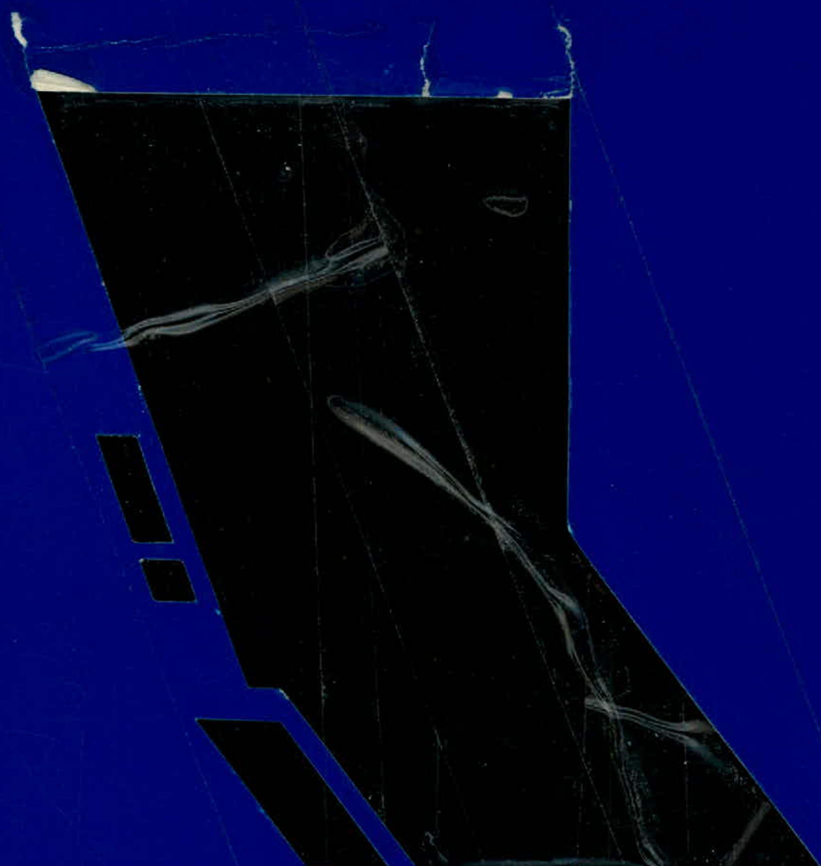
79 Westcoast Transmission Company Limited

Annual Report



Contents

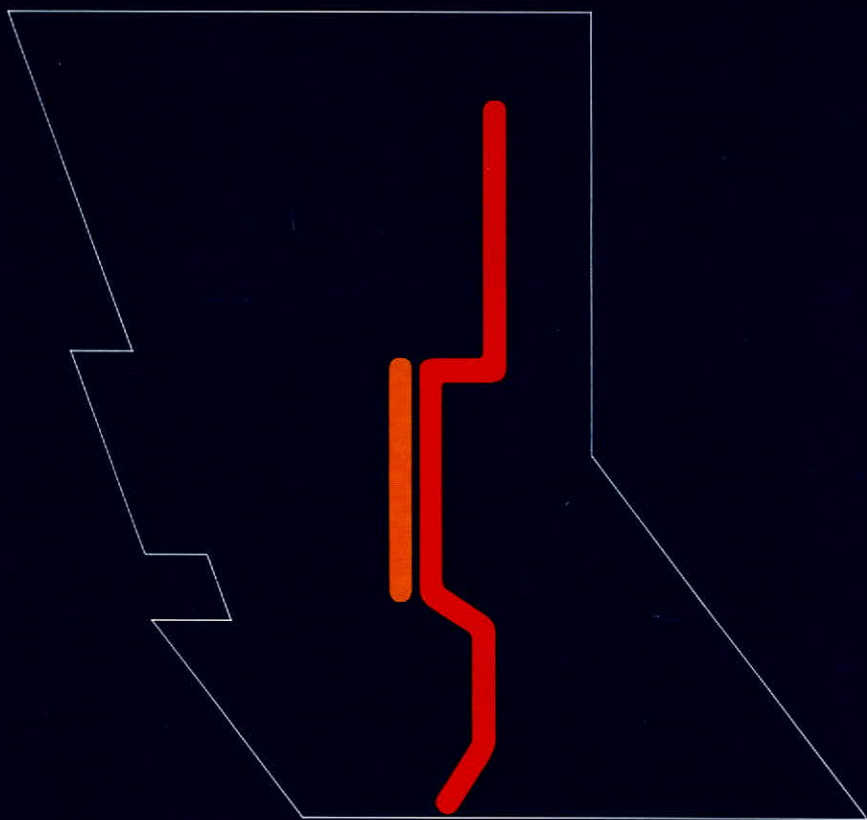
The Company

Westcoast Transmission Company Limited is engaged in the gathering, processing and transportation of natural gas. It serves the British Columbia and western United States markets with gas from British Columbia, Alberta, the Yukon Territory and the Northwest Territories.

Through one subsidiary, the Company has an interest in large holdings of prospective oil and gas lands in western Canada, the Northwest Territories and the Arctic Islands and is engaged in exploration and production. Through another, it distributes natural gas in west-central British Columbia.

Westcoast is co-sponsor of the approved Alaska Highway gas pipeline project and the proposed Alaskan oil pipeline project in the same all-land energy corridor. A federally incorporated Company, Westcoast shares are listed on the Toronto, Montreal and Vancouver Stock Exchanges in Canada and on the New York and Pacific Coast Stock Exchanges in the United States.

At December 31, 1979 the Company had 12,660 common shareholders and approximately 96 percent of its shares were held in Canada.



Information
This report has been prepared for our shareholders, securities regulatory agencies and the stock exchanges. However, it is hoped it may provide a convenient and useful source of information to members of the public and investors. We have attempted to provide all basic and practical material relating to Westcoast's operations in 1979. If further information is required we invite you to write either the Secretary of the Company or the Information Services Department –

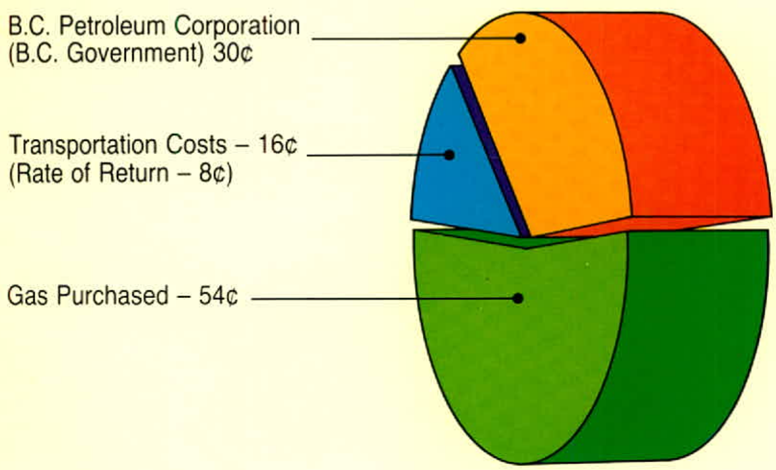
Westcoast Transmission
Company Limited
1333 West Georgia Street
Vancouver, British Columbia
V6E 3K9
Canada

Annual Meeting
The annual meeting of the shareholders of Westcoast Transmission Company Limited will be held in the Social Suite of the Hotel Vancouver, in the City of Vancouver, British Columbia, on Wednesday, April 23, 1980 at 10:00 a.m. P.S.T.

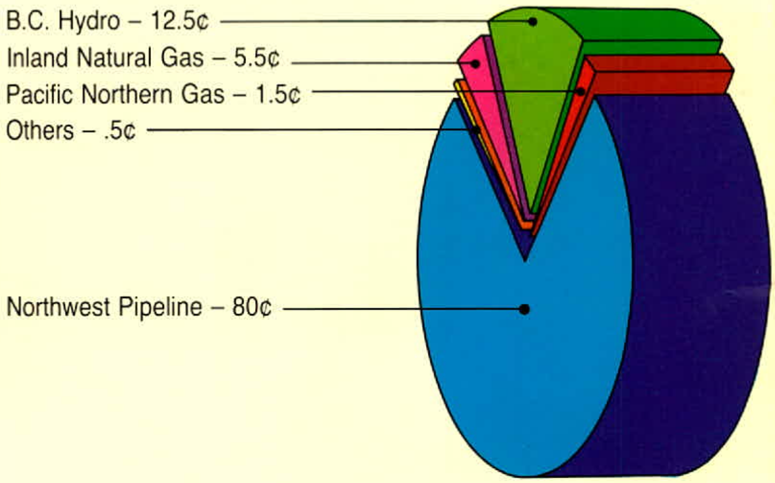
Results in Brief	**1979**	**1978**
Financial		
Total Operating Revenues *(increased by 30.2%)*	$1,098,401,000	$843,902,000
Net Income *(increased by 11.0%)*	49,870,000	44,938,000
Net Income Applicable to Common Shares *(increased by 11.9%)*	46,471,000	41,538,000
per share *(increased by 9.9%)*	1.33	1.21
Cash Flow *(increased by 27.9%)*	109,757,000	85,805,000
per share *(increased by 25.7%)*	3.13	2.49
Total Assets *(increased by 19.2%)*	1,145,870,000	961,338,000
Common Shareholders' Equity *(increased by 7.8%)*	349,910,000	324,646,000
per outstanding share *(increased by 5.4%)*	9.88	9.37
Common Shares – weighted average *(increased by 1.8%)*	35,043,940	34,408,106
Operating		
Total Gas Sales, Mcf	383,598,000	344,449,000
Total Gas Sales, 10^3m^3	10 866 503	9 757 496
Average Daily Sales, Mcf	1,050,953	944,000
Average Daily Sales, 10^3m^3	29 771	26 741
Peak Day Sales, Mcf	1,406,006	1,369,000
Peak Day Sales, 10^3m^3	39 829	38 781

Mcf means one thousand cubic feet, and all gas volumes are expressed at a base pressure of 14.73 pounds per square inch absolute and at a base temperature of 60 degrees Fahrenheit. **10^3m^3** means one thousand cubic meters, and all gas volumes are expressed at a standard temperature of 15 degrees Celsius, and at a standard absolute pressure of 101.325 kilopascals.

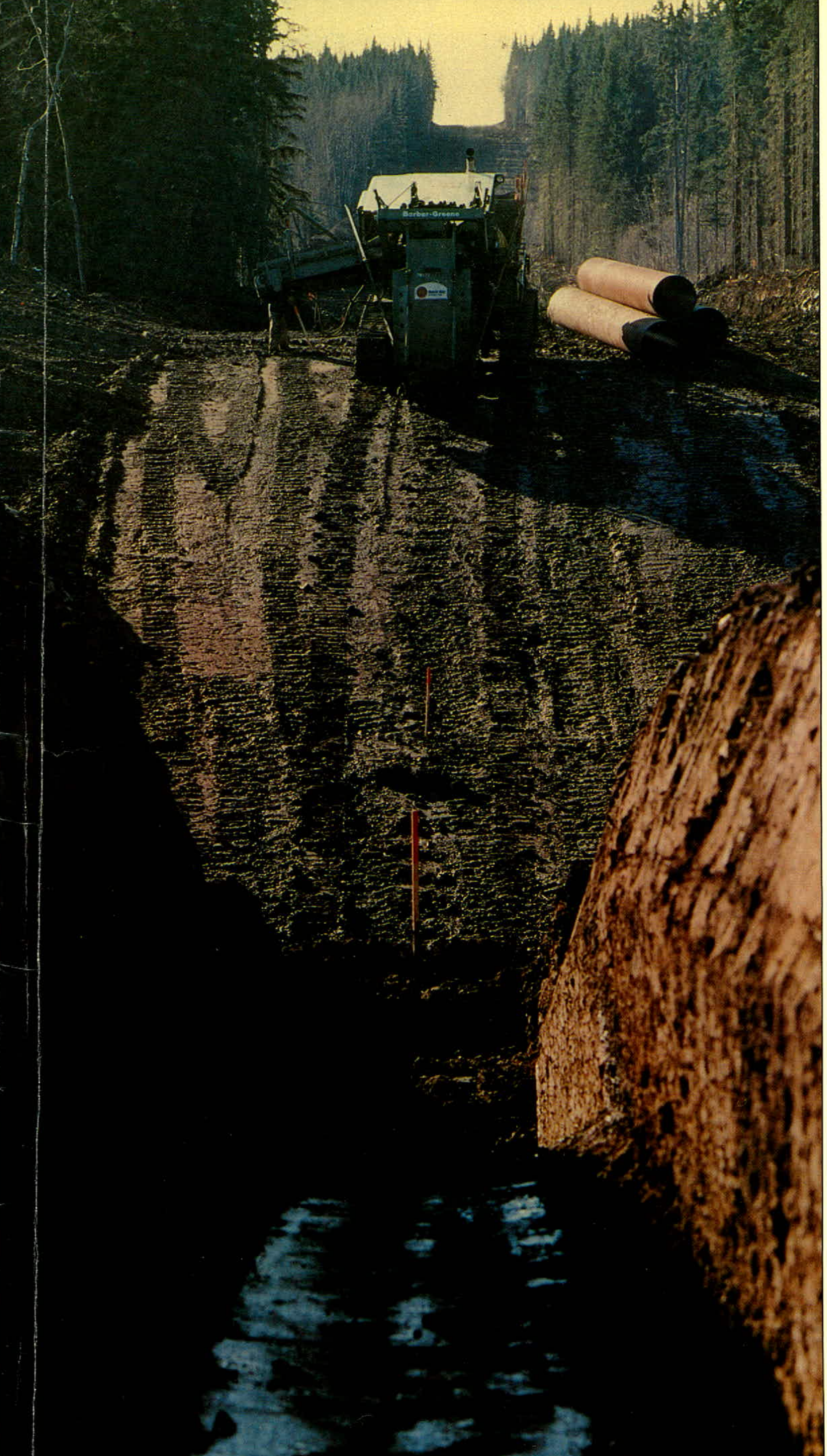
Distribution of Gas Sales Revenue Dollar



Source of Gas Sales Revenue Dollar



Report to Shareholders



Pipeline trenching in the rolling forest lands of east-central British Columbia. Yawning trench in foreground is ready to receive pipe. Ditching machine at top centre prepares to extend the trench.

To Our Shareholders

Leaving the 1970's and moving into the 1980's, Westcoast Transmission is well positioned to share in Canada's economic growth in the decade ahead. There were more energy developments of international significance during the seventies than in the last century. Your Company has emerged from that decade stronger in both a corporate sense and as to its energy system. It has also developed a strategic position from which it can expand existing interests and enter new energy-oriented projects in the decade ahead.

Natural gas will reach its most prominent position as an energy source in Canada in the 1980's and 1990's. Proven reserves are surplus to the nation's requirements; much of the infrastructure to deliver it to market is in place; it is an environmentally-acceptable form of energy; and, by most yardsticks and in most regions, it is competitive in price.

Furthermore, it is Westcoast's perception that Canada has much to gain through the substitution of natural gas for other less-efficient and less-abundant energy forms. In greater measure than other forms, gas holds the realistic prospect of moving both Canada and British Columbia closer to energy self-sufficiency and of improving Canada's trade balance. These are crucial requirements for greater stability in the national economy. With particular reference to British Columbia, natural gas is but one factor in its abundance of natural resources. With gas, oil, water, coal, minerals, forests, agriculture and fisheries it is one of the world's most fortunate regions.

A federal government policy which recognizes the advantages of favouring abundant natural gas over other diminishing and costly fuels, and a British Columbia government energy policy which will rely heavily on the private sector to meet energy needs, further enhance our industry's future prospects. In these circumstances, and as a pioneer in the natural gas industry in Canada, your Company's outlook for expansion is most encouraging.

C.D. Williams, Q.C., Vice President, General Counsel and Secretary of the Company, retired at the end of the year. His many contributions to the Company's success over a period of 13 years are gratefully acknowledged.

Westcoast's marked progress during 1979 was due in great measure to the loyalty, dedication and resourcefulness of its employees and, on behalf of the Board of Directors, I express to them our sincere appreciation.

On behalf of the Board of Directors,

E.C. Phillips
President and
Chief Executive Officer

Vancouver, British Columbia
Canada, March 5, 1980

Report on Operations

The year 1979 has been a very successful and active period for your Company and for the natural gas industry generally. Natural gas has become one of the major cornerstones of the British Columbia economy and our projections show that the recent growth in both production volumes and revenue dollars will continue for some years to come.

In the gas fields of north-eastern British Columbia, drilling activity during 1979 continued at an all-time high as wells were drilled at an average rate of more than one per day. As a result, proven reserves continue to grow faster than production. In 1978, additions to reserves exceeded production by approximately 500 billion cubic feet. While 1979 figures are not yet available, we are confident that reserves at the end of the year will have increased by at least the same amount.

More and more energy users in the province are switching to natural gas, mainly from imported oil. The total volume of natural gas consumed in British Columbia increased from 135 Bcf in 1978 to 146 Bcf in 1979.

The export market is also growing. Westcoast successfully applied to the National Energy Board in 1979 for the right to increase the existing export quantity from 809 million to 869 million cubic feet per day.

Connecting the booming gas fields in north-eastern B.C. to these growing markets is the Westcoast pipeline system. During 1979 the Company took action to ensure tha its development can keep pace with the demands of the marketplace. For example, a new gas processing plant was completed at Pine River at a total cost of $98 million. Westcoast is proud of the high environmental standards designed into this plant. Undoubtedly, it will become a model for the industry.

Several pipeline construction projects were completed during the year at a total cost of some $41 million.

Westcoast is also growing in terms of personnel. Primarily due t staffing the new processing plant, adding personnel for the expandec Northern District and for the Alaska Highway gas pipeline project, the number of employees reached an all-time high of 727.

Throughout this very busy year fc the Company and for the industry, Westcoast continued to show stable and steady growth. For the ninth consecutive year, net income dividends, operating revenue, cash flow and net income per common share established new record levels. Attaining the billion-dollar mark in total operating revenues was a noteworthy accomplishment.

There are new records to be set for 1980 and plans are well underway to ensure that our growt continues.

John Anderson
Executive Vice President and
Chief Operating Officer

Crossing the Coquihalla River with 36-inch diameter pipe. All such river crossings are supervised by fish and wildlife authorities to assure habitat protection. Above, the river after the pipe is buried in riverbed.

Financial Results

For the ninth consecutive year, net income reflected an increase over the previous year. Total operating revenues exceeded one billion dollars for the first time in the Company's history. They were $1,098,401,000, an increase of approximately 30 percent from $843,902,000 in 1978.

Net income in 1979 was $49,870,000, up 11 percent from $44,938,000 in the previous year. Cash flow increased almost 28 percent to $109,757,000 from $85,805,000. Net income per common share of $1.33 compared with $1.21 a year earlier, an improvement of almost 10 percent. As further evidence of the Company's growth, the rate base of $720,206,000 at December 31, 1979 was nearly 22 percent higher than the $590,586,000 at year end 1978. Substantial investments in the Company's utility system resulted in the higher rate base and to a large extent the higher net income in the year.

Capital expenditures of the consolidated operations totalled $156 million in 1979 and it is anticipated they will be approximately $170 million in 1980. As the Alaska Highway gas pipeline project moves closer to the start of construction, Westcoast's financial commitments to this project continue to rise. They amounted to $22 million during 1979 bringing the Company's total expenditures to $47 million at December 31, 1979.

In the third quarter of the year under review the sale of $75 million of 20-year debentures at a rate of 10½ percent was completed. The funds were used to repay interim borrowings incurred for expansion activities.

Rate Decision

After more than two years of hearings and deliberations, the National Energy Board ruled on the Company's comprehensive rate application in a decision dated September 20, 1979. It re-affirmed its decision of May 24, 1978 that the Company adopt normalized tax accounting. It also increased the average depreciation rate from 3.1 percent to 3.9 percent. The effect of these two rulings will increase the Company's annual cash flow by approximately $50 million commencing November 1, 1979. Westcoast was granted a 14.25 percent rate of return on common equity on an approved capitalization ratio of 55 percent debt, 5 percent preferred shares and 40 percent common equity.

The NEB's decision allowing recovery of foreign exchange losses in servicing the United States debt resulted in payment to the Company of an estimated $1.6 million in 1979 as compared with an exchange loss of $2 million in 1978.

Decision Appealed

After studying the rate decision, the Company applied to the NEB to review and vary its decision regarding corporate capital tax and income tax calculations. Westcoast contended the method of calculating normalized income taxes was not just and reasonable and resulted in its return on common equity being eroded to 13.75 percent from 14.25 percent. The Company's application for a review was denied. However, this decision is being appealed to the Federal Court of Appeal.

The B.C. Petroleum Corporation, B.C. Hydro and Power Authority and some industrial users of gas have served notice that they intend to appeal certain aspects of the decision.

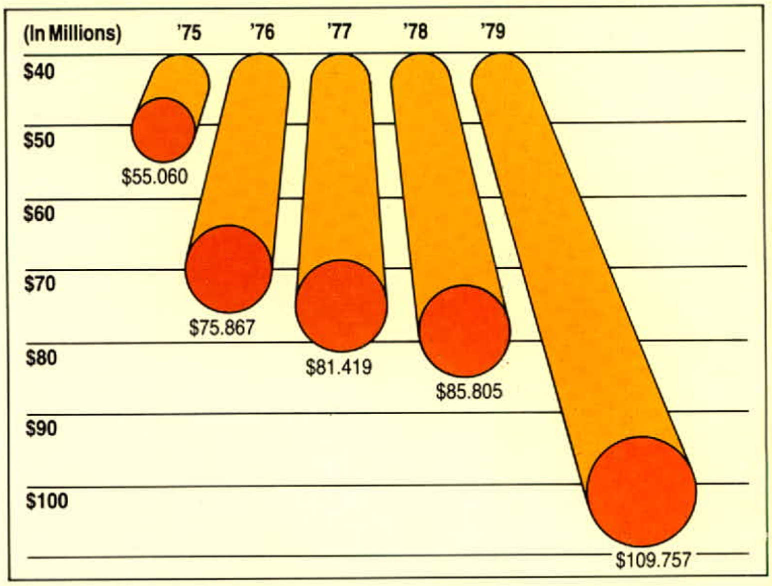
Cost-of-Service

The Company's cost-of-service contract with the British Columbia Petroleum Corporation continued in force during the year. Under its provisions, all British Columbia gas is purchased from the corporation at the wellhead. It is then gathered, processed, transported and sold by the Company to its domestic and export customers. A sum to cover the Company's operating costs is retained. These costs include maintenance and administrative expenses, depreciation, taxes and the approved return on rate base. As a result of the NEB decision, effective November 1, 1979, the return on rate base was increased to a pre-tax 16.94 percent and normalized income taxes now are included in the cost-of-service. The resulting return on rate base on an after-income-tax basis is 10.88 percent.

Gas Sales

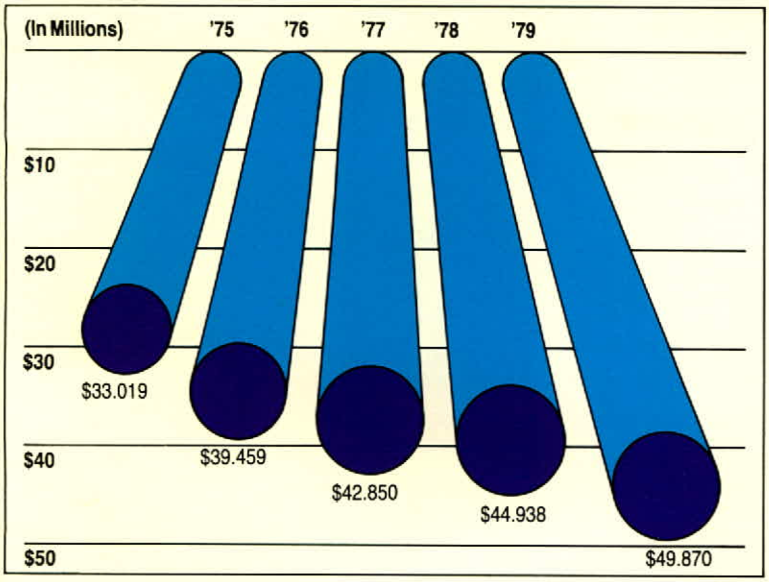
Gas sales increased in all market areas served by the Company. Total sales were up by 11.6 percent, to 384 billion cubic feet from 344 billion cubic feet. Average daily sales were 1,051 million cubic

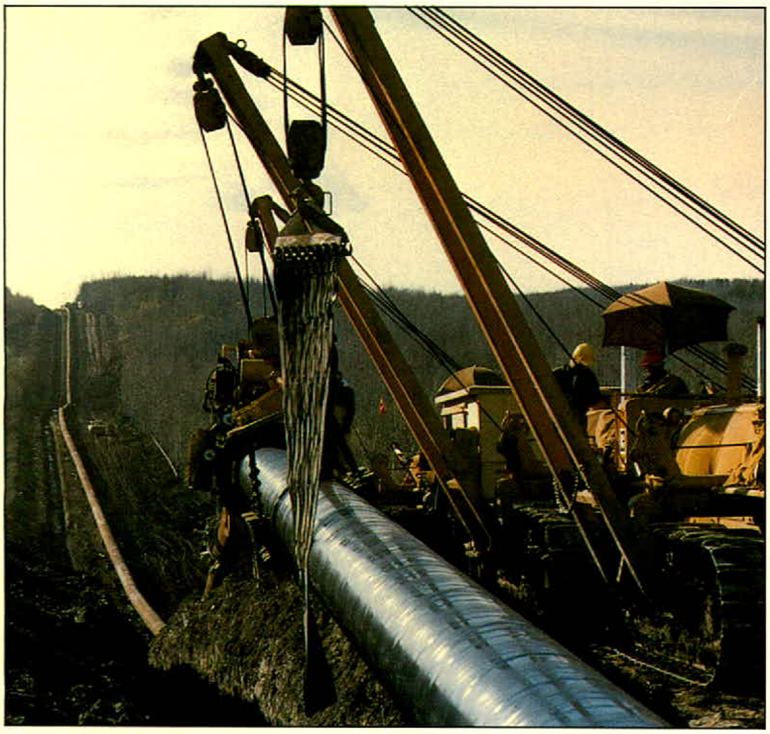
Cash Flow



The welders' keen eyes concentrate on crucial joining of steel pipe sections.

Net Income





Wrapping and coating 36-inch pipe in a looping project.

feet compared to 944 million cubic feet in 1978.

The largest of the three domestic customers, British Columbia Hydro and Power Authority, increased its purchases by 7.3 percent despite an unusually warm December. This resulted from continuing conversions to gas from oil in residential and commercial markets. Also, B.C. Hydro used significant volumes of gas for the first time in four years in its Burrard thermal generating station near Vancouver. Total purchases by Hydro were 85.8 Bcf, up from 80 Bcf. Purchases by Inland Natural Gas Co. Ltd. increased 8.5 percent to 45.8 Bcf. Pacific Northern Gas Ltd. increased its purchases by 16.9 percent to 10.9 Bcf.

Residential and commercial conversions to natural gas again were a contributing factor in increased sales to the latter two customers. Pacific Northern Gas conducted a highly successful incentive program to encourage consumers to convert to natural gas from oil. The rate of conversions in its smaller service area on a relative basis exceeded that in the heavily populated area of Greater Vancouver and environs.

A new element detected in the British Columbia market is that many consumers are making a conscious effort to conserve energy. While overall sales of gas increased the average use by customer declined.

Sales Recaptured

Sales to the export customer, Northwest Pipeline Corporation, were higher by 13.1 percent, totalling 237 Bcf as against 210 Bcf in the previous year.

Residual oil prices rose in the United States Pacific Northwest region, enabling gas to recapture some large industrial markets which had been lost when oil prices were low.

Northwest Pipeline has been selling large volumes into the Nevada and California markets on a "best efforts" basis. Furthermore, U.S. gas distributors aggressively promoted their product and general concern about the actions of the OPEC countries on price and supply of oil persuaded an increasing number of consumers to opt for gas.

Export Price Rises

Three increases in the export border price of gas took place during the year. In sequence, the increases ordered by the federal government were (U.S.$): on May 1, from $2.16 per million British thermal units (approximately 1,000 cubic feet) to $2.30; on August 11, to $2.80; and on November 3, to $3.45. The wholesale price to British Columbia distributors was unchanged through the year at approximately $1.20, about 30 percent of the export price.

On January 18, 1980 the federal government announced a further increase in the export price to $4.47 in U.S. funds (about $5.20 Canadian), effective February 17, 1980.

The effect of the last three export price increases on the competitiveness of gas cannot be fully evaluated until the spring when the winter demand for gas for space heating declines and the surplus is normally absorbed by industry.

For the second consecutive year, the loss of authorized export sales volume emphasized the need to

expand throughput capacity by further looping of the mainline. During periods of peak demand in January, February, November and December our export customer's full requirements could not be met due to insufficient mainline capacity. The Company has applied to the National Energy Board for a major looping project which will be actively pursued early in 1980.

Increased Exports Approved

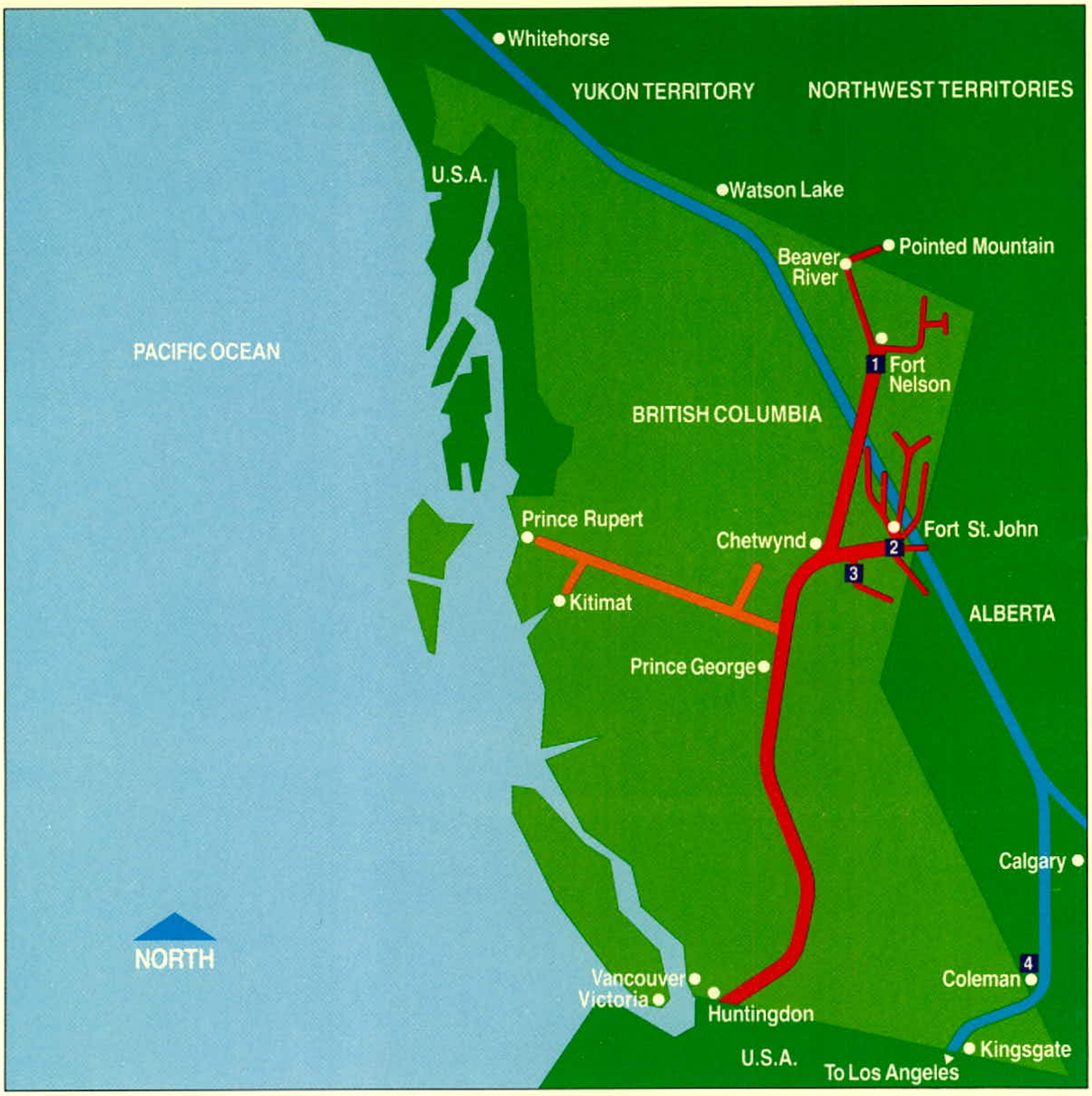
The National Energy Board rendered its decisions on December 6, 1979 on its omnibus hearing earlier in the year on future gas exports. Westcoast was authorized to increase its maximum day sales to the export market from 809,200 Mcf to 869,200 Mcf through October 31, 1989. This will enable the Company to implement a sales agreement with El Paso Natural Gas Company for 60 million cubic feet per day, commencing November 1, 1980. The sale will be at 100 percent load factor which will materially increase overall sales in the future. It is estimated this single sale will provide a minimum of $80 million annually in additional revenue to British Columbia gas producers and the provincial government.

The El Paso agreement is significant in that it is the first direct, firm sale since 1973 to a company whose prime market is California, which is a logical market for surplus British Columbia gas. California's enormous requirements for natural gas hold the prospect of further expansion of export sales.

The NEB also approved the export of 40 million cubic feet a day by Columbia Gas Development of Canada Limited. Westcoast will transport this volume from the Yukon Territory to the export point at Huntingdon, B.C.

In the same decision the NEB authorized Westcoast to extend its exports of Alberta gas through Kingsgate, B.C. under Licence GL-4 from the existing termination date of December 31, 1981 to October 31, 1984 at full volumes; and for three additional years to October 31, 1987 with a 25 percent reduction in daily and annual volumes in each of these three years.

An application by the Company to extend GL-41 which authorizes export sales at Huntingdon from November 1, 1989 to October 31, 1995 was denied by the NEB on the ground that the time frame involved was beyond the test periods used by the Board to determine volumes of gas which are surplus to Canadian requirements.



Westcoast Transmission Mainline	Pacific Northern Gas Ltd.	3 Pine River Plant
Gas Gathering Lines	1 Fort Nelson Plant	4 Saratoga Plant
Foothills Pipe Lines	2 McMahon Plant	

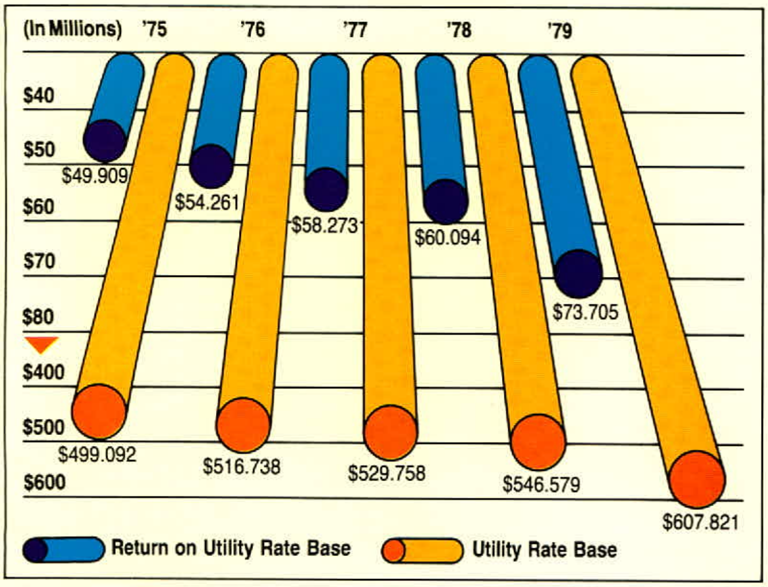
Gas Supply

Gas reserves in the Company's supply area continue to increase. As of January 1, 1979, reserves were 7.8 trillion cubic feet, an increase from 7.3 Tcf on January 1, 1978. These reserves do not include the Alberta reserves which support the 200 million cubic feet per day contract the Company has with Pan-Alberta Gas Ltd.

Land sales, drilling activity and the discovery rate also continued at record levels in northeastern British Columbia. A total of 399 wells were drilled resulting in the completion of 190 gas wells and 79 oil wells. In the previous year the comparative figures were 387 wells drilled, resulting in 187 gas wells and 64 oil wells. 205 of the 399 wells drilled in 1979 were exploratory or "wildcat" wells. 66 of these were gas discoveries and three were oil discoveries.

All available data clearly demonstrate an adequate gas supply is available to meet the current and future contract requirements of domestic and

Return on Utility Rate Base and Utility Rate Base



export customers and to support a natural gas pipeline to Vancouver Island.

Eight land sales were held in British Columbia during the year. Seven of the sales yielded record revenues of $191 million to the provincial government. This was $14 million more than bonus payments in 1978. The eighth sale of the year contained permit lands in the virtually unexplored Nechako sedimentary basin located some 30 miles west of Westcoast's mainline between Quesnel and Williams Lake. A large Canadian exploration company was awarded 43 out of 51 permits offered for a commitment to do $27.5 million worth of exploratory work over the next 5 years.

The Pine River process plant and Grizzly Valley pipeline complex will add a supply of 150 million cubic feet a day when it is fully operational. Operations started in February 1980 and the volumes of gas available to the plant will rise gradually to full capacity by the fall of 1980.

By the spring of 1980 natural gas supplies will be further augmented when the new Junior-Sierra gathering system in the Fort Nelson area is completed. It will add 195 million cubic feet a day to supply. Construction of this gathering line began in January 1980.

Deep Basin Progresses

Developments in the Deep Basin area, which straddles the British Columbia-Alberta border, indicate large new volumes of gas will continue to be added to proved Canadian reserves. In Alberta two gas processing plants with combined capacity of 90 million cubic feet a day commenced operation in the Elmworth region of the Deep Basin late in the year. Throughout this potentially rich hydrocarbon area in Alberta numerous geological zones have been identified as capable of producing gas and oil. Wells drilled to date in this area of British Columbia have reported gas flows from at least five different zones.

Operations and Construction

During the year a number of construction projects were carried out to expand, upgrade and generally improve the efficiency of the Company's pipeline system. The largest project was the new Pine River process plant. At a cost of $98 million, it was one of the largest projects built by the Canadian gas industry in 1979. This plant, using the latest technology, is a model for the industry. The sulphur unit recovers more than 99 percent of the sulphur in the raw gas stream, reducing air pollution to the absolute minimum.

All liquid effluent is contained on the plant site and thus no waste is discharged into nearby streams. Some 20 miles of the mainline in the Coquihalla Pass were looped with 36-inch pipe at a cost of $20 million. The high cost of this project is indicative of the difficult, mountainous terrain encountered by construction crews.

A new provincial government highway in the interior of the province is to be built through the narrow Coquihalla Pass and it was essential that the looping project be completed prior to highway construction. Sections of the 30-inch original mainline in the Coquihalla Pass also will be replaced or relocated in 1980. Another small loop of 5.5 miles of 36-inch pipe was completed near Summit Lake during 1979. This looping in a tight section of the system increased throughput capacity by nearly 26 million cubic feet per day.

Small sections of the original 30-inch mainline were replaced with heavier wall pipe at Chetwynd, Dragon Lake, 100-Mile House and Chilliwack. This strengthening of the pipe was required because of population increases adjacent to the mainline right-of-way.

New Computers in Service

Operations at 17 mainline compressor stations, 14 field booster compressor stations, 4 gas processing plants and 4 major gas sales delivery points are automatically and continuously monitored and controlled in the Company's gas control office in Vancouver by a computerized "Master Station" which is tied in to 35 remote terminal units.

As the pipeline system has expanded since 1972, so also have the requirements for the Master Station facilities, and in 1979 the original computers reached the limit of their capacity and were replaced with faster units with sufficient capacity and capability to accommodate system requirements for at least the next five to ten years. These new computers also provide the capabilities for the development and use of more complex and useful programs such as system optimization, trend analysis and graphic displays.

Industrial Relations

A year of excellent management-employee relations was marred by a nine-week strike by 11 members of the Union of Operating Engineers at the Taylor process plant. The strike ended September 11 with settlement of a one-year contract, retroactive to February 1, 1979.

New collective bargaining agreements were negotiated with the Oil, Chemical and Atomic Workers International Union at the Fort Nelson process plant and the Canadian Pipeline Employees Association on the transmission system. The term of the OCAW contract is two years, from February 1, 1979, and the CPEA agreement is for one year, effective April 1, 1979.

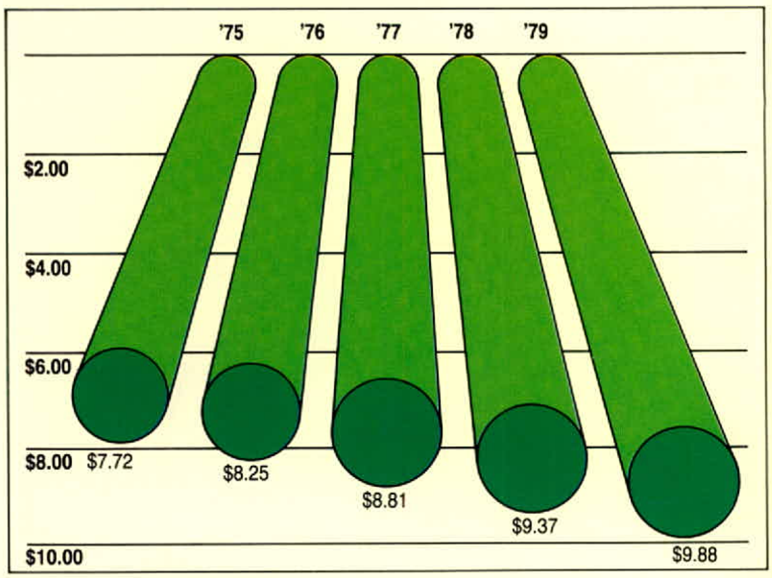
The total number of Company employees was 727 at December 31, 1979, an increase from 638 a year earlier. Most of the additional staff were required for the new Pine River process plant, the remainder being engaged for the transmission and gathering system and the Alaska Highway gas pipeline project.

Engineering

Design plans for many new system facilities and modernizations were completed by the Engineering Division during the year. Most of the projects will be executed in 1980. Among them is the Junior-Sierra gathering pipeline east of Fort Nelson, which comprises 83 miles of pipe ranging from 24 inches to 12¾ inches in diameter. It is scheduled for completion in March 1980 at a cost of $34 million. A $5.1 million modification to the sulphur recovery unit at the Fort Nelson process plant will be required to handle gas from this gathering system thus raising capacity to 660 from 410 long tons per day. Design for a new sulphur recovery unit at the McMahon process plant, to cost $12.3 million, is also underway.

Capacity will be raised to 460 from 323 long tons per day. Plans were reviewed for proposed additional looping of the mainline with 36-inch pipe. Final footages have yet to be determined but it is expected, subject to National Energy Board approval, that approximately 44 miles will be looped which would leave unlooped only 38 miles of the 570 miles of 30-inch mainline south of Station 2 near Chetwynd, British Columbia. Estimated cost of the 1980 looping program is $42.3 million.

***Shareholders' Equity per Common Share**

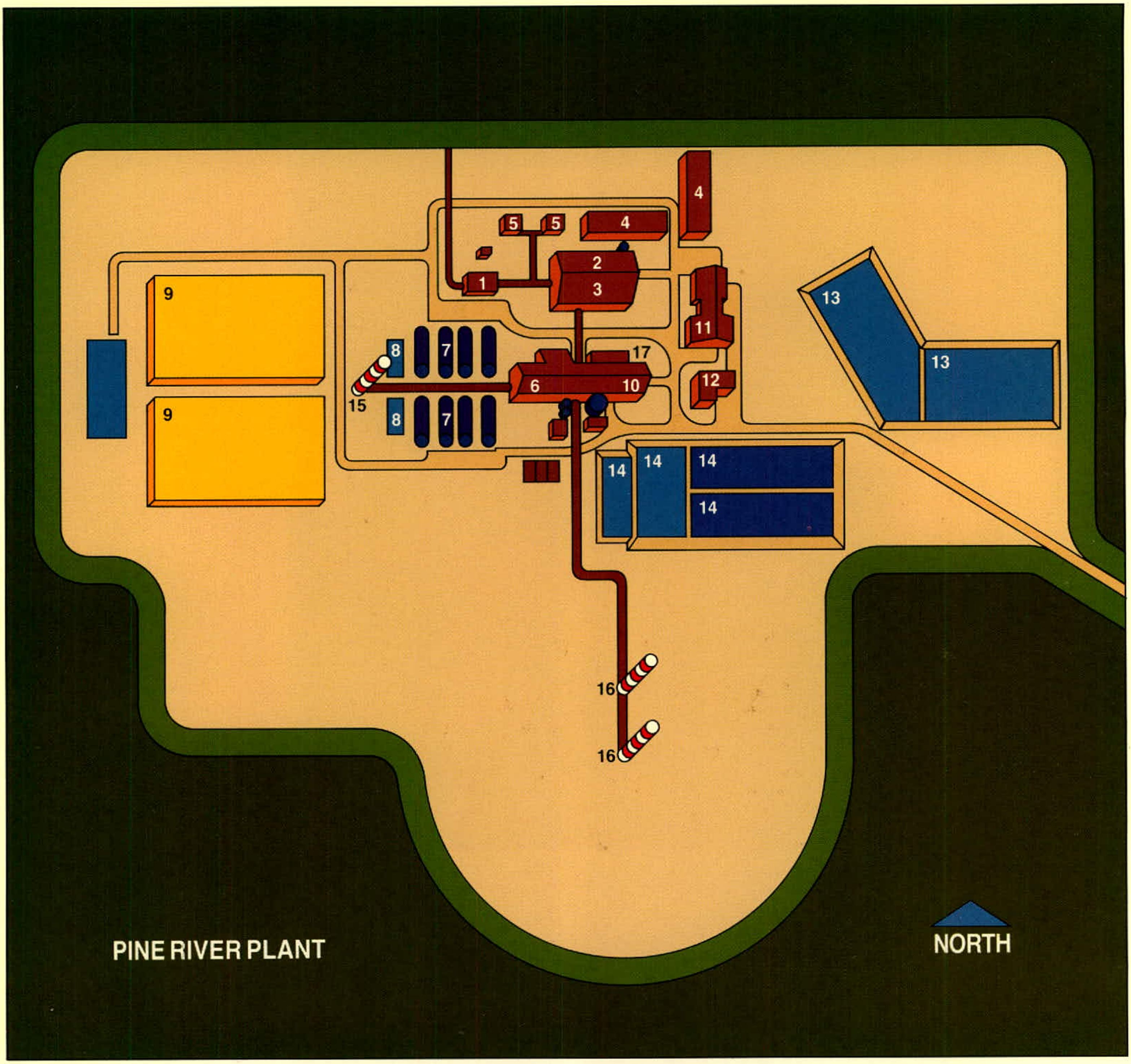


**Reflects three-for-one share split.*

Engineering has been completed for upgrading the 26-inch line at Fort St. John at a cost of $11.2 million; 3.2 miles of 36-inch pipe at Dragon Lake to cost $3.3 million; and 1.9 miles of 18-inch pipe at Taylor to cost $1.3 million. In addition, a section of 30-inch mainline in the Coquihalla Pass will be upgraded at a cost of $1.7 million.

The Engineering Division has developed a 5-year program to replace 16 mainline gas turbines which were purchased in the period between 1964 and 1966 and are now becoming obsolete. The first two units will be installed in 1980 at a cost of $7.8 million. The use of new-generation turbines will achieve greater efficiency through reductions in fuel and general maintenance costs. The initial savings in fuel for the first two units will be over $1 million a year at today's gas prices.

Above, men and machines lay pipe through a sparsely-populated area in the Fraser Valley, east of Vancouver.
At left, work proceeds with little inconvenience to residents; the restored road after work crews moved on.



1. Inlet & sales gas metering building	6. Sulphur plant equipment building	11. Garage, maintenance shop, warehouse	16. Flare stacks
2. Gas sweetening plant	7. Sulpher plant converters	12. Office building	17. Control room
3. Sweet gas dehydration	8. Liquid sulphur storage pits	13. Blowdown evaporation ponds	
4. Treating solution coolers	9. Sulphur blocks	14. Treated effluent ponds	
5. Waste gas coolers	10. Boilerhouse & generator building	15. Thermal oxidizer stack	

The Company's new processing plant at Pine River as it neared completion in mid-1979. Above, thermal oxidizer unit at bottom of the stack incinerates waste gases and minimizes the emission of impurities into the atmosphere.

Subsidiary Companies

Westcoast Petroleum Ltd.

The Company holds 3,750,000 or 58 percent of the outstanding common shares of Westcoast Petroleum. This is an oil and gas exploration and production company which also operates a 505-mile oil pipeline in British Columbia.

Westcoast Petroleum reported net income available to common shareholders of $8,606,000 or $1.33 per common share in 1979, as against $7,731,000 or $1.23 per common share in the previous year.

Westcoast Petroleum participated in the drilling of 112 exploratory and development wells in 1979, resulting in 35 gas well completions and 14 oil well completions.

Another 17 wells were cased for further evaluation. At December 31, 1979 the Company had proved and probable reserves of crude oil and liquids totalling 11,764,000 barrels and proved and probable natural gas reserves of 400,390,000 Mcf. Its interests include a total of 7,314,000 gross acres (1,827,000 net acres) of prospective oil and gas lands in western Canada, the Yukon Territory, the Northwest Territories and the Arctic Islands.

Pacific Northern Gas Ltd.

Westcoast owns 45 percent of the common shares and all of the voting shares of Pacific Northern Gas. This utility distributes natural gas to communities and industries in west-central British Columbia. Pacific Northern Gas reported net earnings in 1979 of $1,952,000 or $1.22 per common share, compared with $1,021,000 or 64 cents per share in 1978. Total sales revenue increased to $21,188,000 from $15,850,000 and sales volumes increased to 10.7 Bcf from 9.1 Bcf in 1978.

During 1979 the company paid its first common share dividend amounting to 25 cents per share.

Saratoga Processing Company Limited

The Company owns 25 percent of Saratoga's common shares, including all of the voting shares. Saratoga owns and operates a gas gathering and processing system and a sulphur extraction plant in southwestern Alberta. Its processing facility, which has a capacity of 52 MMcfd of raw gas, treats Westcoast gas and other gas for sale in southeastern British Columbia and the United States.

Saratoga Processing had net income in 1979 of $350,000 or 70 cents per common share, which compares with $329,000 or 66 cents per common share a year earlier.

Alaska Highway Gas Pipeline Project

A series of developments during 1979 brought the Alaska Highway natural gas pipeline nearer to the start of construction. With the encouragement of President Carter, the three major Alaskan gas producers, Exxon, Sohio, and ARCO are actively negotiating to participate in financing the Alaskan section. The available volumes of Alaskan gas have now been committed by sales agreements to U.S. customers. TransCanada Pipelines Ltd. took a 30 percent equity position in Northern Border Pipeline Co. which will build the eastern leg in the United States from Monchy, Saskatchewan to a point near Chicago.

Regulatory hearings both in Canada and the United States established tariff structures and incentive rates of return which are prerequisites for financing. Additional hearings in both countries relating to the approval of project financing plans are expected to be completed by the second quarter of 1980.

The U.S. Federal Energy Regulatory Commission expedited regulatory procedures, approved the pipeline pressure, location and size, and the location of the gas processing plant at Prudhoe Bay. The responsibility for gas processing costs is not yet settled pending the outcome of the financing discussions with the three producers. The overall U.S. regulatory process, which had slowed the project in its early stages, matched the pace of Canadian regulatory activities by late 1979.

Largely due to the earlier regulatory delays in the United States, the completion date for the whole project was rescheduled from January 1983 to late 1984. Cost estimates for the Canadian section were revised accordingly, to $5.8 billion from $4.3 billion.

Pre-build Decision Awaited

The pre-build or Phase I segment of the project received a set back in December with the decision of the National Energy Board regarding new gas export licences. Although the gross volume of 3.75 Tcf (trillion cubic feet) which was authorized for export from Canada was sufficient to permit Phase I to proceed, the volume allocated specifically to Pan-Alberta Gas Ltd. (the Canadian exporter in the pre-build plan) was only 1.8 Tcf over seven years. The American and Canadian sponsors of the project have announced that the volume was not sufficient and the term of the licence was too short to make financing of Phase I feasible.

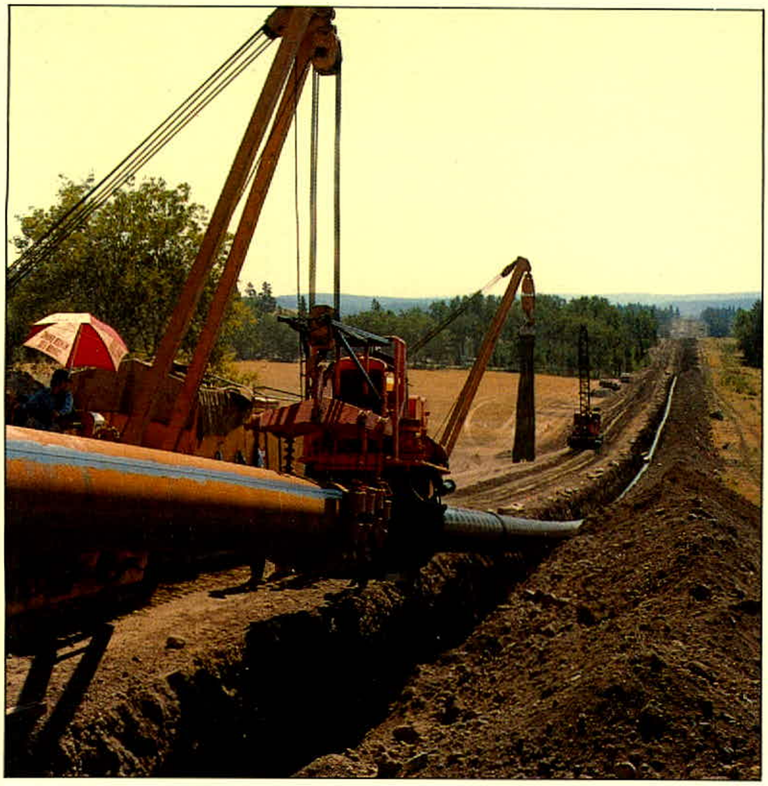
A new pre-build plan has been developed with the cooperation of the project sponsors, new gas export licence holders and TransCanada Pipelines Ltd., to enable the pre-build facilities to be constructed as scheduled with completion of the Western leg by November 1, 1980 and the Eastern leg by November 1981.

Applications were made to the National Energy Board in February 1980 for approval of these plans, including a request for additional volumes of gas to be added to Pan-Alberta's export licence, and modifications to some of the previous Board orders. A decision is expected to be handed down during the first quarter of 1980.

Westcoast has a 50 percent interest in Foothills Pipe Lines (Yukon) Ltd., the sponsor of the Canadian segment of the Alaska Highway gas pipeline project, as well as a 50 percent interest in Foothills Oil Pipe Line Ltd., which proposes an oil pipeline in the same energy corridor to transport Alaskan oil to southern markets.

Foothills Oil Pipeline Project

Foothills Oil Pipe Line Ltd. took several strategic initiatives in 1979 in an effort to expedite selection of a new route to transport Alaskan oil to the mid-west and north-central United States. The intent was to test the acceptability of its project at the highest



Upgrading of the mainline in the Cariboo district of British Columbia. Pipe with thicker walls replaces older sections to strengthen the system in an area where increased public activity is anticipated.

governmental levels in both Canada and the United States and eventually to gain international approval for an all-land oil pipeline shortcut across Canada to the U.S. mid-west.

In early April, Prime Minister Trudeau endorsed the Foothills all-land oil pipeline route along the Alaska Highway in the same energy corridor as the natural gas pipeline. The Foothills overland route for an oil pipeline also was supported by Premier Bennett of British Columbia, and subsequently by Prime Minister Clark.

As unanimous Canadian support for the Foothills oil pipeline developed, the company applied on April 24 to the National Energy Board for approval of its project. On October 2, the National Energy Board hearing began in Ottawa on the Foothills application and the competing Trans Mountain Pipe Line Co. Ltd. proposal. The latter involved tanker movement of crude oil from Valdez, down the British Columbia coast into the Strait of Juan de Fuca to a new oil port and from there by pipeline to Edmonton.

Developments Complicated

As a result of a number of rapid developments, Foothills determined that a new Alaskan oil transportation project was neither timely nor immediately urgent. Consequently, Foothills temporarily "stepped aside" from the National Energy Board hearing on October 15. The NEB granted Foothills permission to continue at the hearing as an intervenor.

After a statutory extension of the United States deadline, President Carter selected the all-American Northern Tier oil "tanker/pipeline" proposal on January 17. Northern Tier, however, is required to demonstrate its ability to finance its project within a year. If it fails to do so, the Trans Mountain plan will receive American support. However, since the President's decision the National Energy Board in Canada has rejected Trans Mountain's application as presented for failing to deal with the marine impact of its proposal. Because the official positions of Premier Bennett of British Columbia and the Canadian government both support the Foothills all-land project, there is the possibility of further international negotiations on the oil pipeline at a more appropriate time.

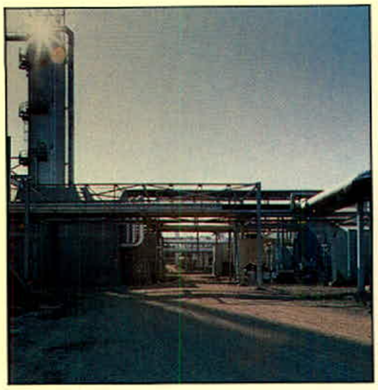
Foothills is satisfied that its initiatives throughout 1979 were prudent under the complicated circumstances. It is, furthermore, optimistic that its all-land route can still prevail. The long-term view of energy transportation from both the Canadian and United States arctic regions would demand an oil pipeline in the Alaska Highway energy corridor. From an environmental point of view, the all-land route is decidedly superior to Alaskan oil tanker traffic along the west coast into a proposed port for oil supertankers in the Strait of Juan de Fuca.

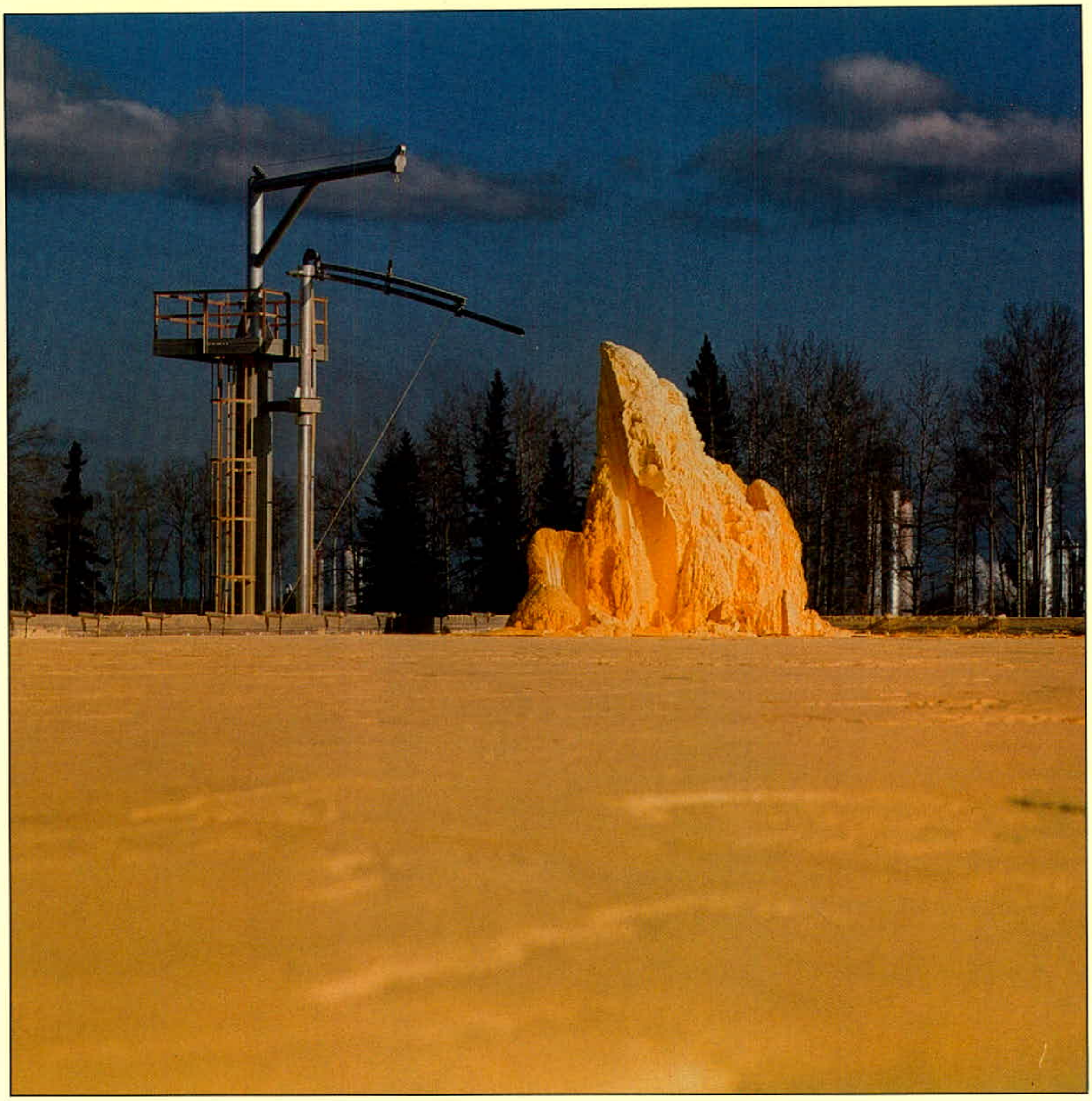
Foothills stands prepared to reactivate its application and complete the project should unfolding developments, whether for reasons of energy security or economics, cause the United States to give new consideration to the widely-proclaimed Canadian sensitivity to unnecessary Alaskan oil-tanker traffic along the west coast to a new oil port to be built a mere 15 miles from the capital city of British Columbia.

Vancouver Island Pipeline

A detailed assessment of the on-going engineering studies for a natural gas pipeline to Vancouver Island was completed during the year. In November a proposal to construct the pipeline was submitted to the provincial government by Westcoast and its subsidiary, Pacific Northern Gas Ltd. The system entails 487 miles of transmission and lateral pipelines, including twin submarine pipelines 18.9 miles in length. Estimated cost of the project is $260 million of which $185 million would be Westcoast's share.

Westcoast would construct 224 miles of 16-inch pipeline from its mainline near Williams Lake to Powell River and twin 8-inch diameter crossings under the Gulf of Georgia to Comox on Vancouver Island. It would also build a 69-mile lateral to link Squamish, Woodfibre and Port Mellon, northwest of Vancouver.





A monolith of sulphur, the product of the Fort Nelson sulphur recovery plant. The sulphur assumed this unique shape as it sprayed in molten form from the tower at left.

On Vancouver Island, Pacific Northern Gas would install a 158-mile distribution pipeline between Victoria in the south, Nanaimo, and Campbell River to the north, as well as a 17-mile lateral to Port Alberni on the west coast. It would also be responsible for distribution systems within communities on both the island and the mainland.

Northern Route Superior

Following the initial submission to the British Columbia government in November, PNG, which is incorporated in British Columbia, placed its proposed plans for the system before the British Columbia Energy Commission on December 21, 1979. Because it is federally incorporated, Westcoast will make its application for the project to the National Energy Board.

The flexibility of the Westcoast-PNG plan enables the companies to consider using the southern crossing of the Strait of Georgia if this is determined to be the government's preference. However, the northern route is strongly favoured for a number of technical, geophysical, economic and security reasons which have been outlined to the government.

Furthermore, the northern route would serve the largest number of communities and industries. It would provide natural gas at competitive prices to 70 percent of Vancouver Island's population, to four mainland communities and to at least seven major pulp mills or pulp-paper-lumber complexes.

Given the necessary governmental approvals, the system could be in operation within three years. It is estimated the markets to be served would require 22.4 billion cubic feet in 1983 and that by 1987 this volume would increase to approximately 44.3 billion cubic feet per year.

Petrochemical Plant

As manager of a three-company joint venture, Westcoast is finalizing plans for a new world-scale methanol plant at Kitimat on the British Columbia coast. Engineering cost estimates which confirmed the viability of the project were received in November from consultants. The proposed plant capacity is 1,250 tons per day, which would be manufactured from feedstock of 40 million cubic feet of natural gas per day. The cost is estimated at $175 million and the three joint venture participants are equal partners in the project.

Sales contracts are being negotiated with Japanese firms for most of the product. Necessary applications will be made to the appropriate provincial government agencies for authorization to build the facility. It is hoped that contracts for construction could be let in 1980 in which event production could commence in late 1982. A construction period of 18 months is projected, providing employment for 600 construction workers. When in production, the plant will require a permanent staff of approximately 85.

Methanol will be marketed in Canada and the United States, as well as in Japan. A high potency fuel, methanol also has many industrial uses.

Feedstock natural gas will be supplied by the Company's subsidiary, Pacific Northern Gas Ltd., with further economic benefit to the Westcoast group of companies.

On February 4, 1980 the provincial government announced a new energy policy and its impact on the methanol project has not yet been determined.

Financial Statements

An intricate web of pipe in the Fort Nelson sulphur recovery plant.

Consolidated Balance Sheet
December 31, 1979 and 1978

Assets	**1979**	**1978**
	(in thousands)	
Plant, property and equipment – at cost (Note 1)	$1,223,059	$1,070,259
Less accumulated depreciation and depletion	318,127	284,143
	904,932	786,116
Current assets:		
Temporary cash investments	13,567	15,819
Deposits with trustees	4,346	4,833
Accounts receivable	151,150	109,387
Materials and supplies – at cost	5,534	5,134
Line pack gas – at cost	6,824	4,656
Prepayments	621	720
	182,042	140,549
Deferred charges:		
Debt discount, premium and expense	7,671	6,599
Northern pipeline projects (Note 2)	46,796	24,444
Other	4,429	3,630
	58,896	34,673
	$1,145,870	$ 961,338

(See accompanying accounting policies and notes)

Westcoast Transmission Company Limited
(Incorporated under the laws of Canada)

Shareholders' Equity	1979	1978
	(in thousands)	
Capital stock (Note 3):		
Authorized:		
5,000,000 preferred shares without nominal or par value		
75,000,000 common shares without nominal or par value		
Issued:		
792,080 $4.25 cumulative redeemable preferred shares series A (1978 – 800,000 preferred shares series A)	$ 39,604	$ 40,000
35,407,614 common shares (1978 – 34,662,834 common shares)	182,599	175,762
	222,203	215,762
Contributed surplus	1,361	1,280
Retained earnings	165,950	147,604
	389,514	364,646
Liabilities		
Long term debt (Note 6)	417,734	376,393
Deferred income taxes	41,363	25,697
Current liabilities:		
Bank indebtedness	62,712	14,201
Accounts payable	142,629	105,804
Sundry taxes	2,855	2,637
Interest on debt	10,473	7,013
Long term debt due within one year	20,510	12,008
	239,179	141,663
Minority interest in subsidiary companies:		
Preferred shares	9,199	11,175
Common shares	48,881	41,764
	58,080	52,939
	$1,145,870	$961,338

On behalf of the Board:

E. Phillips

Director

John Anderson

Director

Consolidated Statement of Operations

For the years ended December 31, 1979 and 1978

	1979	1978
	(in thousands)	
Operating revenues:		
Gas and by-product sales	$1,086,801	$832,749
Other	11,600	11,153
	1,098,401	843,902
Operating revenue deductions:		
Cost of gas sold	861,311	660,213
Operation and maintenance	76,992	56,364
Depreciation and depletion	37,583	30,189
Taxes – other than income taxes	23,440	17,799
	999,326	764,565
Operating income	99,075	79,337
Other income:		
Allowance for funds used during construction	8,271	4,305
Allowance for funds capitalized on northern projects	3,598	—
Investment and other income	2,685	2,523
	113,629	86,165
Income deductions:		
Interest on long term debt	36,317	29,032
Debt discount, premium and expense	591	516
Other interest and amortization	4,504	1,260
	41,412	30,808
Income before minority interest and income taxes	72,217	55,357
Minority interest	5,648	4,100
Income before income taxes	66,569	51,257
Income taxes:		
Current	1,033	634
Deferred	15,666	5,685
	16,699	6,319
Net income	49,870	44,938
Provision for dividends on preferred shares	3,399	3,400
Net income applicable to common shares	$ 46,471	$ 41,538
Common shares outstanding – weighted average	35,044	34,408
Per common share – weighted average (Note 3)	$1.33	$1.21
– fully diluted (Note 3)	$1.28	$1.17
Dividends per common share (Note 3)	$ .80	$ .69

(See accompanying accounting policies and notes)

Consolidated Statement of Retained Earnings

For the years ended December 31, 1979 and 1978

	1979	1978
	(in thousands)	
Unappropriated retained earnings:		
Balance, beginning of year	$111,604	$101,718
Net income	49,870	44,938
	161,474	146,656
Deduct dividends paid:		
Preferred shares	3,402	3,400
Common shares	28,122	23,652
	31,524	27,052
	129,950	119,604
Transferred to appropriated retained earnings	3,604	8,000
Balance, end of year	126,346	111,604
Appropriated retained earnings (Note 4):		
Reserve for redemption of preferred shares		
Balance, beginning of year	36,000	28,000
Transferred from unappropriated retained earnings	4,000	8,000
Transferred to unappropriated retained earnings for redemption (Note 3)	(396)	—
Balance, end of year	39,604	36,000
Retained earnings, end of year	$165,950	$147,604

Consolidated Statement of Contributed Surplus

For the years ended December 31, 1979 and 1978

	1979	1978
	(in thousands)	
Balance, beginning of year	$ 1,280	$ 470
Contributions in aid of construction	81	810
Balance, end of year	$ 1,361	$ 1,280

(See accompanying accounting policies and notes)

Consolidated Statement of Changes in Financial Position

For the years ended December 31, 1979 and 1978

	1979	1978
	(in thousands)	
Funds derived from:		
Operations –		
Net income	$ 49,870	$ 44,938
Add items not involving a flow of funds:		
Minority interest	5,648	4,100
Deferred income taxes	15,666	5,685
Depreciation, depletion and amortization	37,982	30,566
Debt discount, premium and expense	591	516
	109,757	85,805
Common shares issued	6,837	9,463
Additional long term debt (net of financing costs)	73,329	92,830
Working capital decrease	56,023	20,201
Other	(1,420)	685
	$244,526	$208,984
Funds used for:		
Additions to plant, property and equipment	$155,878	$137,219
Long term debt retirement (including exchange)	32,822	19,809
Long term debt converted to common shares	837	9,254
Dividends	31,524	27,052
Dividends paid by subsidiaries to minority interests	717	469
Investment in Westcoast Petroleum Ltd.	—	751
Northern pipeline projects	22,352	14,430
Retraction of preferred shares	396	—
	$244,526	$208,984
Changes in working capital components:		
Temporary cash investments	$ (2,252)	$ (2,833)
Deposits with trustees	(487)	3
Accounts receivable	41,763	17,397
Materials and supplies	400	453
Line pack gas	2,168	300
Prepayments	(99)	(154)
Bank indebtedness	(48,511)	(11,943)
Accounts payable	(36,825)	(21,421)
Sundry taxes	(218)	(255)
Interest on debt	(3,460)	(2,229)
Long term debt due within one year	(8,502)	481
Working capital decrease	$ (56,023)	$ (20,201)

(See accompanying accounting policies and notes)

Consolidated Statement of Long Term Debt

December 31, 1979 and 1978

	Due Date	1979 United States Dollars	1979 Canadian Dollars	1978 United States Dollars	1978 Canadian Dollars
			(in thousands)		
Westcoast Transmission Company Limited					
First Mortgage Pipe Line Bonds					
6% Series C	1980	$ 230	$ 247	$ 490	$ 527
5¾% Series D	1984		15,111		18,109
5¾% Series E	1984		5,553		6,615
7% Series F	1988	34,869	37,574	38,950	41,972
8% Series G	1991		78,450		82,300
Less purchased in advance of repayment requirements			(6,026)		(4,009)
9¾% Series H	1996	50,000	49,229	50,000	49,229
Debentures					
7½% Convertible, First Series (Note 6)	1991		2,337		3,174
8½% Debentures, 1993 Series	1993		43,100		47,836
Less purchased in advance of repayment requirements			(228)		(943)
9⅞% Debentures, 1998 Series	1998		75,000		75,000
10½% Debentures, 1999 Series	1999		75,000		—
Subordinate Debentures					
5½% Series A	1988	13,708	13,644	15,345	15,274
Less purchased in advance of repayment requirements		(1,300)	(1,293)	(1,426)	(1,420)
5½% Series B	1988	1,615	1,547	2,325	2,228
Less purchased in advance of repayment requirements		(51)	(49)	(52)	(50)
5½% Series C	1988	2,102	2,020	2,335	2,244
Less purchased in advance of repayment requirements		(334)	(321)	(115)	(111)
Gas Trunk Line of British Columbia Ltd.					
First Mortgage Sinking Fund Bonds					
6% Series A	1979	—	—	420	427
Subordinated Debentures					
6% Series A	1981		1,133		1,280
Less purchased in advance of repayment requirements			—		(5)
Westcoast Transmission Housing Ltd.					
Housing Mortgages, 7%	1993		49		52
Vancal Properties Ltd.					
7½% Secured Notes	1994	3,981	4,271	4,120	4,420
Westcoast Petroleum Ltd.					
Term Bank Loan	1980		1,792		1,892
Sinking Fund Debentures 10%, First Series	1993		20,000		20,000
Subordinate Debentures					
6½% Series A	1981		1,686		2,449
Saratoga Processing Company Limited					
First Mortgage Sinking Fund Bonds					
6¼% Series A	1979	—	—	250	256
Subordinated Debentures					
6% Series A	1981		674		700
Less purchased in advance of repayment requirements					(11)
8½% Promissory Note	1981		60		100
Pacific Northern Gas Ltd.					
First Mortgage Pipe Line Bonds					
7¾% Series A	1988	8,788	9,446	9,713	10,441
9¼% Series B (Note 6)	1991	2,220	2,238	2,405	2,425
Debentures					
11½% 1975 Series	1980		6,000		6,000
			438,244		388,401
Deduct long term debt due within one year			20,510		12,008
			$417,734		$376,393

(See accompanying accounting policies and notes)

Accounting Policies

December 31, 1979 and 1978

Principles of Consolidation:
The consolidated financial statements include the accounts of the Company and the following subsidiaries:

Westcoast Transmission Company (Alberta) Ltd. (100% owned)

Westcoast Transmission Housing Ltd. (100% owned)

Gas Trunk Line of British Columbia Ltd. (100% owned)

Vancal Properties Ltd. (100% owned)

Saratoga Processing Company Limited, (25% owned, including 100% of the voting shares)

Pacific Northern Gas Ltd. (45% owned, including 100% of the voting shares)

Westcoast Petroleum Ltd. (December 31, 1979 – 58.1% owned, including 56.6% of the voting shares, December 31, 1978 – 59.8% owned, including 57.6% of the voting shares)

Regulation:
The Company is subject to the National Energy Board Act and to the jurisdiction of the Board created thereby. That Board regulates accounting matters, export of gas, construction and operation of gas pipelines and rates, tolls and charges of the Company. The Company received decisions from the National Energy Board relating to the Company's rate application which was filed in September 1977. The Board directed the Company to change, effective November 1, 1979, certain of its rate-making and accounting policies applicable to its utility operations. These changes, which are outlined under the appropriate captions, affected rate of return on rate base, depreciation, allowance for funds used during construction and income taxes.

Cost of Service:
The Company and its utility subsidiaries (Westcoast Transmission Company (Alberta) Ltd., Westcoast Transmission Housing Ltd. and Gas Trunk Line of British Columbia Ltd.) operate under a cost of service agreement with the British Columbia Petroleum Corporation, a Crown corporation of the Province of British Columbia. Under this agreement the Company is reimbursed for costs associated with the operation of the utility system including expenses for operating, maintenance, administration, depreciation and taxes other than income taxes and it receives a return on its utility rate base (primarily the undepreciated portion of plant, property and equipment). Effective January 1, 1979, the Company is reimbursed for that portion of the foreign exchange gains or losses on foreign debt which is allocated to the financing of its utility rate base.

Rate of Return on Rate Base:
The National Energy Board directed the Company to change the rate of return on rate base to include a provision for income taxes on the tax allocation basis. The Company recorded, effective November 1, 1979, a return at the rate of 16.94% on a before-tax basis, which the Board had translated from an after-tax rate of 10.88% (for the ten months ended October 31, 1979 and the year ended December 31, 1978 – 11%).

Translation of United States Funds:
The Company's United States funds on deposit with banks and trustees and current liabilities payable in United States funds, with the exception of long term debt due within one year, have been translated to Canadian dollars at the exchange rates prevailing at the end of the fiscal years and the resulting gains or losses have been reflected in income. Long term debt and capital stock issued in United States funds have been translated at the exchange rates prevailing at the respective dates of issue.

Depreciation and Depletion:
Depreciation is calculated using straight-line rates determined on the economic and physical life of the assets in service. For the ten months ended October 31, 1979 and for the year ended December 31, 1978, depreciation was calculated on the assets in service at the commencement of the fiscal periods. Effective November 1, 1979, the National Energy Board directed the Company to commence calculating depreciation in the month following the in-service date of the assets and to amend certain straight-line depreciation rates. As a result of these changes, the depreciation expense charged to the cost of service increased by $1,600,000 for the two months ended December 31, 1979. The various rates used by the Company resulted in a composite rate of 3.6% for the year ended December 31, 1979 (for the year ended December 31, 1978 – 3.3%).

Depletion is calculated using the full cost method of accounting wherein all costs related to the acquisition, exploration for and development of oil and gas reserves are capitalized and depleted by a composite unit-of-production method based on total estimated proven reserves.

Capitalization and Maintenance:
Maintenance and repairs are charged to expense accounts when incurred and betterments which extend the useful life of properties are capitalized. Upon retirement or sale of items of property, the original cost of such items is charged against the applicable accumulated depreciation accounts and the net proceeds of disposal are credited to accumulated depreciation.

Allowance for Funds Used During Construction:
An allowance for funds used during construction was charged to plant, property and equipment at a rate of 11½% for the ten months ended October 31, 1979 and a rate of 11% for the year ended December 31, 1978. The National Energy Board directed the Company to adopt, effective November 1, 1979, a rate of 10.88%.

Allowance for Funds Capitalized on Northern Pipeline Projects:
An allowance for funds advanced for the northern pipeline projects was capitalized, effective January 1, 1979, as a deferred charge at a rate of 11½%.

Income Taxes:
For the ten months ended October 31, 1979 and for the year ended December 31, 1978 the Company provided for income taxes on the taxes payable basis under which no provision is made for income taxes deferred through claiming capital cost and other allowances in excess of amounts recorded in the accounts. The National Energy Board directed the Company to adopt, effective November 1, 1979, the tax allocation basis under which provision is made for income taxes deferred through claiming such allowances. This resulted in an increase in deferred income tax expense of $7,496,000. Westcoast Petroleum Ltd. provides for income taxes on the tax allocation basis. Pacific Northern Gas Ltd. adopted the tax allocation basis commencing July 1, 1978 and Saratoga Processing Company Limited provides for income taxes on the taxes payable basis.

If all the companies had used the tax allocation basis to provide for income taxes for the twelve months ended December 31, 1979, the additional provision for the year would have been $18,200,000 (for the year ended December 31, 1978 – $20,600,000) and the additional accumulated provision to December 31, 1979 would have been $163,100,000 (December 31, 1978 – $144,900,000).

Debt Discount, Premium and Expense:
Debt discount, premium and expense is being amortized over the life of the respective debt issues.

Pension Plan:
The Company has a non-contributory pension plan covering substantially all employees and contributes amounts necessary to provide normal retirement income for the participants. The Company contributed and charged to operations $1,559,000 during the year ended December 31, 1979 (during the year ended December 31, 1978 – $1,115,000). Based on the most recent actuarial evaluation, there is no unfunded liability at December 31, 1979.

Earnings per Common Share:
Fully diluted earnings per common share calculations assume the conversion of the convertible debt and the exercise of share purchase options and warrants. Funds derived from the exercise of options and warrants were assumed to have been invested to produce an annual return of 11% for the years ended December 31, 1979 and December 31, 1978.

Comparative Figures:
The 1978 comparative figures have been reclassified to conform to the 1979 presentation.

1. Plant, Property and Equipment:	1979	1978
	(in thousands)	
Westcoast Transmission and Utility Subsidiaries		
Gathering plant	$ 219,853	$ 214,865
Products extraction plant	208,673	116,733
Transmission plant	486,259	440,490
Miscellaneous plant and equipment	23,342	19,217
Construction work in progress	24,071	47,483
	962,198	838,788
Westcoast Petroleum Ltd.		
Transmission plant	40,545	41,300
Oil and gas properties	157,827	130,577
	198,372	171,877
Other Subsidiaries		
Gathering plant	5,077	5,075
Products extraction plant	6,454	6,416
Transmission plant	33,624	31,721
Distribution plant	9,472	8,313
Miscellaneous plant and equipment	7,654	7,859
Construction work in progress	208	210
	62,489	59,594
Total plant, property and equipment	1,223,059	1,070,259

Deduct:		
Accumulated depreciation		
Westcoast Transmission and Utility Subsidiaries	240,953	216,860
Westcoast Petroleum Ltd.	35,191	32,048
Other Subsidiaries	17,951	16,190
	294,095	265,098
Accumulated depletion		
Westcoast Petroleum Ltd.	24,032	19,045
Total accumulated depreciation and depletion	318,127	284,143
	$ 904,932	$ 786,116

2. Northern Pipeline Projects:
The Company owns 50% of the outstanding common shares of Foothills Pipe Lines (Yukon) Ltd. which has been given the responsibility by the National Energy Board for co-ordinating and directing the Canadian portion of the Alaska Highway Natural Gas Pipeline Project. The Canadian portion of the project has two principal objectives. The first is the transportation of Alaskan natural gas from the Alaska-Yukon border to Monchy, Saskatchewan and Kingsgate, British Columbia at the Canada-United States border. The second objective is the prosecution of the application, which was filed on June 29, 1979, for authorization from the National Energy Board to construct a pipeline, known as the Dempster Link, in the Yukon and Northwest Territories for the transportation of Canadian natural gas from the Mackenzie Delta-Beaufort Basin area to markets in southern Canada.

The Company's ownership in Foothills is recorded as an investment. Funds for pre-construction costs are advanced on the basis of Company percentage participation and recorded as deferred charges. Amounts expended to December 31, 1978 were approved by the National Energy Board as allowable additions to the project costs which will be recovered in the charges for transporting the Alaskan natural gas. Effective January 1, 1979, an allowance for funds capitalized on the advances is recorded in deferred charges at a rate of 11½%.

3. Capital Stock:

(a) Preferred shares:
On November 30, 1979, the Company invited tenders from all holders of the Preferred Shares Series A for the purchase of such shares at a price equal to $50 per share plus accrued and unpaid preferential dividends. All tenders received by February 14, 1980 shall be accepted. As at December 31, 1979, 7,920 shares have been tendered, decreasing preferred shares by $396,000. The Company, during the six month period ending December 31, 1984, will again invite tenders with similar conditions from the holders of the Preferred Shares Series A and all tenders received by February 14, 1985 shall be accepted.

The Preferred Shares Series A are redeemable after December 31, 1979 at the option of the Company at any time in whole or in part on not less than 30 days notice at varying redemption prices ranging from $54.25 if redeemed on or before December 31, 1980 to $50.50 if redeemed after December 31, 1984.

(b) During 1979 the Company issued:
- (i) 100,449 common shares on conversion of 7½% Convertible Debentures, First Series at a conversion rate of $8.33 per share, increasing capital stock by $837,000.
- (ii) 617,331 common shares on Share Purchase Warrants exercised at a price of $9.44 per share, increasing capital stock by $5,828,000.
- (iii) 27,000 common shares on options exercised at option prices of $5.166 and $7.875 per share, increasing capital stock by $172,000.

(c) During 1978 the Company issued:
- (i) 132,971 common shares on conversion of 7½% Convertible Debentures, First Series at a conversion rate of $8.33 per share, increasing capital stock by $1,108,000.
- (ii) 850,162 common shares on conversion of 5½% Subordinate Debentures, Series C at a conversion rate of $9.96 (U.S.) per share, increasing capital stock by $8,140,000
- (iii) 13,581 common shares on Share Purchase Warrants exercised at a price of $9.44 per share, increasing capital stock by $128,000.
- (iv) 15,000 common shares on options exercised at option prices of $5.166 and $6.458 per share, increasing capital stock by $87,000.
- (v) 75 common shares on conversion of 25 capital stock shares of Gas Trunk Line of British Columbia Ltd., increasing capital stock by $240.

(d) Common share reservations and options are as follows:
- (i) Included in the common shares reserved for outstanding options, as set out below are 230,000 common shares optioned to directors and officers (December 31, 1978 – 207,000 common shares).

Expiry date	Option price per share	Number of shares at December 31 1979	1978
July 26, 1980	$ 5.625	12,000	12,000
Oct. 16, 1983	$ 5.166	15,000	30,000
July 29, 1984	$ 6.458	30,000	30,000
April 20, 1986	$ 7.875	138,000	150,000
April 19, 1989	$13.500	162,000	—

- (ii) 446,625 common shares are reserved for options which have not been allocated (December 31, 1978 – 608,625 common shares).
- (iii) 280,553 common shares are reserved for conversion of the 7½% Convertible Debentures, First Series (December 31, 1978 – 381,033 common shares).
- (iv) 4,766,928 common shares are reserved for issuance upon the exercising of Share Purchase Warrants which may be exercised at $9.44 per share until May 15, 1981 (December 31, 1978 – 5,384,259 common shares).

4. Appropriated Retained Earnings:

The Company has provided a Retraction Purchase Fund which will be returned to unappropriated retained earnings as the Preferred Shares Series A are redeemed.

5. Dividend Restriction:

The First Mortgage and the indentures relating to the Company's long term debt and preferred shares contain restrictions as to the declaration or payment of dividends (other than stock dividends) on common shares. Under the most restrictive provision, the amount available for dividends at December 31, 1979 is $75,000,000 (December 31, 1978 – $62,000,000).

6. Long Term Debt:

Long term debt payments required in the five years ending December 31 are:

1980	$20,510,000
1981	$18,225,000
1982	$20,825,000
1983	$21,608,000
1984	$25,780,000

7½% Convertible Debenture, First Series are convertible into common shares at $8.33 per share until December 31, 1980.

Pacific Northern's 9¼% First Mortgage Pipe Line Bonds, Series B include detachable warrants to purchase 50,000 Class A common shares of Pacific Northern at $5 per share until maturity.

The translation of long term debt payable in United States funds at the exchange rate prevailing at the end of the fiscal year would increase long term debt including the portion due within one year to $454,988,000 (December 31, 1978 – $408,504,000). If followed, generally accepted accounting principles used in the United States for translation of foreign currencies would increase net income by $3,359,000 (for the year ended December 31, 1978 – reduction of net income by $9,950,000).

The Company has lines of credit with two Canadian chartered banks which allow the Company to borrow from the banks at each bank's prime lending rate and to issue bankers' acceptances to an aggregate limit of $100,000,000. The lines of credit are subject to annual review by the chartered banks.

The Company's First Mortgage Pipe Line Bonds are secured by a specific First Mortgage of substantially all of the Company's fixed assets, its gas purchase contracts, its gas sales contracts and 807,200 common shares of Westcoast Petroleum Ltd. and by a first floating charge on other assets and its undertakings.

7. Remuneration of Directors and Senior Officers of the Company:
The aggregate remuneration paid to directors and senior officers in their capacity as directors or officers for the year ended December 31, 1979 was $837,000 (for the year ended December 31, 1978 – $641,000).

8. Segmented Information:
More than 90% of the revenue and net income of the Company and its consolidated subsidiaries for the year ended December 31, 1979 are derived from the sales of natural gas produced in Canada. In excess of 90% of the assets of the Company and its consolidated subsidiaries as at December 31, 1979 are situated in Canada and are used for the sale of natural gas produced in Canada.

The revenue of the Company and its consolidated subsidiaries is generated from the following sources for the years ended December 31, 1979 and 1978:

(in thousands)	1979	1978
Canada	$ 236,925	$213,282
United States – Sales to Northwest Pipeline Corporation	861,476	630,620
Total revenue	$1,098,401	$843,902

9. Commitments and Contingencies:

(a) The Company has received approval from the National Energy Board for major construction projects which will cost approximately $73,000,000. Of this amount $14,000,000 has been included in the accounts at December 31, 1979 and an additional $9,000,000 has been committed.

(b) The Company is a party, along with others, to an agreement with the Government of Canada requiring that, in the event the National Energy Board issues a certificate for the construction of the Dempster Link (Note 2), construction will commence as expeditiously as possible. In the event of default by the parties to the agreement, the agreement provides for payment of $50,000,000 to the Government of Canada, the obligation for which is joint and several among the parties.

10. Selected Quarterly Data *(in thousands)* (Unaudited):

1979		For the three months ended		
	March 31	June 30	September 30	December 31
Operating revenues	$276,215	$228,593	$218,045	$375,548
Operating revenue deductions	253,449	207,183	196,291	342,403
Operating income	22,766	21,410	21,754	33,145
Other	7,668	8,015	7,575	9,248
Net income before income taxes	15,098	13,395	14,179	23,897
Provision for income taxes	2,447	1,665	1,687	10,900
Net income	12,651	11,730	12,492	12,997
Provision for preferred dividends	850	850	850	849
Net income applicable to common shares	$ 11,801	$ 10,880	$ 11,642	$ 12,148
Per common share:				
Weighted average	$.34	$.31	$.33	$.35
Fully diluted	$.33	$.30	$.32	$.33

1978		For the three months ended		
	March 31	June 30	September 30	December 31
Operating revenue	$239,219	$185,705	$158,423	$260,555
Operating revenue deductions	219,414	166,780	139,248	239,123
Operating income	19,805	18,925	19,175	21,432
Other	7,123	6,705	6,559	7,693
Net income before income taxes	12,682	12,220	12,616	13,739
Provision for income taxes	1,549	1,263	1,075	2,432
Net income	11,133	10,957	11,541	11,307
Provisions for preferred dividends	850	850	850	850
Net income applicable to common shares	$ 10,283	$ 10,107	$ 10,691	$ 10,457
Per common share:				
Weighted average	$.30	$.30	$.31	$.30
Fully diluted	$.29	$.29	$.30	$.29

11. Replacement Cost Data (unaudited):
In compliance with rules of the Securities and Exchange Commission of the United States, the Company has estimated certain replacement cost data with respect to plant investment and related accumulated depreciation, cost of gas sold, and depreciation expense. The results are explained and quantified in the Company's Form 10-K filed with the Commission and show that a significant increase in capital investment would be necessary to replace existing service capacity. The disclosure of this data is to comply with the Commission's rule and does not indicate a change in the Company's replacement policy.

The Company is under the jurisdiction of the National Energy Board of Canada and operates under a cost of service agreement with the British Columbia Petroleum Corporation. This agreement allows for the recovery of the Company's cost of service, including the cost of gas sold, depreciation based upon the historical plant cost, and a return on a rate base which includes net plant based upon historical cost. The National Energy Board presently does not recognize replacement cost for accounting purposes or rate determinations.

Auditors' Report

To the Shareholders of Westcoast Transmission Company Limited:

We have examined the consolidated balance sheet and the consolidated statement of long term debt of Westcoast Transmission Company Limited as at December 31, 1979 and 1978 and the consolidated statements of operations, retained earnings, contributed surplus and changes in financial position for the years then ended. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as at December 31, 1979 and 1978 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles consistently applied except for the changes, with which we concur, in the depreciation policy and the basis of accounting for income taxes as described in the accounting policies.

Vancouver, Canada,
February 1, 1980.

CLARKSON GORDON
Chartered Accountants

Incinerator stack at right and sulphur pouring towers at the Pine River process plant. One of the most efficient plants in Canada, it incorporates special features to ensure compatibility with the local environment.

Management's Discussion of Operations

The Company's Ten Year Review on page 30 presents financial data which provide the basis for the following discussion of operations.

Year ended December 31, 1979

Substantial increases in operating revenue and operating revenue deductions over 1978 resulted from an increase of 17% in average price of gas sold and from an increase of 12% in volume of gas sold. Operation and maintenance increased over 1978 as a result of increases in maintenance and fuel consumed in operations. Increases in depreciation and depletion over 1978 resulted mainly from additions to depreciable assets during the year. Taxes other than income taxes increased over 1978 primarily due to increases in property taxes and in taxes paid on fuel consumed in operations. The net income of the Company was not appreciably affected by the variances descrbied above because the Company's income from utility operations is based on the cost-of-service agreement with the British Columbia Petroleum Corporation.

Operating income increased because of an increased average utility rate base (11.3%), the change of return on rate base from an after-tax rate of 11% to a before-tax rate of 16.94% effective November 1, 1979 and the increase in operating income of Westcoast Petroleum Ltd.

Allowance for funds used during construction increased relative to 1978 primarily due to the increase in construction activity.

An allowance for funds advanced for the northern pipeline projects was capitalized at a rate of 11½% effective January 1, 1979.

Interest on long term debt increased over 1978 due to the issuance of the 9⅞% debentures on September 1, 1978, the issuance of the 10½% debentures on August 1, 1979 and increased foreign exchange on interest on debt payable in U.S. funds.

Other interest and amortization increased over 1978 due to interest on increased bank borrowings.

The increase in income taxes was due to the adoption of the tax allocation basis, effective November 1, 1979, for providing the Company's income taxes.

Year ended December 31, 1978

Substantial increases in operating revenue and operating revenue deductions over 1977 resulted from an increase of 17% in the average price of gas sold offset by a decrease of 7% in volumes of gas sold. The net income of the Company, however, was not appreciably affected as the Company's income from utility operations is based on the cost-of-service agreement with the British Columbia Petroleum Corporation.

Segmented Statement of Operations *(in thousands)* **Years ended December 31**

	Westcoast Transmission Company Limited and Utility Subsidiaries(a)	Westcoast Petroleum Ltd.	Other Subsidiaries	Consolidated
1979				
Operating revenues	$1,056,850	$31,228	$10,323	$1,098,401
Operating revenue deductions	982,925	15,145	1,256	999,326
Operating income	73,925	16,083	9,067	99,075
Other income	13,402	986	166	14,554
	87,327	17,069	9,233	113,629
Income deductions	35,700	2,463	3,249	41,412
	51,627	14,606	5,984	72,217
Minority interest	—	3,948	1,700	5,648
Income before income taxes	51,627	10,658	4,284	66,569
Income taxes	7,496	6,000	3,203	16,699
Net income	$ 44,131	$ 4,658	$ 1,081	$ 49,870
1978				
Operating revenues	$ 810,827	$25,623	$ 7,452	$ 843,902
Operating revenue deductions	750,240	11,963	2,362	764,565
Operating income	60,587	13,660	5,090	79,337
Other income	6,125	564	139	6,828
	66,712	14,224	5,229	86,165
Income deductions	27,105	1,393	2,310	30,808
	39,607	12,831	2,919	55,357
Minority interest	—	2,981	1,119	4,100
Income before income taxes	39,607	9,850	1,800	51,257
Income taxes	19	5,100	1,200	6,319
Net income	$ 39,588	$ 4,750	$ 600	$ 44,938

(a) Utility subsidiaries are:
Westcoast Transmission Company (Alberta) Ltd.
Westcoast Transmission Housing Ltd.
Gas Trunk Line of British Columbia Ltd.

Operating income increased because of an increased average utility rate base (3.2%) and because operating income also increased by $1,955,000 with respect to Westcoast Petroleum Ltd.

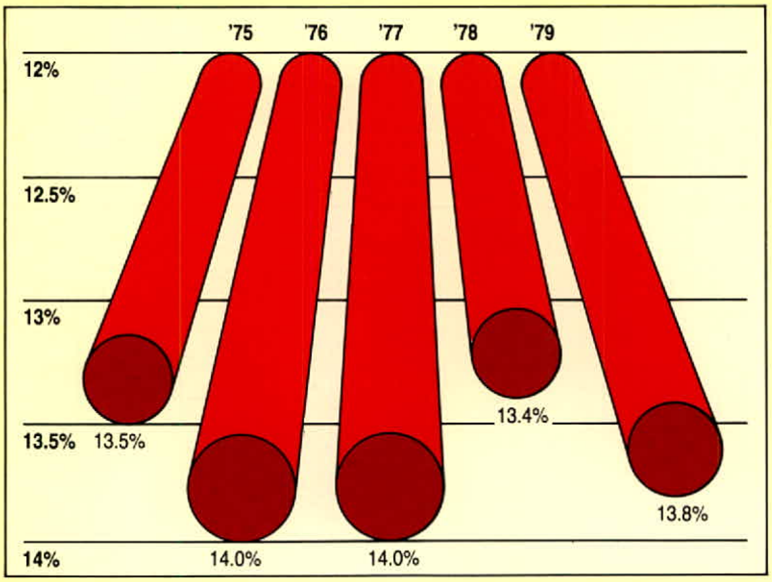
Allowance for funds used during construction increased relative to 1977 because of the increase in construction activity.

Investment and other income decreased from 1977 because reduced surplus funds provided less interest income on amounts available for investment.

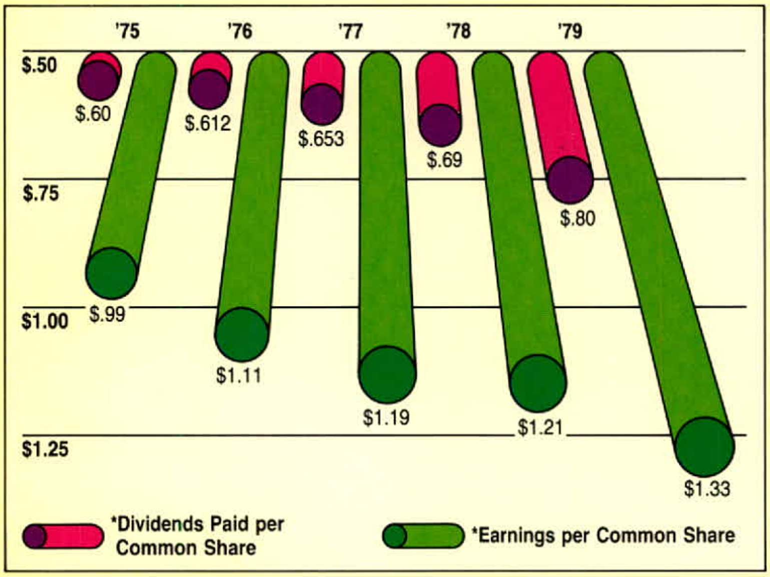
Interest on long term debt increased over 1977 due to the issuance of 9⅞% debentures on September 1, 1978 and foreign exchange on interest on debt payable in U.S. funds offset by reduced debt due to conversions of certain debt securities and scheduled repayments.

Other interest and amortization increased over 1977 due to interest on increased bank borrowings.

Return on Average Common Shareholders' Equity



Dividends Paid per Common Share & Earnings per Common Share



**Reflects three-for-one share split.*

Ten Year Review

(Dollar amounts are in thousands, except per share figures)

Financial
Operations:
Operating revenue
Operating income
Financial charges
Income before special items
Special items
Net income
Dividends on preferred shares
Net income applicable to common shares
Dividends on common shares
Cash flow
Per Common Share:
Net income – weighted average
– fully diluted
Dividends
Dividend payout ratio
Cash flow
Assets:
Plant, property and equipment
Accumulated depreciation and depletion
Net plant, property and equipment
Net additions to plant
Total assets
Rate Base and Return:**
Average utility rate base
Average return on utility rate base
Average return on equity in utility rate base
Capitalization:
Long term debt
Preferred shareholders' equity
Common shareholders' equity
– per common share
Return on average common shareholders' equity
Capitalization Ratios:
Long term debt
Preferred shareholders' equity
Common shareholders' equity
Statistical
Total gas sales –
Thousands of cubic meters
Millions of cubic feet
Average daily sales –
Cubic meters
Thousands of cubic feet
Peak day sales –
Cubic meters
Thousands of cubic feet
System sales capacity –
Cubic meters per day
Thousands of cubic feet per day
Kilometers of transmission pipelines
Miles of transmission pipelines
Kilometers of gathering pipelines
Miles of gathering pipelines
Compressor kilowatts
Compressor horsepower
Shares outstanding at year end*
Number of common shareholders
Number of employees

*Financial information has been restated to give retroactive effect to the three-for-one common share split.

**The nature of the Company's utility operations changed significantly in November 1973 at which time it commenced operating on a cost-of-service basis whereby utility operating costs are recovered and the Company receives a return on its utility investment.

				Years Ended December 31			Nine Months Ended December 31 ▼		
1979	1978	1977	1976	1975	1974	1973	1972	1971	1970
$ 1,098,401	$ 843,902	$ 780,164	$ 579,276	$ 416,677	$ 266,600	$ 168,764	$ 139,492	$ 101,575	$ 69,684
99,075	79,337	74,978	67,930	53,913	49,974	47,093	42,810	26,665	16,254
36,908	29,548	27,398	23,945	25,934	27,680	28,062	26,189	24,960	14,597
49,870	44,938	42,850	39,459	33,019	26,731	24,001	21,314	8,416	3,103
—	—	—	—	—	—	—	(470)	814	—
49,870	44,938	42,850	39,459	33,019	26,731	24,001	20,844	9,230	3,103
3,399	3,400	3,400	3,400	3,400	1,559	—	—	—	—
46,471	41,538	39,450	36,059	29,619	25,172	24,001	20,844	9,230	3,103
28,122	23,652	21,674	19,798	17,654	11,275	6,430	5,112	3,368	3,351
109,757	85,805	81,419	75,867	55,060	47,161	42,082	37,931	21,836	12,779
1.33	1.21	1.19	1.11	.99	.97	.93	.82	.46	.15
1.28	1.17	1.13	1.04	.90	.83	.80	.76	.46	.15
.80	.69	.653	.612	.60	.433	.25	.20	.167	.167
60%	57%	55%	55%	61%	45%	27%	24%	36%	109%
3.13	2.49	2.45	2.34	1.84	1.81	1.64	1.49	1.08	.64
1,223,059	1,070,259	932,821	882,394	736,752	699,954	653,223	618,071	564,769	461,394
318,127	284,143	254,218	227,669	167,632	149,212	131,826	115,262	100,175	89,839
904,932	786,116	678,603	654,725	569,120	550,742	521,397	502,809	464,594	371,555
152,800	137,438	50,427	36,977	36,798	46,731	35,152	53,302	103,375	31,908
1,145,870	961,338	823,289	767,840	675,189	664,999	614,217	571,584	533,836	437,154
607,821	546,579	529,758	516,738	499,092	493,404	—	—	—	—
10.9%	11.0%	11.0%	10.5%	10.0%	9.5%	—	—	—	—
14.1%	14.0%	14.5%	14.4%	14.2%	14.2%	—	—	—	—
417,734	376,393	310,456	317,275	308,037	367,105	386,960	371,098	378,712	305,518
39,604	40,000	40,000	40,000	40,000	40,000	—	—	—	—
349,910	324,646	296,487	268,873	247,670	190,668	174,332	156,508	96,459	89,396
9.88	9.37	8.81	8.25	7.72	7.33	6.78	6.09	4.76	4.45
13.8%	13.4%	14.0%	14.0%	13.5%	13.8%	14.5%	16.5%	9.9%	3.5%
51.8%	50.8%	48.0%	50.7%	51.7%	61.4%	68.9%	70.3%	79.7%	77.4%
4.9%	5.4%	6.2%	6.4%	6.7%	6.7%	—	—	—	—
43.3%	43.8%	45.8%	42.9%	41.6%	31.9%	31.1%	29.7%	20.3%	22.6%
10 866 503	9 757 496	10 467 364	9 791 490	10 005 393	10 261 958	11 675 489	10 443 880	8 148 758	5 591 462
383,598	344,449	369,508	345,649	353,200	362,257	412,156	368,679	287,659	197,384
29 771 241	26 732 869	28 677 710	26 752 727	27 412 029	28 114 928	31 987 627	28 535 171	22 325 341	20 332 562
1,050,953	943,696	1,012,351	944,397	967,671	992,484	1,129,194	1,007,319	788,106	717,759
39 829 100	38 774 354	37 395 270	32 972 331	33 265 722	33 681 688	36 393 966	35 439 119	31 806 244	25 117 701
1,406,006	1,368,772	1,320,089	1,163,955	1,174,312	1,188,996	1,284,742	1,251,035	1,122,791	886,679
37 704 354	36 996 159	36 996 159	36 996 159	36 996 159	36 996 159	36 996 159	34 871 571	31 217 280	24 475 254
1,331,000	1,306,000	1,306,000	1,306,000	1,306,000	1,306,000	1,306,000	1,231,000	1,102,000	864,000
2 294	2 253	2 253	2 214	2 214	2 211	2 211	2 076	1 934	1 555
1,425	1,400	1,400	1,376	1,376	1,374	1,374	1,290	1,202	966
1 968	1 935	1 593	1 548	1 395	1 278	1 151	1 147	1 093	914
1,223	1,203	990	962	867	794	715	713	679	568
337 966	337 966	333 492	333 492	333 492	329 017	285 021	284 275	256 312	214 627
453,220	453,220	447,220	447,220	447,220	441,220	382,220	381,220	343,720	287,820
35,407,614	34,662,834	33,651,045	32,604,651	32,089,857	26,020,200	25,727,931	25,688,829	20,281,023	20,111,451
12,660	12,496	9,870	9,677	9,768	9,525	10,225	10,630	10,450	10,585
727	638	573	508	514	519	515	502	494	518

Corporate Information

REGISTRARS

Common Shares
CANADA TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Toronto, Ont. Montreal, P.Q.

CHEMICAL BANK – New York, N.Y.

Preferred Shares
CANADA PERMANENT TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Bonds
MONTREAL TRUST COMPANY – Vancouver, B.C.

Debentures
Subordinate Debentures:
CITIBANK, N.A. – New York, N.Y.
MONTREAL TRUST COMPANY (co-registrar) – Vancouver, B.C., Calgary, Alta, Toronto, Ont., Montreal, P.Q.

First Series Debentures:
CANADA PERMANENT TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

1993, 1998 and 1999 Series Debentures:
CANADA TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

AUDITORS

Clarkson Gordon
P.O. Box 10101, Pacific Centre
700 West Georgia Street, Vancouver, B.C.

TRANSFER AGENTS

Common Shares, Bonds, Subordinate Debentures
MONTREAL TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Toronto, Ont., Montreal, P.Q.
CITIBANK, N.A. – New York, N.Y.
(Series E Bonds are transferable at the Montreal Trust Company branch in Winnipeg, Man., and Common Shares are transferable at the Montreal Trust Company branch in Regina, Sask.)

First Series Debentures
CANADA PERMANENT TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

1993, 1998 and 1999 Series Debentures
CANADA TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Preferred Shares
CANADA TRUST COMPANY – Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

STOCK EXCHANGES

Listed on the Toronto, Montreal and Vancouver Stock Exchanges in Canada and the New York and Pacific Coast Stock Exchanges in the United States

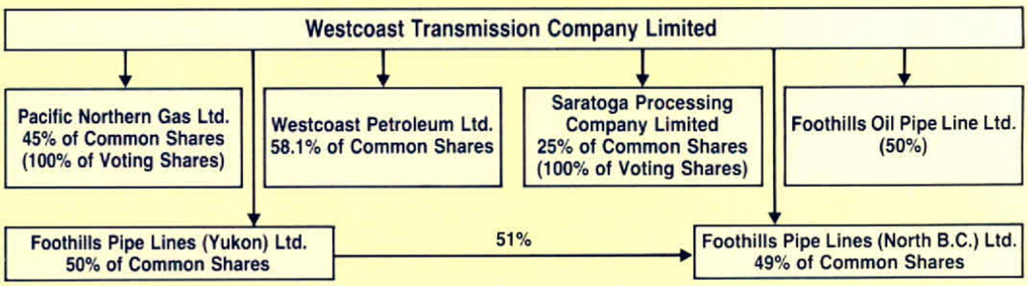
Stock Symbol — WTC

OFFICES

1333 West Georgia Street, Vancouver, B.C. V6E 3K9
1212 - One Palliser Square, Calgary, Alberta T2G 0P6

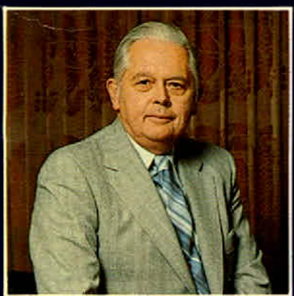
Stock Market Price Ranges *(Common Shares)*	**New York**		**Toronto**	
	Low	**High**	**Low**	**High**
	(U.S. Dollars)		(Canadian Dollars)	
January-March 1979	9⅜	11⅞	11⅛	13¾
April-June 1979	11	13¾	13	15⅞
July-September 1979	12⅛	14	14⅛	16⅜
October-December 1979	10	13¾	11¾	15⅝
January-March 1978	9⅜	10⅜	10⅜	11¾
April-June 1978	9½	10⅝	10⅞	11⅝
July-September 1978	9¾	11⅛	11	12¾
October-December 1978	8¾	10¼	11	11⅞

Earnings and Dividends Paid *(Common Shares)*	**1979**		**1978**	
	Earnings	**Dividends**	**Earnings**	**Dividends**
January-March	$0.34	$0.20	$0.30	$0.167
April-June	0.31	0.20	0.30	0.170
July-September	0.33	0.20	0.31	0.170
October-December	0.35	0.20	0.30	0.183
	$1.33	$0.80	$1.21	$0.690

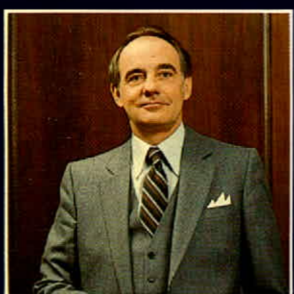


Directors

*John Anderson
Executive Vice President and
Chief Operating Officer
Westcoast Transmission
Company Limited
Vancouver, British Columbia



†James S. Byrn
President and
Chief Executive Officer
Genstar Marine Limited
North Vancouver, British
Columbia



*Alton J. Green
Vice President and Northern
Pipelines Co-Ordinator
Westcoast Transmission
Company Limited
Vancouver, British Columbia

*Edwin C. Phillips
President and
Chief Executive Officer
Westcoast Transmission
Company Limited
Vancouver, British Columbia

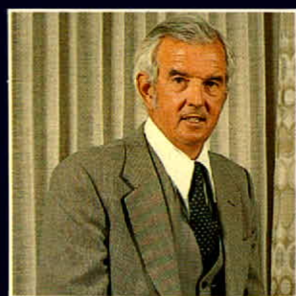
David L. Helliwell
President and
Chief Executive Officer
British Columbia Resources
Investment Corporation
Vancouver, British Columbia

J. Taylor Kennedy
Director
Canada Cement Lafarge Ltd.
Montreal, Quebec

L. Merrill Rasmussen
President
Husky Oil Company
Cody, Wyoming

J. Ernest Richardson
Chairman of the Board
MacMillan Bloedel Limited
Vancouver, British Columbia

†William H. Tye
Vice President
Bow Valley Exploration
Calgary, Alberta



†Charles N.W. Woodward
Chairman of the Board
Woodward Stores Limited
Vancouver, British Columbia

Wilbert H. Hopper
Chairman and
Chief Executive Officer
Petro-Canada
Calgary, Alberta

Frank M. McMahon
Chairman Emeritus of the
Board
Hamilton, Bermuda

Norman R. Whittall
Honorary Director
Vancouver, British Columbia

*Executive Committee
Member
†Audit Committee Member

Officers

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President and
Chief Executive Officer

John Anderson
Executive Vice President and
Chief Operating Officer

A.J. Green
Vice President and Northern
Pipelines Co-Ordinator

J.E. Johnson
Vice President, Operations

J.A. Kavanagh
Vice President, Engineering

L.J. Smith
Vice President, Finance

G.W. Lade
Vice President, General
Counsel and Secretary

J.E. May
Comptroller

W.N. Collett
Treasurer

D.O. Hunter
Assistant Treasurer

P.M. Steele
Assistant Secretary

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