Natural Gas and its Impacts on Greenfield Areas

Prepared for:

Petroleum Research Atlantic Canada

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Table of Contents

SUMMARY

Objectives

Much has been said in reports, provincial franchise applications and in the press about the possible benefits and costs arising from the introduction of natural gas into a region or community. Too often, what has been said or promised is based on limited practical experience. The purpose of this study is to try to remedy this deficiency and to provide some assistance to decision-makers interested in understanding how the introduction of natural gas could affect a community or region.

In its broadest sense, the report may be characterized as a "how to" guide, setting out a method for identifying the socio-economic benefits and costs, both private and public, based on an assessment of what has actually occurred elsewhere. The specific objectives are to:

- determine the types of impacts, both positive and negative, that natural gas has had in a sample of jurisdictions in North America;
- develop a framework model that will enable a systematic and consistent analytical approach in assessing the potential impacts of natural gas introduction into greenfield areas; and,
- apply the framework model by conducting case studies on three regions in the Maritimes.

Greenfield Market Analysis

The study examines five greenfield sites that have received or expanded natural gas service within the last decade.

- **Vancouver Island and the Sunshine Coast**: received natural gas in 1991.
- **Southwestern Manitoba**: six small towns and surrounding area south of Brandon received gas in late 1995. The report also provides information on the Interlake area north of Winnipeg that received natural gas in 2000.
- **Wingham, Blyth, Brussels- Ontario**: received gas in 1996/97. The report also discusses the expansion of gas service to Parry Sound in the Muskoka District on Georgian Bay north of Toronto.
- **Lewis County, New York State**: Gas distribution started in late 1996 in this area in northern New York state
- **Chittenden and Franklin Counties, Northern Vermont:** these two northern most counties received gas in the mid-1960s. The site was of interest because

the system has been expanding and the conditions for expansion could be relevant for this study.

The main findings from the study of the greenfield sites are:

- Areas receiving gas service are better able to retain industries who might have otherwise had to relocate due to environmental standards and/or costs;
- Areas become more competitive with similar communities nearby who already had natural gas to offer to industry;
- Areas can offer present and future consumers a competitively-priced, clean energy source for their advantage.
- Capital subsidies were instrumental in system construction and encouraging fuel switching for commercial and residential users.
- There were a number of combinations of capital and operating subsidies in the greenfield areas, including aids to construct and user fees.
- Environmental regulations were a key driving force for pulp mills in emission reduction and pollution abatement cost reduction.
- Some locations had inherent advantages (in capital costs and fuel-switching costs) due to existing propane-air systems already in place.
- Energy cost savings were the key economic benefit in all sectors, especially for commercial and industrial applications.
- In most cases, the driving factor to bringing in natural gas was the potential load of large industrial users. Marketing to small commercial and residential consumers varied in effort.
- In the majority of case studies, it was difficult to attribute new commercial or industrial investment to the introduction of natural gas.
- No specific employment displacement was noted in any community (e.g., in the residential oil service) due to the introduction of gas service.
- Take up rates varied widely depending on the marketing strategy of the distributor/marketer, and the incentives offered to customers to switch to gas.

Framework Model

The second major output of the study is a framework model that provides the type of questions and data sources that an area seeking natural gas service would need to address. The model sets out specific questions, data requirements and sources under several headings:

- Area energy objectives
- Economic growth and development
- Industry/anchor load
- Commercial/residential market
- Energy supply and market structure
- Economic, social and environmental benefits and costs
- Regulatory framework

- Distribution system costs
- Subsidy regime

Case Studies

The third major output of the study are three case studies that apply the framework model. The main objective of this aspect of the report is simply to show *how the model is to be applied*. The results of the case study analyses could be considered broadly indicative of the financial or economic attractiveness of the projects. But results are derived using very preliminary capital and operating cost estimates drawn from a variety of sources, so *should not be considered definitive*.

The case study areas are:

- ♦ Northeastern New Brunswick, running from Miramichi City to Bathurst to Campbellton;
- ♦ Prince Edward Island, stretching from Charlottetown to Summerside; and
- ♦ Southwest Nova Scotia, bounded on the east by East Chester and on the west by Shelburne.

The analysis was carried out for a 20-year period. Natural gas (the commodity alone) is assumed to cost $4.55 per MMBtu in real terms over the study period. A key assumption for all three case studies is that natural gas would be available to customers at a price 10% less than the expected price of fuel oil. In practice, fuel oil prices may not be high enough to allow this (eg, when oil prices are at or below the cost of producing gas plus transportation charges), but they are under market circumstances in 2002.

Fuel oil prices in this study are consistent with a long-term price of crude oil of $US 24.00 per barrel (see Appendix A for fuel price assumptions). At this crude price, the 2002 commodity cost of gas plus toll charges on the M&NP system would exceed the price of #6 fuel oil. It follows that few if any large industrial users would convert to natural gas *based on price alone*. Those that do convert would presumably operate dual-fired systems (to take advantage of fuel price shifts), and would consequently make at best a modest financial contribution to transportation system costs after commodity costs were covered. In this study, then, we have a worst-case set of circumstances where the market does not support conversion of consumers using #6 fuel. The market for natural gas in the case studies consists of residential households and commercial users including institutions.

The main quantitative benefit of access to natural gas consists of potential energy savings. This conclusion is based on the greenfield sites analysis that finds that, contrary to popular opinion, access to natural gas has not generated substantial economic development effects.

In other words, simply having access to natural gas competitively priced with other energy sources has not been enough to trigger the wave of industrial development often associated with such access. It is possible that long-term access to *relatively inexpensive* gas could trigger such benefits, for example, if gas were available at preferential rates near the source of supply. But this is not predicted to occur in any of the three case study areas under consideration.

New Brunswick

The combined cost of constructing a lateral and distribution system for the study area is estimated to be $159 million. The financial analysis indicates a negative Net Present Value (NPV), so the system is not financially viable given the cost and revenue assumptions. Including energy cost savings in the Cost Benefit Analysis (CBA) enhances the result, but still leaves a negative NPV. This result does not lend support for providing an aid-to-construct. On this basis, the project (lateral and distribution system) does not pass the CBA test and there are no economic grounds to support its implementation.

Prince Edward Island

The combined cost of constructing a lateral and distribution system for the study area is estimated to be about $64 million. The financial analysis indicates a low but positive NPV, so the system could be marginally commercially attractive. Including energy cost savings in the CBA results in a positive NPV. This provides an economic basis that could justify support for an aid-to-construct. A potentially attractive alternative to the case assessed here involving a proposed combined cycle gas-fired generating station could not be incorporated in the analysis due to a lack of cost and revenue data.

Nova Scotia

The combined cost of constructing a lateral and distribution system for the study area is estimated to be about $66 million. The financial analysis indicates a negative NPV, so the proposed system is not likely to be commercially attractive. Including the energy cost savings in the CBA leads to a positive NPV, thus providing an economic basis on which to consider support for an aid-to-construct. Replacing the lateral from the Halifax area with a gas source inside the study area (eg, El Paso's proposed Blue Atlantic Project) would reduce capital costs, resulting in a system that could be attractive to a private sector investor even without an aid-to-construct.

Conclusion

The reader is reminded that the main objective of this study is to promote a better understanding of the kinds of benefits and costs access to natural gas can generate, and how to go about measuring and describing these benefits and costs. The framework model takes the greenfield area results and develops them into an analytical approach that can be applied to other areas. The case studies illustrate how to go about this in a practical way.

The reader is cautioned not to interpret the case study conclusions as anything more than indicative. In each case, the analysis is based on secondary information drawn from a variety of sources. Far more detailed analysis is needed to develop reliable cost estimates and revenue projections leading to definitive conclusions about financial and economic viability.

I.

GREENFIELD STUDY AREAS

1. OVERVIEW

Introduction

The purpose of this section is to report on an examination of five greenfield sites that have received or expanded natural gas service within the last ten years. The term greenfield was meant to denote the absence of natural gas prior to whatever system expansion is included in the site analysis reported here. The five sites examined are:

- **Vancouver Island and the Sunshine Coast**: This area is well known for the extension of the natural gas transmission system from the eastern edge of Vancouver to Squamish, the Sunshine Coast and then to Vancouver Island in 1991.
- **Southwestern Manitoba**: Gas was provided to an area, anchored by six small towns, south of Brandon running to the United States border, in late 1995. The report also provides information on the Interlake area north of Winnipeg that received natural gas in 2000.
- **Wingham, Blyth, Brussels-Ontario**: This area is located close to Lake Huron, north west of London. Union Gas extended service to three towns and surrounding area in 1996/97. The report also discusses the expansion of gas service to Parry Sound in the Muskoka District on Georgian Bay north of Toronto.
- **Lewis County, New York State**: This area is in northern New York state close to the Iroquois Gas Transmission line carrying natural from the Transcanada Pipeline to coastal New England. Gas distribution started in the count in late 1996.
- **Chittenden and Franklin Counties, Northern Vermont:** These two northern most counties received gas in the mid-1960s. The site was of interest because the system has been expanding and the conditions for expansion could be relevant for this study.

Findings Summary

Vancouver Island

- Subsidies were a very important part of building the system – capital subsidies for the transmission line, conversion grants for industry and for the commercial and residential users.

- Environmental issues were the driving force – to get pulp mills off oil to reduce emissions and reduce oil barge traffic in Strait of Georgia.
- Victoria, Nanaimo and Squamish all had propane-air systems prior to natural gas; provided a big base for immediate conversions.
- There is virtually no evidence of an economic development effect; at least none that anyone has been able to cite.
- Biggest economic effect has been cost savings to commercial-industrial users and residents but there are no estimates of its value.

Southwestern Manitoba

- The communities led by the Westman Economic Development Association wanted natural gas.
- The Manitoba government placed a priority in gas service for rural areas, especially following the elimination of the Crow Rate freight subsidy for grain products.
- The capital subsidies, covering 52% of the capital cost, provided by the Canada-Manitoba Infrastructure Works program were critical.
- The communities as a group also had to pay for about 26% of capital costs; customers contributed a little over 2% and Centra about 17%.
- There are no operating subsidies.
- The community contribution took the place of a surcharge on gas price. Community representatives feel this was a key – adding a surcharge to the gas price would have killed the deal in their view.
- Some economic development effects cited – location decisions of feed mill, hog barns, etc. There was a strong view that communities without gas suffer competitively against those that have it.
- The experience of the Interlake area was shaping up to be very similar to that of southwestern Manitoba.

Ontario – Wingham, Blyth, Brussels

- This was a small system with 3,445 existing potential residential, commercial and industrial customers.
- The communities apparently asked for gas service; nearby communities already had service.
- There were no capital subsidies. Customers agreed to a $15 per month market contribution for five years. Union Gas offered minor inducements such as appliance deals to entice hookups.
- There was only one large industrial user in the area with three plants. The most recent plant was built after gas was introduced and gas may have influenced the decision to locate in the area.
- Union Gas estimates that they will capture about 80% of existing potential over first five years; thereafter it will be very modest growth in new customers.

- Anecdotal evidence provides no hint of an economic development impact, although local informants believe that having natural gas is essential if they are to be on a level playing field in competing with other areas for new business developments.
- The major effect appears to be on energy cost savings.

Lewis County – New York

- Two gas suppliers provide gas in Lewis County: New York State Electricity and Gas in the south and St. Lawrence Gas in the north.
- Gas service started in 1997.
- NYSEG mainly interested in the industrial and heavy commercial load; They have not marketed aggressively to residential customers.
- Oil companies have been able to retain market share; apparently considerable inertia on part of residents to convert – local business loyalties and a lack of knowledge about gas have proved to be important market barriers.
- St. Lawrence Gas has only a small system with mainly a residential load.
- There have been no economic development effects yet i.e., no new investments because of natural gas.

Vermont

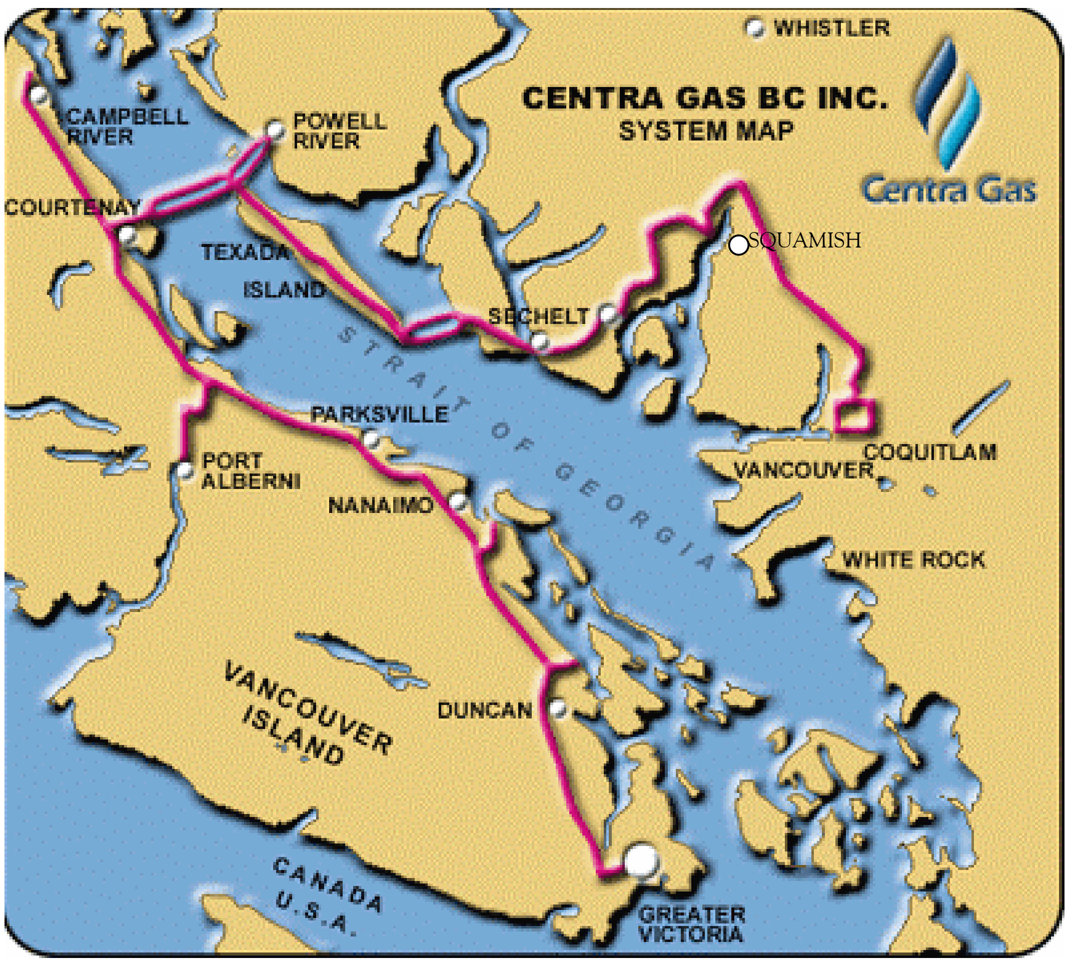
- Only two northern counties, Franklin and Chittenden, have natural gas service. Gas service started in 1965.
- Gas has slowly become the dominant energy source in the two counties.
- There were no subsidies involved in the development of Vermont Gas Systems service.
- There has been no substantial economic development effect from having gas. Only one business was cited where access to gas played a role in attracting it to establish in Franklin County.
- Nevertheless, planners and developers in the two counties promote natural gas service as an attractive location factor.

2. STUDY AREAS

Vancouver Island and the Sunshine Coast

This greenfield site consists mainly of the east coast of Vancouver Island, running from Victoria up to Campbell River. However, because areas along the Sunshine Coast on the mainland, including Powell River, Sechelt and Gibsons, as well as Squamish, all received natural gas at about the same time from the same transmission line, all of the areas mentioned are examined. (See Map 1 for the location of the pipeline and communities served.)

Map 1 – Centra Gas British Columbia Main Transmission Line



Source: Centra Gas (B.C.)

Table 1 shows the populations of the cities and towns along the gas line in 1991 and 2000. They range from the largest, the Victoria Metropolitan Area that has now surpassed 300 thousand, to small towns such as Gibsons and Duncan. Nanaimo grew very rapidly in the early 1990s and has now passed 76,000, although its growth rate has moderated.

Table 1

Population in Urban Areas on the Gas Line, 1991 and 2000

	Population (1991)	**Population (2000)**	**Annual Population Growth % change (Annual Average)***
Gibsons	3,140	3,805	2.2
Sechelt	6,123	8,499	3.3
Duncan	4,301	4,766	1.0
Squamish	11,709	15,357	2.8
Victoria			
-City	71,228	74,996	< 1.0
-Metropolitan Area	287,897	304,287	< 1.0
Nanaimo	60,129	76,645	2.5

Source: B.C. Stats; Statistics Canada.

The structure of the economy across the greenfield area varies considerably. The strong presence of the pulp and papers mills is evident on the Sunshine Coast, Powell River and Duncan. The primary sector is also relatively strong in those areas, reflecting the harvesting operations supporting the mills (Table 2). Service sector employment is lower in the three areas than the other areas, which all run at about the provincial average. As might be expected, government is much stronger in the Victoria area.

Table 2

Labour Demand by Economic Sector by Area, 1996

(%)

	Squamish	Sunshine Coast	Powell River	Nanaimo	Duncan Cowichan	Victoria	BC .
Goods							
-Primary	6.6	10.3	10.1	6.1	9.0	2.7	5.7
-Manfacturing	6.9	10.5	17.9	8.0	12.7	5.0	10.4
-Construction	9.6	10.8	7.7	10.4	8.6	6.5	7.5
Services							
-Non-Government	70.9	63.4	60.5	69.9	63.6	70.5	70.6
-Government	5.9	5.0	3.7	5.6	6.0	15.3	5.9
	99.9	100.0	99.9	100.0	99.9	100.0	100.1

Source: B.C. Stats

Note: The figures reported are for the Regional Districts in which the named areas are located.

The Decision to Provide Natural Gas

The decision was taken in the late 1980s to build a gas transmission line from Coquitlam, on the eastern edge of the Vancouver Metropolitan Area to Vancouver Island. The planned system called for Pacific Coast Energy, the transmission line company, to sell gas directly to seven pulp mills along the route, and to two utility companies, ICG Utilities (B.C.) Ltd., now Centra Gas, and Squamish Gas (a division of B.C. Gas). Natural gas service would also be provided to communities along the transmission line route (as shown on the route map above) including Squamish (by Squamish Gas), the Sunshine Coast (including Powell, River, Sechelt and Gibsons) and on Vancouver Island by Centra. Table 3 provides baseline information.

Communities along the pipeline route had been working for about nine years advocating the introduction of natural gas. In the end, the provincial and federal governments supported construction of the transmission line on the grounds that it would generate both environmental benefits and economic benefits.

The environmental benefits would come in the form of reduced emissions of sulphur dioxide and carbon dioxide when natural gas replaced fuel oil as the energy source for the large pulp and paper mills. In addition, the risk of ocean pollution events would be substantially lowered through a reduction in the volume of petroleum product shipments through the sensitive coastal waters of the Strait of Georgia and the Strait of Juan de Fuca.

The gas pipeline project was expected to generate a variety of economic benefits. These included:

- Increased ability of B.C.-based companies to produce products using natural gas as a fuel or feedstock,
- Increased employment from gas production in northeastern British Columbia based on 10% increase in natural gas sales,
- Royalties to the province of about $95 million over 20 years,
- Property taxes to municipalities from both the transmission line ($1.5 million per year) and distribution systems ($30 million over ten years),
- Plus the associated employment (construction, installation and maintenance).

We note that of the five categories of benefits cited, the first one is the fundamental benefit, the main reason that companies would switch to natural gas. The savings on energy consumption by households switching to natural gas should also be added to this benefit stream. The other four “benefits” are really economic impacts that arise from the consumption of natural gas. In that sense, they must be considered derivative benefits that area related to the first benefit but not incremental to it.

Centra went into the distribution system project with a long-term view. They estimate that from its inception, it has taken about 12 years to achieve a revenue stream that covers costs plus a return on capital.

Table 3

Baseline – British Columbia Study Area

(At the Time of Introduction of Natural Gas)

Indicator	Area:
Location	Vancouver Island and the Sunshine Coast (see map for transmission line route and selected communities served by natural gas distribution).
Population	About 400,000 in 1990; planned service was for about 25 communities and 100,000 people.
Energy use • residential and commercial	October 1991: 6,000 customers on propane systems in Victoria (250 km + and 4,500 customers) and Nanaimo (100 km + and 1,500 customers) plus a few propane satellite systems installed as “pre-build” for natural gas.
Industrial • type (major sectors by employment size) • number of establishments • fuel type: oil, electricity, wood, coal, other • energy use (seasonal, annual)	• Seven large pulp mills, all of which used heavy fuel oil prior to converting natural gas. • Squamish: several lumber companies were the main energy consumers.
Energy market • mix: % energy supply by energy source (oil, electricity, coal, wood, other) • supply structure • prices	• Prior to natural gas service, oil and electricity each had about 40% of the market; the rest was served mainly by propane systems and other sources. • Victoria: – Coal gas distribution started in 1862 – 1929, water gas plant added – 1947, butane/air plant added – 1952, coal gas & water gas shutdown – 1975, converted to propane/air – 1989, converted from 600 BTU to 1350 BTU propane/air (virtually interchangeable with natural gas at this BUT value) • Nanaimo – 1954, piped butane/air system started – 1978, converted to propane air (1150 BTU) – mid 80s, separate vapour system added • These were the only gas distribution facilities on the island prior to natural gas arrival. • Alternative fuel suppliers in 1991: British Columbia Hydro, 10 oil companies and four or five propane suppliers, all of whom

Indicator	Area:
	have disappeared. • Squamish • Propane grid existed prior to natural gas. • Conversion to natural gas was simple and straightforward; those on the grid were converted automatically. • Electricity and propane were the main energy sources with a minor amount of fuel oil. • Centra estimates that a household income of about $45,000 is needed to support a conversion to natural gas.
Competition • Energy market was regulated or free • What was the response to gas by existing energy suppliers?	• Regulated market by British Columbia Utilities Commission. • Hydro was mainly interested in reducing domestic load in favour of export market and hence did not offer competition; electricity can be price competitive. • Initially the oil companies were very competitive until they began to compete amongst themselves for the declining market share. They are no longer considered a serious competitor. • Propane suppliers could not compete on price; they became more complementary than competitive. • High efficiency oil furnaces offer very tough competition for natural gas. • Centra estimates that are still about 20,000 electric heat and fuel oil customers.
Subsidies	Subsidies were provided as follows: • $100 million federal grant and $50 million interest free loan, repayable out of future profits. • $30 million conversion grants for the seven pulp and paper mills along the transmission line route. • $25 million in grants for other commercial, industrial and residential users: – $3,000 grants for commercial and industrial users and apartment buildings to convert space and water heating systems to gas. – Residential grants of up to $700 to convert furnaces to natural gas. • Rate Stabilization Fund set up by province to cover operating deficits of pipeline and distribution companies in early years; objective was to ensure that consumer natural gas prices remain competitive with fuel oil and electricity; advances from the fund were to be repaid out of future profits. • Both the pipeline company (Pacific Coast Energy) and the

Indicator	Area:
	distribution company (Centra Gas) agreed to take reduced returns on investment in the early years. • Centra also had to agree to a minimum number of residential and commercial customers and a minimum number of GJ to be sold in each of the first ten years, with substantial penalties if the targets are missed. (Targets: sign up 20,000 customers in the first year and 16,000 in the second year).

Impacts Attributable to Availability of Natural Gas

Table 4 presents an assessment of the impacts that have occurred in the study area since the introduction of natural gas. We assess the impacts across a set impact area or aspects based on information collected from a variety of sources.

Table 4

British Columbia Study Area- Natural Gas Impacts

Aspect	
Competitive environment • price • non-price	• What has been the behaviour of energy prices over time in this area? • British Columbia Government Rate Stabilization Fund guaranteed to gas price would be 85% of oil and never exceed electricity price; gas price will move up to 90% of oil price in 2002. • Natural. • No significant non-price competition offered by competing fuels. • Centra now markets gas mainly on a life style basis because retirees were a large proportion of the market and they had no interest in a long pay back. • The gas-electric price differential that once existed has disappeared. In the early days British Columbia Hydro was very interested in shedding domestic consumers in favour of the export market. Now electricity is the main competitor for natural gas because British Columbia Hydro (at government insistence) offers an interruptible rate (varies by time of day) that make electricity more competitive with gas (although British Columbia Hydro states that gas is still cheaper than electric heating for anything but a standard efficiency furnace).
Service Expansion	• Centra mainly interested in serving areas with high load (large commercial or industrial user), followed by high density residential areas; new subdivisions serviced first by some type of propane system that would be converted to natural gas when sufficient load develops; little interest in low load areas unless some type of government incentive offered. • Targets as of 1992: 90,000 customers by the beginning of 2001; capture 70-80% of new construction; convert 60% of existing stock. • November 1991: distribution networks in 26 communities, following a nine month system construction period. • The market for gas was strong in 1991 with a lot of new construction related to high rates of inter-provincial migration in the late 1980s and early 1990s; gas has been able to achieve about 90% penetration on new construction. • 1997: 54,000 residential and commercial customers plus seven large pulp mills. • As of October 2001, Centra had about 71,000 customers, split on about ratio of 30% new and 70% conversion. Of these, there are 62,400 residential customers on Vancouver Island and the Sunshine Coast: 20, 600 new construction and 41,800 conversions, and about 8,600 commercial and industrial customers. • Centra estimates that they now have about 80% of the existing

<table>
<tr><th>Aspect</th><th></th></tr>
<tr><td></td><td>commercial/industrial energy market.
• Conversions are becoming a smaller part of the expansion market due to market saturation; in recent years they have been running 60% new construction and 40% conversion.</td></tr>
<tr><td>Energy industry

▪ Structure
▪ Operations
▪ Employment</td><td>Number, type (gas only, gas electric, etc), size of energy companies active in local market.
• Current energy suppliers are:
– Centra Gas: natural gas (has been purchased from West Coast Energy by British Columbia Hydro.
– British Columbia Hydro: electricity.
– Propane: two supplying companies; Centra uses propane for pre-build situations.
– Four or five oil companies.
What types of adjustments have energy supply companies made since natural gas was introduced?
• Employment
– Peak construction employment in early 1991 with 800-1,000 contract construction employees engaged in building the pipeline systems, about one-half each on the transmission and distribution sides.
– Permanent employment: with Centra about 215 people (down from the 1994/95 peak of about 305); at the peak about 150 construction contractors; peak wages were estimated at $30 million.
– Indirect employment: about 80 dealers now providing gas conversion and service (down from the peak of about 160) employing 400+ people on Vancouver Island.</td></tr>
<tr><td>Industry
• new industry/new investment
• gas conversion/ dual fuel
• competitiveness
• supply security</td><td>Has the area gained new industry and/or new investment that can be attributed in whole or in part to the introduction of natural gas? (Number, type, $ amount) Has local industry gained a competitive advantage through a reduction in energy costs?
– Centra Gas officials could not cite any examples, although they did point out that businesses that converted to gas would have experienced increased profitability because of lower energy costs.
– A conversion industry did develop to replace oil burners with gas appliances.
How many conversions to gas or dual fuel have occurred?
• Conversions cited above.</td></tr>
</table>

Aspect	
	Has energy supply security been enhanced by greater diversity of supply? • Increased security of supply is claimed because natural gas provides an alternative to electricity generated off Island; the electricity transmission line would soon reach the point where it needed upgrading or replacement. • Natural gas will soon be the energy source for thermal generation plants on Vancouver Island, an additional benefit that would not have occurred without the pipeline.
Environment • emissions • land use	• Natural gas cited as cleaner burning that any of the alternatives–propane, oil, coal or wood. It will lead to significant reductions in particulate and carbon dioxide emissions. • Natural gas use was expected to reduce sulphur dioxide emissions by 25% at the four pulp mills on Vancouver Island and by 60% at the pulp mills in Howe Sound and Powell River by replacing heavy fuel oil. • Carbon dioxide emissions were expected to fall by about 30% • Use of natural gas was expected to reduce acid rain in the sensitive south coastal area of B.C. • Reducing use of oil by more than two million barrels annually would eliminate over 300 barge movements of oil per year in the Straits of Georgia and Juan de Fuca. • No significant or continuing impacts on the urban or rural landscape.
Business • opportunities	• Having natural gas available is seen as a pre-requisite to attract businesses to locate on Vancouver Island. • Businesses apparently consider natural gas to be a cheap, clean energy source that must be available; locations without natural gas are effectively “out of the game”; experts point out that developing land for industrial purposes is only considered if natural gas service is available.
Government • tax	How did the introduction of natural affect government revenues in the local area or at the provincial level? • As of 1997, Centra paid about $8 million per year in taxes. About 50% go to municipalities and most of the rest to the provincial government. Centra estimates that taxes amount to about 10% of its gross revenues.

Evaluation Insights

The Vancouver Island Pipeline project was the subject of a program evaluation by Natural Resources Canada in 1995. The evaluation examined whether or not the original objectives set for the Program had been met. These objectives were identified to:

- provide an alternative energy fuel source;
- promote regional employment during construction;
- encourage industrial investment, development and employment;
- reduce environmental damage related to heavy fuel oil emissions and oil barge traffic; and,
- increase energy security.

The evaluation found that the short-term project objectives had been met. Gas consumption was higher than expected due to increased demand by pulp mills. Residential consumption, however, was lower than expected. Regional employment during construction was higher than projected, due in part to the $110 million cost overrun. Conversion of the pulp mill boilers to natural gas led to a significant reduction in the demand for heavy fuel oil, with a corresponding reduction in SO_2 emissions. Oil barge and tanker traffic in the Strait of Georgia, Howe Sound and along the West coast of Vancouver Island has also decreased. Reducing dependency on foreign oil and diversifying fuel oil sources has enhanced energy security.

The evaluation also concluded that it was too early to determine the long term benefits of the project. However at the time, there was no evidence that industrial investment, development and employment have increased as a result of the availability of natural gas.

Growth Options

It is worth noting that Centra Gas in British Columbia adopted a go slow approach rather than the traditional approach gas system development.

- Traditional approach: Low capital investment; serve only largest economic loads with immediate payback in the early years (e.g., hospitals, universities, laundries, green houses, other energy intensive users; slow residential market penetration with residents usually waiting several years for the system to expand into their areas).
- Centra approach: Major capital investment based on the view they would have to focus on the long term. Centra was able to do this with financial support from the provincial government and from its parent company (Westcoast Energy). They did try to bring the larger loads on stream but planned on a significant revenue deficiency over the first nine to ten years with natural gas widely available to residential customers within a ten-year timeframe.

Major Benefits of Natural Gas

- Stability: for existing jobs and industry based on a stable fuel price and supply (note however the sharp jump in natural gas prices in late 2000 might lead some people to question this view).

- Opportunity: to expand and/or attract new jobs and industry. The evidence cited here is the current plan to build another transmission line to Vancouver Island that will fuel two cogeneration plants. These plants, it is argued will provide greater security for the Island's future energy needs, something that was coming into question because the existing electricity cable from the mainland is reaching the end of its useful life. Centra argues that this expansion is made possible by the previous introduction of natural gas to the Island.

Southwestern Manitoba

The greenfield site studied in Manitoba lies in southwestern Manitoba, between Brandon and the United States border. The distribution project was designed to bring natural gas primarily to six towns in late 1995. These towns had a total population (1991) of about 8,100 people. Gas would also be available to residents and businesses located outside the towns in the surrounding rural municipalities that had a population of about 4,500 people. Map 2[1] shows the pipeline running south from Brandon connecting the communities of Souris, Hartney, Melita, Boissevain, Deloraine and Killarney, and the Rural Municipalities in which they are located. The pipeline passes through two Rural Municipalities – Cornwallis and Whitewater – which do not receive gas service. These two areas chose not to join the group of communities participating in the financing package arranged to cover the capital costs of the line. One of the terms of that agreement was that non-participating communities would not be permitted access to gas service, a feature that still remains in force.

The area economy is grain based with the towns acting as service centres to surrounding farming areas providing retail service, health care and educational facilities. Tourism is also a significant factor for some communities. There are no large industrial operations in the area served by the gas project. Small manufacturing operations, schools, motels, arenas, a hospital and retirement homes were among the largest potential commercial customers for gas. Grain drying is an important activity that was traditionally based on propane fueled dryers. Natural gas was seen as a good alternative for its ease of conversion and to avoid fluctuations in propane prices that coincided with harvest season. Since the demise of the grain transportation subsidy[2] in 1996, Crow Rate, diversification of the agri-food economic base has been an important priority in Manitoba. One result has been a rapid expansion of hog farming in the southwest area as well as other parts of the province.

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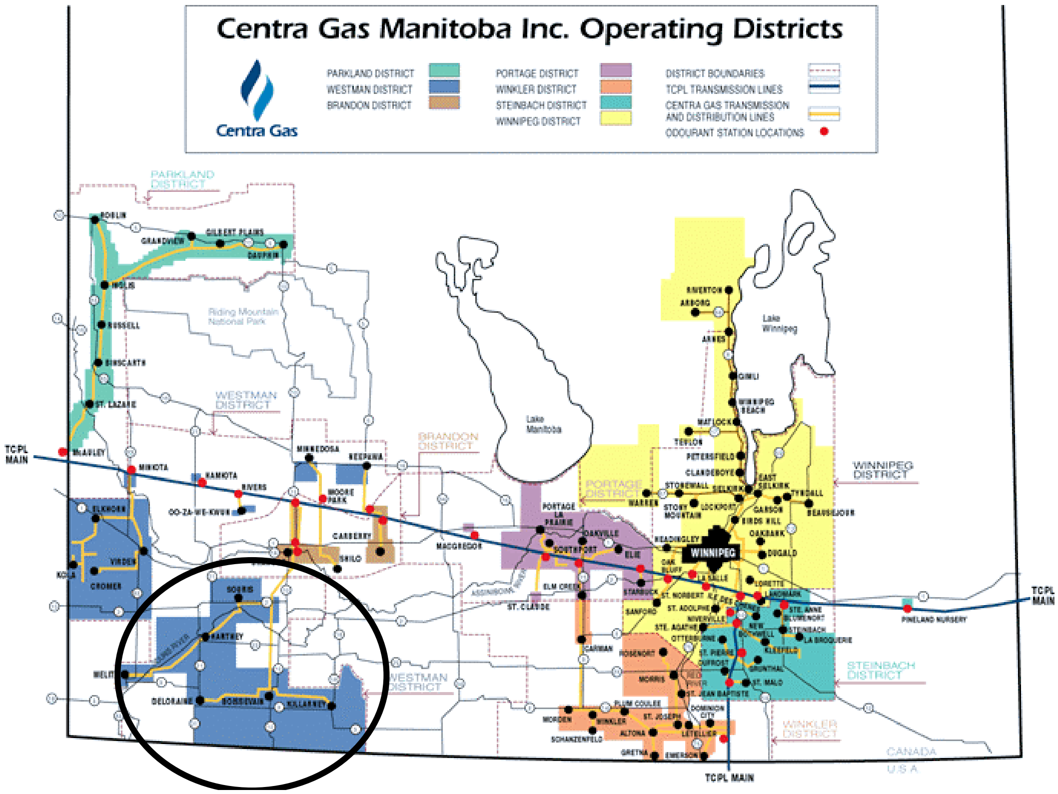
[1] See also http://www.centragas.mb.ca/profile/infrastructure.html

[2] This subsidy was frequently referred to as the Crow Rate.

Map 2: Centra Gas Distribution System, Southwestern Manitoba



The project to bring natural gas service to the Southwestern Manitoba was initiated by the governments of Manitoba and Canada through the announcement of funding through the Canada-Manitoba Infra-Structure program in 1994. Customer sign-ups were sought by a volunteer community organization. Gas customers were required to contribute $300 to the funding partnership as a contribution to the infrastructure financing. The communities achieved an acceptable level of sign-up by January 1995. Centra Gas[3] completed the distribution system in 1996, so 1997 was its first full year of operation. Table 5 outlines the baseline situation at the time gas was introduced.

3 At the time Centra Gas was a private sector gas distribution company. During 2001, Manitoba Hydro purchased Centra Gas. It now operates as a subsidiary of Manitoba Hydro.

Table 5

Baseline – Southwestern Manitoba Study Area

(At the Time of Introduction of Natural Gas)

Indicator	**Area:**
Location	▪ Southwestern Manitoba, between Brandon and the United States border. ▪ Centred on towns of Souris, Hartney, Melita, Boissevain, Deloraine and Killarney and their surrounding Rural Municipalities[4]
Population (1991)	▪ Souris (1665), Hartney (475), Melita (1130), Boissevain (1570), Deloraine (1045) and Killarney (2165).
Residential ▪ Potential gas customers: 2809	Fuel source in 1994 • electric 2522 • oil 210 • propane 77
Commercial/Industrial ▪ Potential commercial customers: 511	Fuel source in 1994 • electric 335 • electric, propane 44 • oil 55 • propane 33 • electric, oil 25 • other mixed 19
Energy market ▪ Mix: % energy supply by energy source (oil, electricity, coal, wood, other) ▪ Supply structure ▪ Prices	• As shown above, the residential market was primarily served by electricity (90%) and oil (7.5%). • The commercial/industrial market was dominated by electricity (66%) with oil at (11%) and other sources less than 10% each.
Competition ▪ Energy market ▪ Response to gas by existing energy suppliers	• Market not regulated for price or service; Centra did have to submit application to Manitoba Utilities Board to demonstrate the financial viability of the proposed system. • Community observers stated there was not competitive response from existing suppliers. • Many people who converted retained their old electric system for diversity (some users did switch back to electricity during the natural gas price spike in 2000). • Manitoba Hydro actually promoted the switch to natural gas because they wanted to export electricity to the United States.

4 A seventh town, Wawanesa, was originally included but dropped out.

Indicator	Area:
Subsidies ▪ All three levels of government provided capital subsidies.	• Total system cost was about $21.5 million financed by: Province $5.7 million Canada $5.7 million Municipalities $5.7 million Centra $3.7 million Customers $0.5 million • Manitoba and Canada contributed through the federal-provincial Infra-structure Works program. The Municipalities issued debentures (explained further in the text). Customers paid $300 each to participate. • No operating subsidies or grants for users although Manitoba Hydro offer a natural gas conversion loan at close to market rates.

Financing the System

The most problematic part of system financing was the municipal portion. It was determined very quickly that simply raising the local tax rate to cover the municipal portion would not be acceptable. The solution involved a combination of issuing debentures, to be paid off by capturing incremental tax revenues from the gas system itself and a small tax increase.

The rationale for the solution was that both the towns and Rural Municipalities through which the pipeline would pass would earn incremental tax revenue based on the assessed value of the system in their area. The regional development association (Westman Economic Development Association) developed a financing plan accordingly. It called for the rural municipalities to contribute an amount equal to the tax benefit for period 20 years plus additional assistance equal to one mill for ten years. The towns would contribute all of the tax revenue from the pipeline for 20 years and a two mill increase for 20 years. A portion of the school tax was also retained by the municipalities and used to help pay for the system on the grounds of improved energy efficiency.

The major benefits to the towns and the rural municipalities cited in materials circulated when the project was under consideration include:

- ♦ Savings on energy costs to publicly funded buildings, e.g., schools, hospitals, rinks, pools, etc.

- Opportunities to build or attract industries that require this type of energy source. e.g., ethanol plants, straw processing, hog operations, pasta plants.
- Savings to existing businesses, allowing increased competitiveness and assisting in long term viability of town/service centres.
- increased assessment in every municipal jurisdiction, creating an assured increase in future tax revenue.
- Increased tax revenue in all municipal jurisdictions resulting from increased assessments.
- Immediate increase in revenue through taxation of any branch lines constructed that are not included in the financing plan.

Conversion Rate

- As estimated in 1995, the market potential was 2,809 residential customers and 511 commercial customers[5]. The potential gas volumes were about evenly split between the residential and commercial sectors.
- Sign ups at that time were at 44% or 1,236 of residential potential and 75% or 383 of the commercial customer potential.
- The estimated rate of conversion was that 70% of residential potential would be connected to gas by the end of 10 years and 80% of the commercial potential by the end of 5 years. The system was designed for these conversions over 10 years plus a factor to allow for moderate load growth.
- By the end 2001, residential customers hook ups had reached 64% of the original estimated potential and commercial had reached 95%. These figures include about 12% new construction that was not part of the estimate of potential. So, the actual conversion rates amount to 62% residential and 83% commercial.

Table 6 summarizes the impacts resulting from the introduction of gas service in Southwestern Manitoba.

[5] Note that these figures exclude Wawanesa which was part of the original plan but subsequently dropped out.

Table 6
Impacts Attributable to Availability of Natural Gas

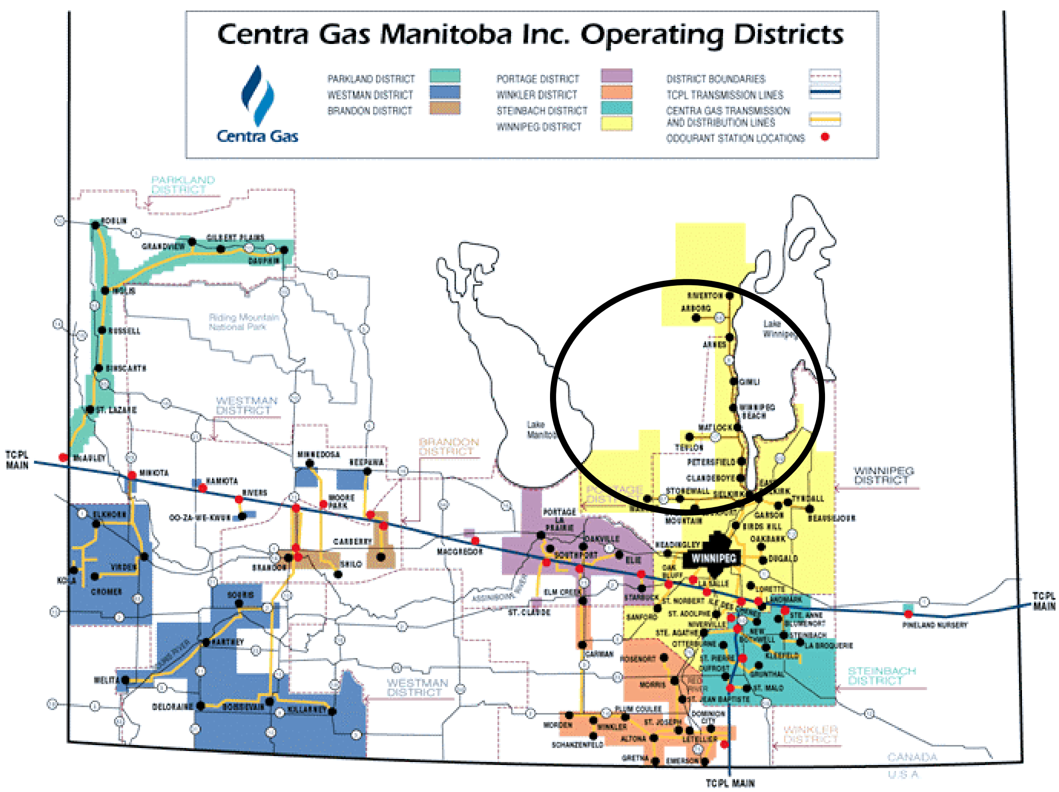
Aspect	
Competitive environment ▪ price ▪ non-price	▪ Natural gas prices have followed the market. When natural gas prices spiked in 2000, there was real concern among those who converted and some of those with dual systems switched back to electricity. ▪ No evidence of non-price competition. ▪ Gas price in late 2001 gave users about a 20% price advantage over competing sources of energy in southwest Manitoba. ▪ Coal shipped in from Saskatchewan can still be competitive in some situations.
Energy industry ▪ structure ▪ operations ▪ employment	▪ Manitoba Hydro supplies electricity. ▪ Centra Gas is the only gas supplier and is now a subsidiary of Manitoba Hydro. ▪ Alternative sources of energy have only minor share of market after gas and electricity
Industry ▪ new industry/new investment ▪ gas conversion/dual fuel ▪ competitiveness ▪ supply security	▪ Gas has played role in attracting or retaining industry. Examples include: – Souris: Feed mill established for which gas was key factor; straw processing plant – does not use gas but wanted option, access to three phase power and proximity to feed mill for transportation access; cheese plant retained, now employs 27 people, planned to leave if no gas; new hog barns in area attracted by gas service. – General observation on hog barns: they are choosing to locate in Rural Municipalities where gas service is available and avoiding neighbouring RMs without gas service. – Killarney: observers estimate that the town of now about 2500 people has gained about 100 jobs since gas service arrived; about $25-30 million of new construction; a new feed mill in the immediately adjacent RM of Turtle Mountain (second largest gas user after the cheese plant); new mindset has emerged about development; also observed that there has been a return of younger generation that they attribute partly to the effects of gas service.
Environment ▪ emissions ▪ land use	▪ Emissions were not a major issue since the electricity and propane were the major energy suppliers prior to the arrival of gas. ▪ No noticeable impact once the pipeline and distribution systems were installed.
Business ▪ opportunities	▪ There has been some business creation and expansion attributed to the natural gas service. Examples are cited above. ▪ Sales of gas appliances, including fireplaces, and servicing of gas appliances are now part of local business activities.
Municipalities and Schools	▪ Energy savings from conversion of schools divisions were estimated as high as $50,000 – 60,000 per division.

Aspect	
Government ▪ tax	▪ The most important direct and immediate impact was the increment in assessed value and associated tax revenue from the pipeline and distribution. ▪ In the longer run, the local development effects – new businesses and expansion of existing operations – will expand the tax base and provide additional tax revenue.

Manitoba – Other Areas

Other rural areas in Manitoba have also received natural gas distribution recently. The following discussion provides some highlights from the experience of the area known as the Interlake Region (that lies north of Winnipeg between Lake Winnipeg and Lake Manitoba). Teulon, a town of about 1,000 people lies at the centre of the region. (See Map 3.)

Map 3: Centra Gas Distribution System, Interlake Area Manitoba



- Gas has played a role in expanded economic development in the area. Examples included a food processing plant that has been helped by the low price of gas. Reduced operating costs were cited for a 16-unit town house complex that switched to natural gas from propane at savings of about 40%. The schools in the area have converted from propane that had replaced fuel oil. Alternatives to gas are mainly propane and electric.
- Around Arbourg, a nearby town of about 1,000 people, it is expected that some hog operations will connect to gas this year. Moreover, using gas has increased efficiency at a local feed company and led to feed cost savings for the local livestock operations.
- The largest farms closest to the towns are connecting to gas for grain drying in the fall and to heat their workshop areas.
- The start up of a new plant in Riverton, (north of Teulon) making erosion mats is partly attributed the availability of natural gas. The local Mennonite colony is very interested for its industrial businesses that have expanded considerably and want the economical energy source.
- As with other areas, key heavy load (large companies; schools) customers drive the economics. The residential load alone would not be enough.
- The Interlake system was installed only because of the government assistance for capital costs. In the view of local observers, it would not have happened otherwise. The federal government introduced a post Crow rate infrastructure assistance program through which the area got $2.35 million in 1998 towards the $7.3 million system. Manitoba contributed a similar amount; municipalities contributed 15% or $1.1 million, financed by about 50% from incremental tax revenue from the distribution system and 50% from a new tax rate. This also included collecting some of the school taxes that are paid as part of property taxes.
- The original targets for 1,100 residential and 250 commercial connections were close to being met when natural gas prices shot up in late 2000 and people chose to wait. Centra and community officials believe interest will resume now that the price of gas has come down.
- The original vision for the project covered as many as 16 communities. All but five dropped out after they were asked to contribute some tax revenue and ratepayers objected.
- Prior to natural gas, propane and electricity were the main energy sources. Fuel oil was relatively unimportant. Wood and combined wood electric units were also used.
- There was little competitive response to gas. Manitoba Hydro has been trying to cut electricity use to have power for export. There was some response by propane for larger users only.
- Some extra business developed for dealers to do installations and one company did send some staff to train as gas installers.
- Environmental issues were not an important factor.
- There have been no new investments yet. The main effect has been on bottom line for companies operating in the area.

In the view of local observers, natural gas is now expected as an energy source by business and by homeowners. Communities need it to be seen as competitively progressive in the area. Prior to its introduction, local communities were losing business to Gimli (located on the eastern edge of the region on the western shore of Lake Winnipeg) because it had gas and they didn't. A Seagram plant had located in Gimli because of a promise of natural gas in the 1960s. This plant is a mainstay of the Gimli economy.

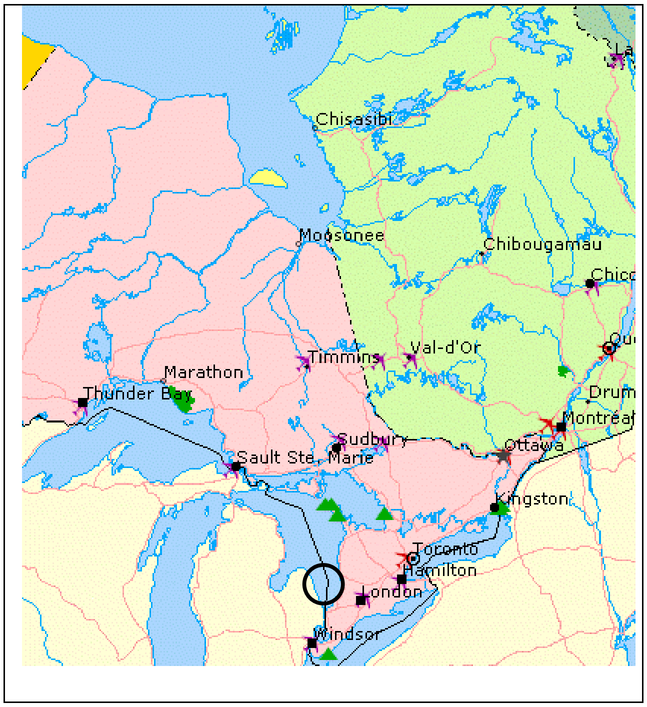
Another area that got gas service is Southeast Manitoba around Steinbach. This is a progressive area with strong economic development based on hog and poultry farming and related businesses and a number of enterprising Mennonite communities. They are apparently taking full advantage of gas.

Ontario – Wingham, Blyth, Brussels

The Wingham area is located in southern Ontario, northwest of London and close to Lake Huron. (See circled areas on Maps 4 and 5.) Including the three major towns of Wingham, Blyth and Brussels, plus other smaller villages and rural areas, the total population of the area was about 6,000 people. The area received natural gas service in 1996/97 following an application to the Ontario Energy Board in 1995 to extend service to the three communities and the surrounding area. Table 7 outlines the baseline situation in the area prior to gas service. The total cost of the system was about $11.8 million, comprised of $6.2 million for a 40.5 kilometre line to transport gas from an existing system in Goderich to the Wingham area and $5.6 million for about 26 kilometers of distribution lines. The area is primarily an agriculture economy where the towns are supporting service centres. At the time of the application there were two major manufacturing plants (owned by the same company) employing about 320 and 100 people. The rest of the businesses were focused on serving the agriculture industry.

Table 8 summarizes the identifiable impacts arising from the introduction of natural gas service.

Map 4: Wingham Area in Southwestern Ontario



Map 5: Wingham Area in Detail

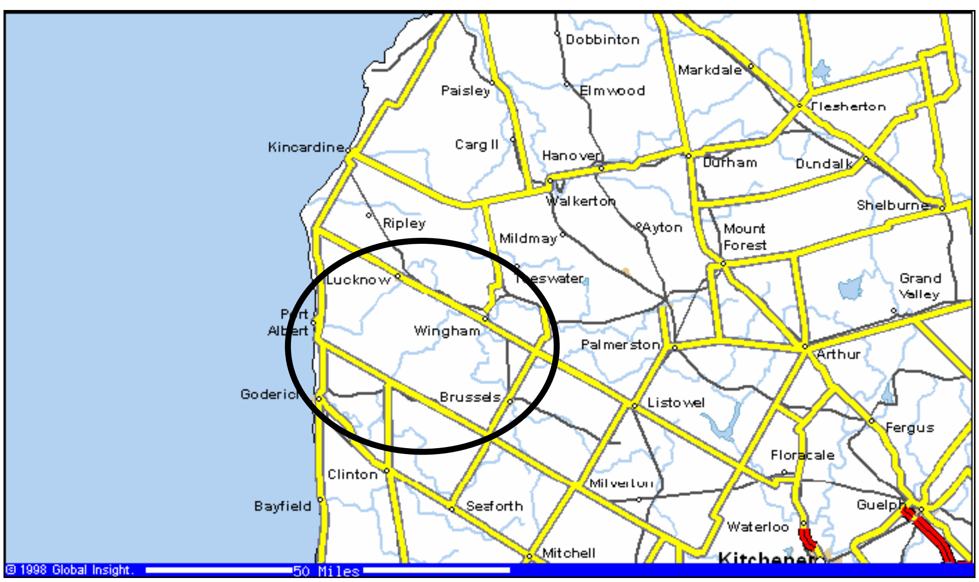


Table 7

Baseline – Study Area

(At the Time of Introduction of Natural Gas)

Indicator	**Area:** Ontario
Location	Wingham Area
Population	Wingham (1996) - 2,941 Brussels (1996) - 1,131 Blyth (1996) - 991
Housing	Households Wingham - 1,190 Brussels - 460 Blyth - 385
Commercial • number of business units • energy use: oil consumption, electricity consumption, other	▪ About 1,400 commercial, institutional and small industrial establishments that could potentially be served by gas ▪ Commercial businesses mainly serve the surrounding local agriculture industry.
Industrial • type (major sectors by employment size) • number of establishments • fuel type: oil, electricity, wood, coal, other) • energy use (seasonal, annual)	• Wescast, casting automotive manifolds, 320 employees. • Western Machining - 100 employees. • Royal Homes - 100-270 employees.
Energy market	▪ Residential fuel service was 45% electricity, 39% fuel oil and 16% propane. ▪ Commercial and industrial users were 100% fuel oil. ▪ Electricity supplied by Ontario Hydro; fuel oil and propane by a mix of small local distributors. ▪ Electric heat was expensive in 1995/96.
Competition	• Electricity regulated; gas project had to be approved by the Ontario Energy Board; The OEB regulates the cost of gas delivery to consumers but not the price of the gas itself. • Ontario Hydro did offer price breaks related to greater off peak use of electricity. • Oil companies did promote oil as safer than natural gas initially; there is still a lingering fear of gas among a part of the community. ▪ There was some attempt by competitors to sign up customers to five year locked in deals (which was apparently not legal).
Subsidies	• There were no subsidies provided for construction of the gas pipeline to Wingham or the distribution system. • Union offered financial incentives for customers who purchased high-efficiency equipment, with reduced incentives for mid-efficiency equipment. Other incentives included energy saving setback thermostats and complimentary “low-flow” showerheads.

Table 8

Impacts Attributable to Availability of Natural Gas

Aspect	Impact
Competitive environment • price • non-price	Energy prices • Natural gas is cheaper than alternatives, although some businesses have not converted because the savings are not great enough to pay of the conversion costs; conversion likely to occur only when replacement of current system (fuel oil, propane) becomes necessary. Non-price competition ▪ Propane remains a preferred fuel in rural areas partly because of the cost of gas connection; propane dealer has offered deals on appliances; there is also a loyalty factor to the local propane business.
Energy industry ▪ structure ▪ operations ▪ employment	• Natural gas is supplied by Union Gas. • Gas-fired heating equipment was available through Union Gas's authorized dealers and 42 independent heating contractors operating in the area. • Competition now comes mainly from local oil companies and to lesser extent propane. • Propane is still a popular fuel in the rural areas outside the towns and there is some customer loyalty to the local supplier..
Industry ▪ new industry/new investment ▪ gas conversion/dual fuel ▪ competitiveness ▪ supply security	New industry • Wescast opened a third plant (North Huron Casting) which employs 206; also expanded its two other plants; although not the only factor, gas service played a role. • Bi-Ax (plastic film) started up in Wingham since natural gas; the influence on natural gas is unclear. Conversions • Union estimated the first year attachments of 1,294 residential, 354 commercial and 1 industrial. The attachments were forecast to grow to a total of 2,557 residential, 473 commercial and 2 industrial customers by the 10th year. Market survey indicated that 78% of respondents expressed a willingness to convert to natural gas and pay a $15 monthly market contribution for five years. • To date attachments are below forecast. Two factors are felt to be important: the responses in the survey of potential customers were over-optimistic; after the first rush of conversions, people will only convert when they need to change their heating system. – Royal Homes also converted to use natural gas. – Feed mill in Blyth did convert their grain dryer to gas with significant savings; however the company continues to use propane to fuel a boiler in their flour mill because the cost of conversion is too high.

Aspect	Impact
	• Residential sector has largely converted in urban centres (e.g., Wingham) and new construction is serviced by gas. • Farmers will switch to natural gas for heating broiler barns and operating grain dryers if it is available (or a connection can be run); hog operations are also expanding and making use of natural where possible. Competitive advantage • It was more a case of being put on an even playing field with other communities in Ontario that already had natural gas service; not having natural gas is seen as a competitive disadvantage. Energy supply security ▪ Area now has full mix of energy sources; the diversity does improve security.
Environment • emissions • land use	• Emissions were not a major issue, but the conversion from fuel oil to natural gas did reduce them. • There were some concerns about the impacts of the pipelines but once installed there was little evidence of their presence. • Any disruption to woodlots and individual trees/hedgerows was minimized by locating the pipeline facilities on road allowances.
Business • opportunities	▪ Other energy suppliers (e.g., oil supply and service) have absorbed the service for natural gas. ▪ No other notable opportunities have developed, in part because of the relatively small market.
Government • tax	• The gas distribution project would generate income taxes (payable by Union Gas, estimated at present value of $2.3 million over the 30 year project life), property taxes (30 year present value of $1.1 million), capital taxes (30 year present value of about $211,000 and GST and provincial sales taxes (no estimate available). • Main impact is the tax revenue generated by the mill rate applied to the pipeline and distribution system.

Parry Sound

Parry Sound (population 6,300; 1996) is another area of central Ontario that has recently received natural gas (Map 6). Delivery started in 2000. Although very recent, some aspects of the project deserve mention. The Parry Sound economy is strongly tourism based (the Parry Sound region population jumps to 75,000 in the summer from the normal 15,000), and also includes a range of high-tech knowledge-based businesses and small-scale manufacturing/assembly.

Map 6: Parry Sound in South Central Ontario

The area around Parry Sound, Ontario, was targeted for the distribution of natural gas in 1999 by Union Gas. The project was designed to install 98 km of pipelines to provide natural gas to approximately 1,800 residential and commercial customers in the first ten years of operation. The $16.5 million project was funded by Union Gas $9.7 million (59%), the Town of Parry Sound and the Township of Seguin $800 thousand (5%), the Federal Government $ 3 million (18%) (through HRDC) and the Province of Ontario's Northern Ontario Heritage Fund $3 million (18%).

The rate of connection to the system has been slower than Union Gas projected in their application to the OEB. Several factors are cited to explain the shortfall, although their relative importance to the rate of connection is unknown. The factors include:

- The area is a popular retirement community and retirees showed some hesitation in switching from their existing fuel sources to natural gas.
- Around the time of project implementation, because of a change in corporate strategy, Union switched from direct marketing through their own sales staff to the use of local partners to market natural gas as the fuel of choice. This may have had some negative influence to lower the success rate.
- Shortly after the introduction of natural gas, gas prices rose sharply (the year 2000 price spike).

In the market projections, it was assumed that natural gas would become the primary source of heat energy for the regional hospital, the largest energy consumer in the Parry Sound area. However, the hospital has not switched to gas yet because it is currently in the process of relocating within the area. It expected to use natural gas at the new location when it is operational in the next two to three years. The Town of Parry Sound is currently in the process of converting their municipal facilities to natural gas over a five-year period.

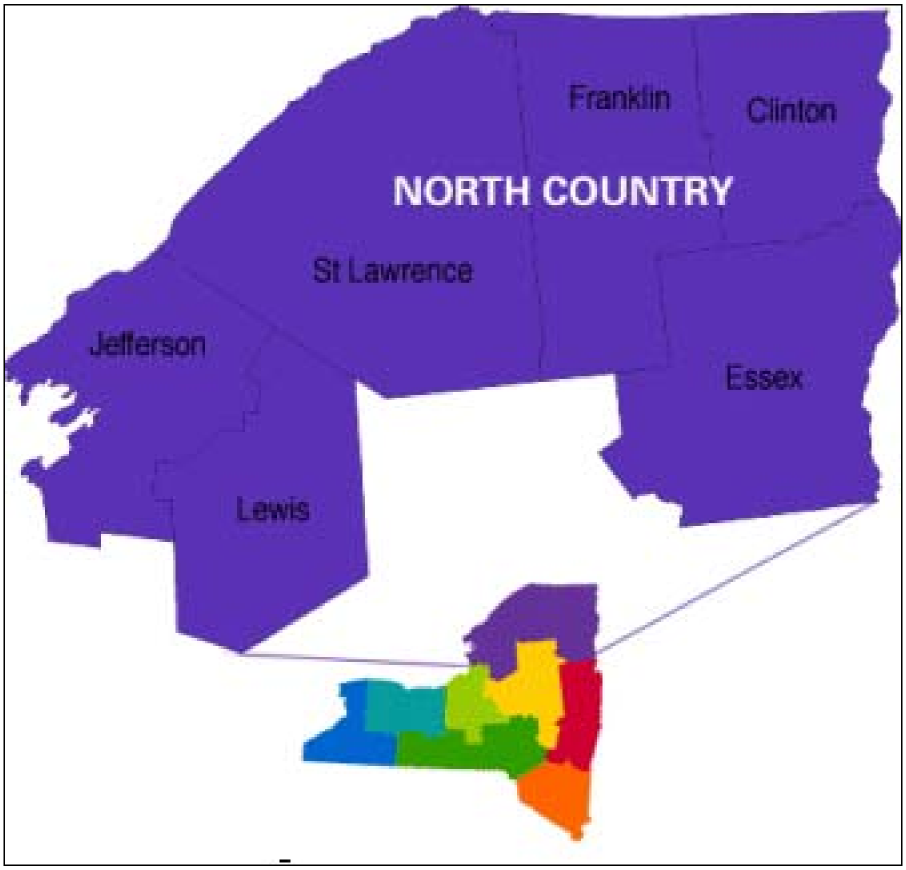
Lewis County, New York State

Lewis County, New York, is a mixture of 17 towns and 9 villages in northern New York State. (Map 7). The two main urban areas are Lowville and Croghan. The county is mainly rural, with some natural resource-based industrial facilities (pulp and paper mills and paper processing). There are approximately 27,000 residents in Lewis County. The county has experienced modest population growth rate over the past ten years. In the year 2000, approximately 86% of residents of Lewis County lived in a rural setting. Of those, 8% lived on farms (1990 US Census). The County had a rental vacancy rate of 13.3%, and an overall vacancy rate of 33.7% (24.6% of the overall vacancy rate is listed as "for seasonal, recreational, or occasional use").

Prior to the availability of natural gas, residential and commercial energy needs were met with a combination of fuel oil/kerosene (54% of residential units), wood (29%), and electricity (11%) (1990 US Census).

The manufacturing sector leads the Lewis County economy (employing over 1,500 in natural resources and food manufacturing industries), followed by the retail trade industry (employing about 750) and the accommodation and foodservices industry (employing about 300). Manufacturing and non-durable goods leads the industrial sector employment, followed by Agriculture, Forestry and Fisheries, and then Construction (1997 Economic Census).

Map 7: Lewis County, New York State



Source: New York State Electricity and Gas (NYSEG).

Baseline – Study Area at the Time of Introduction of Natural Gas

The Iroquois Transmission line continues where the Transcanada Pipeline (TCPL) terminates in Ontario.
The Iroquois line runs through St. Lawrence County in New York State, south through Lewis County, and continues southward through Connecticut, and terminating in Long Island. (See Map 8.)

Map 8: Iroquois Gas Transmission Line

Source: Iroquois Gas.

In 1996, Lewis County, under pressure from local industry (four paper mills, the Kraft Foods Plant, AMF Bowling (equipment manufacturer), and a number of schools and a hospital), sought to bring natural gas into the community, mainly to serve the industrial sector.
Following completion of a rate-of-return study, the New York State Electric and Gas Corporation (NYSEG) agreed to run a distribution system off the Iroquois line to serve the central and southern portion of the county. St. Lawrence Gas (a division of Enbridge) would serve the northern portion of the county as an offshoot of their existing St. Lawrence County system, directly north of Lewis County.
Lewis County is mainly rural, consisting of 17 towns and 9 villages. Until the introduction of natural gas, the main fuel sources were a combination of wood, oil, propane and electricity.

Rationale for the distribution system:

The paper mills were under increasing pressure to meet federal Environmental Protection Legislation, proposed in 1996. It was feared that without the availability of natural gas, these facilities would not be able to operate and would have to move out of the county.

NYSEG agreed to supply gas to the larger industrial energy users, and was obligated to offer gas service to any residential and commercial users who wished to switch to natural gas.

St. Lawrence Gas had a well-established system in St. Lawrence County, and could expand into Lewis County cost effectively with low capital costs. As well, they benefitted from special tariff policies with the Public Service Commission due to their small size.

Table 9 describes the baseline situation in Lewis County prior to gas service and Table 10 summarizes the impacts arising from the introduction of natural gas service.

Table 9

Baseline Indicators – Lewis County, New York

(Prior to installation of natural gas service)

Indicator	**Area:** Lewis County, New York
Location:	Northern Area served by St. Lawrence Gas (mainly Croghan area) Southern Area served by New York State Electric and Gas Corporation (around and south of Lowville)
Population	Lewis County: 26,796 (1990 Census) 27,606 (1997 estimate) 27,167 (2000 Census)
Housing	13,182 housing units (1990 Census) 15,134 housing units (2000 Census) 9,253 occupied housing units (1990 Census) 10,040 occupied housing units (2000 Census) Energy Use ▪ Predominantly fuel oil, kerosene, followed by wood, then electricity.
Commercial	Small commercial operations typical of rural areas Energy Use ▪ Mainly oil and electricity consumption for commercial sector.
Industrial	▪ Major employers: county hospital and Kraft Foods Ltd. Plant (Kraft employs approximately 360).

Indicator	**Area:** Lewis County, New York
	▪ 4 paper mills in the county. Three are operational. ▪ Beaverite plant (gasket and die-cut tools) – employs 200. ▪ Fuel type mainly oil (#2 and #6) and electricity. ▪ Annual energy usage for industrial, seasonal for residential.
Energy market	▪ Traditional suppliers were small companies for oil and kerosene. ▪ Wood: mix of self-supply and small operators. ▪ Electricity supplied by NYSEG.
Competition	▪ New York State Public Service Commission regulates the delivery systems for oil, electricity and gas. At the time the gas system was built, both electricity and gas operated as regulated monopolies. ▪ Now, the delivery systems for electricity and gas are regulated, while the supply of electricity and gas is unregulated: price is competitively determined. ▪ Consumers can buy from Energy Service Companies or from the utilities as they choose. ▪ NYSEG was obligated to offer residential service, though their main purpose to run natural gas into southern Lewis County was to supply the large industrial establishments, e.g., cogeneration facility, paper mills, Kraft foods, AMF Bowling. ▪ NYSEG did not compete aggressively for the residential and commercial gas market. They did little to promote natural gas as a more desirable fuel for residential use. ▪ Oil companies retained market share through general resistance to change to natural gas, and the low price of oil at the time. ▪ There has been considerable resistance to gas by residents who remain firmly committed to their traditional energy source. This was explained as simply inertia on the part of rural dwellers and partly a reluctance to break relationships with traditional suppliers who may be friends or relatives.
Subsidies	▪ No known subsidies for either capital costs or operating costs. ▪ NYSEG offered some small monetary incentives to homeowners to switch to natural gas in the form of discounted natural gas-fired appliances, etc. ▪ St. Lawrence Gas had an advantage, as they were already supplying gas to St. Lawrence County off the Iroquois line when they moved into Lewis County.

Table 10

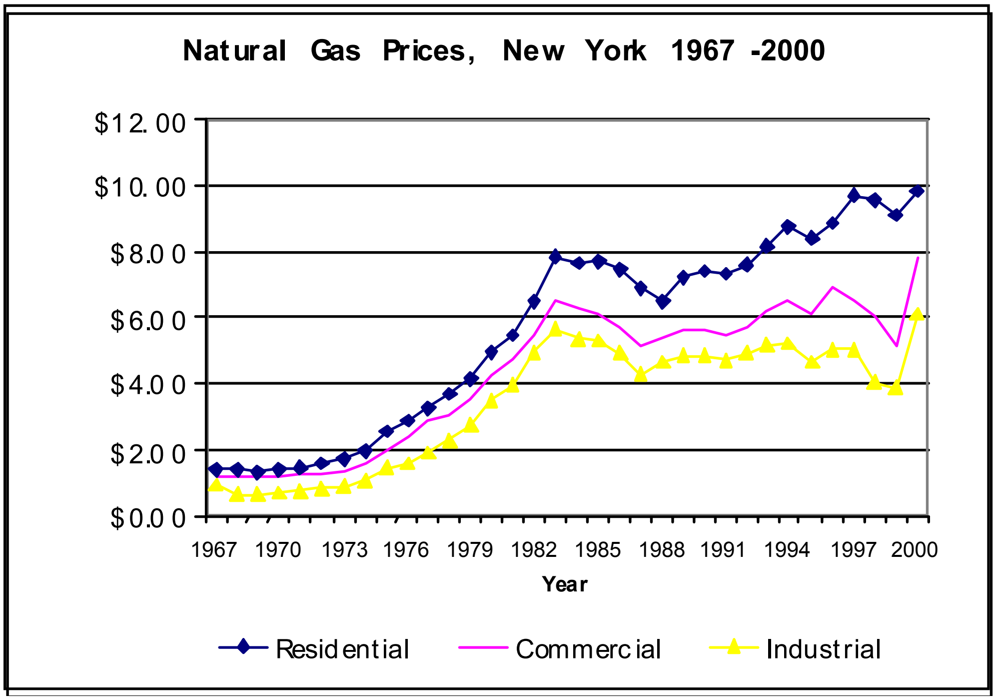
Impacts Attributable to Availability of Natural Gas

Aspect	Impact
Competitive environment • price • non-price	Behaviour of energy prices • Electricity prices in the USA have been on a downward trend since about 1984. • Natural Gas prices in New York, as elsewhere, rose sharply in the year 2000, after a general downward trend since 1996. (Figure 1). Non-price competition ▪ Nothing noted. ▪ St. Lawrence Gas has begun to move into not only the supply, but also the service end of the industry. ▪ In residential areas, there is still some reluctance to switch to natural gas and NYSEG has not sought residential connections vigorously.
Energy industry • structure • operations • employment	Energy Supply • Two geographically separate natural gas utilities supply natural gas: St. Lawrence Gas in the north and NYSEG in the south. • One major oil supplier (Agway) in the northeast portion of the county. Other small oil companies still exist. Adjustments by energy supply companies ▪ No major adjustments by oil companies. ▪ Neither NYSEG nor St. Lawrence Gas appear to be trying to expand aggressively. Employment • No information available.
Industry • new industry/new investment • gas conversion/dual fuel • competitiveness • supply security	New industry and/or new investment • There is no new investment that can be attributed to the availability of natural gas in Lewis County. Conversions to gas • St. Lawrence Gas has 212 residential and small commercial gas users in the Croghan area. • Paper mills have converted to natural gas. One other mill is currently not operational, but natural gas is accessible. • One gasket and die-cut part plant in Croghan has not switched to natural gas, despite gas being accessible because the conversion investment does meet their return on investment criteria. • Hospital and at least two schools are currently using natural gas. • Kraft cream cheese plant is using natural gas.

Aspect	Impact
	• One cogeneration plant served by St. Lawrence Gas off the New Breman Gate Station in northern Lewis County (Beaver Falls, 79 Megawatt Cogeneration Station). Mainly seasonal usage, e.g., only use for it in summer is for air conditioning. Competitive advantage • Large industrial users switched to natural gas following the USA instituting clean air standards. Without natural gas, it was feared the mills would not be able to continue in the County due to elevated abatement costs. Energy supply security • More diverse and secure supply but natural gas is still not widely accepted by potential customers.
Environment • emissions • land use	Emissions • Emissions have been reduced and the four paper mills can continue to operate under stricter federal clean air standards. Impacts on land use • No noticeable effect.
Business • opportunities	Have new businesses been created based on the availability of natural gas? Appliance sales? Service companies? Other? ▪ Most of the natural gas servicing industry has come from within the existing energy market, e.g., oil and propane supply and service companies now service the natural gas market.
Government • tax	▪ The construction of the pipeline was the second biggest source of tax revenue for that year (John McCue, county planner, Lewis County). ▪ No major revenues related to natural gas distribution or use since it started flowing in 1997.

Figure 1

Natural Gas Prices



Northern Vermont

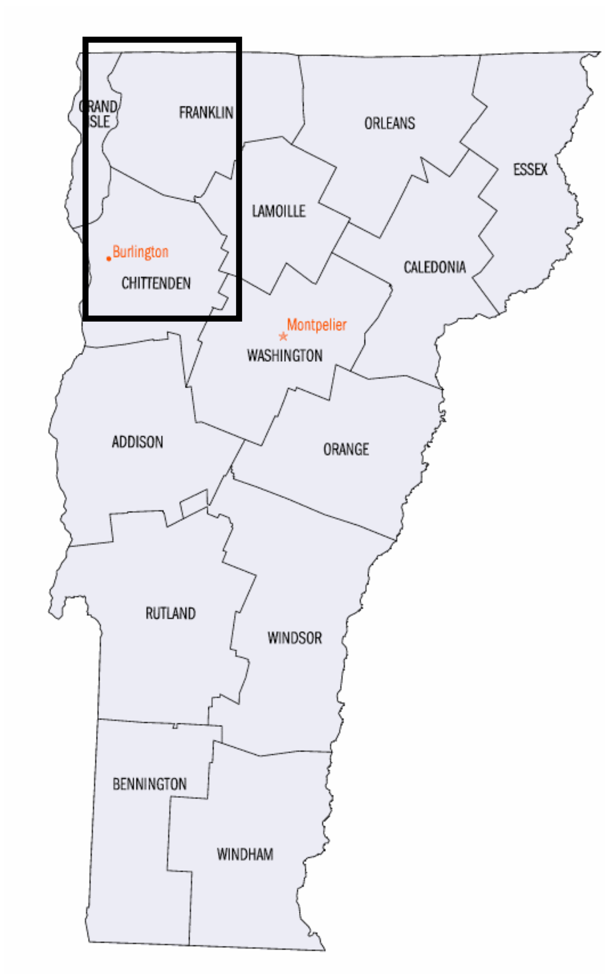
Franklin and Chittenden counties in Vermont are the focus of this green field area. (Map 9). They reflect the character of the state as a whole. Vermont was rated the most rural state in the United States according to the 1990 census, and observers believe this is unlikely to change. Vermont has been described as a collection of rural communities. In 1990 nearly 70% of Vermonters lived in rural areas. People have been moving to rural areas at accelerated rates since the 1960s, such that as a percentage of total population, the number of Vermonters living in rural areas is actually increasing. Vermont has no strong regional or county governance; state government and its various agencies and departments work directly with towns, communities and cities.

Chittenden and Franklin Counties received natural gas around 1965. They are still the only counties with natural gas service in Vermont. Prior to the introduction of natural gas, the communities were using a combination of fuel oil and kerosene, electricity, manufactured gas, and propane gas. Although this time frame is well before the target time frame adopted for this study, it was felt that recent system expansions might have green field characteristics.

In the early 1960s, Chittenden County had a population of around 75,000 of which Burlington accounted for almost 50%. By 2000, the County had a population of 146,571 in 2000, an 11.2% increase from 1990. Since then, the population of the Burlington metropolitan area has grown by about 173%, almost all of which has been in the suburban areas surrounding the City of Burlington. The county has 58,864 housing units and a total vacancy rate of 4.1%. The rental vacancy rate is 1.8%. Sixty-six percent of the population is urban. In 1990, fuel oil and kerosene was the most popular house heating fuel (18,736 units), followed by natural gas (13,717 units) and electricity (8.244 units). Table 11 provides a summary of baseline indicators.

Franklin County is largely rural, with a population of 45,417 in 2000 (a 13.6% increase since 1990). Franklin County had 19,191 housing units in 1990 with a 10.1% vacancy rate, and a 3.1% rental vacancy rate. Eighty-two percent of the population lives in a rural setting. The 1990 Census indicates that fuel oil and kerosene also were the most popular house heating fuels (7,199 units), followed by natural gas (2,517 units) and wood (2,471 units).

Map 9: Chittenden and Franklin Counties, Northern Vermont



According to the 1997 US Economic Census, manufacturing and retail trade were the leading sources of employment, followed by accommodation and food services (Table 11).

Vermont Gas Systems, the gas supplier, is a subsidiary of Gaz Métropolitain. By 2001, it served nearly 34,000 residential (29,500), commercial (4,400) and industrial (50) clients. It ties into the Transcanada Pipeline (TCPL) line at the Vermont/Quebec border at Highgate, where the Vermont Gas transmission line begins. Table 12 summarizes the baseline information for the area.

Table 13 summarizes the impacts that followed the introduction of natural gas into northern Vermont.

Table 11
Number of Employees in Top 3 Employing Industries,
Chittenden and Franklin Counties, Vermont

	Chittenden County	Franklin County
Manufacturing	14,302	2,603
Retail Trade	11,254	1,734
Accommodation & foodservices	6,211	854

Source: U.S. Bureau of Commerce, 1997 Economic Census.

Table 12

Baseline Indicators Vermont Greenfield Area

(At the Time of Introduction of Natural Gas)

Indicator	**Area:** Vermont
Location	Chittenden County Franklin County
Population	Chittenden County (1960[6]) - 74,425 (2000) - 146,571 Franklin County (1960) - 29,474 (2000) - 45,417
Residential	• Growth in proportion to population growth • About 29,500 residential natural gas customers in 2001/2002, account for 27%-35% of natural gas consumption. • The growing dispersion of the population in the rural areas tends to puts limits on the potential expansion of the gas distribution system.
Commercial	• No historical information. • About 4,500 commercial customers of natural gas in 2001/2002 account for 25%-39% of natural gas consumption.
Industrial ▪ type (major sectors by employment size) ▪ number of establishments ▪ fuel type: oil, electricity, wood, coal, other) • energy use (seasonal, annual)	• 36 industrial customers in 2001/2002 account for 27%-38% of natural gas consumption in Vermont; utilities account for 2% to 10% since 1996. • Six are major loads: – 1 paper mill – University of Vermont – 2 food processing plants – 1 hospital – 1 electrical generation facility that uses both wood and gas but has a highly variable load and is not a major load. • Prior to gas, electricity, manufactured gas and propane were the alternative sources for all users.
Energy market	▪ Energy market consisted of a number of manufactured gas distribution companies, fuel oil companies supplying No 2 fuel oil and electricity.
Competition	▪ Gas market, including price of gas, continues to be regulated by the Vermont State Public Service Board.
Subsidies	▪ No subsidies for switching to natural gas.

6 United States Historical Census Browser, Virginia University. http://fisher.lib.virginia.edu/census/

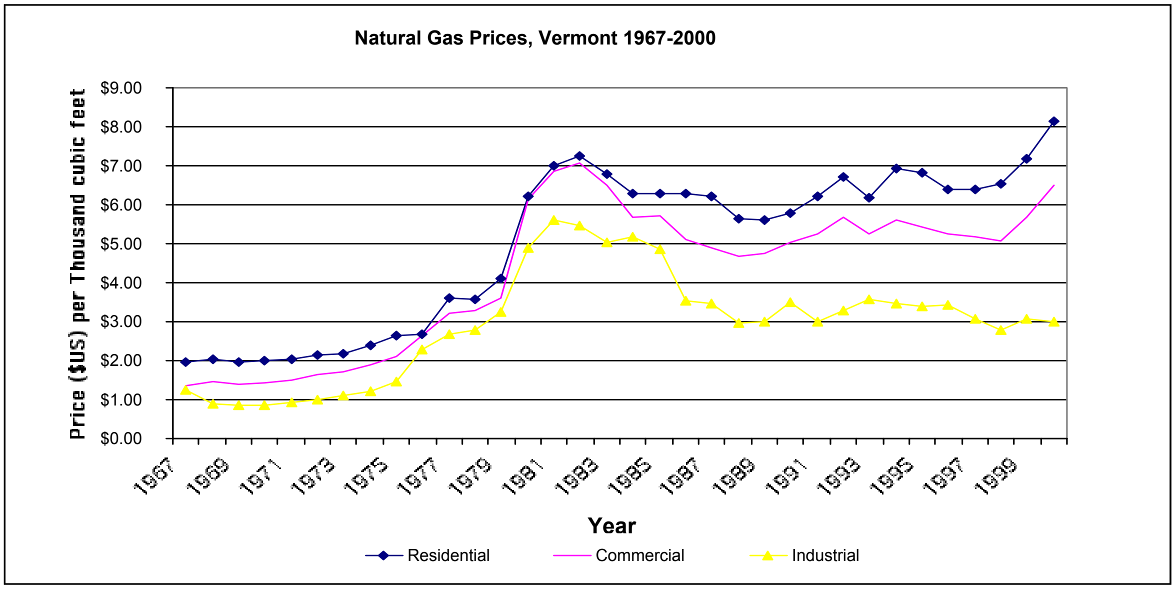
Table 13

Impacts Attributable to Availability of Natural Gas

Aspect	Impact
Competitive environment • price • non-price	• Gas prices over time are shown in Figure 2 • Non-price competition no longer occurs in the two counties because of the high penetration rate of gas as the energy source of choice.
Energy industry • structure • operations • employment	• Manufactured gas has dropped out of the market in the two counties. • Vermont Gas is the only gas company operating in the State of Vermont; it appears to be the dominant energy supplier • No employment information available.
Industry • new industry/new investment • gas conversion/dual fuel • competitiveness • supply security	• No new industry directly attributable to the availability of natural gas. Natural gas may have been a factor for one industrial user (Ben and Jerry's) in St. Albans, Franklin County. VGS actively marketed to the company prior to its choosing to locate in the northern Vermont community. • Most conversions are in new residential areas. No significant industrial anchors to move gas into new areas. • County planning agencies actively market the existence of natural gas supply in promoting development of local industrial parks; they are also promoting the use of cogeneration by industry to reduce electricity costs. – No new major industrial users in recent past. – Natural gas has become the fuel of choice, replacing fuel oil and manufactured gas.
Environment • emissions • land use	• Emissions would have been reduced but this was not a major issue at the time gas was introduced. • As with other areas, land use was not an issue.
Business • opportunities	• The usual service and appliances sales opportunities developed. • No other opportunities noted.
Government • tax	• Taxes paid include corporate income tax at the federal and state level, and local property taxes, but no estimates are available.

Figure 2

Natural Gas Prices



II.
FRAMEWORK MODEL

1. CONCEPTUAL FRAMEWORK

This section sets out a conceptual framework for identifying (and quantifying, where possible) benefits and costs arising from the introduction of natural gas into a greenfield area. The framework is based on the assessment of benefits and costs arising from the introduction of natural gas into the study areas outlined in Chapter 1.

The model design is driven by the three ultimate purposes:

- ♦ Improving the level of public understanding of the potential impacts;
- ♦ Improving the quality of public policy development; and,
- ♦ Providing an empirically based and methodologically sound approach to inform decisions about publicly-funded support or other program issues influencing gas system design, location and timing.

The framework model provides a systematic approach to identifying what types of benefits could reasonably be expected, and the costs of deriving those benefits. When applied to a greenfield area, the model allows governments to address questions such as:

- ♦ Will natural gas create a more competitive fuel market and lead to price reductions? What are the economic impacts of this?
- ♦ Will gas help existing industries and businesses to be more competitive?
- ♦ What new industries or businesses could be attracted because of gas availability and what would be the likely economic and other impacts?
- ♦ What level of employment and other impacts could be expected from the construction and operation of a gas lateral and distribution system, and what losses might be expected in other fuel sectors?

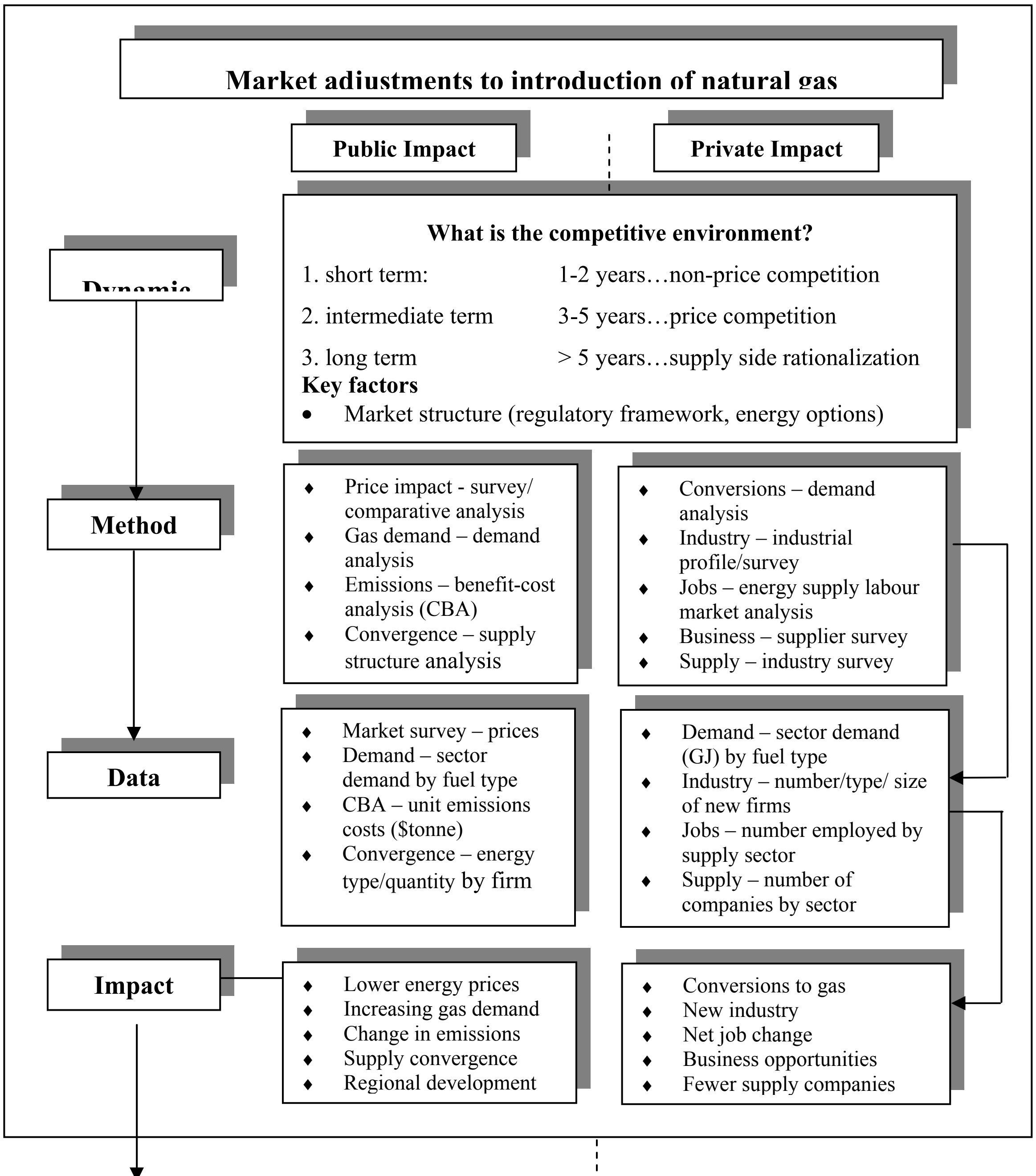
To meet these purposes, the conceptual framework set out in schematic form in Figure 3 provides the analyst with systematic approaches (methods) for:

- ♦ Identifying the economic components likely to be affected, and describing the nature, relative magnitude and timing of any changes (the “dynamic”) arising from the introduction of natural gas into a greenfield area. The analysis in Chapter 1 indicates that impacts (both quantitative and qualitative) flow primarily from market adjustments.

- Specifying the impacts - public and private benefits and costs - that can reasonably be expected to flow from these effects. The model addresses quantitative and qualitative economic, social and environmental impacts.
- Outlining the methodology for quantifying impacts. We adopt the conventional definitions used by economists as the basis for specifying benefits and costs.
- Identifying the data needed to measure or describe the impacts. Data requirements flow from methodology. This draws on the output of Chapter 1.

Figure 3

Conceptual Framework



2. ELABORATING THE FRAMEWORK MODEL - KEY QUESTIONS

Experience elsewhere (as set out in Chapter 1) indicates that inter-fuel competition for market share is the main source of benefits following the introduction of natural gas. The nature and extent of impacts depends largely on how competitive natural gas is, which in turn, depends on such factors as capital cost for laterals and distribution systems, the commodity costs of gas, the nature of the competitive environment, and the characteristics of energy demand in the market area (price, quantity and type of fuels displaced).

The model framework, then, consists of a set of questions addressing each of these factors. Some of these questions can be addressed using quantitative techniques, while others lend themselves to qualitative assessment. The framework model is presented in matrix format (with data requirements and sources) in Table 14.

The questions fall into nine main subject matter areas. The significance of these areas and of the information needed to assess benefits and costs may be summarized as follows.

Area energy objectives – Answers to these questions provide insight into the underlying rationale for the request for access to natural gas by a community or region. The questions effectively encourage a region to examine in a systematic way why access to gas is important. The answers may reveal a clear understanding about natural gas as an energy source, including the terms and conditions under which access could be secured, but the answers could also reveal some misconceptions about these matters.

- What are the area's energy objectives?
- Where does natural gas fit within these objectives?
- Is it possible to meet these objectives with other energy sources?
- What specific energy needs would natural gas meet and under what general relative price assumptions?

Economic growth and development – Answers to these questions provide insight into how natural gas is expected to benefit an area in terms of its contribution to economic growth and development. The answers may reveal a clear understanding about how natural gas could contribute to growth and development, but the answers could also reveal some misconceptions about its relative significance.

- What is the economic structure of the area? What are its competitive advantages and disadvantages?
- What are the area's economic development objectives?
- How would natural gas help in achieving these objectives?
- How does the lack of natural gas present an obstacle to achieving these objectives?

- Do you anticipate that access to gas will encourage industrial development, or at least allow the area to retain industry?

Industry/anchor load – In assessing market potential, natural gas suppliers look to large energy users (energy intensive industries, oil or coal fired electrical generating stations, large institutional users) to provide what is known as an anchor load for a distribution system. Without such load centres, the economics of serving an area tend to be weak because recovering the costs of investing in laterals and distribution systems in a timely manner is difficult. These questions are directed toward establishing the extent to which this key market component is, or might be, present in an area.

- Who are the major industrial companies and large institutional loads in the area?
- How much energy of what type (oil, electricity, wood, other) do they consume on a monthly basis?
- Have any of the companies expressed an interest in switching to natural gas, or to a dual-firing (oil/gas) capability?
- Would their decision to switch be based entirely on economic considerations (relative fuel prices), or would environmental factors also play a role?
- If relative fuel prices are the critical factor, what price spread do the companies feel is necessary to induce conversion?
- Have any new industries expressed an interest in locating in the area and how important is the availability/price of natural gas relative to other factors in attracting them?
- What price spread do prospective companies feel is necessary to cause them to locate in the area, and is this price spread likely to occur in the long run?

Commercial/residential market – These market segments in greenfield areas tend to be of secondary interest from a gas supply standpoint because of the low average demand and the slow rate of customer acquisition. It is helpful to know the potential size of this market and how much support there is for access to gas. It is also helpful to know whether potential customers are prepared to assist development of a distribution system with contributions towards an “aid to construct”.

- How many households are there in the area?
- How many small and large commercial establishments?
- What is the attitude towards natural gas among households?
- What is the attitude towards natural gas among commercial establishments?
- Are there particular aspects of natural gas that make it an attractive/unattractive choice for consumers in the area?

- Is there an expectation that natural gas will be inexpensive relative to competing sources?
- Is access to gas important enough to consumers that they would contribute to an aid to construct through a capital or energy surcharge?

Energy supply and market structure – The ability of natural gas to penetrate a market depends in part on the cost and availability of alternative energy sources, and also on structure and competitiveness of the supply industry. For consumers, natural gas simply represents another option, which may or may not be less costly. The introduction of natural gas may present a competitive threat for market share for some energy suppliers, and for others, an opportunity to diversify business options.

- What are the predominant sources of energy in the area market?
- How many suppliers are there?
- What is the likely competitive response to the introduction of natural gas – price competition among fuels, and/or non-price competition?
- How are the structure and operations of the current energy supply sector likely to be affected by the introduction of natural gas?
- What job losses, if any, are expected among established energy suppliers?
- What job gains, if any, are expected in natural gas distribution?

Economic, social and environmental benefits and costs – These questions focus on the potential non-market benefits and potential costs arising from the distribution and use of natural gas. The benefits provide justification for "aids to construct" when projected system revenues alone provide an insufficient basis to proceed with construction. The potential costs may require some form of compensation or mitigation before the public accepts natural gas.

- What economic benefits are expected to result from the introduction of natural gas: Attraction of new industry? Retention of existing industry? Job creation? Less job loss? Increased income due to higher paying jobs? These benefits are often critical in selling the idea of access to gas, but may be difficult to establish given the reluctance many prospective companies have in revealing the factors behind their location decisions, or the reluctance many existing companies have in revealing the terms and conditions under which they would convert to gas.
- What environmental benefits are expected to result from the introduction of natural gas: Reduced greenhouse gas emissions arising from the substitution of gas for heavy and light oils? Contribution to Canada's commitments under the Kyoto Accord? Reduced risk of oil spills at industrial sites? Reduced risk of oil spills during delivery?

- What social benefits are expected to result from the introduction of natural gas: Greater security of energy supply? Improved energy options for consumers? Enhanced lifestyle?

What potential social costs are expected to result from the introduction of natural gas: Reduced property values due to location of gas facilities (lateral, distribution system, compressor stations, gate stations and meters)? Concerns over risk of explosions or other accidents involving gas?

Regulatory framework – The regulatory framework in the jurisdiction could have a bearing on the rate at which a natural gas distribution system expands into new areas. The two most common approaches are cost of service and performance based. Cost of service regulation allows the pipeline owner a guaranteed or regulated rate of return on invested capital. Performance-based regulation does not provide a guaranteed rate of return, but may allow the regulated company (usually the local distribution company, since transmission line companies are almost always operate under cost of service regulation) to earn high returns in later years as the market develops. Typically, performance-based regulation trades off losses or low returns in early years for high returns in later years. Also, a policy allowing large industrial users to by-pass the distribution system adversely affects system economics by removing an important potential revenue source.

- What is the regulatory approach in the market area?
- Is the service bundled or unbundled, in other words, will gas (the commodity) be sold on a separate and competitive basis (i.e., unbundled from the regulated distribution system) or with the distribution system and fully regulated?
- Are industrial customers permitted to by-pass the distribution system and obtain gas directly from the mainline via a lateral?

Distribution system – The capital cost of the lateral and distribution system into a greenfield area, coupled with the revenue to be generated, are critical to the feasibility of the system expansion. Costs are a function of many factors, but principally the distance of the market from the mainline, the length of the distribution system, and the terrain and soil conditions along the lateral route and in the market area. Revenue is a function of gas sold, which in turn is determined by the number of customers, average consumption, and price paid.

- What is the total cost of the lateral to the market area?
- What is the total cost of the distribution system in the area?
- At what rate will customers in each class hook up to the system?
- What is the average consumption and annual demand by customer class?
- At what price can gas be sold and how much of the revenue accrues to the distribution company, the transmission company, marketers, if any and so on?

Subsidy regime – Many system extensions in Canada have proceeded on the strength of "aids to construct" of one form or another. If some form of assistance is deemed necessary in the market area, what is the preferred approach?

- What type of regime is likely to apply: capital and/or operating subsidies?
- Will consumers be asked to contribute to capital costs: through a one time up front contribution, or through a surcharge on the gas price?

3. ANALYTICAL TOOLS

Applying the model to greenfield areas requires the use of qualitative and quantitative techniques. The approach, information requirements and data sources are discussed below and summarized in Table 14.

Qualitative

The qualitative analysis requires a variety of techniques including interview, survey and data gathering from secondary sources (mainly statistical publications and reports). Questions concerning area energy and development objectives would be addressed through interviews with community leaders and development agency representatives (e.g., RDAs). Questions concerning attitudes toward natural gas and likelihood of conversion, whether in the industrial, commercial or residential sectors, would best be approached through a survey of existing and prospective customers. Matters pertaining to energy industry structure and the competitive environment are most effectively addressed through interviews with energy suppliers and regulatory agencies.

In each case, the results of the interviews and surveys must be incorporated in the overall analysis in order to complete the picture. The challenge when addressing qualitative considerations in a report is to ensure they receive the attention they deserve. To this end, it is important to describe them in complete detail and to emphasize their relevance to any decision on access to gas.

Quantitative

Cost-Benefit Analysis (CBA)

CBA is generally used to determine whether an investment or program can be justified on broad economic grounds. This approach is often used when public funds are involved, or simply as a means of ensuring that the broadest possible perspective on benefits and costs is brought to bear in the analysis.

The framework model is used to identify all private and social benefits and costs. They will be quantified (to the extent possible) using market prices, and where necessary, so-called "shadow prices" reflecting relative scarcity. They will be set out on an annual basis and the annual net benefit derived (this corresponds to net income in a financial analysis).

A subsidy in the form of an "aid to construct" may make economic sense depending on the external or social benefits generated by extending into a greenfield area. Each greenfield area is treated as a discrete "project". This means benefits and costs are not simply identified and quantified, but are incorporated systematically in a formal analysis of the economic merits of the projects in each area.

In essence, this approach views the project from a public or economic standpoint, and not the private or financial standpoint forming the basis of the financial analysis outlined above. The difference lies essentially in how benefits and costs are defined, and how they are quantified in dollar terms.

The financial (private) analysis counts as relevant only those cost and revenue items appearing on a company's income statement. They are valued at prevailing market prices – what the company actually pays. Whether the utility goes ahead with an investment depends on the rate of return it generates. In the current economic (and regulatory) climate, a rate of return in the 11-13% range is considered acceptable. This rate would be used to discount costs and revenues in order to calculate the NPV.

CBA (public) defines benefits and costs from a societal standpoint. This broader perspective means two things: a potentially wider range of costs and benefits (so-called externalities) forms the basis for the analysis, and adjustments are made to the dollar value assigned to benefits and costs where market prices do not reflect relative scarcity (opportunity cost). For example, an improvement in air quality resulting from the substitution of natural gas for oil or coal is a benefit, but not one the gas distributor can capture through conventional pricing. Hence, it does not appear on the income statement and is excluded from the rate of return analysis. From a private standpoint the project is undervalued. CBA corrects for this, explicitly quantifying and including such benefits in the analysis. Any distortions in market prices for key inputs and outputs would also be corrected in the analysis to ensure relative scarcity is captured.

Once all costs and benefits are identified and quantified, the net present value (NPV) or internal rate of return (IRR) of each project is calculated to assess its relative economic merits. A positive NPV (using a discount rate based on the opportunity cost of capital, say, 7.5%) indicates an acceptable project. An IRR at least equal to the opportunity cost of capital also signifies an acceptable project. For the purposes for which this framework is to be used, adopting the NPV test would be an appropriate approach. It is only when comparing projects with different cost and revenue profiles over time that the NPV approach would not yield conclusive results.

Tables summarizing the relationship of costs and benefits and the derivation of NPV are provided in Appendix B.

Data Requirements and Sources

Potential natural gas market. The starting point is Statistics Canada data for thermal and process energy demand by sector (i.e. domestic, commercial/institutional, industrial) and fuel type. This would ordinarily have to be augmented by information obtained through direct contact with industrial users and large commercial/institutional energy users. Potential demand is less than total demand because not all uses lend themselves readily to conversion to natural gas. For example, experience shows that various market segments are unlikely to convert because of high conversion costs: large apartment buildings with separately metered units; some coal-fired electrical generating stations; some pulp and paper mills using waste wood, etc. Other rules of thumb will also be applied. Once such sources of demand are netted out, remaining consumption would be adjusted for changes in efficiency (after conversion) to arrive at potential gas demand.

Fuel prices. Data for the relative fuel price analysis (i.e. No. 2 and 6 fuel oil, propane, electricity, coal) in each sector can be from Statistics Canada and provincial departments of natural resources, and augmented by a survey of suppliers where needed. History has shown that considerable uncertainty surrounds future price changes, so any assessment of competitive prices should include a sensitivity analysis around a base case. For example, in 1999 when applications were submitted for the gas distribution franchise in Nova Scotia, heating oil prices were in the $0.29/litre range. By the winter of 2002, they had risen to double this price.

By relying on experience elsewhere (primarily Phase 1 data from existing greenfield areas), it is possible to specify the delivered cost of gas by sector that would be sufficiently competitive to allow reasonable market penetration. In the case studies that follow, we assume customers would be attracted if gas were priced at least 10% below the alternative energy source. Note that this conclusion leaves our consideration of conversion costs. Customers who wish to convert before their oil-burning equipment is worn out would need a commensurately greater price spread to make conversion worthwhile.

Attracting industry. A careful quantification of the industrial/anchor load market is crucial to the analysis since it is this market segment that can make the difference between viability and non-viability. Industrial customers offer demand characteristics (generally high load factor) that greatly contribute to the viability of a system. The experience of greenfield markets in other areas of North America (Chapter 1) indicates clearly that natural gas alone is ordinarily not enough to attract industry. Except for energy-intensive industries such as smelting, pulp and paper or electricity generation, energy costs ordinarily account for a relatively small part of overall production costs. So, even if the burner tip cost of gas were less expensive than, say, heavy fuel oil (which is *not* the case in the Maritimes), factors such as access to raw materials, quality of labour force and proximity to markets are likely to be more significant in the location decision.

Those promoting access to natural gas should also take note that even if a case could be made on environmental grounds that it makes good corporate sense for a company to use (or convert to) gas, most companies would leave themselves the option of switching fuels (to take advantage of price shifts) by installing a dual-fired system (gas and oil). What all this means is that as long as gas and heavy oil are priced more or less equivalently in energy terms (which is likely in the foreseeable future), the price companies are prepared to pay for gas may do little more than cover the commodity cost of gas. It may not be enough to cover the cost of gas *plus* the lateral toll (let alone a distribution system toll). This means that industrial customers, even if they use gas, could make at best a modest contribution to the financial viability of a distribution system (other than possibly contributing to the viability of the lateral).

Gas demand forecast. By taking the potential market and competitive price information and combining it with assumed capture and penetration rates, it is possible to produce a natural gas market forecast for a 15-20 year period. The capture and penetration rates are based on industry experience in the greenfield areas (augmented with other Canadian experience if necessary), with adjustments for any differences in key factors in the Maritime market areas.

System capital and operating costs. Using industry rules of thumb (e.g., installed costs of pipe [$/m] for laterals and distribution system), it is possible to generate broad estimates of system costs for each area. Such information may be found in existing franchise applications, various studies, and in gas industry publications.

Qualitative factors. Several of the framework model elements include factors that can be assessed in qualitative terms only. Data requirements and sources/methods are indicated in Table 14.

Table 14

Framework Model – Questions, Data Requirements and Sources

Model Element	Data requirement	Data source
Area energy objectives ▪ What are the area's energy objectives? ▪ Where does natural gas fit within these objectives? ▪ Is it possible to meet these objectives with other energy sources? ▪ What specific energy needs would natural gas meet and under	▪ Policy statements from area political leaders ▪ Specific industrial	▪ Government (NB, NS, PEI) ▪ Area RDAs ▪ Phase I Study

Model Element	Data requirement	Data source
what general relative price assumptions?	opportunities for natural gas	Areas
Economic growth and development ▪ What is the economic structure of the area and what are its competitive advantages and disadvantages? ▪ What are the area's economic development objectives? ▪ How would natural gas help in achieving these objectives? ▪ How does the lack of natural gas present an obstacle to achieving these objectives? ▪ Do you anticipate that access to gas will encourage industrial development, or at least allow the area to retain industry?	▪ Economic profile of area ▪ Statements of development objectives ▪ Energy profile of the area ▪ Use of gas in similar circumstances	▪ Area RDAs ▪ Phase I Study Areas ▪ 1999 Franchise applications in Nova Scotia and New Brunswick
Industry/anchor load ▪ Who are the major industrial companies and institutional loads in the area? ▪ How much energy of what type (oil, electricity, wood, other) do they consume on a monthly basis? ▪ Have any of the companies expressed an interest in switching to natural gas, or to a dual-firing (oil/gas) capability? ▪ Would their decision to switch be based entirely on economic considerations, or would environmental factors play a role? • Have any new industries expressed an interest in locating in the area and could natural gas play a role in attracting them?	▪ Industry profile ▪ Energy demand characteristics ▪ Industry location criteria	▪ Area RDAs ▪ Industrial companies in the area ▪ Statistics Canada
Commercial/residential market ▪ How many households are there in the area? ▪ How many small and large commercial establishments? ▪ What is the attitude towards natural gas among households? ▪ What is the attitude towards natural gas among commercial establishments? ▪ Are there particular aspects of natural gas that make it an attractive/unattractive choice for consumers in the area? ▪ Is there an expectation that natural gas will be inexpensive relative to competing sources? ▪ Is access to gas important enough to consumers that they would contribute to an aid to construct?	▪ Housing statistics ▪ Commercial sector statistics ▪ Commercial sector energy demand ▪ Residential sector energy demand	▪ Census ▪ Statistics Canada ▪ Consumer survey ▪ Information from Phase I Case Studies
Energy supply and market structure ▪ What are the predominant sources of energy in the area market? ▪ How many suppliers are there? ▪ What is the likely competitive response to the introduction of natural gas – price and/or non-price competition among fuels?	▪ Energy market profile ▪ Competitive structure	▪ Provincial departments of energy ▪ Information

Model Element	Data requirement	Data source
▪ How are the structure and operations of the current energy supply sector likely to be affected by the introduction of natural gas? ▪ Are job losses expected among established energy suppliers? ▪ What job gains, if any, are expected in natural gas distribution?	▪ Direct employment and income in energy supply sector	from Phase I Case Studies
Economic, social and environmental benefits ▪ What economic benefits are expected to result from the introduction of natural gas: Attraction of new industry? Retention of existing industry? Job creation? Less job loss? Increased income due to higher paying jobs? ▪ What environmental benefits are expected to result from the introduction of natural gas: Reduced greenhouse gas emissions arising from the substitution of gas for heavy and light oils? Contribution to Canada's commitments under the Kyoto Accord? Reduced risk of oil spills at industrial sites? Reduced risk of oil spills during delivery? ▪ What social benefits are expected to result from the introduction of natural gas: greater security of energy supply? Improved energy options for consumers? **Regulatory framework** ▪ What is the regulatory approach in the market area? ▪ Is the service bundled or unbundled, in other words, will gas (the commodity) be sold on a separate and competitive basis (i.e. unbundled from the regulated distribution system) or with the distribution system and fully regulated? ▪ Are industrial customers permitted to by-pass the distribution system and obtain gas directly from the mainline?	▪ Expressions of interest from firms wishing to locate ▪ Risk of firms leaving if gas not available ▪ Type and quantity of displaced fuels ▪ Perceptions among consumers about energy security ▪ Policy and legislation ▪ Details of the approved natural gas supply chain ▪ Details of options for access by industrial sector	▪ Information from Phase I Case Studies ▪ 1999 Franchise applications in NS and NB ▪ Survey of customers (residential, commercial, industrial) ▪ Regulatory authorities
Distribution system ▪ What is the total cost of the lateral to the market area? ▪ What is the total cost of the distribution system in the area? ▪ At what rate will customers in each class hook up to the system? ▪ What is the average consumption and annual demand by customer class? ▪ At what price can gas be sold, and how much of the revenue	▪ Unit cost for lateral and distribution system ▪ Length of lateral and distribution	▪ 1999 Franchise applications in Nova Scotia and New

Model Element	Data requirement	Data source
accrues to the distribution company, marketers, the mainline transmission company and so on?	pipe ▪ Penetration rates by class ▪ Energy demand characteristics (quantity and price)	Brunswick ▪ Current rules of thumb for construction found in reports and studies ▪ Information from Phase I Case Studies
Subsidy regime ▪ What type of regime is likely to apply: capital and/or operating subsidies? ▪ Will consumers be asked to contribute to capital costs: through a one time up front contribution, or through a surcharge on the gas price?	▪ System economics and demonstrated need for aid to construct ▪ Options for subsidy	▪ Information from Phase I Case Studies ▪ Regulatory authorities ▪ Provincial agencies

III.

CASE STUDIES – MARITIME PROVINCES

1. OVERVIEW

Re-cap of greenfield area findings

This chapter uses the framework model described in Chapter II to develop three case studies of sub-provincial areas that could potentially be served by natural gas. The three study areas are located in northeastern New Brunswick, central Prince Edward Island, and southwest Nova Scotia. The analysis makes use of the findings presented in Chapter I on greenfield gas projects in five areas in Canada and the United States who all received natural gas in the recent past. *The narrative that follows is set up to allow each case study to be read independently of the other two. All of the data and assumptions are described fully for each case. This results in some duplication in the text because some assumptions are common to all three cases.*

The Chapter I findings show that most of the short-term effects of gas introduction came from the inter-fuel competition, and not from the introduction and expansion of new and existing industries. While it is often believed that the introduction of natural gas can be an instigating factor for economic growth, the assessment of the experience of the five areas covered in Chapter I show that communities were able to do one or all of the following:

- Retain industries who might have otherwise had to relocate due to environmental standards and costs;
- Become more competitive with similar communities nearby who already had natural gas to offer to industry;
- Offer present and future consumers a competitively-priced, clean energy source for their advantage.

More specifically, the Chapter I findings show that:

- Capital subsidies were instrumental in system construction and encouraging fuel switching for commercial and residential users;
- Environmental regulations were a key driving force for pulp mills in emission reduction and pollution abatement cost reduction;
- Some locations had inherent advantages (in capital costs and fuel-switching costs) due to existing propane-air systems already in place;
- Energy cost savings were the key economic benefit in all sectors, especially for commercial and industrial applications;

- There was a general feeling of increased competitive advantage over communities without gas;
- There were a number of combinations of capital and operating subsidies in the greenfield areas, including aids to construct and user fees;
- In most cases, the driving factor to bringing in natural gas was the potential load of large industrial users. Marketing to small commercial and residential consumers varied in effort;
- In the majority of case studies, it was difficult to attribute new commercial or industrial investment to the introduction of natural gas;
- No specific employment displacement was noted in any community (e.g., in the residential oil service) due to the introduction of gas service;
- Take up rates varied widely depending on the marketing strategy of the distributor/marketer, and the incentives offered to customers to switch to gas.

In this chapter, we are reporting on three case studies that are meant to *demonstrate the application* of the model to potential situations in the three Maritime Provinces. The case studies show the type of information that would have to be assembled for an assessment of whether or not there is any economic rationale for government assistance to extending natural gas service to areas not now served. In this sense the case studies are *illustrative* only. They should be understood as hypothetical examples as opposed to a definitive analysis.

As far as possible, we use actual data from the communities to answer the questions posed in the framework model regarding the possible short and long-term impacts associated with the introduction of a new competitive fuel source. In addition, a formal CBA identifies and measures the types of costs and benefits of introducing natural gas to the three study areas. It should be noted that we use assumptions to overcome any gaps in the available data.

Each CBA starts with a financial analysis to test the financial feasibility of the proposed natural gas system. The financial analysis is converted to a CBA by adding the energy savings from converting to natural gas (and any other quantifiable benefits) to the benefit stream. In both analyses, Net Present Value (NPV) is used as the indicator. The interpretation to be applied to the results of the two analyses is as follows:

Result	Financial Analysis	CBA	Comment
1.	NPV<0	NPV<0	Proposed system is not feasible.
2.	NPV<0	NPV>0	Proposed system is not feasible from a private sector point of view but is feasible from a societal point of view given the energy savings. This result provides an economic justification for an aid-to-construct subsidy.
3.	NPV>0	NPV>0	Proposed system is financially feasible on its own without an aid to construct.

In describing the results for each case study, we report on the prominent issues surrounding the costs, benefits, and viability of introducing natural gas to the area. This allows us to cast the results of the CBA in the broader perspective laid out by the framework model. The questions addressed focus on the following nine areas that correspond to the issues identified in the framework model.

- Area energy objectives
- Economic growth and development
- Industries and anchor loads
- Commercial and residential markets
- Energy supply and market structure
- Economic, social and environmental benefits
- Regulatory framework
- Distribution system
- Subsidy regime

In interpreting the results of the case studies, the reader must bear in mind that they are meant to be illustrative of a method, rather than definitive of a result. Many assumptions are used in the analysis. These assumptions seem reasonable today, but could change substantially as time goes by. This will affect the results. For example, the results are sensitive to fuel price assumptions. If heating oil sells for $0.30/l as it did two years ago, this leaves limited room for gas to compete and allow acceptable returns for producers, pipeline companies, distributors and marketers. The current price of heating oil ($0.60/l) leaves substantially more room, though if the commodity price of gas moves in tandem with oil, this would have negative consequences on distribution system viability

Maritimes & Northeast Lateral Policy

The Maritimes & Northeast Pipeline lateral policy could apply to system expansions required for each of the case studies. Under it, the M&NP would build and own the laterals needed to service various communities, although regulatory approval (from the National Energy Board and/or the relevant provincial regulatory body) would be required to approve the proposed pipeline as a lateral. If approved, the cost of the lateral would be rolled into the cost base of the MN&P main transmission line and therefore would be paid for by all users served by the system. This would reduce the financial cost of the case study system and thus make it more financially attractive. It would not affect the costs in the CBA since they are regarded as societal costs that must be covered regardless of which people or groups actually bear the costs[7]. In any event, given the uncertainty as to whether or not the lateral policy would apply, the case studies include the full cost of the system expansion in both the financial analysis and the Cost Benefit Analysis.

2. New Brunswick

This case study covers an area in Northeastern New Brunswick running from Miramichi City to Bathurst to Campbellton. The outlined area on Map 10 shows the complete study area. Table 15 provides population levels.

[7] There is one qualifier. The system capital costs in the CBA will be reduced to the extent that the rolled in costs of the lateral are actually paid by gas consumers in the United States.

Map 10

New Brunswick Case Study Area

In 1998, the New Brunswick's *primary* energy demand was approximately 316 million MMBtu[8]. The greatest portion of this was met through petroleum products (65%), followed by wood (15%), coal (13%), nuclear (4%) and hydro (3%). End use energy demand was 204 million MMBtu, over half of which was supplied by petroleum. Wood and electricity supplied 23% and 24% of this demand, respectively.

The Industrial sector accounted for 42% of energy demand, followed by transportation at 32%, the Residential sector at 17%, and the Commercial sector at 9%. Natural Resources Canada predicts total energy demand in New Brunswick to increase by 14% from 1998 to 2010. Natural gas is expected to supply 3% of New Brunswick's energy demand by 2005 and 7% by 2020[9].

Table 15

New Brunswick and Selected Case Study Area Populations (1996)

	Population (1996)	Population (2001)	% of County Population (1996)
New Brunswick	738,100	757,100	
Northumberland County	52,100		
Miramichi City	19,241	18,508	37%
Gloucester County	87,600		
Bathurst (City)	13,815	12,924	16%
Beresford	4,720	4,414	5%
Restigouche County	38,700		
Belledune	2,060	1,923	
Campbellton	8,404	7,798	22%
Dalhousie	4,500	3,975	12%

Source: Statistics Canada 1996 Census, 2001 Census, NB Department of Finance (2002).

8 Province of New Brunswick Department of Natural Resources and Energy. 2000. "New Brunswick Energy Policy", pg. 4.

9 ibid., pg.9.

APPLICATION OF THE FRAMEWORK MODEL

Area Energy Objectives

The northeastern portion of the province is economically focussed on natural resources and the services sectors. The largest industrial players (and largest energy users) in the market are in the pulp and paper, forestry, and mining industries in and around Miramichi, Bathurst, Belledune, Dalhousie and Atholville. Many of these industries utilize hog fuel for process heat, and utilize residual (heavy) fuel oil to aid in the combustion of hog fuel.

At present, Regional Development Authorities in this area are focussed on attracting new manufacturing activities to the region, and the development of the port at Belledune. The impending shut-down of the Noranda smelter (in Belledune) has forced the RDA to try and help those manufacturing businesses who rely on it to diversify their activities in order to remain in the marketplace. In the Miramichi area, the main concern regarding getting natural gas into the community is being competitive with the Saint John and Fredericton markets.

Previously, the two major industries in the area were reluctant to express interest in switching to natural gas, though this could be due to the infancy of natural gas distribution in the area and the lack of reassurance of a low-cost fuel source. It still remains that these industries are potential natural gas users in the future.

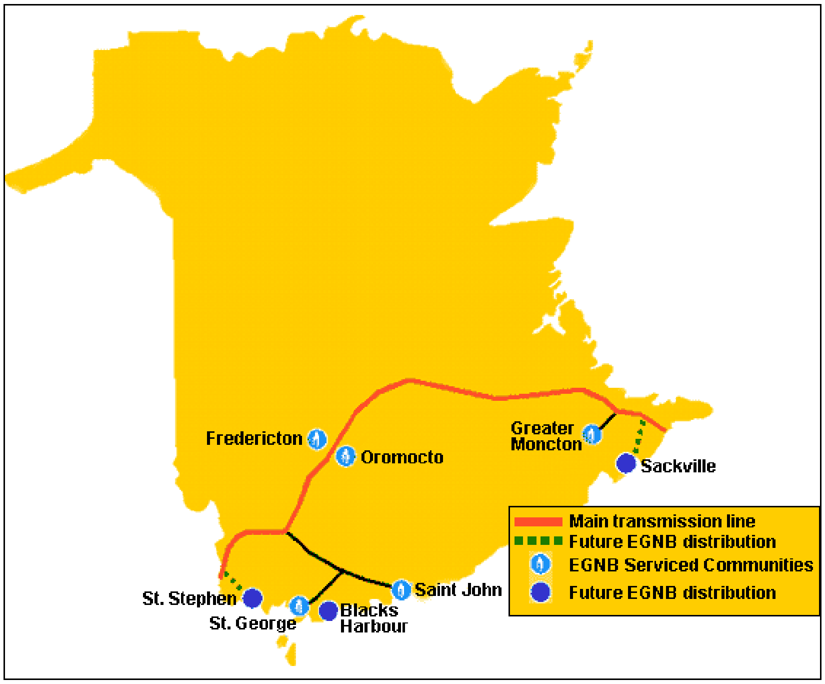
Economic Growth and Development

At this point, northeastern New Brunswick is generally focussed on retaining its existing industry base (chiefly the manufacturing of resource-based products), and expanding its service industry. Regional development corporations see natural gas as creating a “level playing field” for the region, and allowing it to compete successfully with communities along the existing natural gas mainline in attracting new industry.

Map 11 shows the main transmission line through New Brunswick, as well as the currently serviced communities and communities to be serviced in the future.

Map 11

Maritimes & Northeast Main Transmission line and Laterals



Source: Enbridge Gas New Brunswick, http://www.egnb.enbridge.com

Industry/Anchor Load

Currently the large industrial users consume just over 9 million GJ per year in #2 fuel oil, #6 fuel oil, and propane. The industries named in previous studies[10] include UPM (Miramichi), Weyerhaeuser (Miramichi), CFB Chatham, Noranda (Bathurst), Smurfit-Stone (Bathurst), Noranda (Belledune), Bowater (Dalhousie), and AV Cell (Atholville).

One user, who accounts for about 12% of the total thermal energy demand (as measured by #2, #6 and propane usage), is scheduled to shut down operation in the near future, and if so would not be a potential natural gas consumer in the study area. The remaining large industrial energy consumers could be converted to natural gas, depending on each facility's current energy configuration, relative energy prices and the expected costs to retrofit burners and boilers.

Accounting for industrial demand on a lateral for Northeastern New Brunswick, Table 16 shows the demand breakdown.

10 Neill and Gunter, Limited. 1995. "Evaluation of Potential Natural Gas Market in New Brunswick".

Table 16

Industrial Energy Demand by User

Industry	Location	Energy Consumed (MMBtu)	Percentage of Total Demand
Weyerhaeuser	Miramichi	22,566	0.3
REPAP	Miramichi	3,039,957	41.4
CFB Chatham	Chatham	91,970	1.3
Smurfit-Stone	Bathurst	599,638	8.2
Noranda Smelter	Belledune	623,906	8.5
Bowater	Dalhousie	2,455,736	33.4
AV Cell	Atholville	487,436	6.6
1 unnamed industry	unknown	27,481	0.4
Total		7,348,690	100.1

Source: Neill and Gunter Limited, 1995 “Evaluation of Potential Natural Gas Market in New Brunswick”; Enbridge Gas New Brunswick 1999 “Gas New Brunswick Distribution Proposal”.

Costs of conversion of the industrial energy users along the lateral range from anywhere from $60,000 to over $3 million. The 1995 Neill and Gunter report proposes that the cost to convert the industries between the Miramichi and Atholville amount to approximately $8.3 million. The pulp and paper mills along this route would be the most expensive conversions, ranging between $2.9 million and $3.3 million.

Commercial, institutional, and industrial acquisition rates vary. In an Enbridge Gas New Brunswick (EGNB) study, penetration in to the small and medium commercial sector would reach 70% in 15 years, 70% of the medium-large commercial sector in 10 years, and the large and very large sector would see an 80% acquisition rate within 5 years. Institutional users such as hospitals and schools are included in the commercial sector. This forecast does not include the industrial users who, it could be assumed, would all convert to natural gas if it was available at a competitive price.

Proposals to distribute gas to the case study area have already been filed with the public utilities board, but no action has been taken on the part of Maritimes & Northeast pipeline to construct the lateral.

Commercial/Residential Market

The six communities in the study area include approximately 20,905 private dwellings (Enbridge Gas New Brunswick, 1998). According to a survey performed for Enbridge Gas New Brunswick, 45 percent of these dwellings have central heating systems, which would make them good candidates for switching to natural gas, if it were available.

Industrial, commercial and residential take-up rates were varied, and can be seen in Table 17.

Table 17

Take-Up Rates for Residential, Commercial and Industrial Customers, New Brunswick

(number of customers)

Year	Residential	Commercial	Industrial
1	0	0	0
2	0	0	13
3	217	207	14
4	1,053	387	15
5	1,701	590	15
6	2,120	675	15
7	2,444	763	15
8	2,657	848	15
9	2,985	948	15
10	3,488	1,068	15
11	4,245	1,215	15
12	5,135	1,365	15
13	6,116	1,504	15
14	7,040	1,606	15
15	7,915	1,677	15
16	8,692	1,719	15
17	9,393	1,743	15
18	10,040	1,756	15
19	10,563	1,766	15
20	10,981	1,767	15

Source: Enbridge Gas New Brunswick (1999); Neill & Gunter Ltd. (1995).

Residential acquisition rates are influenced by the type of central heating in the overall residential market. Residential consumers with central heating in their homes can convert both their space heating and water heating to natural gas relatively easily and inexpensively. Those without central heating in their homes may only wish to use natural gas for water heating applications until such time as it is economical for them to employ a natural gas-fired heating system (either a fireplace/fan arrangement, or central heating).

Conversion forecasts by EGNB indicate that within 15 years, 80% of homes with central heat will be hooked up to natural gas, while those without central heating would see a 70% acquisition rate in 20 years.

Conversion Costs

Residential consumers who have a central heating system in their dwelling are most apt to switch to natural gas when their current equipment reaches the end of its useful life. Potential savings from switching to natural gas (assumed in this study at 10% below fuel oil) are not high enough to induce conversions before existing equipment is worn out. The conversion costs in Table 18 outline the average costs for these consumers to install natural gas-fired equipment.

Table 18

Cost of Conversion to Natural Gas

Equipment	Natural Gas System	Cost to Consumer for Conversion
Forced Air Oil Furnace	Force Air Furnace	$1,800 - $3,500
Oil Hot Water Radiant	Hot Water Radiant	$1,800 - $4,000
Electric Forced Air Furnace	Forced Air Furnace	$2,400 - $3,400
Electric Baseboard	Forced Air Furnace	$4,000 - $7,000
Electric Baseboard	Space Heaters/Fireplaces	$1,200 - $2,500
Air Tight Wood Stove	Fireplace	$1,600 - $2,500
Forced Air Wood Stove	Forced Air Furnace	$1,800 - $3,500
Propane Forced Air Furnace	Forced Air Furnace	$200 - $400

Source: Maritimes NRG Application.

Smaller commercial energy users (i.e. small retail outlets, offices, etc.) are also likely to choose to switch from oil to natural gas only at the end of the useful life of their current heating equipment. Commercial users who use propane can affordably convert to natural gas as soon as it is made available. Thirteen percent of the commercial energy demand in the study area is currently satisfied by propane.

The New Brunswick case study considers eight major industrial users. Fuel-switching, or moving to dual-fuel capability for these industries can be expensive, depending on the type of process and the type of boiler used by each process. Return on Investment studies (in Neill & Gunter, 1995) suggest positive returns on investment based on a ten-year time frame. However, the Chapter I findings suggest that industries often require a shorter pay-back period (3-5 years) for returns on investment. The particular energy and conversion requirements of each consumer will dictate its willingness to switch to accommodate natural gas.

Energy Cost Savings

Energy cost savings to the consumer can be calculated by comparing the efficiency-adjusted price per heat unit (often calculated per MMBtu[11]) of the currently used fuel, with the effective price per heat unit of natural gas. (Efficiency adjusted prices take into the difference energy content per unit of heating fuels and the relative efficiency of the burners (e.g., furnaces, water heaters, etc.).

In the northeastern New Brunswick case, consumer cost savings were calculated by multiplying the number of potential gas hookups (residential, commercial and industrial) by the cost savings per consumer (a function of energy demand and effective price difference between fuels).

Electricity dominates the residential market in the Northeast area of New Brunswick, followed by light fuel oil (#2). The study assumes that competitively priced natural gas would be about 10% cheaper than #2 fuel oil (before adjusting for efficiency), which in turn is lower priced than electricity. This assumption is used by the CBA.

Based on applying the 10% rule, the natural gas prices offered to consumers in greenfield areas of the Maritimes are shown in Table 19.

Table 19

Assumed Natural Gas Prices for Maritime Consumers

Previous Fuel	Price per Unit	Current Fuel Price per MMBtu	Assumed Natural Gas Price per MMBtu
Residential #2	$0.60/litre	$15.46	$14.61
Commercial #2	$0.40/litre	$10.33	$9.76
Industrial #6	$0.20/litre	$5.04	$4.54

Note: Fuel oil prices based on long-term average of $24.00 $US/bbl.

Source: Gardner Pinfold Consulting Economists Limited.

The assumed commodity cost of natural gas ($4.55/MMBtu) is about 10% less than the price of #6 fuel oil. This is *before* any tolls that would apply to cover transportation (a

[11] 1 MMBtu is equal to 1,000,000 British Thermal Units. 1 MMBtu = 1.05 GJ, or the heat content of approximately 1,000 cubic feet of natural gas.

minimum of $0.69/MMBtu, assuming the M&NP lateral policy applies.). This would put the delivered cost of gas above #6 oil. Under these relative price assumptions and assuming no other pressures to convert, it is reasonable to infer that there would be no industrial conversions from #6 to natural gas purely on economic grounds.

Residential and commercial gas consumption starts in year two and follows the penetration rates assumed by EGNB in their plan for the parts of New Brunswick now served by gas. EGNB estimated conservative gas usage in the 20-year timeline and incorporated no growth rate in any of the consumer classes. Savings increase as the number of conversions increases across the study period.

Commercial users commence energy savings in Year 2 at $930,000, rising to about $7.9 million per year by Year 20, excluding the costs incurred in converting to natural gas. The study adjusts for conversion costs by reducing the energy savings by 10% over the first five years. Commercial energy use is split between three major sources: electricity at 54%, #2 fuel oil at 29%, and propane at 13%.

The residential sector energy savings in Year 2 are approximately $112,000. By Year 20, the energy savings in the residential sector grow to about $5.8 million, partially displacing electricity (62% of potential consumers), #2 fuel oil (26%), and wood (12%). The same 10% reduction in energy cost savings is applied over the first five years to cover the costs of conversion.

Energy Supply and Market Structure

Electricity dominates the residential space heating and hot water heating markets in the study area. A small number of companies service the residential fuel oil delivery market. Many communities (e.g., Atholville, Dalhousie) rely on fuel oil delivery from neighbouring communities. Miramichi and Belledune have the greatest number of fuel oil delivery companies.

Natural gas priced at least 10% lower than #2 fuel oil would make gas a competitive energy source based on price alone. However, the type and age of the heating equipment currently in use in the residential market will dictate whether consumers would be willing to switch to gas, given conversion costs. Converting oil-fired equipment to natural gas may be less costly than changing to natural gas from electric baseboard heating, for example. The exact nature of the electrical-heating market (baseboard versus forced air or hot water radiator) will be the deciding factor in the likely take-up rate of natural gas.

Businesses selling furnaces and appliances that use electricity or fuel oil would be largely unaffected by customers who switch to natural gas as a heating choice, since they can sell equipment for both energy types. Likewise, those industries focussed on service and repair of oil-related appliances can be trained to expand their market to include gas-fired appliances.

Economic, Social and Environmental Benefits

Impacts on local business can be evaluated in two ways: those businesses who will immediately benefit from the introduction of natural gas to the community, and those whose market activities suffer from increased competition in the energy market. Local businesses that can benefit from the introduction of gas will likely be involved in gas hook-ups and installation, gas appliance sales, and the servicing of gas customers. Fuel oil delivery companies are most likely to feel negative impacts after the introduction of gas.

Fuel oil currently has about 26% and 29% of the residential and commercial markets, respectively. The industrial sector's #2 fuel oil use is concentrated on three major establishments: one in Miramichi, one in Belledune, and one in Dalhousie. Heavy fuel oil is used at seven major establishments from Miramichi to Atholville.

Environmental benefits can be realized at a corporate level if switching to natural gas is less than the cost of mechanically reducing harmful emissions (such as SO_2 and NO_x) associated with the alternative fuel source (normally heavy fuel oil.) However, if conversion of heavy fuel oil using processes to natural gas is not a cost saving measure in energy or pollution abatement costs, it is unlikely that industry will invest in natural gas-fired equipment, unless required to do so by environmental regulations.

Changes in environmental regulations such as clean air policies which reduce the level of acceptable emissions of particulate matter and harmful chemicals can raise the cost of abatement to the point that it is no longer economical to remain with heavy fuel oil, thereby making natural gas a more attractive fuel. Where this has happened in the United States, more stringent regulations have forced industries to choose between investing to switch fuels, or paying to increase environmental emission controls. In some cases, industries have had to shut down because the costs of emission control were too high.

Regulatory Framework

Natural gas distribution and marketing are both under provincial jurisdiction in New Brunswick and are regulated by a Provincial public utilities board. New Brunswick has adopted a Cost of Service ("Rate of Return") model for distribution. Natural gas is an unbundled commodity in New Brunswick, separating distributors and natural gas marketers.

The situation in the rest of New Brunswick outside the study area provides some insight into what may occur in the study area should it receive gas service. Under the current regulatory framework, in areas with access to the main gas transmission line (not in Northeastern New Brunswick), natural gas is already a fuel source for a number of larger industries with single end-use franchises. The franchise agreement costs $50,000 and the proceeds go to defray Board expenses related to pipeline safety. There is some distribution in the larger urban centres such as Fredericton, as previously shown on Map 11.

Currently, Enbridge Gas New Brunswick holds the sole franchise to distribute gas to the population, but the unbundled nature of the market precludes EGNB from marketing its gas. EGNB, in its initial proposal, has committed to serving 70,000 customers in 23 communities around the province within 20 years. There are currently five licensed gas marketers in New Brunswick.

A single end use franchise has also been available for facility-specific industrial end users for an annual fee of $50,000, indexed to the consumer price index. The objective is to encourage large industrial customers to act as anchor loads in securing laterals and serves to satisfy the Province's desire to use the Maritimes and Northeast Pipeline lateral policy for as long as it is in effect. To the extent such franchises are taken up, they reduce the volume of gas supplied through a distribution system and hence the revenue potential for a distribution company considering investing in a distribution system in the nearby geographic area. On the other hand, at least the by-pass option facilitates the construction of laterals which might not otherwise occur.

DISTRIBUTION SYSTEM

Maritimes and Northeast Pipeline (M&NP) owns the pipeline originating in Country Harbour, Nova Scotia, which enters New Brunswick in Westmorland County and runs through to St. Stephen, New Brunswick, before serving the New England natural gas market. Enbridge Gas New Brunswick assumed in their distribution proposal that the larger industrial users (i.e. pulp mills) would take advantage of the single end-user franchise agreements in place in New Brunswick and obtain natural gas directly from the M&NP lateral. Smaller consumers would be served via distribution systems in place along the lateral.

The 1995 Neill & Gunter study estimated that the cost to construct a lateral from Westmoreland county to serve the Northeast region (from Moncton, north to Miramichi, Bathurst, Dalhousie, and extending westward to Edmundston via St. Leonard), approximately 567 km, would be approximately $184.2 million. This figure translates to about $325 per metre installed of 10-inch diameter lateral pipeline. Table 20 shows that the cost of installing pipe in Southern Ontario can vary from $243/m to $405/m US.

Table 20

Pipeline Installation Costs in Southern Ontario

Diameter	Cost per metre (1995 US Dollars)[12]	Cost per metre (1995 CDN Dollars)[13]
NPS 8	$243	$333
NPS 10	$270	$370
NPS 12	$300	$412
NPS 16	$405	$556

Source: Industrial Gas Technology Commercialization Centre, quoted in Neill & Gunter (1995)

For this case study, we can exclude the last segment from Campbellton to Edmundston since Edmundston is not in the case study area. Doing so decreases the pipeline distance by approximately 145 km, and the associated cost by about $47 million. So the estimated cost the case study lateral is about $137 million, based on approximately 422 km of NPS 10 pipeline. For the CBA, we assume that the lateral pipeline will be constructed in one season. For the distribution systems, the analysis assumes a seven years installation period, with 30% of the total distribution system completed in the first year, and the balance spread over the following six years.

The distribution system is comprised of the main unit costs that run underground through cities and towns, and City Gate station costs. Table 21 provides estimated costs for the study area. Further costs are incurred to bring natural gas to residences, businesses, and industries from mains.

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12 Source: Industrial Gas Technology Commercialization Center, as quoted in Neill and Gunter (1995)

13 Source: http://www.oanda.com Jan 11/95 to Dec. 31/95 Average exchange rate $US 1 = $CDN 1.37171

Table 21

Estimated Main Unit and Station Costs

Northeastern New Brunswick

Urban Area	Cost of Installing Distribution Main ($ CDN '000)	Station Costs ($ CDN '000)
Miramichi	6,800	855
Bathurst	4,390	855
Beresford	2,500	35
Belledune	829	300
Dalhousie	1,756	300
Campbellton	2,634	300
Total	18,909	2,645

Source: Enbridge Gas New Brunswick (1999).

The combined cost of constructing a lateral and distribution system in this area would be approximately $159 million. Operations and maintenance costs on pipelines were calculated as a function of pipeline distance (in the case of laterals) and on a per-customer basis (in the case of distribution).[14] Annual O&M costs for the lateral line and distribution system combine to a total of $1.1 million in Year 1, rising to approximately $2.3 million in Year 20.

Subsidy Regime

The Province of New Brunswick is committed to encouraging the construction of laterals and distribution systems that are economically justified. The province will not support the broad-based subsidies for lateral construction. Incentives could come as an aid-to-construct. The Province is also committed to looking to form partnerships with the private sector and the federal government in order to secure funding that will assist in the development and expansion of natural gas infrastructure.[15]

Cost-Benefit Analysis[16]

14 This is a commonly used approach. It was also used in the 1999 FGA Consultants report, "Study to Identify the Economic Impacts of a Natural Gas Pipeline to Prince Edward Island".

15 New Brunswick Energy Policy White Paper. New Brunswick Natural Resources and Energy, 2000.

16 The assumptions used in this study are made for economic analysis purposes. A commercial financial analysis would be likely to use a higher discount rate and would be concerned about municipal and other taxes.

The CBA considers construction costs, O&M costs and the cost of gas, compared with the social benefit of energy savings for all of the consumer classes. The net benefits are discounted over a period of 20 years to arrive at a Net Present Value (NPV). A positive NPV would indicate that the benefits gained by constructing and operating natural gas facilities outweigh the costs of the system. A negative NPV indicates that the system costs exceed the benefits of energy cost savings for the three user categories.

The analysis starts by conducting a purely financial analysis[17] which tests whether or not the revenues generated from the sale of gas cover the capital and operating costs of the system. The second step is to convert the financial analysis to a CBA by adding energy cost savings as a benefit accruing to the users of natural gas.

If the financial analysis NPV is positive, the proposed system would be commercially viable and could go ahead without an aid to construct. In cases where the financial NPV is negative, the proposed system may still be socially justifiable (on economic grounds) if the NPV from the CBA is positive, since that means the energy cost savings exceed the costs of the gas system. In this case, it would be in society's interest to provide an "aid to construct" or subsidy to cover part of the costs and facilitate the installation and operation of the system that would not take place on financial grounds alone.

Table 22 indicates the main elements of the financial/CBA.

The financial analysis shows that for the case study assumptions, the NPV is negative at all discount rates, indicating that the project would not be financially viable (Figure 4). Also, the study has ignored any municipal taxes that would increase costs and drive the NPV further negative.

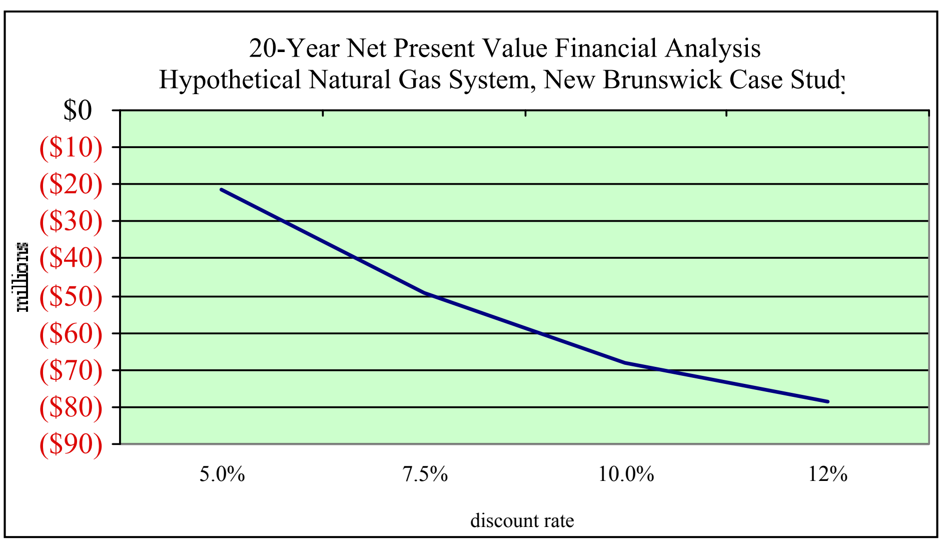
[17] This is a financial analysis conducted as part of an economic analysis. All capital costs are fully charged in the years in which they occur, rather than amortized. Taxes are ignored; including them would of course decrease the financial NPV.

Table 22

Main Elements of Financial and CBA

Item	Duration	Cost ($CDN)
Analysis Period	20 years	-
Construction Costs **Lateral**	First Year	137.0 million
Distribution System	Spread over first seven years	21.6 million
Total		158.6 million
Operating Costs (annual)	Annual from year 2	Start at about $1 million and grow to about $2.3 million
Conversion Rates	At the end of 20 years, 11,000 households, 1,800 commercial units and no industrial conversions based on price of gas and competing fuels.	Costs range from as low s $200 for propane forced air furnace to gas forced air to $7,000 for electric baseboard to gas forced air.
Cost of Natural Gas (annual)	Unit cost held constant at $Can 4.55 per Mmbtu	Total gas cost starts at about $1 million and grows to about $15 million
Energy Cost Savings (annual)	Increases as the number of conversions grows	Starts at about $940,000 and increases to $12 million by year 20
Discount Rate	5%, 7.5%, 10%, 12%	-

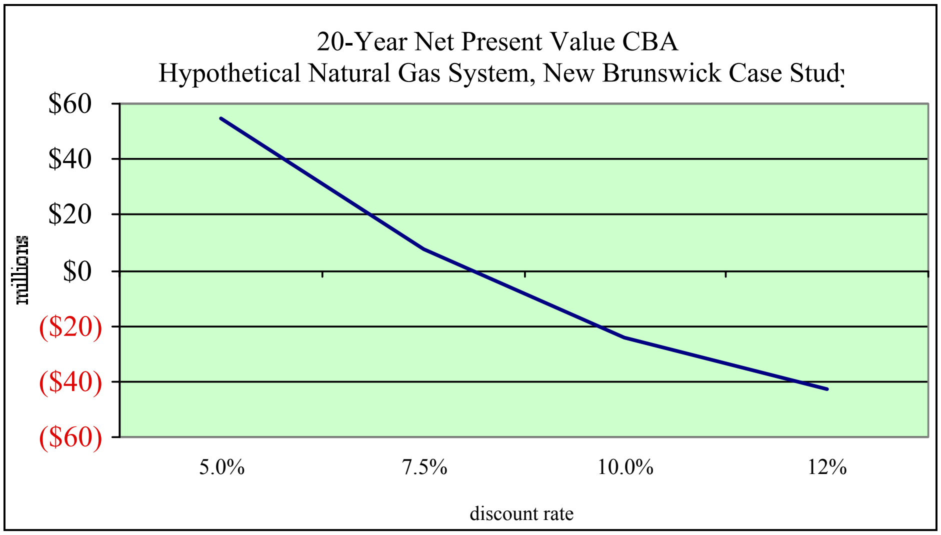
Figure 4



Source: Gardner Pinfold Consulting Economists Limited.

Adding the energy cost savings to convert the financial analysis to a CBA increases the NPV to a positive value ($10 million) at 7.5%. At rates above about 8% the NPV is negative (Figure 5).

Figure 5



Source: Gardner Pinfold Consulting Economists Limited.

The CBA measures the net benefit that customers experience in the form of savings on fuel costs, but does not include quantified values related to environmental benefits from the use of cleaner fuel. There could be other benefits such as industry attraction, industry retention, and intra-provincial (and intra-regional) market competition, but the results in Chapter 1 suggest these are not likely to be large. Nonetheless, should an actual analysis carried out for the area indicate that these or other benefits are likely to arise, then they should be quantified where possible, or at least described fully so that decision-makers can take them into consideration when preparing recommendations.

Sensitivity Analysis

Sensitivity analysis tests the impact on the NPV of changing the base case assumptions for key study variables. Table 23 shows the sensitivity results compared to the base case NPV of $10 million at the 7.5% discount rate. For instance, increasing capital costs by 20% causes the NPV to decrease to -$18 million, while reducing capital costs by 20% will increase the NPV to $39 million. The NPV is much less sensitive to changes in operating costs. The NPV is sensitive to changes in the energy cost savings. Increasing savings by 20%, which could be interpreted as the equivalent of an increase in the rate of conversions, or the same rate of conversions augmented by a growth in the market for gas, increases the NPV by about 120% to $22 million. A 20% decrease in energy savings reduces the NPV by 110% to -$1 million.

The sensitivity analysis results show that it would be important to investigate thoroughly the assumption used for capital costs and energy savings. Regarding the latter, it seems likely that a more favourable gas price that would support conversion by large industrial users converting natural gas from #6 fuel oil would bring about a substantial increase in energy cost savings. This is an area that would require detailed attention in any real application of the model as opposed to the hypothetical example developed in this study.

Table 23

Sensitivity of NPV to Changes in Key Variables

(in millions of Canadian dollars)

Variable	Increase Variable by 20%	Decrease Variable by 20%
Discount Rate: 7.5%; Base Case NPV = 10		
Capital Cost	(18)	39
Operating Costs	7	13
Energy Savings	22	(1)

note: (…) indicates negative value

Summary and Conclusions

This case study examines the feasibility of running a lateral from the current M&NP main gas transmission line north of Moncton to the Bathurst area, and then extending along the coast in northeast New Brunswick as far as the Campbellton area. Gas distribution systems would be installed to serve the customer base in the study area. A key assumption of the case study is that natural gas would be available at a price 10% less than the expected price for #2 and #6 fuel oil. Fuel oil prices were estimated based on an assumed price of crude oil of $US 24.00 per barrel. On this basis, it becames evident that natural gas would not be competitive with #6 fuel oil and that large industrial users are unlikely to convert to natural gas. The remaining market for natural gas consisted of residential households and commercial users including institutions. The study adopted the residential and commercial conversion rate assumptions used by Enbridge Gas New Brunswick for those parts of the province served by its distribution system.

The analysis of the greenfield sites in Chapter I found that access to natural gas did not generate any substantial economic development effects. This is because natural gas is only one of many competitive factors that influence the location of economic development including available labour supply, natural resources, access to markets and so on. Access to cheap gas could make a difference if gas were available at preferential rates near the source of supply as, for example, with the Sable Offshore Energy gas in Guysborough County, Nova Scotia. However the source of supply is not in the case study area and in any event, although the gas is less expensive than some alternative energy sources, the gas is not cheap in an absolute sense. Hence, the only quantitative benefit of access to natural gas is the potential energy saving.

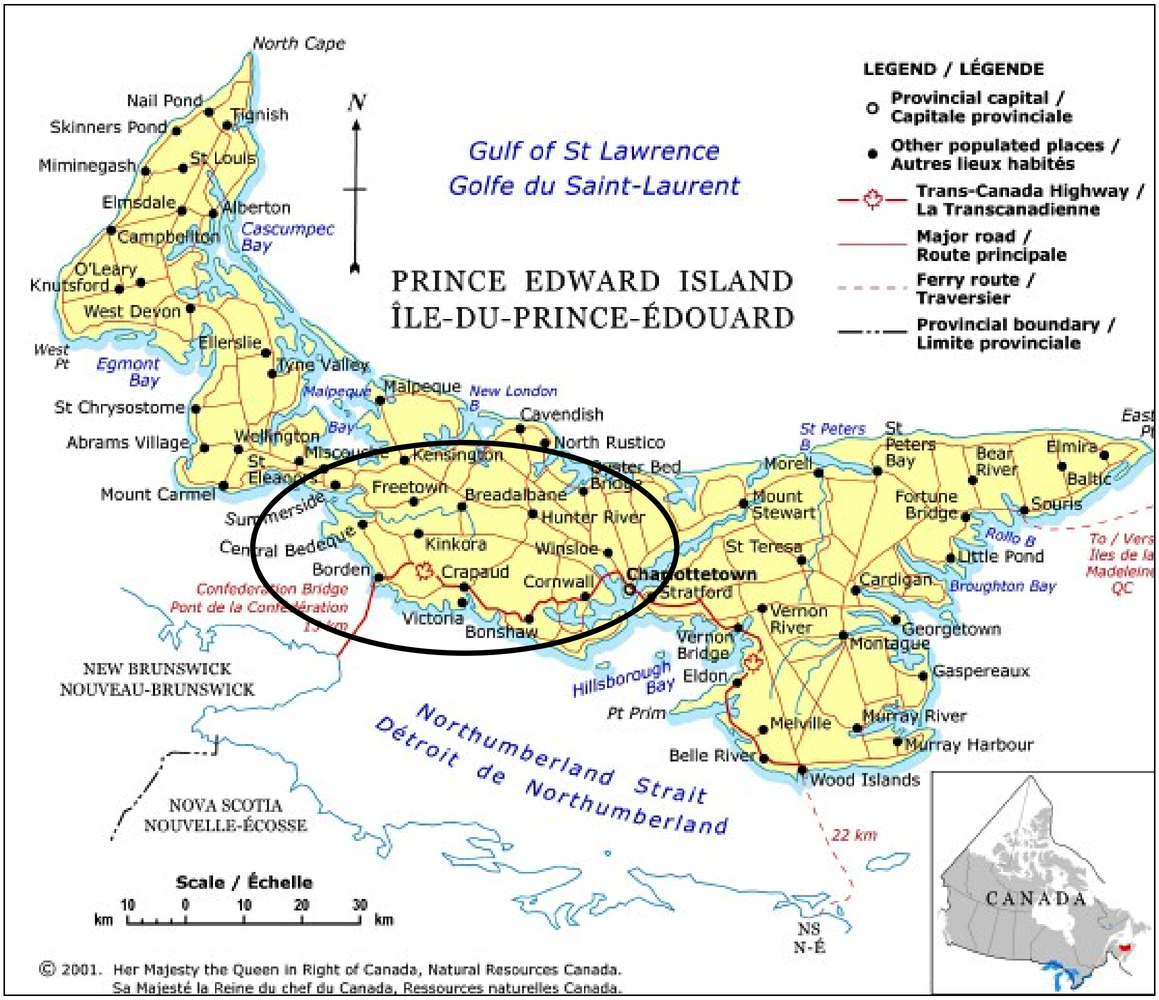
The case study analysis is carried out for a 20-year period. The combined cost of constructing a lateral and distribution system for the study area is estimated to be $159 million. Operating costs start in the second year at about $1 million and grow to about $2.3 million. Natural gas is assumed to cost $4.55 per MMBtu over the study period. The financial analysis indicates a NPV above -$70 million at discount rates over 10%, so the system is not financially viable. Energy cost savings are the substantive benefit arising from access to natural gas. These are estimated to start at about $940,000 in the second year and increase to $12 million annually by year 20. Including the energy cost savings in the CBA results in a NPV of $10 million at the 7.5% discount rate. The NPV turns negative at rates over 8%. These results are relatively weak and do not lend support for providing an aid-to-construct. On this basis, lateral and distribution system examined in this case study does not pass the CBA test and there is no economic basis to support its implementation.

3. Prince Edward Island

This case study covers an area in Prince Edward Island stretching from Charlottetown to Summerside. The outlined area on Map 12 shows the complete study area.

Map 12

Prince Edward Island Case Study Area



In 2001, Prince Edward Island had a population of over 138,000, increasing less than 1% from 2000[18]. The province's final energy demand in 2000 was approximately 24.3 petajoules, or 23 million MMBtu. Of this demand, 39% was for transportation, 26% for residential and agriculture, 11.9% for industrial, and 10.3% for manufacturing.

The Prince Edward Island study area contains the cities of Summerside, Charlottetown (including Stratford and Cornwall), and two agri-food industries near Borden-Carlton (near the Prince Edward Island terminus of the Confederation Bridge.) Charlottetown and Summerside account for over 75% of the province's population. Both major cities show positive growth rates between the 1991 and 1996 census.

18 Statistics Canada, CANSIM II table 0051-0001

Provincial exports (international) of $679 million in 2000 were led by agricultural and fishing products (72%), followed by machinery and equipment (12%), and special transactions (9%). Potatoes accounted for 84.4% ($155 million) of total crops (based on farm cash receipts) in 2000, down from 86.7% ($192 million) in 1999[19].

The area around Borden-Carleton is rural in nature, but has two major manufacturing establishments with relatively high energy demand. The McCain Foods plant in Borden employs approximately 390, while the Cavendish Farms facility in the New Annan area (near Kensington) employs approximately 700. Other than these facilities, residential and commercial/institutional customers in Summerside and Charlottetown would be the main users of natural gas.

Table 24 shows the relevant population data for the Prince Edward Island study area. The dwelling units housing this population provide an indication of the residential market for natural gas in the study area (Table 25).

Table 24

Prince Edward Island Study Area, Population Data

	Population (1996)	Population (2001)
Prince Edward Island		138,514
Prince County	45,260	
Summerside	14,525	14,654
Queen's County	73,720	
Charlottetown	32,530	32,245
Cornwall	4,291	4,412
Stratford	5,869	6,314

Source: Statistics Canada 1996 Census, 2001 Census.

19 Province of Prince Edward Island. Twenty-Seventh Annual Statistical Review. May, 2001.

Table 25
Private Occupied Dwellings in Selected Areas,
Prince Edward Island Study Area

Area	# Dwelling Units
Borden-Carleton	305
Summerside	5,485
Total, Prince County	15,720
Charlottetown	12,935
Cornwall	1,435
Stratford	2,402
Total, Queen's County	25,425
Total, PEI	47,960

Source: Statistics Canada Census, 1996.

Area Energy Objectives

The study area is divided into two urban communities whose main industries are in the tertiary sector (i.e. service industries, retail, etc.) and the two agro-food industries in Borden and New Annan. Electricity, fuel oil (#2 and #6) and to a lesser extent wood are the main energy sources. Diversifying the range of energy alternatives including finding a cheap, clean fuel source for commercial and residential energy users, and remaining competitive with off-Island industries in New Brunswick (in the agro-food sector) are key energy objectives.

As well, the province would welcome the opportunity to attract new industry and encourage the expansion of current manufacturing processes. The possibility of expanding electrical generation on the Island would help serve the growing energy use on the island, offset current energy import costs, as well as assist in justifying the construction of a natural gas lateral to Prince Edward Island.

Historically the province has been heavily dependent on petroleum products for space and water heating in the residential and commercial sectors, and bunker C in the industrial sector. Natural gas could be very competitive with home heating oil, and possibly with #6 oil in industrial processes.

Economic Growth and Development

Prince Edward Island's electricity supply is a mix of imported electricity purchased from NB Power in New Brunswick and other sources, local thermal generation by Maritime Electric using diesel fuel mainly as back-up and peaking power supply, and recently wind turbine generation (on the west side of the Island).

Increased demand for electricity on the Island (through growth of industry and the residential and commercial sectors) will eventually require the installation of a second subsea cable to bring power to the Island. This raises the prospect that natural gas could be used to fuel a combined cycle thermal generation facility to produce electricity for local demand, thereby avoiding the cost of laying a second subsea cable from New Brunswick. Another part of the rationale is that this demand for natural gas would play an important part in providing an anchor load for a pipeline system for natural gas, as well as serving the growing demand for on-Island electricity. While this is a possibility, use of natural gas by a combined cycle facility is surrounded by uncertainty, particularly with respect to overall capital costs and potential revenues from surplus electricity sales. In the absence of cost and revenue estimates this potential anchor load is not included in the analysis.

In the industrial sector, natural gas would likely compete heavily with industrial #2, and possibly with #6 fuel oil. FGA Consultants (1999) concluded in their study that natural gas could possibly encourage industrial expansion in the two agro-food industries, but that expansion of the potato processing would depend more heavily on the expansion of potato growing acreage than on fuel savings costs.

Industry/Anchor Load

The key potential anchor load on the island at present comes from McCain Foods in Borden and Cavendish Farms in New Annan. Together, recent estimates[20] indicate they would use approximately 1.45 million MMBtu per year. Currently, they consume chiefly #6 fuel oil. The industrial sector depends on petroleum products for 69% of its energy. Whether they would convert depends on whether conversion costs could be recaptured through fuel cost savings within a 3-5 year period.

The assumed price of natural gas for #6 fuel oil users ($5.04 per MMBtu) is not likely to be attractive enough to induce industry to convert. It is higher than the assumed commodity cost of gas (about $4.55) *before* any tolls that would apply to cover transportation costs (which would bring the delivered cost above the alternative). Hence for this study, in light of the relative prices *and* conversion costs, we have assumed there would be no industrial conversions to gas.[21] It is important to note that this is a conclusion based on current market conditions and could change in the future. Should conditions support conversion, the increased load on the system would clearly improve its financial viability.

For the small and medium industrial sector (those using #2 fuel oil), take-up rates are assumed to be around 85% at the end of 20 years.[22] Of those converting, 55% would take

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[20] FGA Consultants, Ltd. 1999. "Study to Identify the Economic Impacts of a Natural Gas Pipeline to Prince Edward Island".

[21] This conclusion is consistent with that arrived at by FGA Consultants in its 1999 study.

[22] FGA Consultants Ltd, 1999 op. cit.

up natural gas over the first five years. The remaining 30% would convert slowly over the following 15 years.

If the proposed gas-fired generating station proves to be viable, it would greatly enhance the economics of a lateral to PEI. The project was not incorporated in the PEI case study because the consultants were not provided with the financial data needed to carry out the analysis. This information is at a preliminary stage of development and is considered too sensitive to be made public. Also, natural gas is not competitive with #6 fuel oil at projected crude oil prices, and this study consequently assumes there will be no large industry conversions. For the small and medium industrial sector, take-up rates are assumed to be around 85% at the end of 20 years.[23] Of those converting, 55% would take up natural gas over the first five years. The remaining 30% would convert slowly over the following 15 years.

Commercial/Residential Market

At present, petroleum products supply 62% of the energy demand for commercial establishments and 79% of residential energy demand. The main source is #2 fuel (92%). Over 20 years, FGA[24] estimated that 50% of current residents and 65% of commercial customers would convert to natural gas.

The 50% take up rate assumed by FGA Consultants is a conservative figure, and applies only to existing residential market. It is assumed that 85% of new construction would use natural gas as a heating fuel. In the commercial sector, it is assumed that 75% of new facilities would use natural gas.

Average energy demand for residential and commercial users is estimated to start at around 50 GJ/year (rising to 115 GJ/year) and 1,650 GJ/year, respectively. While initially some residential consumers will use natural gas for heating purposes only, it is assumed that as the market for natural gas grows, the proportion of natural gas-fired appliances outside of the space-heating market will also grow.

Gas sales may be slightly understated since the analysis assumes that no wood users will convert to gas because there would be energy cost savings at the assumed prices and efficiencies for both wood and natural gas. It is still possible that some wood user might switch because of the greater convenience of using gas, but this has not been factored into the analysis. Since wood accounts for about 12% of current residential energy consumption on the Island and convenience would be important only for some of these users, the effect is not likely to be great.

[23] FGA Consultants Ltd, 1999 op. cit.

[24] Ibid.

Conversion Costs – Residential Consumers

Residential consumers who have a central heating system in their dwelling are most apt to switch to natural gas when their current equipment reaches the end of its useful life. The conversion costs in Table 26 outline the average costs for these consumers to install natural gas-fired equipment.

Table 26

Natural Gas Conversion Costs

Selected Heating Systems

Equipment	Natural Gas System	Cost to Consumer for Conversion
Forced Air Oil Furnace	Force Air Furnace	$1,800 - $3,500
Oil Hot Water Radiant	Hot Water Radiant	$1,800 - $4,000
Electric Forced Air Furnace	Forced Air Furnace	$2,400 - $3,400
Electric Baseboard	Forced Air Furnace	$4,000 - $7,000
Electric Baseboard	Space Heaters / Fireplaces	$1,200 – $2,500
Air Tight Wood Stove	Fireplace	$1,600 – $2,500
Forced Air Wood Stove	Forced Air Furnace	$1,800 - $3,500
Propane Forced Air Furnace	Forced Air Furnace	$200 - $400

Source: Maritimes NRG Application.

Smaller commercial energy users (i.e. small retail outlets, offices, etc.) will also choose to switch to natural gas at the end of the useful life of their current heating equipment. Commercial customers who use propane can affordably convert to natural gas as soon as it is made available. Because the majority of residential and commercial users heat with petroleum products, they would likely have affordable options when converting to natural gas.

Energy Cost Savings

Energy cost savings to the consumer can be calculated by comparing the efficiency-adjusted price per heat unit (often calculated per MMBtu[25]) of the currently used fuel, with the effective price per heat unit of natural gas. Efficiency adjusted prices take into the difference energy content per unit of heating fuels and the relative efficiency of the burners (e.g., furnaces, water heaters, etc.).

[25] 1 MMBtu is equal to 1,000,000 British Thermal Units. 1 MMBtu = 1.05 GJ, or the heat content of approximately 1,000 cubic feet of natural gas.

In the case study, consumer cost savings were calculated by multiplying the number of potential gas hookups (residential, commercial and industrial) by the cost savings per consumer (a function of energy demand and effective price difference between fuels).

The study assumes that competitively priced natural gas would be about 10% cheaper than #2 fuel oil (before adjusting for efficiency), which in turn is lower priced than electricity. This assumption is used by the CBA. Based on applying the 10% assumption, the natural gas prices offered to consumers in greenfield areas of the Maritimes are shown in the table below.

Assumed Natural Gas Prices for Maritime Consumers

Previous Fuel	Price per Unit	Current Fuel Price per MMBtu	Assumed Natural Gas Price per MMBtu
Residential #2	$0.60/litre	$16.24	$14.61
Commercial #2	$0.40/litre	$10.85	$9.76
Industrial #6	$0.20/litre	$5.04	$4.54

Note: Fuel oil prices based on long-term average of $24.00 $US/bbl.

Source: Gardner Pinfold Consulting Economists Ltd.

The assumed commodity cost of natural gas ($4.55/MMBtu) is about 10% less than the price of #6 fuel oil. This is *before* any tolls that would apply to cover transportation (a minimum of $0.69/MMBtu, assuming the M&NP lateral policy applies.). This would put the delivered cost of gas above #6 oil. Under these relative price assumptions, given conversion costs, and assuming no other pressures to convert, it is reasonable to infer that there would be no industrial conversions from #6 to natural gas purely on economic grounds.

Energy Supply and Market Structure

Energy in the residential and commercial markets is supplied mainly by home heating oil. At present, approximately 10 companies deliver home heating oil in the cities of Summerside and Charlottetown. Heavy fuel oil is the main fuel source for the large industrial sector.

The Island Regulatory and Appeals Commission (IRAC) currently determines the price of petroleum products on the Island, and as such will play a role in determining the degree of competitiveness in natural gas pricing.

Currently, the province of PEI purchases electricity from NB Power in New Brunswick, and markets it to Island consumers at a price within 10% of the market price of electricity in New Brunswick. Some discussion has been occurring on the Island about increasing the on-island electrical generating capacity but this type of load is not included in the analysis.

As well, space-heating demand for approximately 80 commercial establishments and offices is serviced by the "Trigen Energy from Waste" facility, which supplies district heating in the form of hot water, piped from the north-east of the downtown core. The facility generates steam through the burning of waste wood product and municipal solid waste, but also consumes a certain amount #2 fuel oil. The facility also sells a small amount of electricity to the grid. Energy from this system is not likely to be displaced by the introduction of natural gas, although the facility may be a potential user of natural gas.

Economic, Social and Environmental Benefits

Impacts on local business can be evaluated in two ways: those businesses who will immediately benefit from the introduction of natural gas to the community, and those whose market activities suffer from increased competition in the energy market. Local businesses who can benefit from the introduction of gas will likely be involved in gas hook-ups and installation, gas appliance sales, and the servicing of gas customers. Fuel oil delivery companies are most likely to feel negative impacts after the introduction of gas.

Environmental benefits can be realized at a corporate level if switching to natural gas is less than the cost of mechanically reducing harmful emissions (such as SO_2 and NO_x) associated with the alternative fuel source (normally heavy fuel oil.) However, if conversion of heavy fuel oil using processes to natural gas is not a cost saving measure in energy or pollution abatement costs, it is unlikely that industry will invest in natural gas-fired equipment, unless required to do so by environmental regulations.

Changes in environmental regulations, such as clean air policies to reduce the level of acceptable emissions of particulate matter and harmful chemicals, can raise the cost of pollution abatement to the point that it becomes cost effective to convert to natural gas from heavy fuel oil. This has happened in the United States, where more stringent regulations have forced industries to choose between investing to switch fuels, or paying to increase environmental emission controls.

Regulatory Framework

As previously noted, the Island Regulatory and Appeals Committee oversees utilities on the Island. IRAC approves the price of petroleum products on the Island, as well as monitors the price and regulation of electric power, telephone, and sewerage services.

It is not known what type of distribution regulation would be introduced on Prince Edward Island. Currently New Brunswick is regulating with a cost of service model, and some potential natural gas distributors in Nova Scotia are advocating a cost of service based model. As well, the regulatory authority would have to rule on the possibility of single end-use franchises, where a large user can acquire gas directly from the lateral pipeline rather than through a local distributor company, as is the case in New Brunswick. Such agreements are of interest to large industrial users since they generally mean lower cost of gas. Distributor companies are of course not keen on them since they mean the loss of substantial gas sales. With a high natural gas demand coming from two large industrial users in Prince Edward Island, single-end user franchises may become a regulatory issue.

Distribution System

Transporting gas to the Island involves the construction of a lateral pipeline through south-east New Brunswick, crossing the Northumberland Strait, and splitting to run to both Charlottetown and Summerside, and feeding the industrial load near Borden. Cost estimates by FGA consulting (1999) show an average cost of about $316.00 per metre of installed pipeline, varying from NPS 8 in New Brunswick and on the PEI side of the Strait, and NPS 6 to Charlottetown and Summerside. The cost of running the pipeline through the Strait is approximately $18 million, making the total lateral costs $42.2 million, installed. Annual Operations and Maintenance (O&M) costs are estimated at $2,500 per kilometre for the 125-kilometre line.

Distribution systems in Summerside and Charlottetown are estimated at $21.5 million, with annual O&M costs at about $100 per customer. Annual O&M costs on the distribution system in the first year of distribution are $8,000, rising to $1.6 million by Year 20

The total fixed cost of constructing the lateral and distribution systems is approximately $64 million. Total O&M costs are variable and will grow with the distribution system.

Subsidy Regime

It is possible that a subsidy, often called an "aid to construct", could be required for construction of the lateral and distribution systems. This will be the case when the sales revenue generated from transportation tolls on the system are insufficient to cover the capital and operating costs and generate an acceptable rate of return on investment for the lateral and distribution companies. The financial analysis and cost-benefit analysis reported in the next section provide the test for whether or not an aid to construct can be justified economically.

Cost-Benefit Analysis[26]

The CBA considers construction costs, O&M costs and the cost of gas, compared with the social benefit of energy savings for all of the consumer classes. The net benefits are discounted over a period of 20 years to arrive at a Net Present Value (NPV). A positive NPV would indicate that the benefits gained by constructing and operating natural gas facilities outweigh the costs of the system. A negative NPV indicates that the system costs exceed the benefits of energy cost savings for the three user categories.

The analysis starts by conducting a purely financial analysis[27] which tests whether or not the revenues generated from the sale of gas cover the capital and operating costs of the system. The second step is to convert the financial analysis to a cost-benefit analysis by adding energy cost savings as a benefit accruing to the users of natural gas.

If the financial analysis NPV is positive, the proposed system would be commercially viable and could be expected to go ahead. In cases where the financial NPV is negative, the proposed system may still be socially justifiable (on economic grounds) if the NPV from the Cost-Benefit analysis is positive. In the CBA, energy cost savings are incorporated in the analysis, adding to revenue generated from the sale of gas. If the NPV were positive, it would be in society's interest to provide an "aid to construct" or subsidy to cover part of the costs and facilitate the installation and operation of the system that would not take place on financial grounds alone.

The financial analysis shows that for the case study assumptions (Table 27), the NPV is positive at all discount rates (Figure 6).[28] A commercial analysis would use discount rates in the 11-13% range, in line with rates approved by regulators. The project would be marginally acceptable at these rates, turning negative in the 13% range.

[26] The assumptions used in this study are made for economic analysis purposes. A commercial financial analysis would be likely to use a higher discount rate (the effect of which is similar to shortening the time frame of the analysis) and would be concerned about municipal and other taxes.

[27] This is a financial analysis conducted as part of an economic analysis. All capital costs are fully charged in the years in which they occur, rather than amortized. Taxes are ignored; including them would of course decrease the financial NPV.

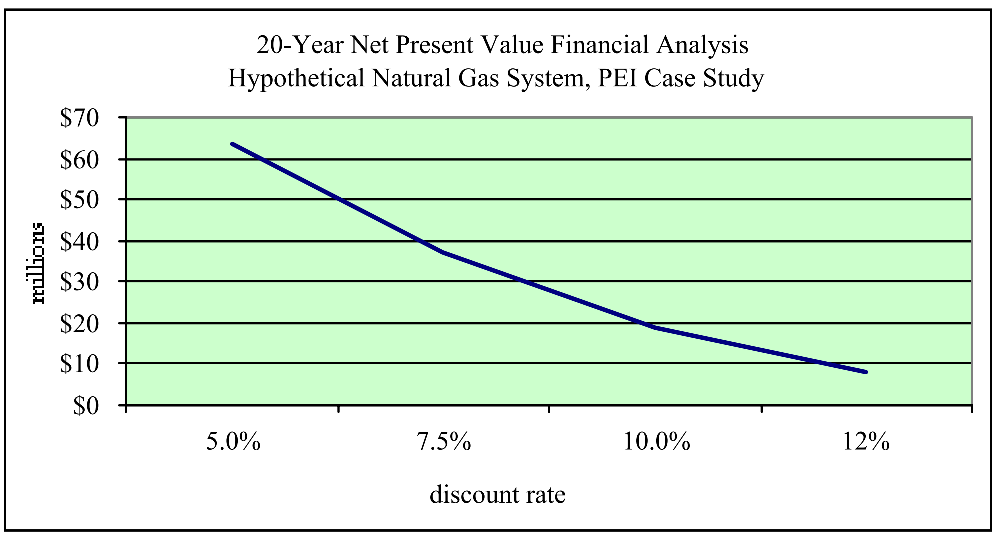
[28] The conclusion that the PEI case yields a positive financial result runs counter to the conclusion reached in the FGA study. This is explained by a difference in approach between the studies. FGA determined viability by incorporating only toll revenues in the analysis. This is appropriate for an assessment of a lateral. In this case study, we incorporate all revenues from the sale of gas. The revenue is not limited to the regulated portion of the burner-tip price (transportation), but captures the full economic value based on alternative fuel prices. Since this study is testing the overall economics of the system that provides access to natural gas, we are not concerned with how revenue is distributed among the system components – producers, transmission company, distributor and marketers.

Table 27

Main Elements of Financial and Cost-Benefit Analysis

Item	Duration	Cost ($CDN)
Analysis Period	20 years	-
Construction Costs **Lateral**	First Year	42.2 million
Distribution System	Spread over first seven years	21.5 million
Total		63.7 million
Operating Costs (annual)	Annual from year 2	Start at about $620,000 and grow to about $1.9 million
Conversion Costs	50% of current residents and 65% of commercial establishments will convert to natural over 20 years	Costs range from $200 for propane forced air to natural gas forced air to as much as $7,000 for electric baseboard to natural gas forced air
Cost of Natural Gas (annual)	Unit cost held constant at $Can 4.55 per MMbtu	Total gas cost starts at about $249,000 and grows to about $14.3 million
Energy Cost Savings (annual)	Increases as the number of conversions grows	Starts at about $285,000 and increases to $6.2 million by year 20
Discount Rate	5%, 7.5%, 10%,12%	-

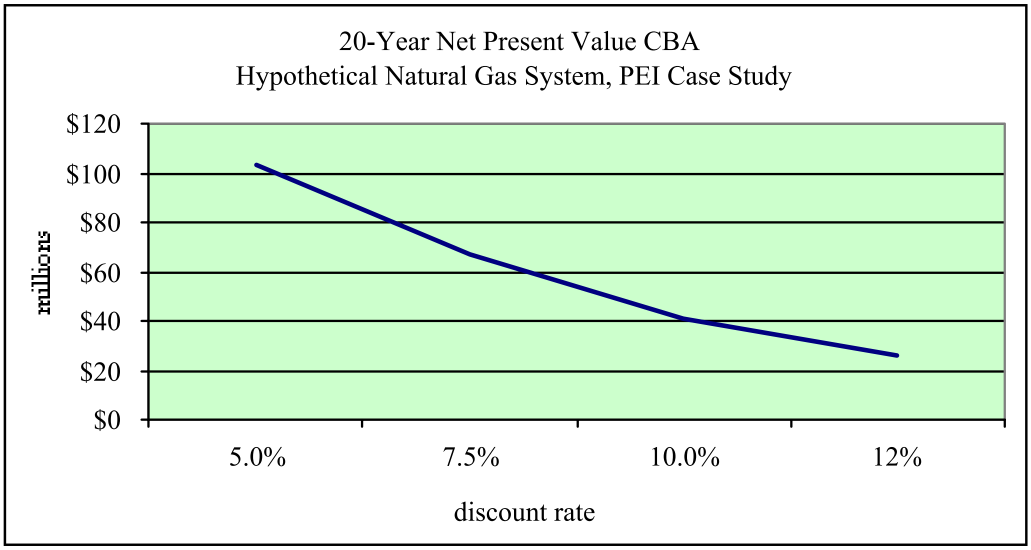
Figure 6



Source: Gardner Pinfold Consulting Economists Limited

Adding the energy cost savings to convert the financial analysis to a cost-benefit analysis increases the NPV substantially to $67 million at the 7.5% discount rate. At 10%, the NPV remains positive at $41 million (Figure 7).

Figure 7



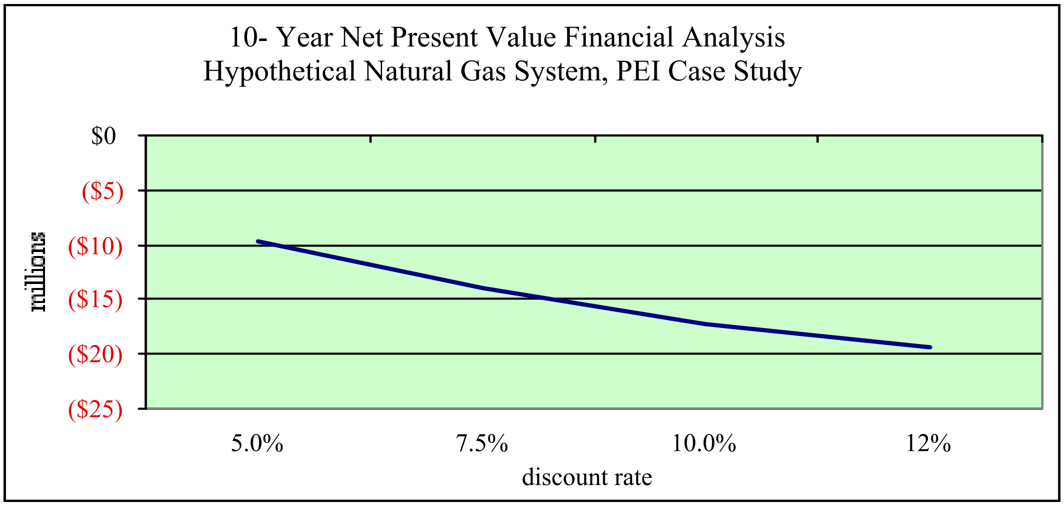
Source: Gardner Pinfold Consulting Economists Limited.

The CBA measures the net benefit that customers experience in the form of savings on fuel costs, but does not include quantified values related to environmental benefits from the use of cleaner fuel. There could be other benefits such as industry attraction, industry retention, and intra-provincial (and intra-regional) market competition, but the results in Chapter I suggest these are not likely to be large.

Sensitivity Analysis

Sensitivity analysis tests the impact on the NPV of changing the base case assumptions for key study variables the time frame for the analysis. The results are sensitive to the length of the analysis period. Reducing the time frame to 10 years from 20 years results in a negative NPV at all three discount rates (Figure 8). This indicates that under the assumptions used, introduction of natural gas to Prince Edward Island is may not be commercially attractive if the investor expects to recover capital costs within a 10-year period. A local distribution company may be seeking a higher rate of return, one that would yield a positive NPV in less than 10 years.

Figure 8



Source: Gardner Pinfold Consulting Economists Limited.

Table 28 shows the sensitivity results around the base case when alternative factors are varied. For instance, increasing capital costs by 20% causes the NPV to decrease to $57 million, while reducing capital costs by 20% will increase the NPV to $76 million. The NPV is much less sensitive to changes in operating costs. The NPV is sensitive to changes in the energy cost savings. Increasing savings by 20%, which could be interpreted as the equivalent of an increase in the rate of conversions, or the same rate of conversions augmented by a growth in the market for gas, increases the NPV to about $72 million. A 20% decrease in energy savings reduces the NPV to $61 million.

The sensitivity analysis results show that the steady accumulation of energy cost savings over the study period is sufficient to withstand a substantial increase in costs or reduction in the level of energy costs savings and still yield a strong positive NPV. A more favourable gas price would support conversion by large industrial users to natural gas from #6 fuel oil and this would bring about a substantial increase in energy cost savings. This is an area that would require detailed attention in any real application of the model as opposed to the hypothetical example developed in this study.

Table 28

Sensitivity of NPV to Changes in Key Variables

Base Case 20 Year Analysis (millions of Canadian dollars)

Variable	Increase Variable by 20%	Decrease Variable by 20%
Discount Rate: 7.5%; Base Case NPV = $67 million		
Capital Cost	57	76
Operating Costs	64	78
Energy Savings	72	69

SUMMARY AND CONCLUSIONS

This case study examines the feasibility of running a lateral from the current M&NP main gas transmission line in New Brunswick, across the Northumberland Strait with a landfall near the Confederation Bridge, and splitting to run to both Charlottetown and Summerside, and feeding the industrial load near Borden. Gas distribution systems would be installed to serve the customer base in this study area.

A key assumption of the case study is that natural gas would be available at a price 10% less than the expected price for #2 and #6 fuel oil. On this basis, it became evident that natural gas would not be competitive with #6 fuel oil and that large industrial users would not convert to natural gas. Residential households and commercial users including institutions comprise the market of current energy consumers who would convert to natural gas. The case study used the residential and commercial conversion rate assumptions adopted by FGA Consultants Ltd. in their 1999 study.

The analysis of the greenfield sites in Chapter 1 found that access to natural gas did not generate any substantial economic development effects. This is because natural gas is only one of many competitive factors that influence the location of economic development including available labour supply, natural resources, access to markets and so on.

Access to relatively inexpensive gas could make a difference if gas were available at preferential rates near the source of supply as, for example, with the Sable Offshore Energy gas in Guysborough County, Nova Scotia. However the source of supply is not in the case study area and in any event, although the gas is less expensive than the alternative energy sources, the gas is not cheap in an absolute sense. Hence, the only quantitative benefit of access to natural gas is the energy savings. It could be said that having access to gas will help to maintain a level playing field between the study area that is currently without gas and other parts of New Brunswick and Nova Scotia that have or soon will have gas service.

The analysis is carried out for a 20-year period. The combined cost of constructing a lateral and distribution system for the study area is estimated to be about $64 million. Operating costs start in the second year at about $620,000 and grow to about $1.9 million. Natural gas is assumed to cost $4.55 per MMBtu over the study period. The financial analysis indicates a NPV of about $8 million at a 12% discount rate, so the system is in principle financially viable (though as noted, the lengthy pay-back period may make the project unattractive). Energy cost savings are the substantive benefit arising from access to natural gas. These are estimated to start at about $285,000 in the second year and increase to an annual value of $6.2 million by year 20. Including the energy cost savings in the CBA results in a NPV of $67 million at a 7.5% discount rate.

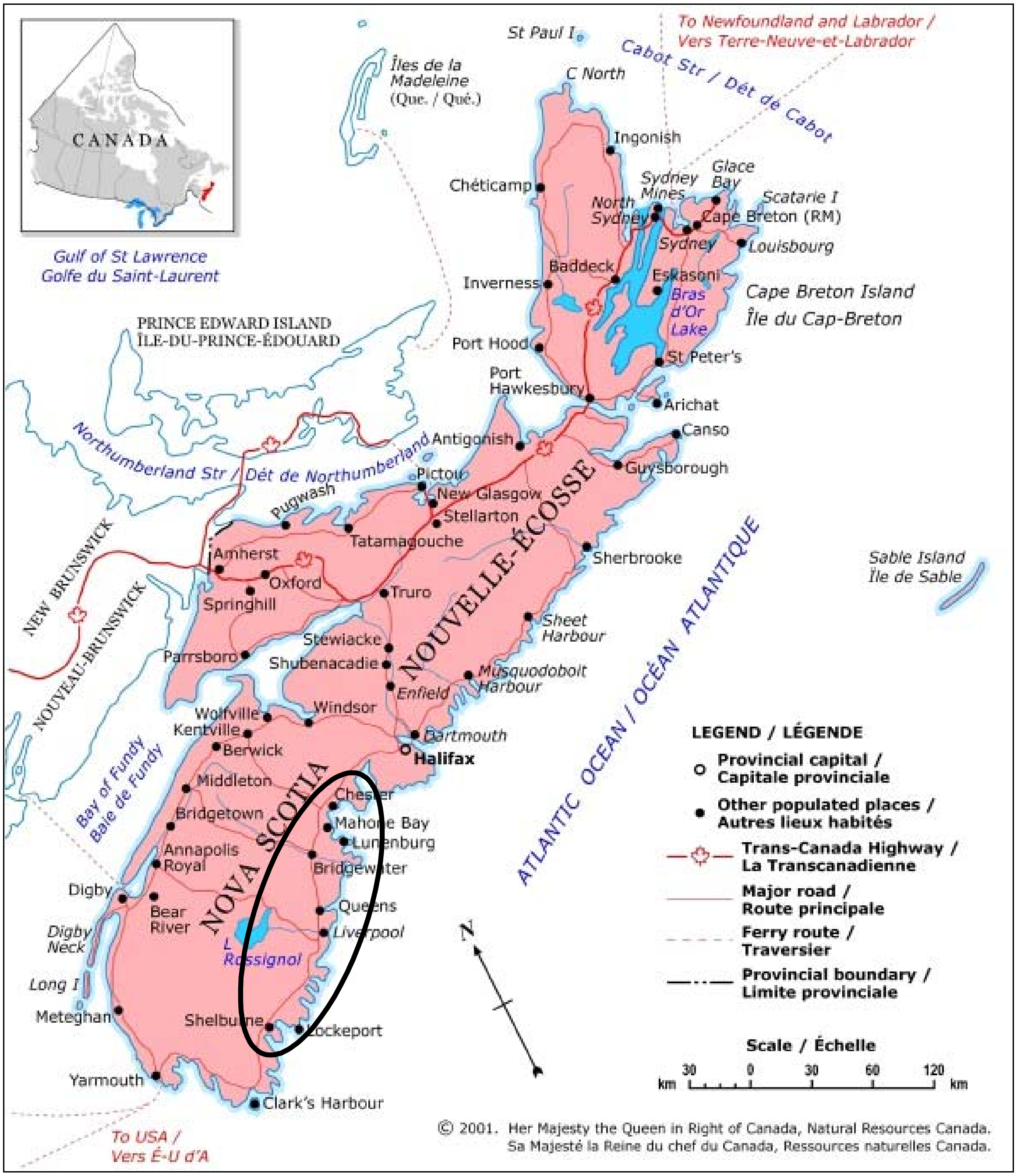
4. NOVA SCOTIA

Study Area

This case study covers an area in Nova Scotia land stretching from East Chester to Shelburne. The outlined area on Map 13 shows the complete study area.

Map 13

Nova Scotia Case Study Area



The Nova Scotia case study area includes five urban communities on the south shore in Lunenburg, Queens and Shelburne counties, as well as a two large industrial users in those counties (see preceding map). The three counties have a mixture of rural and urban population, with the urban centres all close to the coastline (settled due to the high importance and historical reliance on the fishing and fish processing industry). Though still heavily dependent on the fishery, the region is characterized by a diversified economy with a range of industrial, commercial, and tourism-related activities. Table 29 shows the relevant study area population data.

Table 29

Nova Scotia Study Area, Population Data

	Population (1996)	Population (2001)	% of County Population (1996)
Nova Scotia	909,282	908,007	
Lunenburg County	*49,100*		
Mahone Bay	1,017	991	2%
Lunenburg	2,599	2,568	5%
Bridgewater	7,351	7,621	15%
Queen's County	12,000		
Liverpool	3,048		25%
Shelburne County	*16,900*		
Shelburne	2,132	2,013	12.4%

Source: Nova Scotia Statistical Review (2001), Statistics Canada Census 1996, Census 2001.

Provincial Energy Demand

Primary energy supply in Nova Scotia is dominated by oil (62%), followed by coal (31%), biomass (6%), and Hydro (1%)[29]. In 1997, end-use energy demand was about 157 million MMBtu. (Table 30) About sixty percent of this end-use demand is in the residential, commercial/institutional and industrial sectors. Since Sable Gas has been introduced into the province, it has been used in some industrial applications (three uses near the SOEI landfall and NS Power's Tufts Cove generating station in the Halifax Regional Municipality).

29 1999 statistics from Nova Scotia Energy Strategy, Volume 1.

Table 30

Nova Scotia End Use Energy Demand by Sector, 1997

Sector	Demand	
	million MMBtu	%
Residential	34.7	22.2
Commercial/Institutional	31.9	20.3
Industrial	26.7	17.0
Transportation	63.5	40.5
Total	156.8	100.00

Source: Statistics Canada, Cat. No 57-003, 1997.

In 1999 and 2000, Nova Scotia Power Incorporated (NSPI) carried out a $24 million project to convert the Tufts Cove generating station to dual fuel capability, allowing the station to generate electricity using either #6 oil or natural gas. The Tufts Cove station represents about 15% of NSPI's total generating capacity (Nova Scotia's Energy Strategy, Vol. 2). Oil and natural gas comprise about 25% of NSPI's overall generation, while 58% of facilities are coal-fired (Emera 2001 Annual Report). Natural gas rose as a source of energy for NSPI from 0.4% in 2000 to 9.7% in 2001.

Area Energy Objectives

The main economic activities in the study area are in the manufacturing and natural resources sector. Beyond this, service, retail and tourism are important industries.

Currently, the main manufacturing processes in the area are meeting their thermal energy demand through the use of #2 and #6 fuel oil, and steam from a cogeneration facility. Future economic development plans include support for the creation of more small and medium-sized businesses, as well as expansion of value-added industry.

Regional development agencies believe that the presence of natural gas in the area will spur development in the manufacturing industry, as well as offer a low-cost fuel for existing industries and satisfying residential and commercial needs. Natural gas in the area would serve two purposes:

- To retain the current industrial and manufacturing base, and provide a diversity of energy supply to potential industries which may already be looking to locate in the area; and,
- To increase the region's competitiveness (among other regions in Nova Scotia and the Maritimes) for attracting business and expanding their own economic base. With the introduction of new industry is the prospect of spin-off, support, and value-added industrial activity.

Economic Growth and Development

The main objective for the region is to retain existing industry and attract new industry. A secondary supporting objective is to maintain a level playing field with other communities and regions who already have natural gas. At present, it does not appear that the viability of the existing industrial base is being compromised by the prices paid for #2 and #6 fuel relative to natural gas. Nonetheless, there may be a potential for energy savings should natural gas become available.

As of late 2002, there was no natural gas distribution system in the province. Four industrial users relying on gas take it directly from laterals off the main transmission line (three, including the SOEI fractionation plant, are in Richmond County, and the other – the Tufts Cove thermal plant – is in Halifax). The province may award distribution rights for a number of counties along the M&NP mainline and Halifax lateral in 2003, though the franchise area applied for excludes the Study Area.

Given that regions along the mainline and existing lateral are likely to receive gas in the near future, access to gas along the South Shore is seen as important to forestall any real or perceived competitive disadvantage. If proposed offshore projects bring natural gas directly to the Study Area for processing, it is possible that gas could be made available to industry at competitive rates, similar to the current discounted special rate in Guysborough County near the Sable Offshore gas plant[30]. For large industries that are heavy energy users (pulp mills and the like), this could provide a location incentive. But this is still highly speculative since there is no guarantee that gas would or could be made available at a discounted price. Moreover, the gas reserves needed to justify an offshore pipeline project that could bring gas ashore in the area have yet to be discovered (though a project is being developed by a US pipeline company that would carry Scotian Shelf gas direct to markets in the US with a landfall in southwest Nova Scotia). For purposes of this case study, we assume that a lateral would be constructed from the Halifax area.

Industry/Anchor Load

Major market consumers in the study area were identified as the Louisiana Pacific (ABT) hardboard plant in East River, and the Michelin plant in Bridgewater. Brooklyn Energy's 30 MW generating station is a large commercial-sized user which supplies electricity to NS Power's grid, and steam to Bowater Mersey's pulp and paper mill in Brooklyn. It relies mainly on wood and waste wood for fuel and uses about 8,130 MMBtu per year of #2 fuel oil. National Sea Products in Lunenburg is not a major energy consumer and its energy consumption is included in the commercial category discussed below

In Nova Scotia, the current fuel usage breakdown for major market consumers is as follows:

[30] Note however that there are currently no users taking advantage of the Guysborough discount.

Table 31

Fuel Use in Nova Scotia

	Light Fuel Oil	Heavy Fuel Oil	Wood Waste	Propane	Coal	Electricity
Nova Scotia	29%	69%	9%	26%	3%	3%

Note: The figures are based on the number of users using each fuel. Some users consume multiple fuels, so the total does not add to 100.

Source: Maritimes NRG (1998).

Survey data show that the two major market consumers on the South Shore are users of #2 and #6 oil, for a total energy demand of 1.3 million MMBtu. It is assumed that competitively priced gas would induce these industries to switch from #2 or #6 oil to a dual-fuel or natural gas-fired system as soon as gas was made available to them. The challenge facing the distributor is to be able to supply competitively priced gas. Table 32 shows the percentage of energy demand by fuel oil breakdown by the major manufacturing industries in the study area (excluding Bowater Mersey which acquires it energy supply from Brooklyn Energy, as already noted).

Table 32
Breakdown of Industrial Energy Demand, Nova Scotia Case Study

	Annual MMBtu Demand	% of Total Demand
Louisiana Pacific/ABT	920,000	72
Michelin North America	350,000	28

Source: Gardner Pinfold Consulting Economists Limited.

There is a possibility that energy generation (and/or cogeneration) activities can serve to help build an anchor load in the study area, providing electricity to the large industrial users as well as contributing to the grid.

Commercial/Residential Market

This study estimates that the residential market for natural gas distribution in the study area includes over 15,000 privately occupied dwellings in Mahone Bay, Lunenburg, Bridgewater, Liverpool and Shelburne. We estimate the commercial market, which includes small, medium, large commercial and institutional users to be approximately 590 energy users[31]. Based on recent experience, the study adopts a conservative growth

[31] Based on Sempra (1998) and Statistics Canada profile on Canadian Communities (1996 Census) dwelling counts. An average annual use of 1,650 GJ per user was assumed. Naturally, some users will demand less, and some more.

assumption, applying a zero-growth rate in the residential and commercial sectors. This means the population base and business base are assumed to be constant over the analysis period.

Table 33 shows the market characteristics for Nova Scotia for space and water-heating energy sources:

Table 33
Space and Water Heating Market, Nova Scotia

	Fuel Oil	Electricity	Wood	Propane
Space Heating	63%	23%	12%	1%
Water Heating	41%	55%	1%	3%

Source: Maritimes NRG (1998).

For case study purposes, we assume that in the residential market:

- 26% of converting customers would convert from electricity;
- 59% of converting customers would convert from #2 fuel oil; and,
- 14% of converting customers would convert from wood[32].

An additional assumption is that residential users would demand approximately 130 GJ of natural gas on an annual basis[33].

The assumed ten-year penetration rates in the residential heat and hot water markets were as follows[34]: Maximum penetration is reached in year 10.

32 Total does not add to 100 because of rounding.

33 This figure is reported in Sempra Gas "Application for Regulation Class Franchise to Construct and Operate a Gas Distribution System in the Province of Nova Scotia" (1998).

34 Take-up rates for residential, commercial and industrial users taken from Sempra Gas (1998) "Distribution of Gas in Nova Scotia".

Table 34

Natural Gas Penetration Rate

Residential Heat and Hot Water

Year	Penetration rate (% of dwellings)
1	17.4
2	34.8
3	36.2
4	37.7
5	39.2
6	40.6
7	42.1
8	43.6
9	45.0
10	46.5

Source: The rates assumed are from Sempra Gas (1998). They are conservative and lower than the rates assumed by Maritimes NRG in its application.

Small, Medium, and Large Commercial

The small commercial energy market in Nova Scotia is mainly reliant on #2 fuel oil for space heating requirements (67% fuel oil, 18% electricity, 4% propane, 11% wood). Hot water heating in the small commercial market is dominated by electricity at 61%, followed by fuel oil at 28%.

Medium commercial/industrial establishments use fuel oil to varying degrees, depending on the specific process or application, though the data suggest that medium-sized consumers are more reliant on fuel oil and propane than smaller commercial customers.

Large commercial/industrial customers include schools and larger manufacturing companies, which may use energy for space heating, process heat, or a combination of both. Studies show that for large commercial/industrial customers, 76% use #2 fuel oil, 25% use propane, and 10% use heavy fuel oil (some use multiple fuels).

The case study assumes the following conversion rates in the commercial market for space and water heating (including institutional use):

- 45% of converting customers would convert from electricity;
- 36% of converting customers would convert from #2 oil; and,
- 19% of converting customers would convert from wood.

The assumed ten-year penetration rates in the commercial and institutional markets are shown in Table 35. Maximum conversion occurs in year 10.

Table 35

Natural Gas Penetration Rate

Commercial Heat and Hot Water

Year	Commercial and Institutional (% of market)
1	20
2	39
3	42
4	44
5	47
6	50
7	52
8	55
9	57
10	60

Source: The rates assumed are from Sempra Gas (1998). They are conservative and lower than the rates assumed by Maritimes NRG in its application.

Conversion Costs

Given the relative oil-gas price assumption used in this case study (gas is 10% lower), in the absence of any special financial inducements or extraordinary cost savings, residential consumers can be expected to switch to natural gas as a space-heating fuel *only* when their existing equipment has reached the end of its useful life. Replacement costs can vary, depending on the type of equipment already in their home. The average costs to convert to natural gas fired equipment depend on current equipment type as shown in Table 36.

Table 36
Conversion Costs by Original Fuel Source

Equipment	Natural Gas System	Cost to Consumer for Conversion
Forced Air Oil Furnace	Force Air Furnace	$1,800 - $3,500
Oil Hot Water Radiant	Hot Water Radiant	$1,800 - $4,000
Electric Forced Air Furnace	Forced Air Furnace	$2,400 - $3,400
Electric Baseboard	Forced Air Furnace	$4,000 - $7,000
Electric Baseboard	Space Heaters/Fireplaces	$1,200 – $2,500
Air Tight Wood Stove	Fireplace	$1,600 – $2,500
Forced Air Wood Stove	Forced Air Furnace	$1,800 - $3,500
Propane Forced Air Furnace	Forced Air Furnace	$200 - $400

Source: Maritimes NRG (1998).

Energy Cost Savings

Energy cost savings to the consumer can be calculated by comparing the efficiency-adjusted price per heat unit (often calculated per MMBtu[35]) of the currently used fuel, with the effective price per heat unit of natural gas. (Efficiency adjusted prices take into the different energy content per unit of heating fuels and the relative efficiency of the burners (e.g., furnaces, water heaters, etc.).

In the Nova Scotia case, consumer cost savings were calculated by multiplying the number of potential gas hookups (residential, commercial and industrial) by the cost savings per consumer (a function of energy demand and effective price difference between fuels.)

The study assumes that competitively priced natural gas would be about 10% cheaper than #2 fuel oil (before adjusting for efficiency), which is effectively lower priced than electricity. This assumption is tested by the CBA. The forecasts for crude oil and the associated prices for residential #2, commercial and industrial #2, and industrial #6 oil are in Appendix A.

Based on applying the 10% assumption, the natural gas prices offered to consumers in greenfield areas of the Maritimes are shown in Table 37.

[35] 1 Mmbtu is equal to 1,000,000 British Thermal Units. 1 MMBtu = 1.05 GJ, or the heat content of approximately 1,000 cubic feet of natural gas.

Table 37

Assumed Natural Gas Prices for Nova Scotia Consumers

Previous Fuel	Price per Unit	Current Fuel Price per MMBtu	Assumed Natural Gas Price per MMBtu
Residential #2	$0.60/litre	$16.24	$14.61
Commercial #2	$0.40/litre	$10.85	$9.76
Industrial #6	$0.20/litre	$5.04	$4.54

Note: Fuel oil prices based on average of $24.00 $US/bbl.

Source: Gardner Pinfold Consulting Economists Limited.

The assumed commodity cost of natural gas ($4.55/MMBtu) is about 10% less than the price of #6 fuel oil. This is *before* any tolls that would apply to cover transportation (a minimum of $0.69/MMBtu, assuming the M&NP lateral policy applies.). This would put the delivered cost of gas above #6 oil. Under these relative price assumptions and assuming no other pressures to convert, it is reasonable to infer that there would be no industrial conversions from #6 to natural gas purely on economic grounds.

Residential and commercial gas consumption starts in year two and follows the penetration rates assumed by Sempra Atlantic. This amounts to a four percent average increase in the take up rate in residential consumers starting in Year 3 and continuing until year 10. A 5.5% annual increase in the take up rate in commercial and institutional applies over the same period. After year 10, the penetration rates remain constant.

Commercial users commence energy savings in Year 2 at about $1 million, rising to nearly $3.1 million per year by Year 11, not including the costs incurred in converting to natural gas. The study reduces the energy savings by 10% over the first five years to allow for conversion costs that are incurred before the end of the useful life of existing systems. Commercial energy use is split between three major sources: electricity at 46%, #2 fuel oil at 37%, and wood at 19%.

The residential sector energy savings in Year 2 are approximately $1.5 million. By Year 11, the energy savings in the residential sector grow to about $4.1 million, partially displacing electricity (26% of potential consumers), and #2 fuel oil (59%). When natural gas is priced competitively with wood, that market is penetrated as well (currently 14%). The same 10% reduction in energy cost savings applies when conversion is carried out before the end of the useful life of the system.

Energy Supply and Market Structure

The residential market in the study area is dominated by #2 fuel oil, so this fuel would be the most affected by competition with natural gas. Since oil-fired appliances are more easily converted to natural gas, conversions would likely be cheaper for these dwellings.

There are approximately 10-12 companies in the study area who deliver home heating oil, and NS Power Inc, presently markets practically all electricity in Nova Scotia.

As in all the Greenfield Gas case studies, retailers of home heating and water heating appliances would be affected by the introduction of natural gas, but based on experience elsewhere, retraining would allow workers to become gas fitters. Appliances for both energy types would still be in demand. Industries that work in appliance installation and repair can be trained to expand their market to include gas-fired appliances.

Commercial and small industrial markets would likely convert or purchase electrical and oil-fired appliances (e.g., water heaters, forced-air furnaces, etc.) to accommodate natural gas. Large industrial processes using #2 fuel oil or propane would be most interested in the modification of oil-fired applications for use with natural gas. These conversions would rely on the price of gas being competitive with the price of #2. The assumption used in the Cost Benefit Analysis is that gas is competitively priced at 10% lower than the #2. As noted, the assumed price for #6 does not make conversion to natural gas a feasible choice for heavy oil consumers.

Economic, Social and Environmental Benefits

Impacts on local business can be evaluated in two ways: those businesses who will immediately benefit from the introduction of natural gas to the community, and those whose market activities suffer from increased competition in the energy market. Local businesses who can benefit from the introduction of gas will likely be involved in gas hook-ups and installation, gas appliance sales, and the servicing of gas customers. Fuel oil delivery companies are most likely to feel negative impacts after the introduction of gas.

Environmental benefits can be realized at a corporate level if switching to natural gas is less than the cost of mechanically reducing harmful emissions (such as SO_2 and NO_x) associated with the alternative fuel source (normally heavy fuel oil.) However, if conversion of heavy fuel oil using processes to natural gas is not a cost saving measure in energy or pollution abatement costs, it is unlikely that industry will invest in natural gas-fired equipment, unless required to do so by environmental regulations.

Changes in environmental regulations, such as clean air policies that reduce the level of acceptable emissions of particulate matter and harmful chemicals, can increase the cost of abatement to the point that it is no longer economical to remain with heavy fuel oil. At this point, natural gas will become a more attractive fuel. Where this has happened in the United States, more stringent regulations have forced industries to choose between investing to switch fuels, or paying to increase environmental emission controls.

Regulatory Framework

The Nova Scotia Utilities and Review Board (UARB) regulates natural gas in the Province. Currently, there are only a small number of industrial users in Richmond County and Nova Scotia Power in Halifax. There are no users taking advantage of the discounted gas toll at the gas plant site in Guysborough County. The provincial policy on natural gas distribution has recently changed, and incorporates a number of new policies.

Some of the policies currently in place are:

- ♦ The UARB will have the authority to approve cost of service, performance-based regulation, or market-based rates, and supports bundled services.
- ♦ Independent gas marketers are permitted within the distribution regulations.
- ♦ The gas distributor will charge a postage-stamp rate in Nova Scotia.
- ♦ Single end-user class franchises (industrial by-pass) will be discouraged unless distribution is not available in the industry's home area. In special cases, industrial by-pass may be allowed where distribution systems exist, if special conditions are met. Existing direct access user agreements will not be affected by current policy.

Distribution System

The distribution system assumed for case study purposes would service the communities of Mahone Bay, Lunenburg, Bridgewater, Liverpool and Shelburne. As well, the distribution system would include the servicing of key industries such as the Louisiana Pacific hardboard plant in East Chester, the Michelin Plant in Bridgewater, and Brooklyn Energy in Brooklyn.

At present, it is assumed the lateral would come off Maritimes & Northeast Pipeline's Halifax Lateral, prior to the pipeline entering Dartmouth. Estimates indicate that the construction of approximately 216 km of pipeline would cost approximately $56 million for a combination of NPS 6 and NPS 4 pipe.

The distribution system would cost an estimated $6.3 million to serve the communities mentioned above. These costs do not include the costs incurred in bringing gas from the main to the dwelling.

Annual Operations and Maintenance (O&M) costs are approximately $2.55 per metre of lateral line ($2,554 per kilometre[36]). These costs include employment to survey and maintain the lateral line, as well as well as other foreseen costs related to the pipeline. O&M costs on the distribution system are based on the number of users in that system, and are approximated at $100 per user. Lateral O&M costs would commence in Year 1, and distribution O&M costs would commence in Year 2.

The following table shows the associated costs for the lateral and distribution system for the South Shore case study:

[36] Based on estimates by FGA Consultants Ltd. (1999) "Study to Identify the Economic Impacts of a Natural Gas Pipeline to Prince Edward Island".

Table 38
Lateral and Distribution Costs, South Shore Nova Scotia Case Study

	Construction Cost	Annual O&M Cost
Lateral	$56.2 million	$2,554 per km
Distribution System	$6.3 million	$100 per consumer
Total	$62.5 million	$580,000 (average)

Sources: FGA Consultants Ltd. (1999); Maritimes NRG (1998).

If there is a future landfall location for natural gas on the South Shore of Nova Scotia, lateral construction costs could decline by as much as $18 million (covering that portion of the line from Halifax to East Chester). Distribution costs would likely not be affected.

Subsidy Regime

One of the Government of Nova Scotia's four primary objectives for oil and gas development is "to set the stage for expanded industrial, commercial and residential use of gas and gas liquids in Nova Scotia." Whether communities and distributors can access funding to facilitate these types of projects remains to be determined.

Subsidies may be necessary where it is deemed that the project is socially justifiable, but perhaps not financially so. In such cases, an "aid to construct" may come in the form of specific user fees, increased tolls, or subsidies from the provincial government, federal government or both. This point is expanded upon below, in the CBA section.

Cost-Benefit Analysis[37]

The CBA considers construction costs, O&M costs and the cost of gas, compared with the social benefit of energy savings for all of the consumer classes. The net benefits are discounted over a period of 20 years to arrive at a Net Present Value (NPV). A positive NPV would indicate that the benefits gained by constructing and operating natural gas facilities outweigh the costs of the system. A negative NPV indicates that the system costs exceed the benefits of energy cost savings for the three user categories.

The analysis starts by conducting a purely financial analysis[38] which tests whether or not the revenues generated from the sale of gas cover the capital and operating costs of the system. The second step is to convert the financial analysis to a CBA by adding energy cost savings as a benefit accruing to the users of natural gas.

37 The assumptions used in this study are made for economic analysis purposes. A commercial financial analysis would be likely to use a higher discount rate (based on a regulated return on equity of 11-13%) and would be concerned about municipal and other taxes.

38 This is a financial analysis conducted as part of an economic analysis. All capital costs are fully charged in the years in which they occur, rather than amortized. Taxes are ignored; including them would of course decrease the financial NPV.

If the financial analysis NPV is positive, the proposed system would be commercially viable and could be expected to go ahead. In cases where the financial NPV is negative, the proposed system may still be socially justifiable (on economic grounds) if the NPV from the CBA is positive, since that means the energy cost savings exceed the costs of the gas system. In this case, it would be in society's interest to provide an "aid to construct" or subsidy to cover part of the costs and facilitate the installation and operation of the system that would not take place on financial grounds alone.

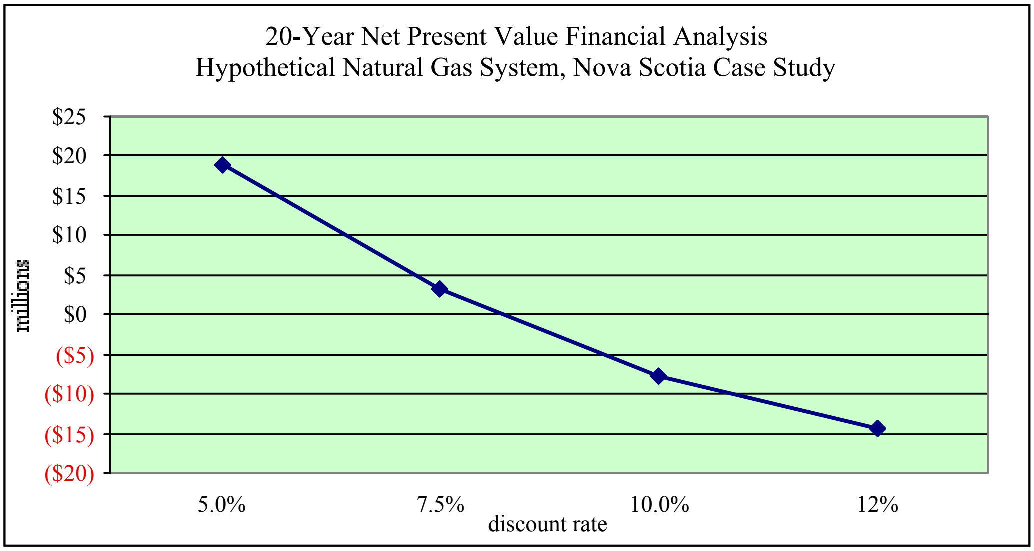
Table 39 shows the main features of the financial/CBA.

Table 39
Main Elements of Financial and CBA

Item	Duration	Cost ($CDN)
Analysis Period	20 years	-
Construction Costs		
Lateral	First Year	$60 million
Distribution System	Spread over first seven years	$6.3 million
Total		$66.3 million
Operating Costs (annual)	Annual from year 2	Start at about $550,000 and grow to about $588,000
Cost of Natural Gas (annual)	Unit cost held constant at $Can 4.55 per MMbtu	Total gas cost starts at just over $1.4 million and grows to about $5.7 million
Energy Cost Savings (annual)	Increases as the number of conversions grows	Starts at about $2.4 million and increases to $6.5 million by year 20
Discount Rate	5%, 7.5%, 10%, 12%	-

The financial analysis shows that for the case study assumptions, the NPV is negative at discount rates in the 11-13% range that are typical of regulated rates of return (Figure 9). In other words, the project would not be financially feasible. Also, the study has ignored any municipal taxes that would increase costs and drive the NPV further negative.

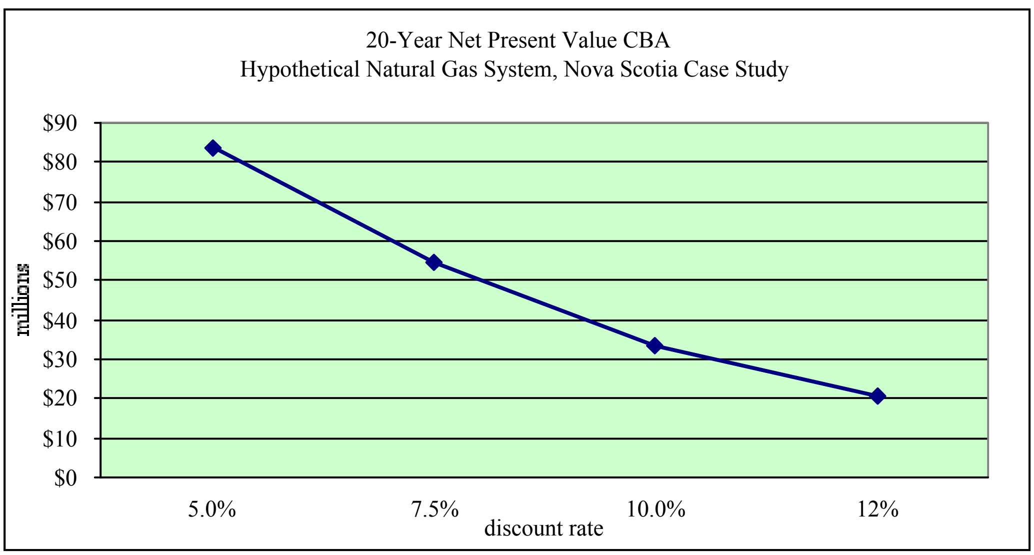
Figure 9



Source: Gardner Pinfold Consulting Economists Limited.

Adding the energy cost savings to convert the financial analysis to a CBA increases the NPV to $55 million at the 7.5% discount rate. The NPV remains positive at all rates tested indicating an economically attractive project.

Figure 10



Source: Gardner Pinfold Consulting Economists Limited.

As stated above, the CBA measures the net benefit that customers experience in the form of savings on fuel costs, but does not include quantifiable values related to environmental benefits from the use of cleaner fuel. There could be other benefits such as industry attraction, industry retention, and intra-provincial (and intra-regional) market competition, but the results in Chapter I suggest these are not likely to be large.

Sensitivity Analysis

Sensitivity analysis tests the impact on the NPV of changing the base case assumptions for key study variables in the CBA. Table 40 shows the sensitivity results compared to the base case NPV of $55 million at the 7.5% discount rate. For instance, increasing capital costs by 20% causes the NPV to decrease to $43 million, while reducing capital costs by 20% will increase the NPV to $66 million. Note that if the source of gas were switched to a south shore location, the capital costs of the system would decline by about $18 million, thereby increasing the NPV, since most these costs would occur in the first year. Such a change would also substantially strengthen the financial analysis. The NPV is much less sensitive to changes in operating costs.

The NPV is sensitive to changes in the energy cost savings. Increasing energy cost savings by 20% increases the NPV by about 18% to $65 million. Such an increase could occur for a variety of reasons:

- an increase in the rate of conversions, or
- the same rate of conversions augmented by a growth in the market for gas, or
- increased energy cost savings that result from a greater difference in relative energy prices, or
- a combination of the above.

A 20% decrease in energy savings reduces the NPV by 20% to $44 million.

The sensitivity analysis results show that it would be important to investigate thoroughly the assumption used for capital costs and energy savings. Regarding the latter, it seems likely that a more favourable gas price that would support conversion by large industrial users converting natural gas from #6 fuel oil would bring about a substantial increase in energy cost savings. This is an area that would require detailed attention in any real application of the model as opposed to the hypothetical example developed in this study.

Table 40

Sensitivity of NPV to Changes in Key Variables

20 Year Analysis (millions of Canadian dollars)

Variable	Increase Variable by 20%	Decrease Variable by 20%
Discount Rate: 7.5%; Base Case NPV = 55		
Capital Cost	43	66
Operating Costs	7	13
Energy Savings	65	44

SUMMARY AND CONCLUSIONS

This case study examines the feasibility of running a lateral from the current M&NP Halifax lateral near Waverley, Nova Scotia, to an area in Southwest Nova Scotia bounded on the east by East Chester and on the west by Shelburne. A gas distribution system would be installed to serve the customer base in this study area. The study also assess the impact of having a direct supply of gas in the area from a sub-sea pipeline that would have landfall and gas processing plant in the study area.

Fuel oil prices were estimated based on an assumed price of crude oil of $US 24.00 per barrel. A key assumption of the case study is that natural gas would be available at a price 10% less than the expected price for #2 and #6 fuel oil. The analysis shows that natural gas would not be competitive with #6 fuel oil and that large industrial users are unlikely to convert to natural gas. The energy market in the study area would be comprised of residential households and commercial users including institutions who would convert to natural gas. The case study used the residential and commercial conversion rates used by Sempra Gas in their gas distribution application. These rates were similar to but more conservative than the conversions rate assumptions used by Enbridge Gas New Brunswick.

The analysis of the greenfield sites in Chapter I found that access to natural gas did not generate any substantial economic development effects. This is because natural gas is only one of many competitive factors that influence the location of economic development including available labour supply, natural resources, access to markets and so on. Access to gas could make a difference if gas were available at preferential rates near the source of supply as, for example, with the Sable Offshore Energy gas in Guysborough County, Nova Scotia. That is a possibility for this study area if the pipeline landfall actually occurs and a preferential pricing regime is established. This scenario was not analyzed since it is still a very uncertain outcome.

Under the assumptions of the case study, natural gas is less expensive than alternative energy sources, but it is not cheap in an absolute sense. Hence, the only quantitative benefit of access to natural gas is the energy savings. It could be said however that having access to gas will help to maintain a level playing field between the study area that is currently without gas and other parts of Nova Scotia and New Brunswick that have or soon will have gas service. This is a potentially important benefit.

The analysis was carried out for a 20-year period. The combined cost of constructing a lateral and distribution system for the study area was estimated to be about $66 million. Operating costs start in the second year at about $550,000 and grow to about $588,000. Natural gas is assumed to cost $4.55 per MMBtu over the study period. The financial analysis indicates a negative NPV at rates above about 8%, so the system is apparently not financially viable.

Energy cost savings are the substantive benefit arising from access to natural gas. These are estimated to start at about $2.4 million in the second year and increase to an annual value of $6.5 million by year 20. Including the energy cost savings in the CBA results in a NPV of $55 million at the 7.5% discount rate.

Replacing the lateral from Waverley with a gas source inside the study area is estimated to reduce capital costs by about $18 million. This will increase the NPV for the system by about the same amount. This indicates that the system studies could be attractive commercially to a private sector investor even without an aid-to-construct to reduce the capital costs of the system. In any event, the strong NPV results from the CBA over 20 years provide an economic basis on which to consider support for an aid-to-construct.