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DISCUSSION PAPER NO. 276

Economy-Wide Implications of Alternative Energy Sector Tax and Pricing Policies: Simulations with the MACE Model

by Surendra Gera and
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Résumé

Dans le présent document, les auteurs examinent, à l'aide du modèle économétrique MACE, les incidences qu'auraient à moyen terme des dosages différents de mesures relatives à la taxation et à la tarification dans le domaine énergétique. Ils effectuent, en outre, un certain nombre de simulations, dont certaines ont été décrites dans le rapport sur l'énergie publié récemment par le Conseil économique du Canada sous le titre Interconnexions - Une stratégie énergétique pour demain. Les simulations visent à déterminer les effets éventuels de politiques alliant la libération des prix du pétrole et du gaz naturel à diverses mesures fiscales. Au nombre des politiques examinées figurent l'application du prix mondial à tout le pétrole produit au Canada, la libération des prix du pétrole et du gaz naturel, l'abolition de la TRPG sur le nouveau pétrole, l'abolition de la TRPG sur tout le pétrole et le gaz naturel, une hausse des redevances provinciales, et enfin une modification à la TRPG et au prélèvement spécial de canadianisation.

Les auteurs mesurent les effets de ces politiques en établissant une solution de base, qui est ensuite soumise à l'action de ces mesures. Le prix nominal mondial du pétrole était de 29 $ US le baril (f.à.b. Golfe persique) en 1983. Dans le scénario de référence du prix pétrolier mondial réel constant (scénario de référence A-1), on suppose qu'il progressera au même rythme que le taux d'inflation aux États-Unis. La solution de base retient les politiques actuelles touchant l'imposition et la tarification des produits énergétiques.

Les résultats de cette simulation indiquent que le relèvement du prix de l'ancien pétrole au cours mondial aurait pour effet d'améliorer la trésorerie de l'industrie pétrolière et d'augmenter les recettes publiques. Il pourrait également contribuer à stimuler l'activité d'exploration au pays si l'industrie éprouvait des problèmes de liquidités. La hausse des prix pétroliers réduirait par ailleurs la demande et les importations de pétrole tout en augmentant la demande de gaz naturel. Elle entraînerait cependant certains effets macroéconomiques négatifs - le PNB réel diminuerait, tandis que les taux d'inflation et de chômage s'élèveraient légèrement.

Pour ce qui est de la libération des prix, qui serait immédiate dans le cas du pétrole et progressive dans celui du gaz naturel, elle conforterait la croissance économique et aurait des effets anti-inflationnistes. Elle favoriserait également la production de pétrole et la prospection et la mise en valeur des ressources pétrolières au Canada, en même temps qu'elle réduirait les importations et encouragerait le développement d'autres formes d'énergie.

Du fait qu'elle lamine les rentrées nettes (après impôt) des producteurs de pétrole et de gaz naturel, la TRPG a un effet de désincitation à l'égard des activités d'exploration et de la mise en valeur de nouvelles réserves. Du point de vue de l'efficacité économique, il est donc souhaitable d'abolir les taxes sur les recettes, telle la TRPG. Une politique qui allierait la libération des prix à l'abolition de la TRPG sur le nouveau pétrole (c'est-à-dire le pétrole découvert depuis 1974) susciterait une augmentation des approvisionnements pétroliers et une vigoureuse relance de l'économie canadienne. Les déséquilibres qui en résulteraient dans les flux des recettes aux parties concernées militent cependant en faveur d'une approche modérée.

En poussant ce scénario à l'extrême, la libération intégrale des prix accompagnée de l'abolition de la TRPG sur tout le pétrole et le gaz naturel stimulerait la prospection et la mise en valeur, ce qui conduirait à une augmentation des approvisionnements d'origine canadienne. Cette politique détournerait cependant vers les producteurs d'importantes recettes perçues actuellement par le gouvernement fédéral et elle favoriserait largement les actionnaires étrangers des entreprises productrices. On pourrait éviter ce résultat excessif en relevant les taux des redevances perçues par les provinces, qui pourraient s'entendre avec les autorités centrales quant au partage de ces recettes.

Rien n'indique qu'un train de mesures alliant la libération des prix à la réforme de la TRPG et du prélèvement pour le remplacement du pétrole provoquerait une nouvelle flambée des prix. Il semble bien que la capacité du Canada à mettre en valeur de nouvelles ressources pétrolières en serait accrue, ce qui améliorerait d'autant la sécurité de ses approvisionnements à long terme.

Pour tester la solidité de ces mesures, les auteurs ont elaboré deux autres scénarios de référence fondés sur des évolutions différentes du prix mondial du pétrole. Dans le scénario postulant une hausse de ce dernier (scénario de référence A-2), le prix f.à.b. du pétrole du Golfe persique augmente, en chiffres réels, au rythme de 5 % par année entre 1985 et l'an 2000. Dans le scénario qui repose sur une baisse du cours mondial (scénario de référence A-3), le prix enregistre une baisse de 5 % l'an, en chiffres réels. Les résultats indiquent qu'une telle politique aurait tendance à protéger l'économie canadienne contre certains effets déstabilisateurs durant les périodes de hausse ou de baisse des prix et qu'elle favoriserait une croissance non inflationniste de l'économie. Elle aurait également pour effet de reduire les importations de pétrole en freinant la demande et en stimulant, grâce à une augmentation de l'investissement, la production et la prospection au Canada même.

Executive Summary

In this paper, we examine the medium-term impact of alternative energy sector tax and pricing policies using the MACE model of the Canadian economy. We have carried out a number of simulations and a few of them have been reported in the new report on energy recently released by the Economic Council of Canada - "Connections, An Energy Strategy for the Future". The simulations focused on various combinations of deregulation of oil and gas prices and changes in taxation policies. The following policies were examined: world price for all Canadian oil; deregulation of oil and natural gas prices; removal of the PGRT on new oil; removal of the PRGT on all oil and natural gas; increased provincial royalties; modifying the PGRT and the modification of the Canadian Ownership Special Charge.

The effects of these policies were assessed through setting up a control solution and then shocking the system accordingly. The nominal world price of oil was $29.00 U.S. per bbl (fob Gulf) in 1983 and then was assumed to grow at the rate of U.S. inflation. The case is termed as a flat real world oil price base case (Base Case A-1). The existing energy taxation and pricing policies were retained in the control solution.

The simulation results indicate that a policy of moving the old oil price to world levels would improve the industry cashflow position and would increase the revenues of the governments. The policy could stimulate domestic oil exploration if industry cashflow are a problem. It would reduce the demand for oil, lower oil imports and increase the demand for natural gas. The policy would, however, have some negative macroeconomic effects, the real GNP would be lower and inflation and unemployment rates would be slightly higher.

Deregulation of oil prices accompanied by a phased-in deregulation of natural gas prices, termed as price deregulation, would stimulate economic growth and would have deflationary effects. The policy would also stimulate domestic oil production and provide oil exploration and development, reduce oil imports, and encourage the development of alternative energy sources.

The PGRT by reducing the after tax netback from oil and natural gas to producers curtails the incentive for exploration and development of new reserves. Thus, from an efficiency point of view, it is preferable that revenue taxes such as the PGRT should be eliminated. A policy of price deregulation accompanied by removal of the PGRT on new oil (discovered since 1974) would lead to more oil supply and a major boost to the Canadian economy.

However, the resulting imbalance of effects on revenue flows to the participants suggest the need for some kind of an intermediate policy.

As an extreme case, a policy of price deregulation accompanied by removal of the PGRT on all oil and natural gas would stimulate oil exploration and development, leading to increased domestic supplies. The policy would, however, result in a transfer of large sums of revenues from the federal government to the producers and a large net gain by the foreign shareholders of producing firms. One possible way around this would be to increase provincial royalty rates. The provinces could agree to share royalties with the federal government.

There is no indication that the policy package (price deregulation + modified PGRT + off-oil charge) would cause a surge of price increases and it appears that Canada's capacity to develop indigenous supplies of oil will be increased, giving greater security of supply for the longer term.

To test the robustnes of our policy package two alternative base cases were developed based on variations on world oil prices. In the rising world oil price scenario (Base Case A-2), the Persian Gulf (FOB) price of oil is assumed to increase at the rate of 5 per cent real per annum from 1985 to 2000. In the declining world oil price scenario (Base Case A-3), the Persian Gulf price decreases at 5 per cent in real terms per annum over the periods 1985 to 2000. The results suggest that the policy package would tend to insulate the economy from destabilizing effects during periods of rising/declining world oil prices and would stimulate non-inflationary economic growth. The package would also reduce oil imports by lowering oil demand and stimulate domestic oil production and exploration through increased oil investment.

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I. Introduction

The experience of the past decade has demonstrated the important and pervasive roles that energy and energy policy play in Canada. The sudden increases in world oil prices in 1973 and again in 1979-80 were followed by a drop in world prices in early 1983. These fluctuations have shown that energy price shocks can have a significant impact on the aggregate level of inflation, output and employment. The analysis of Helliwell (1984) suggests, in fact, that a large proportion of the low GNP growth and high inflation that Canada has experienced since 1973 can be attributed to the OPEC oil price shocks and the accompanying world stagflation.

The world oil market appears to be on the brink of an era of relatively stable and possibly decreasing prices. Although beneficial for inflation and energy consumers in the economy, it leads to the possibility of reduced domestic supplies through lower energy investment, as well as rising government deficits. Past volatility in the world oil market suggests the need for flexible energy policies, which can be adapted to a variety of situations. This paper examines the overall impact of a number of alternative energy tax-pricing policies using the MACE model of the Canadian economy.

In Section II, we outline the key channels of influence of energy within the Canadian economy. In Section III, we present a brief overview of the MACE model. In Section IV, we describe the medium-term impact of alternative energy tax-pricing strategies on the Canadian economy as a whole and on the petroleum industry. There are essentially two threads to our story. One deals with oil and gas price deregulation and the other deals with price deregulation plus changes in taxes and royalties. The conclusions are discussed in Section V.

II. Energy and the Canadian Economy: What are the Key Channels?

What are the key channels of influence of energy prices within the Canadian economy? To begin with, changes in world energy prices affect prices at every level in the economy: at the wellhead, at the wholesale level and at the retail level. Consumer prices are affected directly through increased fuel costs, and indirectly through changes in the price of finished goods as producers pass on part of their increased (or decreased) costs of production. Changes in the relative price of energy provide incentives for firms to adjust their input mix of capital, labour, materials and energy over time. In addition to changing the overall demand for energy, changes in energy prices can change the composition of the demand for energy if there are relative price changes among fuels as well. This can have implications for the balance of trade if this leads to shifts between imported and domestically produced fuels.

Changes in world energy prices have further implications for the balance of trade. As a net energy exporter, Canada experienced an improvement in its terms of trade as a result of the OPEC price shocks in the 1970s. Net energy exports grew from $0.6 billion in 1972 to around $6.5 billion in 1983, resulting in a stronger exchange rate than might otherwise have been the case. The OPEC price shocks also had an indirect influence through their effects of world trade. The recession induced among Canada's trading partners reduced the demand for exports, while higher inflation in the rest of the world resulted in higher prices for imports of non-energy goods. Higher world interest rates put upward pressure on Canadian interest rates, which put a further damper on investment and growth within Canada.

Energy price shocks can affect the distribution of economic activity within Canada among industries and among regions. Although the increase in relative energy prices had a negative influence on many manufacturing industries in Central Canada, it led to a boom in the oil and natural gas industries in the west. Higher investment in energy projects partly offset the decline experienced in other sectors.

Energy taxation has proved to be an important source of revenue for both the governments of the producing provinces and the federal government. In 1983, the Petroleum Monitoring Agency (PMA) estimated that provincial governments received $6.6 billion in revenues from oil and natural gas, with the federal government receiving $4.6 billion.[1] The recent fall in world oil prices, however, has had an adverse effect on government revenues, which has been viewed with concern in light of rising government deficits.

Domestic energy pricing and taxation policies have a number of macroeconomic implications. Maintaining domestic oil prices below world levels reduced the initial impact of world oil price increases during the 1970s, although it also tended to reduce the incentives for producers to develop new sources of domestic oil,[2] and the incentive for consumers to conserve energy. The combined effect would tend to lead to higher imports of foreign oil than would otherwise be the case, and a lower balance of trade. This effect would be partially offset by domestic pricing policies which encouraged consumers to switch from oil to the currently abundant supplies of natural gas.

Energy pricing and taxation policies have important effects on government revenues and on the distribution of revenues among governments. Although the combination of domestic oil prices below world levels and the 'one oil price' policy tended to reduce and equalize the impact of world oil price increases across producing and consuming provinces, it resulted in serious revenue problems for the federal government following the 1979-80 world oil price increases as it faced some $3 billion in import subsidy payments. Taxation and pricing policies have a direct impact on industry activity, which in turn affects the amount of oil and gas revenue available for taxation. The revenues of the one level of government can also be affected by policies introduced by the other, which has been a serious problem in the past.

III. Overview of MACE

The MACE model, developed by Professor John Helliwell and others at the University of British Columbia, was designed specifically to deal with energy issues. MACE is a small, highly aggregated model of the Canadian economy with a detailed energy block.[3] The version used in this paper has been fully described in Helliwell et.al (1983), so the following overview concentrates on the role of energy within the model and on the linkages between the macro model and the energy block.

Energy has several main channels of influence in MACE: through the effects of energy demand and prices, through energy investment, through the balance of trade, and through the effects of energy tax revenues on government balances. The first three sub-sections describe how the demand for energy is modelled in MACE, how energy prices are determined and how energy demand and prices influence the macro structure of the model. The fourth sub-section describes the supply of oil and natural gas in the model and looks at how the interaction between domestic energy demand and supply influences the balance of trade and the exchange rate. The fifth sub-section describes briefly how energy investment is modelled, while the sixth sub-section looks at energy taxation and how it affects government balances. The final sub-section examines some of the limitations of MACE.

III.1 Energy Demand in MACE[4]

There are two sectors in MACE: an energy-producing sector which produces, refines and distributes energy, and an energy-using sector which produces everything else by using capital, energy, and labour. Part of the output of the energy-producing sector is exported, the remainder is consumed by the energy-using sector. The energy-using sector may also import additional energy in order to produce all other goods. The output of the energy-using sector (q) is therefore equal to GDP at factor cost plus net energy imports.

In modelling the output of the energy-using sector, a clear distinction is drawn between the normal output of the employed factors of production and the actual level of output. The normal output of the energy-using sector is obtained by using a nested production structure which first combines energy and capital in a vintage CES subfunction. This vintage bundle of capital-plus-energy is then combined with efficiency units of labour in a Cobb-Douglas outer function. Actual employment and the current value of the vintage bundle of capital-plus-energy are used to define the series for normal output (qsv). The normal output series thus reflects what the level of output would be if all employed factors operated at their normal levels of utilization.

It is assumed that on average over the sample period, firms have used factor ratios which minimize their costs although this does not necessarily hold from year-to-year. This means that most of the parameters of the production function for normal output can be estimated by assuming that desired factor ratios equal their sample averages and that output from the production function has the same average value and trend growth rate as actual output. The actual level of output is modelled as a utilization rate decision, (q/qsv), which depends on unexpected or temporary sales levels (i.e. the ratio of sales to qsv), the current ratio of operating costs to output price (i.e. an inverse measure of profitability) and unintended inventory accumulation (the discrepancy between actual and desired stocks of inventories).

Consistent target demands for capital, labour and energy are derived from the production function for normal output. Current relative factor prices and the expected level of profitable future output (basically trend growth of output adjusted for unintended inventory accumulation) determine the levels of capital, labour and energy which will minimize anticipated production costs.

Actual employment depends on the adjustment of existing employment towards forward-looking desired levels of employment. Investment, estimated as the ratio of investment to the capital stock, depends on the gap between the current and forward-looking desired levels of the capital stock, as well as on relative profitability effects and the lagged dependent variable.

The demand for energy depends on a time trend and the energy requirements of the vintage capital stock. It is assumed that all new capital investment uses energy at an optimal rate based on current relative factor prices. However, there is also some potential for retrofitting previously installed capital so that it too uses energy at the current optimal rate. The energy requirement of the vintage capital stock is therefore equal to the energy used by previously installed capital which has not been brought up to current standards plus the energy used by newly installed and retrofitted capital.

The national demand for energy is then spread across regions and fuels in the detailed energy block. The total demand for energy in each of the five regions (the Atlantic Provinces, Quebec, Ontario, the Prairies, and B.C.) is determined by the region's share of national GDP, the overall user price of energy in the region compared to Canada as a whole, and the total demand for energy within Canada. Energy demand in each region is then split into the demand for oil, natural gas and electricity through estimated regional fuel share equations. The quantity share of each fuel depends on its price, the price of other fuels in the region and on the number of gas pipeline distribution kilometers. The latter variable is included to indicate the availability of natural gas within the region. Fuel prices are moving weighted averages based on the degree of retro-fitting of the capital stock estimated in the macro model. A thermal sub-system estimates the demand for oil, natural gas and coal used to generate thermal electricity in each region. These shares depend mainly on the current relative prices of the alternative fuels.[5]

III.2 Energy Prices in MACE

The overall energy user price index is determined in the energy block using the model's endogenous determination of regional energy demands, fuel shares and user prices for energy.

The two key prices in the energy block are the landed price of imported oil in Montreal and the city-gate price of natural gas in Toronto. Wellhead prices for domestic oil are linked to the import price. The New Oil Reference Price (NORP) is equal to the import price net of transportation costs and is the wellhead price received by producers for all conventional oil discovered after March 1974 and all synthetic oil. Oil discovered before 1974 receives the minimum of $29.75/bbl or 75 per cent of the NORP under the June 1983 amendments to the energy agreements. The production of oil from pre-1974 wells is determined using Alberta Energy Resources and Conservation Board (AERCB) estimates to the end of 1982, and declines over the rest of the decade at about 13 per cent annually. All oil is assumed to be of the same average quality and no quality differentials are modelled.

The refinery acquisition cost of crude oil in each region is equal to the blended domestic oil price plus transportation costs and the Canadian Ownership Special Charge (COSC) of $1.15/bbl. The blended price is modelled as the price of old oil plus the Petroleum Compensation Charge (PCC) which is levied on all oil consumed in Canada so that revenues will finance the subsidy payments for imports and NORP oil. In effect, the blended price is a weighted average of the price of imported oil and the different types of domestically produced oil. The final user price for oil products in each region is determined by the refinery acquisition costs and an estimated regional mark-up equation, which includes refining and distribution mark-ups and excise taxes.[6] Regional mark-ups are determined primarily by the absorption price (from the macro model) and the refinery gate price.

Natural gas prices are linked to domestic oil prices through the current policy of maintaining the Toronto city-gate price at 65 per cent of the btu-parity refinery acquisition cost for oil. City-gate prices in Quebec are equal to the Toronto city-gate price plus transportation costs, while city-gate prices in the West are determined by the wellhead price for domestic sales, the Canadian Ownership Charge (15 cents/mcf) and transportation costs. City-gate gas prices net of the COC are subject to a discount of 25 per cent in the Prairies to reflect provincial pricing policies and the effects of competition among producers for industrial markets in Alberta.

The wellhead price for domestic sales is calculated by netting out transportation charges, the COC, the Natural Gas and Gas Liquids Tax (NGGLT) from the Toronto city-gate price to obtain the Alberta border price. Under the terms of the 1981 energy agreements, the Alberta border price was to be increased by 25 cents/mcf every six months, while the NGGLT would be set so as to maintain 65 per cent btu parity at the Toronto city-gate after transportation costs and the COC had been accounted for. Oil prices have not risen rapidly enough, however, to accommodate both the agreed-upon Alberta border price increases and 65 per cent btu parity pricing at the Toronto city-gate, even when the NGGLT is set to zero. Under the June 1983 amendments, 65 per cent btu parity is maintained for 1984. The Alberta border price will be allowed to drop if 65 per cent parity cannot be maintained through eliminating the NGGLT and federal subsidies of transportation cost increases in excess of five per cent. In 1985 and 1986, it has been assumed that the Alberta border price will again be increased by 25 cents every six months and 65 per cent btu parity will be exceeded in Toronto if necessary.[7]

Regional user prices for natural gas are the sum of the city-gate price and a regional mark-up, similar to that for oil. The estimated mark-ups depend on the absorption price (more strongly than the ones for oil), as well as on a time trend and the growth in pipeline kilometers, reflecting the fact that pipeline tariffs are especially high when the system first goes ito service.

User prices for the third major fuel, electricity, are linked in MACE to changes in GNP deflator, so that higher oil prices influence electricity prices only to the extent that they cause general inflation.

In MACE, the net effect of oil prices on the total price of energy depends on the extent of interfuel substitution and on the prices of individual fuels as well. Interfuel substitution is determined by means of a fuel shares (not expenditures shares) model, based on pooled time series and regional cross-section data, in which the shares of total regional energy demand depend on relative fuel prices and the availability of natural gas. As reported in Helliwell and MacGregor (1983), cross-price share elasticities are all positive and symmetric, but are fairly small, ranging in value from .03 between oil and electricity, to .05 between gas and electricity, and .12 between oil and gas. Homogeneity is imposed, so that the own-price share elasticities are equal to minus the sums of the relevant cross-price elasticities, in total -.17 for gas, -.15 for oil, and -.08 for electricity. The total own-price and cross-price elasticities are obtained by combining these energy share elasticities with the overall price elasticity of the demand for energy. The resulting user price elasticity for oil products is -.66[8].

III.3 Role of Energy Demand and Prices in the Macro Block of MACE[9]

The overall energy price index has a number of direct influences in the macro block of the model. A change in the relative price of energy will change the desired mix of capital and energy within the capital-energy bundle, and the desired mix of the capital-energy bundle with labour. Increasing energy prices by 10 per cent decreases energy use by 5.56 per cent in the long run, increasing employment by 1.02 per cent and capital by 0.16 per cent if all other prices and output are held constant (Helliwell and MacGregor, 1983). The level of normal output from the production function is therefore affected directly.

Changes in the energy price index also enter output prices through a long-run cost variable. The long-run cost variable combines energy prices, the efficiency wage and the rental cost of capital using a function dual to the production function. Since it uses the equilibrium factor proportions corresponding to the current relative prices, firms only pass on the proportionate change in total costs that they will experience after they have fully adjusted their factor mix.

The effects of energy price changes on other prices in the model flow through the effects of energy prices on the output price. A change in the output price will result in a change in the personal consumption deflator (thus influencing real per capita consumption) and the non-energy export price (thus leading to changes in non-energy exports and the balance of trade) and the absorption price deflator. The absorption price is a key factor in determining changes in nominal wage rates and the rental cost of capital.

Total energy expenditures have a number of additional effects on output and final demands. Increased energy expenditures will reduce the profitability of output relative to costs, which is a major factor in determining the utilization rate and, therefore, the actual level of output. Investment is also adversely affected by decreases in relative profitabililty.

Increased energy costs reduce corporate profits in the non-energy sector. This tends to lower non-energy corporate income tax, leading to reduced government balances and increased borrowing. These effects are counteracted, however, by increased tax revenues on the energy sector. Lower corporate profits lead to a reduction in the market value of the non-energy business capital stock, which is a component of private wealth and therefore has an influence on consumption. Higher corporate profits in the energy stock do not increase the market value of the energy capital stock, since this is currently exogenous in MACE. Experiments with a version of the model containing an edongenous market value of energy capital show that its macroeconomic impact is very small (James, 1983). Changes in the market value of the capital stock also affect capital inflows in the balance of payments.

Increased energy prices tend to put upward pressure on nominal interest rates. Short-term nominal interest rates depend on the level of nominal GNP and money demand in MACE. Usually nominal GNP rises in response to an increase in energy prices as the price level effects outweigh the real GNP effects, and this leads to increased interest rates. The net effect on interest rates will depend on the monetary policy that is followed. In our simulations, we have assumed that the monetary authorities trade off a monetary growth rate target with an interest rate target that depends on the short-term U.S. interest rate, foreign exchange reserves, government borrowing and money supply growth. This trade-off policy tends to reduce the impact on short-term interest rates, which flow through to the long-term rates. Higher interest rates have a negative effect on investment and output through the effects on relative profitability, put upward pressure on output prices through the long-run cost variable, and reduce the market value of wealth, and thereby consumption.

The effects of an energy price shock also depend on whether it is the result of domestic changes, or a change in world oil prices. An increase in world oil prices will tend to amplify the real effects of the shock through its impact on world trade. Price and interest rates will tend to rise among Canada's trading partners, while the accompanying recession lowers the demand for non-energy exports. This has been modelled to a limited extent through MACE's participation in an Energy Modelling Forum project on the impact of energy price shocks (see Helliwell and MacGregor 1983). Estimates of the effects of a standardized world oil price shock were averaged across a number of U.S. models and have been used to adjust world prices, incomes and interest rates in the alternative world oil price simulations discussed later.

To summarize briefly, changes in energy prices affect the desired mix of capital, labour and energy. Through its influence on output prices, it affects all other prices in the model leading to changes in consumption, exports and interest rates. Through its effects on relative profitability, it influences investment and output. Its effects on corporate profits influence government revenues and borrowing requirements as well as the value of private wealth, thus affecting consumption. Changes in final sales brought about by changes in consumption, investment and exports will lead to a build-up (or run down) of inventories, which plays a key equilibrating role in MACE. A build-up of inventories will put downward pressure on output and output prices, and upward pressure on non-energy exports, which serve as a vent for excess inventories. Non-energy export prices are reduced as a result of the inventory build-up.

III.4 Oil and Natural Gas Supply and the Balance of Trade in MACE

Natural Gas Supply

Required production of natural gas is determined from the sum of domestic requirements estimated in the demand subroutine, and natural gas exports, an exogenous series based on NEB approvals discounted to reflect softness in the U.S. market.[10] Actual production is limited to the producing capabilities of reserves which are connected in the current year. New reserves are connected from the stock of discovered, unconnected reserves only if existing reserves cannot meet current requirements. Production from newly connected reserves is maintained at a constant rate for 14 years (1 bcf per day for each 7300 bcf of initial marketable reserves), and then declines at 15 per cent per year for a total production life of 28 years. Production in the final year is set to satisfy the reserves constraint.

Discoveries made in the current year are added to the stock of unconnected reserves but cannot be put into production until the following year. The shut-in capacity of the previous year is therefore the maximum that can be added to producing reserves in any year. Future discoveries are based on the NEB projections of additions to marketable reserves reported in 1982 Omnibus Hearings. They are sensitive, however, to the net price received by producers relative to their cost of finding and developing new reserves. The elasticity of the NEB forecast of future gas discoveries with respect to post-1980 changes in the ratio of wellhead netbacks to marginal costs is assumed to be 1.0.

$$\text{GASDISCV} = \frac{\text{NEB projected discoveries * after producer price}}{\text{Marginal cost of new reserves * (1-PIP/nonfrontier gas investment)}}$$

The wellhead netback is the after tax price received by producers operating on Crown lands. Royalties, provincial and federal income taxes and the PGRT are subtracted from the weighted average of domestic and natural gas export prices.[11] The cost of finding, developing and producing new natural gas reserves (GASCOSTM) is equal to operating costs plus the capital costs of new reserves on a delivery basis. The capital costs of new reserves is estimated by

2.308 (cumulative discoveries) - 137.368

A factor of 0.262 is used to put the costs on a delivery basis. In the gas discovery equation, the proportion of nonfrontier investment (INFGAS) covered by PIP grants is netted out so that only the costs actually born by the producer are included.

Cumulative discoveries are limited by the price-responsive ultimate stock of nonfrontier gas. The ultimate recoverable stock of nonfrontier gas was estimated to be 174 tcf in the 1982 NEB report on the omnibus hearings. The elasticity of ultimate gas reserves with respect to changes in the wellhead netback is assumed to be 0.15.

Oil Supply

There are three sources of oil in the model: conventional nonfrontier production, oil sands, and imports. Oil sands production is determined in the oil sands subroutine and depends on the number of plants in operation, which is set exogenously. In the present set of simulations, no new oil sands plants come onstream so production is 175,000 bbl/day for all of the forecast period except the year 2000.

Production from conventional sources is used to meet the remaining Canadian domestic and export requirements.[12] The throughput of the Montreal pipeline sets a ceiling on the amount of western production that can be used to meet the demand for oil in eastern Canada. Imports make up any remaining short-falls. As domestic production falls, so does the throughput of the Montreal pipeline. Eventually, when domestic production is no longer sufficient to meet western requirements, the flow of oil through the Montreal pipeline is reversed and imports flow west.

The production model for oil is very similar to natural gas. Once the desired flow of oil has been determined, new reserves are connected if the maximum flow from existing connected reserves is insufficient. Additions to connected reserves are limited to the previous year's shut in capacity plus current discoveries. Production is maintained at a constant rate (1 bbl/day for every 5000 bbl initial reserves) for eight years and then declines at 15 per cent per year. Total production life is 23 years.

The normal form of the discovery equation takes an exogenous projection of discoveries from the NEB, and makes them sensitive to the ratio of the after-tax wellhead price for new oil received by producers to the marginal cost of finding, developing and producing new reserves which is borne by the producer (note that this includes operating as well as capital costs). The assumed elasticity of future discoveries with respect to changes in this ratio is 1.

$$\text{OILDISCV} = \frac{\text{NEB projected discoveries* after-tax producer price}}{\text{[marginal costs of new reserves*(1-PIP/investment in oil)]}}$$

The after-tax price is the New Oil Reference Price net of royalties, federal and provincial corporate income tax and the PGRT. The marginal cost of finding, developing and producing new reserves is equal to operating costs plus the capital costs on a delivery basis. Total capital costs is given by

.000188 * cumulative discoveries - 2.002

A factor of 2.21 converts this to a delivery basis. Cumulative discoveries are limited to the price responsive ultimate stock of conventional oil. The elasticity of the ultimate stock with respect to changes in the after tax price received by the producer is assumed to be 0.1.

Balance of Trade

The interaction between domestic supply and demand influences the balance of trade. The quantities of oil, natural gas, electricity and coal exported are set exogenously (exports of refined petroleum products are not modelled, but are incorporated in a residual), while the foreign dollar export prices are also exogenous. The Canadian dollar export prices are affected, however, by endogenous fluctuations in the exchange rate.

The key endogenous component in the energy trade balance is the level of oil imports.[13] Pricing or taxation policies which affect either the demand for oil, or the domestic supply, can have a major impact on the level of oil imports, thus affecting the balance of trade and the exchange rate. Changes in the exchange rate have important effects on overall inflation in the model through their impact on import prices for non-energy goods and services, a major component of the personal consumption deflator and the absorption deflator.

III.5 Energy Investment in MACE

Real energy investment, a component of GNP, is divided into an exogenous component made up of investment in electricity, pipelines and refining, and an endogenous element made up of upstream oil and natural gas investment, which is determined in the detailed energy block. This upstream investment includes investment in oil sands, but not in the frontier regions. In our simulations, we have assumed that no new oil sands projects come onstream so that capital expenditures in the oil sands sector are limited to replacement investment.

Investment is modelled in a similar manner for both conventional oil and natural gas. In the normal version of MACE, nominal investment is simply equal to current discoveries multiplied by the capital cost of making those discoveries. This is then converted to real investment using the GNP deflator. Capital costs are an increasing function of cumulative discoveries.[14]

Investment = Discoveries* Capital Costs of Discoveries

The process of oil and natural gas discoveries has already been described in the previous sub-section.

Adding a Cashflow Constraint

With these equations, investment in conventional oil and natural gas is not affected by cashflow considerations. Although the empirical evidence for cashflow constraints is equivocal, many industry analysts feel that it has a strong influence. Accordingly, a special, entirely ad hoc cashflow constraint has been incorporated for the simulations we performed. Five per cent of producer cashflow has been added to nominal investment. With the ad hoc cashflow constraint, the discovery equations are changed to:

discoveries = old discoveries + .05* cashflow/capital costs of new discoveries

where cashflow = gross revenues - operating costs - corporate income tax - royalties - freehold mineral tax - PGRT

In the case of oil, the IORT is also deducted. The capital costs of new discoveries, as described earlier, are derived from estimated equations:

for oil, capital costs = .00018815* cumulated discoveries -2.00228

for natural gas, capital costs = 2.383* cumulated discoveries -137.368

Both of these capital costs are in 1961 $ and are converted to current $ by multiplying by relevant deflator. This means that policies like extending the NORP to old oil would have a positive impact on investment through cashflow effects, which would not occur in the base model. The cashflow influence also tends to amplify the effects of changes which affect both the after tax price received by producers and producer cashflow (e.g., removal of the PGRT). Unlike changes in the after tax producer price, increases in discoveries due to a cashflow effect will not affect the ultimate price-responsive stock of reserves, although it will shift discoveries forward in time.

III.6 Energy Taxation and Government Revenues in MACE

Revenue from energy taxation makes up an important proportion of government revenues. Upstream oil and natural gas taxation is modelled in detail in the energy block. Federal and provincial energy taxes at the retail level are not modelled specifically although they are implicitly included in the estimated regional mark-up equations. Taxes on energy other than oil and natural gas are not dealt with. This sub-section provides a brief description of how oil and natural gas taxation is modelled in the energy block and how this is linked to macro model.

Both the federal and provincial governments collect a variety of taxes on oil and natural gas.[15] Provincial and federal corporate income taxes are modelled separately for oil and natural gas on the basis of gross production revenues net of operating costs, land payments, debt servicing charges (related to the level of debt and interest rates from the macro model) and capital expenditures deductible for income tax purposes. Provincial royalties are deductible for the purpose of provincial corporate income taxes, but not federal. Oil revenues subject to the federal Incremental Oil Revenue Tax (IORT) are equal to the difference between current revenues for production from pre-1981 wells and the revenues that would have been received under the original NEP, and are not subject to corporate income tax. The IORT is equal to 50 per cent of these revenues net of provincial royalties although it has been suspended since 1983. The other main federal tax levied directly on the industry is the Petroleum and Natural Gas Revenue Tax (PGRT), which is levied on gross production revenues net of operating costs.

The main sources of provincial revenues are royalties and bonus bids for land payments. Provincial royalties are modelled according to the royalty formulas for the different categories of oil and natural gas (pre-1974, 1974-81 and post-1981 discoveries), with some allowances made for the reduction in royalties for low productivity natural gas wells. Provincial royalty tax credits are also modelled and deducted from provincial income taxes. Freehold mineral taxes are estimated to be 4 per cent of gross revenues from production on non-crown lands. Land payments for oil and natural gas are estimated on the basis of fitted equations which depend on the after tax producer price relative to the marginal costs of new reserves and the estimated stock of reserves yet to be found.

In addition, a number of indirect federal taxes have been modelled. The oil export tax is equal to the difference between the average wellhead price and the export price, with 50 per cent going to the provinces. The Canadian Ownership Special Charge (COSC) is levied on all domestically consumed oil and natural gas at the refinery-gate level, while the NGGLT is the wedge that was intended to collect the amount by which the 65 per cent btu parity price at the Toronto city gate exceeded the Alberta border price for natural gas.

Subsidies covering the difference in price to refiners between imported and domestic oil, as well as the difference between NORP and old oil, are financed through the Petroleum Compensation Charge (PCC). Petroleum Incentives Payments (PIPs) depend on the level of investment in conventional oil and natural gas (MACE modelling of the frontier regions is not used in our simulations) and an assumed distribution of the different categories of Canadian ownership.

Net government energy revenues affect the aggregate government balance in the macro model, influencing the level of government borrowing. Since government debt is a component of private wealth, changes in energy tax revenues can have some small impact on consumption through that channel. It will also have a slight effect on the growth of the money supply (and therefore interest rates), since the monetary policy used in this simulation is influenced by changes in government debt. Provincial royalties are properly part of government investment income, which is not modelled separately in MACE, but is netted out of government transfers. In this version of the model, changes in royalties do not affect consolidated government borrowing requirements.

III.7 Limitations of MACE

MACE can be used to examine a wide range of macroeconomic issues, but only at the aggregate level. Although it can be used to examine regional implications for energy demand and interfuel substitution issues[16], it cannot be used to analyze the regional implications for real growth, employment and inflation by region, or by industry. Energy employment is not separated from total employment in this version of the model, although there are employment estimates linked to oil sands projects and coal developments.

The version of MACE that we are using deals with oil and natural gas on an aggregate basis, assuming that quality is uniform and that the costs of finding, developing and producing new reserves are the same for all discoveries in a given year. It does not distinguish between heavy and light oil, or between conventional and enhanced oil recovery (EOR) of oil, a process which is becoming increasingly important. Modelling of the discovery process is limited and combines appreciation of previously discovered reserves with new discoveries. The discovery process is influenced by changes in producer prices and taxes, however, as well as capital costs (which increase with increasing discoveries) and government subsidies. Although there are submodels for offshore oil development and Arctic natural gas, they have not been used for our simulations.

Modelling of energy taxes is fairly detailed for oil and natural gas to the city-gate level, though they are not explicitly estimated at the retail level. Retail energy taxes are not separated from general government revenues and so are not specifically affected by changes in energy demand.

MACE does not model the downstream end of the petroleum industry and so does not deal with imports and exports of refined petroleum products, or non-energy use of domestic production. It is assumed that all domestic production (with due allowances for losses) is either exported or consumed as energy.

The great usefulness of MACE in analyzing energy issues comes from the linkages between a detailed energy block on the one hand, and an aggregate macro model on the other. The channels of influence for energy in the macro model are many and varied - prices, aggregate output, employment, investment, consumption, the balance of trade, the financial sector and government revenues. Activity and inflation in the overall economy in turn affect energy demand and supply. The level of detail in the energy block with respect to demands by fuel, the supply and taxation of non-frontier natural gas, conventional and synthetic oil means that the impacts of fairly specific policy or price changes can be analyzed at the level of both the oil and gas industry and the national economy.

IV. Impact of Alternative Energy Tax-Pricing Strategies: Simulations

Significant changes in Canadian energy policy have already been proposed and the quantity and scope of such proposals will, no doubt, increase as the negotiations on a new arrangement get underway.

We have carried out a number of simulations of possible alternatives, a few of which have been reported in Economic Council's energy study.[17] The simulations focussed on the deregulation of oil and gas prices and changes in royalty and taxation policies. The following policies were examined: world price for all Canadian oil; deregulation of oil and natural gas prices; removal of the PGRT on new oil; removal of the PGRT on all oil and natural gas; increased provincial royalties; modifying the PGRT and the modification of the Canadian Ownership Special Charge.[18]

The effects of these policies were assessed through setting up a control solution and then shocking the system accordingly. The nominal world price of oil was U.S. $29.00 per bbl (fob Gulf) in 1983 and then was assumed to grow at the rate of U.S. inflation. The case is termed as a flat real world oil price base case (Base Case A-1). The existing energy taxation and pricing policies were retained in the control solution. The details of the control solution are described in Appendix II.

Case 1: World Price for All Oil Beginning 1985

This simulation examines the impact of pricing all oil at world levels on governments, the energy sector and the overall economy. For Canadian crude oil pricing, the main issue is the regulated price of old oil which is below the world oil price, while the producers of synthetic oil or of conventional oil from pools discovered since 1974, or produced from in-fill drilling of fields discovered previously, receive the New Oil Reference Price (NORP). In the Canadian context, where foreign ownership of the industry is a concern, pricing oil and natural gas below their opportunity value can lead to a welfare loss from over consumption (inhibiting the substitution of other energy sources for oil in consumption and production) if the foregone revenues to Canadians exceed the additional consumer surplus due to lower domestic prices. The net welfare effects, for the national economy as a whole, depend on the size of the efficiency losses and the distribution of the revenues between domestic and foreign residents. Sharp energy price changes may also have important macroeconomic effects; inflation, real output (GNP) and unemployment.

What are the likely effects of this policy on the domestic supply of oil? Economic analysis would suggest that there would be no effect unless there may be some resulting cashflow effects on investment spending since new oil is already receiving the world oil price, as does most enhanced oil recovery (EOR). The empirical evidence on cashflow effects on investment spending, and thus on new oil discoveries, is weak.[19]

The simulation results in Table 1 suggest that there would be two main macroeconomic effects of moving the price of old oil to the world level. First, it would increase the overall price of energy in the economy (0.7 per cent in 1985), thus leading to lower output (real GNP would drop by .15 per cent) and higher inflation (0.2 percentage points), as measured by GNP deflator. Figures 1 and 2 show the results for real GNP and the rate of inflation. Unemployment would rise slightly, mainly because of decreased employment (Figure 3). Consumption and investment expenditures decline.

The other main macro effect of moving the price of old oil to world level flows through its effect on the energy trade balance. As shown in Table 2, the total demand for oil drops by about 0.6 per cent in 1985, imports are down by about 1.5 per cent (see Figure 4) improving the energy trade balance slightly. This leads to a very slight appreciation of the Canadian dollar, which is reflected in the slight drop in the landed price of imported oil and the price of non-energy imports. Due to the deterioration in the non-energy trade balance (imports have increased because of lower import prices and exports decrease because higher domestic inflation has increased export prices), the net positive effect on the current account balance is very small.

Extending the NORP to old oil would raise the average well-head price of conventional oil by 5 dollars/bbl or 14 per cent in 1985 (Table 3). The effects on the blended price[20] would be smaller (1.7 per cent) and the effects on the final price to users even smaller (1.3 per cent). These results are reported in Table 2. One of the reasons that moving old oil to the world oil price has a relatively small effect on the blended city-gate price is that old oil accounts for a relatively small proportion of the oil consumed in Canada. The impact of moving to world oil price for all oil on the blended price is also reduced because the Canadianization levy is a flat rate and does not change proportionately with changes in the wellhead price. The proportionate change in the final price to users is even smaller than the change in the blended price since it is the sum of the city-gate price and the regional mark-up, which includes costs of refining and distribution and excise taxes. These mark-ups are more influenced by the general level of inflation than the price of crude oil and therefore change by a much smaller proportion than the city-gate price.

The linkage between the blended city-gate price of oil and domestic natural gas prices means that moving to the world price could also result in an increase in domestic natural gas prices. The results in Table 2 show that the user price of natural gas would increase but this increase is very small until 1989 because of the assumed path of world oil prices and the natural gas pricing assumptions followed. It is assumed that in 1985, natural gas pricing reverts to the provisions of the original 1981 agreements, which provided for an increase of 50 cents per thousand cubic feet (mcf) annually in the Alberta border price in 1985 and 1986 (even if the 65 per cent btu-parity policy is breached), or an increase which would maintain the Toronto city-gate price at 65 per cent of the btu-parity oil price, whichever was greater. Even by moving the price of old oil to the world level, the blended city-gate oil price is low enough so that the producers receive 50 cents/mcf in both 1985 and 1986 and the btu-parity rises above 65 per cent, although not by as much as in the control solution. In the simulations reported here, it is assumed that the gas producers receive no further increases after 1986 until 65 per cent btu-parity is restored. The 65 per cent btu-parity is restored in 1989 so that this is the first year that the higher blended price results in relatively higher domestic natural gas prices. Final natural gas prices to users do increase slightly before 1989 but only because of the higher level of inflation in the economy.

Higher domestic oil prices reduce the demand for oil by about 0.6 per cent in 1985 and increase the demand for natural gas by 0.1 per cent (Table 2). The demand for electricity is also slightly reduced (.16 per cent). The decrease in total demand for energy by 0.2 per cent results in a lower demand for electricity even though its share of total energy demand has gone up.

The simulation results in Table 3 indicate that moving to world prices has a slight positive impact on oil investment and discoveries (also see Figures 5 and 7). The slight positive response is because of the fact that we have introduced ad hoc cashflow effects into our model discovery/investment equations for oil and natural gas.[21]

The revenue sharing implications of moving the old oil prices to world levels are shown in Tables 5 and 6 and Figure 9. The results suggest that total government and industry revenues would increase by $13.0 billion over the 1985-95 period. Provincial revenues would increase by $4.7 billion, mainly because of increased royalties.[22] Federal revenues would also increase by about $4.0 billion due to increased corporate income tax and PGRT revenues. The aggregate revenues flowing to the oil and natural gas producing industry improve by about $4 billion over the 1985-95 period. This can be seen by the fact that industry cumulative cashflow, after taxes, royalties, and operating costs but before investment increases by about $3.9 billion over this period[23] (Table 4).

Case 2: Deregulation of Oil Prices Accompanied by a Phased-in Deregulation of Natural Gas Prices Beginning 1985 (Price Deregulation)

This simulation examines the effects of pricing all oil at world oil price beginning 1985 accompanied by a phased-in deregulation of domestic natural gas prices. What does deregulation mean for crude oil and natural gas? Domestic oil price deregulation would mean that all oil be sold at market prices with no limitations or subsidies. In the simulation, it is assumed that (i) the old oil price is moved to the world level; and (ii) the Petroleum Compensation Charge (PCC), Oil Export Tax, and subsidy to oil importers which is based on the difference between the old oil price and an import reference price would collapse to nothing.

Decontrolling natural gas is not so easy as oil, because of the complex contractual arrangements between individual producers, markets, pipelines, distributors and end-users. It is therefore recommended that the deregulation of natural gas be done on a phased basis over a period of a few years to enable the producers and buyers of natural gas to negotiate the necessary contracts for the new marketing system. In the simulation, it is assumed, as Helliwell et. al. (1985) rightly point out, that access to the natural gas export market is to some extent limited, and the National Energy Board (NEB) embody the effects of those limits. In these circumstances, there is room for competition among holders of unconnected gas reserves to compete for domestic markets, and thereby to drive the domestic natural gas price below the export price.[24] In this simulation, it has been assumed that deregulation of natural gas prices will be phased in starting in 1985. The btu-parity at the city-gate level is assumed to be 60 per cent in 1985, and 55 per cent from 1986 to 1990.[25] In the 1990s, the btu-parity ratio begins to rise as the gas surplus is reduced or eliminated. By 1994 the parity is back to 65 per cent and thereafter rises.[26]

The Canadian Ownership Special Charge (COSC) is shifted onto oil products only, at the retail level, and does not apply to both gas and oil. The COSC on all products is about to be about 3 per cent.[27] This is a policy change designed to shift energy demand away from fuel products and towards natural gas. It would also raise Canadian prices for oil products closer towards those in most OECD countries.

Deregulation of oil prices accompanied by phased-in deregulation of natural gas prices, hereafter referred to as price deregulation, would raise the conventional oil wellhead price by 14.5 per cent or 5 dollars in 1985 (Table 3). Price deregulation would raise the average price of oil consumed in Canada by about $1.30/bbl in 1985 and would lower the price of natural gas in the first year of deregulation by about 12 per cent. For the remainder of the 1980s, natural gas prices to final users remain around 17 per cent lower than under current policies (Table 2). The combined effect of deregulating both oil and natural gas prices is to lower the overall price index for energy in the economy by about 3 per cent in 1985 and by over 8 per cent in the late 1980s. The drop in energy prices lowers inflation and stimulates growth in the economy.[28]

Inflation, as measured by the GNP deflator, would be lower by about 0.6 percentage points in 1985 and 1 percentage point in 1986 (see Figure 2). Real GNP, on average, would increase by about 0.5 per cent per year over the period 1985-90 (Figure 1). The unemployment rate would drop slightly during the period 1985-88 (see Figure 3). In the late 1980s and 1990s, however, the unemployment rate would start increasing again as the lower energy price encourages the use of more energy and less labour in the production of any given level of desired output.

By raising the price of oil and lowering the price of natural gas, price deregulation gives consumers incentives to shift away from oil to natural gas. The demand for oil would drop by an average of 4 per cent in the late 1980s, while the demand for natural gas would rise by about 13 per cent. This would result in a drop of oil imports of about 9 per cent (see Figure 4) and in a slight improvement in the balance of trade in energy and consequently, the current account of the balance of payments[29] (Table 1).

On the supply side, our results suggest that the oil and natural gas deregulation policy would stimulate domestic oil production and promote oil exploration and development over the next few years. Oil discoveries would rise by an average of about 3 per cent in the 1980s (see Table 3 and Figure 5) assuming that additional cashflow stimulates investment. The wellhead price incentives for newly discovered oil are not affected by minor changes in the exchange rate and inflation-related increases in transportation tariffs, and therefore the additional oil investment comes indirectly, from additional cashflow. The cashflow effects are greater than in Case 1 because the positive impacts on GNP brought about by lower natural gas prices increase the demand for all energy relative to Case 1, including the demand for oil.

Gas production would also increase, but gas-directed exploration and development could be reduced. The drop in natural gas prices reduces producer incentives to discover new gas, and since the price elasticity of demand for natural gas is less than 1, cashflow effects reinforce this. The drop in natural gas investment (Figure 8) is slightly larger than the increase in oil investment (Figure 7) so the net effect on real investment in the petroleum industry is negative (see Table 1).

Industry cashflows rise under price deregulation,[30] assuming that royalty and tax rates remain at present levels. Cumulative industry cashflow, after taxes, royalties, and operating cost -- but before investment -- increases by about $240 million over the period 1985-95 (see Table 4). Both federal and provincial government energy revenues are affected. As can be seen from Table 5, the estimates suggest that the federal government would gain a total of 1.9 billion in cumulated revenues over the 1985-95 period, while the provincial governments lose about $0.9 billion and the industry gains about $1.8 billion (Figure 9). The COSC modification increases federal revenues over the 1985-95 period by $3 billion (sum of current undiscounted dollars) since the levy now increases with increasing oil prices, but has virtually no effect on provincial or industry revenues.

Case 3: Price Deregulation and Removal of the PGRT on New Oil Only

What are the implications of price deregulation accompanied by the removal of PGRT from 1985 onwards on New Oil only?

The PGRT is a tax on gross production revenues net of operating costs. Since it reduces the after tax netback from oil and natural gas to producers it curtails the incentive for exploration and development of new reserves. Removing the PGRT on all domestically produced oil which currently receives the new oil reference price (discovered since 1974) has the advantage of increasing the incentives for new oil discoveries while minimizing the loss of revenues to the federal government. It would also provide a means of phasing out the PGRT on oil entirely as stocks of old oil are depleted.

The simulation results show that there is a significant supply response from the oil side of the industry. The industry's cumulative cashflow increases by 26.8 billion dollars over the period 1985-95 (Table 4) and oil reserve additions and investment in conventional non-frontier oil increase significantly compared to the control levels (see Figures 10 and 12). Although new gas does not receive the same stimulus as oil from removing the PGRT on new oil, total real energy investment increases by over 2 per cent (Table 1). The modest increase in energy investment has small positive impacts on real growth and employment in the economy overall, while the increased supply of oil reduces imports (Table 2) and has positive effects on the current account balance and the exchange rate.

The removal of PGRT from new oil also affects the macroeconomy through its effects on government balances. The results in Table 5 indicate that over the decade to 1995 the federal government takes in about 12 billion dollars less. The provincial government revenues increase by about 5 billion dollars and cumulative industry revenues are up by 30.1 billion dollars over the 1985-95 period (see Figure 14).

Case 4: Price Deregulation and Removal of the PGRT on All Oil and Natural Gas

As an extreme case, we then carried out a simulation that combined price deregulation with the removal of PGRT on all oil and gas, starting in 1985.

The results show a significant incentive to discover more oil and natural gas and a major boost to the Canadian economy. On the supply side, the results suggest that there is a significant positive effect on the discoveries of oil and natural gas reserves (Figures 10 and 11). The supply effects of new conventional oil are virtually identical to the case when the PGRT is removed from new oil only.

Investment in conventional non-frontier oil and natural gas increases (Figures 12 and 13), which increases total real energy investment. The increase in energy investment has positive impacts on real growth and employment in the economy overall, while the increased supply of oil reduces imports and has positive effects on the energy trade balance and the exchange rate.

Removing the PGRT from natural gas does not affect the energy trade balance since natural gas is not imported to any great extent and exports do not increase as a result of increased supplies. The main effect of removing the PGRT on natural gas is to increase shut-in supplies. Natural gas discoveries decline slightly when the PGRT is removed from NORP oil only (Table 3 and Figure 11) since the exchange rate appreciation causes a slight decrease in the blended oil price which is the basis for natural gas pricing. Supplies of synthetic oil are not affected since no new plants come into operation.

The revenue imbalance becomes even greater than in the previous scenario. Cumulative revenues to the federal government would drop by about 53 billion dollars over the 1985-95 period as a result of eliminating the tax. The provincial government revenues would increase ($6.8 billion), while cumulative industry revenues would jump by more than 71 billion dollars (see Table 5 and Figure 14).

The drop in federal revenues at a time when concern is mounting over size of the federal deficit suggests that intermediate policy options are required. These is also the lingering concern about thepotential transfer of rents abroad because of the high degree of foreign ownership among the producing companies. Removing the PGRT would raise the total rents to end-2000 by about 11 billion 1983 dollars, while reducing total rents accruing to Canadians by about $8 billion (1983 dollars). The reduction in net benefits to Canadians arise because the large transfer of benefits from federal government to energy producers includes a large net gain by the foreign shareholders of producing firms.

Case 5: Price Deregulation, Removal of the PGRT on All Oil and Natural Gas and Increased Provincial Royalties

The results in Case 4 show that removing the PGRT on all oil and natural gas would result in a transfer of large sums of revenues from the federal government to energy producers. This results into a large net gain by the foreign shareholders of energy producing firms. One possible way around this would be to increase provincial royalty rates. This is introduced because removing the PGRT provides room for royalties on revenues that would otherwise go to the petroleum industry. For the sake of simplicity in the simulation, royalty rates on both oil and gas are increased, although a more refined analysis might increase oil royalties but decrease gas royalties. The provinces could agree to share royalties with the federal government. Thus, the simulation addresses the following question: What would happen if price deregulation is combined with the removal of the PGRT and the provincial royalty rates are increased?

In this simulation, provincial royalty rates are increased beginning 1985 for conventional oil, synthetic oil and natural gas production with the objective of collecting two-thirds of the foregone PGRT revenues. This means that the supply incentive created by the removal of the PGRT is not completely eliminated but that the transfer of revenues to industry is reduced.

The results show that over the 1985-95 period, the increase in provincial royalties does capture about two-thirds of the lost PGRT revenue. Royalties increase by 42.5 billion dollars over the control solution which is about 76 per cent of the lost PGRT revenue (Table 6). This is in effect shifting government revenues from federal to the provincial government (see Figure 14).

The after-tax price received by producers for new oil is up by around 15 per cent compared to the control solution, which is much lower than the 33 per cent increase received when the PGRT was removed (Table 3). Oil discoveries and investment in non-frontier oil are still well above control levels but have been significantly reduced relative to the PGRT removal case (see Figures 10 and 12).

From a macroeconomic standpoint, the real energy investment and rate of inflation are lower and crude oil imports are higher relative to the previous simulation. Real GNP, on average, is 0.65 per cent higher compared to the control versus 0.84 per cent higher for Case 4 (see Table 1).

Case 6: Policy Package

From the results in Case 5 it is clear that there is in effect a transfer of revenues from the federal government to the provincial government and industry. It is of interest to consider two alternatives to reduce the revenue loss to the federal government. One, instead of removing the PGRT on all oil and natural gas, the PGRT could be modified by making it more sensitive to industry profits by allowing for capital cost deductions as well as operating costs. Two, the federal government could consider introducing an 'Off-Oil Charge' on oil products alone. This shifts the federal tax to the consumer end of the industry. The off-oil charge would increase security of supply in oil through reducing the domestic demand for oil. It would also increase the price of oil relative to natural gas, further tilting demand towards gas and away from oil. It would also offset, at least partially, the lost federal revenues due to modified PGRT.

In the simulation, we ask the following question: What would happen if price deregulation is pursued, PGRT is modified and an 'Off-Oil Charge' (OOC) on oil products alone is introduced? The PGRT is modified to be a tax on production revenues net of operating cost and net of (100 per cent) investment expenditures during the year on oil and natural gas exploration, development and production.

The basic and effective rate of PGRT and small producers' exemption are kept unchanged.

Concurrently, a federal off-oil charge on all oil products of approximately one per cent is introduced. In fact, the Canadian ownership charge could become a Canadian ownership and off-oil charge (4 per cent).

The results show that the introduction of this package would have the following major impacts: Real GNP would increase by an average of about 0.5 per cent per year over the period 1985-90, and inflation would be lower by about 0.4 percentage points in 1985 and 1 percentage point in 1986 (see Table 1 and Figures 1 and 2). The lower inflation rate would be mainly due to the lower domestic price index for energy, which would be down by about 2.5 per cent in 1985 and 5.2 per cent in 1986 (see Table 1). The unemployment rate would be lower during the period 1985-90 (Figure 3). The component of GNP most positively affected would be investment both in the energy and non-energy sector, closely followed by consumption. The significant result from this scenario is that there is scope for non-inflationary growth.

The results show a drop in demand for oil (and, therefore, increased security of oil supplies because of lower imports), and an increase in demand for natural gas. Relative to the base case, the impact on the price of oil to the consumer would average about 2 per cent per year in the period to 1990 (Table 2). The package would reduce the demand for oil by an average of 5 per cent per year during the period to 1990, which would cause oil imports to decline by about 12 per cent per year on average over the period 1985-90 (see Figure 4). Canada's balance of trade in energy would be higher by approximately $9.6 billion over the period 1985-90. The user price of natural gas would decline on average by about 17.4 per cent and the demand for natural gas would be higher by about 13 per cent per year during the period 1985-90 (see Table 2).

On the supply side, the results suggest domestic oil exploration and production would be stimulated. Gas production would also increase, but exploration and development could decrease as lower gas prices would reduce incentives to find new reserves. The package generates a positive supply response as the producer's netbacks (wellhead price after taxes and royalties) from conventional oil increase on average by about 3.6 per cent over the period 1985-90 (Table 3). Oil discoveries increase by about 10 per cent in 1985 and remain above control levels throughout 1990. The netbacks to natural gas producers would be lower by an average of about 8 per cent per year over the period 1985-90 and the decrease in natural gas discoveries would be about 4 per cent per year over this period (Table 3). Although new gas does not receive the same stimulus as oil from modifying the PGRT on oil and natural gas, total real energy investment would be marginally positive (Table 1).

The industry cumulative cashflow after taxes, royalties and operating costs, but before investment, would increase by about $7 billion over the period 1985-90 (see Table 5). Under the policy packge, the federal government would collect $2.2 billion more revenue over the decade to 1995. The provincial government revenues would be lower by $100 million, while cumulative industry gross revenues would be up by $8.8 billion over the 1985-90 period (Figure 9).

Testing Robustness of the Policy Package

Past experience has demonstrated the necessity for energy policies which are robust under a variety of circumstances.

Accordingly, we have compared the implications of our policy package to current policies under two sets of assumptions about future world oil prices.

In the rising world oil price scenario (Base Case A-2), the Persian Gulf (FOB) price of oil is assumed to increase at the rate of five per cent real per annum from 1985 to 2000. In the declining world oil price scenario (Base Case A-3), the Persian Gulf price decreases at five per cent in real terms per annum over the periods 1985 to 2000.

In Base Case A-2, the higher world oil price affects the rest of the world economy, as does, under Base Case A-3, the lower world price. This has a particularly important impact on an economy like Canada's, which is so heavily dependent on foreign trade. Accordingly, assumptions have been made with respect to the impact of higher and lower world oil prices on rest of the world economy.[31]

The assumptions for the rising and declining world oil prices base cases are listed in Appendix II.

Case 7: Policy Package Under Rising World Oil Prices

The policy package improved Canada's economic performance when world oil prices are assumed to remain flat in real terms

(Case 6). How well does it perform relative to current policies when world oil prices are rising (Case 7) or falling (Case 8) in real terms?[32]

The results show that the introduction of this package when world oil prices are rising would have the following major impacts: Compared to current policies, real GNP would increase in all years and unemployment rates would reduce during the period 1985-90. The chief source of the favourable impact on GNP would be investment both in the energy and non-energy sector, closely followed by consumption, although net exports would fall in late 1980s. The rate of inflation would fall fractionally in 1985. In 1986, this fall would be about 0.79 percentage points. The lower inflation rate would be mainly due to the lower domestic price index for energy, which would be down by about 1.19 per cent in 1985 and 3.89 per cent in 1986 (see Table 7).

In the case of the foreign sector, Canada's balance of trade in energy would be higher by approximately $10.3 billion over the period 1985-90. Compared to current policies, the overall balance of trade account would increase by about $11 billion over the period 1985-90 and the exchange rate would appreciate.

The average user price of oil would increase by 3.2 per cent in 1985 and by an average of 2.5 per cent per year over the period

1985-90. This would cause demand for oil to drop by approximately 26.6 per cent by 1990, which would lead to a decline in oil imports of about 12.4 per cent per year on average over the 1985-90 period. The average user price of natural gas would decline by about 14.5 per cent and the demand for natural gas would be higher by about 10 per cent per year during the same period (see Table 9).

The simulation results show that the policy package generates a positive supply response as the after tax price received by producers (wellhead price after taxes and royalties) from conventional oil increase on average by about 3.5 per cent over the period 1985-90 (Table 8). Oil discoveries increase by about 9 per cent in 1985 and remain above control levels throughout 1990. They would be higher by 4.5 per cent in 1990 and 2 per cent in 1995. The after tax prices to natural gas producers would be lower by an average of 5 per cent per year over the period 1985-90 and the decrease in natural gas discoveries would be about 2.4 per cent per year over this period.

The industry cumulative cashflow after taxes, royalties and operating costs, but before investment, would increase by about $9.7 billion over the period 1985-95 (see Table 10). Table 11 shows the revenue sharing estimates for federal government, provincial governments and industry. Under the policy package, revenues to industry, federal government and provincial government would rise. The estimates suggest that the industry would gain a total of $11.4 billion in cumulative revenues over the 1985-95 period, the federal government would gain $7 billion over this period, while the provincial governments gain $710 million.

Case 8: Policy Package Under Declining World Oil Prices

What would happen if the policy package were introduced during a regime of declining world oil prices?

The simulation results[33] suggest that the package would lower Canadian energy prices overall, which would lead to lower inflation, a reduction in unemployment, and an increased average annual real economic growth of 0.9 per cent between 1985 and 1990. An additional consequence would be a change in the composition of energy supply and demand (Table 7).

The results indicate that the oil price would be higher than under current policies (Base Case A-3) by about 1.6 per cent between 1985 and 1990. Demand for oil would drop by about 6 per cent by the late 1980s, leading to a drop in oil imports by about 13 per cent between 1985 and 1990, and, therefore, increased security of oil supplies. Natural gas would drop in price by about 27 per cent between 1985 and 1990, leading to an increase in demand for natural gas by about 22 per cent.

On the supply side, the results suggest domestic oil exploration and production would be stimulated. Gas production would also increase, but exploration and development could decrease as lower gas prices would reduce incentives to find new reserves (Table 8).

Consequently, total real energy investment would fall slightly (0.19 per cent between 1985 and 1990). The drop in gas investment would be larger than the increase in oil investment. The industry cashflows would rise, but, with existing royalty and tax policies, federal and provincial revenues would fall under the policy package.

V. Conclusions

These are some of the simulations which were performed for the new energy study released by the Economic Council of Canada (ECC, 1985). Note that these simulations are not the forecasts or projections of the Canadian economy under alternative exogenous forecasts or alternative policies. These simulations do, however, enable us to come to conclusions about the outcome of certain policy changes.

The simulation results indicate that a policy of moving the old oil price to world levels would improve the industry cashflow position and would increase the revenues of the governments. The policy could stimulate domestic oil exploration if industry cash-flow are a problem. It would reduce the demand for oil, lower oil imports and increase the demand for natural gas. The policy would, however, have some negative macroeconomic effects, the real GNP would be lower and inflation and unemployment rates would be slightly higher.

Deregulation of oil prices accompanied by a phased-in deregulation of natural gas prices would stimulate economic growth and would have deflationary effects. The policy would also stimulate domestic oil production and provide oil exploration and development, reduce oil imports, and encourage the development of alternative energy sources.

The PGRT by reducing the after tax netback from oil and natural gas to producers curtails the incentive for exploration and development of new reserves. Thus, from an efficiency point of view, it is preferable that revenue taxes such as the PGRT should be eliminated. A policy of price deregulation accompanied by removal of the PGRT on new oil (discovered since 1974) would lead to more oil supply and a major boost to the Canadian economy. However, the resulting imbalance of effects on revenue flows to the participants suggest the need for some kind of an intermediate policy.

As an extreme case, a policy of price deregulation accompanied by removal of the PGRT on all oil and natural gas would stimulate oil exploration and development, leading to increased domestic supplies. The policy would, however, result in a transfer of large sums of revenues from the federal government to the producers and a large net gain by the foreign shareholders of producing firms. One possible way around this would be to increase provincial royalty rates. The provinces could agree to share royalties with the federal government.

Finally, there is no indication that the policy package would cause a surge of price increases and it appears that Canada's capacity to develop indigenous supplies of oil will be increased, giving greater security of supply for the longer term. The policy package would also tend to insulate the economy from destabilizing effects during periods of rising/declining world oil prices and would stimulate non-inflationary economic growth. The package would also reduce oil imports by lowering oil demand and stimulate domestic oil production and exploration through increased oil investment.

Table 1

Macroeconomic Effects of Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGRT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:			(Per cent)			
Real Gross National Product (GNP)						
1985	-0.15	0.18	0.37	.49	0.31	0.20
1986	-0.12	0.69	0.88	1.00	0.82	0.70
1985-90 (average)	-0.11	0.47	0.73	.84	0.65	0.53
1995	-0.04	0.35	1.04	1.06	0.72	0.49
Real Energy Investment						
1985	0.03	-0.25	2.42	4.19	1.50	0.58
1986	0.03	-0.54	1.16	2.77	0.70	-0.08
1985-90 (average)	0.02	-0.38	1.20	2.76	0.80	0.60
1995	0.01	0.01	0.84	1.72	0.65	0.13
Real Non-Energy Investment						
1985	-0.16	0.99	1.39	1.69	1.28	0.95
1986	-0.14	2.73	3.22	3.58	3.07	2.71
1985-90 (average)	-0.11	1.42	2.00	2.23	1.81	1.52
1995	-0.04	0.88	1.94	1.85	1.39	1.02
			(Pe-centage Points)			
Inflation Rate						
1985	0.22	-0.58	-0.44	-0.38	-0.50	-0.41
1986	-0.03	-1.09	-1.01	-0.93	-1.02	-1.10
1985-90 (average)	0.03	-0.17	-0.18	-0.14	-0.15	-0.16
1995	0.03	-0.34	-0.47	-0.36	-0.31	-0.36
Unemployment Rate						
1985	0.01	-0.08	-0.12	-0.15	-0.11	-0.08
1986	0.01	-0.24	-0.29	-0.33	-0.28	-0.24
1985-90 (average)	0.02	-0.04	-0.11	-0.15	-0.09	-0.07
1995	-0.004	0.20	0.07	0.06	0.12	0.16
User Price Index for Energy						
1985	0.67	-2.94	-3.01	-3.03	-2.98	-2.49
1986	-0.38	-5.10	-5.13	-5.12	-5.13	-5.18
1985-90 (average)	0.06	-1.15	-1.22	-1.19	-1.17	-1.11
1995	-0.04	0.04	-0.13	-0.03	0.05	0.02
			S Billions)			
Current Account Balance						
1985	0.11	0.59	0.83	0.69	0.66	0.73
1986	-0.06	1.05	1.35	0.97	1.05	1.18
1985-90 (average)	-0.09	1.73	2.47	1.94	1.79	1.91
1995	-0.11	4.77	7.86	6.54	5.14	5.25

1 These figures are deviations from Base Case (A-1) values.

2 In this scenario, the Canadian Ownership Charge Special (COSC) is modified and shifted onto oil products only, at the retail level, and does not apply to both gas and oil.

3 Policy Package includes price deregulation, modified PGRT, and modified COSC.

Source Economic Council of Canada, MACE Model, July 1984.

Table 2

Effects of Alternative Energy Tax and Pricing Policies on Consumer Prices and Energy Demand, Canada, 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGRT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:			(Per cent)			
Average User Price of Oil						
1985	1.25	2.14	2.00	1.97	2.06	3.07
1986	0.54	1.31	1.12	1.07	1.18	2.23
1985-90 (average)	0.54	1.33	1.02	1.05	1.17	2.22
1995	-0.31	-0.27	-1.57	-1.06	-0.53	0.46
Average User Price of Natural Gas						
1985	0.06	-12.16	-12.30	-12.34	-12.24	-12.20
1986	0.08	-22.60	-22.79	-22.83	-22.74	-22.60
1985-90 (average)	0.19	-17.32	-17.61	-17.59	-17.47	-17.38
1995	-0.38	-4.29	-5.66	-5.15	-4.60	-4.58
Canadian Demand for Crude Oil						
1985	-0.62	-2.94	-2.85	-2.81	-2.88	-3.38
1986	-0.39	-5.04	-4.89	-4.79	-4.93	-5.59
1985-90 (average)	-0.41	-4.19	-4.00	-3.89	-4.04	-4.76
1995	0.19	-0.88	-0.22	-0.14	-0.50	-1.43
Canadian Demand for Natural Gas						
1985	0.10	6.55	6.66	6.71	6.62	6.66
1986	0.08	14.81	15.04	15.17	14.98	14.99
1985-90 (average)	0.02	12.69	13.00	13.11	12.91	12.87
1995	0.24	3.04	3.82	3.88	3.47	3.32
Imports of Crude Oil Per Day						
1985	-1.54	-7.07	-11.57	-11.67	-9.27	-8.96
1986	-0.99	-11.13	-17.46	-17.56	-14.20	-13.35
1985-90 (average)	-1.08	-9.19	-17.51	-17.69	-13.21	-11.67
1995	0.02	-1.66	-10.95	-11.24	-6.12	-3.67
Demand for Energy						
1985	-0.22	1.06	1.12	1.16	1.10	0.90
1986	-0.14	3.30	3.43	3.52	3.40	3.13
1985-90 (average)	-0.17	3.33	3.51	3.61	3.47	3.17
1995	0.16	1.15	1.76	1.83	1.50	1.08

Note For the footnotes, see Table 1.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 3

Effects of Alternative Energy Tax and Pricing Policies on Oil and Natural Gas Discoveries, Production and Investment, Canada, 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGPT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:			(Per cent)			
Discoveries of Oil (Reserve Additions) Per Annum						
1985	0.88	1.99	46.11	48.03	23.84	9.99
1986	1.65	4.84	58.25	61.17	31.62	11.14
1985-90 (Average)	1.17	2.27	50.00	52.18	25.78	8.37
1995	0.81	0.84	39.64	40.58	19.39	3.83
Actual Oil Production Per Day						
1985	0.06	0.14	3.21	3.34	1.66	0.70
1986	0.12	0.32	5.43	5.67	2.86	1.12
1985-90 (Average)	0.18	0.43	8.24	8.61	4.30	1.58
1995	0.54	0.82	22.79	23.70	11.58	3.43
Discoveries of Natural Gas (Reserve Additions) Per Annum						
1985	-0.15	-4.49	-4.70	14.41	0.62	-0.27
1986	-0.13	-8.86	-9.19	8.77	-4.13	-5.72
1985-90 (Average)	-0.08	-6.63	-7.00	12.42	-1.31	-3.76
1995	-0.029	0.18	-0.54	24.13	7.68	1.58
Actual Natural Gas Production Per Day						
1985	0.06	4.21	4.28	4.32	4.25	4.30
1986	0.05	8.76	8.90	8.97	8.87	8.86
1985-90 (Average)	0.01	7.40	7.[illegible]2	7.80	7.60	7.54
1995	0.17	2.27	2.86	2.91	2.60	2.49
Investment in Non-Frontier Oil						
1985	0.79	1.10	34.87	36.45	17.57	7.16
1986	1.07	1.95	35.53	37.54	18.41	5.95
1985-90 (Average)	0.87	0.91	33.40	35.13	16.52	5.05
1995	0.87	-0.41	39.68	41.63	18.42	2.92
Investment in Non-Frontier Gas						
1985	0.04	-4.82	-4.90	13.67	0.18	-0.61
1986	0.04	-9.99	-10.13	7.81	-5.21	-6.67
1985-90 (Average)	0.09	-7.35	-7.58	11.73	-2.07	-4.42
1995	-0.18	-2.64	-3.90	25.02	5.82	-0.94
Well-head Price of Oil						
1985	14.40	14.47	14.24	14.17	14.34	14.35
1986	13.03	13.06	12.75	12.63	12.84	12.93
1985-90 (Average)	11.23	10.69	10.26	10.08	10.45	10.57
1995	5.71	3.68	2.12	2.65	3.30	3.38
Well-head Price of Oil After Taxes and Royalties						
1985	-0.03	0.01	33.29	33.21	15.48	5.80
1986	-0.02	-0.04	33.17	33.04	15.28	3.80
1985-90 (Average)	-0.03	-0.54	32.38	32.38	14.61	3.55
1995	0.10	-1.76	30.02	30.69	13.10	0.89
Well-head Price of Natural Gas						
1985	-0.02	-8.51	-8.73	-8.80	-8.64	-8.63
1986	-0.03	-16.88	-17.23	-17.37	-17.13	-17.06
1985-90 (Average)	0.05	-12.75	-13.21	-13.30	-13.05	-12.92
1995	-0.34	-2.91	-4.63	-4.13	-3.39	-3.27
Well-head Price of Natural Gas After Taxes and Royalties						
1985	-0.03	-7.69	-7.88	19.10	-0.72	-1.42
1986	-0.04	-15.39	-15.70	8.68	-9.34	-10.89
1985-90 (Average)	0.05	-11.65	-12.06	13.92	-5.12	-7.54
1995	-0.37	-2.77	-4.37	26.27	5.01	-0.92

Note For the footnotes, see Table 1.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 4

Effects of Alternative Energy Tax and Pricing Policies on the Cumulative Cash Flow of Industry, (After Taxes, Royalties and Operating Costs, and Before Investment), 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGRT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:			($ Billions)			
Cash Flow in 1985	0.5	0.3	1.7	4.3	2.0	1.0
Cash Flow in 1986	0.4	0.1	1.6	4.6	1.9	0.7
Cumulative Cash Flow 1985-95	3.9	0.2	26.8	69.3	28.7	7.0

Note For the footnotes, see Table 1.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 5

Change in Cumulative Revenue Sharing Estimates Under Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGRT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:				($ Billions)		
Federal Goverment Revenues	4.2	1.9	-12.1	-52.6	-53.2	2.2
Provincial Government Revenues	4.7	-0.9	5.3	6.8	35.9	-0.1
Industry Revenues	4.1	1.8	30.1	71.5	31.0	8.8
Total Government and Industry Revenues	13.0	2.7	23.3	25.7	13.7	10.9

Note For the footnotes, see Table 1.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 6

Cumulative Revenue Sharing Estimates Under Alternative Energy Sector Tax and Pricing Policies, Canada, 1985-95

	Flat World Oil Prices[1]					
	Case 1: World Oil Price For All Oil	Case 2: Price Deregulation[2]	Case 3: Price Deregulation and Removal of PGRT on New Oil Only	Case 4: Price Deregulation and Removal of PGRT on All Oil and Natural Gas	Case 5: Price Deregulation, Removal of PGRT on All Oil and Natural Gas and Increased Provincial Royalties	Case 6: Policy Package[3]
Change in:			($ Billions)[4]			
Federal Goverment Revenues						
Canadianization Levy	0.0	-13.8	-13.8	-13.8	-13.8	-13.8
Natural Gas and Gas Liquids Tax	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum and Gas Revenue Tax	1.9	0.0	-16.3	-55.4	-55.4	-5.2
Incremental Oil Revenue Tax	0.7	0.7	0.7	0.7	0.6	0.7
Corporate Income Tax	3.3	0.2	2.7	1.3	0.7	0.3
Oil Export Tax	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Modified Canadian Ownership Charge	0.0	16.5	16.4	16.5	16.5	22.0
Petroleum Incentive Payments	(0.1)	(0.7)	(0.1)	(0.2)	(0.1)	(0.1)
Total Federal Revenues	4.2	1.9	-12.1	-52.6	-53.2	2.2
Provincial Governments Revenues						
Royalties Net of Incentive Payments	5.8	1.3	6.7	7.3	42.5	2.0
Land Payments	0.0	-0.6	0.5	2.6	0.4	-0.2
Oil Export Tax	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Corporate Income Tax	0.7	-0.1	0.3	-0.3	-4.9	-0.1
Petroleum Incentive Payments	(0.0)	(-0.3)	(0.4)	(1.0)	(0.3)	(0.0)
Total Provincial Revenues	4.7	-0.9	5.3	6.8	35.9	-0.1
Industry Revenues						
Operating Costs	0.2	1.1	3.3	3.6	2.3	2.3
Land Payments	(0.0)	(-0.6)	(0.5)	(2.6)	(0.4)	(0.2)
Cashflow	3.9	0.2	26.8	69.3	28.7	7.0
Petroleum Incentive Payments	(0.1)	(0.7)	(0.5)	(1.2)	(0.4)	(0.1)
Total Industry Revenues	4.1	1.8	30.1	71.5	31.0	8.8
Total Government and Industry Revenues	13.0	2.7	23.3	25.7	13.7	10.9

Note For footnotes 1 to 3, see Table 1.

4 The figures are undiscounted sums of revenues from 1985 to 1995, inclusive. These cases include the continuation of the IORT suspension announced in the 1983 federal budget.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 7

Macroeconomic Effects of Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	(Per cent)	
Real Gross National Product (GNP)		
1985	0.08	0.33
1986	0.44	0.97
1985-90 (average)	0.42	0.91
1995	0.51	1.11
Real Energy Investment		
1985	0.72	0.44
1986	0.14	-0.29
1985-90 (average)	0.16	-0.19
1995	0.17	-0.08
Real Non-Energy Investment		
1985	0.53	1.37
1986	1.81	3.59
1985-90 (average)	1.38	2.53
1995	0.98	2.82
	(Percentage points)	
Inflation Rate		
1985	-0.10	-0.74
1986	-0.79	-1.40
1985-90 (average)	-0.17	-0.34
1995	-0.41	-0.60
Unemployment Rate		
1985	-0.05	-0.11
1986	-0.16	-0.32
1985-90 (average)	-0.08	-0.14
1995	0.14	0.29
	(Index)	
User Price Index for Energy		
1985	-1.19	-3.78
1986	-3.89	-6.38
1985-90 (average)	-1.07	-2.16
1995	-0.07	-0.12
	($ Billions)	
Current Account Balance		
1985	0.66	0.77
1986	1.02	1.30
1985-90 (average)	1.82	2.48
1995	5.56	7.33

1 Includes price deregulation, modified PGRT and modified COSC.

2 These figures are deviations from Base Case A-2 values.

3 These figures are deviations from Base Case A-3 values.

Source Economic Council of Canada, MACE Model, July 1984.

Table 8

Effects of Alternative Energy Tax and Pricing Policies on Oil and Natural Gas Discoveries, Production and Investment, Canada, 1985-95

	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	(Per cent)	
Discoveries of Oil (Reserve Additions) Per Annum		
1985	9.26	10.61
1986	9.17	13.29
1985-90 (Average)	7.20	11.20
1995	2.23	8.62
Actual Oil Production Per Day		
1985	0.68	0.70
1986	1.07	1.15
1985-90 (Average)	1.52	1.69
1995	3.02	4.13
Discoveries of Natural Gas (Reserve Additions) Per Annum		
1985	1.56	-2.02
1986	-2.69	-8.78
1985-90 (Average)	-2.36	-8.21
1995	1.35	-6.53
Actual Natural Gas Production Per Day		
1985	3.01	5.62
1986	6.06	11.89
1985-90 (Average)	5.93	9.92
1995	2.08	-1.74
Investment in Non-Frontier Oil		
1985	7.00	7.21
1986	5.56	6.27
1985-90 (Average)	4.94	5.38
1995	2.16	3.66
Investment in Non-Frontier Gas		
1985	1.42	-2.59
1986	-3.31	-10.21
1985-90 (Average)	-2.87	-9.22
1995	-0.77	-10.77
Well-head Price of Oil		
1985	14.22	12.38
1986	12.72	11.47
1985-90 (Average)	10.35	9.42
1995	2.23	3.66
Well-head Price of Oil After Taxes and Royalties		
1985	5.72	5.87
1986	3.71	3.91
1985-90 (Average)	3.47	3.66
1995	0.36	0.51
Well-head Price of Natural Gas		
1985	-5.32	-11.88
1986	-11.43	-22.78
1985-90 (Average)	-9.56	-21.41
1995	-3.34	-18.50
Well-head Price of Natural Gas After Taxes and Royalties		
1985	1.74	-4.51
1986	-5.57	-16.24
1985-90 (Average)	-4.90	-15.30
1995	-0.92	-14.26

For footnotes, see Table 7.

Source Economic Council of Canada, MACE Model, July 1984.

Table 9

Effects of Alternative Energy Tax and Pricing Policies on Consumer Prices and Energy Demand, Canada, 1985-95

	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	(Per cent)	
Average User Price of Oil		
1985	3.22	2.77
1986	2.50	1.89
1985-90 (average)	2.53	1.65
1995	0.41	-0.86
Average User Price of Natural Gas		
1985	-8.52	-15.70
1986	-16.33	-28.61
1985-90 (average)	-14.51	-26.74
1995	-4.08	-18.90
Canadian Demand for Crude Oil		
1985	-2.88	-3.77
1986	-4.57	-6.51
1985-90 (average)	-4.43	-6.30
1995	-1.35	-3.32
Canadian Demand for Natural Gas		
1985	4.62	8.72
1986	10.21	20.14
1985-90 (average)	10.23	21.55
1995	2.96	14.87
Imports of Crude Oil Per Day		
1985	-8.04	-9.60
1986	-11.86	-14.53
1985-90 (average)	-12.17	-13.45
1995	-5.09	-5.39
Demand for Energy		
1985	0.43	1.40
1986	1.97	4.32
1985-90 (average)	2.40	5.50
1995	0.95	5.09

Note For the footnotes, see Table 7.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 10

Effects of Alternative Energy Tax and Pricing Policies on the Cumulative Cash Flow of Industry (After Taxes, Royalties and Operating Costs, and Before Investment), Canada, 1985-95

	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	($ Billions)	
1985	1.13	0.86
1986	0.86	0.42
Cumulative cash flow 1985-95	9.73	0.08

Note For the footnotes, see Table 7.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 11

Change in Cumulative Revenue-Sharing Estimates Under Alternative Energy Tax and Pricing Policies, Canada, 1985-95

	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	($ Billions)	
Federal government revenues	7.1	-12.1
Provincial government revenues	0.7	-11.4
Industry revenues	11.4	1.3
Total government and industry revenues	19.2	-22.1

Note For the footnotes, see Table 7.

Source Economic Council of Canada, MACE Model, July, 1984.

Table 12

Cumulative Revenue Sharing Estimates Under Alternative Energy Sector Tax and Pricing Policies, Canada, 1985-95

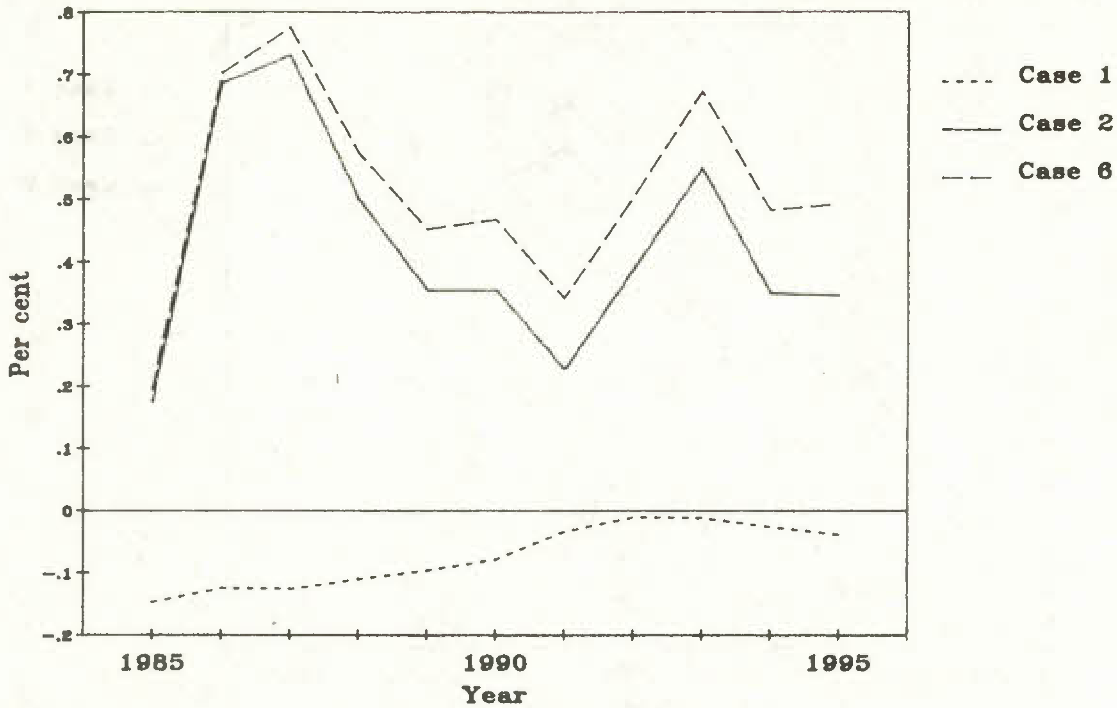
	Policy Package[1]	
	Case 7: Rising World Oil Prices[2]	Case 8: Declining World Oil Prices[3]
Change in:	($ Billions)[4]	
Federal Goverment Revenues		
Canadianization Levy	-12.3	-15.2
Natural Gas and Gas Liquids Tax	0.0	0.0
Petroleum and Gas Revenue Tax	-6.2	-8.3
Incremental Oil Revenue Tax	2.6	0.4
Corporate Income Tax	0.1	-7.1
Oil Export Tax	-2.1	-1.3
Modified Canadian Ownership Charge	25.0	19.4
Petroleum Incentive Payments	(0.0)	(0.0)
Total Federal Revenues	7.1	-12.1
Provincial Governments Revenues		
Royalties Net of Incentive Payments	3.7	-7.6
Land Payments	0.4	-0.5
Oil Export Tax	-2.1	-1.3
Corporate Income Tax	0.4	-2.1
Petroleum Incentive Payments	(0.1)	(-0.1)
Total Provincial Revenues	0.7	-11.4
Industry Revenues		
Operating Costs	1.3	0.9
Land Payments	(0.4)	(-0.5)
Cashflow	9.7	-0.1
Petroleum Incentive Payments	(0.1)	(-0.1)
Total Industry Revenues	11.4	1.3
Total Government and Industry Revenues	19.2	-22.1

Note For footnotes 1 to 3, see Table 7.

4 The figures are undiscounted sums of revenues from 1985 to 1995, inclusive. These cases include the continuation of the IORT suspension announced in the 1983 federal budget.

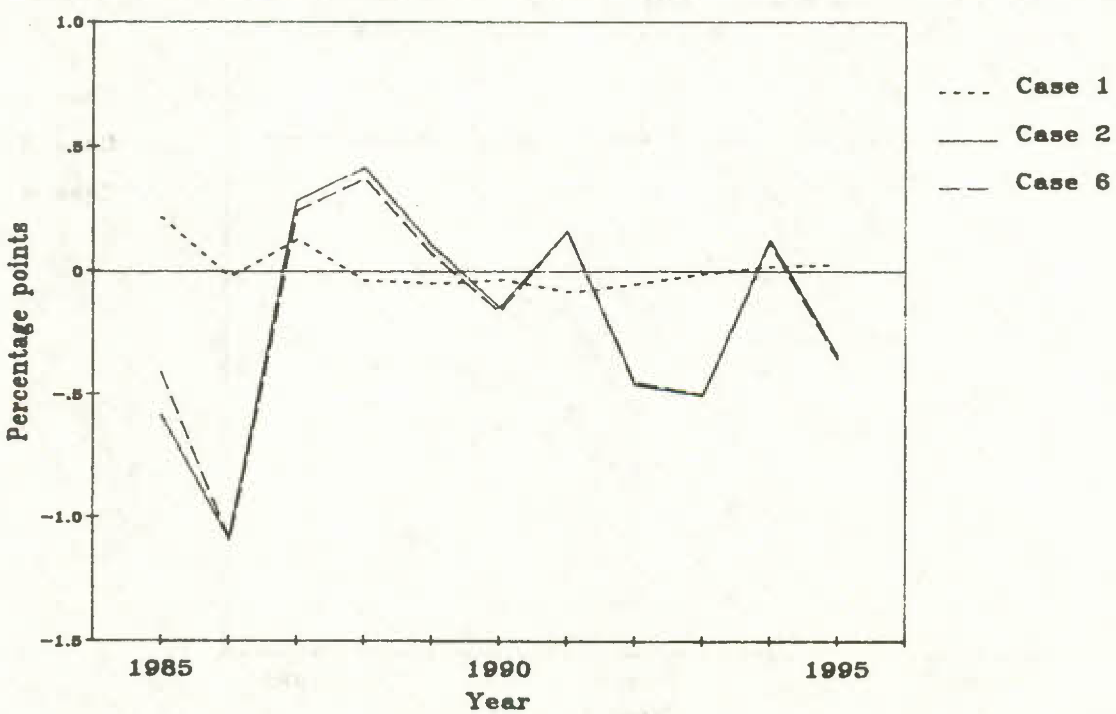
Source Economic Council of Canada, MACE Model, July, 1984.

Figure 1
Effect[1] of Alternative Energy Tax and Pricing Policies on Real Gross National Product, Canada, 1985–95



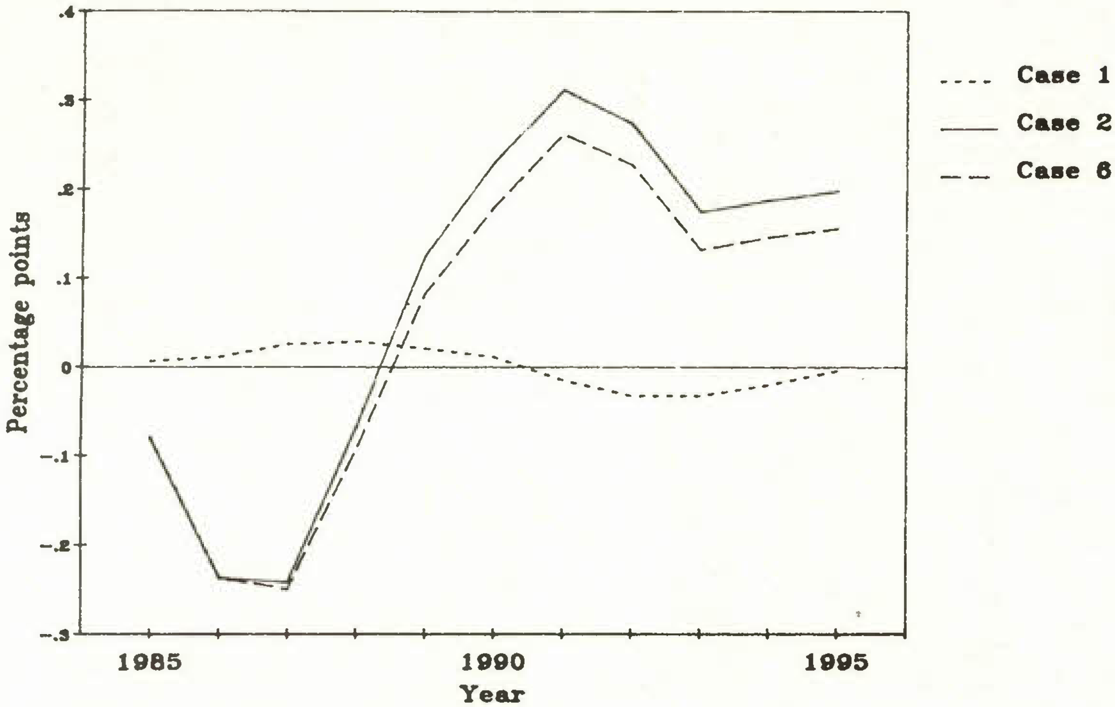
1 Expressed as a change relative to the base case values

Figure 2
Effect[1] of Alternative Energy Tax and Pricing Policies on the Rate of Inflation, Canada, 1985–95



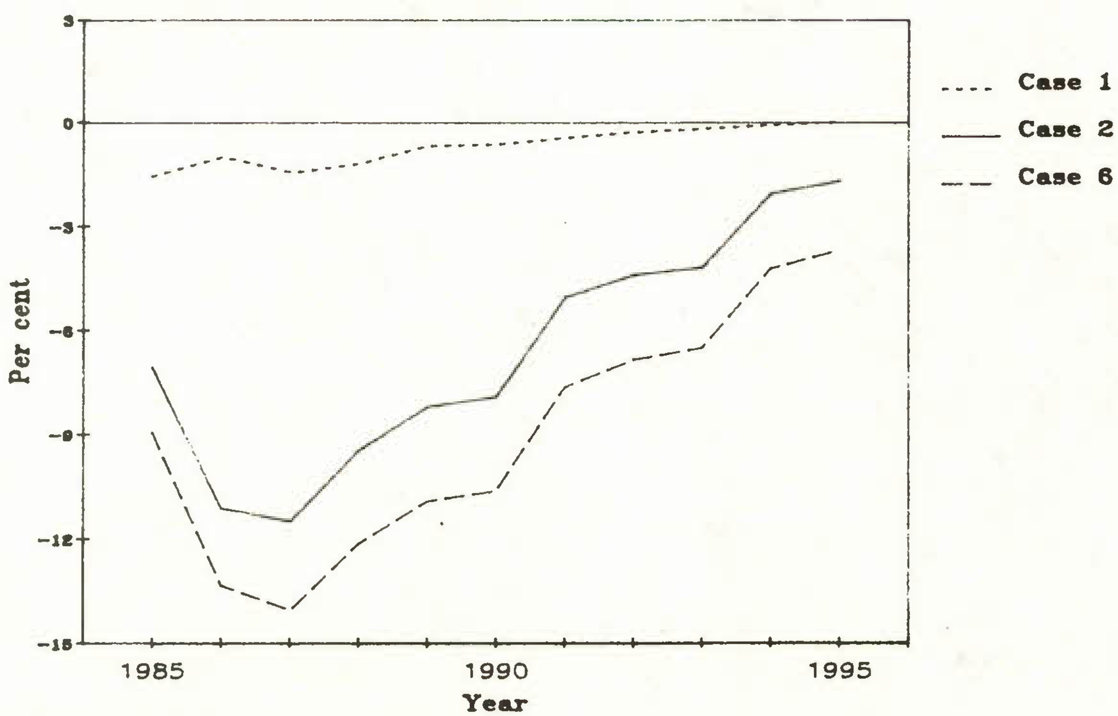
1 Expressed as a change relative to the base values.

Figure 3
Effect[1] of Alternative Energy Tax and Pricing Policies on the Unemployment Rate, Canada, 1985–95



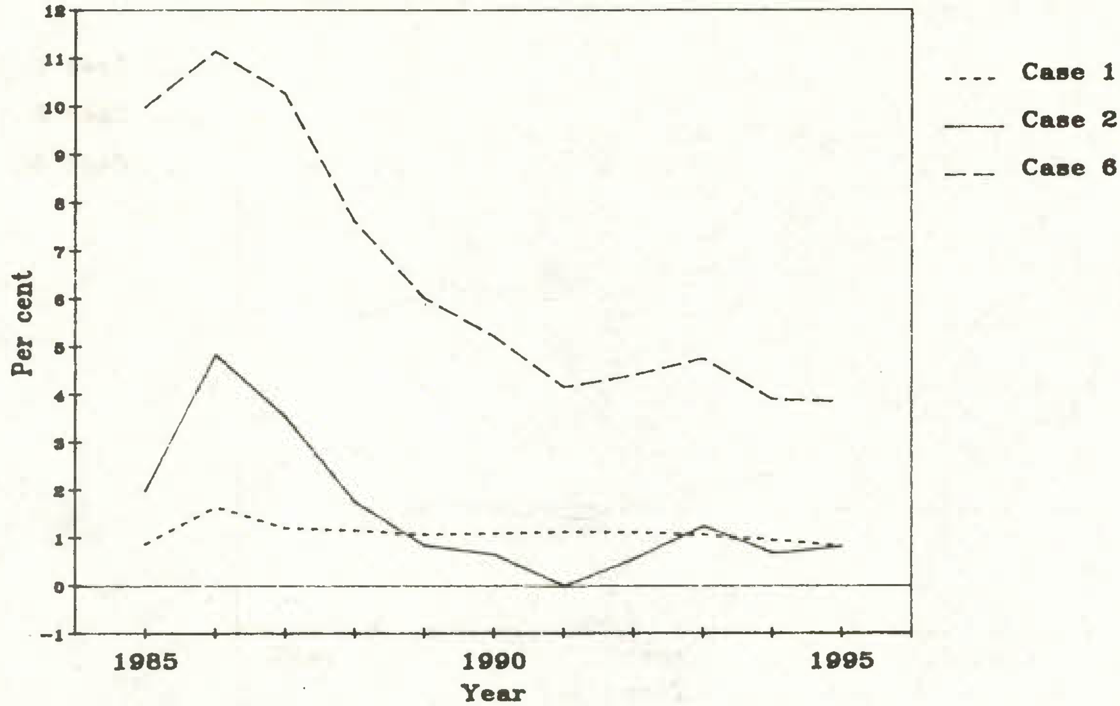
1 Expressed as a change relative to the base values.

Figure 4
Effect[1] of Alternative Energy Tax and Pricing Policies on Imports of Crude Oil, Canada, 1985–95



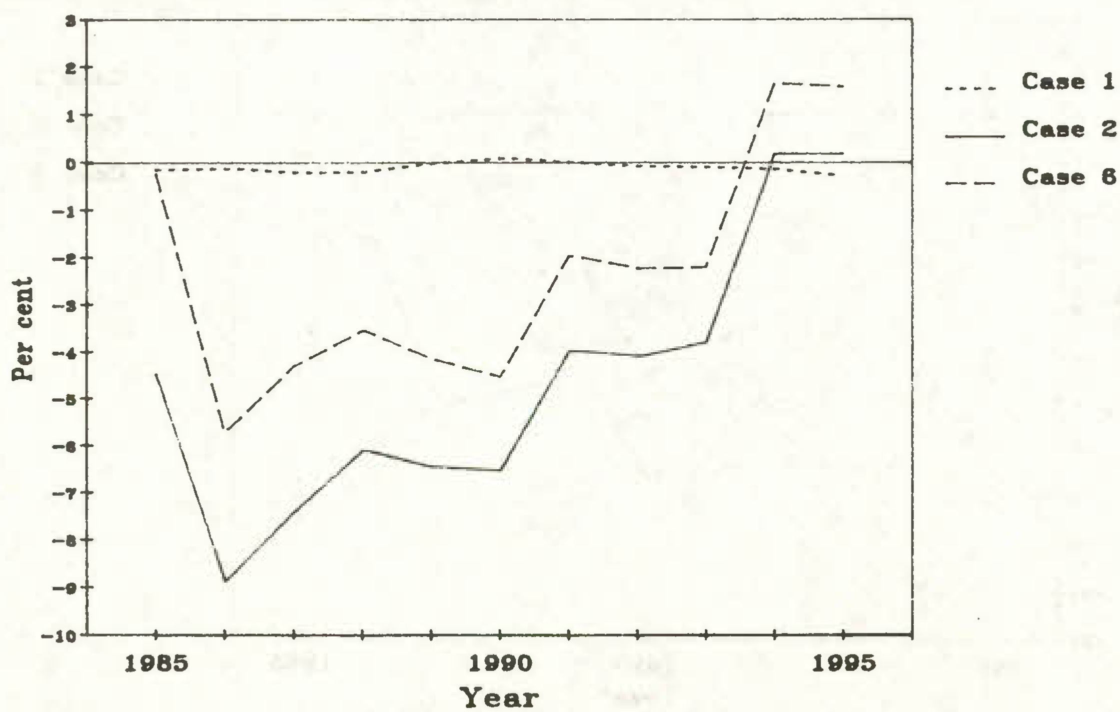
1 Expressed as a change relative to the base case values.

Figure 5
Effect[1] of Alternative Energy Tax and Pricing Policies on Discoveries of Conventional Oil (Reserve Additions), Canada, 1985–95



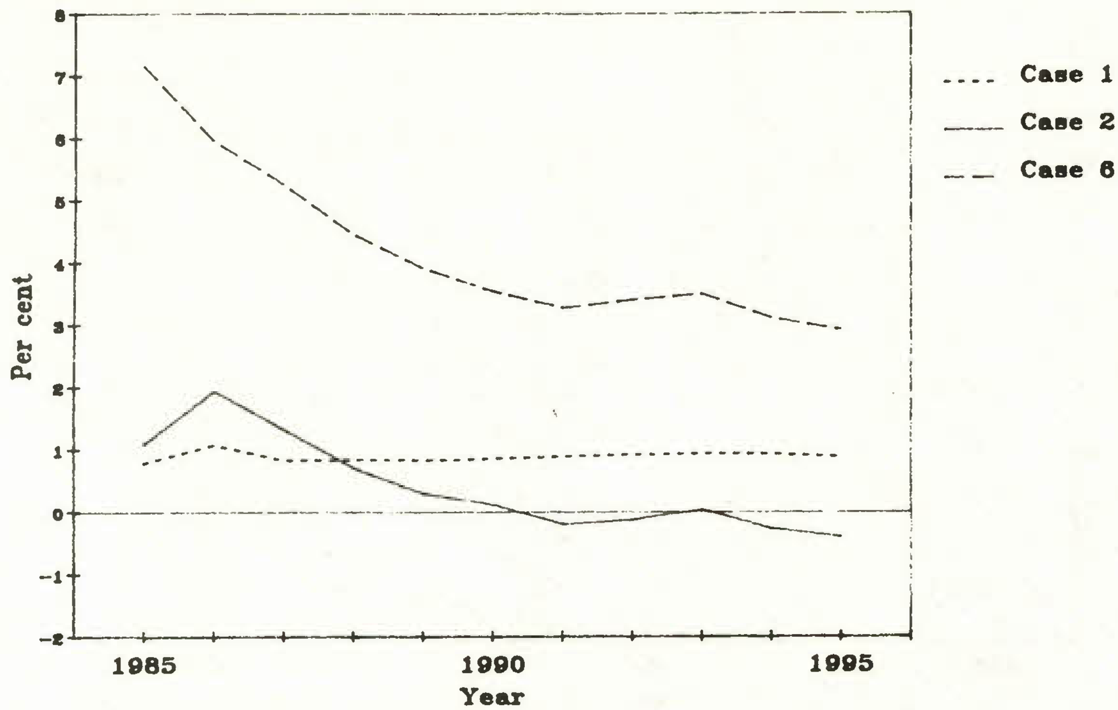
1 Expressed as a change relative to the base case values.

Figure 6
Effect[1] of Alternative Energy Tax and Pricing Policies on Discoveries of Natural Gas (Reserve Additions), Canada, 1985–95



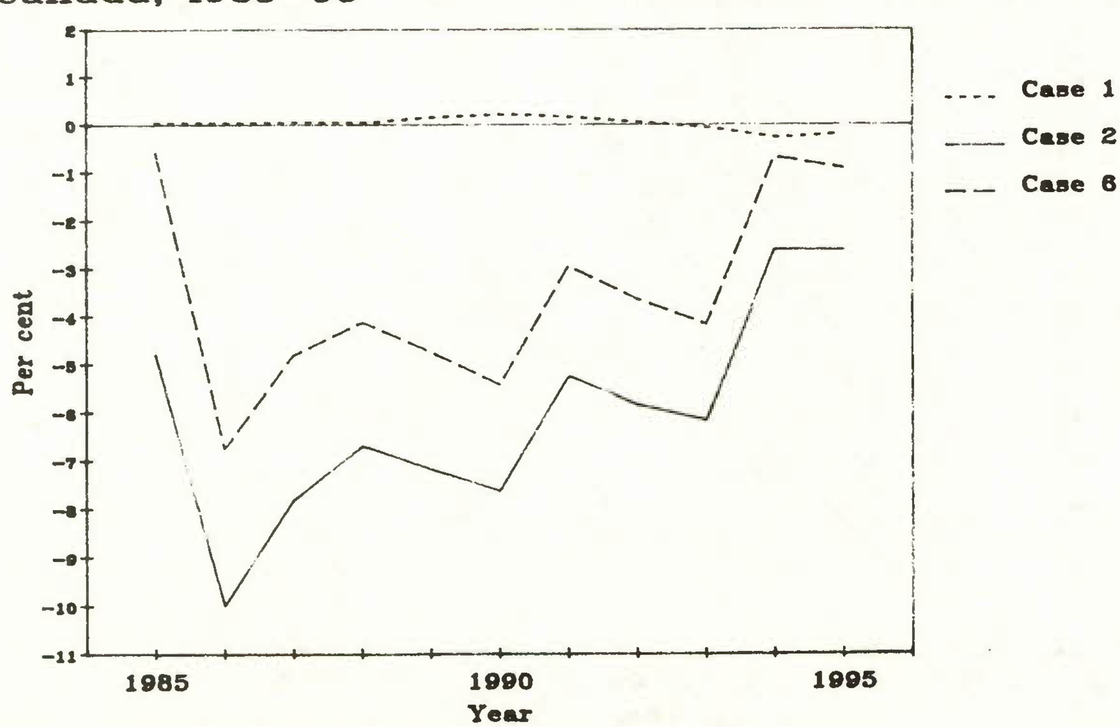
1 Expressed as a change relative to the base case values.

Figure 7
Effect[1] of Alternative Energy Tax and Pricing Policies on Investment in Conventional Oil, Canada, 1985–95



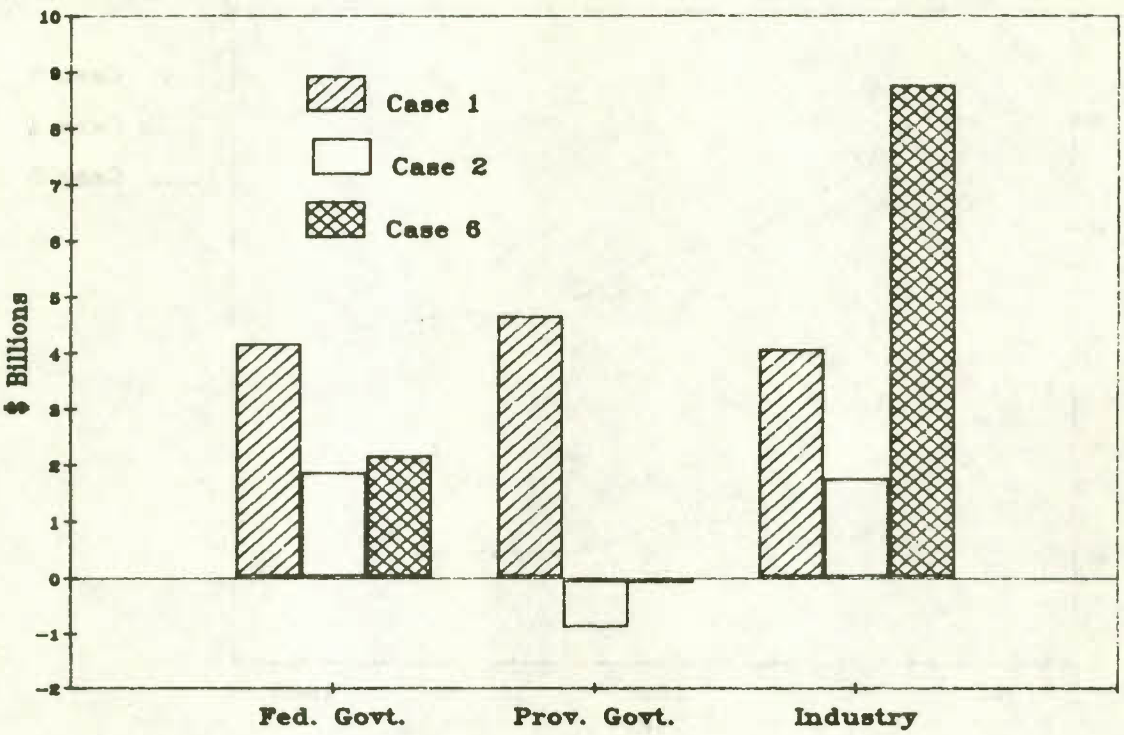
1 Expressed as a change relative to the base case values.

Figure 8
Effect[1] of Alternative Energy Tax and Pricing Policies on Investment in Natural Gas, Canada, 1985–95



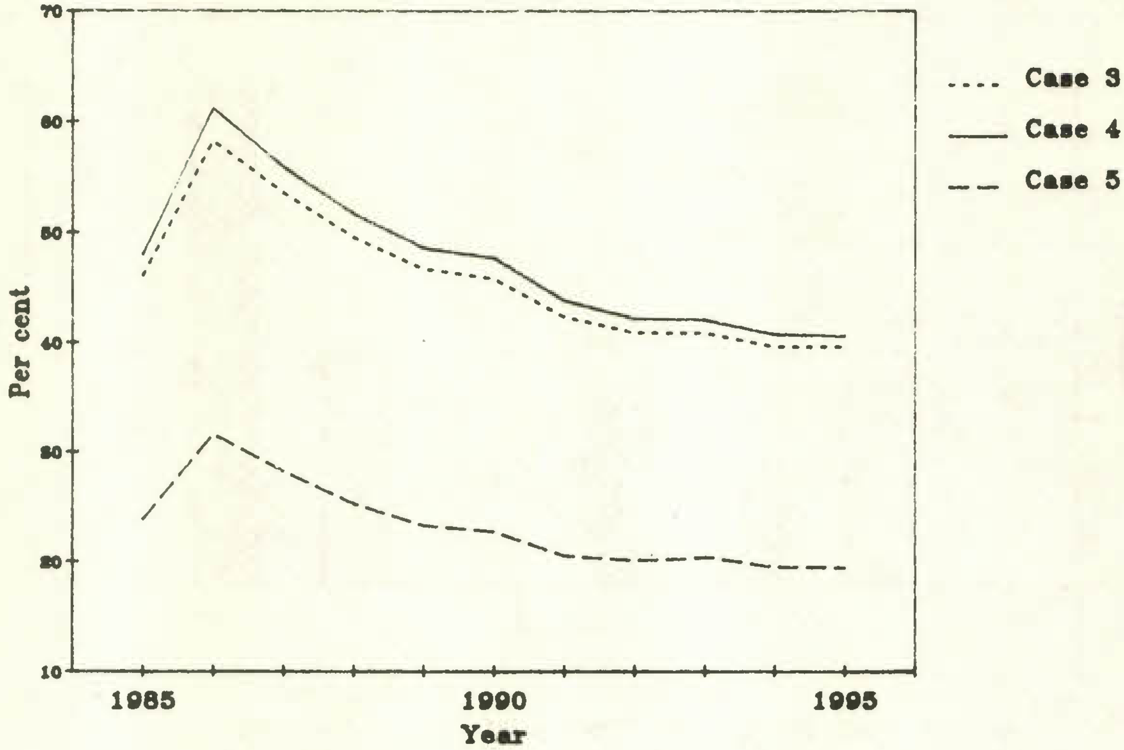
1 Expressed as a change relative to the base case values.

Figure 9
Effect[1] of Alternative Tax and Pricing Policies on Cumulative Revenue Shares, Canada, 1985–95



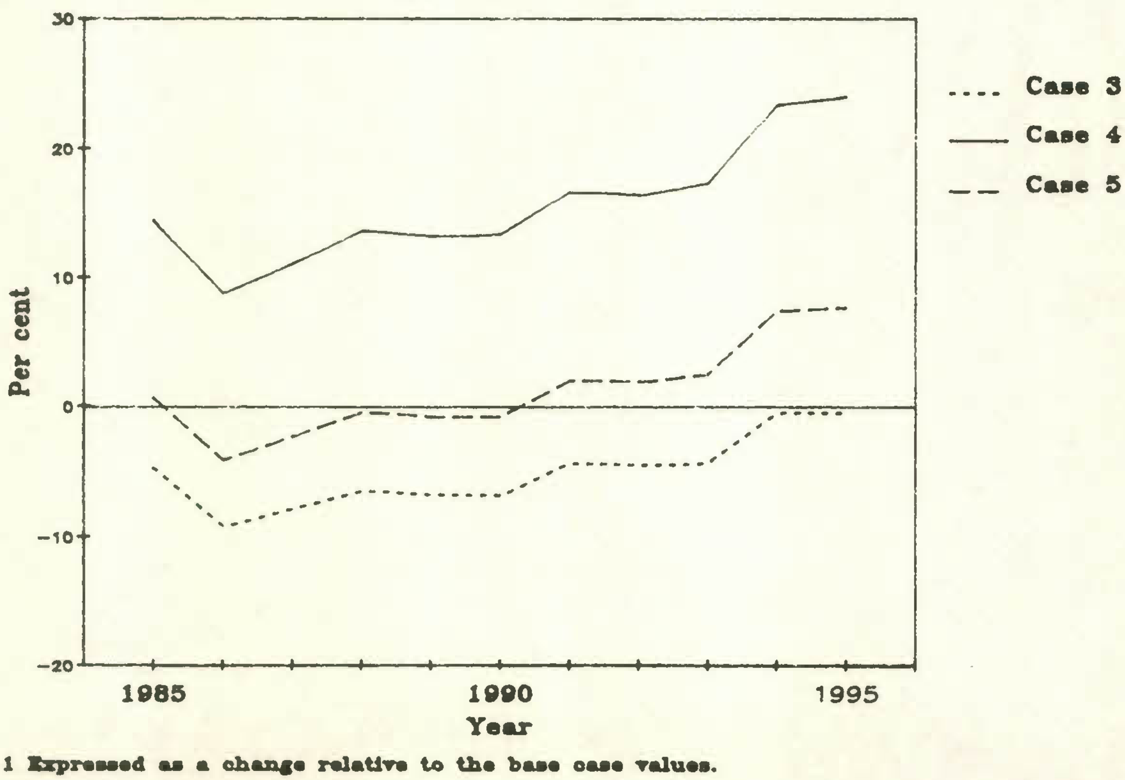
1 Expressed as a change relative to the base case values.

Figure 10
Effect[1] of Alternative Energy Tax and Pricing Policies on Discoveries of Conventional Oil (Reserve Additions), Canada, 1985–95



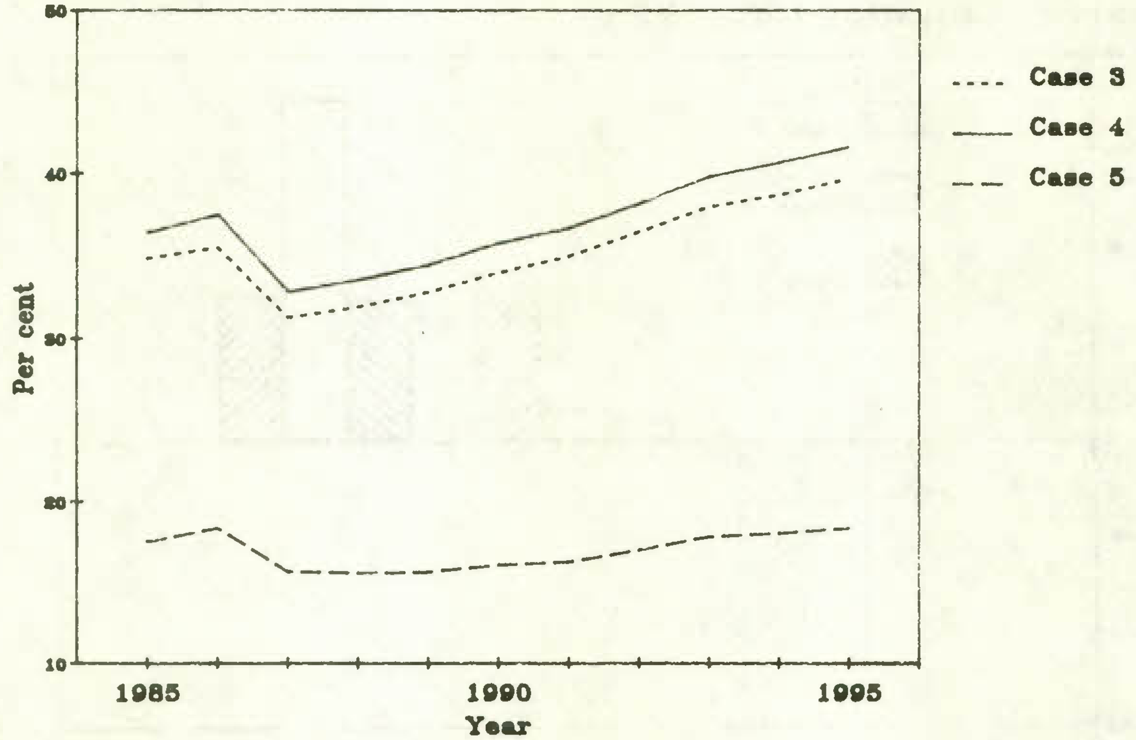
1 Expressed as a change relative to the base case values.

Figure 11
Effect[1] of Alternative Energy Tax and Pricing Policies on Discoveries of Natural Gas (Reserve Additions), Canada, 1985–95



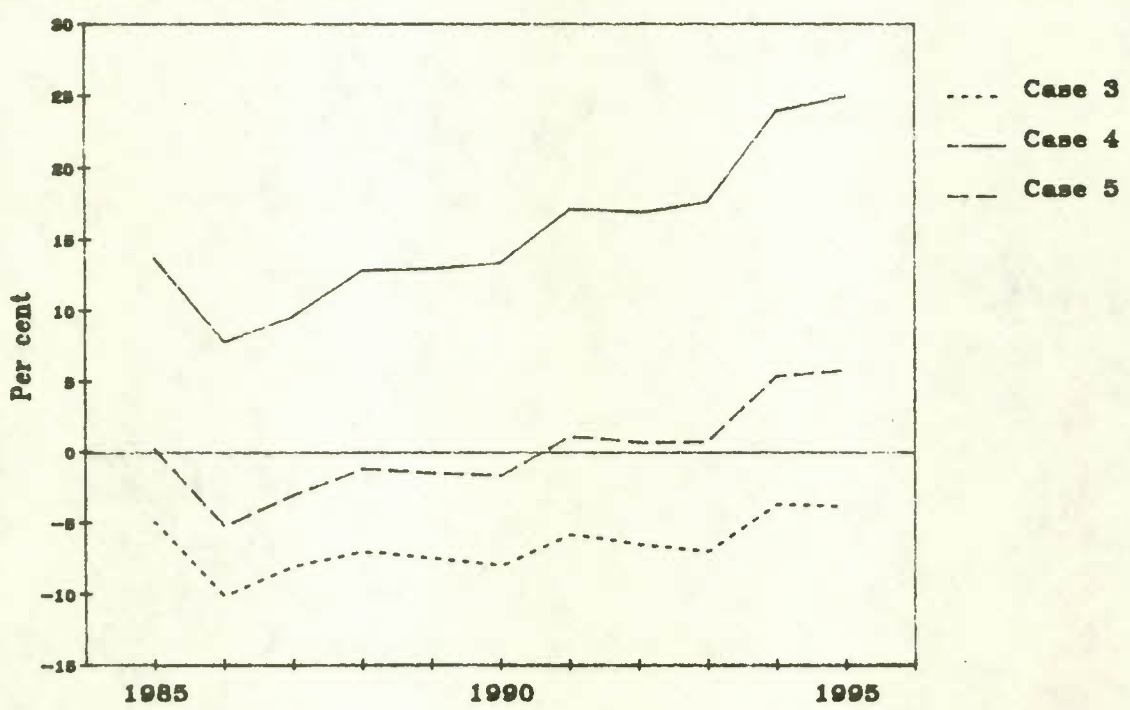
1 Expressed as a change relative to the base case values.

Figure 12
Effect[1] of Alternative Energy Tax and Pricing Policies on Investment in Conventional Oil, Canada, 1985–95



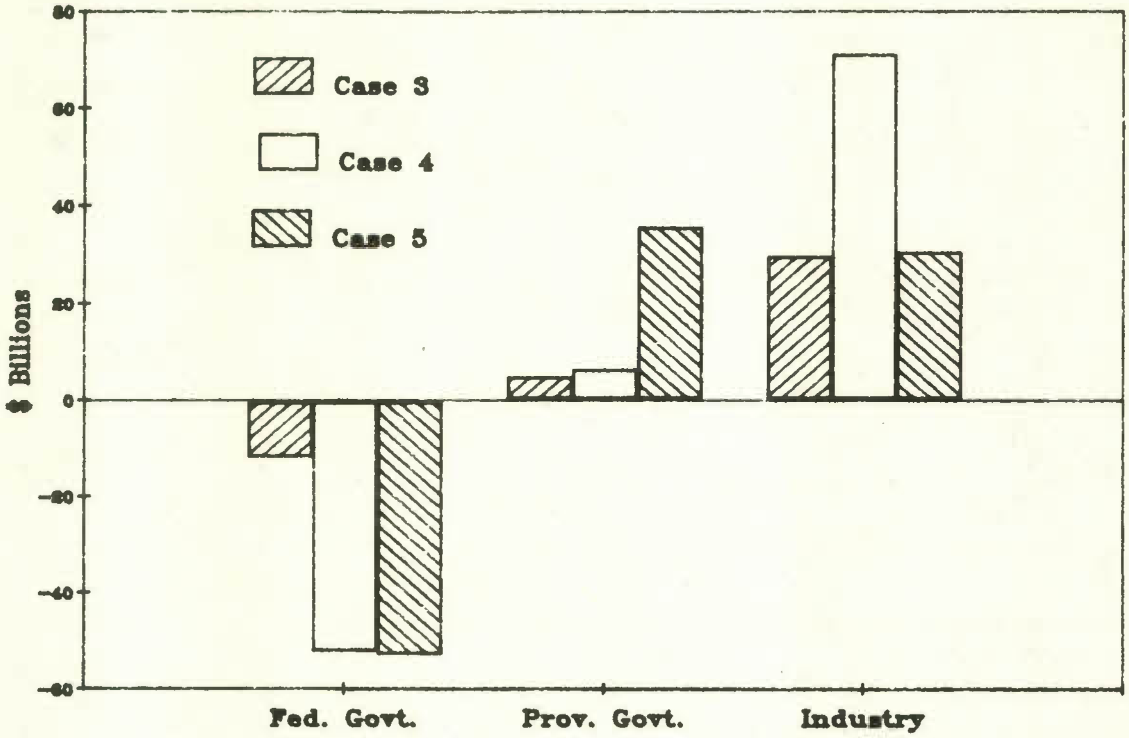
1 Expressed as a change relative to the base case values.

Figure 13
Effect[1] of Alternative Energy Tax and Pricing Policies on Investment in Natural Gas, Canada, 1985–95



1 Expressed as a change relative to the base case values.

Figure 14
Effect[1] of Alternative Energy Tax and Pricing Policies on Cumulative Revenue Shares, Canada, 1985–95



1 Expressed as a change relative to the base case values.

Notes

1 This does not include any provincial or federal excise taxes on motive fuels.

2 As a result of the 1981 energy agreements between the producing provinces and the federal government, producers receive the world price for discoveries of new oil, so that the negative effects of receiving less than world prices for pre-1974 oil would be confined to possible cashflow constraints.

3 The model contains 11 sectors involving some 800 endogenous variables, 300 exogenous variables, and 540 coefficients. The macro part of the model is relatively small (60 endogenous variables, about 20 stochastic equations, and some 40 exogenous variables). The energy part of the model is much larger and contains regionally disaggregated energy demand, supply, cost, taxation and revenue sharing.

4 This section draws heavily on Helliwell et al (1983), and Helliwell and MacGregor (1983). For details of the underlying production structure in MACE, see Appendix I.

5 For a detailed description of the energy demand sector of the MACE model, see Gera (1982).

6 The refining and distribution mark-ups and excise taxes are not estimated separately.

7 While conducting the policy simulations described in the final sections of the paper, we have assumed that after 1986, the Alberta border price will not be increased until 65/btu parity is restored.

8 As reported in Helliwell and MacGregor (1983), a 20 per cent increase in the refinery-gate crude oil price leads to a 15 per cent increase in the user price of oil products. If the city-gate natural gas price is held fixed, the overall price index for energy rises by 7.5 per cent. If, on the other hand, the policy link between natural gas and crude oil prices is maintained, the overall energy price index for final energy users rises by 12.7 per cent in response to the 20 per cent increase in the price of crude oil.

9 This section is based on Helliwell and MacGregor (1983).

10 See Appendix II for details.

11 Natural gas export prices are estimated using the Duncan-Lalonde formula and EMR discounts to reflect softness in the U.S. market. The Toronto city-gate price net of the Canadian ownership charge is the driving variable for all domestic prices. The price received by producers is a weighted average of eastern and western city-gate prices net of transportation costs, the NGGLT and the Canadian ownership charge.

12 Oil exports are set exogenously at 75,000 bbl/day to 1986, declining thereafter at 20 per cent annually.

13 Coal imports for thermal electricity are also endogenous but not nearly as important. Imports of electricity, refined oil products and natural gas are not modelled but are incorporated in a residual.

14 In the normal course of events, the causal flow would be from investment to discoveries, but as long as there is a set relationship like this between discoveries and investment, this becomes one of those chicken and egg questions and does not make any behavioural difference whether we work from discoveries to investment or vice versa. We would imagine that discoveries were chosen as the starting place for reasons of convenience - to make sure that you don't discover more than is there. It is also closer to being an exogenous, technical series.

15 The complexities of Canadian energy pricing and taxation are briefly explained in Helliwell, MacGregor, and Plourde (1983).

16 See, for example, Sumner (1983).

17 <u>Connections: An Energy Strategy for the Future</u>, Economic Council of Canada, 1985.

18 The simulation results for some of these scenarios, although under slightly different assumptions, were submitted by the Chairman of the Economic Council of Canada to the Standing Senate Committee on Energy and Natural Resources, Ottawa, May 24, 1984.

19 In our simulations, we introduce 5 per cent cashflow additions to discoveries. We modify the discovery equations for the cashflow constraint and let that flow into investment.

20 The blended price is the Toronto refinery-gate crude oil price plus the petroleum compensation charge and the Canadianization levy.

21 In the absence of any cashflow effects, the simulation results show that moving to world prices has a slight negative impact on oil investment and discoveries through its indirect effects on the NORP. The NORP is euqal to the landed price of imported oil net of transportation costs between the Prairies and Eastern Canada. Since the positive effect on energy trade balance brought about by the decrease in oil imports has resulted in an appreciation of the Canadian dollar, the landed import price has dropped slightly. Higher inflation has also increased transportation costs as the combined effect is to reduce the NORP slightly. This results in lower oil discoveries and investment. The absence of positive supply response from changing the price of old oil can also be explained as follows. Since the newly discovered oil already receives world pricing the investment in non-frontier oil is not affected by pricing old oil to world levels. This is because the model equations for oil and gas investment, which depend on after-tax netbacks on new discoveries, do not embody cashflow effects. Moreover, the gas investment equation does not take proper account of the growing inventory of discovered but unsold gas. The build-up of unsold gas would probably hold investment down in any case. Helliwell et. al. (1983) point out that "suppliers of new oil are already being offered the world price, so that the supply response from changing the price of old oil is limited. Oil from new enhanced recovery projects in an old oil field already receives the NORP so the main effect of giving producers the world price for old oil would be to reduce any cashflow constraints that are preventing the exploration and development of new reserves. From an efficiency standpoint, the objective is to give the NORP to new oil and to ensure that the cashflow constraint is not significantly more binding than in other industries", (p. 291).

22 Although the new oil royalty rate is lower, the provincial share of royalties increases because the lower rate is applied to a higher price level.

23 In order to assess the overall costs and benefits of raising the old oil price to world levels, Helliwell, MacGregor and Plourde (1983) estimate the present value of net economic benefits accruing to oil and gas producers, energy users, and the governments. Due to the presence of high degree of foreign ownership in the oil and gas industry, they conclude that from an overall Canadian perspective, there is a slight net economic advantage in moving the price of old oil to world levels. The net gains by the foreign shareholders are relatively large. In general, moving to world prices increases economic efficiency, and hence the present value of total economic rents, by providing better price signals to energy suppliers and users.

24 Helliwell et. al. (1985), in the deregulation case, assume that domestic and export markets will both be freely available to producers and that there will be enough competition among them to ensure that the same price prevails in both markets. In this case then, the export quantities will have to be determined by domestic producers, without limits posed by U.S. or Canadian regulations. This also requires the assumption that the NEB export forecasts embody the results of producer decisions trading off immediate export sales against the possibility of higher revenues from later sales.

25 In the Senate Submission (1984), for the price deregulation scenario, it was assumed that natural gas prices would decline upon gas price deregulation to about 50 per cent parity to oil prices at Toronto by 1987. Moreover, no assumptions were made about the COSC modifications.

26 Helliwell et. al. (1985) use the current version of MACE which incorporates modelling of the U.S. demand for Canadian natural gas. They have added to MACE a simplified form of the gas trade model (GTM) developed recently by Beltramo, Manne and Weyant (1984). Helliwell et. al. report that "The GTM is a linear programming model involving Canada, Mexico, and a number of producing and consuming regions in the United States. These results were used to construct equations for the U.S. natural gas price as a function of the price of Canadian export gas (in U.S. dollars) relative to the prices of U.S.-produced natural gas. For most of the analysis in this paper, we use the inverted form of the U.S. demand equation for Canadian gas to set the export price at which the National Energy Board (NEB) forecasts of natural gas exports would be achieved. In our base case, the regulated Toronto city gate price acts as a floor to the export price".

27 The Canadian Ownership Charge (COSC) was introduced as a temporary measure to help finance PetroCanada's takeover activity. In the April 1983 federal budget, however, the federal government announced that the tax would be continued indefinitely. In this simulation we modify the COSC in two steps. First the COSC is completely removed from natural gas. The reduction in the domestic retail price of natural gas will not affect producer prices, but will encourage consumers to shift from oil to natural gas. This shift in demand will help to reduce imports of foreign oil and to alleviate the current surplus of natural gas on the market. The second modification is to change the COSC from a flat rate tax at the city-gate level of a $1.15/bbl to an ad valorem tax on oil products at the retail level. The switch from a flat rate to an ad valorem tax means that revenue from the tax will be more responsive to increases or decreases in world oil prices. Shifting the tax to the retail level also means that the COSC will no longer be included in the city-gate oil price used to

calculate the btu-parity of natural gas prices under current pricing policies. The tax on retail oil products was designed to collect the same amount of revenue as the current form of the COSC on both oil and natural gas using 1984 as the base year. With total COSC revenues of slightly more than $1 billion in 1984, oil consumption of 590 million barrels, and an average retail price of $56.67/bbl, this would mean collecting 3 per cent of the retail price.

28 Helliwell et. al. (1985) estimate that under combined oil and gas deregulation, the average user price of oil products would rise by 3.8 per cent, the average user price of natural gas would fall by 3.6 per cent, and the overall price of energy would rise by 0.8 per cent in 1985 and be lower thereafter than in the regulated case. The level of real GNP is projected to be slightly higher, by amounts starting at 0.1 per cent in 1985 and averaging 0.4 per cent over the 1985-90 period. These results differ slightly from those obtained by us for various reasons. They have re-estimated and re-specified the macro model, including the macro demand for energy. As a result, energy demand (and the demand for oil) is about 15 per cent lower in their current control solution than in our base case and imports make up a substantially lower proportion of domestic oil consumption. They have also incorporated quality differentials for light and heavy oil into their current version of the model. In our case, it is essentially assumed that all oil is light oil. Higher imports and a higher estimate for the NORP levy financing requirements lead to a higher blended price estimate in our base case, even though import prices are similar. Estimates of the level of the city gate price under world pricing are similar, however, since most Canadian consumption is light oil. In addition, they have modelled the links between quantities and prices of exported natural gas, and have linked the domestic natural gas price to the deregulated export price. This gives a smaller drop in domestic natural gas prices than was exogenously estimated by us for our deregulation experiments.

29 Our simulation results suggest that even in the absence of oil and natural gas price deregulation, the modifications to the COSC alone would lower the price of natural gas to consumers relative to oil. The demand for natural gas would increase by about 2 per cent, and the demand for oil would be lower by around 1 per cent in 1985. Oil imports would be lower by 2.3 per cent leading to an improvement in the energy trade balance and a slight appreciation of the Canadian dollar. The landed price of imported oil would drop marginally in Canadian dollar terms, reducing the price of domestically produced oil which is tied to it. The blended city-gate price of oil, therefore, would drop slightly more than the $1.15/bbl accounted for by the removal of the COSC from the city-gate

level. Despite this drop in city-gate prices, retail prices for oil products would rise by slightly less than 1 per cent since the ad valorem tax at the retail level is now collecting all of the COSC revenue from oil, instead of the two-thirds that it was collecting before. Because the COSC is no longer collected at the city-gate level for either oil or natural gas, the btu-parity price at the city gate level shows little change.

The drop in natural gas prices combined with the shift by consumers from oil to gas is enough to offset the increased oil prices to Canadians. Energy prices as a whole drop by 0.7 per cent in 1985, lowering the overall price level by 0.1 per cent and stimulating the growth of real GNP slightly. The shift from a flat rate to an ad valorem tax results in a progressively larger proportionate increase in oil prices over time (0.9 per cent increase in 1985 vs. 1.2 per cent in 1990), while the elimination of a flat rate tax on natural gas has progressively less effect in reducing natural gas prices over time (3.7 per cent lower in 1985 compared to 3.0 lower in 1990). This tends to increase the growth of energy prices in the 1990s, although not enough to affect the general level of inflation and the overall price index for energy remains below control levels.

30 When we compare these results with those submitted by the Economic Council of Canada to the Senate Committee (1984), we find that macro effects are not that different, a slightly different effect on oil discoveries and investment, with the main difference being on the distribution of revenues between industry and governments. In our results to the Senate Committee it was suggested that industry cumulative cashflow (after taxes, royalties, and operating costs but before investment) would increase by about 6.7 billion dollars over the period 1985-95. The federal government would lose a total of $8.6 billion in cumulated revenues over the period 1985-95, while the provincial governments lose $6.3 billion. The difference in results in the two sets of sumulations can be explained by the following facts: first, as mentioned earlier, the assumptions about the decline in natural gas prices were different in the two sets of simulations; second, no assumptions were made about the COSC modifications in the Senate Submission results; and finally, after the Senate Submission, it was discovered that in the control solution taxable income from oil exceeded the gross income from oil and that the problem could be traced in the model to the way that the corporate income tax exemption had been handled for the revenues subject to the PGRT.

31 The exogenous assumptions were based on Project LINK simulation results given to the MACE team at the University of British Columbia by the Stanford Energy Modelling Forum #7.

32 Note that the simulation results for Case 6, reported in Tables 1 to 6, are deviations from the base case (A-1) that includes flat world oil prices. The results for Case 7 are reported as deviations from the base case (A-2) which includes rising world oil prices.

33 The results for Case 8 are reported as deviations from the Base Case A-3 which includes declining world oil prices.

APPENDIX I

The Underlying Production Structure in MACE[1]

The broad theoretical structure MACE employs is that of a two sector national economy. The energy producing sector uses capital and a resource base to produce energy. The energy using sector has a weakly separable production function

(1) $q = f(g(K,E),N)$

wherein capital and energy are combined in a vintage CES bundle of capital-plus-energy services. This CES function is then nested within a constant-returns Cobb-Douglas function for the gross output of the non-energy sector.

Underlying the vintage bundle, the long-term relationship for capital-plus-energy is

(2) $g(K,E) \equiv KE \equiv [\beta KNE^{(\sigma-1)/\sigma} + \gamma E^{(\sigma-1)/\sigma}]^{\sigma/(\sigma-1)}$

where 'σ' is the elasticity of substitution between capital and energy

KNE is business fixed capital stock in the non-energy sector (including housing and excluding energy), billion 1971$

E is energy expenditure, billion 1971$

β and γ = parameters for production function

The vintage structure is modelled on the assumption that the energy intensity of capital is variable before installation and thereupon imbedded. The rate at which the putty becomes malleable again is a parameter to be estimated and should be expected to be faster than the rate of depreciation, given the substantial opportunities for rebuilding and retrofitting energy-using buildings and equipment. If the energy coefficient unsticks at the rate δ, and if the rate of normal depreciation is δ_2, the vintage bundle of capital and energy can be defined recursively by

$$(3) \quad \bar{k}_{ev} = (1-\delta_1-\delta_2)\bar{k}_{ev-1} + i_{new}[\beta+\gamma(\gamma p_k/\beta p_e)^{\sigma-1}]^{\sigma/(\sigma-1)},$$

where $i_{new} = i_{ne} + \delta_1 k_{ne-1}$ is re-investment with energy use malleable in the current year and

- i_{ne} is business fixed investment (excluding energy investment), billion 1971\$
- i_{new} is re-investment with energy use malleable in the current year, billion 1971\$
- $\bar{k}_{ev}$ is vintage measure of capital and energy, billion 1971\$
- p_k is the price of capital
- p_e is price of energy to final users, 1971 = 1.0.

If newly preferred energy/capital ratios can be installed only with new gross investment, then it is possible to define the vintage based energy requirement as:

(4) $e_v = (1-\delta_1-\delta_2)e_{v-1} + (\gamma p_k/\beta p_e)^{\sigma} i_{new}$

In order to define the above series, it is necessary to have estimates of the CES parameters σ, β, and γ. Estimates of the ratio $\frac{\gamma}{\beta}$ and of the elasticity of substitution σ can be obtained from the energy demand equation to be described later, and the sum of β and γ can be set to scale the vintage stock of energy-using capital k_{ev} so that it should have the mean value as the corresponding capital stock series k_{ne}.

The potential output, q_{sv} is thus given by,

$$q_{sv} = a(\bar{k}_{ev})^{\alpha} (N_e * ELEFF)^{1-\alpha}$$

where N_e is the number employed and ELEFF is the labour efficiency factor.

Energy demand:

(5) $\ln e = \ln e_v + 0.010024t - 0.69028$
(23.22) (23.54)

2SLS 1954-80;s.e.e. = 0.0165;$\bar{R}^2$=0.9987;D-W=1.29;F-test on constraint=0.007.

Vintage based synthetic supply:

(6) $q_{sv} = 3.5196(\bar{k}_{ev})^{\alpha}(\Pi N_e)^{1-\alpha}$

δ_1	Estimated parameter	Annual rate at which energy/capital proportions become malleable in $\bar{k}_{ev}$ $\delta_1 = 0.72$
δ_2	Exogenous	Depreciation rate for non-energy capital stock (including housing) $\delta_2 = 0.05$
Π	Estimated	Labour productivity index for Harrod-neutral technical progress in Cobb-Douglas function for q. The annual growth rate is 1.99 per cent
p_r	Exogenous	Real supply price of capital, per cent $p_r = 0.70$
$\alpha, \beta, \gamma, \sigma$	Estimated	Parameters for nested production functions $\alpha = 0.356$; $\beta = 0.70584$; $\gamma = 0.034455$; $\sigma = 0.6$.

Appendix I - Notes

1 This section draws very heavily on Helliwell and McRae (1981), Helliwell (1981), Helliwell, Boothe and McRae (1982), and Helliwell (1984).

APPENDIX II

Control Solution and Underlying Assumptions

The control solution is obtained by solving the model dynamically for the period 1981-2000, 1980 being the latest year for which we have data on all variables in the model. In preparing our base case we make the following assumptions.

DOMESTIC ASSUMPTIONS

A. Macro

1. Exchange rate: uses a "leaning into the wind" rule. The authorities intervene to smooth the adjustment path but always permit the exchange rate to move in the direction indicated by the balance of payments.

2. Monetary policy: a trade off between interest rate targets and money growth targets. The supply of high powered money is set equal to the geometric mean of the two targets. The target money growth rate declines over the period to reflect decreasing inflation.

1983-84	10%	target growth rate
1985-86	10%	
1987-88	8%	
1989-91	6%	
1991 +	5%	

The interest rate target is determined by an estimated policy reaction function which depends on the short-run U.S. interest rate, the growth of government debt, foreign exchange reserves and the money supply.

3. Fiscal policy: personal and indirect tax rates are adjusted from their 1982 levels to take into account the tax measures introduced in the April 1983 federal budget. Government spending follows the budget projections to 1985 and then grows at 2 per cent real. Starting in 1988, real government spending is reduced in accordance with the government's announced intention of compensating for the special recovery program ofthe 1983 budget.

B. Energy

1. Domestic Energy Policies: energy taxation and pricing follow currently announced policies.

a) Domestic oil: oil discovered before March 31, 1974 receives 75 per cent of the New Oil Reference Price but is never allowed to fall below $29.75/bbl. All other oil is assumed to be of uniform quality and no quality price differentials are observed.

b) Natural gas: natural gas at the Toronto city-gate is priced at 65 per cent btu-parity with domestic oil to the end of 1984. In 1985-86, producers receive annual increases of 50¢/mcf and the btu parity price is allowed to rise once the NGGLT falls to zero. After 1986, producers forego any increases in the wellhead price until 65 per cent btu parity is regained (EMR assumption). Btu-parity again increases in the 1990's to reflect the increasing scarcity of natural gas.

c) Electricity prices: grow at the rate of the GNP deflator.

d) Coal prices: grow at rate of GNP deflator.

e) Energy transportation costs: grow at rate of GNP deflator.

2. Energy Exports

a) Natural gas:

- approved export quantities are reduced over the 1983-87 period to reflect softness in the U.S. market. Discount factors are based on EMR

1983	60%
1984	50%
1985	40%
1986	20%
1987	10%
1988+	0%

From 1992-97, natural gas exports are maintained at 1.2 tcf per year (EMR assumption) and then decline at 20 per cent per year as the scarcity increases. The decline in natural gas exports seems reasonable in view of the increasing dependence on foreign oil and the rising domestic price.

- export prices are based on the Duncan-Lalonde formula but are also discounted from 1983-89 because of softness in the U.S. market.

$$P_{xgas} = \frac{[.75 * \text{current } P_{moil} + \text{lag } (P_{moil})]}{5.803} - 1.25 * \text{transport. costs.}$$

where P_{xgas} = export price of natural gas

P_{moil} = import price of crude oil.

Discount factors for price are from EMR:

1983	.13
1984	.13
1985	.13
1986	.13
1987	.09
1988	.06
1989	.03
1990	.0

b) Oil: export volumes (Mbbl/day) are from EMR

1983	370 (Mbbl/day)
1984	315
1985	315
1986	315
1987	252
1988	252
1989	252
1990	214
1995	189
2000	126

Prices are set equal to the landed price of imported oil, retaining the 1982 quality discount.

c) Electricity: prices grow at same rate as GNP deflator. Quantities are from EMR net export series to 1990 and are then held constant

1983	35.0 MWh
1984	37.7
1985	36.8
1986	40.8
1987	39.3
1988	38.9
1989	38.6
1990+	38.3

d) Coal: export volumes grow at 8%/year from 1984-90, 3% from 1991 onwards;

export prices grow at U.S. rate of inflation.

3. Megaprojects: no new oilsands plants or frontier sources come on stream.

C. FOREIGN ASSUMPTIONS

The assumptions are listed in Table II-1.

a) U.S. projections are based on an amalgam of several long-term forecasts. Real growth is assumed to average 3 per cent from 1985-91, 2.5 per cent thereafter.

b) Inflation is assumed to average 6 per cent.

c) Short-term interest rates average 9 per cent.

d) Real growth and inflation in other OECD countries is assumed to follow the U.S.

e) World price of oil U.S. $29.00 per bbl (fob Gulf) in 1983 and then grows at the rate of U.S. inflation.

The Three Base Cases

First a base case was run through the model, based on the assumptions of a flat real world oil price (Base Case A-1). The nominal price of oil was assumed to grow at the same pace as the rate of inflation in the United States.

To test the robustness of our policy package, two alternative base cases were developed, based on variations in world oil prices. In the rising world oil price scenario (Base Case A-2), the price of oil (fob Persian Gulf) is assumed to increase at the rate of 5 per cent per year in real terms between 1985 and the year 2000. In the declining world oil price base case (Base Case A-3), the Persian Gulf price is assumed to decrease at 5 per cent per annum in real terms over the same period.

In all three base cases, the nominal world price of oil is assumed to be U.S. $29/bbl (fob Persian Gulf) in 1983. In addition, the current set of energy taxation and pricing policies is maintained: oil discovered before 31 March 1974 receives 75 per cent of the new-oil reference price (NORP) but is never allowed to fall below $29.75/bbl.

Natural gas at the Toronto city gate is priced at a 65 per cent btu-parity with domestic oil to the end of 1984. In 1985-86, producers receive an annual increase of 50¢/mcf and the btu-parity is allowed to rise once the natural gas and gas liquids tax (NGGLT) falls to zero. After 1986, the producers forgo any increase in the wellhead price until the 65 per cent btu-parity is regained. The btu-parity rises in the 1990s to reflect the increasing scarcity of natural gas.

In Base Case A-2, the higher world price of oil affects the rest of the world economy, as does, under Base Case A-3, the lower world price. This has a particularly important impact on an economy like Canada's, which is so heavily dependent on foreign trade. Accordingly, exogenous assumptions have been made with respect to the impact of higher and lower world oil prices on real and nominal GNP, the GNP deflator and interest rates in the United States and on the output deflator in the OECD.

Table II-1

Forecast Assumptions for Exogenous Foreign Variables

	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000
1. Growth of real U.S. absorption (%/yr)	3.2	5.1	3.0	3.0	3.0	3.0	3.0	3.0	2.5	2.5
2. Growth of U.S. absorption price deflator (%/yr)	4.3	4.7	5.5	5.5	6.0	6.0	6.0	6.0	6.0	6.0
3. Short term U.S. interest rates (%)	8.8	9.1	9.4	9.0	9.0	9.0	9.0	9.0	8.0	8.0
4. Long term U.S. interest rates (%)	10.7	10.7	10.7	10.0	10.0	10.0	10.0	10.0	9.0	9.0
5. U.S. earnings/price*	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48
6. Growth of real OECD** income	2.0	3.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.5
7. Growth of OECD output** deflator	5.3	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	6.0
8. Growth of world export prices	2.4	5.6	6.2	5.9	5.4	6.0	6.0	6.0	6.0	6.0
9. Growth of non-energy import prices	2.4	5.6	6.2	5.9	5.4	6.0	6.0	6.0	6.0	6.0
10. World oil price ($US/bbl fob Gulf)***	29.00	30.38	31.39	33.52	35.26	37.31	39.49	41.83	44.36	76.45

* Continues at 1982 levels.

** 1983-84 from OECD Economic Outlook, then follows U.S. approximately.

*** After 1983, grows at U.S. rate of inflation.

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