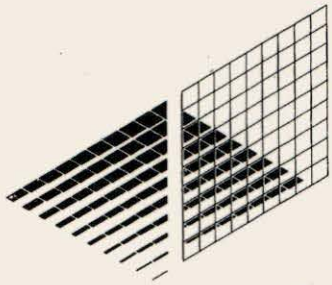
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Gardner Pinfold Consulting Economists Ltd.

Development and Use of Natural Gas: Socio-Economic Impact on the Cape Breton Regional Municipality

prepared for:

Nova Scotia Petroleum Directorate

prepared by:

Gardner Pinfold Consulting Economists Limited
and
Hillary & Associates

March, 1999

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MEMORANDUM

FROM: Study Steering Committee
D. Burchell, J. Whalley - CBRM
A. Crandlemire, G. Hoffman - NSPD

DATE: 14 April 1999

SUBJECT: **GARDNER PINFOLD STUDY: SOCIO - ECONOMIC IMPACT OF NATURAL GAS ON THE CBRM**

Preface

Since this study was commissioned, changes in federal policy have placed the future of coal mining in the study area in serious doubt and uncertainty. It might be supposed that the negative impacts of the Sable Offshore Energy Project (SOEP) on the Cape Breton Regional Municipality have been thus diminished and subsumed by that intervening event. The opposite is true. Intervening damage to the economy of the study area in fact aggravates the negative impacts of the SOEP, especially in regard to the prospect that it will result in a further loss of competitive position if natural gas is available to other areas of the province and not to the Cape Breton Regional Municipality.

For that reason it must be recognized that, where the negative impact of the SOEP might have been addressed in relative isolation, any mitigating measures must now

be formulated in the context of larger problems facing the economy of the study area. As a result, the following recommendations are broader in scope than they otherwise might have been in an attempt to deal with the reality that the negative impact of the SOEP on the study area will occur in the context of enlarged and aggravated economic difficulties.

Recommendations:

1) The Steering Committee accepts and endorses the recommendations which are set forth and more fully amplified in the attached report of the consultants, Gardner/Pinfold and Hillary and Associates. In summary, the recommendations are:

a) In light of the on-going weakness of the CBRM economy and the implications of the closure of CBDC, a framework for ensuring CBRM gains early access to natural gas should be given careful consideration by government;

b) A specific initiative is needed to try to pool resources in the CBRM to promote more effective participation in SOEP and other offshore projects;

c) Programs to provide training for jobs in natural gas distribution should be developed and established at one or more institutions in the CBRM; and

d) The general public would benefit from a review of provincial energy policy aimed at specifying government objectives with respect to the conditions of energy supply and demand in the province, and elaborating initiatives to achieve those objectives.

2) It is the opinion of the Steering Committee that, under present conditions, the measure most directly responsive to the negative impact of the SOEP on the study

area would be to construct without delay between the Strait of Canso and the CBRM a lateral natural gas pipeline adequate to meet the region's domestic and industrial needs, both present and prospective. It is necessary to add that, by itself, such a mitigating measure will not adequately address the economic crisis that now afflicts the study area.

3) Against that background and the possibility that construction of the recommended line may be delayed or abandoned given the deteriorating economic circumstances within the study area, the Steering Committee is impelled to recommend an alternative or supplementary measure.

Under the stress of the present economic crisis, a variety of proposals have been advanced by stakeholders, agencies of government and other interested parties. These include trade union proposals for a continuation of coal mining operations; proposals for the development and promotion of the so-called Sydney Harbour Ports; a tax incentive regime similar to the existing Nova Scotia Equity Tax Credit program but tied to job creation in regions of the province that chronically suffer from abnormally high rates of unemployment; and there are many others. An inherent difficulty is that such proposals are generally uncoordinated and prone to the risk that competing advocates will proceed, if not at cross-purposes, in pursuit of conflicting objectives and thus dissipate resources and support that otherwise might be marshalled effectively through a comprehensive and coordinated approach. What seems to be missing and sorely needed is an over-arching plan supported by a partnership of all levels of government.

Being of that opinion, the Steering Committee recommends the prompt creation of an Economic Recovery Commission with powers equivalent to those of a royal commission to be jointly established by the federal and provincial governments and having a non-partisan membership appointed by the federal, provincial and regional

governments.

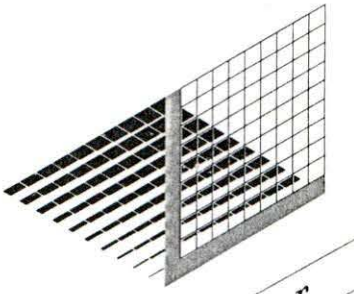
The task of the Commission would be to identify economic priorities through consultation with government agencies, community and other stakeholder groups and to develop, through such a process, both short and long term plans and supporting strategies for the economic recovery of the region. At this juncture it is inappropriate to suggest further specific terms of reference that, in any event, must be settled by the participating governments, but it is the view of the Steering Committee that the Commission should be required to produce a short term plan in 3 to 6 months and a long term plan within 2 years.

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SUMMARY

CBRM ECONOMY AND NATURAL GAS

Over the past 30 years, the CBRM economy has undergone substantial change, reflected in a decline in importance of raw materials and manufactured goods production and an increasing dependence on services as a source of employment and income. This transition is similar to that taking place other parts of Nova Scotia and Canada. But the similarity ends there. The growth in the CBRM service sector, while welcome, has not been sufficiently strong to offset the decline elsewhere in the local economy.

Virtually all socio-economic indicators point to difficulties:

- consistent decrease in employment opportunities;
- relatively low and declining participation rate;
- an official unemployment rate double the provincial average;
- relatively low earned income; and,
- a declining population.

Within the CBRM, there are both optimism and concerns about the potential impact of natural gas. On the one hand, there is hope for improved economic performance arising from participation in offshore exploration and development, and also from lower energy costs through access to gas. On the other hand, there is concern about weaker economic performance arising from the displacement of coal by natural gas to generate electricity.

NATURAL GAS DEVELOPMENT AND ASSOCIATED PROJECTS

Expenditures

Between 1997 and 2007, an estimated $4.0 billion in capital spending is planned for natural gas development, transportation, distribution and associated projects in Nova Scotia. Projected spending levels by project over time are:

Project	$ millions	Timeframe
SOEP Phase I	2,000	1997-1999
SOEP Phase II	1,000	2002-2004
M&NPP	335	1999-2000
NS Distribution System	465	2000-2007
NSPI	230	2000-2004
Total	$4,030	

On-going offshore exploration and other projects arising from access to natural gas (including additions to electrical generating capacity by large industrial users) could add a minimum of $300-400 million to this total over the next decade. Not included in these figures are other possible offshore developments, nor any downstream gas projects such as a petrochemical facility.

Regional SOEP & M&NP Impacts

SOEP and M&NP are having a generally positive impact on the Nova Scotia economy, though the main employment and income impacts are concentrated in the areas of project activity. This is the triangle bounded by Halifax in the south, the Strait of Canso in the northeast, and Amherst in the northwest.

- Several companies and individuals based in the CBRM are competing, and with some success, for SOEP contracts and employment. But the level of participation is relatively low mainly because industrial capacity in the region is limited.

- Nova Scotia content is expected to range between 20-25% of SOEP Phase I expenditures. Nova Scotia content arising from construction of M&NP is expected to be in the 40-45% range. In both cases, most of the content is derived from construction activities. The province has limited capacity to supply materials and equipment, and lacks the specialized vessels and equipment to participate in offshore activities.

Lateral and Distribution System Impacts

Construction of a CBRM lateral and distribution system are determined to be uneconomic as stand-alone projects, based on projected market size and using a conventional cost of service analysis. If the CBRM is to have access to gas as set out in the *Gas Distribution Regulations*, then some form of aid to construct or system-wide cross-subsidization would be required.

Gas distribution system impacts arising from construction are expected to be positive. They will be widely distributed in the province given the extent of the system and the type of the construction work. Local content in most areas of the province should exceed 60%, based on local availability of construction trades, equipment and materials (excluding pipe, which accounts for a small percentage of overall costs).

Future Offshore Projects

Proposed exploration in the Sydney and Laurentian Basins should lead to positive impacts on adjacent coastal areas, in this case, the CBRM. The scale of the impact depends on the type and level of exploration activity. If seismic surveying leads to exploration drilling, opportunities linked to developing and operating a supply base and providing support services could arise.

Future exploration and possible developments on the Scotian Shelf can be expected to have continued positive impacts concentrated in the Halifax area.

ACCESS TO NATURAL GAS

Impact on the Electrical Energy Market

The availability of natural gas in the Nova Scotia market can be expected to lead to competition with other fuels to meet demand for thermal electrical energy. The experience in other jurisdictions shows that natural gas has the potential to displace competing fuels, particularly high-sulphur coal. The main factors explaining the expanding share of gas in the electrical generation market elsewhere are:

- More stringent environmental standards
- De-regulation of the electricity industry
- Low relative costs of gas-fired technology

These factors also can be expected to have an impact in Nova Scotia. NSPI plans to convert its Tuft's Cove generating station to a dual-firing capability (oil and natural gas). It also expects the next addition to system capacity to be fired with natural gas. This could be a plant owned and operated by NSPI, or one built by one of its large industrial customers.

The maximum projected use of natural gas over the study period, 1998-2010, could reduce NSPI's overall coal requirements by as much as one million tonnes. The impact on CBDC coal could be a reduction of no more than 100,000 tonnes from the 1995-97 production level of 2.4 million tonnes. Limiting the impact to this level depends largely on CBDC's continued ability to deliver competitively-priced coal over and above the minimum quantities specified in its long-term contract with NSPI.

If CBDC is unable to continue to produce and sell quantities of coal at NSPI's avoided cost, then demand for CBDC coal presumably would drop to the contract minimum. But it would drop to this level, *regardless of any competition from natural gas.*

The validity of this conclusion rests on three main assumptions:

- The quantity of gas used to generate electricity does not exceed 94,000 MMBtu. This is the combined total of NSPI's contracted volume for its planned Tuft's Cove conversion plus the addition of a 250 MW gas-fired combined-cycle unit. It is possible that in a de-regulated market (should this occur in Nova Scotia), others could build plants and sell electricity into the Nova Scotia market. This would add to the quantity of coal displaced.

- It continues to be uneconomic to convert coal-fired plants to natural gas. The economics of conversion depend critically on a substantially lower unit cost for gas than coal. Available forecasts do not support such a price spread.

- Growth in demand for electricity does not decline from historic levels. Not only does a decline seem unlikely, but NSPI is pursuing sales of electricity in export markets. To the extent NSPI is able to expand into the export market, the negative impact on coal from all sources would diminish.

Impact on the Energy Market

Nova Scotia households and businesses spend about $1 billion annually on energy in final demand applications including space heating, hot water, cooking and process heat. The CBRM accounts for 12-15% of demand. The main energy sources are petroleum products and electricity. Displacing petroleum products (fuel oil, propane and heavy oil) represents the main opportunity for marketing natural gas.

Natural gas enjoys a market share upwards of 50% in central and western Canada. It achieved this largely through relatively low and stable pricing, Achieving this market share in Nova Scotia is likely to take many years because low oil prices leave limited room for the kinds of price differences (30-60%) that allowed natural gas to gain the high penetration rates it experienced elsewhere. Given the likely cost of gas and estimated distribution costs in Nova Scotia, a 10% price difference is more likely, at least in the early years. By 2010, market shares of 35% (residential), 50% (commercial), and 65% (industrial) are projected.

The positive impacts arising from access to and use of gas are of three main kinds: savings due to lower energy costs, reduced greenhouse gas emissions, and more attractive location for industry. The negative impacts are the potential loss of employment and income in the energy distribution sector.

- **Gas in the CBRM**: a market share at the projected level and assuming a 10% price differential would result in annual savings to consumers of about $1.7 million. The value of reduced greenhouse gas emissions and enhanced locational characteristics are not quantified. There is likely to be a small and gradual net loss of jobs in energy distribution.

- **Gas on Mainland Nova Scotia**: a market share at the projected level and assuming a 10% price differential would result in annual savings to consumers of about $10 million. The value of reduced greenhouse gas emissions and enhanced locational characteristics are not quantified. There is likely to be a small and gradual net loss of jobs in energy distribution.

In the event that economics does not support extension of the distribution system to the CBRM, the positive impacts identified would not occur. CBRM may benefit from generally lower oil prices arising from inter-fuel competition, but any such benefits would be modest. On the negative side, the lack of natural gas would mean relatively higher energy costs than elsewhere in the province, and could act as a disincentive from an industrial development standpoint.

RECOMMENDATIONS

1. In light of the on-going weakness of the CBRM economy and the implications of the closure of CBDC, a framework for ensuring the CBRM gains early access to natural gas should be given careful consideration by government.

2. A special initiative is needed to try to pool resources in the CBRM to promote more effective participation in SOEP and other offshore projects.

3. Programs to provide training for jobs in natural gas distribution should be developed and established at one or more institutions in the CBRM.

4. The general public would benefit from a review of provincial energy policy aimed at specifying government objectives with respect to the conditions of energy supply and demand in the province, and elaborating initiatives to achieve those objectives.

INTRODUCTION

1. CONTEXT

Development of the Sable gas fields is at its mid-point, with production expected late in 1999 or early 2000. SOEP received regulatory approval in 1997, following a lengthy review process. For many Nova Scotians, SOEP means jobs and industrial opportunity. In the near future, it will also mean access to natural gas.

Most of the expected average daily production of 530 million cubic feet of gas is destined for export to the US. Interest among prospective users in Nova Scotia in obtaining gas was initially slow to emerge, but by early 1998, several industries including Nova Scotia Power Inc. (NSPI) had signed long-term agreements to take large quantities of gas.

One of the main implications of introducing natural gas into the Nova Scotia market is the displacement of other fuels. In most cases, this is welcomed by consumers since it adds to choice, and also represents competition with the prospect of lower energy costs. Established energy suppliers are less enthusiastic since it means lower margins and possible loss of market share.

The matter is more complex in the case of the Cape Breton Regional Municipality (CBRM). On the one hand, there is concern that if gas is available in the province, it could displace coal in thermal electric generating plants. Coal is a mainstay of the CBRM economy. On the one hand, there is also the recognition that access to gas is essential from an industrial development perspective, particularly if it is available in other parts of the province.

2. OBJECTIVES

The Province of Nova Scotia and the CBRM require an analysis of how the development of the Sable Gas Projects and the availability of gas in the province are likely to affect the CBRM. There is also a need for guidance on what policies can be developed which would maximize benefits and mitigate any potential negative effects.

In view of these needs, the Study has three main objectives:

- To assess quantitatively any opportunities and impacts on the CBRM arising from the development and transportation of natural gas (the Sable Offshore Energy Project, SOEP, and the Maritimes & Northeast Pipeline project, M&NP).

- To assess quantitatively any opportunities and impacts on the CBRM arising from the availability of natural gas in the province. This covers two situations:

  i) where gas is available throughout Nova Scotia, excluding the CBRM; and,

  ii) where gas is available throughout Nova Scotia, including the CBRM. A key element of this analysis is determining the impact on the use of coal by NSPI and how this could affect production and employment at the Cape Breton Development Corporation's (CBDC) Prince and Phalen mines.

- To recommend actions to maximize benefits and minimize any potential negative effects arising from the projects, and the introduction of natural gas into the energy market.

3. APPROACH

To meet these objectives, several tasks are carried out:

- We start with SOEP and M&NP, tracing project spending within Nova Scotia and the CBRM. This forms the basis for determining so-called "Project Impacts". Of interest in this analysis is the level of interest and participation in the projects by companies based in the CBRM. The Project Impact Analysis is a fairly self-contained element of the study.

- Assessing so-called "Energy Impacts" divides into two main parts:

  - impacts of natural gas on *final* energy demand – the use of energy (eg, oil products, electricity, wood) in homes and businesses for heating, hot water, cooking, etc; and,

  - impacts on *primary* demand – the use of energy sources (coal, oil, hydro) for generating electricity.

- To determine these impacts we compare projections of final and primary energy demand *without* gas with cases *with* gas. Specific "Cases" involving various assumptions about gas prices and availability in the province are made to facilitate the analysis.

- The assessment of Energy Impacts is conducted against the backdrop of a range of factors influencing the demand for gas in the province. The key factors are relative energy prices and environmental standards governing emissions.

- The Energy Impact analysis allows conclusions to be drawn about two issues of particular importance:

  - the impact of gas on coal used to generate electricity;

  - the conditions under which gas can compete effectively with alternate energy sources in the CBRM.

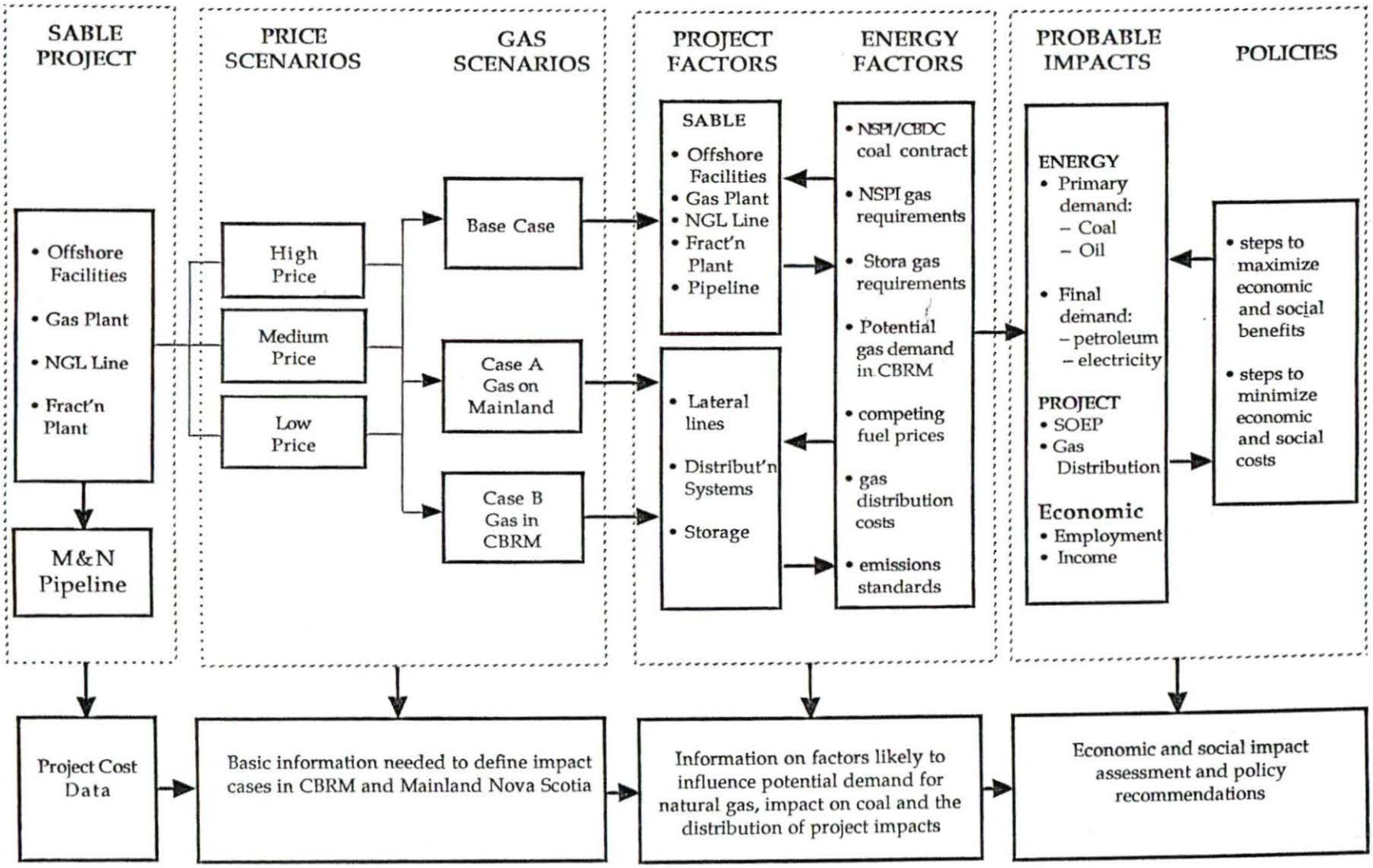
- The Report concludes with recommendations on how positive impacts can be enhanced and negative impacts reduced or eliminated.

The approach is shown in schematic form in Fig. 1.

4. OUTLINE

The report is presented in five chapters plus several appendices. This introduction is followed by an overview of the CBRM economy. Chapter II provides a detailed description of the natural gas projects, and the opportunities and benefits they generate. An overview of potential opportunities for the CBRM arising from future offshore exploration and development projects is set out in Chapter III. This is followed by an assessment in Chapter IV of the potential market for natural gas in Nova Scotia, and how having access or not having access could affect the CBRM. And finally, how the availability of natural gas in the province is likely to affect the demand for coal is assessed in Chapter V. The Appendices provide technical support for the main findings.

FIGURE 1: SCHEMATIC OUTLINE OF THE PROBABLE IMPACTS OF THE SABLE GAS PROJECTS ON THE CAPE BRETON REGIONAL MUNICIPALITY



I.

CBRM ECONOMY

1. HISTORICAL OVERVIEW

Recent Trends in Industrial Activity

The structure of the economy of the Cape Breton Regional Municipality (CBRM) has undergone substantial change since the 1960s, characterized mainly by a shift from goods to services production. Goods-producing industries (eg, fishing, mining, manufacturing, construction) are much less important as sources of employment and income than they were 30-40 years ago. Between 1961 and 1996, the share of employment accounted for by this sector declined from about 46 to just over 26%. An increasingly important service sector is emerging as it has elsewhere in Canada, though it is evolving more slowly than elsewhere. The expansion of service sector activities is marked by growth in the trade and business and personal services industries.

Coal and steel, the dominant goods-producing industries in Cape Breton, declined markedly after World War II with the widespread conversion to oil of electrical generating stations, home heating and ocean and rail transportation. Some 40 collieries closed between 1920 and 1965. Employment dropped to 6,500 from a peak of 17,000. The operator of most of the Island's remaining mines announced their closure in 1965.

The steel industry also faced serious difficulties. It lost its competitiveness as newer technologies developed and the location of steel markets changed. The operator of the mill did not adapt and the Sydney plant grew obsolete and lost the advantage it once had due to its proximity to coal. Employment dropped from about 5,500 at its peak in the 1950s, to about 4,000 in 1968 when the operator decided to close the facility. Coal and steel employed over 20% of the Cape Breton labour force at the time these closures were announced.

The Cape Breton Development Corporation (CBDC) was created in 1967 to rationalize the coal mining industry and to create alternative employment through a program of industrial development. With soaring oil prices following the Gulf crisis of 1973, CBDC instead found itself planning the development of new mines. By 1980, some 4,300 miners were employed. This number declined over the next decade, as improved technology and modern mining techniques were introduced.

An important element in the revival of the mining industry was Nova Scotia's decision to convert its electrical generating capacity to coal. With rising demand from NSPI and the development of export markets, coal production reached the 4.0 million tonne range in 1993, and employed over 2,300. Since then, production difficulties caused output to decline to the 2.4 million tonne range, with employment dropping to about 1,700. Severe production difficulties in 1998 saw production decline to about 1.6 million tonnes. In early 1999, the Federal Government announced its intention to withdraw from the coal mining industry, and to seek private sector operators for the collieries.

The steel plant was saved from closure by the Government of Nova Scotia which continues to operate it through a Crown Corporation, SYSCO. Employment steadily dropped as the plant was down-sized, and reached the 1,500 range in 1985 when the decision was made to modernize it. It no longer relies directly on coal, but has a single electric-arc furnace. It currently employs about 650, but has not operated at full capacity for several years. Government is seeking a buyer to take over the plant.

Other efforts to promote industrial diversification during the late 1960s and early 1970s focussed on large-scale enterprises. At the Strait of Canso (outside the CBRM) a pulp and paper mill was established providing employment for 1,000 in the mill and another 1,000 in the woods. An oil refinery and a heavy water plant were also established, but the former closed in 1980 due to changing market conditions and the latter in 1985 due to a lack of demand for the product. A second heavy water plant (established in Glace Bay in 1975) also closed in 1985. These closures left about 1,000 jobless.

More recent efforts to accelerate development met with limited success. Enterprise Cape Breton Corporation, a federal agency created in 1985 spent some $150 million in the 1985-1990 period to attract new industry. Several businesses opened, but few lasted into the 1990s. A report on this initiative concluded that most of the firms were insufficiently grounded in the community to survive, having set up in the area mainly in response to attractive financial arrangements.

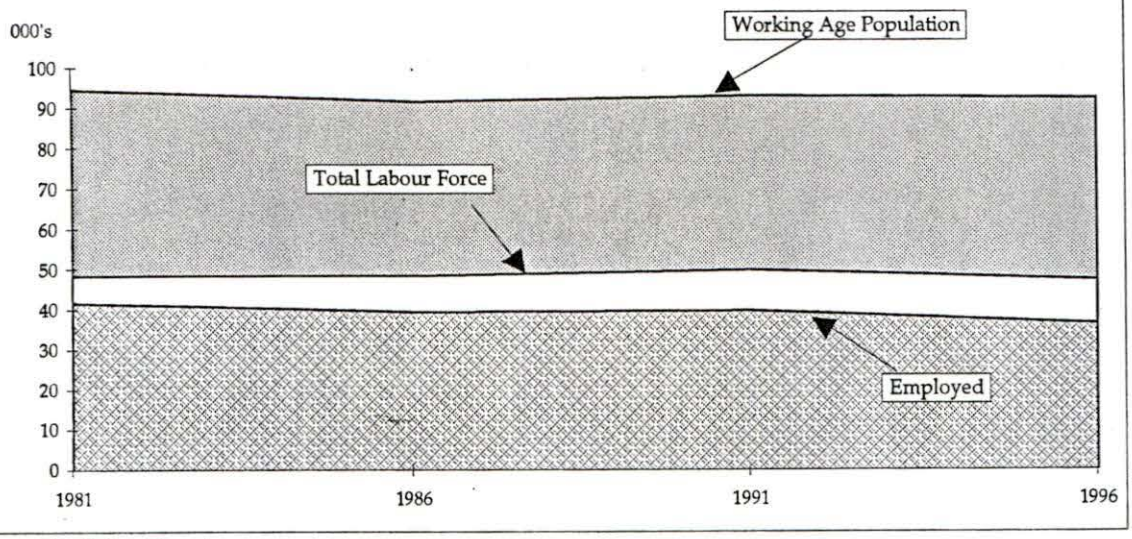
The general decline of the CBRM economy is reflected in the key economic and demographic indicators outlined in the Section 2, below.

2. LABOUR FORCE CHARACTERISTICS

Working Age Population

Between 1981 and 1996, the size of the working age population in the CBRM (aged 15 years and over) *decreased* by just over 7 %, from 127,000 to 118,000 (Fig. I-1). By contrast, the working age population in Nova Scotia *increased* by about 7.5 % (Table I-1). The higher growth in Nova Scotia as a whole is explained by lower net out-migration relative to natural population increase. The relatively high annual net out-migration from the CBRM reflects the area's generally weak economic conditions.

Fig. I-1: Principal Labour Force Statistics,
Cape Breton Regional Municipality,
1981-1996



Source: Statistics Canada.

Table I-1
Principal Labour Force Statistics*
Nova Scotia and Cape Breton Regional Municipality (CBRM), 1981-1996

Cape Breton Regional Municipality:

	Population >15 (000s)	Total Labour Force (000s)	% Labour Force Growth	Employed (000s)	Unemployed (000s)	Participation Rate	Unemployment Rate
1981	95	49		42	7	52.5	15.3
1986	95	51	0.51	40	11	54.1	22.3
1991	93	50	-0.27	40	10	53.3	19.7
1996	93	48	-0.44	37	11	51.2	22.7

Nova Scotia:

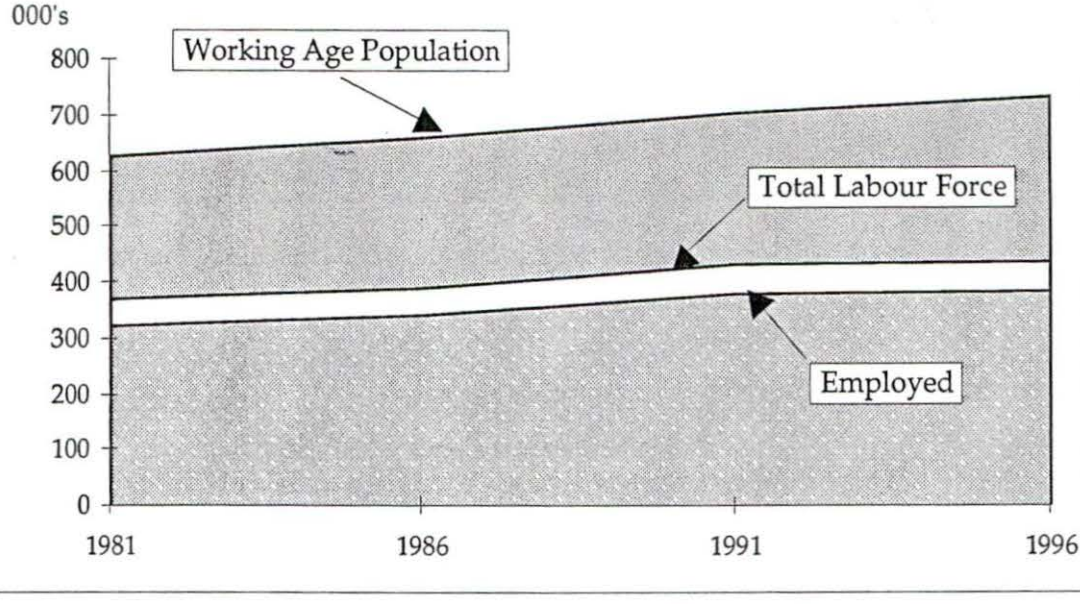
Year	Population >15 (000s)	Total Labour Force (000s)	% Labour Force Growth	Employed (000s)	Unemployed (000s)	Participation Rate	Unemployment Rate
1981	625	369	n.a.	322	38	57.3	10.1
1986	660	392	0.62	341	51	58.4	13.1
1991	706	434	1.07	382	52	61.5	12.0
1996	732	439	0.11	385	54	60.0	11.2

Source: Statistics Canada 71-529 Labour Force Annual Averages, and 71-001 Labour Force Survey.
* Numbers are independently rounded.

Labour Force

The CBRM labour force increased by about 6% between 1981 and 1986, but by 1996 had fallen back to its 1981 level of 48,000, (Fig. I-2). The drop was due mainly to the recession of the early 1990s. It is reflected in a decrease in the working age population (due to demographic factors and migration), and also to a decline in the participation rate.

Fig. I-2: Principal Labour Force Statistics, Nova Scotia, 1981-1996



Source: Statistics Canada.

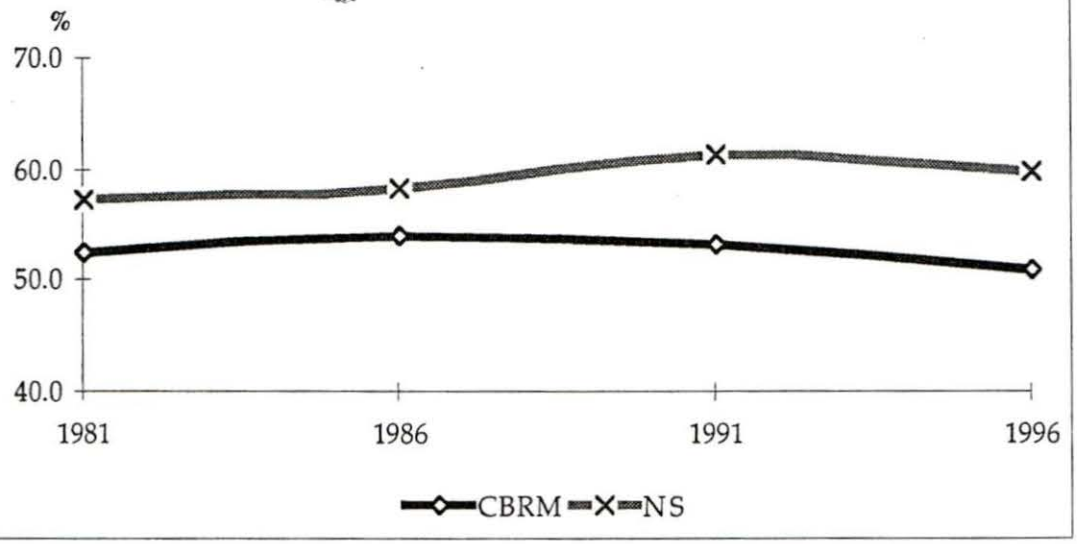
The Nova Scotia labour force, in contrast, grew steadily, rising by 19% between 1981 and 1996 (though there was a slight drop in the growth rate after 1991). This growth is reflected in consistent growth in the working age population and in the participation rate over the period.

Participation Rate

The participation rate measures the proportion of the working age population active in the labour force, whether employed or unemployed. It depends to some extent on social and cultural factors, but is also influenced heavily by employment opportunities. Generally, the greater the employment opportunities the higher will be the participation rate, and vice versa.

The participation rate in the CBRM fluctuated around the 53% mark from 1981 to 1991. It peaked at 54% in 1986, as employment opportunities increased with economic growth in the early 1980s. It declined thereafter, dropping to 51% by 1996 (Fig. I-3).

Fig. I-3: Labour Force Participation Rates, Cape Breton Regional Municipality and Nova Scotia, 1981-1996



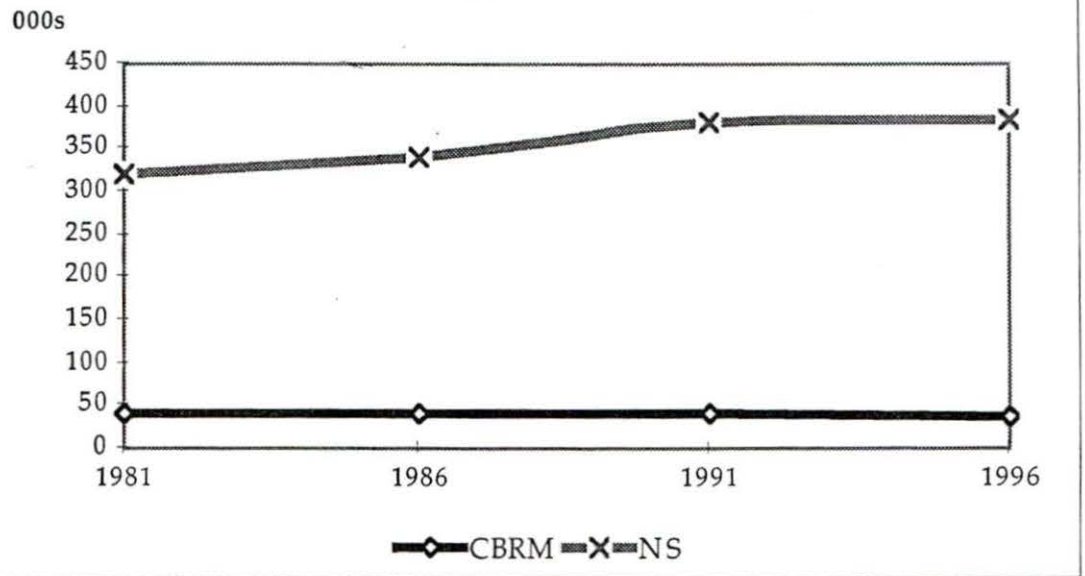
Source: Statistics Canada.

The Nova Scotia participation rate increased steadily from 57% in 1981 to the 60% range in 1996. In 1986, there was a difference of less than 5% points between the CBRM and Nova Scotia levels. By 1991 the gap had widened to some 8 percentage points. Nova Scotia was clearly benefiting from the economic expansion of the late 1980s in a way the CBRM was not. This relatively higher rate reflects not only a more favorable economic climate elsewhere in the province, but also differences in the *type* of employment available. The provincial data are heavily influenced by service sector activity in the Halifax area which offers considerable employment opportunities for women. Opportunities on the same scale are not available in Cape Breton.

Employment

The relative weakness of the CBRM economy is best reflected in employment figures. Employment declined during the recession of the early 1980s, dropping from 42,000 in 1981 to 40,000 in 1986, where it stabilized until 1991 (Fig. I-4). This decline is explained mainly by a drop in primary sector activity. The effects of the several plant closures suffered by the CBRM show up in the statistics in 1986, but are obscured in the aggregate data by improvements in other sectors.

Fig. I-4: Employment, Cape Breton Regional Municipality and Nova Scotia, 1981-1996



Source: Statistics Canada.

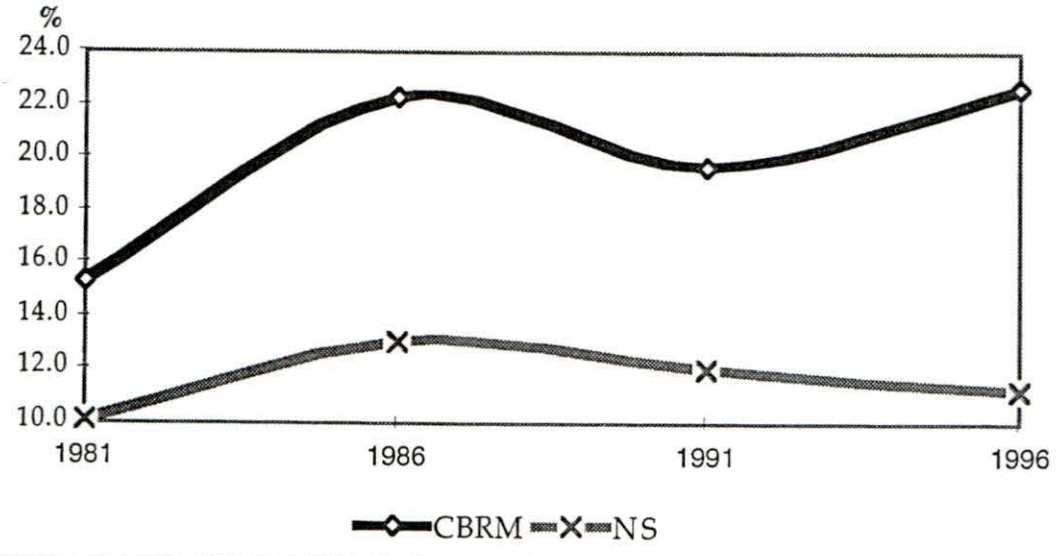
Employment continued to fall after 1991, dropping to a level of 37,000 by 1996 (a 13% decrease from 1981 levels). A review of detailed employment data indicates the sources of decrease came in primary sector activities (mainly fishing), manufacturing and construction.

In Nova Scotia, employment increased from 322,000 in 1981 to 341,000 in 1986, dropped slightly during the recession in the early 1990s, and then climbed to 385,000 by 1996. The increase over the period was about 20%. The transportation, services and trade sectors showed the strongest growth over the period.

Unemployment

The unemployment rate in the CBRM is high relative to the provincial level and is generally about double the national average. The official unemployment rate fluctuated around 15% during the early 1980s, rising to about 22.7% by 1986 (Fig. I-5). By 1991, the unemployment rate had decreased, though this was due largely to a decrease in the participation rate from 1986 to 1996. The drop in employment in the early 1990s caused the trend to reverse, and by 1996 the unemployment rate had climbed to 23%. It is worth noting this increase in the unemployment rate was accompanied by a drop in the participation rate, suggesting that real unemployment was probably higher than the official figures indicate.

Fig. I-5: Unemployment Rates, Cape Breton Regional Municipality and Nova Scotia, 1981-1996



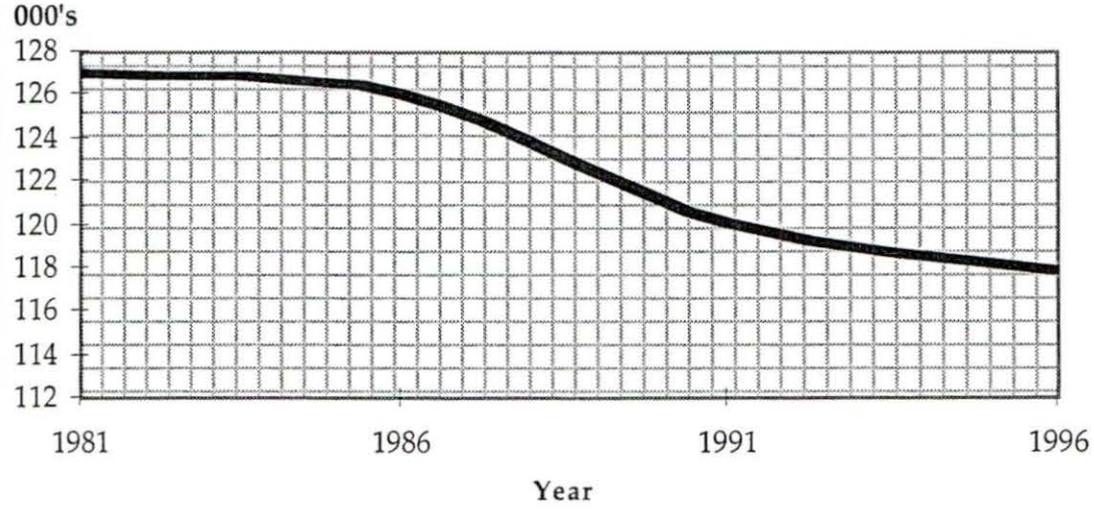
Source: Statistics Canada.

The unemployment rate in Nova Scotia has declined steadily since the late 1980s, dropping to 11.2% in 1996 from 13.1% in 1986. The decline came as the result of sustained employment growth. The decline would have been greater, but as employment opportunities increased, so did the numbers entering the labour force.

Population

With declining economic opportunities, the CBRM population dropped by about 7% between 1981 and 1996 (Fig. I-6). The annual natural increase (births minus deaths) was more than offset by net out-migration over the period, which has averaged about 1,800 since 1986.

Fig. I-6: Population, Cape Breton Regional Municipality, 1981-1996



Source: Statistics Canada.

Nova Scotia experienced consistent net out-migration during the late 1970s, but this was more than offset by natural population increase. During the recession of the early 1980s, out-migration declined and net migration was positive. There was a return to net out-migration with the economic recovery of the late 1980s, but as before, this was more than offset by natural increases. By 1991, the estimated population had increased to 900,000 from 847,000 in 1981. Overall, the Nova Scotia population increased from 847,000 to 909,000 between 1981 and 1996, (a 7.3% increase).

3. INCOME

Money Income

Per capita money income (pre-tax) is substantially lower in the CBRM as compared to the province of Nova Scotia as a whole (Table I-2). In 1986, total pre-tax income for the province of Nova Scotia was roughly, $11,350 per person, while pre-tax income in the CBRM was $8,580 per person (77% of the provincial per capita income). By 1995 the gap had narrowed, with CBRM pre-tax income increasing to roughly $14,400 per person or 89% of the Nova Scotia level, ($16,000 per person).

Table I-2: Income Characteristics, Cape Breton Regional Municipality and Nova Scotia 1986 and 1995

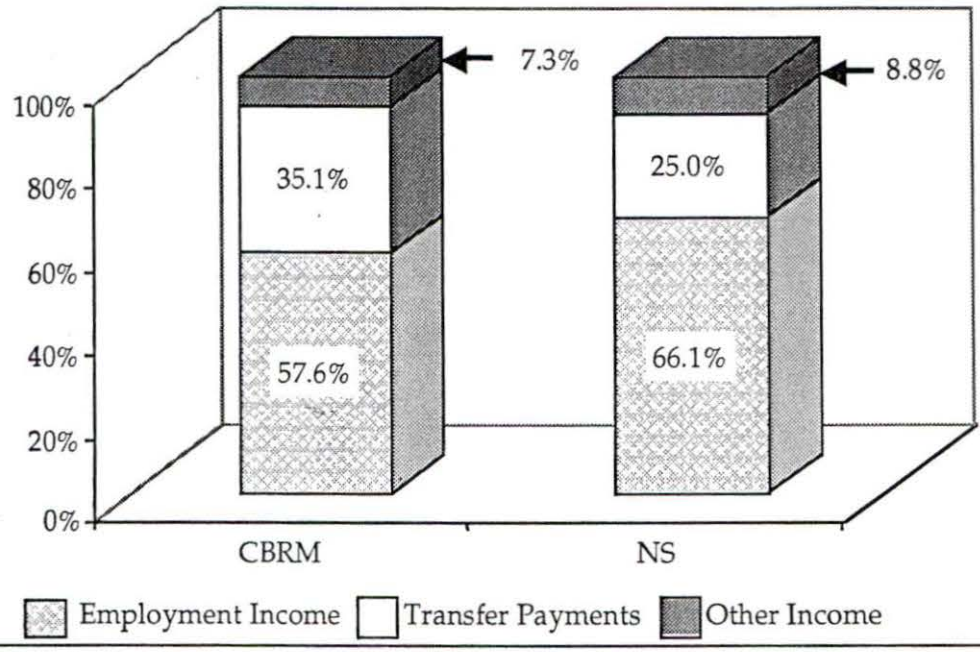
	1986		1995	
	CBRM (1)	NS	CBRM	NS
		($ millions)		
Total Pre-tax Income	1,072	10,572	1,683	14,608
Composition of Total Income:				
Employment Income	696	7,281	969	9,662
Government Transfer Payments	272	1,964	591	3,655
Other Income	104	1,327	123	1,291
		($ thousands)		
Per Capita Pre-tax Income	8.6	11.9	14.4	16.1
As Percent of Total Income:				
Employment Income	64.9%	68.9%	57.6%	66.1%
Government Transfer Payments	25.4%	18.6%	35.1%	25.0%
Other Income	9.7%	12.6%	7.3%	8.8%

Source: Statistics Canada 13-216 and 13-576.
(1) Estimated from 1986 Income Tax Returns by County, Revenue Canada.

Earned Income from Employment

The main source of pre-tax money income is earned income from employment. In the CBRM, however, the proportion of total income derived from earnings is substantially smaller than for the province of Nova Scotia. In 1986, per capita earned income in the CBRM represented roughly 65%of total pre-tax income (Fig. I-7). By 1995, total earned income in the CBRM represented roughly 58% of total pre-tax income. Earned income also declined in relative importance in Nova Scotia over the same period, but to a smaller degree. Limited employment growth and a relatively high unemployment rate account for the increasingly smaller share of total income attributable to earnings in the CBRM. The deterioration in the proportion of income accounted for by employment earnings continued throughout the later part of 1980s and into the 1990s in this region.

Fig. I-7: Composition of Household Income, Cape Breton Regional Municipality and Nova Scotia, 1995



Source: Statistics Canada.

Income from Transfer Payments

Government transfers (mainly unemployment insurance) are the other important source of money income, with investment income and non-employment income making minor contributions. Transfers have become an increasingly important source of income in the Atlantic Provinces generally, but to a relatively greater extent in the CBRM. In 1986, transfers accounted for 25% of income in the CBRM compared with 19% for Nova Scotia (Table I-2). By 1995, government transfer payments had increased to 35% of total money income in the CBRM as opposed to 25% for the province as a whole (Fig. I-7).

Several factors explain the lower earned income in the CBRM: an industry structure with generally lower wage and salary levels, lower participation rates, higher unemployment levels, and a higher dependency ratio (the ratio of non-working-age to working-age population).

4. THE POTENTIAL IMPLICATIONS OF NATURAL GAS

Overview

The CBRM has an important stake in the development of offshore natural gas, and its availability for use in the province. This stake manifests itself in three ways.

- On the positive side, there is potential for improved economic performance arising from participation in offshore exploration and development.
- Securing access to natural gas for domestic, commercial and industrial use also holds positive economic potential, this arising from reduced energy costs and maintaining a competitive playing field vis á vis other areas of the province. Conversely, not securing access could put the region at a competitive disadvantage.
- On the negative side, there is the potential for weaker economic performance arising from the displacement of coal by natural gas to generate electricity.

Participation in Offshore Exploration and Development

The CBRM shares with other parts of the province an interest in having its businesses and individuals participate in offshore oil and gas development. They are doing this by supplying goods and services to the Sable Offshore Energy Project (SOEP), now in the final year of its $2.0 billion Phase I development. Phase II, with an estimated $1.0 billion capital cost, is expected to begin development in 2002 (though this could be advanced, depending on market conditions).

Opportunities for participation in offshore activity also arise closer to the CBRM. Hunt Oil holds petroleum rights to two exploration licences located in Sydney Basin, just off the northeast coast of Cape Breton. Hunt bid $2.1 million for each licence and is expected to conduct a seismic program at some point over the next few years. Depending on the results of the seismic survey, a well could be started sometime before the end of 2003.

Future activity is also possible in the Laurentian Subbasin, to the east of the CBRM. Mobil Canada and Gulf Resources hold petroleum rights over large blocks straddling the boundary between Nova Scotia and Newfoundland. Settling the boundary dispute should lead to exploration activity, given the potentially large reserves the area holds.

While it is too early to speculate about the prospects in these areas, clearly discoveries leading to SOEP-scale developments would have a highly positive impact on the CBRM economy.

Opportunities may also arise from petrochemical development, through use of liquids or ethane as feedstock. SOEP production is expected to yield quantities of liquids (propane, butane and condensate). The sales gas is composed mainly of methane, but also includes ethane. Current plans are for the liquids to be stripped from the gas at the gas plant at Goldboro, and shipped to Point Tupper on the Strait of Canso for fractionation and shipment as raw product. Quantities are considered too small to justify development of a petrochemical facility.

A proposal has been put forward to use ethane from the sales gas as the basis for an ethylene plant to be located in the Strait of Canso area. Little more has been heard of the proposal since it was put forward late in 1998. There is some doubt whether there is sufficient ethane to support even a small plant. Moreover, the producers are likely to be reluctant to strip the ethane from the sales gas, since to do so would reduce the latter's energy content and hence its market value.

Access to Natural Gas

The CBRM shares with other parts of the province an interest in securing access to natural gas. There is the hope that gas would be a potentially cheaper source of energy, resulting in reduced energy costs and higher disposable income. There is also the view that gas represents an important basis for industrial development, given its handling and combustion characteristics compared with oil.

There are concerns within the CBRM that the area may not have access to gas, given the high transportation costs and relatively small market. If this were the case, the fear is that this would place the area at a competitive disadvantage with the rest of the province. This is a reasonable fear, given the already precarious position of the local economy.

Natural Gas as a Source of Electrical Energy

Coal plays an important role in the CBRM, providing direct employment for some 1,700 and injecting over $140 million in operations spending annually into the regional economy. Mine operations account for about 4-5% of the total jobs in the CBRM.

Virtually all of the coal is sold to Nova Scotia Power Inc. (NSPI) to fire its generating stations in Lingan, Point Aconi and Point Tupper. Coal is used to generate about 80% of electricity in Nova Scotia, with about 80% of the coal supplied by mines in the CBRM.

The availability of natural gas could reduce the future demand for CBRM coal as a source of electrical energy. NSPI has announced its intention to convert its Tuft's Cove Generating Station (in the Halifax Regional Municipality, HRM) to gas from oil. While this poses little if any threat to coal, NSPI has also indicated that future additions to generating capacity are likely to be gas-fired. These plans are consistent with those of utilities elsewhere. Natural gas is becoming an increasingly important source of electrical energy, particularly where high sulphur coal is used (eg, U.S. northeast, U.K.). The main driving forces behind the shift to natural gas are the need to reduce greenhouse gas emissions and relative costs.

II.

NATURAL GAS PROJECTS AND DEMANDS

1. DEVELOPMENT, TRANSPORTATION & DISTRIBUTION

Sable Offshore Energy Project (SOEP)

Several discoveries of natural gas have been made on the Scotian Shelf since the early 1970s. Six of these fields are being developed under SOEP, three in Phase I (Thebaud, Venture and North Triumph), and three in Phase II (South Venture, Glenelg and Alma). These fields lie immediately to the east and west of Sable Island, in water depths ranging from 20-80 metres. These fields are estimated to contain 85 billion cubic metres (3.0 trillion standard cubic feet) of recoverable gas reserves.

SOEP development began late in 1997, with Phase I gas production expected to come on stream late in 1999. Average daily production (sales gas) is expected to be in the 508 MMscf range. This level will be maintained by bringing on additional fields as required. At this production level, Phase II is expected to come on stream in 2007. The project life is estimated at 25 years.

SOEP consists of five main components (these are illustrated on the map in Fig. II-1):

- Offshore wells: engineering, drilling, completion, production and maintenance. These are located at the offshore project site around Sable Island.

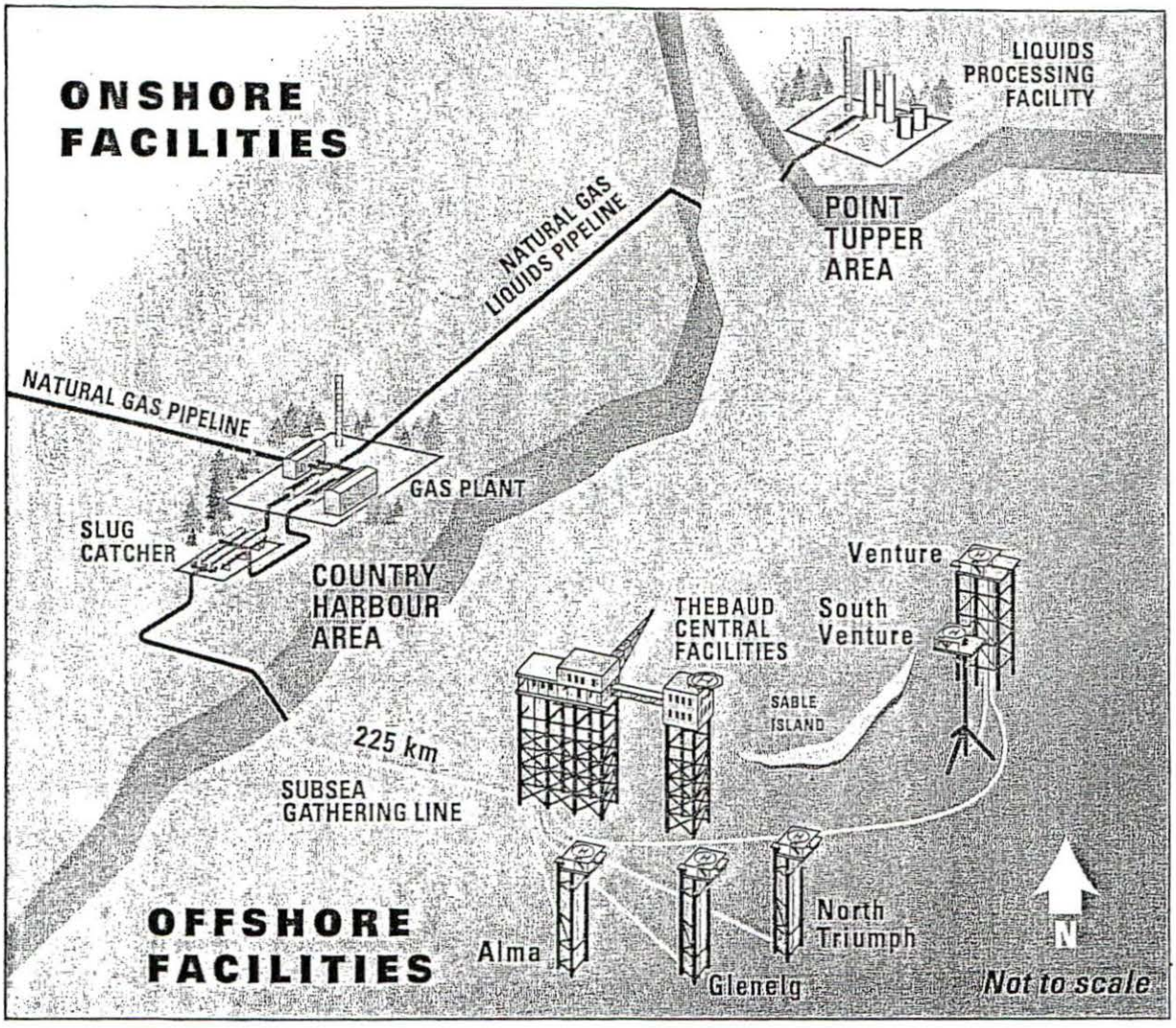
- Offshore production platforms: engineering, fabrication, installation, operation and maintenance. These are located at the offshore project site around Sable Island.

- Pipelines: engineering, fabrication, installation operation and maintenance of main subsea pipeline, interfield flowlines, and onshore liquids pipeline. These are located (respectively) at the offshore project site around Sable Island, between the project site and the landfall at Country Harbour, and between the Gas Plant at Goldboro and the fractionation plant at Point Tupper.

- Onshore facilities for process gas and liquids: engineering, construction, operation and maintenance.

- Project management.

Fig. II-1: SOEP Onshore and Offshore Facilities



Capital costs for the project are estimated at $3.0 billion, with $2.0 billion spent in Phase I and $1.0 billion in Phase II. Annual operating costs are estimated at $85 million. The project is being implemented by SOE Inc., a company jointly owned by the project partners: Mobil, Imperial, Shell, Nova Scotia Resources Limited and Mosbacher Operating Ltd.

Maritimes and Northeast Pipeline Project (M&NPP)

Gas will be transported to markets in the U.S. via a 558 km main transmission pipeline (the M&NPP) across Nova Scotia and southern New Brunswick (Fig. II-1). Within Nova Scotia (234 km), it traverses the northeastern part of the mainland, in a more or less straight line, between the gas plant at Goldboro in Guysborough County and the border with New Brunswick just north of Amherst.

The pipeline will be constructed in 1999, with construction scheduled for completion late in the year to coincide with the start-up of SOEP gas production. Two construction spreads are envisaged: one working westward from Goldboro to Oxford, and a second from Oxford to Tidnish. Total capital cost is estimated at $570 million, with about $244 million spent on facilities in Nova Scotia.

Nova Scotia Laterals, Distribution System and Associated Projects

Planned and proposed projects directed towards distribution and consumption of natural gas in Nova Scotia fall into three main categories:

- Laterals for which applications have already been made to the National Energy Board (NEB). These are the Halifax Lateral needed to deliver gas to NSPI for its Tuft's Cove generating station, and the Point Tupper Lateral, needed to deliver gas to several industrial customers in the Strait of Canso area.

- Laterals and distribution system needed to serve residential, commercial and industrial customers within Nova Scotia.

- Construction of electrical generating facilities.

Laterals: According to the Nova Scotia *Gas Distribution Policy and Regulations*, within seven years gas should be available to all counties in the province, with potential access available to at least 62% of dwellings. This implies construction of several laterals, with an estimated capital cost in the range of $225 million.

Distribution Systems: According to the Nova Scotia *Gas Distribution Policy and Regulations*, some 200,000 mainland households should have the option of using natural gas within seven years. This includes some 27,000 dwellings in the CBRM. This implies installation of distribution systems in all urban and many rural areas, with a total pipe length estimated at 3,500 km. Total capital cost is estimated to be in the $140 million range, with an additional $100 million required for hook-up to distribution mains. For purposes of analysis, we assume a build-out over 3-5 years in some of the larger communities.

Tuft's Cove Conversion: This is planned for 1999, with in-service scheduled for 2000. Capital costs are in the $30 million range.

New NSPI Generating Capacity: NSPI anticipates a need to expand system generating capacity by the year 2004. A 300 MW gas-fired combined-cycle generating station is in the early planning stages. This unit is expected to cost in the range of $200 million, and for purposes of this analysis is assumed to be constructed over a three-year period (mid-2001 to mid-2004).

Conversion to Gas: To assess the impact of converting to natural gas it is necessary only to determine the net costs – the costs attributable exclusively to the availability of natural gas. At the assumed prices, savings due to gas are likely to be minimal. This means conversions would take place, if at all, *only* when users would otherwise replace their equipment. Thus costs, with and without gas are the same, so the net effect is zero.

Expenditures for these projects are estimated at $790 million (Table II-1).

Table II-1
Capital Cost Estimates for Projects Associated with the Availability of Natural Gas in Nova Scotia

	($ millions)
Lateral (1) to:	
Halifax	100.0
Point Tupper	22.1
Antigonish	8.4
New Glasgow	5.4
Truro	4.5
Amherst	4.2
Digby	50.0
Yarmouth	55.4
Sydney	35.0
Other	15.0
sub-total	300.0
Distribution Systems and hook-up	
Mainland NS (2)	225.0
CBRM (3)	35.0
NSPI Tuft's Cove Conversion (4)	30.0
NSPI System Expansion (4)	200.0
Total Project Expenditures	790.0

Source:
1. Maritimes and Northeast Pipeline estimates for all laterals, excluding Digby, Yarmouth and Sydney, which are estimated based on unit costs of $250,000/km.
2. Total length of 3,000 km @ $40,000/km plus $85 million for hook-up.
3. Total length of 500 km @ $40,000/km plus $15 million for hook-up.
4. NSPI for Tuft's Cove and System Expansion estimates.

2. PROJECT OPPORTUNITIES

SOEP

In assessing opportunities and benefits, it is important to understand that contracting for offshore projects tends to occur on a global scale, involving large and highly specialized companies. From a locational perspective, the work needed to complete a project can be divided into three categories. Activities:

- taking place at or near the project site, relying on conventional contracting and supply capabilities (eg, civil construction, marine and air transportation);
- taking place at or near the project site, relying on specialized contracting and supply capabilities (eg, drilling development wells, installing offshore facilities and pipelines); and,
- which could take place anywhere, but where local participation depends on the interest and capabilities of local contractors (eg, design engineering, fabrication of structures and facilities).

In these respects, SOEP is no different from other large offshore projects. The main contractors are all well-known international firms. Until about a decade ago, the procurement process for large offshore projects tended to revolve around fixed-price, lump-sum contracts. This approach had certain advantages for both parties, but also had major disadvantages, including lack of flexibility and high costs in the event of design changes. This approach also made it difficult for local companies to get involved, since they invariably lacked the capacity to bid and had little or no leverage to participate as sub-contractors.

SOEI has adopted an Alliance approach to contracting. Contractors are selected on the basis of performance, rather than price. They enter into a partnership with SOEI, with established cost targets and a mechanism for sharing savings. Generating benefits for local industry is among the factors taken into consideration in judging performance. Instead of detailed specifications issued by SOEI, technical solutions to particular challenges are provided by the contractors who work closely with SOEI and other Alliance members. This introduces considerable flexibility, and also allows faster implementation of the project. And since contractors are not bound by lump-sum contract constraints, more flexibility is built-in to promote participation by local contractors.

The various project activities outlined above present a range of opportunities for Nova Scotia companies and individuals. The extent to which provincial interests are taking advantage of these opportunities depends on the location and nature of these activities, and the interest and capability of local companies and individuals. It also depends on their interest and capacity for entering into joint-venture arrangements with Alliance members.

With SOEP (Phase I) past the half-way point and all main contracts awarded, preliminary estimates of Nova Scotia content are available. These show that up to the end of 1998, Nova Scotia content stood at about 22%. Table II-2 shows the main Alliance partners and the Phase I contracts for which they are responsible. Much of the international spending falls into the category requiring highly specialized skills (eg, project design and management) and equipment (eg, drilling rigs, lift barges, pipelaying vessels) not available in Canada. By the end of the project (Phase II), SOEI expects this to rise to the 30% range, with about 17% spent in the rest of Canada, and the balance (53%) spent internationally.

Table II-2
Content Estimates for Major SOEP Phase I Contracts

		Percentages		
Contractor	Scope	N.S.	R.O.C.	Foreign
Allseas Canada Limited	Offshore Pipeline	26.00	19.00	55.00
Saipem (UK) Limited	Transport/Install	11.00	3.00	86.00
BBA	Onshore Facilities	89.00	11.00	0.00
Kvaerner Oil & Gas	Topsides	0.01	0.05	99.40
Peter Kiewit & Sons	Main Jackets	0.00	0.00	100.00
MMI/Brown & Root	Topsides North Triumph	96.00	4.00	0.00
MMI/Brown & Root	Early Jackets	76.90	0.00	23.10
Fabco/CKT	Living Quarters	70.00	0.00	30.00
Agra Monenco/Brown & Root	Front End Engineering	10.00	60.00	30.00
Agra Monenco/Brown & Root	Project Management	10.00	30.00	60.00
Elsag Bailey	Automation Systems	12.00	54.00	34.00
Rowan/Sante Fe	Well Construction	20.00	30.00	50.00
Weighted Average		30.00	17.00	53.00

Source: SOE Inc.

M&NPP

Preliminary content estimates for the main transmission line (M&NP) indicate contractors expect to spend $100 million on goods and services in Nova Scotia (42% content). The contract for construction of the main transmission line was awarded to BFC-Marine, an Alberta-based joint venture company. Some sub-contracting opportunities will be available for local companies (mainly in land clearing and trucking). The main contractor proposes to hire locally as much as possible, and about 70% of the construction workforce is expected to be Nova Scotian. The main source of local impact will arise from construction labour, equipment purchases and rentals, accommodation, and the supply of construction materials.

Laterals and Distribution System

Construction of most of the laterals and a Nova Scotia distribution system would take place over the 2000-2010 period. The Point Tupper and Halifax laterals are scheduled to be constructed in 1999, though the Halifax lateral may not be built until 2000. There are abundant opportunities for individuals and companies to participate in construction and operation. These opportunities arise throughout the province, given the nature of the system.

Much of work in lateral and distribution system construction is familiar to contractors experienced in civil works such as road building and installation of water and sewer lines. But there are important differences in approach and equipment requirements. Also the inspection and testing requirements are much more stringent. Accordingly, experienced contractors from central and western Canada are likely to be involved in the early years. To keep costs down and to enhance their opportunities to participate, they would be interested in joint ventures with local contractors. Local contractors would benefit through technology transfer, but at the same time, they would contribute valuable knowledge about local conditions.

At peak in the 2003-2005 period some 500-700 are expected to be employed annually at various locations in the province. Construction would be seasonal, generally during the April-October period. Within the CBRM, construction of the 500 km distribution system would take 3-4 years, and could involve as many as 100 during the seasonal peak. There should be an adequate supply of skilled labour in the province, though special training would be required for fusion welders engaged in installation of plastic pipe for the distribution system. Training programs are of relatively short duration (a matter of a few days for certified welders) and could be offered through community colleges or union locals.

3. PROJECT BENEFITS

Contracting

The type and distribution of benefits within Nova Scotia depend largely on the type of activity, where initial expenditures are made, and the degree of involvement of local contractors.[1] In reviewing these factors, it is clear that a high proportion of expenditures takes the form of direct employment income. This suggests that the resulting impacts would tend to be localized around the area where the activities take place.

[1] For further information on the types of opportunities, *see SOEP – Socio-Economic Impact Statement*, Vol. 4, Section 8.

- **SOEP** activities fall into three main categories: services (engineering management, supply), fabrication of steel structures (jackets and topsides), and construction contracting (gas plant, fractionation plant and pipe coating). Activities are concentrated in four areas of Nova Scotia – the Halifax Regional Municipality (services and fabrication), Country Harbour area (landfall facilities and gas plant), Strait of Canso (fractionation plant and liquids pipeline), and Sheet Harbour (pipe coating). Companies are involved to varying degrees in:

  - project management
  - engineering and design
  - fabricating offshore facilities
  - constructing onshore facilities
  - supplying materials and providing support services
  - providing marine and air transportation

- **M&NP** activities and the contracting needed to support them are concentrated along the pipeline route from the Gas Plant in Goldboro to the New Brunswick border.[2] Construction is expected to commence in April or May of 1999. It is too early to tell how Nova Scotia firms could get involved, but among the more likely areas are:

  - providing professional services including surveying, inspection and testing
  - providing services for land clearing and preparation of right of way
  - supplying construction materials
  - supplying heavy equipment services (eg, truck bulldozer, backhoe, etc) and
  - providing accommodation and catering services

- **Lateral and Distribution System** activities and the contracting needed to support them are distributed throughout the province.[3] Opportunities for participation include:

  - surveying and site preparation
  - engineering and design
  - construction contracting
  - sub-contracting trucking and heavy equipment services
  - sales, service and leasing vehicles and equipment
  - supplying pipe and fittings
  - supplying materials including sand, gravel, concrete and asphalt
  - providing accommodation and food services

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2 For further information on the types of opportunities, see *Proposed Maritimes & Northeast Pipeline Project, Country Harbour, Nova Scotia to St. Stephen, New Brunswick, Corridor Selection – Environmental and Socio-Economic Impact Assessment*, Annex 4, Socio-Economic Report, Sections 1 and 4; and also the *Socio-Economic Impact Assessment and Public Consultation Report*, for the Halifax and Point Tupper Lateral Pipeline Projects, Sections 1 and 4.

3 For further information on the type of opportunities available through lateral and distribution system construction see the Socio-Economic Impact Statements contained in the applications for natural gas distribution franchise submitted to the Nova Scotia Public Utilities and Review Board by Maritimes NRG (Nova Scotia) Limited and Sempra Atlantic Gas, January 1999.

Employment

The job opportunities linked to these project activities number in the thousands. By main category of activity they include:

SOEP PROJECT COMPONENTS			M&NPP	NS DISTRIBUTION SYSTEM
Services	**Fabrication**	**Construction**	**Pipeline and Laterals**	**Distribution System**
project manager engineer accountant office staff supply base staff marine crew air crew drilling services inspection testing catering staff	engineer planner supervisor pipe fitter plate fitter welder (various certifications) computer technician electrician instrument fitter and technician	engineer foreman pipefitter welder carpenter equipment op. bulldozer crane truck electrician instrument fitter mechanic labourer	engineer foreman equipment op. drill sideboom bulldozer backhoe ditcher tow tractor low bed truck fuel truck pump welder mechanic powderman inspection testing	foreman welder (steel and plastic) equipment op. drill backhoe concrete cutter truck labourer helper inspection testing

4. PARTICIPATION BY CBRM FIRMS

Several companies and individuals based in the CBRM are competing, and competing successfully, for SOEP contracts and employment. But the level of participation is relatively low and limited mainly to pipe fabrication for the onshore facilities, and fabrication of some topsides facilities components for the offshore platforms. Total CBRM content during Phase I is estimated to be in the range of $10-12 million. This excludes any employment income earned by individuals working on other project components (eg, drilling rigs, onshore construction).

What is discouraging is that so few CBRM firms are showing an interest in participating. For each of the 25 sub-contracts related to onshore work at the Strait of Canso (the most accessible SOEP opportunities), bids were received from at most 1-2 Cape Breton firms. Competitiveness is also an issue. Cape Breton firms won just five of the 25 contracts (two going to a single CBRM firm and three to two Strait area firms). About half of the Strait of Canso contracts were won by firms based in the HRM.

With respect to interest more generally, by mid-1998, 60 firms from Cape Breton had registered with BIDS, the point of entry to receive SOEP information and bid documents (Table II-3). Of these, 25 are based in the CBRM, and the rest mainly in the Strait area. By contrast, some 850 firms based on mainland Nova Scotia are registered.

Table II-3
Nova Scotia Firms Registered to Bid on SOEP Contracts

	Number
Nova Scotia (mainland)	850
Cape Breton (outside CBRM)	35
CBRM	25
Total	900

Source: BIDS Nova Scotia Limited.

5. CONTENT ESTIMATES

By applying the content estimates from Table II-1 to project expenditure data obtained from the proponents, it is possible to develop a spending profile by impact area and over time (Table II-4). Content figures beyond 1998 are preliminary estimates only (for both Phase I and II). SOEP impacts are concentrated in the HRM and Strait of Canso areas. M&NP impacts are widely distributed, though with some concentration along the pipeline route.

From the expenditure estimates in Table II-4 it is clear that the industrial impacts from SOEP and M&NP are relatively small in the CBRM. This can be attributed mainly to a lack of industrial capacity. Few firms have the capacity to compete effectively for contracts. To do so, they must be competitive in price, quality, delivery and service.

Table II-4
Base Case
Estimated SOEP and M&NP Expenditures by Impact Area, 1998-2010
(1997 $ millions)

	SOEP				M&NP			
Year	NS (1)	CBRM	Other (2)	Total	NS (1)	CBRM	Other (2)	Total
Phase I								
1997	21.1	0.0	76.9	98.0	-	-	-	-
1998	204.8	5.0	709.3	919.1	-	-	-	-
1999	273.3	6.0	602.5	881.8	100.0	0.0	130.0	230.0
2000	65.8	0.0	63.5	129.3	-	-	-	-
2001	49.5	0.0	18.4	67.9	-	-	-	-
Phase II								
2002	92.4	0.0	89.1	181.5	-	-	-	-
2003	179.4	4.0	160.9	344.3	-	-	-	-
2004	106.1	3.0	106.7	215.8	-	-	-	-
2005	81.1	0.0	86.6	167.7	-	-	-	-
2006	61.6	0.0	22.8	84.4	-	-	-	-
2007	88.8	0.0	48.1	136.9	-	-	-	-
2008	119.9	0.0	75.0	194.9	-	-	-	-
2009	65.4	0.0	24.2	89.6	-	-	-	-
2010	65.4	0.0	24.2	89.6	-	-	-	-
Total	1,474.6	18.0	2,108.6	3601.2	100.0	0.0	130.0	230.0

(1) All of Nova Scotia excluding the CBRM.
(2) Expenditures made outside NS.

Source: Sable Offshore Energy Inc. and Maritimes & Northeast Pipeline.

This lack of capacity is largely due to structural issues in the CBRM economy. The economy is heavily dependent on resource-based industries. The basis and opportunity for developing the kind of manufacturing and service capacity needed to participate in offshore projects has not been present in the local economy. Indeed, there is a limited basis for participation within the economy of Nova Scotia as a whole. The lesson from other jurisdictions is that it takes many years and *consistent project activity* for such capacity to develop.

It is too early to tell what participation levels may be achieved during construction of the CBRM lateral and distribution system. It is reasonable to expect that a substantial share of the overall $70 million estimated capital cost would remain in the local economy. Though the work involves a type of construction activity with which local contractors are familiar, some outside expertise would be required. Netting out spending on non-local contracting and the cost of imported materials (mainly steel and plastic pipe and fittings), we would expect upwards of 60% of the cost to be spent on goods and services supplied locally.

III.

PARTICIPATING IN FUTURE OFFSHORE PROJECTS

1. POTENTIAL PROJECTS

Exploration

In the over 40 years of exploration in the Nova Scotia offshore area, the petroleum industry has acquired over 300,000 km of seismic data and has drilled 153 wells. This has resulted in 22 significant discoveries containing recoverable reserves of over 6.4 trillion cubic feet (TCF) of natural gas and 220 million barrels of oil and condensate. The Geological Survey of Canada (GSC) estimates these discoveries represent about 35% of the gas reserves and 20% of the oil reserves predicted to exist in Nova Scotia's offshore area.

There are two projects, so far:

- SOEP, accounting for 6 of the 22 significant discoveries, and about half the 6.4 TCF of recoverable reserves. Phase I, involving three of the six fields is nearing completion. Phase II is expected to begin development in 2002.

- Cohasset/Panuke (COPAN), a small oil field, began production in 1992 and is expected to produce 45-50 million barrels (MMbbl) of light oil by the time the field is abandoned, possibly in 1999. Further drilling is currently underway to try to extend the life of the project.

Looking ahead, it is likely that at least 3-4 of the other significant discoveries will be developed over the next decade, now that the SOEP infrastructure is in place. It becomes economic to develop smaller fields once offshore production and transportation systems and onshore processing and transportation systems are established. Several significant discoveries exceed the 100 billion cubic feet (BCF) threshold considered to be economic.[1] Most of these lie in the Sable basin where SOEP is located. The timing of their development could depend on requirements to maintain SOEP gas production at an optimal level.

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[1] For more information on the size and location of significant discoveries, see Canada-Nova Scotia Offshore Petroleum Board, *Technical Summaries of Scotian Shelf Significant and Commercial Discoveries*, 1997.

The Scotian Shelf and adjacent regions in the 400,000 km^2 Nova Scotia Offshore Area hold eight other promising geological areas (these are identified on the map in Fig. III-1):

- **Laurentian Subbasin**: this area to the east of Cape Breton contains some 300 promising structures based on seismic analysis, but no wells have yet been drilled. Characteristics are similar to the Sable Subbasin. The GSC estimates 8-9 TCF of gas reserves and 600-700 MMbbl of oil in the area. Exploration is awaiting resolution of the boundary dispute between Nova Scotia and Newfoundland.

- **Sydney Basin**: two wells drilled in this area discovered shallow gas bearing sands. The structural characteristics suggest the basin should contain many other gas plays. That the area contains extensive and thick coal reserves provides encouragement that gas reservoirs may be discovered. Hunt Oil holds exploration licences for two blocks in the area.

- **Georges Bank**: is similar geologically to the Sable subbasin. Resource estimates are 5.3 TCF of gas and 1 MMbbl of oil. A moratorium on exploration has prevented drilling, so the potential is unknown. Future activity depends on whether or not the moratorium is extended after its expiration in 2000.

- **Fundy and Shelburne Basins**: these areas are considered prospective for hydrocarbons. They contain thick sediments, but only a few wells have been drilled to evaluate them.

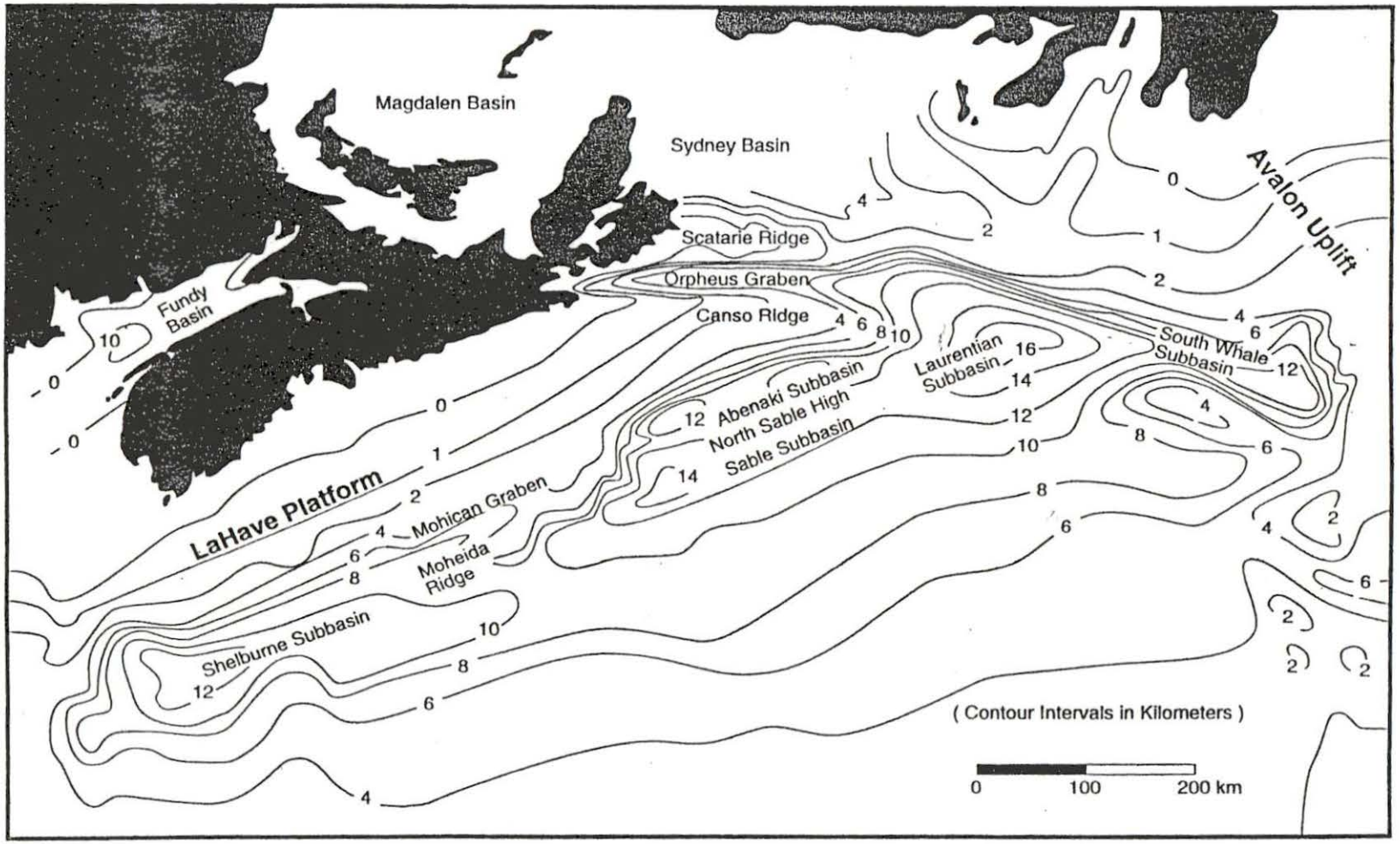
- **Abenaki Carbonate Bank**: this extensive structure running along the edge of the Scotian Shelf to the southwest of Sable Island has been lightly explored. COPAN produces from only a small part of this structure; at least three other plays remain to be explored.

- **Deeper reservoirs and deep water slope**: there is possible potential in the Scotian Basin in the deeper structures lying under the SOEP fields. These structures await further definition. Similarly, there may be potential in the areas seaward of the Scotian Shelf slope in waters exceeding 2000 m depth. Advances in seismic technology and deep water drilling techniques should allow exploration in these areas in the future.

When exploration activities may begin in these areas is not known with certainty. Seismic work in the Sydney Basin should commence some time within the next five years as a condition of the licence. Drilling would follow if encouraging plays are identified. A similar timeframe is possible for the Laurentian Subbasin.

Elsewhere on the Scotian Shelf, there are work commitments totaling over $160 million. Mobil Oil holds petroleum rights to two exploration licences to the west of Sable Island. Extensive seismic work and at least two wells are expected during the next five years. Chevron holds petroleum rights farther to the southwest. Extensive seismic work is also expected here, with the likelihood of two wells over the next five years.

Fig. III-1: Scotian Basin and Sub-Basins



Source: Canada-Nova Scotia Offshore Petroleum Board, Technical Summaries of Scotian Shelf Significant and Commercial Discoveries, March 1997.

Development

What happens during development, and where, is dependent on the nature and extent of offshore activities. Confining our attention to the Sydney and Laurentian Subbasins, what is possible over the next decade may be summarized as follows:

- **Logistical and Service Support** for development (as well as exploration) drilling in the Sydney Subbasin and the Nova Scotia portion of the Laurentian Subbasin would be met from facilities in the CBRM. There are excellent ports (eg, Sydney, North Sydney and Louisbourg) suitable for development as a supply base. Sydney airport would provide an excellent base for helicopter support. Companies providing technical support for rig operations may also open a forward office in the CBRM during exploratory drilling. Other services such as catering and warehousing are also likely to be based in the CBRM, close to the marine and air transport facilities.

- **Field Development**: should exploration in the Sydney and Laurentian Subbasins result in the discovery of commercially recoverable reserves, this would lead to field development. The timing is dependent largely on economics, with energy markets playing an important role. Generally, fields are developed within 5-10 years of discovery. Time is required to determine the size of the reserves (delineation drilling), design the production system, meet regulatory approvals, and implement the project. But fields can take much longer to reach the development stage. SOEP, for example, originally discovered in 1979 and scheduled for development in the mid-1980s, was put on hold due to weak markets and not developed for another decade.

  Development of a field in the Sydney and Laurentian Subbasins would trigger a range of onshore demands. The type and scale of demands depend on the size of the discovery and whether it is oil or gas. Demands may be similar to those experienced with SOEP or COPAN. Regardless of what is discovered, there is need for shore support (eg, supply base) for offshore work. Offshore facilities, whether fixed or floating platforms, need to be built. Fixed platforms are more likely in the relatively shallow water of Sydney Basin. Floating facilities are possible in deeper water (Laurentian Subbasin), particularly if oil is discovered.

  Transportation of hydrocarbons to shore may be by pipeline (if gas), or tanker (pipeline is also possible, but only if quantities are substantial). Facilities onshore would include a gas processing plant and pipeline to markets, if gas. Oil may be shipped directly to refineries from the offshore facilities (as is the case with COPAN), or could be shipped via shuttle tanker to shore facilities and then transshipped to markets.

Downstream Projects

SOEP gas is composed mainly of methane (88%), but is rich also in ethane (5%) and natural gas liquids (butane, propane and condensate). These are all used as feedstocks for the production of a wide array of primary petrochemicals, which may then be further processed into intermediate petrochemicals and finally into end products.

At the most general level, there are essentially two options for using SOEP or possibly other, yet to be discovered gas, for primary petrochemical production (see Fig. III-2).

- **Methane**: Instead of using the methane stream for direct sales gas to energy users, it could be used for production of such compounds as methanol, acetylene and ammonia.

- **Natural Gas Liquids**: Instead of using the NGL stream for direct processing and sale as ethane, propane and butane (a class of compounds known as paraffins), the NGls could be processed into olefins (ethylene, propylene and butylene) or aromatics (benzene, toluene and xylenes).

The idea of a petrochemical complex goes beyond primary petrochemical production. The primary products are mixed with other chemicals to produce a broad range of intermediate products and derivatives for use in the manufacture of such compounds as adhesives, plastics, solvents, pharmaceuticals and fibres. Some of the possibilities are shown schematically in Fig. III-3.

Initial studies by the Nova Scotia Department of Natural Resources concluded that the development of a petrochemical complex based on SOEP gas is not feasible.[2] A scoping study identified the possible options and narrowed these down to three, all using methane as a feedstock: methanol, ammonia and urea. These options were assessed in greater depth.[3] The economics of developing a complex are weak mainly because the methane has a higher value as an energy source then as a petrochemical feedstock.

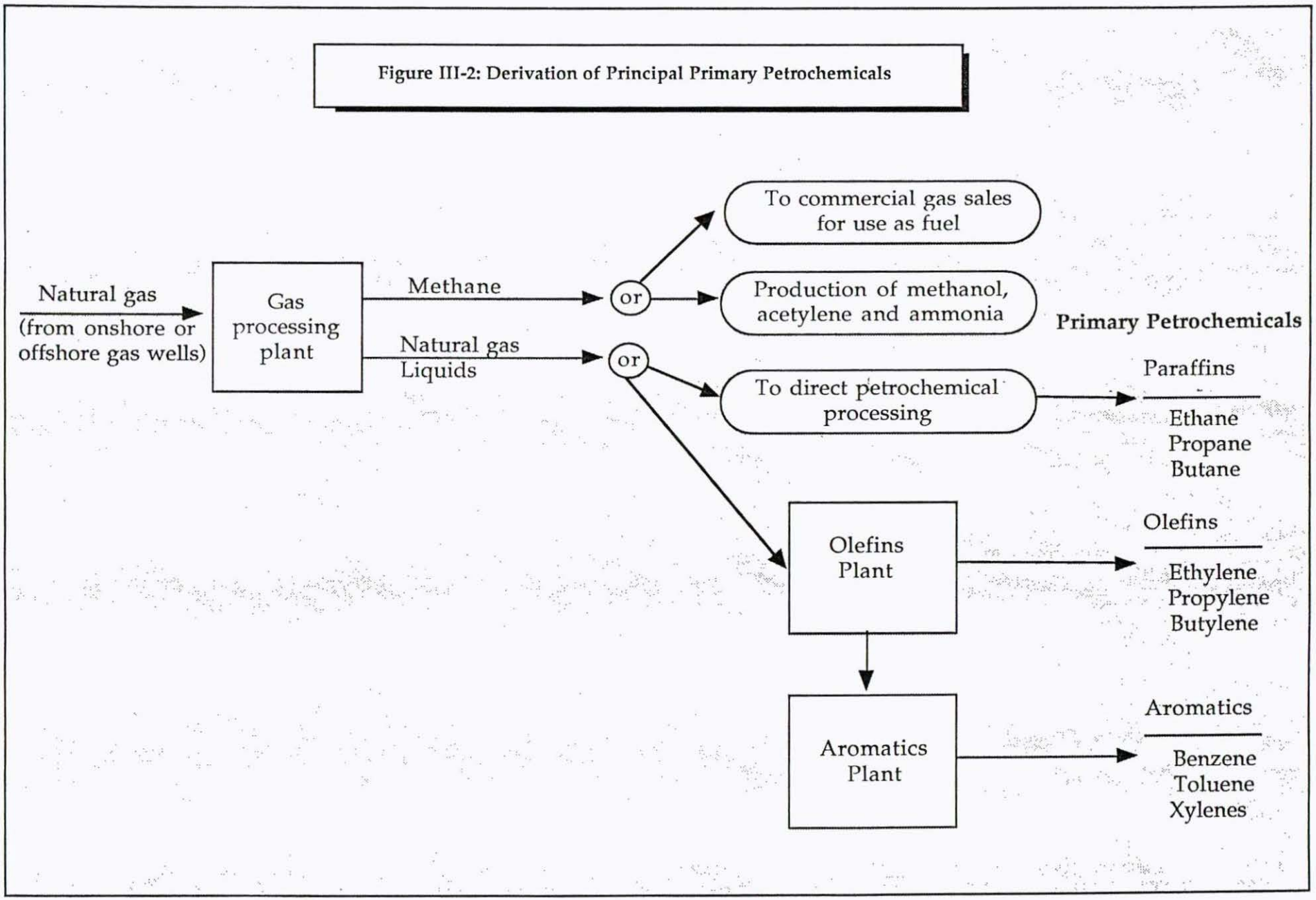
Opinion is divided on the feasibility of the more recent proposal to develop an ethylene plant. There are concerns there is insufficient ethane to sustain a world scale facility. There are also concerns that removing the ethane from the gas stream, by reducing the energy content and volume of the sales gas, would undermine the economics of M&NP. The SOEP partners have made commitments to specific gas flows on both the Canadian and US portions of the M&NP; these commitments may be difficult to maintain without additional gas supplies, if a petrochemical plant proceeds. If built, the facility would be located at the Strait of Canso. The proposal continues to be assessed.

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2 CHEMInfo Services Inc., A Scoping Study to Identify Petrochemical Opportunities Based on Offshore Natural Gas in Nova Scotia, 1996.

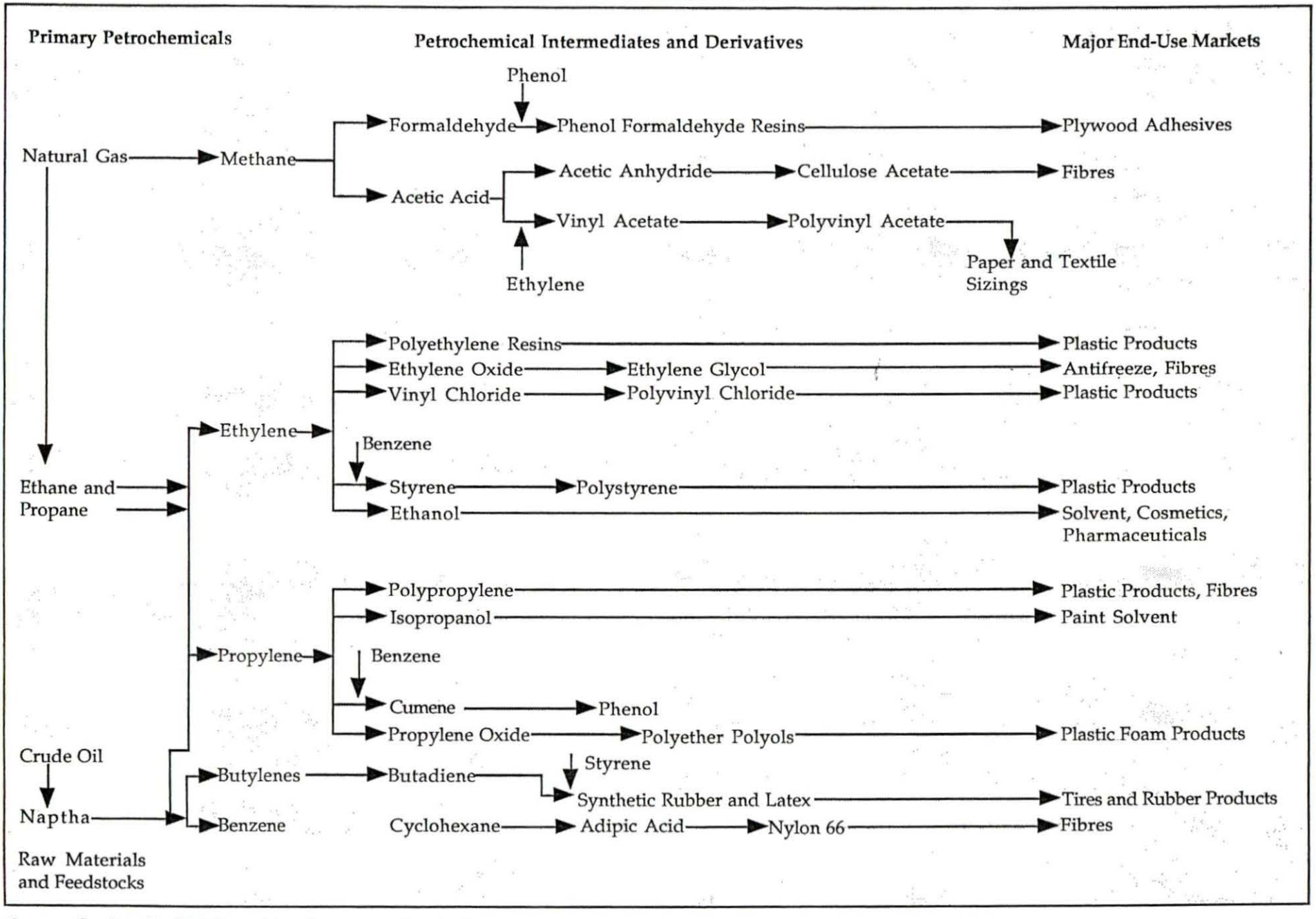
3 Sigurdson & Associates, Market/Technical Evaluation of the Opportunity for Ammonia and Methanol Plants for Nova Scotia, 1997.

Figure III-2: Derivation of Principal Primary Petrochemicals



Source: Gardner Pinfold Consulting Economists Limited.

Figure III-3: Relationship between Selected Petrochemical Products



Source: Gardner Pinfold Consulting Economists Limited.

2. OPPORTUNITIES AND BENEFITS

Project Scale

Offshore projects are usually divided into four phases: Exploration, Development, Production and Abandonment. The scale and duration of activities, and hence the requirements, vary considerably by phase. They also vary depending on whether the project involves gas or oil. Gas projects require smaller and less complex production and processing facilities than oil, and hence generally are smaller in scale. Geological structures on the Scotian Shelf are believed to be primarily gas-bearing, so future projects are likely to be on a moderate to small scale by world standards.

SOEP, as a so-called "seed" project, may turn out to be one of the largest developments we are likely to see. COPAN on the other hand, though a light oil project, ranks on the moderate to small end of the scale. Future developments linked to SOEP infrastructure, are likely to be in the small to moderate category, depending on how many fields are tied into a single project. Order of magnitude estimates regarding duration, cost and employment are summarized in Table III-1.

Table III-1
Scale Parameters Associated with Scotian Shelf Gas Projects (1)

	Large (>500 MMscf/day)	Medium (300-500 MMscf/day)	Small (<300 MMscf/day)
Exploration			
➢ # wells/fields	4-8	3-5	1-2
➢ Duration	3-5 years	2-4	1-2
➢ Cost	$25-40 million/well	$25-40 million/well	$25-40 million/well
➢ Employment	250 drilling/services	250 drilling/services	250 drilling/services
Development			
➢ # of platforms	4-6	2-3	1-2
➢ Duration	3-4 years	2-3 years	1-2 years
➢ Cost	$1,500–2,500 million	$750–1,500 million	$250–750 million
➢ Employment	2,500–3,500 P-Y	1,500–2,500 P-Y	1–1,500 P-Y
Production			
➢ Annual Cost	$75–100 million	$50–75	$40–50
➢ Employment	250–300 persons	150–250	100–150

1. Estimates assume fields would be tied into SOEP facilities. If not, another $250-350 million should be added for offshore pipeline and gas processing facilities. These additional costs are likely to render medium- and small-scale developments uneconomic at today's energy prices.

- **Exploration**: A single-well exploration program on the Scotian Shelf lasts from 3-6 months, and could cost from $25 to $40 million. Total employment would range from 200-300, depending on such factors as the type of rig (jack-up or semi-submersible) and the number of support vessels required.

- **Development**: Construction, installation and commissioning of facilities could take from 3-5 years, depending on project scale. COPAN and SOEP (Phase I), for example, are 3-4 year projects. Capital costs also depend on scale. For example, development costs for COPAN (two platforms plus tanker loading facilities) were in the $500 million range, while those for SOEP (Phase I) are in the $2,000 million range. With offshore infrastructure in place, development costs for smaller fields in the Sable Island area (platform, drilling and flow lines) are expected to be in the $250 million range. Labour requirements range from about 1,000 person-years for small field development, to upwards of 3,500 for larger fields (eg, SOEP-scale).

- **Production**: Project life varies with reservoir size and production rate, and could range from 5-10 years for small projects such as COPAN, to more typically 20-30 years for larger projects such as SOEP. Annual spending at full development could range from $50 to $100 million, with employment ranging from 50 for a small project (COPAN) to 250 (SOEP).

- **Abandonment**: This involves removing all offshore structures to eliminate any potential hazards to navigation and to marine-related activities such as fishing. Most of the work is offshore using heavy-lift vessels with diving support; onshore activity is limited essentially to logistical support. This activity would occur outside the study period and is not examined further in this report.

Opportunities and the Distribution of Benefits

Offshore exploration, development and production generate a wide array of employment and service opportunities. Table III-2 presents a listing of the main categories, and within many of these there would be several sub-categories.

In principal, all the opportunities identified would be open to individuals and businesses in the local area where an offshore development takes place. But in practice, few areas have all the capabilities and capacity to meet a project's demands. Even in areas with decades of offshore development experience (eg, the North Sea), competition for work and contracts is still a global affair and local or regional content is not 100%.

Table III-2: Offshore Oil and Gas Employment and Service Opportunities				
	Exploration	**Development**	**Production**	**Abandonment**
Employment	• seismic vessel crew • support vessel crew • drill rig crew • shore base staff • catering staff	• support vessel crew • drill rig crew • shore base staff • catering staff • project mgt staff • engineers/consultants • divers • fabrication trades – plate/pipe fitters – welders – instrument fitters – electricians – construction trades – fitters – welders – electricians – civil trades • barge/crane crews	• project admin. staff • offshore platform staff • gas plant staff • shore base staff • support vessel crew • well maintenance	• barge/crane crews • support vessel crew • fabrication trades – plate/pipe fitters – welders • divers
Services	• marine transportation • air transportation • drilling services • catering • vehicle leasing • equipment rental • warehousing • consulting • wholesale trade • retail trade	• engineering • fabrication • construction • transportation • maintenance • marine transportation • air transportation • catering • vehicle leasing • equipment rental • warehousing • consulting • wholesale trade • retail trade	• office services • well services • transportation • marine transportation • air transportation • catering • warehousing	• marine transportation • fabrication

Typically, the content level in frontier areas (areas new to offshore development) is initially low (10-20%). For example, in the early years of UK offshore development, content was in the 25-30% range; this, in a country of 60 million with substantial industrial capacity and capability.[4] Local involvement builds gradually as offshore development gains momentum and provides a basis to sustain risk-taking. Individuals seek training and gain experience. Businesses invest in equipment and processes, and some form joint ventures with experienced companies. It is a slow process, and one highly dependent on expectations regarding continued offshore development.

Going back to look at Table II-2 (Chapter II), we see that Nova Scotia content during SOEP Phase I stands at about 30%. This Table reflects a pattern of participation not unlike that experienced elsewhere, and not unlike that with the CBRM could experience if development occurred in the Sydney or Laurentian Basins. This information is re-worked into types of activity, with locational considerations and factors affecting the competitive environment (Table III-3). These factors dictate to a large extent where work is likely to take place and by whom it is likely to be carried out (local or non-local contractors). These factors may change over time, but that depends on the development of local capability. The where and by whom play a direct role in determining employment opportunities.

From Table III-3, the following general observations may be made about the distribution of benefits (across CBRM, Nova Scotia, Canada and foreign) arising from projects implemented over the next decade:

- **Project Management and Engineering**: The prospect for local participation in project management and engineering is constrained by the approach to implementation. Offshore projects are large, complex and costly. Owners generally do not have the resources to manage implementation (except at the project level) and design facilities. These activities are contracted out to multinational firms specialized in so-called EPC contracting (Engineering, Procurement, Construction). Such firms specialize in onshore or offshore components, and sometimes both. The list in Table II-2 contains many of the top companies. Local firms, if they have a hope of participating at this level, would do so through a joint venture with one of these companies, or by sub-contracting a particular aspect of the work. It would take considerable experience and substantial resources to compete internationally at this level.

- **Onshore Support for Offshore Activity**: The strongest prospect for local participation arises from onshore support for offshore activity. At a minimum, this means a marine supply base and associated warehousing needs. There are also good opportunities for catering, vehicle and equipment leasing, and provision of vessel and rig supplies. If local companies have an interest in supply vessels and helicopters, it may also mean involvement in marine and air transportation.

[4] For a good overview of the early years of North Sea development from the UK perspective, see MacKay, D.I. and MacKay, G.A., *The Political Economy of North Sea Oil*, London, Martin Robinson, 1975; p. 79.

Table III-3
Factors Affecting the Geographical Distribution of Offshore Opportunities

Component	Location of Activity	Competition	Comments
Project Management and Engineering	Local and Global	International among experienced EPC contractors	➢ Overall project mgt at or near project site ➢ Engineering and mgt of components mainly at contractor's site
Onshore Support for Offshore Activities	Local	Local for port & airport facilities. International for supply vessel, helicopter, service contracts.	➢ Marine and air base close to project site ➢ Logistics and services locally-based, but could be supplied by non-local interests
Fabrication of Offshore Facilities	Global	International	➢ Steel structures built and shipped globally ➢ Local yards must meet int'l QA/QC standards ➢ Local fabrication capability helpful but not essential
Construction of Onshore Facilities	Local	Local and International	➢ Main contract likely to EPC contractor ➢ Sub-contract civil, mechanical, electrical ➢ Modularized approach also possible – limits local involvement
Supply of Materials and Equipment	Global	International	➢ Local manufacturing capability very limited
Offshore Construction and Installation	Local	International	➢ Activity is local, but no Canadian equipment (rigs, vessels, barges).

- **Fabrication of Offshore Structures**: There are good prospects for local participation in fabrication of offshore structures. Offshore structures include jackets, decks and topside facilities. They are constructed of steel and fabricated separately, with topsides components often in modularized form, to facilitate transport and installation. The work is often spread among several yards, in order to ensure schedules are met. This approach gives even small yards the opportunity to participate (mainly as sub-contractors), as COPAN and SOEP experience in Nova Scotia shows. It also shows that some of the major fabrication requirements (eg, topsides and main jackets) were met by non-Canadian yards. Even to qualify to be invited to submit a bid, it is essential that yards employ stringent quality control (QC) and quality assurance (QA) procedures, and that their construction practices meet stringent health, safety and environment (HS&E) standards. To be successful, they must be competitive on price, delivery and service. In practice, few yards in Atlantic Canada currently meet these requirements.

- **Construction of Onshore Facilities**: There are good prospects for local participation in construction of onshore facilities. Onshore construction is an activity well-known to local contractors, though the specific types of facilities required may not be. These include gas plant, slug catcher, and possibly a gas fractionation plant. It could also include a petrochemical plant, if gas composition and quantities on the supply side, and market conditions on the demand side warrant. In all likelihood, the prime contract to construct any such facilities would go to an experienced Canadian or international company, with sub-contracting opportunities available to local contractors.

- **Materials and Equipment**: There are limited prospects to supply materials and equipment. The capability to supply most materials and equipment does not now exist in Nova Scotia, and in the case of some steel and manufactured items, does not exist in Canada. The limited number of projects likely on the Scotian Shelf over the next decade (SOEP Phase II, plus possibly one other) is unlikely to provide sufficient basis to develop or to attract new manufacturing capacity. It may be possible to attract a branch plant of an international supplier linked to export markets, though the prospects of a global expansion in any area of offshore supply would be considered slim in light of low oil prices and a slow-down in offshore activity.

- **Offshore Construction and Installation**: There is limited scope for local participation in seismic surveying (ships), exploration drilling (rigs), marine construction and installation (heavy lift vessels), offshore pipelaying (pipelay barges). This is because each of these activities requires investment in vessels costing from $50 million to several hundred million dollars. In none of these areas are there any Canadian contractors. Suppliers are almost exclusively U.S. and European based companies. The content estimates for these activities for Nova Scotia shown in Table II-2 reflect mainly employment on the vessels, with shore support for pipecoating in the case of the offshore pipeline.

3. ELEMENTS OF SUCCESS

SOEP and COPAN were implemented in the context of benefits plans aimed at maximizing the participation of Nova Scotia companies and individuals. The project proponents held many supplier development workshops and introduced various initiatives to ensure the community was well-versed in project requirements, standards and bidding procedures.

The proponents also pre-qualified potential bidders through on-site visits and questionnaires. Where suppliers were deficient (particularly those interested in fabrication), they were advised on the steps needed to meet pre-qualification criteria. The experience of those who attempted to pre-qualify, as well as those who actually competed (whether successfully or not), offers several important lessons for companies interested in participating in future offshore projects.

Lessons from Experience

- **QA/QC Standards**: Inadequate knowledge and experience with the high QA/QC standards required by the oil and gas industry ranks as one of the leading weaknesses among prospective bidders for fabrication and construction contracts.

- **HS&E Standards**: The failure to incorporate acceptable HS&E standards also ranks as a key shortcoming. Safety practices and standards must be raised and infuse the entire operation, not just supervision.

- **Bid Responsiveness**: Many bids were not fully responsive to the bid documents, making them difficult to assess. Suppliers should take care to ensure that bid documents are well understood, and each requirement is carefully and completely addressed.

- **Costs**: Bids from Nova Scotia companies tended to be higher, and in some cases substantially higher, than those received from international suppliers. Local companies seemed to have difficulty (or lack confidence) in assessing contingency costs, compared with more experienced overseas companies. Also, there may be an assumption that because companies are local, price competitiveness is not critical. SOEP and COPAN did place some contracts locally, even though costs were higher, but these were exceptional cases.

- **Award Criteria**: Companies tend to focus primarily on costs during the bid procedure, not appreciating the weight put on other issues of importance to the project. These include safety, quality and benefit reporting.

Steps to Improve CBRM Participation

The lessons emerging from the first full year of SOEP development are applicable to all firms in Nova Scotia, including those in the CBRM.

- **Training and Up-grading**. More time and effort need to be spent to increase the number of firms who pre-qualify. This could be accomplished by giving all firms more time between project origin and the bidding process to ensure they have access to the training they need to understand the bidding system, how to approach joint venturing, the QA/QC and HS&E standards expected and how to meet them, the Request for Quote process, etc.

- **Initiative**: Firms have to take greater responsibility for informing themselves of opportunities and how to pursue them. SOEP officials indicate that prospective suppliers should be more aggressive in making inquiries, both before and during the bid process. They point out that in many cases weak bids could have been improved considerably if bidders had simply called for clarification on specific points.

- **Responsiveness**: Nova Scotia suppliers must improve their responsiveness to bid requests. An emphasis on Nova Scotia benefits is not an excuse for slow communication from potential suppliers, late bids, and general misunderstanding of the demanding schedule required by this type of work.

- **Joint Venturing**: Local companies bidding on contracts jointly with companies more familiar with the offshore industry tended to do better than those who tried to bid independently. In advising local companies on strategies for participation, both SOEP and government development agencies have placed considerable emphasis on the value of forming joint ventures.

- **Feed-back**: Obtaining an explanation from SOEP on why a bid was unsuccessful, though valuable, is not always requested by the bidder (they are entitled to this). The more detailed the explanation about why bids are unsuccessful the better; otherwise, firms may simply assume their price was too high, which is not always the case.

Beyond these points of general applicability, two issues apply specifically to the CBRM. First, there is a need for leadership to pool the resources in the region to identify and take advantage of opportunities. Acting on their own, most firms lack the resources to provide an effective basis for competitive bidding. Second, there is a need for investment in throughput capacity that would allow firms to take on projects of the type and scale normally associated with the offshore. Existing capacity tends to be geared to the smaller and simpler requirements of traditional industries.

The important caution that needs to be highlighted, is that the offshore sector generally does not provide a stable basis for industrial development. It is a cyclical industry, often with extended periods between projects. Any firm planning to invest in supply capacity should ensure its capabilities are diversified enough to meet demands of other markets, including those arising from export markets.

IV.

GAS IN THE NOVA SCOTIA ENERGY MARKET

1. THE POTENTIAL NATURAL GAS MARKET

Consumers in Nova Scotia rely on four main sources of primary energy: crude oil, coal, hydro and wood (Table IV-1). The coal and hydro are converted into electricity. Oil products and wood are used directly by consumers in a variety of applications, but mainly transportation and heat.

Table IV-1
Nova Scotia Primary Energy Demand, 1996

	Energy	
	MMBtu	%
Petroleum	143,400	57
Coal	85,700	34
Hydro	11,600	5
Wood	9,500	4
Total	250,200	100

Source: Statistics Canada, Cat. No. 57-003, 1996.

Nova Scotians spend about $2 billion annually to meet their energy needs. About half of this is spent on electricity, petroleum and wood to meet heating, lighting and operating demands in the residential, institutional, commercial and industrial markets. The other half is spent on petroleum products to meet transportation needs.

With natural gas entering the provincial market in 2000, the historical pattern of energy supply and demand will change. Natural gas has the potential to displace such fuels as light and heavy fuel oil, coal and propane. Electricity may also be displaced in certain circumstances. An estimate of the potential natural gas market in final demand applications (ie, excluding use as fuel to generate electricity) by fuel type is set out in Table IV-2.

Table IV-2
Nova Scotia Energy Expenditures by Sector and Fuel Type, 1996
($ millions)

	Residential		Commercial Institutional		Industrial	
	million mmbtu	$ million	million mmbtu	$ million	million mmbtu	$ million
#2 oil	19.4	170.0	7.3	40.0	1.8	10.0
#6 oil	–	–	1.6	4.8	8.3	23.1
Propane	.7	10.5	.9	12.2	.9	8.8
Electricity	12.7	298.0	10.7	250.0	10.1	236.5
Wood	.4	1.8	–	–	–	–
Total	33.2	480.3	20.6	307.0	21.1	278.4

Source: Statistics Canada, Cat. No. 57-003. Expenditures based on 1998 fuel prices.

2. FACTORS AFFECTING NATURAL GAS DEMAND

It is important to note that the mere availability of natural gas in Nova Scotia does not in itself guarantee a market. It must compete with existing fuels whose suppliers, including CBDC, would like to retain their market share. The ability of natural gas to compete in the Nova Scotia market depends on several factors including inter-fuel economics, Nova Scotia gas distribution and lateral policies, environmental considerations, CBDC production capability and cost, and (in the longer term) the deregulation of electricity supply.

The effects on gas demand of inter-fuel economics and the gas distribution regulations are summarized below and explained in greater detail in Appendix A. Environmental factors, CBDC production conditions, and deregulation are addressed in the next chapter dealing with the impact of gas on coal.

Inter-fuel Economics

Among fuels offering the same long-term supply security and reliability of delivery, cost tends to be the single most important factor in determining choice of fuel. Four factors go into the determination of cost from the consumer's perspective: fuel price, capital costs, combustion efficiency, and complying with emissions standards. Among these price is often the critical factor.

Price is what the consumer pays for fuel delivered to the plant or residence. Relative prices for fuels available in Nova Scotia in late 1998 are shown in Table IV-3. The coal prices shown are for minimum quantities under the long-term contract between CBDC and NSPI, and are derived from annual reports. Also shown in Table IV-3 are price assumptions for natural gas obtained from the Petroleum Directorate as part of this study. Actual prices in Nova Scotia will not be known until tolls and tariffs for the main transmission line, laterals and distribution system are determined by the respective regulatory agencies.

Table IV-3
Fuel Prices in Nova Scotia, 1998

	Price $/unit	Efficiency (Combustion/ Conversion)	Delivered Cost ($/MMBtu)
# 2 oil			
Domestic (litre)	.32	.75	11.64
Commercial (litre)	.20	.80	6.82
Industrial (litre)	.20	.80	6.82
# 6 oil			
Commercial (litre)	.12	.84	3.61
Industrial (litre)	.11	.83	3.35
Propane			
Domestic (litre)	.42	.70	23.30
Commercial (litre)	.32	1.00	12.42
Industrial (litre)	.25	.80	12.13
Coal			
CBDC (tonne)	65	.33	7.43
Imported (tonne)	55	.33	6.29
Natural Gas (1)			
Low Price (MMBtu)	2.30	.80	2.88
Medium Price (MMBtu)	2.70	.80	3.60
High Price (MMBtu)	3.15	.80	3.94

1. Gas price excludes lateral and distribution tariffs, so it is not directly comparable to the other fuel prices which represent delivered cost. Tariffs could add another $4.00-6.00/MMBtu to the price, depending on the capital cost of the facilities and how the tariffs are structured.

Source: NS Department of Natural Resources; various petroleum distribution companies; NSPI and CBDC annual reports.

In order to penetrate markets in Nova Scotia, gas will have to be priced competitively. In new and expanding markets in Canada and the U.S., the experience indicates that inducing consumers to convert from oil to gas generally requires a gas price below the energy equivalent price of the alternative fuels, particularly if existing combustion equipment does not need to be replaced. Gas has been able to achieve this pricing differential because market conditions (eg, relative costs of production and delivery) allowed it.

- **Residential**: In the residential sector, price differentials as high as 30-50% between gas and oil have not been uncommon. Such differentials are needed to overcome conversion costs and long-established consumption patterns. When oil and gas prices converge (as is the case in the current market), conversions from oil to gas become more difficult, and may only occur when equipment otherwise needs to be replaced.

- **Commercial and Industrial**: The differential in the commercial and industrial sectors varies depending on the type of fuel displaced. The differential is high where high-priced fuels such as propane are displaced (and generally, this is an easy conversion), but low where cheaper heavy oil is displaced. Most large industries would maintain a dual-firing capability (gas and oil) in order to take advantage of relative price changes. From the numbers in Table IV-3, it would appear that at current oil prices, gas would have difficulty competing with #6 oil in industrial applications once lateral costs (and any distribution costs) are added.

- **Electric Utilities**: The same factors apply in the case of electrical utilities, though much depends on the fuels and technology in use. The prospect of favourable gas prices would be needed to induce conversion to dual-firing in the case of conventional oil-fired generators, given current low oil prices. Coal-fired units are more costly to convert and generally would not have dual-firing capability (though some utilities take advantage of the combustion and low emissions properties of gas and use it in conjunction with coal, so-called "co-firing"). What is more likely, and what is occurring elsewhere, is the use of gas to power higher efficiency ("Combined-Cycle") generating units when *additional* generating capacity is required. These units are not only far less costly to construct than coal-fired plants, but they cut down substantially on greenhouse gas emissions.

A key question in all this is whether Sable gas actually will be able to be sold at prices sufficiently below competing fuels to encourage conversion. The delivered (burner-tip) price of Sable natural gas for wide distribution in Nova Scotia is not yet known, so it is difficult to make comparisons.

Oil, coal and electricity prices occupy the other side of the fuel competition equation.

- Oil prices tend to be highly variable (and unpredictable) because the oil market is international in scope and subject to abrupt change for a variety of political and economic reasons. This said, we are now in a period of historically low prices, a situation expected to continue in the short to medium term.

- **Coal** prices are relatively stable. Coal markets tend to be mainly regional, and subject to long term contracts primarily with electrical utilities. There is a spot market, with prices rising and falling in response to oil prices. The long-term trend, though, is to lower coal prices.

- **Electricity** prices are stable because most utilities are regulated (though this is changing), and because the variable factor, fuel, generally accounts for half or less of the total costs. In Nova Scotia, electricity price stability is closely linked to the long-term contract between NSPI and its major coal supplier, CBDC.

In 1998, oil prices fell to their lowest point (in real terms) since the 1973 and 1979 Gulf crises sent prices sharply upwards. Where energy prices are heading in the long term is impossible to predict with any confidence, particularly in the current climate of uncertainty over economic recovery in the Far East and how this will affect commodity prices.

A recent forecast by the U.S. Department of Energy (Fig. IV-1) predicts North American crude oil and natural gas prices are likely to rise slightly over the next 10 years, while coal and electricity prices are expected to drop.[1]

- **Natural Gas**: Stable natural gas prices are explained by the balance in demand and supply within the North American market. The trend towards increasing gas utilization for electrical generation provides upward pressure on prices, while improved transportation capacity and supply capability provide a moderating influence. Though gas and oil are substitutes (at least in the long term), their markets differ in that oil trades globally, while gas markets tend to be regional or continental due to high transportation costs.

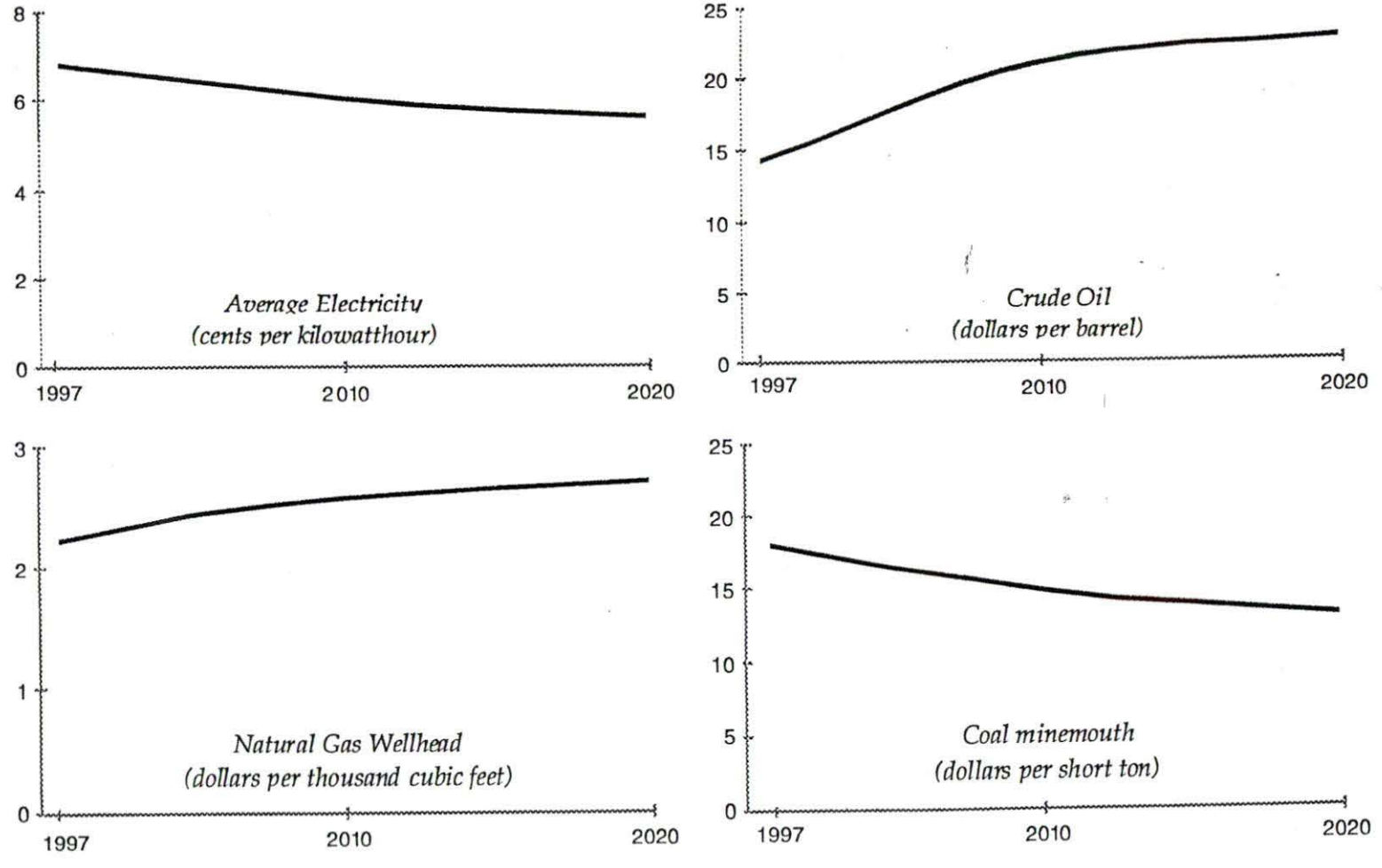
- **Crude Oil**: The moderately rising trend for crude oil is explained by strengthening international markets in the early 2000s, and expectations of moderate supply expansion as producing nations reach production-sharing agreements. This said, a prolonged recovery of Asian economies following events in 1998 may serve to extend the turning point of oil prices, particularly if weak markets undermine agreements among producers.

- **Coal**: Declining coal prices are due to a combination of declining production costs and reduced demand as emissions limits cause electrical utilities to look to natural gas to meet expansion requirements. Gas supply potential is strong, with transportation capacity and reach continuing to expand within North America.

- **Electricity**: Declining electricity prices, though highly regional, are explained by reduced costs of production (though expansion is predicted to be mainly gas-fired, much of the installed capacity will be coal-fired for many years), and greater competition due to deregulation of electricity markets.

1 U.S. Department of Energy, EIA, *"Early Release of the Annual Energy Outlook 1999"*.

Figure IV-1
Fuel Price Projections, 1997-2020
(1997 U.S. Dollars)



Source: U.S. Department of Energy, Early Release of Annual Energy Outlook 1999, November, 1998

Not all forecasters share the perspective of the U.S. Department of Energy. For example, Natural Resources Canada projects oil prices to remain stable at about US$18/bbl over the next 20 years.

Nova Scotia Gas Distribution and Lateral Policies

In addition to inter-fuel economics, the extent to which natural gas alters the province's existing energy mix (and the economic impact this generates) also depends on the policy framework governing gas distribution and transportation.

Nova Scotia's distribution regulations, published in November 1998, embody a framework with three key provisions aimed at maximizing access to gas:

- **Single franchise**: the province will be served by a single franchise. This is regarded as the most economically feasible and expeditious way of developing the system. It should promote level rates, consistent service and efficient financing.

- **Wide gas distribution**: the coverage area for natural gas must be as widespread as economically feasible. The provisions specify that access to gas must be available to a target number of households in each county.

- **Single toll**: the Utilities and Review Board is required to create a single province-wide toll or rate so that all consumers pay the same transportation charge. This toll is intended to be performance-based, thereby providing the franchise holder with an incentive to comply with its required access commitments.

In practice, it is not yet clear how the regulations will be implemented, what approach will be taken to developing a single toll (market-determined or cost of service), nor how the test of economic feasibility will be applied. But however these matters are resolved, the extent to which gas is actually distributed (and hence any impact from access) ultimately will depend on economics – being able to deliver it at a competitive price.

It should be noted that the distribution regulations apply only to distribution systems, and not to the laterals needed to transport gas to these systems from the main pipeline. The proposed Halifax and Strait of Canso laterals are governed by M&NP's "Lateral Policy". In essence, application of the Policy means that:

- If a proposed lateral and the contracted demand of that lateral generate sufficient revenue (based on a test toll of $0.60/MMBtu) to cover the annual cost of service, M&NP would proceed to construct the lateral without any incremental financial contribution from shippers (or governments on their behalf).

- If the test toll exceeds the $0.60/MMBtu threshold, then some form of "aid to construct" would be required to avoid cross-subsidization of these higher-cost users by lower-cost users elsewhere on the system.

In applying the Lateral Policy to the proposed Halifax and Strait of Canso laterals, both failed to meet a strict application of the threshold test. M&NP waived the need for an "aid to construct" or customer contribution on the grounds that the test would be met if it were applied to extended markets over the full economic life of the lateral.[2]

At the time of writing, two companies had filed applications with the Board for full regulation class franchises. Two others, who had earlier announced their intention to apply, withdrew, stating that the regulatory framework (the target access provisions in particular) made the project uneconomic given prevailing conditions in energy markets.

3. NATURAL GAS DEMAND IN NOVA SCOTIA

Cases

The objective is to identify and measure the impacts (eg, changes in energy expenditures, employment, etc) arising from access to natural gas. An alternative Case approach is used as the basis for the analysis of change. Two cases are examined:

- **"Gas on Mainland Nova Scotia"**: gas is available on mainland Nova Scotia (including those parts of Cape Breton outside the CBRM) starting in 2000, but not in the CBRM; and,

- **"Gas in CBRM"**: gas is available in the CBRM starting in 2001.

In order to determine the change in energy demand and supply patterns, these Cases are examined against a "No Gas" base case which simply projects current demand and supply patterns out to 2010.

Assumptions

The analysis rests on several key assumptions:

- **Price**: Relative prices of energy forms now available are assumed to remain constant in real terms at today's levels. Natural gas is assumed to be distributed to consumers at a price at least 10% below the price of oil. This is considered to be the minimum needed to induce conversions, particularly if conversion costs are borne in whole or part by consumers.

2 See, Maritimes & Northeast Pipeline, "Halifax Lateral Pipeline Project, NEB Facilities Application", 1998, p. 68; and, Maritimes & Northeast Pipeline, "Point Tupper Lateral Pipeline Project, NEB Facilities Application", 1998, p. 69.

- **Delivered Cost of Gas**: The analysis is conducted using the Low Price Case for gas shown in Table IV-3 ($2.30/MMBtu). To this are added an assumed lateral tariff of $0.70/MMBtu, and an assumed distribution tariff of $5.50/MMBtu. These assumptions bring the delivered cost of gas to the residential sector to the $8.50/MMBtu range, about 11% below the cost of #2 oil after adjustments for relative efficiency. The Medium and High Price Cases for gas ($2.70 and $3.15/MMBtu in Table IV-3) would make gas uneconomic at these tariff levels. The delivered cost of gas for the commercial and industrial sectors is lower, reflecting lower competing oil prices. In the industrial sector, gas is unlikely to be competitive if it has to bear any distribution costs, and even then, may not be competitive (compared with #6 oil) once the lateral tariff is added to the cost of gas (see Table IV-3).

- **Feasibility**: The actual cost and feasibility of distributing natural gas is not assessed, except for the Gas in CBRM Case. A conventional cost of service analysis is used, treating the lateral and distribution system on an incremental basis. The analysis is not carried out over the life of the system, but only over the study period (to 2010).

- **Customers**: The demand projection takes three customer classes into consideration: residential, commercial and industrial. It excludes electrical utilities and independent generators. The latter are considered in the Chapter V dealing with the impact of gas on coal.

- **Population and Economy**: These are assumed to grow at average levels experienced during the 1990s.

- **Gas Demand**: No explicit attachment rate is developed. Rather, to simplify the analysis, gas demand is projected based on the quantity of competing fuel displaced. For example, by year ten, 35% of residential energy demand is assumed to be met by natural gas. This is a conservative estimate based largely on relative energy prices, but also on prevailing economic conditions. The higher rates of use in the commercial and industrial sectors are based on relative prices and other factors such as ease of handling and reduced greenhouse gas emissions.

4. BASE CASE: NO GAS – ENERGY DEMAND TO 2010

The demand estimates in Table IV-1 form the starting point for the assessment of impacts natural gas is expected to have on *final* demand for energy. Total annual expenditure levels by energy source are projected over the study period (to 2010). This Base Case "without gas" energy expenditure projection is set out in Table IV-4. Over the period, energy expenditures increase from $1,066 million in 1998 to $1,332 million in 2010.

Supporting tables showing demand change by sector are contained in Appendix B.

TABLE IV-4

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	786,000	219,600	27,900	31,500	1,750	0	1,066,750
1997	824,240	222,894	28,319	31,973	1,750	0	1,109,175
1998	820,000	226,237	28,743	32,452	1,750	0	1,109,183
1999	862,000	229,631	29,174	32,939	1,750	0	1,155,494
2000	849,600	233,075	29,612	33,433	1,750	0	1,147,470
2001	854,000	236,572	30,056	33,934	1,750	0	1,156,312
2002	871,200	240,120	30,507	34,443	1,750	0	1,178,021
2003	883,200	243,722	30,965	34,960	1,750	0	1,194,597
2004	892,400	247,378	31,429	35,485	1,750	0	1,208,441
2005	907,200	251,088	31,901	36,017	1,750	0	1,227,956
2006	922,400	254,855	32,379	36,557	1,750	0	1,247,941
2007	937,600	258,678	32,865	37,105	1,750	0	1,267,998
2008	956,000	262,558	33,358	37,662	1,750	0	1,291,327
2009	970,000	266,496	33,858	38,227	1,750	0	1,310,331
2010	987,200	270,494	34,366	38,800	1,750	0	1,332,610

5. GAS IN MAINLAND NOVA SCOTIA

Based on the favourable relative energy price assumptions outlined above, natural gas demand rises from about 8.1 million MMBtu in 2000 (average of 22,000 MMBtu/day) to 20.2 million MMBtu in 2010 (58,350 MMBtu/day). Expenditures on gas rise from $8.5 to $95.1 million annually.

Demand and energy expenditure projections for this case are set out in Table IV-5. Supporting tables showing demand change by sector are contained in Appendix B. The various incentive programs to encourage conversion to natural gas are discussed in Appendix E.

6. GAS IN THE CBRM

Demand and Expenditures

Consumers and businesses in the CBRM spend about $140 million annually on energy in final demand applications for which there is at least some potential for conversion to natural gas. Energy use and expenditures estimates by sector and fuel type are given in Table IV-6.

Table IV-6
CBRM Energy Expenditures by Sector and Fuel Type, 1996 (1)
($ millions)

	Residential		Commercial Institutional		Industrial	
	million mmbtu	$ million	million mmbtu	$ million	million mmbtu	$ million
#2 oil	2.41	21.1	.91	5.0	.27	1.5
#6 oil	–	–	.20	.6	1.25	3.5
Propane	.10	1.3	.11	1.5	.14	1.3
Electricity	1.58	37.0	1.33	31.0	.152	35.5
Wood	.05	.2	–	–	–	–
Total	4.14	59.6	2.55	38.1	3.18	41.8

(1) Estimates for the residential and commercial sectors derived by applying CBRM population to per capita provincial demand data (Table IV-2). Industrial demand estimated from actual energy consumption data provided by industrial consumers including SYSCO and CBDC. SYSCO energy consumption is based on 1992-1997 production levels.

TABLE IV-5

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	682,791	192,226	23,834	27,386	1,502	0	927,739
1997	716,053	195,109	24,192	27,797	1,502	0	964,652
1998	712,343	198,036	24,555	28,213	1,502	0	964,649
1999	748,828	201,006	24,923	28,637	1,502	0	1,004,897
2000	735,301	194,043	20,906	26,819	1,502	13,623	992,194
2001	736,340	189,344	18,879	25,444	1,502	23,479	994,987
2002	748,344	184,925	17,859	24,328	1,502	32,228	1,009,187
2003	755,788	180,331	16,804	23,174	1,502	41,219	1,018,818
2004	760,767	176,002	15,767	22,115	1,502	50,140	1,026,292
2005	770,441	171,022	14,637	20,872	1,502	59,687	1,038,161
2006	780,359	165,852	13,470	19,586	1,502	69,514	1,050,284
2007	790,177	160,117	12,220	18,686	1,502	79,604	1,062,306
2008	802,584	154,582	10,978	17,879	1,502	89,727	1,077,252
2009	811,191	151,164	10,888	17,496	1,502	96,871	1,089,113
2010	825,575	153,432	11,051	17,758	1,502	98,355	1,107,675

Assumptions

1. Electricity price is $23.45/mmbtu ($22.24/GJ or $0.08/kwh).
2. #2 fuel oil price is: res. - $0.32/l ($11.64/mmbtu or $11.04/GJ @ 75%); com'l and ind'l - $.20/l ($6.82/mmbtu or $6.47/GJ @ 80%).
3. #6 fuel oil price is: com'l - $0.12/l (Com'l –$3.61/mmbtu or $3.42/GJ @ 84%; Ind'l - $0.11/l ($3.31/mmbtu or $3.14/GJ @ 84%).
4. Natural gas burner tip price is $8.50/mmbtu or $8.06/GJ in the residential sector ($10.35/mmbtu or $9.81/GJ @ 82%).
5. Natural gas burner tip price is $2.75/mmbtu or $2.61/GJ to displace #2 oil and #6 oil in the ind'l and com'l/inst'l sectors.

The conditions governing the demand for natural gas demand in the CBRM market are the same as those for mainland Nova Scotia outlined in the assumptions, above.

The analysis indicates that natural gas demand rises from about 1.7 million MMBtu in 2001 (4,740 MMBtu/day), to 4.0 million MMBtu by 2010 (10,890 MMBtu/day). Over this period expenditures on gas rise from $5.3 to $16.0 million annually.

Demand and energy expenditure projections for this case are set out in Table IV-7. Supporting tables showing demand change by sector are contained in Appendix C.

Feasibility

Because assessing the implications of the CBRM *not* having access to natural gas is one of the main objectives of this study, determining the economics of both the lateral to the CBRM, and distribution systems within it, become important matters (notwithstanding the provincial regulations mandating wide access). The results of the analysis indicate the circumstances under which it is feasible to provide access.

A simplified cost of service analysis indicates that it would not be economic to develop the infrastructure and deliver gas to the CBRM in the foreseeable future, as long as the CBRM lateral and distribution system are considered as a stand-alone project. This conclusion rests on four key factors:

- estimated capital and operating costs: lateral and distribution system costs are estimated at $35 and $20 million, respectively (excluding hook-up costs);
- validity of the price assumptions at which gas would have to be sold in order to compete with other fuels;
- the minimum commodity price at which gas is likely to be sold is realistic (by assumption, this is set at $2.30/MMBtu); and,
- the industrial load in the CBRM is not large enough to anchor the lateral and distribution system. SYSCO holds the key. Their gas load could vary anywhere from about 4,000 to 20,000 MMBtu/day, depending on production level. At recent production levels, the figure is at the low end of the range. Attempts are being made to sell the plant. Should a buyer be found and production levels increase, the economics of the lateral and distribution system would improve considerably. By the same token, the economics of the plant are also likely to improve with access to natural gas.

The cost of service analysis shows that the system would incur substantial losses in each year. Annual losses over the first seven years start at $5.3 million and stabilize at just over $10 million by year three. It is important to remember that these figures flow directly from the assumptions made. Any combination of lower capital costs, higher demand levels, or higher prices for competing fuels would improve the economics. The results are summarized in Table IV-8. Details are provided in Appendix C.

To make a lateral and distribution system to the CBRM economic, it seems clear that substantial assistance would be required. This could be accomplished through an "aid to construct" from government, or through "cross-subsidization" within an integrated provincial system. The approach taken could affect the timing and capacity of the system.

TABLE IV-7

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	103,625	27,507	4,059	4,136	213	0	139,541
1997	108,623	27,920	4,120	4,199	213	0	145,075
1998	108,091	28,339	4,182	4,261	213	0	145,086
1999	113,628	28,764	4,245	4,325	213	0	151,174
2000	111,993	29,195	4,277	4,390	213	0	150,068
2001	112,181	27,277	1,291	3,022	213	5,340	149,324
2002	114,041	26,371	1,056	2,787	213	6,870	151,337
2003	115,207	25,707	1,039	2,701	213	8,028	152,894
2004	115,997	25,156	1,027	2,628	213	9,134	154,156
2005	117,505	24,438	1,008	2,535	213	10,362	156,061
2006	119,050	23,692	988	2,438	213	11,626	158,008
2007	120,582	22,911	962	2,324	213	12,938	159,929
2008	122,509	22,482	977	2,313	213	14,028	162,521
2009	123,858	22,035	992	2,300	213	15,142	164,539
2010	125,602	21,847	1,006	2,302	213	16,033	167,003

Assumptions

1. Electricity price is $23.45/mmbtu ($22.24/GJ or $0.08/kwh).
2. #2 fuel oil price is: res. - $0.32/l ($11.64/mmbtu or $11.04/GJ @ 75%); com'l and ind'l - $.20/l ($6.82/mmbtu or $6.47/GJ @ 80%).
3. #6 fuel oil price is: com'l - $0.12/l (Com'l –$3.61/mmbtu or $3.42/GJ @ 84%; Ind'l - $0.11/l ($3.31/mmbtu or $3.14/GJ @ 84%).
4. Natural gas burner tip price is $8.50/mmbtu or $8.06/GJ in the residential sector ($10.35/mmbtu or $9.81/GJ @ 82%).
5. Natural gas burner tip price is $2.75/mmbtu or $2.61/GJ to displace #2 oil and #6 oil in the ind'l and com'l/inst'l sectors.

Table IV-8
Economics of Supplying Natural Gas to the CBRM
($000s)

Year	1	2	3	4	5	6	7
Potential Revenue (1)	5.3	6.9	8.0	9.1	10.4	11.6	12.9
Commodity Cost (2)	3.9	4.7	5.2	5.6	6.2	6.7	7.2
Cost of Service (3)	6.7	9.5	13.1	13.6	15.6	15.7	15.8
Total costs	10.6	14.2	18.3	19.2	21.8	22.4	23.0
Surplus/(Deficit) (4)	(5.3)	(7.3)	(10.3)	(10.1)	(11.4)	(10.8)	(10.1)

1. From Table IV-7.
2. By multiplying natural gas demand from Appendix C by assumed minimum commodity gas price of $2.30/MMBtu.
3. From Appendix C.
4. Difference between Potential Revenue and Total costs.

7. IMPACTS OF ACCESS TO NATURAL GAS

Impacts at the Provincial Level

Access to natural gas is expected to have a generally favourable impact in the province. Assuming gas is available throughout the province in conformance with provincial regulations, then the following kinds of impacts could be expected:

- Energy: If natural gas can be offered to consumers at prices likely to induce conversion from petroleum products (at least 10% less than competing fuels), then by 2010 it could command roughly a 10% share of the estimated $1 billion energy market ($100 million). Assuming annual savings with gas are in the 10% range, the gross impact would be a $10 million annual increase in disposable income. Most of this saving would occur in the residential and commercial sectors. Savings in the industrial sector are expected to be marginal, given the difficulty gas will have competing with #6 oil at current and anticipated prices.

  Actually achieving this market share is expected to be difficult given current and projected conditions in energy markets. Current prices for the fuels gas would displace are low relative to their historic levels. There is little incentive for most consumers to convert unless gas prices were even lower and expected to remain lower. Whether gas could be offered at such low prices is open to question given the costs of constructing laterals and distribution systems, and the need to ensure these systems are economically viable.

- **Distribution System Operations:** A lasting impact arises from jobs created in gas distribution. At full development, a province-wide distribution system could employ 250-350 people, paying wages and salaries in the $10-15 million range. This positive impact would be more or less offset by job losses in petroleum distribution and service support.

- **Industrial Development:** Gains in industrial competitiveness due to the availability and lower costs of gas are possible in the long run. Such gains could be small over much of the study period, given the difficulty gas will have in competing with oil at current prices.

- **Environment**: The environment will benefit from access to gas to the extent it leads to the displacement of fuel oil for space heating and other uses. The benefit lies in the reduction of harmful greenhouse gas emissions.

- **New Business Development**: The introduction of natural gas into Nova Scotia will create new business opportunities in several areas including: the manufacture and distribution of gas-using appliances; appliance installation, service and maintenance; and, consulting services in fuel choice and heating system design.

Positive Impacts in the CBRM

Access to natural gas would have a generally favourable impact in the CBRM. Assuming gas is available in the region in conformance with provincial regulations (ie, wide distribution at a uniform province-wide price), then the following kinds of impacts could be expected:

- **Energy**: Gas could take about a 10% share of the estimated $170 million CBRM energy market. Assuming annual savings with gas are in the 10% range, the gross impact would be a $1.7 million annual increase in disposable income. Most of this saving would occur in the residential and commercial sectors. Savings in the industrial sector are expected to be marginal, given the difficulty gas will have competing with #6 oil at current and anticipated prices.

- **Distribution System Operations:** A lasting impact arises from jobs created in gas distribution. Given its size, a district office would likely be opened in the CBRM. At full development, this office could employ 25-40 people, paying wages and salaries in the $1 million. This positive impact would be offset to at least some extent by job losses in petroleum distribution and service support.

- **Industrial Development:** Gains in industrial competitiveness due to the availability and lower costs of gas are possible in the long run. Sysco would be one of the main beneficiaries of any such lower costs. As one of the province's most energy-intensive industries, an opportunity to reduce costs would be welcome, particularly given the internationally competitive nature of the steel market.

- **Environment**: The environment would benefit from access to gas to the extent it leads to the displacement of fuel oil for space and process heat and other uses. The benefit lies in the reduction of harmful greenhouse gas emissions.

- **New Business Development**: The introduction of natural gas into the CBRM would create new business opportunities in several areas including: the manufacture and distribution of gas-using appliances; appliance installation, service and maintenance; and, consulting services in fuel choice and heating system design.

Some Caveats about CBRM Access to Gas

Current market conditions are not favourable for the extension of natural gas supply to the CBRM. The market is small and uncertain. Prices for the fuels gas would try to displace are relatively low so there would be little incentive for consumers to convert. The costs of constructing a lateral and developing a distribution system are high relative to market potential.

- **Sysco Uncertainty**: The potential market for natural gas in the CBRM is relatively small and highly uncertain. Uncertainty stems from a declining population and weak industrial base. Over the past 15 years, the CBRM population has dropped by about seven percent, a reflection of poor economic prospects. The industry needed to anchor a lateral and distribution system consists almost exclusively of Sysco, one of the largest consumers of petroleum products in the province. At full production, Sysco would make a major contribution to justifying the costs of access. But at considerably less than full production and facing an uncertain future, Sysco is not in a position to sign the kind of long-term agreement that would anchor construction of a lateral to the CBRM.

  This is problematic, not just for the CBRM, but also for Sysco itself. Access to natural gas would facilitate Sysco's adoption of alternative production processes, thereby enhancing its efficiency and asset value. Whether access to gas would add sufficiently to Sysco's value to attract a purchaser is difficult to say. It would at least be a step in the right direction.

- **CBDC Uncertainty**: Similarly, the other potential, significant industrial load to anchor a gas distribution system could result from the conversion of one or more power generation units by NSPI within the CBRM. The federal government has announced its intention to withdraw from the coal mining industry. With the closure of the Phalen Mine and without an alternate source of local coal, NSPI faces the prospect of having to import coal to meet its thermal needs. Converting or replacing one or more of the units at Lingan with gas-fired capability could provide the load the CBRM needs to anchor the lateral and assure access to gas. The obvious drawback to this suggestion, if technically and economically feasible, is that a reduction in coal demand would undermine whatever prospects there are for developing new mines (eg, Donkin).

Implications of No Access to Natural Gas

The uncertainty surrounding the industrial demand for gas in the CBRM contributes to the already weak economics of the lateral and distribution system. The provincial distribution policy is intended to address revenue shortfalls in weak markets through a province-wide toll. But there remains the "worst-case" outcome – that the policy cannot overcome weak energy market and demand conditions, and that a lateral to the CBRM is not built until a firm and substantial market develops. This could take many years.

This would leave the CBRM (and other areas in the province in similar circumstances) at an economic disadvantage compared with areas of the province where access to gas may be only a year or two away. For the CBRM the potential negative implications are two-fold:

- **Industrial opportunity would be compromised.**
  - From a purely economic standpoint, the availability of natural gas provides industry with a wider array of energy options, thereby improving competitiveness. This would apply particularly to Sysco, the CBRM's leading industrial sector energy user. Access to natural gas would place the CBRM on an equal footing with "have" areas, thereby leveling the playing field at least with respect to energy.
  - From an environmental standpoint, the availability of gas is likely to become an increasingly important criterion for industrial location as emissions standards throughout North America are tightened. Areas without gas would be at a competitive disadvantage arising from the additional investments needed to reduce emissions when using oil or coal.
- **Existing economic base is threatened.**
  - While the availability of gas elsewhere in the province does not appear to represent an immediate threat to coal, it does afford NSPI and its larger industrial customers a long-term solution for reducing harmful emissions. This is a positive outcome, but one with a doubly negative side-effect for the CBRM. If the area does not also have access to gas, then declining demand for coal in the long run means loss of industrial base on the one hand, and on the other hand, the area fails to gain any potential benefits which gas could provide.

V.

NATURAL GAS IMPACT ON COAL

1. FUTURE COAL DEMAND WITHOUT NATURAL GAS

Relevant Factors

In order to determine the possible impact of natural gas on the demand for coal to generate electricity, it is necessary first to set out a basis for comparison. This is essentially a projection of how, *in the absence of natural gas,* NSPI would meet its load growth forecast. In other words, the question is, "What energy sources would NSPI be likely to use, and at what cost, to satisfy electrical energy needs?". NSPI currently relies on three primary sources – coal, oil and hydro – (and occasionally imported energy), to meet demand.

Considerable uncertainty surrounds any projection of NSPI's sources of electrical energy. This uncertainty stems mainly from three factors reviewed in Appendix A:

- **Relative prices of coal (CBDC and imported) and oil**
  - Would it be cheaper to burn oil or coal in existing units over the next five years, or would it be more cost-effective to import electrical energy?
  - Would NSPI's next electrical generating unit be oil- or coal-fired, or instead, would increased imports of electrical energy be the most cost-effective option for meeting load growth?
- **Complying with emissions standards**
  - Would the cap on NSPI SO_2 emissions (set by legislation at 145,000 tonnes/year) be modified to provide for increasing coal and oil use to meet short-term (1999-2004) load growth?
  - Would the cap remain at the current level forcing NSPI to rely increasingly on imported electrical energy and imported low-sulphur coal?
- **De-regulation of the electric industry in Nova Scotia**
  - Would Nova Scotia de-regulate the electricity supply industry, and if so, when?
  - Would a de-regulated market lead to increased imports of electricity from suppliers elsewhere in Canada and the U.S., thereby reducing demand for thermal electrical energy sources in Nova Scotia?

A Basis for Comparison

In light of these factors, several projections are possible: coal-fired expansion, oil-fired expansion, import-based expansion, or some combination of these three. From the perspective of the impact on coal, we would argue that the matter is to a certain extent academic. The most relevant base against which to measure the impact on coal would seem to be what CBDC is capable of producing over the study period, not some hypothetical quantity linked to rising NSPI demand. Arguably, the best measure of this capability is the quantity of coal CBDC produced over the past several years.

To illustrate what a coal-fired expansion would mean in terms of coal demand, a projection of NSPI's sources and costs of electrical energy (without natural gas) is presented in Table V-1. Coal demand grows from about 3.2 million tonnes in 1998 to about 3.9 million tonnes in 2010.

Table V-1
NSPI Sources of Electrical Energy Without Natural Gas

	Load	Coal (1)		Energy Source $					
				Oil (1)		Hydro (2)		Purchases (3)	
	GWh	t 000s	$	Mega l	$	GWh	$	GWH	$
1996	9,825	3,067	198.9	159.4	35.7	1,112		255	17.2
1997	10,305	3,224	189.2	204.5	22.6	935		340	21.5
1998	10,315	3,183	191.0	236.6	23.7	965		300	19.0
1999	10,775	3,344	200.7	248.7	24.9	965		300	19.0
2000	10,620	3,290	190.8	244.6	24.5	965		300	19.0
2001	10,675	3,309	188.6	246.0	24.6	965		300	19.0
2002	10,890	3,385	189.6	251.7	25.2	965		300	19.0
2003	11,040	3,438	189.1	255.6	25.6	965		300	19.0
2004	11,155	3,478	191.3	258.6	25.9	965		300	19.0
2005	11,340	3,543	194.9	263.4	26.3	965		300	19.0
2006	11,530	3,610	198.5	268.4	26.8	965		300	19.0
2007	11,720	3,677	202.2	273.4	27.3	965		300	19.0
2008	11,950	3,758	206.7	279.4	27.9	965		300	19.0
2009	12,125	3,819	210.1	284.0	28.4	965		300	19.0
2010	12,340	3,895	214.2	289.6	29.0	965		300	19.0

(1) Coal and oil use increase in proportion to 1997 energy.
(2) Hydro supply equals 1993-1997 average production.
(3) Purchases equal to 1993-1997 average.

Source: NSPI 1997 Annual Report for years 1996 and 1997.

The case set out in Table V-1 would only be possible if the emissions standards were modified to allow release of substantially greater quantities of SO_2, if low sulphur imported coal were used, or if scrubbers were installed on all new units and retro-fitted on older plants. Scrubbers would add substantially to cost and electricity prices, and would in all likelihood render local coal a prohibitively expensive choice. Oil, though a less costly fuel at current prices, also contains high sulphur levels. From an environmental perspective, it does not represent a superior alternative.

In short, the high cost of meeting environmental standards seems likely to place a cap on the use of local coal, or any coal. It may be more economic for NSPI to meet load growth through electricity imports. But whatever option is selected, it would appear that the relevant basis for determining the impact of natural gas is the historical level of CBDC production, and not some hypothetical level of coal demand.

2. FUTURE COAL DEMAND WITH NATURAL GAS

Relative Prices

Natural gas could play an important role as a future source of electrical energy in Nova Scotia; how important depends on relative fuel prices and pressures to reduce sulphur and other emissions. The significance of relative fuel prices is illustrated in Table V-2, showing the maximum prices gas could sell for in order to compete with coal and heavy oil in today's market. This comparison yields three main conclusions:

- It would be uneconomic to spend millions to convert a coal-fired plant to natural gas, or to shut down a coal-fired plant if not fully depreciated and replace it with a gas-fired plant. A substantial spread between coal and gas prices would be required to re-capture such investments. With world coal prices heading downward, this price spread is unlikely to emerge in the foreseeable future. This is confirmed by the experience elsewhere and by recent studies.*

* In particular see, K. Morgan MacRae, *"Natural Gas Utilization for Selected Generating Units in Nova Scotia: Economics and Emissions"*, Canadian Energy Research Institute, 1997.

Table V-2
Relative Fuel Prices for Electrical Generation in Nova Scotia

	Price	mmbtu/unit	Efficiency	Cost/mmbtu
CBDC Coal (tonne)	65.00	26.50	0.33	7.43
Natural Gas (mmbtu)	2.50	1.00	0.33	7.58
Heavy Oil (#6)	15.90	6.29	0.33	7.66
Imported Coal (tonne)	55.00	26.50	0.33	6.29
Natural Gas (mmbtu)	3.50	1.00	0.55	6.36

Note: CBDC coal price is estimated using public documents. This price applies only to coal purchased under the long-term agreement between NSPI and CBDC. Coal purchases by NSPI from CBDC over the minimum quantity specified in the long-term agreement are priced at internationally competitive levels. See Appendix A for more information on the long-term agreement between NSPI and CBDC.

- Gas will have a hard time displacing coal and oil at today's prices in circumstances where natural gas is used in a conventional thermal generating unit (like Tuft's Cove). It is only at a price less than about $2.50/mmbtu, that gas is competitive on a pure cost/Btu basis. A price this low is unlikely to be achieved if it includes both the commodity price of gas and the transmission toll. A more realistic minimum would be in the $2.80-3.00/mmbtu range. Of course, it may still make sense to use gas even at these higher prices, since it allows the avoidance of costs associated with reducing sulphur emissions in coal plants.

- Gas becomes a more attractive alternative when used in higher efficiency systems (eg, combined-cycle plants). At prices below $3.50/MMBtu (a more realistic range if both the commodity price and transmission toll are included), gas can compete with imported coal and is some 20% cheaper than CBDC coal (at the current contract price) and #6 oil. These relative prices, coupled with lower capital costs, make gas-fired combined cycle technology the more attractive option when additions to system generating capacity are required.

Proposals To Use Gas To Generate Electricity

NSPI has entered into a long-term contract (10 years) for gas delivery to the termination point of the Halifax lateral in Tuft's Cove. Though NSPI has the option of selling the gas if oil prices are relatively low, for purposes of this analysis, we assume the maximum volume of gas is used (61,400 MMBtu/day). NSPI's current system expansion plans call for a 300 MW gas-fired combined cycle plant to be constructed at Tuft's Cove for in-service in 2004. This unit would use the 61,400 MMBtu and simply displace the base load capacity of the existing plant. The latter could be used for peaking purposes using either oil or gas. Both these projects would reduce the demand for coal.

Stora Forest Industries at Point Tupper is assessing the feasibility of constructing its own gas-fired combined-cycle electrical generating unit. It is reported to be considering a 250 MW plant to meet its own 185 MW power need, with sale of the surplus. It is assumed to come on stream in mid-2003. If it proceeds, it would reduce NSPI's load and the need for capacity expansion in 2004. The net effect on coal would be to advance the timing and increase the reduction in demand arising from the NSPI plan.

At this point, two caveats are in order.

- Whether coal is affected at all in 2000 and beyond, depends on NSPI's ability to expand into export markets. This in turn depends on NSPI's delivered cost of electricity compared with prevailing prices in those markets. Any impact on coal from natural gas would be reduced to the extent NSPI is successful in penetrating export markets.

- Whether CBDC coal or coal supplied by others (including imports) is affected depends largely on their relative prices, and to some extent also on relative sulphur content. The reader is reminded that in the years leading up to 1998, non-CBDC coal met as much as 25% of NSPI's total coal requirements (Appendix A and Fig. V-2, below).

3. IMPACT ON COAL

Coal Demand Drops Assuming no Electricity Exports

In the absence of very detailed information about export markets, it is difficult to determine how realistic the export case is. For purposes of assessing the impact on coal, we take a conservative approach and assume zero electricity exports.

Taking all these factors into account, and assuming maximum use of natural gas, estimates of electricity production by energy source and the resulting impact on coal requirements depend to some extent on whether NSPI or Stora's plans proceed:

- The initial impact, as the Tuft's Cove conversion comes on stream in 2000, backs out oil completely, and also causes a reduction in the need for coal-fired energy elsewhere on the system (Table V-3). The demand for coal drops by about 400,000 tonnes (Fig. V-1).

- A second impact on coal arises in either 2003 or 2004, depending on whether NSPI's planned 300 MW or Stora's 250 MW gas-fired combined cycle plant comes on stream.

  - NSPI's 300 MW unit would use the original 61,400 MMBtu/day, but at a higher efficiency (55-60% vs. 33%). Other things equal, this 67% gain in efficiency would cause a further decline in the need for coal-fired energy (Table V-3). The demand for coal drops by about 500,000 tonnes in 2005 compared with its 2003 level (Fig. V-1).

  - Stora's 250 MW unit would use an estimated 33,500 MMBtu/day. This would bring total gas use for electricity generation to about 94,000 MMBtu/day (Tuft's Cove conversion *plus* Stora), leading to a greater reduction in the need for coal-fired energy (Table V-4). The demand for coal in this case drops by 650,000 tonnes in 2004 compared with its 2002 level (Fig. V-1).

Whose Coal is Cut Back Depends on Price

Under a zero electricity export case, the key question becomes whose coal is displaced by gas: CBDC, other (either domestic or imported), or both. Fig. V-2 shows that between 1993 and 1998, NSPI relied on coal from sources other than CBDC to meet an increasing proportion of its needs. This was due mainly to production constraints at CBDC, causing supplies to NSPI to plateau at about 2.4 million tonnes annually. If this recent plateau represents a realistic production ceiling for CBDC, then future coal requirements over and above this level (projected in Table V-1 to reach 3.9 million tonnes in 2010) would have to be met from other sources.

With the availability of natural gas, coal requirements decline to about 2.8 million tonnes in 2000, and at worst (with Tuft's Cove and Stora) drop to a low point of about 2.3 million tonnes in 2004. This is some 900,000 tonnes below NSPI's 1997 requirements, and about 100,000 tonnes *below* CBDC's 1997 sales level to NSPI (Table V-3). In short, unless the use of gas exceeds the 94,000 MMBtu/day level, the demand for coal would drop only slightly below CBDC's recent 2.4 million tonne production plateau.

In assessing the impact on CBDC, it is important to note that NSPI demand exceeded the minimum quantity under its contract with CBDC by some 500,000 tonnes in the years leading up to 1997. This coal was purchased at the avoided cost to NSPI, ie, the world price. Presumably, as long as CBDC can supply NSPI on these terms, reductions in coal requirements due to natural gas would be reflected first in reduced imports and supplies by others (depending on other contractual arrangements).

In short, though natural gas can be expected to reduce NSPI coal requirements significantly, the decrease would be felt not by CBDC, but rather by other suppliers, *as long as CBDC is able to produce at NSPI's avoided import cost.* If not, then NSPI demand for CBDC coal would presumably drop to the contract minimum, where it would be regardless of any competition from gas. This minimum (1.9 million tonnes) is currently well below the projected low point (2.3 million tonnes) as a result of natural gas (Fig V-1). In other words, over the period under consideration (to 2010), the availability of natural gas is not the limiting factor in determining demand for CBDC coal; rather, it is whether CBDC can continue to offer coal to NSPI on a competitive basis with other coal supplies. The impact, based on continuing CBDC competitiveness, is shown in Fig. V-2.

Figure V-1: NSPI Coal Demand with Natural Gas, 1999-2010

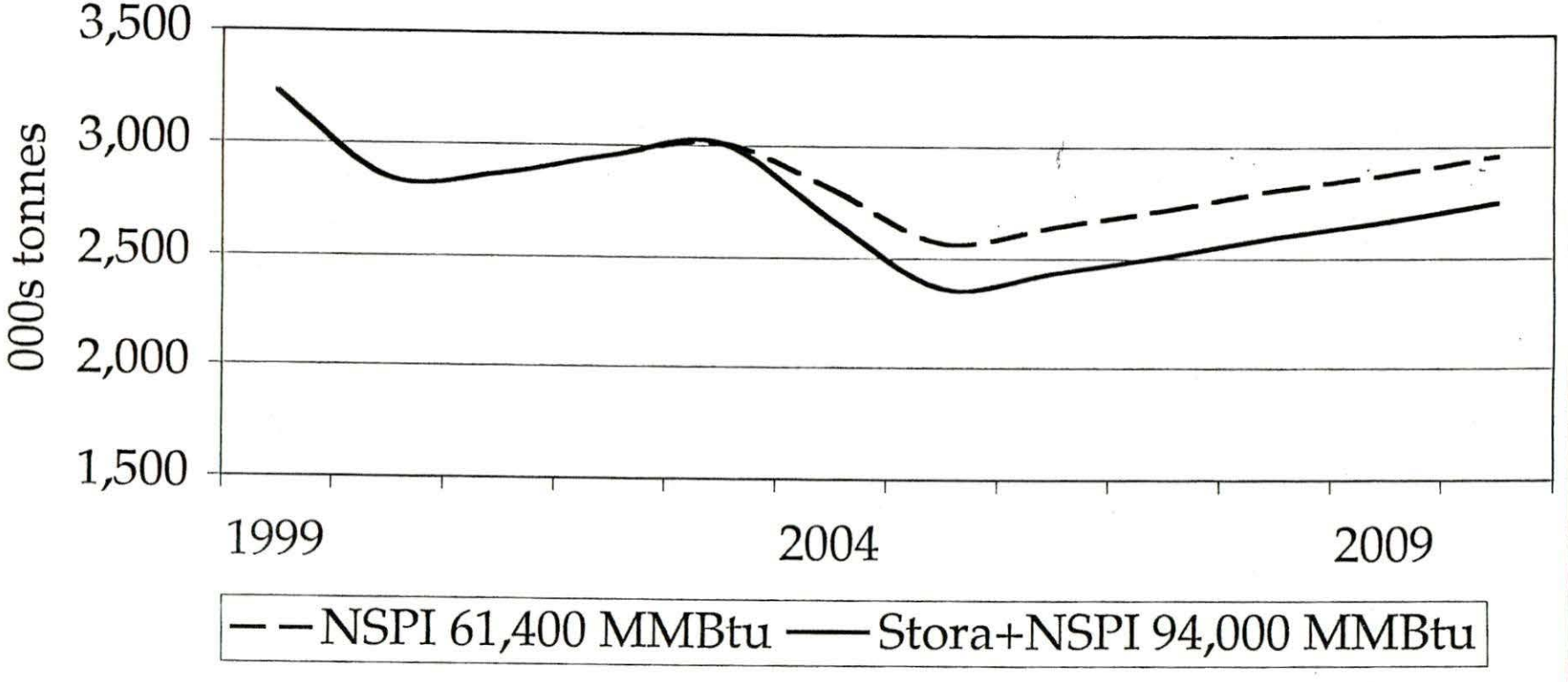
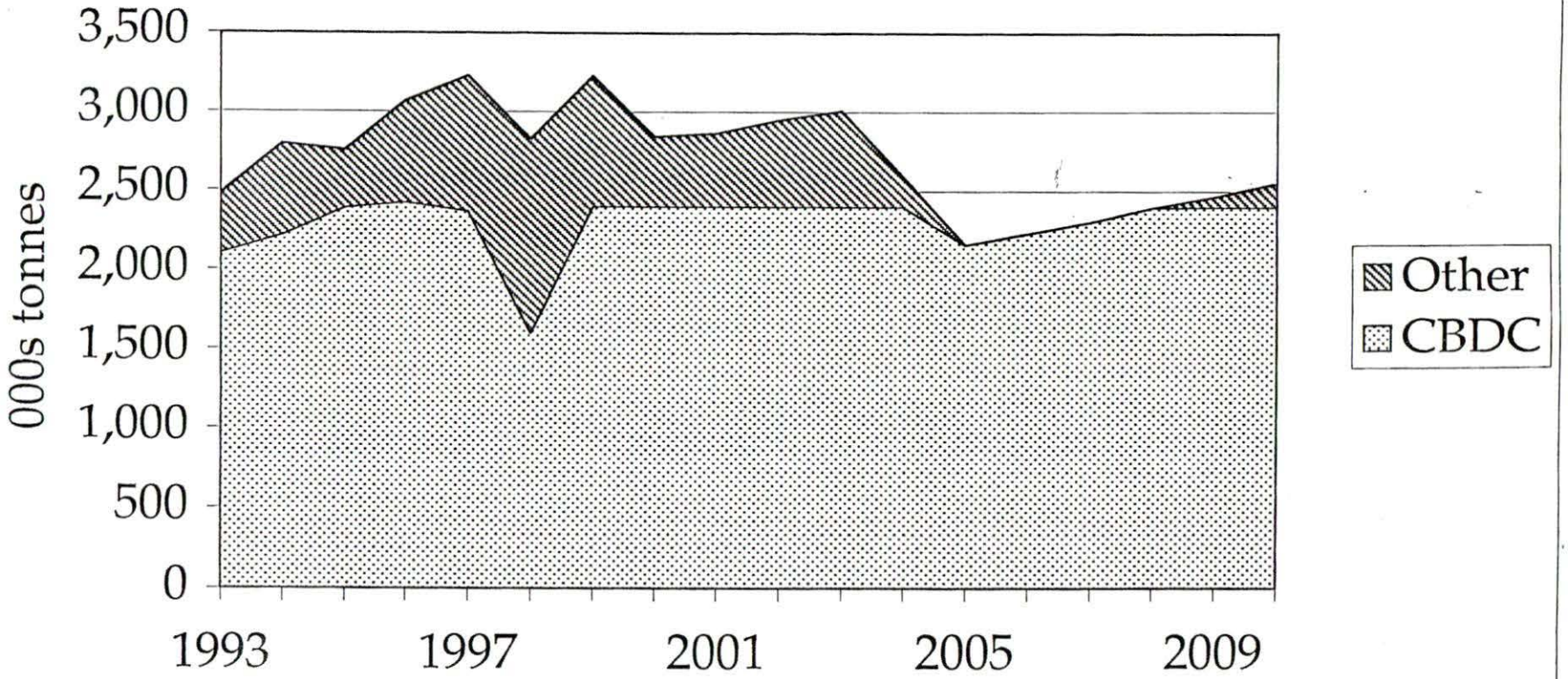


Figure V-2: Impact of Natural Gas on NSPI Coal Requirements



For its part, NSPI (as a publicly traded company) can expect to come under increasing pressure from shareholders and the market (particularly in the event of de-regulation) to continue to keep its costs down. By ensuring it is using the least costly mix of fuels, NSPI furthers this objective.

Other Factors

Two other factors could have a bearing on NSPI's gas utilization and system expansion plans, and hence on the impact on coal:

- **Industrial Generators**: Existing NSPI customers could use gas to fire their own combined cycle electrical units (as Stora is considering), should their circumstances warrant such a shift (this is mainly a cost consideration). This would further reduce the demand for coal. There are few large industrial customers for whom this would be a viable option; nonetheless, it is something to be considered in any long-range coal development planning.

- **De-regulation**: There is the possibility that in a de-regulated environment, new companies could enter the Nova Scotia electricity supply market to compete with NSPI, either by developing gas-fired generating capacity in the province, or simply by importing electricity. These lower cost sources could displace existing coal-fired capacity, effectively stranding these assets. Stranded assets are ones without a market, but whose costs are not fully depreciated. Jurisdictions moving toward a de-regulated electricity market would ordinarily introduce a mechanism to spread these costs among consumers using a fixed charge of some kind. Not to do so would impose an unfair burden on the utility whose assets are stranded.

  The U.S. and U.K. offer good examples of jurisdictions were de-regulation is fairly well-advanced. In both areas, the combination of relatively inexpensive natural gas, advances in combined-cycle technology, and pressure to reduce greenhouse gas emissions, led to substantial increases in gas-fired electric generating capacity. This expanded use of gas came mainly at the expense of coal (but also nuclear), often resulting in the closure of coal-fired capacity before it was fully depreciated. A discussion of the possible implications of deregulation is set out in Appendix A. Appendix D sets out brief case studies of de-regulation in the U.S., the U.K., and Alberta.

Economic Impact

The impact of gas on coal production illustrated in Fig. V-2 would result in the loss of a small number of jobs for about two years. As long as CBDC is able to sell coal over and above the contract minimum to NSPI at competitive prices, then at no time does gas itself cause any more than a 100,000 tonne (about 4%) drop in CBDC coal production. This drop is temporary, occurring mainly in 2004, with full recovery by the end of 2005.

If gas is used by industries other than Stora to generate electricity and this reduces demand on the NSPI system, then the demand for coal would be reduced commensurately. This would increase the size and duration of job loss. It is impossible to estimate what this impact might be in the absence of specific information on new gas-fired generating capacity.

VI.

RECOMMENDATIONS

These recommendations focus on steps to be taken to enhance positive impacts on the CBRM and to mitigate negative ones associated with Sable gas projects as well as ones arising from future natural gas projects and access to natural gas in the province. The main positive impacts flow from industrial development through the supply of goods and services to offshore projects, and early construction of a lateral and distribution system. Delayed access to natural gas is identified as the main potential negative impact.

The substitution of natural gas for coal in electrical generation was identified as a major factor and formed part of the impetus for this study. Though the study concludes that the impact of gas on CBDC coal is likely to have been relatively small over the next decade, concerns about this have been overtaken by events. The impending closure of CBDC would result in a much more serious negative impact on the CBRM economy. And though the closure itself does not fall within the terms of reference as a potential impact to be studied, it represents an additional factor to be considered in assessing the impacts of changes in the energy sector.

1. **In light of the on-going weakness of the CBRM economy and the implications of the closure of CBDC, a framework for ensuring the CBRM gains early access to natural gas should be given careful consideration by government.**

   The *Gas Distribution Act* Regulations indicate that access to natural gas is deemed to be desirable on public policy grounds. Applications to develop a natural gas distribution system are before the Nova Scotia Utilities and Review Board. Though the targets set out in the policy indicate that the CBRM should gain access, there is no stipulation as to timing other than required access should be achieved within seven years.

   A seven-year wait may be too long for the CBRM. It could put the region at a competitive disadvantage with other areas of the province, precisely at a time when the economy is most vulnerable. Early access to gas would at least contribute to a more even playing field. Also, it could enhance the value of Sysco, which would be of immediate benefit to the region insofar as access to gas could improve the competitiveness of the company and its attractiveness to prospective purchasers.

2. **A special initiative is needed to try to pool resources in the CBRM to promote more effective participation in SOEP and other offshore projects.**

   CBRM firms played a limited role in supplying goods and services to SOEP (Phase I). Firms tend to be small and lack the capacity for successful bids on contracts. Moreover, there is an understandable reluctance to commit scarce financial resources to developing capacity, given the uncertainty about how long offshore activity may last and what future requirements may be.

   This uncertainty aside, there is optimism the participation level in Phase II and in future projects could be higher. To achieve this requires not just increased interest on the part of the business community, but a concerted effort to develop the necessary capacity through a combination of investment and development of joint venture partnerships. This requires leadership to harness the pool of local resources, and to search out opportunities. It may also require tangible support from government, and continued advice and encouragement from the oil and gas industry.

3. **Programs to provide training for jobs in natural gas distribution should be developed and established at one or more institutions in the CBRM.**

   Special courses for gas fitters and related occupations are required to support development of the gas distribution industry. It may make sense to concentrate the training programs in one or two institutions in the province. If so, consideration should be given to locating a program in a technical institution in the CBRM.

4. **The general public would benefit from a review of provincial energy policy aimed at specifying government objectives with respect to the conditions of energy supply and demand in the province, and elaborating initiatives to achieve those objectives.**

   The energy policies of the 1970s and 1980s placed coal firmly at the centre of a strategy combining economic development and security of energy supply. The energy landscape in the province has changed over the years, and is likely to shift substantially over the next decade in response to changes in many of the factors influencing patterns of demand and supply. Among these shifts are: the arrival of natural gas; the impending closure of CBDC; lower oil costs; the possibility of de-regulation of the electricity supply industry; and, the possibility of more stringent environmental standards leading to a reduction of greenhouse gas emissions.

   A policy review would be very helpful for Nova Scotians wishing to gain a better understanding of what the future holds for them. In particular, it would allow residents of the CBRM some insight into the role coal is likely to play in electrical generation in the future. This is important for the economy as a whole, not just for those working in coal production and at electrical generating stations.

   The review should be comprehensive, identifying the full range of factors influencing change, and the likely direction and magnitude of change; what policy objectives government holds and how these objectives are to be achieved; and finally, what the impact of any policy initiatives are likely to be.

APPENDIX A

NOVA SCOTIA ENERGY MARKET

A.

NOVA SCOTIA ENERGY MARKET

1. OVERVIEW

Nova Scotians spend about $2 billion annually to meet their energy needs. About half of this is spent on electricity, petroleum and wood to meet heating, lighting and operating demands in the residential, institutional, commercial and industrial markets. The other half is spent on petroleum products to meet transportation needs (Table A-1).

Table A-1
Nova Scotia Final Energy Demand by Sector, 1996

	Energy (000s MMBtu)	$ (millions)
Residential	33,300	470
Commercial/Institutional	28,700	280
Industrial	27,900	245
Transportation	61,800	1,050
Total	151,700	2,045

Statistics Canada, Cat. No. 57-003, 1996. Expenditure estimates based on 1998 fuel prices.

The primary energy sources used to meet these needs fall into four main categories: crude oil, coal, hydro and wood. The proportions of each are set out in Table A-2.

Table A-2
Nova Scotia Primary Energy Demand, 1996

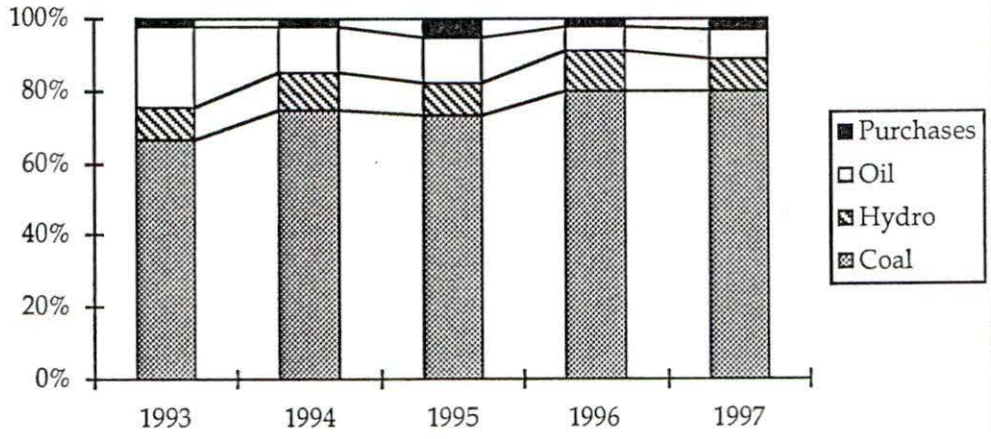
	Energy	
	000s MMBtu	%
Petroleum	143,400	57
Coal	85,700	34
Hydro	11,600	5
Wood	9,500	4
Total	250,200	100

Statistics Canada, Cat. No. 57-003, 1996.

Energy demand has shown little change over the past decade. To some extent this is due to efficiency gains offsetting demand growth. But it also because trends are difficult to distinguish, given the strong influence of winter temperatures on demand and the wide annual variation of these temperatures.

The final demand data in Table A-1 obscure the role played by local resources in meeting primary energy demand. Electricity, accounting for about 45 percent of non-transportation end-use demand is generated mainly from coal produced in the CBRM. Coal is the source of about 80 percent of electrical energy. Hydro accounts for about 10 percent. Imported oil and electricity purchases (including imports) account for the other 10 percent (Fig A-1).

Figure A-1: NSPI Electrical Energy by Source, 1993-1997



With natural gas entering the provincial market in 1999 or 2000, the historical pattern of energy supply and demand will change. Natural gas has the potential to displace such fuels as light and heavy fuel oil, coal, propane and electricity (the latter most cost-effectively through supplementary methods rather than outright conversion).

If experience elsewhere offers any guidance, the main targets for initial conversion to natural gas would be energy-intensive industries and electric utilities. Institutional, commercial and residential sectors would follow once pipelines and laterals are installed to meet the industrial and utility demand.

It is important to note that the mere availability of natural gas in Nova Scotia does not in itself guarantee a market. It must compete with existing fuels whose suppliers, including CBDC, would like to retain their market share. The ability of natural gas to compete in the Nova Scotia market depends on several factors:

- inter-fuel economics and conversion costs
- contractual obligations
- environmental considerations
- gas distribution and lateral policies
- deregulation of electricity supply
- CBDC production capability and cost
- natural gas pricing in Nova Scotia

2. FACTORS AFFECTING NATURAL GAS DEMAND IN NOVA SCOTIA

INTER-FUEL COMPETITION

Issues

Among fuels offering the same long-term supply security and reliability of delivery, cost tends to be the single most important factor in determining choice of fuel. Three factors go into the determination of cost from the consumer's perspective: price, combustion efficiency and complying with emissions standards.

Price

This is what the consumer pays for fuel delivered to the plant or residence. Relative prices for fuels available in Nova Scotia in late 1998 are shown in Table A-3. The coal prices shown are not a matter of public record. The coal price for minimum quantities under the long-term contract is derived from and NSPI annual reports.

Table A-3
Fuel Prices in Nova Scotia, 1998

	Price $/unit	Efficiency (Combustion/ Conversion)	Delivered Cost ($/mmbtu)
# 2 oil			
Domestic (litre)	.32	.75	11.64
Commercial (litre)	.20	.80	6.82
Industrial (litre)	.20	.80	6.82
# 6 oil			
Commercial (litre)	.12	.84	3.31
Industrial (litre)	.11	.83	3.61
Propane			
Domestic (litre)	.42	.70	23.30
Commercial (litre)	.32	1.00	12.42
Industrial (litre)	.25	.80	12.13
Coal			
CBDC (tonne)	65	.33	7.43
Imported (tonne)	55	.33	6.29

Source: NS Department of Natural Resources; various petroleum distribution companies; NSPI and CBDC annual reports.

In order to penetrate markets in Nova Scotia, gas will have to be priced competitively. In new and expanding markets in Canada and the U.S., the experience indicates that inducing consumers to convert from oil to gas generally requires a gas price below the energy equivalent price of the alternative fuels. Gas has been able to achieve this pricing differential because market conditions (eg, relative costs of production and delivery) allowed it.

- In the residential sector, price differentials as high as 30 percent between gas and oil have not been uncommon. Such differentials are needed to overcome conversion costs and long-established consumption patterns.

- The differential in the commercial and industrial sectors varies depending on the type of fuel displaced. The differential is high where high-priced fuels such as propane are displaced (and generally, this is an easy conversion), but low where cheaper heavy oil is displaced. Most large industries would maintain a dual-firing capability (gas and oil) in order to take advantage of relative price changes.

- The same factors apply in the case of electrical utilities, though much depends on the fuels and technology in use. The prospect of favourable gas prices would be needed to induce conversion to dual-firing in the case of conventional oil-fired generators (an unlikely prospect in today's market). Coal-fired units are more costly to convert and generally would not have dual-firing capability (though some utilities take advantage of the combustion and low emissions properties of gas and use it in conjunction with coal, so-called "co-firing"). What is more likely, and what is occurring elsewhere, is the use of gas to power higher efficiency ("Combined-Cycle") generating units when additional generating capacity is required.

- Three effects are evident with the shift to market de-regulation elsewhere in North America. The first is improved customer choice: the end-user (particularly in the industrial sector) now has the opportunity to contract directly for gas with the term, price and supply flexibility tailored to customer requirements. The second is decontrol of transportation from gas supply: this means customers can contract for interruptible gas supply in the off-season, thereby realizing price discounts for both the gas and transportation capacity. Third, decontrol has also resulted in development of many supplier options. With the resultant competition for customer load, the competitive opportunities for gas generally exceed those found with other fuels.

A key question in all this is whether Sable gas actually will be able to be sold at prices sufficiently below competing fuels to encourage conversion. The delivered (burner-tip) price of Sable natural gas for wide distribution in Nova Scotia is not yet known, so it is difficult to make comparisons.

It should be noted that the price consumers pay for natural gas in Nova Scotia will be composed of four separate elements, each involving distinct corporate entities:

- the commodity price of the gas at the gas plant – this pays Mobil and its partners for the development and production of the Sable gas fields;
- the toll to cover the costs of transportation – this toll pays for the pipeline or lateral line capacity needed to deliver the gas to the community, or so-called "city-gate";
- the toll to cover distribution system costs – this toll pays for the small diameter lines needed to take the gas from the laterals to consumers in each community; and,
- a margin to cover the costs of gas marketing – gas is expected to be marketed by an company independent from the distribution franchise holder.

Until more is known about the commodity price of gas and the cost structures and tolls for laterals and distribution systems, the likely competitiveness of gas remains unclear.

Oil, coal and electricity prices occupy the other side of the fuel competition equation.

- Oil prices tend to be highly variable (and unpredictable) because the oil market is international in scope and subject to abrupt change for a variety of political and economic reasons.
- Coal prices are relatively stable. Coal markets tend to be mainly regional, and subject to long term contracts primarily with electrical utilities. There is a spot market, with prices rising and falling in response to oil prices. The long-term trend, though, is to lower coal prices.
- Electricity prices are stable because most utilities are regulated (though this is changing), and because the variable factor, fuel, generally accounts for half or less of the total costs. In Nova Scotia, electricity price stability is closely linked to the long-term contract between NSPI and its major coal supplier, CBDC.

How changing relative prices influence fuel choice may be seen from the shift in NSPI's fuel mix in the five years leading up to 1997 (Table A-4). In the face of moderately falling coal prices and sharply rising oil prices, the proportion of NSPI's total electrical generation fueled with coal increased from 66 to 80 percent (Fig. A-1). Oil declined from 22 to just over 7 percent (hydro and purchases make up the balance).

Table A-4
Nova Scotia Power Inc.
Unit Costs of Energy Production, Coal vs. Oil, 1993-1997

	1997	1996	1995	1994	1993
Energy (GWh)					
Coal	8,247	7,850	7,053	7,160	6,346
Oil	781	609	1,239	1,206	2,117
Cost of Fuel ($ 000,000s)					
Coal	189.2	198.9	189.5	204.4	179.6
Oil	35.7	22.6	39.0	35.2	60.5
Cost per MWh ($ 000s)					
Coal	22.9	25.3	26.9	28.5	28.3
Oil	45.7	37.1	31.5	29.2	28.6

Nova Scotia Power Inc. Annual Report, 1998.

In 1998, oil prices fell to their lowest point (in real terms) since the 1973 and 1979 Gulf crises sent prices sharply upwards. Where energy prices are heading in the long term is impossible to predict with any confidence, particularly in the current climate of uncertainty over economic recovery in the Far East and how this will affect commodity prices.

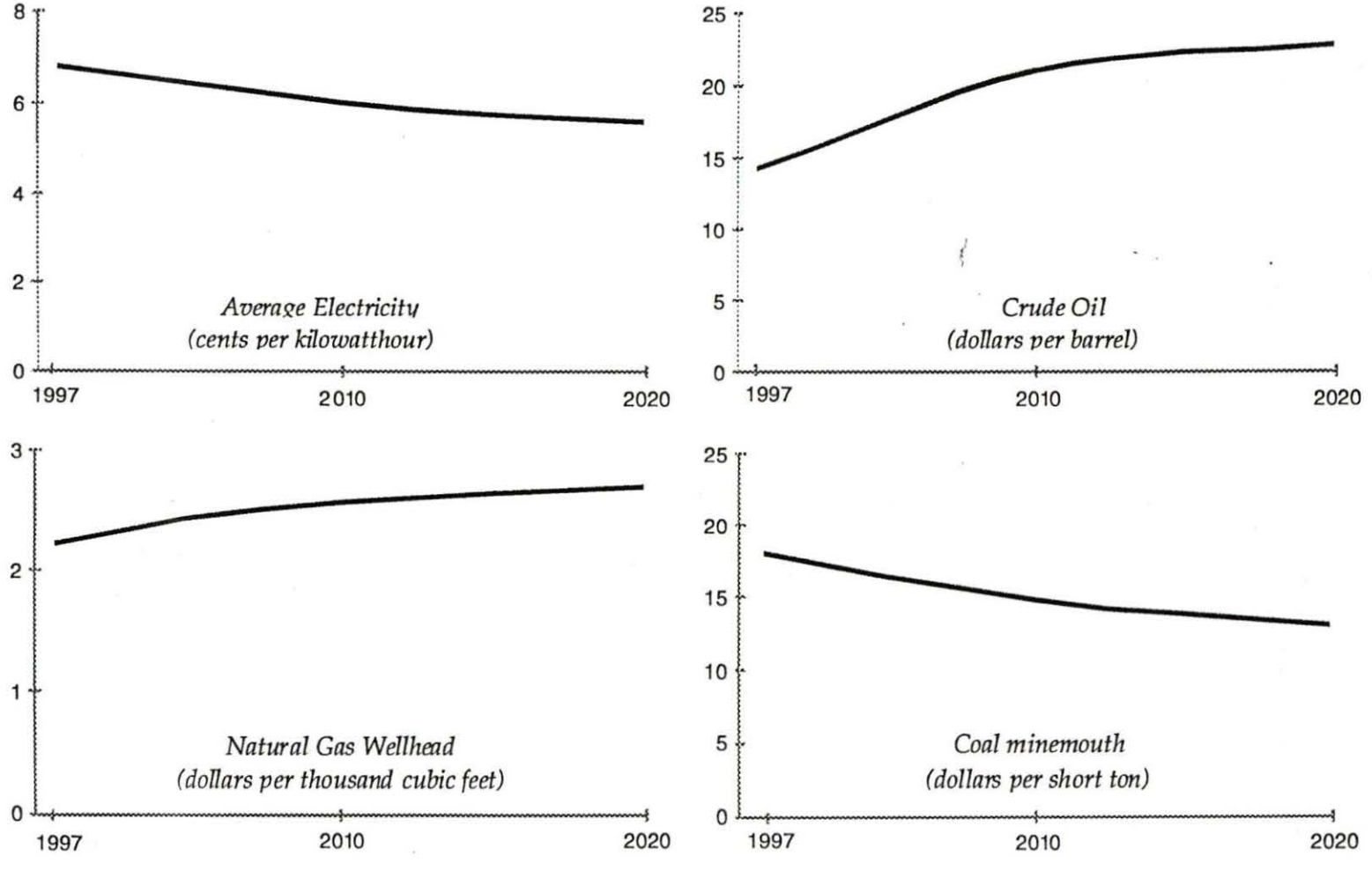
A recent forecast by the U.S. Department of Energy (Fig. A-2) predicts North American crude oil and natural gas prices are likely to remain fairly flat over the next 10 years, while coal and electricity prices are expected to drop.*

- Stable natural gas prices are explained by the balance in demand and supply within the North American market. The trend towards increasing gas utilization for electrical generation provides support for prices, while improved transportation capacity and supply capability provides a moderating influence. Though gas and oil are substitutes, their markets differ in that oil trades globally, while gas markets tend to be regional due to high transportation costs.

- The rising trend for crude oil is explained by strong international markets and expectations of moderate supply expansion. A prolonged recovery of Asian economies following events in 1998 may serve to extend the turning point of oil prices.

* U.S. Department of Energy, EIA, "Early Release of the Annual Energy Outlook 1999".

Figure A-2
Fuel Price Projections, 1997-2020
(1997 U.S. Dollars)



Source: U.S. Department of Energy, Early Release of Annual Energy Outlook 1999, November, 1998

- Declining coal prices are due to a combination of declining production costs and reduced demand as emissions limits cause electrical utilities to look to natural gas to meet expansion requirements. Gas supply potential is strong, with transportation capacity and reach continuing to expand within North America.

- Declining electricity prices, though highly regional, are explained by reduced costs of production (though expansion is predicted to be mainly gas-fired, much of the installed capacity will be coal-fired for many years), and greater competition due to deregulation of electricity markets.

Combustion Efficiency and Operating Characteristics

Combustion efficiency determines the actual cost of energy once it is converted to the user's needs. A shift to natural gas would cut the total amount of energy consumed, where the shift is based on installation of high efficiency combustion units. Conversions to dual-fired capability (gas and oil) would not ordinarily result in improved efficiency, and could result in a net loss of efficiency when gas is used.

The scope for improved efficiencies and cost savings varies by sector:

- Gains for residential customers depend on the efficiency of the system currently in use, and the options available for oil conversion. Most residential oil furnaces achieve efficiencies ranging from 60-78 percent, though newer designs ("Standard Condensing") can achieve efficiencies up to 86 percent. Mid- and High-Efficiency gas furnaces achieve 82 and 96 percent efficiency, respectively.

- Industry would experience a small net loss in combustion efficiency in converting to natural gas, (from about 83 to 78 percent), though this would be offset by improved operating characteristics and reduced emissions resulting in a more or less neutral impact on costs. Given the similar overall operating characteristics, most industrial customers maintain a dual-firing capability (oil and gas) in order to take advantage of relative price shifts.

- Combustion efficiencies for conventional coal- and oil-fired electrical generating stations are in the 33 percent range. Natural gas offers the potential for substantial improvements in combustion efficiency (to the 50-60 percent range), assuming construction of new combined-cycle units (see Annex II for an explanation of this technology). A simple conversion of an existing oil-fired plant to dual-firing capability (as is planned at the NSPI Tuft's Cove station) would cause a small drop in efficiency.

Complying with Emissions Standards

The measures needed to comply with emissions standards may impose direct or indirect costs on fuel users. Costs may take the form of investment in emissions control technology (eg, scrubbers on smoke stacks), taxes linked to emissions levels, or purchases of emissions rights in areas where emissions trading regimes are in place.

Air Quality Regulations under the *Nova Scotia Environment Act*, limit NSPI to a cap on sulphur dioxide (SO_2) emissions of 145,000 tonnes. With its heavy dependence on coal with high sulphur content (2.2-3.5 percent), NSPI is currently at or near this limit (137,750 tonnes in 1997). Increasing the proportion of oil in the fuel mix is not a solution (unless relatively expensive low sulphur oil is used), mainly because the heavy oil used also has a relatively high sulphur content (2.4-3.0 percent).

Among the options open to NSPI to contain or reduce SO_2 emissions are:

- cut back on electricity production and increase electrical energy imports;
- use low sulphur imported coal as a substitute for Cape Breton coal;
- substitute natural gas (which contains no SO_2) for oil and/or coal; and,
- put scrubbers on the stacks of one or more generating stations.

NSPI is acting on, or plans to act on, each of the first three options, though not necessarily for reasons related to meeting emissions limits.

- A small percentage of annual energy requirements are met through imports (when economically attractive). This could increase if necessary, depending on relative costs.
- To date, relatively high sulphur coal has been imported from the U.S. and elsewhere to meet demand when production shortfalls from CBDC are incurred. Low sulphur coal could be used instead if emissions limits are approached.
- NSPI plans to convert its 330 MW oil-fired Tuft's Cove generating station to dual-fired capability (natural gas and oil). Use of gas (scheduled in-service in 2000) would cut SO_2 emissions by at least 10,000 tonnes.
- The cost of installing scrubbers on the stacks of the Lingan Power Station is estimated by NSPI to be in the range of $200 million. The economics of this option are not attractive considering the age of the facility (20 years) and the alternatives for reducing emissions.

What this means for the CBRM

The combined effects of probable relative price changes for sources of electrical energy, relative combustion efficiencies of alternative gas-fired and other units, and more stringent emissions standards suggest that natural gas will become an increasingly attractive fuel for future electrical generating stations in Nova Scotia.

CONTRACTUAL OBLIGATIONS

Issues

NSPI entered into a 32-year coal contract with CBDC in 1978. The contract is one based on mutual dependence. It was negotiated at a time of rapidly rising oil prices and considerable instability in energy markets. NSPI gained supply security and relative price stability, while CBDC obtained the guaranteed market needed to support long-term investments in mine development. The contract expires in 2010.

NSPI burned about 3.2 million tonnes of coal in 1997, up from about 2.5 million tonnes in 1993 (Table A-4). CBDC supplied about 2.4 million tonnes in 1997 (75 percent), some 500,000 tonnes over the contract minimum. The contract minimum is purchased at the contract price, with any additional coal purchased at prices linked to world prices (and presumably above CBDC's cost of production). This arrangement allows CBDC to maintain production levels, and NSPI to reduce or limit the increase in its cost of production.

Coal requirements over and above CBDC supply are met through imports obtained at spot market prices. Imports rose substantially in 1998 due to various production problems at CBDC which reduced NSPI purchases to the 1.6 million tonne range.

Central to the contract are terms relating to quantity and price; these are open to re-negotiation every five years (the last re-opening was in 1995 when both quantity and price were adjusted downward). NSPI is committed to taking a minimum quantity of coal each year at the contract price. This had been over 2.0 million tonnes, but currently stands at 1.9 million tonnes (with a tolerance of 10 percent). The contract price is confidential, but is estimated to be in the $65/tonne range.

Officials in CBDC and NSPI indicate the contract sets out four principles the parties should consider in negotiating the coal price:

- alternative fuel costs (eg, historically, oil and imported electrical energy; in the future, natural gas as well);
- cost of production;
- world market price for CBDC-quality coal; and,
- cost of imported coal on a long term basis (in today's energy market, 1-5 years).

The application of these principles led to an 18 percent drop in the price in 1995 when the contract was last re-opened (this drop was phased in over three years). Oil prices had been declining up to that point (see Table A-4), and it was beginning to be cheaper for NSPI to use oil to generate electricity. The price decrease coupled with rising oil prices after 1995 caused NSPI's use of coal to increase. Declining world coal prices also contributed to NSPI's increased use of coal.

What this means for the CBRM

World coal prices are expected to continue to decline as utilities are forced away from coal-fired generating capacity in order to reduce greenhouse gas emissions. When the contract is re-negotiated in 2000, these factors, coupled with the availability of natural gas in the province, are expected to put continuing downward pressure on the coal price. To remain competitive, CBDC costs of production have to decrease from levels estimated to be currently in the range of $55/tonne.

ENVIRONMENTAL CONSIDERATIONS

Issues

Global concern about the environmental effects of greenhouse gas emissions is reflected in the Kyoto Protocol on Climate Change, negotiated in December 1997. Its central feature is a set of binding emissions targets for industrial nations: achieving by 2010 a 6-8 percent reduction in emissions below an agreed baseline level (1990 or 1995, depending on the gases in question).

If the Protocol is ratified, steps would have to be taken to reduce consumption of particularly polluting fuels such as coal and heavy fuel oils. These steps could involve so-called pollution taxes that would increase operating costs leading users to seek alternative fuels, and emissions trading systems which would reward users for reducing use. Conversely, energy policies would promote the use of cleaner fuels such as natural gas which, when burned, emits no SO_2, about 60% the level of carbon dioxide (CO_2), and lower levels of nitrogen oxide (NOx).

What this means for the CBRM

Whether the Kyoto Protocol becomes a binding agreement and what kind of framework is implemented to achieve its targets remain to be seen. But nonetheless, against this backdrop of international concern and in the context of the province's existing Air Quality Regulations, the future of coal and oil for purposes of electrical generation is constrained. Strict application of the emission targets would drive up the costs of using CBDC coal, since scrubbers would have to be installed on any new units, and could also lead to the need to fit scrubbers on old coal-fired units.

GAS DISTRIBUTION AND LATERAL POLICIES

Issues

The extent to which natural gas alters the province's existing energy mix, and the economic impact this generates, depend to a large extent on the policy framework governing gas distribution and transportation.

Nova Scotia's distribution regulations, published in November 1998, embody a framework with three key provisions aimed at maximizing access to gas:

- **Single franchise**: the province will be served by a single franchise. This is regarded as the most economically feasible and expeditious way of developing the system. It should promote level rates, consistent service and efficient financing.
- **Wide gas distribution**: the coverage area for natural gas must be as widespread as economically feasible. The provisions specify that access to gas must be available to a target number of households in each county.
- **Single toll:** the Utilities and Review Board is required to create a single province-wide toll or rate so that all consumers pay the same transportation charge. This toll is intended to be performance-based, thereby providing the franchise holder with an incentive to comply with its required access commitments.

In practice, it is not yet clear how the regulations will be implemented, and in particular, how the test of economic feasibility will be applied. It is possible that a toll satisfying the feasibility criterion for the distribution system, when added to the other price components, would result in a price too high to allow gas to compete effectively with alternative fuels.

It should be noted that the distribution regulations apply only to distribution systems, and not to the laterals needed to transport gas to these systems from the main pipeline. The proposed Halifax and Strait of Canso laterals are governed by M&NP's "Lateral Policy". In essence, application of the Policy means that:

- If a proposed lateral and the contracted demand of that lateral generate sufficient revenue (based on a test toll of $0.60/mmbtu) to cover the annual cost of service, M&NP would proceed to construct the lateral without any incremental financial contribution from shippers (or governments on their behalf).
- If the test toll exceeds the $0.60/mmbtu threshold, then some form of "aid to construct" would be required to avoid cross-subsidization of these higher-cost users by lower-cost users elsewhere on the system.

In applying the Lateral Policy to the proposed Halifax and Strait of Canso laterals, both failed to meet a strict application of the threshold test. M&NP waived the need for an "aid to construct" or customer contribution on the grounds that the test would be met if it were applied to extended markets over the full economic life of the lateral.*

How (or if) the Policy would be applied in the case of any other proposed laterals remains to be seen. Its wider application is subject to discussions between M&NP and the province under the terms of the 1997 Memorandum of Understanding.

What this means for the CBRM

Taken at face value, the distribution regulations and lateral policy imply that gas will be delivered to and distributed within the CBRM (and other markets in the province), provided it is economic to do so. The test of economic feasibility, though expressed differently for lateral and distribution purposes, amounts to the same thing: if the market is capable of generating sufficient revenue to cover costs of service, then gas service would be supplied. Whether there is sufficient revenue depends on the size of the market and burner-tip gas prices based on inter-fuel competition.

Regardless of how the lateral policy and regulations are applied, and whether widespread access to natural gas is feasible or not, the impact on coal is likely to be limited. If conversion of coal-fired plants to natural gas is unlikely (and this would appear to be the case based on economics), then the only way demand for gas could affect current levels of coal demand is through a change in the demand for electricity.

Gas and electricity are not easily substituted.

- Electricity demand in the industrial sector is confined mainly to requirements to drive machinery and equipment, and is not readily displaced by natural gas. The opportunities for gas in the industrial sector are confined essentially to displacing petroleum products for space heating, process heat and feedstock uses.

* See, Maritimes & Northeast Pipeline, "Halifax Lateral Pipeline Project, NEB Facilities Application", 1998, p. 68; and, Maritimes & Northeast Pipeline, "Point Tupper Lateral Pipeline Project, NEB Facilities Application", 1998, p. 69.

- To the extent electricity is used for heating purposes in the other sectors, displacing it depends on the economics of supplementary heating methods, or retrofitting homes and buildings with gas-fired units and pipes or ducts. Though electricity prices are high in Nova Scotia, it is unlikely that the difference between gas and electricity prices would be great enough to induce many consumers to incur the costs and inconvenience of a full conversion (few convert to oil, even with a substantial price differential). But there is scope to displace existing domestic supplementary heating devices now fuelled by propane, oil or wood.

- Natural gas availability at competitive prices in the future can be expected to capture most new residential and commercial construction applications for space and water heating requirements. This is likely to be particularly evident in competition with electricity due to the high relative cost of electricity as a competing energy source.

DEREGULATION OF ELECTRICITY SUPPLY

Issues

The electricity industry is being deregulated in many areas in North America and Europe. This means it is shifting from being a regulated monopoly to an industry driven by competitive market principles. Deregulation is occurring at two levels: generating capacity and marketing. Transmission and distribution are continuing to be regulated since competition in these areas would not serve the public interest (having more than one set of transmission and distribution lines would be costly and pointless).

The electricity industry in Nova Scotia conforms to the classic model of a regulated industry. It has a monopoly on electrical generation, transmission, distribution and marketing, with rates and service regulated by the Nova Scotia Utilities and Review Board. Deregulation would cause these functions to be "unbundled", allowing for competition in electrical generation and marketing.

What this means for the CBRM

If the industry were deregulated in Nova Scotia (the process is underway elsewhere in Canada and throughout the United States), it could affect the energy market in the province in three key ways:

- New Suppliers: Competition would open the market to new suppliers of electricity. For example, new electrical generation companies could enter the market to compete with NSPI, or existing high-demand industries could establish their own generating capacity (by-passing NSPI and even selling surplus energy into the grid).

- **Demand for Natural Gas**: In the long run, the demand for natural gas could increase, since gas-fired combined-cycle generating capacity offers considerable advantages over conventional oil- and coal-fired technology. To the extent new capacity is able to displace existing capacity, the demand for coal for conventional plants would decrease. A key point in this is that only NSPI is bound by the coal contract.

- **Greater Competition**: In a broad, regionally deregulated market (say, eastern Canada and the northeast U.S.), Nova Scotia could become either a net exporter or importer of electrical energy. This could have a positive or negative impact on coal, depending on relative costs of production within the area served by the regional grid.

At this point it is impossible to predict the implications of de-regulation, or how long it will take for those implications to work themselves out. But several things seem clear:

- **De-regulation will not occur overnight.** Even if Nova Scotia were to adopt a de-regulation policy, it could take several years to plan and implement. One of the thorniest issues facing policy-makers in areas already on the road to de-regulation is what to do with so called "stranded assets" – the generating capacity which is no longer economic, but which is not fully depreciated. Who pays and how? What impact does this have on electricity prices and what constraint does this impose on the economics of lower cost gas-fired combined-cycle plants?

- **Gas-fired plants are most cost-effective.** In a de-regulated (competitive) environment, the market rewards low-cost electricity producers. With today's technology, natural gas-fired combined-cycle plants represent the most cost-effective option. They are cheaper and quicker to plan and build than conventional thermal units, and generally cheaper to operate. In those jurisdictions in U.S. and Europe where de-regulation is most advanced, new generating units are almost exclusively gas-fired.

- **Impacts may be many years away.** The effects of de-regulation may not be felt for many years, particularly in small isolated markets. This means it could have limited impact on coal within the 12-year life of the existing CBDC-NSPI contract.

CBDC PRODUCTION CAPABILITY AND COST

Issues

Coal will continue to be an important source of electrical energy in Nova Scotia for many years to come. NSPI's coal-fired generating plants are relatively new (most built after 1980) with at least 20 years of useful life remaining. NSPI indicates that at current relative prices of coal and gas it would not be economic to replace these plants with gas-fired units, or to convert them to gas. This is supported by the findings of a 1997 study by the Canadian Energy Research Institute.

The issue, then, is not whether there is a future for coal in Nova Scotia– there is – but rather what CBDC's role is likely to be in that future. Production has declined over the past several years, dropping from over 4.0 million tonnes in 1993, to below 2.0 million tonnes in 1998 (Table A-5). The company has been unable to meet production targets in 1998 due to various problems in the mines. An increasing share of NSPI coal requirements is being met through imports.

Table A-5
CBDC Coal Production, 1993-1998

	1998	1997	1996	1995	1994	1993
Sales (000 tonnes)						
NSPI	1,600*	2,368	2,424,	2,392	2,221	2,104
Export	0	25	135	852	909	1,852
Other	0	21	21	25	31	102
Total	1,600	2,414	2,580	3,269	3,161	4,058

*Approximate

Cape Breton Development Corporation Annual Report, 1997-98.

Related to the question of production capability is production cost. At an estimated $55-60 per tonne, CBDC is a relatively high cost producer. By comparison, average mine-mouth prices in the U.S. are about half – in the range of CDN $30 per tonne, and are declining with advances in technology and production practices. By 2020, average U.S. mine-mouth prices are expected to drop to the CDN $22 per tonne range. These comparisons are meant to illustrate relative prices only; western U.S. production is from surface mines with thick seams and low overburden ratio, while eastern mines are able to make extensive use of inexpensive longwall techniques.

What this means for the CBRM

CBDC's production difficulties and relatively high costs serve to weaken the company's competitive position as a supplier to NSPI. The long term contract provides some protection from market forces, provided CBDC is able at least to operate at these levels. But even the contract minimum and price clauses offer only short-term protection. Long-term viability depends on reduced production costs and higher and more stable production levels. CBDC is developing a strategy for addressing these issues in its next 5-year plan.

NATURAL GAS PRICING IN NOVA SCOTIA

Issues

Natural gas prices throughout North America are now determined by market-driven factors. In this post-decontrol era, governments at all levels in both the United States and Canada no longer attempt to directly control or influence the commodity price for natural gas.

Most delivered natural gas is no longer sold as a "bundled" service by the distributor. Natural gas, the commodity, is bought separately as energy. The transportation service to deliver it to the consumer is a separately negotiated and purchased service. The regulatory regime for gas distribution proposed for Nova Scotia identifies these elements as distinct features, such that consumers will have a choice of suppliers from whom they can purchase natural gas, the commodity. Transportation delivery service will be supplied by the distributor and paid for as a separate item at rates established and approved by the Nova Scotia Utilities and Review Board.

Canada is now part of a fully integrated transportation, distribution and marketing system in North America for natural gas. Market clearing prices are now largely determined by the relative balance of supply and demand and by inter-fuel competition. While prices are now determined by market based negotiation between buyers and sellers, the contract prices vary within a range, reflecting differing supply arrangements, market knowledge, end use requirements, timing and term of delivery and bargaining acumen.

The major North American supply basins are the U.S. Gulf Coast, both on-shore and now increasingly, off-shore, the Permian Basin in Texas and New Mexico, and the Western Canadian Sedimentary Basin in Alberta, British Columbia and Saskatchewan.

The primary regions of gas consumption are the New York-New England area, Chicago, California and Texas-Louisiana. Major pipeline systems interconnect these supply regions to these major market areas, typically with supply moving to several markets and each market area receiving gas from several supply regions.

Price Determinants

Gas on gas price competition characterizes the pricing determinants for each market region. Prices received by suppliers in the supply basins are determined by the market clearing price set in the consuming markets, less the cost of transportation to reach that market.

North American price signals for natural gas are largely a reflection of demand in the United States market, due to its overwhelming dominance in terms of energy consumption in the North American context. The development of trading hubs located at strategic points on the major transmission systems as a reference pricing point for the purchase and sale of natural gas has provided price transparency for most natural gas transactions.

More significantly, it has also led to the development of a dynamic spot price and futures market with contracts of varying terms openly traded on the New York Mercantile Exchange (NYMEX). Other trading hubs and futures markets are being developed in addition to the Louisiana buy-sell transfer point (the Henry Hub) used as the basis of the NYMEX contracts.

Future Natural Gas Price Outlook

Current long term forecasts for the price of natural gas in North American over the next fifteen to twenty years indicate a sustained but gradual increase in wellhead prices (ie, prices paid to producers). The rate of increase in 1997-dollar terms is estimated to be less than one percent per year. The U. S. Department of Energy, EIA Annual Energy Outlook 1999, released in preliminary form in mid-November, notes that *delivered* prices for natural gas are forecast to actually decline as the result of reductions in transportation costs.

In the short to medium term, the effect of lower oil prices and the economic slowdown resulting from a protracted Asian recession are likely to keep natural gas prices essentially flat. Significant supply additions into the Chicago market area as a result of substantial pipeline capacity additions from Western Canada may also serve to keep prices constant in the period from 2000 through 2003, or until that excess supply can be fully absorbed throughout the marketplace.

SOEP Gas and the North American Market

Sable gas entering this North American market will be directly affected and largely determined by the market price for gas set in this broader context. To a degree, it will also influence the price for gas in the New England and New York consumption region. Overall, Sable gas will be a price taker and not a price setter.

The key interface for Sable gas to the North American market will be in the Boston market area, the terminus destination for the Maritime & Northeast Pipeline system. This will provide the principal interconnection point to the North American grid of major gas pipeline transportation systems.

Pricing Determinants for Natural Gas in the Boston Area

Natural gas prices in the Boston area are largely determined by the price of gas from the Gulf Coast region, the largest supply basin in North America. Since this is also the principal supply basin for markets in New York-New England, Chicago and the Gulf region, prices are set in large measure by the open trading activity at the Henry Hub. The delivered price for gas into the Boston area (the city gate price) is the sum of the commodity price of the gas in the Gulf Coast region (at the Henry Hub) and the cost of transportation from the Gulf Coast to the Boston city gate.

Currently, Canadian gas from Western Canada also reaches the Boston market. Since its relative share of this market is still small, and the transportation cost to reach the Boston market is higher than the cost of transportation from the Gulf Coast, Western Canadian gas to the Boston area is essentially a price taker.

Impact of Sable Gas on the Boston market

With the advent of Sable gas into the Boston market area, the supply balance into the region will be altered. The degree to which this occurs is dependent upon the volume of Sable gas entering this market, the size of that overall market, and the rate of expansion in that market.

Since pipeline expansions such as M&NP tend to represent large and essentially lumpy rather than gradual increases in supply into a market area, the relative supply/demand balance in that market area can be significantly altered. The duration of this impact is thus a function of market growth and the presence or absence of other pipeline expansions into the same market area.

In the case of Sable gas, the majority of the supply will flow through to the New England and Boston area. This additional capacity to the Boston Area, coupled with the completion of the Portland Natural Gas Transmission System (PNGTS), will increase the supply availability of gas to the Boston and New England area by approximately 620 mmcf/d by the year 2000.

The market growth in this region is forecast to require an additional 550 to 1100 mmcf/d gas supply by the year 2005. In addition, the Sable gas coupled with gas supplies off PNGTS will access new and previously unserved markets in Main and New Hampshire to the north of the traditional Boston market area. These markets, while still subject to pricing determinants in the Boston area, will be supplied almost exclusively by Sable and PNGTS gas supplies. Given the continuation of reasonably stable economic conditions in the region, Sable gas volumes, when considered in isolation, will overbalance the supply to this market area marginally for the first three years of deliveries with full absorption occurring by 2003 to 2004. Accordingly, Sable gas should have little significant dislocative impact on supply or prices due to the size of this market.

On this basis, the wholesale (city gate) price for natural gas in the Boston area is not expected to be significantly impacted by the addition of Sable gas into the area in the 1999/2000 gas year or in subsequent years.

Prices for Sable gas in the Boston market will continue to be largely determined by the price for gas at the city gate from current traditional supply regions, principally the Gulf Coast, with only a minor downward dampening effect to reflect the impact of Sable supply additions to the market in the first few years of operation.

Price Basis for Sable Gas in Nova Scotia

Given this overall pricing scenario, the commodity price for Sable gas at the inlet to the Maritimes & Northeast Pipeline at Country Harbour will be a direct function of the Boston city gate price as determined by its North American reference to the Henry Hub, less the sum of the transportation costs on the Canadian and U.S. portions of the Maritimes & Northeast Pipeline. The Boston area reference price, generally expected to be based on gas sales to areas north of Dracut, Massachusetts, a transportation pricing point off the Tennessee Gas Pipeline system to the north of Boston, is anticipated to be the commodity pricing point for the purchase and sale of Sable gas, including in particular, that portion of the gas sold into Nova Scotia markets. Since these commodity prices will be the result of individual customer requirements, negotiation and some measure of competition between suppliers, individual contract prices will vary. This is a normal function of market based pricing as evidenced elsewhere in the North American gas markets and in the future markets.

With a projected toll of $0.60/MMBtu on the Canadian and $0.40/MMBtu on the U.S. portions of the M&NP system, this means the price for gas to Nova Scotia markets off the M&NP mainline system or off any of the Maritimes & Northeast Laterals (Point Tupper and Halifax to date) will be approximately equal to the Boston city gate price, less $0.35 to $0.40/MMBtu, less any applicable discounts negotiated for Nova Scotia deliveries during the first few years of operation (pursuant to the terms of the Memorandum of Understanding dated December 17, 1997 between Nova Scotia, New Brunswick, Sable producers and Maritimes & Northeast Pipeline Project). Note, this price will only be available to direct connect customers, principally large industrial customers, to the Maritimes & Northeast system. It will also represent the price at the inlet to the provincial distribution system.

What this means for the CBRM

The key message in this discussion for consumers in the CBRM and elsewhere in Nova Scotia is the price for gas in the province will be set by demand and supply conditions in the dominant market – Boston.

More specifically, the delivered price of gas to distribution consumers in Nova Scotia, based on current government policy which is designed to ensure province-wide distribution tolls for each class of customer within the province, will be the sum of the Boston city gate price, less applicable discounts to the Maritimes & Northeast toll, plus the provincial distribution toll for that customer class.

While the Boston city gate price (less toll discount and plus local distribution costs) establishes the floor for local gas prices, the ceiling is established by competing fuels. In other words, consumers can expect to pay a price for gas no less than the adjusted Boston city gate price, and no greater than the price of competing fuels.

APPENDIX B

ENERGY DEMAND BY SECTOR

TABLE B-1

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

RESIDENTIAL ENERGY DEMAND

	Electricity	Petroleum		Wood	Natural Gas	Total Energy
	gwh	LFO (mega l)	Prop (mega l)	tonnes	('000 mmbtu)	('000 mmbtu)
1996	3,730	530	25	17,500	0	34,394
1997	3,788	538	25	17,500	0	34,912
1998	3,793	546	26	17,500	0	35,246
1999	3,987	554	26	17,500	0	36,256
2000	3,929	563	27	17,500	0	36,380
2001	3,950	571	27	17,500	0	36,784
2002	4,029	580	27	17,500	0	37,402
2003	4,085	588	28	17,500	0	37,941
2004	4,127	597	28	17,500	0	38,439
2005	4,196	606	29	17,500	0	39,033
2006	4,266	615	29	17,500	0	39,640
2007	4,336	624	29	17,500	0	40,252
2008	4,422	634	30	17,500	0	40,922
2009	4,486	643	30	17,500	0	41,525
2010	4,566	653	31	17,500	0	42,186

TABLE B-2

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

COMMERCIAL-INSTITUTIONAL ENERGY DEMAND

	Electricity	Petroleum			Natural Gas	Total Energy
	gwh	LFO (mega l)	HFO (mega l)	Prop (mega l)	('000 mmbtu)	('000 mmbtu)
1996	3,140	200	40	35	0	19,635
1997	3,437	203	41	36	0	20,783
1998	3,383	206	41	36	0	20,733
1999	3,556	209	42	37	0	21,462
2000	3,505	212	42	37	0	21,427
2001	3,523	215	43	38	0	21,631
2002	3,594	219	44	38	0	22,017
2003	3,643	222	44	39	0	22,333
2004	3,681	225	45	39	0	22,611
2005	3,742	229	46	40	0	22,970
2006	3,805	232	46	41	0	23,337
2007	3,868	236	47	41	0	23,706
2008	3,944	239	48	42	0	24,122
2009	4,001	243	49	42	0	24,480
2010	4,072	246	49	43	0	24,884

TABLE B-3

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

INDUSTRIAL ENERGY DEMAND

	Electricity	Petroleum			Natural Gas	Total Energy
	gwh	LFO (mega l)	HFO (mega l)	Prop (mega l)	('000 mmbtu)	('000 mmbtu)
1996	2,955	50	210	35	0	20,229
1997	3,078	51	213	36	0	20,801
1998	3,075	52	216	36	0	20,945
1999	3,233	52	220	37	0	21,640
2000	3,186	53	223	37	0	21,640
2001	3,203	54	226	38	0	21,858
2002	3,267	55	230	38	0	22,242
2003	3,312	55	233	39	0	22,562
2004	3,347	56	237	39	0	22,849
2005	3,402	57	240	40	0	23,209
2006	3,459	58	244	41	0	23,578
2007	3,516	59	247	41	0	23,949
2008	3,585	60	251	42	0	24,364
2009	3,638	61	255	42	0	24,725
2010	3,702	62	259	43	0	25,130

TABLE B-4

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

TOTAL ENERGY DEMAND

	Electricity	Petroleum			Wood	Natural Gas	Energy
	gwh	LFO (mega l)	HFO (mega l)	Propane (mega l)	t	('000 mmbtu)	('000 mmbtu)
1996	9,825	780	250	95	17,500	0	74,259
1997	10,303	792	254	96	17,500	0	76,497
1998	10,250	804	258	98	17,500	0	76,924
1999	10,775	816	261	99	17,500	0	79,358
2000	10,620	828	265	101	17,500	0	79,447
2001	10,675	840	269	102	17,500	0	80,273
2002	10,890	853	273	104	17,500	0	81,662
2003	11,040	866	277	105	17,500	0	82,835
2004	11,155	879	282	107	17,500	0	83,898
2005	11,340	892	286	109	17,500	0	85,212
2006	11,530	905	290	110	17,500	0	86,554
2007	11,720	919	294	112	17,500	0	87,907
2008	11,950	933	299	114	17,500	0	89,408
2009	12,125	947	303	115	17,500	0	90,729
2010	12,340	961	308	117	17,500	0	92,200

TABLE B-5

BASE CASE: NO NATURAL GAS IN NOVA SCOTIA

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	786,000	219,600	27,900	31,500	1,750	0	1,066,750
1997	824,240	222,894	28,319	31,973	1,750	0	1,109,175
1998	820,000	226,237	28,743	32,452	1,750	0	1,109,183
1999	862,000	229,631	29,174	32,939	1,750	0	1,155,494
2000	849,600	233,075	29,612	33,433	1,750	0	1,147,470
2001	854,000	236,572	30,056	33,934	1,750	0	1,156,312
2002	871,200	240,120	30,507	34,443	1,750	0	1,178,021
2003	883,200	243,722	30,965	34,960	1,750	0	1,194,597
2004	892,400	247,378	31,429	35,485	1,750	0	1,208,441
2005	907,200	251,088	31,901	36,017	1,750	0	1,227,956
2006	922,400	254,855	32,379	36,557	1,750	0	1,247,941
2007	937,600	258,678	32,865	37,105	1,750	0	1,267,998
2008	956,000	262,558	33,358	37,662	1,750	0	1,291,327
2009	970,000	266,496	33,858	38,227	1,750	0	1,310,331
2010	987,200	270,494	34,366	38,800	1,750	0	1,332,610

TABLE B-6

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO

RESIDENTIAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum		Wood	Natural Gas	Total Energy
		LFO	Propane			
1996	11,154	17,026	564	283	0	29,027
1997	11,327	17,281	573	283	0	29,465
1998	11,340	17,541	581	283	0	29,746
1999	11,921	17,804	590	283	0	30,599
2000	11,632	17,348	593	283	774	30,631
2001	11,575	17,058	578	283	1,422	30,915
2002	11,687	16,755	555	283	2,099	31,380
2003	11,726	16,440	532	283	2,793	31,775
2004	11,725	16,111	509	283	3,506	32,134
2005	11,794	15,768	484	283	4,243	32,573
2006	11,864	15,412	458	283	5,002	33,020
2007	11,930	15,042	465	283	5,749	33,469
2008	12,031	14,657	472	283	6,522	33,966
2009	12,073	14,463	479	283	7,126	34,425
2010	12,288	14,680	487	283	7,236	34,974

Assumptions

1. Natural gas enters the Nova Scotia mainland market in 2000.
2. Natural gas displaces 10% of electrical load for domestic heating by 2010.
3. Natural gas captures about 35% of the domestic fuel oil market by 2010.
4. Natural gas achieves minimum of 10% higher efficiency than displaced oil furnaces.
5. Natural gas displaces no wood demand.
6. Natural gas is assumed to be sold at minimum of 10% less than heating oil (equivalent energy content).

TABLE B-7

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO COMMERCIAL-INSTITUTIONAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Natural Gas	Total Energy
		LFO	HFO	Propane		
1996	9,389	6,425	1,386	790	0	17,991
1997	10,277	6,521	1,407	802	0	19,008
1998	10,114	6,619	1,428	814	0	18,976
1999	10,633	6,718	1,450	826	0	19,627
2000	10,480	6,478	1,398	797	477	19,629
2001	10,534	6,229	1,344	766	969	19,842
2002	10,746	5,971	1,289	734	1,475	20,215
2003	10,894	5,704	1,231	701	1,996	20,527
2004	11,008	5,510	1,189	678	2,418	20,802
2005	11,190	5,219	1,126	642	2,976	21,154
2006	11,378	4,919	1,062	605	3,551	21,514
2007	11,565	4,541	980	558	4,237	21,881
2008	11,792	4,225	912	520	4,838	22,286
2009	11,965	3,898	841	479	5,456	22,640
2010	12,177	3,957	854	487	5,538	23,012

Assumptions

1. Natural gas enters the Nova Scotia market in 2000.
2. Natural gas displaces 0% electrical load in the commercial-institutional sector.
3. Natural gas captures 50% of the commercial-institutional fuel oil market by 2010.
4. Natural gas achieves 5% lower efficiency than displaced oil-fired boilers.
5. Natural gas assumed to be sold at a minimum 10% below #6 fuel oil (efficiency adjusted energy equivalence).

TABLE B-8

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO

INDUSTRIAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Natural Gas	Total Energy
		LFO	HFO	Propane		
1996	8,574	1,559	7,062	767	0	17,962
1997	8,931	1,582	7,168	778	0	18,459
1998	8,922	1,606	7,276	790	0	18,593
1999	9,379	1,630	7,385	802	0	19,196
2000	9,244	1,323	5,997	651	2,084	19,299
2001	9,292	1,175	5,326	578	3,173	19,544
2002	9,479	1,108	5,020	545	3,758	19,909
2003	9,610	1,038	4,703	511	4,359	20,220
2004	9,710	966	4,376	475	4,977	20,503
2005	9,871	891	4,038	438	5,613	20,851
2006	10,036	814	3,688	400	6,267	21,206
2007	10,202	734	3,328	361	6,940	21,564
2008	10,402	652	2,955	321	7,631	21,961
2009	10,554	662	3,000	326	7,745	22,287
2010	10,741	672	3,045	331	7,861	22,650

Assumptions

1. Natural gas enters the Nova Scotia market in 2000.
2. Natural gas displaces 0% electrical load in the industrial sector.
3. Natural gas captures 65% of the industrial market by 2010 (though most industrial boilers assumed dual-fired).
4. Natural gas achieves 5% lower efficiency than displaced oil-fired burners.
5. Natural gas assumed to be sold at a minimum 10% below #6 fuel oil (efficiency adjusted energy equivalence).

TABLE B-9

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO

TOTAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Wood	Natural Gas	Energy
		LFO	HFO	Propane			
1996	29,117	25,009	8,449	2,121	283	0	64,980
1997	30,535	25,384	8,576	2,153	283	0	66,932
1998	30,377	25,765	8,704	2,185	283	0	67,315
1999	31,933	26,152	8,835	2,218	283	0	69,421
2000	31,356	25,149	7,395	2,041	283	3,335	69,559
2001	31,400	24,462	6,670	1,922	283	5,564	70,302
2002	31,912	23,834	6,308	1,835	283	7,331	71,504
2003	32,230	23,182	5,934	1,744	283	9,148	72,522
2004	32,442	22,586	5,565	1,661	283	10,902	73,439
2005	32,855	21,879	5,164	1,564	283	12,833	74,578
2006	33,278	21,145	4,750	1,464	283	14,820	75,740
2007	33,696	20,317	4,308	1,385	283	16,926	76,915
2008	34,225	19,534	3,867	1,313	283	18,991	78,213
2009	34,592	19,024	3,841	1,284	283	20,327	79,352
2010	35,206	19,309	3,899	1,304	283	20,635	80,636

TABLE B-10

CASE A: NATURAL GAS ON MAINLAND NOVA SCOTIA AND STRAIT OF CANSO

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	682,791	192,226	23,834	27,386	1,502	0	927,739
1997	716,053	195,109	24,192	27,797	1,502	0	964,652
1998	712,343	198,036	24,555	28,213	1,502	0	964,649
1999	748,828	201,006	24,923	28,637	1,502	0	1,004,897
2000	735,301	194,043	20,906	26,819	1,502	13,623	992,194
2001	736,340	189,344	18,879	25,444	1,502	23,479	994,987
2002	748,344	184,925	17,859	24,328	1,502	32,228	1,009,187
2003	755,788	180,331	16,804	23,174	1,502	41,219	1,018,818
2004	760,767	176,002	15,767	22,115	1,502	50,140	1,026,292
2005	770,441	171,022	14,637	20,872	1,502	59,687	1,038,161
2006	780,359	165,852	13,470	19,586	1,502	69,514	1,050,284
2007	790,177	160,117	12,220	18,686	1,502	79,604	1,062,306
2008	802,584	154,582	10,978	17,879	1,502	89,727	1,077,252
2009	811,191	151,164	10,888	17,496	1,502	96,871	1,089,113
2010	825,575	153,432	11,051	17,758	1,502	98,355	1,107,675

Assumptions

1. Electricity price is $23.45/mmbtu ($22.24/GJ or $0.08/kwh).
2. #2 fuel oil price is: res. - $0.32/l ($11.64/mmbtu or $11.04/GJ @ 75%); com'l and ind'l - $.20/l ($6.82/mmbtu or $6.47/GJ @ 80%).
3. #6 fuel oil price is: com'l - $0.12/l (Com'l –$3.61/mmbtu or $3.42/GJ @ 84%; Ind'l - $0.11/l ($3.31/mmbtu or $3.14/GJ @ 84%).
4. Natural gas burner tip price is $8.50/mmbtu or $8.06/GJ in the residential sector ($10.35/mmbtu or $9.81/GJ @ 82%).
5. Natural gas burner tip price is $2.75/mmbtu or $2.61/GJ to displace #2 oil and #6 oil in the ind'l and com'l/inst'l sectors.

APPENDIX C

GAS IN CBRM

TABLE C-1

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY

RESIDENTIAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum		Wood	Natural Gas	Total Energy
		LFO	Propane			
1996	1,578	2,410	80	40	0	4,108
1997	1,603	2,446	81	40	0	4,170
1998	1,605	2,483	82	40	0	4,210
1999	1,687	2,520	84	40	0	4,331
2000	1,662	2,558	85	40	0	4,345
2001	1,654	2,492	83	40	119	4,388
2002	1,671	2,451	81	40	215	4,458
2003	1,676	2,407	80	40	315	4,518
2004	1,676	2,362	78	40	417	4,574
2005	1,686	2,315	77	40	522	4,640
2006	1,697	2,266	75	40	631	4,708
2007	1,706	2,214	73	40	742	4,777
2008	1,721	2,161	72	40	858	4,852
2009	1,727	2,106	70	40	976	4,919
2010	1,739	2,078	69	40	1,069	4,994

Assumptions

1. Natural gas enters the Nova Scotia mainland market in 2000.
2. Natural gas displaces 10% of electrical load for domestic heating by 2010.
3. Natural gas captures about 30% of the domestic fuel oil market by 2010.
4. Natural gas achieves 5% higher efficiency than displaced oil furnaces.
5. Natural gas displaces no wood demand.
6. Natural gas is assumed to be sold at minimum of 10% less than heating oil (equivalent energy content).

TABLE C-2

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY COMMERCIAL-INSTITUTIONAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Natural Gas	Total Energy
		LFO	HFO	Propane		
1996	1,328	909	196	112	0	2,546
1997	1,454	923	199	114	0	2,690
1998	1,431	937	202	115	0	2,685
1999	1,504	951	205	117	0	2,778
2000	1,483	965	198	119	0	2,765
2001	1,490	833	180	102	206	2,811
2002	1,520	746	161	92	348	2,867
2003	1,541	707	152	87	424	2,911
2004	1,557	676	146	83	488	2,950
2005	1,583	633	137	78	569	3,000
2006	1,610	589	127	72	653	3,051
2007	1,636	536	116	66	750	3,103
2008	1,668	544	117	67	761	3,157
2009	1,693	552	119	68	772	3,204
2010	1,723	560	121	69	784	3,257

Assumptions

1. Natural gas enters the Nova Scotia market in 2000.
2. Natural gas displaces 0% electrical load in the commercial-institutional sector.
3. Natural gas captures 50% of the commercial-institutional fuel oil market by 2010.
4. Natural gas achieves 5% lower efficiency than displaced oil-fired boilers.
5. Natural gas assumed to be sold at a minimum 10% below #6 fuel oil (efficiency adjusted energy equivalence).

TABLE C-3

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY INDUSTRIAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Natural Gas	Total Energy
		LFO	HFO	Propane		
1996	1,512	275	1,246	135	0	3,169
1997	1,575	279	1,265	137	0	3,257
1998	1,574	283	1,284	139	0	3,280
1999	1,654	288	1,303	141	0	3,387
2000	1,631	292	1,323	144	0	3,389
2001	1,639	178	269	29	1,369	3,483
2002	1,672	165	204	22	1,484	3,548
2003	1,695	153	207	23	1,522	3,600
2004	1,713	155	211	23	1,545	3,646
2005	1,741	142	214	23	1,585	3,705
2006	1,770	128	217	24	1,625	3,764
2007	1,799	120	220	24	1,660	3,824
2008	1,835	118	224	24	1,688	3,889
2009	1,862	117	227	25	1,717	3,947
2010	1,895	119	230	25	1,743	4,012

Assumptions

1. Natural gas enters the Nova Scotia market in 2000.
2. Natural gas displaces 0% electrical load in the industrial sector.
3. Natural gas captures 65% of the industrial market by 2010 (though most industrial boilers assumed dual-fired).
4. Natural gas achieves 5% lower efficiency than displaced oil-fired burners.
5. Natural gas assumed to be sold at a minimum 10% below #6 fuel oil (efficiency adjusted energy equivalence).

TABLE C-4

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY

TOTAL ENERGY DEMAND (000s MMBtu)

	Electricity	Petroleum			Wood	Natural Gas	Energy
		LFO	HFO	Propane			
1996	4,419	3,595	1,443	327	40	0	9,823
1997	4,632	3,648	1,464	332	40	0	10,117
1998	4,609	3,703	1,486	337	40	0	10,176
1999	4,846	3,759	1,508	342	40	0	10,495
2000	4,776	3,815	1,521	347	40	0	10,499
2001	4,784	3,503	448	214	40	1,693	10,683
2002	4,863	3,362	365	195	40	2,048	10,873
2003	4,913	3,266	360	189	40	2,261	11,030
2004	4,947	3,193	356	184	40	2,450	11,170
2005	5,011	3,090	350	178	40	2,676	11,345
2006	5,077	2,982	344	171	40	2,909	11,523
2007	5,142	2,870	336	163	40	3,152	11,703
2008	5,224	2,823	341	163	40	3,307	11,898
2009	5,282	2,774	346	162	40	3,466	12,070
2010	5,356	2,757	351	163	40	3,596	12,263

TABLE C-5

CASE B: NATURAL GAS IN THE CAPE BRETON REGIONAL MUNICIPALITY

TOTAL ENERGY EXPENDITURES ($ 000s)

	Electricity	Petroleum			Wood	Natural Gas	Total
		LFO	HFO	Propane			
1996	103,625	27,507	4,059	4,136	213	0	139,541
1997	108,623	27,920	4,120	4,199	213	0	145,075
1998	108,091	28,339	4,182	4,261	213	0	145,086
1999	113,628	28,764	4,245	4,325	213	0	151,174
2000	111,993	29,195	4,277	4,390	213	0	150,068
2001	112,181	27,277	1,291	3,022	213	5,340	149,324
2002	114,041	26,371	1,056	2,787	213	6,870	151,337
2003	115,207	25,707	1,039	2,701	213	8,028	152,894
2004	115,997	25,156	1,027	2,628	213	9,134	154,156
2005	117,505	24,438	1,008	2,535	213	10,362	156,061
2006	119,050	23,692	988	2,438	213	11,626	158,008
2007	120,582	22,911	962	2,324	213	12,938	159,929
2008	122,509	22,482	977	2,313	213	14,028	162,521
2009	123,858	22,035	992	2,300	213	15,142	164,539
2010	125,602	21,847	1,006	2,302	213	16,033	167,003

Assumptions

1. Electricity price is $23.45/mmbtu ($22.24/GJ or $0.08/kwh).
2. #2 fuel oil price is: res. - $0.32/l ($11.64/mmbtu or $11.04/GJ @ 75%); com'l and ind'l - $.20/l ($6.82/mmbtu or $6.47/GJ @ 80%).
3. #6 fuel oil price is: com'l - $0.12/l (Com'l –$3.61/mmbtu or $3.42/GJ @ 84%; Ind'l - $0.11/l ($3.31/mmbtu or $3.14/GJ @ 84%).
4. Natural gas burner tip price is $8.50/mmbtu or $8.06/GJ in the residential sector ($10.35/mmbtu or $9.81/GJ @ 82%).
5. Natural gas burner tip price is $2.75/mmbtu or $2.61/GJ to displace #2 oil and #6 oil in the ind'l and com'l/inst'l sectors.

TABLE C-6: CAPE BRETON REGIONAL MUNICIPALITY NATURAL GAS LATERAL AND DISTRIBUTION SYSTEM PRO FORMA COST OF SERVICE ANALYSIS

Rate Base Calculation			Year 1		Year 2		Year 3		Year 4		Year 5		Year 6		Year 7	
			%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)
Rate Base																
	Initial			0		42,848		55,288		64,493		67,408		69,120		69,472
	Plant Additions															
		Main Lateral	100%	35,000		0		0		0		0		0		0
		Distribution Lines	10%	2,000	40%	7,000	30%	6,000	10%	2,000	10%	2,000		0		0
		Meters												1,000		1,000
		Telemetry														
		Maintenance Shops														
		Service Offices														
		Corporate														
		Testing														
		Field Equipment														
		Inventory	10%	2,000		1,000		1,000		1,000		500		250		250
		Service Connections				1		1		1		1		1		1
		Less Aid to Construct				-1		-1		-1		-1		-1		-1
		Net Service Connnect		0		0		0		0		0		0		0
		Line Pack		0		1,000		200		0		0		0		0
		Captialized O&M				5,000		4,000		2,000		1,250		1,250		1,250
		Hearing Costs		500		150						100				100
		Working Capital	10%	4,000	10%		5%		5%		4%		4%		4%	
		Sub Total Additions		43,500		14,150		11,200		5,000		3,850		2,500		2,600
	Deductions															
		Depreciation	1.5%	(653)	3%	(1,710)	3%	(1,995)	3%	(2,085)	3%	(2,138)	3%	(2,149)	3%	(2,162)
		Cumulative		(653)		(2,362)		(4,357)		(6,442)		(8,580)		(10,728)		(12,890)
	Year End			42,848		55,288		64,493		67,408		69,120		69,472		69,910

TABLE C-6: CAPE BRETON REGIONAL MUNICIPALITY NATURAL GAS LATERAL AND DISTRIBUTION SYSTEM PRO FORMA COST OF SERVICE ANALYSIS

Cost of Service Components			Year 1		Year 2		Year 3		Year 4		Year 5		Year 6		Year 7	
			%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)
Capital Structure																
	Equity @35%		35%	14,997	35%	19,351	35%	22,573	35%	23,593	35%	24,192	35%	24,315	35%	24,468
		Rate @	12%	1,800	12%	2,322	12%	2,709	12%	2,831	12%	2,903	12%	2,918	12%	2,936
	Debt @65%		65%	27,851	65%	35,937	65%	41,920	65%	43,815	65%	44,928	65%	45,157	65%	45,441
		Rate@	9.25%	2,576	9%	3,234	9%	3,773	9%	3,943	9%	4,044	9%	4,064	9%	4,090
Operating & Maintenance																
	Gross Expense															
		Wages & Salaries														
		Office Rent														
		Office Equip & Supplies														
		Equipment Leases														
		Maintenance														
		Training														
		Engineering														
		Legal &Permitting														
		Right of Way														
		Highway Restoration														
		Net HST														
		Sub Totals	est.	5,000	est.	4,000	est.	4,000	est.	4,000	est.	5,000	est.	5,000	est.	5,000
	Capitalized @		100%	5,000	100%	4,000	50%	2,000	50%	2,000	25%	1,250	25%	1,250	25%	1,250
	Net O&M			-		-		2,000		2,000		3,750		3,750		3,750
Gas Cost																
	Lost & Unaccounted For		0%	0	2%	20	2%	20	1%	30	1%	40	1%	40	1%	45
Property Taxes																
	Municipal Taxes @		3%	1,285	3%	1,659	3%	1,935	3%	2,022	3%	2,074	3%	2,084	3%	2,097
Depeciation			1.5%	653	3%	1,710	3%	1,995	3%	2,085	3%	2,138	3%	2,149	3%	2,162
Income Taxes																
	Net Income			0		0		0		0		0		0		0
	Taxable Income			0		0		0		0		0		0		0
	Large Corporation Tax		1%	428	1%	553	1%	645	1%	674	1%	691	1%	695	1%	699
	Income Tax		45%	0	45%	0	45%	0	45%	0	45%	0	45%	0	45%	0
TOTAL ANNUAL COST OF SERVICE				6,742		9,498		13,076		13,586		15,639		15,699		15,779

TABLE C-6: CAPE BRETON REGIONAL MUNICIPALITY NATURAL GAS LATERAL AND DISTRIBUTION SYSTEM PRO FORMA COST OF SERVICE ANALYSIS

Rate Base Calculation		Year	1	Year	2	Year	3	Year	4	Year	5	Year	6	Year	7
Rate Base		%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)	%	$ (000's)
Initial			0		42,848		55,288		64,493		67,408		69,120		69,472
Plant Additions															
	Main Lateral	100%	35,000		0		0		0		0		0		0
	Distribution Lines	10%	2,000	40%	7,000	30%	6,000	10%	2,000	10%	2,000		0		0
	Meters												1,000		1,000
	Telemetry														
	Maintenance Shops														
	Service Offices														
	Corporate														
	Testing														
	Field Equipment														
	Inventory	10%	2,000		1,000		1,000		1,000		500		250		250
	Service Connections				1		1		1		1		1		1
	Less Aid to Construct				-1		-1		-1		-1		-1		-1
	Net Service Connnect		0		0		0		0		0		0		0
	Line Pack		0		1,000		200		0		0		0		0
	Captialized O&M				5,000		4,000		2,000		1,250		1,250		1,250
	Hearing Costs		500		150						100				100
	Working Capital	10%	4,000	10%		5%		5%		4%		4%		4%	
	Sub Total Additions		43,500		14,150		11,200		5,000		3,850		2,500		2,600
Deductions															
	Depreciation	1.5%	(653)	3%	(1,710)	3%	(1,995)	3%	(2,085)	3%	(2,138)	3%	(2,149)	3%	(2,162)
	Cumulative		(653)		(2,362)		(4,357)		(6,442)		(8,580)		(10,728)		(12,890)
Year End			42,848		55,288		64,493		67,408		69,120		69,472		69,910

TABLE C-6: CAPE BRETON REGIONAL MUNICIPALITY NATURAL GAS LATERAL AND DISTRIBUTION SYSTEM PRO FORMA COST OF SERVICE ANALYSIS

ASSUMPTIONS USED IN DEVELOPING MODEL

Rate Base

Lateral cost -$35 million, distribution system - $20 million
Distributor will build out basic system as quickly as possible to have service ready for customer connections to gain early revenue
Lateral is built out in first year,
Distribution system (street mains) built out-
- 10% in Year 1
- 40% in Year 2
- 30% in Year 3
- 10% in Year 4
- 10% in year 5

Meter costs in years 6 & 7 are additional capital
Service connections (@ $700 to $1000) are charged out to customer connects @ 100% so no net cost to distributor
No government aids to construction of system
Line pack (the "static" amount of gas filling the pipes) is bought in year 2 and topped-up in year 3 at build out of main pipe system
Working capital requirements by % higher in early years (counted in only once)
Depreciation @ 3% moderates but does not reverse the rate base built in first 7 years
No AFUDC used as calculations are too imprecise to have timing impact adjustment be meaningful

Cost of Service

Equity ratio is 35%, mid range for distributors
Return on equity @ 12% is high end reflecting a grass roots system with no assurance of customer connections
Debt interest rate is currently in use to year 3, extended thereafter
Operating and maintenance costs are estimates
- First year is set-up year
- Much of cost is in capital and with contractors
- More normalized O&M ratios start to emerge in years 6 & 7 as system has been built out and becomes operational with sufficient customers
- Capitalized @ 100% in years 1 & 2 since this is greenfield build-out situation,
- Capitalized @ 50% in years 3 & 4 to reflect continued build-out but commencement of regular operations
- Capitalized @ 25% in years 5, 6 & 7 as system approaches normalized operation
- Net amount of O & M is used for annual cost of service

Lost and unaccounted for gas is a % of sales volumes; in early years, it is primarily from losses in testing and new connections; $ numbers here are estimates only
No franchises but municipal/county taxes paid on rate base at 3%
Depreciation is straight lined @ 3% but first year @ 1.5% to reflect timing on construction (a number normally used for adjusting revenue requirements "to fit")
Income taxes on earnings are assumed to be zero in first years due to lack of revenue and significant expense carry-forwards from construction and set-up
Large Corporation Tax is assumed to be payable on asset base each year

Annual Cost of Service is the cost of operation against which the distributor needs to collect its revenue requirement

APPENDIX D

CASE STUDIES

D.

CASE STUDIES

1. COAL AND NATURAL GAS USAGE IN ELECTRICITY GENERATION: UNITED STATES

Introduction

An examination of the primary fossil fuels used in electricity generation, namely, coal and natural gas, reveals a shift in the market toward natural gas in recent years. The trends in electricity generation in the U.S. reveal the need for new capacity to meet demand over the next 20 years and the emergence of natural gas as the preferred choice of fuel to power most new capacity.

Examining the distribution of fuels usage in generating capacity in the U.S. over the recent past shows that most new capacity has been met with the use of gas turbine or internal combustion generation. Natural gas has made its greatest gains in gas-fired turbine generation, where it has increased from 4.1 percent of total generating capacity in 1993 to 5.2 percent in 1997. Coal usage has remained fairly stable at roughly 43 percent of total generating capacity over this same period. Although coal is projected to remain the dominant fuel, coal-powered generation is projected to decrease in fuel share percentage while increasing in absolute terms.

This shift in fuel supply for generation can be attributed to three major causes:

- Regulatory Changes;
- Differences in the Relative Costs of Fuel; and,
- Environmental Factors.

Regulatory Changes in the Electric Industry

The electric industry in the U.S. is in a period of deregulation and rapid restructuring. The legislative and regulatory landscape for electricity markets in the United States is changing almost daily. For the most part, U.S. generating capacity is now in the hands of investor-owned utilities, which have for years been operating under State and Federal regulations that provided the utilities with local monopolies in exchange for obligations to serve the public in their areas of control. However, State governments, and their public utility commissions, have proposals under consideration for restructuring that would change this relationship.

The current movement to restructure U.S. electricity generation markets and make them more competitive is expected to impact the market for fuels used in electricity generation. The subsequent impact of electricity restructuring has led to a shift away from coal toward natural gas, causing coal's market share to decline relative to gas. This has occurred largely due to the changing structure of the electric power industry and the increased consolidation of natural gas and electric industries.

The Changing Structure of the Electric Power Industry

The U.S. electric industry is dominated by vertically integrated utilities that generate, transmit and distribute electricity to consumers in a highly regulated monopolistic market. Wholesale electricity sales and interstate transmission are regulated by the Federal Energy Regulatory Commission (FERC). Retail sales and intrastate transmission are under state jurisdiction. Restructuring has been under way at the federal level since 1978. Individual states are also undertaking restructuring initiatives.

The industry is currently in the midst of changing from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Advances in power generation technology, large variations in regional electricity prices, and the trend to competitive markets in other regulated industries have all contributed to the transition. Industry changes brought on by this movement have resulted in a more competitive industry, increasingly reliant on the most efficient fuels.

Increased Consolidation of Natural Gas and Electric Industries

As a result of the deregulation of the industry, electricity marketers and brokers have taken advantage of the opportunities expected under more competitive conditions. Alliances between electric and natural gas companies, and electric company mergers have been established, as firms seek to reduce costs and increase the range of services that they can provide. Utilities are positioning themselves for a more competitive environment. Many vertically integrated utilities are voluntarily separating their generation, transmission, and distribution components into business units.

The resulting generation, transmission, and distribution companies may in turn re-integrate to gain efficiency. Re-integration would include partnerships between electric companies, or between electric and gas companies. Additionally, electric distribution companies that divest their generation assets may focus on selling energy services rather than simply electricity. Energy distributors and marketers would seek the best technology for a given energy need. In this respect, consolidation of the two industries would intensify the competition between electricity and natural gas for end-uses. As restructuring continues to unfold, vertically integrated utilities continue to unbundle their services.

Differences in the Relative Costs of Fuel

Projections of ample natural gas supplies and low generating costs, relative to coal, have made it the preferred fuel for many independent power producers. The relative modularity of gas turbines as compared with coal plants, in combination with their low initial capital outlay, gives them advantages in a marketplace driven by competition, as competitive markets tend to favor lower risk, less capital-intensive investments. The primary factors contributing to differences in the relative costs of natural gas and coal in electricity generation include advancements in natural gas-powered-generating technology, differences in relative prices of fuels across regions, differences in coal production and quality across regions, and coal transportation costs.

- **Advancements in natural gas-powered generating technology:** Technological advancements have enabled lower cost electricity generation than is the case for utilities that use older fossil-fueled or nuclear-fueled steam-electric technologies. The new natural gas combined-cycle gas turbine (CCGT) generators can be built and put into operation quickly, sometimes as an alternative to utility capacity at existing central station plants. More than one-half of currently operating nuclear capacity is expected to retire by 2020. The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010. Forty seven percent of the new CCGT and 58 percent of the new coal capacity is expected to be introduced between 2010 and 2020.

- **Regional Differences in Relative Prices of Fuels to Electricity Suppliers:** Capacity by energy source generally shows a geographical pattern of significant petroleum-fired capacity in the East, hydroelectric in the West, and gas-fired capacity in the Coastal South. The amount and geographical distribution of capacity by energy source is a function of availability and price of fuels and/or regulations. Much of what has been happening with regard to electricity demand in recent years, and most of the consequent impacts on natural gas demand, have been concentrated in the West South Central (WSC) region (Texas, Louisiana Oklahoma and Arkansas), which accounts for a large portion of the total U.S. consumption of natural gas for power generation (50.1% in 1997). Since 1997, the region's incremental reliance on gas has been strengthened somewhat because of ongoing problems and the high price associated with coal transportation which renders natural gas less expensive relative to coal in this region.

- **Regional Differences in Coal Production and Quality:** Regional differences in the cost of production and the quality of coal result in regional differences in the usage fuels used for electricity generation. Labor productivity improvements make western low-sulfur coal the least-cost low-sulfur fuel in most regions. Eastern mines are losing market share to less expensive, lower sulfur coal from western mines. The eastern share of national production, which fell from 93 percent in 1970 to 53 percent in 1996, is projected to be 45 percent in 2020.

  Western coal has lower heat content, however, than eastern coal, and therefore more is consumed in order to generate the same amount of electricity: for example, western coal, at 17 to 18 million Btu per ton, and Appalachian coal at 24 to 26 million Btu per ton. Thus, an increase in the heat content of a coal, other things being equal, tends to broaden its market potential. Several processes have been developed, however, to produce high-Btu, environmentally compliant solid fuels from western coal. If they prove to be physically stable and the economics are favorable, these products, with heat contents increased by up to 40 percent, will greatly enlarge the geographic market area for western coal.

- **Coal Transportation Costs:** The competition between coal, natural gas, and other fuels, and among coalfields, is influenced by coal transportation costs. Coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and the largest markets at competitive delivered prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal.

Environmental Factors

Environmental factors have also played a large role in the choice of fuels for electricity generation in the United States. Key environmental factors include new national ambient air quality standards, differences in coal emissions across regions, costly technologies for improving coal emissions, and differences in the cost of compliance across regions.

- **New National Ambient Air Quality Standards:** Under CAAA90, annual emissions of sulfur dioxide by electricity generators are, in general, capped at 8.95 million short tons a year in 2000 and thereafter, although "banking" of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NOx) emissions, leading to regulations that impose limits on electricity generators for NOx emissions.

  For compliance with the new standards, it is expected that utilities will need to install NOx and sulfur dioxide (SO_2) removal technologies that are more efficient than those widely used at present. The most widely accepted possibilities include switching from coal to gas as the generating fuel, selective catalytic reduction, and derating boilers to produce less steam and, hence, less NOx and SO_2. Similarly, utilities may need to install wet cyclone or wet ionizing scrubbers to capture very fine particles.

- **Innovative Technologies are Costly:** Innovative technologies that are more efficient in removing SO_2, NOx and particulates than those that are currently widely employed have high capital costs. The cost to utilities of new scrubbers to reduce soot alone could run into the billions of dollars. Adding an SCR unit to an existing 500-megawatt coal-fired generator would cost between $30 and $35 million. The additional costs, both investment and operating costs, of the SCR unit would increase the plant's generating costs by roughly 10 to 15 percent.

- **Regional Differences in Coal Emissions:** Continued progressive tightening of the regulatory sulfur and nitrogen oxide emissions cap and engineering limits on the use of low-rank coal in older boilers mandate the use of scrubbers and other clean coal combustion technologies to meet emissions limits. Eastern mines are losing market share to less expensive, lower sulfur coal from western mines. Many older eastern boilers will operate efficiently on western bituminous coals, which, while they are more expensive than subbituminous coals, are lower in emissions potential and less expensive than eastern low-sulfur bituminous coals. In the long run, however, it is expected that a market for inexpensive higher sulfur coals will persist. Eastern coalfields contain extensive reserves of higher sulfur coal suited to inexpensive longwall mining. With natural gas prices projected to rise relative to coal prices after 2010, the projected construction of coal boilers with scrubbers will lead to expanded mining of Appalachian medium- and high-sulfur coals.

- **Regional Differences in the Cost of Compliance:** The cost of compliance with the new rules will not be distributed evenly across the country. Compliance costs are expected to be lower in the Northeast, where utilities have made significant reductions in nitrogen oxides in recent years, than in the Midwest and Southeast, which have large amounts of coal-fired baseload capacity. In general, the extended time line for compliance with the new rules may help to dampen the costs. In the case of the new ozone rules, States will not need to submit their plans to EPA until 2003. Implementation of the plans can occur between 2005 and 2012. For PM2.5 particulates, pollution monitors will need to be sited and the data collected and reviewed before compliance strategies are submitted. Implementation is not required until at least 2007 and can extend to 2016.

Stranded Costs and State Restructuring Initiatives

Most states are investigating a range of restructuring options, and several have initiated proposals to restructure electric services. These proposals include unbundling generation, transmission and distribution functions; alternatives to cost-based rate setting; and retail wheeling legislation. Most states undergoing restructuring initiatives also have initiated systems to deal with the "stranded costs" of replaced facilities. The following discussion provides a brief overview of the restructuring initiatives being undertaken by some of the Eastern states, as well as the methods used to deal with the stranded costs associated with the transition to natural gas.

Massachusetts: In Massachusetts, all consumers are expected to be able to choose their suppliers in 1998. As in California, an independent body will be set up to operate the transmission system and provide a short-term pool for energy transactions. Utilities are required to separate the operations of their different business sectors—generation, transmission, and distribution—and to operate them as separate companies. In fact, they are encouraged to divest themselves fully of their generating assets, and several utilities in the State have announced plans to sell their non-nuclear generating assets. A fee of 0.1 cent per kilowatthour will be collected to support renewable energy.

Stranded Costs: Utilities are required to make efforts to mitigate their potential stranded costs through cost reductions. They will be afforded the opportunity to recover any remaining stranded costs over a 10-year transition period through an access fee. Full recovery of stranded costs is not guaranteed.

New York: In New York, full retail access is being phased in over 4 to 5 years. As in California and Massachusetts, an independent body will operate the State's transmission system. Large industrial customers will, in general, have access earlier, followed by commercial and residential customers in 2001 and 2002.

Stranded Costs: Individual agreements are being negotiated with each of New York's major utilities to phase in retail access and recover stranded costs. Each of the proposed agreements calls for some level of rate reduction over the phase-in period, but the amount varies by company and customer class. The agreements also require each of the companies to sell off a portion of its generating assets to ensure that there will be enough suppliers to make the market competitive.

New Hampshire: In New Hampshire, retail pilot programs began in 1996, bringing significant rate reductions to many customers. Retail access for all customers will begin in 1998. Utilities must functionally unbundle their different business sectors, and an ISO will run the transmission system. A fee of 1.5 mills per kilowatthour will be assessed to support energy efficiency and integrated resource planning programs.

Stranded costs: Initial stranded costs have been estimated by comparing each utility's rates with average regional rates. Final stranded costs will be determined when assets are sold off.

Rhode Island: In Rhode Island, where industrial customers were given full retail access to electricity suppliers in July 1997, all customers are to have retail access by July 1, 1998. Utilities are required to provide a standard offer to their customers that is equal to their rates as of September 30, 1996, adjusted for 80 percent of the change in the consumer price index (CPI). Utilities are working on selling off their generating assets.

Stranded Costs: A stranded cost fee has been established to recover regulatory assets, nuclear obligations (including decommissioning and costs independent of operation), above-market payments for purchased power, and net unrecovered costs of generating plants. The fee is set at 2.8 cents per kilowatthour between July 1, 1997, and December 31, 2000, and will be adjusted by the State's public utilities commission as needed between December 31, 2000, and December 31, 2009.

Conclusion

Natural gas is well poised to capture an increasing share of the evolving electric industry in the U.S. Gas-fired generation holds many advantages over competing fuels. The low capital cost, operating flexibility, short construction period, ability to add capacity in small increments, and substantially lower emissions make natural gas a favorable choice for electricity generation.

Initially, many forecasts predicted that natural gas would capture a large share of incremental electricity generation. As restructuring proceeds, however, expectations have been tempered. As the demand for natural gas increases, the projected price of natural gas is expected to rise after the year 2000.

2. COAL AND NATURAL GAS USAGE IN ELECTRICITY GENERATION: UNITED KINGDOM

Introduction

Over the last ten years, the electricity industry in the United Kingdom has witnessed a steady conversion toward natural gas (away from coal) as the preferred fuel for new power generation. At a time when many countries are looking to deregulate their utility industries and introduce greater competition, it is not surprising that these developments in the United Kingdom have attracted wide international attention.

To set recent developments in context, natural gas has moved from comprising less than one percent of fuels used for electricity generation in 1989, (the last year before restructuring), to 17 percent in 1995. Coal, on the other hand, has decreased from 65 percent of fuels used for electricity generation in 1989 to 48 percent in 1995. Although natural gas continues to grow in relative importance in the United Kingdom, it still supplies a smaller share of total generation than coal.

The conversion to natural gas has resulted in the United Kingdom due to three key factors:

- **Regulatory Changes:** The restructuring of the electric industry in the United Kingdom has resulted in the privatization of almost all the electricity companies and the introduction of competition. A growing number of new entrants are now generating electricity for sale. The introduction of competition has resulted in increased cost-reduction and an increased reliance on the most cost-efficient fuel.

- **Relative Cost of Fuels:** The new combined cycle gas turbines (CCGTs) involve low capital cost in comparison with the coal-fired stations. Also, their short construction times allow for greater flexibility in deciding when to build new stations, and their modular design makes them ideal for turnkey contracts which place full responsibility on plant and equipment suppliers. By contrast, coal plants had become relatively expensive to construct, and more importantly, very expensive to operate given the high and rising U.K. coal costs.

- **Environmental Factors:** The CCGTs are particularly attractive as they also offer major environmental advantages. In comparison with coal-fired plant, CCGTs consume 27% less fuel, emit 58% less carbon dioxide and 80% less nitrogen oxides for each unit of electricity generated. Moreover, they emit no sulfur dioxide, and thus represent one of the best ways of tackling environmental problems such as acid rain and global warming.

Regulatory Changes

There are three separate electricity systems in the United Kingdom: England and Wales, Scotland, and Northern Ireland. The previous structure of the nationalized industry in England and Wales was dominated by one large generating and transmission company, the Central Electricity Generating Board (CEGB), which sold electricity in bulk to 12 area distribution boards, each of which served a closed supply area. In Scotland and Northern Ireland there were vertically integrated boards which also exercised regional monopolies. Centrally planned investment and a cost-plus pricing mechanism characterized a monopolistic system under all three of the previous electricity systems in the United Kingdom.

The 1989 Electricity Act laid the legislative foundations for the restructuring and privatization of the industry and resulted in a change of ownership from the state to private investors and in the introduction of a competitive market. To facilitate competition it was crucial that the monopoly elements of the business (transmission and distribution), be separated from those elements which would be subject to competition (generation and supply). The Electricity Act (EA) introduced competition into electricity generation and supply and a system of independent regulation into transmission and distribution.

Competition has changed the emphasis in the way the generation business is managed in the United Kingdom. In England and Wales, all the major generating companies are now required to sell the electricity they produce into an open commodity market (i.e., the "Pool"). The generators no longer have any obligation to supply a particular market, nor do they have any assured market. They have to compete for their share of an increasingly competitive market.

In Scotland, although the two primary electricity companies remain vertically integrated, the generation, transmission, distribution and supply activities are now regulated separately. Each company is obligated to account for each of its businesses, to ensure there is no cross-subsidy and that excessive profit is not made from use-of-system charges. The generating companies have agreed to make electricity available in Scotland to suppliers at the competitive price offered by the "Pool" in England and Wales.

In Northern Ireland, the previous monopoly, Northern Ireland Electricity (NIE), has retained responsibility for the transmission and distribution sectors but has been divested of its generation function. NIE now purchases electricity from privately-owned generating companies.

The successor generation companies to the old regime throughout the UK are now not the only players in the wholesale market. A growing number of new entrants are all now generating electricity for sale. All this has led to an increasingly competitive market for base load generation and an increased reliance on natural gas as the least cost fuel.

Relative Cost of Fuel

Electricity is a commodity that cannot be differentiated by source or quality and therefore, the challenge is to be the least cost producer. All the generating companies in the United Kingdom have implemented a range of measures to reduce costs and have diversified fuel sources and the range of fuels used. This means burning natural gas in new, more efficient CCGT plants, and securing supplies of gas by contracting for independent gas production or joining with others in exploration. Companies are looking to buy coal at world prices, whether from the UK or overseas, taking advantage of low sulfur coal. These measures have already led to major reductions in fuel costs.

The intensive drive to reduce operating costs is a result of management facing the pressures of surviving in a competitive market. The availability of plants is being improved because the Pool only pays when a plant is available. Improvements in thermal efficiency are being sought, so that progressively higher output can be achieved. In addition, about 11,000 MW of the least efficient plants has now been closed and a further 6,000 MW has been placed into reserve by the major generating companies.

Environmental Factors

In recent years, UK electricity companies have made significant strides towards improved environmental performance. Emissions of carbon dioxide, in terms of units generated, continue to decline. The reduction in total CO_2 emissions from electricity production between 1979 and 1994 was 29%. Emissions of sulfur dioxide and nitrogen oxides also continue to decline. This continuing fall is achieved by increased usage of new gas-fired CCGTs (with substantially lower emissions than coal-fired plants), increased nuclear output, (which produces no carbon dioxide), the development of combined heat and power (CHP), and the use of renewable sources.

Under the European Large Combustion Plant Directive and the Climate Change Convention agreed at the Rio Earth Summit in June 1992, the Government has committed the UK to reductions in emissions of sulfur dioxide, nitrogen oxides and carbon dioxide. The electricity industry has achieved these reductions to date, well ahead of the per annum Government target for the entire UK.

The UK electricity industry has spent around £180 million retrofitting low nitrogen oxide burners to coal-fired stations and about £1 billion installing flue gas de-sulphurisation plants. In addition, substantial sums have been spent on new gas-fired replacement capacity.

Conclusion

Regulatory changes have lead to the elimination of monopolies and the reduction of governmental intervention in the electric power industry in the United Kingdom. Reforms include the reduction of price controls and tariff restrictions and the elimination of subsidies. Structural changes are characterized by the division of the industry into its three major functions - generation, transmission and distribution - and a commitment from governments to ensure that independent producers and other power-related enterprises will have full and fair participation in each of these functions. Ownership trends include an emphasis on privatization and commercialization.

The restructuring of the British electric power industry has been premised on the ability of private ownership, markets, and competition, to perform tasks previously addressed by other institutions. While in some sense the experiment has worked, it is more accurate to say the experiment has been made to work. The enormity of the initial changes has been matched by the enormity of the problems that have since arisen. Among the problems that appear to be the result of initial design defects are the following:

- The market power of generators. This has resulted in unwarranted price increases in some cases and persistent manipulation of other aspects of the system.

- Loose regulation of the distribution stage. The initial specification of price caps allowed for substantial price and profit increases at the expense of customers.

- More recently, the threat of reintegration of portions of the industry. Efforts to merge vertical stages of production raise competitive concerns and move the industry into unexpected directions.

Thus, despite some operational success, British restructuring of electric power has encountered a number of significant difficulties, including challenges to some of its premises, the inadequacy of key institutions, and the ironic need for rescue by regulation. Some of the problems have been successfully addressed, but others have not. Some issues may well be inherent difficulties presented by electricity reforms, difficulties that go beyond those found in other industries.

The opening of market access has affected the mix of generating technologies in the United Kingdom. Private developers favor smaller gas-fired units, with lower capital costs and investment risks, over large coal-fired power plants. Technology has also helped the transition toward natural gas. As the combined cycle gas turbines (CCGTs) generating units become more efficient, coal becomes more expensive in terms of relative costs per Btu.

As improved technologies for emissions become available, their costs have also increased. This, in turn, has increased the cost of coal relative to natural gas. Where natural gas has been chosen over coal for new generating capacity, greenhouse gas emissions have been be reduced. Where natural gas replaces retiring nuclear capacity, however, emissions have increased.

3. CASE STUDY: TRENDS IN ELECTRICITY GENERATION IN ALBERTA

Introduction

Unlike the current restructuring in the United States and the previous restructuring in the United Kingdom, the restructuring of Alberta's electric utility industry is not expected to alter the distribution of fuels used for generation. Although competition has been introduced to the industry's generation and retail services markets, coal remains the preferred fuel for generation. Unleashing competitive forces increases incentives for efficiency, puts downward pressure on electricity prices and further enhances the advantage of inexpensive high quality coal in Alberta.

Coal is by far the fuel of choice for electricity generation in Alberta. Coal provides the sustainable option for stable costs and long-term reliability of electricity supply, with rates that are among the lowest in North America. Currently, coal-fired electricity generation comprises 76 percent of total generation capacity in Alberta. Natural gas accounts for 13 percent and hydro accounts for 11 percent of total generation capacity.

Alberta has a competitive advantage in coal production over many jurisdictions due to:

- the wide distribution of coal in Alberta;
- the low production cost of coal; and,
- the diverse technical characteristics of Alberta coal.

For these reasons, coal will remain the predominant fuel for electricity generation in Alberta.

Wide Distribution of Coal in Alberta

Alberta's total coal resources are estimated at 2,600 gigatonnes, of which 800 gigatonnes are considered to be recoverable. These include 790 gigatonnes of sub-bituminous coal and 10 gigatonnes of bituminous metallurgical and thermal coal. Alberta's coal reserves contain nearly twice the energy of all Alberta's non-renewable energy resources, including oil, natural gas, and oilsands. Seventy percent of Canada's coal reserves are located in Alberta.

Coal is distributed over three distinct areas in Alberta. In the Plains Region subbituminous coals are found. Subbituminous coal has a moisture, mineral-matter-free, heating value of from 19.3 to 26.7 megajoules per kilogram and is non-agglomerating. It is used in an as-mined condition, as fuel for mine site electricity generating stations. Some is also used for domestic purposes. In terms of actual generation, sub-bituminous coal is used to generate about 90% of Alberta's electricity needs. About 26 million tonnes of sub-bituminous coal are produced on the plains annually.

The Mountain Region contains low to medium volatile bituminous coals (metallurgical). Metallurgical bituminous coal is an agglomerating coal, and is therefore suitable for coke making. It has a moist, mineral-matter-free, heating value of more than 26.7 megajoules per kilogram. It is mined and cleaned in the Mountain Region. Bituminous coal production comprises about 7 million tonnes of metallurgical coal, all of which is exported, and 3.2 million tonnes of thermal coal, of which about 2 million tonnes are exported from Canada, plus about 460 thousand tonnes sold to Ontario Hydro.

The Foothills Region contains high volatile bituminous coals (thermal). Thermal bituminous coal has a moisture, mineral-matter-free heating value of more than 26.7 megajoules per kilogram. It is usually non-agglomerating, but sometimes an agglomerating high-ash coal is used as a thermal coal. Most of the production is in the Foothills Region and is exported after cleaning. Some high-ash thermal coal is burned locally.

Low Production Cost for Coal

The low production cost of coal in Alberta can be attributed to inexpensive mining methods, the minimal preparation requirements and the low transportation costs associated with coal used for electricity generation.

- **Inexpensive Mining Methods:** Most Alberta coal is produced by surface mining, either strip or open pit mining, which are cheaper methods of extraction than underground mining methods. Strip mining is used on the plains to extract the sub-bituminous coals used for electricity generation. Following extraction from strip mining, the overburden is replaced and graded, creating a landscape that is often better suited to agricultural or recreation uses than the original. As strip mining is a temporary land use, continuing reclamation programs return the land to its former or improved productivity in only a few years. Open pit mining is used most often in mountainous areas, where the coal seams are irregular and localized. As the pits become larger, overburden can be stored in the pits from which coal has been removed. When the pit is abandoned, final reclamation is carried out.

  Some coal is also extracted using underground room and pillar and longwall methods. Underground methods are used because the larger coal seams lie at depths too great for economic recovery by surface mining technology.

- **Coal Used for Electricity Generation Requires No Preparation:** Alberta's sub-bituminous coal, used as a fuel for electricity generation in the province, does not require preparation. Bituminous coals, on the other hand, must be upgraded by a preparation plant, to meet the rigid specifications of customers. Each preparation plant is designed specifically for the particular coal to be treated. Coal washing plants employ various combinations of hydro-cyclones, dense media systems, jig washers, separation tables and froth flotation cells.

- **Coal Used for Electricity Generation Requires Little Transportation:** Sub-bituminous coals are consumed by nearby power stations and require little transportation. This contributes to the low cost of coal as a fuel for electricity generation in Alberta. Getting other types of coal to market is more difficult and costly. Coal producers are faced with moving coal for export to Ontario markets or to Pacific tidewater, both over a thousand kilometres away. Transportation from Alberta mines to Pacific tidewater is provided by Canadian National Railways.

  The two Pacific bulk handling ports normally used by Alberta's export coals are Neptune Bulk Terminals at Burrard Inlet and Westshore Terminals at Roberts Bank, both in the Vancouver area. These terminals receive the coals and either load them onto customer's vessels or stack the coal and reclaim it for loading onto vessels when they arrive. Ridley Terminals Inc., at Prince Rupert, also handles some Alberta export coals. Terminal facilities at Thunder Bay, Ontario, were completed in 1978. They receive Alberta coal destined for Ontario Hydro and transfer it to lake vessels for onward movement to the utilities.

Diverse Technical Characteristics

Regardless of rank, Alberta coals are very low in sulfur, from 0.2 to 0.7%. This contributes to the continuing attractiveness of Alberta coal in electricity generation. Coal combustion also produces carbon dioxide (CO_2). Governments are engaged in policy decisions about restricting CO_2 production. The use of coal for electricity generation creates discharges of fly ash and gases, which are removed by modern technology. Continued development and usage of "clean coal technology" is on-going in Alberta to handle the environmental problems associated with coal usage.

Reclamation technology is employed in Alberta to ensure that mined lands are restored to serve pre-determined uses. Improved drainage, fertilization, land use management and planned programs often result in land of higher productivity than adjacent lands that have not been disturbed by mining. Alberta's coal producers are committed to mitigating the environmental impacts associated with coal usage and mining by maintaining the natural environment and the protection of air, land and water.

Restructuring of the Electric Industry

The first step of the restructuring of Alberta's electricity industry was the passage of the Electric Utilities Act (EUA) in 1995. The Act created the open-access, independently operated Power Pool through which electric energy is traded in the province. The Pool is governed by the Power Pool Council, responsible for its fair, safe and efficient operation. As well, an independent transmission administrator oversees the use of the transmission system by buyers and sellers to ensure fair rates, non-discriminatory access for all market participants and the safe, reliable operation of the system. It introduced the industry structure and regulatory reforms designed to increase efficiency in the electric industry. All consumers share the costs and benefits of the generation facilities in existence in 1995 when the Act was passed. This sharing is accomplished through legislated financial arrangements. The costs for new generation brought on line after the passage of the Act are not shared. The addition of new generation facilities is now based on market considerations.

Since that time, the Alberta Department of Energy worked with stakeholders to set a timetable for achieving that vision. As a result of that process, the government introduced the Electric Utilities Amendment Act in the spring of 1998 to move forward with the restructuring of Alberta's electric industry. This Act is designed to eliminate the need for future regulatory hearings on generation costs, enable customers to choose their retail supplier of electricity, create better market incentives for efficiency and put downward pressure on electricity rates. The government has set targets for implementing customer choice in 1999 and deregulation of generation by January 1, 2001.

Under this system, Alberta proposes to allow independent, non-utility firms to compete to offer services to consumers. Only the building and maintenance of the transmission and distribution wires would be regulated with other services being provided by any firm, to any customer. These retailers would offer consumers a variety of rate and service options. Consumers would then choose which retailer and which rate and service options best suits their particular needs. The pace at which customer choice is introduced will depend on technology, such as the customer's meter type.

A primary goal of deregulation is to create an environment in which generators have incentives to reduce costs and their decisions about pricing and investment are guided by competitive market forces. Deregulation will be based on the principle that all consumers in Alberta share both the benefits and the costs associated with existing regulated generating units. Customers will benefit through greater choices for their power needs and downward pressure on rates which results from increasing competition. Starting in 1999, customers will receive the right to choose their retailer of electricity. At the same time, power services will be "unbundled," meaning that they can be offered and priced separately by competing retailers. Generation owners will benefit from the elimination of regulation, enabling them to focus on being more efficient, rather than preparing for regulatory hearings. The legislation will be designed to ensure a level playing field for all buyers and sellers of electricity and existing utilities will not have unfair advantages over new participants in the market.

In spite of the ongoing restructuring process in Alberta's electricity industry, and corresponding increased competition and least cost production methods which will ensue, coal will remain the preferred fuel in electricity generation.

Stranded Costs and Residual Benefits

Stranded costs are not a major issue in Alberta, since coal will remain the preferred choice of fuel to generate new capacity and most existing generating units will be competitive in the new environment. The move to a market environment increases the value of some plants, creating residual benefits, and lowers the value of others, creating stranded costs. According to the principles outlined in the deregulation legislation, Alberta consumers must share these benefits and costs. Prior to the passage of the EUA, utilities built new generation on the understanding that they could recover their investments as long as the Electric Utilities Board (EUB) deemed these investments to be prudent. These investments are recovered from Alberta's electricity consumers through rates approved by the regulator. The investments include a rate of return that adds a premium for risks faced by the utilities. Customers shared some of the risks by paying the regulated rate.

Residual benefits are associated with a generating plant if, solely by virtue of moving to a market environment, the owner is able to earn an excess profit that would not have been earned under a regulatory environment. This does not mean that a utility cannot earn higher profits if it becomes more efficient, just that the higher profits cannot result solely from leaving regulation earlier than anticipated when the generating plant was first approved. Stranded generation costs can be defined as investments approved in a regulated environment that cannot be mitigated or recovered in a competitive environment.

At present, residual benefits and stranded costs are measured and shared on an ongoing basis by the legislated financial arrangements set up under the EUA. These legislated arrangements require regulatory approval and were never intended to achieve deregulation of generation. They were established to allow a smooth transition from the old regulated structure to the new structure. Although they perform two important functions -- sharing of costs and benefits and creating a disincentive to abuse market power -- they still require regulatory approval.

These arrangements will be replaced no later than January 1, 2001 with a tradable instrument. The tradable instrument will be designed to ensure:

1. consumers receive the residual benefits created by the transition to a competitive marketplace;

2. owners of regulated generation have a reasonable opportunity to recover any costs that may become stranded by the transition to a competitive marketplace, and;

3. owners have an opportunity to earn greater profits if they become more efficient.

A major issue for the government to resolve is how long the instrument should be in place to ensure a fair sharing of costs and benefits. The process to determine the details of the tradable instrument will be set in mid-1998 so that consumers, utilities and independent power producers are able to make investment decisions with full knowledge of how Alberta's electricity system will be structured in the future.

APPENDIX E

INCENTIVE PROGRAMS TO ENCOURAGE CONVERSION TO NATURAL GAS

E.

USE AND EFFECTIVENESS OF INCENTIVE PROGRAMS TO ENCOURAGE CONVERSION TO NATURAL GAS

1. RESISTANCE TO CONVERSION

Development of a new natural gas distribution system into areas previously unserved by natural gas often requires some measure of incentive program to encourage conversion to the newly available energy source. The barriers to conversion are:

i. Fear for the safety of natural gas in dwellings,

ii. Demonstrable cost savings both immediate and long term from natural gas when compared to the cost of their current fuel supply, and;

iii. The high cost of conversion as an immediate capital outlay.

The first issue is normally overcome through aggressive public advertising campaigns normally sponsored by the distribution company and often supported by government agencies and municipal governments. Product suppliers for space and water heating equipment often compliment this public awareness campaign.

The second and third concerns are economic in nature and require specific cost stabilization or cost reduction measures directed to the end user in most circumstances where the cost of natural gas is not significantly lower than that for other currently used fuels.

To address this cost of conversion issue to encourage rapid and high conversion rates to natural gas, a number of alternative measures are available, many of which have been effectively applied in other jurisdictions. These measures generally fall into three broad categories:

i. Cost reduction measures for the mainline distribution system,

ii. Conversion cost reduction measures, and

iii. Gas price stabilization or reduction measures.

The approaches available under each of these categories are discussed. Where appropriate reference is made to actual situations where these approaches have been applied, both successfully and unsuccessfully.

2. COST REDUCTION MEASURES FOR THE MAINLINE DISTRIBUTION SYSTEM

The objective is to reduce the actual distribution cost of delivering gas to the burner tip, as distribution tolls are often one of the most significant cost components in determining the price for gas delivered to the end user. Of the four key cost components; gas commodity price, transmission costs, distribution costs and taxes, the distribution cost component can often represent 30 to 40 percent of the final delivery price.

Two general approaches are used to reduce the cost of the gas distribution or delivery system for the end use customer: aids to construct mainline facilities and toll reduction techniques.

Aids to Construct Mainline Facilities

In situations where the population base is low and the distances between population centers is great, the rate base (cost of facilities) is disproportionately skewed toward the high relative cost of mainline transmission facilities to service these far flung municipal centers. The effect on distribution rates is significant as this is not a cost typically borne in regions of high population and close densities. The Cape Breton Regional Municipality, like many areas in Nova Scotia would fall into this category.

One of the approaches used to ameliorate the impact this widely spaced, low density load has on distribution rates is through direct subsidy or cost sharing by government directed specifically to construction of a distributor's mainline laterals.

Canadian examples of this type of government assistance are found in Alberta and Quebec.

In Alberta, the province embarked upon a rural gasification program to bring gas service to smaller communities and rural homesteads commencing in the early 1960s and the program continues to this day. As a significant part of this rural gasification effort, the provincial government paid for the mainline laterals or backbone system of gas distribution to provide access to gas supplies for small regional gas co-operatives and small municipal franchises. This financial contribution to build the basic infrastructure allowed these smaller distribution entities to more economically develop their own local distribution network without the direct cost burden of the long distance transmission access costs. The program has been very successful in providing gas service to essentially all areas of the province and at a distribution cost to rural consumers effectively equal to that paid by urban consumers.

In Quebec, the gas distribution system was expanded outside the urban Montreal and Hull regions in the mid to late 1980s, including gas service to Quebec City and as far north as the Sauganay. Similar problems of long distance and low population density were encountered. Substantial financial assistance was provided by the Federal Government to aid in the construction costs of the mainline and lateral systems. The funding was allocated from special tax levies collected from natural gas producers under the National Energy Program to finance the future developments of new natural gas markets (MDIP). The effect was to permit the rapid expansion of the basic gas distribution system to many regions and communities in Quebec that otherwise could not support the development of a gas distribution system supported only by toll revenue.

In the Nova Scotia context and particularly applicable to the CBRM situation, a similar effect can be achieved through an expanded and more liberally interpreted Laterals Policy applicable to the Maritimes & Northeast Pipeline Project. The current approach taken by M&NE appears to be moving directionally to this end. If a M&NE lateral to serve additional market areas can be justified on a cost allocation basis without exceeding the nominal $0.60/MMBtu toll, either by relaxation of the time frame in which cost recoveries are calculated or through aids to construct for the excess costs, the cost of the long line laterals can be rolled into the M&NE tolls. Since only a portion of these M&NE costs are paid in the tolls collected from Nova Scotia consumers, it equates to an effective cost shift to extra-provincial transportation customers. The remaining costs of local distribution are then recovered in the provincial distribution toll.

Toll Reduction Techniques

Distribution tolls for each consumer class are normally set by the provincial utility board with jurisdiction. In Nova Scotia, this function will be administered by the Nova Scotia Utilities and Review Board under guidelines yet to be finalized and more fully developed. To date, there has been no requirement for such determination in the absence of a gas distribution system in the province.

Several rate design mechanisms are and have been used by other regulatory boards to reduce the high transportation tolls normally resulting from the construction of an entirely new distribution system. The scope of this examination does not permit a full exploration of all of the mechanisms available to reduce user rates.

However, the rate reduction techniques often used involve making adjustments to a number of cost of service items to reduce their impact in the early years of service when the customer load is not sufficiently developed or insufficient to service these costs. These techniques, currently in use in other jurisdictions, can include:

- Extension to the term for depreciation of the facilities,
- Forward levelizing the rates based on estimates of applicable rates over a defined future term,
- Reducing the allowed rate of return on equity in early years to offset high initial undepreciated rate base costs,
- Government guarantees of debt component to reduce the cost of borrowing,
- High capitalization rates of Operating and Maintenance expenses into rate base to reduce current year impacts in rates,
- Adjustments to the timing of income tax charges reflected in the rates,
- Cost savings incentive programs.

One approach no longer used in today's unbundled service allocation environment is:

- Cross-subsidization between rate classes to shelter certain customer types from their fully allocated costs of service.

3. CONVERSION COST REDUCTION MEASURES

The key problem to be overcome at the individual consumer level in converting to natural gas is the high capital cost of conversion and retrofit of space heating systems in residential dwellings. These costs can be considerable. They include the individual line service connection from the distribution street main to the dwelling, the conversion or change-out of the space heating and/or water heating units (furnace and water heaters), and reducing the heat distribution system throughout the dwelling. Individual costs can range from an estimated $1,000 to $9,000 dollars per dwelling. Unless funding assistance is available, it is unlikely in most circumstances that natural gas price savings alone will be sufficient to economically recover the initial capital costs of conversion over time.

A number of approaches have been successfully employed in other jurisdictions to overcome this significant economic barrier to conversion. These generally fall into two basic categories;

- Loans or loan assistance to homeowners, and
- Grants as aids to construct to reduce the homeowner's capital cost to convert.

These methods are discussed in the context of the types of costs incurred.

Service Connection Cost Assistance

The cost to bring gas service from the street main into a dwelling often ranges from $600 to $2,000 per installation. Several approaches have been used successfully in other jurisdictions.

- **Partial subsidization by the distribution utility:** The cost to connect is often approved as a direct charge-out cost to the consumer at a direct contribution cost less than the actual cost of installation. For example, if the actual cost of installation averages $700, the installation cost charged out to the consumer is much less, with the balance added into the utility's rate base and paid for by all customers in that rate class over time. This approach works best where the distribution system is mature and the percentage of new connections is relatively low. An example is found in the approved residential rates for BC Gas Utility Ltd.

- **Capped partial subsidization by the distribution utility:** This is a variant of the previous example used to limit the upside exposure to costs for existing ratepayers. The customer cost is capped at the predetermined level as long as the service connection cost falls below a preset maximum. If the service connection cost exceeds that maximum, the customer pays the additional amount as well.

- **Partial subsidization by government:** The mechanism is the same as in the first example. However, the government provides the funding for the additional cost above the customer contribution amount. This mechanism does not result in a significant increase in rate base to existing customers and is particularly suited to immature or low density distribution systems. A form of this approach is currently in use in Alberta for both investor owned urban distribution customers and for rural co-ops on the same basis.

- **Capped partial subsidization by government:** The mechanism is the same as in the second example. The government provides the funding assistance. In this case, it is the government's cost exposure that is protected by requiring the consumer to pay for the costs in excess of the predetermined maximum. This is currently in use in Alberta.

- **Loan assistance and payment scheduling by the distribution utility:** The customer capital cost of the service connection can remain as a serious conversion impediment, with or without partial subsidization by the distributor or government. Many utilities also provide a loan facility arranged through them with a financial institution. The loan rate is often better than that obtainable by the customer individually. Repayment can be stretched over a number of years, normally up to 10 years. The application is made to and through the utility and the payments collected directly by the financial institution or on the utility bill. Several Canadian utilities offer this financing assistance.

- **Loan assistance guaranteed by government:** This approach is essentially similar to the last example. However, the financing arrangements were initially made with the assistance of government and the government has provided a guarantee of performance to the financial institution. This results in a lower borrowing rate for the consumer and was used during times of high interest rates. Alberta used this approach in the 1970s but today, the previously described loan assistance program is now in effect.

Household Conversion Cost

These costs are normally those incurred within the house to convert both the energy consuming equipment to natural gas and to modify or replace the space heating delivery system throughout the house (re-ducting). Equipment conversion can range from nozzle switch-outs for propane to natural gas systems to complete replacement of furnace systems. If a house is electrically heated, conversion also requires construction of a complete forced air ducting system. Costs range from a few hundred dollars to several thousand dollars.

Several approaches are used to offset the high initial costs of these types of conversion expenses.

- **Homeowner grants by government:** This approach is useful in greenfield situations where a general grant program can be widely applied in situations where natural gas conversion/consumption is considered to be in the broader public interest. The British Columbia government introduced a similar program to encourage rapid conversion to gas on Vancouver Island when it became available in the early 1990s.

- **Homeowner loans through the distribution utility:** This is essentially a credit facility arranged by the distribution utility and available to conversion customers. The applications are processed through the distributor, but the financial arrangements are arranged directly between the consumer and the financial institution. Often the loan rates and security requirements are better than the individual could otherwise arrange himself. This one-stop shopping approach offered by the distributor encourages conversion even if the cost remains with the homeowner. A variant of this approach is in use in Alberta.

- **Homeowner loans with government guarantee:** This is a variant of the preceding example. In this case, a form of government guarantee is provided that has the effect of reducing the consumer's borrowing costs.

- **Equipment purchase subsidies by distribution utility:** This is a relatively common approach adopted by many utilities in one form or another. Often space heating equipment is offered for sale directly by the distributor and at a discounted price. These are often combined with installation services at special rates. To reduce cost shock, these equipment purchases can also be financed and paid for over time as a direct charge to the monthly utility bill.

4. GAS PRICE SUBSIDIZATION

Natural gas prices in Canada and the United States are no longer controlled directly by government. Accordingly, programs used previously in Canada under the National Energy Program to stabilize not subsidize prices at a lower level are no longer acceptable. However, there are a number of approaches still available to achieve a direct reduction in the commodity cost of gas to the consumer.

- **Sales tax relief/rebate:** Most provincial jurisdictions in Canada, including Nova Scotia, impose a sales tax on the retail consumption of energy. It is anticipated that a similar tax would normally be imposed on natural gas once it becomes available. To encourage conversion to natural gas and to ensure a pricing advantage relative to other forms of energy, the sales tax could be waived for a limited time or for an indefinite term. The cost savings to the consumer can be significant and may provide the additional pricing advantage to natural gas to encourage early conversion. While this is a direct cost to the government, if it is a provincial resource, the loss is all or partially offset by resource taxes on production (royalties), increased production volumes and hence royalties, and additional income tax and sales tax on conversion expenses. If the program is applied selectively to certain rate classes only, or if complicated by the HST mechanism for collection, it can be offered as rebate on the utility bill. Quebec employed this sales tax exemption approach for several years in the late 1980s to encourage the conversion to gas from electricity. This freed up additional electricity supplies for export to the United States.

- **Direct price subsidy by government:** This requires a price guarantee for natural gas relative to the price for an alternative existing fuel supply. The importance of this type of program lies in the consumer's price guarantee that he will never pay as much or more for natural gas than he is paying at the current time. For the conversion customer, it eliminates the price risk of conversion. However, since prices for heating oil are not controlled, the government liability to pay the subsidy to producers is somewhat open-ended. In today's environment, it is not a favoured approach. This approach was adopted for several years by the British Columbia government to encourage conversion on Vancouver Island when gas service was introduced in the early 1990s. Natural gas delivered on the island was capped at 90% of the regulated price for gas applicable elsewhere in B.C. Prices are no longer regulated.