



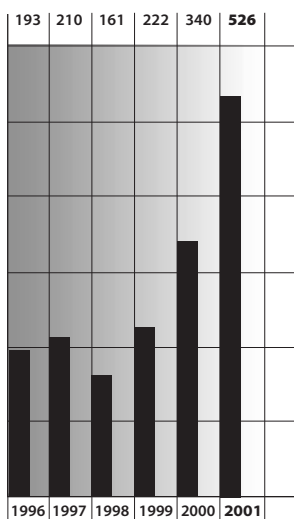
Westcoast Energy Inc., a Duke Energy Company

ANNUAL REPORT 2001

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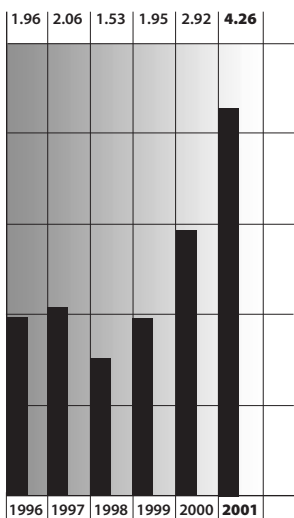
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# Management's Discussion & Analysis



**Net Income Applicable to Common Shares**

\$million



**Earnings per Common Share (EPS)**

dollars

This discussion and analysis of the Company should be read in conjunction with the consolidated financial statements and accompanying notes. The results reported herein have been prepared in accordance with Canadian generally accepted accounting principles and are presented in Canadian dollars. The effects on net income arising from the variances between Canadian and United States generally accepted accounting principles are described in Note 19 to the consolidated financial statements.

The consolidated financial statements include the accounts of the Company, its subsidiaries and its proportionate share of joint venture investments.

For the second consecutive year, the Company announced record net income applicable to common shares. Net income for the year ended December 31, 2001 was \$526 million, compared with \$340 million for 2000, an increase of 55%.

The Company's earnings were adversely impacted in 2001 and 2000 by warmer than normal weather. The unusually warm temperatures in the Company's gas distribution franchise areas particularly affected the 2001 results. Weather, measured in heating degree-days, was 12.7% warmer than normal in 2001 and 2.3% warmer than normal in 2000. Normal heating degree-days are determined each year as the simple average of the previous 30 years actual heating degree-days. Weather normalized earnings per common share were \$4.44 and \$2.96 for 2001 and 2000, respectively.

Fiscal 2001 and 2000 results were favourably impacted by the contributions of \$33 million (\$0.27 per common share) and \$46 million (\$0.40 per common share), respectively, arising from reductions in corporate income tax rates. As a result of federal and provincial corporate income tax rate reductions announced in 2001 and 2000, becoming effective in the period to 2004, the deferred income tax assets and liabilities have been adjusted to reflect the current and substantively enacted income tax rates.

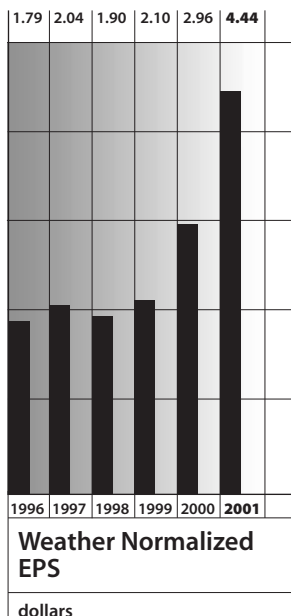
In September 2001, Duke Energy Corporation (Duke Energy) announced plans to expand its position in the North American natural gas marketplace by acquiring the Company in a cash and stock transaction valued at approximately US\$8 billion, including debt assumed, under a Plan of Arrangement. The transaction was completed on March 14, 2002.

Normalizing for weather, the impact of the corporate income tax rate reductions, the \$0.86 per common share gain on the sale of the Company's interests in two Canadian power generating facilities, Westcoast Capital Corporation (Westcoast Capital) and Union Energy Inc. (Union Energy) in 2001, and the costs related to the acquisition of the Company by Duke Energy, normalized earnings per common share were \$3.38 and \$2.56 for 2001 and 2000, respectively. Normalizing for these items is consistent with the Company's prior practice but these measures do not have standardized meaning prescribed by Canadian generally accepted accounting principles and are therefore unlikely to be comparable to similar measures presented by other enterprises.

## CONSOLIDATED OPERATIONS

Years ended December 31 (\$million)	2001	2000
Net income applicable to common shares	526	340
Weather	22	5
Weather normalized earnings	548	345
Reduction in corporate income tax rates	(33)	(46)
Sale of two Canadian power generating facilities	(85)	—
Sale of Westcoast Capital and Union Energy	(22)	—
Costs related to the planned acquisition of the Company by Duke Energy	8	—
Weather and significant items normalized earnings (\$/share)	416	299
Earnings per common share	\$4.26	\$2.92
Weather	0.18	0.04
Weather normalized earnings per common share	4.44	2.96
Reduction in corporate income tax rates	(0.27)	(0.40)
Sale of two Canadian power generating facilities	(0.69)	—
Sale of Westcoast Capital and Union Energy	(0.17)	—
Costs related to the planned acquisition of the Company by Duke Energy	0.07	—
Weather and significant items normalized earnings per common share	\$3.38	\$2.56

Results for the year ended December 31, 2001 from the Transmission & Field Services segment reflect a strong performance by the British Columbia Pipeline and Field Services divisions and Maritimes & Northeast Pipeline, primarily as a result of higher interruptible and short-term firm service revenues, which were partially offset by merchant capacity losses on the Alliance and Vector pipelines. The Gas Distribution segment benefited from significantly higher storage and transportation revenues from Union Gas Limited (Union Gas), which were partially offset by warmer weather and lower use per customer caused by high gas prices. The International segment results for the year ended December 31, 2001 reflected higher operating income from four



operational units at the Cantarell Nitrogen Facilities (Cantarell) compared with the same period in the prior year when the project was still in the final stages of commissioning. A strong performance from Engage Energy<sup>(1)</sup> contributed to the good fiscal 2001 results for the Services segment.

Fiscal 2000 enjoyed higher contributions from new pipeline projects and strong contributions from the British Columbia Pipeline and Field Services divisions, due primarily to increased throughputs and higher natural gas prices. The 2000 results showed continuing improved results from Engage Energy, reflecting the addition of new gas and electric structured products and successful trading operations, and from Union Energy, reflecting higher revenues and improved margins. Fiscal 2000 results also reflect customer growth and increased storage and transportation revenues at Union Gas as well as higher contributions from international projects.

Divestitures in 2001 included the sale of the Company's interests in two Canadian power generating facilities, its wholly owned subsidiaries Westcoast Capital and Union Energy and its remaining 49% interest in NGX Canada Inc. (NGX), which provided in total an after-tax gain of \$112 million or \$0.90 per common share. Divestitures in 2000 included the sale of the Company's 74% interest in the EastCoast Power Project in Australia, a 51% interest in NGX and its 50% interest in the Liberty Electric Power Project, which provided in total an after-tax gain of \$15 million or \$0.13 per common share.

The increase in operating revenues and cost of sales in 2001 over 2000 primarily reflects the impact of increasing natural gas and electricity prices and the acquisition of the additional 50% interest in Engage Energy Canada L.P., increasing the Company's interest to 100% in October 2000. In addition, revenues from Cantarell, commencing from its partial in-service date of June 2000, have also contributed to the increase.

The effective consolidated income tax rate for 2001 was 18.7%, compared with 12.7% in 2000. The lower effective tax rate in 2000 is mainly attributable to a tax adjustment arising from the re-filing of a prior year's tax return and the impact of the federal and provincial income tax rate reductions recorded in 2000. Details of the consolidated income tax provisions are provided in Note 5 to the consolidated financial statements.

<sup>(1)</sup> For the nine months ended September 30, 2000, Engage Energy represents the Company's 50% interest in Engage Energy Canada, L.P. and Engage Energy U.S., L.P. With the termination of the joint venture agreement with The Coastal Corporation on October 2, 2000, Engage Energy represents the Company's 100% interest in Engage Energy Canada, L.P. and Engage Energy America LLC.

## CONSOLIDATED QUARTERLY RESULTS

(\$million, except for share data)

2001	For the three months ended				
	Mar-31	Jun-30	Sep-30	Dec-31	Total
Operating revenues	5,271	2,090	2,172	2,364	11,897
Net income	143	115	139	175	572
Earnings per common share					
—basic	\$1.08	\$0.84	\$1.02	\$1.32	\$4.26
—diluted	\$1.07	\$0.80	\$0.93	\$1.20	\$3.87

(\$million, except for share data)

2000	For the three months ended				
	Mar-31	Jun-30	Sep-30	Dec-31	Total
Operating revenues	1,754	1,761	2,130	3,310	8,955
Net income	130	82	36	140	388
Earnings per common share					
—basic	\$1.03	\$0.60	\$0.20	\$1.09	\$2.92
—diluted <sup>(2)</sup>	\$1.03	\$0.51	\$0.20	\$1.00	\$2.75

<sup>(2)</sup> diluted per share amounts have been restated to reflect the adoption in January 2001 of the new recommendations of The Canadian Institute of Chartered Accountants (CICA) with respect to earnings per share.

The fourth quarter results in 2001 were adversely impacted by significantly warmer than normal weather, compared with the colder than normal weather experienced in the fourth quarter of 2000. Weather reduced earnings by \$0.10 per common share for the three months ended December 31, 2001 and increased earnings by \$0.05 per common share for the three months ended December 31, 2000.

Fourth quarter 2001 results were favourably impacted by the after-tax gain of \$22 million or \$0.17 per common share arising from the sale of Westcoast Capital and Union Energy. Earnings in the fourth quarter of 2001 also reflected the solid performance from Engage Energy, capitalizing on the volatility in the North American natural gas and electric markets. The Canadian government's federal budget in October 2000 also provided further corporate income tax rate reductions, which provided a contribution of \$30 million (\$0.26 per common share) in the fourth quarter of 2000. After adjusting for weather, the corporate income tax rate reductions, the gain on the sale of Westcoast Capital and Union Energy and the costs related to the acquisition of the Company by Duke Energy, normalized earnings per common share for the three months ended December 31, 2001 and 2000 were \$1.29 and \$0.78, respectively.

## RESULTS BY BUSINESS SEGMENT

The operations of the Company are grouped according to the following business segments:

- Transmission & Field Services - natural gas gathering, processing and transmission;
- Gas Distribution - natural gas distribution and storage and transmission;
- Power Generation - electrical and thermal energy generated from natural gas;
- International - international operations;
- Services - energy marketing, retail energy services, customer billing system and financial services. The retail energy services and financial services businesses, operated by Westcoast Capital and Union Energy, were sold in 2001;
- Other - other activities, including corporate expenses, business development expenditures and corporate financing expenses.

The contribution to net earnings by these business segments, after allocation of acquisition costs, was:

Years ended December 31 (\$million)	2001	2000
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES		
Transmission & Field Services	195	188
Gas Distribution	116	112
Power Generation	108	16
International	32	29
Services	150	45
Other	(75)	(50)
	526	340

Additional segmented information is provided in Note 18 to the consolidated financial statements.

### TRANSMISSION & FIELD SERVICES

The contribution to net earnings for Transmission & Field Services was:

Years ended December 31 (\$million)	2001	2000
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES		
British Columbia Pipeline and Field Services Divisions	122	109
Non-NEB regulated Field Services Division	1	1
Foothills Pipe Lines	6	10
Empire State Pipeline	9	6
Maritimes & Northeast Pipeline	27	14
Alliance Pipeline	34	35
Aux Sable	(5)	—
Vector Pipeline	(4)	8
Other	5	5
	195	188

The increase in the contribution to net earnings for Transmission & Field Services in 2001 over 2000 is primarily due to the strong performance by the British Columbia Pipeline and Field Services divisions and Maritimes & Northeast Pipeline, reflecting higher interruptible and short-term firm service revenues, partially offset by merchant capacity losses on the Alliance and Vector pipelines.

#### British Columbia Pipeline and Field Services Divisions

The Company's integrated natural gas gathering, processing and transmission system (the BC Pipeline System) in British Columbia, Alberta, and the Yukon and Northwest Territories consists of approximately 5,600 kilometres of natural gas gathering and transmission pipelines and five gas processing facilities, three of which include sulphur recovery plants. These facilities are regulated by the National Energy Board (NEB).

The majority of the Transmission & Field Services segment's net earnings continue to be generated from the British Columbia Pipeline and Field Services divisions. In 2001 and 2000, earnings benefited from increased firm contract and interruptible service revenues, partially offset by higher operating and maintenance expenses. The return on common equity realized by these divisions was 14.63% in 2001, compared with 13.57% in 2000.

Natural gas is delivered to markets in British Columbia, other parts of Canada and the western United States. Total throughput on the transmission mainline in

2001 was 659 billion cubic feet (Bcf), compared with 682 Bcf in 2000. The lower volumes in 2001 were largely due to two factors. First, demand for natural gas declined due to high natural gas prices experienced late in 2000 and early 2001. Second, 2001 was warmer on average than the previous year resulting in weaker demand in temperature sensitive sectors.

#### NEB Toll Application for Mainline Transmission

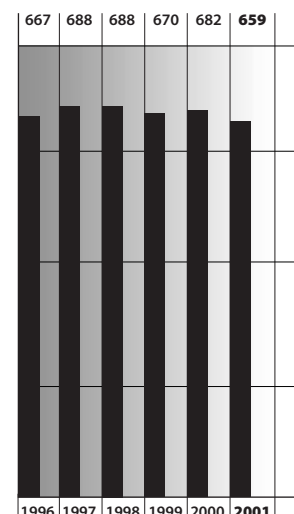
##### Facilities and Operations

Between January 1, 1997 and December 31, 2001 the British Columbia Pipeline Division operated under the multi-year incentive toll settlement under which shippers were given a one-time option of contracting for fixed tolls for a contract term of five years, or tolls that were adjusted annually in accordance with a prescribed incentive methodology. With the expiration of the multi-year toll settlement, the Company filed a toll application with the NEB in December 2001 with respect to its federally regulated mainline transmission facilities and operations, requesting approval of tolls for a one-year period commencing on January 1, 2002.

Since filing the toll application in December, the Company has reached a toll settlement (the 2002/2003 Settlement) with its major stakeholders for the period from January 1, 2002 to December 31, 2003. The 2002/2003 Settlement establishes methods for setting revenue requirements and tolls for the two-year period and provides toll certainty for both the Company and the shippers. The 2002/2003 Settlement increases the depreciation rate for the Company from a composite rate of 1.89% to 2.625%. Customers and the Company will also share in discretionary revenues generated above the base revenue requirement. On March 26, 2002, the Company filed an application with the NEB amending its toll application filed in December 2001 and is seeking approval of the 2002/2003 Settlement.

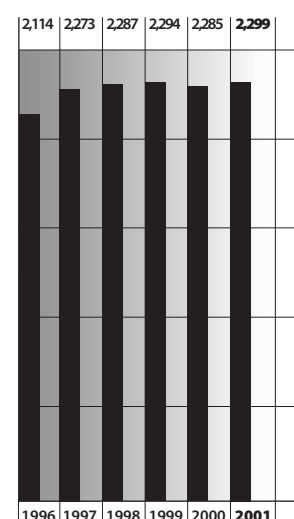
#### Gathering and Processing Regulation

The Company and its major customers operate under a Framework for Light-Handed Regulation (the Framework) applicable to the gathering and processing facilities. The Framework establishes policies and guidelines, among other things, which permit the negotiation by the Company of contracts for gathering and processing services with new and existing shippers, the timely resolution of complaints by shippers against the Company and the interconnection of third party facilities with the Company's gathering and processing facilities. The Framework provides that the Company is responsible for the level of utilization of its gathering and processing facilities and, consequently, bears the opportunities and risks associated with that responsibility.



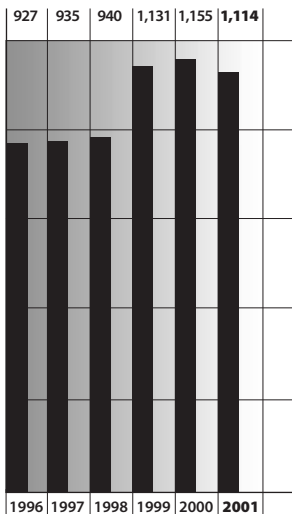
#### B.C. Pipeline Division Volumes

billion cubic feet



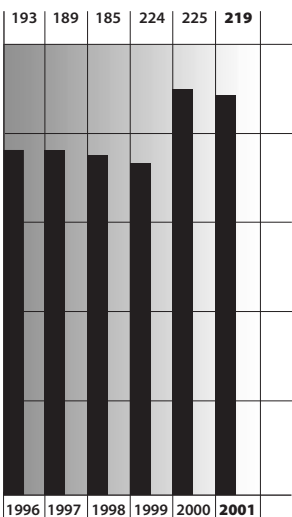
#### B.C. Pipeline and Field Services Divisions Average Rate Bases

\$million



### Foothills Pipe Lines Volumes

billion cubic feet



### Foothills Pipe Lines Average Rate Base

proportionate share / \$million

#### Contractual Developments

##### Pipeline Division

The Company's Southern mainline and Fort Nelson mainline systems are currently fully contracted. In September 2001, customers elected to renew virtually all contracts on these systems that were set to expire on October 31, 2002. As in 2000, the Fort St. John mainline continues to be underutilized by approximately 43 million cubic feet per day (MMcf/d) or 7% of its total contractible capacity.

In April 2001, the Company initiated an open season process for incremental firm transportation service capacity on its Southern mainline system (Compressor Station 2 to Huntingdon/Sumas). The target in-service date for this expansion capacity is November 1, 2003. As a result of the open season, shippers executed service agreements for approximately 200 MMcf/d of new service, having a volume weighted average term of 27 years. In January 2002, the Company filed an application with the NEB for approval of the 200 MMcf/d expansion of its Southern mainline facilities. The total capital expenditures for this expansion are expected to be approximately \$317 million, excluding Allowance for Funds Used During Construction (AFUDC). Recently, BC Gas Inc. agreed to release and re-contract capacity on the Company's Southern mainline system effective on the in-service date of the proposed expansion. This will allow the Company to reduce the expansion north of Compressor Station 8A by 55 MMcf/d. The total capital expenditures for the expansion, as so modified, are expected to be approximately \$255 million, excluding AFUDC. The Company will amend its application to the NEB to reflect the agreement of BC Gas Inc. to release and re-contract capacity on the Company's Southern mainline system. A hearing of the application for this expansion project is scheduled for the summer of 2002.

The Company is also expanding the Fort Nelson mainline which runs from the Fort Nelson processing plant to Compressor Station 2. This \$8-million expansion (excluding AFUDC), which is underpinned by long-term contracts exceeding 15 years, will increase the capacity of this line by 43 MMcf/d to 1,243 MMcf/d and is expected to begin service in November 2002. An application for approval to construct this project has been filed with the NEB.

##### Field Services

The Company has renegotiated essentially all of the gathering and processing service contracts that expired on November 1, 2001. These arrangements with shippers achieve a more balanced expiry profile of one to ten years, with terms tailored to the service needs of the Company's customers. As of December 31, 2001, 90% of the total available processing capacity was contracted for with varying terms. The Company's exposure to gas price sensitive tolls has been substantially reduced as most customers have chosen fixed price, demand charge contracts.

On July 18, 2001, the NEB approved the Company's application for the construction of the Kwoen gas processing plant and related facilities. The Kwoen facilities are currently under construction and are expected to begin service in the third quarter of 2002. The project will result in additional residue gas capacity of approximately 100 MMcf/d at the Company's Pine River processing plant near Chetwynd, B.C. The project uses a method of re-injecting the acid gas extracted at the Kwoen plant into a nearby depleted gas well.

In a related project, the Company has applied to the NEB for approval of the construction of an extension to its Grizzly Valley raw gas gathering pipeline which is expected to be completed by the end of the first quarter of 2003. The total capital expenditures for the Kwoen gas processing plant, related facilities and the extension to the Grizzly Valley raw gas gathering pipeline are expected to be \$165 million, excluding AFUDC.

The Company has firm contracts for the redesign of the Fort Nelson processing plant to increase the capacity by 88 MMcf/d to 878 MMcf/d. Capital expenditures are expected to be approximately \$20 million, excluding AFUDC. An application was filed with the NEB on January 31, 2002 and the project is proceeding on schedule.

##### Non-NEB Regulated Field Services Division

Westcoast Gas Services Inc. (WGS) owned interests in four provincially regulated natural gas processing plants and one liquids pipeline system. In May 2001, WGS sold its Jedney, Jedney Expansion and Highway gas processing plants and related gas gathering lines to JH Equipment Trust for \$201 million. WGS entered into an operating lease agreement for the facilities and has management and control of the equipment, with the lease obligations guaranteed by the Company. WGS may, but is not required to, re-acquire the facilities on certain dates as well as at the end of the lease agreement. In the event that the assets are not re-acquired, the Company has guaranteed the residual value of the assets up to an amount of approximately \$160 million.

##### Foothills Pipe Lines (Foothills)

The Company has a 50% interest in Foothills, which, through subsidiaries, transports Canadian natural gas to markets in the United States through portions of the pre-built (Phase 1) Canadian segment of the Alaska Natural Gas Transportation System (ANGTS Project). The ANGTS Project is a joint Canadian-United States project to transport gas from Alaska through Canada to southern markets in North America. A number of competing proposals have developed over the last year for bringing natural gas from Alaska and from the Mackenzie Delta to the North American market. The Company believes ANGTS is well positioned to compete for the transportation of the Alaskan supply.

Fiscal 2001 results were adversely impacted by expenses related to the northern projects and a lower approved return on equity. Earnings in 2000 were

positively impacted by a higher rate base and a higher NEB determined return on equity.

The NEB approved return on equity for 2002 is 9.53%, compared with 9.61% in 2001. The common equity component of rate base remains at 30%.

#### Empire State Pipeline

In March 2001, the Company purchased an additional 50% interest in the Empire State Pipeline (Empire), increasing its interest to 100%, for cash of \$122 million. Empire, located in upper New York State, indirectly connects the natural gas transportation and storage facilities of Union Gas in Ontario with markets in upper New York State. Lower earnings in 2000 are the result of owning only 50% of Empire and were impacted by lower interruptible revenues due to delays in the completion of the Pendleton interconnect and downstream operating constraints at the Lysander interconnect. The 2001 results reflect initial transaction costs related to the transfer of operations to the Company.

In January 1997, the New York Public Service Commission approved new tolls effective November 1, 1996, which included a 12.5% rate of return on common equity, and maintained the common equity component of rate base at 40%. The tolls are based on a 7-year average rate base of US\$156 million. In 2001 and 2000, the pipeline earned less than the awarded return.

#### Maritimes & Northeast Pipeline

The Company has a 37.5% interest in the Maritimes & Northeast Pipeline (M&NP), which transports in excess of 500,000 million British Thermal Units (MMBtu) per day of natural gas sourced from offshore fields near Sable Island to markets in Nova Scotia, New Brunswick and the northeast United States. The 1,355-kilometre main pipeline and associated lateral pipelines cost approximately \$2 billion. The Company's share of M&NP net earnings was \$27 million in 2001, compared with \$14 million in 2000. Higher earnings were primarily the result of increased interruptible and short term service revenues, reflecting the continued strength in the U.S. markets, as well as write-offs that occurred in 2000 in relation to M&NP Canada's initial rate decision from the NEB. Demand for natural gas continues to increase in the northeast United States due primarily to the completion of new, efficient, gas-fired power plants in that area. M&NP Canada currently has contracted firm service agreements totalling approximately 550,000 MMBtu per day.

M&NP Canada has reached a settlement with its Tolls and Tariff Working Group on 2001-2002 tolls, which was approved by the NEB in the fourth quarter of 2001. As a result of the settlement, total 2002 cost of service for M&NP Canada has been set at \$141 million, subject to certain deferral accounts such as interest costs and interruptible revenues. The return on common equity was set at 13% for both 2001 and 2002 with a rate base of approximately \$880 million for 2001 and approximately \$900 million for 2002.

In June 2001, M&NP announced an agreement with PanCanadian Petroleum Limited (PanCanadian) to transport up to 400,000 MMBtu per day (400 MMcf/d) of natural gas from the Deep Panuke project offshore Nova Scotia starting in 2004-5. A mainline expansion, representing an approximate \$500 million investment, would be required in order to transport the PanCanadian volumes. M&NP has filed applications with the NEB and the United States Federal Energy Regulatory Commission (FERC) for expansion of its mainline to accommodate an additional 400,000 MMBtu per day of capacity. In September 2001, M&NP received the results on an open season held in conjunction with the mainline expansion. Response from potential shippers was strong, with requests for over 1.7 Bcf per day received for service commencing over the next several years. M&NP is currently in discussions with shippers regarding contract terms.

In December 2001, M&NP received full approval from the FERC to construct its Phase III expansion project. This project consists of 25 miles of new pipeline to extend the M&NP system from Methuen, Maine, to an interconnection with Algonquin Gas Transmission Company's proposed HubLine project at Beverly, Maine. Construction is planned for 2002.

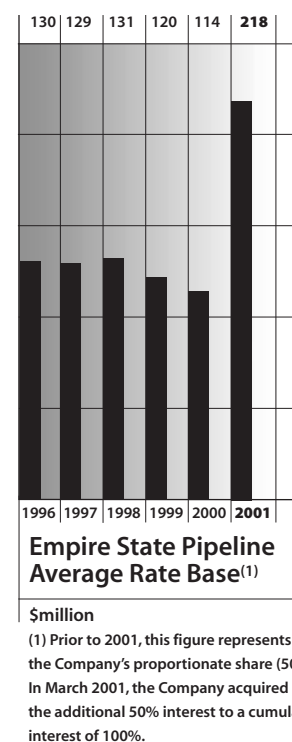
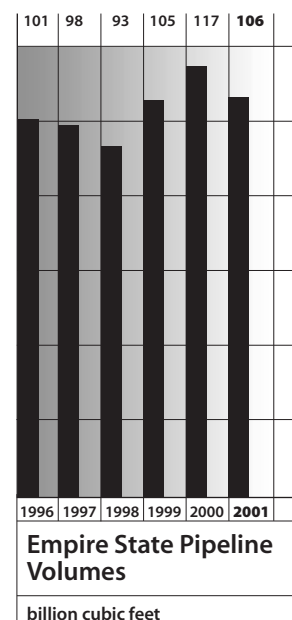
In June 2001, following construction of a pressure reducing station and receipt of final Leave-to-Open from the NEB, M&NP began service on the Point Tupper lateral, which services three industrial customers in the area. M&NP's purchase of the lateral, which operates under conditions approved by the NEB, was also completed in June 2001.

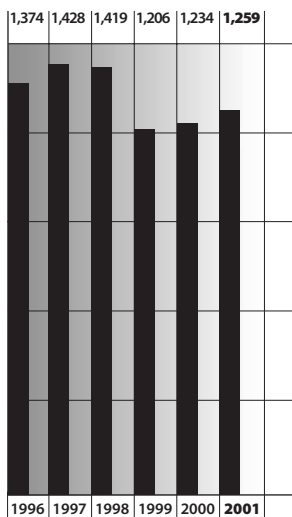
#### Alliance Pipeline and Vector Pipeline

The Alliance Pipeline (Alliance), in which the Company has a 23.6% interest, has a transportation capacity of 1.3 Bcf per day of natural gas from Western Canada to the Chicago area and is fully contracted by shippers. Capital costs, including AFUDC, for the 3,686-kilometre pipeline were \$5.3 billion.

Earnings related to the investment in Alliance were \$34 million in 2001 compared with \$35 million in 2000. These earnings are inclusive of Alliance merchant capacity losses, which totalled \$9 million and \$1 million for the years ended December 31, 2001 and 2000, respectively. The 2001 results for Alliance reflect operating earnings as the pipeline commenced operations in December 2000, whereas the earnings for the comparative period in 2000 are primarily from the recording of AFUDC.

The Vector Pipeline (Vector), in which the Company has a 30% interest, connects with Alliance and other natural gas transmission systems near Chicago. At its eastern end, Vector connects with the Union Gas Dawn-Trafalgar pipeline system. Vector serves markets in Indiana, Michigan and Ontario and, through connecting pipelines, other markets in Eastern Canada and the northeast regions of the United States. Capital costs, including AFUDC, for the 553-kilometre pipeline were approximately US\$674 million.





### Gas Distribution Customers<sup>(1)</sup>

thousands

(1) includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.

Vector began operation on December 1, 2000 with an initial capacity of 700 MMcf/d, which increased to 1 Bcf per day following completion of the Highland Compressor Station in early January 2002. The Company's loss related to the investment in Vector for the year ended December 31, 2001 was \$4 million. Earnings of approximately \$8 million in fiscal 2000 were primarily from the recording of AFUDC prior to the commencement of operations in late 2000. The earnings are inclusive of Vector merchant capacity losses, which totalled \$7 million and \$1 million for the years ended December 31, 2001 and 2000, respectively. Vector returns were adversely affected by cost overruns during construction, which will result in Vector earning significantly less than the FERC-approved recourse rates. In addition, a portion of the capacity on Vector has not been contracted on a long-term firm basis. This capacity is being sold on a short-term basis at market prices.

The Company's capacity commitments on Alliance and Vector are currently expected to cost more than the market value of the transportation in the near term and therefore are expected to generate losses until a further gas supply response from the Western Canada Sedimentary Basin is experienced. Physical and financial hedges are in place for a portion of the merchant capacity through October 2002.

#### Aux Sable Liquids Facility

The Aux Sable natural gas liquids recovery facility (Aux Sable) associated with Alliance, in which the Company has a 23.6% interest, cost approximately US\$441 million to construct and began operations in December 2000. The Company realized a net loss of \$5 million for the year ended December 31, 2001 related to its investment in Aux Sable. As a result of commodity hedges and only one month of operations in 2000, results for 2000 were approximately break-even. Profitability of the project is highly dependent on the relationship between natural gas prices and natural gas liquids prices. This relationship tends to be very volatile. Under the current natural gas liquids market conditions, the Company does not expect to obtain a satisfactory return on this investment in the immediate future.

#### Transmission & Field Services Outlook

Demand forecasts for natural gas in North America indicate continued growth, both in Canada and the United States. Natural gas reserves in North America, including the Mackenzie Delta, Alaska North Slope and the Scotian Shelf, are felt to be sufficient to meet the forecast demand growth over the longer term. The Company's processing and transmission assets are well positioned to benefit from increased supply from the traditional Western Canada Sedimentary Basin, southern Northwest Territories and East Coast Offshore. Growth in demand for natural gas is forecast to be generated primarily by demand from the gas fired power generation sector as well as continued economic expansion and increased penetration of existing markets.

#### Competition

The Company's gathering and processing facilities in northeast British Columbia continue to be exposed to competition. The forecasted increased growth in demand for natural gas throughout North America, the current high level of exploration and development activity in the Company's service area, and the Company's ability to negotiate flexible service agreements with shippers should allow the Company to compete effectively.

During 2000, completion of Alliance, which increased transportation capacity from the Western Canadian Sedimentary Basin, introduced competition for the transportation of natural gas in the traditional supply areas served by the Company's Southern mainline transmission facilities. The Southern Crossing Pipeline (SCP), connecting the Alberta Natural Gas pipeline owned by TransCanada Pipelines Limited in southeastern British Columbia with the BC Gas Inc. pipeline facilities in the southern Okanagan Valley, competes in traditional markets with the BC Pipeline System. The Company also anticipates BC Gas Inc. will continue to pursue these traditional markets through a proposed expansion of the SCP. An open season for this expansion, known as the Inland Pacific Connector, is expected to occur by mid 2002. Management does not believe that this will have a material adverse effect on the Company's future consolidated results of operations, cash flows or financial position.

#### GAS DISTRIBUTION

The contribution to net earnings for Gas Distribution was:

Years ended December 31 (\$million)	2001	2000
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES		
Union Gas	105	97
Centra Gas British Columbia	17	14
Pacific Northern Gas	2	3
Other	(8)	(2)
	116	112

The gas distribution businesses are sensitive to variations from normal weather conditions. Colder than normal weather conditions produce higher revenues and earnings, with the opposite result occurring in warmer than normal weather conditions. Earnings were reduced by \$22 million (\$0.18 per common share) and \$5 million (\$0.04 per common share) in fiscal 2001 and 2000, respectively, due to warmer than normal weather.

Periods of warm weather have an adverse impact on revenues which is partially offset by the opportunities created for Union Gas storage and transportation activities. A portion of revenues at Union Gas are associated with industrial customers who use natural gas for their processes and are therefore not weather sensitive.

Excluding the impact of weather, net earnings from the gas distribution businesses in 2001 were \$138 million compared with \$117 million in 2000. The 2001 and 2000 results reflect growth in the number of natural gas distribution customers and higher storage and transportation revenues. In 2001, these results were partially

offset by lower average customer use caused by high gas prices. Fiscal 2001 results also include a \$7-million write-down in anticipation of a sale of a small non-regulated natural gas project.

The allowed rates of return on common equity are determined in each province by the respective provincial regulatory authority. Some of these rates of return are set by a formula that is based on a forecast of long Canada bond rates. The rates of return on common equity and the common equity components of the respective rate bases of the regulated businesses for 1999 to 2001 are outlined in Note 1 to the consolidated financial statements.

The Company's gas distribution businesses are highly seasonal, with the majority of natural gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

Over the last nine months, the average cost of natural gas has decreased substantially from record high prices that prevailed in January 2001. The gas distribution businesses charge the purchase cost of gas directly through to customers. High natural gas prices may result in decreased demand for natural gas from all customer segments.

The higher price of natural gas in 2000 and part of 2001 also increased the working capital financing requirements and related costs for accounts receivable and gas inventory.

Natural gas volumes delivered by the gas distribution businesses were:

Years ended December 31 (Bcf)	2001	2000
<b>VOLUMES</b>		
Union Gas	1,148	1,263
Centra Gas British Columbia	26	26
Pacific Northern Gas	30	31
Other	14	15
	1,218	1,335

The number of customers for the gas distribution businesses were:

Years ended December 31 (thousand)	2001	2000
<b>NUMBER OF CUSTOMERS</b>		
Union Gas	1,147	1,123
Centra Gas British Columbia	71	69
Pacific Northern Gas	39	40
Other	2	2
	1,259	1,234

#### Union Gas

Union Gas distributes natural gas in Ontario. It also transports and stores natural gas for customers in Ontario, Quebec and the central and eastern United States. Union Gas' underground natural gas storage facilities have a working capacity of 150 Bcf and are the largest in Canada.

Results in 2001 continued to be adversely affected by warmer than normal weather for the fourth consecutive year. Weather reduced earnings by \$22 million and \$5 million in 2001 and 2000, respectively. The increase in 2001 earnings

compared with 2000 is primarily related to continued customer growth and higher storage and transportation revenues. The improved results were partially offset by warmer weather and lower average customer use caused by high gas prices. Union Gas is able to pass through natural gas costs to the customer.

Over the past several years, the average amount of natural gas consumed by Union Gas residential customers has declined. This decline is caused primarily by warmer than normal weather and the replacement of older heating equipment by newer, more efficient equipment, and by more energy-efficient housing.

#### Performance-Based Regulation

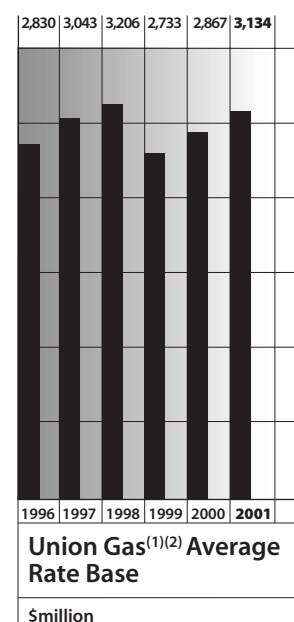
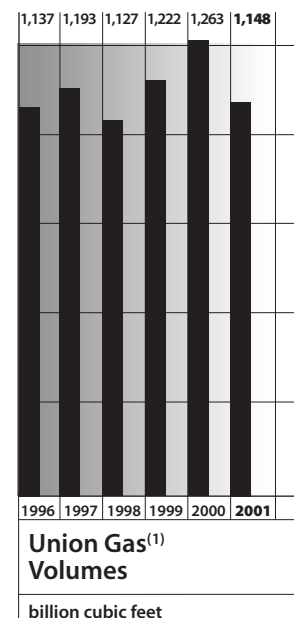
In July 2001, the Ontario Energy Board (OEB) approved final 2000 rates that reflected, among other things, an increase to the allowed rate of return on common equity to 9.95%. At that time, the OEB also released its decision related to Union Gas' 1999 application for rates for the year 2000 and beyond using a Performance-Based Regulation (PBR) mechanism. The decision fixed the allowed rate of return on common equity at the 2000 level of 9.95%. Rates for a trial period from 2001 to 2003 will be adjusted by formula from the 2000 level by a rate escalator that is increased for inflation less a fixed factor of 2.5% to provide for productivity gains. The rate escalator for 2001 was 1.4%. The PBR mechanism provides for some pricing flexibility, including the ability to negotiate longer term rates with customers. The decision also provides for an earnings sharing mechanism as well as the continuation of certain deferral accounts for storage and transportation revenue and gas costs. Under PBR, Union Gas accepts somewhat more risk than it would otherwise under the prior cost of service method of regulation in exchange for more opportunity to benefit from growth and cost efficiencies.

As part of PBR, Union Gas is required to participate in a customer review process in which Union Gas and its customers negotiate specific PBR terms for the applicable period and other matters relevant to rates. A hearing is then held before the OEB to approve any settlement reached through the customer review process and hear evidence on unresolved issues. Union Gas concluded a hearing before the OEB on April 16, 2002 to set rates for 2001 and 2002. A decision approving final 2001 and 2002 rates is pending. Union Gas expects to begin the customer review for 2003 rates in the summer of 2002.

The July 2001 decision on PBR had no material affect on the previously reported earnings reported to date.

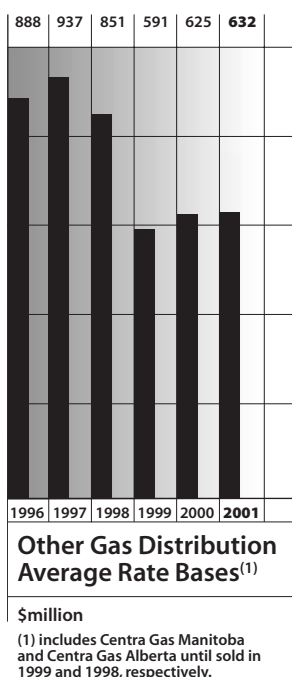
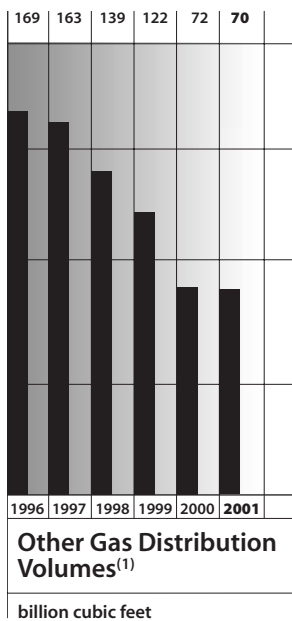
#### Centra Gas British Columbia

In December 1995, the Company and the Province of British Columbia entered into an agreement replacing the previous financial arrangements relating to the natural gas pipeline to Vancouver Island and connected distribution systems owned by Centra Gas British Columbia Inc. (Centra Gas BC).



(1) includes Centra Gas Ontario Inc. which was amalgamated with Union Gas effective January 1, 1998

(2) On January 1, 1999, Union Gas transferred approximately \$500 million of net assets to Union Energy



For the years 1996 to 2002, the agreement provides for a deemed common equity component of rate base of 35% and a return on the common equity component of rate base of 3.625% over the Government of Canada long term bond rate. The agreement also provides for a reduction in the return on equity of approximately \$2 million per year for the years 1996 to 2011. For 2001, Centra Gas BC's effective rate of return on common equity was 8.1%, compared with 8.4% in 2000. The increase in earnings in 2001 is primarily due to the recognition of the future tax benefit to be received from the realization of prior years shareholder tax losses. Centra Gas BC increased its customer base by 2.5% in 2001 over 2000. Increased royalty revenues, combined with effective management of gas supply costs, have resulted in the revenue deficiency incurred in 2001 under the existing regulatory framework being lower than it otherwise would have been. The cumulative revenue deficiency under the existing regulatory framework was approximately \$85 million at the end of 2001.

In March 2002, the Company sold its wholly owned subsidiaries Centra Gas BC and Centra Gas Whistler Inc. for proceeds of \$292 million, of which \$240 million was cash and \$52 million by way of a non-interest bearing note receivable, resulting in a pre-tax gain of \$24 million. The note receivable is due on or before December 31, 2011, with early repayment contingent on certain events. The transaction was effective for financial purposes on January 1, 2002.

#### Pacific Northern Gas

Pacific Northern Gas Ltd. (PNG) delivers gas to customers in west-central British Columbia and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast. Five large industrial customers in the petrochemical, pulp and aluminum businesses accounted for approximately 69% of total gas deliveries in 2001.

The rate of return on common equity for PNG, as determined by a formula approved by the British Columbia Utilities Commission (BCUC), was 10.00% for 2001, compared with 10.25% for 2000, on a deemed common equity component of rate base of 36%.

Gas deliveries to Methanex Corporation (Methanex) are about 60% of the volumes transported on the PNG system and provide about 50% of PNG's total operating margin when the plant is operating at normal levels. The methanol plant was shut down from July 2000 to July 2001. Deliveries to Methanex are made pursuant to three agreements for firm transportation service and interruptible sales, which contain take or pay obligations for up to 80% of the contract demand and that expire between 2002 and 2009. The largest of these contracts with Methanex, representing approximately 77% of the total Methanex contract demand, expires on October 31, 2002.

On December 1, 2001, PNG filed a 2002 rate application with the BCUC seeking approval to increase its rates effective January 1, 2002. A public hearing on the

application was completed in March 2002. On March 20, 2002, PNG and Methanex signed a Memorandum of Agreement on a new long-term take or pay contract, which, subject to BCUC approval, will become effective November 1, 2002 and extends through 2009. The new agreement will replace the three existing contracts between PNG and Methanex. PNG has requested the BCUC to reopen the 2002 rate hearing to consider the impact of the Memorandum of Agreement between PNG and Methanex.

The uncertainty relating to deliveries to Methanex over the past two years has made it difficult for PNG to raise capital on acceptable terms. During that time frame, PNG's short-term lender reduced PNG's line of credit and increased the cost of borrowing. New long-term financing in the amount of \$12 million was issued in November 2001 and used to redeem PNG's 2002 Series Debentures on December 31, 2001.

The Company's current investment in PNG is approximately \$30 million.

#### Gas Distribution Statistics

The average rate bases for the gas distribution businesses were:

Years ended December 31 (\$million)	2001	2000
RATE BASE		
Union Gas	3,134	2,867
Centra Gas BC	434	429
PNG	171	172
Other	27	24
	<u>3,766</u>	<u>3,492</u>

#### POWER GENERATION

The Company has interests in four operating natural gas fired cogeneration plants in Canada and is developing an additional project.

The contribution to net earnings for Power Generation was:

Years ended December 31 (\$million)	2001	2000
NET INCOME APPLICABLE TO COMMON SHARES	108 <sup>(1)</sup>	16

<sup>(1)</sup> includes an after-tax gain of \$85 million on the sale of the Island Cogeneration Plant and the Whitby Cogeneration Plant

In September 2001, the Company sold its 100% interest in the 250-megawatt (MW) Island Cogeneration Plant (ICP) and its 50%-interest in the 50-MW Whitby Cogeneration Plant to Calpine Canada Investments Corporation for proceeds of approximately \$342 million, of which \$146 million was cash. The Company recorded a net gain after taxes and other costs of approximately \$85 million.

The Power Generation segment had a successful year, primarily related to above average plant availabilities, revenues generated from the sale of power at ICP for the period May through September 2001 and the \$5 million favourable impact from corporate income tax rate reductions. Fiscal 2001 results also benefited from the resale of gas at the Lake Superior and McMahon cogeneration plants and a price increase for the Ontario plants, partially offset by the expensing of certain start-up costs for the Bayside Power and Frederickson Power projects. Fiscal 2000 results include revenue from the resale of gas at the

McMahon Cogeneration Plant and the Lake Superior Cogeneration Plant and effective utilization of power transmission capacity in New England acquired in anticipation of the Bayside Power Plant. Fiscal 2000 results also include a \$3 million after-tax gain on the sale of the Company's 50% interest in the Liberty Electric Power Project.

#### Bayside Power Plant

The Bayside Power Plant, in which the Company has a 75% interest, re-powered an existing 100-MW heavy fuel oil fired generating plant located in Saint John, New Brunswick, into a natural gas fired combined cycle plant with a design capacity of 280 MW. The plant cost approximately \$139 million to construct, excluding interest during construction. An additional \$22 million for in-plant refurbishment and interconnection costs has been financed by New Brunswick Power Corporation (NB Power). The refurbished equipment will be leased back to the project by NB Power. Merchant production for the summer period will be delivered into the U.S. New England Power Pool (NEPOOL) market, with winter production sold under a 20-year contract to NB Power. Construction and initial performance testing of the Bayside Power Plant was completed and power sales to the NEPOOL market commenced in September 2001. Direct deliveries to NB Power for the winter season commenced in November 2001. A settlement has been reached with the prime contractor to address compensation for plant thermal performance deficiencies relative to contractual guarantees, and project completion holdbacks are in place until an agreement is finalized.

#### Frederickson Power Project

The Frederickson Power partnership, in which the Company has a 60% interest, owns a fully permitted 250-MW natural gas fired electricity generation project located between Tacoma and Olympia in the State of Washington. The purchase price for the pre-existing, partially built facility was US\$25 million. In March 2001, the Frederickson Power partnership entered into a 20-year power sales agreement with three Pacific Northwest public utility districts for approximately 50% of the output from the plant. The agreement places responsibility for gas costs with the public utility districts. The balance of the power produced will be sold on a merchant basis. Construction on site is progressing on schedule with commercial operations expected to commence in the third quarter of 2002. Total capital costs are estimated to be US\$179 million.

#### Liberty Electric Power Project

In February 2000, the Company sold its 50% interest in the proposed 500-MW Liberty Electric Power Project near Philadelphia, Pennsylvania, to Columbia Electric, the primary developer of the project, for \$13 million, resulting in an after-tax gain of \$3 million.

## INTERNATIONAL

The operating businesses included in this business segment are power generation facilities located in Irian Jaya, Indonesia, and two projects in Mexico.

The contribution to net earnings for International was:

Years ended December 31 (\$million)	2001	2000
NET INCOME APPLICABLE TO COMMON SHARES	32	29

The improvement in the results for the year ended December 31, 2001 reflects higher operating income from Cantarell due to full plant operation compared with the prior year when the project was in the final stages of commissioning. The results for Cantarell have been favourably impacted by the recovery of deferred income taxes as a result of the plant starting operations. The improved Cantarell earnings were partially offset by the effects of the continued delay in the start-up of the Campeche Natural Gas Compression Services Project (Campeche). Included in the fiscal 2000 results is the \$8 million after-tax gain on the sale of the Company's 74% interest in the EastCoast Power Project in Australia, offset by deferred income tax expense of \$13 million arising from inflationary gains and the relative strength of the Mexican peso against the U.S. dollar.

The contributions from the two Mexican projects will continue to be impacted by deferred income taxes, which are dependent on the relative value of the Mexican peso to the U.S. dollar against the Mexican inflation rate as well as several other factors.

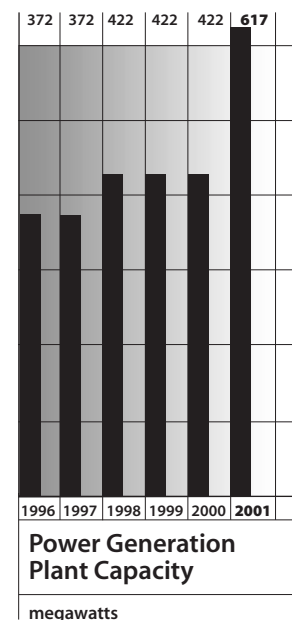
#### Indonesia - Irian Jaya Power Plant

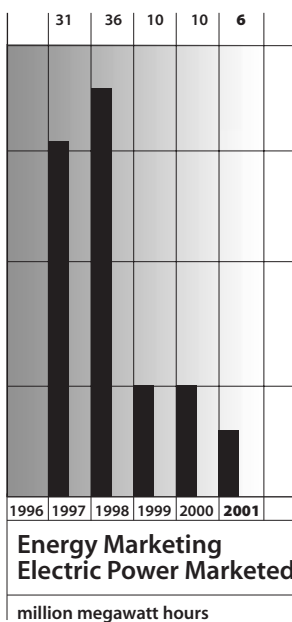
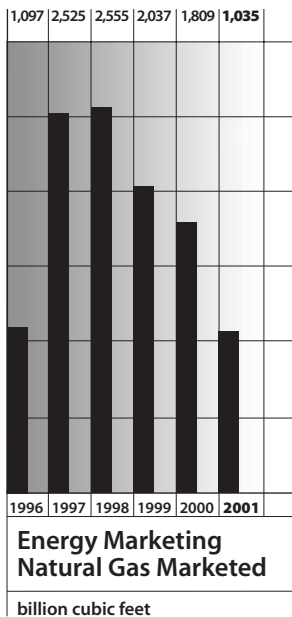
The Company has a 43% interest in P.T. Puncakjaya Power (PJP) which owns and operates approximately 388 MW of power generation capacity, a related transmission line and associated facilities providing electrical power to the Grasberg mine under a long-term contract.

Payments to PJP are denominated in United States dollars and are payable in the United States. The Company is therefore effectively sheltered from fluctuations in the value of the Indonesian currency. The mine, operated by P.T. Freeport Indonesia, is a low-cost producer of copper and also produces gold. Although Indonesia suffers from periodic political unrest, operations at PJP have not been affected.

#### Mexico - Cantarell Nitrogen Facilities

During the fourth quarter of 2001, the Company purchased an additional 10% (to a cumulative interest of 30%) in Cantarell from an existing partner for cash of \$56 million. The additional interest acquired includes a \$49 million promissory note and \$7 million of accrued interest. The facilities, which cost \$1.5 billion, sell nitrogen under a long-term take or pay agreement with Pemex Exploración y Producción (PEP), a subsidiary of the national oil company of Mexico, to enhance the production and recovery of oil from the Cantarell oil field located in the Bay of Campeche, Gulf of Mexico. The nitrogen supply





contract with PEP provides for fixed capacity payments in United States dollars.

Nitrogen production in 2001, the first full year of operation, averaged 1,079 MMcf/d, or 89% of design capacity. Production was impacted during the first quarter of 2001 by the need for repairs to the air and nitrogen compressors on all four air separation units. Subsequently, production was reduced by remedial work required to repair and mitigate corrosion and erosion damage to the cooling water system caused by the intake of excessive suspended solids.

Various modifications to the existing cooling water system are being undertaken to reduce the intake of excessive suspended solids and to minimize the associated damages to the water system. The work will continue until the first quarter of 2003, although many of the modifications will be completed by the third quarter of 2002. The consortium is pursuing recovery of the unanticipated remediation costs for the cooling water system from its insurers and the engineering, procurement and construction contractor.

The consortium has requested and received from its lenders an extension to March 2, 2003 as the date by which it is required to achieve financial completion. This extension accommodates the modifications to the project's cooling water system.

As of December 31, 2001, the Company's investment in the Cantarell facilities was US\$109 million.

#### Mexico – Campeche Natural Gas Compression Services Project

During the fourth quarter of 2001, the Company purchased an additional 5% (to a cumulative interest of 50%) in Campeche from existing partners for nominal cash consideration. Campeche is an international consortium which has entered into a five-year take or pay contract with PEP to provide 250 MMcf/d of offshore natural gas compression and liquids recovery services on a platform in the Cantarell oil field in the Bay of Campeche, Gulf of Mexico. The fixed capacity charge payable by PEP under the take or pay contract is payable in United States dollars. The consortium owns and operates the offshore compression platform which was constructed at a cost of approximately US\$314 million.

Commissioning of the compression platform was completed during the third quarter of 2001. Fourth quarter results were negatively impacted during October when platform operations were constrained by a two-week shut down to repair a minor leak in the secondary flare system alongside the platform which is owned by PEP. During the final two months of 2001, all three compression modules were fully operational with natural gas deliveries to PEP averaging 251 MMcf/d.

The contractual in-service date prescribed by PEP was extended to October 30, 2001, thereby eliminating any exposure to penalties for late completion. Campeche is in the process of securing non-recourse project financing

which is expected to close by the end of the second quarter of 2002.

#### China - Shanghai Power Plant

The Company had a 32.5% interest in a power project to produce 50 MW of electrical power at the Baosteel Group Shanghai No.1 Iron & Steel Company Ltd. facilities in China. The plant, which uses waste blast furnace gas as its primary fuel, cost approximately \$75 million.

The power plant commenced commercial operations on June 1, 2000, contributing net earnings of \$3 million and \$2 million in 2001 and 2000, respectively. The Company sold its interest in the Shanghai Power Plant to its joint venture partner in March 2002 for proceeds of \$16 million, resulting in a loss of \$7 million after tax.

#### Australia – EastCoast Power Project

In April 2000, the Company sold its 74% interest in the EastCoast Power Project to a subsidiary of Duke Energy for approximately \$17 million, resulting in an after-tax gain of \$8 million.

#### SERVICES

Included in this business segment are businesses that provide energy marketing, retail energy services, customer billing system and financial services. The retail energy services and financial services businesses, operated by wholly owned subsidiaries Westcoast Capital and Union Energy, were sold in October 2001.

The contribution to net earnings for Services was:

Years ended December 31 (\$million)	2001	2000
<b>NET INCOME (LOSS) APPLICABLE TO COMMON SHARES</b>		
Energy Marketing	107	35
Union Energy	11 <sup>(1)</sup>	—
Westcoast Capital	36 <sup>(2)</sup>	21
Enlogix	(9)	(16)
NGX	5 <sup>(3)</sup>	5 <sup>(3)</sup>
	<b>150</b>	<b>45</b>

<sup>(1)</sup> includes an after-tax gain of \$10 million on the sale of Union Energy

<sup>(2)</sup> includes an after-tax gain of \$12 million on the sale of Westcoast Capital

<sup>(3)</sup> includes an after-tax gain of \$5 million and \$4 million on the sale of the Company's interests in NGX in 2001 and 2000, respectively

In October 2001, the Company sold its wholly owned subsidiaries Union Energy and Westcoast Capital for cash of approximately \$176 million, resulting in an after-tax gain of \$22 million.

The increase in earnings in fiscal 2001 compared with 2000 is also attributable to a continued strong performance by Engage Energy.

#### Energy Marketing

Engage Energy contributed net earnings in 2001 of \$107 million, compared with \$26 million in 2000. Engage Energy performed extremely well in both the merchant power and merchant gas business in fiscal 2001. Exceptional trading and structured origination results, across both natural gas and power, contributed to the increase in earnings. The price volatility in the North American natural gas and electric

markets during 2001 created increased opportunities for trading and structured products. The 2001 results also reflect a \$5 million favourable impact from corporate income tax rate reductions. Results from trading around assets of affiliates are recognized on an as realized basis and are not marked-to-market.

The fiscal 2000 results for the energy marketing business is also in part impacted by the sale in the second quarter of 2000 of the capacity on the Kern River Pipeline, and a portion of the associated upstream capacity on Northwest Pipeline, offset partially by a loss on the residual upstream capacity in the fourth quarter. All of the capacity on the Kern River Pipeline has now been permanently assigned to other parties, and as of the end of 2000, the Company holds only a small amount of remaining upstream capacity on Northwest Pipeline.

In October 2000, the Company and The Coastal Corporation terminated their Engage Energy joint venture and divided the operations into separate entities which are owned and operated independently by each company. Details of the termination of the joint venture agreement are provided in Note 12 to the consolidated financial statements.

#### *Energy Marketing Risk Management*

Energy Marketing operates in a competitive environment characterized by volatility and often by narrow margins. Engage Energy operates an energy merchant and trading business, in which its portfolio of physical and financial forward transactions has inherent market, credit and operations risks. The Company's risk management policy defines the methodology to be employed in measuring risks and the authorized levels of risk exposure. The risks of the Company's energy marketing portfolio are monitored by an internal Risk Management Committee to ensure compliance with Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. The Company utilizes derivative and other financial instruments to manage the impact of market fluctuations on assets, liabilities or other contractual commitments.

#### **Union Energy**

The Company sold Union Energy in the fourth quarter of 2001. Union Energy served 1.1 million customers and operated 45 branches providing heating, ventilating and air conditioning sales and services. In addition, Union Energy offered customers rental and financing options.

Union Energy contributed net income applicable to common shares of \$11 million for the ten months ended October 2001 until the date of sale, compared with minimal earnings for the year ended December 31, 2000. Fiscal 2001 results reflect the \$10 million after-tax gain on the sale of the company. In addition, a decrease in operating costs and significant margin improvements contributed to the improved performance of the equipment rental businesses, which offset continuing losses

in the heating, cooling and fireplace business. Mild weather conditions in early summer 2001 negatively impacted sales from air conditioning related products and services.

#### **Westcoast Capital**

The Company sold Westcoast Capital in the fourth quarter of 2001. Westcoast Capital provided selected financial services to complement the Company's other product offerings. Westcoast Capital's business was largely focused on energy-related investments and was divided into two distinct sectors, Retail Finance and Structured Finance. The Retail Finance business included the financing and rental of household appliances to individual homeowners while the Structured Finance business included the financing of capital equipment for businesses.

Westcoast Capital contributed net income applicable to common shares of \$36 million for the ten months ended October 2001 until the date of sale, compared with \$21 million for the year ended December 31, 2000. Fiscal 2001 results reflect the \$13 million favourable impact from corporate income tax rate reductions as well as the \$12 million after-tax gain on the sale of the company and structured finance investments. Earnings in 2000 were also favourably impacted, although not to the same extent, by corporate income tax rate reductions and the early buyout of a gas transportation agreement.

In 2000, Westcoast Capital received proceeds of approximately \$360 million on the securitization of rental assets and asset-backed finance contracts to WestCap Trust. The proceeds were used to reduce external borrowings.

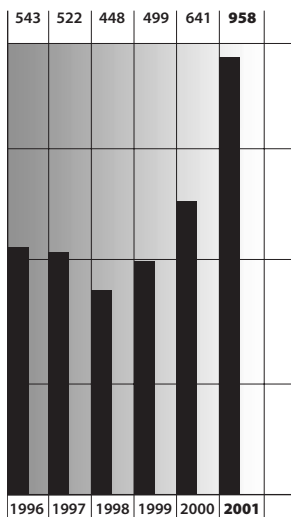
#### **Enlogix**

Enlogix Inc. (Enlogix) provides billing and customer information services to the energy and utility sectors, providing 13 clients with billing services for their 3 million customers, approximately 2.4 million of which are customers of subsidiaries of the Company. Enlogix systems support clients in the regulated and unregulated gas, electric, water, and energy services sectors across North America.

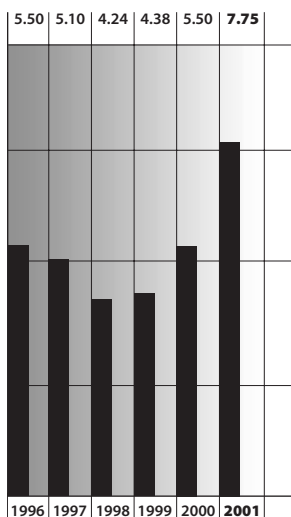
A net loss applicable to common shares of \$9 million and \$16 million was incurred for the years ended December 31, 2001 and 2000, respectively. The 2001 net loss includes approximately \$1 million after-tax in restructuring costs. The reduced loss reflects revenue growth and the implementation of cost savings programs. These programs resulted in a 29% reduction in operating costs.

#### **NGX**

In January 2001, the Company sold its remaining 49% interest in NGX to OM Gruppen of Sweden, a European electronic exchange owner and operator for \$10 million, resulting in an after-tax gain of \$5 million. The Company sold the initial 51% of its natural gas exchange operation to OM Gruppen in 2000 for \$8 million, resulting in an after-tax gain of \$4 million.



**Operating Cash Flow**  
\$million



**Operating Cash Flow per Common Share**  
dollars

### Competition

The Services segment operates in a highly competitive environment and in many cases competes for business against large and well-established firms. In some cases the Services segment depends on technology or market lead which can be overtaken by others. To compete successfully, the services group must maintain or grow its market position, focus on cost efficiency and develop innovative product leadership.

### OTHER

This business segment includes corporate expenses, business development expenditures and corporate financing expenses.

The contribution to net earnings for this segment was:

Years ended December 31 (\$million)	2001	2000
NET INCOME (LOSS) APPLICABLE TO COMMON SHARES		
Corporate financing	(74)	(79)
Business development	(1)	(5)
Other	—	34
	(75)	(50)

Corporate financing expenses include unallocated preferred share dividends of \$45 million and \$48 million in 2001 and 2000, respectively. The balance of unallocated interest amounted to \$29 million in 2001, relating to approximately \$600 million of debt, compared with \$31 million in 2000, relating to approximately \$750 million of debt.

The years ended December 31, 2001 and 2000 reflect the favourable impact of \$11 million and \$35 million, respectively, of the corporate income tax rate reductions.

Effective January 1, 2001, the Company changed its accounting policy with respect to accounting for pre-operating costs incurred for development projects. Under the new accounting policy, pre-operating costs are expensed as incurred. Prior to the adoption of the new accounting policy, pre-operating costs incurred for development projects which benefited future periods were deferred and amortized on a straight-line basis over the expected period of benefit upon commencement of operations.

This accounting policy change has been applied retroactively without restatement of prior periods. As of January 1, 2001, the effect of adopting the new accounting policy was to decrease deferred charges by \$28 million, decrease fixed assets by \$75 million, decrease investments by \$9 million, decrease deferred income tax liabilities by \$39 million and decrease opening retained earnings by \$73 million. For the year ended December 31, 2001, application of the new accounting policy decreased after-tax earnings by \$11 million.

### Business Development

#### Millennium Pipeline Project

The Company has a 21% interest in the proposed Millennium Pipeline Project (Millennium) which is designed to deliver 700 MMcf/d of natural gas from

southwest Ontario to New York City and other markets in the eastern United States. The 670-kilometre pipeline, with the potential to purchase additional existing pipeline, is expected to cost approximately \$1 billion. An Interim Certificate of Public Convenience & Necessity was issued by the FERC in December 2001 for the Millennium Pipeline. NEB approval of the project is also required.

Further development of the project is subject to a number of conditions including receipt of regulatory approval, conclusion of satisfactory definitive transportation agreements and construction of upstream transportation facilities.

### ACQUISITION BY DUKE ENERGY

In September 2001, Duke Energy announced plans to acquire the Company in a cash and stock transaction valued at approximately US\$8 billion, including debt assumed. The plan of arrangement was completed on March 14, 2002.

The transaction provided for the acquisition of all outstanding common shares of the Company in exchange for a combination of cash, Duke Energy common shares and exchangeable shares of a Canadian subsidiary of Duke Energy such that approximately 50% of the aggregate consideration was paid in cash and approximately 50% paid in stock.

### LIQUIDITY AND CAPITAL RESOURCES

#### Cash Generated from Operations

Cash generated from operations was \$600 million for the year ended December 31, 2001, compared with \$573 million in 2000, respectively. The increase in the operating cash flow is primarily due to strong origination and trading results from Engage Energy and higher interruptible and short-term firm service revenues from the British Columbia Pipeline and Field Services divisions and the U.S. portion of M&NP.

The contribution to consolidated operating cash flow after non-cash working capital changes by business segment was:

Years ended December 31 (\$million)	2001	2000
CASH FLOW FROM OPERATING ACTIVITIES		
Transmission & Field Services	379	299
Gas Distribution	374	285
Power Generation	34	32
International	83	77
Services	144	22
Other	(56)	(74)
Operating cash flow	958	641
Non-cash working capital changes	(358)	(68)
	600	573

#### Investing Activities

In 2001 and 2000, capital expenditures and investments totalled approximately \$860 million and \$1.3 billion, respectively. Capital expenditures amounted to \$647 million in 2001 compared with \$747 million in 2000. The multi-year capital expansion and investment program in

which the Company had been engaged was completed in 2000 at a three-year cost of \$4 billion and capital spending is returning to more normal levels. The majority of capital spending in fiscal 2001 is related to the British Columbia Pipeline and Field Services divisions, Union Gas and the Bayside Power and Frederickson Power projects. Capital expenditures in 2000 were primarily related to Union Gas, Alliance, Vector and Aux Sable, in addition to the Bayside Power Plant and ICP.

The planned spending for 2002 is primarily for the British Columbia Pipeline and Field Services divisions, Union Gas and the Frederickson Power Project.

The Company's 2001 acquisitions reflect the purchase of the additional 50% interest in Empire in the first quarter of 2001. Acquisitions in 2000 consisted of the purchase of the additional 50% interest in Engage Energy Canada L.P.

Over the past several years, certain non-strategic assets were divested and proceeds used to fund a portion of the expansion in the transmission and field services, power generation and services businesses. Investing activities in 2001 reflect cash of \$552 million provided by the dispositions of certain power assets, gas gathering and processing facilities, rental assets, gas transportation agreements, and the Company's interest in Westcoast Capital, Union Energy and NGX. Investing activities in 2000 reflect cash of \$501 million provided by the dispositions of interests in NGX, EastCoast Power Project, Bayside Power Plant, Liberty Electric Power Project and Frederickson Power Project. The sale of certain rental assets and asset-backed finance contracts by Westcoast Capital provided cash proceeds of approximately \$360 million in 2000.

During the first quarter of 2002 the Company divested itself of its interests in Centra Gas BC and the Shanghai Power Plant.

### Financing Activities

The Company, its subsidiaries and joint ventures have the ability to draw on operating lines of credit in excess of \$1,800 million with commercial banks. These operating lines of credit enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances and to support commercial paper programs.

The Company, its subsidiaries and joint ventures make use of short term indebtedness to finance working capital as well as provide interim financing in advance of long term debt or equity issues. At times, the resulting consolidated short term indebtedness and the portion of long term debt due within one year result in negative working capital.

In 2001, from the issuance of long term debt and common equity and the addition of new bank facilities, the Company, its subsidiaries and joint ventures raised cash of \$549 million (2000 - \$856 million). In March 2001, the Company raised \$200 million from the issue of 7.15% Medium Term Note (MTN) Debentures, Series 8,

maturing in 2031. In May 2001, Union Gas raised \$250 million from the issue of 6.65% MTN Debentures, Series 3, maturing in 2011. In July 2001, the Company redeemed the remaining \$28 million of outstanding principal of its 10.6% Debentures. In September 2001, the Company repaid \$100 million principal amount of 11.0% Debentures, Series M, at maturity. In January 2002, Union Gas redeemed the remaining \$36 million of outstanding principal of its 10.625% Debentures. In February 2002, the Company repaid \$100 million principal amount of 9.05% Debentures, Series N, at maturity.

In January 2000, the Company raised \$150 million from the issue of 7.20% MTN Debentures, Series 7 and in June 2000, Union Gas raised \$185 million from the issue of 7.20% MTN Debentures, Series 2. In June 2000, WEI Holdings (US) Inc., a wholly owned subsidiary of the Company, arranged a US\$150-million term credit facility. In November 2000, the Company issued 4,000,000 common shares for cash under a public offering at a price of \$32.25 per share, thereby increasing common stock by \$129 million. The net proceeds of the common stock issuance were used to retire commercial paper previously issued by the Company, pre-fund the planned acquisition of the additional 50% interest in Empire in New York State and other corporate purposes.

The Series 2 Preferred Shares were converted into common shares of the Company in October 2001, resulting in the issuance of 2,916,312 common shares of the Company. The Series 5 Preferred Shares were redeemed by the Company in December 2001 for cash of \$200 million plus accrued dividends.

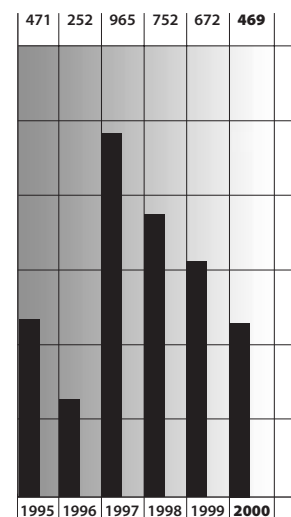
The Company issued common shares through its Dividend Reinvestment and Share Purchase Plan which was terminated effective February 13, 2002. Common shares issued under the Plan increased common stock by \$61 million in 2001 compared with \$50 million in 2000.

Details of long term debt, preferred share issues and common share issues are provided in Notes 2, 10, and 11, respectively, to the consolidated financial statements.

### NEW ACCOUNTING PRONOUNCEMENTS

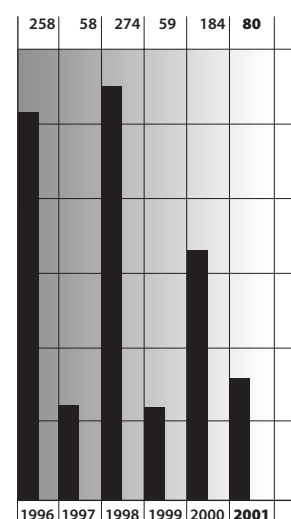
#### Stock-Based Compensation

In December 2001 the CICA issued a new standard, Section 3870 of the CICA Handbook "Stock-Based Compensation," which brings Canadian recognition, measurement and disclosure requirements in line with U.S. standards. It requires that stock-based payments to non-employees and direct awards to employees and non-employees be accounted for using a fair value-based method of accounting. The new Section also encourages, but does not require, the use of the fair value-based method to account for all other stock-based transactions with employees. When an enterprise does not use the fair-value based method, it must disclose pro-forma fair value-based income and earnings per share information.



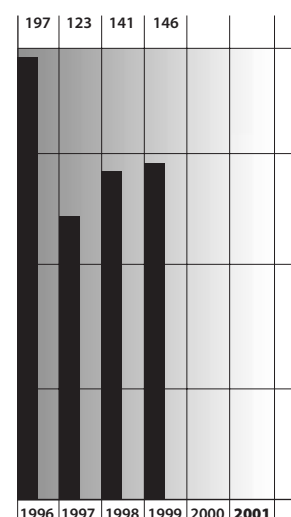
### Long Term Debt Issued

\$million



### Common Shares Issued

\$million



### Preferred Shares Issued (net)

\$million

The new standard is effective for fiscal years beginning on or after January 1, 2002. The Company, in accordance with the new section, will continue to use the intrinsic value-based method to account for stock-based transactions with employees. Adoption of the above recommendations is not expected to have a significant impact on the consolidated financial statements.

#### *Foreign Currency Translation and Hedging Relationships*

In December 2001 the CICA amended the standard, Section 1650 of the CICA Handbook "Foreign Currency Translation," effective fiscal 2002. The new standard eliminates the deferral and amortization method for unrealized translation gains and losses on non-current monetary assets and liabilities and requires the disclosure of exchange gains and losses included in net income.

The CICA also issued a new Accounting Guideline "Hedging Relationships" in December 2001, which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting, and also with the discontinuance of hedge accounting. The new guideline is effective fiscal 2003.

Adoption of the above recommendations is not expected to have a significant impact on the consolidated financial statements.

#### **BUSINESS RISK MANAGEMENT**

2001 was a year in which the Company was exposed to, but not materially impacted by, many of the risks inherent with the Company's lines of business. In particular, market risks and the potential severity of those risks increased significantly throughout the industry. Examples include commodity risks, market and regulatory risks and credit/counterparty failure and associated legal risks, all linked to the swings experienced in spot and futures gas prices throughout North America. The severity of the PG&E Corp. and Enron Inc. situations are examples of significant business risks not previously experienced in the industry; however, the Company was not materially impacted by these risks.

As part of an increased focus on business risk management practices, the Company had implemented certain risk management policies and procedures which assisted the operating and functional units in removing and/or mitigating potential exposure to loss. Information-for-decision-making was significantly improved upon, enhancing the Company's ability to identify, mitigate and monitor risks from a variety of external influences. Examples of ongoing risk management initiatives include an expanded commodity risk policy, formal risk mitigation strategy review through a risk management committee, aggregate

counterparty exposure tracking, and improved risk management reporting.

In addition, the Company expanded its capital allocation review methodology to include a risk assessment and prioritization process to identify, quantify and prioritize business risks associated with large capital projects. All significant capital projects requiring senior management approval undergo formal risk assessment, risk mitigation strategizing and must provide ongoing reporting about those risks to the appropriate operational or functional management.

#### **MARKET OUTLOOK**

Notwithstanding the dramatic swings in natural gas pricing over the past two years, long-term forecasts continue to predict a North American natural gas market of approximately 30 trillion cubic feet per annum by 2015. Continued growth in infrastructure will be required to supply this market.

The largest contributor to the current growth in natural gas demand remains the generation of electric power. The long-term view is for growth in demand for electricity to continue, necessitating construction of additional generating capacity to meet the incremental demand. Natural gas fired generation of electricity is expected to be a significant source of incremental power supply.

Increasingly, natural gas supply from Canada will be required to meet increases in demand for natural gas in North America. Some of the key incremental supply regions in Canada include the offshore region of Nova Scotia, northeast British Columbia and the southern Northwest Territories. The Company is well positioned in each of these producing regions with pipeline systems that connect these regions with attractive and growing natural gas markets.

# Management Responsibility for Financial Reporting

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles and include certain estimated amounts which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised of a majority of directors who are not employees of the Company or of its subsidiaries. The Audit Committee meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Audit Committee, as does the Director of Internal Audit Services. The Audit Committee reports its findings to the Board of Directors.

Ernst & Young LLP performed an independent audit of the consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

March 14, 2002

**Robert T.F. Reid**  
President

**Lindsay A. Hall**  
Vice President, Finance and Controller

## Auditors' Report

To the Shareholders of Westcoast Energy Inc.

We have audited the consolidated balance sheets of Westcoast Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of operations, retained earnings and cash flow for each of the years in the three year period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flow for each of the years in the three year period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

**Ernst & Young LLP**  
Chartered Accountants  
Vancouver, Canada  
February 8, 2002, except as to Note 24, which is as of May 1, 2002

# Consolidated Statements of Operations

For the years ended December 31

\$million, except for share data	2001	2000	1999
OPERATING REVENUES	11,897	8,955	6,265
OPERATING EXPENSES			
Cost of sales	9,431	6,755	4,258
Operation and maintenance	877	801	826
Depreciation	438	426	401
Taxes – other than income taxes	172	158	157
	<b>10,918</b>	<b>8,140</b>	<b>5,642</b>
OPERATING INCOME	979	815	623
OTHER INCOME			
Equity earnings	32	44	22
Foreign exchange gain	6	10	1
Allowance for funds used during construction	11	7	34
Investment and other income	224	107	149
	<b>1,252</b>	<b>983</b>	<b>829</b>
OTHER EXPENSES			
Interest (Note 2)	510	516	499
Other	26	11	7
	<b>536</b>	<b>527</b>	<b>506</b>
INCOME BEFORE UNDERNOTED ITEMS	716	456	323
INCOME TAXES (Note 5)			
Current	40	104	79
Deferred	94	(46)	(33)
	<b>134</b>	<b>58</b>	<b>46</b>
	<b>582</b>	<b>398</b>	<b>277</b>
NON-CONTROLLING INTEREST	10	10	10
NET INCOME	572	388	267
PROVISION FOR DIVIDENDS ON PREFERRED SHARES	46	48	45
NET INCOME APPLICABLE TO COMMON SHARES	526	340	222
COMMON SHARES – WEIGHTED AVERAGE (million)	123	117	114
EARNINGS PER COMMON SHARE – BASIC (Note 6)	<b>\$4.26</b>	\$2.92	\$1.95
– DILUTED (Note 6)	<b>\$3.87</b>	\$2.75	\$1.80
DIVIDENDS PER COMMON SHARE	<b>\$1.36</b>	\$1.28	\$1.28

See accompanying notes

# Consolidated Statements of Cash Flow

For the years ended December 31

<b>\$million, except for share data</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
<b>OPERATING ACTIVITIES</b>			
Net income	572	388	267
Add (deduct) items to reconcile to net cash			
Non-controlling interest	10	10	10
Deferred income taxes	94	(46)	(33)
Depreciation and amortization	446	431	396
Net assets from price risk management activities	(28)	(67)	(13)
Dividends in excess of (less than) equity earnings	15	(44)	(22)
Other	(151)	(31)	(106)
Operating cash flow	<u>958</u>	<u>641</u>	<u>499</u>
Non-cash working capital changes (Note 9)	(358)	(68)	(43)
	<u>600</u>	<u>573</u>	<u>456</u>
<b>INVESTING ACTIVITIES</b>			
Additions to fixed assets	(647)	(747)	(1,305)
Acquisitions (Note 12)	(182)	(66)	(39)
Dispositions (Note 13)	552	501	255
Investments and other	9	(471)	(48)
Net cash used by investing activities	<u>(268)</u>	<u>(783)</u>	<u>(1,137)</u>
<b>FINANCING ACTIVITIES</b>			
(Decrease) increase in bank indebtedness	(104)	55	102
Long term debt additions	469	663	809
Long term debt repayments	(320)	(404)	(240)
Preferred shares issued (Note 10)	—	—	272
Preferred shares redeemed (Note 10)	(200)	—	(126)
Common shares issued (Note 11)	80	184	59
Dividends paid	(217)	(197)	(191)
Dividends paid to non-controlling interest	(6)	(8)	(10)
Net cash (used) provided by financing activities	<u>(298)</u>	<u>293</u>	<u>675</u>
<b>INCREASE (DECREASE) IN CASH AND SHORT TERM INVESTMENTS DURING THE YEAR</b>	<b>34</b>	<b>83</b>	<b>(6)</b>
<b>CASH AND SHORT TERM INVESTMENTS, BEGINNING OF YEAR</b>	<b>184</b>	<b>101</b>	<b>107</b>
<b>CASH AND SHORT TERM INVESTMENTS, END OF YEAR</b>	<b>218</b>	<b>184</b>	<b>101</b>
<b>OPERATING CASH FLOW PER COMMON SHARE (Note 6)</b>	<b>\$7.75</b>	<b>\$5.50</b>	<b>\$4.38</b>

See accompanying notes

# Consolidated Balance Sheets

December 31

\$million	2001	2000
<b>ASSETS</b>		
CURRENT ASSETS		
Cash and short term investments	218	184
Accounts receivable		
Trade	1,258	1,330
Other	193	103
Deferred income taxes (Note 5)	7	15
Assets from price risk management activities (Note 16)	603	1,340
Inventory	339	315
Prepayments	20	20
	2,638	3,307
INVESTMENTS (Note 14)	920	970
DEFERRED INCOME TAXES (Note 5)	182	306
ASSETS FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 16)	429	561
FIXED ASSETS (Notes 2 and 17)		
Plant, property and equipment	12,946	12,589
Less accumulated depreciation	3,547	3,222
	9,399	9,367
DEFERRED CHARGES AND OTHER ASSETS (Note 7)	468	556
	14,036	15,067

On behalf of the Board:

**"signed Robert T.F. Reid"**  
Director

**"signed David G. Unruh"**  
Director

\$million	2001	2000
<b>LIABILITIES</b>		
CURRENT LIABILITIES		
Bank indebtedness (Note 3)	731	834
Accounts payable and accrued liabilities		
Trade	854	1,173
Other	211	180
Income and other taxes payable	51	66
Deferred income taxes (Note 5)	96	35
Liabilities from price risk management activities (Note 16)	640	1,223
Interest on debt	88	89
Long term debt due within one year (Note 2)	398	209
	<u>3,069</u>	<u>3,809</u>
LIABILITIES FROM PRICE RISK MANAGEMENT ACTIVITIES (Note 16)	<u>297</u>	<u>612</u>
LONG TERM DEBT (Note 2)	<u>5,932</u>	<u>5,971</u>
DEFERRED INCOME TAXES (Note 5)	<u>710</u>	<u>880</u>
NON-CONTROLLING INTEREST		
Preferred	130	130
Common	42	36
	<u>172</u>	<u>166</u>
<b>PREFERRED SHAREHOLDERS' EQUITY</b>		
PREFERRED STOCK (Note 10)	<u>550</u>	<u>865</u>
<b>COMMON SHAREHOLDERS' EQUITY</b>		
COMMON STOCK (Note 11)	2,138	1,944
CUMULATIVE TRANSLATION ADJUSTMENT (Note 21)	80	17
RETAINED EARNINGS	1,088	803
	<u>3,306</u>	<u>2,764</u>
	<u>14,036</u>	<u>15,067</u>
COMMITMENTS AND CONTINGENCIES (Notes 2,16,20 and 22)		

See accompanying notes

# Consolidated Statements of Retained Earnings

For the years ended December 31

<b>\$million</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
RETAINED EARNINGS, BEGINNING OF YEAR	803	641	643
ADJUSTMENTS			
Change in accounting for project development costs (Note 1)	(73)	—	—
Change in accounting for income taxes (Note 1)	—	(25)	—
Adoption of mark-to-market accounting (Note 1)	—	—	(36)
Transfer of retail services business (Note 23)	—	—	(38)
	<u>730</u>	<u>616</u>	<u>569</u>
NET INCOME	572	388	267
Share issue costs (Notes 10 and 11)	—	(3)	(4)
	<u>1,302</u>	<u>1,001</u>	<u>832</u>
DIVIDENDS			
Common shares	168	150	146
Preferred shares	46	48	45
	<u>214</u>	<u>198</u>	<u>191</u>
RETAINED EARNINGS, END OF YEAR	<u>1,088</u>	<u>803</u>	<u>641</u>

See accompanying notes

# Notes to Consolidated Financial Statements

December 31, 2001

## 1. ACCOUNTING POLICIES

### Accounting Principles

The Company is incorporated under the laws of Canada and prepares its financial statements in accordance with Canadian generally accepted accounting principles which, as applied in these financial statements except as described in Note 19, conform in all material respects with United States generally accepted accounting principles. The consolidated financial statements are presented in Canadian dollars.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities.

### Consolidation

The consolidated financial statements include the accounts of the Company, its subsidiaries and its proportionate share of joint venture investments.

#### Major Subsidiaries (a) (wholly owned unless otherwise indicated)

Westcoast Gas Holdings Inc.  
Westcoast Gas Inc.  
UEI Holdings Inc.  
Westcoast Gas Services Inc.  
Centra Gas Holdings Inc.  
Centra Gas Utilities Inc.  
Union Gas Limited  
Centra Gas British Columbia Inc. (Note 24)  
Pacific Northern Gas Ltd. – 41% owned, including 100% of the voting shares  
Empire State Pipeline (Note 12)  
Engage Energy (Note 12)  
Westcoast Power Holdings Inc.  
Westcoast Power Inc.  
Westcoast Energy International Inc.  
Westcoast Energy Risk Inc.  
Enlogix Inc.

#### Major Joint Ventures (b)

Foothills Pipe Lines Ltd. – 50% owned  
Maritimes & Northeast Pipeline Limited Partnership  
– 37.5% owned  
Maritimes & Northeast Pipeline, L.L.C. – 37.5% owned  
McMahon Cogeneration Plant – 50% owned  
Lake Superior Power Limited Partnership – 50% owned  
P.T. Puncakjaya Power – 43% owned  
Cantarell Nitrogen Facilities – 30% owned (Note 20)  
Campeche Natural Gas Compression Services Project  
– 50% owned (Note 20)  
Bayside Power Project – 75% owned  
Frederickson Power Project – 60% owned

(a) In 2001, the Company sold its wholly owned subsidiaries Westcoast Capital Corporation and Union Energy Inc. In 1999, the Company sold its wholly owned subsidiary Centra Gas Manitoba Inc. (Note 13)

(b) In 2001, the Company sold its interests in the Island Cogeneration Plant and the Whitby Cogeneration Limited Partnership. (Note 13)  
For interests acquired or disposed of during the year, purchase accounting is applied on a prospective basis from the date of the transaction.

### Revenue Recognition

The Company recognizes revenue when the service has been performed or delivered or when it is available for delivery under take-or-pay contracts. Revenue from the sale of goods is recognized when the products have been delivered.

Gas sales are recorded on the basis of meter readings plus an estimate of customer usage since the last meter reading date prior to the end of the year.

Revenues derived from selling power and steam are recognized as service is provided at the rates defined in the individual power sale agreements.

See Price Risk Management for the revenue recognition policy on risk management activities for energy marketing operations.

Rental income from assets under operating leases is recognized over the term of the lease on a straight-line basis. Interest income related to finance receivables is recognized on an accrual basis to provide a constant effective yield on the net investment in the receivables.

## Price Risk Management

Certain of the Company's operations engage in price risk management activities to manage exposure to changes in the market prices of natural gas, electric power, interest rates, foreign currency exchange rates and transportation contracts.

The cash flow impact of financial instruments is reflected as cash flows from operating activities in the Consolidated Statements of Cash Flow.

### *Energy Marketing*

Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. This accounting policy change has been applied on a cumulative retroactive basis without restatement of individual prior years. This accounting change reduced retained earnings on January 1, 1999 by \$36 million.

Under the mark-to-market method of accounting, all physical and financial marketing transactions are recorded at market value, net of any premiums/discounts or future physical delivery related costs, and are shown as Assets and Liabilities From Price Risk Management Activities on the Consolidated Balance Sheets. Unrealized gains and losses from newly originated contracts, contract restructurings and the impact of price movements are recorded in Operating Revenues in the Consolidated Statements of Operations. Changes in the assets and liabilities from price risk management activities result primarily from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. The market prices used to value these transactions reflect management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. The values are adjusted to reflect the potential impact and associated costs of liquidating the Company's position in an orderly manner over a reasonable period of time under present market conditions.

### *Non-trading activities*

Derivative and other financial instruments are also utilized in connection with non-trading activities. The Company enters into forward, future, swap and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is recognized in the financial statements.

## Project Development Costs

Effective January 1, 2001, the Company changed its accounting policy with respect to accounting for pre-operating costs incurred for development projects. This accounting policy change has been applied on a cumulative retroactive basis without restatement of individual prior periods as the effect of the accounting policy change is not reasonably determinable for individual prior periods. The effect of adopting the new accounting policy on retained earnings as at January 1, 2001 is as follows:

<b>(\$million)</b>	<b>2001</b>
Fixed assets	(75)
Investments	(9)
Deferred charges	(28)
Deferred income tax liabilities – long term	39
Retained earnings	<u>(73)</u>

Under the new accounting policy, pre-operating costs are expensed as incurred. Prior to the adoption of the new accounting policy, pre-operating costs incurred for development projects which benefited future periods were deferred and amortized on a straight-line basis over the expected period of benefit upon commencement of operations. For the year ended December 31, 2001, application of the new accounting policy decreased after-tax earnings by \$11 million.

## Earnings Per Share

Effective January 1, 2001, the Company adopted, on a retroactive basis, the new recommendations of The Canadian Institute of Chartered Accountants (CICA) with respect to the presentation and computation of earnings per share. The new recommendations require the presentation of basic and diluted earnings per share figures for net income on the Statements of Operations. The treasury stock method is to be used for determining the dilutive effect of warrants and options. The comparative Consolidated Financial Statements and Notes to the Consolidated Financial Statements have been restated to conform to the 2001 presentation. For the years ended December 31, 2001, 2000 and 1999, application of the new recommendations increased the diluted earnings per share figure by \$0.07, \$0.05 and \$0.02, respectively.

## **Income Taxes**

Effective January 1, 2000, the Company adopted the new recommendations of the CICA with respect to accounting for income taxes. This accounting policy change was applied on a cumulative retroactive basis without restatement of individual prior years. The effect of adopting the liability method of tax allocation was to reduce retained earnings as at January 1, 2000 by \$25 million.

Under the new recommendations, the liability method of tax allocation is used in accounting for income taxes for non-regulated businesses. Under this method, deferred income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. Prior to the adoption of the new recommendations, income tax expense was determined using the deferral method of tax allocation. Deferred tax expense was based on items of income and expense that were reported in different years in the financial statements and tax returns and measured at the tax rate in effect in the year the difference originated.

Rate-regulated businesses of the Company continue to use the income taxes currently payable method as directed by the regulators and as permitted under the new recommendations. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

## **Employee Benefit Plans**

Effective January 1, 2000, the Company adopted, on a prospective basis, the new recommendations of the CICA with respect to accounting for employee future benefits. The new recommendations modify the previous CICA requirements for pension costs and obligations and apply the modified requirements to non-pension benefits. Under the new recommendations, the Company has replaced pay-as-you-go method of accounting for post-retirement benefits other than pensions with accrual accounting that recognizes the liability and expense for the period when the benefits are earned, not received. The new recommendations for accounting for employee future benefits do not impact certain rate-regulated businesses of the Company, which continue with pay-as-you-go accounting as directed by the regulators.

Under the new recommendations, the Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value. The calculation of the expected return on assets is based on the market-related value of assets.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The excess of the net unamortized cumulative actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the market-related value of plan assets at the beginning of the year is amortized over the average remaining service period of the active employees.

The average remaining service period of the active employees covered by the pension plans is 17 years. The average remaining service period of the active employees covered by the other retirement benefits plans is 17 years.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs.

## **Cash and Short Term Investments**

Short term investments, consisting of money market instruments with original maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value.

## **Inventory**

Materials and supplies are valued at the lower of average cost or net realizable value. Natural gas inventories are valued at costs approved by the regulators.

## **Investments**

Investments in which the Company exercises significant influence, but not control or joint control, are accounted for by the equity method. Other investments are carried at cost, net of write downs for declines in value that are other than temporary in nature. Finance contracts represent customer financing for the purchase of natural gas appliances which are due over periods of up to 10 years.

## **Leases**

Certain equipment is leased on terms which transfer substantially all of the benefits and risks of ownership to customers, and accounted for as direct financing leases. Finance income is recognized over the term of the lease in a manner that produces a constant rate of return on the lease investment.

Assets under operating leases are recorded at cost. Depreciation is computed on a straight-line basis over the estimated useful lives of the related assets.

### **Fixed Assets**

Plant, property and equipment are recorded at cost. In accordance with normal utility practice, the cost of utility plant, property and equipment includes an allowance for funds used during construction. For non-regulated businesses, interest costs incurred during construction are capitalized as part of the cost of the asset.

Assets employed in utility businesses are depreciated on the straight-line basis at rates approved by regulatory authorities. Power generation facilities are depreciated on a unit of production basis. Other non-utility assets are depreciated on the straight-line basis. The rates used resulted in a composite rate of 3.4% for the year ended December 31, 2001 (for the year ended December 31, 2000 – 3.5%, for the year ended December 31, 1999 – 3.4%).

Upon retirement or sale of items of utility plant, property or equipment, the original costs associated with such items are charged against the applicable accumulated depreciation accounts and the cost of removal net of proceeds of disposal are charged to accumulated depreciation.

The cost of fixed assets is reduced by contributions and grants in aid of construction received from customers and from governmental bodies in support of specific pipeline and distribution facilities.

### **Capitalization and Maintenance**

Maintenance and repairs are charged to expense accounts when incurred. The costs of major replacements, extensions or improvements are capitalized as plant, property and equipment.

### **Deferred Charges**

Costs as required or permitted by the regulators have been deferred to be recovered from future revenues. Certain regulatory deferrals are subject to future decisions by the relevant regulators who will determine the treatment to be given the various items.

Costs related to long term debt are deferred and amortized on a straight-line basis over the term of the respective debt issues.

### **Goodwill**

Goodwill represents the excess cost of an investment over the fair value of the net assets acquired and is amortized on a straight-line basis over a maximum period of 20 years. Goodwill will be written down to net recoverable value if declines in value, considered to be other than temporary, occur based upon expected undiscounted cash flows.

Effective January 1, 2002, the Company ceased to record amortization on goodwill pursuant to the new recommendations of the CICA with respect to accounting for goodwill and intangible assets. Goodwill amortization for the years ended December 31, 2001, 2000 and 1999 was \$3 million, \$1 million and \$1 million, respectively.

### **Foreign Currency**

The Company's foreign businesses maintain their accounts in United States dollars or local currency. These businesses are operationally and functionally self-sustaining and accordingly, the assets and liabilities are translated into Canadian dollars at the year-end exchange rate, and revenues and expenses are translated into Canadian dollars at the average exchange rate for the year. The resulting unrealized cumulative translation gains or losses are deferred as a separate component of Common Shareholders' Equity.

For development expenditures applicable to foreign businesses, costs are translated into Canadian dollars at the prevailing exchange rate as incurred.

Funds on deposit with banks and current liabilities payable in United States dollars have been translated into Canadian dollars at the year-end exchange rate. Any resulting gain or loss is reflected in income.

The Company enters into foreign currency swaps to manage certain foreign currency risks.

### **Stock-Based Compensation Plan**

The Company has one stock-based compensation plan, which is described in Note 15. No compensation expense is recognized for this plan when the stock options are issued to employees. Any consideration paid by employees on exercise of stock options is credited to share capital. Share appreciation rights exercised are charged to retained earnings.

## Regulation

Certain operations of the Company are engaged in utility businesses which are subject to regulation by federal, provincial or state agencies within Canada and the United States. The regulatory authorities exercise statutory authority over matters such as rate of return, natural gas exports, construction and operation of natural gas facilities, accounting practices and rates, tolls and charges. The regulatory rates of return on common equity applicable to utility businesses are:

### For the years ended December 31 (percent)

	Equity Component of Rate Base			Return on Common Equity		
	2001	2000	1999	2001	2000	1999
Westcoast Energy Inc.						
– Pipeline	30	30	30	(a)	(a)	(a)
– Field Services	38.4	38.4	38.6	(a)	(a)	(a)
Foothills Pipe Lines Ltd.	30	30	30	9.61	9.90	9.58
Empire State Pipeline	40	40	40	12.50	12.50	12.50
Union Gas Limited (b)	35	35	35	9.95	9.61	9.61
Centra Gas British Columbia Inc.	35	35	35	8.14	8.42	7.76
Pacific Northern Gas Ltd.	36	36	36	10.00	10.25	10.00
Maritimes & Northeast Pipeline	25	25	25	13-14	13-14	13-14
Alliance Pipeline	30	30	30	10.9-11.2	10.9-11.2	10.9-11.2
Vector Pipeline (recourse rates)	30	30	30	14.00	14.00	14.00

(a) The Company and its major customers operate under a framework for light-handed regulation of the gathering and processing facilities which are regulated by the National Energy Board.

The framework defines the principles under which the Company negotiates service contracts individually with new and existing shippers, including tolls applicable to gathering and processing services. Consistent with these principles, the Company is responsible for the utilization of its gathering and processing assets.

Transmission services operate under a multi-year incentive-based toll settlement, which is currently being renegotiated.

(b) The decision by the Ontario Energy Board in July 2001 established delivery rates for the year 2000 and approved a trial three-year Performance Based Regulation plan for the years 2001-2003. The financial statements at December 31, 2001 and for the year then ended have not been materially impacted by this decision.

## Gain on Sale of Finance Assets

The Company, through its wholly owned subsidiary Westcoast Capital Corporation (Note 13), periodically sold certain of its asset-backed finance contracts to securitization vehicles. Securitization transactions were accounted for as sales of finance contracts. These sales were non-recourse to the Company except to the extent of the Company's retained interest in these securitization vehicles. These transactions resulted in the removal of the finance contracts from the Company's Consolidated Balance Sheets, the recording of assets received and a gain on sale when the significant risks and rewards of ownership were transferred to the purchaser. The assets received were generally cash and a retained interest in the cash flow of the finance contracts sold. Such retained interest was recorded at estimated fair value and may have included cash collateral accounts, excess spread assets, and securities backed by the finance contracts sold. Proceeds on sale were computed as the aggregate of the initial cash consideration and the present value of any additional sale proceeds, net of a provision for anticipated credit losses on the securitized finance contracts and the amount of an arm's length servicing fee.

Any gains resulting from securitization transactions were deferred and amortized over the expected life of the securitized portfolio.

Income was earned on the securitization investments on an accrual basis. The carrying value of this asset was reduced, as required, based on changes in the Company's share of the estimated credit losses and the effects of changes in the payment rate on the securitized finance contracts. The Company managed the securitized finance contracts and recognized income equal to an arm's length servicing fee over the term of the securitized finance contracts.

## Comparative Figures

Certain comparative figures have been reclassified to conform to the 2001 presentation.

## 2. LONG TERM DEBT

December 31 (\$million)	Due Date	2001	2000
<b>WESTCOAST ENERGY INC.</b>			
Unsecured Debentures			
8.0% – average fixed rate (2000 – 8.2%)	2002 – 2027	2,187	2,110
<b>CENTRA GAS UTILITIES INC. AND SUBSIDIARIES</b>			
Unsecured Senior Debentures			
8.8% – average fixed rate (2000 – 9.1%)	2002 – 2025	1,944	1,705
Secured Term Bank Loans and Other			
7.7% – average fixed rate (2000 – 8.1%)	2002 – 2019	235	239
<b>CENTRA GAS HOLDINGS INC.</b>			
Secured Term Bank Loans			
5.0% – average year end rate (2000 – 6.0%)	2003	350	348
<b>FOOTHILLS PIPE LINES LTD.</b>			
Term Bank Loans			
6.4% – average year end rate (2000 – 7.4%)	2004 – 2005	161	165
<b>PACIFIC NORTHERN GAS LTD.</b>			
Secured Debentures			
9.0% – average fixed rate (2000 – 9.1%)	2002 – 2027	82	86
<b>MARITIMES &amp; NORTHEAST PIPELINE</b>			
Senior Secured Bonds			
US\$90 million			
7.7% – average year end rate (2000 – 7.7%)	2019	143	135
Senior Secured Notes			
6.9% – average fixed rate (2000 – 6.9%)	2019	98	98
Secured Term Bank Loans			
2.3% – average year end rate (2000 – 5.9%)	2009	166	168
US\$87 million (2000 – US\$99 million)			
7.6% – average fixed rate (2000 – 7.6%)	2009	139	145
<b>CANTARELL NITROGEN FACILITIES</b>			
Secured Term Bank Loans			
US\$174 million (2000 – US\$125 million)			
5.9% – average year end rate (2000 – 7.4%)	2008 – 2010	278	187
<b>EMPIRE STATE PIPELINE</b>			
Secured Term Bank Loans			
US\$67 million (2000 – US\$38 million)			
6.3% – average year end rate (2000 – 7.1%)	2009	107	57
<b>WESTCOAST POWER HOLDINGS INC. AND SUBSIDIARIES</b>			
Senior Secured Notes			
9.3% – average fixed rate (2000 – 9.3%)	2006	14	18
Secured Term Bank Loans and Other			
3.7% – average year end rate (2000 – 6.6%)	2004 – 2006	35	261
<b>WESTCOAST (P.J.P.) HOLDINGS INC.</b>			
Secured Term Bank Loans			
US\$139 million (2000 – US\$156 million)			
6.1% – average year end rate (2000 – 8.0%)	2009	221	235
<b>WESTCOAST ENERGY ENTERPRISES (U.S.) INC.</b>			
Term Bank Loans			
US\$107 million (2000 – US\$149 million)			
2.6% – average year end rate (2000 – 7.3%)	2003	170	223
		<b>6,330</b>	<b>6,180</b>
		<b>398</b>	<b>209</b>
Deduct long term debt due within one year		<b>5,932</b>	<b>5,971</b>

Consolidated long term debt repayments, including sinking fund obligations, are:

<b>Due Date</b>	<b>\$million</b>	<b>Due Date</b>	<b>\$million</b>
2002	398	2007 – 2011	1,761
2003	888	2012 – 2016	653
2004	429	2017 – 2021	679
2005	415	2022 – 2026	439
2006	509	2027	159
	<u>2,639</u>		<u>3,691</u>

Consolidated interest on long term debt for the year ended December 31, 2001 was \$481 million (for the year ended December 31, 2000 – \$467 million, for the year ended December 31, 1999 – \$460 million).

The majority of the long term debt held by various Company subsidiaries and joint ventures is secured and non-recourse to the Company. When security is provided, it is typically a pledge of the borrowing entity's assets, key agreements, ownership interests or a combination thereof. The Company has provided guarantees or has arranged letters of credit which support the debt of the Cantarell Nitrogen Facilities, certain debt of Westcoast Energy Enterprises (U.S.) Inc. and debt of certain Westcoast Power Holdings Inc. subsidiaries, totalling \$474 million. The guarantee related to the Cantarell Nitrogen Facilities will be released after completion and satisfactory testing of the project facilities.

### **3. BANK INDEBTEDNESS**

The Company, its subsidiaries and joint ventures have operating lines of credit in excess of \$1,800 million with Canadian chartered banks that enable the Company, its subsidiaries and joint ventures to borrow directly from the banks, to issue bankers' acceptances, and to support commercial paper programs.

The average year end interest rate applicable to the consolidated bank indebtedness at December 31, 2001 was 2.5% (December 31, 2000 – 6.3%).

### **4. RELATED PARTY TRANSACTIONS**

The Company's transactions with companies related through joint control and significantly influenced investees are as follows:

<b>For the years ended December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Engage Energy (to September 30, 2000)			
Natural gas purchases and services	—	4	8
Cantarell Nitrogen Facilities			
Interest income received	—	—	22
Campeche Natural Gas Compression Services Project			
Interest income received	15	16	9
Maritimes & Northeast Pipeline			
Management fee received	7	9	10
Alliance Pipeline			
Natural gas sales and transportation	(53)	55	—
Vector Pipeline			
Natural gas sales and transportation	(25)	(2)	—

These transactions are in the normal course of operations and are recorded at exchange amounts established and agreed between the related parties.

Other accounts receivable in 2000 included an advance to Compania de Servicios de Compresion de Campeche of \$14 million, bearing interest at a fixed rate of 11.78%.

## 5. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

<b>December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>
<b>Deferred tax liabilities</b>		
Capital cost allowance claimed for income tax purposes		
in excess of depreciation and amortization	727	765
Loss carryforwards	(167)	(51)
Other – net	246	201
Total deferred tax liabilities	<u>806</u>	<u>915</u>
<b>Deferred tax assets</b>		
Depreciation and amortization		
in excess of capital cost allowance claimed for income tax purposes	89	219
Loss carryforwards	64	80
Other – net	36	22
Total deferred tax assets	<u>189</u>	<u>321</u>
Net deferred tax liabilities	<u>617</u>	<u>594</u>

For financial reporting purposes, income before income taxes and non-controlling interest includes the following components:

<b>For the years ended December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Income before income taxes and non-controlling interest			
Canada	620	354	273
Foreign	96	102	50
	<u>716</u>	<u>456</u>	<u>323</u>
Current income taxes			
Canada	29	103	83
Foreign	11	1	(4)
	<u>40</u>	<u>104</u>	<u>79</u>
Deferred income taxes			
Canada	84	(91)	(47)
Foreign	10	45	14
	<u>94</u>	<u>(46)</u>	<u>(33)</u>
Provision for income taxes	<u>134</u>	<u>58</u>	<u>46</u>

Significant components of the provision for income taxes attributable to continuing operations are as follows:

<b>For the years ended December 31 (\$million)</b>	<b>Liability Method</b>		<b>Deferred Method</b>
	<b>2001</b>	<b>2000</b>	<b>1999</b>
Current tax expense	40	104	79
Deferred income tax expense relating to origination and reversal of temporary differences	39	31	(35)
Deferred income tax benefit resulting from recognition of loss carryforwards	23	1	13
Deferred income tax expense resulting from rate change	(34)	(53)	—
Net regulated deferrals included for tax purposes	82	(5)	(2)
Regulatory drawdown of deferred income taxes	(16)	(20)	(9)
Income tax expense	<u>134</u>	<u>58</u>	<u>46</u>

At December 31, 2001, the Company has loss carryforwards of \$708 million for income tax purposes that expire as follows: 2002 – \$11 million; 2003 – \$24 million; 2004 – \$3 million, and thereafter – \$670 million. For financial reporting purposes a deferred tax asset of \$231 million (December 31, 2000 – \$131 million) has been recognized in respect of these loss carryforwards.

The reconciliation of income tax attributable to continuing operations computed at the statutory tax rates to income tax expense is:

For the years ended December 31 (\$million)	Liability Method		Deferred Method
	2001	2000	1999
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	42.3	44.8	45.0
Statutory income tax rates applied to accounting income	303	204	145
Increase (decrease) in income taxes resulting from:			
– The use of the income taxes currently payable method applicable to utility operations:			
– Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	(49)	(55)	(22)
– Other items recognized for income tax purposes subsequent to (in advance of) accounting income recognition	(5)	10	(27)
	(54)	(45)	(49)
– Foreign earnings subject to different tax rates	(7)	(20)	(10)
– Utilization of prior years' losses which have not been previously recognized	—	(5)	(25)
– Resource allowance deduction	(7)	(11)	(10)
– Equity earnings	(13)	(19)	(2)
– Deferred income tax rate adjustments	(34)	(53)	—
– Large corporation tax in excess of surtax	19	17	19
– Regulatory drawdown of deferred income taxes	(16)	(20)	(9)
– Non-taxable capital gains	(26)	(5)	(5)
– Other – net	(31)	15	(8)
	(169)	(146)	(99)
Provision for income taxes	134	58	46
Effective rate of income taxes (percent)	18.7	12.7	14.2

Certain of the Company's utility businesses have been directed by their respective regulators to refund deferred taxes collected in prior years by applying them against future costs in order to reduce tolls. The deferred taxes will be reduced in future years as the timing differences which gave rise to these deferred income taxes reverse, or as amounts are applied to reduce tolls.

If all the companies had used the liability method for fiscal 2001 and 2000, or the income tax allocation method for fiscal 1999, for regulated utility operations, the additional deferred income tax liabilities and assets and additional deferred income tax expense would be:

For the years ended December 31 (\$million)	Liability Method		Deferred Method
	2001	2000	1999
Deferred tax liability – long term, beginning of year	659	689	704
Deferred income tax (recovery) expense	43	(30)	16
Adjustment on transfer of retail services business (Note 23)	—	—	(31)
Deferred tax liability – long term, end of year	702	659	689

## 6. EARNINGS AND OPERATING CASH FLOW PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year and an adjusted net income applicable to common shares, which reflect the potential exercise of share purchase options and the conversion of preferred shares.

For the years ended December 31	2001	2000	1999
Net income applicable to common shares (\$million)	526	340	222
Effect of dilutive securities			
Convertible preferred shares			
Westcoast Energy Inc. Preferred Shares, Series 2	—	9	9
Westcoast Energy Inc. Preferred Shares, Series 4	—	—	7
Westcoast Energy Inc. Preferred Shares, Series 5	—	10	10
Westcoast Energy Inc. Preferred Shares, Series 6	6	6	6
Westcoast Energy Inc. Preferred Shares, Series 9	6	6	1
UEI Holdings Inc. Series 2	1	1	1
Net income applicable to common shares and assumed conversions (\$million)	539	372	256
Basic weighted average shares for the year (million)	123	117	114
Effect of dilutive securities			
Convertible preferred shares			
Westcoast Energy Inc. Preferred Shares, Series 2	2	3	5
Westcoast Energy Inc. Preferred Shares, Series 4	—	—	6
Westcoast Energy Inc. Preferred Shares, Series 5	5	6	9
Westcoast Energy Inc. Preferred Shares, Series 6	4	4	6
Westcoast Energy Inc. Preferred Shares, Series 9	4	4	1
UEI Holdings Inc. Series 2	—	1	1
Options	1	—	1
Diluted weighted average shares for the year (million)	139	135	143
Earnings per common share			
—basic	\$4.26	\$2.92	\$1.95
—diluted	\$3.87	\$2.75	\$1.80

In 2000, there were 1,581,259 (1999 – 1,432,000) stock options outstanding that could potentially dilute basic earnings per share in the future but were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

Operating cash flow per common share is also calculated using the weighted average number of common shares outstanding during the year applied to cash flow from operating activities before adjusting for non-cash working capital changes. Diluted operating cash flow per common share is calculated using the adjusted average number of common shares outstanding during the year.

For the years ended December 31	2001	2000	1999
Operating cash flow per common share			
—basic	\$7.75	\$5.50	\$4.38
—diluted	\$6.97	\$5.00	\$3.74

## 7. DEFERRED CHARGES AND OTHER ASSETS

December 31 (\$million)	2001	2000
Regulatory	170	176
Development projects (Notes 1 and 13)	35	38
Debt discount, premium and expense	39	49
Goodwill (Note 12)	52	32
Other	172	261
	468	556

## 8. EMPLOYEE BENEFITS

The Company, its subsidiaries and joint ventures have defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees. Information about the defined benefit plans, in aggregate, is as follows:

For the years ended December 31 (\$million)	Pension Benefit Plan		Other Benefit Plans	
	2001	2000	2001	2000
<b>Accrued benefit obligations</b>				
Balance, beginning of year	532	518	69	64
Current service cost	15	15	3	2
Interest cost	37	35	5	5
Benefits paid	(32)	(36)	(3)	(2)
Prior service costs	11	—	—	—
Actuarial gain	(14)	—	(16)	—
Divestitures	(11)	—	(2)	—
Balance, end of year	538	532	56	69
<b>Plan assets</b>				
Fair value, beginning of year	560	493	—	—
Actual return on plan assets	(94)	83	—	—
Employer contributions	17	15	—	—
Employees' contributions	3	3	—	—
Benefits paid	(33)	(34)	—	—
Divestitures	(14)	—	—	—
Fair value, end of year	439	560	—	—
Funded status – plan (deficit) surplus	(99)	28	(56)	(69)
Unamortized net actuarial loss (gain)	66	(47)	(18)	—
Unamortized prior service costs	11	—	—	—
Unamortized transitional obligation	30	32	57	61
Contributions remitted after measurement date	4	—	1	—
Accrued benefit asset (liability)	12	13	(16)	(8)

The non-pension defined benefit plans are unfunded. The accrued benefit obligations and fair value of plan assets of defined benefit pension plans with accrued benefit obligations in excess of plan assets are \$538 million and \$439 million, respectively (December 31, 2000 – \$141 million and \$127 million, respectively).

The following is a summary of the weighted average significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

For the years ended December 31	Pension Benefit Plan		Other Benefit Plans	
	2001	2000	2001	2000
Discount rate	7.25%	7%	7.25%	7%
Expected long-term rate of return on plan assets	8.5%	7.5%	—	—
Rate of compensation increase	3.25%	3.25%	3.25%	3.25%

In addition, in determining the expected cost of health care benefit plans, it is assumed that the health care inflation will decrease gradually to 5% in 2003 and remain level thereafter.

The Company's net benefit plan expense is as follows:

For the years ended December 31 (\$million)	Pension Benefit Plan		Other Benefit Plans	
	2001	2000	2001	2000
Current service cost	13	12	2	2
Interest cost	36	35	5	4
Expected return on plan assets	(42)	(36)	—	—
Amortization of transitional obligation	3	3	4	4
Net benefit plan expense	10	14	11	10

The defined contribution pension expense for the years ended December 31, 2001 and 2000 was \$6 million and \$5 million, respectively. The defined contribution and benefit pension expense for the year ended December 31, 1999 was \$8 million.

## 9. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes

For the years ended December 31 (\$million)	2001	2000	1999
Accounts receivable	2	(808)	44
Inventory and prepayments	(58)	(106)	(67)
Accounts payable and accrued liabilities	(261)	809	27
Interest and taxes payable	(54)	23	17
	(371)	(82)	21
Attributable to financing and investing activities	(13)	(14)	64
Attributable to operating activities	(358)	(68)	(43)

Interest and tax payments

For the years ended December 31 (\$million)	2001	2000	1999
Interest	562	556	514
Income taxes	71	84	43

## 10. PREFERRED STOCK

The Company is authorized to issue an unlimited number of preferred shares, in two classes issuable in series, without nominal or par value. Preferred shares issued for cash and outstanding are:

December 31 (\$million)	2001	2000
nil (2000 – 4,597,187) – 8.08% Cumulative First Preferred Shares, Series 2 (a)(f)	—	115
nil (2000 – 8,000,000) – 4.90% Cumulative Redeemable First Preferred Shares, Series 5 (b)(f)	—	200
5,000,000 – 4.72% Cumulative Redeemable First Preferred Shares, Series 6 (c)(f)	125	125
6,000,000 – 5.50% Cumulative First Preferred Shares, Series 7 (d)(f)	150	150
6,000,000 – 5.60% Cumulative First Preferred Shares, Series 8 (e)(f)	150	150
5,000,000 – 5.00% Cumulative Redeemable First Preferred Shares, Series 9 (c)(f)	125	125
	550	865

(a) The Series 2 Preferred Shares were converted into common shares of the Company in October 2001, resulting in the issuance of 2,916,312 common shares of the Company. In 2000 and 1999, preferred shareholders exercised their conversion privileges, resulting in the issuance of 13,514 and 18,660 common shares, respectively, of the Company (Note 11).

(b) The Series 5 Preferred Shares were redeemed by the Company in December 2001 for cash of \$200 million plus accrued dividends.

(c) The Series 6 and 9 Preferred Shares are convertible into common shares of the Company, at the option of the holder, on or after April 15, 2003 and January 15, 2005, respectively, at the ratio determined by dividing \$25.00 together with accrued and unpaid dividends, by the greater of \$3.00 and 95% of a 20 day weighted average trading price of the Company's common shares.

The Company has the option to redeem the Series 6 and 9 Preferred Shares on or after January 15, 2003 and October 15, 2004, respectively, at \$25.00 plus accrued and unpaid dividends or to convert these shares into common shares of the Company, at the ratio determined by dividing \$25.00 together with accrued and unpaid dividends, by the greater of \$3.00 or 95% of a 20 day weighted average trading price of the Company's common shares.

(d) The Company has the option to redeem the Series 7 Preferred Shares on or after October 15, 2013 at \$25.00 per share plus accrued and unpaid dividends.

(e) The Company has the option to redeem the Series 8 Preferred Shares on or after July 15, 2004 at prices ranging from \$25.00 to \$26.00 per share plus accrued and unpaid dividends.

(f) The issue costs of preferred shares, net of income taxes, have been charged to retained earnings.

## 11. COMMON STOCK

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Common shares issued and outstanding are:

	shares	\$million
Balance – December 31, 1998	112,670,767	1,695
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$25.98 to \$30.51 per share.	1,989,110	55
(b) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from \$17.69 to \$24.02 per share.	168,978	4
(c) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 10)	18,660	1
Balance – December 31, 1999	114,847,515	1,755
(a) Shares issued for cash under a public offering at a price of \$32.25 per share. The issue costs of these shares, amounting to \$5 million, less income taxes of \$2 million, have been charged to retained earnings.	4,000,000	129
(b) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$21.93 to \$27.84 per share.	2,121,003	50
(c) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from \$17.69 to \$34.45 per share.	461,334	10
(d) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 10)	13,514	—
Balance – December 31, 2000	121,443,366	1,944
(a) Shares issued for cash under the Dividend Reinvestment and Share Purchase Plan at prices ranging from \$27.84 to \$36.95 per share.	1,787,173	61
(b) Shares issued for cash on options exercised and shares issued under share appreciation rights, at option prices ranging from \$17.69 to \$34.45 per share.	809,060	19
(c) Shares issued on the conversion of First Preferred Shares, Series 2 (Note 10)	2,916,312	114
Balance – December 31, 2001	<b>126,955,911</b>	<b>2,138</b>

In 2001, the Directors granted 941,300 options, at \$33.69 per share based on a 5 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange. At December 31, 2001, 4,825,192 common shares were under option at prices ranging from \$17.69 to \$34.45 per share, of which 3,416,560 are eligible for share appreciation rights that allow the holder to receive 50% of the appreciated value in cash and the balance in common shares of the Company. At December 31, 2001, 2,024,355 common shares were reserved for issuance upon the exercise of options.

At December 31, 2001, 5,201,894 common shares were reserved for issuance under the Dividend Reinvestment and Share Purchase Plan.

Preferred shares amounting to \$20 million held by a non-controlling interest in UEI Holdings Inc. are convertible into common shares of the Company at any time at the option of the holder at 95% of a 20 day weighted average trading price of the Company's common shares on The Toronto Stock Exchange.

## 12. ACQUISITIONS (Note 20)

### Empire State Pipeline

During 2001, the Company purchased, from its partner, an additional 50% interest in the Empire State Pipeline, increasing its interest to 100%, for cash of \$122 million. The costs of acquiring the Company's additional interest in the Empire State Pipeline exceed the equivalent proportion of the acquired net assets by \$43 million. The acquisition has been accounted for by the purchase method as follows:

December 31 (\$million)	2001
Fixed assets	130
Goodwill	43
Assumption of long term debt	(51)
Cash purchase price	<u>122</u>

### Engage Energy

During 2001, Engage Energy purchased a 100% interest in Distributed Power Systems for cash of approximately \$6 million. The acquisition, accounted for by the purchase method, was entirely attributed to energy contracts.

During 2000, the Company and The Coastal Corporation (Coastal) terminated their Engage Energy joint venture. The termination of the joint venture agreement resulted in the Company purchasing the additional 50% interest in Engage Energy Canada L.P. (Engage Canada), increasing its interest to 100%. The costs of acquiring the Company's interest in Engage Canada exceed the equivalent proportion of the acquired net assets by \$16 million. This excess has been allocated to assets from price risk management activities and goodwill. The acquisition has been accounted for by the purchase method as follows:

December 31 (\$million)	2000
Fixed assets	6
Working capital	29
Assets from price risk management activities	
Current	213
Long term	107
Goodwill	10
Liabilities from price risk management activities	
Current	(204)
Long term	(94)
Deferred income taxes	(10)
Cash purchase price	<u>57</u>

In conjunction with the termination of the joint venture agreement, the Company purchased for cash approximately \$9 million of contracts from Engage Energy US, L.P. and subsequently sold its 50% interest in Engage Energy US, L.P. to Coastal for cash of \$81 million.

### Vector Pipeline

During 1999, the Company purchased a 30% equity interest in the Vector Pipeline (Vector) from an existing Vector partner for cash of \$30 million. The costs of acquiring the Company's interest in Vector exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Vector by \$6 million. This excess is being amortized on a straight-line basis over 15 years beginning December 1, 2000, the commencement date of operations.

### Heating, Ventilation and Air Conditioning (HVAC) Businesses

During 1999, the Company purchased 100% of the outstanding shares in, or certain assets of, 13 HVAC businesses. The acquisitions have been accounted for by the purchase method as follows:

December 31 (\$million)	1999
Fixed assets	2
Working capital	3
Goodwill	5
Assumption of long term debt	(1)
Cash purchase price	<u>9</u>

### 13. DISPOSITIONS (Notes 12 and 24)

#### 2001

- The Company sold its 100% interest in the Island Cogeneration Plant and its 50% interest in the Whitby Cogeneration Plant for proceeds of \$342 million, of which \$146 million was cash, resulting in a pre-tax gain of \$108 million.
- The Company sold its wholly owned subsidiaries Westcoast Capital Corporation and Union Energy Inc. for cash of \$176 million, resulting in a pre-tax gain of \$40 million.
- The Company sold its 49% interest in NGX Canada Inc. for cash of \$10 million, resulting in a pre-tax gain of \$7 million.
- Westcoast Capital Corporation sold certain of its rental assets as a direct financing lease for proceeds of \$19 million. The proceeds approximated net book value.
- The Company sold certain of its gas gathering and processing facilities for proceeds of \$201 million, resulting in a deferred pre-tax gain of \$34 million. The Company subsequently entered into an operating lease agreement for the facilities with the lease obligations guaranteed by the Company. The Company may, but is not required to, re-acquire the facilities on certain dates, as well as at the end of the lease agreement. In the event that the assets are not re-acquired, the Company has guaranteed the residual value of the assets up to an amount of approximately \$160 million.

#### 2000

- Westcoast Capital Corporation sold certain of its rental assets as a direct financing lease for proceeds of \$344 million. The proceeds approximated net book value.
- The Company sold its interests in the EastCoast Power Project in Australia, the Liberty Electric Power Project and NrG Information Services Inc. for total cash proceeds of \$32 million, resulting in a pre-tax gain of \$15 million.
- The Company sold a portion of its interests in NGX Canada Inc., Bayside Power Project and Frederickson Power Project for total cash proceeds of \$44 million, resulting in a pre-tax gain of \$5 million.

#### 1999

- The Company sold its wholly owned subsidiary Centra Gas Manitoba Inc. for cash of \$245 million, resulting in a pre-tax gain of \$76 million.
- The Company sold its interest in the Fort Nelson Powerline joint venture for cash of \$10 million, resulting in a pre-tax gain of \$5 million.

Supplemental cash flow information regarding dispositions is as follows:

December 31 (\$million)	2001	2000
Cash and short term investments	97	31
Total assets other than cash and short term investments	989	1,209
Total liabilities	528	745

### 14. INVESTMENTS

December 31 (\$million)	2001	2000
Alliance Pipeline, 23.6% interest (a)	429	408
Aux Sable, 23.6% interest	142	148
Vector Pipeline, 30% interest (Note 12)	317	274
Finance contracts (b)	22	116
Other	10	24
	<u>920</u>	<u>970</u>

(a) The costs of acquiring the Company's interests in the books of the Alliance Pipeline exceed the figure at which the equivalent proportion of the net assets is recorded in the books of the Alliance Pipeline by \$20 million. This excess is being amortized on a straight-line basis over 25 years beginning December 1, 2000, the commencement date of operations.

(b) In 2001, Westcoast Capital Corporation sold certain of its asset-backed finance contracts for cash proceeds of \$63 million, (2000 – \$19 million, of which \$18 million was cash; 1999 – \$77 million, of which \$74 million was cash). The proceeds approximated net book value.

## 15. STOCK-BASED COMPENSATION PLAN

### Stock Option Plan

Under the Long Term Incentive Share Option Plan 1989 (1989 Plan), the Company has granted regular, key employee retention, and performance-based stock options to its employees. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of the Company's shares on the date of grant.

Regular stock options vest in five equal stages with the first stage vesting immediately on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of grant. Key employee retention stock options commence vesting two years after the date of issuance and then vest in three equal annual installments. The maximum term of both stock options awarded under the 1989 Plan is ten years. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

Performance-based stock options commence vesting when a pre-determined performance threshold has been achieved. The options then vest in three equal annual stages commencing on the date the performance threshold is achieved. The maximum term for performance-based options awarded under the 1989 Plan ranges from five to eight years. Share appreciation rights have not been attached to performance-based options awarded under the 1989 Plan.

A summary of the status of the Company's stock option plan as of December 31, 2001 and 2000, and changes during the years ending on those dates is presented below:

	2001		2000	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of year	4,873,719	\$25.82	4,690,853	\$25.36
Granted	941,300	\$33.69	951,600	\$26.37
Exercised	(809,060)	\$23.33	(461,335)	\$21.29
Forfeited	(180,767)	\$27.52	(307,399)	\$27.27
Outstanding at end of year	<u>4,825,192</u>	\$27.69	<u>4,873,719</u>	\$25.82
Options exercisable at year-end	<u>2,113,245</u>		<u>2,042,160</u>	

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding At 12/31/01	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/01	Weighted-Average Exercise Price
\$17 – 22	887,000	1.9	\$20.66	887,000	\$20.66
\$24 – 25	1,649,440	7.7	\$24.67	698,030	\$24.55
\$28 – 32	557,420	7.9	\$28.67	233,900	\$28.70
\$33 – 35	<u>1,731,332</u>	1.0	\$33.86	<u>294,315</u>	\$33.98
\$17 – 35	<u>4,825,192</u>			<u>2,113,245</u>	

## 16. FINANCIAL INSTRUMENTS

### Energy Marketing

Engage Energy engages in the marketing and trading of natural gas and electric power and executes financial derivatives related to these commodities for overall management of its contractual portfolio and physical positions. Engage Energy's portfolio of natural gas and electric power contracts is comprised primarily of contracts for purchase and delivery of natural gas and power and the following financial contracts: forward, netbacks, future, swap and option contracts for periods of up to 15 years, which also include related fixed and floating price commitments. These transactions give rise to certain business risks, including market and credit risk.

### Market Risk

Market risk is the risk that the value of the portfolio will change, either favourably or unfavourably, in response to changing market conditions including but not limited to commodity price changes. Market risks are monitored by an internal Risk Management Committee to ensure compliance to Company standards. The Company monitors and manages its exposure to market risk through a variety of risk management techniques. Such procedures include measurement of risk, market comparisons, monitoring of all commitments and positions, and daily reporting to senior management. In addition, sensitivity to changes in market price and market volatility are examined on a daily basis.

## Credit Risk

Credit risk is the risk of loss from non-performance by suppliers, customers or financial counterparties to a contract. In connection with the market valuation of its energy trading, leasing and finance contracts, the Company maintains certain reserves for a number of risks and costs associated with these future commitments. Among others, these include reserves for credit risks based on the financial condition and short and long term exposures to counterparties. The Company maintains credit policies which management believes significantly minimizes overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure, monitoring of concentration of exposure to any one individual or counterparty or industry, monitoring of aggregate exposure against limits by the internal credit risk management group and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. The credit risk management group reviews and monitors the application of these policies for suppliers, customers and counterparties. Customers not meeting minimum credit standards must provide security. The Company's energy marketing operations are primarily concentrated in the natural gas and electric power industries and major customers' operations are also heavily concentrated in the same industries. The counterparties associated with assets from price risk management activities net of reserves as of December 31, 2001 and 2000 are summarized as follows:

December 31 (\$million)	2001		2000	
	Investment Grade (a)	Total	Investment Grade (a)	Total
Gas and electric utilities	213	221	122	122
Energy marketers	193	193	497	519
Financial institutions	19	20	284	284
Independent power producers	10	32	2	6
Oil and gas producers	202	202	294	511
Industrials	25	25	7	9
Pipelines and other	332	339	142	259
Energy retailer	—	—	—	191
Total	<u>994</u>		<u>1,348</u>	
Assets from price risk management activities (b)		<u>1,032</u>		<u>1,901</u>

(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of collateral, which may encompass letters of credit, parent company guarantees and property interests. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Dominion Bond Rating Service rating of BBB- or Moody's rating of Baa3, respectively, or minimum implied (through internal financial credit analysis) Standard & Poor's equivalent rating of BBB-.

(b) Two and six customers' exposures at December 31, 2001 and 2000, respectively, comprise greater than 5% of Assets From Price Management Activities. All are included above as Investment Grade.

## Commodity Price Risk

The natural gas supply of the Company's Gas Distribution businesses includes gas supply contracts with pricing mechanisms that vary with gas price indices, rather than fixed prices. For some of these contracts, the effective purchase price has been fixed through the use of gas price swap contracts. The differences between the price of natural gas used for toll purposes and the effective cost of gas purchased is deferred for future disposition as approved by the respective regulators. The difference, if any, between amounts actually recorded as receivable or payable at year end and amounts actually approved for recovery by the regulator is charged to income at the time of the regulator's decision. The net receivable position of these deferrals at December 31, 2001 was approximately \$212 million (December 31, 2000 – net payable \$40 million).

Approximately 36% of the forecast 2002 gas supply of the Gas Distribution businesses from January through December 2002 is indexed to variable pricing mechanisms. At December 31, 2001 the purchase price applicable to 12 billion cubic feet (Bcf) or 25% of this indexed supply has been effectively fixed through the use of natural gas swaps and other contracts.

## 16. FINANCIAL INSTRUMENTS (CONTINUED)

### Notional Amounts of Derivative Instruments

The approximate notional amount of natural gas derivative instruments at December 31, 2001 is 2,373 Bcf (December 31, 2000 – 2,424 Bcf) with a maximum 7 and 8 years, respectively, in term.

Notional amounts reflect the volume of transactions but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not accurately measure the Company's exposure to market or credit risks. The maximum terms in years detailed above are not indicative of likely future cash flows as these instruments may be traded in the markets at any time in response to the Company's risk management needs.

### Interest Rate Swaps

The Company uses interest rate swaps to manage the fixed and floating interest rate mix of the total debt portfolio. By entering into interest rate swap agreements, the Company agrees to exchange with the Canadian chartered banks the difference between the fixed rate and floating rate interest payments calculated by reference to bankers' acceptances rates and on an agreed notional amount. The notional amount does not represent the amount exchanged by the counterparties, and therefore is not a measure of market or credit exposure. The Company or its subsidiaries have entered into floating to fixed rate swap agreements on \$838 million with an average pay rate of 6.4% and an average maturity date of approximately 5 years.

### Foreign Currency Contracts

The Company periodically enters into commodity transactions which create Canadian versus United States dollar exposure. To reduce risk and protect margins, the Company enters into forward foreign exchange contracts which establish the foreign exchange rate for the cash flows from these purchase and sale transactions.

In order to fix the costs associated with certain construction and maintenance contracts, the Company entered into forward contracts to purchase Swiss francs and sell United States dollars. At December 31, 2001, Swiss franc contracts with a notional amount of \$7 million were outstanding, maturing through to January 2002.

To reduce the impact of changes in the Canadian – United States exchange rate in the translation of certain income denominated in United States dollars arising in 2002, the Company has fixed the translation rate on US\$46 million of income at a weighted average rate of 1.5464.

### Fair Market Values

The following fair market value (FMV) information is provided solely to comply with financial instrument disclosure requirements. The Company cautions readers in the interpretation of the impact of these estimated fair market values due to the regulated nature of some of the Company's operations. Based on the current regulatory process, any gains or losses arising from the use of financial instruments as approved by respective regulators may be deferred for future disposition by the regulators.

Fair market values have been estimated by reference to quoted market prices for the actual or similar instruments where available. The fair market values of accounts receivable and current liabilities approximate carrying values. The carrying values and approximate fair market values of the Company's financial instruments, excluding energy trading activities which are marked to market, and are therefore recognized in the consolidated financial statements, are:

December 31 (\$million)	2001		2000	
	Carrying Value	Approx FMV	Carrying Value	Approx FMV
<b>ASSETS</b>				
Investments	920	936	970	967
Natural gas	—	—	—	32
Foreign currency contracts	—	—	—	1
<b>LIABILITIES</b>				
Long term debt (including current portion)	6,330	6,830	6,180	6,414
Natural gas	—	13	—	—
Interest rate swaps	—	46	—	23

## 17. FIXED ASSETS

December 31 (\$million)	2001	2000
<b>PLANT, PROPERTY AND EQUIPMENT</b>		
<b>Transmission &amp; Field Services</b>		
Natural gas pipeline systems	3,732	3,434
Processing plants	1,136	1,306
Other	197	200
Construction work in progress	137	28
	<u>5,202</u>	<u>4,968</u>
<b>Gas Distribution</b>		
Natural gas pipeline and distribution systems (a)	4,912	4,728
Natural gas storage	662	636
Other	457	457
Construction work in progress	45	33
	<u>6,076</u>	<u>5,854</u>
<b>Power Generation</b>		
Power generation plants	454	605
Construction work in progress	—	48
	<u>454</u>	<u>653</u>
<b>International</b>		
Power generation plant and other	1,105	861
<b>Services and Other</b>		
Rental assets and other (a) (Note 13)	109	253
	<u>12,946</u>	<u>12,589</u>
<b>ACCUMULATED DEPRECIATION</b>		
Transmission & Field Services	1,486	1,690
Gas Distribution	1,788	1,300
Power Generation	123	113
International	118	57
Services and Other	32	62
	<u>3,547</u>	<u>3,222</u>
	<u>9,399</u>	<u>9,367</u>

(a) Natural gas pipeline and distribution systems includes the depreciated cost of the transmission and distribution plant of the Company's subsidiary, Pacific Northern Gas Ltd. (PNG), of \$67 million (2000 – \$169 million). Although efforts continue to secure a new long-term firm transportation service agreement with Methanex Corporation (Methanex), a major customer of PNG, following a temporary shutdown of a plant by Methanex, the recovery of the PNG investment in these gas distribution assets is uncertain. Rental assets and other includes the depreciated cost of a customer billing system of \$48 million (2000 – \$57 million), the recovery of which is uncertain.

In accordance with current accounting standards, management uses estimated expected future net cash flows to measure the recoverability of its investment in these assets. The estimation of expected future net cash flows is inherently uncertain and relies to a considerable extent on assumptions regarding current and future economic, market and regulatory conditions. If, in future periods, there are changes in the estimates or assumptions incorporated into the impairment review analysis, the changes could result in an adjustment to the carrying amount of the transmission and distribution plant or the customer billing system.

## 18. SEGMENTED INFORMATION

The operating segments presented are those adopted by senior management based on the Company's internal reporting system.

The operations of the Company have been grouped according to the following business segments:

**Transmission & Field Services** – natural gas gathering, processing and transmission;

**Gas Distribution** – natural gas distribution and storage and transmission;

**Power Generation** – electrical and thermal energy generated from natural gas;

**International** – international operations;

**Services** – energy marketing, retail energy services, customer billing system and financial services. The retail energy services and financial services businesses, operated by wholly owned subsidiaries Westcoast Capital Corporation and Union Energy Inc., were sold in 2001 (Note 13);

**Other** – other activities, including corporate expenses, business development expenditures and corporate financing expenses.

Inter segment revenues are earned in the normal course of operations and are recorded at amounts established and agreed upon between the operating segments.

The Company has international businesses and development projects which are primarily located in the United States, Mexico, Indonesia and China. The percentages of the Company's consolidated operating revenues net of cost of sales, consolidated operating income and consolidated fixed assets and goodwill represented by these businesses and development projects are:

For the years ended December 31	2001	2000	1999
Operating revenues, net of cost of sales	12%	11%	5%
Operating income	17%	13%	13%
Fixed assets and goodwill	19%	15%	

Statements of segmented operations for the years ended December 31 are as follows:

(\$million, except for share data) 2001	Transmission	Gas	Power	International	Services	Other	Total
	& Field Services	Distribution	Generation				
Total revenues	906	2,195	197	192	9,130	2	12,622
Inter segment revenues	—	(11)	—	—	(714)	—	(725)
Operating revenues	906	2,184	197	192	8,416	2	11,897
Depreciation	(155)	(188)	(17)	(44)	(29)	(5)	(438)
Other operating expenses	(366)	(1,627)	(138)	(79)	(8,225)	(45)	(10,480)
Operating income (loss)	385	369	42	69	162	(48)	979
Interest income	7	—	—	—	18	(8)	17
Equity earnings	32	—	—	—	—	—	32
Interest expense	(192)	(207)	(9)	(37)	(13)	(52)	(510)
Other items	8	—	109	7	48	26	198
Income (loss) before undernoted items	240	162	142	39	215	(82)	716
Income taxes	(43)	(37)	(34)	(7)	(65)	52	(134)
Non-controlling interest	—	(9)	—	—	—	(1)	(10)
Net income (loss)	197	116	108	32	150	(31)	572
Provision for preferred dividends	(2)	—	—	—	—	(44)	(46)
Net income (loss) applicable to common shares	195	116	108	32	150	(75)	526
Per common share – basic	\$1.58	\$0.94	\$0.88	\$0.25	\$1.22	\$(0.61)	\$4.26
Operating cash flow	379	374	34	83	144	(56)	958
Operating cash flow per common share	\$3.07	\$3.02	\$0.28	\$0.67	\$1.17	\$(0.46)	\$7.75
Additions to fixed assets and goodwill	300	245	80	20	34	1	680
Total assets	4,844	5,536	362	1,189	1,700	405	14,036

(\$million, except for share data) 2000	Transmission		Gas	Power		Services	Other	Total
	& Field Services	Distribution	Generation	International				
Total revenues	825	1,870	128	127	6,613	5	9,568	
Inter segment revenues	—	(14)	—	—	(597)	(2)	(613)	
Operating revenues	825	1,856	128	127	6,016	3	8,955	
Depreciation	(141)	(189)	(17)	(28)	(49)	(2)	(426)	
Other operating expenses	(321)	(1,282)	(85)	(46)	(5,933)	(47)	(7,714)	
Operating income (loss)	363	385	26	53	34	(46)	815	
Interest income	4	—	3	4	2	8	21	
Equity earnings	44	—	—	—	—	—	44	
Interest expense	(186)	(207)	(6)	(28)	(8)	(81)	(516)	
Other items	7	4	2	24	19	36	92	
Income (loss) before undernoted items	232	182	25	53	47	(83)	456	
Income taxes	(42)	(61)	(9)	(24)	(2)	80	(58)	
Non-controlling interest	—	(9)	—	—	—	(1)	(10)	
Net income (loss)	190	112	16	29	45	(4)	388	
Provision for preferred dividends	(2)	—	—	—	—	(46)	(48)	
Net income (loss) applicable to common shares	188	112	16	29	45	(50)	340	
Per common share – basic	\$1.62	\$0.97	\$0.13	\$0.25	\$0.38	\$(0.43)	\$2.92	
Operating cash flow	299	285	32	77	22	(74)	641	
Operating cash flow per common share	\$2.56	\$2.44	\$0.28	\$0.66	\$0.19	\$(0.63)	\$5.50	
Additions to fixed assets and goodwill	192	238	191	92	59	1	773	
Total assets	4,761	5,177	628	921	3,253	327	15,067	

(\$million, except for share data) 1999	Transmission		Gas	Power		Services	Other	Total
	& Field Services	Distribution	Generation	International				
Total revenues	722	1,876	119	68	3,890	2	6,677	
Inter segment revenues	(5)	(7)	—	—	(400)	—	(412)	
Operating revenues	717	1,869	119	68	3,490	2	6,265	
Depreciation	(123)	(183)	(19)	(18)	(56)	(2)	(401)	
Other operating expenses	(292)	(1,331)	(91)	(12)	(3,484)	(31)	(5,241)	
Operating income (loss)	302	355	9	38	(50)	(31)	623	
Interest income	2	1	1	2	3	46	55	
Equity earnings	22	—	—	—	—	—	22	
Interest expense	(172)	(208)	(6)	(21)	(9)	(83)	(499)	
Other items	23	83	7	1	1	7	122	
Income (loss) before undernoted items	177	231	11	20	(55)	(61)	323	
Income taxes	(22)	(68)	—	(5)	23	26	(46)	
Non-controlling interest	—	(9)	—	—	—	(1)	(10)	
Net income (loss)	155	154	11	15	(32)	(36)	267	
Provision for preferred dividends	(1)	—	—	—	—	(44)	(45)	
Net income (loss) applicable to common shares	154	154	11	15	(32)	(80)	222	
Per common share – basic	\$1.35	\$1.35	\$0.10	\$0.13	\$(0.28)	\$(0.70)	\$1.95	
Operating cash flow	238	246	25	38	14	(62)	499	
Operating cash flow per common share	\$2.09	\$2.16	\$0.22	\$0.33	\$0.12	\$(0.54)	\$4.38	
Additions to fixed assets and goodwill	555	292	183	217	105	(35)	1,317	

## 19. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company prepares its accounts in accordance with Canadian generally accepted accounting principles (Canadian GAAP) which in the main, parallel United States generally accepted accounting principles (US GAAP). The following tables reflect the major differences in accounting principles.

Consolidated net income under US GAAP would be:

<b>For the years ended December 31 (\$million, except for share data)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Net income under Canadian GAAP	572	388	267
Adjustments			
Pension and post-retirement benefits other than pensions (a)	1	2	(7)
Income taxes (b)	51	(53)	—
Costs of start-up activities (c)	(26)	(2)	(45)
Initial adoption of mark-to-market accounting (e)	—	—	(36)
Derivative instruments and hedging activities (i)	55	—	—
Other (d)(f)(g)	(8)	1	(2)
Net income under US GAAP	645	336	177
Provision for dividends on preferred shares (f)	46	48	45
Net income under US GAAP applicable to common shares	599	288	132
Common shares – weighted average (million)	123	117	114
Earnings per common share under US GAAP – basic	\$4.85	\$2.47	\$1.16
– fully diluted	\$4.39		

Consolidated comprehensive income under US GAAP would be:

<b>For the years ended December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Net income under US GAAP applicable to common shares	544	288	132
Change in the Cumulative Translation Adjustment	63	14	(31)
Net unrealized gains on cash flow hedges (i)	(18)	—	—
Reclassification into earnings (i)	3	—	—
Comprehensive income under US GAAP	592	302	101

The Consolidated Statements of Comprehensive Income are not required under Canadian GAAP, and the Cumulative Translation Adjustment is recorded as a separate component of Common Shareholders' Equity.

After adjusting for certain differences, selected consolidated balance sheet items under US GAAP would be:

<b>December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>
<b>ASSETS</b>		
Current assets (g)	2,638	3,563
Investments (g)	920	1,023
Assets from price risk management activities (i)	417	—
Derivative assets (i)	28	—
Fixed assets (g)	9,561	9,694
Deferred income taxes (b)(g)(i)	69	99
Deferred charges and other assets (a)(b)(c)(g)(i)	1,440	1,614
<b>LIABILITIES</b>		
Current liabilities (b)(g)	3,070	3,829
Liabilities from price risk management activities (i)	285	—
Long term debt (f)(g)	6,128	5,966
Long term obligations (a)(g)	30	412
Deferred income taxes (a)(b)(i)	1,508	2,051
Non-controlling interest – preferred shares (f)	135	135
Additional paid in capital (d)	11	7
Accumulated other comprehensive income	61	13
<b>RETAINED EARNINGS</b>	<b>1,115</b>	<b>684</b>

### Pensions and Post-Retirement Benefits Other than Pensions

(a) Effective January 1, 2000, accounting for pension and post-retirement benefits other than pension under Canadian GAAP was modified and is similar to the requirements under US GAAP. Pension fund assets are measured at current market values and the accrued pension plan obligations are discounted using current interest rates. Post-retirement benefits other than pension are recorded on an accrual basis.

Previously as permitted by Canadian GAAP, the Company measured the pension fund assets at the average market related values and the accrued pension plan obligations were discounted using management's long term assumptions for interest rates. Post-retirement benefits other than pensions were recorded using the pay-as-you-go method of accounting.

### Income Taxes

(b) Effective January 1, 2000, Canadian GAAP require accounting for income taxes using the liability method of tax allocation, similar to the requirements under US GAAP. However, there remain two significant differences between Canadian and US GAAP:

(i) Canadian GAAP require that deferred income tax balances be adjusted to reflect substantively enacted rates rather than current legislated tax rates under US GAAP.

(ii) Under Canadian GAAP, rate-regulated businesses use the income taxes currently payable method as directed by the regulators. No provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and deferred expenditure items. For these businesses, US GAAP require the recording of deferred income taxes and the corresponding deferred charges which are to be collected from regulated customers in future years.

Deferred income taxes under US GAAP would be:

December 31 (\$million)	2001	2000
Deferred income taxes under Canadian GAAP	617	594
Difference related to rate change adjustment	—	53
Rate-regulated businesses deferred income taxes	899	1,338
Derivative instruments and hedging activities	28	—
Other adjustments	(16)	(13)
Deferred income taxes under US GAAP	<u>1,528</u>	<u>1,972</u>

### Costs of Start-Up Activities

(c) Effective January 1, 2001, the Company changed its accounting policy under Canadian GAAP with respect to accounting for pre-operating costs. Under the new policy, which is similar to the requirements under US GAAP, pre-operating costs are expensed as incurred. Under Canadian GAAP, the cumulative effect of a change in accounting principle is recorded as a charge to retained earnings. The cumulative effect of the change under US GAAP, in accordance with the Statement of Position (SOP) 98-5, Reporting on the Costs of Start-Up Activities, effective January 1, 1999, is included in the determination of 1999 net income. Of the \$45 million included in the determination of net income in 1999, \$23 million represents the cumulative effect of the accounting change on prior years.

### Stock-Based Compensation

(d) Effective January 1, 1996, the Company adopted Statement of Financial Accounting Standards (SFAS) 123, Accounting for Stock-Based Compensation, which requires that the fair market value of benefits related to stock-based compensation be charged to income over the applicable vesting period under US GAAP rather than as a capital transaction under Canadian GAAP. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for stock options granted in 2001, 2000 and 1999, respectively: expected dividend yields of 4.0%, 4.9% and 5.0%, expected volatility of 15.0%, 14.7% and 12.9%, risk free interest rate of 4.7%, 5.3% and 6.0% and expected life of 10 years for all grants.

### Energy Marketing Operations

(e) Effective January 1, 1999, the Company adopted mark-to-market accounting for the Company's energy marketing operations. The cumulative effect of a change in accounting principle under US GAAP is included in the determination of 1999 net income. Under Canadian GAAP, the cumulative effect is recorded as a charge to retained earnings.

## **19. RECONCILIATION OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (CONTINUED)**

### **Debt-Like Preferred Shares**

(f) Canadian GAAP require debt-like preferred shares and their dividends to be treated as long term debt and interest expense respectively. Under Securities and Exchange Commission (SEC) rules, these shares are to be recorded as mezzanine debt and the dividend as a charge to retained earnings.

### **Sale of Finance Contracts, Rental Assets and Gas Gathering and Processing Facilities**

(g) Under Canadian GAAP, in 2001 and 2000 the Company sold certain of its asset-backed finance contracts and rental assets to a special purpose entity (SPE), resulting in the removal of the finance contracts, assets and obligation from the consolidated balance sheet. In 2001, the Company sold certain of its gas gathering and processing facilities to a SPE, resulting in the removal of the assets and obligations from the consolidated balance sheet. Unlike Canadian GAAP, US GAAP require these SPEs to be consolidated in the accounts of the Company because the owners of record of the SPEs to which the assets were transferred have not made a substantive residual equity capital investment that is at risk.

### **Investments in Joint Ventures**

(h) Canadian GAAP require the proportionate consolidation of the Company's investments in joint ventures. The SEC regulations permit the filing of financial statements using proportionate consolidation provided that condensed statements of operations, cash flow and balance sheets detailing the Company's share of its investments in joint ventures are provided (Note 20).

### **Derivative Instruments and Hedging Activities**

(i) Effective January 1, 2001 the Company adopted SFAS 133, Accounting for Certain Derivative Instruments and Hedging Activities, which requires that all derivatives be recorded on the balance sheet at fair value. Derivatives that are not hedges are adjusted to fair value through income. If the derivative qualifies as a hedge, depending on the nature of the hedge, the effective portion of changes in the fair value of the derivative are either offset against the change in fair value of the hedged items through earnings or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of changes in fair value is immediately recognized in earnings.

In accordance with the transition provisions of SFAS 133, the Company reported an asset from the cumulative net effect of adoption of approximately \$41 million, a deferred regulatory liability of \$45 million, a reduction in assets and liabilities from price risk management activities of \$40 million and a reduction in other comprehensive income of \$4 million.

### **Business Combinations, Goodwill and Other Intangible Assets**

(j) In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 141, Business Combinations, and SFAS 142, Goodwill and Other Intangible Assets. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Use of the pooling-of-interests method is no longer permitted.

SFAS 142, effective for the Company January 1, 2002, requires that goodwill and indefinite lived intangible assets no longer be amortized over an estimated useful life. Instead, these amounts will be subject to a fair-value-based annual impairment assessment. Separable intangible assets that are not deemed to have an indefinite life will continue to be amortized over their useful lives. The Company believes that the adoption of SFAS 142 will not have a significant impact on the consolidated financial statements.

### **Accounting for Asset Retirement Obligations**

(k) In June 2001, FASB issued SFAS 143, Accounting for Asset Retirement Obligations. SFAS 143 provides the accounting requirements for retirement obligations associated with tangible long-lived assets. The new standard is effective for fiscal years beginning after June 15, 2002. While early adoption is permitted, the Company will adopt the standard in fiscal 2003. The Company has not yet calculated the impact that the adoption of this new standard will have on its financial position and results of operations.

### **Accounting for the Impairment or Disposal of Long-Lived Assets**

(l) In August 2001, FASB issued SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. The new rules supercede SFAS 121 and are effective for the Company January 1, 2002. The new rules retain many of the fundamental recognition and measurement provisions, but significantly change the criteria for classifying discontinued operations and assets held-for-sale. The Company believes that the adoption of SFAS 144 will not have a significant impact on the consolidated financial statements.

## 20. INVESTMENTS IN JOINT VENTURES

The following condensed statements of operations, cash flow and balance sheets detail the Company's share of its investments in joint ventures that have been proportionately consolidated:

<b>For the years ended December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Proportionate Statements of Joint Venture Operations			
Operating revenues	425	4,504	3,881
Operating expenses	(239)	(4,310)	(3,763)
Other income	8	9	28
Interest on debt	(100)	(100)	(62)
Income taxes	(11)	(39)	(4)
Net income	<u>83</u>	<u>64</u>	<u>80</u>

<b>For the years ended December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>	<b>1999</b>
Proportionate Statements of Joint Venture Cash Flow			
Operating activities	261	156	112
Investing activities	(161)	(204)	(710)
Financing activities	(74)	96	598
Increase in cash and short term investments during the year	<u>26</u>	<u>48</u>	<u>—</u>

<b>December 31 (\$million)</b>	<b>2001</b>	<b>2000</b>
Proportionate Joint Venture Balance Sheets		
Current assets	304	185
Investments	—	1
Fixed assets	2,223	2,024
Deferred charges and other assets	98	99
	<u>2,625</u>	<u>2,309</u>
Current liabilities	907	479
Long term debt	1,136	1,173
Deferred income taxes	84	85
Westcoast Energy's investment carrying value, including bridge financing	498	572
	<u>2,625</u>	<u>2,309</u>

During 2001, the Company purchased an additional 5% (to a cumulative interest of 50%) in the Campeche Natural Gas Compression Services Project (Campeche) from existing partners for nominal cash consideration. The costs of acquiring the Company's interest in Campeche exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Campeche by \$2 million. This excess has been allocated to fixed assets.

During 2001, the Company purchased an additional interest in the Cantarell Nitrogen Facilities (Cantarell) from an existing partner for cash of \$56 million. The additional interest acquired includes a 10% interest (to a cumulative interest of 30%) in Cantarell, a \$49 million promissory note from Cantarell bearing interest at LIBOR plus 1%, and \$7 million interest receivable from Cantarell. Subsequent to the acquisition, the interest rate on the promissory note was increased to 10%. The costs of acquiring the Company's additional 10% interest in Cantarell exceed the figure at which the equivalent proportion of the net assets is recorded in the books of Cantarell by \$10 million. This excess has been allocated to fixed assets.

Cantarell is a consortium which has entered into a contract with PEP to build, own and operate a large nitrogen supply and delivery complex to enhance the production and recovery of oil from the Cantarell oil field. The consortium has requested and received from its lenders an extension to March 2, 2003 as the date by which it is required to achieve financial completion. This extension accommodates required modifications to the project's cooling water system, scheduled for completion in the latter half of 2002.

## 21. CUMULATIVE TRANSLATION ADJUSTMENT

The cumulative translation adjustment balance represents the net unrealized foreign currency translation gain on the Company's net investment in self-sustaining foreign businesses.

December 31 (\$million)	2001	2000
Beginning of year	17	(1)
Effect of changes in exchange rates during the year on:		
Consolidated operations	60	17
Equity accounted investments	3	1
End of year	<u>80</u>	<u>17</u>

## 22. CONTINGENCIES

Due to the size, complexity and nature of the Company's operations, various legal matters are pending. In the opinion of management, these matters will not have a material effect on the Company's consolidated financial position or results of operations.

## 23. TRANSFER OF RETAIL SERVICES BUSINESS

On January 1, 1999, following the approval of the OEB, Union Gas Limited transferred its net assets relating to the retail services business to UEI Holdings Inc. This transaction has been accounted for at the carrying amounts and resulted in a charge to retained earnings of \$38 million. The unrecorded deferred income taxes arose through the use, prior to the transfer, of the income taxes currently payable method by Union Gas Limited for the retail services business pursuant to regulatory direction.

## 24. SUBSEQUENT EVENTS

(a) In March 2002, the Company sold its wholly owned subsidiaries Centra Gas British Columbia Inc. and Centra Gas Whistler Inc. for proceeds of \$292 million, of which \$240 million was cash and \$52 million by way of a non-interest bearing note receivable, resulting in a pre-tax gain of \$24 million. The note receivable is due on or before December 31, 2011, with early repayment contingent on certain events.

(b) In March 2002, Duke Energy Corporation (Duke Energy) acquired the Company in a cash and stock transaction valued at approximately US\$8 billion, including debt assumed. The transaction provided for the acquisition of all outstanding common shares of the Company in exchange for a combination of cash, Duke Energy common shares and exchangeable shares of a Canadian subsidiary of Duke Energy such that approximately 50% of the aggregate consideration was paid in cash and approximately 50% paid in stock.

# Consolidated Quarterly Results

Unaudited

(\$million, except for share data)	For the three months ended				
	Mar-31	Jun-30	Sep-30	Dec-31	Total
2001					
Operating revenues	5,271	2,090	2,172	2,364	11,897
Operating expenses	4,972	1,880	1,997	2,069	10,918
Operating income	299	210	175	295	979
Other net expenses	107	115	—	51	273
Income taxes	49	(20)	36	69	134
Net income	143	115	139	175	572
Provision for dividends on preferred shares	12	12	12	10	46
Net income applicable to common shares	131	103	127	165	526
Earnings per common share – basic	\$1.08	\$0.84	\$1.02	\$1.32	\$4.26
Earnings per common share – diluted	\$1.07	\$0.80	\$0.93	\$1.20	\$3.87

(\$million, except for share data)	For the three months ended				
	Mar-31	Jun-30	Sep-30	Dec-31	Total
2000					
Operating revenues	1,754	1,761	2,130	3,310	8,955
Operating expenses	1,477	1,602	2,006	3,055	8,140
Operating income	277	159	124	255	815
Other net expenses	89	86	106	88	369
Income taxes	58	(9)	(18)	27	58
Net income	130	82	36	140	388
Provision for dividends on preferred shares	12	12	12	12	48
Net income applicable to common shares	118	70	24	128	340
Earnings per common share – basic	\$1.03	\$0.60	\$0.20	\$1.09	\$2.92
Earnings per common share – diluted (1)	\$1.03	\$0.51	\$0.20	\$1.00	\$2.75

(1) diluted per share amounts have been restated to reflect the adoption in January 2001 of the new recommendations of The Canadian Institute of Chartered Accountants with respect to earnings per share.

The Company's natural gas distribution businesses are highly seasonal, with the majority of gas deliveries occurring during the winter heating season from mid-October to mid-April. Gas sales during this period typically account for approximately two-thirds of annual gas distribution revenues, resulting in strong first quarter results, second and third quarters that show either small profits or losses, and strong fourth quarter results.

The earnings contribution of the Company's natural gas distribution businesses are also subject to weather variances. Excluding the positive and negative impact of weather, earnings per common share for the Company were \$4.44 in 2001 compared with \$2.96 in 2000.

For the three months ended (\$ dollar / share)	Mar-31	Jun-30	Sep-30	Dec-31	Total
2001					
Net income per common share	1.08	0.84	1.02	1.32	4.26
Weather impact – gas distribution	0.06	0.02	—	0.10	0.18
Weather normalized net income per common share	1.14	0.86	1.02	1.42	4.44
2000					
Net income per common share	1.03	0.60	0.20	1.09	2.92
Weather impact – gas distribution	0.09	0.01	(0.01)	(0.05)	0.04
Weather normalized net income per common share	1.12	0.61	0.19	1.04	2.96

# Ten-Year Review

Unaudited

	2001	2000	1999
<b>FINANCIAL</b>			
<b>OPERATIONS (\$million)</b>			
Operating revenues	11,897	8,955	6,265
Operating expenses	10,918	8,140	5,642
Operating income	979	815	623
Other net expenses	273	369	310
Income taxes	134	58	46
Net income from continuing operations	572	388	267
Discontinued operations	—	—	—
Net income (loss)	572	388	267
Provision for dividends on preferred shares	46	48	45
Net income (loss) applicable to common shares	526	340	222
Dividends on common shares	168	150	146
Operating cash flow			
– From continuing operations	958	641	499
– After discontinued operations	958	641	499
<b>PER COMMON SHARE (dollars)</b>			
Net income (loss) – basic			
– From continuing operations	\$4.26	\$2.92	\$1.95
– After discontinued operations	\$4.26	\$2.92	\$1.95
Operating cash flow			
– From continuing operations	\$7.75	\$5.50	\$4.38
– After discontinued operations	\$7.75	\$5.50	\$4.38
Dividends	\$1.36	\$1.28	\$1.28
<b>ASSETS (\$million)</b>			
Fixed assets	9,399	9,367	9,108
Investments	920	970	454
Assets from price risk management activities	429	561	186
Current assets	2,638	3,307	1,554
Deferred income taxes	182	306	—
Deferred charges and other assets	468	556	475
Total assets	14,036	15,067	11,777
<b>CAPITALIZATION (\$million)</b>			
Long term debt	5,932	5,971	5,550
Liabilities from price risk management activities	297	612	175
Preferred shareholders' equity	550	865	865
Common shareholders' equity	3,306	2,764	2,395
Deferred income taxes	710	880	333
Current liabilities	3,069	3,809	2,293
Non-controlling interest in subsidiary companies	172	166	166
Total equity and liabilities	14,036	15,067	11,777

1998	1997	1996	1995	1994	1993	1992
7,376	7,312	4,875	4,184	3,827	3,674	1,818
6,726	6,519	4,088	3,445	3,208	3,107	1,473
650	793	787	739	619	567	345
404	432	460	436	360	353	224
48	123	115	109	95	68	36
198	238	212	194	164	146	85
—	—	—	—	—	—	(161)
198	238	212	194	164	146	(76)
37	28	19	18	13	13	11
161	210	193	176	151	133	(87)
133	122	105	81	76	65	49
448	522	543	384	342	363	233
448	522	543	384	342	385	292
\$1.53	\$2.06	\$1.96	\$2.01	\$1.76	\$1.70	\$1.23
\$1.53	\$2.06	\$1.96	\$2.01	\$1.76	\$1.70	\$(1.45)
\$4.24	\$5.10	\$5.50	\$4.41	\$3.98	\$4.64	\$3.88
\$4.24	\$5.10	\$5.50	\$4.41	\$3.98	\$4.91	\$4.87
\$1.26	\$1.20	\$1.05	\$0.93	\$0.89	\$0.82	\$0.80
8,569	8,025	7,304	7,056	6,390	5,674	5,678
374	195	184	162	100	32	87
—	—	—	—	—	—	—
1,596	1,574	1,328	994	974	939	844
—	—	—	—	—	—	—
281	281	250	239	182	145	118
10,820	10,075	9,066	8,451	7,646	6,790	6,727
5,297	4,941	4,743	4,715	3,647	3,383	3,396
—	—	—	—	—	—	—
716	570	445	245	245	120	195
2,368	2,056	1,890	1,542	1,417	1,320	1,005
340	400	366	396	399	391	593
1,935	2,045	1,517	1,441	1,828	1,465	1,400
164	63	105	112	110	111	138
10,820	10,075	9,066	8,451	7,646	6,790	6,727

# Ten-Year Review

Unaudited

	2001	2000	1999
<b>STATISTICAL</b>			
VOLUMES (Bcf)			
British Columbia Pipeline Division	659	682	670
Foothills Pipe Lines	1,114	1,155	1,131
Empire State Pipeline	106	117	105
Maritimes & Northeast Pipeline	354	290	—
Union Gas*	1,148	1,263	1,222
Other Gas Distribution <sup>#</sup>	70	72	122
	3,451	3,579	3,250
RATE BASE (\$million)			
British Columbia Pipeline and Field Services Divisions	2,299	2,285	2,294
Foothills Pipe Lines (proportionate share – Phase I – 27%)	219	225	224
Empire State Pipeline >	218	114	120
Union Gas* ^	3,134	2,867	2,733
Other Gas Distribution <sup>#</sup>	632	625	591
	6,502	6,116	5,962
NUMBER OF CUSTOMERS (thousand)			
Union Gas*	1,147	1,123	1,099
Other Gas Distribution <sup>#</sup>	112	111	107
	1,259	1,234	1,206
COMMON SHARES			
Shares outstanding at year-end	126,955,911	121,443,366	114,847,515
Toronto Stock Exchange price ranges			
– high	\$42.20	\$36.60	\$31.60
– low	\$30.15	\$20.10	\$22.40
Number of common shareholders at year-end	6,407	8,047	8,556
Employees at year-end (consolidated – excluding joint ventures)	4,399	5,455	5,648

\* amalgamated with Centra Gas Ontario Inc. on January 1, 1998.

^ transferred approximately \$500 million of net assets to Union Energy on January 1, 1999.

<sup>#</sup> includes Centra Gas Manitoba and Centra Gas Alberta until sold in 1999 and 1998, respectively.

> prior to 2001, this figure represents the Company's proportionate share (50%). In March 2001, the Company acquired the additional 50% interest to a cumulative interest of 100%.

1998	1997	1996	1995	1994	1993	1992
688	688	667	647	605	579	512
940	935	927	920	852	615	534
93	98	101	114	43	6	—
—	—	—	—	—	—	—
1,127	1,193	1,137	1,166	1,034	991	317
139	163	169	165	160	156	147
2,987	3,077	3,001	3,012	2,694	2,347	1,510
2,287	2,273	2,114	1,807	1,353	1,236	1,142
185	189	193	193	192	169	157
131	129	130	89	92	88	—
3,206	3,043	2,830	2,718	2,496	2,304	2,115
851	937	888	989	937	899	837
6,660	6,571	6,155	5,796	5,070	4,696	4,251
1,075	1,041	1,002	965	932	892	852
344	387	372	358	347	332	318
1,419	1,428	1,374	1,323	1,279	1,224	1,170
112,670,767	103,245,876	100,747,253	87,972,872	86,444,582	85,318,602	72,678,965
\$36.35	\$33.50	\$24.40	\$22.75	\$24.63	\$22.63	\$21.13
\$27.25	\$22.65	\$20.00	\$19.25	\$19.63	\$16.25	\$15.00
8,645	8,753	8,499	8,447	8,782	8,602	7,828
6,300	5,932	5,991	6,380	6,258	6,043	6,257

# Statement of Corporate Governance Practices

## GENERAL

The Board believes that a sound and effective corporate governance system is essential to the well being of the Corporation and its shareholders. The Board has carefully considered the corporate governance guidelines adopted by The Toronto Stock Exchange (“TSE guidelines”) and has put in place suitable and effective processes and structures to guide the direction and management of the business and affairs of the Corporation.

## BOARD OF DIRECTORS

The Board oversees the conduct of the business of the Corporation and the activities of management. Management is responsible for the day to day operations of the business. The Board acts independently of management either directly or through the Audit Committee of the Board which is delegated some of the Board’s responsibilities. The Board’s fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Corporation meets its obligations on an ongoing basis and operates in a reliable and safe manner.

- **Composition of the Board**

The Board is comprised of 5 directors which it believes is adequate to effectively discharge its responsibilities. All of the common shares of the Corporation were acquired by Duke Energy Canada Exchangeco Inc., an indirect wholly-owned subsidiary of Duke Energy Corporation, on March 14, 2002. Duke Energy Canada Exchangeco Inc. is therefore the significant shareholder of the Corporation.

Based on an assessment of each individual director’s relationship with the Corporation and with others having relationships with the Corporation, the Board has concluded that 3 of the 5 directors of the Corporation are outside directors and 2 are unrelated. In conducting its analysis, the Board applied the definition of an unrelated director as one who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director’s ability to act with a view to the best interests of the Corporation, other than interests and relationships arising from shareholdings. Mr. Brown is an unrelated director. Mr. Evans is a full-time officer of Duke Energy Gas Transmission Corp., an affiliate of the Corporation and an affiliate of Duke Energy Canada Exchangeco Inc., the Corporation’s significant shareholder. Mr. Evans is not a related director of the Corporation

under the TSE guidelines. Two of the directors, Mr. Reid and Mr. Unruh, are full-time officers of the Corporation and are therefore considered to be related directors. Arthur H. Willms, who retired as President and Chief Operating Officer of the Corporation on October 31, 1999 after holding various positions within the Corporation since 1971, provided services to the Corporation until April 30, 2002 and is a director of several significant affiliates of the Corporation. He is therefore viewed as outside but related.

The Corporation is of the view that the composition of the Board fairly reflects the investment in the Corporation by shareholders other than Duke Energy Canada Exchangeco Inc., the holder of 100% of the issued and outstanding voting shares of the Corporation.

- **Responsibilities of the Board**

The Board has retained responsibility for the Corporation’s governance system and is responsible for establishing criteria for Board membership, composition of the Board and the Audit Committee, assessing directors’ and Board performance on an ongoing basis and ensuring that there is in place an orientation and education program for new members of the Board.

The Board is responsible for searching for and recommending to the significant shareholder new candidates for election to the Board. In identifying such candidates for election, the Board seeks to select well-qualified candidates with a diversity of background, experience and expertise to maintain a well-balanced and highly competent group of directors with the ability to act together effectively. Special attention is given to candidates who have broad business exposure and are financially literate.

The Board is responsible for reviewing human resources and compensation policies and guidelines for application to the Corporation. It is also responsible for ensuring that the Corporation has a process to provide for the development and orderly succession of the Corporation’s senior management personnel.

The Board is responsible for reviewing and monitoring the environmental policies and activities of the Corporation and the activities of the Corporation as they relate to the health and safety of the Corporation’s employees in the workplace.

## **AUDIT COMMITTEE**

The Board has an Audit Committee that meets regularly and operates under specific terms of reference approved by the Board. These terms of reference are reviewed periodically and modified where appropriate. The Audit Committee is chaired by an outside and unrelated director and is composed of a majority of outside directors. One member of the Audit Committee, Mr. Reid, is a full-time officer of the Corporation. A calendar of activities for the Audit Committee is prepared annually and approved by the Board.

The Audit Committee is broadly responsible for ensuring that the Corporation's management has designed and implemented an effective system of internal financial controls and financial reporting. It is also responsible for ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts. As part of its function, the Audit Committee monitors the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management. The Audit Committee reviews, at least annually, the independence of the Corporation's external auditors to satisfy itself of their independence as auditors.

## **SHAREHOLDER FEEDBACK AND CONCERNS**

The Corporation has adopted a disclosure policy which establishes procedures to provide the public with broad disclosure on a timely basis of material information concerning the affairs of the Corporation. The Corporation's practices encourage the free flow of accurate and appropriate communication and, at the same time, discourage selective disclosure of material information that has not been publicly disclosed.

## **DECISIONS REQUIRING BOARD APPROVAL**

The Board discharges its responsibilities directly and through the Audit Committee. In addition to those matters which in law must be approved by the Board, the Board retains the responsibility for the approval of matters of a material nature including the approval of major transactions, the adoption and implementation of the strategic plan, the approval of the annual operating and capital budgets, capital expenditures and financial commitments above approved minimum thresholds, the approval of the Corporation's dividend policy and the monitoring of the principal risks of the business and activities of the Corporation. It also manages its own affairs including the development of the Board's meeting agendas, the nomination of candidates for election to the Board, membership to committees of the Board and director's compensation.

## **EXPECTATIONS OF MANAGEMENT**

Ongoing, the Board expects management to be accountable for the Corporation's financial and competitive performance at a high standard consistent with enhancing the Corporation's value. It also expects management to provide to the Board timely, complete and accurate information on the business operations of the Corporation and to provide for the development of its executives and a plan for their succession.

# Board of Directors and Senior Officers

## BOARD OF DIRECTORS

**Robert B. Evans**, Chairman of the Board  
Director since 2002

**Robert T. F. Reid**, President  
Audit Committee  
Director since 2002

**David G. Unruh**, Senior Vice President and General Counsel  
Director since 2002

**William C. Brown**, Retired President and  
Chief Executive Officer of  
BC Sugar Refinery, Limited  
Audit Committee  
Director since 1995

**Arthur H. Willms**, Retired President and  
Chief Operating Officer of  
Westcoast Energy Inc.  
Audit Committee  
Director since 1983

## SENIOR OFFICERS

**Robert B. Evans**  
Chairman of the Board

**Robert T. F. Reid**  
President

**David G. Unruh**  
Senior Vice President and General Counsel

**Eric L. Schwitzer**  
Senior Vice President, Strategic Development

**P. Wayne Soper**  
Senior Vice President, Governmental and Public Affairs

**Murray P. Birch**  
Senior Vice President, Business Development

**Douglas J. Haughey**  
President, BC Pipeline and Field Services Divisions

**Dorothy M. Ables**  
Senior Vice President – Finance and Administration

**Alan N. Harris**  
Senior Vice President of Strategic Development and Planning

**Theopolis Holeman**  
Senior Vice President, Transmission and Engineering

**Bradford N. Reese**  
Senior Vice President for Northern Development

# Shareholder Information

## PREFERRED SHAREHOLDER SERVICES

Preferred shareholders with questions about their accounts, transfer requirements, address changes or other services should call Computershare Trust Company of Canada toll free at (888) 661-5566. E-mail requests should be sent to [caregistryinfo@computershare.com](mailto:caregistryinfo@computershare.com). Written requests should be addressed to:

Computershare Trust Company of Canada  
510 Burrard Street  
Vancouver, British Columbia  
Canada V6C 3B9

## STOCK EXCHANGE LISTING

Westcoast Energy preferred shares are listed on The Toronto Stock Exchange.

4.72% First Preferred, Series 6 – WPR.G

5.50% First Preferred, Series 7 – WPR.H

5.60% First Preferred, Series 8 – WPR.J

5.00% First Preferred, Series 9 – WPR.K

## AUDITORS

### Deloitte & Touche LLP

P.O. Box 49279, Four Bentall Centre  
Suite 2100 – 1055 Bentall Centre  
Vancouver, BC V7X 1P4

## REGISTRARS AND TRANSFER AGENTS

### Preferred Shares

Computershare Trust Company of Canada

## REGISTRARS AND TRUSTEES

### Debentures

Computershare Trust Company of Canada

## TAXATION

A resident of the United States receiving investment income generated in Canada is subject to withholding tax under the Income Tax Act of Canada and the Canada-United States Income Tax Convention. With certain exceptions, dividends paid by the Company are subject to withholding tax at a rate of 15%.

## DUPLICATE MAILINGS

Registered holders of Westcoast Energy Inc. preferred shares may receive duplicate mailings of annual reports or other shareholder mailings. If you receive such duplications, please contact the Computershare Trust Company of Canada toll free at (888) 661-5566.





**WESTCOAST ENERGY INC., A DUKE ENERGY COMPANY**

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