Canadian Fiscal Systems for Oil and Gas: An Overview of the Last Two Decades

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Working with data at the industry level, this paper provides an analysis of the effects of changes in Canadian oil and gas policy during the last two decades. Effects on the oil and gas industry's financial position are examined by comparing appropriately defined scenarios run through a simulation model of the Canadian economy that includes a detailed representation of the industry in Western Canada. Information on drilling activity and exploration expenditures is used to assess the federal government's attempt to shift such activities from conventional to frontier areas by way of fiscal incentives. Lessons to be learned from a quantitative overview of the changing policy regime in the oil and gas industry are set out in the last section of the paper.

En se basant sur des données de niveau industriel, cet article offre une analyse des effets causés par les changements au sein de la politique de pétrole et de gaz au Canada au cours des deux dernières décennies. Les effets sur la position financière de l'industrie du pétrole et du gaz sont examinés en les comparant avec des scénarios bien définis et soumis au test d'un modèle de simulation de l'économie canadienne comprenant une représentation détaillée de l'industrie de l'ouest du Canada. L'information concernant l'activité de forage et les dépenses d'exploration nous permet d'évaluer la tentative du gouvernement fédéral à déplacer de telles activités en dehors des régions conventionnelles en direction des frontières en offrant des primes d'encouragement. Dans la dernière section de l'article sont présentées les leçons à tirer d'une vue générale et quantitative des changements du régime de politique dans l'industrie du pétrole et du gaz.

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1. Introduction[1]

Following a few relatively uneventful decades, a series of major disturbances have rocked the world oil market since the early 1970s. The emergence of OPEC as the dominant supply-side player has been accompanied by periods of both rapid increases and sharp drops in oil prices. These developments contributed to increasing the degree of uncertainty which characterizes the world oil market. As a consequence, the operating environment for the oil and gas industries of most countries also became more uncertain.

The governments of a number of OECD countries reacted to these external-based developments by adopting a plethora of measures aimed at the energy sectors of their respective countries. Canada was no exception to this trend and the 15 years or so that followed the early 1970s witnessed a number of dramatic changes in Canadian oil and gas policy at both provincial and federal levels. There is general agreement among

1 / This is a revised and condensed version of a paper prepared for ENERGY OPTIONS, a public review and examination of energy issues sponsored by Energy, Mines and Resources Canada. The paper draws in part on research by the author and three colleagues (Helliwell, MacGregor, McRae and Plourde [hereafter, HMMP] 1989).

industry observers and analysts that these changes in policy made the operating environment of the Canadian oil and gas industry even more uncertain.[2] The consequences of this policy-induced uncertainty on the stability of the industry's financial position, however, have not been the subject of much analysis. An objective of this paper is thus to provide some empirical evidence on the overall nature of the changes in Canadian oil and gas policy during the last two decades, and to attempt a limited assessment of their impact on the industry's financial position.

A related issue concerns the impact of policy on the geographical distribution of oil- and gas-related activities within Canada. An important (and arguably under-studied) aspect of post-1970 Canadian energy policy is the attempt to use the fiscal system to shift such activities from conventional to frontier areas, in particular to the so-called Canada lands.[3] This paper will use information on drilling activities and exploration expenditures to assess the consequences of this policy objective.

The last section of the paper attempts to identify lessons to be learned from past Canadian energy policies and examines current approaches to oil and gas policy within that context.

2. Setting the Stage

After an extended period of low and relatively stable values, world oil prices took two sharp upward jumps within a decade (in 1973-74 and 1979-80). In late 1985/early 1986, five years or so after the second shock, prices on world oil markets fell precipitously, approaching levels not encountered since the mid-1970s. What was the basic tenor of Canadian oil and gas policy during this period of significant fluctuations in world oil prices?

First, for most of this period, domestic energy prices were used by governments as redistribution mechanisms. The average FOB price of Canadian crude oil imports, used to represent developments on world markets, is shown in Figure 1,[4] from which the three episodes described in the previous paragraph can easily be identified. A comparison of the import price series with that of average wellhead crude oil prices in Western Canada provides an indication of the extent to which government intervention prevented Canadian prices from reflecting developments on world markets. In natural gas markets, government intervention took the form of regulated export prices (and volumes) and of a policy rigidly linking domestic gas prices to the price of Canadian-produced crude oil.[5]

Second, as Figure 2 reveals, the world oil pricing episodes find counterparts in the share of Western Canadian upstream oil and gas revenues accruing to governments.[6] If one interprets this share as an average effective royalty/tax rate on gross production revenues, then it would appear that between 1967 and 1986 the overall thrust of Canadian policy towards the upstream conventional oil and gas industry has been characterized by sharp increases in effective royalty/tax rates when prices rose, and reductions

2/ See, for example, Carmichael and Herrera (1984) and Scarfe (1985, Section IV).

3/ In the 1970s and early 1980s, this term was used to represent Canadian territory outside the boundaries of any of the provinces and thus under sole federal jurisdiction. Since the mid-1980s, the term has fallen into disuse and "frontier areas" is now commonly used in its place. This paper will respect the new convention.

4/ The use of average FOB prices of Canadian crude oil imports for the above purpose is predicated purely on convenience; it is one of the few relevant data series available for the entire sample period. For 1967-1985, this price series was taken from the Canadian Petroleum Association (CPA) *Statistical Handbook* (Section IX, Table 4). Average wellhead prices of crude oil and field prices of natural gas in Western Canada between 1967 and 1985 were taken from the CPA *Statistical Handbook* (Section VI, Table 1). Values for 1986 are estimates taken from *Oilweek* (26 January 1987, p. 10) and (23 February 1987, pp. 9-13 and 22), for natural gas and crude oil respectively. The natural gas price shown is for about 5.8 thousand cubic feet, a quantity approximately equivalent to a barrel of oil in energy content.

5/ In 1975, an agreement between the federal and Alberta governments effectively pegged natural gas prices at 85% of the BTU-equivalent domestic crude oil price, delivered to Toronto. The National Energy Program and the 1981 Energy Agreements later reduced the parity ratio to 65%. As will become clear later, this practice was ended in 1985.

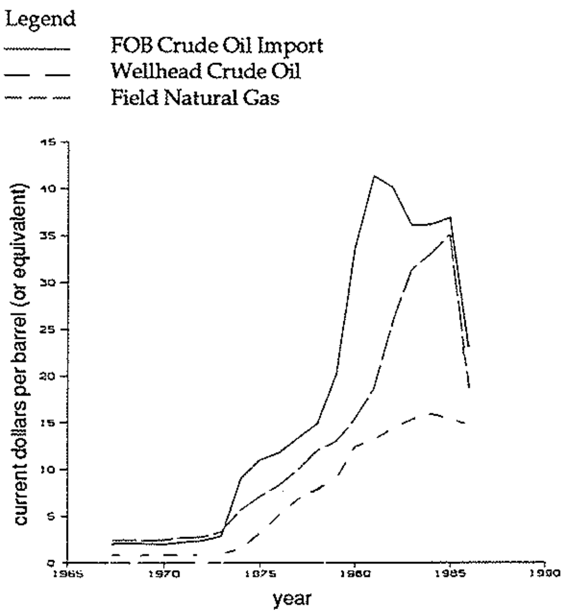

Figure 1: Average Canadian Crude Oil and Natural Gas Prices, 1967-1986

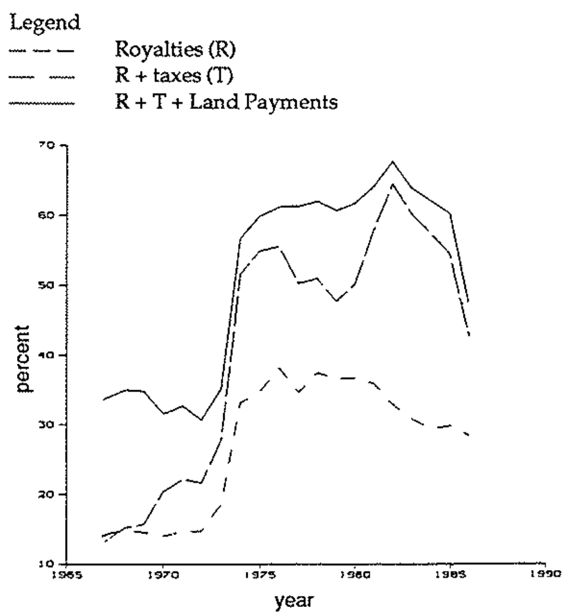

Figure 2: Government Share of Gross Oil and Gas Production Revenue, 1967-1986.

in these rates as prices fell, or at least stopped growing as quickly. This is particularly true if land payments are included in the calculation of the share of upstream oil and gas revenues accruing to governments. In that case, changes in the average effective royalty/tax rate are rather closely aligned with the evolution of Canadian wellhead prices of crude oil and field prices of natural gas. As Figure 2 shows, during the second half of the 1970s, increases in land payments effectively offset the decreases in government revenues generated by other instruments.

This suggests that as prices, and hence economic rents in intra-marginal deposits, rose, the average effective royalty/tax rate on the upstream industry also increased. Conversely, as prices, and hence rents, fell, the share of upstream revenues collected by governments also fell. This implies that the overall pattern of fiscal measures applicable to the upstream sector of the Canadian oil and gas industry was positively correlated with its ability to pay, as measured by rent generation.

How was this achieved? The evolution of Canadian oil and gas policy in the post-1973 period has been the subject of extensive analysis in numerous forums.[7] As contributions to this literature point out, numerous explicit changes in

6/ These series are based on information collected from publications issued by the federal government, the governments of the producing provinces, and the CPA *Statistical Handbook*. Revenues and expenditures relating to oil sands operations are excluded. Included in the calculations are revenues from federal and provincial corporation income taxes (net of credits), provincial royalties and land payments, the Petroleum and Gas Revenue Tax, and the Incremental Oil Revenue Tax, as applicable. Incentive grants to activities on provincial land are also included in the calculations. Values for 1986 are estimates. Estimates of corporation income tax receipts are obtained from the detailed modelling of this tax incorporated in the MACE model of the Canadian economy. Note that throughout this paper, "Western Canada" refers to the oil- and gas-producing provinces of Manitoba, Saskatchewan, Alberta and British Columbia.

7/ McRae (1985), and Watkins and Scarfe (1985) are useful references on this score. A full chronology of related developments is available in Plourde (1986). An overview of key policy changes is presented in HMMP (1989, Appendixes 5.1 and 5.2).

policy have occurred since the early 1970s. The first world oil price shock was accompanied by significant increases in provincial royalty rates, and the introduction of exploration incentive programs financed by the governments of producing provinces. Before the end of 1975, royalty rates had been further increased, and the federal government had frozen the price of Canadian-produced oil, moved to eliminate exports of light and medium crudes, replaced automatic or percentage depletion with an earned depletion system,[8] made the tax treatment of development expenditures less favourable from the industry's perspective, and eliminated the deductibility of provincial royalty payments for income tax purposes. This last measure was eventually replaced by a so-called resource allowance, whereby 25% of resource revenues net of operating expenditures and capital cost allowances were deducted, in lieu of royalty payments, in the calculation of taxable income. As Figure 2 makes clear, the overall effect of these developments was a sharp increase in the average effective royalty/tax rate applicable to the upstream oil and gas industry.

During the second half of the 1970s, changes in Canadian oil and gas policy were both less frequent and less dramatic. Certain provincial incentive programs were extended beyond their originally planned expiry dates. Some reductions in royalty rates were effected, particularly as applicable to high-cost deposits. The federal government extended some broadly based investment incentives through the corporation income tax. Agreements were negotiated between the federal government and governments of the producing provinces (mainly Alberta) which brought about phased increases in the prices of oil and gas produced in Canada. As Figure 2 reminds us, one of the most significant developments of this period turns out to have been changes in land regulations enacted by Alberta in 1976. Overall, the share of upstream oil and gas revenues accruing to governments was relatively stable until the early 1980s.

The second world oil price shock, however, brought another round of increases in the share of upstream oil and gas revenues accruing to governments. In October 1980, after negotiations with the governments of the producing provinces had failed, the federal government unilaterally introduced the National Energy Program (NEP). From the perspective of Figure 1, the NEP continued the upward movement of Canadian oil and gas prices, but fell significantly short of extending world-equivalent prices on conventional production. On the fiscal side, the system of earned depletion allowances was replaced by a system of cash grants (called the Petroleum Incentives Program, PIP), and a new tax on production revenues net of operating costs, the Petroleum and Gas Revenue Tax (PGRT), was also instituted. It is an understatement to say that the NEP was not well received by the governments of the producing provinces, or in industry circles.

After almost a year of stalemate, the 1981 Energy Agreements were signed by the federal government and the governments of the producing provinces. In particular, these Agreements continued the progressive upward movement of Canadian oil prices by conferring world-equivalent prices to all domestic production from reservoirs discovered after 1980 and extending higher prices than originally proposed under the NEP to almost all other domestic oil production.[9] These price increases, however, were combined with a rise in the PGRT rate and the introduction of a new federal tax, the Incremental Oil Revenue Tax (IORT), on a measure of revenues from the production of oil discovered prior to 1974.

Over the following three years or so, as it became clear that the world oil price projections on which the NEP and the 1981 Energy Agreements had been based were too high, the federal and provincial governments acted to increase

8/ Under percentage depletion, firms were allowed to deduct automatically 33 1/3% of resource profits in the calculation of taxable income. The introduction of earned depletion meant that deductions would now be earned at a rate of $1 per $3 of eligible exploration and development expenditures.

9/ Figure 1 reminds us that the increase in domestic oil prices were large enough to bring about increases in field prices of natural gas, even though the BTU-equivalence price ratio fell from 85% before the NEP to 65% afterward.

industry cash flows and reduce the effective royalty/tax rate on upstream revenues. The key measures adopted during this period include reductions in provincial royalty rates, and the extension of incentive and tax credit programs as well as royalty holidays (notably by Alberta in April 1982 and March 1984); the June 1982 update to the NEP, which increased the average price of Canadian-produced oil and gas, reduced effective PGRT rates, and introduced the first of a series of one-year suspensions of the IORT;[10] and the June 1983 amendment to the 1981 Energy Agreements, whereby the average prices of oil and gas produced in Canada were further increased. The first steps toward the deregulation of oil and gas exports were also taken during this period.

The average royalty/tax rate faced by the Canadian oil and gas industry continued on its downward trend with the signing of the Western Accord in March 1985. The Accord brought about the deregulation of Canadian crude oil prices and export transactions (the Natural Gas Agreement of October 1985 would perform a similar task for gas, thus ending a decade of rigid linkages between the prices of domestically produced crude oil and natural gas), reductions in PGRT rates, and plans for its gradual elimination. A few months later, the Alberta government announced significant reductions in royalty rates, the extension of a number of incentive programs, and the enrichment (from the perspective of producers) of others.

During the last few months of 1985, world oil prices began to fall, a development which would continue well into 1986. Since then, numerous relief programs have been extended to the industry, including further reductions in provincial royalty rates, extensions of incentive and related programs, and the elimination of the PGRT earlier than scheduled in the Western Accord. The consequences of these moves are evident in Figure 2, where the average effective royalty/tax rate on upstream revenues is shown to have fallen sharply between 1985 and 1986.

Overall, the above suggests that the fiscal system that has applied to the upstream oil and gas industry since the first world oil price shock can perhaps more accurately be described as a sequence of systems, with rules changed by governments as events unfolded. While the fiscal rules have indeed varied significantly over time, Figures 1 and 2 and the ensuing discussion make it clear that these rule changes were not uniformly detrimental to the financial health of the domestic oil and gas industry: some indeed worsened the industry's position, but others enhanced it.

3. Counterfactual Experiments: Description and Results

The MACE model of the Canadian economy incorporates detailed modelling of the activities of the upstream oil and gas industry in Western Canada.[11] I have chosen to use this model to perform a series of counterfactual experiments designed to shed some light on the possible consequences of alternative oil and gas policy systems over the period extending from 1974 to 1986. The ultimate goal of this exercise is to generate information that permits a quantitative assessment (albeit, a limited one) of whether the frequent and dramatic policy changes experienced since the early 1970s, which have made the operating environment of the Canadian oil and gas industry more uncertain, have also acted to destabilize the industry's financial position.

The counterfactual experiments undertaken take the form of four alternative simulations of the MACE model. Individual simulations differ only in their assumptions about Canadian oil and gas policy, and are thus based on common

10/ As it turns out, the IORT would not be levied again until its formal elimination by the Western Accord. The only important exception to this is the production of the GCOS (Suncor) oil sands plant, which continued to be subject to the IORT until the end of 1984.

11/ An overall description of the version of the model used in this paper can be found in Helliwell, MacGregor, McRae, Plourde and Chung (1987). A more detailed discussion of the approach used to model the supply of conventional oil and gas is provided in HMMP (1989, Chapter 8 and Appendix 8.1). Note that the results reported in this section apply only to the Western sedimentary basin, and thus exclude the consequences of activities in frontier regions.

assumptions about, for instance, monetary and exchange rate policy, fiscal policy (other than that specific to the upstream oil and gas industry), demographics, and the state of the world economy. In particular, all simulations share the same historical pattern of fluctuating world oil prices.

The first of the simulations performed reflects the actual evolution of Canadian oil and gas policy during the period under consideration. As such, it embodies all the key policy changes, including domestic price and export controls and changes in the fiscal regime, as they occurred. This case will be called the "actual prices and policies" case, or ACTUAL.[12] The second simulation, called "price deregulation" (PDEREG), differs from the actual prices and policies case only in terms of pricing assumptions. Instead of allowing domestic and export prices of oil and gas to track their actual historical values, it has been assumed that, during the entire simulation period, these prices had never been the subject of government regulation.

The third simulation is referred to as "deregulation" (DEREG), and differs from the price deregulation case only in its assumptions about export policy. In this case, it is assumed that since 1974 domestic producers of oil and gas have been able to determine export volumes with few restrictions imposed by Canadian authorities. The fourth and final alternative modelled, called the "current policies" case or CURRENT, retains DEREG's treatment of pricing and export determination, but differs from the latter in its assumption that the royalty/tax policies in place at the end of 1986 apply for the entire period under consideration.[13]

Based on the evidence presented in the previous section, the first three cases can be characterized as embodying a fiscal system contingent on the state of the world, for which the elements of contingency were not pre-announced, but rather emerged as events unfolded. DEREG, however, is different. Although this case embodies some limited element of contingency (notably in the determination of provincial royalty rates),[14] it will be thought of as one in which relatively rigid rules are specified ahead of time, and not modified as developments occurred.

For the purposes of this paper, what is price deregulation understood to mean? For crude oil, price deregulation simply means that all domestic production is sold for world-equivalent prices. In the case of natural gas, the absence of comparable world markets makes much more arbitrary any assumption about the behaviour of prices under deregulation. With this in mind, I have chosen to assume that all natural gas produced in Canada is priced at 85% BTU-equivalence with delivered crude oil prices in Toronto, which is not far outside the historical range.

On a similar note, what does deregulation of export quantities imply? In general terms, it is assumed that the consequences of past policies and activities are inherited in 1974. This means, in particular, that the model does not allow the stocks of discovered but unconnected reserves at the end of 1973 to be used to generate additional exports. Therefore, any exports in excess of historical levels must be supported by post-1973 discoveries or reserves connected as of the end of 1973.[15] Given these constraints, the MACE model can then be used to calculate estimates of

12/ The main elements of this case are thus outlined in the previous section. For a more complete description, see HMMP (1989, Chapters 3 to 5).

13/ The main elements of this case consist of provincial royalty rates slightly higher than those prevailing at the end of 1973, the existence of numerous activity incentive programs, no broadly based system of depletion allowances, and the availability of a 25% resource allowance combined with the non-deductibility of provincial royalty rates for purposes of the federal income tax. The corporation income tax system allows exploration expenditures to be deducted from income in the year they occur, but development and land-related expenditures are deducted according to 30% and 10% declining-balance methods, respectively.

14/ Existing provincial legislation generally calls for royalty rates to depend on production flows, prices, and the time at which individual deposits were discovered. The degree of responsiveness to price changes, however, tends to be rather small. The modelling of provincial royalties incorporated in MACE reflects this limited responsiveness of royalty rates to prices.

15/ This provides a domestic supply cushion equivalent to daily production rates of about 100 thousand barrels of crude oil and about 5 billion cubic feet of natural gas at the beginning of the simulation period.

export volumes. These are simply the difference between values of two variables endogenous to the model, domestic flow supply capabilities and domestic requirements (net of import levels, in the case of crude oil).[16]

A different complication arises in the case of natural gas. Since the late 1970s/early 1980s, a persistent situation of deliverability surplus in the United States has reduced the marketability of Canadian-produced natural gas in its traditional export markets. In light of this, it has been assumed that beginning in 1980 Canadian gas export volumes could not have exceeded observed (i.e., actual) volumes, even in the absence of federal regulation. Therefore, only between 1974 and 1979 are export markets assumed to act as additional vents for domestic gas production from post-1973 discoveries and reserves connected at the beginning of 1974.

What happens to industry returns under these alternative cases? Table 1 reports average rates of return for the upstream oil and gas industry, both by sector and combined. As we proceed from ACTUAL, to PDEREG, to DEREG, the fiscal system stays the same, but assumptions about price and export regulation are progressively relaxed. Overall, the effects are not only that average rates of return rise (especially for oil), but their variability increases as well. CURRENT, the simulation with the most stable policy assumptions, yields the highest and most variable industry rates of return of the four alternatives modelled.

Why do we observe this pattern of results? In the version of the MACE model used in this paper, activity levels (and hence investment) in the upstream oil and gas industry depend primarily on the current and lagged values of the marginal profitability of production (net of royalties and taxes), and on current industry cash flow. In light of this, it is easy to understand why, given a fiscal system, price and export deregulation bring about higher rates of return. Through increased wellhead and field prices, price deregulation results in higher industry revenues (net of royalties and taxes), which, in the MACE model, give rise to less-than-proportional increases in activity levels and thus boost rates of return for oil and gas. These higher activity levels also push up domestic production capabilities for both fuels. Under PDEREG, however, producers are not able to take full advantage of these opportunities since price-induced reductions in domestic energy demand are accompanied by access restrictions to export markets due, in part, to continued regulation.

With the assumed lifting of export controls in DEREG, producers are now able to use export markets as vents for domestic production. As a result, both domestic production and export volumes are higher in DEREG than in either PDEREG or ACTUAL. This, of course, boosts industry cash flow and, ultimately, rates of return. These effects are much weaker for natural gas because, in an effort to reflect the conditions prevailing in Canadian gas export markets in the early 1980s, these are prevented **by assumption** from serving as vents for domestic production

Table 1: Average Annual Rates of Return (1974-1986) for the Upstream Oil and Gas Industry under Alternative Pricing and Fiscal Systems (%)*

	ACTUAL	PDEREG	DEREG	CURRENT
Oil (excluding oil sands)	12.5 (4.5)	16.6 (6.3)	20.6 (9.2)	31.2 (10.8)
Natural Gas	11.8 (4.2)	14.4 (8.7)	15.3 (10.9)	15.4 (13.6)
Oil & Gas (including oil sands)	13.4 (4.1)	15.9 (7.6)	17.3 (8.9)	20.1 (11.8)

*standard deviation in parentheses

Source: Author's calculations based on alternative simulations of the MACE model of the Canadian economy.

Note: These results apply only to activities in Western Canada, and thus exclude the consequences of activities in frontier regions.

16/ The existence of the supply cushion described in the previous footnote means that, in the simulations performed, export volumes are the first claim on domestic production to be cut back as it falls. In the four cases examined, this is only ever a problem for crude oil. In terms of the provision of the Canada-U.S. free-trade agreement, this means that **net** export volumes are a more meaningful measure of export activity than are absolute levels.

after 1979. The higher activity levels are thus accompanied by a progressively larger stock of shut-in gas reserves, which checks the growth in rates of return.

As far as CURRENT is concerned, the higher rates of return simply indicate that average and marginal effective royalty/tax rates are lower in this case than in DEREG (which incorporates the actual fiscal system as it evolved between 1974 and 1986). The results for natural gas emphasize once again the important role played by export markets in allowing the industry to realize the higher returns.

The above explains why industry rates of return are higher. But why are they more variable? At this stage, it is useful to remember that activity levels in MACE depend to a significant extent on current profitability and current cash flow, and that the model reflects the fact that world oil prices experienced both rapid increases and sharp falls between 1974 and 1986. To put it simply, returns are more variable under PDEREG and DEREG because the responsiveness of the fiscal system to the price and revenue fluctuations implicit in these two cases is not sufficient to prevent large swings in activity levels. Even though historical effective royalty/tax rates were positively correlated with world oil price movements, the implied changes in the fiscal treatment of upstream oil and gas revenues are not sufficient, under price and export deregulation, to prevent such fluctuations from triggering short-term responses in producer behaviour that may not be warranted from a longer-term perspective. If it turns out, as it does here, that these short-term responses are inconsonant with desired behaviour in the longer run, then the variability of industry rates of return will rise. When considered over the entire simulation period, the growing stock of discovered but unconnected reserves also contributes to making returns to natural gas more variable.

The same argument applies even more strongly under CURRENT. In this case, the structure of the fiscal system is rigid and essentially does not respond to price changes. Royalty and tax rates do not vary with world oil prices, and thus give producers even more incentive to respond to short-term price fluctuations. As a comparison of the results for DEREG and CURRENT in Table 1 reminds us, a rigid fiscal system such as this one could well increase the variability of industry returns in the face of volatile conditions on the world oil market.

Of course, actual producer behaviour is likely to be much more sophisticated than that represented by the MACE model's estimated equations. However, if these were to provide an unbiased approximation to actual behaviour, then the element of myopia present in the model will find a counterpart in the real world.

The evidence presented in this section seems to support three general conclusions. First, the results in Table 1 make clear that foreign-based developments (e.g., the lack of export markets for natural gas) play an important role in shaping the financial health of the domestic oil and gas industry. Second, the fiscal system is not the only aspect of domestic energy policy which affects the operating environment of the oil and gas industry. As the results for PDEREG and DEREG reveal, price regulation and export controls have significantly affected the industry's operations.

Finally, while it appears reasonable to assume that frequent and often dramatic changes in the fiscal regime may well make the oil and gas industry's operating environment more uncertain, it does not necessarily follow that this translates into a more unstable financial position for the industry. A comparison of the results for DEREG and CURRENT suggests that producer uncertainties about the future structure of the fiscal system may in part offset the uncertainties related to the expected volatility of key foreign-determined variables such as future values of the world oil price. In turn, this may serve to dampen swings in activity levels and thus reduce the variability of industry returns.

4. The Push to the Frontiers

So far, the discussion has dealt exclusively with activities in Western Canada. Between 1977 and the middle of the 1980s, however, an important element of Canadian energy policy consisted of using fiscal instruments to encourage exploration for oil and gas on the country's geographical frontiers. Two specific instruments, super depletion and PIP grants, played an important role in inducing private-sector firms to behave in ways compatible with the federal government's objectives.[17]

The federal budget of March 1977 introduced "super depletion," whereby corporations and individuals could earn an additional depletion allowance of 66 2/3% of eligible exploration expenditures, incurred before April 1980, in excess of $5 million per well. Although the legislation did not **explicitly** treat activities in different regions of the country differently, it **effectively** did so since only wells in frontier regions approached the necessary minimum expenditure level.

Seven months after super depletion expired, the federal government introduced, as part of the NEP, the PIP in which activities in different regions of the country were **explicitly** treated differently. An additional objective of encouraging greater participation by Canadian-owned firms in frontier activities was pursued through the institution of preferential treatment for these firms. In particular, exploration incentives and earned depletion rates were higher for exploration activities in frontier regions undertaken by firms with a high Canadian ownership ratio (COR). For example, in 1983 a firm with a COR of at least 69% would earn an incentive grant of 80% and a depletion allowance of 20% of eligible exploration expenditures net of grants. This compares with a 35% rate of incentive payment and an earned depletion allowance of 10% of net eligible expenditures for the same firm undertaking exploration activities in Alberta.

Even though the rate of incentive payment fell sharply with the COR, it did not prove to be much of a binding constraint in frontier regions as firms were very successful in negotiating inter-corporate arrangements ensuring that almost all eligible expenditures incurred qualified for grants at the highest rate. During the first six years of this program (1981 to 1986), a total of $6.97 billion in federal incentive payments were made. Of this amount, $6.41 billion, or about 92%, were to firms with CORs high enough to qualify for 80% grants on exploration activities. Even if it were assumed that **all** of the $511 million in federal grants extended in non-frontier areas qualified for exploration incentive payments at an 80% rate, still more than 90% of federal grants to activities in frontier regions ($5.90 of $6.46 billion) were triggered by expenditures incurred by firms qualifying for incentive grants at the highest rate available.[18]

Column (2) of Table 2 gives real exploration expenditures in Northern and offshore Eastern Canada between 1967 and 1985.[19] These reveal that there have so far been two pushes to the geographical frontiers: one beginning around 1969 and peaking in 1972-73, and another that began in 1978 and reached a maximum in 1984. A review of events and reports in the industry press in the late 1960s and early 1970s suggests that the first movement to the Canadian frontiers was inspired, in large part, by successes on Alaska's North slope. During the year following the June 1968 confirmation that the oil field discovered under Prudhoe Bay was gigantic by in-

17/ Through Petro-Canada and other Crown firms, the government also participated directly in the frontier exploration effort. Even though Petro-Canada was one of the most active firms involved in frontier exploration between 1976 and 1986, this paper focuses on fiscal aspects and treats Crown firms as any other corporate participant in the push to the frontiers. For a detailed discussion of Petro-Canada's role in frontier oil and gas activities, see Halpern, Plourde and Waverman (1988).

18/ This information was computed from information contained in the Annual Reports of the Petroleum Incentives Administration (1981-1983, Tables 4 and 7, p. 16; 1984, Table 6, p. 16 and Table 8, p. 18; 1985, Table 7, p. 16 and Table 9, p. 17; 1986, Table 7, p. 17 and Table 9, p. 19). During this period, development incentive grants accounted for less than 3% of total grants to activities in frontier regions.

19/ Exploration expenditures offshore from Canada's West coast were omitted since a ban on exploration activities in this region was in effect between 1971 and the mid-1980s. Data reported in column (2) of Table 2 were taken from the CPA *Statistical Handbook* (Section VI, Tables 6A and 11) before being corrected for inflation using the absorption price deflator. Note that for the purposes of this paper, "Northern Canada" refers to the Yukon and Northwest Territories and contiguous offshore areas.

Table 2: Exploration Expenditures, Tax Expenditures and Grants: Northern and Offshore Eastern Canada (millions of 1985 dollars)

Columns:
(1) Year
(2) Actual Expenditures
(3) Earned Depletion
(4) Super Depletion
(5) Other Tax Expenditures
(6) PIP Grants
(7) Grants and Tax Expenditures
(8) Corporate Contribution
(9) Corporate/Actual (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1967	119.2	0.0	0.0	39.8	0.0	39.8	79.4	66.7
1968	164.0	0.0	0.0	56.4	0.0	56.4	107.7	65.7
1969	312.0	0.0	0.0	107.2	0.0	107.2	204.8	65.7
1970	460.7	0.0	0.0	158.2	0.0	158.2	302.5	65.7
1971	675.7	0.0	0.0	228.7	0.0	228.7	446.9	66.1
1972	866.4	0.0	0.0	289.0	0.0	289.0	577.5	66.7
1973	921.7	0.0	0.0	301.3	0.0	301.3	620.5	67.3
1974	865.8	75.6	0.0	364.4	0.0	440.0	425.9	49.2
1975	752.7	93.7	0.0	356.1	0.0	449.8	303.0	40.3
1976	696.9	105.3	0.0	394.4	0.0	499.7	197.2	28.3
1977	697.4	105.4	87.9	388.9	0.0	580.2	117.2	16.8
1978	872.3	131.5	219.0	464.4	0.0	804.4	68.0	7.8
1979	993.3	150.3	248.4	457.0	0.0	858.1	135.3	13.6
1980	1136.9	180.6	129.7	543.1	0.0	854.5	282.4	24.8
1981	1521.1	147.9	0.0	445.3	588.5	1181.6	339.4	22.3
1982	1803.7	111.3	0.0	335.4	1106.3	1553.1	250.5	13.9
1983	2401.0	99.7	0.0	499.4	1343.7	1942.8	458.2	19.1
1984	2535.5	48.0	0.0	481.5	1487.3	2016.9	518.6	20.5
1985	2078.9	0.0	0.0	439.8	1148.0	1587.8	491.1	23.6

Sources: see footnotes 19 and 22 in text.

Notes:
1/ These calculations assume that all activities were undertaken by principal-business corporations in a fully taxable position.
2/ The main elements included in "Other Tax Expenditures", column (5), are tax expenditures arising as eligible expenditures net of their consequences on percentage depletion (when applicable) and an arbitrary 4-year allocation of the depletion deductions earned by eligible expenditures undertaken between November 1969 and May 1974, as per federal legislation.
3/ "Grants and Tax Expenditures", column (7), is the sum of columns (3), (4), (5) and (6).
4/ "Corporate Contribution", column (8), is the difference between columns (2) and (7), and includes Petro-Canada and other Crown corporations.
5/ "Corporate/Actual", column (9), is the ratio of columns (8) and (2).

dustry standards, for example, the offshore acreage held under federal exploration permits more than doubled.[20]

By the end of 1974, however, years of disappointing results brought about massive cancellations of offshore drilling permits by permit holders. Private-sector firms' disenchantment with the prospects for profitable oil and gas discoveries grew over the next few years, and it is partly in response to the observed fall in frontier activity levels that the federal government introduced super depletion in 1977. The next year heralded the beginning of the second push to the frontiers, which was strengthened by the introduction of the NEP's grant-based exploration incentive program late in 1980.

Figure 3[21] suggests that the two booms in fron-

20/ See Plourde (1986, items 68.7 and 69.5).

Legend

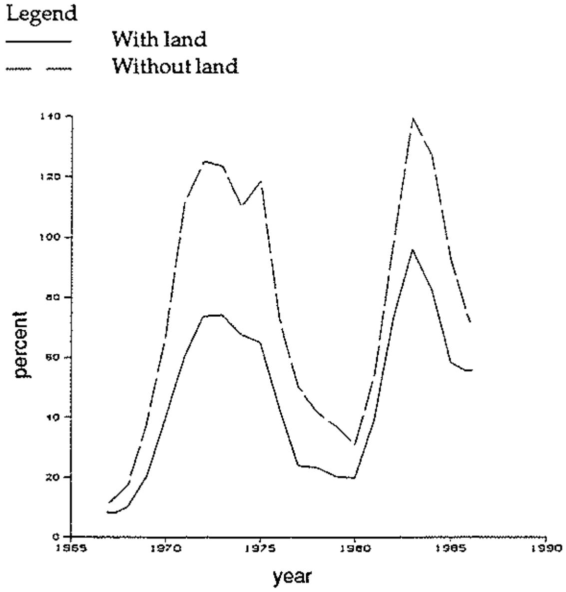

Figure 3: Exploration Expenditures in Northern and Offshore Eastern Canada as a Proportion of Exploration Expenditures in Western Canada, 1967-1986.

tier oil and gas exploration were obtained, to some extent, at the expense of activities in Western Canada. The shift away from the Western sedimentary basin was relatively more important during the second of these episodes, and especially so following the introduction of the NEP, since expenditures in frontier regions reached much higher levels during that time.

Table 2[22] presents some evidence on the role played by fiscal policy in bringing about these developments. The results in column (9), the proportion of real exploration expenditures effectively borne by firms, support the notion that the first push to the frontiers was not predicated mainly on tax-related developments. The magnitude of the tax consequences of super depletion and the incentive grant system, however, suggests that the second push was strongly encouraged by these changes in fiscal policy. Furthermore, it would appear that the $5 million ticket price to the super depletion stakes proved too high for many participants. In fact, even though the average share of real expenditures borne by firms was lower under this form of exploration incentive than under the NEP's system of incentive payments, growth in real expenditure levels was more sluggish under the former and, as Figure 3 shows, the share of total exploration expenditures undertaken in frontier areas actually fell between 1977 and 1980.

Another consequence of the preferential tax treatment extended to frontier exploration activities emerges from Table 3.[23] Average real drilling costs in frontier areas have been much higher during the period when enriched incentives were available. Between 1969 and 1976, for example, the average cost of drilling an exploration well in Northern Canada was about 7.2 million 1985 dollars, and 9.2 million 1985 dollars in the East coast offshore region. During the decade when super depletion and the NEP's grant-based incentive system were in effect, these figures reached 49.5 and 53.5 million 1985 dollars, respectively. Furthermore, a comparison of average real costs in the two peak years of the

21/ These series have been calculated with data reported in the CPA *Statistical Handbook* (Section VI, Tables 3A, 4A, 5A, 6A, 7A and 11). Note that in Figure 3, "With Land" and "Without Land" refer to whether or not land-related expenditures are included in the Western Canadian totals.

22/ Columns (3) to (9) report estimates obtained from a purpose-built tax accounting module. Column (8) is based on information contained in various issues of the Petroleum Monitoring Agency's *Monitoring Surveys* (table entitled "PIP Grants by Area and Type of Expenditure"). The tax consequences of super depletion - column (4) - have certainly been underestimated since it is assumed that all exploration wells drilled during the relevant period were equally costly.

23/ These series were calculated using information reported in the CPA *Statistical Handbook* (Section I, Tables 5, 5A and 5B; Section VI, Tables 3A, 4A, 5A, 6A, 7A and 11). The absorption price deflator was used to correct for the effects of inflation. In constructing this table, I did not have access to cost information for individual wells. The CPA *Statistical Handbook* and its predecessors, however, report total expenditures on exploration drilling and well completions by region, on an annual basis. To the extent that expenditures on individual wells are incurred in a different year than these wells are completed, then my annual estimates of average drilling costs will be inaccurate. Over longer periods of time, however, the degree of inaccuracy will be quite low.

Table 3: Average Drilling Cost of Exploration Wells

Year	(millions of current dollars) Northern Canada	East Coast Offshore	Western Canada	(millions of 1985 dollars) Northern Canada	East Coast Offshore	Western Canada
1967	0.21	n.a.	0.08	0.75	n.a.	0.30
1968	0.27	n.a.	0.08	0.94	n.a.	0.28
1969	0.59	5.90	0.07	1.97	19.82	0.25
1970	0.65	1.49	0.08	2.09	4.82	0.25
1971	1.06	1.66	0.07	3.30	5.16	0.23
1972	1.93	2.69	0.09	5.73	8.01	0.26
1973	2.06	1.96	0.09	5.68	5.40	0.23
1974	3.49	2.86	0.12	8.47	6.94	0.28
1975	4.87	6.29	0.12	10.55	13.64	0.25
1976	10.03	4.82	0.13	19.94	9.59	0.25
1977	15.44	11.90	0.17	28.33	21.84	0.32
1978	37.40	9.94	0.26	63.58	16.90	0.43
1979	23.34	34.03	0.43	36.38	53.05	0.67
1980	40.73	41.81	0.53	57.24	58.76	0.75
1981	62.05	43.14	0.58	77.86	54.14	0.73
1982	65.64	91.17	0.54	74.64	103.67	0.61
1983	81.98	66.26	0.59	87.99	71.12	0.63
1984	34.56	68.52	0.48	36.08	71.51	0.50
1985	20.82	42.32	0.50	20.82	42.32	0.50
1986	12.47	40.29	0.62	12.10	39.09	0.60

Source: see footnote 23 in text.

Note: "n.a." means "not available".

frontier booms identified in Figure 3 reveals that an average exploration well in Northern Canada or the East coast offshore region cost, in real terms, about 12 times more to drill at the second peak than the first.[24]

How does all this compare with costs in Western Canada? Between 1969 and 1976, the average exploration well in this region cost approximately 250 thousand 1985 dollars to drill. This rose by a factor of about 2.3, to 570 thousand 1985 dollars during the 1977-1986 period. Therefore, average drilling costs rose about 5 times faster in frontier regions than in Western Canada. Overall, between 1977 and 1986, the same amount of expenditures were incurred by society when one average exploration well was drilled in Northern Canada as when approximately 86 average exploration wells were drilled in Western Canada. During the same period, every average well drilled in the East coast offshore region cost the same amount as did more than 90 average exploration wells in Western Canada.

Although it is granted that technological changes may have contributed to the emergence of these trends, the sharp fall in the share of expenditures effectively borne by the firms doing the exploration must also have played an important role. The design of the frontier exploration incentives themselves is thus at least partly responsible for these developments.

As Table 2 shows, about 20 billion 1985 dollars have been spent on frontier exploration since 1967. Approximately 70% of these expenses have been incurred since the introduction of enriched frontier exploration incentives in 1977. The evidence presented here and in HMMP (1989, Chapter 9) shows that while there have not been substantially more frontier wells drilled, each of

24/ The average depth of frontier exploration wells also increased dramatically during this period. See HMMP (1989, Figure 9.3).

them has been drilled to greater depths and at much higher real costs. Furthermore, it is widely recognized that this massive investment program, financed at least in part at the expense of exploration activities in Western Canada, has not generated much in the way of recognized reserve additions.[25] Canada's forays into frontier oil and gas exploration have thus proven to be expensive propositions with little to show in the way of tangible output.

5. Lessons from the Past and Prospects for the Future

Section 3 reminds us that, while the fiscal system is an important element of the oil and gas industry's operating environment, it is not the only such element which is under domestic control. Domestic price determination and export restrictions are two other aspects of energy policy which have been shown to play an important role in shaping the operating environment of the upstream oil and gas industry. Therefore, focusing on one particular element to the exclusion of others may yield an incomplete picture.

The results of MACE model simulations also suggest that the historical pattern of changing royalty and tax rates may in fact have contributed to keeping the financial position of the oil and gas industry on a relatively stable footing, at least when compared to a more rigid fiscal system such as CURRENT. This pattern of results emerged because under the actual historical policies, average and marginal effective royalty/tax rates followed the cycle of prices and, according to the estimated equations in the MACE model, this meant that the short-run behaviour of producers was made to track more closely behavioural patterns based on longer-term considerations. When the policies prevailing at the end of 1986 are treated as having applied during the entire simulation period (the CURRENT case), the implicit lower and more constant effective royalty/tax rates bring about higher and more variable rates of return. Given the history of Canadian energy policy between 1974 and 1986, it seems reasonable to conclude that, if future price fluctuations are to be as important as those observed in the past, then the fiscal system embodied in CURRENT can probably best be seen merely as one of a sequence of fiscal systems that have been put in place since 1974. Under new market conditions, another fiscal system might be designed. The March 1987 introduction of the Canadian Exploration and Development Incentive Program (CEDIP) and the extension of preferential tax treatment to flow-through share financing, the subsequent announcements of the Canadian Exploration Incentive Program (CEIP, a combination supplement/successor to CEDIP) and of numerous changes to provincial royalty and incentive systems confirm the likelihood that fiscal change will continue.

It is possible, however, for one to accept the notion that average effective royalty and tax rates should follow the cycle of prices, but to decry the use of any approach to implement such a fiscal system that involves frequent discrete policy changes. After all, frequent changes in policy do make the operating environment more uncertain and invite investments directed at influencing the policy-making process in self-serving ways. Why use a particular approach if alternatives exist that can perform the same task with fewer undesirable side-effects?

An alternative approach that could potentially meet the above criterion would be a fiscal system in which the effective royalty and tax rates on upstream revenues depended on prices to a higher degree than is currently the case. As prices varied in the future, effective royalty and tax rates would vary in predictable fashion since the rules governing these rates would have been established and known prior to the price fluctuations being experienced. This could include, for example, fixed-rate provincial royalties that are levied on a measure of revenues net of some classes of expenditures instead of on gross production revenues, as is presently the case.[26]

25/ On this, see HMMP (1989, pp. 21-23).

26/ Note that this would imply a change in the nature of royalties, from payments for production rights to something more akin to taxes.

In these times of relatively low world oil prices, downward pressure on natural gas prices, and clear indications by governments of their willingness to alter, if necessary, the fiscal system to bolster the industry's financial health, a more flexible royalty/tax system having the characteristics outlined in the previous paragraph would find little if any support amongst government and industry officials. This may change, however, when the next sharp increase in world oil prices is followed, if history is any guide, by the announcement of new measures to bring about pronounced increases in effective royalty and tax rates on upstream oil and gas revenues.[27] Governments and industry may well come to realize that disputes of the type which followed the introduction of the NEP are costly, and that a more flexible fiscal system may help avoid them.

Based on the evidence presented in section 4, it seems clear that the policy of offering enriched frontier exploration incentives resulted in billions of dollars being diverted from other uses which would have been more socially profitable. Now that the NEP's grant-based system is almost completely phased out, is there hope that incentives for frontier oil and gas exploration will be brought more closely into line with economic realities? Current prospects on this front do not appear to be particularly encouraging. In October 1985, the federal government introduced a new policy towards exploration (and subsequent development and production) activities in frontier regions. This "new" system in fact combines elements of the two regimes in place since 1977. For firms in a fully taxable position, the 25% exploration tax credit for eligible expenditures in excess of $5 million per well is rather similar in its overall tax-expenditure impact to super depletion at a rate of approximately 56%. For non-taxpaying firms, the new policy's provisions allowing for a 40% cash refund of unused credits are similar to incentive grants at a rate of about 10%.

The October 1985 frontier policy also extends additional exploration incentives, but ties these to subsequent development and production of discoveries. At first look, this practice may appear desirable from the perspective of improving the efficiency of the royalty/tax system. However, it could well increase the pressure for tax and other concessions by proponents of high-cost frontier development projects in order to allow them to proceed with development and production, and thus realize the full value of the tax benefits "earned" by the exploration activities. If the federal government were to yield to such pressures, an even greater proportion of the risks associated with frontier oil and gas activities would end up being borne by the public.

Why has the federal government sought to encourage oil and gas exploration in frontier areas? Simply put, the primary objective during the late 1970s and early 1980s was the quest for security of energy supply. In the aftermath of the first world oil price shock and the transformation of Canada into a net oil importer, it was felt that the frontiers offered the prospects of huge discoveries, and thus of dramatically reducing the country's dependence on foreign sources of crude oil. As we know, this has not come to pass. Furthermore, the notion of national security of energy supply has been overtaken by events. The terms of the Canada-US free-trade agreement are such that US consumers are guaranteed proportional access to Canadian energy supplies, even when these are not sufficient to meet domestic requirements. From this perspective, frontier activities cannot be rationalized on the basis of enhancing domestic security of supply any more than on that of serving US energy markets.

More recently, the federal government has announced its intention to provide a financial assistance package worth over $1 billion toward the proposed development of the Hibernia oil field, located offshore from Newfoundland. It is widely acknowledged that without public-sector assistance this project would not break even

27/ If anything, the Canada-US free-trade agreement probably makes such fiscal responses more likely since it increases the cost to governments of using alternative instruments like price controls and export restrictions to meet distributional objectives in the face of foreign-based developments such as increases in world oil prices.

at the world oil prices prevailing in early 1989.[28] The high unemployment rates in Newfoundland, however, have been used by the government to rationalize the assistance to the Hibernia project on the basis of regional development policy. The use of energy policy as a regional development tool obscures the fact that these types of intervention in fact squander part of the value of non-renewable resource deposits such as Hibernia by developing and producing them too early.

Canadian oil and gas policy should reflect the fact that it makes good economic sense to discover and exploit lower-cost deposits before proceeding to higher-cost ones. With their emphasis on frontier activities, some policies in place between 1977 and 1986 did not do so, and some current policies do not appear to do so either. One cannot rely forever on low world oil prices to dampen the enthusiasm of firms to drill expensive wells in frontier areas when the tax treatment afforded such activities is as favourable as it is.

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28/ See, for example, Canada: Energy, Mines and Resources (1988) and *Doig's Digest* (August 1988, pp. 1-7).