205	97.6	238.724	17.36667	4,046.34	25.52	17.38100	104.6	5.90	107.27	3,964.59	0.00	3,964.59	6,149.98
20091	200B022K093I16-00	204	9102*	99.7	225.600	27.00000	6,072.93	45.06	26.93057	114.5	17.56	541.47	5,576.52	5,576.52	0.00	5,576.52
07386	100150108719W6-00	745	745	56.8	.000	.00000	0.00	288.67	20.00000	69.1	27.21	274.24	14.43	0.00	14.43	0.00
07455	200B059F093P10-00	205	7382*	67.9	225.142	22.77918	3,482.29	10.19	22.76996	72.9	5.11	84.82	3,407.66	0.00	3,407.66	2,826.02
16181	200C029B093P10-00	205	205	467.3	225.142	26.86095	28,260.10	149.32	26.81261	521.4	5.90	824.83	27,584.59	0.00	27,584.59	27,726.64
18822	200B081H094H07-00	439	7235	43.1	211.562	27.00000	2,461.95	22.66	26.91419	45.9	8.80	108.71	2,375.90	2,375.90	0.00	2,375.90
19258	200C035B093P10-00	205	205	191.8	225.142	18.91350	8,167.27	19.21	18.91590	209.6	5.90	233.92	7,952.56	0.00	7,952.56	11,344.71
													Totals for	2006/03	64,847.43	86,340.96
														Difference:		21,493.53-

* Facility reported on the BC08 is different than the facility recorded on RMS
X Exemption from Gas Royalty used this month
N means UWI does not receive the compression component of the PCOS, even though its linked facility does have compression

Sample 7.1(8)

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RMS98570

GOVERNMENT OF BRITISH COLUMBIA GAS ROYALTY/TAX INVOICE 2006/08/14
Issued by The Ministry of Finance, Mineral, Oil and Gas Revenue Branch
Gas Royalty/Tax Invoice Summary

Royalty/Tax Payor: 0999 ABC Company

REN	Prod Period	Invoice Number	Current Invoice Amount	Previous Invoice Amount	Difference
50999	2006/03	5-0999-200603-003	32,503.24	18,740.07	13,763.17
60999	2006/03	6-0999-200603-004	64,847.43	86,340.96	-21,493.53
50999	2006/04	5-0999-200604-002	50,705.42	35,958.16	14,747.26
60999	2006/04	6-0999-200604-002	806,988.00	610,812.23	196,175.77
50999	2006/05	5-0999-200605-001	46,122.34	.00	46,122.34
60999	2006/05	6-0999-200605-001	673,571.12	.00	673,571.12
			-------------	-------------	-------------
Total of 6 invoices generated.		Total amount of invoices:	1,674,737.55	751,851.42	922,886.13
			=============		

Sample 7.1(9)

7.1 Gas Royalty Invoicing – After February 2006

Starting with production in March 2006 the Ministry changed to well-based reporting of allocations of marketable gas and by-products. A new allocations reporting form called the Marketable Gas and By-Product Producer Allocations (BC08) was introduced for production after February 2006. See BC-08 Marketable Gas and By-Product Producer Allocations Guidelines for a description of this report and related procedures.

Well-based reporting of marketable gas and by-product allocations on BC08 reports enables the Ministry to calculate net gas royalties and taxes for each well event. Commensurate with this reporting change, gas royalty and tax invoices were changed to a well-based format. Invoices for production in March 2006 and later are generated from BC-08 reports.

As a rule, the Ministry will issue gas royalty invoices once per month to each producer. These will include initial invoices for the most current production month and amendments to invoices for previous production months.

There are two types of invoices for gas royalty and tax on production after February 2006: one for gas produced from oil wells that are in Production Entities (PE invoices) and one for gas produced from oil wells that are not in PE's and gas wells (Non-PE invoices). The Ministry will issue each invoice and related schedules in the form of an MS Word document and as a CSV file that can be more readily uploaded into other systems. This section provides an explanation of the MS Word version of the invoices and related schedules. Section 7.2 provides and explanation of the CSV version.

The MS Word version of the invoice for PE's is illustrated in Sample 7.1(1). The Non-PE invoice is illustrated in Sample 7.1(3). The MS Word version of the schedule that includes the minimum royalty is illustrated in Sample 7.1(3a).

Each invoice has a schedule that shows details of by-product sales volumes and values and by-product royalty or tax payable for each PE or well event. The MS Word versions of these are illustrated in Sample 7.1(2) for PE's and 7.1(4) for other wells.

The invoice for oil wells that are not in PE's and gas wells also has a "Non-PE – Incentive Deduction Details" schedule that shows how the royalty rate for each well event has been determined. This is illustrated in Sample 7.1(5).

Each invoice for oil wells that are not in PE's and gas wells also has a schedule that shows details of how balances in deep well banks have been derived. This schedule is illustrated in Sample 7.1(6). The MS Word version of the schedule that includes the 3% minimum royalty is illustrated in Sample 7.1(6a).

Invoice amendments for PE's and for other wells are illustrated in Samples 7.1(7) and 7.1(8), respectively.

Sample 7.1(9) illustrates a Gas Royalty/Tax Invoice Summary for a producer and month.

GAS ROYALTY OR TAX INVOICE

The following is an explanation of information displayed on a Gas Royalty Invoice and related shedules. The explanation is divided into parts as follows:

Part A – Gas Royalty Invoice Details
Part B – By-Product Details Schedule
Part C – Royalty Rate Incentive Deductions Schedule
Part D – Deep Well Bank Schedule
Part E – Amended Invoices
Part F – Invoice Summary

A. GAS ROYALTY OR TAX INVOICES

The **Gas Royalty/Tax Invoice – PE Operations, PE – Gas Details** [**Sample 7.1(1)**] and the **Gas Royalty/Tax Invoice – Non-PE Operations, Non-PE Gas Details** [**Sample 7.1(3)** and **Sample 7.1(3a)**] provide significant items of information used or calculated in determining royalties payable for each PE or well event, respectively.

(i) **Header:** Except for the titles, headers are the same PE and Non-PE invoices. The headers provide the following information.

Invoice Date: This is the date on which the invoice is sent.

Payment Due Date: This is the later of 15 days after the Invoice Date or the 25th of the 3rd month after the Production Period.

Invoice: This is an identifying number for the invoice, consisting of the 5-digit REN, 6-digit Production Period, and the number of invoices that have been issued for the REN and Production Period.

To Royalty Payor: This is the name of the person responsible for payment.

Royalty Payor Code: This is the ministry's 4-digit client code for the Royalty Payor.

REN: This is the ministry's 5-digit number for the Reporting Entity. For PE gas royalty invoices, it consists of the number 5 followed by the 4-digit client code for the Royalty Payor. For Non-PE invoices, it consists of a 6 followed by the 4-digit code for the Royalty Payor. The REN should be referenced when applying payments on the BC15 Remittance Advice.

Production Period: This is the month in which the gas was produced.

GAS ROYALTY OR TAX INVOICE cont'd

PE and/or Non-PE invoices list the following items of information used in calculating the royalty or tax payable on the producer's share of gas produced from each PE for PE invoices or well event for Non-PE invoices.

PE — On PE Invoice details only, this is the ministry's 4-digit code for the Production Entity, as provided on BC08 reports.

WA# — On Non-PE Invoice details only, this is the 5-digit Well Authorization code assigned by the Oil & Gas Commission to its permit for the well to be drilled. This is taken from BC08 reports.

Unique Well Identifier — On Non-PE Invoice details only, this is the 16-digit identifier for the well event from which the gas was produced. This is taken from BC08 reports.

Plant — This is the 4-digit code for the gas processing plant at which the marketable gas and by-products were produced, as provided on BC08 reports. This determines the Reference Price that is used in the royalty calculations.

Gas Type — On PE Invoice details only, this is the classification of the gas that is used to determine the royalty rate. This is obtained from ministry records. Possible classifications for PE's are as follows:

- CONS-C - conservation gas from Crown land
- CONS-F - conservation gas from Freehold land

Reporting Facility — On Non-PE Invoice details only, this is the 5-digit code to which the reporting facility to which the well is connected. This is obtained from the OGC records of well-to-facility connections, which may differ from the facility that is reported for the well event on the BC08. The Reporting Facility determines the PCOS rate that is used in the royalty calculations for the well event.

Marketable Gas Volume (1000m3) — The amounts in this column are the royalty payer's share of marketable gas produced from each PE or well event during the Production Period, as provided on a BC08 report.

Reference Price — The amounts in this column are the values in \$ per 10^3m^3 that are used in the calculation of the royalty payable for each PE or well event. Reference Prices are the greater of the royalty payer's average sales price (Producer Price) and the Posted Minimum Price at each Plant, as determined by the Ministry of Energy, Mines and Natural Gas from sales information.

GAS ROYALTY OR TAX INVOICE cont'd

Marketable Gas Royalty Rate (%)

The amounts in this column are the % royalty rates that are applied to the royalty payer's share of marketable gas produced from each PE or well event during the Production Period. For each PE, this is determined by the **Reference Price** and the rate formula for the **Gas Type**. If the **Gas Type** is CONS-C, the formula is

$$\frac{400 + 15\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{ , minimum 8 \% .}$$

If the **Gas Type** is CONS-F, the formula is

$$\frac{245 + 9\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{ , minimum 9 \% .}$$

For each Non-PE well event, details of the **Net Marketable Gas Royalty Rate** calculation are provided in the **Non-PE Incentive Deduction Details** schedule.

Marketable Gas Royalty ($)

The amounts in this column are the royalty payable by the royalty payer's share of marketable gas from each PE or well event before PCOS Allowances and Deep Well Deductions. For each PE or well event, this is equal to the **Marketable Gas Volume** x **Reference Price** x **Marketable Gas Royalty Rate**.

By-Product Royalties ($)

The amounts in this column the gross royalties payable on the royalty payer's share of all by-products produced from each PE or well event during the Production Period. Details of the **By-Product Royalties** calculation are provided for each PE and non-PE well event in the **PE – Gas By-Product Details** and **Non-PE By-Product Details** schedules, respectively.

Weighted Average Royalty Rate (%)

The amounts in this column for each PE or well event are the average of the marketable gas and by-product royalty rates weighted in accordance with their sales values. This is calculated by the ministry. The sales value for marketable gas is the **Marketable Gas Volume** x **Reference Price**. The **Weighted Average Royalty Rate** is used in calculating the PCOS Allowance.

Raw Gas Volume (1000 m3)

The amounts in this column are the royalty payor's share of raw gas from each PE or well event that is delivered to the listed **Plant** for processing, as provided on BC08 reports.

PCOS Rate ($)

This column lists the rates per 10^3m^3 of are used by the ministry in calculating the PCOS Allowance for each PE or well event. These rates are set by the Ministry of Energy, Mines and Natural Gas for each **Reporting Facility**.

GAS ROYALTY OR TAX INVOICE cont'd

PCOS Allowance ($) The amounts in this column are the PCOS Allowance that is deducted from marketable gas and by-product royalties for each well event. PCOS Allowances compensate the royalty payer for the cost of gathering, dehydration, compression and field processing of the portion of the gas that is paid to the Crown in royalties. The PCOS Allowance for each PE or well event is equal to the **Weighted Average Royalty Rate** x **Raw Gas Volume** x **PCOS Rate**.

Gas and By-Product Royalty less PCOS ($) The amounts in this column for each PE or well event are equal to the **Marketable Gas Royalty** + **By-Product Royalties - PCOS Allowance**.

Deep Well Deduction ($)

For production periods prior to April 2013, the **Deep Well Deduction** is the lessor of the **Gas and By-Product Royalty less PCOS** for the well event and the remaining balance in the Royaly Payor's deep well bank for the well.

For Production periods after March 2013, the minimum royalty program applies. See section 5.10 for a description of how this program affects the deep well deduction. Under the rules of the minimum royalty program, the net effect on the well events deep credit bank can be an **addition** to the deep bank (denoted by the letter "a" to the right of the amount of the adjustment to the deep well credit bank). Under these same rules, the net effect on the well events deep well credit bank can be a **decrease** (denoted by the letter "d" to the right of the deep well credit bank). Details of the deep well bank calculations are provided in the **Deep Well Bank Calculation** schedule.

Net Royalty Payable ($) **Net Royalty Payable** for each PE is equal to the Gas and By-Product Royalty less PCOS. **Net Royalty Payable** for each well event is equal to the **Gas and By-Product Royalty less PCOS – Deep Well Deduction**, if any.

GAS ROYALTY OR TAX INVOICE cont'd

Previous Royalty Payable ($)	The amounts in this column are the Net Royalty Payable for each PE or well event on the immediately preceding invoice, if any, for the REN/Production Period. For example, for each well event on invoice number 60999-200605-002 this would be the Net Royalty Payable for each invoice 60999-200605-001.
Net Effect of Minimum Royalty on Deep Well Credit Bank	The amounts in this column (Column 3) are equal to Gas and By-Product Royalty less PCOS ($) (Column 1) less Net Royalty Payable ($) (Column 2).
Tier	If the well is a Tier 1 well, the digit 1 will be shown.

Each **Gas Royalty/Tax Invoice** states the **Totals** of the **Net Royalty Payable** and **Previous Royalty Payable** for all of the PE's or well events on the invoice, and the **Difference** between the two **Totals**.

B. BY-PRODUCT DETAILS SCHEDULE

The **PE – Gas By-Product Details** [**Sample 7.1(2)**] and **Non-PE By-Product Details** [**Sample 7.1(4)**] schedules provide by-product sales volumes, sales values and gross royalties for each PE or well event, respectively.

(i) **Header:**
To identify the invoice to which the schedule relates, the top of each schedule provides the same information as the header on the Invoice Details.

(ii) **By-Product Details:**

Column heading	Description
PE	On **PE – Gas By-Product Details** only, this is the ministry's 4-digit code for the Production Entity. This is taken from BC08 reports.
WA#	On **Non-PE By-Product Details** only, this is the 5-digit Well Authorization code assigned by the Oil & Gas Commission to its permit for the well to be drilled. This is taken from BC08 reports.
Unique Well Identifier	On **Non-PE By-Product Details** only, this is the 16-digit identifier for the well event from which the by-products were produced. This is taken from BC08 reports.
Plant	On **PE – Gas By-Product Details** only, this is the 4-digit code for the gas processing plant at which the by-products were produced, as provided on BC08 reports.
Gas Type	On **PE – Gas By-Product Details** only, this is the classification of the gas produced from the PE.
Ethane Sales Volume	Amounts in this column are volumes of ethane produced from each PE or well event that were sold during the Production Period, as provided on a BC08 report.

GAS ROYALTY OR TAX INVOICE cont'd

Ethane Sales Value ($)	This column lists the value received or receivable of sales during the Production Period of ethane produced from each PE or well event, as provided on a BC08 report.
Propane Sales Volume	Amounts in this column are volumes of propane produced from each PE or well event that were sold during the Production Period, as provided on a BC08 report.
Propane Sales Value ($)	This column lists the value received or receivable of sales during the Production Period of propane produced from each PE or well event, as provided on a BC08 report.
Butane Sales Volume	Amounts in this column are volumes of butane produced from each PE or well event that were sold during the Production Period, as provided on a BC08 report.
Butane Sales Value ($)	This column lists the value received or receivable of sales during the Production Period of butane produced from each PE or well event, as provided on a BC08 report.
Plant Pentanes Sales Volume	Amounts in this column are volumes of pentanes + produced from each PE or well event that were sold during the Production Period, as provided on a BC08 report.
Plant Pentanes Sales Value ($)	This column lists the value received or receivable of sales during the Production Period of pentanes + produced from each PE or well event, as provided on a BC08 report.
Field Cond Sales Volume	Amounts in this column are volumes of condensate produced in the field from each PE or well event that were sold during the Production Period, as provided on a BC08 report.
Field Cond Sales Value ($)	This column lists the value received or receivable of sales during the Production Period of condensate produced in the field from each PE or well event, as provided on a BC08 report.
Nat. Gas Liquid Sales Value ($)	Amounts in this column are the total of the **Ethane, Propane, Butane, Plant Pentanes** and **Field Cond Sales Values** for each PE or well event.
Nat. Gas Liquid Royalty ($)	The amount in this column for each PE or well event is the **Nat. Gas Liquid Sales Value** times the royalty rate for natural gas liquids. The royalty rate is 20% for natural gas liquids produced from Crown land and 12.25% for liquids produced from freehold land.
Sulphur Sales Volume	Amounts in this column are volumes of sulphur produced from each PE or well event that were sold during the Production Period, as provided on a BC08 report.

GAS ROYALTY OR TAX INVOICE cont'd

Sulphur Sales Value ($) This column lists the value received or receivable of sales during the Production Period of sulphur produced from each PE or well event, as provided on a BC08 report.

Sulphur Royalty ($) The amount in this column for each PE or well event is the **Sulphur Sales Value** times the royalty rate for sulphur. The royalty rate is 16.667% for sulphur produced from Crown land and 10.25% for sulphur produced from freehold land.

Total By-Product Royalty ($) Amounts in this column are the sum of the **Nat. Gas Liquid Royalty** and the **Sulphur Royalty** for each PE or well event. The amounts in this column are equal to the amounts in the **By-Product Royalties** column on the **Invoice Details** for each PE or well event**.**

C. ROYALTY RATE INCENTIVE DEDUCTIONS SCHEDULE

The **Non-PE - Incentive Deduction Details** schedule [**Sample 7.1(5)**] provides items of information that were used in calculating the royalty rate for the royalty payor's share of marketable gas produced from each non-PE well event. This schedule is not provided for PE invoices

(i) **Header:**
To identify the invoice to which the schedule relates, the top of each schedule provides the same information as the header on the Invoice Details.

(ii) **Royalty Rate Calculation Details:**

WA# On **Non-PE By-Product Details** only, this is the 5-digit Well Authorization code assigned by the Oil & Gas Commission to its permit for the well to be drilled. This is taken from BC08 reports.

Unique Well Identifier On **Non-PE By-Product Details** only, this is the 16-digit identifier for the well event from which the by-products were produced. This is taken from BC08 reports.

Plant On **PE – Gas By-Product Details** only, this is the 4-digit code for the gas processing plant at which the by-products were produced, as provided on BC08 reports.

Reference Price These are the values in $ per 10^3m^3 that are used in the calculation of the **Base Royalty Rate** for each well event. These are the same as the Reference Prices for each well event on the **Non-PE Invoice Details**.

GAS ROYALTY OR TAX INVOICE cont'd

Class Base Rate

These are the classification of the gas from each well event for royalty purposes. This is obtained from ministry records. Possible classifications are as follows:

- CONS-C for conservation gas from Crown land
- CONS-F for conservation gas from Freehold land
- 15-C for non-conservation gas from wells spud before June 1998 on Crown land (Base 15)
- 9-C for non-conservation gas from wells spud after June 1998 on Crown land for which oil and gas rights were issued after June 1998 and which have a completion date not more than 60 months after the date on which rights were issued (Base 9)
- 12-C for non-conservation gas from wells on Crown land other than 15-C and 9-C wells (Base 12)
- Fhld for non-conservation gas from Freehold land

BCS1 Volume

This is the volume in 10^3m^3 of raw gas produced from each well event during the Production Period, as reported by facility operators on Monthly Production Statements (BCS1 reports).

Hours of Production BCS1

This is the number of hours in the Production Period during which each well event produced marketable gas, as reported by facility operators on BCS1 reports.

Average Daily Production

This is the average daily rate of raw gas production in 10^3m^3 for each well event during the Production Period. It is equal to

24 x **BCS1 Volume** / **Hours of Production BCS1**

Daily Volume Cutoff

This is the average daily rate of raw gas production in 10^3m^3 below which production related reductions in the royalty rate take effect for each well event. Possible rates are 60.0 for ultra-marginal well events, 25.0 for marginal well events, 17.0 for coalbed methane well events, and 5.0 for all other gas well events.

GAS ROYALTY OR TAX INVOICE cont'd

Base Royalty Rate (%)

This is the basic royalty rate for each well event before production related reductions, if any. The base royalty rate for each well event depends on the **Class Base Rate** and the **Reference Price** as follows

CONS-C: Crown Land: Conservation

$$\frac{400 + 15\,(\text{Reference Price} - 50)}{\text{Reference Price}}, \quad \text{minimum } 8\ \%$$

15-C: Crown Land: Non-conservation, Base 15

$$\frac{750 + 25\,(\text{Reference Price} - 50)}{\text{Reference Price}}, \quad \text{minimum } 15\ \%$$

12-C: Crown Land: Non-conservation, Base 12

$$\frac{12 \times \text{Select Price} + 40\,(\text{Reference Price} - \text{Select Price})}{\text{Reference Price}}, \quad \text{minimum } 12\%, \ \text{maximum } 27\ \%$$

9-C: Crown Land: Non-conservation, Base 9

$$\frac{9 \times \text{Select Price} + 40\,(\text{Reference Price} - \text{Select Price})}{\text{Reference Price}}, \quad \text{minimum } 9\ \%, \ \text{maximum } 27\ \%$$

CONS-F: Freehold Land**:** Conservation

$$\frac{245 + 9\,(\text{Reference Price} - 50)}{\text{Reference Price}}, \quad \text{minimum } 9\ \%$$

Fhld: Freehold Land: Non-conservation

$$\frac{460 + 15\,(\text{Reference Price} - 50)}{\text{Reference Price}}, \quad \text{minimum } 5\ \%$$

Royalty Rate Reduction Factor

If the **Average Daily Production** for a well event during the Production Period is less than the **Daily Volume Cutoff** for the well event, the **Base Royalty Rate** is reduced by this factor times the **Base Royalty Rate (%)**. These factors have a value □0 and □1. They are determined as follows:

- Ultra-marginal well events:
((60 - **Average Daily Production**) / **60**) ^{2}
- Marginal well events:
((25 - **Average Daily Production**) / **25**) ^{2}
- Coalbed methane well events:
((17 - **Average Daily Production**) / **17**) ^{2}
- All other gas well events (low productivity well events)
((5 - **Average Daily Production**) / **5**) ^{2}

Royalty Rate Reduction

This is the production related reductions, if any, from the basic royalty rate for each well event. The reduction for a well event is equal to **Base Royalty Rate x Royalty Rate Reduction Factor** for the well event.

Net Royalty Rate

For each well event, this is equal to the **Base Royalty Rate - Royalty Rate Reduction**.

GAS ROYALTY OR TAX INVOICE cont'd

Batch Number — This is a number assigned by the ministry to the batch of BC08 reports that included the BC08 on which the royalty calculations for the well event were based.

Entry Date-Time — This is the date and time that the BC08 report on which the royalty calculations for the well event were based was submitted. For BC08 reports that are created with the Excel file provided by the ministry, this is the date and time at which the submit button was clicked to create the CSV file. For BC08 reports that are submitted using the online BC08 screen on the ministry's website, this is the date and time at which the submit button was clicked. The date is in year/month/day format. The time uses the 24:00 hour format to the nearest one hundredth of a second.

D. DEEP WELL BANK CALCULATION SCHEDULE

The **Deep Well Bank Calculation** schedule [**Sample 7.1(6)** and **Sample 7.1(6a)**] provides information that was used in calculating the available balance in the deep well bank for qualifying well events. This schedule is not relevant for PE invoices.

(i) **Header:**
The top of each schedule provides the name and code of the Royalty Payer whose deep well banks are listed on the schedule.

(ii) **Deep Well Bank Calculation Details:**

WA Number — This is the 5-digit Well Authorization code assigned by the Oil & Gas Commission to its permit for each deep well. Although a well may have more than one well event that qualifies as deep, there can be only one deep well bank for a well. The deep well bank is determined by the deepest of the qualifying deep well events in the well.

Unique Well Identifier — For each deep well in which the royalty payer has an interest, this is the 16-digit identifier for the deepest deep well event. The initial deep well bank for each well is based on the deep well depth of this well event.

Initial WA Bank — For each deep well, this is the full amount of deep well deduction that was initially available for the well, as calculated by the ministry. This amount is allocated to royalty payers in proportion to their ownership interests in the well event identified by the **Unique Well Identifier**. To understand how this is calculated, see section 5.9 of this Handbook.

Payor % Interest — For each deep well, this is the Royalty Payer's ownership interest in the **Unique Well Identifier** in the month in which it began producing. This is obtained from ownership interests reported to the ministry on BC12 Reporting Interest Statements.

GAS ROYALTY OR TAX INVOICE cont'd

Initial Client-Bank	For each deep well, this is the initial amount of deep well deduction that was available to the Royalty Payer. This is equal to the **Initial WA Bank x Payor % Interest.**
Prodn Period	For each deep well, these are the production periods to which the **Opening** and **Closing Balance**, **Transfers**, and **Deep Deduction** relate. The production periods that are listed.
Opening Balance	For each production period for a deep well event, this is the balance that was available at the beginning of the production period for deduction by the Royalty Payer from royalties payable on production from deep well events in the well. This is equal to the **Initial Client-Bank + Transfers In - Transfers Out - Deep Deductions** in all previous production periods.
Transfers In	These are deep well deductions that have been obtained by the Royalty Payer in each production period as a result of acquiring an interest in the well event identified by the **Unique Well Identifier** from a royalty payer for whom there was a balance available for deduction at the time of the acquisition. The amount transferred in for a well is equal to the other royalty payer's closing balance at the end of the previous production period times the proportion of the other royalty payer's interest that was acquired.
Transfers Out	These are the balances of deep well deductions that have been transferred to another royalty payer in each production period as a result of disposing of an interest in the well event identified by the **Unique Well Identifier.** The amount transferred out for a well is equal to the Royalty Payer's closing balance at the end of the previous production period times the proportion of the Royalty Payer's interest that was disposed of.
Potential Deep Deduction (Column 1)	This is the amount of Gross Royalties less PCOS on the gas royalty invoice. It is equal to Column 1 on the gas invoice. This amount represents the **maximum** deep well bank deduction for the well event in the production period.
Deferred Deep Deduction (Column 2)	This amount is equal to the amount of minimum royalty that has been charged on the invoice. It is equal to Column 2 on the gas royalty invoice.
Actual Deep Deduction (Column 3)	This amount is the difference between the Potential Deep Deduction (Column 1) and the Deferred Deep Deduction (Column 2). It is noted that where this amount is negative, the result of deducting a negative number from the deep bank is to **add to the bank**.

GAS ROYALTY OR TAX INVOICE cont'd

Deep Deduction	These are the amounts deducted form royalties payable on gas produced in each production period. They will equal the sum of the **Deep Well Deduction** amounts for all deep well events in the well on the **Non-PE Invoice Details** for the production period. Well events in the same well can be identified on the **Non-PE Invoice Details** by a common **WA#**.
Closing Balance	For each production period for a deep well event, this is the balance that was available for deduction by the Royalty Payer at the end of the production period. This is equal to the **Opening Balance + Transfers In - Transfers Out - Actual Deep Deduction** for the production period.

E. AMENDED INVOICES

Amended gas royalty invoices [**Sample 7.1(7)** and **7.1(8)**] have the same items of information as initial invoices, the only difference being that there is likely to be non-zero amounts for each PE or well event in the **Previous Royalty Payable ($)** column. Amended invoices list only those PE's or well events for which royalty information has changed from the previous invoices.

F. GAS ROYALTY INVOICE SUMMARY

The ministry issues one set of initial and amended gas royalty invoices per month to a royalty payer. A monthly set of invoices is accompanied by a **Gas Royalty/Tax Invoice Summary** [**Sample 7.1(9)**], which summarizes the net royalties payable for all of the invoices in the set.

(i) **Header:**
The top of each schedule provides the name of the Royalty Payer to whom the invoices have been issued.

(ii) **Invoice Summary Information:**

REN	For each Invoice, this is the ministry's 5-digit **REN** shown in the header of the invoice. For PE invoices, it consists of a 5 and the 4-digit client code for the Royalty Payor. For non-PE invoices, it consists of a 6 followed by the Royalty Payor code. The **REN** should be referenced when applying payments on the BC15 Remittance Advice.
Prod Period	For each Invoice, this is the 6-digit **Production Period** shown in the header of the invoice.
Invoice Number	This is the identifying number of each invoice, as shown in the header of the invoice. It consists of the **REN, Production Period,** and the number of invoices that have been issued for the **REN** and **Production Period**.
Current Invoice Amount	This is the total **Net Royalty Payable** for all PE's or well events on each invoice, as shown on the **Invoice Details** of each invoice.

GAS ROYALTY OR TAX INVOICE cont'd

Previous Invoice Amount	This is the total **Previous Royalty Payable** for all PE's or well events on each invoice, as shown on the **Invoice Details** of each invoice.
Difference	This is the difference between the total **Net Royalty Payable** and total **Previous Royalty Payable** for all PE's or well events on each invoice, as shown on the **Invoice Details** of each invoice.

The **Gas Royalty/Tax Invoice Summary** also provides the total number of invoices in the set and the total of the **Current Invoice Amounts, Previous Invoice Amounts** and **Differences** for all invoices in the set.

7.2 CSV Gas Royalty Invoices – After March 2014

Starting with production in March 2006 the Ministry changed to well-based reporting of allocations of marketable gas and by-products. Commensurate with this reporting change, the ministry revised its gas royalty invoices to provide net royalties payable by Productin Entity (PE) or well event.

As with previous invoices, the revised invoices are delivered to producers as an MS Word document and in the form of a Comma Separated Variable (CSV) file that can be uploaded into producers' accounting systems. To assist producers with setting up this upload, this section provides a description of the content and layout of the CSV file.

For a given producer and production period, the CSV file has one record for every UWI/Plant or PE/Plant allocation. The following schedule presents a description of each field of data in a record. Every item is zero filled from the left and except for the last item, is followed by a comma. There are 77 data fields for a total record length of bytes. The CSV files can be viewed as an Excel spreadsheet with an allocation record in each row. In the following descriptions, column letters are used as identifiers for the data fields in each record.

The CSV file includes a number of data items that are not included on the MS Word version. The following fields include information that was used in determining the net royalty/tax payable, but is not included on the MS Word invoice due to space limitations: O, P, Q, T, U, AT, AY, BA, BC, BD, BF, and BJ. Fields AC, AF, AI, AL, AO, AR, and AX in the CSV file include calculations of Crown royalty share in physical units for marketable gas and each by-product. These items are not used in calculating net royalty payable, but are provided for producers who need this information for reporting purposes. Fields D, F and BN to BR are extra information to assist producers in resolving problems with royalty charges.

The following table provides a description of the CSV file for a gas royalty invoice. The CSV file includes all data items that are provided on the MS Word version of the invoice. In the following table, these data fields are noted by a "W" after the field name. Section 7.1 of this Handbook provides more detailed descriptions of many of these fields.

Gas Royalty Invoice - CSV File Layout Field	Field Name		Start	Length	Format	Description
A	Royalty Payor Code	**W**	1	4+1= 5	X(4),	4-digit client code
B	Production Period	**W**	6	6+1= 7	YYYYMM,	Month in which gas was produced
C	Plant	**W**	13	8+1= 9	X(8),	8-digit plant code reported on BC08
D	Reporting Facility	**W**	22	8+1= 9	X(8),	8-digit facility code reported on BC08
E	Linked Facility		31	8+1= 9	X(8),	Facility to which well is linked per OGC records
F	Production Source		40	8+1= 9	X(8),	Production source code reported on BC08
G	Unique Well Identifier	**W**	49	16+1=17	X(16),	16-character unique well identifier
H	WA #	**W**	66	5+1= 6	X(5),	Well Authorization

						number issued by OGC
I	PE	**W**	72	4+1= 5	X(4),	4-digit Production Entity Code
J	Raw Gas Volume	**W**	77	9+1=10	9(7).9(1),	Raw gas volume from BC08
K	Marketable Gas Volume	**W**	87	9+1=10	9(7).9(1),	Marketable gas volume from BC08
L	Gas Type	**W**	97	4+1= 5	X(4),	Royalty rate classification for PE invoices
M	Crown or Freehold		102	1+1= 2	X(1),	C=Crown, F=Freehold
N	Reference Price	**W**	104	7+1= 8	9(3).9(3),	Price used to calculate royalty
O	Producer Price		112	7+1= 8	9(3).9(3),	Average sales price of producers gas at the plant
P	Reference Price Value		120	10+1=11	9(7).9(2),	Reference Price x Marketable Gas Volume
Q	Producer Price Value		131	10+1=11	9(7).9(2),	Producer Price x Marketable Gas Volume
R	Base Royalty Rate	**W**	142	8+1= 9	9(2).9(5),	Royalty rate on non-PE before production-based reduction
S	S1 Volume	**W**	151	9+1=10	9(7).9(1),	Production for the well event as reported by facility operator on S1 report
T	Exempt S1 Volume		161	9+1=10	9(7).9(1),	Production per S1 x Exempt S1 Fraction
U	Exempt S1 Fraction		171	9+1=10	9(1).9(7),	Fraction (not %) of S1 volume that is exempt
V	Hours of Production S1	**W**	181	3+1= 4	9(3),	Hours of production as reported by facility operator on S1
W	Daily Volume Cutoff	**W**	185	5+1= 6	9(3).9(1),	Average Daily S1 Volume below which production-based rate reductions take effect
X	Average Daily Production	**W**	191	13+1=14	9(5).9(7),	(S1 Volume / Hours) x 24
Y	Royalty Rate Redn Factor	**W**	205	8+1=9	9(2).9(5),	Fractional multiplier to base rate, >0, <1
Z	Royalty Rate Reduction	**W**	214	8+1=9	9(2).9(5),	% amount deducted from Base Royalty Rate
AA	Net Royalty Rate	**W**	223	8+1=9	9(2).9(5),	Base Royalty Rate less Royalty Rate Reduction
AB	Marketable Gas Royalty	**W**	232	10+1=11	9(7).9(2),	Royalty on marketable gas before deductions
AC	Gas Crown Share		243	9+1=10	9(7).9(1),	Marketable Gas Volume x Net Royalty Rate / 100
AD	Ethane Sales Volume	**W**	253	9+1=10	9(7).9(1),	Volume of ethane (10^3 m^3) reported on BC08
AE	Ethane Sales Value	**W**	263	10+1=11	9(7).9(2),	$ Value of ethane reported on BC08
AF	Ethane Crown Share		274	9+1=10	9(7).9(1),	Ethane Sales Volume x Liquid Royalty Rate
AG	Propane Sales Volume	**W**	284	9+1=10	9(7).9(1),	Volume of Propane (10^3 m^3) reported on BC08
AH	Propane Sales Value	**W**	294	10+1=11	9(7).9(2),	$ Value of Propane reported on BC08
AI	Propane Crown Share		305	9+1=10	9(7).9(1),	Propane Sales Volume x

						Liquid Royalty Rate
AJ	Butane Sales Volume	**W**	315	9+1=10	9(7).9(1),	Volume of Butane (10^3 m^3) reported on BC08
AK	Butane Sales Value	**W**	325	10+1=11	9(7).9(2),	$ Value of Butane as reported on BC08
AL	Butane Crown Share		336	9+1=10	9(7).9(1),	Butane Sales Volume x Liquid Royalty Rate
AM	Pentane Sales Volume	**W**	346	9+1=10	9(7).9(1),	Volume of Pentanes (10^3 m^3) reported on BC08
AN	Pentane Sales Value	**W**	356	10+1=11	9(7).9(2),	$ Value of Pentanes reported on BC08
AO	Pentane Crown Share		367	9+1=10	9(7).9(1),	Pentane Sales Volume x Liquid Royalty Rate
AP	Field Cond Sales Volume	**W**	377	9+1=10	9(7).9(1),	Volume of Condensate (10^3 m^3) reported on BC08
AQ	Field Cond Sales Value	**W**	387	10+1=11	9(7).9(2),	$ Value of Condensate reported BC08
AR	Cond Crown Share		398	9+1=10	9(7).9(1),	Condensate Sales Volume x Liquid Roy Rate
AS	Nat. Gas Liquid Sales Value	**W**	408	10+1=11	9(7).9(2),	Sum of Sales Values of liquids above
AT	Liquid Royalty Rate		419	8+1=9	9(2).9(5),	Royalty rate for liquid products
AU	Nat. Gas Liquid Royalty	**W**	428	10+1=11	9(7).9(2),	Total liquids royalty before deductions
AV	Sulphur Sales Volume	**W**	439	9+1=10	9(7).9(1),	Weight of Sulphur (tonnes) reported on BC08
AW	Sulphur Sales Value	**W**	449	10+		
AX	Sulphur Crown Share		460	9+1=10	9(7).9(1),	Sulphur Sales x Sulphur Royalty Rate
AY	Sulphur Royalty Rate		470	8+1=9	9(2).9(5),	Royalty rate for Sulphur
AZ	Sulphur Royalty	**W**	479	10+1=11	9(7).9(2),	Sulphur royalty before deductions
BA	By-Product Sales Value		490	10+1=11	9(7).9(2),	Sum of $ Value of liquids and sulphur
BB	Total By-Product Royalty	**W**	501	10+1=11	9(7).9(2),	Total liquids and sulphur royalty
BC	Total Sales Value		512	10+1=11	9(7).9(2),	Sum of Ref Price Value and By-prod Sales Value
BD	Total Gross Royalty		523	10+1=11	9(7).9(2),	Sum of Marketable Gas Royalty and By-Product Royalty
BE	Weighted Average Roy Rate	**W**	534	8+1=9	9(2).9(5),	Total Gross Royalty / Total Sales Value
BF	UWI Compression Flag		543	1+1=2	X(1),	Y if UWI not under compression, but facility is Blank if UWI and facility under compression N if neither UWI nor facility under compression
BG	PCOS Rate	**W**	545	10+1=11	9(7).9(2),	Sum of PCOS component rates UWI is eligible for
BH	PCOS Allowance	**W**	556	10+1=11	9(7).9(2),	PCOS Allowance deducted from royalties
BI	Gas and By-Product	**W**	567	10+1=11	9(7).9(2),	Total Gross Royalty –

BJ	Royalty Less PCOS Exempt Deduction		578	10+1=11	9(7).9(2),	PCOS Deduction Exempt S1 Fraction x Gross Royalty Less PCOS
BK	Deep Well Deduction	**W**	589	10+1=11	9(7).9(2),	Deduction due to deep well bank
BL	Net Royalty Payable	**W**	600	10+1=11	9(7).9(2),	Gross Royalty Less PCOS less Exempt and Deep Well Deductions
BM	Previous Royalty Payable	**W**	611	10+1=11	9(7).9(2),	Net Royalty Payable on previous invoice
BN	Change Type		622	3+1=4	X(3),	NEW = no previous record UPD = replaces a previous record
BO	Received Date		626	8+1=9	YYYYMMDD,	Date from Datetime Stamp on BC08
BP	Processed Date		635	8+1=9	YYYYMMDD,	Date when BC08 was posted
BQ	Calc Royalty Date		644	8+1=9	YYYYMMDD,	Date of royalty calculation
BR	Calc Royalty Time		653	6+1=7	9(6),	Time of royalty calculation
BS	Invoice Date	**W**	660	8+1=9	YYYYMMDD,	Date on which invoice is sent
BT	Invoice Count		669	4+1=5	9(4),	Invoice version number
BU	Total Net Royalty Payable	**W**	674	13+1=14	9(10).9(2),	Producer's total net payable for the REN/period
BV	Deep bank effect of the minimum royalty % used (a, d, or z)	**W**	688	1+1	X(1),	To show the effect of the minimum royaltyon the deep bank, (a)ddition, (d)eduction, or (z)ero
BW	Minimum royalty % used	**W**	690	6 + 1	9(2).9(3),	Displays the minimum royalty applied
BX	Effect on Deep Bank	**W**	697	10+1=11	9(7).9(2)	Net effect on the deep well bank of the minimum royalty
BY	Identifies the Deep Bank Tier that applies	**W**	708	1+0	X(1)	Deep bank tier, will be 1, 2, B or blank

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RMS67500 GOVERNMENT OF BRITISH COLUMBIA NATURAL GAS AND BY-PRODUCTS NOTICE OF ASSESSMENT 2001/10/26

Issued by The Ministry of Provincial Revenue, Mineral, Oil and Gas Revenue Branch

Assessment Notice Date: 2001/10/26 Payment Due Date: 60 days after Assessment Notice Date Invoice:05500-200109-3

To Royalty Payor:	ABC Co. Ltd.	REN:	09999	PCOS Rates $/1000m3	
Royalty Payor Code:	0999	Production Period:	2001/09	Conservation:	16.00
Plant:	0437 DUKE FORT NELSON B-84-G/94-J-10	BC10 Received Date:	2001/11/23	Non-Conservation:	======
Reporting Facility:	9999 HOPE B12K	Reference Price $/1000m3:	110.00	Gathering & Dehydration:	3.74
Crown Interest %:	100.0000000	Select Price $/1000m3:	50.000	Compression:	3.46
Batch Number:	W-2001-11-23			Field Processing:	.00 7.20

	Sales Volumes	Ref Price Value $	Royalty Rate	Royalty Share	Gross Royalty $
Marketable Gas (1000m3)					
Conservation Gas	298.5	32,835.00	11.81818	35.27727	3,880.50
Non-Conservation Gas					
Base 15	302.1	33,231.00	20.45455	61.79320	6,797.25
Low Prod Reduction	104.7		5.09073-	5.32999	586.30-
Base 12	460.8	50,688.00	27.00000	124.41600	13,685.76
Low Prod Reduction	199.0		1.72044-	3.42368	376.60-
Base 09	129.0	14,190.00	25.90909	33.42273	3,676.50
Low Prod Reduction	129.0		8.13701-	10.49674	1,154.64-
Byproducts (m3)					
Ethane	.0	.00	.00000	.00000	.00
Propane	.0	.00	.00000	.00000	.00
Butane	.0	.00	.00000	.00000	.00
LPG Mix	.0	.00	.00000	.00000	.00
Plant Pentanes	.0	.00	.00000	.00000	.00
Field Condensate	50.0	12,000.00	20.00000	10.00000	2,400.00
Sulphur (Tonnes)	.0	.00	.00000	.00000	.00
Totals		142,944.00			28,322.47

RAW GAS DELIVERED	VOLUME
Total Volume:	1301.1
Less: Returned Gas Volume:	45.0
Plus: Field Sales:	.0
PCOS Raw Gas Volume:	1256.1

Wghtd Ave Roy Rate =TotalGross Roy/Total Ref Price Value

19.81368 = 28,322.46 / 142,944.00

PCOS ALLOWANCE	Conservation	Non-Conservation
PCOS Raw Gas Volume:	315.0	941.1
Weighted Ave Royalty Rate (%):	19.81368	19.81368
PCOS Rate:	16.00	7.20
PCOS Allowance:	998.61	1,342.59

CALCULATION of NET ROYALTY PAYABLE	Amount
Total Gross Royalty:	28,322.47
Less: PCOS Allowance	2,341.17-
Less: Royalty Exempt Value:	.00-
NET ROYALTY PAYABLE:	25,981.30

PCOS Raw Gas Volume Calculation

{[Conservation Gas/(Conservation Gas + Total Non-Cons.)]* PCOS Raw Gas Volume} = Cons. Raw Volume
{[298.5/(298.5 + 302.1 + 460.8 + 129.0)]* 1256.1} = 315.0

{[Non-Conservation Gas/(Conservation Gas + Total Non-Cons.)] * PCOS Raw Gas Volume} = Non-Cons. Raw Volume
{[(302.1 + 460.8 + 129.0)/(298.5 + 302.1 + 460.8 + 129.0)] * 1256.1 } = 941.1

Payable at: CIBC 8th Avenue S.W. Calgary.
or at: Mineral, Oil and Gas Revenue Branch,
P.O. Box 9328 Stn. Prov. Govt.
Victoria, B.C. V8W 9N3

Sample 7.3(1)

RMS67521_NON GOVERNMENT OF BRITISH COLUMBIA NATURAL GAS AND BY-PRODUCTS INVOICE LOW PRODUCTIVITY CALCULATION 2003/01/10
Issued by The Ministry of Provincial Revenue, Mineral, Oil and Gas Revenue Branch

Royalty Reduction Calculation by REN for Low Productivity Gas Wells

Royalty Payor:	0999	ABC CO. LTD.
Reporting Entity:	09999	ENCANA SIERRA A-26-K/94-I-11
Production Period:	2001/09	
Crown Interest:	100.0000000	
Reporting Facility:	00009999	HOPE B12K
Plant:	00000437	DUKE FORT NELSON B-84-G/94-J-10

UWI	Prod Type	Month Volume =Vm	Fract of Vol Vm/sum(Vm) =Fv	Month Hours =H	Ave Daily Vol Vm/(H/24) =Vd	Low Prod Rdn Factor $[(5 - Vd)/5]^2$ =Rf	Low Prod Weighted Rdn Factor Rf x Fv =Wrf	Base Rate =Rt	Rate Rdn Rt x Wrf =Rd
200A015H094H07-00	Base15	52.0	0.4234528	400	3.1200000	0.1413760	0.05987		
200A063D094H08-00	Base15	30.0	0.2442997	300	2.4000000	0.2704000	0.06606		
200D075D094H08-00	Base15	40.8	0.3322476	500	1.9584000	0.3700530	0.12295		
Total Production:	Base15	122.8	1.000000	Total Weighted Reduction Factor:			0.24888	20.45455	5.09073
200B016A094A14-00	Base12	53.0	0.2294372	360	3.5333333	0.0860445	0.01974		
200D037I094H07-00	Base12	58.0	0.2510823	400	3.4800000	0.0924160	0.02320		
200D071J094H07-00	Base12	120.0	0.5194805	720	4.0000000	0.0400000	0.02078		
Total Production:	Base12	231.0	1.000000	Total Weighted Reduction Factor:			0.06372	27.00000	1.72044
200D002L094H09-00	Base09	49.0	0.3141026	600	1.9600000	0.3696640	0.11611		
200D004L094H09-02	Base12	53.0	0.3397436	560	2.2714286	0.2978041	0.10118		
200D006L094H09-00	Base09	54.0	0.3461538	550	2.3563636	0.2795525	0.09677		
Total Production:	Base09	156.0	1.000000	Total Weighted Reduction Factor:			0.31406	25.90909	8.13701

Sample 7.3(2)

7.3 Gas Royalty Invoicing

Gas royalty invoices are generated from BC-10 forms for April 2001 production and later. The invoice for gas royalty or tax is illustrated in Sample 7.1(1). Sample 7.1(2) illustrates a schedule to the invoice, which is titled 'Royalty Reduction Calculation by REN for Low Productivity Gas Wells'. This schedule shows how low productivity rate reductions on an invoice are calculated.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION

The following is an explanation of information displayed on a Gas Royalty Invoice and how it is derived using an example in which there is only one royalty payor at a facility. The example is divided into parts as follows:

Part A - Background Data
Part B - Gas Royalty Invoice
Part C - Low Productivity Reduction in Royalty Rates

A. BACKGROUND DATA

Raw gas production and hours on production for the production period for the Reporting Entity's wells as reported on the BC-S1:

	Hours on Production	Production 10^3m^3
Oil Wells - Conservation Gas:		
200B016H094H07-00	600	350.1
Total raw gas - Conservation		350.1
Non-conservation Gas Wells - Base 15:		
200A015H094H07-00	400	52.0
200A063D094H08-00	300	30.0
200D075D094H08-00	500	40.8
Total from low productivity wells - Base 15		122.8
200C017H094H07-00	600	225.6
Total raw gas - Base 15		348.4
Non-conservation Gas Wells - Base 12:		
200B016A094A14-00	360	53.0
200D037I094H07-00	400	58.0
200D071J094H07-00	720	120.0
Total from low productivity wells – Base 12		231.0
200C028H094H07-00	720	310.6
Total raw gas - Base 12		541.6
Non-conservation Gas Wells - Base 9:		
200D002L094H09-00	600	49.0
200D004L094H09-02	560	53.0
200D006L094H09-00	550	54.0
Total from low productivity wells - Base 9		156.0
Total raw gas - Base 9		156.0

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

- Total raw gas production for the facility and Reporting Entity — **1,396.1** 10^3m^3
- Total raw gas delivered to a plant for processing — **1,301.1** 10^3m^3
- Plant recovery factor — **91.5%**
- Marketable gas volume attributed to the facility — **1,190.5** 10^3m^3
- Residue gas returned from a plant for lease fuel — **45.0** 10^3m^3
- Conservation PCOS rate — $**16.00**
- Non-conservation PCOS rate – gathering & dehydration — $**3.74**
- All of the wells at the facility are under compression. Non-conservation PCOS rate – compression — $**3.46**
- Royalty payor's Reference Price (greater of the royalty payor's Producer Price and the Posted Minimum Price for the plant) — $**110.000** /$10^3m^3$
- Select Price for the year — $**50.00**

Marketable gas volumes from the Reporting Entity's wells reported on the BC-10 are as follows.

	Conservation Gas	Non-Conservation Gas		
		Base 15 / Freehold	**Base 12**	**Base 9**
Reporting Entity Total	298.5 10^3m^3	302.1 10^3m^3	460.8 10^3m^3	129.0 10^3m^3
From Low Productivity Wells		104.7 10^3m^3	199.0 10^3m^3	129.0 10^3m^3
From Field Sales	10^3m^3	10^3m^3	10^3m^3	10^3m^3

The facility and Reporting Entity produced 50 m^3 of condensate which were sold for $12,000.

B. GAS ROYALTY OR TAX INVOICE

(i) Header: The top of each gas royalty or tax invoice includes the following information.

Assessment Notice Date: This is the date on which the invoice is sent.

Payment Due Date: This is the later of 15 days after the Invoice Date or the 25th of the 3rd month after the Production Period.

Invoice: This is an identifying number for the invoice, consisting of the 5-digit REN, 6-digit production period, and the number of invoices that have been issued for the REN and production period.

To Royalty Payor: This is the name of the person responsible for payment.

Royalty Payor Code: This is the ministry's 4-digit client code for the Royalty Payor.

Plant: This is the ministry's 4-digit code and name for the plant through which the gas was processed.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

Reporting Facility: This is the ministry's 4-digit code and name for the facility at which the gas was produced.

Batch Number: This is an internal control reference used by the ministry.

REN: This is the ministry's 5-digit number for the Reporting Entity.

Production Period: This is the month in which the gas was produced.

BC10 Received Date: This is the date on which the ministry received the report of marketable gas volumes and by-products allocated to the Reporting Entity for the production period.

Reference Price: This is the value in $\$/10^3m^3$ for the Royalty Payor that was used in the royalty calculations, which is the greater of the Royalty Payor's Producer Price and the Posted Minimum Price for the processing plant.

Select Price: The Select Price is a parameter in the royalty rate formulas for Base 9 and Base 12 gas. This is the value in $\$/10^3m^3$ used for the Select Price in the royalty rate calculations.

PCOS Rates: These are Producer Cost of Service rates that were used in calculating the PCOS Allowance for conserving conservation gas, and for gathering and dehydration, compression and field processing of non-conservation gas.

(ii) Marketable Gas (1000 m^3)

Sales Volumes: The amounts in the column under Sales Volumes are the volumes for each class of marketable gas from all of the Reporting Entity's wells and for non-conservation gas from each classification of low productivity wells, <u>as reported on the BC-10.</u>

Reference Price Value: The amounts in the column under Reference Price Value for each class of marketable gas is the Sales Volume multiplied by the Reference Price shown in the header information. For example, in Sample 7.1(1) Reference Price Value of $33,231 for Base 15 is the Sales Volume of 302.1 10^3m^3 X the Reference Price of $\$110/10^3m^3$.

Royalty Rate: The amounts in the column under Royalty Rate in the **Conservation Gas** and **Non-conservation Gas Base 15**, **Base 12 and Base 9** rows are the royalty or tax rates that were calculated for each of these classes of marketable gas.

Royalty rates are derived from the following formulas for each class of gas:

Crown Land: Conservation

$$\frac{400 + 15\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{, minimum 8 \%}$$

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

Royalty Rate: cont'd

Crown Land: Non-conservation, Base 15

$$\frac{750 + 25\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{, minimum 15 \%}$$

Crown Land: Non-conservation, Base 12

$$\frac{12 \times \text{Select Price} + 40\,(\text{Reference Price} - \text{Select Price})}{\text{Reference Price}}\text{, minimum 9 \%, maximum 27 \%}$$

Crown Land: Non-conservation, Base 9

$$\frac{9 \times \text{Select Price} + 40\,(\text{Reference Price} - \text{Select Price})}{\text{Reference Price}}\text{, minimum 9 \%, maximum 27 \%}$$

Freehold Land**:** Conservation

$$\frac{245 + 9\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{, minimum 9 \%}$$

Freehold Land: Non-conservation

$$\frac{460 + 15\,(\text{Reference Price} - 50)}{\text{Reference Price}}\text{, minimum 5 \%}$$

For example, in Sample 7.1 (1) the Royalty Rate for **Conservation Gas** is [400 + 15 (110 – 50)] / 110 = 11.81818 %. For **Non-conservation, Base 12**, the formula results in [12 x 50 + 40 (110 – 50)] / 110 = 27.27272 which is greater than 27, so the rate is 27 %.

The amounts in the Royalty Rate column in the **Low Prod Reduction** rows under Base 15, Base 12 and Base 9 rows are reductions in the Royalty Rates for Sales Volumes from low productivity wells in these classes. Calculation of these rate reductions are explained in **Part C** of this section.

Royalty Share: The amounts in the column under **Royalty Share** are equal to each **Sales Volume** multiplied by each **Royalty Rate.** For example, in Sample 7.1 (1) the Royalty Share amount of 61.79320 for Non-conservation Base 15 is the Sales Volume of 302.1 10^3m^3 x 20.45455. The Royalty Share amount of 5.32999 in the Base 15 Low Prod Reduction row is the Sales Volume of 104.7 10^3m^3 x 5.09073. A positive sign is given to the product because it is a volume, even though is a reduction in the total Royalty Share for Base 15 wells.

Gross Royalty: The amounts in the column under **Gross Royalty** are equal to each **Royalty Share** multiplied by the **Reference Price**. For example, in Sample 7.1 (1) the Gross Royalty amount of $6,797.25 for Non-conservation Base 15 is the Royalty Share of 61.79320 10^3m^3 x $110 / 10^3m^3. The Gross Royalty amount of –586.30 in the Base 15 Low Prod Reduction row is the Royalty Share of 5.32999 10^3m^3 x $110 / 10^3m^3 with a negative sign to indicate a reduction in the Gross Royalty.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

(iii) By-products (m^3):

Sales Volumes: The amounts in the column under Sales Volumes are the volumes for each type of by-product from all of the Reporting Entity's wells as reported on the BC-10.

Reference Price Value: The amounts in the column under Reference Price Value for each by-product are the Sales Value as reported on the BC-10.

Royalty Rate: The amounts in the column under Royalty Rate are the royalty or tax rates for each by-product. For all by-products other than sulphur the rate is 20%. For sulphur it is 16 2/3 %.

Royalty Share: The amounts in the column under **Royalty Share** are equal to each **Sales Volume** multiplied by each **Royalty Rate.** For example, in Sample 7.1 (1) the Royalty Share amount of 10 m^3 for condensate is 20% of 50 m^3.

Gross Royalty: The amounts in the column under **Gross Royalty** are equal to each **Reference Price Value** times the **Royalty Rate**. For example, in Sample 7.1 (1) the Royalty Share amount of $2,400 for condensate is 20% of $12,000.

(iv) Totals

Reference Price Value: This is the total of the Reference Price Values for all classes of marketable gas and all by-products.

Gross Royalty: This is the total of the Gross Royalty for all classes of marketable gas and all by-products.

(v) Raw Gas Delivered

Total Volume: This is the Reporting Entity's share of raw gas volumes delivered to a plant for processing as reported on the BC-10.

Less Returned Gas Volume: This is the Reporting Entity's share of raw gas volumes measured at a sales meter but subsequently removed from the gathering line for use in the field and raw gas equivalent of residue gas delivered from a processing plant to the producer for use in the field, as reported on the BC-10. Since royalty is not payable on gas that is used by the producer in the field, no PCOS Allowance may be deducted for these volumes. In deriving the volume on which PCOS Allowance is calculated, returned gas volumes are therefore deducted from the volume delivered to a plant.

Plus Field Sales: This is the Reporting Entity's share of raw gas sold for use in the field without being processed at a plant, as reported on the BC-10. Since royalty is payable on gas that is sold by the producer to other producers for use in the field, PCOS Allowance may be deducted for these volumes. They are, therefore, added to the volume delivered to a plant for processing.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

PCOS Raw Gas Volume: This is the raw gas volume that is used in calculating the Reporting Entity's PCOS Allowance. It is equal to the **Total Volume** less the **Returned Gas Volume** plus **Field Sales** volume of raw gas.

(vi) Weighted Ave Roy Rate:

This is the Reporting Entity's weighted average royalty rate for all classes of marketable gas and all by-products. It is equal to the **Total Gross Royalty** for all Marketable Gas and By-products divided by the **Total Reference Price Value** for Marketable Gas and By-products.

(vii) PCOS Allowance

PCOS Raw Gas Volume: Since different PCOS rates apply to Conservation and Non-conservation gas, the PCOS Allowance is calculated separately for each. This requires the PCOS Raw Gas Volume to be prorated to Conservation and Non-conservation gas. The prorating is done in proportion to the relative volumes of Marketable Gas shown on the invoice. For example, the **PCOS Raw Gas Volume** for **Conservation gas** would be the PCOS Raw Gas Volume x Marketable Conservation Gas Sales Volume / total Marketable Conservation and Non-conservation Gas Sales Volume. In Sample 7.1 (1) this would be 1256.1 x 298.5 / (298.5 + 302.1 + 460.8 + 129.0). The detailed calculation is shown on the bottom left side of gas invoices that are for volumes of both Conservation and Non-conservation gas.

PCOS Allowance: For Conservation gas, this is the **PCOS Raw Gas Volume for Conservation gas** x the **Weighted Ave Roy Rate** x the **PCOS Rate** for **Conservation**. For Non-conservation gas, this is the **PCOS Raw Gas Volume for Non-conservation gas** x the **Weighted Ave Roy Rate** x the sum of the **PCOS Rates** for **Gathering & Dehydration**, **Compression** and **Field Processing** of **Non-conservation** gas. For example, in Sample 7.1 (1) the PCOS Allowance of $1342.59 for Non-conservation gas would be 941.1 x 19.81368% x 7.20.

(viii) Calculation of Net Royalty Payable

Net Royalty Payable: **Net Royalty Payable** is **Total Gross Royalty** less the total **PCOS Allowance** for Conservation and Non-conservation gas less any Royalty Exemptions for wells reported on the Reporting Entity.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

C. LOW PRODUCTIVITY REDUCTIONS IN ROYALTY RATES

The low productivity royalty rate reduction is a reduction in royalty rates on marketable gas from wells that produce less than 5000 m^3 per day of raw gas. The rate reduction is the base royalty rate for the particular class of gas multiplied by a reduction factor that increases from 0 to 1 as raw gas production declines from 5000 m^3 per day to nil. See **section 5.2** for a complete explanation of the low productivity rate reduction.

Ideally the low productivity rate reduction for a well would apply to the actual marketable gas from a well. However, the Ministry only requires reporting of marketable gas volumes by Reporting Entity and royalty class, and does not capture volumes of marketable gas for individual wells. The Ministry therefore uses raw gas production volumes reported on BC-S1 reports to calculate low productivity rate reductions and applies the reductions to marketable gas from all of a Reporting Entity's wells in each class. The Ministry's method is based on an assumption that all of a Reporting Entity's wells in each royalty class have the same quality of gas.

The Ministry's calculation of the low productivity royalty rate reductions on a gas royalty invoice are shown in an accompanying schedule called the 'Royalty Reduction Calculation by REN for Low Productivity Gas Wells'. Following is an explanation of information on these schedules using raw gas production data in Part A and **Sample 7.1 (2)** and base royalty rates in **Sample 7.1 (1)**.

(i) Header:

The top of each schedule includes the following information to identify the invoice to which the schedule applies

Royalty Payor **:**	This is the ministry's 4-digit client code for the Royalty Payor.
Reporting Entity **:**	This is the ministry's 5-digit number for the Reporting Entity.
Production Period **:**	This is the month in which the gas was produced.
Crown Interest **:**	This is 100 if the gas was produced from Crown land or 0 if it was produced from freehold land.
Reporting Facility **:**	This is the ministry's 4-digit code and name for the facility at which the gas was produced.
Plant **:**	This is the ministry's 4-digit code and name for the plant through which the gas was processed.

GAS ROYALTY OR TAX INVOICE, INCLUDING LOW PRODUCTIVITY CALCULATION cont'd

(ii) Calculation of Royalty Rate Reductions for Low Productivity Wells

Column heading	**Description**
UWI, Prod. Type :	Wells with average daily gas production volumes lower than 5 m^3 are listed in UWI numerical order and grouped by Base 15, Base 12 and Base 9 royalty classes.
Month Volume = Vm:	The sum of measured and prorated gas production for each well as reported on the BC-S1 in 10^3m^3 is shown under this heading, along with subtotals of production volumes from low productivity wells in each royalty class.
Fract of Vol Vm/sum (Vm) = Fv:	The Fraction of Volume column lists for each low productivity well the fraction during the month that raw gas production from the well is of total raw gas production from all low productivity wells of the same class. This is the production from each well divided by the total production from all wells in the same class in the Month Volume column. The Fraction of Volume column also shows the sum of the fractions for all of the low productivity wells in each class, which is always 1.0.
Month Hours = H:	The sum of measured and prorated hours of production for each well as reported on the BC-S1 is shown under this heading.
Ave Daily Volume = Vm/(H/24) = Vd:	The **Average Daily Volume** (**Vd**) during the period in 10^3m^3 is shown under this heading for each well. This is equal to **Month Volume (Vm)** for the well divided by the number of days it was on production. The number of days a well was on production is equal to the **Month Hours (H)** for the well divided by 24. For example, in Sample 7.1 (2) the Average Daily Volume for Base 12 UWI 200D037I094H07-00 is 58/(400/24) = 3.48.
Low Prod Rdn Factor [(5 - Vd)/5]^2 = Rf:	The **Low Productivity Reduction Factor** (**Rf**) for each well is shown under this heading. For each well this is the difference between 5000 m^3 and its average daily volume as a proportion of 5000 raised to the power of 2. With the **Average Daily Volume** (**Vd**) being in 10^3m^3, it is calculated as 5 minus **Vd** all divided by 5 and raised to the power 2. For example, in Sample 7.1 (2) the Low Productivity Reduction Factor (Rf) for Base 12 UWI 200D037I094H07-00 is $[(5 - 3.48) / 5]^2$ = .092416.

GAS ROYALTY OR TAX INVOICE - LOW PRODUCTIVITY ROYALTY REDUCTIONS cont'd

Low Prod Weighted Rdn Factor Rf x Fv = Wrf: The Low Productivity Reduction Factor column lists for each low productivity well the Low Productivity Reduction Factor weighted by the proportion that production from the well is of total production during the month from all low productivity wells in the same class. This is calculated by multiplying the factor in the Low Productivity Reduction Factor column by the fraction in the Fraction of Volume column.

Also listed in this column is the sum of the Weighted Reduction Factors for all low productivity wells in each royalty class.

Base Rate = Rt: Under the **Base Rate (Rt)** heading the basic royalty rates on the related gas royalty invoice for each class of Non-conservation gas is shown. For example, in Sample 7.1 (1) the **Base Rate (Rt)** for Base 12 wells is 27.00000, as shown on Sample 7.1 (1) of the related Gas Royalty Invoice.

Rate Reduction Rt × Wrf = Rd: Under the **Rate Reduction (Rd)** heading are the low productivity reductions in the royalty rates on marketable gas from all of the Reporting Entity's wells in each royalty class. The low productivity rate reduction for each class is the product of the **Base Rate (Rt)** for the class times the **Total Weighted Reduction Factor** for all of the Reporting Entity's wells in the class. For example, in Sample 7.1 (1) the Rate Reduction for Base 12 low productivity wells is 27.00000 x .06372 = 1.72044.

These Rate Reductions for each royalty class are transferred to the related Gas Royalty Invoice where they are multiplied by the volume of marketable gas from all of the Reporting Entity's low productivity wells in each royalty class. If the ratio of marketable gas to raw gas is the same for all wells in the royalty class, this results in the same reduction in the Royalty Share as separately applying the **Low Productivity Reduction Factor** (**Rf**) for each well to the actual volume of marketable gas from each well.

8.0 ROYALTY/TAX RECONCILIATIONS REPORTS

OIL ROYALTY/TAX RECONCILIATION

For production months before August 2005, producers were required report their calculation of the amount of royalty or tax payable on their production of oil at a facility on a Monthly Crown Royalty Statement, Oil (BC-13). Ministry's royalty management system performs a series of edits on sales value and royalty or tax information reported by producers on amended BC-13 reports for those months. If discrepancies are found, the system generates one or more of the following reports, which are returned to the royalty payor for resolution.

1. Crown Royalty Share by Reporting Entity
2. Crown Royalty Share by REN - Heavy Oil Details
3. Oil Royalty/Tax Recalculation
4. Oil Royalty Calculation Error Report

The following sections provide guidelines to help royalty/tax payors understand these reports and resolve any discrepancies they may encounter.

GAS ROYALTY/TAX RECONCILIATION

Sales information for marketable gas and by-products and value information for by-products are reported on the BC-10, Natural Gas and By-Product Volumes and Values Report. This information is processed with royalty factors and linkages on the Royalty Management System to produce:

- Gas Royalty/Tax Invoice
- BC-10 Error Report

The following sections provide guidelines to help royalty/tax payors understand the reports and resolve any discrepancies they may encounter.

8.1 Oil Royalty/Tax Recalculation

OVERVIEW

When a Monthly Crown Royalty Statement, Oil (BC-13) is processed, the Ministry's royalty management system verifies the report by doing royalty or tax calculations using the Reporting Entity information on the system, volumes reported on the BC-S1, and sales and transportation costs reported on the BC-13.

A Oil Royalty Recalculation report is generated by the Ministry's royalty management system when:

- the royalty or tax calculated by the system differs from the royalty or tax reported by a royalty/tax payor by more than the established tolerance, or
- changes are made to the underlying royalty factors of a Reporting Entity (eg., oil vintage, royalty exemptions, production volumes, REN-UWI linkages, UWI-Facility linkages, reporting percentages) after a BC13 has been processed.

When an Oil Royalty Recalculation is generated for a Reporting Entity, it is sent to the royalty or tax payor for review.

ADMINISTRATIVE POLICIES

If You Agree With The Recalculation:

DO NOT PREPARE AN AMENDED BC13.

Any additional royalty/tax payable should be remitted immediately to the Mineral, Oil and Gas Revenue Branch. Any unpaid balance will be included in the account balance on which interest is calculated.

An overpayment should be claimed by deducting it from the following month's royalty/tax payment for the Reporting Entity.

For either transaction, report the amount paid or claimed with the Reporting Entity number and production month on a Petroleum & Natural Gas Remittance Advice (BC-15).

If You Disagree With The Recalculation:

Contact the Mineral, Oil and Gas Revenue Branch to resolve the discrepancies.

If discrepancies cannot be resolved, a notice of objection may be filed with the Administrator.

A report entitled "Crown Royalty Share by Reporting Entity" is generated for each Oil Royalty Recalculation. This report is designed to help you determine how the system calculated a different royalty/tax obligation for the Reporting Entity in question.

Crown Royalty Share by Reporting Entity

Royalty Payor: B.D.E. Oil & Gas Co. Ltd
Client ID: 9999
Reporting Entity: 02274
Production Period: 1998/08
Crown Interest: 100.0000000

UWI or PE/Tract	Participation Interest	Production or Allocated Vol	Exempt Percent	Tier 3 Heavy	New Vintage Percent	Total Crown Share	Reporting Percentage	REN Portion of Crown Share
100023608418W6-00	0.0000000	141.7	0.000		100.0000000	19.0	100.0000000	19.0
100041808417W6-00	0.0000000	231.7	0.000		100.0000000	45.7	100.0000000	45.7
100042408418W6-00	0.0000000	120.0	0.000	Tier 3	0.0000000	10.9	100.0000000	10.9
100061308418W6-02	0.0000000	0.0	0.000		0.0000000	0.0	100.0000000	0.0
100102408418W6-00	0.0000000	0.0	0.000		0.0000000	0.0	100.0000000	0.0

Total PE/UWI Production: 493.4

Total REN Portion of Crown Share: 75.6

SAMPLE 8.2(1)

Report: RMS6830A

MINISTRY OF PROVINCIAL REVENUE
Resource Management System
3th Fl. 1802 Douglas St., Victoria, B.C. V8T 4K6

1999/01/12
20:31

Crown Royalty Share by Reporting Entity

Royalty Payor: ABC Company Limited
Reporting Entity: 99998
Production Period: 1998/06
Crown Interest: 100.000000

Client ID: 9999

UWI or PE/Tract		Participation Interest	Production or Allocated Vol	Exempt Percent	Third Tier	New Vintage Percent	Total Crown Share	Reporting Percentage	REN Portion of Crown Share
0007	0001	0.3940000	4.3	0.000		0.0000000	0.0	25.0128000	0.0
0007	0003	0.4240000	4.6	0.000		0.0000000	0.0	25.0128000	0.0
0007	0004	4.3600000	47.3	0.000		0.0000000	2.8	32.8125000	0.9
0007	0006	1.7560000	19.1	0.000		0.0000000	0.5	32.8125000	0.2
0007	0007	3.1180000	33.8	0.000		0.0000000	1.4	32.8125000	0.5
0007	0012	0.6660000	7.2	0.000		0.0000000	0.1	32.8125000	0.0
0007	0013	3.4210000	37.1	0.000		0.0000000	1.7	32.8125000	0.6
0007	0015	1.1200000	12.2	0.000		0.0000000	0.2	32.8125000	0.1
0007	0016	0.0370000	0.4	0.000		0.0000000	0.0	32.8125000	0.0
0007	0017	0.8410000	9.1	0.000		0.0000000	0.1	32.8125000	0.0
0007	0028	1.5740000	17.1	0.000		0.0000000	0.4	32.8125000	0.1
0007	0031	5.6620000	61.7	0.000		0.0000000	4.8	8.9330000	0.4
0007	0032	4.3600000	47.3	0.000		0.0000000	2.8	24.6093750	0.7
0007	0033	2.8460000	30.9	0.000		0.0000000	1.2	32.8125000	0.4
0007	0036	3.1180000	33.8	0.000		0.0000000	1.4	32.8125000	0.5
0007	0037	0.6060000	6.6	0.000		0.0000000	0.1	32.8125000	0.0
0007	0038	0.5750000	6.2	0.000		0.0000000	0.0	32.8125000	0.0
0007	0039	1.3620000	14.8	0.000		0.0000000	0.3	32.8125000	0.1

Total PE/UWI Production: 1,085.6

Total REN Portion of Crown Share: 4.5

SAMPLE 8.2(2)

8.2 Crown Royalty/Tax Share by Reporting Entity

OVERVIEW

The Crown Royalty/Tax Share by Reporting Entity report is used in conjunction with the Oil Royalty Recalculation report to help royalty/tax payors determine why the ministry has calculated a different Crown royalty or tax obligation than was reported on the BC-13.

The report lists the unique well identifiers (UWI's) for all wells with reporting interests linked to the particular Reporting Entity during the month according to information in the system. For a unitized operation, it lists the Production Entity tract numbers linked to the Reporting Entity.

Sample 8.2 (1) illustrates the report if it is a listing of wells in which a Reporting Entity has a reporting interest during the month. For each well the report will show the following information:

(1) production from the well during the month in cubic meters according to information reported on the BC-S1,
(2) the percentage of production during the month that is exempt,
(3) the percentage of production that is classified as new oil,
(4) an indication of whether the oil is classified as Third Tier or Heavy,
(5) the royalty or tax share of production from the well during the month in cubic meters, which is calculated by applying the appropriate royalty rate formula to production from the well during the month,
(6) the Reporting Entity's reporting interest in the well as a percentage,
(7) the Reporting Entity's share in cubic meters of the royalty or tax share, which is the royalty or tax share from the well times the Reporting Entity's interest in the well divided by 100.

Sample 8.2 (2) illustrates the report if it is a listing of tracts in a unitized operation in which the Reporting Entity has a reporting interest during the month. For each tract the report will show the following information:

(1) the tract's participation in production from the unitized operation as a percentage,
(2) production allocated to the tract during the month in cubic meters, which is total production during the month from wells in the unitized operation as reported on the BC-S1 times the tract's participation interest divided by 100,
(3) the percentage of production allocated to the tract that is exempt,
(4) the percentage of production allocated to the tract that is classified as new oil,
(5) the royalty or tax share of production allocated to the tract during the month in cubic meters,
(6) the Reporting Entity's reporting interest in the tract as a percentage,
(7) the Reporting Entity's share in cubic meters of the royalty or tax share, which is the royalty or tax share for the tract times the Reporting Entity's interest in the well divided by 100.

OVERVIEW cont'd

If the unitized operation is subject to a royalty agreement with the Province, the royalty or tax share for the tract will be calculated by substituting production allocated to the tract into the appropriate royalty or tax rate formula to get the rate and multiplying by production allocated to the tract during the month. If the unitized operation is not subject to a royalty agreement with the Province, the royalty or tax share for the tract will be determined by calculating the share for each well in the unitized operation using the appropriate royalty or tax rate formula and allocating a portion of the total share from all wells in the unitized operation to the tract in accordance with the tract participation interest.

These documents should be kept as supporting information for the Oil Royalty/Tax Recalculation and for reference when corresponding with the Mineral, Oil and Gas Revenue Branch.

MINISTRY OF PROVINCIAL REVENUE
Mineral, Oil and Gas Revenue Branch
3th Fl. 1802 Douglas St., Victoria, B.C. V8T 4K6

Crown Royalty Share by REN - Heavy Oil Details

Royalty Payor:	0999 ABC Limited	Wellhead Price (W):	146.494
REN:	02921	Threshold Price (T):	110.000
Production Period:	1999/11	Price Factor (F):	
Crown Interest	100.0000000	F = 1 + 2.5 (W-T)/W =	1.62279

UWI or PE/Tract	Production Volume (P)	Royalty Rate for P<=20: Zero	Royalty Rate for 20<P<=200: 2 $\frac{F \times (P - 20)}{24 \times P}$	Royalty Rate for P>200: $\frac{F \times [(P-200) \times 11+1350]}{P}$	Reporting Percentage	REN part of Crown Share	Exempt Percent	Exempt Share Royalty
200A014D094P07-02	248.1			12.291	100.0000000	30.5	0.000	0.0
200A040F094P07-02	0.3	0.000			100.0000000	0.0	0.000	0.0
200A097L094P02-00	28.8		0.182		100.0000000	0.0	0.000	0.0
200B005D094P07-00	71.4		2.502		100.0000000	1.8	0.000	0.0
200B016D094P07-03	33.0		0.346		100.0000000	0.2	0.000	0.0
200B025D094P07-00	9.3	0.000			100.0000000	0.0	0.000	0.0
200B026D094P07-00	3.6	0.000			100.0000000	0.0	0.000	0.0
200B035E094P07-03	3.3	0.000			100.0000000	0.0	0.000	0.0
200B045E094P07-02	35.6		0.462		100.0000000	0.2	0.000	0.0
200B064D094P07-00	114.5		5.274		100.0000000	6.0	0.000	0.0
200B084L094P02-00	1.1	0.000			100.0000000	0.0	0.000	0.0
200B085L094P02-00	23.1		0.028		100.0000000	0.0	0.000	0.0
200B094L094P02-00	85.2		3.374		100.0000000	2.9	0.000	0.0
200D003E094P07-00	8.1	0.000			100.0000000	0.0	0.000	0.0
200D007D094P07-00	7.8	0.000			100.0000000	0.0	0.000	0.0
200D007E094P07-00	2.9	0.000			100.0000000	0.0	0.000	0.0
200D008D094P07-00	9.9	0.000			100.0000000	0.0	0.000	0.0
200D011E094P07-00	0.3	0.000			100.0000000	0.0	0.000	0.0
200D014D094P07-00	26.6		0.111		100.0000000	0.0	0.000	0.0
200D015D094P07-00	72.0		2.539		100.0000000	1.8	0.000	0.0
200D015E094P07-00	18.7	0.000			100.0000000	0.0	0.000	0.0
200D015E094P07-02	7.8	0.000			100.0000000	0.0	0.000	0.0
200D016D094P07-00	2.7	0.000			100.0000000	0.0	0.000	0.0
200D017D094P07-00	42.5		0.805		100.0000000	0.3	0.000	0.0
200D017D094P07-00	18.8	0.000			100.0000000	0.0	0.000	0.0
200D024D094P07-00	13.5	0.000			100.0000000	0.0	0.000	0.0
200D026D094P07-00	1.9	0.000			100.0000000	0.0	0.000	0.0
200D026D094P07-02	0.9	0.000			100.0000000	0.0	0.000	0.0
200D027D094P07-02	9.8	0.000			100.0000000	0.0	0.000	0.0
200D027E094P07-00	0.3	0.000			100.0000000	0.0	0.000	0.0
200D037D094P07-00	1.5	0.000			100.0000000	0.0	0.000	0.0
200D045E094P07-03	8.0	0.000			100.0000000	0.0	0.000	0.0
200D046D094P07-02	245.5			12.232	100.0000000	30.0	0.000	0.0
200D048D094P07-02	0.8	0.000			100.0000000	0.0	0.000	0.0
200D055D094P07-00	1.0	0.000			100.0000000	0.0	0.000	0.0
200D056D094P07-00	31.7		0.292		100.0000000	0.2	0.000	0.0
200D056D094P07-03	13.6	0.000			100.0000000	0.0	0.000	0.0
200D065D094P07-02	38.8		0.616		100.0000000	0.2	0.000	0.0
200D065L094P02-02	187.0		10.084		100.0000000	18.8	0.000	0.0

SAMPLE 8.3

8.3 Crown Royalty Share by REN – Heavy Oil Details

OVERVIEW

Sample 8.3 illustrates the "Crown Royalty Share by REN – Heavy Oil Details" report. This report is used in conjunction with the Crown Royalty Share by REN to help royalty/tax payors understand how the Ministry calculated the Crown royalty or tax obligation for wells classified as Heavy oil.

For the REN (Reporting Entity Number) and month in question, the report shows the following information:

(1) production from the well during the month in cubic meters according to information reported on the BC-S1;
(2) wellhead price, which is the average net value on the BC-13;
(3) threshold prices, which is set by order for the year;
(4) result of the calculation of the Price Factor;
(5) result of the calculation of the relevant royalty rate;
(6) the REN's reporting interest in the well as a percentage;
(7) the REN's share in cubic meters of the royalty or tax share, which is the royalty or tax share from the well times the REN's reporting interest in the well divided by 100;
(8) the percentage of production during the month that is exempt;
(9) the REN's royalty exempt share, which is the REN's share in cubic meters of the royalty or tax share times the Exempt percent.

Oil Royalty Recalculation
As of 1998/09/30

Royalty Payor: 9999 B.D.E. Oil & Gas Co. Ltd.
REN: 02274
Production Period: 1998/08
Crown Interest: 100.0000000
Facility/PE: 00000128
Facility/PE Oper: 0999

Form Received Date: 1998/09/25
Batch Number: D-1998-09-01

Reporting Entity Sales:

	Gross Price	Sales Volume	Gross Value of Sale	Clean Oil Trans. Cost	Net Sales Value
	151.00	1,232.9	186,167.90	0.00	186,167.90
Totals		1,232.9	186,167.90	0.00	186,167.90

	Volume Received	Opening Inventory	V.A.S.	Closing Inventory	Sales Volume
Crown Royalty Share:	75.6	0.0	75.6	0.0	75.6

Classification	Volume	Ave. Net Value ($)	Royalty Value($)
Crown Share:	75.6	151.000	11,415.60
Royalty Exempt:	0.0	151.000	0.00
Net Crown Royalty Payable			11,415.60

If you agree with the above Net Crown Royalty Payable, please adjust any balance outstanding on your next BC-15 submission.
DO NOT submit an amended BC13 report.

SAMPLE 8.4(1)

Oil Royalty Recalculation Report
As of 1998/12/31

Royalty Payor: 9999 ABC Company Ltd.
REN: 99998
Production Period: 1998/06
Crown Interest: 100.0000000
Facility/PE: 8888
Facility/PE Oper: 9999

Form Received Date: 1998/12/24
Batch Number: D-1998-12-17

Reporting Entity Sales:

	Gross Price	Sales Volume	Gross Value of Sale	Clean Oil Trans. Cost	Net Sales Value
	110.10	112.3	12,364.23	0.00	12,364.23
Totals		112.3	12,364.23	0.00	12,364.23

	Volume Received	Opening Inventory	V.A.S.	Closing Inventory	Sales Volume
Crown Royalty Share:	4.5	0.0	4.5	0.0	4.5

Classification	Volume	Avg. Net Value ($)	Royalty Value($)
Crown Share:	4.5	110.100	495.45
Royalty Exempt:	0.0	110.100	0.00
Net Crown Royalty Payable			495.45

If you agree with the above Net Crown Royalty Payable, please adjust any balance outstanding on your next BC15 submission.
DO NOT submit an amended BC13 report.

SAMPLE 8.4(2)

8.4 How to Analyze an Oil Royalty Recalculation

OVERVIEW

Samples 8.4 (1) and 8.4 (2) illustrate the "Oil Royalty or Tax Recalculation" report. Data fields on this report correspond to fields on the BC-13. Following are descriptions of each of these fields as possible causes of discrepancies between a royalty payor's BC-13 and the Ministry's calculation of royalties or tax payable.

FINDING ERRORS

Gross Price, Sales Volume, Gross Value of Sales, Clean Oil Trans. Cost, Net Sales Value

The data shown in these fields should always reflect what was reported on the BC-13. They are provided as a convenient reference and cannot be a cause of any discrepancy in the recalculation of Net Royalty Payable.

Crown Royalty Share - Volume Received

This is the Ministry's calculation of the Reporting Entity's royalty or tax share in m^3 for the month. If there is a difference in the Net Royalty Payable between the BC-13 and the Recalculation report, the difference will often be due to a difference in this number. The causes of a difference in this number will depend on whether the Reporting Entity has direct reporting interests in wells, or whether it has reporting interests in tracts that are part of a unitized operation.

Finding Volume Received Errors - Reporting Entities with direct reporting interests in wells: an error in the Volume Received could be due to an error in one or more of the following factors.

(1) **Reporting Entity to Well Linkages** Compare the well events (UWI's) listed for the Reporting Entity on the Crown Royalty Share by Reporting Entity report [Sample 8.2 (1)] with those used in completing the BC-13 for the production month. Compare the reporting interest percentage for each well. If the BC-13 takes into account changes in well ownership that have not been reported to the Mineral, Oil and Gas Revenue Branch, a BC-12 should be submitted to the Branch as soon as possible.

(2) **Production** Check whether production for each well used in completing the BC-13 agrees with production data on the Crown Royalty Share by Reporting Entity report. Incorrect production data will result in incorrect royalties payable. Correct production figures attributed to the wrong wells may also result in errors because of differences between wells in vintage or exemption status.

(3) **Exemptions** Compare the exempt status for wells listed on the Crown Royalty Share by Reporting Entity report to the exempt status used in completing the BC-13. Ensure that a royalty share was calculated for exempt wells and included in the royalty share for the Reporting Entity. The value of this portion is deducted from gross royalty on the BC-13.

FINDING ERRORS cont'd

(4) **Vintage** For each well compare the percentage of production that is classified as New Oil on the Crown Royalty Share by Reporting Entity report with the percentages used in completing the BC-13.

(5) **Total Crown Share** Compare the total Crown share for each well as listed on the Crown Royalty Share by Reporting Entity report with the total Crown share that was calculated for each well when completing the BC-13. Where there are differences, ensure that the correct royalty or tax rate formula was used and calculations were done correctly.

(6) **REN Portion of Crown Share** This should be equal to the Crown Share for each well times the Reporting Entity's reporting percentage for the well. Compare the reporting interests used in completing the BC-13 with the reporting percentages listed on the Crown Royalty Share by Reporting Entity report. Ensure that the Reporting Entity's portion of the total royalty or tax share has been correctly calculated for each well and totaled.

Finding Volume Received Errors - Reporting Entities with Reporting Interests in Tracts in Unitized Operations: an error in the volume received could be due to an error in one or more of the following factors.

(1) **Reporting Entity to Tract Linkages** Compare the tracts listed for the Reporting Entity on the Crown Royalty Share by Reporting Entity report [Sample 8.2 (2)] with those used in completing the BC-13 for the production month. Compare the reporting interest percentage for each tract. If the BC-13 takes into account changes in tract ownership that have not been reported to the Mineral, Oil and Gas Revenue Branch, a BC-12 should be submitted to the Branch as soon as possible.

(2) **Tract Participation Interest** Compare the tract participation factors on the corresponding Crown Royalty Share by Reporting Entity report [Sample 8.2 (2)] with the participation factors used in completing the BC-13.

(3) **Production** Check that total production by the unitized operation as shown at the bottom of the Crown Royalty Share by Reporting Entity report agrees with the total volume on which the BC-13 was based. This total is based on production reported on BC-S1 statements for one or more reporting facilities. Since a BC-S1 for a reporting facility can include non-unit wells, care must be taken to exclude this production from total production by the unit.

(4) **Allocated Volumes** Compare the volumes allocated to each tract on the Crown Royalty Share by Reporting Entity report with the volumes used in completing the BC-13. The volume of production allocated to each tract will be the participation interest for the tract multiplied by the total production by the unit.

(5) **Exempt Percent** The exempt percentage for every tract in a unitized operation is the total production from exempt wells in the unit divided by total production by the unit. Check the exempt status of wells in the unit. The value of this portion is deducted from gross royalty on the BC-13.

FINDING ERRORS cont'd

(6) **New Vintage Percent** Check the percentage of New Oil on the Crown Royalty Share by Reporting Entity report with the percentages used in completing the BC-13. All unitized operations have a percentage of New Oil set by the royalty administrator. Since this percentage rarely changes, this is an unlikely source of error.

(7) **Total Crown Share** Ensure that the correct steps have been followed in calculating the Total Crown share for each tract. If the unitized operation is not subject to a royalty agreement with the Crown, the royalty or tax share is calculated for each well based on the volume of production from the well and the total royalty/tax share from all of the wells in the unit is allocated to each tract. Check that the correct production and royalty or tax rate formula was used for each well and that the results were correctly totaled. Check that the total share was correctly allocated to each tract in the Reporting Entity.

(8) **Total Crown Share - Production Entity** If the unitized operation is subject to a royalty agreement with the Crown, the royalty share is calculated for each tract using the volume of production allocated to the tract. Checking for errors in a Production Entity involves the following steps.

(a) Check that the correct volumes and rate formulas were used in calculating the royalty rates for each tract for New Oil and Old Oil.

(b) Check that the New Vintage percentage is the same as that shown on the Crown Royalty Share by Reporting Entity report.

(c) Check that the New Oil percentage and the Old Oil percentage add up to 100 for each tract.

(d) Check that the New Oil royalty share for each tract is equal to the volume allocated to the tract times the New Oil rate for the tract times the same New Vintage.

(e) Check that the Old Oil royalty share for each tract is equal to the volume allocated to the tract times the Old Oil rate for the tract times (1 minus the New Vintage percentage/100).

(f) Ensure that the New and Old Oil royalty shares are correctly added together to get the total royalty share for each tract.

(9) **Reporting Entity Portion of the Royalty Share** Ensure that the Reporting Entity's portion of the total royalty or tax share has been correctly calculated for each tract and totaled.

Royalty Share - Opening Inventory

If in the previous month there was production of oil on which royalty was payable and the royalty share in m^3 was reported as Volume Received, but there were no sales in the previous month to determine a value for it, it would be reflected in the royalty share Closing Inventory for that month. Ensure that the Opening Inventory agrees with the Closing Inventory on the BC-13 for the immediately preceding month.

FINDING ERRORS cont'd

Royalty Share - Volume Available for Sale (V.A.S.)

The V.A.S. should be equal to the sum of the Volume Received and the Opening Inventory.

Royalty Share - Closing Inventory and Sales Volume

If any sale of oil is listed on the BC-13, it is used to value the entire royalty or tax share Volume Available for Sale. Therefore either the Closing Inventory or the royalty share Sales Volume should be zero and the other equal to the Volume Available for Sale. If any sales are listed, regardless of whether their total is more or less than the Volume Available for Sale, the Closing Inventory should be zero and the royalty share Sales Volume should equal the Volume Available for Sale. If no sales are listed, the Closing Inventory should equal the Volume Available for Sale and the royalty share Sales Volume should be zero.

Volume - Crown Share

The Volume - Crown Share should always be the same as royalty share Sales Volume.

Volume - Royalty Exempt

Volume - Royalty Exempt is the amount of total royalty share that does not have to be paid to the Province. If the Reporting Entity has direct reporting interests in wells, compare the Reporting Entity's portion of the royalty share for exempt wells on the Royalty Share by Reporting Entity report. For each well the exempt volume is the exempt percent times the REN portion of Crown Share. Check that the exempt volumes for all wells were totaled correctly.

If the Reporting Entity is part of a unitized operation, check that the Volume - Crown Share has been multiplied by the exempt percentage shown on the Royalty Share by Reporting Entity report for the unitized operation.

Average Net Value - Crown Share and Royalty Exempt

This value should be equal to the Total Net Sales Value as shown on the Recalculation report divided by the Total Sales Volume on the report.

Royalty Value - Crown Share and Royalty Exempt

These amounts should be equal to the Crown Share and Royalty Exempt volumes multiplied by the Average Net Value.

Oil Royalty Calculation Error Report
As of 1998/12/31

Royalty Payor: ABC Oil & Gas Co. Ltd. Client ID: 0999
Address: 1234 Main Street
City: CALGARY Prov/State: AB
Country: CANADA Post/Zip Code: T2P 0Z1

SALES Batch Number	REN	Production Period	Facility /PE	PE Operator	Purchaser Code	Explanation
D19981217	04758	1998/11	00003177	0099	0000	This purchaser code is not a valid client id.
D19981217			00003177	0099		S1 forms for related UWIs have not been received.
D19981217			00003177	0099		This purchaser code is not a valid client id.

SAMPLE 8.5

8.5 Oil Royalty/Tax Calculation Error Report

OVERVIEW

This section provides a list of the discrepancy messages that may be encountered on the "Oil Royalty Calculation Error Report". For each message, guidelines are provided to help correct errors. Sample 8.5 is an example of an Oil Royalty Calculation Error Report.

ADMINISTRATIVE POLICIES

This report lists discrepancies identified on the Monthly Crown Royalty Statement, Oil (BC-13). If the discrepancies are due to errors by the royalty payor is completing the related BC-13, they should be corrected by submitting an amended BC-13. If the discrepancies are due to a data entry error, advise the Mineral, Oil and Gas Revenue Branch of the error.

Oil Royalty Calculation Error Reports will continue to be generated and sent to the royalty payor if discrepancies are not addressed.

DISCREPANCY MESSAGES

"***This purchaser code is not a valid client I.D."***

This message means the indicated client code used to identify an oil purchaser in the Reporting Entity Sales section of the BC-13 was not recognized by the royalty management system. Ensure that the code is a valid 4-digit client identification code, i.e., ABC Oil Co.'s client code would be "0999". If you cannot find a code, contact the Mineral, Oil and Gas Revenue Branch.

"***The S1 forms for related UWIs have not been received."***

This message indicates that a BC-13 was received, but no BC-S1 production information was received for the same production period. The only time this situation is valid is all sales in a month are from inventory, and royalty share was carried forward in inventory from the previous month because there were no sales in the previous month by which to value it. If this is the case, advise the Mineral, Oil and Gas Revenue Branch that this has happened.

Otherwise, review the applicable BC-13 to ensure that production information has not been omitted. Also, check the REN/UWI linkages and Facility/UWI linkages to ensure that the well(s), facility and REN are properly established.

"***No BC-13 form was submitted for this REN/production period."***

This message indicates that oil production has been reported on an BC-S1 for the facility to which the REN is linked, but no BC-13 has been received for the REN. For any month in which oil production is reported, a BC-13 must be submitted for every REN linked to the facility to account for the Crown royalty or tax share volume, even if the royalty payor made no sales by which to value it.

DISCREPANCY MESSAGES cont'd

Submit a BC-13 to report any production of oil attributable to the REN during the month and, if there was a sale, the related Crown royalty calculation. If no oil was sold during the period, but production occurred, the Crown royalty/tax share should be reported as Volume Received and in closing inventory on the BC-13. The Crown royalty/tax share will be held in inventory until a sale occurs, at which point it will valued by that sale.

RMS67540

MINISTRY OF PROVINCIAL REVENUE
ROYALTY MANAGEMENT SYSTEM

BC-10 ERROR REPORT
AS OF 2002/01/31

Royalty Payor ABC LIMITED Client Id: 0999

Address: 1212 Main Street

City: Calgary Prov/State: AB

Country: Canada Post/Zip code: T2P 2S2

Batch Number	REN	Production Period	Facility /PE	Facility /PE Operator	Explanation
L-2002-01-02	04753	2001/11	00000203	0525	ERROR: S1 forms for related UWIs not received

SAMPLE 8.6

8.6 BC-10 Error Report

OVERVIEW

When processing a royalty payor's "Natural Gas and By-Product Volume and Value Reports" (BC-10's), the ministry does edit checks that result in a "BC-10 Error Report" when possible errors or omissions are found. See Sample 8.6 for an example. For each occurrence that is listed on a BC-10 Error Report provides a message to explain the discrepancy that has occurred. This section lists the possible messages and what actions should be taken for each.

DISCREPANCY MESSAGES AND ACTIONS REQUIRED

"The S1 forms for related UWIs have not been received."

This message indicates that a BC-10 was received but that no BC-S1 production information was received for the Reporting Entity's wells for the same production period.

The only time this situation will be valid is when natural gas by-products are sold from inventory. If this is the case, advise the Mineral, Oil and Gas Revenue Branch. Otherwise, ensure that BC-S1 reports have been submitted to the Branch showing production information for the Reporting Entity's wells. Also, check the REN/UWI linkages and Facility/UWI linkages to ensure that the well(s), facility and REN are correctly linked.

"Reference Price not found."

This message indicates that the ministry does not have a Producer Price for the Reporting entity. This means no invoices have been submitted to the Ministry of Energy, Mines and Natural Gas for sales of marketable gas by the royalty payor from the plant to which the Reporting Entity is linked.

This discrepancy is usually caused when a facility is connected to more than one plant and 'swing gas' is reported on a BC-10 for a REN that is not linked to the plant through which the gas was processed. Amended BC-10's should be submitted to reverse the error in the incorrect REN and to report the volumes for the correct REN. This may also require a secondary REN to be established if this has not already been done. Since PCOS rates and processing charges or GCA vary between plants, this will have an impact on royalty payable.

Consolidated Statement of Accounts

STATEMENT DATE: 2003/12/31

Royalty Payor 0999 ABC Limited
99 2nd Street West
Calgary, Alberta
T2P 4V4

	Account Type	Opening Balance	Current Charge	Payment	Closing Balance
Interest Bearing Accounts:					
	Oil Royalty	1,603.17-	6,868.09	7,711.22-	2,446.30-
	Gas Royalty	41,254.92	19,495.87	10,753.83-	49,996.96
	Cash Suspense	50.00-	0.00	50.00	0.00
	Sub Totals	$39,601.75	$26,363.96	$18,415.05-	$47,550.66
Non-Interest Bearing Accounts:					
	Estimate	10,500.00-	10,500.00	12,000.00-	12,000.00-
	Cash Held	0.00	0.00	5,251.60-	5,251.60-
	Interest	121.40	323.99	121.40-	323.99
	Penalty	1,720.00	3,300.00	1,500.00-	3,520.00
	Assessment	0.00	15,000.00	15,000.00-	0.00
	Sub Totals	$8,658.60-	$29,123.99	$33,873.00-	$13,407.61-
	Grand Totals	$30,943.15	$55,487.95	$52,288.05-	$34,143.05

Non-Refundable Credit Accounts:

Account Type	Opening Balance	Credit Allocated	Credit Taken	Closing Balance
Summer Drilling Credit	$14,134.00-	$35,866.00-	$15,000.00	$35,000.00-

SAMPLE 9.1
December 2003

9.0 CLIENT ACCOUNTS MANAGEMENT REPORTS
9.1 Consolidation Statement of Accounts

OVERVIEW

The Consolidated Statement of Accounts is a summary of a client's account status with the Mineral, Oil and Gas Revenue Branch as at a specified date. It includes a summary of the Reporting Entity activity that is detailed on the Oil Royalty Account Transaction Listing and the Gas Royalty Account Transaction Listing. In addition, the statement includes a summary of gas estimate, interest, penalty and assessment transactions as well as any amounts in the cash suspense and cash held accounts.

GUIDELINES

An illustration of the Consolidated Statement of Accounts is presented in Sample 9.1.

Following are descriptions of items on the Consolidated Statement of Accounts:

Statement Date This is the last day of the calendar month in which reports (including amendments) and payments were received. Reports received by the Mineral, Oil and Gas Revenue Branch after the date shown will not be reflected on the statement.

Royalty Payor This is the royalty payor's client identification code and address. Any errors or changes should be communicated to the Mineral, Oil and Gas Revenue Branch immediately.

Refundable and Non-refundable Account Types Accounts types are either "refundable" or "non-refundable". Refundable accounts that have a credit balance can be paid to the royalty payor on request. The closing account balances form the accounts receivable (payable) balance for the royalty payor. Non-refundable credit account balances cannot be paid to the royalty payor. The closing balance in non-refundable accounts does not form part of the accounts receivable (payable) balance for the royalty payor. A debit balance in a non-refundable account is due immediately to the Mineral, Oil and Gas Revenue Branch.

Refundable Account Types There are eight refundable account types summarized on the Consolidated Statement of Accounts. The accounts are separated those in which interest is charged or credited on closing balances (Oil Royalty, Gas Royalty, Cash Suspense), and those that do not bear interest (Estimate, Cash Held, Interest, Penalty, Assessment). For each type the statement presents an opening balance, total current charges, total payments and a closing balance. The **Opening Balance** for each type is equal to the closing balance at the end of the previous month. The **Closing Balance** for each type is the opening balance plus current charges less payments during the month. **Current Charges** and **Payments** consist of the following for each account type:

GUIDELINES cont'd

(1) **Oil Royalty** The amount under **Current Charge** in this account consists of total oil royalties payable for all of the royalty payor's RENs from BC-13 reports and amendments received during the month. If a calculation error is found in a report as filed, the Current Charge will include the royalty payable as calculated by the ministry. The **Payment** is the total of all payments allocated to the royalty payor's oil RENs on BC-15 reports received during the month.

(2) **Gas Royalty** The **Current Charge** in this account consists of total gas royalties payable for all of the royalty payor's RENs from gas royalty invoices, BC-14 reports and amendments processed during the month. If a calculation error is found in a BC-14 report as filed, the Current Charge will include the royalty payable as calculated by the ministry. The **Payment** is the total of all payments allocated to the royalty payor's gas RENs on BC-15 reports received during the month.

(3) **Cash Suspense** The **Payment** amount in this account is any payment received from the royalty payor during the month that is in excess of the total payable reported on BC-15 reports during the month. The **Current Charge** is any reversal of an amount in the Payment column in a previous month, which means the excess payment in the previous month has been applied against royalties, interest or penalties payable. When payments received from the royalty payor during the month are less than the total payable on BC-15 reports during the month, the difference will first reduce any credit balance in the Cash Suspense account from the previous month, then the Payment amount in the Estimate account, and thereafter the Payment amounts in the Royalty accounts. Consequently, the Closing Balance in the Cash Suspense account will never be a positive amount.

(4) **Estimate** This account contains gas royalty estimate amounts. The **Current Charge** is the gas royalty estimate payment for the immediately preceding month as reported on line 46 of BC-15 reports received in the month. The **Payment** is the gas royalty estimate payment for the current month as reported on line 45 of BC-15 reports received in the month.

(5) **Cash Held** The **Payment** in this account is the total of amounts reported on BC-15 reports received in the month for REN's for which BC-10 and BC-13 reports that were received, but could not be processed. Royalty reports can sometimes not be processed because necessary information about a well is not available to the ministry, which is usually because a BC-11 report for the well has not been filed. The **Current Charge** is reversals of payments for royalty charges processed during the month for which payments were reported on BC-15 reports in a previous month. No interest is paid on a credit balance in this account.

GUIDELINES cont'd

(6) **Interest** The **Current Charge** in this account includes interest charged or credited to the royalty payor on the following amounts:

(i) the sum of any positive (debit) closing balances in the Oil Royalty and Gas Royalty, accounts less any negative (credit) closing balances in these accounts and the Cash Suspense account at the end of the month, for the number of days in the month,
(ii) the difference between 90% of gas royalty charges in the month for all of the royalty payor's REN's and the Estimate account Payment in the previous month, for the number of days in the month,
(iii) the difference between 110% of gas royalty charges in the month for all of the royalty payor's REN's and the Estimate Account Payment in the previous month, for the number of days in the month,
(iv) any upward adjustments to royalties payable resulting from assessments, from their due date to the date of assessment,
(v) Prior period interest on adjustments to royalties that were due in months prior to the current month, excluding interest that has been included in assessments in (iv).

The Current Charge in the Interest account will be positive when the royalty payor is charged interest and negative when the royalty payor is credited with interest. The **Payment** is the payment of interest as reported on line 47 of BC-15 reports received during the month. The Payment will be negative when the royalty payor has claimed interest

previously credited to his account by recording an amount in brackets on line 47 of BC-15 reports received during the month.

(7) **Penalty** The **Current Charge** in this account consists of penalty charges that the royalty payor has been assessed in the month for filing reports late. If a penalty charge is waived by the Royalty Administrator, the reversal will be included here as a negative amount. The **Payment** is the payment of penalties as reported on line 48 of BC-15 reports received during the month.

(8) **Assessment** The **Current Charge** in this account consists primarily of royalty assessments issued during the month as a result of audits of royalty payors' records. It may also occasionally be used for sundry charges or credits to royalties payable. The **Payment** is the payment of assessments as reported on line 49 of BC-15 reports received during the month.

GUIDELINES cont'd

Non-refundable Account Type There is one non-refundable account type shown at the bottom of the Consolidated Statement of Accounts. This account is the Summer Drilling Credit account. The Opening Balance is equal to the closing balance at the end of the previous month. The Closing Balance is the opening balance plus the credit allocated less the credit taken during the month. Credit allocated and credit taken consists of the following for the Summer Drilling Account:

The amount under Credit Allocated in this account consists of the total summer drilling credits allocated to this royalty payor from BC-25 reports and amendments received during the month. The amount under Credit Taken in this account consists of the summer drilling credits claimed or repaid on the BC-15 reports received during the month.

STATEMENT DATE: 2002/01/31

Royalty Payor 0099 ABC Limited OIL Royalty Opening Balance → $ 1,603.17-

REN	Period	Form	Transaction Description	Form Received		Amount		
04758								
04758					Previous Balance →	1,536.16-		
	2001/11	BC13	Royalty reversal	2001/12/27		9,598.18-		
		BC13	Amendment recalculated	2002/01/25		8,952.89		
		BC15	Credit taken	2002/01/25		680.36		
	2001/12	BC13	Original recalculated	2002/01/25		4,296.86		
		BC15	Payment Received	2002/01/25		5,175.06-		
					Current Balance →	2,379.29-	$	2,379.29-
04815					Previous Balance →	0.00		
	2001/11	BC13	Royalty reversal	2001/12/27		1,130.76-		
		BC13	Amendment accepted	2002/01/25		1,058.28		
		BC15	Credit taken	2002/01/25		72.48		
	2001/12	BC13	Original accepted	2002/01/25		2,909.63		
		BC15	Payment received	2002/01/25		2,909.63-		
					Current Balance →	0.00	$	0.00
04816					Previous Balance →	42.39-		
	2001/11	BC13	Royalty reversal	2001/12/27		475.55-		
		BC13	Amendment accepted	2002/01/25		459.29		
		BC15	Credit taken	2002/01/25		16.00		
		JOUR	Automatic write-off			0.26		
	2001/12	BC13	Original accepted	2002/01/25		395.37		
		BC15	Payment Received	2002/01/25		395.37-		
					Current Balance →	42.39-	$	42.39-
04971					Previous Balance →	24.62-		
					Current Balance →	24.62-	$	24.62-
					Oil Royalty Closing Balance		**$**	**2446.30-**

SAMPLE 9.2

9.2 Oil Royalty Account Transactions Listing

OVERVIEW

The 'Oil Royalty Account Transaction Listing' is a detailed listing of charges and payments made to the Oil Reporting Entities (REN's) of each royalty payor. Any REN with transactions reported on forms received by the Mineral, Oil and Gas Revenue Branch during the month ending on the Statement Date or with an outstanding balance will be included on this statement.

GUIDELINES

An illustration of the Oil Royalty Account Transaction Listing is presented in Sample 9.2. Following are descriptions of items on this statement:

Statement Date This is the last day of the calendar month in which reports (including amendments) were received. Reports and payments received by the Ministry after the date shown will not be reflected on the statement. They will appear on the next statement.

REN This lists the Ministry's 5-digit codes for each of the royalty payor's Oil Reporting Entities. The statement groups transactions by REN and provides balances due or overpaid for each REN.

Period This refers to the production month to which the royalty charges relate.

Form This refers to the form type from which the transaction is recorded.

Transaction Description This provides a brief description of each transaction.

Form Received This is the date the Ministry received the form on which the transaction was reported.

Oil Royalty Opening Balance This is the Oil Royalty Closing Balance carried forward from the previous statement period. It will also appear as the opening balance on the Consolidated Statement of Accounts for the Oil Royalty Account.

Previous Balance The amounts listed by Previous Balance in the **Amount** column are the closing balances for each Oil REN at the end of the previous statement period. The sum of Previous Balances for all of the Oil REN's is equal to the Oil Royalty Opening Balance.

Current Balance The amounts listed by Current Balance in the **Amount** column for each REN are the sum of the Previous Balance and all of the transactions in the current month.

Oil Royalty Closing Balance This is the sum of the Opening Balance and all of the transactions listed. It is equal to the sum of the Current Balances for all of the royalty payor's Oil REN's. As with the opening balance, this amount will also appear as the closing balance for the Oil Royalty Account on the Consolidated Statement of Accounts.

STATEMENT DATE: 2002/01/31

Royalty Payor 0099 ABC Limited

REN	Period	Form	Transaction Description	Form Received		Amount		
					GAS Royalty Opening Balance →		$	41,254.92
05253								
05253					Previous Balance →	5,458.72		
	2001/08	BC14	Royalty reversal	2002/01/31		27,438.44-		
		BC14	Amendment audited	2002/01/31		30,063.52		
	2001/09	BC10	Royalty reversal	2002/01/29		24,368.23-		
		BC10	Amended invoice	2002/01/29		24,368.23		
	2001/10	BC10	Original invoice	2001/12/18		10,753.83		
		BC15	Payment Received	2002/01/25		10,753.83-		
					Current Balance →	8,083.80	$	8,083.80
					Previous Balance →	29,259.68		
05450								
	2001/08	BC14	Royalty reversal	2002/01/31		15,092.50-		
		BC14	Amendment audited	2002/01/31		17,294.75		
					Current Balance →	31,461.93	$	31,461.93
05451					Previous Balance →	222.93-		
	2001/08	BC14	Royalty reversal	2002/01/31		37,068.84-		
		BC14	Amendment audited	2002/01/31		37,174.25		
					Current Balance →	117.52-	$	117.52-
05453					Previous Balance →	6,866.69		
	2001/08	BC14	Royalty reversal	2002/01/31		36,874.41-		
		BC14	Amendment audited	2002/01/31		40,683.71		
					Current Balance →	10,675.99	$	10,675.99
05555					Previous Balance →	107.24-		
					Current Balance →	107.24-	$	107.24-
					GAS Royalty Closing Balance		$	**49,996.96**

SAMPLE 9.3

9.3 Gas Royalty Account Transaction Listing

OVERVIEW

The 'Gas Royalty Account Transaction Listing' is a detailed listing of charges and payments made to the Gas Reporting Entities (REN's) of each royalty payor. Any REN with transactions from gas royalty invoices issued by the Ministry during the month or transactions reported on BC-14 (for amendments to production months before April 2001) or BC-15 forms received by the Ministry during the month ending on the Statement Date or with an outstanding balance will be included on this statement.

GUIDELINES

An illustration of the Gas Royalty Account Transactions Listing is presented in Sample 9.3. Following are descriptions of items on this statement:

Statement Date This is the last day of the calendar month in which reports (including amendments) were received. Reports and payments received by the Ministry after the date shown will not be reflected on the statement. They will appear on the next statement.

REN This lists the Ministry's 5-digit codes for each of the royalty payor's Gas Reporting Entities. The statement groups transactions by REN and provides balances due or overpaid for each REN.

Period This refers to the production month to which the royalty charges relate.

Form This refers to the form type from which the transaction is recorded.

Transaction Description This provides a brief description of each transaction.

Form Received This is the date the BC-10, BC-14, or BC-15 form on which the transaction was reported was received by the Ministry.

Gas Royalty Opening Balance This is the Gas Royalty Closing Balance carried forward from the previous statement period. It will also appear as the opening balance on the Consolidated Statement of Accounts for the Gas Royalty Account.

Previous Balance The amounts listed by Previous Balance in the **Amount** column are the closing balances for each Gas REN at the end of the previous statement period. The sum of Previous Balances for all of the Gas REN's is equal to the Gas Royalty Opening Balance.

Current Balance The amounts listed by Current Balance in the **Amount** column for each REN are the sum of the Previous Balance and all of the transactions in the current month.

Gas Royalty Closing Balance This is the sum of the Opening Balance and all of the transactions listed. It is equal to the sum of the Current Balances for all of the royalty payor's Gas REN's. As with the opening balance, this amount will also appear as the closing balance for the Gas Royalty Account on the Consolidated Statement of Accounts.

STATEMENT DATE: 2003/12/31

Royalty Payor 0099 ABC Limited

Account Type	Period	Form	Transaction Description	Cash Received		Amount
Estimate					Previous Balance →	10,500.00-
	2001/10	BC15	Estimate reversal	2002/01/25		10,500.00
	2001/11	BC15	Payment Received	2002/01/25		12,000.00-
					Current Balance →	12,000.00-
Cash-Held					Previous Balance →	0.00
		JOUR	Payment Received	2002/01/25		5,251.60-
					Current Balance →	5,251.60-
Cash-Suspense					Previous Balance →	50.00-
		BC15	Payment Received	2002/01/25		50.00
					Current Balance →	0.00
Interest					Previous Balance →	121.40
			Interest charge			282.70
			Prior period adjustment			41.29
			Payment Received			121.40-
					Current Balance →	323.99
Penalty					Previous Balance →	1,720.00
			Penalty charge			3,300.00
		BC15	Payment Received			1,500.00-
					Current Balance →	3,520.00
Assessment					Previous Balance →	0.00
		JOUR	Manual assessment charge			15,000.00
		BC15	Payment Received			15,000.00-
					Current Balance →	0.00
					Previous Balance →	14,134.00-
Summer Drilling		BC25	SD Credit reversal			14,134.00
		BC25	SD Credit revised			50,000.00-
		BC15	SD Credit taken			15,000.00
					Current Balance →	35,000.00-

SAMPLE 9.4

9.4 Other Accounts Transaction Listing

OVERVIEW

The 'Other Accounts Transaction Listing' is a detailed listing of charges and payments to the Estimate, Cash Held, Cash Suspense, Interest , Penalty, and Assessment accounts. Any of these account types with transactions during the month ending on the statement date or with an outstanding balance will be included on this statement.

GUIDELINES

An illustration of the Other Accounts Transaction Listing is presented in Sample 9.4. Following are descriptions of items on this statement.

Statement Date This is the last day of the calendar month in which transaction generating reports were received. Reports received by the Ministry after the date shown will appear on the next statement.

Account Type This refers to the type of account in which the transaction is recorded. It may include Estimate, Cash Held, Cash Suspense, Interest, Penalty or Assessment accounts. See section 9.1 for an explanation of each account type.

Period This refers to the production month to which transactions in the Estimate account relate. It is not applicable to the Assessment, Cash Held, Cash Suspense, Interest, and Penalty accounts.

Form This refers to the form type from which the transaction is recorded.

Transaction Description This provides a brief description of each transaction.

Cash Received For transactions generated from the Petroleum and Natural Gas Remittance Advice (BC-15), the date the cash was received is shown.

Previous Balance For each account type this is the Current Balance carried forward from the previous statement period. It will also appear as the Opening Balance for the account type on the Consolidated Statement of Accounts.

Current Balance For each account type the Current Balance is the Previous Balance plus the current transactions as shown. It will also appear as the Closing Balance for the account type on the Consolidated Statement of Accounts.

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MINISTRY OF PROVINCIAL REVENUE
ROYALTY MANAGEMENT SYSTEM
INTEREST CALCULATION DETAIL LISTING

2002/02/18
19:58
Page 1

STATEMENT DATE: 2002/01/31

Royalty Payor 0099 ABC Limited

Account Type	Closing Balance
Oil Royalty	2,446.30-
Gas Royalty	49,996.96
Total Balance	$ 47,550.66
Interest Rate (Prime + 3)	7.00000
Days in Statement Month	31
Interest Amount	$ 282.70

SAMPLE 9.5

9.5 Interest Calculation Detail Listing

OVERVIEW

The 'Interest Calculation Detail Listing' shows all of the information used to calculate the interest charge or credit for the current period in a royalty payor's Interest account. It is intended to assist the royalty payor in understanding these charges.

GUIDELINES

An illustration of the Interest Calculation Detail Listing is presented in Sample 9.5. Following are descriptions of items on this listing.

Statement Date This is the last day of the calendar month for which interest is calculated. Interest is calculated up to and including the Statement Date.

Account Type and Closing Balance This is a list of account types and the balance for each that is brought into the interest calculation. This includes Oil Royalty, Gas Royalty and Cash Held accounts. The balance for each is the closing balance for the account on the Consolidated Statement of Accounts on the Statement Date.

Total Balances This is the sum of the Closing Balances and the amount on which interest is calculated.

Interest Rate The rate per annum in effect for the statement period. Interest is charged at a rate equal to prime +3% while interest is paid on credit balances at prime.

Days in Statement Month The number of days in the statement period for which interest has been calculated.

Interest Amount This is the amount charged or credited to the royalty payor's Interest account with the Transaction Description "Interest Charge" on the Other Accounts Transaction Listing. As explained in section 8.1, the total Current Charge to a royalty payor's Interest account may also include other interest charges or credits.

Statement Date: 2002/05/31

Client:XXXX John Doe Client

Product	REN	Prod Month	Payment Due Date	Interest Period	Previous Statement Date	Previous Royalty Charge	Current Royalty Charge	Royalty Adjustment	Cumulative Adjustment
GAS									
	xxx17	2000/01	2000/04/25	2000/05	2000/08/31	2,883.87	2,955.68	71.81	
	xxx20	2000/01	2000/04/25	2000/05	2001/08/31	7,415.02	7,238.65	-176.37	
	xxx74	2000/01	2000/04/25	2000/05	2001/08/31	9,257.99	9,142.78	-115.21	
	xxx20	2000/01	2000/04/25	2000/05	2002/03/31	2,590.45	2,662.29	71.84	

								-147.93	-147.93 for 2000/05

								0.00	-147.93 for 2000/06

								0.00	-147.93 for 2000/07

								0.00	-147.93 for 2000/08

								0.00	-147.93 for 2000/09

								0.00	-147.93 for 2000/10

								0.00	-147.93 for 2000/11

								0.00	-147.93 for 2000/12

								0.00	-147.93 for 2001/01

								0.00	-147.93 for 2001/02
GAS									
	xxx17	2000/11	2001/02/25	2001/03	2001/02/28	2,296.72	2,416.07	119.35	
	xxx20	2000/11	2001/02/25	2001/03	2001/02/28	16,916.80	23,470.24	6,553.44	
	xxx74	2000/11	2001/02/25	2001/03	2001/02/28	68,166.26	83,985.37	15,819.11	
	xxx16	2000/11	2001/02/25	2001/03	2001/02/28	4,624.03	5,166.17	542.14	
	xxx59	2000/11	2001/02/25	2001/03	2001/02/28	5,939.71	5,939.56	-0.15	
	xxx28	2000/11	2001/02/25	2001/03	2001/02/28	469,066.62	468,879.14	-187.48	
	xxx61	2000/11	2001/02/25	2001/03	2001/02/28	23,201.86	22,733.49	-468.37	
	xxx42	2000/11	2001/02/25	2001/03	2001/02/28	5,967.79	3,949.85	-2,017.94	
	xxx84	2000/11	2001/02/25	2001/03	2002/05/31	0.00	1,925.91	1,925.91	
	xxx73	2000/11	2001/02/25	2001/03	2001/10/31	75,291.02	74,294.37	-996.65	
	xxx47	2000/11	2001/02/25	2001/03	2002/05/31	0.00	397.72	397.72	
	xxx37	2000/11	2001/02/25	2001/03	2001/02/28	5,272.37	5,365.64	93.27	

								21,780.35	21,632.42 for 2001/03

SAMPLE 9.6 (1)

Statement Date: 2002/05/31

Client:XXXX John Doe Client

Product GAS	REN	Prod Month	Payment Due Date	Interest Period	Previous Statement Date	Previous Royalty Charge	Current Royalty Charge	Royalty Adjustment	Cumulative Adjustment
	xxx17	2000/12	2001/03/25	2001/04	2002/05/31	0.00	71.60	71.60	
	xxx20	2000/12	2001/03/25	2001/04	2001/03/31	35,658.22	49,791.81	14,133.59	
	xxx74	2000/12	2001/03/25	2001/04	2001/03/31	143,865.74	156,440.14	12,574.40	
	xxx16	2000/12	2001/03/25	2001/04	2001/03/31	13,090.40	14,157.06	1,066.66	
	xxx58	2000/12	2001/03/25	2001/04	2001/03/31	188,450.82	188,650.63	199.81	
	xxx59	2000/12	2001/03/25	2001/04	2001/03/31	14,318.30	14,436.21	117.91	
	xxx28	2000/12	2001/03/25	2001/04	2001/03/31	1,137,784.85	1,138,624.06	839.21	
	xxx42	2000/12	2001/03/25	2001/04	2001/03/31	31,609.95	33,298.22	1,688.27	
	xxx25	2000/12	2001/03/25	2001/04	2001/03/31	40,906.30	40,751.14	-155.16	

								30,536.29	52,168.71 for 2001/04

								0.00	52,168.71 for 2001/05

								0.00	52,168.71 for 2001/06

								0.00	52,168.71 for 2001/07

								0.00	52,168.71 for 2001/08

								0.00	52,168.71 for 2001/09

								0.00	52,168.71 for 2001/10

								0.00	52,168.71 for 2001/11

								0.00	52,168.71 for 2001/12

								0.00	52,168.71 for 2002/01

								0.00	52,168.71 for 2002/02

								0.00	52,168.71 for 2002/03

								0.00	52,168.71 for 2002/04

Statement Date: 2002/05/31

Client: XXXX John Doe Client

Interest Period	Opening Balance on Interest-Bearing Accounts	Cumulative Adjustment	Closing Balance on Int-Bearing Accounts	Principal 1	Rate 1	Interest 1	Principal 2	Rate 2	Interest 2	Principal U	Rate U	Interest U
--------	--------------	---------------	-------------	-----------	-------	-----------	-------------	--------	-----------	--------------	--------	------------
			-									
2000/05	21,694.17	-147.93	21,546.24							-147.93	9.750%	-1.18
2000/06	27,243.94	-147.93	27,096.01							-147.93	9.750%	-1.22
2000/07	20,807.74	-147.93	20,659.81							-147.93	10.500%	-1.27
2000/08	-1,002.46	-147.93	-1,150.39							-147.93	7.500%	-0.94
2000/09	-3,899.88	-147.93	-4,047.81							-147.93	7.500%	-0.94
2000/10	-119,578.90	-147.93	-119,726.83							-147.93	7.500%	-0.91
2000/11	-249,087.60	-147.93	-249,235.53							-147.93	7.500%	-0.94
2000/12	-117,698.37	-147.93	-117,846.30							-147.93	7.500%	-0.91
2001/01	-129,452.69	-147.93	-129,600.62							-147.93	7.500%	-0.94
2001/02	-136,278.43	-147.93	-136,426.36							-147.93	7.500%	-0.94
2001/03	10,668.83	21,632.42	32,301.25							21,632.42	10.500%	174.24
2001/04	-25,381.18	52,168.71	26,787.53	25,381.18			26,787.53	9.750%	221.82			
2001/05	-40,501.81	52,168.71	11,666.90	40,501.81	6.750%	224.70	11,666.90	9.750%	93.50			
2001/06	-5,848.85	52,168.71	46,319.86	5,848.85	6.750%	33.53	46,319.86	9.750%	383.57			
2001/07	-1,037.77	52,168.71	51,130.94	1,037.77	6.250%	5.33	51,130.94	9.250%	388.74			
2001/08	-19,780.33	52,168.71	32,388.38	19,780.33	6.250%	105.00	32,388.38	9.250%	254.45			
2001/09	-13,567.51	52,168.71	38,601.20	13,567.51	6.250%	72.02	38,601.20	9.250%	303.26			
2001/10	-71,950.61	52,168.71	-19,781.90							52,168.71	5.750%	246.55
2001/11	-71,152.17	52,168.71	-18,983.46							52,168.71		
2001/12	-52,349.83	52,168.71	-181.12							52,168.71		
2002/01	-67,500.24	52,168.71	-15,331.53							52,168.71		
2002/02	-54,857.46	52,168.71	-2,688.75							52,168.71	4.000%	177.23
2002/03	-58,156.57	52,168.71	-5,987.86							52,168.71	4.000%	160.08
2002/04	-71,512.35	52,168.71	-19,343.64							52,168.71	3.750%	166.15
						---------			-----------			--------
					Interest Totals:	440.58			1,645.34			914.06
Interest Grand Total =		2,999.98			Interest Charge	2,999.98						

March 2003

SAMPLE 9.6 (2)

9.6 Prior Interest Calculation

OVERVIEW

When adjustments are made, either by amendments or assessments, to royalties or taxes due in previous months, interest is charged or credited on the adjustments from their due date to the beginning of the current month. This is referred to as prior period interest. By compensating for the value of funds over time Prior Period interest is intended to bring financial status of government and industry as close as practical to what it would be if all amounts payable had been determined correctly in the first place.

GUIDELINES

There are two reports to assist royalty and tax payors to understand how prior period interest charges or credits have been calculated: a "Prior Period Adjustment Summary", and a "Prior Period Adjustment Interest Calculation".

PRIOR PERIOD ADJUSTMENT SUMMARY REPORT

The ‘Prior Period Adjustment Summary’ lists the adjustments to royalties or taxes that were due in previous months that appear on the account statement as of the indicated statement date. An illustration of this report is provided as Sample 9.6 (1). Following is a description of the data that appears in each column of the listing.

Statement Date This is the last day of the month in which the adjustments are added to balances in interest bearing accounts.

Client This is the royalty/tax payor to whose account the adjustments will be added or subtracted.

Product For each adjustment, this is the type of product for which the royalty or tax has been changed. Products may be gas or oil.

REN For each adjustment, this is the number of the reporting entity for which the royalty or tax has been changed.

Prod Period For each adjustment, this is the production month for which royalty or tax has been changed.

Payment Due Date For each adjustment, this is the date from which interest is being charged. If the product type is gas, this will be the 25th day of the 3rd month after the Prod Period. If the product type is oil, this will be the 25th day of the month after the Prod Period.

Interest Period For each adjustment, this is the first month for which interest is charged or credited. Interest is charged or credited from the 26th day of one month to the 25th day of the following month. The "Interest Period" is the month in which most of the days for which interest is charged occur.

PRIOR PERIOD ADJUSTMENT SUMMARY REPORT cont'd

Previous Statement Date For each adjustment, this is the date of the last statement on which the "Previous Royalty Charge" can be found.

Previous Royalty Charge For each adjustment, this is the amount of royalty or tax to which the adjustment applies. This is the last charge to the REN for the production month.

Current Royalty Charge For each adjustment, this is the amount of royalty or tax charged to the REN for the production month after the adjustment.

Royalty Adjustment This column lists the amount of each adjustment to royalty or tax. If the current charge is less than the previous charge, the adjustment is shown as a negative amount. This column also gives a subtotal of the adjustments for each production month.

Cumulative Adjustment Starting with the oldest production months, this column lists the cumulative total of all royalty and tax adjustments to all REN's as of the end of each production month, and for each total indicates the Interest Period for which interest charges or credits are based on that total. The Interest Period is the month in which most of days for which interest is charged occur. For example, for Interest Period 2002/05, interest is charged from April 26 to May 25, 2002.

PRIOR PERIOD ADJUSTMENT INTEREST CALCULATION REPORT

The 'Prior Period Adjustment Interest Calculation' lists the amount of interest charged or credited on adjustments in all of a royalty payor's reporting entities for each interest period. It also shows the total interest charge or credit for all interest periods. This is the amount that will show on the royalty payor's statement for the Statement Date indicated on the report. An illustration of this report is provided as Sample 9.6 (2).

Interest Period This is the period of time for which an interest charge or credit is calculated on a balance in the royalty payor's interest bearing accounts. An Interest Period starts on the 26th day of one month and ends on the 25th day of the following month. The numeric reference for an Interest Period is the calendar month in which the end of the Interest Period occurs, which is the month in which most of days for which interest is charged occur.

Opening Balance on Interest-Bearing Accounts This is the total balance in the royalty payor's interest bearing accounts as of the beginning of the month indicated in the Interest Period column before adjustments have been added or subtracted.

Cumulative Adjustment This is the cumulative amount of adjustments for all production months up to the beginning of the month indicated in the Interest Period column.

Closing Balance on Int-Bearing Accounts This is what the total balance in the royalty payor's interest bearing accounts would have been as of the beginning of the month indicated in the Interest Period column after adjustments have been added or subtracted.

PRIOR PERIOD ADJUSTMENT INTEREST CALCULATION REPORT cont'd

Principal 1 A Principal 1 amount occurs if the Cumulative Adjustment for an Interest Period is opposite in sign and greater in absolute value than the Opening Balance for Interest Bearing Accounts for the period. When this happens, the adjustments change the balance in interest bearing accounts at the beginning of the month from an over payment to an underpayment, or vice versa. In these cases, two rates of interest must be used to calculate the Prior Period Interest charge or credit for the period: one for the negative or overpayment balance and one for the positive or underpaid balance. The Principal 1 amount is the Opening Balance in Interest Bearing Accounts in these circumstances.

Rate 1 This is the interest rate that is used to calculate interest on Principal 1. If the Opening Balance for Interest Bearing Accounts was an overpayment, this is the interest rate that was used the last time interest was credited on that balance. If the Opening Balance for Interest Bearing Accounts was an underpayment, this is the interest rate that was used the last time interest was charged on that balance.

Interest 1 This is the interest charged or credited on Principal 1 for the Interest Period, which is Principal 1 times Rate 1 times the number of days in the Interest Period divided by number of days in the year.

Principal 2 A Principal 2 amount occurs in the same circumstances as a Principal 1 amount, and two rates of interest must be used to calculate the Prior Period Interest charge or credit for the period: one for the negative or overpayment balance and one for the positive or underpaid balance. Principal 2 is the amount by which the Cumulative Adjustment exceeds the Opening Balance in Interest Bearing Accounts in these circumstances.

Rate 2 This is the interest rate used to calculate interest on Principal 2 for the Interest Period, which was the prescribed rate for the Interest Period.

Interest 2 This is the interest charged or credited on Principal 2 for the Interest Period, which is Principal 1 times Rate 1 times the number of days in the Interest Period divided by number of days in the year.

Principal U A Principal U (for Uniform) amount occurs if the Cumulative Adjustment for an Interest Period has the same sign as the Opening Balance for Interest Bearing Accounts for the period, or is opposite in sign and smaller in absolute value than the Opening Balance for Interest Bearing Accounts for the period. When this happens, the adjustments do not change the balance in interest bearing accounts at the beginning of the month from an overpayment to an underpayment, or vice versa, and one rate of interest applies to the Cumulative Adjustment for the period.

Rate U This is the rate for overpayments or under payments that prevailed during Interest Period. If the Cumulative Adjustment for an Interest Period has the opposite sign and smaller absolute value than the Opening Balance for Interest Bearing Accounts for the period, Rate U is the interest rate that was used when interest was last charged or credited on that balance.

PRIOR PERIOD ADJUSTMENT INTEREST CALCULATION REPORT cont'd

Interest U This is the interest charged or credited on Principal U for the Interest Period, which is Principal U times Rate U times the number of days in the Interest Period divided by number of days in the year.

Interest Charge This is the total of the interest charges for all of the Interest Periods. This amount will be included in the charges or credits to the Interest Account in the Consolidated Statement of Accounts for the client for the same Statement Date.

MINISTRY OF PROVINCIAL REVENUE
ROYALTY MANAGEMENT SYSTEM
PENALTY SUMMARY - BCS1, BCS2, BC10, BC11, BC12, BC13, BC15

STATEMENT DATE: 2002/01/31

Client ID:	0999	ABC Limited	Amount
BCS1			$560.00
BC11			$2,200.00
BC12			$540.00

		Total Assessed Penalty for Client: 0999	$3,300.00

SAMPLE 9.7 (1)

RMS43182 **MINISTRY OF PROVINCIAL REVENUE** 2002/02/18
ROYALTY MANAGEMENT SYSTEM 19:58
PENALTY DETAIL LISTING - BCS1, BCS2, BC10, BC13 Page 1

STATEMENT DATE: 2002/01/31

Client Id: 0999 ABC LIMITED

Form	REN/Fac	Facility Name	Prod.Month	Due Date	Date Received	Days Late	Penalty Assessed @$20/day	Original Batch Number
BCS1	3177	ABC BLUEBERRY 12-29-88-	2001/11	2001/12/27	2002/01/24	28	$560.00	B-2002-01-01

Total Assessed BCS1, BCS2, BC10, BC13 Penalty for Client 0099: $560.00

RMS43185 **MINISTRY OF PROVINCIAL REVENUE** 2002/02/18
ROYALTY MANAGEMENT SYSTEM 19:58
PENALTY DETAIL LISTING - BC11 Page 1

STATEMENT DATE: 2002/01/31

Client Id: 0999 ABC LIMITED

Ctl Num	UWI	WANum	Product	Facility	Effective Date	Due Date	Received Date	Days Late	Penalty @$20/day
07193	102081108725W600	14073	Gas	3573 ABC HALFWAY 5-12-87-25	2001/11/26	2001/12/20	2002/02/13	55	$1,100.00
07194	102081108725W602	14073	Gas	3573 ABC HALFWAY 5-12-87-25	2001/11/26	2001/12/20	2002/02/13	55	$1,100.00
									$2,200.00

RMS43186 **MINISTRY OF PROVINCIAL REVENUE** 2002/02/18
ROYALTY MANAGEMENT SYSTEM 19:58
PENALTY DETAIL LISTING - BC12 Page 1

STATEMENT DATE: 2002/01/31

Client Id: 0999 ABC LIMITED

Ctl Num	First REN	Fac/PE		Earliest Eff. Period	Due Date	Received Date	Days Late	Penalty Assessed @$20/day
649	04324	0107	ABC STODDART 11-30-86-20	2001/11	2001/12/20	2002/01/03	14	$280.00
646	04953	3573	ABC STODDART 5-12-87-25	2001/11	2001/12/20	2002/01/02	13	$260.00
								$540.00

9.7 Penalty Summary and Penalty Detail Listing

OVERVIEW

The 'Penalty Summary' is a summary of the penalty charges to a client for the last filing of prescribed reports received during the month. The 'Penalty Detail Listing' provides details of the penalties charged for each type of report that was late. Clients are encouraged to examine these reports and take steps to ensure their procedures allow reports to be filed on time.

GUIDELINES

Illustrations of the Penalty Summary and Penalty Detail Listing are presented in Samples 9.7(1) and 9.7(2). Following are descriptions of the Penalty Summary and Penalty Detail Listing reports

Statement Date This is the last day of the calendar month in which reports were received. Reports received by the Mineral, Oil and Gas Revenue Branch after the date shown will not be reflected on the statement.

Penalty Summary This report summarizes the penalty charges by form type and amounts for a client.

Penalty Detail Listing This report provides information regarding the report on which a late filing penalty is charged. For all types of reports the Penalty Detail Listing shows the due date, date received, days late and assessed penalty. Depending on the type of report, it will also show the following information:

BC-S1, BC-S2, BC-10 or BC-13 reports: facility number, facility name, production month and the Ministry's batch reference number,

BC11 reports: a Ministry control number, the Unique Well Identifier (UWI), Well Authorization number (WANum) and main Product (oil or gas) for the well for which a change in status was reported, and the facility to which the well is connected,

BC12 reports: a Ministry control number, the first 5 digit reporting entity number listed on the BC-12 that was late (First REN), and the Ministry's code and name for the facility or production entity (Fac/PE) to which the BC-12 relates.

10.0 VALIDATIONS AND EXTERNAL AUDIT

OVERVIEW

The Validations/Audit Section of the Mineral, Oil and Gas Revenue Branch was formed to verify information related to petroleum and natural gas royalty transactions. The primary objective of this section is to ensure that reported petroleum and natural gas royalties and freehold production taxes are complete and accurate, in accordance with the appropriate legislation and regulations.

OBJECTIVES

The primary objectives of Validations are as follows:

- To monitor the compliance of industry within the self-assessing framework of the oil and natural gas royalty/tax reporting system in British Columbia.
- To review production and royalty submissions from industry and verify the integrity of the data with third-party sources or physical inspections.
- To identify and resolve incorrect royalty payments.

VALIDATION AND AUDIT FUNCTIONS

The major functions of the Validations/Audit Section focus on verifying the completeness and accuracy of oil and gas royalty/tax factors. These include:

- Completeness of production and sales volumes,
- Appropriateness of deductions,
- Legitimacy of exemptions,
- Accuracy of prices used to determine royalty/tax.

10.1 Notice of Assessment

ASSESSMENT PROCEDURES

The Validations/Audit Section of the Ministry of Finance provides a post transaction review of royalty and tax submissions. When errors have been made in filing BC-S1, BC-S2, BC-09, or BC-08 reports, the Section will prepare amended reports where they have enough information to do so. Companies receiving amended reports should verify these reports, by comparing their third party data sources to the amended reports. If the company disagrees with the amended report, they should contact the person who prepared the amendment by email for further clarification. If the Section does not have enough information to prepare an amended report, they will request an amendment.

ADMINISTRATIVE POLICIES

(1) Producers who receive a Request for Amendment have 60 days after the date shown on the request to remit the requested reports or information. Producers who fail to comply with a request within the required time may be subject to a penalty of $20 per day up to a maximum of $6,000.

(2) If an amendment has not been filed within the 60 day Request for Amendment time period, the Validations/Audit Section may prepare the necessary assessments based on the best information available (i.e., third party data, average pricing).

(3) Producers who receive a Notice of Assessment have 60 days after the date shown on the assessment to pay the amount of royalty or tax owing, if any.

APPEALS

(1) A producer who does not agree with a Notice of Assessment may request reconsideration by the Royalty Collector. Requests for reconsideration are to be made by registered mail before the 60-day period expires in order to avoid assessment of filing penalties.

(2) Producers may appeal a decision of the Royalty Collector to the Minister of Finance. This must be done in writing within 60 days of the decision of the Royalty Collector. The notice of appeal is to be addressed to the Royalty Collector who shall, along with the appeal, provide all relevant information to the Minister of Finance. The Minister of Finance with or without a hearing, shall confirm, vary or reverse the decision of the Royalty Collector. This decision will be conveyed in writing to the person who made the appeal.

10.2 Use of the Assessment Account

OVERVIEW

From time to time, the Validations/Audit Section will summarize assessments that relate to numerous production periods. In these cases, BC-13 or BC-08 forms for these specific production periods are not required. The Validations/Audit Section will issue a summarized Notice of Assessment and direct that this amount be paid on the Royalty Remittance Advice (BC-15) under “Assessment”.

GLOSSARY

Acquisition Order A document issued to a producer by the Ministry of Energy, Mines and Natural Gas in relation to a natural gas sale contract between the producer and a buyer. Through the Acquisition Order, the Ministry purchases from, and immediately sells back to, the producer all natural gas produced for that sale contract.

Acquisition Order Price The unit price at which the Ministry of Energy, Mines and Natural Gas purchases from, and sells back to, the producer the volume of natural gas produced in a particular month. The Acquisition Order Price is determined monthly by the Ministry and the producer is advised of the Price in writing.

Administrator The person appointed as the royalty administrator under the *Petroleum and Natural Gas Act*. Currently, this is the Assistant Deputy Minister, Resource Development Division.

Amendments Regular monthly production and sales reports may be adjusted by industry up to 72 months after the month of production. The original documents are resubmitted containing amended values.

AO See *Acquisition Order*.

Average daily natural gas production volume This means, in relation to a well event in a producing month, the volume of natural gas produced in the producing month from the well event, expressed in m^3, divided by the number of hours during which the well event produced natural gas in the producing month and multiplied by 24.

Battery A system or arrangement of tanks or other surface equipment receiving the effluents of one or more wells prior to delivery to market or other disposition, and may include equipment or devices for separating the effluents into oil, gas or water and for measurement.

Calendar Days Consecutive days, including weekends and holidays.

Calorie The amount of heat required at a pressure of one atmosphere to raise the temperature of one gram of water one degree centigrade.

Client An individual or corporate entity that may from time to time be required to pay royalties or taxes to the Crown or to provide information relating to determination of royalties or taxes. A client may be a royalty payor, facility operator, gas plant operator, purchaser of oil, transporte of gas or oil.

Commingled Production Product produced from two or more zones in the same well bore that is reported as one production volume on reporting form BC-S1; the product must be the same type of product.

Completed Well A well in which the productive formation is open to well bore with equipment installed in the well and at the wellhead so that the well is physically able to produce oil or gas.

Concurrent Production Gas produced from an oil well where the oil well is part of an approved concurrent production scheme under section 97 of the *Petroleum and*

Natural Gas Act.

Conservation Gas Natural gas produced from an oil well where the marketable gas is conserved but does not include gas produced from an oil well granted concurrent production status under section 97 of the *Petroleum and Natural Gas Act*.

Contract Carrier A person who is the owner or operator of a pipeline that transports oil or natural gas, or both, for more than one producer and whose tariff has been approved by a public regulatory body having jurisdiction over that person.

Crown Land Land where the Crown has retained ownership of underlying oil and natural gas. Production of oil and natural gas from Crown lands requires a lease under the *Petroleum and Natural Gas Act*.

Crown Oil Oil produced from Crown lands. Crown oil is subject to a royalty under section 73 of the *Petroleum and Natural Gas Act*.

Cubic Metre A volume of oil or natural gas measuring one metre by one metre by one metre at 101.325 kPa and 15^{o}C.

Custom Processing Fee A fee in money or in kind for processing gas. It is charged by processing plant owners to a party that does not own an interest in the facility, or whose throughput at the facility exceeds its percentage ownership in that facility.

Custom User A gas royalty client who pays gas processing plant owners a custom processing fee.

Deemed Value For a volume of oil, marketable gas or natural gas by-products, the monetary value fixed by the royalty administrator or the Minister of Energy, Mines and Natural Gas.

Delivery Point The location at which the first arm's length transfer of custody occurs. Under an acquisition order, the delivery point is the location where the natural gas enters the pipeline system in British Columbia. For a sale, the delivery point is the location on the pipeline system where the buyer takes title to the natural gas from the producer.

Discovery Oil Oil discovered in a new pool discovery well completed after June 30, 1974.

Discovery Well The first producing well in a pool or, where through special circumstance no well in the pool is producing, the completed well that, in the opinion of the Minister, is capable of being the first producing well in the pool.

Established Market Price
A price set by the administrator and published around the middle of each month for marketable gas that becomes available for disposition during that month. It is essentially a forecast of the average price at processing plant inlets for the month. It is set by:

1. forecasting average prices at several locations in the province using historical data and expected volumes and prices provided by various producers, marketers, pipelines, utilities and publications (Inside FERC and the Canadian Natural Gas Market Report),
2. deducting average transportation and processing costs applicable to each point to derive forecasts of plant inlet prices,
3. calculating a weighted average plant inlet price from the derived forecasts of inlet prices and direct forecasts of plant inlet prices provided by a few producers and marketers.

The locations at which prices are forecast are Station 2, Huntingdon/Sumas and the BC Gas lower mainland drop-off point. The forecast price at each location is an average for all types of sales (domestic and export, short and long term, firm and interruptible). Average transportation and processing costs are determined from Westcoast Energy's published tolls, Gas Cost Allowances for producer-owned plants and recent data on average load factors.

Exempt Well
A well whose production is exempt from assessment of Crown royalty for a limited number of periods (months, years).

Facility
A battery, oil treater, pumping station, compressor station, dehydrator, gas injection station, waste disposal or processing station, water disposal or injection station or, upon designation of an officer of the Ministry, any other system of vessels and equipment designed to accommodate production and/or disposal of well effluent products and by-products, but does not include a gas processing plant.

Field
The surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area.

Field Sales
Oil or raw gas which is sold by the producer for use in the field.

Fiscal Year
The 12-month period commencing April 1 and ending the next March 31. For 1996-96, the Fiscal Year is the period from April 1, 1996 to March 31, 1997 inclusive.

First Title
Ownership of a volume of natural gas arising when the natural gas becomes a chattel.

Freehold Land
Land other than Crown land in respect of which the Crown has granted a person the right to work, win or carry away petroleum or natural gas.

Production of oil and natural gas from freehold lands does not require a lease under the *Petroleum and Natural Gas Act*.

Freehold Oil	Oil produced from a well or allocated to a tract in a unitized operation if the well or tract is located on freehold lands. Since January 1, 1993, freehold oil has been subject to a Freehold Production Tax under section 80 of the *Petroleum and Natural Gas Act*. Producers are responsible for reporting and submitting the Freehold Production Tax as prescribed in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Before 1993 freehold lands were assessed an annual property tax under the *Mineral Land Tax Act*, which was based on the value of oil and natural gas production from the land in the previous year.
Freehold Production Tax	A tax on production of oil, natural gas and natural gas by-products from freehold lands.
Freehold Production	Oil, natural gas or natural gas by-products produced from freehold land.
Freehold Owner	Any person who has a right to work, win or carry away oil or gas from freehold land.
GJ	Gigajoule.
GCA	Gas Cost Allowance.
Gas	See *natural gas*.
Gas Cost Allowance (GCA)	An allowance to a producer that is established by order of the administrator under section 7(6) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation to offset the cost of a natural gas processing plant or a natural gas sales line that is owned and operated by the producer and is used by the producer to process or deliver natural gas that (a) the producer owns, produces and sells, or (b) is owned by another producer who pays the owner of the processing plant or natural gas sales line for its use, or (c) is delivered to a storage facility.
Gas Processing Plant	A plant for the extraction from gas of hydrogen sulphide, carbon dioxide, helium, ethane, natural gas liquids or other substances, but does not include a production facility.
Gas Well	A well in which casing is run and that, in the opinion of the Minister, is producing or is capable of producing from a natural gas bearing zone.
Gathering System	A pipeline system which collects fluids and transports them to a processing system.
Gross Royalty	A value of the Crown’s royalty share of all production in a producing month prior to the deduction of any allowances or the value of exempt volumes.

Heavy oil	This is oil, produced from an oil well event, with a density of a least 890 kilograms per cubic meter.
In Kind	The taking by an owner of his or her share of oil, natural gas or liquids for separate marketing or disposition, rather than permitting the share to be disposed of jointly with other owners.
Incremental Oil	Oil that the administrator considers would not have been recovered without an approved infill drilling program, new pressure maintenance scheme, improved pressure maintenance scheme or other enhanced oil recovery scheme methods.
Injected Gas	Gas which has been introduced into a reservoir for the purpose of maintaining reservoir pressure, displacing liquids or storage.
Injection Scheme	A facility used to inject volumes of product or other substance into a reservoir for pressure maintenance, storage, or for secondary/enhanced recovery purposes.
Joule	A metric unit of energy or work, equivalent to 1 watt per second or .239 calories.
L.P.G.	Liquified Petroleum Gas.
Lease	A subsisting lease issued under the *Petroleum and Natural Gas Act*.
Lessee	A person in whose name a lease is recorded in the Ministry's records.
Liquids Price	The sales value of the natural gas liquids sold divided by the total volume of the natural gas liquids sold.
Location	The lands described in a permit, licence or lease.
Low productivity well	In the case of a well not part of a coalbed methane project, the well event produces in the producing month, an average daily natural gas production volume of less than 5000 $m^{3.}$
m^3	See *Cubic Metre*.
Marketable Gas	Natural gas that is available for sale for direct consumption as a domestic, commercial or industrial fuel, or as an industrial raw material, whether it occurs naturally or results from the processing of natural gas.
Metering Difference	Difference between volumes determined by different meters measuring the same gas stream, occasioned by the fact that gas volumes are not precisely determinable.
Minister	The Minister of Finance.
Ministry	The Ministry of Finance.
Month	Calendar month.
Monthly Allowable Production	The product of the calculated daily gas and daily oil allowable rate and 31 days.

Natural Gas	All fluid hydrocarbons, before and after processing, which are not defined as petroleum, and includes hydrogen sulphide, carbon dioxide and helium produced from a well.
Natural Gas By-Products	Natural gas liquids, sulphur and substances other than marketable gas, which are recovered from raw natural gas by processing or normal 2 phase field separation.
Natural Gas Components	Substances, other than marketable gas, which are recovered from natural gas by processing, including sulphur, liquids (ethane, propane, butanes, pentanes) and other condensates.
Natural Gas Liquids (NGL)	Ethane, propane, butanes or pentanes plus and any other condensates, or any combination of them, recovered from natural gas.
Netback Price	The effective wellhead price to the producer of natural gas, based on the downstream market price for the natural gas less the charges for delivering the natural gas to market.
New Oil	(a) oil, other than heavy oil or third tier oil, from an oil well event that (i) draws from an oil pool having on October 31, 1975 no completed well, or (ii) is outside the outline shown in each plat in Schedule A, of the surface area of the oil pool named on the plat, (b) incremental oil other than incremental oil that qualifies as third tier oil under paragraph (b) of the definition of "third tier oil", (c) oil, from an oil well event, that received the new oil reference price under the National Energy Program, or (d) oil from an oil well event that is completed within the outline referred to in paragraph (a) (ii) if the oil well event (i) resumed production on or after January 1, 1981 and had not produced oil for a period of a least 36 months immediately preceding that date, and (ii) was not an injection, pressure maintenance or observation well event during the period referred to in subparagraph (i), whether or not the period was more than 36 months. Schedule A consists of plats dated December 31, 1976 describing areas in the Peace River District that have been exempted from publication in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. These plats may be inspected at the Mineral, Oil and Gas Revenue Branch of the Ministry of Provincial Revenue.
Net Royalty Payable	Gross royalty less allowances and the value of exempt volumes.
Non-conservation Gas	Natural gas other than conservation gas.
Oil	See *Petroleum*.
Oil Well	See *Petroleum Well*.

Old Oil Oil other than new oil, heavy oil or third tier oil.

Owner
(a) the Crown in right of the Province for land so owned;
(b) a person registered in the land title office as the registered owner of the land surface or as its purchaser under an agreement for sale;
(c) a person to whom a disposition of Crown land has been issued under the *Land Act*; and
(d) for a well, includes a person entitled to produce and dispose of petroleum and natural gas from the well;

Operator The owner responsible to the Ministry for the drilling, completion, production and abandonment of a well or the general construction, operation and reclamation of any facility or plant.

PCOS See *Producer Cost of Service.*

PE See *Production Entity.*

PMP See *Posted Minimum Price*.

Petroleum Crude petroleum and all other hydrocarbons, regardless of gravity, that are or can be recovered in liquid form from a pool through a well by ordinary production methods, or that are or can be recovered from oil sand or oil shale.

Petroleum Well A well in which casing is run and that, in the opinion of the Minister, is producing or is capable of producing from a petroleum-bearing zone.

Pipeline Includes a pipeline or system or arrangement of pipes wholly in the Province by which is conveyed petroleum or natural gas, or water used or obtained in drilling for or in the production of petroleum or natural gas, and property used for, with or incidental to their operation, but does not include a pipe or system or arrangement of pipes to distribute natural gas in a community to ultimate consumers.

Plant The facility at which gas is processed or reprocessed.

Pool An underground reservoir containing an accumulation of oil, gas or both, separated or appearing to be separated from any other such accumulation.

Posted Minimum Price An amount equal to a percentage set by order of the royalty administrator of the established market price.

Producer

(a) a holder of a location who markets or otherwise disposes of oil, natural gas or both, that has been produced by

(i) the holder of the location, or

(ii) a person authorized to do so by the holder of the location, and

(b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder's behalf, oil, natural gas or both.

Producer Cost of Service

An allowance of such amounts as may be established by order of the administrator to cover a producer’s costs of:

- main field gathering, dehydration and field compression of non-conservation gas,
- conserving conservation gas, and
- processing natural gas for use as fuel in paragraphs (a) and (b), and

where the producer undertakes such operations with respect to that producer's own natural gas produced and sold or delivered to a storage facility.

Producing Month

In relation to a well, means a calendar month in which any quantity of oil, natural gas or water is produced from the well.

Producing Well

A completed well that has been placed on regular production.

Production

The volumetric measure of effluent from a producing well.

Production Entity

A unitized operation for which there is a royalty agreement between the Crown and the producers. For Production Entities royalty agreements require royalty rates to be based on production allocated to tracts, instead of production from a well.

Production Tract

A parcel of land in a unitized operation to which production of petroleum is allocated under the terms of the unit agreement.

Proration Battery

A battery that gathers from more than one well and where the oil volume, water volume, and gas volume produced from the wells are measured at the battery outlet and are then allocated to each well based on test results.

REN

See *Reporting Entity Number.*

Raw Gas

Gas as it issues from a well. It is a mixture that may contain methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium or minor impurities, which are recovered or are recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Reference Price

(a) For marketable gas other than sour gas, the greater of the following:

(i) the amount obtained by dividing the sales value of a volume of marketable gas by its volume, and

(ii) the posted minimum price for the month in which the marketable gas becomes available for disposition, and

(b) for sour gas, the amount obtained by dividing the sales value of the volume of the portion of sour gas that is marketable gas by its volume.

Reporting Entity

A consolidation of a royalty payor's interest in a group of wells with the following common attributes:

- product - either oil or gas,
- reporting facility or production tract for unitized operations,
- type of land - either Crown or freehold,
- for gas wells – gas plant.

Reporting Entity Number

A 5-digit code assigned to a Reporting Entity.

Reporting Month

The calendar month in which a report is made.

Residue Gas

Marketable gas that results from the processing of natural gas.

Royalty

A payment to the Crown for the Crown share of oil or natural gas sold by the producer.

Royalty Payor

See *producer*.

Royalty Regulation

Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation (B.C. Reg. 495/92).

Royalty Share

The share of production of oil, natural gas, or natural gas by-products from Crown land that is reserved in kind to the Crown in the right of the Province. The Royalty Share is valued, with some restrictions, at the price payable to the producer from the sale of the production to determine the amount of money payable to the Crown.

Sales Value	(a) for oil, the consideration, without deductions, that is received or receivable by a producer for the disposition of oil, or where there is a deemed value, the deemed value of the oil disposed of, (b) for natural gas (i) the acquisition order price for the volume of marketable gas disposed of by the producer less any gas cost allowance received by the producer for that volume of natural gas, or (ii) if there is a deemed value, the deemed value of the marketable gas disposed of, and (c) for natural gas by-products (i) the consideration received or receivable by a producer for the disposition of the natural gas by-products less the actual costs, approved by the administrator, incurred by the producer for transporting and processing the natural gas by-products from the point of production to the point of sale, or (ii) if there is a deemed value, the deemed value of the natural gas by-products disposed of.
Sales Volume	For oil, the volume sold by a producer during a production month. For residue gas, the quantity that is available for sale as determined from gas processing plant production reports, which may not be the same as actual deliveries under sales contracts. For raw gas and natural gas by-products, the volumes sold by a producer in a production month.
Select price	A price for gas established for each calendar year by order of the administrator.
Sour Gas	**For PMP** Natural gas containing greater than or equal to ten percent of H_2S by volume.
Spacing Area	The drainage area required by the *Petroleum and Natural Gas Act* for, or allocated by regulation to, a well for drilling for and producing petroleum or natural gas, and including at all depths the subsurface areas bounded by the vertical planes in which the surface boundaries lie.
Spud Date	The date selected by the Oil and Gas Commission as the date on which the ground was first penetrated for the purposes of drilling the well.
Storage Facility	An underground reservoir that is used for the storage of marketable gas.
Storage Reservoir	A naturally occurring underground reservoir that is capable of being used for the introduction, storage and recovery of petroleum or natural gas.
Sulphur	Market grade elemental sulphur which is obtained from processing natural gas.
Sulphur Price	The sales value of the sulphur sold divided by the total volume of the

	sulphur sold.
Tariff	Rates or charges approved by a public regulatory body having jurisdiction over a contract carrier or contract processor.
Tax	The freehold production tax under section 80 of the *Petroleum and Natural Gas Act*.
Tax Share	The share of production of oil, natural gas, or natural gas by-products from freehold land that is reserved in kind to the Crown in the right of the Province. The Tax Share is valued, with some restrictions, at the price payable to the producer from the sale of the production to determine the amount of money payable to the Crown.
The System	The royalty management system used in the Mineral, Oil and Gas Revenue Branch.
Third tier oil	(a) oil, other than revenue sharing oil and heavy oil, produced from oil well events that draw from an oil pool having, on June 1, 1998, no completed well, or (b) incremental oil, other than revenue sharing oil, that is derived from a pressure maintenance scheme, or an enhanced oil recovery scheme, that was approved after December 31, 1999 under section 100 of the Act.
Threshold Price	For a class of oil, the price that is established, by order of the administrator under section 2 (10), as the threshold price for that class of oil.
Throughput	The volume of raw gas received at the inlet of each gas processing facility.
Total Gross Royalty	See *Gross Royalty*.
Tract	A parcel of land in a unitized operation to which production of petroleum is allocated in accordance with the terms of a unit agreement.
Tract Participation Factor	The percentage share of the total production in a unitized operation allocated to a tract of land within the unit (i.e., the division of a pool between interests).
Unique Well Identifier (UWI)	A 16-character code signifying geographic location which is assigned by the Ministry to a well, to provide a unique numerical identity for the well. The unique well identifier, although based on the legal survey position of a well, is primarily for identification, rather than location.
Unit	Unit agreement.
Unit Agreement	An agreement among the Crown and all holders of locations in an area for unitized operation of the area. A unit agreement specifies how production from the unitized area and costs of development and operation will be allocated to holders of locations.

Unitized Operation

The development or production of petroleum and natural gas, or the implementing of a program for the conservation of petroleum and of natural gas or the coordinated management of interests in them in, on or under a location, part of a location or a number of locations combined for that purpose under a unit agreement.

The interest of owners are combined and production allocated to owners in accordance with an agreed upon formula or schedule of participation, regardless of which tracts producing wells are located on. Costs of the operation are distributed among owners according to the schedule of participation. This allows the operation to be managed as if there is only one owner and one tract.

UWI

Unique well identifier.

Vintage

The classification of oil as either Old Oil or New Oil.

Volumes Available for Sales

The volumes or quantities of gas or gas products obtained during a producing month at a gas processing plant, or the volumes of gas and gas products delivered from a gathering system during a producing month, excluding volumes delivered to a gas processing plant.

Well

A hole in the ground

(a) made or being made by drilling, boring or in any other manner from which petroleum or natural gas is obtainable, or to obtain petroleum or natural gas or to explore for, develop or use a storage reservoir for the storage of petroleum or natural gas;

(b) used, drilled or being drilled to obtain water for injection or for injecting natural gas, air, water or another substance into an underground formation in connection with the production of petroleum or natural gas; or

(c) used, drilled or being drilled to a depth in excess of 600 m to obtain geological or geophysical information respecting petroleum or natural gas;

Working Days

Days when offices are normally open, not including Saturday, Sunday or holidays.

Zone

A stratum or strata designated by the Minister as a zone generally or for a designated area or a specific well.