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Mechanisms for Supporting Natural Gas Community Expansion Projects

Re: Generic Hearing on Natural Gas System Expansion for Rural and remote Communities – OEB File No. EB-2016-0004

A Report Prepared by
John Todd, President
Elenchus Research Associates Inc.

On Behalf of:
Municipality of Kincardine
Municipality of Arran-Elderslie
Township of Huron-Kinloss
(Collectively, the Municipalities)

21 March 2016

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1. OVERVIEW

The Ontario Energy Board ("OEB" or Board") issued Decision and Procedural Order No. 2 for EB-2016-0004, *Generic Proceeding on Natural Gas Expansion in Communities That Are Not Served* on March 9, 2016 ("Decision"). The Decision included an Issues List that identifies several policy issues that are rooted in the developments that have led to this proceeding. As the Board observes in the introductory section of the Decision, the genesis of this generic proceeding was "the Ontario Government's 2013 Long-Term Energy Plan [in which] the Government indicated that it would look at opportunities to expand natural gas service to communities in Ontario that are not currently served."[1] The Decision also notes that the subsequent developments in response to this policy direction have included:

- The Ontario Government's announcement of a loan and grants program;[2]
- The Ontario Minister of Energy's February 17, 2015 letter to the Chair of the OEB encouraging the Board "to examine opportunities to facilitate access to natural gas services to more communities";
- The OEB's February 18, 2015 letter "stating that it will hear requests for regulatory flexibility or appropriate exemptions in the context of an application made for approvals pertaining to expansion projects";
- The filing of an application (EB-2015-0179) by Union Gas Limited ("Union") which has been put on hold until the completion of the Generic Proceeding

A theme that is central to these developments and the Board's Issues List is a re-examination of the system expansion methodology currently used by the OEB-regulated natural gas distributors and, more fundamentally, an examination of the most efficient and effective means of extending natural gas service to unserved communities, particularly those that do not meet the current EBO 188 economic feasibility criteria.

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1 Decision and Procedural Order No. 2, EB-2016-0004, page 2.

2 The program announced in a Press Release dated April 24, 2015 included two components that will expand natural gas access to areas of the province that are not currently served: a $200 million Natural Gas Access Loan and a $30 million Natural Gas Economic Development Grant.

To assist the Board in its deliberations on these matters, the Municipality of Kincardine, the Municipality of Arran-Elderslie and the Township of Huron-Kinloss (collectively, the Municipalities) asked Elenchus Research Associates Inc. (Elenchus)[3] to prepare evidence that reviews the evolution and policy context of the existing economic feasibility framework used by the OEB-regulated natural gas distributors and to provide illustrative examples of approaches that have been utilized in other Canadian jurisdictions and other Canadian sectors to address the challenge of meeting the needs of unserved communities at affordable rates.

Extending service to unserved communities is not a new challenge. Much of the existing natural gas infrastructure in Ontario, and across Canada, was developed with the assistance of either explicit or implicit support from the general public (i.e., taxpayers) and/or existing natural gas customers, many of whom were benefitting from previous subsidies, resulting in a form of "paying it forward". Cross-subsidization is also a feature of other regulated sectors, including electricity and telecommunications.

In the case of Ontario's natural gas sector, the current Rolling Project Portfolio approach, which relies on the Economic Feasibility test established by the EBO 188 Decision of the Ontario Energy Board ("OEB"), explicitly allows projects to be undertaken that have a profitability index that is less than 1.0. The EBO 188 Decision refined and clarified a long standing practice of balancing the expansion of the natural gas distribution infrastructure with the impact that the expansion has on distribution rates.

A rationale for embedding cross-subsidization in rate structures is the reality that under the rate making methodologies used by regulators across Canada, natural gas distribution rates are based on the depreciated historic cost of the existing infrastructure. This cost is below the cost of new infrastructure for two reasons. First, the historic cost is lower than the current cost of identical facilities due to inflation.

[3] The evidence has been prepared by John Todd, President of Elenchus. See the Elenchus website for John Todd's current curriculum vitae. It also appears as Appendix A. Mr. Todd was retained as an expert for parties participating in the EBO 188 settlement discussions, proceedings related to the expansion of natural gas to Vancouver Island, transmission rate setting in Ontario and the referenced CRTC proceedings. Form A, Acknowledgment of Expert's Duty appears as Appendix B.

Second, existing infrastructure has been partially amortized; hence, the rate base and associated carrying costs are lower than the cost of new facilities. As a result, the cost of the distribution infrastructure used to serve customers as reflected in a utility's revenue requirement is lower for existing customers than it will be for identical new customers. Consequently, when new customers are attached, the rates that all customers pay are below the marginal cost that conceptually would be charged in a competitive market. Average rates based on embedded historical costs are therefore typically below the conceptual market price based on the current marginal cost of a new stand-alone entrant.

This report initially reviews the Ontario experience beginning with the Distribution System Expansion Program ("DSEP") which subsidized system expansion in the early 1980's (section 2) and then provides an overview of the subsequent E.B.O. 134 process that established a policy framework for evaluating whether system expansion projects were in the public interest (section 3). Section 4 provides an overview of the evolving policy context for the E.B.O. 188 process that established the current Rolling Project Portfolio approach.

Section 5 looks outside Ontario and provides an overview of the approach used to extend natural gas service from the British Columbia Mainland to Vancouver Island through a combination of explicit and implicit subsidies to assist both the incumbent distributor and new entrants to develop the necessary facilities.

Returning to Ontario in section 6, the pooling of costs for electricity transmission facilities for setting rates is examined as another approach to addressing cost differentials for utilities with inherently higher- and lower-cost facilities.

Finally, section 7 provides a brief overview of the approach that has been adopted by the Canadian Radio-television and Telecommunications Commission ("CRTC") for subsidizing High Cost of Service Areas ("HCSAs") in order to ensure that Canadians in unserved and underserved areas would have affordable access to telecommunications services. The CRTC is currently considering redesigning the regime to support the deployment of wideband service to rural and remote areas of Canada where wideband services are currently uneconomic.

2. DISTRIBUTION SYSTEM EXPANSION PROGRAMME (DSEP)

DSEP was part of the National Energy Program ("NEP") which was passed by the federal Liberals in 1980 and was ended by the Conservatives in 1985. The NEP was a response to rising world oil prices precipitated by political turmoil in the Middle East, particularly in Iran, and was intended, in part, to protect Canadians by increasing self-sufficiency and reducing the dependence on foreign supplies. Under DSEP the federal government provided a partial subsidy for the cost of the expansion of natural gas distribution systems in eastern Canada into areas that were otherwise not economically justifiable. The level of the subsidy provided in each project related to the amount of oil that was forecast to be displaced.[4]

In conjunction with DSEP, the federal government also established the Canadian Oil Substitution Program ("COSP"), which offered homeowners up to $800.00 towards the conversion of their heating systems from oil to natural gas. Although it was not a direct subsidy of the natural gas infrastructure, by reducing one of the barriers to customers connecting to the natural gas system, this program provided indirect assistance towards the expansion of the utility distribution systems.

While all three of the major gas utilities operating in Ontario at the time took advantage of DSEP, Northern and Central Gas, now part of Union Gas, had many community expansion projects approved, the largest being the North Shore Project which developed a lateral that runs from Sault Ste. Marie to Espanola.[5]

The OEB's view of the benefits of system expansion at the time are evident at pages 6 and 7 of the Decision in E.B.L.O. 197, a copy of which is attached as Appendix C, in which the OEB indicated that it was regrettable that the DSEP grants alone did not allow the proposed projects in that instance to meet the utility's feasibility test but that other associated, sometimes unquantified, benefits were sufficient to make up the shortfall.

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[4] DSEP and the National Energy Program ("NEP") were operational prior to the keeping of electronic records being commonplace and therefor there is limited information available electronically.

[5] This lateral was approved in E.B.L.O. 208.

The Board's E.B.L.O. 197 oral Decision (13 June 1983) also provides a clear indication of its view of cross-subsidization, as based on the economic feasibility test, at that time.

> *Using the Applicant's economic test, there could be the perception of some subsidization by existing customers. As mentioned earlier this perception could be dependent on, for example, the rate of return being achieved. It would be very difficult to quantify this cross subsidy without an array of assumptions concerning the key variables as there is no empirical way in which to conclude that a certain subsidy is "undue". The Board's judgment must ultimately encompass other components of the public interest in arriving at a conclusion.*
>
> *There are benefits to the residents of the communities for which service is proposed, both customers and non-customers. The economic benefits of lower energy prices and the resulting multiplier effect have been referred to in the evidence. There will be jobs created in the communities and elsewhere. Gas service replacing oil, where possible, is Federal and Provincial Government policy and Federal, Provincial and Municipal buildings will be converted to gas if service proceeds. Savings in energy costs will flow to taxpayers at all levels, including existing gas customers. In addition, municipal and business taxes payable by Northern will also benefit all taxpayers.*
>
> *Nationally, oil displacement increases security of supply by reducing Canada's dependence on foreign oil, with associated cost savings which benefit all citizens. Payments from Alberta to the Federal Government under the Alberta Market Development Incentive Projects are possible if gas sales increase, and excise taxes are currently payable on all volumes of gas sold.*
>
> *It is regrettable that the DSEP grant is not sufficient to satisfy Northern's economic feasibility tests but the Awards are an immediate benefit. Without them the projects would not have been brought before the Board. With these grants insured only for a short while, and with the Canadian Oil Substitution Program, these proposals are opportune.*
>
> *Our consideration of these benefits, some of which have been quantified in the evidence, and some of which are less tangible and quantifiable has led us to the conclusion that any cross subsidy which may result is offset by the benefits and that the projects should be approved.*
>
> *The Board will therefore approve all the Applications before us subject to the conditions which have been agreed on by the Applicant and subject to the undertakings made by its counsel and witnesses during the hearing.*
>
> *Specifically, the following Applications for approval of the terms and conditions of Municipal Franchise Agreements are granted:*

- *Township of Brighton,*
- *Town of Picton,*
- *Village of Bloomfield,*
- *Village of Wellington,*
- *Township of Hallowell,*
- *Township of Sophiasburg,*
- *Town of Mattawa.*

The Board's Order will dispense with the assent of the Municipal Electors in each case.

The Application for an amendment to the certificate of public convenience and necessity for the Town of Valley East to delete the community of McCrae Heights is approved. The Board notes the undertaking by Northern to apply for a DSEP grant in 1984 for an extension of the system to McCrae Heights.

The Board is satisfied that public convenience and necessity requires that approval be given to the Applications for certificates of public convenience and necessity for Mattawa, Picton, Bloomfield, Wellington and the Township of Hallowell.

The Board is of the opinion that construction of the pipelines in Prince Edward County, to the Towns of Mattawa and Brighton and to the communities in the Town of Valley East is in the public interest. Approval will be given subject to the conditions noted earlier. The Board is satisfied that Northern has offered each affected landowner an easement agreement in the form filed in the proceedings, and which is hereby approved.

The costs of the Board will be charged to the Applicant. The Board will, therefore, issue Orders in accordance with these Reasons for Decision and requests that the Applicant prepare draft orders for the Board's consideration.

Before concluding the hearing there is just one note, as we are aware there is a Board sponsored study of feasibility tests and construction practices which we expect to get underway shortly and the results may have some bearing on future applications of this nature.

The study referred to in the final paragraph quoted above led ultimately to the E.B.O. 134 Report of the Board which was issued June 1, 1987.

3. E.B.O. 134 REPORT OF THE BOARD

Subsequent to the E.B.L.O. 197 Decision, The Consumers' Gas Company Limited ("Consumers") filed six applications to extend service to communities that were heard in the summer of 1986 (E.B.L.O. 216 et al.) The applications were denied, however, the Board concluded in its Reasons for Decision "that the criteria used by the utilities to assess and justify system expansion should be reviewed." On January 9, 1987 the Board issued Notice of a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario ("the Review"). This process was concluded with the issuance of the E.B.O. 134 Report of the Board on June 1, 1987 ("EBO 134 Report").

Paragraph 2.13 of the EBO 134 Report identified the questions that the process sought to address.

> *2.13 The Board indicated in its Reasons for Decision that certain important questions concerning system expansion to smaller communities should be considered:*
>
> - *with DSEP discontinued, what are the means whereby marginally uneconomic areas of Ontario are to be served, if at all;*
> - *what is the role of the Board in the light of the removal of DSEP and to what extent should it be encouraging gas service to marginally uneconomic areas;*
> - *with Ontario utilities facing mature markets, is expansion into uneconomic areas appropriate;*
> - *should the shareholders or customers of utilities subsidize uneconomic expansion into smaller communities;*
> - *are there lower limits of return that should be permitted on a project basis? Are size of project or amount of subsidy factors that should be considered in assessing a project;*
> - *have the changing circumstances with respect to energy resulted in the test of public interest being changed;*

- *are the current methods used by the utilities for assessing the economic feasibility of projects appropriate and what changes, if any, should be made;*
- *should the economics of system expansion be considered on the basis of marginal/incremental costs or on a fully allocated cost basis?*

In the section of the EBO 134 Report entitled The Public Interest, the Board's Findings appear at paragraphs 5.13 through 5.21. In part, the Board states:

> 5.14 *The Board reiterates that the concept of public interest is dynamic and it must change according to the circumstances. …*
>
> 5.15 *There can be no firm criteria for determining the public interest and the Board will not attempt to define these criteria closely. The waiting the Board attaches to each criterion considered can also change with the circumstances of a specific application.*
>
> 5.16 *When considering the public interest in prior proceedings the Board has been satisfied if the welfare of the public is enhanced without imposing an undue burden on any individual, group or class. The Board will continue to be guided by this general principle in determining the extent to which gas service should be extended into other areas of the province.*
>
> 5.20 *The Board recognizes that the views of the local community may differ from those of an industrial customer or of a utility. In reaching its decision, the Board attempts to accommodate differing interests in its assessment of the public interest….*

Section 6 of the EBO 134 Report deals with Economic Feasibility Tests. The final paragraph (6.79) of the Board's Findings on this topic states:

> 6.79 *The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.*

The Board's Findings on the matter of a Subsidy appear as paragraphs 7.24 through 7.32 which include the following comments.

> 7.24 *As noted earlier, the Board considers that in general, the public interest is satisfied if the welfare of the public is enhanced without imposing an undue burden on any individual, group or class.*

7.27 The implication of accepting an economic test which has a broader definition of economic feasibility than that employed in the past is that the subsidy required may in general be greater than that which was deemed reasonable to the Board in the past.

7.29 The Board finds that a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply gas into a new area and where the evaluation process demonstrates an undue burden on existing customers.

7.30 The Board would expect an agreement to be reached between the utility and the community regarding the contribution before an application is made to the Board.

7.31 In certain cases, the Board considers that special rates and/or loans by the utility to finance a contribution-in-aid of construction may facilitate the expansion of the natural gas system.

7.32 A number of the participants strongly suggested that the provincial government encouraged expansion of the natural gas system in Ontario by developing a program to fund uneconomic projects. The Board considers that, in addition to the methods of subsidy referred to above, some government support might be justified where the overall benefits to the community as a whole warrant such action.

The EBO 134 Report of the Board guided the Board and parties in dealing with system expansion and economic feasibility until the approach was again reviewed a decade later through a process that resulted in the E.B.O. 188 Report of the Board dated January 30, 1998.

4. EBO 188 INTERIM AND FINAL REPORTS OF THE BOARD

The EBO 188 process reopened many of the issues that had been addressed in the EBO 134 Report; however, with the passage of time some of the principles established by the earlier report had become contentious. The division among parties quickly became apparent during the alternate dispute resolution ("ADR") phase that had been adopted as part of the procedure. The facilitator, Mr. O.J. Cook, submitted a report to the Board that contained the views of two groups of stakeholders (Group "A" and Group "B") and sought direction from the Board with respect to the fundamental principles that

should be used to guide the discussions. The Board addressed this dilemma by issuing the EBO 188 Interim Report of the Board on August 15, 1996.

The fundamental difference in views between these groups was noted in the EBO 188 Interim Report.

> *1.1.6 The Board received the Report of Mr. O.J. Cook, C.A. Including Reports of the Parties to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas System Expansion in Ontario on December 21, 1995 ("the ADR Report").*
>
> *The Report stated:*
>
> > *By the end of the first day there was "consensus agreement" that there were essentially two opposing principles or philosophies among the participants. In the opinion of the facilitator, the views of the parties on fundamental principles were clearly divergent and those views, which were strongly expressed in the ADR conference must be recognized and respected.*
>
> …
>
> *1.1.8 The Report of Group "A" stated:*
>
> > *The central feature of the Group "A" approach is that some subsidy of system expansion may be acceptable where necessary to obtain societal benefits, defined by the Societal Cost Test ... or a variant thereof.*
>
> …
>
> *1.1.10 The Report of Group "B" stated:*
>
> > *...Group B suggest that in the ordinary course the public interest should only include:*
> >
> > *Security of Supply*
> >
> > *Safety*
> >
> > *Obligation to serve in areas where existing service is available...*
> >
> > *A **new business** project must pass the Financial Test.*

The principles identified in the EBO 188 Interim Report of the Board included:

> *4.2.8 In the E.B.O. 134 Report at para. 5.14 the Board stated:*
>
> > *The Board reiterates that the concept of public interest is dynamic and it must change according to the circumstances.*

The Board is still of this view.

…

4.2.12 The climate in which the natural gas industry operates has changed since the passage of the various Acts referred to. When making its determinations on the public interest and the principles raised in this proceeding the Board has considered the public interest in the context of the current circumstances of the natural gas industry.

4.2.13 In determining the overall public interest, the Board has considered access to gas supply, operational efficiency, environmental protection and regulatory costs as well as economic feasibility.

…

4.4.1 In any discussion of subsidization in a natural gas distribution system it must be recognized that there is inherently subsidization in any distribution system. For example, in order to set rates, costs are allocated to customer classes that are comprised of customers with similar characteristics. Each customer in the class pays rates that reflect the average cost to serve a customer in that class. These group rates result in customers with the lowest cost of service subsidizing customers that have higher service costs since all customers in the same class pay the same rate for the same natural gas service. In regard to new facilities, unless each customer pays the actual cost to provide that customer with gas service there will be subsidization among customers in any new service. In fact the Board has approved facilities applications where accidents of timing and geography or the inclusion in a project of financially viable customers has meant that service could be extended to some customers that otherwise would not be served by the project because service to these customers would not be financially viable on a stand alone basis.

While the Board did endorse in this proceeding the Rolling Project Portfolio approach which involves the subsidization of some uneconomic system expansion projects, it identified limitations to the subsidization that should occur.

4.5.6 The Board agrees with GEC's statement that "...the Board's role is not simply to enhance the situation of existing customers without regard to others." The Board is of the view that it is no longer reasonable that these customers should continue to expect to receive a benefit from the addition of new customers in the form of lower rates. Similarly, the Board also believes that it is not the role of the Board to enhance the situation of potential new customers without regard for existing customers. Therefore, the Board does

not believe that existing customers should subsidize new customers through higher rates as a result of the construction of financially unfeasible new distribution system projects.

4.5.7 *In addition, the Board notes that it has not been given a convincing rationale for selecting an appropriate level of subsidization that could be applied universally to all distribution system expansion projects.*

Having received guidance on some key disputed issues in the EBO 188 Interim Report of the Board, the parties were able to focus on the outstanding issues which ultimately resulted in the EBO 188 Final Report of the Board which was issued January 30, 1998. This Report of the Board forms the basis of the current practices related to the Rolling Project Portfolio approach, the standardized methods for financial feasibility analysis (which is consistent with the current methodology set out in Appendix A of the electricity Distribution System Code), and the customer connection and contribution policies.

5. PROVISION OF NATURAL GAS TO VANCOUVER ISLAND

A few years after the DSEP was terminated, the British Columbia and Canadian governments undertook an initiative to extend the natural gas infrastructure serving the BC mainland to Vancouver Island. Information on the project as originally planned is contained in an application filed in November of 1988 by the Pacific Coast Energy Corporation ("PCEC") with the British Columbia Utilities Commission ("BCUC"). The application sought approval to build the facilities required to extend natural gas service to customers on Vancouver Island.[6]

The PCEC Application was the result of an understanding between the Federal and Provincial Governments on funding for the project. A Statement of Principles between the Governments was signed September 22, 1988. The BCUC Report of April 6, 1989 also provides a catalogue of the project incentives which appears in Figure 2.1, at page 6 of the Report. Both the incentives and party involved were identified in Figure 2.1.

a) Utility customers: (i) Government Conversion Grants and (ii) market sensitive pricing;

[6] See the British Columbia Utilities Commission Final Report, April 6, 1989. (Attached as Appendix D)

b) LDCs: (i) LDC Financial & Market Guarantees and (ii) reduced ROE;

c) PCEC: (i) Government Grants and Loans, (ii) Rate Stabilization Facility, and (iii) PCEC reduced ROE;

d) BC Gas Tolls: BC Gas Opportunity Cost Pricing;

e) Westcoast Tolls: Westcoast Incentive Tolls; and

f) Producers: Flowback Pricing

PCEC's role in the overall expansion was to develop the natural gas transmission pipeline from Coquitlam on the BC Mainland to Vancouver Island. From this transmission line, laterals were used to connect industrial complexes and several communities that were served by LDCs both on the Mainland and the Island. The LDCs included both BC Gas, an incumbent distributor that served the Squamish area through its subsidiary company Squamish Gas; and Vigas and a new distributor that was awarded the LDC rights to serve 28 communities on Vancouver Island and the Sunshine Coast.

The BCUC Report commented as follows regarding the sharing of risk.

> *PCEC has stated that the project was designed to impose risks on those participants who will have the potential to be rewarded while largely isolating customers from risks inherent in the project. The greatest risks in the project clearly lie with the Provincial Government in the open-ended RSF*[7] *and with the natural gas producers in the acceptance of the flowback pricing mechanism. Secondary risks exist for the Federal and Provincial Governments in the provision of capital grants and repayable loans. A lesser risk would be absorbed by the various utilities involved in the project through the reduced ROE in the early years and the financial and market guarantees provided by Vigas. Finally, PCEC and its sponsor partners are at risk to the extent of their equity contributions.* (Emphasis in original)

Subsequent to the completion of the project, the BC Ministry of Energy, Mines and Petroleum Resources 91/92 Annual Report commented on the pipeline at page 13:

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[7] The RSF is the Rate Stabilization Facility. Under the RSF the Provincial Government committed to "provide money to PCEC when there are inadequate revenues to meet the utilities' costs of service. PCEC assumed that the RSF would be refunded when residual revenues exceeded their cost of service." (BCUC Report, p. 7)

Vancouver Island Natural Gas Pipeline

In September 1991, natural gas began flowing on the new Vancouver Island Natural Gas (VIGAS) pipeline to serve customers on Vancouver Island and the Sunshine Coast. Completion of the VIGAS project follows three decades of planning and public discussion and two years of construction. The 531-kilometre pipeline was built by Pacific Coast Energy Corporation (PCEC), with funding assistance from the federal and provincial governments. As owner and operator of the pipeline, PCEC delivers natural gas directly to seven pulp mills and to some 28 communities. Community gas distribution is handled by Centra Gas British Columbia Inc. and Squamish Gas Company Ltd.

The report also commented on the subsidy program in general terms at page 49:

Power and Gas Extensions

The provincial Power and Gas Extension Program (PGEP) provides grants to help expand electricity and natural gas service to rural areas of British Columbia. PGEP is intended to lower heating costs for consumers, promote economic development and clean energy, and reduce reliance on imported oil. During 1991/92, grants amounting to $2.9 million were awarded to 41 separate natural gas extension projects. A total of 3,427 new customers in 29 communities were connected to gas service by fiscal year·end.

The Ministry's Annual report includes a Summary of Expenditures that identifies Vancouver Island Natural Gas Pipeline Assistance in the amounts of $7,046,165 and $27,964,281 for the 1990/91 and 1991/92 fiscal years, respectively.

The BCUC also commented on the program in Order G-60-92 (Centra Gas British Columbia Revenue Requirements) dated July 30, 1992. It noted that:

The rural distribution system was expanded significantly in the last few years with the assistance of government financing under the provincial Power and Gas Extension Program ("PGEP"). (Page 1)

…

As a requirement of obtaining the franchise rights to provide natural gas service to Vancouver Island and the Sunshine Coast, the Province entered into Rate Stabilization Agreements with Victoria Gas Company (1988) Limited and Vigas for their service areas and ICG (B.C.) for the Nanaimo service area. These are commonly referred to as the RSA areas. (Page 2)

In the 1992 hearing before the BCUC a Centra Gas BC witness provided the following direct evidence regarding the company's costs related to the PGEP which indicates that

the PGEP was available prior to the extension of natural gas distribution to Vancouver Island. The program assisted the extension of service to smaller communities on the mainland.[8]

> *3) 1986 PGEP Program $2,073,989*
>
> *In the Spring of 1986, upon receiving a PGEP grant from the Province of British Columbia, the Company undertook to install gas mains to service the North Pine, Cecil Lake and Taylor Ski Hill areas. The North Pine project involved installing 16.1 kilometres of 2" aluminum transmission line and a total of 87.83 kilometres of 3/4" through 2" gas main and three regulator stations, to provide service for 114 farms and residences. Additionally, these mains provided access to supply two compressor stations with an annual load of 53,000 GJ's. This system tied into the Montney service area but, because of the increased demands, required an upgrading of the Scurry Rainbow line from the Fort St. John Town Border Station to the east side of St. John's Creek.*
>
> *The Cecil Lake System involved installing 12.5 kilometres of 1 1/4" aluminum transmission line from a new purchase station located on the Westcoast Boundary Lake line, three regulator stations and 148.1 kilometres of 3/4" to 2" P.E. gas main, to provide service to 148 farms and residences. Additionally, these mains provide access to six compressor stations with an annual load of 56,000 GJ's.*
>
> *4) 1990 PGEP Program $1,123,676*
>
> *In 1990 the Company made application to the Government for PGEP funds to construct mains in the Rose Prairie area and for "infills" in the rural systems.*
>
> *The Rose Prairie System consisted of installing approximately 80 kilometres of 3/4" to 3" PE gas mains to provide service to 84 farms and residential homes. The infills consisted of 10 individual extensions consisting of 15.7 kilometres of 3/4" to 2" PE gas main and provided gas service to 66 farms and residences.*

The August 5, 1992 BCUC Decision in G-63-92 notes at page 49 that the PGEP program was discontinued after 1991:

> *The Commission was told that much of the increase in new accounts in 1991 over the forecasts for that year was due to the introduction of the Provincial Power and Gas Extension Program ("PGEP") in mid-1991. This program was not extended into 1992 and therefore BC Gas did not feel that the 1992 forecasts should be revised, despite the apparent increases in the interior regions."*

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[8] Tab 4, Page 4 (Page 75 of PDF) Testimony of Donald G. Olsen (G-60-92)

6. POOLED COST: TRANSMISSION RATES IN ONTARIO

Another example of rates that embed implicit cross-subsidies as a means of increasing equity among customers, reflecting the policy perspective that increased rate equity is in the public interest is the approach to setting transmission rates in Ontario.

The revenue requirements of the OEB regulated electricity transmission utilities are recovered through a mechanism that pools their costs and establishes Uniform Transmission Rates ("UTRs"). The rate setting methodology is succinctly summarized in the most recent UTR Decision.

> *There are five licensed electricity transmitters in Ontario that recover their revenues through Ontario's uniform transmission rates (UTR): Canadian Niagara Power Inc., Great Lakes Power Transmission Inc., Five Nations Energy Inc., Hydro One Networks Inc. and B2M Limited Partnership. The Ontario Energy Board (OEB) approves the revenue requirements and charge determinants of the individual transmitters and uses them to calculate the UTR.*
>
> *The revenue requirements of the five transmitters are allocated to three transmission pools, Network, Line Connection and Transformation Connection on the basis of a cost allocation study conducted annually by Hydro One Networks. The costs are then divided by forecast consumption (charge determinants) to establish the UTR. The Independent Electricity System Operator (IESO) charges these rates to all wholesale market participants, including electricity distributors.* [9]

One implication of this approach is that the approved costs of each of the five transmitters are recovered from all users of the transmission network on the same basis. In essence, comparatively high-cost transmitters are cross-subsidized by comparatively low-cost transmitters. Put differently, customers that are relatively low-cost to serve subsidize the high cost to serve customers. Consistent with the concept of "postage stamp rates" all customers pay the same rates based on their connection configuration, regardless of the embedded cost of the facilities that they actually require or actually utilize.

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[9] The 2016 UTRs were established in Decision and Rate Order EB-2015-0311, 2016 Uniform Transmission Rates, January 14, 2016.

7. HIGH COST OF SERVICE AREAS (THE CRTC REGIME)

In the Canadian telecommunications sector, customers in rural and remote areas were implicitly cross-subsidized through the rate setting process which based rates primarily on the type of telephone service provided (e.g., private versus multi-party line) and the number of lines within the local calling area, rather than on the basis of the cost of serving customers in particular communities or rural areas. The end result was that the customers that required the most expensive facilities because they resided in low density areas tended to have the lowest rates for basic local service. This approach reflected the value of service as measured by the number of subscribers within a customer's local calling area.

The long-standing approach to rate-setting for telephone service also embedded a cross-subsidy from long distance service that was used to keep basic local service as affordable as possible.

With the introduction of long-distance, and subsequently local, competition in the telecommunications sector, this cross-subsidy regime was no longer sustainable. Consequently, the implementation of competition was accompanied by the introduction of both the CRTC Price Cap Regime and the National Fund that has been used ever since to subsidize high-cost serving areas ("HCSAs").

On April 11, 2015 the CRTC initiated a Review of Basic Telecommunications Services, Telecom Notice of Consultation CRTC 2015-134 ("Telecom Notice") that "will examine which telecommunications services Canadians require to participate meaningfully in the digital economy and the Commission's role in ensuring the availability of affordable basic telecommunications services to all Canadians". The proceeding is considering, among other matters, changes to the local service subsidy regime that has been in place since 2000.

The Telecom Notice contains a succinct description of the existing subsidy regime.

Local service subsidy regime

16. In certain rural and remote areas of Canada, the cost to provide residential wireline telephone service that meets the basic service objective exceeds the price that customers pay.

17. Because of this, pursuant to subsection 46.5(1) of the Act, the Commission requires certain TSPs [telecommunications service providers] to contribute to a fund to support continued access by Canadians to basic telecommunications services.

18. The current local service subsidy regime, along with the associated contribution mechanism and the National Contribution Fund (NCF),[10] was established to subsidize the provision of basic residential local services in high-cost serving areas (HCSAs).[11] These subsidies are currently provided only to ILECs in regulated HCSAs, since they have the obligation to provide residential wireline local telephone services.[12] In 2014, the Commission determined that video relay service (VRS) is a basic telecommunications service to be funded through the NCF.[13]

19. TSPs, or groups of related TSPs, with annual Canadian telecommunications revenues of $10 million or more are required to contribute to the NCF. Contribution (money) is collected by means of a revenue-percent charge that is applied to the contribution-eligible revenues of a TSP.[14] Certain revenues (e.g. from retail Internet and paging services) and other amounts (e.g. intercompany payments) are currently excluded from the calculation of a TSP's contribution-eligible revenues. [Footnotes in original]

This CRTC consultation raises issues that are analogous to the issues being addressed in the current OEB generic proceeding. Specifically, the issues identified by the CRTC include:

Issues to be examined

32. The Commission hereby initiates a proceeding to conduct a comprehensive review of its policies regarding basic telecommunications services in Canada and of the telecommunications services that Canadians require to participate meaningfully

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[10] The local service subsidy regime was established in Decision 2000-745. A summary of the current regime can be found in Telecom Circular 2007-15.

[11] An HCSA is a clearly defined geographical area where the ILEC's monthly costs to provide basic service are greater than the associated revenues generated by service rates.

[12] The local service subsidies totalled approximately $114 million in 2014.

[13] See Telecom Regulatory Policy 2014-187. An annual funding cap of $30 million was established for delivering VRS in Canada.

[14] The revenue-percent charge for 2014 was 0.55%. See Telecom Decision 2014-627.

in the digital economy. In this regard, the Commission will examine how these telecommunications services are used by Canadians, and what prices Canadians should be expected to pay for these services.

33. The Commission will also examine the availability of telecommunications services to determine which areas in Canada are underserved or unserved. The Commission will consider what its role should be in ensuring the availability of basic telecommunications services, particularly in rural and remote regions of Canada.

34. As stated above, the Commission will examine whether a mechanism is required in Northwestel's operating territory to support the provision of modern telecommunications services by funding capital infrastructure investment in transport facilities as well as the cost of maintaining and enhancing these facilities. The Commission will also examine whether such a mechanism should be considered for other rural and remote areas in Canada. The aim of any such mechanism would be to complement, and not replace, other investments from the private sector and governments.

35. As well, the Commission will examine whether changes should be made to (i) the various regulatory measures related to basic telecommunications services, such as the basic service objective, the obligation to serve, the national contribution mechanism, and the local service subsidy regime, and (ii) the price cap regimes, as applicable.

This CRTC consultation is currently ongoing; however, it is worth noting that parties to the process are recommending enhancements to the subsidy regime that would subsidize the deployment of broadband-capable facilities to unserved and underserved regions of the country, as well as the adoption of an auction process that would make the subsidy funding available to new entrants, as well as incumbents, by means of a process that relies on a competitive process that awards the right to deploy the new facilities to the entity that requires the smallest subsidy to provide service that meets defined standards.

Proposals for this mechanism to subsidize deployment of new facilities would continue to be funded through an enhanced National Contribution Fund that requires all significant service providers, and hence implicitly all telecommunications customers, to contribute a percentage of revenue to the funding regime.

8. CONCLUSIONS

The expansion of natural gas distribution facilities to serve new communities has often been supported by mechanisms that facilitate bringing the benefits of natural gas to new customers, consistent with policy objectives that are relevant to the times. This evidence reviews two illustrations of programs implemented by government that provided direct subsidies that allowed natural gas to be made available to communities although the extensions would not have been economic without that assistance. These programs reflected policy priorities that have included reducing demand for imported oil and removing financial barriers to introducing natural gas in communities where the external benefits (i.e., community and societal benefits that are not captured by the rates charged by the distributor) justify government subsidies.

In addition, regulators approve system expansions where the costs are rolled into the utility's revenue requirement in setting standard rates for all customers. The result is that existing customers cross-subsidize new customers in the short run. When the profitability index is below 1.0, system expansions are subsidized in the long run. While providing service to new communities when the forecast costs are less than the forecast revenues is contrary to standard investment principles, in the case of regulated natural gas utilities, it is a practice that is employed by regulators as a means of realizing the external benefits of natural gas availability in any community.

Put simply, it is equitable to require customers that have benefited from past policies that have enabled them to gain access to natural gas to in turn continue the chain by paying rates based on a blending of (a) the costs of the existing infrastructure that has benefitted from the various types of assistance in the past, with (b) the higher costs of servicing customers in new expansion areas.

APPENDIX A

CURRICULUM VITAE: JOHN D. TODD

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for over 35 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 200 regulatory proceedings and provided expert evidence in over 100 hearings. His clients include regulated companies, producers and generators, competitors, customers groups, regulators and government.

PROFESSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (ERAI) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc., (ECS) **1980**

- ECS was divested as a separate company in 2003.
- There are presently four ECS consultants: Bill Harper, Mark Garner, Shelley Grice and James Wightman. Web address: www.econalysis.ca

Education

1975	Masters in Business Administration in Economics and Management Science, University of Toronto
1972	Bachelors of Science in Electrical Engineering, University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**
Research Assistant **1973 - 1978**
Univ. of Toronto, Faculty of Management Studies

Bell Canada **1972 - 1973**
Western Area Engineering

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant for:

Before the Ontario Energy Board

2013
- Enbridge Gas Distribution (EB-2012-0459)
  (Evidence: Cost Allocation Methodology, with Michael Roger)
- IESO Fees Case
  (Evidence: Review of IESO Fees Billing Determinant)

2012
- Hydro One Transmission 2013-2014 Revenue Requirement (EB-2012-0031)
  (Evidence: Ontario Cost Allocation and Export Tariff Service, with Michael Roger)

2011
- Cost Allocation evidence for several Ontario electricity distributors (2012 Cost of Service)

2010
- Natural Resource Gas Rate Case
  (Evidence: Proposed Incentive Regulation Mechanism
- Cost Allocation evidence for several Ontario electricity distributors (2011 Cost of Service)

2009
- Hydro One Distribution Rate Case
  (Evidence: Principles for Density Based Rates)
- Cost Allocation evidence for several Ontario electricity distributors (2010 Cost of Service)

2008
- Provided technical and strategic assistance to eight second tranche electricity distribution companies in preparing their rebasing applications for rates for 2009.
  (Evidence: Cost allocation model updates (for two LDCs))

2007
- Third generation Incentive Regulation
  (Evidence: Inclusion of a capital expenditure factor)
- Provided technical and strategic assistance to six first tranche electricity distribution companies in preparing their rebasing applications for rates for 2008.

2006
- Cost Allocation Review (EB-2005-0252)
- Transmission Revenue Requirement Adjustment Mechanism (EB-2005-0501)
- Second Generation Incentive Regulation Mechanism (EB-2006-0088-0089)
  (Evidence: Capital Investment Factor)

2005
- Sub-metering Review (EB-2005-0317)
  (Evidence: Comments on Staff Discussion Paper on Sub-metering)
- Union Gas Rate Hearing
  (Evidence: Evaluation of Avoided Cost Methodology)

2004
- Enbridge Gas Distribution 2005 Rates (RP-2003-0203)
  (Evidence: Determining the Fair Rate of Return for a 15-Month Period)
  (Evidence: Stand-alone System Supply Costs)

2003
- Generic Proceeding on Electricity Distributor Boundary Changes (RP-2003-0044)
  (Evidence: The Benefits of Competition in the Electrical Distribution Sector)
- Union Gas Limited, 2004 Rates (RP-2003-0063)
  (Evidence: Monthly Demand Charge for Brighton Beach Power Station (with Paula Zarnett))

2002
- Union Gas Limited, 2003 Rates (RP-2002-0130/EB-2002-0363)
  (Evidence: Review of Union's Delivery Commitment Credit (with Joyce Poon))

2001
- Union Gas, Further Unbundling of Rates (RP-2000-0078)
  (Evidence: Regulatory Framework and Cost Responsibility)
- Hydro One Networks, Cost Allocation and Rate Design for RP-2000-0023
  (Evidence: Cost Allocation Model (with Bruce Bacon))

1999
- Propose Electric Distribution Rate Handbook
  (Evidence: Comments on Staff Proposals)
- Standard Supply Service Code, (RP-1999-0040)
- (Evidence: Comments and Alternate Proposal)
- Enbridge, Year 2000 Rate Application (RP 1999-0001)
- Enbridge, Performance Based Regulation Application (EBRO 497-01)
- Enbridge, Ancillary Service Separation & Rental Wind Down (EBO 179-14/15)

1998
- Consumers Gas, 1999 Test Year Rates Application (EBRO 497)
- Union Gas, Separation of Ancillary Services (EBO 177-17)

1997
- Town of Aurora, Franchise Renewal (EBA 795)
- Union Gas, Customer Information System (EBO 177-15)
- Legislative Change (EBO 202)
- System Expansion Generic Hearing (EBO 188)
- Consumers Gas, 1998 Test Year Rates Application (EBRO 495)

1997
- Ten Year Market Review Working Group
- Union Gas/Centra Gas Amalgamation Application

1996
- Union Gas/Centra Gas, 1997 Rates Application (EBRO 493/494)
- Consumers Gas, 1997 Test Year Rates Application (EBRO 492)
- Ontario Hydro, Review of 1997 Rates (HR-24)

1995
- Ontario Hydro, Review of 1996 Rates (HR-23)
- Consumers Gas, 1996 Test Year Rates Application (EBRO 490)
- Union Gas, 1996 Test Year Rates Application (EBRO 486)
- Union Gas/Centra Gas, Shared Services Hearing (EBRO 486/489)

1994
- Centra Gas, 1995 Test Year Rates Application (EBRO 489)
- Ontario Hydro International Hearing (EBRLG - 36)
- Ontario Hydro Corporate Restructuring and 1995 Rates (HR-22)
- Consumers' Gas, 1995 Test Year Rate Case (EBRO 487)

1993
- Joint Hearing on Direct Purchase Issues (EBRO 474-B/476/483/484/485)
  (Evidence: Return-to-System Policies for Ontario LDCs)
- Centra Gas, 1994 Test Year Rates Application (EBRO 483/484)

1993
- Consumers' Gas, 1994 Test Year Rate Case (EBRO 485)
- Union Gas, 1994 Test Year Rate Case (EBRO 476-03)
  (Evidence: Equity Effects of Union's Depreciation Study)

1992
- Consumers' Gas, 1993 Test Year Rate Case (EBRO 479)
- Union Gas, 1993 Test Year Interim Rate Increase (EBRO 476)

1991
- Consumers' Gas, 1992 Test Year Rate Case (EBRO 473)
  (Evidence: Direct Purchase Issues)
- Union Gas, Application for Rates and Cost of Gas (EBRO 462)
- Centra Gas, 1992 Test Year Rates Application (EBRO 474)
  (Evidence: Direct Purchase Issues)

Before the Public Utilities Board of Manitoba

2014
- Manitoba Hydro, NFAT DSM and Load Forecasting

2013
- Need for and Alternatives to Manitoba Hydro's Preferred Development Plan
  (Evidence: Review of Manitoba Hydro's Load Forecast)
  (Evidence: Review of Demand Side Management and Energy Efficiency issues)

2005
- Manitoba Public Insurance, 2006 General Rates Application
  (Evidence: Rate Stabilization Reserve and Related Issues)

2003
- Centra Gas Manitoba, 2003/04 General Rate Application,
  (Evidence: Comments on the Future Regulatory Methodology)

2002
- Manitoba Hydro, Rate Status Update
  (Evidence: Manitoba Hydro's Financial Requirements and Proposed Curtailable Rate Program, with William Harper)
- Manitoba Hydro, Integration Proceeding
  (Evidence: Assessment of Manitoba Hydro/Centra Manitoba Integration, with William Harper)

2001
- Manitoba Public Insurance, 2002 General Rate Application
  (Evidence: Rate Stabilization Issues)
- Centra Gas Manitoba, Primary Gas Rates
  (Evidence: Centra Gas Manitoba's Rate Setting Methodology)

2000
- Centra Gas Manitoba, Rate Management
- Manitoba Public Insurance, 2001 General Rate Application
  (Evidence: MPI's Rate Stabilization Reserve Surplus)
- Manitoba Hydro, Surplus Energy Program

1999
- Centra Gas Manitoba, Western T-Service and Agency Billing and Collection Service
  (Evidence: Assessment of the Proposals of the Company)
- Manitoba Public Insurance, 2000 General Rate Application
  (Evidence: Rate Stabilization Reserve Risk Analysis)

1999
- Manitoba Hydro Purchase of Centra Manitoba
  (Evidence: Implications for Rates and the Regulatory Regime)

1998
- Centra Gas Manitoba, Rates Flowing from Board Order 79/98

- Manitoba Public Insurance, 1999 General Rate Application
  (Evidence: Rate Stabilization Reserve, Allocation of Costs and IT Expenditures)
- Centra Gas Manitoba, Feasibility Cost Assumptions Application
  (Evidence: Comments on Centra's Proposed Changes to the Feasibility Test)
- Centra Gas Manitoba, 1998 Test Year General Rate Application
  (Evidence: Comments on Centra's Proposed Customer Information System)

1997
- Centra Gas Manitoba, Ste. Agathe Franchise Application
- Manitoba Hydro, Review of ISE/DFH/SESS Programs
- Manitoba Public Insurance, 1998 General Rate Application
- Centra Gas Manitoba, Continuation of Shared Services Application

1996
- Centra Gas Manitoba, 1997 General Rate Application
- Centra Gas Manitoba, Cost of Service and Rate Design Review
- Generic Hearing on the Role of the LDC in Manitoba
  (Evidence: The Future Role of Centra Manitoba in the Supply of Natural Gas)
- Manitoba Hydro, General Rate Application, 1996 and 1997

1995
- Centra Gas Manitoba, Price Management and Direct Purchase Issues
- Application of the Gladstone, Austin Natural Gas Co-op Ltd.
- Manitoba Hydro, Review of Prospective Cost of Service Study (GRA)
  (Evidence: Comments on the Prospective COSS Methodology)

1995
- Manitoba Hydro, Dual Fuel Heating and Industrial Surplus Energy Rates
- Centra Gas Manitoba, Rural Expansion/Brandon Facilities Upgrade Hearings
- Centra Gas Manitoba, 1995 General Rate Application
  (Evidence: Review of Centra's Weather Normalization Methodology)

1994
- Centra Gas Manitoba, Rural Expansion Hearing
  (Evidence: Rural Mains Expansion Feasibility Test)
- Centra Gas Manitoba, Future Test Year Application
  (Evidence: Comparison of the Future and Historic Test Year methods of RB-ROR regulation)
- Manitoba Hydro, General Rate Application, 1994 and 1995

1993
- Centra Gas Manitoba, Inc. 1994 General Rate Application
- Manitoba Telephone System, Interconnect Hearing
- Manitoba Telephone System, 1993 General Rate Application

1992
- Manitoba Telephone System, 1992 General Rate Application
  (Evidence: The appropriate debt ratio for a crown corporation)
- Manitoba Hydro, General Rate Application, 1992
- Centra Gas Manitoba, Inc. General Rate Application

1991
- Manitoba Telephone System, General Rate Application, 1991
- Centra Gas Manitoba, Inc. Application for Interim Refundable Rate Increase

1990
- Manitoba Hydro, Major Capital Projects
  (Evidence: Hydro's 1000MW Ontario Sale and system planning risks)
- ICG Utilities (Manitoba) Ltd., Generic Hearing on Rate Setting
  (Evidence: Implications of using a future versus historic test year)

Before the British Columbia Utilities Commission

2006	• British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement
2005	• Insurance Corporation of British Columbia, Financial Allocation Workshop • FortisBC, General Rates Application (Evidence: Review of FortisBC Performance under PBR, 1996 to 2004) w. S. Motluk
2004	• Insurance Corporation of British Columbia, Financial Allocation Methodology (Evidence: Review of ICBC's Financial Allocation Methodology, with ICBC)
2002	• Pacific Northern Gas West and Northeast, General Rate Application
2001	• Utilicorp Networks Canada (formerly West Kootenay Power), Annual Review, 2001
2000	• Pacific Northern Gas, 2000-01 General Rate Application (negotiated) • West Kootenay Power, Annual Review, 2000
1999	• Centra Gas BC, 2000-02 Rates Application (negotiated) • BC Gas, Market Unbundling Group (Report to the BCUC) • West Kootenay Power, 2000-02 Rate Application (negotiated) • Pacific Northern Gas, 1999-00 General Rate Application (negotiated) • Annual Reviews of WKP and BC Gas • West Kootenay Power, Transmission Access Application
1998	• BC Gas, Southern Crossing Pipeline Application (Revised) • Pacific Northern Gas, 1998-99 Revenue Requirement/Rate Design (Evidence on PNG's Cost of Service Methodology)
1997	• BC Gas, Southern Crossing Pipeline Application (Evidence on the impact of ratepayer risks related to the SCP due to developments in the competitive environment in the natural gas sector) • Annual Reviews of WKP and BC Gas. • West Kootenay Power, Cost of Service and Rate Design (negotiated settlement)
1997	• Pacific Northern Gas Shared Services • Retail Access and Unbundling Tariff Hearing (suspended) (Evidence on the impact of market restructuring on costs and rates)
1996	• BC Gas - 1996 Rate Design (negotiated settlement) (Evidence: Alternative Methods for Allocating Distribution Mains Costs to Customer Classes) • BC Gas - 1996-1997, Revenue Requirement & IRP (negotiated settlement) • West Kootenay Power - Brilliant Generating Station Transactions • West Kootenay Power - General Rate Application/IRP (negotiated settlement)
1995	• Generic System Expansion Hearing • BC Gas - General Rate Application (negotiated settlement)
1994	• BC Hydro, 1994 Rate Increase Application • West Kootenay Power, 1994/95 Rates and Integrated Resource Plan (Evidence: Review of WKP's Integrated Resource Plan)
1993	• BC Hydro, 1993 Rate Increase Application • BC Gas, Rate Design Hearing (Evidence: Analysis of BC Gas' cost studies and their use in setting rates)

- BC Gas - General Rate Application (settled and withdrawn prior to hearing)
- Generic Hearing into the New Provincial Domestic Natural Gas Supply Policy

Before the Régie de l'énergie

2014
- Régie de l'énergie
  Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions

2001
- Hydro Québec, Transmission Rates (R-3401-98)
  (Evidence: HQT's Transmission Tariff Rate Design Methodology, with B. Bacon)
- Inclusion of Operating Costs in the Gasoline Price Floor Set By the Régie
  (Evidence: Review of Principles) (Régie File R-3457-2000)

2000
- SCGM Unbundling of Tariffs (R-3443-2000)
  (Evidence: SCGM's Unbundling Tariff Proposal, with R. Higgin)
- Gazifère, Rates (R-3446-2000)
  (Evidence: Cash Working Capital and Other Issues, with G. Morrison)

1999
- Operating Costs Borne by Gasoline or Diesel Fuel Retailers (R-3399-98)
  (Evidence: Methodology for Determining Operating Costs)
- Small Hydro Within Hydro Quebec's Resource Plan (R-3410-98)
  (Evidence: Determining the Purchase Price for Small Hydro)

1999
- Gazifère, Year 2000 Rate Case
  (Evidence: Assessment of Cost Allocation and Revenue Sharing Proposals)

1998
- Hydro Québec, Rate-Setting Methodology Under s. 167 of the Régie de l'énergie Act.
  (Evidence: Recommendations on Regulatory Framework)
- Hydro Québec,The Role of Wind Power in the Quebec Energy Portfolio
  (Evidence: Issues Related to Establishing a Set-Aside)

Before the Alberta Energy and Utilities Board

2001
- Generic, Gas Rate Unbundling (2001-093)
  (Evidence: Canadian Experience and Approaches)
- Generic, Gas Cost Recovery Rate Methodology (2001-040)

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

2013
- Newfoundland Hydro General Rate Application
- Newfoundland Power, General Rate Application (2013-2014)

2009
- Newfoundland Power, 2010 General Rate Application
  (Evidence: Assessment of five hearing issues)

2007
- Newfoundland Power, 2008 General Rate Application
  (Evidence: Regulatory instruments and other issues)

2006
- Newfoundland Power, 2007 Amortization and Cost Deferrals Application

2005
- Newfoundland Power, 2006 Accounting Policy Application
  (Evidence: Assessment of Newfoundland Power's Proposals)

Before the New Brunswick Energy and Utilities Board

2013	• New Brunswick Power, PLGS Deferral Account (Matter No. 171) (Evidence: Options for the Recovery of the Point Lepreau Nuclear Generating Station Deferral Account Balance)
2010	• New Brunswick Power Distribution Corp, 2010 Rate Review
2009	• EGNB, Development Period hearing • New Brunswick Power Distribution Corp, 2009 Rate Review
2008	• New Brunswick Power Distribution Corporation, PDVSA Deferral Account
2007	• New Brunswick Power Distribution Corporation, PDVSA Deferral Account (Evidence: Treatment of the Petroleos De Venezuela, S.A. (PDVSA) Settlement in Setting Rates)

Before the Nova Scotia Utility and Review Board

2013	• NSPI Capital Expenditures for the South Canoe Wind Project (CI# 42127) (Evidence: Treatment of costs associated with competitive wind power project) • Town of Antigonish Electric Utility Large User Rate (Evidence: Cost Allocation)
2011	• Nova Scotia Power, 2011 Annual Capital Expenditure Plan • Nova Scotia Power, Load Retention Tariff (Evidence: Load Retention Tariff Methodology) • Heritage Gas, 2012 General Tariff Application • Efficiency Nova Scotia, Compliance Filing (Cost Allocation Methodology Report)
2008	• Town of Antigonish Electric Utility rate process (Evidence: Comments on the Town of Antigonish Electric Utility Revised Cost of Service Study)

Before the National Energy Board

1999	• BC Gas, Southern Crossing Project

Before the Canadian Radio television and Telecommunications Commission

2010	• Obligation to Serve and Other Matters (NC 2010-43) (Evidence: Analysis of Issues Related to Local Service Subsidy)
2006	• Review of Price Cap Framework (PN 06-5)
2001	• Implementation of Price Cap Regulation for Québec-Téléphone & Télébec (PN 01-36) (Evidence: Designing a Consistent Price Cap Regime) • Price Cap Review (PN 01-37) (Evidence: The Second Generation Price Cap Regime) • Recovery of 2000 and 2001 Income Tax Expense (PN 00-108)

(Evidence: Appropriate Recovery of MTS Income Tax Expense)

2000
- Scope of Price Cap Review (PN 00-99)
- Sunset Rule for Near-Essential Facilities (PN 00-96)
- Access to Municipal Property in the City of Vancouver (PN 99-25)
- Review of Contribution Collection Mechanism (PN 99-6)
  (Evidence: Review of Contribution Collection Mechanism)
- Review of Direct Connection Charges

1999
- Review of Frozen Contribution Rate Policy (PN 99-5)
  (Evidence: Comments on the Frozen Contribution Rates Policy)
- High Cost of Serving Areas (PN 97-42)

1998
- Local Number Portability Start-up Costs (PN 98-10)
- Competition in the Provision of International Telecommunications Services (PN 97-34)

1997
- Implementation of Price Caps (PN 97-11)
- Review of Joint Marketing Restrictions (PN 97-14/97-21)
- Forbearance from Regulation of Toll Services Provided by Dominant Carriers (96-26)
- -Regulation of Telecom Services Offered by Broadcast Carriers (PN 96-36)

1996
- Scope of Contribution (PN 96-19)
- Bell Canada, Business Rate Restructuring (PN 96-13)
- Price Cap Regulation and Related Issues (PN 96-8)
  (Evidence: Evidence addressing the design of the price cap system)

1996
- Local Interconnection and Network Component Unbundling (PN 95-36)
  (Evidence: Mechanisms for Collecting Contribution)
- AGT, General Rate Application
- Local Services Pricing Options (PN 95-49/95-56)
  (Evidence: Mechanisms for Pursuing the Goal of Universally Available Basic
- Telephone Service in Low-Penetration Exchanges)

1995
- Review of Phase II (PN 95-19)
- Regulatory Framework for Ontario Independent Telephone Cos. (PN 95-15)
- Split Rate Base Hearing (PN 94-52, 94-56 and 94-58)
  (Evidence: Applicability of the Decision 94-19 Regulatory Framework to MTS)

1995
- Review of the Regulatory Framework of Teleglobe Canada Inc. (PN 95-11)
- Review of the Quality of Service Indicators (PN 94-50)
- Bell SYGMA Hearing (PN 94-53)

1994
- Regulatory Framework
  (Evidence: A Proposed Regulatory/Structural Alternative)
- Maritime Tel, General Rate Increase
- Island Tel, General Rate Increase
- BC Tel, General Rate Increase
- AGT, General Rate Increase
- Northwestel, General Rate Increase (paper hearing)
- Bell Canada, General Rate Increase
- Teleglobe, Annual Construction Program Review (paper hearing)
- New Brunswick Tel, Annual Construction Program Review (paper hearing)

1992
- Bell Canada - 1992 Annual Construction Program Review
- AGT - 1992 Annual Construction Program Review

1991
- Bell Canada - 1991 Construction Program Review

1990
- Maritime Telegraph & Telephone, Review of Revenue Requirement 1990-91
  (Evidence on the impact of modernization)
- Island Telephone Company, Review of Revenue Requirement 1990-91
  (Evidence on the impact of modernization)
- Review of Cable Television Regulations
  (Evidence on alternative forms of regulation)

Before the Ontario Telephone Services Commission

1992
- Review of Rate-of-Return Regulation for Public Utility Telephone Companies.
  (Evidence: The need for OTSC regulation of municipal public utility telcos)

Before the Ontario Securities Commission

1985
- Securities Industry Review
  (Evidence: Industry structure and the form of regulation)

1983
- Role of Financial Institutions in the Securities Industry
  (Evidence: Discount Brokerage and the Role of Financial Institutions)

1982
- Institutional Ownership of, and Diversification by, Securities Dealers
  (Evidence: The impact of foreign and institutional entry)

1981
- The Unfixing of Brokerage Commission Rates
  (Evidence: The impact of price competition on the securities industry)

Before the Ontario Municipal Board

1995
- Appeal of Boundary Expansion by Lincoln Hydro Electric Commission
  (Affidavit prepared on the tests for boundary expansions)

1992
- Evidence dealing with the *Rental Housing Protection Act, 1989*

Before the Supreme Court of Ontario

1990
- Challenge of the Residential Rent Regulation Act (1986) under the *Canadian Charter of Rights and Freedoms*
  (Evidence: The impact of rent regulation on Ontario's rental housing market)

Before the Saskatchewan Court of Queen's Bench

1993
- Evidence regarding market dynamics and competition policy.

Non-Hearing Processes (Task Forces, Lawsuits and Arbitrations)

2012	• Review of SaskPower's Cost Allocation Methodology (with Michael Roger)
2011	• Developing a regulatory training course for Ontario electricity distributors
2010	• Expert Advisor to the Ontario Energy Board for the Cost Allocation Review
2009	• Expert Advisor to New Brunswick Department of Energy on regulatory matters related to the proposed purchase of NB Power assets by Hydro Quebec
2008	• Expert Advisor to Ontario Energy Board for the Rate Design Review
2007	• Workshop on Electricity Market Design for the Electricity Regulatory Authority of Vietnam
2006	• Workshop on Regulatory Methodology for the Government of Vietnam (electricity regulator, Ministry of Energy and state-owned enterprises) with Marie Rounding
2004	• Vitamin Price Fixing • Allocation of debt related to separation of electric utilities
2001	• BC Gas, Second Generation Performance Based Regulation Negotiation • Telecommunications Industry, Price Cap Review Negotiation
1999	• PBR Task Force (Electricity), Ontario Energy Board • Market Unbundling Group (BC Gas), British Columbia Utilities Commission • Western Supply Transportation Service (Centra Gas Manitoba), Manitoba PUB
1998	• Market Design Task Force, Ontario Energy Board
1997	• Ten Year Market Review, Ontario Energy Board

Commercial Arbitrations

Current: Two arbitrations in Alberta

2013	• Analysis of options for pricing of live chickens under Regulation 402
2006	• Disputed Power Purchase Agreement (PPA)
2004	• Evidence on the interpretation of a Gas Purchase Agreement (GPA)

Facilitation Activities

2010	• Strategic Planning Process for the Boards of Directors of an Ontario electricity distributor
2008	• Strategic Planning Processes for the Boards of Directors of electricity distributors
2007	• Stakeholder facilitation for Ontario Power Generation in relation to its Regulated Payment Amounts
2004	• Ontario Energy Board, Review of Further Efficiencies in the Electricity Distribution Sector (RP-2004-0020) (with IBM Consulting) • Visioning Session: Structural Review of an association of Ontario electric LDCs

- Business Plan Visioning Session with the Board of Directors of an Ontario electric LDC

2000
- Ontario Energy Board, Distribution Access Rule Task Force

Other Regulatory Issues Researched for Clients

- Analysis of strategic options for an Ontario electricity distributor
- Review of productivity enhancements for an Ontario electricity distributor
- Review of Conditions of Service for several Ontario electricity distributors
- Review of Economic Evaluation models and methodologies for several Ontario electricity distributors
- "Benchmarking for Regulatory Purposes" (with First Quartile Consulting) for the Canadian Association of members of Regulatory Tribunals (CAMPUT)
- "Review of Potential Regulatory Cost Measures" (a Report for the OEB)
- "Survey of Regulatory Cost Measures" (a Report for the Ontario Energy Board)
- OEA Working Dialogue on OEB Regulating Efficiency and Effectiveness (2007)
- Regulatory Cost Measures for the Ontario Energy Industry (2007)
- "Designing an Appropriate Lost Revenue Adjustment Mechanism (LRAM) for Electricity CDM Programs In Ontario"
- Small Hydro PPA Terms and Conditions
- Ontario Electricity Supply Mix
- Mitigation of Regulatory Risk for Utilities
- Regulatory Benchmarking
- Cross-jurisdictional Survey of Regulatory Efficiency
- Renegotiation of Municipal Franchise Agreement

Regulated Industries:

Papers and Research Projects

- *Report on the Effects of Separating Hydro One's Transmission and Distribution Functions.*
- *Report on Hydro One Privatization Options.*
- *The Impact of Complete Deregulation on Market Efficiency of the Gas and Electric Industry in Alberta Post-2005 Assuming Current Market Dominance.*
- *Analysis of a Possible Equity Infusion for Ontario Hydro: Potential Implications for Financing Costs.*
- *Volatility in the Ontario Electricity Market, by ECS with Snelson International Energy.*
- *An Assessment of Price Volatility in the Ontario Electricity Market.*
- *Analysis of MTS Privatization Plan.*
- *Comments on the Issues Identified in the December 1995 Working Paper of the Advisory Committee on Competition in Ontario's Electricity System, A submission on behalf of The Power Workers'Union.*
- *Telecommunications Municipal/Franchise Tax Design Options (with Dr. E. Slack).*
- The Implications of Phase III Costing for the Rates and Toll Settlements of Independent Telephone Companies (with Andrew Roman).
- Submission to the Department of Communications (Canada) (August 1990): *Towards Competition in Telecommunication and Cable TV Services: A Single Switched Broadband Distribution Facility* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the Department of Communications (Canada) (May 1990): *Fibre Optic Networks: Facilitating Competition in Telecommunication and Television Services for the Benefit of All Users* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the CRTC concerning cable television regulation on behalf of the Public Interest Advocacy Centre (with Carmen Baggaley).
- Analysis of financing alternatives for Toronto Hydro's 13.8 kV conversion program for the City of Toronto Parks and Recreation Department.
- Analysis of the MacEachen White Paper on "Inflation and the Taxation of Personal Investment Income" for the Ontario Economic Council.
- Submission to the Parliamentary Committee commenting on the April 1985 Finance Green Paper, "The Regulation of Financial Institutions: Proposals for Discussion" prepared on behalf of the Public Interest Research Centre.

Financial Markets:
Papers and Research Projects

- Analysis of the potential consumer benefits from insurance retailing by financial institutions in Canada for the Public Interest Research Centre.
- Development of a financial model for projecting the financial implications of alternative corporate structures.
- Developed model for projecting cash flows for a major land development project.
- Analysis of the impact on the capital markets of changes to the investment rules for public sector pension funds for the Task Force on the Investment of Public Sector Pension Funds (with Prof. John Bossons).
- Review of the OSC proposals and alternatives for relaxing ownership restrictions in the securities industry prepared for the Ontario Securities Commission for submission to the Premier's Office (with Prof. Tom Courchene).
- Analysis of the Impact of Opening the Ontario Securities Market on the Economy of Toronto for a major Canadian securities dealer.
- Response to the December 1984 "Interim Report of the Ontario Task Force on Financial Institutions" for Consumer and Corporate Affairs (Canada).
- Report on functional integration in the Canadian financial services sector for the Australian Merchant Bankers' Association.
- Analysis of the Canadian and American Experience with Partially Negotiable Brokerage Commission Rates for the Australian Merchant Bankers Assoc.
- Served as a North American contact for the Office of Fair Trading (United Kingdom) providing information on developments in the debate over unfixing of brokerage fees, entry of banks into securities dealing and related matters.
- Development of a computerized package for analyzing the effects of alternative tax systems on business investment. Prepared for the Ontario Government reference to the Ontario Economic Council to study a separate personal income tax for Ontario.
- "An Analysis of the Use of Component Internal Rates of Return for Fund Performance Measurement" for Canadian National Investments.
- Analysis of Canadian Stock Market Data (development of a computer package for evaluating investment portfolio efficiency).
- Redesign and periodic updating of the financial, analysis methodology for Alfred Bunting and Co.
- Developed an APL computer package for teaching Business Finance concepts.

Housing:
Papers and Research Projects

- Potential Impact of Rent De-Control on Selected Markets in Ontario
- Review of the Ontario Auditors analysis of the cost of social housing.
- *Future Social Housing Delivery Opportunities in Metro Toronto*.
- Development of a model for projecting core need households to 2011.
- Analysis of the City of Toronto's approach to the valuation of certain properties developed under the *Rental Housing Protection Act, 1989*.
- *Security of Tenure Issues Pertaining to Co-operative Housing*.
- *Rent Regulation in Ontario*, a report prepared as expert Evidence for a Charter of Rights challenge of Ontario's system of rent regulation (with W.T. Stanbury).
- Feasibility study of enhancements to long term housing forecasting models (demographic factors) with David Foot.
- Feasibility study of enhancements to long term housing forecasting models (economic factors).
- Review of the housing situation in the Greater (Toronto) Metropolitan Region in 1988 and the next decade for the Ontario Ministry of Housing.
- Treatment of the Assisted Rental Program under rent regulation for the Ontario Ministry of Housing.
- Alternatives for implementing of the chronically depressed rent provision of the Residential Rent Regulation Act, 1986.
- Projected rental housing requirements to 1996, by unit rent level for Ontario Ministry of Housing.
- Analysis of the effects of the Canadian Home Ownership Stimulation Program on housing starts for Canada Mortgage and Housing Corporation.
- Energy Efficiency of New Housing (with Peat, Marwick and Partners and Scanada Consultants Limited) for Canada Mortgage and Housing Corporation.
- A Model of Supply and Demand in the Market for Housing for the Ontario Ministry of Housing.
- Several publications and presentations shown in the Academic Profile (see below).

Other Areas:
Papers and Research Projects

- Economic analysis of the market impact of the merger of two Canadian trucking companies in the context of the Competition Act.
- Assisted a Joint Task Force of the Ontario Ministries of Social Services and Health to develop a cost project model of alternative long term health care delivery systems.
- Study of Tax Incentives for Film and Television (joint project with Dr. E. Slack) for the Canadian Film and Television Association.

- Economic Analysis of Tax Incentives for the Film Industry (joint project with Dr. E. Slack) for the Department of Communications.
- Economic Impact of Cultural Institutions for Ontario Association of Art Galleries with the Ontario Federation of Symphony Orchestras and the Toronto Theatre Alliance.
- Economic Impact of Art Galleries' Expenditures on their Local Communities for the Ontario Association of Art Galleries.
- Developed a case study of the potash pro-rationing scheme invoked by the Saskatchewan government for the Faculty of Management Studies, Univ. of Toronto.
- Analysis of Regional Municipality of Niagara financial information for the Niagara Region Review Commission.
- Analysis of Ottawa/Carleton regional government's financial information, and comparison with other regional governments, using the MARS database (with Dr. E. Slack).
- A Dynamic Simulation Model of the North York Secondary School System for Planning for Declining Enrolment for the Ontario Institute for Studies in Education, Department of Educational Planning (with Dr. S. Padro).
- Development of an extension to the Limits to Growth World III Model incorporating commodity prices, technology, disaggregated regions and energy resources into the model.
- Development of a computer program for solving the Dynamic Transportation Problem (with Professors Sethi and Bookbinder at the Faculty of Management Studies, University of Toronto).

PRESENTATIONS

- MEARIE Training Program, Regulatory Specialist Certificate Course, (2011 – 2014)
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How To Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Ass
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.
- "Low-Income Energy Plan for Peterborough City & County", 2006 LIEN-AHAC Conference
- "The "Deregulated Retail Energy Sector in Ontario", Toronto Association of Business Economists, Oct. 2003.
- "Other Approaches to Rate Regulation", CAMPUT Annual Meeting, Sept. 2003.

- "Price Projection: Will the Rate Freeze be Revenue Neutral?" at Canadian Institute Conf., The Impact of Ontario's New Electricity Market on Large Power Consumers Jan. 2003.
- "Managing Energy Price Risk: Impact of Market & Regulatory Developments on Price Risk Management", Canadian institute Conference, Toronto, October 21, 2002.
- "Location Based Marginal Pricing: Will it Happen?" Ontario Energy Contracts, Insight Conference, Toronto, October 1, 2002.
- "The Evolution of the North American Energy Market" Canadian Gas Association Executive Conference, Vancouver, June 2002.
- "Alternate Dispute Resolution: Can Everyone Win?" Canadian Gas Association Breakfast, Whistler, British Columbia, May 7, 2002.
- "Incentive Regulation and Commodity Competition Impacts on Quality of Service & Rates", CAMPUT Regulatory Educational Conference, Whistler, BC, May 7, 2002.
- "Energy Deregulation Developments and Impacts on the HVACR Industry", HRAI's 33rd Annual Meeting, August 23-25, 2001 Huntsville, Ontario.
- "Natural Gas Delivery Regulation in Canada", HRAC Conference on Natural Gas in Nova Scotia, Halifax, Nova Scotia, August 25, 1999.
- "Licensing as a Regulatory Approach" Thirteenth Annual CAMPUT Regulatory Educational Conference, Saint John, New Brunswick, May 4, 1999.
- "The Impact of Restructuring Electricity Markets on Customers", West Kootenay Power 1998 Annual Conference, The Dawn of Customer Choice, Kelowna, B.C., Dec. 2, 1998.
- "Gaining Access to the Retail Customer", *Electricity Competition in Ontario, New Rule, New Opportunities, New Players* (Canadian Institute Conference), Toronto, Oct. 1998.
- "The Future: Mega-BTU Inc.?" (Plenary session) Twelfth Annual CAMPUT Regulatory Educational Conference, Banff, Alberta, April 27, 1998.
- "Protecting Low Income Consumers' Access: Lessons Learned From Other Countries," Twelfth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 26-27, 1998.
- "Competition: What happens downstream of the meter?" (Plenary) Eleventh Annual CAMPUT Regulatory Educ. Conference, Whistler, B.C., May 6, 1997.
- "Brokers, Marketers and the Public Interest" Eleventh Annual CAMPUT Regulatory Educational Conference, Whistler, B.C., May 6, 1997.
- "Separation of Gas Supply, Merchant Functions & Other Alternatives," Tenth Annual CAMPUT Regulatory Educ. Conf., Niagara-on-the Lake, May 1, 1996.
- "The Impact of Deregulation on the Public Interest," Tenth Annual CAMPUT Regulatory Educational Conference, Niagara-on-the Lake, April 30, 1996.
- "Marketing to Low and Moderate Income Consumers in the New Competitive Market: Lessons Learned From Other Industries," Tenth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 22, 1996.
- "Where Should We be Going?" OEB Ten Year Market Review Workshop, Jan. 31, 1996.
- "Restructuring the Electrical Power Industry in Ontario" for the Board of Directors of Ontario Hydro on behalf of the Power Workers' Union, August, 1995.

- "A New Vision for Ontario's Electric Demand/Supply Future" panel presentation, Opening Plenary Session of the Canadian Independent Power Conference, Toronto, Dec. 1993.
- "Trends in Rental Housing Affordability by Income Level in Ontario" presented at the 1992 meetings of the Canadian Economics Assoc., Charlottetown, PEI.
- "An Evaluation of Rent Regulation as an Instrument for Meeting the Housing Needs of Renters in Ontario," presented to the Ontario Standing Committee on General Government, August, 1991.
- with S.W. Hamilton (Sept 1990) "Housing and the Regulatory Environment", a paper presented at the Housing Young Families Affordability Symposium, (Vancouver: Canadian Housing and Renewal Association/Canada Mortgage and Housing Corp.)
- "New Telecommunications Technologies: Who Pays? Who Benefits?" presented at the 1990 (June) meetings of the Canadian Economics Assoc., Victoria, B.C.
- with W.T. Stanbury, (1989) "Rent Controls as a Prisoner of War Game", Canadian Real Estate Research Bureau, Faculty of Commerce and Business Administration, University of British Columbia, #89-ULE-019.
- "The Implications of Rent Regulation for Housing Market Models" presented at 1989 (June) meetings of the Canadian Economics Association, Quebec City.
- "Price Caps - An Alternative to Rate of Return Regulation?" at the Canadian Association of Members of Public Utility Tribunals/Centre for the Study of Regulated Industries, Annual Regulatory Studies Training Programme, McGill University, May 14-18, 1989.
- "Living with Rent Regulation in Ontario" at the 35th North American meetings of the Regional Sciences Association, Toronto, November 1988.
- "A Survey of the Research of the Thom Commission," at *Rent Control: The International Experience*, John Deutsch Institute Roundtable, Queen's University, September, 1987.
- Invited address on "Forecasting the Regulatory Environment of Financial Institutions" sponsored by the University of Michigan - Flint as the 1985 paper for their annual *Lectures on the American Economy and the Business Community* series.
- "Collapsing Barriers Between Banking and Other Financial Institutions" at the 1984 Canadian MBA Conference, McMaster University.
- The economic impact of cultural activities for conferences of National Museums of Canada, Canadian Conference on Heritage Resources, Canadian Museums Association, Ontario Association of Art Galleries, and Ontario Federation of Symphony Orchestras.

PUBLICATIONS

Refereed Books and Monographs:

- with W.T. Stanbury (February 1990) *Rent Regulation: The Ontario Experience*, (Vancouver: The Canadian Real Estate Research Bureau).
- with W.T. Stanbury (January 1990) *The Housing Crisis: The Effects of Local Government Regulation*, (Vancouver: The Laurier Institute).
- with T. Courchene and L. Schwartz (October 1986) *Ontario's Proposals for the Canadian Securities Industry*, Observation No. 29, (Toronto: C.D. Howe Inst.).
- (1983) *Price Competition in the Canadian Securities Industry: A Test Case of Deregulation*, (Toronto: Ontario Economic Council).
- with G.F. Mathewson (1982) *Information Entry and Regulation in Markets for Life Insurance - Part II Overview and Policy Implications*, (Toronto: Ontario Economic Council).

Refereed Articles:

- with W.T.Stanbury (1990) "Landlords as Economic Prisoners of War", *Canadian Public Policy*, XVI no.4.
- with G.D. Quirin and S.P. Sethi (1977) "Market Feedbacks and the Limits to Growth", *INFOR*, Vol. 15, No. 1.

Other Publications:

- (1992) *Technology, Competition and Cross-subsidization in the Canadian Telecommunications Industry*, (Ottawa: Public Interest Advocacy Centre).
- (April 1990) *Paying for What You Need: Technological Advances and Competition in Telecommunications*, (Ottawa: Public Interest Advocacy Centre).
- with Andrew Roman and Robert Horwood, (1989) *Insurance Retailing by Financial Institutions in Canada*, (Ottawa: Public Interest Research Centre).
- with Douglas G. Hartle (1983) "The TAX-2 Model and Results" in *A Separate Personal Income Tax for Ontario: An Economic Analysis*, Special Research Report, (Toronto: Ontario Economic Council).
- (1982) "Commentary" in *Inflation and the Taxation of Personal Investment Income: An Analysis and Evaluation of the Canadian 1982 Reform Proposals* (edit. D.W. Conklin), Special Research Report (Toronto: Ontario Economic Council).

TEACHING

1989	Economics of Housing, Scarborough College, University of Toronto
1979 – 1985	Engineering Economy, Faculty of Engineering, University of Toronto
1982 – 1985	Computerized Business Systems (B.A. Program), and Management Information Systems (M.B.A.), Canadian School of Management
1979	Introductory Economics at St. George Campus, University of Toronto
1977 – 1979	Economic Principles at Erindale College, University of Toronto
1980 – 1985	Scuba diving instruction for Basic Diver, Sport Diver, Assistant Instructor and Instructor courses (National Association of Underwater Instructors).

RESEARCH MANAGEMENT

1983 – 1987

- Research Director: Commission of Inquiry Into Residential Tenancies.
- Directing a staff of four in house researchers on various background studies on Ontario's housing market and the literature related to rent regulation. Managed thirty external projects on topics related to the housing market and rent regulation.

1978 – 1980

- Research Officer: Ontario Economic Council.
- Research was conducted in the areas of regulation of the securities industry, mineral resource taxation policy, and Federal Provincial energy policy.
- Other duties included managing ten external research contracts on topics in regulation and directing the work of research assistants.

OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Participation on behalf of OCAP in consultative processes related to direct purchase and integrated resource planning in the Ontario natural gas industry.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Former Chairman of the Board of Directors of the Festival of Canadian Theatre.
- Articles in the editorial section of the Financial Times of Canada on policies for reforming Ontario's system of rent regulation (June 1990) and federal proposals regarding bank directorships (February 1991).

- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.
- Refereed articles and research studies for *Canadian Public Policy*, *Queen's Quarterly* and Consumer and Corporate Affairs, Canada.
- Several organizations have been assisted in developing their research agendas, writing submissions to government on economic issue, or in other advisory capacities. Clients include the Public Interest Research Centre (topics include airline deregulation, Via Rail, telephone solicitation, Bell Canada's rate structure, frequent flyer programs, price cap regulation, and home equity conversion), Ontario Association of Art Galleries (arts funding and economic impact), Public Affairs Management, Inc., City of Toronto, Parks and Recreation Department, and Goldfarb Consultants.

CLIENTS

Private Sector Companies

Alfred Bunting & Co.
Auto Haulaway Inc.
BC Gas Utilities Limited
BC Rail
Buttcon Ltd.
Canavest House Ltd.
Canadian National Investments
Entergrus (Chatham-Kent Energy)
Comdisco Canada Inc.
Coral Energy
Devon Canada
Direct Energy
EnCana
ENERconnect
Enbridge Gas Distribution
EnCana Corporation
Enron Trade and Capital Canada
Financial Times of Canada
Fine Line Communications Ltd.
FortisBC
Fuji Electric (Tokyo)
Goldfarb Consultants
Great West Life Assurance Co.
Highmark Properties
Hydro One Networks Inc.
Hydro Québec
Insurance Corp. of British Columbia
McLeod Young Weir
New Brunswick Power (Disco)
Ontario Hydro Services
Ontario Power Generation
Shulman Communications Inc.
Sithe Canada
Star Produce
Terasen Gas
The Morassutti Group
Union Gas Limited
Wirebury Connections Inc.
Over 30 Ontario electricity distributors

Industry and Other Associations

Association for Furthering Ontario's Rental Development
Australian Merchant Bankers' Association
Canadian Association of Members of Public Utilities Tribunals (CAMPUT)
Canadian Business Telecommunications Alliance
Canadian Film and Television Association
Canadian Independent Telephone Association

Canadian Museums Association
Cornerstone Hydro Electric Concepts
Electricity Distributors Association
Manitoba Keewatinowi Okimakanak
Ontario Association of Art Galleries
Ontario Energy Association
Ontario Federation of Symphony Orchestras
Power Workers' Union (CUPE 1000)
Toronto Theatre Alliance

Consumers' Associations

Alberta Council on Aging
Alert on Welfare
British Columbia Old Age Pensioners' Association
Canadian Pensioners Concerned
(Nova Scotia Division)
Consumers Association Of Canada
(National)
(Manitoba Branch)
(Alberta Branch)
(Northwest Territories Branch)
Consumers Fight Back Association
Council of Senior Citizens' Organizations
Co-operative Housing Association of Ontario
Federated Anti-Poverty Groups of British Columbia
Action réseau consommateurs (formerly La Fédération
Nationale des Associations de Consommateurs du Québec)
Manitoba Society for Seniors
The National Anti-Poverty Organization
Nova Scotia League for Equal Opportunities
Ontario Coalition Against Poverty
Option Consommateurs
PEI Council for the Disabled
PEI Senior Citizens Federation
People on Welfare for Equal Rights
Public Interest Research Centre
Rural Dignity of Canada
Rural Dignity, PEI Chapter
Senior Citizen' Association
Social Action Commission

Counsel for Consumers' Associations

British Columbia Public Interest Advocacy Centre
Legal Aid Manitoba, Public Interest Law Centre
Newfoundland Consumer Advocate
Public Interest Advocacy Centre (Ottawa)

Government

Federal

Canada Mortgage and Housing Corporation
Canadian Conference on Heritage Resources
Consumer and Corporate Affairs (Canada)
Department of Communications (Canada)
Director of Investigation and Research, Combines Investigation Act
St. Lawrence Seaway Authority

Provincial

Alberta Department of Energy
Commission of Inquiry into Residential Tenancies
New Brunswick, Department of Energy
Niagara Region Review Commission
Ontario Economic Council
Ontario Energy Board
Ontario Institute for Studies in Education, Department of Educational Planning
Ontario Ministry of Community and Social Services
Ontario Ministry of Health
Ontario Ministry of Housing (Corporate Policy and Planning; Rent Review Policy, Housing Field Operations)
Ontario Securities Commission
Ontario Task Force on the Investment of Public Sector Pension Funds
Ottawa/Carleton Region Review Commission
University of Toronto

Other

City of Calgary Electrical System
City of Peterborough
City of Toronto, (Telecom; Housing; Parks and Recreation)
Halifax Regional Municipality
Manitoba NDP Caucus
Office of Fair Trading (United Kingdom)
St. Francis Xavier University
Toronto Harbour Commissioners
Four municipally operated public utility telephone system

APPENDIX B

FORM A, ACKNOWLEDGMENT OF EXPERT'S DUTY

FORM A

Proceeding EB-2016-0004

ACKNOWLEDGMENT OF EXPERT'S DUTY

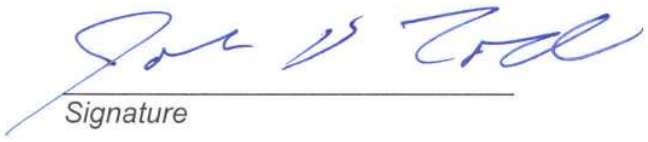
1. My name is John D. Todd. I live at Toronto, in the province of Ontario.

2. I have been engaged by or on behalf of the Municipalities to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date March 16, 2016



Signature

APPENDIX C

ONTARIO ENERGY BOARD DECISION E.B.L.O.197

Rep: OEB
Doc: 11538
Rev: 0

1

E.B.L.O. 194, 195, 196, 197
E.B.C. 124, 125, 123-A
E.B.A. 415, 416, 417, 419, 420,
421, 422

2

ONTARIO ENERGY BOARD

3

IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1980, C. 332, as amended;

4

AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an order granting leave to construct a 27.7 km natural gas transmission line from a take-off point from Northern's existing gas transmission line (in Lot 5, Concession 22, Town of Rayside-Balfour) to a point in Lot 1, Concession 4, Town of Valley East;

5

AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an Order of the Board varying Board Order E.B.C. 123, dated October 29, 1982.

6

IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1980, C. 332, as amended;

7

AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an Order granting leave to construct a 6", 4" and 3" diameter pipeline from a point adjoining TransCanada PipeLines transmission line in Lot 30, Concession 4, Township of Brighton in the County of Northumberland south along Northumberland County Road 26; easterly along White's Road; southerly along Georgina Street and westerly along Dundas Street, a total distance of approximately 7.5 miles (12 km) to a proposed District Regulator Station site in Lot 35, Concession A in the Town of Brighton;

8

AND IN THE MATTER of The Municipal Franchises Act, R.S.O. 1980, C. 309;

9

AND IN THE MATTER OF a proposed bylaw granting Northern and Central Gas Corporation Limited the right to construct works to supply and to supply gas to the inhabitants of the Township of Brighton.

10 IN THE MATTER OF The Municipal Franchises Act, R.S.O. 1980, Chapter 309;

11 AND IN THE MATTER OF a proposed bylaw granting Northern and Central Gas Corporation Limited the right to construct works to supply and to supply gas to the inhabitants of the Town of Picton; Village of Bloomfield and the Township of Hallowell; Township of Sophiasburgh; Village of Wellington;

12 AND IN THE MATTER OF The Municipal Franchises Act, R.S.O. 1980, C. 309, Section 8, and amendments thereto;

13 AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for Certificates of Public Convenience and Necessity to construct works and to supply gas to the inhabitants of the Town of Picton; the Village of Bloomfield; the Village of Wellington and the Township of Hallowell in Prince Edward County;

14 AND IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

15 AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an Order granting leave to construct a 24 km. natural gas transmission pipeline from a take-off point in Lot 15, Concession 1 in the Township of Sophiasburgh on Northern's existing gas pipeline in Provincial Highway 49 to a proposed district regulator station for the Village of Wellington adjacent to the said Highway 33 at a point in Lot 3, Concession 1, northwest of West Lake, Township of Hallowell; and a 13.1 km. long natural gas transmission pipeline from a point of intersection of Provincial Highways 33 and 14 in the Village of Bloomfield (Wellington and Stanley Streets) to ,sales metering station for the Department of National Defence Mountain View Airport at a point in Lots 60-61, Concession 1 BF in the Township of Sophiasburgh.

16 IN THE MATTER OF The Municipal Franchises Act, R.S.O. 1980, Chapter 309, Section 8 and amendments thereto;

17 AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for a Certificate of Public Convenience and Necessity to construct works and to supply gas to the inhabitants of the Town of Mattawa in the District of Nipissing;

AND IN THE MATTER OF a proposed bylaw granting Northern and Central Gas Corporation Limited the right to construct works to supply and to supply gas to the inhabitants of the Town of Mattawa;

Was Page 3. See Image [OEB:11537-0:3]

AND IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an Order granting leave to construct a 3.4 km natural gas transmission pipeline commencing from a take-off point on the TransCanada PipeLines's transmission line at a point in Lot 10, Concession 11, Township of Papineau to a proposed Town Border Station site in Lot 7, Registered Plan 1 of the Town of Mattawa.

DECISION

Hearing held at 14 Carlton Street, 8th Floor, on the 8th and 15th days of June, 1983.

BEFORE:

MR. I.C. MacNABB The Presiding Member

MR. J.C. HUNTER Member

MR. H. R. CHATTERSON Member

MISS S.J. WYCHOWANEC, Q.C. Member

APPEARANCES:

MS. DIANNE SAXE Board Counsel

MR. PETER F. SCULLY Counsel for Northern and Central Gas Corporation Limited.

Was Page 4. See Image [OEB:11537-0:4]

---On commencing at 2:35 p.m. THE PRESIDING MEMBER: Good afternoon. The Board is sitting today to render its Decision on a series of Applications dealing with the installation of gas distribution systems in the following communities: - Town of Brighton; - Communities within the Town of Valley East; - Town of Picton, Villages of Bloomfield and Wellington and surrounding areas; and - Town of Mattawa. The Applicant has basically adopted a common approach in developing the evidence supporting these applications and the Board's Reasons for Decision will similarly deal concurrently with all applications. Each application, however, has been carefully considered on its own merits. In dealing with an application for leave to construct a pipeline or for a certificate of public convenience and necessity, the Board must decide whether it is in the public interest that the facilities be constructed. Neither the Municipal Franchises Act nor the Ontario Energy Board Act specifically requires the Board to consider an economic feasibility test; although for most, but not all such applications, an economic test is an important factor. An obvious example of an exception would be facilities required essentially for security of supply.

Was Page 5. See Image [OEB:11537-0:5]

In past decisions the Board has stated that economic feasibility should be con- sidered in projects such as those before us, but that it should not be the sole criterion examined, nor the determining factor in the approval process. In the Applications before us evidence was led on many aspects of the public interest not directly related to economic feasibility. For example, the list of conditions requested by Board Counsel relates largely to construction and environmental matters which go beyond a narrow economic approach but which also require consideration. The Applicant has agreed with all of the conditions proposed by Board Counsel, as amended during the hearing, with the exception of a condition which would require financial contribution by shareholders of Northern. In Board Counsel's opinion this

further contribution is necessary to 19 prevent a dilution of the economics of Northern's 20 overall system, necessitating rate increases to 21 customers. 22 The calculation of the required 23 contribution in each case is related to the 24 differential between the Distribution System 25 Expansion Program Award and the amount of the 26 contribution necessary to provide an overall rate 27 of return of 12.23 per cent in the fifth year. 28 In every estimate in Norther's 29 proforma statements of rate base and return (Table 14) 30

Was Page 6. See Image [OEB:11537-0:6]
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1 became fact, and if the allowable rate of return 2 was achieved for the existing system, something that 3 has not happened in the recent past, there would be 4 cross subsidization in favour of the customers in 5 the communities being considered. Whether this cross 6 subsidy would be "undue" would be for the Board to 7 decide. In any event, such estimates are only as 8 reliable as the underlying assumptions. And, the 9 Board has given careful thought to this evidence, 10 particularly that concerning customer acquisition, 11 comparative prices for gas and alternative forms 12 of energy, and estimated construction costs. 13 We have concluded that, in these key 14 areas, Northern has adopted the conservative approach 15 and as a result the fifth year rate of return is 16 more likely to be higher than lower. Some factors 17 supporting this conclusion are: 18 (1) No new building construction or 19 development is assumed although an economic recovery 20 appears underway and, particularly in a small 21 community like Mattawa, relatively few additional 22 sales could significantly improve the economics. 23 (2) Capture rates for existing 24 customers are based on a 65 per cent relationship 25 between gas and heating oil prices and there are 26 some indications that this ratio may improve because 27 of competitive and political factors. 28 (3) Bids on the bulk of construction 29 have been received and have been incorporated. 30

Was Page 7. See Image [OEB:11537-0:7]
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1 The Board notes that Northern also 2 assumes continuation of the Canadian Oil Sub- 3 stitution Program which, because of the extreme 4 importance of the objective of increasing Canada's 5 oil self-sufficiency, will likely retain a high 6 priority. 7 Using the Applicant's economic test, 8 there could be the perception of some subsidization 9 by existing customers. As mentioned earlier this 10 perception could be dependent on, for example, the 11 rate of return being achieved. It would be very 12 difficult to quantify this cross subsidy without 13 an array of assumptions concerning the key variables 14 as there is no empirical way in which to conclude 15 that a certain subsidy is "undue". The Board's 16 judgment must ultimately encompass other components 17 of the public interest in arriving at a conclusion. 18 There are benefits to the residents 19 of the communities for which service is proposed, 20 both customers and non customers. The economic 21 benefits of lower energy prices and the resulting 22 multiplier effect have been referred to in the 23 evidence. There will be jobs created in the 24 communities and elsewhere. Gas service replacing 25 oil, where possible, is Federal and Provincial 26 Government policy and Federal, Provincial and 27 Municipal buildings will be converted to gas if 28 service proceeds. Savings in energy costs will flow 29 to taxpayers at all levels, including existing gas 30 customers. In addition, municipal and business taxes

Was Page 8. See Image [OEB:11537-0:8]
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1 payable by Northern will also benefit all taxpayers. 2 Nationally, oil displacement increases 3 security of supply by reducing Canada's dependence on 4 foreign oil, with associated cost savings which 5 benefit all citizens. 6 Payments from Alberta to the Federal 7 Government under the Alberta Market Development 8 Incentive Projects are possible if gas sales increase, 9 and excise taxes are currently payable on all volumes 10 of gas sold. 11 It is regrettable that the DSEP grant 12 is not sufficient to satisfy Northern's economic 13 feasibility tests but the Awards are an

immediate 14 benefit. Without them the projects would not have 15 been brought before the Board. With these grants 16 insured only for a short while, and with the Canadian 17 Oil Substitution Program, these proposals are 18 opportune. 19 Our consideration of these benefits, 20 some of which have been quantified in the evidence, 21 and some of which are less tangible and quantifiable 22 has led us to the conclusion that any cross subsidy 23 which may result is offset by the benefits and that 24 the projects should be approved. 25 The Board will therefore approve all 26 the Applications before us subject to the conditions 27 which have been agreed on by the Applicant and subject 28 to the undertakings made by its counsel and witnesses 29 during the hearing. 30 Specifically, the following Applications

Was Page 9. See Image [OEB:11537-0:9]

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for approval of the terms and conditions of 2 Municipal Franchise Agreements are granted: 3 Township of Brighton, 4 Town of Picton, 5 Village of Bloomfield, 6 Village of Wellington, 7 Township of Hallowell, 8 Township of Sophiasburg, 9 Town of Mattawa. 10 The Board's Order will dispense with 11 the assent of the Municipal Electors in each case. 12 The Application for an amendment to 13 the certificate of public convenience and necessity 14 for the Town of Valley East to delete the community 15 of McCrae Heights is approved. The Board notes the 16 undertaking by Northern to apply for a DSEP grant 17 in 1984 for an extension of the system to McCrae 18 Heights. 19 The Board is satisfied that public 20 convenience and necessity requires that approval 21 be given to the Applications for certificates of 22 public convenience and necessity for Mattawa, Picton, 23 Bloomfield, Wellington and the Township of Hallowell. 24 The Board is of the opinion that 25 construction of the pipelines in Prince Edward 26 County, to the Towns of mattawa and Brighton and 27 to the communities in the Town of Valley East is in 28 the public interest. Approval will be given subject 29 to the conditions noted earlier. The Board is 30 satisfied that Northern has offered each affected

Was Page 10. See Image [OEB:11537-0:10]

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landowner an easement agreement in the form filed 2 in the proceedings, and which is hereby approved. 3 The costs of the Board will be charged 4 to the Applicant. The Board will, therefore, issue 5 Orders in accordance with these Reasons for Decision 6 and requests that the Applicant prepare draft orders 7 for the Board's consideration. 8 Before concluding the hearing there 9 is just one note, as we are aware there is a Board 10 sponsored study of feasibility tests and construction 11 practices which we expect to get underway shortly 12 and the results may have some bearing on future 13 applications of this nature. 14 Thank you. The hearing is concluded. 15 16 ---Whereupon the hearing adjourned at 2:50 p.m. 17 18 19 20 21 22 23 24 25 26 27 28 29 30

Was Page 11. See Image [OEB:11537-0:11]

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AND IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332;

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AND IN THE MATTER OF an Application by Northern and Central Gas Corporation Limited for an Order granting leave to construct a 3.4 km natural gas transmission pipeline commencing from a take-off point on the TransCanada PipeLines's transmission line at a point in Lot 10, Concession 11, Township of Papineau to a proposed Town Border Station site in Lot 7, Registered Plan 1 of the Town of Mattawa.

DECISION

Hearing held at 14 Carlton Street, 8th Floor, on the 8th and 15th days of June, 1983.

Was Page 12. See Image [OEB:11537-0:12]

June 22, 1983.

ERRATA

Decision on Northern's Facilities E.B.L.O. 194, 195, 196 and 197.

Front page Butler not Hunter.

Page 2, line 29 "If" in place of "in".

Page 3, line 8 delete "And".

line 14 "a" in place of "the".

Page 5, line 8 "Payments" in place of "Projects'.

<signed>
Ian C. MacNabb,
Vice-Chairman.

APPENDIX D

BCUC FINAL REPORT, APRIL 6, 1989

Vancouver Island Gas Pipeline Final Report April 6, 1989
CAARS

1.0 INTRODUCTION

This report represents the final report of the British Columbia Utilities Commission ("the Commission) with respect to the Applications for Energy Project Certificates made by Pacific Coast Energy Corporation ("PCEC"). The Commission has previously provided an Interim Report to the Lieutenant-Governor in Council with respect to the Commission's findings from Phases I and II of the hearing. This report considers the Commission's findings with respect to Phase III, Markets, Gas Supply and Financial Matters. The consolidated conclusions and recommendations of the Commission with respect to all phases of the hearing are provided in the Executive Summary, produced as a separate report.

The public hearing was the result of the Application of November 1988 by PCEC seeking an Energy Project Certificate and an Energy Operating Certificate from the Government with respect to its proposed natural gas transmission pipeline to be constructed from Coquitlam, B.C. to Vancouver Island. The routing of the pipeline would be via Coquitlam Lake and Indian River to Squamish. The line would continue past Wood Fibre, Port Mellon, Gibsons and Sechelt to a shore approach north of Secret Cove where a crossing of the Malaspina Strait to the southern end of Texada Island would occur. At the north end of Texada Island the pipeline would make underwater crossings to Powell River on the Mainland and to Little River on Vancouver Island. The main transmission line would continue via Comox southward to Nanaimo and Duncan, terminating at Victoria. Laterals to the industrial complexes on the Island would be extended including lines which would service loads at the communities of Port Alberni and Campbell River.

The PCEC Application was the result of an understanding between the Federal and Provincial Governments on funding for the project. The Statement of Principles between the Governments was signed on September 22, 1988. The Binding Agreement between the parties is yet to be finalized at the date of this report.

2

The Terms of Reference for the Commission review were issued on December 20, 1988 by the Minister of Energy, Mines and Petroleum Resources and the Minister of Environment. Those Terms of Reference requested that the Commission provide its Report and Recommendations to the Government by March 22, 1989, or as soon thereafter as practical. The Commission responded to this request for an expedited proceeding by issuing its Order No. G-111-88 on December 20, 1988. That Order set January 24, 1989 as the first day of hearings.

As a result of a Pre-hearing Conference held on January 18, 1989, the phases of the hearing were established as follows:

Phase I	Facilities and Capital Costs
Phase II	Environmental and Socio-Economic Considerations
Phase III	Markets, Gas Supply and Financial Matters

The phasing of the hearing recognized that there were significant deficiencies in the PCEC Application. By deferring the review of Markets, Gas Supply and Financial Matters to the third phase of the hearing, it was hoped that PCEC would be able to augment its Application in these areas by reaching Agreements with producers, the industrial customers, the distributor utilities and BC Gas Inc. ("BC Gas"). It was also anticipated that the Binding Agreement between the two Governments would be completed and the financial arrangements resulting from the Agreement would be made known to the hearing. As the hearing progressed the Commission became aware of the sale of British Columbia Hydro and Power Authority's ("B.C. Hydro") Victoria Propane Distribution Grid to Vancouver Island Gas Co. Ltd. ("Vigas") on January 27, 1989, and the award of distribution rights to other areas of Vancouver Island, Powell River and the Sunshine Coast to Vigas on February 20, 1989. Little progress was made during the course of the hearing with respect to any other deficiencies in the PCEC Application.

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On February 21, 1989 the Commission heard motions from Intervenors that the level of information available with respect to the third phase of the hearing was so deficient that the final phase could not be started. Following a communication by the Commission with the Ministers of Energy and Environment, the Ministers issued Supplemental Terms of Reference to the Commission on Friday, February 24, 1989. Those Supplemental Terms of Reference requested the Commission provide a Report and Recommendations on the first two phases of the hearing by March 14, 1989. The Commission panel sat for 17 days to hear evidence and argument on the first two phases of the hearing. The Interim Report of the Commission of March 14, 1989 responded to the Supplemental Terms of Reference.

On March 2, 1989, the Commission issued Order No. G-17-89 requiring PCEC to file specific information to fill gaps in the Applicant's Phase III evidence. That material was provided to the Commission on March 6, 1989 and the hearing of Phase III evidence commenced on March 9, 1989. The Commission sat for 13 days during the hearing of Phase III evidence and argument. The Commission made repeated attempts during the hearing to seek sufficient information on several important outstanding items. At the completion of the hearing the following major items remained outstanding:

1. The Inter-Governmental Binding Agreement.
2. Gas Supply Contracts with Producers.
3. Gas Sales Contracts with the Forest companies.
4. Wheeling Agreement between BC Gas and PCEC.
5. Gas Sales Agreements with Local Distributor Utilities ("LDC").
6. Gas Storage Agreement with Unocal Canada Limited ("Unocal").
7. Westcoast Incentive Tolls Agreement (subject to NEB approval).
8. PCEC/Westcoast Operating Agreement.

As a result of the foregoing, this Report and the Commission's conclusions and recommendations have been prepared with a focus on the evaluation of a range of assumptions and alternatives.

3

Because of the severe time constraints on all parties to the hearing, dictated by the project in-service date of September 1, 1990 and consequent requirement for a May 4, 1989 construction start, the Commission has been obliged to proceed under less than ideal conditions. Nevertheless, it has heard all the evidence of Intervenors and believes it has clearly identified those issues impacting the public interest.

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2.0 PROJECT DESCRIPTION

2.1 Project Structure

The physical description of the PCEC project and its capital costs have been discussed in detail in the Commission panel's Interim Report dated March 14, 1989. The review of the project in this report focuses on the financial assessment of the project as it has been structured by PCEC.

The project structure proposed by PCEC and the various incentives put in place by all parties related to this project result in an unusually complicated financial support system for the project. Figure 2.1 provides a schematic of the revenues and costs to the project along with the various project incentives that will be put in place at each stage of the project. The project concept is that end-use customers will pay market-sensitive prices at a discount to the cost of oil products currently being consumed in the market area. The Provincial Government will provide conversion grants to assist utility customers and the forest companies in converting their fuel burning equipment to natural gas.

Vigas is the distributor utility awarded the local distribution company ("LDC") rights to serve the markets on Vancouver Island and the Sunshine Coast. BC Gas retains its right to distribute natural gas in the Squamish area through its subsidiary company Squamish Gas Co. Ltd. ("Squamish Gas"). Vigas has entered into Agreements with the Provincial Government whereby the LDC has guaranteed its performance with respect to signing-up customers and maintaining an agreed-upon cost of service (Exhibits 84 and 85). Vigas has also committed to accept a lower return on equity ("ROE") during the initial years of the project.

The revenues available from the LDC and forest companies will flow to PCEC. PCEC has also committed to accept a reduced ROE during the initial three years of operations of the project. The Federal and Provincial Governments have committed to provide grants and

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FIGURE 2.1

PCEC Project Structure

Project Structure		Project Incentives
Forest Companies	Utility Customers	Government Conversion Grants Market Sensitive Pricing
	LDC	LDC Financial & Market Guarantees LDC reduced ROE
	PCEC	Government Grants and Loans Rate Stabilization Facility PCEC reduced ROE
	BC Gas Tolls	BC Gas Opportunity Cost Pricing
	Westcoast Tolls	Westcoast Incentive Tolls
	Producers	Flowback Pricing

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loans to reduce the capital cost of the project that PCEC would have to finance. The Provincial Government has also committed to provide a rate stabilization facility ("RSF") which will provide money to PCEC when there are inadequate revenues to meet the utilities' costs of service. PCEC assumed that the RSF would be refunded when residual revenues exceeded their cost of service.

The cost of transmission across the BC Gas system from Huntingdon to Coquitlam has not been agreed upon by the parties. However, the offer currently made by BC Gas provides for a reduced rate to PCEC compared to the fully-costed rates to other industrial customers.

Westcoast Energy Inc. ("Westcoast") intends to apply to the NEB for reduced tolls on PCEC volumes during the first three years of operations. These are referred to as the Westcoast Incentive Tolls.

The natural gas producers have been approached by PCEC on the basis that natural gas would be purchased at a minimum base price plus a potential for the flowback of extra revenues available from the project after all costs have been met and the RSF has been fully repaid.

It is clear from the foregoing that all participants related to this project are being expected to assist the project financially in its inception. Even the end-use customers can be seen as contributors, in part, to the project since their retail gas prices will be tied directly to the future cost of comparable oil products at a modest discount.

PCEC has stated that the project was designed to impose risks on those participants who will have the potential to be rewarded while largely isolating customers from risks inherent in the project. The greatest risks in the project clearly lie with the Provincial Government in the open-ended RSF and with the natural gas producers in the acceptance of the flowback pricing mechanism. Secondary risks exist for the Federal and Provincial Governments in the

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provision of capital grants and repayable loans. A lesser risk would be absorbed by the various utilities involved in the project through the reduced ROE in the early years and the financial and market guarantees provided by Vigas. Finally, PCEC and its sponsor partners are at risk to the extent of their equity contributions.

2.2 Project Financing

2.2.1 Assumptions in the Application

The total capital cost of the project was estimated at approximately $250 million with an in-service date of September 1, 1990. According to PCEC's proposal and the Statement of Principles, funds to cover the costs of the pipeline to start-up date would be provided by a combination of sponsor companies' equity investment and debt financing in the amount of approximately $75 million, with loans and contributions from the Federal and Provincial Governments for the balance of $175 million. In addition, the LDC's would commit to capital expenditures of approximately $140 million in distribution facilities; the Provincial Government would provide grants of $55 million for the conversion of fuel oil burning equipment to enable burning natural gas; and, the Provincial Government would establish an RSF up to a maximum of $70 million to ensure project viability during the early years. In total, each Government would provide support of $150 million to the project in either grant or loan form (see Exhibit 56, Schedule B of the Statement of Principles.)

The financial contribution of the sponsors was proposed to comprise $50 million external debt financing and an equity investment of $25 million, aiming towards a debt-equity ratio of approximately 65:35. This capital structure would mirror Westcoast's capital structure. While PCEC is expected to be a 50:50 partnership between Alberta Energy Company ("AEC") and Westcoast, evidence presented in the hearing indicated that PCEC is still 100% owned by AEC pending legal transfer of shares to Westcoast (T 3406).

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The sponsors would commit their contributions subject to a list of prerequisite permits and agreements, including an Energy Project Certificate ("EPC") (T 3464). Mr. Willms, policy witness for PCEC, testified that the project debt would be financeable, based on opinions from financial institutions, and that the signing of long-term industrial and utility gas supply contracts would strengthen project financeability.

2.2.2 Update of Financial Arrangements

Operational forecasts of financial performance presented by PCEC during the hearing proposed financial arrangements for the treatment of Government grants, repayment of Government loans and operation of the RSF which differ from the general description of financial arrangements in the Statement of Principles. Witnesses for PCEC testified that their version was thought to reflect the current intent of all parties to the Binding Agreement.

PCEC provided a summary of its assumed arrangements in comparison to those contained in the Statement of Principles (Exhibit 75, Tab 1) showing a different PCEC treatment in the repayment of the RSF. Furthermore, Mr. Willms explained that certain areas of financial arrangements between the Federal Government, the Provincial Government and PCEC, were likely to be modified, e.g. the RSF would be uncapped and, if necessary available for the full 20-year project period. In addition, eligible capital costs would only exclude overhead and interest accrued prior to the approval of an EPC. Mr. Willms maintained that, while there were areas still under discussion, any changes arising from these discussions were unlikely to dramatically affect project economics (T 3393-3397). An example would be allowing more flow-through in order to induce gas producers to sign-up long-term contracts by transferring some proposed RSF repayments to producer netback in earlier years. While the Statement of Principles is a statement of intent of the Binding Agreement, to this date the Binding Agreement has not been signed.

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3.0 MAJOR COMPONENTS OF PROJECT STRUCTURE

3.1 Markets

Two LDC's, Vigas and BC Gas will be providing natural gas service to marketing areas on Vancouver Island and several communities along the coastal mainland. BC Gas will serve the Squamish area and Vigas will serve the 28 communities listed in Table 3.1.

TABLE 3.1

Communities to be Served by Vigas

Campbell River	Gibsons	Powell River
Central Saanich	Ladysmith	Qualicum Beach
Chemainus	Langford	Royston
Colwood	Laslo/Little River	Saanich
Comox	Metchosin	Sechelt
Courtenay	Nanaimo	Sidney
Crofton	North Saanich	Victoria
Cumberland	Oak Bay	View Royal
Duncan/Cowichan	Parksville	
Esquimalt	Port Alberni	

Source: Exhibit 82, p. 8

Currently, the residential and commercial customers in the above communities operate principally on propane, LFO, electricity or wood. The LDC's have selected propane and LFO users as the target market.

There are two key elements in the marketing strategy; a competitive burner tip price and conversion grants. Assured price discounts in favour of natural gas are expected to provide a significant incentive for customers to convert and permit the distribution utilities a high degree of confidence in their marketing forecasts outlined in the following sections.

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3.1.1 Vigas

3.1.1.1 Burner Tip Price

Forecast burner tip prices have been based on the residential and commercial light heating fuel rate (in constant 1988 $) published on December 12, 1988 by the Ministry of Energy, Mines and Petroleum Resources ("MEMPR"). A 4% inflation factor was assumed to predict natural gas prices over the 20-year time frame based on discounts established in Schedule 14 of the Vigas Rate Stabilization and Disposition Agreement (Exhibit 85). This schedule shows a 15% discount in year 1, declining uniformly to a 10% discount in year 7 and remaining at 10% thereafter.

The customer population was broken down into two customer classifications:

Small General Service

Residential Market

- includes detached homes, trailers, multiple dwellings excluding apartment blocks

Small Commercial if less than 24,163 ft^2

Large General Service

Commercial

- includes office buildings, nursing homes, hotels, motels, apartments, warehouses, retail stores (T 3833).

An exception to this pricing mechanism is the rate to be set for large apartments currently purchasing fuel through oil-buying cooperatives. Initially the rate will be determined by negotiation with these associations and later may be made to converge with the current commercial formula.

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The final bill a customer pays is dependent not only on the burner tip price, but on the efficiency of heat transfer in his appliance. An efficiency adjusted price comparison of gas with competing energy forms was illustrated in Exhibit 117. It is obvious from this analysis that natural gas will have a strong presence in the space heating market. In both Small and Large General Service, the price advantage of gas over LFO in the early years is about 36% dropping to about 28% in the 20th year[1].

3.1.1.2 Vigas Market Study

The marketing study was prepared for service to the communities shown in Table 3.1, with the objective of establishing high, low and medium forecasts of consumption and demand over a 10-year time frame. It was assumed that most of the growth will occur over that period with the 20-year forecast being achieved by an extrapolation of the 10-year curve.

Two primary assumptions of the market analysis were that consumers currently burning wood or consuming electricity for heating would not be potential conversion customers and that the B.C. Hydro "Electric Plus" Program would be terminated in each community.

Initial market surveys were conducted in all communities to be served to identify concentrations of population, current building stock and heating consumption rates. This information provided a data base for existing conditions. New construction predictions were based on population growth forecasts developed from Statistics Canada data and on discussions with local community planning groups.

The capture rate for new customers was estimated to be the same in all service areas. Small General Service account capture was calculated at 50% in the first year and at 75% of the remaining
potential customers in all

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1 Furnace efficiency - natural gas = 75%, LFO = 65%

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subsequent years. Natural gas was assumed to be the energy of choice for all Large General Service accounts and a 100% capture rate was expected for this classification.

A conversion rate profile was developed separately for each community. This ranged from 2 to 5%/year in Qualicum Beach, to 10 to 15%/year in Powell River.

The final phase of the study applied heat conversion estimates to these accounts resulting in a consumption and demand forecast for the service area by year. A range of three forecasts was formulated and the results are displayed in Table 3.2. The "Low" forecast, although based on the 10% price differential, assumes that the marketplace will be reluctant to accept the attractiveness of gas as a primary heating fuel (T 3726).

TABLE 3.2

Vigas Forecast Sales Volumes (TJ)

Year	Low[1]	Medium[1]	High[2]	% Med to High
1	2802.9	2934.9	3058.1	4.2
2	4732.6	5119.2	5355.2	4.6
3	6750.6	7366.0	7894.0	7.2
4	8293.4	9110.1	10021.2	10.0
5	9140.6	10094.8	11244.3	11.4
6	9634.1	10653.8	11905.5	11.7
7	9988.6	11046.6	12416.1	12.4
8	10334.,0	11421.7	12825.4	12.3
9	10680.8	11796.6	13231.8	12.2
10	11023.2	12165.6	13638.3	12.1

1. Based on 10% gas price discount to LFO.
2. Based on 15% gas price discount to LFO in early years.

Source: Exhibit 82A and Exhibit 116

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3.1.1.3 Vigas Marketing Program

Vigas will embark on a marketing campaign which has four features: an appliance financing plan, furnace rebate program, rental arrangements, and conversion subsidies.

Financing will be offerred up to 85% of the cost of purchasing and installing appliances. The interest rate will be set at 1% over current rates for mortgages of equal term between one and three years.

Customers will have the option of entering into a long-term rental agreement for furnaces and hot water tanks.

Vigas intends to sell medium efficiency furnaces (estimated at 75%) with promotional discounts from manufacturers in the range of 15-25% off the retail price. Even with this discount the expected shortfall in conversion cost will be about $450, with a five year payback period (see Table 3.3).

TABLE 3.3

Conversion Grant Calculation
Vigas Service Area

	Light Fuel Oil ("LFO")	Natural Gas ("NG")
Efficiency Adjusted Rate	$13.37/GJ (60% Eff.)	$9.63/GJ (75% Eff.)
Consumption	60 GJ	60 GJ
TOTAL BILL	$802.20	$577.80
Savings		$224.40
Savings Over 5 Years		$1,122.00
Furnace Cost		$2,100.00
Grant Required - no furnace discount		$978.00
- 25% furnace discount		$453.00

Source: Commission Staff

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Maximum conversion subsidies of $700 for residential customers and $1,000 for commercial customers will be made available for the first five years.

3.1.2 BC Gas

3.1.2.1 Burner Tip Price

BC Gas has based its Squamish market forecast on a crude oil price of $18 (U.S.)/bbl and gas at a 10% price discount to LFO, with both assumed to escalate at 4%. In the residential sector the price advantage of gas over LFO ranges from 30-40% while in the commercial sector the price advantage ranges from 15-20%.

3.1.2.2 BC Gas Market Study

The Market Study was conducted in three phases to develop the total 20-year market projection. The first phase was made up of an initial customer count and a forecast of potential customers not currently served by the existing propane grid system. This was based on a forecast of future population growth prepared from "Municipal Statistics" 1986 census data supplemented by information from the Central Statistics Bureau of the Ministry of Environment. These two sources provided a data base for present and future customer expansion in areas where distribution mains were expected to be placed.

Inland Natural Gas Co. Ltd.'s ("Inland's") historical capture rates were applied to forecast information on new construction. Similarly, Inland's conversion rates were applied to existing dwellings using alternative energy. "Use per customer" consumption levels were applied in the final phase to achieve the consumption forecast shown in Table 3.4.

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TABLE 3.4

BC Gas Forecast Sales Volumes (TJ)

	Residential	Commercial	Total
1990	64	156	221
1991	74	159	233
1992	83	161	245
1993	92	163	255
1994	100	164	265
1995	109	166	275
1996	118	168	286
1997	127	170	297
1998	136	172	308
1999	145	175	320
2000	153	177	330
2001	162	179	341
2002	169	180	349
2003	177	182	359
2004	184	183	367
2005	190	184	375
2006	196	186	382
2007	202	187	389
2008	208	188	396
2009	213	189	402

Note: Residential Average Use = 90 GJ/yr.
Commercial Propane Conversion = 889 GJ/yr.
Commercial New Customer = 400 GJ/yr.

Source: Exhibits 101 and 102
(Exhibit 101 adjusted for error in Commercial account addition.)

Overall, the market projections in Table 3.4 are very close to those contained in the independently produced Canadian Resourcecon Report (Exhibit 25). Although the first year difference between the two predictions is 52 TJ the cumulative total separation in year 20 is only 14 TJ or 3.5% from the BC Gas forecast.

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3.1.2.3 BC Gas Marketing Program

Residential conversions are expected to be to mid-efficiency natural gas forced-air furnaces with an efficiency rating of about 80% (Exhibit 102, p. 2). To assist in this conversion, BC Gas is prepared to offer financing to residential conversion customers at a rate of prime plus 4%. It is assumed that unless the payback for conversion is less than five years, residential customers would not take up the option and a grant in excess of $900 per customer will be required to make up the difference (Exhibit 102, p. 4). A current propane customer, on the other hand, would require a much smaller grant of about $100 (Exhibit 102, p. 4).

3.1.3 Industrial Market

Seven pulp mills currently make up this market sector. Their locations, and the loads they are expected to generate, are shown in Table 3.5. The displacement of HFO by natural gas will require about 10,934 TJ of energy per year. The load forecast maintains this consumption level over 20 years of the project life although, as a proportion of the total load, it declines as residential and commercial load builds. The industrial load declines from approximately 75% in year one to about 35% in year 20.

These loads are principally affected by the newsprint side of the industrial operation. Although currently this section is running at 100% of plant name plate capacity, a downturn in production is not expected to result in a drop in load, rather, it is expected to be replaced by additional new capacity. Effectively, there is not expected to be any change in consumption (T 3888). As energy costs rise, energy conservation will reduce demand but this again is expected to be replaced by capacity additions, thus maintaining the projected load at about current levels (T 3889-3890).

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The industrial load factor is expected to be about 87.5% if the mills nominate firm gas volumes at twice the fuel requirement of their kilns (T 3872).

Vigas stated that it believed it had the right to develop and serve new industrial loads within its franchise area in order to diversify its customer base and provide for the possibility of peak shaving through industrial curtailment (Exhibit 116, p. 14). There is a possibility that future industrial loads may come on-stream on Texada Island in the Vigas service area and at Britannia Beach in the BC Gas - Squamish service area.

TABLE 3.5

Industrial Load Forecast

Company	Location	1992 Annual Fuel Use (bbl's)	Estimated Natural Gas Consumption (TJ)	% Load
Fletcher Challenge	Crofton	272,667	1,865	17.0
Fletcher Challenge	Elk Falls	70,000	479	4.4
Howe Sound Pulp & Paper	Port Mellon	153,000	1,046	9.5
MacMillan Bloedel Ltd.	Harmac	226,400	1,548	14.1
MacMillan Bloedel Ltd.	Port Alberni	219,500	1,501	13.7
Western Pulp Limited Partnership	Squamish	226,407	1,548	14.1
MacMillan Bloedel Ltd.	Powell River	435,250	2,976	27.2
		1,603,224	10,934*	100.0

Source: Exhibit 118, individual mill estimates, from COFI to PCEC.
* Conversion @6.838 GJ/bbl adjusted for 365 days (T 3883).

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3.1.4 Commission Conclusions

Because of the proposed 15% starting price discount, the Commission believes the Vigas "High" forecast is within reasonable expectations and the Commission has adopted this forecast in preparing its base case financial projections in Section 4.0.

Considering the closeness of the independent Canadian Resourcecon and BC Gas forecasts the Commission believes that the Squamish Gas forecast loads are suitable for use in the financial projections. This load represents only about 7% of the total LDC market in the first year.

The Electric Plus Program, future expectation of low electric prices,* and the heating oil supplier's initial defensive reaction to natural gas in its traditional markets may all have a negative impact on the Vigas market projections. The Electric Plus program is expected to be phased out by the end of 1989 (T 3731). Competitive reaction by LFO suppliers is unlikely to be sustainable in other than the short-term. There remains some concern that, in the event of high oil price escalation, electricity may become the competitor fuel for natural gas.

The Commission has adopted the loads forecast in Exhibit 109 adjusted for the difference between purchase gas and sales gas in its financial projections in Section 4.0. This exhibit is based on the Vigas high forecast, the BC Gas forecast shown in Table 3.4 and the Industrial forecast shown in Table 3.5.

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* Future expectation of continued low electric rates is likely diminished by recent Provincial Government announcements following the March 30, 1989 budget.

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3.2 Peak Shaving Requirements

3.2.1 PCEC Position

The PCEC pipeline was not designed to deliver the total system gas requirements on the coldest days of the year. As with other pipeline systems, PCEC expects to curtail industrial customers and have the LDC minimize its demands on the transmission utility on those coldest days.

If the LDC is to provide peak shaving,* the pipeline can be designed to a smaller size to reflect the reduced demand conditions. On the other end of the line, an improved system load factor** would allow PCEC to attain better prices from producers.

PCEC originally proposed to meet a 50% load factor (Exhibit 7, Tab 2) but this was later revised to a 45% level (T 2801).

PCEC based this decision on two analyses:

- The Pacific Northern Gas ("PNG") load curve was examined, after removing company-use gas and small industrial consumption. This resulted in a load factor determination of about 45% for the PNG system (T 2801-2802).

- B.C. Hydro presented an exhibit in the 1982-1983 hearings (Exhibit 93) which showed interruptible, firm, send-out and contribution of peak shaving facilities to the overall gas load profile. Since this information resulted in a load factor of 39.5%, it was concluded that a 45% load factor was appropriate for Vancouver Island service (T 2801-2803).

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* Peak Shaving is the use of a supplemental supply of energy to augment normal pipeline supplies during peak demand periods of relatively short duration.

** Load factor is the average daily requirement divided by the maximum daily requirement stated as a percentage.

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In the case of the industrial customers, PCEC assumed that the various mills would require firm natural gas service without any curtailment to the lime kilns. PCEC estimated the non-curtailable load to be 18 TJ/day and included this in their design criteria.

The PCEC methodology was attacked by various participants at the hearing as being simplistic and generally a step back from the demand/commodity pricing concepts that have developed in recent years. It is generally conceded that the demand/commodity method of pricing provides appropriate economic signals to all parties so that peak shaving will occur at various points of the pipeline system to the extent that it is economically viable to do so. However, PCEC argued that their methodology would induce the LDC's to improve their load factor under the gate station pricing scheme and that the 45% load factor stipulation was a proxy for the economic allocation of peak shaving requirements on the system.

3.2.2 BC Gas Position

BC Gas considered -15^{O}C as an appropriate design day temperature for Vancouver Island and the Sunshine Coast so that a 30% load factor was recommended for the project (Exhibit 101). A level fixed at 45%, as with any fixed level, fails to provide the correct economic pricing signals from producers and transporters of the gas to the distribution utility and the consumer.

BC Gas had four recommendations (Exhibit 101, p. 5-6):

- The PCEC pipeline should be sized initially to deliver full residential and commercial peak demands as future capacity may be very expensive to acquire.
- Industrial customers should be converted to dual fuel systems so that full interruption is feasible.

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- PCEC could improve its load factor on the Westcoast system in later years of the project by obtaining gas across the Inland system, using possible Fraser Delta underground storage or expansion of Liquified Natural Gas ("LNG") facilities.

- BC Gas proposed that peak shaving for Squamish could be accomplished through peak shaving in the Lower Mainland area.

In summary, BC Gas stated that it was possible to achieve a 45% load factor in the Squamish service area by converting the existing propane plant to a propane-air peak shaving facility. The addition of air compression and blending equipment would cost $260,000 and existing propane facilities would be retained in the Squamish Gas cost of service (Exhibit 101, p. 3). However, the utility proposed that if the pipeline design permitted, peak shaving should be accomplished in the Lower Mainland area (Exhibit 101, p. 6).

3.2.3 Vigas Position

Vigas expected its load factor would fall in the range of 22% to 36.5% in normal year weather and be between 19% and 31.5% in extreme cold conditions. A 45% load factor would limit the maximum daily take from the pipeline to about 80% of the peak required in a normal year and 70% in a cold year (Exhibit 117, p. 7).

Vigas considered the 45% load factor to be an arbitrary number which did not reflect the extreme temperatures on the Island (T 3700-3701). In fact, when the Agreement for their service area was negotiated with the Provincial Government, Vigas assumed the industrials would be 100% interruptible and no provision for peak shaving was included in the Agreement (T 3783-3787). As capital costs were not included in rate base until a desired ratio of capital expenditures to volumes was reached, the cost of service was effectively capped. The contract would have to be reopened to address capital costs for peak shaving equipment, otherwise, Vigas would have a strong motive to pass these costs onto the RSF (T 3789-3790).

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Vigas emphasized that it had little opportunity to improve its load factor without the advantage of large industrial load customers. In a few isolated circumstances it would be possible to interrupt large commercial customers, but this would be expensive as customers will want to be compensated for their costs of dual fuel capability by lower energy costs (Exhibit 116, p.9). This discount was estimated to be about $1.50/GJ (in Exhibit 140) with accompanying lost revenue when the interrupted customer goes on alternative fuel.

Vigas contended that since PCEC intends to pressurize the transmission pipe to 2,000 psi, it would be impossible to put propane in the transmission line. In order to maintain propane in vapour form, it would have to be superheated. The pressure to the mills however, is proposed to be 250 psi which is a more suitable level for propane injection and propane peak shaving facilities could be provided at these locations (T 3696-3697). The LDC would supply the load serving the lime kilns with propane in the winter months, based on the assumption that the kilns can be operated on propane. If the logistics of transportation, placement of the peak shaving facility and arrangements with the mill can be worked out, this would be a viable alternative. However, the displaced load only meets the system demands between a normal and extreme cold day (T 3844).

In Exhibit 140 Vigas confirms that the displacement of lime kiln volumes and interruption of large institutional and commercial customers (hospitals and Department of National Defense at Comox) would not be sufficient to provide peak shaving requirements to meet the 45% threshold during extreme temperature conditions. Additional propane-air facilities costing between $26 million and $32.6 million would have to be built and would entail peak shaving installations at some 26 sites throughout the service area (Exhibit 140, p. 8).

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3.2.4 Commission Conclusions

Insufficient evidence was advanced during the hearing to permit the Commission to form any conclusions on peak shaving. In its normal regulatory role under Part 3 of the Utilities Commission Act, the Commission will have to work with both the LDC's and PCEC in the coming months to finalize the most economic method of peak shaving so as to minimize the overall cost of the system and the draws made on the RSF. In the current absence of sufficient facts to determine this issue, the Commission offers the following general views to assist the Government in analyzing the economics of the project.

Natural Gas Peak Shaving

The ideal method of peak shaving is to have LNG storage or underground storage of natural gas near or downstream of the market to be served. This option is not currently available to Vigas and is discussed further in Section 3.8.

Conversion of Lime Kiln Load

From Exhibit 116 it is clear that conversion of the lime kiln load to propane or propane vapour would increase the extreme peak day load factor to about 36.7% in year 10. The financial runs undertaken in Section 4.0 have included Commission estimates of the costs for providing propane-air facilities to supply the lime kiln loads at all mills.

Interruptible Rates

Interruptible rates could be offered to industrial and institutional customers to induce them to maintain their existing oil burners and oil storage that would be used during a curtailment period.

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Propane-Air Plants

Propane-air plants can be constructed by the LDC's to inject propane into the natural gas stream on the coldest days so as to meet all the residential and commercial loads while not increasing the LDC's requirement for natural gas. The cost of the propane-air plants must be compared with the additional cost that would be incurred to increase the pipeline service itself. These costs include: the increased nomination on the Westcoast system, increased gas supply costs (including storage), the costs of advancing compressor additions on the PCEC system, increased operating costs to PCEC, and finally the potential increase in costs for wheeling gas across the BC Gas system. Insufficient information exists to determine this matter definitively now. The Commission would anticipate working with PCEC and the LDC's to resolve this matter outside of the hearing process. This matter is dealt with further in the Commission's recommendations in Section 6.0.

In assessing the financial impacts of peak-load requirements on the Commission's determinations in Section 4.0 of this report, the Commission has assumed in its base case that the LDC's would be able to maintain a load factor of 40%. The pessimistic case assumes the LDC's would be able to maintain a load factor of 35% by peak shaving the lime kiln loads. In the optimistic financial assessment the Commission has adopted the PCEC proposal that a mandated 45% load factor be maintained.

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Therefore, with respect to the additional costs of peak shaving, the Commission's financial cases have included the peaking costs required to meet the assumed load factors. To meet the pessimistic case load factor of 35%, the Commission has included $6 million of capital cost into the Vigas cost of service projection to allow for peak shaving the lime kiln load. The Commission's base case allows for an initial capital expenditure of $15 million plus about $200,000 annually to approximate the LDC cost of service for peak shaving to a 40% load factor. In the Commission's optimistic case, the addition to the Vigas estimates is $30 million to allow for peak shaving to a 45% load factor.

The Commission has also considered the timing of propane-air plant addition. The load profile of the project and the incentive rates from Westcoast are such that these plants can be added to the system in year 3.

3.3 Cost of Service

3.3.1 BC Gas

This utility operates a propane distribution grid serving approximately 900 customers in the Squamish area. The Company was purchased by Inland from Superior Propane Ltd. in 1987. In Exhibit 102, the Company provided its initial 20-year forecast on load growth, rate base and cost of service. The latter were developed based on current experience plus a general 4% cost escalation. Capital cost reflected an abandonment of the existing propane plant and the assumption that PCEC would provide all required gas based on Squamish Gas forecast load factor.

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A revised submission (Exhibit 101, Appendix A) was provided reflecting the retention and upgrading of the propane plant for peaking purposes in response to PCEC's assumed load factor of 45% for LDC gas supply. Cost of service therefore would increase slightly resulting in lower gate prices. These gate prices would be further lowered if the discount were adjusted to 15% relative to fuel oil prices in the initial years, declining to 10% in later years parallel to the assumptions of Vigas and PCEC.

The Commission believes that Squamish Gas has reasonably forecast its cost of service associated with the market resulting from natural gas supply in the Squamish area and will incorporate such information in the financial and market analyses.

3.3.2 Vigas

Vigas is a subsidiary of Inter-City Gas Corporation which distributes natural gas across Canada and in the United States. In February 1989, Vigas purchased the Victoria propane-air distribution system from B.C. Hydro and was awarded distribution rights for communities on Vancouver Island and the Sunshine Coast. It currently operates a propane distribution system in Nanaimo with approximately 1,200 customers.

In Exhibits 82 and 82A, Vigas provided market and cost of service forecasts with high, medium and low market penetration scenarios. In developing the medium scenario, the utility adopted a gas price based on a 10% discount in relation to the price of LFO. The Provincial Government has now set the discount at 15% for the first two years, declining to 10% in later years. As a result, Vigas believes that it can achieve the volumes illustrated in the high scenario, and that this should be viewed as the most likely case.

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Vigas' forecast did not use deferral accounts to mitigate the impact of the relatively high cost of service on the RSF in earlier years of the project. The forecast was prepared on a stand-alone basis. Debt cost, equity component and rate of return are in accordance with the LDC agreements with the Provincial Government. Other cost of service components were developed based on Vigas' experience on Vancouver Island. Vigas forecasts a capital investment of $191 million over the first 10-year period. Sales volumes and revenues were based on Vigas' own forecast load factor with no provision for peaking services.

The forecast gate prices available to PCEC in the first two years were below the $2.00/GJ minimum assumed by PCEC in its original Application. This minimum requirement was withdrawn by PCEC in later analyses as shown in Exhibit 87.

In response to a Commission staff request, Vigas provided Exhibit 140 outlining its peak shaving alternatives in the event it would be required to meet the 45% load factor requirement imposed by PCEC. The cumulative gate revenue available to PCEC as a result of the higher cost of service required to meet the higher load factor would be reduced by $233 million or 15%, from Vigas' original forecast (Exhibit 82, Schedule 10-4) over the 20-year projection period. However, the impact on gate prices will be much greater in earlier years, ranging from a 60% lower price in year 2 to 11% reduction in year 20.

The Commission believes that Vigas' cost of service projections, contained in the medium scenario referred to in the LDC agreement with the Provincial Government, should be used in the pessimistic case scenario for the analysis of PCEC's financial performance. The high Vigas scenario should be viewed as the base case in analysing the economic viability of the Vancouver Island gas pipeline.

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3.3.3 PCEC

The Commission's Terms of Reference require it to "review and assess pro forma financial statements, rate base, and cost of service estimates for the period 1990 through 2010 and the assumptions used in their preparation." PCEC in its Application (Exhibit 8) detailed its initial assumptions with respect to project costs, sales volumes and revenues, Government grants and loans, debt and equity financing, cost of gas and associated transmission and storage costs, and other cost of service components.

The following are revised treatments of the above assumptions proposed by the Applicant during the hearing. Many have the effect of lowering the cost of service in the earlier years of the project and more closely reflect the current status of discussions on outstanding agreements.

Depreciation

PCEC proposed in its initial submission to write-off the cost of land rights as depreciation expenses. Since the standard depreciation schedule approved by the Commission does not make allowance for land rights depreciation, PCEC revised the above provision to reflect normal Commission practice. The result is reduced depreciation expenses.

PCEC excluded the value of assets represented by the repayable Government loans of $75 million from depreciable assets resulting in reduced depreciation expenses in the period prior to repayment. This is a desirable treatment of the repayable grant.

PCEC proposed to depreciate half of the plant additions made during the year, but the Commission System of Accounts allows depreciation based only on each year's beginning balances. PCEC revised the above provisions to conform to Commission practice resulting in reduced depreciation expenses in the same period.

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Interest and Return on Equity

PCEC provided its forecast interest expenses, capital structure and return on equity in Exhibit 8, Tab 1, p. 4. PCEC in Exhibit 74 revised its original forecast interest rate from 10.5% to 11.5%. In order to improve early year project performance PCEC also proposed lower returns on its common equity in earlier years of the project: 10.5% in the first year rising to 14% in the third year. From year 4 forward, normal treatment would ensue. PCEC estimated the ROE for years 4 to 20 to be 14.5%.

Corporate Taxes

In response to a Commission Information Request, PCEC amended its tax rate of 42.59% to 42.84% [Exhibit 20, Tab 3, c. 2.1(v)]. As in the calculation of depreciation in the initial Application, PCEC deducted the $75 million repayable Government loan from Undepreciable Capital Cost in determining Capital Cost Allowance for Income Tax calculation. Section 13(7.1) of the Income Tax Act specifies that only forgivable loans and grants need to be deducted for such purpose. PCEC revised its Capital Cost Allowance calculations in its later versions of the financial model resulting in lower Income Tax expenses in earlier years of the project.

O & M Costs

PCEC provided details by cost elements [Exhibit 20, Tab 3, 2.1 (vii)]. These costs were escalated by 4% to reflect price level changes during the 20-year period and based on operating experience of Westcoast in pipeline operations. The details are to be contained in an operating agreement that has yet to be finalized between Westcoast and PCEC. The costs forecast by PCEC appear to be reasonable for normal pipeline operations, and the Commission accepts these costs for financial analysis purposes subject to the above agreement being scrutinized by the Commission in its future reviews.

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Property Taxes

PCEC assumed that no property taxes would be levied on the pipeline in the first three years. Intervenors disputed the validity of such assumption, with the result that the impact of property tax payment was tested in some of the sensitivity analyses of the financial model.

3.3.4 Cost of Service Optimization

As required by the Terms of Reference, the Commission and the hearing participants examined alternative ways to enhance project economics and feasibility. Exchange of information between PCEC and Commission staff prior to the hearing revised certain financial assumptions as described in Section 3.3.3.

In addition, PCEC assumed that the RSF would be repaid first, before Government loans were repaid; this however would be contrary to the financial arrangements described in the Statement of Principles. PCEC also assumed loan repayments would be made in the following year rather than in the current year, as the cumulative surplus reached specified amounts. The impact of the above assumptions was to delay the buy-back of assets resultant from refinancing Government loans, thereby maintaining rate base at lower levels and reducing cost of service in the earlier years.

Financial witnesses for COFI suggested that depreciation is the rate making mechanism for recovery of capital, and proposed that the sponsors should defer depreciation expense until the RSF had been fully repaid (Exhibit 123). This method would improve early-year flow-through to producers and at the same time would reduce the draw on the RSF.

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The COFI witnesses suggested that the project could be financed on the basis of 75% debt and 25% equity, since project risk would be significantly reduced by existence of the RSF. A higher debt ratio would also reduce cost of service and improve overall project profitability.

The response of PCEC as shown in Exhibit 73, item 1, indicates that lowering costs in earlier years will eventually increase total project costs over its life. The Commission, after exploring conceivable methods to enhance project economics such as deferral of depreciation, higher debt to equity ratio, lower allowed returns, etc., accepts PCEC's position and is satisfied that a reasonable balance between short-term gain and long-term cost has been achieved in the proposal submitted by PCEC and amended as described in this section.

3.4 Gate Station Revenue

The gate station revenue to PCEC is to be the result of subtracting the cost of service of each LDC from the total revenue of each distribution utility. The PCEC revenue will vary with both the size of the market and the components of the LDC cost of service. Including peak shaving facilities in the LDC cost of service, for example, will decrease the gate station revenue available to PCEC. As Exhibit 22 shows, the ultimate impact of all project shortfalls will be on the RSF and on the gas supplier (see Figure 4.1, p. 50).

Vigas stated that according to the "Vigas Rate Stabilization and Disposition Agreement" it is possible for the gate station price to the LDC to become negative. In that event, the RSF would compensate the LDC's cost of service. The utility would continue to earn its rate of return subject to the restrictions on costs and volumes provided for in the Agreement (T 3851-3852).

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3.5 Industrial Revenue

Agreements between PCEC and the seven mills remain unresolved at this time. The proposed contract pricing formula develops a value for gas based on the price of heavy fuel oil of the same quality and specifications which the industrial customers are currently able to use. The effect of recently announced government regulations on sulphur content must also be factored into the equations. As the proposed contract allows the distributor of the gas the right of curtailment to maintain a high system load factor, the industrial client is also required to maintain dual fuel burning capability. These items, which affect the PCEC revenues also remain to be settled in negotiations.

3.5.1 Price

The proposed pricing formula depends on six factors that determine natural gas prices equivalent to low or high sulphur heavy fuel oil purchased in Los Angeles and transported to the coast of British Columbia. Currently, negotiations between PCEC and COFI have not settled the appropriate freight charges, conversion factor (to equate the price of high sulphur residual fuel oil in Los Angeles to the West Texas Intermediate crude price) or the conversion factor that equates barrels of oil to gigajoules of gas.

The sulphur content of displaced fuel oil also remains an outstanding issue between the Provincial Government and the four plant owners. It has been the industry's position with MEMPR that natural gas would be considered provided that there was no net cost increases (T 3954) and that an equivalent price did not factor in a low sulphur content. The sulphur content of the oil that the mills had been using averaged 1.35% in 1988 (T 4118). However, on Monday, March 20, 1989, the Ministry of the Environment stated that the sulphur content of heavy fuel oil was to be limited to 1.1%. This amounts to a premium of $2.00/bbl at least and this amount has been included in the Commission's financial analyses.

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3.5.2 Agreement

Curtailment

Natural gas has a lower calorific content than HFO which poses a particular problem to lime kilns if required to change fuels. Therefore the mills propose to exclude the kiln load of 13.75 TJ/d from curtailment and to limit other curtailment to five days per year. This seems appropriate in their opinion given other mills in the interior have similar curtailment restrictions (T 3873-3876).

According to Exhibit 109, PCEC proposes to provide the industrials with a curtailed load down to 18 TJ/d, over the 20-year forecast period, or 4.25 TJ/d over their requirement for kiln supply. The total annual curtailment actually drops from 275 TJ in 1991 to 168 TJ in 2010. This occurs as a result of the industrial load decreasing in proportion to that of the LDC. As the poorer LDC load factor comes to dominate the total supply, PCEC is required to increase its nomination level, thus reducing the industrial curtailment level (T 3902-3903). The Commission concludes that the curtailment of all of the mill load, except kiln requirements, is reasonable.

Dual Fuel Capability

To maintain dual fuel capability at each plant the industrial customers will be required to store more fuel than is currently necessary. On the average, incremental storage will cost about $136,000/mill. The mills want some recognition of this requirement in rates (T 3876). This matter has not been concluded and the Commission has made no allowance for it in its financial analyses.

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Term of Contract

The mills are prepared to enter into purchase contracts that match the term and security of natural gas supply probably in the range of 10 years (T 3955). PCEC, however, wants the term defined as the greater of either ten years or the retirement of the RSF and Federal and Provincial loans (T 3955). Under some scenarios that could conceivably extend up to 20 years. The Commission concludes that the agreement should be for the length of 10 years or until the RSF and government loans are repaid.

"Most Favoured" Nation Clause

COFI wishes to ensure that future industrial customers are treated no better than the mills. The Commission believes this is only reasonable except in cases where alternate fuel availability reduces the competitive position of natural gas.

3.6 BC Gas Inc. Wheeling Agreement

PCEC made two Applications to the Government for EPC's. The principal Application assumed that PCEC would negotiate a wheeling agreement with BC Gas to transport natural gas across the BC Gas system from Huntingdon to Coquitlam. An alternative Application was supplied which would have PCEC initiating its transmission system directly from the Westcoast gate station at Kilgard. PCEC asked that the alternative Application not be considered by the Commission and has pursued the negotiation of a wheeling agreement with BC Gas.

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Throughout the hearing PCEC maintained that they were very close to completing a wheeling agreement with BC Gas. Representatives from both parties stated that negotiations were progressing and agreement had been attained on all matters except for price. However, the two parties are widely apart in their price assumptions. PCEC has offered to pay a rate of approximately $2 million in year one of the project, rising to nearly $3 million in year 20. The BC Gas proposal, based on PCEC's avoided cost, assumes rates of approximately $4 million in year one rising to $4.3 million in year 7, and remaining constant thereafter.

Unfortunately this agreement remains uncompleted. The Commission understands that the PCEC proposal is based on their assessment of the incremental costs that BC Gas would incur to wheel the gas, while BC Gas methodology reflects the philosophy of the bypass legislation adopted by the Provincial Government. It also reflects the positions taken by the Commission that utilities such as BC Gas may discount their rates from full cost rates to those industrial customers who have an alternate fuel or other option. Any discounted rates must cover at least the variable costs of the utility and must be approved by the Commission.

The Commission recognizes that any eventual agreement between the parties must be accepted by the Government in the case of BC Gas, and by the Commission in the case of PCEC. Therefore, if the parties continue to be unable to resolve their differences, the Commission will need to become involved at some point. For the purposes of the Commission's financial runs in Section 4.4 of this report, it has used the BC Gas offer contained in Exhibit 75 for the purposes of its pessimistic and base case runs. The Commission has adopted the PCEC estimates in its optimistic scenario.

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3.7 Westcoast Transportation Tolls

Westcoast proposes to assist the Vancouver Island natural gas pipeline by offering incentive tolls in the first three years of operations. Westcoast intends to apply to the NEB for approval of the incentive tolls as part of its rate filing to be made in the spring of this year. The proposal is that PCEC be offered a discount of $0.25/GJ in the first year of operations, $0.20/GJ in the second year and $0.15/GJ in the third year.

Mr. Maas of Westcoast testified that the reduced tolls would be beneficial to all existing customers on the Westcoast system since the load would be incremental to existing loads and could be accommodated in the first three years without requiring new capacity additions to the Westcoast pipeline. He argued that because the incentive tolls would recover substantially more than the variable cost incurred by Westcoast, the incremental sale would therefore benefit everyone. This view was supported by BC Gas representatives who noted that Inland had received assistance from Westcoast in the initial years of its distribution service.

Other participants at the hearing, notably the Independent Petroleum Association of Canada ("IPAC"), were concerned that a discount from the fully-costed tolls of Westcoast could be interpreted as a subsidy from existing shippers on Westcoast to the PCEC project.

In argument PCEC encouraged the Commission to enlist the intervention of the Provincial Government before the National Energy Board ("NEB") in support of the incentive tolls.

The Commission has considered the positions taken by each party on this matter and generally supports the notion that if the PCEC load increment in the early years of operation can be accommodated within the existing system capacity of Westcoast, then a potential exists to discount the tolls to PCEC without harming any existing shippers

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on the Westcoast system. So long as the incentive toll covers the variable costs of Westcoast, plus the cost of service for any modifications to accommodate the incremental load, PCEC will at least contribute a rate which will not cause the tolls of other shippers to rise. Over the longer run the development of the Vancouver Island load will benefit all parties.

While holding the above views, the Commission concurs with IPAC to the extent that existing shippers on the Westcoast system should not be expected to contribute direct subsidies to the development of the PCEC system. The Commission views a direct subsidy as being an increase in tolls to existing shippers above that which they would have paid had PCEC not been on the system during the initial three-year period. In this regard, the Commission notes the evidence of Mr. Willms of Westcoast that Westcoast shareholders would not be inclined to support the incentive tolls through a reduced return on equity. If Westcoast is not prepared to provide a direct subsidy to PCEC, it should not expect its existing shippers to provide that subsidy either.

The matter of the incentive tolls must be decided by the NEB. For the purposes of its financial runs the Commission has included the three-year incentive tolls in both base and optimistic cases. In the Commission's pessimistic financial assessment it has assumed that fully-costed tolls of Westcoast would be applied.

With respect to future tolls from Westcoast after the incentive period, PCEC assumed that rates would remain constant at current levels. PCEC witnesses noted that rates since 1981 had actually fallen 7.5% per annum in real terms. This testimony was discounted by other evidence pointing to the large drop in export sales in 1980/81. In final argument PCEC set the upper boundary of price increases at 2% per year. Vigas speculated that Westcoast tolls would rise about 3% per year.

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The Commission does not foresee Westcoast tolls rising until new facility additions are required. This is unlikely to occur during the three year incentive toll period. In the future when an ethane extraction plant or new sales to the United States require facility additions, tolls will rise.

In the Commission's base case it is assumed that fully-costed Westcoast tolls stay constant until 1994, and then escalate at 3% per year. The pessimistic case has rates rising with inflation from year one. The optimistic case assumes that rates stay constant into the future.

It is noteworthy that the financial impact of the Commission's base case assumption is small compared to the PCEC estimate that rates could go up by 0-2% per year from the initial year. If the Commission's base case assumption is conservative the positive impact on the RSF would be about $2 million.

3.8 Natural Gas Storage

In order to purchase its gas supplies at an attractive, high load factor PCEC intends to contract with Unocal for storage in Unocal's Aitken Creek storage field. PCEC estimated they would be able to contract for that storage at a cost of $0.55/Mcf for the first 10 years of the project. Negotiations have not been concluded with Unocal.

The Commission demanded further information on this matter in its Order No. G-17-89. The response provided by PCEC to the hearing (Exhibit 75) included letters from Unocal dated April 14, 1988 and March 3, 1989. The most recent letter stated that "Unocal is prepared to provide storage space at an initial demand charge of $0.55 to $0.60/Mcf based on a flat delivery profile extending over a 150 day delivery period. The actual cost at the time this project commences and the cost in subsequent years will be determined using this base cost adjusted by an escalator which is yet to be negotiated".

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In response to an Information Request by Vigas (T 3101), PCEC filed Exhibit 124. That exhibit responded that Unocal's most recent position was that the $0.50 to $0.60/Mcf price was a mixture of fixed costs based on peak day demand and operating costs based on actual amount of gas withdrawn. PCEC noted that they would again meet with Unocal on April 5, 1989.

At this point, PCEC does not have an agreement with Unocal with respect to the price for storage, the amount of storage to be used, or the method of withdrawal. Unocal had proposed that withdrawals occur on a flat delivery profile, but PCEC has assumed fluctuations in deliveries to match its demand profile. In the absence of any commitments with respect to this natural gas storage, the Commission has assumed that, for the purpose of its base case financial run, the cost of storage would be $0.55/Mcf in year one of the project, escalating thereafter at the general inflation rate. The Commission assumes that PCEC may withdraw natural gas to smooth its load profile as required, rather than on a flat delivery profile. The Commission's pessimistic case assumes the initial storage cost to be $0.60/Mcf escalating at inflation. The optimistic case adopts the PCEC proposal that storage be at $0.55/Mcf during the first 10 years of the project, escalating thereafter at inflation.

The availability of storage is integral to the gas contracting plans of PCEC. Any conditions attached to an EPC related to gas supply must also apply to natural gas storage.

While storage at Aitken Creek would assist PCEC in increasing its load factor of natural gas purchases, it is unfortunate that this storage is located at the upper end of the Westcoast system rather than in closer proximity to the PCEC markets. The Commission heard testimony that wells drilled on Vancouver Island in recent years had been unsuccessful and Mr. de Grasse of Vigas testified that it was unlikely that underground storage would be found on Vancouver Island. Other natural gas storage

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facilities located downstream of the Westcoast system include the LNG plant owned by BC Gas and storage fields located in Washington State. Those facilities are currently dedicated to BC Gas customers, but Vigas noted that the existing storage contracted by BC Gas in Washington State could come up for renegotiation in the next few years. BC Gas provided other evidence that there could be a potential for the development of underground natural gas storage in the Lower Mainland if a suitable structure could be found.

In summary, there is no available natural gas storage downstream of the Westcoast system currently available to PCEC. The Commission has, therefore, not assumed any storage becoming available downstream of Westcoast in its financial runs. The future availability of natural gas storage on Vancouver Island or in the Lower Mainland would be highly beneficial to the project.

3.9 Natural Gas Supply

PCEC proposes to contract directly with producers for all the natural gas supplies needed to satisfy the markets of the distributor utilities and the industrial customers. The natural gas purchases are to be made at a high load factor so as to minimize the price. It has become common in British Columbia that Producers are willing to offer significant discounts to large volume/high load factor customers. For example, the British Columbia Petroleum Corporation ("BCPC") field price available to industrial customers with a high load factor is $1.03/GJ.

To improve the load factor of the markets served by PCEC, the transmission company intends to maintain relatively high volume purchases from producers in summer months and to inject the natural gas not immediately needed into Unocal's Aitken Creek storage. The gas would be taken from storage during the peak winter period and delivered to market. PCEC would thereby purchase gas at a high load factor under a "take or release contract" specifying a minimum load factor of 75%.

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PCEC has made preliminary inquiries with Producers attempting to purchase gas at a minimum price of $1.06/GJ, plus flowback of excess revenues from the project if oil prices rise in future. The flowback occurs after all repayable grants and the RSF are repaid and retail prices generate surplus funds after paying utility costs and the minimum field price. The minimum price offered to the Producer was based on PCEC's understanding of the competitive price when it first discussed matters with Producers in the spring of 1988 (Exhibit 73). PCEC has also stated that it would be willing to purchase gas at the wellhead or after processing. Natural gas from Alberta delivered to the project would be purchased at the inlet to the Westcoast system in Alberta.

Under the proposed flowback pricing scheme, producers require two events to occur to do well from sales to PCEC. First, crude oil prices would have to rise so that the retail price in the market place, which is tied to retail oil products prices, would also rise. Higher oil prices in themselves would be insufficient to provide a superior return to producers: for producers to do well under the flowback pricing scheme it is necesssary that the spread between natural gas prices and oil prices widen in future years. These two events would be consistent with a market where natural gas was in continuing over-supply, which would lead to depressed gas prices and wide spreads between natural gas and crude oil prices. This requirement was confirmed by Mr. Rutherford of PCEC when examined by Commission Counsel (T 3302-3303).

The spread between natural gas prices and oil prices is currently at an historic high. Recent projections, including the NEB forecast of December, 1988, expect the spread between natural gas and crude oil prices to narrow in the 1990's. This speculation is largely premised on the anticipated depletion of natural gas deliverability in the United States and a substantial increase in exports from Canada. This would tend to tighten the natural gas supply/ demand balance and improve prices for natural gas producers.

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PCEC stated they were optimistic that they could sign up volumes sufficient to meet the third year deliverability requirements of PCEC's own market forecast. In the absence of any reasonable information on gas supply from PCEC in its Application, the Commission ordered the production of all information by Order No. G-17-89. The response, filed on March 2, 1989, was included in Exhibit 75. The information was again updated in Exhibit 104 and 104A. PCEC has had correspondence with Westcoast Petroleum Ltd., Chieftain Development Co. Ltd., Texaco Canada Resources, BP Canada, Remington Energy Ltd. and two other producers who wish to remain anonymous. The volumes of natural gas assumed by PCEC to be available from these producers are as follows:

1.	Chieftain Development Co. Ltd.	-	9 MMcf/d
2.	Westcoast Petroleum Ltd.	-	2 MMcf/d
3.	Texaco Canada Resources	-	3-5 MMcf/d
4.	Remington Energy Ltd.	-	15-17 MMcf/d
5.	BP Canada	-	5-10 MMcf/d
6.	Others	-	5 MMcf/d
	TOTAL		39-48 MMcf/d

The Commission notes from the correspondence that the above volumes from the identified producers could not be categorized as commitments to the project. At best, they may be interpreted as preliminary expressions of interest. BP Canada withdrew its support for the project by letter dated March 23, 1989 noting, amongst other matters, that BP Canada does not support the PCEC rationale that requires them to purchase gas on behalf of end-users and LDC's.

The greatest stumbling blocks to signed gas supply contracts appear to be the minimum price offered by PCEC and the uncertainty regarding flowback. Representatives from IPAC indicated that, in their view, the price would be insufficient to attract sufficient volumes from producers. This view was echoed by Vigas. Indeed, even the representative of AEC, a sponsor of the pipeline project and owner of Chieftain, indicated that the proposed pricing would be insufficient for the latter company (T 3465-3466).

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PCEC has stated that they must have sufficient long-term contracts of natural gas to meet not only the requirement to finance the project, but also to meet the Provincial Core Market Policy tests, as administered by the Commission. PCEC counsel noted in argument that PCEC believed that the Commission should specify a condition to any approval of an EPC that the Core Market gas supply tests be met.

The Commission views the lack of progress on attaining a natural gas supply for this project as being the most serious impediment to its financing and completion. It is quite clear that any increase in producer prices negotiated in future would flow directly to the account of the Provincial Government, to be financed under the RSF. Consequently, the full risk of negotiating higher prices of natural gas will be borne by the Government, not PCEC. This risk to the Government cannot be overstated.

In the Commission's base case financial runs it is assumed that the initial base price of $1.06/GJ will have to be escalated, at least at inflation, during the 20 years of the project. In addition, the producers would enjoy the flowback of excess revenues from the project when they were attained. Based on the anticipated price of crude oil at $20.25 (U.S.)/bbl in 1991 escalating at inflation, the producers would begin to see flowback in 1997. At that time the RSF would be paid off.

However, under the pessimistic financial case, the natural gas price assumptions are the same as in the base case, but the value of crude oil is set at $15.40 (U.S.)/bbl escalating thereafter at inflation. In that case Producers never see any flowback of excess revenue, the Government grants are never repaid, and the RSF grows to a maximum value of $270 million in the year 2007.

The optimistic financial case presumes that PCEC would negotiate contracts at the $1.06/GJ plus flowback. In this case, the Commission assumed crude oil prices to be the average of the high and low forecasts issued by the NEB

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in December, 1988. In this case, producers obtained flowback in the first year of the project and there is never any draw made upon the RSF.

The uncertainty of gas prices at this time and the risk of future fluctuations in oil prices creates a significant financial exposure to the Provincial Government which cannot be over-emphasized. In final argument, PCEC speculated that if the minimum price of natural gas had an escalator attached to it, the company might be able to negotiate a cap on prices in later years. Such a cap on future prices was first put forward by Vigas and would be extremely valuable if oil prices rose rapidly, because other energy, particularly electricity, could become the competitor of natural gas in the retail markets if oil product prices rose to very high levels.

The Commission is dissatisfied with the performance of PCEC with respect to gas supply and has made this view known to PCEC's witnesses and its counsel several times during the course of the hearing. At this juncture, the Commission believes that any activity by PCEC to negotiate natural gas prices after the issuance of a conditional EPC should require participation on behalf of the Provincial Government so that prices and terms can be negotiated with assurance of timely approval. These negotiations must be completed before May 4, 1989 so that the final award of an EPC can be confirmed before PCEC must order pipe and award construction contracts to meet the in-service target date of September 1, 1990.

3.10 Reassessment of Facilities and Capital Costs

3.10.1 Pipe Size

In Section 2.4.1 of its "Interim Report - Phases I and II, March 14, 1989", the Commission noted that "In the event that Phase III evidence on market projections results in a 20-year sales forecast substantially in excess of the projections utilized by PCEC, consideration should be given to possibly upsizing a portion of the pipeline system to 323.9 mm O.D."

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There was considerable evidence advanced in Phase III to argue both for and against the installation of larger pipe for a portion of the route. The LDC's suggested that larger pipe was required to provide for the possibility of future peak shaving with underground storage in the B.C. Lower Mainland or Washington State (T 3530, 4510). The LDC's also argued (T 3704-3706 and Exhibit 116) that their load forecast for year 20 exceeded the pipeline capacity of 150 MMcf/d. They also suggested that a future loss of pipeline capacity was to be expected due to construction of an ethane stripping plant in the Taylor area (T 3851). These arguments were countered by PCEC in the testimony of Mr. Kavanaugh (T 4270-4283 and Exhibit 135). PCEC's position essentially relied on the fact that, while the most economical "ultimate capacity" of the 273.1 mm O.D. pipeline was 150 MMcf/d, this could be increased to about 200 MMcf/d for a very slight increase in operating cost by the use of additional compression. A capacity of 200 MMcf/d would enable PCEC to supply pipeline gas for the LDC's design day (i.e., extreme) forecast as well as the extreme Industrial load as forecast by COFI. The situation is summarized in Table 3.6 below.

TABLE 3.6

Pipeline Capacity Requirements, Year 20

	TJ/d	MMcf/d
Vigas extreme (Exhibit 116)	157.8	143.5
BC Gas extreme (Exhibit 103)	3.7	3.4
Industrial extreme (T 3902)	48.0	43.6
Total	209.5	190.5

From Table 3.6 it can be seen that since all present load forecasts are accommodated with the 273.1 mm O.D. pipeline, the decision on pipe size really amounts to how best to deal with future unknown industrial loads. While the Commission recognizes that various participants mentioned rumours of such loads at Britannia Beach, Texada Island and Powell River, (T 4552), there was no evidence of definite plans in any of these locations.

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It is the Commission's view, therefore, that the only reason for installing pipe larger than 273.1 mm O.D. is to preclude future looping of the pipeline through areas of extreme construction difficulty or environmental sensitivity. With this in mind, based on the evidence in Phase I of this hearing, the one area which qualifies as a candidate for larger pipe is the Coquitlam Watershed. The Commission believes that the risks in traversing the watershed are manageable now, particularly since the Greater Vancouver Water District ("GVWD") has the option of taking this watershed out of service for part of the year, if necessary. In future, this option may not be available and in any case, future looping of the pipeline through the watershed would entail otherwise avoidable risks.

PCEC stated in Exhibit 135 that 323.9 mm O.D. pipe could be installed through the watershed for an additional cost of about $2 million and that this would preclude future looping in the watershed (T 4426). The Commission concludes that this cost is justified in order to eliminate future intrusions into the watershed for pipeline construction. With this exception, the Commission does not believe that any further system capacity increases can be economically justified now, since the proposed system can handle even the most optimistic load forecasts over the 20-year project life.

3.10.2 Campbell River Lateral

The loads forecast by COFI for the Elk Falls Mill at Campbell River fell far short of those forecast for the other mills due to technical difficulties in the conversion of kilns (Exhibit 118). As a result, the Commission became concerned that the Campbell River Lateral, consisting of some 48.8 km of 114.3 mm O.D. pipeline, might not be economically justifiable. PCEC was requested to evaluate this and report back to the Commission (T 3503) and as a result filed Exhibit 144.

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Exhibit 144 shows that the RSF rises to a higher amount without the Campbell River loads than it does with them. The exhibit also shows that once the RSF is paid off, producer unit revenues are lower without the Campbell River case. The Commission concludes that the Campbell River Lateral would make a positive financial contribution to the project and should continue to be considered part of the project for that reason.

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4.0 FINANCIAL MODELS

4.1 Introduction

Section 5 of the Terms of Reference directs the Commission to review and assess the cost of service of the proposed project including pro forma financial statements and the assumptions used for the 20-year projected period. A number of financial cases were examined to achieve this objective.

The Statement of Principles dated September 22, 1988 lays out a framework of project financing and on-going assurance of competitive rates to gas users, pending the completion of a Binding Agreement. PCEC developed a financial model incorporating its project cost and financing assumptions to demonstrate financial feasibility of the proposed pipeline. As noted in Section 2.2.2, many of the assumptions differ from those of the Statement of Principles, but PCEC advised the hearing that the adjustments more closely represent the current thinking of the parties to the proposed Binding Agreement.

4.2 The Model

The mechanics of the financial model, developed in support of PCEC's project, use the regulatory process as a starting point. Rate base comprises capital costs and working capital less grants; cost of service is developed with sales volumes projected by PCEC for industrial customers and by LDC's for core market customers; sales prices are calculated in relation to the price of light fuel oil and competitive industrial fuels. The gate price to each LDC is calculated by taking their total sales revenue less their cost of service. A surplus or deficit results after deducting from the total PCEC gate revenue the cost of storage, Westcoast tolls, BC Gas wheeling, gas purchases and PCEC's own cost of service. A deficit would trigger the withdrawal of funds from the RSF; a surplus first repays any outstanding balances from the RSF and then flows-through to producers as netback revenue. Exhibit 22 provided a graphical demonstration of the proposed overall concept of the project and is reprinted here as Figure 4.1.

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FIGURE 4.1

PCEC Project Financial Flows

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A basic PCEC assumption was that revenues in excess of cost of service would be used to either reduce the RSF balance or to flowback as improved gas purchase payments to the producers. Government loans were to be repaid from funds generated from depreciation recovery, shareholders equity or additional financing by PCEC.

The results of the cost of service model were applied to the pro forma financial statements, which were presented on a corporate basis in the various runs prepared by PCEC. These statements basically reflected the results of the cost of service model and its assumptions related to PCEC's assets, liabilities and equity for the 20-year projection period. The Statement of Changes in Financial Positions reflected PCEC's projected cashflow to meet its financial obligations and to maintain a reasonable capital structure such that funds could be raised for timely capital expenditures. Interest coverage tests were shown in Exhibit 20, Tab 3, c. 2.3, which indicated that the normal interest coverage requirement of two times could be met.

4.3 PCEC Base Case

In addition to the financial model presented in the Application, PCEC established a Base Case model (Exhibit 87 and revised as Exhibit 87A) for the purpose of future financial comparisons as the hearing progressed. The results indicated that the cumulative RSF could reach $13 million in year 3, and be fully repaid in year 4; the Producers would start receiving netback revenue in year 5. PCEC believed that their Base Case was conservative and represented a reasonable balance of probabilities. BC Gas agreed in part with the conclusion of PCEC but noted that a wide range of outcomes could occur depending on the assumptions made.

Counsel for Vigas, in argument, contended that the PCEC Base Case was too optimistic. COFI suggested that the financial runs performed by PCEC did not reflect the principles set forth in the Statement of Principles.

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4.4 Range of Scenarios

Many financial cases were run during the course of the hearing with outputs ranging from a required draw on the RSF of $550 million in the worst case to zero draw on the RSF in the best case.

PCEC provided a schedule, in final argument, showing the impact on the RSF of changes in each major variable and concluded that the dominant variables were Westcoast tolls, capital cost overrun and peak shaving related to LDC load factors. BC Gas concluded that none of the financial model runs had demonstrated the correct scenario. Vigas suggested that Exhibit 114 which had been prepared according to COFI assumptions was too pessimistic. COFI pointed out that changes in the oil price assumption would have the greatest impact on the RSF.

In view of the differing opinions of participants and considering the wide range of assumptions and unsigned agreements, the Commission staff requested PCEC to prepare Exhibit 143, setting the upper and lower limits of each variable within a reasonable range, yet excluding the extreme circumstances. The intent was to provide a degree of confidence as to the pessimistic, likely and optimistic occurrence of all variables. For the purpose of running the financial models, PCEC's interpretation of financial arrangements contemplated in the Binding Agreement was accepted. Any significant variance in the signed Binding Agreement could vary the results.

Exhibit 143 was prepared based on PCEC's calculation of change in LDC revenues and cost of service, which reflected the different assumptions of load factors and peak shaving conditions. More recent Vigas cost of service estimates, including peak shaving alternatives, were provided in Exhibit 140.

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The Commission has considered all of the evidence and the many financial runs undertaken by participants at the hearing. The wide range in the estimates and the implications for financial support from the RSF are the result of the many outstanding agreements which have previously been discussed in Section 1.0 of this report. PCEC has no agreements with its downstream customers or its upstream transporters and gas suppliers. Estimates must be made of the market size, load factor, sales, PCEC cost of service, BC Gas wheeling cost, Westcoast transmission cost, gas storage costs and producer prices. On top of these estimates there exists a very large business risk related to the future of oil prices.

As required by the Terms of Reference, and in view of the wide range of estimates made by PCEC and the various intervenors, the Commission has created three financial scenarios for presentation in this report. Table 4.1 tabulates the assumptions of the Commission for each of the three scenarios. The pessimistic scenario should not be interpreted as being a worst-case scenario. In the pessimistic case the Commission has included reasonably probable, but negative, findings for the project compared to the Commission's Base Case. Equally the optimistic case could be exceeded if oil prices rose rapidly and/or other fortuitous events occurred.

The largest impacts on the project finances, as reflected in the RSF, result from changes in oil prices, the spread between crude oil and natural gas field prices, peak shaving requirements, and changes in capital costs. By far, the most volatile factor is the forecast of oil prices. For example, the value of West Texas Intermediate crude oil hit a low of $13 (U.S.)/bbl in mid 1988 and has risen recently to a high exceeding $20 (U.S.)/bbl. Forecasts of future prices vary considerably.

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Figure 4.2 illustrates the three crude oil forecasts used in the Commission runs. The pessimistic case assumes a low crude oil price with oil and natural gas prices escalating at equal rates. The base case assumes a higher oil price but retains the percentage spread between oil and gas prices into the future. The optimistic case assumes a high crude oil price and a rapidly widening spread between the crude oil and natural gas prices into the future.

FIGURE 4.2

Comparison of Crude Oil Price Forecasts

Source: Case A - $15.14 (U.S.)/bbl escalated at 4%
Case B - $20.25 (U.S.)/bbl escalated at 4%
Case C - Average of high and low NEB forecast of December, 1988

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Tables 4.2 through 4.4 illustrate the financial highlights of the Commission's cases. The detailed assumptions have been explained in Section 3 and are consolidated on Table 4.1.

The Commission's base case, (Table 4.3) assumes an oil price of $20.25 (U.S.)/bbl in 1991 with the Producer natural gas price being $1.06/GJ. This spread between natural gas and oil prices is higher than in the pessimistic case and the Commission's base case assumes that the first year relationship between natural gas and oil prices continues until the flowback to the producer occurs in year 1997. The base case is predicated on a load factor of 40% for the LDC's and a PCEC capital cost of $256 million.

The Commission views the base case as having the highest probability of occurrence. The greatest variant to the base case is likely to come about as a result of future oil prices. These prices tend to be very volatile and historically oil price forecasts have proved to be poor when compared with the actual price movements that did occur. In the base case the RSF rises to $13 million in 1994 and is paid out by 1997. The loans are fully repaid in 2002.

The Commission's pessimistic case, (Table 4.2) is a combination of low oil prices with natural gas prices maintaining their current spread with oil prices. This case assumes an LDC load factor of 35% and a capital cost overrun of some $20 million over the Commission's base case. The output from this model run indicates that the RSF would continue to rise to the year 2007 when it would reach a maximum level of $270 million. At the end of the 20-year assessment period, the RSF would continue to have a deficit of $260 million. In addition there would be no repayment of either the Federal or Provincial loans in this scenario.

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The financial implications of the Commission's pessimistic case are most serious. The assumptions which lead to this result have some probability of occurrence. It is for this reason that the Commission strongly encourages the Government to assert its position with respect to the negotiation of gas prices for this project and the scrutiny of the construction bids made to PCEC.

The Commission's optimistic case, (Table 4.4) assumes that oil prices rise more rapidly than natural gas prices so that there is a widening spread between these commodities throughout the forecast. This forecast also assumes that the LDC's are capable of meeting a 45% load factor and the capital costs of the project come in $17 million less than the base case. In the optimistic case, the RSF is never used to support the cost of service of PCEC. The natural gas producers receive a flowback of surplus revenues from the project in the first year of the project. The repayable loans to the Governments are repaid starting in 1994 with the final payment being made in 1997.

It should be noted that the desirable results of the optimistic case also have a reasonable prospect of occurring. For example, the Commission is aware that the pipe prices tendered to PCEC are less than those budgetted. Further, if PCEC is able to take advantage of the current lull in pipeline construction activity, it may be able to attain the capital cost identified in the optimistic case. With respect to oil prices, the Commission has not used the NEB's high oil price, but has averaged the Board's low and high forecasted prices for the 20-year period.

In summary, the financial runs indicate that the project is viable depending on future oil and natural gas prices. The negative effects of the potentially low oil prices impact directly on the RSF and the Provincial Government. The Provincial Government must protect itself from this possibility.

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TABLE 4.1

BCUC - Financial Assumptions

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TABLE 4.2

Financial Highlights -
Commission Case A (Pessimistic)

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TABLE 4.2

(continued)

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TABLE 4.3

Financial Highlights -
Commission Case B (Base)

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TABLE 4.3

(continued)

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TABLE 4.4

Financial Highlights -
Commission Case C (Optimistic)

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TABLE 4.4

(continued)

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5.0 TRANSPORTATION SERVICE ALTERNATIVE

The Energy Project Applications by PCEC were structured on the concept that all customers would purchase natural gas through PCEC. PCEC would do all contracting with producers and attempt to package the purchases and deliveries in the best method to improve the load factors and prices for all customers (see Section 3.9). This type of arrangement is commonly called "sales service".

It was clear from the outset of the hearing that the industrial customers and LDC's wished to purchase their natural gas directly from producers. This type of arrangement has become common in British Columbia and Canada since 1985. "Transportation Service" is consistent with the initiatives of the Federal and Provincial Governments to deregulate the purchasing practices for the natural gas industry as expressed in the Agreement on Natural Gas Markets and Prices, October 31, 1985.

Following the award of natural gas rights in Victoria, Vancouver Island and the Sunshine Coast to Vigas, the distributor utility stated it also would prefer to make use of transportation service. BC Gas also supported transportation service.

Vigas dealt further with the matter of direct sales and transportation service in the written direct evidence of Mr. de Grasse which was filed as Exhibit 116 of the hearing. Vigas was uncertain whether direct sales would reduce gas purchase costs, but they did see two possible benefits. First, that the direct negotiations would bring producers and market participants closer together, thereby improving each party's understanding of the other. Second, Vigas felt that gas purchase arrangements might be perceived more positively if negotiated by parties not affiliated with companies having producing interests in British Columbia. Vigas further stated it would be willing to work with industrial customers to co-ordinate their gas purchases.

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The industrial customers also stated through their direct evidence that they were prepared to enter into contracts with the Producers if it would assist bringing the project to fruition. The industrial customers were willing to consider arrangements with LDC's to ensure that the gathering, processing and transportation tariffs were effectively co-ordinated to minimize costs. The benefit that the industrial customers saw in direct sales was that, after the RSF was paid down, the industrial customers could purchase natural gas and pay transportation service without having the retail price tied to the price of heavy fuel oil.

The PCEC response to the desire for transportation service changed as the hearing proceeded. In Exhibit 56, PCEC took the position that it must enter into long-term contracts for the purchase of natural gas to cover the market requirements in the early years of the project. It was noted that the negotiation of the Government loans and RSF were fashioned with the overall sales service concept in mind. Notwithstanding that, PCEC stated that it might be able to allow the large industries the option of converting a progressively increasing portion of their requirements to transportation service after five years.

Later, in response to an Information Request from Commission staff dated March 21, 1989, PCEC provided additional information with respect to transportation service (Exhibit 136). The financial assessment undertaken by PCEC was intended to show that it would be very difficult to duplicate the efficiencies that PCEC had built into its project application if one were to undertake transportation service. PCEC maintained that any proposal for structuring the project on a transportation basis could only be considered in the context of the Binding Agreement. Apart from being advised from time to time that negotiations were continuing, the Commission received no information on the evolution of the Binding Agreement during the course of the hearing. All financial cases in this report are based on the Commission's understanding of the Statement of Principles entered into by the Federal and Provincial Governments in September, 1988 and PCEC's understanding of negotiations towards a Binding Agreement.

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PCEC made it clear that if transportation service were to be offered in the early years of the project it must be decided immediately. If the industrial customers or LDC's made an initial choice for sales gas, PCEC felt it would not be possible to convert to transportation service for some period of years because of the commitments which PCEC would have undertaken to secure a supply of gas for its customers on a long-term basis. In final argument, Counsel for PCEC further hardened PCEC's position by encouraging the Commission to consider any transportation option as being outside the perview of the Commission.

In assessing the arguments on this matter, the Commission recognizes that a change in project structure to allow for transportation service would be very difficult to accomplish at this late date while still attempting to complete the project to provide gas service in September, 1990. However, there are many difficulties with the proposed method of natural gas contracting put forward by PCEC. The sales service concept not only appears to be a backward step in conflict with the Government's initiatives to decontrol wellhead activities of the Producers, but the flowback structure advocated by PCEC could lead to regional development problems in future years. Since the flowback scheme distributes all surplus revenues in future years to the Producers, the Producers selling gas to this project will do well if crude oil prices rise quickly and natural gas prices in the other competitive markets remain low compared to crude oil prices. In such an event, industries would be induced to locate at areas other than those served by PCEC so that they could take advantage of the lower natural gas prices that would exist elsewhere.

The Commission is also aware that the proposed purchase practices of PCEC are premised upon producers offering a lower than market price in early years of the project in anticipation of receiving substantial flowbacks later. Any change to transportation service based upon existing contracting methodologies would have a substantial impact

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upon the RSF in the early years of the project. Mr. Rutherford of PCEC acknowledged this in his direct evidence (Exhibit 56) when he stated that it would be necessary for the direct purchaser of natural gas on a non-netback basis to offer the Producers more in the early years of the project to compensate for the absence of the potentially higher prices if oil prices rose significantly.

While the Commission acknowledges all of the problems that the provision of transportation service could cause to the timely completion of this project, the Commission does not accept the assertions by PCEC that transportation service would necessarily cause higher overall prices for the project. Clearly a different contract approach with the Producers would cause differences in the amounts and timing of flows from and to the RSF. However, so long as the contracting methodology (sales or transportation service) was undertaken in a co-ordinated manner, the benefits of deregulation could flow to the market served by the PCEC project without a higher overall cost to the RSF.

As the Government is aware, the initiatives it has undertaken to decontrol the natural gas purchasing activities have led to substantial benefits to the consumers of natural gas. In implementing these policies, the Commission and the utilities have worked industriously over the past three years to ensure that transportation arrangements were put in place which married the benefits of direct natural gas purchases with transportation arrangements so that the benefits of load-factor resulting from common nominations, curtailment and interruptible service could be shared by all users. Structures can be put in place for the PCEC system which will mirror the benefits available elsewhere in the province. For example industrial customers in the interior of the province not only blend their purchases between interruptible and firm gas purchases, but the industries allow themselves to be curtailed by the distributor so that their pipeline space and natural gas can be used to serve the peak requirements of residential and commercial customers on the coldest days of the winter. In return, the industrial customers are awarded a lower cost of service from the distributors and can nominate reduced capacity on the Westcoast system.

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The resolution of this matter is beyond the ability of the Commission to deal with since it is dependent upon the structure of the Binding Agreement. If the Governments were to agree on a funding mechanism which would accommodate transportation service the Commission would encourage that it be offered. However the Commission believes it would be virtually impossible to put all the necessary arrangements in place in time to permit a May 4, 1989 construction start even if an appropriate Binding Agreement were to be concluded immediately.

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6.0 CONCLUSIONS AND RECOMMENDATIONS ON PHASE III

This section contains the Commission's recommendations with respect to Phase III of the hearing, Markets, Gas Supply and Financial Matters. As stated in Section 1.0, the Commission has previously provided an Interim Report to the Lieutenant Governor in Council with respect to the Commission's findings from Phases I and II of the hearing. The principal conclusions and recommendations of the Commission with respect to all phases of the hearing are included in an Executive summary, produced as a separate report.

The Interim Report and the previous sections of this report encompass a full review of all matters related to the Application as directed in the Terms of Reference for the hearing.

In reaching its conclusions and recommendations the Commission has been mindful of the project schedule to deliver natural gas to Vancouver Island markets by September 1, 1990. To preserve this delivery schedule, the critical path requires that PCEC commit to marine surveys by April 18, 1989 and issue contracts for pipe and construction by May 4, 1989. PCEC will require a conditional EPC by April 18, 1989 and would have to meet those conditions before May 4, 1989. A Binding Agreement would also be required by May 4, 1989.

The Commission has used PCEC's amended interpretation of the Statement of Principles on the assumption that it more closely represents the likely outcome of the Binding Agreement. In negotiating the Binding Agreement, the Governments should consider the financial impacts of any changes from this interpretation, as they will affect the project economics.

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6.1 Markets

As indicated in Section 3.1, the Commission concludes that the LDC market forecasts are appropriate for the financial analysis of the project. Its concern regarding competition from electric energy has been reduced by recent Government statements on future electric pricing trends. However, the market sensitive pricing concept should make provision for the potential of electricity becoming the prime competitor of natural gas under a high oil price scenario.

6.2 Gas Supply and Storage

The Commission concludes that gas supply contracts and the availability of storage are inextricably linked and are central to the project economics. The Commission is concerned with the lack of progress by PCEC in resolving these key issues. Since time is of the essence, THE COMMISSION RECOMMENDS THAT AN EPC SHOULD REQUIRE THE FOLLOWING CONTRACTS TO BE COMPLETED BY PCEC AND APPROVED BY THE PROVINCIAL GOVERNMENT BY MAY 4, 1989:

> LONG-TERM GAS SUPPLY AND STORAGE CONTRACTS SUFFICIENT TO MEET THE THIRD YEAR LOAD OF THE LDC PLUS THE INDUSTRIAL LOAD.
>
> LONG-TERM GAS SALES AGREEMENTS WITH THE INDUSTRIAL CUSTOMERS.

IN ADDITION, THE COMMISSION RECOMMENDS THAT A REPRESENTATIVE OF THE PROVINCIAL GOVERNMENT PARTICIPATE IN THE PROCESS SO THAT PRICES AND TERMS CAN BE NEGOTIATED WITH THE ASSURANCE OF TIMELY APPROVAL.

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The impact of future crude oil and natural gas prices on the RSF is extreme. The Province should not allow the project to proceed without assuring itself that these risks are managed through final long-term gas supply contracts. The Commission's pessimistic case scenario shows a maximum draw on the RSF of $270 million which would not be repaid in the 20-year project analysis period.

6.3 Peak Shaving

PCEC's proposal to require the LDC's to meet a 45% load factor creates problems for the LDC's. Vigas did not include any allowance in its service proposal to the Provincial Government for the capital cost of peak shaving equipment. Squamish Gas did not include peak shaving in its market and financial assessment.

Peak shaving is a brad and complex issue involving all participants in the project.

The Commission concludes that insufficient evidence was advanced to permit a rational and timely resolution of the appropriate allocation of peak shaving responsibilities among the participants. THE COMMISSION RECOMMENDS THAT THIS COMPLEX PROBLEM BE RESOLVED BY THE INTERVENTION OF THE COMMISSION WITH THE LDC'S, INDUSTRIALS AND PCEC UNDER PART 3 OF THE UTILITIES COMMISSION ACT. SINCE THE COMMISSION'S FINANCIAL MODELS INCORPORATE A RANGE OF PEAK SHAVING POSSIBILITIES, THE COMMISSION BELIEVES THAT THE OPTIMUM SOLUTION CAN BE ACHIEVED AFTER THE ISSUANCE OF A CONDITIONAL EPC.

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6.4 LDC Cost of Service

The Commission accepts the cost of service forecast by BC Gas and Vigas, subject to resolution of peak shaving requirements as recommended in Section 6.3 above. These forecasts are incorporated in the Commission's financial analysis of the project and the Commission has allocated funds for peak shaving to the cost of service of the LDC's to meet the minimum load factors assumed in the three Commission runs.

6.5 PCEC Cost of Service

The Commission concludes that PCEC's cost of service assumptions, as modified during the hearing, produce a reasonable balance between short-term gain and long-term cost to the project.

The Commission considered deferred depreciation and a higher debt/equity ratio as methods of reducing cost of service in the early years, but did not include them in its financial analysis because of their long-term implications on project economics.

6.6 PCEC/Industrial Contracts

The Commission concludes that the minimum term of contract between PCEC and its industrial customers should be the grater of 10 years or the time required for repayment of the RSF. The participation of the mills in this project is vital to its economics, and, therefore, THE COMMISSION RECOMMENDS THAT THE PROJECT NOT PROCEED WITHOUT LONG-TERM AGREEMENTS AND THAT THE PRICE OF NATURAL GAS TO THE INDUSTRIAL CUSTOMERS BE BASED ON THE PRICE OF ALTERNATIVE LOW SULPHUR FUEL OIL DELIVERED TO THE MILLS. The Commission accepts PCEC's evidence that the mills individually will not be curtailed below their lime kiln load.

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6.7 PCEC/LDC Contracts

The Commission concludes that PCEC will require long-term contracts with the LDC's to finance the project. In turn, the LDC's will require long-term gas supply contracts if they are to sign up for sales service. The Commission believes that gas supply to the core market should be contracted on a long-term basis with an initial volume equal to the third year volumes of the LDC's.

6.8 BC Gas Wheeling

The Commission concludes that a PCEC agreement with BC Gas covering wheeling costs between Huntingdon and Coquitlam is essential to the project in order to preclude a review of the Applicant's alternative (Kilgard) Application.

The Commission's financial analysis utilized the positions of both the parties in its sensitivity tests. The Commission reiterates its willingness to assist the parties to reach an agreement.

6.9 Westcoast Tolls

The Commission believes that, if the PCEC load increment during the first three years of operation can be accommodated within the existing Westcoast system capacity, then "incentive tolls" would not harm existing shippers on Westcoast's system. The incentive tolls would be highly beneficial to the project economics in the first three years. This toll will require the approval of the NEB.

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6.10 Pipe Size

THE COMMISSION RECOMMENDS PIPE SIZE BE INCREASED FROM 273.1 MM O.D. TO 323.9 MM O.D. THROUGH THE GVWD COQUITLAM WATERSHED TO ELIMINATE FURTHER INTRUSIONS FOR CONSTRUCTION PURPOSES SHOULD LOOPING OF THE PIPELINE BE REQUIRED IN FUTURE YEARS.

6.11 Campbell River Lateral

THE COMMISSION RECOMMENDS THE CAMPBELL RIVER LATERAL BE RETAINED DESPITE LOWER THAN ANTICIPATED INDUSTRIAL LOADS.

6.12 Transportation Service

The Commission has considered the evidence from intervenors at the hearing with respect to transportation service, which involves direct contracting of gas between producers, LDC's and industrials. While the Commission recognizes that the transportation service approach is more in tune with current trends in gas marketing, it concludes that this option, although highly desirable, should not be considered a viable alternative at this time for two reasons:

- the possible impact of such a change on the final Binding Agreement; and
- the potential jeopardy to the September 1, 1991 in-service date.

If the project's in-service date is delayed substantially the Commission would recommend that transportation service be incorporated into the project structure.

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6.13 Commission Costs

Pursuant to Section 133 of the Utilities Commission Act, the Commission determines that its costs incurred incidental to all phases of this hearing are to be paid by PCEC.

IN THE MATTER OF
the Utilities Commission Act,
S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF
an Application and an Alternative Application
by Pacific Coast Energy Corporation for
an Energy Project Certificate to Construct
and Operate Natural Gas Pipeline
Transmission Facilities to and on Vancouver Island

FINAL REPORT
PHASE III

April 6, 1989

Before:

J.G. McIntyre, Chairman
N. Martin, Commissioner
F.C. Leighton, Commissioner

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ALLWEST REPORTING LTD.		Court Reporters and Hearing Officer

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ABBREVIATIONS

AEC	Alberta Energy Corporation
bbl	Barrel
BC Gas	BC Gas Inc.
B.C. Hydro	British Columbia Hydro and Power Authority
BCPC	British Columbia Petroleum Corporation
COFI	Council of Forest Industries
the Commission	British Columbia Utilities Commission
EPC	Energy Project Certificate
GVWD	Greater Vancouver Water District
HFO	Heavy Fuel Oil
ICG	ICG Utilities (British Columbia) Ltd.
Inland	Inland Natural Gas Co. Ltd.
IPAC	Independent Petroleum Association of Canada
LDC	Local Distribution Company
LFO	Light Fuel Oil
LNG	Liquified Natural Gas
MEMPR	Ministry of Energy, Mines and Petroleum Resources
NEB	National Energy Board
NG	Natural Gas
PCEC the Applicant	Pacific Coast Energy Corporation
Producers	Natural Gas Producers
ROE	Return on Equity
RSF	Rate Stabilization Facility
Squamish Gas	Squamish Gas Co. Ltd.
Unocal	Unocal Canada Limited
Vigas	Vancouver Island Gas Company Ltd.
Westcoast	Westcoast Energy Inc.