National Energy Board

Office national de l'énergie

Reasons for Decision

Province of New Brunswick

MH-2-2002

September 2002

Export Order Procedures

National Energy Board

Reasons for Decision

In the Matter of

Province of New Brunswick

Application Respecting Short-term Export Order Procedures

MH-2-2002

September 2002

Cat. No. NE22-1/2002-4E
ISBN 0-662-32704-7

This report is published separately in both official languages.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-Mail: publications@neb-one.gc.ca
Fax: (403) 292-5503
Phone: (403) 299-3562
1-800-899-1265

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

N° de cat. NE22-1/2002-4F
ISBN 0-662-87657-1

Ce rapport est publié séparément dans les deux langues officielles.

Exemplaires disponibles sur demande auprès du:
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta), T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : (403) 292-5503
Téléphone : (403) 299-3562
1-800-899-1265

En personne, au bureau de l'Office :
Bibliothèque
Rez-de-chaussée

Imprimé au Canada

Table of Contents

List of Tables

List of Figures

Abbreviations

Act	*National Energy Board Act*
AIMS	Atlantic Institute for Market Studies
Alberta	Alberta Department of Energy
Bcf	billion cubic feet
Board or NEB	National Energy Board
CAPP	Canadian Association of Petroleum Producers
Cartier	Cartier Pipeline and Company, Limited Partnership
CEPU	Communications, Energy and Paperworkers Union of Canada
CGPC	Canadian Gas Potential Committee
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
Duke Energy	Duke Energy Marketing Limited Partnership
EGNB	Enbridge Gas New Brunswick
EnCana	EnCana Corporation
GHR-1-87	*Review of Natural Gas Surplus Determination Procedures*
GHW-1-91	*Proposed changes to the Application of the Market-Based Procedure*
GJ	gigajoule(s)
GLJ	Gilbert Laustsen Jung
GSC	Geological Survey of Canada
IGUA	Industrial Gas Users Association
Joint Position	Joint Position on Tolling and Laterals
LDC	local distribution company
Maritime Electric	Maritime Electric Company, Ltd.

MBP	Market-Based Procedure
Mirant	Mirant Canada Energy Marketing, Ltd.
MMBtu/d	million British thermal units per day
MMcf/d	million cubic feet per day
M&NP	Maritimes & Northeast Pipeline Management Ltd.
M&NE	Maritimes & Northeast Pipeline, L.L.C.
MW	Megawatts
NAFTA	*North American Free Trade Agreement*
NB Power	New Brunswick Power Corporation
New Brunswick or the Applicant	Province of New Brunswick
Nova Scotia	Province of Nova Scotia, Department of Energy
PEI	Province of Prince Edward Island
Quebec	Procureur général du Québec
SDLs	Significant Discovery Licences
Sempra Atlantic	Sempra Atlantic Gas Inc.
SOEP	Sable Offshore Energy Project
Tcf	trillion cubic feet
Tractebel	Tractebel Energy Marketing Inc.
TransCanada	TransCanada PipeLines Limited
U.S.	United States

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* (the Act) and the regulations made thereunder; and

AND IN THE MATTER OF an application dated 28 February 2002, as amended, by the Queen in Right of the Province of New Brunswick, as represented by the Minister of Natural Resources and Energy, under paragraph 12(1)(b) and subsections 21(1) and 24(3) of the Act requesting that the Board hold a hearing to establish a set of rules that will apply when it considers applications for short-term export orders for incremental supplies of Scotian offshore gas;

AND IN THE MATTER OF National Energy Board Hearing Order MH-2-2002;

HEARD at Fredericton, New Brunswick on 15-20, 22-26, 29 and 30 July 2002.

BEFORE:

J.-P. Théorêt	Presiding Member
K.W. Vollman	Member
D.W. Emes	Member

APPEARANCES:

I. Blue, Q.C. A. Hamilton	Province of New Brunswick
N.J. Schultz	Canadian Association of Petroleum Producers
G. Sarault	Industrial Gas Users Association
C. Worthy	BP Canada Energy Company
D. Lutz	Chevron Canada Resources
P. Jeffrey	Duke Energy Marketing Limited Partnership
J. MacIssac	Emera Energy Inc.
D. Davies	EnCana Corporation
J. Reynolds	GasWorks Installations Inc.
D. Brett	Imperial Oil Resources/ExxonMobil Canada Ltd.
M. Gelowitz	J.D. Irving, Limited/New Brunswick Power
W. Lea, Q.C.	Maritime Electric Company, Ltd.

L.E. Smith, Q.C. N. Gretner	Maritimes & Northeast Pipeline Management Ltd.
M. Stauft	Mirant Canada Energy Marketing, Ltd.
F. Basham	Talisman Energy Inc.
P. Keys	TransCanada PipeLines Limited
B.L. Crowley	Atlantic Institute for Market Studies
G. Clavette	Comité d'énergie de la Vallée St-Jean et de l'Est du Québec
S. Shrybman	Communications, Energy and Paperworkers Union of Canada
D. Coon A. Secord	Conservation Council of New Brunswick
N. Getty R. Pearly	Union of New Brunswick Indians
M.E. Donovan	Halifax Regional Municipality
C.J.C. Page	Alberta Department of Energy
J. Brisson Y. Migué	Procureur général du Québec
H.D. Williamson, Q.C. J. Lagacé	Province of Nova Scotia, Department of Energy
R. King A. Taylor	Province of Prince Edward Island
M.A. Fowke A.D. Ross	Board Counsel

Chapter 1

Introduction

1.1 Application

On 28 February 2002, the Queen in Right of the Province of New Brunswick (New Brunswick or the Applicant) filed an application with the National Energy Board (the Board or NEB) pursuant to paragraph 12(1)(b) and subsections 21(1) and 24(3) of the *National Energy Board Act* (the Act) requesting the Board to hold a hearing to establish a set of rules that will apply when it considers applications for short-term export orders for incremental supplies of Scotian offshore gas when those supplies cannot meet both Canadian and export requests for service. Specifically, New Brunswick asked for an order at the end of the hearing:

(a) declaring that the market for incremental Scotian offshore gas in eastern Canada is less well developed and less robust than the market in the northeastern United States (U.S.) or the market for Western Canada Sedimentary Basin gas.

(b) declaring that, because of (a), the Board's Market Based Policy, as amended in sub-paragraphs (c) to (f) below, should apply to applications for short-term export orders for incremental Scotian offshore gas.

(c) declaring, consistent with (b) above, that any person, government or entity may make a complaint in respect of an application for a short-term export order for incremental Scotian gas.

(d) declaring, in order to give purposive effect to (c) above, that the Board will require an applicant for a short-term gas export order for incremental Scotian gas to publish a public notice of such an application and make such application available for public viewing.

(e) declaring, in order to give purposive effect to (c) and (d) above, that once public notice of the application has been published, the Board will establish a short, efficient comment process in respect of the application. (New Brunswick suggested that it would be reasonable to require written comments, complaint or objection in respect of the application to be provided to the Board and to the applicant within two weeks of the public notice and to require that the applicant reply to comments within three weeks of the public notice and that a Board decision follow shortly after that indicating whether the order will be granted/denied or that a further process is required. New Brunswick stressed that these time limits are by way of example only, and that actual time limits will depend upon circumstances. Nothing in these suggestions is meant to override the comments made in GHW-1-91 at page 40 such as "If objections are filed with the Board, the Complainants and the Applicant may attempt to resolve outstanding differences. Indeed, the Board itself may decide not to set down an export application for hearing until parties have been given an opportunity to attempt to cure any complaints".)

(f) declaring that the Board reserves the right to bump up any application for a short-term export order to a public hearing matter under subsection 24(3) of the Act.

(g) declaring that once the Board considers the written comments and the applicant's reply, or, alternatively, the evidence at any public hearing, the Board will proceed to decide the short-term application in accordance with the criteria in section 118 of the Act.

New Brunswick requested that the hearing be held before the Board considered any further applications for the short-term export of incremental Scotian offshore gas and that it be held either before or at the same time as the Board considers any application by Maritimes & Northeast Pipeline Management Ltd. (M&NP) for an order under section 58 of the Act for its proposed system expansion. The Applicant also sought an order reviewing and varying the Board's GHR-1-87 and GHW-1-91 Decisions respecting Market-Based Procedures as far as required to accommodate any rules that the Board may establish in the export issues hearing. Further details on the complaints procedure requested for short-term export orders for Scotian offshore gas can be found in section 4.1.

On 23 April 2002, the Board issued Hearing Order MH-2-2002, which set down New Brunswick's application for a hearing commencing 15 July 2002 and established Directions on Procedure and a preliminary List of Issues. On this date, the Board also decided to deny New Brunswick's request that the Board not consider any short-term order applications for the export of incremental Scotian offshore gas before holding the hearing, as it was of the view that such a request would be premature and unnecessary in the circumstances. Although the Board allowed for comments on the Preliminary List of Issues, no party suggested any changes. On 10 May 2002, the Board finalized the List of Issues for the hearing.

The Board heard evidence in Fredericton, New Brunswick on 15-20, 22-26 July 2002 and final argument on 29 and 30 July 2002.

1.2 Context of the Application

1.2.1 Natural Gas Export Approval Procedures

Section 118 of the Act requires the Board, upon application for a natural gas export licence, to "satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of oil or gas in Canada". Licences are required for persons who wish to export natural gas for a period of more than two years, up to a limit of 25 years. This provision of the Act has remained unchanged since the legislation was enacted in 1959.

Together, sections 116 and 119 of the Act empower the Board to approve natural gas exports for periods of less than two years pursuant to *National Energy Board Part VI (Oil & Gas) Regulations*[1] (the

[1] SOR/96-244, as amended

Regulations) made by the Governor in Council. Exports for periods of less than two years are approved under Board Orders pursuant to the Regulations.

The Board has used various procedures over the years to assess and approve applications for natural gas export licences; similarly the Governor in Council has approved many changes in the Regulations that apply to short-term export orders. As discussed below, the most important changes took place in the mid-1980s, when government policies towards the natural gas industry changed markedly from the application of quantitative surplus tests to a market-based approach.

On 28 March 1985, the Governments of Canada, Alberta, British Columbia and Saskatchewan signed an agreement on oil and gas pricing and taxation known as the Western Accord. It defined the policy framework for federal regulation of the oil and gas industry and stated that a more flexible and market-oriented pricing mechanism was required for the domestic pricing of natural gas. To facilitate this, a task force was set up.

Subsequently, the *Agreement Among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices* (more commonly known as the "Halloween Agreement") was signed 31 October 1985 to meet the objectives of the Western Accord. The intention of the Agreement was to foster a competitive market for natural gas in Canada. As part of the policy direction, the Board was asked to review the surplus determination procedures it used for assessing applications for natural gas export licences.

The Board held two hearings on the matter and, in July 1987, decided to assess applications for export licences according to a new "Market-Based Procedure" (MBP)[1]. The fundamental premise of the MBP is that the marketplace will generally operate in such a way that Canadian requirements for natural gas will be met at fair market prices. However, the MBP was designed to provide for intervention if there was evidence that the market was not working to adequately and fairly serve Canadian needs.

The MBP, which was confirmed in 1992[2], has two components: public hearings and ongoing monitoring. A key element of the public hearing component is the Complaints Procedure. Under the Complaints Procedure, Canadian natural gas buyers have an opportunity to intervene with respect to an application for a natural gas export licence if they believe they have not been able to purchase natural gas on terms and conditions that were similar to those of the proposed export. Although there have been some changes to the MBP since 1987, the Complaints Procedure has remained as a central element of the MBP.

Under the monitoring component of the MBP, the Board undertakes periodic assessments of the long-term outlook for energy supply and demand in Canada. In addition, the Board conducts a number of shorter-term focussed reports, entitled Energy Market Assessments. Through its regular monitoring of

---

[1] NEB Reasons for Decision in the Matter of *Review of Natural Gas Surplus Determination Procedures*, GHR-1-87, July 1987.

[2] NEB Reasons for Decision *Proposed Changes to the Application of the Market-Based Procedure*, GHW-1-91, May 1992.

the market, the Board assures itself and Canadians that the market is, in fact, generally working to meet Canadian requirements for natural gas at fair market prices.

In 1985, the Regulations governing the export of natural gas under short-term orders were changed to allow short-term exports without volume restrictions. In 1986, to reflect the new market-based policies of the federal government, the Regulations were further amended to remove the Board's ability to place conditions on export orders with respect to pricing. Since that time, the Regulations allow the Board to include in orders terms and conditions respecting, among other things, the point of exportation, and the maximum daily, monthly, annual and term quantities of the gas that may be exported. The intent of the changes was to allow short-term trade in natural gas to take place with a minimum of regulatory intervention.

Since 1991, the Board has approved blanket short-term export orders, which provide natural gas exporters with the ability to export gas at multiple export points. This provides exporters with additional flexibility to participate in the short-term market on a real time basis.

Since the implementation of the Halloween Agreement and the MBP, there has been rapid growth in natural gas production and exports. Production has more than doubled and exports have increased fivefold from pre-Agreement levels. At the same time, the method by which gas is exported has changed as exporters have elected to rely more on short-term orders and less on long-term licences.

1.2.2 Development of the Scotian Basin

Since the early 1970s, significant accumulations of natural gas have been discovered on the Scotian Shelf near Sable Island. Six natural gas fields were initially identified for development: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma. These fields lie near the edge of the Scotian Shelf, in water depths between 20 and 80 metres, and are being developed by the Sable Offshore Energy Project (SOEP), a consortium of producers.

In 1996, the SOEP consortium and M&NP filed applications with the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), the NEB, and the Nova Scotia Energy and Mineral Resource Conservation Board. A Joint Review Panel was struck to consider the applications. Public hearings began in April 1997 and continued for 56 days, concluding on 14 July 1997. The Joint Review Panel released its decision in October 1997, recommending approval of the SOEP and M&NP projects. After all regulatory approvals were received, gas production from three of the six SOEP fields began in late 1999. Additional fields will be developed as required to maintain the planned sales gas rate for the life of the project.

Studies conducted on the Scotian offshore basin resulted in discovered and undiscovered resource estimates of 512 billion cubic metres (18 trillion cubic feet or Tcf) by the Geological Survey of Canada (GSC). In light of recent interest and activity, there have been additional estimates put forward by several industry players and governments. A recently-discovered field, the Deep Panuke gas field, has had plans prepared for development and new exploratory wells are being drilled in the shallow and deep water areas of the Scotian basin.

1.2.3 Development of the Domestic Market

During the Joint Review Panel hearing, M&NP requested approval of a postage stamp toll methodology and a Lateral Policy which it argued were inseparable. The Lateral Policy had the objective of encouraging the development of natural gas markets in the Maritimes by tolling laterals on a rolled-in basis if they generated sufficient revenue to cover the annual cost of service at a specified test toll.

During the hearing, a *Joint Position on Tolling and Laterals* (Joint Position) was negotiated between representatives of SOEP, M&NP and the provinces of Nova Scotia and New Brunswick. The Joint Position supported the postage stamp toll design but offered discounts for deliveries in Nova Scotia and New Brunswick in the initial years of the project. The Joint Position also supported M&NP's Lateral Policy and committed M&NP to build laterals to Halifax, Nova Scotia and Saint John, New Brunswick. M&NP also committed to develop work plans for laterals to Cape Breton and northern New Brunswick for future in-service dates as demand reaches an economic threshold. Further, the Joint Position committed the SOEP proponents to put aside 10,000 million British thermal units per day (MMBtu/d) of production for sale to the local distribution companies (LDC) in each province for the initial three years of production.

M&NP commenced deliveries of natural gas in late December 1999. The northeast U.S. market has been using natural gas for many years and was ready to accept production from the SOEP. In contrast, natural gas had never been available in the Maritime market. Therefore, considerable preparatory work was necessary before domestic users could begin to take delivery of natural gas. Laterals had to be constructed from the mainline, distribution facilities had to be developed and end-users had to make the necessary investments to be able to receive and burn natural gas.

In 1999, gas distribution franchises were awarded in Nova Scotia to Sempra Atlantic Gas Inc. (Sempra Atlantic) and in New Brunswick to Enbridge Gas New Brunswick (EGNB). The construction of a local distribution system in Nova Scotia was begun in 2000 but was abandoned by Sempra Atlantic after only 15 km of pipeline was constructed. Sempra Atlantic has since surrendered its franchise and the Nova Scotia Utility and Review Board has recommenced the process to select an LDC. A hearing to consider the applications is set for October 2002. M&NP has constructed two laterals in Nova Scotia. The Halifax Lateral was completed in November 2000 and the Point Tupper Lateral was completed in June 2001.

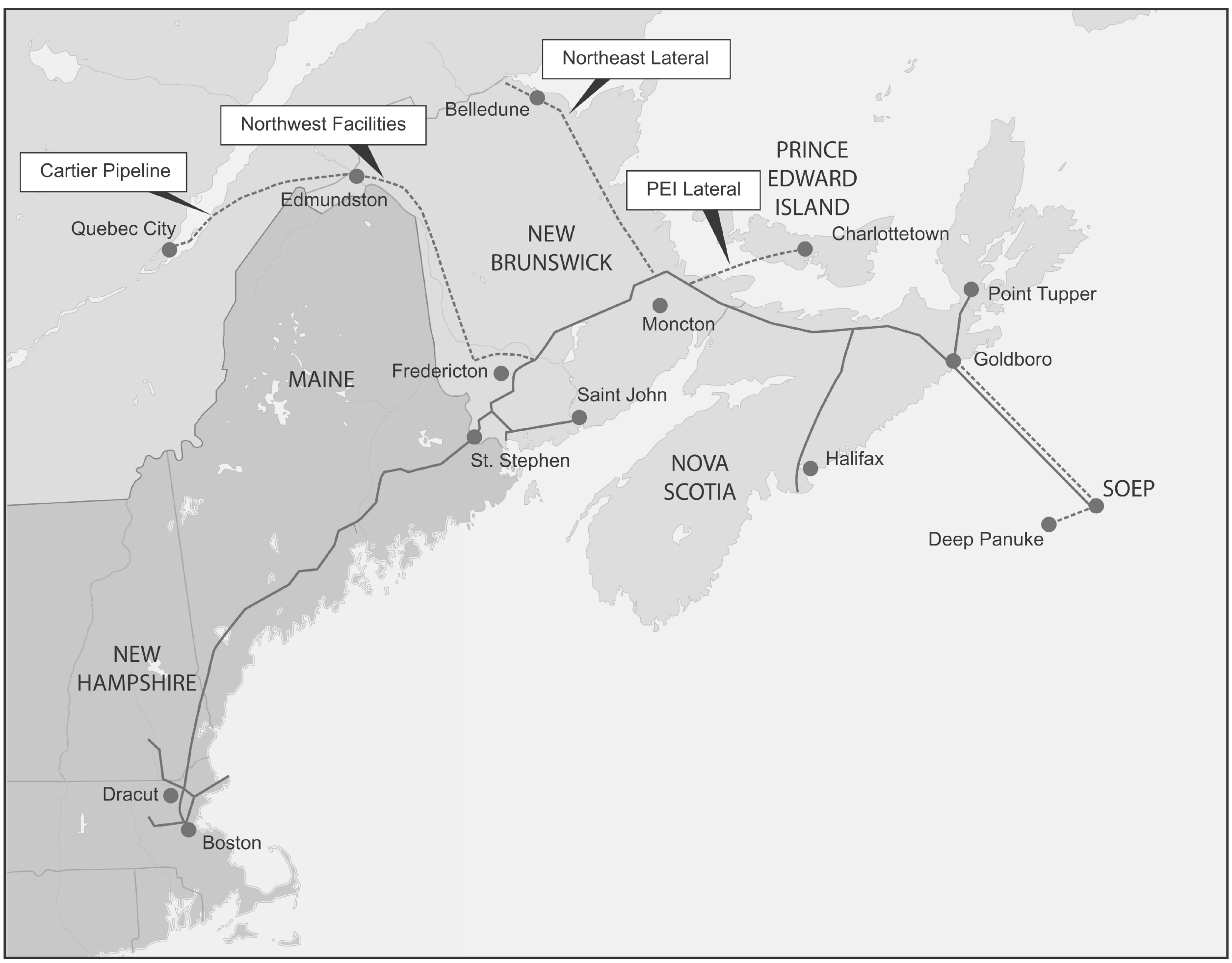
In New Brunswick, M&NP constructed laterals to Saint John, Moncton and St. George, the Lake Utopia Extension and delivery facilities for EGNB. These facilities were completed between November 2000 and November 2001. Since that time the extraordinary high prices of natural gas experienced in late 2000 - early 2001 have abated and EGNB is experiencing greater success in attracting additional load.

M&NP has had discussions with proponents for a new pipeline from Fredericton to the Quebec border near Edmundston, New Brunswick (the Northwest Facilities), with proponents for a new lateral from near Moncton north to Belledune (the Northeast Lateral), and is continuing to have discussions with the proponents of a new lateral to Prince Edward Island (PEI).

The Province of New Brunswick announced that it is proceeding with a restructuring of its electric power industry, effective 1 May 2002. Private power generation can be constructed and connected to New Brunswick Power Corporation's (NB Power) transmission facilities. Accordingly, there is considerable interest in constructing private gas-fired power plants in New Brunswick and, in particular, a large combined-cycle power plant at Belledune that could provide an anchor load to support the construction of a pipeline lateral to northeastern New Brunswick. The private power generation facilities, or merchant plants, intend to sell a portion of their output to NB Power and target the remainder to the export market in the U.S. northeast. Transmission facilities in the U.S. northeast are relatively constrained and securing firm transportation access in that market presents an additional challenge for power developers. In that connection, NB Power has an application before the NEB for a new inter-tie aimed at helping to alleviate this constraint.

Figure 1-1 shows the location of the facilities discussed in the hearing.

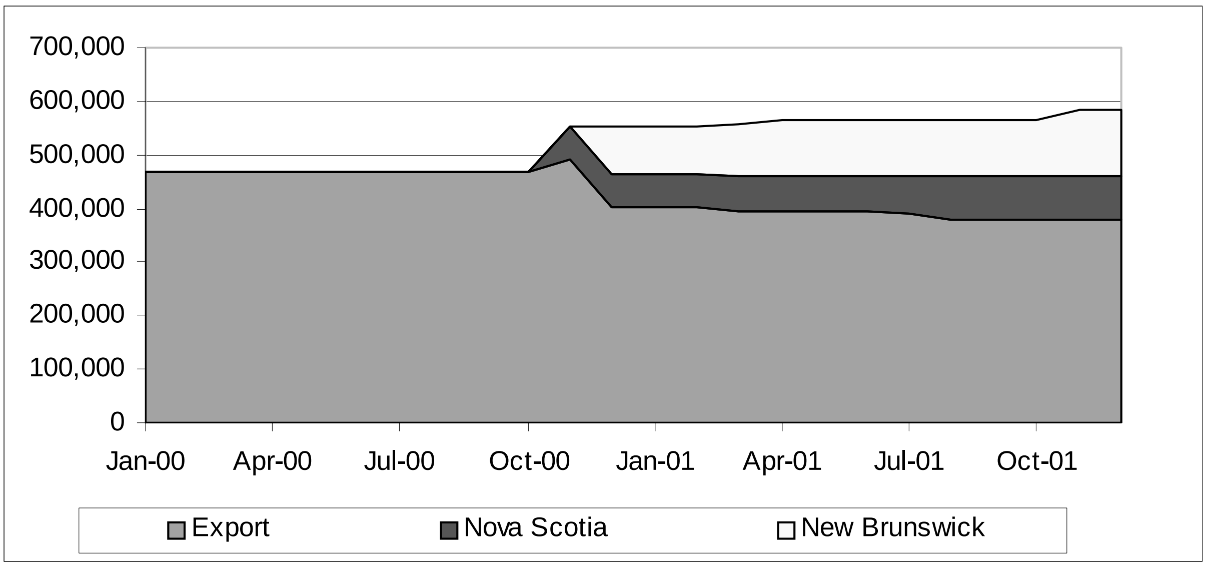
Figure 1-1
M&NP/M&NE System Map



1.2.4 Disposition of Supply

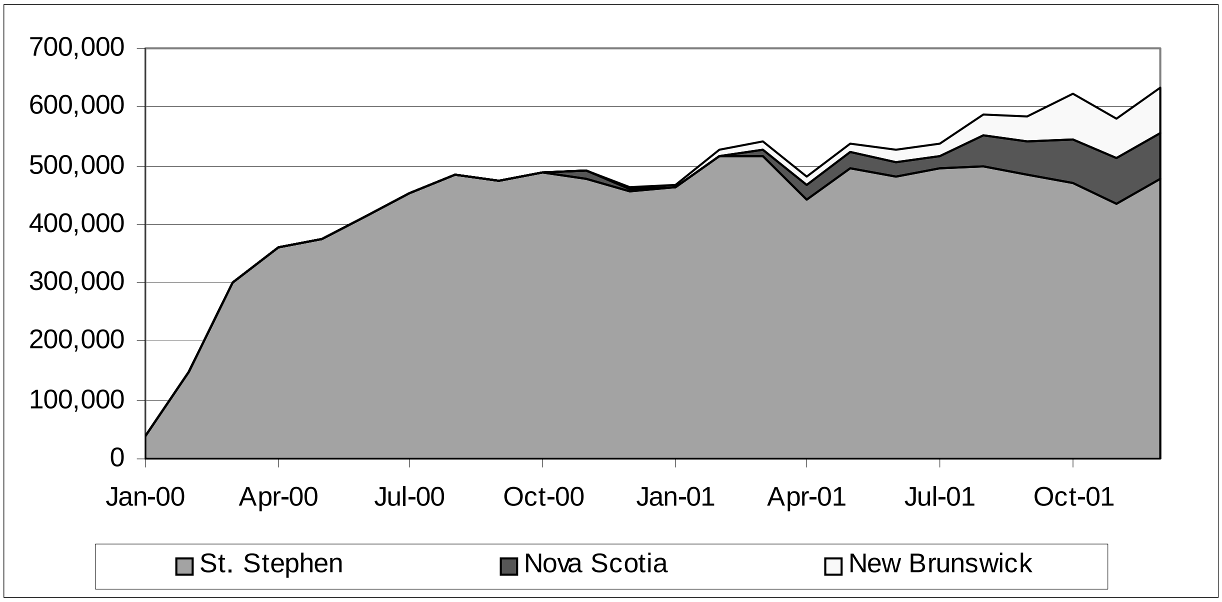
M&NP has a total firm contracted load of approximately 585,500 GJ/d (555,180 MMBtu/d). This includes approximately 205,800 GJ/d (195,142 MMBtu/d) of deliveries scheduled to primary delivery points in Canada. The balance, approximately 379,700 GJ/d (360,036 MMBtu/d), is contracted to the St. Stephen export point. Figure 1-2 shows the firm contracted volumes on the M&NP system. The figure illustrates that the export market has provided the anchor load for the M&NP system. Domestic contracted volumes began flowing in late 2000 in Nova Scotia followed by New Brunswick. Domestic firm service contracts have increased the total contract volumes for the M&NP system. However, the increase in domestic contract volumes has been partially offset by reduced deliveries to the export market.

Figure 1-2
Contract Volumes on M&NP Pipeline (GJ/d)



The actual gas flows on M&NP's system do not reflect the contractual split between domestic and export markets. Figure 1-3 shows that since the major Canadian laterals commenced service in the latter part of 2000, Canadian deliveries have increased significantly. More recent data indicates that Canadian deliveries have stabilized at an average level of approximately 145,000 GJ/d (137,490 MMBtu/d) during the first eight months of the gas contract year (Oct/01-May/02). This represents approximately 70 per cent of Canadian shippers' firm contracted entitlement to M&NP capacity. The balance of the Canadian entitlements are largely used to export gas to markets in the U.S.

Figure 1-3
M&NP Average Monthly Throughput (GJ/d)



Chapter 2

Adequacy of Scotian Offshore Supply

Issue 1 on the Board's List of Issues is "The adequacy of Scotian offshore gas supply to meet the reasonably foreseeable requirements of domestic and export markets."

New Brunswick stated that the main reason Maritime gas buyers are having difficulty accessing Scotian offshore basin natural gas supply is due to stringency of supply. Deep Panuke is the only new source expected to be developed over the next five years; buyers have few options for obtaining gas other than negotiating with the producer of this source, EnCana Corporation (EnCana).

New Brunswick engaged geophysical consultants, Dr. James Wright and Mr. Ian Atkinson, to review the geological setting offshore Nova Scotia, the natural gas reserves, discovered resources and undiscovered potential and to comment on the future availability of supply from this region in the near and medium term. Dr. Wright and Mr. Atkinson concluded that while the potential for new reserves to be discovered is large, the exploration drilling effort over the last 10 years indicates that this potential is unlikely to be discovered and proven in time to maintain gas deliverability from SOEP and Deep Panuke as these fields decline. The last Significant Discovery Licence (SDL) issued prior to Deep Panuke was for South Venture in 1988.

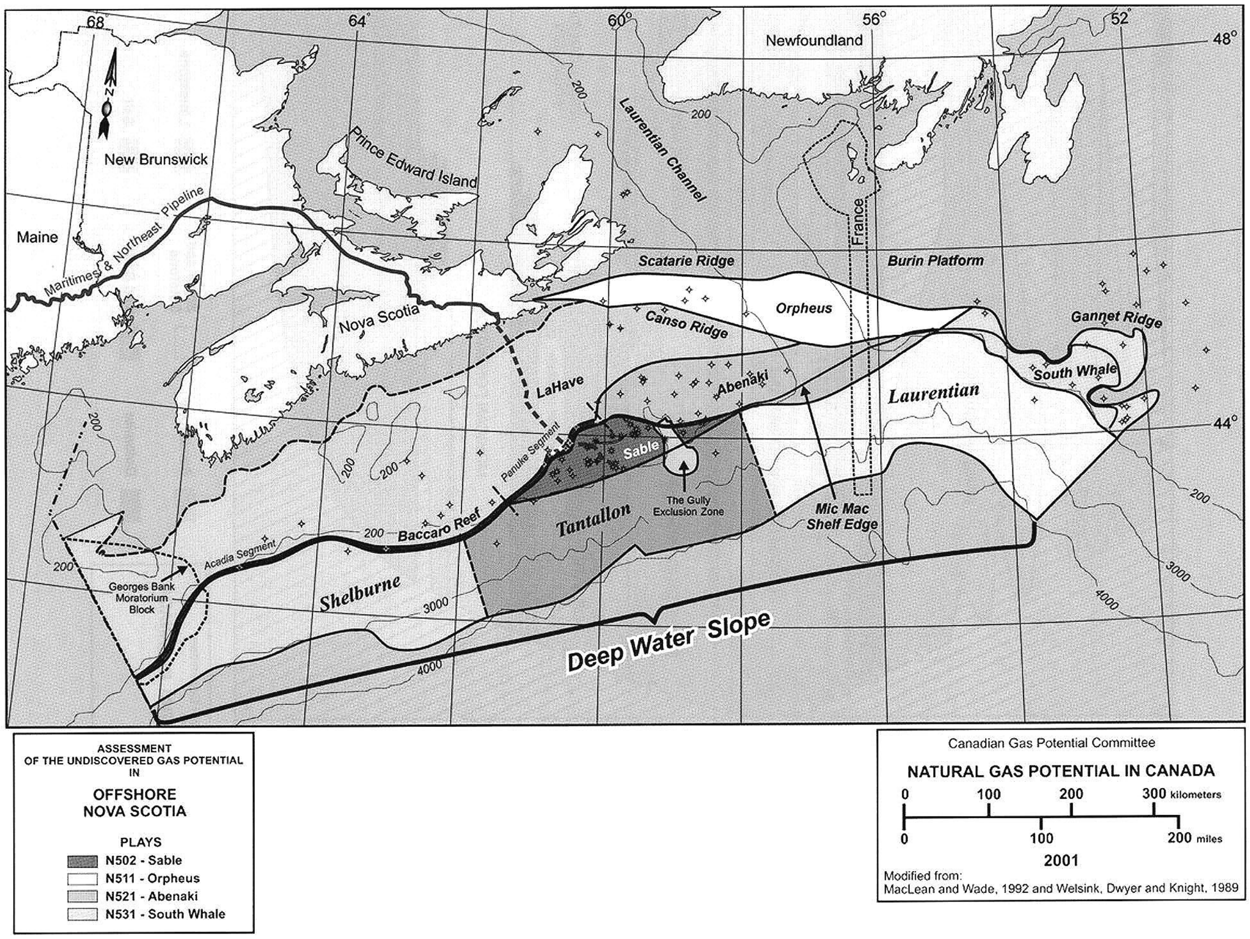
This chapter reviews the evidence provided by New Brunswick and other parties regarding the geological setting, the existing knowledge of reserves and resources, and the outlook for gas production.

2.1 Geological Setting

The Nova Scotia offshore region includes several basins of which the Scotian basin is the largest. Within this basin exists the Sable sub-basin where the significant discoveries have been made over the last 20 to 25 years. The Sable sub-basin lies in shallow waters in the Sable Island area where most offshore drilling has taken place to date.

In the last few years, much interest has been shown in the deeper waters of the Scotian basin beyond the Scotian shelf, specifically the area along the edge of the shelf where the water depth exceeds 1000 metres. Other sub-basins in the Scotian basin include the Georges Bank and Laurentian Channel which are considered to have potential resources but are as yet undrilled. Also, the LaHave platform and the Orpheus and Abenaki sub-basins are estimated to hold potential gas resources. The location of the basins and play groups referred to in this hearing is provided in Figure 2-1, which has been reproduced with permission of the Canadian Gas Potential Committee (CGPC).

Figure 2-1
Nova Scotia Offshore Basins and Play Groups



The Scotian basin is a relatively unexplored geologic basin which has had some discoveries and is promising in regard to further exploration, potential for discoveries, and further gas production. Several exploration licences have been awarded to major producers who are conducting exploration programs.

The Scotian basin has discovered reserves at SOEP and discovered resources in the SDL areas in the Sable sub-basin. Most of the previous Sable discoveries have been in the Missisauga and Mic Mac zones. The Deep Panuke field has gas in the deeper Abenaki reef play. The deep water area is believed to be a turbidite play. Turbidite plays in other areas of the world are prime exploration targets because they contain large reserves and resources.

2.2 Reserves and Resources

The only current Scotian offshore production is from the SOEP which commenced in December 1999. Discovered reserves of some 2.6 Tcf have been estimated by the producers for the six SOEP fields which include Venture, Thebaud, North Triumph, South Venture, Alma, and Glenelg fields. This estimate and estimates by others are shown in Table 2.1. The three SOEP Tier I fields (Venture, Thebaud, and North Triumph) have been producing for over two and one half years. The group of producers operating the SOEP fields include ExxonMobil Canada Limited (ExxonMobil), Shell Canada Limited (Shell), Imperial Oil Resources Limited (Imperial), Emera Energy and Mosbacher Operating Limited. The three Tier II fields are now being developed to maintain the current SOEP production rate. In addition, exploration is being conducted for SOEP Phase 2, which are the other SDL resources near the six SOEP fields. With this production, the SOEP producers expect to be able to continue to serve, at current rates, domestic and export markets for approximately 13 years.

Table 2-1
Comparison of Scotian Offshore Reserves and Resources Estimates (Tcf)

	SOEP Reserves (Tier I & II)	SDL Discovered Resources	Sable Undisc. Resources	Deep Panuke Reserves	Deep Panuke Undisc. Resources	Deep water Undisc. Resources	Ultimate Potential
New Brunswick	2.6	1	0 to 3.5	0.9	3 to 4	5 to 25	20.5 to 49
SOEP producers	2.6						
CNSOPB	3	1.9		1			18
Nova Scotia	3	1.9	4.75 (CGPC)	1			28
GLJ	4.5	(incl. in 4.5)	3.5	0.9	4	5 to 25	low- 11 med. - 18 high - 89
EnCana				0.9	9.1	15	25
CGPC	6	(incl. in 6)	4.75	(incl. in 6)		(incl. in 4.75)	11
GSC					l.0		18
NEB	3	1.9					18 to 31*
First Energy							12
Ziff Energy							50
El Paso							50-100

* 31 Tcf includes Georges Bank and Laurentian Channel

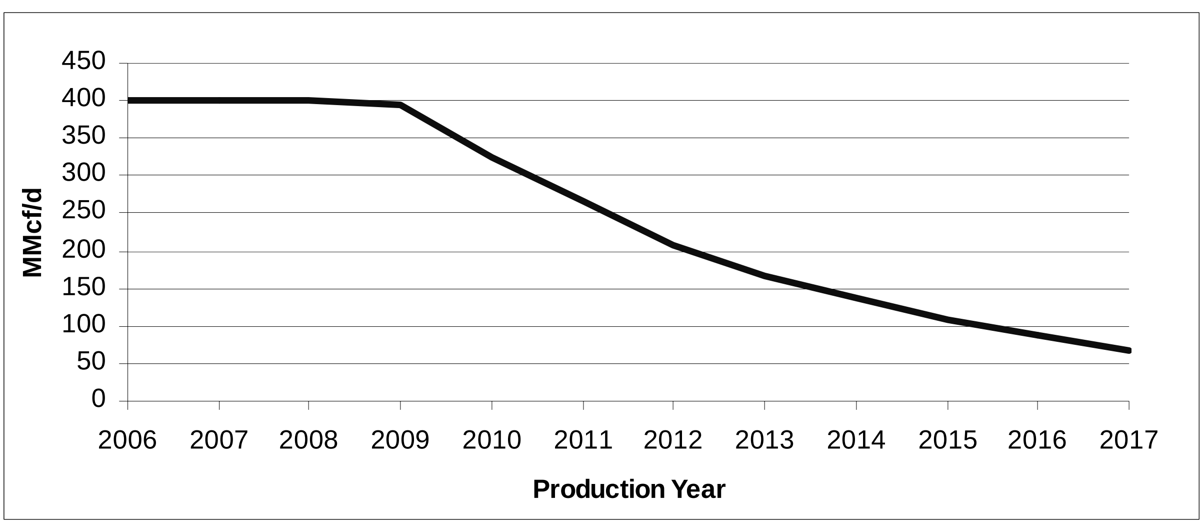
New Brunswick submitted that the Potential Gas Resources table, from the 2002 Gilbert Laustsen Jung (GLJ) Scotian Basin Supply study, which includes estimates of discovered reserves and resources of 4.5 Tcf for the SOEP fields and the SDLs, is optimistic since not all of the SDLs would likely be commercial. The undiscovered resources add a further 3.5 Tcf according to GLJ, but since the best prospects are drilled first and activity has moved from the shallow water to the deep water, New Brunswick was of the view that the potential for commercial status of the undiscovered resources in the shallow water area could be zero. New Brunswick indicated that a total of 3.6 Tcf (2.6 discovered and 1.0 Tcf for the SDLs) is reasonable considering recent reserves reductions at SOEP.

Dr. Wright and Mr. Atkinson pointed out that the SOEP reserves were reduced after only two years of production; further, declines in production may occur earlier than the original forecast of 2014. New Brunswick suggested that this puts in question all the Scotian offshore basin resource. The Tier II and significant discovery licenses only maintain production and there is little current exploration and investment in them.

The Province of Nova Scotia, Department of Energy (Nova Scotia) stated that within the Sable sub-basin, in which the SOEP fields are located, there are additional discovered resources. There are a total of 22 fields which have significant discovery status and have been assigned discovered resources. The CNSOPB has assigned a total of 1.9 Tcf of recoverable resources to them. Nova Scotia submitted a production forecast by Shell that shows some of these fields may be placed on production by 2007 and will act to maintain current SOEP gas production.

EnCana has submitted development plans to the CNSOPB and to the Board with respect to the Deep Panuke field. EnCana has prepared economic estimates of sales gas reserves for the field which indicate an expected mean value of 26.3 10^9m^3 (935 billion cubic feet or Bcf) of recoverable gas reserves. Four existing gas wells may begin production by early 2006 at a combined rate of 11 330 $10^3m^3/d$ (400 million cubic feet per day or MMcf/d). The production forecast indicates production is expected to remain flat for three years and then decline over the life of the field for a total of 11.5 years to a level of 50 MMcf/d (see production forecast, Figure 2-2). Additional wells may be drilled as necessary to maintain production and compression could be added. Additional infill or extension wells are not expected to add reserves or increase production based on current data; however, production data would be analysed in this regard.

Figure 2-2
EnCana Deep Panuke Gas Production Forecast



EnCana described the Deep Panuke project as requiring a development investment of $1.1 billion; however, EnCana will not consider sanctioning the project until after receiving regulatory approvals. If the project proceeds, production information will assist in assessing the reserve estimate and EnCana hopes to have significant information regarding this after six to nine months of production, as there are operational uncertainties regarding the reservoir. Adjustments may be made to the production decline forecast as more data becomes available. EnCana has stated that it is unable to unconditionally commit gas to buyers until the production profile is more firmly established. EnCana based its economics for analysis of the development plan on the production level of 11 300 $10^3m^3/d$ (400 MMcf/d) for three years and then declining, and stated that this rate is necessary given the investment involved. It also stated that lowering the production in an attempt to lengthen the life of the field would negatively affect the project economics.

Dr. Wright and Mr. Atkinson stated that the undiscovered resource estimate is inferred from porosity maps derived from seismic data. Two recent well abandonments by EnCana in this play indicate that seismic definition of the prospective, porous zones within the reef front is not a straightforward exercise and, therefore, the undiscovered resource potential of 4.0 Tcf that is attributed to this play by GLJ has considerable risk associated with it and may be high. As a result, they concluded that the entire Abenaki reef in which the Deep Panuke reservoir is located is not prospective for gas resources. They submitted that the GLJ estimate of 4.0 Tcf of undiscovered resources assigned here may be high. New Brunswick used an estimate of 3.0 to 4.0 Tcf of undiscovered resources for the Deep Panuke Abenaki reef. EnCana has estimated undiscovered resource potential in the Abenaki reef of 9.1 Tcf. The two wells just south of Deep Panuke were not successful but did provide additional information for reserves evaluation of the field.

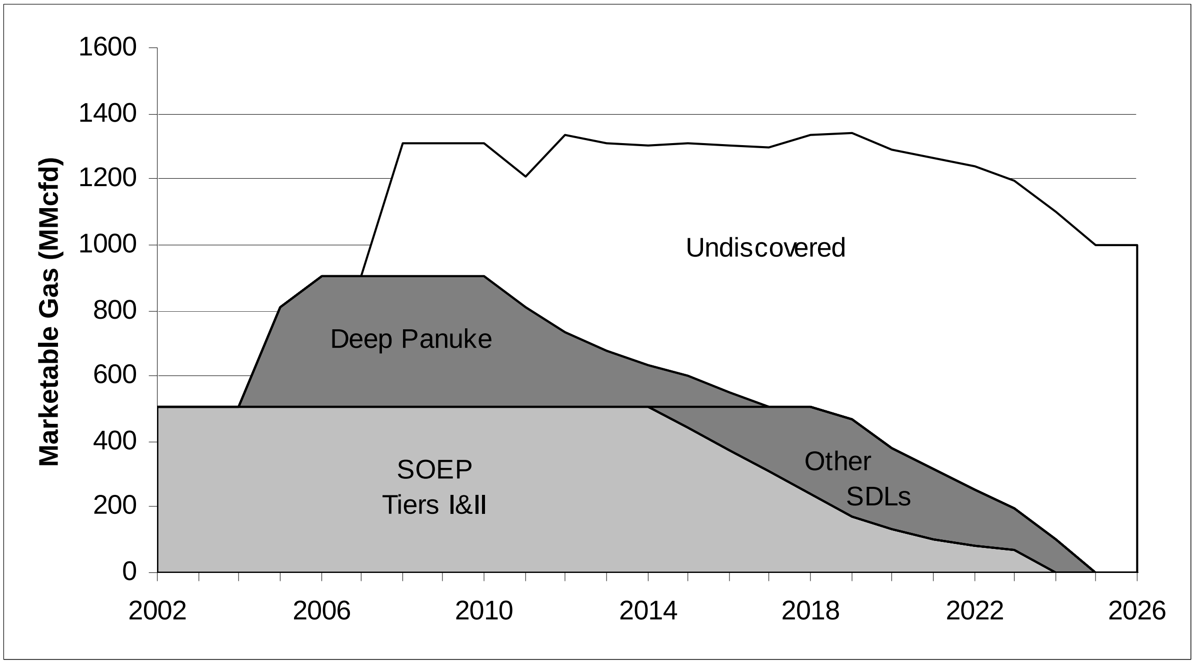
New Brunswick’s position on the Scotian offshore basin is that although the gas resource potential is large and there are significant exploration work commitments and interest, it is not a proven resource. Exploration is slow, there are long lead times from discovery to production, resource estimates are uncertain, proven reserves have been reduced, and steep production declines are prevalent; consequently there is a stringency of supply. Discoveries could result in production by 2010 at the earliest but it is unknown what type of production profile will occur. The results of drilling programs over the next few years will be critical in indicating the production potential of the basin.

2.3 Outlook for Supply

Dr. Wright and Mr. Atkinson noted the difficulty in arriving at reliable estimates of gas supply but agreed that it was necessary to develop such estimates. They derived their estimate from a number of public sources, notably the GLJ report, which served as a focal point of much of the discussion during the hearing. Table 2 of the GLJ report is reproduced here as Figure 2-3.

The GLJ production forecast shows the production estimates for SOEP, the SDLs, Deep Panuke, and the undiscovered potential. The SDLs are shown to begin producing in 2015 and decline after five years, while Deep Panuke is shown to begin production in 2005, and decline after six years. The undiscovered resources are forecast to begin producing in 2008; however, the Applicant suggested this would be difficult to accomplish.

Figure 2-3
Scotian Offshore Basin Gas Production Forecast



Dr. Wright and Mr. Atkinson prepared and submitted an adjusted Scotian basin potential production forecast for each of the periods 2002 to 2005, 2006 to 2010, and 2011 to 2020 as follows:

<u>2002 - 2005:</u>
500 MMcf/d from SOEP - no additional production available.

<u>2006 - 2010:</u>
900 MMcf/d from SOEP and Deep Panuke. There remains the possibility of additional gas production by 2008 if there is a significant discovery by 2003. It appears as though the current SDLs are not of sufficient commercial viability to be brought into production. A new (significant - Deep Panuke size) discovery is required by 2003 to increase deliverability by 2008.

<u>2011 - 2020:</u>
It is possible that combined production could rise to 1300 MMcf/d, but this will require the equivalent of at least 3 to 5 Deep Panuke size discoveries (either Abenaki or Deepwater). This will compensate for the decline in production from both the SOEP and Deep Panuke fields early in the next decade. For this target to be met, an average of one significant (Deep Panuke size) discovery per year is required between 2004 and 2008. With the discovery rate in the past decade, this is an ambitious undertaking and a difficult goal to achieve.

The Applicant suggested that the deep water area (turbidite play) is estimated to have significant gas potential. The deep water area extends along most of the outer edge of the Scotian basin and is largely untested. New Brunswick stated that the pace of drilling will have to accelerate for discoveries to be made in the deep water area to add additional production by 2010 and this is not a reasonable scenario. Currently there are two wells drilling to test the resources in the deep water area.

The Canadian Association of Petroleum Producers' (CAPP) view is that Scotian offshore supply is in its infancy. Success rates are typically low in a new basin; hence exploration is high risk and in offshore areas, costs are high and lead times are long. There are production challenges to consider and production additions may not be smooth. CAPP stated that producers have undertaken large exploration programs covering over six million hectares with work commitments of $1.5 billion. Wells are currently being drilled and more producers are interested. CAPP pointed out that producers would not drill prospects and make commitments unless they have confidence in increasing the production level.

EnCana also noted increasing exploration levels and that there are prospective exploration licences with $1.5 billion in work commitments. EnCana expects to drill eight to 15 wells in the next three to five years. Additionally, EnCana forecasts there will be between 20 and 30 exploration wells drilled by industry before 2006 under the existing work commitments and suggested that two to three discoveries are possible given a 10 to 20 per cent success rate.

Nova Scotia stated that there is significant interest, activity, and expenditure occurring that should result in discoveries and eventual production. Nova Scotia pointed out that exploration wells cost up to $90 million and as such, decisions to drill are high-risk and require careful examination of all data. Large land positions are held by major producers such as ExxonMobil, Shell, BP Canada Energy Company, Chevron Canada Limited, EnCana, Imperial, Kerr-McGee Offshore Canada Limited, and Marathon Canada Limited.

Nova Scotia stated that there are 59 exploration licences with $1.5 billion in work commitments which include drilling. About one third are on the shallow water Scotian shelf, while the remaining two thirds are in the deep water area. The licences need to be drilled by 2006 to avoid forfeitures amounting to 25 per cent of the exploration work commitments.

Several parties expressed concern that until more discoveries are made and new fields found and developed, incremental production from the Scotian basin will be irregular (lumpy), as individual projects are developed one at a time and likely not in a sequential manner. Nova Scotia indicated that Shell predicts that the Sable area fields (SDLs) will begin to be developed by 2007 to at least maintain production. Essentially all parties agreed that it is not certain that exploration successes will be made that could result in additional gas production. However, most parties did agree that discoveries are likely to be made given the level of interest and investment in the Scotian basin. The length of time from discovery to production in the offshore is significant, but it does shorten as experience is obtained, according to Nova Scotia.

Views of the Board

The Board is of the view that there is adequate supply to maintain the current level of deliveries to the domestic and export markets. Production from the development of the SOEP Tier II fields and additional future production from development of the shallow water SDLs should ensure that at least the current level of production is maintained for approximately 13 years.

The outlook for incremental supply remains very uncertain, although promising in light of the geological potential and commitments by producers to some $1.5 billion in exploration expenditures over the next five years.

In the near term, the gas recently discovered at the Deep Panuke field could almost double current production rates from the Scotian offshore. However, securing this source of supply for domestic markets will present a number of challenges. First is the fact that EnCana is only prepared to make conditional supply commitments. EnCana estimates that the production profile can only be known with some degree of certainty after six to nine months of production. A second difficulty is the short flat life and steep production decline projected for the field. Negotiations between EnCana and domestic buyers will have to address the sharing of supply risk that these challenges present. These matters are discussed more fully in section 3.3.

In the longer term, production from the Scotian offshore basin is highly dependent on the results of the exploration work commitments in the shallow water areas as well as the deep water areas. Exploration drilling successes are needed to continue the development of the basin. The estimates of undiscovered resources on the Scotian basin in the shallow water areas and the deep water areas are considerable. While the success and timing of such supply additions cannot be known, nor can future field sizes, production levels and profiles be specified, it is likely that domestic buyers and governments who wish to use offshore supplies to underpin new infrastructure will need to continue to show creativity in addressing supply risk until the basin reaches a level of maturity where supply security is no longer an issue.

Chapter 3

Access to Scotian Offshore Gas

Issue 2 on the Board's List of Issues is: "Whether domestic gas buyers have a fair opportunity to purchase Scotian offshore gas." Issue 3 is: "The role of infrastructure in determining the domestic market's opportunity to access Scotian offshore gas." As the hearing developed, it became apparent that these issues are very inter-related. Therefore the Board has decided to address both issues in this chapter.

3.1 Structure of the Market

At the hearing, there was significant discussion concerning the nature of the Maritime gas market. Some parties argued that it is a well-functioning market connected to the rest of North America, while others argued that it is an isolated market in which Maritime gas buyers face disadvantages compared with U.S. buyers in competing for available supplies of Scotian offshore gas.

New Brunswick argued that the Maritime Canadian market is not a well-functioning market. It stated that supply is highly concentrated, with 60 per cent of current production coming from one producer, a share that is large enough to dominate the market. New Brunswick also noted that, at the moment, there is only one potential supplier of incremental supplies of Scotian offshore gas and that there is a single monopoly transportation system. Given this concentration on the supply side, New Brunswick maintained that it would be theoretically possible for a gas seller to raise prices above a competitive level for sustained periods.

More specifically, New Brunswick argued that attempts by EnCana to obtain compensation from Canadian gas buyers for toll impacts associated with the expansion economics on M&NP's mainline are illustrative of market power (see section 3.3.3.2 for further discussion). Maritime Electric and NB Power also suggested that EnCana has market power, respectively noting that EnCana is the only source of new supply and that there is no competitive market for a buyer who wishes to access incremental gas supplies.

New Brunswick contrasted the Maritime gas market with the Western Canada Sedimentary Basin, which contains over 600 gas producers. In this market, New Brunswick indicated that it would not be possible for one or two gas sellers to exercise market power because of the degree of competition.

New Brunswick also stated that prices and terms in the Maritime market are not transparent because they are directly negotiated between buyers and sellers with no public disclosure. As a result, there is no source of readily available information on domestic gas prices and Maritime gas buyers do not have adequate information to determine what terms and conditions are available. However, New Brunswick did concede that, through the connection of M&NP to Dracut, Maritime gas buyers could price gas purchases as a basis differential to robust markets in the U.S., including the Henry Hub.

Despite the availability of Dracut as a pricing reference point, both New Brunswick and Maritime Electric were of the view that, until there is a more competitive market at Goldboro, Canadian gas buyers would not have equal leverage in price negotiations compared with gas sellers, and sellers would not have an incentive to negotiate fairly. Nonetheless, Maritime Electric acknowledged that it had not seen any evidence that producers are not negotiating in good faith.

On the other hand, CAPP and Nova Scotia argued that the Maritime gas market is connected to the larger North American market. Specifically, CAPP argued that gas producers are price takers in the competitive North American natural gas market and that prices in the Maritimes could be effectively priced off the Boston market at Dracut. It noted that this is the method by which prices are set in places such as Manitoba or Montreal, where gas is priced, respectively, off the market in Alberta at the AECO-C hub and at the Dawn hub in Ontario.

CAPP also noted that the SOEP producers sell natural gas to a variety of buyers who resell the gas to secondary buyers. In addition, the transportation capacity on M&NP is widely held by a number of shippers who can assign the transportation to other users. There are also a number of marketers who are entering the Maritime gas market. All of these factors contribute to making the Maritime gas market more competitive than if only the number of gas producers were considered.

Nova Scotia argued that the Scotian offshore basin is a nascent basin and, as such, it is only natural that there are only a few sellers and limited price transparency. Nova Scotia noted that price transparency generally develops at hubs where there are a large number of secondary market transactions, and that these transactions form the basis for price discovery. It noted that prices for primary transactions are not disclosed in any North American natural gas market and that it would not be reasonable to expect Scotian basin producers to disclose the terms and conditions of their primary sales contracts. Nova Scotia agreed with CAPP that Maritime gas buyers can effectively price their gas purchases off the Dracut pricing point.

3.2 Failure of Maritime Gas Buyers to Obtain Natural Gas

In support of its contention that the Maritime gas market is not well functioning, New Brunswick offered evidence of Canadian customers who were unable to purchase Scotian natural gas.

3.2.1 Tractebel

Tractebel Energy Marketing Inc. (Tractebel), with the support of NB Power, wanted to build a 350 MW combined-cycle combustion turbine at Belledune, New Brunswick. On 2 June 1999, Tractebel sent Duke Energy Marketing Limited Partnership (Duke Energy) a draft term sheet offering to purchase approximately 55,000 MMBtu/d of natural gas for receipt at Goldboro. Although Tractebel's proposed term sheet was for 25 years of supply, under cross examination this number was revised to between 15 to 25 years. Tractebel was not able to obtain gas supply from Duke Energy.

New Brunswick suggested that the Tractebel project was an attractive opportunity which, had it gone forward, would have enabled M&NP to build a lateral in northeastern New Brunswick under the Lateral Policy, and allowed EGNB to begin distribution in that part of the province. NB Power had signed a

Precedent Agreement with M&NP for a lateral to transport 57,000 MMBtu/d of natural gas and planned to increase that throughput to 96,000 MMBtu/d. NB Power believed that the lateral would be economic because, under the Lateral Policy, it was entitled to pool credits from the surplus on the Saint John Lateral with the expected shortfall on the Northeast Lateral if they were built within the same time frame. With respect to electricity transmission, New Brunswick indicated that Tractebel had firm transmission in New Brunswick and transmission access on the Maine Electric Power Company system.

New Brunswick claimed that the Tractebel project did not proceed because it could not obtain gas supply from Duke Energy. It argued that Duke Energy did not provide a satisfactory explanation for not meeting to negotiate terms over the summer of 1999. The Applicant suggested that the only inference to be drawn was that Duke Energy was not prepared or did not want to sell gas to Tractebel. It concluded that Tractebel's inability to obtain natural gas was an example of market failure.

Duke Energy responded that by 1999 production from SOEP was largely committed. Duke Energy submitted that, months before production from SOEP commenced, it informed Tractebel that there was no way of knowing the availability of incremental gas with any certainty until after gas had flowed for some six to nine months. In addition, Duke Energy informed Tractebel that it did not have long-term gas supply available in the volume Tractebel requested that was not already attached to transportation commitments to the United States. Nevertheless, Tractebel sent Duke Energy an offer to purchase gas supply at Goldboro. Since Duke Energy's available supply was already attached to transportation commitments to the United States, Duke Energy believed that it did not have the product that Tractebel was seeking on the terms it was willing to pay.

Nova Scotia and CAPP suggested that the reason Duke Energy could not provide Tractebel with gas had nothing to do with alleged misbehaviour but was due to the fact that Tractebel was looking for a 15 to 25-year firm gas supply. These parties argued that there was a mismatch between available gas supply and the Tractebel project gas supply requirements. CAPP claimed that there was no discrimination, no bad faith, and no refusal to supply, but that Tractebel was looking for supply after gas sales and transportation commitments had already been made. TransCanada PipeLines Limited (TransCanada) argued that there was no evidence to conclude that Tractebel was denied a sale on terms and conditions that were made available to export customers. CAPP concluded that, while Tractebel could be disappointed, a disappointed buyer is not evidence of market failure.

Duke Energy, CAPP and Nova Scotia argued that more than just gas supply was outstanding for the Tractebel project at Belledune. They indicated that the project was at a preliminary stage of development and faced significant challenges. It would require a 220 kilometre lateral, the cost of which would have to be fully rolled into the M&NP rate base, which was uncertain. Moreover, as a merchant plant, the Tractebel project would require firm transmission capacity in New England for 250 MW of its output. In this connection, Tractebel was near the bottom of the Interconnection Study queue of power-generation projects seeking to deliver power into the New England market. CAPP submitted that Tractebel was a global energy company that had many projects under evaluation and it would not be unusual for a project to be abandoned after an evaluation stage.

New Brunswick argued that all the other major components of the project were in place or that there were means for resolving outstanding issues so that it was the lack of gas supply which caused the cancellation of the Tractebel project. In support of this view, New Brunswick argued that there were two projects in the queue subsequent to Tractebel, which the New England Independent System Operator approved, and many projects before Tractebel that were not approved. Therefore, it was not Tractebel's position in the queue but rather the merits of the project that determined approval.

3.2.2 Cartier

New Brunswick submitted that the inability of Cartier Pipeline and Company, Limited Partnership (Cartier) to obtain incremental Scotian offshore gas for markets in northern New Brunswick, Quebec and Ontario was evidence of a market problem. It suggested that potential Cartier shippers cannot obtain these supplies without making a formal complaint to the Board, but were reluctant to do so because that might prejudice the proponents' other business interests.

New Brunswick argued that Cartier is willing to contract for gas supply at Goldboro on the same terms and conditions that apply to gas destined for the market in Dracut. It suggested that the Cartier project would offer Scotian producers higher netbacks than they could receive from the U.S. northeast market. New Brunswick concluded that Scotian producers are not basing their stance on market considerations. It viewed the inability of potential Cartier shippers to contract for gas as evidence of Scotian producers exercising market power and preferring markets in the U.S. northeast over markets in Maritime Canada.

Duke Energy responded that, like Tractebel, Cartier was in the market for a long-term supply of natural gas, approximately one year after Tractebel. Duke Energy claimed that Cartier had a fair chance to access any incremental long-term gas that would become available to ExxonMobil. If the gas were to become available, ExxonMobil was willing to commit long-term gas to Cartier as the sale would offer the advantage of diversifying its markets for Scotian offshore gas. Duke Energy described its extensive effort in trying to arrange the gas sale to Cartier. Duke Energy and ExxonMobil pursued the prospect of supplying gas to Cartier to the point of developing a fairly extensive set of terms and conditions (the Term Sheet), conditional on the availability of long-term gas supply. An agreement on the Term Sheet with Cartier was reached on 25 October 2000, after SOEP had been producing for nine months. The timing of the agreement on the terms of a prospective sale was consistent with the information that Duke Energy had provided Tractebel regarding when it would be able to determine whether an incremental supply of SOEP gas would become available. However, sufficient incremental SOEP gas did not become available and therefore the negotiations did not proceed beyond this point and a gas sales agreement was never reached.

CAPP noted that the Cartier project sponsors chose not to participate in the hearing and that they have confirmed that more gas supply would need to be established before Cartier could proceed. CAPP also noted that, while New Brunswick suggested that Montreal could provide an anchor market for Cartier, Montreal was not a liquid pricing point and was a tough market for gas due to a high capability for fuel switching. CAPP indicated that the Cartier Project would not be viable without a large contribution from M&NP and its stakeholders in the form of a major pipeline from Fredericton to Edmundston.

Nova Scotia claimed that the Cartier project and its tie to the proposed Northwest Facilities was the real reason for New Brunswick's application. Nova Scotia disagreed with New Brunswick's claim that Cartier would offer higher netbacks to producers than would be available from the U.S. northeast; if this were the case, profit-minded producers would have pursued that market. Nova Scotia also questioned why the Cartier sponsors were not prepared to make the financial commitments necessary to make the otherwise uneconomic Northwest Facilities economic.

3.2.3 Other Power Generation Projects

New Brunswick suggested that other power projects in the Province had been unable to obtain gas at reasonable prices. For example, New Brunswick submitted that Northland Power Inc. and the Louisbourg Power Corporation were offered gas at a price which included transportation charges in the U.S., that is, a Boston Price.

In support, NB Power asserted that a number of power projects in New Brunswick did not proceed because sufficient quantities of natural gas could not be contracted at what it considered to be fair market prices, while projects located some distance from the mainline were also unable to take advantage of M&NP's Lateral Policy. Specifically, projects located near the pipeline had opportunities for gas but only at prices that would be equal to or higher than those in the Boston/New York market.

CAPP submitted that Irving Oil had access to natural gas but chose to abandon the Courtney Bay No. 4 project due to a combination of transmission difficulties and its view of the market. With respect to NB Power's evidence concerning other generation projects, CAPP submitted that these projects, like Tractebel, would require access to the constrained transmission facilities in the U.S., and would also require a long-term supply of incremental gas that was not available. Alternatively, the gas could be bid back from the Boston market, but this was not economic as these generation projects were targeted to the export market.

With respect to NB Power's own generation plans, CAPP submitted that natural gas was the high-cost option in the fuel mix available to NB Power. Accordingly, CAPP suggested that the NB Power primary plan was for the Coleson Cove facility to use Orimulsion(R) and for Point Lepreau to remain nuclear. CAPP further noted that NB Power informed the Board in its Power Line Application that it had no plans for the development of gas-fired generation facilities. Such projects would depend on the ability to sell electricity into the New England market by third-party project developers.

Nova Scotia submitted that gas-fired generation has never been viewed as a preferred alternative in any of the assessments NB Power has done of its generation requirements.

With respect to the Tractebel, Cartier and other power generation projects, CAPP and other parties challenged the quality of New Brunswick's evidence. They noted that the only first-hand evidence provided was from a former employee of Tractebel who had a limited role, for a brief period of time, in the evaluation of the Belledune power project. CAPP also claimed that other portions of New Brunswick's evidence were hearsay as they were obtained second-hand from discussions with others. CAPP suggested that New Brunswick's explanation that potential Canadian purchasers were reluctant to participate in the hearing did not make sense as they were large, sophisticated national and international businesses.

Several intervenors noted that, by 1999, the expected production from SOEP was to a great extent already committed to markets in Canada and the U.S. In this connection, subsequent Canadian purchasers looking for a long-term supply of natural gas would have to either wait until additional Scotian offshore gas became available, or purchase gas that was originally destined for the U.S. market and reimburse the seller for the transportation commitments that had been made to transport that gas to the U.S.

3.2.4 Maritime Electric

Maritime Electric is planning to install three 50 MW gas turbines, two of which will be in combined cycle configuration. The third will be a cogeneration configuration at a large food processing plant. After some initial lack of progress, Maritime Electric believes that it and the Government of Prince Edward Island will be able to negotiate satisfactory terms upon which M&NP will construct a lateral to PEI.

With respect to gas supply, Maritime Electric stated that it has been negotiating the purchase of Scotian offshore gas with a number of producers and marketers and that the negotiations are at different stages with different parties. However, after nearly a year, Maritime Electric has not managed to negotiate a supply of gas. It noted that one of the outstanding issues is the price of gas supply. Maritime Electric expressed the concern that negotiations were not proceeding quickly enough as this was its last opportunity to secure supply until another significant expansion of the M&NP system occurs. Maritime Electric suggested that this situation was not unique as any purchaser in the Maritimes who wants to build a project, or requires infrastructure, would be facing similar circumstances.

Maritime Electric acknowledged that negotiations for gas supply were taking place in good faith and that all the producers to whom it had talked have indicated a willingness to deal, subject to the availability of supply and the ability to negotiate a suitable price. However, Maritime Electric claimed that, while it was prepared to match the price that producers could obtain in the U.S. net of delivery costs, gas suppliers have argued that there is value provided in the U.S. which is not provided by Maritime Electric. Therefore, the gas suppliers maintain that some adjustment or premium to the U.S. price is warranted. From Maritime Electric’s perspective, this would result in a situation where it would not be paying for gas on equivalent terms and conditions as the export market.

PEI acknowledged that there is no evidence that producers are not operating in good faith. However, it suggested that the window of opportunity is quickly closing and its failure to reach an agreement with producers suggests that there may be a problem with the process that warrants intervention.

New Brunswick acknowledged that both Maritime Electric and PEI have testified that negotiations with EnCana are taking place in good faith. However, the Applicant argued that EnCana has huge bargaining leverage that gives EnCana the ability to exercise market power. New Brunswick contended that, if there were other supplies of incremental gas at Goldboro, Maritime Electric could purchase natural gas from another party.

EnCana submitted that negotiations are taking place in good faith and that it is prepared to make sales to Canadian customers on terms and conditions, including price, equivalent to those available in the export market. It argued that if a deal could not be reached between Maritime Electric and EnCana, the Board should do nothing as it is a sign only that two parties have not been able to reach mutually acceptable terms and conditions. CAPP noted that there is nothing unusual about negotiations being protracted and that the parties acknowledged that negotiations were proceeding in good faith.

3.3 Factors Affecting Gas Supply Negotiations

3.3.1 Gas Supply Risk

As discussed earlier, several parties suggested that there is a mismatch between the term for which gas supply is available and the term for which Canadian buyers want a commitment.

EnCana submitted that there are uncertainties surrounding its Deep Panuke project, and given these uncertainties, it does not expect to be in a position to determine whether it can make unconditional sales until six to nine months following the start of production. EnCana argued that this does not mean it could not reach a deal with a Canadian buyer in the interim. Rather, the risks would have to be recognized and factored into the commercial negotiations and the parties would have to agree on how to share the risks.

EnCana suggested that, in the interim, any party that wants to buy Deep Panuke gas but who is not prepared to accept any risk of non-delivery, or who is not prepared to reward EnCana for accepting the risk of non-delivery, is likely to leave the negotiating table disappointed. EnCana claimed that this is not a market failure, but an inability to agree on commercial terms.

CAPP questioned New Brunswick on the fit between domestic demand requirements and EnCana’s projected Deep Panuke production profile. New Brunswick acknowledged that there were not too many projects in eastern Canada or the U.S. that would proceed on the basis of that profile. The Province agreed that projects such as greenfield pipelines, new large scale plants, or significant plant conversions would not likely look favourably upon building on the basis of a short-term supply that is conditional. In this connection, New Brunswick was not able to provide any evidence that Canadian buyers have not had fair access to Scotian offshore gas on the terms of the projected Deep Panuke production profile. Witnesses for New Brunswick indicated that their evidence was indicative of a potential problem and they believed that they were being proactive rather than reactive in alerting the Board to that potential.

In argument, New Brunswick suggested that the mismatch between projected supply and demand requirements should not be a concern. It noted that EnCana plans further drilling and therefore the final production profile for the Deep Panuke Project has not been established. In addition, New Brunswick noted that two prospective purchasers of natural gas, Maritime Electric and NB Power, have stated that they were prepared to sign 10-year contracts with EnCana for their needs based on EnCana's production profile, thereby taking the risk of gas supplies beyond a 10-year period. New Brunswick therefore argued that its evidence is not dependent on whether or not customers who wanted to build anchor facilities could do so on the basis of EnCana's Deep Panuke production profile.

Nova Scotia claimed that New Brunswick’s case was about a potential problem and not the existence of a problem in the market. Nova Scotia argued that New Brunswick’s case could not be saved by Maritime Electric or NB Power as none of their witnesses could point to any evidence that EnCana, Duke Energy or any other producer was bargaining with anything other than the utmost good faith.

M&NP suggested that it is understandable that buyers are reluctant to assume risk or incur obligations which are greater than those presented by other energy options to which they have access. In its view, that was a healthy dynamic, not market failure.

CAPP cited Maritime Electric as an example of a consumer addressing the lumpiness of supply and risk by commercial means. CAPP indicated that, while the shape of all the projects that would be developed is unknown, time and more production are the key factors to address the availability of supply and the ability of Canadians to have the confidence required to make long-term commitments to infrastructure.

Duke Energy indicated that parties buying short-term gas are taking a risk and betting on the assumption that gas would be available in the long term. Duke Energy concluded that the evidence indicates that end-users who are located close to infrastructure are willing to take the risk of utilising short-term gas to satisfy long-term requirements.

Chevron Canada Resources and TransCanada noted that the lumpy production profile does not match with consumer needs for long-term secure supply to underpin project financing for infrastructure development. In this connection, they suggested that the problem was not market dysfunction or market power, but rather a problem related to supply. Duke Energy submitted that limits on supply do not equate to a problem with the operation of a market. Similarly, TransCanada suggested that a lack of acceptable long-term supply was the problem, not a lack of access to the available supply.

3.3.2 Transportation Considerations

EnCana has signed conditional agreements with M&NP for transportation on the Canadian and U.S. portions of the pipeline. These agreements will ensure that Deep Panuke gas can access the U.S. northeast market and will permit EnCana to transport 400,000 MMBtu/d of gas for a term of 10 years.

New Brunswick submitted that, while these agreements contain provisions for EnCana to reduce its transportation commitment by up to 200,000 MMBtu/d, it must decide to do so by 31 July 2003. Once the agreements become binding, EnCana would be committing between $0.7 billion and $1.4 billion in demand charges over the life of the contract, depending on the level of throughput.

New Brunswick questioned why EnCana was prepared to take the risk of making unconditional transportation arrangements prior to production when it would not take a similar risk by making unconditional commitments to Canadian customers for gas supply until six to nine months after Deep Panuke goes into production. New Brunswick argued EnCana’s treatment of transportation contracts was different from supply contracts and, therefore, discriminatory. New Brunswick further argued that EnCana’s gas supply contract with its affiliate, EnCana Energy Service Inc., which extends to 2008 and covers all of EnCana’s gas including Deep Panuke gas, was not consistent with its position that it would not make unconditional gas sales commitments until after production has been established.

EnCana submitted that the transportation agreements do not preclude EnCana from making gas sales to Canadian customers. As New Brunswick stated, the agreements each contain a specific provision, a step-down clause, that allows EnCana to elect prior to 31 July 2003, to decrease the daily transportation quantity by any amount to a floor of 200,000 MMBtu/d. Therefore, if sales of Deep Panuke gas to

Canadian buyers occur prior to 31 July 2003, EnCana could reduce its commitment to transportation on M&NP accordingly. EnCana further submitted that the transportation agreements would not preclude EnCana from making gas sales to Canadian customers after 31 July 2003. Deep Panuke gas would be sold into the export market on a short-term basis and there is nothing that would stop a Canadian gas buyer from contracting with EnCana at any time either before or after the project commences operation. However, since EnCana would not be able to exercise the step-down election after 31 July 2003, any subsequent agreement with a Canadian buyer would have to take into account the transportation commitments undertaken by EnCana.

EnCana argued that the different treatment of supply and transportation contracts was not discriminatory. EnCana submitted that it has no choice but to accept the supply risk related to the unconditional transportation commitments to M&NP if it is to be able to move Deep Panuke production to market. On the other hand, EnCana noted that it does have a choice whether or not to accept an incremental supply risk when negotiating with prospective gas purchasers.

Mirant Canada Energy Marketing, Ltd. (Mirant) argued that the risk of long-term sales obligations are separate from the risk of sufficient supply for pipeline capacity and therefore, the supply risk associated with a sale of gas is incremental to the supply risk associated with transportation commitments. Moreover, unlike the pipeline commitments, these are avoidable risks because the market, as it operates, does not require sellers to assume the additional risk associated with long-term sales obligations. Mirant contended that, if implementation of New Brunswick's proposal were to force those parties to assume additional long-term sales contract risks, it would be a completely unfair and inappropriate outcome.

Maritime Electric argued that it does not have the same opportunities that export buyers have to purchase Scotian offshore gas. Because the pipeline capacity is tied to the quantity of gas the producers have available for export, a Canadian buyer like Maritime Electric has a fairly narrow window of opportunity to purchase Scotian offshore gas, which is something that export purchasers do not face.

Maritime Electric submitted that the situation is becoming critical because if an agreement is not reached by 31 July 2003, Maritime Electric will not have the ability to access Scotian offshore gas required for its projects, unless it agrees to pay the U.S. transportation costs. For this reason, Maritime Electric concluded that it is up against a deadline and has not yet been able to acquire Canadian gas even though it is willing to match the export prices.

EnCana acknowledged that there was a perception by some Canadian buyers that 31 July 2003 represents a deadline for concluding a deal with EnCana to purchase Deep Panuke gas. EnCana indicated that it would like to accommodate these purchasers and that a deal would be concluded when they have been offered a package of terms and conditions, including price, as favourable as those available to EnCana in the export market.

3.3.3 Valuation

3.3.3.1 Boston Price

As indicated in previous sections, New Brunswick submitted that marketers of Scotian offshore gas have been requiring potential Canadian purchasers to commit to paying the Boston price for gas, even though that price incorporates Maritimes & Northeast Pipeline, L.L.C.'s (M&NE) U.S. pipeline toll and Canadians do not require transportation in the U.S. It suggested that producers appear to be using this requirement to try to pass along to Canadian customers costs that the producers have incurred as a result of long-term transportation commitments on M&NE's system. New Brunswick acknowledged that, while this may be justified for those volumes subject to the pipeline utilization agreements for minimum volumes of 360,000 MMBtu/d, it is not justified for volumes over that level that are not subject to long-term transportation contracts. New Brunswick submitted that, by insisting on a Boston price, producers are creating a significant barrier to Canadian purchasers by requiring the payment of transportation costs that are not required by the Canadian users.

New Brunswick claimed that this is an example of market power and that producers would be exercising market power unless they would be prepared to sell gas to a buyer at Goldboro for the Dracut price less the transportation cost. Although New Brunswick recognized that producers may have incurred a fixed cost in obtaining transportation, New Brunswick suggested that a seller would be exercising market power unless it was prepared to forego compensation for the demand charges that it had committed to pay to the pipeline.

NB Power indicated that, since there was no transparent liquid market at Goldboro, netback pricing was a reasonable way to determine fair market prices for Scotian offshore gas as it would give producers the same equivalent netback price that they would receive if they had to pay transportation charges to ship the gas to the Boston/New York market. However, NB Power indicated that it would be appropriate for producers to seek transportation charges for the gas that they sell after they have made firm service transportation commitments. NB Power indicated that, unless the Scotian offshore gas is made available to Canadian purchasers before those firm service transportation commitments are entered into by the producers, there is a significant risk that the only way a Canadian purchaser would be able to obtain access to that gas is by paying a premium equal to the transportation cost between Goldboro and Dracut.

EnCana submitted that, if negotiations are occurring with a Canadian buyer in advance of 31 July 2003, the starting point for the negotiations would likely be the Boston price less the Goldboro to Boston (Dracut) transportation charges. If negotiations were to occur after EnCana has made the commitment to transportation, the starting point for the negotiations would likely be the Boston price due to the fact that EnCana is paying for transportation to Boston. EnCana noted that while the starting point for negotiations would be either the Boston price, or the Boston price less transportation tolls, the determination of a price is not a simple mechanistic assessment. EnCana argued that the price may be affected by a number of other factors including the term of the contract, load factors, delivery and purchase obligations, credit requirements and transportation obligations. EnCana concluded that the determination of price is truly a negotiation, not just a simple arithmetic calculation.

EnCana argued that the Boston price became a non-issue as the hearing progressed. Maritime Electric, PEI and NB Power all agreed that if a seller of Scotian gas made firm transportation commitments to Boston, that fact would need to be recognized in the pricing negotiations. EnCana suggested that the only party that had difficulty with that concept was New Brunswick's witness who contended that a Scotian gas producer that had paid for transportation to Boston should be prepared to sell at Goldboro for the Boston price less the transportation tolls. EnCana argued that, instead of losing their transportation charges, producers would elect to ship the gas to Boston to obtain the price in that market.

CAPP submitted that a purchaser bidding on gas that has been committed to Dracut can have no reasonable expectation of having the fixed charges deducted from the Dracut price. Since demand charges are sunk, the only incremental cost for transporting the gas to Dracut would be the variable cost of transportation, namely the fuel and commodity toll. Even with a greater number of sellers at Goldboro, the economics would remain the same. CAPP argued that supply would need to be constrained by a lack of pipeline capacity in order to change the economics.

Mirant submitted that, since price differentials less than the full cost of transportation are common and occur even in liquid markets such as Alberta, they cannot by themselves be evidence of market power. Mirant argued that there is nothing wrong with a seller attempting to charge a price that will recover its costs and that this would not be an unfair or an unreasonable market outcome.

3.3.3.2 Foregone Toll Reduction Opportunity

M&NP currently has an application before the Board to expand its mainline by adding four compressor stations. The pipeline has stated that these facilities are required to provide natural gas transportation service of up to 422,000 GJ/d to EnCana commencing in late 2005. M&NE has also proposed to expand the U.S. system by a similar volume to provide transportation service to EnCana.

M&NP described the proposed expansion as "a very economic project" because the addition of compression to the mainline will result in the postage stamp toll being reduced from $0.68 /GJ today to approximately $0.48 /GJ in 2005, assuming the full 422,000 GJ/d are transported. M&NP also noted that, in a future expansion, the tolls could increase if relatively more expensive facilities were required for the expansion.

NB Power submitted that producers have an incentive to move all of the expected incremental Scotian gas to Dracut. NB Power noted that, under the current proposed expansion, the maximum toll discount would be achieved by transporting the entire amount of incremental production to Dracut. Since a lower toll would increase profit to the producers by increasing the netback price, the more the toll would be lowered, the more profitable gas sales would become to the producers. New Brunswick and NB Power argued that producers therefore have a strong incentive to sell all of the expected incremental production at Dracut rather than diverting any of that gas to Canadian customers.

These parties suggested that, in the alternative, producers could withhold supply unless domestic buyers agreed to prices which compensated producers for the smaller toll reductions that would result if Canadian sales were made. For example, EnCana could refuse to enter into transactions with Canadian purchasers until after firm transportation commitments have been made to move all of the expected Deep

Panuke gas to Dracut. NB Power argued that, while this would increase the profit for EnCana, the withholding of gas from Canadian customers or Canadian customers having to pay more than U.S. customers would negatively affect the Canadian public interest.

M&NP argued that it has no incentive and no preference for all of EnCana's production to flow directly to the U.S. M&NP explained that, if half of the EnCana volumes were diverted to the Northwest Facilities in New Brunswick, the combined M&NP U.S. and Canadian rate-base investment would be approximately $90 million higher than if the full EnCana volumes went to the United States. M&NP stated that it should seize any opportunity to expand its system economically and to provide Canadians with an opportunity to access new long-term or short-term supply options.

EnCana argued that the objective of maximizing the value of Deep Panuke gas is not inconsistent with selling natural gas in Canada. EnCana submitted that it has no preference between the U.S. and Maritime market, and is prepared to make sales to Canadian customers on terms and conditions, including price, equivalent to those available in the export market. EnCana noted that it is in the Canadian public interest for Canadians to have access to natural gas, and in this connection, stated that the existing pipeline infrastructure, and the decrease in tolls as a result of the proposed expansion required to accommodate Deep Panuke gas, would assist in the commercial development of the Deep Panuke project.

However, EnCana noted that any sales to Canadian buyers would need to recognize the tolling implications that would result from a reduced capacity expansion on the M&NP and M&NE systems. EnCana argued that this issue, like all issues in a gas sales arrangement, will be the subject of negotiations between the buyer and the seller, with give and take occurring on many different levels between the parties.

EnCana suggested that the effects of a smaller toll reduction are not only negotiable, but could be argued to either increase or decrease the price. For example, a buyer could propose that EnCana would be better off by not having the transportation costs and associated risks on its books. EnCana noted that this issue only arises in the situation where a deal is reached in advance of making transportation commitments. In that situation, the starting point would be the Boston price less the transportation costs. EnCana argued that, even if the effect of a smaller toll reduction was to increase the price, the increase in price would be far less than the cost of transportation. In this case the Canadian customer would still be paying less than the Boston price.

Maritime Electric contested EnCana's claim that the determination of the equivalent Canadian price should be left to negotiation between the parties. It suggested that, since EnCana has the only foreseeable increment of supply, negotiations are not occurring in a fully functioning and liquid market in which Maritime Electric has any alternatives. In the absence of a liquid market, EnCana can effectively dictate the price that Maritime Electric would have to pay.

3.4 Short-Term Orders

Since deregulation, Canadian exports of natural gas to the United States have increased from about 2 Bcf/d in 1985 to roughly 10 Bcf/d in the year 2000. Approximately 80 per cent of natural gas exports are occurring under short-term export orders. New Brunswick argued that short-term orders exacerbate the problems in the Maritime Canadian gas market by putting the gas beyond the reach of Canadian customers who may want to buy it on equivalent terms and conditions. In New Brunswick's view, as well as facing scarcity of supply, non-transparent pricing, limited information regarding available sales volumes and publically unavailable contracts, customers have no way of knowing about a short-term export order being granted, no opportunity to comment on the merits of the export, and no way to obtain the gas even if they are offering equivalent terms. Moreover, these customers do not have a quick and efficient means of complaining to the Board about their dealings with producers.

From M&NP's perspective, the ability to divert gas on a short-term basis to the export market has been an important factor in domestic customers subscribing for capacity on its system. It suggested that Canadian end-users see benefit in being able to use flexible short-term orders to divert gas to the U.S. northeast in order to defray costs associated with plant shutdowns, turnarounds or to use alternative fuel opportunities when economically warranted. Since market dynamics can change those inter-relationships quickly and often, M&NP reasoned that a flexible means to capitalize on these opportunities is clearly of benefit to Canadian system users. M&NP therefore concluded that the existing short-term export procedures enhance Canadian access to gas, rather than limit it.

In CAPP's view, the changes in procedures for export authorization have kept pace with the changes in contracting practices in North America and have also helped to support the evolution of a competitive and integrated North American gas market. CAPP noted that the Board's 1987 Surplus Review Decision (GHR-1-87) recognized that, in a market system, export procedures must be consistent with the operation of the market. CAPP indicated that the current gas market is fluid, dynamic, highly transactional and very short-term in its focus and suggested that short-term export orders are the congruence of regulation and market reality. From its perspective, access to the U.S. market provides Canadian buyers with the flexibility to manage the risk of their purchases to their own best advantage.

CAPP submitted that producers are willing to serve any market that offers a good economic prospect and that the Maritime market will be increasingly served as supply grows and the economics of development dictate, although for some users, it may never make economic sense to choose natural gas. However, CAPP noted that, in the meantime, no energy need is going unmet as there are many energy options.

Duke Energy suggested that New Brunswick's real concern is the speculation that, in the future, gas may be surreptitiously exported under short-term orders for long-term requirements in the U.S. without Canadian end users having the opportunity to access the gas on equal terms. Duke Energy argued that New Brunswick was not able to provide any evidence that this was, in fact, the case. Moreover, Duke Energy's witness, confirmed that the gas being exported under short-term orders to Duke Energy's U.S. affiliate is not being sold under long-term contracts.

Nova Scotia submitted that Canadian demand is being willingly met by offshore producers. It argued that any allegation of misuse of power in the Maritime gas market is refuted by the fact that more gas is flowing into the domestic market than anyone reasonably anticipated and the fact that gas is being resold from that market into the United States.

PEI claimed that the fundamental issue is whether the short-term export order procedures will allow Canadians to access Scotian offshore gas at terms and conditions similar to those offered to the export market.

3.5 The Role of Infrastructure

All Scotian offshore gas is transported to market via the M&NP system. For the domestic market, access to Scotian offshore gas has been facilitated through M&NP's Lateral Policy, which was proposed by M&NP in the Sable Gas Project proceeding. Under the Lateral Policy, M&NP has constructed the Point Tupper, Halifax, and Saint John Laterals, a spur line to Lake Utopia, laterals to Moncton and St. George, and delivery facilities for EGNB in Fredericton. Laterals to northeastern and northwestern New Brunswick and Prince Edward Island have also been under discussion.

New Brunswick stated that the extension of pipeline infrastructure is essential to enable its industries, businesses and residents to reap the economic and environmental benefits of Scotian offshore gas. If the supply of Scotian offshore gas were unlimited, New Brunswick asserted that M&NP would build all the facilities necessary to serve Ontario, Quebec, northern New Brunswick and PEI, since every normal pipeline company likes to add to its rate base.

In New Brunswick's view, it is the stringency of offshore gas supply for the foreseeable future, coupled with the use of short-term export orders, that prevents domestic customers from being able to access Scotian offshore gas and motivates the pipeline's refusal to put further infrastructure in place to serve the domestic market.

In response, M&NP stated that it appears that the difficulty in serving those Canadian customers currently beyond the economic reach of the M&NP system relates to the challenge of developing economic new infrastructure rather than the alleged "stringency" of offshore gas supplies. M&NP indicated that it is committed to further develop the domestic market and to expand and extend the infrastructure. However, M&NP stressed that it is in no one's long-term interest to build uneconomic infrastructure since uneconomic pipeline infrastructure will burden, not benefit, Atlantic Canadians, who may have viable opportunities to access these gas supplies over the long term. M&NP stated that it is committed to constructing whatever infrastructure makes sense for willing buyers and willing sellers provided the project is supported by a viable gas supply and market and the project is economic.

CAPP suggested that developing the infrastructure needed to serve areas of small demand is a challenge. In its view, overcoming the challenge requires the demand side of the market to step up to make the financial commitments that will support development. Further, CAPP stated that infrastructure is costly. For those who carry the risk, there must be a corresponding benefit. Producers are motivated to underpin pipeline construction for the purpose of accessing large demand areas that can absorb the produced gas at market value. CAPP noted that, on the M&NP system, there is a Lateral Policy and, when the laterals that New Brunswick wants to serve the northwest and northeast of the province meet that policy, those laterals will be built.

The Province of PEI advised that it and M&NP have come to a general understanding on the cost of building a lateral to PEI. In order for M&NP to begin detailed engineering and final route selection, M&NP must be satisfied that the PEI project will have access to long-term gas supplies. PEI indicated that, if a lateral to its province is not economic under the Lateral Policy, PEI would consider paying any aid-to-construct that may be required.

During cross-examination, New Brunswick's policy witness stated that, in general terms, the government's policy is against subsidies for laterals to northern New Brunswick. However, under special circumstances, an aid-to-construct may be considered as a last resort.

On this matter, Duke Energy stated that M&NP's Lateral Policy has worked well so far. If governments or other interests seek penetration of natural gas into regions and they are not able to satisfy the economic test of the Laterals Policy, it is open to those governments to make the contribution-in-aid of construction. Duke Energy submitted that governments, such as New Brunswick, who express an aversion to do so, should not be permitted to manipulate the Board's process so that such a subsidy is extracted from other market participants.

Views of the Board

The Board notes that Maritime gas consumption has been increasing and that Canadian gas buyers have been reselling natural gas in excess of their requirements into the export market. This fact provides a strong indication that Canadians do have adequate access to natural gas supplies in today's gas market. It also suggests that the short-term export orders have provided Canadians with a suitable means to manage their purchases of natural gas.

The hearing produced no direct, first-hand, convincing evidence that Maritime gas buyers have not had access to Scotian natural gas supplies on terms and conditions similar to those in the export market. With respect to Deep Panuke production volumes, the New Brunswick witnesses agreed that they were unable to produce any such evidence. Instead, New Brunswick stated the evidence was indicative of a potential problem and that alerting the Board to that potential, and suggesting a change in procedures before a major problem developed, seemed to be the appropriate approach to take. As well, the hearing produced no evidence that any seller of Scotian offshore gas had refused to deal in good faith.

In regard to the role of infrastructure in accessing gas, the Board notes M&NP's submission that it has had many meetings with developers concerning facilities to northwest and northeast New Brunswick and to PEI but, to date, those discussions have not resulted in an application to the Board for new facilities. The Board agrees with M&NP that any application for new facilities should only be advanced on the basis of sound economics so that an unnecessary burden is not placed on existing shippers.

Nonetheless, the Board is of the view that there are significant qualitative differences between the Maritime market and other markets for gas in Canada and the U.S. In all other gas markets, buyers have the option of purchasing gas from a wide range of selling agents. For example, while there is no market hub in Montreal, gas buyers in that city can purchase gas under a variety of arrangements at the highly liquid Dawn hub upstream of Montreal, where there is a high degree of price transparency. The same holds true, for example, for gas buyers in Manitoba who have the ability to purchase gas at the AECO-C hub in Alberta, again at an upstream location.

In contrast, Maritime gas buyers do not have access to an upstream hub in the Maritimes that would provide them with high liquidity and price transparency. The Board recognizes that prices at Dracut provide a relevant pricing point to assist Maritime gas buyers in negotiating prices with gas sellers. However, the fact that Dracut is located downstream of the Maritime gas market means that Maritime gas buyers cannot participate as effectively in the market at this point. The Board recognizes that many of these differences are not a function of inappropriate behaviour by market participants, but rather due to the fact that the Scotian basin and the Maritime market are in relatively early stages of development.

Further, in the Board's view, the nature of the Maritime market creates a number of challenges for Maritime gas buyers in negotiating for gas supplies and for the proponents of additional domestic laterals. Those challenges include a mismatch between the expected production profile of incremental gas supply and domestic market requirements for a secure long-term source of supply. While the Board is of the view that risk is best addressed between the parties through good faith commercial negotiations, it nonetheless presents an additional challenge to Maritime consumers.

Producers require access to a large liquid market in order to economically develop Scotian resources. The current size of the Maritime market is not sufficient to drive Scotian offshore development without relying on the size and high level of liquidity of the U.S. northeast as the anchor market. Therefore a producer such as EnCana must ensure that it has access to the U.S. northeast in order to guarantee it has a market for its gas.

Another challenge faced by domestic customers, in the near term, is that the expansion economics of the mainline appear to favour incremental sales of gas to the U.S. over the construction of new laterals in Canada. This potentially creates a difficulty for Maritime gas buyers who would like to access incremental gas supplies from the Scotian basin to underpin new laterals.

At this time, the Maritime market is highly concentrated with few producers and sellers. Maritime gas buyers have limited options in purchasing natural gas and there may be only one potential provider of incremental supplies over the next five years. Prospective Maritime gas purchasers are under a time constraint as they have until 31 July 2003 to contract with EnCana for gas supply before it makes unconditional commitments to firm transportation on M&NP and M&NE. While the Board recognizes the need for producers to secure access to the anchor market, it notes that the commitments to transportation in the U.S. present an additional challenge to Canadians striving to develop domestic markets for natural gas.

Given these circumstances, the Board shares the concerns of New Brunswick and PEI about access to incremental gas supplies and recognizes that Canadian buyers, at this time, have to overcome a number of difficulties to compete for Scotian offshore gas.

Chapter 4

Distinct Approval Procedures for Scotian Offshore Gas

4.1 Applicant's Views

Issue 4 on the Board's List of Issues is: "Whether it is possible, and in the public interest, to implement distinct approval procedures for the export of Scotian offshore gas and, if so, the appropriate procedures."

The Applicant stated that the fundamental reason that it was requesting these procedures is that it believes that the Maritime gas market is less well developed and less robust than other markets in Canada, and that Maritime gas buyers require additional protection to ensure that they can access Scotian natural gas on terms and conditions that are equivalent to those offered in the export market.

New Brunswick explained some of the details of its proposed process as follows. In order to ensure that Canadian gas buyers had a solid understanding of the terms and conditions surrounding the proposed export, the applicant for a short-term order would be required to file the following information:

(i) the amount of gas to be exported in daily, monthly and annual quantities;

(ii) the products to be exported, such as firm gas, interruptible gas, seasonal gas, peaking gas;

(iii) the pricing mechanism for each service and the reference price for each such mechanism;

(iv) the long-term sales commitment, if any, for the exported gas sales;

(v) whether the application is for incremental offshore gas; and

(vi) the export point.

Any interested party who wished to file a letter of comment would be required to set out all the facts of which it was aware and clearly state the relief that it was requesting from the Board. The applicant for the order would have a right of reply. The Board could then decide to dismiss the complaint on the grounds that the interested party had not made a *prima facie* case that there was a problem. Alternatively, the Board could decide to conduct a public hearing on the export order application if there were substantive issues which required examination. After the public hearing, the Board could decide to deny the request for the export order if the Board determined that Canadian gas buyers were unable to purchase natural gas on terms and conditions similar to those contained in the proposed export sales.

Following the application, New Brunswick suggested that the Board could post the application on its website, which would allow all interested parties to quickly review it and make a determination if they had an interest in filing a letter of comment. It submitted that this process would ensure that Canadians would receive notice of applications for short-term orders, something that does not exist under the current procedures.

In New Brunswick's submission, this information would allow Canadian gas buyers to assess the comparability of the terms and conditions of proposed export sales and the terms and conditions that were offered to them by the prospective exporter. It also noted that requiring exporters to disclose this information would help make the Maritime gas market more transparent and improve its functioning.

New Brunswick provided several other clarifications around the "rules" that would apply to its proposed procedure. First, it provided some illustrative timelines with which applicants and intervenors would have to comply with respect to the notice and comment period, but stressed that the Board could select the timelines that made the most sense in its view. New Brunswick stated that its intent was to establish a short and efficient process in order to minimize any potential disruption to normal trading practices.

Second, it also argued that the Board should be prepared to hear from any interested party who had a valid comment to make concerning a proposed export order. It stated that governments have a responsibility to protect the interests of their citizens and that it would be appropriate to allow government agencies to file complaints about the availability of gas supplies for their citizens. It noted that government representation on behalf of gas buyers would be similar to CAPP's representations on behalf of gas producers.

Third, it stated that it was asking for the procedure to apply only to applications to export incremental volumes above a base level of 522,000 MMBtu/d. New Brunswick noted that it would be more logical to apply the procedure to all applications for short-term orders, but was of the view that it would be fairest to grandfather the original volumes that were flowing from SOEP and exempt these volumes from any new approval process. It selected the level of 522,000 MMBtu/d based on the average flows of gas from SOEP over the last year of its production life.

Fourth, New Brunswick defined the Maritime market to include the provinces of Nova Scotia, New Brunswick, Newfoundland and PEI, as well as the portion of Quebec east of Quebec city. However, it agreed that any Canadian gas buyer who could reasonably be connected to Scotian basin gas, including buyers in Ontario, should have the right to lodge a complaint with the Board.

Fifth, in assessing the comparability of terms and conditions between domestic and export sales, the Board should limit its analysis to whether or not the terms and conditions included in the export sale were or were not equivalent to those offered to domestic buyers. The Board should not try to judge whether an exporter would gain equivalent value from a domestic sale as it would from an export sale.

Finally, it noted that it supported private commercial negotiations and that such negotiations could continue even after a complaint had been filed and set down for a hearing.

In support of its request, New Brunswick noted that almost all incremental natural gas exports from Canada have been flowing under short-term orders and that, under the current procedures, Maritime gas buyers would not have an opportunity to comment about the terms and conditions under which Scotian basin gas was being exported. The Applicant noted that a new producer, such as EnCana, could wait until its production was ready to flow before requesting the NEB to grant it a blanket export order and there would be no possibility of intervention by Canadian gas buyers. It argued that this procedure does not fulfil the intent of the Board's Market-Based Procedure, which is to ensure that Canadian gas buyers have access to Canadian produced natural gas on similar terms and conditions, including price, as export buyers.

New Brunswick also noted that it supports any other initiative the Board may take to improve the amount and quality of information in the Maritime gas market. It supported the provision of increased information in the Board's monthly postings, such as providing the range of export prices and the median of that range at each export point. However, New Brunswick stated that monitoring would not be a substitute for its request for a complaints procedure to apply to short-term orders.

4.2 Views of Supporting Parties

New Brunswick's request for a separate procedure for the approval of gas export orders from the Scotian basin was supported by a number of parties, although several of them introduced certain qualifications.

PEI supported the establishment of a complaints procedure to apply to short-term orders of Scotian offshore gas. PEI and Maritime Electric both argued that the intent of the Board's regulation of gas exports is to ensure that Canadians have access to natural gas on similar terms and conditions as gas intended for the export market. They argued that the fact that short-term exports are exempt from the Complaints Procedure creates a situation in which the Board cannot properly fulfil its public interest mandate. NB Power supported New Brunswick's proposed procedures.

PEI argued that a form of a complaints procedure for short-term exports is necessary to ensure that Canadian interests are protected, but stated that, in its view, only Canadian gas purchasers who had been active in the market should be eligible to participate. Both PEI and Maritime Electric stated that the complaints procedure to be implemented should be short and efficient to ensure that natural gas exports would not be unnecessarily delayed.

Maritime Electric noted that the Complaints Procedure for long-term export licences has been in existence for 15 years as part of the Board's Market-Based Procedure, and that a complaint has never been filed. It suggested that this demonstrated that the mere existence of the Complaints Procedure helped to ensure that Canadians had the opportunity to purchase natural gas on terms similar to terms for exported gas.

PEI argued that, if the Board were not entirely satisfied with the details of the proposed procedures, the Board had a sufficiently detailed hearing record upon which it could adopt a variant that made sense in its view. Maritime Electric noted that, prior to the implementation of the Fair Market Access policy which is applied to the regulation of electricity exports, the Board conducted an extensive consultation process. Maritime Electric suggested that, if necessary, the Board could conduct further consultations on the details of any complaints procedure prior to implementation.

The Procureur général du Québec requested the Board implement a procedure to apply to short-term exports, but it did not explicitly support or reject the specifics of New Brunswick's proposal.

Mr. Andy Savoy, Member of Parliament for Tobique-Mactaquac, also made an appearance and a brief argument in support of New Brunswick's application. The Communications, Energy and Paperworkers Union of Canada (CEPU) also supported New Brunswick's application. However, the CEPU argued that, to put into effect the intent of the Act, the Board must go further and play a more proactive role to protect the Canadian public interest with respect to natural gas exports.

Industrial Gas Users Association (IGUA) stated that it sees some merit in New Brunswick's application, although it has some reservations about disclosure of all commercial terms and conditions to a sale. IGUA would like to see the Board implement some type of procedure which would ensure that Canadian gas buyers had equal and fair access to Scotian basin gas, but did not have any specific recommendation; rather, it stated that it would rely on the Board's judgment concerning the most appropriate procedure.

The Union of New Brunswick Indians was in agreement with New Brunswick that there should be some form of public notice and opportunity for public input before the authorization of short-term natural gas exports. It also stated that there is an obligation to consult with Aboriginal people prior to an export application.

The Regional Municipality of Halifax stated that it is relying on the NEB to devise appropriate procedures to ensure that the public interest is protected in relation to short-term orders for the export of natural gas. The Municipality expects the NEB to achieve the appropriate balance between the interests of natural gas exporters and domestic gas consumers. J.D. Irving, Limited stated that Canadian buyers should have access to Scotian incremental gas supplies at fair market prices.

In addition, the Board received numerous letters of comment from parties who were interested in gas service, primarily in northern New Brunswick. They supported New Brunswick's application and stated that access to natural gas would provide them with economic and environmental benefits.

Some of the parties who supported New Brunswick, such as PEI and NB Power, were also supportive of enhanced monitoring and reporting activities by the Board. However, the Board was cautioned to maintain the confidentiality of first-hand sales between the producer and the first buyer. Like New Brunswick, PEI and Maritime Electric stated that monitoring in itself would not provide the relief that was being requested through a complaints procedure.

4.3 Views of Opposing Parties

Parties opposed to New Brunswick's proposal included members of the natural gas producing community, natural gas pipelines, marketing agents, the Provinces of Nova Scotia and Alberta, and the Atlantic Institute for Market Studies (AIMS). Although the specific arguments of each party varied, their arguments were generally made under four broad categories:

(i) there was no evidence of a market failure; hence there is no problem that needs fixing;

(ii) the proposed procedure is inconsistent with the realities of the current natural gas market and would result in a number of market distortions;

(iii) the real "problem" is the need for more supply and the proposed procedure would hinder, not promote, the development of additional supply; and

(iv) the procedure would, in any event, be impractical.

Almost every party arguing against New Brunswick's proposal argued that the Applicant had not made a case that there is a problem that needs to be resolved. It was argued that the onus rests on New Brunswick to demonstrate to the Board that the market is not working before the Board moves to implement any new procedures.

Opposing parties stated that New Brunswick should produce evidence of a refusal to negotiate in good faith or evidence that gas buyers with economic projects could not obtain natural gas at fair market terms and conditions. CAPP, Chevron, EnCana and Duke Energy all stated that there was no such evidence; rather the evidence indicated that a few speculative projects had not proceeded, as one would expect in a normally-functioning market. It was pointed out that the inability of a buyer and seller to come to terms, such as in the Tractebel case, was not necessarily an indication of market failure. Both CAPP and TransCanada noted that there was a mismatch between the expected production profile of the Deep Panuke project and the supply needs of Tractebel. It is to be expected that potential sellers and buyers will not always agree on mutually satisfactory terms and conditions, and the negotiations with Tractebel were simply one example.

Further, it was argued that there was considerable evidence that good faith negotiations were in fact proceeding between EnCana and potential gas buyers. These negotiations, in these parties' view, are evidence that the market is working as it should.

Several parties, including CAPP, Mirant and Imperial/ExxonMobil noted that there has been considerable growth in the Maritime gas market since SOEP commenced production. Further, it was noted that domestic gas buyers have been reselling and exporting considerable quantities of their gas purchase entitlements. These facts indicate that Maritime gas needs are being met and that there has been no unwillingness to sell Scotian offshore gas into Maritime markets.

Several of the opposing parties argued that intervention in the market as proposed by New Brunswick would be completely inconsistent with the realities of the current marketplace. CAPP and EnCana argued that such a procedure would impact on private contract negotiations, inappropriately giving Canadian gas buyers undue leverage in negotiations. EnCana stated that the proposed information requirements would be tantamount to requiring an exporter to reveal its entire marketing plan for the next two years. CAPP suggested that the existence of such a procedure would encourage some buyers to rely on regulatory solutions, rather than pursuing private contractual negotiations. CAPP was further concerned that, once in place, it would be very difficult to retract any procedure.

TransCanada argued that it would be inappropriate to single out the Scotian basin for special regulatory treatment, particularly when natural gas from this basin competes with natural gas from other basins.

Several parties, including Nova Scotia, EnCana, CAPP, TransCanada, Imperial/ExxonMobil, and AIMS argued that the real solution to the needs of Maritime gas buyers was the development of more gas supply. These parties all noted that the proposed procedures would do nothing to create more gas supply and would, in fact, hinder the development of additional supply.

These parties suggested that additional regulatory hurdles applied to Scotian basin gas would, other things equal, render investment in the Scotian basin less attractive. EnCana noted that the procedure would be directly targeted at its Deep Panuke project because existing gas production would be grandfathered. EnCana stated that the procedure would disadvantage Scotian offshore gas and discourage further investment in the basin, rendering investment elsewhere relatively more attractive. Nova Scotia shared this view and, along with EnCana, encouraged the Board to decisively reject New Brunswick's application in order to provide a clear signal that a market-based approach to export regulation would continue.

The Alberta Department of Energy (Alberta) argued that the implementation of restrictive export approval procedures would likely have a negative impact on all natural gas produced in Canada, regardless of the production source. Alberta urged the Board to continue its market-based approach to regulation.

AIMS argued that New Brunswick's proposal would restrict trade, reduce investment, lower the availability of gas and choke off the benefits that would otherwise come from development of Scotian offshore gas supplies. AIMS and other parties argued that the results would be contrary to the goals that New Brunswick itself wishes to achieve in terms of enhanced access to natural gas for Maritime gas buyers.

Finally, EnCana and CAPP argued that the procedure would be impractical. EnCana pointed out that there are many factors that enter into a gas sales contract, including such things as minimum take provisions, penalties for failure to deliver, the nature of the delivery terms, and the service category (interruptible, firm, seasonal). Contract prices are affected by many of these factors and, hence, any comparison of prices in two different situations can become very complicated. Both CAPP and EnCana argued that it was highly likely that any procedure allowing for a complaint would develop into a protracted exercise and would effectively prevent the export sale from proceeding.

In addition to the above four general arguments against the implementation of the proposed procedure, some parties made additional comments.

TransCanada, CAPP and EnCana noted that there are already existing avenues under which parties can bring their concerns forward to the NEB, including section 12 of the Act, pursuant to which New Brunswick made the current application. In addition, it was suggested that gas buyers could have recourse to provincial processes and possibly the Competition Tribunal. Accordingly, it was argued that there is no need to implement a special complaints procedure that would apply to each and every application to export natural gas on a short-term basis.

M&NP stated that it supports the Board's market monitoring activities and would be supportive of enhanced monitoring of the prices paid by domestic gas buyers. EnCana also suggested that enhanced monitoring and reporting on prices could potentially assist with price transparency in the market. In final argument, counsel for CAPP also stated that, if the Board is to take any action, it should continue to do the things that work, such as monitoring, studies, surveys and publications. However, CAPP cautioned the Board that private agencies are best placed to publish such things as price indices.

Finally, several parties stated that, if the Board were to seriously consider implementing some type of procedure despite their objections, the Board should first make a clear statement on what the problem is that needs to be rectified. Subsequently, the Board should initiate a thorough consultative process before any procedure is implemented. Consultation would ensure that the most workable procedure could be devised, while limiting the damaging effects on the producing industry.

Views of the Board

The National Energy Board has a responsibility to ensure that its regulation of natural gas exports serves the Canadian public interest. The Board is of the view that a key indicator that the Canadian public interest is being served is that Canadians pay fair market prices for natural gas in the context of the North American market. This means that prices paid for natural gas in the domestic market should be no less favourable than for gas sold into the export market under similar terms and conditions.

The Board believes that, in the current context of market-oriented trade and energy policies, it must strive to develop regulatory procedures that are compatible with and support such policies. A key consideration is that regulatory approaches not impede the development of new gas supplies which could meet the needs of both Canadians and export customers.

In a market-based economy, the operation of the market determines the supply, demand and price of natural gas. In the 1987 and 1991 Surplus Review Decisions, the Board revised its surplus determination procedures, recognizing that its export procedures must be consistent with the operation of the market. Since that time, the natural gas industry has moved increasingly to short-term commercial transactions. The Board is of the view that its export procedures have kept pace and have facilitated the evolution of the natural gas market. This approach provided market participants with a predictable regulatory environment in which the industry has grown considerably over the past 15 years.

The Board believes that the public interest is best served by allowing markets to work unless there is clear evidence of significant market dysfunction. It is in this context that the Board has come to the following conclusions.

The Board has decided that it would be inappropriate at this time to implement procedures that would unduly interfere with the normal operation of the market. In reaching this conclusion, the Board notes that the hearing did not produce any direct evidence that Maritime gas buyers have not had access to Scotian offshore gas supplies on terms and conditions similar to those in export markets. Further, there was no evidence that any gas seller had refused to negotiate in good faith.

The Board also has concerns about the practicality of New Brunswick's proposal. The Board believes that the proposed procedure for short-term orders would be of no direct assistance to Canadian buyers, such as Maritime Electric, the Cartier proponents or New Brunswick Power, who require a long-term gas supply of 10 years or more to underpin investments in new infrastructure.

Furthermore, the Board is of the view that the requirement to disclose commercially sensitive information and the potential for delay would place unreasonable burdens on potential exporters with respect to their short-term commercial arrangements. It would also be difficult to assess the comparability of terms and conditions for short-term sales for which the market parameters are constantly changing.

The Board is also concerned that the additional regulatory burden that such a procedure would impose on exporters would send a negative signal to potential investors in the Scotian offshore basin. With this consideration in mind, the Board does not believe that it would be prudent to adopt new procedures in the absence of any direct evidence that Canadians have in fact been denied access to gas on terms and conditions similar to those offered to export customers.

The Board notes that New Brunswick and other interested parties argued that there is considerable potential that Canadians will not be accorded equal access to Scotian offshore gas in the future. The Board agrees that there are a number of characteristics of the Maritime market which give rise for concern.

First, there is only one potential provider of incremental gas supplies over the next five years. While the Board recognizes that there has been growth in the number of sellers in the market, it is nonetheless of the view that the negotiating power of domestic buyers is constrained due to the limited choice of sellers.

Second, as a developing market, Maritime gas buyers require investment in new infrastructure and they require reasonable assurances of access to long-term secure supplies of natural gas to justify these investments. In contrast, gas buyers in the United States do not require new infrastructure and, due to the large size of the existing market, are able to absorb large volumes of gas into the short-term sales market. These market characteristics create challenges for domestic gas buyers in competing for available gas supplies.

Third, there is a mismatch between the expected production profile of the Deep Panuke project, and possibly of other future projects, and the needs of new Maritime gas markets for long-term supplies.

Fourth, the benefits to shippers and producers from the current expansion economics on the M&NP mainline appear to be favourable compared with the economics of attaching new laterals on M&NP. This factor, combined with the above-noted characteristics of the domestic market, may create hurdles for domestic gas buyers that are not faced by export customers.

In summary, the Board is of the view that the developing Maritime gas market faces many challenges that are not faced by buyers in the mature export market.

Given these market realities, the Board shares the concerns of New Brunswick and PEI about access to incremental gas supplies on fair market terms. Although the Board does not believe that the record in this hearing warrants direct regulatory intervention, it did raise sufficient concern that the Board believes it must enhance its monitoring efforts in Maritime Canada.

In this regard, the Board has decided to take the following actions:

(i) The Board will mobilize a team that will be responsible for ongoing monitoring of the Maritime gas market by meeting with buyers, sellers, producers, pipelines and government representatives. Public reports will be issued on the state of the market from time to time, with the first report being published well before 31 July 2003.

(ii) To improve price transparency in Maritime Canada, the Board will publish additional data gathered from the reports it receives on a monthly basis from export order holders. Further, the Board will move to collect data on domestic and export prices through surveys and publish the results in an aggregated format.

The Board is of the view that efficient markets are characterized by broadly dispersed market information that is easily available to all market participants and that the proposed monitoring program will act to increase the amount and quality of information available to Maritime market participants.

Finally, the Board is of the view that the public hearing on New Brunswick's application has helped raise awareness of the issues facing Maritime natural gas buyers. The Board notes that it was during the course of the Joint Review Panel Hearing on the original SOEP and M&NP projects that the producers, the provincial governments and the pipeline came together and formally recognized the needs of Maritime gas buyers.

The Board recognizes that it is through the application of highly specialized knowledge, technology and risk capital that the producing community brings offshore natural gas reserves into the reality of a producing project. Offshore development provides many benefits, such as jobs, tax revenues, increased demand for local services and opportunities to develop new skills in a new industry. The Board believes, however, that the greater public interest requires that offshore development also proceed with regard to the needs of domestic energy users.

Chapter 5

NAFTA Considerations

The Preliminary List of Issues published with the Hearing Order did not include any reference to the *North American Free Trade Agreement* (NAFTA). Although the Board solicited comments on the List of Issues, no party asked that consideration of NAFTA be added. However, in final argument, counsel for CAPP suggested that the Applicant had an obligation to explain how the procedures would be permissible under NAFTA. New Brunswick questioned this suggested requirement but complied by filing a written argument on NAFTA and the Board subsequently established a procedure for the filing of written submissions on this matter.

New Brunswick argued that its request that the Board establish procedural rules to be used in consideration of short-term export orders for incremental Scotian offshore gas did not trigger provisions of NAFTA. It suggested that only if the Board were to impose export restrictions would it have to consider these matters and that any argument of a violation of NAFTA was not ripe for adjudication given that no factual context for the issue has occurred. Further, nothing in the energy chapter of NAFTA would prevent the Board from establishing a procedure to ensure that applications for short-term orders take into account all relevant factors, including whether Canadians have had an opportunity to purchase gas on terms and conditions similar to exports.

The CEPU concurred with New Brunswick and stated that so long as any procedures imposed were implemented in a non-discriminatory manner, there was no constraint under NAFTA on the Board's ability to adopt procedures that would enhance the transparency of the approval process, including providing notice of applications and an opportunity to comment. If, in the examination of an application the Board was to be persuaded that an export application did not meet the surplus test, the Board would have to determine whether its decision to refuse the application would raise NAFTA issues. Until that time, without knowing the precise circumstances of the case, the matter is speculative.

Despite having raised the matter and suggesting that New Brunswick had not fulfilled its duty to justify the application pursuant to NAFTA, counsel for CAPP argued that there is no need to interpret NAFTA or determine how a change in procedure would or would not affect it, given that the market is working. However, CAPP filed a written submission arguing, among other things, that the New Brunswick proposal was a back-door attempt at price regulation which is contrary to NAFTA. It also suggested that the procedures would give a Canadian buyer a regulatory advantage over export customers and establish a quantitative restriction, which would distort the marketplace and restrict trade and is contrary to NAFTA except in limited circumstances.

CAPP discussed the various articles which would allow for restrictions and argued that there is no evidence that any of these provisions could be met. With respect to the ripeness of consideration of the issues, CAPP argued that the procedures are before the Board and must be considered. Further, the Board must consider the proposed regulatory system and policy in light of the real economic objectives of the Applicant. CAPP concluded that granting the application would violate NAFTA.

It was noted by M&NP that New Brunswick's proposal will involve quantitative export restrictions despite the Applicant's claim to the contrary; if none are foreseen, there is arguably no basis for the proposed change in procedures. Further, it would be contrary to NAFTA for the Board to refuse to issue export authorizations needed to maintain the access to incremental Scotian offshore gas enjoyed by U.S. buyers over the previous 36 months. M&NP noted that NAFTA refers to the enhancement of free trade of petrochemical goods through sustained and gradual liberalization. It argued that the Applicant's proposal would impose protectionist policies rather than liberalizing the export regime.

Duke Energy argued that a "set aside" of gas for domestic use or a process which requires that domestic interests be satisfied before negotiations conclude with export purchasers would violate the principles of NAFTA. It was suggested by Alberta that the proposal put forth would constitute a restriction on exports, both because it would examine applications on unspecified merits and it would involve delay in the order- granting process. For this reason, the proposal would have a significant risk of being contrary to Canada's international trade obligations.

In its reply submission, New Brunswick argued that none of the parties commenting were able to show that establishing procedures of itself constitutes an export restriction or that the matter is ripe for consideration given that it is currently a hypothetical argument that NAFTA could be violated. The Applicant noted that NAFTA allows parties to administer a system of export licensing for energy and that Part VI of the Act was not revoked or amended to restrict the Board's ability to establish procedures. It argued that it was seeking only a fair procedure for notice and comment or complaints on applications for short-term gas export orders.

Views of the Board

The Board is of the view that New Brunswick's obligation to discuss NAFTA was only invoked when the matter was raised as an issue in the hearing. If CAPP was of the view that the Applicant should justify its proposal in light of NAFTA, it was open to CAPP to ask that the issue be added to the List of Issues when the Board went out for comment. Absent that, in the Board's view, there was no obligation on the Applicant to justify its application on these grounds. Indeed, being raised as it was, the Board sees some merit in New Brunswick's assertion that the burden of showing that the procedure proposed is contrary to NAFTA rests with CAPP.

Nonetheless, given the Board's decisions in the foregoing chapters, the Board is of the view that it is not necessary to make a determination on any matter relating to NAFTA and therefore will not further address this issue.

Chapter 6

Disposition

The foregoing chapters constitute our Decision and Reasons for Decision on matters considered in the MH-2-2002 proceeding.

J.-P. Théorêt
Presiding Member

K.W. Vollman
Member

D.W. Emes
Member

Calgary, Alberta
September 2002