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Death by a Thousand Cuts? Western Canada's Oil and Natural Gas Policy Competitiveness Scorecard

A lack of market access and taxes on investment – not emissions prices – are the main policy-induced competitiveness problems for conventional energy producers in Western Canada.

Benjamin Dachis

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The Study In Brief

Pipelines face delays or are not built at all. Governments are adding greenhouse gas emissions prices. Provinces have introduced higher corporate income taxes. Property and other municipal taxes on energy producers have also been on the rise. Taken together, what are the costs of these recent policies for the western Canadian energy sector? And how does each compare in its effect on the competitiveness of Canadian provinces, both in relation to each other and to US energy-producing states?

To assess the effect of policy-induced competitiveness costs on energy producers, this *Commentary* calculates the cumulative change in profitability that energy producers would face for an otherwise identical well because of government policies that affect taxes and pipeline access. In the first of what will be an annual series – updated as policymakers change the policy-induced costs on conventional oil and natural gas producers – this *Commentary* finds that:

- pipeline constraints have greatly reduced the price that oil producers receive. This effect is by far the largest competitiveness cost on energy producers;
- corporate taxes and provincial royalties are major policy costs for producers. Canadian provinces have historically been competitive with the US on taxes, but recent changes in the US highlight the need to examine the cost of taxation – the outcome of Alberta's recent royalty review was a step in the right direction;
- greenhouse gas emission taxes have been big news politically and publicly, but so far have not been economically important for energy producers. Further, the Alberta (and similar federal) system gives companies a strong incentive to reduce their emissions with little competitiveness cost. Indeed, companies with below-average emissions are better off under the current system; and
- finally, property and municipal taxes have enormous variation across Canada and the US. There is room for provinces to reduce the cost of both provincial and municipal property taxes on energy producers.

Policymakers now need to take steps to ensure that approved new pipelines get built and to reduce the burden of corporate income, royalty, property and greenhouse gas emissions taxes.

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One after another, policy changes are piling on to affect the competitiveness of energy producers in Western Canada. Provinces have introduced higher corporate income taxes.

Pipelines face delays or are not built at all. Governments are adding costs through greenhouse gas (GHG) emissions policies. Each policy might seem to have only a small effect on competitiveness, since no single policy is likely to significantly reduce investment in the Canadian energy sector. But, taken together, what are the costs of these recent policies for the western Canadian energy sector? And how does each compare in its effect on competitiveness? How do western Canadian provinces compare, both domestically and with the United States?

This *Commentary* is the first in what is intended to be an annual apples-to-apples comparison – adding and improving estimates of policy costs every year – of the cost of corporate income taxes, royalties, property taxes, regulatory delays and emissions charges to Western Canada's energy sector, aside from oil sands projects, relative to that elsewhere in North America. Canada's energy producers start from the enviable position of having access to some of the most productive oil and natural gas deposits in North America. Governments can do nothing about inherent geology. They can, however, control a number of policies that influence the competitiveness of upstream energy producers in their region. The analysis in this *Commentary* is premised on taking an economically marginal dry natural gas well and an oil well with the geological, cost and productivity features that are common in northwestern Alberta, the location of much new investment in the energy sector, and placing them in a number of North American jurisdictions that compete for energy investment – namely, Alberta, British Columbia, Saskatchewan, Texas, Colorado, Pennsylvania and North Dakota (see Box 1).

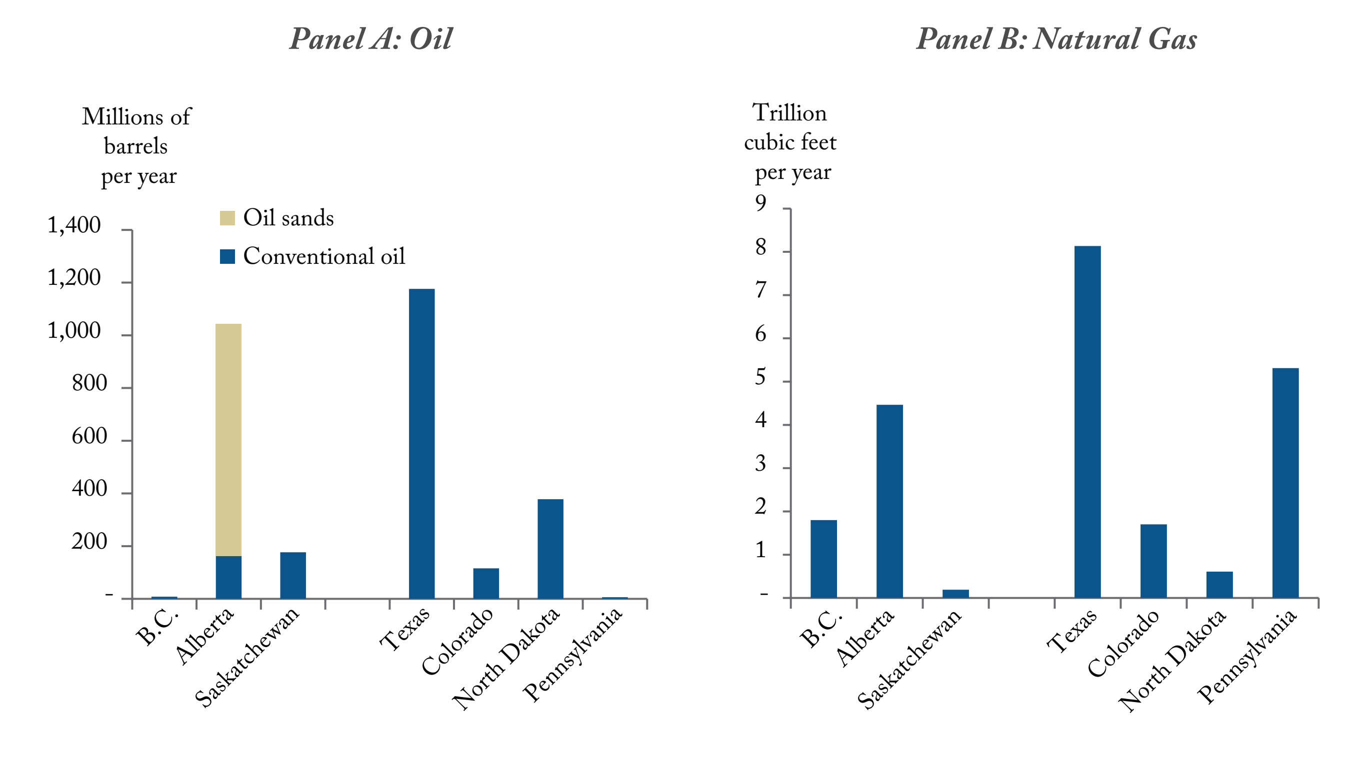
To assess the effect of policy-induced competitiveness costs on energy producers, I calculate the cumulative change in profitability that energy producers would face for an otherwise identical well because of government policies that affect taxes and pipeline access. Such a measure indicates the likelihood that an energy company would choose to invest in Western Canada as opposed to elsewhere in North America for an otherwise similar investment decision. The analysis shows that, mainly because of pipeline delays, producers of conventional Canadian oil are at a severe policy-induced competitive disadvantage relative to producers in US states, although many policies, such as recent reforms to royalties in Alberta, are not major barriers to competitiveness. Canadian natural gas producers are also at a competitive disadvantage relative to producers in some US states, but governments could easily improve the competitiveness of the sector by reforming the royalty and property taxes that companies pay. Notably, emission pricing is not currently a major competitiveness cost on conventional oil and gas producers in Western Canada.

Many thanks to Vincent Thivierge for excellent research assistance on a number of sections. Blake Shaffer, Energy Policy Council members, Grant Sprague, Vincent Thivierge, and many anonymous reviewers provided excellent comments on earlier versions of this paper and some of the data underlying this paper. The author retains responsibility for any errors and the views expressed.

Box 1: Competing North American Energy-producing Jurisdictions

In this first edition of the annual energy competitiveness scorecard, I used jurisdictions for which information was available on all factors I investigate, with data from Mintz and Crisan (2016) on taxation of capital investment being the main limiting variable. Fortunately, this source provided enough data to examine the competitiveness of the main energy-producing provinces. Alberta was the top producing province of both oil and natural gas in 2016, British Columbia was the second-largest producer of natural gas and Saskatchewan the second-largest producer of oil. I did not compute competitiveness metrics for oil sands projects or offshore production in Eastern Canada; these projects have substantially different economics from those of most wells in competing US jurisdictions – a more appropriate comparison would be with locations such as Norway or the US Gulf Coast. There are also enough data to include the top two US states for both oil and natural gas production in 2016: Texas was the top producer of both oil and natural gas, Pennsylvania was the second-largest producer of natural gas and North Dakota was the second-largest oil producer. Although Colorado was the seventh-largest producer of both oil and natural gas, it is included in the analysis because of its similarity to western Canadian provinces in terms of energy production.

Box Figure: Oil and Natural Gas Production in Selected US and Canadian Jurisdictions, 2016



Source: Author's calculations from Canadian Association of Petroleum Producers and US Energy Information Agency.

This analysis is far from an all-encompassing analysis of potential regulatory costs on upstream energy companies, as it excludes the oil sands and offshore production. Other policies that might affect the competitiveness of the energy sector and that are omitted from the analysis presented here include regulatory delays in approval of wells, those that protect endangered species (see Bošković and Nøstbakken 2017 for an analysis of how important these are) and those that affect labour costs. Also omitted are such factors as refineries and costs added at the end use through policies such as fuel standards and renewable fuel content regulations. Over time, this annual analysis will incorporate additional competitiveness issues in the western Canadian energy sector to create as comprehensive a metric as possible of policy-driven competitiveness. From this analysis, I conclude that policy-driven competitiveness costs could be reduced by eliminating barriers to the construction of approved oil pipelines, reducing taxes on investment, reducing property and municipal taxes and reducing the competitiveness cost of GHG emissions policies.

Remove barriers to the construction of approved oil pipelines: The single policy-influenced factor that most reduces the competitiveness of oil producers in Western Canada relative to those in the United States is the lack of pipeline access. Most Canadian governments, both provincial and municipal, have supported the building of pipelines, but some have put in place policies that have hindered such development. For the average new western Canadian oil well, which requires an investment of about $4 million, the lack of pipeline infrastructure reduces its profitability by an estimated $600,000, an amount that represents about 15 percent of total well-specific cash flows and that reduces revenues by around $5 per barrel, making some investments non-economical. If Canadian governments allowed pipelines to be built expeditiously, the competitiveness of western Canadian oil producers would be greatly improved.

Reduce taxation costs on investment: Policies that affect competitiveness in the energy sector that are within more immediate control of governments are excessive corporate income taxes and badly designed provincial royalties on oil and gas production. Oil and gas production is a capital-intensive industry, meaning that small changes in the tax on investment can lead to large swings in the total dollar competiveness cost per well. Among all the provinces in 2016, Alberta had the highest tax on investment, while British Columbia had the lowest, but in both provinces total tax costs are in the middle of the pack relative to those in US states. Accordingly, the provinces should reform their royalty regimes on oil and gas wells to reduce the future tax burden on new investment. Alberta introduced a reform that reduced capital costs starting in 2017; other provinces should follow suit. Both the federal government and Alberta could also improve the energy sector's tax competitiveness by reforming the corporate tax system to reduce the tax cost of new investment.

Reduce property and municipal taxes: Western Canadian oil and gas producers pay significant property and local taxes amounting to tens of thousands of dollars over the life of a well, with producers in Alberta facing the highest local tax burden. The provinces are competitive on property and local taxes relative to, say, Texas, but have a much higher cost relative to states, such as North Dakota and Pennsylvania, that impose no local property taxes on oil and gas producers. Accordingly, the provinces – in particular, Alberta – should simplify their assessment regimes for machinery and equipment on oil and gas properties and reduce local property tax rates. The energy sector should, of course, pay for the many services that local governments provide. However, instead of levying mandatory property taxes based on the assessed value of wells, local governments – in particular, rural municipalities and counties – should base more of the costs they levy on oil and gas companies on the actual services companies use, instead of applying the broad-based charges they currently levy.

Reduce the competitiveness cost of GHG emissions policies: Relative to other costs, GHG emissions pricing has had a relatively small effect on the competitiveness of non-oil-sands western Canadian energy producers. Alberta's policy of providing rebates to energy producers based on a province-wide benchmark of emissions intensity – a policy the federal government has mimicked – creates an incentive for companies to reduce emissions while having a minimal net impact on the competitiveness of the energy production sector. Alberta should retain this system, and other provinces should adopt it as they tackle GHG emissions reductions.

Measuring Western Canadian Energy Competitiveness

The overall competitiveness of western Canadian energy producers depends on two key factors: the region's inherent characteristics and government policy. There is little that governments can do about the inherent geology and productivity of oil or natural gas fields in their jurisdiction. Other costs, such as labour, water and electricity, are influenced by government policy, but are still largely determined by market forces. Governments can, however, control the effects of some of their policies on well profitability. To isolate these effects on competitiveness, my analysis takes the cost and productivity characteristics of an average oil well in Alberta and an average natural gas well along the border with British Columbia, and uses them as "reference wells" to estimate the cost of policies elsewhere if that reference well moved to another jurisdiction.

Why Examine Policy-driven Competitiveness?

In making their investment decisions, oil and gas companies weigh many more factors than are included in this analysis. In the absence of any government policy and no transportation barriers, companies will choose to invest where the marginal cost of production is the lowest. Government policies, however, can increase the cost of doing business in a particular location, and since capital can be highly mobile, governments need to pay close attention to their policy competitiveness lest they see investment relocate.

A good example of this framework is that used by the Alberta Royalty Review Advisory Panel (2016). For the panel, consultants Wood Mackenzie analyzed the share of overall revenues from every barrel of oil that goes to governments, private landowners (in US states, as discussed below) and the company itself. Such an analysis is a critical first step in assessing overall competitiveness that this *Commentary* aims to build on with more detail of the specific policy drivers of competitiveness. The analysis can also show how adjustments to regimes can boost the local economy by attracting more investment, leading to higher incomes, higher government revenues and more jobs. As the energy sector changes and companies begin to invest elsewhere, governments also need to understand their strategic position by examining the policies of similar jurisdictions, particularly those in the United States, that are competing for resource investment. As the panel report emphasizes, however, such policies should not be so generous to companies that they effectively result in subsidizing companies to invest at the expense of the imposition of higher taxes on people or the creation of environmental liabilities – for an example of such a risk, see Dachis, Shaffer, and Thivierge (2017).

There is no single comprehensive and regularly updated metric with which to gauge the economic cost of the cumulative effect of detrimental policies on the competitiveness of western Canadian energy producers. The only existing annual metrics are survey-based measures of the perceptions of energy executives (Green, Jackson, and Sholes 2016). But such surveys are imperfect. For example, respondents might not be able to compare policies consistently across jurisdictions or they might have an incentive to understate or exaggerate the true competitiveness effects of government policies. This competitiveness measure, however, is not a complete economic cost: a dollar lost due to capital taxation, for example, might do more economic harm than the dollar cost of other policies, such as GHG pricing – indeed, a higher cost for GHG emissions could be economically efficient. Although it is not the final determinant of whether a company would choose to invest in any given region, this measure of the cost of government policies on the total profitability of a well investment is one of the drivers of competitiveness of a region.

It is important to differentiate between average and marginal effects on competitiveness of government policies. A key example of marginal effects is that caused by GHG emissions policies: a carbon-pricing policy can result in a company's having a strong incentive to reduce its emissions. In contrast, a credit back to firms based on a benchmark of industry-wide emissions intensity could mean the average cost of emissions is low. The result is that, with proper incentives, GHG emissions pricing can have little effect on competitiveness, leading companies to choose to invest in areas with high emissions prices as opposed to areas with few emissions regulations. Similarly, a cash-flow royalty can result in companies' paying a large amount of taxes as a share of their investment, but having a low or no tax cost on every dollar they invest (see Boadway and Dachis 2015).

Choosing the Hypothetical Natural Gas and Oil Wells

The location of a natural gas or oil well – both geographical and geological – is the single most important determinant of cost, production and eventual profit. Even within Western Canada, the typical well varies dramatically by location. A well in a place with abundant and easy-to-develop reserves can be profitable to develop even in the face of onerous government policies, and even an unproductive well might be profitable in a jurisdiction with a low regulatory or tax burden. As a result, the government policies of a region might reflect the productivity of the wells in that region, making it difficult to compare policies across jurisdictions. For this reason, the analysis in this *Commentary* is based on a hypothetical scenario of a "horizontal"[1] oil or gas well exploiting a prolific geological formation in northwestern Alberta for seven years. The analysis computes what the policy cost on that well would be if it were located in a different province or US state. These reference wells have capital costs and production levels that are similar to those for the average well in northwestern Alberta, but only break even in terms of profitability.[2]

Capital Costs

The initial cost of developing oil and gas extraction sites in Canada ranges from a few hundred thousand dollars for a simple vertical well to many millions of dollars for a site that has multiple horizontally drilled wells. Wells in northwestern Alberta or northeastern British Columbia tend to have much higher capital costs than those elsewhere in Canada – in particular, the cost of bringing workers to remote sites is high. An additional large cost is the physical inputs – fracturing sand and liquids – drilling companies use to liberate oil and gas from rocks. I assumed that a typical

1 Traditionally, wells were drilled vertically; the modern approach is to drill horizontally to the specific depth of the geological formation that is being developed.

2 I used capital cost and well productivity metrics that result in a well's having an internal rate of return of close to 0 percent, so that its owner would be close to indifferent about developing it, given a cost of capital of 10 percent.

oil or gas well developing the Montney formation in northwestern Alberta requires an upfront investment of $3.8 million.[3] This is the capital cost I assumed for a reference oil or gas well in the following analysis.

Production and Operating Costs

In addition to having widely varying capital costs, wells differ dramatically in terms of their operating costs and productivity. According to the National Energy Board, the typical natural gas well drilled in northwestern Alberta reaches an initial productivity of 3,400 thousand cubic feet (Mcf) per day a few months after drilling, then rapidly declines – this forms the assumed gas production level through time in this analysis.[4] Every month, Alberta Energy produces the average price for natural gas delivered to the market in the province, which is referred to as the par price. I used the average 2016 Alberta-wide natural gas reference price, and assumed that the producer receives that price in every future month.[5] According to the Alberta Energy Regulator (2017), the typical oil well in the most productive region of northwestern Alberta produces around 2,200 barrels of oil in the first month of production;[6] production then drops off dramatically over time, a decline that is modelled in the analysis.[7] As with the analysis for a natural gas well, I computed the monthly gross revenue of an oil well using the Alberta par price for light grade oil in 2016.[8]

The Alberta Energy Regulator also provides estimates of fixed and variable operating costs that allowed me to create a well production and profitability profile for my reference gas and oil wells (Figure 1).[9] By deducting these costs, I constructed monthly gross revenue, cost and pre-tax cash flow estimates for these reference

3 From the wide range of capital costs – $1.4 million to $4.1 million for an oil well, $2.4 million to $6.4 million for a gas well – I chose those of the Petroleum Services Association of Canada well cost study for northwest Alberta and northeastern British Columbia (PSAC 2015) and the Alberta Energy Regulator (2017).

4 In order for a pure natural gas well at this capital cost to be economic, I used an initial production level of 3,600 Mcf per day, and declined the production rate using data from the National Energy Board, available online at https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/01-08mntngswlls-eng.html.

5 I used a reference price of $1.8 per Mcf and assume the well has no other by-products, such as liquids production. Other wells with a mix of natural gas and oil or liquids production will face a combination of policy costs between the two types of wells used in this paper. For the archive of reference prices, see http://www.energy.alberta.ca/NaturalGas/1316.asp.

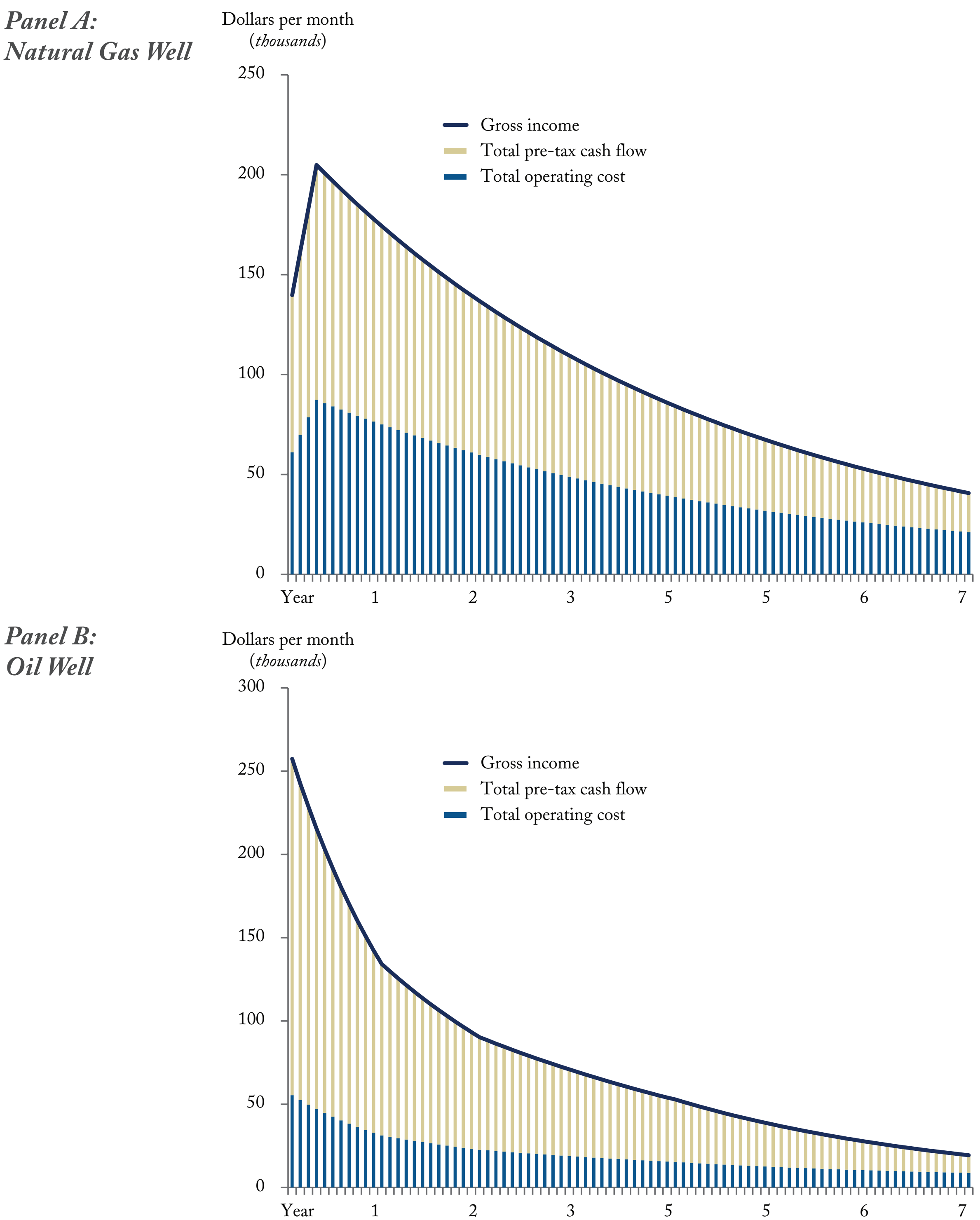
6 To model a well that is just economic, I used one that produces 5,700 barrels in the first month, or around 190 barrels per day. This is a higher level of production than that reported in the Montney in 2016 by the Alberta Energy Regulator, but less than production levels in the nearby Dunvegan area, where initial production has been up to 1,000 barrels per day. See Jaremko (2017). I chose a lower production level to model a barely economic well given a discount rate and cost of capital of 10 percent.

7 I created a monthly production decline value by prorating annual decline rates of: first year, 69 percent; second year, 39 percent; third year, 26 percent; fourth year, 27 percent; fifth year and beyond, 33 percent.

8 Light grade oil is the reference grade for common price benchmarks, such as the West Texas Intermediate (WTI) index. I used a par price of $45 for oil, which is representative of the average price for light oil in Alberta over 2016, a higher price than what oil sands producers fetch for their heavier product. The prices I used do not include the total transportation cost to end markets, only transportation to the local Alberta transportation hub. For Alberta Energy oil par prices, see http://www.energy.alberta.ca/Oil/770.asp.

9 The Alberta Energy Regulator (2017) reports a variable cost of $0.77 per Mcf and a fixed cost of $56,000 per year for gas, and a variable cost of about $9 per barrel and a fixed cost of $60,000 per year for oil. I assumed that these amounts, and revenues, remain constant, and I treated these expenses in real terms.

Figure 1: Natural Gas and Oil Well Production, Cost and Profit Profile, Alberta



Source: Author's calculations, based on data from Alberta Energy Regulator, Alberta Energy, and National Energy Board.

wells. Finally, in presenting a single metric using future values such as cash flow, property taxes and emissions costs, I do so in constant 2016 Canadian dollars in present-value terms using a discount factor of 10 percent, which I also used as a firm's cost of capital. Although this produces only a rough estimate of the well's profitability, it is sufficient for the purposes of this analysis, as the factor of most interest is variations in policy, to which I now turn.

Policy-influenced Factors that Reduce Investment Competitiveness

Taxes on Investment and Royalties

Taxes on a company's profits, investments or oil and gas production increase the cost of investment. A higher cost of investment will result in fewer investments being worthwhile and, thus, lower investment. The ideal way to measure the effect of taxes on a company's decision to invest is through the marginal effective tax rate (METR) on investment. The METR is the measure of the wedge between the rate of return a company needs to earn before taxes to satisfy investors and what it must earn to pay both investors and taxes. For example, if the global gross rate of return that a company expects is 10 percent, but it must earn 12 percent also to be able to pay taxes, the METR is 20 percent ([12%–10%]/10%).

Obviously, taxes paid do not disappear in a vacuum. To the extent that some higher taxes result in better government services, they might offset the competitiveness cost of some policies and positively influence some firms' decision to locate in an area with higher taxes. For a commodity such as oil or natural gas, however, the effect of such better services is unlikely to be a major driver of investment in wells. Further, most services that provinces and the federal government provide directly benefit workers, not firms, and therefore are unlikely to affect the investment decision. In any case, in most METR analyses, it is common to exclude the potential benefits of government services.

The METR in the oil and gas sector has two major parts. First, the combined federal and provincial/state tax system reflects both the statutory corporate income tax rate and other important characteristics, such as how it defines the tax base or special tax breaks or credits. It also includes retail sales taxes that add to the cost of purchasing investments, since companies cannot claim input tax credits on investments as they can using value-added taxes such as the goods and services tax (GST) or harmonized sales tax (HST). Second, extraction-specific taxes that governments, mostly sub-national ones, levy on extraction range from resource royalties set by provinces as the owners of the asset to severance taxes levied by US states (see Box 2).

The two tax systems interact – for example, taxes or royalties that a company pays to one government might be deductible from the taxes it pays to another – so it is best to view the total burden together. According to Mintz and Crisan (2017), Alberta's 2016 METR on energy investment was the highest among the major energy-producing provinces, at 35 percent (Figure 2); recent changes to Alberta's royalty regime, however, have reduced the burden to 26.7 percent.[10] Among US states, Pennsylvania had the lowest overall METR, at 25.9 percent on resource investment, while Texas had the highest, at 36.7 percent.

To obtain a single-dollar figure, I converted the METR into the difference between the pre-tax and post-tax rate of return that companies require. I

10 British Columbia and Saskatchewan also made changes in 2017 that affect the METR on investment, which will be reflected in future updates of this analysis.

Box 2: Corporate Taxes and Resource Royalties

Alberta, British Columbia and Saskatchewan each impose a corporate income tax and a resource royalty on both oil and gas producers. In 2016, the federal corporate income tax was 15 percent and the provincial corporate income tax was 12 percent in Alberta and Saskatchewan and 11 percent in British Columbia. British Columbia and Saskatchewan also levy a retail sales tax, which increases the input costs of producers, increasing METRs. Royalty rates in all provinces vary with the prices of oil and natural gas and factors such as the age, region, depth and productivity of a well. Rates range between 0 and 40 percent.

The US federal government in 2016 imposed a statutory corporate income tax rate of 35 percent, but with various deductions. At the state level, corporate income tax rates are 4.63 percent in Colorado, 4.31 percent in North Dakota and 9.99 percent in Pennsylvania. All of these states levy a (mostly) fixed rate on energy production, known as a severance tax and/or a royalty. Colorado thus has a combined tax of 21.67 percent, North Dakota levies a 10 percent tax and Texas a 4.6 percent tax on oil and a 7.5 percent tax on natural gas. Pennsylvania did not levy a severance tax in 2016.

A number of assumptions underlie the METRs. Mintz and Crisan (2016) assume an oil price of $50 per barrel and an oil well's daily production of 50 barrels per day. However, I used actual average prices of $45 per barrel and production of around 200 barrels per day. US royalty and severance rates are generally fixed, making the METRs less sensitive to assumptions about well productivity or energy prices. I assumed that the market requires a nominal 10 percent rate of return, which is higher than the 5 percent real rate of return that Mintz and Crissan (2016) use, which is a net-of-risk return on capital.

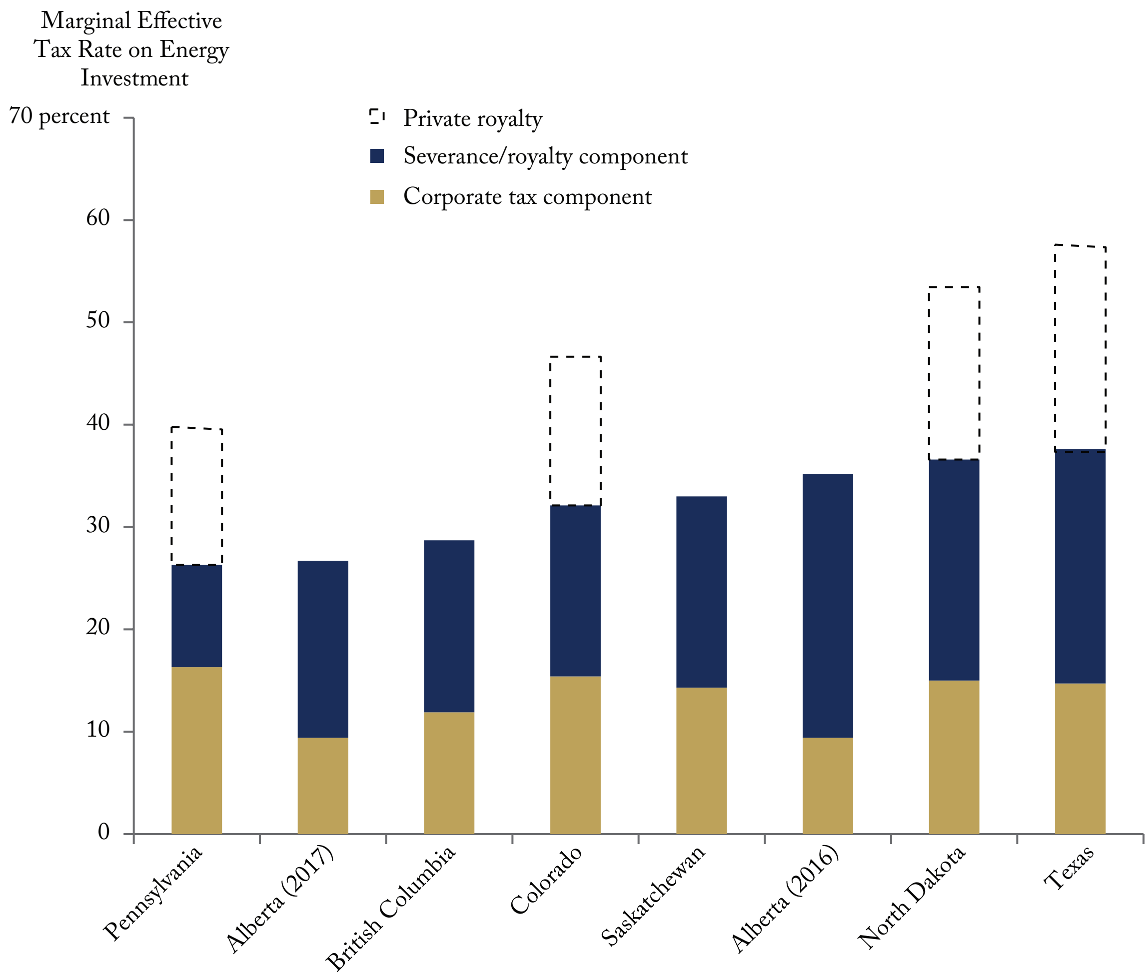
Source: Mintz and Crisan (2016).

assumed that the market requires a 10 percent rate of return (a standard cost of capital in the energy sector), meaning that the actual rate of return companies must obtain ranges from 13.78 percent in Texas to 12.6 percent in Pennsylvania.[11] The policy-induced higher cost of capital is thus between 2.6 and 3.6 percent. Multiplying that higher rate of return by the actual capital cost of the reference wells results in additional capital costs of between $100,000 in Pennsylvania for an oil well to around $200,000 in Texas for a gas well.

Energy producers in the United States often must pay private landowners high costs on top of the royalty and/or severance taxes they pay states. Governments do not influence these costs, however, which are set in a competitive market. In these cases, private landowners can decide to lower their royalties to make their individual plot more

11 I took the 10 percent rate of return and multiplied that by the METR. For Pennsylvania, for example, with a 25.9 percent METR, the calculation of 10 percent times 25.9 results in a firm needing to obtain a 12.59 percent rate of return.

Figure 2: Marginal Effective Tax Rate on Energy Capital Investment, Selected Jurisdictions, 2016



Source: Brown, Fitzgerald, and Weber (2016); Mintz and Crisan (2017).

competitive. One analysis of a database of private royalty agreements (Brown, Fitzgerald, and Weber 2016), produced a preliminary estimate of private royalty rates of 20.0 percent in Texas, 17.1 percent in North Dakota, 13.5 percent in Pennsylvania and 14.8 percent in Colorado. As a first attempt at including these private royalties, I added the private royalty rate to the METR shown in Figure 2. These private royalties make all US states less competitive than Canadian provinces. Private royalties, however, have a high degree of uncertainty about these metrics as well as the limited government control of these costs, which I reflect using hollow shading for private royalty amounts.[12]

Local Taxes

Property taxes are a form of capital taxation. When property taxes are higher than the worth of the services governments provide business, they act to discourage new investment. To assess local tax burdens on the oil and gas industry, I estimated the total per year of property taxes and other location-specific taxes for a typical producing well in emerging, but representative, energy-producing regions in Canada and heavily studied ones in the United States. For example, in the United States, I selected Gaines County, Texas, which has a tax rate in the mid-range among energy-producing parts of the state (Raimi and Newell 2014). In Canada, I used the tax rate in Grand Prairie County, Alberta, at the epicentre of the recent boom in oil and gas production; the rate is in the mid-range of local property tax rates in the province which, including provincial property taxes, are upwards of 30 percent in some rural Alberta municipalities (Figure 3).

Previous C.D. Howe Institute studies have reframed property taxes using the METR method discussed above (see, for example, Found and Tomlinson 2017). Property taxes levied on the oil and gas sector, however, have a number of differences that make it more difficult to incorporate them into a METR model. Thus, I estimated the present value of future local taxes that the owners of the reference oil and gas wells would pay were the wells located in the specific region within each state or province I investigated (see Box 3 for details on local taxes).

Local governments use some of the taxes they collect from oil and gas producers to provide local infrastructure or services, such as roads or local public safety. However, it is difficult to calculate the value of such services, particularly in rural municipalities and counties. Some jurisdictions use taxes to pay for services; others, instead of levying taxes, require companies to source services, such as building and maintaining roads that operators must use to access new well sites. Many companies, however, absorb such expenses on their own to reach the final locations of new wells. I focused only on government costs, not benefits, as these costs are ones that producers have no ability to mitigate by finding more efficient providers, as would be the case if they were required to seek out services such as road construction.

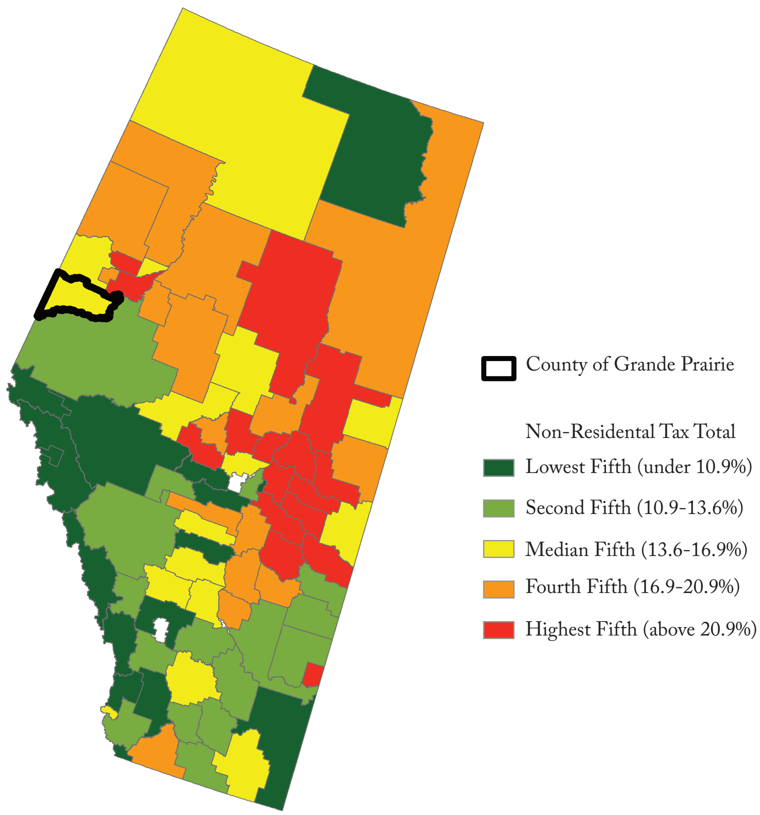
In Canada, producers in Alberta face the highest local tax burden: a present value of between $50,000 and $60,000 in property taxes for a typical well (Figure 4). In the United States, energy producers in many states face much lower, or no, property taxes; in Texas, however, taxes are high: almost $90,000 for a reference natural gas well and $165,000 for an oil well.

Pipeline Delays

Energy producers in Canada sell their product at a price that buyers are willing to pay. End users of energy, however, are often not where the energy was produced. Pipelines are generally the lowest-cost means to transport energy from producing locations to end consumers. Indeed, they are the only economical way of doing so over land for natural gas. Pipelines to deliver western Canadian oil to markets in the United States and abroad have faced repeated delays and cancellations because of policy decisions by governments. For example, the Keystone XL pipeline, which would bring Canadian oil to markets on the US Gulf Coast, originally was to have been completed by 2013, but its approval

12 In particular, these private royalty rates are not entirely consistent with the rest of the METR analysis. Mintz and Crisan (2016) account for the variations in the severance and production tax designs, which I cannot do with private royalties.

Figure 3: Total Non-Residential Property Taxes in Rural Alberta Municipalities, 2016



Source: Canadian Association of Petroleum Producers and AltaLIS

was delayed, and then rejected, by the US federal government, only to be approved by the Trump administration in 2017. Such delays in pipeline construction have meant that less Canadian oil has reached global markets than otherwise would have been the case; for producers, the resulting oversupply of oil in Western Canada has meant lower prices than those in global markets. I used estimates from other studies (Burt and Crawford 2014; Galay and Thile 2017; National Energy Board 2016) that show that, if Canada had built more pipelines in recent years, light oil producers would have received a net price about $5 per barrel higher than they did. At such a price, the discounted present value of cash flow from the reference oil well would have increased by around 15 percent, or $600,000 (Figure 5).[13] As future pipelines are built and the discount producers

13 I assumed, in the without-pipelines scenario, that prices stay constant at $45 Canadian per barrel in real terms, which is consistent with prices seen in 2016 for producers delivering to the Edmonton market and with futures contracts for oil, which project prices similar to those today. In the with-pipelines scenario, I assumed a price of $50 Canadian per barrel. The results in Figure 5 are a simple net present value of future cash-flows.

Box 3: Calculating Property Taxes for Energy Producers

Both local governments and western Canadian provinces charge a property tax. Provinces call it an education tax, but the tax has no relationship to school spending, and businesses pay more than residents. Property taxes range from $20 for every $1,000 of assessed value in the Rural Municipality of Estevan No. 5 (which is representative of energy-producing regions in Saskatchewan) to around $15 per $1,000 of assessed value in the Peace River Regional District in British Columbia and the County of Grande Prairie in Alberta. There is more to a property tax, however, than just the tax rate or the mill rate. Assessment regimes create wide differences between the value of one kind of an asset relative to another. Beyond typical property taxes, Alberta municipalities can also levy taxes on the value of machinery and equipment (a direct tax on capital) and a one-time tax on the depth of a well, a distinct municipal excise tax. For Alberta tax purposes, I assumed that a reference well's value is three-quarters linear property and one-quarter machinery and equipment, which is in line with the overall assessment values of oil and gas assets in the province. I thus calculated property taxes as distinct from taxes on machinery and equipment. I also assumed that a well's depth is 4,000 feet, resulting in a well-drilling equipment tax of $12,780 according to the 2016 tax rules.

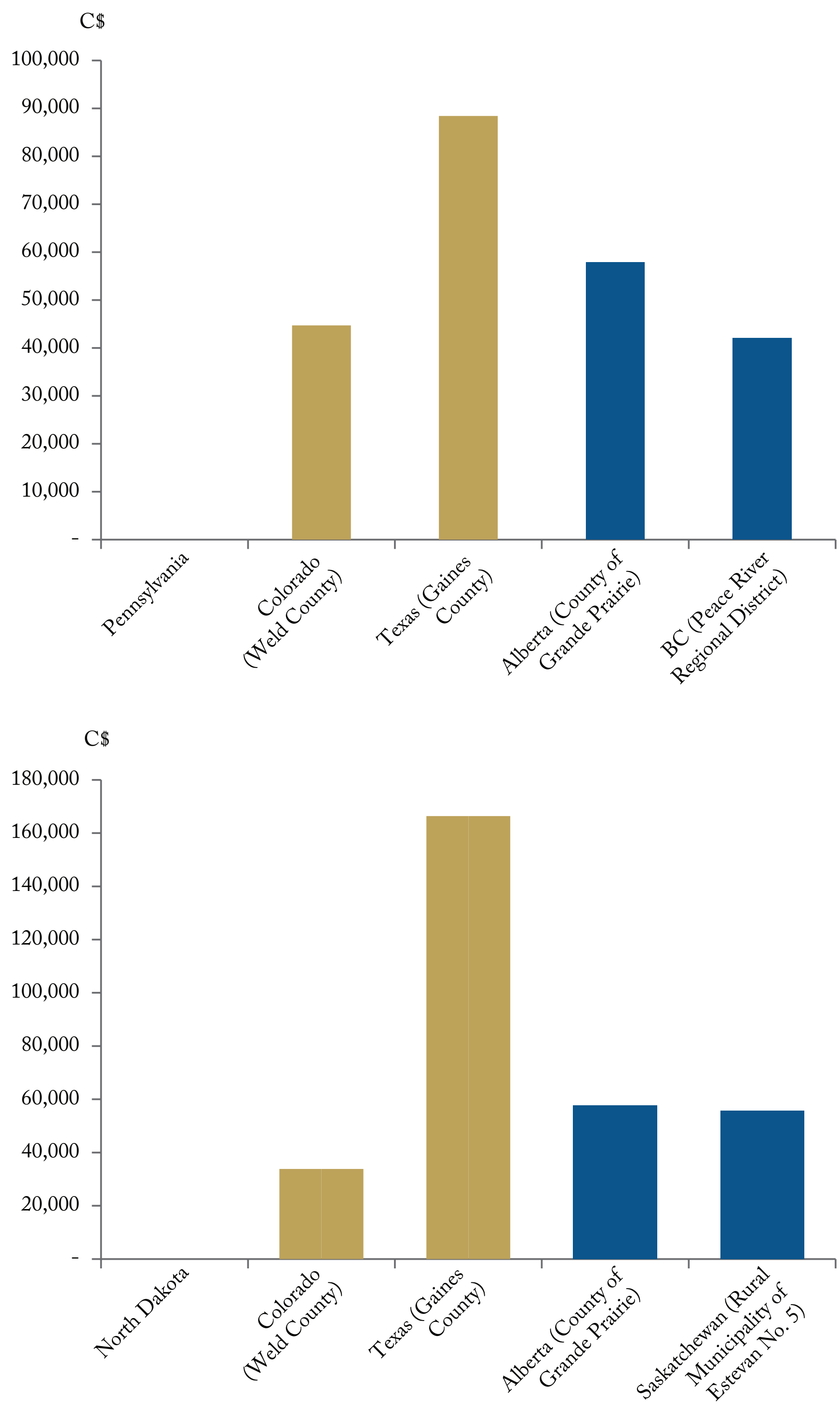
I assumed that the reference wells have an original assessed value of $800,000. This is higher than the average of all wells in Alberta in 2016 – $319,000 for an oil well and $265,000 for a gas well (Alberta 2016a) – as this paper's reference wells are newer and more capital intensive than existing wells. I also assumed that the reference wells have the same value in any other location, which follows the assumption of relocating identical wells across jurisdictions, even if wells in other locations tend to have a lower value than wells in Alberta. To calculate the depreciated assessed value of the wells, I followed provincial assessment guidelines. I assumed that the assessed value falls by 10 percent a year in Saskatchewan and British Columbia to a maximum depreciation rate of 40 percent. For Alberta, I assumed an immediate 25 percent reduction in assessed value in the first year, adding 5 percent a year to a maximum depreciation of 40 percent, as per the province's assessment regime. I added an additional 23 percent reduction for machinery and equipment taxation in all years relative to the original value, as machinery and equipment is taxed at only 77 percent of its assessed value.

In North Dakota and Pennsylvania, local governments are not allowed to levy property taxes on oil and gas production or property. In Weld County, Colorado, the location of most oil and gas activity in the state, the assessed value of a well is 87.5 percent of the gross value of the production from that well in the previous 12 months. That is subject to a tax of around US$57 per $1,000 of assessed value. However, companies can deduct the majority (87.5 percent) of their property taxes from their state severance tax, which I assumed reduces their property tax costs. In Texas, the assessed value of a well is based on its future profitability, for which the assessor follows a set formula that I adopted in my calculations (Texas 2015).

Figure 4: Cumulative Property Taxes over the Life of a Natural Gas and an Oil Well, Selected Jurisdictions

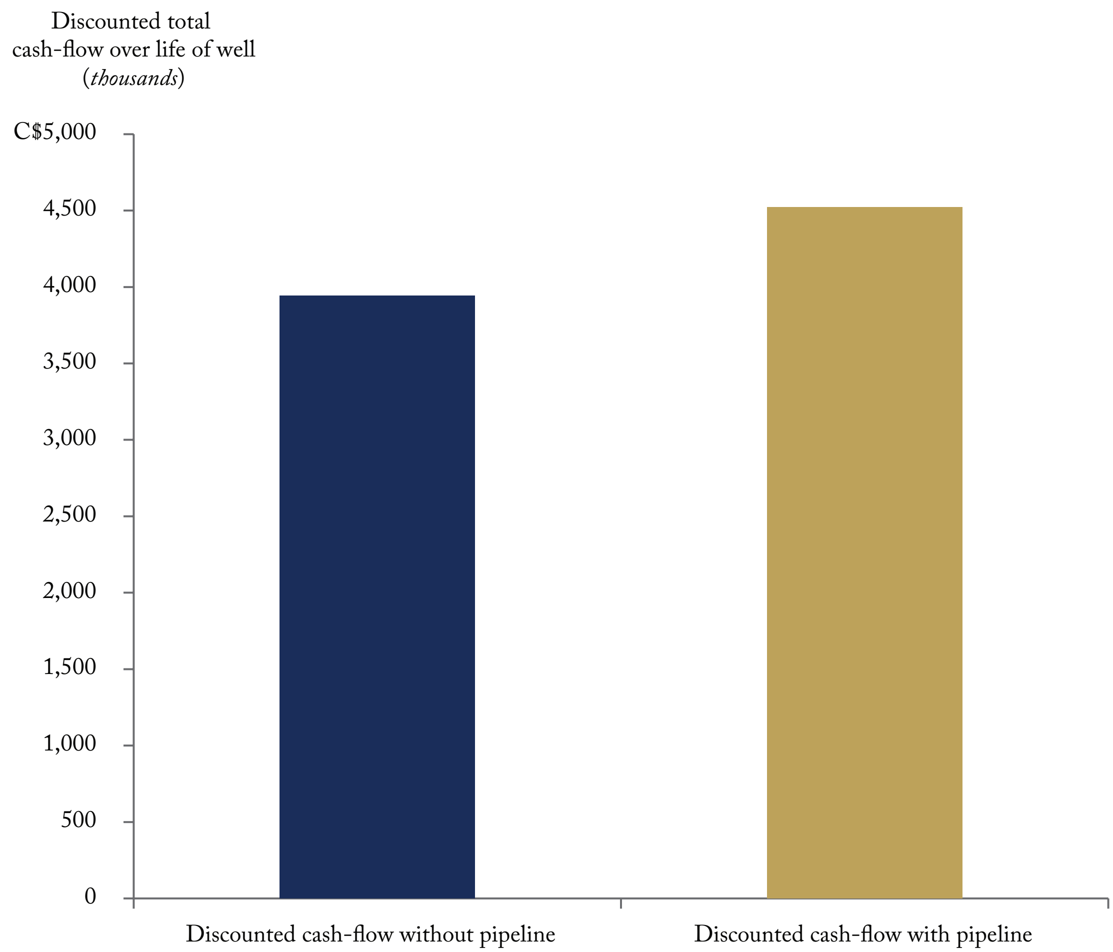
Panel A: Natural Gas Well

Panel B: Oil Well



Source: Author's calculations, from Alberta Energy Regulator, Alberta Energy, and National Energy Board, and local and provincial government websites.

Figure 5: The Effect of Pipeline Restrictions on Discounted Future Cash Flows from an Oil Well



Source: Author's calculations, from Alberta Energy Regulator, Alberta Energy, and National Energy Board, and Burt and Crawford (2014).

receive diminishes, future iterations of this scorecard should show the increase in competitiveness of Canadian energy producers.

Natural gas producers in Western Canada face a similar price discount relative to global markets, but it is less clear that policymakers are responsible for this. The largest single outlet for western Canadian natural gas is Eastern Canada via TransCanada's Mainline pipeline. The National Energy Board has allowed TransCanada to set tolls on the pipeline that allow the company to receive a set rate of return on capital. The pipeline has been running at well below its total maximum capacity, however, with the result that tolls were higher than many producers were willing to bear; in March 2017, TransCanada agreed to cut the tolls by more than half. The alternative shipping option for western Canadian producers would be liquefied natural gas (LNG) exports from the West Coast; that no such project has been built is difficult to ascribe to government policy.

Emissions Costs

Canadian governments have recently taken to introducing a price on GHG emissions. These policies vary from a direct tax on emissions in British Columbia to a carbon levy system in Alberta. The price on each tonne of emissions also varies by province: in 2016, the price in British Columbia was $30, while in Alberta it was only $10; moreover, conventional oil producers in Alberta are exempt from the levy until 2023. The federal government has also announced that it will set a carbon price in provinces that did not introduce their own equivalent carbon price by 2018, starting at $10 per tonne of emissions, eventually reaching $50 per tonne in 2022. In the United States, notably, most energy-producing regions are not subject to any form of GHG emissions pricing.

The price of carbon emissions is, however, only one part of the overall competitiveness effect of emissions pricing on energy producers. Alberta's emissions pricing policy, which is similar to the federal system, rebates producers an amount based on their total output that offsets some of the cost of emissions pricing: starting in 2023, oil companies in Alberta effectively will pay only about 20 percent of total carbon emissions costs, on average. British Columbia, in contrast, offers no such rebate. The types of emissions that are subject to the tax also vary by province – for example, both British Columbia and Alberta charge a carbon price on combustion emissions and emissions from flaring (the burning of flammable gas), but only Alberta is set to levy a price on vented emissions. For Saskatchewan, I assumed that the federal backstop policy applies, with prices slowly increasing from $10 per tonne in 2018. I also assumed that the federal backstop includes the output-based allocation, as in Alberta. I did not include indirect costs, such as increases in electricity pricing, as output-based allocations as designed by Alberta and the federal government will mitigate those costs. Further, British Columbia has few sources of emissions in its electricity sector.

In addition to carbon pricing, Canada and the United States are considering introducing regulations on fugitive methane emissions, which are not covered under any provincial carbon pricing regime and which would impose a large cost on many natural gas wells. Future competitiveness scorecards will incorporate the costs of fugitive emissions policies once those regulations are in force.

Production of oil represents about 12 percent of the total life cycle emissions from a given unit of oil – the end consumption is by far the largest component (Forrest and Rocque 2017). I assumed that the average conventional oil well releases 35 kg of carbon dioxide equivalent (CO_2e) emissions per barrel of oil it produces.[14] For a natural gas well, I took aggregate natural gas production data, well counts and greenhouse gas emissions for 2015 from wells in British Columbia.[15] Assuming that all oil and gas facility emissions in British Columbia are from natural gas production, that results in average

14 This estimate was taken directly from National Energy Technology Laboratory (2009), which provides an explicit estimate for emissions from Canadian conventional oil production. This amount is similar to more recent estimates by Forrest and Rocque (2017), who examine a wide range of North American conventional well emissions estimates but do not analyze Canadian conventional wells.

15 Here I used data from the BC government on well counts, available online at https://ams-reports.bcogc.ca/ords-prod/f?p=AMS_REPORTS:WELLS_DRILLED_BY_STATUS:8666821063193; and industrial facility emissions, available online at http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg.

natural gas well emissions of 134 tonnes of CO_2e per year, excluding fugitive emissions.[16]

I calculated the present value of emissions costs from a typical oil and gas well over a seven-year production period, taking into account the future commitments of governments to increase emissions prices over this time (Figure 6). This total cost does not take into account downstream emissions, such as from refining or transportation. Over the course of seven years, in present-value terms, an operator of an oil or gas well would pay between around $13,000 and $18,000 in emissions costs in British Columbia, a few thousand dollars in net costs or less, after rebates, in Saskatchewan (assuming the federal backstop applies) and nothing in Alberta (as producers there are exempt past the seven-year window in this analysis).

Total Government-influenced Costs

Bringing all the policy variables together points to a few lessons about the relative competitiveness effects of government policies, both between various government policies and across jurisdictions (Table 1 and Figure 7). Among the provinces, oil and gas wells in Alberta faced the largest total competitiveness cost in 2016, but producers in the other provinces had a similar cost. An Alberta oil well encountered around $770,000 in policy-induced costs, while wells in US states faced less than half such costs. This is a major cost compared with the approximately $3.8 million capital investment in the average northwestern Alberta well, and amounts to around $6–7 per barrel – a substantial share of the approximately $50 per barrel that an oil producer would receive on the global market (Figure 7). Natural gas producers, in contrast, face policy-induced costs of around 4–5 cents per Mcf, compared with a market price in 2016 of around $1.8 per Mcf.

Lessons and Recommendations

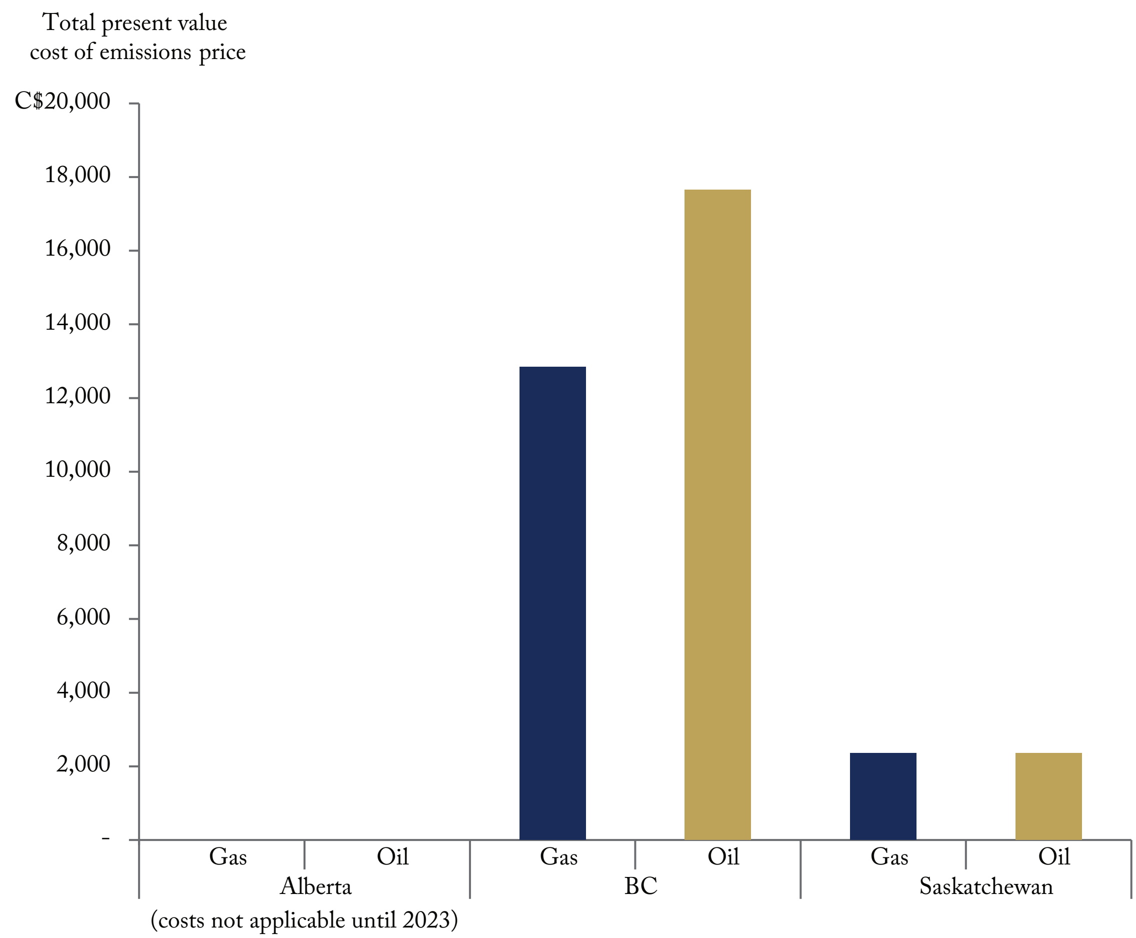
What are the key lessons from this first annual energy sector competitiveness scorecard? First, by far the largest individual competitiveness burden on Canadian energy producers and the main reason for their lack of competitiveness with producers in US states is the restrictions on market access for Canadian oil. The effect of the reduced profits that oil producers receive because of lower prices is larger than that of all other policy variables combined.

Second, the cost of greenhouse gas pricing is a relatively small burden on the competitiveness of energy producers in Canada relative to other polices. They are especially small in jurisdictions with an output-based rebate.

Third, corporate taxes and royalties are the largest policy costs for the natural gas sector and second largest for oil. This is a result both of high marginal effective tax rates in the conventional energy sector and the highly capital-intensive nature of the energy sector. With large upfront investments in the millions of dollars, it is no surprise that taxes on capital have a large total cost. The royalty change that took effect in Alberta in 2017 noticeably improved the competeveness of wells in that province, changing it from the least competitive jurisdiction in Canada to the most competitive,

16 For both oil and natural gas wells, these are total emissions from all sources except fugitive methane emissions, which are not subject to carbon pricing. According to the provincial government Alberta (2016b), combustion emissions from oil wells are 68 percent of total emissions; I assumed that venting is 15 percent and flaring 5 percent of total emissions. For natural gas wells, I assumed that combustion emissions are 39 percent of emissions, flaring emissions are 10 percent and venting 29 percent. I used these shares to estimate total emissions in Alberta and British Columbia that are subject to each province's carbon price. I assumed that the federal backstop system is equivalent to Alberta's system.

Figure 6: Cost of Emissions Policies for Oil and Natural Gas Wells, Alberta, British Columbia and Saskatchewan



Source: Author's calculations, based on data from Alberta Energy and Government of British Columbia.

putting it on par with US jurisdictions for natural gas production.

Fourth, property and local taxes are also a major cost to energy producers in Canada. Property taxes are the major driver of competitiveness differences between the provinces and states, such as North Dakota and Pennsylvania, that do not levy property taxes.

Finally, aside from the economic cost of the inability of Canadian oil producers to bring their products to global markets, the provinces are actually quite policy competitive, and would be within reach of having the most competitive policy regime for energy producers if they were to take a few steps to improve the competitiveness of local producers. Once problems of market access are solved, governments should continue to monitor the provinces' policy competitiveness and ensure that new policy costs do not reduce the competitiveness of Canada's energy sector, particularly in light of recent US tax reforms.

Table 1: Total Policy-induced Cost to Natural Gas and Oil Wells, Selected Jurisdictions

Policy-induced Cost	Alberta	British Columbia	Saskatchewan	Texas	North Dakota	Colorado	Pennsylvania
	Natural Gas Well *Total cost per well (C$ thousands)*						
Taxes and royalties	133	109		139		120	98
Private royalties				76		56	51
Property and local taxes	58	42		88		45	
Emissions costs		13					
Total cost	**191**	**164**		**304**		**221**	**150**
	Oil Well *Total cost per well(C$ thousands)*						
Taxes and royalties	134		125	140	136	120	
Private royalties			76	65	57		
Property and local taxes	58		56	166		45	
Emissions costs	1		2				
Pipeline delays	581		581				
Total cost	**773**		**764**	**383**	**202**	**222**	

Source: Author's calculations from sources described above.

Canadian governments could limit the effects on competitiveness of property taxes, emissions costs, corporate income taxes, royalties and pipeline delays by undertaking a number of important steps, as follows.

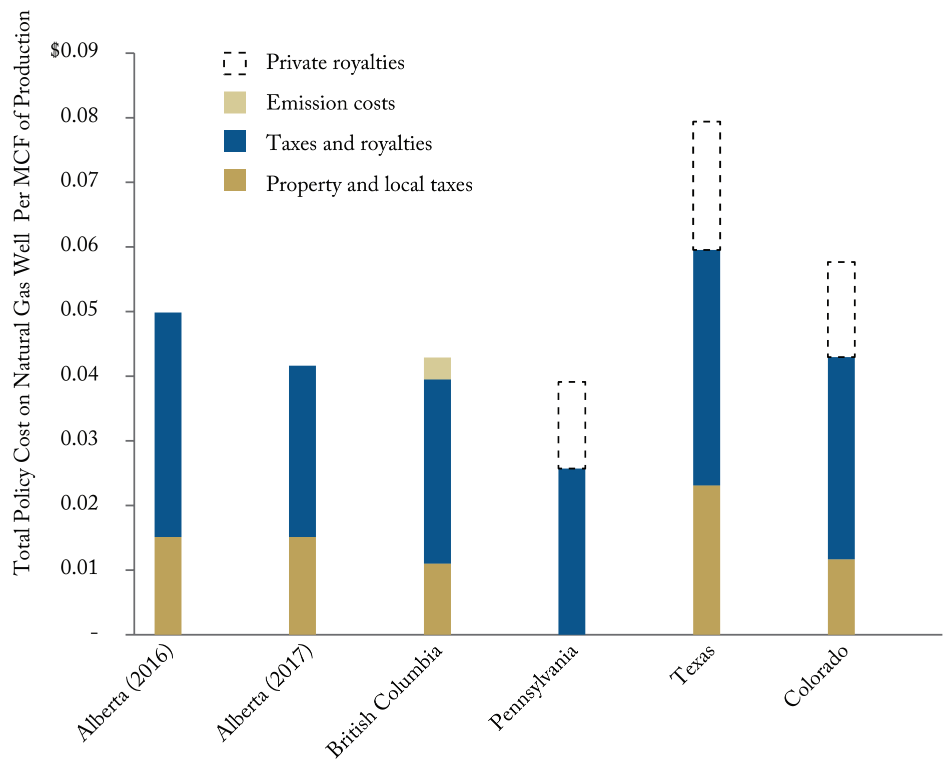
Build Pipelines

Lack of market access is a key problem for Canadian energy producers. As of 2017, the federal government had approved three major pipeline expansions (one each from Kinder Morgan, TransCanada and Enbridge). These pipeline expansions will likely satisfy the production needs of Western Canada through to the end of the next decade. Construction has yet to start, however, on any major pipeline expansion due to procedural hurdles. These hurdles are likely the largest competiveness cost for Canadian oil producers relative to US producers. The federal government should ensure that the projects it has approved as being in the national interest are not bogged down by further procedural delays.

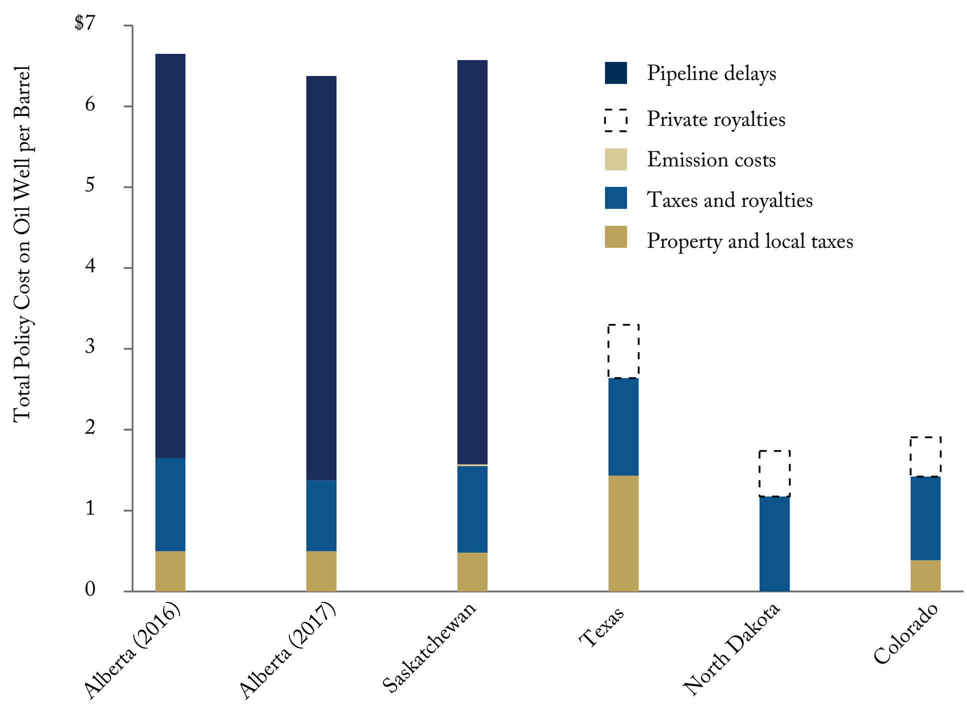
TransCanada announced in October 2017 that it would not proceed with its Energy East proposal to ship western Canadian oil to the Maritime provinces. The case for Energy East was weakened by the decline in global oil prices since 2014 and the precipitous fall in the forecast for western Canadian oil production: the Canadian Association of Petroleum Producers' forecast for production by 2030 has declined by more than 2 million barrels per day in that time (Leach 2017). TransCanada's decision, however, was also based on the expectation

Figure 7: Cumulative Competitiveness Cost of Government Policies on a Natural Gas Well and an Oil Well, Selected Jurisdictions

Panel A: Natural Gas Well

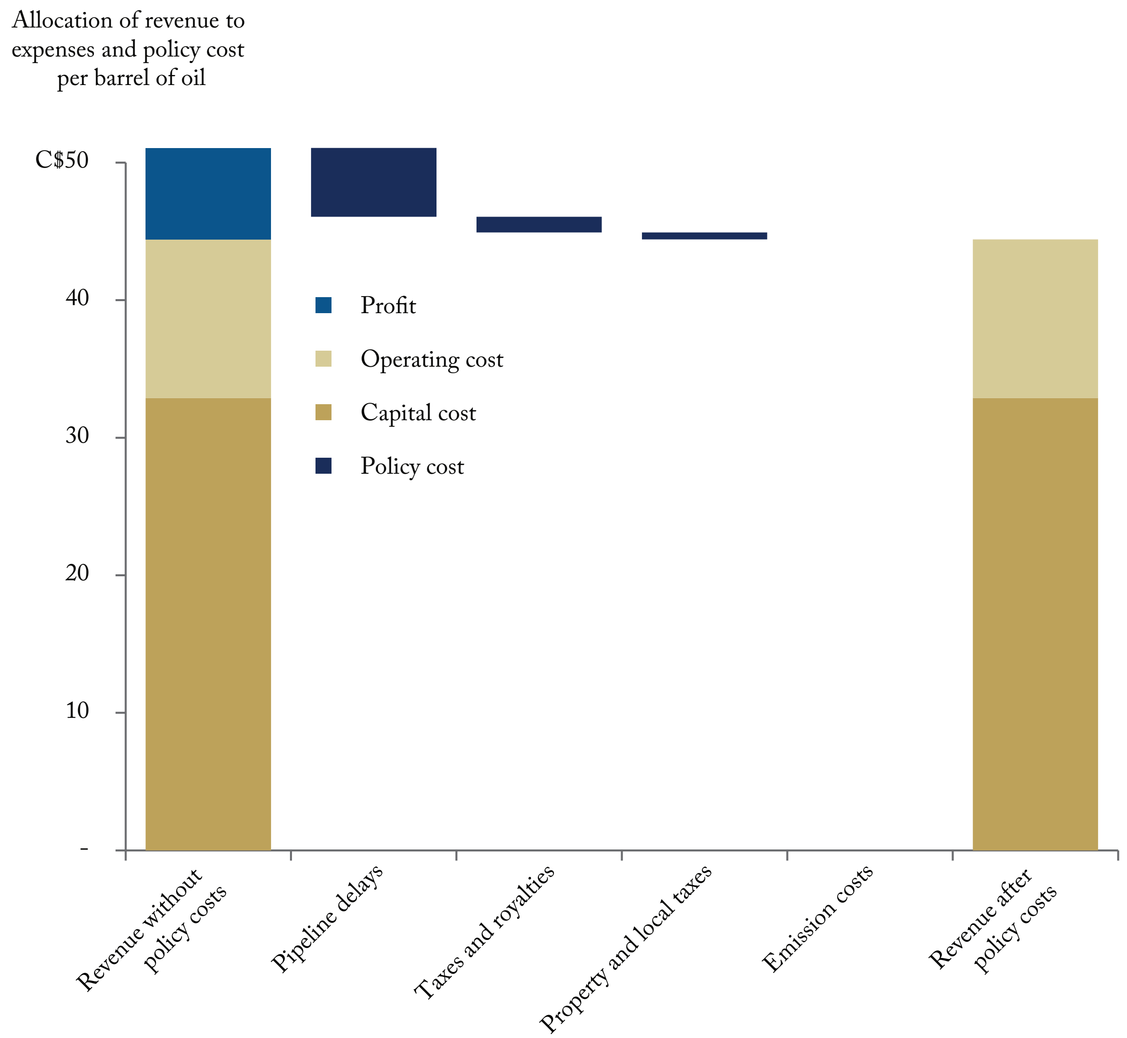


Panel B: Oil Well



Source: Author's calculations from Alberta Energy Regulator, Alberta Energy, and National Energy Board.

Figure 8: Revenue and Policy Cost per Barrel from an Alberta Oil Well Drilled in 2016



Source: Author's calculations from Alberta Energy Regulator, Alberta Energy, and National Energy Board.

that other approved pipelines will be completed, which is still not certain. If they are not built, oil producers in Western Canada will face severe competitiveness challenges relative to producers elsewhere.

Reduce Investment Taxation

One of the largest costs energy producers face is the current gross revenue royalties they pay to provincial governments in Western Canada. Accordingly, these governments could take the key step of replacing gross revenue royalties with modern cash flow royalties. Alberta recently embarked on a major change in its resource royalties and adopted some of the international best practices of cash flow tax design. In so doing, the province was able to reduce the tax bite on investment and improve its competitiveness without necessarily reducing its total revenue take from energy producers.

Cash flow royalties apply only to companies after they have recouped their all-in cost of production – for details, see Boadway and Dachis (2015). A well-designed cash flow royalty allows companies to deduct fully their exploration and development costs and to carry deductions forward at the long-term government bond rate. Alberta has adopted such a system, which appreciably reduced its policy-induced costs between 2016 and 2017, and should not pursue any changes to its system in the near-term as companies digest the recent changes. Other western provinces should consider changing their royalty regimes to reflect these best practices. Most important, governments can collect the same or more revenue from a cash flow royalty than from a gross revenue royalty without affecting the competitiveness of energy producers. A cash flow royalty should apply only to profits over and above a threshold rate of return, and would sidestep competitiveness concerns since firms could earn a normal rate of return on their investments.

Similarly, the federal government – and Alberta, which administers its own corporate income tax – should consider replacing its corporate income tax with a tax that reflects the same principles of a cash flow royalty or an allowance for corporate equity. Such a move would have a number of benefits for the energy sector. First, it would reduce the capital cost of investment, which is especially important now that the United States has reduced taxes on businesses (Mintz and Crisan 2017). Second, by instituting an allowance for corporate equity, the federal government could put all sectors of the economy on a more level playing field by not treating some kinds of capital investment for tax purposes more favourably than others (Boadway and Tremblay 2016). For example, the energy sector receives deductions that are analogous to capital cost allowances through the Canadian Exploration Expense and the Canadian Development Expense, which Ottawa regards as subsidies. Rather than try to fine-tune such policies, a better approach would be to replace all such deductions and capital allowances and allow all firms in all sectors to deduct capital expenses at once.

Another option for the western provinces – in particular British Columbia and Saskatchewan – is to lower their taxes on investment by reforming their provincial sales taxes. These taxes have a cascading cost on investment, unlike value-added taxes such as the GST or HST. As suggested by British Columbia's Commission on Tax Competitiveness (British Columbia 2016), these provinces should start by exempting business capital expenditures and by considering broader reform such as a full exemption for businesses or adopting provincial-level value-added taxes.

Reduce Local and Provincial Property Taxes

Most measures of the tax burden on investment do not include the cost of local or provincial property taxes. Part of the reason for this exclusion is that collecting comprehensive information about tax rates, assessment regimes and related information is extraordinarily difficult. According to Found and Tomlinson (2017), business property taxes represent about two-thirds of the total tax wedge on investment in the largest cities in each province; as Figures 6 and 7 also show, property taxes are a major burden on energy investors.

The provinces label their property taxes as education taxes, but in reality they are general revenue taxes (Found and Tomlinson 2017). These should be reduced. Municipal taxes are a greater problem. In many parts of Alberta, the ratio of business tax rates to residential tax rates is more than 5:1 – in the Fort McMurray area it is nearly 18:1, and in one county it is 25:1. Ontario has imposed a maximum ratio of municipal residential property tax rates to non-residential property tax rates; the western provinces should do likewise. Recent reforms to Alberta's *Municipal Act* have resulted in a maximum cap of 5:1 in that province; this ratio should gradually be reduced still further.

Obviously, municipal governments need revenues to finance local services from which oil and gas companies benefit – for example, the roads companies use to reach well sites. These roads are subject to considerable damage, however, by the heavy trucks companies use to bring equipment to the well sites. The solution is for municipalities to be able to charge tolls based on the damage vehicles cause, rather than blunt instruments such as Alberta's Well Drilling Equipment Tax, which uses depth of well as a proxy for the weight of equipment heading to a site (Dahlby and Conger 2015).

Many regional municipal governments in Alberta are rural and have few residents in their taxing jurisdiction; their main source of property tax revenues is oil and gas properties. Governments of the urban areas where the workers who service the wells live charge their residents property tax. These same workers then travel to another, rural jurisdiction, using services – such as protective and other services that cannot be fully financed from user fees – provided by local governments to which they pay no tax. The solution is for urban and rural municipalities to enter into more service-sharing agreements, so that services for workers that must be provided in rural areas with few residents are partly paid for by residential taxes in urban jurisdictions (Spicer and Found 2016). The result would be lower taxes in rural areas and better matching of those who benefit from government services with those who pay for them.

The problem with property taxes goes beyond high tax rates. In Alberta, because of the complexity of the assessment regime – which has a number of highly prescriptive assessment and depreciation rules that can be costly for companies to understand – otherwise similar properties fall into different property tax classes based on the whim of a local government assessor. Alberta has two main property classes – machinery and equipment and linear property – and the boundaries of what kind of property falls into one tax class or the other are often unclear. As of January 2018, however, the province has centralized the assessment of industrial properties; this should reduce differences in assessments from one municipality to another and ease some of the administrative burdens of property taxation.[17]

Reduce the Competitiveness Cost of GHG Emissions Policies

Finally, although the competitiveness cost of GHG emissions policies is relatively small, they are still worth examining through the lens of competitiveness. British Columbia was the first province to introduce a carbon tax, and used the revenues to reduce corporate and personal income taxes, which in turn reduced the tax burden on new investment. The province has since raised corporate income taxes, however, and the new government plans to move away from the original plan to reduce corporate and personal taxation in line with carbon tax revenue. This will disadvantage gas producers in British Columbia relative to those in Alberta and, once the federal backstop system is in place, those in Saskatchewan and especially in the United States.

Producers in Alberta face a lower competitive disadvantage than those in British Columbia because, although they pay the full cost of their own emissions, they receive a credit per unit of output, with the amount of the credit based on a provincial

17 See Alberta, Municipal Affairs, "Centralized Industrial Property Assessment," available online at http://www.municipalaffairs.alberta.ca/centralized-industrial-assessment.

average emissions benchmark. Companies still have a strong incentive to reduce their emissions – indeed, companies with below-average emissions are better off in this system. British Columbia should adopt a similar system.

Conclusion

Government policies are reducing the competitiveness of Canadian energy producers relative to producers – especially of oil – in the United States. Although other factors also affect an energy-producing region's competitiveness, governments should recognize the cumulative competitiveness cost of their policies. Policymakers now need to take steps to ensure that approved new pipelines get built and to reduce the burden of corporate income, royalty, property and GHG emissions taxes.

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