

Effective Tax and Royalty Rates on New Investment in Oil and Gas after Canadian and American Tax Reform

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Executive Summary

In the wake of the January 1, 2018 US tax reform, multinational businesses with US operations are re-evaluating investment, financing, and other operating activities to determine their most profitable strategies. Policy makers in other countries are also reevaluating their business tax systems to determine the best course of action in response to sweeping US tax reform. On November 21, 2018, the Canadian federal government announced its response to the US reform by introducing accelerated cost recovery for capital expenditures.

This study provides an analysis of Canadian oil and gas tax competitiveness in the wake of US tax reform and the recent Canadian response. We estimate the impact of all taxes and resource levies on investment returns by estimating the marginal effective tax and royalty rate (METRR) on capital (costs related to other inputs such as labour and energy are not included). This is a summary measure that accounts for corporate income taxes, sales taxes on capital purchases, capital taxes, transfer taxes, stamp duties, profit-based resource levies, and royalties as a share of the pre-tax rate of return on investments. The modelling is based on a “time-to-build” model that used two phases of production: (i) exploration and development to prepare reserves (capital building) and (ii) extraction from reserves (use of capital).

The purpose of resource levies is to collect resource rents on behalf of a government or, in the case of private ownership, the landowner. Thus, one might argue that royalties and other resource levies are payments made by private firms for the use of resources owned by the government. Resource rents are the excess of revenues over the opportunity costs of using labour, capital, and other inputs in production. We focus on marginal investment decisions in that profits are just sufficient to compensate for investors who could invest in alternative assets with the same after-tax returns, net of inflation and risk. In other words, no economic rents are earned at the margin. Taxes, including resource levies, discourage marginal investments even though there are no rents to be earned and therefore should not be subject to resource taxes.

We compare Alberta, British Columbia, Saskatchewan, Newfoundland and Labrador, and Nova Scotia, representing over 95% of Canadian hydrocarbon production with 15 US states, including the ten highest producing jurisdictions for both oil and gas,

representing over 79% of oil and 86% of natural gas production in the United States: Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Mississippi, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming.¹ To the extent that the METRR is higher, there is less incentive to invest in a particular jurisdiction, all else being equal. Of course, various non-tax factors such as production, exploration and development costs, distance to markets, the quality of the resource, skilled labour supply, regulations, infrastructure, political risk, and perhaps most important, market price, also affects a firm's investment decisions. All else being equal, tax will have some impact on investment—as found in numerous economic studies mentioned below—but it is only one among several criteria that impacts investment.

For oil, we find that Canada's weighted average METRR has moved significantly below that of the 2018 post tax-reform United States as a result of the accelerated depreciation announced by the Canadian federal government on November 21, 2018.² This follows a period after US, but prior to Canadian, tax reform, in which the two were neck and neck (on average, 28.5% for Canada and 28.6% for the United States, based on provincial/state jurisdictions included here), and a prolonged period prior to US tax reform when the US METRR was much higher at an average of 33.9%.³ Both Canada's package of accelerated depreciation, and US expensing provisions for short-lived capital (primarily machinery) in the recent tax reform, are legislated to be phased-out after 2027. It is worth noting, Congress has extended bonus depreciation for machinery several times since 2001, depending on the state of the economy.

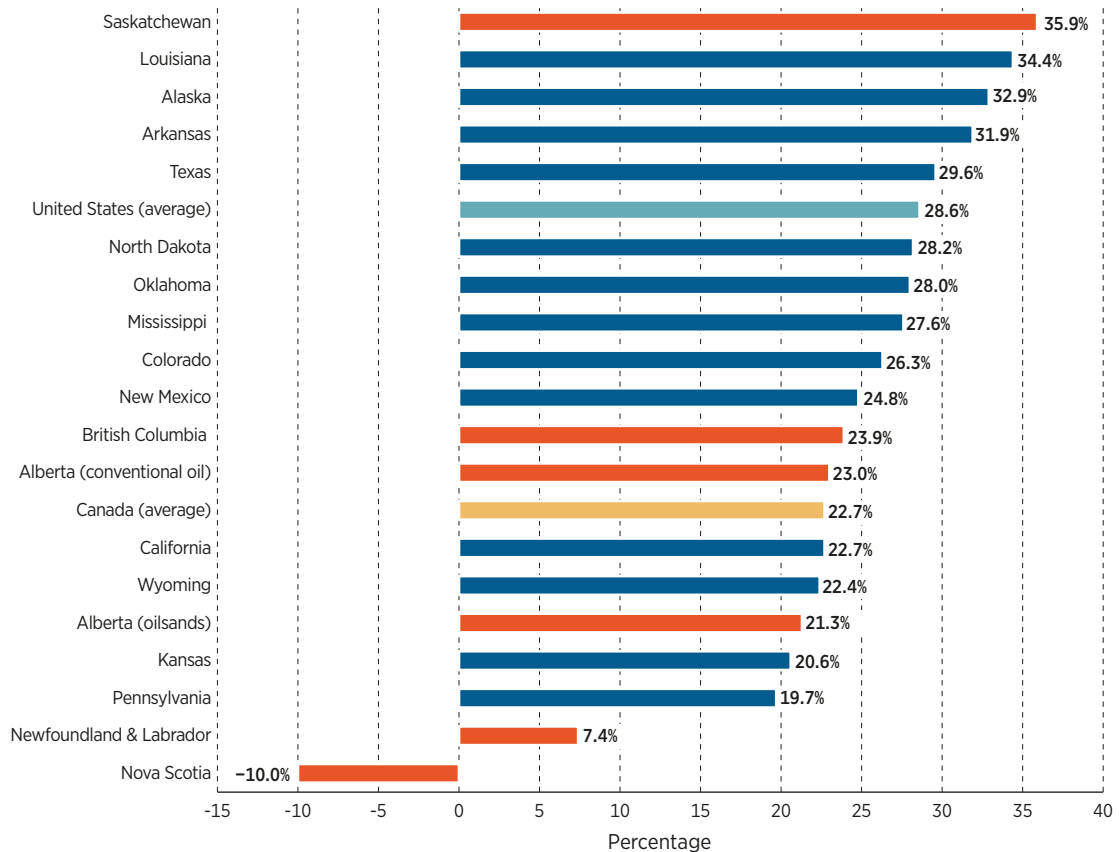
Internationally, Canada is less tax competitive compared to Australia (-24.7%) with its unusually generous treatment of exploration costs, but much more tax competitive than Brazil (66.5%) with its various tax and resource levies impinging on investment. Canada provides some tax advantage compared to Norway (32.4%) but less so relative to the United Kingdom (5.8%) (Bazel, Mintz and Thompson, 2018; authors calculations).

1. Production volume is based on 5-year averages, with 2017 as the latest available year. US figures are based on Energy Information Administration data, Canadian figures are based on data from the Canadian Association of Petroleum Producers.

2. Eight provinces having tax collection agreements with the federal government shall adopt the same accelerated depreciation measures. Quebec, which has its own corporate income tax, has announced dropping its additional capital-cost allowance in favour of the federal provisions. Alberta, which also has its own corporate income tax, has made no announcement, although we assume in our calculations the same measures are adopted.

3. The value of 33.9% is based on earlier unpublished work provided to Natural Resources Canada including a sub-set of US jurisdictions presented here, and excludes Alaska, California, Louisiana, and New Mexico. All of these are High METR jurisdictions and thus the difference is likely understated here.

Figure A: METRRs (%) on oil in select jurisdictions of Canada and the United States, 2018



Notes: All values 2018, after the US & Canadian tax reforms. US results are for conventional production; Canada represents conventional and unconventional production.

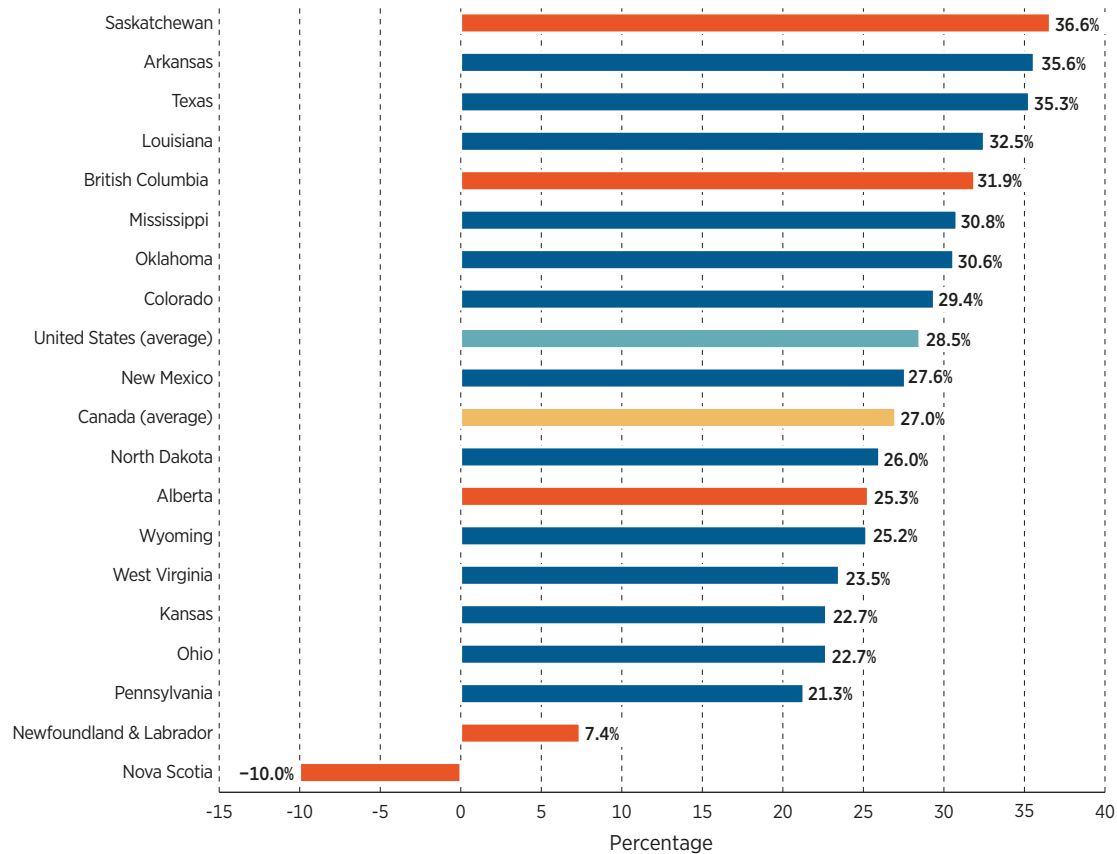
Source: Authors' calculations.

For Canada and US oil in 2018, Saskatchewan levies the highest METRR on oil investments (35.9%) followed by Louisiana (34.4%) and Alaska (32.9%). The lowest METRRs are found in Nova Scotia (-10.0%), Newfoundland & Labrador (7.4%), and Pennsylvania (19.7%).

For natural gas, the results differ slightly. Canada's METRR is on average 27.0%, roughly 1.5% less than the United States (28.5%). As with oil, Canada is less tax competitive compared to Australia and the United Kingdom and more tax competitive than Norway.

Natural gas investment faces a higher METRR largely as a result of revenue-based resource levies on natural gas, which has a lower price-cost margin compared to oil. Saskatchewan (36.6%), Arkansas (35.6%) and Texas (35.3%) have the highest METRR on investments. Nova Scotia and Newfoundland & Labrador are lowest at -10.0% and 7.4%, respectively, followed by Pennsylvania at 21.3%.

Figure B: METRRs (%) on natural gas in select jurisdictions of Canada and the United States, 2018



Notes: All values 2018, after US tax reform.

Source: Authors' calculations.

A significant factor underlying the differences in METRRs across jurisdictions is the rate and types of resource levies on investments. US jurisdictions tend to apply levies on revenues such as royalties and severance taxes. (Pennsylvania is an exception by not applying any severance tax, while royalty lease rates are among the lowest across included jurisdictions.)⁴ while Australia, Canada, Norway, and the United Kingdom levy profit-based resource levies that in principle only tax the economic rents earned from developing and extracting the resource.⁵ With US corporate tax reform, the United States has greatly increased its competitive standing, and offset the disadvantage of royalties that do not provide a deduction of costs against taxable revenues and therefore discourage

4. For additional information, see Appendixes B and C.

5. For more information on international jurisdictions, see *Deloitte's Oil and Gas Taxation in ___ series. Deloitte International Oil and Gas Tax Guides*, <<https://www2.deloitte.com/global/en/pages/energy-and-resources/articles/international-oil-gas-tax-guides.html>>.

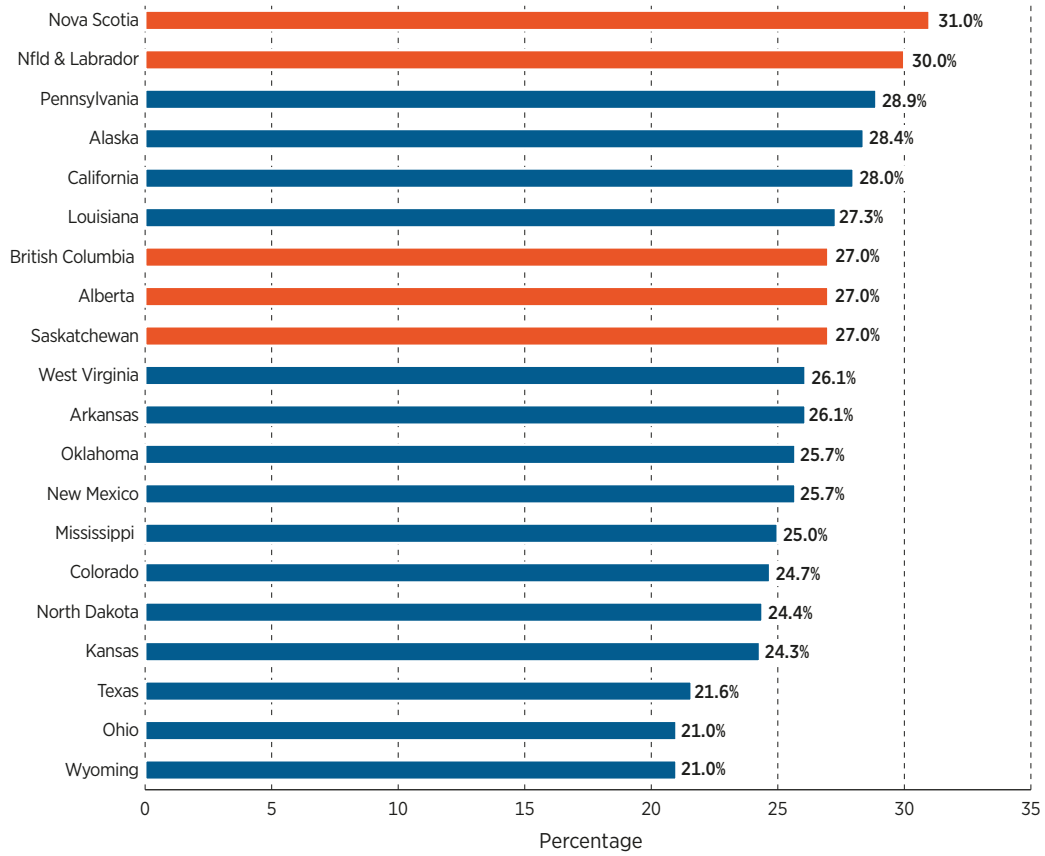
marginal investments that do not earn rents. Canada in response to US tax reform has introduced temporary incentives to invest in capital and, in so doing so, has effectively reduced its overall tax burden on the resource-producing sector. Though the impact of Canada's 2018/19 tax reform has a smaller impact in the overall resource sector than the manufacturing sector, the result is enough to restore a competitive tax advantage over the United States in aggregate and across most jurisdictions surveyed for this study.

We should emphasize that the METRR calculations do not fully account for all aspects of tax competitiveness. In particular, the Canadian response by introducing temporary accelerated depreciation in response to US tax reform affects most marginal investments. Projects with high rates of return on capital are also influenced by differences in corporate income-tax rates as shown in **figure C**. Generally, the combined federal-provincial corporate income-tax rates in Canada are higher than those of most of the US states, especially Texas, which accounts for a large share of oil and gas production.

These differences in corporate income-tax rates also create incentives to push financing and general administrative costs into Canada, leading to corporate tax-base erosion. A higher corporate income-tax rate in Canada compared to the United States encourages companies to shift profits to the United States by, for example, reallocating debt to Canadian entities from the United States or by choosing transfer prices to increase costs in Canadian-related companies. Further, a low tax rate on intangible income—intellectual property, marketing, services, and mining—creates an incentive to draw intangible activities to the United States.

Other competitive factors, such as regulations, labour taxes, and energy taxes, not included in these calculations, will also help towards an understanding whether Canada is sufficiently competitive to attract international investment in oil and gas development and production going forward.

Figure C: Combined corporate income-tax rate (%) in select jurisdictions of Canada and the United States, 2018



Source: Canada Revenue Agency; Tax Foundation, Washington, D.C.; authors' calculations.

Introduction

With 2018 US tax reform, various countries are examining whether their corporate tax policies need to be revised. This is not surprising. For at least two decades, most countries, including Canada, lowered corporate tax rates well below the US corporate income tax rate. As a result, US and foreign multinationals tended to keep investment and profits out of the United States even if they found it advantageous to operate in a market that accounts for a fifth of the world economy. As of January 1, 2018, this has reversed remarkably. US tax reform will incent companies to put investment and profits into the United States, a reversal of past practice. Since US tax reform was passed in December 2017, some countries are already reacting, with Belgium, France, and Sweden announcing corporate tax rate reductions leaving Canada now having eighth highest corporate income tax rate among OECD countries.

Taxation is far from being the only determinant to business investment—economic, regulatory, and other factors play a significant role. As various economic studies have shown, all else equal, countries with higher taxes on investment tend to have less of it (e.g., Feld and Heckemeyer, 2011; De Mooij and Ederveen, 2008; Parsons, 2008). Taxes discourage the location of investment projects (the extensive margin) and the amount of investment in a particular jurisdiction (the intensive margin).

This point also applies to the oil and gas sector. In the analysis below, we particularly focus on marginal investment since aggregate capital expenditure varies by the scale and number of projects in the market. This paper provides a comparison of tax and royalty impacts on investment in oil and gas for Alberta, British Columbia, Saskatchewan, Newfoundland & Labrador, and Nova Scotia, representing over 95% of Canadian hydrocarbon production, with 15 US states including the ten highest producing jurisdictions for both oil and gas, representing over 79% of oil and 86% of natural gas production in the United States: Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Mississippi, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming.¹

1. Production volume is based on 5-year averages, with 2017 as the latest available year. US figures are based on Energy Information Administration data (Crude Oil Production and Dry Natural Gas Production series). Canadian figures are based on data from the Canadian Association of Petroleum Producers (*CAPP Statistical Handbook*).

The rest of this paper is divided as follows. In the next section, we provide brief overview of the methodology. The following two sections provide a comparison of marginal effective tax and royalty rates (METRRs) in Canada and United States for oil and natural gas respectively. The final section summarizes our conclusions. Appendices provide the theoretical model (Appendix A), data summary (Appendix B) and specific tax and resource levy provisions for each jurisdiction (Appendix C).

Some Background

This analysis follows earlier work (Mintz and Chen, 2012; Crisan and Mintz, 2016; Mintz, 2016) by estimating the marginal effective tax and royalty rate (METRR) on capital in a “time-to-build” model based on two stages of capital building and use: (i) the exploration and development phase to prepare reserves; and (ii) the extraction phase.

In theory, businesses invest in capital until the return on capital is just sufficient to cover economic costs of investment (the marginal investment, sometimes called the hurdle rate). Economic rents, which are defined as profits earned in excess of the opportunity costs of using capital² (including the imputed cost of equity financing), labour, and other inputs in production, are equal to zero for marginal projects that earn a rate of return on capital just sufficient to cover capital costs, including taxation, incurred by owners.

It is often argued that resource levies are not taxes in that they are payments made by oil and gas companies to acquire the right to extract oil or natural gas from lands owned privately or publicly. These levies are thus intended to capture rents for landowners. However, if there are no rents, as in the case of a marginal project, no resource rents are generated and therefore no royalties should be collected in principle. Thus, a royalty that is based on revenues or output discourages marginal investments in the market by creating a wedge between the pre- and post-tax and royalty rate of return on capital. On the other hand, a rent-based royalty that applies to revenues net of all opportunity costs would not affect the marginal investment decisions since no rents are earned on such investments.

These points are contained in the model as explained in detail in Appendix A (p. 23). The model is generic, accounting for whatever type of resource levy is designed and whatever type of project is considered (conventional oil and gas, oil sands, and offshore developments). In all cases, the model accounts for not only resource levies but also other taxes impinging investment. Effectively, as shown in the appendix, one can think of the marginal project as one in which the discounted value of cash flows is equal to the initial cost of investment. It applies no matter how long or short the project’s time frame.

2. “Opportunity costs” refers to the alternative income that could be earned if capital, labour, or other factors of production are employed elsewhere, adjusting for risk and inflation.

The marginal effective tax and royalty rate (METRR) results provide an indication as to how tax and resource levies affect the decision to invest in oil and gas marginal projects in each jurisdiction. With marginal analysis, there is no need to specify project revenues and costs since companies will invest in capital until the rate of return on capital is equal to the cost of capital. This being the case, we simply require measuring the cost of capital with adjustments made for taxes and resource levies.

There have been other studies that focus on average cash flows earned by the industry, which requires a specification of revenues and costs that are best representative of the industry even though in practice revenues and costs widely vary by project. Specific companies in planning their investments would reasonably use their own revenues and costs based on the geological and other factors that affect their cash flows. Average effective tax and royalty rates are calculated as a share of the average rate of return, inclusive of rents, earned on resource investment projects, which is typically above the cost of capital used for marginal analysis.

The average effective tax and royalty rate is quite sensitive to the average rate of return. For example, with a high average rate of return, a fiscal regime with a high statutory rate and accelerated cost deductions and tax credits could have an average effective tax and royalty rate that is greater than the case under a regime with low rates and broad bases. With a low average rate of return, the opposite could hold if low-rate and broad-based tax and royalty systems have a smaller tax impact than high rates and narrow bases, since few rents are earned subject to the low statutory tax. Thus, in comparison with the marginal analysis (which focuses on low risk-adjusted internal rates of return equal to the observed cost of capital at the margin), the average effective tax rate analysis could lead to a conclusion that a high-rate, narrow-base regime imposes a higher tax burden on capital investments than a low-rate, broad-base regime with a high average rate of return on projects.

While it would be useful to understand how marginal and average tax analyses compare—often making little difference—the data needed for the average tax rate analysis is more demanding since risk-adjusted average rates of return are specific to projects. Marginal effective tax-rate analysis requires a measurement only of the cost of capital, since the pre-tax and resource levy (net-of-risk) rate of return on capital is equal to it.³

3. Our treatment of risk is to express cash flows in “certainty-equivalent” returns—in other words, reduce the expected return on capital by a risk premium on capital. An equivalent approach is to measure expected returns and adding the risk premium to the cost of capital, which is conventional in the finance literature. See Mintz, 1995.

Thus, it is the marginal project that is particularly relevant to investment decisions across jurisdictions since the last dollars of investment are spent so long as economic, tax, and regulatory costs are covered in each location. A firm decides to allocate capital to a jurisdiction only if the post-tax return on capital is sufficient to cover its economic capital costs (the hurdle rate). Companies have latitude to scale projects up and down in size as well as deciding upon how much total capital should be allocated to projects over time. Given that many firms operate in a market, some are marginal since their costs (hurdle rates) may be higher than others. The higher the fiscal costs, the lower the rate of return, with some projects no longer viable to cover the hurdle rate. Less investment takes place since marginal investments will be squeezed out of the market, as owners are not able to fully recover costs. This does not mean the complete absence of investment: investments with inframarginal net-of-tax returns above the hurdle rate will be adopted.

The METRR is a summary measure of taxes and resource levy impacts on investment. We include corporate income taxes (rates and cost deductions), sales taxes on capital purchases, transfer taxes and stamp duties on financial and real-estate transactions, and asset-based taxes (for example, Saskatchewan's capital tax and some US franchise taxes). Due to lack of measurement, municipal property taxes are not included. We also include resource levies including profit-based, volume-based, and revenue-based royalties. While these payments are made for the extraction of oil and gas from land owned privately or, in most cases, by governments, they are intended to capture the economic rents from resource developments. Privately developed freehold oil and gas is common in the United States so we use state government royalties for oil and gas developments on state lands. We do not include labour and energy taxes in measuring the effective tax rates on capital since these are different inputs.⁴ To do a full assessment of taxes on competitiveness, a different approach is needed to calculate effective tax rates for each input (labour, capital, and energy, for example) and aggregate by cost shares to estimate a marginal effective tax rate on costs (see McKenzie, Mintz, and Scharf, 1997).

Oil and gas companies invest in five types of capital expenditures: exploration, development, depreciable capital, inventories, and land. The asset structure, based on Canadian data made available, is assumed to be the same across jurisdictions in order to isolate

4. As pointed out by McKenzie, Mintz, and Scharf (1997), it is inappropriate to include labour and other non-capital taxes expressed as share of the return on capital since it biases upwards effective tax-rate measures and makes comparisons unreliable.

the impact of taxes on capital (there is certain differentiation between offshore, oil sands, and conventional oil and gas data). Other economic parameters such as the price-cost margin in selling resources, real financing costs, the debt-asset ratio, and economic depreciation rates are also assumed to be the same across jurisdictions with values typically averaged over five years to avoid short-term shifts in price and cost variables. Inflation rates, however, are assumed to differ across countries since countries with higher inflation tend to adjust policies to soften the impact on investors, including indexing profits for inflation as in the case of certain Latin American countries. Appendix B (p. 27) provides details on the data used for estimates of METRRs.

Some incentives that are not relevant at the margin are not included in the paper's analysis. Tax holidays often come with requirements that hurt profitability and therefore are not simple to measure accurately in terms of their impact on investment. Capped allowances improve total profitability by lowering the "average tax rate" but have no marginal impact since expenditures are in excess of those eligible for the incentive. This goes back to the point that the analysis in this paper is focused on the marginal investment for determining investment decisions.

Tax Reform in the United States

We update all tax parameters to reflect 2018 tax law as presently known. The most important change is a result of the extensive US tax reform. The key changes adopted with business tax reform included the following:

1. A reduction in the US federal corporate income-tax rate from 35% to 21% beginning January 1, 2018.
2. Expensing of investment in assets with a recovery of less than 20 years (primarily machinery and equipment) except by companies not subject to the interest limitation rule described below (construction, real estate, and regulated public utilities). Expensing is to be phased out after 2022 by a fifth each year (and therefore no longer available after January 1, 2027).
3. Research and development expenditures incurred in tax years after 2025 will be amortized over a 5-year period (15 years for expenditures attributable to research conducted outside the United States).
4. A general limitation on the deductibility of interest expense to be no more than 30% of adjusted profits (regulated public utilities and finance would be largely exempt). The legislation limits, until January 1, 2022, the deduction of net interest expense to 30% of the business's adjusted taxable income not taking into account interest, depreciation, amortization, depletion, or net operating losses (disallowed amounts may be carried forward five tax years). After 2021, the limit will be based on 30% of the business's pre-tax earnings gross of interest (disallowed amounts may be carried forward indefinitely).
5. Limitation in the use of non-operating losses deductions to be no more than 80% of profits and the elimination of the corporate minimum tax as of January 1, 2018.
6. An exemption for dividends received from foreign affiliates with at least 10% ownership by the US parent according to value (voting shares shall no longer be relevant in determining the ownership test). New anti-abuse rules are also introduced.

7. As a transitional measure, existing foreign earnings accumulated abroad since 1986 would be subject to a mandatory toll (transitional tax) payable over eight years: 15.5% for earnings held in cash and 8% for the remainder.
8. A tax on global intangible low-tax income (GILTI) earned by US affiliates offshore. GILTI is the excess of income over a deemed tangible income return with the latter measured as 10% return on tangible assets excluding passive income, foreign oil and gas income, and certain related party payments. GILTI is taxed at a rate of 10.5% until January 1, 2026, when it becomes 13.125% thereafter. A tax credit is given for 80% of foreign taxes without a carry back or forward to other years.
9. Domestic corporations are provided a reduced tax rate on foreign-derived intangible income (FDII). The effective tax rates on FDII will therefore be equal to 13.125% prior to January 1, 2026, and 16.406% thereafter.
10. A base erosion and anti-abuse tax (BEAT) applies to foreign companies operating in the United States. The BEAT is a minimum tax of 10% (to be 12.5%, beginning January 1, 2026) on taxable income gross of base erosion payments (a one-point higher tax rate applies to registered security dealers). BEAT is levied on companies with deductions higher than 3% of total deductions and for those with gross receipts of more than \$500 million. The cost of goods sold and certain service cost deductions (such as those subject to no mark-up values) are not included as a disallowed deduction.

US business tax reform not only affects investment decisions but also financing and the location of intangible income (intangible includes intellectual property, marketing, certain services, and mining exploration and development). Companies with US operations will have an incentive to shift income to the United States since US corporate tax rates are now lower than Canadian rates in many oil and gas states, but also to avoid the impact of interest and loss limitation rules and BEAT. US multinationals have incentive to pay dividends from Canadian subsidiaries from accumulated earnings and profits to pay down debt in the United States. Thus, not only is investment affected but also the distribution of corporate and resource taxes paid to US and foreign countries. In our analysis, we consider the corporate rate reduction, expensing provisions, and interest limitations (the latter plays little role when the limitation is based on earnings before the deduction of depreciation, depletion, and amortization).

US tax reform will also lead state governments to adjust their corporate tax rates and bases to the extent they follow the federal base adjustments (some do so automatically). In the oil and gas sector, corporate tax rates among states with most oil and gas production vary widely: Alaska (9.4%), Arkansas (6.5%), California (8.84%) Colorado (4.6%), Kansas (4.1%), Louisiana (8.0%), Mississippi (5.0%), New Mexico (5.9%), North Dakota (4.3%), Ohio (0.26% gross receipts tax instead of a corporate income tax), Oklahoma (6%), Pennsylvania (9.99%), Texas (0.75% gross margin tax instead of a corporate income tax), West Virginia (6.5%), and Wyoming with no corporate or gross receipts tax.⁵ Most corporate tax rates in major oil and gas states are below the GDP-weighted state income-tax rate in the United States (7.1%).

State income taxes are deductible from the federal corporate tax base and state governments need not conform to the federal tax base. Arkansas does not conform its corporate tax base to the federal base, while Texas and Wyoming do not levy a corporate income tax and so are not affected by federal tax reform. The other six states—Colorado, Kansas, Mississippi, North Dakota, Oklahoma, and Pennsylvania—conform on a rolling basis: they adopt federal base changes by legislation over time and in some cases, or not at all. Given that US tax reform broadens the federal tax base in general, state governments will receive more revenues if they adopt the base changes. Some states may not conform to federal base changes or might adjust corporate rates if they wish to keep corporate tax revenues the same. In our analysis below, we include current state income-tax rates and bases as of December 31, 2018.

5. A gross receipts tax affects investment decisions but not financing decisions since interest expense is not deducted from gross receipts to determine tax liability. The corporate income-tax rate is relevant to profit shifting and investment and therefore potential base erosion in Canada.

Tax Reform in Canada

On November 21, 2018, the federal government announced its response to US tax reform. No change was made to the federal corporate income-tax rate but provisions for temporary, accelerated investment incentives were announced. Manufacturing and processing equipment and clean energy investments would be expensed in the first year (instead of qualifying for a 25% deduction in the first year followed by 50% in the second year and 25% in the last year). Other assets including development expenditures would be written off in the first year at 1.5 times the normal amortization rate (the half-year convention is also suspended). Exploration costs were already expensed in the first year. Certain mining (non-oil-sands) assets currently subject to provisions that are phasing out accelerated depreciation are not eligible for enhanced capital-cost allowance deductions in the first year.

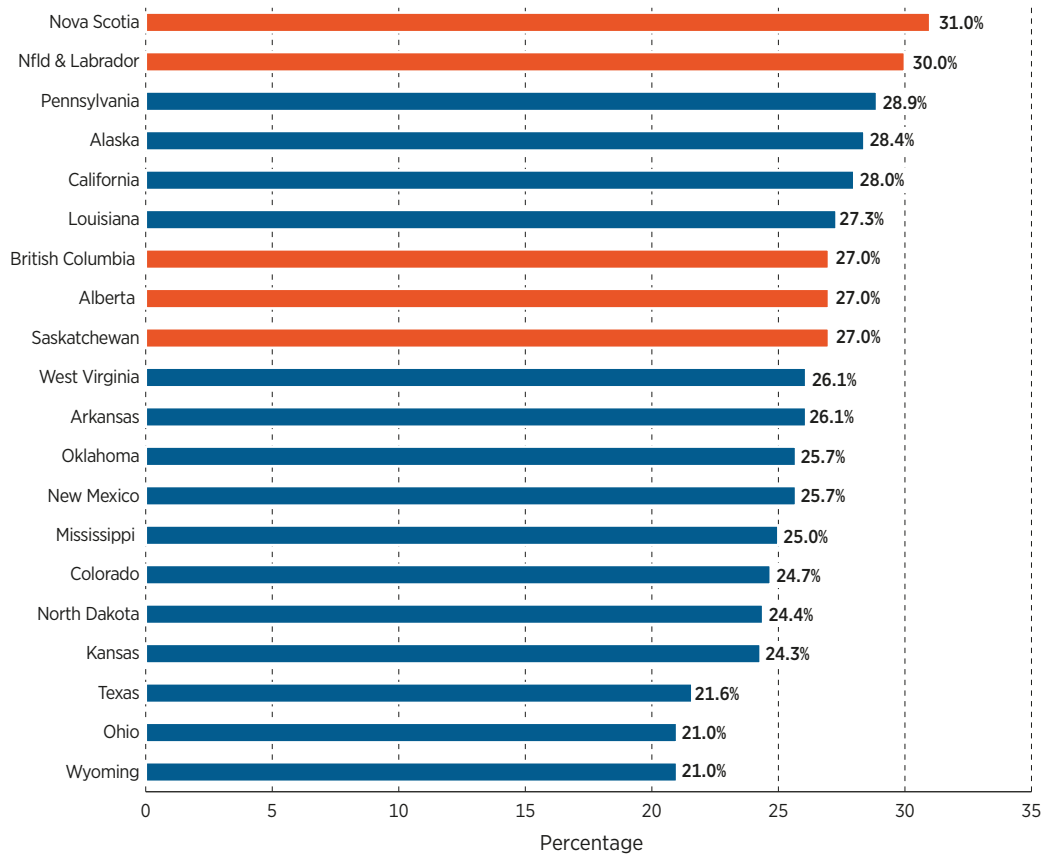
The measures are applicable for the period from November 21, 2018 until scheduled to be phased out after 2024, with full expiration after 2027. Provinces with corporate tax collection agreements with the federal government will parallel the rules. Alberta and Quebec, which are not bound by the Federal Tax Collection Agreement are not obligated to adopt the federal tax base and thus the new measures. While Quebec has announced its adoption of the federal changes following a rescinding of its additional capital cost allowance, enhanced in the March 2018 Quebec budget, Alberta has not yet announced whether it will adopt the same accelerated incentive measures. For purposes below, we assume that Alberta, which is relevant to this study, is assumed to parallel the federal measures.

Canadian tax reform in 2018 provides temporary tax relief for capital investments, only addressing those features of the US tax reform that were also granted on a temporary basis, namely tax depreciation allowances. Not addressed are other competitive features of the US reform, such as the sizable reduction in the federal corporate income-tax rate from 39.1% to 21.0% as well as base changes making it more attractive to keep profits in the United States.

The combined US federal-state corporate income-tax rate varies from 21% in Texas and Ohio, which have no corporate income tax, to 28.9% in Pennsylvania. On average, US federal-state corporate income-tax rates generally fall below those of the oil and gas

Canadian jurisdictions (figure 1). As a result, multinational companies with high project returns may find the United States more tax competitive for this reason. Canada’s relatively high corporate income-tax rate also encourages companies to shift costs such as interest expenses and general administrative expenditures into Canada to minimize tax liabilities.

Figure 1: Combined corporate income-tax rate (%) in select jurisdictions of Canada and the United States, 2018



Source: Canada Revenue Agency; Tax Foundation, Washington, D.C.; authors’ calculations.

Base changes as part of the American reform make it attractive to keep profits in the United States and not in Canada. Limitations on interest and loss deductions in the United States are now more restrictive compared to Canada. The Base Erosion and Anti-Avoidance Tax (BEAT), described above, encourages Canadian and other foreign-controlled companies to hold more taxable income in the United States to “beat” the BEAT.

Also, the low US federal tax rate of 13.25% on foreign-derived “intangible income” in the United States provides a competitive advantage to hold marketing, service, intellectual

property, and mining exploration, and development income (but not oil and gas) in the United States. Under the new US law, intangible income is measured as income net of a 10% allowance on tangible assets. While companies might find incentive to reduce related tangible assets in the United States to generate more income, the new rules encourage companies to shift marketing and other functions to the United States to earn tangible income. None of this is captured by our calculations of METRR below.

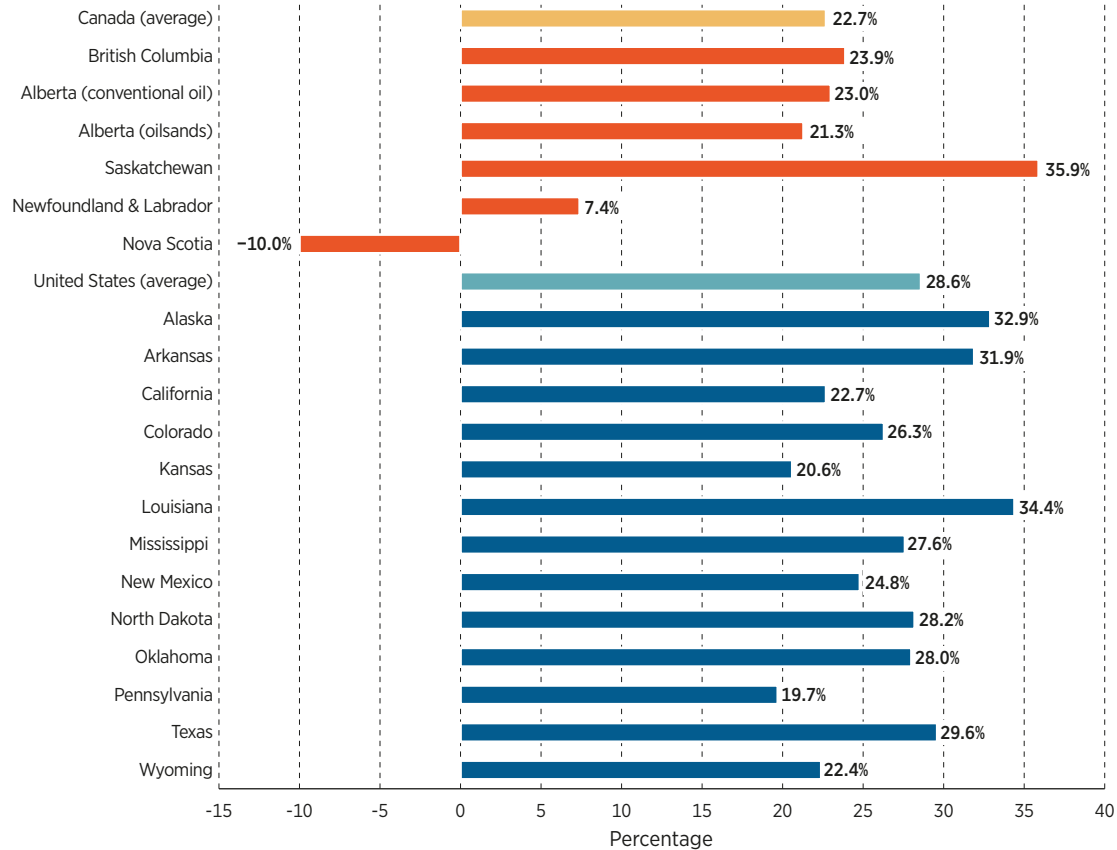
Marginal Effective Tax and Royalty Rates for Oil

Marginal Effective Tax and Royalty Rates (METRRs) for oil are provided by jurisdiction in figure 2, with provinces and states aggregated on a capital-weighted basis to derive the average Canadian and American METRRs. Although Nova Scotia does not produce oil, we include it in our estimates, as oil developments are possible. We assume the average well produced 50 barrels per day at a market price of US\$50. Canada’s weighted average METRR is 22.7%, which is 5.9% below that of the United States at 28.6% in 2018—and well below the 2017 US METRR of 33.9%, prior to the US tax reform. The US average represents conventional production only, whereas Canada’s METRR includes conventional, unconventional (Alberta oil sands), and off-shore production (for both Newfoundland & Labrador and Nova Scotia). US offshore, which is federally owned, is not included in US state measures and is not analyzed here.

In Canada, Saskatchewan has the highest METRR on conventional oil and gas investments as a result of its retail sales tax on capital inputs—though exemptions exist for oil and gas “down-hole work” and for the purchase of oil and gas drilling and service rigs—and its resource royalty. We note with regards to Saskatchewan’s royalty rate that it includes a resource surcharge of 1.7% on the value of sales, though only for corporations with paid-up capital of over \$20 million, which we assume to be the case. The lowest METRR is applied to investments in off-shore oil and gas in Nova Scotia. In Nova Scotia, resource taxation is a two-tiered mix of revenue and rent-based levy. A gross revenue payment is paid at rates varying from 1% to 5% on revenues according to the return and tier. Under the basic generic system, the net revenue royalties are paid once costs are recovered at rates rising from 20% to 35% of net revenues (costs are deducted from revenues and uplifted each by a factor including the bond rate plus a factor equal to 5, 20, and 25 percentage points, depending on the tier). Thus, Nova Scotia’s generic royalty regime provides an extremely generous return allowance at which costs in excess of accumulated revenues are carried forward, leading to negative METRR calculations.

In the United States, the lowest METRR across our group of 13 states is found in Pennsylvania. This is largely a result of the fact that Pennsylvania does not levy a severance tax on mineral production in the state and appears to have on average among the

Figure 2: METRRs (%) on oil in select jurisdictions of Canada and the United States, 2018



Notes: All values 2018, after the US & Canadian tax reforms. US results are for conventional production; Canada represents conventional and unconventional production.

Source: Authors' calculations.

lowest negotiated royalty rates at $\frac{1}{8}$ (12.5%) across the US states considered here. The highest METRRs among the group are found in Louisiana and Alaska. Alaska, which has no severance taxes, has the single highest royalty rate across the group at 35%, which equates to the highest state resource levy even when considering severance taxes in addition to royalties across the remaining jurisdictions. Louisiana oil is subject to relatively high royalty rates at an average of 21.9%, and in addition has the highest severance tax among the group at 12.5%, resulting in a combined resource levy of 34.4%, just behind Alaska's. Additionally, Louisiana has the highest combined state and local sales tax rate on capital inputs across the group, at over 10%. The third and fourth highest METRRs in the group are found in Arkansas and Texas, which have among the lowest severance taxes, but the highest royalty rates reaching $\frac{1}{4}$ (25%) on average. In addition, Arkansas and Texas levy the second and fourth highest effective sales tax on capital inputs, respectively.⁶ A general difference from Canada is that sales taxes on intermediate and

6. Investment in Texas due to shale developments has been particularly strong even though its fiscal system is less favourable. This demonstrates that factors other than taxation influence investment.

capital purchases in the United States are quite high on oil and gas extraction business inputs in the United States (Cline, Mikesell, Neubig, and Phillips, 2005).

As for the corporate income tax and its provisions, all jurisdictions surveyed here provide expensing for exploration. Development is optionally expensed in the United States while amortized at 30% in Canada. Wyoming has the most favourable corporate income-tax regime among the group, having no state corporate income tax. Texas also has no corporate income tax although it does apply a franchise tax in the form of a gross margin tax (see figure 3 for a breakdown of components of the METRR).

We have not conducted detailed sensitivity estimates of METRRs for different price scenarios; this would require additional research (for analysis of this sort, see Crisan and Mintz, 2017). Given that royalty rates vary according to prices in some cases (typically the case in Canada), and based on firm production and return characteristics in some other jurisdictions (profit-based royalties in Nova Scotia and Newfoundland & Labrador), METRRs would increase with higher price levels or at various stages of pay-out and profitability. On the other hand, better pricing improves price-cost margins for firms, reducing the impact of revenue-based resource levies, and thereby lowering the METRR. This would be the case in the United States with a flat royalty structure. If oil prices move higher than US\$50 on a sustained basis, the METRR in Canada would generally move up while it would fall in the United States.

Two further points are worth mentioning here. Even though oil-sands production in Alberta (along with Australia, Norway, and the United Kingdom to name a few) is subject to a rent-based resource tax, which provides a deduction for labour and capital expenditures from revenues, it is not a pure rent tax. First, as shown by Mintz and Chen (2012), a rent tax is not neutral in the presence of a corporate income tax even with deductibility of the resource levy from corporate taxable income. Intuitively, a government may fully share profits and risks under a rent-based tax by allowing unused deductions to be carried forward at a rate of interest (although if the project fails the deductions may not be used especially under ring-fencing of project profits). However, while the rent tax shares risk-adjusted profits earned by companies, it aggravates the corporate tax burden leading to a higher computed METRR. In the absence of corporate income taxation, the rent base tax would be neutral.

Second, the rent base may itself be distorted. Australia allows unused expenditure deductions to be carried forward at an uplift factor equal to a long-term government bond rate plus 15 percentage points (the uplift factor is being reduced to bond rate plus 5 percentage

points beginning July 1 2019). Given that the government shares risks with the private sector through the rent-based tax by allowing losses to be deducted at full value over time, the carry-forward rate is excessive (Australia was considering a change to lower the carry-forward rate but it was controversial and so far no change has been made).⁷ The same point applies to Nova Scotia's profit-based royalty system (also the basis for British Columbia's shale-gas royalty) and that of Newfoundland & Labrador prior to its recent reform, which led to low or negative METRRs (see Crisan and Mintz, 2017). Norway also limits the use of unused deductions that must be written off within five years. The United Kingdom comes closest to a rent tax, in part because of its relatively low corporate income-tax burden.

These points are relevant to the asset-by-asset estimate of METRRs as provided in table 1 below.⁸ Under corporate income tax, exploration and development tends to

Table 1: Oil METRR by asset type for select Canadian and US jurisdictions, 2019

	Exploration	Development	Depreciable K	Inventory	Aggregate
Canada—average	13.7%	16.9%	23.0%	31.3%	22.7%
British Columbia	24.2%	26.8%	19.6%	27.0%	23.9%
Alberta—conventional oil	25.2%	27.7%	15.1%	27.0%	23.0%
Alberta—oil-sands	-1.0%	3.2%	24.9%	34.9%	21.3%
Saskatchewan	28.4%	30.9%	47.5%	28.2%	35.9%
Newfoundland & Labrador	-3.0%	-0.3%	39.0%	51.9%	7.4%
Nova Scotia	-6.9%	-25.6%	25.4%	34.7%	-10.0%
	Exploration	Development	Depreciable K	Inventory	Aggregate
United States—average	34.4%	35.0%	22.5%	17.6%	28.6%
Alaska	42.9%	43.6%	13.6%	20.1%	32.9%
Arkansas	34.9%	35.5%	26.4%	18.3%	31.9%
California	20.8%	21.7%	25.5%	19.7%	22.7%
Colorado	28.8%	29.4%	21.4%	17.2%	26.3%
Kansas	18.9%	19.7%	23.2%	16.9%	20.6%
Louisiana	38.6%	39.3%	26.5%	19.2%	34.4%
Mississippi	29.8%	30.5%	23.2%	17.4%	27.6%
New Mexico	26.0%	26.7%	22.1%	17.9%	24.8%
North Dakota	32.4%	33.0%	20.0%	17.0%	28.2%
Oklahoma	29.4%	30.1%	25.2%	18.0%	28.0%
Pennsylvania	14.4%	15.4%	28.7%	20.5%	19.7%
Texas	34.3%	34.8%	20.9%	14.8%	29.6%
Wyoming	25.6%	26.2%	15.9%	14.4%	22.4%

Source: Author's calculations

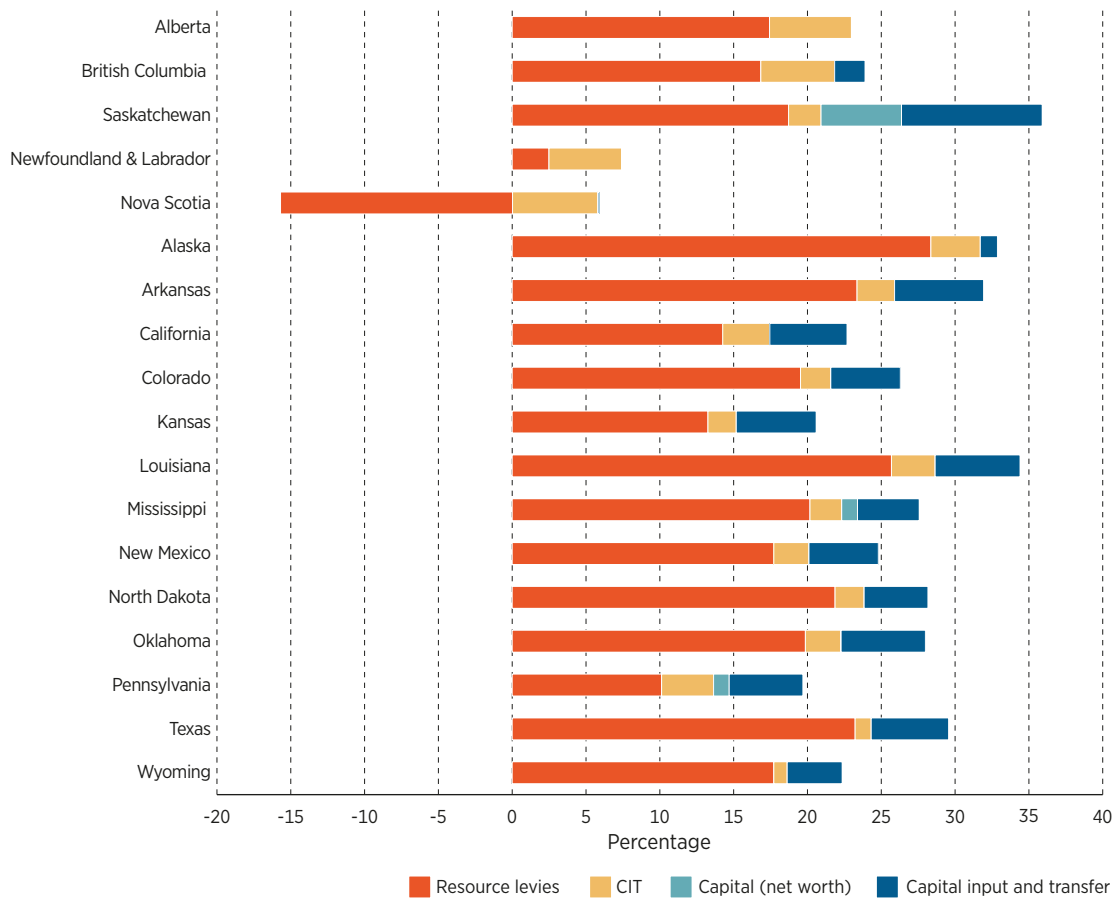
7. See the *Callaghan Review* of the petroleum resource-rent tax (Australian Government, 2017). The carry-forward rate for exploration costs had been particularly criticized (see Hill, 2018).

8. In these calculations based on earlier Finance Canada data, we differentiate capital structures for oil sands and conventional oil and gas.

be favoured since the costs can be written off prior to the income created from the extraction of available reserves. However, under revenue-based royalties, exploration and development is discouraged because governments tax income without allowing a deduction for costs. So for US and Canadian conventional oil and gas, which are subject to revenue-based royalties, exploration and development are highly taxed except in Pennsylvania. On the other hand, with rent-based resource levies, exploration and development is less highly taxed, which is shown most clearly in the case of Nova Scotia.

In figure 3, we provide a breakdown of the METRR for conventional oil components: corporate income taxes; resource levies (revenue-based and rent-based); and other tax components (capital or wealth taxes along with sales taxes on capital purchases and real estate transfers). We calculate each component by taking the aggregate METRR and

Figure 3: Components of conventional Oil METRRs (%) in select jurisdictions of Canada and the United States, 2018



Notes: All values 2018, after the US & Canadian tax reforms. US results are for conventional production; Canada represents conventional and unconventional production.

Source: Authors' calculations.

then remove one tax at a time, leaving the resource levies as the final component (interactions of taxes affect the values of each component so the ordering is important). For Canada, resource levies dominate impacts with sales taxes on capital inputs being of secondary importance. In the United States, severance taxes and revenue-based royalties are the most important components of taxes on capital while corporate income taxes are relatively low in importance. Other taxes are generally not significant except for the retail sales tax on capital purchases.

Marginal Effective Tax and Royalty Rates for Natural Gas

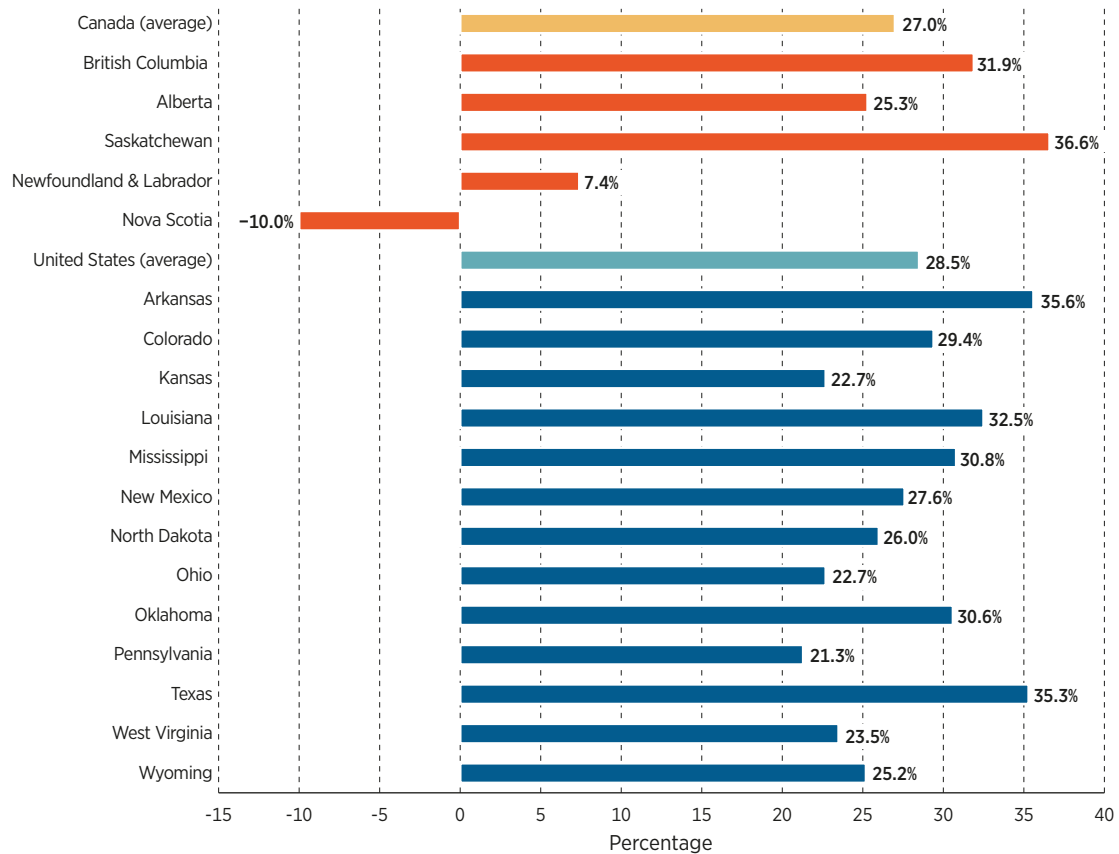
This section provides comparisons of METRRs on investments in natural gas for the same jurisdictions presented above. In general, non-resource tax provisions apply to natural gas as they do to oil. Some jurisdictions, especially those that rely on revenue-based levies, have specific resource levies for natural gas—the royalty rates will differ from those applied to oil. Jurisdictions with rent-based resource levies tend not to distinguish between oil and natural gas since costs are deductible from resource profits, thereby making it less important to apply specific provisions to account for differences in costs and production characteristics. As with oil, natural gas producers are provided various royalty credit programs but these credits are limited in size and therefore are more effective for investment location as opposed to expansion of production once the limit is reached.

We assume that the average natural gas well produces 600,000 cubic meters at Canadian price of \$3 per gigajoule (GJ), the five-year average. Some of our data, particularly for capital structures, do not differ across conventional oil and natural gas since they are aggregated. However, price-cost margins (costs measured as non-capital operating expenditures) vary. The price-cost margin for conventional oil is 0.77 and for conventional natural gas is 0.69. The lower the price-cost margin, the greater the impact of a royalty on the METRR. This same point does not apply to the rent-based resource levies in Newfoundland & Labrador and Nova Scotia since costs are deductible from revenues in determining resource payments (see Appendix A, p. 23).

In figure 4, overall, we find that the METRR for natural gas is lower for Canada (27.0%) than the United States (28.5%), largely driven by the lower METRR in Alberta and the high METRR in Texas—both of which account for a large portion of the weighted average based on the size of their natural gas industries.

Effective tax rates across Canada and the United States for natural gas investments tend to be higher than oil but follow a similar pattern (figure 4). Natural gas is taxed at higher royalty and severance tax rates than oil in Texas, British Columbia, and

Figure 4: METRRs (%) on natural gas in select jurisdictions of Canada and the United States, 2018



Notes: All values 2018, after US tax reform.

Source: Authors' calculations.

Saskatchewan, and at lower rates in North Dakota. Pennsylvania has the lowest natural gas METRR among US jurisdictions at 21.3% followed by Ohio and Kansas (22.7%) and West Virginia (23.5%). Newfoundland & Labrador and Nova Scotia have the lowest METRR among Canadian jurisdictions; the results for these two provinces do not differ from their oil results as both are assumed to be operating in the profit-based tier of their respective royalty frameworks, similar to the case for oil.

Again, we find in Canada that Saskatchewan has the highest METRR on natural gas investments. Similarly, this is a result of its retail sales tax on capital inputs and its resource royalty. Here we note with regards to Saskatchewan's royalty rate on natural gas that: [a] it includes the resource surcharge of 1.7%; and [b] that the royalty value is sensitive to both well-production volume and market price. Our base case assumption of 600,000 M3 holds across all jurisdictions but represents only a handful of wells in

Saskatchewan as production wells in the province tend to yield lower volumes than this. To get a sense of how this assumption affects the royalty rate we have used, please see the government of Saskatchewan’s production royalty matrix (Gov’t of Saskatchewan, n.d.: Royalty/Tax Rate Calculator).

As with oil, the natural gas METRRs vary across asset expenditures with exploration and development being most highly taxed when revenue-based systems are used (table 2).

Table 2: Gas METRR by asset type for select Canadian & U.S. Jurisdictions, 2019

	Exploration	Development	Depreciable K	Inventory	Aggregate
Canada—average	31.5%	33.9%	16.0%	25.3%	27.0%
British Columbia	38.0%	40.5%	17.8%	25.1%	31.9%
Alberta	29.5%	32.3%	14.0%	25.1%	25.3%
Saskatchewan	32.1%	34.8%	42.8%	25.1%	36.6%
Newfoundland & Labrador	-3.0%	-0.3%	39.0%	51.9%	7.4%
Nova Scotia	-6.9%	-25.6%	25.4%	34.7%	-10.0%
	Exploration	Development	Depreciable K	Inventory	Aggregate
United States—average	31.1%	31.8%	23.3%	17.3%	28.5%
Arkansas	40.7%	41.3%	26.2%	18.3%	35.6%
Colorado	33.7%	34.3%	21.3%	17.2%	29.4%
Kansas	22.2%	23.0%	23.2%	16.9%	22.7%
Louisiana	36.3%	35.6%	26.5%	19.2%	32.5%
Mississippi	34.8%	35.5%	23.2%	17.4%	30.8%
New Mexico	30.5%	31.2%	22.1%	17.9%	27.6%
North Dakota	29.2%	29.8%	19.6%	17.0%	26.0%
Ohio	23.8%	24.4%	20.5%	14.6%	22.7%
Oklahoma	34.4%	35.0%	23.3%	18.0%	30.6%
Pennsylvania	17.0%	17.9%	28.7%	20.5%	21.3%
Texas	43.3%	43.8%	20.7%	14.8%	35.3%
West Virginia	23.2%	24.0%	23.4%	18.3%	23.5%
Wyoming	30.1%	30.6%	15.9%	14.4%	25.2%

Source: Authors’ calculations.

Conclusions

With US tax reform adopted in 2018, the Canadian tax advantage for investment in both oil and natural gas was significantly diminished. For oil, we find that Canada's weighted average METRR has moved significantly below that of the 2018 post-tax-reform United States as a result of accelerated depreciation announced by the Canadian federal government on November 21, 2018. This follows a period after US, but prior to Canadian, tax reform, in which the two were neck and neck (on average, 28.5% for Canada and 28.6% for the United States, based on provincial/state jurisdictions included here), and a prolonged period prior to US tax reform when the US METRR was much higher, at an average of 33.9%. For natural gas Canada currently enjoys only a very small advantage over the United States following the move to accelerated depreciation.

With Canada adopting US-style temporary accelerated depreciation in late 2018, the effective tax and royalty rate on oil and gas investments in Canada will remain below those of the United States from 2019 until the temporary measures in both countries expire (2026 in the United States and 2027 in Canada). Barring any change in resource levies Canada will maintain its competitive advantage in oil and gas METRRs.

The Canadian tax reform of November 21 only addresses the tax treatment of depreciation costs. The US corporate income-tax rate, including state corporate rates, is significantly below Canada's in major oil and gas jurisdictions: Texas has no corporate income tax, for example. The low tax rate on "intangible income" of 13.25% in the United States applies to marketing, service, and intellectual property activities and is a significant advantage, one that is not captured in the calculation of METRRs.

Other factors that affect the competitiveness of oil and gas industries including Canada-US differences in energy (carbon and fuel taxes) and labour taxation, infrastructure, and regulation will determine whether Canada is sufficiently competitive to attract international investment in oil and gas in the future.

Appendix A: The “Time-to-Build” Model

The theoretical model follows Mintz, 2016. The “time-to-build” analysis results in a higher cost of capital for a company since income is earned after spending on exploration and development has taken place with a financing cost. Tax payments are affected since tax deductions for exploration and development expenditures are taken prior to income being earned when the resource is exploited, thereby leading to a mismatching of income and costs for tax purposes. The delay in creating income raises the cost of capital but the mismatch of income and expenses under the tax system reduces the cost of capital.

A resource firm maximizes the present value of cash flows from its project subject to the constraint that the extracted resources equal the amounts discovered over time. Let T be the period in which reserves are discovered and prepared for extraction that begins at that time.

$$(1) \text{ Max } V = \sum_{0}^{\infty} (1+R)^{-t} CF_t \text{ dt}$$

$$(2) \text{ subject to } \sum_{T}^{\infty} Q_t[L_t, k_t] = X = \sum_{0}^T f[e_t] \text{ (accumulated reserves equals total extraction)}$$

$$\text{with } CF_t = P_t Q_t[L_t, k_t] - w_t L_t - (\delta K_t + k_t)(1+\pi)^t - TAX_{c[t]} - TAX_{R[t]} \text{ for } t \geq T$$

$$CF_t = -e_t (1+\pi)^t - T_{c[t]} \text{ for } t \leq T$$

V is the present value of the firm’s nominal cash flows CF , discounted by the nominal financing rate R over the lifetime of the firm’s project. The nominal cost of finance is the weighted average of debt and equity finance ($R = Bi(1-u) + (1-B)\rho$) used by the firm for all of its projects, adjusted for the deductibility of interest expense (B is the portion of assets financed by debt, i is the nominal cost of debt and ρ is nominal cost of equity, net of risk with all values expressed in certainty-equivalent terms). These costs are determined by international markets and depend on tax planning opportunities.

Note that P_t = nominal price of output normalized to one and rises at the same inflation rate as other prices ($P_t = P(1+\pi)^t$) and $w_t L_t$ are current costs (which we will later denote as C and $w_t = w(1+\pi)^t$). The marginal productivity of outputs declines with the use of factors of production. Current costs, $C_t[Q_t, k_t]$, Q_k , and Q_L , can therefore be alternatively treated as a strictly joint convex in output Q (denoted as $C_Q > 0$ and $C_{QQ} > 0$) and capital that

reduces costs (denoted as $C_K < 0$ and $C_{KK} < 0$) with K_t = depreciable capital stock, k_t = new investment = $K_{t+1} - K_t$ and δ = economic depreciation. (Note that $C_Q = w/Q_L$ with profit maximization). Capital is treated as the numeraire with a real price equal to one.

Note that $f[e_t]$ are reserves found through spending on exploration in period t with the function being strictly concave in expenditure on exploration and development ($f' > 0$ and $f'' < 0$).

$TAX_{c[t]}$ = company tax payments (paid in each period and can be negative) and

$TAX_{R[t]}$ = resource payments in each period t (only paid after extraction begins).

The company tax is imposed on the revenues earned from the sale of resources net of the costs of production, which include current extraction costs, capital cost allowances, and exploration and development costs (exploration is expensed but development is capitalized and written off at the declining balance rate σ). This implies the following:

$$(3) \quad TAX_{c[t]} = u\{P_t Q_t - wL_t(1+\pi)^t - \alpha D_t - \sigma E_t(1+\pi)^t - T_{R[t]}\}$$

$$(4) \quad D_t = (\delta K_s + k_s)(1+\pi)^t - \alpha D_{t-1}$$

$$(5) \quad E_t = e_t(1+\pi)^t - \sigma E_{t-1}$$

(6) with α = capital cost allowance rate, D_s = the undepreciated capital cost base, and E_s = the undepreciated “stock” of exploration and development spending at time s .

Manipulating the terms associated with capital-cost allowances and investment, $(\delta K_t + k_t)(1+\pi)^t$, in equation (1) with the insertion of terms in (3), (4), and (5), one can show that the investment costs are reduced by the present value of capital allowances so that:

$$CF_t = \{PQ_t - wL_t\}(1-u)(1+\pi)^t - (\delta K_t + k_t)(1-uZ)(1+\pi)^t - TAX_{R[t]}(1-u) \text{ for } t \geq T$$

$$CF_t = -e_t(1-uZ')(1+\pi)^t - TAX_{R[t]}(1-u) \text{ for } t < T$$

$$\text{with } Z = \alpha(1+R)/(\alpha+R) \text{ and } Z' = \sigma(1+R)/(\sigma+R).$$

Note that resource payments in the exploration and development phase are “negative” if such costs are deductible from the royalty base, which will be the case for the rent tax.

Revenue-based royalty

Revenue-based royalties are a percentage of the value of extracted output and the corporate income-tax system allows companies to deduct exploration and development expenses against other income earned. Let τ be the *ad valorem* payment on sales, PQ ,

so that $T_R = TPQ$ (suppressing time scripts from here on unless needed). Maximizing equation (1), subject to (2), choosing L , K , k , and E , with appropriate substitutions, yield the following.

Output decision

The choice of Q yields the following result (λ is the Lagrange multiplier for the constraint in (2)):

$$(7) \quad (1+r)^{-t}(P(1-\tau) - C_Q)(1-u) = \lambda$$

with $r = R - \pi = Bi(1-u) + (1-B)\rho - \pi$.

The implied Hotelling Rule by using two first-order conditions is the following: $\{(p_{t+1} - p_t)(1-\tau) - (C_{Q,t+1} - C_{Q,t})\} / \{p_t(1-\tau) - C_{Q,t}\} = r$. The firm extracts output until the net of royalty gain from holding a unit of reserve is equal to financing costs that could be saved by selling one more unit of output.

The shadow price of extracted output λ is equal to marginal value of extracting a marginal unit of output. The royalty rate on *ad valorem* sales generally reduces quasi-rents and the incentive to extract since the royalty reduces revenues relative to costs of extraction. On the other hand, the deductibility of interest expense from taxable income lowers the cost of finance and, therefore, increases extraction to early periods.

Depreciable capital

The choice of capital stock and new investment, after exploration and development, as well as the undepreciated capital cost base and changes to it, yields the following cost of capital for depreciable capital:

$$(8) \quad -C_K = (\delta + R - \pi)(1 - uZ) / (1 - u)$$

This is the familiar cost-of-capital expression, noting that R is the weighted average of the cost of debt and equity finance and Z is the present value of depreciation.

Exploration and development

The choice of exploration and development, e , yields the following for the cost of capital:

$$(9) \quad (P_T - C_T)'f_t' = (1 - uZ')(1 + r)^{(T-t)} / [(1 - u)\{1 - \tau P / (P - C')\}]$$

The quasi-rent earned by investing in exploration $(P_T - C_T)'f_t'$ is equal to the interest-adjusted cost of exploration (the price of exploration and development is set equal to unity) divided by the one minus the royalty imposed on the cost of capital. The term

in the denominator $\tau P/(P-C')$ is the *ad valorem* tax paid as a share of the quasi-rents on incremental sales (this is expected to be less than one so long as the *ad valorem* tax rate is less than the margin $(P-C')/P$). The cost of exploration is reduced by interest deductions taken early at time t relative to the earning of income at time T . Given the deductibility of interest expense from income, the effect of corporate taxation is to reduce the real cost of finance (r) and the discount factor $(1+r)^{(T-t)}$, resulting in a lower cost of capital (and lower effective tax rate on capital).

Rent-based levy on cash flows

Cash flow is equal to the revenues net of both current and capital costs incurred in undertaking the project. Interest expense is not deductible and unused deductions, fully written off in later years, are carried forward at the riskless bond rate (the uplift factor).

The levy payment after payout is the following: $T_R = \tau[P_t Q_t - C(Q_t, K_t)(1+\pi)^t - (\delta K_t + k_t)(1+\pi)^t - e_t(1+\pi)^t]$, which is substituted into equation (3).

The determination of output, Q , accords with the following Euler equation:

$$(10) \quad (1+r)^{-t}(1-\tau)(P-C')(1-u) = \lambda,$$

implying that only interest deductibility of debt financing costs (incorporated in r) affects the extraction decision $\{(p_{t+1} - p_t) - (C_{Q,t+1} - C_{Q,t})\} / \{p_t - C_{Q,t}\} = r$.

Depreciable capital

The user cost for depreciable capital is similar to equation (9), but royalties directly affect the cost of capital because current costs are deductible from the royalty base. That is, changes in the stock of capital reduce current costs, which are netted from royalty payments.

$$(11) \quad -C_K = (\delta + R - \pi)\{1 - \tau(1-u) - uZ\} / [(1-u)(1-\tau)]$$

Exploration and Development

The user cost for exploration and development for the cash flow tax is the following:

$$(12) \quad (P-C')f_t' = (1-uZ' - \tau(1-u))(1+r)^{(T-t)} / [(1-u)(1-\tau)].$$

If the corporate tax terms are zero ($u=0$ and $Z=1$), the royalty term appearing in equation (12) disappears. Otherwise, the royalty is not neutral as it increases the corporate tax burden on capital.

Appendix B: Model Parameters

Canadian parameters

	AB Conv.	AB SAGD	AB Sur-M	BC	SK	NL	NS
Combined Federal-Provincial Statutory Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	30.0%	31.0%
Federal Tax Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Provincial Tax Rate	12.0%	12.0%	12.0%	12.0%	12.0%	15.0%	16.0%
Time to Build—T—t _E (O : NG)	5 : 3	5	5	5 : 3	5 : 3	5 : 5	5 : 5
Time to Build—T—t _D (O : NG)	3 : 1	3	3	3 : 1	3 : 1	10 : 10	3 : 3
Revenue-Based Oil (Base)	21.1%	2.2%	2.2%	20.2%	23.5%	5.0%	5.0%
Revenue-Natural Gas (Base)	21.2%			27.0%	22.2%	5.0%	5.0%
Profit-Based Royalty Oil (Base)	0.0%	40%	40%	0%	0%	50%	20%
Profit-Based Royalty Natural Gas (Base)	0.0%			0%	0%	50%	20%
Sales Tax—Capital Inputs	0.0%	0.0%	0.0%	0.8%	5.7%	0.0%	0.0%
Transfer Tax—Real Estate	0.2%	0.2%	0.2%	2.0%	0.3%	0.4%	1.5%
Resource Surcharge					1.7%		
No uplift or return allowance for income taxes							
Uplift _u for Exploration	N/A	LTBR**	LTBR**	N/A	N/A	N/A	20%+LTBR
Uplift _u for Development	N/A	LTBR**	LTBR**	N/A	N/A	N/A	20%+LTBR
Uplift _u for Depreciable	N/A	LTBR**	LTBR**	N/A	N/A	N/A	N/A

Note *: (O : NG) signify split results for oil and natural gas; e.g., oil result : natural gas result for the same jurisdiction and production

	AB Conv.	AB SAGD	AB Sur-M	BC	SK	NL	NS
Inflation	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Real interest rate	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
Nominal Interest Rate	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
Debt-to-Asset ratio	40%	40%	40%	40%	40%	40%	40%
Cost of Equity	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%
Nominal Financing Cost	4.9%	4.9%	4.9%	4.9%	4.9%	4.9%	4.9%
Real Financing Cost	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
Net-of-Tax Return on Capital	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
Capital weights							
Depreciable assets	33%	80%	80%	33%	33%	21%	21%
Inventory	2%	3%	3%	2%	2%	0%	0%
CEE	27%	2%	2%	27%	27%	25%	25%
CDE	38%	15%	15%	38%	38%	53%	53%
Aggregate-including E&D	100%	100%	100%	100%	100%	100%	100%

Source: Authors' estimates.

American parameters

[table continues →

	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Mississippi
Effective Statutory Tax Rate ($F+S \times (1-F)$)	28.4%	26.1%	28.0%	24.7%	24.3%	27.3%	25.0%
Federal Tax Rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
State Tax Rate	9.4%	6.5%	8.8%	4.6%	4.1%	8.0%	5.0%
Time to Build— $T-t_E$	5	5	5	5	5	5	5
Time to Build— $T-t_D$	3	3	3	3	3	3	3
Revenue-Based Oil	35.0%	25.0%	16.7%	20.0%	12.5%	21.9%	20.0%
Severance Tax Oil	0.0%	5.0%	1.1%	5.0%	4.3%	12.5%	6.0%
Revenue-Based Natural Gas	—	25.0%	—	20.0%	12.5%	21.9%	20.0%
Severance Tax Natural Gas	—	5.0%	—	5.0%	4.3%	4.3%	6.0%
Sales Tax—Capital Inputs (effective)	1.8%	9.3%	7.4%	7.4%	8.7%	10.0%	7.1%
Transfer Tax—Real Estate	0%	0.3%	0.2%	0%	0%	0.3%	0.3%
Capital/Franchise Tax	0%	0%	0%	0%	0%	0%	0.0013%

	Alaska	Arkansas	California	Colorado	Kansas	Louisiana	Mississippi
Inflation	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Real interest rate	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Nominal Interest Rate	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Debt-to-Asset ratio	40%	40%	40%	40%	40%	40%	40%
Cost of Equity	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Nominal Financing Cost	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%
Real Financing Cost	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
Net-of-Tax Return on Capital	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
Capital weights							
Depreciable assets	33%	33%	33%	33%	33%	33%	33%
Inventory	2%	2%	2%	2%	2%	2%	2%
CEE	27%	27%	27%	27%	27%	27%	27%
CDE	38%	38%	38%	38%	38%	38%	38%
Aggregate-including E&D	100%	100%	100%	100%	100%	100%	100%

Source: Authors' estimates.

New Mexico	North Dakota	Ohio	Oklahoma	Pennsylvania	Texas	West Virginia	Wyoming
25.7%	24.4%	21.2%	25.7%	28.9%	21.6%	26.1%	21.0%
21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
5.9%	4.3%	0.0%	6.0%	10.0%	0.0%	6.5%	0.0%
5	5	5	5	5	5	5	5
3	3	3	3	3	3	3	3
18.8%	18.8%	—	18.8%	12.5%	25.0%	—	16.7%
3.8%	10.0%	—	7.0%	0.0%	4.6%	—	6.0%
18.8%	18.8%	16.7%	18.8%	12.5%	25.0%	12.5%	16.7%
3.8%	2.7%	1.0%	7.0%	0.0%	7.5%	5.0%	6.0%
7.7%	6.6%	7.2%	7.7%	6.3%	8.1%	6.4%	5.5%
1.0%	1.0%	0.3%	0%	0.1%	0%	0.7%	0%
0.16%	0.16%	0.26%	0%	0%	0.75%	0%	0%

New Mexico	North Dakota	Ohio	Oklahoma	Pennsylvania	Texas	West Virginia	Wyoming
2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
40%	40%	40%	40%	40%	40%	40%	40%
4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
4.2%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%
2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
33%	33%	33%	33%	33%	33%	33%	33%
2%	2%	2%	2%	2%	2%	2%	2%
27%	27%	27%	27%	27%	27%	27%	27%
38%	38%	38%	38%	38%	38%	38%	38%
100%	100%	100%	100%	100%	100%	100%	100%

Appendix C: Description of Tax and Resource Levy Provisions

Canada

Federal

Overview

The federal CIT rate is 15%, under which all provincial royalty payments are deductible. The Atlantic Investment Tax Credit of 10% for qualifying investment expenditures in resource and manufacturing industries is provided (phased out by 2015).

Company income tax

The special tax provisions include: a 100% allowance for exploration cost, a 30% annual allowance for development, and a 25% allowance for a special class of depreciable assets (Class 41), covering a broad range of assets used by the resource sector.

Royalty

The federal government collects royalties only from oil and gas produced on the “frontier lands”, including the “territorial sea” and “continental shelf”, which are outside the scope of this study.

Rent-based tax

None

Alberta

Overview

Royalties are deductible under the corporate income tax.

Company income tax

The corporate income tax rate is 12% and the tax base matches that of the federal government.

Royalty

For conventional oil and gas, the royalty rate is based on gross revenue or production and is sensitive to both the market price and well productivity. Following 2017, the royalty ranges from zero to 40%, and for natural gas 5% to 36%. There is also an initial 5% royalty that applies in the first 12 months with a volume cap. As for oil sands, a progressive gross royalty ranging from 1% to 9% applies before payout. It is creditable against the net royalty (unused credits are carried forward at the investment allowance rate).

Rent-based tax

For the oil sands only, in addition to a pre-payout gross royalty, there is a net royalty of 25% to 40% after payout depending on the price level of the oil.

British Columbia

Overview	Company income tax	Royalty	Rent-based tax
Royalties are deductible under the corporate income tax.	The CIT rate is 12% and the tax base matches that of the federal government.	<p>For conventional oil and gas, the royalty is based on gross revenue. The royalty rate differs first by product category, such as density of oil or type of gas (i.e., conservation versus non-conservation gas) and by well age (except for heavy oil and conservation gas). Then the formulation of the royalty rate for a given product category differs between oil and gas. For oil, the royalty rate is sensitive mainly to productivity; for gas, the royalty is sensitive only to price.</p> <p>For certain high-cost shale gas projects, there is a pre-payout 2% royalty on gross revenue (see next column).</p>	For certain high-cost shale gas projects, a newly introduced net profit royalty program with four tiers of royalty rates applies: a pre-payout 2% royalty on gross revenue and three post-payout tiers associated with a royalty that is the greater of 5% of gross revenue and a higher rate of net revenue (i.e., 15%, 20%, or 35%, depending on the tier order). To reach each of the three tiers of net royalty, a progressive return allowance applies.

Saskatchewan

Overview	Company income tax	Royalty	Rent-based tax
The crown royalties and freehold production taxes are deductible for CIT purposes. There is also a resource surcharge under the corporate capital tax regime, which is deductible for CIT purposes.	The general corporate income tax rate is 11.5% and the tax base matches that of the federal government. Resource surcharge is equal to 1.7% on production undertaken after 2002.	The crown royalty and the freehold production tax (FPT) on oil and gas are determined using formulas containing parameters that are adjusted monthly by the government. Both royalty and FPT are sensitive to price and well productivity and differ by product in terms of their vintage and characteristics (e.g., type of product, well, and location). The FPT is lower than the crown royalty by a production tax factor (PTF), which varies by the type of product and ranges from 6.9 to 12.5 percentage points.	None

Newfoundland & Labrador

Overview	Company income tax	Royalty	Rent-based tax
The royalties are deductible for CIT purposes. The generic royalty regime consists of a basic royalty and a two-tier net royalty. Note that unsuccessful exploration expenditure is disallowed for the purpose of calculating the royalty.	The corporate income tax rate is 15% and the tax base matches that of the federal government.	Under the generic offshore oil royalty structure: a basic royalty is charged on adjusted gross revenues at rates rising from one to 7.5% as cumulative production rises to the point the <i>R</i> factor is greater than 1.25. The basic royalty is payable over the entire production period. But, after payout it is creditable against the net royalty. <i>R</i> factor is calculated as: $R = (\text{cumulative gross sales revenue and incidental revenue less cumulative transportation costs less cumulative basic and net royalty paid to prior month}) \div (\text{cumulative pre-development, capital \& operating costs})$.	Net royalty set to one tier with a sliding scale of rates ranging from 10% (for $1 \leq R \leq 3$) to 50% ($R > 3$). Rates are based on the same <i>R</i> factor as that defined for the revenue-based royalty.

Nova Scotia

Overview	Company income tax	Royalty	Rent-based tax
The royalties are deductible for CIT purposes. The generic offshore royalty regime consists of a two-tier gross-revenue royalty and a two-tier net royalty depending on the gross and net revenue levels, respectively. Note that unsuccessful exploration expenditure is disallowed for the purpose of calculating the royalty.	The corporate income tax rate is 16% and the tax base matches that of the federal government.	The revenue-based or gross royalty is two-tiered—2% before payout and 5% after payout—and deductible for calculating the base for the net-revenue royalty. Note that regardless of the revenue and profit level being reached, the 2% gross royalty applies for a minimum of 24 months, and the 5% gross royalty applies for a minimum of 36 months. This implies that there is no net royalty or rent tax payable for the first five years after the commencement of production.	The two-tier net royalty rate is 20% and 35%, depending on the net-revenue tier reached. Even after the net royalties become payable, only the greater of 5% of gross revenue and 20% or 35% of the net revenue is payable. To reach each of the two tiers of the net royalty scheme, a progressive return allowance applies: 20 percentage points above LTBR for Tier 1 and 45 points above LTBR for Tier 2.

United States

Federal

Overview

The main tax is the federal corporate income tax. There is also a federal royalty payable by oil and gas producers on federal properties, which is deductible for CIT purposes.

Company income tax

The federal corporate income tax rate is 21.0%, down from 31.85% prior to 2018, and applies to “domestic productive activities” including oil and gas business. The E&D expenditure may be either expensed or depleted after the commencement of production.

Royalty

The royalty arising from the federal properties is $\frac{1}{8}$ of the value of onshore production and $\frac{1}{8}$ offshore. But this royalty is beyond the focus of our study.

Rent-based tax

None

Arkansas

Overview

There are three principal levies in the state: oil and gas severance tax, royalties, and corporate income tax. The severance tax is deductible for royalty purposes, and both severance tax and royalty payments are deductible for income tax purposes.

Company income tax

The corporate income tax rate is progressive with the top rate being 6.5% on net taxable income exceeding \$100,000.

Royalty

The general severance tax is 5% with a reduced rate of 1.5% available to new discovery gas (for the first two years) and high-cost gas (for the first three years).

Arkansas sets a minimum statutory royalty rate at $\frac{1}{8}$ but negotiated rates of $\frac{1}{4}$ are common.

Rent-based tax

None

Alaska

Overview

The principal levies are the income tax and production tax on oil & gas tax. The production (severance) tax has been established by the state at a fixed rate.

Company income tax

The corporate income tax rate is progressive in Alaska with a top rate of 9.4% on taxable income exceeding \$220,000. The definition of taxable income in Alaska is based on the federal base for taxable income with some adjustments.

Multistate corporation income is subject to an apportionment formula, while oil and gas corporations are subject to a modified apportionment formula applied to worldwide income

Royalty

The current oil and gas production tax was imposed by the state legislature in 2013 in a bill known as the “More Alaska Production Act” or “MAPA”. The bill established a fixed rate of 35% on the net value of oil and gas at the point of production.

Rates for oil and gas produced at the Cook Inlet are currently capped at the rate that was previously established in 2006.

Rent-based tax

None

California

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax, a small per-unit statewide assessment on oil and gas production and negotiated royalties.	The corporate income tax rate in California is flat at 8.84% on taxable income exceeding \$100,000. However, banks or financial corporations in California are subject to a rate of 10.84%.	There are no severance taxes in California. Instead the state levies an “assessment” on oil and gas production established as a per-unit cost. The rate is reassessed annually based on market prices. The current assessment is \$0.5547 per barrel of oil or MCF of gas. Royalties are negotiated and commonly established at $\frac{1}{6}$; higher rates exist though appear less common.	None

Colorado

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax and the severance tax. The royalty appears to be a local levy that may be partially creditable against the severance tax.	In Colorado, corporate income tax is levied at a flat rate of 4.63%.	The severance tax is 7% for oil and gas. Under legislation approved in 2014, effective July 1, 2015, oil and gas from newly spudded wells are taxed at 2% for the first 36 months of production. Royalties are negotiated and commonly established at $\frac{1}{6}$. Royalty rates of $\frac{3}{16}$ and $\frac{1}{4}$ exist but are less common.	None

Kansas

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax and the mineral severance tax. The royalty appears to be a freehold agreement between mineral rights owner and producer. In addition, there is a small Oil and Gas Conservation Tax, levied on a per-unit-of-production basis.	Corporations in Kansas are subject to a flat 4% rate, with an additional 3% surtax on income over \$50,000. This implies an effective rate of 4.12% over \$50,000.	The mineral severance tax is 8% of gross value of oil and gas, less property tax credit of 3.67%. For an effective rate of 4.33%. Oil and Gas Conservation Tax 9.1c/bbl. crude oil, and 1.3c/1,000 cu. ft. of gas sold. Royalties are negotiated and commonly established at $\frac{1}{6}$.	None

Louisiana

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax and severance tax. The royalty appears to be a negotiated agreement between mineral rights owner and producer.	The corporate income tax rate is progressive in Louisiana with a top rate of 8% on gross taxable income exceeding \$200,000	The mineral severance tax is 12.5% of oil value at time and place of severance. For gas the severance is \$0.11 per MCF. Royalty rates are negotiated and are established on average at 21.9%.	None

Mississippi

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax and severance tax. The royalty appears to be a freehold agreement between mineral rights owner and producer. Mississippi also levies a small franchise tax at 0.15%.	The corporate income tax rate is progressive with the top rate being 5% on net taxable income exceeding \$10,000	The mineral severance tax is 6% of gross value of oil and gas. Reduced rates of 3% and 1.3% are offered for enhanced recovery and horizontal drilling respectively, for the first 30 months, or until payout. Royalties are negotiated and commonly established at $\frac{1}{8}$.	None

New Mexico

Overview	Company income tax	Royalty	Rent-based tax
There are three principal levies in the state: oil and gas severance tax, royalties, and corporate income tax.	The corporate income tax rate is two tiered in New Mexico with a top rate of 5.9 % on gross taxable income exceeding \$500,000. Income below \$500,000 is taxed at 4.8% of net income.	The severance tax on crude oil and natural gas is 3.75%. Royalty rates for oil and gas production appear to be fixed at 18.75%. While royalty rates for “discovery leases” face a royalty of $\frac{1}{8}$.	None

North Dakota

Overview	Company income tax	Royalty	Rent-based tax
The principal levies are the income tax and the severance tax. The royalty appears to be a freehold agreement between mineral rights owner and producer.	The corporate income tax rate is progressive with the top rate being 4.31% on net taxable income exceeding \$50,000	The severance tax is 10% for oil production (5% production tax, 5% extraction tax) and \$0.0705 per Mcf on natural gas in 2019 (equivalent effective rate of 2.4% at CA\$3.0 per GJ). Royalties are negotiated and commonly established at $\frac{1}{8}$ or $\frac{3}{16}$.	None

Ohio**Overview**

The principal levies are a small per unit severance tax, the Commercial Activity tax (CAT)—effectively a gross receipts tax—and a negotiated royalty agreement between mineral rights owner and producer.

Company income tax

There is no corporate income tax in Ohio. The state levies a Commercial Activity tax (CAT)—effectively a gross-receipts tax—at a rate of 0.26% on receipts over \$1,000,000. A tiered minimum tax is established for businesses with receipts of \$150,000 or more.

Royalty

Ohio imposes a unit-based severance tax on oil and gas production. The tax is relatively small at \$0.025 per MCF of natural gas, \$0.10 per barrel of oil. Royalties are negotiated and appear to exist in a range between 12.5% and 20%. We have taken the common $\frac{1}{8}$ or 16.67% as the baseline for modeling.

Rent-based tax

None

Oklahoma**Overview**

The principal levies are the income tax and the severance tax. The royalty appears to be a freehold agreement between mineral rights owner and producer.

Company income tax

The corporate income tax rate in Oklahoma is a flat rate at 6%.

Royalty

The severance or “gross production” tax on crude oil and natural gas is established at 7.0% in Oklahoma. Royalty rates are commonly established at $\frac{3}{16}$.

Rent-based tax

None

Pennsylvania**Overview**

There are two principal state levies: income tax and loans tax, effectively a capital tax on debt. A long debate has surrounded whether the state should have a severance tax on resources. However, a proposal initially including a severance tax in House Bill 542 was finally passed without a severance tax included.

Company income tax

The CIT rate is 9.9%. The loan tax is 0.4 cents (4 mills) on each dollar of the nominal value of all scrip, bonds, certificates and evidences of indebtedness.

Royalty

Pennsylvania does not impose a severance tax on the production of oil and gas. Royalties rates are negotiated, but legislation in Pennsylvania establishes a minimum a rate of $\frac{1}{8}$. Barring evidence that higher rates are common, we have used the rate of $\frac{1}{8}$ as the baseline in our model.

Rent-based tax

None

Texas

Overview	Company income tax	Royalty	Rent-based tax
There are three levies on state-owned resource properties: a royalty, a severance tax (or oil and gas production taxes), and a franchise tax. The royalty is deductible in calculation of the severance tax, and both payments are deductible for the purposes of the state franchise tax.	The Franchise Tax is 0.75% based on the taxable margin, which is the least of the following three calculations: total revenue minus cost of goods sold, total revenue minus compensation, or total revenue times 70%.	The severance tax or production tax is based on the total production at market value. The rate is 4.6% for crude oil and 7.5% for natural gas. Royalties can be “fixed” or negotiated and appear to be commonly established at the state fixed rate of $\frac{1}{4}$. Negotiated Royalty rates of $\frac{1}{6}$ and $\frac{1}{8}$ exist but appear less common.	None

West Virginia

Overview	Company income tax	Royalty	Rent-based tax
There are three principal levies in the state: oil and gas severance tax, royalties, and corporate income tax.	The corporate income tax rate is progressive with a top rate of 6.5% on net taxable income exceeding \$60,000. The income tax base in West Virginia is based on federal adjusted gross income.	The gross production severance tax on crude oil and natural gas is established at 5.0% in West Virginia. Royalty rates are commonly established at $\frac{1}{6}$.	None

Wyoming

Overview	Company income tax	Royalty	Rent-based tax
There are only two primary levies on resource production in Wyoming: a royalty and severance tax. Notably, Wyoming has no state corporate income tax. The royalty is deductible in calculation of the severance tax.	Wyoming is free from state corporate income tax, franchise tax, or any real estate transfer taxes.	The severance tax on crude oil, lease condensate, and natural gas is 6%. “Stripper oil” faces severance at 4%.	None

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Founded in 1974, we are an independent Canadian research and educational organization with locations throughout North America and international partners in over 85 countries. Our work is financed by tax-deductible contributions from thousands of individuals, organizations, and foundations. In order to protect its independence, the Institute does not accept grants from government or contracts for research.

Nous envisageons un monde libre et prospère, où chaque personne bénéficie d'un plus grand choix, de marchés concurrentiels et de responsabilités individuelles. Notre mission consiste à mesurer, à étudier et à communiquer l'effet des marchés concurrentiels et des interventions gouvernementales sur le bien-être des individus.

Peer review—validating the accuracy of our research

The Fraser Institute maintains a rigorous peer review process for its research. New research, major research projects, and substantively modified research conducted by the Fraser Institute are reviewed by experts with a recognized expertise in the topic area being addressed. Whenever possible, external review is a blind process. Updates to previously reviewed research or new editions of previously reviewed research are not reviewed unless the update includes substantive or material changes in the methodology.

The review process is overseen by the directors of the Institute's research departments who are responsible for ensuring all research published by the Institute passes through the appropriate peer review. If a dispute about the recommendations of the reviewers should arise during the Institute's peer review process, the Institute has an Editorial Advisory Board, a panel of scholars from Canada, the United States, and Europe to whom it can turn for help in resolving the dispute.

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