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AN ANALYSIS OF THE LONG-TERM PROSPECTS FOR CANADIAN PETROCHEMICALS

by

© SURINDAR SINGH

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

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Date: May 6, 1985

ABSTRACT

This study analyzes the historical development and the future prospects of petrochemicals in Canada. The petrochemicals considered are ammonia, benzene, butadiene, ethylene, ethylene glycol, methanol, polyethylene, polypropylene, propylene, styrene, vinyl acetate and vinyl chloride.

The Eastern Canadian petrochemical industry developed primarily as an offshoot of the crude oil refining industry at Montreal and Sarnia. In Alberta the petrochemical industry developed due to the availability of low cost natural gas and the associated natural gas liquids. Until 1973, because the capital and transportation penalties were greater than its feedstock cost advantages, the Alberta industry developed at a relatively slow pace. After the 1973 world oil price shock, feedstock costs became an increasingly dominant component of the petrochemical price. In Canada domestic oil price was set lower than the world oil price. In Alberta, the feedstock cost advantage offset the capital and transportation penalties. This spurred petrochemical activity in Canada. Currently, it is a modern, mature industry.

During the next three decades the issues that face the industry relate to feedstock availability and cost, capital availability and cost, product prices and export markets. Using a linear programming framework these issues are studied. The analysis shows that in the future the Eastern

Canadian producers will continue to supply the regional ammonia market and the domestic as well as export markets in aromatics, butadiene and propylene; the Alberta producers will continue to supply the regional and export market in ammonia and the total available markets in ethylene derivatives and methanol.

The analysis shows that restricting natural gas exports would not be beneficial to the petrochemical industry since it will result in restricting the supply of natural gas liquids. If the natural gas reserves are lower than assumed in the base scenario, the Alberta petrochemical industry will decline, since the residential and commercial users as well as the industrial energy users can outbid the petrochemical industry for the natural gas. If capital availability is restricted, the cost of capital projects may rise to the point where some marginal petrochemical projects are excluded. The deregulation of natural gas prices will prove beneficial to Eastern Canadian ammonia producers who will become more competitive than the Alberta producers in the U.S. Midwest market. Lowering the petrochemical prices will have a major adverse impact on certain ethylene derivatives. Finally, even in alternate modes of operation using combinations of crude oil and natural gas liquids, Petrosar will not be competitive with the Alberta ethylene producers.

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CHAPTER I: INTRODUCTION

Previous assessments of the prospects of Canadian petrochemicals have adopted the traditional process economics methodology (23,24). This approach is necessary but not sufficient. It should be coupled with an analytical framework which encompasses the complementary and the competitive natures of the energy and the petrochemical sectors. Such a framework can be used to gain insights into how the sector will react under different scenarios. Such insights are useful for planners and policy makers in government and industry. An analytical framework has been developed for Alberta but has been used primarily to study energy issues (101). In this thesis the framework has been expanded and been used to assess the long-term prospects of Canadian petrochemicals under various scenarios.

In order to identify plausible scenarios it is necessary to have a proper understanding of the present structure of the petrochemical industry and the issues that played a role in its development. In two excellent surveys done in 1949 and 1970, the evolution of the Canadian petrochemical industry is described (135,136). Their value lies in the identification of the relevant issues; for example, the role of the second world war and the impact of new chemical technologies. However, they are outdated and are lacking in statistical data.

For a quantitative framework it is necessary to have a comprehensive statistical data base. For Canadian petrochemicals, the data base is inadequate. The Statistics Canada data base, for confidentiality reasons, is neither comprehensive nor sufficiently disaggregated

(131,132). In this thesis, qualitative and quantitative data has been extracted from various chemical engineering publications. An updated history and statistical data base are presented in the next chapter. They form the basis for the subsequent analysis.

Thus, the novel and unique features of this thesis are the identification of the issues that have played key roles in the evolution of the Canadian petrochemical industry and an analysis of these issues using a proper analytical framework, in order to assess its long-term prospects.

The central theme of the thesis is that in spite of temporary aberrations, the evolution of the Canadian petrochemical industry has been logical and rational. Therefore, it is perfectly reasonable to expect future evolution of the industry to be based on fundamental technical and economic considerations.

The search for a proper analytical framework began with a study of formal mathematical techniques, the essential elements of which are presented in Chapter III. It revealed that for long-term analysis a clairvoyant, optimizing technique, wherein crises could be averted by perfect knowledge about the future, was more appropriate than trend-analysis techniques which lacked appropriate feedback mechanisms. Due to the size of the problem under investigation, general equilibrium modelling wherein all factors of production are in equilibrium with each other, was not considered suitable since the computing times would have been excessive. Partial equilibrium modelling, based on an optimization technique, was used. Of all the optimizing techniques, linear programming was selected because of its solution efficiency and the existence of computer software packages which facilitated data input and had report generation capabilities. The computer software used was the Haverly Systems MAGEN package (73); it is described in Appendix 'A'.

Next, in order to identify the features that ought to be included in the analytical framework, the available optimization models were examined. They were primarily energy models but the features identified could also be used in an energy-petrochemical sector analysis. The survey of the models is presented in Chapter IV. The only model devoted exclusively to the petrochemical industry was intended to assess the potential of new technologies being developed in the United States (121,127,128). Its use as an analytical framework for the purpose of this thesis was not feasible. The only energy-petrochemical sector analysis was a regional one (139) which lacked sufficient detail to study the issues identified in Chapter II. It was selected for further development.

Its further development involved the introduction of an Eastern Canadian petrochemical production centre, five market regions for petrochemicals, nine market regions for natural gas, explicit transportation and tariff schemes, explicit natural gas liquids streams and a more comprehensive set of petrochemicals.

The model optimizes a future course of development, starting with existing conditions. An existing plant will continue to operate if it can meet its cash costs only; all capital costs are treated as sunk costs. Thus, existing plants were permitted to operate under capacity. The modified model provided a comprehensive, flexible framework with which to study the long-term prospects of Canadian petrochemicals.

In Chapter V, the main features of the model are described. The model equations have been included in Appendix 'B'. In Chapter VI, the petrochemicals and energy data base used in the analysis is presented.

Using the analytical framework and data base, a 'base' or 'reference' scenario was established against which various other scenarios could be compared. The model results for the base scenario are presented in Chapter VII.

Using seven different scenarios, the impact of certain key parameters was investigated. Comparisons of these scenarios' results to the base scenario results are presented in Chapter VIII. The effects of the key parameters on individual petrochemicals are presented in Chapter IX.

Finally, in Chapter X the long-term prospects of Canadian petrochemicals are assessed in terms of the issues that will affect their development.

CHAPTER II: A BRIEF HISTORY OF CANADIAN PETROCHEMICALS

World War II precipitated the Canadian petrochemical industry. The need for explosives and synthetic rubber resulted in the construction of the world's first natural gas based ammonia plant in Alberta and one of the world's first synthetic rubber plants at Sarnia. Since the Eastern Canadian industry was dependent on refinery off-gases, its development occurred in the major refining centres, Sarnia and Montreal. The Alberta petrochemical industry was based on natural gas and natural gas liquids (NGLs). Thus, feedstock availability was a primary factor in the development of the Canadian petrochemical industry.

The industry was expected to keep pace with the rapid rate of development of the U.S. petrochemical industry. It grew, but not nearly as rapidly. Analysts (55,67,74,91,92,122) have blamed this on the following factors:

1. small domestic markets;
2. ineffective domestic tariff barriers and high foreign tariff barriers;
3. high transportation costs;
4. high construction costs and the lack of capital;
5. an excessive number of small plants using outmoded technology; and
6. unimaginative foreign ownership.

The evolution of the Canadian petrochemical industry is examined in context of these factors.

1. Small Domestic Markets

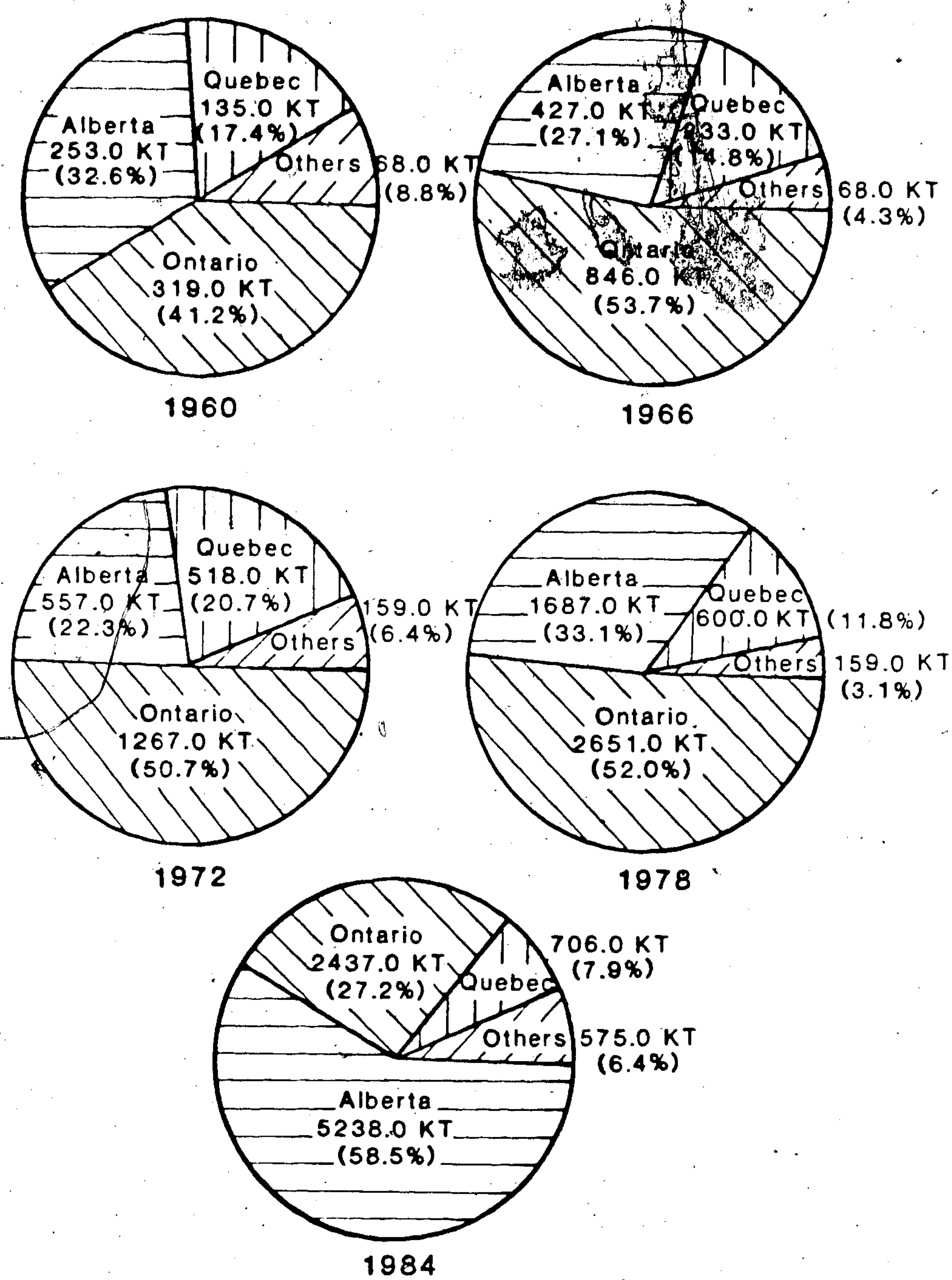
Small regional markets certainly played a role in the development of the Alberta ammonia, methanol and ethylene-based industries. Ammonia production depended on the development of the Western Canadian fertilizer industry; methanol was dependent on the use of formaldehyde in the forest industries and ethylene production was restricted to one small ethane-based plant at Edmonton.

With larger regional markets, the petrochemical industry developed more rapidly in Eastern Canada than in Alberta. As shown in Figure 1, in 1960 Eastern Canada accounted for 58.6% of the Canadian primary petrochemical capacity.

2. Tariff Barriers

Tariff barriers played a significant but not dominant role in the development of the industry. There was no U.S. tariff barrier on ammonia but the high ammonia capital and transportation penalties limited ammonia exports from Alberta to the United States until the mid-1970's, when the penalties were offset by the feedstock cost advantage in Alberta. The U.S. tariff barrier on ethylene derivatives was higher than the corresponding Canadian barrier (87). Canadian producers supplied the domestic market but were effectively denied access to the U.S. ethylene derivatives market. However, even with no such barrier the Eastern Canadian producers would have had to compete for the Northeastern U.S. markets with the larger, cheaper U.S. Gulf Coast plants.

Figure 1. Canadian Primary Petrochemical Capacity



3. Transportation Costs

Transportation costs played a key role in the development of the industry. Due to the high transportation costs involved, in the early 1950's Alberta could not compete in British Columbia and Ontario with the well-established inorganics-based ammonia industry existing in those provinces (111). In the 1960's, with pipeline access to Alberta natural gas, the Eastern Canadian ammonia industry expanded. Due to access to cheap foreign oil, other sectors of the Eastern Canadian petrochemical industry also expanded. Alberta's petrochemical capacity-share dropped to 27.1% in 1966 and reached its lowest point in 1972 at 22.3% (Figure 1). The situation persisted until the mid-1970's when Alberta's feedstock cost advantage finally offset the transportation and capital penalties.

4. Capital Costs

High capital costs played a key role in the development of the industry. Capital costs in Eastern Canada were ~15% higher than at the U.S. Gulf Coast. Capital costs in Alberta were 10% higher than in Eastern Canada (53). Consider the production costs of ammonia in Alberta shown in Table 1; the values are estimates, based on actual natural gas prices (19), current capital costs deflated by the Chemical Engineering index and the current operating costs deflated by the CPI index. In 1953, capital costs and natural gas costs contributed 54.84% and 11.80% respectively to the production costs. In Eastern Canada the capital [illegible] 10% lower. Assuming the same operating costs at

	1953	1958	1963	1968	1973	1978	1983
Capital							
Costs (MM$/y)	7.25	8.23	8.76	9.72	12.33	18.72	27.11
(%)	(54.84)	(57.14)	(54.41)	(53.79)	(47.50)	(35.16)	(29.78)
Operating							
Costs (MM$/y)	4.41	4.79	5.09	5.94	7.43	11.55	18.3
(%)	(33.36)	(32.08)	(31.61)	(32.87)	(28.62)	(21.69)	(20.11)
Natural Gas							
Costs (MM$/y)	1.56	1.61	2.25	2.41	6.20	22.97	45.61
(%)	(11.80)	(10.78)	(13.98)	(13.34)	(23.88)	(43.15)	(50.11)

Table 1: Production Costs of Ammonia in Alberta

The capital to feedstocks cost ratio declined from 3.89 in 1963 to 1.99 in 1973 and then to 0.59 in 1983. As this occurred, it became increasingly attractive to build such plants in Alberta. As shown in Figure 1, Alberta's petrochemical capacity share increased from 22.3% in 1972 to 33.1% in 1978 and then to 58.5% in 1984.

5. Small Plants

The number of Canadian plants and their average size for ammonia, methanol and ethylene is shown in Table 2. The data indicates that the number of these plants has not changed much since 1963. However, the average plant size has increased substantially. This is because the Canadian petrochemical industry upgraded to world-scale plants in the mid-1970's.

6. Ownership

Until the mid-1970's two-thirds of the Canadian petrochemical industry was under foreign ownership (22). Since then, a number of domestic companies (Nova, Allarco, Ocelot, Petrosar) have begun to play an increasingly important role. But to attribute the rejuvenation of the industry to mainly this factor is not correct.

The 1973 world oil crisis revived the Canadian petrochemical industry. As shown in Table 1, the sharp rise in feedstock price made it the dominant petrochemical cost component. Since Canada chose to maintain its domestic oil prices below world oil prices and because of its relatively secure feedstock availability, Canada began to look very attractive to investors.

	1963		1968		1973		1978		1983	
	#	Average Size (KT/y)	#	Average Size (KT/y)	#	Average Size (KT/y)	#	Average Size (KT/y)	#	Average Size (KT/y)
Ammonia	8	74	10	131	10	129	9	265	10	302
Methanol	1	23	3	28	1	45	2	203	3	633
Ethylene	6	38	6	70	4	132	5	206	5	300
TOTAL	15		19		15		16		17	

Table 2: Some Petrochemicals: Number and Average Sizes of Canadian Plants

The perception in Ontario was that because of its access to cheaper Alberta oil as compared to oil imported at world prices, a chemical refinery at Sarnia was feasible. The Ontario entrepreneurs had incorrectly concluded that their major Canadian competition could continue to be from Montreal. From 1962 onwards, due to the policy (46) that markets west of the Ottawa Valley had to be served by the more expensive Alberta oil whereas areas east of the valley could use cheaper imported oil, the Sarnia refineries had been protected from competition from Montreal refiners. As shown in Figure 2, this policy caused Sarnia to maintain its refining capacity share with its attendant petrochemical spinoffs. In 1973, with the domestic prices set lower than world oil prices, Sarnia felt that its future was assured. However, it soon developed that the competition came from the natural gas based Alberta industry.

Compare the petrochemical feedstocks, oil and gas; due to its low transportation costs, there is a fairly uniform world price for crude oil. On the other hand, the transportation costs of natural gas are relatively high; its price is set in competition with fuel oil and electricity in the major consuming centres. In North America the major population and industrial areas are along the coasts of the Great Lakes, and the Atlantic and Pacific Oceans. Except for the U.S. Gulf Coast, such areas are generally far from the gas producing regions. The gas prices in the producing regions are lower and the petrochemical plants located in such areas enjoy a feedstock advantage over the plants located in the major consuming centres.

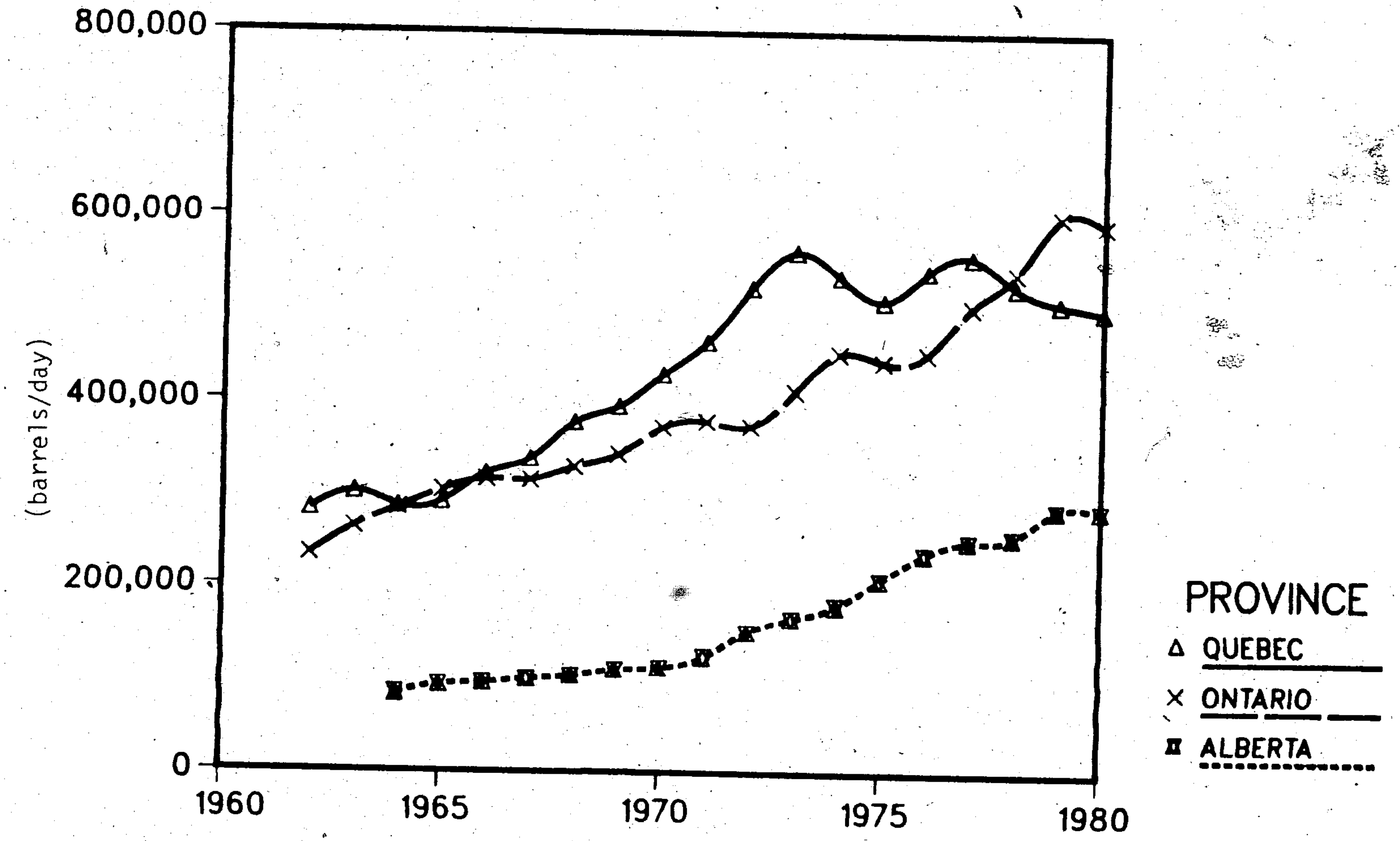


FIGURE 2. REFINERY RUNS TO STILL

Furthermore, associated with natural gas production is the production of ethane and the natural gas liquids (propane, butane and condensates). The natural gas liquids compete in the transportation and the portable heating fuel markets; due to this, compared to natural gas and ethane, they are a premium product. As an example, until recently in New Zealand, which has no domestic crude oil supplies, the natural gas liquids were produced, whereas the natural gas was flared. The ethane can either be converted to ethylene, synthetic natural gas or remain an unextracted component of natural gas.

In Alberta, until the mid-1970's, only a small fraction of the ethane was extracted for an Edmonton-based ethylene plant. As the feedstock cost advantage became increasingly greater, ethane-extraction plants and then a world-scale ethylene plant and an ethane/ethylene pipeline to the East were constructed in Alberta. As shown in Figure 1, in the 1980's Alberta displaced Ontario as the major Canadian petrochemicals producing province.

In Eastern Canada, the startup of the chemical refinery (Petrosar) was followed in 1979 by the second world oil price shock. With the large differential between world and regulated domestic oil prices, the initial years of operation of the plant were profitable. In the early 1980's a world wide recession caused the world oil prices to decline whereas the regulated domestic prices kept rising; the combined impact of the recession and the lower differential caused Petrosar to experience severe losses. Currently, it has commenced a study on the use of natural gas liquids feedstocks (85). Under present circumstances in Canada the production of oil-based petrochemicals is limited by the demand for refined-oil products.

The lesson for an investor is that for large capital projects amortized over long periods, it is unwise to rely on current government policies, i.e. to build plants on the basis of government subsidies which are likely to change every few years. A project viable under its own terms has far fewer political risks than one that, in order to be profitable, requires continued government intervention.

In the following paragraphs, a brief history of the individual petrochemicals is presented.

A. Ammonia

Ammonia is made up of nitrogen and hydrogen atoms. Atmospheric nitrogen is available everywhere. Therefore, the plant location depends on the hydrogen source. Prior to World War II, an inorganics-based ammonia industry was well established in Ontario and British Columbia.

The first natural gas based ammonia plant was built in 1941 near Calgary, Alberta, to provide ammonium nitrate for explosives. After the war the government sold the plant to a private company. The company developed a fertilizer market for its product. Its success led to the construction of two more ammonia plants in Alberta (52).

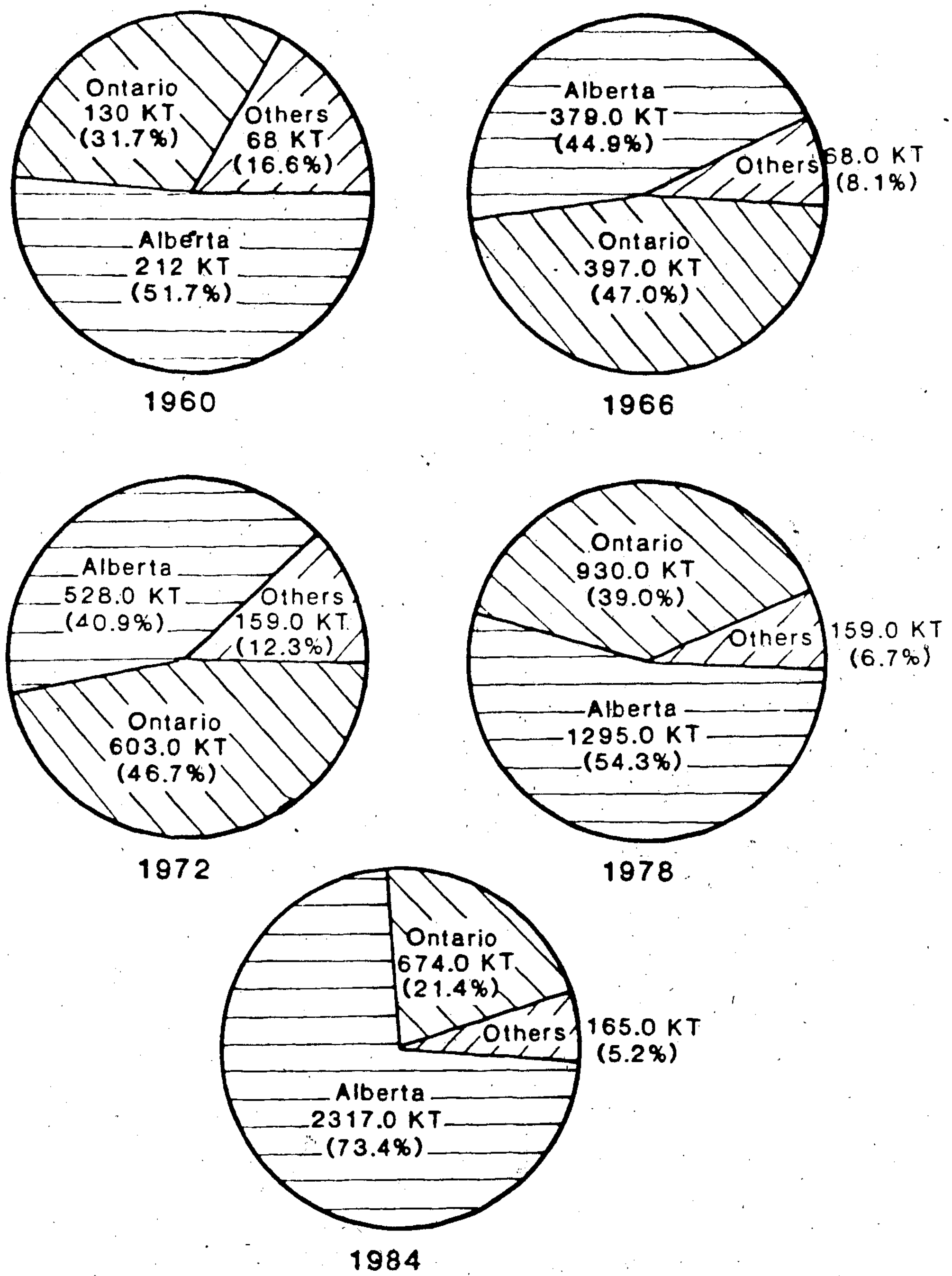
As shown in Figure 3, in 1960 51.7% of the Canadian ammonia capacity was in Alberta. In the late 1950's, access to Alberta gas via pipelines in Ontario gave impetus to the ammonia industry there. The Ontario producers reasoned that since it was cheaper to pipeline natural gas than to transport ammonia by rail, their domestic market was adequately protected and furthermore, they ought to be able to enter the U.S. Midwest market. New capacity was introduced by all four major Ontario producers, causing a surge in capacity (Figure 4). There was a corresponding surge in exports (Figure 5). Some capacity had been introduced in Alberta, but in 1966 Ontario had surpassed Alberta as the principal ammonia producer.

In the late 1960's in the midst of a worldwide surplus of ammonia capacity new plants were started in Manitoba and Alberta. The capacity surge caused a serious overcapacity problem which lasted until the early 1970's (Figure 4). This caused the moth-balling of a plant in Sarnia.

In 1974-75, the fertilizer market suddenly turned buoyant. Prices increased by one-third. As shown in Figure 5, Canadian ammonia exports increased substantially. The moth-balled Sarnia plant was moved to Courtright and it operated until 1978 when another domestic overcapacity problem forced it to shut down.

In 1974 a number of new plants were planned in Alberta. To alleviate the high transportation costs problem, consideration was given to building an ammonia pipeline to the United States (34). In 1976 two world-scale ammonia plants came onstream in Alberta, causing a capacity surplus just as exports to the U.S. peaked at ~600 KT/y.

Figure 3. Canadian Ammonia Capacity



In Table 3, static life index is defined as the ratio of natural gas reserves at year-end to the annual production. As shown in this table, in the mid-1970's the static life index for natural gas had declined from 39 years to 24.1 years. There was a brief natural gas supply shortage scare (104) during which Alberta ammonia producers signed long-term contracts for natural gas at relatively high prices; due to this a number of export-oriented proposals lost their U.S. partners (80). Thus, the perception about natural gas reserves affected the development of the Canadian ammonia industry.

Between 1977 and 1980 total U.S. ammonia imports doubled (26). As shown in Figure 5, Canada did not capture the incremental import market.

As shown in Table 3, by 1978 the natural gas static life index had increased to 31.6 years. Ammonia capacity expansion schemes were resumed in Alberta and Ontario. In 1983, when the Alberta plant expansions came onstream, the market had declined (Figure 4). The new plants operated intermittently until, in 1984 the market improved, ammonia prices almost doubled and the new plants began operating at capacity.

This history shows that the petrochemical market is volatile. Sharp price fluctuations are not unexpected. Therefore, an issue worth investigation is the impact of petrochemical price fluctuations on the future development of petrochemicals.

	1963	1968	1973	1978	1983
Reserves (TCF)	33	55	61	82	92.3
Production (TCFy)	0.85	1.41	2.53	2.60	2.21
Static Life Index (y)	39.0	39.0	24.1	31.6	41.7

Table 3: Natural Gas Reserves and Production (19)

FIGURE 4. CANADIAN AMMONIA STATISTICS

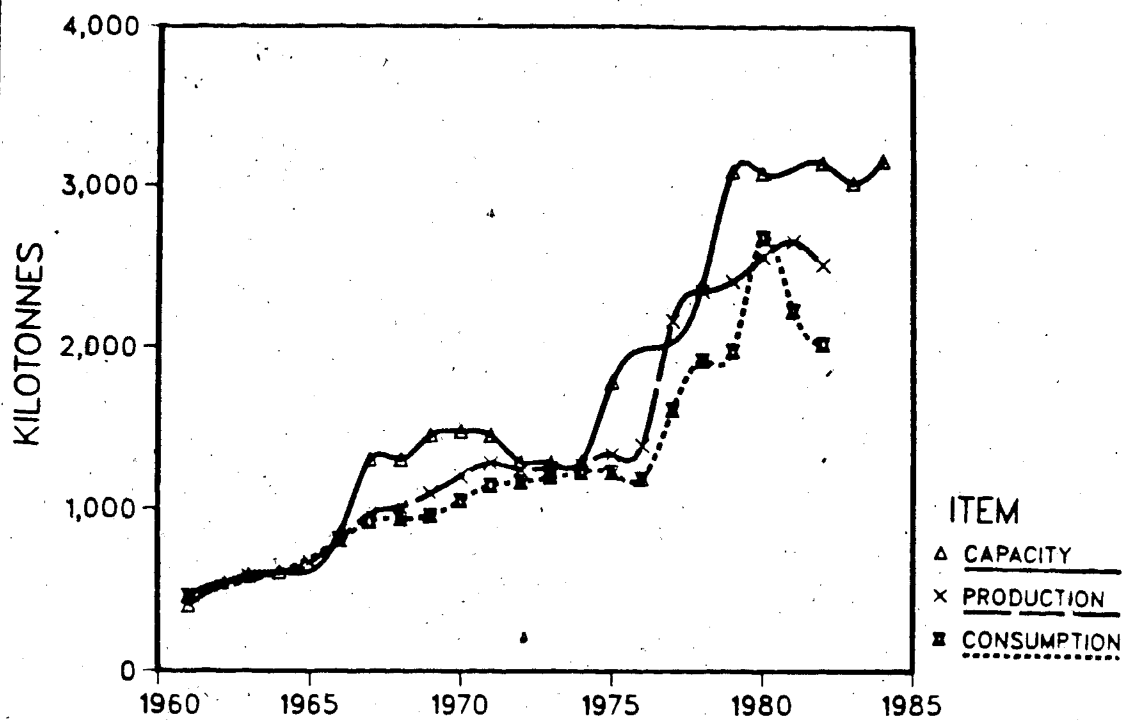
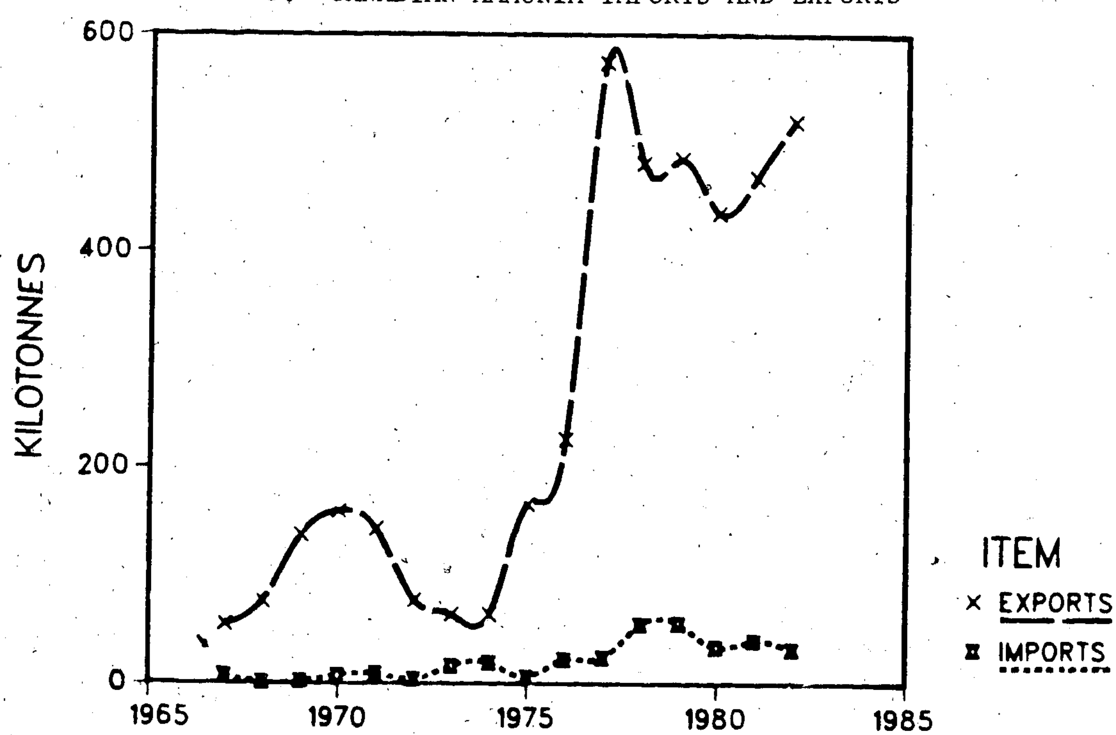


FIGURE 5. CANADIAN AMMONIA IMPORTS AND EXPORTS



B. Methanol

During the 1960's the U.S. methanol production more than doubled (9). Canadian methanol production did not emulate the U.S. pattern. The domestic market was limited and the U.S. tariff barrier was high.

Until the late 1960's the only Canadian methanol plant, at Edmonton, recovered methanol from the oxidation of natural gas liquids. Therefore, Alberta had 100% of the Canadian methanol capacity (Figure 6). Eastern Canada imported methanol from the United States (11), until two naphtha-based plants came onstream at Cornwall, Ontario and Montreal, Quebec.

Due to the relatively few producers, methanol production data is not available (Figure 7). However, during the operation of the Montreal plant, Canada exported methanol (Figure 8). In the early 1970's, during a period of world methanol surplus, the Edmonton and Montreal plants were shut down. The Edmonton plant was shut down because of outmoded technology whereas the relatively new but small Montreal plant lacked the economy of scale necessary to be able to compete in the export market.

Until 1973, methanol feedstocks were naphtha and natural gas liquids. It was used in the manufacture of formaldehyde and industrial solvents. After 1973 came the realization that methanol "was reformed natural gas in a more transportable form" (17). Natural gas has been the feedstock of all methanol plants constructed since then.

Figure 6. Canadian Methanol Capacity

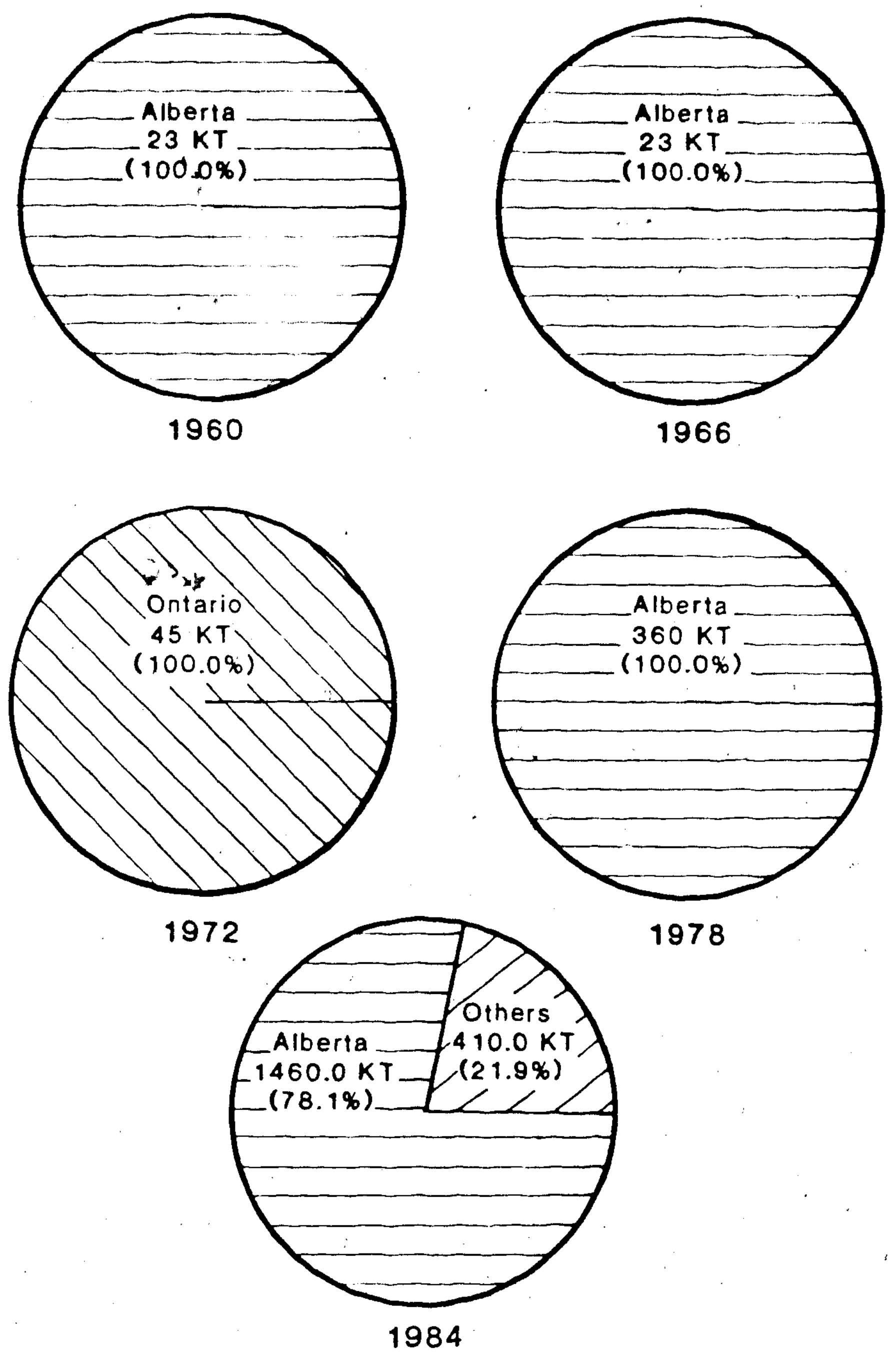


FIGURE 7. CANADIAN METHANOL STATISTICS

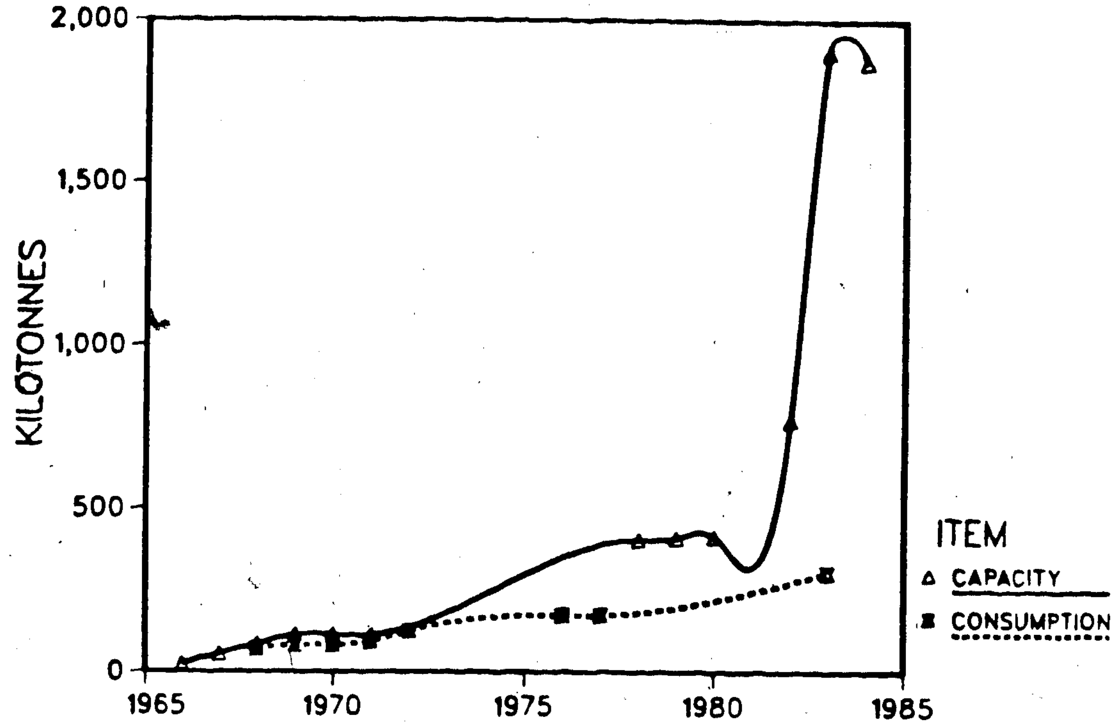
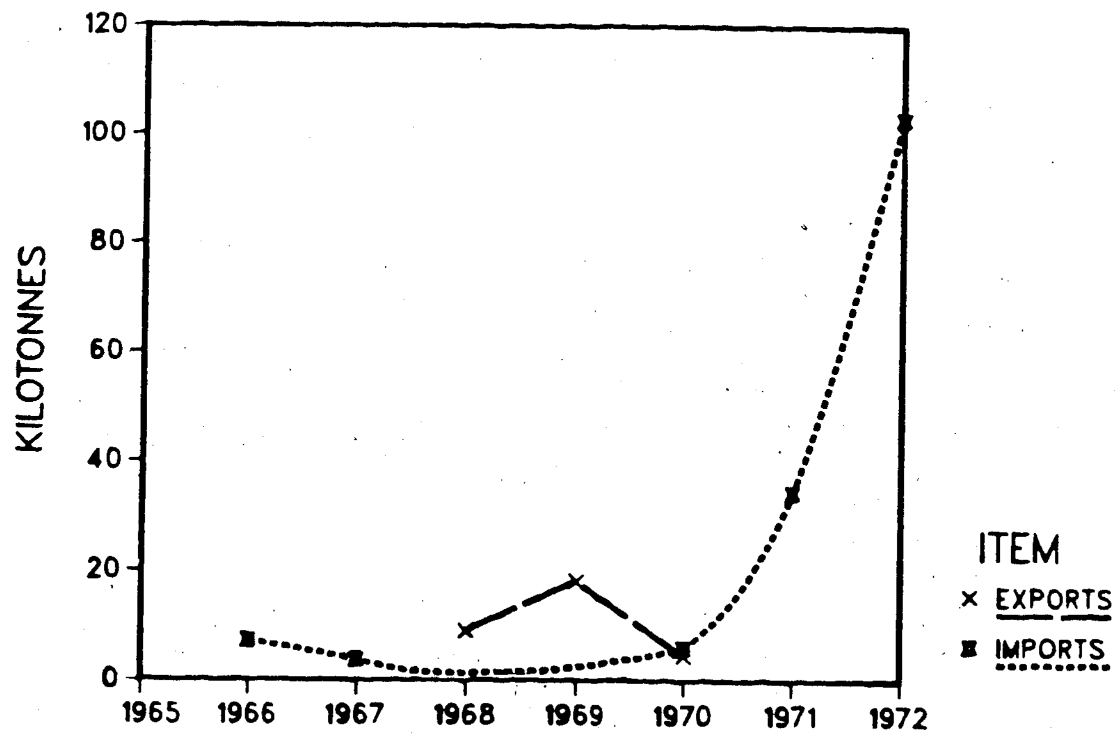


FIGURE 8. CANADIAN METHANOL IMPORTS AND EXPORTS



An Alberta-based consortium constructed a plant at Medicine Hat, Alberta, and aggressively entered the U.S. market (17). Its market success, combined with the demand for methanol in Japan (37), resulted in more proposals for export-oriented methanol plants. However, like ammonia, methanol was also affected by the natural gas supply shortage scare. Consideration was given to using a coal feedstock but natural gas was shown to be the preferred feedstock (90).

In 1978, U.S. producers brought a dumping action against the Medicine Hat plant. They claimed that its feedstock was being subsidized, since the natural gas was priced lower than its export price. The claim was unsuccessful since the company owned its natural gas. Later, the capacity at the Medicine Hat plant was doubled. The construction of export-oriented methanol plants at Edmonton, Alberta, and Kitimat, British Columbia commenced.

In the early 1980's a West German consortium planned to build in Alberta a methanol plant which was to be three times the size of the Edmonton plant. The product was intended exclusively for the West German fuel market.

The new methanol plants at Edmonton and Kitimat came onstream in the early 1980's. This resulted in a methanol capacity over six times the domestic consumption (Figure 6). The recession caused methanol prices to decline. The Canadian plants operated at near-capacity but, due to the depressed prices, made almost no profits (31).

U.S. tariff on methanol imported for chemical-related use is 20%, whereas on methanol imported for fuel-related use there is no tariff. Canadian exports to the U.S. are intended primarily for chemical-related use. In spite of this tariff, Canadian methanol is competitive in the U.S. market and has forced some U.S. methanol plants to shut down.

This history shows the competitive nature of the petrochemical market, where a plant at Edmonton continues to operate while its U.S. owners have shut down their thirteen year old Texas plant (27).

It is interesting to compare the development of ammonia and methanol in Canada. Ammonia grew with the domestic fertilizer market; with tariff-free access to the U.S. market, it did well after the mid 1970's. Methanol lacked a major domestic market; its major development occurred only when Alberta entrepreneurs, perceiving a growing feedstock advantage, pushed it aggressively in the export markets.

Methanol's future development in Canada is tied to the development of its fuel-related market, both domestic and export. However, the competition will be severe from Pacific Rim countries which have a surplus of natural gas, since they have no alternate uses for their gas.

C. Ethylene and its Derivatives

Whereas ammonia and methanol were relatively established chemicals in the early twentieth century, ethylene was first used in Canada in the early 1940's in the manufacture of synthetic rubber at Sarnia. It was extracted from refinery off-gases (136).

In the early 1950's an ethane-based plant was started at Edmonton and oil-based plants were started in Sarnia and Montreal. Naphtha crackers were brought onstream at Sarnia in 1958 and at Montreal in 1963.

As shown in Table 3, the 1960's Alberta natural gas production was around 1 TCF/year. Sufficient ethane could have been extracted to provide feedstock for the eastern Canadian ethylene plants. However, they chose the naphtha route. The Kirk-Othmer (89) analysis for U.S. plants was applicable to the Eastern plants: "Ethane shows the least investment and annual operating costs, but also offers the lowest gross margin (defined as the difference between product sales revenue and feedstock cost). This combination of effects makes ethane the least desirable feedstock, measured by the criterion of percent cash flow on total investment, after taxes."

Kirk-Othmer's analysis is shown in Table 4. The return on investment for all feedstocks was above 30%. However, because of higher co-product revenues, propane and naphtha were the preferred feedstocks.

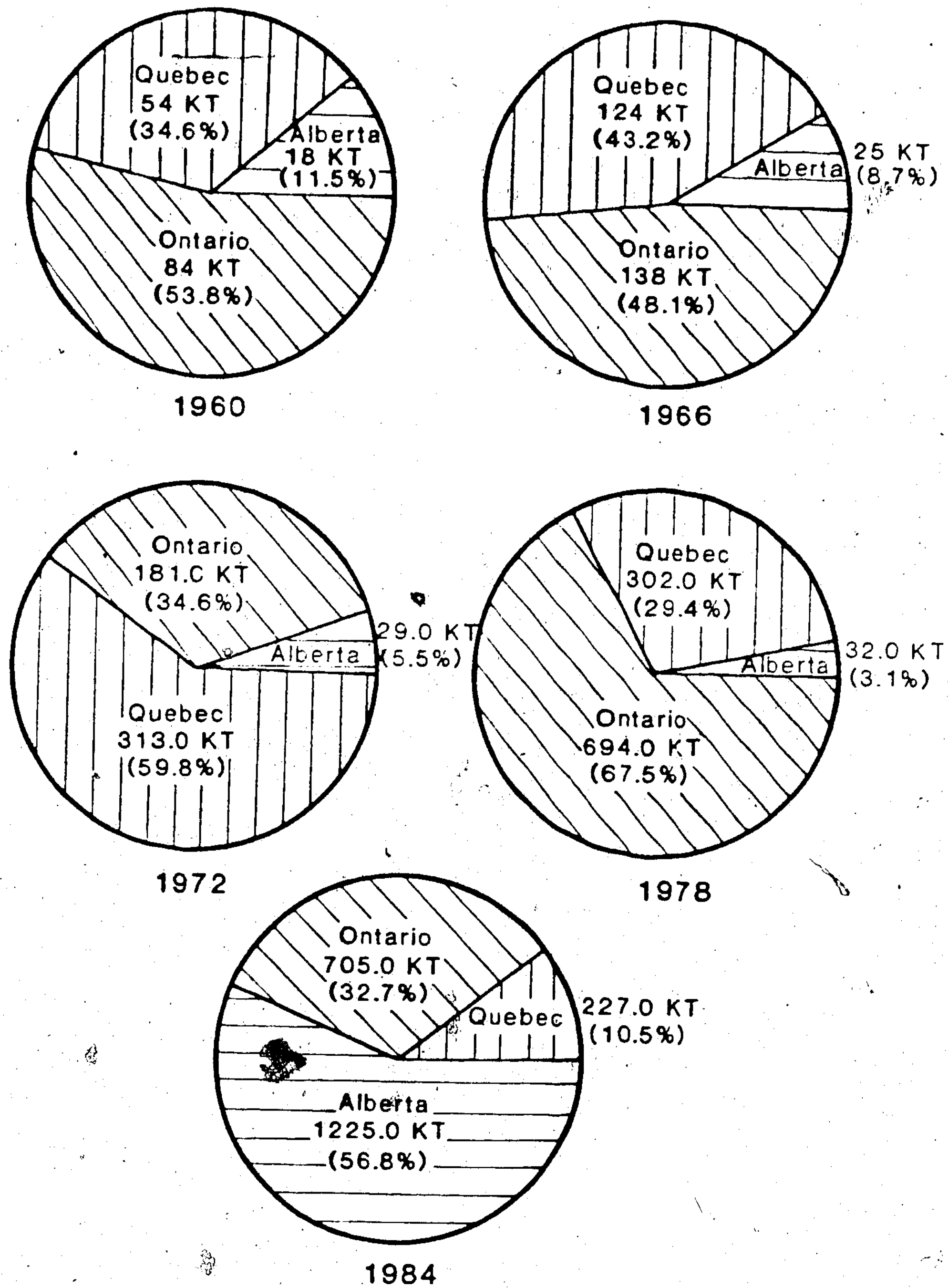
In the early 1960's, proximity to the world markets gave the Montreal refiners a modest cost advantage. As shown in Figure 9, they increased their ethylene capacity share from 34.6% in 1960 to 43.2% in 1966. Sarnia producers countered this by opting for a staged capacity increase, based on surplus refinery-propane.

	Ethylene Feedstock*		
	Ethane (MM$/y)	Propane (MM$/y)	Naphtha (MM$/y)
1. Feedstock Cost	4.30	4.92	14.08
2. Products Revenue	12.77	16.46	27.00
3. Gross Margin	8.47	11.54	12.92
4. Capital Costs	0.97	1.09	1.23
5. Operating Costs	2.21	2.46	2.85
6. Total	3.18	3.55	4.08
Gross Income (3) - (6)	5.29	7.99	8.84
Income Taxes at 48%	-2.54	-3.84	-4.24
Net Income	2.75	4.15	4.60
Depreciation	0.97	1.09	1.23
Cash Flow	3.72	5.24	5.83
Return on Investment	30.07	38.05	38.01

*Ethylene Production = 113.4 KT/year

Table 4: Economics of Ethylene Production in 1966 (89)

Figure 9. Canadian Ethylene Capacity



If there had been sufficient regional demand, the return on investment values in Table 4 show that the ethane-based Alberta industry would have developed. However, through the 1950's and 1960's, due to low regional demand and a lack of economic access to the major markets, the Alberta ethylene industry stagnated.

As shown in Figure 10, in 1969 there was a surplus of ethylene capacity in Canada (77,78). Yet there were plans for naphtha-based plants in Ontario and the Atlantic Provinces. The refiners objected, since they felt that the ethylene co-products would compete with their products (79). The proposed plants were never built. This example shows the competitive nature of the petroleum and petrochemical sectors.

In the early 1970's, a small Ontario p[illegible] shut down. Ethylene imports grew faster than exports (Figure 11). The need for a new ethylene plant resulted in the chemical refinery proposal called Sarnia olefins and aromatics project, "SOAP" (16).

Since a synthetic rubber producer was interest in a domestic butadiene source, the SOAP consortium rejected ethane as a feedstock. Unable to get a satisfactory long-term naphtha supply, the consortium decided to use crude oil (12). Three chemical companies with no petroleum marketing experience decided to compete with the traditional refiners.

FIGURE 10. CANADIAN ETHYLENE STATISTICS

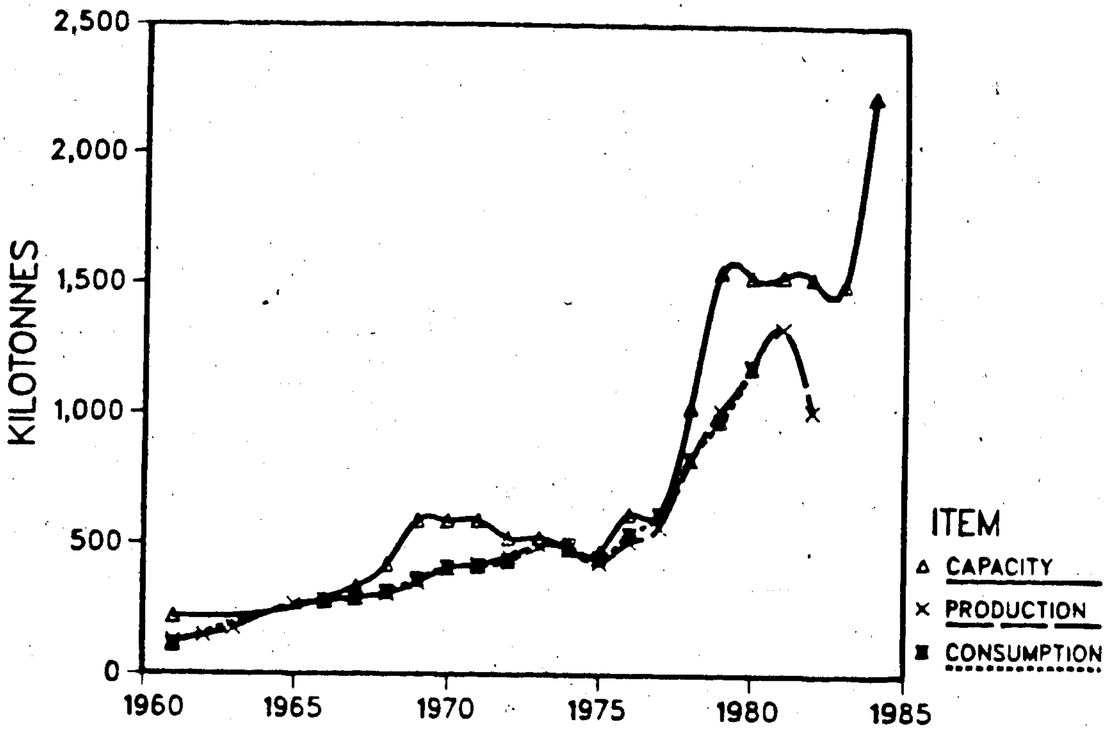
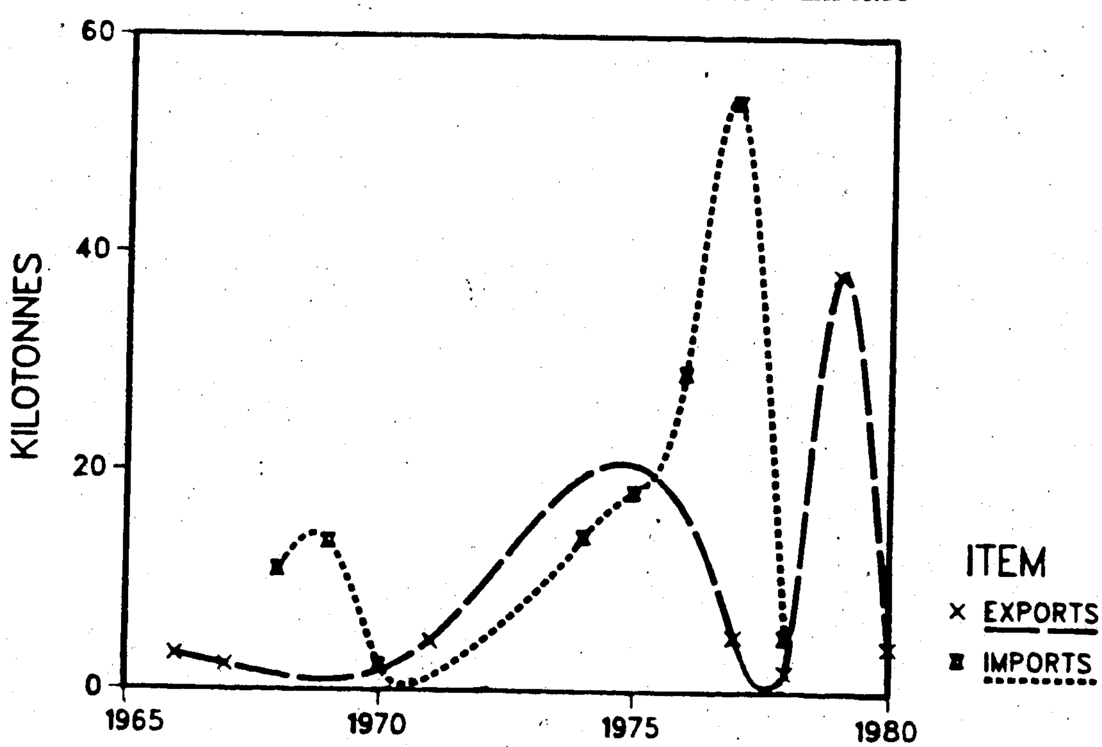


FIGURE 11. CANADIAN ETHYLENE IMPORTS AND EXPORTS



The SOAP proposal was opposed on three fronts (16,33,126):

a. in Quebec, the ethylene producers perceived it as a major competitor and voiced objections to the use of federal subsidies;

b. in Alberta, the provincial government perceived it as a threat to plans for ethane-based ethylene plants. The Premier publicly stated that it was unfair to provide cheap Alberta oil for the SOAP plant when its product would compete with the unsubsidized ethane-based Alberta plants;

c. in Sarnia, producers felt that the propane-based staged-capaçity increase was more viable than the SOAP proposal and also voiced objections to the use of federal subsidies.

The federal government allayed the Quebec and Sarnia producers' fears by stating that there would be no subsidies for SOAP. The SOAP consortium countered Alberta's arguments by stating that there was domestic demand for the co-products of a naphtha-based plant. The consortium had considered a naphtha-based plant in Alberta, but had rejected it "because of

The Alberta government received a proposal to construct a world-scale ethane-based ethylene plant. The ethylene would be shipped out of the province via the Cochin pipeline. Another proposal, wherein the ethylene would be upgraded within the province, was received. The provincial government favored the latter proposal.

By 1975, the Alberta government felt that Petrosar and two Alberta ethane-based plants could not be brought onstream simultaneously. It requested the two competing groups in Alberta to submit a joint proposal. This was done and approved by the provincial government in 1975.

In 1977 the Petrosar plant came onstream (18). It had been intended to use 170,000 barrels/day crude oil. It had difficulty marketing the heavy fuel oil product due to competition from the traditional refiners and from natural gas and electricity. In 1979, Petrosar decided to reduce the heavy fuel oil output by switching to 100,000 barrels/day Alberta crude oil and 20,000 barrels/day Alberta condensate. In late 1979, the Alberta ethylene plant came onstream at Joffre. Canada began exporting large volumes of ethylene (Figure 11).

When the new Ontario and Alberta plants came onstream, the existing ethylene plants in Montreal were consolidated under the newly-formed Petromont. As long as the ethylene export market boomed, they felt that they could remain viable.

In the early 1980's the situation looked so good in Alberta that serious consideration was given to accelerating the construction schedule of two additional world-scale ethylene plants proposed by the consortium that built the first plant. Another consortium also submitted a proposal for an ethylene plant to the Alberta government. However, the recession started and the ethylene markets declined (Figures 10 and 11). The latter proposal was shelved (59).

In 1982, U.S. Gulf Coast ethylene prices declined by about one-third (25). The declining ethylene prices had caused feedstock prices to decline correspondingly. In Alberta, the ethane price tied to the Alberta border price for natural gas kept escalating. Canadian ethylene capacity utilization dropped to 59% (61). This anomaly exposed the inflexible nature of the Alberta ethane pricing arrangement. In 1982, ethylene exports to the U.S. were negligible.

In 1982, the Eastern plants, Petrosar and Petromont, asked the federal government for a $7/barrel subsidy on their crude oil feedstock. Since the federal government had previously assured their competitors that there would be no subsidy, it responded by offering Petrosar a $25 million loan guarantee and Petromont a $25 million loan, provided their respective provincial governments matched the offer. Petromont accepted the loan but Petrosar did not, since it felt a loan guarantee helped the lender and not the borrower. Both plants continued to operate.

In 1984, the heavy operating losses of Petromont resulted in the withdrawal of one consortium member, which gave up its share to it erstwhile partners for a nominal amount (62). Petrosar also experienced heavy operating losses. It began to look for alternative feedstocks; specifically, it investigated the feasibility of using a combination of crude oil and natural gas liquids. It wanted the federal government to assure that there would be adequate propane and butane supplies for its plant by restricting, if necessary, the export of these natural gas liquids. The federal government has not yet reacted to their recommendation.

The issue is about opportunity values. In the domestic and export markets propane and butane have high opportunity values as fuels. Restricting their exports in order to satisfy a lower valued use as a petrochemical feedstock would not be economical. Apparently, that is the problem faced by the federal government.

Furthermore, the second Alberta ethylene plant came onstream in 1984. Subsidizing natural gas liquids feedstocks in order that the Eastern Canadian plants can compete with the two Alberta plants would raise difficult regional issues. In this thesis the natural gas liquids option for Petrosar is further investigated on a strictly economic basis.

C1. Polyethylene

Polyethylene was commercialized in 1941 for wartime use. Its Canadian production started in the early 1950's at Edmonton, Montreal and Sarnia.

Its initial growth rate was 20%/year but the small domestic market was easily saturated and high tariffs made it difficult to penetrate the export market.

During the 1960's, Alberta production stagnated at around 30 KT/y. In the East, there was steady expansion. However, due to the higher production costs compared to the U.S. Gulf Coast and the lower Canadian tariff barrier the profitability of this petrochemical was very low and in the late 1960's, during a period of world-wide overcapacity, Canada was the only developed country that had to import polyethylene (21).

As shown in Figure 13, polyethylene imports peaked in 1974 at around 100 KT. The differential between the world and domestic oil prices improved the profitabilities of Canadian petrochemicals. In Eastern Canada, plant expansions and new plant construction occurred. Feasibility studies for polyethylene plants in Alberta were done by two private companies (75).

The two companies did not like the cost-of-service ethylene pricing arrangement which tied ethylene price, through ethane, to the regulated Alberta border price for natural gas. They preferred a price for ethylene tied not to the Alberta border price but to the deregulated market price for natural gas used by industry. The two companies shelved their Alberta polyethylene plans.

With feedstock from Petrosar, a world-scale polyethylene plant was started in Sarnia. This caused a capacity surge (Figure 12). In 1978, polyethylene exports finally exceeded imports (Figure 13).

In the early 1980's, plans were announced in Sarnia for two major capacity expansions and a new polyethylene plant. In Alberta two new world-scale plants were planned. The reason for this was the availability of a domestic ethylene. If all the plans had reached fruition the polyethylene capacity surplus would have increased from 19.4% in 1980 to 59.2% in 1984 (119). Due to the recession, the Sarnia plant expansion plans and plans for one new Alberta plant were deferred. The new Sarnia plant came onstream in 1983 and the Alberta plant came onstream the following year. Two-thirds of the latter's production was contracted for long-term exports to the United States (60).

With world-scale plants and a relatively secure feedstock supply situation it remains a growth petrochemical in Canada.

C2. Ethylene Glycol

Ethylene glycol was commercialized in 1923. One of its principal uses was as an antifreeze in automobiles. Aggressive marketing made it "one of the most powerful forces in the establishment of the U.S. petrochemical industry" (4). The first Canadian plant was built in Sarnia in

In 1961, while the export market was shrinking (107) an ethylene glycol plant was brought onstream at Montreal. There was a slight surplus of this petrochemical due to relatively static demand until the 1970's (Figure 14).

In 1975 there was a major supply shortage and ethylene glycol imports peaked at around 30 KT (Figure 16). In the following year plant expansions resulted in a small capacity surplus. In the late 1970's exports and imports were balanced.

In 1983 a world-scale ethylene glycol plant came onstream in Alberta. It caused a sharp increase in ethylene glycol capacity (Figure 14). Since its output was greater than the domestic demand, it needed an export market. However, it came onstream just as there was a major world-wide surplus. Prices were so depressed that in Western Europe it was the biggest money-losing petrochemical (28).

The future development of this petrochemical will depend on its competitiveness in export markets.

C3. Styrene

The Canadian production of styrene started in the early 1940's at Sarnia. It used benzene from coke oven off-gases and ethylene from refinery off-gases. During the Second World War it was used in the manufacture of synthetic rubber.

FIGURE 14. CANADIAN ETHYLENE GLYCOL STATISTICS

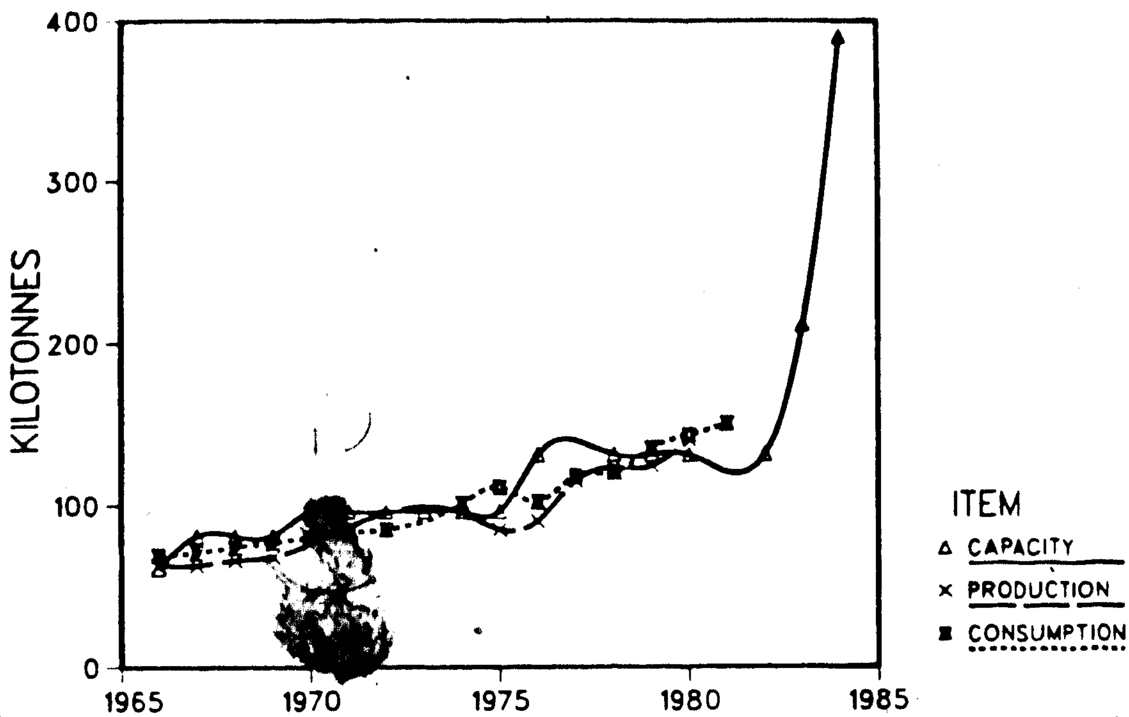
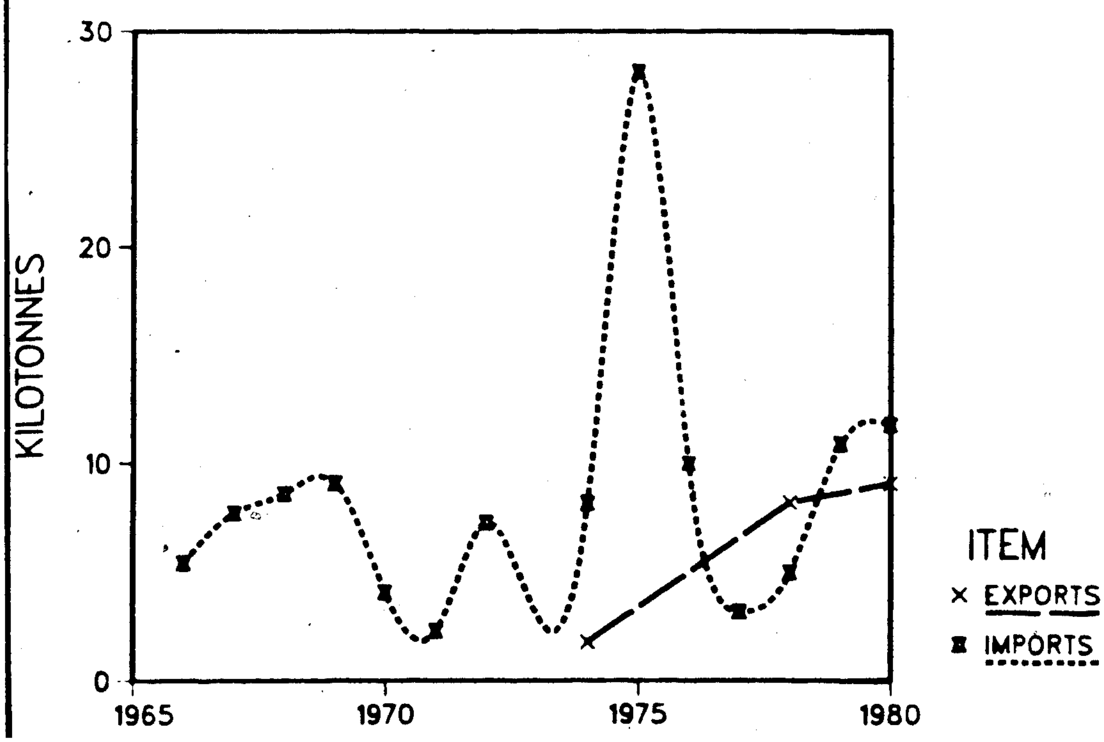


FIGURE 15. CANADIAN ETHYLENE GLYCOL IMPORTS AND EXPORTS



Due to the relatively few producers, styrene statistics are incomplete. In the 1960's due to the availability of ethylene and benzene the only two Canadian producers were located in Sarnia. In 1967 one obsolete unit was replaced and the capacity of the other was doubled. As shown in Figure 16, until the mid 1970's production remained at near capacity.

In 1978, a sharp capacity increase occurred when a world-scale plant was started at Sarnia, using benzene and ethylene from Petrosar. At that time one of the older Sarnia plants was moth-balled (82). As shown in Figure 17, the capacity increase caused a sharp increase in styrene exports, in spite of a world styrene surplus (81). The rise in exports did not prevent a major capacity surplus which lasted till the mid 1980's (Figure 16).

The startup of the Sarnia plant in 1978 caused the second Canadian producer to shelve its plant expansion plans (105).

In spite of the capacity surplus, in 1984 a world-scale styrene plant was brought onstream at Scotford, Alberta. It was constructed because a new synthetic oil refinery would have a benzene surplus; this surplus could either be exported or upgraded to styrene by using ethylene from the second Alberta ethylene plant. Banking on Pacific rim markets (8), the latter option was chosen.

Styrene is a hybrid oil and gas-based petrochemical. Its benzene feedstock has an alternative use as a transportation fuel octane-enhancer; its ethylene feedstock may be either oil or gas-based. Therefore, its

FIGURE 16. CANADIAN STYRENE STATISTICS

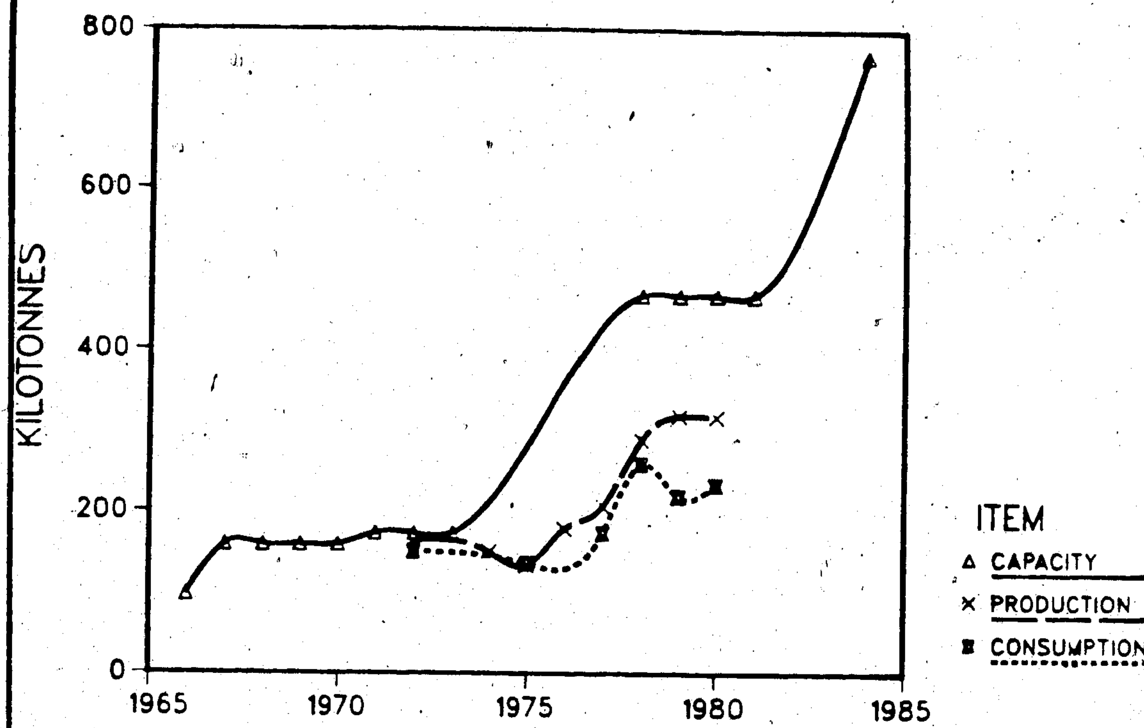
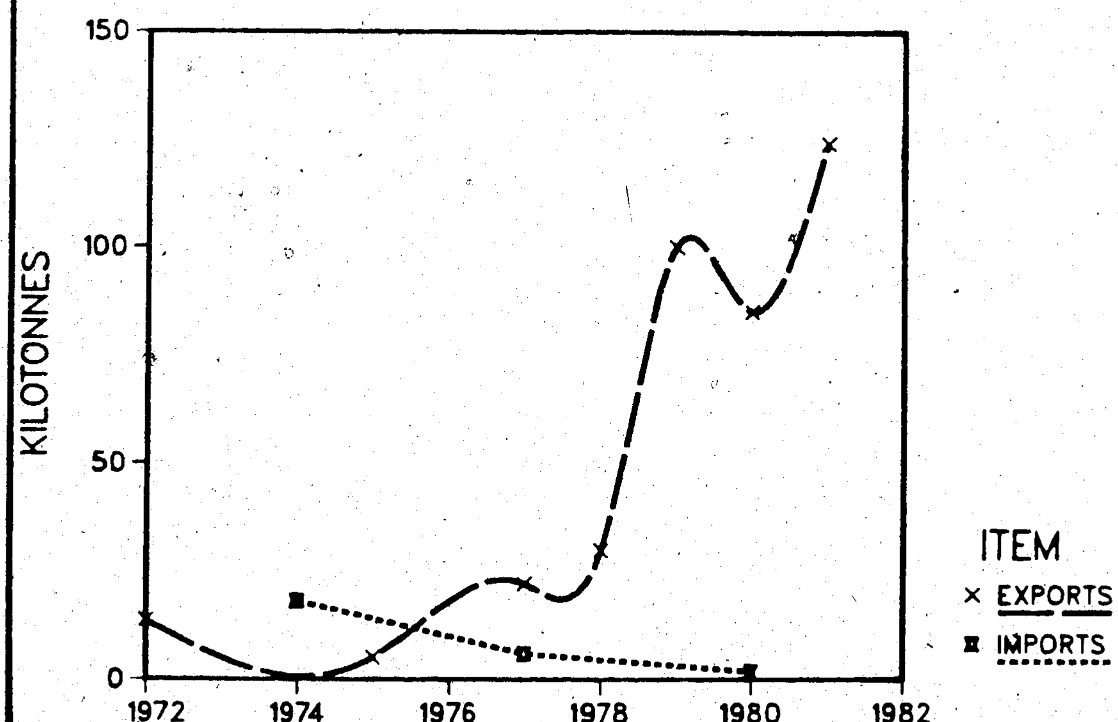


FIGURE 17. CANADIAN STYRENE IMPORTS AND EXPORTS



opportunity value is tied to the world oil price. With its gas-based ethylene feedstock the Alberta styrene plant should be able to compete in the export market; 25% of its output is earmarked for Japan and 50% for the United States.

C4. Vinyl Chloride Monomer (VCM)

In the early 1970's, there were two small VCM plants located at Montreal and Sarnia. The Montreal plant used an acetylene feedstock. At Sarnia it was produced from the ethylene dichloride byproduct of the ethylene glycol plant (13).

In the late 1960's, the Sarnia plant doubled its capacity and an ethylene-based plant was started at Montreal. Due to a lack of data the impact of the latter plant on VCM capacity is shown only after 1972 (Figure 18).

VCM was expected to have a strong growth, since its U.S. growth rate during the 1960's had been 14%/year (35). However, in the early 1970's, there was a VCM surplus and its price dropped by one-half.

In the mid-1970's the market had recovered and, anticipating a burgeoning PVC demand, construction commenced on a world-scale plant in Alberta. This plant came onstream in 1980 (Figure 18) using ethylene feedstock from the first Joffre plant.

FIGURE 18. CANADIAN VINYL CHLORIDE STATISTICS

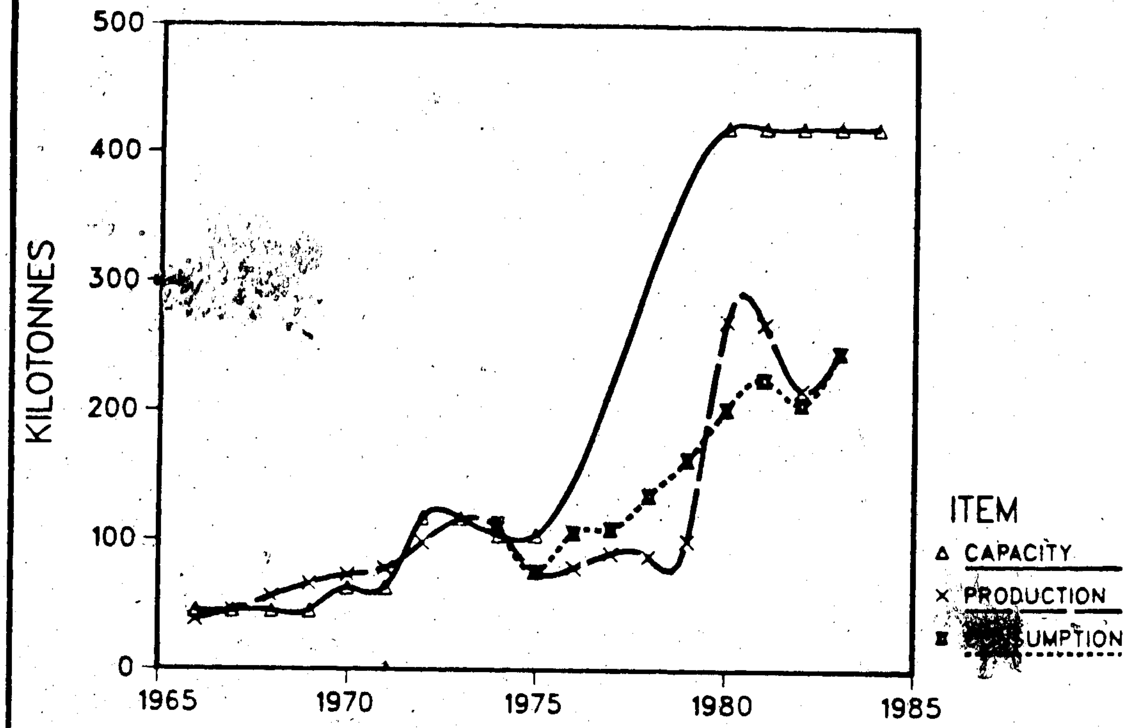
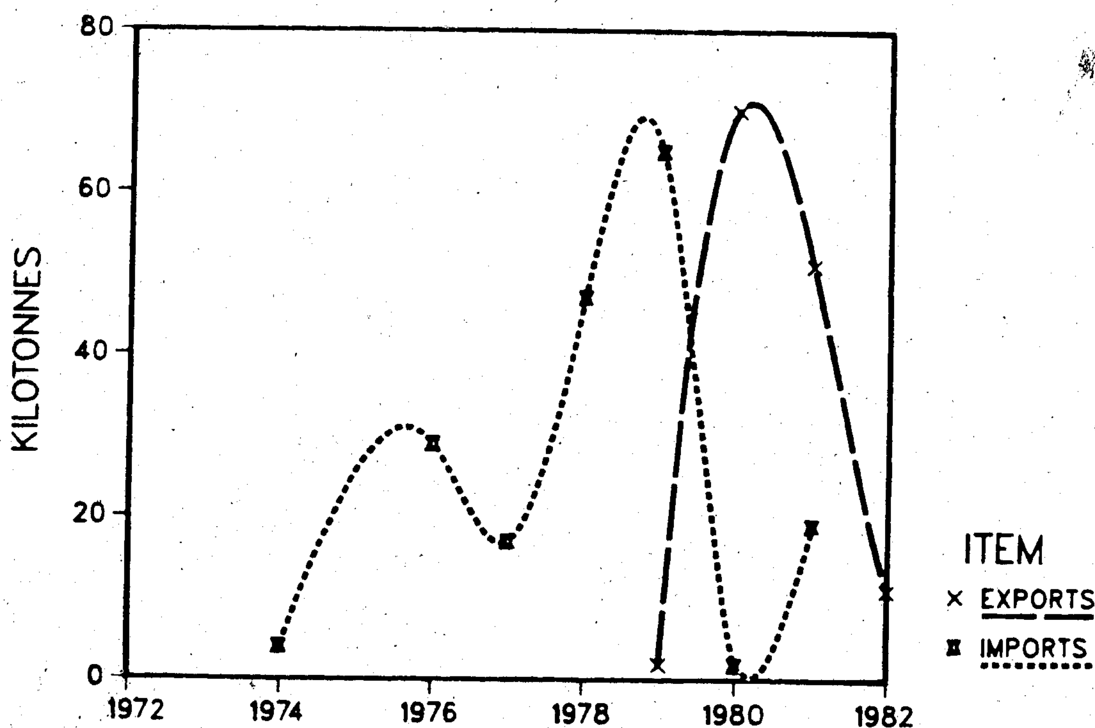


FIGURE 19. CANADIAN VINYL CHLORIDE IMPORTS AND EXPORTS



As shown in Figure 19, VCM exports increased sharply and then declined sharply in the early 1980's. The VCM consumption increased steadily since the mid 1970's but when the Alberta plant came onstream there was a serious overcapacity problem (Figure 18). In fact, in the early 1980's its capacity utilization was around 50%.

The future development of VCM capacity is tied to its competitiveness in the export market.

C5. Vinyl Acetate Monomer (VAM)

In the early 1960's, VAM was manufactured at Montreal from acetylene and acetaldehyde. Competition from lower-priced ethylene-derived VAM forced the shutdown of this plant in 1971 and the petrochemical was imported from the United Kingdom.

As shown in Figures 20 and 21, VAM statistics are incomplete. Until 1979, imports were equal to the domestic consumption.

In 1979, a small VAM plant was brought onstream at Edmonton, Alberta. Originally, it was to expand to a world-scale plant but due to poor domestic and export markets the plans were postponed.

From Figure 20 it is clear that the domestic market will not support a world-scale plant. Therefore, the future of this petrochemical depends upon its competitiveness in export markets.

FIGURE 20. CANADIAN VINYL ACETATE STATISTICS

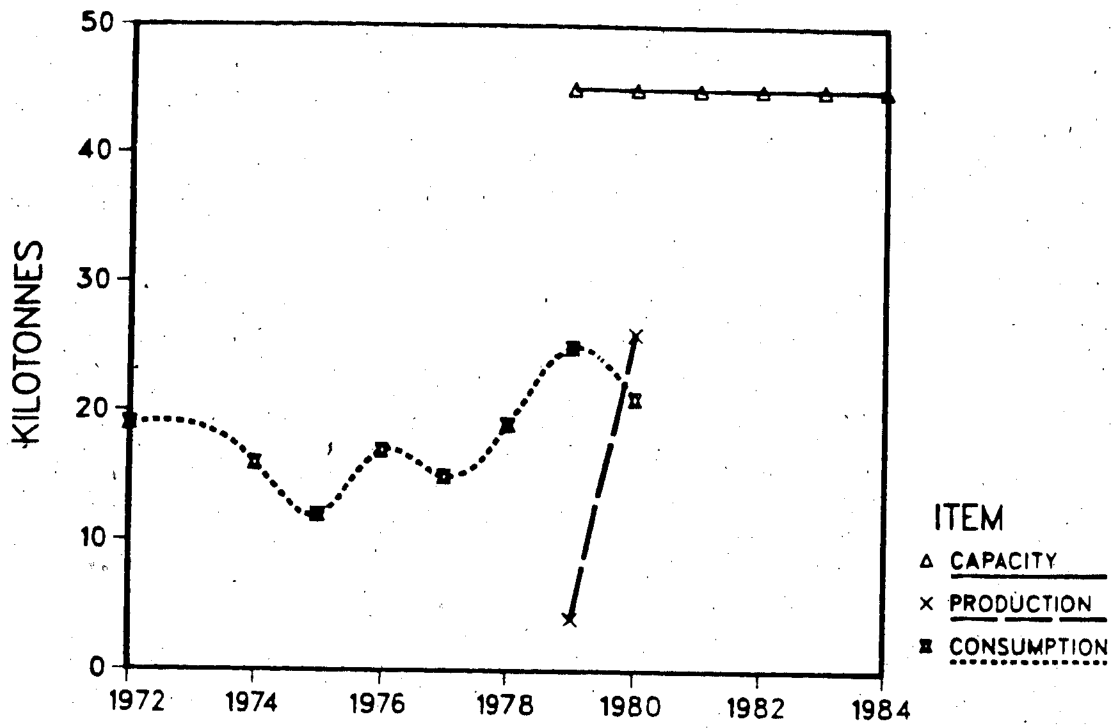
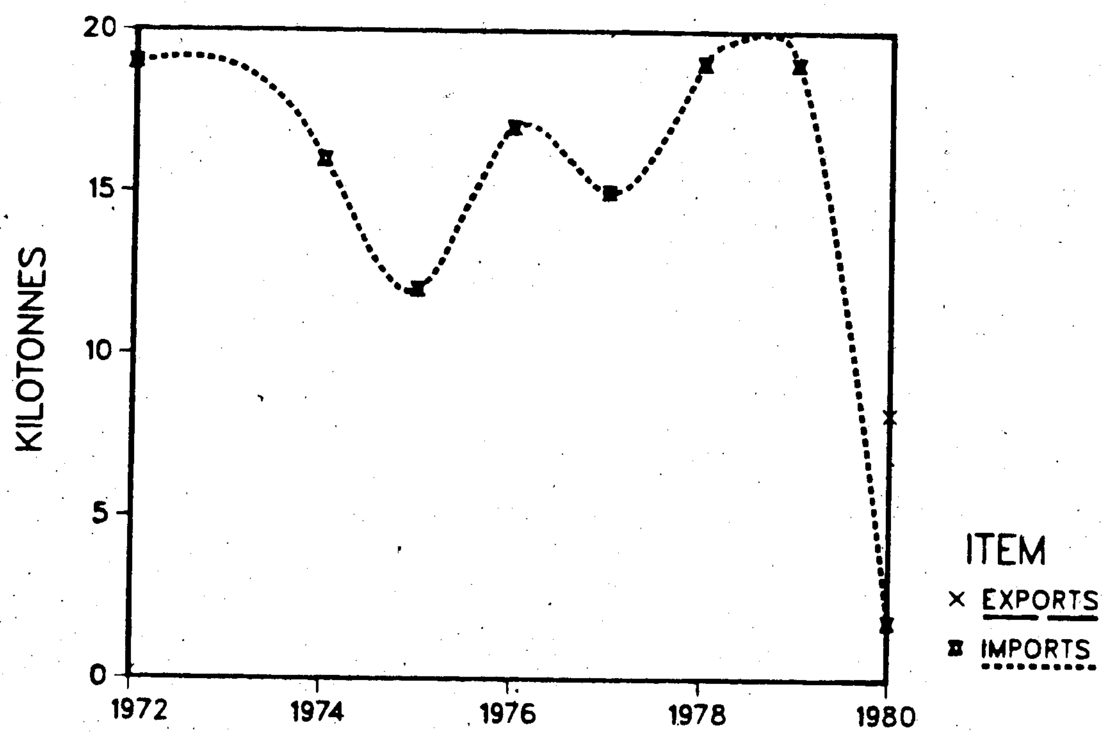


FIGURE 21. CANADIAN VINYL ACETATE IMPORTS AND EXPORTS



D. Propylene and Polypropylene

Propylene production was started in 1953 at two Montreal refineries. Its principal use was in the refined petroleum sector; only 7% was used as a petrochemical feedstock (10).

As shown in Figure 22, Ontario became an increasingly dominant Canadian producer of this petrochemical. It was a major by-product of naphtha-based ethylene plants.

When it is an ethylene by-product, the propylene concentration is 95%, whereas refinery-grade propylene concentration is 50%. Therefore, the ethylene by-product makes a better petrochemical feedstock (129).

As shown in Figures 23 and 24, propylene statistical data is incomplete. In the 1960's it remained a by-product of the Eastern ethylene plants (14). Its major capacity increase occurred in 1977 when Petrosar came onstream; at this time propylene exports increased, in spite of a propylene surplus in the United States.

In the late 1960's, two feasibility studies were done for setting up polypropylene plants in the East (15). As shown in Figure 25, demand for this petrochemical was increasing rapidly. The demand was being met by imports (Figure 26). However, the domestic market was not considered adequate to support a world-scale plant; the plans were postponed until 1974.

Figure 22. Canadian Propylene Capacity

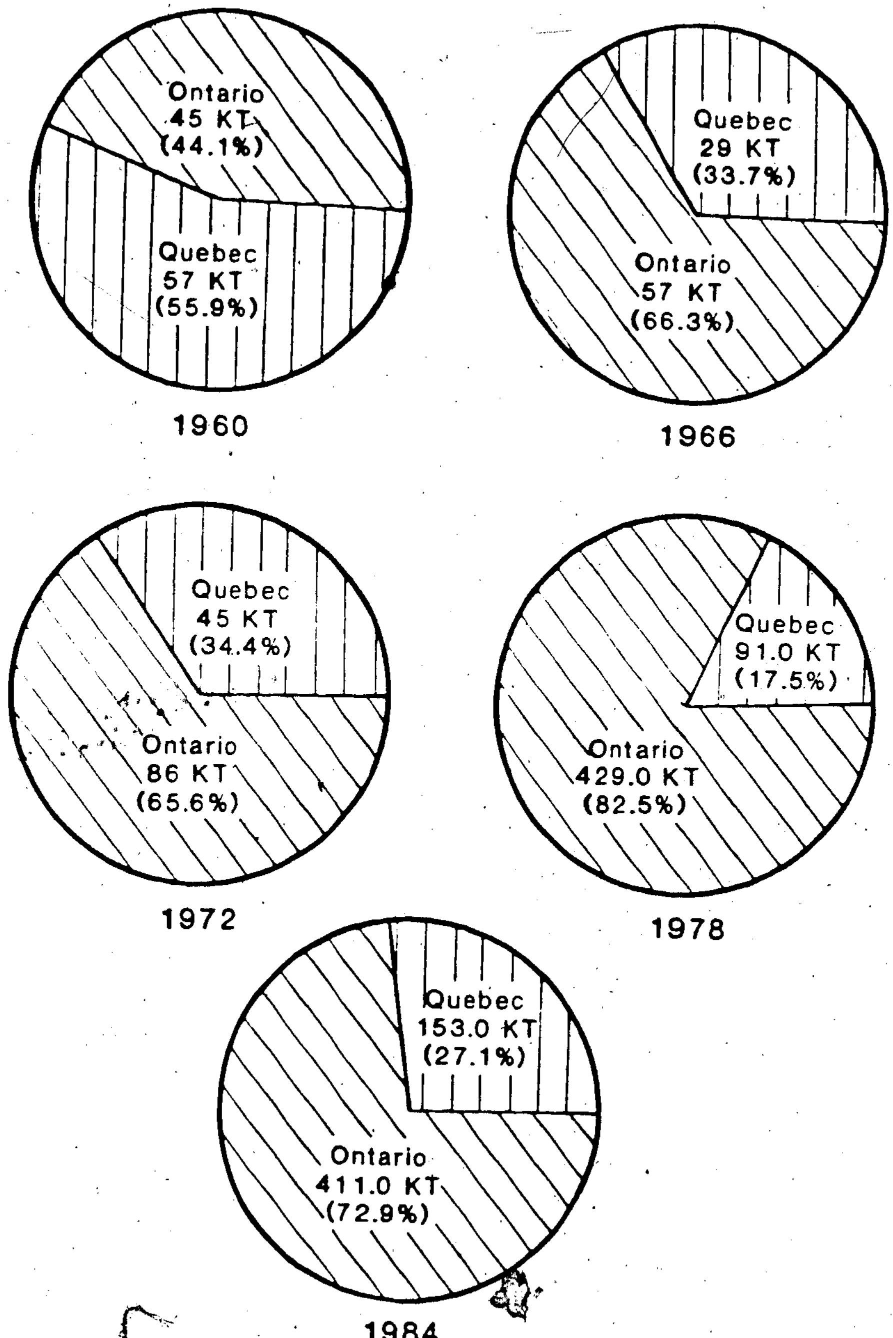


FIGURE 23. CANADIAN PROPYLENE STATISTICS

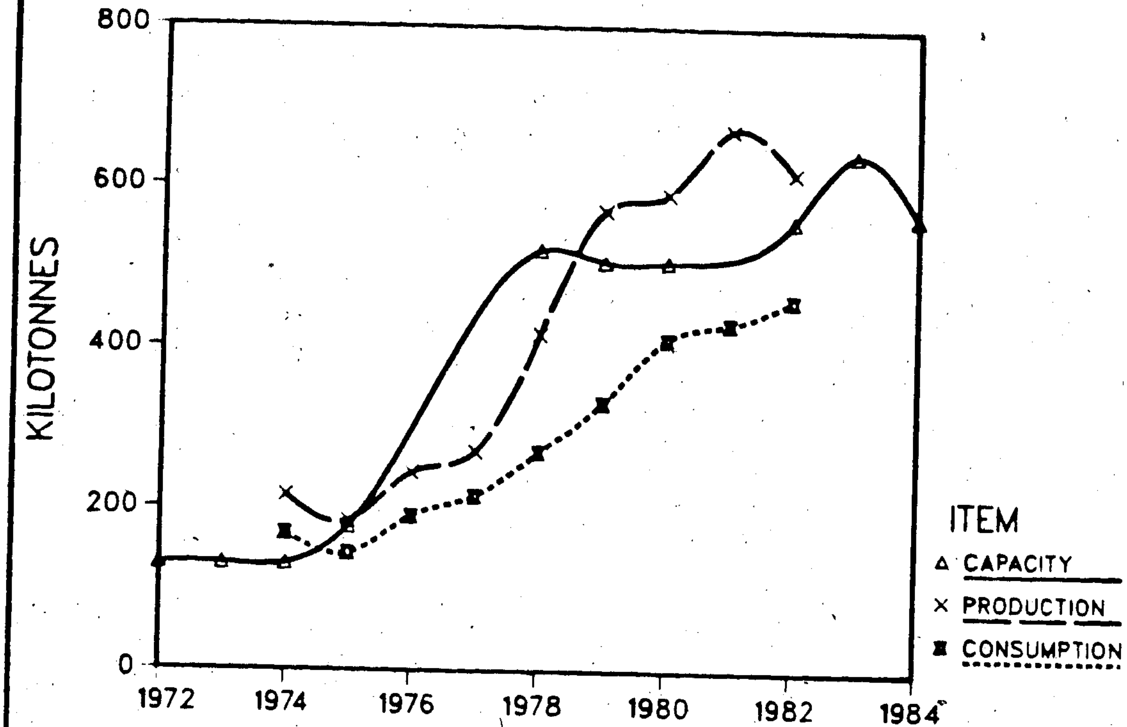
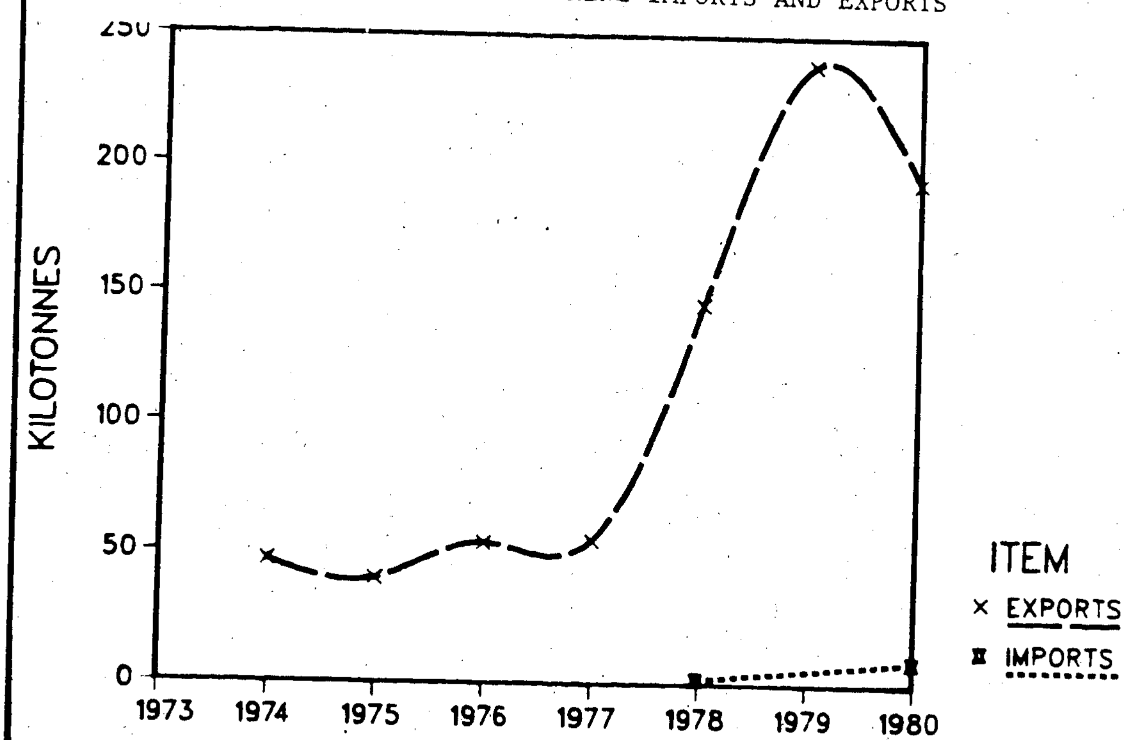


FIGURE 24. CANADIAN PROPYLENE IMPORTS AND EXPORTS



Since it was an ethylene by-product, propylene was expected to be the lowest cost monomer. Its derivative, polypropylene, had the potential to compete with high density polyethylene, polystyrene and polyvinyl chloride (109). As shown in Figure 25, the growth rate of polypropylene during the 1970's was strong. A plant was proposed in Alberta (83); however, in Alberta the refinery-grade propylene was used in the refineries' own alkylation units.

In 1974, on the basis of propylene availability from Petrosar, the construction of two mid-sized polypropylene plants started. The first plant came onstream with Petrosar. The second plant came onstream in 1980. The polypropylene plants came onstream at a time of world-wide shortage. The availability of a strong domestic market and an export market resulted in a good performance of this petrochemical.

The development of polypropylene is tied to the development of refineries and oil-based ethylene plants. Although propylene is still used mainly as a fuel, the octane rating of the propylene-based alkylate is not good. As lead is phased out from gasoline, propylene should become increasingly available as a chemical feedstock.

E. Butadiene

The Canadian production of butadiene started in 1941 at Sarnia. The feedstock was extracted from refinery off-gases. It was used in the manufacture of synthetic rubber for World War II. After the war, in spite of the return of the availability of natural rubber, due to some superior qualities of synthetic rubber the plant continued to operate.

FIGURE 25. CANADIAN POLYPROPYLENE STATISTICS

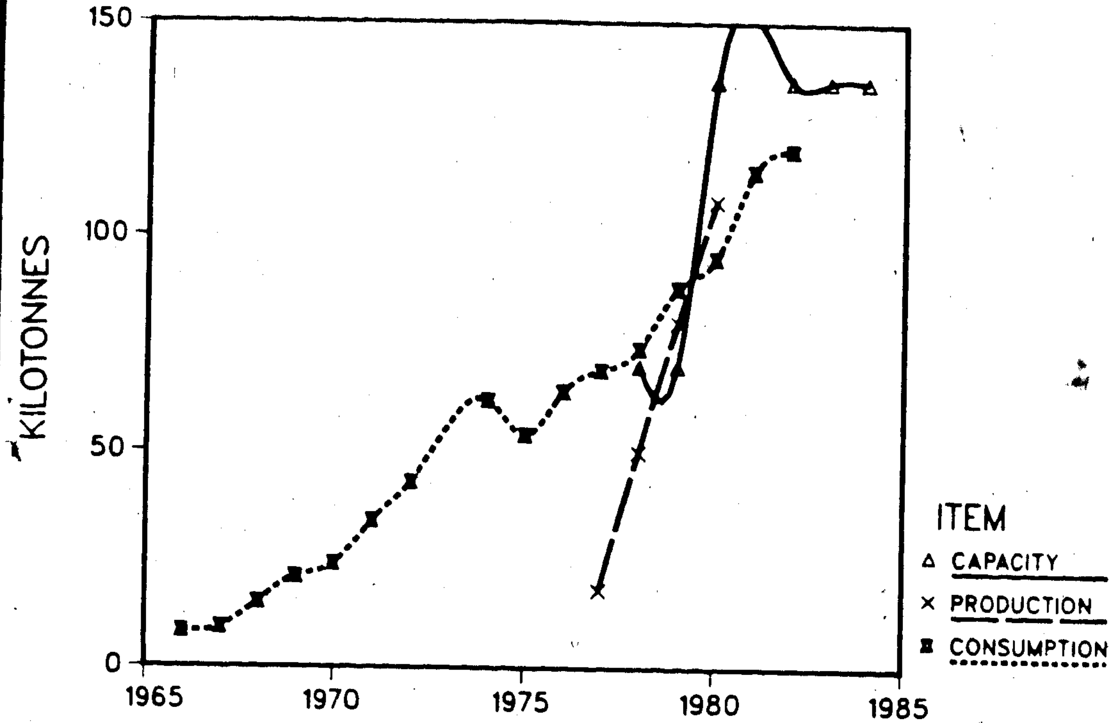
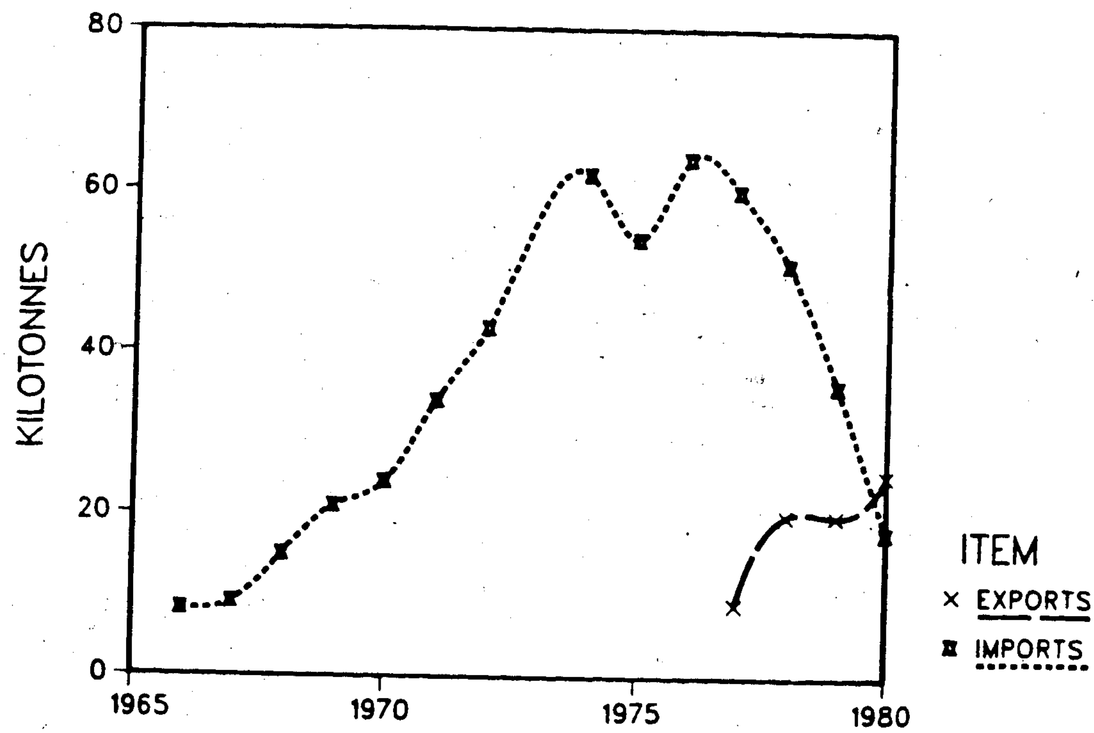


FIGURE 26. CANADIAN POLYPROPYLENE IMPORTS AND EXPORTS



Butadiene production was limited by the availability of refinery off-gases in the Sarnia area. In the early 1950's the Sarnia company Polysar investigated the feasibility of building a plant in Alberta. It decided that it would be cheaper to import butadiene. Until the early 1970's this petrochemical was manufactured only in Ontario (Figure 27).

The butadiene statistical data base is incomplete. As shown in Figures 28 and 29, in spite of there being surplus capacity butadiene imports continued throughout the 1970's. The high domestic butadiene costs resulted in the synthetic rubber costs being higher than in other regions of the world; Polysar had difficulty retaining the domestic synthetic rubber market (12). It decided that if it wanted to [illegible] in the synthetic rubber business it needed a cheaper source of butadiene. That is why it became a member of the Petrosar consortium.

When Petrosar came onstream, the butadiene capacity increased sharply (Figure 28). Some outdated butadiene plants were forced to shut down. As shown in Figure 29, the butadiene imports declined.

If Petrosar shuts down, the synthetic rubber producer in Sarnia would have to look for a new butadiene source. Domestic sources are limited by refinery capacities and high production costs. The alternatives will be to either import it or manufacture it from some other feedstock, possibly butane. Under current conditions, the import option appears to be more economically feasible.

Figure 27. Canadian Butadiene Capacity

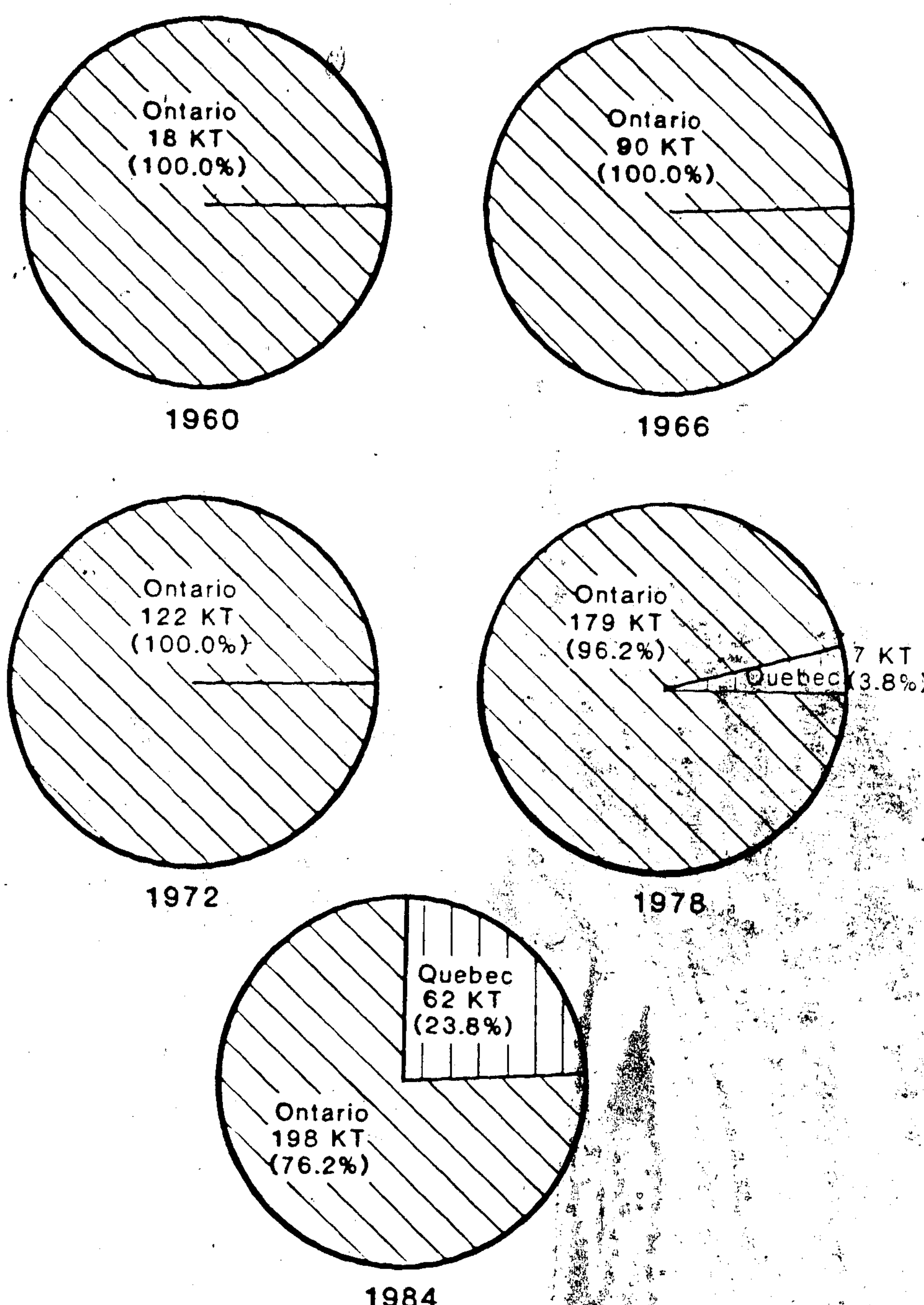


FIGURE 28. CANADIAN BUTADIENE STATISTICS

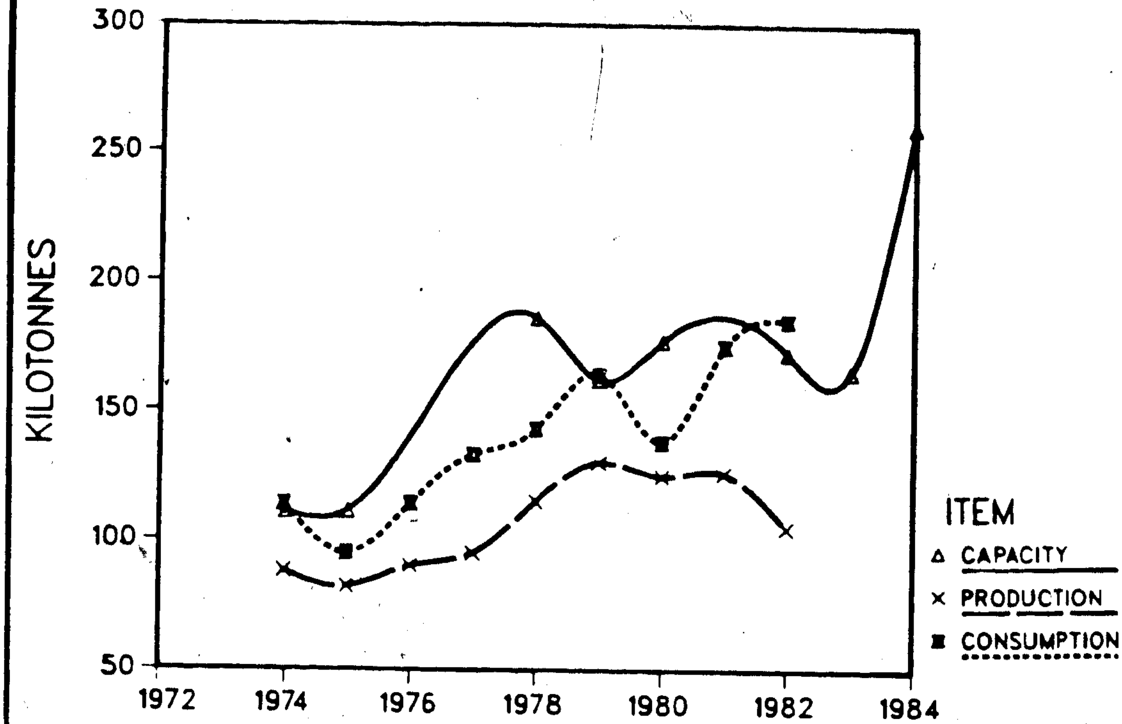
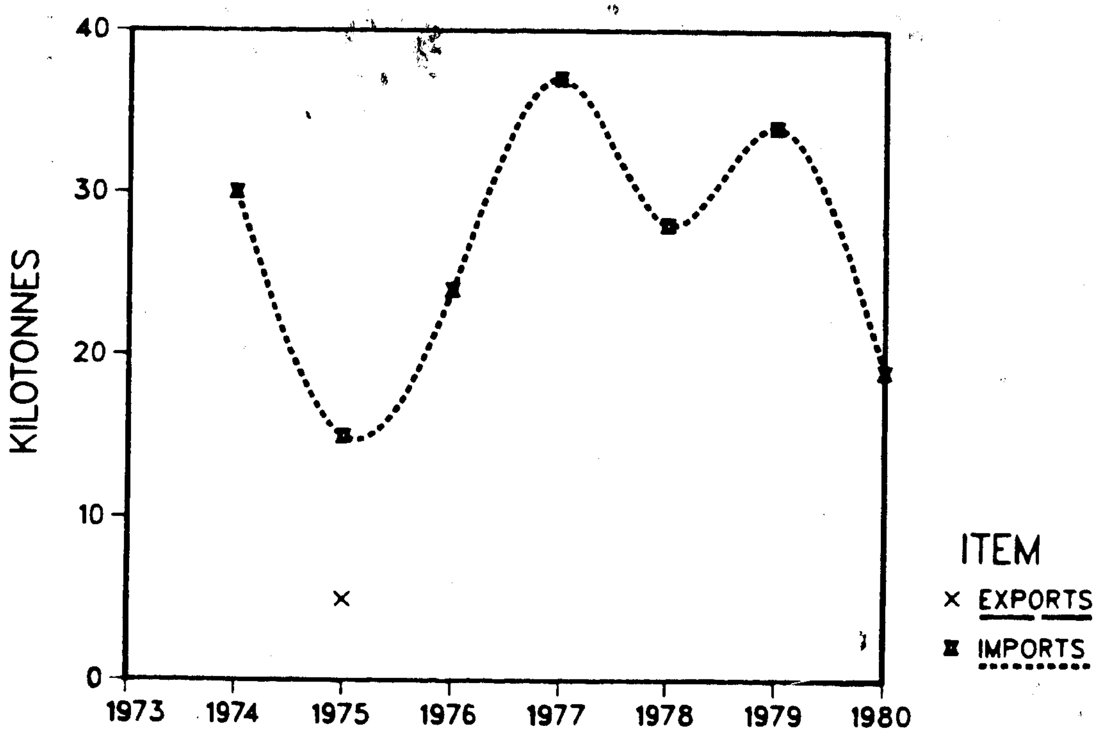


FIGURE 29. CANADIAN BUTADIENE IMPORTS AND EXPORTS



F. Aromatics

In 1941 benzene was extracted as a by-product of the Canadian steel industry's coke oven production and was used in the manufacture of styrene. This source was unable to satisfy the growing demand for this petrochemical and in 1957 the first petroleum-based benzene unit came onstream at Corunna, Ontario. By 1961, 80% of the Canadian benzene capacity was refinery-based. To remain viable the largest benzene unit had to depend upon export markets.

Benzene, toluene and xylenes (BTX) are used mainly as octane-enhancers in premium-grade gasoline. The major petrochemical use of benzene is in the manufacture of styrene (7). As shown in Figure 30, Ontario had around two-thirds of the Canadian benzene capacity until the Scotford, Alberta synthetic oil refinery came onstream in 1984.

As shown in Figure 31, the benzene capacity buildup resulted in over-capacity; benzene was exported throughout the 1960's (Figure 32). In the early 1970's there was another capacity surge in Eastern Canada. The new product was intended for the export market in which the benzene prices were very volatile.

In 1975, there was a proposal to build a world-scale benzene plant in Alberta, using a condensate feedstock. In 1977, another similar proposal was made. Neither proposal was successful.

Figure 30. Canadian Benzene Capacity

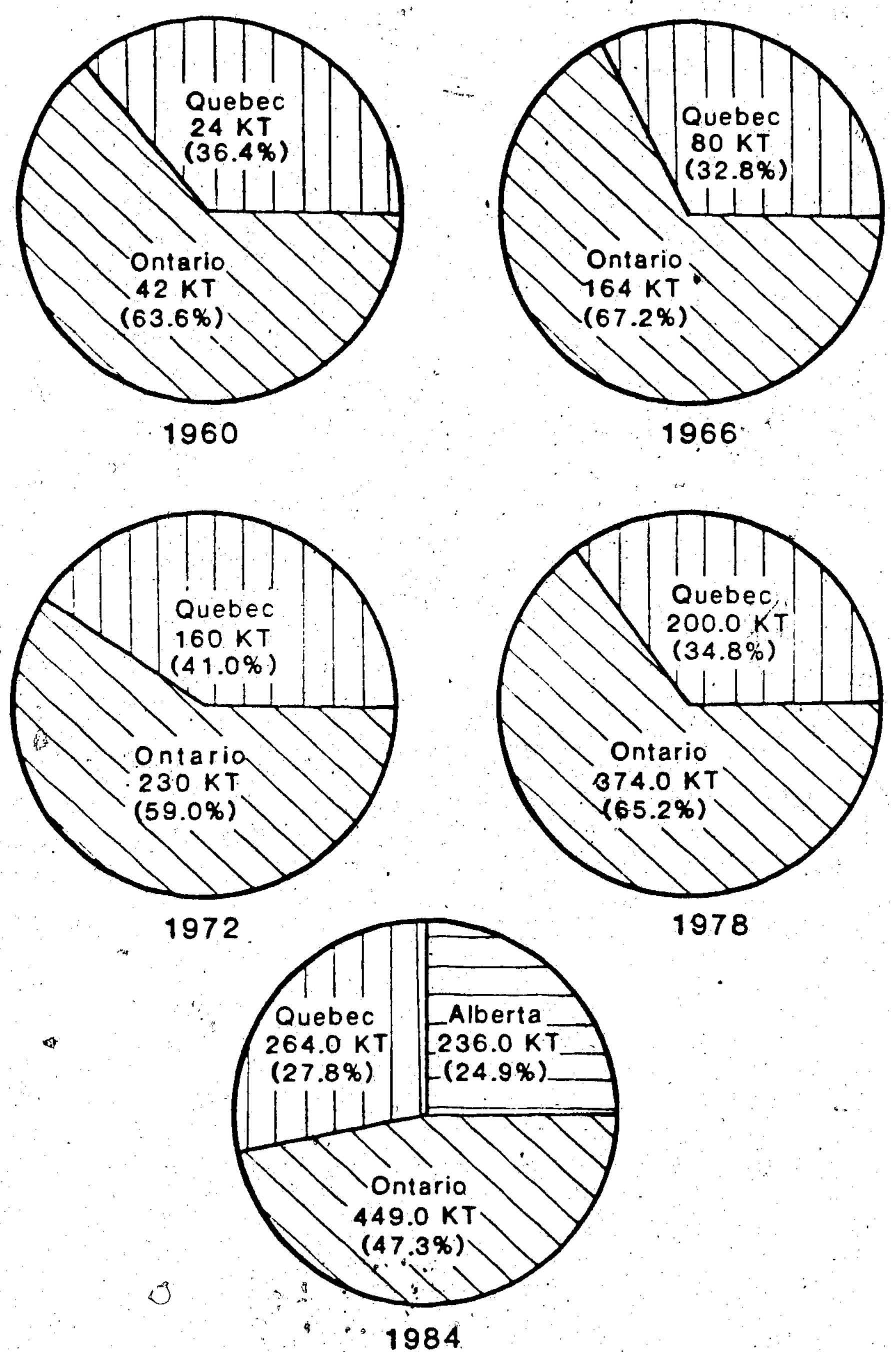


FIGURE 31. CANADIAN BENZENE STATISTICS

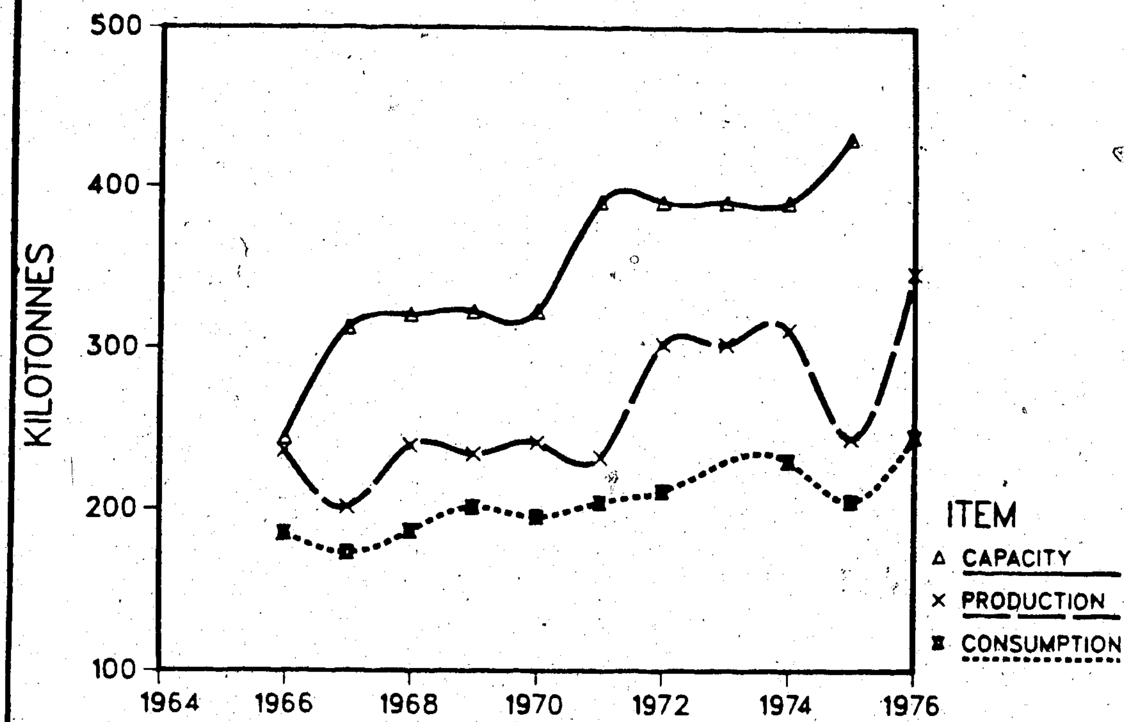
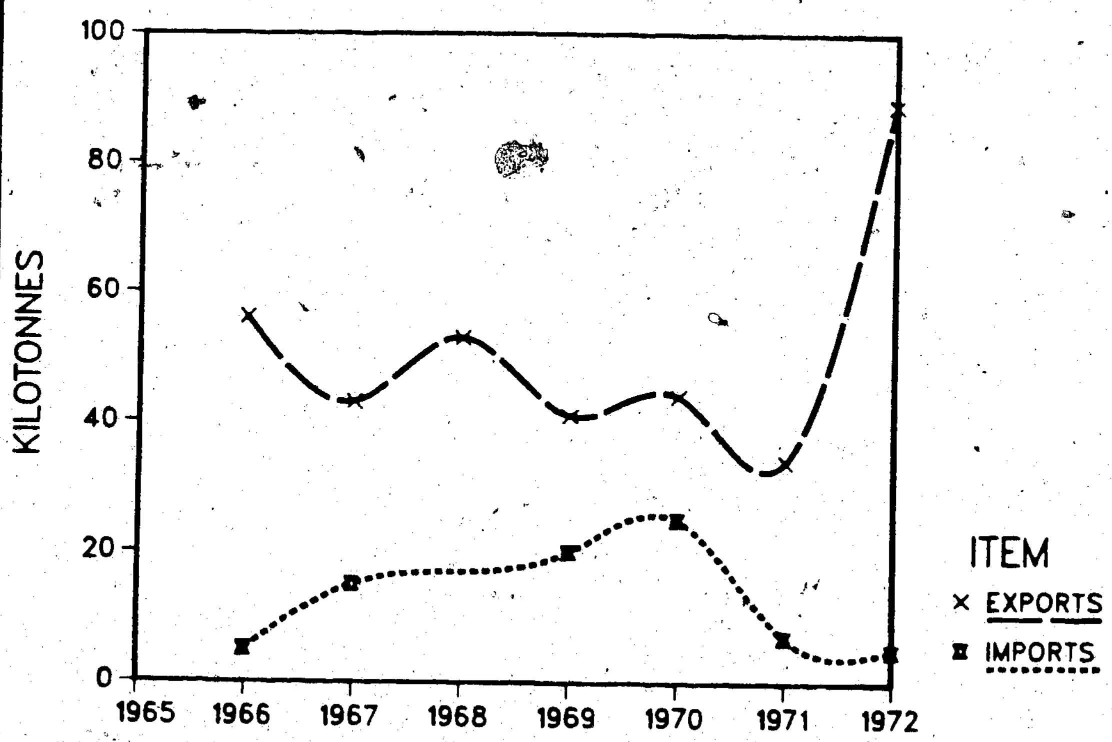


FIGURE 32. CANADIAN BENZENE IMPORTS AND EXPORTS



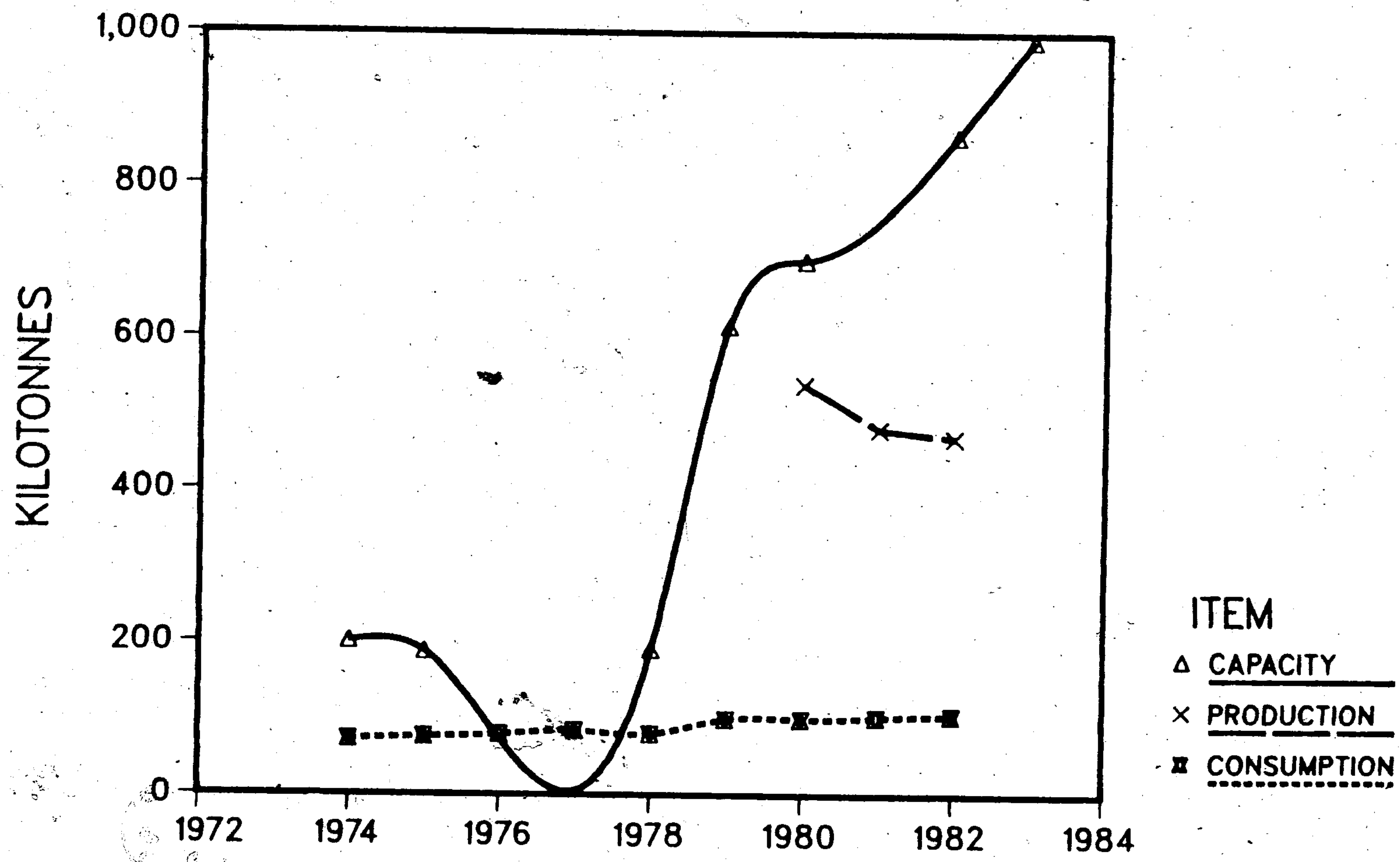
When Petrosar came onstream in 1977, it caused an increase in BTX capacity. In the late 1970's, because of plant expansions and new plants in Ontario and Quebec, the toluene capacity increased sharply (Figure 33). The BTX statistical data is incomplete; however during the 1970's, BTX export levels remained high. In the early 1980's, the aromatics market softened and prices declined; Canadian producers increased their exports while uneconomic, outmoded U.S. plants were shut down. In 1984, the Scotford, Alberta unit came onstream.

BTX, being refinery by-products are limited by domestic refinery capacity. Plans to use a condensate feedstock have not yet materialized. The development of these petrochemicals is dependent on the markets for premium-grade gasoline and for styrene.

This completes the historical survey of individual petrochemicals. This survey has served two purposes; it has identified the key issues in the development of the Canadian petrochemical industry and it has presented capacity, production, consumption, import and export statistics of the major petrochemicals. The latter was used in the development of a consistent data base for the model, whereas the former was used in the development of reasonable scenarios.

Next, the mathematical modelling process is examined.

FIGURE 33. CANADIAN TOLUENE STATISTICS



CHAPTER III. THE MATHEMATICAL MODELLING PROCESS

Modelling conceptualizes a system within a specified environment. It encodes causal relationships which ultimately determine the degree and techniques of system controllability. Therefore, it should be an important tool of the policy-maker. However, it is not well understood by policy-makers and is not often used in the process of decision-making.

In order to be effective the policy-maker must be perceived to have made the 'correct' decision. The traditional approach is to seek justification in precedents. During periods of rapid societal structural change precedents may be lacking or inadequate. In order to understand the possible implications of such change, a mathematical model is useful. Mathematical models may be predictive or prescriptive.

Predictive modelling involves making forecasts based on empirical relationships. The simplest models involve the mechanical extrapolation of historical data pertaining to the variable under consideration. Such models may be categorized as naive, moving average or mathematical trend models. In a naive model, projections are made on the basis of an assumed growth rate; the growth rate may be positive, zero or negative. Moving average models have a series of averages that approximate the trend of a series of data by cancelling out the high and low values. Mathematical trend models use mathematical relationships to represent or fit the data to be projected. More sophisticated models use econometric techniques. In such models forecasts are made on the basis of information obtained from other variables [illegible] than on the history of the

Predictive models are useful but have the following drawbacks:

1. There are no material, energy or monetary balances. For example, the projected slate of products may violate technical reality.

2. The models are myopic, i.e. decisions are made entirely on current conditions.

3. There is no choice between alternatives, since individual processes are not modelled.

4. There is no feedback mechanism. For example, the independent variable (price) may result in the dependent variable (demand) projections which are so high that product scarcity would in reality cause higher prices; but the model would not recognize this possibility.

Predictive models may be used for petrochemical demand modelling. Either mechanical extrapolation or econometric techniques may be used. In the latter case, the exogeneous or 'input' variables may include petrochemical prices, the population and the gross national product. Since the long-term price elasticity of petrochemical demand has not been investigated, the model would be appropriate only for short-term forecasts. For long-term forecasts, extrapolation techniques would be easier, quicker and as good as econometric techniques.

Prescriptive modelling involves optimizing a system. For example, a model may minimize the cost involved in meeting a projected demand. The societal costs that may be minimized include the costs of capital, operations, raw materials, energy, transportation, environmental pollutants and unemployment. Alternatively, the societal benefits which may be maximized include profits, personal consumption, leisure and employment. Such an optimization may be accomplished by using process economics and mathematical programming techniques. Such models would be useful in petrochemical supply modelling.

Prescriptive models may involve either generalized or partial equilibrium. Generalized equilibrium modelling involves a two-way linkage between a sector and the rest of the economy. A two-way linkage implies that the sector under investigation simultaneously affects and is affected by the remaining sectors of the economy: For example, the Canadian energy sector depends on and contributes to the Canadian economy. Such models have the capability of examining how government policy decisions with respect to one sector will affect overall economic performance (117). Furthermore, the modelling is elegant but is currently applicable to only relatively small models; otherwise a model run may be too expensive.

Partial equilibrium modelling involves a one-way linkage between energy and the rest of the economy. Linear programming models are usually partial equilibrium models.

Mathematical programming models have material and energy balances. They permit choices between alternative processes. They have feedback mechanisms and have clairvoyance. In a clairvoyant model, decisions at a given point in time are made with full knowledge of all future conditions; therefore, timely corrective action prevents future crises. Thus, they provide a consistent framework within which to analyze long-term issues.

Mathematical programming models may be categorized as either non-linear or linear. Since in real life non-linearities are common, the former type of models would be preferable except that their solution techniques are relatively inefficient compared to linear programming techniques. Thus, for any moderate or large sized model linear programming is generally used, in which case the non-linearities are approximated by piece-wise linear relationships. Linear programming has the further advantage that commercial pre-processing, solution and report writing computer packages are available.

Most commercially available linear programming packages use a revised-simplex routine, wherein matrix multiplication is necessary at every iteration. This restricts the size of a linear program that can be economically solved. Efficient solution algorithms that take advantage of the special structure in the constraint matrix have been developed (42). The fastest known constrained optimization routines are pure transportation problems, for which it is relatively easy to find an initial basic feasible solution and due to their property of basis pure transportation problem. Therefore, 'capacitated trans shipment' or 'network flow' problems have been formulated for which there are several efficient algorithms, including primal-simplex, out-of-kilter, primal-dual, dual, path and negative-cycle. Such routines are almost as efficient as pure transportation routines. Network flow algorithms can be 'generalized' in order to handle constraints that do not fit the network structure. Such generalized network problems can be solved by combining network flow algorithms with various decomposition schemes (49). One such solution package is commercially available (48).

For this analysis, commercially available linear programming packages, using the standard-revised-simplex routine, were used. They were the Haverly Systems pre-processor MAGEN and the IBM solution algorithm called MPSX.

Having selected a solution technique the next step is to look at the desirable features of linear programming models.

CHAPTER IV. A LITERATURE SURVEY OF PETROCHEMICAL AND ENERGY MODELS

There are several excellent surveys of linear programming energy models (69,98,112). A linear programming energy model has three basic features:

1. Limited resources and competing conversion schemes: It is a resource allocation model, which implies choices among limited resources. Primary energy exists in several non-renewable and renewable forms. Non-renewable energy reserves have to be found, delineated and extracted. Renewable energy has to be harnessed. Primary energy has to be converted to usable energy and petrochemical forms. There are several conversion steps. At every step there are competing processes. The starting point and the level of detail varies from model to model.

2. Transportation schemes: At every conversion step the feedstocks and products must be stored and transported. Transportation may occur by pipeline, road transport, railway, waterways or transmission lines. Such schemes may be explicit or implicit. In the latter case, transportation costs may be included in the conversion costs, eliminating the necessity of any spatial features.

3. Temporal features: Every model has a planning horizon, comprising of one or more time periods. A linear program provides the gross picture within a time frame. For example, if a time period is ten years, the model results may show that within the 10-year span, five petrochemical plants will come onstream; the precise years in which they come onstream is not known. However, if the 10-year period is replaced by ten 1-year periods, then the precise timing of the new plants will be known. Furthermore, multi-period models permit greater precision with respect to production, deliverability and demand constraints. Of course, the greater the number of time periods the larger the model and the more expensive it is to obtain results. This imposes a limit on the number of time periods, which may be extended if special-purpose decomposition routines (49) are used.

Within a particular time period, the types of constraints in a model include the following:

1. Supply: The supplies of competing resources are limited. Without such constraints only the cheapest resource would be produced. In cost minimization models the total supply must equal or exceed the demand; in profit-maximization models demand is met only if supply is available and it is profitable to do so.

2. Demands: An exogeneous schedule of demands provides the driving force for the model. In minimization models, the demands are met at lowest cost; in maximization models the maximum demand at a specified price is available to the suppliers. Therefore, price-elastic demand can be explicitly modelled.

3. Capacity: Production and transportation capacities often limit resource availability. Initial capacities and capacity retirement schedules are exogeneous. A key model output is the timing of the capacity additions, required to satisfy demand.

4. Production schedules: Extraction and conversion processes have production schedules. If a production schedule is not imposed by the modeller on a resource, then it might be depleted faster than is technically feasible.

5. Material and energy balances: Such constraints ensure that for conversion and transportation processes technical feasibility is maintained.

6. Product quality and product inventory: Product quality specifications may be included. For example, gasoline may be required to meet an octane rating standard. If an excess of any product is available, it may be stored in the form of a product inventory for a subsequent time period.

7. Capital constraints: Capital may be disaggregated into different cost categories to reflect risk factors. Limits on the availability of capital may be imposed.

8. Labour constraints: Labour may be disaggregated into different skill categories. Limits on its availability may be imposed. For example, there may be a limit on the number of carpenters and machinists available in a particular time period.

9. Environmental constraints: Certain models restrict the emission of sulphur dioxide and other pollutants into the environment.

10. Political constraints: Such constraints include limits on import and export levels and constraints imposed to ensure that domestic reserves are given priority in development.

The problems related to developing a linear programming model are either structural or data-related. The major structural problem is that choices are made on an "all-or-nothing" basis. Thus, if several competing technologies produce a common product and if one technology holds even a slight economic advantage over the others, then the model will choose that technology, to the exclusion of all others. In reality, if a number of producers have fairly close production costs, then they will co-exist provided they can all make a reasonable return on investment.

The problem can be resolved in two ways. One, by imposing upper limits on all the competing technologies, the modeller leaves "room" for a new technology, providing it can generate the stipulated yield on investment. Two, piece-wise cost curves are used for the technologies.

Other structural problems relate to the aggregation of demand and supply data, non-linearities in the system and end-effects. In order to maintain a reasonable model size the modeller must aggregate the data. Thus the identification of actual conversion plants has to be done off-model. Non-linearities are approximated by stepwise linear relationships; again, the number of steps is limited by the necessity of maintaining a reasonable model size. Finally, in a linear programming model, the end-effects may result in unrealistic capital flows and capacity-additions in the final time period. Such end-effects may be minimized in two ways. One, the planning horizon may be extended beyond the time span under consideration and the number of time periods may be increased. Two, capital costs may be annualized.

There are three critical data areas which will be discussed in turn. Energy supply models are driven by exogeneously specified demand and price trajectories for energy and petrochemical products. This is the first critical data area. Perceptions about energy price and demand trajectories have changed markedly in the last decade. After constant scrutiny, the energy price-demand relationships are only now being understood. Clearly, world oil prices have the most significant impact, since the prices of many other energy forms and petrochemicals are tied to it, some through administered regulations, others through the market mechanism. The modeller must ensure that the price and demand trajectories of a particular petrochemical or energy form are consistent with each other and with other petrochemical and energy forms. This is particularly difficult for petrochemicals, since their price-demand relationships are not accurately known.

The second critical data area involves estimating the reserves and extraction costs of the primary fuels, crude oil and natural gas. The exploration and development function in the oil and gas industry is analagous to plant capital expenditures in manufacturing where these pre-production expenses are amortized over the production in subsequent years. The actual cost of a unit of production is a sum of the capital charges and operating costs. Reserves and extraction cost estimates are usually based on the prevailing consensus rather than on any mechanistic formulae (138).

The third critical data area lies in estimating the process economics of the relevant energy conversion technologies and petrochemical plants. Reasonably good estimates of the technical and economic parameters of established technologies are available. With developing technologies the modeller must reconcile projections which are highly uncertain.

Having identified the nature of a linear programming energy and petrochemical model and the problems associated with developing such a model, let us examine how the problems were tackled in actual modelling exercises. The objective of this survey is to identify the innovations introduced by various modellers.

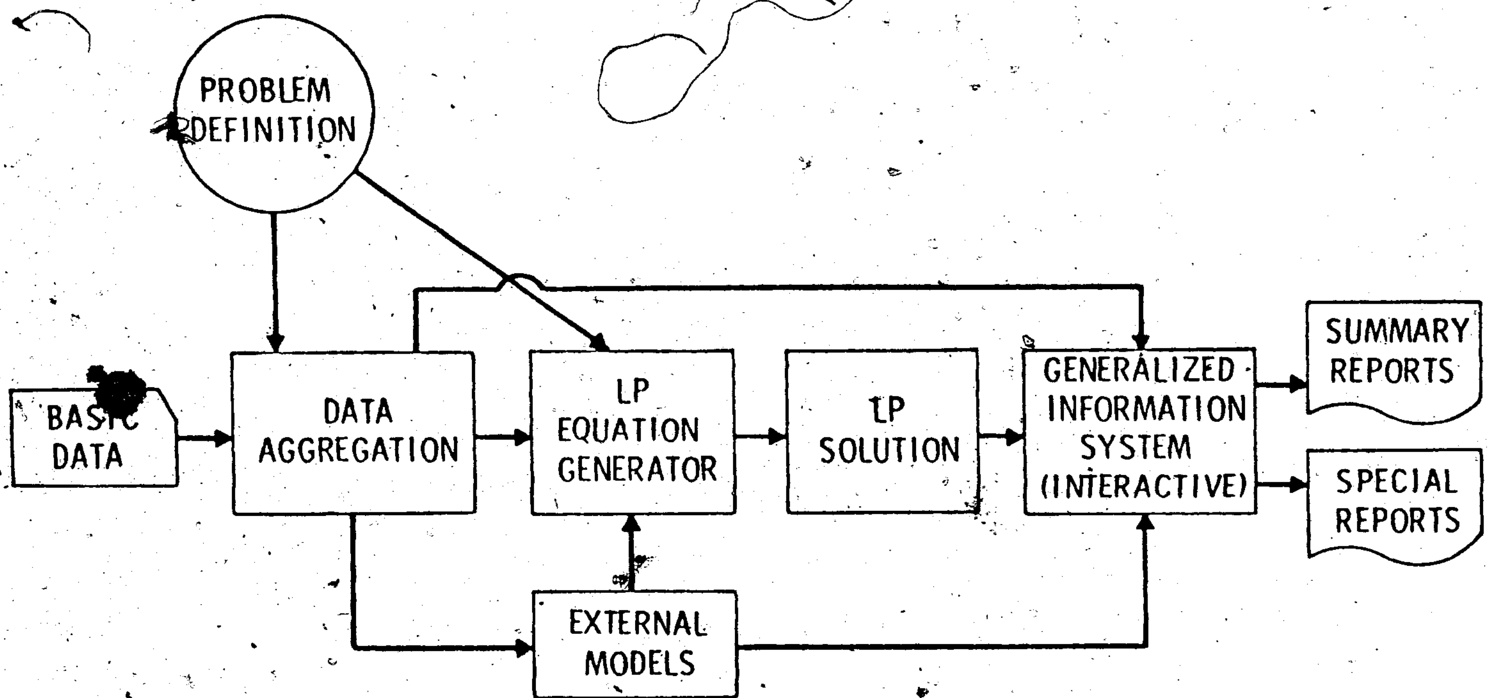
In 1947, Dantzig (42) developed the first efficient solution algorithm for linear programs. One of its earliest applications was in the scheduling of petroleum refineries (134). In 1958, Manne (95,96) applied linear programming to the United States petroleum refining sector. It was a single period model with no spatial features. It reduced the whole refining sector to a representative refinery. It was intended to simulate the United States market conditions in 1953. It modelled 25 types of crude oil and 9 products in the aggregate refinery. At specified levels of jet fuel, it maximized the non-jet fuel product mix. At 105 constraints and 205 variables, it was as large a model that computers could reasonably handle at that time.

In 1963, Marschak (99) introduced a regional element to the above model. His model had four regions and a relatively detailed transportation sector. Introduction of detail in one area usually meant aggregation in another area. In order to retain a reasonable model size, he reduced the crude oil types from 25 to 3 and the number of refinery products from 9 to 6. In spite of the aggregation, the model had 195 constraints and 1332 variables.

Manne's and Marschak's models were the precursors of the so-called 'energy models' that were developed in the early 1970's.

In 1968, Deonigi and Engel (50) developed a large scale multi-period linear programming model (Figure 34) which determined the optimum future electrical generation supply in the United States. There were thirty-five 2-year intervals. A pre-processor was used to generate the 4000

FIGURE 34. DEONIGI & ENGEL: ENERGY MODEL



constraint, 9000 variable model. In a particular time period the variables represented various types of power plants. A power plant was identified by the plant design, fueling scheme and an exogeneous lifetime load history. The constraints included material balances, technological introduction rates, fuel price step functions, committed plant construction and fuel processing capacities. It handled end-effect problems by providing special termination formulae to avoid overstating costs and understating benefits in the final time period. It was probably as sophisticated a model as any built since.

Deonigi and Engel also investigated the use of the shadow price generated by the linear program as the value of a particular energy form to the system being modelled. They concluded that "year-to-year variations for a given shadow price had very little explanatory power" (50). The use of reduced costs for a variable as the reduction in its cost coefficient required to make it eligible for entry into the optimal primal solution, was also discussed.

In 1969, Debanne developed the first model for North American oil supply and distribution (47). Its objective was to assess the economic impact of the Arctic oil fields on the North American oil industry. Key modelling innovations were the representation of the oil supply and distribution system as an interconnected network and the use of a unique network flow algorithm to minimize the oil transportation costs. The unit transportation costs depended on the oil throughputs. Debanne devised an iterative procedure, wherein the unit costs were altered according to the throughputs occurring after every iteration. It was one of the first models to use an iterative technique. The network had 30 supply centres and 30 demand centres. It was subsequently extended to encompass total energy supply-distribution systems (49). Debanne devised a solution algorithm called 'MULTINET 0/1' to handle multi-period, multi-commodity, production/distribution and plant location/allocation/expansion optimization.

In 1972, Waverman (137) modelled N[illegible]can natural gas flows. In order to use a [illegible]sportation linear programming code, he devised a synthesized nat[illegible] production-transportation unit cost. He assumed that the produc[illegible]osts were linear and constant functions of output and he based these costs on a unit area rate. The transportation costs were based on distance and terrain factors. The model minimized the total costs of producing and shipping natural gas from 19 supply points to 19 demand points. In spite of the lack of process details and pipeline capacity constraints, the model was simple and elegant. Its policy-function was explicitly stated. His model results showed that Canada was paying an annual penalty, due to the East-West nature of its existing natural gas pipeline network, rather than the market-directed North-South network.

In 1972, Hoffman (84) developed an integrated energy model of the United States. It was one of the earliest integrated energy linear programming models. Its function was to serve as a planning framework for technological, environmental and resource conservation strategies. With 13 supply and 15 demand categories, the model had a transportation-type framework, with a set of 'extra-transportation' constraints. The latter included environmental, solar energy, pumped storage and off-peak electric power constraints, which could not be assimilated into the transportation framework. The solution algorithm was a standard revised-simplex routine. Hoffman's Ph.D. dissertation was based on a single-period, 30-year model which minimized energy costs of the United States. There were 58 constraints and 165 variables. In spite of its high level of aggregation, it had a significant amount of process detail.

Hoffman's model formed the basis of the Reference Energy System methodology developed at the Brookhaven National Laboratory. It was 'a network representation of all the technical activities required to supply various forms of energy to end-use activities'.(b). The activities included primary energy extraction, refinement, conversion, transportation, distribution and utilization. The systems were developed for the years 1980, 1985, 1990, 2000 and 2020. Using the Brookhaven Energy System Optimization Model (BESOM) they were used in an assessment to evaluate new technologies.

In 1972, Adams and Griffin (1) developed an economic-linear programming model of the United States petroleum refining industry. This model served as a precursor of the energy-economy models which were developed shortly thereafter. In this model, the refinery product demands were generated by using an econometric sub-model. Then, a linear program with 227 constraints and 334 variables was used to minimize the costs for crude oil, natural gas liquids, royalty and catalysts. The linear programming model was not described in detail but was "a modification of a typical Gulf Coast 200,000 barrel per day (B/D) refinery LP model by Bonner & Moore Associates". The latter was a commercially available refinery linear programming model.

Adams and Griffin (1) stated that the product prices used in their model were determined econometrically, although it would have been possible to use the shadow prices generated by the linear program. They stated "while the shadow prices measure product opportunity costs, their use to explain actual prices proved to be not as effective as the somewhat less rigorous formulation which was used".

In 1972, Chilton and Jimeson (29) developed an energy-environmental model for the United States, which minimized the national energy distribution costs, based on a sulphur dioxide emissions reduction proposal. The linear programming details were not given. However, since it was regionalized into 244 Air Quality regions, the size of the linear program must have been substantial. The Dantzig-Wolfe decomposition routine was used to solve the linear program. Their experiences with this routine were not reported.

In 1973, the Energy Research Unit at Queen Mary College, London, developed a 3550 constraint, 13500 variable world energy model (65). It minimized the resource costs used in satisfying a given demand for crude oil. The costs considered were the avoidable costs, i.e. "cash costs which would vary if the allocation of refinery equipment and labour were changed". There were 52 types of crude oil, 25 refining centres and 25 markets. The model used detailed refinery and transportation constraints. The modellers stated that the large model size was compatible with their objective of being "realistic".

Their model results included details of refinery plant construction, tankship construction and operation, capital expenditures and equilibrium prices. The short-term equilibrium prices were the "marginal values from the LP solution". Exclusive of capital costs, these prices were in equilibrium with demand in a given quarter or year. The equilibrium crude oil prices ranged from $1.85 to $3.13 per barrel.

Another world oil model was developed in 1974 by Kennedy (88). The six-region, five-product, single-period, 10-year model was based on a linear programming representation of crude oil refining technology supplied by Bonner & Moore Associates. The four sectors of the model were crude oil production, transportation, refining and products consumption. The reported model size was 57 constraints and 173 variables. It minimized the long-run cost of capital-equipment and crude oil.

In order to endogenize the crude prices and product demands, the linear program was coupled with a set of demand and supply equations. The model output included levels of consumption, production and price for each commodity in each region. The modeller considered the crude oil price increases in 1973 and based on his model runs, stated unequivocally that during the 1970-1980 period under consideration, "current price levels are unlikely to be maintained in constant dollars". He added, "the results presented here indicate that either investment plans or political concessions made on the basis of an expectation of seven dollar oil or the fear of twelve dollar oil would likely be regretted in the long run".

This exemplifies the hazard of making categorical predictions based on linear programming models. It also exemplifies the dilemma faced by a modeller: should he present his results categorically and risk being proven incorrect or should he cover his bets with a causal approach and risk not being understood? The solution is to treat his results as a 'scenario' rather than a forecast.

In 1974, Cazalet (20) developed a general equilibrium model called the SRI-Gulf model. It was highly aggregated but covered all major energy forms, conversion processes and transportation modes and it explicitly modelled supply elasticity, interfuel competition and end use demands. It had 8 demand regions and 30 supply regions. There were 17 time periods in a planning horizon of 52 years. It used an iterative algorithm which generated tentative price and demand estimates in a way that converged to an equilibrium solution of the model. Between 30 and 60 iterations were required.

In 1974, Finon (68) developed a linear program for the French energy sector, which minimized the discounted capital and operating costs. The model had a planning horizon of 25 years, with time periods of 5,5,5 and

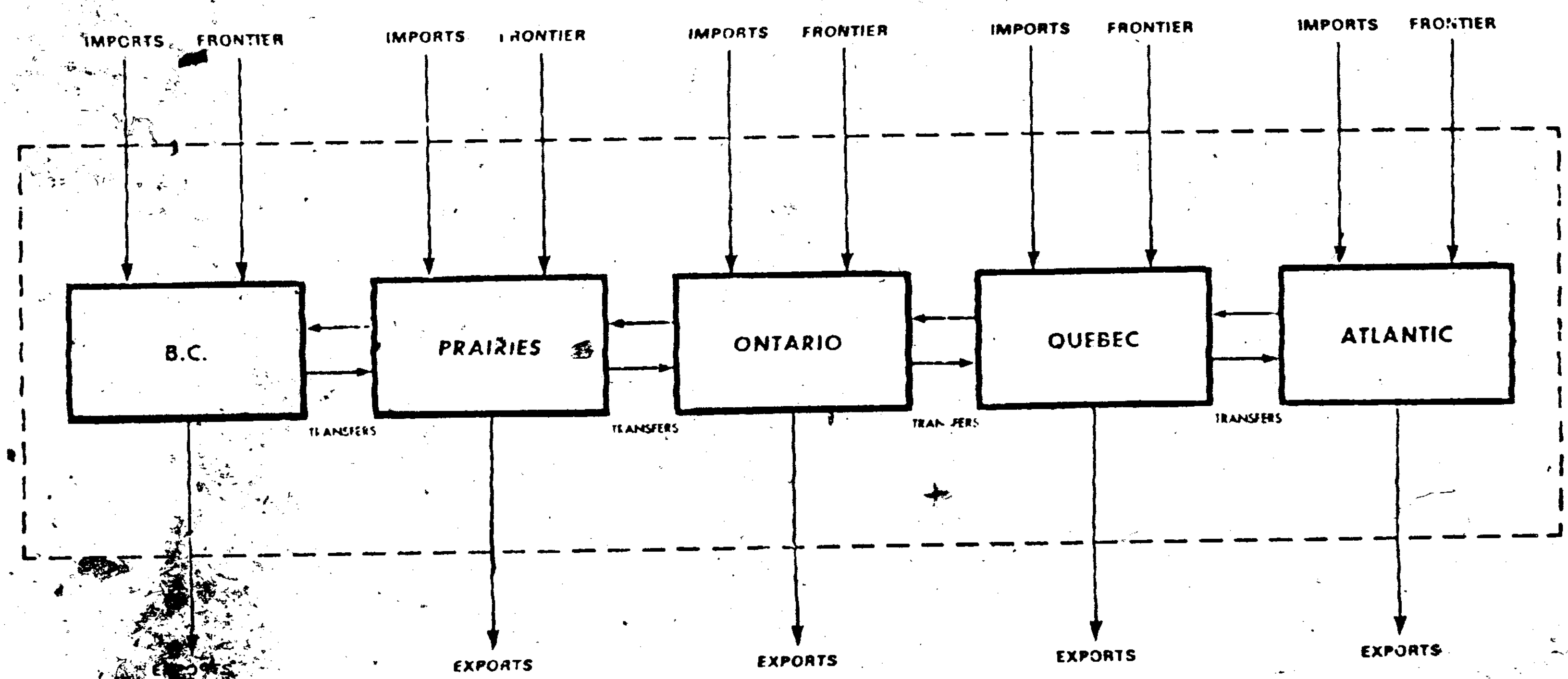
10 years. Finon eliminated the final period end-effects problem by adding a time period of 20 years, thereby increasing the total time-span covered by the model to 45 years, although the planning horizon remained unchanged.

Starting in 1976, Dantzig (43,44,108) directed a group in the Systems Optimization Laboratory at Stanford University, which developed a 40-year, 8-time period model called PILOT. It maximized the discounted per capita bill-of-goods. It had 800 constraints and 1800 variables, and was one of the first large scale energy-economic models based exclusively on linear programming. In PILOT, energy demand was endogeneously determined based on an income effect [illegible]rade-off between work and leisure time. End-effects were [illegible]d by using post-horizon constraints.

In 1976, Matthews (100) developed a long-range Canadian energy supply model, which minimized the total costs of satisfying a set of exogeneous energy demands. Its explicit policy-making function was to serve as a "long-range strategic planning tool". It consisted of 400 constraints and 550 variables.

Matthews' model consisted of five regions, linked by energy transfer movements. Within a region, energy sectoral modelling was used (Figure 35). Modelling experience and model results were not presented.

FIGURE 35. MATHEW'S CANADIAN ENERGY MODEL



From 1976 onwards, a number of Western Canadian energy models were developed. In Edmonton, Feick and McConaghy developed an energy resource allocation model called AERAM. Originally, it was a one-period, one-region model with 112 constraints and 189 variables. It minimized the capital and operating costs of satisfying a set of exogeneous energy demands (Figure 36). A number of aggregate refineries for different crude types were modelled.

Later, (114) the following extensions were made:

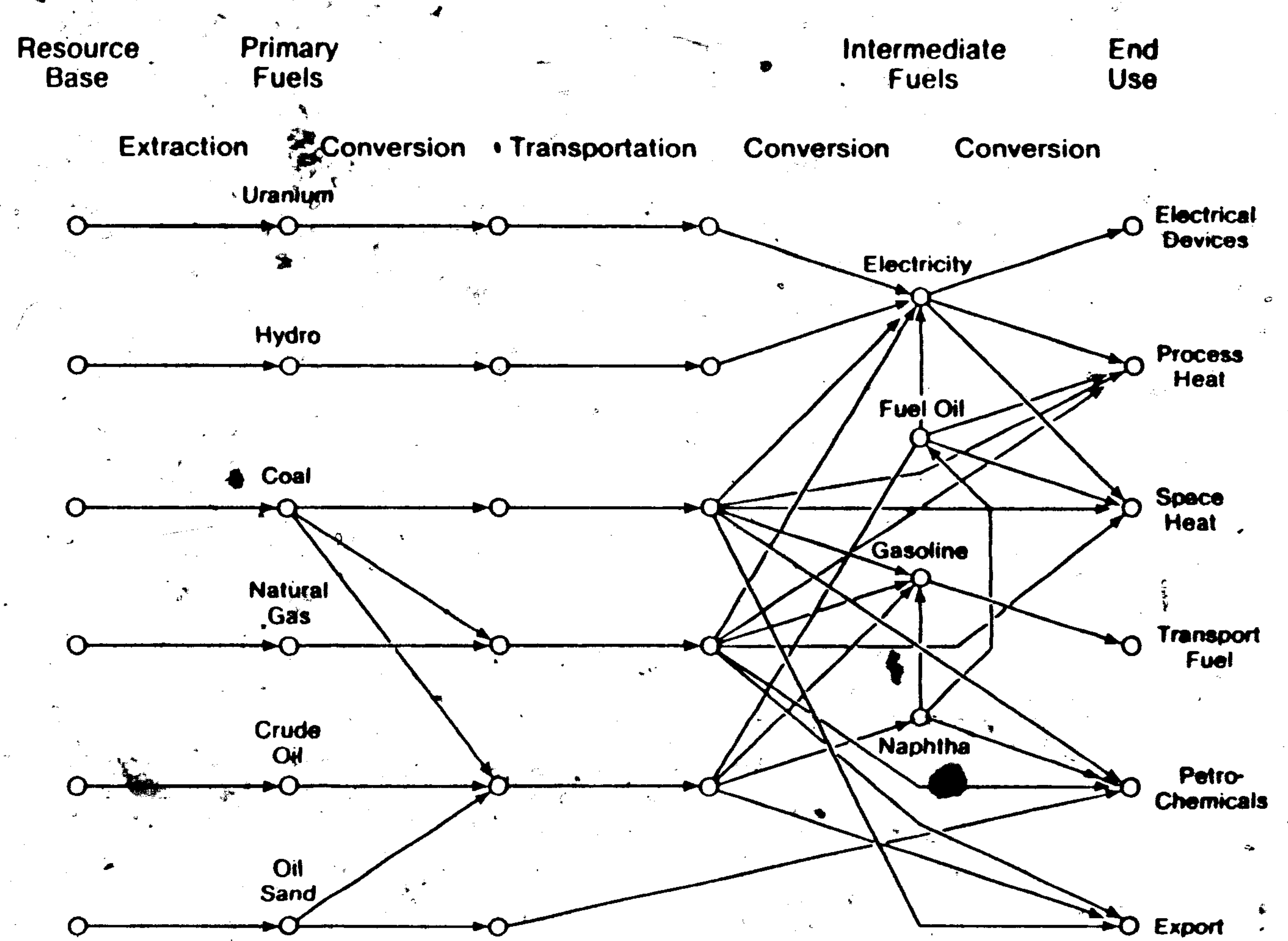
1. Specific labour constraints were introduced, e.g. constraints on the number of pipefitters and electricians. Model results showed that such constraints were not tight, due to the capital intensive nature of the energy projects. Subsequently, off-model calculations were made to project specific labour demands.

2. Environmental constraints, relating to societal costs of farmland and water were introduced. Model results indicated that there was no shortage of land or water for energy projects in Alberta.

3. Based on quality and cost considerations, coal was segregated into a number of categories.

4. Nuclear, solar and wind power resources were added. Model results indicated that in Alberta these energy forms were insignificant with respect to established energy forms.

FIGURE 36. ALBERTA RESEARCH COUNCIL'S AERAM MODEL



5. In order to determine the timing of energy projects in Alberta, the model was made multi-period and clairvoyant.

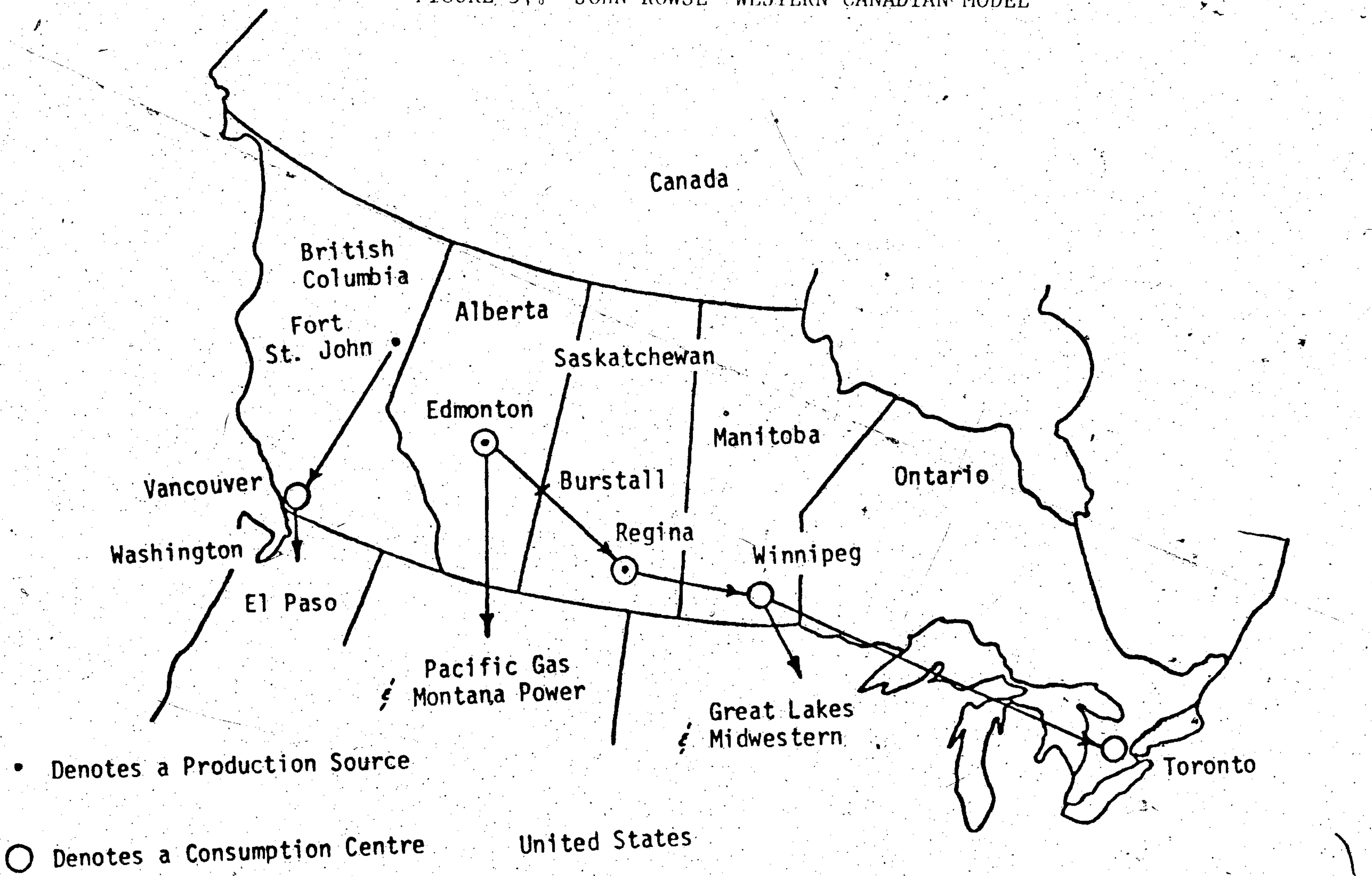
6. To study specific energy policy issues, the model was regionalized.

The four-time period model underwent several transformations. After reaching a maximum size of 4000 constraints and 10000 variables, the model was re-written in the MAGEN software language and its size was reduced. The ~~1982~~ version of the model is described in the next chapter.

Using AERAM as a starting point, Daniel and Goldberg (40,41) developed an Alberta energy planning model called BALANCE. It incorporated a dynamic version of Hogan's 'Project Independence' equilibrium-seeking mechanism (66) and was used to establish energy equilibrium prices. It also incorporated an end-effects eliminating procedure suggested by Grinold (72).

In 1979, Rowse developed a single-period energy supply model for Western Canada (Figure 37). Its explicit objective was to "maximize net value added in energy industries subject to ceilings on demands instead of minimizing costs of energy provision subject to floors on demands" (120). The model set up a number of primary energy networks and included production, transport, marketing and labour variables. The model was intended to form "the core of a dynamic national energy model and analyze regional and temporal adjustments to wealth accrual, natural

FIGURE 37. JOHN ROWSE' WESTERN CANADIAN MODEL



resource rents, production, labour requirements and economic growth potential associated with different energy resource development scenarios" (120).

Using a linear process model of energy supply, conversion and distribution linked to a demand model for energy and other services, Fuller (70) constructed a dynamic, long-term model of the Canadian energy sector. Non-linear programming was used to find the supply-demand equilibrium by maximizing the discounted sum of consumers' plus producers' surplus over all periods. There were two regions and six time periods. It was intended to analyze issues of energy pricing, the timing of the introduction of new technologies, the impacts of such technologies and of various policy constraints.

Within specified feedstock supply and process capacity constraints, Rudd's model (121) minimized the total production costs to the U.S. petrochemical industry. The production costs comprised of feedstock costs, costs of other raw materials, utilities, labour and capital. Any surplus production of petrochemicals was penalized by being assigned a heating value instead of a chemical value. There were 182 processes involved in the transformation of 131 chemical intermediates and feedstocks. It was an excellent integrated model of the U.S. petrochemical industry, but not quite as well integrated with the energy industry and its focus was to assess process technologies and not to assess the long-term prospects of the industry.

It is not the intention to judge the relative merits of the models just surveyed but to show that the problems associated with the planning of large scale energy projects have no simple solutions. However, linear programming presents a consistent framework for such decision-making. The usefulness of a modelling effort is limited due to two major problems:

1. <u>Data Aggregation:</u> There is a trade-off between model size and aggregation level. The smaller the constraints matrix, the higher is the aggregation level required. The level of aggregation selected depends on the objectives of the model, e.g. in order to study a specific energy industry, it must be modelled in detail, whereas within the same model the other energy and non-energy sectors may be highly aggregated. This is done to ensure that the model size remains reasonable.

   The fundamental problem is whether the model results from a small, highly aggregated linear programming model are equivalent to the results from a large scale, disaggregated linear programming model. The models surveyed here have ranged from a small transportation model to very large linear programs. Obviously, the causal relationships in the latter models are much more explicit and detailed but is this level of explicitness and detail essential to the decision-making process?

2. **Prices and Costs:** Price projections and the costing of esoteric, newer technologies forms are other problems faced by the modeller. The modellers agree that equilibrium prices consistently underestimate the actual prices. Furthermore, model results are entirely dependent on the unit costs selected, e.g. it is possible to eliminate the production of a specific petrochemical by pricing it too high. Finally, in his attempts to get 'reasonable' results, the modeller may select a set of price projections and costs consistent with his perception of an energy future.

Therefore, the objective of linear programming supply models is not to make forecasts of industrial development but to gain insights into how such development occurs and the factors that play a role. Hence, the novelty of this thesis is not in the model development but in the insights gained from running the model. In the next chapter, the model is described.

CHAPTER V. MODEL DESCRIPTION

In 1976, AERAM was conceived at the Alberta Research Council. It was a techno-economic representation of the provincial energy sector, linking primary resources to exogeneous levels of energy demand. By the development of various plausible energy supply scenarios, its purpose was to assist in formulating the long range energy-oriented research activities at the Council (113). Its potential as a tool for policy analysis attracted policy groups in the provincial government. Its further development was partially financed by Alberta Energy and Natural Resources and later on, by the Energy Resources Conservation Board. Technically, AERAM evolved into a normative, regional, inter-temporal, demand-driven, deterministic energy supply model, with clairvoyant features.

Its explicit objective was to provide answers to the following question (101):

"What is the optimum allocation of Alberta's energy resources, over some planning period, which would satisfy future national and provincial energy demands which would be reasonably expected of them, subject to pertinent physical and external constraints?"

In 1978, the model identified the preferred options to be: (a) increased natural gas exports, and, (b) accelerated oil sands development. Another significant conclusion was that non-energy factors such as land, water, construction manpower and social infrastructure would not be limiting and would not alter the schedule of energy projects. Regarding petrochemicals, it concluded that coal would become the principal feedstock for new methanol and ammonia plants (113).

A subsequent analysis (115) showed that the export market could outbid the petrochemical industry for natural gas. It recommended that "the government mandate the use of coal as a feedstock for future methanol and ammonia production and that the natural gas so conserved be made available for export. A portion of the incremental gas export revenues would be used to compensate the petrochemical producers for switching to coal-based processes."

In the summer of 1980, the model was translated from IBM's Mathematical Programming System (MPSX) language to the Haverly System's software preprocessor called MAGEN (73).

MAGEN has the following features:

1. Unlike many other input systems such as the unaugmented MPSX system, the MAGEN matrix generator program need not, and should not, contain any input data. Instead, these data can all be included in a 'DATA' section in the form of 'TABLES'. As a consequence, the user can run a number of scenarios merely by altering 'TABLE' entries, without having to alter the program.

2. The MAGEN matrix generator programming system uses a high-level user-oriented computer language, which makes extensive use of the concept of 'CLASSES'. Many of the activities or variables in an energy model can be aggregated into natural groups which are called 'CLASSES'. The MAGEN system uses 'CLASSES' for essentially the same purposes that a language like FORTRAN uses loops, but without the necessity of keeping track of all the indices. In an energy model logical 'CLASSES' might include:

i. Primary energy forms - coal, gas, oil, uranium.

ii. Secondary energy forms or services - electricity, refinery products (gasoline, diesel, fuel oil), petrochemical products (ammonia, methanol, aromatics, ethylene, derivatives), process heat, space heat.

iii. Energy conversion processes or devices - refinery processes, power generating plants, synthetic oil and synthetic gas technologies, petrochemical processes, industrial and residential heating systems.

iv. Discrete time periods, covering the planning horizon.

In summary, the separation of the input data section from the matrix generator program section permits the user to make a whole series of analyses without having to alter the program. If structural changes are needed, the powerful MAGEN programming language enables these changes to be made in a relatively easy manner.

An application of the MAGEN-MPSX system to a test problem (117) is included in Appendix 'A'. This is done so that the reader can understand the formulation of the expanded and modified version of the model which was used to generate the results presented in Chapters VII and VIII.

Up to 1981, all the versions of the model had minimized the energy supply costs for meeting an exogeneous set of demands. The demands had to be met regardless of whether it was economic to do so or not. In 1981 the objective was changed from cost minimization to profit maximization; demands were met only if it were profitable to do so. This simulated more realistically the response of the Alberta energy sector to a specific scenario. Petrochemicals were modelled in greater detail; there were 10 petrochemicals and 15 petrochemical processes modelled. The results were compared to the Energy Resources Conservation Board's Industrial Development Profile and two key conclusions were that "the pace of oil sands development will be determined by government policy rather than by process economics" and that "Alberta will be into a decade of immense petrochemical development" (102).

In 1982, due to the recession, perceptions had changed. There was a more pessimistic perception of the world crude oil price profile. To reflect this change a 1982 scenario was developed (140). It indicated a considerable scaling down of Alberta petrochemical activities and a delay in oil sands plant construction.

The 1982 model version was modified and expanded so that it could serve as an analytical framework which could be used to assess the long term prospects of Canadian petrochemicals. In order that the reader may gain an appreciation of the amount of effort that went into developing the model so that it could be used to achieve the objectives of this thesis, the 1982 model version is described below.

For a time period t there were 19 sets of constraints:

1. Alberta Oil Balance

Conventional oil, synthetic crude and condensates formed the 'oil' pool, from which oil went to existing and new refineries and to Eastern Canada. The conventional oil production was exogeneously bounded.

2. Alberta Gas Balance

Natural gas and synthetic natural gas from coal formed the 'gas' pool. Natural gas was exported to the U.S., sent to Eastern Canada, used in existing and new industrial plants as a fuel and/or feedstock and was required to meet provincial consumers requirements for space heating. Natural gas production, exports and ex-Alberta deliveries were bounded.

3. Utility Coal Balance

Alberta utility coal production was intended for existing and new coal-fired power plants.

4. Non-Utility Coal Balance

Alberta non-utility coal production was the feedstock to synthetic natural gas and petrochemical plants.

5. Petrochemical Balance

Existing and new petrochemicals production went to satisfy the petrochemicals demand. The petrochemical demands curves were based on netback pricing of demands in Western Canada, the U.S. and the Pacific rim countries.

6. Secondary Energy Balance (electricity, refined oil products)

Secondary energy production satisfied industrial and consumers demands in Alberta.

7. Natural Gas Liquids Balance (ethane, propane, butane and condensates)

NGL produced at gas reprocessing plants, refineries and industrial plants was either sent to other provinces, exported, satisfied Alberta consumer's demands or served as a petrochemical feedstock.

8. **Natural Gas Liquids Feedstock Balance**

This accounting constraint was intended to sum the total NGL required for various petrochemical processes.

9. **Ethane Extraction Capacity Limit**

Existing and new high-yield ethane extraction was a function of the quantity of export and ex-Alberta gas.

10. **Ethane Extraction Capacity Expansion Limit**

Additional ethane extraction activities were a function of existing ethane extraction activities.

11. **Propane Extraction Capacity Limit**

Propane extraction activities could not exceed the total existing and new ethane extraction activities.

12. **Canadian Oil Balance**

Ex-Alberta, frontier and imported oil satisfied domestic oil demand and exports.

13. Canadian Natural Gas Balance

Ex-Alberta gas, British Columbia and frontier gas production satisfied domestic, ex-Alberta and British Columbia export gas demand. Thus, the NGL production associated with British Columbia exports was not included in the Alberta NGL totals. The B.C. production was exogeneously specified.

14. Alberta Industrial Activities

This was an accounting constraint which summed the existing and new industrial activities, including refineries, power plants, NGL extraction plants and petrochemical plants.

15. Total Demand for Alberta Petrochemicals

This was an accounting constraint which summed the petrochemicals demands from the incremental demand curve.

16. Capital by Type

This constraint summed the capital requirements for sets of similar activities.

17. Capital Balance

The capital required for new industrial plants was summed.

18. Total Annualized Capital Costs

The total annualized capital costs were a function of the total capital costs.

19. Annualized Capital and Operating Costs

The annualized capital and operating costs were summed.

20. Objective Function

The discounted revenues from the domestic and export sale of energy forms and petrochemicals were summed. From this value, the discounted costs from the Alberta production of energy and petrochemical forms was deducted. The "profits" or economic rents were maximized.

The expanded and modified model had 45 sets of constraints per time period:

1. Alberta Production of Conventional Crude from Various Categories

There are three categories of Alberta oil identified by different exploration, development and lifting costs. The three categories are 'discovered', 'tertiary' and 'undiscovered'. Discovered oil represents the remaining proven reserves, tertiary oil represents the reserves that are accessible through tertiary recovery and undiscovered oil represents the oil that may be discovered in the future.

In this set the annual production from the three categories is summed.

2. Hibernia Oil Deliverability

Preproduction activities (exploration and development) result in a quantity of Hibernia oil from a particular field, which will be available for production, based on an exogeneous deliverability profile. This is called the annual potential production from that field. If it is not produced in that time period, it is available for production in subsequent time periods.

In this set the preproduction activities in all time periods up to and including the period in question, t, are multiplied by the appropriate deliverability coefficient and then summed to give the total annual potential production in time period t.

3. Hibernia Oil - Total Preproduction Costs

The preproduction activities incur costs which are amortized based on the production schedule. The total preproduction costs in a time period, t, are the summation of amortized capital cost coefficients multiplied by the preproduction activities in all the time periods up to and including time period t.

4. Hibernia Oil - Total Oil Annual Production

The total annual oil production in Hibernia is the summation of the annual potential production from the individual fields.

5. Hibernia - Cumulative Oil Production

The cumulative production at the end of time period t is equal to sum of the cumulative production at the end of time period (t-1) plus the product of the total annual production and the number of years in a time period.

6. Alberta Gas Production From Various Fields

There are three categories of Alberta natural gas identified by different preproduction and lifting costs. The three categories are 'discovered', 'undiscovered' and 'tight'. Discovered gas represents the remaining proven reserves, undiscovered gas represents the gas that may be discovered in future and tight gas represents available reserves that are currently too expensive to produce, being in concrete-hard geological formations called tight sand.

In this set the annual production from the three categories is summed.

7. Alberta Gas Deliverability

Preproduction activities result in a quantity of natural gas which will be available for production, based on an exogeneous deliverability profile. If it is not produced in a particular time period it is available for production in future time periods. The natural gas deliverability in time period t is summation of the potential and carried forward deliverabilities from time periods up to and including time period t.

8. Alberta - Unused Gas Deliverability

The unused gas deliverability is equal to the difference between the deliverability and production in a time period.

9. Alberta - Gas Preproduction Costs

The preproduction activities incur costs which are amortized based on the production schedule. The total preproduction costs in a time period, t, are the summation of preproduction activities from period 1 to t multiplied by the appropriate amortized capital cost coefficients.

10. Alberta - Cumulative Gas Production

The cumulative production at the end of time period t is equal to the sum of the cumulative production at the end of time (t-1) plus the product of the total annual production and the number of years in time period t.

11. Eastern Offshore Gas Balance

The Eastern offshore natural gas production goes to the Atlantic Provinces, Toronto and North-eastern United States markets.

12. Eastern Offshore Gas Production

There are two categories of natural gas - proven and probable. This constraint set sums the annual production from these categories.

13. Eastern Offshore Gas Deliverability

Preproduction activities result in a quantity of Eastern Offshore natural gas which will be available for production, based on an exogeneous deliverability profile. If it is not produced in a particular time period it is available for production in future time periods. Natural gas deliverability in time period t is the summation of the potential and carried forward deliverabilities from time periods up to and including time period t.

14. Eastern Offshore - Unused Gas Deliverability

The unused gas deliverability is equal to the difference between the deliverability and production in a time period.

15. Eastern Offshore - Gas Preproduction Costs

The preproduction activities incur costs which are amortized based on the production schedule. The total preproduction costs in a time period t are the summation of preproduction activities from periods 1 to t multiplied by the appropriate amortized capital cost coefficients.

16. Eastern Offshore - Cumulative Gas Production

The cumulative production at the end of time period t is equal to the sum of the cumulative production at the end of time period (t-1) plus the product of the total annual production and the number of years in time period t.

17. Alberta Natural Gas Liquids Balance

The net production of natural gas liquids from the Alberta energy sector less the Western demand is equal to the natural gas liquids sent to Eastern Canada and the United States.

18. Eastern Canadian Natural Gas Liquids Balance

The net production of natural gas liquids from the Eastern Canadian energy sector plus the natural gas liquids received from Alberta is equal to the Eastern Canadian consumers' demand.

19. Alberta Synthetic Crude Limits

The production of synthetic crude from existing oil sands plants and new mined and in situ oil sands plants is restricted by exogeneous limits.

20. Alberta Bitumen Limits

The bitumen production from the two types of in situ oil sands plants is restricted by exogeneous limits.

21. Alberta Synthetic Crude Balance

The net production of synthetic crude from oil sands plants less what is used in Alberta refineries is sent either to Eastern Canada or is exported.

22. Alberta Refined Oil Products Balance

The domestic production plus imports less exports of individual refined oil products satisfies the Western Canadian demand for that product. There is a cost penalty imposed on imports and a discount on exports to discourage either activity.

23. **Gas Balance on Reprocessing Plants**

Only gas exported from Alberta goes through reprocessing plants where the ethane and propane components are extracted. Production from existing plants, new straddle plants and new deep-cut plants is modelled.

24. **Operational Modes for Straddle Plants**

Existing straddle plants can handle both 'old' and 'new' gas, differentiated by the levels of natural gas liquids. New gas is leaner.

25. **Alberta Capacity Additions**

If new capacity is added in a time period, t, then its production will be based on an exogeneous production profile. This is where the clairvoyance of the model is apparent - a new plant will not discontinue production due to some future catastrophe; if it cannot maintain production during the catastrophic period, then it will not be built.

The capacity additions of individual technologies that are available in time period t are the sum of the capacities added during periods 1 to t multiplied by the appropriate production coefficients.

26. **Alberta - Annualized Costs for Capacity Additions**

The total annualized costs for all technologies is equal to the total annual operating costs and the total annualized capital costs.

27. Eastern Canada - Capacity Additions

The capacity additions of individual technologies that are available in time period t are the sum of the capacities added during periods 1 to t multiplied by the appropriate production coefficients.

28. Eastern Canada - Annualized Costs for Capacity Additions

The total annualized costs for all Eastern Canada technologies is equal to the total annual operating costs and the total annualized capital costs.

29. Alberta - Balance on All Energy and Petrochemical Streams

The net production of an individual energy or petrochemical form is equal to the energy form produced or consumed in existing and new plants in Alberta.

For crude oil, the net production surplus to Alberta's requirements is either sent to Eastern Canada or is exported. For natural gas, the net production is either consumed in Alberta industries which have not been modelled (exogeneous demand) or is sent either to Eastern Canada or exported.

For coal, the net production is exported and for electricity the net production meets the exogeneous consumers' demands for it.

30. Eastern Canada - Balance on All Energy and Petrochemical Streams

The net production of an individual energy or petrochemical form is equal to the energy form produced or consumed in existing and new plants in Eastern Canada.

For crude oil, the net production plus conventional and synthetic crude from Alberta, Hibernia oil, and Eastern condensate is equal to the Eastern Canadian demand for it.

For natural gas, the net production plus the natural gas from Alberta and the Eastern Offshore is equal to the Eastern Canadian demand for it.

31. Total Capital Expenditures in the Alberta Energy Industry

The total capital expenditures are equal to the capital expenditures in the natural gas sector (separately modelled, as shown previously) and capital expenditures in the other energy and petrochemical sectors.

32. Alberta - Types of Capital Used

Three different capital pools which represent the capital pools available for oil sands and petrochemical and utilities plant construction are modelled. For each time period, each pool has made available a certain quantity of capital at some annualized cost. In a case where economic activities in the time period exceed this level of capital investment, additional capital can be made available - but at a higher annualized cost - to take into account the premium that must be paid for capital, labor and materials. In other words, each pool is represented with a two-step supply function.

The significance of the annualized capital costs on each individual project is self-evident. For projects such as oil sands plants, where capital cost is a major cost, changing the minimum required rate of return by a couple of percentage points could mean the project can change from a profitable to a non-profitable venture and vice versa. Another significant effect is that since intermediate energy forms are not priced, the required rate of return will determine the price of the intermediate energy product to the downstream processes. (In this case, price is equal to cost.) An example of this is ethylene where it is priced at cost of service to the second derivative plants.

33. Total Gas Exports from Alberta to the U.S.

There are seven U.S. market regions for Alberta gas. In this set the natural gas exports to the seven regions is totalled. Using this constraint set the total natural gas exports to the U.S. can be bounded.

34. Gas Imports Balance in Two U.S. Market Regions

In Northeastern U.S. markets, the maximum demand at a specific exogeneous border price is available to Alberta and Eastern offshore natural gas producers.

35. **Alberta Industrial Gas Usage**

The industrial gas usage in Alberta is the sum of the usage in existing and in new industrial plants.

36. **Demands for Petrochemicals in Market Regions**

The demand for an individual petrochemical in a market region may be satisfied either by Alberta production or by Eastern Canadian production.

37. **Economic Rent for Oil in Alberta**

The economic rent is equal to the difference between the oil revenues and costs.

38. **Economic Rent for Oil in Eastern Canada**

The economic rent is equal to the revenues generated by Hibernia oil less the capital and operating costs involved.

39. **Economic Rent for Gas in Alberta**

The economic rent is equal to the revenues generated by exports, Eastern Canadian sales, Alberta industrial sales, ethane replacement revenues, Alberta residential and commercial sales less the capital and operating costs involved.

40. Economic Surplus in Energy Sector

The economic surplus is the difference between the revenues from the sales of all petrochemicals and energy products and the related costs for their production, transportation and sale, in a particular time period.

41. Limits on Eastern Frontier Reserves of Oil

The preproduction activities in all time periods cannot find more oil than is available in a particular category.

42. Limits on Alberta Natural Gas Reserves

The preproduction activities in all time periods cannot find more gas than is available in a particular category.

43. Limits on Frontier Gas Reserves

The preproduction activities in all time periods cannot find more Eastern offshore gas than is available in a particular category.

44. Limits on Oil Sands Reserves

The preproduction activities in all time periods cannot use more oil sands reserves than are available in a particular category.

45. Objective function

The present worth of the economic surpluses from each time period is maximized.

It can be seen that the model was greatly expanded and modified. To summarize, the current version of AERAM contains the following major structural changes:

1. It is far more specific in examining the competitors to Alberta's energy products. For conventional oil, the production from the Hibernia field is endogenous. For natural gas, the production from Sable Island is endogenous. Production from a significant segment of the petrochemical industry in Eastern Canada is endogenous. Recognition of the belief that in world petrochemical markets (particularly in the Pacific rim countries), the swing suppliers will be the U.S. Gulf Coast producers, operating on a cash cost basis.

2. Markets for Alberta's energy products are specified in much more detail. U.S. demand for Canadian natural gas is specified for seven regions, with an individual demand-price stepwise curve for each region. Demand and price for Alberta's petrochemicals is specified for each of five different regions. Markets and prices for condensate-bitumen blends in the U.S. are estimated.

3. Exploration and development activities for conventional oil and gas are modelled more realistically, taking into account the production profile of a field after it has been discovered.

4. Recognizing the overcapacity in many parts of the energy sector, the model uses only cash costs for existing energy facilities.

The technical description includes a set of input-output coefficients, covering all relevant material streams, for each energy technology that is perceived to be significant over the planning period covered in the model. The energy streams that are specifically accounted for include:

1) Primary energy forms: sub-bituminous thermal coal; conventional crude oil (light or medium); heavy crude oil; bitumen from oil sands; synthetic crude oil; coal liquids via coal liquefaction; natural gas components; and synthetic natural gas from coal

   In addition, alternative Canadian primary energy sources are included in the analysis.

   Production of Saskatchewan heavy and light crude oil and the surplus production of BC natural gas are exogenous variables.

   However, production of oil from Hibernia and Beaufort as well as production of natural gas from Sable Island, Beaufort Sea-Delta and Arctic Islands are determined endogenously.

2) Secondary energy products: electricity; refined oil products; primary petrochemicals (ethylene, propylene, butylene, benzene); secondary petrochemicals, ammonia, methanol for chemical and fuel-related uses, low density polyethylene, high density polyethylene, ethylene glycol, styrene, vinyl acetate monomer, vinyl chloride monomer, polypropylene and butadiene.

Production of certain petrochemicals from a segment of the petro-chemical industry in Eastern Canada (primarily the Petrosar complex) is modelled.

The economic description of the energy sector includes a specification for each relevant production or conversion technology, the capital costs, as of the beginning of production (including all preproduction expenses and carrying charges during construction), fixed operating costs, variable operating costs (which are proportional to production) and the costs of capital.

The model includes a forecast of relevant economic conditions, over which the Canadian energy sector has little or no control.

These projections include: a forecast of world oil prices in U.S. dollars; a forecast of Can-U.S. exchange rates; a forecast of prices of Canadian oil (and refined oil products) and for natural gas (and natural gas liquids); a forecast of Canadian demand for oil (and refined oil products) and natural gas that is consistent with the price forecasts; a forecast of U.S. demand for Canadian gas by region and by price, in stepwise curves; a forecast of U.S. demand and price for petrochemical markets serviced by Canadian manufacturers, including U.S. and Pacific rim countries; a forecast of transportation costs for primary and secondary energy products.

The model handles the end-effects problem discussed in Chapter IV by selecting a sufficiently long planning horizon (36 years) and by using annualized capital costs. The fraction of capital costs to be assigned annually are calculated as a function of discount rate and plant life.

A six time-period version of the model comprises 742 constraints and 1625 variables and takes 20.65 CPU seconds to run on an IBM 3081 computer. A model listing may be obtained by contacting the author at the Alberta Research Council, 7th Floor, Terrace Plaza, 4445 Calgary Trail South, Edmonton, Alberta, T6H 5R7.

CHAPTER VI. DATA DEVELOPMENT

In this chapter, the data tables are described. They are divided into seven sections. The sections are primary energy reserves, demand projections, freight/tariff projections, price projections, energy/ petrochemical technical-economic data, production/deliverability bounds and fixed parameters tables. Unless otherwise noted, all dollar values are in mid-1983 Canadian dollars. The values shown in this chapter have been used in the base scenario run described in the next chapter.

SECTION A: PRIMARY ENERGY RESERVES

There are three tables in this section:

1. TABLE ROS: Oil Sands Reserves,
2. TABLE MCOIL: Conventional Oil Reserves and Costs,
3. TABLE MCGAS: Natural Gas Reserves and Costs.

Alberta's oil sands deposits are estimated to contain 1200 billion barrels of oil in place. Only a small fraction of the deposits, where the thick rich oil sands beds are overlain by less than 150 feet of sediments, can be produced by surface mining techniques. The remaining deposits are deeply buried and must be recovered by in situ methods. Such methods involve production from a well after some sort of stimulation. In Table 5 there are three categories of reserves. ORM represents the reserves that are recoverable by surface mining techniques, OR1 represents the best quality of in situ reserves and OR2 represents the in situ reserves that are 25% more expensive to produce than OR1.

	Reserves (MMB)
ORM	9000
OR1	3000
OR2	14000

Table 5: TABLE ROS: Oil Sands Reserves

According to ERCB estimates (58), there are 25 billion barrels of synthetic oil recoverable by surface mining techniques. Each 100,000 barrels per day plant, operating over 25 years, requires 912.5 million barrels reserves over its operating life. Assuming that one plant can be built every four years, over the 36 year planning horizon nine plants will require 8.21 billion barrels. In Table 5 the ORM value is more conservative than the ERCB estimate.

Since in situ oil sands technology is still immature there are no formal estimates of the recoverable in situ reserves. The best in situ site is located at Cold Lake, Alberta. Based on private communications with people knowledgeable in the area, estimates indicate that over the planning horizon, potential exists for 300,000 barrels per day of synthetic oil production from Cold Lake-type deposits. There are many in situ sites that are around 25% inferior to the best deposits; a reasonable estimate is that the potential from such sites is 1.5 million barrels per day.

In Table 6, the Alberta and Hibernia conventional oil reserves are shown. OWA, OWB and OWC represent the three categories of Alberta oil called 'discovered', 'tertiary' and 'undiscovered'. OHA and OHB represent the 'discovered' and 'undiscovered' Hibernia reserves, respectively. The exploration and development function in the oil and gas industry is analagous to plant capital expenditures in manufacturing where these expenses are amortized over the production profile in subsequent years. The actual cost of a unit of production is a sum of the capital charges and operating costs, with the former being 2-3 times the

	Reserves (MMB)	Preproduction Costs ($/BBL)	Lifting Costs ($/BBL)
OWA	3100	0.00	5.00
OWB	1300	0.00	24.00
OWC	1400	0.00	28.00
OHA	1500	8.65	9.90
OHB	4000	11.00	13.00

Table 6: TABLE MCOIL: Conventional Oil Reserves and Costs

value shown in the first column, depending upon the cost of capital and the production profile. In this analysis the real cost of capital of 12% for conventional oil and gas and 15% for frontier oil and gas has been used.

Since the OWA reserves have already been discovered their preproduction costs are zero; the lifting costs are based on current estimates. The OWA and OWB reserves values are based on ERCB estimates (58). The OWC reserve value is between the Geological Survey's 'high confidence' and 'average expectation' values (110). The OWB and OWC costs shown in the third column are the total costs including the amortized preproduction costs; the values are based on current tertiary recovery cost estimates. The Geological Survey's estimate of Eastern Offshore discovered reserves is used for OHA; the OHB reserves values are based on their 'high confidence' values. The OHA and OHB costs are estimates based on recent Economic Council studies (54).

In Table 7 the Alberta and Sable Island natural gas reserves are shown. GWA, GWB and GWC represent the three categories of Alberta natural gas reserves called 'discovered', 'undiscovered' and 'tight'. GFA and GFB represent the 'discovered' and 'undiscovered' Sable Island reserves, respectively. The GWA reserves values are ERCB estimates (58); since the reserves have already been discovered there are no preproduction costs. GWA lifting costs are assumed to be one-third the OWA lifting costs. The GWB reserves values are based on the Geological Survey's 'average expectation' case. The GWC reserves value is a judgmental value; it is speculative but may be justified since in the model runs

	Reserves (TCF)	Preproduction Costs ($/MCF)	Lifting Costs ($/MCF)
GWA	59.04	0.00	0.25
GWB	118.75	0.25	0.40
GWC	187.50	0.90	1.00
GFA	5.00	0.75	1.25
GFB	15.00	1.05	2.00

Table 7: TABLE MCGAS: Natural Gas Reserves and Costs

GWC reserves are not produced until the final periods and are not exhausted during the planning horizon. The GWB and GWC costs are consistent with a recent Economic Council study (54). The GFA and GFB reserves and costs are judgmental estimates based on the Geological Survey numbers and other sources.

SECTION B: DEMAND PROJECTIONS

There are three types of tables in this section:

1. TABLE DSECE: Secondary Energy Demand;
2. TABLE PCHDE: Petrochemicals Demand;
3. TABLE GPDR(I): US Regional Demand for Canadian Gas.

In Table 8 the secondary energy demands include the demand in Eastern (EC) and Western Canada (WC) for gasoline (GSL), middle distillates (DTN), heavy fuel oil (HFO), asphalt (ASP), natural gas (GAS), propane (PRP), butane (BUT) and electricity (ELE). The five-letter column name comprises of the product and the region. For example, column GASMR represents the Maritimes Region consumers' demand for natural gas. Using the price projections shown in Section D of this chapter, the federal InterFuel Demand Substitution Model, IFDSM, was used to generate the secondary demand profiles (64). The primary energy demands in this table include OILEC, ETHWC and CDSWC; OILEC stands for the Eastern Canadian crude oil demand for the product of the Eastern Canadian refineries which have not been modelled. The OILEC projections are also based on the IFDSM run mentioned above. ETHWC and CDSWC stand for the ethane and

Year	GSLWC (MMB/Y)	DTNWC (MMB/Y)	HFOWC (MMB/Y)	ASPWC (MMB/Y)
1985	43.16	42.19	5.03	4.59
1991	41.90	49.57	6.04	5.15
1997	40.63	57.94	6.67	5.79
2003	38.81	64.79	8.53	6.24
2009	38.57	69.22	9.75	6.94
2015	39.75	71.32	10.04	7.59

Year	GASWC (BCF/Y)	GASEC (BCF/Y)	GASMR (BCF/Y)	ETHWC (B#/Y)
1985	282.60	1052.13	0.01	0.85
1991	330.55	1186.46	106.88	1.25
1997	371.93	1363.57	180.75	0.0
2003	418.46	1580.13	210.81	0.0
2009	444.20	1677.34	223.78	0.0
2015	471.53	1780.54	237.54	0.0

Year	PRPWC (B#/Y)	PRPEC (B#/Y)	BUTWC (MMB/Y)	BUTEC (MMB/Y)
1985	0.89	1.48	5.99	2.99
1991	0.97	1.62	6.55	3.27
1997	1.06	1.77	7.16	3.57
2003	1.16	1.93	7.83	3.91
2009	1.27	2.12	8.56	4.27
2015	1.39	2.31	9.36	4.67

Year	ELEWC (BKH/Y)	ELEEC (BKH/Y)	OILEC (MMB/Y)	CDSWC (MMB/Y)
1985	24.02	25.27	314.50	2.3
1991	29.99	27.63	314.50	4.1
1997	34.08	30.21	314.50	2.8
2003	37.06	33.04	314.50	0.0
2009	41.20	36.12	328.86	0.0
2015	45.80	39.50	359.59	0.0

Table 8: TABLE DSECE: Secondary Energy Demand

condensate requirements for miscible flooding in Western Canada: they are included here because miscible flooding has not been explicitly modelled. The ETHWC and CDSWC values are based on ERCB estimates (57).

In Table 9 the demands for ammonia (AMM), methanol (MEO), fuel-related methanol (MEF), low density polyethylene (LPE), high-density polyethylene (HPE), ethylene glycol (EGC), styrene (STY), vinyl chloride (VCM), vinyl acetate (VAM), polypropylene (PPY), butadiene (BIE) and aromatics (BTX) are projected in the five market regions (Figure 38) of Western Canada (WC), Eastern Canada (EC), the U.S. Midwest (MW), the U.S. Pacific Coast (PC) and the Pacific Rim countries (PR). The PC market includes California, the Pacific Northwest and Mountain Regions; the MW market includes the Central and Northeastern United States. For example, AMMMW represents the chemicals-related demand for Canadian ammonia in the U.S. Midwest, at the price shown in TABLE PCHPP. In some cases, market data was available only for regions more aggregated that those selected for this model. Arbitrary market splits were assumed.

As explained in Chapter II, the aggregate Canadian demand for individual petrochemicals was collated from various literature sources. No regional demands or demand projections were available. The first step was to prepare aggregate-demand projections, based on S-curve concepts. Historical data presented in Chapter II showed whether the Canadian demand for a petrochemical was on the initial, steepest or final path of the S-curve; then the demand curve was projected into the future. Once this was completed, based on historical and potential market shares, the

	AMMWC (KT/Y)	AMMEC (KT/Y)	AMMMW (KT/Y)	AMMPC (KT/Y)	AMMPR (KT/Y)	MEOWC (KT/Y)	MEOEC (KT/Y)	MEOMW (KT/Y)
1985	1612.50	537.50	304.00	304.00	76.00	135.00	135.00	177.50
1991	2212.50	737.50	384.00	384.00	96.00	225.00	225.00	193.75
1997	2572.50	857.50	420.00	420.00	105.00	285.00	285.00	207.50
2003	2775.00	925.00	446.00	446.00	111.50	325.00	325.00	218.75
2009	2940.00	980.00	464.80	464.80	116.20	347.50	347.50	227.50
2015	3067.50	1022.50	478.00	478.00	119.50	365.00	365.00	234.25

	MEOPC (KT/Y)	MEOPR (KT/Y)	MEFWC (KT/Y)	MEFEC (KT/Y)	MEFMW (KT/Y)	MEFPC (KT/Y)	MEFPR (KT/Y)	LPEWC (KT/Y)
1985	177.50	284.00	140.00	60.00	46.26	46.25	74.00	57.00
1991	193.75	310.00	280.00	120.00	90.00	90.00	144.00	83.25
1997	207.50	332.00	399.00	171.00	123.00	123.00	196.80	114.75
2003	218.75	350.00	472.50	202.50	147.50	147.50	236.00	132.75
2009	227.50	364.00	521.50	223.50	167.50	167.50	268.00	145.50
2015	234.25	375.80	560.00	240.00	183.75	183.75	294.00	154.50

	LPEEC (KT/Y)	LPEMW (KT/Y)	LPEPC (KT/Y)	LPEPR (KT/Y)	HPEWC (KT/Y)	HPEEC (KT/Y)	HPEMW (KT/Y)	HPEPC (KT/Y)
1985	323.00	12.75	12.75	204.00	26.00	234.00	4.75	4.75
1991	471.75	19.00	19.00	304.00	37.00	333.00	11.25	11.25
1997	650.25	22.75	22.75	364.00	48.00	432.00	14.75	14.75
2003	752.25	25.25	25.25	404.00	58.00	522.00	17.25	17.25
2009	824.50	27.50	27.50	440.00	65.50	589.50	19.25	19.25
2015	875.50	29.25	29.25	468.00	71.00	639.00	20.75	20.75

	HPEPR (KT/Y)	EGCWC (KT/Y)	EGCEC (KT/Y)	EGCMW (KT/Y)	EGCPC (KT/Y)	EGCPR (KT/Y)	STYWC (KT/Y)	STYEC (KT/Y)
1985	66.50	7.75	147.25	20.00	30.00	120.00	64.50	150.50
1991	157.50	9.25	175.75	27.80	41.70	166.80	93.00	217.00
1997	206.50	10.50	199.50	33.00	49.50	198.00	133.50	311.50
2003	241.50	11.50	218.50	37.00	55.50	222.00	149.00	371.00
2009	269.50	12.25	232.75	40.00	60.00	240.00	177.00	413.00
2015	290.50	12.75	242.25	42.50	63.75	255.00	190.50	444.50

Table 9: TABLE PCHDE: Petrochemical Demands

	STYMW (KT/Y)	STYPC (KT/Y)	STYPR (KT/Y)	VCMWC (KT/Y)	VCMEC (KT/Y)	VCMMW (KT/Y)	VCMPC (KT/Y)	VCMPR (KT/Y)
1985	27.00	27.00	162.00	9.00	291.00	5.00	5.00	60.00
1991	36.00	36.00	216.00	13.50	436.50	10.00	10.00	120.00
1997	42.00	42.00	252.00	17.10	552.90	13.00	13.00	156.00
2003	46.00	46.00	276.00	19.35	625.65	15.25	15.25	183.00
2009	49.50	49.50	297.00	21.30	588.70	17.00	17.00	204.00
2015	52.00	52.00	322.00	22.65	732.35	18.40	18.40	220.80

	VAMWC (KT/Y)	VAMEC (KT/Y)	VAMMW (KT/Y)	VAMPC (KT/Y)	VAMPR (KT/Y)	PPYWC (KT/Y)	PPYEC (KT/Y)	PPYMW (KT/Y)
1985	1.35	25.65	1.00	1.00	16.00	6.00	114.00	0.0
1991	1.80	34.20	12.90	12.90	206.40	9.00	171.00	0.0
1997	2.25	42.75	17.25	17.25	276.00	13.00	247.00	0.0
2003	2.55	48.45	19.75	19.75	316.00	17.00	323.00	0.0
2009	2.75	52.25	21.75	21.75	348.00	19.50	370.50	0.0
2015	2.90	55.10	23.25	23.25	372.00	21.25	403.75	0.0

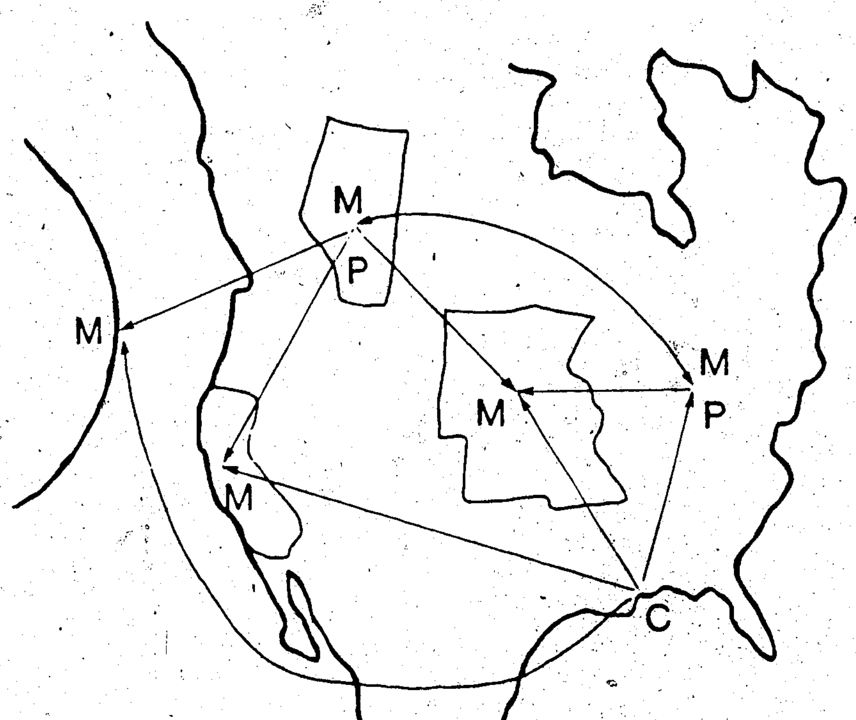
	PPYPC (KT/Y)	PPYPR (KT/Y)	BIEWC (KT/Y)	BIEEC (KT/Y)	BIEMW (KT/Y)	BIEPC (KT/Y)	BIEPR (KT/Y)	BTXAA (KT/Y)
1985	1.25	22.50	19.00	171.00	2.50	2.50	0.01	141.00
1991	5.50	99.00	24.00	216.00	11.00	11.00	0.01	158.25
1997	9.75	175.50	28.00	252.00	17.00	17.00	0.01	226.00
2003	13.00	234.00	30.50	274.50	20.50	20.50	0.01	235.00
2009	15.65	281.70	32.50	292.50	23.00	23.00	0.01	300.00
2015	17.75	319.50	34.00	306.00	23.50	23.50	0.01	305.00

	BTXBB (KT/Y)	BTXMW (KT/Y)	BTXPC (KT/Y)	BTXPR (KT/Y)
1985	799.00	292.00	292.00	73.00
1991	896.75	302.00	302.00	75.50
1997	904.00	298.00	298.00	74.50
2003	940.00	294.00	294.00	73.50
2009	900.00	292.00	292.00	73.00
2015	915.00	292.00	292.00	73.00

Table 9: Table PCHDE (Continued)

FIGURE 38

PETROCHEMICAL MARKET REGIONS



M = MARKETS (Western Canada, Eastern Canada, U.S. Mid-West, U.S. Pacific Coast, Pacific Rim countries)

P = PRODUCERS (Alberta, Eastern Canada)

C = COMPETITOR (U.S. Gulf Coast)

demand was regionalized into Eastern and Western Canadian demands. For example, the demand for chemical-related methanol was based on historical market shares in Eastern and Western Canada, whereas the demand for fuel-related methanol was based on judgmental (or 'potential') market shares, due to the lack of any historical data for the latter.

The U.S. demand for Canadian petrochemicals was available, but the Stanford Research Institute (130) and Chemsystems (24) estimates were at variance with each other. Existing demands in the U.S. and Pacific rim countries were projected to increase in accordance with current perceptions about the future potential of the petrochemicals. For example, the export demands for fuel-related methanol were expected to grow faster than the export demands for chemical-related methanol. Thus, the export demands represented the maximum demands for Canadian petrochemicals in the individual export regions.

Admittedly, the regional demand projections for petrochemicals were speculative, but they were based on the best available data and were projected in a consistent manner. A major data deficiency identified by this analysis was a lack of regional petrochemical price/demand relationships.

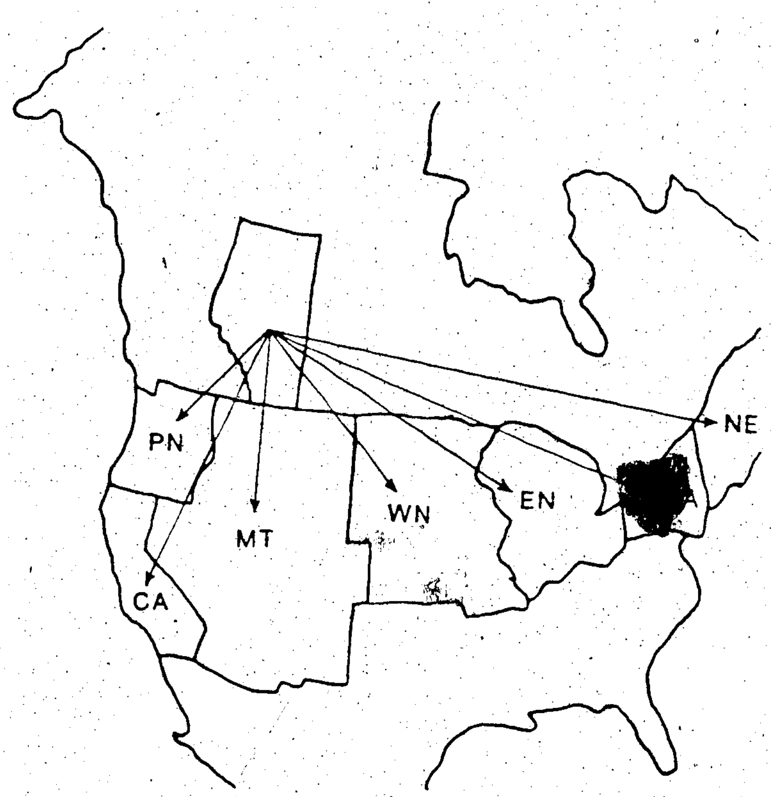
Table 10 represents the demand in a specific time period at various border prices for Canadian natural gas in the seven U.S. market regions shown in Figure 39 - New England (NE), Mid Atlantic (MA), East North Central (EN), West North Central (WN), Mountain (MT), California (CA) and the Pacific Northwest (PN). The data in this table is based on the

Border Price (US $/MCF)	U.S. Demand for Canadian Gas, by Region (BCF/y) NE	MA	EN	WN	MT	CA	PN
300	148	525	860	600	415	813	130
400	75	325	645	520	359	585	112
475	70	325	600	450	350	560	100
500	60	193	415	355	257	435	83

(TABLE GPDR03: There are similar tables for GPDR01, GPDR02, GPDR04, GPDR05 and GPDR06)

Table 10: TABLE GPDR(I): U.S. Regional Demand for Canadian Gas

Figure 39. U.S. Natural Gas Market Regions



PN - Pacific North West
CA - California
MT - Mountain

WN - West North Central
EN - East North Central
MA - Mid Atlantic
NE - New England

1982 Sherman-Clark submission to the National Energy Board (123); to reflect the current perceptions of U.S. demand for Canadian gas, the Sherman-Clark values were reduced. For example, TABLE GPDR03 represents the demand in the third time period; in this table row name '400' and column name 'CA' represents the Californian demand for Canadian gas at the border price of US $4.00/MCF at 585 BCF/y. When the border price is increased to US $4.75/MCF, the Californian demand is reduced to 560 BCF/y. Therefore, this table provides the price elasticity of demand for Canadian natural gas in the seven U.S. regions (5).

SECTION C: FREIGHT AND TARIFF PROJECTIONS

There are two tables in this section:

1. TABLE TRANSC: Transportation Costs;
2. TABLE TARIF: Import Duties. *

In Table 11, current estimates of the energy and petrochemical transportation costs from Alberta, Eastern Canada and the U.S. Gulf Coast to the five market regions are based on published freight rates. Since the transportation costs are dependent on a number of factors like the annual tonnage and packaging and because a number of petrochemicals are not currently being transported from the producing to the consuming regions, the costs shown are 'representative' and not the 'actual' transportation costs. The costs are usually based on what the market can bear. However, there is no scientific correlation that can be established between transportation costs and market prices. Therefore, the petrochemical transportation costs were escalated on the basis of the price escalations in Table 20.

Destination		Western Canada	Eastern Canada		U.S. Midwest			U.S. Pacific Coast			Pacific Rim		
Source		EC	WC	GC	WC	EC	GC	WC	EC	GC	WC	EC	GC
AMM	($/T)	102.72	103.72	113.91	93.54	56.80	75.84	75.22	109.68	108.34	261.04	360.01	167.81
MEO	($/T)	60.22	60.22	113.91	70.22	47.94	54.17	79.30	76.09	75.18	66.86	177.68	74.42
LDPE	($/T)	115.00	68.75	83.63	55.76	56.58	64.84	90.55	109.90	108.60	185.26	278.47	122.71
HDPE	($/T)	115.00	68.75	83.63	55.76	56.58	64.84	90.55	198.90	108.60	185.26	278.47	122.71
EGC	($/T)	80.60	80.60	97.67	81.74	47.94	44.37	86.25	76.09	75.18	91.74	231.75	70.83
STY	($/T)	80.60	80.60	91.49	84.84	55.80	54.17	96.85	73.10	72.22	114.99	223.64	72.85
VCM	($/T)	80.60	80.60	97.67	84.84	56.80	54.17	96.85	76.09	75.18	220.01	328.65	163.42
VAM	($/T)	80.60	80.60	97.67	84.84	56.80	54.17	99.95	76.09	75.18	200.80	309.45	163.42
PPY	($/T)	115.00	68.75	83.63	55.76	56.80	64.84	90.55	109.90	108.60	185.26	278.47	122.71
BIE	($/T)	90.44	90.44	97.67	95.44	56.80	54.17	108.97	135.06	133.44	133.95	239.28	81.37
BTX	($/T)	64.50	64.50	50.50	51.00	30.60	30.60	45.00	79.50	50.00	80.00	75.50	75.50

Destination		Eastern Canada	Export
Source		WC	WC
OIL	($/B)	1.60	1.54
HEO	($/B)	2.00	1.75
COL	($/T)	61.96	27.18
CDS	($/B)	1.54	1.54
ETH	($/#)	3.60	3.60
PRP	(¢/#)	2.67	2.67
BUT	($/B)	1.59	1.59

Table 11: TABLE TRANSC: 1985 Transportation Costs

The petrochemical import duties for Canada, the United States and Japan are presented in Table 12. They are based on the current import duties. For example, consider rows 'MEO' and 'MEF' and column 'United States'; the U.S. import duties on chemical-related and fuel-related methanol are respectively 18% and 0% of the Canadian methanol price. If the modeller so desires, the tariffs in future time periods can be altered; the reason for providing this capability was to be able to investigate the impact of a North American common market in petrochemicals. A model run indicated that the major impact would be on the ability of chemical-related methanol to penetrate the U.S. market; this run was not treated as an official "scenario".

SECTION D: PRICE PROJECTIONS

There are nine tables in this section:

1. TABLE OIL: Conventional Crude Oil;
2. TABLE HEO: Heavy Oil;
3. TABLE GAS: Natural Gas;
4. TABLE RGPS: U.S. Regional Gas;
5. TABLE CTS: Sub-Bituminous Coal;
6. TABLE NGL: Natural Gas Liquids;
7. TABLE IFPP: Intermediate Fuels;
8. TABLE PCHPP: Petrochemicals;
9. TABLE RFPP: Refinery Products.

	Ad Valorem Duty, (%)		
Petrochemical	Canada	United States	Pacific Rim
AMM	0.0	0.0	0.0
MEO	10.0	18.0	4.9
MEF	10.0	0.0	4.9
LDPE	9.5	12.5	10.0
HDPE	9.5	12.5	10.0
EGC	10.0	12.0	12.0
STY	11.3	7.4	6.6
VCM	9.5	10.1	5.8
VAM	0.0	3.8	7.0
PPY	9.5	12.5	12.5
BIE	0.0	0.0	0.0
BTX	0.0	0.0	0.0

Table 12: TABLE TARIF: Petrochemical Tariffs

In Table 13 column 'EXP' represents the world oil price and 'AWH' represents the Alberta well head price. The world oil price forecast calls for a drop in real prices until 1985, a small increase until the end of the decade and a real rise of slightly under 2% annually to the turn of the century, with a long-term annual increase of approximately 1.5% per annum. The projections are in line with consensus forecasts, such as those by IIASA (86), but there is no assurance that the consensus is right. The Alberta well head oil price is the Toronto city gate price less transportation cost between Edmonton and Toronto. This is consistent with current pricing policies.

Heavy oil cost projections are provided in Table 14. The current lifting costs for Lloydminster-type heavy oil are $6/barrel. For 'undiscovered' heavy oil reserves, the total costs are estimated at $15/barrel. Based on these costs and exogeneous production projections for existing and 'undiscovered' reserves (58), a representative costs profile is generated.

Table 15 has four columns, Alberta border price (ABP), Toronto city gate (TCG), the cost of ethane and NGLs on a fuel equivalent basis (PPF) and the intra-Alberta industrial price (IPF). PPF and IPF are shown as fractions of the Alberta border price. The Toronto city gate price of natural gas is fixed at 65% of the oil price on a fuel equivalent basis throughout the forecast period. This is consistent with current regulations; however, regulations are subject to change. Therefore, the assumption has to be valid even in a deregulated market. The assumption

	AWH ($/BBL)	EXP ($/BBL)
1985	34.03	35.82
1991	35.57	37.45
1997	39.72	41.71
2003	43.96	46.05
2009	48.14	50.35
2015	42.43	55.06

Table 13: TABLE OIL: Conventional Oil Prices

	CPA ($/BBL)
1985	6.00
1991	6.00
1997	6.61
2003	7.49
2009	9.56
2015	10.69

Table 14: TABLE HEO: Heavy Oil Costs

	ABP ($/MCF)	TCG ($/MCF)	PPF (Frac)	IPF (Frac)
1985	2.83	4.08	1.0	0.6
1991	3.14	4.53	1.0	0.6
1997	3.52	4.96	1.0	0.6
2003	3.94	5.44	1.0	0.6
2009	4.31	5.95	1.0	0.6
2015	4.71	6.50	1.0	0.6

Table 15: TABLE GAS: Natural Gas Prices

	Border Price, (US ¢/MCF)						
	NE	MA	EN	WN	MT	CA	PN
1985	400	400	400	400	400	400	400
1991	400	400	400	400	400	350	350
1997	450	450	450	450	450	450	450
2003	450	450	450	450	450	450	450
2009	500	500	500	500	500	500	500
2015	500	500	500	500	500	500	500

Table 16: TABLE RGPS: Natural Gas Border Prices

the Canadian and United States governments. As oil prices increased, Canada pegged the gas export price to that of competing energy sources. In 1976 the United States requested that Canada adopt a uniform border price. This was formalized in 1980 by the so-called Duncan-Lalonde formula, which accepted the concept of substitution value. Initially, the U.S. pipeline companies were able to roll in the higher-priced Canadian gas with low cost, regulated U.S. domestic supplies.

In 1978 the U.S. enacted the natural gas policy act which categorized gas into several classes and lifted price controls from the 'high cost' gas. Since gas distributors anticipated a shortage of gas, they were prepared to contract for new [illegible] supplies at premium prices; producers began to explore for and develop the 'high cost' reserves. As the 'high cost' gas was brought into production, it became increasingly difficult to roll in the Canadian gas. Canadian gas exports were reduced to the minimum levels permitted in the take-or-pay contracts. In the United States, further decontrol of natural gas prices is scheduled in 1985. The market mechanisms will cause the cheaper reserves to be developed first; Canadian gas will have to compete with the new low-cost reserves. Therefore, the one-border-price system for Canadian gas export needs revision. TABLE RGPS may be used to study the impact of a flexible border price. It is used in conjunction with TABLE GPDR(I); the modeller specifies a border price projection in TABLE RGPS, and the regional demand for Canadian gas at the exogeneously specified price is presented in TABLE GPDR(I). If it is profitable to do so, Alberta and Sable Island producers will satisfy the demand.

Coal is used in coal-fired power plants and is the feedstock for plants that convert coal to liquid and gaseous fuels. In Table 17 the current price of coal is taken as the industrial price in Alberta (CPA). The current price is escalated at 1% per annum throughout the forecast period. Its export price (EXP) is the Alberta price plus transportation costs to Vancouver. There are similar tables for bituminous thermal coal and metallurgical coal.

In Table 18 the ethane (ETH), propane (PRP) and butane (BUT, prices are based on current Alberta values. Their long-term escalation is at 1.5% per annum, real. Because it is a seasonal transport fuel, condensate commands a premium over oil prices in the winter months and a penalty during the summer months; condensate prices are assumed to be equal to the world oil prices specified in TABLE OIL.

In Table 19, due to its better quality, synthetic crude from oil sands (SYC) is assumed to command a slight premium over world oil prices. The bitumen-condensate export blend (BDX) prices are a weighted average of the bitumen and condensate prices. The heavy oil condensate export (HDX) and Eastern Canadian (HDA) prices are weighted averages of heavy oil and condensate prices. The intermediate coal liquids (ICL) prices are based on oil prices, with appropriate sulphur and nitrogen penalties.

In Table 20 the regional petrochemical prices are projected. Because of the volatile nature of the prices this is not an easy task. In the 1960's, due to lower feedstock costs, major technology improvements and

	CPA ($/T)	EXP ($/T)
1985	8.16	33.66
1991	8.66	35.73
1997	9.19	37.93
2003	9.76	40.26
2009	10.36	42.74
2015	11.00	45.37

Table 17: TABLE CTS: Coal Prices

	ETH (¢/#)	PRP (¢/#)	BUT ($/B)	CDS ($/B)
1985	7.73	9.32	28.20	35.82
1991	8.46	10.62	29.70	37.45
1997	9.26	11.62	31.86	41.71
2003	10.13	12.84	34.27	46.05
2009	11.08	14.14	37.22	50.35
2015	12.12	15.46	40.71	55.06

Table 18: TABLE NGL: Natural Gas Liquids Price

	SYC ($/BBL)	BDX ($/BBL)	HDX ($/BBL)	HDA ($/BBL)	ICL ($/BBL)
1985	36.07	26.29	28.50	32.55	29.34
1991	37.70	27.73	30.09	34.37	31.14
1997	41.96	30.02	32.47	37.08	33.06
2003	46.30	32.66	35.27	40.29	35.62
2009	50.60	35.73	38.57	44.05	38.94
2015	55.31	39.06	42.17	48.16	42.58

Table 19: TABLE IFPP: Intermediate Fuel Prices

	AMMGC	AMMPR	MEOGC	MEOPR	LPEGC	LPEPR
1985	311.36	222.40	233.52	189.04	1017.48	928.52
1991	320.82	229.15	255.34	206.70	1042.97	997.41
1997	330.56	236.12	279.20	226.02	1174.05	1071.40
2003	340.60	243.29	305.29	247.14	1261.16	1150.89
2009	350.95	250.68	333.81	270.23	1354.72	1236.28
2915	361.60	258.29	365.00	295.48	1455.23	1327.99

	HPEGC	HPEPR	EGCGC	EGCPR	STYGC	STYPR
1985	1084.20	950.76	717.24	633.84	856.24	889.60
1991	1185.51	1039.60	836.66	739.37	930.73	966.99
1997	1296.28	1136.74	975.95	862.47	1011.70	1051.11
2003	1417.40	1242.95	1138.44	1006.06	1099.71	1142.55
2009	1549.84	1359.09	1327.98	1173.56	1195.37	1241.95
2015	1694.66	1486.08	1549.09	1368.95	1299.31	1349.99

	VCMGC	VCMPR	VAMGC	VAMPR	PPYGC	PPYPR
1985	583.80	483.72	845.12	700.56	1117.56	989.68
1991	665.22	551.19	929.57	770.56	1200.47	1063.10
1997	758.00	628.06	1022.45	847.56	1289.53	1141.98
2003	863.73	715.66	1124.62	932.26	1386.20	1226.70
2009	984.19	815.47	1236.99	1025.40	1487.97	1317.71
2015	1121.46	929.21	1360.49	1127.86	1598.36	1415.47

	BIEGC	BIEPR	BTXGC	BTXPR
1985	772.84	667.20	435.90	380.30
1991	820.38	708.24	462.72	403.70
1997	870.85	751.81	491.18	428.53
2003	924.42	798.05	411.40	454.89
2009	981.29	847.15	553.47	482.88
2015	1041.65	899.27	587.52	512.58

All values are in $/tonne.

Table 20: TABLE PCHPP: Petrochemical Prices

world petrochemical production over-capacity, the nominal prices of petrochemicals declined. In the early 1970's the prices recovered. Since 1973 the petrochemical prices have become volatile, changing as much as 50% in a single year. There are two reasons for this:

1. As shown in Chapter I, feedstock prices have become a dominant price component of petrochemicals; as feedstock prices fluctuate so will the petrochemical price, and vice versa. For example, at the U.S. Gulf Coast in 1982-83, the NGL prices dropped in unison with ethylene prices.

2. In the 1960's, plants based on crude oil feedstock began to compete with the NGL-based petrochemical industry at the U.S. Gulf Coast. In the 1970's, as oil prices escalated, whereas the gas industry, with regulated prices and long-term contracts was slower to respond, the oil-based plants became the swing suppliers and set the petrochemical prices. During periods of surplus capacity, as prices dropped oil-based plants were forced to operate at cash costs; as prices dropped even lower and reached the cash costs of NGL-based plants, the oil-based plants had to be shut down. Producers have tried to minimize the impact of feedstock price fluctuations by retrofitting for feedstock flexibility. However, retrofitting is expensive and is not a universal solution.

Because it is the largest production centre in North America petrochemical prices are generally set at the U.S. Gulf Coast. Publicly available capital cost data usually refers to this location. For the current analysis the U.S. Gulf Coast prices were estimated by completing a discounted cash flow analysis of petrochemical plants. This yielded the prices shown in Table 20, with column-names ending with 'GC'. For example, VCMGC is the vinyl chloride monomer price at the U.S. Gulf Coast. Market prices in the regional U.S. and Canadian markets were the U.S. Gulf Coast prices plus appropriate transportation and tariffs from TABLE TRANSC and TABLE TARIF. In the competitive Pacific rim market, as per the Chem Systems methodology (24), the prices are based on cash costs plus transportation costs from Houston. In TABLE PCHPP the Pacific rim prices have column-names ending in 'PR'.

In Table 21, the refinery product prices are based on the conventional oil prices; the products are gasoline (GSL), refinery-grade propylene (PLI), heavy fuel oil (HFO), asphalt (ASP) and middle distillates (DTN). Prices are developed for Western (W) and Eastern Canada (E). The difference in the two regional prices is in the heavy fuel oil prices. Since the market for this product in Western Canada is limited, its price is assumed to be $5/barrel lower than in Eastern Canada. In this table, a premium is imposed on imported refined oil products in order to discourage such imports. Also, a penalty is imposed on surplus refined products, in order to minimize the surplus.

	GSLW ($/BBL)	PLIW (E6$/KT)	HFOW ($/BBL)	ASPW ($/BBL)	DTNW ($/BBL)
1985	46.480	0.531	23.560	38.150	44.030
1991	48.600	0.555	24.640	39.880	46.040
1997	54.120	0.618	27.450	44.410	52.270
2003	59.750	0.682	30.304	49.032	56.602
2009	65.333	0.745	33.135	53.613	61.891
2015	71.437	0.815	35.231	58.622	67.674

* Similar values for Eastern Canada, exports and imports.

Table 21: TABLE RFPP: Refinery Product Prices

SECTION E: ENERGY AND PETROCHEMICAL TECH-ECON DATA

There are four tables in this section:

1. TABLE ENTC: Technological Input-Output Matrix;
2. TABLE WNEX: Existing Alberta Plants;
3. TABLE ENEX: Existing Eastern Plants;
4. TABLE TPC: Technological Progress Curve.

In Table 22, the following energy and petrochemical plants are modelled:

1. Five refineries: high gasoline (RHM), medium gasoline (RMM), heavy oil (RHE), synthetic oil (RSN) and chemical-type (RNA);

2. Four power plants: coal-fired (PWC), gas-fired (PWG), hydroelectric (HYD) and nuclear (NUC);

3. Five oil sands plants: surface-mined (OSM), #1 in situ bitumen (OS1), #2 in situ bitumen (OS2), #1 in situ integrated-gas-only (IGI), and #1 in situ integrated-with-coal (IC1);

4. Two upgraders: for heavy oil (HOU) and for bitumen (RUB);

5. Four coal conversion plants: coal liquefaction (CLI), Slagged Lurgi gasifier (SLU), HyGas (HYG), and CO_2-Acceptor (COA);

6. Two ammonia plants: gas feedstock (AMG) and coal feedstock (AMC);

1. Refineries

	UNITS	RHM	RMM	RHE	RNA	RSN
SIZE	MBD	100.0	100.0	100.0	100.0	100.0
CAPI	MM$	900.0	660.0	556.0	720.0	1912.0
OPER	MM$/Y	92.0	92.0	60.0	95.0	93.0
DISF	%/Y	'10'	'20'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'05'	'05'	'05'
OIL	MMB/Y	-36.5	-36.5	0.0	-36.5	0.0
HEO	MMB/Y	0.0	0.0	-36.5	0.0	0.0
SYC	MMB/Y	0.0	9.0	0.0	0.0	-36.5
GAS	BCF/Y	-5.9	-5.9	-11.1	-5.9	-21.4
ELE	BWH/Y	-2.0	-2.0	-2.0	-2.0	-2.0
GSL	MMB/Y	18.3	12.7	0.0	2.3	15.0
DTN	MMB/Y	12.5	17.9	8.6	7.1	25.6
HFO	MMB/Y	1.4	1.6	3.6	16.7	0.0
ASP	MMB/Y	1.0	1.0	23.0	0.0	0.0
PLI	KT/Y	45.4	45.4	45.4	0.0	45.4
ETN	KT/Y	0.0	0.0	0.0	266.8	0.0
PLE	KT/Y	0.0	0.0	0.0	200.1	0.0
PRP	B#/Y	0.2	0.2	0.0	0.0	0.1
BTL	MMB/Y	0.0	0.0	0.0	1.2	2.8
BTX	KT/Y	0.0	0.0	0.0	186.7	473.7

2. Power Plants

	UNITS	PWC	PWG	HYD	NUC
SIZE	MW	750.0	750.0	1000.0	1200.0
CAPI	MM$	683.0	512.0	1770.0	1914.0
OPER	MM$/Y	16.0	12.6	10.0	106.0
DISF	%/Y	'07'	'07'	'07'	'07'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'	'05'
CTS	MMT/Y	-2.3	0.0	0.0	0.0
GAS	BCF/Y	0.0	-39.4	0.0	0.0
URN	T/Y	0.0	0.0	0.0	-30.0
ELE	BKH/Y	3.6	3.6	4.7	5.7

TABLE 22: TABLE ENTC: Energy and Petrochemical Technologies

3. Oil Sands Plants

	UNITS	OSM	OSI	OS2	IG1	IG2
SIZE	MBD	100.0	100.0	100.0	100.0	100.0
CAPI	MM$	5718.0	1749.0	2186.0	4137.0	4334.0
OPER	MM$/Y	368.0	237.0	296.0	464.0	440.0
DISF	%/Y	'10'	'10'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'	'25'
PROG	-	'44'	'44'	'44'	'44'	'44'
GAS	BCF/Y	-17.4	-66.8	-83.5	-21.4	-15.5
ELE	BKH/Y	-0.2	-0.9	-0.9	-0.9	-0.9
CTS	MMT/Y	0.0	0.0	0.0	0.0	-0.3
ORM	MMB/Y	-36.5	0.0	0.0	0.0	0.0
OR1	MMB/Y	0.0	-36.5	0.0	-36.5	-36.5
OR2	MMB/Y	0.0	0.0	-36.5	0.0	0.0
RSR	MMB	910.0	910.0	910.0	910.0	910.0
BIT	MMB/Y	0.0	36.5	36.5	0.0	0.0
SYC	MMB/Y	36.5	0.0	0.0	36.5	36.5

4. Upgraders

	UNITS	RUB	HOU
SIZE	MBD	100.0	100.0
CAPI	MM$	2167.0	2136.0
OPER	MM$/Y	142.0	91.0
DISF	%/Y	'10'	'10'
LIFE	Y	'25'	'25'
PROG	-	'44'	'44'
HEO	MMB/Y	0.0	-36.5
BIT	MMB/Y	-48.6	0.0
SYC	MMB/Y	36.5	33.8

5. Coal Conversion Plants

	UNITS	CLI	SLU	HYG	COA
SIZE	BCF/Y	-	91.3	91.3	91.3
CAPI	MM$	6840.0	2590.0	2158.0	2310.0
OPER	MM$/Y	250.0	233.0	194.0	208.0
DISF	%/Y	'10'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'44'	'05'	'05'	'05'
CTS	MMT/Y	-30.0	-7.9	-7.6	-7.2
ICL	MMB/Y	36.5	0.0	0.0	0.0
GAS	BCF/Y	-122.3	91.3	91.3	9.3

TABLE ENTC: (Continued)

6. Methane-Based Plants

	UNITS	AMC	AMG	MEC	MEG
SIZE	KT/Y	500.0	500.0	660.0	660.0
CAPI	MM$	720.0	316.0	683.0	297.0
OPER	MM$/Y	63.0	18.3	59.6	20.0
DISF	%/Y	'10'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'05'	'00'	'05'	'00'
CTS	MMT/Y	-1.4	0.0	-1.3	0.0
GAS	BCF/Y	0.0	-16.8	0.0	-25.8
ELE	BWH/Y	-22.0	-27.0	-28.0	-46.0
AMM	KT/Y	500.0	500.0	0.0	0.0
MEO	KT/Y	0.0	0.0	660.0	660.0

7A. Ethylene Plants

	UNITS	ETE	ETP	EPE	ETF
SIZE	KT/Y	680.0	680.0	680.0	680.0
CAPI	MM$	578.0	815.0	737.0	1170.0
OPER	MM$/Y	35.2	48.0	44.5	71.5
DISF	%/Y	'07'	'07'	'07'	'07'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'	'00'
ETH	B#/Y	-1.9	0.0	-1.1	0.0
PRP	B#/Y	-0.0	-3.1	-1.5	0.0
DTN	MMB/Y	0.0	0.0	0.0	-18.5
GAS	BCF/Y	-17.5	-1.75	-1.75	0.0
ELE	BWH/Y	-97.0	-97.0	-97.0	-97.0
ETN	KT/Y	680.0	680.0	680.0	680.0
PLE	KT/Y	15.3	221.7	129.3	386.3
BTL	MMB/Y	0.3	0.6	0.3	2.7
OIL	MMB/Y	0.2	0.6	0.4	2.6

7B. Ethylene Plants (Continued)

	UNITS	ETC	ETO	ETB
SIZE	KT/Y	680.0	680.0	680.0
CAPI	MM$	1281.0	1834.0	1503.0
OPER	MM$/Y	76.0	240.0	206.0
DISF	%/Y	'07'	'07'	'07'
LIFE	Y	'25'	'25'	'25'
PROG	-	'05'	'05'	'05'
CDS	MMB/Y	-18.9	0.0	0.0
HEO	MMB/Y	0.0	-42.2	0.0
BIT	MMB/Y	0.0	0.0	-30.7
ELE	BWH/Y	-97.0	-97.0	-97.0
ETN	KT/Y	680.0	680.0	680.0
PLE	KT/Y	390.7	226.7	226.7
BTL	MMB/Y	2.7	1.4	1.4
OIL	MMB/Y	2.8	28.8	16.1
GAS	BCF/Y	0.0	5.1	8.0

TABLE ENTC: (Continued)

8. Ethylene Derivatives

	UNITS	HPE	LPE	EGE	VCE	LHP
SIZE	KT/Y	100.0	200.0	200.0	200.0	100.0
CAPI	MM$	128.0	234.0	297.0	155.0	50.0
OPER	MM$/Y	19.9	17.0	22.6	23.8	8.0
DISF	%/Y	'10'	'10'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'	'00'	'00'
ETN	KT/Y	-102.0	-206.0	-167.0	-96.0	0.0
ELE	BWH/Y	-75.0	-57.0	-88.0	-57.0	0.0
GAS	BCF/Y	-0.3	-0.4	-1.3	-1.8	0.0
EGC	KT/Y	0.0	0.0	200.0	0.0	0.0
HDPE	KT/Y	100.0	0.0	0.0	0.0	100.0
LDPE	KT/Y	0.0	100.0	0.0	0.0	-100.0
VCM	KT/Y	0.0	0.0	0.0	200.0	0.0

9A. Other Petrochemicals

	UNITS	SEB	VME	PLP	PPP
SIZE	KT/Y	300.0	400.0	100.0	200.0
CAPI	MM$	255.0	525.0	95.0	39[illegible]
OPER	MM$/Y	17.3	53.8	15.0	51.5
DISF	%/Y	'10'	'10'	'10'	'10'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'	'00'
ETN	KT/Y	-86.1	-156.0	0.0	0.0
MEO	KT/Y	0.0	-162.4	0.0	0.0
BTX	KT/Y	-234.9	0.0	0.0	0.0
PLI	KT/Y	0.0	0.0	-133.0	0.0
PLE	KT/Y	0.0	0.0	100.0	-226.0
GAS	BCF/Y	-4.5	-10.5	0.0	-5.1
ELE	BWH/Y	-53.0	-97.0	0.0	-31.0
STY	KT/Y	300.0	0.0	0.0	0.0
VAM	KT/Y	0.0	400.0	0.0	0.0
PPY	KT/Y	0.0	0.0	0.0	200.0

TABLE ENTC: (Continued)

9B. Other Petrochemicals

	Units	BTB	BZN	BZC
SIZE	KT/Y	100.0	400.0	400.0
CAPI	MM$	175.0	355.0	348.0
OPER	MM$/Y	35.0	65.0	57.0
DISF	%/Y	'12'	'12'	'12'
LIFE	Y	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'
BTL	MMB/Y	-2.1	0.0	0.3
HEO	MMB/Y	0.0	-8.7	0.0
CDS	MMB/Y	0.0	0.0	-13.8
ELE	BWH/Y	0.0	-200.0	-283.0
BTX	KT/Y	0.0	400.0	400.0
DTN	MMB/Y	0.0	0.0	8.4
HFO	MMB/Y	0.0	0.0	0.3
GAS	BCF/Y	0.0	0.0	2.8
BIE	KT/Y	100.0	0.0	0.0

10. Gas Processing

	UNITS	GPS	GPF	GP3	GEF
SIZE	BCF/Y	341.0	3000.0	2400.0	375.0
CAPI	MM$	147.0	0.0	112.0	105.0
OPER	MM$/Y	6.5	900.0	9.6	9.5
DISF	%/Y	'07'	'07'	'07'	'07'
LIFE	Y	'25'	'25'	'25'	'25'
PROG	-	'00'	'00'	'00'	'00'
RGA	BCF/Y	0.0	-3775.0	0.0	0.0
GSH	BCF/Y	24.8	775.0	22.0	0.0
GS1	BCF/Y	-386.0	3000.0	0.0	48.0
GS2	BCF/Y	341.0	-2422.0	-423.0	
GS3	BCF/Y	0.0	0.0	2400.0	375.0
ETH	B#/Y	1.0	0.39	0.91	1.0
PRP	B#/Y	0.51	6.24	0.0	0.6
BUT	MMB/Y	1.15	25.2	0.0	1.3
CDS	MMB/Y	0.51	55.7	0.0	0.6

TABLE ENTC: (Continued)

7. Two methanol plants: gas feedstock (MEG) and coal feedstocks (MEC);

8. Seven ethylene plants: ethane (ETE), propane (ETP), ethane/propane (EPE), naphtha (ETF), condensate (ETC), heavy oil (ETO) and bitumen (ETB) feedstocks.

9. Seven ethylene-derivative plants: high density polyethylene (HPE), low density polyethylene (LPE), low-to-high density polyethylene (LHP), ethylene glycol (EGE), vinyl chloride (VCE), styrene (SEB) and vinyl acetate (VME);

10. Five other petrochemical plants: benzene-from-condensate (BZC), benzene-from-naphtha (BZN), refinery-grade to chemical-grade propylene (PLP), butylenes-to-butadiene (BTB) and propylene-to-polypropylene (PPP);

11. Four gas re-processing plants: field plant (GPF), straddle plant-ethane (GPS), straddle plant-deep cut ethane (GP3) and Eastern Canadian straddle plant (GPE).

Therefore, forty-seven technologies have been modelled. The capital and operating data was obtained from chemical and petroleum engineering literature. A median plant size was selected and the costs were adjusted for an Alberta location as follows:

1. Preference was given to Alberta studies (e.g. submissions made to the ERCB), in which case the capital and operating costs were updated by using the Chemical Engineering and Consumer Price indices respectively.

2. If no Canadian study was available, the costs of a U.S. Gulf Coast plant were updated by using the appropriate indices. Then an exchange factor of 1.235 and a location factor of 1.3 were applied.

3. If there were no Canadian or U.S. studies available, the cost estimates were based on estimates for similar plants. This was done only for the PLP and LHP technologies.

4. Plant life was assumed to be 25 years. Discount factors of 7%, 10% and 12% were used, as explained later on.

5. If a feedstock or product stream was not explicitly modelled, its annual cost/revenue was deducted from or added to the operating costs.

6. Technological Progress coefficients were assumed and the capital costs of newer technologies were adjusted as explained in TABLE TPC.

The technical coefficients were extracted from Canadian and U.S. studies. A major data source was Rudd (121,127,128). The feedstock

In Table 22 the row names include plant size (SIZE), capital costs (CAPI), operating costs (OPER), discount ra[illegible]SF), plant life (LIFE), technological progress coefficient (PROG), [illegible]ted reserves (RSR), and the names of the feedstock and product streams provided in Appendix 'B'.

There are five refinery types. RHM produces 50% gasoline (GSL) and 34% middle distillates (DTN). RMM produces 35% GSL and 49% DTN. RHE uses heavy oil (HEO) and produces a predominantly asphalt slate - 63% ASP. RSN uses synthetic crude from oil sands (SYC) and produces 41% GSL, 43% DTN and significant volumes of aromatics (BTX) and butylenes (BTL). RNA is the original Petrosar-type chemical refinery which produces significant volumes of ethylene, chemical-grade propylene, aromatics and butylenes.

In accordance with median sizes, plant sizes of coal- and gas-fired power plants are 750 MW, for hydroelectric plants 1000 MW and for nuclear reactors 1200 MW. Their capital and operating costs have been updated from National Energy Board publications (103). The technical coefficients are based on stoichiometric principles. Since coal-, gas-fired and hydroelectric technologies are well established, their technological progress factor is zero; for nuclear power plants a technological progress factor of '05' implies that technological progress will reduce the capital costs at 0.5% per annum.

There are five types of oil sands plants. OSM is modelled after the aborted Alsands project which was to have produced 140,000 barrels/day from the Alsands submission to the ERCB has been updated (3). OS1 is an in situ-bitumen process which is modelled after the experimental Cold Lake project. OS2 is another in situ-bitumen process with 25% higher capital and operating costs and 25% more natural gas usage than OS1. IG1 is an integrated in situ process which produces synthetic oil; it uses natural gas as a hydrogen and fuel source. IC1 is similar to IG1 except that coal supplies a fraction of the fuel requirements. Data for IC1 and IG1 is based on the original Esso proposal to produce synthetic oil at Cold Lake.

There are upgraders for heavy oil and bitumen, whose product is synthetic oil (SYC). The coal liquefaction process, CLI, is based on the German Saarbarwarke process (2). For coal gasification, the data for the three processes SLU, HYG and COA are based on literature sources.

Ammonia and methanol can be produced from either natural gas or coal. The data for such plants were taken from ERCB submissions. Data for ethylene, ethylene-derivatives and other petrochemical plants were taken from ERCB submissions and Rudd (121).

In Table 23 existing capacities of the following energy and petrochemical plants in Alberta are modelled:

1. High gasoline, heavy oil and synthetic oil refineries;

1. Refineries

	Units	RHM	RHE	RSN
CAPA	MBD	323.2	23.5	47.2
OPER	MM$/Y	297.2	21.6	43.9
OIL	MMB/Y	-118.0	0.0	0.0
HEO	MMB/Y	0.0	-8.6	0.0
SYC	MMB/Y	00.0	0.0	-17.2
ELE	BWH/Y	-6.0	-2.0	-2.0
GAS	BCF/Y	-19.1	-2.6	-10.1
GSL	MMB/Y	59.2	0.0	7.1
DTN	MMB/Y	42.1	2.1	7.4
HFO	MMB/Y	4.4	0.9	0.0
ASP	MMB/Y	3.1	5.4	0.0
PLI	KT/Y	146.9	10.7	21.5
PRP	B#/Y	0.5	0.0	0.1
BTL	MMB/Y	0.0	0.0	1.3
BTX	KT/Y	0.0	0.0	223.7

2. Bitumen and Heavy Oil Blends

	UNITS	HEX	BEX	HEA	BEA
CAPA	MMB/Y	1000.0	1000.0	1000.0	1000.0
OPER	MM$/Y	0.0	0.0	0.0	0.0
HEO	MMB/Y	-1000.0	0.0	-1000.0	0.0
BIT	MMB/Y	0.0	-1000.0	0.0	-1000.0
CDS	MMB/Y	-300.0	-500.0	-300.0	-500.0
HDX	MMB/Y	1300.0	0.0	0.0	0.0
BDX	MMB/Y	0.0	1500.0	0.0	0.0
HDA	MMB/Y	0.0	0.0	1300.0	0.0
BDA	MMB/Y	0.0	0.0	0.0	1500.0

3. Power Plants and Oil Sands Plants

	UNITS	PWC	PWG	HYD	OSM
CAPA	MW	4443.0	242.0	802.0	161.0*
OPER	MM$/Y	83.5	3.4	8.0	592.5
ORM	MMB/Y	0.0	0.0	0.0	-58.8
CTS	MMT/Y	-13.2	0.0	0.0	0.0
GAS	BCF/Y	0.0	-12.7	0.0	-28.0
ELE	BKH/Y	21.0	1.2	3.8	-0.3
SYC	MMB/Y	0.0	0.0	0.0	58.8

* MBD

Table 23: TABLE WNEX: Existing Alberta Plants

4. Ammonia, Methanol and Ethylene Plants

	UNITS	AMG	MEG	ETE
CAPA	KT/Y	2650.0	1500.0	1224.0
OPER	MM$/Y	77.0	45.45	63.4
ETH	B#/Y	0.0	0.0	-3.4
GAS	BCF/Y	-88.9	-58.6	-31.5
ELE	BWH/Y	-143.0	-105.0	-103.0
AMM	KT/Y	2650.0	0.0	0.0
MEO	KT/Y	0.0	1500.0	0.0
ETN	KT/Y	0.0	0.0	2224.0
PRP	B#/Y	0.0	0.0	0.0
PLE	KT/Y	0.0	0.0	27.5
BTL	MMB/Y	0.0	0.0	0.6
OIL	MMB/Y	0.0	0.0	0.4

5. Petrochemical Derivatives

	UNITS	LPE	EGE	VCE	VME	SEB
CAPA	KT/Y	338.0	419.0	318.0	45.0	300.0
OPER	MM$/Y	28.7	47.4	37.8	5.5	17.3
ETN	KT/Y	-348.1	-349.9	-152.6	-17.6	-93.0
MEO	KT/Y	0.0	0.0	0.0	-18.3	0.0
BTX	KT/Y	0.0	0.0	0.0	0.0	-234.9
GAS	BCF/Y	-0.9	-2.7	-2.8	0.0	-4.5
ELE	BWH/Y	-100.0	-185.0	0.0	0.0	0.0
LDPE	KT/Y	338.0	0.0	0.0	0.0	0.0
EGC	KT/Y	0.0	419.0	0.0	0.0	0.0
VCM	KT/Y	0.0	0.0	318.0	0.0	0.0
VAM	KT/Y	0.0	0.0	0.0	45.0	0.0
STY	KT/Y	0.0	0.0	0.0	0.0	300.0

6. Gas Processing Plants

	UNITS	GPX	GPB	GPF	GP4	GP5
CAPA						
OPER	MM$/Y	136.0	1200.0	600.0	0.0	0.0
RGA	BCF/Y	0.0	0.0	-3775.0	0.0	0.0
RGB	BCF/Y	0.0	-3775.0	0.0	0.0	0.0
GSH	BCF/Y	321.0	775.0	775.0	0.0	0.0
GS1	BCF/Y	-2743.0	3000.0	3000.0	-1000.0	0.0
GS2	BCF/Y	2422.0	0.0	0.0	0.0	-1000.0
GAS	BCF/Y	0.0	0.0	0.0	1000.0	1000.0
ETH	B#/Y	7.1	0.39	0.39	0.0	0.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

2. Dummy plants which blend heavy oil and bitumen with condensates to permit the pipelining of the former to Eastern Canada and the United States;

3. Coal-fired, gas-fired and hydroelectric power plants;

4. Surface mined oil sands plants;

5. Ammonia and methanol plants with natural gas feedstocks;

6. Ethane-based ethylene plants;

7. Ethylene-derivatives including low density polyethylene, ethylene glycol, styrene, vinyl chloride and vinyl acetate;

8. Gas processing straddle plants.

In this table, the operating costs and technical coefficients are based on TABLE ENTC values. Energy capacities are from various public estimates; petrochemical capacities are based on the data presented in Chapter II.

In Table 24, existing capacities of the following energy and petrochemical plants in Eastern Canada are modelled:

1. The original Petrosar refinery

1. Petrosar, Ammonia, Ethylene

	UNITS	RNA	AMG	ETF
CAPA	KT/Y	170.0	709.0	501.5
OPER	MM$/Y	161.5	26.0	52.7
OIL	MMB/Y	-62.1	0.0	0.0
GAS	BCF/Y	0.0	-23.8	0.0
ELE	BWH/Y	-3.0	-38.0	-72.0
GSL	MMB/Y	3.9	0.0	0.0
DTN	MMB/Y	12.1	0.0	-13.6
HFO	MMB/Y	28.4	0.0	1.9
ETN	KT/Y	453.5	0.0	501.5
PLE	KT/Y	340.1	0.0	284.9
BTL	MMB/Y	2.0	0.0	2.0
BTX	KT/Y	317.5	0.0	0.0
AMM	KT/Y		709.0	0.0

2A. Other Petrochemicals

	UNITS	BEC	PEC	SEB	PPP	BTB
CAPA	KT/Y	397.5	58.7	335.0	135.0	165.0
OPER	MM$/Y	63.6	8.8	19.3	35.0	57.8
ETN	KT/Y	0.0	0.0	-103.9	0.0	0.0
BTX	KT/Y	397.5	0.0	-284.8	0.0	0.0
PLE	KT/Y	0.0	58.7	0.0	-153.7	0.0
BTL	MMB/Y	0.0	0.0	0.0	0.0	-3.4
GAS	BCF/Y	0.0	0.0	-5.1	-3.5	0.0
ELE	BWH/Y	-0.0	-0.0	-59.0	-66.0	0.0
PRP	B#/Y	0.0	0.04	0.0	0.0	0.0
STY	KT/Y	0.0	0.0	335.0	0.0	0.0
PPY	KT/Y	0.0	0.0	0.0	136.0	0.0
BIE	KT/Y	0.0	0.0	0.0		165.0

2B. Other Petrochemicals

	UNITS	HPE	LPE	EGE	VCE
CAPA	KT/Y	163.0	662.0	82.0	91.0
OPER	MM$/Y	32.4	56.3	9.3	10.8
ETN	KT/Y	-166.3	-681.9	-68.5	-43.7
GAS	BCF/Y	-0.4	-1.5	-0.5	-0.8
ELE	BWH/Y	-122.0	[illegible]7.0	-72.0	0.0
HDPE	KT/Y	163.0	0.0	0.0	0.0
LDPE	KT/Y	0.0	662.0	0.0	0.0
EGC	KT/Y	0.0	0.0	82.0	0.0
VCM	KT/Y	0.0	0.0	0.0	47.8

Table 24. TABLE ENEX: Existing Eastern Canadian Plants

2. Ammonia from natural gas and ethylene from naphtha;

3. Aromatics and propylene from refineries (BEC and PEC);

4. Styrene, polypropylene, butadiene, high density polyethylene, low density polyethylene, ethylene glycol and vinyl chloride plants.

In this table, the operating costs and technical coefficients are based on TABLE ENTC values. Petrochemical capacities are based on the data presented in Chapter II.

Based on technological progress, the objective of Table 25 is to reduce the capital costs of developing technologies: the modeller can select from the following options:

- '00' no cost reduction attributable to technical progress;
- '05' 0.5% annual improvement;
- '10' 1.0% annual improvement;
- '33' 1.0% annual improvement till 2006, 0.5% annual improvement till 2015 and no improvement thereafter;
- '44' 0.5% annual improvement to 2006 and no improvement thereafter.

The model specifies the technological progress curves for various technologies in TABLE ENTC, row 'PROG'.

Year	Type of Technological Progress Curve				
	00	05	10	33	44
1985	1.000	1.000	1.000	1.000	1.000
1991	1.000	0.971	0.942	0.942	0.971
1997	1.000	0.942	0.887	0.887	0.942
2003	1.000	0.914	0.836	0.857	0.914
2009	1.000	0.887	0.788	0.849	0.901
2015	1.000	0.861	0.742	0.840	0.901

Table 25: TABLE TPC: Technological Progress Curve

SECTION F: PRODUCTION AND DELIVERABILITY BOUNDS

There is just one table in this section, Table 26 wherein production and deliverability bounds are specified. Production from Alberta conventional oil categories OWA, OWB and OWC are exogeneously specified in columns OILOWA, OILOWB, OILOWC respectively; OWA production is declining whereas OWB and OWC production increases until the turn of the century and then declines. The sum of OWA, OWB and OWC production is the ERCB conventional oil production profile. Heavy oil is divided into existing production (HEOW) and new production (HEON); HEOW declines, HEON increases. The sum of HEON and HEOW is the ERCB heavy oil profile. Column 'OILH' imposes limits on Hibernia oil production from 100,000 barrels/day in the first time period to around 400,000 barrels/day during and after the third time period. This profile is based on current perceptions about the Hibernia oil potential. Column 'RGAF' places limits on natural gas production from Sable Island, based on current perceptions about its production potential. Column 'LOSW' imposes limits on surface mined oil sands production; if these limits were not imposed, due to the nature of linear programming, this technology would push out all other competing technologies. Columns 'BDXW', 'HDXW' and 'HDAW' impose limits on bitumen-blend exports and on heavy oil-blends exports and ex-Alberta supplies, respectively; they are essentially market-imposed constraints based on current perceptions of the U.S. and ex-Alberta demands for these energy forms (45). Imported crude oil 'IOIL' has been limited, as a matter of policy, to approximately 400,000 barrels/day. Exports of synthetic crude from oil sands 'ESYC' have been limited to approximately 270,000 barrels/day; this is a

	OILOWA MMB/Y	OILOWB MMB/Y	OILOWC MMT/Y	HEON MMB/Y	HEOW MMB/Y
1985	286.2	18.4	13.0	0.01	32.14
1991	136.2	38.2	39.8	0.01	27.55
1997	73.5	45.9	43.6	2.00	27.55
2003	44.4	44.4	38.2	5.00	25.25
2009	26.5	37.2	32.2	15.00	22.96
2015	12.0	26.0	26.2	22.50	20.66

	OILH MMB/Y	RGAF BCF/Y	LOSW MMB/Y	BDXW MMB/Y
1985	36.5	30.0	60.0	146.0
1991	75.0	350.0	108.0	146.0
1997	150.0	1500.0	149.0	146.0
2003	150.0	1500.0	239.0	146.0
2009	150.0	1500.0	279.0	146.0
2015	150.0	1500.0	319.0	146.0

	HDXW MMB/Y	HDAW MMB/Y	IOIL MMT/Y	ESYC MMB/Y
1985	109.5	16.38	150.0	100.0
1991	109.5	16.38	150.0	100.0
1997	109.5	16.38	150.0	100.0
2003	109.5	16.38	150.0	100.0
2009	109.5	16.38	150.0	100.0
2015	109.5	16.38	150.0	100.0

	PHYD BKH/Y	GASBC BCF/Y	OILSK MMB/Y	HEOSK MMB/Y
1985	4.21	80.0	31.86	17.65
1991	4.21	100.0	28.22	18.75
1997	4.21	122.5	25.00	19.89
2003	4.21	150.0	22.15	21.11
2009	4.21	165.0	19.62	22.41
2015	4.21	175.0	17.38	23.79

Table 26: **TABLE ULLT: Production and Deliverability Bounds**

limited to 4.21 BKWH/year. Natural gas production in British Columbia 'GASBC', conventional oil production in Saskatchewan 'OILSK' and heavy oil production in Saskatchewan 'HEOSK' are based on current production projected into the future; the GASBC, OILSK and HEOSK productions are added to Alberta gas and oil production, so that the model includes the total Western Canadian energy production.

SECTION G: FIXED PARAMETER TABLES

There are eight tables in this section:

1. TABLE ALPC: Miscellaneous Constants;
2. TABLE APRT: Time-Dependent Constants;
3. TABLE DISF: Discount Factors;
4. TABLE ACC: Annualized Capital Cost Factors;
5. TABLE CAC: Capital Cost Factors;
6. TABLE CAQ: Total Capital Available;
7. TABLE PPP: Plant Production Profile;
8. TABLE CCF: Capital Charge Factor.

In Table 27 the constants are the discount rate 'DISF', societal discount rate 'SDSF', the fraction of economic rent that accrues to the government from oil 'FERO' and gas 'FERG', and the cost of converting Eastern Canada naphtha crackers to NGL crackers as a fraction of the cost of new NGL crackers, 'REP'. DISF is the discount rate used to convert future revenues and costs to present value. It is specified

Item	Units	Value
DISF	%/Y	5.0
SDSF	%/Y	5.0
REP	Frac	0.50
FERO	Frac	0.95
FERG	Frac	0.95

Table 27 TABLE ALPC: Miscellaneous Constants

debate about the appropriate discount rate to choose. A zero discount rate implies that in decision-making, the future is given equal consideration with the present and that capital commands no rent. Since this is obviously not true, a zero discount rate is not appropriate. A very high discount rate implies that decision-making is based almost totally on present considerations; future generations can look after themselves. Since this is a philosophy not held in a modern industrial state, a very high discount rate is not appropriate. Societal decision-making usually uses a low discount rate, usually 3% per annum. Commercial decision-making would be based on relatively high discount rates, usually between 7 and 10% per annum. Therefore a discount rate for governmental policy-making, which involves both societal and commercial considerations will lie between 3% and 7% per annum. In this analysis, the average of these two values is used. In the model, if the economic rent from oil and gas sales accrues only to the government, then private industry will have no incentive to develop the cheapest reserves first; however, even a 5% incentive implied by taking FERO and FERG values as 0.95, ensures that the cheapest reserves are developed first. Finally, Eastern Canadian naphtha-based ethylene plants are permitted to retrofit so that NGL feedstocks can be used; the retrofit option should be cheaper than building new plants, otherwise it would make no sense to retrofit. Therefore, REP specifies the retrofitting costs as a fraction of the new plant costs.

In Table 28, the U.S.-Canadian exchange rate factor 'EXCC' is assumed to be 1.235 throughout the planning horizon. The propane 'PRP', butane 'BUT' and condensate 'CDS' content of existing natural gas fields in Alberta is based on the assumption that as the deeper reserves are produced, the percentage of propane, butane and condensate decreases (56).

Table 29 specifies the discount rate factors. For example, if in TABLE ALPC, 'DISF' is assumed to be '05' then all first time period revenues and costs must be multiplied by 0.9286 to get their present worth. The modeller has the option of selecting one of the following discount rates: 3%, 5%, 7%, 10%, 12% or 15% per annum.

To avoid end-effects problems in Table 30 the capital costs are annualized over the assumed plant life. In this table, the fraction of capital costs to be assigned annually are calculated as a function of discount rate and plant life.

Table 31 assigns a capital penalty for excessive capital use. Table 32 specifies the capital available during a time period on which there would be no penalty imposed by TABLE CAC.

Since a new plant is assumed to start up at the beginning of a time period, the plant will not operate at full capacity from startup. Furthermore, its final operational year may be in the middle of a period. In Table 33, the production profile of a plant for every time period following startup is specified as a fraction of the unit size specified in TABLE ENTC. For example, consider the value in column '20'

	EXCC (US$-C$)	PRP	BUT	CDS
		(Fraction of 1980 values)		
1985	1.235	0.95	0.90	0.75
1991	1.235	0.90	0.84	0.61
1997	1.235	0.87	0.80	0.51
2003	1.235	0.87	0.80	0.51
2009	1.235	0.87	0.80	0.51
2015	1.235	0.87	0.80	0.51

Table 28: TABLE APRT: Time Dependent Constants

	Discount Rate				
Period	03	05	07	10	12
01	[illegible]	[illegible]	0.9019	0.8638	0.839[illegible]
02	0.8009	0.6929	0.6010	0.4876	0.4254
03	0.6707	0.5171	0.4005	0.2752	0.2155
04	0.5617	0.3859	0.2669	0.1554	0.1092
05	0.4704	0.2879	0.1778	0.0877	0.0553
06	0.3940	0.2149	0.1185	0.0496	0.0280

Table 29: TABLE DISF: Discount Factors

Discount Rate %/Y	Life of Plant - Yrs 20	25	30	15
03	0.0672	0.0574	0.0510	0.0838
05	0.0802	0.0710	0.0651	0.0963
07	0.0944	0.0858	0.0806	0.1098
10	0.1175	0.1102	0.1061	0.1315
12	0.1339	0.1275	0.1241	0.1468
15	0.1598	0.1547	0.1523	0.1710

Table 30: **TABLE ACC: Annualized Capital Costs**

	ANC
CXL	0.0944
CXH	0.1175
CYL	0.1061
CYH	0.1334
CZL	0.1468
CZH	0.1710

CXL = Utilities @ 7% real, N = 20;
CXH = Utilities @ 9% real, N = 20;
CYL = Oil Sands, Heavy Oil, Coal Liquids @ 10% real, N = 30;
CYH = Oil Sands, Heavy Oil, Coal Liquids @ 13% real, N = 30;
CZL = Petrochemical Plants @ 12% real, N = 15;
CZH = Petrochemical Plants @ 15% real, N = 15.

Table 31: TABLE CAC: Capital Penalty Charge

	CAPX MM$	CAPY MM$	CAPZ MM$	CAPU MM$	CAPV MM$
01	30000	20000	20000	16000	12000
02	33000	22000	22000	16000	12000
03	36300	24200	24200	16000	12000
04	39900	26600	26600	16000	12000
05	43900	29300	29300	16000	12000
06	48300	32200	32200	[illegible]000	12000

Table 32: TABLE CAQ: Total Capital Available

and row '04'; a 20-year plant life implies that the plant will cease to operate after two years in time period 4. Therefore, at full capacity the annual production in that period would be 2/6 or 0.33. The value specified is somewhat lower, to reflect the age of the plant. Also specified in this table are the production profiles for certain primary energy developments.

Table 34 gives the capital amortization factor in which the annualized capital charges are assessed only for the life of the plant. Since 15, 20 and 25 are not divisible by 6, fractional entries occur in the last time period.

This completes the data development. Next, the results from the base scenario run are presented.

Time Periods After Startup	Life of Plant - years 15	20	25	30
01	0.95	0.92	0.92	0.92
02	1.00	1.00	1.00	1.00
03	0.[illegible]8	1.00	1.00	1.00
04	0.00	0.31	0.94	1.00
05	0.00	0.00	0.15	0.94
06	0.00	0.00	0.00	[illegible].00

Table 33: TABLE PPP: Plant Production Profile

Time Periods After Startup	Life of Plant - years 15	20	25	30
01	1.00	1.00	1.00	1.00
02	1.00	1.00	1.00	1.00
03	0.57	1.00	1.00	1.00
04	0.00	0.36	1.00	1.00
06		0.00		

Table 34: TABLE CCF: Capital Charge Factor

CHAPTER VII. BASE CASE RESULTS

In order to validate the model structure approximately 200 trial runs were made. The trial runs were mainly in the smaller two- or four-period versions. All the new variables and constraints were tested. The testing of a new technology was done by setting its costs equal to zero; in the trial run that technology would displace its competitors. Trial runs were made to ensure that the oil and gas prices were consistent with their real costs of production. Due to the inherent weaknesses in linear programming discussed in Chapter I, trial runs were made and the production and deliverability bounds were adjusted to ensure that a plausible scenario was generated. After being satisfied that the model structure was valid and using the data described in the previous chapter, a six-year, six-period 'base' scenario (scenario #1) was generated.

The model output of scenario #1 is presented in Appendix 'C'. Throughout this chapter and the next, selected projections from this model are presented. As explained in Chapter III, the projections are not intended to be forecasts; they are reflections of how the economy would react to the assumptions implicit in the model structure and data. Therefore they are intended to provide insights into the behaviours of and interactions between the energy and petrochemical sectors. Such insights are discussed in the final two chapters. Since the output values are the average values for the periods in which they occur, they have been plotted at the mid-points of the periods.

The detailed assumptions in scenario #1 have already been presented in the previous two chapters. The key data assumptions relate to the world oil price projections, Alberta natural gas reserves, limits on surface mined oil sands activity, and the capital cost surcharge for excessive industrial activity in a given time period.

1. Natural Gas

It is necessary to investigate the Alberta natural gas production trends, since the Alberta petrochemical industry relies on gas and its associated natural gas liquids for its feedstock.

The production profiles of the three Alberta gas categories described earlier are endogenously generated. In Figure 40 the sum of these profiles is shown as the Alberta marketable gas production. 'Discovered' gas production lasts until 2003. Preproduction activities for 'undiscovered' gas reserves start from the mid-1980's although production starts in the early 1990's. The reason for this is that during the early 1990's the first level of capital is exhausted by oil sands and petrochemical activities; for the preproduction activities to be synchronous with production, a capital surcharge would be needed. In the mid-1980's, with low energy and petrochemical activities, the preproduction activities for 'undiscovered' gas are within the first level of capital availability. Therefore the capital surcharge constraint minimizes the overheating of the provincial economy. The 'undiscovered' gas production peaks in 2003 and 'tight' gas is required by 2009.

FIGURE 40. BASE CASE: ALBERTA MARKETABLE GAS PRODUCTION

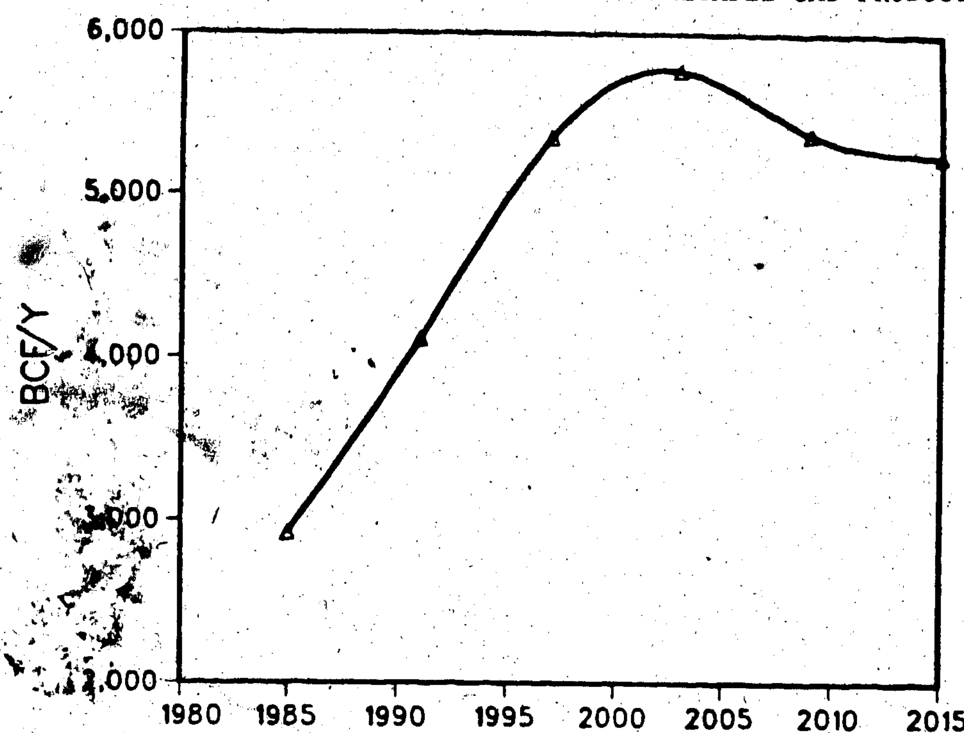
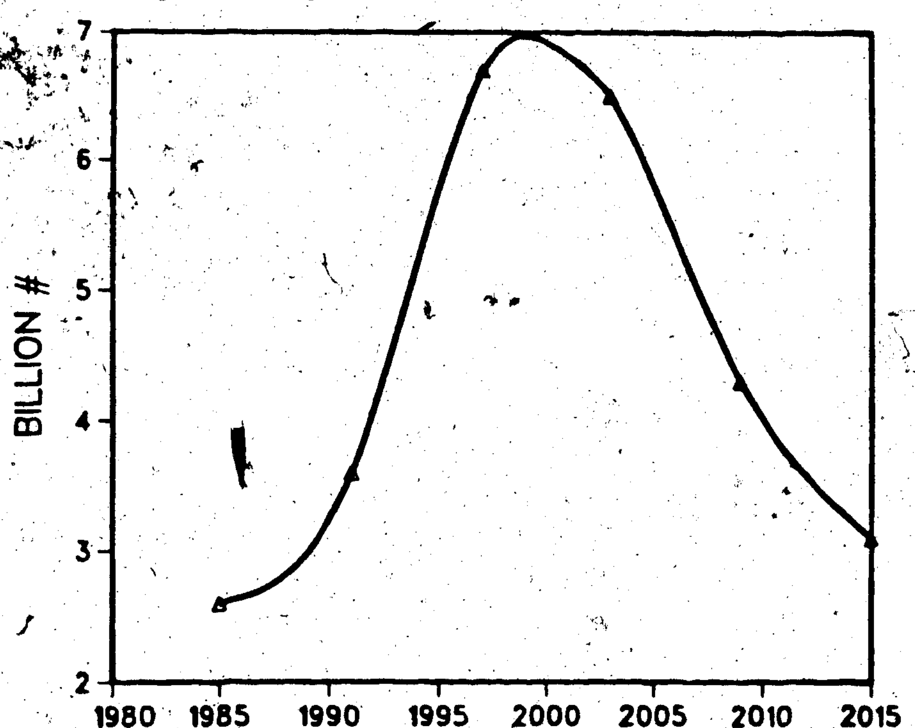


FIGURE 41. BASE CASE: 'SURPLUS' ETHANE



The total marketable gas production satisfies both Canadian and export demands. Priority is given to Canadian consumer demands. However, at the specified border prices for natural gas to the seven U.S. market regions, natural gas exports occur to all the regions. In Figure 40, the peak is caused by the exports which correspondingly peak in the early 2000s.

The production of the higher-cost 'undiscovered' gas causes the real costs of natural gas to triple between 1985 and 1997. The escalation rate is faster than the escalation in gas prices. Therefore, the natural gas rents are lower. The next escalation in real costs occurs in 2009 as the 'tight' gas reserves are produced.

Ethane and NGLs production is associated with the production of natural gas. The ethane and NGLs will satisfy the provincial industrial and consumer demands; any production surplus to provincial requirements is available for export and ex-Alberta demand. At the natural gas production levels shown in Figure 40, an ethane surplus occurs. This surplus follows the natural gas production trend. It peaks in the late 1990's (Figure 41). The propane and butane surpluses exhibit similar peaks.

The surplus condensate curve is quite different from the surplus ethane curve. Its requirements as a diluent for bitumen and heavy oil causes the surplus to decline until 2009. In 2009, a decline in the bitumen-blend requirements causes the condensate surplus curve to peak (Figure 42).

FIGURE 42. BASE CASE: 'SURPLUS' CONDENSATE

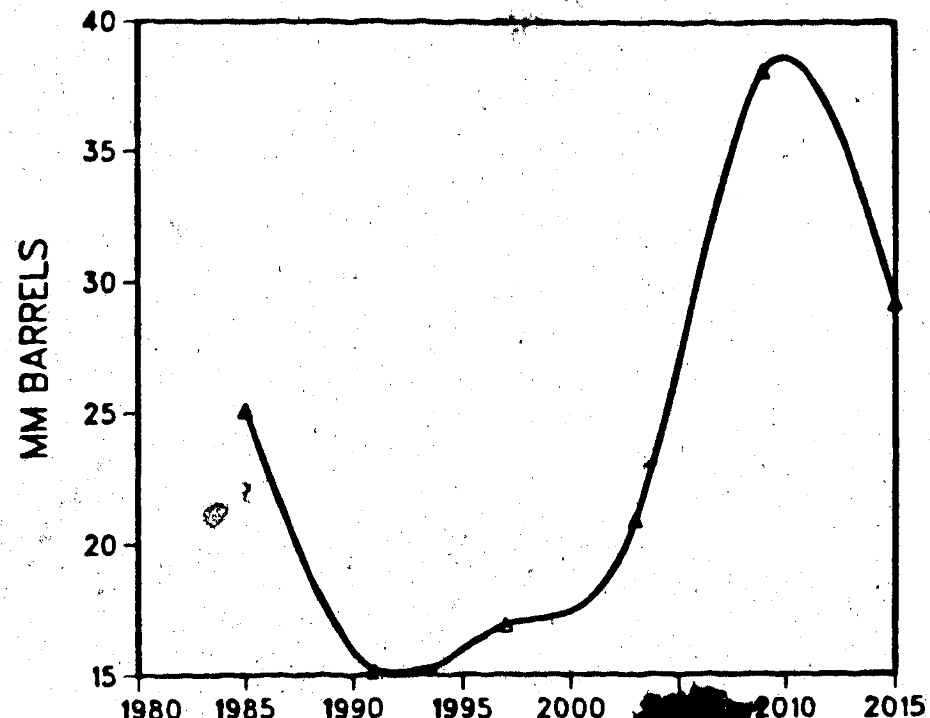
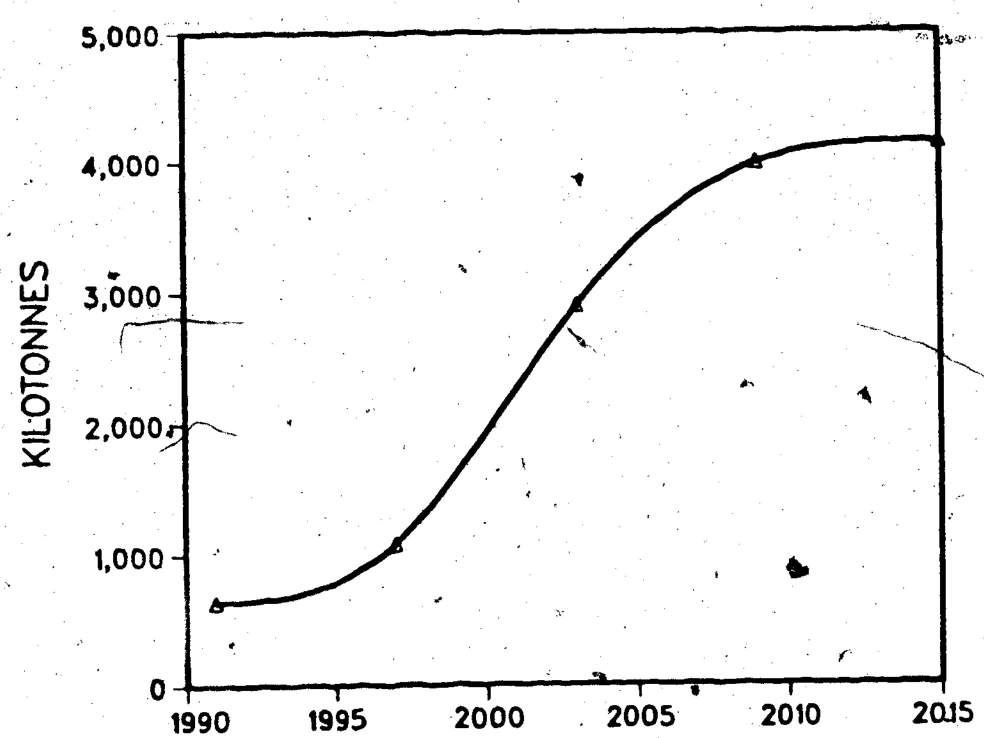


FIGURE 43. BASE CASE: CUMULATIVE AMMONIA-FROM-GAS ADDITIONS



Natural gas, ethane and natural gas liquids are the principal feedstocks of the petrochemicals industry in Alberta.

2. Methane-Based Petrochemicals

The model results show that there is a slight surplus in the Alberta ammonia capacity. No capacity additions are needed until 1991; major new capacity additions occur between 1997 and 2009, in order to meet the increasing regional demand and to replace the existing plants (Figure 43). This production is directed towards the Western Canada, U.S. Mid-west and U.S. Pacific Coast markets. Since the transportation costs from Alberta to Eastern Canada and the Pacific Rim countries are very high, Alberta producers do not penetrate these markets.

In Eastern Canada, production increases steadily over time to satisfy the regional demand (Figure 44). As shown in Table 35, in spite of a substantial feedstock price advantage for Alberta, the transportation penalty is sufficient to shelter the Eastern Canadian producers.

Throughout the planning horizon the preferred feedstock for ammonia production is natural gas, not coal. Please refer to Table 15. The natural gas cost to Alberta producers is the product of ABP and IPF; the cost to Ontario producers is TCG. From Table 22 the gas input to ammonia and methanol plants is obtained. From Table 11, the transportation costs from Alberta to Ontario are extracted. The transportation advantages for Ontario producers are the transportation costs divided by the gas input, as shown. The gas advantage is the difference between

	Gas Input (MCF/T)	Transp. Costs ($/T)	Trans. Adv. ($/MCF)	Gas Adv. ($/MCF)	Net Adv. ($/MCF)	Net Adv. ($/T)
Case A*						
Ammonia	33.54	102.72	3.06	-2.38	0.68	22.81
Methanol	39.09	60.22	1.54	-2.38	-0.84	-32.84
Case B**						
Ammonia	33.5[illegible]	102.72	3.06	-1.25	1.81	60.71
Methanol	39.[illegible]9	60.22	1.54	-1.25	0.29	11.34

* Case A

Eastern Canadian producers pay ABP + transportation	=	$4.08/MCF
Alberta producers pay Alberta industrial price (AIP)	=	$1.70/MCF
DIFFERENCE		$2.38/MCF

** Case B

Eastern Canadian producers pay AIP + transportation	=	$2.95/MCF
Alberta producers pay AIP	=	$1.70/MCF
DIFFERENCE		$1.25/MCF

Table 35: Competitive Position of Eastern Canadian Methane-Based Petrochemicals

FIGURE 44. BASE CASE: EASTERN CANADIAN AMMONIA PRODUCTION

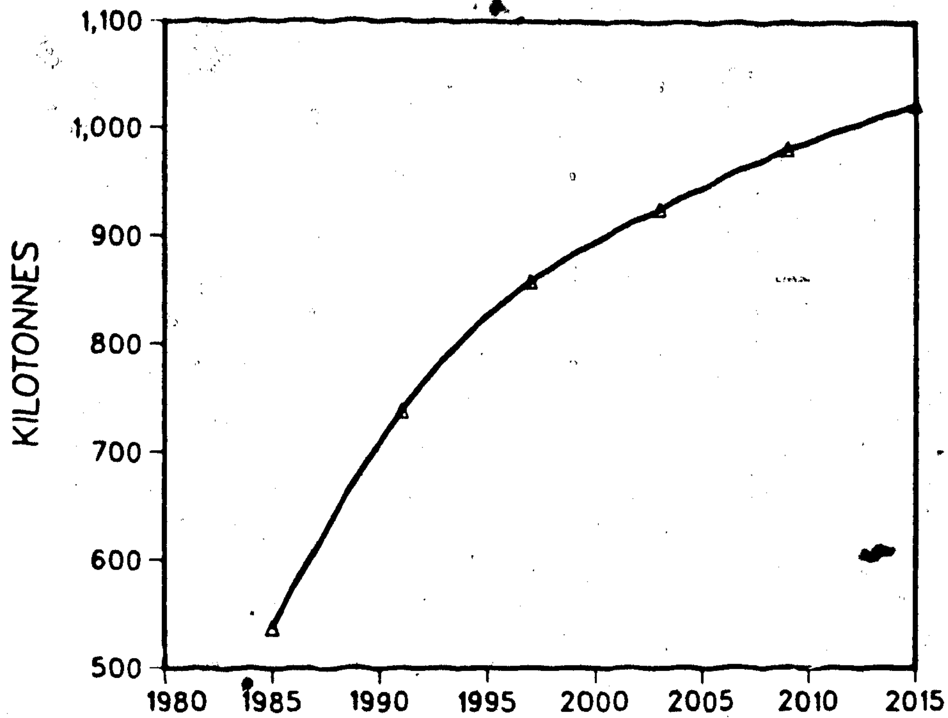
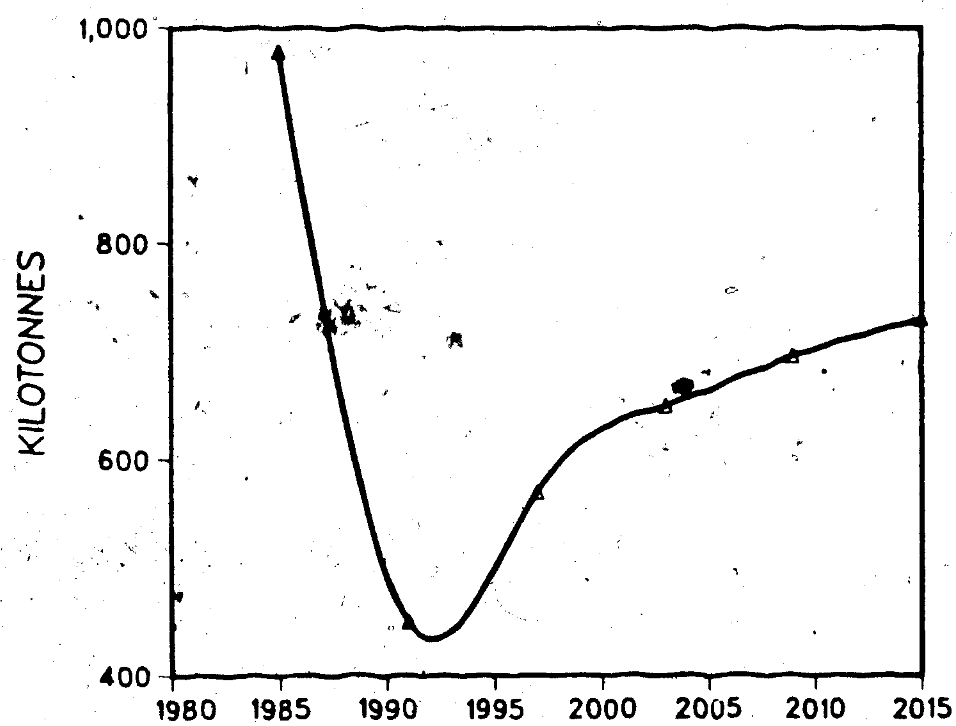


FIGURE 45. BASE CASE: ALBERTA CHEMICAL-RELATED METHANOL PRODUCTION



TCG and the Alberta industrial price. For Ontario producers the ammonia transportation advantage outweighs the gas disadvantage. Therefore, Alberta ammonia production cannot penetrate the Eastern Canadian market.

For Ontario producers the methanol transportation advantage does not outweigh the gas disadvantage; therefore, Alberta methanol production can penetrate the Eastern Canadian market. Currently, the Alberta producers have free market gas prices, whereas the Eastern Canadian producers are charged a regulated price. If the Eastern Canadian producers are also permitted to pay free market Alberta prices, then their natural gas costs would be the Alberta industrial price plus transportation; therefore, the natural gas disadvantage would be reduced from \$2.38/MCF to \$1.25/MCF. In this case, for Ontario producers the methanol transportation advantage would outweigh the gas disadvantage and Alberta methanol production would not be able to penetrate the Eastern Canadian market and new methanol capacity would be added in the East.

Methanol can be used either for manufacturing chemicals or for fuel-related uses. There are two reasons for segregating it on the basis of its uses. First, for fuel-related uses, the United States imposes no duty on methanol, whereas for chemical-related uses it imposes a 18% ad valorem duty; second, the chemical-related market is well established and mature whereas the fuel-related market is small but growing fast and has potential for enormous growth.

The model results show that methanol-for-chemicals can penetrate the export market only in the first time period. As the opportunity costs of natural gas increase, gas as a feedstock for methanol is diverted to other uses. However, the domestic market continues to grow (Figure 45). Fuel-related methanol production increases steadily (Figure 46). Since it can enter the U.S. market tariff-free, it is projected to capture a portion of that market. However, this market is only in its early stages of development and the Alberta surplus production capacity in methanol remains until 1997.

Fuel-related methanol begins to dominate from 1991 onwards. No new methanol plants are needed until 2003, at which time both coal and natural gas are the feedstocks to the new plants (Figures 47 and 48). The reason for the dual feedstocks is that natural gas and natural gas liquids production is conserved in order to meet the requirements in the later time periods; furthermore, the natural gas prices are escalated faster than the coal prices so that in the later periods coal becomes a competitive feedstock for methanol.

3. Ethane- and Higher-Based Petrochemicals

As shown in Figure 10, there is a substantial ethylene over-capacity in Canada. The model results indicate that, compared to Alberta, the Eastern Canadian naphtha-based plants are not competitive. In Table 36, the production costs of ethane-based (ETE), naphtha-based (ETF) and ethane-propane based (EPE) ethylene plants are compared.

FIGURE 46. BASE CASE: ALBERTA FUEL-RELATED METHANOL PRODUCTION

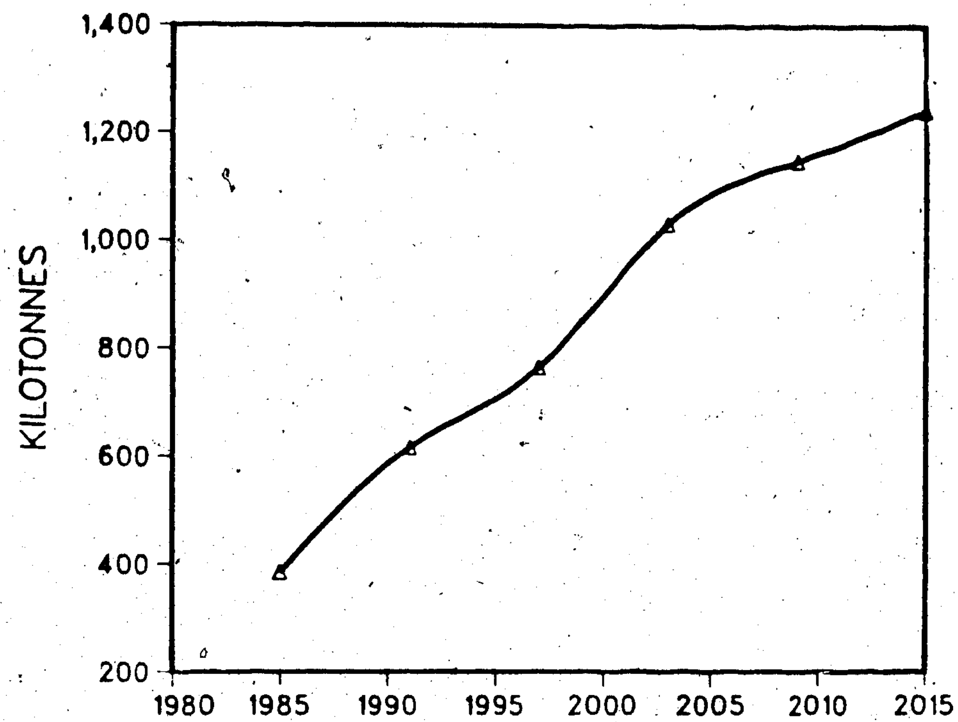


FIGURE 47. BASE CASE: CUMULATIVE METHANOL-FROM-GAS ADDITIONS

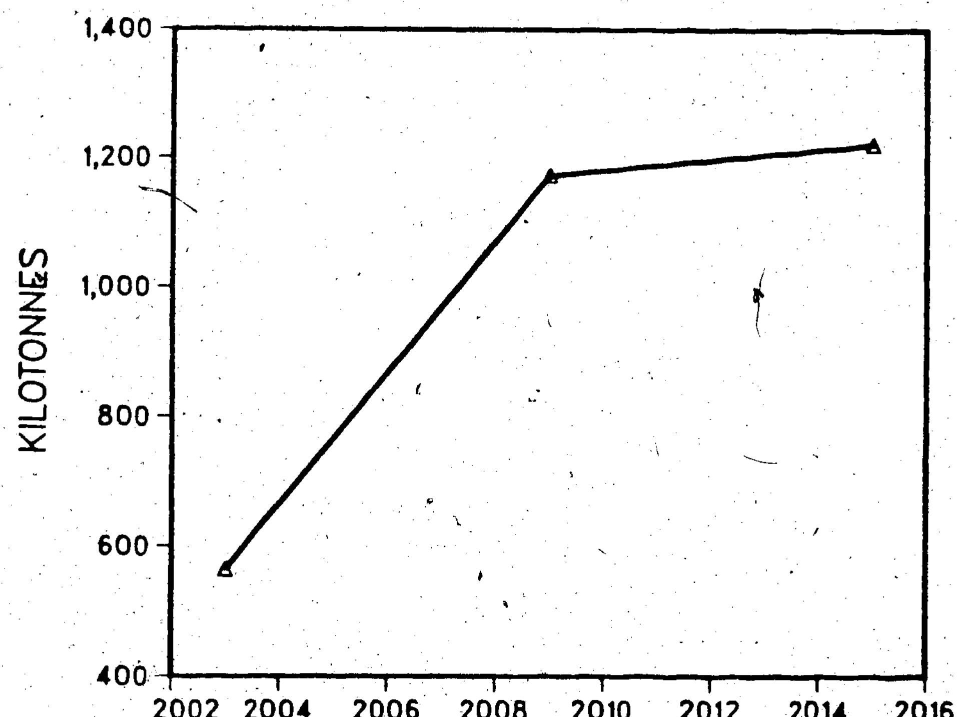


FIGURE 48. BASE CASE: CUMULATIVE METHANOL-FROM-COAL ADDITIONS

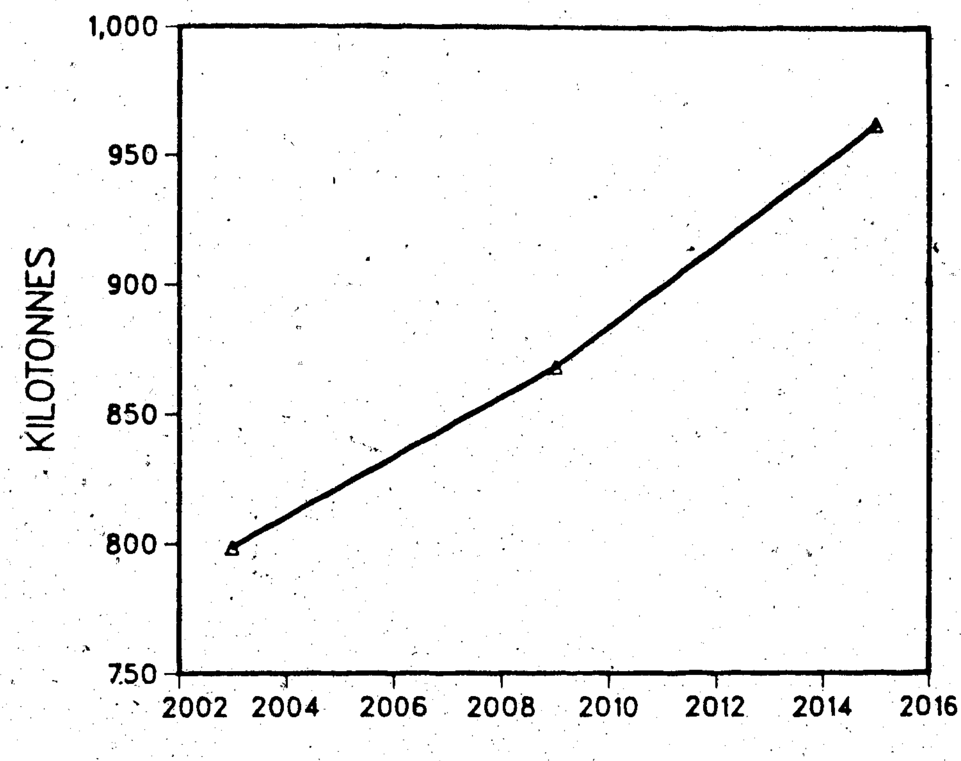
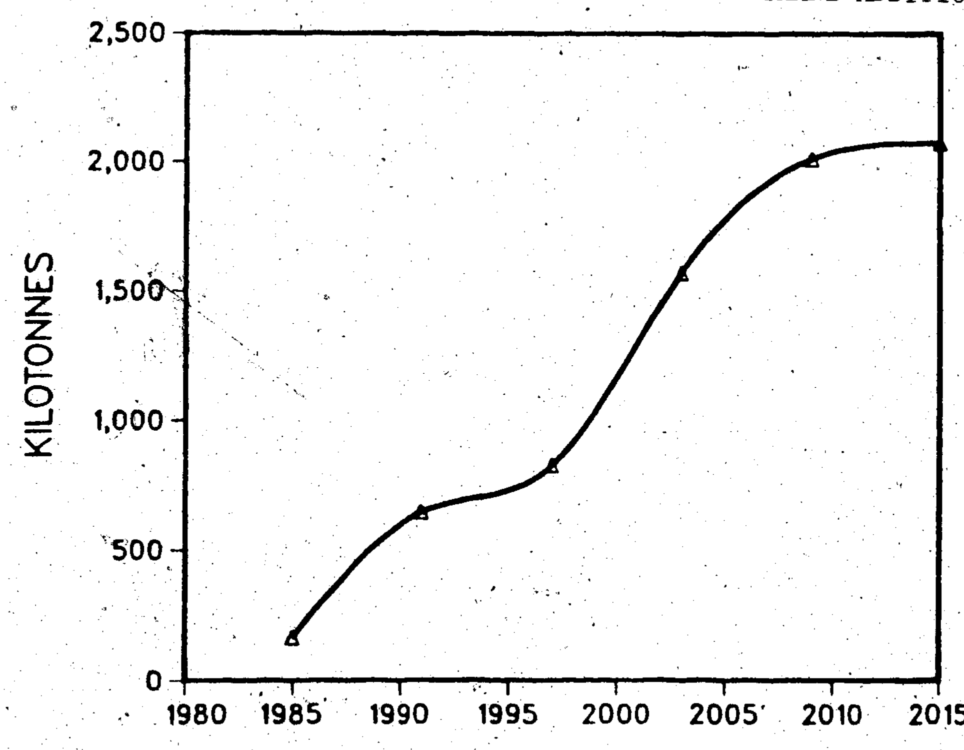


FIGURE 49. BASE CASE: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS



	Feedstock Costs	Ethylene Plants ETE (MM$)	ETP (MM$)	EPE (MM$)
1. Costs				
Capital	-	49.59	100.39	63.32
Operating	-	35.20	71.50	44.50
Gas	$1.70/MCF	29.75	-	2.98
Electricity	3.2 ¢/kwh	3.10	3.10	3.10
Ethane	7.73 ¢/#	145.32	-	81.94
Propane	9.32 ¢/#	2.42	-	138.96
Naphtha	$44.03/bbl	-	813.23	-
		265.38	988.22	334.71
2. By-Product Credits				
Butylene		8.69	76.14	8.23
Fuel Oil		6.81	87.46	14.56
Propylene		6.75	205.13	-
Ethylene		-	-	243.20
		22.25	368.73	265.99
3. Production Costs				
Ethylene (¢/lb)		16.53	41.32	-
Propylene (¢/lb)		-	-	24.1

Table 36: Ethylene and Propylene Costs

The technical and economic coefficients are from TABLE ENTC; the feedstock and product prices are from the various price tables. If the natural gas costs are assumed to be 60% of the Alberta border price, then the Alberta ethane-based plant can produce ethylene at a cost-of-service of 16.22 ¢/lb. If this ethylene price is used in the EPE case, then the propylene price is 24.1 ¢/lb. If the natural gas costs are at Alberta border price, the ETE ethylene costs increase to 17.53 ¢/lb and the EPE propylene costs decrease to 17.91 ¢/lb. The transportation penalty for shipping ethylene from Alberta to Eastern Canada is ~3 ¢/lb. Therefore, an Eastern producer has to compete with 19.22-20.53 ¢/lb ethylene. As shown in Table 36, the naphtha-based ethylene producer's ethylene price is 41.32 ¢/lb. If the capital costs of these plants are considered as sunk, the ethylene price is 34.62 ¢/lb. The conclusion is that in Canada no process based upon crude oil or naphtha feedstock can produce ethylene or propylene at competitive costs compared to ethane and propane based processes.

In the U.S. Gulf Coast, ethylene prices are set by the high cost swing supplier, probably a naphtha-based plant. Even if conditions were such that the Eastern Canadian petrochemical producers could compete in the U.S. markets, the Alberta supplier could supply ethylene to those markets at lower costs.

To meet the projected domestic and export demands for the ethylene-derivatives, the model results show that a world scale ethane-based plant will be required in Alberta by 1991 and a mixed ethane-propane plant shortly thereafter (Figures 49 and 50). In 2003 and 2015 the pattern will be repeated. The propylene from the mixed ethane-propane plant will be used in the manufacture of polyproylene in Alberta.

As shown in Figures 51 and 52, as Alberta moves to capture the available markets in Eastern Canada, the U.S. and the Pacific rim countries, the existing polyethylene capacity should be fully utilized and substantial new capacity will be needed.

In ethylene glycol, there is currently a production overcapacity in Alberta. The model results show (Figures 53 and 54) that no new plants will be needed until the beginning of the next century, after which there will be a steady growth in capacity until the end of the forecast period.

Styrene is manufactured from benzene and ethylene. For crude oil based petrochemicals like benzene there is no feedstock price advantage for Alberta. Therefore, the styrene markets in Eastern Canada and the U.S. are projected to be retained by the Eastern Canadian producers. The Pacific rim and Western Canadian markets will be accessible to Alberta styrene. The current styrene plants will operate at capacity and no new capacity will be needed until 2003 (Figure 55).

Vinyl chloride markets in Canada and the U.S. will be economically accessible to Alberta producers. However, no new VCM plant will be needed until 1991 (Figure 56).

FIGURE 50. BASE CASE: CUMULATIVE ETHYLENE-FROM-ETH/PRP ADDITIONS

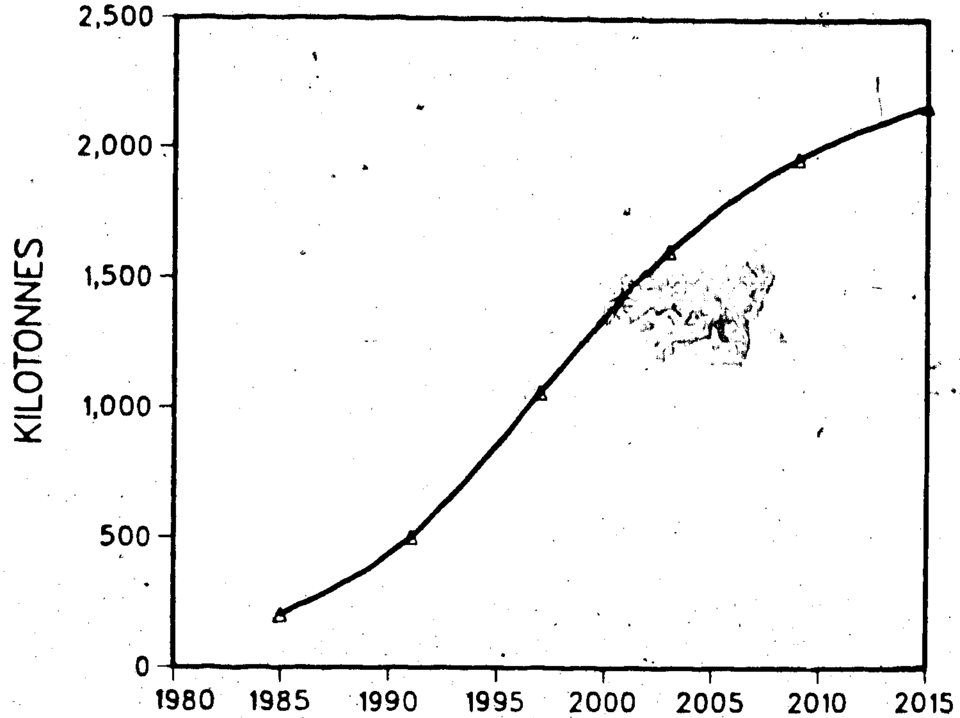


FIGURE 51. BASE CASE: CUMULATIVE LOW DENSITY POLYETHYLENE ADDITIONS

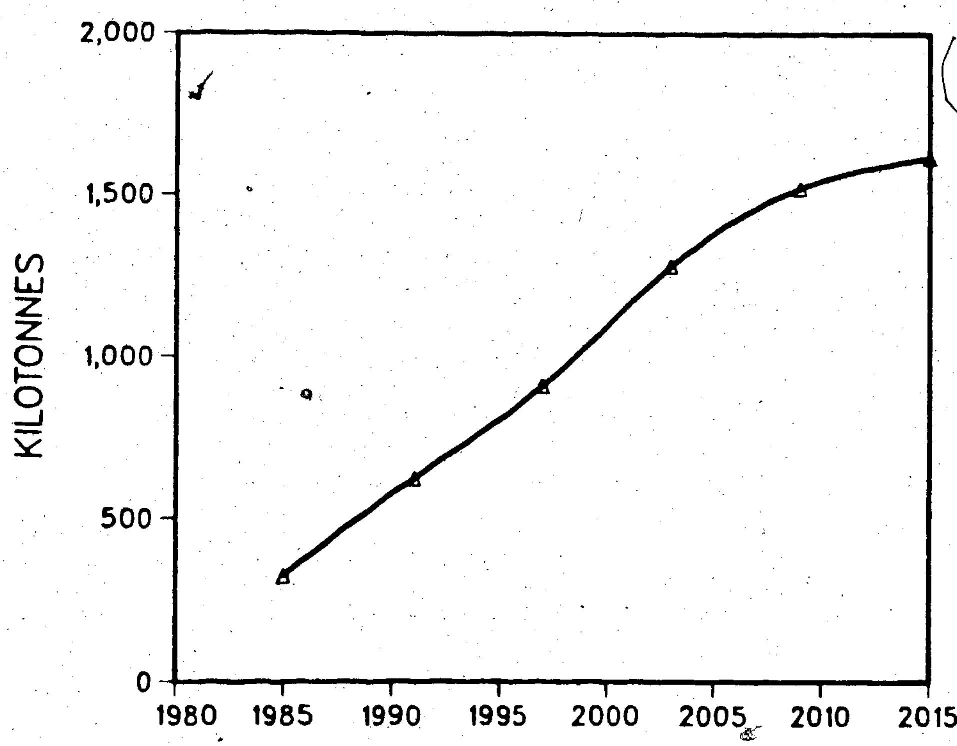


FIGURE 52. BASE CASE: CUMULATIVE HIGH DENSITY POLYETHYLENE ADDITIONS

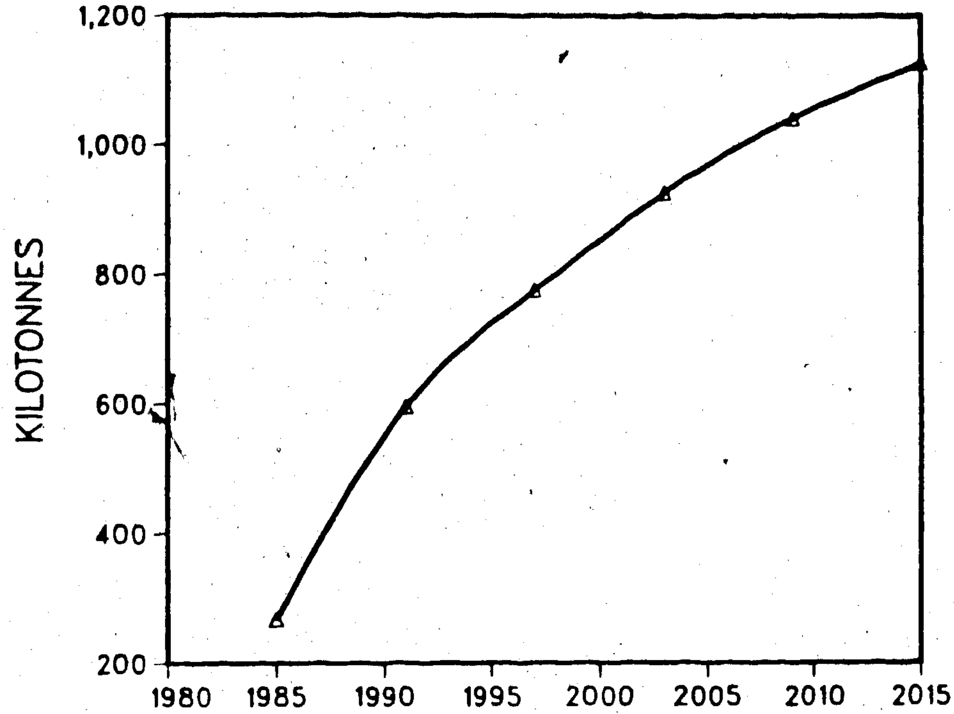


FIGURE 53. BASE CASE: ALBERTA ETHYLENE GLYCOL PRODUCTION

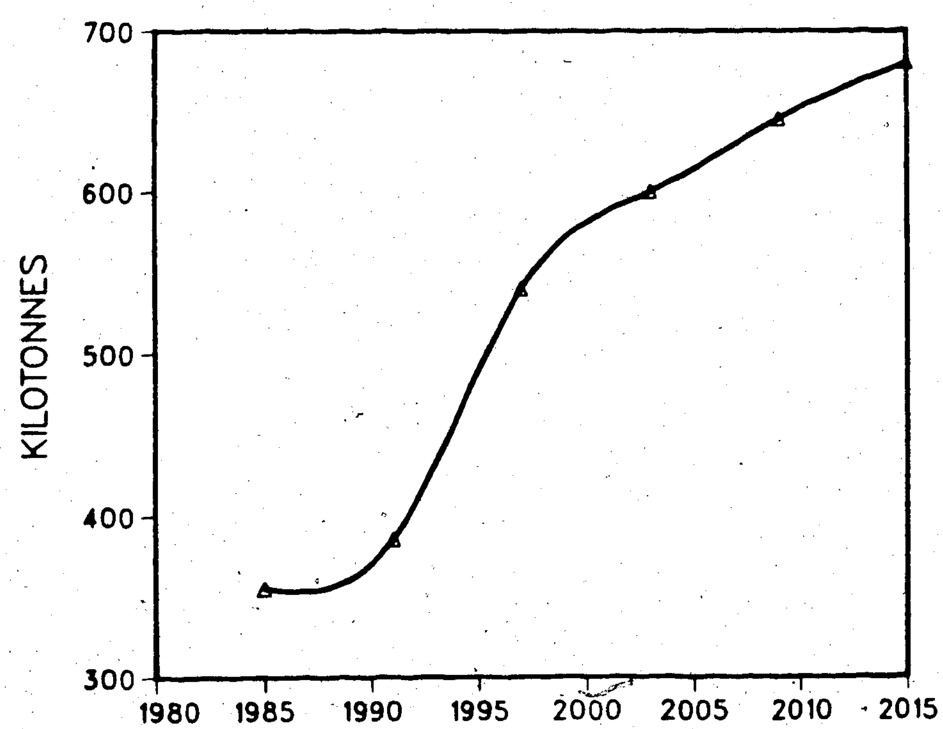


FIGURE 54. BASE CASE: CUMULATIVE ETHYLENE GLYCOL ADDITIONS

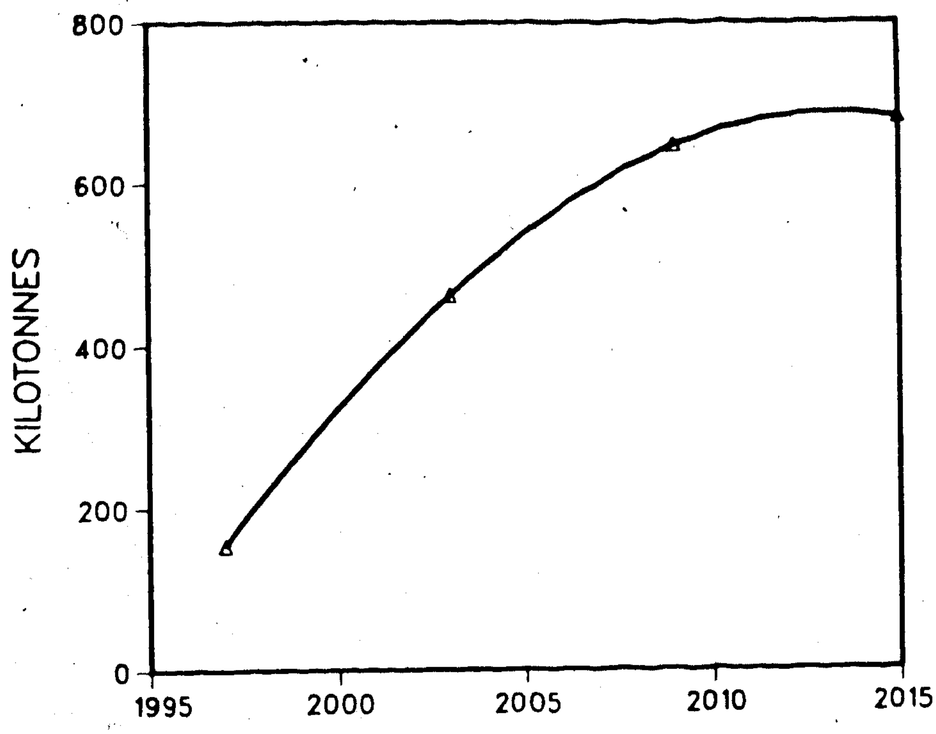


FIGURE 55. BASE CASE: CUMULATIVE STYRENE ADDITIONS

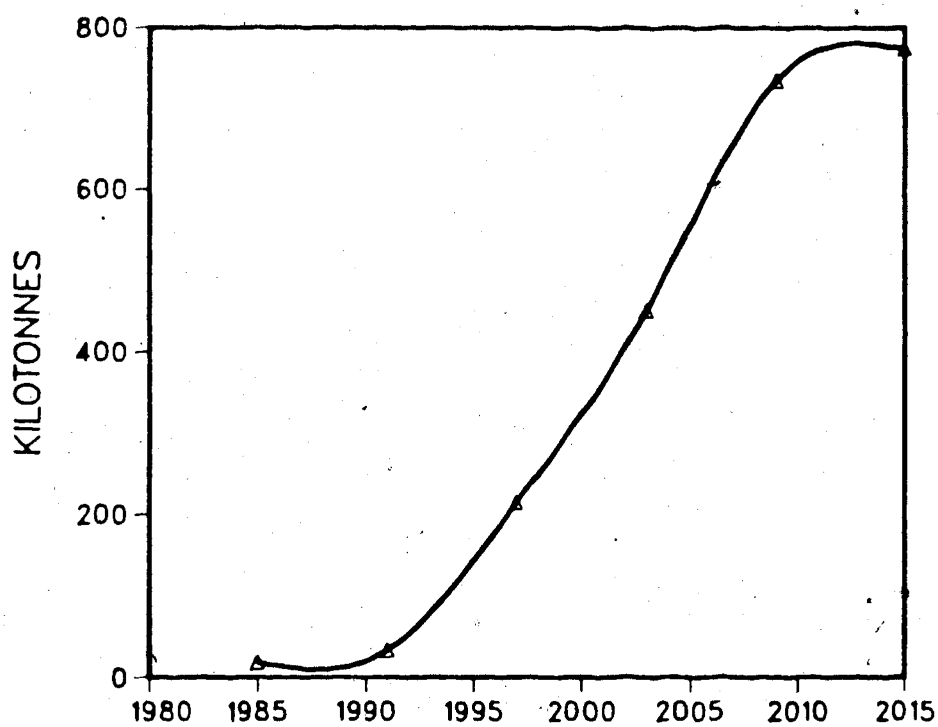


FIGURE 56. BASE CASE: CUMULATIVE VINYL CHLORIDE ADDTIONS

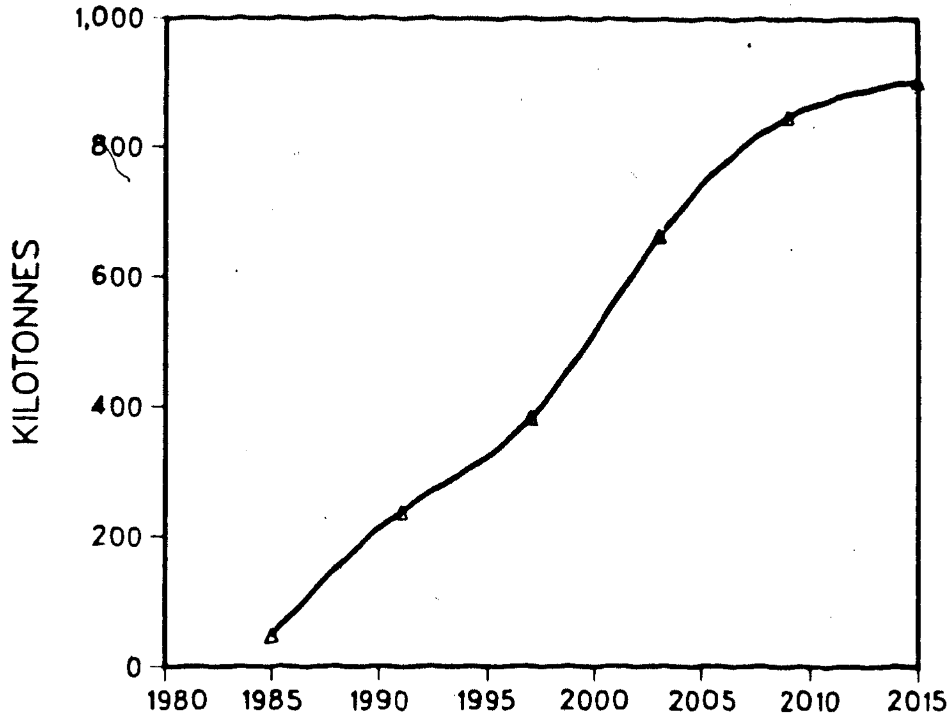
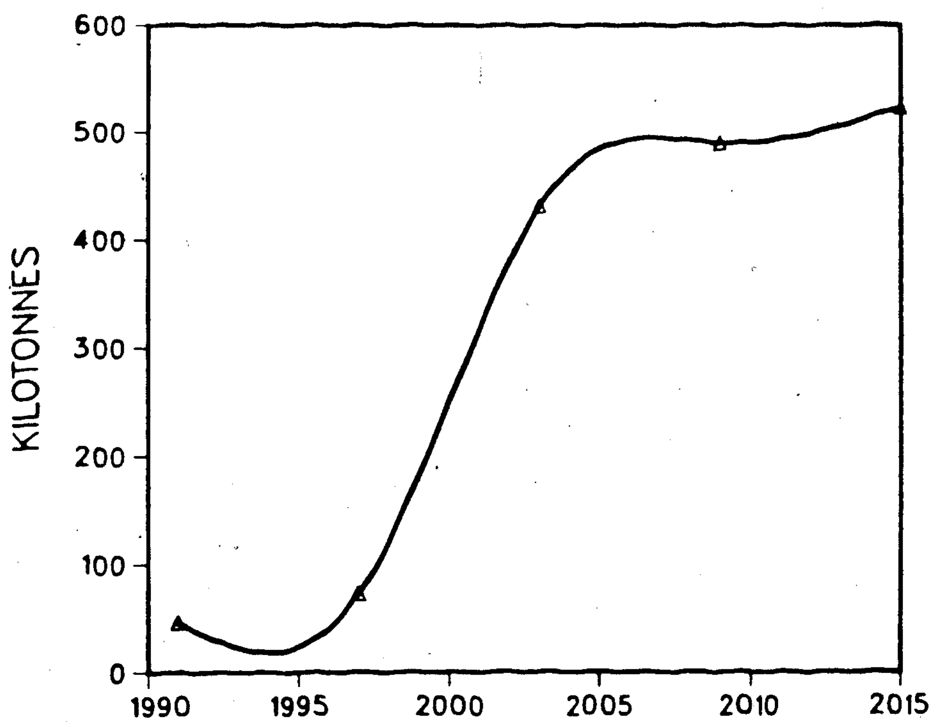


FIGURE 57. BASE CASE: CUMULATIVE VINYL ACETATE ADDITIONS



Vinyl acetate monomer production in Alberta will satisfy the relatively small domestic and U.S. demands. The major demand will come from the Pacific rim countries, but this region will not be economically accessible until 2003, at which time there will be a surge in the Alberta production capacity (Figure 57).

In the early 1990's, with the availability of propylene, an Alberta polypropylene plant will become feasible. The Western Canadian and U.S. demands will be relatively small. The Pacific rim market will not be economically accessible. Alberta polypropylene will meet the demand additions for this petrochemical in Eastern Canada (Figure 58).

The construction of a mixed ethane-propane ethylene plant will also spawn a butadiene plant in Alberta at the turn of the century (Figure 59). It will satisfy the Western Canadian demand and the additional demand in Eastern Canada.

The aromatics domestic and export markets will remain in Eastern Canada.

4. Investments in Alberta Petrochemicals

As shown in Figure 60, major investments in Alberta petrochemicals will occur in the 1997-2009 period, as the current overcapacity problem is alleviated and as currently existing plants are phased out.

FIGURE 58. BASE CASE: CUMULATIVE POLYPROPYLENE ADDITIONS

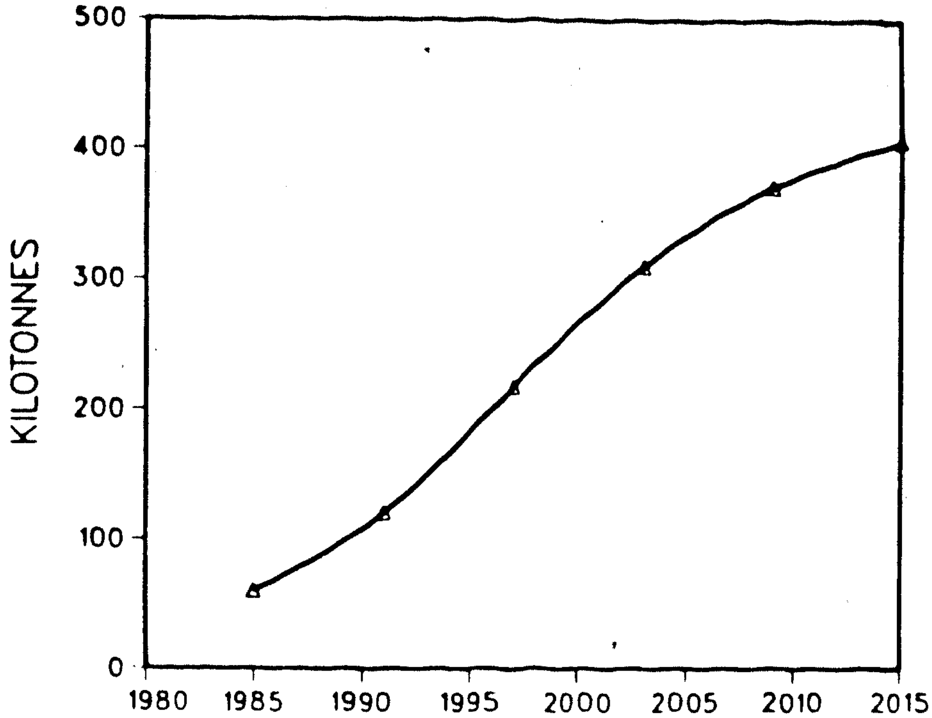


FIGURE 59. BASE CASE: CUMULATIVE BUTADIENE ADDITIONS

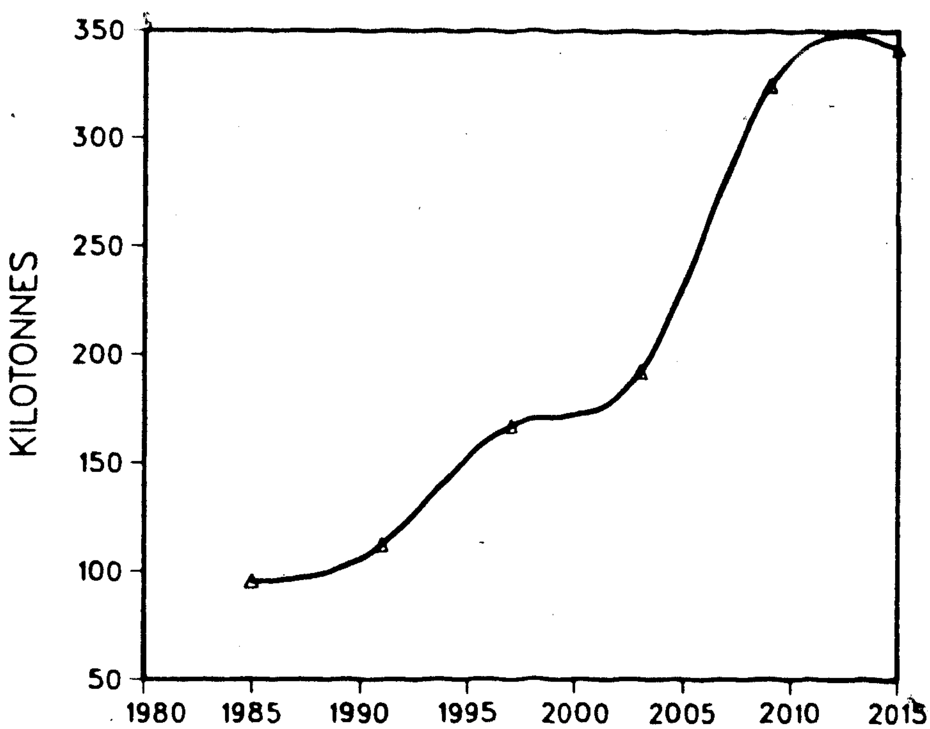
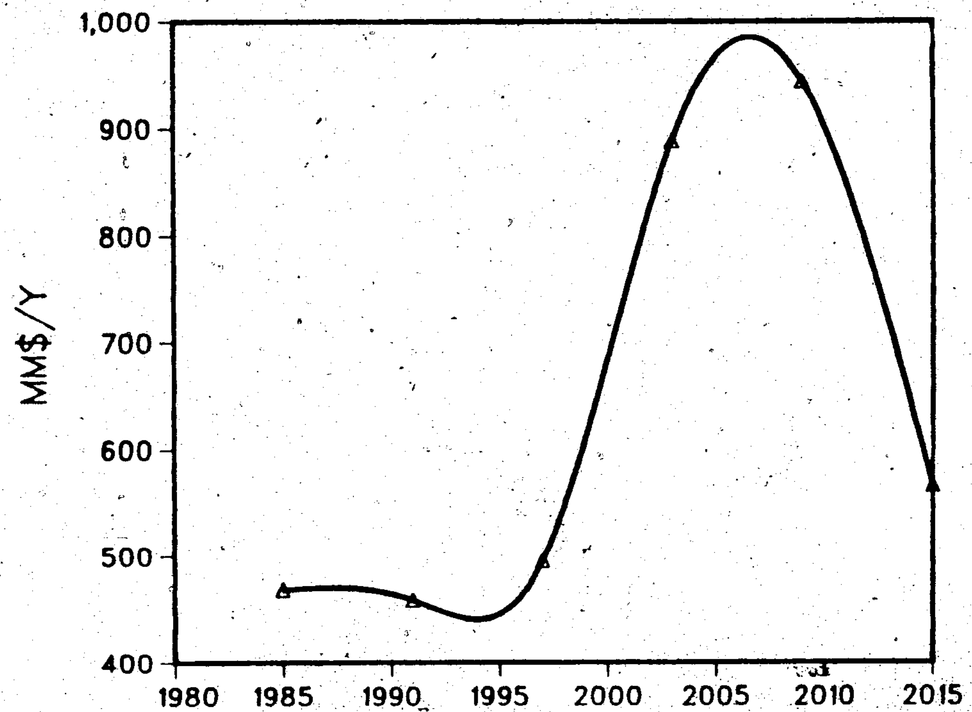


FIGURE 60. BASE CASE: INVESTMENTS IN PETROCHEMICALS



CHAPTER VIII. SCENARIO ANALYSIS

The major issues confronting the modernized, export-oriented Canadian petrochemical industry include the long term feedstock availability, capital availability, feedstock costs, product prices and the competition between Alberta and Eastern Canadian producers. Using scenario #1 as the reference, these issues were studied in a set of seven scenarios.

A scenario was constructed by altering some data assumptions in the model. After the scenario had been completed, the altered assumptions were reverted to the 'base' values. One of the problems in constructing scenarios is that altering one set of assumptions usually affects the other assumptions. For example, if the Alberta gas reserves are lower than the values in scenario #1, the producers will not sell the gas at a discount; therefore, the impact of lower reserves would be higher prices than were assumed in the base scenario. The result of increasing the natural gas prices would be that all the energy and petrochemical price schedules would have to be altered. If all the changes were made the impact of lower natural gas reserves would not be transparent. Therefore, the practice of altering one set of assumptions at a time was adopted.

The impact on the petrochemical industry of natural gas availability was studied in two scenarios; first, by restricting the natural gas exports and second, by reducing the natural gas reserves figures. Capital availability was studied in two scenarios; first, by altering the initial level of capital and second, by increasing the required rates of, return. Feedstock costs were studied by increasing the Alberta industrial price of natural gas and by reducing ethane costs. Product prices were studied by reducing the petrochemical prices throughout the planning horizon. Finally, the competitiveness of the Alberta and Eastern Canadian petrochemical industries was studied by providing Petrosar with alternate modes of operation, using a combination of natural gas liquids and crude oil.

Scenario #2 investigates the impact on the petrochemical industry of restricting the natural gas exports to current levels. This scenario tests the view that natural gas exports ought to be restricted in order to ensure its long-term availability as a feedstock for the petrochemical industry. The only change made to the base scenario is to restrict the natural gas exports to the United States to 700 BCF/y throughout the planning horizon.

Scenario #3 investigates the impact on the petrochemical industry of more pessimistic natural gas reserves assumptions than were made in the base scenario. Essentially, the new estimates are very conservative with respect to future gas discoveries. Regulatory bodies, such as the ERCB and National Energy Board tend to take this stance; this is because proper regulation demands a conservative rather than a speculative approach. However, it must be pointed out that when 4-5 TCF/year are being discovered it is quite unreasonable to assume that no further discoveries will be made in the future. Therefore, the 'undiscovered' reserves (118.75 TCF in the base scenario) are reduced to 30 TCF and not to zero. The 'tight' gas reserves, which have yet to be delineated, are reduced from 187.5 TCF in the base scenario to 50 TCF.

Scenario #4 comprises of two sub-scenarios; scenario #4A investigates the impact on the petrochemical industry of increasing the first level of expenditure by 50% and scenario #4B investigates the impact of a 50% decrease from the base scenario. By altering the first level of capital the robustness of the model results to this constraint can be investigated.

Scenario #5 investigates the impact on the petrochemical industry of requiring high rates of return for most energy projects. Higher rates of return are usually required in times and regions of economic and political instability. This scenario reflected the prevailing sentiment in the industry during the early 1980's. The only change made to the base scenario is to increase the real costs of capital from the 'base' values of 10% p.a. to 15% p.a.

Scenario #6 investigates the impact on the petrochemical industry of lower petrochemical prices through the planning horizon. It was selected because past forecasts of petrochemical prices have not been generally reliable. The only change made to the base scenario is to reduce the petrochemical prices by 30%.

Scenario #7 comprises of two sub-scenarios; in scenario #7A the Alberta industrial price is assumed to be equal to the Alberta border price throughout the planning horizon and in scenario #7B the replacement cost of unprocessed ethane and natural gas liquids is assumed to be 60% of the Alberta border price, on a fuel-equivalent basis. It was selected due to the current re-thinking of the provincial government's natural gas and NGL pricing policy.

Scenario #8 investigates the impact on the petrochemical industry of a switch by Petrosar to a combination crude oil-NGL feedstock. It was selected because Petrosar had stated that such a change would make it economically viable. Changes have been made to the base scenario to permit Petrosar to operate in two additional feedstock modes.

In this chapter, the seven scenarios are compared to the base scenario results.

A. A COMPARISON OF SCENARIOS #1 AND #2

When the natural gas exports are restricted to 700 BCF/y, the Alberta marketable gas production profile no longer has the peak that it had in scenario #1 (Figure 61). 'Undiscovered' Alberta gas reserves are not developed until the turn of the century and no 'tight' gas is required in the planning horizon.

FIGURE 61: SCENARIO 2. ALBERTA MARKETABLE GAS PRODUCTION

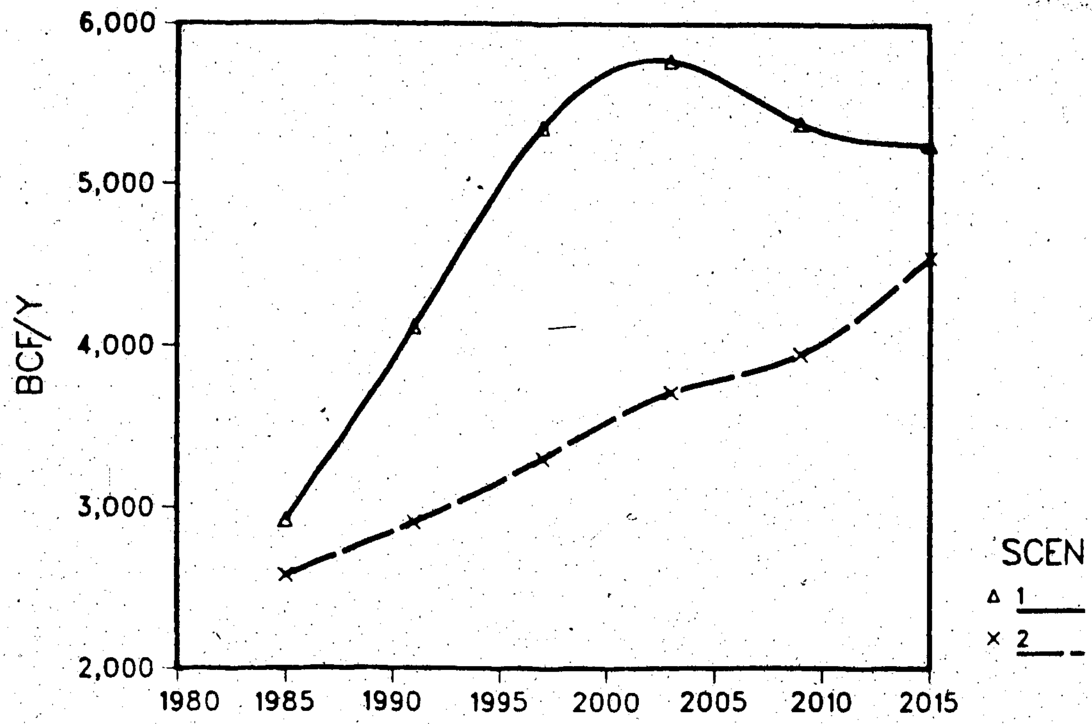
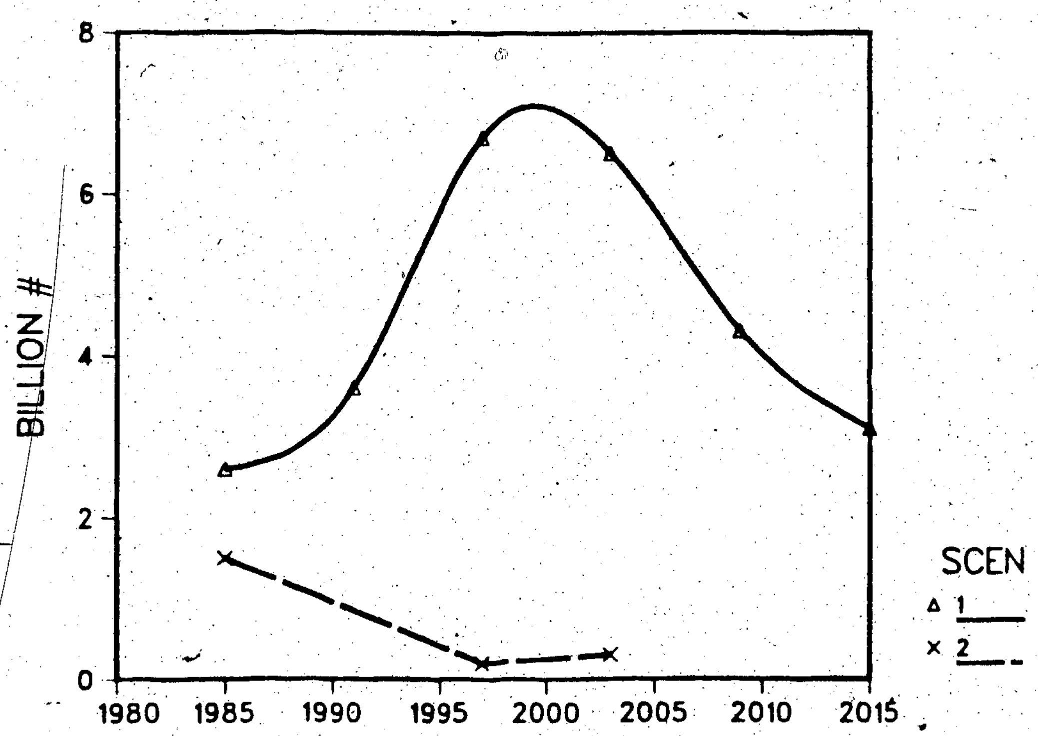


FIGURE 62: SCENARIO 2. 'SURPLUS' ETHANE



As shown in Figure 62, the reduced gas production results in a greatly reduced ethane surplus. In fact, from 1995 onwards the ethane surplus virtually disappears. The propane and butane surpluses follow a similar trend. There is no condensate surplus from the late 1980's to the late 2000s (Figure 63).

Methane-Based Petrochemicals

In accordance with current practice, the model is formulated so that ethane is not extracted when the natural gas is used within Alberta. Ex-Alberta gas, destined for Eastern Canadian and export markets, is processed in a straddle plant where the ethane and remaining natural gas liquids are extracted. Although the modelling has been done to reflect current reality, this turns out to be a limitation. As shown in Figure 63, there is a condensate shortage in Alberta in time periods #2, 3 and 4. Therefore, in time periods #2 and 3 the natural gas for the production of Alberta ammonia intended for the U.S. Midwest, is diverted to Eastern Canada in order that the condensate remaining in it may be extracted, along with the ethane, in the straddle plant. From period #4 onwards the condensate requirements are no longer limiting and the U.S. Midwest market reverts back from Eastern Canada (Figure 65) to Alberta (Figure 64). In reality, if there ever was an ethane or natural gas liquids shortage, a plant would be set up to extract these petrochemical feedstocks from intra-Alberta gas. The net effect of restricted natural gas exports on ammonia production is not significant.

FIGURE 63. SCENARIO 2: 'SURPLUS' CONDENSATE

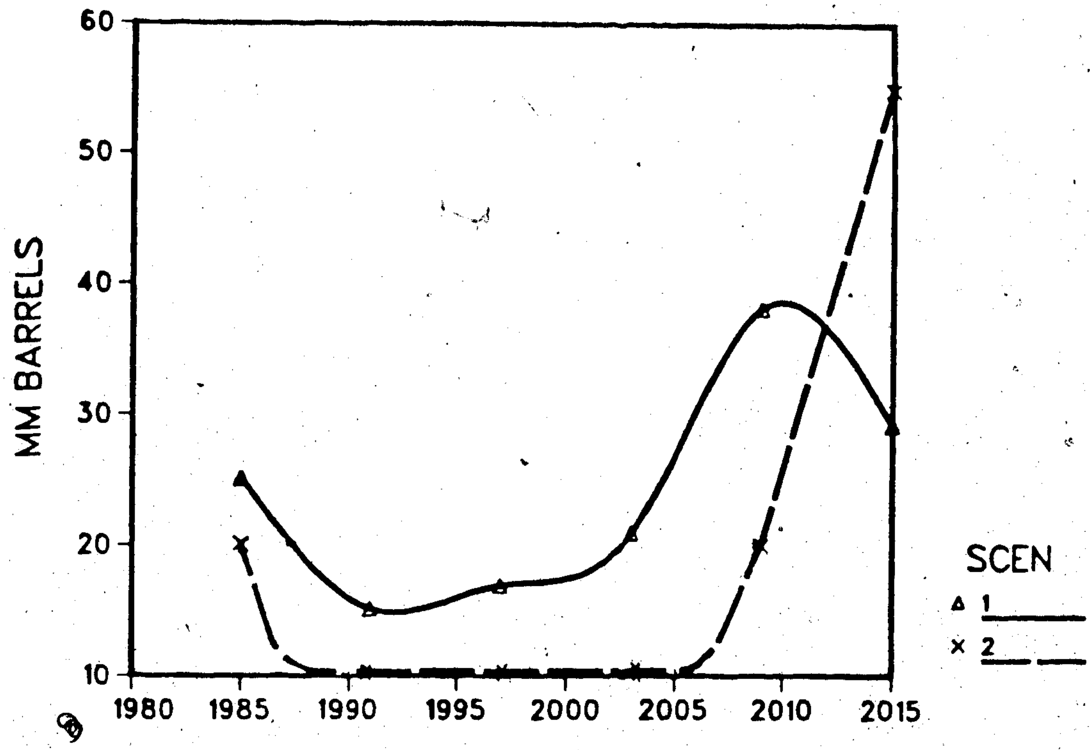


FIGURE 64. SCENARIO 2: ALBERTA AMMONIA PRODUCTION

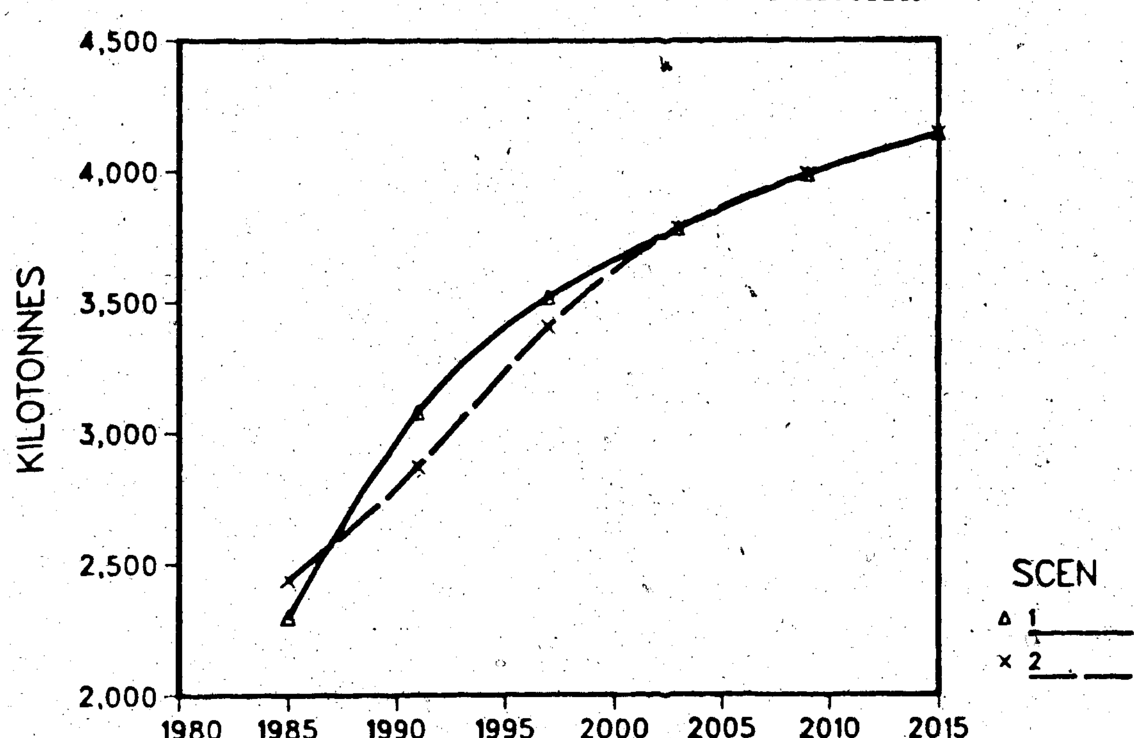


FIGURE 65. SCENARIO 2: EASTERN CANADIAN AMMONIA PRODUCTION

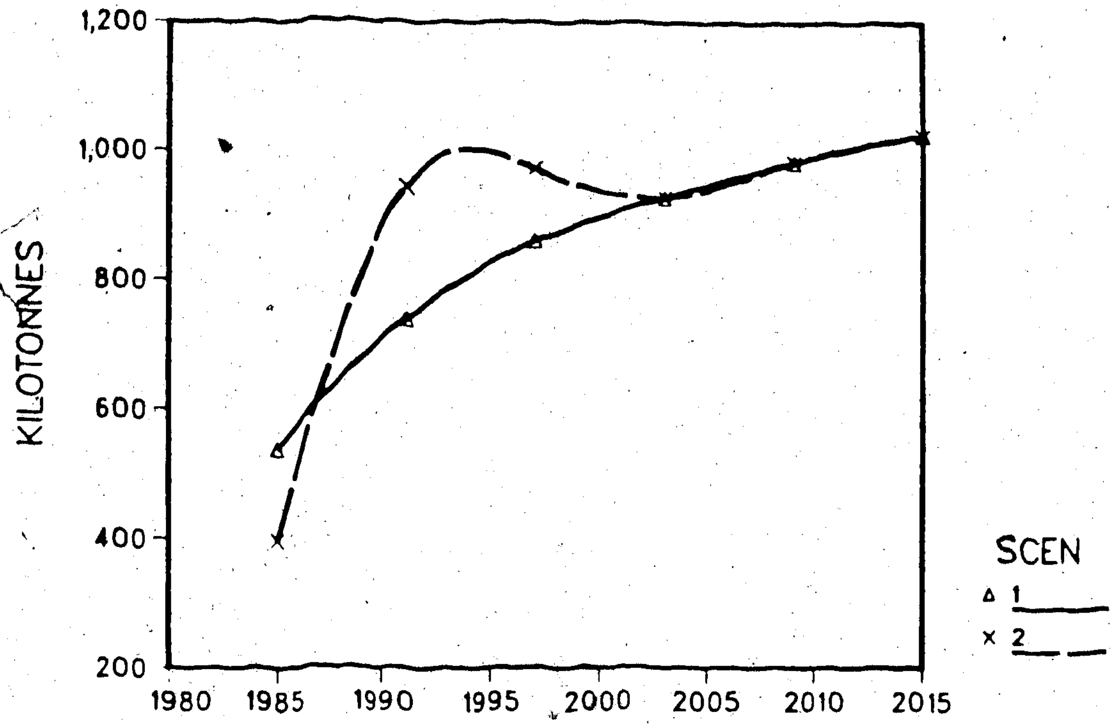
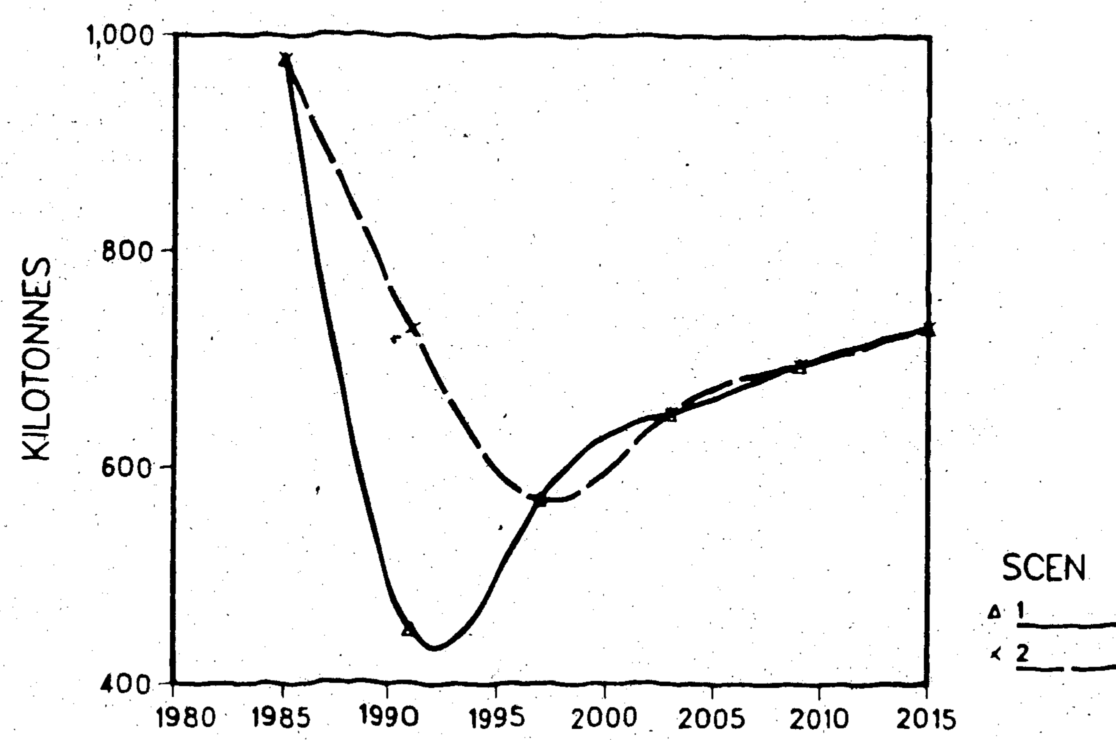


FIGURE 66. SCENARIO 2: ALBERTA CHEM-RELATED METHANOL PRODUCTION



Since the highly profitable natural gas export market is restricted, the model seeks to satisfy the other, lower value uses of natural gas. Therefore, during 1985-1991 it exports methanol to the Pacific rim countries and there is no methanol surplus capacity in Alberta (Figure 66). As shown in Figure 67, the fuel-related methanol production also increases in 1997.

In the base case, in order to meet the export demand for natural gas, 'undiscovered' gas is produced earlier than in scenario #2; due to the nature of the production profile the gas is also used for methanol production. With delayed 'undiscovered' gas production and no 'tight' gas production, the model uses more coal feedstock for methanol production than in the base case (Figures 68 and 69). This is a natural gas production profile imposed constraint.

Other Petrochemicals

As shown in Figure 70, compared to the base case, the ethane-based ethylene plant additions are lower in 1991, higher in 1997 and then lower again in 2009 and 2015; the ethane/propane based plant additions are lower in 1997 and higher in 2009 and 2015 (Figure 71), with a corresponding impact on Alberta polypropylene production (Figure 72). The 1997 effect is difficult to explain; the 2009 and 2015 changes reflect the fact that there is no ethane surplus in those time periods. The overall ethylene production is not changed; the production profiles of ethylene-derivatives, butadiene and aromatics are similar to the base case profiles.

FIGURE 67. SCENARIO 2: ALBERTA FUEL-RELATED METHANOL PRODUCTION

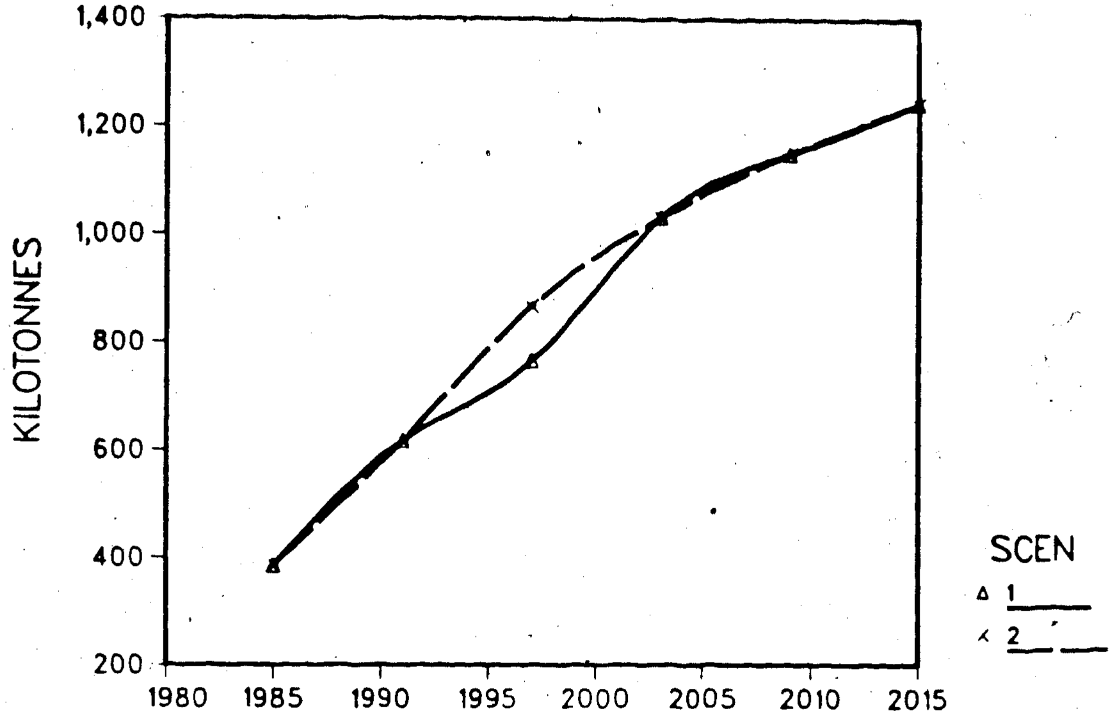


FIGURE 68. SCENARIO 2: CUMULATIVE METHANOL-FROM-COAL ADDITIONS

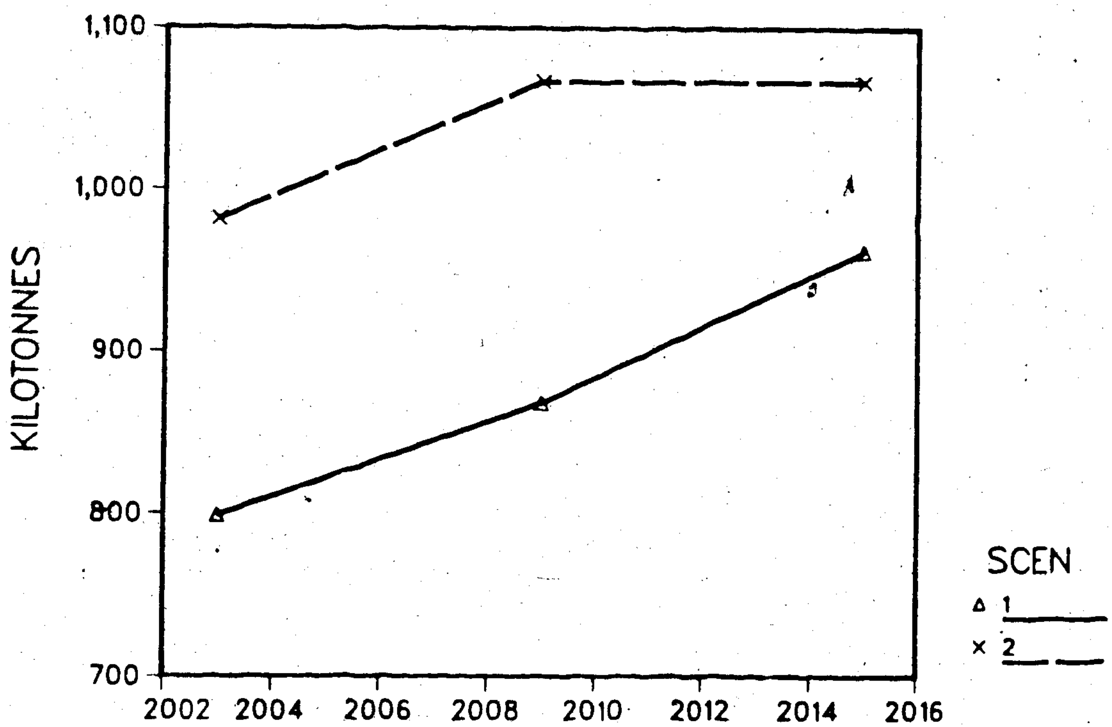


FIGURE 69: SCENARIO 2: CUMULATIVE METHANOL-FROM-GAS ADDITIONS

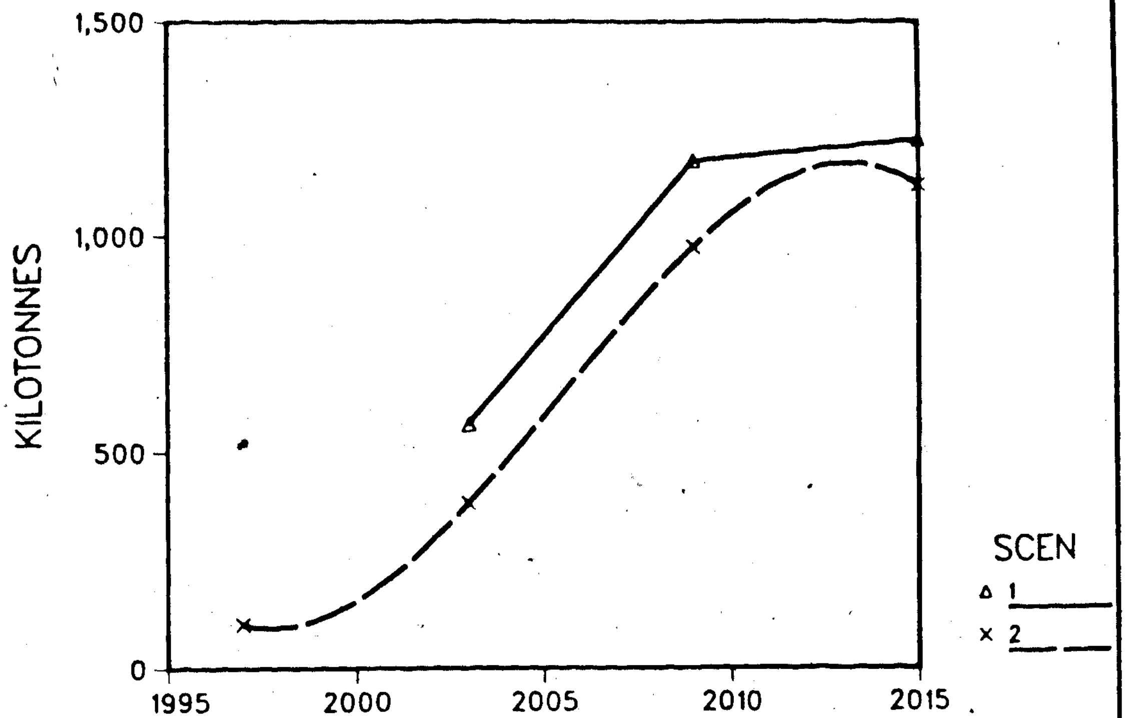


FIGURE 70. SCENARIO 2: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

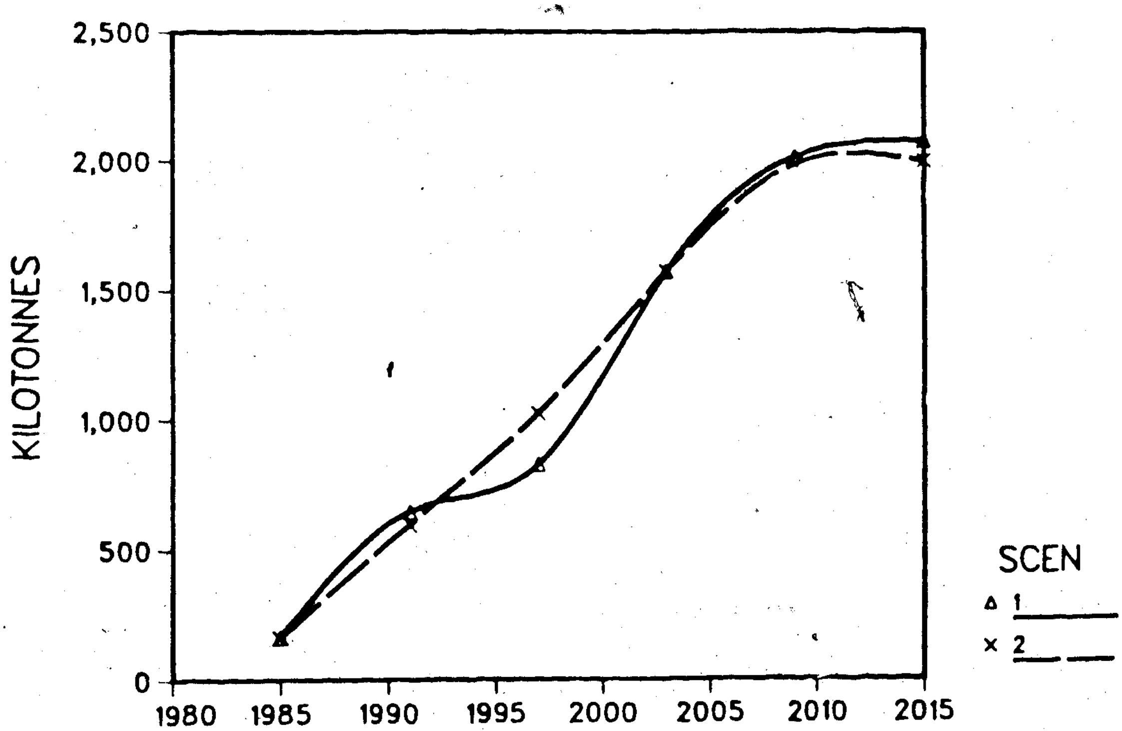


FIGURE 71. SCENARIO 2: CUMULATIVE ETHYLENE-FROM-ETH/PRP ADDITIONS

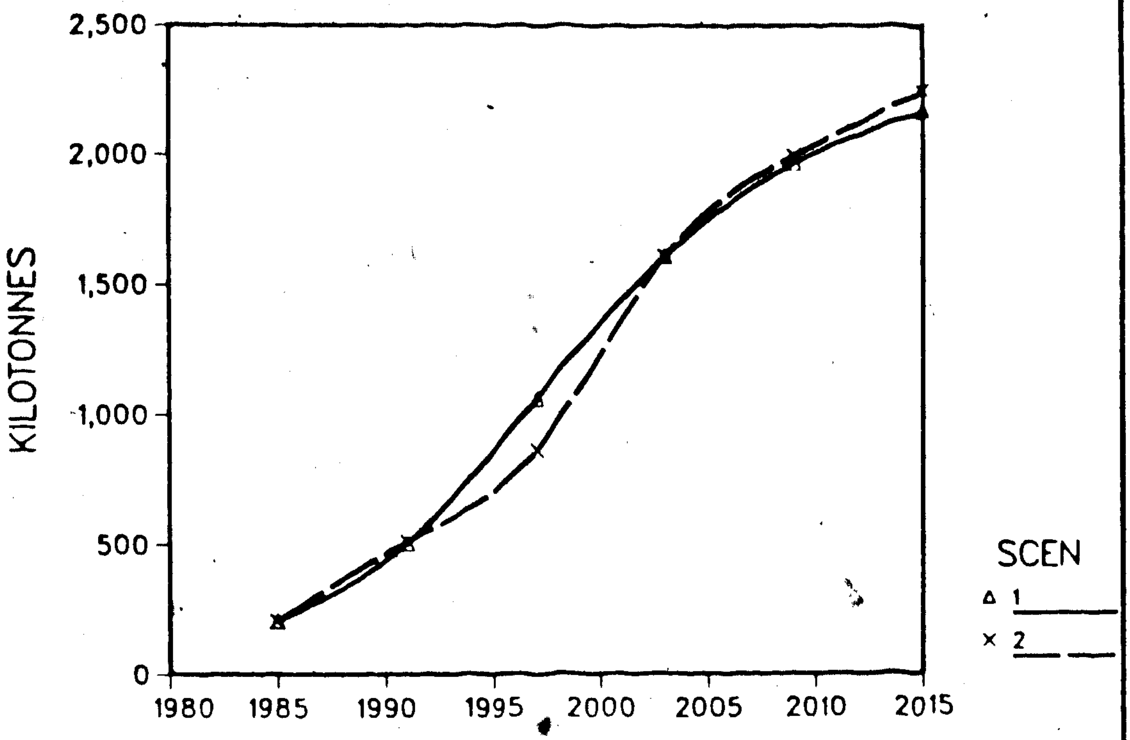
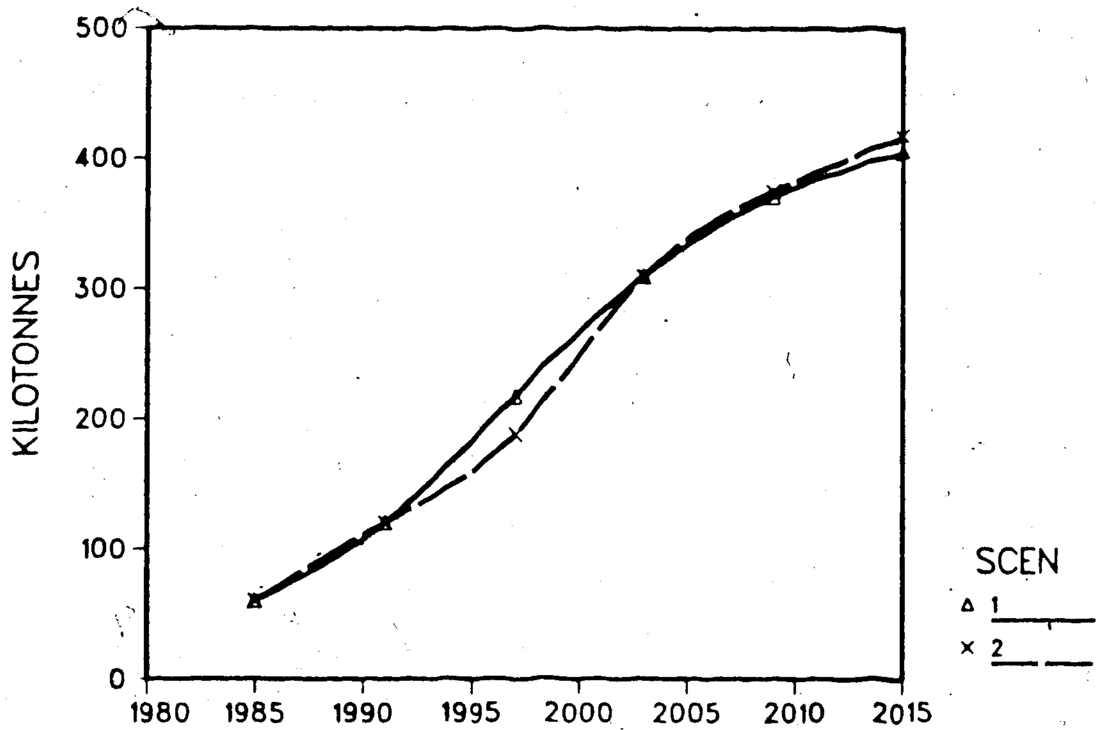


FIGURE 72. SCENARIO 2: ALBERTA POLYPROPYLENE PRODUCTION



Investments

Since the petrochemical exports are relatively unaffected, the impact on petrochemical investments is not very severe (Figure 73).

Conclusion

The scenario analysis shows that the main impact of restricting natural gas exports is that during the initial time periods, Alberta is able to export more methanol. However, the lower natural gas exports mean that the economic rents will be substantially lower. Therefore, the combined effect on the energy and petrochemical sectors of such a scenario would be negative.

B. A COMPARISON OF SCENARIOS #1 AND #3

The reduction in the 'undiscovered' and 'tight' gas reserve estimates results in a disaster scenario for the petrochemical industry. As shown in Figure 74, the Alberta marketable gas production is greatly reduced. 'Undiscovered' gas production is lower and 'tight' gas has to be brought in sooner. Beyond 2009, coal gasification is necessary.

The reduced natural gas production causes the surplus of ethane and propane to disappear after 2003 (Figure 75). The butane surplus is greatly reduced and the condensate supply is limiting from the mid-1990's to the late 2000s (Figure 76).

FIGURE 73. SCENARIO 2: INVESTMENTS IN PETROCHEMICALS

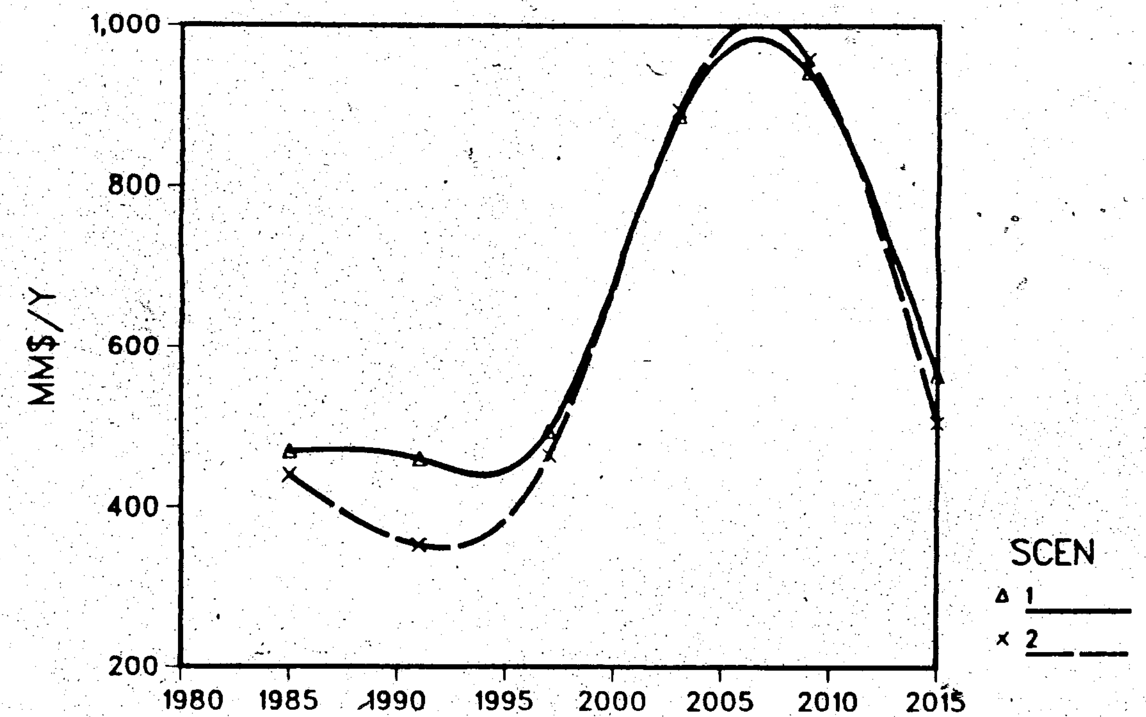


FIGURE 74. SCENARIO 3: ALBERTA MARKETABLE GAS PRODUCTION

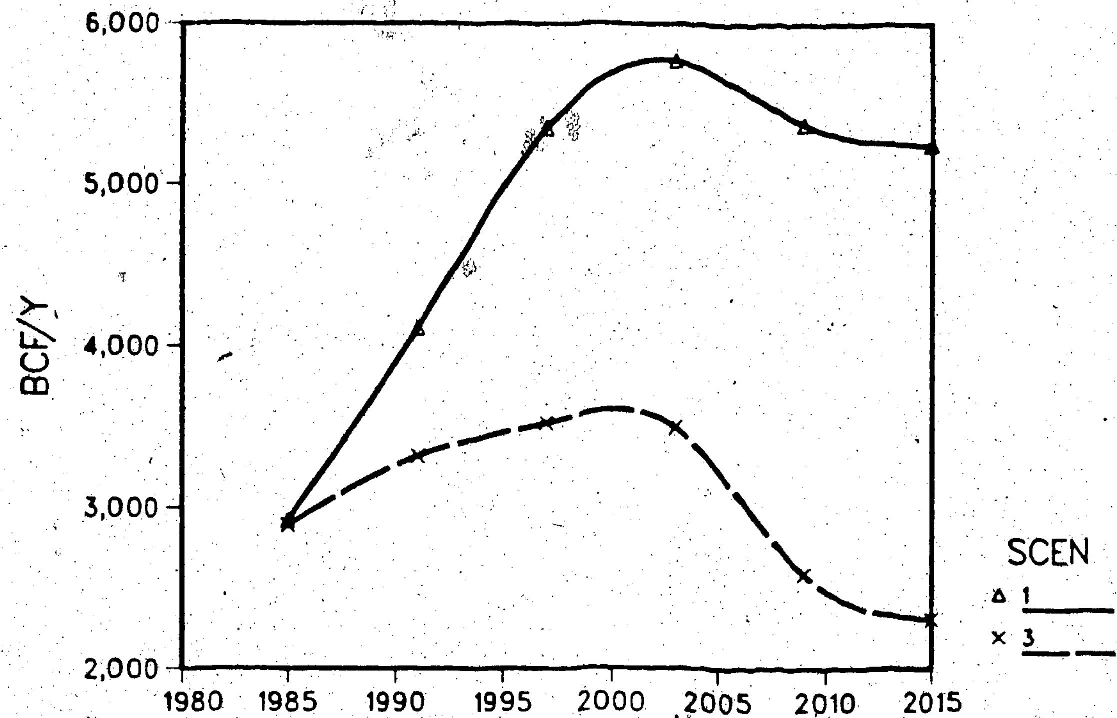


FIGURE 75. SCENARIO 3: 'SURPLUS' ETHANE

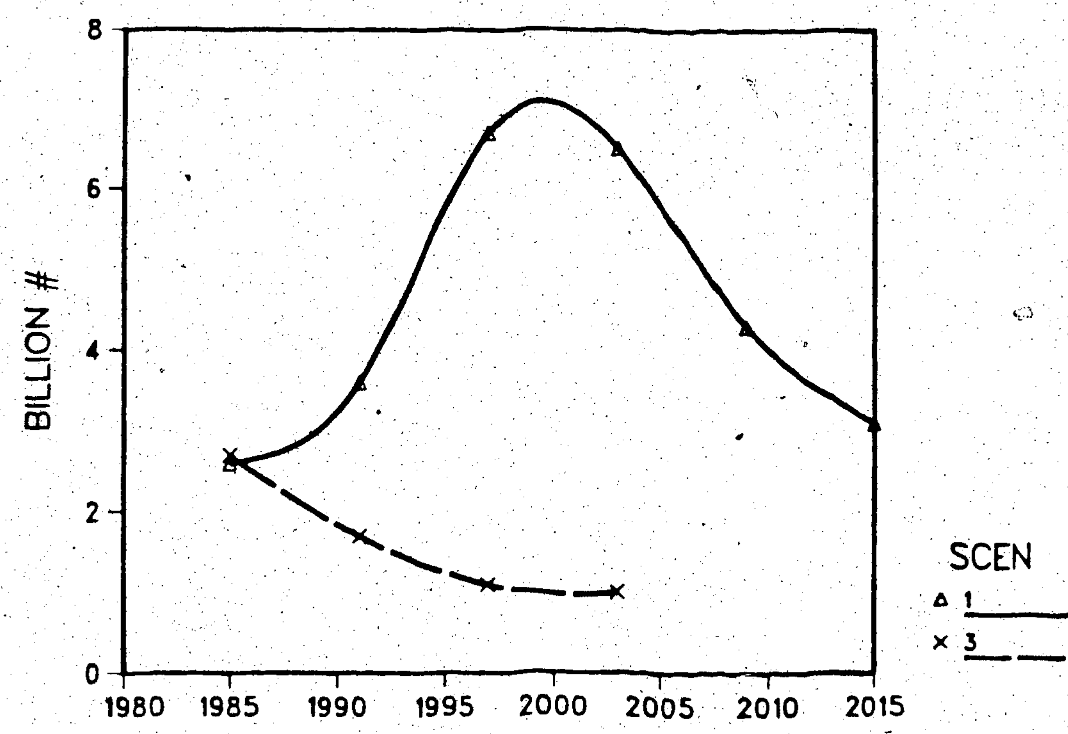


FIGURE 76. SCENARIO 3: 'SURPLUS' CONDENSATE

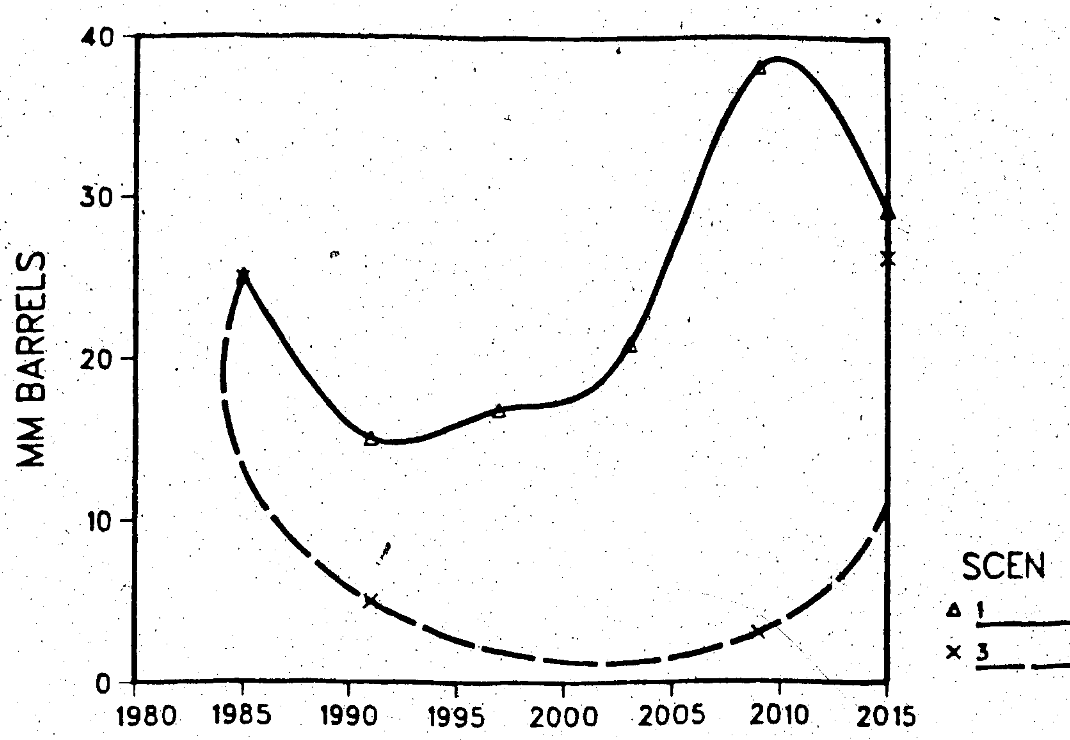
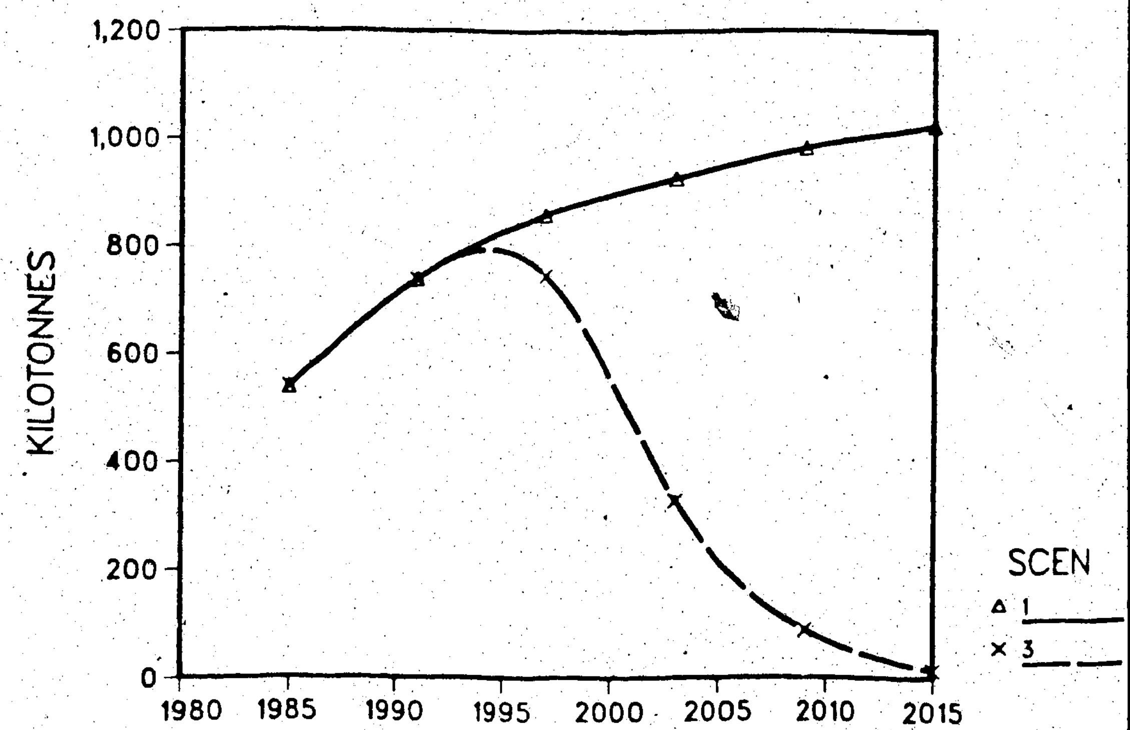


FIGURE 77. SCENARIO 3: EASTERN CANADIAN AMMONIA PRODUCTION



Methane-Based Petrochemicals

The Alberta ammonia production profile in both scenarios is similar. As shown in Figure 77, Eastern Canadian ammonia production is the same as the base case production for the first two time periods, after which it declines rapidly. Alberta gas sent to Eastern Canada is intended mainly to satisfy the exogeneously specified residential and commercial demand. This is consistent with reality since residential and commercial customers should normally be in a position to outbid the industrial customers. The available Eastern Canadian ammonia market is not captured by the Alberta producers, due to the high ammonia transportation costs between the two regions. This implies that, given the scenario assumptions, ammonia would have to be imported into Eastern Canada by 1997. Alternatively, in Eastern Canada a hydrogen source would have to be found which could produce ammonia at a competitive price.

The natural gas shortage and higher costs have a major impact on Alberta methanol production (Figures 78 and 79). Due to the low production there is serious overcapacity until the mid-1990's. No exports of chemical-related methanol occur. In Figure 79 the drop in fuel-related methanol production in 2003-2009 is due to the loss of export markets. As shown in Figure 80, coal becomes the dominant feedstock. Coal methanol is needed to satisfy the domestic demand for methanol. Since coal prices are exogeneously escalated slower than the methanol prices, the fuel-related methanol export market is re-entered in the final time period (Figure 79).

FIGURE 78. SCENARIO 3: ALBERTA CHEM-RELATED METHANOL PRODUCTION

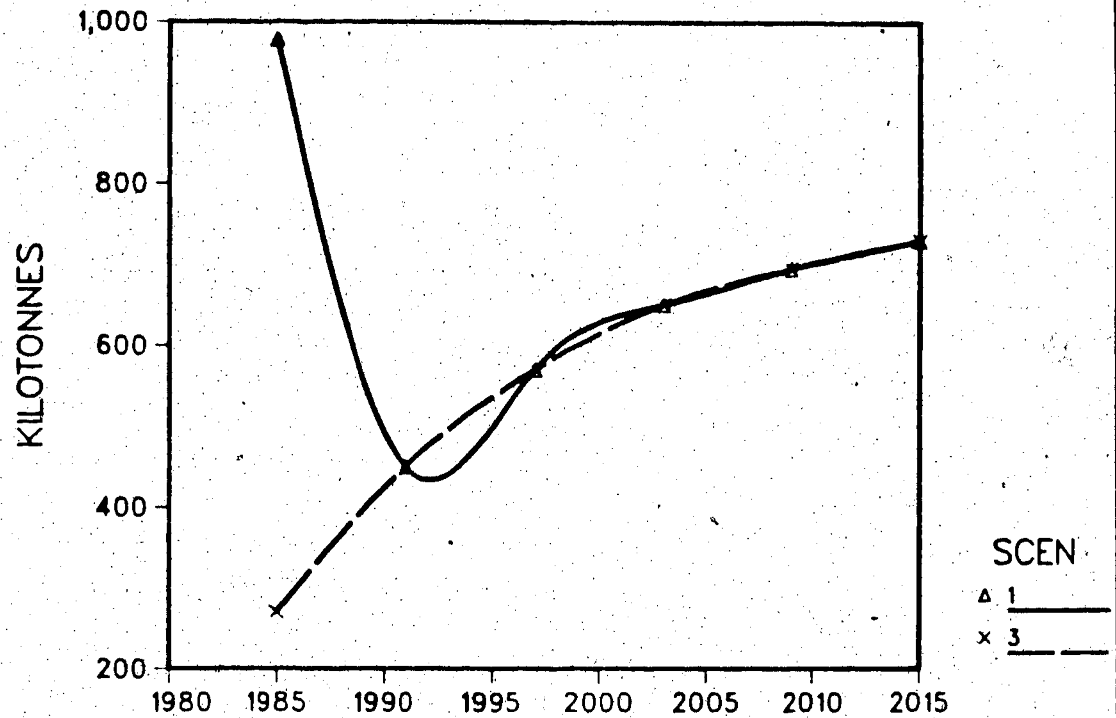


FIGURE 79. SCENARIO 3: ALBERTA FUEL-RELATED METHANOL PRODUCTION

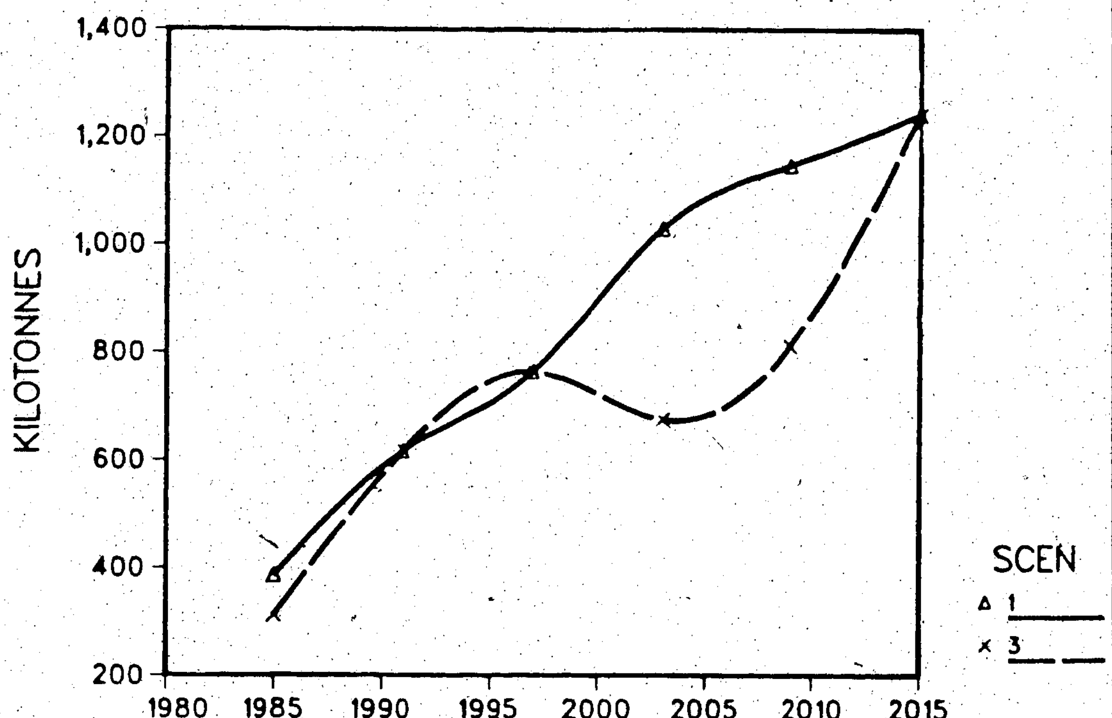


FIGURE 80. SCENARIO 3: CUMULATIVE METHANOL-FROM-COAL ADDITIONS

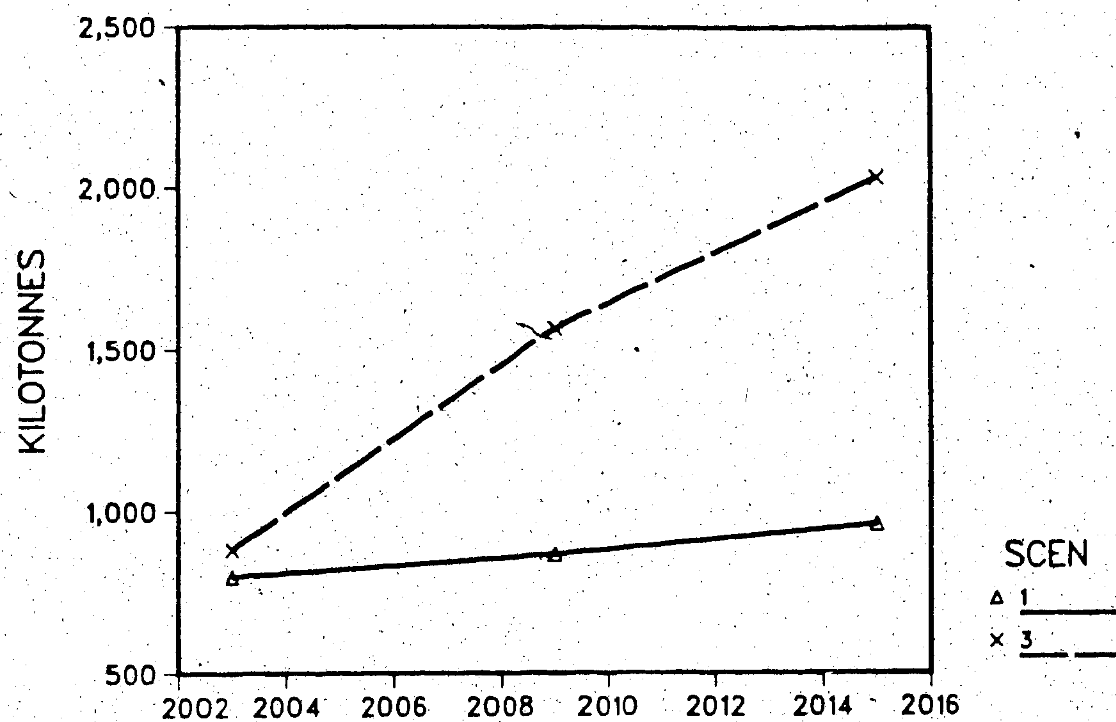
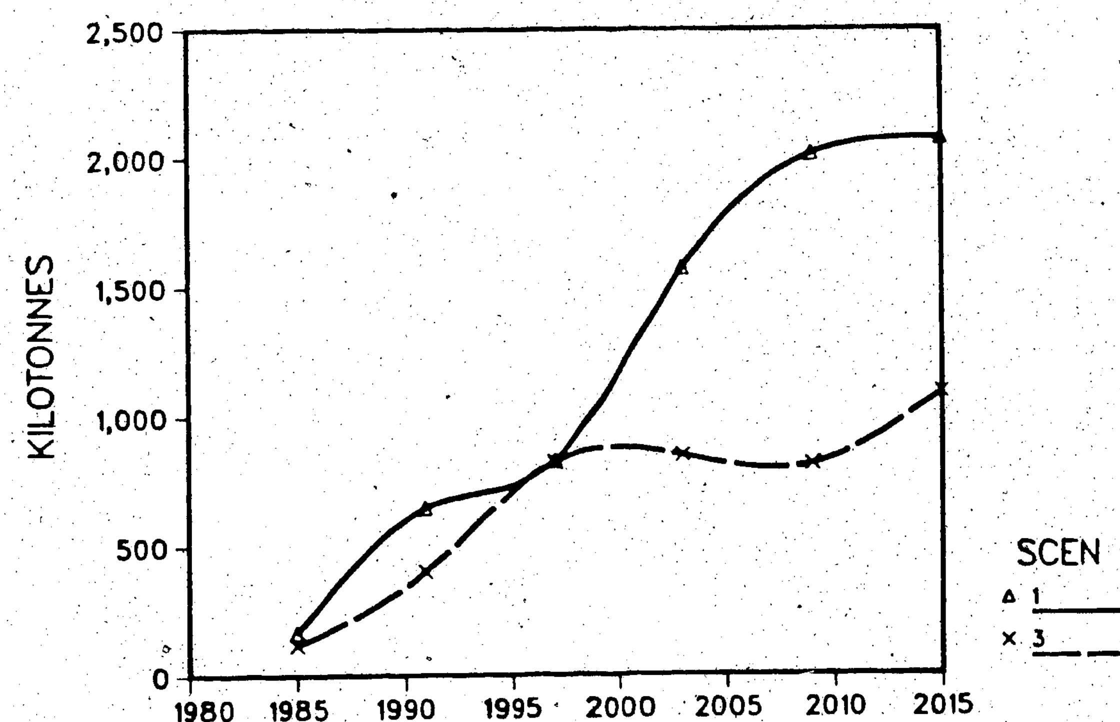


FIGURE 81. SCENARIO 3: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS



Other Petrochemicals

The ethylene plant additions in the two scenarios are quite different (Figures 81 and 82); in scenario #3 there are fewer ethane-based additions and more ethane/propane additions. As explained earlier, beyond 2003 the total ethane and propane production is used in the manufacture of ethylene. The total ethylene production is lower than in the base case.

The high density polyethylene plant additions are lower in the initial time period and both low- and high-density polyethylene plant additions are lower in the final two time periods, compared to the base scenario (Figures 83 and 84). Ethylene glycol does not gain access to the Pacific rim and U.S. Pacific Coast markets (Figure 85). This decreases the number of ethylene glycol plant additions from three in the base scenario to one (Figure 86). Both styrene and vinyl chloride production is lower than in the base scenario (Figures 87 and 88), but the most affected ethylene derivative is vinyl acetate. In scenario #3 no world-wide vinyl acetate plant is needed (Figures 89 and 90).

The increase in the ethane-propane ethylene plant additions results in correspondingly higher polypropylene plant additions in 1991 and 2003 and lower additions in 2009 and 2015 (Figure 91). In scenario #3 Alberta polypropylene is exported to the U.S. Midwest and the Pacific rim countries. The impact on butadiene is similar but not quite so pronounced. Aromatics production continues as before.

FIGURE 82. SCENARIO 3: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

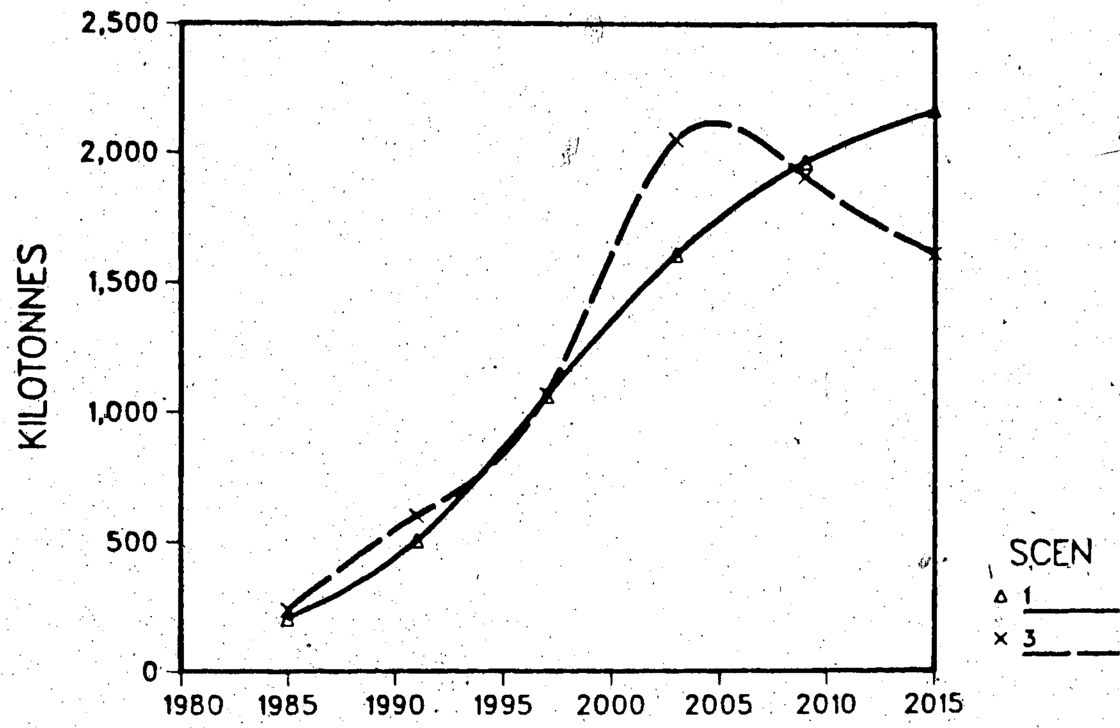


FIGURE 83. SCENARIO 3: CUMULATIVE HIGH DENSITY POLYETHYLENE ADDITIONS

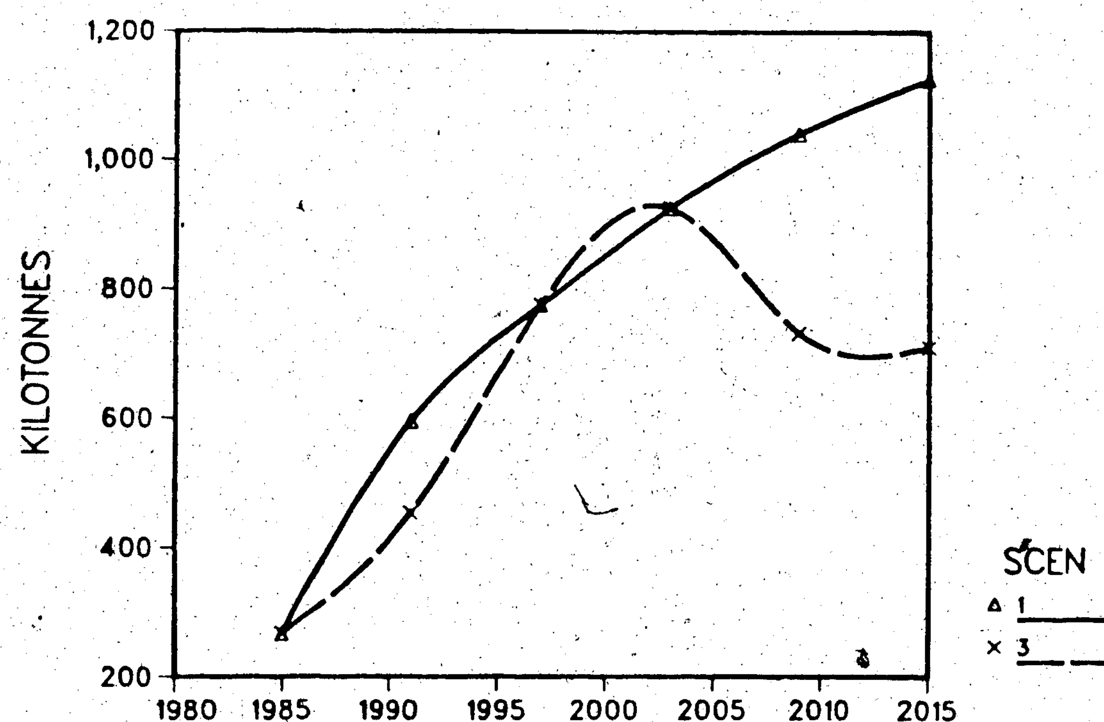


FIGURE 84. SCENARIO3: CUMULATIVE LOW DENSITY POLYETHYLENE ADDITIONS

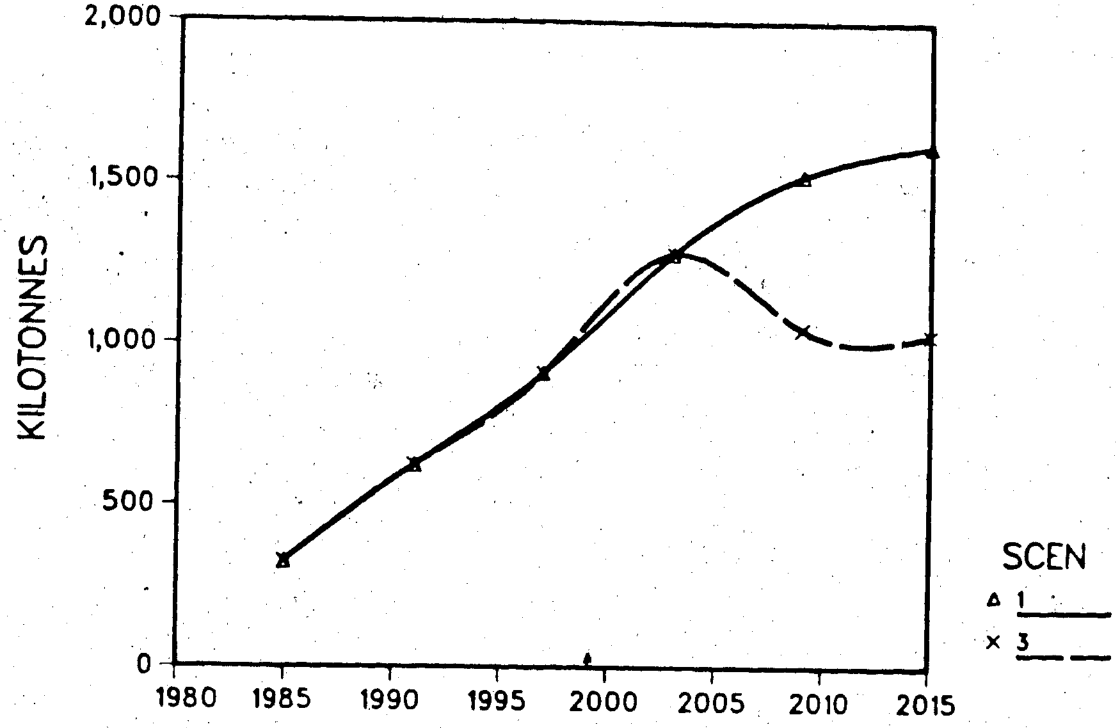


FIGURE 85. SCENARIO 3: ALBERTA ETHYLENE GLYCOL PRODUCTION

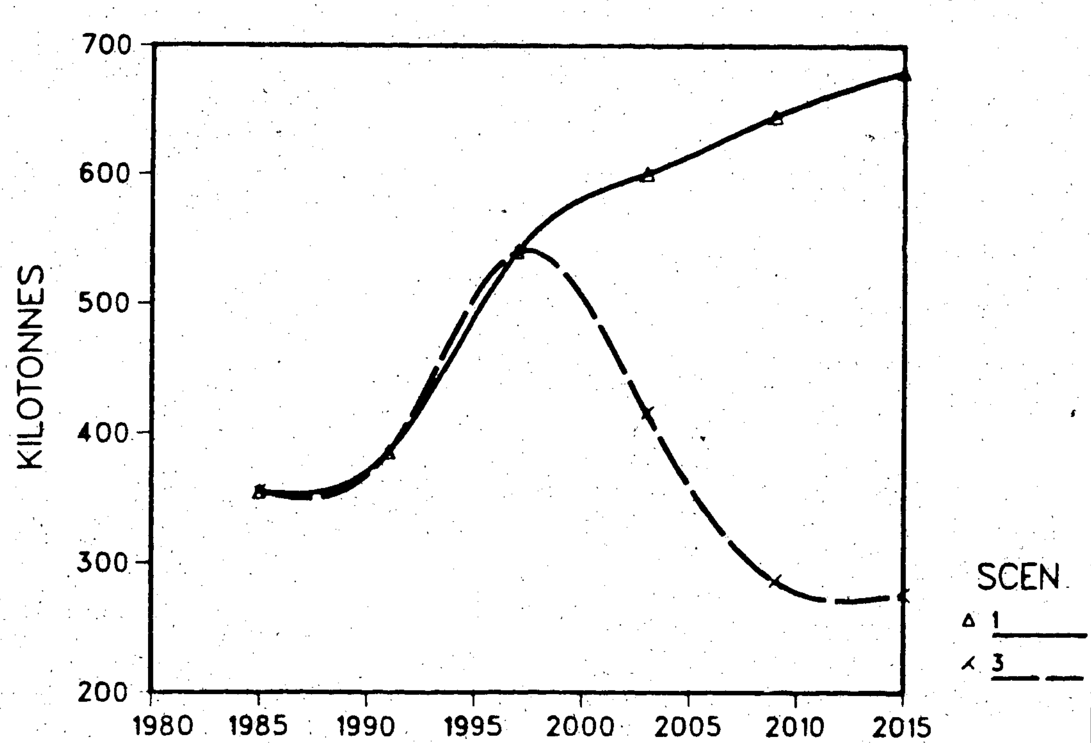


FIGURE 86. SCENARIO 3: CUMULATIVE ETHYLENE GLYCOL ADDITIONS

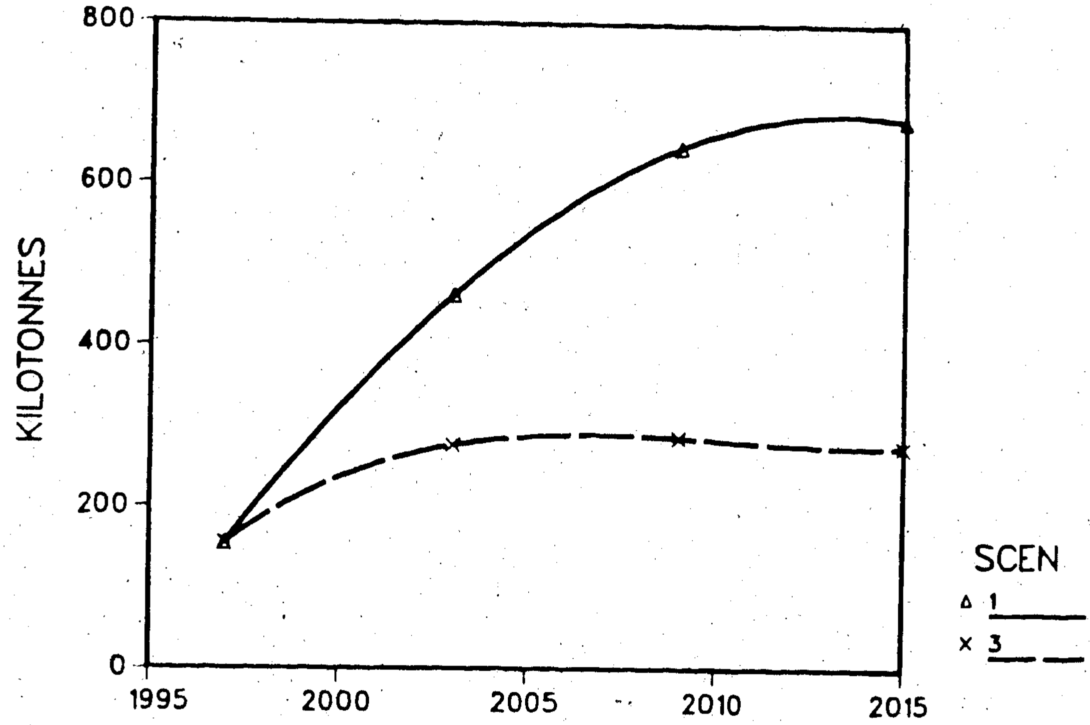


FIGURE 87. SCENARIO 3: ALBERTA STYRENE PRODUCTION

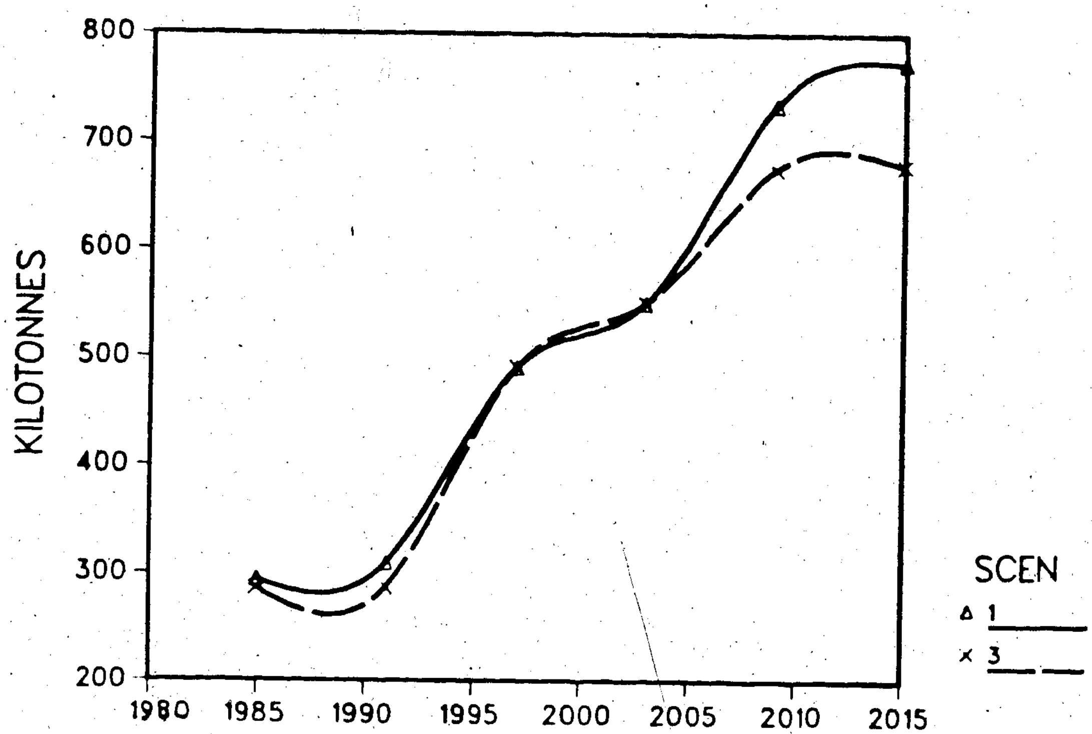


FIGURE 88. SCENARIO 3: ALBERTA VINYL CHLORIDE PRODUCTION

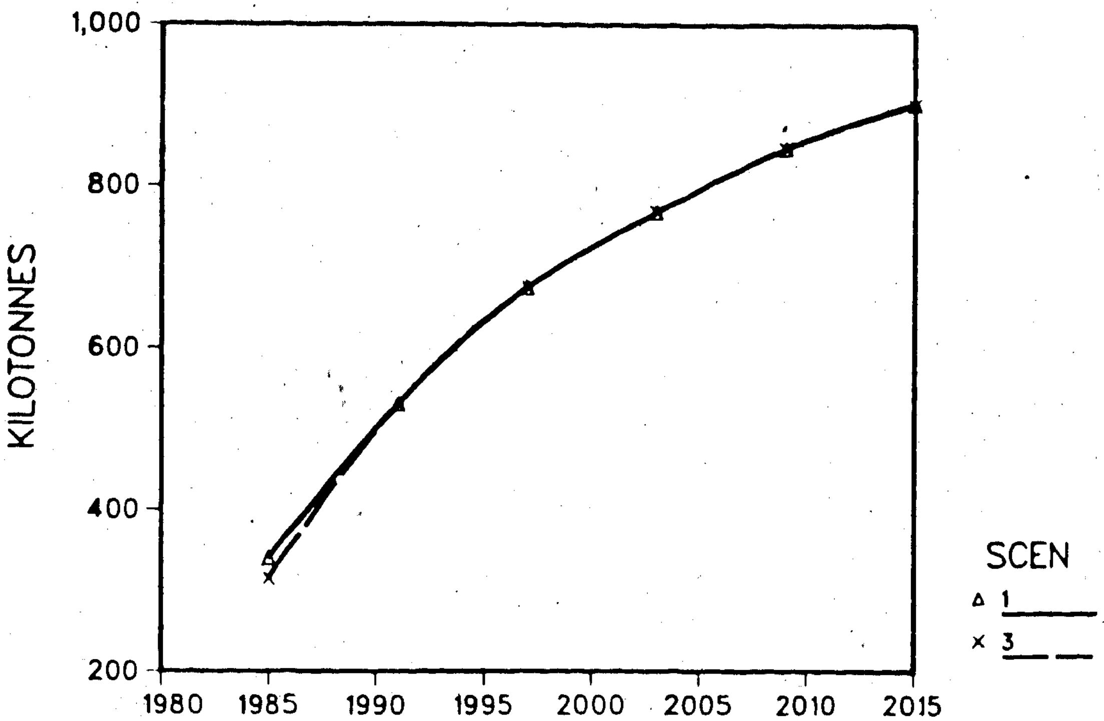


FIGURE 89. SCENARIO 3: CUMULATIVE VINYL ACETATE ADDITIONS

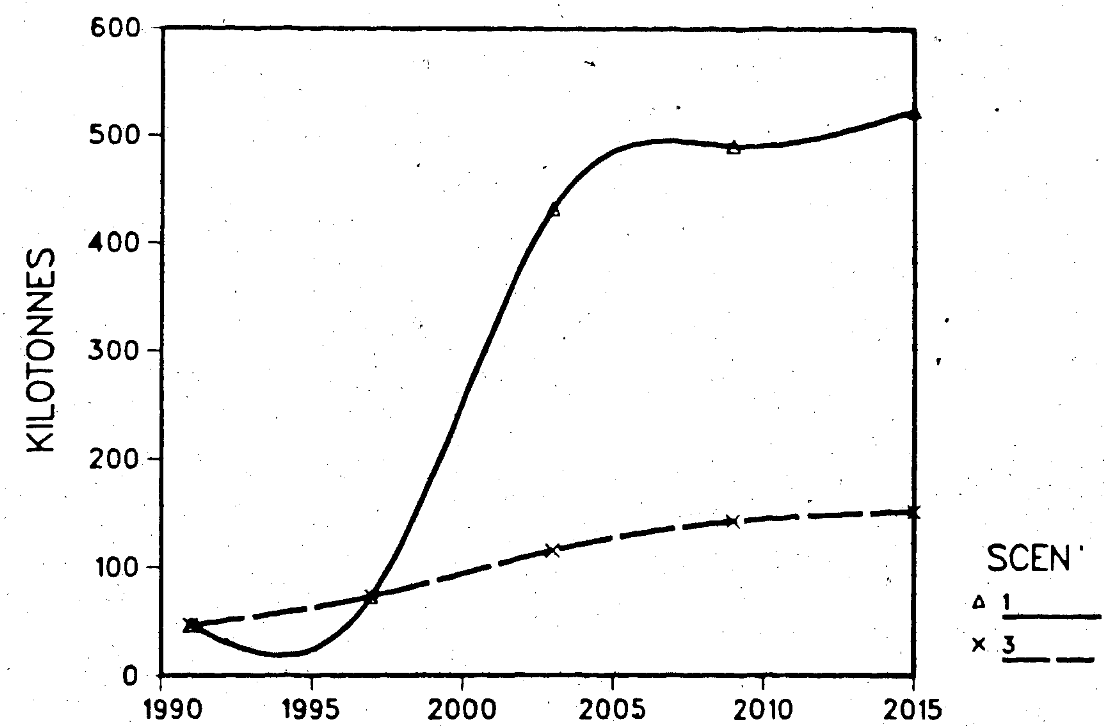


FIGURE 90. SCENARIO 3: ALBERTA VINYL ACETATE PRODUCTION

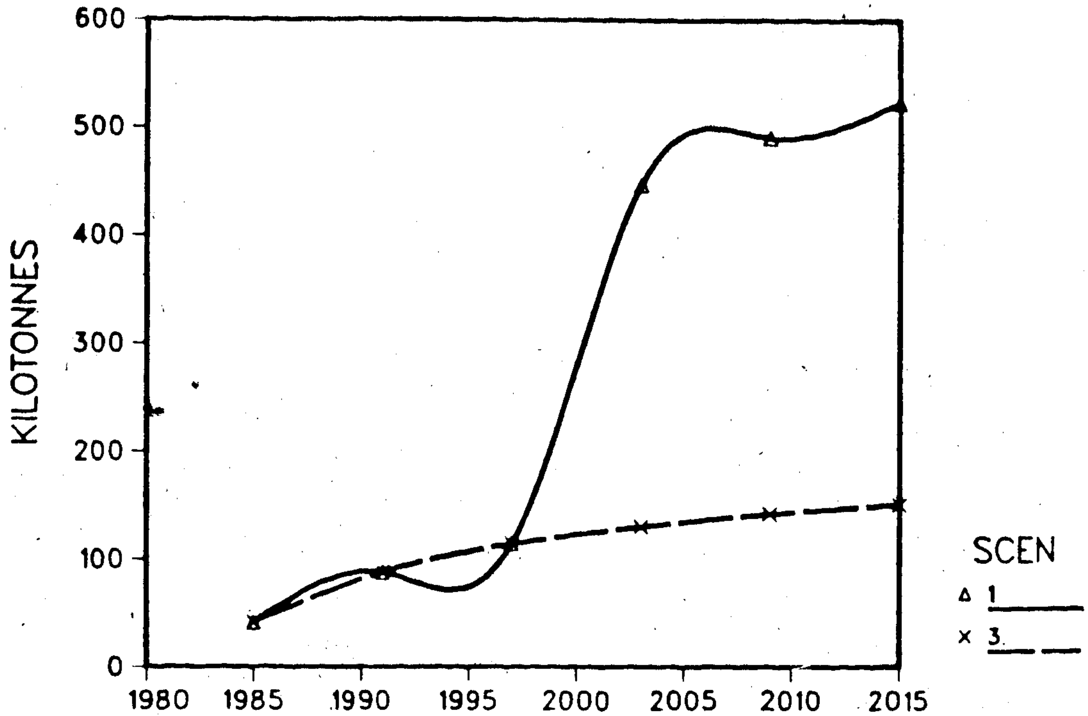
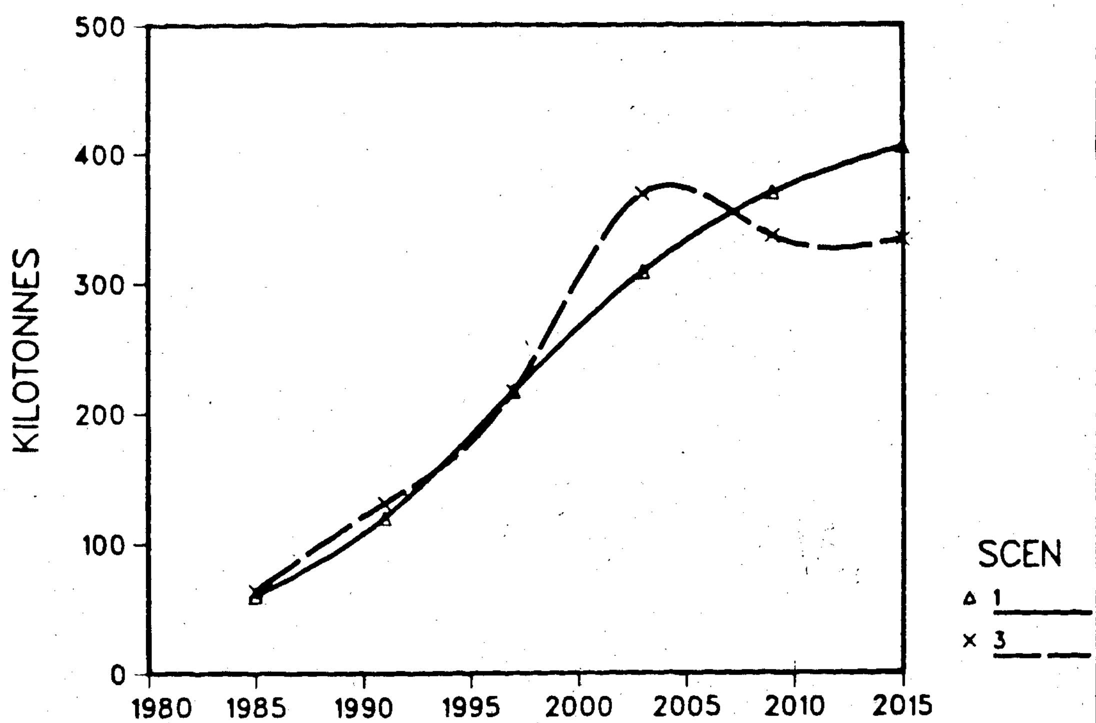


FIGURE 91. SCENARIO 3: CUMULATIVE POLYPROPYLENE ADDITIONS



Investments

Compared to the base scenario, the petrochemical investments in scenario #3 are much lower as the petrochemical activities in the later periods are lower (Figure 92).

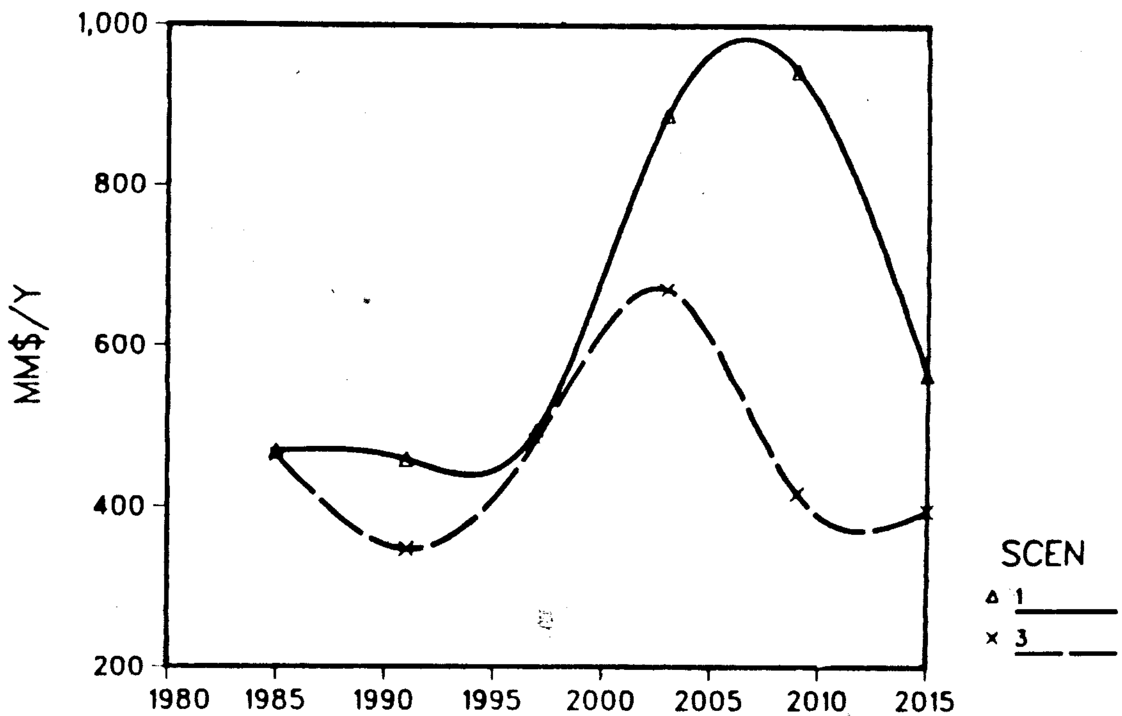
Conclusion

Lower Alberta natural gas reserves do not affect the Alberta ammonia production, but drastically reduce the Eastern Canadian ammonia production. They affect methanol production, initially causing serious overcapacity problems and later on, an exclusively coal feedstock for new methanol plants. They affect ethylene production, initially causing more propane to be used as feedstock and after 2003, causing the ethylene industry to decline. The increased propane use results in higher polypropylene and butadiene production in Alberta until the final time period. The oil-based aromatics production is not affected.

C. A COMPARISON OF SCENARIOS #1 AND #4

Scenario #4A is a 50% increase in the first level of capital availability; scenario #4B is a 50% decrease in the level, compared to the base scenario values. In scenario #1, \$5.2 billion were spent in natural gas preproduction activities in the first time period, although the production of the gas discovered during such activities did not start until the second time period (Table 37). This was because of the capital surcharge constraint. As expected, when the constraint is relaxed in scenario #4A, the preproduction activities are deferred until the gas is

FIGURE 92. SCENARIO 3: INVESTMENTS IN PETROCHEMICALS



Period	Scenario #1 (Billion C$)	Scenario #4A (Billion C$)	Scenario #4B (Billion C$)
1985	5.2	0.0	11.4
1991	22.0	29.7	6.3
1997	19.7	0.0	12.0
2003	6.5	5.0	1.2
2009	20.7	42.5	30.6
2015	29.3	50.4	39.6

Table 37: Natural Gas Exploration and Development Costs

actually needed. This can be clearly seen in Table 37, where $29.7 billion are spent in the second time period, for 'undiscovered' gas and the next major activity occurs beyond 2009 for 'tight' gas. In Table 37, the effect of tightening the capital surcharge constraint may also be seen; the preproduction expenditures are increased in the initial period; the capital available is insufficient and this results in lower Alberta marketable gas production beyond 1997 (Figure 93). In Figure 93, the impact of scenario #4A is noticeable only in the final time period, when more gas is produced than in the base scenario. Apparently the penalty imposed by earlier-than-required preproduction activities is less severe than in the base scenario and higher exports of natural gas to the United States occur in the final period.

The changes in the Alberta natural gas production are reflected in the ethane surplus projections (Figure 94). In scenario #4B, the ethane surplus is initially higher; the lower capital availability results in lower activity in ethylene derivatives and thereby less ethane-propane based ethylene plant additions than in the base case. In scenario #4B, the condensate supply becomes limiting beyond 2003 (Figure 95).

Methane-Based Petrochemicals

In both scenarios #4A and #4B the Alberta ammonia production is not affected. In scenario #4A the Eastern Canadian ammonia production is not affected whereas in scenario #4B, due to the lower natural gas production, Eastern Canadian ammonia production is lower than in the base scenario (Figure 96).

FIGURE 93. SCENARIO 4: ALBERTA MARKETABLE GAS PRODUCTION

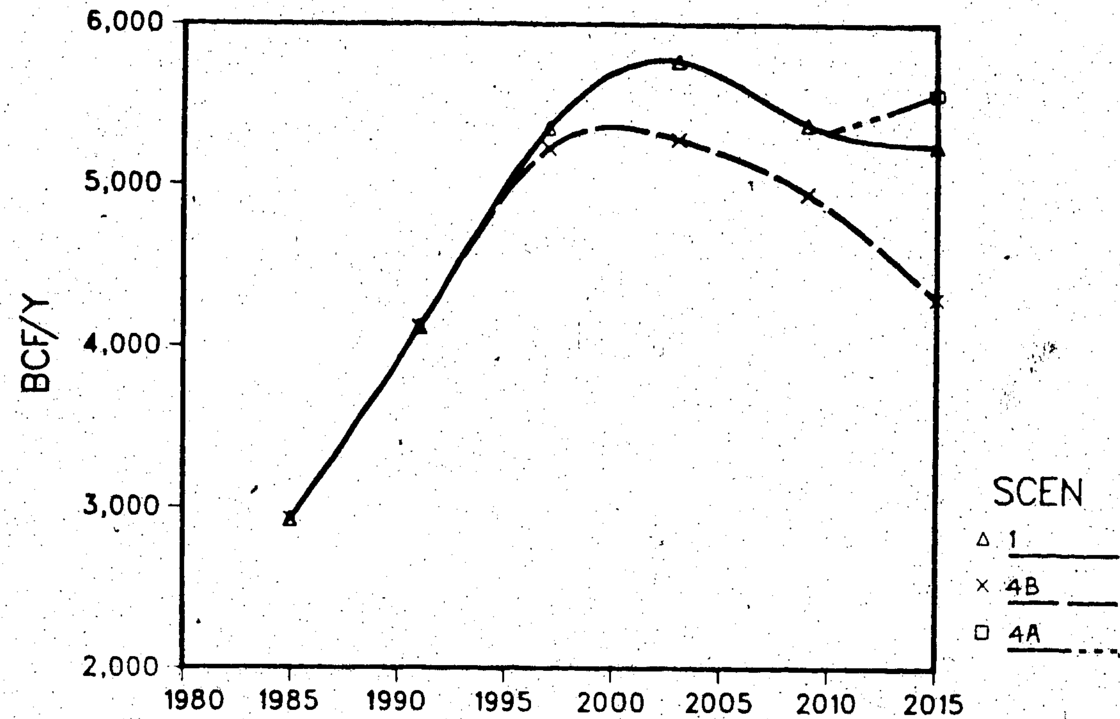


FIGURE 94. SCENARIO 4: 'SURPLUS' ETHANE

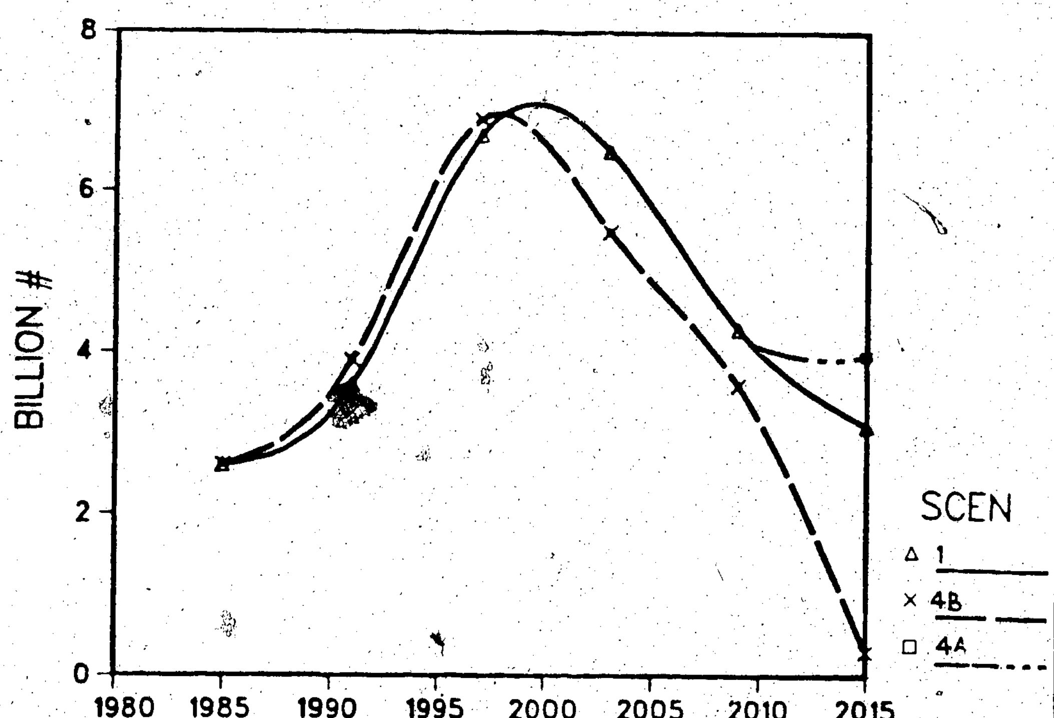


FIGURE 95. SCENARIO 4: 'SURPLUS' CONDENSATE

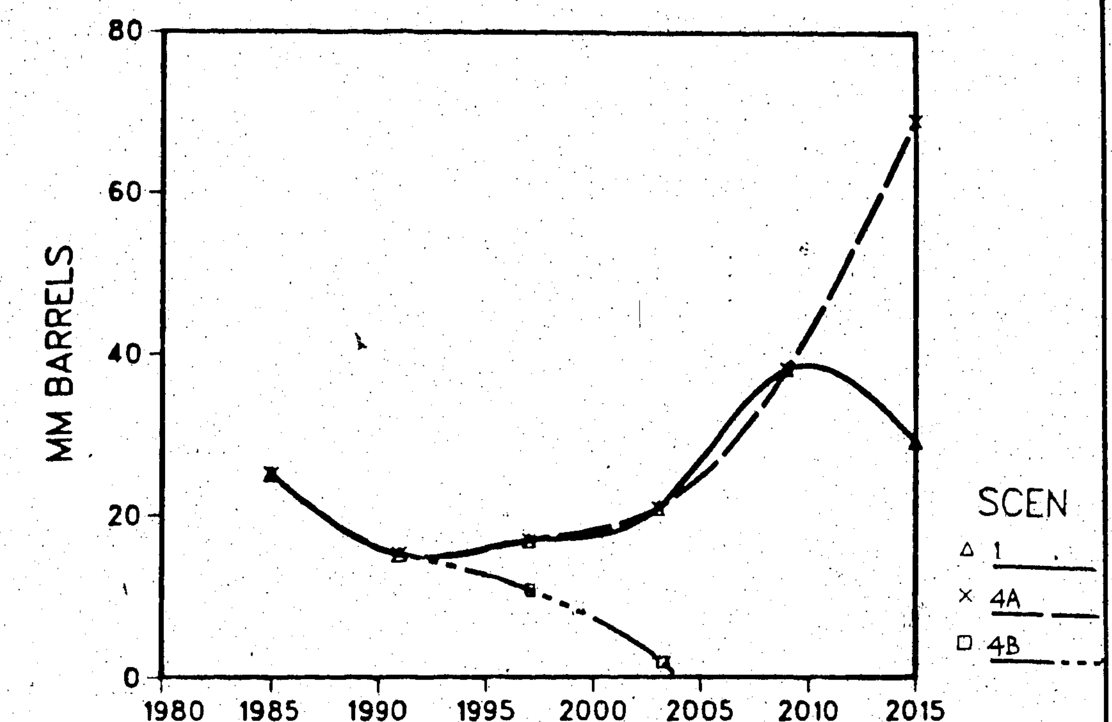
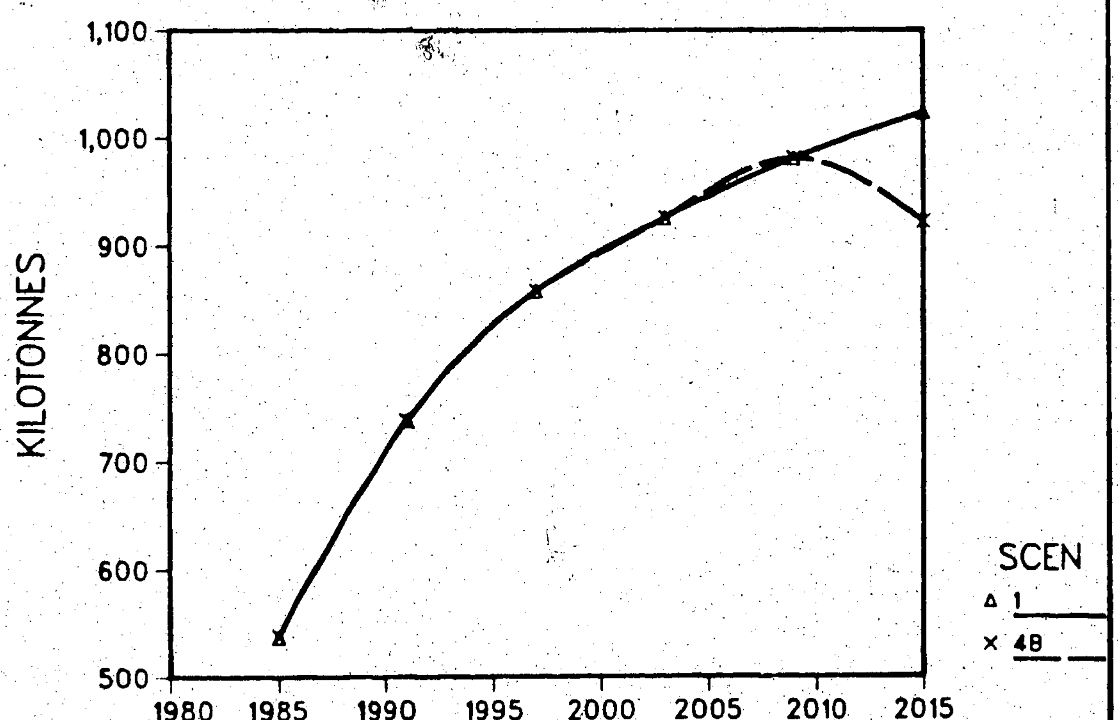


FIGURE 96. SCENARIO 4: EASTERN AMMONIA PRODUCTION



In scenario #4A, the methanol production remains largely unaffected; in the final time period, due to increased natural gas availability, more natural gas is used in methanol capacity additions than in the base scenario (Figure 97). In scenario #4B natural gas based methanol capacity additions are very low; new capacity is almost exclusively coal-based (Figure 98). This affects the fuel-related methanol production which, beyond 1997, is lower than in the base scenario (Figure 99).

Other Petrochemicals

In scenario #4A, there is more ethane used in the ethylene plants during 1991-2003 than in the base scenario (Figure 100). The ethylene derivatives production is not affected. Due to lower propane usage in ethylene plants (Figure 101), the Alberta polypropylene production is lower (Figure 106) and the Alberta butadiene additions are lower (Figure 107).

In scenario #4B, the restricted capital availability seriously affects the ethylene and derivatives industry. As shown in Figure 102, due to a lack of penetration of the Pacific rim markets, the high density polyethylene production in Alberta is much lower than in the base case. Ethylene glycol capacity additions are slightly lower (Figure 103). Styrene production is slightly lower (Figure 104). Vinyl chloride production and low density polyethylene production is unaffected. Vinyl acetate production is much lower between 1997-2015 (Figure 105). Therefore, if the ethylene derivatives are ranked in terms of the impact of

FIGURE 97. SCENARIO 4: CUMULATIVE METHANOL-FROM-GAS ADDITIONS

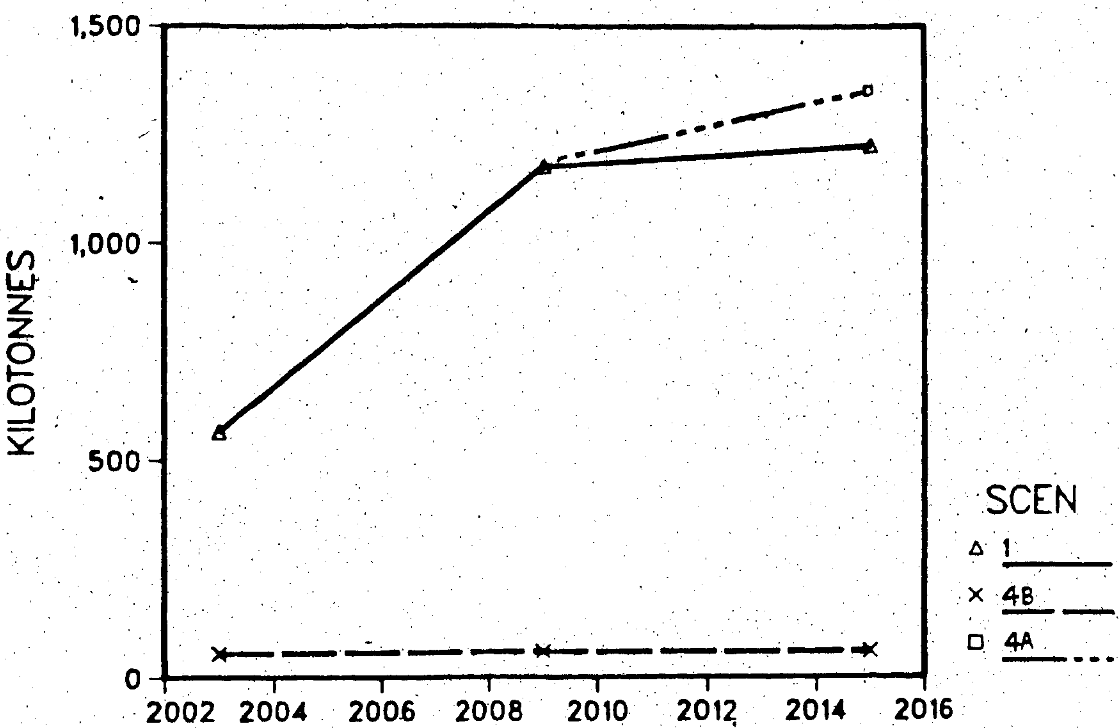


FIGURE 98. SCENARIO 4: CUMULATIVE METHANOL-FROM-COAL ADDITIONS

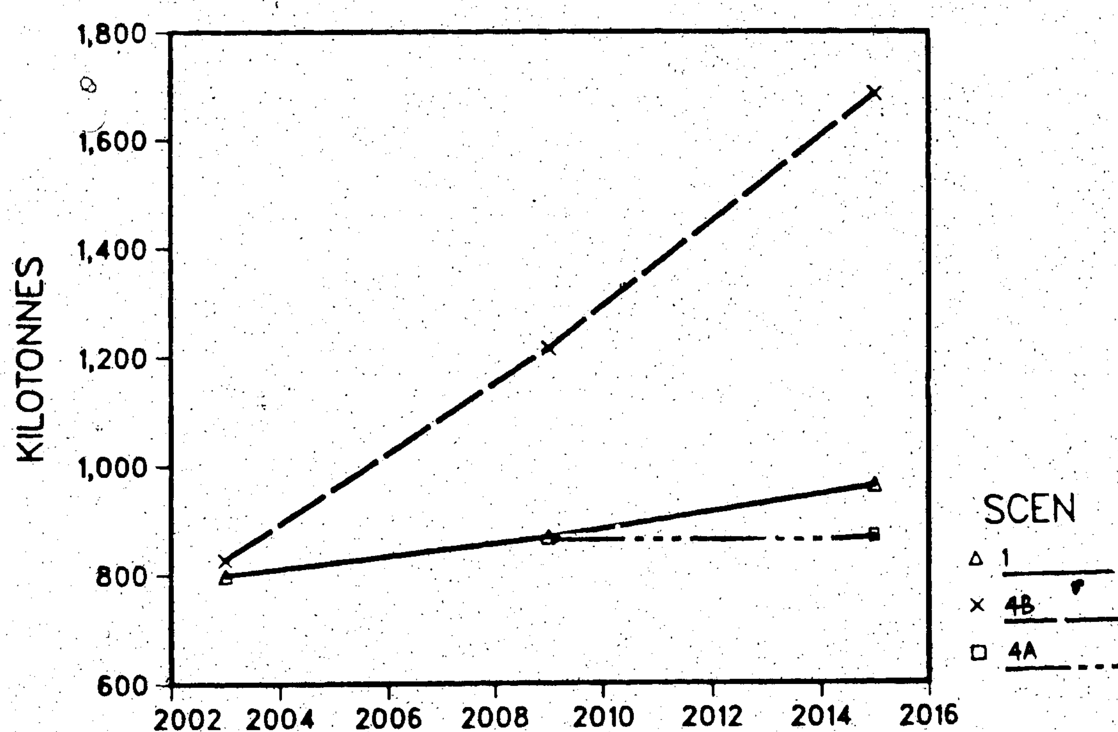


FIGURE 99. SCENARIO 4: ALBERTA FUEL-RELATED METHANOL PRODUCTION

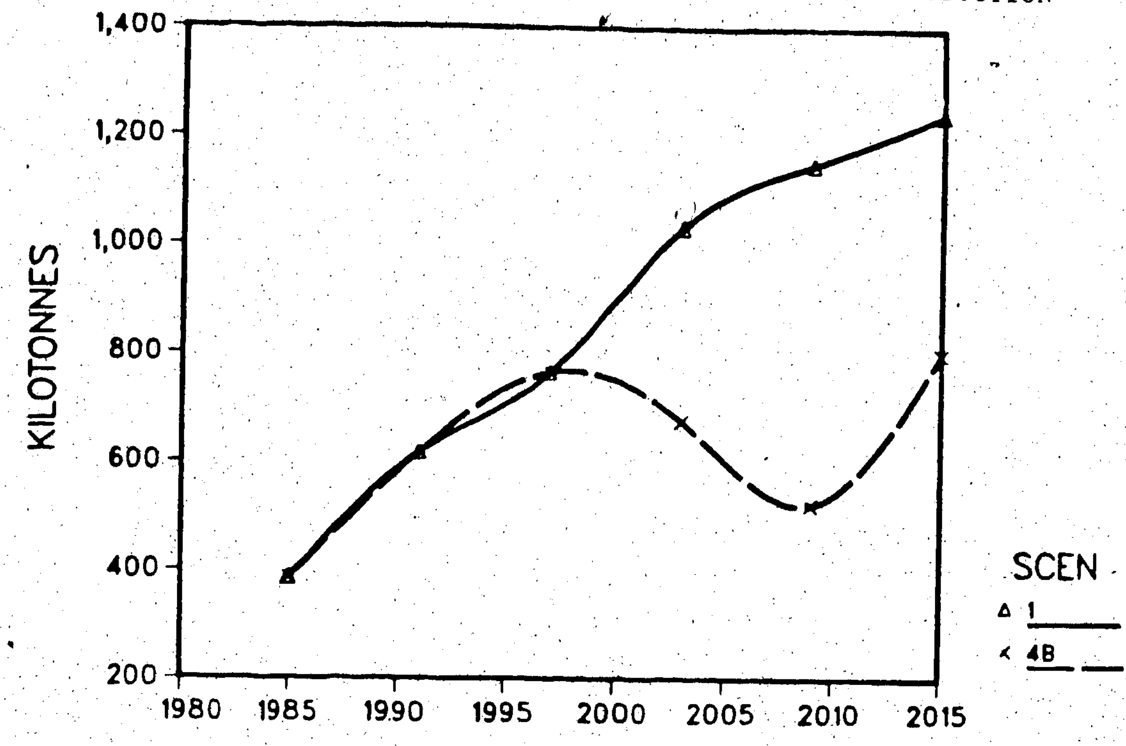


FIGURE 100. SCENARIO 4: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

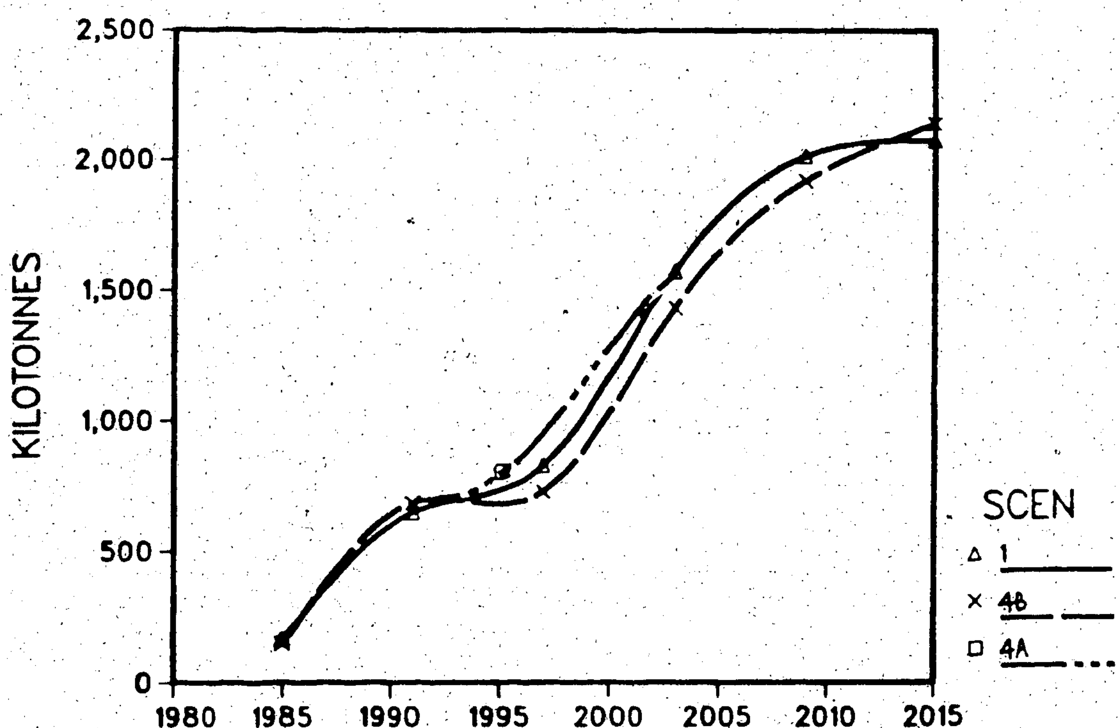


FIGURE 101. SCENARIO 4: CUMULATIVE EHTYLENE-FROM-ETH/PRP ADDITIONS

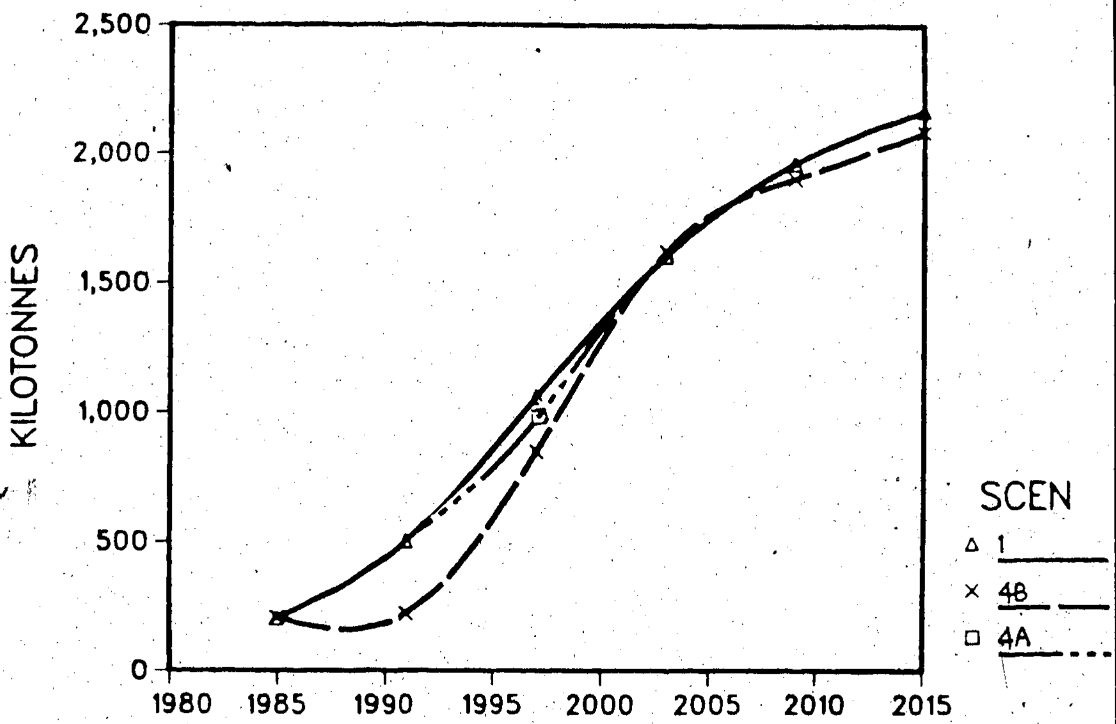


FIGURE 102 SCENARIO 4: ALBERTA HIGH DENSITY POLYETHYLENE PRODUCTION

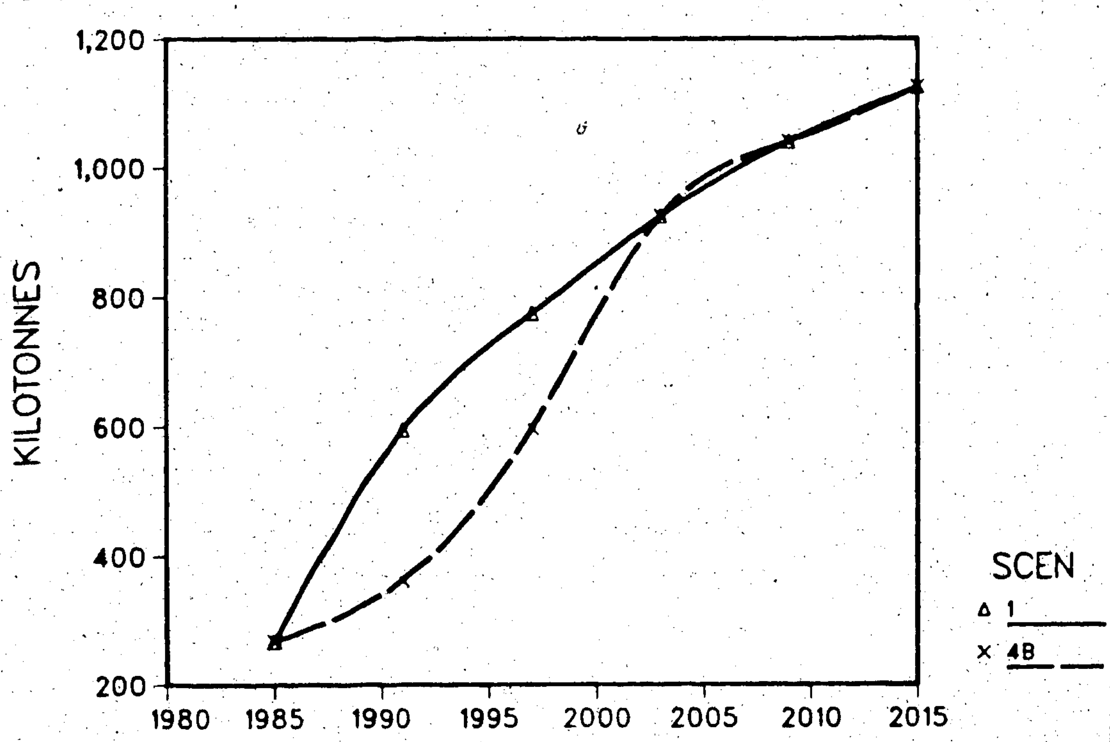


FIGURE 103. SCENARIO 4: CUMULATIVE EHTYLENE GLYCOL ADDITIONS

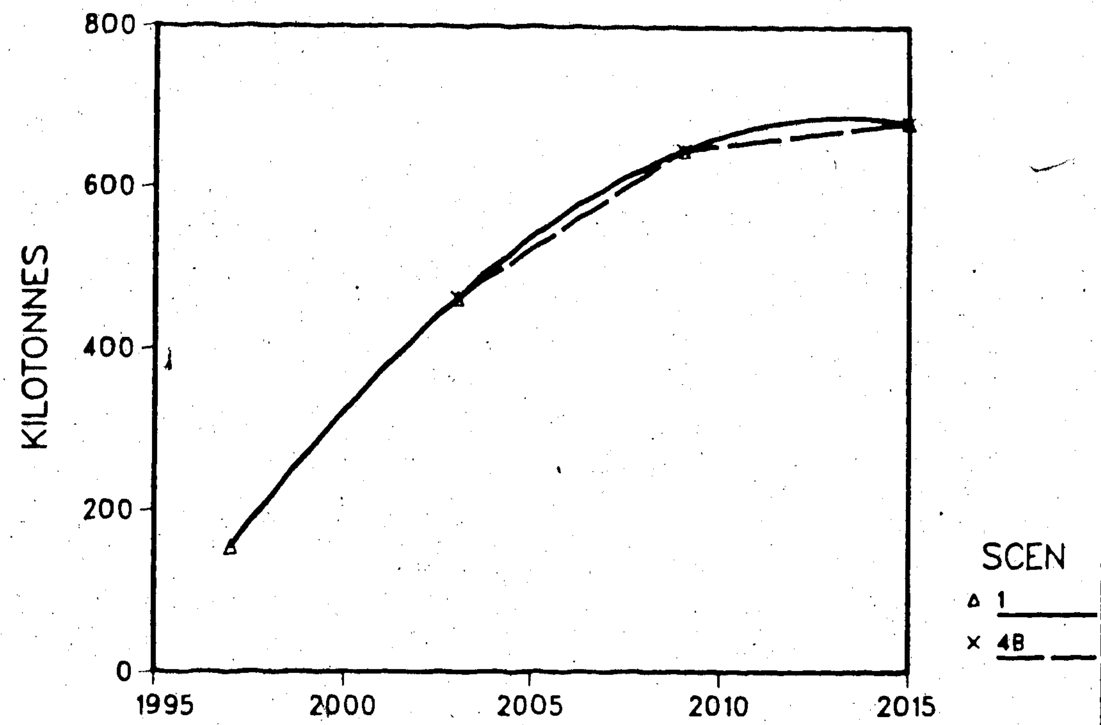


FIGURE 104. SCENARIO 4: ALBERTA STYRENE PRODUCTION

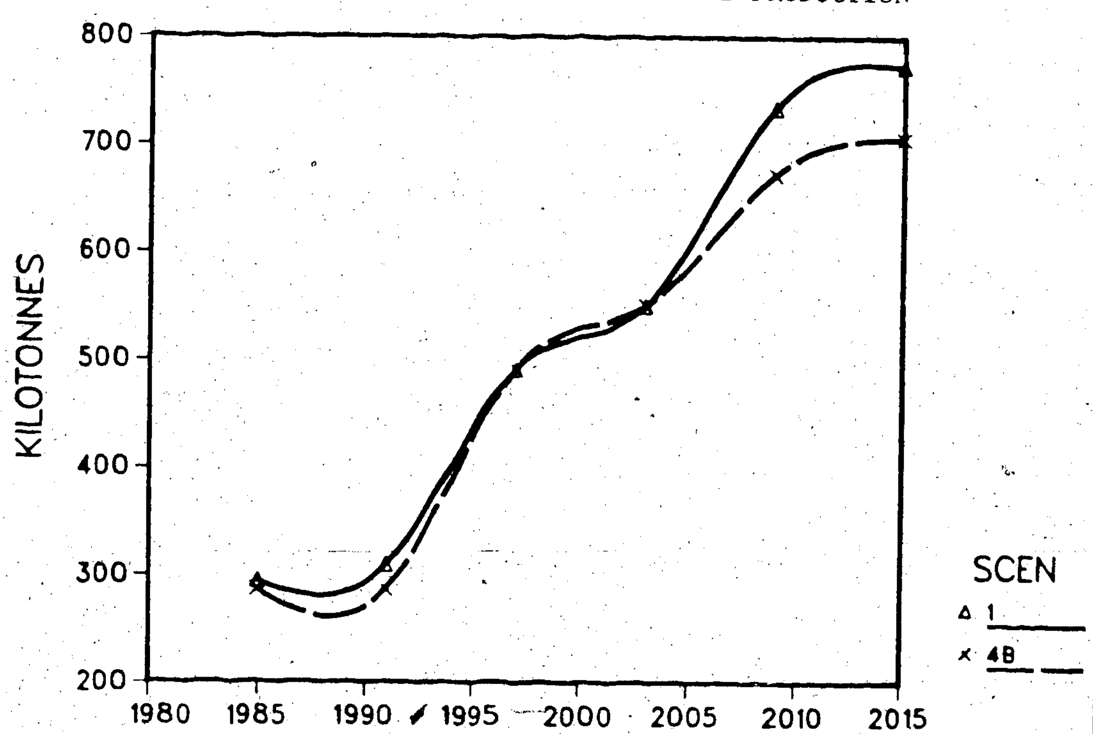


FIGURE 105. SCENARIO 4: ALBERTA VINYL ACETATE PRODUCTION

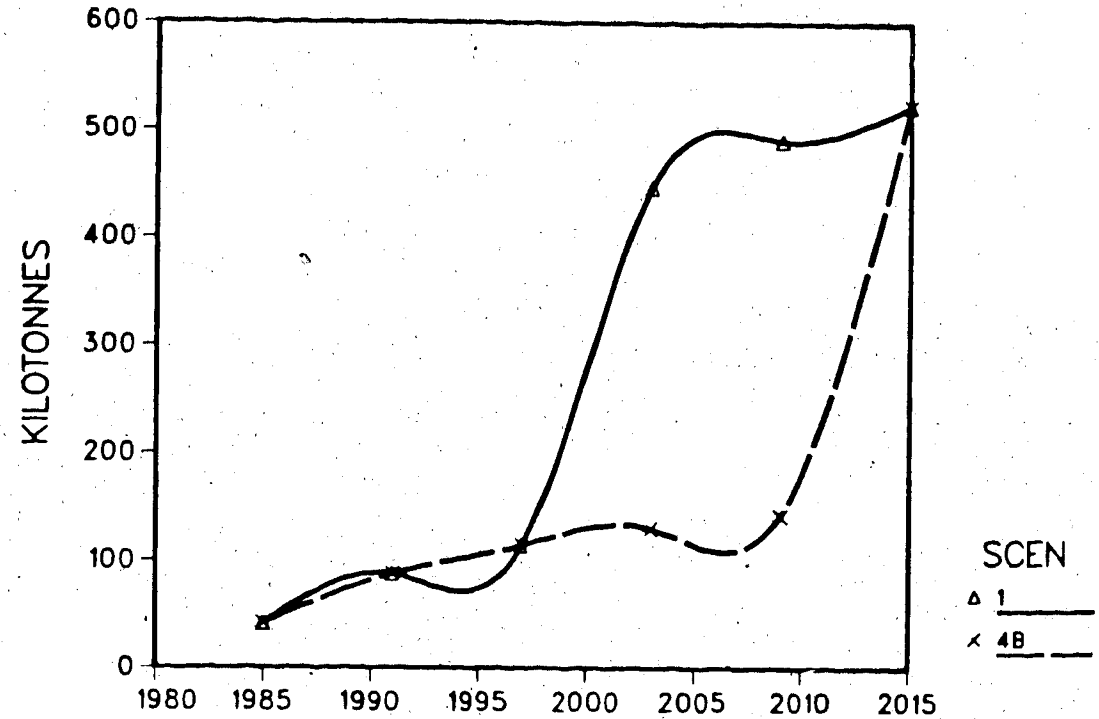


FIGURE 106. SCENARIO 4: ALBERTA POLYPROPYLENE PRODUCTION

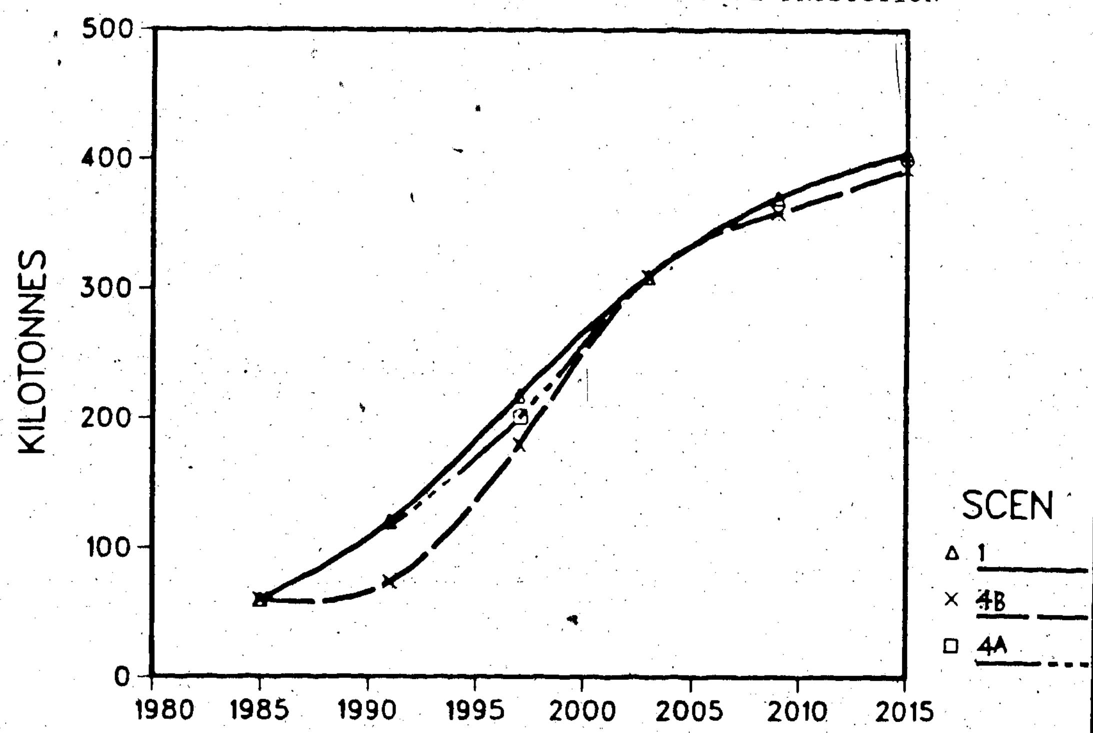


FIGURE 107. SCENARIO 4: CUMULATIVE BUTADIENE ADDITIONS

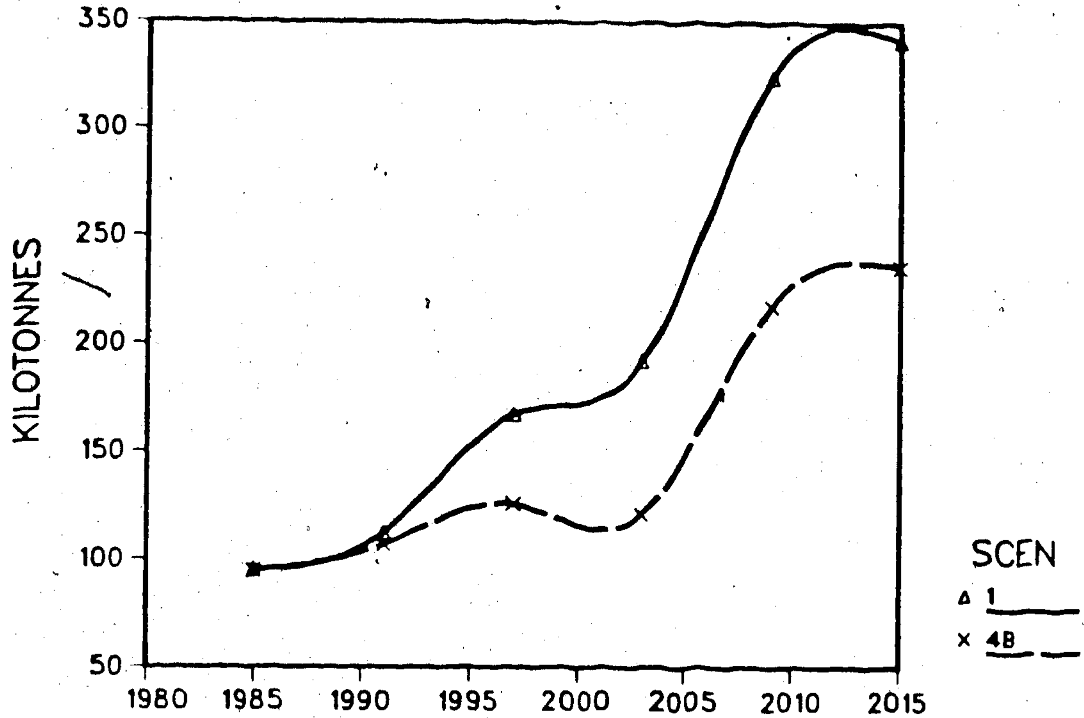
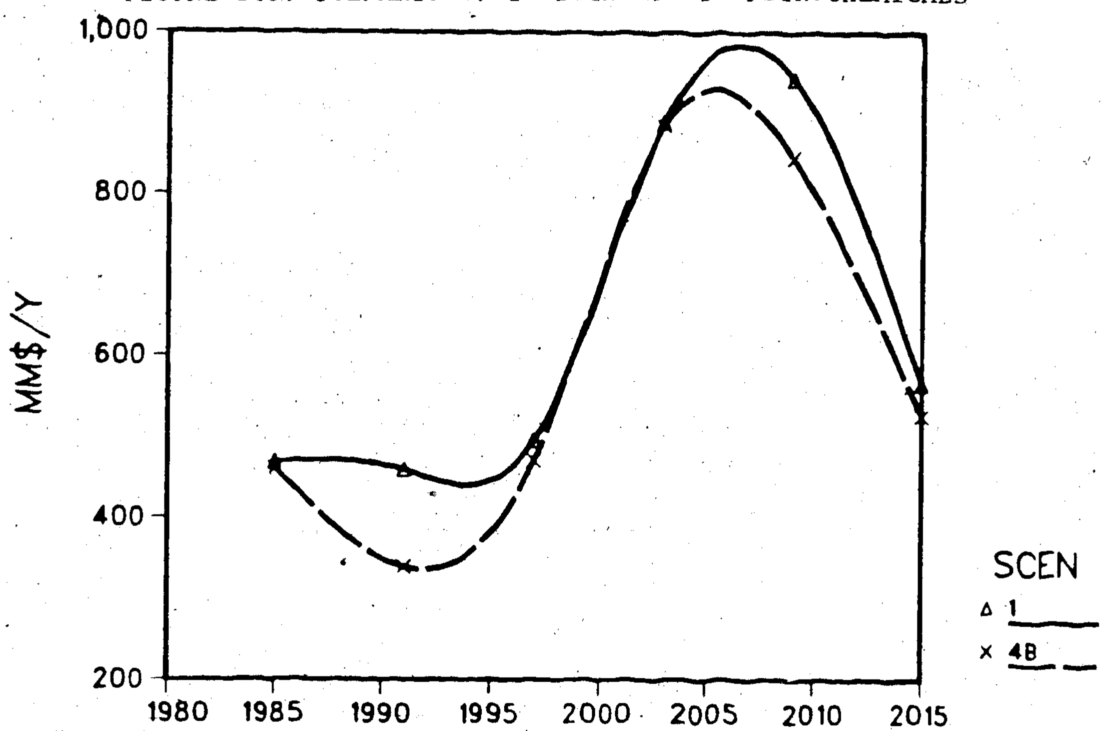


FIGURE 108. SCENARIO 4: INVESTMENTS IN PETROCHEMICALS



restricted capital on their production, vinyl chloride and low density polyethylene are the 'best'; high density polyethylene and vinyl acetate are the 'worst' insomuch as they have the lowest returns on capital.

Investments

In scenario #4A, petrochemical investments are not affected. In scenario #4B, due to the capital restrictions, petrochemical investments are generally lower, (Figure 108).

Conclusions

More capital availability does not have a major impact on the Canadian petrochemicals industry. Capital availability at projected values, is not a limiting factor in the future development of the industry.

Reduced first-level capital availability does have a major impact on the petrochemical industry; the greater preproduction activities penalty affects the Alberta methanol production and the Eastern Canadian ammonia production; the plant investments penalty results in lower ethylene and derivatives production levels.

D. A COMPARISON BETWEEN SCENARIOS #1 AND #5

The increase in the required return on capital results in lower petrochemical activity and causes a slight reduction in the Alberta marketable gas production profile (Figure 109).

FIGURE 109. SCENARIO 5: ALBERTA MARKETABLE GAS PRODUCTION

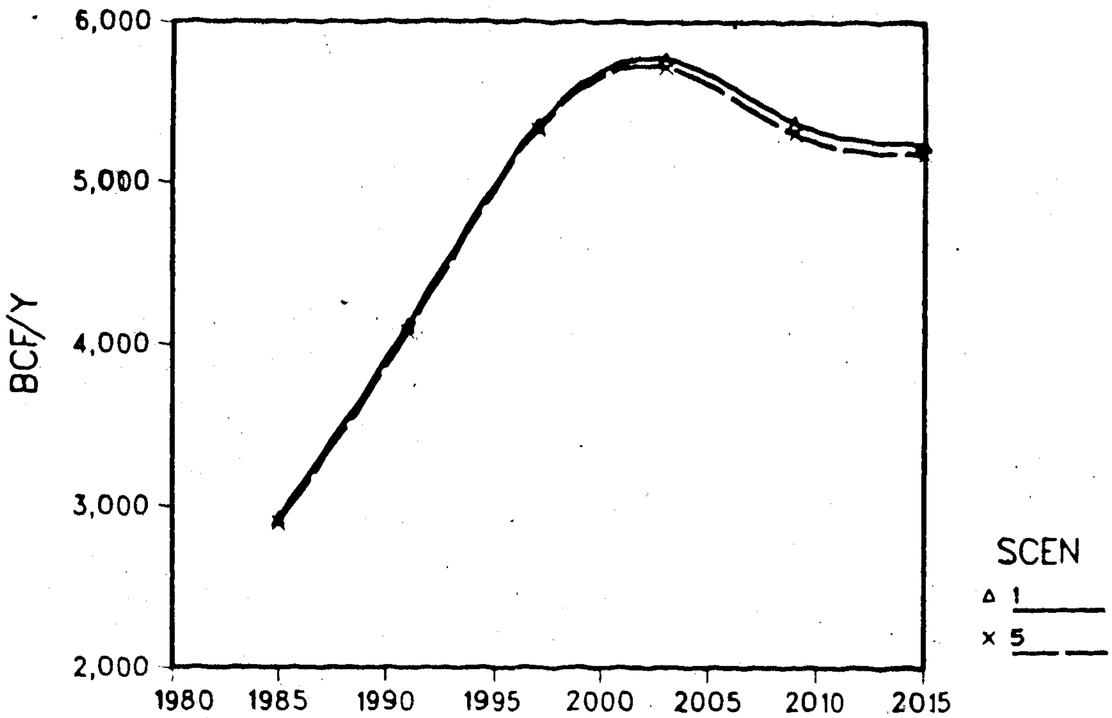
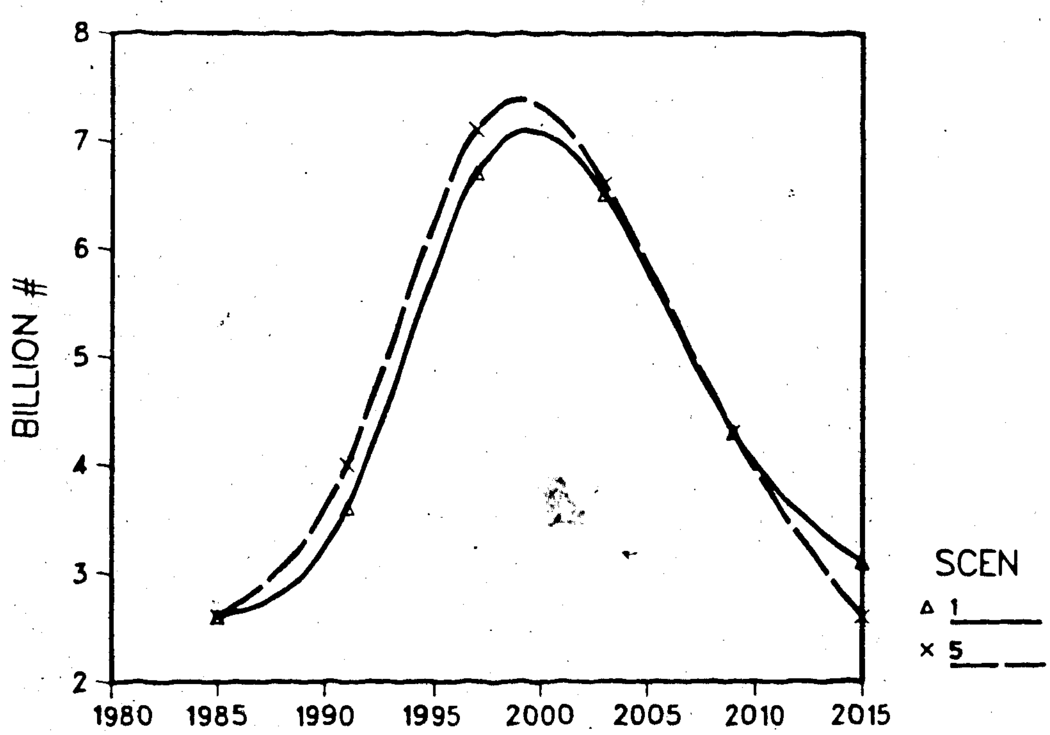


FIGURE 110. SCENARIO 5: 'SURPLUS' ETHANE



As the ethylene production is reduced, the ethane surplus increases (Figure 110). As the upgraders become uneconomic, more bitumen and heavy oil are exported, causing a steady reduction in the condensate surplus (Figure 111).

Methane-Based Petrochemicals

As the exports to the U.S. Midwest are reduced, there is a marginal reduction in Alberta ammonia production in 1985 (Figure 112). The export market temporarily lost by the Alberta producers is supplied by the Eastern Canadian ammonia producers (Figure 113). The reason for this behaviour is explained in Figures 117 and 118. The Alberta ethane-based ethylene capacity is higher than in the base case; the ethane-propane capacity is lower but additional ethane is required. This ethane is extracted by diverting some natural gas from Alberta ammonia producers to Eastern Canada. In subsequent time periods, Alberta ammonia production reverts to its base scenario values (Figure 112). In the final time period the Eastern Canadian ammonia production is lower (Figure 113).

The higher required rate of return increases the preproduction expenses for natural gas, pushing out the lower valued uses of the gas. As shown in Figures 114 and 115, methanol production is one of the lower valued uses that is affected. Since the coal mining activity has not been explicitly modelled, the exogeneous coal costs are not affected in this scenario; therefore coal becomes the preferred feedstock for new

FIGURE 111. SCENARIO 5: 'SURPLUS' CONDENSATE

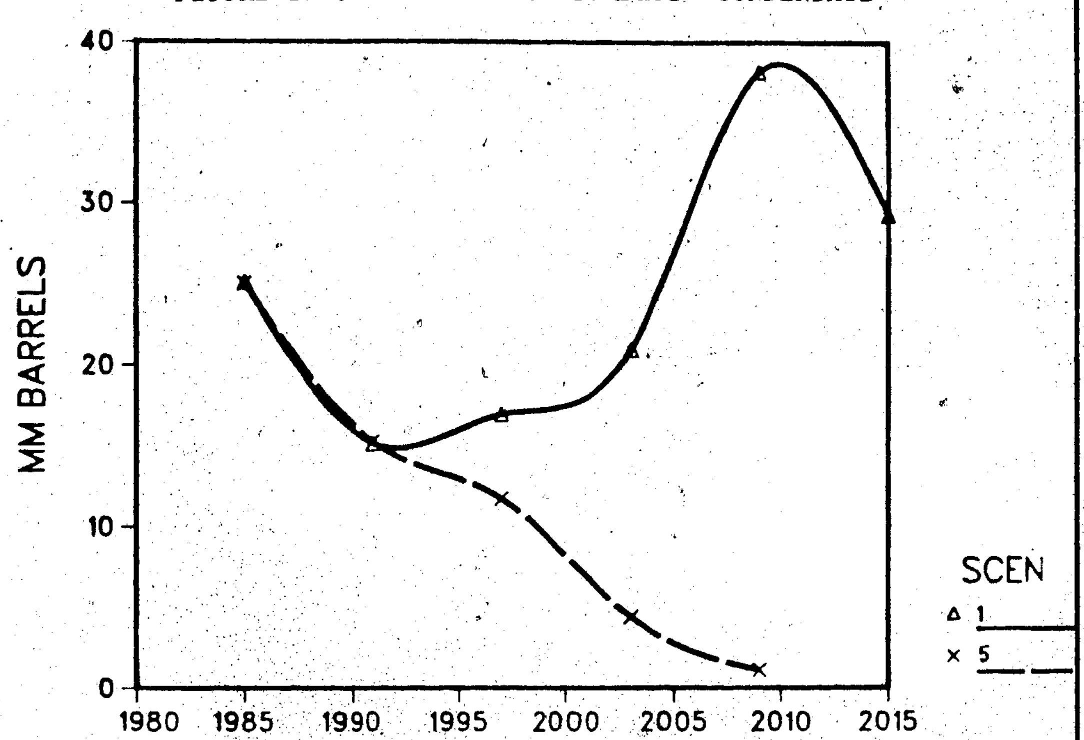


FIGURE 112. SCENARIO 5: ALBERTA AMMONIA PRODUCTION

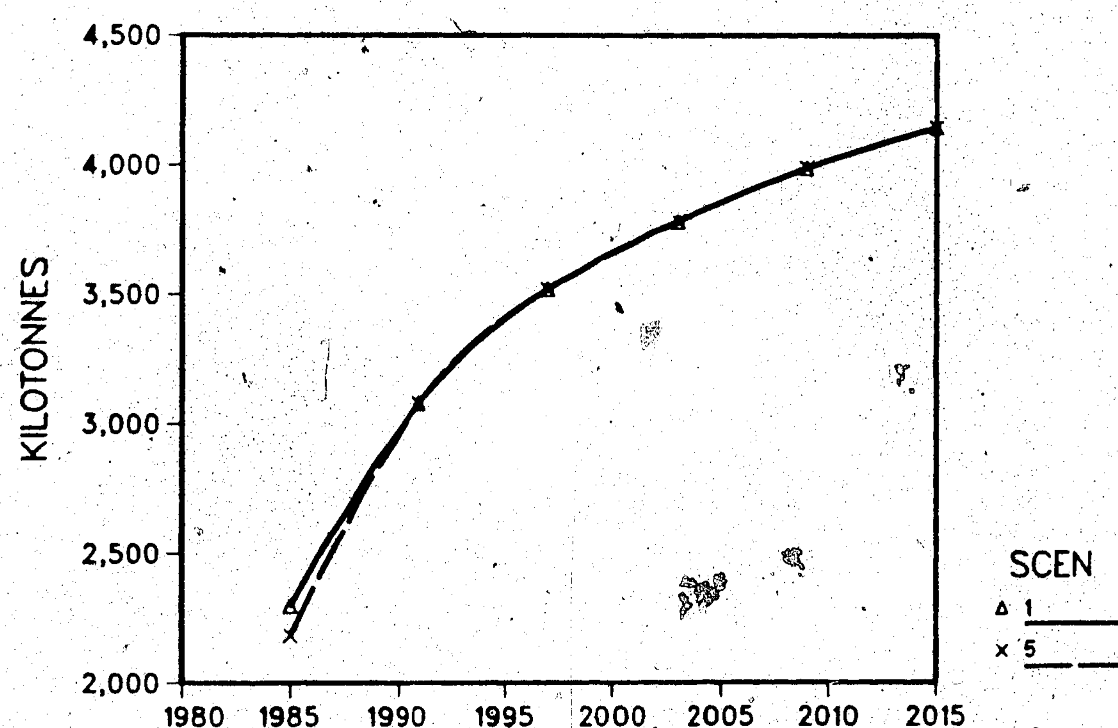


FIGURE 113. SCENARIO 5: EASTERN CANADIAN AMMONIA PRODUCTION

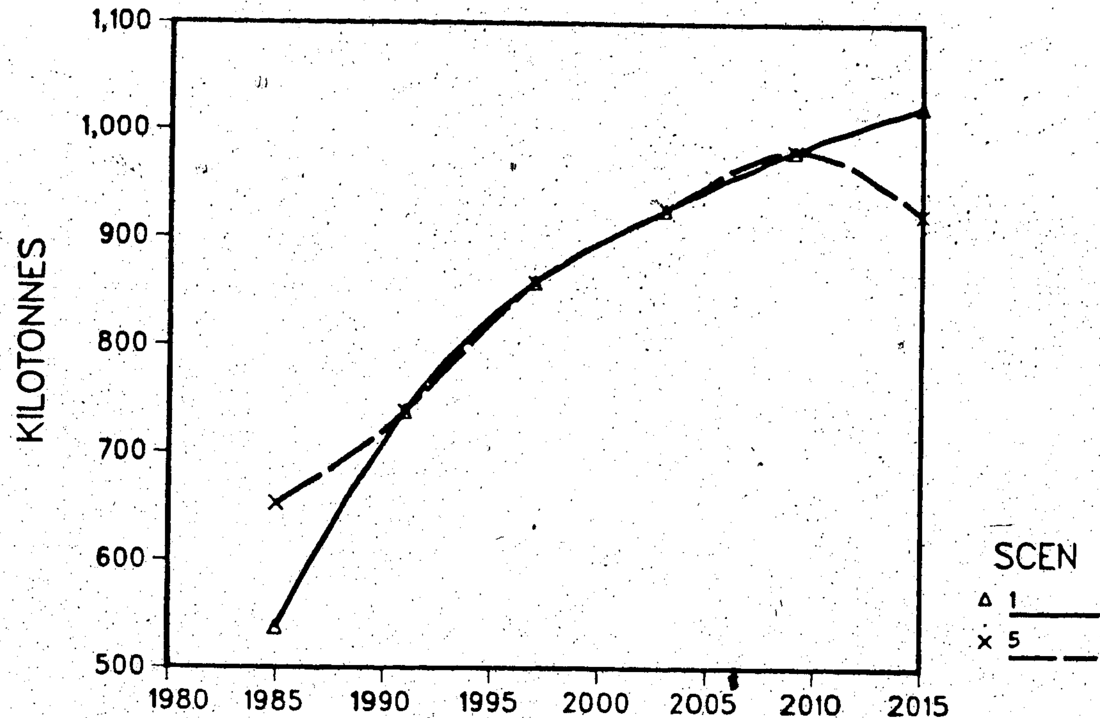


FIGURE 114. SCENARIO 5: ALBERTA CHEM-RELATED METHANOL PRODUCTION

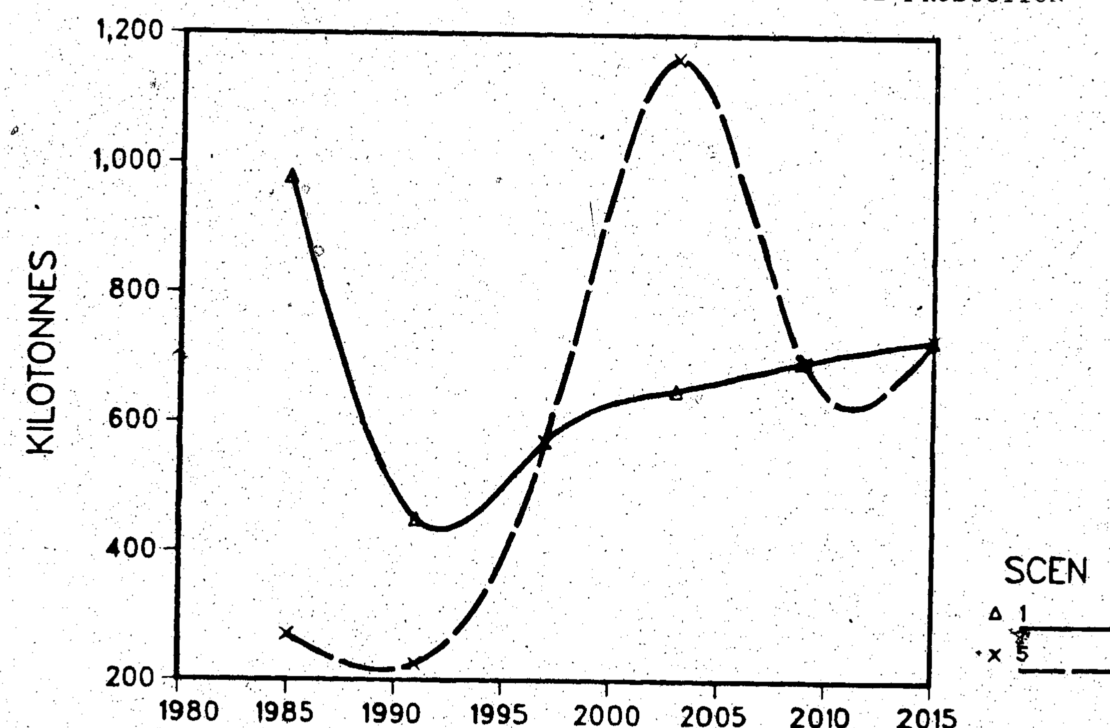


FIGURE 115. SCENARIO 5: ALBERTA FUEL-RELATED METHANOL PRODUCTION

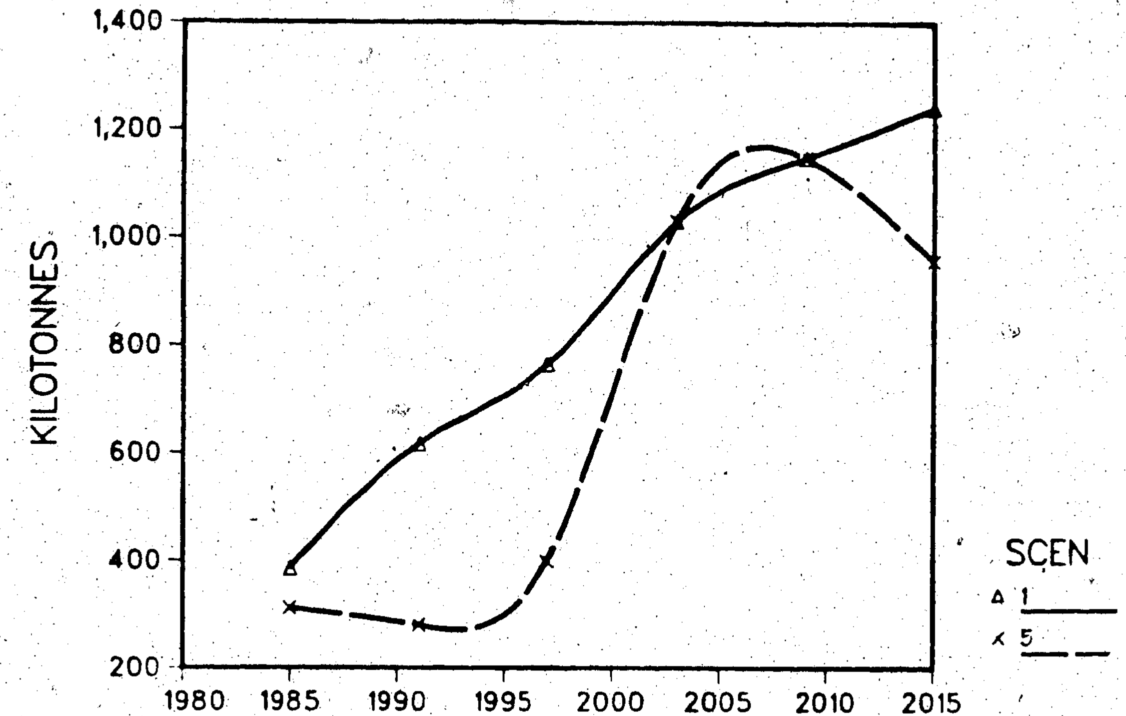
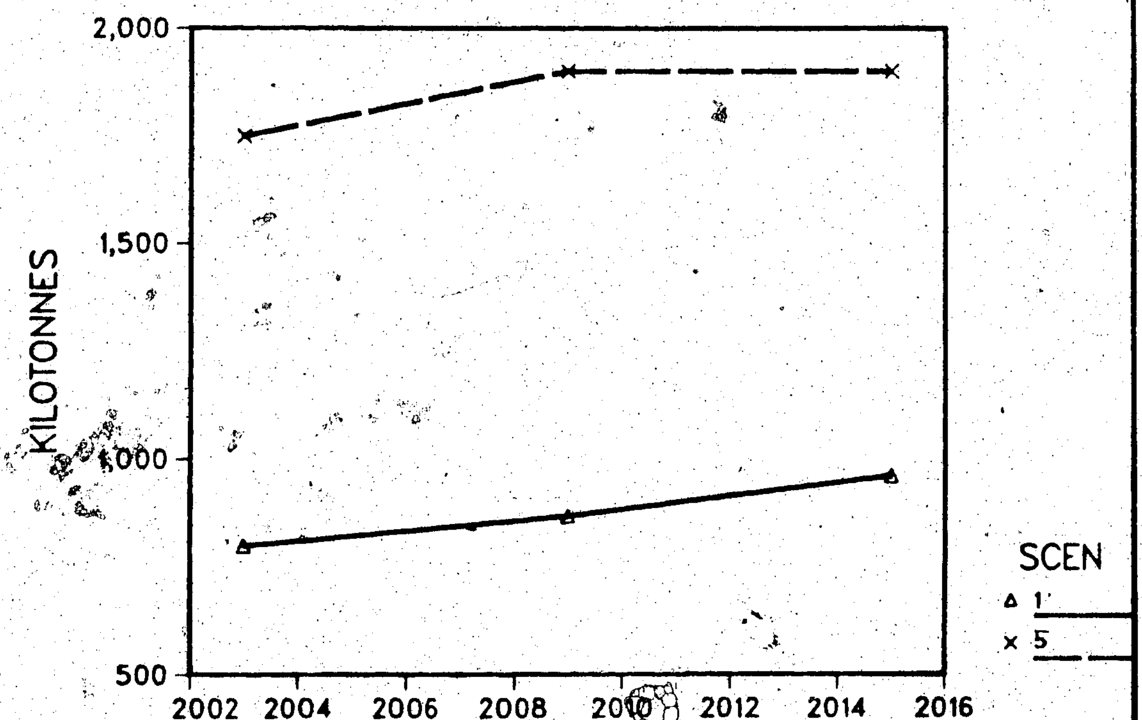


FIGURE 116. SCENARIO 5: CUMULATIVE METHANOL-FROM-COAL ADDITIONS



methanol plants (Figure 116). This is another model limitation, since in reality, if the return required for natural gas preproduction activities are higher, so will the return required for coal mining activities be higher than in the base scenario.

Other Petrochemicals

Compared to the base scenario values, more pure ethane plant additions and less ethane-propane plant additions of ethylene occur (Figures 117 and 118). This could be because the ethane-based plants have lower capital costs than ethane-propane plants or because the increased costs result in the reduction of polypropylene production in Alberta (Figure 124). Also, it could be a combination of these two impacts. The overall ethylene production is lower.

As in scenario #4, the ethylene derivatives least affected by this scenario are low density polyethylene and vinyl chloride (Figure 122). Ethylene glycol and styrene capacity additions are slightly reduced (Figures 120 and 121). Most affected are high-density polyethylene and vinyl acetate (Figures 119 and 123). Therefore the impacts of lower capital availability or higher cost of capital are, as expected, similar.

Like polypropylene, the butadiene production is lower than in the base case.

FIGURE 117. SCENARIO 5: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

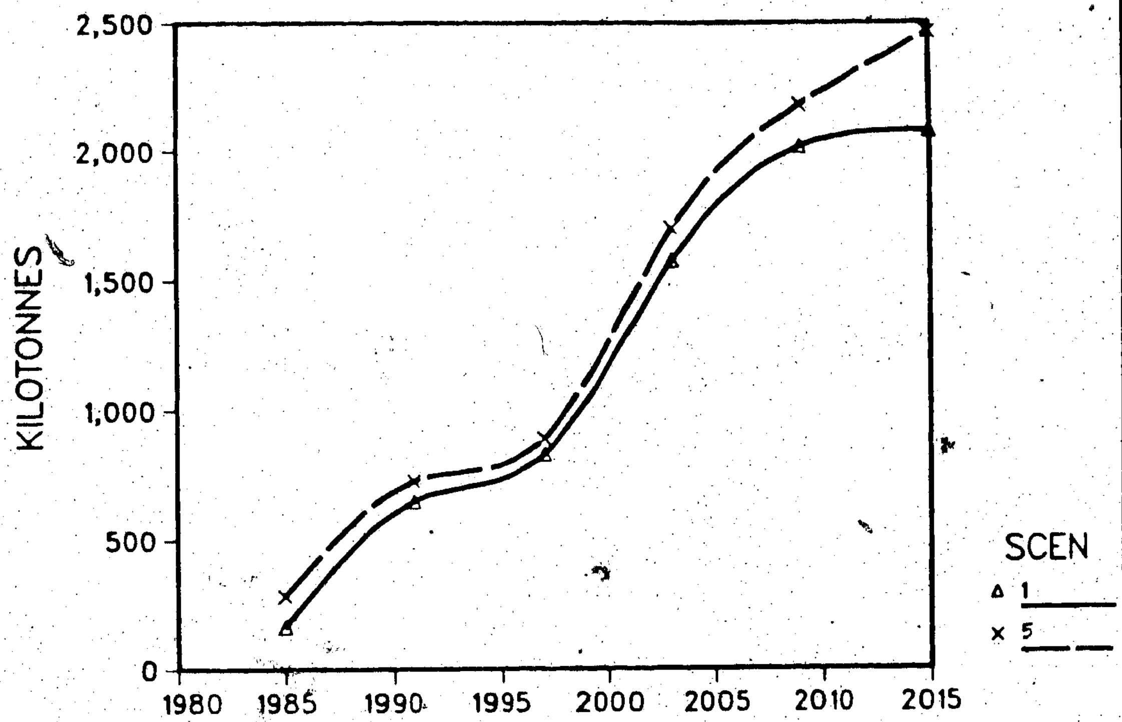


FIGURE 118. SCENARIO 5: CUMULATIVE ETHYLENE-FROM-ETH/PRP ADDITIONS

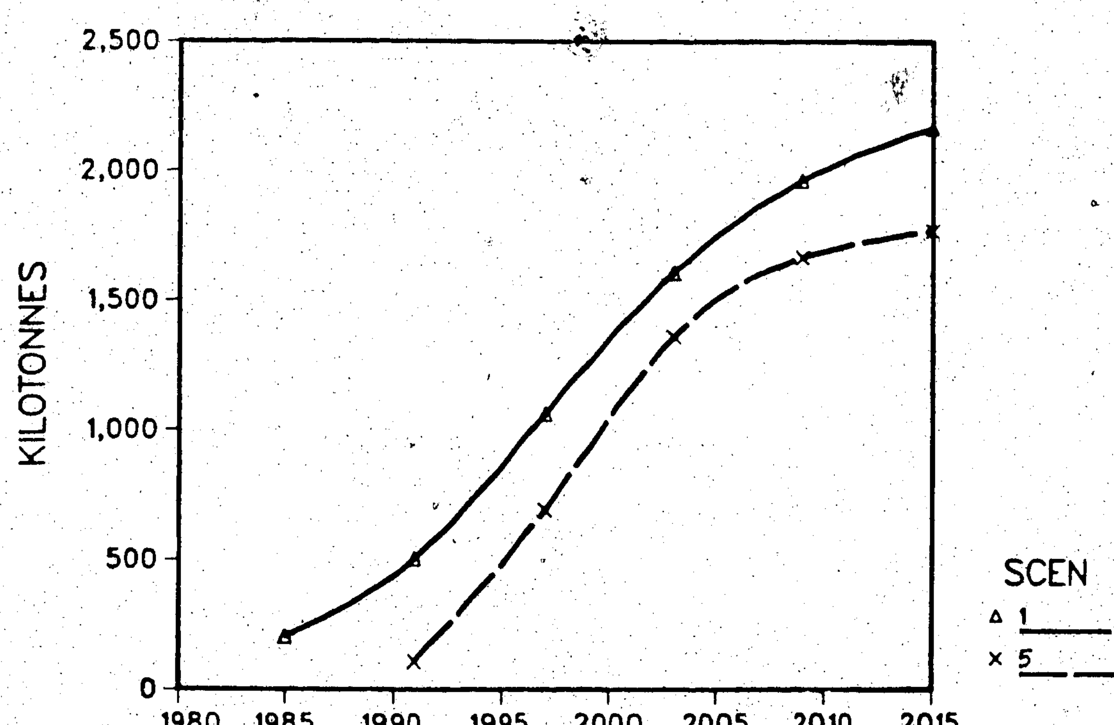


FIGURE 119. SCENARIO 5: CUMULATIVE HIGH DENSITY POLYETHYLENE ADDITIONS

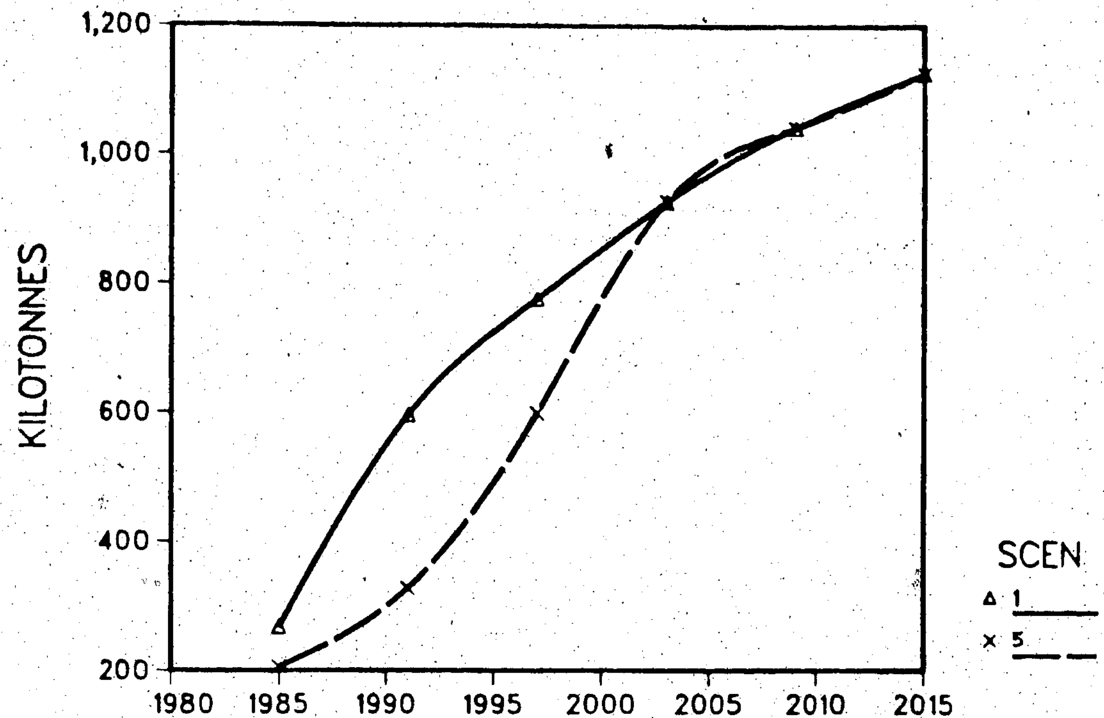


FIGURE 120. SCENARIO 5: CUMULATIVE ETHYLENE GLYCOL ADDITIONS

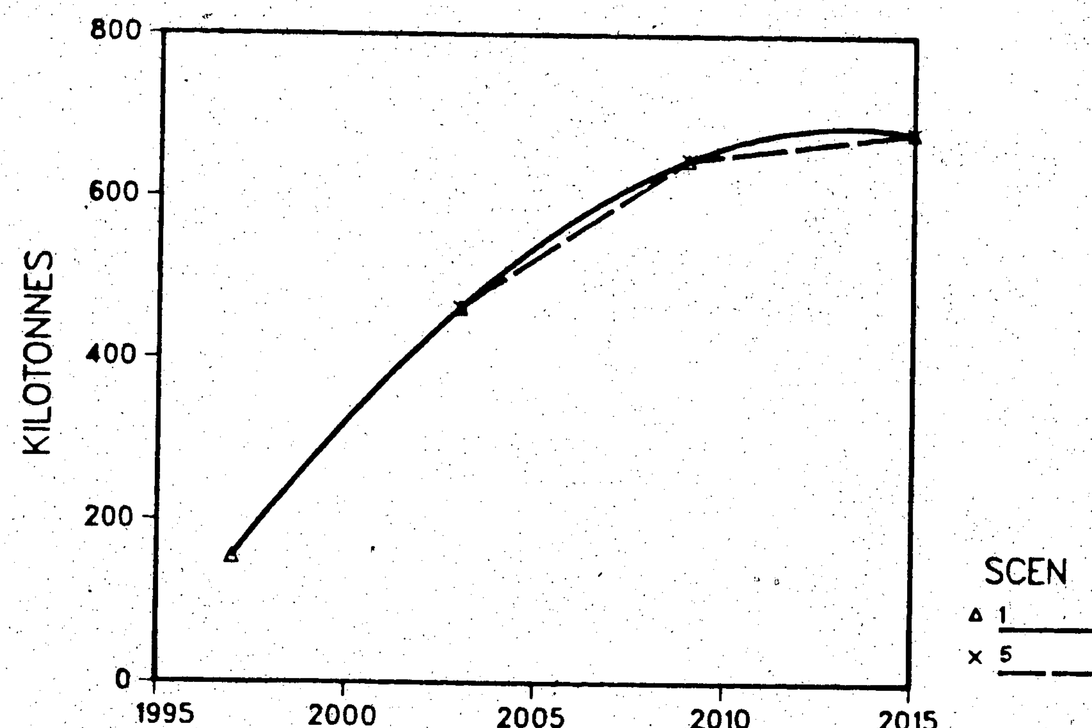


FIGURE 121. SCENARIO 5: CUMULATIVE VINYL CHLORIDE ADDITIONS

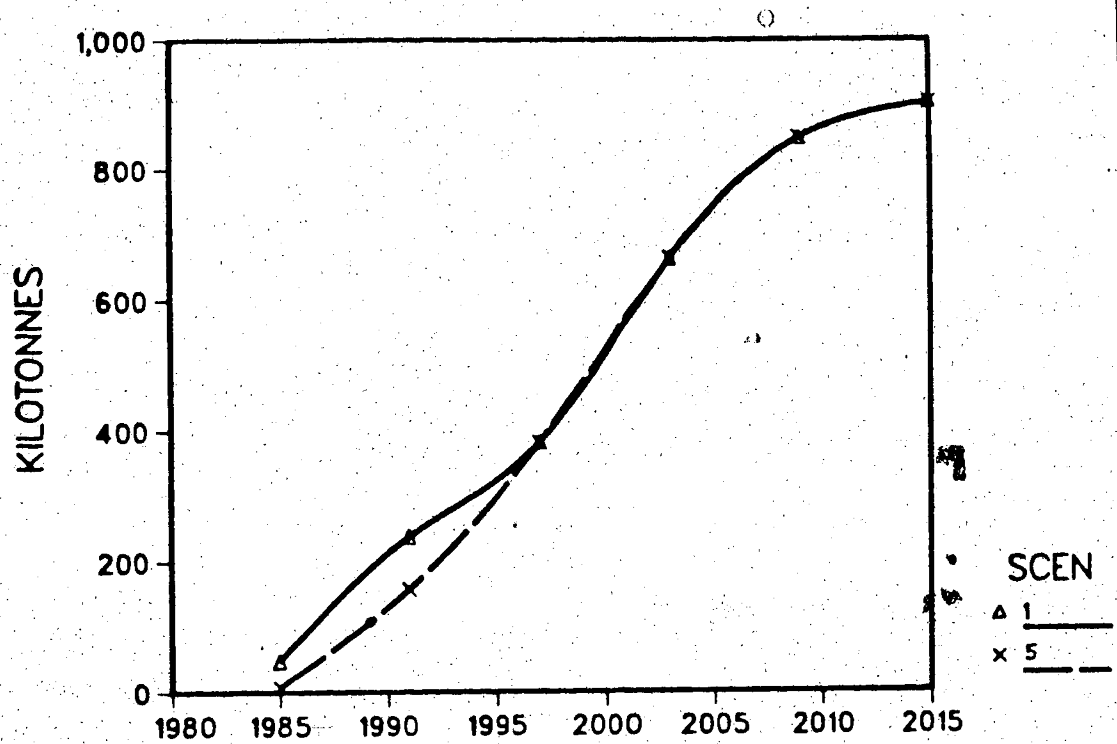


FIGURE 122. SCENARIO 5: CUMULATIVE STYRENE ADDITIONS

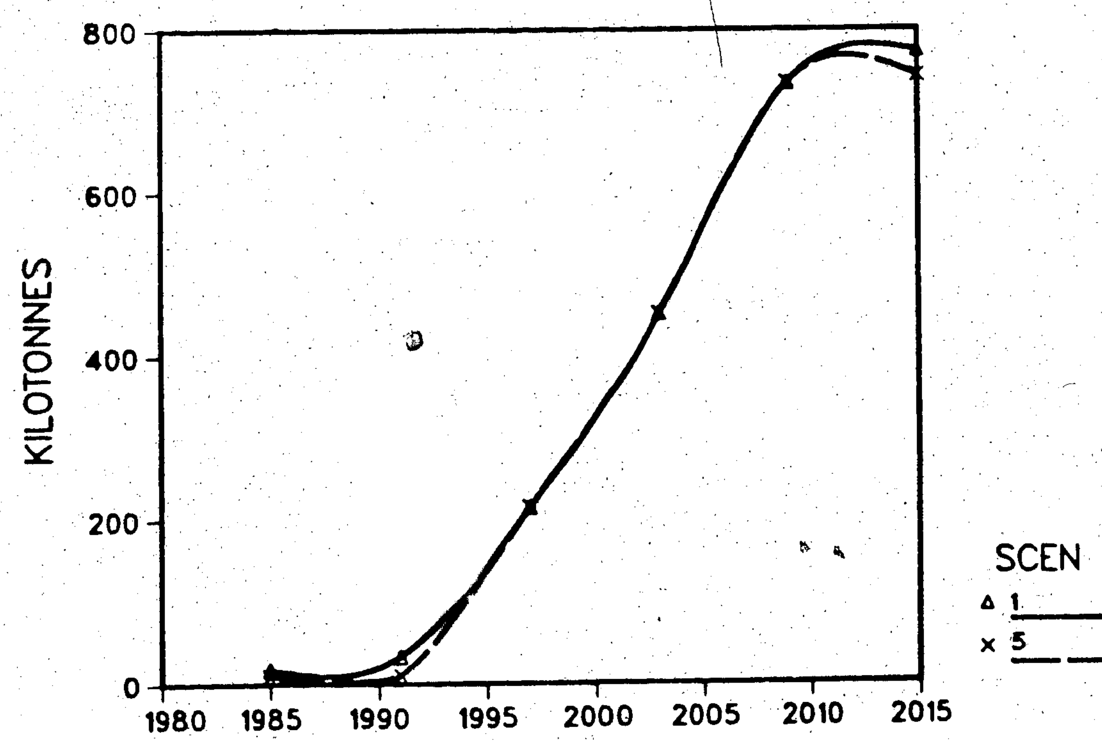


FIGURE 123. SCENARIO 5: CUMULATIVE VINYL ACETATE ADDITIONS

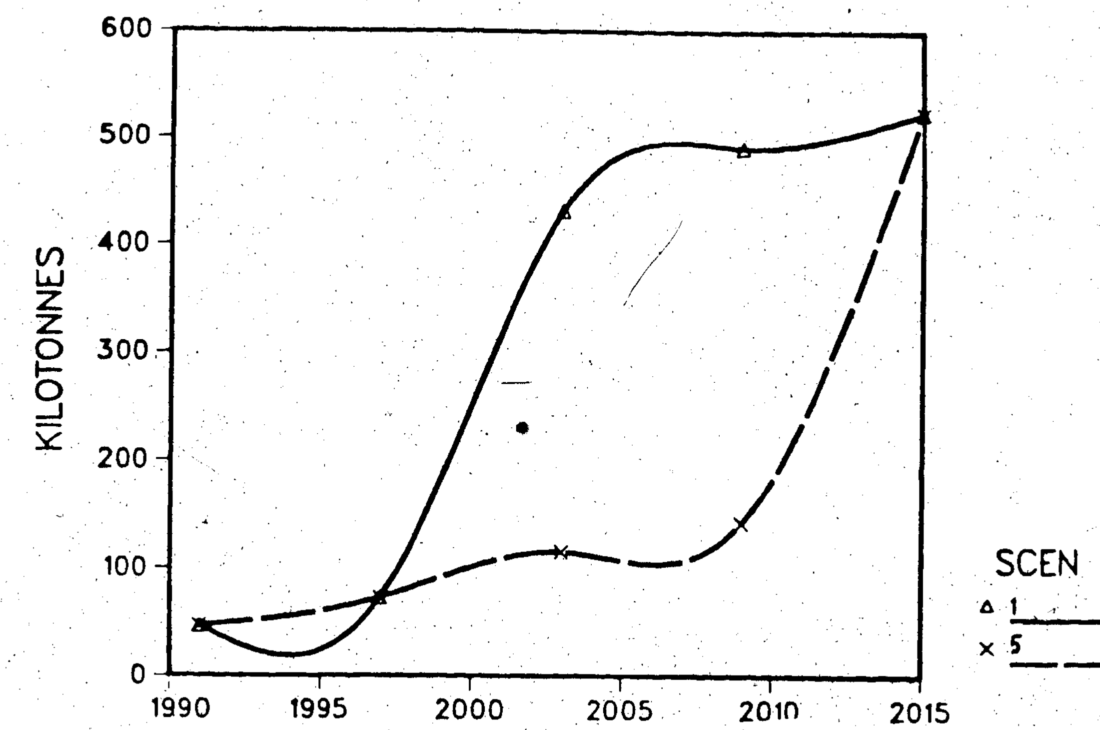
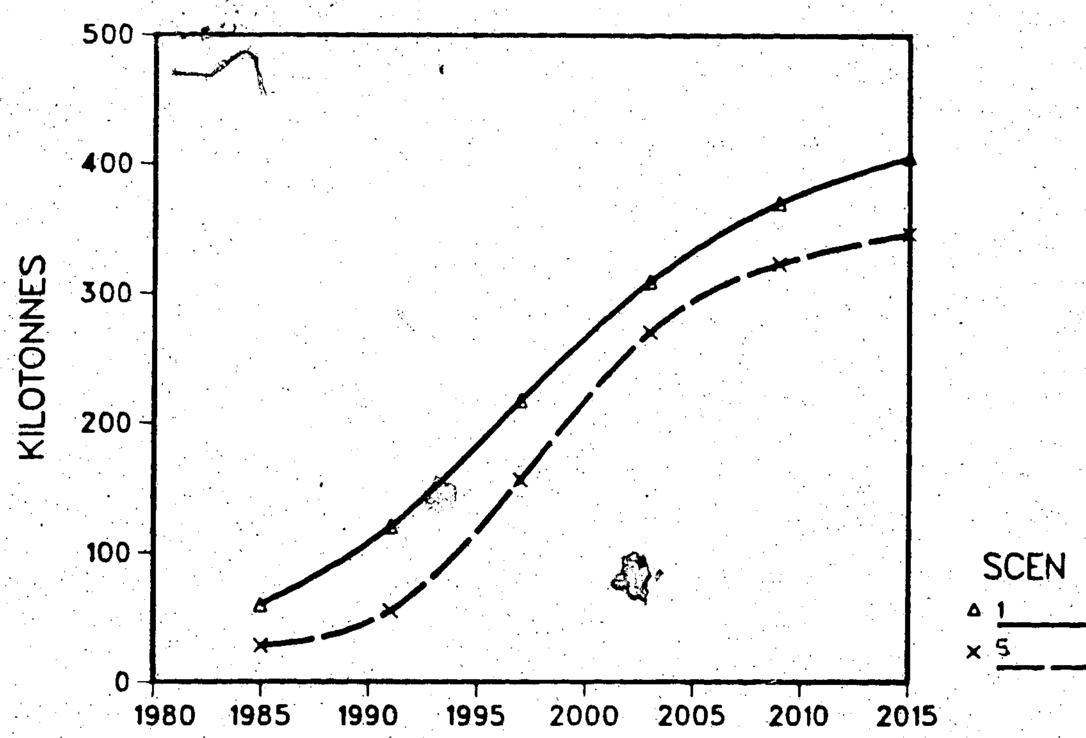


FIGURE 124. SCENARIO 5: CUMULATIVE POLYPROPYLENE ADDITIONS



Investments

Due to fewer plant additions, the petrochemical investments are lower than in the base scenario (Figure 126).

Conclusions

The increase in the required rate of return results in lower petrochemical plant additions. The petrochemicals most affected are methanol, high density polyethylene and vinyl acetate.

E. A COMPARISON BETWEEN SCENARIOS #1 AND #6

Having identified the capital-sensitive petrochemicals in the previous two scenarios, the next step is to identify the price-sensitive petrochemicals. The reduction in petrochemical prices results in lower petrochemical activity than in the base scenario and thereby, lower Alberta marketable gas production (Figure 127). The latter is not as drastically affected as the petrochemicals since the dominant natural gas demands from domestic residential and commercial consumers and from energy projects are still being satisfied.

In spite of the lower marketable gas production, due to the reduced petrochemical activity the ethane surplus is greater than in the base case (Figure 128). The effect on propane is similar. Because of the lower marketable gas production and because its use in the energy industry is not affected, the condensate surplus is lower (Figure 129).

FIGURE 125. SCENARIO 5: CUMULATIVE BUTADIENE ADDITIONS

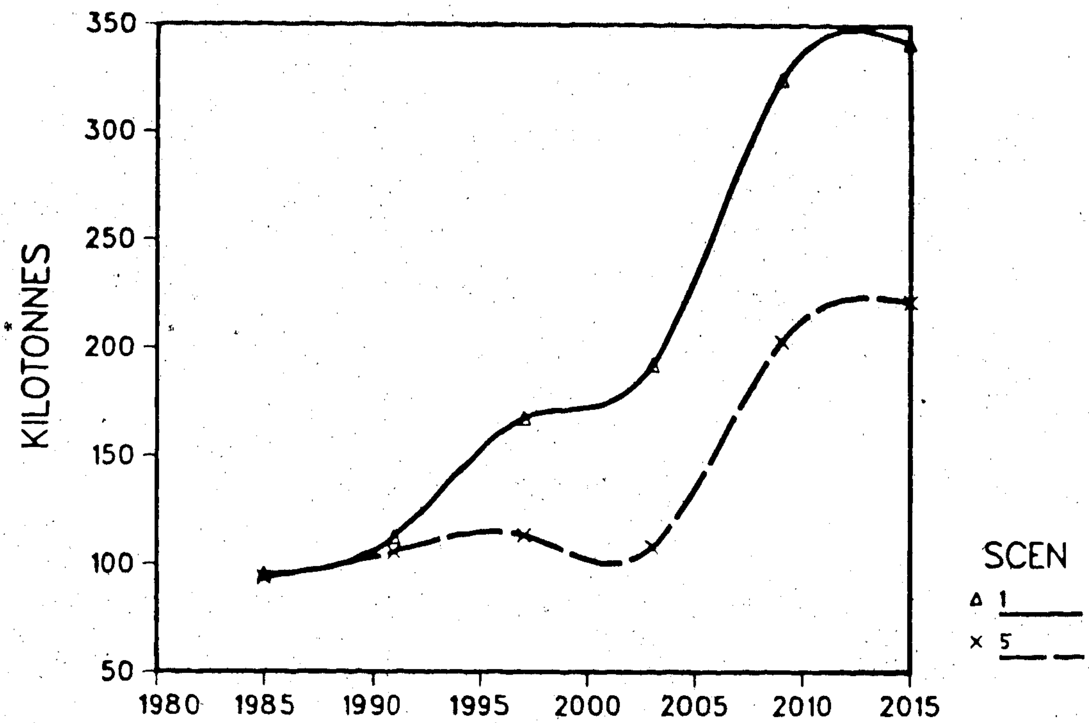


FIGURE 126. SCENARIO 5: INVESTMENTS IN PETROCHEMICALS

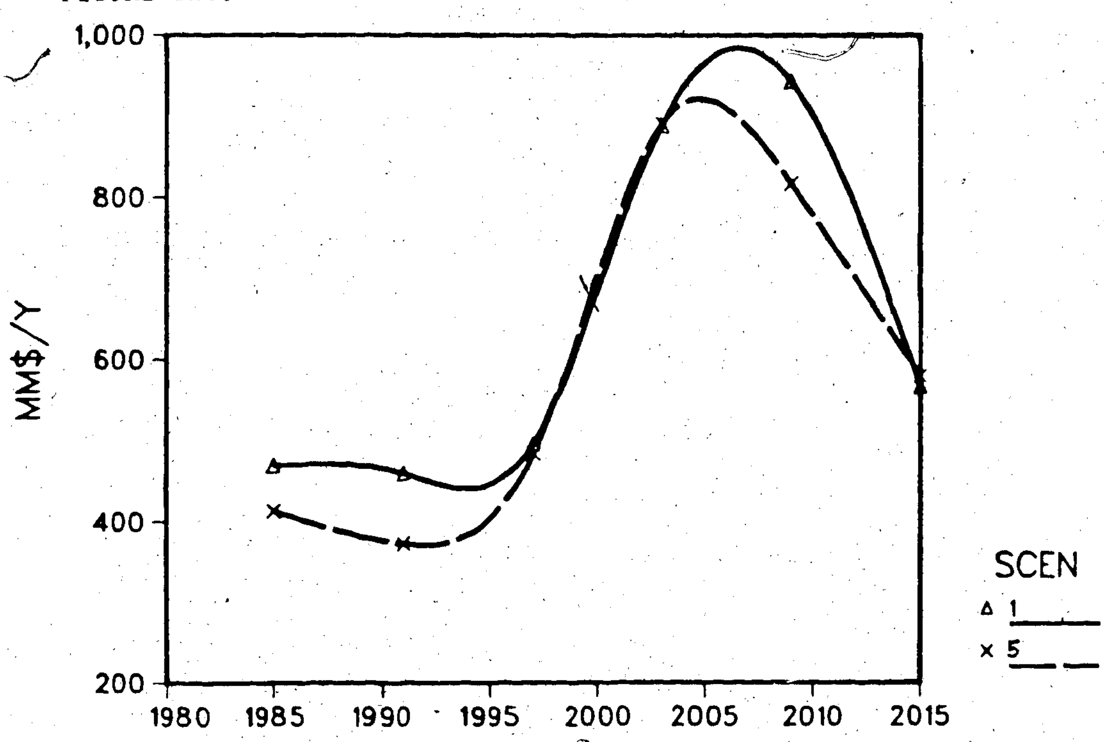


FIGURE 127. SCENARIO 6: ALBERTA MARKETABLE GAS PRODUCTION

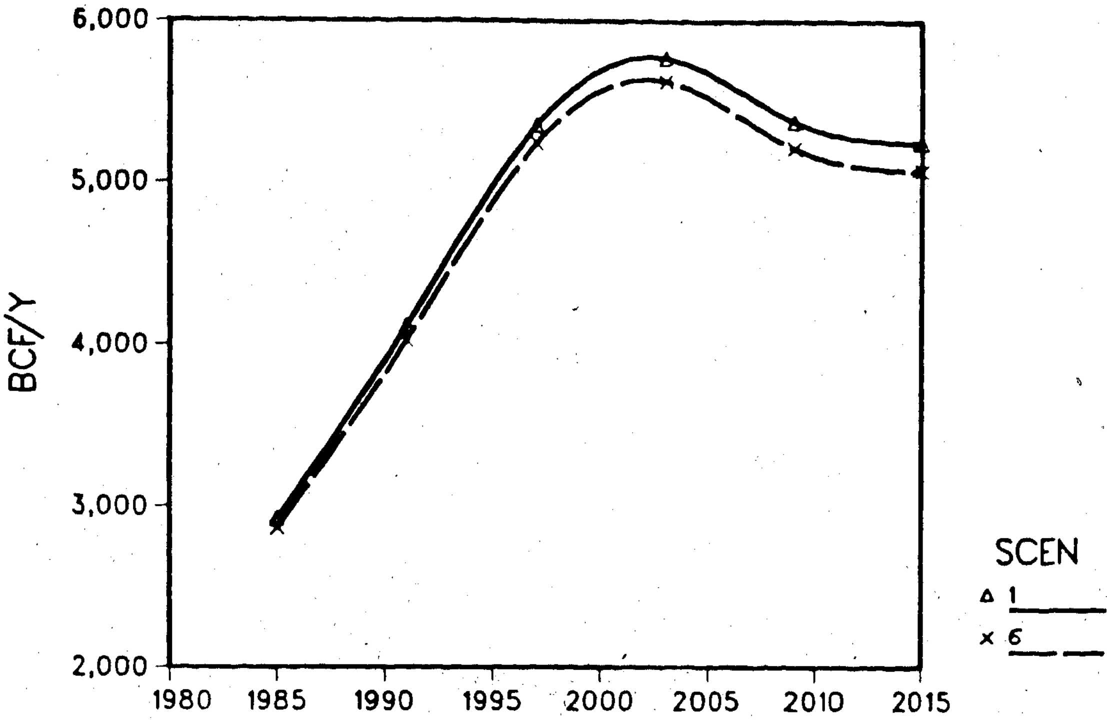


FIGURE 128. SCENARIO 6: 'SURPLUS' ETHANE

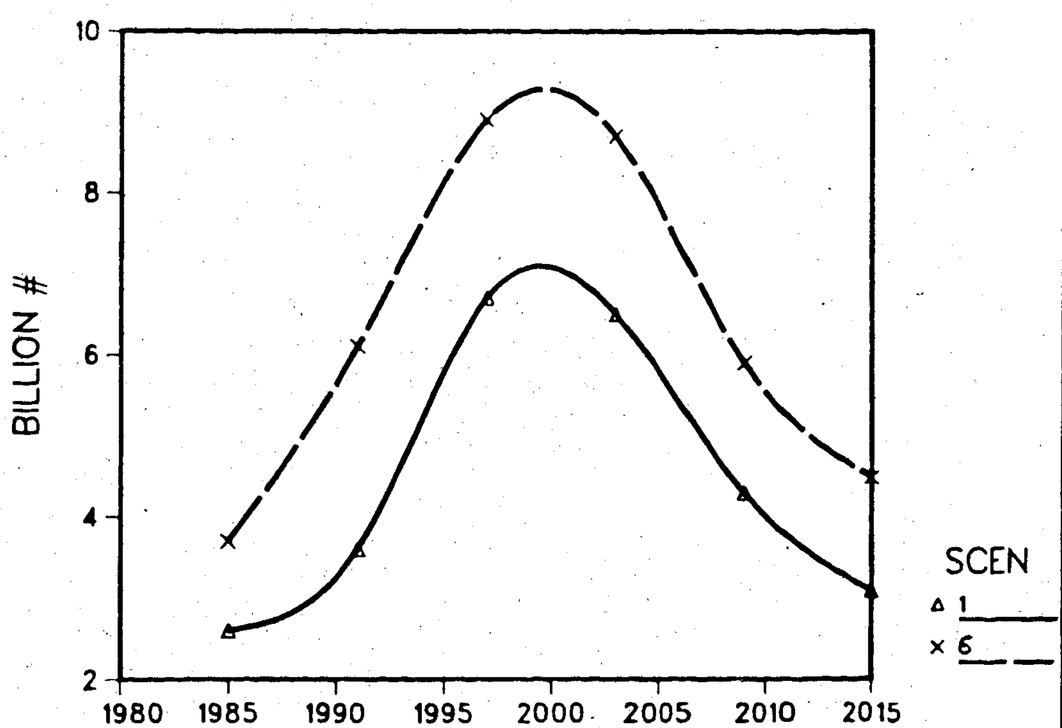


FIGURE 129. SCENARIO 6: 'SURPLUS' CONDENSATE

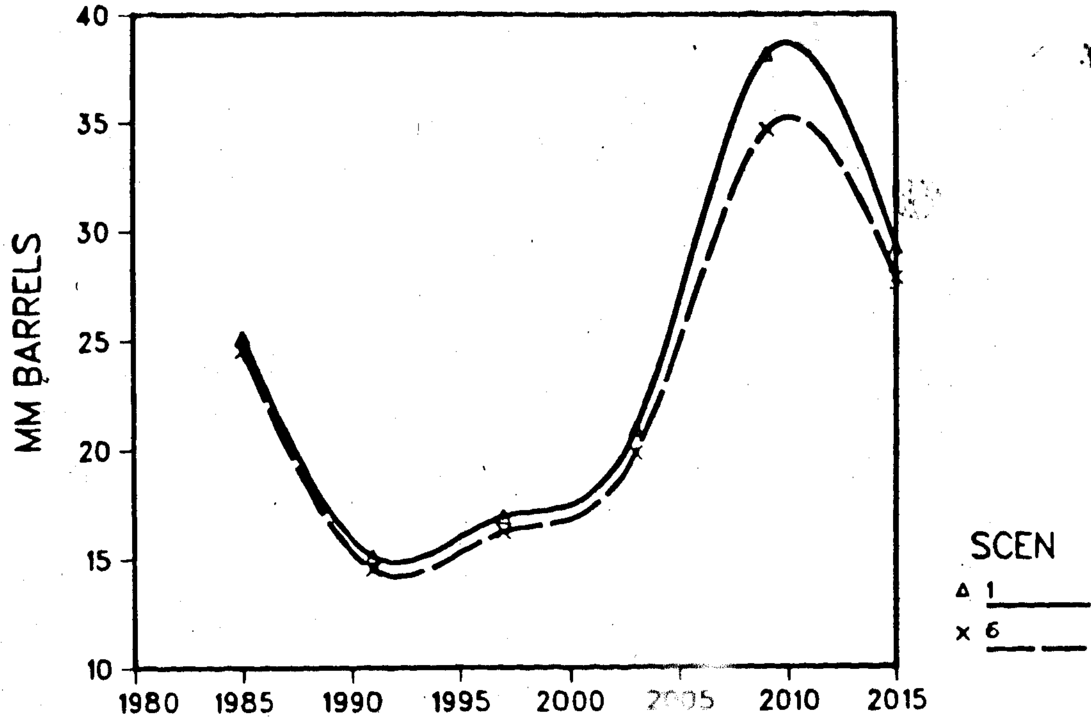
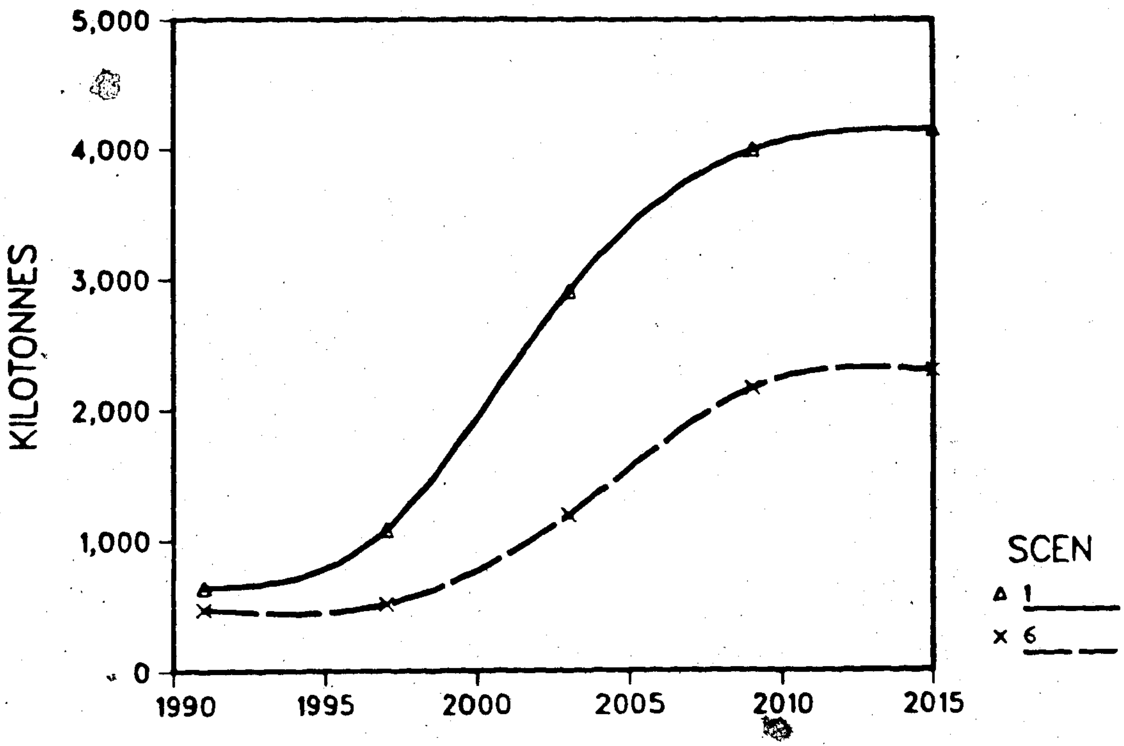


FIGURE 130. SCENARIO 6: CUMULATIVE AMMONIA-FROM-GAS ADDITIONS



Methane Based Petrochemicals

The lower ammonia prices make the U.S. Midwest market economically inaccessible to Alberta. There is a greater overcapacity problem than in the base scenario. Beyond 1991, the ammonia capacity additions in Alberta are at lower levels than in the base scenario (Figure 130).

In Eastern Canada, in order to increase the condensate production, the ammonia production is initially higher. The additional production goes to the U.S. Midwest. In the second time period the price-effect takes hold and Eastern ammonia production begins to peter out and the Eastern Canadian ammonia market becomes available to low-cost imports (Figure 131).

As shown in Figures 132 and 133, the Alberta methanol production is seriously affected as even the Eastern Canadian market is not economically accessible. Coal becomes the dominant feedstock (Figure 134); the reason for this is the fluctuating methanol supply and the lack of an explicit coal mining activity in the model. Methanol production is a marginal use for natural gas. As long as the economically accessible demand is escalating, the model can indulge in some preproduction for and assign some natural gas production to methanol; even under those circumstances, coal, which has no exogeneous production profile, becomes a methanol feedstock. In scenario #6 the fluctuating methanol demand makes it infeasible for the model to discover and assign natural gas for methanol production; it prefers to use coal, the quantity of which can be conveniently varied from time period to time period. To some extent

FIGURE 131 SCENARIO 6: EASTERN CANADIAN AMMONIA PRODUCTION

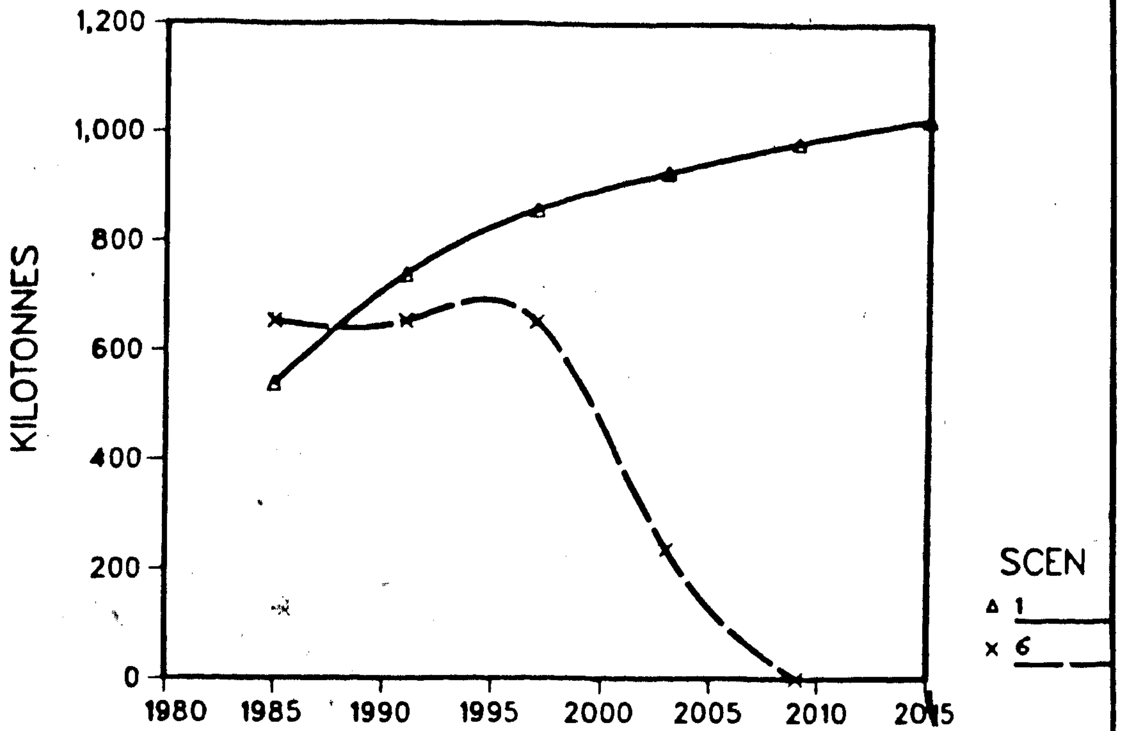


FIGURE 132. SCENARIO 6: ALBERTA CHEM-RELATED METHANOL PRODUCTION

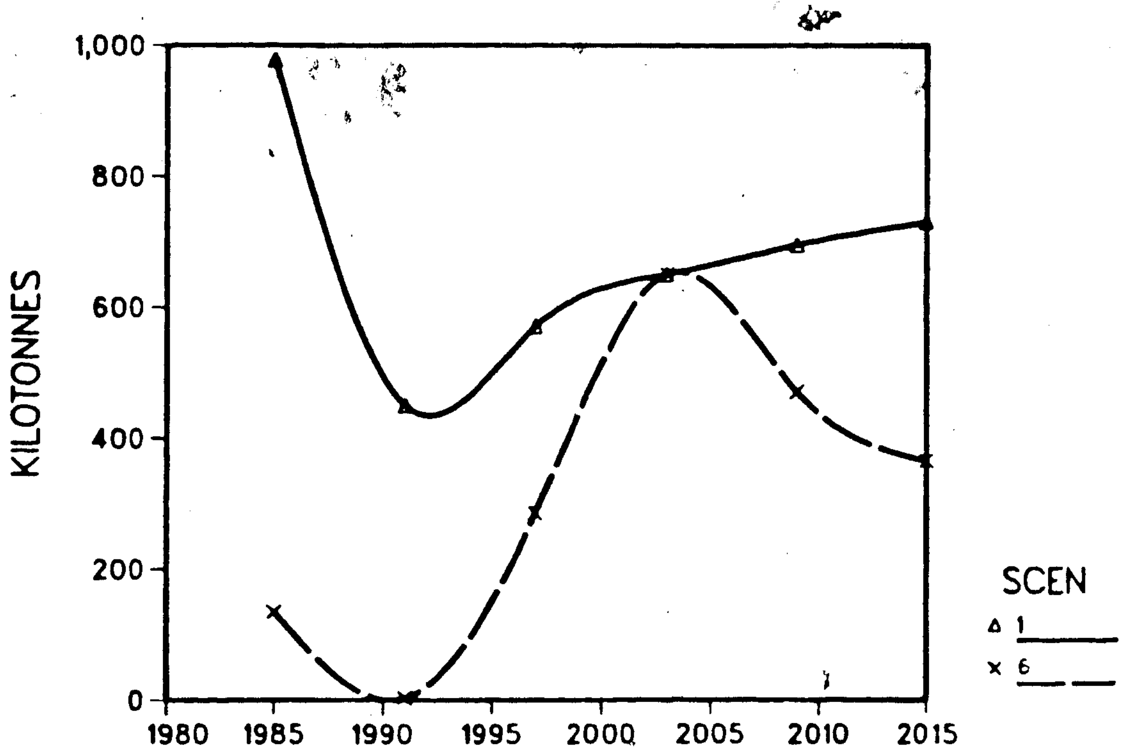


FIGURE 133. SCENARIO 6: ALBERTA FUEL-RELATED METHANOL PRODUCTION

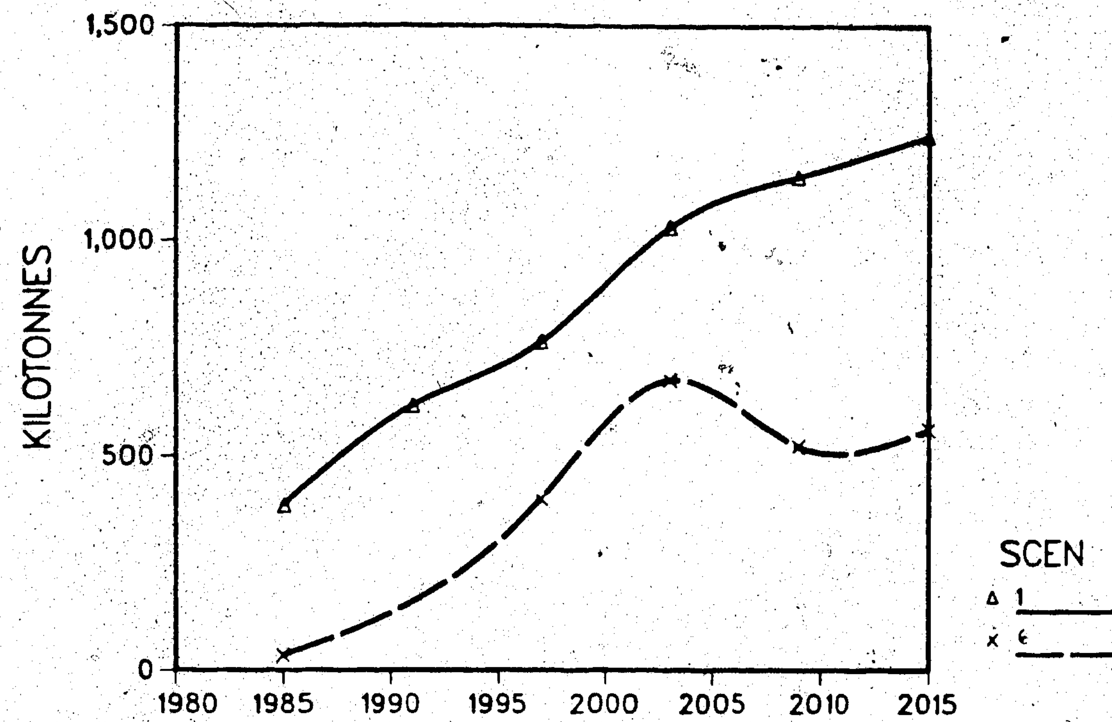
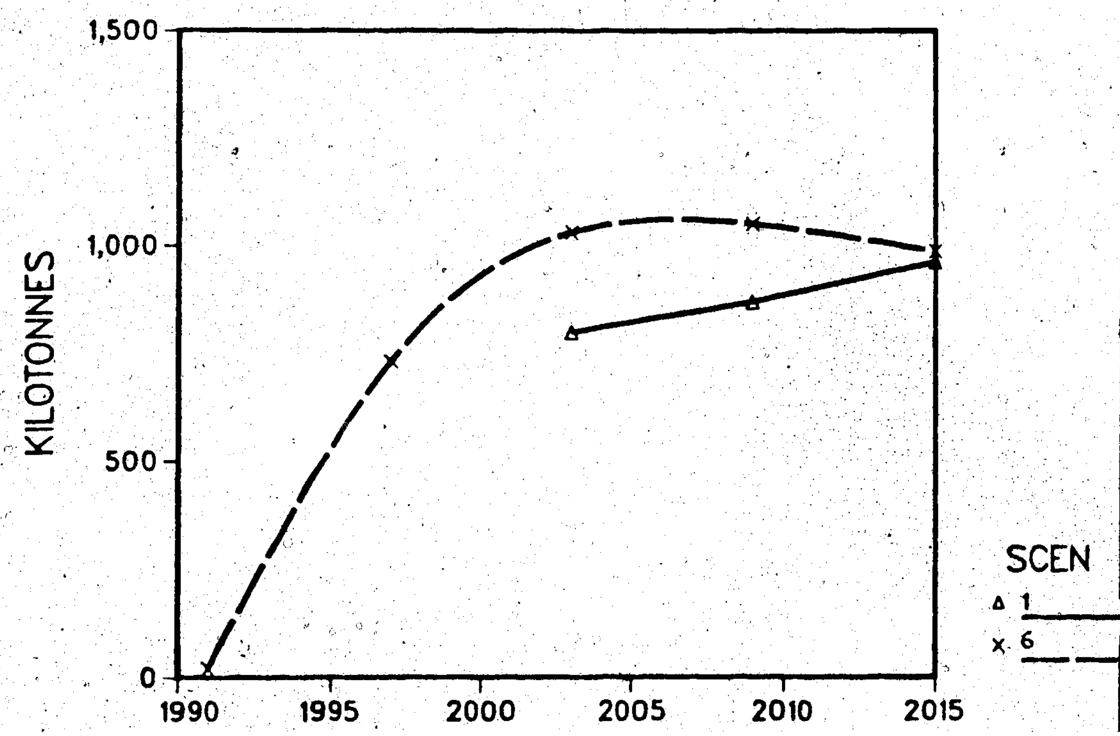


FIGURE 134. SCENARIO 6: CUMULATIVE METHANOL-FROM-COAL ADDITIONS



this is a model limitation. However in reality the coal production profile is flat and with the l[illegible]scovered coal reserves in Alberta it would not be necessary to indu[illegible] in any preproduction activities for coal. Therefore, if the lifetime feedstock costs of a plant are considered, the model results are reasonable.

Other Petrochemicals

The lower petrochemical prices cause an ethylene overcapacity problem in 1985, as the vinyl acetate and ethylene glycol plants operate below capacity. The ethane-based ethylene capacity additions are delayed until 1997 (Figure 135). Although the overall ethylene capacity additions are lower than in the base scenario, there are no ethane-propane capacity additions and the ethane-based additions are higher than the base scenario values in the final two periods.

Capacity additions of all the ethylene derivatives are affected. Both low- and high-density polyethylene are affected (Figures 136 and 137), as the export markets are virtually eliminated. The ethylene glycol capacity additions are postponed to 2009 and occur at a much lower level (Figure 138). Vinyl chloride capacity additions are postponed to 2003 and occur at a lower level (Figure 139). Vinyl acetate capacity additions are less than one-fourth the base scenario values (Figure 140).

Styrene capacity additions are delayed until 2003. In the final two periods the styrene additions are higher than in the base scenario,

FIGURE 135. SCENARIO 6: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

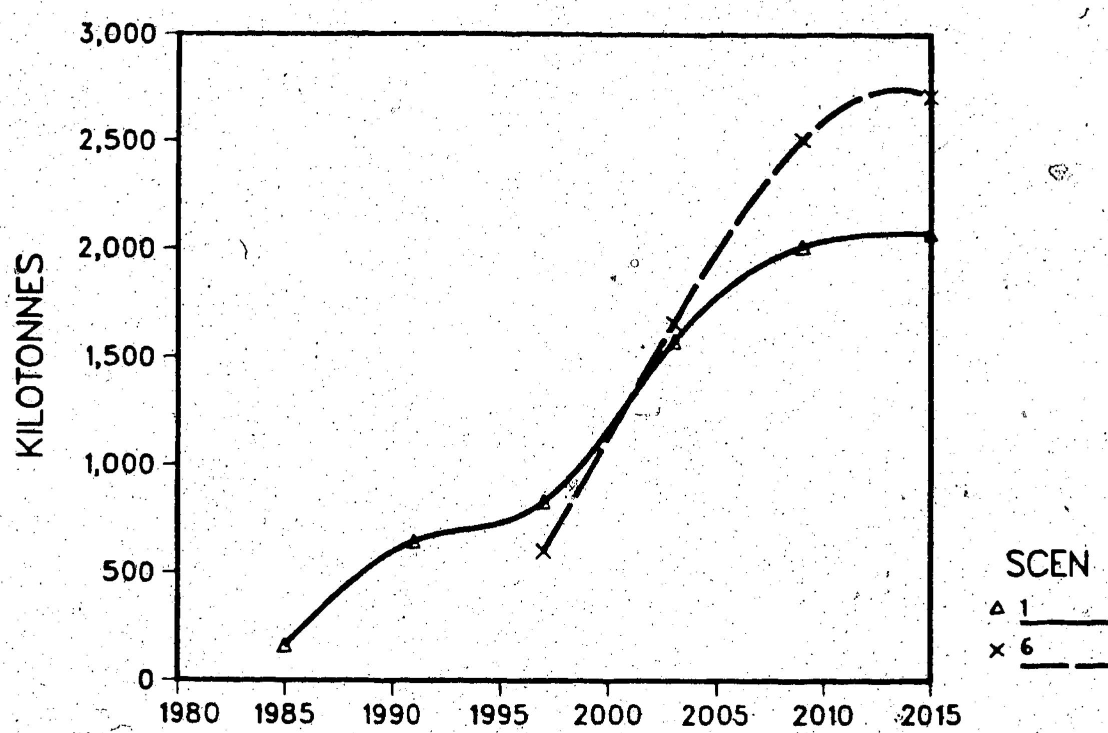


FIGURE 136. SCENARIO 6: CUMULATIVE LOW DENSITY POLYETHYLENE ADDITIONS

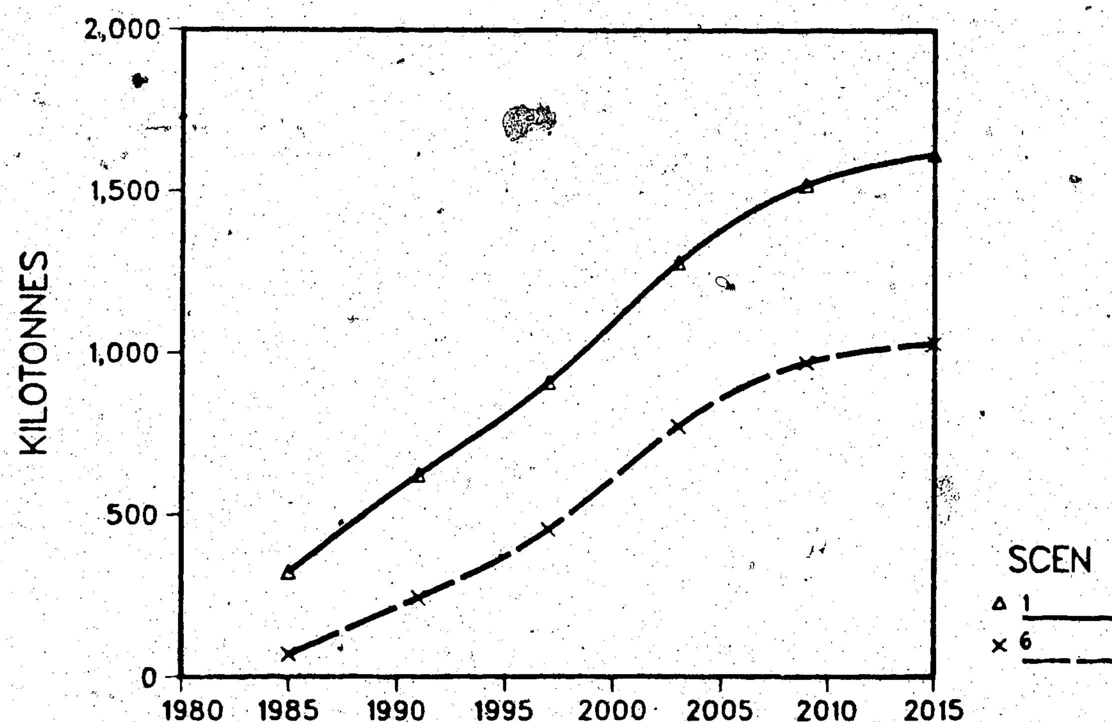


FIGURE 137. SCENARIO 6: CUMULATIVE HIGH DENSITY POLYETHYLENE ADDITIONS

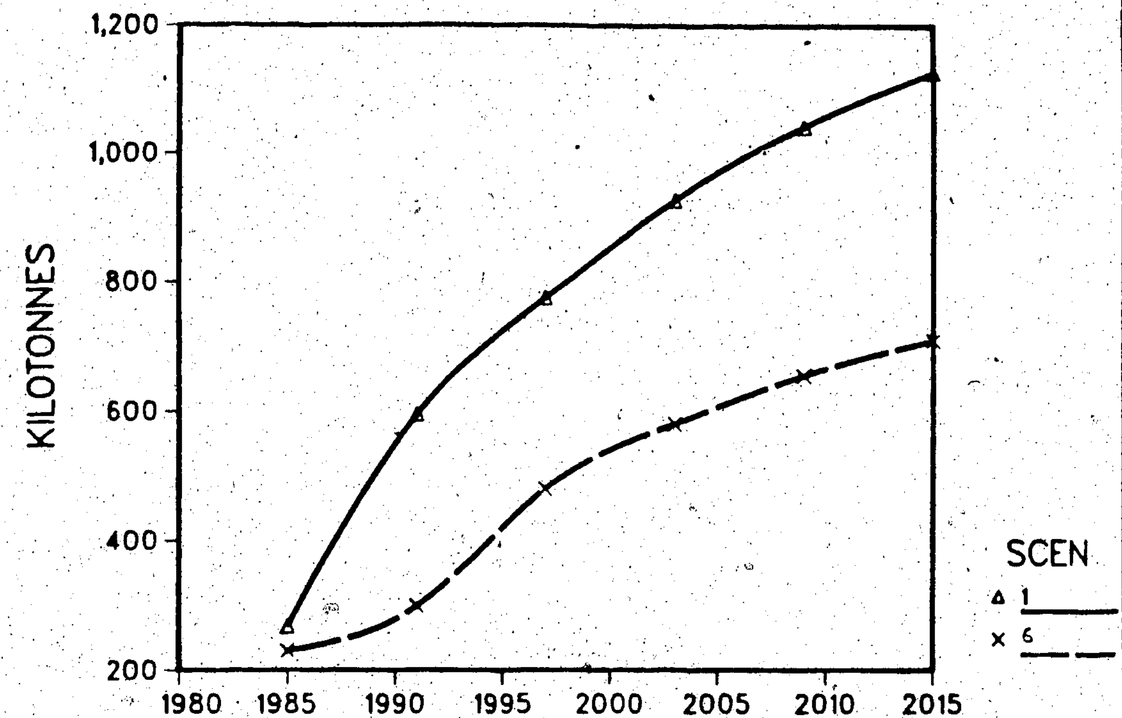


FIGURE 138. SCENARIO 6: ALBERTA ETHYLENE GLYCOL ADDITIONS

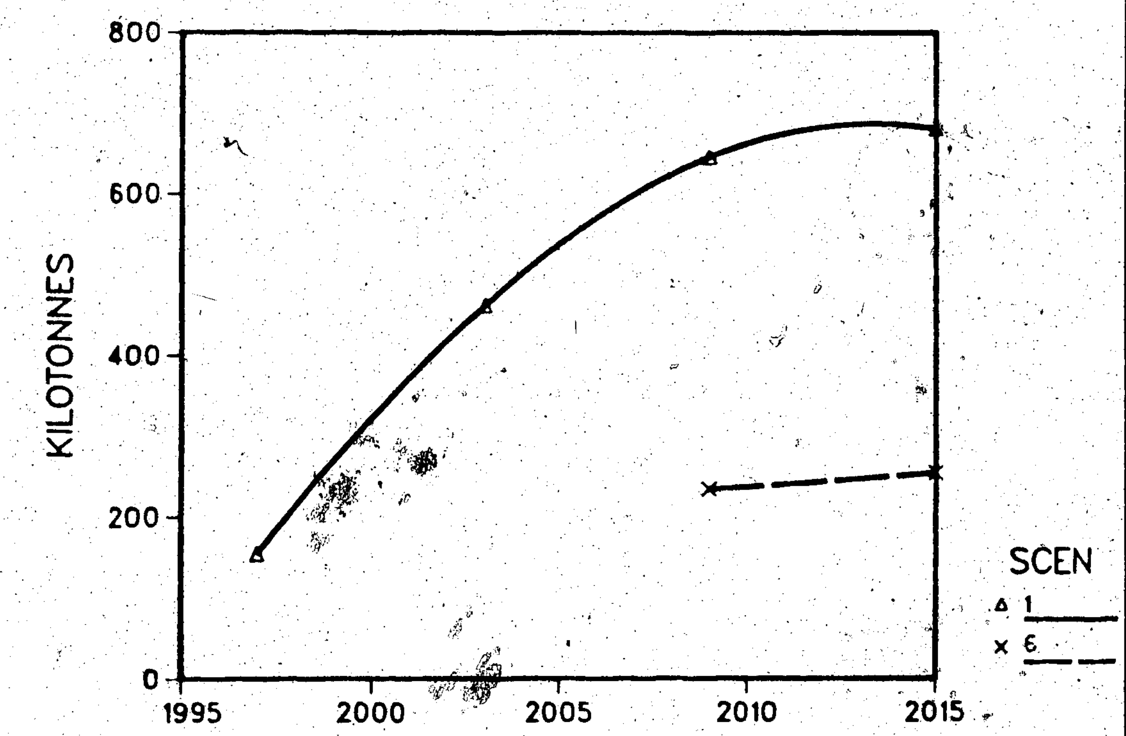


FIGURE 139. SCENARIO 6: ALBERTA VINYL CHLORIDE ADDITIONS

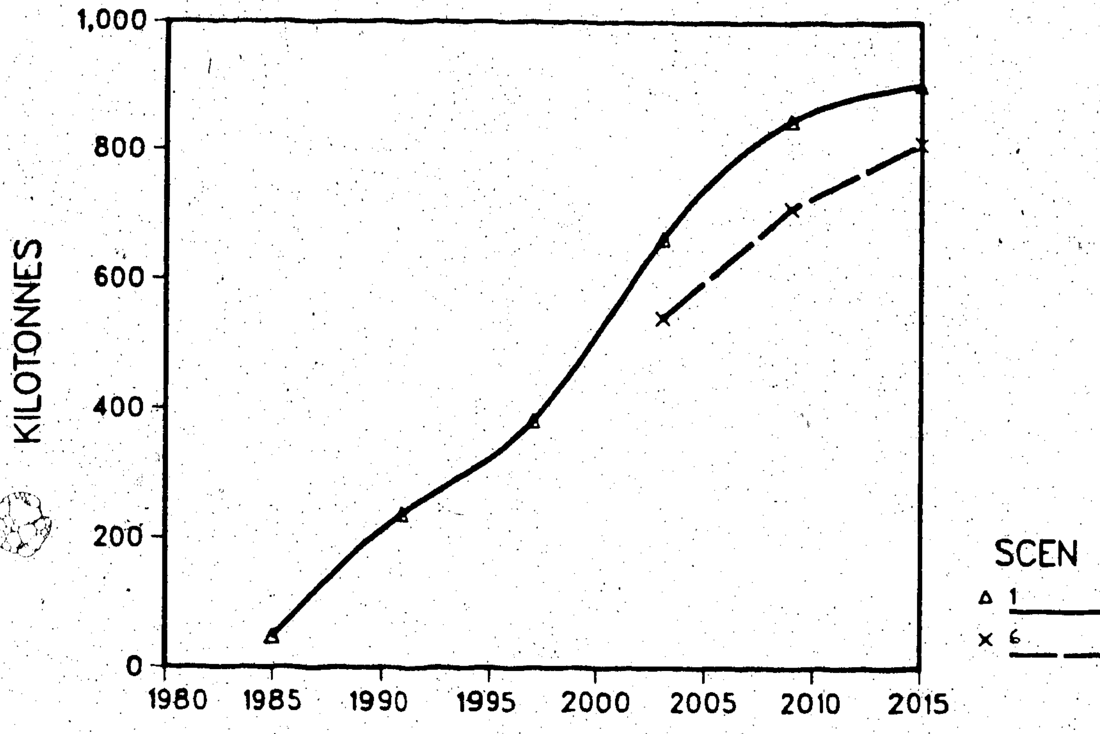
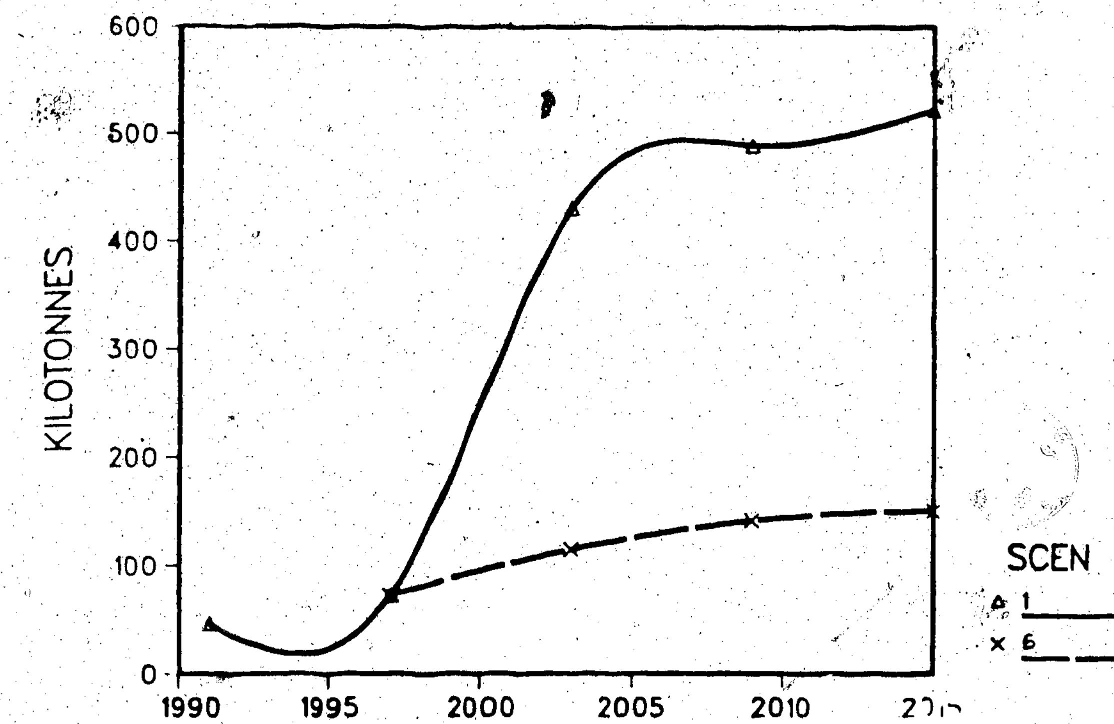


FIGURE 140. SCENARIO 6: CUMULATIVE VINYL ACETATE ADDITIONS



Since there are no ethane-propane ethylene capacity additions the polypropylene and butadiene capacity additions in Alberta are refinery-based (Figures 142 and 143); therefore they are lower than in the base scenario. Alberta aromatics exports are virtually zero but Eastern Canadian exports remain at the base scenario levels.

Investments

Due to lower capacity additions, the petrochemical investments are consistently lower (Figure 144).

Conclusions

A major price reduction in petrochemicals results in reduced petrochemical production, as only the regional markets remain economically accessible. All the ethylene derivatives are price sensitive; since both high- and low-density polyethylene plant capacity additions occur from the first time period, they could be less price sensitive than the other ethylene derivatives.

F. A COMPARISON OF SCENARIOS #1 AND #7

This scenario comprises of scenario #7A where the Alberta industrial price is equated to the Alberta border price and scenario #7B where the replacement costs of ethane are lower than in the base scenario. Scenario #7A implies that the domestic price for natural gas is the Alberta border price plus transp[illegible] i.e. Alberta petrochemical

FIGURE 141. SCENARIO 6: CUMULATIVE STYRENE ADDITIONS

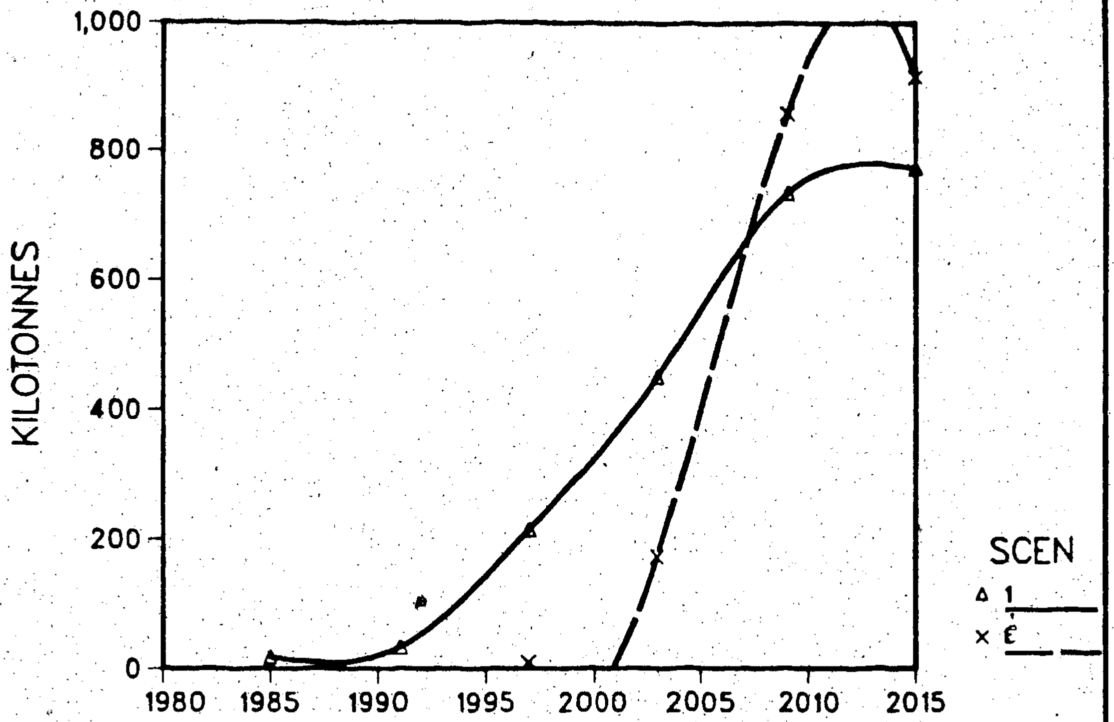


FIGURE 142. SCENARIO 6: ALBERTA POLYPROPYLENE PRODUCTION

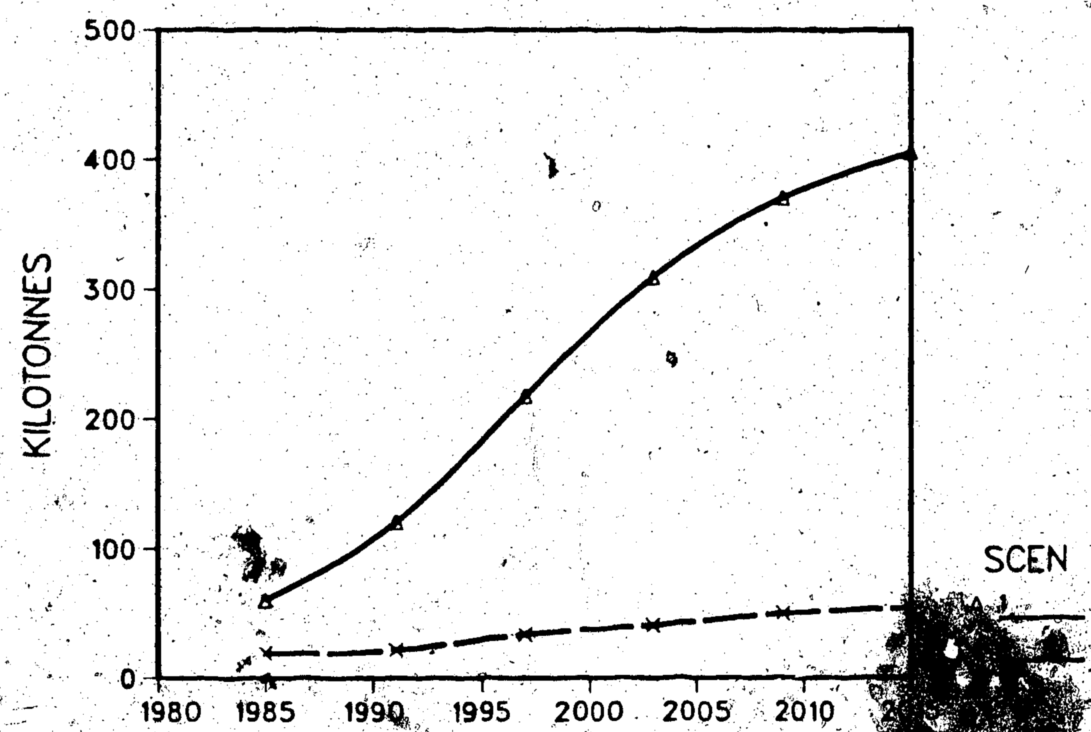


FIGURE 143. SCENARIO 6: CUMULATIVE BUTADIENE ADDITIONS

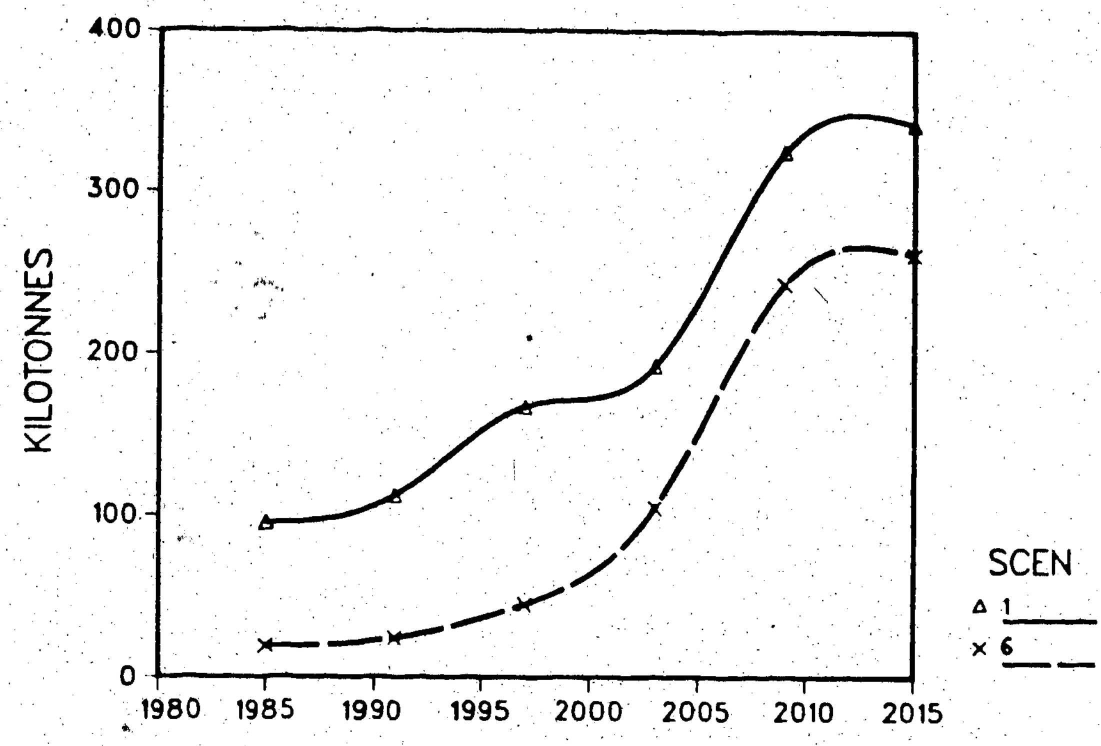
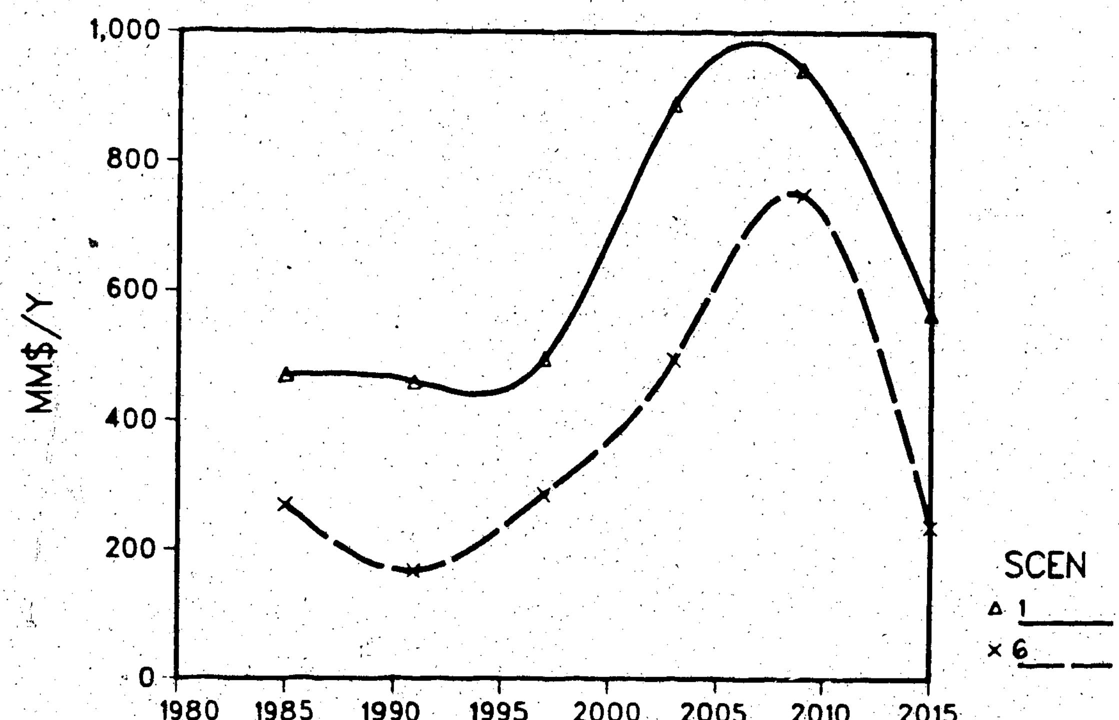


FIGURE 144. SCENARIO 6: INVESTMENTS IN PETROCHEMICALS



Alberta to Eastern Canada. Scenario #7B is already beginning to occur as in recent months the Alberta government works with the ethane and ethylene producers to make their prices more market-oriented.

The impact of scenario #7A is that the Alberta marketable gas production is lower, as coal becomes the exclusive feedstock for new methanol plants. The impact of scenario #7B is that the marketable gas production is marginally higher (Figure 145).

In scenario #7A the ethane surplus is higher (Figure 146) and the propane surplus is lower; this is because more propane is used as a feedstock for new ethylene plants. In scenario #7B the ethane surplus is lower as it becomes the exclusive feedstock for ethylene plants. In both scenarios the condensate surplus is marginally affected.

Methane Based Petrochemicals

In scenario #7A, with equal feedstock prices and only the natural gas transportation disadvantage, the Eastern Canadian ammonia producers, rather than the Alberta producers, have the cheapest economic access to the U.S. Midwest ammonia market. This results in substantially lower capacity additions in Alberta. The insight that this scenario gives is that Alberta ammonia producers would not be in favor of total price deregulation in natural gas. As expected, in scenario #7B the Alberta and Eastern Canadian ammonia production remains unaffected.

FIGURE 145. SCENARIO 7: ALBERTA MARKETABLE GAS PRODUCTION

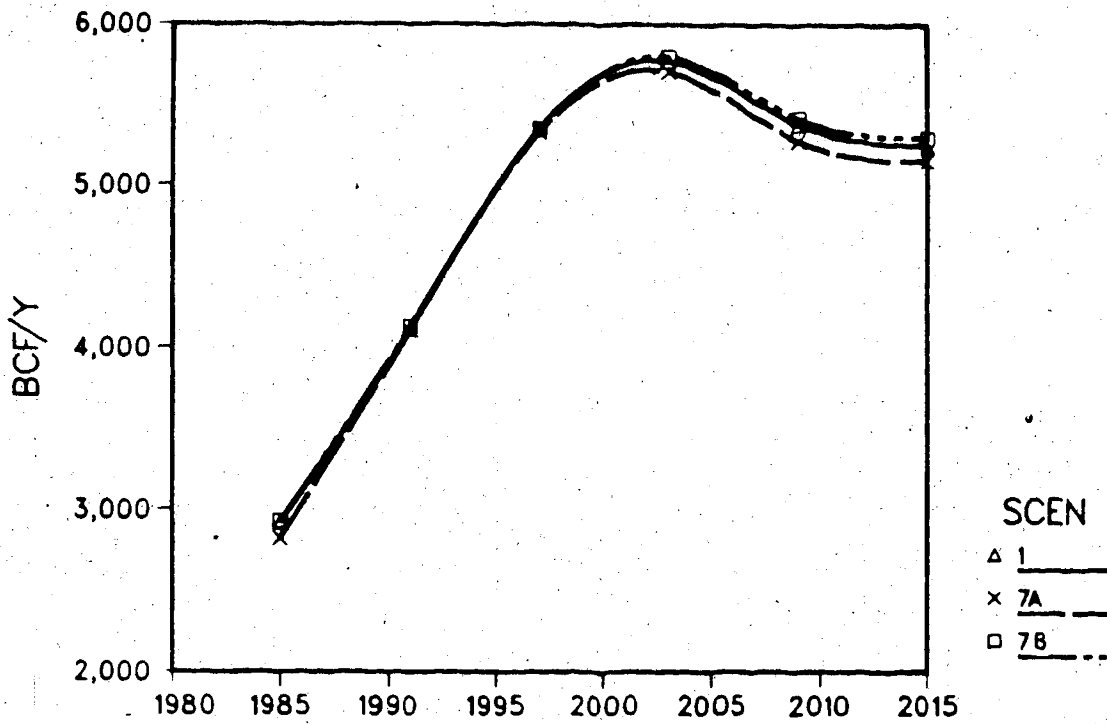
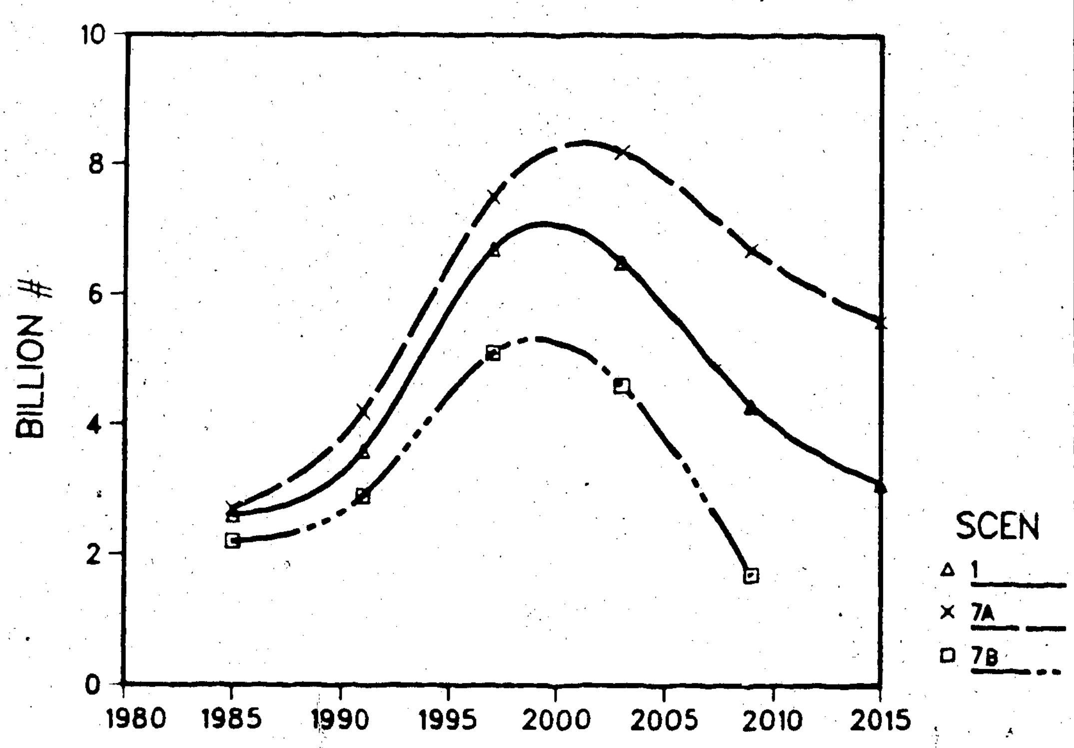


FIGURE 146. SCENARIO 7: 'SURPLUS' ETHANE



In scenario #7A, with higher feedstock costs, the methanol export markets are severely curtailed; there are no exports for chemical-related uses and drastically lower export levels for fuel-related uses. Capacity additions are lower than in the base scenario and, due to the higher gas prices, coal is the exclusive feedstock for new methanol plants (Figure 147). In scenario #7B, methanol production is not affected.

Other Petrochemicals

In scenario #7A the increased industrial price of natural gas results in more propane being used as an ethylene feedstock (Figures 148 and 149). As shown in TABLE ENTC, natural gas requirements for purely ethane-based plants are substantially higher than for ethane-propane based plants. In scenario #7B, due to the lower ethane costs, ethane becomes the exclusive feedstock for the new ethylene plants in Alberta.

In scenario #7A, the increased natural gas costs cause lower capacity additions in Alberta for high density polyethylene, vinyl acetate and vinyl chloride; therefore, the overall ethylene requirements are lower. However, due to increased propane usage, the Alberta polypropylene production is higher than in the base scenario.

In scenario #7B, the lower ethylene costs cause increased capacity additions in the above-mentioned marginal petrochemicals (high density polyethylene, vinyl acetate and vinyl chloride). Therefore, the overall

FIGURE 147. SCENARIO 7: CUMULATIVE ETHYLENE-FROM-ETHANE ADDITIONS

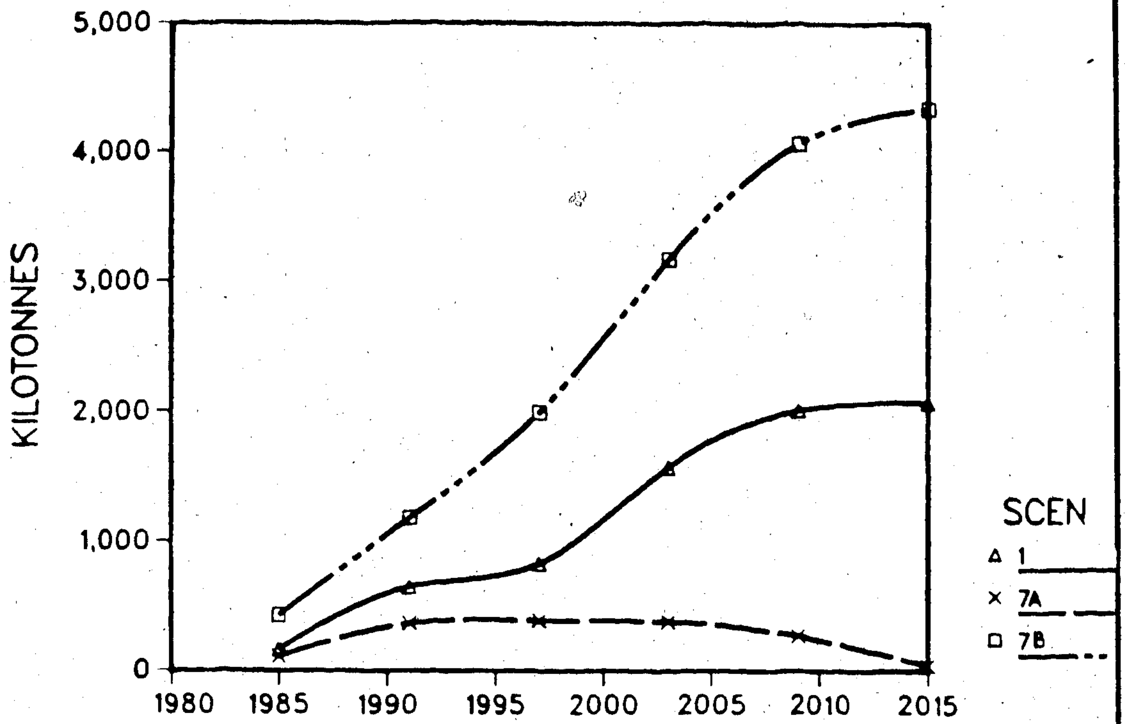


FIGURE 148. SCENARIO 7: CUMULATIVE ETHYLENE-FROM-ETH/PRP ADDITIONS

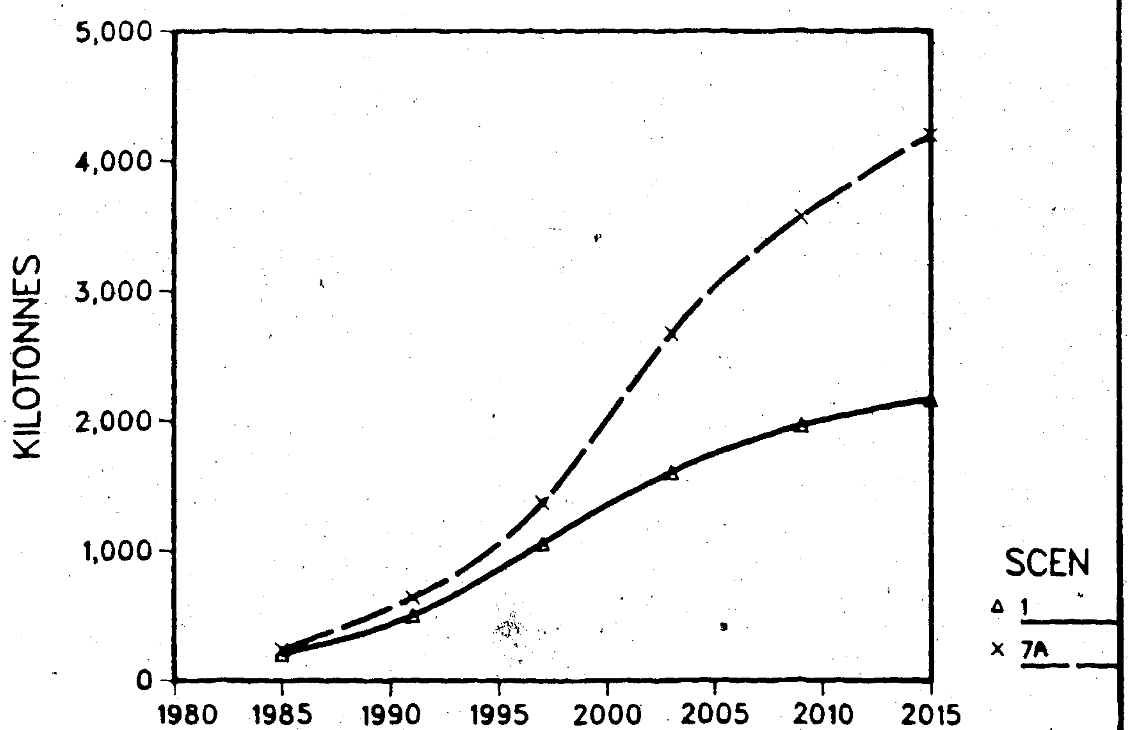
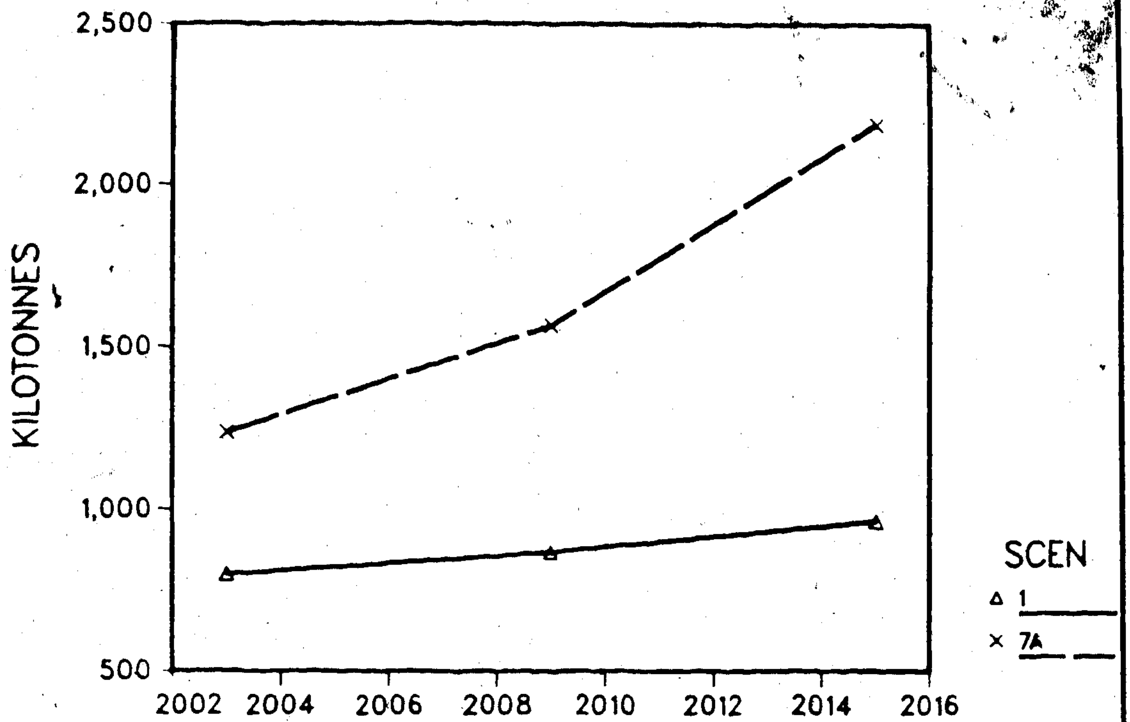


FIGURE 149. SCENARIO 7: CUMULATIVE METHANOL-FROM-COAL ADDITIONS



ethylene production is higher than in the base case. Because propane is not used as an ethylene feedstock, the polypropylene and butadiene production in Alberta is lower than in the base scenario.

Investments

In scenario #7A, due to lower plant capacity additions the Alberta petrochemical investments are lower; in scenario #7B, due to more ethylene and ethylene-derivatives plant capacity additions, the petrochemical investments are higher.

Conclusions

The increased natural gas industrial price severely affects the methane-based industry in Alberta, and causes more propane to be used as an ethylene feedstock, with lower ethylene derivatives but higher propylene and butylene derivatives production.

In scenario #7B, the reduction in the replacement costs for ethane obviously does not affect the methane-based industry. Ethylene is now produced only from ethane rather than from mixed ethane-propane feedstocks.

G. A COMPARISON OF SCENARIOS #1 AND #8

In the previous scenario comparisons, the Alberta and Eastern Canada competition has been mainly in the production of ammonia. As shown in the previous chapter, Eastern Canada is not competitive with Alberta in natural gas-based methanol and the oil-based ethylene industry in Eastern Canada is not competitive with the ethane-based industry in Alberta. The only production that Eastern Canada has been able to retain, with no significant competition from Alberta, is in the oil-based petrochemicals like styrene and aromatics. Since Petrosar did not operate, the regional market for butadiene and propylene was not satisfied. As variations in oil prices have not been investigated, in these scenarios the impact of the scenarios on the latter oil-based petrochemicals in Eastern Canada has been marginal. An issue that is worth investigation is a comparison between the competitiveness of an ethane- and NGL-based industry in Eastern Canada and in Alberta.

Ethane-based ethylene production in Eastern Canada would require the addition of new capacity. The last time new ethylene capacity was added in Eastern Canada was over seven years ago, when Petrosar came onstream. Petrosar rejected ethane as a feedstock because of the lack of co-products from an ethane-based plant. Furthermore, Alberta was already considering the construction of two ethane-based plants and by the regulation of ethane supply and prices could, if it so wanted, tilt the competitive edge in favor of the plants located in Alberta.

As it turned out, the ethane pricing formula worked out in Alberta was based on the Alberta border price of natural gas and, if Petrosar had used an ethane feedstock, it would have had only a feedstock transportation cost disadvantage. With the likelihood of a market-oriented ethane price within Alberta, if the ex-Alberta ethane price remains linked to the Alberta border price for natural gas, then a new ethane-based ethylene plant in Eastern Canada would have a further feedstock price disadvantage. On the other hand, if the new Eastern Canadian ethylene plant is given the same ethane price deal as in Alberta, then the Eastern Canadian ammonia producers will want a similar deal for their feedstocks. It appears that the market oriented ethane price is intended not only to improve Alberta ethylene exports but also to discourage the construction of a new ethane-based plant in Eastern Canada.

The other possibility is that Petrosar could retrofit to accept either an ethane or a natural gas liquids feedstock. The ethane retrofit option is too expensive. The retrofit that Petrosar proposes "would convert the operation from a petrochemical refinery that depends mainly on oil as a raw material to a plant that would use cheaper natural gas liquids for up to 50 per cent of its feedstock needs. Feedstocks from oil would still be needed because a large part of Petrosar's production cannot be made from gas" (85). The configurations proposed by Petrosar are shown in Table 38. In scenario #8, the operation of Petrosar was permitted in any of the three modes shown in this table.

The Alberta marketable gas production is marginally lower, within 6 BCF/Y; furthermore, slightly more propane is used for ethylene feedstock than in the base scenario. Therefore, the ethane surplus is slightly higher and the propane surplus is slightly lower than in the base scenario. The reason for this is given later. The butane and condensate surpluses are marginally lower.

Item	Units	Proposed Petrosar Configurations Base	Propane-Oil	Butane-Oil
1. Feedstocks				
Crude & Condensate	(MBD)	61	33	33
Propane	(MBD)	0	15	0
Butane	(MBD)	0	0	20
2. Products				
Ethylene	(KT/Y)	431	431	431
Propylene	(KT/Y)	328	252	308
Butadiene	(KT/Y)	94	73	77
Butylenes	(KT/Y)	71	43	60
Benzene	(KT/Y)	111	68	80
Other Aromatics	(KT/Y)	76	15	27
Fuel Oil	(MBD)	7	2	3

Table 38: Proposed Petrosar Configurations

Methane Based Petrochemicals

The production of ammonia and methanol is unchanged from the base scenario.

Other Petrochemicals

In order to determine the preferred feedstock mode of operation, the Petrosar plant was forced into marginal operation in both scenarios #1 and #8 by specifying a lower bound in the 'bounds' section of the linear program. In the base scenario the ethylene produced in the 'base mode' of Petrosar was used in the manufacture of styrene, while the propylene and butylenes were used in the manufacture of polypropylene and butadiene, respectively. In scenario #8, the preferred mode of operation was the 'propane-oil' mode; in this mode less propylene was produced than in the 'base mode' and the greater use of propane as an Alberta ethylene feedstock was to make up the polypropylene shortfall that resulted, as shown in Table 39. Clearly, the increased propane usage is a model limitation which would not have occurred if Petrosar were not forced into marginal operation.

The reason that 'propane-oil' is the preferred feedstock-mode may be seen in Table 40. In this table the product prices are based on current values. It is quite clear from this table that none of the feedstock modes is economically viable. Assuming that the crude oil prices do not

	Alberta Production (KT/Y)			Eastern Production (KT/Y)		
	Scenario #1	Scenario #8	Δ	Scenario #1	Scenario #8	Δ
1985	59.8	87.1	27.3	60.2	32.9	27.3
1991	119.8	134.7	14.7	60.2	45.3	14.9
1997	217.0	228.8	[illegible]1.8	72.2	60.5	11.7
2003	309.0	313.6	4.6	70.0	65.4	4.6
2009	370.0	370.0	0.0	66.9	66.9	0.0
2015	405.5	405.0	0.0	72.0	7[illegible].0	0.0

Table 39: Polypropylene Production

	Price	Units	Proposed Petrosar Configuration (MM$/Y) Base	Propane-Oil	Butane-Oil
1. Feedstock Costs					
Crude Oil	3[illegible].82	$/bbl	798	431	431
Propane	9.32	¢/#	0	91	0
Butane	28.20	$/bbl	9	9	206
			8[illegible]	522	637
[illegible] Product Revenues					
Ethylene	2[illegible]	[illegible]/lb	212	212	212
Propylene	[illegible]	¢/lb	136	104	128
Butadiene	31.[illegible]	¢/lb	65	50	53
Isobutylene	28.0	¢/lb	44	27	37
Benzene	1.47	$/USG	51	32	37
Other Arom.	1.00	$/USG	24	6	8
Fuel Oil	28.56	$/bbl	73	21	31
			605	452	506
3. (Costs - Revenues)			193	70	131

Table 40: Costs and Revenues of Petrosar Feedstock Modes

change, the only ways to make Petrosar viable are that the propane or butane costs are lowered or if the petrochemical prices rise. Since the opportunity values of propane and butane are linked to the crude oil prices, the Petrosar recommendation to the federal government to impose export quotas, which would certainly result in lower butane and propane prices, is not a particularly good idea. Increased petrochemical prices would not hide the fact that the Alberta ethane-based plants are more competitive than Petrosar.

Conclusions

In no feedstock mode is Petrosar competitive with the Alberta ethylene plants.

CHAPTER IX. FUTURE PROSPECTS OF THE PETROCHEMICAL INDUSTRY

This brief chapter reorganizes the impacts of the scenarios investigated in the previous chapter.

1. Ammonia

Restricting natural exports has no impact on the Canadian ammonia industry. There are sufficient natural gas reserves to sustain the natural gas export levels projected in the base scenario and it is not necessary to 'reserve' the natural gas for the production of ammonia and other petrochemicals. However, if the natural gas reserves are not as high as currently perceived then Alberta ammonia production is unaffected but Eastern Canadian ammonia production begins to peter out as residential and commercial consumers can outbid the Eastern ammonia producers for the natural gas.

Restricted capital availability has no impact on Alberta ammonia production; Eastern Canadian ammonia production is lower than in the base scenario due to the lower natural gas production, confirming that Eastern ammonia production is a marginal use for natural gas.

Increased required rates of return does not have any significant impact on Canadian ammonia production.

Lower ammonia prices make the U.S. Midwest market economically inaccessible to Canadian producers. The Alberta producers continue to satisfy regional demand but the Eastern Canadian ammonia production peters out and the Eastern market remains economically inaccessible to Alberta ammonia producers.

Increased feedstock costs in Alberta also result in the loss of the U.S. Midwest market; since the feedstock costs of Eastern Canadian ammonia producers have not increased, they are able to replace the Alberta producers in the U.S. Midwest market. The insight gained is that Alberta ammonia producers would not be in favor of a deregulated natural gas price.

The alternate Petrosar feedstock configurations do not affect the Canadian ammonia production.

Therefore, Alberta ammonia producers face a fairly robust future, whereas Eastern Canadian producers face an uncertain future.

2. Methanol

The scenario analyses show that methanol production represents a low-value use of natural gas; if we restrict other uses, the low-value user share increases. For example, if natural gas exports are restricted, there is an increase in methanol exports. However, if there is a shortage of natural gas, then methanol is among the first petrochemicals whose production for export will be discontinued and whose domestic production will become coal based.

In new methanol capacity additions, natural gas and coal feedstocks can co-exist, natural gas will satisfy the 'base' demand, while coal handles any demand 'peaks', very much akin to the various electricity sources. This is because natural gas reserves have to be discovered and produced in a bell-shaped production profile whereas there are sufficient coal reserves in Alberta and the coal production profile is flat.

Due to the low methanol transportation costs, Eastern Canadian methanol production is not competitive with Alberta production.

Restricted capital availability results in lower natural gas production and the new methanol capacity additions are almost exclusively coal-based, resulting in lower methanol production than if more first-level capital is available.

An increase in the required rate-of-return has a severe impact on methanol production as even the Eastern Canadian methanol market is not economically accessible. Lower methanol prices have a similar effect, thus confirming that methanol production is a low value use of natural gas. Higher natural gas costs in Alberta cause a severe curtailment of methanol exports, resulting in lower capacity additions which are coal-based.

The alternate Petrosar feedstock configurations do not affect the Alberta methanol production.

Most scenarios adversely affect methanol. Currently, with over six times the capacity required for domestic consumption, methanol has become an export petrochemical. In the relatively unstable export market, the future of methanol is not assured. It will require aggressive marketing, especially for fuel-related uses, and in the long term, coal will become an important feedstock for methanol.

3. Other Petrochemicals

Natural gas exports, restricted to 700 BCF/Y, have no major impact on the ethylene, propylene and butylene based industry. There is sufficient ethane and propane produced, although in the last two time periods the lack of ethane causes greater propan[illegible] by the Alberta ethylene industry. Extrapolating this trend, if the natural gas exports are reduced to zero, the ethane and propane supply may not be sufficient to sustain the growth in the ethylene industry. Therefore, the concept of 'reserving' natural gas for petrochemicals may actually be detrimental to the health of the petrochemical industry.

Lower ~~natural~~ gas reserves adversely affect the Alberta ethylene industry. As in the previous scenario, due to insufficient ethane supply, there is more propane used by the ethylene industry, which results in higher polypropylene and butadiene production. However, in the long term, since there is no ethane and natural gas liquids production associated with coal gasification, all these industries decline. The ethylene-derivatives least affected by this scenario are low- and high-density polyethylene and vinyl chloride; the ones most affected are vinyl acetate and ethylene glycol.

Restricted first-level capital availability results in a lower growth of the ethylene-based industry, especially high density polyethylene and vinyl acetate. This implies that the capital requirements of the energy industry take precedence over the requirements of the ethylene-based industry. In this scenario the model prefers to add ethane-based capacity, since its capital requirements are lower than ethane-propane capacity additions. Therefore, the polypropylene and butadiene production is lower.

Increased required rates of return cause lower growth in the Alberta ethylene industry, especially in high density polyethylene and vinyl acetate. As in the previous scenario, compared to the base scenario, more pure ethane plant additions and less ethane-propane additions occur. Therefore, the polypropylene and butadiene production is lower.

Lower petrochemical prices affect the production of vinyl acetate and ethylene glycol, causing delays in and lower ethylene capacity additions. The propylene and butylene derivatives industry is virtually non-existent, as no ethane-propane capacity additions occur.

A decrease in the ethane costs makes it the exclusive feedstock for Alberta ethylene plants. The propylene and butylene derivatives industry is non-existent because no ethane-propane ethylene capacity additions occur. The overall ethylene production is higher, with production increases in high density polyethylene, vinyl acetate and vinyl chloride. An increase in Alberta natural gas costs results in higher ethane-propane ethylene capacity additions which use less natural gas than ethane-based plants. The overall ethylene production is lower, with lower production of high density polyethylene, vinyl acetate and vinyl chloride. The propylene and butylene derivatives production is higher than in the base scenario.

Finally, the alternate feedstock modes for Petrosar have no significant impact on the ethylene, propylene and butylene industries.

In all the above scenarios there is no economically viable production of ethylene in Eastern Canada. The Alberta ethylene industry is fairly robust.

4. Aromatics

The aromatics production is oil-based. Therefore, it is not seriously affected by the scenarios investigated here, except for scenario #6 (lower petrochemical prices) in which there is a loss of export markets.

5. Petrochemical Investments

Restricted natural gas exports have no major impact on petrochemical investments. Lower natural gas reserves result in greatly reduced investments. Restricted first-level capital availability and higher required rates of return each result in generally lower investments. Increased natural gas costs result in lower investments. Reduced petrochemical prices result in greatly reduced investments. The only scenario in which the investments are marginally increased is when ethane costs are reduced. The Petrosar scenario has a minimal impact on industry. It is clear that whereas the petrochemical industry is important to Alberta, it is not as important as the energy industry.

CHAPTER X. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE STUDIES

The Canadian petrochemical industry is a capital-intensive, energy-intensive industry which needs a relatively sophisticated workforce, and a competitive construction industry and a fairly industrialized market (51;125,133). In the 1940's and 1950's, in spite of being at the leading edge of technology, Canada was not able to match the high petrochemical growth rates that occurred in countries like the United States and West Germany. There were three reasons. First, the lack of an industrial infrastructure, especially in Western Canada, and the harsh climate imposed a high capital penalty. Second, the distance between the feedstock sources and the petrochemical markets plus the lack of an adequate transportation system imposed a transportation penalty. The capital and transportation penalties resulted in limited access to world petrochemical markets and low returns in the domestic market. Third, there was a loose segregation of the petroleum and petrochemical sectors. The reason for this segregation was the differences between the two sectors. Petroleum refining was a high-volume, mature-technology sector with products like transportation and space-heating fuels which were readily usable by Canadian consumers and were essential to their well-being. Petrochemical manufacturing was a relatively low-volume, emerging-technology sector with products that needed further processing and which were intended to replace existing products like steel and paper. The two sectors had different feedstock procurement and product marketing strategies. A petroleum company would find it difficult to adjust to a petrochemical marketing strategy and vice versa. Therefore, in the United States, companies either specialized in petrochemicals or in petroleum refining. Due to its harsh climate, low population, the travel distances involved and an existing market for transportation fuels, in Canada the petroleum industry was given priority. This was reflected in government policy, when the National Oil Policy was enacted in the early 1960's, whereas the petrochemical sector was treated to a series of reviews by ad hoc committees and task forces.

In Canada, petroleum companies like Esso and Gulf played an important role in the development of the petrochemical industry. In fact, as explained in Chapter II, during the 1960's the petroleum companies tried to emulate in Canada the pattern of success of the European and Japanese naphtha-based plants. However, with no feedstock advantage and high costs, the Eastern naphtha-based plants had no advantage over similar plants elsewhere in the world, except for their proximity to the U.S. market. The export market ensured the survival of these plants but during the 1960's the performance of the Canadian petrochemical industry was marginal.

During the 1970's the conditions that had retarded the development of the Canadian petrochemical industry changed. The increased domestic market size made the construction of world-scale plants feasible. Furthermore, the petrochemical technology had matured and the world-scale plant sizes had stabilized. With the 1973 world oil price shock the Canadian feedstock advantage was finally able to offset the capital and transportation penalties. Provincial governments took a more active role in promoting petrochemical growth and consciously attempted to improve the industrial infrastructure. Finally, the traditional petrochemical companies and new domestic petrochemical companies began to play an increasingly important role in the Canadian petrochemical sector.

During the 1970's government energy policy played a role in the development of the Canadian petrochemical industry. This happened in three ways. First, tests developed in the 1960's to ensure that oil and gas exports were surplus to current and future domestic requirements resulted in the phasing out of oil exports and the imposition of an artificial limit on natural gas exports, causing a problem of shut-in oil and gas. Since no such 'surplus test' was imposed on petrochemical exports, investments were channeled from the oil and gas sector to the petrochemical sector. Second, the maintenance of low, regulated domestic oil prices gave Eastern petrochemical producers a short term feedstock cost advantage over foreign producers; within Alberta, a market-responsive price of natural gas prevailed, where ex-Alberta gas had a higher, regulated price. The feedstock advantage resulted in the rapid development of the Western Canadian ammonia and methanol sector. Third, the federal-provincial dispute over the sharing of the economic rent generated in the oil and gas sector resulted in such low netbacks that it stifled the sector. In 1980 the federal government enacted the nationalistic National Energy Program (63), which was based on the precept that government policy could better allocate resources than market forces. It channeled investment away from Western Canada to the unproductive, but federally owned, 'frontier' off-shore regions. This federal energy policy is now under review. The industry has asked for deregulated oil and gas prices, a lower government share of the economic rent and modifications to the 'surplus test' for oil and gas. If these changes are made, they will affect the petrochemical industry. The impacts of some of these proposed policy changes have been investigated in some of the scenarios.

The issues that confront the Canadian petrochemical industry are not the issues of yesteryear. In the 1950's and 1960's, it was a small, immature industry dominated by the oil and gas industry. In the 1970's it was the beneficiary of the oil price shocks and government energy policy. In the early 1980's, it suffered because the government energy policy did not recognize that energy and petrochemicals were two different sectors. The issues of the future relate to feedstock availability, capital availability, product prices and domestic competition.

The feedstocks to the Canadian petrochemical industry may be oil-based, natural gas-based or coal-based. Table 41 shows the static life indices of the three energy forms. The static life index is calculated by dividing the reserves by the 1983 production. The oil static life index is low and it is clear that any feedstock advantage bestowed on oil-based petrochemical producers by artificially low, regulated price is a short-term benefit. That is why the impact of manipulating domestic oil prices was not investigated during the scenario analysis. The coal static life index is very high and it is clear that in the very long term coal or its products will become the principal petrochemical feedstocks in Canada. However, over the next 30-40 years, natural gas and

	*	(1) 1983 Production (*/Y)	(2) Remaining Reserves (*)	SLI_1 (Y)	(3) Ultimate Reserves (*)	(4) SLI_2 (Y)
Conventional Oil	MMB	493.7	4600	9.32	11300	22.9
Natural Gas	TCF	2.21	92.26	41.7	385.3	174.3
Coal	MMT	44.79	22730	507.5	946×10^3	21121

$SLI_1 = (2) \mid (1)$

$SLI_2 = (3) \mid (1)$

Table 41: Canadian Energy Static Life Indices (SLI)

its associated liquids will be the principal feedstocks. That is why the scenario analyses have focussed on these feedstocks.

About 85% of the total conventional inexpensive gas reserves of Canada are located in the province of Alberta. The provincial government owns essentially all of the mineral rights in Alberta and can therefore be said to be the owner of the gas. The federal government has jurisdiction over interprovincial and export trade in natural gas. Any industrial user seeking to locate in Alberta and seeking a long term supply of gas, such as a petrochemical manufacturer, must first obtain a permit from the Energy Resources Conservation Board, a provincial regulatory body, and subsequent approval by the provincial cabinet.

Presumably, the provincial government, in deciding on the merits of a particular natural gas proposal, seeks to:

1. Realize a significant economic rent, in the form of royalties, from the natural gas produced; and

2. Promote economic activities in Alberta and in the rest of Canada.

An energy or petrochemical project may be assessed in terms of the economic rent and economic activity that it will generate. The main types of uses for Alberta's natural gas are:

1. Provincial residential, commercial and industrial fuel use;
2. Provincial use in the energy industry and the petrochemical industry;

3. Domestic use in the rest of Canada;

4. Export to the United States;

5. Export to Japan, and

6. Deferral to a later time.

The deferral option generates no economic activity and, due to the large natural gas reserves relative to production, at any reasonable discount rate and price projection, the present value of this economic rent is low. It is the least desirable option.

The most desirable option is for provincial residential and commercial use, since natural gas is a clean-burning, easy-to-handle fuel. Considering their proximity to the natural gas fields, the provincial consumers should be able to outbid other users of the gas and generate the maximum economic rent. However, with low, regulated domestic prices and the currently high export prices, exports to the United States generate the maximum economic rent. Petrochemical plants generate somewhat lower economic rents but higher economic activity.

In terms of the scenario analyses, the restricted natural gas exports (scenario #2) represent the deferral option. As shown in the analysis of this scenario no sector gains from this option. If, however, the natural gas reserves are not as great as currently perceived, the market imposes its own deferral scheme (scenario #3). The key element in this scheme is clairvoyance with respect to reserves and demands. The discovery and delineation of natural gas reserves and the constant monitoring of natural gas demand aid in the process of clairvoyance and should be encouraged as a matter of government policy. Note however the American experience with the 1978 Natural Gas Policy Act, which means that even now consumers are paying for expensive, deep gas.

Conventional oil plays a significant role in the scenario buildup insomuch as its production is declining whereas the demand for its products is relatively steady. In the early 1990's, in order to meet the shortfall in this demand, large investments in oil sands plants, will be needed. The modelling results show that if capital availability is restricted, the energy uses take priority over the petrochemical uses.

The rejuvenated and modernized Canadian petrochemical industry requires government policy especially tailored for it. One policy issue relates to the setting up of a North American free market in petrochemicals. The model results show that tariffs are significant but not insurmountable barriers to the efficient allocation of petrochemicals. If, as anticipated, the U.S. petrochemical industry remains in a state of decline, tariff-barriers will impede the development of sectors which need the final petrochemical products. If petrochemical imports into the United States are inevitable, then Canada can gain a competitive edge over other countries by the setting up of a North American free market. As long as there are no major capacity surpluses, such a market would be especially beneficial to Eastern Canada because ethane-based, NGL-based and naphtha-based ethylene plants will of necessity co-exist, since there is no single cheap feedstock that can satisfy the demands of the North American ethylene industry.

The disadvantage of a North American free market is that the competition for the feedstocks will intensify. The Eastern Canadian ethylene producers are planning to convert to natural gas liquids feedstocks. Natural gas liquids are seasonal transportation fuels. The Eastern Canadian producers would like to see export restrictions on natural gas liquids, which will cause a domestic oversupply and bring down their free-market prices to a level that the Eastern Canadian producers can afford to use them. This is a situation that the natural gas liquids producers would naturally resist, since it is a lower-valued use for their product.

In order to develop a coherent petrochemical policy, it is important for federal and provincial governments to identify the location and size of potential markets. The studies that have been done to date lack any price elasticity of demand (24, 130) for petrochemicals. This ought to be the immediate target for governments to pursue and is recommended for future research.

The modelling exercise shows that under the most likely future scenarios, export and domestic petrochemical demands will be met primarily by Alberta producers. Except for methanol, where there is serious over-capacity, Alberta producers should perform well. If export markets are established, the Alberta industry has a buoyant future. In Eastern Canada, the ammonia industry should keep pace with regional demand and the aromatics industry will depend upon refinery operations; however the ethylene-based industry is in trouble. The modelling exercise shows that investment should be in viable, growing industries. Whereas capital is free to move from East to West, the problem faced by

Alberta is labour movement. A relatively sophisticated workforce is required to support Alberta's energy and petrochemical development plans. In order to move from the relatively more industrialized East to Alberta, skilled workers need assurance with respect to their long term employment. Government petrochemical policy should recognize this problem but should work in the direction that market forces dictate.

The model assumes that petrochemical producers cannot compete for natural gas with residential and commercial users. If in future there is a shortage of natural gas in the United States, the petrochemical industry will be affected; therefore, it will be a logical market for Alberta petrochemicals. The tariff barrier between the United States and Canada will no longer be needed. Making this change should be a government policy priority.

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APPENDIX 'A': TEST PROBLEM DESCRIBING THE MPSX AND MAGEN INPUT FILES

Mathematically, a linear programming model may be expressed as:

FORMULATION A

Find that set of values of the variables x_1, $x_2 \ldots, x_n$ so as to minimize (or maximize) the objective function

$$z = c_1\ x_2 + c_2\ x_2\ \ldots + c_n\ x_n$$

subject to

$$1)\ a_{11}\ x_1 + a_{12}\ x_2 + \ldots + a_{1n}x_n\ (\leq,\ =,\ \geq)\ b_1$$

$$2)\ a_{21}\ x_1 + a_{22}\ \quad + \ldots + a_{2n}x_n\ (\leq,\ =,\ \geq)\ b_2$$

$$m)\ a_{m1}\ x_1 + a_{m2}\ x_2 + \ldots + a_{mn}x_n\ (\leq,\ =\ \geq)\ b_m$$

where $x_1, x_2, \ldots, x_n \geq 0$

and where each of the equations or inequations takes on one only of the signs in the bracket.

In economic models, an inequality of equality is referred to as a constraint row and the variables $(x_1, \ldots x_2, \ldots x_n)$ as activities. The value of a variable, say x_i, is called the level of the ith activity.

The model may be formulated, as given above, by writing the complete set of constraints and the objective function. An alternative formulation has the following format:

FORMULATION B

Find the levels of the activities x_1, x_2, ..., x_n so as to minimize (or maximize) the objective function:

$$z = c_1x_1 + c_2x_2 + \dots + c_nx_n$$

subject to:

$$x_1 \begin{bmatrix} a_{11} \\ a_{21} \\ \vdots \\ a_{m1} \end{bmatrix} + x_2 \begin{bmatrix} a_{12} \\ a_{22} \\ \vdots \\ a_{m2} \end{bmatrix} + \dots + x_n \begin{bmatrix} a_{1n} \\ a_{2n} \\ \vdots \\ a_{mn} \end{bmatrix} \begin{matrix} < \\ = \\ > \end{matrix} \begin{bmatrix} b_1 \\ b_2 \\ \vdots \\ b_m \end{bmatrix}$$

We will use the latter, Formulation B, for two reasons:

1. The very efficient, commercially available, linear programming computer solution packages, such as IBM's MPSX, require the input coefficients (the a_{ij}s, and the b_i's) to be arranged in column form.

2. The coefficients, when grouped according to activities rather than according to constraints, permit a more logical physical interpretation.

For a relatively simple model such as AERAM, the activities are essentially <u>extraction activities</u> (of the primary energy fuels) and <u>conversion activities</u>. The technical coefficients for each activity, as represented by the corresponding vector in Formulation B, represents essentially input and output coefficients.

The procedure will be illustrated using a very simple energy model.

TEST MODEL PROBLEM

Given a projection new demand for electricity in each of the next 2 five-year periods, and assuming that this demand will be sustained for the foreseeable future:

given that this increased demand for electricity can be satisfied by either of two technologies - coal-fired or gas-fired power plants;

given the fuel costs, capital costs, financing costs and operating costs of these two alternatives;

given that once a plant is built, economic considerations dictate that it operate at capacity for the duration of the planning period;

given that before a plant is built, fuel for it must be assured for the life of the plant;

given existing reserves for coal and for natural gas;

<u>what is the optimal mix of power plants to be built in the two time periods which satisfy the demand at minimum costs?</u>

Define the variables as follows:

X1 annual increment production of electricity from coal-fired power plants built in Time Period 1, BKWH/Y (billion kilowatt hours per year);

X2 annual increment production of electricity from gas-fired power plants built in Time Period 2, BKWH/Y;

X3 annual coal production in Time Period 1, TBTU/Y (trillion BTU's per year);

X4 annual gas production in Time Period 1, TBTU/Y;

X5 total annualized capital charges for plants built in Time Period 1, MILLION \$/Y;

X6 total annual operating costs for plants built in Time Period 1, MILLION \$/Y;

Y1 annual incremental production of electricity from coal-fired power plants built in Time Period 2, BKWH/Y;

Y2 annual incremental production of electricity from gas-fired power plants built in Time Period 2, BKWH/Y;

Y3 annual coal production in Time Period 2, TBTU/Y;

Y4 annual gas production in Time Period 2, TBTU/Y;

Y5 total annualized capital charges for plants built in Time Period 2, MILLION \$/Y;

Y6 total annual operating costs for plants built in Time Period 2, MILLION \$/Y.

The input data is shown in Tables 42-45; the energy reserves, conversion technologies, time-dependent parameters and miscellaneous parameters are specified.

The complete set of constraints plus the objective function using Formulation A, is shown, with the appropriate coefficients, in Figure 150.

Fuel	Reserves (TBTU)
Coal	60,000
Gas	20,000

Table 42: Primary Energy Fuels

A. Coal-Fired Power Plant

Basis: 1 BKWH/Y output at busbar

Inputs:	Coal, TBTU,Y		10.8
	Capital Cost (initial)	MM$	180.0
	Operating Costs,	MM$/Y	10.0
Other:	Life of Plant,	Y	30.0

B. Gas-Fired Power Plant

Basis: 1 BKWH/Y output as busbar

Inputs:	Gas, TBTU/Y		10.2
	Capital Cost (initial),	MM$	150.0
	Operating Costs,	MM$/Y	5.0
Other:	Life of Plant,	Y	30.0

Table 43: Energy Technologies

	Time Period	
	One	Two
Coal, cost, MM$/TBTU	0.50	0.50
Gas cost, MM$/TBTU	2.00	2.50
*Electricity Demand, BKWH/Y	11.2	20.7
Annual Capital Service Charge	0.10	0.13
Discount Factor (10% annually)	1.0	0.621

*New demand that cannot be met with existing capacity at beginning of Period 1.

Table 44: Time Dependent Parameters

Length of period, years	5
No. of periods	2

Table 45: Miscellaneous Parameters

EXPLANATION OF CONSTRAINTS

1. Calculate annual coal requirements (X3) in Time Period 1 in TBTU/Y.

2. Calculates annual gas requirements (X4) in Time Period 1 in TBTU/Y.

3. Demand for electricity in Period 1 must be met from new plant capacity measured in BKWH/Y.

4. Calculates total annual capital charges (X5) from new power plants in Time Period 1. For each type of power plant, the annual capital charge is the sum of a straight-line depreciation component plus an interest charge, in MM$/Y.

5. Calculates total annual operating costs (X6) from new power plants in Period 1 in MM$/Y.

6. Calculates annual coal requirements (Y3) in Period 2, which includes the coal required to meet the capacity added in Period 1 as well as the capacity added in Period 2, in TBTU/Y.

7. Calculates new annual gas requirements (Y4) in Period 2 in TBTU/Y. Same structure as in eq. (5).

FIGURE 150: Mathematical Formulation of Energy Model in Equation Form

1. $-10.8 * X1 + X3 = 0$
2. $-10.2 * X2 + X4 = 0$
3. $X1 + X2 \geq 11.2$
4. $-A41 + X1 - A42 * X2 + X5 = 0$
5. $-10.0 * X1 - 5.0 * X2 + X6 = 0$
6. $-10.8 * X1 - 10.8 * Y1 + Y3 = 0$
7. $-10.2 * X2 - 10.2 * Y2 + Y4 = 0$
8. $X1 + X2 \quad Y1 + Y2 \geq 20.7$
9. $-A41 * X1 - A42 * X2 - A91 * Y1 - A92 * Y2 + Y5 = 0$
10. $-10.0 * X1 - 5.0 * X2 - 10.0 * Y1 - 5.0 * Y2 + Y6 = 0$
11. $324 * X1 + 324 * Y1 \leq 60{,}000$
12. $306 * X2 + 306 * Y2 \leq 20{,}000$

13. $\text{MIN } 5.0 * [(0.5 * X3 + 2.0 * X4 + X5 + X6) + 0.62 * (0.5 * Y3 + 2.5 * Y4 + Y5)]$

$A41 = 180/30 + 180 * 0.10 = 24.0$ $\qquad$ $A42 = 150/30 + 150 * 0.10 = 20.0$

$A91 = 180/30 + 180 * 0.13 = 29.4$ $\qquad$ $A92 = 150/30 + 150 * 0.13 = 24.5$

8. New demand for electricity in Period 2 is satisfied by new power plant capacity built in both Periods 1 and 2, in BKWH/Y.

9. Calculates total capital charges (Y5) in Period 2 arising from plants built in Periods 1 and 2, in MM$/Y.

10. Calculates total operating charges (Y6) in Period 2 arising from plants built in Periods 1 and 2, in MM$/Y.

11. Total dedicated coal production cannot exceed existing reserves, in TBTU.

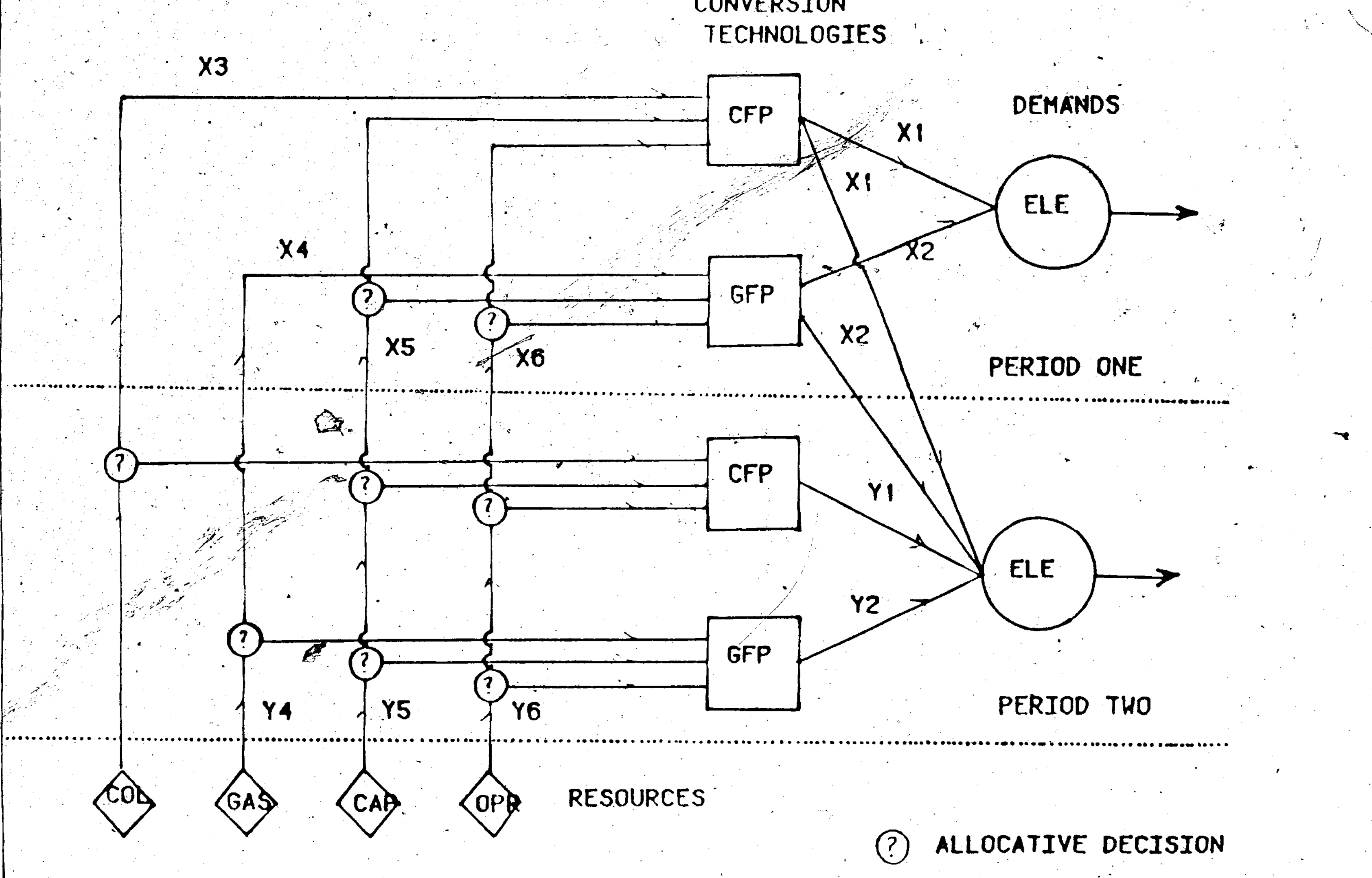
12. Total dedicated gas production cannot exceed existing reserves, in TBTU.

13. The objective function to be minimized is the total discounted costs or the present value of such costs in MM$.

The energy model has now been reduced to an explicitly stated mathematical programming problem.

Figure 151 shows the flows in the form of a network. In order to meet a demand for electricity, specified over time, allocative decisions must be made distributing the available primary resources of coal, gas, in addition to capital and operating funds, over the two available technologies and overtime.

FIGURE 151: Network of Energy Flow



Plant capacity built in the first time period continues to be utilized in the second (and subsequent) time periods. All the input and output flows reflect this assumption.

Figure has been rewritten in the format of Formulation B and shown in Figure 152 where the variables have been given alphanumeric names, which will be defined later. The constraints have also been named.

The techniques of solving a linear programming problem are well-known, permitting us to solve small problems manually. However for large problems involving hundreds or even thousands of variables and constraints, computer solution packages are invariably used. The most popular and one of the most efficient packages is IBM's so-called MPSX program. However, the input data must be prepared in a particular, rigidly specified way.

FIGURE 152: Mathematical Formulation of Energy Model in Matrix Form

	PCFP01	PGFP01	PCOL01	PGAS01	TCAP01	TOPR01	PCFP02	PGFP02	PCOL02	PGAS02	TCAP02	TOPR02		RHS
1. RCOL01	-10.8		1.0										=	0
2. RGAS01		-10.2		1.0									=	0
3. RELE01	1.0	1.0											$\geq$	11.2
4. RCAP01	-24.0	-20.0			1.0								=	0
5. ROPR01	-10.0	-5.0				+1.0							=	0
6. RCOL02	-10.8						-10.8		1.0				=	0
7. RGAS02		-10.2						-10.2		1.0			=	0
8. RELE02	1.0	1.0					1.0	1.0					$\geq$	20.7
9. RCAP02	-24.0	-20.0					-29.4	-24.5			1.0		=	0
10. ROPR02	-10.0	-5.0					-10.0	-5.0				1.0	=	0
11. RTCOL	324.0						324.0						$\leq$	60000
12. RTGAS		306.0						306.0					$\leq$	20000
OBJ			2.5	10.0	5.0	5.0			1.553	7.763	3.105	3.105	Min	

NAME OF CONSTRAINTS AND ACTIVITIES

MPSX format requires the user to identify all rows (or constraints) and all variables (or activities) with alphanumeric names (combinations of letters and numbers). All the constraints and variables in Figure 150 have been relabelled as follows:

Rows (constraints)

Constraint No.	Name or Mnemonic*	Relationship
1	RCOL01	=
2	RGAS01	=
3	RELE01	≥
4	RCAP01	=
5	ROPR01	=
6	RCOL02	=
7	RGAS02	=
8	RELE02	≥
9	RCAP02	=
10	ROPR02	=
11	RTCOL	≤
12	RTGAS	≤
13	OBJ	

Variables (activities)

Activity	Name or Mnemonic
X1	PCFP01
X2	PGFP01
X3	PCOL01
X4	PGAS01
X5	TCAP01
X6	TOPR01
Y1	PCFP02
Y2	PGFP02
Y3	PCOL02
Y4	PGAS02
Y5	TCAP02
Y6	TOPR02

The vector of right-hand side constants is simply called RHS.

For using MPSX, it is more convenient to use the mathematical model format shown in Figure 152.

THE MPSX FORMAT

In MPSX, after the names of all rows have been specified, the matrix of coefficients in Figure 152 is fed into the computer program by columns. When introducing the columns, the activity name is inserted, then the name of the row in which the activity appears with a non-zero coefficient, and finally the coefficient itself; there are two entries for each line. The MPSX formulation is shown below:

Rows

The symbol O indicates the objective function; the symbol E an equality; the symbol L indicates the inequality $\leq$ (i.e. the L.H.S. is less than the R.H.S.); the symbol G indicates the inequality $\geq$.

O	OBJ
E	ROL01
E	RGAS01
G	RELE01
E	RCAP01
E	ROPR01
E	RCOL02
E	RGAS02
G	RELE02
E	RCAP02
E	ROPR02
L	RTCOL
L	RTGAS

Columns

PCFP01	RCOL01	-10.8	RELE01	1.0
PCFP01	RCAP01	-24.0	ROPR01	-10.0
PCFP01	RCOL02	-10.8	RELE02	1.0
PCFP01	RCAP02	-24.0	ROPR01	-10.0
PCFP01	RTCOL	324.0		

PGFP01	RGAS01	-10.2	RELE01	1.0
PGFP01	RCAP01	-20.0	ROPR01	-5.0
PGFP01	RGAS02	-10.2	RELE02	1.0
PGFP01	RCAP02	-20.0	ROPR02	-5.0
PGFP01	RTGAS	306.0		
PCOL01	RCOL01	1.0	OBJ	2.5
PGAS01	RGAS01	1.0	OBJ	10.0
TCAP01	RCAP01	1.0	OBJ	5.0
TOPR01	ROPR01	1.0	OBJ	5.0
PCFP02	RCOL02	-10.8	RELE02	1.0
PCFP02	RCAP02	-29.4	ROPR02	-10.0
PCFP02	RTCOL	324.0		
PGFP02	RGAS02	-10.2	RELE02	1.0
PGFP02	RCAP02	-24.5	ROPR02	-10.0
PGFP02	RTGAS	306.0		
PCOL02	RCOL02	1.0	OBJ	1.553
PGAS02	RGAS02	1.0	OBJ	7.763
TCAP02	RCAP02	1.0	OBJ	3.105
TOPR02	ROPR02	1.0	OBJ	3.105

Right Hand Side

RHS	RELE01	11.2
RHS	RELE02	20.7
RHS	RTCOL	60000
RHS	RTGAS	20000

In a large linear program, this formulation has two shortcomings. First, it is difficult to alter and update the model. Secondly, it is difficult to interpret the results. These shortcomings can be overcome by using a software package like the Haverly Systems MAGEN. MAGEN facilitates the updating and altering of the model and it has an excellent report generator.

THE MAGEN PROGRAM FILE

The DICTIONARY Section

This section establishes the various classes to which reference can be made in the rest of the program. Each class is identified by a unique name, with up to 8 alphanumeric characters. Each member name may not have more characters than the class name.

Any logic or mathematical procedure specified as being performed on a class is performed on each member of the class in turn. A class reference consists of a class name enclosed by parentheses.

Suppose that class PEN has as members COL and GAS and that class PQ has members 01 and 02, then the group of activities given by the expression P(PEN) (PQ) is equivalent to the set of activities [PCOL01, PGAS01, PCOL02, PGAS02].

It should be noted that temporary classes can be established (without being listed in the DICTIONARY) by giving a dummy title, say XXXX and then listing all the members of the temporary class, using the expression, e.g. "FOR XXXX = BCOL,BGAS".

A useful programming device is a linked class reference which permits the selection of a member of one class depending upon the current active member of another class.

Suppose CLASS PP has the following members, in that order [01,02,03] and that CLASS PQ has as members [02,03,04]. Then if the program is currently dealing with the first member of CLASS PP (i.e. 01), then the expression RCOL(PQ/PP) becomes RCOL02, since the first member of CLASS PQ is named 02.

The DATA Section

This section consists of various tables of data. All TABLE rows and columns are given alphanumeric names.

All entries are referenced, first with the column name followed by the row name. Thus, the expression TABLE PEF (TBTU,COL) refers to the entry corresponding to column TBTU and row COL in TABLE PEF. In a TABLE, the characters "H>" mean that only characters to the right of these columns are read; all characters to the left can be used for comments.

The characters "+R" in the first two columns denote a continuation line and are used when the TABLE has either many columns or has internal explanations that prevent the TABLE from being displayed naturally without running past column 72.

The TABLE TRANSFORMATION Section

This section creates new TABLES and modifies the entries in existing TABLES. A common procedure is to use generally accepted units of measure for TABLES in the DATA section and to convert to other units in this section. Example: Suppose that TABLE ENC has column headings [01,02,03,04] which are all members of CLASS PQ, and a row named CRO, and the entries represent costs of crude oil in $/BBL. We can convert these costs to $/MMBTU by dividing the entries by 5.8 (MMBTU/BBL) using the statement:

```
FROM TABLE ENC ((PQ,CRO) = TABLE ENC ((PQ),CRO)/5.8
```

MAGEN converts the input data into a MPSX input file by generating row, column, right-hand-side and bounds sections as follows:

THE ROW ID Section

This section identifies all the constraints by NAME and specifies whether they will be equality rows (FIX), less-than-or-equal-to rows (MAX), or greater-than-or-equal-to rows (MIN). The constraints themselves are not generated here, but only named. The coefficients will be generated in the next section.

The COLUMNS Section

This section generates the numerical entries in the LP matrix, column by column. The column or activity vector is named, then the non-zero entries are generated by naming the row and specifying the entry. This entry can be a table entry, an explicit numerical constant, or some algebraic combination. In order to have a completely data-driven model, TABLE references, rather than numerical data should be inserted.

Example: Suppose we wish to enter the activities PCFP(PQ). Further suppose that CLASS PQ has members (01,02) and CLASS PP has members (02,03), then the following program statements,

```
FORM VECTOR PCFP(PQ)
     RCOL(PQ) = TABLE ECP(CFP,COL)
     RCOL(PP/PQ) = TABLE ECP(CFP,COL)
```

are interpreted to mean:

a) The FORM VECTOR statement generates a vector for each member of CLASS PQ. Since CLASS PQ has members (01,02) then vectors PCFP01 and PCFP02 are generated in turn.

b) The vector PCFP01 has an entry in row RCOL01, which entry can be found in column CFP and row COL of TABLE ECP.

c) Vector PCFP01 also has an entry in row RCOL02. - The last statement says that if we are dealing with the current member of CLASS PQ, namely 01, we should also be dealing with the corresponding member of CLASS PP, namely 02 (the first member of the class in each case).

d) Similarly, the vectors PCF002 has entries in RCOL02 and RCOL03.

The RHS or Right Hand Side Section

This section generates the RHS constants and is similar to the previous section.

The BOUNDS Section

This section allows the programmer to set specific bounds on individual variables by naming the variable. Specifying the type of bound (UP, LO or FIX), and giving the bound value as either a constant or a data table entry, or some combination of both. It is much more efficient computationally to have bounded variables instead of row constraints, where they are mathematically equivalent.

It should be noted that MPSX requires that vectors being bounded must be defined in the same order in this section as in the FORM VECTORS Section.

The listing of the file containing the MAGEN program for the Test Model, is given in Figure 153. There are 5 classes and 4 tables. The tables correspond to Tables 142-145. Next, the rows are identified. The columns and right-hand-sides are generated by the "FORM VECTOR" statements. Finally, there is a report writer program which converts the optimal solution generated by MPSX into a tabular form. The model can be easily updated. For example, if the gas reserves have been increased by 10,000 TBTU then in TABLE PEF, row "GAS", column "QR", the value is changed from 20000 to 30000. Structural changes are easily made. For example, if only gas-fired power plants are to be considered then in CLASS ENT, the line referring to CFP is deleted. MAGEN facilitates model development and scenario analysis.

FIGURE 153: File Listings of MAGEN Program

```
*
GENERATE
     DICTIONARY
          CLASS PQ TIME PERIODS
               02,03
          CLASS PP TIME PERIODS PLUS ONE
               01,02
          CLASS PEN PRIMARY ENERGY FORMS
               COL    COAL
               GAS    NATGAS
          CLASS SEF SECONDARY ENERGY FORMS
               ELE    ELECTRICITY
          CLASS ENT ENERGY TECHNOLOGIES
               CFP    COAL FIRED POWER PLANT
               GFP    GAS FIRED POWER PLANT
*    DATA
          TABLE PEF PRIMARY ENERGY FUELS
*              FUEL    RESERVES (TBTU)
*                        QR
               COL     60000
               GAS     20000
*
          TABLE ECP ENERGY CONVERSION PROCESSES
*
*         COAL FIRED POWER PLANT
*         BASIS: 1 BKWH/Y OUTPUT AT BUSBAR
                              H>                CFP
            I: COAL TBTU/Y                      COL              -10.8
            I: INIT CAP COST      981$)         CAP             -180.0
            I: ANN OPER COSTS (MM1981$/Y)       OPR              -10.0
            O: ELECTRICITY BKWH/Y               ELE                1.0
               LIFE OF PLANT                    LFP               30.0
*
```

```
*        GAS FIRED POWER PLANT
*        BASIS: I BKWH/Y OUTPUT AT BUSBAR
*
+R                                                   H>                GFP
             I: GAS TBTU/Y                            GAS              -10.2
             I: INIT CAP COST (MM81$)                 CAP             -150.0
             I: OPER COSTS (MM81$/Y)                  OPR               -5.0
             O: ELECTRICITY BKWH/Y                    ELE                1.0
                LIFE OF PLANT                         LFP               30.0
*
         TABLE TDP TIME DEPENDENT PARAMETERS
*             COSTS          DEMAND      INTEREST       DISC FACT
*            MM$/TBTU        BKWH/Y        RATE          AT 10%/Y
             COL    GAS       ELE          INT             DSF
        01   0.50   2.00      11.2         0.10            1.0
        02   0.50   2.50      20.7         0.13            0.621
*
         TABLE MSP MISCELLANEOUS PARAMETERS
*                                                      H>          ALP
         LENGTH OF PERIOD YRS                           LGP         5.0
         NO OF PERIODS                                  NPR         2.0
*
NAME TEST
*    THE FOLLOWING MAGEN PROGRAM GENERATES THE LP MATRIX.
*    FIRST, THE ROWS ARE IDENTIFIED IN MAGEN NOMENCLATURE.
*
*    FORM ROW ID
         OBJ = OBJ
    FORM SECTION (PQ)
         R (PEN)(PQ) = FIX
         R (SEF)(PQ) = MAX
         RCAP(PQ) = FIX
         ROPR(PQ) = FIX
    FORM SECTION, END
         RTCOL = MIN
         RTGAS = MIN
```

```
*    THIS SECTION GENERATES THE LP MATRIX, COLUMN BY COLUMN
     COPY
COLUMNS
*
     FORM VECTOR                                  EXTRA
          OBJ = 0.0
     FORM SECTION (PQ)
     FORM VECTOR                                       P(PEN)(PQ)
          R(PEN)(PQ) = 1.0
          OBJ = TABLE MSP(ALP,LGP)*TABLE TDP ((PEN),(PQ))*TABLE
                TDP(DSF,(PQ))
     FORM VECTOR                                       P(ENT)(PQ)
          R(PEN)(PQ) = TABLE ECP ((ENT),(PEN))
          R(PEN)(PP/PQ) = TABLE ECP ((ENT),(PEN))
          R(SEF)(PQ) = TABLE ECP ((ENT),(SEF))
          R(SEF)(PP/PQ) = TABLE ECP ((ENT),(SEF))
          RCAP(PQ) = TABLE ECP ((ENT),CAP)/TABLE ECP((ENT),LFP)
                     + TABLE ECP((ENT),CAP)*TABLE TDP (INT,(PQ))
          RCAP(PP/PQ) = TABLE ECP ((ENT),CAP)/TABLE ECP ((ENT),LFP)
                        + TABLE ECP ((ENT),CAP)*TABLE TDP (INT,(PQ))
          ROPR(PQ) = TABLE ECP ((ENT),OPR)
          ROPR(PP/PQ) = TABLE ECP ((ENT),OPR)
          RT(PEN)(PQ) = TABLE ECP ((ENT), LFP)*TAB[illegible]CP (CENT),(PEN))
     FORM VECTOR                                  TCAP(PQ)
          RCAP(PQ) = 1.0
          OBJ = TABLE MSP (ALP,LGP)*TABLE TDP (DSF,(PQ))
     FORM VECTOR                                  TOPR(PQ)
          ROPR(PQ) = 1.0
          OBJ = TABLE MSP (ALP,LGP)*TABLE TDP (DSF,(PQ))
     FORM SECTION, END
*
     COPY
RHS
*
     FORM VECTOR                                  RHS
          RTCOL = TABLE PEF(QR,COL)
          FTGAS = TABLE PEF(QR,GAS)
          RELE01 = TABLE TDP(ELE,01)
          RELE02 = TABLE TDP(ELE,02)
ENDATA
```

```
*     THE MAGEN REPORT WRITER PROGRAM TO FOLLOW ILLUSTRATES A USER
*     ORIENTED RESULT FORMAT.
*
      FORM LINE
           H20 = **********************
      SPACE
      FORM LINE
           H10 = TEST PROGRAM
           TOTPR = 0
      SPACE
      FORM LINE
S          H20 = OBJECTIVE FUNCTION VALUE
           V60.1 = N,NPRFIT
           X = P,OBJ
           TOTPR = N,TOTPR,X
Z          V120 = N,X*0.01
      FORM LINE
S          H20 = ****CASE INFEASIBLE****
U          V120 = N,TOTPR
      SPACE
      FORM LINE
           H10 = TABLE ONE - ENERGY FLOWS
      FORM LINE
           D30 + 10(PQ) = (PQ)
      FORM LINE
           D5 = COAL TBTU/Y
           V30.1 + 10(PQ) = X,PCOL(PQ)
      FORM LINE
           D5 = GAS TBTU/Y
           V30.1 + 10(PQ) = X,PGAS(PQ)
      FORM LINE
           D5 = ELEC FROM COAL BKWH/Y
           V30.1 + 10(PQ) = X,PCFP(PQ)
      FORM LINE
           D5 = ELEC FROM GAS BKWH/Y
           V30.1 + 10(PQ) = X,PGFP(PQ)
FN
      END
COMPILE
END JOB
```

APPENDIX 'B': MODEL VARIABLES AND CONSTRAINTS

The data was input in terms of the following classes:

CLASS CBP	Coal Based Processes
CLASS CDE	Consumers Demands
CLASS CGT	Canadian Gas Prod Tech
CLASS CONP	Condensates Production
CLASS COT	Oil Prod Technologies
CLASS EBP	Ethylene-Based Processes
CLASS EEP	Eastern Canadian Existing Processes
CLASS EE1	Eastern Canadian Existing Processes
CLASS EE2	Eastern Canadian Existing Processes
CLASS EE3	Eastern Canadian Existing Processes
CLASS EFE	Eastern Canada Energy Streams
CLASS EMT	Eastern Canadian New Processes
CLASS EPP	Power Plants
CLASS ER	Export Market Regions
CLASS EWP	Albertan Processes
CLASS EW1	Albertan Processes
CLASS EW2	Albertan Processes
CLASS EW3	Albertan Processes
CLASS EW4	Albertan Processes
CLASS EYP	Ethylene Plants
CLASS FGT	Frontier Gas Prod Tech
CLASS FIVE	Indexing Class
CLASS FOUR	Indexing Class
CLASS HOB	Blends for Bit and Heo
CLASS GCR	Canadian Gas Reserves
CLASS GFR	Eastern Frontier Gas Reserves
CLASS GM	U.S. Gas Marketing Regions
CLASS GPT	Nat Gas Processing Plants
CLASS GWR	Albertan Gas Reserves
CLASS IFP	Intermediate Fuels
CLASS LPP	Natural Gas Liquids
CLASS MAE	All Energy Forms
CLASS MBP	CH4 or Coal Based Petrochems
CLASS MET	All Alta Energy Technologies
CLASS MP	Time Periods
CLASS MP02	2 Time Periods
CLASS MP04	4 Time Periods
CLASS MP06	6 Time Periods
CLASS MP08	8 Time Periods
CLASS MP12	12 Time Periods
CLASS MP16	16 Time Periods
CLASS MPE	Primary Energy Forms
CLASS MSE	Secondary Energy Forms
CLASS MSP	Mixed Feed Processes
CLASS NGL	Natural Gas Liquids

CLASS NGP	Natural Gas Uses
CLASS OCR	Oil Reserves
CLASS OIP	Other Intermediate Plants
CLASS OSR	OilSands Reserves
CLASS PCP	Primary Petrochemicals
CLASS PCS	Secondary Petrochemicals
CLASS PSP	Other Single Feed Processes
CLASS PTP	Petrochemicals Processes
CLASS PT	Time Periods Minus One
CLASS PQ	Time Periods
CLASS PP	Time Periods Plus One
CLASS P2	Time Periods Plus Two
CLASS P3	Time Periods Plus Three
CLASS P4	Time Periods Plus Four
CLASS P5	Time Periods Plus Five
CLASS P6	Time Periods Plus Six
CLASS P7	Time Periods Plus Seven
CLASS P8	Time Periods Plus Eight
CLASS P9	Time Periods Plus Nine
CLASS PN	Time Periods Plus Ten
CLASS PE	Time Periods Plus Eleven
CLASS PW	Time Periods Plus Twelve
CLASS PH	Time Periods Plus Thirteen
CLASS PF	Time Periods Plus Fourteen
CLASS PV	Time Periods Plus Fifteen
CLASS PS	Time Periods Switch
CLASS R	Producing Regions
CLASS RROIL	Conv Oil Reserves
CLASS SIX	Indexing Class
CLASS SYC	Synthetic Crude Processes
CLASS SYG	Synthetic Gas Processes
CLASS T	Capital Type
CLASS UPG	Upgraders for Bit and Heo
CLASS WGT	Alta Gas Prod Technologies

Each class comprised a set of members. For example, Class GM had the following seven members:

NE	New England
MA	Middle Atlantic
EN	East North Central
WN	West North Central
MT	Mountain
CA	California
PN	Pacific Northwest

The variables and constraints referred to these classes. For example, if class PR consisted of members #01, 02, 03 then the variable name EG(GM)(PR) would represent 21 variables in the linear program:

EGNE01 EGNE02 EGNE03	Export of Alberta gas to New England region in periods #01, 02, and 03;
EGMA01 EGMA02 EGMA03	Export of Alberta gas to Middle Atlantic regions in periods #01, 02, and 03;
EGEN01 EGEN02 EGEN03	Export of Alberta gas to East North Central regions in period #01, 02, and 03;
EGWN01 EGWN02 EGWN03	Export of Alberta gas to West North Central regions in period #01, 02, and 03;
EGMT01 EGMT02 EGMT03	Export of Alberta gas to Mountain region in periods #01, 02, and 03;
EGCA01 EGCA02 EGCA03	Export of Alberta gas to California region in periods #01, 02, and 03;
EGPN01 EGPN02 EGPN03	Export of Alberta gas to Pacific Northwest region in periods #01, 02, and 03.

The major class members are shown below:

SECTION A: PRODUCING & MARKET REGIONS

CLASS R

	Producing Regions
W	Alberta
E	Eastern Canada

CLASS RG

	Market Regions
WC	Western Canada
EC	Eastern Canada
MW	U.S. Mid-West
PC	U.S. Pacific Coast
PR	Pacific Rim

CLASS GFR		
	East Frontier Reserves	
GFA		Proven Sable I. Gas
GFB		Prob Sable I. Gas
GFC		Prob Arctic Gas
CLASS GCR		
	Canada's Gas Reserves	
GWA		Proven Alta Gas
GWB		Probable Alta Gas
GWC		Prob Alta Tight Gas
GWD		Proven B'fort-Delta Gas
GWE		Prob B'fort-Delta Gas
GFA		Proven Sable I. Gas
GFB		Prob Sable I. Gas
GFC		Prob Arctic Gas
CLASS MPE		
	Primary Energy	
ORM		Mineable Oil Sands
OR1		Hi Grade In Situ O.S.
OR2		Med Grade In Situ O.S.
OIL		Conventional Oil
RGA		Raw Nat Gas - Old
RGB		Raw Nat Gas - New
HEO		Heavy Oil
CTS		Thermal Coal Sub-Bit
CTB		Thermal Coal Bit
COM		Metallurgical Coal
CLASS NGL		
	Natural GAs Products	
GAS		Fuel Gas Std
GS1	Int Gas Stream	
GS2		Fuel Gas Tupe 2
GS3		Fuel Gas Type 3
GS4		Fuel Gas Type 4
ETH		Ethane
PRP		Propane
BUT		Butane
CDS		Condensate
CLASS LPP		
	Natural Gas Liquids	
ETH		Ethane
PRP		Propane
BUT		Butane
CDS		Condensate
CLASS IFP		
	Intermediate Fuels	
HDX		Heo-Dil Exp. U.S.
SYC		Synthetic Crude

ICL	Coal Liquids (Inter)
BIT	Bitumen (Oil Sands)
BDX	Bit-Dil Exp. U.S.
BDA	Bit-Dil Ex-Alta
HDA	Heo-Dil Ex-Alta
CLASS NGP	
	Natural Gas Uses
CNG	Compressed Nat Gas
LNG	Liquefied Nat Gas
CLASS RFP	
	Refinery Products
GSL	Gasoline
DTN	diesel, Turbo, Naphtha
HFO	Heavy Fuel Oil
ASP	Asphalt
PLI	Refinery Grade Propylene
CLASS PCP	
	Primary Petrochemicals
ETN	Ethylene
PLE	Propylene
BTL	Butylenes
CLASS PCS	
	Secondary Petrochemicals
AMM	Ammonia
MEO	Methanol
MEF	Methanol Fuel-Related
LPE	LLDPE/LDPE
HPE	HDPE
EGC	Eth Glycol
STY	Styrene
VCM	VCM
VAM	Vinyl Acetate
PPY	Polypropylene
BIE	Butadiene
BTX	BTX
CLASS MSE	
	Secondary Energy Forms
ELE	Electricity
(IFP)	
(NGL)	
(FRP)	
(PCP)	
(PCS)	
CLASS MAE	All Energy FOrms
(MPE)	
(MSE)	

SECTION C: ENERGY & PETROCHEMICAL PROCESSES

CLASS COT	
	Oil Production Technologies
WO1	Produces Oil From OWA
WO2	Produces Oil From OWB
WO3	Produces Oil From OWC
BO1	Produces Oil From OBA
HO1	Produces Oil From OHA
HO2	Produces Oil From OHB
CLASS WGT	
	Alta Gas Prod Tecfhnol
WG1	Prod RGA From GWA
WG2	Prod RGA From GWB
WG3	Prod RGA From GWC
WG4	Prod RGA From GWD
WG5	Prod RGA From GWE
CLASS FGT	
	Frontier Gas Prod Tech
FG1	Prod RGA From GFA
FG2	Prod RGA From GFB
FG3	Prod.RGA From GFC
CLASS CGT	
	Can Gas Prod Technol
WG1	Prod RGA From GWA
WG2	Prod RGA From GWB
WG3	Prod RGA From GWC
WG4	Prod RGA From GWD
WG5	Prod RGA From GWE
FG1	Prod RGA From GFA
FG2	Prod RGA From GFB
FG3	Prod RGA From GFC
CLASS REF	
	Refinery Processes
RHM	High Gasoline
RMM	Medium Gasoline
RHE	Heavy Oil
RNA	Chemical Type
RSN	Synthetic Crude
CLASS GPT	
	Nat Gas Processing Plants
GPS	Gas Strad Plant (Eth)
GPF	Field (Old Gas)
GPB	Field (New Gas)
GP3	Deep Cut Ethane
GP4	Dummy
GP5	Dummy
GPX	Exist Strad Plant
GPE	Exist Can Gas Plant

CLASS EPP		
	Power Plants	
PWC		Coal Fired
PWG		Gas Fired
HYD		Hydro Electric
NUC		Nuclear
CLASS SYC		
	Syn Crude Process	
OSM		Mined OS Syncrude
OS1		Insitu OS Bitumen
OS2		Insitu OS Bitumen
IG1		Insitu OS Syncrude
IC1		Insitu OS Sync (+Coal)
CLI		Coal Liquefaction
CLASS UPG		
	Bit & Heo Upgraders	
RUB		Bitumen Upgrading
HOU		Heavy Oil Upgrading
CLASS HOB		
	Heo-, Bit-, CDS Blendes	
HEX		Heo-CDS Export
BE		Bit-CDS Export
HEA		Heo-CDS Domestic
BEA		Bit-CDS Domestic
CLASS SYG		
	Syn Gas Processes	
SLU		Lurgi
HYG		Hygas
COA		CO2 Acceptor
CLASS CDE		
	Consumers Demands	
MTF		Transport Fuels
HTF		Heating Fuels
CLASS MBP		
	Meth- or Coal-Based Petrochem	
AMC		Ammonia From Coal
AMG		Ammonia From Gas
MEC		Methanol From Coal
MEG		Methanol From Gas
MED		Methanol to Fuel
CLASS CBP		
	Coal Based Processes	
CLI,AMC,MEC		

CLASS EYP

	Ethylene Plants
ETE	Ethylene From Ethane
ETP	Ethylene From Propane
EPE	Ethylene Fr Eth & Prp
ETF	Ethylene From Naphtha
ETC	Ethylene From Condensate
ETO	Ethylene From Heavy Oil
ETB	Ethylene From Bitumen

CLASS OIP

	Other Intermediate Plants
BZN	BTX From Heavy Oil
BZC	BTX From Condensate
PLP	Propylene From Refinery
BTB	Butadiene From Butylene

CLASS EBP

	Ethylene Based Processes
HPE	HDPE From Ethylene
LPE	LDPE From Ethylene
EGE	Eth Gl[illegible]l From Ety
VCE	VCM Fr[illegible]thylene

CLASS PSP

	Misc Pe[illegible] Processes
PPP	Polyp[illegible]ne From PLE
SEB	Styrene From ETY & BZ
VME	VAM From MEOH & ETY
BTB	Butadiene From Butylene

CLASS PTP

	Petrochemical Processes
AMC	Ammonia From Coal
AMG	Ammonia From Gas
MEC	Methanol From Coal
MEG	Methanol From Gas
MED	Methanol To Fuel
ETE	Ethylene From Ethane
ETP	Ethylene From Propane
EPE	Ethylene Fr Eth. Prp
ETF	Ethylene From Naphtha
ETC	Ethylene From Condensate
BZN	BTX From Heavy Oil
BZC	BTX From Condensate
PLP	Propylene From Refinery
BTB	Butadiene From Butylene
BGS	Butane to GSL Pool
HPE	HDPE From Ethylene
LPE	LDPE From Ethylene
LHP	LDPE Conv to HDPE
EGE	Eth Glycol From Ety
VCE	VCM From Ethylene

SEB	Styrene From ETY & BZ
VME	VAM From MEOH & ETY
PPP	Polyproylene From PLE

The variable names were:

		Units
CAP(T)W(PR)	Total Energy Sector Investments From (T) In Alberta	MM$
CD(COT)E(PR)	Total Capital Charges for Oil from Technology (COT)	MM$/Y
CD(FGT)F(PR)	Total Capital Charges for Gas from Technology (FGT)	MM$/Y
CD(WGT)W(PR)	Total Capital Charges for Gas from Technology (WGT)	MM$/Y
CD(COT)E(PR)	Cumulative Oil Production from Technology (COT)	MMB
CP(FGT)F(PR)	Cumulative Gas Production from Technology (FGT)	BCF
CP(WGT)W(PR)	Cumulative Gas Production from Technology (WGT)	BCF
DEM(PR)	Accounting Variable for Energy Sector Economic Surplus	MM$/Y
D(COT)E(PR)	Hibernia Oil E&D Activity	MMB
D(FGT)F(PR)	Frontier Gas E&D Activity	BCF
D(WGT)W(PR)	Alberta Gas E&D Activity	BCF
EASYC(PR)	Synthetic Crude from Alberta to Eastern Canada	MMB/Y
EA(NGL)(PR)	Sale of NGL from Alberta to Eastern Canada	As spec
EA(TTT)(PR)	Sale of Oil and Gas from Alberta to Eastern Canada	As spec
EGASW(PR)	Export of Natural Gas from Alberta	BCF/Y
EG(GM)(PR)	Export of Alberta Gas to US Market Regions	BCF/Y
EG(GM)F(PR)	Export of Sable Island to US Market Region	BCF/Y
E(NGL)W(PR)	Export of NGL from Alberta	As spec
ESYCW(PR)	Export of Synthetic Crude from Alberta	MMB/Y
E(TTT)W(PR)	Export of Oil and Coal from Alberta	As spec
FTGAS(PR)	Gas from Sable Island to Toronto Area	BCF/Y
GTESS	Present Value of Alta Energy Sector Surplus	MM$
IDGW(PR)	Natural Gas Used in the Alberta Energy Sector	BCF/Y
IOIL(PR)	Import of Oil to Eastern Canada	MMB/Y
I(RFP)W(PR)	Imports of Refinery Products into Alberta	MMB/Y
OIL(SS)(PR)	Oil Production from Different Canadian Fields	MMB/Y
PC(OSR)	Oil Sands Committed Reserves	MMB
P(COT)E(PR)	Oil Produced from Technology (COT)	MMB/Y
(PCS)(RG)E(PR)	Petrochemical Production from Eastern Canada to Regions (R)	KT/Y

(PCS)(RG)W(PR)	Petrochemicrals Production from Alberta to Regions (RG)	KT/Y
PE(EEP)E(PR)	Production from Existing Facilities in Eastern Canada	Level
P(EMT)E(PR)	Capacity Additions of Technologies in Eastern Canadad	Level
PE(EWP)W(PR)	Production from Existing Facilities in Alberta	Level
P(FGT)F(PR)	Gas Production from Technology (FGT)	BCF/Y
P(IFP)(PR)	Net Production of Intermediate Products in Alberta	MMB/Y
P(MET)W(PR)	Capacity Additions of Technologies (MET) in Alberta	As spec
P(MPE)W(PR)	Production of Primary Energy in Alberta	units/y
P(NGL)E(PR)	NGL Net Production in Eastern Canada	As spec
P(NGL)W(PR)	NGL Net Production in Alberta	As spec
POILH(PR)	Oil Production from Hibernia Fields	MMB/Y
P(PCP)E(PR)	Net Production-Primary Petrochemicals in East.Canada	KT/Y
P(PCP)W(PR)	Net Production-Primary Petrochemicals in Alberta	KT/Y
PRGAF(PR)	Gas Production from Eastern Frontier	BCF/Y
P(RFP)E(PR)	Net Production of Refinery Products from Petrosar	As spec
P(RFP)W(PR)	Production of Refinery Products in Alberta	As spec
P(WGT)W(PR)	Gas Production from Technology (WGT)	BCF/Y
S(RFP)W(PR)	Surplus of Refinery Products in Alberta	As spec
TCAPW(PR)	Total Capital Sector Investment in Alberta	MM$
TC(EMT)E(PR)	Total Amortized Annual Costs of Additional Capacity in Eastern Canada	MM$/Y
TC(MET)W(PR)	Total Amortized Annual Costs of Additional Capacity in Alberta	MM$/Y
TD(FGT)F(PR)	Total Gas Deliverability from Technology (FGT)	BCF/Y
TD(WGT)W(PR)	Total Gas Deliverability from Technology (WGT)	BCF/Y
TECRG(PR)	Total Economic Rent from Natural Gas in Alberta	MM$/Y
TECRGF(PR)	Total Economic Rent from Eastern Frontier Gas	MM$/Y
TECRO(R)(PR)	Total Economic Rent from Oil in Region (R)	MM$
TESS(PR)	Undiscounted Energy Sector Surplus	MM$/Y
TP(EMT)E(PR)	Total Cumulative Capacity Additions in East.Canada	level
TP(MET)W(PR)	Total Cumulative Capacity Additions in Alberta	level
TP(PCS)E(PR)	Total Production of Petrochemicals (PCS) in Petrosar	level
TP(PCS)W(PR)	Total Production of Petrochemicals (PCS) in Alberta	level
TR(GFR)F	Frontier Gas Reserves Developed	MMB
TR(GWR)W	Alberta Gas Reserves Developed	MMB

TR(OCR)E	Hibernia Oil Reserves Developed	MMB
UD(FGT)R(PR)	Unused Gas Deliverability from Technology (FGT)	BCF/Y
UD(WGT)W(PR)	Unused Gas Deliverability from Technology (WGT)	BCF/Y

The model constraints were:

1. RTOILW(t) <u>ALBERTA PRODUCTION OF CONVENTIONAL CRUDE FROM VARIOUS CATEGORIES - MMB/Y</u>

OIL(SSS)(t)	Annual production from (SSS) categories
for SSS = OWA,OWB,OWC	
- POILW(t)	Total annual production in Alberta
= 0	

2. RD(COT)E(t) <u>HIBERNIA - OIL DELIVERABILITY - MMB/Y</u>

$-\sum_{i=1}^{t}$ Table PPP (HORPP,i)*D(COT)E(i)	Deliverability profile * Preproduction activities (exploration + development)
+ P(COT)E(t)	Annual potential production
= 0	

3. RC(COT)E(t) <u>HIBERNIA - TOTAL PREPRODUCTION COSTS - MM$/Y</u>

$\sum_{i=1}^{t}$ Table ENTC ((COT),CAPI)*Table PPP(HOCXX,i)*D(COT)F(i)	Capital costs * Amortization schedule * (exploration + development) activities
where XX = discount rate	
- CD(COT)E(t)	Total preproduction costs
= 0	

4. **RTOILH(t)** <u>HIBERNIA - TOTAL OIL PRODUCTION - MMB/Y</u>

P(COT)E(t)	Annual potential production from various fields
- POILH(t)	Total annual production
= 0	

5. **RCP(COT)(t)** <u>HIBERNIA - CUMULATIVE OIL PRODUCTION - MMB</u>

- Table ALPC(ALPC,LNTH)*E(COT)E(t)	(years/time period) * annual production
- CP(COT)E(t-1)	Cumulative production at end of period (t-1)
+ CP(COT)E(t)	Cumulative production at end of period (t)
= 0	

6. **RTRGAW(t)** <u>ALBERTA GAS PRODUCTION FROM VARIOUS FIELDS - BCF/Y</u>

P(WGT)W(t)	Annual potential production from various fields
- PRGAW(t)	Total annual production
= 0	

7. **RD(WGT)W(t)** <u>ALBERTA GAS DELIVERABILITY - BCF/Y</u>
(*Except WGT = WGI)

$-\sum_{i=1}^{t}$ Table PPP(WGRPP,i)*D(WGT)W(i)	Summation of (Deliverability Profiles * Exploration + Development Activities)
$-\sum_{i=1}^{t}$ Table PPP(UWGPP,i)*UD(WGT)W(i)	Summation of (Carried forward deliverabilities from previous periods)
+ TD(WGT)W(t)	Deliverability
= 0	

8. RU(WGT)W(t) <u>ALBERTA - UNUSED GAS DELIVERABILITY - BCF/Y</u>

$- \sum_{i=1}^{t}$ Table PPP(UWGPP,i)*UD(WGT)W(i)	Summation of previous periods unused deliverability
- TD(WGT)W(t)	Current deliverability
+ P(WGT)W(t)	Production
+ UD(WGT)W(t)	Surplus deliverability
= 0	

9. RC(WGT)W(t) <u>ALBERTA - GAS PREPRODUCTION COSTS</u>

$\sum_{i=1}^{t}$ Table ENTC(WGT,CAPI)* Table PPP(WGCXX,i)*D(WGT)W(i)	Capital costs * Amortization schedule * Preproduction activities
- CD(WGT)W(t)	Preproduction costs
= 0	

10. RCP(WGT)(t) <u>ALBERTA CUMULATIVE GAS PRODUCTION - BCF</u>

- Table ALPC(ALPC,LNTH)*P(WGT)W(t)	(years/period) * Annual production
- CP(WGT)W(t-1)	Cumulative production at end of period (t-1)
+ CP(WGT)W(t)	Cumulative production at end of period (t)
= 0	

11. RTRGAF(t) <u>EASTERN OFFSHORE - GAS BALANCE - BCF/Y</u>

PRGAF(t)	Production
- FTGAS(t)	To Toronto area
- EG(GM)F(t)	To NE USA Markets
= 0	

12. RRGSF(t) EASTERN OFFSHORE - GAS PRODUCTION - BCF/Y

P(FGT)F(t)	Production from (FGT) categories
- PRGAF(t)	Total annual production in Alberta
= 0	

13. RD(FGT)F(t) EASTERN OFFSHORE - GAS DELIVERABILITY - BCF/Y

$- \sum_{i=1}^{t}$ Table PPP(FGRPP,i)*D(FGT)F(i)	Summation (Deliverability Profiles * Preproduction activities)
$- \sum_{i=1}^{t}$ Table PPP(UGFPP,i)*UD(FGT)F(i)	Summation (Unused deliverabilities from previous periods)
+ TD(FGT)F(t)	Current deliverability
= 0	

14. RU(FGT)F(t) EASTERN OFFSHORE - UNUSED GAS DELIVERABILITY - BCF/Y

- TD(FGT)F(t)	Deliverability
+ P(FGT)F(t)	Production
+ UD(FGT)F(t)	Surplus deliverability
= 0	

15. RC(FGT)F(t) EASTERN OFFSHORE - GAS PREPRODUCTION COSTS - MM$/Y

$\sum_{i=1}^{t}$ Table ENTC((FGT),CAPI)* Table PPP(FGCXX,i)*D(FGT)F(t)	Capital costs * Amortization schedule * Preproduction activities
- CD(FGT)F(t)	Preproduction costs
= 0	

16. RCP(FGT)(t) EASTERN OFFSHORE - CUMULATIVE GAS PRODUCTION - BCF

- Table ALPC(ALPC,LNTH)*P(FGT)F(t)	(years/period)*annual production
- CP(FGT)F(t-1)	Cumulative production at end of period (t-1)
+ CP(FGT)F(t)	Cumulative production at end of period (t)
= 0	

17. RT(NGL)W(t) ALBERTA - NATURAL GAS LIQUIDS BALANCE - A.S.

*Excluding CDS

P(NGL)W(t)	Net production from energy sector
- E(NGL)W(t)	Exports
-EA(NGL)(t)	To Eastern Canada
= Table DSECE((NGL)WC,t)	Western demand

18. RT(NGL)E(t) EASTERN CANADA - NATURAL GAS LIQUIDS BALANCE - A.S.

*Except CDS

P(NGL)E(t)	Production
+ EA(NGL)W(t)	From Alberta
= Table DSECE(NGL)EC,t)	Eastern Consumer's demand

19. RLOS(t) ALBERTA - SYNCRUDE PRODUCTION LIMITS - MMB/Y

Table ENTC(OSM,SYC)*TPOSMW(t)	New Mined Oil Sands production
+ Table ENTC(OS1,SYC)*TPIG1W(t)	New insitu - high quality production
+ Table ENTC(OS2,SYC)*TPIG2W(t)	New insitu - std. quality production

+ Table WNEX(OSM,SYC)*PEOSMW(t)	Existing production
< Table ULLT(LOSW,t)	Exogeneous limits

20. RLIS(t) <u>ALBERTA - BITUMEN PRODUCTION LIMITS - MMB/Y</u>

Table ENTC(OS1,BIT)*TPOS1W(t)	Bitumen Production Insitu #1 Quality
+ Table ENTC(OS2,BIT)*TPOS2W(t)	Bitumen Production Insitu #2 Quality
< Table ULLT(LISW,t)	Exogeneous Limit

21. RTSYCW(t) <u>ALBERTA - SYNCRUDE BALANCE - MMB/Y</u>

PSYC(t)	Net production
- ESYCW(t)	Exports
- EASYC(t)	To Eastern Canada
= 0	

22. RT(RFP)W(t) <u>ALBERTA - REFINED OIL PRODUCTS BALANCE - A.S.</u>

P(RFP)W(t)	Production
+ I(RFP)W(t)	Imports
- S(RFP)W(t)	Surplus
= Table DSECE((RFP)WC,t)	Demands

23. REGPP(t) <u>GAS BALANCE ON REPROCESSING PLANTS</u>

Only gas exported from Alberta goes through reprocessing plants

Table ENTC(GPS,GS2)*TPGPSW(t)	New straddle plant production

+ Table ENTC(GP3,GS2)*TPGP3W(t)	New deep-cut plant prod.(#GS2)
+ Table ENTC(GP3,GS3)*TPGP3W(t)	New deep-cut plant prod.(#GS3)
+ Table WNEX(GPX,GS2)*PEGPXW(t)	Existing Production
- EAGAS(t)	Ex-Alberta gas
- EGASW(t)	Gas exports from Alberta
= 0	

24. **RFGP(t)** <u>OPERATIONAL MODES FOR STRADDLE PLANTS</u>

Existing straddle plants can handle both old and new gas

PEGPFW(t)	'Old' gas production
+ PEGPBW(t)	'New' gas production
< Table CCF(20,t)	Level

25. **RB(MET)W(t)** <u>ALBERTA - CAPACITY ADDITIONS - Levels</u>

$\sum_{i=1}^{t}$ Table PPP(XX,i)*P(MET)W(i) for XX=Table ENTC((MET),LIFE)	Summation (production profile * level of operation)
- TP(MET)W(t)	Capacity additions available in (t)
= 0	

26. **RCMETW(t)** <u>ALBERTA - ANNUALIZED COSTS FOR CAPACITY ADDITIONS - MM$/Y</u>

$\sum_{i=1}^{t}$ {Table ENTC((MET),CAPI)*Table TCA((MET),ACA)*Table TPC ((YY),i)*Table CCF((XX),i)	Annualized capital costs

+ Table ENTC((MET),OPER)*
 Table PPP((XX),i)}*P(MET)t   Operating costs

- TC(MET)W(t)   Total annualized costs

= 0

{See section under VECTOR CAP(T)W(t) to amortize capital surcharge when capital expenditures exceed the specified amount}

27. RB(EMT)E(t) EASTERN CANADA - CAPACITY ADDITIONS - Levels

$\sum_{i=1}^{t}$ Table PPP((XX,i)*P(EMT)E(i)   Summation (production profile * level of operations)

- TP(EMT)E(t)   Capacity additions available in (t)

= 0

28. RC(EMT)E(t) EASTERN CANADA - ANNUALIZED COSTS FOR CAPACITY ADDITIONS - MM$/Y

$\sum_{i=1}^{t}$ {Table ENTC((EMT),CAPI)*Table
 TCA((EMT),ACA)*Table TPC((YY,i)*
 Table CCF((XX),i)   Annualized capital costs

+ Table ENTC((EMT,OPER)*Table
 PPP((XX),i}*P(EMT)t   Operating costs

- TC(EMT)E(T)   Total

= 0

29. R(MAE)BW(T) ALBERTA - BALANCE ON ALL THE ENERGY AND PETROCHEMICALS STREAMS - A.S.

GENERAL EQUATION

Table ENTC((MET),(MAE))*TP(MET)W(t)   New technologies I/O

+ Table WNEX((MET),(MAE)*PE(EWP)W(t)   Existing Technologies I/O

- P(MAE)W(t)   Net production

= 0

For (MAE)=OIL, Add

+ PCDSW(t)	Condensate to oil pool
- EAOIL(t)	To Eastern Canada
- EOILW(t)	Exports

For (MAE)=GAS, Add

- EAGAS(t)	To Eastern Canada
- EGASW(t)	Exports
- IDGW(t)	Alta industrial demand
$-\sum_{i=1}^{t}$ Table PPP(DLGPP,i)*DLG(i)	Dome LNG project
and RHS is Table DSECE(GASWC,t)	Exogeneous Alta consumers and other industries demand

For (MAE)=CTS, Add

- ECTSW(t)	Exports

For (MAE)=ELE, Add

to RHS Table DSECE(ELEWC,t)	Exogeneous Alta consumer's demand

30. R(EFE)BE(t) EASTERN CANADA - BALANCE ON THE ENERGY AND PETROCHEMICALS STREAMS - A.S.

GENERAL EQUATION

Table ENTC((EMT),(EFE))*TP(EMT)E(t)	New technologies I/O
+ Table ENEX((EEP),(EFE)*PE(EEP)E(t)	Existing technologies I/O
- P(EFE)E(t)	Net production
= 0	

FOR (EFE)=OIL, Add

+ EAOIL(t)	Conventional crude from Alberta
+ POILH(t)	Hibernia oil
+ PCDSE(t)	Condensate to oil pool

+ IOIL(t)	Oil imports
+ EASYC(t)	Syncrude from Alberta
and RHS is Table DSECE(OILEC,t)	Demand

FOR (EFE)=GAS, Add

EAGAS(t)	From Alberta
+ FTGAS(t)	From Eastern Offshore
and RHS is Table DSECE(GASEC,t)	Demand

31. RTCAPW(t) TOTAL CAPITAL EXPENDITURE IN THE ALBERTA ENERGY INDUSTRY* - MM$

*excluding the oil sector - where exogeneous, aggregated values are used

Table ENTC(WGT),CAPI)*D(WGT)W(t)	Gas sector
+ Table ENTC((MET),CAPI)* Table TPC ((YY),t)*P(MET)W(t)	Industrial requirements
- TCAPW(t)	Total capital expenditures
= 0	

32. RCAP(t) ALBERTA - TYPES OF CAPITAL USED - MM$

TCAPW(t)	Total capital
- CAP(T)W(t)	Σ Capital from individual pools
= 0	

33. RTGEUS(t) TOTAL GAS EXPORTS FROM ALBERTA TO THE USA - BCF/Y

EG(GM)(t)	Exports to seven individual regions
- EGASW(t)	Total exports
= 0	

34. RGD(GM)t. GAS IMPORTS BALANCE IN THE SEVEN US MARKET REGIONS - BCF/Y

EG(GM)(t)	From Alberta
+ EG(GM)F(t), GM=NE,MA	From Sable Island
< Table RNGDE((GM),t)	Maximum regional gas demand

35. RIGASW(t) ALBERTA INDUSTRIAL GAS USAGE - BCF/Y

IDGW(t)	Industrial gas usage
+ Table ENTC((MET),GAS)*TP(MET)W(t)	New plants
+ Table WNEX((EWP),GAS)*PE(EWP)W(t)	Existing plants
= 0	

36. R(PCS)(RG)t DEMANDS FOR PETROCHEMICAL (PCS) IN MARKET REGION (RG) - KT/Y

(PCS)(RG)W(t)	Satisfied by Alberta production
+ (PCS)(RG)E(t)	Satisfied by Eastern production
< Table PCHDE((PCS)(RG),t)	Demand limits

37. RECROW(t) ECONOMIC RENT FOR OIL IN ALBERTA - MM$/Y

- Table MCOIL(MCO,(SSS))*OIL(SSS)t	Costs
+ Table OIL(AWH,t)*DOILW(t)	Revenue
- TECROW(t)	Economic rent
= 0	

38. RECROE(t) ECONOMIC RENT FOR OIL IN EASTERN CANADA - MM$/Y

- TABLE ENTC((COT),OPER)*P(COT)E(t)	Operating costs
- CD(COT)E(t)	Capital costs
+ Table OIL(EXP,t)*POILH(t)	Exports
- TECROE(t)	Economic rent
= 0	

39. RECRG(t) ECONOMIC RENT FOR GAS IN ALBERTA - MM$/Y

- Table ENTC((WGT),OPER)*P(WGT)W(t)	Operating costs
- CD(WGT)W(t)	Capital charges
- TECRG(t)	Economic rent
+ Table GAS(ABP,t)*EG(GM)t	Exports
+ Table GAS(ABP,t)*EAGAS(t)	Eastern Canadian sales
+ Table GAS(IPF,t)*Table GAS(ABP,t)*IDGW(t)	Industrial sales
+ Table ENTC((MET),GSHR)*Table GAS (PPF,t)*TP(MET)W(t)	For new ethane extraction plants
+ Table WNEX((EWP),GSHR)*Table GAS(PPF,t)*PE(MET)W(t)	For existing ethane extraction plants
= - Table DSECE(GASWC,t)* Table GAS(IPF,t)*Table GAS(ABP,t)	Exogeneous demand

40. RESS(t) ECONOMIC SURPLUS IN ENERGY SECTOR - MM$/Y

{Table DSECE(ELEWC,(t))*Table ELE(ELE,(t))
+ Table DSECE(GASWC,(t))*Table GAS(ABP,(t))*Table GAS(IPF,(t))
+ Table DSECE((RFP)WC,(t))*Table RFPP((RFP)W,(t))
+ Table DSECE(PRPWC,(t))*Table NGL(PRP,(t))*10
+ Table DSECE(PRPEC,(t))*Table NGL(PRP,(t))*10
+ Table DSECE(BUTWC,(t))*Table NGL(BUT,(t)) Secondary
+ Table DSECE(BUTEC,(t))*Table NGL(BUT,(t)) Energy
+ Table DSECE(OILEC,(t))*Table OIL(EXP,(t)) Sales
+ Table DSECE(GASEC,(t))*Table GAS(TCG,(t))}*DEM(t)

- Table ENTC((COT),OPER)*P(COT)E(t) Eastern Frontier Oil costs

- CD(COT)E(t)	Eastern Frontier Oil capital charges
- Table ENTC(WGT,OPER)*P(WGT)W(t)	Alberta gas costs
- CD(WGT)W(t)	Alberta gas charges
- Table ENTC((FGT),OPER)*P(FGT)F(t)	Eastern gas costs
- CD(FGT)F(t)	Eastern Frontier gas charges
- Table (MPE)(CPA,(t))*P(MEP)W(t) when MPS=HEO,CTS	Heavy oil and coal costs
- Table TRANS(GASST,(t))*FTGAS(t)	Transport costs Sable Island-Toronto
{+ Table(777)(EXP,(t))-Table TRANS (EX(777),(t))*E(777)W(t)} for 777=OIL,CTS	Exports - oil, coal
{0.01*Table RGPS1((GM),(t))*Table APRT(EXCC,(t)) - Table TRANS (GAS(GM),(t))}*EG(GM)(t)	Gas exports from Alberta
+ 0.01*Table RGPS1((GM),(t))*Table APRT(EXCC,(t)) - Table TRANS (GAS(GM)F,(t))†*EG(GM)F(t)	and Sable Island
- {Table GAS(TCG,(t))-Table GAS (ABP,(t))†*EAGAS(t) - §Table TRANS(EAOIL,(t))}*EAOIL(t)	Transportation costs
- Table OIL(EXP,(t))*IOIL(t)	Import costs
+ Table ALPC(ALPC,HV(NGL))*Table GAS(ABP,(t))*E(NGL)W(t)	Exports Natural Gas Liquids

- Table TRANS(EA(NGL),(t))*10, (EA(NGL)(t) for NGL=ETH,PRP - Table TRANS(EA(NGL),(t))*EABUT(t)	Transportation East NGL
- Table RFPP(I(RFP)W,(t))*I(RFP)W(t) + Table RPFF(S(RFP)W,(t))*S(RFP)W(t) + Table RFPP((RPF)E,(t))*P(RFP)E(t)	refined products imports, surplus and exports
- TC(MET)W(t)	New capacity costs - Alta
- Table ALPC(ALPC,FERR)*TECRG(t)	Rent retained by Govt for gas
- Table ALPC(ALPC,FERR)*TECRO(t)	Rent retained by Govt for oil
- TC(EMT)E(t)	New capacity costs (East)
- Table WNEX((EWP),OPER)*PE(EWP)W(t)	Existing production oper.costs-Alta
- Table ENEX((EEP),OPER)*PE(EEP)E(t)	Existing production oper.costs-East
+ Table IFPP((IFP),(t))*P(IFP)(t)	Intermediate fuels
- Table TRANS(EAOIL,(t))*EASYC(t)	Syncrude East - transport cost
{Table IFPP(SYC,(t)) - Table TRANS(EXOIL,(t))}*ESYCW(t)	Syncrude exports
+{Table PCHPP(CPCS)(RG),(t))-Table TRANS(W(PCS)(RG),(t))-Table TARIF ((PCS)(RG),(t))}*(PCS)(RG)W(t)/1000	Petrochemicals for Alberta to market regions
+{Table PCHPP(CPCS)(RG),(t))-Table TRANS(E(PCS)(RG),(t))-Table TARIF (CPCS)(RG),(t))}*(PCS)(RG)E(t)1000	Petrochemicals from Eastern Canada to market regions

- DPCT(t)		Dome costs
+ DPCT(t)		Dome revenue
- TESS(t)	= 0	Economic surplus

41. RTESS   TOTAL SURPLUS IN ENERGY SECTOR - MM$

- GTESS		Total surplus
+ Table ALPC(ALPC,LNTH)*Table DISF ((XX),t)*TESS(t)		Present value of economic surplus
	= 0	

42. ROR(OCR)E   LIMIT ON EASTERN FRONTIER RESERVES OF OIL - MMB

- TR(OCR)E		Total reserves
+ D(COT)E(t)		Σ Activities per period
	= 0	

43. RGR(GWR)W   LIMITS ON ALBERTA GAS RESERVES - BCF

TR(GWR)W		Total reserves (bounded)
- D(WGT)W(t)		Activities
	= 0	

44. RGR(GFR)F   LIMITS ON FRONTIER GAS RESERVES - BCF

- TR(GFR)F		Total reserves (bounded)
+ D(FGT)F(t)		Activities
	= 0	

45. RC(OSR)   LIMITS ON OIL SANDS RESERVES IN ALBERTA - MMB

- PC(OSR)		Total reserves (bounded)
+ Table ENTC((MET),RSR)*P(OSR)W(t)		Activities
	= 0	

46. RDPCT(t) DOME LNG CAPITAL AND OPERATING COSTS - MM$/Y

$$-\sum_{i=1}^{t} \text{Table DPLG(CAP,PPL)*Table ACC(20,(XX))}$$

	Pipeline cap. costs
+ Table DPLG(CAP,LQP)*Table ACC(20,(YY))	Liquefaction plant cap.costs
+ Table DPLG(OPER,PPL)	Pipeline operating costs
+ Table DPLG(OPER,LQP)	Liquefaction plant oper.costs
+ Table DPLG(ELE,LQP)*Table DPLG(ELC,LQP)	Elec.costs
+ Table DPLG(OPER,MGT)	Marine transp.oper.costs
+ Table PPP(PLGPP,i)*Table GAS(ABP,i)}*DLG(i)	Gas costs
+ DPCT(t)	

= 0

47. RDPRV(t) REVENUE FROM THE DOME LNG PROJECT - MM$/Y

- DPRV(t)	Revenue
$+\sum_{i=1}^{t}$ {Table DLPG(GSEF,TQT)*Table PPP(DLGPP,i)*Table GAS (LNGJ,i)}*DLG(i)	Gas efficiency * Production profile * Unit Price * Activity

= 0

OBJ MM$

Please see RTESS ← OBJ=GTESS

APPENDIX 'C': SCENARIO #1: MODEL OUTPUT

OBJECTIVE FUNCTION VALUE = 162298 MM 1983 C$

INDEX OF TABLES

TABLE 1 - EXOGENOUS DATA

1.A - INFORMATION ON RUN

DATE OF RUN	MAY 22/84
NAME OF RUN	TEST G
DICOUNT RATE % ANN.	5
FRACT ECON RENT TO GOVT	.95
NO. OF TIME PERIODS	6
LENGTH OF OF TIME PERIOD, YRS	6

FINANCIAL RESULTS ARE IN CONSTANT 1983 CAN. DOLLARS

1.B - ESTIMATES OF CANADA'S ENERGY RESOURCE BASE

NOMENCLATURE

RSV	RECOVERABLE RESERVES (MARKETABLE)
PPC	PREPRODUCTION EXPLORATION AND DEVELOPMENT COSTS FOR EACH UNIT OF RECOVERABLE RESERVES
OPR	LIFTING COSTS PER UNIT OF PRODUCTION (TOTAL COSTS FOR DISCOV. ALTA OIL AND GAS)

1.B.1 - CRUDE OIL

	RSV	PPC	OPR
	MMB	$/BBL	$/BBL
DISCOV. ALTA OIL	3100		5.00
TERT RECOV ALTA OIL	1300		24.00
UNDISCOV. ALTA OIL	1400		28.00
PROVEN HIBERNIA OIL	1500	8.65	9.90
PROBABLE HIBERNIA OIL	4000	11.00	13.00

1.B.2 - NATURAL GAS

	RSV	PPC	OPR
	BCF	$/MCF	$/MCF
PROVEN ALTA GAS	59040		.31
PROBABLE ALTA GAS	118750	.31	.50
PROB ALTA TIGHT GAS	187500	1.13	1.26
PROVEN SABLE I. GAS	5000	.94	1.57
PROB SABLE I. GAS	15000	1.32	2.20

1.C - FORECAST OF ENERGY PRICES

NOMENCLATURE

OWPT	WORLD OIL PRICE (TORONTO)
AWHP	ALTA OIL WELL-HEAD PRICE
HEOP	ALTA HEAVY OIL WELL-HEAD PRICE
THCC	THERMAL COAL PRICE (ALTA)

1.C.1 - OIL AND COAL PRICES

	OWPT	AWHP	HEOP	THCC
	$/BBL	$/BBL	$/BBL	$/TNE
1985	35.82	34.03	6.00	8.16
1991	37.45	35.57	6.00	8.66
1997	41.71	39.72	6.61	9.19

2003	46.05	43.96	7.49	9.76
2009	50.35	48.14	9.56	10.36
2015	55.06	52.43	10.69	11.00

1.C.2 - NATURAL GAS PRICES

NOMENCLATURE

GABP	GAS - ALBERTA BORDER PRICE
GAIN	GAS - ALBERTA IND. PRICE
GAEE	ALTA ETHANE PRICE (FUEL EQUIV)
GTCG	GAS - TORONTO CITY GATE

	GABP	GAIN	GAEE	GTCG
	$/MCF	$/MCF	$/MCF	$/MCF
1985	2.83	1.70	2.83	4.08
1991	3.14	1.88	3.14	4.53
1997	3.52	2.11	3.52	4.96
2003	3.94	2.36	3.94	5.44
2009	4.31	2.59	4.31	5.95
2015	4.71	2.83	4.71	6.50

*.C.3 - NATURAL GAS LIQUIDS PRICES

NOMENCLATURE

PETH	PRICE OF ETHANE (BASED ON, COST OF SERVICE)
PPRP	OPPORTUNITY PRICE OF PROPANE (EXPORT PRICE)
PBUT	OPPORTUNITY PRICE OF BUTANE
PCDS	OPPORTUNITY PRICE OF CONDENSATE (CRUDE OIL BLEND)

	PETH	PPRP	PBUT	PCDS
	C/#	C/#	$/BBL	$/BBL
1985	8.92	9.32	28.20	34.03
1991	9.68	10.62	29.70	35.57
1997	10.62	11.62	31.86	39.72
2003	11.66	12.84	34.27	43.96
2009	12.58	14.14	37.22	48.14
2015	13.57	15.46	40.71	52.43

	PETH	PPRP	PBUT	PCDS
	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
1985	3.99	4.32	6.70	5.87
1991	4.34	4.93	7.05	6.13
1997	4.76	5.39	7.56	6.85
2003	5.23	5.96	8.14	7.58
2009	5.64	6.56	8.84	8.30
2015	6.08	7.17	9.67	9.04

TABLE 2 - REAL COSTS OF CANADIAN ENERGY

NOMENCLATURE

ACAO	AVER COST ALTA OIL
ACEO	AVER COST EASTERN OIL
ACAG	AVER COST ALTA GAS
ACEG	AVER COST EASTERN GAS

	ACAO	ACEO	ACAG	ACEG
	$/BBL	$/BBL	$/MCF	$/MCF
1985	7.04	27.36	.49	
1991	12.66	27.37	1.07	2.74
1997	16.50	31.15	1.43	2.74
2003	18.56	32.96	1.43	2.74
2009	20.09	34.45	1.93	2.80
2015	22.08	35.07	2.63	3.27

THE TABLES TO FOLLOW (WITH THE EXCEPTION OF TABLE 4.A) ARE OUTPUT RESULTS FROM THE MODEL

TABLE 3 - NATURAL GAS BALANCES

ALL VALUES ARE FOR MARKETABLE GAS

3.A - ALBERTA GAS SUPPLY

NOMENCLATURE

PEGF	PRODUCTION FROM EXISTING GAS FIELD GWA
PNGB	PRODUCTION FROM NEW GAS FIELD GWB
PNGC	PRODUCTION FROM NEW GAS FIELD GWC
~~TPRG~~	TOTAL MARKETABLE GAS PRODUCTION
NGRB	NEW ADDITIONS TO GAS RESERVE GWB
NGRC	NEW ADDITIONS TO GAS RESERVE GWC
TNGR	TOTAL NEW GAS RESERVE ADDITIONS
RREG	REMAINING RESERVES OF GWA GAS
RRNGB	REMAINING RESERVES OF GWB GAS
RRNGC	REMAINING RESERVES OF GWC GAS
TRAG	TOTAL REMAINING ALTA GAS

	PEGF	PNGB	PNGC	TPRG
	BCF/Y	BCF/Y	BCF/Y	BCF/Y
1985	2921			2921
1991	2712	1400		4112
1997	1438	3907		5346
2003	673	5095		5768
2009		3618	1755	5373
2015		1574	3668	5242

	NGRB BCF	NGRC BCF	TNGR BCF
1985	16431		16431
1991	69968		69968
1997	7972	15205	23177
2003		5708	5708
2009		18297	18297
2015		25891	25891

	RREG BCF	RRNFB BCF	RRGNC BCF	TRAG BCF
1985	41512	118750	187500	347762
1991	25238	110351	187500	323089
1997	16608	86908	187500	291016
2003	12570	56336	187500	256406
2009	12568	34629	176972	224169
2015	12566	25183	154967	192716

3.B.- ALBERTA GAS BALANCE

NOMENCLATURE

PGAS	ALTA MARKETABLE GAS PRODUCTION
GRRC	ALTA DEMAND EXCL ENERGY INDUSTRY (EXDG)
GREE	ALTA EXISTING ENERGY INDUSTRY DEMAND
GRNE	ALTA NEW ENERGY INDUSTRY DEMAND
EGCN	ALTA GAS TO EASTERN CANADA
EGUS	ALTA GAS EXPORT TO U.S.A.

	PGAS BCF/Y	GRRC BCF/Y	GREE BCF/Y	GRNE BCF/Y	EGCN BCF/Y	EGUS BCF/Y
1985	2921	283	151	36	1075	1000
1991	4112	331	140	139	1217	1773
1997	5346	372	146	280	1400	2500
2003	5768	418	59	556	1620	2500
2009	5373	444		746	1717	1944
2015	5242	472		838	1822	1620

3.C - SABLE ISLAND GAS SUPPLY

NOMENCLATURE

SLGD	LOW COST SABLE ISLAND GAS DEVELOPED
SLGP	LOW COST SABLE ISLAND GAS PRODUCED
SLRR	LOW COST SABLE GAS RESERVES REMAINING
SHGD	HIGH COST SABLE ISLAND GAS DEVELOPED
SHGP	HIGH COST SABLE ISLAND GAS PRODUCED
SHRR	HIGH COST SABLE GAS RESERVES REMAINING

SLGD BCF	SLGP BCF/Y	SLRR BCF	SHGD BCF	SHGP BCF/Y	SHRR BCF

1985			5000			15000
1991	1011	75	4550			15000
1997	1278	150	3650			15000
2003	1697	225	2300			15000
2009	1014	214	1016	149	11	14934
2015		116	320	1360	109	14280

3.D - EASTERN CANADA GAS BALANCE

NOMENCLATURE

EAG GAS FROM ALTA TO EASTERN CANADA

SIT SABLE ISLAND GAS TO TORONTO AREA

RGD EASTERN DEMAND

FNG SABLE ISLAND GAS PRODUCTION

MRD MARITIMES DEMAND

EXG EXPORT OF GAS TO U.S.

	EAG BCF/Y	SIT BCF/Y	RGD BCF/Y	FNG BCF/Y	MRD BCF/Y	EXG BCF/Y
1985	1075		1052			
1991	1217		1186	75	75	
1997	1400		1364	150	150	
2003	1620		1580	225	211	14
2009	1717		1677	225	224	1
2015	1822		1781	225	225	

TABLE 4 ALTA GAS EXPORTS TO U.S.A.

NOMENCLATURE

MARKET REGIONS

NE NEW ENGLAND

MA MIDDLE ATLANTIC

EN EAST NORTH CENTRAL

WN WEST NORTH CENTRAL

MT MOUNTAIN

CA CALIFORNIA

PN PACIFIC NORTHWEST

4.A - PRICES IN MARKET REGIONS (EXOG)

U.S.	NE $/MCF	MA $/MCF	EN $/MCF	WN $/MCF	MT $/MCF	CA $/MCF	PN $/MCF
1985	4.00	4.00	4.00	4.00	4.00	4.00	4.00
1991	4.00	4.00	4.00	4.00	4.00	3.50	3.50
1997	4.50	4.50	4.50	4.50	4.50	4.50	4.50
2003	4.50	4.50	4.50	4.50	4.50	4.50	4.50
2009	5.00	5.00	5.00	5.00	5.00	5.00	5.00

2015	5.00	5.00	5.00	5.00	5.00	5.00	5.00

4.B - ALTA GAS SOLD IN MARKET REGIONS

	NE	MA	EN	WN	MT	CA	PN	
	BCF/Y	BCF/Y	BCF/Y	BCF/Y	BCF/Y	BCF/Y	BCF/Y	TOTAL
1985	40	200	250	40	150	200	120	1000
1991	70	248	435	100	310	450	160	1773
1997	38	325	800	450	350	438	100	2500
2003	90	300	800	450	350	410	100	2500
2009	65	249	550	400	300	285	95	1944
2015			550	400	300	275	95	1620

TABLE 5 "SURPLUS" NAT GAS LIQUIDS
(AVAILABLE FOR EXPORT MARKESTS)

NOMENCLATURE

ETH	ETHANE
PRP	PROPANE
BUT	BUTANE
CDS	CONDENSATE

	ETH	PRP	BUT	CDS
	B#/Y	B#/Y	MMB/Y	MMB/Y
1985	2.6	6.5	20.2	25.1
1991	3.6	8.8	28.5	15.1
1997	6.7	11.2	39.8	16.9
2003	6.5	10.9	42.8	20.9
2009	4.3	8.4	37.6	38.1
2015	3.1	7.0	34.7	29.2

TABLE 6 - CONV CRUDE BALANCES

6.A - ALBERTA CRUDE BALANCE

NOMENCLATURE

PCRA	ALTA CRUDE PRODUCTION
PCDO	CRUDE FROM CONDENSATE POOL
CEAR	CRUDE USED IN EXISTING ALTA REFINERIES
CNAR	CRUDE USED IN NEW ALTA REFINERIES
EXEC	CRUDE FROM ALTA TO EASTERN CANADA
EXUS	EXPORT OF ALTA CRUDE TO U.S.

PCRA	PCDO	CEAR	CNAR	EXEC	EXUS

	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y
1985	317.6	25.1	94.5		205.2	50.0
1991	214.2	15.1	114.4		101.9	26.6
1997	163.0	16.9	117.7	2.6	18.6	50.0
2003	127.0	20.9	42.4	70.1	.0	38.1
2009	95.9	38.1	.0	79.5	.0	37.8
2015	64.2	29.2	.0	81.0	.0	2.5

6.B - HIBERNIA OIL SUPPLY

NOMENCLATURE

HLOD	LOW COST HIBERNIA OIL DEVELOPED
HLOP	LOW COST HIBERNIA OIL PRODUCED
HLRR	LOW COST HIBERNIA RESERVES REMAINING
HHOD	HIGH COST HIBERNIA OIL DEVELOPED
HHOP	HIGH COST HIBERNIA OIL PRODUCED
HHRR	HIGH COST HIBERNIA RESERVES REMAINING

	HLOD	HLOP	HLRR	HHOD	HHOP	HHRR
	MMB	MMB/Y	MMB	MMB	MMB/Y	MMB
1985	521	37	1281			4000
1991	613	75	831			4000
1997	366	78	365	1031	72	3566
2003		43	105	617	107	2926
2009		15	16	984	135	2115
2015		3		702	135	1307

6.C - EASTERN CANADA CRUDE BALANCE

NOMENCLATURE

OILF	FRONTIER CRUDE PRODUCTION
EACO	CONV OIL FROM ALTA
EASC	SYN CRUDE FROM ALTA
IOIL	IMPORTED OIL

	OILF	EACO	EASC	IOIL	TOTAL
	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y
1985	36.5	205.2	.0	85.2	326.9
1991	75.0	101.9	.0	150.0	326.9
1997	150.0	18.6	30.9	127.3	326.8
2003	150.0	.0	135.8	32.8	318.6
2009	150.0	.0	192.7	.0	342.7
2015	137.3	.0	237.2	.0	374.6

TABLE 7. ALTA THERMAL COAL BALANCE

NOMENCLATURE

PCTS	ALTA THERMAL COAL PRODUCTION

CPWC	COAL FOR POWER GENERATION
CAMM	COAL FOR AMM AND MEO PRODUCTION
CCLI	COAL FOR COAL LIQUEFACTION
CSGC	COAL FOR COAL GASIFICATION
CEXP	COAL EXPORT (EXOG)

	PCTS	CPWC	CAMM	CCLI	CSGC	CEXP
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	13.3	13.3	.0	.0	.0	.0
1991	18.0	18.0	.0	.0	.0	.0
1997	21.9	21.8	.0	.0	.0	.0
2003	28.1	26.5	1.6	.0	.0	.0
2009	32.6	30.9	1.7	.0	.0	.0
2015	36.3	34.4	1.9	.0	.0	.0

TABLE 8 - ALBERTA SYNTHETIC FUEL BALANCE

NOMENCLATURE

MOSS	MINED OIL SANDS SYN CRUDE
IOSS	IN SITU OIL SANDS SYN CRUDE
IOBT	IN SITU OIL SANDS BITUMEN PROD.
SBLP	TOTAL OIL SANDS PRODUCTION AS FRACT. OF EXOGENOUSLY IMPOSED LIMIT
HOUS	SYN CRUDE VIA HEAVY OIL UPGRADER
SCCL	SYN CRUDE FROM COAL LIQUEFACTION
DSWR	DEMAND FOR SYN CRUDE - WEST REFINING
DSEC	DEMAND FOR SYN CRUDE - EASTERN CANADA
DSUS	DEMAND FOR SYN CRUDE - EXPORT TO U.S.A.

8.A - SUPPLY OF SYNTHETIC CRUDE

	MOSS	IOSS	IOBT *	SBLP	HOUS	SCCL
	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y
1985	60.0	.0	15.0	1.0	.0	.0
1991	93.3	.8	40.0	.9	.0	.0
1997	159.0	.0	80.0	1.0	.8	.0
2003	239.0	17.0	120.0	1.0	11.5	.0
2009	279.0	63.1	140.0	1.0	16.3	.0
2015	319.0	67.0	160.0	1.0	20.3	.0

8.B - DEMAND FOR SYNTHETIC CRUDE

	DSWR	DSEC	DSUS
	MMB/Y	MMB/Y	MMB/Y
1985	17.2	.0	42.8
1991	17.2	.0	76.1
1997	28.1	30.9	100.0
2003	31.7	135.8	180.0

2009	65.8	192.7	100.0
2015	69.0	237.2	100.0

TABLE 9 - ALBERTA REFINED PRODUCT BALANCE

NOMENCLATURE

GSL	GASOLINE
DTN	DIESEL,TURBO,NAPHTHA
HFO	HEAVY FUEL OIL
ASP	ASPHALT
PLI	REFINERY-GRADE PROPYLENE

9.A - PRODUCTION FROM ALTA REFINERIES

	GSL MMB/Y	DTN MMB/Y	HFO MMB/Y	ASP MMB/Y	PLI KT/Y
1985	54.7	42.2	3.8	4.6	143.6
1991	64.7	49.6	4.6	5.2	168.5
1997	71.7	57.9	5.3	8.5	195.8
2003	58.8	64.8	5.2	6.2	186.3
2009	54.8	69.2	4.3	6.9	190.6
2015	56.6	71.3	4.4	7.6	197.6

9.B - FRACTION OF DEMAND MET BY PRODUCTION

	GSL	DTN	HFO	ASP
1985	1.27	1.00	.76	1.00
1991	1.54	1.00	.76	1.00
1997	1.76	1.00	.80	1.48
2003	1.52	1.00	.61	1.00
2009	1.42	1.00	.44	1.00
2015	1.42	1.00	.44	1.00

TABLE 10 - ALBERTA HEAVY OIL BALANCE

NOMENCLATURE

PHEOW	ALTA HEAVY OIL PRODUCTION
HDX	HEO-DIL EXP. U.S.
BIT	BITUMEN (OIL SANDS)
BDX	BIT-DIL EXP. U.S.
BDA	BIT-DIL EX-ALTA
HDA	HEO-DIL EX-ALTA

PHEOW MMB/Y	HDX MMB/Y	BIT MMB/Y	BDX MMB/Y	BDA MMB/Y	HDA MMB/Y

1985	32.2	21.0	15.0	22.5		16.4
1991	27.6	15.0	40.0	60.0		16.4
1997	29.6	10.9	80.0	120.0		16.4
2003	30.3	.0	120.0	144.0		16.4
2009	38.0	.0	140.0	83.9		16.4
2015	43.2	.0	160.8	184.2		16.4

TABLE 11 - ALBERTA CONDENSATE BALANCE

NOMENCLATURE

CDSNG	ALTA CONDENSATE PROD FROM NAT GAS
CDBDX	CDS IN BIT-OIL EXP U.S.
CDHDX	CDS IN HEO-OIL EXP U.S.
CDHDA	CDS IN HEO-OIL EX-ALTA
CDBDA	CDS IN BIT-OIL EX-ALTA

	CDSNG MMB/Y	CDBDX MMB/Y	CDHDX MMB/Y	CDHDA MMB/Y	CDBDA MMB/Y
1985	43.8	7.5	4.9	3.8	
1991	47.1	20.0	3.5	3.8	
1997	66.6	40.0	2.5	3.8	
2003	74.0	48.7		3.8	
2009	70.3	28.0		3.8	
2015	68.4	35.4		3.8	

TABLE 12 - OPERATING CAPACITY LEVELS

12.A - EXISTING ALBERTA ENERGY PLANTS

NOMENCLATURE

RHM	HIGH GASOLINE
RHE	HEAVY OIL
RSN	SYNTHETIC-CRUDE
GPX	GAS STRAD PLANT (EXIST)
GPF	FIELD PLANT WITH 3000 BCF/Y CAPACITY

12.A.1 - CLASS EW1 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	RHM	RHE	RSN	GPX	GPF
1985	.80	.39	1.00	.00	.97
1991	.97	.40	1.00	.00	1.00
1997	1.00	1.00	1.00	.00	1.00
2003	.36	.36	.36	.00	.36
2009	.80	.80	.80	.00	.00

2015	.00	.00	.00	.00	.00

NOMENCLATURE

PWC	COAL FIRED
PWG	GAS-FIRED
HYD	HYDRO-ELECTRIC
OSM	MINED OIL SANDS

12.A.2 - CLASS EW2 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	PWC	PWG	HYD	OSM
1985	1.00	.64	1.00	1.00
1991	1.00	.45	1.00	1.00
1997	1.00	.30	1.00	1.00
2003	.36	.27	.36	.36
2009	.00	.00	.00	.00
2015	.00	.00	.00	.00

NOMENCLATURE

AMG	AMMONIA FROM GAS
MEG	METHANOL FROM GAS
MED	METHANOL TO FUEL
ETE	ETHYLENE FROM ETHANE

12.A.3 - CLASS EW3 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	AMG	MEG	MED	ETE
1985	.94	[illegible]	.28	1.00
1991	1.00	.00	.45	1.00
1997	1.00	1.00	.55	1.00
2003	.36	.36	.75	.36
2009	.00	.00	.83	.00
2015	.00	.00	.90	.00

NOMENCLATURE

LPE	LDPE FROM ETHYLENE
EGE	ETH GLYCOL FROM ETY
VCE	VCM FROM ETHYLENE
VME	VAM FROM MEOH & ETY
SEB	STYRENE FROM ETY & BZ

12.A.4 - CLASS EW4 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	LPE	EGE	VCE	VME	SEB
1985	1.00	.92	1.00	1.00	1.00
1991	1.00	1.00	1.00	1.00	1.00
1997	1.00	1.00	1.00	1.00	1.00
2003	.36	.36	.36	.36	.36
2009	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	.00

12.B - EXISTING EASTERN CANADA PETROCHEMICAL PLANTS

NOMENCLATURE

RNA	CHEMICAL-TYPE
AMG	AMMONIA FROM GAS
ETF	ETHYLENE FROM NAPHTHA
BEC	BTX FROM OTHER PL
PEC	PROPYLENE FROM OTHER PL

12.B.1 - CLASS EE1 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	RNA	AMG	ETF	BEC	PEC
1985	.20	.82	.00	.00	.00
1991	.20	1.00	.00	.00	.00
1997	.20	1.00	.05	.00	.00
2003	.07	.36	.21	.00	.00
2009	.00	.00	.00	.00	.00
2015	.00	.00	.00	.00	.00

NOMENCLATURE

EGE	ETH GLYCOL FROM ETY
HPE	HDPE FROM ETHYLENE
LPE	LDPE FROM ETHYLENE
VCE	VCM FROM ETHYLENE

12.B.2 - CLASS EE2 ENERGY PLANTS

PRODUCTION AS A FRACTION OF CAPACITY

	EGE	HPE	LPE	VCE
1985	.00	.21	.00	.00
1991	.11	.00	.00	.00
1997	.00	.00	.00	.00
2003	.00	.00	.00	.00
2009	.00	.00	.00	.00
2015	.00	.00	.00	.00

TABLE 13 - REFINERY CAPACITY ADDITIONS

NOMENCLATURE

RHM	HIGH GASOLINE
RMM	MEDIUM GASOLINE
RHE	HEAVY OIL
RNA	CHEMICAL-TYPE
RSN	SYNTHETIC-CRUDE

13.A - INCREMENTAL CAPACITY ADDITIONS

RHM	RMM	RHE	RNA	RSN

	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y
1985	.0	.0	.0	.0	.0
1991	.0	.0	.0	.0	.0
1997	.0	2.8	.0	.0	11.8
2003	.0	73.2	2.3	.0	14.9
2009	.0	3.8	5.8	.0	42.5
2015	.0	1.5	.5	.0	.6

13.B - CUMULATIVE CAPACITY ADDITIONS

	RHM	RMM	RHE	RNA	RSN
	MMB/Y	MMB/Y	MMB/Y	MMB/Y	MMB/Y
1985	.0	.0	.0	.0	.0
1991	.0	.0	.0	.0	.0
1997	.0	2.6	.0	.0	10.9
2003	.0	70.2	2.2	.0	25.5
2009	.0	79.5	7.7	.0	65.8
2015	[illegible]	81.0	8.7	.0	69.0

TABLE 14 - POWER PLANT CAPACITY ADDITIONS

NOMENCLATURE

PWC	COAL FIRED
PWG	GAS-FIRED
HYD	HYDRO-ELECTRIC

14.A - INCREMENTAL CAPACITY ADDITIONS

	PWC	PWG	HYD
	BKWH/Y	BKWH/Y	BKWH/Y
1985	.1	.0	.0
1991	8.1	.0	.0
1997	5.9	.0	.0
2003	22.0	.0	.0
2009	14.4	.0	.8
2015	12.1	.0	.8

14.B - CUMULATIVE CAPACITY ADDITIONS

	PWC	PWG	HYD
	BKWH/Y	BKWH/Y	BKWH/Y
1985	.10	.00	.00
1991	7.60	.00	.00
1997	13.66	.00	.00
2003	34.40	.00	.08
2009	48.80	.00	.00
2015	54.25	.00	.00

TABLE 15 - SYN CRUDE CAPACITY ADDITIONS

NOMENCLATURE

OSM	MINED OS SYNCRUDE
OS1	INSITU OS BITUMEN
OS2	INSITU OS BITUMEN
IG1	INSITU OS SYNCRUDE
IC1	INSITU OS SYNC(+COAL)
CLI	COAL LIQUEFACTION
RUB	BITUMEN UPGRADING
HOU	HEAVY OIL UPGRADING

15.A - OIL SANDS & CO[illegible] LIQUID PLANTS

15.A.1 - INCREMENTAL CAPACITY ADDITIONS

UNIT SIZE: 100.00 BBL/CAL DAY

	OSM	OS1	OS2	IG1	IC1	CLI
1985	.04	.45	.00	.00	.00	.00
1991	.99	.71	.00	.00	.00	.00
1997	1.87	[illegible]	.00	.00	.00	.00
2003	3.34	[illegible]	[illegible]	.00	.00	.00
2009	1.63	.00	.93	.00	.00	.00
2015	2.03	.00	1.27	[illegible]	.00	.00

15.A.2 - CUMULATIVE CAPACITY ADDITIONS

UNIT SIZE: 100.00 BBL/CAL DAY

	OSM	OS1	OS2	IG1	IC1	CLI
1985	.03	.41	.00	.00	.00	.00
1991	.95	1.10	.00	.00	.00	.00
1997	2.75	2.19	.00	.00	.00	.00
2003	5.97	3.19	.10	.00	.00	.00
2009	7.64	2.87	.96	.00	.00	.00
2015	8.74	2.18	[illegible]	.00	.00	.00

15.B - UPGRADERS

15.B.1 - INCREMENTAL CAPACITY ADDITIONS

UNIT SIZE: 100.00 BBL/CAL DAY

	RUB	HOU
1985	.00	.00
1991	.00	.00
1997	.00	.00
2003	.51	.37
2009	1.33	.12
2015	.00	.12

15.A.2 - CUMULATIVE CAPACITY ADDITIONS

UNIT SIZE: 100.00 BBL/CAL DAY

	RUB	HOU
1985	.00	.00
1991	.00	.00
1997	.00	.00
2003	.47	.34
2009	1.73	.48
2015	1.84	.60

TABLE 16
SYN FUELS FROM COAL - CAPA ADDITIONS
NO NEW SYNTHETIC GAS FROM COAL [illegible]
BUILT IN PLANNING PERIOD

T[illegible]GAS PROCESSING CAPACITY ADDITIONS
[illegible]ATURE

GPS	[illegible] STRAD PLANT (ETH)
GPF	[illegible] FIELD (OLD GAS)
GPB	[illegible] FIELD (NEW GAS)
GP3	DEEP CUT ETHANE

17.A - INCREMENTAL CAPACITY ADDITIONS

	GPS	GPF	GPB	GP3
	BCF/Y	BCF/Y	BCF/Y	BCF/Y
1985	2575.8	.0	227[illegible]	
1991	912.3	.0	80[illegible]	
1997	1050.4	.0	928.0	
2003	349.5	.0	308.7	
2009	1671.6	.0	1476.7	
2015	855.2	[illegible]	755.5	

17.B - CUMULATIVE CAPACITY ADDITIONS

	GPS	GPF	GPB	GP3
	BCF/Y	BCF/Y	BCF/Y	BCF/Y
1985	2369.8	.0	2093.5	
1991	3415.2	.0	3017.0	
1997	4454.5	.0	3935.2	
2003	4705.5	.0	4157.0	
2009	4181.7	.0	3694.2	
2015	3932.1	.0	3473.7	

TABLE 18 - NEW ALTA PETROCHEMICAL PLANTS

18.A - AMMONIA & METHANOL CAPACITY ADDITIONS

NOMENCLATURE

AMC	AMMONIA FROM COAL
AMG	AMMONIA FROM GAS
MEC	METHANOL FROM COAL
MEG	METHANOL FROM GAS
MED	METHANOL TO FUEL

18.A.1 - INCREMENTAL CAPACITY ADDITIONS

	AMC KT/Y	AMG KT/Y	MEC KT/Y	MEG KT/Y	MED KT/Y
1985	.0	.0	.0	.0	.0
1991	.0	693.8	.0	.0	.0
1997	.0	419.0	.0	.0	.0
2003	.0	1943.3	868.1	[illegible]3.6	.0
2009	.0	1055.6	.0	[illegible]7.7	.0
2015	.0	702.1	101.9	.0	.0

18.A.2 - CUMULATIVE CAPACITY ADDITIONS

	AMC KT/Y	AMG KT/Y	MEC KT/Y	MEG KT/Y	MED KT/Y
1985	.0	.0	.0	.0	.0
1991	.0	638.3	.0	.0	.0
1997	.0	1079.3	.0	.0	.0
2003	.0	2900.6	798.6	564.5	.0
2009	.0	3985.6	868.1	1172.7	.0
2015	.0	4142.8	961.9	1221.3	.0

18.B - ETHYLENE CAPACITY ADDITIONS

NOMENCLATURE

ETE	ETHYLENE FROM ETHANE
ETP	ETHYLENE FROM PROPANE
EPE	ETHYLENE FR ETH & PRP

18.B.1 - INCREMENTAL CAPACITY ADDITIONS

	ETE KT/Y	ETP KT/Y	EPE KT/Y
1985	178.1	.0	220.6
1991	509.5	.0	306.3
1997	152.8	.0	578.1
2003	805.3	.0	555.1
2009	595.7	.0	550.8

2015	491.4	.0	510.1

18.B.2 - CUMULATIVE CAPACITY ADDITIONS

	ETE	ETP	EPE	ETF
	KT/Y	KT/Y	KT/Y	KT/Y
1985	163.9	.0	203.0	.0
1991	646.8	.0	502.4	.0
1997	828.1	.0	1058.7	.0
2003	1570.5	.0	1602.4	.0
2009	2011.7	.0	1960.9	.0
2015	2073.0	.0	2164.5	.0

18.C - BTX, PROPYLENE & BUTYLENE CAPA ADDITIONS

NOMENCLATURE

BZN BTX FROM HEAVY OIL
BZC BTX FROM CONDENSAT
PLP PROPYLENE FROM REFINERY
BTB BUTADIENE FROM BUTYLENE

18.C.1 - INCREMENTAL CAPACITY ADDITIONS

	BZN	BZC	PLP	BTB
	KT/Y	KT/Y	KT/Y	KT/Y
1985	.0	7.0	.0	183.6
1991	.0	12.2	.0	9.5
1997	.0	.0	.0	59.0
2003	.0	.0	.0	28.6
2009	.0	.0	.0	230.5
2015	.0	.0	.0	27.2

18.C.2 - CUMULATIVE CAPACITY ADDITIONS

	BZN	BZC	PLP	BTB
	KT/Y	KT/Y	KT/Y	KT/Y
1985		6.5	.0	95.3
1991		18.2	.0	112.3
1997		19.2	.0	167.3
2003		18.8	.0	192.1
2009		12.5	.0	324.2
2015		1.8	.0	341.0

18.D - ETHYLENE-BASED PETROCHEMICAL CAPA ADDITIONS

NOMENCLATURE

HPE	HDPE FROM ETHYLENE
LPE	LDPE FROM ETHYLENE
EGE	ETH GLYCOL FROM ETY
VCE	VCM FROM ETHYLENE

18.D.1 - INCREMENTAL CAPACITY ADDITIONS

	HPE	LPE	EGE	VCE
	KT/Y	KT/Y	KT/Y	KT/Y
1985	290.4	352.2	.0	51.5
1991	331.1	295.5	.0	202.0
1997	166.9	284.1	167.9	139.0
2003	167.5	399.4	318.8	295.9
2009	381.4	549.9	172.0	232.0
2015	401.8	385.1	34.0	231.9

18.D.2 - CUMULATIVE CAPACITY ADDITIONS

	HPE	LPE	EGE	VCE
	KT/Y	KT/Y	KT/Y	KT/Y
1985	267.2	324.0	.0	47.4
1991	595.0	624.0	.0	237.4
1997	775.0	909.0	154.5	381.4
2003	925.0	1278.0	461.2	661.6
2009	1040.0	1520.0	645.0	846.0
2015	1125.0	1615.0	680.0	902.2

18.E - MISCELLANEOUS PETROCHEMICAL CAPA ADDITIONS

NOMENCLATURE

PPP	POLYPROPYLENE FROM PLE
SEB	STYRENE FROM ETY & BZ
VME	VAM FROM MEOH & ETY
BTB	BUTADIENE FROM BUTYLENE

18.E.1 - INCREMENTAL CAPACITY ADDITIONS

	PPP	SEB	VME	BTB
	KT/Y	KT/Y	KT/Y	KT/Y
1985	65.0	19.5	.0	183.6
1991	59.6	14.6	50.2	9.5
1997	180.5	196.0	24.3	59.0
2003	95.4	248.9	387.6	28.6
2009	117.8	304.4	5.6	230.5
2015	96.6	44.9	77.7	27.2

18.E.2 - CUMULATIVE CAPACITY ADDITIONS

PPP	SEB	VME	BTB
KT/Y	KT/Y	KT/Y	KT/Y

1985	59.81	17.97	.00	95.27
1991	119.81	32.97	46.20	112.30
1997	217.03	214.47	72.60	167.34
2003	308.97	450.61	431.09	192.15
2009	370.02	733.58	490.00	324.16
2015	405.50	773.05	523.00	341.01

TABLE 19

EASTERN PETROCHEMICALS CAPACITY ADDITIONS

NO NEW EASTERN ETHYLENE PLANTS

BUILT IN PLANNING PERIOD

TABLE 20 - PETROCHEMICAL MARKETS

MARKET REGIONS

WC	WESTERN CANADA
EC	EASTERN CANADA
MW	U.S. MID-WEST
PC	U.S. PACIFIC COAST
PR	PACIFIC RIM

20.A - PETROCHEMICALS FROM ALTA TO VARIOUS MARKETS

20.A.1 - AMMONIA

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	1612.5	.0	532.0	152.0	.0	2296.5
1991	2212.5	.0	672.0	192.0	.0	3076.5
1997	2572.5	.0	735.0	210.0	.0	3517.5
2003	2775.0	.0	780.5	223.0	.0	3778.5
2009	2940.0	.0	813.4	232.4	.0	3985.8
2015	3067.5	.0	836.5	239.0	.0	4143.0

20.A.2 - METHANOL

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	135.0	135.0	142.0	282.3	284.0	978.3
1991	225.0	225.0	.0	.0	.0	450.0
1997	285.0	285.0	.0	.0	.0	570.0
2003	325.0	325.0	.0	.0	.0	650.0
2009	347.5	347.5	.0	.0	.0	695.0
2015	365.0	365.0	.0	.0	.0	730.0

20.A.3 - METHANOL - FUEL REL

	WC	EC	MW	PC	PR	TOTAL
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	140.0	60.0	18.5	92.5	74.0	385.0
1991	280.0	120.0	34.0	180.0	.0	614.0
1997	399.0	171.0	49.2	144.6	.0	763.8
2003	472.5	202.5	59.0	295.0	.0	1029.0
2009	521.5	223.5	67.0	335.0	.0	1147.0
2015	560.0	240.0	73.5	367.5	.0	1241.0

20.A.4 - LLDPE/LDPE

	WC	EC	MW	PC	PR	TOTAL
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	57.0	323.0	51.0	81.0	153.0	635.0
1991	83.3	471.8	76.0	76.0	228.0	935.0
1997	114.8	650.3	91.0	91.0	273.0	1220.0
2003	132.8	752.3	101.0	101.0	303.0	1390.0
2009	145.5	824.5	110.0	110.0	330.0	1520.0
2015	154.5	875.5	117.0	117.0	351.0	1615.0

20.A.5 - HDPE

	WC	EC	MW	PC	PR	TOTAL
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	26.0	203.2	19.0	19.0	[illegible]	267.2
1991	37.0	333.0	45.0	45.0	13[illegible]	[illegible]95.0
1997	48.0	432.0	59.0	59.0	17[illegible]	775.0
2003	58.0	522.0	69.0	69.0	207.0	925.0
2009	65.5	589.5	77.0	77.0	231.0	1040.0
2015	71.0	639.0	83.0	83.0	249.0	1125.0

20.A.6 - ETH GLYCOL

	WC	EC	MW	PC	PR	TOTAL
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	7.8	147.3	50.0	30.0	120.0	355.0
1991	9.3	167.8	69.5	41.7	97.3	385.5
1997	10.5	199.5	82.5	49.5	198.0	540.0
2003	11.5	218.5	92.5	55.5	222.0	600.0
2009	12.3	232.8	100.0	60.0	240.0	645.0
2015	12.8	242.3	106.3	63.8	255.0	680.0

20.A.7 - STYRENE

	WC	EC	MW	PC	PR	TOTAL
	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y	KT/Y
1985	64.5	.0	.0	67.5	162.0	294.0
1991	93.0	.0	.0	.0	216.0	309.0
1997	133.5	.0	.0	105.0	252.0	490.5
2003	159.0	.0	.0	115.0	276.0	550.0
2009	177.0	61.6	74.3	123.8	297.0	733.6
2015	190.5	62.6	78.0	130.0	312.0	773.1

20.A.8 - VINYL CHLOR MON

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	9.0	291.8	15.0	25.0	.0	340.0
1991	13.5	436.5	30.0	50.0	.0	530.0
1997	17.1	552.9	39.0	65.0	.0	674.0
2003	19.4	625.6	45.8	76.3	.0	767.0
2009	21.3	688.7	51.0	85.0	.0	846.0
2015	22.7	732.3	55.2	92.0	.0	902.2

20.A.9 - VINYL ACETATE

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	1.4	25.7	2.0	2.0	10.4	41.4
1991	1.8	34.2	25.8	25.8	.0	87.6
1997	2.3	42.8	34.5	34.5	.0	114.0
2003	2.6	48.5	39.5	39.5	316.0	446.0
2009	2.8	52.3	43.5	43.5	348.0	490.0
2015	2.9	55.1	46.5	46.5	372.0	523.0

20.A.10 - POLYPROPYLENE

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	6.0	53.8	.0	.0	.0	59.8
1991	9.0	110.8	.0	.0	.0	119.8
1997	13.0	174.8	9.8	19.5	.0	217.0
2003	17.0	253.0	13.0	26.0	.0	309.0
2009	19.5	303.6	15.7	31.3	.0	370.0
2015	21.3	331.0	17.8	35.5	.0	405.5

20.A.11 - BUTADIENE

	WC KT/Y	EC KT/Y	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	19.0	73.8	.0	2.5	.0	95.3
1991	24.0	77.3	.0	11.0	.0	112.3
1997	28.0	122.3	.0	17.0	.0	167.3
2003	30.5	141.1	.0	20.5	.0	192.1
2009	32.5	268.7	.0	23.0	.0	324.2
2015	34.0	283.5	.0	23.5	.0	341.0

20.A.12 - BTX EXPORTS

	MW KT/Y	PC KT/Y	PR KT/Y	TOTAL KT/Y
1985	.0	.0	.0	
1991	.0	.0	.0	
1997	.0	.0	.0	

2003	.0	.0	.0	
2009	.0	292.0	.0	292.1
2015	.0	292.0	.0	292.1

20.B - PETROCHEM FROM EASTERN CANADA TO VARIOUS MARKETS

20.B.1 - AMMONIA

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	537.5	.0	537.5
1991	737.5	.0	737.5
1997	857.5	.0	857.5
2003	925.0	.0	925.0
2009	980.0	.0	980.0
2015	1022.5	.0	1022.5

20.B.2 - METHANOL

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	.0	.0	
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.B.3 - METHANOL - FUEL REL

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	.0	.0	
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.B.4 - LLDPE/LDPE

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	.0	.0	
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.B.5 - HDPE

EC	MW	TOTAL

	KT/Y	KT/[illegible]	KT/Y
1985	30.0	[illegible]	30.0
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.8.6 - ETH GLYCOL

	EC	MW	TOTAL
	KT/Y	KT/Y	KT/Y
1985	.0	.0	
1991	8.0	.0	8.0
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.8.7 - STYRENE

	EC	MW	TOTAL
	KT/Y	KT/Y	KT/Y
1985	150.5	40.5	191.0
1991	217.0	54.0	271.0
1997	311.5	63.0	374.5
2003	371.0	6[illegible].0	440.0
2009	351.4	.0	351.4
2015	381.9	.0	381.9

20.8.8 - VINYL CHLOR MON

	EC	MW	TOTAL
	KT/Y	KT/Y	KT/Y
1985	.0	.0	
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.8.9 - VINYL ACETATE

	EC	MW	TOTAL
	[illegible]Y	KT/Y	KT/Y
1985	.0	[illegible].0	
1991	.0	.0	
1997	.0	.0	
2003	.0	.0	
2009	.0	.0	
2015	.0	.0	

20.8.10 - POLYPROPYLENE

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	60.2	.0	60.2
1991	60.2	.0	60.2
1997	72.2	.0	72.2
2003	70.0	.0	70.0
2009	66.9	.0	66.9
2015	72.7	.0	72.7

20.B.11 - BUTADIENE

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	19.1	.0	19.1
1991	19.1	.0	19.1
1997	23.6	.0	23.6
2003	25.2	.0	25.2
2009	.0	.0	.0
2015	.0	.0	.0

20.B.12 - BTX EXPORTS

	EC KT/Y	MW KT/Y	TOTAL KT/Y
1985	.1	292.0	292.1
1991	.1	302.0	302.1
1997	.1	298.0	298.1
2003	.1	294.0	294.1
2009	.1	292.0	292.1
2015	.1	292.0	292.1

TABLE 21 - ECONOMIC RENTS

21.A - ALBERTA NATURAL GAS

CATEGORIES OF GAS

IDGW METHANE BASED ENERGY INDUSTRY
GPCE ETHANE & HIGHER COMPONENTS
GRRC ALTA RES AND COMM
ECGN ALTA GAS TO EASTERN CANADA
EGUS ALTA GAS TO U.S.A.

	IDGW MM$/Y	GPCE MM$/Y	GRRC MM$/Y	ECGN MM$/Y	EGUS MM$/Y	TOTAL MM$/Y
1985	324	400	341	2514	2339	5919
1991	298	510	269	2518	3668	7262

1997	354	672	254	2926	5225	9429
2003	599	851	389	4058	6264	12161
2009	492	719	292	4891	4631	10225
2015	168	591	94	3798	3376	8027

21.B - CANADIAN CRUDE OIL

CATEGORIES OF OIL

ALCC ALBERTA CONV. CRUDE

OSHB OFF-SHORE (HIBERNIA & BEAUFORT)

	ALCC MM$/Y	OSHB MM$/Y	TOTAL MM$/Y
1985	8571.3	308.8	8880.1
1991	4906.9	756.0	5662.9
1997	3784.5	1584.1	5368.5
2003	3225.7	1963.8	5189.5
2009	2689.7	2384.7	5074.5
2015	1948.4	2745.5	4693.9

21.C - ALBERTA ENERGY SECTOR

NOMENCLATURE

FBG FLOWBACK FROM U.S. GAS EXPORTS

OSS OIL SANDS SURPLUS (NEW PLANTS)

MBP METHANE-BASED PETROCHEM SURPLUS

EBP ETHANE-BASED PETROCHEM SURPLUS

	FBG MM$/Y	OSS MM$/Y	MBP MM$/Y	EBP MM$/Y
1985	1459	102	552	547
1991	1781	595	378	281
1997	3665	2042	180	193
2003	2585	5165		
2009	2504	8022	100	404
2015	1695	10943	462	1111

NOMENCLATURE

OSM MINED OS SYNCRUDE

OS1 INSITU OS BITUMEN

OS2 INSITU OS BITUMEN

IG1 INSITU OS SYNCRUDE

IC1 INSITU OS SYNC(+COAL)

CLI COAL LIQUEFACTION

RENTS BASED UPON REAL COSTS OF GAS

	OSM $/BBL	OS1 $/BBL	OS2 $/BBL	IG1 $/BBL	IC1 $/BBL	CLI $/TONNE
1985	8.34	8.99	5.82	9.82	9.89	7.61-
1991	10.20	9.47	6.08	11.47	11.65	6.84-
1997	14.78	10.32	6.81	15.88	16.13	3.68-

2003	19.61	12.32	8.84	20.57	20.83	4.50
2009	23.90	13.98	10.30	24.74	25.09	9.32
2015	28.27	15.56	11.55	29.05	29.50	12.32

RENTS BASED UPON INDUSTRIAL PRICE OF GAS

	OSM	OS1	OS2	IG1	IC1	CLI
	$/BBL	$/BBL	$/BBL	$/BBL	$/BBL	$/TONNE
1985	7.77	6.78	3.06	9.11	9.38	18.94-
1991	9.81	7.98	4.22	10.99	11.31	14.47-
1997	14.46	9.07	5.25	15.48	15.85	10.08-
2003	19.16	10.62	6.71	20.03	20.44	4.23-
2009	23.58	12.78	8.79	24.36	24.81	3.14
2015	28.12	15.19	11.09	28.93	29.42	10.44

THE NEXT SET OF TABLES GIVES THE ECONOMIC RENT OR PROFITABILITY OF A SELECTED NUMBER OF PETRO CHEMICAL PROCESSES, SERVING VARIOUS MARKET REGIONS, BASED UPON EITHER THE REAL COSTS OF GAS OR THE PROJECTED PRICES OF GAS.

NOMENCLATURE

MEG METHANOL FROM GAS
MEC METHANOL FROM COAL
HPE HDPE FROM ETHYLENE
LPE LDPE FROM ETHYLENE
EGE ETH GLYCOL FROM ETY.

RENTS BASED UPON REAL COSTS OF GAS AND SALES TO PACIFIC RIM MARKET

	MEG	MEC	HPE	LPE	EGE
	$/MCF	$/TONNE	$/MCF	$/MCF	$/MCF
1985	.59	50.20-	2.00	3.01	.92
1991	.30	44.86-	2.16	3.00	1.45
1997	.26	39.00-	2.60	3.25	2.35
2003	.61	32.59-	3.46	3.88	3.79
2009	.50	25.55-	3.93	4.89	5.02
2015	.22	17.84-	4.28	4.15	6.34

RENTS BASED UPON PROJECTED PRICES OF GAS AND SALES TO PACIFIC RIM MARKET

	MEG	HPE	LPE	EGE
	$/MCF	$/MCF	$/MCF	$/MCF
1985	.62-	.02	1.83	.95-
1991	.51-	.48	1.31	.15-
1997	.42-	.94	1.58	.78
2003	.32-	1.44	1.86	1.88
2009	.16-	2.07	2.22	3.25

2015	.82	2.76	2.61	4.89

RENTS BASED UPON REAL COSTS OF GAS
AND SALES TO U.S. MIDWEST MARKET

	MEG	MEC	HPE	LPE	EGE
	$/MCF	$/TONNE	$/MCF	$/MCF	$/MCF
1985	.57	50.66-	3.29	3.93	1.01
1991	.28	45.37-	3.57	3.99	1.55
1997	.23	39.56-	4.14	4.31	2.47
2003	.58	33.20-	5.15	5.02	3.93
2009	.46	26.22-	5.77	5.31	5.18
2015	.18	18.57-	6.30	5.46	6.52

RENTS BASED UPON PROJECTED PRICES OF GAS
AND SALES TO U.S. MIDWEST MARKET

	MEG	HPE	LPE	EGE
	$/MCF	$/MCF	$/MCF	$/MCF
1985	.64-	1.31	1.95	.87-
1991	.54-	1.89	2.38	.05-
1997	.45-	2.48	2.64	.90
2003	.35-	3.13	2.99	2.01
2009	.20-	3.91	3.45	3.41
2015	.02-	4.78	3.93	5.07

RENTS BASED UPON REAL COSTS OF GAS
AND SALES TO EASTERN CANADIAN MARKET

	MEG	MEC	HPE	LPE	EGE
	$/MCF	$/TONNE	$/MCF	$/MCF	$/MCF
1985	1.90	24.04-	5.60	6.20	2.03
1991	1.73	16.26-	6.09	6.43	2.74
1997	1.83	7.73-	6.90	6.93	3.86
2003	2.32	1.61	8.17	7.84	5.56
2009	2.37	11.84	9.08	8.34	7.08
2015	2.26	23.04	9.91	8.71	8.74

RENTS BASED UPON PROJECTED PRICES OF GAS
AND SALES TO EASTERN CANADIAN MARKET

	MEG	HPE	LPE	EGE
	$/MCF	$/MCF	$/MCF	$/MCF
1985	.69	3.62	4.22	.16
1991	.92	4.42	4.74	1.15
1997	1.14	5.25	5.26	2.29
2003	1.39	6.15	5.81	3.64
2009	1.71	7.22	6.47	5.31
2015	2.06	8.39	7.18	7.29

TABLE 23 - CAPITAL REQUIREMENTS

NOMENCLATURE

NREF	NEW REFINERIES
NPWP	NEW POWER PLANTS
NMOS	NEW MINED OIL SANDS PLANTS
NISO	NEW IN SITU OIL SANDS PLANTS
NBUG	NEW BITUMEN UPGRADERS
NGPE	NEW GAS PROC. AND ETHYLENE PLANTS
NMBP	NEW METHANE-BASED PETROCHEM PLANTS
NETB	NEW ETHYLENE-BASED PETROCHEM PLANTS
NMSP	NEW MISCELLANEOUS PETROCHEM PLANTS
NCBP	NEW COAL-BASED ENERGY TECHNOLOGIES
NPCP	TOTAL NEW PETROCHEM PLANTS
NOED	NEW OIL EXPLOR AND DEVELOPMENT (EXOG)
NGED	NEW GAS EXPLOR AND DEVELOPMENT
NOSP	TOTAL NEW OIL SANDS PLANTS

ALL INVESTMENTS ARE IN CONSTANT 1983 UNDISCOUNTED CAN. DOLLARS FOR WHOLE TIME PERIOD

	NREF MMC$	NPWP MMC$	NMOS MMC$	NISO MMC$	NBUG MMC$
1985		20.4	208.5	781.3	
1991		1567.7	5485.2	1198.4	
1997	670.2	1129.5	10078.8	1861.4	
2003	2139.6	4241.8	17466.8	1836.7	1004.1
2009	2383.8	2761.9	8378.8	1827.0	2594.2
2015	63.9	2323.3	10438.2	2496.2	

	NGPE MMC$	NMBP MMC$	NETB MMC$	NMSP MMC$	NCBP MMC$
1985	1476.8	.0	823.7	326.9	.0
1991	1149.8	438.5	926.1	213.2	.0
1997	1199.4	264.8	903.0	581.3	.0
2003	1433.4	1504.3	1384.3	952.9	821.1
2009	1808.3	940.6	1566.9	940.0	.0
2015	1331.2	443.7	1195.1	379.5	95.0

	NPCP MMC$	NOED MMC$	NGED MMC$	NOSP MMC$	TOTAL MMC$
1985	2814.7		5169.8	989.7	8812.6
1991	2754.7		22010.6	6683.6	33000.0
1997	2971.8		19727.5	11940.2	36300.0
2003	5324.9		6464.4	28307.6	39988.8
2009	5659.3		20721.1	12800.0	43900.0
2015	3397.0		29321.7	12934.4	48300.0