National Energy Board

Reasons for Decision

Canadian Hydrocarbons Marketing Inc.

CanWest Gas Supply Inc.

Enron Gas Marketing, Inc.

New York State Electric & Gas Corporation

Unigas Corporation

GH-7-92

June 1993

Volume I

Gas Exports

National Energy Board

Reasons for Decision

In the Matter of

Canadian Hydrocarbons Marketing Inc.

CanWest Gas Supply Inc.

Enron Gas Marketing, Inc.

New York State Electric & Gas Corporation

Unigas Corporation

Applications Pursuant to Part VI of the *National Energy Board Act* for Licences to Export Natural Gas

GH-7-92

June 1993

Volume I
Gas Exports

Cat. No. NE22-1/1993-6-1E
ISBN 0-662-20354-2

This report is published separately
in both official languages.

Copies are available from:

Regulatory Support Office
National Energy Board
311 Sixth Avenue S.W.
Calgary, Alberta
T2P 3H2
(403)292-4800

For pick-up at NEB office:
Library
Ground Floor

Printed in Canada

Cat. No. NE22-1/1993-6-1F
ISBN 0-662-98110-3

Ce rapport est publié séparément dans les deux
langues officielles.

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
311, 6e Avenue s,-o.
Calgary (Alberta)
T2P 3H2
(403)292-4800

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

Imprimé au Canada

Table of Contents

List of Tables

List of Figures

List of Appendices

Abbreviations

ACQ	Annual Contract Quantity
Act	*National Energy Board Act*
Amerada	Amerada Hess Canada Ltd.
ANG	Alberta Natural Gas Company
APL	APL Oil & Gas Ltd.
APMC	Alberta Petroleum Marketing Commission
BCEMPR	British Columbia Ministry of Energy, Mines and Petroleum Resources
BCPC	British Columbia Petroleum Corporation
Bcf	billion cubic feet
Board	National Energy Board
CanWest	CanWest Gas Supply Inc.
Cascade	Cascade Natural Gas Corporation
CHMI	Canadian Hydrocarbons Marketing Inc.
Conoco	Conoco Canada Limited
Crestar	Crestar Energy
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
EIA	Export Impact Assessment
El Paso	El Paso Natural Gas Company
Empire	Empire State Pipeline Company, Inc.
Enron	Enron Gas Marketing, Inc.
EPS	Enron Power Services, Inc.

ERCB	(Alberta) Energy Resources Conservation Board
FERC	(United States of America) Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FS	Firm Service
GHR-1-87	*Review of Natural Gas Surplus Determination Procedures*
GJ	gigajoule(s)
Iroquois	Iroquois Gas Transmission System, L.P.
LDC	local distribution company
MAQ	Minimum Annual Quantity
MBP	Market-Based Procedure
MDQ	Maximum Daily Quantity
MMBtu	million British thermal units
MMcf	million cubic feet
MPCC	March Point Cogeneration Company
MW	megawatt (1000 kilowatts)
NEB	National Energy Board
Niagara Mohawk	Niagara Mohawk Power Corporation
Northwest	Northwest Pipeline Corporation
Northwest Natural	Northwest Natural Gas Company
NOVA	NOVA Corporation of Alberta
NYPSC	New York Public Service Commission
NYSEG	New York State Electric & Gas Corporation
Paloma	Paloma Petroleum Ltd.
Part VI Regulations	*National Energy Board Part VI Regulations*
PG&E	Pacific Gas & Electric Company

PGT	Pacific Gas Transmission Company
Puget Sound Power	Puget Sound Power & Light Company
PURPA	(United States of America) Public Utility Regulatory Policies Act
QF	qualifying cogeneration facility
Ranger	Ranger Oil Limited
RR/P	remaining reserves to production ratio
SoCalGas	Southern California Gas Company
TGMI	Texaco Gas Marketing Inc.
TM Star	TM Star Fuel Company
TransCanada	TransCanada PipeLines Limited
TRMI	Texaco Refining and Marketing Inc.
Unigas	Unigas Corporation
Universal	Universal Explorations Ltd.
Sithe	Sithe/Independence Power Partners, L.P.
Three Cities	The cities of Burbank, Glendale and Pasadena
Westcoast	Westcoast Energy Inc.

Recital and Appearances

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

AND IN THE MATTER OF applications under Part VI of the *National Energy Board Act* for new licences to export natural gas by:

Canadian Hydrocarbons Marketing Inc.; CanWest Gas Supply Inc.; Enron Gas Marketing, Inc.; New York State Electric & Gas Corporation; and Unigas Corporation;

AND IN THE MATTER OF Hearing Order GH-7-92, as amended;

HEARD in Calgary, Alberta on 22 and 23 February 1993.

BEFORE:

R.L. Andrew, Q.C.	Presiding Member
R.B. Horner, Q.C.	Member
C. Bélanger	Member

APPEARANCES:

R.B. Brander	Canadian Hydrocarbons Marketing Inc. and Centra Gas Ontario Inc.
S. Carscallen	CanStates Gas Marketing
L.G. Keough	CanWest Gas Supply Inc. and Enron Gas Marketing, Inc.
N.M. Gretener	New York State Electric & Gas Corporation
D.G. Davies	Unigas Corporation and Northwest Natural Gas Company
N.W. Boutillier	Alberta and Southern Gas Co. Ltd.
D.G. Hart, Q.C. A.G. Menzies	Alberta Natural Gas Company Ltd. and Pacific Gas Transmission Company
J.H. Smellie	CNG Transmission Corporation
J. Scott	Crestar Energy
C. Macfarlan	Foothills Pipe Lines Ltd.
M.J. Samuel	TransCanada PipeLines Limited

G. Britton	Western Gas Marketing Limited
W.M. Moreland	Alberta Petroleum Marketing Commission
J. Robitaille	Procureur général du Québec
J. Syme D. Champagne	Board Counsel

Chapter 1

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-7-92 proceeding, the National Energy Board ("the Board") examined six applications for eight gas export licences from the following parties:

1. Canadian Hydrocarbons Marketing Inc. ("CHMI");

2. CanWest Gas Supply Inc. ("CanWest");

3. Enron Gas Marketing, Inc. ("Enron");

4. New York State Electric & Gas Corporation ("NYSEG");

5. Unigas Corporation ("Unigas") for export to Northwest Natural Gas Company ("Northwest Natural"); and

6. Unigas for export to each of the cities of Burbank, Glendale and Pasadena ("Three Cities").

The gas export licence application of CanStates Gas Marketing ("CanStates") was to have been considered by the Board in GH-7-92. However, by letter dated 3 February 1993, CanStates requested that the Board suspend consideration of its application. The Board granted this request.

This volume, Volume I, deals with the applications by CHMI, CanWest, Enron, NYSEG and Unigas for export to Northwest Natural. The remaining application, that of Unigas for export to Three Cities, will be included in Volume II of these Reasons which will be issued at a later date.

Table 1-1

Summary of Applied-for Licences

GH-7-92

Application	Buyer (Type of market)	Term	Export Point	Maximum Quantities Applied For Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1. CHMI	Cascade (system supply)	1 Nov. 1992 to 31 Oct.1996	Huntington, British Columbia	136.4 (4.8)	49.8 (1.8)	199.3 (7.0)
2. CanWest	T.M. Star (cogen. plant)	15 years following first deliveries	Huntingdon, British Columbia	273.2 (9.6)	100.0 (3.5)	1495.0 (53.0)
3. Enron	Sithe/ Independence (cogen. plant)	First deliveries to 31 Oct. 2004	Chippawa, Ontario	805.0 (28.4)	294.0 (10.4)	2940.0 (104.0)
4. NYSEG	NYSEG (system supply)	10 years following first deliveries	Chippawa, Ontario	283.3 (10.0)	103.5 (3.7)	1035.0 (37.0)
5. Unigas	Northwest Natural (system supply)	6 years from later of first deliveries and 1 Nov. 1993	Kingsgate, British Columbia	396.6 (14.0)	144.8 (5.1)	868.6 (30.7)
6. Unigas	City of Burbank (power generation)	Later of first delivery and 1 Nov. 1993 to 31 Oct. 1999	Kingsgate, British Columbia	136.5 (4.8)	49.8 (1.8)	298.9 (10.5)
7. Unigas	City of Glendale (power generation)	Later of first delivery and 1 Nov. 1993 to 31 Oct. 1999	Kingsgate, British Columbia	115.4 (4.1)	42.1 (1.5)	252.7 (8.9)
8. Unigas	City of Pasadena (power generation)	Later of first delivery and 1 Nov. 1993 to 31 Oct. 1999	Kingsgate, British Columbia	115.4 (4.1)	42.1 (1.5)	252.7 (8.9)

1.2Environmental Screening

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the *Environmental Assessment and Review Process Guidelines Order* ("EARP Guidelines Order"). To that end, the Board performed a screening, pursuant to Hearing Order GH-7-92, wherein it considered submissions from each of the applicants.

Each applicant filed with the Board information concerning the potential environmental effects that would be caused by the sending or taking of gas from Canada.

CHMI, CanWest and Unigas, for export to Northwest Natural, submitted that the development of new gas transmission facilities under the Board's jurisdiction would not be required to accommodate their applied for exports. As a result, they submitted that their export licence applications fell within the ambit of the Board's List of Automatic Exclusions ("Exclusion List") pursuant to the EARP Guidelines Order.

Both the Enron and NYSEG export proposals would require new facilities to be constructed on TransCanada PipeLines Limited's ("TransCanada's") system. Enron and NYSEG both submitted that pursuant to the Federal Court of Appeal's decision in *Attorney General of Québec* v. *National Energy Board*, [1991] 3 F.C. 443 (the "Hydro-Québec decision") the Board's jurisdiction with respect to the environmental screening of gas exports is restricted to the actual export of the energy commodity in question. They went on to submit that an assessment of the environmental impact of exporting natural gas therefore relates only to the sending or taking of gas by means of a high pressure underground pipeline from Canada to the U.S.

By letter dated January 1993, the Speak Up for Wildlife Foundation ("Speak Up") intervened in GH-7-92. By letter dated 21 January, Speak Up advised the Board that it was concerned about the impact oil and gas exploration, production and export have on Western Canada's wildlife and wilderness ecosystems, fisheries, and the energy security and future of Canadian residential and industrial natural gas consumers.[1] Speak Up submitted that the GH-7-92 export applications would draw gas from a vast area from southern Alberta to northeastern British Columbia - representing prairie, foothill, mountain and boreal forest ecosystems, and encompassing a wide range of environmental issues. Finally, Speak Up submitted that the proposed exports involve hundreds of wells, dozens of fields, many jurisdictions, and an untold number of wildlife populations and habitats, and fisheries populations and watersheds.

1. The issue of energy security, ie: ensuring that gas proposed for export is surplus to reasonably foreseeable Canadian requirements, is addressed in section 1.3 on the Market-Based Procedure.

1.2.1 Views of the Board

The Board, by means of a screening pursuant to the EARP Guidelines Order, has completed its environmental screening of the applications considered in this hearing and has concluded that the applications of CHMI, CanWest and Unigas, for export to Northwest Natural, fall within the ambit of Note 3 of the Board's Exclusion List.[1]

As both the Enron and NYSEG export proposals would require new facilities to be constructed on the TransCanada system, they are not excluded from the EARP Guidelines Order Process. As a result of the Hydro-Québec decision, the Board is of the view that its environmental screenings of gas export licence applications must consider the environmental consequences of the exports themselves. In that case, the Court considered the definition of "export" under the *National Energy Board Act* (the "Act"). The Act provides that "export" means, with reference to electricity, "to send from Canada by line of wire or other conductor electricity produced in Canada...". In the light of the definition of export, the Court ruled that in considering an electricity export licence application, the only question for the Board to consider "is the environmental consequences of the export, namely the consequences for the environment of [sending] from Canada...power produced in Canada".

Since the Board's jurisdiction to issue export licences for natural gas is similar to its jurisdiction to authorize exports of electricity, the Board is of the view that, in respect of gas export applications, the Board has jurisdiction to consider the environmental effects of sending gas from Canada *per se*. The environmental and related social effects of the additional facilities required on TransCanada to transport the gas in question will be examined by the Board in the context of applications for authorization to install and operate these facilities.

With respect to the Enron and NYSEG applications, the Board has determined, pursuant to section 12 of the EARP Guidelines Order that none of subsections (a) to (f) set out therein are applicable as the sending of gas from Canada has no potentially adverse environmental effects.

Speak Up raised a number of issues with respect to all of the proposed exports' environmental impact on upstream gas development and production areas. However, subsection 92(A)(1) of the *Constitution Act*, *1867*, confers upon the Provinces exclusive jurisdiction to make laws in relation to "exploration for non-renewable natural resources" and "development, conservation and management of non-renewable natural resources and forestry resources in the province, including laws in relation to the rate of primary production therefrom". Therefore, as a federal regulatory body, the Board does not have jurisdiction to consider the environmental effects of the proposed exports on gas development or production areas.

---

1. Note 3 provides for the automatic exclusion of "...applications for natural gas exports, imports, exports for subsequent import and imports for subsequent export authorized:

   (ii) by licence where the development of new facilities for production, processing, storage or transmission would not be required".

1.3 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the Act, which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of 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 gas in Canada.

In July 1987, pursuant to a *Review of Natural Gas Surplus Determination Procedures* ("GHR-1-87"), the Board implemented a new procedure, known as the Market-Based Procedure ("MBP"), founded on the premise that the marketplace would generally operate in such a way that Canadian requirements for natural gas would be met at fair market prices.

The MBP provides that the Board will act in two ways to ensure that natural gas to be licensed for export is both surplus to reasonably foreseeable Canadian requirements and in the public interest: it will hold public hearings to consider applications for licences to export natural gas; and it will monitor Canadian energy markets on an ongoing basis.

The public hearing portion of the MBP provides that the Board consider:

- complaints, if any, under the Complaints Procedure;
- an Export Impact Assessment ("EIA"); and
- any other considerations that the Board deems relevant to its determination of the public interest.

The following description of these three components is general in nature and applies to each application heard in GH-7-92.

1.3.1 Complaints Procedure

The basic premise of the Complaints Procedure is that, in a market which is working satisfactorily, Canadian purchasers will be able to obtain domestic natural gas supplies under contract on terms and conditions, including price, similar to those offered to purchasers in the United States of America ("U.S."). In order to test whether the market is in fact working in this manner, in the GHR-1-87 Decision the Board stated that:

> "The inclusion of a complaints mechanism in the new surplus determination procedures is based on the principle that gas should not be authorized for export if Canadian users have not had an opportunity to buy gas for their needs on terms and conditions similar to those of the proposed export. Applicants for export licences will have to be prepared to address any concerns on this score which may be identified in the complaints procedure ..."

The Complaints Procedure seeks to ensure that Canadian gas buyers who have been active in the market have access to gas on terms and conditions no less favourable than export customers. The Complaints Procedure enables these buyers to assess the terms and conditions of the gas sales contracts underlying export licence applications relative to the terms and conditions they are being offered. If the terms and conditions being offered to export customers are more favourable than those available to domestic customers, a Canadian buyer may wish to file a complaint with the Board. The

Board would adjudicate each complaint on the basis of an assessment of whether, as a matter of fact, the complainant has or has not been able to obtain additional gas supplies on terms and conditions, including price, similar to those contained in the gas export licence application submitted to the Board.

Domestic gas purchasers who wish to file a complaint must demonstrate that they have attempted to contract for additional gas supplies and that they have not been able to obtain such supplies on terms and conditions similar to those contained in the gas sales contract. At the same time, export licence applicants are expected to respond to concerns expressed by a complainant. If the Board finds that a complaint is valid, it would then have to determine what action needs to be taken to remedy the situation. This could involve a delay in the licence proceeding, a denial of the export licence application or some other action appropriate to the circumstances of the particular application.

1.3.2 Export Impact Assessment

The purpose of the EIA is to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The Board periodically produces an EIA using several projections of exports. The study, which is prepared in consultation with the natural gas industry and other interested parties, covers long-term natural gas supply, demand, prices and export levels and endeavours to provide an adequate statement of assumptions and explanation of the analytical technique used.[1]

Applicants and intervenors have the option of using the Board's analysis or of preparing and submitting their own analysis. In the absence of any adjustment-related problems being identified by the Board itself or being raised by interested parties, the Board presumes that the proposed export would not trigger a market-adjustment problem.

1.3.3 The Other Public Interest Considerations

As part of its assessment of the other public interest considerations, the Board normally:

- makes an assessment of the likelihood that licensed volumes will be taken;
- makes an assessment of the durability of gas sales contracts;
- has regard to whether gas sales contracts were negotiated at arm's length;
- verifies that there is producer support for a gas export application;
- verifies that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract; and
- determines the appropriate length of term for an export licence, having regard to:
    (i) evidence on the adequacy of the gas supplies available to the export licence applicant to support the applied-for volumes over the requested licence term;

1. By letter dated 3 September 1992, the Board announced that it was undertaking to produce its second EIA. A workshop to promote discussion and exchange of information took place in April 1993.

(ii) evidence on the necessity of the requested term in light of the terms of the associated gas sales and transportation contracts and the terms of the approvals from other regulatory bodies; and

(iii) any other evidence which the Board deems to be relevant to the appropriate term of the licence.

The above statement on the other public interest considerations should be interpreted as providing guidance to parties as to which considerations the Board normally has regard to in assessing the merits of gas export licence applications. However, in the context of each specific export licence application, the Board has regard to whatever factors appear to it to be relevant to the Canadian public interest.

In assessing the considerations above, the Board takes into account information regarding gas supply, transportation, markets, sales contracts and the status of regulatory authorizations. This information is provided by the applicant in response to the information filing requirements of the *National Energy Board Part VI Regulations* and during the public hearing process.

Gas Supply

In its assessment of gas supply, the Board reviews the contractual arrangements pertaining to supply and the adequacy of both reserves and productive capacity.

In making its assessment as to the adequacy of the gas supplies available to the export licence applicant to support the applied-for volumes over the requested licence term, the Board is flexible but normally expects applicants to demonstrate that established reserves are equal to or exceed the applied-for volume and that productive capacity is adequate to meet the proposed annual export volumes over the majority of the applied-for licence term.

Each applicant is required to provide an estimate of established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducts geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and an assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board uses its estimate of reserves, along with basic deliverability data for each pool for which estimates of reserves were submitted, in preparing its productive capacity projections. These projections are generally adjusted to reflect production at the annual level of requirements. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are usually based on an annual load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements. If load factors are lower than anticipated, productive capacity would be sustained beyond the time the Board's analysis indicates.

Transportation

Regarding the transportation arrangements underpinning an export project, the Board reviews the status of upstream and downstream transportation arrangements, including all transportation contracts, either in final form or as precedent agreements. The Board also reviews the term and volume of the transportation arrangements.

Markets

The applications dealt with in GH-7-92 were for sales to three types of end-use markets: sales for system supply, sales for power generation and sales to cogeneration facilities, which are defined as facilities that produce electricity and thermal energy for use in commercial or industrial operations. The Board's review of these types of markets includes consideration of the following for each market type:

- for exports for system supply and for power generation, consideration of the purchaser's current and projected requirements and supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio; and,

- for exports to a cogeneration facility, consideration of the contractual chain, from the gas contract to the power and thermal sales contracts. The Board also considers the markets for the power and thermal output of the facility and the status of project financing and construction schedules.

For each type of end-use market, the review includes consideration, among other items, of the load factors at which the proposed exports are expected to flow.

Sales Contracts

The Board's review of the contractual arrangements includes consideration of the contractual obligations between the Canadian sellers and the U.S. buyers, including executed gas sales contracts. The Board's review also includes any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including the filing of these downstream contracts.

Status of Regulatory Authorizations

The Board reviews the status of pertinent regulatory authorizations in Canada and the U.S., including provincial removal authorizations, Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization and, for cogeneration facilities, qualifying cogeneration facility ("QF") certification under the U.S. *Public Utility Regulatory Policies Act*.

The Board's review also includes evidence of producer support and the status of any necessary state regulatory commission approvals.

1.4 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial period of time during which, if the export of gas commences, then the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually starts to flow within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

As a matter of general policy, and after questioning each applicant, the Board has set the timeframe by which exports must commence at approximately two years from the expected commencement of the licence term.

1.5 Views of the Board

The Board notes that there were no complaints registered with respect to the applications for export licences in the GH-7-92 proceeding.

The applicants examined in these Reasons adopted the Board’s most recent EIA, dated 7 September 1989. As neither the Board nor any interested parties identified any adjustment-related problems, the Board concludes that the proposed exports would not trigger a market-adjustment problem.

Since no complaints were registered with respect to the subject applications and the Board has determined that the proposed exports would not trigger a market-adjustment problem, the Board is satisfied that the quantity of 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 gas in Canada.

The remaining chapters of these Reasons review the evidence of each applicant pertaining to the Other Public Interest Considerations. The findings of the Board in respect of these considerations and any other factors the Board has deemed to be relevant are contained in the "Views of the Board" section at the end of each chapter.

Chapter 2

Canadian Hydrocarbons Marketing Inc.

2.1 Application Summary

By application dated 13 November 1992, Canadian Hydrocarbons Marketing ("CHMI") sought, pursuant to Part VI of the Act, a licence for the export of natural gas for sale to Cascade Natural Gas Corporation ("Cascade") with the following terms and conditions:

Term	- 1 November 1992 to 31 October 1996
Point of Export	- Huntingdon, British Columbia
Maximum Daily Quantity	- 136.4 10^3m^3 (4.8 MMcf)
Maximum Annual Quantity	- 49.8 10^6m^3 (1.8 Bcf)
Maximum Term Quantity	- 199.3 10^6m^3 (7.0 Bcf)
Tolerances	- ten percent per day and two percent per year

The gas to be exported to Cascade would be produced from a pool in British Columbia. The gas would be transported on the Westcoast system to the export point, at Huntingdon. From the international border, the gas would be shipped by Northwest Pipeline Corporation ("Northwest") to the points of interconnection with the facilities of Cascade.

2.2 Gas Supply

2.2.1 Supply Contracts

CHMI has executed gas purchase contracts with Conoco Canada Limited ("Conoco") and Ranger Oil Limited ("Ranger"). Conoco and Ranger will supply the required gas from reserves they own in the Sikanni Debolt "C" pool. Both companies have dedicated reserves from the c-41-I/94-G-3 well, amounting to a total of about 20 percent of the pool's production rates. Conoco and Ranger control nearly 100 percent of the total reserves in the pool.

2.2.2 Reserves

Table 2-1 shows that the Board's estimate of CHMI's gas reserves is approximately 40 percent lower than CHMI's range of estimates for the reserves dedicated to the proposed export. However, the Board's estimate does exceed the applied-for volume by 48 percent.

Table 2-1

Comparison of Estimates of CHMI's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

CHMI[1]	**NEB**[2]	**Applied-for**[3] **Volume**
494 - 500 (17.4 - 17.6)	294 (10.4)	199.3 (7.0)

1. As of 1 September 1992; estimate dependent upon which compression option is selected; a surface loss factor of three percent was applied to CHMI's estimates of raw gas reserves of 509 - 515 10^6m^3 (18.0-18.2 Bcf).
2. As of 1 September 1992.
3. The licence term volume will be 174.6 10^6m^3 (6.2 Bcf) due to 1 May 1993 commencement.

CHMI's reserves estimate for the Sikanni Debolt "C" pool is based on a material balance analysis with an assumed recovery factor of 85 percent. Reserves were then assigned to the c-41-I/94-G-3 well based on its productivity relative to the entire pool. While the Board agrees with CHMI's estimate of gas-in-place for the pool, it is concerned with the decline in production rates which are apparently due to water influx in two wells presently shut-in. The Board has thus assumed a 65 percent recovery factor for the pool, and then allocated reserves to the c-41-I well based on its productivity.

2.2.3 Productive Capacity

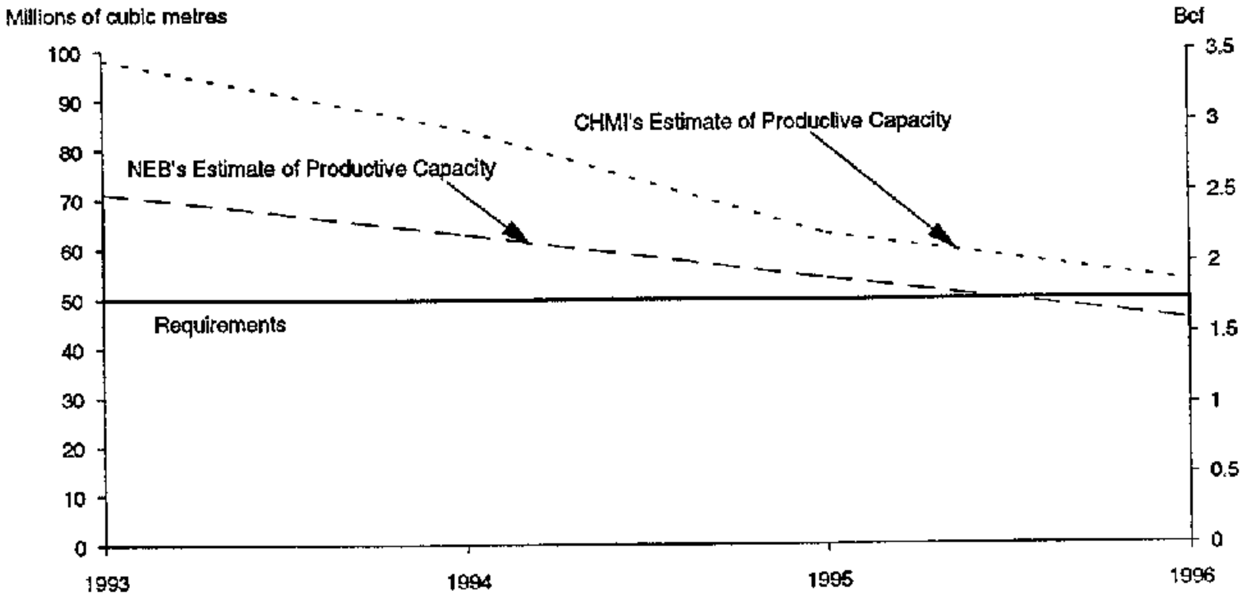
Figure 2-1 compares CHMI's and the Board's projections of productive capacity with CHMI's annual requirements. Both projections assume installation of compression in 1993, and the Board's projection assumes production at the annual requirement of 49.8 10^6m^3 (1.8 Bcf). CHMI demonstrated that it could meet the export requirement throughout the proposed term of the licence, whereas the Board projects that CHMI could fall short in the last year of the proposed export. CHMI stated that potential shortfalls in productive capacity could be mitigated either by adding uncontracted reserves from the rest of the Sikanni Debolt "C" gas pool, from its producers' corporate reserves, or from other contracted supply.

2.3 Transportation

Transportation from the supply area to the international border at Huntingdon, B.C. would be on the facilities of Westcoast. Cascade would take delivery of the gas at the international border. In the U.S., the gas would be transported on the Northwest system to the points of interconnection with the facilities of Cascade pursuant to two long-term contracts dated 24 June 1988, as amended,

Figure 2-1

Comparison of CHMI's and NEB's Estimates of Annual Productive Capacity



and 27 August 1991 between Cascade and Northwest.

No new facilities are required in Canada or the U.S.

2.4 Market

The gas proposed for export would be sold to Cascade, a local distribution company serving the States of Washington and Oregon, as a component of its firm system supply. Gas has been flowing under the contract supporting this application pursuant to a short-term order authorized by the Board.

Cascade's largest service territories include the cities of Bellingham, Bremerton and Yakima in Washington. More than 116,000 residential, commercial and industrial customers are served by Cascade. Sales are projected to increase from 1 546.1 10^6m^3 (54.6 Bcf) in 1992 to 1 725.5 10^6m^3 (60.9 Bcf) in 1996, an increase of approximately 12 percent. This growth is attributed to an expected increase in residential customers.

Cascade obtains its gas supply from a number of sources. The proposed export would represent approximately three percent of Cascade's projected total requirements. Purchases from CHMI are expected to occur at a 90 percent load factor based upon its existing sales to Cascade since 1 November 1990.

2.5 Gas Sales Contract

CHMI and Cascade have executed a gas sales contract dated 1 November 1990. The term of the contract commenced on 1 November 1990 and continues to 31 October 1996. There are no renewal provisions. The contract can be terminated by either party if the necessary long-term Canadian and U.S. regulatory authorizations are not received by 1 October 1993. CHMI stated that the contract was negotiated at arm's length.

The contract provides for a DCQ of 136.4 10^3m^3 (4.8 MMcf). If Cascade fails to purchase at least 55 percent of the sum of the DCQs for the year, the minimum annual quantity, then CHMI may elect to reduce the DCQ by the ratio of the amount taken to the minimum annual quantity. Should CHMI fail to deliver the quantity of gas nominated on any day, then CHMI will indemnify Cascade for the incremental costs incurred by purchasing gas from other sources.

The contract price consists of four components: a Westcoast demand charge, a commodity charge, a fuel gas charge, and a reservation fee.

The Westcoast demand charge applies to firm Westcoast transportation from the Sikanni receipt point to the delivery point, at Huntingdon.

The commodity charge is negotiated annually. In the event that the parties are unable to reach a negotiated settlement, the contract provides for final offer arbitration. Under this form of arbitration, each party submits its final offer to the arbitrator. The arbitrator is then required to select one of the offers. The commodity charge will be determined to ensure that the total delivered price of gas shall remain reasonably equivalent to expected prices to be paid by other LDCs supplied by the Northwest system in Cascade's market area.

The fuel gas charge is the product of the commodity charge and the amount of gas consumed by

Westcoast for fuel and unaccounted for gas losses for transportation from the Sikanni receipt point to the export point.

The reservation fee is negotiated annually by the parties and is applied to the DCQ. As with the commodity charge, final offer arbitration will be invoked if the parties fail to reach a negotiated settlement.

CHMI estimated that, under the terms of the contract, the price at the British Columbia border during January 1993 would have been $Cdn. 1.99/GJ ($Cdn. 2.10/MMBtu).

2.6 Status of Regulatory Authorizations

CHMI has applied for an energy removal certificate for a term and volume commensurate with the applied-for export. A decision from the British Columbia Ministry of Energy, Mines and Petroleum Resources ("BCEMPR") is pending.

Cascade has applied to the Department of Energy, Office of Fossil Energy ("DOE/FE"), for import authorization for a volume and term commensurate with the applied-for export. A decision is pending.

2.7 Views of the Board

The Board notes that Cascade is obligated to purchase a minimum annual quantity. In addition, Cascade is required to pay a reservation fee regardless of the level of its nominations. The Board also recognizes that Cascade has historically purchased gas from CHMI at high load factors. For these reasons, the Board is of the view that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board recognizes that the contract price is market sensitive since it is negotiated annually. In addition, the Board notes CHMI's evidence that it is highly unlikely that any circumstances would arise that would result in the termination of the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term and is, therefore, durable.

The Board has reviewed the gas sales contract between CHMI and Cascade and notes that it has been negotiated at arm's length.

Since Conoco and Ranger own the gas supply destined for export, a finding of producer support is not necessary.

The gas sales contract requires Cascade to reimburse CHMI for Westcoast's demand charges for firm transportation regardless of whether the gas is taken. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds the applied-for volume by approximately 50 percent. The Board's estimate of productive capacity shows that CHMI can meet its requirements from existing supply until late 1995, assuming that compression is added in 1993. Backstopping could be provided from other portions of the pool if necessary.

The Board notes that the expiry date of the gas sales contract is identical to the applied-for expiry date of the proposed export. Transportation has been arranged on all required pipelines for the proposed export term. The Board also notes that the applied-for regulatory authorizations are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested term is appropriate.

Finally, the Board notes that CHMI has applied for a commencement date of 1 November 1992. Since the Board does not backdate its licences, the applied-for term volume must be adjusted to account for a shorter export term. Assuming a commencement date of 1 May 1993, the Board has reduced the applied-for term volume by 24.7 10^6m^3 (0.9 Bcf). This volume is the product of the DCQ and the number of days between 1 November 1992 and 1 May 1993. During the hearing, CHMI agreed with the Board's method of calculating this reduction in the applied-for volumes.

2.8 Decision

The Board has decided to issue a gas export licence to CHMI, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

Chapter 3

CanWest Gas Supply Inc.

3.1 Application Summary

By application dated 13 November 1992, CanWest Gas Supply Inc. ("CanWest") sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- for 15 years following the first day of the month following the later of the date the Northwest Pipeline Corporation ("Northwest") Phase I expansion becomes operational or the date all required authorizations are received
Point of Export	- Huntingdon, British Columbia
Maximum Daily Quantity	- 273.2 10^3m^3 (9.6 MMcf)
Maximum Annual Quantity	- 100 10^6m^3 (3.5 Bcf)
Maximum Term Quantity	- 1 495 10^6m^3 (53.0 Bcf)
Tolerances	- ten percent per day and two percent per year

The gas proposed for export would be produced from reserves mainly in British Columbia under contract to CanWest and would be transported on the Westcoast system for delivery to TM Star Fuel Company ("TM Star") near Huntingdon, British Columbia. The gas would then flow on the Northwest system. The gas, to be used primarily at the March Point Cogeneration Company ("MPCC") near Anacortes, Washington, would be delivered through the Cascade system. Steam and electricity produced at MPCC would be sold to Texaco Refining and Marketing Inc. ("TRMI") and Puget Sound Power & Light Company ("Puget Sound Power") respectively.

3.2 Gas Supply

3.2.1 Supply Contracts

CanWest will provide the gas for the export from its contracted supply pool mainly in British Columbia. This supply pool is characterized by dedicated, reserve-based gas purchase contracts with about 155 producers.

3.2.2 Reserves

Table 3-1 shows that the Board’s estimate of CanWest’s gas reserves as of 1 November 1992 is about 11 percent lower than CanWest’s but exceeds its total requirements by about 20 percent.

Table 3-1

Comparison of Estimates of CanWest's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

CanWest[1]	NEB[2]	Applied-for[3] Volume
66 059 (2,331.9)	61 575 (2,173.6)	1 501 (53.0)

1. As of 1 November 1992.
2. As of 31 December 1991. The Board's estimate of remaining reserves would be at least 2 800 10^6m^3 (99 Bcf) less than shown if adjusted to 1 November 1992.
3. This represents about 3 percent of CanWest's total requirements, which are 48 808 10^6m^3 (1,724 Bcf).

Approximately 90 percent of CanWest's pools are on production, with the majority of the largest pools having produced for more than 15 years, thus enabling production decline and material balance analysis methods to be used for determining estimates of reserves.

3.2.3 Productive Capacity

Figure 3-1 compares the Board's and CanWest's projections of productive capacity with CanWest's total requirements at 100 percent load factor. In 1994, the applied-for requirement represents three percent of CanWest's total requirements. Both projections indicate shortfalls beginning in 1999 if CanWest were to produce its reserves at capacity. However, if CanWest were to satisfy only its existing long-term and short-term commitments, the Board expects that it could meet these requirements over the majority of the term of the proposed export. CanWest also stated that it would remedy shortfalls in productive capacity by contracting additional reserves or developing new reserves on existing contracted lands. It also stated that it could curtail short-term sales.

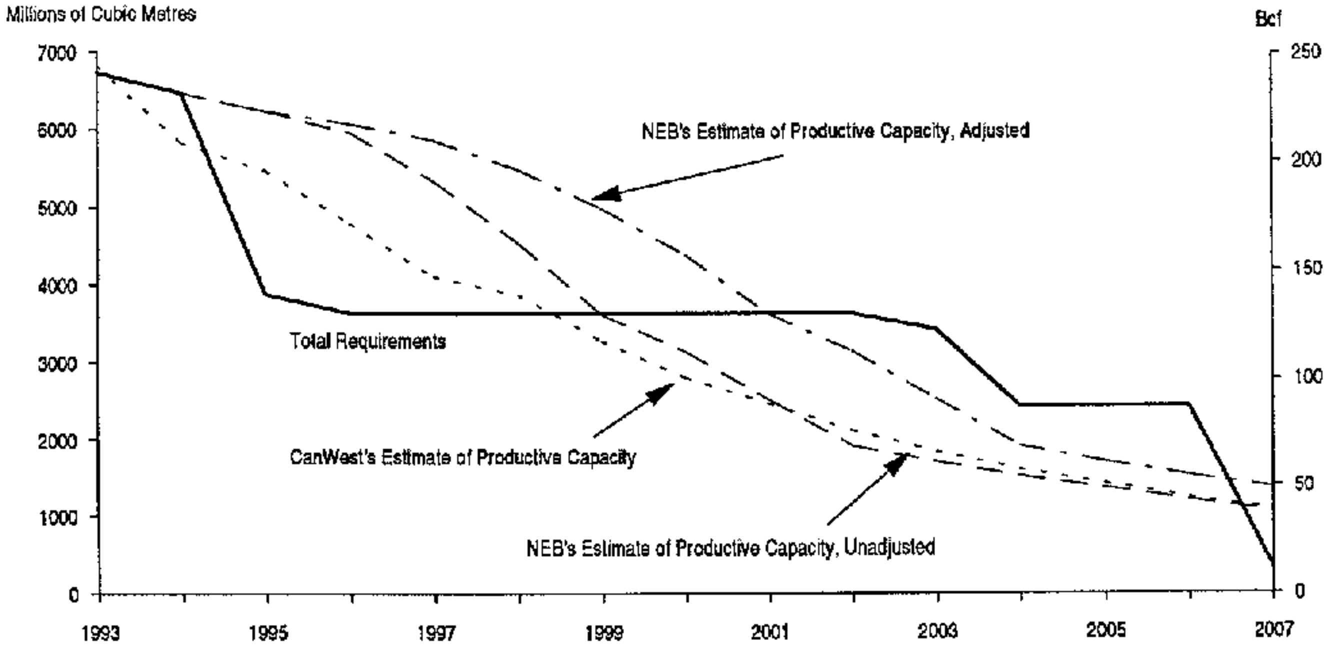
3.3 Transportation

CanWest executed an FS transportation agreement with Westcoast on 30 April 1992 to deliver the proposed export volumes from receipt points in British Columbia to the interconnection of the Northwest and Westcoast systems near Huntingdon, British Columbia. The contract is for sufficient capacity and is renewable by CanWest in accordance with Westcoast's tariff.

Texaco Gas Marketing Inc. ("TGMI") executed an FS transportation agreement with Northwest on 5 July 1990 to deliver 31 580 GJ (30,000 MMBtu) daily from the international border near Sumas, Washington to the interconnection of the Northwest and El Paso Natural Gas Company ("El Paso") systems near Blanco, New Mexico. This capacity was expected to be assigned to TM Star by

Figure 3-1

Comparison of CanWest's and NEB's Estimates of Annual Productive Capacity



April 1993. Northwest has agreed to deliver 10 525 GJ (10,000 MMBtu) of the 31 580 GJ (30,000 MMBtu) to the inlet of the Cascade system. MPCC has contracted with Cascade for daily FS transportation of 42 105 GJ (40,000 MMBtu) for a term of 20 years commencing on 1 August 1991.

If the fuel requirements of the MPCC facility are less than estimated, then the gas proposed for export would be directed to TGMI to serve cogeneration facilities in California. TGMI has already contracted for sufficient firm transportation service with El Paso and Mojave Pipeline Operating Co.

3.4 Market

TM Star, owned by Texaco Inc. and SCEcorp, was formed for the purpose of buying natural gas supplies from the U.S. and Canada and reselling and arranging transportation of such supplies for the benefit of affiliated cogeneration facilities. MPCC and TM Star are owned by the same principals.

The gas proposed for export would be used primarily to fuel MPCC's 140 MW cogeneration facility to be located within TRMI's Puget Sound Plant, a refinery near Anacortes, Washington. The facility's normal daily gas requirement is 35 263 GJ (33,500 MMBtu). U.S. and Canadian sourced gas would be used at the facility. As a back-up market, the gas proposed for export may also be used at various cogeneration facilities located near Bakersfield, California, including facilities owned by the Kern River Cogeneration Company and the Sycamore Cogeneration Company.

The MPCC cogeneration facility was constructed in two phases. The first phase commenced operation on 11 November 1991, the second phase on 1 January 1993. Sales from CanWest to TM Star commenced on a short-term basis in January 1993. The facility is expected to nominate gas at a 90 percent load factor.

Pursuant to an agreement dated 7 August 1991, thermal energy from the facility would be used at TRMI's Puget Sound Plant for use in refinery operations. The arrangement has a term of 20 years.

The power purchase agreement for the first phase of the cogeneration facility, dated 29 June 1989, was executed between Puget Sound Power and San Juan Energy Company and was assigned to MPCC on 28 July 1989. The agreement for the second phase, dated 27 December 1990, was executed between Puget Sound Power and MPCC. Both agreements are effective until 31 December 2011. The price under the power purchase agreement escalates, in part, with the U.S. inflation rate.

Power from the facility would be sold to Puget Sound Power as baseload. Puget Sound Power generates, purchases, transmits, distributes and sells electric power in western and central Washington state. The utility serves approximately 750,000 customers.

3.5 Gas Sales Contract

TM Star and CanWest executed a gas sales contract on 7 October 1992, with an initial term of 15 years. The term commences on the first day of the month following the later of the date the

Northwest Phase I expansion becomes operational or the date all required authorizations are received. The contract continues year-to-year thereafter until cancelled by either party. The contract term was expected to commence on 1 April 1993.

The contract provides for an MDQ of 10 525 GJ (10,000 MMBtu) and is subject to the term commencing by 30 September 1993 unless the parties agree otherwise. If all regulatory authorizations are not received by 1 November 1993, either party may terminate the contract. These authorizations must be received by 1 June 1995 or the contract is terminated. The parties may submit to binding arbitration should any disagreement or controversy arise from the contract. CanWest stated that the contract was negotiated at arm's length.

TM Star is obligated to purchase a minimum of 90 percent of the MDQ on an annual basis and is obligated to pay CanWest a deficiency charge equal to 30 percent of the contract price for volumes taken below this minimum annual volume obligation. TM Star has a 60-day period to make up any deficient volumes. CanWest is to use reasonable efforts to utilize the pipeline capacity on Westcoast, either through third-party sales or capacity brokering, should TM Star nominate less than the MDQ.

The price commencing 1 April 1993 for gas sold under the contract will be $U.S. 1.74/GJ ($U.S. 1.83/MMBtu) at the international border. Commencing each 1st January thereafter, the price escalates by the annual U.S. inflation rate. The price escalation is bounded by a four percent minimum and a six percent maximum increase.

CanWest submitted that, on 1 January 1993, the British Columbia border price that would have been in effect under the terms of this contract was $Cdn. 2.22/GJ ($Cdn. 2.34/MMBtu).

3.6 Status of Regulatory Authorizations

CanWest filed an application for a long-term energy removal certificate from the BCEMPR on 3 December 1992. CanWest will rely upon a short-term certificate until receipt of the long-term energy removal certificate. CanWest received a finding of producer support from the BCPC on 30 November 1992. As well, TM Star received DOE/FE import authorization on 16 February 1993 for a term and volume commensurate with the applied-for licence.

Northwest has received approval from the FERC to expand its system for this export. The capacity is expected to be available in April 1993. As well, MPCC received QF status from FERC on 25 November 1991. The Washington Utilities and Transportation Commission has approved the power purchase agreements associated with MPCC.

3.7 Views of the Board

The Board notes that TM Star must purchase at least 90 percent of the MDQ on an annual basis if it is to avoid payment of a deficiency charge. The Board is aware that MPCC's markets for electricity and thermal energy are likely to be long term and stable. The Board also notes that sales from CanWest to TM Star commenced on a short-term basis in January 1993. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the escalation rates of the prices under the gas sales contract and the power purchase contract are similar and that the gas sales contract is subject to binding arbitration.

As well, the Board notes CanWest's evidence that it is unlikely that any circumstances would arise that would cause CanWest and TM Star to terminate the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term and is, therefore, durable.

The Board has reviewed the gas sales agreement and notes that it has been negotiated at arm's length.

CanWest obtained a finding of producer support from the BCPC on 30 November 1992.

The Board notes that the contract price will likely be sufficient to recover Canadian demand charges throughout the term of the contract. As well, CanWest is contractually obligated to use reasonable efforts to utilize capacity on Westcoast should TM Star nominate less than the MDQ. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation demand charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds CanWest's total requirements by approximately 20 percent. The Board's estimate of adjusted productive capacity shows that CanWest can meet its long-term and existing short-term requirements from existing supply over the majority of the proposed licence term. Backstopping could be provided with contracting of new supply and further development of contracted lands. The Board observes that the term of the transportation, gas sales, power purchase and thermal energy contracts and of other required regulatory authorizations is consistent with the terms of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

3.8 Decision

The Board has decided to issue a gas export licence to CanWest, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

Chapter 4

Enron Gas Marketing, Inc.

4.1 Application Summary

By application dated 12 November 1992, Enron Gas Marketing, Inc. ("Enron") applied for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	- the date of first deliveries to 31 October 2004	
Point of Export	- Chippawa, Ontario	
Maximum Daily Quantity	- 805 10^3m^3	(28.4 MMcf)
Maximum Annual Quantity	- 294 10^6m^3	(10.4 Bcf)
Maximum Term Quantity	- 2 940 10^6m^3	(104.0 Bcf)
Tolerances	- ten percent per day and two percent per year	

The gas proposed for export would be produced from reserves in Alberta owned or controlled by seven producers. Unigas has entered into Letter Agreements with these suppliers for the purchase of the gas, for subsequent resale to Enron. The gas would be transported on NOVA and TransCanada to the international border near Chippawa, Ontario. At the export point, Enron Power Services, Inc. ("EPS") will take delivery of the gas from Enron and resell it to Sithe/Independence Power Partners, L.P. ("Sithe"). Empire and Niagara Mohawk would ship the gas to the proposed cogeneration plant located in the town of Scriba, New York.

4.2 Gas Supply

4.2.1 Supply Contracts

Unigas, as the supplier to Enron, has executed Letter Agreements with seven producers: Archer Resources Ltd., Blue Range Resource Corp., Canada Northwest Energy Ltd., Canor Energy Ltd., Crestar Energy ("Crestar"), Inverness Petroleum Ltd. and Petro-Canada. Under the provisions of the agreements, each producer (except Crestar) has dedicated certain specific lands and reserves to Unigas. Crestar has provided its corporate supply; accordingly, no specific pools have been contractually dedicated to the proposed sale.

4.2.2 Reserves

Table 4-1 shows that the Board's estimate of Enron's gas reserves is less than Enron's but is higher than the applied-for volume. Both Enron's and the Board's estimates are as of 31 December 1991. When both are adjusted for Unigas' estimated production to 1 November 1994, the expected date of commencement of gas flows, the Board's estimate would be about seven percent lower than Enron's, and five percent lower than the applied-for volume.

Table 4-1

Comparison of Estimates of Enron's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Enron[1]	**NEB**[1]	**Applied-for Volume**
4 032 (142.3)	3 838 (135.5)	2 940 (104.0)

1. As of 31 December 1991, except the Unigas/Petro-Canada portion which is as of 1 October 1992. Both Enron's and the Board's estimates of remaining established reserves would be at least 1 050 10^6m^3 (37.1 Bcf) less than shown if adjusted for production from 1 January 1992 to 1 November 1994.

4.2.3 Productive Capacity

Figure 4-1 compares the Board's and Enron's projections of productive capacity with Enron's applied-for annual requirements (plus fuel) based on a 100 percent load factor. Both projections indicate that Enron will be able to meet its requirements for six to seven years of the term of the proposed licence. The Board notes that the individual producers contracted to Enron are obligated to dedicate additional reserves in order to maintain sufficient supply to meet the MDQ. Should the producer not deliver the contracted volume, then the producer is to indemnify Unigas for incremental costs associated with acquiring any additional reserves, and the producer is responsible for transportation demand charges and penalty costs. Enron also stated that Unigas may enter into additional gas purchase contracts, and that Unigas may use its corporate supply to backstop potential shortages.

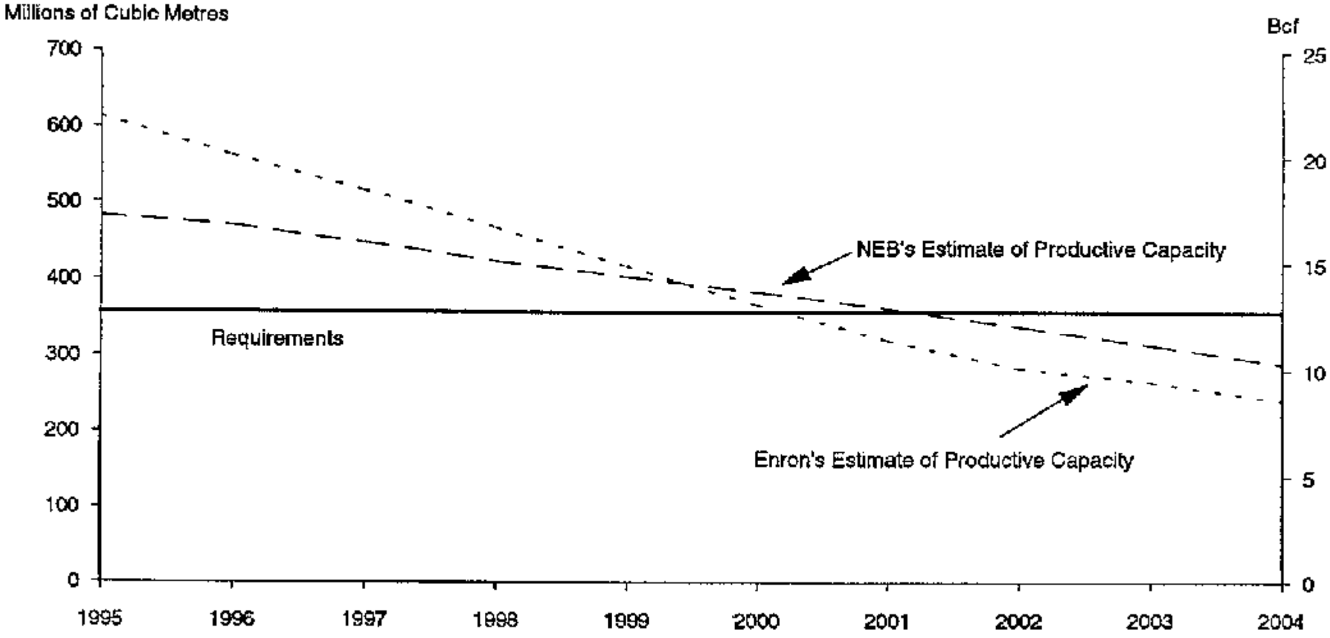
4.3 Transportation

Unigas has existing contracts with NOVA to deliver the proposed export volumes from receipt points in Alberta to Empress. Enron and Enron Gas Services Corp. executed a Precedent Agreement with TransCanada on 31 March 1993 for the transportation of the gas from Empress to Chippawa, Ontario. In the U.S., the gas would be shipped on Empire under an agreement dated 28 February 1992 and on Niagara Mohawk under an agreement dated 11 March 1992.

4.4 Market

The gas proposed for export will be used to power a 1000 MW combined cycle power plant, to be owned and operated by Sithe. The cogeneration facility would be located at the Alcan Rolled Products Company ("Alcan") plant in Scriba, New York. No. 2 fuel oil will be the back-up fuel for the plant.

Figure 4-1
Comparison of Enron's and NEB's Estimates of Annual Productive Capacity



Alcan will purchase the thermal energy and some of the electricity under an energy sales contract dated 18 November 1992 which extends for a 22-year term. Consolidated Edison of New York, Inc. and Niagara Mohawk will purchase the bulk of the electricity under agreements dated 20 May 1991, as amended, and 24 July 1992, respectively. The two electricity purchase agreements are for terms of 20 years and were approved by the NYPSC.

The cogeneration facility has received QF status from FERC. The project obtained permanent financing on 27 January 1993 and, at the time of the hearing, the plant was nearly 30 percent completed. Enron expects that exports would occur at a load factor approaching 100 percent.

4.5 Gas Sales Contract

Unigas and Enron executed a gas sales contract dated 15 December 1992 for a term beginning on the date of first deliveries and ending on 31 October 2004. The contract provides for a DCQ of 878 10^3m^3 (31 MMcf) and can be terminated by either party unless all regulatory authorizations and transportation contracts are concluded by 1 November 1994. Commencement of deliveries would occur at about that time.

Enron stated that the contract was negotiated at arm’s length.

Enron must purchase at least 60 percent of the Annual Contract Quantity ("ACQ"). If it does not nominate the minimum quantity, Enron will pay a fee of 15 percent of the applicable commodity charge on the deficient quantity. Enron is not permitted to displace the gas volumes to be provided by Unigas with gas from other sources.

Unigas is responsible for the payment of NOVA transportation charges from the revenues generated under the gas sales contract. Enron pays the demand charge on TransCanada for the transportation of the gas to Chippawa.

On or before 25 November of each contract year, the contract price is determined based on a Base Price ("BP") developed by using the NYMEX average price for a 12-month period minus $U.S. 0.39/GJ ($U.S. 0.41/MMBtu) adjusted by an Empress Adjustment ("EA"). The EA is an amount equal to $U.S. 0.095/GJ ($U.S. 0.10/MMBtu), escalating annually at five percent. An Empress Reference Index ("ERI") is then compared to a range comprising BP plus and minus the EA in order to determine the contract price. If the ERI is within or equal to the range, the contract price is the BP. Otherwise, the contract price could be BP minus EA or BP plus EA. The contract does not contain a provision for renegotiation and arbitration of the contract terms.

Enron submitted that, on 1 January 1993, the Alberta border price would have been $Cdn 1.69/GJ ($Cdn 1.78/MMBtu) under the terms of the contract.

4.6 Status of Regulatory Authorizations

Approval by the NYPSC of the new pipeline to be built by Niagara Mohawk from the Empire pipeline to the cogeneration plant is expected to be received in the second half of 1993. Unigas applied to the ERCB for a removal permit on 31 March 1993. As well, Enron has received DOE/FE import authorization.

4.7 Views of the Board

The Board notes that Enron must nominate at least 60 percent of the DCQ if it is to avoid payment of a deficiency charge. Enron is also prevented from making any gas purchases that may displace its supply from Unigas. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board has noted the market-oriented approach used to determine the contract price on an annual basis. As well, the Board notes Enron's evidence that it is unlikely that any circumstances would arise that would cause Enron and Unigas to terminate the gas sales contract. The Board is thus satisfied that the contract will remain attractive to the parties over its proposed term and is, therefore, durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

The execution of contracts between Unigas and its suppliers, dedicating reserves to Unigas for resale to Enron, is evidence of producer support.

The Board notes that Enron is responsible for the transportation charges on TransCanada and that the revenues generated under the contract will likely be sufficient to enable Unigas to cover NOVA demand charges. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the contract.

The Board's estimate of reserves is five percent lower than the applied-for volume and its estimate of productive capacity shows that Enron can meet its requirements from existing supply until the year 2001. The Board is satisfied that Unigas will be able to make up any shortfalls since its producers are required to dedicate additional lands in order to meet their MDQ. Additionally, the producers have provided an indemnity clause to Unigas in the event of supply shortfalls. The Board notes that Unigas can mitigate potential shortfalls either by entering into additional gas purchase contracts with other producers or by drawing on its own corporate gas supply pool on a temporary basis.

As well, the Board notes that an application for the ERCB energy removal authorization has been made and that all other regulatory authorizations are in progress. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these applied-for authorizations, transportation arrangements and of the gas sales contract are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

4.8 Decision

The Board has decided to issue a gas export licence to Enron, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

Chapter 5

New York State Electric & Gas Corporation

5.1 Application Summary

By application dated 12 November 1992, New York State Electric & Gas Corporation ("NYSEG") applied for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	- ten years following the first day of the first month after the commencement of deliveries
Point of Export	- Chippawa, Ontario
Maximum Daily Quantity	- 283.3 10^3m^3 (10.0 MMcf)
Maximum Annual Quantity	- 103.5 10^6m^3 (3.7 Bcf)
Maximum Term Quantity	- 1 035 10^6m^3 (37.0 Bcf)
Tolerances	- ten percent per day and two percent per year

The gas proposed for export would be produced from pools owned by Crestar Energy ("Crestar"). The gas would be transported by NOVA and TransCanada to the international border near Chippawa, Ontario, the interconnection with Empire State Pipeline Company, Inc. ("Empire"). Empire would deliver the gas to the interconnection with the facilities of NYSEG. In turn, NYSEG would ship the gas to markets in Lockport, Auburn and Geneva, in New York State, via two new pipelines.

5.2 Gas Supply

5.2.1 Supply Contracts

NYSEG has executed a ten-year natural gas purchase agreement with Crestar for approximately 283.3 10^3m^3/d (10 MMcfd). Crestar warrants gas supply and delivery, and indemnifies NYSEG for replacement supply for any gas not delivered.

Crestar will provide the gas for the proposed export from an Alberta supply pool, representing approximately 50 percent of Crestar's corporate supply. Accordingly, no specific pools have been contractually dedicated to the proposed sale.

5.2.2 Reserves

Crestar submitted ERCB estimates of reserves for those Alberta gas pools from which it intends to provide the required volumes. Table 5-1 shows that the Board's estimate of Crestar's reserves is approximately four percent lower than that submitted by Crestar, but is significantly higher than the applied-for volume and is more than double Crestar's total requirements of 6 378 10^6m^3 (225 Bcf).

Table 5-1

Comparison of Estimates of NYSEG's Established Gas Reserves With the Applied-for Term Volume

10^6m^3
(Bcf)

NYSEG[1]	**NEB**[2]	**Applied-for**[3] **Volume**
14 651 (517.2)	14 018 (494.8)	1 035 (37.0)

1. As of 30 June 1992.
2. As of 31 December 1991.
3. This represents about 16 percent of Crestar's total requirements, which are 6 378 10^6m^3 (225 Bcf).

5.2.3 Productive Capacity

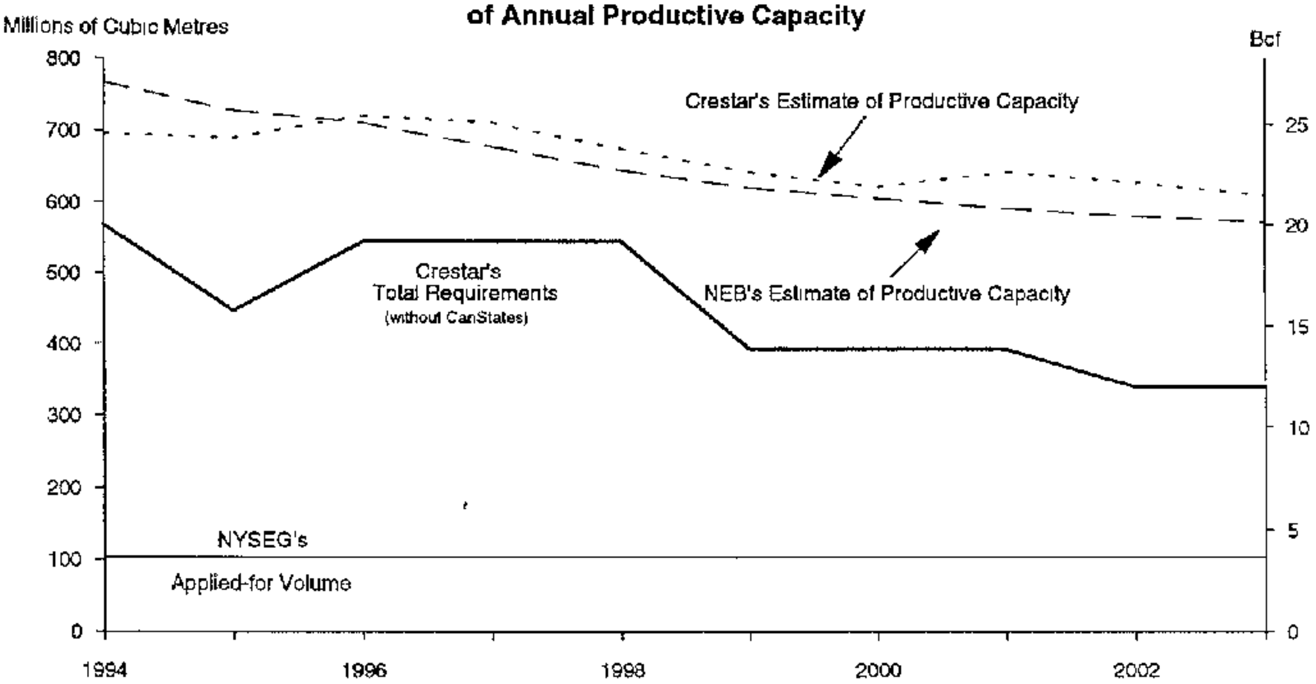
Figure 5-1 compares the Board's and Crestar's projections of productive capacity with Crestar's annual requirements on a contract year basis. In 1994, the NYSEG requirement, at a 100 percent load factor, represents 18 percent of Crestar's total requirements. Crestar's total requirements consist of several long-term and short-term sales. The Board adjusted Crestar's requirements to exclude Crestar's supply obligation to CanStates given that CanStates suspended its export application. Both projections indicate adequate productive capacity throughout the proposed export term.

5.3 Transportation

Crestar currently holds sufficient firm NOVA capacity for the proposed export volumes for the initial two years commencing 1 November 1993 and will renew and/or contract for more capacity if necessary. NYSEG signed a precedent agreement with TransCanada dated 16 March 1993 for a 14-year term for the transport of the gas to Chippawa, Ontario. NYSEG concluded a precedent agreement with Empire dated 3 March 1993 for a 15-year term.

Figure 5-1

Comparison of Crestar's and NEB's Estimates of Annual Productive Capacity



5.4 Market

The gas will be sold to NYSEG, a local distribution company serving more than 220,000 gas customers in New York State. The company provides both sales and transportation service and, in total, delivers more than 1 415 10^6m^3 (50 Bcf) annually to its existing franchise areas. The proposed export would be used to meet the existing and projected peak day and annual demand in Lockport, Auburn and Geneva, New York. NYSEG expected that exports would occur at a load factor in excess of 90 percent.

NYSEG anticipates increases in demand resulting from additional market penetration and the opening up of markets along the new pipeline routes. NYSEG projected an average annual growth rate of 0.84 percent in total demand over the period 1993-2000.

5.5 Gas Sales Contract

Crestar and NYSEG executed a gas sales contract dated 22 February 1993, which superseded a binding Letter Agreement dated 26 August 1992. The contract has a term of ten years from the commencement of deliveries which is expected to occur on or about 1 November 1993. The contract continues from year to year thereafter until cancelled by either party on six months' written notice. The contract provides for a MDQ of 283.3 10^3m^3 (10 MMcf) and can be terminated by either party unless all regulatory authorizations and transportation contracts are concluded by 31 December 1994. NYSEG stated that the contract was negotiated at arm's length.

NYSEG must purchase at least 60 percent of the MDQ plus any deficient volumes from the preceding contract year. If NYSEG fails to nominate and take delivery of the minimum quantity in any contract year, Crestar may reduce the MDQ by the same proportion.

The contract includes a two-part pricing structure, consisting of a demand charge and a commodity price. NYSEG pays the NOVA demand charge component for the transportation of the export volumes to Empress. As well, NYSEG pays the demand charge on TransCanada.

The commodity component will be determined monthly, equal to a Base Price ("BP") adjusted by selected index ratios for Alberta and U.S. gas delivered into the Tennessee Pipeline Company system. The index ratios are obtained from index prices contained in the Canadian Gas Price Reporter and Inside FERC Gas Market Report.

If NYSEG nominates the minimum quantity (i.e., 60 percent of the MDQ), it would pay the BP. The price for quantities taken between 60 percent and 80 percent of the MDQ would be 90 percent of the BP. If deliveries were above 80 percent of the MDQ, NYSEG would pay 87 percent of the BP on the volumes in excess of the minimum.

The contract provides for binding arbitration in the event that NYSEG and Crestar are unable to agree on the contract price. Arbitration would be dealt with under the rules of the British Columbia International Commercial Arbitration Centre.

NYSEG submitted that, on 1 January 1993, the Alberta border price would have been $Cdn 1.68/GJ ($Cdn 1.77/MMBtu) at the minimum take under the terms of the contract.

5.6 Status of Regulatory Authorizations

On 8 January 1993, Crestar applied to the ERCB for a long-term removal permit. A decision on the application is pending. As well, NYSEG obtained DOE/FE import authorization on 3 March 1993.

5.7 Views of the Board

The Board notes that NYSEG must nominate at least 60 percent of the MDQ if it is to avoid the risk of a MDQ reduction by Crestar. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the commodity prices. As well, the Board notes NYSEG's evidence that it is unlikely that any circumstances would arise that would cause NYSEG and Crestar to terminate the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term and is, therefore, durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

Producer support was demonstrated by the fact that Crestar executed the contract with NYSEG.

The Board notes that the contract price contains a demand charge component equal to Crestar's demand charge obligations on NOVA. In addition, NYSEG is responsible for paying the demand charge on TransCanada. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds NYSEG's total requirements by more than 100 percent. The Board's estimate of productive capacity shows that NYSEG can meet its requirements from existing supply throughout the proposed licence term. As well, the Board notes that an application to the ERCB has been made, that DOE/FE import authorization has been received, and that all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contract are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

5.8 Decision

The Board has decided to issue a gas export licence to NYSEG, subject to the approval of the Governor in Coucil. Appendix I contains the terms and conditions of the licence to be issued.

Chapter 6

Unigas Corporation for Export to Northwest Natural Gas Company

6.1 Application Summary

By application dated 19 October 1992, Unigas Corporation ("Unigas") applied for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	- commencing on the later of the date of first deliveries and 1 November 1993 for a term of six years
Point of Export	- Kingsgate, British Columbia
Maximum Daily Quantity	- 396.6 10^3m^3 (14.0 MMcf)
Maximum Annual Quantity	- 144.8 10^6m^3 (5.1 Bcf)
Maximum Term Quantity	- 868.6 10^6m^3 (30.7 Bcf)
Tolerances	- ten percent per day and two percent per year

The gas proposed for export would be produced from reserves in Alberta owned or controlled by Amerada Hess Canada Ltd. ("Amerada"), APL Oil & Gas Ltd. ("APL"), Paloma Petroleum Ltd. ("Paloma") and Universal Explorations Ltd. ("Universal"). The gas would be transported on NOVA and Alberta Natural Gas Company Ltd. ("ANG") to the international border near Kingsgate, British Columbia. PGT and Northwest would ship the gas to Northwest Natural, a local distribution company serving markets in the states of Washington and Oregon.

6.2 Gas Supply

6.2.1 Supply Contracts

Unigas has executed gas purchase contracts with four producers: Amerada, APL, Paloma and Universal. Under the provisions of the contracts, each producer has dedicated certain specific lands and reserves to Unigas. The contract with APL, which commenced in 1988, is for a 15-year term, while the remaining three contracts are for 10-year terms starting 1 November 1993.

Amerada, Paloma and Universal have a covenant to supply Unigas volumes of gas up to their individual MDQs and upon failing to supply their MDQs over any two week period, they have the option of restoring their deliverability during a six-month period or accepting a reduced MDQ. APL's deliverability is to be used by Unigas to supplement the daily volumes supplied by the other three producers to meet the daily requirements under this contract, up to the MDQ of 396.6 10^3m^3 (14.0 MMcf). Therefore, APL's supply provides backstopping capability to the other producers.

6.2.2 Reserves

Table 6-1 shows that the Board's estimate of Unigas' gas reserves is higher than that of Unigas; however, the Board's estimate is as of 31 December 1991 whereas Unigas' estimate is as of 1 November 1993. As of that date, the Board's estimate would be about 22 percent lower than the applicant's but 16 percent higher than the applied-for volume.

Table 6-1

Comparison of Estimates of Unigas' Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Unigas[1]	**NEB**[2]	**Applied-for Volume**
1 302 (46.0)	1 736 (61.3)	868.6 (30.7)

1. As of 1 November 1993.
2. As of 31 December 1991. The Board's estimate of remaining established reserves would be approximately 725 10^6m^3 (25.7 Bcf) less than shown if adjusted for production from 1 January 1992 to 31 October 1993.

Production was estimated to 31 October 1993 for all properties currently on production except for the properties owned by Paloma, which are currently contracted to Western Gas Marketing Ltd. ("WGML"). These properties are being decontracted from WGML and effective 1 November 1996 will be available to Unigas. Production was estimated to 1 November 1996 for these pools.

6.2.3 Productive Capacity

Figure 6-1 compares the Board's and Unigas' projections of productive capacity with Unigas' applied-for annual requirements based on a 100 percent load factor.

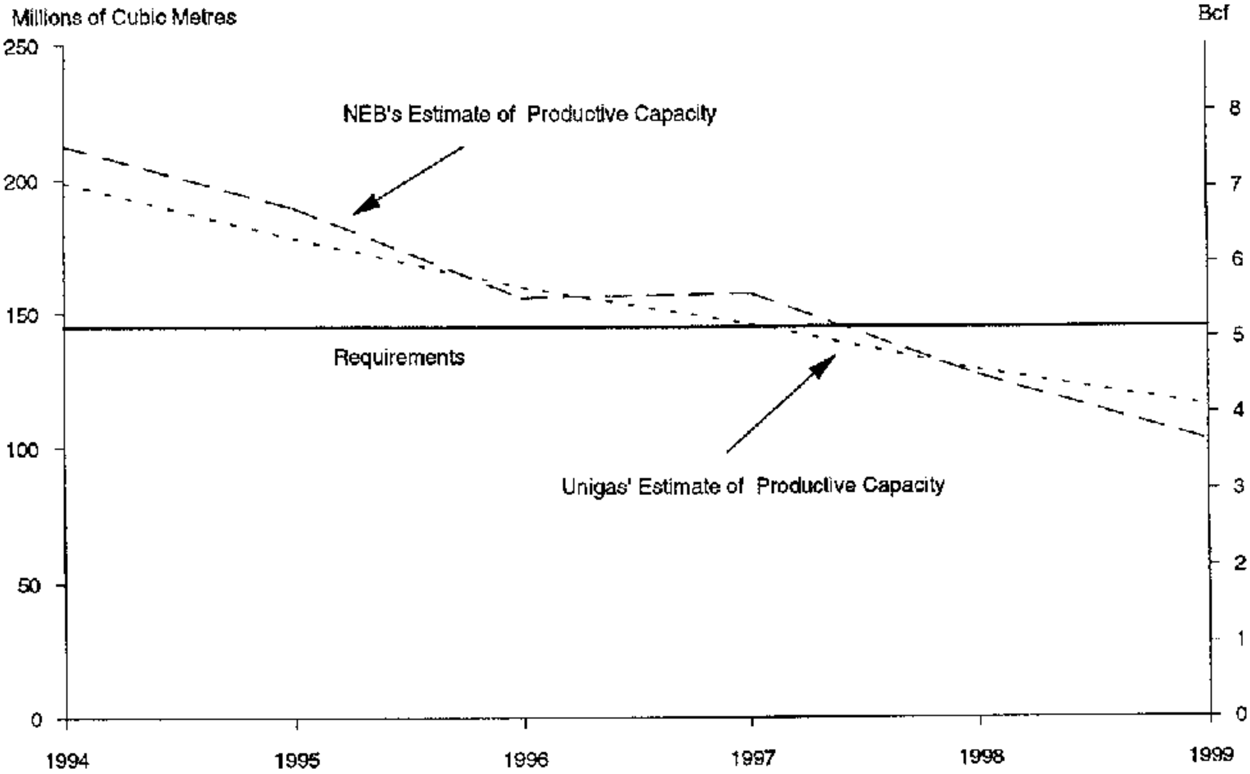
Both the Board's and Unigas' projections assume that excess productive capacity from APL will be used to meet applied-for requirements. The Board's projection indicates that Unigas will be able to meet its requirements at 100 percent load factor for four of the six year proposed term. Unigas expects, however, to operate at an 85 percent load factor.

If APL is unable to backstop possible shortfalls of the other producers, Unigas indicated that it would make up shortfalls from its own corporate supply on a temporary basis. Unigas stated that it could also alleviate any deficiency in either reserves or deliverability by requesting that the producers dedicate additional reserves or by Unigas entering into additional gas purchase contracts.

6.3 Transportation

Figure 6-1

Comparison of Unigas' and NEB's Estimates of Annual Productive Capacity



Unigas executed a firm service contract with NOVA, dated 1 September 1991, to deliver the proposed export volumes to the Alberta/British Columbia border at Coleman. Northwest Natural concluded an agreement with ANG, dated 12 June 1991, to transport the gas to Kingsgate, British Columbia. Northwest Natural will likely assign its ANG capacity to Unigas for a term and volume consistent with the gas sales contract.

Northwest Natural executed a 30-year FS transportation contract with PGT, dated 12 June 1991, under which the gas would be delivered to a point of interconnection with the facilities of Northwest. In turn, under a 15-year contract dated 29 June 1990, Northwest would transport the gas to Northwest Natural's citygate.

6.4 Market

The gas will be sold to Northwest Natural, a local distribution company serving more than 320,000 customers in Oregon and Washington. The company provides both sales and transportation service and, in total, delivers more than 2 830 10^6m^3 (100 Bcf) annually.

Growth in the number of customers and in total deliveries averaged 3.7 percent and 5.2 percent per year, respectively, between 1985 and 1990. Northwest Natural forecast that sales will increase by two percent per year during this decade, attributed to the current low per capita use of natural gas in its service territory and the competitive price of natural gas. The expected growth in sales will come predominantly from the residential and commercial sectors.

Northwest Natural currently purchases about two-thirds of its gas requirements from Canada. The company owns or contracts for storage capacity at five different facilities. Northwest Natural relies on this capacity to meet more than one-half of its peak day firm load and about 20 percent of its annual requirements. Unigas expected that exports would occur at summer and winter load factors of 50 and 85 percent, respectively.

6.5 Gas Sales Contract

Northwest Natural and Unigas executed a gas sales contract on 1 June 1991, with an initial term extending to 1 October 2003. The contract continues from year to year thereafter until cancelled by either party on five months' written notice and provides for a DCQ of 396.6 10^3m^3 (14.0 MMcf). The contract can be terminated by either party unless all regulatory authorizations and transportation contracts are concluded by 1 November 1994. Unigas received a finding of producer support from the APMC on 28 November 1991. As well, Unigas stated that the contract was negotiated at arm's length.

Northwest Natural must purchase at least 85 percent of the MDQ in the winter and 50 percent in the summer. If it does not, Northwest Natural will pay a fee of 15 percent of the applicable commodity charge on the deficient quantity.

The Selling Price includes a demand charge and a commodity price. The demand charge component will be a monthly amount equal to Unigas's demand charge obligations to transport the export volumes to the delivery point, including charges incurred on NOVA and ANG, if Unigas is assigned the Northwest Natural transportation agreement on ANG. The commodity component will be negotiated annually based on market conditions. The parties expect to meet no later than 60 days prior to the commencement of the contract year to determine the commodity component. In arriving at the commodity price, the price of other gas sold under similar terms and conditions in the Pacific Northwest from U.S., British Columbia and Alberta sources will be considered.

The contract provides for binding arbitration in the event that Unigas and Northwest Natural are unable to agree on the Selling Price. Arbitration would be based on such factors as the opportunities available to Unigas to sell gas to others, to Northwest Natural to purchase gas from others, and the final offer price.

Unigas submitted that the 1 January 1993 Alberta border price could not be properly estimated but, through the negotiation process, would result in a reasonable and fair market Selling Price.

6.6 Status of Regulatory Authorizations

On 16 November 1992, Unigas applied to the ERCB for a removal permit. A decision is pending. Northwest Natural received DOE/FE import authorization on 4 December 1992.

6.7 Views of the Board

The Board notes that Northwest Natural must nominate at least 85 percent and 50 percent of the DCQ in the winter and summer, respectively, if it is to avoid deficiency charge payments. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the Selling Price on an annual basis. As well, the Board is aware of Unigas' evidence that it is unlikely that any circumstances would arise that would cause Unigas and Northwest Natural to terminate the gas sales contract. The Board is thus satisfied that the contract will remain attractive to the parties over its proposed term and is, therefore, durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

The Board notes that the APMC finding of producer support was filed as evidence of the producers' support for the proposed export.

The Board notes that the Selling Price contains a demand charge component equal to Unigas' demand charge obligations on NOVA. In addition, Northwest Natural is responsible for paying the demand charge on ANG. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds the applied-for volume by 16 percent. The Board's estimate of productive capacity shows that Unigas can meet its requirements from existing supply until 1997, assuming all of APL's deliverability will be available. Further, backstopping could be provided from Unigas' corporate supply on a temporary basis, from producers dedicating additional reserves or by Unigas contracting for more reserves. As well, the Board notes that an application for an ERCB energy removal permit has been made and that all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contract are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

6.8 Decision

The Board has decided to issue a gas export licence to Unigas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

Chapter 7
Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-7-92 proceedings and included in this Volume.

R.L. Andrew, Q.C.
Presiding Member

R.B. Horner, Q.C.
Member

C. Bélanger
Member

Calgary, Alberta
June 1993

Appendix I

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to Canadian Hydrocarbons Marketing Inc.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of Governor in Council approval and shall end on 31 October 1996.

   (b) The term of this Licence shall end on 1 May 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that CHMI may export under the authority of this Licence shall not exceed:

   (a) 136 400 cubic metres in any one day;

   (b) 49 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 174 600 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to CanWest Gas Supply Inc.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the first day of the month following the later of the date the Northwest Phase I expansion becomes operational or the date the authorizations described in Section 12.3 of the Gas Sale/Purchase Contract dated 7 October 1992 between CanWest and TM Star have been received and shall extend for a term of 15 years thereafter.

   (b) The term of this Licence shall end on 1 April 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that CanWest may export under the authority of this Licence shall not exceed:

(a) 273 200 cubic metres in any one day;

(b) 100 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 1 495 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to Enron Gas Marketing, Inc.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end on 31 October 2004.

   (b) The term of this Licence shall end on 1 November 1996 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that Enron may export under the authority of this Licence shall not exceed:

   (a) 805 000 cubic metres in any one day;

   (b) 294 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 940 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to New York State Electric & Gas Corporation

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end ten years following the first day of the first month following commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that NYSEG may export under the authority of this Licence shall not exceed:

   (a) 283 300 cubic metres in any one day;

   (b) 103 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 035 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to Unigas Corporation for Export to Northwest Natural Gas Company

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of the date of first deliveries and 1 November 1993 and shall end six years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that Unigas may export under the authority of this Licence shall not exceed:

   (a) 396 600 cubic metres in any one day;

   (b) 144 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 868 600 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by

ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.