Royalty Information Briefing #3
- Royalties - History and Description -

Introduction:
Alberta has two basic royalty structures – one for natural gas and conventional oil, and the other for oil sands. For conventional oil and natural gas, the royalty is referred to as an ad valorem royalty, which is assessed on a sliding scale where the rate changes depending on oil or natural gas price and the level of production. For oil sands, the royalty is a combination of the traditional fixed royalty (1%) and a 25% profit share[1] based on net revenue. Reliance is placed mostly on the profit share.

The difference in systems results from the fundamentally different nature of the oil sands resource. Oil sands projects have much higher levels of costs than those for a typical oil or natural gas well. In addition, the scope and size of typical oil sands projects requires a longer time between initial investment and first production. The lead time between initial investment and first production for an oil sands project is a number of years whereas this time is measured in days or months for conventional operations where the project is a single well or group of wells.

Figure 1 and 2 compare the cash flow structure for a typical conventional well with that for a representative oil sands mining extraction project. The conventional well sees production peak early and then decline quite sharply. Oil sands production takes longer to reach peak levels however these levels can be sustained for a considerable period. Profit sharing systems similar to that applied to the oil sands are common around the world for large capital intensive oil and gas projects. Examples include, the Federal system for Canada's North, the fiscal terms applied offshore Newfoundland and Labrador, and the new petroleum profits tax applied in Alaska.

This briefing provides an overview of the royalty formulas and rates applied to natural gas, conventional oil, and oil sands production in Alberta.[2]

History:
Figure 3 provides a historical chronology illustrating some of the major developments in the evolution of Alberta's royalty structures. In the early years, Alberta followed a system similar to that applied in the United States whereby the royalty was a fixed flat percentage such as 5%, 12.5%, or 16 2/3%. Following the first oil price shock in the early 1970s Alberta refined its royalty formula to make it sensitive to change in prices. At that time, distinction was made between "Old" production and "New." In 1978, the royalty formulas were also made sensitive to the level of production from the well. In 1992, royalty rates were modified and an additional vintage distinction - "Third Tier" - was introduced for conventional oil pools discovered after August 31, 1992.

Incentive programs were introduced in the 1980s in response to low prices. Most of these programs have now been removed. The remaining programs are discussed in a separate briefing – Information Briefing #7 – Royalty Programs.

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[1] See *Royalty Information Briefing #1 – What are Royalties?*
[2] A detailed description of these systems can be found in *Oil and Gas Fiscal Regimes for the Western Canadian Provinces and Territories*, Alberta Department of Energy, February, 2007 - http://www.energy.gov.ab.ca/docs/tenure/pdfs/FISREG.pdf.

The generic oil sands royalty was introduced in 1997. Prior to this, royalties for oil sands projects were prescribed in separate Crown agreements – contracts – for each project. This produced an ad hoc approach to fiscal system design and application. This approach was manageable, given the small number of commercial oil sands projects in Alberta at the time. However, it did represent a time consuming process, and it did not provide certainty about the royalty treatment for future projects or a level playing field across all projects. As interest in oil sands development increased, it became obvious that a formal generic royalty structure for the oil sands sector was required.

Natural Gas Royalty Structure

Alberta classifies natural gas resources into Old and New vintages based on the discovery date of the reservoir. About 90 per cent of Alberta's current gas production is classified as New Gas discovered in 1974 or later.

Natural gas royalty rates are sensitive to price, vintage, and gas composition [the in-stream components (ISC) which include Methane (C_1), Ethane (C_2), Propane (C_3), Butanes (C_4), and Pentanes-Plus (C_{5+})].[3] Production from low productivity gas wells is subject to a reduced royalty rate as described below. The royalty rate for natural gas is determined as the weighted average of the royalty rates for the ISC. The royalty is levied on gas and extracted liquids at the outlet of the gas processing plant.

The royalty rate for C_1 and C_2 can range between 15 and 35 percent depending on the price level and well vintage (See Figure 4). The rates for C_3 and C_4 can range between 15 and 30 percent depending on the price level (i.e., there is no vintage adjustment for C_3 and C_4). For C_{5+} these rates are 22% to 50% for Old vintage and 22% to 35% for new (See Table below).

	Methane		**Natural Gas Liquid Components (ISC & Extracted Liquid)**					
	Old C_1	**New C_1**	**Old C_2**	**New C_2**	**C_3**	**C_4**	**Old C_5**	**New C_5**
Minimum Rate	15%	15%	15%	15%	15%	15%	22%	22%
Maximum Rate	35%	30%	35%	30%	30%	30%	50%	35%

Low productivity gas wells reporting an average gas production rate below 16, 900 cubic meters per day (600,000 cubic feet per day) in a production month are subject to the low productivity well allowance. This allowance can reduce the natural gas royalty rate to a minimum of 5% (See Figure 5).

Conventional Oil Royalty Structure

Alberta's conventional crude oil royalty rate varies with the following factors:

1. Oil Vintage;
2. Oil Density; and,
3. Oil Price and Well Production Volume.

1. Vintage

Conventional oil has three vintages: Old - oil pools discovered up to March 31, 1974, New - oil pools discovered after March 31, 1974, and Third Tier - oil pools discovered after September 1, 1992. The maximum royalty for old is 40%, for new 35%, and for third tier 29%. Figure 6 shows the royalty rate for

[3] The liquids composition of the gas stream varies significantly from plant to plant. Dry gas consists of methane with no natural gas liquids (NGL's), while wet gas contains measurable amounts of these liquids.

the three vintages at a current typical production rate of 20 barrels of oil per day (bopd). In 2006, 26% of conventional oil production was classified as old, 55% new, and 19% third tier.

2. Oil Density

The royalty rate for heavy oil is generally less than that for light-medium oil. This reflects the lower value of heavy oil to refineries. As a result, oil is classified into two densities for royalty purposes: Light-Medium – densities < 900kg/m^3 (>25.72 API)[4] and Heavy - > 900kg/m3 (< 25.72 API). In 2006, 70% of production was light-medium oil, while 30% was heavy oil. The proportion of heavy oil production from Alberta is expected to increase over time.

3. Price & Production Volume

Figure 7 illustrates how the royalty rate varies with both price and the level of production. Up to a price of about $40 per barrel the royalty rate changes as price changes. The chart also shows the rate to be higher or lower, depending on the level of production from a well. For example, at a well productivity of 20 bopd and a price of $30 per barrel the rate is 5%. This rate increases to about 17% for a well producing 40 bopd at a price of $40 per barrel.

Oil Sands Royalty Structure

Project Based:

Oil sands projects are typically mining projects or thermal in-situ projects (such as Steam Assisted Gravity Drainage - SAGD or Cyclic Steam Stimulation - CSS). For royalty calculation purposes, the oil sands project can be defined to include or not include an upgrader. Upgraders convert bitumen into lighter, higher valued synthetic crude oil. If the royalty project is defined to include the upgrader, the revenue included in the royalty calculation is based on the price for the synthetic crude oil.

Once a project proponent has their production schemes, operations, processing plants, wells and facilities approved by the Alberta Energy and Utilities Board, they can then apply to the Department of Energy under the “Oil Sands Royalty Regulation, 1997.” Oil sands recovery schemes that do not apply for project status under the generic regime, or are not approved as oil sands projects, pay royalty at conventional oil rates.

Royalty Structure and Rates:

The oil sands royalty has two components – a 1% rate based on gross revenue and a 25% rate based on net revenue.

Gross Revenue:

The gross revenue of an oil sands project is the sum of all the quantities of oil sands products produced (e.g. bitumen from a mine or synthetic crude oil from an upgrader) multiplied by their respective prices (less the cost of any diluents included in product sales). The price is adjusted to take into account all handling charges, such as pipeline tariffs, terminal charges, processing charges, etc. that are paid to move the oil sands product from the royalty calculation point[5] to the point of sale.

Net revenue:

Net revenue is the gross revenue less all allowed costs (operating and capital). These costs are 100% credited to the project in the year in which they are incurred.

[4] kg/m3 – kilograms per cubic metre. API – American Petroleum Institute gravity - a standard, indexed measure of density.

[5] The royalty calculation point is the project boundary as defined in the royalty application.

Costs:
To qualify as an allowed cost the cost must be:

- directly attributable to the project.
- reasonable under the circumstances.
- incurred by or on behalf of the project owners.
- incurred on or after the effective date of the project.
- incurred for one of the purposes set out in the Regulation: to recover, purchase, process, transport, or market oil sands products, provide services in support of these activities, or conduct research on oil sands recovery.

Payout:
The net royalty component only applies after a project has reached payout. Payout is the point where the developer has recovered all the allowed costs of the project, including a return allowance on those costs equal to the Government of Canada long-term bond rate - LTBR.

After a project reaches payout, the royalty payable to the Crown is equal to the greater of: (a) 1% of gross revenue for the period and (b) 25% of net revenue for the period. Gross royalty is a credit against net royalty.

Figure 1: Conventional Production Cash Flow

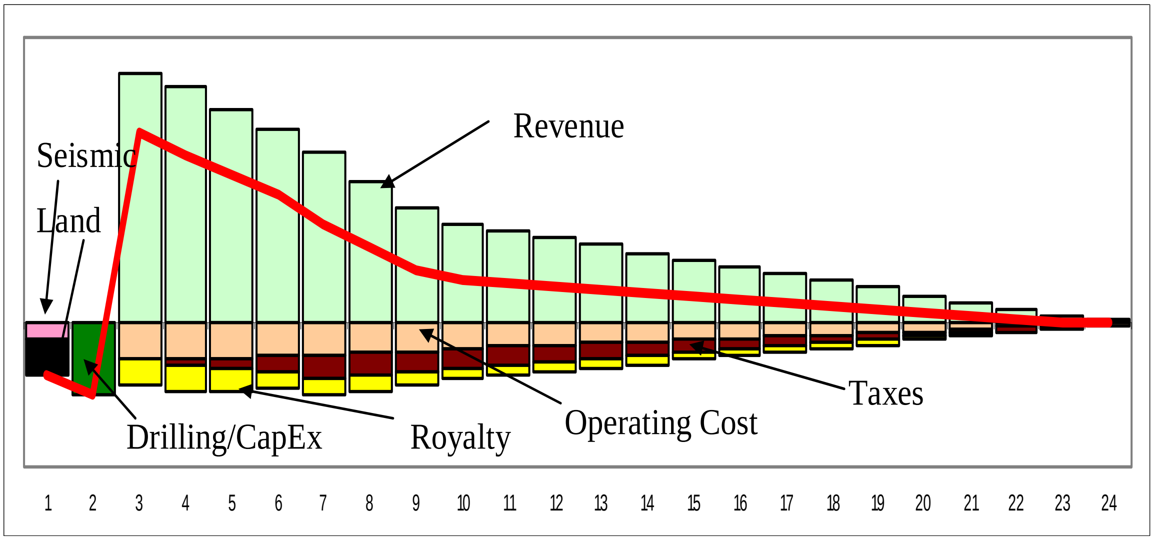


Figure 2: Oil Sands Production Cash Flow

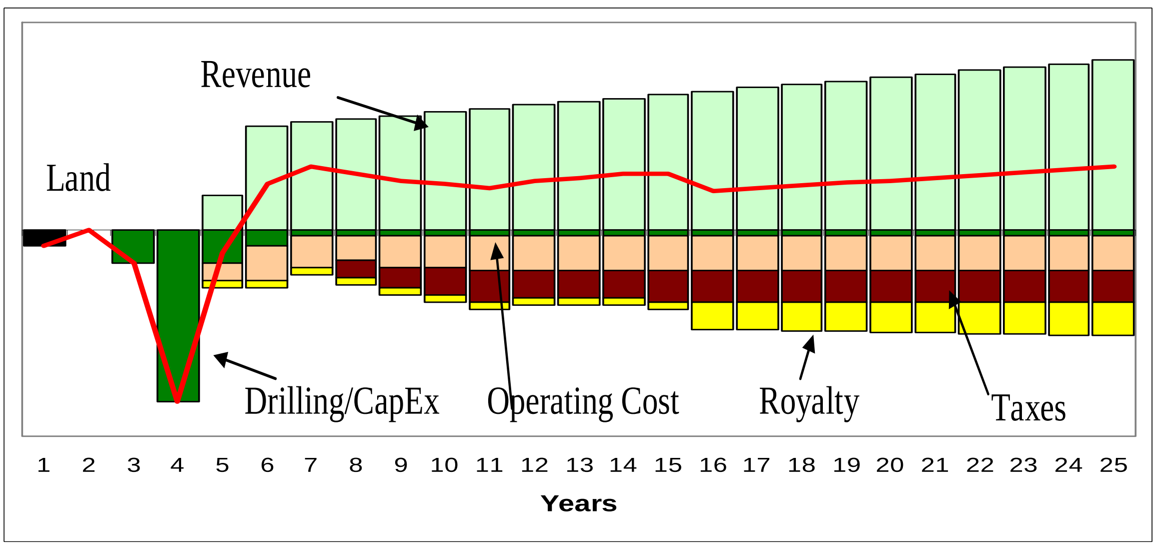


Figure 3: Major Events in Alberta's Royalty History

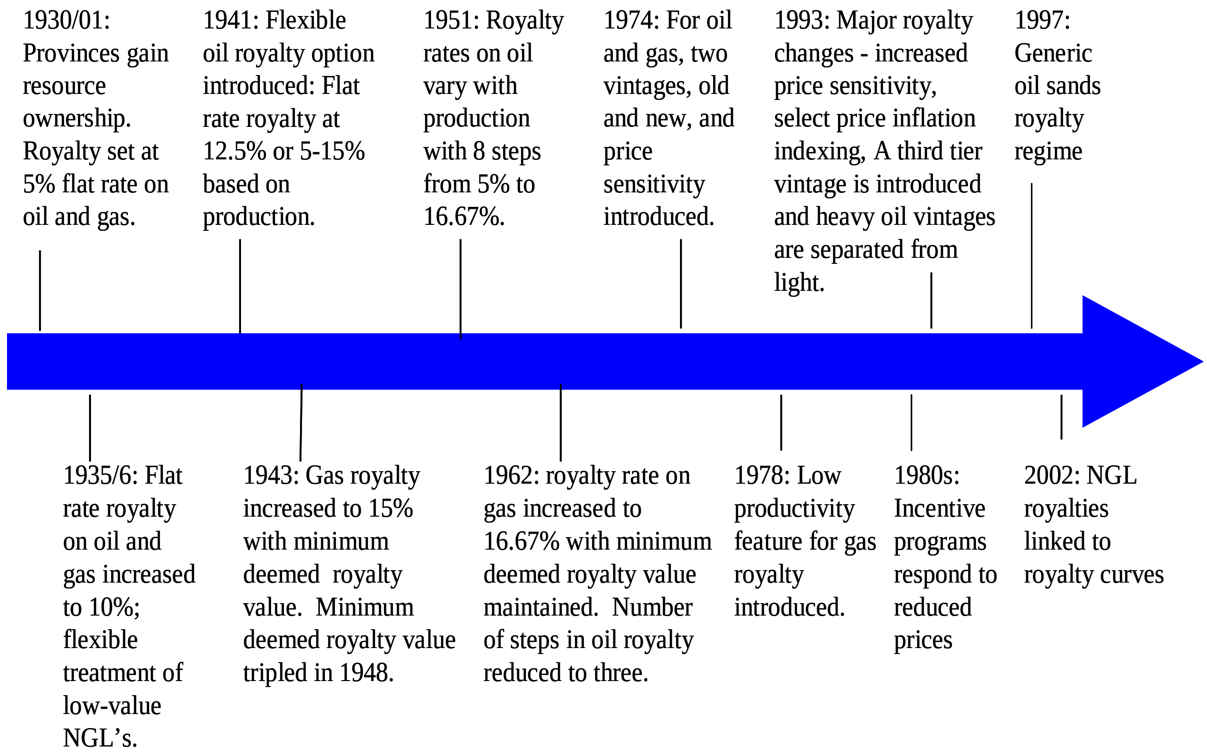


Figure 4 Natural Gas Royalty Rates Price Sensitivity[6]

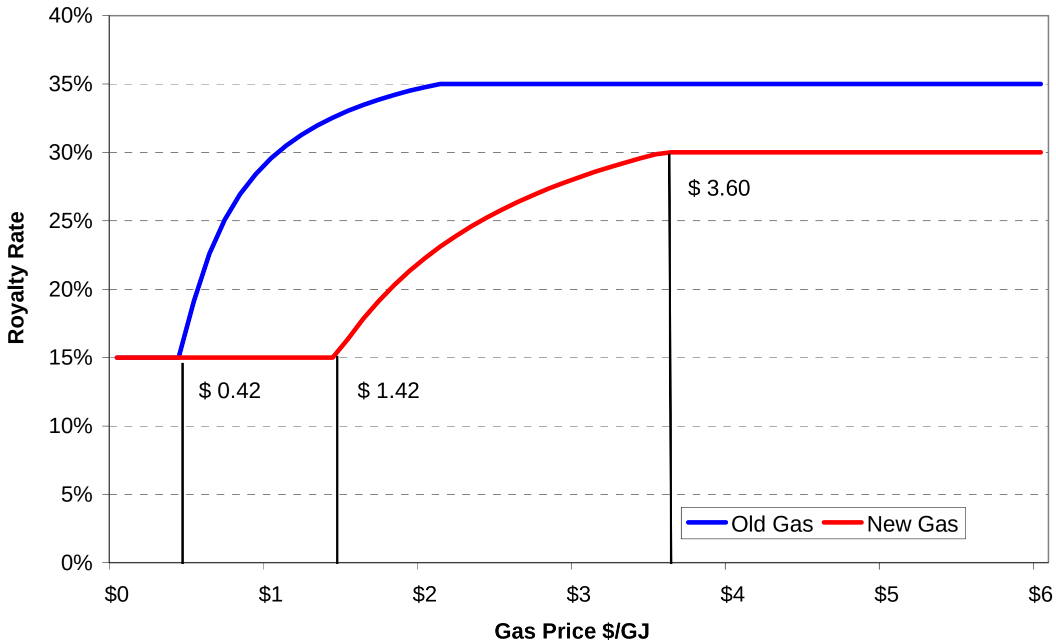
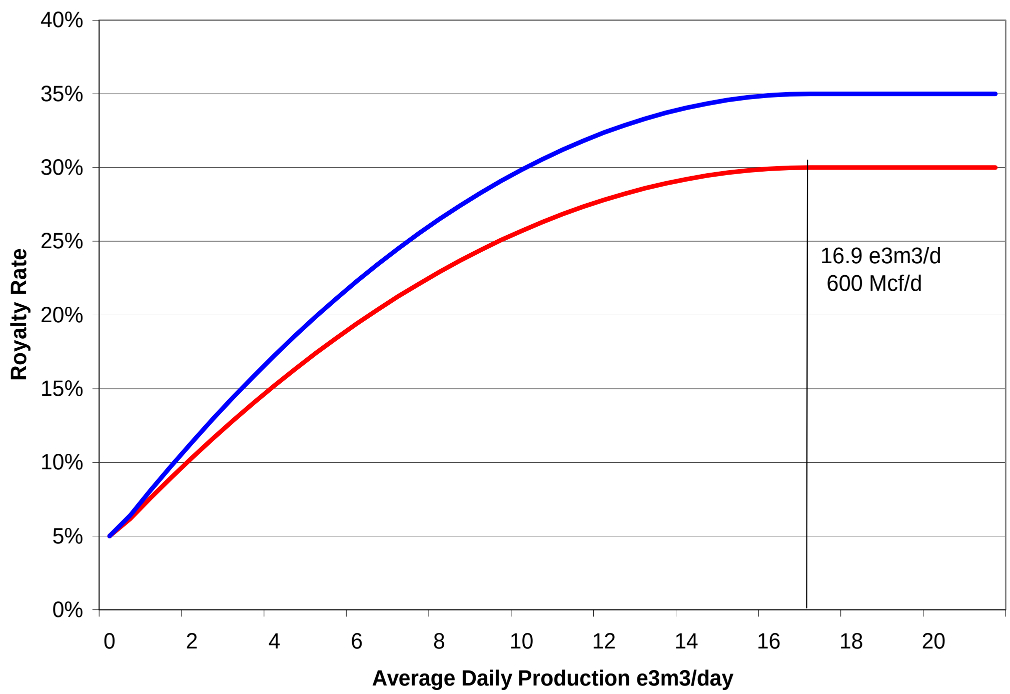


Figure 5 Natural Gas Royalty Rate Production Sensitivity



[6] The royalty rates presented by vintage are applicable for C_1 and C_2 only. C_3 and C_4 are not sensitive to vintage and are depicted as New Gas.

Figure 6: Oil Royalty Rates by Vintage

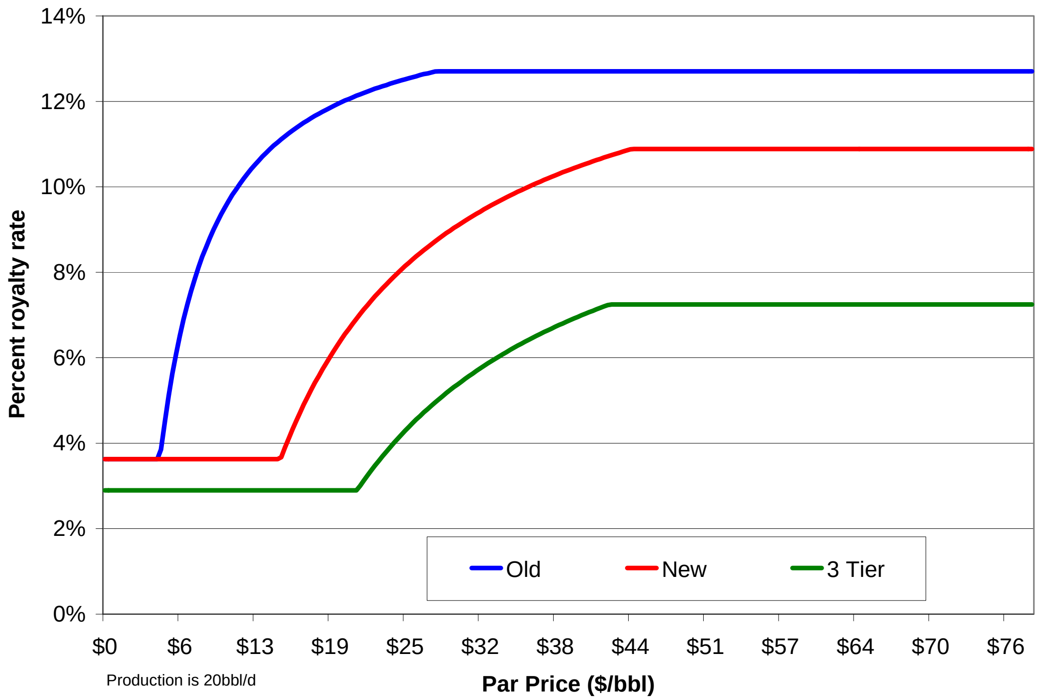


Figure 7: Oil Royalty Rates by Price and Production