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TAXING CANADA'S CASH COW: TAX AND ROYALTY BURDENS ON OIL AND GAS INVESTMENTS

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SUMMARY

This paper addresses in depth the impact of both corporate taxes and royalties on the decision to invest in the oil and gas sector for British Columbia, Alberta, Saskatchewan, Nova Scotia and Newfoundland & Labrador and in comparison to Texas. Similar to Chen and Mintz (2009), we estimate the marginal effective tax rate on capital for the oil and gas sector, comparable to other sectors in the economy. In our assessment, we include federal and provincial corporate income taxes, sales taxes on capital purchases and other capital-related taxes in our assessment such as severance taxes and royalties. Except for oil and gas investments in Nova Scotia and Newfoundland & Labrador offshore developments, oil and gas investments bear a higher tax burden compared to other industries in Canada. In other words, oil and gas investments are generally not "subsidized" but bear a higher level of taxes and royalties on investment compared to other industries.

* We wish to thank two anonymous referees and Robert Mansell for comments. Other comments were received at a seminar held at the University of Calgary and from numerous others who provided assistance or reaction at different stages of the work.

INTRODUCTION

Energy is on the front burner of political discussions today given its centrality in our everyday activities and its impact on the environment. Canada's oil and gas sector is responsible for a significant share of business activity and of revenues paid to governments. In any assessment of public policy, therefore, it is crucial to know just how much government tax and royalty policies affect the investment decisions the oil and gas industry makes relative to those of other sectors of the economy. Treating oil and gas investments differently than other investments would undermine Canada's productivity and competitiveness by shifting resources to sectors that bear lower relative tax burdens. It is also important to coordinate the impact on the oil and gas sector of tax and royalty regimes, which impinge on the rents paid to the provinces as resource owners.

In this paper, we conclude that oil and gas investments generally bear a higher tax and royalty burden than do investments in other industries, the exception being the Atlantic offshore investments that are favourably treated under the Nova Scotia and Newfoundland and Labrador royalty structures and the federal corporate income tax.

One might criticize our including royalties in our estimate of the marginal burden on investments since these are payments to provincial governments to exploit oil and gas deposits that the provinces own. In principle, the Crown receives a royalty as its share of the rents — that is, income earned in excess of the economic cost of exploration, development, and extraction — from public oil and gas resources.[1] On marginal investments, rents are zero since the return on capital, net of taxes and royalties, is just equal to the cost of capital. On investments that are not marginal, rents are earned since the return on capital exceeds the cost of capital. If rents are positive, the business will keep investing in capital until the marginal rent is zero.

As we show, however, oil and gas royalties in Canada are not true rental payments, and so they distort oil and gas investment decisions and reduce the rents that otherwise could be earned. If the royalty were structured properly to maximize rents shared by governments and private producers, marginal investment decisions would be unaffected. With a pure rent tax — such as the pre-2009 Alberta royalty on oil sands — the royalty burden on marginal investment projects would be zero since rents are zero (except for any potential interactions with other taxes). Poorly structured royalties, however, impose a fiscal burden on new investment projects and, therefore, should be included in any assessment of their fiscal effects on capital decisions.

[1] The economic cost of a project is equal to the income paid to factors of production, including employee compensation, and competitive returns paid to attract both debt and equity financing from owners (for example, borrowing costs and the imputed cost of equity). Note that capital expenditures are equal to the time value of true depreciation and financing costs of capital.

In this paper, we use a new methodology that takes into account the time used to explore and develop a deposit before it can be exploited for production purposes.[2] We assess the full impact of both taxes and royalties on the decision to invest in the oil and gas sector in Alberta, British Columbia, Newfoundland and Labrador, Nova Scotia, Saskatchewan, and the US state of Texas by estimating the *marginal effective tax and royalty rate* (METRR) on capital.[3] This estimate is based on measuring the annualized value of taxes and royalties paid as a share of the pre-tax profits earned on investments for projects that earn just enough income to attract investor financing from international markets. We include federal and provincial corporate income taxes, sales taxes on capital purchases, and other capital-related levies such as severance taxes and royalties. We do not include property levies, given the lack of data available by sector and province.

Our results are quite striking and can be grouped specifically as follows:

- Except in Nova Scotia and Newfoundland and Labrador offshore developments, oil and gas investments bear a higher fiscal burden than those in other industries. In other words, oil and gas investments generally are not "subsidized" but bear a higher level of government levies, largely as a result of poorly designed royalty systems, than do other industries.
- Since royalties on conventional oil and gas are applied at relatively high rates on revenues without any deduction for costs, they tend to discourage investments in conventional oil and gas relative to non-conventional projects. The highest fiscal burden on marginal conventional projects is in Alberta, followed by those in Saskatchewan and British Columbia. The burden is higher in Saskatchewan than in British Columbia in part because the latter is harmonizing its sales tax with the federal goods and services tax (GST) and thereby removing significant taxes on business purchases of capital.
- Alberta's oil sands investments are subject to a lower fiscal burden than conventional oil and gas investments because the royalty regime provides for an explicit deduction of costs from the base.
- Marginal investments in oil and gas in Newfoundland and Labrador and Nova Scotia bear a very low tax and royalty burden — in fact, they obtain a fiscal subsidy with a "negatively" measured burden — due to both a royalty structure that provides excessive deductibility for investment costs and the federal Atlantic investment tax credit.
- Conventional oil and gas investments in Alberta are subject to a higher fiscal burden than those in Texas when royalty payments to private owners in that state are treated as a tax similar to Alberta's conventional oil and gas royalties.

[2] Jack Mintz, "Measuring Effective Tax Rates for Oil and Gas in Canada," Technical Paper (Calgary: University of Calgary, The School of Public Policy, 2009).

[3] This methodology is similar to that used in Duanjie Chen and Jack Mintz, "The Path to Prosperity: Internationally Competitive Rates and a Level Playing Field," *C.D. Howe Institute Commentary* 295 (Toronto: C.D. Howe Institute, 2009).

- In the absence of royalties, the oil and gas sector bears a lower tax burden than do non-resources sectors. This is largely due to the expensing of exploration costs, which is a significant capital expenditure for oil and gas companies. For tax purposes, exploration costs are treated similar to research and development expenditures, as both enable companies to capture the return on investments that create knowledge for other companies.[4]

Royalty systems and taxation, in short, should treat investments in the oil and gas sector the same as investments in other sectors if the allocation of resources in the economy is not to be distorted. Governments should also restructure their royalty systems to improve their efficiency as rent-collecting devices. Royalties should be applied, however, as rent levies on oil and gas production. Such rent royalties could be easily implemented if they were applied to cash flows, whereby companies deduct current and capital costs from revenues (but no deduction should be given for borrowed money costs since capital expenditures are fully deducted). Any unused deductions could be carried forward by an investment allowance that reflected the cost of riskless investments, since governments already share the gains and losses on investments under the royalty structure. This system — similar to the royalty Alberta applied to oil sands development prior to 2009 and that British Columbia applies to mining — is an ideal rent tax.

EXISTING CORPORATE TAX AND ROYALTY STRUCTURES

Canadian oil and gas businesses pay taxes and royalties to all levels of government. In 2009 corporate income taxes were levied on resource profits at a rate of 19% at the federal level (scheduled to decline to 15% by 2012) and at provincial rates of 10% (Alberta and British Columbia), 12% (Saskatchewan), 14% (Newfoundland and Labrador), and 16% (Nova Scotia).[5] Similar to the treatment of other industries, deductions from income are provided for depreciation, inventory, borrowing, and other costs incurred to extract resources, including provincial royalty payments. Exploration and development costs are also deducted from profits — expensed in the case of exploration costs, and written off at a 30% declining balance rate for development costs. In the Atlantic region, the oil and gas sector, similar to other primary, resource, and manufacturing industries, is eligible for the 10% federal Atlantic investment tax credit for qualifying depreciable expenditures.

Provinces collect royalties from private producers as payments for the use of oil and gas deposits the provinces own. Historically, royalties have been assessed as a percentage of gross revenues received from extracting conventional oil and gas, with royalty rates rising with price and daily volume as a rough way to assess payments according to profit margins that are sensitive to prices and costs. Since rates vary according to volume, we take as one benchmark a well that produces 80 barrels per day, which implies a royalty rate in 2009 on conventional oil revenues equal to 23.85% in British Columbia and 22.0% in Saskatchewan.

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[4] See Technical Committee on Business Taxation, *Report* (Ottawa: Department of Finance, 1998).

[5] We focus on 2009 and any legislated 2012 METRRs since upcoming federal and provincial budgets likely will lead to some tax rate revisions in 2010.

In Alberta, the royalty rate on such a well varies with the price of oil, which, based on five-year historical data, is an average of $72 with a statistical variation of $22 around the average — that is, prices equal to $50 and $95 — so that the 2009 royalty rates for conventional oil at these three prices are 29%, 40%, and 47%, respectively. A similar approach is used to assess royalty rates on conventional natural gas from wells that produce 600 thousand cubic feet per day.[6] On the oil sands, Alberta applies a royalty on the rents (or net profit) of the project when payout begins (otherwise a minimum tax is levied). Before 2009, a single rate of 25% was applied on revenues net of current and capital costs, with a small minimum tax on gross revenues if the net revenue tax was not paid. Unused deductions could be carried forward at the government bond rate to preserve the time value of the deduction. Now, however, the oil sands royalty rate varies by price, with a rate of 25% applying on prices below $55 per barrel, rising to a maximum of 40% at $120 per barrel.

In the offshore Atlantic region, royalties on oil and gas production are assessed by the Newfoundland and Labrador and Nova Scotia governments. These royalty structures are considerably more complex than that in Alberta, with different rates applying to net profits according to various tiers that are determined by the value costs carried forward from earlier stages.

In Newfoundland and Labrador, the offshore generic royalty (on all oil and gas projects except Hibernia and Terra Nova) has two parts: a basic royalty on gross revenues (net of transportation costs) at rates rising from 1% to 7.5% as cumulative production rises, and a net royalty after accumulated unused deductions for operating costs, capital costs, successful exploration costs, the basic gross royalty and the return allowance are exhausted. The return allowance is an "interest" rate by which unused deductions are carried forward, and is equal to the long-term government bond rate plus an additional 5 or 15 percentage points to determine the next tier of royalty payments assessed at higher rates. Effectively, the allowance is in excess of the marked interest rate that would be used to preserve the time value of expensing capital costs and, hence, delays the time by which a net royalty is paid once unused deductions are exhausted, in part, as a result of some pre-production costs not being fully deducted from the royalty base. The first-tier net royalty rate is 20%, and is applied to net revenues once the payout begins after unused deductions are exhausted, based on a return allowance equal to 5 percentage points plus the long-term government bond rate applied to unrecovered costs. The basic royalty on gross revenues is credited against the first-tier net royalty. The second-tier net royalty rate is 10% (added to the 20% first-tier rate), and is applied to net revenues based on a return allowance equal to 15 percentage points plus the long-term government bond rate (and therefore incremental to the first-tier royalty, resulting in a potential royalty rate of 30% on net revenues). The royalty rate therefore rises as the return on capital invested in the project rises.

[6] We also consider smaller wells in assessing royalty rates. A number of incentive programs are used to reduce royalty payments, but most are subject to limits and so are not important at the margin or are in place only temporarily, and we do not include them in our calculations of METRRs. We also do not include the accelerated capital cost deduction under the corporate income tax for oil sands projects that is being phased out.

Nova Scotia also uses a profit-sensitive approach, but it differs from that of Newfoundland and Labrador in that the federal investment tax credit reduces project costs, eligible costs include past royalties paid to determine the computation of the project payout (but not the net revenue), and the return allowance is not compounded. Nova Scotia's generic regime (which does not apply to either the Cohasset-Panuke or Sable Offshore Energy Projects) has four tiers. The first tier is a 2% royalty applied to gross revenues. The second tier is a 5% royalty applied to gross revenue once accumulated revenues are in excess of accumulated operating and capital project costs and the non-compounded rate of return allowance, which is equal to the long-term bond rate plus 5%. The third tier is a 20% royalty on net revenues once unused operating and capital costs, carried forward on the long-term government bond rate plus 20%, are exhausted. The fourth tier is similar to the third except that unused deductions are carried forward at the long-term government bond rate plus 45%.

MEASURING THE METRR

To measure the effect of taxes and royalties on investment decisions in the oil and gas sector, we calculate the marginal effective tax and royalty rate as the amount of taxes and royalties paid as a percentage of the pre-tax-and-royalty return on capital that would be required to cover taxes, royalties, and the financing of capital with debt and equity. For example, if a business invests in capital that yields a pre-tax and royalty rate of return equal to 10% and, after taxes and royalties, a rate of return equal to 6%, then the METRR is 10% minus 6% divided by 10%, giving a result of 40%.

It is important to understand that the METRR does not provide an estimate of the overall taxes and royalties governments collect, since those amounts depend on both the marginal and inframarginal returns that projects earn. Rather, the METRR is a benchmark with which to determine the effects of taxes and royalties on investment decisions.

The unique aspect of our work is its accounting for the time taken to develop oil and gas projects before they are available for extraction.[7] There are two stages of production. The first is an exploration and development phase to discover reserves and make them available for extraction; in this stage, the analysis is based on a flow of inputs to develop a reserve available for production of oil and gas — a "time-to-build" analysis. The second stage of production — the extraction phase — depletes the discovered reserves until exhaustion.[8]

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7 Our modelling follows that found in Robin Boadway, Neil Bruce, and Jack Mintz, "Taxation, Inflation and the Effective Marginal Tax Rate on Capital in Canada," *Canadian Journal of Economics* 17 (1, 1984): 62-79; Robin Boadway et al., "Marginal Effective Tax Rates for Capital in the Canadian Mining Industry," *Canadian Journal of Economics* 30 (1, 1987): 1-16; Jeffrey Mackie-Mason and Jack Mintz, "Corporate Taxation and the Building of Capital: Implications for Expensing and Capitalization of Costs" (mimeographed, University of Toronto, 1991); and Kenneth J. McKenzie, Mario Mansour, and Ariane Brûlé, "The Calculation of Marginal Effective Tax Rates," Working Paper 1997-15 (Ottawa: Department of Finance, 1997). For details, see Mintz, "Measuring Effective Tax Rates for Oil and Gas in Canada."

8 The "time-to-build" analysis results in a higher cost of capital for a company since its income is earned after spending has taken place for a period of time. Tax payments are affected since tax deductions for exploration and development spending are taken prior to income being earned when the resource is exploited. 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.

To derive the METRR for resource companies, we include exploration, development, depreciable capital, land, and inventories. The analysis is based on calculating the present value of income earned from projects that yield an annualized rate of return on capital. The gross-of-tax-and-royalty rate of return on capital is equal to the inflation-adjusted cost of financing capital (taking into account interest deductibility), adjusted for taxes. The net-of-tax-and-royalty rate of return on capital is equal to the weighted average of the interest rate for debt and the imputed cost of equity finance provided by savers to fund the investment. The tax and royalty the business pays is the difference between the gross-of-tax-and-royalty rate of return on capital and the net-of-tax-and-royalty rate of return on capital. The METRR on capital is equal to the tax and royalty paid divided by the gross-of-tax-and-royalty rate of return on capital.[9] The analysis includes federal and provincial/state corporate income, capital, and sales taxes, as well as provincial royalties. We also take into account various features of taxes, such as the valuation of inventories, capital cost allowances, statutory tax rates, and the Atlantic investment tax credit.

THE TAX AND ROYALTY BURDEN ON THE OIL AND GAS SECTOR

As part of our assessment of the tax and royalty burden on the oil and gas sector in producing provinces, we examine by way of contrast the situation in a significant competing jurisdiction, Texas. In that state, oil and gas deposits are owned privately, and royalties are collected as a share of production revenues, in a structure similar to government royalties on conventional oil and gas in Canadian provinces.[10] The US federal and Texas state governments collect corporate income and severance taxes on oil and gas production, with the severance tax applying on a base similar to the conventional royalty.

Below, we provide various estimates of METRRs to which we refer throughout the next several sections. Tables 1 and 2 provide estimates of METRRs for conventional and unconventional oil projects for 2009 and 2012 in Alberta, British Columbia, Saskatchewan, Newfoundland and Labrador, Nova Scotia, and Texas under various assumptions regarding price, volume, and other relevant parameters for the oil industry, while Tables 3 and 4 provide corresponding estimates for METRRS pertaining to the natural gas industry.

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[9] The specific formulas used to derive the effective rates are provided in Mintz, "Measuring Effective Tax Rates for Oil and Gas in Canada."

[10] One might also argue that Canadian provincial royalties are consistent with observed contractual ones in the private sector and, therefore, should not be viewed as part of the fiscal burden on investments. We take the view, however, that governments have greater ability to assess royalties on a base that allows for the deduction of costs.

Table 1: Marginal Effective Tax and Royalty Rates for Oil, Selected Jurisdictions, 2009

	MARGINAL EFFECTIVE TAX AND ROYALTY RATE (METRR)			MARGINAL EFFECTIVE Tax Rate (METR)	Non-resource METR[d]
	Oil Price: $50/bbl	Oil Price: $72/bbl[a]	Oil Price: $95/bbl		
	(percent)				
Alberta, conventional oil	35.1	41.1	44.6	7.8	20.5
Alberta, oil sands	22.2	23.6	25.6	15.1	20.5
British Columbia	31.6	29.0	27.8	9.1	29.5
Saskatchewan	34.3	31.9	30.8	13.6	26.7
Newfoundland and Labrador[b]	–3.9	–3.9	–3.9	–2.4	15.5
Nova Scotia[b]	–20.0	–20.0	–20.0	0.9	20.4
Texas[c]	37.3	35.2	34.2	22.2, 21.8, 21.6	

a $72 is the average price of oil over the period 2003-08 (in Canadian dollars).

b The royalty regimes in Newfoundland and Labrador and Nova Scotia are not sensitive to price; the percentages in the table are based on METRRs for the pre-payout period — see Table 5 for estimates of METRRs by tier.

c The royalty in Texas is payable to property owners, most of whom are private entities; taxes include the severance tax imposed on the market value of total production and hence are sensitive to price in terms of the tax on net value (METRs excluding royalties are sensitive to the three assumed prices and are presented accordingly).

d Non-resource METRs are estimated as the average of all other sectors, excluding mining and oil and gas, in each province; for 2009 estimates, see Chen and Mintz, "The Path to Prosperity."

SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

Table 2: Marginal Effective Tax and Royalty Rates for Oil, by Jurisdiction, 2012*

	MARGINAL EFFECTIVE TAX AND ROYALTY RATE (METRR)			MARGINAL EFFECTIVE Tax Rate (METR)	Non-resource METR
	Oil Price: $50/bbl	Oil Price: $72/bbl	Oil Price: $95/bbl		
	(percent)				
Alberta, conventional oil	33.7	39.7	43.2	6.3	18.5
Alberta, oil sands	19.0	20.3	22.2	12.6	18.5
British Columbia	28.8	26.2	25.0	6.3	18.9
Saskatchewan	33.3	30.9	29.8	12.6	24.9
Newfoundland and Labrador	–9.6	–9.6	–9.6	–7.1	13.1
Nova Scotia	–26.7	–26.7	–26.7	–4.7	16.1
Texas	37.1	34.9	33.9	21.9, 21.5, 21.3	

Notes: See Table 1.

* Compared to 2009, the main tax changes are the following: (1) the federal corporate income tax rate will be reduced to 15%, which is the only change applied to the model for Alberta and Newfoundland and Labrador ; (2) in British Columbia, the corporate income tax rate will be reduced to 10% from the 2009 rate of 11% and the provincial sales tax will be harmonized with the federal goods and services tax; (3) in Nova Scotia, the capital tax (0.175% for 2009) will be eliminated; and (4) in the United States, the federal corporate income tax rate will be 31.85% for domestic oil and gas production.

SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

Table 3: Marginal Effective Tax and Royalty Rates for Natural Gas, by Jurisdiction, 2009[a]

	MARGINAL EFFECTIVE TAX AND ROYALTY RATE (METRR)[c]			MARGINAL EFFECTIVE Tax Rate (METR)
	Gas Price: $3.69/Mcf	Gas Price: $6.33/Mcf	Gas Price: $9.5/Mcf	
	(percent)			
Alberta, 2009A	30.3	36.1	41.9	7.8
Alberta, 2009B	13.3	20.7	28.1	7.8
Alberta, pre-2009	41.0	33.7	31.3	7.8
British Columbia[b]	32.5	29.8	28.7	9.1
Saskatchewan	30.2	31.5	32.0	9.5
Texas	37.5	35.3	34.5	18.6

a All calculations assume a daily production level of 600Mcf, except for Alberta, 2009B, for which the daily production level is 200Mcf.

b The royalty regime in British Columbia is similar to that of Alberta before 2009, the only difference being in the setting of the base royalty rate and the maximum royalty rate. As the maximum rate can be reached at a relative low price (below $3.69/Mcf), the METR can be rather high at a rather low price, but it quickly falls as price rises with a fixed maximum royalty rate.

c Royalty rates in Saskatchewan are obtained from the government royalty calculator for the three chosen prices corresponding to the chosen production level of 600Mcf/day.

SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

Table 4: Marginal Effective Tax and Royalty Rates for Natural Gas, by Jurisdiction, 2012

	MARGINAL EFFECTIVE TAX AND ROYALTY RATE (METRR)			MARGINAL EFFECTIVE Tax Rate (METR)
	Gas Price: $3.69/Mcf	Gas Price: $6.33/Mcf	Gas Price: $9.5/Mcf	
	(percent)			
Alberta, 2009A	28.8	34.7	40.5	6.3
Alberta, 2009B	11.9	19.3	26.7	6.3
Alberta, pre-2009	39.6	32.3	29.8	6.3
British Columbia	29.7	27.0	26.0	6.3
Saskatchewan	28.9	30.1	30.6	8.1
Texas	37.2	35.0	34.2	18.2

Notes: See Table 3.

SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

Conventional Oil and Gas

METRRs on oil and gas vary by price for the product and, in the case of conventional oil and gas, by production volumes. As Tables 1 and 2 show, conventional oil and gas projects in Alberta, British Columbia, and Saskatchewan, particularly the larger wells, are highly taxed, with METRRs over 30% in most cases, particularly in Alberta. Conventional oil and gas investments bear a higher tax burden than either oil sands or Atlantic offshore investments. In Alberta and, to a lesser extent, Saskatchewan, METRRs rise with price, given the price sensitivity of royalty rates; as a share of the gross margin earned from extraction, the effective royalty rate increases in the two provinces. In British Columbia, METRRs fall somewhat with price since royalty rates in that province are not price sensitive. In the case of natural gas, Alberta generally imposes the highest fiscal burden on investments in larger-producing wells (Table 3, row Alberta 2009A), but smaller wells bear lower METRRs than do wells in British Columbia and Saskatchewan. Pre-2009 METRRs in Alberta were especially high at low prices but generally below the 2009 burden at higher price levels. In Texas, in contrast, METRRs on oil and gas are about 35%, with some variation depending on prevailing product prices, suggesting that the state's tax and royalty regime is less competitive than those of British Columbia and Saskatchewan even when one includes private royalties in Texas as a tax on the return to capital.

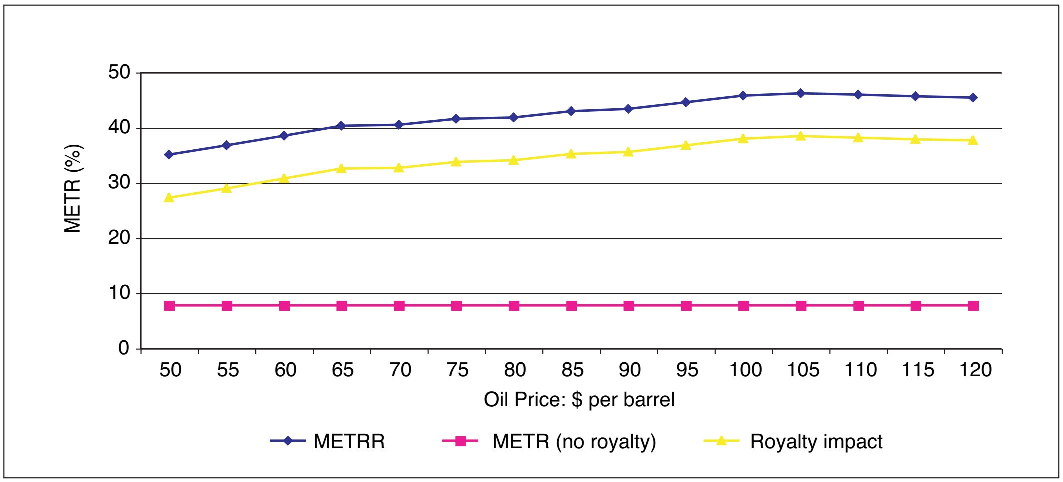
In 2012, METRRs on Canadian oil and gas are scheduled to decline as a result of both federal and provincial corporate income and capital tax cuts and sales tax harmonization in British Columbia. As a result of these changes, the provinces will become more tax competitive. Indeed, sales tax harmonization will reduce METRRs in British Columbia significantly — in the case of conventional oil, the effective rate, based on a price of $72 per barrel, will decline from 29.0% to 26.2%. The oil and gas sector in Alberta will continue to face the highest fiscal burden, while METRRs in British Columbia and Saskatchewan will remain below those in Texas. Conventional oil and gas projects in all three provinces will continue to carry a higher fiscal burden than other sectors of the economy, however, with METRRs in Alberta almost double those of other industries and METRRs in British Columbia and Saskatchewan higher by about a quarter.

A significant reason for these high METRRs is that, since royalties on conventional oil and gas are not a true rent tax by not allowing for a deduction of costs, they discourage investments in marginal projects. If no royalties were imposed, the corporate tax rate on conventional oil and gas would be lower — for example, in 2012, the marginal effective tax rate in Alberta, excluding royalties, would be about two-thirds less than the marginal effective tax rate faced by other industries. This result is due largely to the expensing of exploration costs, which are a significant component of investment. As the Technical Committee on Business Taxation argued, companies do not fully capture resource exploration costs since companies with nearby leases could benefit from the information obtained on the potential for successful exploration. As a result, companies underinvest in exploration since they do not fully appropriate returns that accrue to the industry as a whole. This is akin to patented research and development (R&D) expenses for non-resource companies when their innovations benefit other firms, not just themselves.[11]

[11] See Technical Committee on Business Taxation, *Report*. In our estimates of resource and non-resource marginal effective rates, we do not include R&D tax credits or grants (in the United States, grants play a bigger role in R&D support). As a share of business capital, R&D is relatively small, so that tax credits and grants for that purpose have only a small impact on marginal effective rates. Note that including R&D support would reduce marginal effective tax rates for non-resource industries more than for oil and gas.

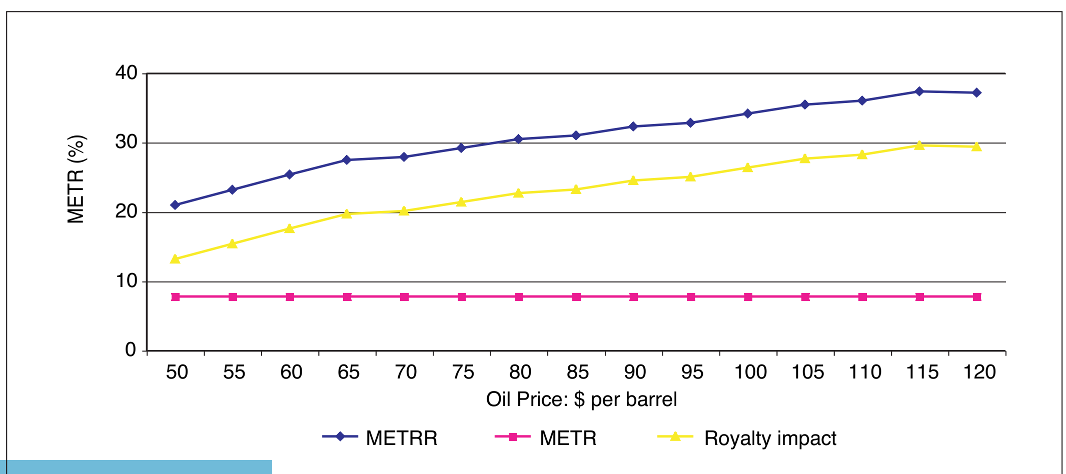
Conventional oil investments in Alberta are highly sensitive to volume and price (see Figures 1 and 2). For production at 80 barrels per day, METRRs rise from 35% to 45% as the price per barrel increases from $50 to $120, with a small dip at the higher price (since the royalty rate does not increase proportionately as much with prices, so that the effective royalty rate relative to the gross margin declines). For wells producing 30 barrels per day, METRRs begin at 21% and rise steeply over the same price range. Royalty rates that vary with price do increase revenues for the Alberta government, but at the significant cost of deterring investments. The detrimental impact of Alberta's price-sensitive royalty rates for conventional oil can be seen in Figure 3, which compares rates in Alberta and Texas. At $50 per barrel, Alberta is relatively competitive, at least at production of 80 barrels per day; above $55 per barrel, however, Alberta's METRRs on capital rise sharply, not only discouraging investments but also making the province's oil sector less competitive than that in Texas.

FIGURE 1: Marginal Effective Tax and Royalty Rate on Conventional Oil, Alberta, at 80 Barrels per day



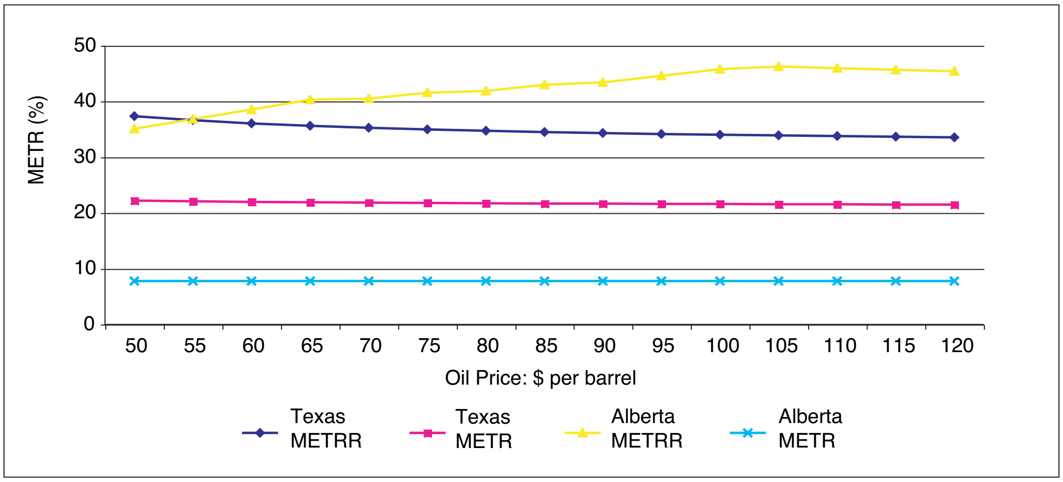
SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

FIGURE 2: Marginal Effective Tax and Royalty Rate on Conventional Oil, Alberta, at 30 Barrels per day



SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

FIGURE 3: Marginal Effective Tax and Royalty Rate on Conventional Oil, Texas and Alberta, at 80 Barrels per day



SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

In summary, the conventional oil and gas industry, particularly in Alberta, faces a higher tax and royalty burden on new investments than do other sectors of the economy, and at higher prices per barrel of oil Alberta's tax and royalty regime becomes less competitive than that of Texas.

The Oil Sands

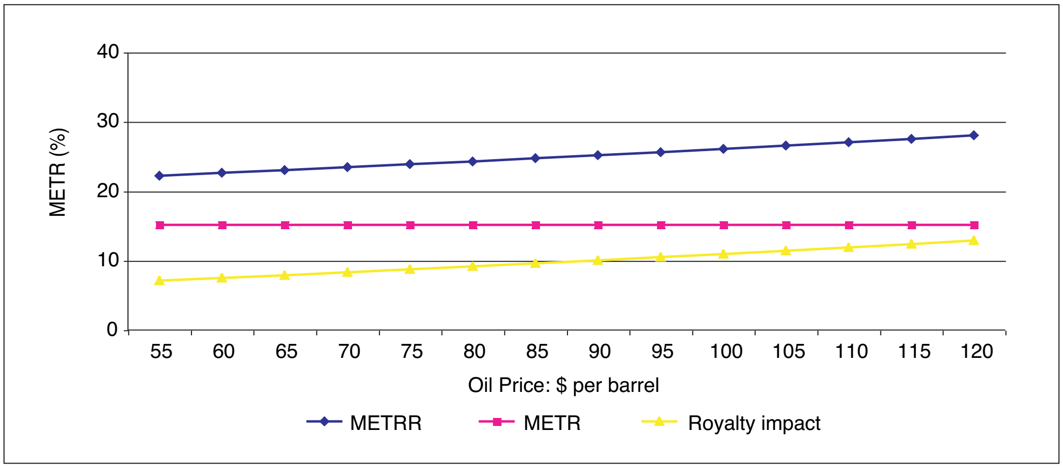
Unlike conventional oil deposits, Alberta's oil sands require huge capital investments to extract bitumen and upgrade to synthetic oil. Such investments are especially important in "time-to-build" projects in which a large cash commitment is needed up front to develop the resource. As noted earlier, in 1997 Alberta adopted a true rent tax for oil sands projects by which payment is assessed on revenues net of current and capital expenditures (with unused expenditures carried forward at the government bond interest rate). In 2009 the province adopted price-sensitive royalty rates for the oil sands, the implications of which we discuss below.

As Tables 1 and 2 show, oil sands investments bear a much smaller tax and royalty burden than do investments in conventional oil, with an METRR of 23.6% in 2009 (scheduled to fall to 20.3% in 2012) when prices average $72 per barrel; without royalties, METRRs drop to 15.1% in 2009 (and to 12.6% in 2012). As with conventional oil and gas, however, oil sands investments bear a higher tax and royalty burden than do other industries in Alberta at all price levels.[12] Moreover, as Figure 4 shows, the higher the oil price, the higher the METRR.

[12] Given that Alberta's royalty structure resembles a true rent tax, with all costs deducted from the rent base, and is deductible from corporate profits to determine corporate income tax payments, it might be surprising that the royalty should have any impact on marginal effective rates. But the corporate income tax and royalty provisions interact with each other, resulting in tax and royalty payments on income earned from projects that are more than the tax value of capital cost deductions. See Mintz, "Measuring Effective Tax Rates for Oil and Gas in Canada."

However, the price sensitivity of the royalty rate encourages companies to bunch investment expenditures at the top of a business cycle, when prices are expected to decline, and to avoid investments at the bottom of a cycle, when prices are expected to rise. This is explained as follows. At the top of a cycle, investments can be written off at a relatively high royalty rate, with income taxed at a later period when royalty rates are lower. Similarly, at the bottom of a cycle, investments can be written off at a lower royalty rate, with income taxed at a higher rate. Thus, tax planning during a business cycle can have a significant effect on investment decisions.[13]

FIGURE 4: Marginal Effective Tax and Royalty Rate, Alberta Oil Sands, at Various Prices



SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

To make this point clear, suppose the METRR on oil priced at $72 per barrel (and no change in price over time) is 20.3% (see Table 2). In the case where the price is anticipated to rise from $50 per barrel when deductions are taken to $72 per barrel when income is earned, the METRR is 35.5%. In the case where the price is expected to decline from $95 to $72 per barrel, the METRR is –23.5%. As can be seen from these calculations, the METRR on capital investments in the oil sands becomes procyclical, discouraging investments at the bottom of the cycle, when prices are anticipated to rise, and encouraging investments at the top of the cycle, when prices are expected to fall. Price-sensitive royalty structures, therefore, could aggravate macroeconomic cycles, given the importance of the industry to total private investment in Alberta, although empirical testing would have to be undertaken to determine if the effect is significant.

13 A similar issue arises with incremental R&D tax credits that are provided for investments in excess of a threshold based on past average R&D expenditures. Cyclical R&D expenditures arise from the use of the incremental credit since companies will bunch up incentives in the years they expect R&D expenses to be in excess of the threshold. For a discussion of this point, see Technical Committee on Business Taxation, *Report*.

Atlantic Offshore Oil and Gas

Atlantic offshore oil and gas projects are subject to federal and provincial corporate taxes (14% in Newfoundland and Labrador,[14] 16% in Nova Scotia) and to royalties assessed by the Newfoundland and Labrador and Nova Scotia governments. The corporate tax regime is similar to that in the western provinces except for the federal Atlantic investment tax credit of 10%.

As noted earlier, the Newfoundland and Labrador and Nova Scotia royalty systems are both unique and complex. Similar to the Alberta oil sands royalty, current and capital expenditures are deducted from the rent base to determine the royalty payment. However, the royalty rate varies by "tiers" whereby cost deductions are carried forward at large allowance rates to determine the new level of rents subject to a higher royalty rate. Effectively, the carry forward of costs and allowances shelters rents from royalty payments until all amounts carried forward are exhausted. Thus, a company that invests heavily in the early years of a project may shelter not only marginal but also inframarginal rents from royalties in later periods. In other words, there is a significant incentive to incur costs early on to reduce future royalty payments.

As Tables 1 and 2 show, the METRR on Atlantic offshore oil and gas investments is negative. This does not imply that governments are failing to raise revenues, since inframarginal returns (returns in excess of costs) are subject to high tax and royalty rates — for example, in 2009 the combined Nova Scotia corporate income and royalty statutory rate was 58.6% on revenues earned at the second tier of the royalty structure. The large negative numbers do imply, however, that companies have an incentive to overinvest in capital.

Negative METRRs — at least, in the case of Newfoundland and Labrador — arise because of two provisions. One is the federal Atlantic investment tax credit, since the tax savings from the combined depreciation deductions and tax credits offset any income tax paid on future earnings (in Nova Scotia, this provision leads to an METRR close to zero).[15] The more significant provision, however, is with respect to the carry forward of costs under both the Newfoundland and Labrador and Nova Scotia royalty systems.

Table 5 provides estimates of METRRs for Atlantic offshore oil and gas investments depending on when the investment takes place (whether pre-payout, first tier, or second tier). The most negative METRR occurs when the investment reaches the first or second tier, when corporate income tax and royalty savings, including the carry forward of allowances, are the largest. The allowances are especially generous in Nova Scotia, resulting in very low marginal effective tax rates in that province; if the allowances were the same as those in Newfoundland and Labrador, METRRS in Nova Scotia would be considerably higher, although still negative.

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[14] In Newfoundland and Labrador, an additional 5% is levied on manufacturing and processing activities.

[15] We obtain similar results for other resource and manufacturing industries that qualify for the Atlantic investment tax credit; see Chen and Mintz, "The Path to Prosperity."

Table 5: Marginal Effective Tax and Royalty Rates for Oil and Gas, Newfoundland and Labrador and Nova Scotia, 2009

	Pre-payout	First Tier	Second Tier
	(percent)		
Newfoundland and Labrador	-3.9	-8.3	-11.6
Nova Scotia	-20.0	-134.9	-77.9
Nova Scotia, assuming return allowances are the same as those in Newfoundland and Labrador	-3.0	-18.9	-13.5

SOURCE: Tax and Economic Growth Program, The School of Public Policy, University of Calgary.

Unlike investments in conventional oil and gas and oil sands production, investments in Atlantic offshore oil and gas are treated favourably compared to investments in other industries (see Tables 1 and 3), which is not surprising given the highly negative METRRs. Thus, the tax and royalty systems of Newfoundland and Labrador and Nova Scotia encourage too much investment in offshore investment compared with what would occur with a neutral corporate tax system and a true rent tax.

REFORMING TAX AND ROYALTY STRUCTURES

Our overall conclusion is that investments in the Canadian oil and gas sector, except for Atlantic offshore projects, bear a higher fiscal burden than do other sectors of the economy. In our view, oil and gas investments should be treated similarly to investments in other industries under general corporate tax levies (corporate income, capital, and sales tax regimes). If royalties were levied as true rent taxes, this would minimize economic distortions in the allocation of capital and improve economic efficiency. Further, given the length of time it takes to complete projects and the volatility of prices, it is important for governments to provide a stable fiscal regime to minimize the impact of frequent tax and royalty changes on investment decisions.

Corporate Tax Measures

In recent years, federal and provincial governments have moved to a corporate income tax base that provides a more neutral treatment of oil and gas relative to other sectors. Resources profits are now taxed at the same corporate income tax rate as other industries. Royalties are deducted from profits as with other fees for the use of a publicly provided service (in this case, the oil and gas deposits owned by provinces). Exploration costs are expensed similar to R&D costs to encourage oil and gas discoveries that ultimately benefit other firms looking for resources in the same area.

One remaining source of non-neutrality, however, is the 10% federal Atlantic investment tax credit, which benefits agriculture, fishing, forestry, oil and gas, and manufacturing industries with qualifying capital expenditures, but not construction, utilities, communications, transportation, trade, or services, where the tax credit results in exceptionally low marginal effective tax rates on capital and in many instances cannot be used by capital-intensive companies with insufficient profits for many years.[16] Given substantial federal corporate rate reductions and capital tax elimination over the past decade, we believe that the Atlantic investment tax credit is no longer needed. If it should be retained, however, the rate should be cut significantly and broadened to include all industries.

Provincial Royalty Reform

The major distortions of investment decisions in the oil and gas sector are associated with provincial royalty structures, which are poorly designed as rent payments. Accordingly, royalties should be converted to rent taxes — that is, levies on returns in excess of the true economic costs incurred in carrying out a project. Properly structured, a rent tax would have little or no impact on investments. The provinces, as owners of the resources, would still collect substantial resource revenues on returns in excess of the economic costs. A royalty applied to rents could take the form of a cash flow tax,[17] which would fall on revenues net of current and capital expenditures. No deduction would be given for interest expenses, although an investment allowance would be given to preserve the time value of deductions carried forward to years in which amounts could be deducted from rents.

Some might argue that royalty regimes should be used to slow down oil and gas production either to preserve deposits for use by future generations or to curtail environmental degradation. In our view, however, oil and gas extraction need not compromise future generations so long as the owners — governments — reinvest the money in endowments to fund future public services. Moreover, consideration of environmental issues should be left to regulatory regimes, to incentives to develop and adopt new technologies to reduce emissions, or to special levies (such as a carbon tax[18]) that focus on the source of environmental damage.

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[16] See Chen and Mintz, "The Path to Prosperity."

[17] The cash flow tax as a rent tax has been discussed extensively in the literature. For a discussion on the treatment of capital costs and risk, see Jack M. Mintz, "The Corporation Tax: A Survey," *Fiscal Studies* 16 (4, 1995): 23-68.

[18] See Technical Committee on Business Taxation, *Report*, chap. 9.

Each royalty structure comes with its own set of problems. With respect to conventional oil and gas, royalties are levied on revenues with no deduction for costs. As a rough way to reduce royalty payments on higher-cost deposits, the royalty rate varies by price and volume, with the idea that higher rent margins would be associated with high prices or production scales. Other incentives, such as royalty credits and royalty holidays to reduce the impact of conventional royalties, typically are given for high-cost wells. In principle, it would be far better to levy a royalty based on cash flows by allowing current and capital costs to be deducted from revenues (with a carry forward of costs at the government bond rate since the public sector shares the risks fully with the private sector). Such a reform, however, would mean that, instead of applying the royalty on a well-by-well basis (where costs are difficult to measure), a more general cash flow levy on firms would be assessed.

With respect to oil sands, the Alberta generic royalty prior to 2009 was closest to a true levy on rents since the full value of costs was deducted from the rent base. Under this regime, the royalty rate was 25% (with a minimum royalty applied to revenues), and costs could be carried forward at the government bond rate. In 2009, the province introduced a price-sensitive royalty regime that sees royalty rates rise as the price of oil increases above $55 per barrel. This regime, however, encourages overinvestment at the peak of a business cycle and underinvestment at the trough, one consequence of which is to aggravate investment cycles that would otherwise arise due to booms and recessions in the business cycle. To maximize the time value of rents, the province would be better off to apply a price-insensitive royalty rate to cash flow, whereby royalty payments would increase automatically as prices rose above the economic cost of production.

With respect to Atlantic offshore oil and gas, the net-profit royalty regimes of Newfoundland and Labrador and Nova Scotia are highly distortionary, resulting in excessive investments and insufficient rents from the projects at a given royalty rate. Many of these problems could be avoided by eliminating the different tiers and applying a single royalty rate to cash flow, with full costs carried forward at the government bond rate. In other words, future offshore oil and gas projects should be subject to a single royalty rate on rents, similar to Alberta's pre-2009 oil sands royalty structure.

In short, provincial governments need to pay much more attention to the incentive effects of their royalty regimes on investments, since a large positive or negative royalty burden on marginal investments reduces the rents to be shared by private producers and government.

CONCLUSIONS

From our analysis of oil and gas taxation and royalty structures, we come to several important conclusions. First, reflecting poorly structured royalty regimes, oil and gas investments (except those in Newfoundland and Labrador and Nova Scotia) generally are not "subsidized" but bear a higher fiscal burden than do other industries.

Second, the highest tax and royalty burden applies to marginal conventional projects in Alberta, followed by those in Saskatchewan and British Columbia (British Columbia is harmonizing its sales tax with the federal GST, which will remove significant taxes on business purchases of capital).

Third, marginal investments oil and gas in Newfoundland and Labrador and Nova Scotia bear a negative or very low tax and royalty burden as a result of provincial royalty structures and the federal Atlantic investment tax credit.

Fourth, conventional oil and gas investments in Alberta bear a higher tax and royalty burden than do similar investments in Texas even when royalty payments to private owners in that state are treated as a tax similar to Alberta's conventional oil and gas royalties.

Finally, provincial royalty structures should be reformed so that they operate as true rent levies, with a full and proper deduction for costs, as in the case of a cash flow tax.

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Dr. Jack M. Mintz was appointed the Palmer Chair in Public Policy at the University of Calgary in January 2008.

Widely published in the field of public economics, he was touted in a 2004 UK magazine publication as one of the world's most influential tax experts. He serves as an Associate Editor of *International Tax and Public Finance* and the *Canadian Tax Journal*, and is a research fellow of CESifo, Munich, Germany, and the Centre for Business Taxation Institute, Oxford University. He is a regular contributor to Canadian Business and the National Post, and has frequently published articles in other print media.

Dr. Mintz presently serves on several boards including Brookfield Asset Management, Imperial Oil Limited, Royal Ontario Museum and the Board of Management, International Institute of Public Finance. He was also appointed by the Federal Minister of Finance to the Economic Advisory Council to advise on economic planning and served as research director for the Federal-Provincial Minister's Working Group on Retirement Income Research.

Dr. Mintz held the position of Professor of Business Economics at the Rotman School of Business from 1989-2007 and Department of Economics at Queen's University, Kingston, 1978-1989. He was a Visiting Professor, New York University Law School, 2007; President and CEO of the C. D. Howe Institute from 1999-2006; Clifford Clark Visiting Economist at the Department of Finance, Ottawa; Chair of the federal government's Technical Committee on Business Taxation in 1996 and 1997; and Associate Dean (Academic) of the Faculty of Management, University of Toronto, 1993-1995. He was founding Editor-in-Chief of *International Tax and Public Finance*, published by Kluwer Academic Publishers from 1994-2001, and recently chaired the Alberta Financial and Investment Policy Advisory Commission reporting to the Alberta Minister of Finance.

In 2002, Dr. Mintz's book, *Most Favored Nation: A Framework for Smart Economic Policy*, was winner of the Purvis Prize for best book in economic policy and runner-up for Donner Prize for best book in public policy.

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