Errata

Changes and updates have been made to the Independent Assessment report published on this site on October 8, 2021. The current posted Independent Assessment contains changes and updates as described in the table below.

Page Number	**Change**
5 (Executive Summary)	The amounts of infrastructure royalty credits awarded, released and outstanding have been updated
All	General formatting and layout changes

A Review and Assessment of the Natural Gas Royalty System in British Columbia

Prepared for the Government of British Columbia

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Executive Summary

The Province of British Columbia is undertaking a review of its oil and gas royalty system. To inform that review, our report examines the current natural gas royalty system and its ability to support the core policy objectives for all resource development and use in the province. These objectives are securing a fair return for BC's natural resources; contributing to a strong economy with employment and training opportunities for British Columbians; supporting BC's reconciliation initiatives and partnerships with First Nations that show respect, meaningful engagement, and recognition of Indigenous rights and title; supporting BC's climate commitments; and protecting and enhancing BC's air, water, land, and ecosystem environmental resources. The BC royalty system is highly complex. It consists of components and programs that were designed and introduced when market conditions and extraction technologies were very different than they are today, and what is forecast for the future. Our report discusses these complexities and the effect they have on royalties collected and administering and auditing the system. We also discuss the incentives and outcomes these complexities may create that run counter to provincial policy goals.

This report provides a detailed description of BC's current royalty system that illustrates the combined effect of the system's many components on royalty payments over time. We cover lessons from Alberta's 2015-2016 Royalty Review and its new system introduced in 2017. We conclude with an assessment of BC's royalty system and offer a set of specific areas of concern with some suggested ways the system could be modernized and better aligned with provincial goals.

The Current Royalty System and its Challenges

As of July 2021, BC has 35,917 wells, and an additional 8,598 well authorizations granted. Of these close to 36,000 wells, 36 percent are active. Active wells are predominantly gas wells (86 percent of active wells). At least 95 percent of the petroleum and natural gas in BC is owned by the province and is on Crown lands, with revenue sharing arrangements to support co-development of resources with Treaty 8 First Nations. The Province grants rights to companies in the form of leases to develop and extract the petroleum and natural gas. The royalty system is a mechanism for sharing between the government and lease-holder the net returns arising from natural resource extraction. The structure of royalty rates is intended to maximize the net returns to the province whilst not unduly affecting the competitiveness of the industry.

The Government of British Columbia relies on oil and gas producers to develop petroleum and natural gas resources on its behalf. The energy companies, the BC government on behalf of its citizens, and some First Nations share the *economic value* created by developing those resources. This value is conceptually measured as the price received for each unit produced of the resource less the cost of producing and selling it (including the cost to transport the resource to market). Measuring economic value is challenging. It requires answers to such questions as: what price to use, which costs to deduct, and how both are measured. These are factors that a royalty system must grapple with even before determining the share going to each party; maximizing value means more than what royalty rate to set. Royalty rates in BC vary from month to month, and depend on many factors including prices, well production, well vintage, the fluid produced, well classification, cost allowances, incentives, and more. The market price of the resource is affected primarily through competition (number of firms and volume of production in other jurisdictions) and market access. Costs are a function of geology, geography, and technology. The share of value split between the Province and the energy companies depends on what net value is available, an amount that can vary considerably over time and reflects the risks associated with the industry.

The current royalty system has its origins in the 1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. The current system began relatively simply but over its 30 years, subsequent governments added provisions and made modifications designed for conditions at the time. Many of these provisions no longer reflect the current state of the industry and market. These amendments introduced different base royalty rates depending on well vintage, programs with lower royalty rates for wells with low monthly production volumes (low productivity, marginal, and ultra-marginal programs), deep-well drilling credits, and infrastructure credits to promote access to deposits and investment in less emissions-intensive practices. Each of these component parts are described in the report in **Error! Reference source not found.**. With each adjustment to the system, there was generally no transition for wells developed under previous regimes, leading to a plethora of well definitions and royalty formulas and calculations.

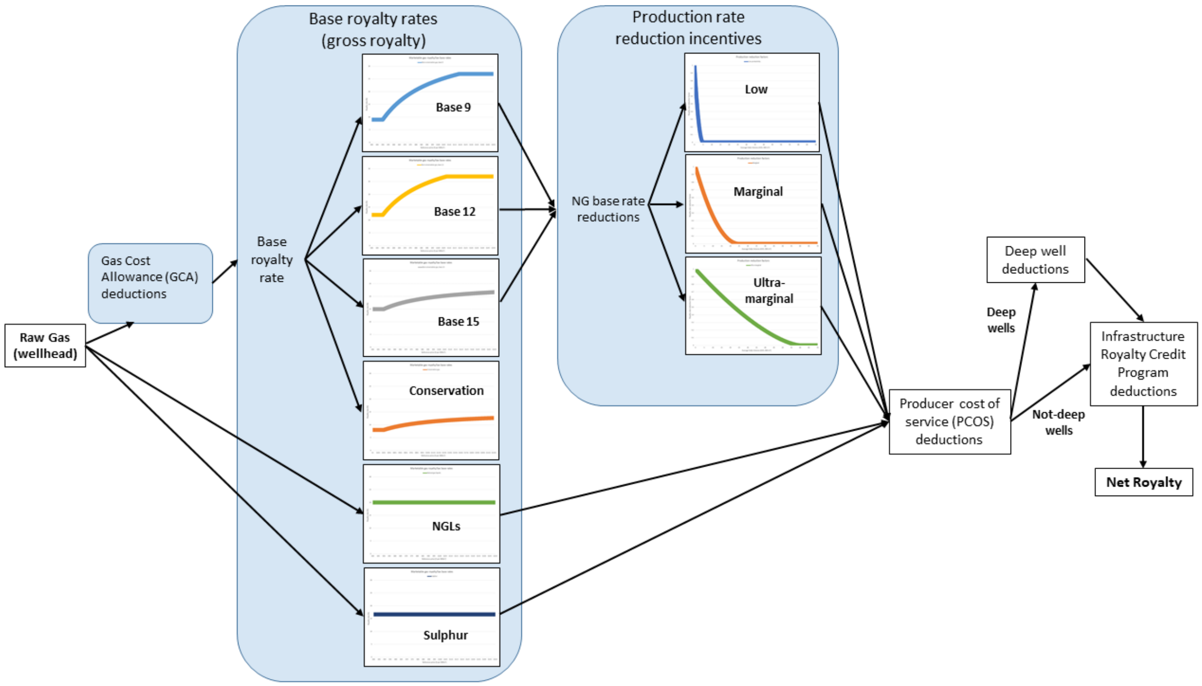
The current royalty system is complex. Administration of the royalty system is currently shared among three agencies: the Ministries of Energy, Mines, and Low Carbon Innovation (EMLI) and Finance (FIN), and the Oil and Gas Commission (OGC). EMLI is the lead in setting royalty policy. FIN operationalizes the policy set by EMLI, and the OGC is the regulator and provides data for royalty billing. The complexity contributes to administrative burden, borne by government and industry, and makes it challenging to audit and for observers to evaluate the system.

The Workings of the BC Royalty System: An Assessment

Royalty payments are calculated and paid each month. Royalty calculations start with the volume of raw product extracted from the well bound for intake at a processing plant. Numerous stages are needed to calculate the royalty payable to the government, with component parts reflecting the primary product determination, royalty rate structure for gross royalty rates, and eligibility for allowances, credits and deductions based on well classification. Combined, these stages determine the effective net royalty rate and amount payable. The figure below provides a simplified schematic of the stages between the wellhead and computation of the net royalty payable for natural gas and related products, BC's major products. (Oil is covered in the report but not highlighted here.)

BC's royalty system has a complex process of imputing values because transactions at the plant inlet typically do not have market-based prices. Each product — natural gas (methane), natural gas liquids (ethane, propane, butane, and pentane), gas condensates, and oil have a unique schedule of gross royalty rates. The primary product of a well determines the royalty system it is subject to. There are also different schedules for natural gas depending on when drilling commenced. The component parts of BC's royalty system: gas processing costs, production rate reduction incentives, producer costs of service, and credit programs are core to understanding the complexity of the system and where issues arise. Each is briefly described along with our assessment of the issues arising from each component.

Natural Gas Royalty System



Gas Processing Costs

Gas processing costs are accounted for with the *gas cost allowance* (GCA). This allowance represents the Crown's share of capital and operating costs of processing the raw gas and thus is a component in determining the value of the resource. The average GCA per gigajoule (GJ) as a share of processing plant inlet prices has risen from 10 percent in fiscal 2003/04 to approximately 75 percent in 2020/21. The GCA was 26 percent of total plant outlet value in 2013 and is 34 percent in 2020. (Plant inlet prices are used to determine royalty payments.) Why have costs for processing natural gas risen considerably? Our concern is that by placing the starting point for the royalty system at the intake of gas processing plants, BC may be getting a smaller share of the net value due to the method for computing these processing costs. The process of determining GCA is a mixture of 'market-based' processing and imputed costs that may also be contributing to making BC a higher cost region as well as adding to complexity. This is because an individual firm's costs directly affect its royalty payment. Increasing costs are partially borne by the province via a lowered royalty payment by the firm, and so an individual firm has a reduced incentive to lower its gas processing costs. Moving to the plant outlet, as in the Alberta system, for the point of determining gross royalties is a potential solution by having more of the costs (and prices) market-based and their determination more transparent and auditable.

Production Rate Reduction Incentives

The current programs — low productivity, marginal, and ultra-marginal well rate reductions — comprise a class of incentives that are designed to encourage production by reducing the royalty rate per unit volume from wells that might otherwise be shut in and encourage development of new wells that might otherwise be uneconomic. Each of these programs was initiated at times when there was concern over the viability of BC's gas supply due to projections of declining output, and they are designed for vertical drilling (i.e., prior to the ‘shale revolution’). These incentives are not price sensitive. They are based on wells’ monthly volumes (low productivity designation) or initial classification of the well (marginal and ultra-marginal designation); the magnitude of the royalty rate reduction is a function of the volume of production. The incentives can reduce royalty rates substantially depending on the level of daily production. For each incentive category there is a reduction factor that decreases as daily production volumes increase. In other words, the incentive and the reduction in the royalty rate is strongest when little natural gas is extracted. The goal in each case was to maximize volumes, not values. At the time the incentives were introduced, maximizing volume was more strongly connected to generating value than is the case today.

The rate-reduction programs are outdated given shale technology and current market conditions. From multiple viewpoints — encouraging efficient production, meeting climate and environmental goals, and the Crown and First Nations securing a fair share of the net returns to the resource from natural resource development — provincial policy ideally should be neutral with regard to the quality of the well. The exception is if there are reasons to believe that there are market imperfections or failures that are interfering with efficient development within the industry. Efficient production should have a profile where the wells go out of production when the expected returns do not cover costs. Rate reduction programs may be encouraging continued extraction from wells that should have reached their economic end date. Encouraging the production of more gas supply, particularly from less productive wells, when natural gas markets are oversupplied, adds to downward pressure on prices and increases greenhouse gas emissions that might otherwise not have occurred.

Producer Cost of Service (PCOS)

PCOS is an allowance designed to offset the producer’s cost of moving raw gas from the wellhead to the inlet of a gas processing plant — costs for gathering lines, compressors, line heaters, dehydrators, field processing units, and well-site operations. These components depreciate over time and have associated maintenance costs in order to maintain delivery of products downstream. Depreciation and technological change mean that PCOS calculations change from year to year as older equipment is replaced with newer (and potentially lower cost) equipment. The calculations also vary by geography and operator. PCOS is typically expressed as a monetary value ($) per processing volume. PCOS is a deduction from royalty payments after application of the rate reduction programs. PCOS is calculated on an annual basis for each reporting facility producing non-conservation natural gas. The PCOS allowance is calculated for each reporting facility, and the deduction from the total gross royalty is determined by multiplying the volume of raw gas produced by the weighted-average royalty rate for that well by the PCOS rate for that facility. The PCOS allowance cannot exceed 95 percent of the total gross royalty for the well.

Each component in the process of moving raw gas to the processing plant is included in PCOS. These components were identified and cost factors specified by a consulting company in 2011. These cost factors are complex, may be outdated, and have not been revised since 2011 despite attempts to secure another consultant to update them. PCOS allowances are relatively steady in aggregate but have a major effect on net royalty payments. This is at a time when studies of extraction in the Montney indicate that average costs of production may be declining. If BC’s royalty system was based on the output from processing, a much more simplified system of accounting for these costs would be possible (as is the case in Alberta).

Royalty Credit Programs: Deep Well Royalty and Infrastructure Royalty Credits

These programs provide credits in the form of reducing royalty payments owing. The *Deep Well Royalty Credit programs (DWCP)* were initiated in 2003 and are designed to deliver credits to offset higher drilling and completion costs incurred by wells that are considered particularly deep. A well qualifies for a total allowable credit based on its characteristics (vertical depth and/or horizontal length) and location. From the total credit associated with a well, a portion is applied each month against royalties owing for each deep well event (i.e., after PCOS is applied up to 95 percent of the gross royalty limit). The deep well credit applied reduces the effective royalty rate, up to a minimum of three or six percent depending on the type of deep well. There is a substantial accumulation of credits, primarily due to the complex interactions within the royalty system. As of March 2021, the accumulated deep well credits total $7.325 billion. Of that, $3.56 billion have been drawn down. Once a well ceases production, the credit expires. The total draw-down of the outstanding balance could be lower than $3.755 billion if wells become non-producing prior to utilizing all their credits.

The DWCP is outdated. As with the production rate reductions, the program was introduced prior to the widespread commercialization of shale technology and likely contributes to a 'higher cost' and more inefficient industry than might otherwise occur. It may incentivize companies to drill to access the credit rather than to minimize costs and maximize revenue. Moreover, the credit allocations are not necessarily aligned with current cost structures.

The *Infrastructure Royalty Credit Programs* were established in 2004 to encourage companies to invest in infrastructure that allows development of oil and gas wells. Examples are costs of building roads or pipelines to explore and access new and under-developed areas of the province. Starting in 2016, the program was expanded to cover investment in infrastructure that reduces companies' greenhouse gas emissions. In response to request for applications, producers submit their proposals to EMLI specifying the intended investments. The proposals are evaluated on what percent of total economic activity the project represents, how quickly royalty credits issued would be applied against royalty payments from incremental production enabled by the infrastructure, and would the project have gone ahead without the credit. The program can cover up to a maximum of 50 percent of the specified capital costs; it is typically oversubscribed so not all applicants are successful. Credit holders have three years to complete their infrastructure project but no timeline is specified for drilling wells. Once monthly production begins, earned infrastructure credits apply automatically to any royalties owing and can result in a zero balance for that month. Overall, from 2004 to 2020 a total of $1.733 billion has been awarded, $0.679 billion released, leaving a balance of $1.054 billion. A total of $409.3 million over all three programs has been cancelled or represents stranded assets, leaving $644.8 million in net outstanding credits.

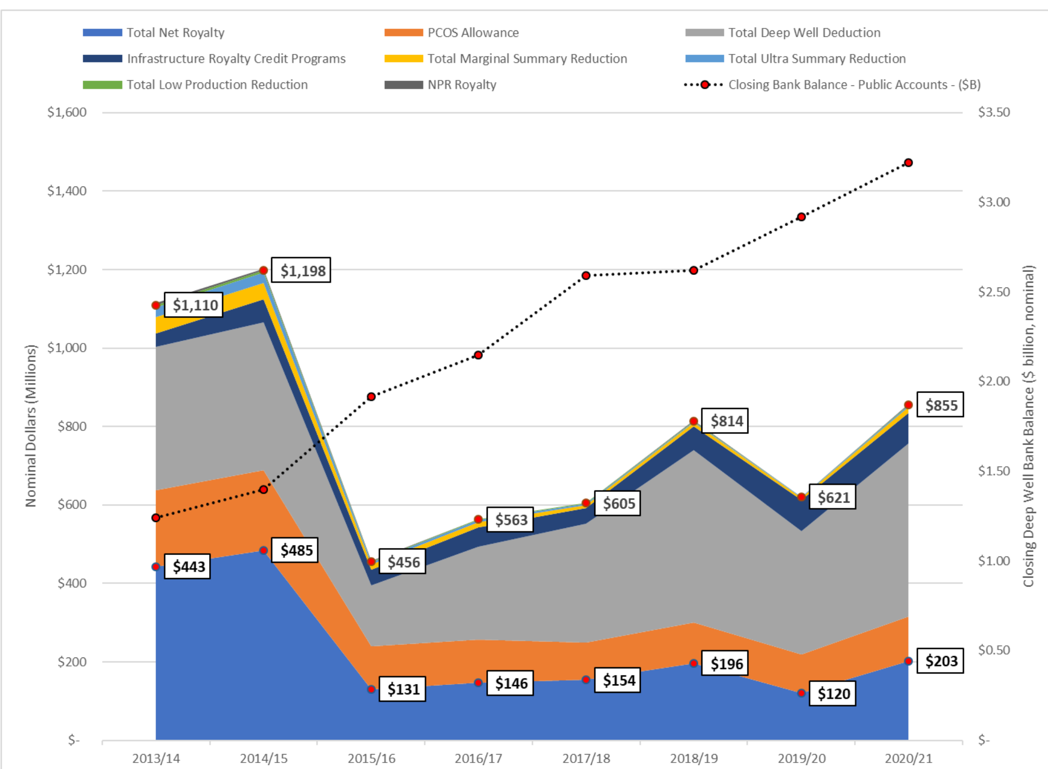
Are these infrastructure credit programs needed to generate additional investment and GHG reductions that would otherwise not occur? Due to the complexity of the royalty system and existence of other programs in the province incenting reductions in GHG emissions, infrastructure credit holders may receive multiple deductions for the same costs. In other words, there may be inadvertent double dipping due to overlapping components in multiple programs. There are also other programs in the province to support reductions in GHG emissions under CleanBC.

The deep well royalty and infrastructure credit programs can encourage extensive development beyond what would occur in their absence. They are not compatible with environmental goals to the extent that they contribute to more GHG emissions, land disturbance, and do not take into account cumulative effects from road and pipeline development. Without the infrastructure credits, production might be less dispersed. If there were no deep well credits or infrastructure credits, it is likely fewer wells would be drilled. A rationale for royalty credits is to lower effective royalty rates at the beginning of a well's productive life to help offset the costs of establishing the asset. Generally, effective royalty rates (and royalties collected) rise as the well produces over time. This has not happened in BC due to market conditions and the use of these credits to drive net royalty payments to close to zero. As more wells are drilled under the various credit programs — and production from wells that never received any credits declines with age — the contribution of wells with credits to total production rises and hence the province's royalty revenues will decline. There is a fundamental question of how much the Crown should offset the costs of fossil fuel development given its multiple objectives. It is appropriate to account for costs in determining the net economic value from developing the resource, but the credit programs may be contributing to or possibly overcompensating for costs with the combined effect of all the programs (credits, rate reductions, PCOS, GCA). There is no apparent market failure that currently justifies the continuation of these credits.

Natural Gas Royalties Collected

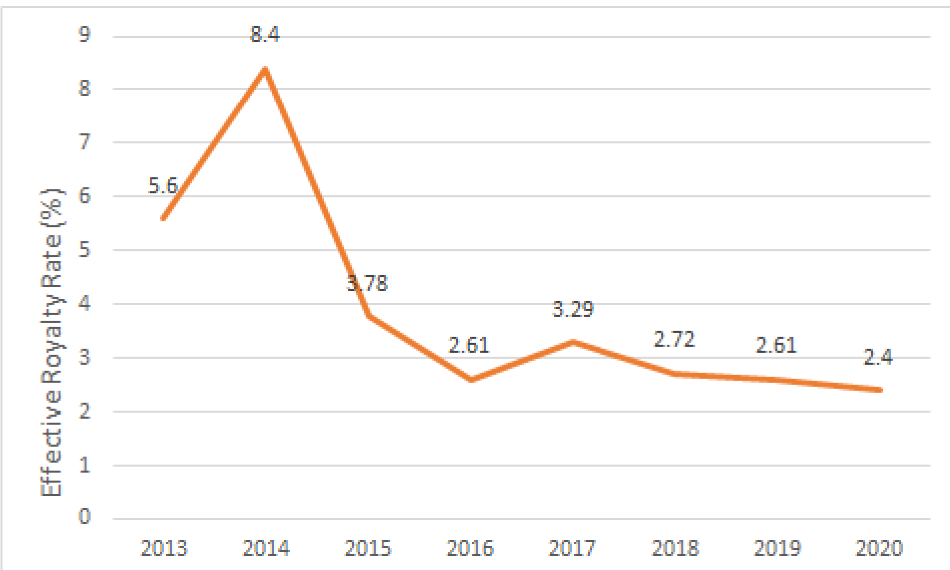
Natural gas royalties paid have declined over time. The figure below provides natural gas royalties by fiscal year and depicts the impacts of the components of the system in reducing gross royalty revenues to net. Net royalty revenues range from 40 percent of gross in fiscal 2013/14 and 2014/15 to a low of 19 percent in 2019/20. Royalty revenues would be significantly higher in the absence of the various credit programs and deductions, all other factors being equal.

Value of Gross Royalties, Net Royalty and Royalty Credits by Fiscal Year



An effective royalty rate provides another measure of the share of natural gas revenues accruing to the Province. To be comparable to other jurisdictions such as Alberta, we illustrate an effective royalty rate measured as the value of net royalties per year divided by the value of natural gas at the plant outlet — the price point for determining royalty payments in Alberta's royalty system — rather than plant inlet, BC's starting point. This calculation values the gas at its market price and is inclusive of actual cost allowances that go into determining net royalty payments, making it more representative of the net economic returns from the resource. The effective royalty rate falls over the past eight years more than three-fold from a high of 8.4 percent in 2013 to 2.4 percent in 2020. Looking at the effective royalty rate provides a strong indication that the Crown's declining share of net revenues from natural gas extraction over time is due not only to the market price of natural gas but also to complex components of BC's royalty system.

Effective Royalty Rate: value of net royalties per year divided by the value of natural gas at the plant outlet (percent), 2013 - 2020



The Way Forward

The BC royalty system for natural gas and oil is broken. It does not support and contribute to government and societal goals. It consists of piecemeal modifications to a system that was designed for a different era with different risks, technology, and market conditions. The system is excessively complex, has large compliance costs for industry and large administrative and auditing costs for government. It creates incentives that do not promote efficiency in the sector. It has contributed to a significant decline in the Crown's share of the net economic value from petroleum and natural gas resources over the past 15 years and a transfer of value from the province to industry. While the appropriate share of value for the Province is not within our scope, we identified areas of concern with each of the program areas that indicate the system also fails to maximize *shared* value. It is our view that nothing short of a comprehensive overhaul of the royalty system will 'fix' it. The royalty review should be comprehensive and broad ranging, aiming to put in place a modern system that is simpler, accountable, transparent, less costly to operate, promotes efficiency, and supports government and societal goals.

The following points summarize our specific areas of concern.

1. All of the royalty deduction programs are out of date. They were introduced at a time with more favourable product prices, and do not take into account changing extraction technology and shift to natural gas liquids in the product mix and investment profile.
2. The exploration and extraction risk profile of the sector has declined substantially since the early 2000s and the combined effect of the programs has resulted in an over-compensation for risks that are no longer as apparent and relevant.
3. The system is characterized by piecemeal changes over time with programs that have led to compounding effects that substantially reduced royalty payments as a share of net value of the resource.
4. The system is set up to incentivize lower-value wells. A firm has a fixed amount of capital to spend in a year and the system may be inducing investment and operating decisions that target these lower-valued wells. This is by incentivizing behaviour where these decisions are based more on accessing royalty payment reductions than would be warranted under efficient operation. This may be one factor contributing to BC being deemed a 'high cost' region and lower overall resource value in the province.
5. Wells benefitting from deep well credits or deep well credits and marginal programs now form a large share of natural gas production. Adding in the other programs and credits which reduce gross royalty rates and royalty payments (e.g., low productivity production or an infrastructure royalty credit), further reduces the Crown's share of net resource value.
6. Given existing market conditions, virtually no wells face a price-sensitive gross royalty rates. Unless there is a change in the way in which product prices are incorporated into the calculations of royalties, this situation will persist for as long as the supply-demand balance for oil and gas sustains current prices.
7. The current system relies on primary product and natural gas production volumes to determine wells' eligibility for different royalty rate reductions and credit programs. This increases complexity and creates incentives for firms to chase specific products and credits rather than the most valuable outcome.
8. The system accounts for costs in ways that are administratively burdensome, reduces the Crown's share of the total net value of the resource by reducing the effective royalty rate, can promote inefficiencies, and thus may also contribute to lower total net economic value. To appropriately define value and shared value requires an accurate picture of the net economic value of the resource: something more akin to the way profits under corporate taxation are calculated, or as a proxy for this, Alberta's revenue minus cost model.
9. The cost calculations (PCOS and GCA) are well-specific, meaning that a company's decisions about costs directly affects their royalty payment. This reduces companies' incentives to lower their costs and preserve value. Moving to a system where companies are granted an industry average cost allocation would eliminate this problem.
10. Determining gross royalties at the intake of raw product to processing plants with extraction costs determined by the PCOS methodology adds to complexity, administrative costs, and use of non-market values. It is an outdated and complex system that cannot be readily audited and updated. Moving the gross royalty calculation to processing plant outflows, as in the Alberta

system, and adopting Alberta's methodology for computing costs would serve to alleviate these issues.

11. The current cost calculations (PCOS and GCA) are meant to account for the Crown's share of costs. However, unlike a royalty payment on the value of the products, the cost calculations are not scaled by the royalty rate. If the PCOS allowance and GCA are already fractions of firms' costs, this is not an issue. Still, it is worthwhile to assess relative cost-sharing.
12. Alberta undertook a major reform of its oil and gas royalty system, phasing in its new system in 2017. Given the Montney's shale deposits straddle the BC-Alberta border, moving to a system such as Alberta's would better align production, reduce any incentive to shift production from one province to the other to minimize royalty payments, and overall promote a more efficient and equitable system.
13. A simpler system would substantially reduce administrative burden for the government and compliance burden for industry, as well as reduce reporting errors that require many hours to revise royalty calculations. The total costs of administering BC's oil and gas royalty system include all the costs incurred by the three agencies (EMLI, FIN, OGC) to collect and analyse the data, compute monthly royalties, correct for errors, and send out the invoices. Industry faces all the costs of compliance for the system in collecting and providing the data to government. Administration of the current system with all its complexity means accounting for multiple past and current structures applying to wells of different vintages and classifications. Any "tinkering" with the system without a comprehensive overhaul would add to the administrative burden requiring more grandfathering of the multiple structures in the system.
14. Goals such as transparency; ease in understanding the system; and ability to update cost, price, and other elements are not met in the current system. The complexity of the system makes it extremely difficult to explain it to anyone not deeply immersed in the system and can lead to misinterpretations of the data and impacts the system has. The BC Royalty Handbook is 192 pages of dense technical complexity. Alberta's guidelines are presented in 57 pages. The multiple entities responsible for the system make it challenging to communicate with industry and the public.
15. Removing or 'fixing' problematic aspects of the system (e.g., removing one type of credit) may result in unintended consequences. In our view, a system wide and comprehensive reform of the entire system is warranted.

Transition from an old to a new system is always challenging and requires careful analysis of ways to minimize any potential adverse impacts. The royalty system is one part of a well's lifecycle, and changes to the system will affect lifecycles of future wells and current wells, depending on the transition mechanisms relative to the status quo. By engaging with affected and interested parties, building on the knowledge and expertise within BC's three governmental entities, and learning from other jurisdictions' approaches, the royalty review can examine ways to address these challenges and move forward.