BRITISH COLUMBIA UTILITIES COMMISSION

Vancouver Island Natural Gas Pipeline Project

REPORT AND RECOMMENDATIONS
to the
LIEUTENANT-GOVERNOR IN COUNCIL

In the Matter of The Utilities Commission Act
S.B.C. 1980, c. 60 as Amended

and

In the Matter of
Applications for Energy Project Certificates
to Construct and Operate Pipeline Facilities
for the Transmission of Natural Gas to
Vancouver Island and on Vancouver Island

APPLICANTS

British Columbia Hydro and Power Authority
I C G Island Transmission Ltd. and
Vancouver Island Gas Company Limited
Inland Natural Gas Co. Ltd.
Westcoast Transmission Company Limited

June 1984

VANCOUVER ISLAND NATURAL GAS PIPELINE PROJECT

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CHAPTER 1 INTRODUCTION

Interest in the transport and distribution of natural gas to Vancouver Island began in 1956 with the provision of natural gas services to the Lower Mainland of British Columbia. Service was not extended to Vancouver Island at that time since the potential market was not considered large enough to warrant the cost of the extension, and because the necessary submarine crossing was beyond the limits of technology of that period. Renewed interest in providing natural gas to Vancouver Island markets developed in 1972, when the Public Utilities Commission of British Columbia held a hearing. A report on the hearing was not issued and the project did not proceed.

By the late 1970s, refinement of modern marine pipeline technology and growth of the potential market for natural gas on the Island, coupled with rising oil prices and uncertainty regarding external oil supplies, revived interest in providing natural gas service to Vancouver Island. In 1977 the Provincial Government directed the British Columbia Energy Commission to review the technical and economic considerations related to gas supply to the Island. Following the report of the Energy Commission in 1979, the Provincial Government called for applications to provide service to the Island.

In February 1980, the Government of British Columbia set a target for reducing the Province's oil consumption from 45% to 40% of overall energy requirements. In the same year, the Vancouver Island Natural Gas Project received an impetus from the Federal Government National Energy Program. That document states :

> "... It is expected that natural gas service will be extended to Vancouver Island .... The Government of Canada will set aside up to $500 million to be used if required, to support both the eastern Canada System Extension and the new line to Vancouver Island."

This offer of capital contribution was particularly important for the Vancouver Island Project. The British Columbia Energy Commission had reported that, although it was technically feasible to deliver gas to the Island and a net benefit would be realized, the project was still not viable without subsidization.

In 1981, the Provincial Government instructed B.C. Hydro and Power Authority to prepare an application for construction of a pipeline to Vancouver Island. Later that year the Provincial Government deferred decision on who should build the pipeline facilities until a public hearing had been held.

In April 1982, the Government of British Columbia again called for applications, and in June 1982, Robin J. Abercrombie was retained by the Ministry of Energy, Mines and Petroleum Resources (MEMPR) to provide a technical review of the project before initiation of public hearings. The MEMPR report, Natural Gas Supply to Vancouver Island - Technical Report, was released in February 1983.

The major findings of the Technical Report are :

- The project is technically feasible utilizing the abilities of Canadian and International engineering, manufacturing and construction industries.

- The net economic benefits over the project lifetime are estimated to be $700 million in 1982 dollars.

- The project would incur significant revenue deficiencies and therefore financial support would be critical to the timely development of a Vancouver Island Natural Gas Pipeline.

In April 1983, the Provincial Government reaffirmed its intention to hold hearings concerning the Vancouver Island Gas Pipeline Project and called for submission of applications by May 1983. Five companies applied to construct transmission pipelines for supply of natural gas both to, and on, Vancouver Island.

Figure 1.1 illustrates the routing proposed by each Applicant. The five companies that submitted applications are :

British Columbia Hydro and Power Authority (B.C. Hydro)

B.C. Hydro is the largest Crown Corporation in British Columbia. Established in 1964 by the Hydro and Power Authority Act, the company is the largest distributor of natural gas in British Columbia, and the third largest gas distributor in Canada.

B.C. Hydro applied to provide natural gas service both to the Island and on the Island. For the transmission components to the Island, B.C. Hydro proposed two sizes of marine pipeline, which could be laid in the proposed pipeline corridor from the Lower Mainland of British Columbia to nearby Cedar on Vancouver Island. B.C. Hydro proposed to construct one of five different project options on the Island which would supply natural gas to Island communities and potentially to Powell River, both with or without the proposed fertilizer plant.

Centennial Natural Gas Pipeline Ltd. (Centennial)

Centennial is a private company that was provincially incorporated in 1971 and has its head office in Vancouver. The company is a wholly-owned subsidiary of H.A. Simons (Overseas) Ltd. based in British Columbia. The principal business of the H.A. Simons group is the design and project management of pulp and paper plants in British Columbia elsewhere in Canada, and in many other countries.

Centennial proposed two pipeline construction options in a northern routing from Williams Lake to Comox, via Powell River. Both proposals involved the same pipeline corridor and only altered the pipe size from Williams Lake to Powell River to accommodate a fertilizer plant at Powell River.

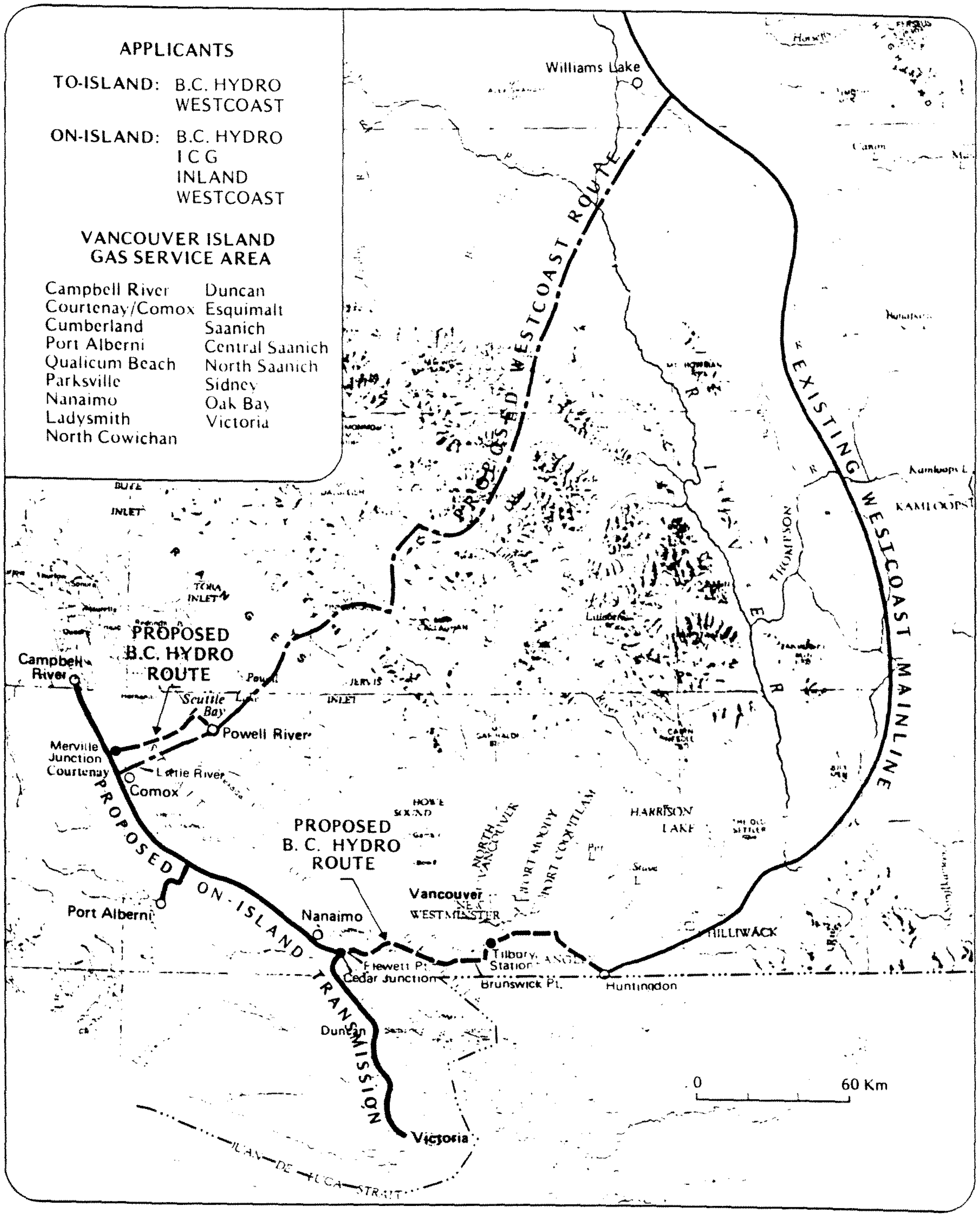
Centennial withdrew its application on August 31, 1983.

Inland Natural Gas Co. Ltd. (Inland)

Inland is the principal distributor of natural gas in the interior of the Province, serving the areas of North and Central Cariboo, Okanagan, and the East and West Kootenays.

FIGURE 1.1

Proposed Pipeline Routes — Vancouver Island Natural Gas Pipeline Project



Inland Natural Gas Co. Ltd. - (cont'd)

Inland applied to provide transmission pipeline services only on Vancouver Island. The company would take custody of the natural gas at either the southern supply point near Cedar or at the northern supply point near Comox.

ICG Island Transmission Ltd. (ICG)

ICG Island Transmission Ltd. is a wholly-owned subsidiary of Vancouver Island Gas Company Ltd. In turn, Vancouver Island Gas Co. is 94% owned by Inter-City Gas Corporation of Winnipeg, Manitoba. Subsidiaries of the parent company operate distribution systems in a number of northern communities in British Columbia, Alberta, Quebec and the Northwest Territories. Vancouver Island Gas Co. Ltd. supplies both propane air and propane vapour to Nanaimo and ICG Utilities (British Columbia) Ltd. (Port Alice) supplies propane to the northern Vancouver Island community of Port Alice.

ICG, like Inland, applied to transmit natural gas only on Vancouver Island. The ICG proposal provides three alternative gas supply options based on a northern or southern routing.

Westcoast Transmission Company Limited (Westcoast)

Westcoast is one of Canada's major natural gas pipeline transmission companies. Westcoast gathers its natural gas from the gas fields in northeast British Columbia, the Yukon Territory, Northwest Territories and Alberta. The company's principal markets are the gas utilities in British Columbia and export to the U.S. Pacific Northwest area. A wholly-owned subsidiary, Pacific Northern Gas Ltd., distributes gas in northwestern British Columbia. Westcoast is a member of a consortium proposing the construction of a world scale fertilizer plant in the Powell River area.

Westcoast made application to provide natural gas service both to, and on, Vancouver Island as well as to Powell River. The application outlined only one proposal which includes a fertilizer complex at Powell River. The transmission pipeline would commence at Williams Lake, proceed in a southwesterly direction to Powell River, with an underwater crossing to Little River near Comox on Vancouver Island. The On Island transmission would extend from Comox to Victoria.

The applications to transmit natural gas to, and on, Vancouver Island were referred to the British Columbia Utilities Commission (BCUC) for review, assessment and public hearing, pursuant to Section 19 (1)(a) of the Utilities

Commission Act, S.B.C. 1980, by the Honourable Stephen Rogers, Minister of Energy, Mines and Petroleum Resources, and the Honourable A.J. Brummet, Minister of Environment. The Letter of Transmittal dated July 21, 1983 and the Terms of Reference are provided in Appendices C and D.

Among other matters, the Terms of Reference directed that the Commission :

> "Identify the relative merits of the competing applications and to recommend on the applicant or applicants best able to construct and operate the project having regard particularly to : timeliness, safety, reliability, and efficiency in project construction and operation ; the minimization of any adverse environmental, resource use, and socio-economic impacts and the maximization of benefits from positive impacts ; and, only in regard to those matters within the control of applicants, the minimization of any revenue deficiencies which may be associated with the project, with particular emphasis on the minimization of capital costs and cost of service, in a manner which would not jeopardize the attainment of the foregoing objectives ; and
>
> Identify the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the project."

The members of the Division of the Commission appointed for this hearing were :

Marie Taylor, Chairman

Peter C.M. Freeman, Commissioner

D. Howard Hushion, Commissioner

Norris Martin, Commissioner

The Commission divided its review of the applications into three phases :

1. Markets
2. Transmission to Vancouver Island
3. Transmission on Vancouver Island

On receipt of the Terms of Reference on July 22, 1983, the Commission issued a Notice of Public Hearing. The Commission's review commenced with a Pre-Hearing Conference on August 19, 1983 which adjourned pending receipt of a schedule of wholesale natural gas prices for the project from the MEMPR. The schedule was received on September 1, 1983 and the first day of public hearing was September 27, 1983.

In March 1984, the Commission requested that the Minister propose to the Lieutenant Governor in Council that the Terms of Reference be amended to permit preparation of a report at the end of Phase Two of the hearing which would identify :

1. the Applicant best able to construct and operate the pipeline to the Island ; and

2. the size of the Federal capital contribution, sufficient to eliminate any revenue deficiencies associated with the project.

On April 11, 1984, Amended Terms of Reference were issued that authorized the Commission to adjourn the hearing at the end of the To Island Phase and report to the Lieutenant Governor in Council. The amended Terms of Reference are contained in Appendix E.

During Phases 1 and 2, the Commission heard from 103 Intervenors and conducted hearings in Vancouver, Victoria, Nanaimo, Courtenay-Comox, Powell River, Alkali Lake, Whistler and Mount Currie. The Panel sat for 98 hearing days, 466 exhibits were filed at the hearing and the official transcript filled 17,861 pages.

The final day of argument concluding the hearing was May 11, 1984.

CHAPTER 2 MARKETS

Phase 1 of the hearing consisted of a limited review and assessment of the Applicants' market projections for the first 20 years of the project, both with and without the proposed fertilizer plant at Powell River. Item 7(l) of the Terms of Reference relating to markets directed the Commission to concentrate on those aspects of the project for which

> ". . . there are sufficiently large differences between the forecasts of Applicants, intervenors, or the Technical Report to have a significant impact on system design, capital costs, revenues, and cost of service."

In addition, Item 7(2) directed the Commission to review and assess marketing proposals which would maximize penetration of natural gas into Vancouver Island markets.

2.1 Forecast Overview

2.1.1 Vancouver Island Natural Gas Demand

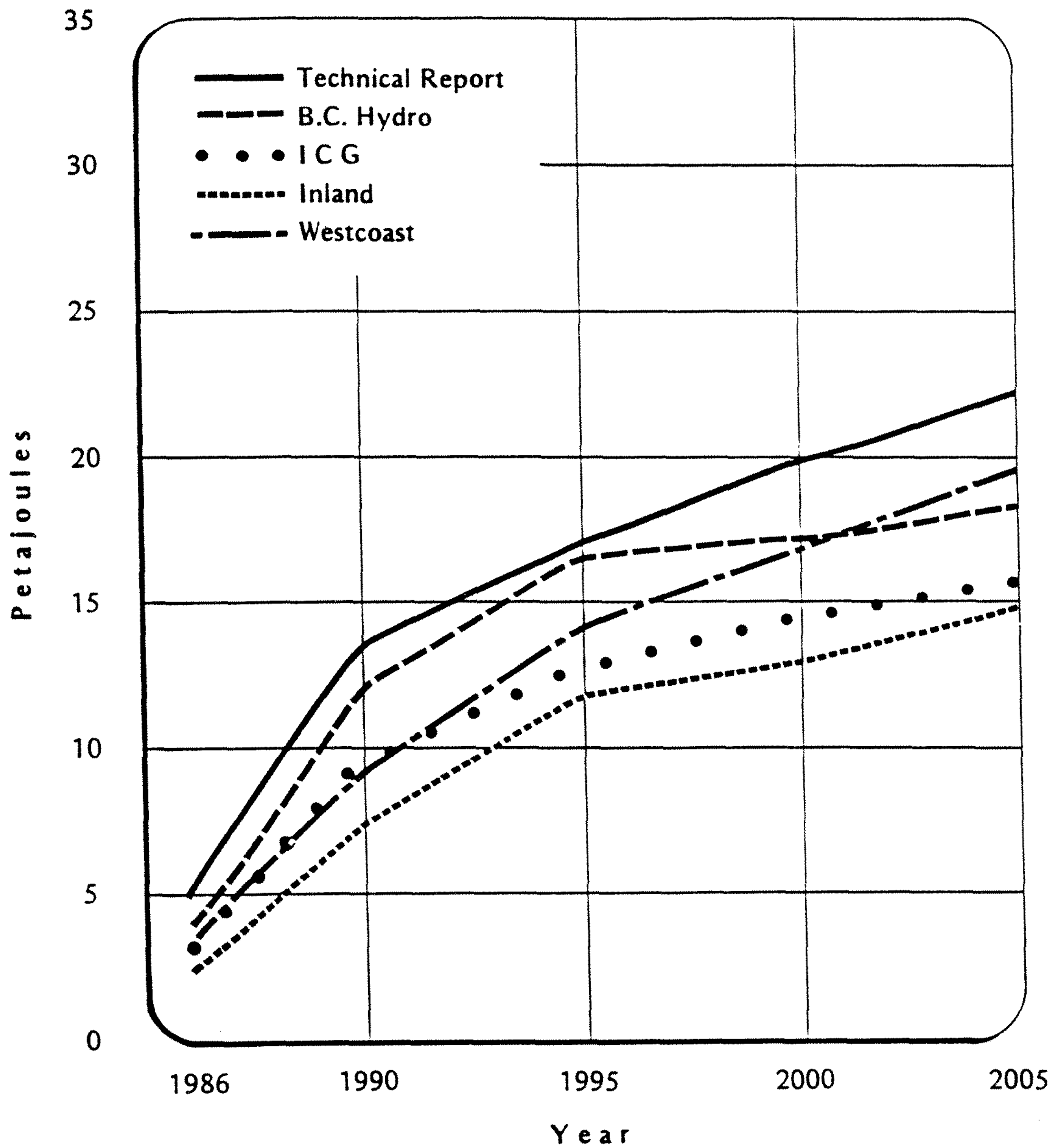
(a) Residential/Commercial Sector*

In Figure 2.1, the forecasts of the Ministry of Energy, Mines and Petroleum Resources Technical Report (MEMPR), April 1983, for the Vancouver Island Residential and Commercial Sector Natural Gas Demand are compared with those of the Applicants. The Technical Report projects the demand increasing more rapidly and remaining higher throughout the 20 year forecast period than the corresponding updated estimates of the Applicants.

* The residential and commercial sectors have been combined to avoid inconsistencies between Applicants in the definition of these two sectors.

FIGURE 2.1

Residential/Commercial Sectors Load Forecasts
(Excluding Powell River)



Among the Applicants, the B.C. Hydro forecast indicates the most rapid build-up of load. The Westcoast, Inland and ICG forecasts are considerably lower for the first five to ten years of the project. The long-term forecasts of Westcoast and B.C. Hydro are the highest, 18.4 to 19.5 petajoules (PJ) in 2005, whereas the ICG and Inland forecasts are the lowest 14.8 to 15.7 PJ in 2005. By comparison, the Technical Report forecast for the year 2005 is 22.27 PJ. The Applicants' market projections range from a low of 14.8 PJ to a high of 19.5 PJ.

(b) Industrial Sector

The industrial sector on Vancouver Island consists of four large pulp mills that could convert from heavy fuel oil (HFO) to natural gas. Except in the Council of Forest Industries (COFI) forecast, this sector also includes the Canadian Occidental chemical plant at Harmac.* The forecasts contained in the Technical Report and those presented by the Applicants and COFI for the Island industrial sector are shown in Figures 2.2 and 2.3.

The forecasts in this sector vary considerably. The Applicants assumed in their forecasts that there would be a total, immediate and permanent conversion from heavy fuel oil to natural gas. On the other hand, COFI projected a partial conversion from oil to gas because its members needed the flexibility to purchase competitively priced fuel and/or to take advantage of technological change. At the low end of the range are the COFI and Inland Case B** forecasts in which industrial sector demand initially peaks at 6 to 10 PJ and then falls to four to six petajoules by the year 2005. The Technical Report's base case is an intermediate estimate which starts at a very

* The Canadian Occidental demand is a very small component of this sector, and is estimated to be 0.2 PJ.

** Inland provided two industrial sector forecasts. Inland's preferred industrial forecast is Case B which is premised upon heavy fuel oil becoming more competitive relative to natural gas. Inland's Case A, which is the alternative forecast, is based on heavy fuel oil prices rising relative to natural gas prices.

FIGURE 2.2

Heavy Industrial Sector Load Forecasts (High Scenario)

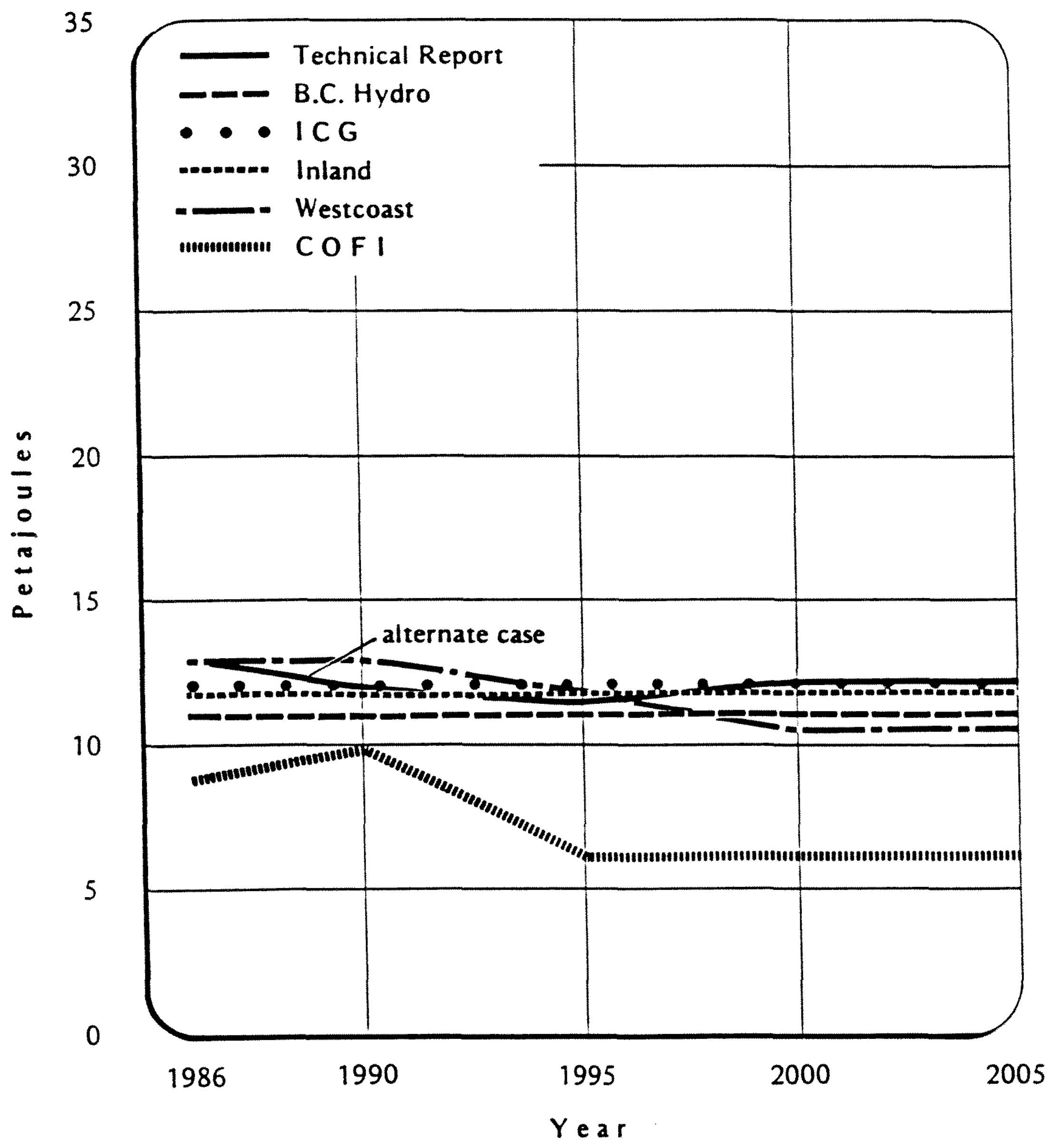
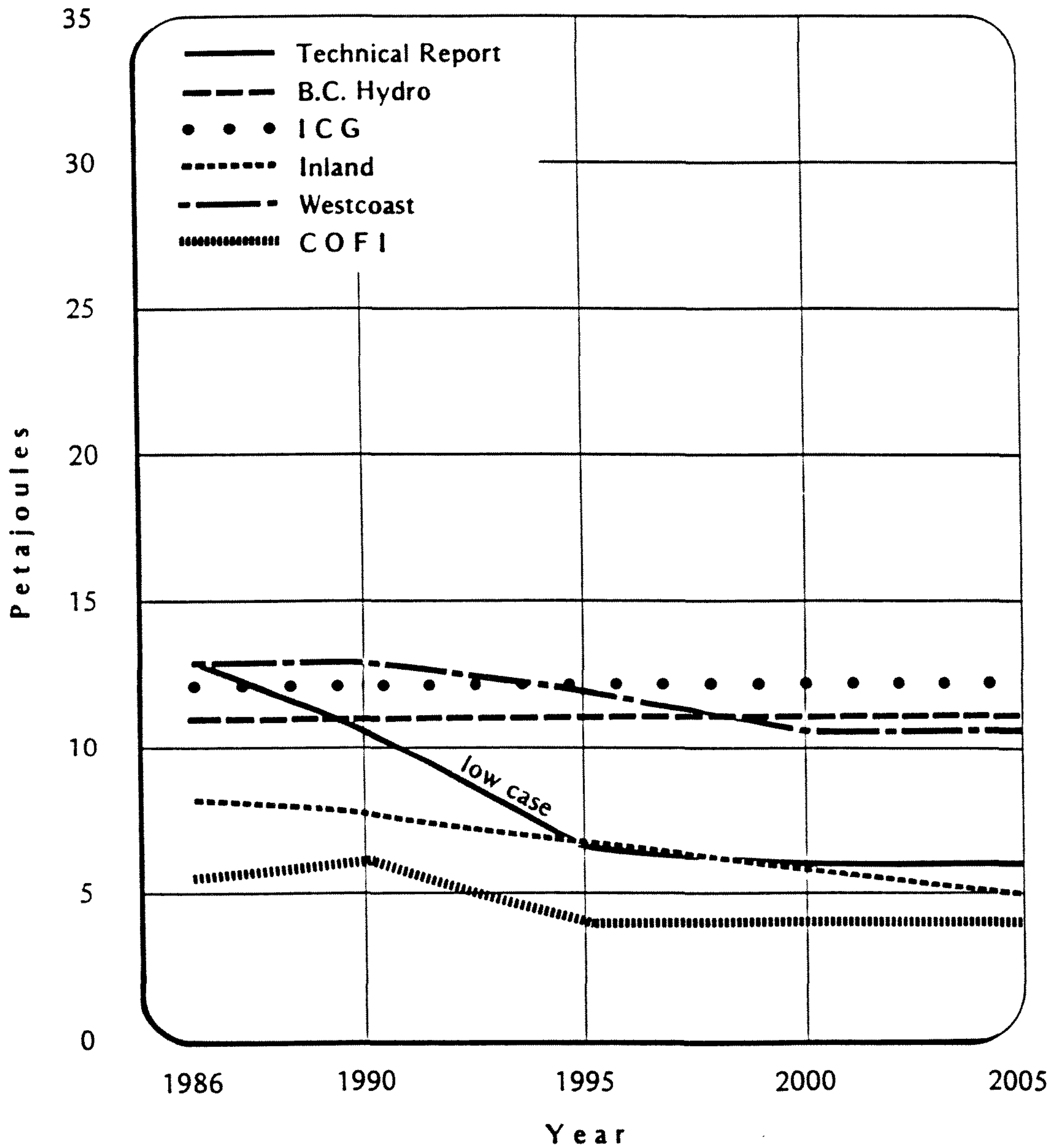


FIGURE 2.3

Heavy Industrial Sector Load Forecasts
(Low Scenario)



high level of demand (13 PJ) and then decreases over the forecast period to six petajoules by the year 2005. The high end of the forecast range includes the Technical Report alternate* case, B.C. Hydro, Westcoast, ICG and Inland Case A. In all of these forecasts, industrial demand starts and remains at from 10 to 13 PJ throughout the 20 year period.

(c) Total Vancouver Island Residential/Commercial/ Industrial Demand

The total forecasts for the Vancouver Island residential, commercial and industrial sectors for the Gas Service Area (GSA), as presented in the Technical Report and by the Applicants, are shown in Figures 2.4 and 2.5.

The Technical Report's alternate case*, which combines a high residential/ commercial sector forecast with the retention of a high industrial sector forecast, is the largest projected demand (34 PJ) by the year 2005. Inland's preferred Case B combines a conservative residential/commercial forecast with declining industrial sector demand, and is the lowest demand estimate. At 19.6 PJ in 2005, Inland's forecast is over 40% less than the alternate case described in the Technical Report.

The total demand shown in the forecasts of Westcoast, B.C. Hydro, ICG, Inland's Case A and the base case of the Technical Report* are all relatively close. The Technical Report's base case demand forecasts increase more rapidly than the others, but they all converge in the 26-30 PJ range at the end of the forecast period.

It is important to recognize, however, that while a similar total level of demand is reached, the base case sectoral forecasts in the Technical Report are quite different from those of the Applicants. The Technical Report's base case forecast is predicated on large residential and commercial sector sales,

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* The base case in the Technical Report assumes a reduction in the industrial market demand due to low heavy fuel oil prices. The alternate case assumes that natural gas maintains its share of the industrial market.

FIGURE 2.4

Total Gas Service Area (GSA) Forecasts
(High Scenario)

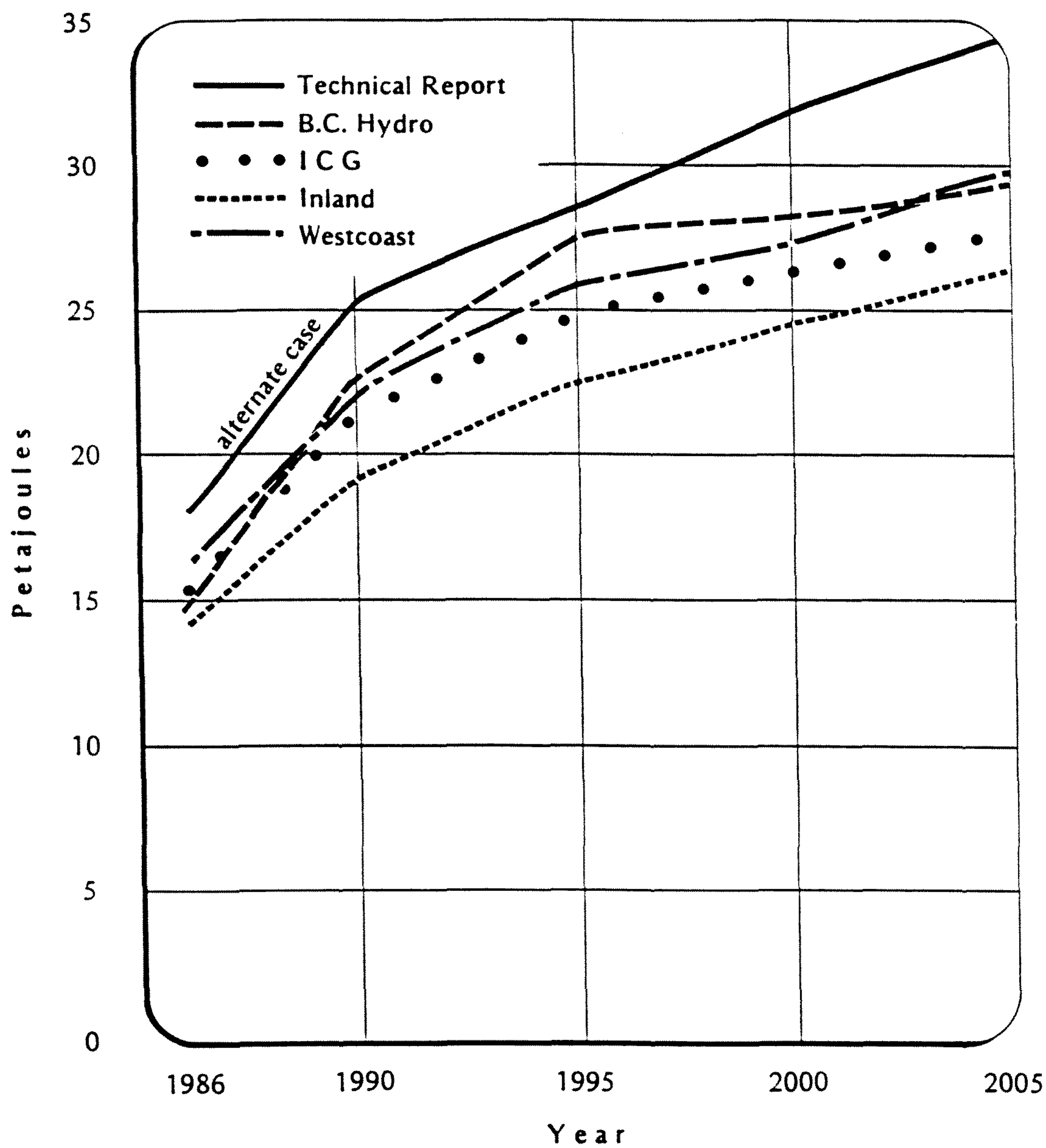
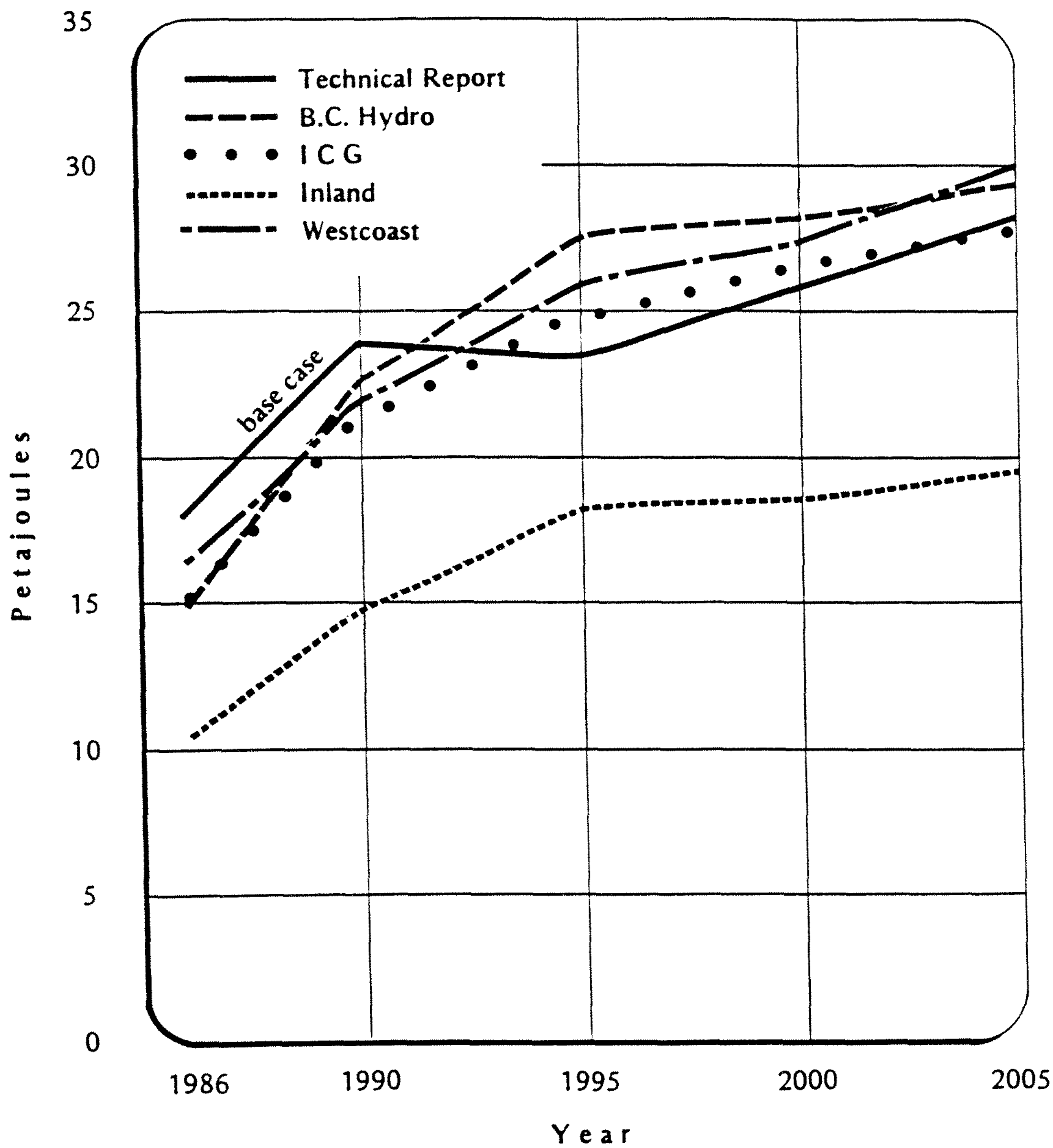


FIGURE 2.5

**Total Gas Service Area (GSA) Forecasts
(Low Scenario)**



while the Applicants' forecasts (with the exception of Inland Case B) are predicated on the maintenance of large industrial sales. The make-up of the load is a critical factor to the design of pipeline capacity. A project involving a relatively high component of residential sales would require a considerably greater design capacity than a project relying extensively on industrial sales due to the poor load factor of residential sales.

The evidence before the Commission indicated that there may be less demand in the residential/commercial sector than forecast in the Technical Report. UNDOUBTEDLY THIS IS A KEY REASON WHY ALL THE APPLICANTS INDICATED THAT CONTRACTUAL COMMITMENTS FROM THE INDUSTRIAL USERS ARE CRITICAL TO THE VIABILITY OF THE PROJECT.

2.1.2 Fertilizer Plant Demand

Westcoast was the only Applicant that presented an independent forecast of fertilizer plant demand. Its forecast indicated that the fertilizer plant proposed for Powell River would require 14.2 PJ in 1986 and 21.5 PJ in each subsequent year. The Technical Report indicated annual fertilizer plant requirements of 22.55 PJ commencing in 1986. The Fertilizer Consortium panel later testified that, assuming approval in 1984, the earliest on-stream date for the fertilizer plant would be 1988.

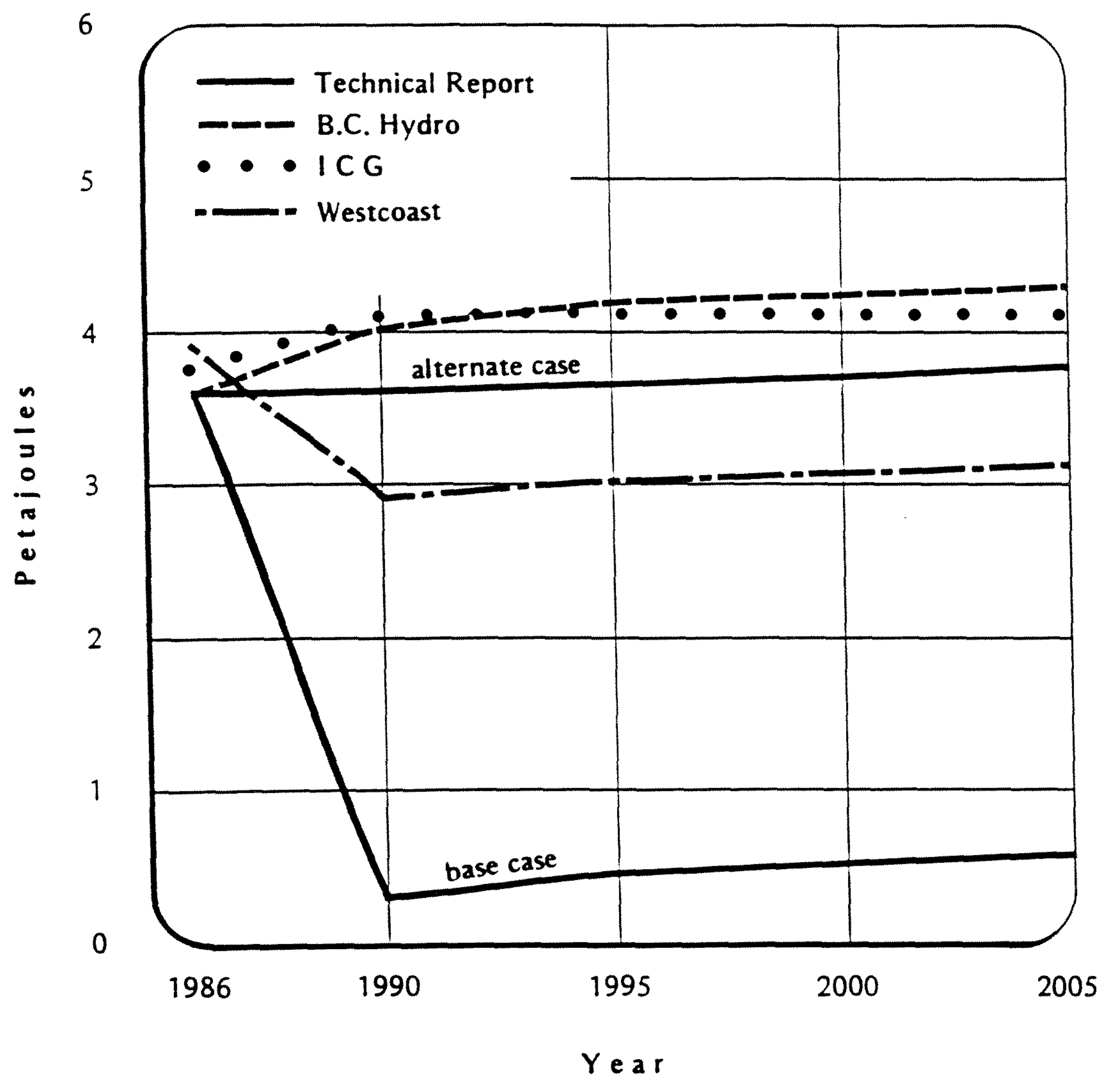
2.1.3 Powell River Demand

The forecasts of natural gas demand for Powell River, as presented by Westcoast, B.C. Hydro, ICG and in the Technical Report, are shown in Figure 2.6.

The Technical Report alternate case forecast and the Applicants' forecasts project a demand between 2.9 and 4.3 PJ over the entire forecast period. It should be noted that these forecasts are predicated on significant sales to the MacMillan Bloedel pulp mill in Powell River from 2.6 to 3.6 PJ, each year

FIGURE 2.6

Powell River Load Forecasts



throughout the forecast period. The Technical Report alternate case forecast and those of the Applicants include both residential/commercial and industrial loads. These demands range from 2.9 to 4.3 PJ over the forecast period. The Technical Report base case, which excludes industrial load, predicts a demand of 0.6 PJ by the year 2005.

2.1.4 Natural Gas Vehicle Demand

The forecasts for Vancouver Island Natural Gas Vehicle (NGV) demand, as presented in the Technical Report and by B.C. Hydro (medium case) are shown in Figure 2.7. The other Applicants did not submit independent NGV forecasts. Inland adopted the forecast presented in the Technical Report, while ICG indicated that the future use of compressed natural gas was too speculative to permit forecasts at this time. Westcoast agreed that both the B.C. Hydro and Technical Report forecasts are attainable, although the timing of this demand remains uncertain.

The B.C. Hydro and Technical Report forecasts show NGV demand on the Island increasing to between 2.2 and 3.3 PJ by the year 2005, with the Technical Report forecast being the more conservative of the two. B.C. Hydro's forecast assumes that over 75,000 vehicles, which is approximately 16% of all Vancouver Island vehicles, will be using compressed natural gas by 2005.

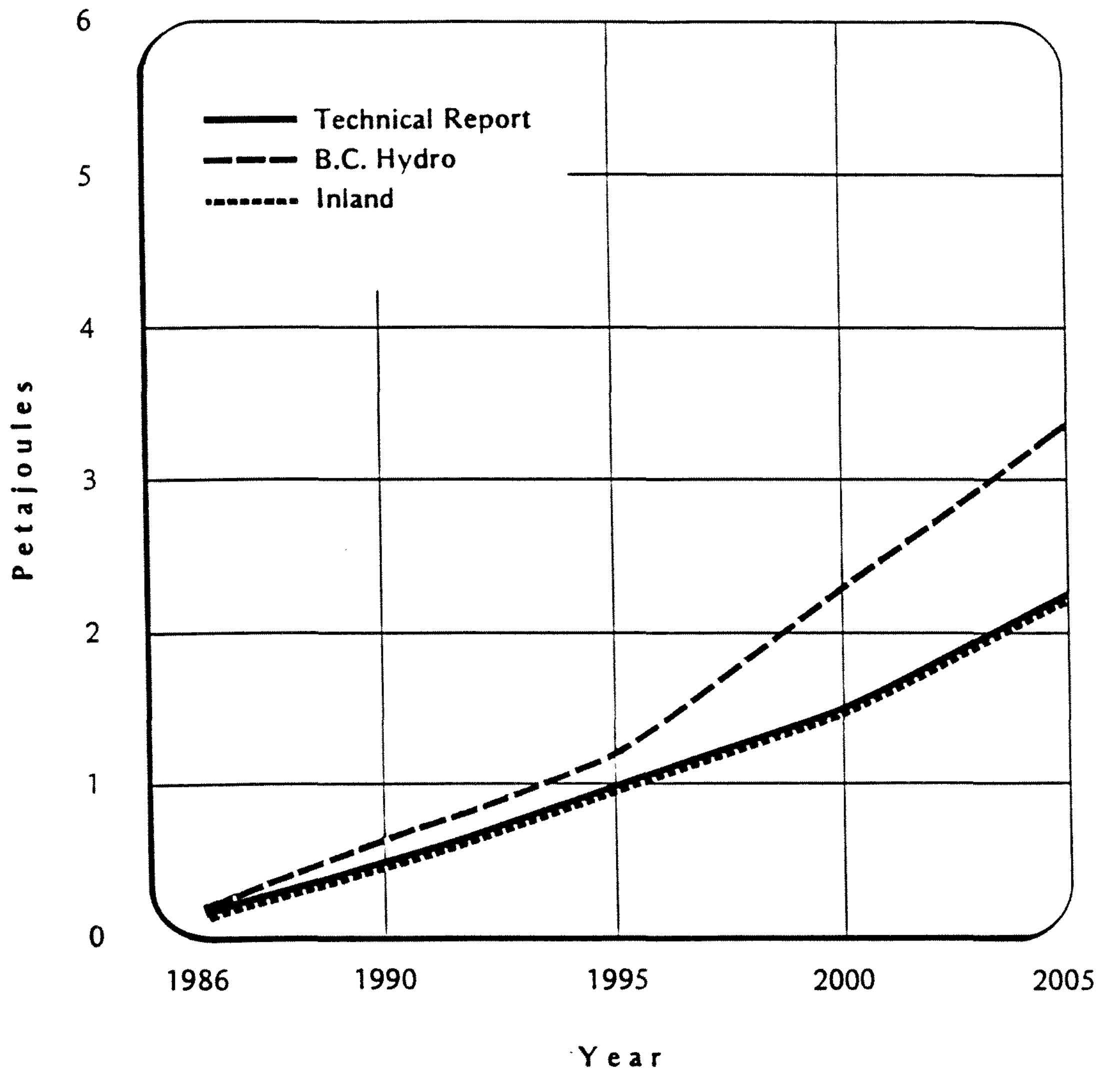
2.2 General Issues

2.2.1 Basic Assumptions and Methodology

In developing their forecasts of Vancouver Island gas demand, the Applicants identified the area that they assumed would have access to gas, and made certain assumptions regarding the timing of gas availability. They estimated how many existing potential customers would convert to gas, how many new customers would be captured, and the volume of gas that each type of customer would use.

FIGURE 2.7

Natural Gas Vehicle Forecasts



The Commission did not undertake an evaluation of the methodology employed by the Applicants, although there was limited cross-examination regarding differences in forecast methodology used by the Applicants.

(a) Market Area

The GSA's assumed by the Applicants are generally similar to one another and to the market area assumed in the Technical Report. There are, however, some minor differences that should be identified.

B.C. Hydro's gas service area includes Victoria, Cowichan Valley, Nanaimo, Alberni and Comox Census Divisions and appears to be the same as the GSA covered by the Technical Report. ICG identifies a similar market, but has added Royston to the service area, while the Inland proposal includes the communities of Langford, Metchosin, Chemainus and Crofton. Westcoast's market area is similar to that of Inland's , but with the further addition of census subdivison B of the Capital Regional District.

(b) Timing

All the evidence presented by the Applicants was based on gas being available toward the end of 1985 or beginning of 1986. ICG and Westcoast identified an in-service date of November 1, 1985, while B.C. Hydro and Inland assumed 1986 as the first year of service.

The Applicants were asked to comment on the impact of a delay in gas availability on their forecasts. Inland, Westcoast and ICG did not provide a quantitative response to this question. However, Westcoast did indicate that the forecast gas demand would not be affected. ICG indicated that the effect would depend on the reasons for the delay. For example, if the delay resulted in uncertainty regarding whether gas would ever become available, this could then result in the selection of alternative fuels by potential customers who would not later convert to natural gas.

B.C. Hydro provided a quantitative estimate of the impact of a delay in gas availability. On the assumption that new units constructed during the delay would use electricity for heating and would not be subsequently converted to gas, B.C. Hydro estimated that a six month delay would reduce annual residential and apartment demand by 0.091 PJ. Similarly, a 12 month delay would reduce annual demand by 0.183 PJ.

All Applicants indicated that they would not undertake any pre-build of facilities prior to certification and arrangement of satisfactory financial commitments.

(c) Forecast Methodology

While each Applicant and the author of the Technical Report derived their forecast in a different manner, they all followed what is termed an "end-use" engineering approach. Generally, to derive sectoral demand forecasts, market sectors were identified and projections formulated on the basis of the number of customers and estimated use per account or use per unit of activity. In developing their forecasts, each of the Applicants made energy price assumptions regarding the price of gas relative to competing fuels.

2.2.2 Data Base

The Applicants used different types of data to determine the size and existing energy use patterns of the residential and commercial sectors. B.C. Hydro employed its June 1982 billing records to obtain an inventory of residential fuel use by type of dwelling. Total use of liquefied petroleum gas and refined petroleum products by commercial and light industrial users was obtained from government sources and then used to project demand by these sectors on an aggregate basis.

ICG conducted a detailed market survey in early 1979 to identify the numbers of structures and current fuel use in both the residential and commercial sectors. ICG used B.C. Hydro's accounts as a data base for Victoria, Esquimalt and Oak Bay.

Inland used published statistical data on population and numbers of households, and used Regional and Municipal records as well as interviews with fuel distributors to estimate the location and fuel use of residential and commercial buildings.

Westcoast utilized census data and information from B.C. Hydro to estimate the numbers of existing dwellings and types of fuel use in the residential sector. The floorspace and associated fuel use for the eight categories of facilities in the commercial sector was estimated using B.C. Assessment Authority data.

Each Applicant also conducted detailed interviews with representatives from potential large industrial customers.

2.2.3 Energy Prices and Distribution Margins

The forecasts presented by the Applicants assumed a price relationship between natural gas and competing energy sources in which gas has a competitive price advantage. The accuracy of that assumption will depend on future Federal and Provincial Government policy.

In the residential/commercial sector, B.C. Hydro's forecast was based on a 25% price advantage for natural gas over fuel oil. B.C. Hydro did not envisage any difficulty in realizing the residential/commercial price advantage of natural gas if the city gate price of gas outlined in the Minister's letter of September 1, 1983 (Appendix F) is maintained.

In the heavy industrial sector, B.C. Hydro's forecast was based on a 10% price advantage for gas over heavy fuel oil. B.C. Hydro acknowledged that (1) natural gas prices are set at 65% of the Vancouver city gate crude oil price ; and (2) should the ratio of heavy fuel oil prices to crude oil remain at 75%, it would be difficult to realize a 10% price advantage for gas in this sector once distribution margins are taken into account. No specific estimates of sectoral distribution margins were provided in B.C. Hydro's forecast.

Inland assumed a 25% efficiency-adjusted* price advantage for gas in the residential and commercial sectors and a 10% price advantage in the industrial sector. Inland indicated, as did ICG, that these price advantages would not be realized given the Ministry's proposed city gate prices. Based on its distribution margin estimate, and preferred Case B forecast, Inland identified revenue deficiencies for the first nine years of the project.

Westcoast, unlike the other Applicants, developed its forecast on the basis of crude oil, electricity and natural gas price forecasts. This allowed Westcoast to consider changes in consumption of natural gas due to price changes of natural gas independent of the relative prices of competing fuels.** Westcoast then estimated the distribution margins based on the experience of its subsidiary Pacific Northern Gas Ltd. (PNG).

ICG assumed that, on an efficiency-adjusted basis, natural gas initially must have a 15% advantage over competitive fuels in the residential and commercial sectors, and would decline to 10% over a five-year period and then remain at 10% beyond this date. In the industrial sector, a 10% price advantage over heavy fuel oil was assumed. ICG indicated that these price advantages, while required
to achieve the gas penetration rates in their forecast, would not be

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* Efficiency adjustment takes into account the differences in usable heat content for various fuels.

** This is the commonly referred to "own-price" effect.

realized without distributor subsidies or a change in the Ministry's natural gas city gate pricing policy. Based on ICG's forecast of the price of alternative fuels and its estimate of distribution costs, the city gate price of natural gas that any of the Applicants could pay would be considerably less than the price established by the Ministry. <u>ICG estimated that a capital grant to the distribution system in the order of $175 to $200 million would be required if the distributors had to pay the proposed city gate price</u>. A $200 million capital grant in present value terms is equivalent to the revenue deficiency for the first 10 years of the project when discounted at 13%. Other present values for different discount rates are shown in Table 2.1. <u>ICG indicated that it would be necessary to reconsider its application if the proposed city gate prices are not changed</u>.

<u>TABLE 2.1</u>

ICG's Estimate of the Distribution Systems' Revenue Deficiency Assuming MEMPR Pricing Schedule for the <u>First 10 Years of the Project</u>

Discount Rate (%)	Revenue Deficiency ($million)
0	508.1
2	440.9
4	384.4
6	336.6
8	296.0
10	261.5
13	200.2

Although B.C. Hydro and Westcoast did not provide convincing evidence on expected distribution margin requirements, they both, nevertheless, based their market projections on some assumed relative price relationships between natural gas and competing fuels. Only ICG and Inland conducted specific assessments of the distribution margins. The actual magnitude of these margins, given the city gate price, would affect prices at the burner tip. This would in turn alter the price relationships between natural gas and competing fuels.

Based on evidence provided by ICG and in Inland's Case B, the Commission notes that the required distribution margin may well exceed the available margin from the city gate price if gas is to be priced competitively on the Island. In this case, the city gate price must be lower if distribution margins are to be realized without subsidy.

The Commission recognizes that completion of the Cheekye-Dunsmuir transmission line has greatly increased the potential capacity for transmission of electrical energy to Vancouver Island. If electricity is marketed aggressively in the future, the Commission is concerned that the ability of natural gas to penetrate the market may be significantly affected.

Distribution margins and the relative price relationships between competing fuels are issues which will have to be resolved and may require revision to Government policy. However, the Commission recognizes that markets for gas sales, particularly in commercial and industrial markets, will be diminished if current city gate prices are maintained and no financial assistance is provided to distribution utilities.

2.2.4 Marketing Programs and Policies

In addition to the specified price advantages, the Applicants' forecasts all assumed varying levels of conversion assistance and marketing efforts. Two federal conversion assistance plans are presently in effect. The Canadian Oil Substitution Program (COSP) provides a taxable grant for 50% of conversion costs up to a maximum $800 in the residential sector and $5,500 in the commercial sector. The Industrial Conversion Assistance Program (ICAP) provides 50% of the conversion costs in the industrial sector. All Applicants except Westcoast assumed that both COSP and ICAP would continue to provide conversion assistance. Westcoast did not consider ICAP conversion assistance in its forecasts.

B.C. Hydro did not include any distribution financial assistance, but rather based its forecast on an "aggressive" marketing campaign.

ICG assumed that 75% of residential conversion costs would be provided by grants - 50% from COSP and the remaining 25% from the distributor. This higher level of conversion assistance allowed ICG to calculate lower relative price advantages in the residential sector than the other Applicants. ICG further calculated that this distributor conversion assistance program would add from $0.14 to $0.39 per gigajoule (GJ), depending on the year, to the average distribution margin.

Only Inland's proposed medium case forecast assumed that loans would be provided by the distributor to recover the remaining cost of conversion. The effects of different levels of conversion cost assistance on demand were also examined by Inland.

2.3 Residential Sector Issues

2.3.1 Sector Definition

All Applicants defined the residential sector to include single detached, duplex, row housing, and mobile home stocks. The Technical Report and Westcoast also included apartments in their definition. B.C. Hydro analyzed apartment stocks separately and then added them back into the industrial sector, while ICG and Inland included them in the commercial sector.

2.3.2 Housing Stock and Growth Rate

The first step taken by all Applicants in forecasting residential sector demand was to analyze the housing stock in the GSA in order to estimate (1) the number of existing dwellings that could be converted to gas ; and (2) the number of new dwellings that could be captured by the gas market.

B.C. Hydro defined the conversion market as buildings currently using oil and propane. These constituted 68.4% of the total single detached, duplex and row housing stock in the GSA and amounted to a total of about 71,700 households as of June 1982. While acknowledging the existence of a significant number of dwellings that use wood as their primary fuel, B.C. Hydro did not make allowance for this fact in their forecast. With respect to new dwellings for the capture market, B.C. Hydro assumed an average annual growth rate of 2.7% in the number of households in the GSA over the forecast period.

ICG defined the conversion market as 100% of existing structures using propane and 75% of those using oil. The latter figure reflects the fact that wood is actually the primary fuel in some dwellings recorded as using oil. ICG assumed a 2.2% average annual growth rate in the number of households over the forecast period.

Inland originally estimated the "vulnerable" stock of single detached homes as those not currently heated electrically. In its revised forecast presented at the hearings, Inland reduced the vulnerable stock from a potential of over 60,000 to about 50,000 in 1986. This reduction was explained as being due to a greater than previously estimated conversion from oil to wood. Inland projected a 1.95% average annual growth rate in the number of households over the forecast period.

Westcoast, like B.C. Hydro, considered all non-electrically heated dwellings as potential natural gas users and did not make an allowance for conversions from oil to wood. Data from B.C. Hydro were used to estimate current fuel use. The projected average annual growth rate in households over the forecast period was 1.95%.

Given the evidence on conversion to wood, as provided from federal COSP assistance, the assumptions of both B.C. Hydro and Westcoast for the convertible housing stock would appear to be high. Wood conversion may not be a long-term phenomenon, although the number of wood conversions that have already taken place has reduced the size of the convertible housing stock. Since only one COSP grant is available to each household, once this grant has been used for conversion, it would no longer be available for future conversion to natural gas.

The Commission used ICG and Inland assumptions regarding existing convertible housing stock (approximately 50,000) in its market forecast.

2.3.3 Accessibility

In the early years of the project, the number of buildings that could potentially use gas and have reasonable access to gas mains is an important variable for predicting the build-up of the load. High conversion rates of the potential stock will be difficult to achieve if the number of buildings within reach of gas mains is low. The Applicants all agree that accessibility will range from 80 to 100% in the GSA after a number of years. However, their predictions regarding how quickly this will occur tend to vary.

Neither B.C. Hydro nor ICG developed accessibility factors as part of their forecasts. B.C. Hydro's implied accessibility would have to be high to allow the predicted capture and conversion rates since in the first year of the project, B.C. Hydro forecasts that 25% of the existing stock and 40% of new dwellings would be connected to gas. After seven years, B.C. Hydro expects that 85% of the single detached and duplex residences would be converted to gas. Gas accessibility to virtually the entire market area is a prerequisite for achievement of these rates. In contrast to B.C. Hydro, ICG implied accessibility is much lower since it projects that only 10% of the existing potential stock will convert to gas in the first year, and that this will rise to 75% over a ten year period.

Inland's estimate of accessibility factors for each community in the GSA ranged from 80 to 100% for single detached houses. However, the factors were ultimate values, and evidence regarding the rate of build-up was not provided.

Westcoast was the only Applicant to provide estimates of annual accessibility. It assumed that 30% of the single detached and single attached stock would have access to gas service in the first year of service, and that this would reach 90% by the tenth year of the project. The relatively low accessibility of these stocks to gas during the initial years of service is in marked contrast to B.C. Hydro's forecast.

2.3.4 Effective Conversion and Capture Rates

Effective conversion and capture rates are numerical indicies which represent the percentage of total potential housing stock that use gas. They include the joint effect of accessibility with conversion and capture rates. Effective conversion rates for single detached houses are summarized in Table 2.2.

TABLE 2.2

Cumulative Conversion Rates of Potential Residential Market

Year	B.C. Hydro	ICG	Inland	Westcoast	Technical Report
1986	0.25	0.10	0.08	0.03	0.19
1987	0.40		0.23		0.41
1988	0.50		0.38		0.56
1989	0.60		0.46		0.68
1990	0.70		0.51	0.26 (1991)**	0.72
1995	0.85	0.75	0.73	0.53 (1996)	0.76
2005	0.85	0.75*	0.90	0.80 (2006)	0.76

As indicated in Table 2.2, the Technical Report and B.C. Hydro assumed much higher conversion rates during the first five to ten years of the project than the other Applicants. As a result, the Technical Report and B.C. Hydro residential forecasts are significantly higher than the other estimates over this period. By the year 2005, Inland expects the highest rate of conversion, although this Applicant assumes a smaller potential market than B.C. Hydro. B.C. Hydro projected the largest number of conversions in terms of numbers of single detached houses.

The effective capture rates for single detached new homes are shown in Table 2.3 :

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* This conversion rate applies to all homes on refined petroleum products.

** Westcoast did not provide figures for the years 1990, 1995 or 2005.

TABLE 2.3

Effective Annual Residential Capture Rates
For Single Detached Homes

	B.C. Hydro	ICG	Inland	Westcoast	Technical Report
1986	0.40	0.75	0.70	0.31	0.34
1987	0.60	0.75	0.75	0.45	0.51
1988	0.70	0.75	0.75	0.54	0.63
1989	0.75	0.75	0.80	0.58	0.72
1990	0.80	0.75	0.80	0.62	0.76
1995	0.80	0.75	0.90	0.79	0.81
2000	0.80	0.75	0.90	0.77	0.76
2005	0.80	0.75	0.90	0.76	0.71

Although there is considerable variation in the early years, all forecasts predict capture rates in the 70 to 90% range by the end of the forecast period. The forecasts of B.C. Hydro, Westcoast and the Technical Report all begin with low capture rates. Westcoast and the Technical Report recognized that limited accessibility would reduce capture rates, while B.C. Hydro predicted difficulty in convincing contractors to install gas in new homes.

With respect to conversion rates, the Commission notes that B.C. Hydro's projected conversions occur very quickly, in marked contrast to Westcoast's particularly slow build-up of natural gas conversions. Both of these extremes appear to be unrealistic. One projection assumes virtually total accessibility in the first year of service as well as maximum sustained rates of conversion, while the other projection is too conservative. By comparison, both ICG and Inland, by relying on their distribution experience and detailed accessibility surveys, projected a moderate and likely more realistic load build-up. In terms of capture rates, Westcoast's projection is again the lowest, while

Inland's projection, in the 90% range by 1995, is the highest. The Commission believes that ICG's projections are more realistic and they have been used in the Commission's forecast.

2.3.5 Use Per Account

To derive forecasts of total residential energy demand, the Applicants estimated input energy requirements, or use per account, for the existing dwellings that would convert to gas and new dwellings that will install gas.

B.C. Hydro estimated that in existing single detached houses, input energy requirements for space and water heating would average about 123 GJ per year. If gas use for cooling, clothes drying and swimming pools is included, the average requirement would increase to 128.8 GJ per year. In new single detached houses, the input energy requirement was expected to average 63 GJ per year for space and water heating and 66 GJ per year for all uses.

ICG's estimated use per account of 115 GJ for single detached dwellings during the forecast period was derived using a formula based on the average floor area and a coefficient that measures energy consumption per unit of space per year. For new housing stock, the use per account was assumed to be 10% lower due to conservation. This is comparable to the current provincial average consumption of 120 GJ per household per year. ICG indicated that consumption of natural gas on Vancouver Island could be expected to be lower than the provincial average because of the milder climate.

In its updated forecast, Inland estimated the output energy requirements for space and water heating of existing single detached dwellings at 75 GJ per year. On an efficiency-adjusted basis, this is equivalent to an annual input requirement of 107 GJ in 1986. For new single detached dwellings, estimated output requirements of 68 GJ result in input requirements of 97.5 GJ per year in 1986. Input requirements are expected to decline with time, primarily due to greater utilization of more efficient furnaces.

Westcoast, in its final submission on demand, revised its use per account projections upwards. It believed that the general lowering of energy prices in absolute terms will result in higher consumption. Westcoast indicated that input energy requirements in existing houses will average 138.3 GJ per year as compared to the 129.6 GJ per year figure presented in its original forecast. Westcoast's forecast of use per account is higher than all of the other forecasts.

The estimated ranges of use per account differed significantly among the Applicants. B.C. Hydro estimated 128 GJ per year for existing single detached units and 66 GJ per year for new units. ICG forecast an average use per account of 115 GJ per year, while Inland estimated 107 GJ per year for existing single detached units and 97.5 GJ per year for new units. Westcoast projected an average of 138.3 GJ per year per unit. The Commission is not in a position to independently estimate the appropriate use per account for Vancouver Island, but notes the wide variation between the Applicants' forecasts as well as the conflicting evidence submitted by B.C. Hydro and Westcoast.

THE COMMISSION CONCLUDES THAT ICG'S ESTIMATE IS THE MOST PROBABLE GIVEN THE CURRENT PROVINCIAL AVERAGE CONSUMPTION OF 120 GJ PER YEAR PER HOUSEHOLD AND THE APPLICANT'S EXPERIENCE WITH VANCOUVER ISLAND WEATHER AND CUSTOMERS. THE COMMISSION USED THIS ESTIMATE IN ITS FORECAST.

The Commission is aware of the inroads that high-efficiency residential natural gas furnaces have made in recent years. These new furnaces could reduce input energy requirements for space heating by 40% compared with conventional furnaces. During the past year, the price of high-efficiency furnaces has been approaching that of conventional furnaces. It is possible, therefore, that the new high-efficiency furnaces may become a standard installation by the time conversions are being made on Vancouver Island. Consequently, the Commission notes that natural gas use per account may be less than that estimated by each of the Applicants.

2.3.6 Residential Load Forecasts

The resulting residential sector forecasts of the total load requirements provided in the Technical Report and by each Applicant are shown in Table 2.4 :

TABLE 2.4

Residential Load Forecasts
(PJ)

	B.C. Hydro*	ICG	Inland	Westcoast*	Technical Report*
1986	2.78	1.06	0.96	0.92	2.72
1990	7.89	4.96	3.48	4.38	9.30
1995	10.66	6.59	6.29	8.26	11.34
2000	10.66	7.62	6.29	10.21	12.52
2005	11.25	8.39	7.25	11.96	13.20

* Includes apartment stock

2.4 Commercial and Light Industrial Sector Issues

2.4.1 Sector Definition

The commercial sector is a residual category consisting of all buildings, service and industrial activities not included in the residential or heavy industrial sectors. B.C. Hydro defined the commercial sector as apartments*, commercial and institutional buildings, food and beverage, wood product, printing, metal fabricating and machinery industries. ICG and Inland used a similar sectoral definition. Westcoast's commercial sector consists of

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* Apartment requirements were reported separately and have been added back into the residential sector.

retail, office, service entertainment, tourist accommodation, hospital, schools and all manufacturing activities that were not included in their heavy industrial sector.

2.4.2 Forecast Methodology

The methodology used to forecast commercial sector growth varied among the Applicants. To estimate commercial demand, ICG and Inland applied conversion and capture rates and use per account to the total number of accounts. B.C. Hydro applied capture and conversion rates to non-electric fuel use in this sector, thereby estimating non-apartment demand. Apartment demand was estimated in the same manner as in the residential sector. Westcoast applied conversion and capture rates to estimate future total floorspace in each sub-category of commercial building, and then used an estimate of energy requirements per unit of floor area to forecast demand. An energy coefficient per employee was used for the light industrial component of this sector.

The varying forecast methods and different definitions of sub-sectors in the commercial sector hampered a simple assessment of the issues. The same factors as discussed for the residential sector, (i.e. accessibility, use per account, and conversion and capture rates) also influence this commercial and light industrial sector, and are therefore discussed below.

2.4.3 Accessibility

Westcoast was the only Applicant to provide specific accessibility factors throughout the life of the project. It estimated that 50% of all commercial accounts would have access to gas in the first year, while 80% would have access by year five. There was a general consensus among the Applicants that accessibility in the commercial sector would be realized more rapidly than in the residential sector.

2.4.4 Effective Conversion and Capture Rates

The effective conversion and capture rates assumed for this sector by the Applicants are summarized in Table 2.5 and Table 2.6. These rates apply to commercial accounts excluding apartment units.

TABLE 2.5

Effective Cumulative Conversion Rates of
Fossil Fuel Heated Commercial Accounts
(%)

	B.C. Hydro	ICG	Inland	Westcoast
1986	0.15	0.10	0.20	0.07
1987	0.30		0.40	0.21
1988	0.45		0.60	0.36
1989	0.55		0.70	0.47
1990	0.65		0.75	0.58
1991	0.75		0.80	0.66
1995	0.85	0.75	0.94	0.77
2000	0.85	0.75	0.98	0.86
2005	0.85	0.75	0.98	0.95

TABLE 2.6

Effective Cumulative Capture Rates
of Fossil Fuel Heated Commercial Accounts
(%)

	B.C. Hydro	ICG	Inland	Westcoast
1986	0.90	0.75	0.95	0.40
1987	0.90	0.75	0.95	0.56
1988	0.90	0.75	0.95	0.63
1989	0.90	0.75	0.95	0.67
1990	0.90	0.75	0.95	0.70
1991	0.90	0.75	0.95	0.73
1995	0.90	0.75	0.95	0.71
2000	0.90	0.75	0.95	0.69
2005	0.90	0.75	0.95	0.66

There was a wide range in the conversion and capture rates estimated by the Applicants. ICG and Westcoast were generally more conservative than B.C. Hydro and Inland. The latter two envisage a very rapid rate of conversion of all accounts in the first five years (65-75%) and very high capture rates for new accounts (90-95%). This is in marked contrast to Inland's residential and apartment forecast, where much lower conversion and capture rates were assumed.

2.4.5 Growth Rates and Use Per Account

B.C. Hydro estimated the growth in this sector in two categories, apartment stock and "other" commercial.* The apartment units are expected to increase from 24,566 in 1986 to 43,843 units in the year 2006 ; this is equivalent to a growth rate of 3.6% per year. In the "other" commercial category, the energy demand is expected to increase at a rate of 0.145 PJ per year. The use per account is estimated to be 45.5 GJ per year for apartment stock and 79.5 GJ per year for the "other" commercial sector in 1986. These estimates are expected to decrease due to conservation effects to 42.5 GJ per year and 67.5 GJ per year respectively by 2006.

All Applicants used different methods to develop their commercial sector forecasts. ICG did not provide estimates of the growth rate in this sector. However, it adopted B.C. Hydro's estimates in the Capital Regional District sub-district. For the remainder of the GSA, ICG assumed the same growth rate for natural gas demand as in the residential sector. Inland projected a growth rate of 3.6% per year in the number of commercial accounts, although no use per account data was provided.

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* The "Other" commercial category in B.C. Hydro's sectoral classification is a residual one, which includes the commercial and light industrial sub-sectors.

Westcoast estimated growth rates for different categories of commercial space by using the forecast of population growth rates. The retail floor space was expected to increase at 1.5% per year, office floor space at 1% per year, and tourist accommodation at 3% per year. Use per account estimates were not provided in Westcoast's updated forecast.

2.4.6 Commercial Sector Load Forecasts

The resulting commercial sector load forecasts by each Applicant, as well as that presented in the Technical Report, are shown in Table 2.7.

TABLE 2.7

Commercial Sector Load Forecasts
(PJ)

	B.C. Hydro*	ICG	Inland	Westcoast*	Technical* Report
1986	1.10	2.19	1.43	2.52	2.41
1990	4.24	4.94	4.04	4.84	4.44
1995	6.07	6.42	5.55	5.82	5.82
2000	6.60	6.79	6.60	6.70	7.45
2005	7.12	7.34	7.57	7.56	9.07

* Excludes apartment stock

The Commission notes that despite the different approaches adopted by the Applicants to estimate the load demand in this sector, after adjustment for different sectoral definitions, they all converge to a range of seven and eight petajoules per year by 2005, while the Technical Report forecasts 9.07 PJ per year by that date.

2.5 Heavy Industrial Sector Issues

2.5.1 Sector Definition

The heavy industrial market in the GSA on Vancouver Island consists of five potential customers : four pulp and paper mills and one chemical plant, Table 2.8.

TABLE 2.8

Companies and Location of Heavy Industrial Mills/Plants on Vancouver Island

Company	Location	Mill/Plant
MacMillan Bloedel	Harmac	Harmac
MacMillan Bloedel	Port Alberni	Alpulp
B.C. Forest Products	Crofton	Crofton
Crown Forest	Campbell River	Elk Falls
Canadian Occidental	Harmac	Chemical Plant

In terms of total heavy industrial demand on the Island, the four mills are by far the most significant potential users since the chemical plant's demand would be relatively insignificant at about 0.2 PJ.

2.5.2 Convertible Energy Load Estimates and Forecasts

B.C. Hydro approached the industrial load as an "all or nothing" situation. It assumed that if the price of natural gas is a competitive alternative for one customer, then it should be practical for all heavy industrial users. Given this approach and the assumption that only heavy fuel oil (HFO) and not hog fuel will be replaced by natural gas, B.C. Hydro estimated a total potential load of 13.7 PJ. In forecasting the actual load demand, it reduced this potential by 20% since this industry has not historically operated at full capacity. This reduction resulted in a load forecast for the Vancouver Island GSA of 10.9 PJ per year.

ICG's forecast for this sector assumes that 100% of the industrial market would be captured, and that all convertible fuel requirements would be supplied by natural gas. This results in a load projection for the Vancouver Island GSA of 11.9 PJ per year.

Inland estimated the potential convertible fuel requirement at a maximum of 14.2 PJ per year. It projected two scenarios in the development of the actual forecast for this sector. Case A projects maximum penetration by natural gas and assumes HFO prices to be 70% of the west coast crude price, increasing to 75% over time. The load was estimated at 90% of the maximum potential value, resulting in a forecast of 11.7 PJ per year.* Case B assumes that HFO prices will decline over time, thereby reducing natural gas requirements. In this case, the total load would decrease to 4.82 PJ per year in 2005.

In Westcoast's 1983 updated forecast, the estimate of convertible fuel requirement was revised to account for anticipated trends in energy prices, technology and market conditions. This updated forecast is 20% higher than its 1982 forecast. The total convertible fuel demand for the mills in the GSA is now estimated to be just over 14 PJ per year, the actual forecast is 90% of this total, or about 12.8 PJ per year. This total decreases somewhat over time due to reduced industry requirements.

Table 2.9 is a summary of the load forecasts developed by each of the Applicants.

TABLE 2.9

Heavy Industrial Sector Load Forecasts
(PJ)

	B.C. Hydro	ICG	Inland A	Inland B	Westcoast
1986	10.92	11.9	11.7	8.04	12.80
1990	10.92	11.9	11.7	7.36	12.80
1995	10.92	11.9	11.7	6.51	11.82
2000	10.92	11.9	11.7	5.67	10.36
2005	10.92	11.9	11.7	4.82	10.36

* This potential excludes the B.C. Forest Product's lime kilns.

All forecasts of the Applicants, with the exception of Inland's Case B, assume that either all or a high percentage of the potential market would be captured by natural gas. This forecast does not consider the potential effects of such factors as price competition from HFO, future technological change resulting in conversion to electricity as a fuel source, and consideration of contractual terms reflecting market fluctuations and peaking requirements. These factors may alter the Applicants' load projections and are discussed in detail in Sections 2.5.3 to 2.5.5.

2.5.3 Heavy Fuel Oil

Future trends in the supply and demand of heavy fuel oil (HFO) and their resultant effects on HFO prices could have a marked impact on the industrial sector forecast. This is most clearly illustrated in the two alternatives developed by Inland.

Inland's Case A forecast assumed elimination of the expected HFO surplus that would be caused by gas service to the Island. This elimination is accomplished by diminishing supply and strong export demand. However, in Case B, Inland assumed that supply is maintained and exports are reduced.

This in turn results in a lower HFO price in order to clear the product within its market. Specifically, Inland Case B assumes declining crude oil quality (more heavy end products) at the local refineries, continued operation of existing refineries, the elimination of export licences and the continuation of the Oil Importation Program. These factors would produce relatively more HFO supply, and thereby markedly reduce the HFO price forecast.

Westcoast projected a significant domestic HFO surplus by 1986, where the level of surplus would approach 12% of the volume consumed in 1980. But Westcoast does not believe this would decrease gas demand. Contrary to the views of the other Applicants and COFI, Westcoast suggested that natural gas does not have to be priced below HFO in order for it to capture the market, but rather that natural gas should be able to command a price premium because of its superior quality as a fuel. It was indicated further by Westcoast's policy witness that the future movement of HFO prices is to some extent irrelevant because long-term contracts would be in place for gas delivery to the industrial customers.

2.5.4 Contractual Commitment

There was a general consensus among the Applicants that long-term contracts of 10 to 20 years would be required to service the industrial markets. They also agreed that contractual terms and conditions will have to be flexible. The Applicants repeatedly emphasized that the traditional force majeure clause cannot be interpreted to include production cutbacks necessary due to market weakness. However, they recognized that stricter terms and conditions could significantly affect the level of firm demand.*

The Commission believes that contracts can be successfully negotiated between the gas supplier and the industrial customers, although the actual volumes contracted may change significantly as a result of differences in the terms and conditions of the contracts. With respect to the question of contract terms and expected sales, the following synopsis of COFI evidence is considered most pertinent.

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* The level of firm demand directly relates to the degree of contract flexibility. The more flexible the contract, the higher is the contracted volume of demand. This contracted volume, however, cannot then be construed as "firm" since the flexibility of the contract would reduce the obligation of the user to purchase the gas.

2.5.5 COFI Position

COFI stated that in the five GSA mills (including MacMillan Bloedel's Powell River mill), 12 hog-fuel boilers, four oil-fired boilers, one recovery boiler and nine lime kilns could be converted from heavy fuel oil to natural gas. On this basis, COFI estimated a 1986 Maximum Oil Replacement (MOR) of 9.98 PJ per year without the Powell River mill and 13.5 PJ per year with this mill. However, actual oil replacement would be less than this because of peaking requirements, curtailments and a reluctance to negotiate contracts for full volumes if there is no flexibility in annual contract volumes or a liberal force majeure clause.

COFI's technical panel estimated the range of contract volumes as percentages of the MOR. In Case A, where natural gas can meet all periods of peak demand and the force majeure clause recognizes production cutbacks due to soft markets, contract volume of firm gas demand may reach 80% of MOR. However, in Case B, where the natural gas cannot meet any peaking demand and the force majeure clause does not include production cutbacks, firm gas demand may drop to as low as 50% of the MOR.

The COFI panel did not identify any immediate plans for capacity additions but indicated that it expects the MOR would increase to about 16.2 PJ (including Powell River) in the event of an improvement in the economic climate resulting in increased mill production. However, the panel did believe that there will be some fluctuation in the MOR value over the long-term. The change to Chemical Thermal Mechanical Pulp (CTMP) and conversion to Thermo-Mechanical Pulp (TMP) at the Alberni mill during the next 10 years is considered possible. Both of these processes utilize electric power. Moreover, by the year 1995, the five mills in the GSA will have undergone major revisions to maintain their competitiveness. This would result in a further decline of the MOR to about 10.13 PJ. The resulting potential range of load demand projected by COFI is summarized in Table 2.10.

TABLE 2.10

COFI Load Forecasts
(PJ)

		1986	1988	1995
Case A	- (including Powell River)	11.58	12.96	8.10
	- (excluding Powell River)	8.67	9.69	6.06
Case B	- (including Powell River)	7.24	8.10	5.06
	- (excluding Powell River)	5.42	6.06	3.78

COFI's technical panel presented evidence on the historical price relationships between HFO and crude oil. On a heat-efficiency basis, HFO has been priced at about 75% of crude. COFI indicated that the market for HFO on the west coast is very favourable, and that the forest industries expect this situation to continue in the future.

COFI emphasized that for natural gas to capture the industrial market, it must offer a superior combination of price and conditions of sales relative to HFO. COFI was adamantly opposed to and recommended the rejection of any direct or indirect requirement for the use of natural gas by the GSA mills which would adversely affect their competitive market position.

COFI suggested that the forest industries likely will not convert to gas if a 65% city gate price of natural gas in relation to crude oil is established. It further suggested that the forest industry will require a price discount of natural gas relative to HFO of 24% in the first two years, and eight percent thereafter. The 24% price discount includes a 16% price reduction to fully depreciate the costs of conversion over two years beyond the assistance provided by the ICAP. COFI indicated that the costs incurred by the five mills would be approximately $12.25 million, and that the two-year pay-back period would be a management policy matter. This price discount calculation was based on COFI's original estimates of the actual oil replacement volume. A higher discount would be required to cover the costs of conversion if this volume were less than projected.

The Commission concludes that contractual terms and conditions as well as future technological changes will be critical factors in determination of the actual volumes of firm gas sales.

2.6 Natural Gas Vehicle Demand

Table 2.11 shows the natural gas vehicle demand forecast in the Technical Report and by B.C. Hydro. The forecasts are predicated on a 16% conversion of all Vancouver Island vehicles to natural gas by the year 2005. The other Applicants did not provide NGV forecasts.

TABLE 2.11

Natural Gas Vehicle Demand (PJ)

	Technical Report	B.C. Hydro
1986	0.14	0.16
1990	0.50	0.65
1995	1.00	1.20
2000	1.50	2.30
2005	2.25	3.30

2.7 Fertilizer Plant Demand

Westcoast initially indicated that the proposed fertilizer plant would require 14.2 PJ in 1986 and 21.5 PJ in each subsequent year. This projection was subsequently revised by a Westcoast panel for the fertilizer plant. The evidence given was that if a site for the plant can be made available in June 1984, and an acceptable price for natural gas is agreed upon in July 1984, the fertilizer plant could be brought on stream by approximately 1988 at the earliest.

This new forecast is premised on : (1) a commitment being made to construct the plant prior to receiving an energy project certificate, given an acceptable plant site and gas prices ; and (2) the energy project certification process requiring between 8 and 12 months to complete.

With respect to the stability of the load, a representative of the fertilizer plant consortium from Union Oil of California stated that unprecedented downside protection will be made available because Union Oil will proportionately curtail production in its other plants, rather than the B.C. plant, in the event of a decrease in the demand for fertilizer.

2.8 Powell River Demand

Powell River could be serviced with gas by either the Westcoast northern route or the B.C. Hydro southern route (Systems A and B). Forecasts of Powell River residential, commercial and industrial loads were presented by Westcoast, B.C. Hydro and ICG, and are shown with the Technical Report forecast in Table 2.12.

The residential/commercial load by itself is very small. As indicated in Table 2.12, the industrial sector initially accounts for over 90% of the load. Even at the end of the forecast period, it represents 78% to 88% of the load in all forecasts except for the Technical Report base case.

2.9 Commission Assessment of the Market

2.9.1 General Issues

With respect to general issues, the Commission has assessed the market based on the evidence presented by the Applicants at the hearing.

1. All of the Applicants presented separate forecasts which in general projected lower residential and commercial demands than

TABLE 2.12

Powell River
Residential, Commercial and Industrial Forecast (PJ)

	Technical Report (Base)			Technical Report (Alternate)			Westcoast			B.C. Hydro			ICG		
	R/C	I	Total	R/C	I	Total	R/C	I	Total	R/C	I	Total	R/C	I	Total
1986	0.17	3.45	3.62	0.17	3.45	3.62	0.16	3.78	3.94	0.20	3.39	3.59	0.13	3.64	3.77
1990	0.32	0	0.32	0.32	3.31	3.63	0.33	2.57	2.90	0.64	3.39	4.03	0.46	3.64	4.10
1995	0.46	0	0.46	0.46	3.18	3.64	0.46	2.57	3.03	0.83	3.39	4.22	0.48	3.64	4.12
2000	0.52	0	0.52	0.52	3.19	3.71	0.52	2.57	3.09	0.87	3.39	4.26	0.48	3.64	4.12
2005	0.58	0	0.58	0.58	3.19	3.77	0.58	2.57	3.15	0.91	3.39	4.30	0.48	3.64	4.12

R/C Residential and Commercial
I Heavy Industrial

those stated in the Technical Report. As a result, the Applicants' overall forecasts only approach the Technical Report base case if all of the estimated convertible heavy industrial requirements are captured by natural gas.

2. All of the Applicants based their forecasts on a late 1985 or early 1986 in-service date. Any delay would cause some modest reduction in forecast load due to interim losses in the capture market.

3. There was significant conflicting evidence presented by the Applicants. In September 1983, both Inland and Westcoast submitted updated forecasts that differed significantly from their original projections. Inland substantially reduced its load estimates because of changes in energy use patterns that would result from changes in energy prices and policies. Westcoast, on the other hand, increased its use per account estimates, citing the lower energy price outlook as the basis for the increase. The other Applicants also modified their forecasts and, in addition, presented evidence on distribution margin estimates that was either inadequate or widely divergent.

4. With the exception of Westcoast, all the Applicants based their forecasts on assumed price relationships between natural gas and competing fuels. Given the Ministry of Energy, Mines and Petroleum Resources' city gate prices and subsequent distribution margins, the resultant burner tip prices may not be the same as those based on competitive fuel price relationships. Therefore, these forecasts may not be realizable.

2.9.2 Sectoral Assessment

(a) Residential and Commercial Sectors

The following is a summary of the Commission's comments on major issues in the residential and commercial sectors.

1. There have been significant conversions to wood on Vancouver Island and this has diminished the potential gas conversion market. However, only Inland, and to some extent ICG, considered this trend in preparing their forecasts for the residential sector.

2. B.C. Hydro's high conversion rates in the early years of the project were based on the full accessibility of the GSA in the first year. The Commission believes that it is unrealistic to assume that accessibility can be realized so rapidly in the residential sector.

3. Use per account estimates were developed on the basis of the Applicants' judgment, and as a result, their validity is difficult to assess. However, it is the opinion of the Commission that Westcoast's estimates are high, since they are higher than the current provincial average and do not reflect the trend of decreased consumption observed over the last several years.

4. The commercial sector forecasts of all the Applicants are relatively close to one another, but significantly lower than those in the Technical Report. This sector is difficult to assess because of the widely divergent assumptions and sector definitions used by the Applicants.

(b) Heavy Industrial Sector

The following are the important issues related to the heavy industrial sector.

1. The estimates of the MOR values in this sector are similar among the Applicants, COFI and in the Technical Report. The significant issue is how much of this market would be captured, when and for how long.

2. With the exception of Inland, all Applicants adopted an "all or nothing" approach to the heavy industrial sector, with a high proportion of the potential convertible requirements being captured and little change in requirements over time. This conclusion conflicts with COFI's evidence and is considered unlikely because of factors associated with contractual terms and conditions, heavy fuel oil competition, and technological change. As stated by COFI, such factors could significantly reduce natural gas requirements in this sector. Finally, the infrastructure to allow HFO firing is in place and the industry has stated that this dual-firing capability will be maintained.

3. Inland provided two alternative scenarios whereby natural gas would capture the total (Case A), and less than half (Case B) of the industrial market. Inland's development of Case A and Case B is a reflection of the uncertainty surrounding the future price movement of HFO, and therefore casts some doubt on the ability of natural gas to retain the entire heavy industrial market as indicated by the MOR estimate. Inland indicated that Case B is the most likely scenario, and this is more consistent with COFI's evidence.

2.9.3 Natural Gas Vehicle Demand

Although the potential NGV market is large, the achievable load is expected to be small without government incentives. In addition, some of the Applicants indicated that this market is highly speculative. B.C. Hydro's forecast appears optimistic given the current conversion rate.

2.9.4 Fertilizer Plant Demand

The Commission has concluded that the load and timing estimates presented by the Fertilizer Consortium are extremely optimistic. Many hurdles that may cause a substantial delay in the construction of this facility have not been fully considered by the Consortium. If Westcoast is awarded the project, there may be a subsequent National Energy Board hearing that could cause delays. In addition, inter-government negotiation regarding the project's required subsidy may cause further delays. The Consortium's allowance of eight months to a year for the energy project certification process would appear overly optimistic given that environmental or socio-economic impact assessments have not been conducted at this time. While it would be desirable to secure a long-term contract with the fertilizer plant, Westcoast does not require such a contract to proceed with the construction of the pipeline. B.C. Hydro did not attempt to determine the likelihood and timing of the fertilizer plant load, but indicated that, if awarded the energy project certificate, a contractual commitment from the fertilizer plant would have to be in place before they would proceed with the construction of System B.

Other than these hurdles, market conditions will dictate the eventual viability of the fertilizer plant proposal. As stated by the fertilizer panel witnesses, the cost of the feedstock is ultimately determined by the opportunity cost of gas, as represented by its export price. The higher the export price, the higher the opportunity cost of gas. This will in turn affect the cost of production and the plant's competitiveness. World market conditions will then determine the economic viability of the fertilizer plant given its competitiveness. The Commission finds that such considerations cast uncertainty on the projected load and timing of this proposal.

2.9.5 Powell River Demand

COFI's estimate of the industrial load at Powell River is summarized in Table 2.13.

TABLE 2.13

COFI's Estimate of Powell River Industrial Load (PJ)

	Case A	Case B
1986	2.91	1.82
1988	3.27	2.04
1995-2005	2.04	1.28

The Commission accepts COFI's estimate of the industrial load at Powell River and believes that the total load will be much lower than projected because the industrial load accounts for 80-90% of the Powell River total.

2.9.6 Market Assessment and Conclusions

The Commission reviewed all the Applicant and intervenor submissions and has produced a summary Market Assessment for the service area of the proposed natural gas pipeline. This assessment is shown in Tables 2.14 and 2.15 and Figures 2.8, 2.9 and 2.10.

The Commission recommends that ICG's forecast be adopted as being the most reasonable market assessment in the residential and commercial sectors. The Commission based its decision on ICG's more realistic conversion and capture rates and its implied use per account. These data have been included in Table 2.14 and Table 2.15.

In the heavy industrial sector, the Commission recommends the use of three scenarios (low, base and high cases) :

For the low case, the Commission adopted COFI's Case B which projected a decline after 1988 to a level of 3.8 PJ by the year 2005. This is due to major technological upgrading by the industry beyond 1988 to maintain international competitiveness.

For the base case, COFI's Case B was again adopted, but only up to 1988. Instead of a decline, the demand is held constant beyond 1988. This reflects some optimism regarding future capacity expansion of the industry that will offset the expected decline.

For the high case, the Commission modified COFI's Case A. This reflects an optimistic outlook regarding future new industrial demands in the GSA rather than a belief that COFI's Case A will be realized. The contractual terms and conditions upon which COFI's Case A was predicated have been regarded as being unacceptable by the Applicants.

It should be emphasized that the Commission's assessments have been based on evidence presented during the hearing which deals almost exclusively with the demands of existing industrial customers on Vancouver Island. No attempts have been made to assess the likelihood of specific new major industrial development on the Island that may lead to a higher demand for natural gas.

However, the history of natural gas pipeline developments has been that introduction of a pipeline opens an energy corridor which attracts development and industry. The Commission believes that with appropriate government policy, this experience would be repeated on Vancouver Island.

<u>In calculating the Total Required Capital Contribution in Chapter 5 Financial Analysis, the Commission used its Market Assessment for Base Case as shown in Figure 2.9.</u>

TABLE 2.14

Commission Market Assessment Summary
(Excluding Powell River and Natural Gas Vehicle)
(PJ)

	Residential/ Commercial	Heavy Industrial (PJ)			Total (PJ)		
	(PJ)	High	Base	Low	High	Base	Low
1986	3.25	8.70	5.42	5.42	11.95	8.67	8.67
1987	5.33	8.70	5.90	5.90	14.03	11.23	11.23
1988	7.22	9.70	6.10	6.10	16.92	13.32	13.32
1989	8.96	9.70	6.10	5.60	18.66	15.06	14.56
1990	9.90	9.70	6.10	5.30	19.60	16.00	15.20
1991	10.69	9.70	6.10	5.10	20.39	16.79	15.79
1992	11.67	9.70	6.10	4.80	21.37	17.77	16.47
1993	12.19	9.70	6.10	4.50	21.89	18.29	16.69
1994	12.69	9.70	6.10	4.00	22.39	18.79	16.69
1995	13.02	9.70	6.10	3.80	22.72	19.12	16.82
1996	13.29	9.70	6.10	3.80	22.99	19.39	17.09
1997	13.55	9.70	6.10	3.80	23.25	19.65	17.35
1998	13.84	9.70	6.10	3.80	23.54	19.94	17.64
1999	14.11	9.70	6.10	3.80	23.81	20.21	17.91
2000	14.42	9.70	6.10	3.80	24.12	20.52	18.22
2001	14.71	9.70	6.10	3.80	24.41	20.81	18.51
2002	15.03	9.70	6.10	3.80	24.73	21.13	18.83
2003	15.34	9.70	6.10	3.80	25.04	21.44	19.14
2004	15.68	9.70	6.10	3.80	25.38	21.78	19.48
2005	15.73	9.70	6.10	3.80	25.43	21.83	19.53

TABLE 2.15

Commission Market Assessment Summary
(Including Powell River Excluding Natural Gas Vehicle)
(PJ)

	Residential/ Commercial	Heavy Industrial (PJ)			Total (PJ)		
	(PJ)	High	Base	Low	High	Base	Low
1986	3.38	11.61	7.24	7.24	14.99	10.62	10.62
1987	5.46	11.61	7.83	7.83	17.07	13.29	13.29
1988	7.35	12.97	8.14	8.14	20.32	15.49	15.49
1989	9.09	12.97	8.14	7.54	22.06	17.23	16.63
1990	10.03	12.97	8.14	7.15	23.00	18.17	17.18
1991	11.15	12.97	8.14	6.85	24.12	19.29	18.00
1992	12.13	12.97	8.14	6.46	25.10	20.27	18.59
1993	12.65	12.97	8.14	6.06	25.62	20.79	18.71
1994	13.15	12.97	8.14	5.47	26.12	21.29	18.62
1995	13.48	12.97	8.14	5.17	26.45	21.62	18.65
1996	13.77	12.97	8.14	5.08	26.74	21.91	18.85
1997	14.03	12.97	8.14	5.08	27.00	22.17	19.11
1998	14.32	12.97	8.14	5.08	27.29	22.46	19.40
1999	14.59	12.97	8.14	5.08	27.56	22.73	19.67
2000	14.90	12.97	8.14	5.08	27.87	23.04	19.98
2001	15.19	12.97	8.14	5.08	28.16	23.33	20.27
2002	15.51	12.97	8.14	5.08	28.48	23.65	20.59
2003	15.82	12.97	8.14	5.08	28.79	23.96	20.90
2004	16.16	12.97	8.14	5.08	29.13	24.30	21.24
2005	16.21	12.97	8.14	5.08	29.18	24.35	21.29

FIGURE 2.8

Commission Market Assessment — High Case

"Including Powell River Excluding Natural Gas Vehicle"

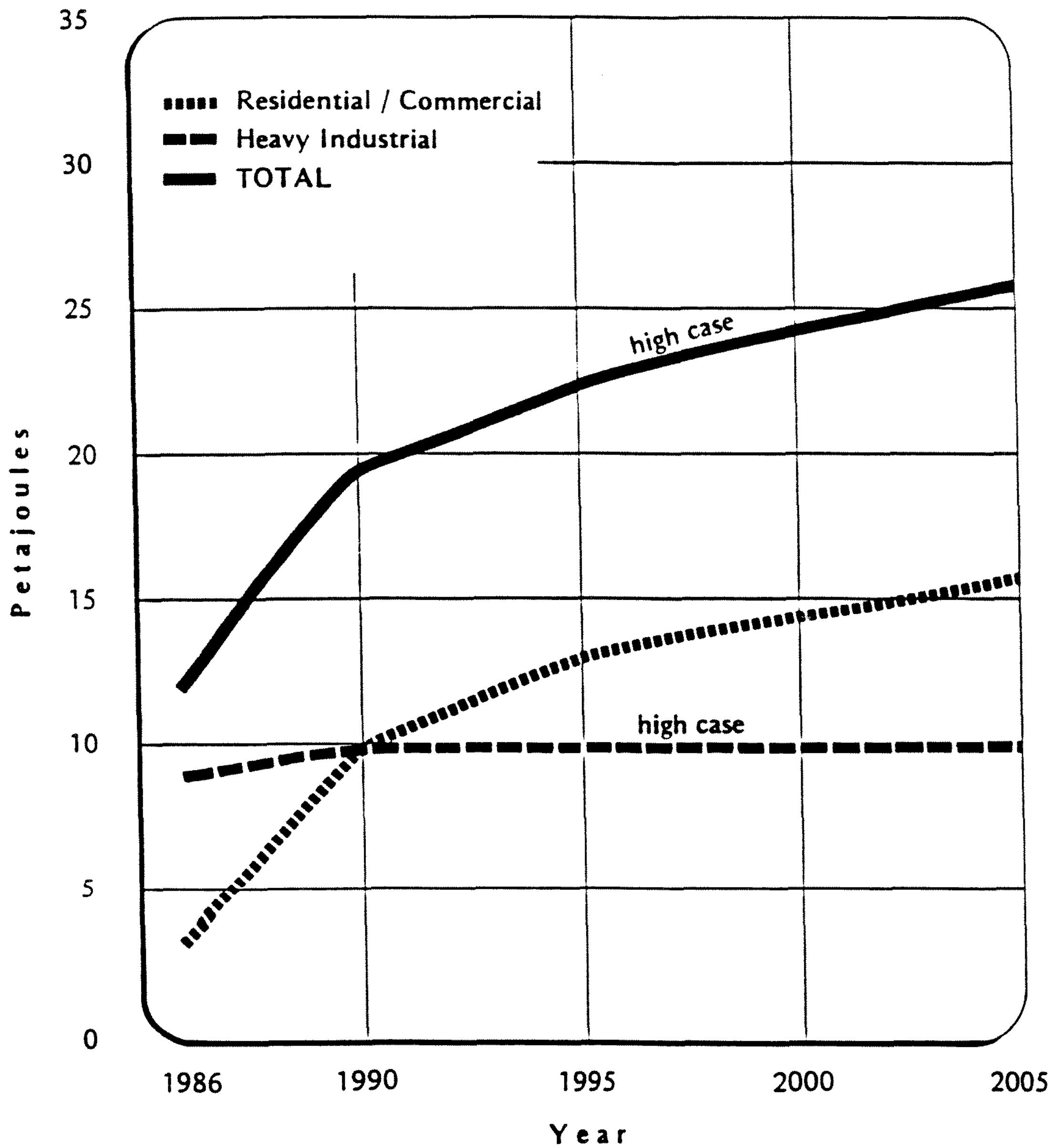


FIGURE 2.9

Commission Market Assessment — Base Case

"Including Powell River Excluding Natural Gas Vehicle"

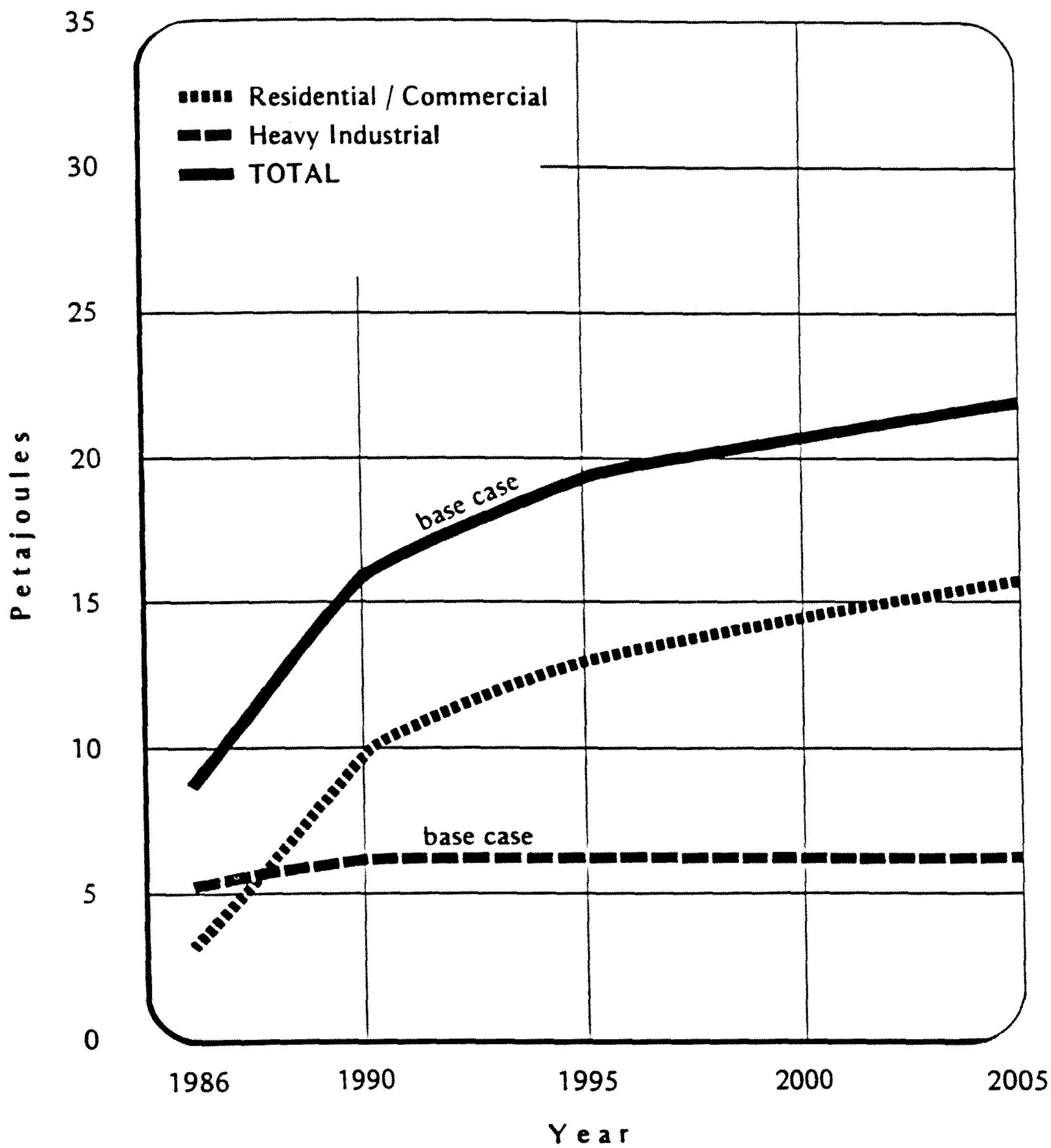
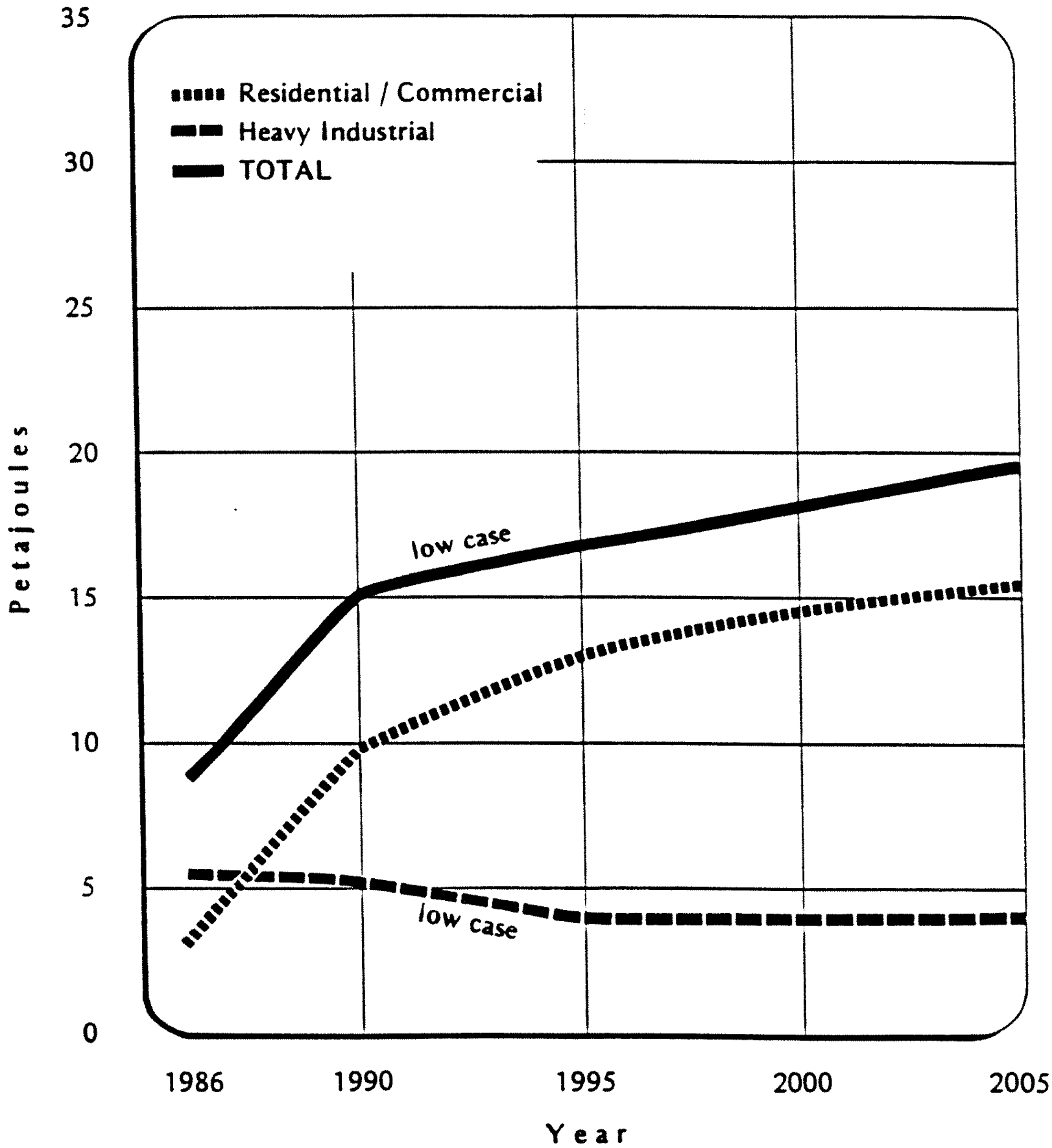


FIGURE 2.10

Commission Market Assessment — Low Case

"Including Powell River Excluding Natural Gas Vehicle"



CHAPTER 3 FACILITIES AND CAPITAL COSTS

3.1 Westcoast - To Island

The Commission has assessed all matters requested in the Terms of Reference, matters of public concern raised at the hearing, and other matters of concern to the Commission related to the safe, reliable and least cost natural gas service to Vancouver Island.

Westcoast introduced two alternative proposals for the transportation of natural gas to Vancouver Island. The first assumes that a fertilizer plant requiring natural gas feedstock would be constructed at Powell River, while the second proposal assumes this associated facility would not be constructed at present, see Figure 3.1.1. Both proposals envisage construction of a 389 km, single 406 mm O.D. pipeline system from Williams Lake to Powell River across the Coast Mountain Ranges. The only differences between the two alternatives are the total number of required compressor stations and the timing of their construction.

Westcoast proposes to deliver gas to Vancouver Island at the island beachhead of Little River, and assumed that all facilities to pressurize the gas and transport it to the main north-south trunkline on the Island would be part of the Island transmission system and therefore would be considered during Phase 3 (On Island Phase).

3.1.1 Land Facilities

(a) Design and Operation

Westcoast's engineering design and cost estimates in support of their application are at a preliminary stage. Detailed or final design will not commence until award of an Energy Project Certificate. However, to expedite the regulatory approvals process, Westcoast has already submitted an application to the National Energy Board, identical in cost and similar in content to its application to the B.C. Utilities Commission.

Westcoast prepared its own contractor style estimate and did not seek estimates from pipeline contractors. Westcoast is prepared to stand behind this estimate on the basis of its experience and continuing contractual arrangements with contractors in the expansion of its existing pipeline system.

If granted an Energy Project Certificate, Westcoast would immediately commence final design which would involve : finalization of river crossing locations and designs ; finalization of route selections ; completion of engineering design, plans and specifications ; and preparation of all necessary bid documents. Tendering contractors will prepare their own construction plans and bids, while Westcoast would provide overall contract supervision and coordinate the project.

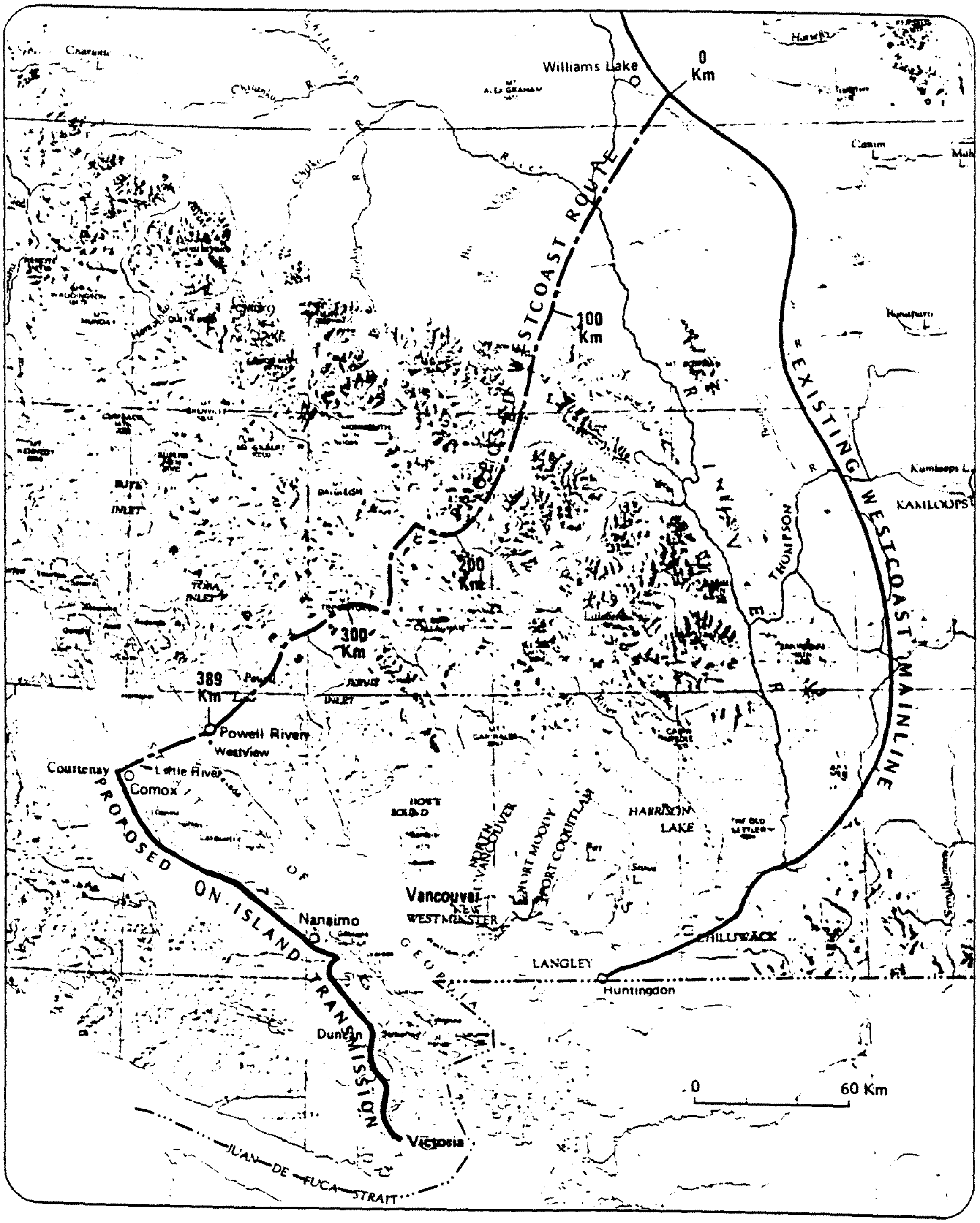
Cross-examination of Westcoast focused on the extent to which its proposal is preliminary and on the reliability of Westcoast's construction schedule and cost estimates. Westcoast was convinced that the proposed pipeline can be built using modern pipelining techniques, although innovative construction methods will be necessary for some portions of the route.

(b) Route

Westcoast's proposed pipeline corridor extends for approximately 389 km from Compressor Station 6A on their existing mainline near Williams Lake to Powell River. It proceeds southwest through the gently rolling Cariboo-Chilcotin ranchlands and traverses the Fraser River (elev. 350 m) below the confluence of the Chilcotin River. The corridor then climbs steeply (elev. 1400 m) and parallels the Churn Creek valley, where it crosses a number of tributary creeks including Gaspard, Stobart, West Churn, Dash and Lone Valley.

FIGURE 3.1.1

Proposed Westcoast Pipeline Route — Vancouver Island Natural Gas Pipeline Project



The pipeline would then cross a height of land (elev. 1750 m) before entering the Mud Creek valley, and the rugged topography of the Chilcotin Mountains. The corridor parallels Mud Creek, Relay Creek and Tyaughton Creek, and passes west of Tyaughton Lake and east of Gun Lake. It crosses the Bridge River near the Lajoie Dam and the small settlement of Gold Bridge.

The corridor then extends upstream along the Hurley River and through the Railroad Pass (elev. 1375 m) into the narrow Railroad Creek valley. The pipeline descends sharply into the Lillooet River valley (elev. 250 m) and turns west to follow this valley to Meager Creek. The corridor again turns south and follows Meager Creek upstream to cross a wide pass (elev. 1280 m) before descending into the Elaho River valley up to its confluence with Sims Creek (elev. 250 m).

The corridor traverses Sims Creek valley, crosses the Coast Mountains over Casement Pass (elev. 1400 m) and then descends along Hunaechin Creek to the head of Jervis Inlet at Queens Reach (at sea level). From this point, it ascends the rocky highlands of the Coast Mountains by way of Lausmann Creek and crosses a pass near Mount Alfred (elev. 1200 m) before descending into the Eldred River valley. The corridor proceeds westward adjacent to Goat Lake, Dodd Lake and Haslam Lake, and then passes through the Municipality of Powell River to a marine beachhead on the Strait of Georgia.

In general, the route has not yet been rigidly defined within the proposed corridor. The pipeline would parallel existing roads or would be located within the road ditch for about 25% of the route. During final design, discussions related to alignment would be held with logging companies and other groups or individuals having land use interests within the proposed corridor. In the event that Westcoast is unable to negotiate satisfactory agreements with these parties, it is willing to relocate the pipeline away from roads.

Final engineering of the river crossings has not been initiated and no drilling or geophysical investigations have been conducted to date at any of the river crossings or elsewhere along the proposed Westcoast route. Westcoast maintains that a thorough assessment of all crossings would be undertaken during final design, and that the crossings would be properly designed using current engineering principles. Westcoast's witnesses stated that the location of river crossings could change during final design when more information is available.

THE COMMISSION CONCLUDES THAT ALTHOUGH THE LOCATION OF THE ROUTE WITHIN THE GENERAL CORRIDOR COULD CHANGE SLIGHTLY TO ACCOMMODATE DIFFERENT RIVER CROSSING LOCATIONS AND POSSIBLE LAND USE CONFLICTS, THERE IS NO EVIDENCE THAT WOULD PRECLUDE CONSTRUCTION OF A PIPELINE ALONG WEST- COAST'S PROPOSED CORRIDOR.

(c) Design

Westcoast's fundamental design recognizes that for much of its length, the proposed pipeline corridor passes through terrain characterized by unstable surficial features such as snow avalanches, rock falls, slush flows, debris torrents, gravel fans and meandering river channels. The corridor also traverses many narrow, constricted mountain valleys that would have to accommodate both the pipeline and existing roadways and streams.

Westcoast's application is based on a preliminary design that addresses these fundamental difficulties. Deep burial is proposed to anchor the pipe in stable soils or bedrock beneath the unstable surficial features, while pipe with a heavier wall than that required by the CSA code is planned where risks to pipeline integrity are perceived to be higher than normal.

Westcoast proposes to use Grade 483 steel for line pipe. Although no Canadian mill presently manufactures steel pipe of this strength for this size, Westcoast believes that this product will be available from Canadian mills by the time construction begins. Westcoast used unit costs for a lower-strength steel pipe with a proportionately thicker wall in their cost estimates. Since the increased tonnage of heavier walled pipe was taken into account in estimating pipe costs, the Commission is satisfied that pipe costs are realistic.

The Commission also considers other aspects of Westcoast's pipe design, such as flow diagrams, pipeline lengths, wall thicknesses, pipe diameters, operating pressures, coatings, rock shield and swamp weights to be adequate for this stage of design.

THE COMMISSION CONCLUDES THAT WESTCOAST'S PRELIMINARY DESIGN RESPONDS TO THE EXIGENCIES OF THEIR PROPOSED CORRIDOR AND IS THEREFORE CONSIDERED FEASIBLE.

(d) Comparability

The proposed gas requirements in the Westcoast and B.C. Hydro proposals necessitate looping on Westcoast's mainline north of Williams Lake.

The Westcoast To Island system is not entirely comparable to B.C. Hydro's since the B.C. Hydro proposal includes land facilities from Flewett on Vancouver Island to the juncture of the Island mainline. In order to make them comparable, the Commission has included additional project costs from Westcoast's beachhead at Little River to the main north-south lateral. These costs include 11.7 km of 323.9 mm pipeline and a compressor station at Comox.

(e) Compatibility

Westcoast's potential lateral to Squamish conflicts with B.C. Hydro's long-term plans to install a hydro-electric project that would flood the Elaho valley. The water reservoir could extend up to the mainline and the planned location of Compressor Station V-3. Westcoast would relocate the compressor station and reroute the pipeline as necessary. Westcoast had not considered the impact on the Squamish lateral reservoir area or locating the pipe alongside any new logging roads as this extension did not form part of its present application.

(f) Construction

Westcoast stated that methods and procedures to be used for constructing the mainland portion of the pipeline would be similar to those employed on its other pipeline projects in B.C. The rugged mountainous terrain of portions of the route, however, will require considerable rock blasting and rock removal to prepare a suitable right-of-way and to excavate a trench.

The proposed pipeline corridor, which will be 18 m wide, is largely accessible by public or forestry roads. Some upgrading of existing forestry and mining roads and construction of new roads will be necessary to provide access to the right-of-way for heavy equipment.

Pipeline construction would be divided into three construction spreads, with a fourth spread to construct the 5.8 km Casement Pass section. Six construction camps to house the workers would be located along the route where motel or hotel accommodation is not available. In addition, a small camp would be used for the Fraser River crossing. For segments of the pipeline near Williams Lake and Powell River, the work force will be housed in available accommodation.

Construction of the pipeline would be completed in two years. Clearing, rock blasting and right-of-way grading would be undertaken during the first year together with upgrading of roads, where necessary. The only pipeline construction during the first year would be the spread immediately west of Williams Lake.

Following preparation of the right-of-way, the pipeline would be installed during the second year of construction. Since winter access and winter work would be difficult, the construction season for pipe installation would extend from late spring (May or June) to late fall-early winter when snow avalanche hazards are lowest. Construction operations would remain flexible to match any unusual or unexpected snow avalanche danger or activity. Avalanche control before construction operations would be an option if the potential for avalanche interfered unduly with construction activities.

A major concern related to the Northern route is that the pipeline would traverse terrain which is more rugged than that previously encountered by pipeline contractors in Canada. However, pipelines have been constructed over difficult terrain by Canadian pipeline contractors during the last 25 years, such as the Coquihalla Canyon, the Sikanni Chief River embankment, the Kasiks-Arden Pass, Boulder Mountain and Flathead Ridge. All of these pipeline sections are in B.C. and it is the contention of Westcoast that such areas are representative of the difficult terrain where standard pipelining is practiced in B.C. Westcoast has many years of experience in the construction of high pressure gas pipelines through mountainous terrain in B.C. and design, construction and maintenance of gas pipelines is well understood by Westcoast.

B.C. Hydro presented experts who claimed that the hazards created by terrain and climatic conditions on some sections of the Northern route present a greater hazard to pipeline integrity than those experienced on any other route in B.C. In fact, one expert maintained that a tunnel through Casement Pass was the only safe and reliable method of construction notwithstanding the estimated additional cost of $4-5 million.

Casement Pass is the most difficult part of the Northern Route. There are other high passes and slopes along the route that are comparable to Casement Pass in terms of steepness and vertical rise. These include the west bank of the Fraser River, the east bank of Gaspard Creek, and very steep and rugged slopes in the Mount Alfred and Haslam Lake areas.

Casement Pass, however, received the most attention during cross-examination. Westcoast presented two construction plans for the west slope of Casement Pass. In the first plan, the rough grade would be carved into bedrock and undisturbed soil, and a 1.8 m deep trench would be blasted into the bedrock.

In the second method of construction, substantially less rock would be removed for the rough grade and a shallow trench with buttressing over the pipe would be used. The pipe being 406.4 mm and more flexible than large diameter pipe would conform easily to the contours of the ground surface. This plan had been suggested to Westcoast by contractors who had examined the Pass on its behalf.

Westcoast indicated that the spread between Powell River and Casement Mountain would be built from west to east from Powell River, over Alfred Pass, around Queens Reach and then up to the west abutment of Casement Pass. This approach was proposed to overcome access problems near the precipitous bluff at Queens Reach. In response to evidence that it would be difficult to get over the steep and rugged Alfred Pass from the west within the available time, Westcoast stated that an extra crew could be barged into Queens Reach. This crew would work first towards Casement Pass from the west and then approach Alfred Pass from the east.

The issues raised during cross-examination showed that Westcoast had not developed a precise construction plan. However, Westcoast indicated that the contractor to whom the work would be awarded would devise the ultimate plan utilizing his experience and ingenuity. That plan would be subject to approval by Westcoast.

Westcoast proposes 100% radiographic inspection of each weld and an internal audit would also be conducted on each x-ray film. The pipeline would also be hydrostatically tested and inspected by running a "smart" pig through the pipeline before and after the hydrostatic test. Westcoast's quality control, inspection and testing procedures exceed industry standards in several respects and are acceptable for the proposed project.

THE COMMISSION CONCLUDES THAT CONSTRUCTION OF THE SECTIONS OF PIPELINE APPROACHING CASEMENT MOUNTAIN IN THE HUNAECHIN AND SIMS RIVER VALLEYS WILL BE BOTH VERY DIFFICULT AND COSTLY. HOWEVER, CASEMENT PASS ITSELF WITH ITS LONG AND STEEP SLOPES, TALUS MATERIAL AND SEVERE CLIMATIC CONDITIONS REPRESENTS PROBABLY THE GREATEST CHALLENGE FOR LAND PIPELINE CONSTRUCTION THAT HAS EVER BEEN ATTEMPTED IN BRITISH COLUMBIA. WHILE THE COMMISSION VIEWS CASEMENT PASS AS A MOST DIFFICULT CONSTRUCTION AREA, THE COMMISSION BELIEVES THAT A FEASIBLE PLAN FOR CONSTRUCTION OF THE PIPELINE WITHIN A TWO-YEAR PERIOD COULD BE DEVELOPED BY WESTCOAST UTILIZING THE SKILLS OF CANADIAN PIPELINE CONTRACTORS AND WESTCOAST'S DEMONSTRATED ABILITIES.

(g) Schedule

Westcoast's proposed schedule, established on the basis of the company's experience, indicates that a two-year period would be required to complete the entire project. The schedule covers the period from receipt of necessary permits through pipeline start-up.

Westcoast has divided the 389.9 km route into three pipeline construction spreads with lengths of 139, 159 and 86 km, and a fourth spread of 5.8 km for the difficult Casement Pass section. The schedule calls for almost all clearing, rough grade and grade rockwork to be completed in a 5 1/2 month period in the first year of construction with the remainder of the pipelaying activities occuring during four months in the second construction year.

At Casement Pass Westcoast's initial schedule called for completion of the 5.8 km rough grade over the Pass to be completed in two months with construction to be completed within the month of August in the second year. This schedule was revised however, during the hearing, increasing the schedule to 79 days for rough grade in the first year and four months for the remaining activities in the second year. The Applicant stated that this revised schedule included a 10% weather contingency and a 30% equipment contingency.

During cross-examination it was argued that, even with reasonable weather and equipment contingencies being applied to the schedule, more than 79 days would be required to drive an access road to the top of the Pass, to scale rock from the bluffs above the Pass, to construct a road across the Pass and to install a double drum winch on the crest of the west slope.

Completion of construction within the scheduled time would also be dependent on the effectiveness of two dozers when slung from the double drum winch at the top of the Pass. Decreased productivity associated with the handling of the winch cables controlling the dozers and the potential need for removal of greater amounts of rock have not been fully evaluated by Westcoast.

The Commission recognizes that there are uncertainties related to scheduling, including whether deep snow and avalanche conditions would impede progress of the work crews and whether Westcoast has made adequate allowance for unforeseen conditions that may be encountered in the Pass and along the route. However, the Commission realizes that, should it be necessary, a contractor can expedite a project, although sometimes at increased cost.

THE COMMISSION THEREFORE CONCLUDES THAT WESTCOAST WOULD BE ABLE TO CONSTRUCT THE PIPELINE ALONG THE PROPOSED ROUTE WITHIN THE SPECIFIED TWO-YEAR PERIOD.

(h) Operations and Maintenance

Westcoast claims that service interruptions over the pipeline's lifetime would be unlikely. Westcoast maintained that with a properly designed pipeline and the safety inherent in their proposed use of deep pipe burial and thick-walled pipe in hazardous areas, the likelihood of a failure occurring is remote. Furthermore because of its conservative design, Westcoast considers the probability of a failure occurring at a time and place which could not be reached and repairs completed within 24 to 48 hours is even more remote than the possibility of a failure.

Westcoast admitted that emergency repairs in the west chute of Casement Pass could require a longer period due to the difficult terrain, snow and potential avalanche conditions. The primary difficulty is transporting personnel, materials and equipment into the narrow valleys and high passes of the Coast Mountains during winter when deep snow covers the ground, particularly when avalanche danger is high and visibility low. It may require several days for personnel to get from Queens Reach to Casement Pass or other remote locations. For this reason Westcoast has considered placing machinery for emergency repairs over the winter period at the head of Queens Reach as the equipment is generally only used during the summer. In accordance with Westcoast's normal practise, pipe stockpiles along with mechanical aids would be strategically placed along the entire pipeline route.

Although emergency repair plans had not been completely defined, Westcoast had considered assembling a smaller diameter line at the top of Casement Pass which would enable repairs to be made without transporting welding equipment to the Pass during the winter. A mechanical aid such as a small winch, could be used to lower the pipe down the west chute, and a tie-in could be made at the bottom and top with a mechanical clamp.

The normal flow regime of rivers can be significantly altered by heavy rains, producing debris torrents or some other natural occurrence at locations such as North Creek. Westcoast proposes to remedy the problem by sending a maintenance crew, when conditions permit, to construct river training works that would return the creek to its original condition.

Depending on the load to the Island at the time of a failure, Westcoast stated that it would have one to three days of line pack which would enable it to make a repair without losing any continuity of service. Westcoast stated that there is probably one week in every ten years when it would be absolutely impossible to gain access to a repair site.

THE COMMISSION CONCLUDES THAT WESTCOAST'S PROPOSED OPERATION AND MAINTENANCE PLAN IS GENERALLY ACCEPTABLE ALTHOUGH THE REPAIR PROCEDURE IS CONSIDERED ADEQUATE ONLY IN AREAS WITH EASY ACCESS. In the high passes and areas with high avalanche risk, reliability must be ensured by carefully constructing the pipeline to a high standard so as to minimize the possibility of a failure and subsequent need for repair. Equal care must be taken when designing crossings of many of the creeks including Capricorn Creek and North Creek.

(i) Load Variations

The capacity of the 406 mm landline can be increased by increasing compression, looping or a combination of both. When the maximum capacity of the proposed line is reached by increasing compression, it would be difficult to loop sections where roads, rivers or mountains converge on the corridor. It should be noted that if a fertilizer plant were not constructed, the capacity of the proposed landline would handle any foreseeable Vancouver Island and Powell River load.

(j) Capital Costs

WESTCOAST CAPITAL COSTS HAVE BEEN USED BY THE COMMISSION IN ITS IDENTIFICATION OF THE SUBSIDY REQUIRED TO CONSTRUCT AND OPERATE THAT COMPANY'S PROPOSAL. IN ORDER TO MAKE THE WESTCOAST AND B.C. HYDRO SYSTEMS COMPARABLE THE COMMISSION HAS ADDED THE EXTRA FACILITIES BETWEEN LITTLE RIVER AND THE CAMPBELL RIVER LATERAL WHICH HAVE BEEN PREVIOUSLY DESCRIBED, AND HAS THEREFORE INCLUDED THE COST OF 11.7 KM OF PIPELINE AT $6.335 MILLION IN 1986 AND THE COST OF $15,695,000 FOR COMPRESSOR STATION V-5 AT COMOX, WHICH WOULD BE REQUIRED IN 1989.

Westcoast's capital cost estimates were not detailed to the Commission to the degree of the B.C. Hydro estimates. Unlike B.C. Hydro, Westcoast presented preliminary estimates based on its preliminary design. B.C. Hydro, as previously noted, has been involved in this project for a long time. This lengthy involvement has provided it with the opportunity to expend considerable funds to bring its route nomination and design to the final stage and to develop detailed cost estimates in support. Westcoast's involvement has been shorter, less costly and it has proceeded only to the preliminary stage of design, with preliminary cost estimates.

Westcoast testified that it had detailed preliminary estimates but refused to produce sufficient detail of those estimates for the Commission to determine whether the preliminary estimates were high or low. Accordingly, the preliminary estimates have been used as presented without benefit of more careful scrutiny.

3.1.2 Submarine Crossing

Westcoast proposes to transport natural gas to Vancouver Island through 273.1 mm O.D. dual submarine pipelines across the northern Strait of Georgia. This crossing is considered feasible because of the current state of deep sea pipeline technology. The pipeline would extend 32 km from Westview, Powell River to a point on Vancouver Island near Little River, and would be located at a water depth of over 360 m at its deepest point.

At the present time, a pipeline between Tunisia and Sicily in the Mediterranean Sea is located at water depths greater than 650 m. That pipeline is the only one located at water depths greater than those associated with the proposed crossing to Vancouver Island. A pipeline located at a comparable depth to the one proposed by Westcoast was laid across the Norwegian trench in the North Sea during 1983. This particular subsea pipeline is noteworthy because it was constructed in an area having much more severe conditions than those anticipated in the Strait of Georgia.

THE COMMISSION CONCLUDES THAT THE PROPOSED PIPELINE CROSSING IS FEASIBLE. The concerns of the Commission relate to the cost of the crossing and specific details regarding the method of its construction. Previous feasibility studies indicated that a crossing of the type proposed by Westcoast would be feasible using either the pull method (Bechtel 1965) or the Reel barge method (Fluor 1972). Studies conducted by Brown and Root (1983) for the Centennial Gas Pipeline Application suggest that a route similar to the one proposed by Westcoast is technologically feasible, while the present B.C. Hydro application indicates that a crossing north of Harwood Island is also feasible.

The following sections discuss design premises including route selection and the adequacy of evidence provided by Westcoast on design, operations, construction methods, schedules and costs related to the submarine pipeline component of their application.

In contrast to the large number of technical witnesses comprising the several B.C. Hydro marine panels, Westcoast presented only a single panel of five members. As a result of the limited preliminary marine design undertaken by Westcoast, the examination of Westcoast's design and capital costs was less extensive than that directed to B.C. Hydro. Nevertheless, the Commission believes that the detail elicited during examination was adequate to evaluate technical feasibility, preliminary design and preliminary costing.

(a) Development of Design Premises

1. Data Collection, Marine and Geotechnical Surveys

In developing its design, Westcoast used baseline oceanographic and meteorological information such as waves, currents, winds, etc. provided in earlier feasibility studies by Bechtel 1966 and Fluor 1972. These investigations summarized historic data from various sources (publications, government data records) on conditions within this portion of the Strait of Georgia, but did not involve collection of site specific information on currents or other oceanographic parameters. Although the data cited in these studies are not recent, the Commission believes they are acceptable for preliminary design and cost estimates.

A marine hydrographic survey including hydroacoustic measurements with side scan sonar was conducted to assist Westcoast in its preliminary geotechnical feasibility studies. Full interpretation of the results of this study was hampered to a certain extent by intermittent malfunctioning of the side scan sonar.

To determine the location of rock along the proposed subsea route, a total of 22 substrata core samples was taken during the marine hydrographic study. Seventeen of these cores were described in evidence, but several were either missing or failed to produce adequate information to determine whether rock was encountered. In addition, since grab samples rather than core samples were taken in the shore approach areas it is not known if rock will be encountered during excavation of the shore approaches. But since the Fluor, Bechtel and B.C. Hydro reports provide evidence that rock is present in these areas, the Commission suggests that rock conditions should be assumed to exist until further studies are completed.

It is important to know the characteristics of the surface of the sea bottom for the design of the pipeline protective coating. Both Bechtel (1966) and Fluor (1972) indicated that rock outcrops were encountered in the region of the proposed crossing, while the hydrographic study completed for Westcoast also indicated this possibility. However, Westcoast maintained that rock outcrops do not exist, although areas of concentrated cobbles with scattered boulders are present near the proposed crossing site. Westcoast's evidence was based on studies conducted with an acoustic bottom profiler ("DESO"*) and a remote controlled vehicle (RCV). The RCV was used to visually confirm certain features on the sea bottom by recording information on video tape.

The video tape records provided evidence that rock outcrops are unlikely on Westcoast's route. On the other hand, some areas apparently contain many large cobbles and small boulders which would pose a similar hazard to the protective coating. The video records also indicated the presence of a boulder approximately five metres high near the proposed route. Many other boulders were observed during the bottom surveys, but were not of a size or concentration to prevent the installation of the pipeline.

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* DESO is a trade name for the Atlas Deso 10 Survey Echo Sounder.

On the basis of geotechnical investigations, Westcoast concluded that the earthquake potential in the northern parts of the Strait of Georgia is somewhat higher than in the southern portion of the Strait. Earthquakes can cause liquefaction of soil, although Westcoast's engineering consultant concluded that significant liquefaction would be unlikely. In cross-examination, evidence was presented that liquefaction had occurred in the area during an earthquake in 1946. However, Westcoast maintained that liquefaction is a localized phenomenon and indicated that slope instability, which is another earthquake related risk to pipeline integrity, did not occur during the 1946 earthquake.

2. Route Selection

Westcoast envisioned supplying gas service to Texada Island. Accordingly, route investigations emphasized surveying the north end of Texada Island, as well as the area south of Harwood Island near Rebecca Rock. Although two routes were considered feasible, a route which began at Grief Point, crossed Malaspina Strait, traversed Texada Island and then crossed the Strait of Georgia to Cape Lazo was subsequently discarded.

The 32 km preferred route starts at Westview (Powell River) and follows a line approximately at right angles to the shore and just south of Rebecca Rock to about the middle of the Strait. From this point, the route curves slightly before following a straight line to Little River on Vancouver Island. Water depths seven kilometres from Westview increase to approximately 260 m then 10 km from shore near Rebecca Rock, decrease to 60 m depth and then increase to a maximum depth of approximately 360 m at the point where the route deviates slightly to the north. Westcoast proposed to install a "tee" in a shallow area near Rebecca Rock for a future tie-in to provide service to Texada Island.

Westcoast's consultants testified that pipe spans could occur in two areas near Rebecca Rock, although it is not possible to estimate the lengths of these spans on the basis of available information. However, since the water is comparatively shallow in this area, Westcoast believes that any necessary span correction would not be difficult.

Westcoast did not consider their preferred route to be completely final, but stated that the corridor selected is adequate and that final routing would be very close to the one proposed. BASED ON THE EVIDENCE PRESENTED AT THE HEARING, THE COMMISSION CONCLUDES THAT THE ROUTE SELECTED BY WESTCOAST IS FEASIBLE.

3. Pipe Design Criteria

While the Westcoast design has some inconsistencies, the Commission was able to satisfy itself that the preliminary cost estimates were sufficient to meet the requirements of this feasibility study.

(b) Design and Pipe Installation Methods

Westcoast expects that the Laybarge, Reel Barge, Bottom Pull and Bottom Tow methods are all acceptable installation techniques. Due to the size of line required to service its projected Vancouver Island Gas load, Westcoast has proposed the bottom tow method which it believes to be more economical. However, this method imposes some design restrictions.

1. Design Requirements of the Bottom Tow Method

The proposed bottom tow method involves the onshore welding of 300 m long pipe strings. The first string is attached to one or more large tugs and towed into the water; then the second string is welded to it. This procedure is repeated until the full length of the pipeline has been towed into place. Since the amount of tow force required is proportional to the weight of the pipe, a key factor in Westcoast's design is to carefully control the maximum weight of the pipeline so that it can be towed by the tugs selected.

The minimum tolerable pipe weight depends on the amount of negative buoyancy (weight of pipe and protective coating submerged in water) that is required to hold the pipe on the sea bottom when it is subjected to hydrodynamic or buoyancy forces. Hydrodynamic forces are drag and lift created by water flowing over the pipe as it rests on the sea bottom. These forces act on the pipe much in the same way that drag and lift forces act on an airplane wing as air flows over its surfaces. In the case of a pipeline, these forces are resisted by negative buoyancy and friction between the pipe and the sea bottom. Negative buoyancy can be adjusted by specifying a pipe wall thickness which will produce the desired effective weight. Concrete coating is usually applied when it is too expensive to use steel to obtain desired weight. Although the principal purpose for application of a concrete coating is usually for weighting, it also provides protection against abrasion to the pipe's corrosion prevention coating. Concrete coating is usually a desirable design feature for a submarine pipeline but is not essential. If the weight of the pipe is too great for purposes of towing, it can be reduced by adding buoys to the welded pipeline string before the tow. The buoys are then removed after installation is complete.

In order to use the bottom tow method for pipeline installation in the Strait of Georgia, Westcoast's engineering consultant had to consider weighting the pipeline so that it would be heavy enough to withstand the hydrodynamic forces and light enough to be towed by the tugs available in the Vancouver area. An average submerged weight of .072 kN/m (five pounds per foot) was chosen to achieve this balance. A wall thickness of 10.41 mm (.410 inch) creates the desired weight for a 273.1 mm O.D. pipe.

There was conflicting evidence regarding the strength of tidal currents. In Volume 3 (pages 2-5) the surface tidal current is reported to be 1.5 knots while in Drawing 1-206 of the same volume this tidal current is shown as 1.0 knot at a depth range of 0-180 m. If charts 1-206 and 1-207 in Volume 3 are correct, then a pipeline with a weight of five pounds per foot would be unstable in a current of approximately 1.0 knot. Tidal currents up to 0.99 knots have been measured at the surface (Bechtel 1966), and according to Chart 1-206 (Volume 3), extend down to a depth of 180 m at this velocity. The Commission concludes that Westcoast's anticipated design weight of five pounds per foot is marginal based on the foregoing.

The force required to tow the pipe along the bottom is the product of the total submerged weight of the pipeline, its length, and an estimated "pull" factor which is related to friction. The latter is a factor used to estimate the maximum pulling force that will be required and it reflects the friction of seabottom and experience in past projects. To arrive at the pull factor, Westcoast assumed that the friction between the sea bottom and the pipe would have an average coefficient of 0.65. This was increased by an experience component of 50% to arrive at a pull factor of 0.975 which was then rounded off to 1.0. During cross-examination Westcoast stated that pull factors as high as 1.5 have been observed.

The weight of the pipe is also extremely important in evaluation of the tow force, and a variation of the weight per foot by one pound on the positive side will increase the total required pull force by 20%.

Based on the pipe weight of five pounds per foot and the pull factor of 1.0, Westcoast calculated that the required tow force for the longest section of pipe they expect to tow would be 160 tonnes. Two tugs located in the Vancouver area can apparently sustain a bollard pull (i.e. pull force) of 80.3 tonnes each, and, working in tandem, could pull 160.6 tonnes. If these tugs cannot achieve their rated pull or the tow force is greater than calculated, additional tugs would have to be contracted and this would increase project costs.

It is generally accepted that the corrosion prevention coating on a pipeline should have some protection to prevent abrasive damage when it is dragged over rocks or other hard surfaces. This is traditionally accomplished by application of a high density, high strength concrete. However, since concrete increases the weight of the pipe, Westcoast considered eliminating the usual concrete coating on the longest sections that must be towed. Westcoast's rationale for this decision is that little abrasion is likely because no rock outcrops have been identified along the selected route. Westcoast also plans a test program in which sections of pipe will be coated with various types of abrasion resistant coating over fusion-bonded epoxy, or epoxy without protective coating and dragged over the sea bottom. Depending on this test program, Westcoast will either use the fusion-bonded epoxy without protective coating, another tested protective coating, or a conventional concrete coating.

During the course of the hearing, Westcoast indicated that a new protective coating called Forton could provide a high level of protection when applied in a relatively thin layer. Westcoast stated that 13 km of each submarine pipeline would be coated with a two millimetre layer of Forton.

Cross-examination by B.C. Hydro established that tests conducted on Forton involved the use of a 3-4 mm Forton coating as opposed to the 2 mm layer proposed by Westcoast. B.C. Hydro further stated that marine pipeline tests in the North Sea where pipe with fusion-bonded epoxy without abrasion coating was pulled over the seafloor were unsuccessful and the pipeline was eventually installed with a concrete coating. B.C. Hydro also maintained that the full length of submarine pipelines should be protected from abrasion.

<u>The Commission concludes that marine pipelines which would be installed by towing the line along the seafloor should be protected from abrasion damage. Moreover, in this particular area where relatively little is known regarding</u>

the sea bottom conditions, it would not be prudent to install the pipeline by the tow method without abrasion prevention coating on the entire length of the line. The Commission notes that Forton coating on the full line length can be accommodated in Westcoast's coating cost estimates. However, Westcoast has not evaluated the effect or cost of the added weight of the pipeline on the required tow force and/or some method of increasing buoyancy of the line during actual installation.

Additional problems with the pipeline weight may be associated with the steel pipe itself. Steel pipe cannot be manufactured with all joints having the precise wall thickness desired and as a result, manufacturing tolerances are allowed. Westcoast's pipe specifications called for tolerances of -5% and +15% of the specified wall thickness. Due to these tolerances, the submerged weight of pipe delivered from the mill could vary from 2.93 to 11.60 lb/ft (.043 to .169 kN/m). In addition, the steel mill that supplied the quote to Westcoast indicated that the +15% manufacturing tolerance is unrealistic and proposed a 20% tolerance. Westcoast maintains that the mill would be able to cull pipe joints that are over the +15% tolerance level. Nevertheless, there still appears to be a reasonable possibility that the average weight of the pipe could be higher than the design value.

Both Westcoast and B.C. Hydro proposed to use seamless steel pipe for the marine crossing. This is partly the source of the wall thickness tolerance problem. Manufacturing tolerances for electric resistance weld (ERW) pipe can be controlled within a much narrower range than is possible with seamless welds. THE POTENTIAL ADVANTAGES ASSOCIATED WITH USE OF ERW PIPE SHOULD BE REVIEWED SINCE ERW CAN BE PURCHASED FROM CANADIAN MILLS, AND THE COMMISSION MAINTAINS THAT CANADIAN PIPE MANUFACTURERS SHOULD NOT BE PRECLUDED FROM BIDDING UNLESS THERE IS FIRM EVIDENCE THAT ERW PIPE CHARACTERISTICS ARE UNSUITABLE FOR THE PROPOSED MARINE CROSSING.

Based on all of the evidence presented in relation to Westcoast's Bottom tow method and pipe design, the Commission concludes that several aspects of the proposed design are of marginal acceptability, particularly the questions of pipe stability, abrasion resistance and tow force. Changes to the design could eliminate many of the Commission's present concerns, although it is considered likely that the resultant design will involve use of heavier pipe than is currently envisioned. However, the Commission is aware that methods are available to offset potential weight problems. Therefore, although the Commission's concerns reflect potential for increased costs, the project remains feasible.

2. Other Design Factors

As indicated earlier, earthquake-induced liquefaction of the soil could be a risk. However, Westcoast maintained that small areas of liquefaction which are probable in the event of an earthquake would not affect the integrity of the pipeline. Additional design considerations such as slope instability, spans, vibration, collapse and buckling were adequately addressed by Westcoast based on current knowledge of the sea bottom.

(c) Operations and Maintenance

The life of the pipeline will depend on the final design of the corrosion protection system. Westcoast intends to use of an impressed current corrosion protection system.

The standard procedure of installing dual pipelines in important marine crossings will virtually eliminate the risk of service interruption due to anchor or trawl damage. Since no large vessels or large trawlers now frequent the area, the probability of damage to the pipeline as a result of marine vessel activities is considered remote.

Maintenance requirements for the submarine pipeline are expected to be minimal; nevertheless, Westcoast proposed a maintenance program which will include periodic visual inspection of the pipe by RCV. Light erosion could occur over a period of time, and this could cause low grade scour near the pipe that may eventually increase spans. This erosion could be periodically evaluated by comparison of the annual visual inspection records and remedial actions initiated when and where appropriate.

Laybarge repair of a pipeline rupture in water exceeding 180 m on either the north or south Strait of Georgia submarine crossing would require three to six months to be completed, and the costs of this emergency action would be high. Westcoast described a possible, but not yet budgeted, contingency plan which would involve stockpiling pipe and retaining the original launching equipment to allow installation of up to 22 km of line in the event of an emergency. If a rupture occurred in the deep water, over the longest section between Little River and the Rebecca Rock tie-in, equipment available in the Vancouver area would be mobilized to initiate necessary repairs. This is similar to the pipe stockpiling plan in force for the 650 m deep Tunisia to Sicily pipeline crossing in the Mediterranean Sea.

THE COMMISSION CONCLUDES THAT WESTCOAST SHOULD HAVE A PLAN IN PLACE, AND FUNDS AVAILABLE, TO DEAL WITH A DEEPWATER REPAIR AT SOME POINT IN THE PROJECT LIFE. <u>The pipe stockpiling proposal put forward by Westcoast would be an adequate method at reasonable cost. Westcoast indicated that a preliminary estimate of the cost of stringing 22 km of pipeline was $5 million, of which up to $2 million would be the capital cost of the pipe.</u> THE COMMISSION HAS THEREFORE INCREASED THE CAPITAL COSTS BY $2 MILLION AND OPERATION EXPENSES BY $3 MILLION.

(d) Construction

There are separate construction components to Westcoast's marine pipeline installation : construction of the pipelines from the shore approaches to a tie-in point near Rebecca Rock; the actual tie-in near Rebecca Rock ; and burial of the pipelines in nearshore areas where the water depth is less than 110 m.

Westcoast stated that it will encourage competitive bids on any possible method of construction from qualified contractors. The Applicant expects that laybarge, reel barge, bottom pull and bottom tow methods would be acceptable installation techniques. Each of these methods except the bottom tow has been successfully used to install long pipelines in relatively deep water. To date, the bottom tow has only been used on a few comparatively short lines up to about five kilometres in length. However, the engineering requirements for the bottom tow are relatively well defined and comparable to the bottom pull method. Consequently, it should be an acceptable method, although, because of the length of the tow, adequate margins of safety in both design and installation are essential.

Westcoast based their construction plans and costs on the bottom tow method. Strings of pipe in 300 m lengths would be fabricated on the shore near Little River. The two 10 km strings of pipe required for the dual pipeline between Powell River (Westview) and Rebecca Rock would be towed separately across the Strait to the shore approach area at Powell River. The ends of the pipe string would be positioned as close to shore as allowed by the minimum depth in which the tugs can work. The pipeline would then be pulled the remainder of the way to shore through a prepared trench using a large winch. This winch must be large enough to pull the full 10 km section of pipe and must be fixed on a solid foundation which can withstand the force of the pull.

After the pipelines are in place from the mainland to Rebecca Rock, the two 22 km sections between Rebecca Rock and Vancouver Island would be separately towed into place between Rebecca Rock and Vancouver Island. Near Rebecca Rock, the pipelines would be placed on the sea bottom adjacent to the lines from the mainland, allowing a short overlap for the subsequent tie-in procedure.

The problems that may be associated with this method of pipeline installation were noted previously in this chapter, and the Commission has stated its reservations regarding the design parameters proposed by Westcoast. However, Westcoast also emphasized that other construction methods would be considered. In this regard, the costs identified in the withdrawn Centennial application and those estimated by B.C. Hydro for the return line to Powell River, were based on use of laybarge and the Centennial cost estimate was not substantially greater than the bottom tow method. It should be noted, however, that the accuracy of the Centennial estimate was not tested at the hearing. Furthermore, the higher estimate for B.C. Hydro's northern crossing was not challenged by Westcoast. Indeed Westcoast's own estimates of laybarge installation would appear to preclude use of this method unless market conditions resulted in contractors waiving mobilization costs or some such other major charge that would result in an equivalent price reduction.

The l0 and 22 km sections of pipeline from Little River and Westview will be tied-in near Rebecca Rock where the water depth is approximately 60 m. Numerous underwater welds have been made at this depth using an underwater chamber which is placed over the pipe, and water removed by pumping. Divers then enter the chamber and complete the necessary welds. This procedure is referred to as hyperbaric welding.

Instead of using this hyperbaric technique, Westcoast proposed to recover the pipe from the sea bottom using a surface vessel, and while the two pipe ends were above water, the ends would be matched and welded together. The pipeline would then be lowered to the seafloor. The use of davits and tension lines to support the pipeline during the lifting operation was described differently in the Westcoast application than in their response to the BCUC request for information. In addition, calculations of the estimated stress on the pipe during this operation were not submitted in spite of the BCUC information request. Westcoast also failed to provide the requested stress estimates during subsequent cross-examination at the hearings.

The tie-in plan explained by Westcoast during cross-examination requires the application of tension to each pipe end by the tie-in barge. Tension would have to be applied in two opposite directions, and although this is considered theoretically possible, the Commission is not aware of the successful application of this technique to date by anyone in the offshore industry. The rigging of the barge for this procedure would be difficult and probably expensive, and it may be necessary to employ a second barge to satisfactorily complete the required welds. An anchoring system capable of holding the barge on station during the pick-up and welding, and then allowing the barge to move carefully to one side (using its anchors) to lay the pipe back on the seafloor, must be a sophisticated design.

Another potential problem with the surface tie-in method is that a long section of pipe will be off the bottom during the tie-in. This pipe would be completely exposed to surface currents which may have velocities approaching 1.5 knots (2.8 km/hr.) ; therefore, substantial lateral force could be exerted on the elevated pipe in this configuration. At the time of cross-examination, Westcoast had not considered whether the pipe would be overstressed under these circumstances. These matters would require considerable planning in final design.

Due to the slight risk posed by fish trawling activities in this region, Westcoast proposed to bury the pipeline 0.9 m below the seafloor in areas from the shore seaward to waters of 110 m deep using a specially designed plough. However, because the seafloor in areas near the shore approaches is characterized by the presence of large cobbles and boulders and because many of these features protrude above the bottom by more than the diameter of the pipeline, it may be unnecessary to bury the pipe to the water depth specified in the preliminary design. Furthermore, Westcoast stated that the pipeline would not be damaged by trawlboards at the greater depths because of the strength of the pipeline.

Although several ploughs are available in different parts of the world, the costs of transport of this equipment to Vancouver would be excessive in relation to original costs. At the same time, soil conditions at each job site are typically unique and necessitate a specific plough design. Consequently, Westcoast has included in its estimated project costs the funds required to design and fabricate a new plough.

Westcoast plans to use a large tug to pull the plough. However, since seafloor lithology near the shore approaches is not well documented at this time, it is not possible to predict: (1) the size of the plough that will be necessary, (2) the force that will be required to pull the plough along the sea bottom, or (3) the size of tug that will be required to achieve this force. Therefore, the cost of this operation cannot be reasonably estimated at the present time. In addition, it is probable that some hard rock requiring use of explosives will be encountered during the burial operation.

IT IS CONSIDERED UNUSUAL TO BURY A PIPELINE IN WATER DEPTHS TO 110 M. THE COMMISSION BELIEVES THAT CONSIDERABLE COST SAVINGS COULD BE REALIZED BY LIMITING THE ZONE OF PIPELINE BURIAL TO WATER DEPTHS OF 15-20 M. THIS WOULD OFFSET THE NEED FOR A SPECIALIZED PLAN DURING INSTALLATION OF THE PIPELINE AND ALLOW CONVENTIONAL DREDGING METHODS TO BE USED.

(e) Schedule

Westcoast prepared a schedule indicating that a total of 20 months would be required for project construction (Volume 3, Drawing # 1-102). A start date should be chosen that would result in completion of the tie-in during a month when weather conditions are least likely to hamper this relatively complicated operation.

The critical path in the proposed schedule will be the design and procurement of the pipe and coating. The schedule allows adequate time on this, and there may be potential tasks within the schedule where time savings can be realized.

(f) Marine Pipeline Costs

Westcoast based their cost estimate on installation of the pipeline using the bottom tow method. As indicated in previous sections certain aspects of this design and construction method have been questioned by the Commission and several of the perceived concerns have cost implications. Westcoast has stated that these problems would be examined and rectified during the final design.

The need for a full protective coating and resultant effects on pipe weight are likely to have the greatest cost implications. In addition, three major items were not specifically identified in Westcoast's cost estimate. These are : (1) the probable need for rock blasting and excavation at the shore approaches, (2) remedial work for the correction of spans, and (3) an overlooked allowance for the mobilization of shore-based personnel and equipment.

Another major cost is contractor overhead and profit. Westcoast testified that these costs were included in the equipment and labour rates used for the estimate. However, review of the basis of cost in Volume 3, Tab 6, indicated that the estimate treated each category of work as a subcontract. A cost was not identified for a prime contractor. A project of this size and nature must be completed under the supervision of a major contractor who would have both field and office overhead rates to apply to the overall project costs. This overhead could range from 15% to 25% of the total project costs. In addition, a high risk project that was bid on a lump sum basis would likely include a substantial mark-up. Assuming that part of the overhead has already been included in the equipment rentals and labour rates used for the cost estimate, the Commission believes that the total project cost should be increased to account for remaining prime contractor overhead costs.

On the other hand, estimated project costs could be reduced by the elimination of plough requirements for shore trenching and limitation of pipeline burial to areas within the 20 m water depth. The Commission favours use of a protective coating on the full length of the pipeline, and notes that the funds to provide this coating are available within Westcoast's budget. If this recommendation were followed, Westcoast would not have to undertake tests where the pipe is towed without protective coating, and resultant cost savings may partly offset the additional costs of increased tow force requirements or provision of positive buoyance.

THE COMMISSION HAS EVALUATED THE COST IMPLICATIONS ASSOCIATED WITH EACH OF THE POTENTIAL BUDGET UNDER-ESTIMATES AND RECOMMENDED CHANGES IN PROJECT DESIGN, AND EXPECTS THAT THE OVERALL INCREASE IN CAPITAL COST WILL BE LESS THAN $5 MILLION. THE COMMISSION VIEW THAT POTENTIAL COSTS COULD TEND TO INCREASE MORE THAN DECREASE IS BASED ON : (1) THE LIMITATIONS OF THE PRELIMINARY INFORMATION PRESENTED BY WESTCOAST; AND (2) THE NEED TO FURTHER EXAMINE MANY ASSUMPTIONS AND OPTIONS DURING FUTURE SURVEYS AND FINAL DESIGN.

Westcoast's capital cost estimate for the submarine pipeline is provided in Table 3.1.1. These costs do not include the stockpiling of 22 km of pipe to restring the line in the event of a line break.

3.1.3 Total Capital Costs

IN ASSESSING THE TOTAL CAPITAL COSTS OF WESTCOAST'S PIPELINE AND RELATED FACILITIES TO DELIVER NATURAL GAS FROM WILLIAMS LAKE TO THE MAIN NORTH-SOUTH TRANSMISSION LATERAL ON VANCOUVER ISLAND, THE COMMISSION HAS ACCEPTED THE COSTS PUT FORWARD BY WESTCOAST WITH ADJUSTMENTS, SO AS TO MAKE THE SYSTEMS COMPARABLE, TO INCLUDE THE COST OF PIPELINE FROM THE VANCOUVER ISLAND BEACHHEAD TO THE COMOX COMPRESSOR STATION AND THE COST OF THE COMOX COMPRESSOR STATION. THE ADDITIONAL CAPITAL COSTS IN CURRENT DOLLARS ARE $6.335 MILLION FOR PIPELINE IN 1986 AND $15.695 MILLION IN 1989 FOR THE COMPRESSOR STATION. THE COMMISSION HAS ALSO ADDED $2 MILLION IN 1986 FOR STOCKPILING PIPE FOR A DEEP WATER REPAIR.*

Tables 3.1.2 and 3.1.3 provide the capital cost addition and plant-in-service totals in current dollars for the without fertilizer and with fertilizer cases respectively. The total capital costs are $402 million for the without fertilizer case and $447 million with the fertilizer plant at Powell River.

<u>As previously noted, the Commission was not able to fully evaluate the preliminary cost estimates presented by Westcoast. Consequently, the Commission has accepted these cost estimates although the Commission holds the view that cost increases are more likely than cost reductions.</u>

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* $3 million was also added for operations and maintenance. B.C. Hydro included $39.1 million in operations and maintenance for a deep water repair.

TABLE 3.1.1

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Pg. 6 (Rev.)

WESTCOAST TRANSMISSION COMPANY LIMITED

Major Capital Expansion Cost Estimate
Vancouver Island Gas Pipeline

Schedule C

273.1 mm Submarine Pipeline — Length : km. 0.0 to km 32.0 (32.0 km) (Dual)

Description		(1984 - 1985) Cost 1983 $
Land and Land Rights		$ 460,000
Materials		7,085,000
Type 'A' and 'B' Pipe	$4,745,000	
Fabricated Assemblies	756,000	
Internal Coating	280,000	
External Coating	1,266,000	
Miscellaneous Material	38,000	
Installation		12,795,000
Dredging	1,587,000	
Trenching	2,520,000	
Survey	331,000	
Land (Makeup)	3,380,000	
Tugs	817,000	
Auxilliary Equipement	973,000	
Connection	1,040,000	
Submersible	416,000	
Diving	723,000	
Fabricated Assemblies	854,000	
Field Radiography	154,000	
Start-Up and Test Heads		220,000
Inspection and Miscellaneous		60,000
Total Direct Cost		20,620,000
Engineering and Overhead		4,060,000
Sub-total		$24,680,000
Omissions and Contingency		3,889,000
Interest During Construction		2,351,000
TOTAL COST		$30,920,000

TABLE 3.1.2

Westcoast Transmission Company Limited
Williams Lake to Comox Without Fertilizer Plant
(Costs Escalated at 6%)
Plant-In-Service and Depreciation

($000)

	Additions	1985 (A)	1986 (B)	1987 (C)	1988 (D)	1989 (E)	1990 (F)	1991 (G)	1992 (H)	1993 (I)	1994 (J)	1995 (K)
1	Pipeline	297199	6388	113	179	253	336	352	373	396	419	444
2	Compr Equip	17596	8	18	28	21795	11209	166	175	184	196	208
3	Compr Service	1955	1	2	3	1678	1245	18	19	20	22	23
4	Total Additions	316750	6397	133	210	23726	12790	536	567	600	637	675

	Additions	1996 (L)	1997 (M)	1998 (N)	1999 (O)	2000 (P)	2001 (Q)	2002 (R)	2003 (S)	2004 (T)	2005 (U)	Total
1	Pipeline	471	499	529	561	595	630	669	709	751	0	311866
2	Compr Equip	220	233	247	262	27535	418	442	469	497	0	81906
3	Compr Service	24	26	27	29	3059	46	49	52	55	0	8353
4	Total Additions	715	758	803	852	31189	1094	1160	1230	1303	0	402125

TABLE 3.1.3

Westcoast Transmission Company Limited
Williams Lake to Comox With Fertilizer Plant
(Costs Escalated at 6%)
Plant-In-Service and Depreciation

($000)

	Additions	1985 (A)	1986 (B)	1987 (C)	1988 (D)	1989 (E)	1990 (F)	1991 (G)	1992 (H)	1993 (I)	1994 (J)	1995 (K)
1	Pipeline	297141	6387	112	177	250	331	350	371	393	417	441
2	Compr Equip	21271	12509	68	146	15848	202	24024	439	411	13100	523
3	Compr Service	2363	1390	8	16	1017	22	2669	49	46	1456	58
4	Total Additions	320775	20286	188	339	17115	555	27043	859	850	14973	1022

	Additions	1996 (L)	1997 (M)	1998 (N)	1999 (O)	2000 (P)	2001 (Q)	2002 (R)	2003 (S)	2004 (T)	2005 (U)	Total
1	Pipeline	468	496	525	557	590	626	663	703	745	0	311743
2	Compr Equip	555	589	624	661	700	743	787	13972	16014	0	123186
3	Compr Service	62	65	69	73	78	83	87	1552	1779	0	12942
4	Total Additions	1085	1150	1218	1291	1368	1452	1537	16227	18538	0	447871

3.2 B.C. Hydro To Island

B.C. Hydro submitted three proposals to transmit natural gas to Vancouver Island and Powell River. These are identified on Figure 3.2.1 and are referred to as Systems A, B and D. Each proposal starts from the end of B.C. Hydro's existing natural gas transmission mains at Tilbury gate station in the Municipality of Delta (Delta). A compressor station would be constructed nearby Tilbury and 18.5 km of new pipeline would cross Delta to Brunswick Point. Dual pipelines were proposed for crossing the Strait of Georgia to Valdes Island, then on across Stuart Channel to the Vancouver Island landfall at Flewett. An additional 4.8 km of single pipeline would connect the Vancouver Island beachhead to Cedar Compressor Station. Cedar was proposed as the custody transfer point on Vancouver Island and would be the terminus of System D.

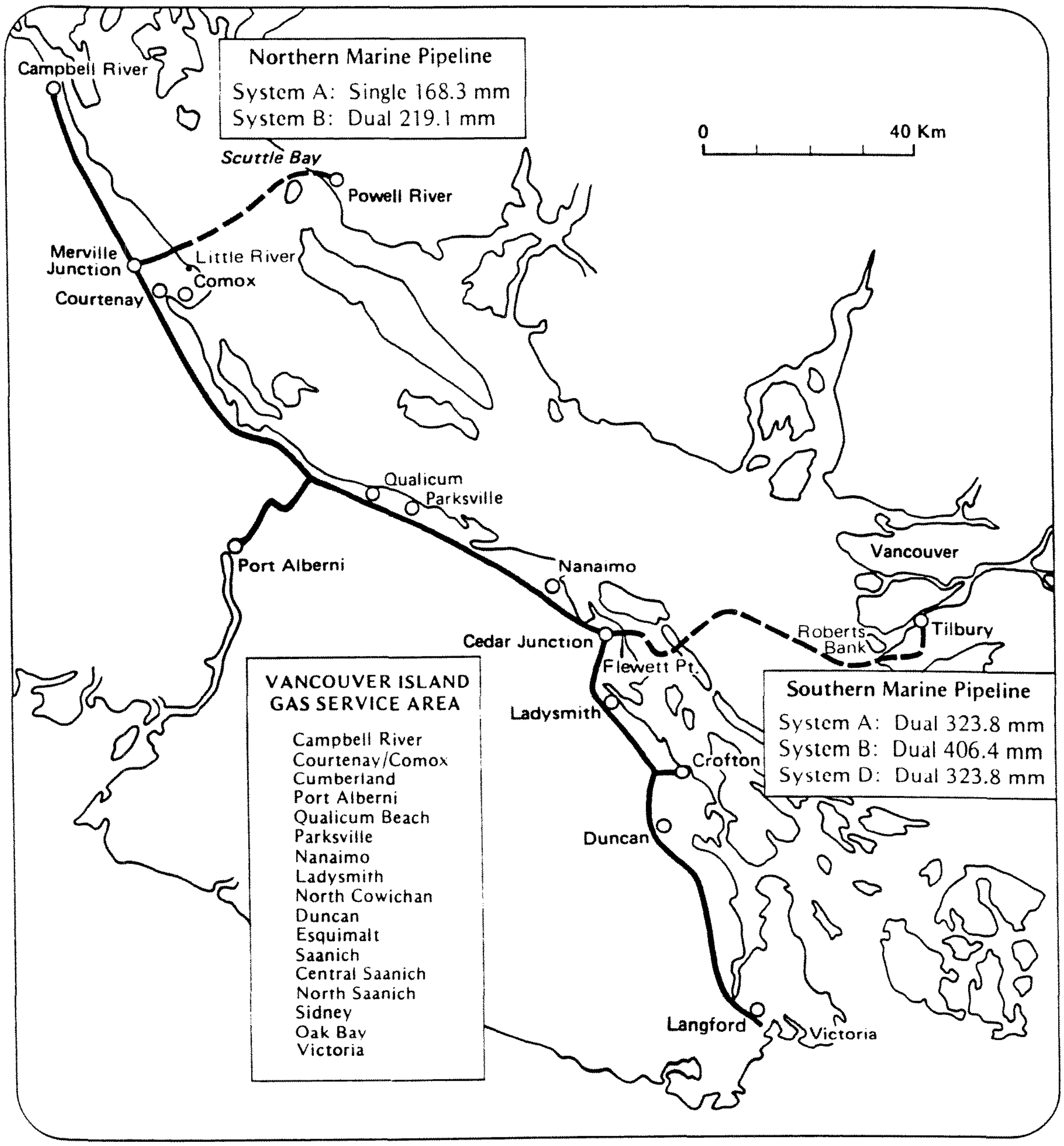
In Systems A and B , B.C. Hydro proposes a return pipeline from just north of Courtenay to just north of Powell River. The return link to Powell River includes a 7.8 km pipeline lateral from Merville Junction, northwest of Courtenay/Comox, to the shore approach north of Little River. For System A, B.C. Hydro proposes a 29 km single marine pipeline of 168.3 mm diameter. For System B, B.C. Hydro proposes twin 219.1 mm marine pipelines in the same corridor to accommodate the requirements of a fertilizer complex.

Systems A and B both anticipate a compressor station at Merville at some point in the project life. System D does not include a return to the Mainland.

The Commission has assessed all matters requested in the Terms of Reference, matters of public concern raised at the hearing, and other matters of concern to the Commission related to the safe, reliable and least cost natural gas service to Vancouver Island. The following sections address those issues relevant to the design and operation of the three proposed B.C. Hydro systems.

FIGURE 3.2.1

**Proposed B.C. Hydro Systems A, B and D —
Vancouver Island Natural Gas Pipeline Project**



The transmission facilities for each of the B.C. Hydro proposals are detailed on the pipeline schematics, Figures 3.2.2, 3.2.3, and 3.2.4. These schematics are based on the updated load projections undertaken by B.C. Hydro during the course of the hearing.

3.2.1 Land Facilities

In discussing design of the land facilities, the proposed systems have been divided into the following components :

- Tilbury Gate Station to Brunswick Point, including Tilbury Compressor Station
- Valdes Island
- Flewett Shore Assembly to Cedar Junction, including Cedar Compressor Station
- Merville Junction to Little River Shore Assembly, including Merville Compressor Station
- Scuttle Bay Shore Assembly to Powell River Gate Station.

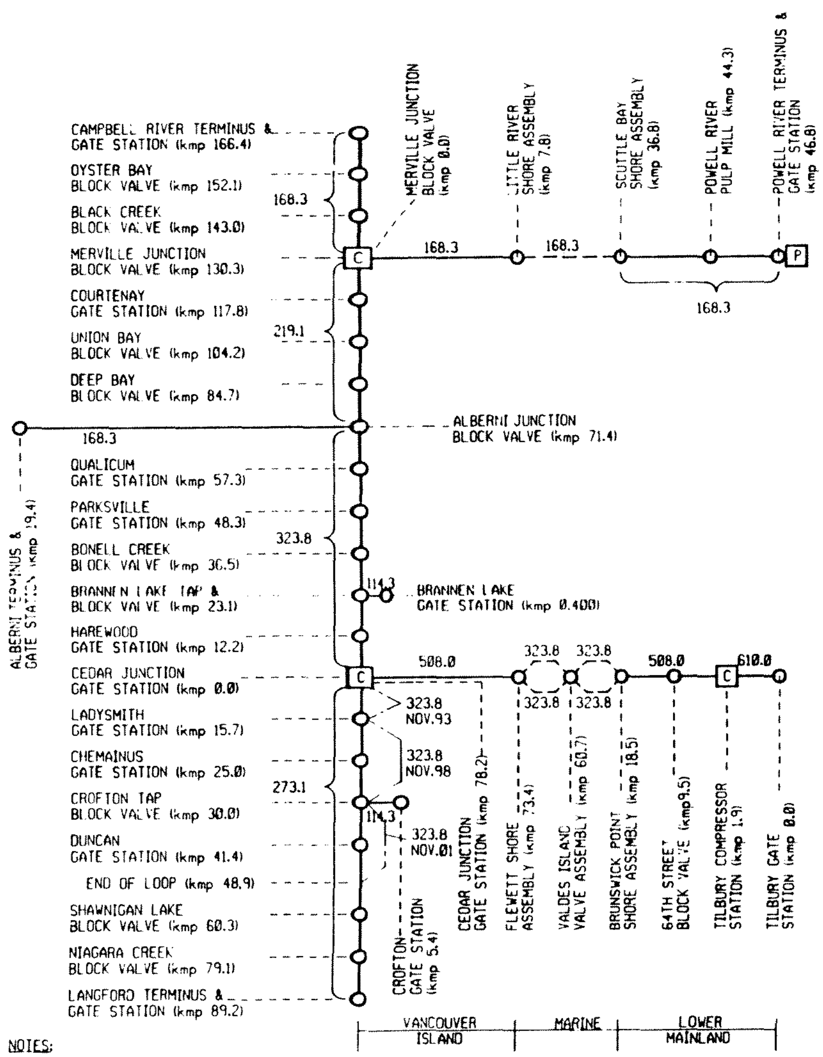
(a) Tilbury Gate Station to Brunswick Point, including Tilbury Compressor Station

B.C. Hydro proposes to construct the same pipeline facilities from Tilbury gate station to Brunswick Point in each of its systems. However, the size and timing of compressor units at Tilbury station vary.

B.C. Hydro evaluated route alternatives within a general corridor for the 18.5 km pipeline across Delta and chose a route which generally follows existing energy corridors. The Commission is satisfied with the corridor identified by B.C. Hydro subject to co-operation with Delta to minimize pipeline impacts.

FIGURE 3.2.2

B.C. Hydro System A — Pipeline Schematic



NOTES:
ALL PIPE SIZES ARE IN MILLIMETRES.

LEGEND

- LAND TRANSMISSION PIPE
- MARINE TRANSMISSION PIPE
- C — COMPRESSOR STATION
- P — PROPANE AIR PLANT
- LOOPING PROGRAM DIAMETER AND YEAR REQ'D
- 168.3 — PIPE OUTSIDE DIA. (MM)
- ER — ELECTRIC MOTOR DRIVEN RECIPROCATING
- GR — GAS MOTOR DRIVEN RECIPROCATING
- TC — TURBINE DRIVEN CENTRIFUGAL

EQUIVALENT PIPE SIZES: (O.D.)

METRIC (mm)	IMPERIAL (inches)
114.3	4.500
168.3	6.625
219.1	8.625
273.1	10.75
323.8	12.75
406.4	16.0
508.0	20.0
610.0	24.0

EQUIVALENT DRIVER SIZES

METRIC (KW)	IMPERIAL (HP)
2984	4000
895	1200
670	900
520	700

1983 LOAD FORECAST

COMPRESSOR STATIONS

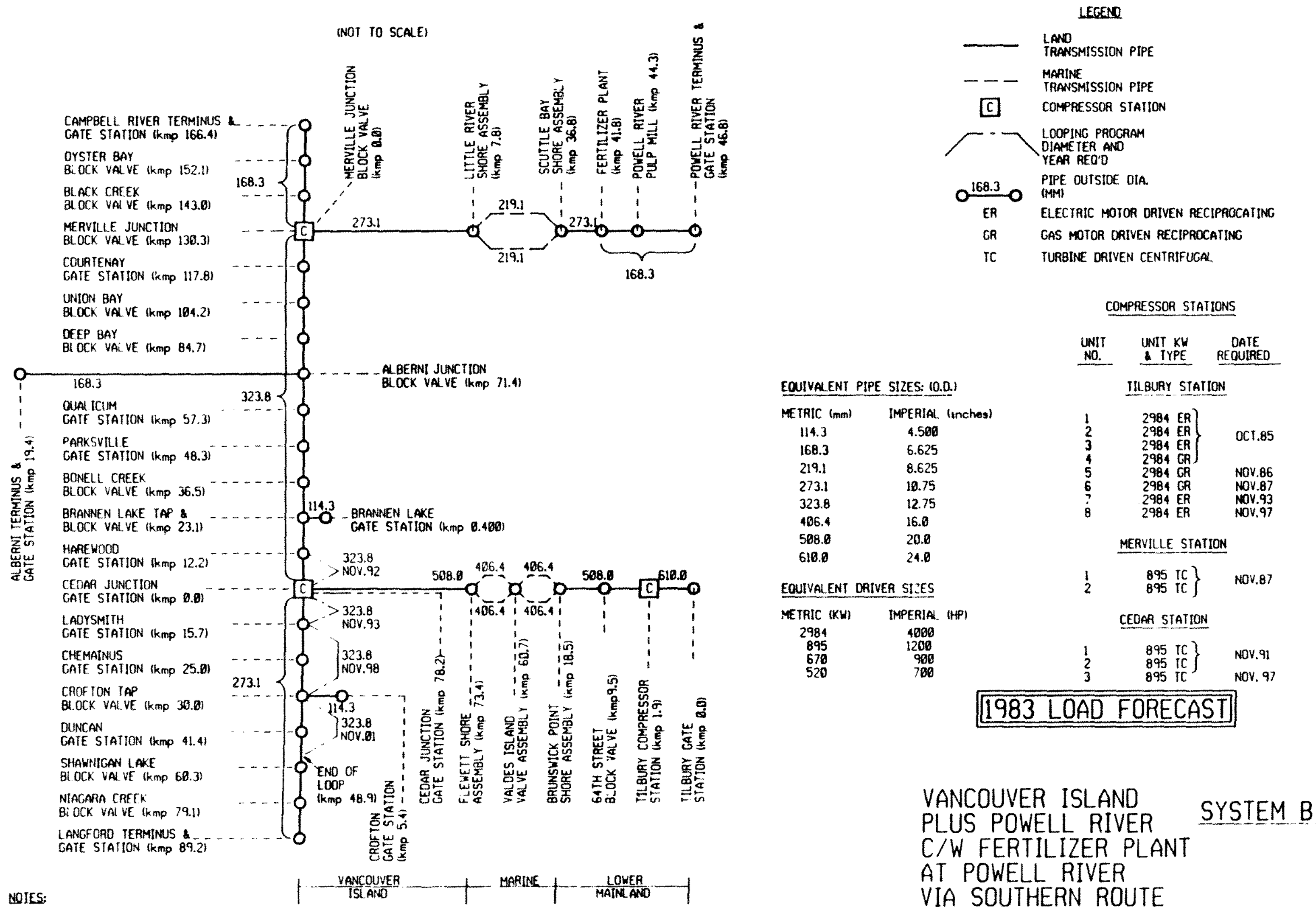
UNIT NO.	UNIT KW & TYPE	DATE REQUIRED
TILBURY STATION		
1	2984 ER	OCT.85
2	2984 GR	
3	2984 GR	NOV.86
4	2984 ER	NOV.88
5	2984 ER	NOV.90
6	2984 ER	NOV.93
7	2984 ER	NOV.00
CEDAR STATION		
1	895 TC	NOV.91
2	895 TC	
3	895 TC	NOV.94
4	895 TC	NOV.00
MERVILLE STATION		
1	520 TC	NOV.95
2	520 TC	
3	520 TC	NOV.00

VANCOUVER ISLAND PLUS POWELL RIVER VIA SOUTHERN ROUTE 20 YR. SYSTEM SCHEMATIC

SYSTEM A

FIGURE 3.2.3

B.C. Hydro System B — Pipeline Schematic

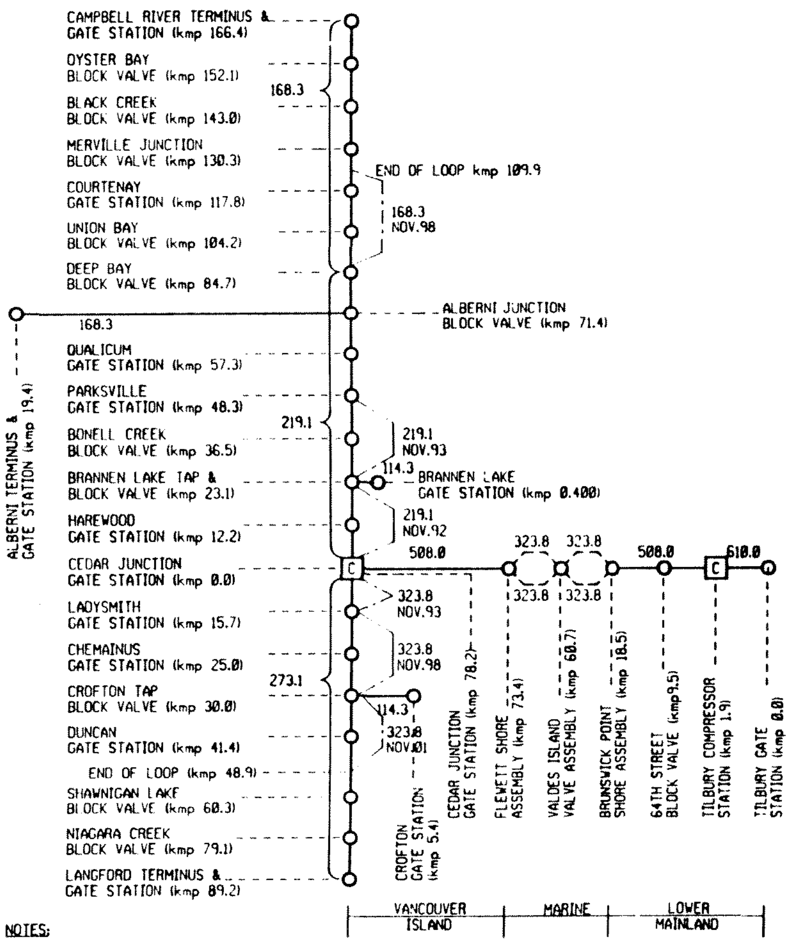


NOTES:

ALL PIPE SIZES ARE IN MILLIMETRES.

FIGURE 3.2.4

B.C. Hydro System D — Pipeline Schematic



NOTES:

ALL PIPE SIZES ARE IN MILLIMETRES.

LEGEND

———	LAND TRANSMISSION PIPE
– – –	MARINE TRANSMISSION PIPE
[C]	COMPRESSOR STATION
	LOOPING PROGRAM DIAMETER AND YEAR REQ'D
168.3	PIPE OUTSIDE DIA. (MM)
ER	ELECTRIC MOTOR DRIVEN RECIPROCATING
GR	GAS MOTOR DRIVEN RECIPROCATING
TC	TURBINE DRIVEN CENTRIFUGAL

EQUIVALENT PIPE SIZES: (O.D.)

METRIC (mm)	IMPERIAL (inches)
114.3	4.500
168.3	6.625
219.1	8.625
273.1	10.75
323.8	12.75
406.4	16.0
508.0	20.0
610.0	24.0

EQUIVALENT DRIVER SIZES

METRIC (KW)	IMPERIAL (HP)
2984	4000
895	1200
670	900
520	700

COMPRESSOR STATIONS

UNIT NO.	UNIT KW & TYPE	DATE REQUIRED
TILBURY STATION		
1	2984 ER	OCT.85
2	2984 GR	
3	2984 GR	NOV.86
4	2984 ER	NOV.88
5	2984 ER	NOV.91
6	2984 ER	NOV.94
7	2984 ER	NOV.01
CEDAR STATION		
1	670 TC	NOV.91
2	670 TC	
3	670 TC	NOV.94
4	670 TC	NOV.99
5	670 TC	NOV.03

1983 LOAD FORECAST

VANCOUVER ISLAND SYSTEM D
VIA SOUTHERN ROUTE
20 YR. SYSTEM SCHEMATIC

Delta expressed a number of concerns at the hearing regarding the proposed pipeline. In particular, the issues of potential impacts on agricultural land, access of farm and other vehicles to agricultural land, corrosion of municipal services, and future increased costs for the installation and repair of municipal services were identified. B.C. Hydro described measures it would take to avoid salt water contamination of topsoil and pointed out that pea pod strippers, the heaviest agricultural equipment used in Delta, would not be restricted from crossing the pipeline.

As a Crown Corporation, B.C. Hydro is not required to conform to municipal by-laws. However, B.C. Hydro indicated that the corporation always has and will continue to work in a cooperative manner with all municipalities affected by its projects. This general principle will be applied in addressing many of the concerns raised by Delta.

<u>The Commission recognizes that utilities must co-exist to make efficient use of existing corridors.</u> THEREFORE, THE COMMISSION RECOMMENDS THAT B.C. HYDRO AND DELTA NEGOTIATE AN AGREEMENT COVERING CORROSION PROTECTION AND THE ALLOCATION OF THE COST OF REPAIRS TO MUNICIPAL UTILITIES THAT ALREADY EXIST IN DELTA. Other issues related to socio-economic and environmental concerns have been addressed in Chapter 4.

The pipeline would be constructed to CSA Class III location standard. From Tilbury gate station to the compressor station, 1.9 km of 610.0 mm O.D. pipe will be required. The proposed pipe grade is 359 MPa with a wall thickness of 6.87 mm to provide a maximum operating pressure of 4020 kPa. This operating pressure is consistent with the B.C. Hydro gas transmission system upstream of Tilbury gate.

From the compressor outlet to Brunswick Point B.C. Hydro proposes to build 16.6 km of 508.0 mm pipe. The pipe wall thickness would be 11.26 mm of 448 MPa grade to provide a maximum operating pressure of 9930 kPa. B.C. Hydro projected that this pipe size would minimize pressure loss and avoid any need for looping in the next 20 years. The design operating pressure was used to size each pipeline link to, and on, Vancouver Island.

The section of pipeline from Tilbury Gate to Brunswick Point poses no new construction problems. The pipe diameter is not unusually large and appreciable amounts of rock work are not expected. B.C. Hydro intends to bury the pipe to 1.2 m cover, which is greater than CSA code requirements. This can be done at minimal extra cost and would ensure unrestricted crossings by heavy farm equipment.

The location of the compressor station was a significant concern at the hearing. B.C. Hydro evaluated several locations, but during the hearing reached an agreement in principle with the B.C. Development Corporation (BCDC) to use land in the BCDC industrial park, near the Tilbury Gate station. Using this site will result in slightly higher costs than those identified in the application, but will avoid an adjacent cranberry bog. The new site will conform to existing environmental and noise considerations. In particular, it will meet the gas emissions standards of the Federal Clean Air Act and conform with municipal noise level by-laws.

B.C. Hydro proposes to use a combination of electric and gas drivers to boost the inlet pressure. In case of an electric power failure, the gas-driven compression would be sufficient to continue operations. The advantage of electric drivers was to provide low capital and maintenance costs and desirable operation for continuous base load conditions. Electric drivers are 96% efficient while gas drivers are approximately 30-40% efficient. For additional security, B.C. Hydro also proposed that there would always be one spare compressor.

For System A, B.C. Hydro proposes to install one 2984 kW gas driver and a similar capacity electric driver for start-up. A second gas unit would be installed in 1986 followed by four electric units in 1988, 1990, 1993 and 2000. The timing and make-up of compressors can be adapted to the actual load growth, operating experience and possible technical changes related to gas and electric drivers.

For System B the station would eventually house eight compressor units. Four 2984 kW drivers would be required for start-up. System D would require seven compressors in roughly the same timing as System A.

<u>The Commission is satisfied with the design of the Tilbury compressor station and notes that the flexible design would allow B.C. Hydro to time new units to actual load growth and minimize compression costs.</u>

(b) <u>Valdes Island</u>

Twin pipelines would cross Valdes Island, and one valve station would be constructed with appropriate crossover piping to isolate any of the marine segments of the pipeline in the event of a line break.

On the west side of the Island, B.C. Hydro must cross a steep escarpment. The rock work on this short section would be expensive, but would not pose insurmountable construction difficulties.

MacMillan Bloedel, the owner of the existing B.C. Hydro right-of-way on Valdes Island, has been contacted by B.C. Hydro and is in general agreement with the pipeline access plans, including a helicopter pad mid-Island.

The Islands Trust raised concerns regarding the use of chemicals to retard growth on the right-of-way. B.C. Hydro had made a commitment to the

Islands Trust to clear the right-of-way mechanically, but decided later to use chemicals after a change in corporate policy. The Commission rejects the proposition that a general corporate policy of B.C. Hydro to use chemicals on all rights-of-way ought to override the justifiable environmental concerns of the Islands Trust. THE COMMISSION RECOMMENDS THAT THIS MATTER BE RESOLVED BY B.C. HYDRO AND THE LANDOWNER IN FAVOUR OF MECHANICAL CLEARING ON THIS RIGHT-OF-WAY.

Concern was expressed over preserving an Indian burial ground, which was identified as a heritage site. The pipeline right-of-way avoids the site, but would be adjacent to it. THE COMMISSION IS SATISFIED THAT THE CLOSE PROXIMITY TO THE BURIAL GROUND CANNOT REASONABLY BE AVOIDED DUE TO PHYSICAL CONSTRAINTS.

(c) Flewett Shore Assembly to Cedar Junction, <u>including Cedar Compressor Station</u>

The line from the Flewett beachhead to the Cedar compressor station would be 4.8 km long.

The B.C. Hydro design differs from that of Westcoast inasmuch as Westcoast proposes to provide custody transfer immediately beyond its shore assembly at Little River. B.C. Hydro proposes custody transfer at the juncture of the north-south transmission line on Vancouver Island. <u>Both of the design proposals put forward by Westcoast and B.C. Hydro provide certain benefits to the transmission/distribution utilities On Island, and are acceptable to the Commission. However, in comparing the To Island applications of B.C. Hydro and Westcoast it is important to recognize the extra facilities and related costs provided by B.C. Hydro. Westcoast's costs were adjusted in the Commission comparison of To Island facilities.</u>

A compressor station at Cedar Junction is proposed for System A, B and D. For System A, two 895 kW turbine compressors were proposed for 1991, one of which would be a standby unit. A third unit would be installed in 1994 and a fourth in 2000.

System B would require three 895 kW compressors. Two units are planned for 1991 and the third in 1997.

For System D, five 670 kW units are planned, two units to be installed in 1991, and one unit in 1994, 1999 and 2003.

The Commission is not convinced that the cost of maintaining a standby unit at Cedar is warranted, especially in the early years of operation when the station would only operate during occasional peak periods. The provision of added security of standby units may be reasonable in later years after the market matures. Furthermore, the Commission is not convinced that B.C. Hydro needs the number of units proposed. THEREFORE, THE COMMISSION RECOMMENDS REMOVAL OF ONE UNIT FROM EACH OF THE SYSTEM OPTIONS. FOR SYSTEMS A AND D, THE 1994 UNIT WOULD BE REMOVED; FOR SYSTEM B, THE 1997 UNIT WOULD BE REMOVED AND THIS WOULD RESULT IN SAVINGS OF $7.155 MILLION TO SYSTEM A, $3.771 MILLION TO SYSTEM B AND $2.956 MILLION TO SYSTEM D ALL IN AS SPENT DOLLARS. THESE SAVINGS WERE NOT INCLUDED IN THE FINANCIAL COMPARISON OF WESTCOAST AND B.C. HYDRO CONDUCTED IN CHAPTER 5. THE COMMISSION RECOMMENDS THESE REDUCTIONS AS FURTHER COST SAVINGS TO MINIMIZE THE PROJECT SUBSIDY.

(d) Merville Junction to Little River Shore Assembly, including Merville Compressor Station

Systems A and B would both provide service to Powell River and would require a compressor station at Merville Junction. B.C. Hydro included the Powell River link as part of its application for On Island transmission; but the

Commission has evaluated the Powell River link as part of To Island transmission to allow comparisons with Westcoast's application.

System A provides for 7.8 km of 168.3 mm diameter pipe from a compressor station at Merville junction to the shore assembly north of Little River. This link would cross flat farmland and Portugese Creek, and would pose no significant construction problems.

For System A, B.C. Hydro's plan was to install two 520 kW compressors at Merville in 1995 and a third, in 2000. It also planned to build a propane air plant at Powell River to meet the needs of firm gas loads in case the single marine line to Powell River were interrupted. Because this plant would make peak shaving available at Powell River, the Commission is not convinced of the need to install a compressor station in 1995 or during the project's 20 year evaluation period, particularly if the markets on Vancouver Island and Powell River develop as found by the Commission on the evidence as presented in the Markets Phase. THEREFORE, THE COMMISSION RECOMMENDS THE REMOVAL OF THE MERVILLE COMPRESSOR STATION FROM SYSTEM A FOR A SAVING OF $7.136 MILLION. THIS SAVING WAS NOT INCLUDED IN THE FINANCIAL ANALYSIS IN CHAPTER 5.

System B would include natural gas delivery to a fertilizer complex at Powell River. Therefore, to provide maximum security from service interruption, B.C. Hydro proposed a dual marine pipeline for this system. The pipe diameter from Merville to the shore assembly at Little River would be increased to 273.1 mm.

The compressor station at Merville for System B would include two 895 kW gas turbines (one standby unit) to be installed in 1987. THE COMMISSION AGREES THAT, FOR THE ADDED THROUGHPUT OF A FERTILIZER COMPLEX, MERVILLE STATION WOULD BE REQUIRED FOR SUBSTANTIAL PERIODS EACH YEAR AND AS STANDBY IN THE EVENT THAT ONE OF THE DUAL PIPELINES IS OUT OF SERVICE. HOWEVER, THE COMMISSION

IS NOT CONVINCED THAT A STANDBY UNIT IS NEEDED SINCE THE LIKELIHOOD OF A SERVICE INTERRUPTION OF ONE MARINE PIPELINE AT THE SAME TIME AS A FAILURE OF THE MERVILLE COMPRESSOR IS REMOTE. THE COMMISSION THEREFORE RECOMMENDS THE REMOVAL OF THE STANDBY COMPRESSOR AT CEDAR AND MERVILLE RESULTING IN A SAVING OF $2.627 MILLION. THIS SAVING WAS NOT INCLUDED IN THE FINANCIAL COMPARISON CONDUCTED IN CHAPTER 5.

(e) Scuttle Bay Shore Assembly to Powell River Gate Station

The marine pipeline north of Powell River would land within the Sliammon Indian Reserve at Scuttle Bay. B.C. Hydro proposes to build a land pipeline south from Scuttle Bay inland of the dwellings on the reserve, then west of Wildwood Heights substation, and to construct an aerial crossing over the Powell River Reservoir upstream of the dam. South of the reservoir, the route would be adjacent to, or on, cleared B.C. Hydro right-of-way to the Powell River gate station. The proposed fertilizer plant and the pulp mill are north of the city gate.

For System A the 10 km pipeline would be 168.3 mm in diameter. For System B the pipe size would be increased to 273.1 mm as far south as the fertilizer plant and then reduced to 168.3 mm for the remaining distance to the city gate.

The routing, pipe size and valving considerations pose no technical problems. However, B.C. Hydro has opened discussion on access to Indian Reserve land. While it does not anticipate difficulty in reaching an agreement, it has considered other options to avoid Indian land if necessary.

3.2.2 Additional Costs to Existing Pipeline Facilities

The Commission considered what additional costs to existing pipeline facilities would result from increased throughput of natural gas destined for Vancouver

Island. These incremental costs are important in the economic evaluation of the B.C. Hydro route.

(a) <u>B.C. Hydro Incremental Costs</u>

B.C. Hydro stated that the current load projection for the Lower Mainland system indicated that the B.C. Hydro transmission line from Livingstone gate station to Roebuck would need to be looped in 1988 or 1989. If Vancouver Island and fertilizer plant loads were added to this projection, looping would be needed in 1986 or 1987 depending on the timing of the plant. B.C. Hydro estimated the additional cost attributable to the Vancouver Island system at $10,185,000 in June 1983 dollars.

THE COMMISSION RECOGNIZES THAT THE VANCOUVER ISLAND PROJECT WOULD BENEFIT FROM THE LOWER MAINLAND'S PRESENT SYSTEM. FOR THIS REASON, THE COMMISSION FINDS THAT THE $10,185,000 SHOULD BE INCLUDED IN THE CAPITAL COST OF THE VANCOUVER ISLAND PROJECT. INCLUDING THESE COSTS IN THE VANCOUVER ISLAND PROJECT ENSURES THAT LOWER MAINLAND CUSTOMERS WILL NOT BEAR FULL LIABILITY FOR THE NEW FACILITIES. THIS ENABLES THE EVALUATION OF THE PROJECT ON A STAND-ALONE BASIS.

(b) <u>Westcoast Incremental Costs</u>

The evidence presented at the hearing on the extent by which Westcoast would have to expand its mainland system to accommodate the additional gas load to Vancouver Island, was contentious and the record is not clear with respect to the actual facilities that would be required, or their cost.

<u>The Commission believes that all incremental costs of gathering, processing and transmitting natural gas to Vancouver Island by either the Northern or Southern route ought to be included when calculating the financial contribution. The Terms of Reference do not direct the Commission to</u>

consider incremental costs of the Vancouver Island Project above Williams Lake and this has not been undertaken.

The Applicants advanced differing positions on whether incremental costs on the existing Westcoast system between Williams Lake and Huntingdon should be included in calculating the financial contribution for the southern route.

Westcoast testified that its system would incur substantial incremental costs if the southern route was certificated. Under cross-examination Westcoast agreed that based on its projected volumes for the Vancouver Island market without a fertilizer plant and assuming a declining export market to 17,988,180 m^3/D after 1992, the incremental cost south of Williams Lake Compressor Station 6A to Huntingdon would be $16 million ($1983). The cost with a fertilizer plant would be $24 million. Westcoast maintained this position in argument.

B.C. Hydro argued that no incremental cost for the Williams Lake to Huntingdon section ought to be included in the subsidy calculation. B.C. Hydro argued that the difference in the wholesale price of natural gas at Williams Lake and Huntingdon as outlined in the Minister's letter of September 1, 1983, see Appendix F, was intended to account for any incremental costs incurred on the Williams Lake to Huntingdon line which could be attributed to the Vancouver Island project.

In argument ICG concluded that as a result of the predicted decline in Westcoast's natural gas exports to the American market there would be excess capacity in the system upstream of Huntingdon which could be utilized to transmit the Vancouver Island load.

Inland adopted the ICG argument and noted that if the Vancouver Island project resulted in greater utilization of the Williams Lake to Huntingdon system, thereby lowering the cost of service to Westcoast's customers, the cost of natural gas to British Columbia users could be decreased.

THE COMMISSION WAS UNABLE TO DETERMINE FROM THE TERMS OF REFERENCE, THE MINISTER'S LETTER OF SEPTEMBER 1, 1983 OR THE EVIDENCE WHETHER INCREMENTAL COSTS UPSTREAM OF HUNTINGDON WERE REFLECTED IN THE HUNTINGDON WHOLESALE PRICE. IN CALCULATING THE FINANCIAL CONTRIBUTION THE COMMISSION HAS ASSUMED THAT ANY INCREMENTAL COST ON THE WILLIAMS LAKE TO HUNTINGDON LINE WAS INTENDED TO BE ACCOUNTED FOR IN THE HIGHER WHOLESALE PRICE OF GAS AT HUNTINGDON THAN AT WILLIAMS LAKE.

This assumption is supported by the following facts :

1. The wholesale price of natural gas at Huntingdon is higher than at Williams Lake.

2. The wholesale price of natural gas at Huntingdon is higher than the city gate prices on Vancouver Island, see Appendix F. The city gate prices reflect the Provincial Government's policy to set wholesale prices based on 65% of crude oil at the Vancouver refinery gate and the Commission concludes that the Vancouver Island wholesale price of natural gas at Huntingdon is higher than the price for the same gas for distribution on the Lower Mainland.

The Commission's cost comparison of the B.C. Hydro and Westcoast system includes the incremental costs upstream of Huntingdon as this comparison is for the sole purpose of assessing total cost of new facilities constructed in B.C. for the Vancouver Island Project.

3.2.3 Marine Facilities

B.C. Hydro proposes to cross to Vancouver Island in the southern part of the Strait of Georgia from Brunswick Point across Roberts Bank, the Strait, Valdes

Island, and Stuart Channel to Vancouver Island. Pipe diameters would be 323.8 mm O.D. for Systems A and D. System B would employ 406.4 mm O.D. pipe.

B.C. Hydro also proposes to build a single or twin pipeline in the north across the Strait of Georgia from north of Little River to Scuttle Bay. System A would provide a single 168.3 mm O.D. pipeline while System B would have twin 219.1 mm O.D. pipes.

B.C. Hydro conducted technical studies which have brought the southern crossing to the final design stage. The major construction problems facing the project would be the crossing of Roberts Bank, crossing a submerged ridge called the "Galiano Ridge", laying pipe in some of the deepest waters (380 metres) ever encountered on a submarine pipeline project, and a rocky sea bottom near Valdes Island and across Stuart Channel.

(a) Marine Survey

A marine survey should include a hydrographic survey (the marine equivalent to a topographical survey) ; collection of data on wind, waves and currents ; collection of acoustic data on the sub-bottom and surface of the sea bottom ; and collection of soil and rock samples to confirm the composition of the sea bottom to a depth of a few metres.

B.C. Hydro's marine survey panel was made up of the experts who conducted the marine survey. Their major focus was the Galiano ridge, the deep sea bottom of the Strait of Georgia, the shore approaches and the sea bottom of Stuart Channel.

The panel demonstrated that a systematic survey was conducted using state-of-the-art equipment. Extensive questioning of this panel made it clear that obtaining accurate measurements of bottom relief with acoustic instruments in water depths of 380 m is not always possible. In fact, it was necessary to use a manned submersible, the Pisces IV to confirm features on the bottom. While the Pisces IV was down, at least one large rock was discovered which was not previously known to exist.

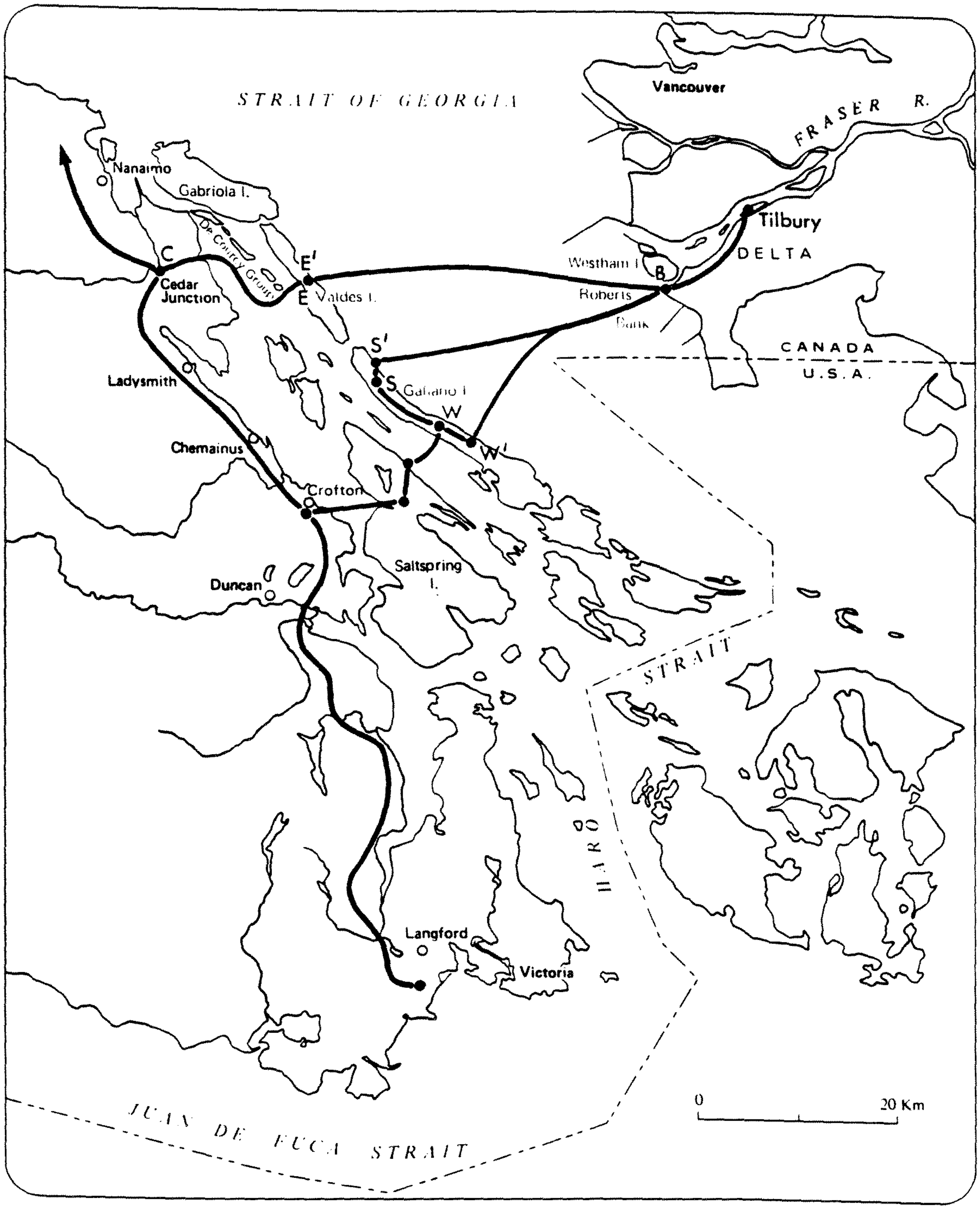
Much of the activity of the marine survey group involved searching for a suitable place to cross the Galiano Ridge, located near Galiano Island. This mountainous feature rises from the sea bottom at 380 m to within 200 m of the surface. It is characterized by step-like slopes, some of which drop vertically as much as 40 m. It would be impractical to place a pipeline across most of this ridge. A route was found over the ridge using a manned submersible in 1972. Electric cables were laid in this area a few years later, so B.C. Hydro decided the 1972 route would not be used because of the proximity of the cables.

Beginning north of the designated cable area a search was made along the ridge with a surface vessel using acoustic instruments. Two potential routes were found that would land the pipe on Galiano Island and are shown as W' and S' on Figure 3.2.5. Considerably farther north, offshore of Valdes Island, an apparent gap in the ridge was located and designated E'. Routes W' and S' were mapped from the acoustic record.

Route E', dubbed the Valdes Gap by the survey crew, could not be completely defined from the acoustic records. Consequently, the gap was the target of extensive visual observation using the Pisces IV submarine. The Pisces IV confirmed the existence of the gap and was then used to map the area. Video records were also made of the sea bottom. These were shown at the hearings together with the acoustic records and constitute strong evidence of the flat bottom through the area. However, the Gap is curved and may cause some difficulty during construction.

FIGURE 3.2.5

Proposed B.C. Hydro Alternate Marine Pipeline Routes



After discovery of the Valdes Gap, the survey concentrated on this route to cross the Galiano Ridge. Extensive work done in the area between the Valdes Gap and Valdes Island indicated that the sea bottom relief would cause spans* if the pipeline were installed. However, the spans could be corrected at reasonable cost, and substantial funds have been budgeted for this purpose.

(b) Geotechnical Considerations

Earthquake and active faults are hazards to a pipeline under certain conditions where the pipe makes the transition from the open sea floor to the restricted trench of the shore approach. Where the pipe is uncovered on the open sea bottom damage is unlikely. An earthquake may displace the earth under or around the pipe and if pipe movement is restricted, damage may result. B.C. Hydro's proposal to use heavy rock backfill assures that the pipe would be held rigidly at this point. THE COMMISSION FINDS THAT THIS DESIGN CRITERIA SHOULD RECEIVE FURTHER CONSIDERATION.

Westcoast questioned the route through the Valdes Gap where the pipelines would be spaced only 40 m apart. It adduced evidence that large boulders, which could be dislodged by earthquakes, rest on the slopes of the Gap. Liquefaction of the sea bottom could happen in the area of the Gap. Westcoast also identified apparent depressions or holes in the sea bottom inferring they might be the result of liquefaction.

The Commission notes that the boulders that exist have been resting on the slopes since they were placed there by glacial deposits and subsequent major earthquakes have not yet dislodged them. This would indicate that the probability of this happening is remote. The holes may have been caused by occasional light currents throughout the Gap and the resultant low grade scour effect is a maintenance consideration.

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* Spans are unsupported lengths of pipeline between two fixed points.

(c) Southern Corridor and Route Nomination

The task of selecting the route for the marine crossing was extremely complicated so B.C. Hydro devised a rating system based on assessing points with the favoured route receiving the lowest number of points. The Commission was not convinced of the objectivity of the rating system.

The Commission notes that the routes described as Galiano 2 and 3 are both shorter than the Valdes Gap Route. Following a shorter route might permit the pull method of pipeline installation which is potentially less expensive than the laybarge method of installation selected by B.C. Hydro for the Valdes route. More detailed investigation of the Galiano routes would have to be undertaken in order to accurately compare the cost saving of either Galiano route with the Valdes route.

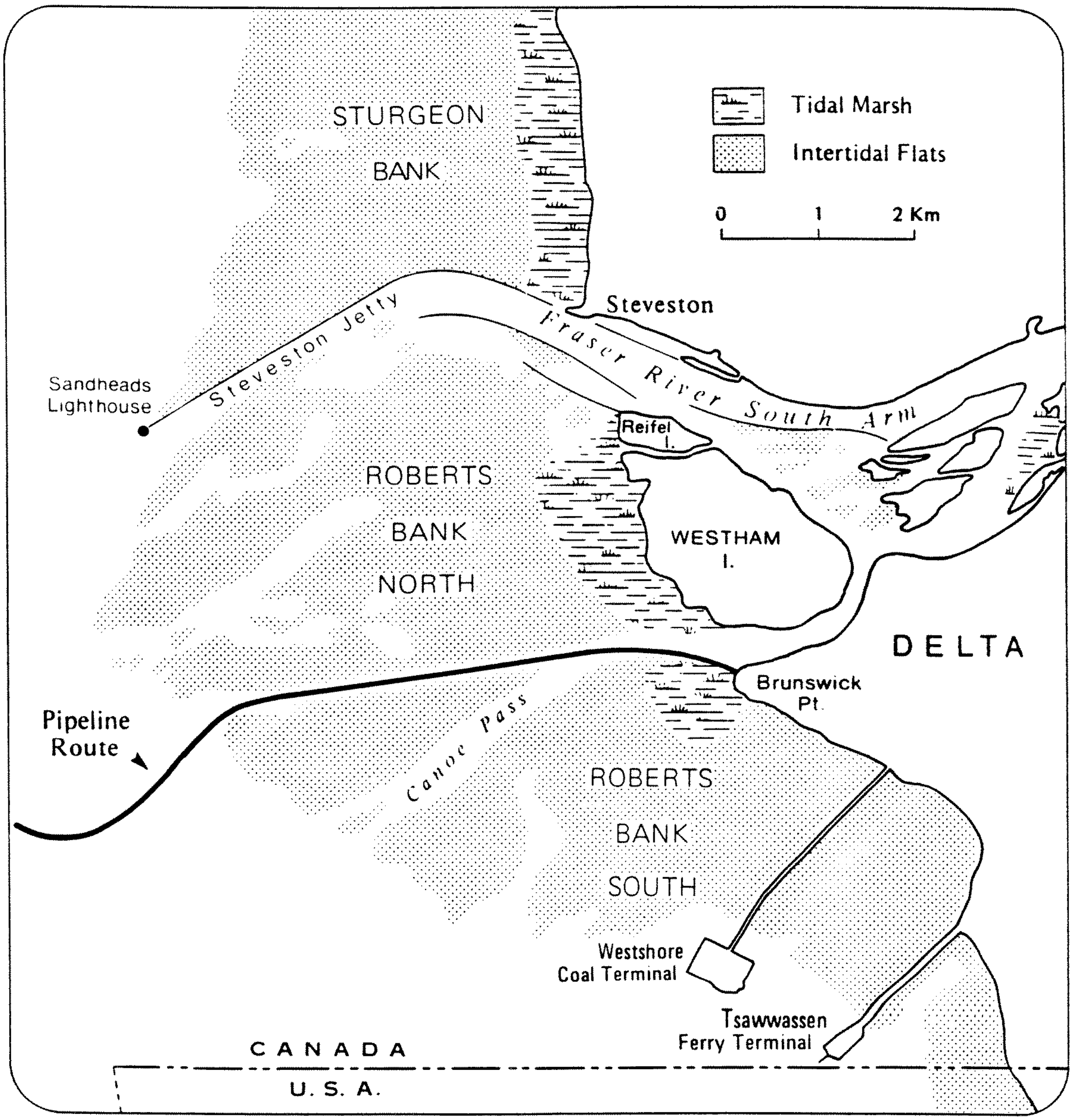
(d) Routing and Burial Across Roberts Bank

The routing and burial depth of the pipeline across Roberts Bank was a controversial issue during the hearings.

Three potential routes were examined, all of which start at the old cannery site on the south shore of Canoe Pass at Brunswick Point. The preferred pipeline routing would proceed from the cannery, along Canoe Pass for a distance of 2700 m before gradually crossing to the north side of the Pass. It would then continue across the mudflat and down the foreslope of Roberts Bank (see Figure 3.2.6). Studies of Canoe Pass indicated the possibility of scour holes to a depth of seven metres below bank elevation. A potential meander pattern extending somewhat south of its present location and north toward the edge of the Fraser River main channel was also identified. The chosen pipeline route provides for a burial depth of seven metres for two-thirds of the distance along the Pass and five metres for the remaining section on the outer slope of Roberts Bank.

FIGURE 3.2.6

Proposed B.C. Hydro Route Across Roberts Bank



A second potential route, would string the pipe south of Brunswick Point and across Roberts Bank, thereby avoiding burial in Canoe Pass. B.C. Hydro indicated that it preferred the Canoe Pass Route as hydro-electric cables, buried south of Brunswick Point, might be detrimental to the pipeline if this route had been selected. The Commission notes that the exact location of the electric cables was not identified and that B.C. Hydro's concern may not be justified. Further investigation of this alternative might produce cost saving when compared to the preferred route.

THE COMMISSION ACCEPTS THE ROUTING PROPOSED BY B.C. HYDRO BUT RECOMMENDS THE DEPTH OF BURIAL ACROSS THE OUTER SECTION OF ROBERTS BANK BE REDUCED TO THREE METRES. THE COMMISSION CONCLUDES THAT REDUCED BURIAL DEPTH POSES NO GREATER HAZARD TO THE PIPELINE THAN FIVE METRE BURIAL AND WILL REDUCE THE ENVIRONMENTAL IMPACT DURING CONSTRUCTION. BASED ON B.C. HYDRO'S EVIDENCE THAT REDUCED BURIAL ON THE OUTER BANK TO 3.5 M AND 5 : 1 SIDESLOPES WOULD SAVE APPROXIMATELY $5 MILLION IN MATERIAL MOVEMENT, THE COMMISSION ESTIMATES THREE METRE BURIAL TO EFFECT A COST SAVING OF $6 MILLION. THIS SAVING WAS NOT INCLUDED IN THE FINANCIAL COMPARISON CONDUCTED IN CHAPTER 5 BUT THE COMMISSION RECOMMENDS THESE REDUCTIONS AS FURTHER COST SAVINGS TO MINIMIZE THE PROJECT SUBSIDY.

(e) Roberts Bank Stability

The stability of Roberts Bank was a subject of considerable interest and controversy. Both sides agreed that earthquakes might cause soil liquefaction, and slope instability, that is an underwater landslide, which could damage the pipeline. B.C. Hydro recognized this but contended that the chance of such an event occuring is remote, and that there is no evidence of this happening in the last 100 to 200 years. It has identified zones of instability and has avoided them on the possible routes across Roberts Bank. Furthermore, it has purposely routed the pipe down the slope parallel to the direction of any slide that might occur, thus minimizing the potential for damage.

(f) Pipe

B.C. Hydro selected a CSA Grade 414 seamless pipe, a product which at the present time cannot be manufactured in Canada in the sizes required. Seamless pipe, as the name implies, is manufactured without a welded seam, eliminating the possiblity of a pipe seam defect. Wall thickness cannot be controlled as well as with a high-quality electric resistance weld (ERW) pipe, which can be manufactured in Canada. THE COMMISSION THEREFORE RECOMMENDS THAT THE B.C. HYDRO PIPE SPECIFICATIONS NOT PRECLUDE CANADIAN MILLS FROM COMPETING UNTIL IT IS CLEARLY ESTABLISHED THAT ERW PIPE WILL NOT BE SUFFICIENTLY RELIABLE.

THE COMMISSION RECOMMENDS THAT PIPE BE INSPECTED BY A THIRD PARTY INDEPENDENT NON-DESTRUCTIVE INSPECTION SERVICE, AT THE PIPE MILL AND AT THE COATING YARD. An x-ray computer enhancement technique is now available, which, when used in combination with present methods of non-destructive testing, can virtually eliminate manufacturing defects in the pipe. The extra cost of this service is justified where pipe is to be used in deep water marine crossings.

The Commission is also concerned that pipe wall thickness may not have been calculated correctly. Generally, a pipe is sized using a nominal wall thickness. However, for sizing pipe and vessels in plant facilities, the codes require that minimum wall thickness based on maximum allowable manufacturing tolerances be used. Similarly, strength-related calculations for submarine pipelines should be based on the minimum wall thickness. THE COMMISSION NOTES B.C. HYDRO'S PIPE CALCULATIONS ARE BASED ON

NOMINAL THICKNESS AND RECOMMENDS THAT IT ENSURE THAT THE PIPE STRENGTH CALCULATIONS ARE BASED ON MINIMUM WALL THICKNESS.

A potential hazard to the pipeline during laybarge installation is buckling which can occur when the pipe is subjected to stress due to bending in deep water. In the event the pipe does collapse or buckle, the pipe can have a propagating buckle*. The risk of buckling is remote if pipe of sufficient wall thickness is used. B.C. Hydro designers have adopted the use of buckle arrestors in their design. This mechanism is designed to stop a buckle at the point at which the arrestor is installed. Adoption of this technique indicates acceptance by B.C. Hydro of the risk of buckle between arrestors. THE COMMISSION RECOMMENDS THAT B.C. HYDRO EMPLOY PIPE OF INCREASED WALL THICKNESS TO REMOVE THIS RISK.

A submarine pipeline can be displaced by the hydrodynamic forces exerted by currents and waves. This has been considered and as a result the pipe is to be coated with concrete to add weight to resist these forces. Appropriate coefficients for drag, lift and friction must be used to calculate the weight required. B.C. Hydro's design is considerably heavier than would be expected for a body of water such as the Strait of Georgia. If it is heavier than necessary, B.C. Hydro would be able to trim costs from the project. THE COMMISSION RECOMMENDS THAT THIS DESIGN DETAIL BE RECONSIDERED IN ORDER TO REDUCE COSTS.

Another potential construction difficulty encountered during marine pipeline construction is the creation of spans. A span, being an unsupported length of pipe between two fixed points, has two difficulties : (1) the pipe could buckle under its own weight if the span is too great, and (2) the pipe span may be subject to vibration caused by hydrodynamic forces.

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* A propagating buckle can collapse the pipeline along its length as the pipe is flattened from its maximum strength round configuration.

The Valdes 1 route would have spans in the area between the Galiano Ridge and Valdes Island as well as other areas. The actual number and length of spans will not be known until the pipeline is installed because of inherent inaccuracy in the use of acoustic instruments and marine positioning systems.

One span which can be predicted would occur in the area of Valdes Gap where the Gap is wide enough for only one pipeline. The second pipeline would cross a large rock feature which rises abruptly from the seafloor to a height of at least five metres. This span would be corrected by buttressing during construction.

The Commission recognizes that the various design recommendations made in this section interact with one another and all recommendations will need to be reviewed together.

(g) Shore Approaches

The shore approaches for consideration are the east and west sides of Valdes Island, and at Flewett on Vancouver Island. If a return line is built to Powell River approaches at Little River and Scuttle Bay must also be considered.

The approaches on both sides of Valdes and at Flewett consist of bedrock. B.C. Hydro proposed blasting the rock and burial of the pipe to a depth of 3.5 m to prevent any conflict with marine traffic and to insure the integrity of the line. THE COMMISSION HAS CONSIDERED THESE MATTERS AND CONCLUDES THAT ALL POTENTIAL MARINE CONFLICTS CAN BE AVOIDED AND THE INTEGRITY OF THE LINE MAINTAINED BY BURIAL TO A DEPTH OF 1.2 M AND RECOMMENDS THIS DESIGN CHANGE BE IMPLEMENTED TO EFFECT COST SAVING IN MINIMIZING THE PROJECT SUBSIDY BY AN ESTIMATED $2.0 MILLION. THIS SAVING WAS NOT INCLUDED IN THE FINANCIAL COMPARISON BETWEEN WESTCOAST AND B.C. HYDRO CONDUCTED IN CHAPTER 5.

A concern raised at the hearing regarded potential damage to water wells at Flewett from offshore blasting. B.C. Hydro proposed to monitor the performance of these wells before and after construction and restore any damaged well to its original state. THE COMMISSION RECOMMENDS THAT B.C. HYDRO'S PROPOSED MONITORING SYSTEM BEFORE AND AFTER CONSTRUCTION AND CORRECTIVE ACTION PROPOSED BE ADOPTED.

The approaches at Little River and Scuttle Bay have not been investigated to the same extent as those at Valdes and Flewett. Preliminary indications were that each of these approaches is rocky. If further investigation confirms that these approaches are bedrock the Commission recommends a burial depth of 1.2 m.

(h) High Voltage Direct Current

B.C. Hydro operates high voltage direct current (HVDC) electric cables to Vancouver Island which are submerged in the lower Georgia Strait. This system includes a return line which is not now used. If B.C. Hydro were forced to use the sea as a return line, the pipeline could suffer severe corrosive damage within three to six months.

B.C. Hydro undertook studies which demonstrate that with the completion of the Cheekye-Dunsmuir system, a spare AC cable could be used as an additional metallic return. This would further limit the use of a sea return in cases involving multiple electrical system failures. The Commission is satisfied that the pipeline can be fully protected by the use of conventional pipe coating, installation of a cathodic protection system with automatically controlled rectifiers at the end points and modification of the electric supply system to Vancouver Island. However, the Commission notes that it is critical to the integrity of the pipeline that the sea return not be used for prolonged periods.

(i) Construction Methods at Roberts Bank

B.C. Hydro proposes to install the pipeline across Roberts Bank using the bathtub method of installation. A pipelaying barge operating directly behind a large dredge would move across the Bank with each unit performing its respective functions simultaneously. The spoil discharge line from the dredge would be run to the rear of the pipelaying barge where the spoil would be deposited over the dual pipelines as they are laid on the bottom of the dredged channel, see Figure 3.2.7.

On a related matter, B.C. Hydro plans sideslopes of the trench to be 5 : 1 slope even though dredging at the nearby coal terminal maintained slopes of 4 : 1, and slopes of 3 : 1 could hold for short periods of time. Steeper slopes would greatly decrease the amount of material moved and would substantially accelerate the construction schedule. THE COMMISSION IS OF THE VIEW THAT SIDESLOPES SHOULD BE CUT FOR A STEEPER SLOPE TO AVOID UNNECESSARY MATERIAL MOVEMENT AND REDUCE THE PERIOD OF DISTURBANCE TO THIS ENVIRONMENTALLY SENSITIVE AREA.

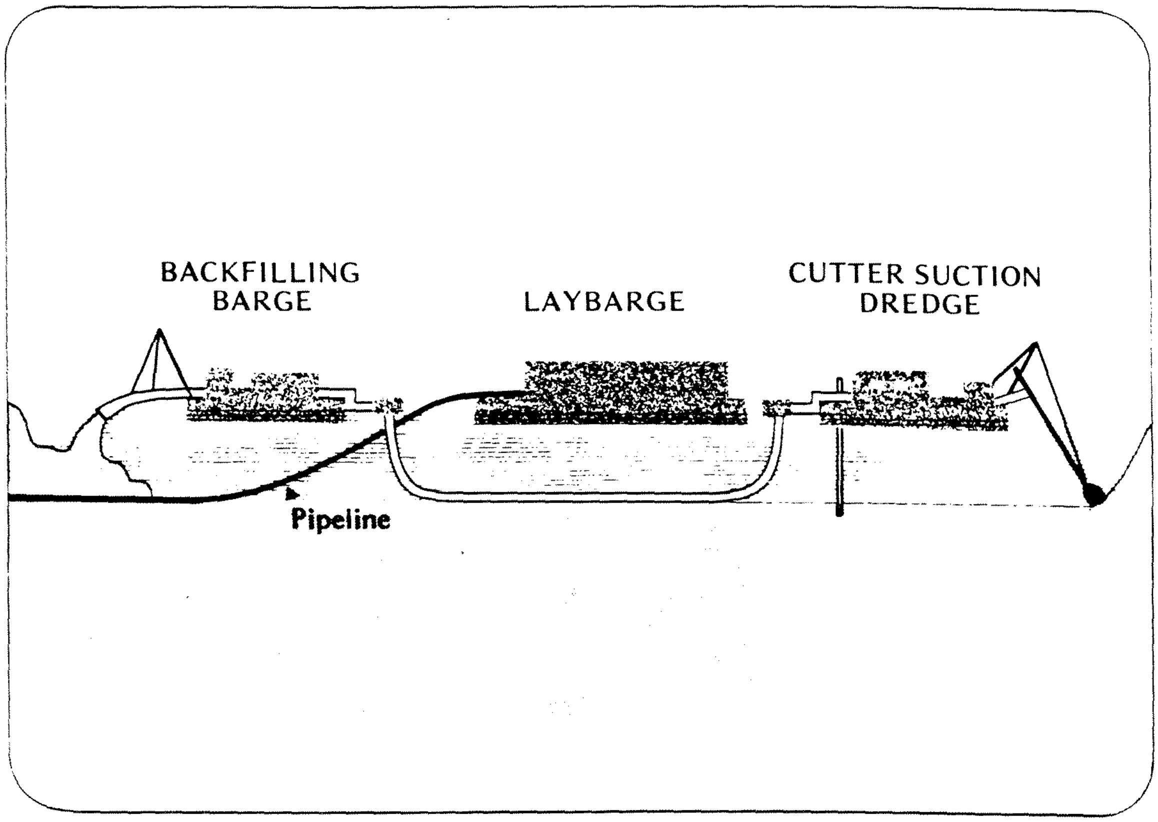
3.2.4 Operations and Maintenance

The Commission reviewed B.C. Hydro's proposed operations and maintenance program for the marine pipeline and found it to be satisfactory. B.C. Hydro proposes to internally inspect the pipeline with a Kaliper pig during commissioning, after two years, and later as considered necessary.

Visual inspection of the deep water pipeline would be made annually in the early years using RCV or manned submersible. Shore approaches and Roberts Bank would be surveyed by sonar. An annual profile survey of Canoe Pass would be made, and the monthly helicopter patrol program for land pipelines would be extended to include visible portions of the Roberts Bank crossing.

FIGURE 3.2.7

Pipeline Installation by Bathtub Method



In the event of the failure of or damage to the pipeline across Roberts Bank, it will be necessary for B.C. Hydro to have its repair program approved by the 908 Committee and DFO. Presumably any such program of repair will have to be carried out during an environmentally acceptable construction window (see Chapter 4). B.C. Hydro has provided ample funds to deal with maintenance such as scour and spans. B.C. Hydro has also included approximately $39 million for repair of a deep water rupture at some point in the operating life.

3.2.5 Capital Costs

B.C. HYDRO'S PROJECTED CAPITAL COSTS WERE SCRUTINIZED IN GREAT DETAIL. THE COMMISSION CONCLUDES THAT THE ACTUAL PROJECT COSTS WILL NOT EXCEED THE ESTIMATES. INDEED, THE COMMISSION EXPECTS THAT WITH CAREFUL PROJECT MANAGEMENT AND WITH THE DESIGN CHANGES RECOMMENDED IN THIS CHAPTER, CAPITAL COSTS COULD BE REDUCED SUBSTANTIALLY FROM THOSE PRESENTED TO THE COMMISSION. THE CONTRACTORS WHO TESTIFIED FOR B.C. HYDRO VIEWED THE PROJECT DESIGN AS CONSERVATIVE AND THE CONSTRUCTION COSTS AS HIGH. FURTHERMORE, A B.C. HYDRO CONSULTANT TESTIFIED THAT THE ESTIMATES WERE $7 MILLION HIGH.

The Commission, therefore, accepts the capital costs put forward by B.C. Hydro in its application. However, the Commission has adjusted them for specific matters in order to facilitate a comparison between B.C. Hydro and Westcoast. Other potential cost savings discussed in this Chapter related to compressor requirements, installation charges, and laybarge acquisition charges, are addressed further in Chapter 6, Conclusions and Recommenda- tions. The original B.C. Hydro estimates are adjusted to reflect the following changes for comparison purposes :

- The additional cost of locating the Tilbury compressor station within the industrial park. These costs, to be incurred in 1985 and 1986 total $758,000 ($1983) for System A and D and $808,000 for System B.

- The additional capital costs on B.C. Hydro's existing mainland system for increased sizing and advanced timing of the Livingstone to Roebuck loop totalling $10,185,000. The small costs of improving Huntingdon gate station are not included. These costs are shown in 1986 allocated $2,000,000 to pipe and $8,185,000 to installation.

- The Commission has modified the To Island facilities and capital costs to conform with the Commission's assessment of markets and peak day demands. B.C. Hydro is able to meet those demands with facilities proposed to be installed between 1984 and 1992.

The B.C. Hydro forecasts of Capital Costs, as adjusted, are provided in Tables 3.2.1, 3.2.2, and 3.2.3 for Systems A, B and D respectively.

TABLE 3.2.1

Vancouver Island Gas Pipeline Project
System A - Transmission to Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993-2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	13591	-	-	-	-	-	-	-	-	-	13591
R/W	-	1811	361	-	-	-	-	-	-	-	2172
CMP STN	-	4042	11235	3900	928	2542	928	3475	2420	-	29470
Pipe	-	8575	5283	-	-	-	-	-	-	-	13858
Other Materials	-	4564	3374	985	-	-	-	-	-	-	8923
Installation	-	27968	71749	-	-	-	-	-	-	-	99717
Eng & Supv	1281	3664	2789	-	-	-	-	-	-	-	7734
Contingency	232	5729	9825	-	-	-	-	-		-	15786
Indirects	950	1868	1724	-	-	-	-	-	-	-	4542
Corporate Overhead	493	1571	2212	1466	278	763	278	1042	726	-	8829
Total (June 83$)	16547	59792	108552	6351	1206	3305	1206	4517	3146	-	204622
Inflation	30	4221	14636	1289	332	1162	522	2343	1918		26453
Interest during constr.	1738	4970	9116	293	56	47	63	297	238	-	16818
TOTAL PROJECT COSTS	18315	68983	132304	7933	1594	4514	1791	7157	5302	-	247893

TABLE 3.2.1 (cont'd)

Vancouver Island Gas Pipeline Project
System A - Service to Powell River
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993-2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	905	-	-	-	-	-	-	-	-	-	905
R/W	-	50	702	-	-	-	-	-	-	-	752
CMP STN	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	844	299	-	-	-	-	-	-	-	1143
Other Materials	-	880	755	105	-	162	-	-	128	-	2030
Installation	-	2	14621	127	-	-	-	-	-	-	14750
Prop. Air Plt.	-	128	2796	-	40	839	-	37	795	-	4635
Eng & Supv	174	795	1197	74	-	-	-	-	-	-	2240
Contingency	36	512	2982	28	-	-	-	-	-	-	3558
Indirects	5	87	632	-	-	-	-	-	-	-	724
Corporate Overhead	43	89	552	100	12	300	-	11	277	-	1384
Total (June 83$)	1163	3387	24536	434	52	1301	-	48	1200	-	32121
Inflation	3	239	3308	88	14	457	-	25	732	-	4866
Interest during constr.	119	311	970	-	-	-	-	-	-	-	1400
TOTAL PROJECT COSTS	1285	3937	28814	522	66	1758	-	73	1932	-	38387

TABLE 3.2.2

Vancouver Island Gas Pipeline Project
System B - Transmission to Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993-2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	13591	-	-	-	-	-	-	-	-	-	13591
R/W	-	1811	361	-	-	-	-	-	-	-	2172
CMP STN	-	5864	16464	5557	3900	-	-	933	2420	-	35138
Pipe	-	13320	5400	-	-	-	-	-	-	-	18720
Other Materials	-	6531	3602	985	-	-	-	-	-	-	11118
Installation	-	27968	74723	-	-	-	-	-	-	-	102691
Eng & Supv	1281	3664	2789	-	-	-	-	-	-	-	7734
Contingency	232	6117	10263	-	-	-	-	-	-	-	16612
Indirects	950	1868	1724	-	-	-	-	-	-	-	4542
Corporate Overhead	493	1813	2418	1963	1170	-	-	280	726	-	8863
Total (June 83$)	16547	68956	117744	8505	5070	-	-	1213	3146	-	221181
Inflation	30	4868	15876	1726	1395	-	-	629	1918		26442
Interest during constr.	1738	5401	10021	392	328	-	-	67	238	-	18185
TOTAL PROJECT COSTS	18315	79225	143641	10623	6793	-	-	1909	5302	-	265808

TABLE 3.2.2 (cont'd)

Vancouver Island Gas Pipeline Project
System B - Service to Powell River
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993-2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	1153	-	-	-	-	-	-	-	-	-	1153
R/W	-	101	702	-	-	-	-	-	-	-	803
CMP STN	-	-	-	795	2420	-	-	-	-	-	3215
Pipe	-	2541	617	-	-	-	-	-	-	-	3158
Other Materials	-	1901	708	296	-	-	-	-	-	-	2905
Installation	-	2	24071	190	-	-	-	-	-	-	24263
Prop. Air Plt.	-	-	-	-	-	-	-	-	-	-	-
Eng & Supv	262	1192	1686	149	-	-	-	-	-	-	3289
Contingency	54	1147	4977	57	-	-	-	-	-	-	6235
Indirects	8	185	883	-	-	-	-	-	-	-	1076
Corporate Overhead	65	191	774	446	726	-	-	-	-	-	2202
Total (June 83$)	1542	7260	34418	1933	3146	-	-	-	-	-	48299
Inflation	4	513	4641	392	865	-	-	-	-	-	6415
Interest during constr.	154	542	1535	70	179	-	-	-	-	-	2480
TOTAL PROJECT COSTS	1700	8315	40594	2395	4190	-	-	-	-	-	57194

TABLE 3.2.3

Vancouver Island Gas Pipeline Project
System D - Transmission to Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993-2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	13591	-	-	-	-	-	-	-	-	-	13591
R/W	-	1811	361	-	-	-	-	-	-	-	2172
CMP STN	-	4042	11235	3900	928	2542	-	1706	4569	-	28922
Pipe	-	8575	5281	-	-	-	-	-	-	-	13856
Other Materials	-	4561	3374	985	-	-	-	-	-	-	8920
Installation	-	27968	71749	-	-	-	-	-	-	-	99717
Eng & Supv	1281	3664	2789	-	-	-	-	-	-	-	7734
Contingency	232	5729	9825	-	-	-	-	-	-	-	15786
Indirects	950	1868	1724	-	-	-	-	-	-	-	4542
Corporate Overhead	493	1571	2212	1466	278	763	-	512	1371	-	8666
Total (June 83$)	16547	59789	108550	6351	1206	3305	-	2218	5940	-	203906
Inflation	30	4221	14639	1289	332	1162	-	1150	3622	-	26445
Interest during constr.	1738	4970	9117	293	56	204	-	122	443	-	16943
TOTAL PROJECT COSTS	18315	68980	132306	7933	1594	4671	-	3490	10005	-	247294

3.3 On Island Transmission Facilities

The Commission did not conduct hearings on the applications of B.C. Hydro, ICG, Inland, and Westcoast for natural gas transmission facilities on Vancouver Island. A detailed review of these facilities will be the subject of a further phase of this hearing or as part of separate hearings dealing with distribution rights.

All Applicants requested that Terms of Reference be initiated quickly so that any further hearings related to On Island matters will not delay the project. The Commission agrees that major delays in the On Island review would delay the project and urges that this review be initiated as soon as possible following a Provincial Government decision on a north or south routing to Vancouver Island.

In March 1984, the Commission determined that the Applicants' proposals for transmission facilities on Vancouver Island were similar for either a northern supply from Comox or southern delivery via Cedar. The Applicants' costs for the provision of the facilities were also comparable. Therefore, the Commission advised the Provincial Government that it would be possible to determine the size of the revenue deficiencies and subsidies required for the Vancouver Island natural gas pipeline facilities without a detailed review of the On Island component of those facilities. The Government responded by amending the Terms of Reference which directed the Commission to adjourn generally and to report following the review of the To Island Phase.

The Commission's To Island review involved the evaluation of facilities to the Vancouver Island transmission line, including compression facilities required for initial delivery. The review of B.C. Hydro's To Island facilities also included a return line to Powell River and compression facilities at Merville Junction. Therefore, the On Island transmission facilities extend from the Victoria city gate north to the city gate at Campbell River, with laterals to Crofton and Port Alberni. The ICG and Inland applications assumed receipt of natural gas at Westcoast's beachhead at Little River. The Commission has previously indicated an adjustment of the Westcoast system to make it comparable to the B.C. Hydro proposal by extending its To Island system to connect with the main north-south On Island lateral (see Section 3.1.1(d), page 66). Accordingly, both the ICG and Inland On Island systems which were designed to connect with a northern supply will be overstated by the approximate cost of the Commission adjustments, which are $6.335 million for pipeline in 1986 and $15.695 million in 1989 for the compressor station.

3.3.1 Westcoast

Westcoast's On Island application involves transmission of gas from its beachhead at Little River to the Vancouver Island Mainline near Comox, and construction of a mainline south from Comox to the Victoria city gate at Langford. The Westcoast application on Vancouver Island did not include laterals to Campbell River, Port Alberni or Crofton since Westcoast has assumed that these laterals would be constructed by the distribution companies. However, to compare Westcoast's capital costs with those provided by the other Applicants, the Commission must include the costs associated with the Campbell River lateral, and the laterals to Port Alberni and Crofton. Cost information for these laterals was provided in Volume 10 of Westcoast's submission dealing with distribution matters. From these costs, the Commission deducted the costs of duplicated facilities and arrived at the amount of $30 million in 1985 to reflect the capital costs of laterals.

Westcoast's On Island costs include facilities to connect the mainline with its beachhead landing at Little River. The Commission, in its To Island analysis, and to compare the Westcoast and B.C. Hydro systems, added those costs to the Westcoast To Island system. In consideration of Westcoast's projected costs of Vancouver Island On Island facilities , the Commission adjusted the Applicant's estimates to exclude the extension from the beachhead at Little

River to the Vancouver Island mainline including the Comox compressor station. Therefore, the Commission has deducted these costs for proper assessment of the On Island costs.*

Westcoast's On Island costs are provided on Tables 3.3.1 and 3.3.2.

3.3.2 B.C. Hydro

From Cedar, B.C. Hydro's proposals provided three alternative Vancouver Island Transmission proposals for each of their Systems A, B and D market requirements. These facilities are shown schematically in Figures 3.2.2, 3.2.3 and 3.2.4 of the B.C. Hydro To Island assessment (page 99, 100 and 101 respectively). In all cases, the compression requirements for the On Island system were reviewed by the Commission during the To Island phase of the hearing.

The B.C. Hydro market assessment and peak day requirements were considerably higher than those of the other Applicants and the BCUC. The facilities provided by B.C. Hydro in 1992 would serve the market forecast by BCUC in the year 2005. It is the Commission's view that the On Island additional facilities prepared by B.C. Hydro after 1992 will not be necessary to satisfy the requirements of the Commission's market forecast. However, because the Commission did not assess the On Island facilities or their costs in detail the cost of those added facilities ($32 million in $1986) was not deleted for this comparison.

The adjusted B.C. Hydro On Island costs are provided in Tables 3.3.3, 3.3.4 and 3.3.5 for Systems A, B and D respectively.

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* In deducting costs for the Comox compressor station, the Commission is aware of a small discrepancy in the timing and valuation of the station. This problem has been dealt with by deducting the actual costs shown by Westcoast in the year they are identified in Volumes 31 and 32 revised.

TABLE 3.3.1

Westcoast Transmission Company Limited

On Island Transmission Facilities Costs
Without Fertilizer Case

Current Dollars
($000)

Year	Plant Additions
1985	136,370*
1986	29
1987	61
1988	97
1989	137
1990	182
1991	191
1992	200**
1993	304
1994	322
1995	342
1996	362
1997	384
1998	407
1999	432
2000	455
2001	483
2002	512
2003	543
2004	575
2005	0
TOTAL	$142,388

* includes $30 million for laterals to Campbell River, Port Alberni, Crofton and less $6.335 million for pipeline connection to Comox.

** less $16,673 for Comox compressor

From Westcoast Volume 32, Revised, Tab 10, pages 3 and 5.

TABLE 3.3.2

Westcoast Transmission Company, Limited

On Island Transmission Facilities Costs
With Fertilizer Case

Current Dollars
($000)

Year	Plant Additions
1985	136,348*
1986	29
1987	61
1988	96
1989	100**
1990	253
1991	354
1992	281
1993	298
1994	315
1995	335
1996	354
1997	376
1998	399
1999	423
2000	448
2001	474
2002	503
2003	532
2004	563
2005	0
TOTAL	$142,542

* includes $30 million for laterals to Campbell River, Port Alberni, Crofton and less $6.335 million for pipeline connection to Comox.

** less $14,024 for Comox compressor

From Westcoast Volume 31, Tab 10, pages 3 and 5.

TABLE 3.3.3

B.C. Hydro

Vancouver Island Gas Pipeline Project
System A - Transmission on Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
CONSTRUCTION COST ($JUNE 83)												
Survey/Invest	3041	-	-	-	-	-	-	-	-	-	-	-
R/W	-	6933	1700	-	-	-	-	-	-	-	85	-
CMP STN	-	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	360	8882	-	-	-	-	-	-	-	818	-
Other Materials	-	1524	4289	-	-	-	-	-	66	-	265	28
Installation	-	3608	46120	-	-	-	-	-	-	-	2322	-
Eng & Supv	412	1867	3850	-	-	-	-	-	-	57	197	-
Contingency	59	1506	5952	-	-	-	-	-	3	6	315	-
Indirects	256	1556	1408	-	-	-	-	-	-	-	-	-
Corporate Overhead	145	469	1661	-	-	-	-	-	21	19	1201	8
Total (June 83$)	3913	17823	73862	-	-	-	-	-	90	82	5203	36
Inflation	9	1258	9959	-	-	-	-	-	55	58	4208	33
Interest during constr.	399	1347	3508	-	-	-	-	-	-	2	155	-
TOTAL PROJECT COST	4321	20428	87329	-	-	-	-	-	145	142	9566	69

TABLE 3.3.3 (cont'd)

B.C. Hydro

Vancouver Island Gas Pipeline Project
System A - Transmission on Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	-	-	-	-	-	-	-	-	-	-	3041
R/W	-	-	-	77	-	-	101	-	-	-	8896
CMP STN	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	-	-	625	-	-	895	-	-	-	11580
Other Materials	-	66	-	223	-	-	322	-	-	-	6792
Installation	-	-	-	2109	-	-	2748	-	-	-	56907
Eng & Supv	-	-	52	175	-	68	231	-	-	-	6909
Contingency	-	3	5	279	-	7	367	-	-	-	8502
Indirects	-	-	-	-	-	-	-	-	-	-	3220
Corporate Overhead	-	21	17	1046	-	22	1399	-	-	-	6029
Total (June 83$)	-	90	74	4534	-	97	6063	-	-	-	111867
Inflation	-	104	95	6441	-	167	11416	-	-	-	33803
Interest during constr.	-	-	2	182	-	3	289	-	-	-	5887
TOTAL PROJECT COST	-	194	171	11157	-	267	17768	-	-	-	151557

TABLE 3.3.4

B.C. Hydro

Vancouver Island Gas Pipeline Project
System B - Transmission on Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
CONSTRUCTION COST ($JUNE 83)												
Survey/Invest	2793	-	-	-	-	-	-	-	-	-	-	-
R/W	-	7065	1733	-	-	-	-	-	-	88	85	-
CMP STN	-	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	360	10361	-	-	-	-	-	-	691	818	-
Other Materials	-	1524	4832	-	-	-	-	-	135	226	265	23
Installation	-	3733	48091	-	-	-	-	-	-	1852	2322	-
Eng & Supv	412	1867	3850	-	-	-	-	-	44	210	197	-
Contingency	59	1531	6253	-	-	-	-	-	7	263	315	-
Indirects	256	1556	1408	-	-	-	-	-	-	-	-	-
Corporate Overhead	145	476	1760	-	-	-	-	-	56	999	1201	7
Total (June 83$)	3665	18112	78288	-	-	-	-	-	242	4329	5203	30
Inflation	9	1279	10556	-	-	-	-	-	148	3058	4208	28
Interest during constr.	369	1328	3620	-	-	-	-	-	1	122	154	-
TOTAL PROJECT COST	4043	20719	92464	-	-	-	-	-	391	7509	9565	58

TABLE 3.3.4 (cont'd)

B.C. Hydro

Vancouver Island Gas Pipeline Project
System B - Transmission on Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	-	-	-	-	-	-	-	-	-	-	2793
R/W	-	-	-	77	-	-	101	-	-	-	9149
CMP STN	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	-	-	625	-	-	895	-	-	-	13750
Other Materials	-	66	32	223	-	-	298	-	-	-	7624
Installation	-	-	-	2109	-	-	2748	-	-	-	60855
Eng & Supv	-	-	52	175	-	68	230	-	-	-	7105
Contingency	-	3	5	279	-	7	364	-	-	-	9086
Indirects	-	-	-	-	-	-	-	-	-	-	3220
Corporate Overhead	-	21	27	1046	-	22	1391	-	-	-	7151
Total (June 83$)	-	90	116	4534	-	97	6027	-	-	-	120733
Inflation	-	104	149	6441	-	167	11348	-	-	-	37495
Interest during constr.	-	-	2	182	-	3	287	-	-	-	6068
TOTAL PROJECT COST	-	194	267	11157	-	267	17662	-	-	-	164296

TABLE 3.3.5 (cont'd)

B.C. Hydro

Vancouver Island Gas Pipeline Project
System D – Transmission on Island
Project Capital Costs in (Thousands of Dollars)

Fiscal Year Ending March 31

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	TOTAL
CONSTRUCTION COST ($JUNE 83)											
Survey/Invest	-	-	-	-	-	-	-	-	-	-	3496
R/W	-	-	-	200	-	-	101	-	-	-	9545
CMP STN	-	-	-	-	-	-	-	-	-	-	-
Pipe	-	-	-	1048	-	-	895	-	-	-	11444
Other Materials	15	66	-	350	-	-	322	4	-	-	6853
Installation	-	-	-	6546	-	-	2748	-	-	-	67893
Eng & Supv	-	-	143	483	-	68	230	-	-	-	8077
Contingency	-	3	14	793	-	7	367	-	-	-	9793
Indirects	-	-	-	-	-	-	-	-	-	-	3220
Corporate Overhead	4	20	47	2826	-	22	1399	1	-	-	11640
Total (June 83$)	19	89	204	12246	-	97	6062	5	-	-	132411
Inflation	20	103	262	17396	-	167	11414	10	-	-	57218
Interest during constr.	-	-	6	491	-	3	289	-	-	-	6848
TOTAL PROJECT COST	39	192	472	30133	-	267	17765	15	-	-	196477

3.3.3 ICG

ICG provided three alternatives for the transmission of natural gas on Vancouver Island which are called Base Case and Alternatives 1 and 2. The Base Case and Alternative 1 are designed to accommodate a southern crossing while Alternative 2 was designed for a northern crossing. In the Base Case, ICG assumed receipt of natural gas at Cedar and it would provide transmission facilities to Victoria in the south, Campbell River in the north and Port Alberni in the west. Alternative 1 is the same as the Base Case with the addition of the required capacity and compression to permit eventual service of the Powell River area and the fertilizer plant. Alternative 2 assumes that gas is received at Little River near Comox, with a transmission network similar to that of the Base Case.

ICG does not anticipate any need for compression in the early years of operation of the Base Case system. For Alternative 1, ICG assumed that one compressor station will be necessary for the Courtenay/Comox and Powell River lateral, or in an alternative design, a small compressor would be installed at the Powell River lateral with additional compression at the Port Alberni lateral. In Alternative 2 involving gas supply via the northern crossing, ICG anticipates the need for one compressor station at Courtenay/Comox in the initial years of the project and a second compressor station near the Parksville lateral during later years of service.

The capital cost for these three systems are summarized in Tables 3.3.6, 3.3.7 and 3.3.8. The costs indicated in Table 3.3.8 will be overstated as previously noted on page 134.

TABLE 3.3.6

ICG ISLAND TRANSMISSION LTD.

PROJECTED CAPITAL COST OF FACILITIES - BASE CASE
Current Dollars ($000)

CODE	DESCRIPTION	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
402	Other Intangible Plant	1,000.0										
	-Intangible Plant	1,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land		300.2									
461	Land Rights		7,311.5									
463	Measuring and Regulating Structures and Improvements		936.2									
465	Mains		116,073.4									
467	Measuring and Regulating Equipment		2,989.9									
	-Transmission Plant		127,611.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land		124.3									
482	Structures and Improvements		145.4									
483	Office Furniture and Equipment		54.7					38.9				
484	Transportation Equipment		185.2			65.1			81.7			101.6
485	Heavy Work Equipment		360.5									
486	Tools and Work Equipment		186.5									
488	Communication Structures and Equipment		12.4									
	-General Plant		1,069.0	0.0	0.0	65.1	0.0	38.9	81.7	0.0	0.0	101.6
496	Unclassified Plant Cost of Engineering and Supervision	5,390.3	6,011.4									
	General Contingency	528.2	12,264.7									
	Administration Overhead Capitalized		359.3									
497	Allowance for Funds used during Construction	1,592.3	5,538.1									
	-Undistributed Plant	7,510.8	24,173.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	8,510.8	152,853.7	0.0	0.0	65.1	0.0	38.9	81.7	0.0	0.0	101.6
	PLANT UNDER CONSTRUCTION	8,510.8										
	GROSS PLANT IN SERVICE		161,364.5	161,364.5	161,364.5	161,429.6	161,429.6	161,468.5	161,550.2	161,550.2	161,550.2	161,651.8

TABLE 3.3.6 (cont'd)

CODE	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
402	Other Intangible Plant										
	-Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land										
461	Land Rights										
463	Measuring and Regulating Structures and Improvements										
465	Mains										
467	Measuring and Regulating Equipment										
	-Transmission Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land										
482	Structures and Improvements										
483	Office Furniture and Equipment	55.9					75.8				
484	Transportation Equipment			124.4			148.2			171.5	
485	Heavy Work Equipment										
486	Tools and Work Equipment										
488	Communication Structures and Equipment										
	-General Plant	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
496	Unclassified Plant										
	Cost of Engineering and Supervision										
	General Contingency										
	Administration Overhead Capitalized										
497	Allowance for Funds used during Construction										
	-Undistributed Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
	GROSS PLANT IN SERVICE	161,707.7	161,707.7	161,832.1	161,832.1	161,832.1	162,056.1	162,056.1	162,056.1	162,227.6	162,227.6

TABLE 3.3.7

ICG ISLAND TRANSMISSION LTD.

PROJECTED CAPITAL COST OF FACILITIES - ALTERNATIVE 1
Current Dollars ($000)

CODE	DESCRIPTION	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
402	Other Intangible Plant	1,000.0										
	-Intangible Plant	1,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land		389.8									
461	Land Rights		7,602.7									
462	Compressor Structures and Improvements		198.9									
463	Measuring and Regulating Structures and Improvements		1,007.7									
465	Mains		131,165.7									
466	Compressor Equipment		2,997.3									
467	Measuring and Regulating Equipment		3,384.1									
	-Transmission Plant		146,746.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land		124.3									
482	Structures and Improvements		145.4									
483	Office Furniture and Equipment		54.7					38.9				
484	Transportation Equipment		185.2			65.1			81.7			101.6
485	Heavy Work Equipment		360.5									
486	Tools and Work Equipment		186.5									
488	Communication Structures and Equipment		12.4									
	-General Plant		1,069.0	0.0	0.0	65.1	0.0	38.9	81.7	0.0	0.0	101.6
496	Unclassified Plant											
	Cost of Engineering and Supervision	5,631.2	6,253.4									
	General Contingency	536.1	14,209.5									
	Administrative Overhead Capitalized		387.1									
497	Allowance for Funds used during Construction	2,021.3	6,199.5									
	-Undistributed Plant	8,188.6	27,049.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	9,188.6	174,864.7	0.0	0.0	65.1	0.0	38.9	81.7	0.0	0.0	101.6
	PLANT UNDER CONSTRUCTION	9,188.6										
	GROSS PLANT IN SERVICE		184,053.3	184,053.3	184,053.3	184,118.4	184,118.4	184,157.3	184,239.0	184,239.0	184,239.0	184,340.6

TABLE 3.3.7 (cont'd)

CODE	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
402	Other Intangible Plant										
	-Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land										
461	Land Rights										
463	Measuring and Regulating Structures and Improvements										
465	Mains										
467	Measuring and Regulating Equipment										
	-Transmission Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land										
482	Structures and Improvements										
483	Office Furniture and Equip.	55.9					75.8				
484	Transportation Equipment			124.4			148.2			171.5	
485	Heavy Work Equipment										
486	Tools and Work Equipment										
488	Communication Structures and Equipment										
	-General Plant	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
496	Unclassified Plant										
	Cost of Engineering and Supervision										
	General Contingency										
	Administration Overhead Capitalized										
497	Allowance for Funds used during Construction										
	-Undistributed Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
	GROSS PLANT IN SERVICE	184,396.5	184,396.5	184,520.9	184,520.9	184,520.9	184,744.9	184,744.9	184,744.9	184,916.4	184,916.4

TABLE 3.3.8

ICG ISLAND TRANSMISSION LTD.

PROJECTED CAPITAL COST OF FACILITIES - ALTERNATIVE 2
Current Dollars ($000)

CODE	DESCRIPTION	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
402	Other Intangible Plant	1,000.0										
	-Intangible Plant	1,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land		271.6		50.0							
461	Land Rights											
462	Compressor Structures and Improvements		7,602.7		264.6							
463	Measuring and Regulating Structures and Improvements		936.2									
465	Mains		130,907.2									
466	Compressor Equipment				6,500.1							
467	Measuring and Regulating Equipment		2,989.9									
	-Transmission Plant		142,707.6	0.0	6,814.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land		124.3									
482	Structures and Improvements		145.4									
483	Office Furniture and Equipment		54.7					38.9				
484	Transportation Equipment		185.2			65.1			81.7			101.6
485	Heavy Work Equipment		360.5									
486	Tools and Work Equipment		186.5									
488	Communication Structures and Equipment		12.4									
	-General Plant		1,069.0	0.0	0.0	65.1	0.0	38.9	81.7	0.0	0.0	101.6
496	Unclassified Plant											
	Cost of Engineering and Supervision	5,250.1	6,165.5	585.2	425.0							
	General Contingency	536.1	13,793.7		697.1							
	Administration Overhead Capitalized		359.3									
497	Allowance for Funds used during Construction	1,844.6	6,101.8	288.8	164.9							
	-Undistributed Plant	7,630.8	26,420.3	874.0	1,287.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	8,630.8	170,196.9	874.0	8,101.7	65.1	0.0	38.9	81.7	0.0	0.0	101.6
	PLANT UNDER CONSTRUCTION	8,630.8		874.0								
	GROSS PLANT IN SERVICE		178,827.7	178,827.7	187,803.4	187,868.5	187,868.5	187,907.4	187,989.1	187,989.1	187,989.1	188,090.7

TABLE 3.3.8 (cont'd)

CODE	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
402	Other Intangible Plant										
	-Intangible Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
460	Land										
461	Land Rights										
463	Measuring and Regulating Structures and Improvements										
465	Mains										
467	Measuring and Regulating Equipment										
	-Transmission Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
480	Land										
482	Structures and Improvements										
483	Office Furniture and Equip.	55.9					75.8				
484	Transportation Equipment			124.4			148.2			171.5	
485	Heavy Work Equipment										
486	Tools and Work Equipment										
488	Communication Structures and Equipment										
	-General Plant	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
496	Unclassified Plant										
	Cost of Engineering and Supervision										
	General Contingency										
	Administration Overhead Capitalized										
497	Allowance for Funds used during Construction										
	-Undistributed Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	YEARLY CAPITAL EXPENDITURE	55.9	0.0	124.4	0.0	0.0	224.0	0.0	0.0	171.5	0.0
	GROSS PLANT IN SERVICE	188,146.6	188,146.6	188,271.0	188,271.0	188,271.0	188,495.0	188,495.0	188,495.0	188,666.5	188,666.5

3.3.4 Inland

Inland proposed pipeline facilities on Vancouver Island to transmit gas from either a southern or northern supply. In April 1984, Inland filed its updated facility design and costs which reflect its reduced market expectations.

In the case of the southern supply alternative, Inland's design assumes receipt of natural gas at Cedar for delivery south to Victoria and north to a location six kilometres north of Courtenay. This northern terminus is expected to be the appropriate tie-in point for a lateral to Powell River. This system also includes laterals to Campbell River, Port Alberni and Crofton.

The island transmission system has been designed with sufficient capacity for existing Powell River loads, and could accommodate gas service to the proposed fertilizer plant through additional compressor system facilities.

In the northern supply alternative, Inland significantly reduced its pipe sizes due to the major reduction in peak day requirements. The pipe diameters have been reduced from 406.4 mm to 323.9 mm between Courtenay and Langford. This reduced size would necessitate the addition of compressor facilities at the juncture of the mainline and Port Alberni lateral, and peak shaving in Victoria and/or Nanaimo as the system load develops. The lines to Campbell River, Port Alberni and Crofton would use the same pipe size as the southern supply alternative.

Inland's capital cost summary is shown in Tables 3.3.9 and 3.3.10. Inland's costs have not been adjusted for the alterations in Westcoast's delivery point and added compression facilities.

TABLE 3.3.9

INLAND NATURAL GAS CO. LTD.

VANCOUVER ISLAND NATURAL GAS TRANSMISSION SYSTEM
SUMMARY OF CAPITAL COST BY COST CATEGORY
SOUTHERN SUPPLY ALTERNATIVE
6% ESCALATED ($000)

ACCOUNT	1983 COST	ESCALATED TO YEAR OF EXPENDITURE 1984	1985	1986	TOTAL COST ESCALATED
LAND/LAND RIGHTS	5,518	1,524	4,289	313	6,126
PIPELINE	105,014	4,283	112,536	972	117,791
STRUCT/IMPROV	395	-	444	-	444
MEASURING/REG.	1,861	-	2,091	-	2,091
COMMUNICATIONS	197	-	221	-	221
TOOLS/EQUIP.	646	-	726	-	726
SUB-TOTAL	113,631	5,807	120,307	1,285	127,399
AFUDC	8,589	401	9,175	-	9,576
TOTAL INVESTMENT	122,220	6,208	129,482	1,285	136,975

TABLE 3.3.10

INLAND NATURAL GAS CO. LTD.

VANCOUVER ISLAND NATURAL GAS TRANSMISSION SYSTEM
SUMMARY OF CAPITAL COST BY COST CATEGORY
NORTHERN SUPPLY ALTERNATIVE
6% ESCALATED ($000)

ACCOUNT	1983 COST	ESCALATED TO YEAR OF EXPENDITURE 1984	1985	1986	1994	TOTAL COST ESCALATED
LAND/LAND RTS.	5,767	1,584	4,457	326	61	6,428
PIPELINE	107,894	4,373	115,643	1,009	-	121,025
STRUCT/IMPROV	867	-	444	-	896	1,340
MEASURING/REG	4,792	-	2,091	-	5,564	7,655
COMMUNICATIONS	197	-	221	-	-	221
TOOLS/EQUIP	743	-	835	-	-	835
SUB-TOTAL	120,260	5,957	123,691	1,335	6,521	137,504
AFUDC	8,988	412	9,431	-	300	10,143
TOTAL INVESTMENT	129,248	6,369	133,122	1,335	6,821	147,647

3.3.5 Commission Assessment of On Island Costs

The total On Island capital costs projected by the Applicants are shown in Table 3.3.11. Differences in their forecasts can be easily explained.

In the case of B.C. Hydro the Commission has reported the full cost of On Island facilities even though it is anticipated that these facilities could be substantially reduced to meet the Commission's market forecast. However, the Commission has not attempted to alter the costs for comparison purposes until a full review of On Island facilities.

The ICG estimates were completed in the spring of 1983, and therefore, do not consider the cost impacts of reduced load estimates, compression at Cedar and Comox, the delivery of gas to the Vancouver Island mainline by Westcoast, or the Commission's 6% inflation. In a similar manner, the cost estimates of Inland do not take account of the implications of delivery of gas to the mainline by Westcoast.

After adjustment for the laterals, Westcoast's costs are likely close to the full cost of the northern supply option.

In assessing On Island costs for revenue deficiencies, the Commission used the B.C. Hydro estimates for southern delivery and Westcoast estimates for northern delivery. This should not be taken to imply any bias by the Commission in favour of these companies. The Commission used these forecasts to maintain maximum continuity with the system facilities proposed by these Applicants in the To Island Phase. In any future assessment of On Island facilities, the Commission anticipates that all Applicants will update their cost estimates to consider the Commission's load forecasts, as well as the conditions of gas supply for the Applicant eventually certified to transmit gas to Vancouver Island.

TABLE 3.3.11

On Island

Total Capital Costs
Current Dollars
($000)

Applicant	South Supply*	North Supply*
B.C. Hydro	196,477	-
ICG	162,227	188,666
Inland	136,975	147,647
Westcoast	-	142,388

* Unadjusted for comparison (see page 155, Section 3.3.5).

3.4 Summary of Capital Costs

The comprehensive review of Westcoast and B.C. Hydro To Island capital costs undertaken in Section 3.1 and 3.2, coupled with the On Island overview of Section 3.3, provide the Commission with complete information to forecast expected total system costs for the Vancouver Island Natural Gas Pipeline Project.

As is evident in the foregoing sections the Commission has made an effort to compare the B.C. Hydro and Westcoast To Island capital costs based on similar system capabilities. Another very significant alteration to facilities was intended to make the On Island facilities the same for each Applicant. The On Island facilities were taken to be the north south mainline on Vancouver Island from Victoria to Campbell River including the laterals to Port Alberni and Crofton. Westcoast was adjusted to bring its custody transfer point to the mainline at Comox, and B.C. Hydro was adjusted to include all facilities from Comox to Powell River in To Island costs.

In assessing the facilities proposed by the Applicants the Commission found that either proposal was capable of providing reliable gas service to Vancouver Island. However, as shown on Table 3.4.1, the capital costs of providing service to Vancouver Island via the B.C. Hydro proposals are much less than the Westcoast proposals. Total transmission facility costs to deliver gas to the Vancouver Island markets are minimized by B.C. Hydro System D, at a capital cost of $460 million (as spent dollars at 6% inflation). In the case of a fertilizer plant at Powell River, B.C. Hydro System B provides the lowest capital cost to serve the markets of Vancouver Island, Powell River and a fertilizer plant. The total capital cost is $512 million.

TABLE 3.4.1

To and On Vancouver Island

Total Capital Costs
Current Dollars
($000)

	Without Fertilizer	With Fertilizer
B.C. HYDRO *		
- System A	453,837	
- System B		511,298
- System D	459,771	
WESTCOAST	544,513	590,413

* Includes $16 million for Systems A and D, and $24 million for System B to reflect capital additions upstream of Huntingdon. These additions are deducted before cost of service evaluations since they are included in the wholesale prices at Huntingdon.

CHAPTER 4 ENVIRONMENTAL AND SOCIO-ECONOMIC IMPACTS

Item 4 (l) of the Terms of Reference directed the Commission to :

> ". . . review and assess key impacts of each applicant's proposal on the physical environment, resources, and land use, as well as significant socio-economic impacts".

The Commission's finding and conclusions with respect to the environmental and socio-economic impacts of the B.C. Hydro and Westcoast pipeline proposals are summarized in this chapter. In addition, this Chapter includes a summary of the issues presented at the community hearings.

4.1 Environmental Impacts

4.1.1 Westcoast - The Northern Route

Westcoast's proposed northern route would involve the transport of natural gas from Williams Lake overland to Powell River, and then across the Strait of Georgia to a terminal near Comox. The pipeline route crosses several climatic zones, ranging from the continental interior plateau to the maritime climate of the coast. In general the pipeline would be buried in a cleared and revegetated right-of-way, 18 m wide. The proposed route is presently accessible for about 75% of its 390 km length by existing public and logging roads. The right-of-way would not be maintained as a road, and the only road extension would be an additional 15 km of forestry road to provide access to the compressor station near Dash Creek. Routine maintenance in remote areas would be carried out by helicopter. The project would increase access to remote wilderness areas only marginally because it would be difficult to travel over the many steep slopes and major stream crossings that characterize the right-of-way. Nevertheless, Westcoast stated that they would cooperate with Federal and Provincial Government Ministries in preventing access along the pipeline right-of-way.

The project is not expected to cause any major or long-term environmental impacts. Westcoast has indicated that more detailed environmental studies will be conducted during the final design phase. These studies would include investigations of (1) the heritage resource at the Fraser River crossing ; (2) the Bighorn sheep herd in the south Chilcotin ; (3) the moose population in the Elaho ; and (4) the fishery resources at all important stream crossings. Although no long-term impacts on these resources are expected, such studies would aid in developing all necessary mitigative measures.

Specific environmental issues that were raised and discussed in the hearing are summarized below.

(a) Potential Impacts

1. Wildlife

Concern was expressed over the possible effect of the pipeline on moose wintering habitat in the Elaho Valley. In general, no serious impacts are expected from road development if the road does not occupy more than 20% of the habitat. Since the pipeline would pass through short sections of moose habitat (between km 272 and 282), and would occupy well under 20%, and since it would involve less long-term disturbance than a road, no negative impacts on the moose population are expected. In fact, the right-of-way would provide potential positive impacts due to the eventual growth of browse vegetation on right-of-way clearings.

Compressor station V-3 is also located in the Elaho Valley but is outside the moose wintering habitat. Furthermore, the compressor station noise level at a distance of 200 m is expected to be only 50 Dba, which is comparable to a dishwasher in an adjoining room.

Although Westcoast cannot prevent workers from hunting on their own time and in their own vehicles if they have proper permits, the company practice is to limit the use of firearms and prevent the use of company vehicles by employees for hunting during construction.

2. Fish

The pipeline right-of-way will cross 63 streams. Several concerns regarding the potential impacts on fish resources were voiced during the hearing. While information on the locations of salmonid spawning areas in the Fraser, Skawkwa and Lillooet rivers is adequate, virtually no information is available on fish resources in the majority of the streams to be crossed by the pipeline, although some of the smaller watercourses likely do not support significant fish resources. Final design will avoid sensitive areas to minimize impacts of construction on important fish species.

The scheduling of construction for river crossings is important. Rivers must be crossed at a time when construction will have the least impact on fish ; this time period is designated as the "construction window". Westcoast indicated that river crossings could easily be completed within the specified construction windows, particularly since many crossings are small and can be finished in a single day. However, any proposed construction outside the specified construction windows, would require prior approval from the appropriate fisheries agency.

3. Revegetation

Revegetation of the right-of-way is important to prevent drainage and erosion problems and to minimize negative aesthetic impacts. The revegetation program would spread over two seasons following construction of the pipeline, and post-construction monitoring would be initiated to ensure success. Westcoast indicated that its previous revegetation programs have been generally successful.

Ranchers in the region are concerned that where the pipeline crosses rangeland, undesirable weeds, especially knapweed, might be introduced. Westcoast testified that it would steam clean machinery and vehicles before allowing them to enter the construction sites in order to prevent the introduction of knapweed seed. It would also prevent workers from straying off the right-of-way during construction. If a knapweed infestation did occur, Westcoast would cooperate with Federal and Provincial Government Agencies to control the problem.

4. Forestry

An issue developed concerning the correct procedure for valuing the approximately 900 hectares of forest lands to be withdrawn from the forest land base for the pipeline right-of-way. Westcoast calculated the present value of this loss at approximately $26,146 ($1983), based on the potential growth and yield on the withdrawn forest land. Given a rotation period of 100 years, the value of the potential growth was estimated as the value of timber that would have accumulated on that land at the end of 100 years had the lands not been withdrawn from production. This value was then discounted at five percent. In support of this method of evaluation, Westcoast testified that in the Cariboo, Kamloops, and Vancouver forestry regions affected by the pipeline right-of-way, the Ministry of Forests' designated land base would not be reduced. Therefore, the annual allowable cut of timber, as designated by the Ministry of Forests, would not be reduced or affected. Westcoast also contended that the Ministry of Forests, in determining the forest land base, has provided for the removal of land to accommodate such items as rights-of-way.

B.C. Hydro contended that the forestry loss should be evaluated in a different manner. It argued that the forestry land withdrawn for the pipeline right-of-way should be considered a direct reduction in the annual allowable cut values for the named regions. This valuation method would result in a greater loss estimate. Since the losses would start at the time of construction rather than 100 years later, B.C. Hydro calculated the present value of the forestry loss at approximately $584,000.

The Commission finds that insofar as forest lands are withdrawn due to pipeline right-of-way development, a resource loss would be sustained. This would be true regardless of whether such withdrawals have been accounted for in the regional forest management plans.

(b) Mitigation

Westcoast's evidence suggests that discussions with timber companies and Federal and Provincial Government regulatory agencies responsible for managing land, water, forests, fish, wildlife, minerals, recreation areas, rangelands, etc. have contributed to the selection of the proposed pipeline route, thereby avoiding areas of major environmental concern.

Mitigation of project impacts would also be achieved through compliance with the statutory requirements of appropriate Federal, Provincial and Regional Governments. Many of the permits, licences and approvals that must be obtained before pipeline construction have provisions for mitigation. These permits and licences include : the waste management permits for discharge of gaseous emissions, liquid effluent and solid waste ; the water licence for hydrostatic testing of the pipeline ; Crown grant of right-of-way through Crown lands ; the licence to cut timber from Crown lands ; water crossing approvals from the Federal Environmental Protection Service, Federal Department of Fisheries and Oceans, and B.C. Ministry of Environment ; and permits under the Navigable Waters Protection Act and Ocean Dumping Control Act for the Strait of Georgia underwater crossing.

(c) Monitoring

Westcoast stated that terms requiring proper environmental management are incorporated in the contractual agreements between the company and its contractors. In addition an environmental inspector will be employed by Westcoast in areas considered environmentally sensitive. The costs of such monitoring have been included in Westcoast's cost estimates.

(d) Commission Conclusions

The Commission concludes that the Ministry of Forests is in the best position to determine the actual value of the loss, and therefore the appropriate compensation to be paid to the Crown. The procedure for evaluating this loss should be the same as that recommended by the B.C. Utilities Commission in the Site C Report and by B.C. Hydro at these hearings. The Site C price and stumpage assumptions would have to be updated.

The Commission concludes that the environmental impact of the proposed northern route would be relatively low. Given successful mitigative measures, including adherence to appropriate construction timing windows, no serious long-term impacts from the project are anticipated.

4.1.2 B.C. Hydro - The Southern Route

Due to the value and sensitivity of its resources, the Fraser River Estuary, including the outer marshes and Roberts Bank area, has been the subject of a joint Federal/Provincial study aimed at determining land and water use policies and guidelines to minimize the environmental impacts of any development in this area.

In 1977, B.C. Order in Council No. 908 was issued and the Environmental Impact Assessment Committee (908 Committee) was established to review all development proposals on Roberts Bank and the Estuary. The 908 Committee assesses development proposals to ensure that environmental impacts are minimized or avoided (see Appendix B).

Three major environmental issues are associated with B.C. Hydro's proposed pipeline construction in the Canoe Pass and Roberts Bank area. The first is the value of the intertidal marshes as rearing habitat for salmonids and wintering areas for waterfowl. The second involves the fishery resource, particularly the juvenile salmonids, which occupy the Roberts Bank area during spring and summer. The third is the crab resource on the intertidal flats and foreslope.

The B.C. Hydro route avoids disturbing the intertidal marsh by deep burial of the pipeline along Canoe Pass to a point seaward of the marsh. This route, combined with B.C. Hydro's proposed use of a "bathtub"* dredging operation, minimizes potential environmental disturbance.

Three options regarding pipeline construction in the Roberts Bank area were considered by B.C. Hydro : to start at the foreslope as early as possible in the year and finish at Brunswick Point before February 28 (the landward sequence) ; to start at Brunswick Point on July 15 and finish at the foreslope in December or January (the seaward sequence) ; and to start one construction train at Brunswick Point on August 1 working seaward and a second construction train starting at the foreslope on September 1 working landward (the dual spread sequence).

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* See B.C. Hydro Marine Facilities Section, page 123.

These construction methods and repair procedures* must be evaluated and approved not only by the 908 Committee but also by the Department of Fisheries and Oceans (DFO). Both the 908 Committee and the DFO strive to control access and interruption to this area** during certain particularly sensitive times of the year. Generally, this period lasts from approximately the beginning of September to the end of February (the construction window), but these dates vary from year to year. The B.C. Hydro proposals must be evaluated on the basis that the methods of pipeline installation are capable of completion within the construction window. It is noted that both the 908 Committee and DFO have the ability to set the dates for construction start-up ; and, if monitoring during construction indicates unacceptable damage to species on the Bank, the DFO can stop construction. These facts have important scheduling and cost implications for B.C. Hydro. The cost of maintaining a construction train in the Vancouver area for a second construction season, or remobilizing a laybarge from another area are untenable.

(a) The Landward Sequence

The landward sequence would not interfere with the major migration of adult salmon, the native food fisheries or summer vessel traffic in Canoe Pass. The impact on juvenile salmon would be negligible if dredging were completed by late February, when downstream migration of salmon begins in the Fraser River. However, the construction window overlaps the time when wintering waterfowl are present in the area. B.C. Hydro testified that this sequence would be the least costly of the three and would permit B.C. Hydro to complete difficult work at the foreslope during a period when weather conditions are most favourable.

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* See B.C. Hydro Facilities To Island, page 125.

** Brunswick Point is not included in this sensitive area.

(b) The Seaward Sequence

The seaward sequence may interfere with the migration of adult salmon and could also interfere with the native food fishery and summer vessel traffic in Canoe Pass. However, it would avoid disturbance of wintering waterfowl as well as the potential loss of salmon smolts due to construction activity on the foreslope. A disadvantage of this sequence is that the more difficult work at the foreslope would have to be completed in December and January when adverse weather conditions may prevail. This sequence is estimated to cost $4 million more than the landward sequence.

(c) The Dual Spread Sequence

The dual spread sequence would have potential impacts similar to that of the seaward sequence in Canoe Pass but would avoid any impacts on salmon smolts on the foreslope. However, this method would involve moving service and supply vessels to the construction train along Canoe Pass during the period when waterfowl are wintering. This sequence would also produce a depression in the intertidal flats, where the two construction trains meet, twice the size of that produced by the landward or seaward sequence. Canoe Pass is the obvious source of fill for this depression. It is also likely the two construction trains will have to dredge their way to deeper water. This sequence, although it would permit the construction to be completed in a shorter time period could have an additional cost in excess of $4 million for the second laybarge.

The 908 Committee favoured the dual spread sequence as it would result in a shorter construction sequence and would minimize potential impacts on waterfowl and fish resources.

(d) Intervenor Positions

A policy witness from DFO emphasized that on the basis of experience and recent data, the risk of damage to the fishery resource is high and increases during the period from March to August. DFO would monitor fish density in the summer up to the month of August in the year of proposed construction and determine whether August 1 is an acceptable start-up date. DFO stated that the dual spread sequence should be considered to ensure that construction would be completed within the construction window and in one season.

B.C. Hydro in scheduling its landward construction through Canoe Pass across Roberts Bank has targeted a start-up date of August 1. B.C. Hydro acknowledged that this sequence would have minimal potential impact on the fish and fisherman if dredging could be completed between September 1 and February 28, and also acknowledged that the potential impacts of dredging on fish would be lower if the start-up date was September 1. B.C. Hydro maintained that it had sufficient time in its schedule to complete work between September 1 and February 28. It has, however, targeted the August 1 start-up date so that it would have a longer contingency period to cover cessation of construction due to mechanical breakdown or adverse weather conditions.

The Commission finds that with a start-up date of September 1, and with reasonable allowance made for contingencies, B.C. Hydro could complete the landward construction sequence in the September 1 to February 28 time period. This would be even more feasible if burial depth is decreased as recommended in Chapter 5 Financial Analysis, Section 3.2.3 (d) since less material would need to be moved. The Commission, therefore, urges the 908 Committee to review reduced burial depth across Roberts Bank as a method of further minimizing the environmental impacts.

The Commission is aware that, if the 908 Committee, after its review, does not approve the landward sequence B.C. Hydro must adopt the dual spread sequence at an estimated additional cost of $4 million.

(e) Potential Impacts

1. Fish

B.C. Hydro argued that the landward sequence would minimize potential damage to the fishery resource. B.C. Hydro further testified that the overall impacts of dredging would be relatively short-term since bottom dwelling fauna of the Fraser Estuary recover rapidly following disturbance. Significant recolonization of benthic organisms would occur one year after completion of construction and therefore no long-term or permanent alteration of the aquatic environment is expected.

The potential impacts of dredging on juvenile salmonids is the most serious environmental concern. B.C. Hydro consultants indicated that, at worst, one percent of one year's fishery resource in this area could be lost. The start-up date of construction is highly critical to the completion within the construction window for Roberts Bank. Past sampling efforts indicate that fish density varies substantially during August, although the numbers of fish apparently increase in the areas around the outer foreslope during August. Therefore an August 1 start-up date may not be possible during the year of construction.

2. Shore Approaches

Some blasting will be required to excavate at shore approaches in the Gulf Islands and potentially at Scuttle Bay. The impact on fish could be mitigated by scheduling the blasting for the summer months and by monitoring fish present during the blast sequence. The specific timing of the blast will require DFO approval.

3. Crabs

The loss of crabs in the Roberts Bank area is considered unavoidable although the seaward construction sequence would minimize these losses. The proportion of the crab population that would be lost has been estimated at about one to two percent of the annual crab yield on Roberts Bank. Assuming a destruction of one to two percent for a period of seven years, B.C. Hydro estimated that approximately 27.6 metric tonnes of this resource having a gross value of $45,000 measured in constant 1983 discounted dollars would be lost.

The pre-trapping of crabs along the construction route was considered but deemed impractical. B.C. Hydro concluded that the overall impacts of pipeline construction on this crab resource would not be serious.

4. Wintering Waterfowl

The marsh habitat in the Fraser Delta area is important for migratory bird species, particularly during the fall and winter. The impacts on migratory birds would be noise and human disruption associated with the project. B.C. Hydro's wildlife expert testified that migrating birds would suffer no long-term dislocation.

B.C. Hydro's wildlife consultant conducted three field inspections in November 1983 to determine the distribution of waterfowl in the area which would be affected by the project. He concluded that, although the seaward sequence would have marginally less impact than the landward sequence, the potential impacts of the latter construction method are still expected to be insignificant because the construction train would largely avoid the marsh lands.

(f) Compensation

B.C. Hydro has budgeted compensation for the crab fishermen (approximately ten) who would be denied access to portions of the crabbing grounds during the one-and-a-half to two month period that Canoe pass is closed.

DFO contended that compensation values for loss of the salmon and crab resources have not yet been established. DFO argued that payment of compensation for the resource loss must be distinguished from private compensation such as that proposed to be paid by B.C. Hydro to the crab fishermen.

(g) Monitoring

B.C. Hydro indicated that it would follow the recommendations of the DFO and the 908 Committee regarding fish monitoring before, at the beginning of, and during construction. Monitoring programs would be conducted during all phases of construction. As previously indicated, DFO may also be involved in construction monitoring perhaps by stationing fisheries officers on the dredge.

(h) Commission Conclusions

The Fraser River Estuary, including Canoe Pass and Roberts Bank, are sensitive environmental areas. The Commission concludes that overall environmental impacts can be reduced to an acceptable level by following recommendations and guidelines established by the 908 Committee and the DFO. The Commission recognizes that these authorities and B.C. Hydro must cooperate to establish procedures that will minimize environmental impacts yet ensure that construction is completed in one year, thereby avoiding increased environmental and financial costs.

4.2 Socio-Economic Impacts

4.2.1 Westcoast Proposal

The overland portion of Westcoast's northern route passes through rural and unsettled areas until it reaches the District of Powell River. At this point, the pipeline would pass through a lightly developed rural residential district for about one kilometre, and then enter the forested southern end of District Lot 450 to reach the marine crossing beachhead.

The size of the construction crews would vary with the segment and stage of pipeline construction. For the right-of-way clearing, the work force would range from 40 to 175 persons, but would increase to about 450 for grading through to completion of the pipeline including construction of the compressor station. The crews would be almost exclusively from Canada and approximately 80% would be British Columbia residents. Most accommodation for the workforce would be in local motels and hotels, which are currently underutilized. The additional 28 person operation and maintenance crews for the mainland section would be located in the Williams Lake and Powell River areas. A negligible burden on local social service infrastructure is expected because of the short construction period and the small permanent crews.

The Westcoast proposal would provide direct benefits to local governments through tax revenues collected for the life of the pipeline. The estimated tax revenue generated by the proposed pipeline facilities would result in approximately $560,000 ($1983) of tax annually, and thereby represents a significant contribution to the local economies.

Although the Commission encouraged Westcoast to present particular evidence of future industrial growth along the northern corridor Westcoast only identified potential mining development.

(a) Native Concerns

Westcoast's proposed route passes through areas traditionally used by natives for hunting, fishing and food gathering. In particular, members of the Alkali Lake Indian Band identified their concerns at the hearings at Alkali Lake and Vancouver.

The native population is primarily concerned about the potential negative impacts of the pipeline development on their culture and traditional life style. Although no specific, direct tangible impacts from past pipeline developments on natives have been identified, they believe that the pipeline would be an incremental threat in a continual process whereby the land upon which their life style and culture depend is gradually opened up for various forms of industrial development and non-native use. The threat to the native communities, therefore, comes from the cumulative impacts of development in general, rather than specific impacts of the present Westcoast proposal.

4.2.2 B.C. Hydro Proposal

The adverse socio-economic impacts of the B.C. Hydro proposal are expected to be minimal. The major source of impact would be the presence of construction workers in the region. However, since the construction crews will be relatively small, 350 personnel at peak construction in Delta and an additional 265 for the marine crossing, they could be easily accommodated by existing social infrastructures in Delta and adjacent Lower Mainland areas. In addition, B.C. Hydro anticipates that the majority of the labor force involved in construction of the compressor station and land pipeline through Delta would be residents of the region, who would commute to construction sites, further decreasing the project's demand on local social services and accommodations. B.C. Hydro estimates that 85% of the work force would be residents of British Columbia, and the remainder would come mostly from elsewhere in Canada. However, personnel from outside Canada would be required for supervisory positions on the deepwater laybarge.

In order to maximize the positive impacts of the project, B.C. Hydro testified that preference may be given to tenders that propose to use products manufactured in British Columbia and Canada.

4.2.3 Intervenors' Position

The Municipality of Delta is concerned with the potential negative impacts that pipeline construction would have on the community. With construction through cultivated farmlands, estimated by B.C. Hydro to be about 32 ha, a season's production would be disrupted. In addition, there is concern that the pipe would not be buried deeply enough through cultivated farmlands to allow farmers to operate their large harvesters and tractors.

An additional concern of the municipality is that the final alignment of the right-of-way may conflict with its development plans and cut lots into sizes that cannot be readily developed. For the Commission recommendations regarding this concern (see Chapter 3, page 102).

4.2.4 Commission Assessment

The Commission concludes that the potential negative socio-economic impacts of both the northern and southern routes would not be significant. However, a number of positive impacts would result from the project. First, the construction activities would generate demands for goods and services in communities along the pipeline routes. Given the underutilized capacity of most of the businesses in these communities, the project would provide much needed economic stimulus. Second, Westcoast's northern route would provide significant direct benefits to local governments through tax revenues collected for the life of the project. Third, employment opportunities would be available to local residents along the route, particularly in Westcoast's northern route where unskilled labour is needed for clearing the route.

An illustration of both projects' potential positive economic impacts on B.C. and Canada using the Statistics Canada "Inter-Provincial Input-Output Model" is shown in Annex 1.

Several conclusions can be reached on the basis of this simulation exercise. Both projects generate a significant amount of employment and income in British Columbia and Canada as a whole. The Westcoast proposal, however, will generate more income and employment than B.C. Hydro's. Expenditures on materials and services for the Westcoast proposal will indirectly generate an estimated $56.4 million of income (in $1983) and 2,700 man years of employment in Canada. Expenditures on materials and services for the B.C. Hydro proposal will indirectly generate an estimated $29.6 million ($1983) of income and 1,345 man years of employment. The primary reason for the greater impacts of the Westcoast proposal is the greater level of expenditures that it entails. Impacts per dollar of expenditure are quite similar for the two projects, from a national point of view.

In order to take into account the different tax, employment and other impacts in the project comparisons, the Commission developed estimates of the social (economic) costs of the two projects. The derivation of the social costs is made on the following basis :

1) Taxes are netted out of the project costs as they are transfer payments and hence not real costs to society ;

2) The social costs of labour are used in place of market wages to take into account the high employment benefits, given current and expected unemployment rates ;

3) The social values of the resource losses are added as part of the project costs ; and

4) A social cost premium for imports is added to project costs to reflect the economic cost that foreign exchange outflows have on the economy.

More details on the background and approach for this assessment is provided in Annex 2. The principal results are as follows :

Social adjustments reduce the real economic cost of both projects. The most significant social adjustment is for municipal taxes and grants in lieu of taxes. The social cost of labour adjustment also significantly reduces the real economic costs. Resource and foreign exchange cost adjustments are relatively minor.

Because of the relative magnitude of this tax and employment impacts, the social adjustments are significantly greater for the Westcoast project than for B.C. Hydro's. Almost 30% of the expenditures for the Westcoast project do not constitute real economic costs. For B.C. Hydro, it is only about 17% of the expenditures which do not constitute real economic costs.

The difference in the social adjustments, though substantial, is not enough to offset the large differences in actual expenditures. The B.C. Hydro proposal, for both the with and without fertilizer case, exhibits lower costs even after all social adjustments are made.

4.3 Community Hearings

In addition to hearings in Vancouver, the Commission convened community hearings at the locations and on the dates listed below :

Victoria	October 18, 1983 (included continuation of Market Phase evidence)
Nanaimo	October 27, 28, 1983

Powell River	November 1, 2, 3, 4, 1983
Courtenay	November 8, 1983
Alkali Lake	November 9, 10, 1983
Mount Currie	April 16, 1984
Whistler	April 17, 1984

At these community hearings, both registered and unregistered intervenors testified expressing their opinions or the position of various organizations or local governments. A summary of the evidence on various issues follows.

4.3.1 Market Issues

Many local government and municipal representatives spoke in support of the projects to transport natural gas to Vancouver Island. Some indicated that a substantial conversion to natural gas would occur only if prices were competitive. Others indicated that the market potential of coastal areas could be realized in the future with the development of a lateral to Squamish, Port Mellon and Woodfibre in the northern route alternative. One intervenor requested that natural gas be transported to the Island as soon as possible because the fuel he presently uses for his business (propane) is too expensive. Others thought that the availability of natural gas would attract industries to the Island, and would therefore increase the market.

On the other hand, a number of intervenors argued that market uncertainties are a cause for concern. In particular, intervenors repeatedly mentioned the over-supply of electricity following completion of the Cheekye-Dunsmuir transmission line. In the Nanaimo hearing, one intervenor argued that natural gas is not needed on the Island because of this over supply. Some intervenors reported that the Applicants' market forecasts are overly optimistic, while one individual characterized them as "wish lists".

4.3.2 Socio-Economic Issues

All intervenors representing local governments and municipalities spoke in support of the project, citing numerous positive socio-economic impacts as the basis for their opinions. Interventions on behalf of these groups referred to high unemployment, the idle capacity of industrial and commercial activities and the many associated social problems. They suggested that the project would stimulate employment within the local communities and attract new industries. In particular, the proposed fertilizer plant at Powell River was identified as a preliminary step toward diversification of the industrial base of the community and a concomitant increase in economic security. In addition, construction of the project was described as beneficial to the municipal and rural tax base.

Some intervenors stated a preference for Westcoast's northern route and associated fertilizer plant. This group argued that the northern alternative is in accordance with the Provincial Government's Northern Siting Policy, would result in fewer negative socio-environmental impacts than the southern route, and would involve the participation of the Federal Government. Intervenors in favour of the southern route argued that the project should be kept under Provincial control, and that estimated costs associated with the southern alternative were lower. A strong intervention from Nanaimo argued that its Duke Point industrial facility ought to be considered as the location for the fertilizer complex, serviced by the Southern Route.

Many intervenors who supported the northern alternative were members of the Community of Powell River and its local organizations. These intervenors favoured this route on the ground that the pipeline construction and potential fertilizer plant would benefit the depressed local economy. However, another vocal segment of the community resisted the pipeline for environmental and economic reasons, maintaining it would not benefit the local economy nor that of the Province.

Some intervenors expressed concern about the potential negative impacts of the project. For example, during the Powell River hearing, an intervenor noted that persons moving to the area in pursuit of employment could disrupt the community. In addition, intervenors representing forestry companies based in the Squamish area expressed concern that pipeline construction activities could interfere with logging operations.

At the Alkali Lake and Mount Currie hearings, the native Indians identified concerns relating to the project's potential to disrupt their subsistence economy including hunting, fishing, trapping, and berry picking. Increased non-native access to traditional native hunting grounds was noted as a major source of potential disruption. In addition, many natives expressed concern regarding the long-term socio-environmental impacts of the pipeline. Westcoast was asked to more thoroughly address native concerns, particularly those relating to negative long-term impacts. Other intervenors pointed out that while a proportion of the negative impacts would be intangible, they would still be disruptive. At Alkali Lake, a rancher referred to the potential problems associated with the spreading of knapweed growth during pipeline construction activities as a result of increased access to the area.

4.3.3 Environmental Issues

Interventions at the Powell River hearing relating to environmental issues were concerned with impacts from the proposed fertilizer plant, and to a lesser extent, with the impacts from pipeline construction. Concerns relating to the former were aggravated by the fact that an assessment of environmental impacts of the proposed fertilizer plant had not been conducted. One intervenor argued that this assessment should be completed and its findings evaluated before the pipeline project is approved. Specifically, that intervenor was concerned about how the fertilizer plant would affect water quality in the Strait of Georgia. Another intervenor was concerned about nitrogen-oxide emissions. Acid rain and damage to the ozone layer were identified as possible environmental impacts relating to air quality. On the other hand, another intervenor at the Powell River hearing suggested that any negative environmental impacts associated with the project should be tolerated since the community would receive positive economic impetus. This individual expressed the opinion that most negative environmental impacts could be reduced or eliminated through mitigation measures.

During the community hearing in Nanaimo, one intervenor stated that the proposed use of herbicides on the Valdes Island right-of-way by B.C. Hydro is unacceptable. This individual represented the Islands Trust, an organization established by the Islands Trust Act to preserve and protect the unique amenities and environment of the islands in the Strait of Georgia. He recommended that one of the conditions for project approval be the Applicants agreement not to use herbicides on the Gulf Islands.

In Victoria, another intervenor described the concerns of the Capital Regional District with respect to B.C. Hydro's selection of the terminal site. The proposed site, located within the Agricultural Land Reserve, is subject to flooding in winter, and is close to a school and a shopping centre. The aesthetic quality of the terminal was also questioned. The siting of this terminal as well as other Island matters will be addressed during Phase 3.

4.3.4 Safety and Engineering Issue

Relatively few interventions addressed engineering design and safety issues. The B.C. Hydro proposals B and D to serve Powell River require two crossings of the Strait of Georgia, one in the north and one in the south. Individuals in favour of the northern route stressed that one crossing is more reliable than two. One intervenor in Nanaimo suggested that a single energy system is vulnerable to terrorist attack.

4.3.5 Financial Issues

A relatively large proportion of the intervenors expressed serious concern regarding the project's estimated subsidy requirements. It was noted repeatedly that the size of the subsidy in relation to the number of jobs created render the pipeline an expensive job-creation project. Another individual recommended that the project be abandoned in accordance with the Provincial Government's restraint policies given its cost and the surplus of electricity. Others stated that taxpayers would finance the project regardless of whether the subsidy was received from the Federal or Provincial Government.

4.3.6 Other Issues

Intervenors opposed to the project were dissatisfied with the hearing's Terms of Reference. These individuals stated that the Terms of Reference ought to have encompassed project justification. In addition, many suggested that the Provincial Government should not have accepted the conclusions of the Abercrombie Technical Report, particularly the benefit/cost and cost-effectiveness analyses. Also, several intervenors argued that alternative energy options (e.g. passive solar energy) have not been adequately examined ; others stated that the cost-effectiveness conclusions in the above report were incorrect, given the current surplus of electricity. Some individuals suggested LNG would be preferred to natural gas. In addition, some intervenors expressed general bafflement regarding the Provincial Government's energy policies.

Opinions expressed by participants during the community hearings provided the Commission with valuable insights regarding issues of public concern. While most of the issues discussed at these sessions were presented in evidence during the Vancouver sittings, some new opinions and concerns were expressed, that have formed a part of the Commission's considerations.

ANNEX 1

SOCIO-ECONOMIC IMPACT EVALUATION*

The results of an assessment of the relative magnitude of economic stimulus to B.C. and Canada for both B.C. Hydro and Westcoast To Island using the Statistics Canada "Inter-Provincial Input-Output Model" is shown below.

Although the breakdown of capital expenditures into standard commodity categories used in this assessment and provided by the Applicants were not tested at the hearing, the Commission is reasonably confident of their veracity and hence their implications as discussed below.

Results of Simulated Model Evaluation of Economic
Impacts from B.C. Hydro's and Westcoast's Proposals ($1983)

	B.C. Hydro	Westcoast
1. Industrial Demand by Direct Project Expenditures		
1.1 B.C.	23,547,000	33,588,000
1.2 Canada	38,574,000	74,961,000
2. Total Demand Generated in Domestic Industries by Direct Project Expenditures		
3.1 B.C.	15,361,000	21,738,000
3.2 Canada	29,631,000	56,354,000
3. Total Employment Generated by the Project (man-years)		
4.1 B.C.	921	1,719
4.2 Canada	1,345	2,700
4. Economic Impact Coefficients (derived from 1 and 2)		
	0.768	0.751
5. Labor Intensity Indices (derived from 1 and 3)		
6.1 B.C.	39	51
6.2 Canada	35	36

Several conclusions can be reached on the basis of this simulation exercise. The percentages of income generated by project expenditures that are retained in Canada are reflected in the Economic Impact Coefficients shown in line 4. A higher coefficient indicates that a greater percentage of the generated income is retained in domestic economic activities. B.C. Hydro's proposal would require marginally less imports per dollar of direct project expenditure than the Westcoast proposal.

As indicated by the above Labour Intensity Indices, Westcoast's proposal is more labour intensive on a per dollar expenditure basis than B.C. Hydro's, particularly for the B.C. component of the analysis. This could be a significant factor in evaluation of the positive socio-economic impacts of the alternate proposals given the high unemployment in B.C.

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* There was limited socio-economic data or analysis provided by Applicants and Intervenors, and as a result the Commission prepared this analysis on the bais of information provided during the Hearing.

ANNEX 2

SOCIAL COST COMPARISON - WESTCOAST vs. B.C. HYDRO

Background

A comparison of project costs on a purely financial accounting basis will not necessarily provide an accurate comparison of the real economic costs from the point of view of British Columbia or Canada as a whole. This is particularly the case when the project sponsors are subject to different tax arrangements and return on capital requirements, and when the projects have different labour and environmental cost implications, and when their respective import components in project costs differ.

Objective

The purpose of this review is to compare the competing projects in terms of their real economic costs. Adjustments are made for differences in rate of return requirements (on the assumption that the real cost of capital to society is the same for both projects) ; for taxes (on the assumption that taxes which remain within the jurisdiction are transfers - not economic costs) ; for labour costs (on the assumption that some of the labour hired for the project would not otherwise be employed and that the portion of labour costs that this represents does not contitute a real economic cost, but rather an employment benefit) ; for natural resource losses (on the assumption that these are real costs to society even if not paid by the project sponsors) ; and for foreign exchange impacts (on the assumption that foreign exchange rates do not reflect social costs due to tariffs and implicit government subsidies for imports and exports respectively).

Methodology

The approach that is taken in this analysis is to start with a calculation of the present value of project costs based on all cash flow expenditures as incurred by the proponents. This is basically equal to the private financial cost, except that by using a common discount rate for determining the present values a common return on capital is imposed.

The first step in the economic analysis is to adjust for differences in tax payments. Two adjustments are undertaken here. Firstly, income taxes are eliminated from project costs (these, however, are very small in the capital grant case). Secondly, (and much more importantly in the capital grant case), municipal taxes, except insofar as they reflect real municipal costs, are deducted. The present value cost comparisons after these adjustments reflect the private costs adjusted for the differences in tax benefits afforded by the projects.

The next step in the analysis is to adjust for differences in employment benefits (positive socio-economic impacts) and in resource costs (negative environmental impacts).

With respect to employment benefits, the difference between the actual cost of labour and the social cost of labour is deducted from the project costs. Because some of the persons hired for the project would otherwise be unemployed, the social i.e. real economic cost of labour (which is measured by the value of output which is foregone by dedicating labour to this project as opposed to some other) will be less than the actual private cost. Adjusting for the difference between social and private costs (in other words, the employment benefits) ensures that it is only the social or real economic cost, not the private one which is reflected in the overall cost comparisons.

With respect to resource costs, the estimated reduction in net resource values (i.e. resource rents) attributable to the projects are added into the cost streams. These are real economic costs and adding them in ensures that cost comparisons reflect all real costs, including those borne by third parties in the Province.

With respect to foreign exchange impacts, an adjustment is made to take into account the higher social cost than private cost of imports. The higher social cost arises because the exchange rate does not reflect either the tariffs which domestic consumers must pay for imports or the government subsidy implicit in domestic exports which are required to earn foreign currency.

Results

The base case results are shown in Table 1. For the base case, it is assumed that :

i) All municipal, gas and social service taxes and grants in lieu of taxes are not social costs ;

ii) 25% of the skilled construction workers and 50% of the unskilled workers hired for the projects would not otherwise be employed and their social cost is zero (these percentages are predicated on unemployment rates for unskilled workers remaining in the 10-15% range through the mid-1980's and for skilled workers being around 8-10%) ;

iii) Resource losses are assumed to equal $530,000 for B.C. Hydro (due to agricultural and fisheries impacts) and $500,000 for Westcoast (due to forestry impacts) ;

iv) Foreign exchange costs are assumed to equal 7.5% of estimated imports, based on recent economic studies comparing the social and nominal cost of foreign exchange (Jenkins, Glen P. and Chun-Yan Kuo, Canada Department of Finance, "On Measuring the Social Opportunity Cost of Foreign Exchange", June 1983).

TABLE 1

SOCIAL COST COMPARISIONS - BASE CASE*
(present value in $1983 millions)

	Westcoast National Perspective	Westcoast Provincial Perspective	B.C. Hydro National Perspective	B.C. Hydro Provincial Perspective
Without Fertilizer Plant				
Private Expenditures**	295.5	295.5	204.7	204.7
Tax Adjustments -Income	(3.4)	(1.3)	-	-
-Municipal	(52.8)	(52.8)	(24.8)	(24.8)
Labour Cost Adjustment	(29.5)	(26.7)	(14.0)	(12.6)
Natural Resource Costs	.4	.4	.4	.4
Foreign Exchange Adjustments	1.8	.2	3.9	.4
TOTAL SOCIAL COST	212.0	215.3	170.2	168.1
With Fertilizer Plant				
Private Expenditures	324.4	324.4	235.4	235.4
Tax Adjustments -Income	(3.4)	(1.3)	-	-
-Municipal	(56.9)	(56.9)	(27.7)	(27.7)
Labour Cost Adjustment	(31.4)	(28.5)	(15.8)	(14.2)
Natural Resource Costs	.4	.4	.4	.4
Foreign Exchange Adjustments	1.9	.2	4.4	.5
TOTAL SOCIAL COST	235.0	238.3	196.7	194.4

* Base Case assumptions described in text, page 175.

** Discounted at 8% to reflect a common return on capital.

The base case results indicate that the social costs of the Westcoast project are $212.03 million (in $1983 present value terms). This compares to actual expenditures of $295.52 million. The social costs of the B.C. Hydro project are $170.23 million. This compares to actual expenditures of $204.66 million.

The base case results show that the social costs of the B.C. Hydro project are $41.8 million lower than Westcoast's. In Tables 2, and 3, a number of sensitivity test results are shown, indicating how the base case difference is affected by varying labour cost and discount rate assumptions.

In both cases, social costs are considerably less than private expenditures. The downward adjustments required to take into account tax and employment benefits are the principal reasons for this.

The difference between social and private costs is greatest for the Westcoast projects where social costs are estimated at just over 70% of private expenditures. For the B.C. Hydro project social costs are estimated at approximately 83% of private expenditures.

Despite the larger adjustment for the Westcoast project, it still exhibits higher social costs than B.C. Hydro, for both the with and without fertilizer cases. The base case results show that the social costs of the B.C. Hydro project are $42 to $47 million (in $1983 present value terms) lower than Westcoast's in the without fertilizer case and $38 to $43 million lower in the with fertilizer case.

In Table 2 and 3, the social costs of the two projects are compared for a number of sensitivity tests, where varying assumptions with respect to the social cost of labour and capital were used.

In Table 2 the results using a range of labour cost assumptions are shown. The high social cost case assumes that few of the persons hired for the project would otherwise be unemployed and consequently only a small labour cost adjustment is incorporated. The low social cost case adopts the opposite assumption, namely, that a very large percentage of the persons hired would otherwise be unemployed and consequently a large social adjustment is required. The results show that the lower the social cost of labour, the smaller is the difference in the total social costs of the two projects. However, in all cases considered, the social costs of the B.C. Hydro project are still less than Westcoast's.

In Table 3, the results using a range of discount rate (real cost of capital) assumptions are shown. The results show that the lower the real cost of capital, the greater is the present value difference between the two projects. Again, however, the social cost of the B.C. Hydro project are less than Westcoast's for all cases considered.

TABLE 2

SOCIAL COST COMPARISONS* - LABOUR COST SENSITIVITIES
(present value in $1983 millions)

	Westcoast	B.C. Hydro	Difference
Without Fertilizer Plant			
Base Case	212.0	170.2	41.8
High Social Opportunity Cost of Labour	229.2	179.9	49.3
Low Social Opportunity Cost of Labour	203.2	167.2	36.1
With Fertilizer Plant			
Base Case	234.9	196.8	38.1
High Social Opportunity Cost of Labour	253.2	207.6	45.6
Low Social Opportunity Cost of Labour	225.5	193.3	32.2

* Results shown for national perspective ; very similar results occur from provincial point of view.

TABLE 3

SOCIAL COST COMPARISONS* - DISCOUNT RATE SENSITIVITIES
(present value in $1983 millions)

		Westcoast	B.C. Hydro	Difference
Without Fertilizer Plant				
Base Case	(8%)	212.0	170.2	41.8
	4%	251.7	200.5	51.3
	6%	230.3	184.2	46.1
	10%	196.3	158.1	38.2
With Fertilizer Plant				
Base Case	(8%)	234.9	196.8	38.1
	4%	283.5	232.3	51.2
	6%	257.0	213.1	43.5
	10%	216.1	182.6	33.5

* Results shown for national perspective ; very similar results occur from a provincial point of view.

CHAPTER 5 FINANCIAL ANALYSIS

One of the findings of the Technical Report was that since the Vancouver Island natural gas project would incur significant revenue deficiencies, financial support would be critical to the timely development of the project. The Terms of Reference directed the Commission to

> "... identify the size of the federal capital contribution sufficient to eliminate any revenue deficiencies associated with the project ..."

having considered,

> "... the minimization of any revenue deficiencies which may be associated with the project, with particular emphasis on the minimization of capital costs and cost of service ..."

The Commission accepted that revenue deficiencies associated with each proposal should be a major financial criterion by which to judge the proposals. Accordingly, the Commission developed a model, based on regulatory accounting principles as described in Annex 3. The Commission then used its market projection, determined in Chapter 2 (Figure 2.9), in making the comparison. The model was used to compare proposals in this Chapter and in Chapter 6, and to identify the size of the federal contribution required by the successful Applicant to construct and operate the project during the 20 year evaluation period. This Chapter contains a brief description of how the competing proposals were compared. Tables 5.1 and 5.2 show the results.

5.1 Components of the Required Contribution

For the purpose of this analysis, the Commission evaluated three components of the contribution :

1. Capital Cost of Construction
2. Cost of Service
3. Gain/Loss on Sales

The Capital Cost of Construction* is the aggregate of all capital expenses incurred to construct the Vancouver Island Natural Gas Pipeline Project and to add future facilities when required. This is a major cost component in the comparison and is identified in Tables 5.1 and 5.2, line 6.

The Cost of Service is the total of the cost of capital and expenses that a utility incurs in any one year for the purpose of delivering gas to market. Expenses include operating costs, taxes, fuel costs and depreciation. These components are totalled on line 1 of Tables 5.1 and 5.2.

The Gain/Loss on Sales is the result of the difference between the wholesale and city gate prices of natural gas as outlined in the Minister's letters of September 1, 1983 and October 17, 1983; it does not include any charges for operating or capital costs. In the case of B.C. Hydro there is a net loss on sales, on a discounted basis, which increases the total project cost. In the case of Westcoast there is a small net gain on sales, on a discounted basis, thereby reducing the total project cost. This disparity is because B.C. Hydro pays a higher wholesale price for gas than does Westcoast. The Gain/Loss component is identified on line 4 of Tables 5.1 and 5.2.

5.2 The Applications

The four Applicants submitted a total of ten different proposals of various combinations of routes and markets. ICG and Inland provided a total of five proposals for the On Island section of the project. The remaining five, submitted by B.C. Hydro and Westcoast, represented various alternatives of To and On Island service.

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* This is a sub-component of the cost of service and is identified separately in the Capital Contribution Model, Table 5.1.

TABLE 5.1

COMMISSION COMPARISON

VANCOUVER ISLAND NATURAL GAS PIPELINE
- CAPITAL CONTRIBUTION METHOD

(1986 $000)	Island Only (MA1)	Without Fertilizer Plant (MA2)		With Fertilizer Plant (MA3)	
	Hydro D	Hydro A	West-coast	Hydro B	West-coast
CAPITAL COST	379045	401214	500327	449958	527697
Cost of Service					
Depreciation	-	-	-	-	-
Return	-	-	6968	-	7532
Interest	1876	2099	-	2559	-
Interest Coverage	188	210	-	256	-
Expenses	57612	69977	64182	99524	86655
Taxes - Income	-	-	3397	-	3672
Taxes - Other	74961	81661	146700	93137	155974
(1) Total Cost of Service	134637	153947	221247	195476	253833
(2) Deduct: Fertilizer Plant Operating Contribution	-	-	-	(36402)	(45089)
(3) Net Cost of Service	134637	153947	221247	159074	208744
(4) Loss/(gain) on Sales	63055	70396	(14159)	70396	(14159)
(5) Revenue Deficiency	197692	224343	207088	229470	194585
(6) Capital Cost	379045	401214	500327	449958	527697
(7) Deduct: Fertilizer Plant Capital Contribution	-	-	-	(48744)	(27370)
(8) Capital Contribution	379045	401214	500327	401214	500327
(9) Westcoast add. costs	-	-	15410	-	15410
(10) Total Required Contribution [(5)+(8)+(9)]	576737	625557	722825	630684	710322
(11) Total Fertilizer Plant Contribution [(2)+(7)]	-	-	-	85146	72459

TABLE 5.2

COMMISSION COMPARISON

VANCOUVER ISLAND NATURAL GAS PIPELINE
- OPERATING CONTRIBUTION METHOD

(1986 $000)	Island Only (MA1)	Without Fertilizer Plant (MA2)		With Fertilizer Plant (MA3)	
	Hydro D	Hydro A	West-coast	Hydro B	West-coast
CAPITAL COST	379045	401214	500327	449958	527697
Cost of Service					
Depreciation	67834	73239	91321	82237	95374
Return	-	-	446003	-	467477
Interest	282280	302875	-	340253	-
Interest Coverage	28228	30287	-	34025	-
Expenses	57612	69977	64182	99524	86655
Taxes - Income	-	-	93265	-	97036
Taxes - Other	74961	81661	146700	93137	155974
(1) Total Cost of Service	510915	558039	841471	649176	902516
(2) Deduct: Fertilizer Plant Operating Contribution	-	-	-	(99106)	(141182)
(3) Net Cost of Service	510915	558039	841471	550070	761334
(4) Loss/(gain) on Sales	63055	70396	(14159)	70396	(14159)
(5) Revenue Deficiency	573970	628435	827312	620466	747175
(6) Capital Cost	379045	401214	500327	449958	527697
(7) Westcoast add. costs	-	-	15410	-	15410
(8) Total Required Contribution [(5)+(7)]	573970	628435	842722	620466	762585
(9) Total Fertilizer Plant Contribution	-	-	-	99106	141182

The Commission's assessment of revenue deficiencies and contribution requirements have been categorized into three market area alternatives, referred to as MA 1, MA 2 and MA 3. These are :

MA 1 Vancouver Island Only ;
MA 2 Vancouver Island plus Powell River ; and
MA 3 Vancouver Island plus Powell River with Fertilizer Plant.

B.C. Hydro presented proposals for each of the three market areas based on a southern route crossing to Vancouver Island. Westcoast presented proposals for MA 2 and MA 3 based on a northern route crossing to Vancouver Island.

The On Island costs are included in the comparison of the systems as directed by the Minister's letter of April 11, 1984. The On Island costs are explained in Chapter 3, Section 3.3, On Island Transmission. The Commission has used the estimates of B.C. Hydro and Westcoast without prejudice to any Applicant in Phase 3, to evaluate contribution requirements for the southern and northern routes.

B.C. Hydro and Westcoast presented financial forecasts for capital costs and costs of service in current and constant dollars based upon their own engineering, operating and financing assessments. Particulars of the financial assumptions supporting the B.C. Hydro and Westcoast forecasts are contained in Annex 1 of this Chapter.

B.C. Hydro and Westcoast employed different financial assumptions in their proposals thus making direct comparisons impossible without adjustments (see Section 5.4). The different assumptions are described in the following section.

5.3 Financial Assumptions of B.C. Hydro and Westcoast

(a) The Applicants used different inflation and depreciation rates which are discussed in Annex 1.

(b) B.C. Hydro assumed that the project would be judged in isolation from any of its present business activities, that is, on a "stand-alone" basis. Westcoast assumed that this project would be judged as part of its existing gas transmission facilities, that is, on a "rolled-in" basis.

(c) B.C. Hydro is a publicly-owned corporation. Westcoast is a public investor-owned company. This distinction resulted in several differences between the applications :

- Westcoast argued that although collected and payable, transfer payments, particularly income tax and to a lesser extent property tax, should not be included in calculating the cost of service. B.C. Hydro is not required to pay income tax and therefore no similar transfer payment was included in its application.

  Westcoast pays property tax while B.C. Hydro pays grants in lieu of property tax. The forecast of these property grant payments in B.C. Hydro's application are less than the forecast of property tax payments in Westcoast's application.

- Westcoast, investor-owned, included a return on common equity to its shareholders in the range of 13.25 - 14.75% with common equity representing 35% of its capital structure.

B.C. Hydro, publicly-owned, included an interest coverage charge at a ratio of 1.3 to 1 until such time as the equity component increases to 20% of the capital structure. After that time a coverage ratio of 1.0 to 1 was assumed. The interest coverage of 1.3 to 1 is the corporate coverage to be maintained for current natural gas operations pursuant to B.C. Hydro Special Direction No. 1.

- Westcoast's incentive is the equity return on rate base; the company testified that it did not want a sizeable upfront payment to finance construction, but it would be prepared to accept a capital contribution of $100 to $200 million.* B.C. Hydro testified that it would accept any upfront capital payment to finance construction.

5.4 Commission Adjustments to Facilitate Analysis

The scope of the proposed systems differed. In order to compare the proposals and to facilitate analysis, the Commission :

(a) Applied the same inflation and depreciation rates to each proposal (see Annex 3).

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* If Westcoast undertook the project on a full capital payment basis, return on rate base would be eliminated. Therefore, the company would require to be paid for administering the project perhaps by a management or incentive fee. Westcoast indicated that it would consider that option.

(b) Assessed each proposal on a stand-alone basis so that the true costs of the proposals can be accurately compared.*

(c) Developed two versions of the financial model to account for the differences between publicly-owned B.C. Hydro and investor-owned Westcoast. These versions are referred to as "publicly-owned utility" (POU) and "investor-owned utility" (IOU). The POU version includes provision for interest coverage on a 1.1 to 1 ratio over the entire 20 year project evaluation term,** while the IOU version includes a return to investors. This return, as noted in Annex 3, represents the Commission's forecast of the cost of capital over the next 20 years.

(d) Included taxes in the cost of service calculation on the basis that the payments actually constituted a cash outflow, which must be collected through the cost of service. However, the Commission has calculated and identified separately the total amount of tax payable since Governments providing the capital contribution may view future tax revenues as partial repayment of that contribution.

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* The Commission concluded that the rolled-in approach did not identify the true costs associated with the project but rather shared any such deficiency amongst existing gas users and/or the Provincial Government. The Commission was not directed to consider nor report on spreading the cost of the project throughout the existing system but rather to identify the revenue deficiency associated with the Vancouver Island project. For this reason, the Commission rejected Westcoast's contention that its application be judged on the rolled-in basis.

** Applying 1.1 for the whole project evaluation term approximates the interest coverage as if 1.3 was applied until equity increases to 20% and then 1.0 was applied thereafter.

(e) Made the scope of the systems comparable by making the following adjustments :

- Adding Tilbury compressor station relocation costs to B.C. Hydro's costs (see Facilities and Capital Costs page 126).

- Adding Livingstone to Roebuck capital costs of $10.2 million on B.C. Hydro's existing line to B.C. Hydro's costs (see Facilities and Capital Costs, pages 126).

- Adding the cost of deep water repair facilities of $5.0 million ($2.0 million was allocated to capital and $3.0 million to maintenance) to Westcoast's costs* (see Facilities and Capital Costs, pages 85 and 92).

- Adding fuel gas costs of $12.41 million to Westcoast's system.* This cost was omitted from Westcoast's applications.

- Adding the cost of Campbell River, Port Alberni and Crofton laterals of $30 million to Westcoast system in order to make the systems comparable (see Facilities and Capital Costs - On Island, page 133).

(f) When comparing the On Island costs of the Applicants the Commission did not have an opportunity to review the details of the facilities. It has not deleted the facilities planned for installation after 1992 when comparing costs with Westcoast, ICG and Inland even though the Commission views these facilities as not being required to meet market demands on Vancouver Island.

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* Table 5.1, line 9 and Table 5.2, line 7 allocates $15.41 million to include $12.41 million for compressor fuel and $3 million for deep water repair. B.C. Hydro included $39.1 million in its operations and maintenance costs for a deep water repair.

(g) The Commission adopted flow-through income tax accounting thereby reducing the required subsidy.

Some of the cost savings analyzed and recommended in Chapter 3 are not included in the aforementioned.

5.5 Analytical Methods

Two methods were used to calculate the amounts of the required contribution. These two methods differ in their assumptions of how the capital costs are paid.

The first method, the Operating Contribution Method (OCM), assumes that the cost of construction is financed through the cost of service charges for depreciation, interest, income tax, and return on equity (or interest coverage). The second method, the Capital Contribution Method (CCM) assumes that construction costs are paid by an upfront capital contribution. Since the capital cost would not be financed through cost of service, the charges for depreciation, interest, income tax, and return on equity (or interest coverage) would be virtually eliminated. Under both methods, the cost of service would include expenses and taxes other than income taxes.

In the case of an investor-owned utility, using the CCM of financing the project reduces the total required contributions since income tax payments are reduced.

The OCM assumes that the amount of the total contribution would be placed in a notional trust fund which is assumed to earn a return equal to the discount rate and pay for annual revenue deficiencies during the 20 year project evaluation term. The CCM allocates most of the required contribution directly to cover construction costs and involves the establishment of the notional trust fund only large enough to cover expenses, non-income taxes and any loss on sales.

In both methods the amounts are expressed annually in current dollars. Revenue deficiencies over 20 years (and capital costs in the case of the CCM) are discounted to, and stated in, 1986 dollars.

The CCM is similar to the normal and approved regulatory treatment by the BCUC of Contributions in Aid of Construction as an offset to rate base.

5.6 Comparison Summary

The results of the comparison follows :

MA 1 : Vancouver Island Only

B.C. Hydro's System D is the only application in this category. Costs, as adjusted by the Commission, are as follows :

(1986 $000)	B.C. Hydro D
Capital Cost of Construction Table 5.1 and 5.2, line 6	379,045
Total Required Contribution	
Capital Method (Table 5.1, line 10)	576,737
Operating Method (Table 5.2, line 8)	573,970

Either with an operating or with a capital contribution, the total required is less than for MA 2, which would supply service to Powell River.

MA 2 : Vancouver Island plus Powell River

B.C. Hydro's System A and Westcoast's system, without a fertilizer plant, are the two applications in this category. Costs, after Commission adjustments, are as follows :

(1986 $000)	B.C. Hydro A	Westcoast	Difference
Capital Cost of Construction (Tables 5.1 and 5.2, line 6)	401,214	500,327	99,113
Total Required Contribution			
Capital Method (Table 5.1, line 10)	625,557	722,825	97,268
Operating Method (Table 5.2, line 8)	628,435	842,722	214,287

As noted, B.C. Hydro's System D requires less subsidy than the proposals for service to MA 2 above. Of the MA 2 applications, B.C. Hydro's proposal is the least costly.

MA 3 : Vancouver Island plus Powell River with Fertilizer Plant

B.C. Hydro's System B and Westcoast's System, with the fertilizer plant, are the two Applications in this category. Costs, after Commission adjustments, are as follows :

(1986 $000)	B.C. Hydro B	Westcoast	Difference
Capital Cost of Construction (Tables 5.1 and 5.2, line 6)	449,958	527,697	77,739
Total Required Contribution with Fertilizer Plant			
Capital Method (Table 5.1, line 1 + 4 + 6 + 9)	715,830	782,781	66,951
With Operating Method (Table 5.1, line 1 + 4 + 9)	719,572	903,767	184,195
Deduct : Fertilizer plant contribution			
With Capital Method (Table 5.1, line 11)	85,146	72,459	(12,687)
With Operating Method (Table 5.2, line 9)	99,106	141,182	42,076
Net Required Contribution using the Capital Method (Table 5.1, line l0)	630,684	710,322	79,638
Net Required Contribution using the Operating Method (Table 5.2, line 8)	620,466	762,585	142,119

The Fertilizer Plant Consortium forecast 1988 as the earliest date for start-up of the fertilizer plant. In order to allow for possible delay in application, construction and start-up, and to be conservative in estimating the contribution that the fertilizer plant would make to the project, the Commission has selected 1991 as the start-up date in its analysis.

The Commission applied the formula, provided by the Minister of Energy in a letter dated September 1, 1983, for allocating a share of the cost of service to the fertilizer plant as follows :

> "The Commission is advised to apportion the cost of service between the fertilizer plant and Vancouver Island loads according to the proportion that the peak day volume times distance for each load is of the sum of the peak day volume times distance for the two loads".

This formula provides for charging the fertilizer plant with a portion of the total costs of constructing and operating the project. For both B.C. Hydro and Westcoast, the Commission applied the Minister's ratio to the cost of service each year from 1991 to 2005 to arrive at the fertilizer plant's share and subtracted the discounted cumulative total from the total discounted contribution (see Table 5.1, lines 10 and 11). In the case of a capital contribution, the full incremental cost of the facilities required to accommodate the fertilizer plant load was charged to the fertilizer plant. For B.C. Hydro, it is the difference between B.C. Hydro B and B.C. Hydro A capital costs. For Westcoast, it is the difference between the capital costs of the Westcoast proposals with and without the fertilizer plant.

In review of the figures shown in all the Market Areas, the Required Contribution is in the $570 to $843 million range. B.C. Hydro's application remains the least costly.

5.7 Benefits of Using the Capital Contribution Method

The Commission finds that the Capital Contribution Method (CCM) of financing the project offers the following substantial benefits.

1. Near elimination of income taxes payable by Westcoast. Rate Base, other than working capital, would be eliminated by the capital contribution. A virtual zero net income for tax purposes would result (see Table 5.1).

2. Elimination of risk from interest rate fluctuation.

3. Elimination of risk from foreign exchange rate fluctuation.

4. Elimination of all depreciation expenses (see Table 5.1).

5. Elimination of administrative fees associated with the issue of long-term debt.

5.8 Adjustments to Minimize Westcoast Costs

In order to place the Westcoast application on the most comparable basis, the Commission reduced Westcoast's costs by using :

1. Flow-through taxes to reduce front-end loading.

2. BCUC depreciation rates to lower annual depreciation expense rather than the higher National Energy Board rates.

3. The capital contribution method to virtually eliminate income taxes and return. A management incentive fee was not computed.

4. A 25% reduction to correct an overstatement of forecast property taxes.

These adjustments are reflected in Tables 5.1 and 5.2, providing comparisons of Westcoast and B.C. Hydro.

5.9 Conclusions

AS A RESULT OF THE FINANCIAL COMPARISON THE COMMISSION CONCLUDES :

1. THAT THE USE OF THE CAPITAL CONTRIBUTION METHOD TO FINANCE THE PROJECT OFFERS SUBSTANTIAL FINANCIAL BENEFITS.

2. THAT IN EACH INSTANCE, THE SOUTHERN ROUTE PRODUCES A SMALLER REVENUE DEFICIENCY AND WOULD REQUIRE A SMALLER CONTRIBUTION THAN THE NORTHERN ROUTE.

3. THAT B.C. HYDRO'S APPLICATION D, WHICH PROVIDES NATURAL GAS TO THE VANCOUVER ISLAND MARKET ONLY, REQUIRES THE LEAST CONTRIBUTION.

The project was assumed to be 100% financed by fixed interest long-term bonds. The interest coverage ratio was set at 1.3 until the debt/equity ratio reduced to 80/20, at which time an interest coverage of 1.0 was used.

Charges for interest coverage and depreciation were assumed to accumulate in an account which earned interest at the forecast interest rate for each fiscal year. The interest was applied as an offset to cost of service.

In response to a Commission request, B.C. Hydro resubmitted its cost estimates based on a six percent inflation rate.

An amount for foreign exchange gain was included as an offset to cost of service.

Interest rates were assumed to vary from 12.2% to 10.3% over the project evaluation term.

Westcoast

The application was based on a rolled-in premise i.e. the Vancouver Island project was assumed to be part of the Westcoast system and costs were allocated accordingly.

Westcoast submitted cost forecasts in 1983 dollars adjusted for inflation. It used normalized taxes initially but this was later revised to flow-through. Although the Vancouver Island project will not itself incur a deferred tax balance, a portion of the Westcoast deferred tax balance was allocated to it. The inflation rate forecast used by the company ranged between 6.6% and 3.8% over the 20 year project evaluation term. In response to a Commission request, Westcoast resubmitted its cost estimates based on a six percent inflation rate.

ANNEX 1

DESCRIPTION OF APPLICATIONS

Each application uses 20 year financial projections and includes data on :

1. capital costs
2. cost of service
   - depreciation
   - expenses
   - taxes
   - interest (POU) or return (IOU)

The applications differ in assumptions made regarding the cost of service calculations. These include :

- stand-alone vs. rolled-in costing
- depreciation rates
- methods of financing
- foreign exchange losses/gains

Initially both B.C. Hydro and Westcoast used different markets and rates of inflation.

B.C. Hydro

The application was premised on stand-alone costs.

B.C. Hydro developed its cost forecasts in June 1983 dollars. These dollars were escalated annually (based on an in-house projection of expected inflation rates) to arrive at current dollars. B.C. Hydro applied BCUC depreciation rates to arrive at the annual depreciation expense.

The cost of service included a rate of return on rate base. It was assumed that no contribution would be applied to rate base as a Contribution in Aid of Construction. National Energy Board depreciation rates were used.

The project assumed the following capital structure :

Debt	61%
Preferred Shares	4
Equity	35
	100%

Cost of capital was calculated on a rolled-in basis, i.e. embedded debt cost and existing preferred share financing were allocated to the project. Westcoast used a range of 14.75% to 13.25% for the cost of common equity capital. Working capital was calculated in accordance with procedures approved by the National Energy Board at 1.3 times one month's operating expenses. An amount for foreign exchange loss was included in cost of service.

ANNEX 2

SENSITIVITY ANALYSIS

In order to determine a "range of reasonableness" around the calculated contribution requirement for B.C. Hydro System D, sensitivity analysis was performed on :

- sales
- cost of service
- discount rate
- capital cost

and their effects measured on the capital contribution requirement.

If the actual sales were to differ from the Commission's expected case by 20%, the required contribution would change by 2.19%. Therefore, the required contribution is relatively insensitive to changes in sales. Since the net margin on sales is negative an increase in sales results in an increase in the required contribution.*

If the non-capital components of cost of service (expenses, taxes) were to differ from the present forecast by 20%, the required contribution would increase or decrease by 4.67%. The required contribution is therefore relatively insensitive to changes in cost of service.

* B.C. Hydro's market projection assumes a faster penetration rate than the Commission's findings. Consequently B.C. Hydro presumes sales volumes some 40% higher, in the initial years, declining to 20% higher than this report. The sensitivity analysis indicates that even this magnitude of sales variation would have a result of less than 5% variation in the required contribution.

If the discount rate is raised from 10% to 12% (a 20% increase) the required contribution is reduced by 6.67%. Conversely, if a discount rate of 8% is used (a 20% decrease) the required contribution is increased by 8.46%. Therefore, the sensitivity of the required contribution to discount rates is less than 50%. The inverse relationship between discount rate and required contribution is due to the negative cash flow generated by the project every year.

The largest impact on the required contribution results from variations in capital costs. A 20% change in capital costs will result in a 13.14% change in the required contribution.

The dollar outcomes are tabulated in the table below.

In order to define a range of reasonableness, the Commission has used an optimistic scenario of all of the above factors favouring the project by 10% and a pessimistic scenario with all factors varying by 10% in the opposite direction. The range of subsidy requirement encompassed by these two extremes varies from $500,737,000 to $659,633,000. The worst case scenario is illustrated in a printout reproduced overleaf.

B.C. Hydro System D
Sensitivity Analysis Summary
(1986$000)

	Total Req'd Contrib.	+ 20%	% Change	- 20%	% Change
Sales	576,737	589,348	2.19%	564,126	-2.19%
Cost of Service	576,737	603,665	4.67%	549,809	-4.67%
Discount Rate	576,737	538,240	-6.67%	625,557	+8.46%
Capital Cost	576,737	652,546	13.14%	500,928	-13.14%
All by 10%	576,737	659,633	14.37%	500,737	-13.18%

B.C. HYDRO D - CAPITAL CONTRIBUTION
Sensitivity Run: Worst Case

22-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Sum	NPV
To Island																						
Expenses	[illegible]	2888	2216	3727	3632	3840	3833	4512	4457	5276	5147	5667	5832	7574	5658	7745	7508	8777	9529	9957	[illegible]	[illegible]
Other taxes	[illegible]	2959	4346	5527	5666	2235	5448	5912	6117	6327	6775	6958	7645	7455	7695	3052	8715	8856	9146	9628	115543	5256
Fuel and losses																					0	0
SALES FORECAST	8670	11236	13320	15060	16060	16790	17770	18290	18796	19120	19392	19650	19940	20210	20520	20810	21130	21440	21780	21030	361809	152176
Capital cost	219691	0	0	0	0																219691	219691
Additions	0	7932	1594	4672	0	3496	10605	0	0	0	0	0	0	0	0	0	0	0	0	0	27692	19852
Inventory																						
Line pack																					247294	239454
Other working capital	71	150	155	150	153	139	136	142	137	144	144	148	145	153	149	137	155	163	159	175	2964	1229
On Island																					0	0
Expenses	593	1232	1319	1409	1593	1607	1712	1824	1973	2090	2363	2439	2590	2748	2913	3305	3272	3473	3666	3915	45527	17046
Other taxes	0	1910	1985	2961	2149	2221	2204	2252	3727	3369	3493	3418	3790	3877	4613	4770	4929	5445	5622	5846	67070	24401
Fuel and losses																					0	0
SALES FORECAST																					0	0
Capital cost	107264																				107264	107264
Additions	0	0	0	0	0	0	339	12657	27212	152	39	192	472	39133	0	267	17765	15	0	0	89213	32327
Inventory																						
Line pack																					196477	139591
Other working capital	40	74	68	67	65	64	62	65	75	79	79	79	79	88	94	93	98	101	109	100	1570	666

POU

22-Jun-84

Assumptions:					
Inflation rate:	6.0%	Capital subsidy	1	0	total plant 443771
Discount rate:	9.0%	Marginal k alloc.	0	0	NPV of total plant 379045
Depreciation rate:	2.9%	Load k alloc.	0	---------	0
Cost of debt:	10.0%	Alloca. multiplier	0.900	0	0

COST OF SERVICE	1986 1986	1987	1988	1989	1990 1990	1991	1992	1993	1994	1995 1995	1996	1997	1998	1999	2000 2000	2001	2002	2003	2004	2005 2005	9976 39916	5046 18660
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest expense	111	223	229	229	219	193	186	197	196	205	233	225	200	220	215	220	222	224	222	236	4155	1876
Interest coverage	11	22	22	23	21	19	17	15	20	21	20	21	25	22	22	22	22	22	23	24	416	188
Expenses	905	4129	4535	5236	5135	5512	5544	6442	6396	7329	7410	8446	8402	10282	9522	10854	13780	12259	12715	13072	155567	57612
Other taxes	13	5899	6331	7598	8006	7476	7752	8294	8844	9696	10269	10616	10974	11332	12308	12322	13244	14296	14769	15474	196013	74961
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total cost of service	1144	11291	12218	14274	14709	14520	14651	16454	17002	18970	19692	21217	21555	24042	24273	26288	26595	29484	30512	32566	391766	148101
per GJ	$0.12	$0.91	$0.93	$0.86	$0.83	$0.79	$0.76	$0.82	$0.82	$0.90	$0.92	$0.98	$0.98	$1.08	$1.08	$1.15	$1.15	$1.25	$1.27	$1.36	19	0
Fert. plant ratio	0.00	0.00	0.00	0.00	0.00	0.30	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23		
SALES FORECAST (TJ)	9537	12353	14452	16566	17666	18469	19547	20110	20669	21932	21329	21612	21534	22231	22572	22891	23243	23504	23958	24013	397980	167307
Fert plant cost/GJ	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
COSTS PER GJ																						
Selling price	$3.91	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.50	$6.68	$7.28	$7.69	$8.19	$8.52	$8.93	$9.27	$9.69	$10.43	$11.09	$11.52	$12.25		
Purchase price	$3.30	$3.72	$4.12	$4.68	$5.56	$6.22	$6.69	$7.08	$7.49	$7.90	$8.33	$8.73	$9.20	$9.73	$10.24	$10.77	$11.33	$11.93	$12.54	$13.19		
Margin on sales	0.61	0.38	0.18	(0.08)	(0.41)	(0.50)	(0.55)	(0.58)	(0.61)	(0.62)	(0.64)	(0.63)	(0.68)	(0.80)	(0.97)	(0.08)	(0.90)	(0.93)	(0.92)	(0.94)		
Cost of service	$0.12	$0.91	$0.93	$0.86	$0.83	$0.79	$0.76	$0.82	$0.82	$0.99	$0.92	$0.98	$0.98	$1.08	$1.08	$1.15	$1.35	$1.25	$1.27	$1.36		
Required subsidy	-0.49	0.53	0.65	0.94	1.24	1.29	1.31	1.40	1.43	1.52	1.56	1.61	1.66	1.88	1.95	2.03	2.05	2.18	2.19	2.30		
Dervd cost of gas purch	3.79	3.19	3.47	3.74	4.32	4.93	5.38	5.68	6.06	6.38	6.77	7.12	7.54	7.85	8.29	8.74	9.28	9.75	10.35	10.89		0
Cost without subsidy	3.42	4.63	4.95	5.54	6.39	7.01	7.45	7.90	8.31	8.80	9.25	9.71	10.18	10.81	11.32	11.92	12.48	13.18	13.61	14.55		62
ANNUAL COSTS																						
Gas sales	37290	50647	63084	76204	90590	105643	120019	130774	142203	153113	164020	175082	186878	193523	211509	226392	242424	259424	273392	294159		
Gas purchases	31472	45953	60266	77529	90223	114877	130769	142443	154811	166153	177671	188699	201793	216308	231137	246536	263343	281357	300433	316731		
Margin on sales	5819	4694	2637	-1325	-7243	-9235	-10751	-11669	-12608	-13049	-13651	-13617	-14915	-17785	-19638	-20144	-20919	-21933	-22041	-22572		
Cost of service	1144	11291	12218	14274	14709	14520	14851	16454	17002	18970	19692	21217	21556	24042	24273	26288	26595	29484	30512	32566		
Required subsidy	-4673	6596	9581	15599	21952	23755	25602	28123	29610	32018	33342	34834	36471	41827	43911	46432	47613	51417	52554	55138		
Dervd cost of gas purch	36146	39357	50782	61930	76279	91122	105168	114319	125291	134132	144323	153965	165322	174481	187226	200104	215730	229940	247860	261597		
Cost without subsidy	32615	57244	72565	91802	112932	129390	145620	156897	171812	185131	197562	209916	223349	243350	255419	272824	290638	310641	326945	349297		
																				290610		47517

LUMP SUM SUBSIDIES

Sales margin	-77091
Cost of service	160659
Ongoing K subsidy	421023
Fert. plant K contr.(M)	0
Fert. plant K contr.(L)	0
Total	659533

ANNEX 3

DESCRIPTION OF FINANCIAL MODELLING

The Model Structure

In order to examine the financial implications of the Applicants' proposals, the Commission developed a detailed financial model for the Vancouver Island Natural Gas Pipeline Project. The model was developed using the 1-2-3 program from Lotus Development Corporation on a micro-computer. The structure of the model is described in the following paragraphs, followed by print-outs.

The model is structured as a large worksheet with rows and columns. The rows are numbered and the columns have letter designations ranging from A through W. Column A contains headings for each of the rows. Columns B through U correspond to the modelled time span extending from 1986 through the year 2005. For most rows, Column V gives a numerical summation of the values over the 20 year span and Column W gives the net present value for the time series in each row. Some rows, however, contain special information or calculations instead of time series data.

The top rows of the model contain the input values for the particular case being modelled. The data loaded into these rows comes directly from the applications and revisions to the applications. The input data is listed separately for To Island and On Island portions of the project.

Following the input rows, the model is broken into sections portraying cost of service, gains (losses) on sales, fertilizer plant contribution, Capital or Operating Contribution, and detailed calculations of various components of the cost of service.

The model is structured so that key assumptions can be altered by changing a single cell in the model. Some of the assumptions which can be varied in this manner include discount rate, fertilizer plant cost allocation, and depreciation rate.

Assumptions Used in the Model

In order to facilitate comparisons between the applications the following set of assumptions were used :

1. Each project treated as stand-alone rather than as an extension of the Applicant's existing system.
2. Cash flows discounted at 10% to get net present value (NPV) in 1986 dollars.
3. Capital assets depreciated at 2%.
4. Inflation assumed to be 6%.
5. Costs allocated to fertilizer plant based on factors calculated by Applicants in accordance with a formula provided by the Ministry (Letter dated September 1, 1983).
6. The prices at which the pipeline project purchases and sells gas were provided by the Ministry (Letters dated September 1 and October 17, 1983).
7. Westcoast capital structure as per application for the life of the project.
8. Excess cash used to retire B.C. Hydro debt.
9. Rate of Return

   (a) Investor-Owned Utility (IOU)

      1. Capital structure (debt/equity) provided by Westcoast as prescribed.

2. Cost of capital is weighted average of Commission estimates.

debt	10%
preferred equity	11%
common equity	13%

(b) Publicly-Owned Utility (POU)

1. Interest coverage ratio assumed to be 1.1 to 1 over life of project.

10. Required Contribution Calculation

(a) Definition

Net present value (NPV) of contribution = NPV of Loss on Sales + NPV of Capital Cost of Construction (if any) + NPV of Cost of Service.

(b) Two Methods

1. Operating Contribution - payment of Cost of Service (which includes depreciation and interest costs) plus loss on sales.

2. Capital Contribution - upfront payment of all construction costs plus payment of Cost of Service (which does not include depreciation and little interest costs) plus loss on sales.

Thus paying a capital contribution reduces the amount of the Cost of Service which must be paid.

Inputs Used in the Model

1. Commission findings on markets as per Chapter 2.

2. Expenses, non-income taxes, and working capital as per applications.

3. Capital costs of construction adjusted by Commission as per Chapter 3.

Following are final print-outs, for all the Westcoast and B.C. Hydro cases using the Capital Contribution Method, the results of which are summarized on Tables 5.1 and 5.2.

B.C. HYDRO D - CAPITAL CONTRIBUTION METHOD

22-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Sum	NPV
To Island																						
Expenses	402	2588	3216	3727	3632	3909	3832	4616	4457	5270	5137	5007	5813	7534	5609	7749	7598	8777	9029	9957	110940	40557
Other taxes	12	3989	4345	5527	5866	5255	5448	5912	6117	6329	6775	6999	7226	7455	7695	8052	8315	8851	9146	9629	128943	50560
Fuel and losses																					0	0
SALES FORECAST	8670	11230	13320	15060	16060	16790	17770	18290	18790	19120	19390	19650	19940	20210	20520	20810	21130	21440	21780	21830	361800	152170
Capital cost	219601	0	0	0	0																219601	219601
Additions	0	7933	1594	4671	0	3490	10005	0	0	0	0	0	0	0	0	0	0	0	0	0	27693	19553
Inventory																						
Line pack																					247294	239454
Other working capital	71	150	155	168	153	139	136	142	137	144	144	148	145	158	149	157	156	168	169	175	2964	1329
On Island																					0	0
Expenses	503	1232	1315	1409	1503	1603	1712	1824	1939	2059	2303	2439	2590	2749	2913	3085	3272	3473	3686	3915	45527	17046
Other taxes	0	1910	1985	2061	2140	2221	2304	2392	2727	3369	3493	3618	3748	3877	4613	4770	4929	5445	5622	5846	67070	24401
Fuel and losses																					0	0
SALES FORECAST																					0	0
Capital cost	107264																				107264	107264
Additions	0	0	0	0	0	0	339	12657	27202	132	39	192	472	30133	0	267	17765	15	0	0	89213	32327
Inventory																						
Line pack																					196477	139591
Other working capital	40	74	68	67	65	64	62	65	75	79	79	79	79	88	94	93	98	101	100	100	1570	666

PCU

22-Jun-84

Assumptions:

Inflation rate:	6.0%	Capital subsidy	1	0
Discount rate:	10.0%	Marginal K alloc.	0	0
Depreciation rate:	2.0%	Load K alloc.	0	---------
Cost of debt:	10.0%	Allocn. multiplier	0.000	0

total plant 443771

NPV of total plant 379045

COST OF SERVICE	1986 / 1986	1987	1988	1989	1990 / 1990	1991	1992	1993	1994	1995 / 1995	1996	1997	1998	1999	2000 / 2000	2001	2002	2003	2004	2005 / 2005	9976 / 39910	0 / 0 / 5046 / 18660
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 / 0
Interest expense	111	223	220	229	210	193	186	193	196	205	203	205	200	220	215	220	222	234	232	236	4155	1876
Interest coverage	11	22	22	23	21	19	19	19	20	21	20	21	20	22	22	22	22	23	23	24	416	168
Expenses	905	4120	4535	5136	5135	5512	5544	6442	6396	7329	7410	8446	8402	10292	9522	10834	10780	12250	12715	13872	155567	57612
Other taxes	13	5899	6331	7588	8006	7476	7752	8304	8844	9698	10268	10616	10974	11332	12308	12922	13244	14296	14768	15474	196013	74961
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 / 0
Total cost of service	1040	10264	11108	12976	13372	13200	13501	14959	15456	17253	17902	19288	19596	21856	23067	23898	24268	26804	27738	29605	356151	134637
per GJ	$0.12	$0.91	$0.83	$0.86	$0.83	$0.79	$0.76	$0.82	$0.82	$0.90	$0.92	$0.93	$0.98	$1.08	$1.08	$1.15	$1.15	$1.25	$1.27	$1.36	19	8
Fert. plant ratio	0.00	0.00	0.00	0.00	0.00	0.30	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23		0
SALES FORECAST (TJ)	8670	11230	13320	15060	16060	16790	17770	18290	18790	19120	19390	19650	19940	20210	20520	20810	21130	21440	21780	21830	361800	152170
Fert plant cost/GJ	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
COSTS PER GJ																						
Selling price	$3.91	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.50	$6.88	$7.28	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25		
Purchase price	$3.30	$3.72	$4.12	$4.68	$5.56	$6.22	$6.69	$7.08	$7.49	$7.90	$8.33	$8.73	$9.20	$9.73	$10.24	$10.77	$11.33	$11.93	$12.54	$13.19		
Margin on sales	0.61	0.38	0.18	(0.08)	(0.41)	(0.50)	(0.55)	(0.58)	(0.61)	(0.62)	(0.64)	(0.63)	(0.68)	(0.80)	(0.87)	(0.88)	(0.90)	(0.93)	(0.92)	(0.94)		
Cost of service	$0.12	$0.91	$0.83	$0.86	$0.83	$0.79	$0.76	$0.82	$0.82	$0.90	$0.92	$0.96	$0.98	$1.08	$1.08	$1.15	$1.15	$1.25	$1.27	$1.36		
Required subsidy	-0.49	0.53	0.65	0.94	1.24	1.29	1.31	1.40	1.43	1.52	1.56	1.61	1.66	1.88	1.95	2.03	2.05	2.18	2.19	2.30		
Dervd cost of gas purch	3.79	3.19	3.47	3.74	4.32	4.93	5.38	5.68	6.06	6.38	6.77	7.12	7.54	7.85	8.29	8.74	9.28	9.75	10.35	10.89		0
Cost without subsidy	3.42	4.63	4.95	5.54	6.39	7.01	7.45	7.90	8.31	8.80	9.25	9.71	10.18	10.81	11.32	11.92	12.48	13.18	13.81	14.55		62

ANNUAL COSTS

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gas sales	33900	46043	57276	69276	82739	96039	109108	118885	129275	139194	149109	159165	169889	180473	192272	205811	220395	235840	253084	267418
Gas purchases	28611	41776	54878	70481	89294	104434	118881	129493	140737	151048	161519	171545	183448	196643	210125	224124	239403	255779	273121	287938
Margin on sales	5287	4267	2398	-1205	-6585	-8395	-9774	-10608	-11462	-11854	-12410	-12380	-13559	-16168	-17652	-18313	-19017	-19939	-20038	-20520
Cost of service	1040	10264	11106	12976	13372	13200	13501	14959	15456	17253	17902	19288	19596	21856	23067	23898	24268	26804	27738	29605
Required subsidy	-4249	5997	8710	14181	19957	21595	23274	25567	26918	29107	30311	31667	33155	38024	39919	42211	43285	46743	47776	50126
Dervd cost of gas purch	32860	35779	46163	56307	69307	82833	95537	103923	113819	121941	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	196118	209036	225345	237812
Cost without subsidy	29651	52040	65986	83457	102666	117624	132382	144452	156193	168331	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	263671	282563	300660	317543

LUMP SUM SUBSIDIES

Sales margin	-63055
Cost of service	134637
Ongoing + subsidy	379045
Fert. plant + contr.(M)	
Fert. plant K contr.(L)	0

B.C. HYDRO A - CAPITAL CONTRIBUTION METHOD

22-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Sum	NPV
To Island																						
Expenses	424	2341	3265	2777	3477	3541	3907	4271	4628	5465	5773	6097	6157	7565	6977	8148	7942	9254	9554	10513	114316	41597
Other taxes	15	3991	4349	5253	5362	5255	5595	5935	6145	6526	6821	7348	7274	7504	7746	8037	8646	8934	9231	9633	130102	50955
Fuel and losses																						0
SALES FORECAST	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960	173898
Capital cost	219602	0	0	0	0																219602	219602
Additions	0	7932	1594	4314	1791	7157	5202	0	0	0	0	0	0	0	0	0	0	0	0	0	28291	20581
Inventory																						
Line pack																					247893	240183
Other working capital	71	151	156	167	153	141	173	143	149	147	147	151	145	150	151	163	164	172	174	179	3023	1349
On Island																					0	0
Expenses	524	2067	2265	2349	2500	2659	2832	3011	3209	3394	3754	4042	4296	4564	4643	5129	5447	5784	6132	6504	75244	37989
Other taxes	4	2671	2765	2692	3040	3152	3279	3432	3554	3871	4099	4323	4472	4519	4991	5147	5383	5926	6126	6381	80058	30706
Fuel and losses																					0	0
SALES FORECAST																					0	0
Capital cost	146114																				146114	146114
Additions	0	522	56	1756		72	2077	142	9356	69	0	194	171	11156		267	17762	0	0	0	43829	14917
Inventory																						
Line pack																					189943	161031
Other working capital	52	104	97	95	93	92	96	90	93	95	98	101	102	106	109	111	119	123	123	125	2018	884

FCU

22-Jun-84

Assumptions:			
Inflation rate:	5.0%	Capital subsidy	1
Discount rate:	10.0%	Marginal K alloc.	0
Depreciation rate:	2.0%	Load K alloc.	0
Cost of debt:	10.0%	Allocn. multiplier	0.000

	total plant	437236
NPV of	total plant	401214

COST OF SERVICE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005		
																						0
																						4904
	1986				1990					1995					2000					2005	9976	5046
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910	18650
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest expense	123	254	249	258	237	222	216	217	215	224	223	223	223	229	229	240	247	257	256	260	4617	2099
Interest coverage	12	25	25	26	24	22	22	22	22	22	22	23	22	24	23	24	25	26	26	26	452	219
Expenses	946	5008	5479	6121	6172	6599	6729	7742	7925	8863	9125	10379	10423	12432	11916	13287	13365	15039	15686	17017	190060	69977
Other taxes	16	6652	7133	9446	8909	8407	8859	9367	9599	10397	10530	11371	11745	12123	12737	13186	14031	14870	15357	16014	210160	81661
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
																						0
Total cost of service	1099	11949	12677	14851	15342	15250	15835	17346	17761	19526	20201	21950	22415	24812	24905	26737	27692	30190	31325	33317	405299	153947
per GJ	$0.10	$0.90	$0.83	$0.86	$0.84	$0.79	$0.78	$0.83	$0.83	$0.90	$0.92	$0.99	$1.00	$1.09	$1.08	$1.15	$1.17	$1.26	$1.29	$1.37	19	8
Fert. plant ratio	0.00	0.00	0.00	0.00	0.00	0.30	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23		
																						0
SALES FORECAST (TJ)	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409950	173898
Fert plant cost/GJ	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
COSTS PER GJ																						
Selling price	$3.71	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.54	$6.98	$7.29	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25		
Purchase price	$3.30	$3.72	$4.12	$4.69	$5.56	$6.22	$6.69	$7.09	$7.49	$7.93	$8.33	$8.73	$9.20	$9.73	$10.24	$10.77	$11.33	$11.93	$12.54	$13.19		
Margin on sales	0.61	0.38	0.18	(0.09)	(0.41)	(0.50)	(0.55)	(0.58)	(0.61)	(0.62)	(0.64)	(0.63)	(0.68)	(0.80)	(0.87)	(0.88)	(0.90)	(0.93)	(0.92)	(0.94)		
Cost of service	$0.10	$0.90	$0.83	$0.86	$0.84	$0.79	$0.78	$0.83	$0.83	$0.90	$0.92	$0.99	$1.00	$1.09	$1.06	$1.15	$1.17	$1.26	$1.29	$1.37		
Required subsidy	-0.51	0.52	0.65	0.94	1.25	1.29	1.33	1.41	1.44	1.52	1.56	1.62	1.68	1.89	1.95	2.03	2.07	2.19	2.21	2.31		
Cervd cost of gas purch	3.81	3.20	3.47	3.74	4.21	4.93	5.36	5.67	6.05	6.38	6.77	7.11	7.52	7.84	8.29	8.74	9.26	9.74	10.33	10.86		0
Cost without subsidy	3.40	4.62	4.95	5.54	6.40	7.31	7.47	7.91	8.32	8.80	9.25	9.72	10.20	10.82	11.32	11.92	12.50	13.19	13.83	14.56		62

ANNUAL COSTS

ANNUAL COSTS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Gas sales	40524	54489	66607	79258	93576	110339	124458	135135	146475	157594	168489	179577	191359	202973	215385	230734	246670	263556	282356	298238
Gas purchases	35046	49459	63819	80656	101025	119984	135606	147193	159462	170798	182510	193544	206622	221163	235930	251264	267955	285843	304722	321177
Margin on sales	6478	5030	2788	-1373	-7450	-9645	-11149	-12058	-12987	-13404	-14022	-13967	-15273	-18184	-20045	-20530	-21285	-22293	-22356	-22889
Cost of service	1099	11949	12877	14651	15342	15250	15835	17348	17761	19526	20201	21950	22415	24818	24605	26737	27692	30190	31325	33317
Required subsidy	-5379	6899	10089	16229	22792	24895	26984	29406	30748	32931	34224	35927	37687	43002	44849	47268	48977	52473	53681	56206
Cervd cost of gas purch	40425	42540	53700	64407	78224	95089	108627	117767	128714	137867	148237	158517	168945	173161	191080	203996	218978	233370	251041	264973
Cost without subsidy	36145	61398	73676	95487	116367	135234	151441	164541	177223	190324	202711	215504	229047	245951	260754	278002	295646	316033	336047	354494

LUMP SUM SUBSIDIES

Sales margin	-70396
Cost of service	153947
Ongoing $ subsidy	401214
Fert. plant $ contr. (M)	0
Fert. plant $ contr. (J)	0
Total	[illegible]

B.C. HYDRO B - CAPITAL CONTRIBUTION METHOD

22-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	SUM	NPV
To Island																						
Expenses	455	4297	4648	5172	5694	5350	5531	6209	6113	7010	6931	7992	7965	9871	9147	10495	10444	11909	12373	12511	150620	56269
Other taxes	46	4500	5929	6240	6477	5877	6088	6454	6676	7071	7309	7549	7793	8330	6603	8929	9230	9546	9580	10313	142742	56701
Fuel and losses																					0	0
SALES FORECAST	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960	173898
Capital cost	241181																				241181	241181
Additions	0	10623	6793	0	0	1909	5302	0	0	0	0	0	0	0	0	0	0	0	0	0	24627	19450
Inventory																					----------	----------
Line pack																					265808	260631
Other working capital	84	190	195	195	178	163	159	165	163	171	168	175	175	195	165	195	193	202	205	211	3567	1597
On Island																					0	0
Expenses	539	2485	2773	3211	4143	4361	4710	5069	5373	5713	6184	6534	6904	7293	7697	8121	8602	9094	9524	10188	118518	43255
Other taxes	1	3099	3249	3504	3659	3822	3964	4112	4405	4751	4915	5081	5254	5430	5325	6012	6194	6739	6950	7233	94199	36436
Fuel and losses																					0	0
SALES FORECAST																					0	0
Capital cost	167835																				167835	167835
Additions	0	2395	4190	0	0	0	391	7508	9565	58	0	194	267	11156	0	267	17662	0	0	0	53653	21493
Inventory																					----------	----------
Line pack																					221488	189328
Other working capital	59	121	115	117	121	120	119	122	126	128	131	132	134	139	143	145	153	159	162	165	2611	1125

POU Assumptions: Inflation rate: 6.0% Capital subsidy 1 NPV of K costs with fert. plant 449958 total plant 497296
Discount rate: 10.0% Marginal K alloc. 1 NPV of K costs without fert. plant 401214 NPV of total plant 449958
22-Jun-84 Depreciation rate: 2.0% Load K alloc. 0 ---------- 0
Cost of debt: 10.0% Allocn. multiplier 1.000 Fert. plant K contr. 48744 12836
1986 1990 1995 2000 2005 9976 5046

COST OF SERVICE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910	18660
===============																						0
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest expense	143	310	305	304	288	269	262	268	267	275	272	277	277	299	290	299	302	314	317	323	5661	2559
Interest coverage	14	31	31	30	29	27	26	27	27	27	27	28	28	30	29	30	30	31	32	32	566	256
Expenses	1498	6782	7421	8383	9237	9711	10041	11278	11486	12723	13115	14526	14669	17164	16844	18616	19046	21002	21997	23699	269438	99524
Other taxes	47	7599	9078	9744	10136	9699	10052	10566	11081	11822	12224	12630	13047	13760	14428	14941	15424	16287	16830	17546	236941	93137
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	5829	5740	6089	6184	6634	6758	7147	7253	7933	7897	8369	8493	9077	9312	9776	112490	36402
																						0
Total cost of service	1702	14722	16835	18462	19690	13878	14641	16050	16677	18213	18880	20314	20968	23320	23694	25517	26309	28557	29863	31824	400117	159073
per GJ	$0.16	$1.11	$1.09	$1.07	$1.08	$0.72	$0.72	$0.77	$0.78	$0.84	$0.86	$0.92	$0.93	$1.03	$1.03	$1.09	$1.11	$1.19	$1.23	$1.31	19	8
Fert. plant ratio	0.00	0.00	0.00	0.00	0.00	0.30	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.23		0
SALES FORECAST (TJ)	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960	173898
Fert plant cost/GJ	$0.00	$0.00	$0.00	$0.00	$0.00	$0.29	$0.29	$0.30	$0.31	$0.33	$0.34	$0.36	$0.36	$0.40	$0.39	$0.42	$0.42	$0.45	$0.47	$0.49		
COSTS PER GJ																						
============																						
Selling price	$3.91	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.50	$6.89	$7.28	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25		
Purchase price	$3.30	$3.72	$4.12	$4.68	$5.56	$6.22	$6.69	$7.08	$7.49	$7.90	$8.33	$8.73	$9.20	$9.73	$10.24	$10.77	$11.33	$11.93	$12.54	$13.19		
Margin on sales	0.61	0.38	0.18	(0.08)	(0.41)	(0.50)	(0.55)	(0.58)	(0.61)	(0.62)	(0.64)	(0.63)	(0.68)	(0.80)	(0.87)	(0.88)	(0.90)	(0.93)	(0.92)	(0.94)		
Cost of service	$0.16	$1.11	$1.09	$1.07	$1.08	$0.72	$0.72	$0.77	$0.78	$0.84	$0.86	$0.92	$0.93	$1.03	$1.03	$1.09	$1.11	$1.19	$1.23	$1.31		
Required subsidy	-0.45	0.73	0.91	1.15	1.49	1.22	1.27	1.35	1.39	1.46	1.50	1.55	1.61	1.83	1.90	1.97	2.01	2.12	2.15	2.25		0
Derve cost of gas purch	3.75	2.99	3.21	3.53	4.07	5.00	5.42	5.73	6.10	6.44	6.83	7.18	7.59	7.90	8.34	8.60	9.32	9.81	10.39	10.94		62
Cost without subsidy	3.46	4.83	5.21	5.75	6.64	6.94	7.41	7.85	8.27	8.74	9.19	9.65	10.13	10.76	11.27	11.86	12.44	13.12	13.77	14.50		
ANNUAL COSTS																						
============																						
Gas sales	41524	54489	66607	79253	93575	110339	124458	135135	146475	157354	169488	179577	191359	202979	215865	230734	246670	263561	283366	298289		
Gas purchases	35046	49439	63819	80636	101025	119984	135606	147193	159462	173798	183510	192544	206632	221163	235930	251264	267955	285843	304722	321177		
Margin on sales	6478	5050	2788	-1378	-7450	-9645	-11149	-12058	-12987	-16444	-14022	-13967	-15273	-18184	-20065	-20530	-21285	-22282	-21356	-22889		
Cost of service	1702	14722	16835	18462	19690	13878	14641	16050	16677	18213	18890	20314	20968	23320	23694	25517	26309	28557	29863	31824		
Required subsidy	-4776	9671	14047	19840	27140	23523	25790	28109	29664	31657	32903	34281	36240	41504	43759	46047	47594	50840	52219	54713		
Dervd cost of gas purch	35322	39767	49772	60796	73885	96461	109816	119095	129798	139181	149607	159263	170792	179659	192171	205217	220361	235003	252503	266463		
Cost without subsidy	36748	64160	80654	99058	120715	133861	150248	163243	171139	189011	201391	213556	227600	244453	259622	276781	294263	314403	334585	352901		

LUMP SUM SUBSIDIES
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Sales margin	-70396
Cost of service	159073
Ongoing K subsidy	449958
Fert. plant K contr.(P)	48744
Fert. plant K contr.(L)	0

Total	[illegible]

WESTCOAST WITHOUT FERTILIZER PLANT OPERATING CONTRIBUTION METHOD

26-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	[illegible]
To Island																					0
Expenses	3920	3090	3641	3276	3631	4566	4633	5119	5424	5747	6093	6454	6646	7148	7525	8515	9962	10560	11191	11862	129518
Taxes, other	7228	7744	8185	8792	9562	10148	11066	11332	11951	12632	13252	14127	14944	15911	17776	18417	19481	20518	21827	23196	277349
Fuel and losses																					0
SALES FORECAST(TJ)	10620	13290	15490	17030	18170	19290	20270	20790	21390	21620	21910	22170	22463	22720	23040	23330	23550	23960	24300	24350	409960
Capital cost(open)	316750																				316750
Additions	6297	133	210	23726	13790	536	567	600	637	675	715	759	807	852	31139	994	1160	1231	1307	0	35175
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	4176	4177	4179	4195	4290	4419	4425	4432	4439	4447	4455	4464	4473	4483	4550	4866	4879	4893	4908	4923	90074
Line pack																					0
Other working capital	316	323	329	355	415	455	524	555	595	623	667	694	741	755	557	1031	1079	1144	1212	1283	14401
On Island																					0
Expenses	879	933	874	924	963	1025	1249	2058	2192	2322	2462	2608	2764	2929	3104	3276	3473	3675	3857	4088	45574
Taxes, other	2613	2758	2912	3075	3249	3433	3985	4222	4463	4719	4990	5277	5582	5907	6251	6616	7002	7414	7849	8311	100629
Fuel and losses																					0
SALES FORECAST(TJ)																					0
Capital cost(open)	10637																				10637
Additions	24	61	97	127	182	193	[illegible]	304	322	340	362	384	407	432	455	483	512	543	575	[illegible]	5218
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	1479	1479	1480	1481	1482	1485	1521	1689	1693	1697	1701	1705	1710	1715	1720	1725	1731	1737	1744	1751	32725
Line pack																					0
Other working capital	95	101	55	100	105	111	135	224	237	252	267	283	299	317	336	355	372	394	415	443	4439
	1986				1990					1995					2000					2005	

Assumptions:

26-Jun-84	Inflation rate:	6.0%	Debt	65.0%	Capital subsidy	0	NPV of $ costs with fert. plant	484580	484580
	Discount rate:	10.0%	Common	35.0%	Marginal $ alloc.	0	NPV of $ costs without fert. plant	458173	458173
	Depreciation rate:	3.0%	Preferred	0.0%	Load $ alloc.	0			
	Cost of debt:	10.0%	CCA	7.0%	Allocn. multiplier	0.000	Fert. plant $ contr.	26410	26410

Capital structure assumption flag: 1 (1 if calculated, 0 if inputted)

10%	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	[illegible]	1.00%
COST OF SERVICE																					0	
Depreciation	9062	9191	9195	9201	9478	9938	9952	9969	9986	10005	10025	10047	10072	10094	10119	10752	10784	10817	10853	10890	200528	9321
Return on rate base	50778	50135	49143	49466	50482	50178	49166	48189	47192	46200	45213	44239	43253	43282	43066	43747	42742	41747	40761	39672	917588	446003
Expenses	3799	4020	3915	4200	4800	5591	6094	7137	7516	6959	6553	9062	9634	10177	11035	12793	13395	14199	15949	15950	175102	64182
Taxes, income	17145	759	2615	4955	5771	7437	6949	10138	11292	12331	13264	14099	14842	15501	15756	16676	17238	17725	18151	18553	262179	53265
Taxes, other	9541	10502	11597	11857	12811	13541	14671	15524	16414	17356	13346	19404	20527	21716	22027	23035	26484	28032	29676	31417	377976	146700
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total cost of service	90725	74607	75964	78791	83542	86654	89724	91906	92499	93961	95401	96842	98296	99772	103549	108991	110642	112523	114469	116463	1913472	641473
per GJ	8.54	5.61	4.90	4.57	4.60	4.49	4.38	4.38	4.34	4.35	4.35	4.37	4.38	4.39	4.49	4.67	4.66	4.70	4.71	4.78	96	47
Fert. plant ratio	0.000	0.000	0.000	0.000	0.000	0.304	0.289	0.277	0.266	0.259	0.256	0.251	0.246	0.241	0.236	0.232	0.229	0.224	0.220	0.216	3.74	
SALES FORECAST	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22463	22720	23040	23330	23550	23960	24300	24350	419960	173898
Fert plant cost/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0
COSTS PER GJ																					0	0
Selling price	$3.91	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.56	$6.88	$7.28	$7.69	$8.10	$8.52	$8.97	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25	152	55
Purchase price	$3.07	$3.45	$3.82	$4.34	$5.13	$5.79	$6.22	$6.58	$6.97	$7.38	$7.80	$8.21	$8.63	$9.07	$9.51	$10.04	$10.58	$11.15	$11.77	$12.41	152	56
Margin on sales	$0.84	$0.65	$0.45	$0.26	$0.02	($0.07)	($0.08)	($0.03)	($0.09)	($0.10)	($0.11)	($0.11)	($0.11)	($0.14)	($0.14)	($0.15)	($0.15)	($0.15)	($0.15)	($0.16)	0	1
Cost of service	$8.54	$5.61	$4.90	$4.57	$4.60	$4.49	$4.38	$4.38	$4.34	$4.35	$4.35	$4.37	$4.38	$4.39	$4.49	$4.67	$4.66	$4.70	$4.71	$4.78	96	47
Required subsidy	$7.70	$4.96	$4.45	$4.31	$4.58	$4.56	$4.46	$4.46	$4.43	$4.45	$4.46	$4.48	$4.49	$4.53	$4.63	$4.82	$4.81	$4.85	$4.86	$4.94	95	46
Servd cost of gas purch	($4.63)	($1.51)	($0.60)	$0.03	$0.55	$1.22	$1.76	$2.12	$2.54	$2.93	$3.34	$3.73	$4.14	$4.54	$4.88	$5.22	$5.75	$6.30	$6.91	$7.47	57	12
Cost without subsidy	$11.61	$9.06	$9.72	$9.91	$9.73	$10.29	$10.60	$10.96	$11.31	$11.73	$12.15	$12.58	$13.01	$13.46	$14.00	$14.71	$15.26	$15.85	$16.49	$17.19	248	105
ANNUAL COSTS																					0	0
Gas sales	41524	54489	66607	79258	93575	110339	124458	136135	146475	157394	168488	179577	191359	202979	215985	230734	245670	263561	282766	298268	3239157	1177899
Gas purchases	32603	45851	59172	74778	93212	111689	126079	136798	148391	159556	170898	182016	193630	206161	219110	234237	250217	267154	286011	302184	3299543	1163740
Margin on sales	8921	8638	7435	4480	363	-1350	-1622	-1663	-1916	-2162	-2410	-2439	-2471	-3182	-3125	-3499	-3548	-3594	-3645	-3956	-60385	14159
Cost of service	90725	74607	75964	78791	83542	86654	89724	91906	92499	93961	95401	96842	98296	99772	103549	108991	110642	112523	114469	116463	1913472	641473
Required subsidy	81804	65969	68529	74311	83179	88035	90346	92569	94416	96123	97811	99281	100767	102954	106773	112490	114190	116117	118134	120359	1924256	627314
Servd cost of gas purch	-45200	-20118	-9257	467	10934	23555	35773	44129	53976	63433	73097	82735	93063	103207	112737	121742	136627	151037	167877	181322	1375687	336426
Cost without subsidy	123328	120459	135136	153569	176754	197773	213469	227654	240891	253517	266299	278858	292123	305933	322659	343004	360860	379677	400590	418645	5213415	2045213

LUMP SUM SUBSIDIES

Sales margin	14159	14159
Cost of service	641473	641473
Capital	0	
Fert. plant $ contr.(M)	0	
Fert. plant $ contr.(L)	0	0
Total	627314	627314

WESTCOAST WITHOUT FERTILIZER PLANT - CAPITAL CONTRIBUTION METHOD

22-Jun-84	1986	1987	1988	1989	[illegible]	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910
To Island																					0
Expenses	2929	3090	3341	3276	[illegible]	4536	4615	5119	5414	5747	6091	6454	6540	7243	7535	8515	8961	10563	11151	11552	122566
Taxes, other	7328	7744	8185	8792	[illegible]	10106	10686	11302	11951	12638	13356	14127	14944	15811	17376	16487	19491	20618	21627	22106	277349
Fuel and losses																					0
SALES FORECAST(TJ)	10620	13290	15490	17230	[illegible]	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960
Capital cost(open)	316750																				316750
Additions	6397	133	210	23726	127[illegible]	536	567	600	637	675	715	758	803	852	21139	1094	1160	1230	1303	0	65275
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	4176	4177	4179	4195	42[illegible]	4419	4425	4432	4439	4447	4455	4464	4473	4483	4553	4866	4879	4893	4908	4921	90074
Line pack																					0
Other working capital	316	335	329	355	4[illegible]	495	524	555	588	623	660	699	741	785	860	1031	1079	1144	1212	1285	14031
On Island																					0
Expenses	879	930	874	924	[illegible]	1025	1249	2068	2192	2322	2462	2608	2764	2929	3104	3278	3433	3639	3857	4088	45594
Taxes, other	2613	2758	2912	3075	3249	3433	3935	4222	4463	4718	4990	5277	5583	5907	6251	6616	7003	7414	7549	[illegible]	100629
Fuel and losses																					0
SALES FORECAST(TJ)																					0
Capital cost(open)	136370																				136370
Additions	29	61	97	137	[illegible]	191	209	304	322	342	362	384	407	433	455	483	512	543	575	0	6018
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	1479	1479	1480	1481	1483	1485	1521	1689	1693	1697	1701	1705	1710	1715	1720	1725	1731	1737	1744	1750	32725
Line pack																					0
Other working capital	95	101	95	100	[illegible]	111	135	224	237	252	267	283	299	317	336	355	372	394	418	443	4939
	1986				1990					1995					2000					2005	

Assumptions: Inflation rate: 6.[illegible]% Debt 61.0% Capital subsidy 1 0 2
Discount rate: 10.[illegible]% Common 35.0% Marginal k alloc. 0 0 0
22-Jun-84 Depreciation rate: [illegible]% Preferred 4.0% Load F alloc. 0 --------- 0
Cost of debt: 1[illegible]% CCA 7.0% Allocn. multiplier 0.000 0 0
Capital structure assumption flag: 1 (1 if calculated, 0 if inputed)

10.0%

IOU	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910	
COST OF SERVICE																					0	
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on rate base	673	676	675	690	[illegible]	722	732	765	772	778	786	793	801	810	528	855	894	906	918	931	15722	6968
Expenses	3799	4020	3915	4200	45[illegible]	5591	6084	7187	7616	8059	8553	9062	9604	10177	11039	12793	13395	14199	15049	15950	175102	64182
Taxes, income	328	329	329	331	[illegible]	352	357	373	376	379	383	387	390	395	404	431	436	442	448	454	7564	3397
Taxes, other	9941	10502	11097	11867	125[illegible]	13541	14671	15524	16414	17356	18346	19404	20527	21716	22627	25023	26484	28032	29676	31417	377978	146700
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total cost of service	14741	15527	16015	17078	18649	20206	21845	23849	25178	26583	28067	29646	31322	33099	35898	39132	41209	43578	46091	48752	576462	221247
per GJ	1.39	1.17	1.03	0.99	1.[illegible]	1.05	1.08	1.15	1.18	1.23	1.28	1.34	1.39	1.46	1.56	1.68	1.74	1.82	1.90	2.00	27	12
Fert. plant ratio	0.000	0.000	0.000	0.000	0.000	0.304	0.289	0.277	0.266	0.258	0.256	0.251	0.246	0.241	0.236	0.232	0.228	0.224	0.220	0.216	3.74	
SALES FORECAST	10620	13290	15490	17230	[illegible]	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960	170898
Fert plant cost/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0
COSTS PER GJ																					0	0
Selling price	$3.71	$4.10	$4.30	$4.60	$5.[illegible]	$5.72	$6.14	$6.50	$6.88	$7.29	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25	152	59
Purchase price	$3.07	$3.45	$3.82	$4.34	$5.[illegible]	$5.79	$6.22	$6.58	$6.97	$7.38	$7.80	$8.21	$8.63	$9.07	$9.51	$10.04	$10.58	$11.15	$11.77	$12.41	153	58
Margin on sales	$0.64	$0.65	$0.48	$0.26	$0.[illegible]	($0.07)	($0.08)	($0.08)	($0.09)	($0.10)	($0.11)	($0.11)	($0.11)	($0.14)	($0.14)	($0.15)	($0.15)	($0.15)	($0.15)	($0.15)	[illegible]	1
Cost of service	$1.39	$1.17	$1.03	$0.99	$1.[illegible]	$1.05	$1.08	$1.15	$1.18	$1.23	$1.28	$1.34	$1.39	$1.46	$1.56	$1.68	$1.74	$1.82	$1.90	$2.00	27	12
Required subsidy	$0.55	$0.52	$0.55	$0.73	$1.[illegible]	$1.12	$1.16	$1.23	$1.27	$1.33	$1.39	$1.45	$1.50	$1.60	$1.70	$1.83	$1.89	$1.97	$2.05	$2.16	27	10
Dervd cost of gas purch	$2.52	$2.93	$3.27	$3.61	$4.[illegible]	$4.67	$5.06	$5.35	$5.70	$6.05	$6.41	$6.76	$7.13	$7.47	$7.81	$8.21	$8.69	$9.18	$9.72	$10.25	125	48
Cost without subsidy	$4.46	$4.62	$4.85	$5.[illegible]	[illegible]	$5.84	$7.39	$7.73	$8.15	$8.61	$9.08	$9.55	$10.02	$10.57	$11.07	$11.72	$12.[illegible]	$12.97	$13.67	$14.41	179	70
ANNUAL COSTS																					0	0
Gas sales	41524	54489	66507	79253	93576	110379	124458	135135	146475	157394	168488	179577	191359	202979	215885	230734	246670	263560	282366	296266	3389159	1177895
Gas purchases	32603	45851	59172	74778	92212	111689	126079	136798	148391	159556	170898	182016	193830	206161	219110	234233	250217	267154	286011	332184	3399943	1163740
Margin on sales	8921	8638	7435	4480	363	-1350	-1622	-1663	-1916	-2162	-2410	-2439	-2471	-3182	-3226	-3499	-3548	-3594	-3645	-3896	-10735	14155
Cost of service	14741	15527	16015	17078	18649	20206	21845	23849	25178	26583	28067	29646	31322	33099	35898	39132	41209	43578	46091	48752	576462	221247
Required subsidy	5820	6888	8580	12599	15286	21556	23466	25512	27094	28745	30477	32084	33793	36281	39124	42631	44756	47172	49736	52646	587251	207088
Dervd cost of gas purch	26784	38962	50592	62180	74926	90133	102613	111286	121296	130811	140421	149931	160037	169880	179987	191602	205461	219982	236375	249535	2712697	956652
Cost without subsidy	47344	61377	75187	91857	111551	131895	147924	160647	173569	186138	199965	211661	225152	239260	255996	273565	291425	310722	332102	351936	3876409	1384987

LUMP SUM SUBSIDIES		
Sales margin	14159	14159
Cost of service	221247	221247
Capital	500227	
Fert. plant & contr.(M)	0	
[illegible]	0	

15-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	[illegible]
To Island																					
Expenses	3359	4382	4411	4656	4572	5415	7195	7531	8596	9153	9545	11228	10875	11462	11271	12933	13274	14579	16675	18187	191216
Taxes, other	7817	8341	8812	9368	9836	10941	11562	12236	13228	13989	14762	15605	16498	17445	18449	19513	20640	22148	22797	25196	300138
Fuel and losses																					
SALES FORECAST(TJ)	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22720	23040	23330	23650	23960	24300	24750	409960
Capital cost(open)	323775																				323775
Additions	20266	169	339	17115	555	27047	859	356	14973	1022	1135	1150	1216	1291	1358	1452	1537	1627	18538	[illegible]	127096
AFUDC																					
Start-up cost																					
Financing expense																					
Inventory	4252	4391	4394	4399	4403	4463	4733	4744	4782	4933	4945	4952	4972	4987	5002	5019	5036	5084	5232	5457	96245
Line pack																					
Other working capital	365	475	478	504	526	587	770	816	877	996	1045	1106	1174	1244	1317	1395	1481	1596	1806	2035	20585
On Island																					
Expenses	877	926	871	1658	1734	1822	1927	2042	2164	2291	2429	2574	2728	2891	3064	3248	3443	3649	3962	4094	47598
Taxes, other	2612	2758	2912	3073	3572	3775	3992	4219	4460	4716	4987	5275	5581	5905	6249	6614	7002	7412	7848	8319	101572
Fuel and losses																					
SALES FORECAST(TJ)																					
Capital cost(open)	136348																				136348
Additions	29	61	96	109	257	354	281	299	315	335	354	376	399	422	448	474	503	533	567	0	6194
AFUDC																					
Start-up cost																					
Financing expense																					
Inventory	1478	1479	1480	1509	1650	1653	1657	1660	1664	1669	1672	1676	1681	1686	1691	1696	1702	1708	1714	1720	32844
Line pack																					
Other working capital	95	100	94	115	188	197	209	221	234	248	263	279	295	313	332	352	373	395	419	444	5166
	1986				1990					1995					2000					2005	

Assumptions:	Inflation rate:	6.0%	Debt	61.0%	Capital subsidy	0	NPV of $ costs with fert. plant	484583	434584
	Discount rate:	10.0%	Common	35.0%	Marginal $ alloc.	0	NPV of $ costs without fert. plant	500327	500327
15-Jun-84	Depreciation rate:	2.0%	Preferred	4.0%	Load $ alloc.	0		---------	0
	Cost of debt:	10.0%	CCA	7.0%	Allocn. multiplier	1.000	Fert plant $ contr.	-15744	-15743

Capital structure assumption flag: 1 (1 if calculated, 0 if inputed)

IOU	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910	10.0%
COST OF SERVICE																						
Depreciation	9142	9549	9554	9562	9907	9923	10471	10494	10517	10822	10850	10878	10909	10941	10975	11012	11050	11091	11426	11805	219861	95374
Return on rate base	52001	52133	51112	51039	50966	51465	51969	50941	50700	50471	49434	46404	47382	46367	45560	44362	43372	43208	43997	43817	958520	457477
Expenses	4246	5307	5281	5714	6606	7237	9032	9573	10260	11394	12078	12799	13563	14374	15235	16148	17117	18328	20541	22061	237714	86655
Taxes, income	17149	809	2737	4319	6147	7389	9137	10502	11585	12390	13949	14899	15746	16503	17172	17761	18276	18565	19969	19631	254117	97036
Taxes, other	10429	11099	11725	12681	13498	14715	15574	16455	17688	18705	19756	20680	22079	23350	24697	26127	27642	29560	31645	33500	401710	155974
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	27541	27761	27129	26836	26568	27137	27039	26941	26843	26782	25748	25746	27019	27793	28485	407661	141182
Total cost of service	92968	78897	80408	83316	87054	63189	69422	70835	73914	77414	78923	80921	82739	84693	86658	89661	90717	93734	98785	103132	1655282	761335
per GJ	8.75	5.94	5.19	4.84	4.79	3.28	3.39	3.41	3.47	3.58	3.60	3.65	3.68	3.73	3.76	3.80	3.84	3.91	4.07	4.24	85	44
Fert. plant ratio	0.000	0.000	0.000	0.000	0.000	0.304	0.289	0.277	0.266	0.258	0.256	0.251	0.246	0.241	0.236	0.232	0.228	0.224	0.220	0.216	3.74	
SALES FORECAST	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22720	23040	23330	23650	23960	24300	24750	409960	173399
Fert plant cost/GJ	0.00	0.00	0.00	0.00	0.00	1.36	1.39	1.36	1.34	1.34	1.36	1.35	1.35	1.34	1.34	1.34	1.34	1.35	1.39	1.42	20	7
COSTS PER GJ																						
Selling price	$3.91	$4.10	$4.30	$4.60	$5.25	$5.72	$6.14	$6.50	$6.89	$7.28	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25	152	59
Purchase price	$3.07	$3.45	$3.82	$4.34	$5.13	$5.79	$6.22	$6.58	$6.97	$7.38	$7.80	$8.21	$8.63	$9.07	$9.51	$10.04	$10.58	$11.15	$11.77	$12.41	152	59
Margin on sales	$0.84	$0.65	$0.48	$0.26	$0.02	($0.07)	($0.08)	($0.08)	($0.09)	($0.10)	($0.11)	($0.11)	($0.11)	($0.14)	($0.14)	($0.15)	($0.15)	($0.15)	($0.15)	($0.16)	0	1
Cost of service	$8.75	$5.94	$5.19	$4.84	$4.79	$3.28	$3.39	$3.41	$3.47	$3.58	$3.60	$3.65	$3.68	$3.73	$3.76	$3.80	$3.84	$3.91	$4.07	$4.24	85	44
Required subsidy	$7.91	$5.29	$4.71	$4.58	$4.77	$3.35	$3.46	$3.49	$3.56	$3.68	$3.71	$3.76	$3.79	$3.87	$3.90	$3.95	$3.99	$4.06	$4.22	$4.40	84	43
Dervd cost of gas purch	($4.84)	($1.84)	($0.89)	($0.24)	$0.36	$2.44	$2.76	$3.09	$3.41	$3.70	$4.09	$4.45	$4.84	$5.20	$5.61	$6.09	$6.59	$7.09	$7.55	$8.01	67	15
Cost without subsidy	$11.62	$9.39	$9.01	$9.18	$9.92	$9.07	$9.60	$9.99	$10.44	$10.96	$11.40	$11.86	$12.32	$12.80	$13.27	$13.84	$14.42	$15.06	$15.84	$16.37	237	102
ANNUAL COSTS																						
Gas sales	41524	54489	66607	79258	93576	110339	124458	135135	146475	157394	169488	179577	191359	202979	215885	230734	246670	263560	282366	298288	3259159	1177899
Gas purchases	32603	45851	59172	74778	93212	111689	126079	136798	148391	159556	170898	182016	193830	206161	219110	234233	250217	267154	286011	302184	3299943	1163740
Margin on sales	8921	8638	7435	4480	363	-1350	-1522	-1663	-1916	-2162	-2410	-2439	-2471	-3182	-3226	-3499	-3548	-3594	-3645	-3896	-19785	14159
Cost of service	92968	78897	80408	83316	87054	63189	69422	70835	73914	77414	78923	80821	82739	84693	86658	89661	90717	93734	98785	103132	1655282	761335
Required subsidy	84047	70258	72973	78836	86690	64539	70943	72499	75830	79576	81333	83260	85210	87875	89884	92161	94265	97329	102430	107028	1674066	747176
Dervd cost of gas purch	-51444	-24408	-13601	-4058	6522	47150	56036	64300	72561	79979	89565	93756	103620	118286	129227	142072	155952	169826	183581	195156	1623877	416564
Cost without subsidy	125571	124747	139580	158094	180266	174876	194501	207634	222306	236979	249821	262537	276569	290854	305768	322895	340934	360888	384796	405315	4965225	1935075

LUMP SUM SUBSIDIES

Sales margin	14159	14159
Cost of service	761335	761335
Capital	0	
Fert. plant K contr.(H)	0	
Fert. plant K contr.(L)	0	0
Total	747176	747176

WESTCOAST WITH FERTILIZER PLANT - CAPITAL CONTRIBUTION METHOD

15-Jun-84	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	39910
																					0
To Islanc																					0
Expenses	3369	4391	4410	4656	4872	5415	7105	7531	8096	9103	9649	10225	10835	11483	12171	12900	13674	14679	16675	18787	190016
Taxes, other	7817	8341	8813	9308	9836	10941	11582	12236	13220	13989	14763	15605	16498	17445	18448	19513	20640	22148	23797	25199	300138
Fuel and losses																					0
SALES FORECAST(TJ)	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960
Capital cost(open)	320775																				320775
Additions	20286	188	339	17115	555	27043	859	850	14973	1022	1085	1150	1218	1291	1368	1452	1537	16227	18533	0	127096
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	4252	4391	4394	4398	4403	4463	4733	4744	4782	4933	4945	4958	4972	4987	5002	5019	5036	5084	5292	5467	96245
Line pack																					0
Other working capital	365	475	478	504	528	587	770	816	877	986	1045	1108	1174	1244	1319	1396	1481	1590	1806	2035	20586
																					0
On Island																					0
Expenses	877	926	871	1058	1734	1822	1927	2042	2164	2291	2429	2574	2728	2891	3064	3248	3443	3649	3666	4094	47698
Taxes, other	2612	2758	2912	3373	3572	3775	3992	4219	4460	4716	4987	5275	5581	5905	6249	6614	7002	7412	7846	8310	101572
Fuel and losses																					0
SALES FORECAST(TJ)																					0
Capital cost(open)	136348																				136348
Additions	29	61	96	100	253	354	281	298	315	335	354	376	399	423	448	474	503	532	563	0	6194
AFUDC																					0
Start-up cost																					0
Financing expense																					0
Inventory	1478	1479	1480	1509	1650	1653	1657	1660	1664	1668	1672	1676	1681	1686	1691	1696	1792	1708	1714	1720	32844
Line pack																					0
Other working capital	95	100	94	115	188	197	209	221	234	248	263	279	295	313	332	352	373	395	419	444	5166
	1986				1990					1995					2000					2005	

Assumptions:	Inflation rate:	6.0%	Debt	61.0%	Capital subsidy	1	484585
	Discount rate:	10.0%	Common	35.0%	Marginal % alloc.	1	500329
15-Jun-84	Depreciation rate:	2.0%	Preferred	4.0%	Load % alloc.	0	0
	Cost of debt:	10.0%	CCA	7.0%	Allocn. multiplier	1.000	

Capital structure assumption flag: 1 (1 if calculated, 0 if inputed)

IOU	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	0 39910	10.0%
																					0	
COST OF SERVICE																					0	
																					0	
Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on rate base	686	715	715	724	751	765	817	825	838	869	879	890	901	913	925	939	953	973	1023	1072	17172	7532
Expenses	4246	5307	5281	5714	6606	7237	9032	9573	10260	11394	12078	12799	13563	14374	15235	16148	17117	18328	20541	22881	237714	86655
Taxes, income	335	348	348	353	366	373	398	402	409	424	428	434	439	445	451	458	464	474	498	523	8370	3672
Taxes, other	10429	11099	11725	12681	13408	14716	15574	16455	17688	18705	19750	20880	22079	23350	24697	26127	27642	29560	31645	33500	401710	155974
Fuel and losses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less fert. plant contr.	0	0	0	0	0	7009	7453	7548	7776	8089	8478	8775	9084	9406	9752	10122	10512	11039	11792	12547	139381	45089
																					0	0
Total cost of service	15696	17469	18069	19472	21131	16082	18369	19708	21418	23304	24657	26228	27898	29676	31556	33550	35664	38297	41915	45428	525585	208745
per GJ	1.48	1.31	1.17	1.13	1.16	0.83	0.91	0.95	1.01	1.08	1.13	1.18	1.24	1.31	1.37	1.44	1.51	1.60	1.72	1.87	25	11
Fert. plant ratio	0.000	0.000	0.000	0.000	0.000	0.304	0.289	0.277	0.266	0.258	0.256	0.251	0.246	0.241	0.236	0.232	0.228	0.224	0.220	0.216	3.74	
																					0	0
SALES FORECAST	10620	13290	15490	17230	18170	19290	20270	20790	21290	21620	21910	22170	22460	22730	23040	23330	23650	23960	24300	24350	409960	173898
																					0	0
Fert plant cost/GJ	0.00	0.00	0.00	0.00	0.00	0.35	0.37	0.38	0.39	0.40	0.42	0.44	0.45	0.47	0.49	0.51	0.53	0.55	0.59	0.63	7	2
COSTS PER GJ																					0	0
																					0	0
Selling price	$3.91	$4.10	$4.30	$4.60	$5.15	$5.72	$6.14	$6.50	$6.88	$7.28	$7.69	$8.10	$8.52	$8.93	$9.37	$9.89	$10.43	$11.00	$11.62	$12.25	152	59
Purchase price	$3.07	$3.45	$3.82	$4.34	$5.13	$5.79	$6.22	$6.58	$6.97	$7.38	$7.80	$8.21	$8.63	$9.07	$9.51	$10.04	$10.58	$11.15	$11.77	$12.41	152	58
																					0	0
Margin on sales	$0.84	$0.65	$0.48	$0.26	$0.02	($0.07)	($0.08)	($0.08)	($0.09)	($0.10)	($0.11)	($0.11)	($0.11)	($0.14)	($0.14)	($0.15)	($0.15)	($0.15)	($0.15)	($0.16)	0	1
Cost of service	$1.48	$1.31	$1.17	$1.13	$1.16	$0.83	$0.91	$0.95	$1.01	$1.08	$1.13	$1.18	$1.24	$1.31	$1.37	$1.44	$1.51	$1.60	$1.72	$1.87	25	11
																					0	0
Required subsidy	$0.64	$0.66	$0.69	$0.87	$1.14	$0.90	$0.99	$1.03	$1.10	$1.18	$1.24	$1.29	$1.35	$1.45	$1.51	$1.59	$1.66	$1.75	$1.87	$2.03	25	10
																					0	0
Dervd cost of gas purch	$2.43	$2.79	$3.13	$3.47	$3.99	$4.89	$5.23	$5.55	$5.87	$6.20	$6.56	$6.92	$7.28	$7.62	$8.00	$8.45	$8.92	$9.40	$9.90	$10.38	127	46
Cost without subsidy	$4.55	$4.76	$4.99	$5.47	$6.29	$6.62	$7.13	$7.53	$7.98	$8.46	$8.93	$9.39	$9.87	$10.38	$10.88	$11.48	$12.09	$12.75	$13.49	$14.28	177	69
ANNUAL COSTS																					0	0
																					0	0
																					0	0
Gas sales	41524	54489	66607	79258	93576	110339	124452	135135	146475	157394	169488	179577	191359	202979	215385	230734	246670	263560	282366	[illegible]	3287159	1177899
Gas purchases	32603	45851	59172	74770	93212	111687	126079	136798	148391	159556	170290	182016	193830	206161	219110	234233	250217	267154	286011	[illegible]	3299543	1163740
																					0	0
Margin on sales	8921	8638	7435	4480	363	-1350	-1622	-1663	-1916	-2162	-2410	-2439	-2471	-3182	-3226	-3499	-3548	-3594	-3645	-3396	-10785	14159
Cost of service	15696	17469	18069	19472	21131	16082	18369	19708	21418	23304	24657	26228	27898	29676	31556	33550	35664	38297	41915	45428	525585	208745
																					0	0
Required subsidy	6775	8531	10634	14992	20767	17432	19990	21371	23334	25456	27057	28666	30269	32858	34782	37049	39211	41891	45560	49324	536370	194566
																					0	0
Dervd cost of gas purch	25828	37020	49538	59766	72445	94257	106099	115427	125057	134099	143831	155349	163461	173303	184329	197184	211006	225263	240451	[illegible]	2767574	969154
Cost without subsidy	48299	63320	77241	94250	114343	127771	144448	156506	169810	182859	195555	208243	221728	235837	250666	267763	285881	305451	327926	[illegible]	3825528	1372485
LUMP SUM SUBSIDIES																					0	0
																					0	
																					0	
Sales margin	14159																				14159	
Cost of service	208745																				208745	
Capital	527697																					
Fert. plant & contr.(M)	27370																					
[illegible]	0																					

CHAPTER 6 CONCLUSIONS AND RECOMMENDATIONS

This chapter provides the Commission's recommendation on the Applicant best able to construct and operate the Vancouver Island Natural Gas Pipeline, and the size of the Federal capital contribution necessary to eliminate any revenue deficiencies associated with the project.

Previous chapters of this report provide a full review of all matters related to the Project as directed in the Terms of Reference for the Hearing, as well as additional matters of public concern raised during the Hearing. Numerous findings, conclusions and recommendations of the Commission on specific matters regarding markets, facilities and capital costs, environmental and socio-economic impacts and cost of service have been highlighted throughout the report.

The first and principal objective of the Hearing was to determine the project best able to serve the residential, commercial and heavy industrial markets on Vancouver Island. The second objective included a review and assessment of natural gas requirements to serve a potential fertilizer complex at Powell River.

The Commission finds that on the basis of the evidence presented to the Hearing, Westcoast and B.C. Hydro are both capable of providing safe, reliable natural gas service to meet the market demands on Vancouver Island and for a Fertilizer Plant at Powell River. The Commission has determined that no unacceptable socio-economic or environmental impacts would result if proper design and construction timing are followed. The Commission reached these decisions after exhaustive examination of the competing proposals, particularly the environmental aspects of pipeline construction and operation.

The difference between capital costs and revenue deficiencies is the significant distinguishing factor between the two proposals. B.C. Hydro's proposals are the least costly by a substantial margin.

The Commission analyzed the cost difference between the competing proposals by developing a financial model to compare the cost of service and revenue deficiencies of each Applicant's proposal. Details of this comparison and adjustments made to facilitate this, can be found in Chapter 5, Section 5.4, page 199. The capital contribution differences resulting from this analysis are :

	Vancouver Island	Vancouver Island (Powell River WITHOUT Fertilizer Plant)	Vancouver Island (Powell River WITH Fertilizer Plant)
		(1986 $000,000)	
WESTCOAST		723	783*
B.C. HYDRO			
System D	577		
System A		626	
System B			716*
CAPITAL CONTRIBUTION DIFFERENCES		97	67*

* Includes Fertilizer Plant contribution, see MA 3, page 205.

Therefore :

THE COMMISSION RECOMMENDS THE AWARD OF AN ENERGY PROJECT CERTIFICATE TO BRITISH COLUMBIA HYDRO AND POWER AUTHORITY FOR TRANSMISSION OF NATURAL GAS TO VANCOUVER ISLAND.

THE COMMISSION FURTHER RECOMMENDS THAT THE B.C. HYDRO SOUTHERN ROUTE BE EXTENDED BY THE ADDITION OF A RETURN NORTHERN CROSSING IN THE EVENT THAT A FERTILIZER PLANT IS LOCATED AT POWELL RIVER.

- The Commission's comparative analysis in Chapter 5 confirmed that extension of the B.C. Hydro Southern Route by the addition of a northern crossing to service a fertilizer plant at Powell River is less costly than serving the same facility by the Northern Route. The Southern Route is capable of serving the fertilizer plant at any other location in the Gas Service Area.

- The Commission directed its attention to methods of minimizing the cost of the B.C. Hydro proposals in order to arrive at the Commission's determination of the lowest capital contribution required for the project. The Capital Cost Method of the model which was used in comparison of the competing proposals was also used to calculate the minimum Capital Contribution required by B.C. Hydro. This was accomplished by incorporating the adjustments which were made to the B.C. Hydro proposals for comparison (see page 201) and by identification of financing methods which would reduce the cost of service. Additionally, reductions which are discussed fully in Chapter 3 were incorporated into the calculation to effect further cost saving. These reductions include the elimination of standby compressors at Cedar and Merville, reduced depth of pipe burial at the shore approaches to Valdes Island and Flewett, reduced burial across the outer portion of Roberts Bank, allowance for increased productivity of land and marine installation, reduced laybarge mobilization costs and deletion of all On Island system additions which were not required to service the market forecast by the Commission on the basis of the evidence in Phase I. These capital cost reductions were not included in the financial analysis comparison between Westcoast and B.C. Hydro conducted in Chapter 5.

- As part of its analysis of the southern crossing, the Commission evaluated the cost implications of using 406.4 mm O.D. pipe instead of 323.8 mm O.D. pipe for the marine crossings for B.C. Hydro Systems B and D. This would result in the capital cost being increased by an estimated $13 million from $317 million to $330 million. While the Commission believes that twin 323.8 mm O.D. pipe can transmit sufficient gas for both the Vancouver Island market and the proposed fertilizer complex at Powell River, the larger diameter pipe will provide sufficient throughput capacity for any unforeseen growth in market demand, in the Gas Service Area, either during or after the 20 year project evaluation term. Since the majority of the costs are independent of pipe size, the Commission believes that the larger diameter pipe should be installed for the marine crossing. However, the Commission recognizes that the final choice of pipe size should be made by the Provincial Government based on its policies and development plans for industrial expansion on Vancouver Island.

The Commission identifies the capital cost of construction to be :

	Vancouver Island	Vancouver Island (Powell River WITH Fertilizer Plant)
	(1986 $000,000)	
323.8 mm O.D. pipe	317	389
406.4 mm O.D. pipe	330	402

AS DIRECTED BY THE TERMS OF REFERENCE, THE COMMISSION CALCULATES THE REQUIRED CAPITAL CONTRIBUTION SUFFICIENT TO ELIMINATE ANY REVENUE DEFICIENCIES TO BE :

	Vancouver Island	Vancouver Island (Powell River WITH Fertilizer Plant)
	(1986 $000,000)	
323.8 mm O.D. pipe	515	565
406.4 mm O.D. pipe	528	578

TABLE 6.1

VANCOUVER ISLAND NATURAL GAS PIPELINE PROJECT
TOTAL CAPITAL CONTRIBUTION
(1986 $000)

	Island Only B.C. Hydro D		With Fertilizer Plant B.C. Hydro B	
	323.8 mm	406.4 mm	323.8 mm	406.4 mm
COST OF SERVICE				
Depreciation	-	-	-	-
Return	-	-	-	-
Interest	1,876	1,876	2,559	2,559
Interest Coverage	188	188	256	256
Expenses	57,612	57,612	99,524	99,524
Taxes - Income	-	-	-	-
Taxes - Other	74,961	74,961	93,137	93,137
(1) Total Cost of Service	134,637	134,637	195,476	195,476
(2) Deduct: Fertilizer Plant Cost of Service Contribution	-	-	(36,402)	(36,402)
(3) Vancouver Island Cost of Service	134,637	134,637	159,074	159,074
(4) Add: Loss on Vancouver Island Sales	63,137	63,137	70,396	70,396
(5) Vancouver Island Operating Contribution	197,774	197,774	229,470	229,470
(6) Capital Cost	317,142	330,274	389,075	402,351
(7) Deduct: Fertilizer Plant Capital Contribution	-	-	(54,005)	(54,005)
(8) Vancouver Island Capital Contribution [(6)+(7)]	317,142	330,274	335,070	348,346
(9) Total Contribution [(5)+(8)]	514,916	528,048	564,540	577,816
(10) Total Fertilizer Plant Contribution [(2)+(7)]	0	0	(90,407)	(90,407)

- The total Federal capital contribution for both B.C. Hydro Systems B and D, which are identified in Table 6.1 (line 9), is made up of three components : the discounted capital cost of the project (line 6) ; the loss on gas sales (line 4), which is the loss resulting from the purchase of natural gas at a higher price than the price for sales at the city gate on Vancouver Island (see Appendix F) ; and the discounted value of the project cost of service which is largely related to operating expenses and taxes (line 5).

  In the case of the Fertilizer Plant Option, additional components of the total capital contribution are identified as an operating contribution in Table 6.1 (line 2) and a capital contribution (line 7) which total $90 million (line 10). This calculation of the contribution by the fertilizer plant meets the requirements of the Terms of Reference and pricing dictums provided by the Provincial Government.

- According to the schedule of prices provided by the Government for this Hearing, during most of the project evaluation period, the sale price of gas is less than the wholesale price. In traditional utility operations, the cost of gas purchased plus the cost of service (inclusive of depreciation of capital costs) is recovered by the selling price of the gas. All of the Applicants voiced serious concerns with the gas prices at the Pre-Hearing Conference and throughout the Hearing. <u>The Commission recommends that the Provincial Government consider adjusting gas prices to eliminate any loss on sales.</u>

- The Commission's market projection, which is based on the evidence presented at the Hearing, indicates that the heavy industrial market accounts for over 75 - 80% of the total load in the initial years of the 20 year evaluation term, decreasing to between 30 - 40% of the load at the end of the forecast period. <u>The Commission concludes that substantial conversion of the Vancouver Island heavy industrial sector from heavy fuel oil to natural gas will be critical to the success of</u>

the Vancouver Island Natural Gas Pipeline Project. The Commission recommends that the Provincial Government implement policy that will allow a price advantage to natural gas over heavy fuel oil and which will permit industrial users to maintain a competitive position in world markets. At the same time financial assistance such as that currently available under the federal ICAP may be required to offset some of the conversion costs of heavy industrial facilities to natural gas.

o Natural gas must compete against other types of energy in the residential and commercial market on Vancouver Island. B.C. Hydro, the transmitter and distributor of hydro-electric power in the Province, has increased its transmission capability to Vancouver Island with the completion of the Cheekeye-Dunsmuir line. Certification of B.C. Hydro to construct and operate the Vancouver Island Natural Gas Pipeline will put it in the position of having its subordinate gas division competing with the dominant electric division for and within the same market.

  Recognizing that natural gas must compete with electricity in the Vancouver Island market, the Commission recommends that the Province develop policy to ensure that the fledgling Vancouver Island gas industry can compete favourably in the Vancouver Island market so that neither the gas nor electric industry will be disadvantaged.

- The B.C. Hydro Southern Route proposal has reached a final design stage whereas the Northern Route is at a preliminary stage. The Southern Route can be completed in one year whereas the Northern Route requires two years. These two facts indicate that the least cost Southern Route can be taken to tender quickly, constructed, operating, and providing service to Vancouver Island customers before the Northern Route. The Commission concludes that in the present economic climate in the pipeline industry, highly competitive bids can be expected from potential contractors. This could further reduce the Commission's present forecast of the capital costs of the project.

- The Commission concludes that the B.C. Hydro proposal is of high calibre and the design near completion. However, this achievement was unduly expensive and involved many consultants whose expertise was occasionally duplicated. Notwithstanding the extensive work already undertaken by B.C. Hydro, the Commission has identified areas of potential design changes and cost savings. The Commission also acknowledges that B.C. Hydro placed a great deal of emphasis on the design of a viable system that would satisfy the needs and concerns of various environmental and public interest groups. However, there is little indication that a comparable degree of effort was made to reduce costs to a minimum and still meet the many requirements of the project.

- The Commission notes that most of the design costs associated with the project have already been incurred by B.C. Hydro and the actual cost of the project will depend on final design changes and actual tendering results. The Commission recommends that a Project Manager be employed to oversee the cost conscious completion of the project, particularly the marine components.

- In recommending that B.C. Hydro's southern route be certified, the Commission is cognizant of the environmental sensitivity of the Fraser River Estuary and Roberts Bank. On the basis of the evidence at the Hearing and the continued co-operation of B.C. Hydro with the 908 Committee and DFO the Commission is confident that the project can be constructed in a manner that is environmentally acceptable.

- The Public Hearing process provided the Commission with a forum to review and assess the Vancouver Island Natural Gas Pipeline Project as directed by the Terms of Reference. This Report provides a complete consideration of all matters which the Commission was directed to consider. The Commission's recommendations constitute the basis for the successful implementation of natural gas service to Vancouver Island.

BRITISH COLUMBIA

APPENDIX A

861

APPROVED AND ORDERED MAY 26.1983

Lieutenant-Governor

EXECUTIVE COUNCIL CHAMBERS, VICTORIA MAY 26.1983

On the recommendation of the undersigned, the Lieutenant-Governor, by and with the advice and consent of the Executive Council for the purpose of the review of applications for Energy Project Certificates in connection with the supply of natural gas to Vancouver Island in accordance with a reference to be prepared under section 19 (1) (a) of the Utilities Commission Act by the Minister of Energy, Mines and Petroleum Resources with the concurrence of the Minister of Environment, IT IS DIRECTED as the wish of the Crown that the Division of the British Columbia Utilities Commission charged with responsibility for the review consist of the following members of the Commission:

1. Marie Taylor - Chairman;
2. Norris Martin;
3. Daniel H. Hushion;
4. Peter C. M. Freeman

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes and is not part of the Order.)

Authority under which Order is made:

Act and section: Prerogative

Other (specify):

Statutory authority: Elizabeth King

VANCOUVER ISLAND GAS PIPELINE PROJECT

TABLE OF APPENDICES

APPENDIX B

908

APPROVED AND ORDERED 17 MAR 1977

Lieutenant-Governor

EXECUTIVE COUNCIL CHAMBERS, VICTORIA 17 MAR 1977

Pursuant to the ENVIRONMENT AND LAND USE Act, and upon the recommendation of the undersigned, the Lieutenant-Governor, by and with the advice and consent of the Executive Council, orders that

WHEREAS the Fraser River Estuary and adjacent submerged lands including Boundary and Semiahmoo Bays possess natural environmental significance to British Columbians

AND WHEREAS the Province of British Columbia recognizes the significance of the commercial and sports fisheries, wildlife, recreational and aesthetic values associated with this Estuary,

PURSUANT to the recommendation of the Environment and Land Use Committee every proposed development on the foreshores and land covered by water, more particularly shown outlined and hatched in green on the attached map; lying generally outside the dyking system and known generally as Sturgeon and Roberts Banks and Boundary and Semiahmoo Bays, be subject to a mandatory environmental impact assessment prepared by the proponent

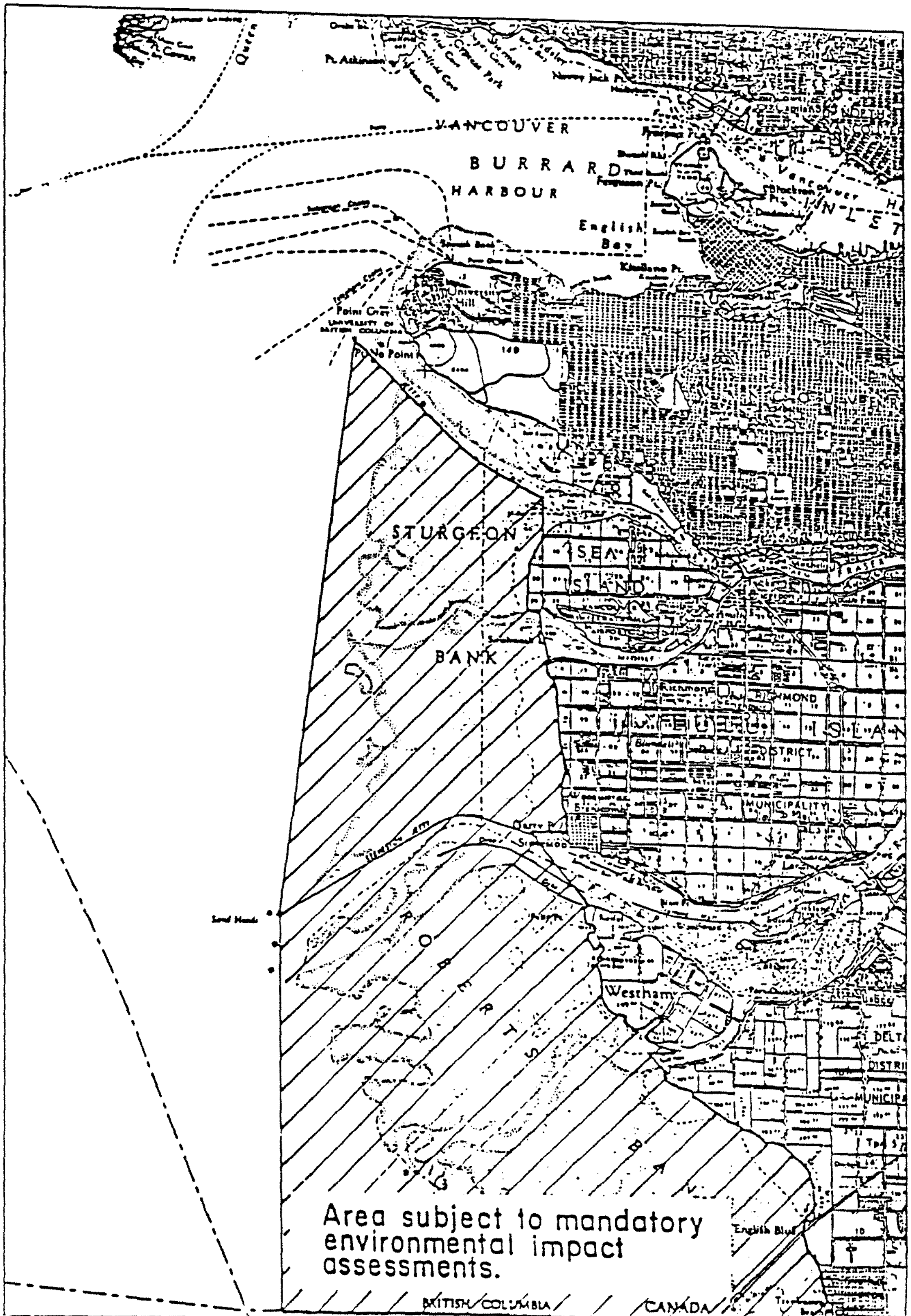
AND THAT no person shall,-

(a) approve a subdivision of land
(b) issue a building permit
(c) issue a lease on Crown Provincial lands
(d) issue a pollution control or sewage disposal permit
(e) approve a land use contract
(f) undertake any new or further construction, alteration, extension or renovation of any building or structure
(g) undertake any dredging or filling of land,

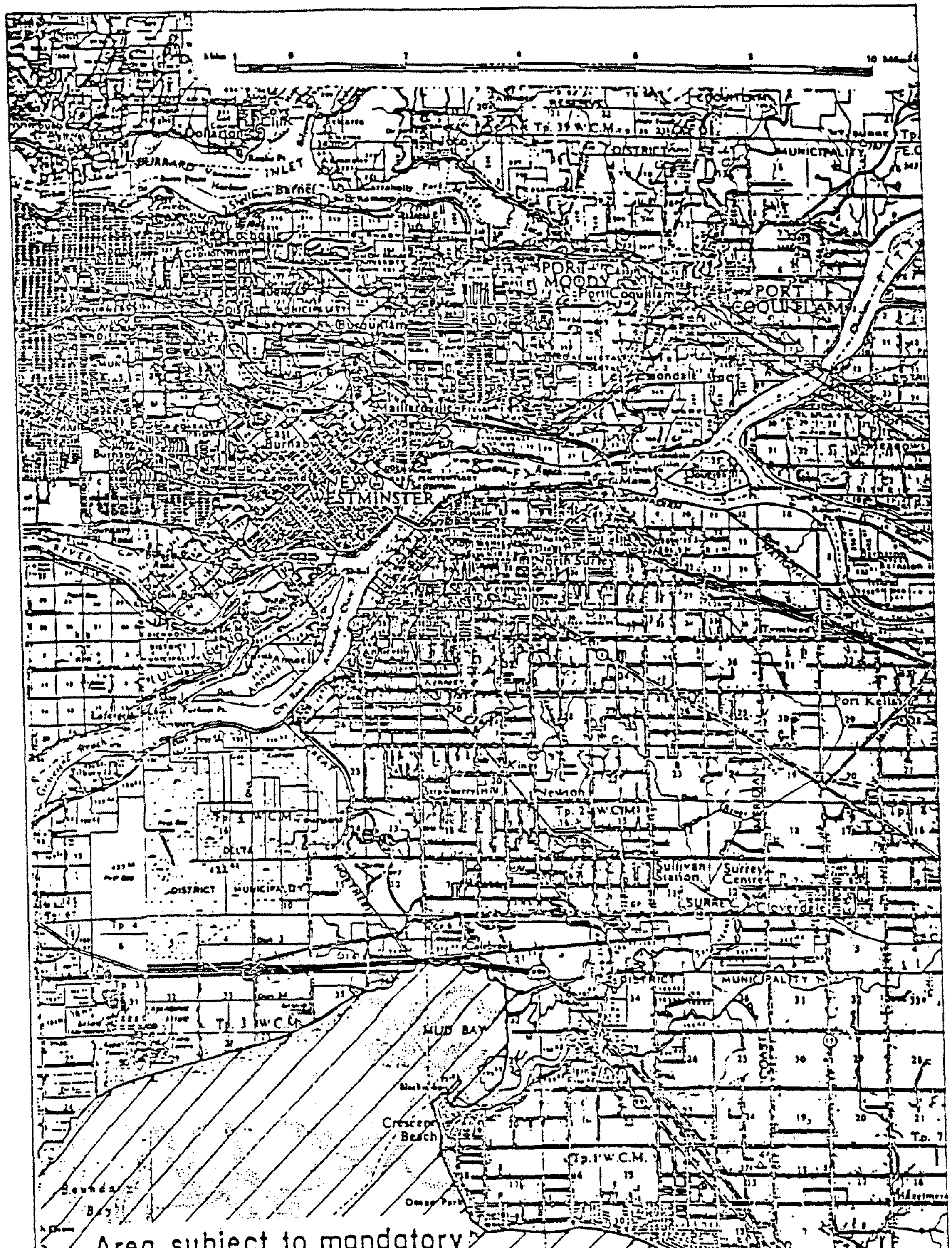
until the environmental impact assessment is reviewed and approved in writing by the Minister of Environment, subject to such terms and conditions as he may prescribe.

Minister of Environment

Presiding Member of the Executive Council



Area subject to mandatory environmental impact assessments.
VANCOUVER
BURRARD
HARBOUR
English Bay
STURGEON
SEA ISLAND
BANK
RICHMOND
DISTRICT
MUNICIPALITY
ROBERTS BANK
Westham
DELTA
DISTRICT
MUNICIPALITY
BRITISH COLUMBIA
CANADA
Point Grey
UNIVERSITY OF BRITISH COLUMBIA
Kitsilano Pt.
Sand Heads
English Bluff


Area subject to mandatory environmental impact assessments.
PORT MOODY
PORT COQUITLAM
NEW WESTMINSTER
BURRARD INLET
MUD BAY
WHITE ROCK
SEMIAHMOO BAY
Crescent Beach
Port Kells
Newton
Sullivan Station
Surrey Centre
Cloverdale
DISTRICT MUNICIPALITY
DELTA

Province of
British Columbia
OFFICE OF THE MINISTER

Ministry of
Energy, Mines and
Petroleum Resources

Parliament Buildings
Victoria
British Columbia
V8V 1X4

APPENDIX C

July 21, 1983.

Mrs. Marie Taylor, Chairman,
British Columbia Utilities Commission,
21st Floor, 1177 West Hastings Street,
Vancouver, British Columbia.
V6E 2L7

Dear Mrs. Taylor:

Pursuant to Section 19(1)(a) of the Utilities Commission Act, the Honourable A.J. Brummet, Minister of Environment, and I have decided that the applications for Energy Project Certificates for the supply of natural gas to and on Vancouver Island shall be referred to the Utilities Commission for review.

In accordance with this decision and pursuant to Section 20 of the Utilities Commission Act, I am pleased to transmit the attached Ministerial Order which specifies the terms of reference for this review. It is to be noted that applications C and E of British Columbia Hydro and Power Authority are based partly on the estimated natural gas requirements for an ammonia/urea fertilizer plant at Duke Point. However, this location is precluded by this government's Northern and Interior siting policy. Accordingly, the terms of reference do not request the Commission's review and assessment of options contained in applications C and E of British Columbia Hydro and Power Authority.

The following material is also enclosed:

1. Application Information Requirements, as prescribed in B.C. Regulation 172/83;

2. Application documents, as per attached list;

.....2

3. Order-in-Council 908/77, Fraser River Estuary Environmental Impact Assessment Guidelines;

4. Natural Gas Supply to Vancouver Island: Technical Report, Ministry of Energy, Mines and Petroleum Resources, April 1983; and

5. File correspondence with the applicants.

Pursuant to earlier discussions on the matter and in order to help expedite the review process, I have arranged for Gordon Davies, Coordinator of Special Projects in this Ministry, to be available as required to provide technical assistance and advice to the panel for the duration of the Commission's review of these applications.

My Cabinet colleagues and I look forward to receiving the Commission's report and recommendations and wish you well in your conduct of this important hearing.

Yours truly,

Stephen Rogers,
Minister of Energy, Mines
and Petroleum Resources.

cc: The Honourable A.J. Brummet,
Minister of Environment.

Attachments.

APPENDIX D

TRANSMISSION OF NATURAL GAS TO AND ON VANCOUVER ISLAND

TERMS OF REFERENCE

IN THE MATTER OF THE UTILITIES COMMISSION ACT
(hereinafter "the Act"),
S.B.C. 1980, c. 60,
and
IN THE MATTER OF APPLICATIONS FOR
ENERGY PROJECT CERTIFICATES BY

British Columbia Hydro and Power Authority;
Centennial Natural Gas Pipeline Limited;
Inland Natural Gas Co. Ltd.;
Vancouver Island Gas Company Limited and
ICG Island Transmission Ltd.; and
Westcoast Transmission Company Limited
(hereinafter "the applicants")

TO CONSTRUCT AND OPERATE PIPELINE FACILITIES
FOR THE TRANSMISSION OF NATURAL GAS TO
VANCOUVER ISLAND AND TO CONSTRUCT AND OPERATE
PIPELINE FACILITIES FOR THE TRANSMISSION OF
NATURAL GAS ON VANCOUVER ISLAND

WHEREAS a technical review by the Ministry of Energy, Mines and Petroleum Resources (Natural Gas Supply to Vancouver Island: Technical Report, April 1983, hereinafter "the Technical Report") demonstrated that the project to transmit natural gas by pipeline to the city gates of communities on Vancouver Island (hereinafter "the project") is justified in terms of its technical feasibility, its cost-effectiveness compared to other energy supply options, and its desirable financial and economic impacts on the people of the province and on the people of the rest of Canada;

AND WHEREAS the Government of British Columbia has determined that the project is justified and in the public interest and has called for applications for the project;

AND WHEREAS the Government of Canada announced in The National Energy Program, 1980 and reaffirmed in subsequent statements its intention to provide financial assistance for the supply of natural gas to and on Vancouver Island, the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the project to therefore be identified in this review;

AND WHEREAS the Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids in May, 1982 included sufficient natural gas volumes for Vancouver Island in total provincial requirements, before estimating the provincial surplus;

AND WHEREAS pursuant to section 18 of the Act applications for Energy Project Certificates for the project were made to the Minister of Energy, Mines and Petroleum Resources;

AND WHEREAS a proposal ancillary to this project for the construction of an ammonia/urea fertilizer facility near the community of Powell River has been advanced by a consortium, which proposal is not part of these applications and is to be subject to separate procedures for certification and contractual arrangements for the supply of natural gas;

AND WHEREAS the granting of franchises for local distribution and the conditions to be attached thereto will be subject to relevant procedures under the Act at a later date;

NOW THEREFORE, under section 19 (1) (a) of the Utilities Commission Act, S.B.C. 1980, I, the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, refer to the British Columbia Utilities Commission ("the Commission") for review by consolidation into one hearing the aforementioned applications.

1 Objectives of Review and Assessment

1(1) The objectives of the review and assessment are to:

(a) Identify the relative merits of the competing applications and to recommend on the applicant or applicants best able to construct and operate the project having regard particularly to: timeliness, safety, reliability, and efficiency in project construction and operation; the minimization of any adverse environmental, resource use, and socio-economic impacts and the maximization of benefits from positive impacts; and, only in regard to those matters within the control of applicants, the minimization of any revenue deficiencies which may be associated with the project, with particular emphasis on the minimization of capital costs and cost of service, in a manner which would not jeopardize the attainment of the foregoing objectives; and

(b) Identify the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the project.

2 General

2(1) The Commission shall consolidate into one hearing all of these applications for Energy Project Certificates.

2(2) To the extent necessary, the Commission shall clearly identify all implications for the project of the proposed ammonia/urea fertilizer facility near the community of Powell River by reviewing and assessing the applications, as appropriate, with the proposed fertilizer facility's natural gas requirements and without any such facility.

2(3) For the purposes of its review and assessment, the Commission shall use the forecasts, to be provided in writing by the Minister of Energy, Mines and Petroleum Resources, of the wholesale price of natural gas at the point of delivery to the project and of the wholesale price of natural gas at the city gates of communities on Vancouver Island. In other matters not to be dealt with specifically in its review and assessment of applications, the Commission may, as appropriate, refer to the Technical Report for the information it requires for the purposes of clarifying provincial government policy and it may, if necessary, request in writing the information it requires from the Minister of Energy, Mines and Petroleum Resources who in turn shall provide the requested information in writing. The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment may, in any event, issue supplementary terms of reference.

3 Design and Operation

3(1) The Commission shall review and assess the design of the proposed pipeline systems to and on Vancouver Island and all ancillary or related facilities that applicants propose to construct, own, or operate as part of the pipeline systems for which applications are made, having regard to timeliness, safety, reliability, and efficiency in project construction and operation. The Commission shall specifically review, assess, and form its own judgement on:

(a) the proposed pipeline system route locations between the Mainland and Vancouver Island and such further route locations as may be required on the Mainland and on Vancouver Island;
(b) the adequacy of proposed pipeline design specifications including flow diagrams, pipeline lengths, wall thicknesses and diameters, operating and design pressures, grades, coatings, and items such as rockshield, swamp weights and details of significant water crossings;
(c) compatibility with existing and potential natural gas transmission and distribution systems;
(d) construction methods, maintenance, and repair procedures particularly in areas of rock work, highway crossings, salt water and river crossings, and other significant right of way crossings and alignments;
(e) the adequacy of system design with respect to minimizing the potential for service interruptions, including avalanche, glacial, seismic, cathodic, or other risks, and any materials, construction techniques and operating procedures which are innovative or not recognized as standard pipeline practice;
(f) the adequacy of system design with respect to minimizing the potential for marine conflicts including vessel traffic, ship anchoring, and submarine transmission cables;
(g) quality control, inspection, and testing procedures for the project;
(h) operating, maintenance, and repair procedures after initial construction of the project;
(i) the schedule of detailed engineering design and other studies, construction schedule and in-service dates and matters which may affect the timing of construction; and
(j) the capability of system design to satisfy variations in the time profile of natural gas load development by advancing or deferring compression, looping, or both.

4 Environmental, Resource Use, and Socio-Economic Impacts

4(1) The Commission shall review and assess key impacts of each applicant's proposal on the physical environment, resources, and land use, as well as significant socio-economic impacts. This review and assessment shall emphasize applicants' proposals for avoiding, managing, or compensating for any adverse impacts during construction and operation and for maximizing benefits from positive impacts.

5 Capital Costs

5(1) The Commission shall review and assess applicants' estimates of capital costs prior to startup and of capital additions during the first twenty years of project operation. The Commission's review and assessment shall include an examination of the costs of the following items:

(a) land and rights of way;
(b) compressor stations;
(c) pipe;
(d) other materials;
(e) installation;
(f) engineering and supervision;
(g) corporate overheads;
(h) contingencies;
(i) allowance for funds used during construction; and
(j) other capitalized costs.

5(2) The Commission shall also review and assess the proposed procedures for monitoring and controlling costs and dealing with construction cost overruns and shall assess applicants' capabilities to complete construction on or below budget.

6 Cost of Service

6(1) The Commission shall review and assess applicants' annual estimates of cost of service and the components thereof, which include the following:

(a) depreciation expense;
(b) interest and return on equity, or interest and interest coverage;
(c) corporate income taxes, if applicable;
(d) operating and maintenance costs, including the cost of transmission fuel and losses; and
(e) other expenses, taxes, or costs added to the cost of service.

6(2) The review and assessment of cost of service shall include an examination of viable means for minimizing the present discounted value of the annual cost of service, such means to include the treatment of corporate income taxes and deferral of depreciation.

6(3) The Commission shall perform a limited review and assessment of margins for local distribution on Vancouver Island.

7 Markets for Natural Gas

7(1) The Commission shall review and assess annual peak day and annual total loads, for the first twenty years of project operation, concentrating on those end uses for natural gas in which there are sufficiently large differences between the forecasts of applicants, intervenors, or the Technical Report to have a significant impact on system design, capital costs, revenues, and cost of service. To the extent that it is necessary to consider retail prices in its review and assessment of loads, the Commission shall determine retail prices by adding local distribution margins to the wholesale price of natural gas at the city gates of communities on Vancouver Island. For this purpose the Commission shall use the forecast of the wholesale price of natural gas at the city gates of communities on Vancouver Island to be provided in writing by the Minister of Energy, Mines and Petroleum Resources.

7(2) The Commission shall also review and assess the impact on load forecasts of any marketing proposals or other similar programs which would maximize market penetration or accelerate the development of load, such as special conversion grants, deferral of development costs, or the predevelopment of local distribution systems.

8 Other Matters

8(1) The Commission shall review and assess the financial capability of each applicant to successfully undertake its proposed project.

8(2) The Commission shall review and assess each applicant's time schedules for detailed engineering design and other studies, ancillary approvals and related studies, construction and in-service dates having regard particularly to the reasonableness of those schedules and their compatibility with each other.

8(3) The Commission Shall review and assess applicants' public information and consultation programs.

9 Recommendations, Report, and Timing

9(1) Based on the assumption that the natural gas requirements of the proposed ammonia/urea fertilizer facility near the community of Powell River, or of any other such facility, are not included in markets for natural gas, the Commission shall recommend to the Lieutenant Governor in Council the applicant(s) to whom Energy Project Certificate(s) should be issued, the route locations for such Certificate(s), and the conditions in the public interest which should be attached thereto. The Commission shall also advise on those changes which it would make in the foregoing recommendations in the event that the natural gas requirements of the proposed ammonia/urea fertilizer facility near the community of Powell River are to be included in markets for natural gas. The Commission shall also recommend on matters to be considered with respect to the issuance of an approval by the Minister of Environment under Order-in-Council 908/77.

9(2) For the purposes of its review and assessment of applications, the Commission shall form its own judgement on, and report on, each of the matters specified in sections 3 to 8 inclusive of these terms of reference and it shall provide reasons for its recommendations on applicant(s), route locations, and conditions in the public interest, having regard particularly to timeliness, safety, reliability, and efficiency in project construction and operation; environmental, resource use, and socio-economic impacts; and the minimization of revenue deficiencies, particularly the minimization of capital costs and cost of service, without jeopardizing the attainment of other objectives.

9(3) The Commission shall identify the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the project only for the pipeline transmission systems recommended by the Commission.

9(4) The Commission shall submit its report and recommendations with reasons to the Lieutenant Governor in Council by December 31, 1983, or as soon thereafter as may be practical. The Commission shall also submit a statement to the Lieutenant Governor in Council on the progress of its review and assessment on or before October 31, 1983. In the event that there are impediments to expeditious review of the project, the Commission shall advise the Minister of Energy, Mines and Petroleum Resources by letter and indicate where government may assist in expediting the review process.

All applications, the Technical Report, and Order-in-Council 908/77 are transmitted to the Commission with this reference.

Dated this 21st day of July, 1983.

Stephen Rogers,
Minister of Energy, Mines
and Petroleum Resources

Anthony J. Brummet,
Minister of Environment

TRANSMISSION OF NATURAL GAS TO AND ON VANCOUVER ISLAND

AMENDMENT TO TERMS OF REFERENCE

IN THE MATTER OF THE UTILITIES COMMISSION ACT
S.B.C. 1980, c. 60,
and
IN THE MATTER OF APPLICATIONS FOR ENERGY PROJECT CERTIFICATES TO CONSTRUCT AND OPERATE PIPELINE FACILITIES FOR THE TRANSMISSION OF NATURAL GAS TO VANCOUVER ISLAND AND TO CONSTRUCT AND OPERATE PIPELINE FACILITIES FOR THE TRANSMISSION OF NATURAL GAS ON VANCOUVER ISLAND

WHEREAS the Minister of Energy, Mines and Petroleum Resources and the Minister of Environment on July 21, 1983 referred to the British Columbia Utilities Commission ("the Commission") for review by consolidation into one hearing applications to transmit natural gas to and on Vancouver Island together with the Terms of Reference for the Commission's review and assessment;

AND WHEREAS the Terms of Reference invited the Commission to advise the Minister of Energy, Mines and Petroleum Resources by letter where government may assist in expediting the review process;

AND WHEREAS the Commission has proposed to the Minister of Energy, Mines and Petroleum Resources by letter dated March 8, 1984 that at the conclusion of Phase II of the hearing ("To Island Transmission") the Commission present a report to the Lieutenant Governor in Council on the recommended applicant for transmission of natural gas to Vancouver Island and on the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the transmission of natural gas to and on Vancouver Island;

AND WHEREAS submission of a report at the conclusion of Phase II of the hearing will expedite implementation of the project;

NOW THEREFORE, under section 19(1)(a) of the Utilities Commission Act, S.B.C. 1980, I, the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, authorize the Commission to adjourn generally the hearing at the end of Phase II and direct the Commission to submit thereafter a report to the Lieutenant Governor in Council, pursuant to sections 9(1), 9(2), and 9(3) of the Terms of Reference dated July 21, 1983, on the recommended applicant(s) for transmission to Vancouver Island. The Commission is further directed to estimate the size of the federal capital contribution sufficient to eliminate any revenue deficiencies which may be associated with the transmission of natural gas to and on Vancouver Island.

Dated this 11th day of April, 1984.

Stephen Rogers,
Minister of Energy, Mines
and Petroleum Resources.

Anthony J. Brummet,
Minister of Environment.

APPENDIX F

Province of British Columbia
OFFICE OF THE MINISTER

Ministry of
Energy, Mines and
Petroleum Resources

Parliament Buildings
Victoria
British Columbia
V8V 1X4

September 1, 1983.

Mrs. Marie Taylor,
Chairman,
British Columbia Utilities Commission,
Twenty-first Floor,
1177 West Hastings Street,
Vancouver, British Columbia.
V6E 2L7

Marie
Dear Mrs. Taylor:

Regarding item 2(3) of the Terms of Reference for public hearings on applications to transmit natural gas by pipeline to and on Vancouver Island, I am enclosing herewith forecasts of the city gate and wholesale prices to be used in the Commission's review and assessment.

In the attached table, 'city gate price' refers to the price received by the project at the low pressure side of the city gate valves serving communities on Vancouver Island and at Powell River. 'Wholesale price' refers to the price paid by the project for natural gas, at the point at which gas is delivered to the project from the existing pipeline system on the Mainland.

The city gate price is calculated as 65 percent of the domestic price of crude oil at the refinery gate in Vancouver. The wholesale prices at the respective dropoff points are based on an average wholesale price in the Province which is phased up linearly to 65 percent of the domestic price of crude oil by 1990. The differences between the wholesale prices at the dropoff points reflect a distance and peak day related allocation of the cost of service on the existing Westcoast Transmission Company Limited system.

It is to be noted that some of the costs of either the northern or southern route with capability to serve a fertilizer plant at Powell River will be attributable to the capital and operating requirements of the system which is designed to serve that load. The Commission is

...2

advised to apportion the cost of service of that pipeline system between the fertilizer plant and Vancouver Island loads according to the proportion that the peak day volume times distance for each load is of the sum of the peak day volume times distance for the two loads.

It may also be noted that, to account for all costs on the Southern route, a wheeling charge on the existing natural gas transmission and distribution system of British Columbia Hydro and Power Authority should be added to the wholesale price at Huntingdon.

I extend again my best wishes for a thorough and timely review of the applications.

Yours sincerely,

Stephen Rogers,
Minister of Energy, Mines
and Petroleum Resources.

Enclosure.

Year	City Gate Price	Wholesale Price For Vancouver Island Volumes* At Huntingdon	At Williams Lake w/o Fertilizer Plant	At Williams Lake with Fertilizer Plant
1985	4.03	3.25	3.09	3.10
1986	4.29	3.62	3.41	3.37
1987	4.50	4.08	3.85	3.78
1988	4.72	4.52	4.28	4.19
1989	5.05	5.13	4.87	4.76
1990	5.65	6.10	5.78	5.63
1991	6.27	6.82	6.51	6.35
1992	6.73	7.34	7.01	6.82
1993	7.13	7.77	7.43	7.22
1994	7.55	8.21	7.87	7.65
1995	7.98	8.66	8.31	8.09
1996	8.43	9.14	8.78	8.55
1997	8.88	9.58	9.24	9.00
1998	9.34	10.09	9.76	9.47
1999	9.80	10.67	10.24	9.95
2000	10.28	11.23	10.76	10.43
2001	10.85	11.81	11.33	11.01
2002	11.44	12.43	11.94	11.61
2003	12.07	13.08	12.57	12.23
2004	12.74	13.76	13.26	12.91
2005	13.44	14.47	13.96	13.61

*Prices are in current dollars per thousand cubic feet of natural gas.

Province of
British Columbia
OFFICE OF THE MINISTER

Ministry of
Energy, Mines and
Petroleum Resources

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British Columbia
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F-4

October 17, 1983.

M.O. 0591

BRITISH COLUMBIA UTILITIES COMMISSION
OCT 19 1983

Mrs. Marie Taylor,
Chairman,
British Columbia Utilities Commission,
Twenty-first Floor,
1177 West Hastings Street,
Vancouver, British Columbia.
V6E 2L7

Dear Mrs. Taylor:

In response to your letter of September 23, 1983 on prices to be used in the Commission's review of applications to transmit natural gas to and on Vancouver Island, I confirm that the Commission should use in its analysis the wholesale prices provided by the Ministry, as well as those provided by the applicants.

The manner in which the two wholesale prices are to be used is as follows:

i) Applicants will first calculate the most that they would be able to pay for gas at the wholesale level without having to incur revenue deficiencies (or experience surpluses). This amount will equal the city gate price, less the full or unsubsidized unit cost of service for delivering natural gas from the dropoff point to the city gates.

ii) The Commission will then calculate revenue deficiencies as the difference between the most that companies could pay for gas and just break even from item (i) above, and the wholesale price at the dropoff points provided earlier by this Ministry, times the relevant volumes of natural gas transmitted.

For a pipeline system with capability to serve a fertilizer plant at Powell River, the above method should be applied using the cost of service to serve Vancouver Island loads, after the cost of service for the fertilizer plant load has been apportioned to that use, in the manner described in my letter to you dated September 1, 1983.

Also, as Item 9(3) of the Terms of Reference makes clear, the revenue deficiencies should be calculated (in the above manner), "only for the pipeline transmission systems recommended by the Commission".

I trust that the foregoing clarifies the concerns raised in your letter.

Yours truly,

Stephen Rogers

Stephen Rogers,
Minister of Energy, Mines,
and Petroleum Resources.

Province of
British Columbia
OFFICE OF THE MINISTER

Ministry of
Energy, Mines and
Petroleum Resources

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British Columbia
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October 17, 1983.

OCT 19 1983

Mrs. Marie Taylor,
Chairman,
British Columbia Utilities
Commission,
21st Floor,
1177 West Hastings Street,
Vancouver, British Columbia.
V6E 2L7

Dear Mrs. Taylor:

To complete the specification of prices to be used in the Commission's review and assessment of applications to transmit natural gas to and on Vancouver Island, I enclose herewith a forecast of the wholesale price for Vancouver Island natural gas volumes delivered at Huntingdon for the case which includes the load of a fertilizer plant at Powell River. This price series is to be used in the same manner as the other wholesale prices provided to the Commission in a letter dated September 1, 1983. The manner in which these prices are to be used was more fully described in my letter to you dated October 17, 1983.

Yours truly,

Stephen Rogers,
Minister of Energy, Mines,
and Petroleum Resources.

Enclosure.

WHOLESALE PRICE FOR VANCOUVER ISLAND VOLUMES
DELIVERED AT HUNTINGDON, WITH FERTILIZER PLANT

YEAR	PRICE ($/Mcf)
1985	3.25
1986	3.44
1987	3.85
1988	4.27
1989	4.83
1990	5.71
1991	6.43
1992	6.90
1993	7.31
1994	7.73
1995	8.17
1996	8.64
1997	9.08
1998	9.56
1999	10.06
2000	10.55
2001	11.14
2002	11.75
2003	12.39
2004	13.08
2005	13.78

Energy Resources Division
1983/09/30

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-66-83

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

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

and

IN THE MATTER OF Applications for an Energy Project Certificate to construct and operate a Natural Gas Transmission Line to Vancouver Island and to construct and operate Pipeline Facilities for the Transmission of Natural Gas on Vancouver Island

BEFORE:	M. Taylor, Chairman; P.C.M. Freeman, Commissioner; D.H. Hushion, Commissioner; and N. Martin, Commissioner	September 1, 1983

O R D E R

WHEREAS pursuant to Section 18 of the Utilities Commission Act, S.B.C. 1980, c. 60, as amended ("the Act"), Applications for Energy Project Certificates were made to the Minister of Energy, Mines and Petroleum Resources to construct and operate pipeline facilities for the transmission of natural gas to, and on, Vancouver Island; and

WHEREAS pursuant to Section 19(1)(a) of the Act the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment referred the Applications to the Commission for review by consolidation into one hearing within prescribed Terms of Reference dated July 21, 1983; and

.../2

WHEREAS the Commission published a Notice of Public Hearing in the July 30, 1983 issue of the Vancouver Sun and the Victoria Times-Colonist and the July 31, 1983 issue of the Vancouver Province, and on Friday, August 19, 1983, convened a Pre-hearing Conference to discuss matters related to the conduct of the public hearing; and

WHEREAS the Commission has considered matters arising from the Pre-hearing Conference.

NOW THEREFORE the Commission hereby orders as follows:

1. The hearing will commence on Tuesday, September 27, 1983 in the Hearing Room of the B.C. Utilities Commission. Daily hearing hours will normally be from 9:30 a.m. to 12:00 p.m. (noon) and from 1:30 p.m. to 4:30 p.m. Tuesday through Friday of each week.

2. The hearing will be segmented into the three phases as follows, to be concluded by Final Oral Argument.

<u>Phase 1</u> - MARKETS

- Submissions
- Oral argument

<u>Phase 2</u> - TO ISLAND TRANSMISSION

- Design and Construction of Facilities
- Environment and Socio-Economic Impact
- Finance
- Policy
- Oral argument

<u>Phase 3</u> - ON ISLAND TRANSMISSION

- Design and Construction of Facilities
- Environment and Socio-Economic
- Finance
- Policy
- Oral argument

FINAL ORAL ARGUMENT

3. The Commission will convene the hearing for the purpose of hearing matters of local concern as follows:

Victoria	- October 18 to October 21 inclusive
Nanaimo	- October 25 to October 28 inclusive
Powell River	- November 1 to November 4 inclusive
Comox/Courtenay	- November 8 to November 9 inclusive

4. Written testimony for Phase 1 of the hearing is required to be delivered to the Commission Secretary not later than September 19, 1983. Written testimony for Phase 2 and Phase 3 is required by September 26, 1983.

5. The Commission costs related to the conduct of this hearing will be shared between the Applicants based on participation in each phase in a manner to be determined by the Commission.

6. The costs that each Applicant incurs in preparing and defending its Application will be borne by the respective Applicant.

7. The costs that each Intervenor incurs related to this hearing will be borne by the respective Intervenor.

8. Information requests by Applicants or Intervenors will be sent directly to the party concerned with copies to the Commission Secretary and all other Applicants and Intervenors. Within seven days of such information request replies thereto are to be provided directly to the originator of the information request, with copies sent to the Commission Secretary and all other Applicants and Intervenors.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of September, 1983.

BY ORDER

M. Taylor

Chairman

CA002020. APPENDIX H

Court of Appeal

BETWEEN: ALKALI LAKE INDIAN BAND APPELLANT AND: WESTCOAST TRANSMISSION COMPANY LIMITED; BRITISH COLUMBIA HYDRO & POWER AUTHORITY; ICG ISLAND TRANSMISSION LTD.; INLAND NATURAL GAS COMPANY LTD.; AND BRITISH COLUMBIA UTILITIES COMMISSION RESPONDENTS	REASONS FOR JUDGMENT OF THE HONOURABLE MR. JUSTICE HUTCHEON

Before: The Honourable Chief Justice Nemetz
The Honourable Mr. Justice Hutcheon
The Honourable Mr. Justice Macfarlane

VANCOUVER
APR 27 1984
COURT OF APPEAL
REGISTRY

Counsel for the Appellant:	Arthur Pape, Esq. Richard Salter, Esq.
Counsel for the Respondent B. C. Utilities Commission:	J. J. Camp, Esq.
Counsel for the Respondent ICG Island Transmission Ltd:	R. B. Wallace, Esq.
Counsel for the Respondent Westcoast Transmission Co. Ltd:	S. B. Armstrong, Esq.
Counsel for the Respondent Inland Natural Gas Company Ltd.:	C. B. Johnson, Esq.
Counsel for the Attorney General for British Columbia:	H. R. Eddy, Esq.

Date heard: March 30, 1984.

Vancouver, British Columbia,
April 27, 1984.

The British Columbia Utilities Commission is presently conducting a public hearing under Section 20 of the Utilities Commission Act, S.B.C. 1980, c.60, to review, among other things, two competing applications for a certificate to construct and operate a natural gas transmission to Vancouver Island.

> 20. (1) Where an application for an energy project certificate is referred to the commission for a review, the commission shall, subject to subsection (3), hear the application in public hearing in accordance with terms of reference specified jointly by the Minister of Energy, Mines and Petroleum Resources and the Minister of Environment, and on conclusion of the hearing shall submit a report and recommendations to the Lieutenant Governor in Council.

One of the powers of the Commission is to grant costs related to the proceedings:

> 133. (1) The costs incidental to a proceeding before the commission, including the costs of the commission, are in the discretion of the commission, and it may order by whom and to whom and in what amount the costs are to be paid.
>
> (2) In this section "costs of the commission" includes costs incurred by the commission for the services of consultants and experts engaged in connection with the proceeding.

The Commission refused to give costs to the Alkali Lake Indian Band, one of the intervenors in the public hearing. An appeal lies to the Court of Appeal from a decision of the Commission with leave (s.115). Mr. Justice Aikins granted leave on 14 March 1984.

Shortly put, the submission on behalf of the Band was that the Commission did not exercise its discretion under s.133 but merely complied with a direction in a letter from the Minister of Energy, Mines and Resources.

That letter is dated August 10, 1983 and reads as follows:

August 10, 1983.

Mrs. Marie Taylor,
Chairman,
B.C. Utilities Commission,
21st Floor, 1177 W. Hastings Street,
Vancouver, British Columbia.
V6E 2L7.

Dear Mrs. Taylor:

RE: Intervenor Funding at B.C.U.C. Hearings

Further to our discussions at the time of the Provincial Budget, I am writing to advise you that in line with government's overall policies of economy and restraint, Cabinet decided that it wished the Commission to discontinue cost awards to participants at its hearings.

It is therefore proposed that the Utilities Commission Act be amended during this sitting of the Legislature. This amendment will allow an Order-in-Council under Section 3 of the Act to be prepared, giving the Commission formal and public direction in this regard.

It is, however, the government's wish that the Commission will continue on its course of "cost recovery" for hearings and that it will recover the costs of the Commission from applicants where in its discretion it feels this is appropriate.

I would like to discuss with you the best means of implementing Cabinet's decision and ensuring that interested parties are able to make valid representations to hearings without additional expenses being borne by the Province's utilities

> and their customers. I am anxious to assist in any way possible, and would suggest that we meet in the near future.
>
> Yours truly,
>
> (signed)
>
> Stephen Rogers,
> Minister of Energy, Mines
> and Petroleum Resources.

At a pre-hearing conference on 19 August 1983 copies of this letter were given to all of the parties in attendance including counsel for the Band. The Commission made the first of its decisions in an order (Order No. G-66-83) dated the 2nd day of September, 1983. The order gave certain directions about the schedule of the public hearings, and then there appear these three decisions:

> 6. The costs that each Applicant incurs in preparing and defending its Application will be borne by the respective Applicant.
>
> 7. The costs that each Intervenor incurs related to this hearing will be borne by the respective Intervenor.
>
> 8. Information requests by Applicants or Intervenors will be sent directly to the party concerned with copies to the Commission Secretary and all other Applicants and Intervenors. Within seven days of such information request replies thereto are to be provided directly to the originator of the information request, with copies sent to the Commission Secretary and all other Applicants and Intervenors.

A copy of the order was sent to all applicants and intervenors with a letter dated September 2, 1983, signed by the Commission Secretary. The last paragraph of that letter reads:

> On the matter of Intervenor costs, the Commission has considered these costs bearing in mind the provisions of the Utilities Commission Act and the Cabinet policy direction outlined in the August 10, 1983 letter from the Minister of Energy, Mines and Petroleum Resources. Based on this information, the Commission has determined that provision for costs incurred by Intervenors will be the responsibility of those Intervenors.

The particular interest of the Band in the proceedings before the Commissioner arises from the proposal of one of the applicants, Westcoast Transmission Company Limited, to put a pipeline through areas in which, among other things, the Band members hunt and fish. As part of its public hearings, the Commission held a community hearing at Alkali Lake Reserve on 9 and 10 November 1983. By letter December 8, 1983, counsel for the Commission requested that a map be prepared for the Commission. This is the letter:

December 8, 1983

Mr. Richard Salter
Pape & Salter
Barristers & Solicitors
300 - 12 Water Street
Vancouver, B.C.
V6B 1A5

Dear Mr. Salter:

Re: Vancouver Island Gas
Pipeline Hearing

I have reviewed the transcripts of the proceedings at Alkali Lake on November 9 and 10, 1983. There are some specific concerns which ought to be addressed formally by the Alkali Lake Indian Band when they give evidence.

It will be of particular interest and assistance if a large map can be produced outlining or highlighting the following matters:

(a) traditional hunting areas with particular game sensitive areas noted;

(b) migration routes of game, if known;

(c) specific delineation of fishing grounds;

(d) specific delineating of sensitive plant and planting areas;

(e) delineation of location of herbs and other plants needed for Indian medicines;

(f) specific delineation of sacred burial grounds or other archaeological sensitive areas;

(g) delineation of cattle grazing lands showing leased and deeded acreage.

It would be appreciated if such a map can be provided in advance of the testimony.

Yours truly,

(signed)

J. J. Camp,
Commission Counsel

JJC:ac

The Band sought financial assistance from the Department of Indian Affairs and when this was refused, on 31 January 1984, made a formal motion to the Commission to reconsider and vary paragraph 7 of Order G-66-83. That motion was heard by the Commission on 7 February, and, on 10 February, the Chairman said this:

> THE CHAIRMAN: Thank you. Mr. McQueen, before you continue with your cross, the Commission would like to deal with one subject, and that is the motion that was put to the Commission earlier this week.
>
> The Alkali Lake Indian Band, a registered intervenor in the proceedings, made application pursuant to Section 114(1) of the Utilities Commission Act requesting that the Commission reconsider, vary, or rescind Paragraph 7 of its Order G-66-83, which ruled that intervenor costs would not be awarded in this proceeding.
>
> The Band also seeks an order pursuant to Section 133 of the Act, awarding intervenor costs to the Band, the amount of which would be determined at the conclusion of the proceeding, and on the basis of the quality and contribution to the proceeding of the Band's intervention.
>
> Counsel for the Band argued that there ought to be a reconsideration on the question of intervenor costs on the basis that the Commission did not exercise an unfettered discretion prior to making its intervenor cost ruling, as contained in Paragraph 7 of Order G-66-83.
>
> It is not necessary for the Commission to determine if it exercised an unfettered discretion on giving its prior ruling on intervenor costs. We have reconsidered the Band's application for costs pursuant to Section 133. We have heard and considered the arguments of counsel for the Band, several intervenors and counsel for the applicants.

> We have benefitted from the Band's participation, and urge its member[s] and counsel to press the Band's concerns.
>
> However, having listened and considered all arguments, we have decided that intervenor costs will not be awarded to the Band, and rule accordingly.

On the substance of the appeal, Westcoast Transmission took no position. The Commission appeared by its counsel, Mr. Camp, but his only role was to provide assistance with background information when that became necessary. Mr. Eddy for the Attorney General, Mr. Johnson for Inland Natural Gas Company Ltd. and Mr. Wallace for ICG Island Transmission Ltd. made submissions in support of the decision.

In the course of those submissions, the proposition was advanced that the decision of the Commission in Order G-66-83 (the September order) was made by the Commission in the exercise of an unfettered discretion. In my view, that proposition is not tenable. The Commission had quite clearly applied "the Cabinet policy direction outlined in the August 10, 1983 letter from the Minister of Energy, Mines and Petroleum Resources". The quotation is taken from the letter of August 2, 1983. In applying that policy direction, the Commission had not exercised the discretion conferred by the legislation in section 133. Whether the Minister intended to give direction to the Commission may be in question, but it is perfectly clear that the Commission acted as it did because of the letter.

It is said that what is under appeal is the February order, and, that whatever flaw in the process there may have been earlier in the making of the September order, there is no evidence to support the view that the Commission failed to exercise its discretion in February. It seems to me, however, that if the Commission decided to make the same order in February, an explanation of the basis of that order was essential.

The failure to give reasons is not an error of law in the absence of some statutory requirement: *MacDonald v. The Queen* [1977] 2 S.C.R. 665. When the circumstances demand reasons, a tribunal that fails to state them must be prepared to accept adverse inferences: *Re Ross and Board of Commissioners of Police for the City of Toronto* (1953) O.R. 556.

The adverse inference that the Commission acted in response to the Minister's direction, and not in the exercise of an unfettered discretion, arises in this case because there is no clear reason to be found in the record for refusing the order for costs. The best way to escape this inference was by reasons that demonstrated the exercise by the Commission of the discretion given to it by the Legislature.

In the absence of reasons, and with a record that reveals no other ground for refusing costs than adherence to its view of the "policy direction" in the letter of August 10, 1983, the order cannot stand. I turn then to the remedy.

All of the respondents urged that, if the appeal were allowed, the matter should be sent back to the Commission for reconsideration. Section 9(1)(a) of the Court of Appeal Act gives this Court the power to make any order that could have been made by the Court or tribunal appealed from.

I have noted that there is no clear reason to be found in the record for refusing the order for costs. In favour of such an order are a number of considerations: substantial interests of the Band stand to be affected by the matters considered in the public hearings; the recognition by the chairman that the Commission had benefited from the Band's participation indicated that the intervention was of value; the Band will not be able to participate in the public hearings without financial assistance; the Band has made reasonable efforts to secure funding from another source.

With these considerations in mind, I think that the proper disposition is to allow the appeal and make an order that the Alkali Lake Indian Band is an intervenor entitled to costs under section 133(1) of the Utilities Commission Act; the scale or tariff of the costs, the particular items for which costs are to be allowed, by whom, and when the costs are to be paid are all matters for the Commission to decide.

The Band seeks an order that it have its costs of this appeal on a solicitor and client basis. By section 118(2) of the Utilities Commission Act the Commission is not liable for costs of an appeal. There is no reason that the other respondents should be liable for costs except on the ordinary scale.

For these reasons, I would allow the appeal.

J.A.

I agree:

Alan Macfarlane J.A.

The Honourable Mr. Justice Macfarlane

I agree:

C.J.B.C.

The Honourable Chief Justice Nemetz

APPENDIX I

LIST OF APPEARANCES

INDIVIDUALS/ORGANIZATIONS	APPEARANCE
Mr. B. Alder	Self
Alkali Lake Indian Band	Mr. R. Salter
Mr. P. Alvano	Self
Associated Chambers of Commerce of Vancouver Island	Did Not Appear
The Association of Professional Engineers of the Province of British Columbia	Did Not Appear
Mr. G.L. Bell	Did Not Appear
B.C. Bingham Coastal Consultants	Did Not Appear
B.C. Chamber of Commerce	Mr. M.A. Thomas
B.C. Hydro and Power Authority	Mr. W.D. Mitchell; Mr. W.H. McQueen and Mr. M. Shoemaker
B.C. Ministry of Environment	Mr. H. Eddy
B.C. Petroleum Corporation	Mr. J.M. Pelrine
B.C. Utilities Commission	Mr. J.J. Camp and Mr. S.J. Mulhall
Mr. Frank H. Cameron	Self
Canadian Petroleum Association	Mr. H.R. Ward
Candol Developments Limited	Mr. J.S. Burns
Canterra Energy Ltd.	Did Not Appear
Capital Regional District	Mr. J.G. Masterton and Mr. F.G. Kasper
Centennial Natural Gas Pipeline Limited	Mr. C.D. Bailey
Chevron Canada Limited	Did Not Appear
City of Nanaimo - Nanaimo Southern Gas Route Committee	Mr. E.D. Strongitharm
City of Williams Lake	Mayor T.E. Mason
Coalition to Protect the Southern Chilcotin Mountains	Mr. D.S. Perry
Cominco Ltd.	Did Not Appear
Corporation of Delta	Mayor E. Burnett
Corporation of the District of Powell River	Mr. D. Lidstone
Council of Forest Industries of British Columbia	Mr. K.E. Gustafson
C.R.B. Logging Ltd.	Mr. N.R. Barr and Mr. B.C. Carson
District of Kitimat	Mr. L. Ellis
District of Powell River	Mr. D. Lidstone
Economic Development Commission - Cariboo Regional District	Ms. M.E. Glover
Economic Development Commission - Sunshine Coast Regional District	Mr. A. Wagner
Federal Department of Fisheries and Oceans	Mr. R. Bell-Irving
Federation of Mountain Clubs of British Columbia	Mr. S.P. Fuller
Great Western Petroleum Corporation	Mr. N.C. Carter
Greater Nanaimo Chamber of Commerce	Mr. L.C. Aldcroft and Mr. H.R. Moffatt

LIST OF APPEARANCES
(cont'd)

INDIVIDUALS/ORGANIZATIONS	APPEARANCE
Greater Vancouver Regional District	Mr. G.F. Farry
Greater Victoria Chamber of Commerce	Mr. I.E. Cairns and Mr. G.J. Edwards
Greater Victoria Water District	Mr. K.N. Pleasance and Mr. D.F. Homer-Dixon
Green Party of British Columbia	Mr. A.J. Timberlake
ICG Island Transmission Ltd.	Mr. R.B. Wallace
Independent Petroleum Association of Canada	Mr. S.J. Haberl
Inland Natural Gas Co. Ltd.	Mr. C.B. Johnson and Mr. P.D. Lloyd
Islands Trust	Mr. J. Rich
Brotherhood of Electrical Workers - Local 213	Mr. N. Czernick
Laurel Explorations Ltd.	Mr. E.D. Weber
Mrs. Denise Lawson	Self
Lillooet Tribal Council	See Mount Currie Session
Mr. E.L. Marzocco	Self
Melville Shipping Ltd.	Did Not Appear
Nanaimo Duncan and District Labour Council	Mr. W. Tickson
Nitrogen Fertilizer Project Consortium	Mr. C.W. Sanderson
Outdoor Recreation Council of British Columbia	Ms. A. Buffinga
Pacific Coast Energy Corporation	Did Not Appear
Pacific Northern Gas Ltd.	Mr. C.P. Donohue
Parksville and District Chamber of Commerce	Mr. T. Tryon
Petro-Canada	Mr. M.E. Scott
Pipeline Information Access Committee of Powell River	Mr. M.G. Conway-Brown
Port Alberni	Mayor P. Reitsma
Powell River Chamber of Commerce	Mr. R.N. Moss
Powell River District Labor Council, C.L.C.	Mr. C. Merrick
Powell River District Teachers'Association	Mr. A.S. Hannon
Powell River Economic Development Commission	Mr. C. Palmer
Powell River Regional District	Mr. L. Emmonds and Mr. G. Calvert
Regional District of Comox-Strathcona - Promotion of Island Pipeline Employment Committee	Mr. S.A. Harasymchuk
Mrs. Elizabeth Rennie	Self
Mr. S.G. Riley	Did Not Appear
Mr. Martin Rossander	Self
Social Justice Commission - Roman Catholic Diocese of Victoria	Mr. R.J. Gathercole

LIST OF APPEARANCES
(cont'd)

INDIVIDUALS/ORGANIZATIONS	APPEARANCE
Society Promoting Environmental Conservation - Vancouver Island	Mr. R.J. Gathercole
Spruce Lake Integrated Resource Management Plan Group	Ms. S. Anderson Ms. S.L. Garrard
Squamish Mills Ltd.	Mr. J.W. Drenka
Squamish-Lillooet Regional District	Did Not Appear
Toosey Indian Band	Chief R. Hance
Union of B.C. Indian Chiefs	Did Not Appear
United Association of Journeymen and Apprentices of the Plumbing and Pipefitting - Industry of United States and Canada Local Union 170	Did Not Appear
Vancouver Island Gas Company Ltd.	Mr. R.B. Wallace
Weldwood of Canada Limited	Did Not Appear
Westcoast Transmission Company Limited	Mr. R.J. Gibbs; Mr. C.W. Sanderson; Mr. S.B. Armstrong and Mr. G.C.W. Weatherall
Western Canada Wilderness Committee	Did Not Appear
Mrs. Kathryn Wilcocks	Self

Alkali Lake, B.C. - November 9 & 10, 1983

Chief Arthur Dick
Ms. S. Harry (Interpreter)
Mr. W. Dick
Ms. L. Robbins
Mr. A. Chelsea
Mr. A. Wycotte
Ms. M. Gilbert
Mr. D. Johnson
Mr. P. Billoux
Mr. M. Balinger
Ms. D. Johnny
Mr. C. Harry
Mr. D. Mervyn
Ms. J. Johnson
Ms. P. Chelsea
Mr. L. Grief
Ms. Johnson (Interpreter)
Mr. F. Johnson
Ms. L. Harry
Ms. G. Squinahan
Mr. E. Harry
Mr. J. Johnson
Mr. J. Johnson
Mr. E. Dick
Chief Evelyn Sargent
Ms. C. Robbins
Mr. I. Johnson
Ms. S. Harry
Ms. S. Harry
Mr. J. McCandless
Ms. L. Johnson
Ms. C. Johnson

LIST OF APPEARANCES
(cont'd)

INDIVIDUALS/ORGANIZATIONS	APPEARANCE
Mount Currie, B.C. - April 16, 1984	
Chief Leonard Andrew (Mount Currie Band)	Chief Perry Redan (Cayoosh Band)
Mr. J. Louie	Mr. J. Williams
Mr. R. Dan	Mr. M. Sam
Mr. B. Richie	Mr. J. McCandless
Chief S. Terry (Bridge River Band)	Mr. C. Sam
Mr. A. Nelson	Ms. R. Joseph
Mr. N. Gabriel	

APPENDIX J

WITNESS BY PHASE AND ORDER OF APPEARANCE

CALLED BY	PANEL MEMBER	COUNSEL
Phase 1		
Pg. 128		
MARKETING		
B.C. HYDRO	M.A. FAVELL J. CAWDERY E.C. SIEVWRIGHT D.W. McGILL C.C. PURVES T.J. NEWTON	M. SHOEMAKER
Page 512		
B.C. HYDRO	M.A. FAVELL G.A. CONSTABLE W.G. BIERLMEIER C.C. PURVES E.C. SIEVWRIGHT	M. SHOEMAKER
Page 657		
ICG ISLAND TRANSMISSION	G.M. HOFFMAN E.C. RIMMER	R.B. WALLACE
Page 1000		
INLAND NATURAL GAS	J.L. RANDALL D.G. HILDEBRAND D.P. BLOOM P.E. TUBB	C.B. JOHNSON
Page 1307		
F.H. CAMERON	SELF	-
Page 1372		
WESTCOAST TRANSMISSION	A.H. WILLMS J.L. TYSON M.A. SINCLAIR W.R. LEE	C.W. SANDERSON

WITNESS BY PHASE AND ORDER OF APPEARANCE
(cont'd)

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VANCOUVER ISLAND GAS PIPELINE PROJECT

COMMISSION STAFF

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MR. RICHARD FLETCHER	Director - Accounting & Financial Analysis
MR. JOHN GREINER	Senior Financial Analyst
MR. JOHN GRUNAU	Director - Economics & Environment
DR. YUWA WONG	Senior Economist
MR. DEREK LEACH	Director - Hearing Coordination
MR. JIM BOGYO	Director - Major Energy Project Review
MR. RAY GODFREY	Project Coordination - Major Energy Project Review
MR. A.C. MICHELSON	Commission Secretary

COMMISSION COUNSEL

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GLOSSARY

EQUIVALENT PIPE SIZES (Outside Diameter [O.D.])

METRIC (mm)	IMPERIAL (Inches)
114.3	4.500
168.3	6.625
219.1	8.625
273.1	10.75
323.8	12.75
406.4	16.0
508.0	20.0
610.0	24.0

EQUIVALENT COMPRESSOR DRIVER SIZES

METRIC (kW)	IMPERIAL (HP)
2984	4000
895	1200
670	900
520	700

EQUIVALENT SUBMERGED PIPE WEIGHTS

METRIC (kg/m)	IMPERIAL (lb/ft)
7.44	5.0

EQUIVALENT GAS VOLUMES

ENERGY (PJ/GJ)	IMPERIAL (bcf/mcf)
1 PJ	.9117 bcf
1 GJ	.9117 mcf

EQUIVALENT GAS PRESSURES

METRIC (kpa)	IMPERIAL (psi)
6.894757	1