Net reserves evaluation and sensitivity analysis of shale gas project under royalty & tax system in British Columbia, Canada

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Abstract. With the declination of production and increasing of fossil-fuel demand, petroleum companies strive to maximize production by conducting more advanced drilling operations, such as extended reach, horizontal and high-pressure /high-temperature (HP-HT) drilling and multi-stage hydraulic fracturing, which are expanding globally into unconventional resources drilling. Shale gas, which constitutes for a significant percentage of the natural gas resource base and offers tremendous potential for future reserve and production growth, was becoming the increasingly important asset for petroleum companies. This paper took a shale gas project in British Columbia (Canada) as an example, combining the characteristics of the shale gas reservoirs with royalty & tax policy of this region. The research on shale gas reserve evaluation and the principles of net reserve calculation under royalty & tax contract was carried out. The four main aspects such as technique, economy, commerce and engineering, were studied to analyze the influence on net reserves from the following factors: production, declining rate, development plan, oil price, Opex(operating costs), Capex(investment) and taxes, etc. Sensibility analysis was conducted by adopting the most weighted factors, such as oil prices, production, Opex and Capex. All the effort was to put forward the corresponding suggestions on optimizing development strategy, solve the current reserves evaluation problems of shale gas, and provide reference for the shale gas assets transaction, development and perfection of reserves value evaluation.

1. Introduction of shale gas resource in Canada
Shale gas is the natural gas produced from shale, a type of sedimentary rock [1-2]. The inclusion of shale gas with conventional gas reserves has caused a sharp increase in estimated recoverable natural gas in Canada. Until the success of hydraulic fracturing in the Barnett Shales of north Texas in 1990, shale gas was classified as "unconventional reserves" and was considered too expensive to recover. There are a number of prospective shale gas deposits in various stages of exploration and exploitation across the country, from British Columbia to Nova Scotia [3]. The Canadian Society for Unconventional Gas estimated in 2010 that there were more than 1100 TCF (trillion cubic feet) shale gas resource in place, and 128-376 TCF marketable shale gas resource potential in Canada [4]. The US Energy Information Administration estimated that there were 573TCF of technically recoverable natural gas in Canada in 2013, mainly distributed in Lower Besa River Formation of British Columbia and Duvernay Formation of Alberta and British Columbia [5-7]. Even so, the shale gas in Canada was widely considered to be under-appreciated, it’s abundant, safe, reliable, and affordable. More and
more major international oil companies were intended to acquire shale gas assets in Canada, and shale gas has become the potential energy resource that meets long-term energy, environment and economy objectives for many countries.

2. Natural gas royalty tax in British Columbia, Canada
Royalty refers to a type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the Royalty interest owners. A Royalty is commonly retained by a Resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to explore for, develop, produce, transport, and market hydrocarbons or minerals within a fixed area for a specific amount of time. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. The production and sale of hydrocarbons from the concession is then subject to rentals, royalties, bonuses, and taxes. Under royalty & tax system, the company typically bears all the risks and costs for exploration, development, and production and generally would hold title to all resources that will be produced while the agreement is in effect. Reserves consistent with the net working interest after deduction of any royalties owned by others are typically reported by the contractor[8-10]. The cost and after-tax profits of contractor are greatly influenced by the production and price, the contractors not only bear the risk that output fall short of the expectations and low prices, but also enjoy high quality gas resources and high prices bring excess profits.

In Western Canada, where the oil and gas resources are concentrated, each province has enacted their own policies of levying mining tax. The calculation methods of mining tax, tax rates and preferential policies are different among different area, especially in British Columbia, which the royalty tax system is most detailed and perfect.

According to Oil and Gas Royalty Handbook issued in July 2014, the royalty/tax rate for gas is dependent upon: (1) Whether it is produced from Crown land or freehold land, (2) whether it is classified as Conventional Gas or Unconventional Gas, (3) if it is Unconventional Gas from Crown land, whether it is Base 15, Base 12 or Base 9, (4) the Reference Price when it exceeds the Select Price for Base 9 or Base 12 Unconventional Gas or when it exceeds $50 per 10³m³ for any other gas, and the average daily rate of raw gas production.

“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 person. Production of oil and natural gas from freehold lands does not require a lease under the Petroleum and Natural Gas Act.

Unconventional gas is classified into Base 15, Base 12 and Base 9. These classifications are defined as follows:

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

Base 9: Unconventional 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 no 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.

Base 12: Unconventional gas, other than revenue sharing gas, produced from well events that are not Unconventional Gas, Base 15 or Unconventional Gas, Base 9.
“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.

“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 when the minimum royalty rate takes effect can be adjusted for inflation. It is currently $50 per 10^3 m^3 until further notice.

The formulae for calculating the royalty and tax rates are the next (table 1):

Table 1. Royalty and tax rates of marketable gas and by products produced from Crown land.

|                     | (i) if \( RP \leq 50 \) | (ii) if \( RP > 50 \) |
|---------------------|---------------------|---------------------|
| Conventional Gas:   | \( R\% = 8 \)       | \( R\% = \frac{400 + 15(RP - 50)}{RP} \) |
| Unconventional Gas, Base 15: | (i) if \( RP \leq 50 \) | \( R\% = 15 \) |
|                     | (ii) if \( RP > 50 \) | \( R\% = \frac{750 + 25(RP - 50)}{RP} \) |
| Unconventional 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 \( RP / SP \geq 28 / 13 \) | \( R\% = 27 \) |
| Unconventional 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 10^3 m^3, \( SP \) is the Select Price in $ per 10^3 m^3 and \( R \) is the royalty rate as a percentage.

Table 2. Royalty and tax rates of marketable gas and by products produced from freehold land.

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

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

From table 1 and table 2, the trend of royalty and tax rates of marketable gas can be summarized as: the tax rates of conventional gas is higher than unconventional gas, and the tax rates of crown land is
higher than freehold land. The royalty and tax rates of marketable gas can reach up to 27% on crown land and low to 5% on freehold land.

![Figure 1](image-url) Figure 1. marketable gas royalty/tax base rates.

From figure 1, if the reference price is equal to or lower than 50$ per $10^3$ m$^3$, the Royalty/Tax rate is fixed. If the reference price is higher than 50$ per $10^3$ m$^3$, Royalty/Tax rates are calculated according to table 1 and table 2.

For the low production well and the marginal well, Royalty and tax has the corresponding preferential policy. The production related reduction factors reduce royalty/tax rates by the basic royalty/tax rate multiplied by the reduction factor, as follows:

$$\text{Royalty/Tax Rate} = \text{Basic Rate} - \text{Basic Rate} \times \text{Reduction Factor}$$  \hspace{1cm} (1)

In addition, the tax preferential policy includes the producer cost of service allowance and gas cost allowance. The producer cost of service 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.

The Gas Cost Allowance (GCA) is a rate per $10^3$ m$^3$ 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.

3. Net reserves evaluation method and cash flow model of shale gas project

3.1. Net reserves evaluation method

Net reserves are recognized in situations where there is an economic interest, and after deduction for any royalty owed to others. Royalties are typically paid to the owner of the mineral rights in exchange for the granting of the rights to extract and produce hydrocarbons.

Net reserves refer to the share of total reserves available under the net economic interest of the contract, which is related to the economic parameters such as working interest, royalty and cost recovery and profit. The annual outputs in the output profiles of total reserves and net reserves are respectively called the total production and net production.
Calculation of net reserves is done by the next formula:

$$R_{net} = \sum_{i=1}^{n} Q_{net,i} = \sum_{i=1}^{n} (Q_{gross,i} \times WI)$$

(2)

where:
- $R_{net}$ = net reserves of contractor
- $I$ = time starting from current-year to ($i$) years in the future
- $Q_{net,i}$ = the net production of ($i$) year
- $n$ = project economic (or contractual) life in years
- $Q_{gross,i}$ = the gross production of ($i$) year
- $WI$ = working interest

It can be seen from the formula (2) that the higher the output and oil price, the higher the net reserves and income of the contractor will be, as long as the project is kept running smoothly.

Royalty volumes that are payable either in-kind or in monetary terms to the owner of the mineral rights. If it is paid in kind, the royalty volumes should be excluded from net reserves. If it is paid in cash, the royalty volumes can be booked by contractor, but the amount of the reserves will not affect the contractor’s cashflow [11-12].

3.2. Cash flow model

Figure 2 shows the cash flow model of contract and government under Royalty & Tax System. Total sales gas gross revenue refers to the gross income of marketable gas sales after deducting the corresponding expenses (such as transportation expense or other expenses, according to the sales contract). Net revenue after tax is calculated by the gross revenue deducted from the royalty, operating expenses, capital and abandonment costs, income tax and other taxes. The government's income is the sum of the royalty, income tax and other taxes, and profit sharing after tax. The contractor’s income is the corresponding profit sharing after tax.

![Cash flow model for sales gas project in British Columbia, Canada.](image)
4. Influential factors for net reserves of shale gas project

Net reserves and net present value evaluation of shale gas project are a comprehensive work, the volumes of net reserves are not only affected by the technical factors, such as planning, development and production, but also related to the contract terms, transportation, sales and many other factors. The influential factors can be divided into four major factors as following:

4.1. Technical factors

4.1.1. Five-year plan. Five-year plan refers to the production, well drilling, recompletion, the corresponding investment plan and supporting data (such as well location maps, structural maps and isopach maps) officially approved by the government. Detailed degree and credibility of the data directly affect the evaluation of PUD reserves (proved undeveloped reserves) and PDNP reserves (proved developed non-producing reserves).

4.1.2. Initial production. Initial production is the starting point of future output profile. The historical output data of the last few months in the annual evaluation has a great impact on the starting point, which will directly affect the future output profile and even the corresponding period. Therefore, there exists a strategy to raise and stabilize production adjacent to the data cut-off point, which has a positive impact on the evaluation of PD reserves (proved developed reserves).

4.1.3. Declining rate. Declining rate is an important parameter of dynamic method, mainly used for developed project. The reasonable determination of evaluation unit, declination type and curved shapes directly affect the prediction of PD reserves. The declining rate should be adjusted according to the actual situation of the project and the dynamic change of production, especially for the project during in the stage of increasing production or no steady declination.

4.1.4. Recovery factor. In the initial production stage or non-production area, dynamic method can’t be used because of lack of production data. Under the circumstances, volumetric method is generally used to calculate GIIP (gas initially in place), analogy with adjacent similar blocks or pilot experiments in the local area are used to determine the recovery factor, and then EUR (estimated ultimate recovery) is calculated. For the recovery factor of P1, it is often required to provide a more rigorous demonstration data. If the secondary oil recovery is not implemented, the primary recovery factor is adopted[13-14].

4.2. Economic factors

4.2.1. Operating cost and economic limit. Opex includes material supplies, maintenance of well equipment and surface facilities, employee salary and management fee, etc. The economic limit refers to the minimum amount of production that can be paid for operating costs. Total reserves are determined by volumetric method, dynamic method and other methods, then the results should be measured and calculated by running the economic model. If the cash flow obtained is positive after running the economic model, then the project has economic benefit. The time point of positive cash flow refers to the economic limit. The reserves are valid above the economic limit. Therefore, optimizing the Opex of oilfield, carrying out reasonable proportion and splitting of costs, may extend the economic limit and have a positive impact on the evaluation of net reserves.

4.2.2. Taxes. Under the royalty & tax system, the important factors that affect the net reserve and profit of oil companies are not only the technical factors, but also the taxes, mainly consists of royalty, asset tax, income tax, additional profit tax, export tax and other taxes[15]. In British Columbia (Canada), some tax rates are floating with the actual production and price, some taxes adopt fixed rate, and royalty rates are linked not only to productivity and price, but also to the drilling time, drilling
depth, well type, well location and gas component. By analyzing various taxes and the impact on the economic benefit of oil and gas field, the rational controlling of royalty and taxes can realize the maximization of the interests of the contractors.

4.2.3. Price. For the royalty & tax system, price changes have the positive correlation with net reserves, which directly affect the benefits of project and the ultimate value of reserves. Low prices affect the economy of reserves, shorten the economic life of the project, and reduce the net reserves and their values. When the prices rise, economic limits are likely to be extended, and net reserves and the value will rise accordingly.

4.3. Commercial factors

4.3.1. Contract restriction. Limitations of the contract period. The reserves are the sum of future proposed output of a project in a certain contract period and economic limit. By the end of the contract period, if the contract is not deferred, even if the project is under good production situation and the economic recoverable resources underground is abundant, the reserves beyond the contract period will not be booked[16].

Limitations of contract terms. For the assessment of natural gas reserves, the corresponding sales contract is required under SEC (U.S. Securities and Exchange Commission) rules, otherwise the reserves cannot be booked as P1 reserves even though the large reserves scale. If the sales contract is signed only for one year, contractor can book only one-year reserves, and the remaining predicted output will be deducted.

4.3.2. Modification of contract. Significant changes in the terms of the contract will significantly affect the economy of reserves. From 2014 to 2016, the major changes in oil prices directly led to some projects that are uneconomic and don’t have reserves. By negotiating with governments to deal with low prices, changing some of the contract’s terms, it is possible to turn the uneconomic projects into economic benefits directly.

4.4. Engineering factors

The integrity of oil and gas field surface engineering (such as infrastructure, pipeline, capacity of gas compressor, oil & gas processing plant, oil refinery and water treatment etc.) and the length of time for putting into use impact the oil and gas transportation and productivity construction, directly affect the implementation capacity of development plan, thus influence the results of reserves evaluation.

5. Sensitivity analysis of main factors

The following example analyzes the sensitivity factors of X shale gas project under R&T system in British Columbia of Canada. The planned annual shale gas production and NGL(Natural Gas Liquids) production respectively are 77536 MMCF(millions of cubic feet) and 16 MMB (million barrels) in 2018. In the term of economic contract, the future marketable shale gas production and NGL production respectively are 1458215 MMCF and 209 MMB. The royalty rate fluctuates during 5% to 16%, according to the Oil and Gas Royalty Handbook of British Columbia. Oil prices is 80 USD/barrel, according to the present Brent oil prices. Gas prices are pegged to oil prices (Table 3).

According to the analysis on economic benefit index of X project, five main parameters were optimized, including shale gas production, NGL production, price, Capex and Opex. Assumption that other factors were constant, the single factor sensitivity analysis was carried out on NPV. The results can be summarized from figure 3 that shale gas production, NGL production and price were positively correlated with NPV, Capex and Opex had the negative correlation with NPV, NGL production and Capex had the greatest effect on NPV of the project. Shale gas production, Opex and Price were relatively insensitive factors for the X project. Although NGL production was the companion production during the shale gas development, its value contributed greatly to the economic benefits of
this project. With the increasing oil price, the economic benefit of the project has been improved significantly. The method of increasing output is the key of this project in the case of limited Capex.

Table 3. X shale gas project summary.

| Project Size | Annual gas production and NGL production in 2018 respectively are 77536 MMCF and 169 MMB. |
|-------------|--------------------------------------------------------------------------------------------|
| Gas Production During RT Term (since 2019.1.1) | 1458215 MMCF |
| NGL Production during RT Term (since 2019.1.1) | 209 MMB |
| Oil Price | Present Brent oil price 80 USD/barrel |
| Capex | CAD 4347 million |
| Opex | CAD 1362 million |
| Royalty Rate | 5%-16% |

Figure 3. Sensitive Analysis of X Shale Gas Project.

6. Conclusions
Net reserves evaluation of shale gas project is a comprehensive work, integrated with technical, economic, commercial and engineering factors, not only affected by the technical factors, such as gas reservoir parameters and development planning, but also related to the contract terms, investment, operation cost, price, taxes, tariff, sales and many other factors. Various related factors should be entirely considered and the key assessment elements should be grasped accurately to make sure that the evaluation result of net reserves is reasonable and objective.

For the shale gas project under the royalty & tax system in British Columbia (Canada), production, prices, Opex, Capex and taxes have different effects on the net reserves and net present value of the assets, which output and prices have the maximum impact on weight coefficients. Annual evaluation works of net reserves usually are confronted with different difficulties and challenges with the change of the production and development level, international oil price, the policy and situation of resource-host country government and local environment. Adequate analytical work should be carried out before the net reserves assessment, corresponding development and evaluation strategy should be formulated to realize the optimization and rationalization of net reserves and net present value of the project.
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