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Changes in Canadian Energy Demand, Supply, and Policies, 1974-1986

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INTRODUCTION

This paper will outline and attempt to explain the major changes that have taken place in Canadian energy demand, supply, and policies in the decade since 1973. To provide a slightly longer range of analysis, energy demand and supply will be projected to 1986 under alternative patterns of world oil prices and domestic energy policies.

In order to explain what has happened, and why, it is helpful to have some benchmarks to which the "actual policies" case can be compared.[1] Two such benchmark cases have been chosen. In one, the "steady growth" case, a world without the two OPEC oil price shocks of the 1970s, is constructed. It is assumed that post-1973 real economic growth and inflation in the rest of the world equal their average rates over the preceding 20 years, and that world oil prices grow only two percent faster than the steady three percent rate of inflation in the United States.

In our second benchmark, the "world pricing" case, the actual values for world oil prices, world growth, and world inflation are used to calculate what Canadian energy demand and supply would have been had Canadian crude oil (and natural gas) prices moved immediately in line with all changes in world oil prices.

By comparing the first benchmark case with the second it can be shown what the Canadian impact of the world oil price changes would have been had Canadian energy prices kept in line with world prices. Comparing the second benchmark case with what actually happened will permit an assessment of the extent to which the slow response of Canadian energy prices influenced energy demand and supply.

To construct the benchmark cases, some framework or model is needed that can be used to reveal what energy demand and supply would have been had prices moved rather differently. The MACE (for MACro plus

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1. After 1982, the actual policies case assumes that current federal and provincial energy policies remain in place, although falling world oil prices are creating pressures for some modifications.

Energy) model of Canada is just such a tool. It attempts to explain how total energy demand is determined jointly with output, employment, investment, and other key macroeconomic variables. It also details how the various pricing and taxation policies, along with other factors, influence the split of energy demand by fuel and by region, the impact of taxation and energy pricing on energy supply, and the complicated distribution of potential energy revenues among producers, consumers, and governments. These latter features are crucially important to the explanation of the Canadian experience since Canadian energy policies must be explained in the context of revenue-sharing conflicts among regions, governments, industries, and nations.

In order for the model to be a convincing tool, it will also have to predict with some accuracy the actual evolution of energy demand over that part of the period for which final data are now available. Such evidence will be presented along with projections of total energy demand, and its distribution by fuel, under the two alternative benchmark cases.

In this paper, the evolution of energy supply and energy trade under actual prices and policies as well as in the two alternative benchmark cases will be examined. The effects of the actual energy policies, and of the alternative world pricing benchmark case, on the size and distribution of energy revenues will also be examined. An attempt is made to summarize and explain the effects of the federal government's National Energy Program (NEP) of October 1980,[2] the federal-provincial energy agreements of late 1981, and other important policy changes influencing Canadian energy demand, supply, and revenue distribution.

The final section of this paper summarizes the results and briefly examines the likely future evolution of Canadian energy demand, supply, and policies, with special attention to the impact of possible future changes in world oil prices.

THE EVOLUTION OF ENERGY DEMAND

Energy demand in Canada grew at an average annual rate of 7.8 percent between 1952 and 1973, but by only 2.7 percent from 1973 through 1981. To determine what happened one needs a clear view of how energy fits into the overall economy. The MACE model embodies our best efforts to develop such a view, and to fit it to the Canadian experience. The technical details of the model and its underlying data are reported elsewhere,[3] but the basic mechanisms can be described fairly simply.

2. *See* ENERGY, MINES AND RESOURCES CANADA, THE NATIONAL ENERGY PROGRAM 1980 (1980).

3. *See* Helliwell, McRae, Boothe, Hansson, Margolick, Padmore, Plourde & Plummer, *Energy and the National Economy: An Overview of the MACE Model* in University of British Columbia,

The economy is divided into two sectors: one produces, transports, refines and distributes energy, and the other uses energy, labor, and capital to produce everything else. The output of this main sector is equal to gross domestic product at factor cost plus net energy imports. The output of the energy-using sector is based on a two-level production function with capital and energy being bundled together at one level, and this bundle then combined with labor to produce output. Long-run factor demands are consistently derived in such a way as to minimize total costs. Energy and capital are bundled together using a so-called "vintage" approach that accounts for the fact that the energy efficiency of buildings and capital equipment varies according to when these were built, and also for the fact that it is usually cheaper to alter energy intensity at the design stage than to "retrofit" at some later date.[4]

The bundling of energy and capital means that the direct determinants of total energy demand are current and past investment expenditures, and current and past values of the price of energy relative to the price of investment goods. All of these variables are combined together to define appropriately the vintage structure of substitution between energy and capital. Naturally, anything that influences the price of energy, the general price level, or the desired size of the capital stock has direct implications for energy demand.

The big drop in energy demand growth from the pre-1973 period to the more recent period was due in part to higher energy prices and in part to lower economic growth. Figure 1 shows actual energy demand to 1981 (curve 1), energy demand in the steady growth case (curve 2), energy demand in the world pricing case (curve 3), and energy demand as predicted by the model (curve 4).[5] The model prediction in curve 4 is based on actual energy prices and investment expenditures; the discrepancy between curve 1 and curve 4 reflects random fluctuations plus errors in the structure of the model. The model suggested that energy demand

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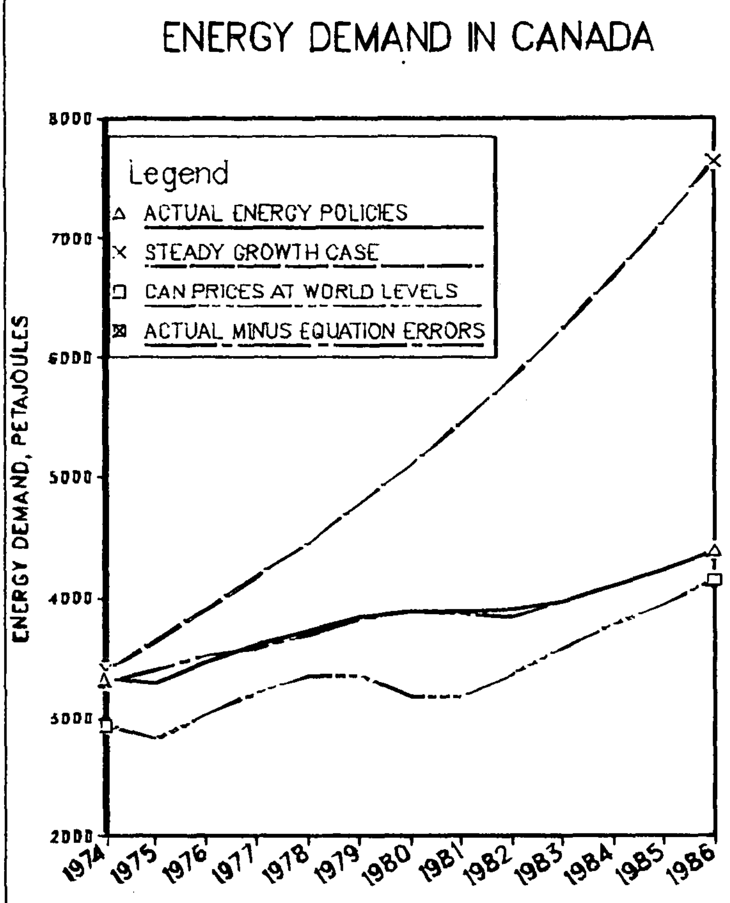
Department of Economics Resources Paper No. 89. *Forthcoming in* PROGRESS IN NATURAL RESOURCE ECONOMICS (A. Scott ed.) (in press).

4. In rigid vintage models, energy intensity is determined at the design stage and remains fixed until the capital is worn out or scrapped. We have adopted a more flexible vintage model in which the rate at which retrofitting is undertaken is an estimated parameter of the model. Energy and capital are combined in a vintage CES function that has an estimated long-term elasticity of substitution of 0.6 between energy and capital. Energy-capital fixity in existing capital is "freed-up" for adjustment at the proportional annual rate of 0.72. The energy-plus-capital bundle is combined with efficiency units of labor in a Cobb-Douglas outer function. Since the utilization rate of employed factors is cyclically variable, the production function parameters are either estimated from the derived factor demand equations, as with the key elasticity of substitution between energy and capital and the vintage parameter, or determined by sample averages and the condition that actual and desired factor use ratios should be the same on average over the 29-year sample period, 1952–1980.

5. In the actual policies and world pricing cases, world oil prices are assumed to be $29(US) in 1983. After 1983, they increase two percent faster than the U.S. rate of inflation. Data on actual energy demand are available only to the end of 1981.

FIGURE 1.


ENERGY DEMAND IN CANADA
Legend
ACTUAL ENERGY POLICIES
STEADY GROWTH CASE
CAN PRICES AT WORLD LEVELS
ACTUAL MINUS EQUATION ERRORS
ENERGY DEMAND, PETAJOULES
8000
7000
6000
5000
4000
3000
2000
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

would be 3.5 percent less than it actually was in 1975, but thereafter the errors rapidly decrease, with the 1981 forecast and actual values being different by only 0.4 percent. The production structure of the model is thus able to capture the striking change in energy demand growth, and can also be used to explain the relative importance of slower economic growth and higher energy prices as factors determining the big drop in energy demand relative to the "business as usual" steady growth case.

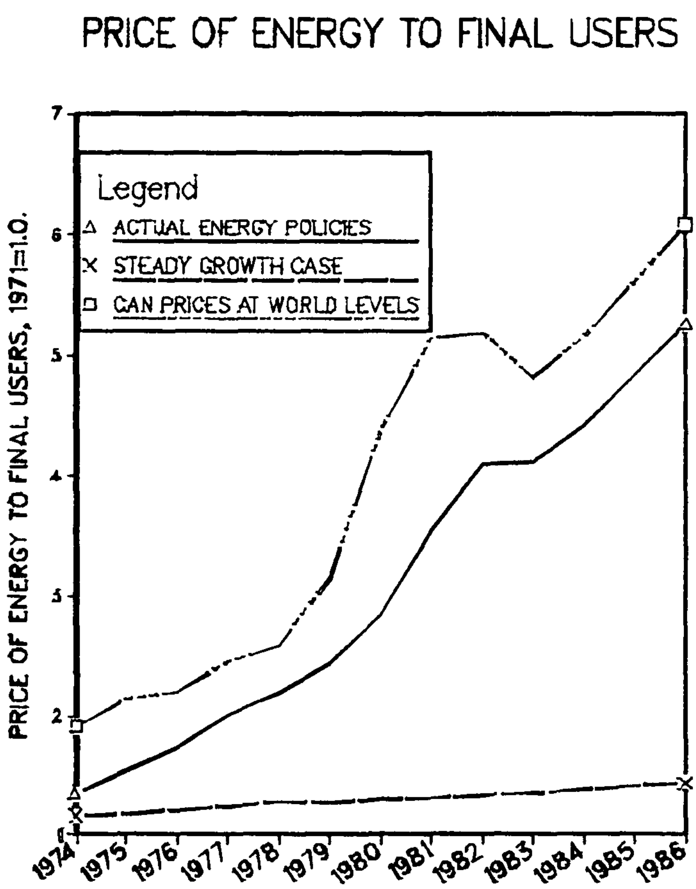
Relative to the steady growth case, predicted energy demand under actual policies was down by 33 percent in 1982. Slightly less than one third of this reduction was due to slower economic growth, with the rest attributable to a higher relative energy price. The price of energy relative to the GNP deflator was 57 percent higher in the actual policies case than in the steady growth case while the capital stock was nine percent lower. The world pricing case involves energy use that is 14 percent below the actual. The capital stock in the world pricing case is only one percent less than actual, and the remaining 13 percent of the 14 percent lower energy use is due to a relative domestic energy price that was, by 1982, about 20 percent higher in the world pricing case than under actual policies.

The different energy price indices that underlie the three cases are shown in Figure 2. The aggregate energy prices are current-weighted implicit deflators of the separate prices of the three final energy forms: oil products, natural gas, and electricity. The prices for individual fuels are those paid by final users and hence include all taxes, distribution markups, and refining charges. In Canada, as in most countries, the costs and profits of refiners and distributors form a large part of the final user prices of energy.

At one time, it may not have mattered very much whether energy studies employed refinery-gate crude oil prices and city-gate natural gas prices rather than the prices paid by final energy users. The several-fold increases in crude oil and city-gate natural gas prices in the 1970s, however, were not accompanied by corresponding increases in pipeline and refinery margins, so that user prices grew much more slowly than crude oil prices. Energy demand models that were based only on city-gate natural gas or crude oil prices would, therefore, have overstated the likely response of energy demands to the higher energy prices of the 1970s. To give a particular example, the average crude oil price in Canada, delivered to the refinery, but before refining charges, distribution charges, various sales and excise taxes, increased from \$3.67 per barrel in 1973 to \$34.16 in 1982.[6] Over the same period the margin covering all the latter costs

6. Unless otherwise stated, all dollar values are expressed in Canadian currency. Energy prices for 1982 are preliminary.

FIGURE 2.


PRICE OF ENERGY TO FINAL USERS
Legend
ACTUAL ENERGY POLICIES
STEADY GROWTH CASE
CAN PRICES AT WORLD LEVELS
PRICE OF ENERGY TO FINAL USERS, 1971=1.0.
7
6
5
4
3
2
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

and charges rose from $7.41 per barrel in 1973 to $15.85 per barrel in 1982.[7] Thus, the user price of oil products grew roughly five-fold from 1973 to 1982 while the crude oil price increased ten-fold, or twice as much.

The total energy demand forecasts from MACE indicate that proper accounting for user prices and allowance for the links between the demands for energy and capital enable the model to explain the dramatic reduction in energy demand growth after 1973. Thus there appears to have been no fundamental change in the underlying structure of the demand for energy, since the dramatic changes in overall energy demand growth are fully explained by the sharp changes in energy prices and economic growth.[8]

There remains to explain why the pace of economic growth fell so much in the post-1973 period. A parallel paper on Canadian stagflation and productivity decline since 1973[9] assesses the relative importance of the various shocks that pushed the Canadian economy away from the steady growth path. The two key factors were the rises in world oil prices and, more importantly, the associated stagflation in other industrial economies. Once these factors were taken into account, by having foreign variables follow their actual rather than their steady growth paths, there was relatively little to account for by domestic monetary and fiscal policies, and by residual factors. As will be discussed further in this paper, Canadian energy policies had the effect of slowing the response of Canadian energy prices to changes in world prices, especially between 1974 and 1980. The smoother path of domestic energy prices, which is shown clearly in Figure 2, also smoothed somewhat the year-to-year changes in economic growth, but had little effect on the size of actual or potential output at the end of the period.

The sharp changes in the rate of growth of the total demand for energy were also accompanied by changes in the demands for individual fuels. The model distributes energy demand by fuel through a set of estimated share equations determined principally by relative prices and natural gas availability. Figures 3, 4, and 5 show the distribution of energy demand

7. In 1973, provincial sales taxes on motor fuels ranged from $0.15 to $0.25 per gallon (from $5.25 to $8.75 per barrel) for gasoline, with automotive diesel fuel generally taxed at a slightly higher rate. Between 1974 and 1979, these specific levies were gradually eliminated in Alberta and very slightly increased in some other provinces, so that the 1979 levies on gasoline ranged from zero to $9.45 per barrel. After the 1979–80 surge in world oil prices, Alberta kept its tax at zero and all of the other provinces shifted to ad valorem taxes that, in 1981, ranged from 16 percent to 22 percent of a specified "normal retail price," or from $7.00 to $11.30 per barrel.

8. Tests were run to see if the structure of the energy demand equation itself was different before and after 1973, and no differences were found.

9. Helliwell, *Stagflation and Productivity Decline in Canada, 1974–1982*, 17 CAN. J. ECON. ___ (1984).

FIGURE 3.

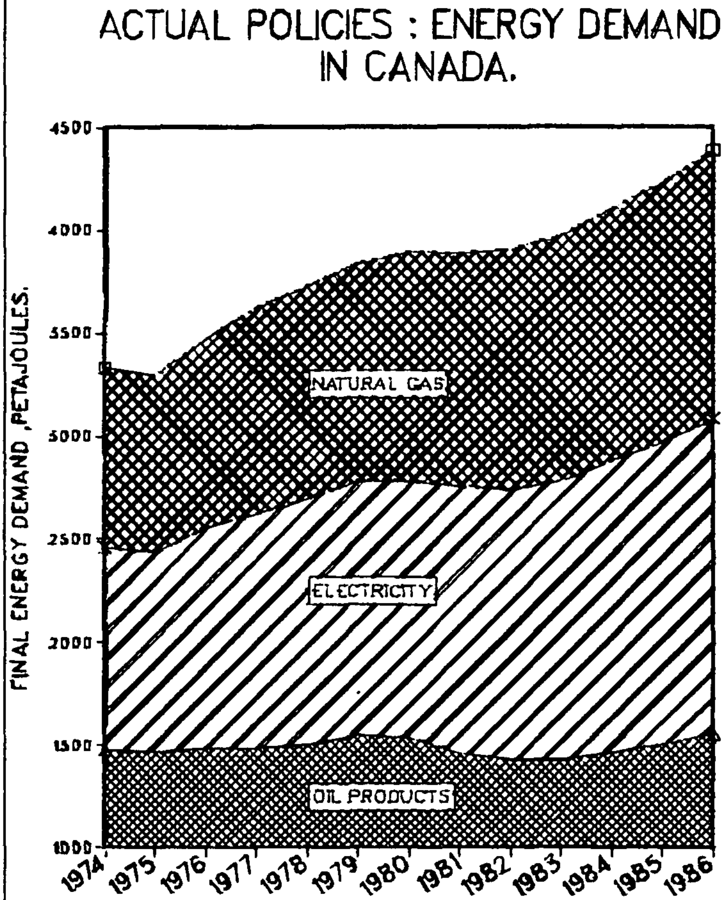

ACTUAL POLICIES : ENERGY DEMAND IN CANADA.
FINAL ENERGY DEMAND ,PETAJOULES.
4500
4000
3500
3000
2500
2000
1500
1000
NATURAL GAS
ELECTRICITY
OIL PRODUCTS
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

FIGURE 4.

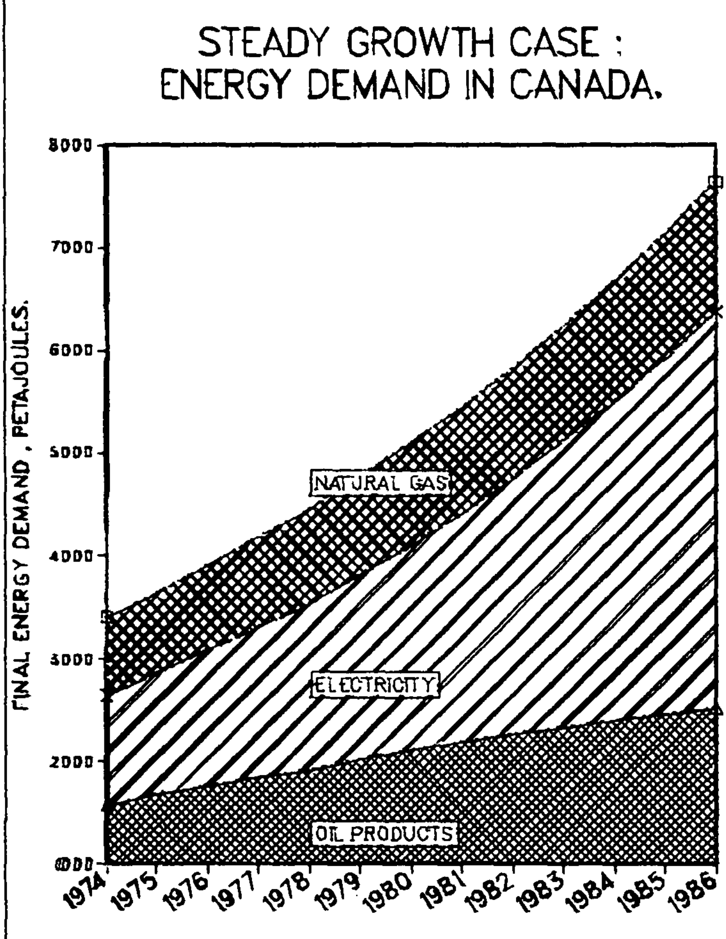
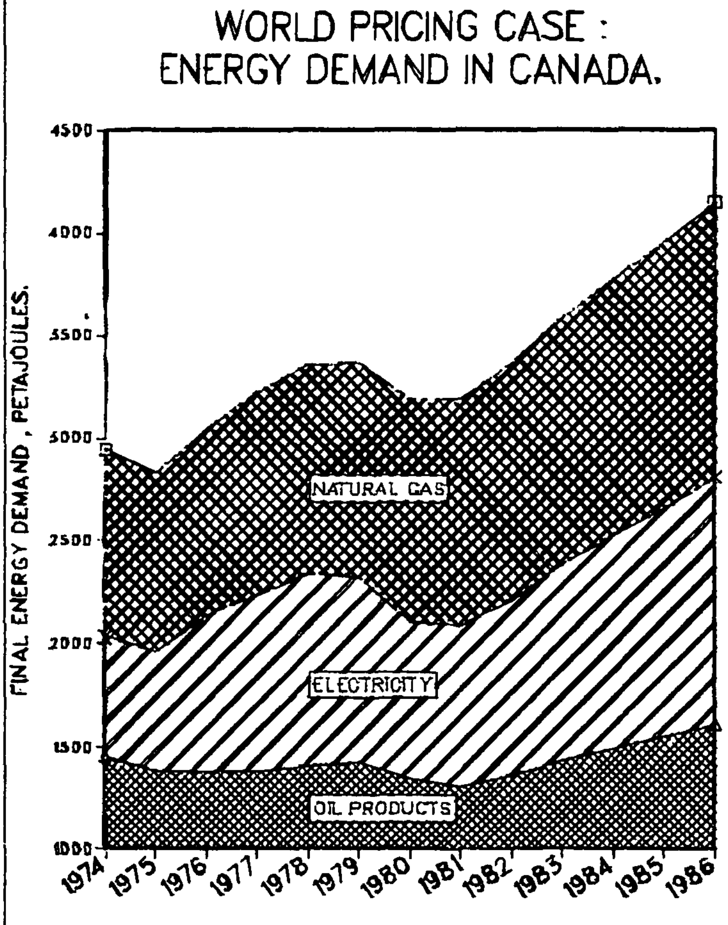

STEADY GROWTH CASE :
ENERGY DEMAND IN CANADA.
FINAL ENERGY DEMAND , PETAJOULES.
8000
7000
6000
5000
4000
3000
2000
NATURAL GAS
ELECTRICITY
OIL PRODUCTS
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

FIGURE 5.


WORLD PRICING CASE :
ENERGY DEMAND IN CANADA.
FINAL ENERGY DEMAND, PETAJOULES.
4500
4000
3500
3000
2500
2000
1500
1000
NATURAL GAS
ELECTRICITY
OIL PRODUCTS
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

by fuel in the actual policies, steady growth, and world pricing cases. The world pricing case involves both crude oil and natural gas being priced (at the city-gate) at world levels; for natural gas, this is taken to be an equivalent price per btu, requiring an increase of $0.15 per thousand cubic feet (mcf) of natural gas for each $1 per barrel increase in the price of crude oil.

Both the actual policies and the world pricing cases involve relatively greater use of electricity than in the steady growth case, because electricity prices rose much less quickly than those for oil products and natural gas. Relative to the steady growth case, natural gas demand is most affected by the higher prices. This is partly because the estimated long-run price elasticities are higher for natural gas than for crude oil products (−0.70 vs −0.66), but mainly because the user price of natural gas rises more than the user price of oil products. This happens because the distributors' margin is proportionately bigger for oil products than for natural gas, thus reducing the proportionate impact of increases in the city-gate price. For example, in 1982 the distributors' margin was one third of the user price of oil products while the corresponding margin for natural gas was only one sixth of the user price.

Changes in Energy Supply and Energy Trade

An earlier paper[10] compared the Canadian energy supply situation with that of the United States. Both countries are relatively well endowed with primary energy sources. Compared to the United States, Canada has substantially less coal, and substantially more hydroelectricity. Both countries have used nuclear power in about the same amount per capita, although Canada's production of nuclear power is concentrated in Ontario. Hydroelectricity is spread somewhat more evenly, with some provinces (Quebec, British Columbia and Manitoba) obtaining almost all their electricity from hydroelectric power plants. Oil, natural gas, and coal are used to generate the remaining electricity needs in the rest of the provinces. Canada's conventional oil and natural gas resources are heavily concentrated in Alberta, which accounts for about 85 percent of the production of each. Most of the remaining crude oil comes from Saskatchewan and most of the remaining natural gas from British Columbia.

The general pattern of Canadian energy trade has involved net imports of crude oil and, until recently, coal, and substantial exports of natural gas and occasionally electricity, both to the United States. Natural gas exports have sometimes been almost as large as Canadian natural gas

10. Helliwell, *Canadian Energy Policy*, 4 ANN. REV. OF ENERGY 175 (1979), for the sources of the comparisons made in the following paragraphs.

use, while electricity exports have occasionally been as high as 10 percent of Canadian use.

How and why have the patterns of Canadian energy supply and trade been altered in the decade since 1973? In the early 1970s, Canadian production and exports of crude oil and natural gas increased rapidly in response to the growing U.S. acceptance of, and demand for, imports of energy. Thus, the unsustainable 1973 production of conventional crude oil (which has not been equalled since) was the result of the same forces that were responsible for the 1973–74 explosion of world oil prices. After 1973, both export policy and natural production limits led to reduced production and exports of crude oil. During the mid-1970s there was also much concern[11] that domestic demand and existing long-term export contracts for natural gas would strain the deliverability of natural gas from western Canada by the early 1980s, and would require construction in the 1970s of a pipeline to tap natural gas resources in the Mackenzie Delta and elsewhere in the Canadian Arctic. It eventually became obvious that such forecasts did not take adequate account of the effects that the higher natural gas prices were already starting to have in reducing demand and increasing supply from non-frontier sources. Since the late 1970s, there have been many applications submitted to permit large increases in natural gas exports, and most have been approved. However, the decline in U.S. energy use has lessened the demand for Canadian natural gas and, in early 1983, exports were flowing at less than half of their permitted volumes.[12]

The effects of prices on energy supply are difficult to quantify. Part of the problem lies in the long time lags required for exploration, development, and construction, the long production period for oil and natural gas, and the non-renewable nature of hydrocarbon energy sources. In addition, there is substantial uncertainty about the costs of some of the likely marginal sources, including synthetic oil from oil sands, heavy oil deposits, Arctic and offshore oil and natural gas deposits, and coal liquefaction.

The MACE model embodies price-responsive drilling activity and estimated cost functions for new discoveries of conventional crude oil and natural gas. The model also contains separate sectors describing the costs and supply of energy from synthetic oil plants, from the sometimes-proposed development of natural gas in the Arctic, and from the currently envisaged development of the two billion barrel Hibernia offshore field near Newfoundland. Each synthetic oil plant or frontier energy project falls in the "megaproject" class, having capital expenditures of several

11. *Id.*
12. *See* 34 OILWEEK 5 (October 24, 1983).

billion dollars. Although the economics of these projects are importantly affected by world and domestic oil prices, as well as by domestic costs and taxes, there are also environmental, regulatory, and other similar considerations that influence their feasibility, scale, and timing. Within these limits, which are treated explicitly in the model, the megaprojects can be switched on at any particular date. In the steady growth case, none of these projects (beyond the original 50,000 barrels per day Great Canadian Oil Sands project constructed in the 1960s) are included. In the two high price cases, the Syncrude oil sands project (which has always received world prices for its output) is included, but no other projects are started before 1986.

Figure 6 shows the crude oil production flows (in thousands of barrels per day) for the actual policies, steady growth, and world pricing cases, while Figure 7 shows net oil imports for the same three cases.

Under the steady growth case, discoveries and eventual production of conventional oil are sharply reduced by very low prices, and by the absence of any expansion of synthetic oil capacity. However, production during the mid-1970s is significantly higher, driven by the much higher domestic oil demand.[13] The world pricing case sometimes has lower and sometimes higher production than the actual policies case. Natural gas prices are raised even more than prices of oil products in the world pricing case, leading to some switching of demand from natural gas to oil products within the smaller overall demand for energy. In addition, cumulative oil discoveries during the 1970s are estimated to be 360 million barrels greater in the world pricing case than in the actual policies case, and these permit higher production levels when demand comes to exceed production capacity.

Net oil imports, which are based on demand in Quebec and the Atlantic provinces less the amounts provided by the Montreal pipeline extension completed in the late 1970s, are highest in the steady growth case and lowest in the world pricing case, with the actual case falling in between.

In all of the three cases considered, Canada remains throughout the period a net importer of crude oil and a net exporter of natural gas. What are the prospects for the longer term? Given the relative abundance of natural gas, it is likely that efforts will continue to encourage substitution of natural gas (and natural gas liquids) for oil products. The key mechanism used has been the natural gas price, with the city-gate price now set at 65 percent of btu-equivalence with the delivered price of crude oil. This policy is assumed to continue to the end of the projection period in 1986. By the end of the century, however, the currently foreseen discoveries of natural gas in the non-frontier areas start becoming unable to

13. Oil exports follow the same pattern in all three cases.

FIGURE 6.

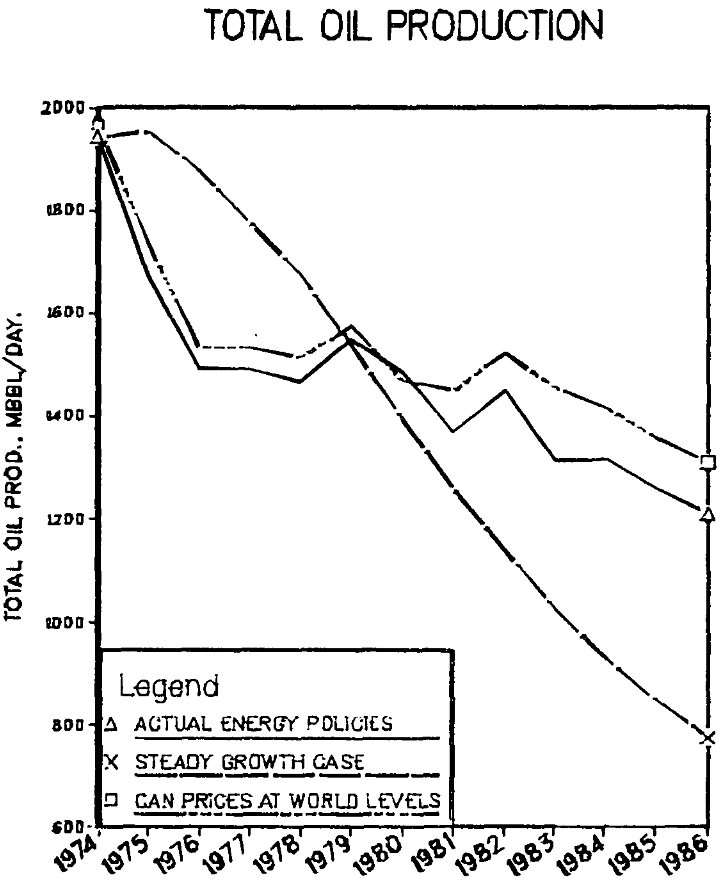
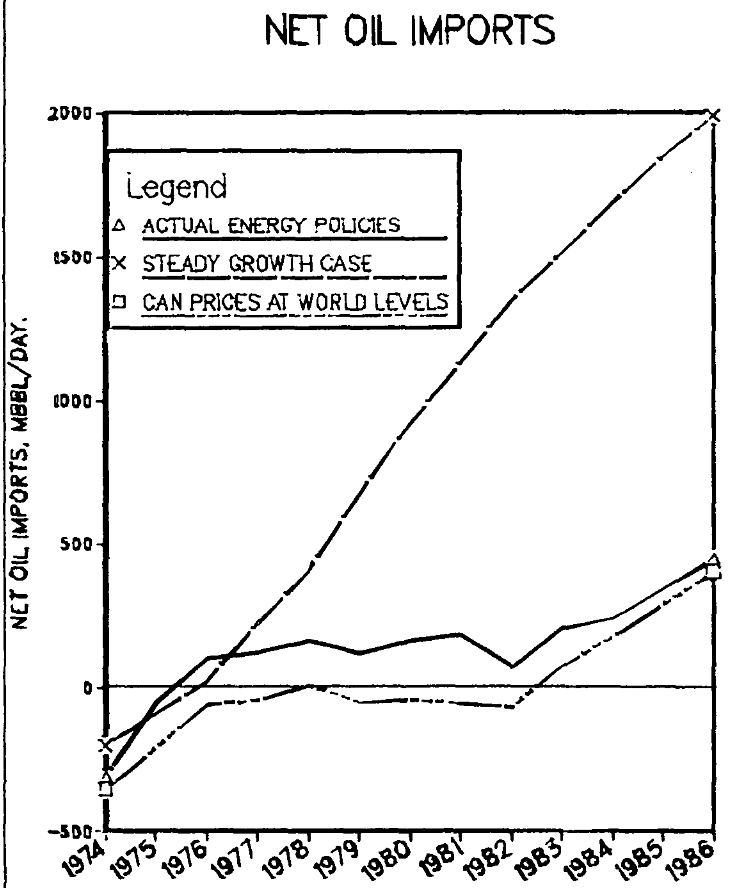

TOTAL OIL PRODUCTION
TOTAL OIL PROD., MBBL/DAY.
2000
1800
1600
1400
1200
1000
800
600
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
Legend
ACTUAL ENERGY POLICIES
STEADY GROWTH CASE
CAN PRICES AT WORLD LEVELS

FIGURE 7.


NET OIL IMPORTS
Legend
ACTUAL ENERGY POLICIES
STEADY GROWTH CASE
CAN PRICES AT WORLD LEVELS
NET OIL IMPORTS, MBBL/DAY.
2000
1500
1000
500
0
-500
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

maintain production levels high enough to provide for domestic demands. This occurs even though approved exports have been terminated and the city-gate price of natural gas has been pushed gradually towards btu-parity with crude oil, reaching 80 percent at the end of the century and 95 percent 15 years later.

The projections of declining natural gas self-sufficiency and increasing import dependence for crude oil (65 percent by the end of the century) make no allowance for new natural gas production from the frontier areas, coal liquefaction, major heavy oil developments, or crude oil from off-shore or Arctic developments. The projections do provide for oil sands production to rise by about 160,000 barrels per day, reaching 312,000 barrels per day, or about 12 percent of total demand, by the end of the century.

At this stage it is not clear what the actual pattern of new developments and projects is likely to be over the next two decades. The most likely, and probably the least costly, of the major frontier or non-conventional sources is the Hibernia offshore development near Newfoundland, which is projected on the basis of currently foreseen reserves to be producing 200,000 barrels per day by 1990. It is also likely that the extensive research on alternative extraction methods for oil sands, heavy oil deposits, and natural gas in tight formations will have borne fruit, and will permit substantial production at costs comparable with, or at least not above, world oil prices in the early 1980s.

It is also quite likely that at some stage the rises in energy prices will combine with design changes and energy-saving electronic technology to reduce energy demand, for any given prices, to levels well below those based on the data from the 1950s through 1980. For example, the MACE equation for total energy demand shows the demand for energy to increase one percent per year faster than is required to minimize costs under the assumption that all technical progress has been Harrod-neutral. This implies that actual technical change has, over the past thirty years, been energy-using in nature. This energy-using bias must have been due in part to the declining prices and relative abundance of crude oil from 1950 to the early 1970s.

We expect that the sharp increases in energy prices over the past decade will, in combination with the largely independent revolution in energy-efficient electronics, lead to an energy-saving bias in technical change over the next 20 years. A change from an increase of one percent to a decrease of one percent in the "technology-induced" portion of energy demand growth, which has not shown up in the data yet, could cumulate to a one-third reduction of energy demand by the end of the century. This would have obvious implications for energy prices and the economic attractiveness of many of the high cost new sources now under consideration.

Until the uncertainties about long-run energy demands, likely world energy prices, and the costs of new sources are reduced somewhat, there is not likely to be immediate development of any of the large high cost sources of petroleum and natural gas. Continued steady exploration and development of conventional deposits, plus continued research and experimentation with oil sands and heavy oils, is the more likely pattern, at least for the next two or three years.

In electricity supply, the sharp rises in oil and natural gas prices have led the electricity utilities (most of which are provincial Crown corporations) to cut their use of natural gas (which was mainly used in the western provinces) and residual oil (mainly used in Ontario and the Atlantic provinces) in the thermal generation of electricity. This was done chiefly by increasing the use of coal, with some increasing reliance placed on nuclear and hydroelectric power sources.

The rising cost of hydrocarbons combined with higher interest rates and construction costs to cause major increases in electricity prices between 1974 and 1982. These prices did not increase nearly as much as the user prices for natural gas and oil products, but rose substantially more than the general rate of inflation. The rising price of electricity and slower economic growth reduced the demand for electricity far below what had been expected when new electricity supply projects were being planned in the early and mid-1970s. As a result of these forecasting errors, the late 1970s and early 1980s have seen substantial excess capacity in the electricity supply systems in most provinces. This has led to sharp increases in exports, since exports are usually undertaken primarily as a vent for surplus supply capacity. There have also been major cutbacks and deferrals of investment spending on new projects. When new electricity supply investment picks up again later in the decade, the marginal sources will continue to be thermal coal in Alberta and Saskatchewan, hydroelectricity in British Columbia, Manitoba, and Quebec, and nuclear and thermal coal in Ontario and the Atlantic provinces. The use of fuel oil and natural gas in electricity generation has already been greatly reduced, and is likely to be entirely eliminated, except for some remote locations supplied by diesel generators, during the rest of the 1980s.

THE ROLE OF ENERGY POLICIES

To understand Canadian energy policy, it is necessary to remember that Canada is a federation in which the federal and provincial governments have overlapping powers relating to the taxation and regulation of natural resources. The main energy resources are owned by the provinces, except for Arctic and offshore resources which belong to the federal government. Until 1981, the provinces could only use direct taxes, royalties, bonus bids, and direct development by Crown corporations as means of collecting revenues from energy resources within their boundaries. This sometimes led to legal restrictions on provincial royalty-like taxes on freehold resources. Under the new Constitution, the provinces are able to use any type of taxation in relation to non-renewable resources, forestry resources, and electricity generation.

The federal government's main powers over energy resources flow from its power to regulate inter-provincial and international trade, and from its powers to raise money by any mode or system of taxation. The main limitation on this power is set by Section 125 of the Canada Act 1982, under which ". . . no lands or property belonging to Canada or any Province shall be liable to taxation."[14]

In summary, the federal powers can be used to limit the prices and quantities of provincial sales of energy to other provinces or to export markets. The provincial governments' ownership gives them the right (in the absence of a perceived emergency, which gives overriding power to the federal government) to withhold production if they are not satisfied with the tax and royalty system. Each level of government thus has the power to thwart the development or revenue-raising powers of the other, and neither, therefore, has sufficient power to proceed contrary to the fundamental interests of the other.

In these circumstances, it comes as no surprise that each of the world oil price shocks was followed by a period of competing and conflicting claims for shares of the potential energy revenues. During each of these periods when some agreed settlement was being sought, the federal government's main tool for redistributing energy revenues was the setting of key energy prices for Canadian users at levels far below their escalating world values. The main tool used by Alberta, the province with 85 percent of the crude oil and natural gas, has been the power to withhold production and to delay approval of new energy projects.

The nature and results of the 1974–75 and the 1980–81 conflicts are rather different, although the net effect of each was to delay the approach of Canadian energy prices toward world levels. The mid-1970s conflicts have been described in detail elsewhere,[15] so we shall concentrate here on the aftermath to the 1979–80 doubling of world oil prices.[16]

14. CANADA ACT 1982, Special issue Can. Gaz.—Part III (1982).

15. Helliwell, *supra* note 9, at 186–210.

16. Two other papers, Helliwell, McRae, Boothe, Hansson, Margolick, Padmore, Plourde & Plummer, *supra* note 3 and Helliwell *supra* note 9, use the MACE model to assess the macroeconomic effects of the phased movement of Canadian energy prices towards world levels. *See* Helliwell,

In order to understand the events of 1980 through 1982, it is useful to bear in mind three key features of the agreed policies that were in place when the world oil prices started to escalate in 1979:

(i) until mid-1979, the Canadian oil price was increasing towards world levels in agreed steps of $1 per barrel every six months, while the Toronto city-gate price of natural gas was set at 90 percent of btu parity with crude oil;
(ii) out of general revenues, the federal government paid a subsidy on imports of crude oil into Quebec and the Atlantic provinces equal to the difference between the average cost of imported oil and the regulated domestic price; and
(iii) the federal government's tax revenues from crude oil and natural gas were essentially limited to the corporation income tax, which included a number of concessionary features for oil and natural gas producers, and an export tax on the declining quantity of oil exports.

The result of these three features was that the 1979–80 doubling of world oil prices converted the federal government's share of net economic rents from crude oil and natural gas from 4.2 percent in 1978 to −3.1 percent in 1980. As shown in Figure 8 the consumer share of the net economic rents went from 32 percent in 1978 to 56 percent in 1980.[17] The average Toronto city-gate crude oil price (including the Syncrude levy used to finance the payment of the world price to producers of synthetic oil) grew from $12.90 per barrel in 1978 to $18.50 in 1980, while at the same time the landed price of imported oil was rising from $16.70 per barrel to $35.80. This meant large benefits for users of crude oil and natural gas, but a large expenditure drain from the federal government: the 1980 subsidy payments for imported oil exceeded $3 billion, or one percent of GNP.

It was in this context that the federal government introduced its National Energy Program (NEP) in October 1980. In November 1979, the Progressive Conservative government had fallen over its budget, which involved some moves towards world oil prices and a federal excise tax on gasoline. A Liberal government was elected in early 1980 on a platform of low

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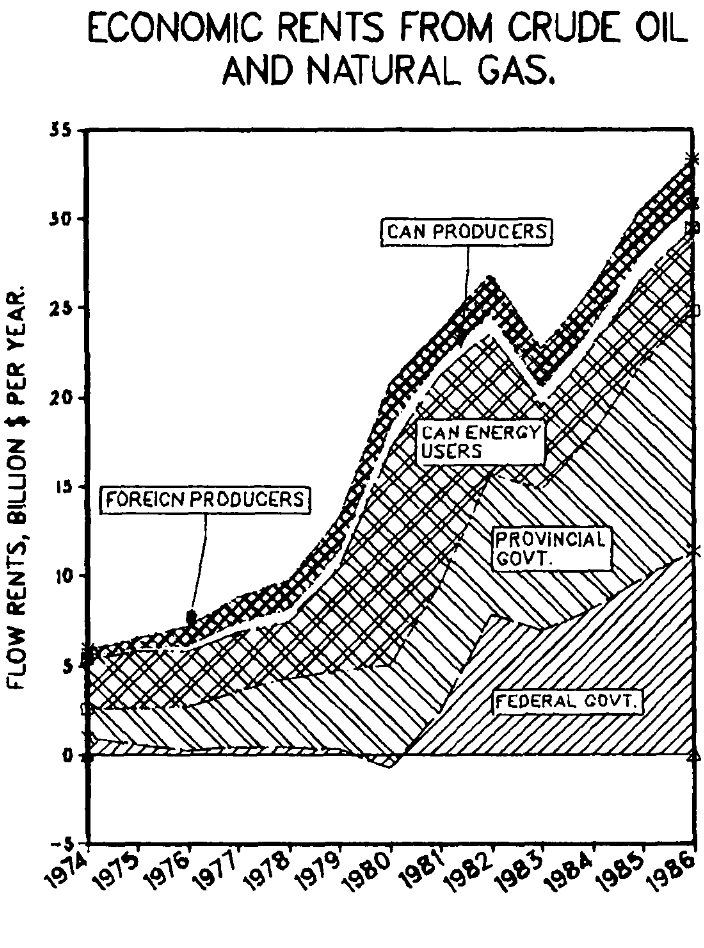
Boothe & McRae, *Stabilization, Allocation and the 1970's Oil Price Shocks*, 84 SCAND. J. ECON. 259 (1982), *and* Helliwell, *supra* note 10.

17. All of the economic rents are measured net of opportunity costs of capital employed (using the economy-wide after-tax return for producers, and the average corporate income tax return for governments) and net of economic waste for energy users (i.e. the rents to energy users are compensated measures of consumer surplus). The top line in the figure represents the total rents received by Canadian energy users, both levels of government, and all firms producing oil and natural gas in Canada. It is less than total rents to the resource because it leaves out rents received by U.S. purchasers of Canadian natural gas. These rents were material in the mid-1970s, but have been much smaller since.

FIGURE 8.


ECONOMIC RENTS FROM CRUDE OIL AND NATURAL GAS.
FLOW RENTS, BILLION $ PER YEAR.
35
30
25
20
15
10
5
0
-5
CAN PRODUCERS
CAN ENERGY USERS
FOREICN PRODUCERS
PROVINCIAL GOVT.
FEDERAL GOVT.
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

energy prices and a strengthened role for PetroCanada, the federal government's recently established national oil company. With this background, and in the light of the inability of the federal and provincial governments to develop a consensus on energy pricing and taxation, it was not surprising that the NEP contained a number of features that were unacceptable to the governments of the producing provinces. The main elements of the NEP[18] were:

(a) the unilateral establishment of a "made in Canada" price for conventional oil, to increase by $2 per barrel per year between 1981 and 1983 (with corresponding increases in the wellhead price of natural gas), and by larger amounts thereafter until reaching a "reference price" of $38 per barrel in terms of 1980 dollars; the immediate establishment of a price of $30 per barrel for oil from tertiary recovery, and $38 per barrel for synthetic oil;

(b) a Petroleum Compensation Charge (PCC) on all oil users, initially set at $5.50 per barrel, eventually intended to cover the subsidies on imported and synthetic oil;

(c) transfer of 50 percent of the oil export tax revenues to the producing provinces;

(d) a new Natural Gas and Gas Liquids Tax (NGGLT) on all natural gas production, starting at $0.30 per mcf and rising to $0.75 per mcf in 1983;

(e) a Petroleum and Gas Revenue Tax (PGRT) levied at eight percent of revenues, net of operating expenditures, from conventional and synthetic petroleum and natural gas production;

(f) the phasing out of depletion allowances, to be replaced by Petroleum Incentive Program (PIP) grants that pay from zero percent to 80 percent of allowable capital expenditures depending on the location (up to 80 percent for exploration in the Arctic and offshore regions, compared to a maximum of 35 percent in provincial lands) and on the degree of Canadian ownership (with maximum rates payable to firms with more than 75 percent Canadian ownership);

(g) the reservation to the Crown of a 25 percent interest in every right on Canada Lands,[19] coupled with the requirement that any operator on Canada Lands must have a minimum of 50 percent Canadian ownership.

The last two measures have received the most attention in international

18. Analysed in some detail in Helliwell & McRae, *The National Energy Conflict*, VII CAN. PUB. POL. 14 (1981).

19. The Canada Oil and Gas Act uses this term to refer to areas that fall under Canadian jurisdiction but outside the jurisdiction of any of the provinces. Canada Oil and Gas Act, 1980–81 Can. Stat. ch. 81.

commentaries, since they involve changes that have differential effects on domestic and foreign firms. In terms of impact on energy demand, supply, and revenue distribution, the other elements were of far more importance. The measures particularly opposed by Alberta were the unilateral setting of wellhead prices, the levy of a tax on exports of natural gas, the royalty-like nature of the PGRT, and the degree of direct federal control involved in the establishment and administration of the ownership-related PIP grants. On October 30th, two days after the introduction of the NEP, the government of Alberta announced that it would make phased cutbacks of up to 15 percent in the production of conventional oil and delay approval of the Alsands and Cold Lake synthetic and heavy oil projects until an agreed resolution could be achieved.

Subsequent economic analysis of the stalemate caused by the NEP and the Alberta cutbacks[20] revealed that the average Canadian (and especially the average Albertan) was worse off under the stalemate than under either the original NEP or the alternative pricing proposals suggested earlier by Alberta. There appeared to be ample incentive to find a compromise solution, particularly one that involved higher prices for energy users as a source of additional revenues for both levels of government and the producing industry.

During the period of stalemate, the federal government introduced two new levies. The first was an addition to the PCC intended to cover the subsidies on additional imports made necessary by the Alberta cutbacks. The second (introduced on May 1, 1981) was a levy of $1.15 per barrel on crude oil and $0.15 per mcf on natural gas to finance the $2 billion plus cost of PetroCanada's post-NEP purchase of all the shares of the previously Belgian-controlled Petrofina.

In September and October of 1981 the stalemate was broken after both levels of government came under increasing pressure, from energy producers and consumers alike, to find some form of accommodation.[21] The key elements of the energy agreements, which cover the 1981 to 1986 period, are:

(a) a distinction is made between "old" oil (discovered before December 31, 1980) and "new" oil. Old oil was to rise in fairly rapid steps to a ceiling of 75 percent of the landed price of imported oil. The wellhead price for old oil reached $29.75 per barrel at the beginning of 1983; under the NEP, the wellhead price for conventional oil at the beginning of 1983, with no

20. *See* Helliwell & McRae, *supra* note 17.

21. Three separate energy agreements were signed by the federal government and the government of each of the oil and natural gas producing provinces. For a discussion of the details of the agreements, *see* Helliwell & McRae, *Resolving the National Energy Conflict: From the National Energy Program to the Energy Agreements*, VII CAN. PUB. POL. 15 (1982).

distinction between old and new oil, was to have been $21.75 per barrel. The extra producer revenue on old oil is to be taxed by an Incremental Oil Revenue Tax (IORT) of 50 percent of incremented revenues net of royalties instead of the normal corporate income tax.

(b) All new oil and synthetic oil, whether from new discoveries, tertiary recovery, or oil sands projects, receives a New Oil Reference Price (NORP) that was to rise quickly to a ceiling of 100 percent of the landed price of imported oil. This world price ceiling has been applicable ever since.

(c) The PCC was altered so that it would continually raise enough revenue to cover the extra costs of new oil, synthetic oil, and imported oil.

(d) The price for natural gas sold from Alberta to the eastern provinces is regulated at the Alberta border rather than at Toronto's city-gate, and is to rise at $0.25 per mcf every six months. The February 1983 Alberta border price for natural gas is $2.57 per mcf under the agreements and would have been $2.27 under the NEP.

(e) All export sales of natural gas are exempted from the NGGLT.

(f) The federal government announced its intention to alter the level of NGGLT on domestic sales so that the wholesale city-gate price of natural gas at Toronto, including the tax, should be 65 percent of the btu-equivalent price of crude oil.

(g) The effective rate of PGRT was raised from 8 percent to 12 percent, by means of raising the statutory rate to 16 percent and applying a 25 percent Resource Allowance.

(h) Within Alberta, the PIP grants would be administered and paid for by the Alberta government. The federal government continued to pay for the PIP grants elsewhere.

Economic analysis showed that the agreements' combination of the world oil price for new oil, high tax rates for old oil, and substantially higher prices for energy users reduced the present value of economic rents to Canadians by $4 billion over the 1981–1986 period, relative to the NEP, and increased them by $1.5 billion relative to the stalemate.[22] Overall economic rents from oil and natural gas were higher under the agreements than under the NEP, the stalemate, or the Alberta proposals, principally because of the closer links to world oil prices.

There is little doubt that the 1981 energy agreements provided a more robust and predictable pricing and taxation framework than had existed at any other time since 1973. This robustness was due in part to their formal nature involving signed commitments by both governments not to make any changes to the detriment of either the industry or the other

22. *See id.* at 18.

level of government over their five-year life. The other source of robustness was the link to world prices. This link means that the agreements are much more capable of spreading the revenue consequences of unforeseen changes in world oil prices according to an agreed-upon pattern. The 1974–78 arrangements and the original NEP, based as they were on fixed nominal increases, were much more likely to come apart under any unforeseen changes in world oil prices.

The main strains that have been placed on the energy agreements since their signing have come from falling rather than rising world oil prices. At the time the agreements were signed in late 1981, it was estimated that the average landed price of imported oil in 1983 would be $54.50 per barrel. By June 1982, when the NEP Update[23] was released, the average 1983 import price was estimated to be $43.67 per barrel. In late March 1983, with an OPEC benchmark price of $29 (U.S.) per barrel, the average 1983 landed import price is estimated to be about $38.60 per barrel.

A companion paper[24] analyzes in more detail the strains placed on the energy agreements by falling world oil prices. In summary, the drop in expected world oil prices between late 1981 and early 1982 led to changes in taxes and royalties by both the federal and Alberta governments. The federal government accelerated the price increases for some old oil, increased the coverage of the NORP, and temporarily reduced the rates of PGRT and IORT. Alberta lowered some royalty rates, especially for higher cost new sources. At the time of their introduction, the Alberta changes were estimated to increase net cash flow to the industry, after all taxes and royalties, by $5 billion over the 1982 to 1986 period. The NEP Update changes were estimated to increase industry cash flow by $2 billion over the same period. The combination of these two sets of changes together more than offset the $5.6 billion reduction in expected industry cash flow because of the lower expected world oil prices.

The further drop in actual and expected world oil prices between mid-1982 and early 1983 led to substantial reductions in expected revenues, especially for the federal govenrment. Figure 8 shows the expected net economic rents flowing to all parties on the assumption that the FOB world oil price is $29 (U.S.) per barrel in 1983 and rises two percent faster than the U.S. inflation in each subsequent year.

It can be seen that the producing industry has been well insulated from the lower world oil prices, principally because the wellhead price increases on natural gas and on old oil have been fixed in dollar terms and

23. ENERGY, MINES AND RESOURCES CANADA, THE NATIONAL ENERGY PROGRAM: UPDATE 1982 (1982).

24. Helliwell, MacGregor & Plourde, *The National Energy Program Meets Falling World Oil Prices*, IX CAN. PUB. POL. 284 (1983).

are not yet heavily influenced by their price ceilings. However, as described more fully in the companion paper,[25] the 75 percent price ceiling on old oil will be found to have breached when the current price of $29.75 is tested in mid-1983 against the likely import price of $38.60. Under the federal interpretation of the agreements, this should lead to a reduction of the old oil price to 75 percent of the import price. The Alberta interpretation is that there should be no rollback, and that the present $29.75 old oil price should be maintained until the 75 percent test again permits an increase. The producers are using this ambiguity to argue that the whole idea of a separate old oil price should be scrapped, and that all oil production should receive the world price. As shown in the companion paper, this would involve a much larger transfer from consumers to governments and the industry than is at stake in the disagreement between Ottawa and Alberta.

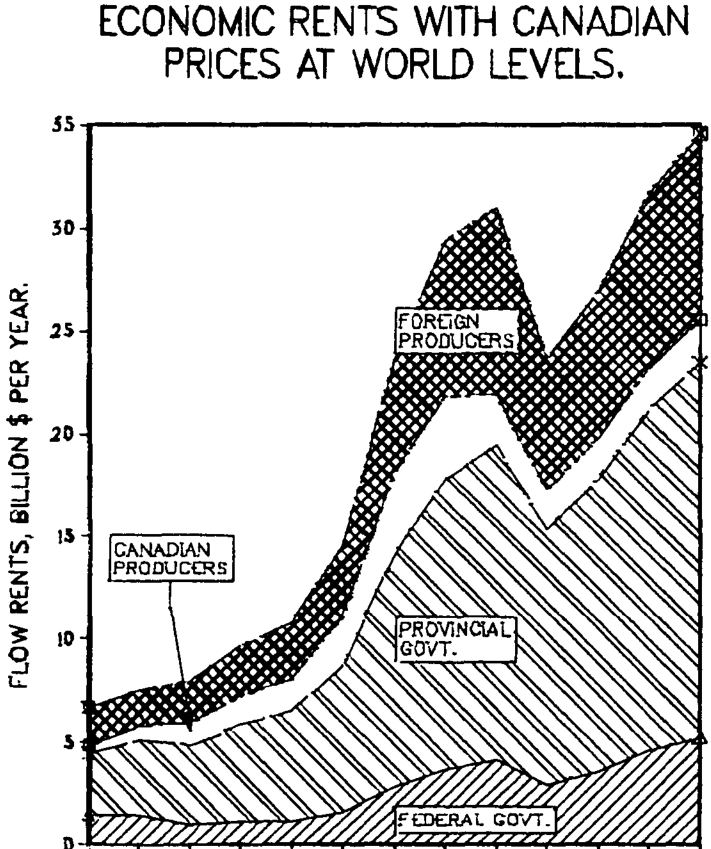
A bigger problem, from the point of view of the federal government, is that its revenues from the NGGLT are being squeezed between the scheduled price increases for producers and the falling user prices, which are linked by the 65 percent policy to the Toronto crude oil price. Even if the old oil price does not fall from its $29.75 per barrel level, the lower prices for imports, new oil, and synthetic oil will reduce the blended oil price paid by oil users and hence the city-gate natural gas price. This is the main reason why the federal revenues take the sharpest reduction in the face of lower-than-expected world oil prices. When the natural gas wellhead price rises far enough to eliminate the natural gas tax revenues entirely, as they do in late 1983, we assume that the 65 percent rule will be overridden in favor of the agreed increases to producers and in the interests of maintaining federal revenues. This is a somewhat anomalous result, however, since it leads to higher user price and lower demand for natural gas at a time when many natural gas producers would be willing to drop prices to bring their gas into production. Existing producers with firm sales contracts naturally take the opposite view.

What can be said about the overall effects of Canadian energy policies on energy demand, supply, and revenue sharing? The best evidence is probably found by comparing Figure 8, based on actual prices and taxes, with Figure 9, which shows the size and distribution of economic rents that would have come about if Canadian oil and natural gas had been priced at world levels, and if tax and royalty rates had remained at their mid-1970s levels.[26] It can be seen that total rents are somewhat higher in the world pricing case in 1980 when the Canadian user price fell far

25. *Id.*

26. Consumer rents have been omitted from Figure 4.2 since consumers capture virtually none of the economic rents in the world pricing case.

FIGURE 9.


ECONOMIC RENTS WITH CANADIAN PRICES AT WORLD LEVELS.
FLOW RENTS, BILLION $ PER YEAR.
0
5
10
15
20
25
30
35
FOREIGN PRODUCERS
CANADIAN PRODUCERS
PROVINCIAL GOVT.
FEDERAL GOVT.
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986

enough to engender substantial waste. The line for total Canadian rents, however, is equal to the world pricing case figure in 1980, and is materially above in each subsequent year.

What do the results indicate about the "Canadianization" policies that were part of the original NEP? The main elements of that part of the policy, at least insofar as it affects conventional oil and natural gas, were the differential PIP grants depending on the degree of foreign ownership and the plans to use PetroCanada to purchase foreign-controlled oil and natural gas companies. Available evidence[27] indicates that post-NEP acquisitions increased the Canadian ownership share of petroleum revenues (upstream and downstream) from 26.1 percent to 32.8 percent, with 60 percent of the increase coming from public sector purchases and the rest from private sector purchases. The total cost of the identified takeovers in 1981 was $7.5 billion. The MACE model results shown in Figure 8 include all of the implications of these takeovers for upstream revenues. The funds used to effect the takeovers are assumed to have a real after-tax opportunity cost of seven percent. The fact that the foreign share of net rents does not narrow after 1981 indicates that the prices paid for the takeovers were too high to permit a seven percent real return in subsequent years.

CONCLUSION

It has been shown in this paper that the very large drop in Canadian energy demand growth since 1973 is one-third due to a lower rate of economic growth and two-thirds to higher energy prices. The demand for energy appears to have maintained the same structure as in the pre-1973 period, with the subsequent dramatic changes in total demand and in the split by fuels, caused chiefly by changes in relative prices and economic growth.

The pattern of energy supply has been marked by a continued decline of production of low cost conventional oil, increasing costs of the synthetic alternatives, and continued expansion of the supply capacity of coal, natural gas, and electricity. For the next decade Canada is likely to remain a modest net importer of crude oil, a substantial exporter of coal and natural gas, and an occasional exporter of electricity.

Canadian energy policies have been seen to be dominated by competition for the substantial economic rents from crude oil and natural gas (exceeding six percent of GNP in the early 1980s). The potential economic rents from hydroelectricity (about one percent of GNP) have generally

27. *See* CANADA PETROLEUM MONITORING AGENCY, CANADIAN PETROLEUM INDUSTRY—MONITORING SURVEY (1982).

been distributed by means of lower average electricity prices in the provinces with a large number of established low cost hydroelectric projects.

The use of low prices as a means of distributing economic rents has constitutional and political causes in the case of oil and natural gas, and political causes in the case of electricity. In both cases, governments moved to raise energy prices and energy taxes as the size of the potential rents grew very quickly during the late 1970s and early 1980s.

For the mid-1980s, it is likely that the user prices of all major forms of energy will be kept fairly close to either the world values or to their long-term replacement costs. This will be partly from a perceived need to increase the efficiency and flexibility of energy demand and supply. Nevertheless, some of the major unprofitable energy-using petrochemical projects and frontier energy supply projects are likely to demand and obtain favored tax or price treatment.

An overall assessment of Canadian energy demand and supply suggests to us that energy policies have succeeded in moderating the speed of domestic energy price changes and in redistributing among regions the very large windfall gains and losses from major changes in world oil prices. Although the pricing policies delayed the pace of adjustment, and fostered some excessively energy-using industrial projects, the overall levels of national income and potential output in 1983 are very similar to what they would have been had world prices continually been used as the benchmark for the prices paid by Canadian energy users.